CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: Market Issues/ADR Committee

From: Anjali Sheffrin, Director of Market Analysis[1]

CC: ISO Governing Board, ISO Executives

Date: August 17, 1999

Re: ***Market Analysis Report***

Key Market Conditions for July 1 to August 6, 1999:

This memorandum summarizes key market conditions, developments, and trends for the period July 1 to August 6, 1999. More detailed information is provided in the attached Weekly Market Reports.

In the California Energy Markets:

July:

- Loads were moderate for the first week of July but hit record highs in the second week. On July 12, system loads in the ISO control area peaked at 45,574 MW, shattering last year's record of 44,759 MW set on August 3, 1998. Loads were also quite high on July 13, 1999 peaking at 44,511 MW but moderated by July 14.

- Loads were down considerably for the second half of July as mild temperatures prevailed throughout the state.

- July energy prices followed load patterns fairly closely. During the first nine days of July, the PX unconstrained price for peak hours averaged $30.93/MWh and the ISO peak hour real-time price average $18.11/MWh. During this period, the ISO was decrementing significant amounts of generation and this tended to depress real-time prices. With significantly higher loads on July 10-13, energy prices rose dramatically. During this three-day period, the PX unconstrained price for peak hours reached $153.83/MWh and averaged $50.11/MWh and the ISO peak hour real-time price reached the $250 price cap in several hours and averaged $93.29/MWh. Milder temperatures during the second half of July brought a reduction in average peak loads to the 35,000 MW level and a significant decline in energy prices. During this period, the PX unconstrained price for peak hours reached $28.80/MWh and the ISO real-time price for peak hours averaged $25.44/MWh.

- As loads dropped sharply after the heat wave of July 12-14, significant over-generation occurred on the morning of July 15, resulting in negative real-time energy prices of -$249/MWh in hours ending 4-5. During these hours, scheduled load exceeded actual load by approximately 2,200 MW in hour ending 4 and 1,200 MW in hour ending 5.

[1] The Market Surveillance Unit has been renamed to reflect its dual roles of monitoring markets and analyzing design changes. We are now the Department of Market Analysis (DMA).

In managing the over-generation condition, ISO operators exhausted available decremental bids in the energy imbalance market and were forced to make several out-of-market calls for decremental energy.

August 1-6:

- A combination of forced transmission outages and higher than expected loads resulted in some high real-time energy prices during the first few days of August.
- On Sunday, August 1, line de-rates on the two major northwest transmission paths (COI and NOB) reduced the supply of imports to the state and caused the ISO to make up the difference from the real-time imbalance energy market. This led to a real-time energy price spike of $169/MWh in hour ending 19.
- System loads came up sharply on Monday and Tuesday, August 2 and 3, with actual loads nearing 40,000 MW on Tuesday, August 3. On these days, real-time prices spiked during several hours when actual loads exceeded the day ahead forecast by 2,500 to 4,500 MW, and final hour-ahead scheduled loads fell short of actual loads by approximately 2,500 on Monday and 4,000 MW on Tuesday. To compensate for this under-scheduling of load, the ISO incremented significant amounts of generation causing several real-time price spikes in excess of $200/MWh during the peak hours of both these days.
- Loads dropped off significantly during the remainder of the week and peak prices returned to more moderate levels. For the week, the unconstrained PX day-ahead energy price averaged $32.09/MWh and the ISO's real-time imbalance energy price averaged $38.81/MWh.

In the Ancillary Service Markets:

Day-ahead Ancillary Service Prices

July:

Average day-ahead ancillary service prices for peak hours increased in July. Most of this increase can be attributed to high prices during July 12-13 when system loads were extremely high. During this period the $250/MW price cap was hit in five hours in the regulation market, three hours in the non-spinning reserve market, and four hours in the replacement reserve market. There were also numerous instances of prices in excess of $200/MW in all four ancillary service markets. Cooler temperatures in the second half of July resulted in a significant decline in ancillary service prices.

Aug 1-6:

With system loads fairly moderate during the first week of August, there was an ample supply of capacity available for the ancillary service markets. During this period, peak prices for regulation, spinning reserve, non spinning reserve, and replacement reserve averaged $12.42/MW, $7.5/MW, $7.92/MW, and $.74/MW respectively.

	Jun 1-30, 1999		Jul 1-31, 1999		Aug 1-6, 1999	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
Regulation	20.06	28.22	28.08	24.60	12.42	13.03
Spin	8.17	1.13	12.58	0.55	7.5	0.88
Non-spin	3.90	0.32	12.11	0.09	7.92	0.05
Replacement	2.02	0.00	12.44	0.00	0.74	0

Ancillary Service Costs

- The cost of Ancillary Services increased from $2.26 to $2.60/MWh of ISO load from June to July, but dropped as a percent of estimated overall energy costs from 8.7% in June to 8.1% in July. This increase is largely due to very high demand and prices for ancillary services during the peak demand days of July 12-13. The total daily cost of ancillary services on July 12 and July 13 were $ 7.9 million and $9.6 million, respectively.

Month	Avg. Daily Cost*	Avg. Cost per MWh of ISO System Load	Percent of Energy Costs*
June	$ 1,442,000	$2.26	8.7%
July	1,801,000	$2.60	8.1%
Aug 1-15	796,000	$1.11	4.3%

*** Includes day-ahead and hour-ahead procurement costs**

**** Energy cost = actual hourly loads multiplied by the PX Day-ahead Unconstrained MCP.**

Over the first two weeks of August, the average daily cost of ancillary services declined significantly, averaging approximately $800,000/day, or just $1.11/MWh of system load and only 4.3% of total estimated overall energy costs. Lower daily costs are likely attributed to moderate loads. Lower loads tend to reduce the overall demand for ancillary services and free up more capacity for providing these services.

In the Congestion Management Markets:

- Congestion costs in July,1999 increased significantly over July, 1998. On Path 15, congestion costs totaled about $4 million in July, compared to only $500,000 the same month last year. On COI, congestion costs increased from less than $4 million in July, 1998 to about $6.2 million in July of this year. Although total available capacity on these lines has actually increased compared to July of last year, the demand for transmission (or initial preferred schedules) has also increased significantly, leading to higher congestion frequency and prices.

- For July, COI was congested during 62% of peak hours and 29% of off-peak hours and NOB was congested in 23% of peak hours and 11% of off-peak hours. Day-ahead prices on COI ranged from $.01/MW to $68.47/MW and averaged $13.25/MW. Day-ahead prices on NOB ranged from $.02/MW to $250/MW and averaged $8.98/MW.

- For August 1-6, congestion levels on the northwest paths increased during peak hours from July levels but declined during off-peak hours. During this period, day-ahead congestion occurred on COI in 64% of peak hours and 19% of off-peak hours and on NOB in 32% of peak hours and 6% of off-peak hours.

- There was little congestion on the southwest paths during peak hours for July. However, there was significant congestion into California during off-peak hours with Eldorado and Palo Verde congested in 22% and 15% of off-peak hours, respectively. During off-peak hours, prices on Eldorado ranged from $.07/MW to $17.51/MW and averaged $4.78/MW. Off-peak prices on Palo Verde ranged from $.01/MW to $18.01/MW and averaged $3.59/MW. There was also significant congestion on Path 15, predominately in the south to north direction. Path 15 was congested in 15% of peak hours and 51% of off-peak hours. Prices on Path 15 ranged from $.01/MW to $58.86/MW and averaged $9.20/MW.

- For the August 1-6, Eldorado continued to be congested in the import direction during off-peak hours with congestion occurring in approximately 44% of off-peak hours. Prices on Eldorado ranged from $.10/MW to $16.44/MW and averaged $3.66/MW. Palo Verde was congested less frequently with congestion occurring in only one off-peak hour at a price of $30/MW. Congestion on Path 15 was down from July with congestion occurring in only 7% of peak hours and 19% of off-peak hours. Congestion on Path 15 was predominately in the south to north direction and prices ranged from $.01/MW to $11.92/MW and averaged $2.38/MW.

<u>Issues under Investigation:</u>

- **Possible Data Release Schedule.** At its July 9 meeting, the Market Surveillance Committee recommended that the ISO should release aggregate bid data as soon as practicable, and release all bid and schedule data (including the identity of the bidders) with a three-month time lag. Approval by the ISO Board and a FERC tariff change are required to implement this recommendation. The issue has also been discussed at MIF and DMA staff is now developing specifications that could be used for the public release of bid data from ISO markets. Proposals addressing the content and implementation of this data release will be presented at MIF meetings in September and October, to help develop a Management recommendation for Board consideration in October. If the Board adopts the recommendation, the ISO would file Tariff language in December, for implementation during the first quarter of 2000.

- **Defining the Criteria and Attributes of Workable Competition.** DMA is developing a procedure for assessing market power in ISO markets. The procedure may be used to analyze the existence of workable competition in the context of new zone creation, and New Generation Connection policy. The procedure includes systematic steps to define the boundary of the relevant geographic markets, screen geographic boundaries based on expected or historical congestion frequency, compute the Residual Supply Index (RSI) profile for the selected markets/boundaries (i.e., the minimum supplier RSI for each hour) over a designated time interval (*e.g.,* a year), determine the frequency of RSI falling below a designated threshold (*e.g.,* 120%). If the result indicates that the RSI is above the designated threshold for a substantial period of the year *(e.g*., more than 95% of the time) sufficiently workable competition is assumed for the specific geographic market/boundary. Otherwise, further study in the relevant market/boundary is to be carried out, including tracking of bid markup.

- **Sale of PG&E Hydro Assets.** As noted in last month's report, in response to a request from the state legislature, DMA has collaborated with ISO Operations to develop a set of market power mitigation principles to govern a scenario in which PG&E's hydro portfolio was transferred to an unregulated affiliate of PG&E. Following the presentation of a white paper to the legislature (provided to the Board last month as an attachment to the Legislative Committee memorandum), the state legislature asked that DMA provide additional comments on the extent to which these market power mitigation principles would apply if PG&E's hydro portfolio was divested to more than one entity. A draft response is being developed which outlines general market power mitigation principles and options that may apply to representative divestiture scenarios. Based on the DMA's preliminary analysis, we believe that potential market power risks from different divestiture options for PG&E's hydro portfolio can be mitigated. In each case, however, it will be necessary to have the flexibility to design measures to mitigate the specific risks that will emerge. Thus, DMA has expressed its opinion that legislation should not attempt to prescribe one specific remedy in advance.

- **Increasing the Depth of the Adjustment Bid Markets.** The depth of the adjustment bid market is a significant measure of the ability of the market to respond to gaming behavior similar to the Silver Peak incident of May 25, 1999. As reported in last month's report, for operating day May 25, 1999, for approximately 16 hours, several thousand MWs were scheduled through the PX across ISO path Silver Peak (SR3) from Nevada to Southern California. Silver Peak has a maximum available capacity of 15 MW. Such strategic bidding affects the PX zonal price, but not other SCs scheduling directly with the ISO. The PX is particularly prone to the consequences of such gaming behavior, as the assessment of Usage Charges to the PX can result in significantly higher clearing prices in the PX day-ahead market. DMA investigated the issue in collaboration with the PX Market Compliance Unit and suggested measures that the PX could implement to prevent this event from re-occurring, or to reduce impacts if it re-occurs. Increasing the depth of the adjustment bid market (ABM) was among such measures. A deep ABM could reduce the Usage Charge and the price impact on the PX day-ahead market. Encouraging market participants to submit adjustment bids not only for the resources with non-zero schedules, but also for those with no day-ahead schedule could achieve this objective. This is particularly important as the FTR market starts operation in early 2000, since strategic use of FTRs could reduce the depth of the ABM.

- **Other Items.** The following issues under investigation are described in separate memos to the Board:
  - ***FTR Position Limits and other Options for Mitigating Potential Market Impacts of FTRs*. -** In accordance with the Board resolution to address Tariff changes needed to ensure workably competitive adjustment bid and FTR markets, DMA is investigating measures to mitigate potential market impacts of FTRs with the 100% release of FTRs with 99.5% availability.
  - ***Price Volatility Limit Mechanism (PVLM) -*** DMA is working with ISO Management to develop Management's recommendation on PVLM for Board consideration at the August meeting. As part of this process, DMA presented straw proposals at the public meeting of the MSC on August 6 and at the MIF on August 11. Following the MIF meeting, the ISO set up a chat room on its website for posting of comments. DMA staff will aggregate these comments and distribute them to the Board in advance of the August Board meeting.
  - ***Pre-dispatch of RMR Generation Requirements Prior to the Day Ahead Market* –** DMA is preparing a memo asking the Board to reaffirm its earlier support of the ISO modifying its tariff to allow for pre-dispatch of RMR generation requirements prior to the Day Ahead Market, and seeking to modify RMR contracts so that RMR generation requirements being met under the "contract path" (under which owners opt to be paid full variable operating costs, rather than market prices) are "netted out" of demand in the day-ahead market by bidding this generation at a price of $0/MWh in the PX day-ahead market.
  - ***Path 26 New Zone Creation*** –DMA is applying its workable competition procedure to the markets and geographic boundaries relevant to the creation of a new zone based on Path 26. DMA also analyzed other options. In the process, DMA also identified important issues related to the implementation of forward market intra-zonal congestion management.