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: June 9, 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 May 2000.

MAY HIGHLIGHTS

Unseasonably high temperatures in late May helped drive prices in the energy and ancillary service markets significantly higher, with prices in the real-time market and hour-ahead ancillary service markets hitting the $750 price cap a total of 23 times. Higher energy and A/S prices were driven up by a combination of factors, including (1) higher than forecasted loads due to unseasonable high temperatures, (2) large amounts of thermal generation were off-line for scheduled and unscheduled maintenance, and (3) higher natural gas prices. The major event for May 2000 was the very high load conditions experienced during the May 21-24 period when loads neared the 40,000 MW level. May 2000 prices in the ISO real-time market rose about 90% from April 2000 levels and were about 200% higher than a year ago in May 1999. Similarly, average constrained PX prices rose about 75% from April 2000 levels and were about 110% higher than May 1999.

Natural gas spot prices rose by about 24% from April , and were about 60% higher than in May 1999. Total system energy increased by 11% relative to May 1999 with the monthly peak load increasing by 21% from the same month last year.

Ancillary service costs jumped from $.95/MWh of load served in April to about $3.15/MWh of load served in May 2000, representing an increase from about 3.4% of total wholesale energy costs to over 6% of total energy costs. Roughly two-thirds of total A/S costs were incurred during the May 21-24 period, when A/S costs averaged 11% of total wholesale energy costs.

The major trend in the congestion markets continued to be significant congestion on both Path15 and Path 26, primarily in the N-S direction, while there was little or no congestion on major southwest or northwest branches. Overall congestion rates for Path 26 and Path 15 were 17% and 20%, respectively.

KEY MARKET CONDITIONS FOR MAY 2000

I. In the California Wholesale Energy Markets

- **Loads -** May 2000 system energy loads totaled 20,000 GWh (or 26,883 average hourly MW), an 11% increase over May 1999 loads. Daily peak loads averaged 31,815 MW, 13% higher than average daily May 1999 peak loads. The peak load for the month was 39,521 MW for hour ending 14 on May 22 which represented a 21% increase over the May 1999 peak. Much of the percentage increase in both peak loads and energy is attributable to the significantly warmer weather this year compared to last.

- **Wholesale Energy Prices** – The differences between peak and non-peak average energy prices widened considerably for both real time prices and constrained PX prices compared to May 1999. The twelve-month percentage price changes for both average real time prices and constrained PX prices were the largest since ISO start up. Compared to May 1999 levels, May 2000 real time prices were 181% higher in NP15 and 244% higher in SP15. Average constrained PX prices were 96% higher in NP15 and 123% higher in SP15 compared to the levels experienced in May 1999. Factors related to the price differences are as follows:

  Large amounts of thermal generation were off-line in May, either for maintenance or economic reasons. Additionally, a number of large generating units were off-line for maintenance during portions of the month, including Diablo Canyon #1, Mojave #2, and Palo Verde #3.

  Significantly higher daily natural gas spot and monthly natural gas prices relative to May 1999. Monthly contract prices were up 30% while average daily natural gas spot prices were up 60% from a year ago. Daily spot prices for PG&E Citygate increased from $3.21/MMBtu on May 1 to $4.90/MMBtu on May 31, a 53% increase within the month.

  Hydro generation remained at levels lower than those experienced in May 1999.

- Prices in both the real time and zonal PX energy markets were significantly higher in SP15 than NP15 for peak period hours. This is due to congestion patterns in both the day ahead and real time markets where there was north to south congestion on Path 15/Path 26 throughout the month. The PX day-ahead market was split during 39% of the hours in May 2000 resulting in peak period constrained PX prices in SP15 being about 33% higher than NP15 prices. The real time market was split in 12% of the hours with peak period prices in SP15 averaging about 18% higher than NP15 prices.

Table 1: Energy Price Summary for May 2000

	System Average	NP15	SP15	ZP26	Pct. Hours of Zonal Pricing
Real Time Price					
Peak	$ 72.33	$ 62.19	$ 82.48	$ 63.53	10%
Off-Peak	$ 39.92	$ 41.77	$ 38.07	$ 37.93	14%
Total	$ 61.53	$ 55.38	$ 67.67	$ 55.00	12%
PX Constrained					
Peak	$ 62.27	$ 56.71	$ 66.73	$ 63.39	45%
Off-Peak	$ 27.93	$ 28.18	$ 27.48	$ 28.14	25%
Total	$ 50.83	$ 47.20	$ 53.64	$ 51.64	39%

- The ISO real time market experienced eight hours where the $750/MW price cap was reached in either SP15 or NP15. Six of these price spikes occurred in SP15 during hours when the real time market was split zonally. Four of the price spikes occurred on May 3 following the forced outage of the Midway-Vincent #3 500kV line which reduced the Path 26 operational transfer limit from 2500 MW to 500 MW. The other two price spikes occurred at HE 16-17 on May 1 due to high demand for incremental generation in the south. The price cap was hit twice system-wide during the extreme load conditions at HE 15-16 on May 22. Constrained PX energy prices exhibited considerable price volatility during the latter part of the month, reaching a maximum of $600/MWh in SP15 on May 28 at HE 16.

II. 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 67% to 96% of A/S MW quantities being procured in the day-ahead market. The following table summarizes weighted average prices and procurements for May 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	$ 45.14	$ 30.01	$ 43.72	560	58	91%
Regulation Down	$ 28.24	$ 15.03	$ 27.70	546	23	96%
Spin	$ 18.17	$ 17.98	$ 18.14	602	119	84%
Non-Spin	$ 7.63	$ 33.71	$ 11.50	704	123	85%
Replacement	$ 43.09	$ 84.76	$ 56.78	231	113	67%

- The May 21-24 period was characterized by numerous price spikes in both the day ahead and hour ahead markets. ISO procurement of hour ahead AS quantities was greatest during the peak hours of May 21, representing nearly 50% of all AS procured for some of those hours. However, high requirements during the afternoon hours of May 22 led to the majority of the $750/MW price spikes in the hour ahead ancillary service markets. Over the May 22-24 period, a greater quantity of AS requirements were procured in the day ahead market with the highest day ahead prices occurring on May 23 & 24. . There are a number of reasons for this, the first being that the forecast load for the DA market were much higher than actual load after Monday, May 22 with actual load declining after the peak day on Monday, May 22. The higher forecasts lead the ISO to purchase more A/S. It also appears that the high prices were partly the result of supply curves in the AS markets shifting “upwards” based on expectations of higher loads and prices in the PX.

- The ISO’s Ancillary Service markets had more hours of zonal procurement in May compared to April, due to increased congestion on Path 26/Path 15 and minimum zonal procurement requirements, particularly for the regulation up market. Combined with a significant amount of generation units being off-line in SP15, this led to significantly higher regulation up prices in SP15 than NP15. 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 and hour-ahead combined).

Summary of Weighted Day-Ahead A/S Prices by Zone and Period – May 2000

	NP15		SP15		Percent of Hours with
	Peak	**Off Peak**	**Peak**	**Off Peak**	**Zonal Procurement**
Regulation Up	$ 37.74	$ 13.49	$112.48	$ 31.45	29%
Regulation Down	$ 23.35	$ 28.72	$ 35.84	$ 36.37	10%
Spin	$ 24.03	$ 1.40	$ 27.55	$ 3.42	7%
Non-Spin	$ 6.18	$ .04	$ 14.59	$ .03	6%
Replacement	$ 22.26		$ 86.52		3%

- The day ahead ancillary service markets did not reach the price cap though both the regulation up and spinning reserve markets reached maximum prices of $675/MW. There were fifteen hours in the hour ahead market where $750/MW was reached with both the non-spinning and replacement markets experiencing five price cap hits each. All hour -ahead markets reached the $750/MW price cap except for the spinning reserve market which reached $749/MW. Nearly all the hour-ahead ancillary service prices above $250/MW occurred in the May 21-22 period.

Ancillary Service Costs

- A/S costs in May increased significantly to $63.2 million compared to the April total of $17.3 million. May 2000 costs were roughly 50% higher than May 1999 levels. Roughly two-thirds of these costs occurred during the high loads days of May 21-24. The high costs were attributable to both the high prices and large MW requirements in both the day ahead and hour ahead markets, particularly for regulation up and replacement reserves. Total A/S costs for May were about 6.1% 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**
February	$ .359	$ .58	1.9%
March	$ .369	$ .60	2.0%
April	$ .576	$ .95	3.4%
May	**$2.037**	**$3.16**	**6.1%**

* 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 $65.7 million since their implementation on August 17, 1999. This represents a saving of about 26% of total A/S costs during this time period. Significant 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. The very high A/S prices and quantities procured during the latter part of May led to the highest monthly savings since the inception of these market reforms.

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%
March	$ 685,000	6%	$1,465,000	13%
April	$ 854,000	5%	$4,242,000	24%
May	$7,166,000	11%	$8,123,000	13%
Total	$20,917,000	8%	$44,781,000	18%

* Savings after implementation on August 17, 1999.

III. Inter-zonal Congestion Management Markets

- The congestion markets in May showed continued significant congestion on Path 15 and Path 26 with very low congestion rates on all other branch groups. The following table summarized congestion rates and average congestion charges by branch group for the day-ahead market.

Day-Ahead Market – Congestion Summary for May 2000

	Percentage Congestion by Period			**Average Congestion Charges ($/MW)**		
	Peak	**Off peak**	**All Hours**	**Peak**	**Off peak**	**All Hours**
COI (Import)	1%	0%	1%	$ 0.50		$ 0.50
Path 15 (N-S)	24%	3%	17%	$27.39	$4.08	$26.08
Path 15 (S-N)	2%	6%	3%	$3.63	$2.30	$2.75
Path 26 (N-S)	17%	0%	11%	$20.69	$3.50	$20.48
Path 26 (S-N)	1%	16%	6%	$6.73	$4.32	$4.64
Cascade (Import)	3%	0%	2%	$10.22		$10.22
Silverpeak (Import)	2%	0%	1%	$43.31		$43.31
Mead (Import)	1%	2%	1%	$4.77	$7.34	$5.91

- Path 26 experienced both S-N and N-S congestion, with most of the congestion in May being in the N-S direction. The overall congestion rate remained at 18%, up slightly from the previous month. Day-ahead congestion charges ranged from $1/MW to $539/MW and averaged $20.48/MW, an increase from April.

- Path 15 congestion increased in May compared to April, rising from a 13% congestion rate to 20%. Roughly 85% of the congestion occurred in the N-S direction predominately during peak hours. Day-ahead congestion charges on Path 15 ranged from $.02/MW to $178/MW and averaged $22.32/MW, down from the April level of $32.52/MW.

- Day-ahead congestion rates on the northwest paths were very low in May. The day-ahead congestion rate for both COI and NOB was under 1% for the month while Cascade experienced a 2% congestion rate. This compares to May 1999 congestion rates of 6% and 1% for COI and NOB, respectively.

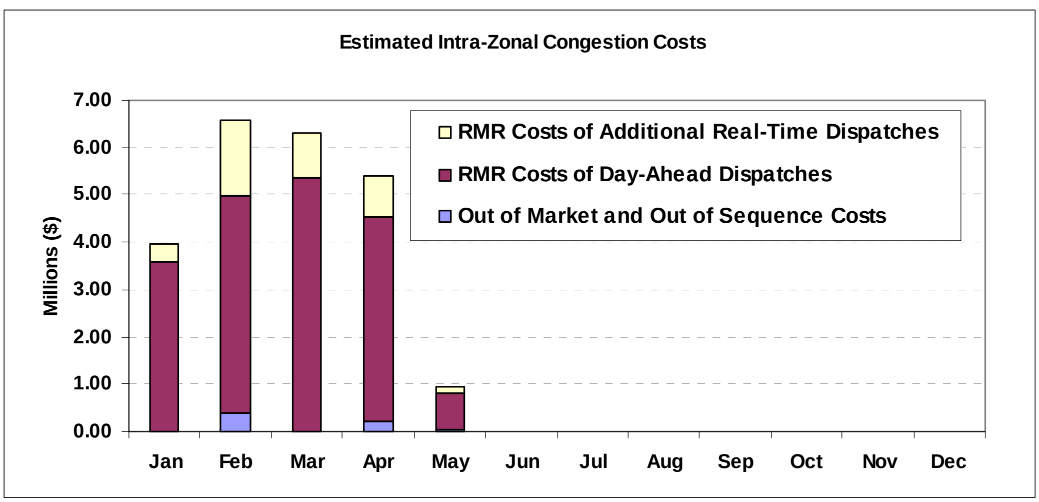
- May congestion on the southwest paths continued at very low levels in May. Both the Palo Verde and Eldorado branch groups did not experience any day ahead congestion during the month. Mead and N. Gila were the only southwest branch groups that experienced congestion, both with congestion rates of 1%.

- Total congestion costs for May were $5,290,000 down somewhat from April costs of $6,300,000, though significantly higher than May 1999 total costs of $788,000. Path 26 costs represented the majority of these costs with a total of $3,831,000 while Path 15 costs were about $501,000, up from last year's costs of $115,000.

IV. Intra-Zonal Congestion Costs

Figure 1 shows the estimated monthly costs of mitigating real-time intra-zonal congestion. These costs are separated into three categories, 1) Real-time RMR Dispatches, 2) Day-ahead RMR Dispatches, and 3) Out of Market and Out of Sequence Dispatches for intra-zonal congestion. A second category of Out of Sequence calls are for local voltage support which are not included in these costs. The ISO dispatches, in the day ahead, Reliability Must Run (RMR) units to support a number of local area reliability needs including meeting n-1 contingencies for transmission and unit outages, voltage support which also help to mitigate intra-zonal congestion. Because all of these reliability needs are interrelated, there is no precise way to apportion Day Ahead RMR costs to a particular reliability need such as intra-zonal congestion.

Figure 1 – Net Intra-Zonal Congestion Costs*



*Does not include out of sequence calls made for local voltage support. From Jan-May 2000, the estimated OOS costs for voltage support is $45.6 million (Jan: $0.0,Feb: $26.5, Mar: $9.8, Apr: $3.4, May: $5.9).

The RMR costs shown in this figure represent estimates of the total net-variable cost payments for RMR day-ahead and real-time dispatches. It is also important to note that all of the costs shown in Figure 1 are net of the ISO Hourly Ex-post price. This is because generators who follow a dispatch instruction from an OOS, OOM, or RMR call provide energy to the imbalance market. Given that this energy is serving the wholesale energy market, only costs above the ISO hourly ex-post price are counted towards intra-zonal congestion costs. It is also important to note that actual intra-zonal costs are based on metered output whereas these cost estimates are based on instructed dispatches. To the extent units fail to follow dispatch instructions, actual costs will vary.

Figure 1 indicates the monthly costs for intra-zonal congestion dropped dramatically from over $ 5 million in April to under $ 1million in May. This decline is largely due to the significant increase in real-time energy prices that occurred in May. Since intra-zonal costs are calculated net of the real-time energy price, higher real-time prices resulted in lower net costs. This was especially true for RMR costs where in many cases the real-time price exceeded the variable cost payment of the unit's RMR contract. Again, out of sequence calls made for local voltage support are not included in these costs.

V. Performance of the FTR Market in May 2000

This report summarizes the performance of the FTR and adjustment bid markets in May 2000.

Secondary Market Activity

The secondary FTR market registered twelve transactions in April and none in May. All of the April transactions were solely between affiliates.

FTR Concentration and Scheduling

FTR ownership concentrations remain virtually the same as in April. There are high ownership concentrations on several important interfaces. A relatively small percentage (41%) of the FTRs have been assigned Scheduling Coordinators.

The FTR ownership and control (scheduling) concentration on some paths is high enough to deserve scrutiny of scheduling behavior to ensure FTR ownership/control is commensurate with scheduling needs. The DMA is also monitoring the scheduling activities of entities with FTRs in the directions inconsistent with the location of their resources within the ISO control area.

On most paths the FTRs have been used primarily for their financial entitlement to hedge against transmission usage charges. The following table shows that the use of FTRs for scheduling priority showed a slight decrease on COI and slight increases on three Southwestern paths (Eldorado, Palo Verde, and IID-SCE) from April to May, 2000, all in the import direction.

Branch Group	COI IMP	ELD IMP	IID-SCE	MEAD IMP	NOB IMP	PV IMP	Sil-Pk IMP	Total
MW FTR Auctioned	422	694	600	366	347	1,650	10	9,553
Avg. MW FTR Scheduled	24	285	405	5	0	615	9	343
% FTR Scheduled	6%	41%	67%	1%	0%	37%	87%	14%
Max MW FTR Scheduled	165	405	445	10	0	857	9	-
Max Single SC FTR Schedule	100	405	445	10	0	600	9	-

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

VI. Issues Under Investigation

1. **Investigation of Market Events of May 22, 2000.** The ISO real-time market hit the $750/MWh price cap during two hours on May 22 and was generally high during the peak hours. High prices also occurred in the A/S markets. It was an unseasonably warm day, with demand significantly higher than forecast, and significant amounts of capacity unavailable due to scheduled and forced outages. Similar demand and supply conditions in neighboring control areas also created a tight regional market for available energy supplies within and outside of California. DMA is collaborating with Market Operations in investigating the May 22 events, in order to identify key "lessons learned" related to future operational procedures and market design issues.

2. **Proposal for Interim Locational Market Power Mitigation (Interim LMPM).** DMA is developing an interim measure to mitigate the exercise of market power by resources that must be dispatched to meet locational needs. This interim measure is intended to remain in effect until the ISO addresses locational market power in a permanent fashion in the context of Congestion Management Reform. This approach is needed because there is no comprehensive measure in place to deal with locational market power. Even in areas with RMR contracts in place, an RMR outage causes the remaining units to bid excessively because they know only their unit will be taken. The approach is based on a clear distinction between market power and scarcity, and draws upon similar approaches that FERC has approved for other ISOs to mitigate locational market power. Locational market power is characterized by: (1) the absence of competitive supply to meet a locational need, where competitive supply entails three or more suppliers each offering at least 50 percent of the needed quantity of incremental or decremental energy, and (2) having to dispatch units out of BEEP merit order to meet the locational need. Such situations do not involve true scarcity since there is generally ample effective, available capacity to meet the need; the problem is that all the effective capacity is in the hands of only one or two suppliers. In these situations, when the resource's INC bid exceeds the market-clearing BEEP price (or when its DEC bid is below the MCP), the bid will be mitigated by substituting a resource-specific bid cap. The bid cap is based on the unit owner's choice of either (a) incremental operating cost plus fixed margin of x percent, or (b) a weighted average of recent MCPs earned by the resource when its bid was in merit order, adjusted for changes in system load and fuel prices. The resource would be paid the larger of its bid cap and the actual MCP, but would not set the MCP if its bid cap

were above the MCP. The ISO is presently discussing this proposal with market participants and obtaining their input and comments.

3. **Response to Section 205 Filing to Increase RMR Payments due to Pre-dispatch of RMR**. DMA is taking the lead in responding to filing by Southern Company under Section 205 of the Federal Power Act to require the ISO to modify its tariff to allow Southern Company to increase the fixed RMR contract payments to include any "collateral costs" imposed on Southern as a result of pre-dispatch of RMR under Amendment 26. The pre-dispatch requirement in Amendment 26 took effect June 1, 2000, following interim approval by FERC until the issue of RMR scheduling could be fully addressed in the context of Congestion Management Reform.

4. **Congestion Management Reform and Redesign.** Measures need to be in place to address locational market power concerns and use of RMR contracts. The DMA is evaluating alternative design proposals with respect to their ability to promote market efficiency, provide consistent market incentives, and adequately address market power concerns. One option is to establish unit-specific or area-specific bid caps that would be activated only for the hours (in the day-ahead, hour-ahead or real-time markets respectively) when congestion conditions (or local requirements) lead to non-competitive supply requirements. The DMA is also working with the Congestion Management Project Team to investigate new ideas including creation of a new "reliability market" with daily auctions subject to a price cap (based on the investment cost of new resources) to limit locational market power, but allow the resource owner to be rewarded for providing a locationally scarce service.

5. **Target Price.** DMA continues to collaborate with Market Operations to address the issue of the target price. As a short term option, DMA is recommending the development of the ability and criteria for mitigating strategic bids that are obvious attempts to manipulate the ISO's market price by screening these out from use in calculating the target price. This approach would allow use of the previous market clearing-target price methodology, and could be implemented on a relatively short-term time frame. Longer-term options that could be implemented after 10-minute settlements goes into effect in August are also being identified and assessed.