California Independent
System Operator

# Memorandum

To: Market Issues/ADR Committee

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Governing Board; ISO Officers

Date: November 17, 2000

***Re: Market Analysis Report***

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***This is a status report only. No Board action is required.***

This report summarizes key market conditions, developments, and trends for October 2000.

## OCTOBER HIGHLIGHTS

- Temperature conditions were mild compared to both September of this year and October of last year, leading to lower energy and A/S prices. The monthly peak reached 35,542 MW, down 3.1% from October 1999, while total energy decreased by 2.9%. Average daily peaks reached nearly 31,000 MW, down from nearly 35,000 MW in September.

- The estimated total energy and A/S cost for October was $1.949 billion, or about $100/MWh of load served, compared to about $2.597 billion ($126 per MWh of load served) in September and $1.046 billion ($52 per MWh of load served) in October 1999.

- The average constrained PX price for the month was $91/MWh, up 90% from the $48/MWh average in October 1999 and down somewhat from the September 2000 value of $104/MWh. Real time prices (SP15 & NP15) averaged $106/MWh, down from the September value of $149/MWh and up 100% from October 1999.

- Average daily peak loads reached 30,700 MW in October 2000 compared to the 32,200 MW level in October 1999, about a 4.7% decrease. It is important to note that this decrease is more reflective of temperature conditions between October 1999 and October 2000 than changes in the annual rate of growth in load.

- October prices (weighted) in the ancillary service markets decreased dramatically compared to September. Regulation up, regulation down, and spinning reserve prices all declined by more than 50%. Non-spin prices declined by over 40% and replacement reserve prices declined by over 80%.

- Ancillary service costs were moderate at $2.95 per MWh of load compared to the September value of $7.38/MWh and the October 1999 value of $2.28/MWh. Total A/S costs were about $57 million in October 2000, which is about 3% of total wholesale energy costs in October, compared to the September rate of 6.2%.

- Daily spot prices for October for PG&E Citygate were $5.61/MMBtu compared to $6.02/MMBtu in September.

- Import and export congestion rates increased in October compared to September, and was concentrated on fewer paths. Total Path 15 congestion increased to 68%, export congestion on NOB increased to 22%, and import congestion on the southwest paths increased moderately with Palo Verde and Eldorado experiencing congestion rates of 17% and 29%. Total congestion costs for October were about $28.7 million, a moderate increase over the September costs of about $24 million, but up 60% from the $17.9 million experienced in October 1999.

**KEY MARKET CONDITIONS FOR OCTOBER 2000**

## I. <u>California Wholesale Energy Markets</u>

- **Loads –** October loads trailed off due to moderate temperatures. Monthly system energy loads totaled 19,365 GWh, a 2.9% decrease from October 1999. The peak load for the month reached 35,542 MW, a 3.1% decrease over October 1999 levels, occurring at HE 15 on October 2. Daily peak loads averaged 30,767 MW, a 4.7% decrease over October 1999.

- **Wholesale Energy Prices** – Energy prices in October declined from those observed during the peak Summer months but remained significantly above prices observed last October. System real time prices averaged $105.88/MWh while constrained PX prices averaged about $90.98/MWh, roughly 87% and 90% increases, respectively, from October 1999 levels. Real time off-peak prices declined significantly compared to September, dropping to $87/MW from $121/MW, but remain high compared to October of last year. Off-peak PX prices remained constant from last month.

  Under-scheduling in the day ahead market subsided somewhat in October compared to what was observed in September. On average, the ISO required nearly 1,200 MW of incremental generation during peak hours and nearly 750 MW during off-peak hours.

  Significant real time congestion persisted on Path 15 in the S-N direction, occurring during 64% of all hours. This resulted in a large difference between the average NP15 real time price of $143.91/MW and the average SP15 real time price of $67.85/MW.

  Natural gas prices have moderated from the highs in September, but remain at double the prices from a year ago. Average daily natural gas spot prices are up about 80% from a year ago, averaging above $5.61/MMBtu compared to $3.15/MMBtu last October.

- Both peak and off-peak period prices in the PX energy markets were slightly higher in SP15 than NP15. The ISO real time market experienced much higher prices in zone NP15 due to the significant real time congestion on Path 15 in the S-N direction. Energy prices by zone and period are listed in Table I.

- The ISO real time market experienced only 20 hours where the $250/MWh price cap was reached in either SP15 or NP15, a drop from 78 hours in September. There were 53 hours and 3 hours of prices at or above the $248/MWh level in NP15 and SP15, respectively. Ninety percent of the hours where prices were at or above $248/MW occurred during peak hours. Constrained PX prices remained below $200/MW during the month of October.

**Table 1: Energy Price Summary for October 2000**

| | System Average | NP15 | SP15 | ZP26 | Pct. Hours of Zonal Pricing |
|---|---|---|---|---|---|
| **Real Time Price** | | | | | |
| **Peak** | $115.31 | $147.61 | $83.02 | $84.99 | 56% |
| **Off-Peak** | $87.02 | $136.52 | $37.51 | $39.22 | 81% |
| **Total** | $105.88 | $143.91 | $67.85 | $69.73 | 64% |
| **PX Constrained** | | | | | |
| **Peak** | $100.26 | $109.00 | $95.90 | $95.87 | 57% |
| **Off-Peak** | $72.43 | $87.06 | $65.09 | $65.15 | 96% |
| **Total** | $90.98 | $101.69 | $85.63 | $85.63 | 70% |

## II. <u>Ancillary Service Markets</u>

***Ancillary Service Prices***

- There ancillary service prices did not hit the price cap in the day ahead markets during October. The hour ahead market had a total of 8 price cap hits, with 7 hits occurring in the regulation-up market.

- The ISO procured most of its A/S requirements in the day-ahead market, with between 72% and 93% of A/S MW quantities being procured in the day-ahead market. Table 2 below summarizes weighted average prices and quantity procurements for September 2000 in both the day-ahead and hour-ahead markets.

- Table 3 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).

**Table 2. Summary of Weighted Day-Ahead A/S Prices by Market – October 2000**

| | Day-Ahead Market (all hours) | Hour-Ahead Market | Quantity Weighted Price | Average Hourly MW Day Ahead | Average Hourly MW Hour Ahead | Percent Purchased in Day Ahead |
|---|---|---|---|---|---|---|
| **Regulation Up** | $54.68 | $50.55 | $54.24 | 532 | 62 | 90% |
| **Regulation Down** | $ 38.25 | $ 25.83 | $ 37.37 | 555 | 42 | 93% |
| **Spin** | $ 15.44 | $ 12.63 | $ 15.01 | 661 | 120 | 85% |
| **Non-Spin** | $ 10.59 | $ 8.21 | $ 10.27 | 673 | 104 | 87% |
| **Replacement** | $ 7.38 | $ 13.60 | $ 9.11 | 203 | 78 | 72% |

**Table 3. Summary of Weighted Day-Ahead A/S Prices by Zone and Period – October 2000**

| | NP15 | | SP15 | | Percent of Hours with |
|---|---|---|---|---|---|
| | Peak | Off Peak | Peak | Off Peak | Zonal Procurement |
| **Regulation Up** | $ 36.11 | $ 43.09 | $ 52.60 | $ 59.65 | 10% |
| **Regulation Down** | $ 20.63 | $ 20.42 | $ 49.22 | $ 64.95 | 3% |
| **Spin** | $ 12.94 | $ 4.30 | $ 17.79 | - $ 20.22 | 2% |
| **Non-Spin** | $ 7.45 | $ 1.83 | $ 19.99 | $ 3.88 | 2% |
| **Replacement** | $ 10.07 | | $ 23.96 | | 1% |

***Ancillary Service Costs***

- A/S costs in October were $57 million compared to the September total of $152 million, a result of lower requirements and load conditions. October A/S costs were about 3% of total energy costs. Day ahead A/S prices in October were generally lower than September, with regulation up prices declining by 54%, regulation down declining by 59%, spin/non-spin experiencing a 35% reduction, and replacement declining by 80% from September prices.

| Month | Avg. Daily A/S Cost* (Millions) | Avg A/S Cost per MWh of System Load ($/MWh) | A/S % of Energy Costs |
|---|---|---|---|
| **June** | $14.533 | $20.19 | 14.3% |
| **July** | $ 4.014 | $ 5.71 | 5.1% |
| **August** | $ 9.097 | $12.18 | 7.3% |
| September | $ 5.077 | $ 7.38 | 6.0% |
| **October** | **$ 1.845** | **$ 2.95** | **3.0%** |

* Includes day-ahead and hour-ahead procurement costs including self-provided MW (valued at MCP)

## III. Out of Market Calls

Figure 1 below shows an estimate of total monthly Out-Of-Market (OOM) calls made in response to general system shortages when all available market bids were exhausted. For October, 3,836 MWh were called out-of-market to meet system conditions at a cost of $737,322.

Figure 2 compares actual OOM costs incurred due to general system shortages when all available market bids were exhausted to the value of these OOM energy purchases at the ex-post price. Total OOM costs averaged $192/MWh, compared to a value of this energy of $190/MWh at real time price.

Total OOM calls made in response to general system shortages over the period June 1, 2000 through October 31, 2000 totaled 250.9 GWh at a total cost of $85.8 million. August 7 through August 31 was the peak period for OOM calls, with approximately 125.5 GWh called at a cost of $31.6 million.

**Figure 1. Summary of Out-of-Market Purchases for General System Shortages**

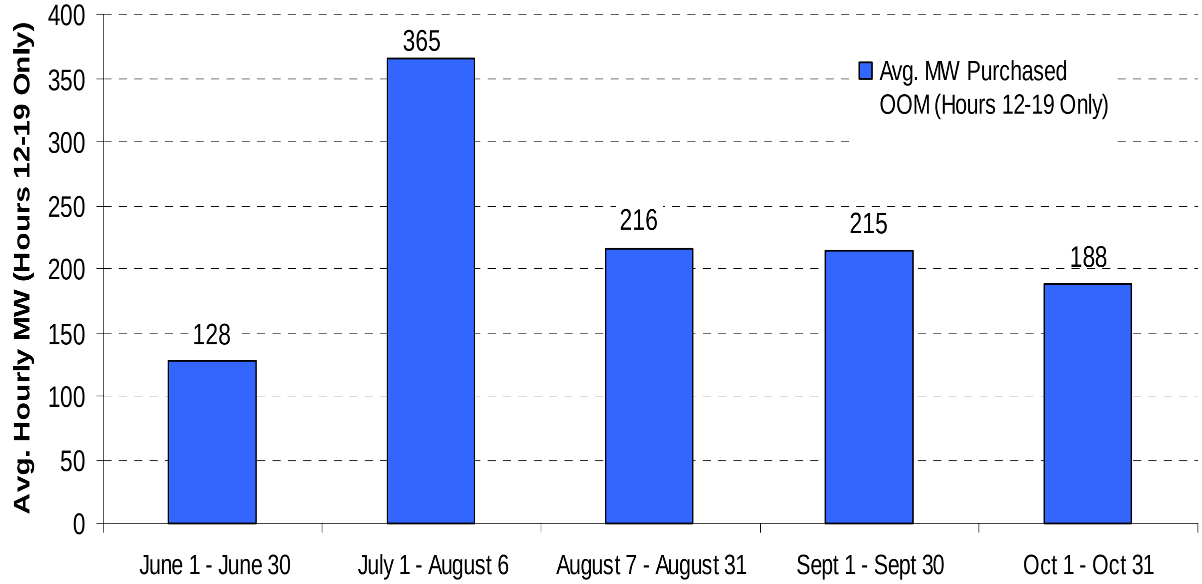
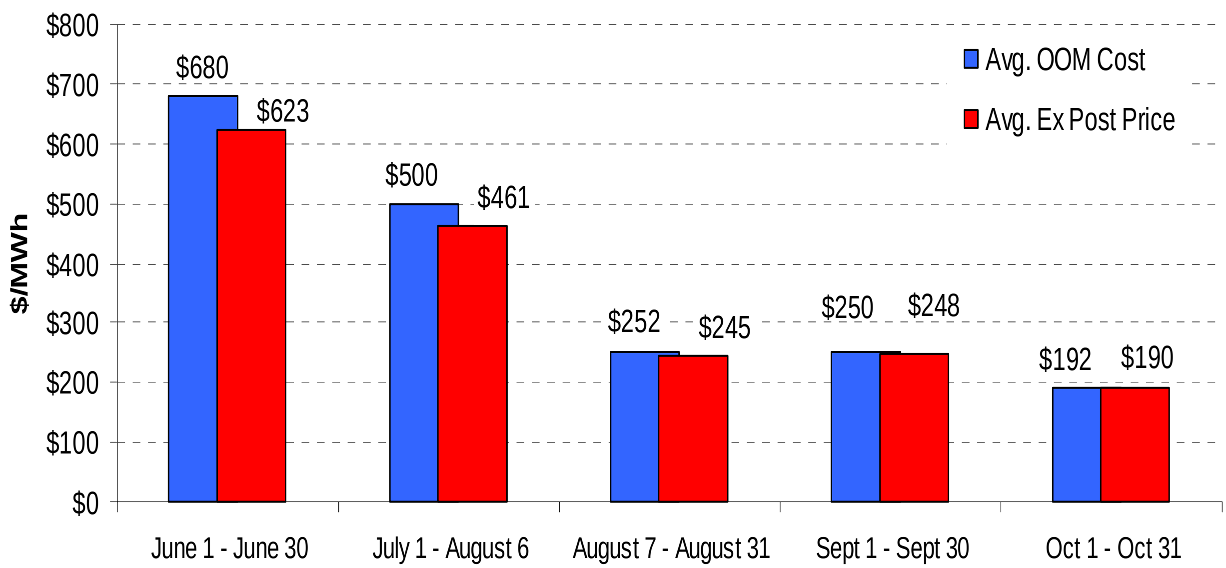



**Figure 2. Comparison of Out-of-Market Purchase Costs to Real Time Prices**



## IV. Inter-zonal Congestion Management Markets

Import and export congestion increased in October as compared to September, and was concentrated on fewer paths. Path 15 (import) and Eldorado (import) congestion rates increased substantially for the month while COI (export) and Sylmar (import) congestion rates dropped to zero. The following table summarizes congestion rates and average congestion charges by branch group for the day-ahead market.

**Day-Ahead Market – Congestion Summary for October 2000**

| | Percentage Congestion by Period | | | Average Congestion Charges ($/MW) | | |
|---|---|---|---|---|---|---|
| | **Peak** | **Off peak** | **All Hours** | **Peak** | **Off peak** | **All Hours** |
| **Path 15 (S-N)** | 58% | 95% | 70% | $24.20 | $23.02 | $23.65 |
| **Eldorado (Import)** | 20% | 46% | 29% | $22.20 | $31.11 | $27.01 |
| **NOB (Export)** | 13% | 40% | 22% | $19.13 | $23.98 | $22.4 |
| **Palo Verde (Import)** | 13% | 27% | 17% | $32.34 | $25.74 | $28.91 |

- The Path 26 N-S congestion rate decrease to only 1% in October compared to the 5% rate in September and the 32% rate in August. Day-ahead congestion charges averaged $7.79/MW, down from $56.94/MW in September and $73/MW in August.

- Total Path 15 congestion increased to 68% in October, up from 59% in September and 42% in August. All of the congested hours were in the S-N direction. Of the congested hours, 77% were in the off-peak period. Day-ahead congestion charges on Path 15 averaged $23.65/MW, a decrease from the September average of $27.20/MW and the August average of $39.13/MW.

- Export congestion NOB increased for October to 22%, up from 12% in September and 17% in August. There was no Import congestion on NOB.

- September import congestion on the southwest paths increased moderately with Palo Verde and Eldorado experiencing congestion rates of 17% and 29%, respectively, up from the 11% and 19% rates experienced in September and the 1% and 3% rates experienced in August. There were no other SW branch groups with any significant day ahead congestion. Average congestion prices for Palo Verde and Eldorado were $28.91/MW and $27.01/MW, respectively.

- Total congestion costs for October were about $28.7 million, a moderate increase over the September costs of about $24 million, but up 60% from the $17.9 million experienced in October 1999. Path 15 incurred the largest congestion costs with a total of $10.4 million.

## V. Performance of the FTR Market in September 2000

### *FTR Concentration*

There have been no secondary FTR market transactions and no new FTR SC assignments since the last month, and thus no change in FTR ownership and control concentration to report.

### *FTR Scheduling*

On most paths the FTRs have been primarily used for their financial entitlement to hedge against transmission usage charges. The relative volume of schedules with FTR priority attached for the period October 1-31, 2000 is indicated in the following table. Only paths on which FTRs were attached to schedules are listed.

| Branch Group | COI IMP | ELD IMP | IID-SCE | MEAD IMP | PV IMP | SilvPk IMP | Total |
|---|---|---|---|---|---|---|---|
| **MW FTR Auctioned** | 422 | 694 | 600 | 366 | 1,650 | 10 | 9,553 |
| **Avg. MW FTR Scheduled** | 25 | 390 | 430 | 9 | 548 | 8 | 1,410 |
| **% FTR Scheduled** | 6% | 56% | 72% | 3% | 33% | 84% | 15% |
| **Max MW FTR Scheduled** | 100 | 455 | 452 | 10 | 1,038 | 9 | - |
| **Max Single SC FTR Schedule** | 100 | 405 | 452 | 10 | 590 | 9 | - |

### *Secondary Market Activity*

There were no secondary transactions during the month of October.

## VI. Issues Under Review and Analysis

1. **Impact of 10-minute Settlement.** DMA is reviewing the market impact of the 10-minute Dispatch and Settlement (10-MDS) implementation that has been in operation since September 1, 2000. The objective of the 10-MDS implementation was: 1) to correct the "stuck price" phenomenon; 2) to reduce uninstructed deviations; and 3) to reduce Regulation requirements. The main concern with 10-MDS implementation was that it could result in a reduction of import participation in the real-time market.

   The stuck price problem, which was the result of pre-dispatch of imports with no provision for intra-hour changes was solved upon implementation of 10-MDS. The impact of 10-MDS in reducing uninstructed deviations has been noticeable. However, it appears that there has been little or no impact thus far in the reduction of Regulation requirements. The reduction of Regulation requirements was the main factor in the cost-benefit analysis of 10-MDS, justifying the implementation cost of 10-MDS for both the ISO and the Market Participants. It is premature to conclude whether or not this benefit can be realized. The control room operations staff must first build up confidence that uninstructed deviations stay at a lower level in a consistent manner not to cause CPS2 violation, before they proceed to reduce their Regulation requirements. The benefit of 10-MDS in reducing Regulation requirements is expected to materialize with a time lag.

   In reviewing the impact of 10-MDS on potential reduction of imports, we can make some initial observations:

- In the first month following implementation of 10-mintue settlements, there appears to be practically no noticeable reduction of import bids into the real-time market from the Northwest, but a rather significant reduction from the Southwest. The reduction of real-time import bids is accompanied by an increase in the volume of imports scheduled in the day-ahead and hour-ahead markets from Southwest. These trends may indicate a shift toward scheduling in the day ahead/hour ahead markets to reduce the price risk associated with real time dispatch and settlement.

- There has been a reduction in the percentage of import bids actually dispatched in real-time. This is partially attributable to the relatively high frequency of S-N real-time congestion that renders import bids from the Southwest rather ineffective in real-time.

- There has been a noticeable reduction of in-state bids in the real-time market. However, it is unclear that this reduction is due to 10-MDS.

2. **Out-of-Market Calls and Potential Gaming.** The DMA investigated the volume and cost of out-of-market purchases made by the ISO in recent months. The main finding are as follows;

- On days when emergency out-of-market purchases were made, OOM purchases represented about 18% of total peak hour imports and 31% of real time energy imports (i.e. energy imports not scheduled in advance but called in real time during the peak hours from 7 a.m to 10 p.m.).

- Emergency OOM purchases at price above the price cap represent only about one-tenth of one percent of peak hour total imports on days when emergency purchases were made, and only about two-tenths of one percent of total real time energy imports on these days.

- Less than 1% of all out-of-market purchases by the ISO have been at price above the price cap.

- The bulk of out-of-market purchases have been made at prices approximately equal to the ex post real time energy price during the hours when these emergency purchases were made.

- In some cases, the ISO must purchase multi-hour “blocks” of energy out-of-market in the morning of an operating day at a pre-agreed price which may subsequently be higher or lower than the actual ex post real time price during some hours of the day. However, the average price paid for out-of-market purchases has closely tracked the average value of these purchases at the real time energy price. Since the price cap was lowered to $250 on August 7, 2000, there has been a minimal difference in the average price paid for out-of-market purchases and the value of these purchases at the average real time price.

- The trends noted above suggest that that “withholding” of supplies to be called out-of-market by the ISO has not represented a major gaming opportunity, and, in fact, may often have represented a “losing strategy” for suppliers in other control areas. When called out-of-market, these suppliers received on average a price only slightly higher than the real time energy price. However, in cases when they were not called, suppliers would have forgone the opportunity to earn the very prices paid for energy supplied through the real time energy market.

3. **Target Price Mechanism.** The ISO modified its methodology for calculating a real time target on April 4, 2000 in order to eliminate a gaming opportunity with the original target price methodology. While this new approach avoided this gaming opportunity, it created potential new sources of market distortions and volatility, including an increased frequency of MCP’s of zero when the ISO is dec-ing resources. The DMA analyzed the new target price and concluded that although it solves the referenced gaming opportunity, it could lead to undesirable market impacts such as practically eliminating a good portion of the decremental bid market, and potentially increasing the volatility of the real-time price. These concerns have been substantiated in practice. As the need to decrement resources has increased in recent months, an increased frequency of zero prices in the real time market has occurred.

DMA has recommended a return to the original target price methodology, with one major exception: only "feasible bids" would be allowed to set the target price. The "feasible bids" would include interchange bids that are pre-dispatched, load bids from dispatchable loads, and generation bids that are capable based on their ramping capability. The DMA continues to recommend implementation of this approach prior to the winter/spring months, when the ISO frequently needs to decrement resources and the negative impacts of the current approach are likely to increase and become significant again.

4. **High NP15 Real-time Prices and High Real-time S-N Path 15 Congestion Frequency.** The DMA is investigating recent high prices in NP15. Real-time congestion in the S-N direction on Path 15 has increased substantially in both peak and off-peak hours, occurring in approximately 80% of off-peak hours and 55% of peak hours for the month of October.

5. **Status of External Investigations.** DMA continues to collaborate with investigations being performed by a variety of outside entities, including the FERC, CPUC, EOB and State Auditor.