CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: Market Issues/ADR Committee

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Governing Board, ISO Executives

Date: June 16, 1999

Re: ***Market Analysis Report***

<u>Key Market Conditions for the May 1 to June 4, 1999:</u>

This memorandum summarizes key market conditions, developments, and trends for the period May 1 to June 4, 1999. More detailed information is provided in the attached Weekly Market Reports.

In the California Energy Markets:

- For the month of May, peak energy prices in the PX day-ahead (unconstrained) market averaged $27.66/MWh, an increase of about 6% from April, 1999 and an increase of about 87% over May of last year. In comparison, the average peak energy price in the ISO real-time imbalance energy market was $22.65/MWh, a decrease of about 21% from April, 1999 and an increase of about 77% from May of last year.

- The decline in the ISO real-time energy prices for May is primarily due to increased hydro supplies and a reduction in the number of price spikes in excess of $200/MWh. Real-time price spikes exceeded $200/MWh for only one hour in May, compared to April, which had five price spikes in excess of $200/MWh.

- Higher energy prices for May of this year compared to May, 1998 can primarily be attributed to the planned outage of several base-load units, moderate snow melt in the Northwest, and significantly less hydro generation from Northern California.

- There were several price spikes in the real-time market during May. On May 18, hour ending 15, the real-time price reached $227/MWh and on May 25, hours ending 16 and 17, the real-time price reached $177/MWh and $162/MWh respectively. The May 18th price spike was due to transmission constraints on Path 26 that precluded using resources located in NP15 for incremental energy. The real-time price spikes on May 25th are still being investigated.

- Over-generation conditions during Memorial Day weekend (May 29-31) led to some negative real-time energy prices in several hours. This occurred for a total of 20 hours (primarily morning hours) with negative prices ranging from –$21/MWh to -$.17/MWh and averaging -$4.55/MWh.

- Peak prices for the first week of June averaged $20.53/MWh in the PX (unconstrained) and $12.02/MWh in the ISO real-time market. Significantly lower system loads and greater hydro availability contributed to the decline in prices for this week.

In the Ancillary Service Markets:

- Regulation, the most volatile of the A/S markets, continues to exhibit significant hour-to-hour and day-to-day volatility. Prices in the regulation market are highest in the morning hours when demand for downward regulation is high and in the evening hours when demand for upward regulation is high.

- Regulation bid sufficiencies remain thin during morning and evening ramping hours.

- Average ancillary service prices in May were generally higher than in April. However, average regulation prices for the first week of June increased significantly. This increase is primarily due to price spikes on Sunday, May 30th when regulation price hit $250/MW in 10 hours. On this day, there was significantly less capacity bid into the regulation market than on previous Sundays. Low energy prices appear to have kept some units off-line and thus, out of the regulation market.

	January-March, 1999		**April-99**		**May-99**		**May 29-June 4, 1999**	
	Peak	**Off-Peak**	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**
Regulation*	12.76	16.36	16.81	20.83	23.33	30.67	44.26	52.62
Spin	4.98	0.94	10.57	1.34	6.58	1.46	3.32	1.42
Non-spin	0.84	0.32	3.00	0.33	4.45	0.57	1.09	0.38
Replacement	1.05	0.00	2.32	0.00	2.48	0.00	0.37	0.00

*** Average Regulation Prices Exclude May 16, 1999, when large negative price spikes occurred.**

- The regulation market received a jolt on May 16, 1999 in hours ending 4-5 with two negative price spikes of -$3,350.28/MW. These spikes were caused by market participants submitting large negative bids for upward regulation with the apparent belief that other bids for downward regulation would set the market-clearing price during these hours. With this bidding strategy, market participants can gain large market shares for upward regulation while receiving a positive price set by high demands for downward regulation. In these particular hours, this strategy backfired as market participants collectively bid enough capacity at negative bid prices to cover demand for both upward and downward regulation. This situation will not occur once the ISO implements software changes necessary for clearing of the upward and downward regulation markets at separate market clearing prices. This change is scheduled for implementation in July 1999.

- For the first quarter of 1999, the average daily cost of ancillary service capacity procured in the day-ahead market was $763,000, with regulation capacity accounting for approximately 87% of the total cost. This daily cost is about 10% of the estimated wholesale value of the total energy scheduled in the ISO control area[1]. During this period, there was very little procurement of ancillary service capacity in the hour-ahead market. On April 6, 1999, in an effort to create a more active hour-ahead market, the ISO began shifting a portion of day-ahead ancillary service requirements to the hour-ahead market. In recent weeks, approximately 10% of the day-ahead requirements have been shifted to the hour-ahead market. For April 1999, the average daily costs of ancillary service capacity bought in both the day-ahead and hour-ahead market was $1,125,000 and for May 1999, the average daily cost was $1,309,000. These daily costs

[1] Wholesale energy value is estimated by multiplying hour-ahead energy schedules by the PX unconstrained market-clearing price.

represent approximately 11% and 16% of the estimated wholesale value of the total energy scheduled in the ISO control area, respectively.

In the Congestion Management Markets:

- Import congestion on the northwest paths dropped significantly from April. For the month of May, COI, the grid's most congested path, was congested (north to south) in roughly 9% of peak hours with an average price of $1.54/MW and in none of the off-peak hours. Congestion on the ISO's portion of the Pacific DC Intertie (NOB) also dropped from April with north to south congestion in May occurring in roughly 8% of peak hours with an average price of $29.21/MW and in only 1% of off-peak hours with an average price of $19.60/MW.

- Congestion levels on the southwest paths were mixed. Import congestion was down on the Eldorado branch group from April levels with congestion in May occurring in approximately 4% of peak hours and 16% of off-peak hours with prices averaging about $5/MW in both periods. However, congestion on Palo Verde was up slightly from April with congestion in 6% of peak hours and 2% of off-peak hours. Prices on Palo Verde during these periods averaged $4.50MW and $3.30/MW, respectively.

- There was very little congestion on other branch groups.

<u>Issues under Investigation:</u>

- **12 Month Annual Performance Report to FERC.** The ISO's Market Analysis Annual Report on Market Issues and Performance was submitted to FERC on June 4, 1999. It provides a comprehensive discussion and analysis of various ISO markets and their performance during the first year of operation (April 1, 1998 through March 31, 1999), the problems and issues encountered, how they were addressed, and what issues remain to be resolved. Several measures of market competitiveness were developed and presented as part of the report. The report reveals valuable lessons learned from the market data collected during the first year of ISO operation. The report was previously delivered to Board members and is posted on ISO's website.

- **Sale of PG&E Hydro Assets.** Market Analysis has been asked to analyze market power mitigation measures for the potential sale of PG&E's hydro assets to its affiliated unregulated entity. The Market Analysis, in collaboration with ISO Operations, has proposed to the legislature safeguards to be included in the conditions for any transfer of the assets. The key condition is to require a minimum capacity bid in A/S markets,, to insure bid sufficiency. PG&E would be a price taker for this minimum amount. PG&E would be able to bid additional amounts in any A/S market at a market index bid cap, and would earn the market-clearing price. The proposal is intended to insure PG&E is not able to set the market-clearing price for the minimum requirements, but continues to have an incentive to compete in all A/S markets.

- **Possible Day-Ahead Congestion Gaming.** 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. The unfeasibility of such scheduling was known to the PX participant who submitted the schedule. This unfeasible schedule was submitted by the PX to the ISO and required the ISO to select several thousand MWs of adjustment bids to relieve the congestion, resulting in significantly higher clearing prices in the PX day-ahead market. This incident has created some concerns about possible market gaming and abuse. Market Analysis is investigating the issue in collaboration with the PX Market Compliance Unit in order to suggest measures which will prevent this event from re-occurring.

- **Intra-zonal Congestion and Creation of New Zones.** Section 7.2.7 of the ISO Tariff includes provisions for creation, modification, and elimination of zones. The Tariff sets a two-part test for the creation of a new zone: 1) the cost of intra-zonal congestion mitigation; and 2) existence of workably competitive generation markets in each of the new zones. However, no definition is provided in the Tariff for a "workably competitive generation market". We are studying the issue to define measures for workable competitiveness. Based on intra-zonal congestion costs associated with Path 26, it appears that this path is a candidate to become an inter-zonal interface. It will be used as a test case. Other options under investigation include raising the transfer capability of Path 26 by implementing Remedial Action Schemes (RAS), moving the boundary of the two active zones from Path 15 to Path 26, and a transmission system upgrade/reinforcement.

- **Use of Real-time Generation Meter Multipliers (GMMs).** At present transmission losses are not accounted for in the balanced forward market (day-ahead and hour-ahead) schedules. A GMM=1 is used in both day-ahead and hour-ahead markets for scheduling purposes. This limitation is due to PX software staging and soon will be alleviated. For settlement purposes, at present GMMs based on hour-ahead schedules are used since actual GMMs (based on telemetered quantities) cannot be computed until ISO's State Estimator is implemented. The SE is a Stage 2 Power Management System (PMS) function, scheduled for implementation in early 2000.

- Presently, an SC can use the hour-ahead GMMs to decide how much to generate at each location to meet its effective schedule commitment with minimal or no real-time deviation. This provides a mechanism for an SC to circumvent the current limitation of having to use GMM=1 for scheduling in the forward markets. However, because actual losses can be different from losses computed based on the hour-ahead schedules, any difference is allocated as part of the Unaccounted For Energy (UFE) and charged to all SCs in proportion to their load.

- As soon as the current software limitations are rectified, the ISO plans to use forecast GMMs (based on day-ahead and hour-ahead markets) for scheduling and real-time GMMs (based on State Estimator results) for settlement purposes. Some participants maintain that using actual GMMs for settlement purposes will undermine their ability to satisfy their forward market commitments. We are studying the issue. Our preliminary conclusion is that using hour-ahead GMMs for settlement purposes is inappropriate, and should be regarded as a temporary procedure; real-time GMMs should be used for this purpose as soon as the software is available. The MAT also believes that as soon as the current limitation in the PX software is rectified, forward market GMMs should be used as a basis for acceptance or rejection of "balanced" schedules.

- **Potential Exercise of Market Power in the Hour-ahead A/S Market.** Starting April 7, 1999, the ISO has been deferring part of its day-ahead A/S requirements to the hour-ahead market. This was a request made by market participants in the ancillary service redesign process to promote a more rational procurement of A/S, increased liquidity of the hour-ahead market, and reduction of A/S costs.

  We expected that initially this would result in higher hour-ahead prices, but that increased liquidity of the hour-ahead market would attract hour-ahead market supply and result in price equilibrium between the day-ahead and the hour-ahead markets. In practice, hour-ahead market prices have constantly increased, particularly in the Regulation market, where the price cap is hit frequently. This problem can be partly attributed to the separate procurement of upward and downward regulation with a single market-clearing price, a temporary practice to be changed this summer, to allow two MCPs. However, we believe the root of the problem is announcing how much is procured in each of the day-ahead and the hour-ahead markets, is providing incentives for some suppliers to withhold capacity from the day-ahead market (or bid very high prices), and show up in the hour-ahead market where relatively limited number of suppliers can provide regulation given the present hydro conditions. Current conditions often force some hydro capacity to run at full load to avoid hydro spill, and stay out of the Regulation market.

We are investigating the problem. In response to these concerns, the ISO has advised Market Participants that the percentage deferred to the hour-ahead market will be varied from day to day and hour to hour based on the discretion of ISO Operations, without announcing the amount deferred.