CALIFORNIA ISO

California Independent
System Operator

# Memorandum

To: ISO Board of Governors

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Officers, ISO Board Assistants

Date: November 19, 2001

***Re: Market Analysis Report for October 2001***

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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 2001.

## EXECUTIVE SUMMARY

Real-time electricity and ancillary service prices in October were similar to the moderate levels seen in September, due primarily to low natural gas prices, weak demand, and service of load by forward contracts. Overall, the average wholesale price of real-time incremental electricity remained relatively constant between September and October, at approximately $42 per megawatt-hour (MWh). The real-time price of decremental electricity decreased approximately 17 percent, to $10/MWh, from $12/MWh in September.[1] Moderate loads have characterized California's electricity markets, with the exception of the first three days of the month, during which California experienced record high temperatures. The California Energy Commission (CEC) reports that total energy consumption has declined 1.5% since October 2000, after normalizing for growth and weather conditions. This trend in conservation savings needs to be monitored closely in order to effectively forecast needs for summer 2002. The Department of Market Analysis (DMA) continues to monitor real-time prices above competitive levels. While a price cap ordered by the Federal Energy Regulatory Commission (FERC) remains in effect for energy procured through the ISO's Balancing Energy Ex-Post Price (BEEP) auction market, it was not binding during any hour in October.

Scheduling coordinators increasingly self-provided Ancillary Services (A/S) in recent months. A/S costs, as a percentage of total energy costs, also continued to decline. Interzonal congestion costs were minimal. Many generators, including a large nuclear unit in Southern California, have gone off-line for scheduled maintenance, resulting in an increase in outage levels during the shoulder season.

## KEY MARKET CONDITIONS FOR OCTOBER 2001

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

- **Loads.** Loads in October 2001 were lower than those in October 2000, due primarily to mild weather, continued conservation efforts by consumers, and a softening economy. Monthly system energy consumption for October totaled 19,105 gigawatt-hours (GWh), a 1.8% decrease from October 2000. The

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[1] As of the September report, the DMA will report separate real-time incremental and decremental energy prices. The real time price is the average of the market clearing price and OOM purchase costs. See Table 1 under the California Wholesale Markets section for a further breakdown.

peak load for the month reached 38,580 megawatts (MW), a 21% increase from the October 2000 peak of 31,899 MW, due to unseasonably warm weather on October 1, 2001. Daily peak loads averaged 30,417 MW, a 1.3% decrease from October 2000.

The California Energy Commission (CEC) provides estimates of conservation after normalizing for growth and weather conditions. In October, the CEC calculated that monthly peak demand for electricity decreased by 8.8 percent from October 2000, and monthly energy dropped by 1.5 percent over the same period.

- **Wholesale Energy Prices.** The FERC's price mitigation order of June 19 continues to be in effect, imposing a soft price cap of $91.87/MWh on wholesale power markets in the Western United States. However, the cap was not binding during any hour in October due to the soft market environment.[2]

  The ISO Department of Market Analysis (DMA) monitors several key price and volume statistics related to the real time market. The BEEP market now consists of several components displayed in numbered columns: (1) the market-clearing prices (MCP) and quantities for incremental and decremental energy procured under the price cap; and (2) the incremental and decremental out-of-market (OOM) procurements scheduled in real-time. The combination of these components yields (3) the total overall average real-time prices. CERS real-time procurements on behalf of the IOU's comprise the bulk of the OOM activity. No energy was procured in the BEEP market as bid above the price cap in October. The averages for each of these segments of total real time purchases for peak, off-peak, and all hours are shown in the following table:

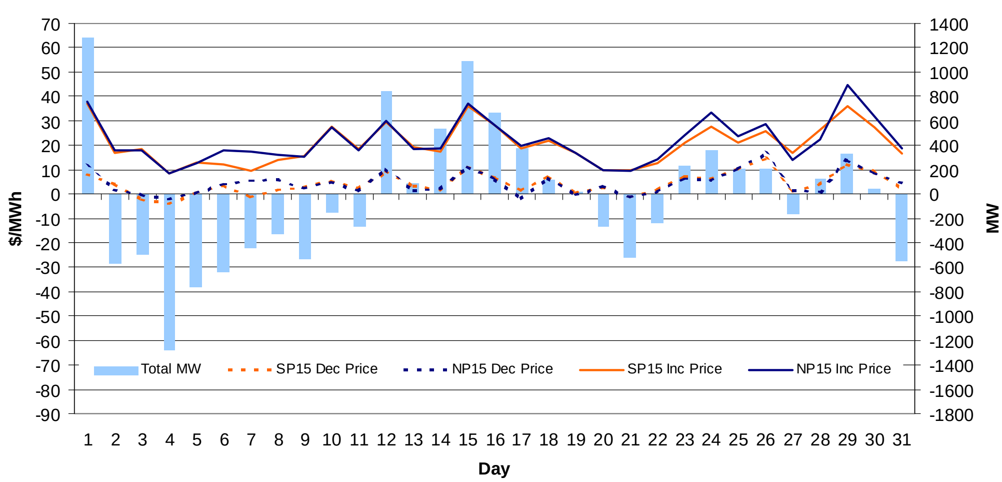
[2] On June 20, the FERC's West-wide price mitigation Order went into effect, initially capping real-time energy and ancillary services prices at $91.87/MWh throughout the WSCC during all California ISO non-emergency hours. The Order caps prices at a formula-determined proxy price. During declared stage emergencies, the cap is determined by calculating the marginal cost of the highest priced unit dispatched. During non-emergency hours, the cap is set at 85 percent of the highest hourly ex-post price calculated during the last full hour of ISO operation under a Stage 1 emergency (which, at present, was $108.08/MWh and occurred in hour ending 10:00 on May 31, 2001). The cap has remained unchanged since the Order went into effect, because the ISO has not operated under a Stage 1 emergency for a full hour since that time. The cap will be reset upon the next full hour of a Stage 1 emergency. Bids accepted above the cap are paid as bid subject to cost justification; however, no generator has yet sufficiently justifiedbids above the cap. FERC also ordered a 10 percent adder to the market-clearing price for generators selling into the ISO markets to account for increased credit risk. Bids in the ISO's BEEP auction market accepted above the price cap are not paid the additional 10 percent credit risk premium adder.

**Table 1: Real Time Energy Price Summary for October 2001[3]**

| | Avg. Market-Clearing Price and Total Volume (1) | | Avg. Out-of-Market Price and Total Volume (2) | | Overall Avg. Real-Time Price and Total Volume (3) | | Avg. System Loads (MW) and Pct. Underscheduling (4) |
|---|---|---|---|---|---|---|---|
| | Inc | Dec | Inc | Dec | Inc | Dec | |
| Peak | $ 62.14 | $ 6.53 | $ 32.63 | $ 16.46 | $ 43.27 | $ 10.91 | 28,008 MW |
| | 89 GWh | 102 GWh | 158 GWh | 80 GWh | 247 GWh | 182 GWh | -0.1% |
| Off-Peak | $ 46.34 | $ 1.30 | $ 25.42 | $ 13.88 | $ 33.44 | $ 8.30 | 21,021 MW |
| | 20 GWh | 61 GWh | 33 GWh | 77 GWh | 53 GWh | 139 GWh | -5.3% |
| All Hours | $ 59.19 | $ 4.56 | $ 31.39 | $ 15.20 | $ 41.53 | $ 9.78 | 25,679 MW |
| | 109 GWh | 163 GWh | 191 GWh | 157 GWh | 300 GWh | 320 GWh | -1.5% |

As noted previously, average real time INC energy prices remained nearly constant from September to October, while DEC energy prices decreased approximately 17%.[4] Average system load decreased to 25,679 MW from 29,763 MW. On average, scheduling coordinators refrained from underscheduling in October; however, DMA observed 1.5% overscheduling, compared with less than 1% underscheduling in September. Figure 1 shows the daily average real-time prices and quantities for incremental and decremental energy in October (monthly averages are noted in column (3) of Table 1 above).

**Figure 1: Daily Average Real-Time INC and DEC Energy Prices and Quantities October, 2001**



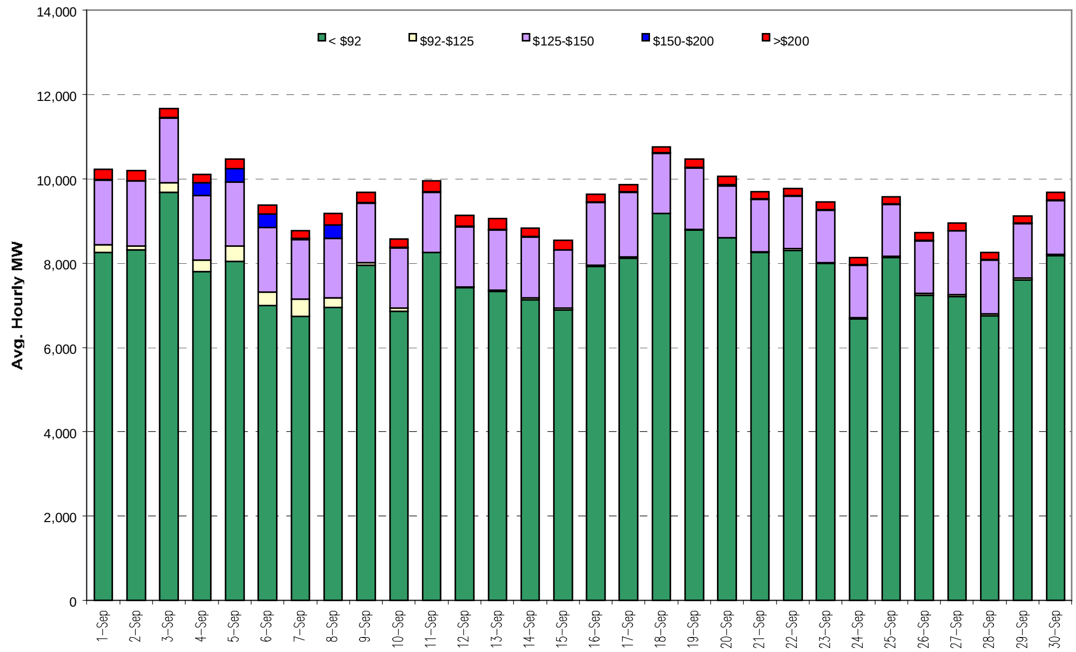

[3] The values in Column (1) of Table 1 do not include the 10 percent risk premium adder that is paid to all sellers receiving the market-clearing price. Dollar figures are $/MWh and GWh figures are total volume. Dollar values are the average prices per MWh transacted in real-time, and do not represent the average cost of electricity. For reference, the average cost of electricity and ancillary services for the entire system (including UDC generation at cost, bilateral transactions at hub prices, and real time costs) for the month of October is estimated at $45/MWh. DMA imputes the real-time price on exchange and recirculation energy OOM trades.

[4] These comparisons are based upon revised September statistics. See Addendum to September Market Analysis Report.

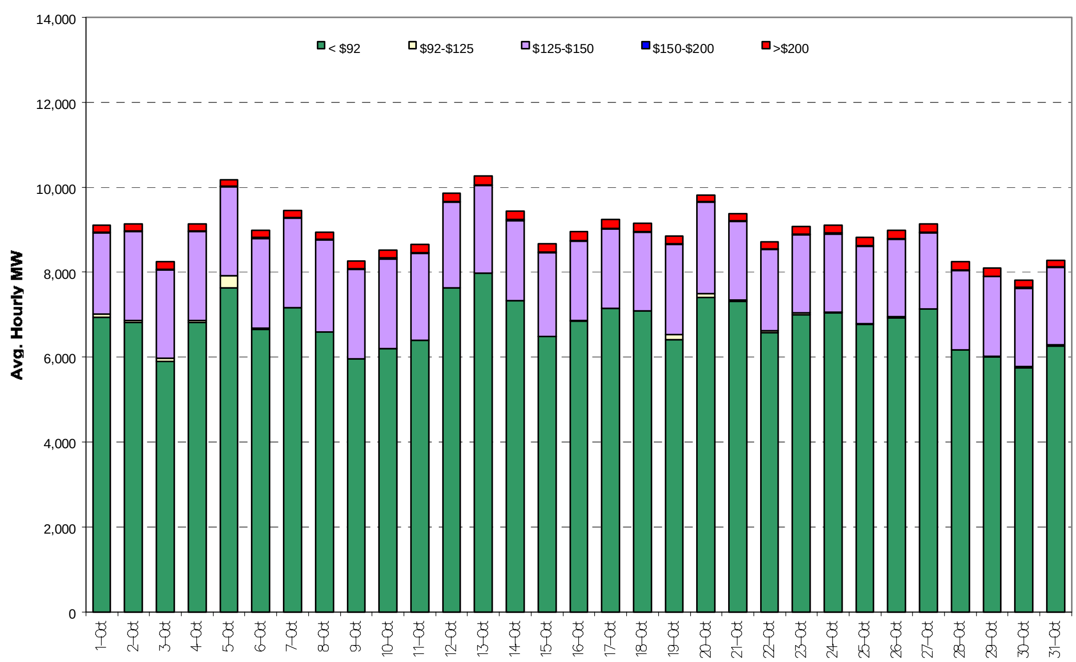
The portion of energy transactions that is traded in the ISO's BEEP market has continued to decline. In January, the Department of Water Resources' California Energy Resources Scheduling Division (CERS) entered into forward contracts on behalf of utility distribution companies (UDCs) that have been sufficient to meet most of the UDCs' net-short load in October.

The soft demand situation has mitigated the ability of generators to exercise market power in the real-time markets. However, real-time prices have persisted above the competitive benchmark through October. The price-to-cost markup had remained relatively low from June to August, but increased in September. Most bids have been below the cap level, but generators continue to bid small portions of their energy above the cap. Figures 2a and 2b show bids into the BEEP stack by price bin for September and October, respectively.

## Figure 2a. Original Bids into BEEP Stack (Hourly Average by Day) – September[5]



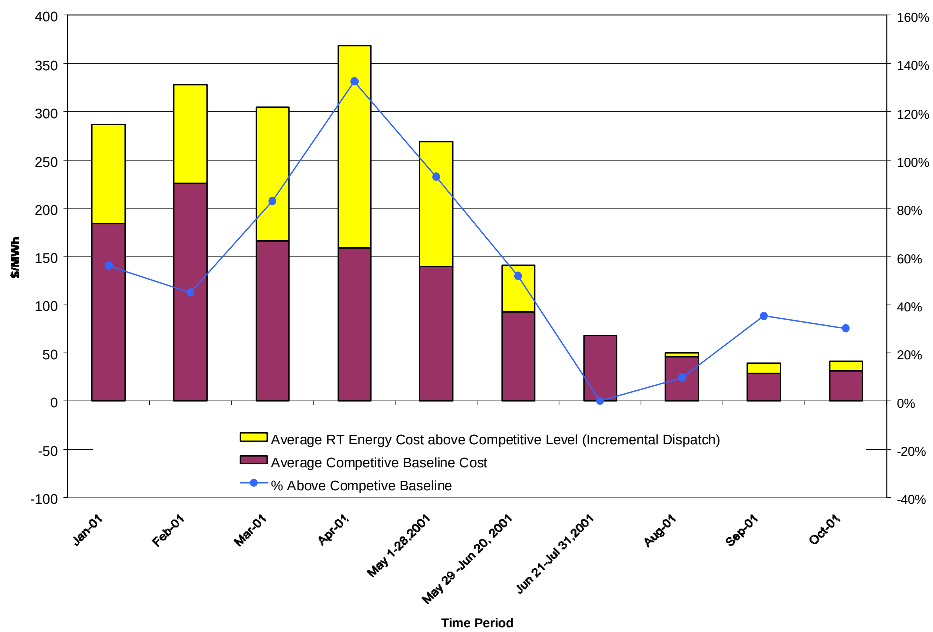

## Figure 2b. Original Bids into BEEP Stack (Hourly Average by Day) – October




[5] This graph depicted erroneous data in the September Report.

Figure 3 compares actual prices of real-time energy to baseline estimates of competitive prices, which approximate the costs of production of electricity.

**Figure 3. Price-Cost Mark-Up in ISO Real-Time Market**




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

### *Ancillary Service Prices*

The five ancillary services (A/S) are procured through a day-ahead and an hour-ahead market to meet reserve requirements. The ISO is interpreting the FERC's Order of June 19, 2001, to cap A/S prices at the effective real time price cap in all hours. Reserve requirements that are not met at prices at or below the soft cap are purchased at the bid price, and again are subject to just and reasonable cost review by the FERC. Since December 31, 2000, the ISO has been rescinding capacity payments for Replacement Reserve services whenever energy is dispatched from the corresponding resource in real time. This has resulted in savings ranging from $10 million to $20 million per month.

Scheduling coordinators (SCs) have been self providing an increasing portion of their A/S requirements. Table 5, below, shows the increase in SCs' self-provision of A/S.

Changes in average prices for A/S were mixed between September and October. Upward and Downward Regulation prices decreased by approximately 33% and 29%, respectively. Spinning and Replacement Reserves stayed relatively constant at $3 and less than $1, respectively, while Non-Spinning Reserves increased from less than $1 to $2. Between 60% and 97% of requirements were purchased in the day-ahead market. Table 2, shown below, summarizes the weighted average prices and quantities of A/S procured in October, in both the day-ahead and hour-ahead markets.

**Table 2. Summary of Weighted Day-Ahead A/S Prices by Market – October 2001**[6]

| | 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 | $ 13 | $ 23 | $ 14 | 521 | 19 | 97% |
| Regulation Down | $ 13 | $ 7 | $ 12 | 490 | 50 | 91% |
| Spin | $ 3 | $ 2 | $ 3 | 1134 | 43 | 96% |
| Non-Spin | $ 2 | $ 3 | $ 2 | 704 | 50 | 93% |
| Replacement | * | * | * | 39 | 26 | 60% |

Since January, SCs have increasingly self-provided A/S. Figure 5 shows the volume of A/S self-provided by SCs, compared with the volume procured through the ISO ancillary service markets. The graph also shows explicit A/S procurement costs as a percentage of total energy costs (in green), which has been declining.[7]

## III. Out of Market (OOM) Calls and BEEP Volumes

Average OOM prices were $31.38/MWh in October, down $3.24/MWh when compared to the September average of $34.62/MWh. On an hourly average basis, 45 MW were purchased out of market in October, with 100% of the OOM electricity coming from imports in each month. The total cost of OOM purchases in October was $358,000.[8]

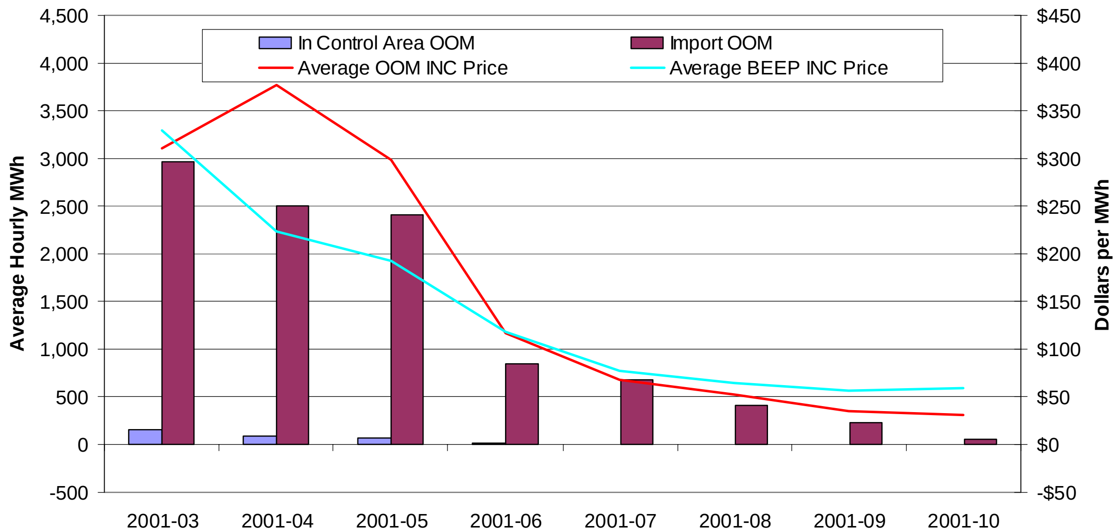
Hourly OOM procurement is shown below in Figure 4.

[6] Values in Table 2 and Table 3 do not include the 10 percent risk premium adder paid to all sellers receiving the market-clearing price. An asterisk (*) indicates a price below $1. Prices that vary between NP15 and SP15 are a result of quantity-weighting of identical prices, and do not indicate zonal procurement due to congestion.

[7] We note that this understates the true economic costs of A/S. When a SC self-provides A/S, the cost of A/S is included in the SC's bid price for energy. This cost is thus not included in computation of the data underlying the green line. However, this cost is presumably small during periods of overscheduling, since most generators have plenty of reserve capacity at that time.

[8] Total OOM costs are net INC and DEC costs.

**Figure 4. Quantities of Out-of-market Purchases (Average Hourly) February - October**[9]




Ample energy in forward schedules, in addition to lower-than-expected loads from June through October, has resulted in decreased reliance on OOM calls to meet load. This trend began in June (with average hourly net OOM volume at 861 MWh, a decrease of 1,605 MWh from the May average) and continued through October, with an hourly average of 45 MWh.

## IV. Summary of Market Costs

The total costs of energy and A/S amounted to approximately $878 million in October, down from $996 million in September. This is the fifth consecutive month in which the total costs of energy and A/S were below those in the same month in 2000. The average cost of energy and A/S decreased from $50/MWh (adjusted) in September to $45/MWh in October. Energy and A/S costs continue to be above those seen in the first two years of operation. Energy and A/S costs for the first ten months of ISO operation in 1998 totaled approximately $5.55 billion, and averaged $33/MWh. Total costs of energy and A/S in 1999 were comparable to 1998 at approximately $7.03 billion (for twelve months), with an average of $33/MWh as well. However, costs increased substantially in 2000. Total costs for energy and A/S in 2000 were over $27 billion, resulting in an average cost of $114/MWh. For January through October 2001, total energy and A/S costs have exceeded $25 billion, with an average cost of $132/MWh of load served. This represents a significant cost increase over the first ten months in 2000, in which energy and A/S costs totaled approximately $16.5 billion. The increase is due primarily to the extraordinary costs incurred between January and May 2001. This trend reversed in June, and prices for the summer have been lower than in 2000. Table 4, on the following page, provides a summary of energy and A/S costs. The costs estimated in this table include estimates for utility generation, CERS purchases, and bilateral transactions to serve load within the ISO control area.

[9] Because of the relative volumes of OOM and BEEP incremental and decremental energy, OOM unit costs to load are higher than BEEP unit costs to load, as shown in Figure 4. This is true in spite of the fact that OOM average incremental and decremental energy prices are less and more expensive than BEEP prices, respectively, as shown in Figure 1.

## Table 4: Summary of Market Costs, January through October 2001

| | ISO Load (GWh) | Forward Energy (GWh)* | Est. Forward Energy Costs (MM$)** | RT Energy Costs (MM$)*** | A/S Costs (MM$)**** | Total Energy Costs (MM$) | Total Costs of Energy and A/S (MM$) | Avg. Cost of Energy ($/MWh) | A/S Cost ($/MWh Load) | A/S % of Energy Cost | Avg. Cost of Energy & A/S ($/MWh Load) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **JAN-01** | 18,770 | 16,950 | $ 2,710 | $ 756 | $ 247 | $ 3,466 | $ 3,713 | $ 185 | $ 13.15 | 7.1% | $ 198 |
| **FEB-01** | 16,503 | 14,876 | $ 2,657 | $ 917 | $ 198 | $ 3,574 | $ 3,772 | $ 217 | $ 12.00 | 5.5% | $ 229 |
| **MAR-01** | 17,857 | 16,744 | $ 2,736 | $ 881 | $ 181 | $ 3,616 | $ 3,797 | $ 203 | $ 10.14 | 5.0% | $ 213 |
| **APR-01** | 17,237 | 16,267 | $ 2,537 | $ 755 | $ 178 | $ 3,292 | $ 3,471 | $ 191 | $ 10.34 | 5.4% | $ 201 |
| **MAY-01** | 19,651 | 18,351 | $ 2,771 | $ 601 | $ 176 | $ 3,372 | $ 3,548 | $ 172 | $ 8.97 | 5.2% | $ 181 |
| **JUN-01** | 19,777 | 19,468 | $ 1,598 | $ 111 | $ 187 | $ 1,709 | $ 1,896 | $ 86 | $ 9.48 | 11.0% | $ 96 |
| **JUL-01** | 20,976 | 20,599 | $ 1,458 | $ 54 | $ 71 | $ 1,513 | $ 1,583 | $ 72 | $ 3.37 | 4.7% | $ 75 |
| **AUG-01** | 21,048 | 21,571 | $ 1,329 | $ 34 | $ 50 | $ 1,363 | $ 1,414 | $ 65 | $ 2.38 | 3.7% | $ 67 |
| **SEP-01** | 19,562 | 19,562 | $ 958 | $ 19 | $ 19 | $ 977 | $ 996 | $ 50 | $ 0.97 | 1.9% | $ 51 |
| **OCT-01** | 19,105 | 19,395 | $ 854 | $ 10 | $ 15 | $ 864 | $ 878 | $ 45 | $ 0.77 | 1.7% | $ 46 |
| **Total 2001** | 190,486 | 183,783 | $ 19,609 | $ 4,138 | $ 1,322 | $ 23,746 | $ 25,069 | | | | |
| **Avg. 2001** | 19,049 | 18,378 | $ 1,961 | $ 414 | $ 132 | $ 2,375 | $ 2,507 | $ 128 | $ 147 | 5.6% | $ 132 |

## V. Inter-zonal Congestion Management Markets

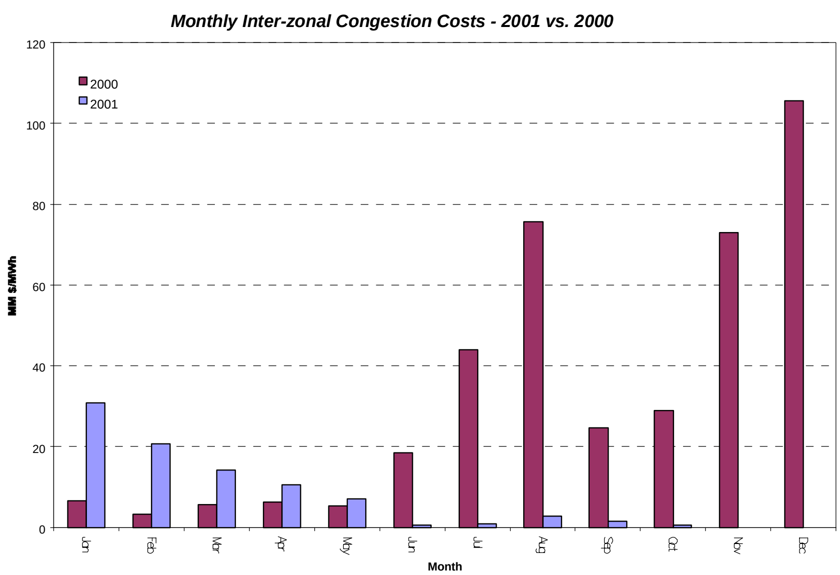
Congestion in October was limited primarily to day-ahead and hour-ahead imports on Eldorado; day-ahead and hour-ahead South-to-North activity on Path 15; and small amounts of day-ahead South-to-North activity on Path 26. Other branch groups had scant activity. Total congestion costs for October decreased to approximately $595,000 in October from $1.6 million in September. Import congestion on Eldorado accounted for over $335,000 of the total congestion costs in October.

The following table summarizes the congestion rates and average congestion charges by branch group for the day-ahead market for October.

**Table 5: Day-Ahead Market – Congestion Summary for October 2001**

| | Percentage Congestion by Period | | | Average Congestion Charges ($/MW) | | |
|---|---|---|---|---|---|---|
| | Peak | Off peak | All Hours | Peak | Off peak | All Hours |
| Eldorado (Import) | 19.4% | 19.8% | 19.5% | $0.81 | $0 | $0.27 |
| Path 15 (S-N) | 11.7% | 97.6% | 40.32% | $0 | $0 | $0 |
| Path 26 (S-N) | | 4.4% | 1.5% | $0 | $0 | $0 |

**Figure 5: Comparison of Monthly Interzonal Congestion Costs**

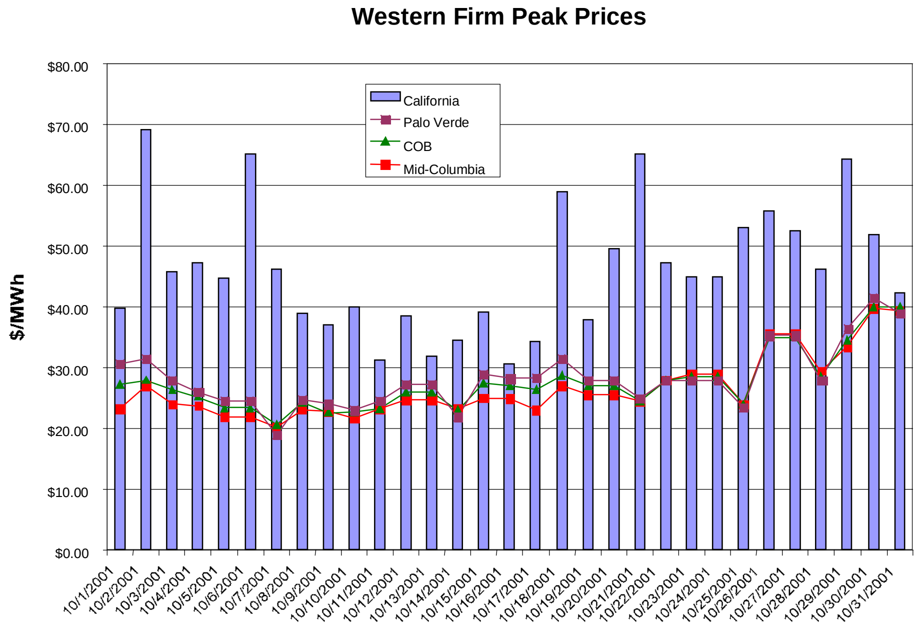



## VI. Western Regional Market Prices

### Western Regional Spot Electric Market Prices

Western peak power prices remained stable between $20 and $30/MWh with little volatility in October. Cooler weather in the southern half of the WSCC reduced cooling demand while falling temperatures to the north lead to some heating demand. Low demand kept prices moderate throughout the month. Increases in the amount of generation units off line for maintenance had little impact on daily prices due to weak demand. Peak power prices in the WSCC rose to near $40/MWh in late October due to rising natural gas prices and hydroelectric curtailments for the annual Vernita Bar fish operation in the Northwest. Figure 6 shows the average ISO real-time price for incremental imbalance energy during peak hours, compared with peak-hour firm trades at the Palo Verde, COB, and Mid-Columbia hubs. Volumes traded at these hubs are not known.

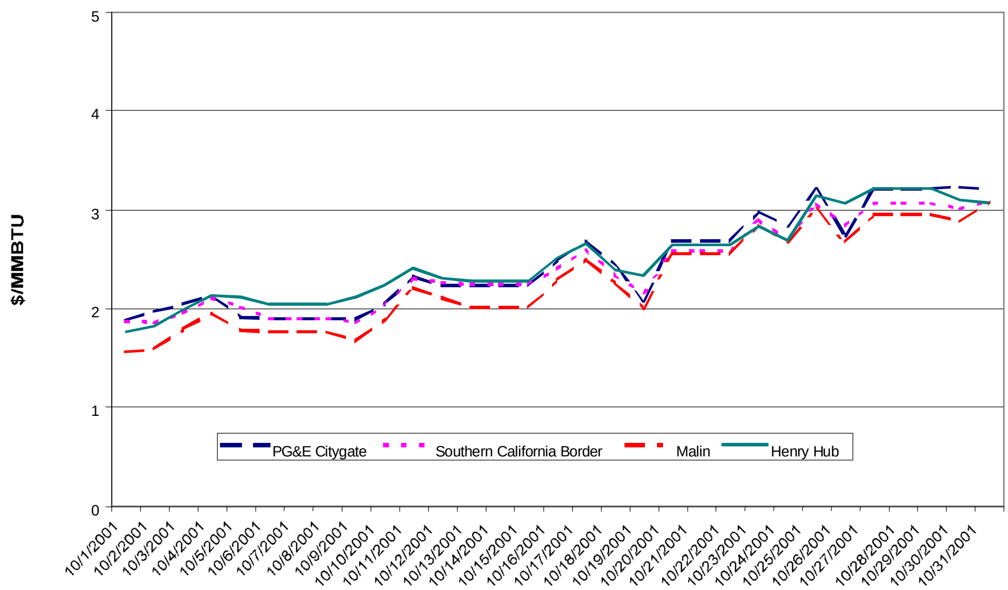
**Figure 6: Regional Spot Price Comparison**




## California Natural Gas Prices

California spot natural gas prices increased in October resulting in prices at California trading points near $3.00/mmbtu by the end of the month. Natural gas prices increased in early October, due to increased demand from cooling and heating loads, due to high and low temperatures, in California and the Midwest, respectively. Prices continued to rise in mid-October, due to continued moderate heating demand, and the shutdown of two units at the Palo Verde nuclear station in Arizona. Arizona Public Service announced that two units at Palo Verde will be down for a month for unexpected maintenance on some of the reactors' key components. The plants' normal energy output will be replaced by gas-fired generation, leading to an increase in gas demand. Each of the three units at the nuclear plant has a capacity of about 1,300 MW. Prices continued to rise in the third week of October, due to a noted analyst's prediction of a winter ranking in the top third of the coldest among the last 106. Prices again increased at the end of the month, due to the influential forecasts of an especially cold winter and near term predictions of a winter storm developing in the Pacific Northwest. Bid week prices for November were $2.95, $2.91, and $3.07 for SoCal Gas, Malin, and PG&E Citygate, respectively.

## Figure 7: Regional Natural Gas Spot Prices




## VII. Performance of the Firm Transmission Rights (FTR) Market in October 2001

### FTR Concentration

There were no secondary FTR market trades and no FTR SC reassignments in October 2001. Since there were no trades or reassignments in August or September either, no changes in FTR ownership concentrations have occurred since those reported in the July 2001 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 on all paths, with FTR priority attached, amounted to 14% of total available FTR volume in October (compared to 17% in September). On some paths, relative volume of schedules was high (e.g., 82% on Eldorado, 65% on Silverpeak, and 63% on IID-SCE, all in the import direction). The following table shows the paths on which 1% or more of the FTRs were attached to schedules, and related statistics. FTR scheduling was insignificant on some paths with high FTR ownership concentration reported in previous Market Analysis Reports (i.e., NOB export and Victorville export).

**Table 6: FTR Scheduling Statistics in October 2001**

| Branch Group | COI IMP | ELD IMP | IID-SCE IMP | MEAD IMP | PV IMP | SilvPk IMP | MEAD EXP | P26 EXP |
|---|---|---|---|---|---|---|---|---|
| MW FTR Auctioned | 600 | 707 | 600 | 487 | 1,819 | 10 | 456 | 1,727 |
| Avg. MW FTR Scheduled | 51 | 578 | 376 | 23 | 373 | 6.5 | 4 | 56 |
| % FTR Scheduled | 9% | 82% | 63% | 5% | 21% | 65% | 1% | 3% |
| Max MW FTR Scheduled | 175 | 707 | 445 | 125 | 829 | 10 | 47 | 263 |
| Max Single SC FTR Schedule | 100 | 582 | 445 | 75 | 400 | 10 | 47 | 263 |

## VIII. Issues Under Review and Analysis

### Must-Offer Requirements for Units with Long Start-up Times

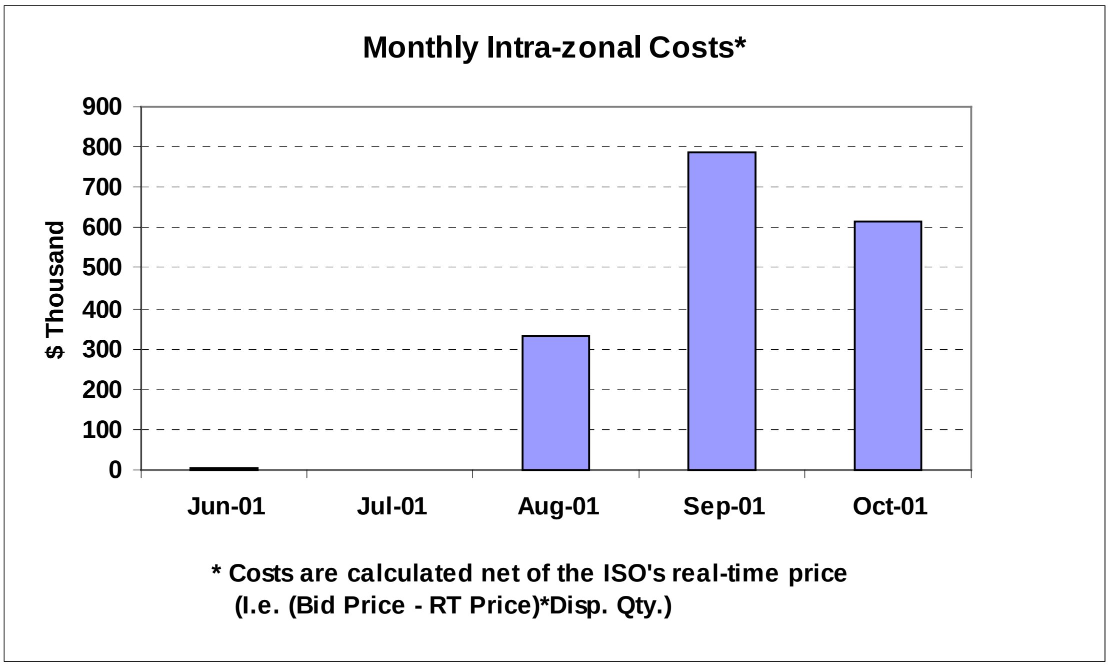
DMA is providing input to the ISO on a proposal to develop a Day-ahead unit-commitment process, to provide for a more workable interpretation of the "must-offer" Tariff provision originating from the FERC Orders of April 26 and June 19, 2001. The intent of this effort is to create a process by which the ISO could commit units for reliability and market competitiveness on a day-ahead basis, and to ensure that suppliers are able to recover their start-up, no-load, and variable production costs. DMA believes the ISO has developed some workable options on this issue. On November 7, the FERC issued an Order directing the ISO to invoice the California Department of Water Resources for all transactions on behalf of Southern California Edison Company and Pacific Gas and Electric Company by November 22.

### Intra-zonal Congestion Market Power Mitigation

Intra-zonal congestion refers to transmission congestion that occurs within a particular congestion zone. Inter-zonal congestion refers to congestion across congestion zones. Under the current ISO Tariff, these two types of congestion are mitigated differently.

Congestion across zones is mitigated in the forward market through the ISO's Day-ahead and Hour-ahead congestion management markets. The ISO currently does not have a process for mitigating intra-zonal congestion in the forward market. The ISO mitigates intra-zonal congestion in real-time, and must face a limited number of resources capable of relieving the congestion constraint, due to the comparatively small geographic area. This difference can often give rise to local market power, in which a supplier, knowing the ISO will need to dispatch its units to relieve congestion, will submit either excessively high or low bids, depending on whether it is needed to increase or decrease generation, respectively. In recent weeks, there has been an increasing number of localized market power events associated with intra-zonal congestion. All of these situations have involved cases where the ISO has had to call on a limited number of suppliers to reduce scheduled output, and such suppliers have submitted large negative decremental energy bids. This means that these suppliers are able to buy energy from the ISO to serve their forward energy obligations at a negative price; or, effectively, to get paid to withhold energy. DMA has been monitoring these incidents and has informed Market Participants engaged in this behavior that it views such bidding behavior as the exercise of market power and will be reporting these incidents to the FERC. In many cases, such discussions with suppliers have resulted in suppliers moderating their bidding behavior, but not to a level that DMA would deem to be acceptable. DMA has expressed these concerns to FERC Enforcement Staff and they have committed to contacting certain suppliers to discuss their bidding behavior. DMA will continue to monitor this issue closely, and is working with an internal team to arrive at a solution and to develop a proposal for Tariff modifications. These modifications would permit the ISO to mitigate intra-zonal congestion in the forward market, and to mitigate bids in cases where local market power is being exercised. Figure 8 shows the intra-zonal congestion for June through October 2001.

**Figure 8: Monthly Comparison of Intra-zonal Congestion Costs**




## Real-time Market Design Issues

DMA is providing input to the ISO on a number of real-time market design issues. These include: changing the target price methodology; developing real-time economic dispatch as a long-term replacement for the target price approach; developing local market power mitigation measures for the real-time market, and developing incentives to minimize significant uninstructed deviations. Some of the major issues relating to uninstructed deviations concern whether there should be payment for energy not requested or scheduled, should deviations be calculated on a unit or portfolio basis, what constitutes a “significant” deviation (i.e. establishing tolerance thresholds).

## Reserve Margin Study

In response to a request from the California Legislature, DMA performed a preliminary study to determine the level of capacity reserve margin in California that would be sufficient to ensure that the average price of energy be reasonably close to the price that would result in a competitive market.

We found that a workably competitive market outcome could be achieved with a *capacity reserve margin* (based on "dependable"[10] rather than "nameplate" capacity in the range of 14 to 19 percent during the peak hour. This new capacity can be supplied from a variety of sources. It could come *all* from price responsive demand with real-time metering, or a resource mix including conservation, demand-side reductions, long-term contracts, and market –driven generation additions. This report does not recommend the appropriate mix of resources to meet the reserve requirement. It does recommend that the location of reserves are critical in promoting competitive market outcomes.

For purposes of this study, we defined a workably competitive market as one where the average annual market price of electricity was no more than 10% higher than the competitive market price; i.e., the annual average price/cost markup is less than 10%. We established a relationship between the residual supply index (RSI, a measure of hourly supply and demand balance, equal to the largest supplier's market share of available capacity), and the price/cost markup in the market using data from Oct 1999 to November 2000. Once this relationship was estimated based on historical base year data, we used it to simulate the effects of new capacity on prices in the market. We found that if additional capacity of about 5,050 to 7,500 MW is added to the 46,300 MW of dependable generating capacity in the ISO's markets in the study's base year of 2000, the goal of a 10% maximum markup can be achieved. The corresponding capacity reserve margin (based on "dependable" rather than "nameplate" capacity) should be 14% to 19% of the annual peak load.

## Refund Proceedings Pursuant to FERC's July 25 Order

DMA continues to play a major role in refund proceedings pursuant to the FERC's July 25 Order. The schedule for the refund proceedings has been separated into 3 issues: (1) determination of the mitigated hourly prices; (2) re-running of ISO and PX settlements with mitigated prices, and (3) determination of refunds due, or adjustments of ISO and PX accounts receivables/payables as a result of this mitigation.

DMA staff submitted testimony on the first of these issues – the mitigated price to be used in determining refunds – on October 9, 2001, along with its calculation of the mitigated price, in accordance with the methodology specified in the July 25 Order. Staff is now working on rebuttal testimony in response to testimony submitted by other parties on November 5, with written rebuttal testimony due on December 10. An evidentiary hearing on the issue of the mitigated price is scheduled for December 17-21.

## Cost Justification Pursuant to April 26 and June 19 Orders

DMA continues to review cost justification for sales over the proxy mitigated price that sellers are required to submit to the ISO and the FERC on the 7th day of each month (for sales during the previous calendar month). The following table provides a summary of sales in the ISO markets subject to cost verification requirements and potential refund pursuant to the FERC's Orders of April 26 and June 19. As noted in a previous section, the FERC has issued rulings disallowing payment for costs above mitigated prices during the months of June and July.

[10] Note the meaning of capacity reserve margin is closer to the conventional system planning reserve margin, which compares installed dependable capacity with annual peak load. This differs from the operating reserve requirement, which depends on hourly system load and generation condition.

**Table 8: Sales of Real Time Energy and Ancillary Services over Mitigated Price Limit Subject to Refund**

| | May 30-31 | Jun 21-30 | Jul | Aug | Sep | Oct |
|---|---|---|---|---|---|---|
| Energy | $1,300,296 | $250,750 | $182,489 | $952 | $0 | $0 |
| Ancillary Services | $297,140 | $1,339,430 | $16,641 | $0 | $0 | $0 |
| **Total** | $1,597,435 | $1,590,180 | $199,129 | $952 | $0 | $0 |
| Number of Sellers | 11 | 14 | 13 | 1 | 0 | 0 |
| Status | Under Review | Refund Ordered | Refund Ordered | Under Review | Not Availa ble | Not availa ble |

Pursuant to the Commission's Order of June 19, no price mitigation was in effect from June 1-20, since price mitigation under the April 26 Order in effect during this period only applied during reserve deficiency hours (Stage 1, 2 or 3 Alerts).

The Commission has not issued a ruling on any sales during hours of reserve deficiency on May 30-31, when the proxy price mitigation of the April 26 Order was in effect. The July 25 Order provides a formula for determining refunds for the period of October 2, 2000, to June 20, 2001. However, language in the July 25 Order excludes from its purview the reserve deficiency hours of May 30-31, and notes that prices during those hours had already been mitigated under the April 26 Order.