California Independent
System Operator

CALIFORNIA ISO

Memorandum

To: ISO Board of Governors

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

cc: ISO Officers, ISO Board Assistant

Date: October 17, 2003

Re: **Market Analysis Report for September, 2003**

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

Executive Summary

September average loads were 2.2% higher than a year ago due to warm weather throughout the month, particularly in the first week. The peak load for the month was 41,394 MW on September 5, 2003. Prices in the real-time balancing market averaged $67.54 for incremental energy and $21.16 per megawatt-hour (MWh) for decremental energy, which were similar to those seen throughout the summer.

For most of the month, scheduled energy was slightly in excess of actual load, with sufficient forward contracting of bulk power. The real-time balancing market remained predominately decremental as decremental instructed volume in real-time exceeded incremental volume by a ratio of 4-to-1.

In the ancillary service markets, prices declined on average since August. However, the operating reserve price spikes observed occasionally in July and August during periods of extreme load continued to occur in September.

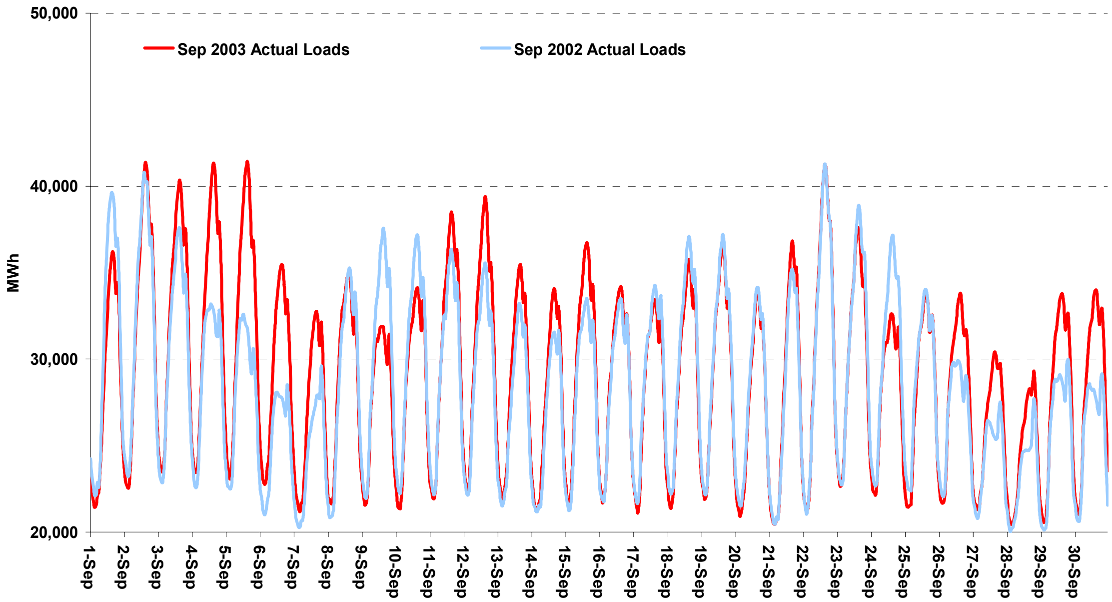
Interzonal congestion costs totaled approximately $1.8 million in September; down from $2.4 million in August as summer loads began to subside. Nearly 40 percent of the costs were incurred on the Palo Verde branch group due to significant imports from the Southwest. Additionally, COI, Path 15 and Path 26 continue to incur frequently day-ahead congestion, however the congestion costs have been minimal due to low congestion prices derived from adequate adjustment bids on those branch groups.

Similar to August, there was a substantial amount of incremental and decremental out-of-sequence (OOS) dispatches in September to address congestion within zones, caused primarily by the ongoing derate of the Vincent substation and new generation in northern Mexico. September OOS dispatches resulted in a net cost (redispatch premium) of approximately $6.1 million.

I. Electricity Market Trends

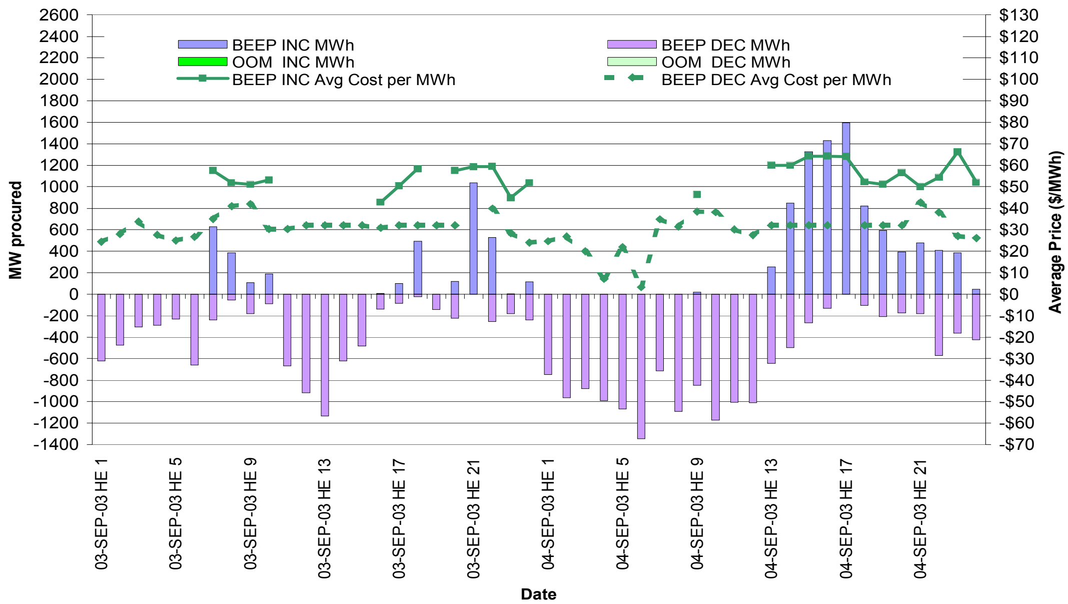
Hot weather in the first week of the month caused loads to average 29,095 MW in September 2003, exceeding averages for both September and August 2002, but below the August 2003 average of 30,600 MW. The September 2003 peak load of 41,394 MW on September 5, HE 15:00, exceeded those of both September and August 2002, but again was below the August 2003 peak of 42,506 MW. The following charts show loads for September 2003 compared to those in September 2002.

Figure 1. September 2003 v. 2002 Actual Loads



As in recent months, there was adequate forward scheduling of resources. The exception was during the first week of September when an unexpected heat wave caused loads to be higher than forecast, resulting in load-serving entities leaning on the real-time market to meet actual load through incremental energy purchases. The following chart shows real-time instructed volumes and hourly average prices for September 2 and 3.

Figure 2. Real-Time Instructed Volumes and Hourly Prices, Sept. 2-3, 2003



II. Real-Time Market

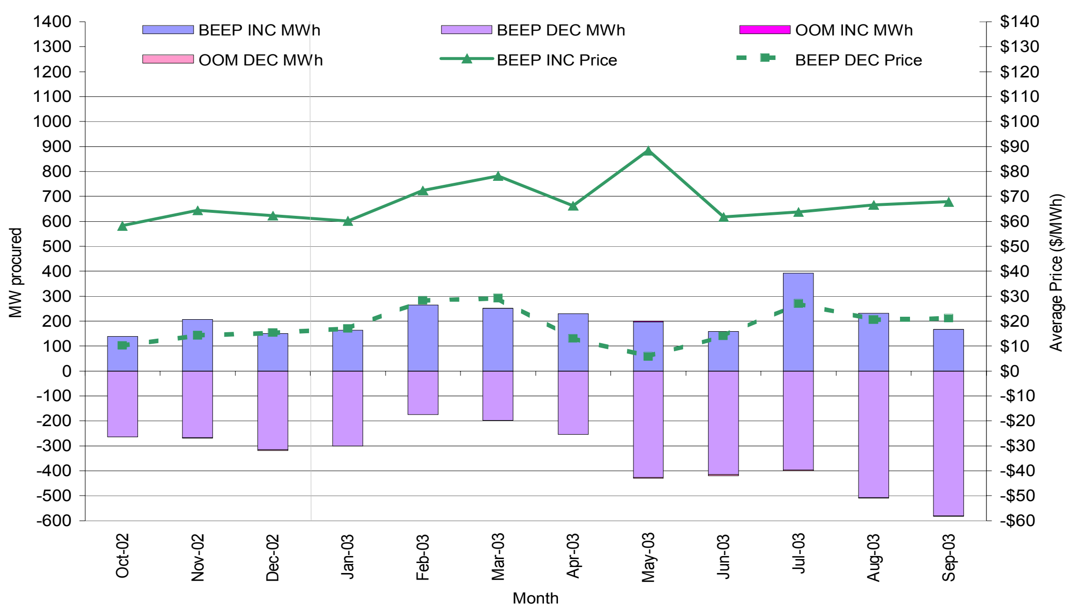
Market Prices and Volumes. The real-time market was stable in September. As in previous months, forward schedules on average have been slightly higher than actual load causing most activity in the market to be in the decremental direction, by nearly a 4-to-1 margin over incremental activity. Price spikes in both incremental and decremental directions had a cumulative market impact of approximately $500,000, compared to $800,000 for a single large incremental spike in August.

Market Prices and Volumes. The real-time incremental (INC) price averaged $67.54/MWh in September, little changed from $66.58/MWh in August. A total of 120 gigawatt-hours (GWh) of INC were dispatched in September, compared to 172 GWh in August. The decremental (DEC) price averaged $21.16/MWh in September, up slightly from the August level of $20.46/MWh. DEC instructed energy totaled 378 GWh in September, compared to 411 GWh in August. The table below shows monthly average prices and total instructed energy in September. The chart that follows shows average prices and volumes for the twelve months through September.

Table 1. Real-Time Average Prices and Total Volumes in September 2003

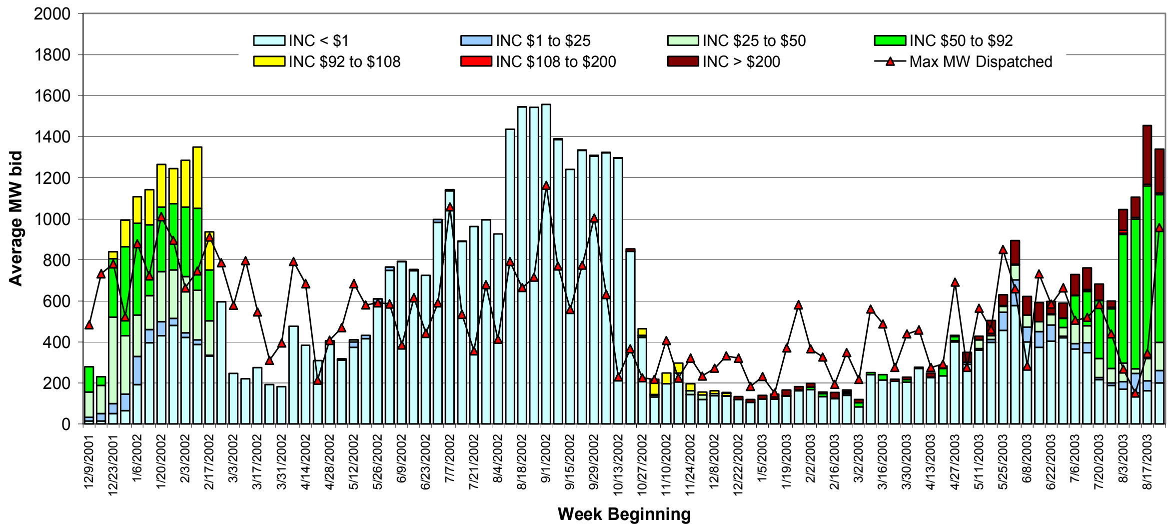
	Overall Avg. Real-Time Price and Total Volume		Avg. System Loads (MW) and Pct. Underscheduling
	Inc	Dec	
Peak	$ 70.78	$ 23.58	32,010 MW
	97 GWh	294 GWh	0.1%
Off-Peak	$ 54.21	$ 15.07	23,263 MW
	24 GWh	117 GWh	-1.3%
All Hours	$ 67.54	$ 21.16	29,095 MW
	120 GWh	411 GWh	-0.2%

Figure 3. Average Real-Time Prices and Volumes through September 2003



Import Bids into Real-time Market. Import bid volume in the real-time market has continued to increase since FERC repealed the requirement that suppliers outside of the ISO control area bid incremental energy into the ISO's real-time market at a price of $0/MWh (zero bid requirement) on June 25, 2003. In September, import bid volume averaged approximately 1,700 MW, compared to approximately 600 MW before FERC's repeal of the zero bid requirement. A brief overview of events leading to the repeal of the zero bid requirement is included in the July/August Market Analysis Report, dated September 19, 2003. The following chart shows weekly average real-time import bid volume by price bin since January 2002.

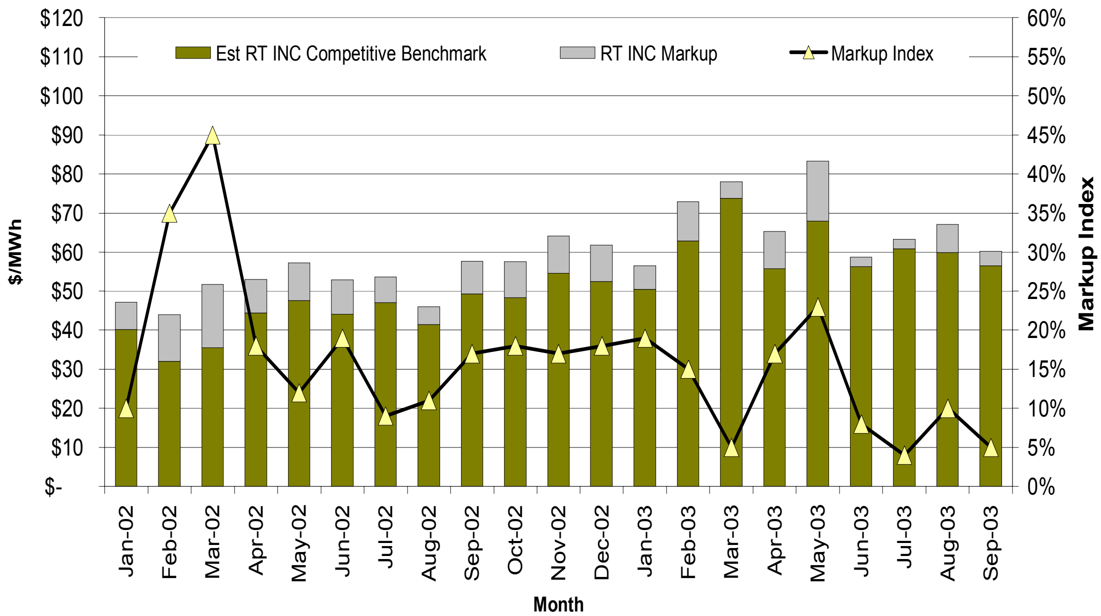
Figure 4. Weekly Average Real-Time Import Bid Volumes through September



Market Competitiveness. The California ISO real-time market continued to perform well in September as it has throughout the summer. Actual market trends were near competitive baselines with an average price-to-cost markup in real-time measured at less than 5 percent. The price-to-cost markup is calculated as the difference between the actual prices paid in the market for wholesale electricity and a competitive baseline price. The Department of Market Analysis is currently using a temporary index focused solely on the real-time market until day ahead energy cost information can be obtained from the California investor-owned utilities. This real-time mark-up index is a conservative estimate of market power because it only includes units that were dispatched by the ISO, as discussed at some length in the Market Analysis Report dated September 19, 2003. It does not include the impact of possible economic and physical withholding.

The following chart shows the real-time markup index by month in 2002 and 2003.

Figure 5. Temporary Real-Time Markup Index through September*



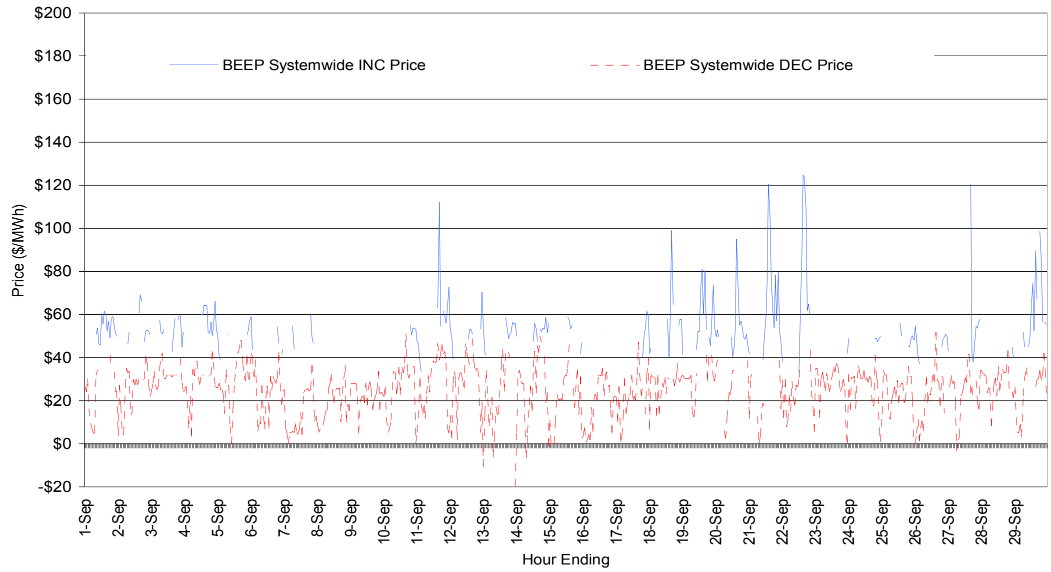
*Index based on resources responding to dispatch instructions. Does not include the impacts of possible physical and economic withholding.

AMP Performance and Review of Price Spikes. One of the main aspects of the current market power mitigation measures is provided under the Automated Mitigation Procedures (AMP) that were put in place on October 30, 2002. AMP is applied whenever the real-time incremental price is predicted to exceed $91.87/MWh by software run prior to the hour of operation. There were incremental price spikes in the month, but in all cases were too short-lived for AMP to have been applied in the hours they occurred. Even if AMP had been applied, in each case the price-setting units bid were within their respective thresholds so as not to trigger price mitigation.[1]

Spikes in the real-time market were minor in September 2003, despite relatively high loads. Those spikes that did occur in September 2003 included several on the DEC side, the first such spikes since April 2003. The following chart shows hourly average incremental and decremental prices in the ISO's real-time Balancing Energy Ex-Post Price auction market (the "BEEP Stack") in September.

[1] A unit will fail the AMP Conduct Test whenever its bid exceeds the minimum of twice its AMP reference level, or $100 above its AMP reference level, *and* the predicted MCP exceeds $91.87/MWh. It still may or may not have an increasing effect on the market-clearing price by a minimum of $50 or 100%, in which case it would fail the Impact Test. A unit will only be mitigated if it fails both the Conduct Test and the Impact Test. This has not yet happened since AMP was implemented on October 30, 2002.

Figure 6. System-wide Hourly Average Incremental and Decremental Prices in September[2]



Several price spikes in the decremental (DEC) direction occurred between Thursday, September 11, and Sunday, September 14. On September 13, the DEC price ranged between -$20 and -$10/MWh within SP15 between midnight at 1:00 a.m., as the ISO mitigated an overload of Path 15 in the south-to-north direction by decrementing generation in SP15 and incrementing generation in NP15. As operators were not able to rely on peaking units subject to minimum run times, units with negative prices (payments required to decrease scheduled generation) were called to mitigate the imbalance of up to 760 MW.

Later on September 13, the DEC price spiked again to -$10/MWh system-wide between 7:00 and 7:40 a.m. as the DEC bid stack was exhausted when operators resolved the imbalance of up to 2000 MW. There was a brief DEC spike again between 11:20 and 11:30 p.m. at -$5/MWh. The market impact of these spikes on September 13 totaled approximately $62,000.

On Sunday, September 14, the DEC price was -$10/MWh between 7:00 and 7:40 a.m., and was -$15/MWh between 11:40 p.m. and 12:00 midnight. The market impact for these spikes totaled approximately $40,000.

On September 21, the Pacific DC Intertie (PDCI, also known as the North-of-Oregon Border Intertie, or NOB) was derated to 0 MW. The resultant imbalance caused the INC price to range between $110 and $120.51/MWh from 2:00 to 3:40 p.m. As the predicted MCP remained below $91.87 for the entire duration of the spike, AMP was not applied during these hours. This spike had a cost impact to the market of approximately $175,000.

On September 22, the INC price spiked between $110 and $130/MWh from 3:10 to 5:40 p.m., due to bid deficiency and unusually high BEEP dispatch volumes, peaking at 2,400 MW between 4:30

[2] In cases that lines are broken, INC or DEC energy was not procured.

and 4:40 p.m. This spike's cost impact was also approximately $175,000. Again, the predicted MCP was below $91.87 during the spike so AMP was not applied.

Out of Market Procurement. There was a single OOM incident on September 22nd when the ISO purchased energy due to a potential inadequacy of real-time supplemental energy bids. The total purchase was approximately 400 MWh spread over the afternoon peak (hours 16 to 18). There were also two minor OOM decremental dispatches early in the month due to overgeneration.

III. Ancillary Services Markets

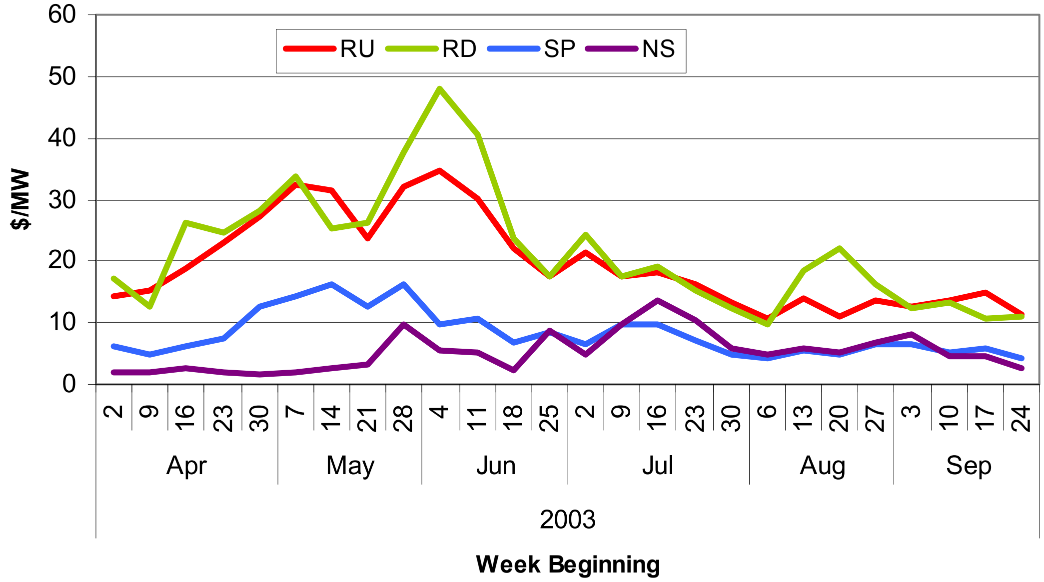
Market prices for ancillary service products in September were similar to those in August although loads were lower. Average prices for regulation up (RU) and non-spinning reserves (NS) were within ten percent of those in August. The average regulation down (RD) price decreased nearly twenty-five percent since August, while the average spinning reserve (SP) price increased more than twenty percent. The following table shows hourly average procurement requirements and volume-weighted average prices in September.

Table 2. Hourly-Average Requirements and Monthly Weighted Average Prices

	Average Required (MW)				Weighted Average Price ($/MW)			
	RU	RD	SP	NS	RU	RD	SP	NS
Aug 03	400	474	914	818	$ 12.32	$ 16.08	$ 4.76	$ 5.29
Sep 03	389	429	896	826	$ 13.02	$ 12.16	$ 5.75	$ 5.22

September saw the lowest monthly average prices for RU, RD, and SP since April due to lower load levels and significant online generation. NS continues to be priced above the prices observed from January through May due primarily to the lack of competitiveness of the operating reserve markets during high load periods. The following chart shows weekly average prices for AS products since April.

Figure 7. Weekly Average AS Prices: April through September 2003



Ancillary Service Price Spikes. Several price spikes occurred in the day-ahead spinning and non-spinning reserve markets in September, particularly during the peak periods on days of high peak load such as September 4, 12, and 20-21. Review of these spikes is currently underway.

Bid Composition. Changes in bid composition were mixed. In regulation up, the middle tier prices ($15-$50/MW) were skewed toward the upper end of that range while low (<$15/MW) and high (>$50/MW) tier volumes were proportionately stable. In regulation down, bid composition generally favored lower prices than in August. In spinning reserves, bid composition favored higher prices than August; the majority of the overall reduction in supply originated in the bids priced below $5/MW. In non-spinning reserves, the reduction in supply came mostly from the middle tier.

IV. Interzonal Congestion Markets

Congestion costs totaled approximately $1.8 million in September, compared to $2.4 million in August. Nearly $0.9 million in costs was incurred on the Palo Verde branch group. Path 26 continues to report significant congestion in the north to south direction, but the congestion cost amounted to only $230,000. Other congestion occurred mostly in the import direction, on COI, Eldorado, Mead, and NOB.

The day-ahead import congestion on Palo Verde occurred September 11 through 15 and September 20 through 24, with the maximum congestion price of $30/MWh occurring on September 22. Except for a few hours on September 10, import capacity was 2,823 MW. Congestion prices were below $15/MWh in most congested hours.

As in July and August, Path 26 continued to experience significant congestion in the north to south direction during peak hours in September. Path 26 was congested in 21 percent of peak hours in the day-ahead market in September; however, congestion prices were lower. The highest congestion prices were reported on September 4 at $8/MWh. In all other congested hours, congestion prices remained below $2/MWh.

In addition, COI, NOB, Eldorado, and Mead also experienced some congestion in September. Most congestion on these paths was associated with path derates due to scheduled maintenance. For instance, COI was derated in the import direction to 2,400 MW for five hours on September 21, causing a congestion price of $4/MWh. Moreover, import capacity on NOB has been derated to 1,148 MW since September 22, significantly lower than its normal import capacity of about 2,000 MW. Finally, a 400 MW derate on Eldorado in the import direction beginning on September 15 caused congestion in a few hours on September 19, and in all off-peak hours on September 24.

Table 3. Interzonal Congestion Frequencies and Prices, September 2003

			DA			HA		
Branch Group	Direction of Cng.	Peak/Off-Peak Hours	No. of Cngs. Hours	Pct of Hours Being Cng.	Avg Cng. Price ($/MWh)	No. of Cngs. Hours	Pct of Hours Being Cng.	Avg Cng. Price ($/MWh)
COI	IMPORT	ON-PEAK	262	55%	0.70	94	21%	11.10
COI	IMPORT	OFF-PEAK				1	0%	0.00
ELDORADO	IMPORT	ON-PEAK				1	0%	0.00
ELDORADO	IMPORT	OFF-PEAK	8	3%	33.46	3	1%	0.00
LUGOTMONA	IMPORT	OFF-PEAK	22	9%	14.73			
LUGOWSTWG	IMPORT	ON-PEAK	16	3%	0.55			
MEAD	IMPORT	ON-PEAK	8	2%	15.00	21	5%	18.87
NOB	IMPORT	ON-PEAK	46	10%	0.57	21	5%	17.47
PALOVRDE	IMPORT	ON-PEAK	88	18%	4.68	49	11%	10.50
PALOVRDE	IMPORT	OFF-PEAK	1	0%	2.00	2	1%	0.01
PATH15	IMPORT	ON-PEAK	10	2%	0.00	3	1%	1.67
PATH15	IMPORT	OFF-PEAK	70	29%	0.00	7	3%	28.98
PATH26	EXPORT	ON-PEAK	103	21%	1.03	34	8%	11.79

Table 4. Interzonal Congestion Costs, September 2003

Branch Group	Day-ahead		Hour-ahead		Total Congestion Cost		Total Congestion Cost		Total Congestion Cost
	Import	Export	Import	Export	Import	Export	Day-ahead	Hour-ahead	
COI _BG	$191,287	$0	$11,642	$0	$202,929	$0	$191,287	$11,642	$202,929
ELDORADO _BG	$259,817	$0	$0	$0	$259,817	$0	$259,817	$0	$259,817
LUGOTMONA_BG	$51,850	$0	$0	$0	$51,850	$0	$51,850	$0	$51,850
LUGOWSTWG_BG	$819	$0	$0	$0	$819	$0	$819	$0	$819
MEAD _BG	$119,008	$0	$11,489	$0	$130,497	$0	$119,008	$11,489	$130,497
NOB _BG	$30,304	$0	$23,781	$0	$54,085	$0	$30,304	$23,781	$54,085
PALOVRDE _BG	$861,211	$0	-$804	$0	$860,407	$0	$861,211	-$804	$860,407
PATH15 _BG	$0	$0	$563	$0	$563	$0	$0	$563	$563
PATH26 _BG	$0	$216,128	$0	$14,189	$0	$230,317	$216,128	$14,189	$230,317
Grand Total	**$1,514,295**	**$216,128**	**$46,671**	**$14,189**	**$1,560,966**	**$230,317**	**$1,730,423**	**$60,860**	**$1,791,283**

V. Firm Transmission Rights Markets

FTR scheduling. On certain paths, FTRs were used to establish the scheduling priority in the day-ahead markets. As shown in the following tables, a high percentage of FTRs was scheduled on some paths (78% on Eldorado, 91% on LUGO-IPP (DC), 94% on Palo Verde, and 100% on Silver Peak, all in the import direction, and 50% on Path 26 in the North-to-South direction). FTRs on those paths are owned primarily by Southern California Edison Company (SCE1) and municipal utilities.

Table 5. FTR Scheduling Statistics for September, 2003*

Direction	Branch Group	MW FTR Auctioned	Avg MW FTR Sch	Max MW FTR Sch	Max Single SC FTR Scheduled	% FTR Schedule - Dir
IMP	BLYTHE _BG	167	5	167	167	3%
IMP	COI _BG	745	314	510	500	42%
IMP	ELDORADO _BG	510	398	510	510	78%
IMP	IID-SCE _BG	600	430	473	453	72%
IMP	LUGOIPPDC_BG**	370	337	366	234	91%
IMP	LUGOTMONA_BG**	167	85	109	77	51%
IMP	LUGOWSTWG_BG**	93	31	46	28	33%
IMP	MEAD _BG	516	10	67	38	2%
IMP	NOB _BG	686	50	211	100	7%
IMP	PALOVRDE _BG	627	592	625	600	94%
IMP	SILVERPK _BG	10	10	10	10	100%
IMP	VICTVL _BG	991	10	25	25	1%
EXP	LUGOMKTPC_BG**	247	3	6	6	1%
EXP	MEAD _BG	464	12	25	25	3%
EXP	NOB _BG	664	17	83	83	3%
N-S	PATH26 _BG	1,425	709	1,344	575	50%

*only those paths on which 1% or more of FTRs were attached are listed.
** The FTRs on these paths were awarded to municipal utilities that converted their lines to ISO operation and thus were not released in the primary auction.

FTR Revenue per Megawatt. The following table summarizes the FTR revenue collected in September. Because an increasing number of congested hours were reported on the interties that connect southern California and the southwest region, increased FTR revenue per MW occurred on Palo Verde, Mead, and the Eldorado branch groups. The FTR revenue on Palo Verde, Mead, and Eldorado was $413/MW, $268/MW and $137/MW respectively in September, higher than that reported in August. FTR revenue on Path26 in the north to south direction, however, decreased from $572/MW in August to $113/MW in September.

Table 6. FTR Revenue Per MW ($/MW), September 2003

Direction	Branch Group	Net $/MW FTR Rev Apr - Imp	Net $/MW FTR Rev May - Imp	Net $/MW FTR Rev Jun - Imp	Net $/MW FTR Rev Jul - Imp	Net $/MW FTR Rev Aug - Imp	Net $/MW FTR Rev Sep - Imp	Cumm Net $/MW FTRREV – Imp	Pro Rated NET $/MW FTRREV – Imp*	FTR Auction Price
IMPORT	BLYTHE	69	0	231	1,422	376	0	2,097	4,195	5,460
IMPORT	COI	723	536	299	138	440	192	2,328	4,657	59,484
IMPORT	ELDORADO	0	0	1	0	0	268	268	537	33,888
IMPORT	LUGOIPPDC**	272	0	0	5,151	8	0	5,431	10,861	N/A
IMPORT	LUGOTMONA**	0	715	7	0	15	310	1,047	2,095	N/A
IMPORT	LUGOWSTWG**	3	0	0	0	0	9	12	24	N/A
IMPORT	MEAD	166	0	14	150	85	137	551	1,102	46,920
IMPORT	NOB	249	203	68	96	118	42	776	1,551	73,470
IMPORT	PALOVRDE	233	15	5	251	355	413	1,273	2,547	88,167
S-N	PATH26	0	0	5	0	0	0	5	9	1,470
IMPORT	SUMMIT	108	0	0	0	0	0	108	217	2,600
EXPORT	IID-SDGE	0	480	0	0	5,651	0	6,131	12,263	364
N-S	PATH15**	0	5	0	0	0	0	5	10	N/A
N-S	PATH26	1,147	1,500	224	780	572	113	4,337	8,674	34,408
EXPORT	SILVERPK	0	0	720	0	0	0	720	1,440	100

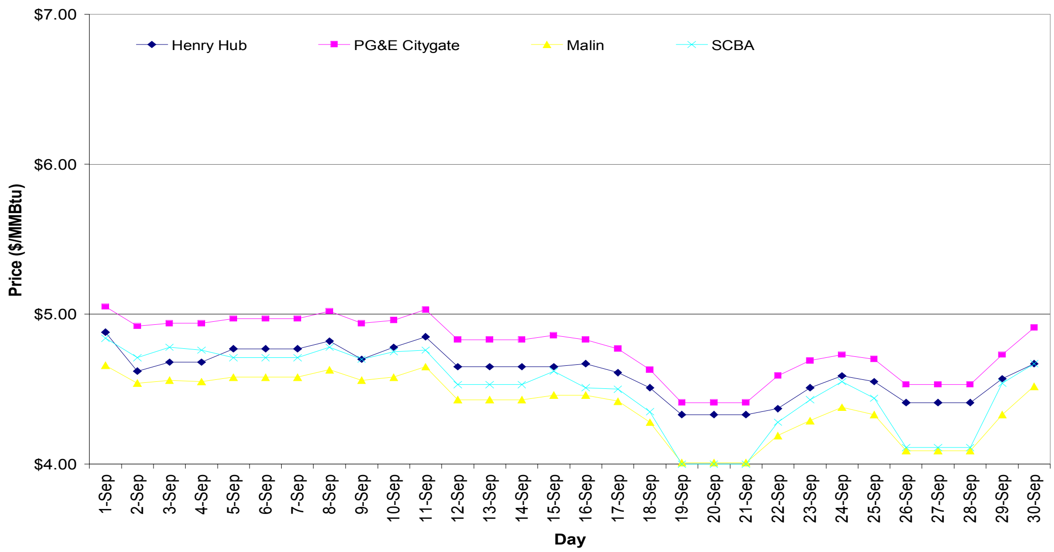
*Prorated Annual FTR revenue is estimated based on the actual FTR revenue collected in this FTR cycle and assumes that FTRs would collect a similar rate of revenue in the remaining months of this FTR cycle.
** FTRs on these paths were awarded to municipal utilities that converted their lines to the ISO, and there were not released in the primary auction.

FTR Concentration. There was no trade in the secondary FTR market in September, therefore the FTR owner concentration table reported in April remains valid.

VI. Natural Gas Spot Markets

Daily prices averaged $4.62/MMBtu at Henry Hub, $4.41/MMBtu at Malin, $4.80/MMBtu at PG&E Citygate, and $4.53/MMBtu at Southern California Border. Average prices during September 2003 were lower than average prices during August. Prices were flat during the first two weeks of September, but steadily declined to monthly lows of $4.00-$4.41/MMBtu on September 19, due to high storage injections and the onset of cooler weather lowering demand from gas fired generation facilities. Prices gradually increased toward the end of the month, up to between $4.49 and $4.88/MMBtu. Average bid week prices for October were $4.37, $4.29, and $4.71 for SoCal Gas, Malin, and PG&E Citygate, respectively, down 10%, 8%, and 7%, from August bid week prices. The following chart shows Western regional daily gas prices for September.

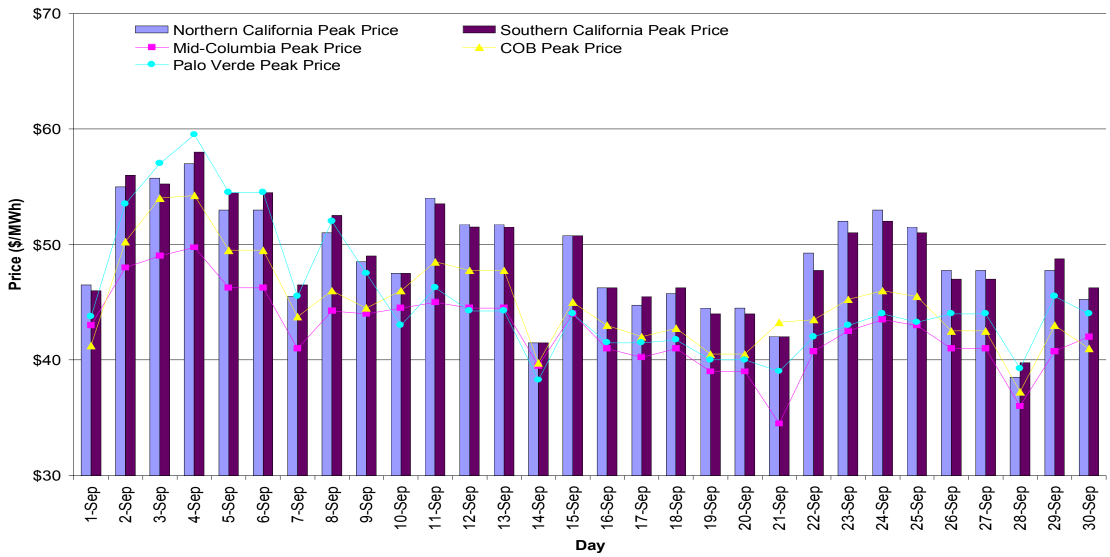
Figure 8. Daily Natural Gas Spot Prices



VII. Bilateral Forward Electricity Trades

Regional bilateral peak period prices (16 hour product) for transactions in the day-ahead averaged $45.47/MWh at the California-Oregon Border, $43.38/MWh at Mid-Columbia, $46.10/MWh at Palo Verde, $49.83/MWh in Northern California, and $49.89/MWh in Southern California on the weekdays in September. Prices were highest during the first week of September, with high temperatures in the West driving cooling demand. During that time, Palo Verde prices reached a monthly high of $59.50/MWh. After the first week, prices at external hubs remained flat at the $45-50/MWh level. California bilateral prices, however, were consistently higher than external hub prices after September 11, owing to high California demand through the remainder of the month. California bilateral prices exceeded $50/MWh for several days after the ISO issued a System Warning notice on 22 September. Prices at the end of the month averaged $42.33/MWh at external hubs and $45.75/MWh in California. The following chart shows day-ahead bilateral electricity prices at Western regional trading hubs in September.

Figure 9. Day-Ahead Bilateral Electricity Prices



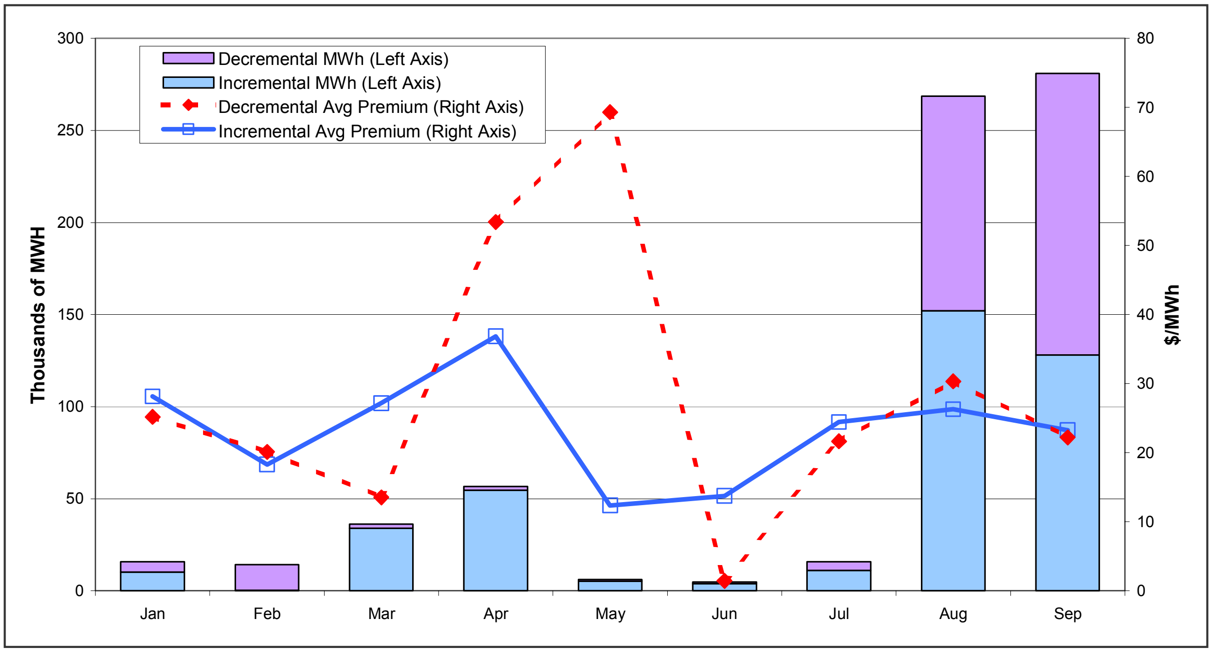
VIII. Intrazonal (within zone) congestion

Similarly to August, there was a substantial number of incremental and decremental OOS dispatches in September to address intrazonal congestion, caused primarily by the ongoing derate of the Vincent substation and new generation in northern Mexico. September OOS dispatches resulted in a net cost (redispatch premium) of approximately $6.3 million. Total OOS dispatch volume was 281 GWh and the average redispatch premium was $22.70/MWh (INC and DEC).[3] Figure 10 below shows the OOS volume and average redispatch premium since the beginning of the year. As shown, the average redispatch premium has been in the moderate range throughout the summer for both incremental and decremental OOS dispatches, however, the OOS dispatch volumes have been extraordinarily high resulting in significant intrazonal congestion costs. The high average decremental redispatch premiums in April and May were a result of OOS decremental dispatches during incremental price spikes, however, the cost impact was small due to the low volume of OOS dispatches, unlike the current situation caused by the new generation in Mexico.

Local market power mitigation of incremental dispatches (AMP LMPM) resulted in moderate savings of $83,007, or about 2.8% of the redispatch premium. Amendment 50 mitigation measures for decremental dispatches resulted in a net redispatch premium over the MCP of $3.4 million.

[3] OOS net cost or redispatch premium is calculated as total redispatch cost minus unconstrained dispatch cost, which is the equivalent dispatch cost at zonal MCP. The premium reflects the increased cost of redispatch and any potential mark-up above marginal cost.

Figure 10. Out-of-Sequence Volume and Average Redispatch Premium

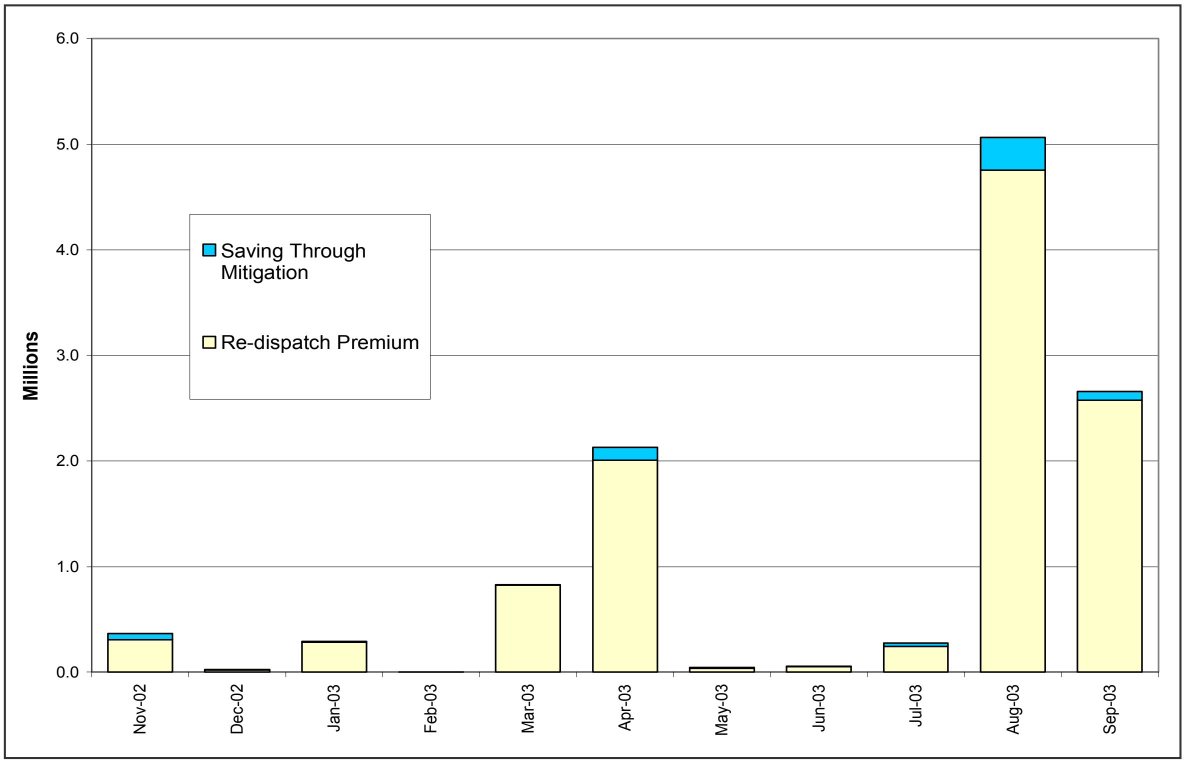


Incremental OOS Dispatches. A total of 128,019 MWh of incremental energy was called out-of-sequence (OOS) by ISO operators to address intrazonal congestion in September. The average price paid was $59/MWh, and the redispatch premium in excess of the Market Clearing Price (MCP) was approximately $2.9 million, or $23.26/MWh. There were a number of reasons for these incremental dispatches.

1. Vincent Transformer Banks: Due to the fire in late March only two of the three Vincent 500/230 kV transformers were in service. The third bank did not enter service in September as planned, but went into service on October 4th. This resulted in a substantial number of incremental dispatches to generators south of Vincent.
2. Sylmar Bank overloads: A lack of loaded generation in the Edison service territory resulted in the overloading of the Sylmar banks.
3. South of Lugo Flows: While there was some congestion south of Lugo, it tailed off as summer retreated. South of Lugo congestion is generally a summertime phenomenon.
4. Miguel Mitigation: The problems with the Mexican generation in the south resulted in further incremental calls to generation units in SP15
5. A number of transmission lines have been intermittently down for maintenance.

All incremental OOS dispatches are subject to mitigation, and Figure 11 shows the re-dispatch premium in yellow and the savings due to mitigation of incremental dispatches in blue. As shown in the chart, very little bid mitigation has taken place due to the large thresholds in AMP for local market power mitigation. Since January 2003, there has been a total of approximately $24.3 million of gross OOS costs. During the first nine months of this year, the current mitigation structure has resulted in approximately $485,953 in cost reductions due to incremental OOS bid mitigation (1.9 percent of gross cost or 4.6 percent of the redispatch premium).

Figure 11. Incremental Re-dispatch Premium and Mitigation Savings



Decremental OOS Dispatches. On the decremental side, a total of 152,876 MWh of energy was dispatched out of sequence. This energy was settled according to the provisions of the Amendment 50 mitigation measures as approved by FERC. The approximate redispatch premium in excess of the Market Clearing Price was $3.2 million. As in July and August, the most prominent reason for the decremental activity was intrazonal congestion in the San Diego region caused by the new generation units located in northern Mexico. Of all the out-of-sequence decremental dispatches, 92% were to units in the CFE (northern Mexico) region.