Memorandum

To: ISO Board of Governors

From: Anjali Sheffrin, Ph.D., Director of Market Analysis

cc: ISO Officers, ISO Board Assistants

Date: November 15, 2002

Re: Market Analysis Report for October, 2002

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

Executive summary

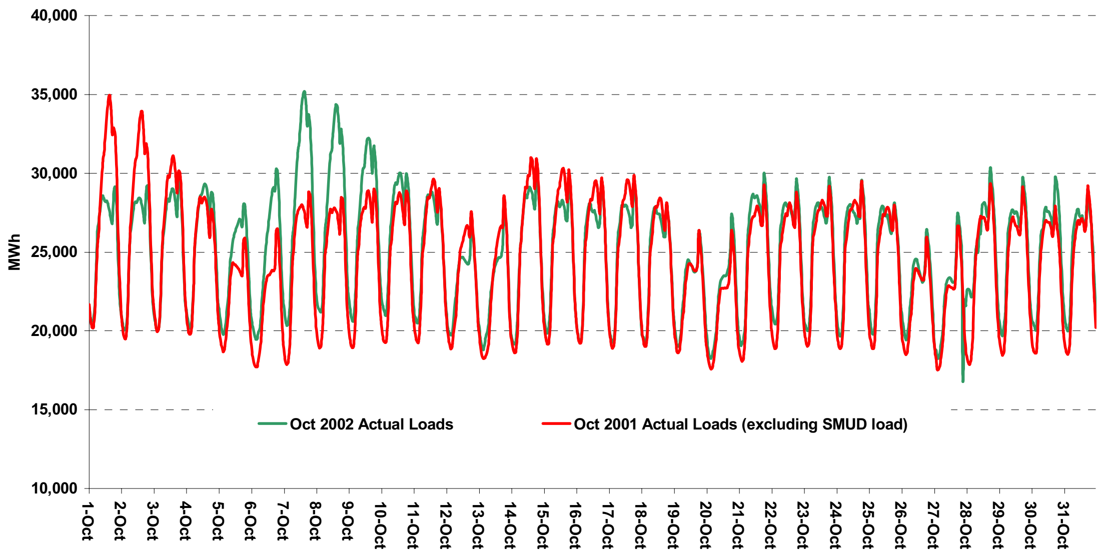
Average wholesale electricity costs to serve load rose in October to $47 per megawatt-hour (MWh), as utilities served a larger portion of load from high-cost long-term energy contracts entered into in 2001. Total forward-scheduled energy was 1.0 percent below actual load on average in October, compared with 3.0 percent in September, reflecting utilities' increased forward purchases. Consequently, the average volume of real-time incremental (INC) energy decreased 60.9 percent to 147 megawatts (MW) in October. The average price of real-time INC energy was $59.62/MWh in October, reflecting a 3.3 percent increase since September. In off-peak hours, forward schedules often exceeded actual load, but average overall real-time decremental (DEC) energy volume still declined 21.1 percent to 265 MW in October.

On October 30, 2002, Phase 1a of the ISO's 2002 Market Redesign (MD02) went into effect. This included an increase in the price cap to $250/MWh and the implementation of Automated Mitigation Procedures. Please see Section II for an overview of the new market features included in Phase 1a.

I. Market Trends through October 2002

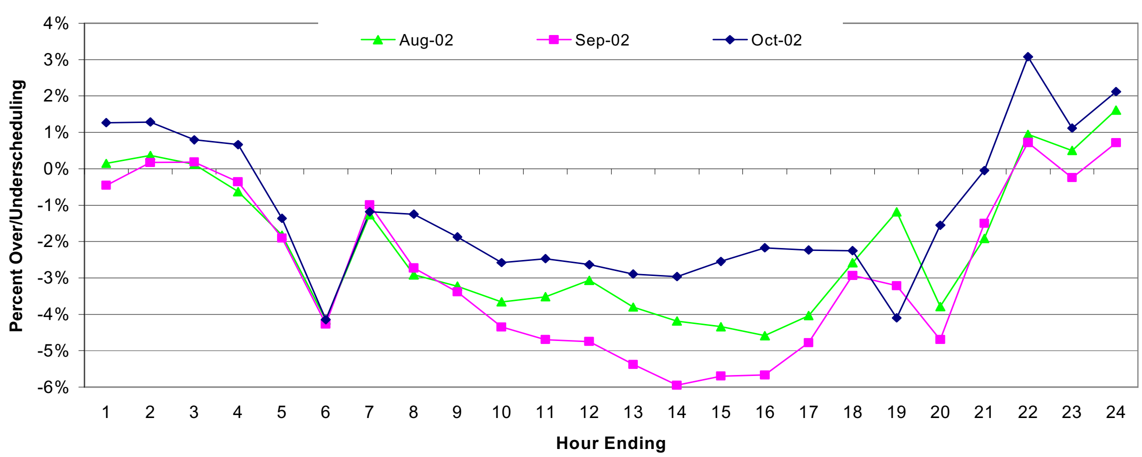
Loads were moderate in October, averaging 25,104 MW. The increase in average load in October 2002 over the same month in 2001 was 2.0 percent, the lowest same-month increase seen since May. The monthly peak in October 2002 of 35,168 MW was 4.2 percent lower than that in October 2001. This was the largest same-month drop in at least a year, bucking the trend of increases seen in recent months, and can be attributed to high peak load a year ago due to unseasonably hot weather on October 1, 2001. The following chart compares loads in October 2001 and 2002.

Figure 1. Actual ISO Loads in October 2001 and 2002[1]



For the previous few months through September, the Department of Market Analysis (DMA) had observed an increasing deficit between the volumes of scheduled delivery of electricity and actual load. Underscheduling during peak hours has abated considerably in October, as loads decreased due to milder weather, and utilities have been able to serve the bulk of their loads with long-term forward contracts. However, this effect was somewhat offset by the increase in overscheduling during off-peak hours. The following chart shows average scheduling deviations by hour of day for August through October.

Figure 2. Scheduling Deviations by Hour of Day for August through October 2002



[1] In order to compare similar days of the week, this chart shows loads for October 1 (Tuesday) through 31 (Thursday), 2002, and loads for October 2 (Tuesday) through November 1 (Thursday), 2001. The peak hour load of 36, 700 MW in October 2001 occurred on Monday, October 1, and thus is not shown on this chart. All loads have been adjusted to reflect Sacramento Municipal Utility District's departure from the ISO control area.

II. MD02 Phase 1a Implementation

The ISO implemented several rule changes mandated by the Federal Energy Regulatory Commission (FERC) on October 30, 2002, commonly referred to as Phase 1a of the 2002 Market Redesign program (MD02). These include:

Soft bid caps on incremental and decremental energy of $250 and -$30/MWh, respectively. Bids outside these caps are allowed and can be dispatched and paid on an "As-bid" basis. "As-bid" procurement, an element of market mitigation first introduced in Orders of the Federal Energy Regulatory Commission of April 26, 2001, and June 19, 2001, refers to real-time energy that was bid above the soft price ceiling (for INCs), or below the soft price floor (for DECs), and is dispatched. An incremental bid above the price ceiling is paid as bid; that is, the seller is paid the price at which she bid, but the bid has no effect on the market-clearing price (MCP) at which all other bids are paid. Similarly, a decremental bid below the price floor is paid as bid, but also has no effect on the MCP. In either case, market participants must justify their costs to FERC or else must refund the difference between the as-bid price and the market-clearing price in the same pricing interval. The increase in the soft price cap for incremental energy increased from $91.87/MWh to $250/MWh on October 30. The new price floor of -$30/MWh on decremental energy may result in as-bid decremental procurement.

Automatic Mitigation Procedures (AMP). Generators within the ISO Control Area who bid at prices well above competitive levels, as determined by several screening tests determined by an independent entity as mandated by FERC , now face automatic mitigation in some situations. The mitigation procedures are based upon *Reference Curves,* [2] which represent relationships between output volume and historical bids for each individual generating unit. A bid will be subject to mitigation if:

- The predicted market clearing price in any zone is at least $91.87/MWh;
- It is higher than the unit's reference price for its level of output at the time of mitigation by at least $100/MWh or 200 percent, whichever is less (the "conduct" test);
- It would have a material impact on the market-clearing price by raising it at least $50 or 200 percent, whichever is less (the "impact" test).

The mitigation will roll the bid back to its reference price and reinsert it into the bid stack. The ISO BEEP algorithm would then recalculate all dispatches in the new merit order. The resulting MCP would be lower when mitigation is triggered. More information on AMP is available in an ISO white paper at http://www.caiso.com/docs/2002/09/13/2002091317303413280.pdf.

Single energy bid curve. Market participants are limited to submitting, for each generating unit, a single energy bid curve to the ISO ancillary services and supplemental energy markets and are subject to rules on any subsequent adjustments to their submitted bid curves, consistent with practices in other ISO's. Previously, participants were permitted to change the offering prices of their energy between the day-ahead and hour-ahead ancillary services markets, and could submit different curves entirely for supplemental energy. The previous rules allowing suppliers to raise

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[2] The constructed bid is specifically calculated as the price for a corresponding level of output on a bid curve based upon a three month weighted rolling average of bids dispatched from the same generating unit.

energy prices after an initial award of ancillary services would have permitted them to command high prices from the underlying energy, should it be needed in real time. In a later phase of MD02, the ISO will jointly optimize DA or HA energy purchases with ancillary services purchases.

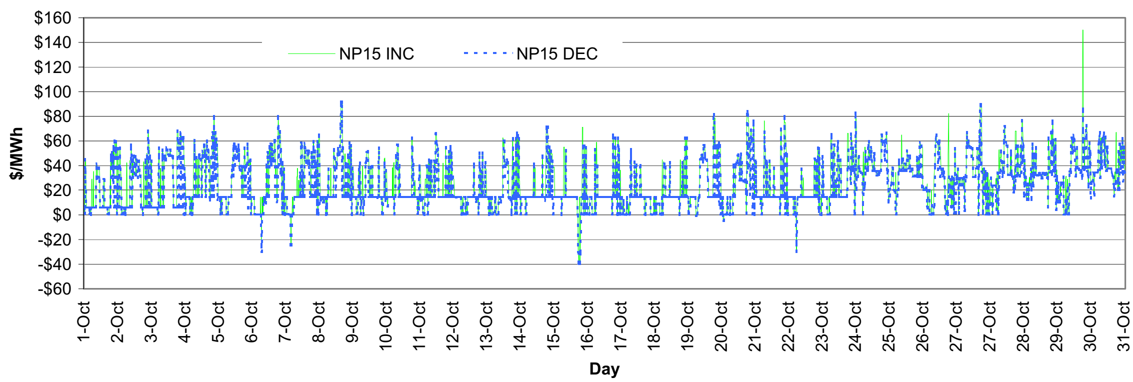
MCP setting eligibility. Hydroelectric resources are now able to set the MCP, but will be subject to AMP. However, imports must still offer electricity at a price of $0/MWh and thus are not eligible to set the MCP.

Credit Risk Adder. Since June 19, 2001, sellers of energy in the BEEP Stack have been entitled to a 10 percent adder to cover credit risk; this will be discontinued going forward.

III. Real-Time Market

The ISO's real-time market volumes decreased substantially between September and October, as the aforementioned improvements in scheduling deviations decreased load-serving entities' reliance on real-time procurement. Real-time INC and DEC volumes averaged 147 and 265 MW in October, respectively, compared with 376 and 336 MW in September. Average real-time prices stayed relatively constant between September and October. The real-time INC price, which the ISO pays to generators to increase output whenever scheduled energy is not sufficient to meet load, averaged $59.62/MWh in October, compared with $57.69/MWh in September. The DEC price, which suppliers pay to the ISO for the privilege of decreasing output when scheduled energy exceeds actual load, averaged $10.08/MWh in October, compared with $10.65/MWh in September. The following chart shows BEEP interval prices for NP15 in October.

Figure 3. BEEP and OOM Prices for NP15 in October[3]



OOM Procurement. The ISO made out-of-market (OOM) calls in 19 hours in October. These occurred during the morning ramp on October 6, in hours ending 10:00 through 18:00 on October 7, in hours ending 11:00 through 17:00 on October 8, and in peak afternoon hours on October 15 and 16. The procurements on October 7 and 8 were due in part to a failure of the Pacific DC Intertie (NOB), and in part to efforts to manage dispatch problems. On October 15, hour ending (HE) 19:00, the ISO had to pay $36.14/MWh to decrement 94 MWh in an effort to manage a derate

[3] SP15 prices were equal to NP15 prices in nearly all intervals in October.

of Path 26. The following day, also in HE 19:00, the ISO was paid $18.82/MWh to decrement 9 MWh of energy.

As-Bid Procurement. There was no as-bid procurement from the BEEP Stack in October. Please see the section above on MD02 Phase 1a implementation for details on the price cap changes and resultant implications for as-bid procurement.

Automatic Mitigation Procedure (AMP). The Automatic Mitigation Procedure (AMP) went into effect with the MD02 Phase 1a mitigation regime on October 30, 2002. AMP is an automatic routine that compares actual bids with their reference prices. If the bid prices are significantly higher than their reference levels and cause a significant market impact, these bid prices would be mitigated to their reference levels. Please see the section above on Phase 1a for further details.

The automatic mitigation conduct test threshold was exceeded by at least one supplier in approximately 4 percent of hours during the first week of its implementation. However, none of the bids that violated the conduct tests caused significant market consequences or significant increases in the BEEP MCP. Therefore no mitigation was activated. The following table summarizes the activity of AMP in its first seven days of implementation.

Table 1. Frequencies of Failures of AMP Conduct and Impact Tests

Day	Percentage of hours Conduct test was violated	Percentage of hours Market Impact test was violated
10/30/2002	8%	0%
10/31/2002	0%	0%
11/1/2002	4%	0%
11/2/2002	4%	0%
11/3/2002	4%	0%
11/4/2002	4%	0%
11/5/2002	0%	0%

Since September 2001, the ISO has reported separate INC and DEC prices for the real-time markets. The following tables show (1) average prices and total volumes for real-time energy procured through the BEEP Stack. Also shown are (2) average OOM prices and volumes. The combination of (1) and (2) comprise (3) average real-time prices and total volumes of all real-time balancing energy. The final column (4) shows average system loads and percent underscheduling.

Table 2. ISO Real-Time Prices and Volumes for October 2002

	Avg. BEEP 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
	Inc	Dec	Inc	Dec	Inc	Dec	
Peak	$ 58.35	$ 11.40	$ 82.19	$ (30.82)	$ 60.18	$ 11.30	27,117 MW
	85 GWh	123 GWh	7 GWh	*	92 GWh	123 GWh	1.0%
Off-Peak	$ 56.72	$ 8.08	No Procurement	No Procurement	$ 56.72	$ 8.08	21,079 MW
	18 GWh	75 GWh	*	*	18 GWh	75 GWh	-0.2%
All Hours	$ 58.07	$ 10.14	$ 82.19	$ (30.82)	$ 59.62	$ 10.08	25,104 MW
	102 GWh	197 GWh	7 GWh	*	109 GWh	197 GWh	1.0%

* Indicates Volumes below 1 GWh.
Excludes out-of-sequence and reliability-must-run procurement.

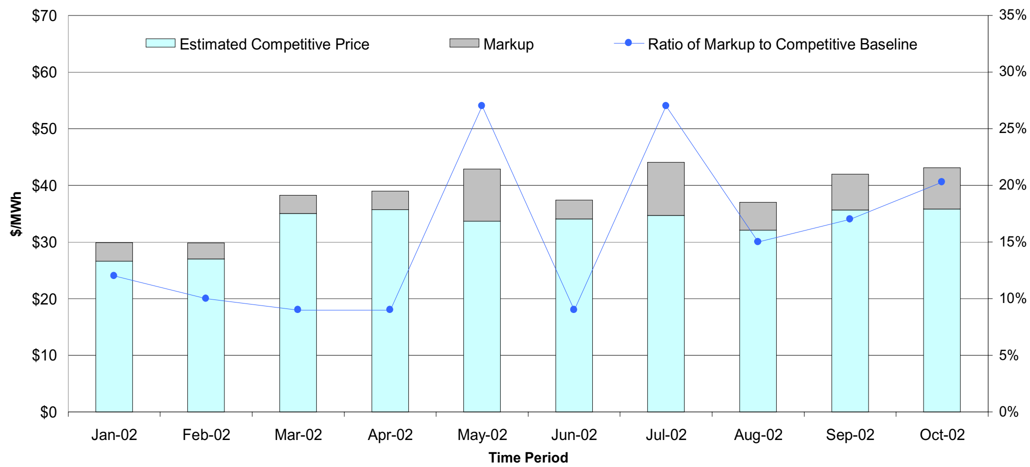
Price Cap Hits. The soft price cap of $91.87/MWh was in effect through October 29, after which the new mitigation regime went into effect. From October 1 through 29, the ten-minute interval market-clearing price (MCP) in the ISO's Balancing Energy Ex-Post Price auction market (the BEEP Stack) came within $1 of the price cap in 7 of 1641 intervals (less than 0.1 percent) in NP15, and in 27 of 1,637 intervals (1.7 percent) in SP15. The MCP did not come within $1 of either of the new caps on October 30 or 31.

Market Power. Market power is often measured by comparing the price paid for energy to an estimate of the price that would exist under competitive conditions. The Department of Market Analysis (DMA) tracks several such indices, all of which are calculated as the ratio of the markup included in the average price paid for wholesale electricity to an estimate of the price that would exist in a competitive market. A perfectly competitive market would be indicated by the index equal to zero (no markup).

One such index is the price-to-cost markup for short-term energy, which includes costs in the ISO's real-time balancing energy market, and day-ahead and hour-ahead bilateral procurement by the Department of Water Resources' California Energy Resources Scheduling Division (CERS), to cover utilities' net-short loads. A detailed description of this index is provided in the September Report, released October 17, 2002. The following chart uses CERS actual figures for July and August 2002, and estimates of CERS purchases for September and October 2002.[4]

[4] The September Report, released October 17, showed markups using CERS actual bilateral purchases through June 2002, and preliminary estimates for July through September. In the present Report, July and August estimates have been replaced with actual data. However, this Report includes preliminary estimates for September and October.

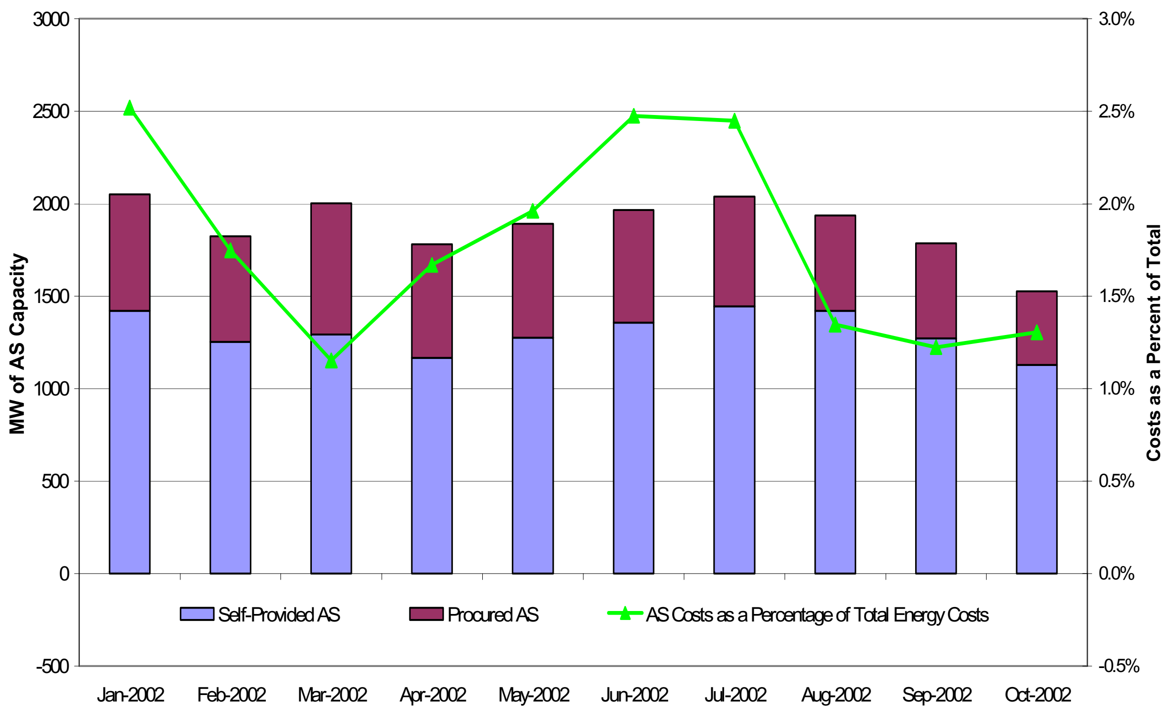
Figure 4. Monthly Average Price-to-Cost Markup in Short-Term Energy through October 29



IV. Ancillary Services Markets

The proportion of ancillary services (AS) that scheduling coordinators self-provided increased slightly to 73.9 percent in October, compared with 71.2 percent in September. Self-provision has been increasing as utilities conserve their hydroelectric resources during the shoulder season, during which they can provide ancillary services. The following chart shows monthly average self-provision and cost as a percentage of total energy costs through October.

Figure 5. AS Self-Provision and Cost as a Percentage of Total Energy Costs



Prices for upward and downward regulation services in the day-ahead market were $14.51 and $14.64/MWh in October, respectively, up $2.18 and $2.64/MWh since September. The price for Spinning Reserves averaged $3.08/MWh, down $0.92/MWh since September. Non-spinning reserves averaged $1.57/MWh in October, up $0.17/MWh since September. Replacement reserves averaged $1.15/MWh in September, down $0.03/MWh since September; however, replacement volumes have been very small. The following chart shows AS price and volume statistics by market for October.

Table 3. AS Prices and Volumes by Market in October

	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	$ 14.51	$ 13.96	$ 14.46	334	33	90%
Regulation Down	$ 14.64	$ 11.96	$ 14.39	353	36	90%
Spin	$ 3.08	$ 2.53	$ 3.06	686	26	96%
Non-Spin	$ 1.57	$ 1.81	$ 1.57	689	17	97%
Replacement	$ 1.15	$ 1.37	$ 1.15	23	*	97%

* Indicates average volume below 1 MW.

V. Congestion Markets

Interzonal Congestion Costs totaled approximately $1.7 million in October, compared with $1.3 million in September. Most costs were incurred in the day ahead, during short periods of high prices on a few key paths, and were due primarily to scheduled maintenance.

Approximately $995,000 was incurred on Eldorado, which was derated during most peak hours on October 4, 19, and 20, all for repairs to component transmission lines. October 4 accounted for over $500,000 of the costs incurred on Eldorado, with usage charges approximately $100/MWh or more; prices on October 19 and 20 were $50/MWh. Approximately $216,000 was incurred in hours ending 06:00 and 10:00 on October 29 on Palo Verde, which also was derated for repairs. Usage charges were $144/MWh and $80/MWh, respectively. Finally, approximately $173,000 was incurred in the day ahead on October 29-30 on the California-Oregon Intertie (COI), derated due to system constraints related to a unit outage in Oregon. Usage charges ranged between $5 and $5.55/MWh. Sylmar (AC) was curtailed for 7 hours on October 1, with charges ranging from $29.60 to $42.60/MWh, and for 18 hours on October 18, with charges at $50/MWh, due to repairs to that path. Total congestion charges on Sylmar were approximately $70,000.

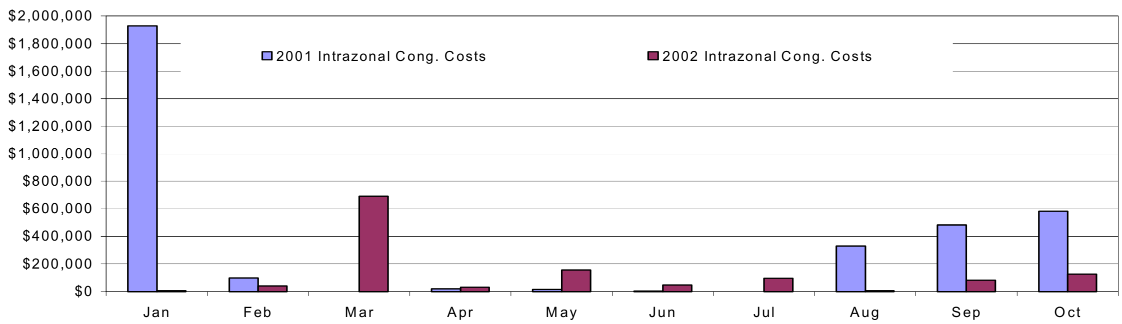
The following table shows day-ahead interzonal congestion statistics and total day-ahead and hour-ahead interzonal congestion costs for October.

Table 4. Day-Ahead Intrazonal Congestion Statistics and Total Congestion Costs for October 2002

Branch Group	Direction of Cong.	Peak Cong. Pctg.	Off-Peak Cong. Pctg.	All-Hours Cong. Pctg.	Avg. Peak Cong. Price	Avg. Off-Peak Cong. Price	Avg. All-Hours Cong. Price	Total Cong. Cost (DA+HA)
BLYTHE	Import	0%	0%	0%				$ 3,572
COI	Import	25%	0%	16%	$ 0.66		$ 0.66	173,420
ELDORADO	Import	6%	0.40%	4%	$ 62.10	$148.00	$ 65.01	995,408
MEAD	Import	0%	0%	0%				60,718
NOB	Import	4%	0%	2%	$ 0.21		$ 0.21	50,744
PALOVRDE	Import	2%	0%	1%	$ 8.21	$144.84	$ 16.77	269,601
PARKER	Import	0%	0%	0%				3,901
PATH15	South -North	0%	17%	6%	$ -	$ -	$ -	4,411
PATH26	South -North	0%	0%	0%	$ 8.00		$ 8.00	78,397
SYLMAR-AC	Import	4%	1%	3%	$ 46.18	$ 50.00	$ 46.48	69,767

Intrazonal (Within-Zone) Congestion Costs totaled approximately $130,000 in October. Ninety-seven percent of the costs were paid for decremental bids dispatched out of economic merit order. The following chart compares total intrazonal costs through October 2001 and 2002.

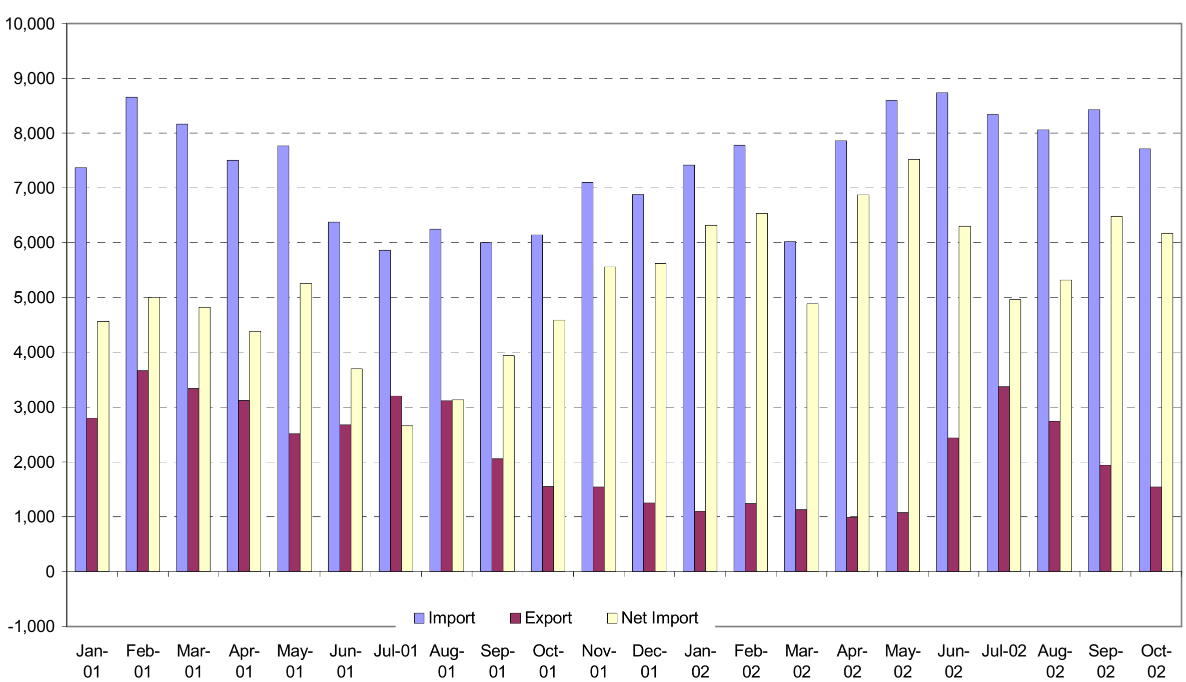
Figure 6. Intrazonal Congestion Costs for 2001 and 2002



VI. Imports and Exports

The average volume of net imports was 6,170 MW in October, down approximately 4.8 percent from September. Imports decreased 8.4 percent between September and October, while exports, primarily to the Southwest, have decreased substantially since that region's peak demand period during the summer. Average exports in October were 1546 MW, down 20.5 percent since September, and down 54.2 percent since the peak month of July. The following chart shows the ISO's monthly average gross imports, exports, and net imports through October.

Figure 7. Monthly Average Imports and Exports through October



VII. Summary of Market Costs

Total cost to load of energy and ancillary services was $877 million in October, or $47/MWh, compared with $44/MWh in September. The average cost index reached its highest level since September 2001, as a larger portion of energy demand was met with high cost long-term contracts entered into in early 2001. Consequently, the average estimated cost of forward energy increased 6.4 percent. The following table shows costs for wholesale energy and AS for 2002 to date, including actuals from CERS through June, and estimates of bilateral purchases at day-ahead hub prices. CERS costs through August are actuals. CERS costs for September and October are estimates; actuals for these months are expected to be available in the report covering November and December, to be released in January.

Table 5. Market Cost Summary for 2002

	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$)	Avg Price of RT INC Energy ($/MWh)	Avg Cost of Energy ($/MWh)	A/S Cost ($/MWh Load)	A/S % of Energy Cost	Avg. Cost of Energy & A/S ($/MWh Load)
Jan-02	19,356	18,940	$ 737	$ 7	$ 19	$ 744	$ 763	$ 45	$ 38	$ 0.97	2.5%	$ 39
Feb-02	17,153	16,654	$ 663	$ 7	$ 12	$ 670	$ 682	$ 45	$ 39	$ 0.68	1.7%	$ 40
Mar-02	18,749	18,282	$ 811	$ 6	$ 9	$ 817	$ 826	$ 52	$ 44	$ 0.50	1.2%	$ 44
Apr-02	18,511	17,937	$ 742	$ 8	$ 13	$ 750	$ 763	$ 53	$ 41	$ 0.68	1.7%	$ 41
May-02	19,690	19,031	$ 774	$ 11	$ 15	$ 786	$ 801	$ 54	$ 40	$ 0.78	2.0%	$ 41
Jun-02	20,232	19,691	$ 786	$ 10	$ 20	$ 796	$ 816	$ 52	$ 39	$ 0.97	2.5%	$ 40
Jul-02	22,079	21,319	$ 931	$ 11	$ 23	$ 942	$ 965	$ 51	$ 43	$ 1.04	2.4%	$ 44
Aug-02	21,588	20,798	$ 914	$ 8	$ 12	$ 922	$ 935	$ 47	$ 43	$ 0.58	1.3%	$ 43
Sep-02	20,498	19,089	$ 885	$ 14	$ 11	$ 899	$ 910	$ 58	$ 44	$ 0.54	1.2%	$ 44
Oct-02	18,677	17,682	$ 858	$ 8	$ 11	$ 866	$ 877	$ 60	$ 46	$ 0.59	1.3%	$ 47
Total 2002	196,534	189,423	$ 8,101	$ 91	$ 145	$8,191	$ 8,337					
Avg 2002	19,653	18,942	$ 810	$ 9	$ 15	$ 819	$ 834	$52	$ 42	$ 0.73	1.8%	$ 42

***** Sum of hour-ahead scheduled quantities

****** Includes UDC (cost of production), estimated CDWR costs, and other bilaterals priced at hub prices

******* includes OOM, dispatched real-time paid MCP, and dispatched real-time paid as-bid

******** Including ISO purchase and self-provided A/S priced at corresponding A/S market price for each hour, less Replacement Reserve refund

September and October forward costs (and resulting totals) are estimated. Values in November-December report will include true-up and may differ from values shown here.

VIII. Firm Transmission Rights Market

Firm Transmission Rights (FTR) Concentration. No secondary FTR market trades or scheduling coordinator reassignments occurred in October. Hence, the FTR ownership concentrations reported in January-February 2002 report for the 2002-2003 FTR cycle remain unchanged.

FTR scheduling. On some paths, FTRs were used to establish the scheduling priority in the day-ahead markets. As shown in the following table, a high percentage of FTRs was scheduled on some path (e.g. 79% on Eldorado, 68% on IID-SCE, 49% on Paloverde, and 96% on Silverpeak in the import direction). FTRs on those paths are mainly owned by Southern California Edison Company (SCE1). FTRs on most of other paths were primarily used for their financial entitlement to transmission usage charges. The following table shows FTR scheduling statistics for October.

Table 6. FTR Scheduling Statistics for October 2002

Branch Group	Direction	MW FTR Auctioned	Avg. MW FTR Sch.	Max MW FTR Sch.	Max Single SC FTR Schedule	% FTR Schedule
COI	Import	658	81	200	150	12%
ELDORADO	Import	793	629	700	700	79%
IID-SCE	Import	600	408	443	443	68%
MEAD	Import	478	95	195	170	20%
NOB	Import	698	22	206	200	3%
PALO VERDE	Import	1167	568	625	431	49%
SILVER PEAK	Import	10	10	10	10	96%
VICTORVILLE	Import	926	14	37	37	2%
PATH 26	North-to-South	1566	349	729	500	22%

* only those paths on which 1% or more of FTRs were attached are listed

FTR Revenue per Megawatt. The following table summarizes FTR revenue per MW through October 2002 in the current FTR cycle. Compared with the summer months, the FTR revenue on COI has decreased significantly in October, to the level of $153/MW. However, the FTR revenue on the Paloverde line in the import direction increased significantly in October and had the highest FTR revenue per MW among the branch groups. There was also some congestion in both directions on Path 26 in September.

Table 7. FTR Revenue Per MW ($/MW)

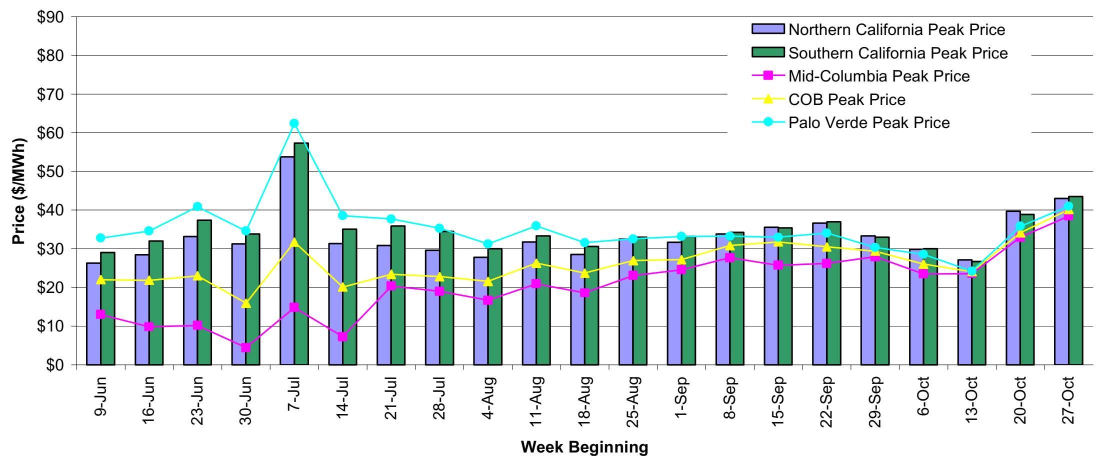
Branch Group		April ($/MW)	May ($/MW)	June ($/MW)	July ($/MW)	Aug ($/MW)	Sep ($/MW)	Oct ($/MW	Cumulative FTR Revenue Up to Sep,2002 ($/MW)	Pro-rate Annual FTR revenue ($/MW)	FTR Auction Price ($/MW)
COI	Import	1088	888	4129	4278	581	562	153	11,680	20,023	17,610
ELDORADO	Import	268	26	2	10	0	37	1,255	1,598	2,739	8,432
MEAD	Import	19	22	0	0	0	0	97	222	381	4,488
NOB	Import	13	0	48	472	14	5	32	585	1,003	5,990
PALO VERDE	Import	23	839	0	0	4	86	226	1,272	2,181	14,868
PATH 26	South-North	0	133	370	0	0	25	28	557	954	3,222
MEAD	Export	0	0	0	262	31	0	0	293	502	7,465
PATH 26	North-South	61	134	125	1703	116	114	23	2,286	3,919	5,907
VICTORVILLE	Export	0	249	724	0	0	0	0	973	1,668	1,118

* Pro-rated Annual FTR revenue is estimated based on the actual FTR revenue collected in this FTR cycle and assuming that FTRs would collect same rate of revenue in the remaining months of this FTR cycle.

IX. Bilateral Spot Electricity Prices

Through much of October, Northern and Southern California electricity prices were higher than Mid-Columbia, California-Oregon Border (COB) and Palo Verde prices. Unusually warm weather in California and the Southwest, in addition to a month-long scheduled outage of Palo Verde #1 (1,270 MW) resulted in prices in excess of $4/MWh above those at the COB and Mid-Columbia delivery points during the second week of October. As temperatures rose in California and the Southwest in the third week of October, they dropped throughout the Northwest, putting upward pressure on demand. Northwestern hub prices eventually converged with those in California, as the Northwest region's loads have increased with the beginning of its winter peaking season and seasonal decreases in hydroelectric production. Prices were sharply higher during the fourth week of October, due to higher natural gas prices and scheduled outages of the Pacific DC Intertie and Diablo Canyon 2 (1,100 MW), each lasting several weeks. Prices continued to increase toward the end of the month, due to the upward trend in natural gas prices, cooler weather, and transmission constraints in southern California. The following chart shows weekly average day ahead bilateral electricity prices for trades through the end of October.

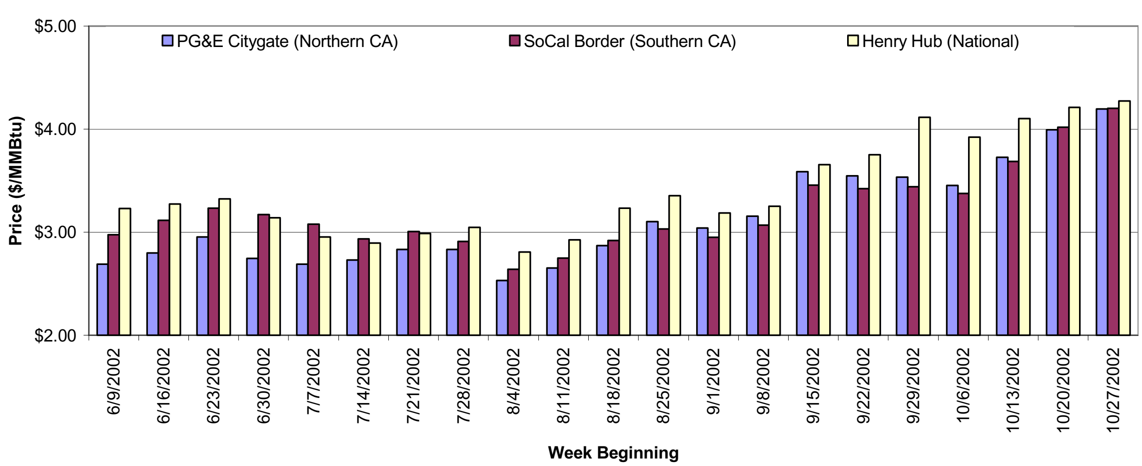
Figure 8. Weekly Average Bilateral Spot Electricity Prices through October



X. Natural Gas Markets

As natural gas production resumed at production facilities in the Gulf of Mexico, following outages due to tropical storms in September, prices declined sharply through much of the nation. Nonetheless, during the first two weeks of October there was a $0.40 to $0.70/MMBtu spread between Henry Hub prices and western prices due to both the drop in production in the East and to weaker electricity demand driven by milder weather in the West. By the second week of October, Henry Hub prices were within the $3.75 to $4.00/MMBtu range, and California prices were between $3.15 and $3.60/MMBtu. Colder weather throughout much of the country, particularly in the Northwest and Northeast, drove natural gas prices higher and caused price convergence between the Western and Henry Hub prices. By the end of October, Henry Hub and California prices had converged, in the range of $4.20 to $4.35/MMBtu. Average bid week prices for November were $4.10, $4.08, and $4.09 for SoCal Gas, Malin, and PG&E Citygate, respectively, up 24%, 23%, and 22% from October bid week prices. The following chart shows weekly average gas prices through the end of October.

Figure 9. Weekly Average Gas Prices through October



XI. Issues under Review

Review of Bidding Behavior. The ISO is reviewing bidding behavior prior to the implementation of the AMP procedure, to ensure that the reference prices used in this procedure accurately reflect historical reference prices under competitive conditions, and do not embody upward influence going forward. While the AMP procedure was implemented on October 30, its implementation and an understanding of the calculation and use of the reference price have been anticipated for some time.

CPUC withholding report. The ISO continues to review and analyze the findings of the CPUC report released in September 2002. The CPUC report analyzed bidding, dispatch, and outage data for the 38 days where non-firm and firm load was curtailed in the ISO control area in the Winter and Spring of 2000-2001. The CPUC report concluded that significant physical withholding occurred over these days and that the majority of hours where load was curtailed occurred unnecessarily.

Bid Sufficiency in the Interzonal Congestion Market. When congestion exists on a transmission path, the right to use the path is auctioned in the ISO's congestion markets. Those who submitted the highest bids are given the right of way, and are charged the price equal to the lowest winning adjustment bid. DMA conducted an informal investigation to determine the sufficiency of adjustment bids submitted by importers, and found that many transmission users are submitting adjustment bids.

A/S Procurement Study. DMA is looking into whether there has been any significant changes in the procurement of Ancillary Services during the summer of 2002. Recently some scheduling coordinators have requested that DMA review the ISO's procurement of AS this past summer, compared to that in previous summers. DMA is reviewing the many factors that may have contributed to changes in the ISO's total procurement of AS and will issue a report in the future.