Memorandum

To: ISO Board of Governors

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

cc: ISO Officers, ISO Board Assistant

Date: July 18, 2003

Re: **Market Analysis Report for June 2003**

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

Executive Summary

California wholesale energy prices moderated in June as more generation returned to the market and natural gas prices decreased significantly from May levels in response to moderate demand and reports of significant gas storage injections. Actual California ISO system load averaged 26,913 megawatts (MW) in June 2003, 1.6 percent lower than in June 2002, due to mild weather, with a brief heat wave causing the monthly peak load on June 27, 2003 to reach 40,117 MW, exceeding that of June 2001 and 2002. This is the fourth consecutive month that peak loads have exceeded those of last year. There was also significant improvement in forward scheduling in June, particularly during peak hours, where forward schedules were within one-half of one percent of actual load. On June 1, approximately 2,500 MW of capacity additions became available to serve utility load requirements as part of the summer seasonal portfolio of long-term contracts managed by the California Department of Water Resources.

The real-time imbalance energy market, which is used to make up the difference between forward scheduled generation and actual load, has been largely decremental since October 2002, as more generation has been scheduled than was needed to meet actual load. There has been an increase in bid volumes for both incremental and decremental energy into the imbalance energy market as generation units returned from seasonal maintenance. This has also been the case for units available to provide ancillary services. By late June, units capable of providing regulation services returned from scheduled maintenance and provided increased bid sufficiency into the regulation markets. In addition, as the spring seasonal runoff began to subside, many hydro units were once again available to provide reserve services, relieving the ISO from relying on more expensive combustion turbine units to provide these services. Increased bid sufficiency has lowered cost in both the ancillary services (AS) and real-time markets in June, when compared with prices in previous months.

Abundant Northwest hydro energy in the Pacific Northwest combined with high seasonal demands in California and the Southwest resulted in day-ahead congestion in the North-to-South direction on the California-Oregon Intertie (COI) and on Path 26, a transmission artery between Northern and

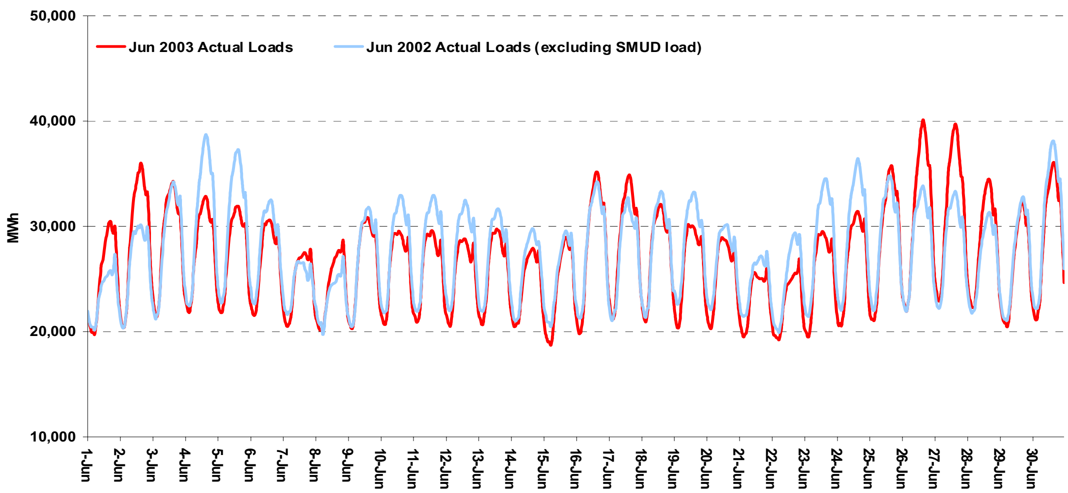
Southern California. Congestion was exacerbated somewhat by intermittent derates of the COI due to planned maintenance.

On June 24, the Federal Energy Regulatory Commission (FERC) approved Amendment 52 to the ISO Tariff, repealing its earlier direction that imports, also known as system resources, may bid energy into the ISO's real-time market only at a price of $0/MWh. While still ineligible to set the market-clearing price, importers are now free to specify prices at which they are willing to participate in the real-time Balancing Energy Ex-Post Price Auction Market (the BEEP Stack).

I. Trends

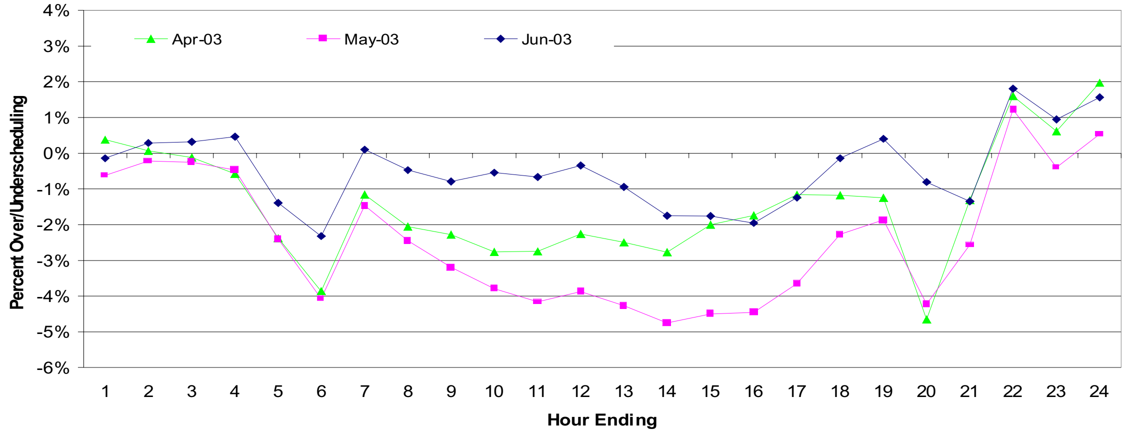
Load averaged 26,913 megawatts (MW) in June 2003, 1.6 percent lower than in June 2002, thanks to generally mild weather. However, the mild weather trend in June 2003 was punctuated by a few brief heat waves, spiking load to peaks above those seen in June 2001 and 2002, when adjusted for SMUD's exit from the ISO control area. The monthly peak load in June 2003 was 40,117 MW, or 3.6 percent higher than the June 2002 peak The following chart shows hourly loads in June 2003 compared to hourly loads in June 2002.

Figure 1. Actual Loads: June 2003 vs. June 2002



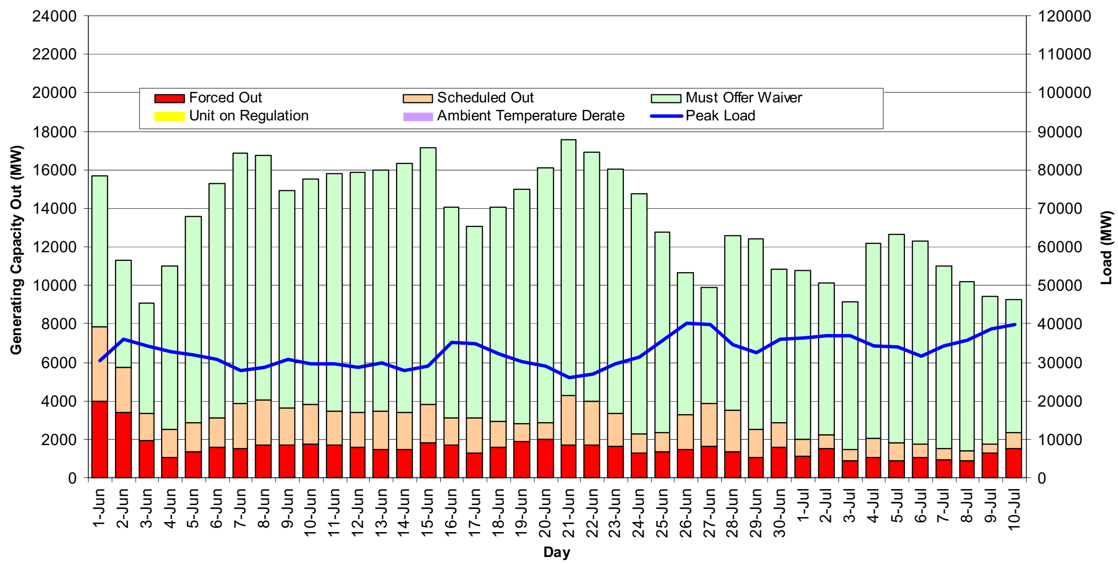
Meanwhile, forward scheduling improved to within 0.5 percent of actual load in June 2003, compared to more than 3 percent in May. Scheduling accuracy improved, particularly during the morning and evening ramping periods, between 4:00 and 7:00 a.m. and between 7:00 and 9:00 p.m., as well as during peak hours. The following chart shows scheduling deviations for the three months through June.

Figure 2. Monthly Average Scheduling Deviations by Hour of Day, April through June 2003



Outages. Several units returned from seasonal maintenance in June resulting in lower levels of scheduled outages than in May. Forced outages also decreased in June. The following chart shows daily outages by type for June through early July.

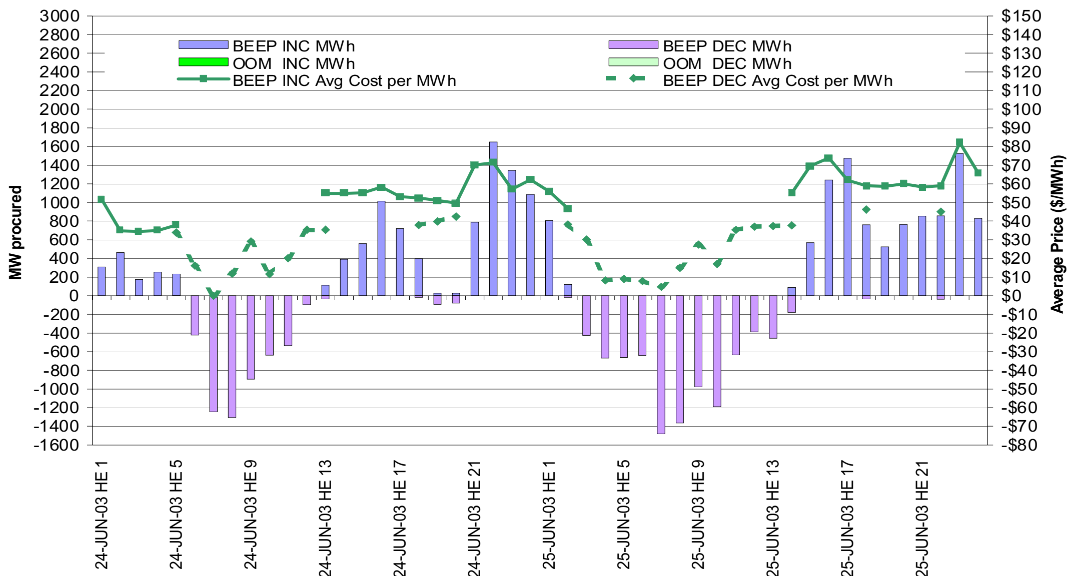
Figure 3. Daily Average Volume of Generation Out, by Outage Type: June 1 through July 10, 2003



II. Real-time Market

With the unseasonably cool weather and robust forward generation schedules in June, price spikes were less frequent than in previous months. The trend of heavy decrementing that has been seen in at least seven of the previous nine months continued in June; however, the latter two weeks of the month saw a much more even balance between incremental and decremental energy purchased in the imbalance energy market. During this period, operators typically called on incremental dispatches during peak afternoon and evening hours, and decremental dispatches during the off-peak night and morning hours. Because incremental resources become relatively scarce when the incremental imbalance requirement is high, prices tend to rise with incremental dispatch volumes. Similarly, decremental resources become scarce when the decremental requirement is high, forcing prices down as decremental dispatch volumes rise (in the negative direction). This pulls incremental average prices upward and decremental average prices downward. As an example, the following chart shows an hourly profile of the real-time market for June 24 and 25.

Figure 4. Real-time Market Hourly Profile, June 24-25



The real-time Incremental (INC) price, which the ISO pays to generators to increase output when generation is not sufficient to meet load, averaged $61.75/MWh in June, compared to $88.36/MWh in May. Incremental volume totaled 114 GWh in June, or an average dispatch of 159 MW, compared to an average 198 MW in May. The real-time Decremental (DEC) price, which generators pay to the ISO for decreasing output when generation is in excess of actual load, averaged $13.81/MWh in June, compared to $5.81/MWh in May. Decremental volume totaled 302 GWh in June, or an average dispatch of 419 MW, compared to an average 430 MW in May. All else being equal, lower INC prices and higher DEC prices result in lower overall costs to load.

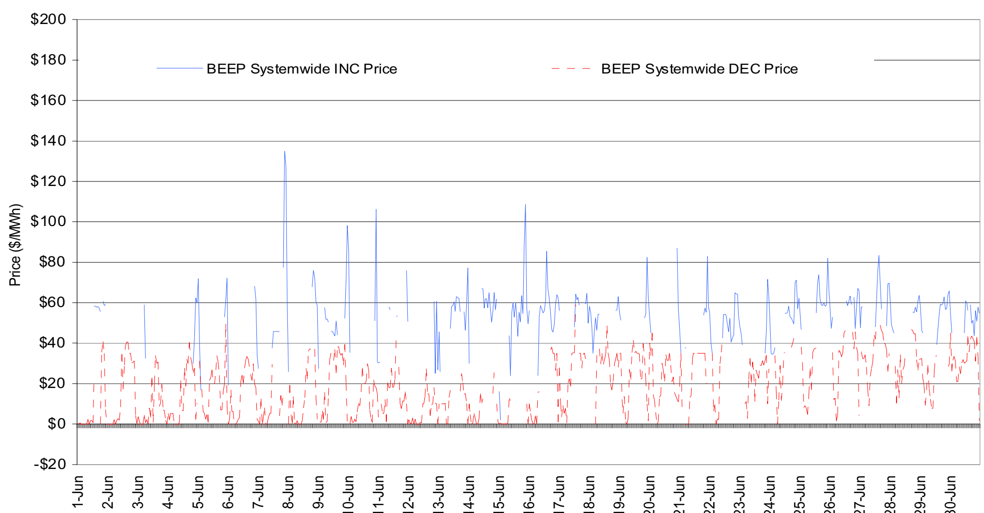
The following table shows average INC and DEC prices and total dispatched energy, and average system loads and underscheduling for June.

Table 1. Real-Time Average Prices and Total Volumes, Average System Loads, and Underscheduling, in June 2003

	Overall Avg. Real-Time Price and Total Volume		Avg. System Loads (MW) and Pct. Underscheduling
	Inc	Dec	
Peak	$61.40 81 GWh	$16.31 229 GWh	29,289 MW 0.7%
Off-Peak	$62.62 33 GWh	$5.98 73 GWh	22,161 MW 0.0%
All Hours	$61.75 114 GWh	$13.81 302 GWh	26,913 MW 0.5%

Overall, June was a relatively quiet month with respect to anomalous activity in the real-time market, when compared with previous months in 2003. There were only three hours in June in which the hourly average INC price spiked to at least $100/MWh. The decrease in incremental dispatches at moderate prices dampened the overall impact of the hourly price spikes in June, as summer schedules and units returning from seasonal maintenance increased bid volume into the imbalance energy market. For similar reasons, the otherwise frequent phenomenon of the zero price for DECs occurred only once in the final week of the month. The chart below shows hourly average prices for the ISO real-time market in June.

Figure 5. Hourly Average Real-Time Prices in June



Out-of-Market (OOM) Procurement. There was no incremental OOM procurement during the month of June as the BEEP stack was sufficient to meet incremental imbalance loads. However, on the decremental side there was a total of 1,410 MWh of OOM energy sold across the interties. These sales occurred between June 1 and June 8, and were undertaken to relieve overgeneration, generally during the morning ramp (hours ending 7:00 and 8:00) due to insufficient decremental energy bids in the BEEP stack.

Out-of-Sequence Procurement. A total of 3,833 MWh of energy was dispatched out of sequence for incremental energy. The average price paid was $61/MWh, and the total of re-dispatch premiums above the Market Clearing Price was approximately $53,000. Most of these calls were necessitated by intra-zonal congestion in either the Vincent substation or Lugo areas.

On the decremental side, a total of 16 MWh of energy was dispatched out of sequence. Generators paid an average of $7/MWh to the ISO to reduce output, with re-dispatch premiums totaling $675.

Locational Market Power Mitigation. AMP allows for the mitigation of OOS dispatches to mitigate instances of locational market power. AMP for local market power mitigation (AMP LMPM) uses only a conduct screen (no impact screen) and a lower threshold. If the bid price is $50/MWh or 200% more than the MCP, the bid will be mitigated to the higher of MCP or the unit's Reference Price. Since the implementation of Phase 1a on October 30, 2002, mitigation of incremental OOS dispatches has occurred every month, with the exception of February 2003, as indicated in Figure 5 and Table 2 below. Mitigation of decremental bids began on July 1, 2003, and prior to that was subject to a soft cap of -$30/MWh.

Figure 6. Components of Out-Of-Sequence Costs and Effect of AMP on Local Market Power Mitigation

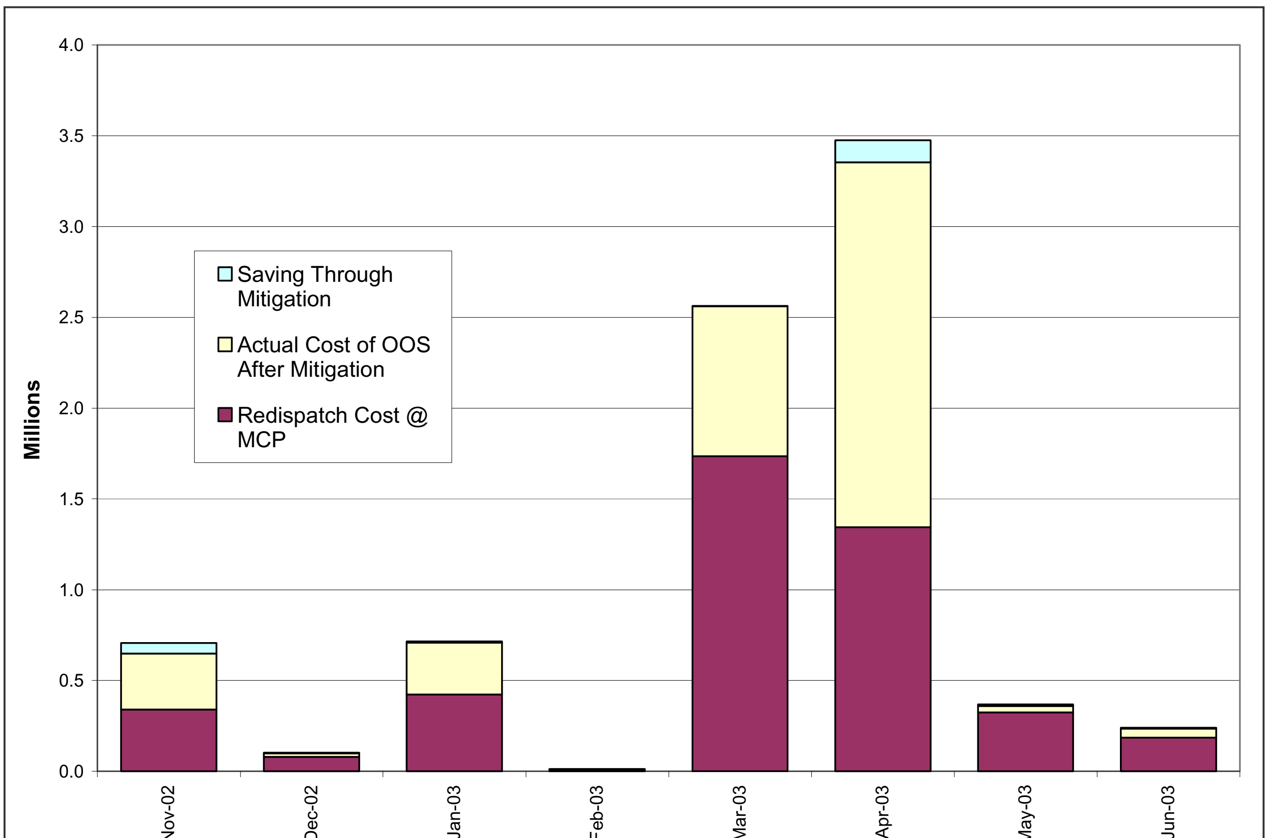


Figure 5 shows the re-dispatch cost valued at the market clearing price in red, and the actual cost in yellow (comprising both true marginal cost as well as any remaining mark-up due to local market power), while actual savings through mitigation are shown in light blue. This area is small, since the thresholds in AMP for local market power are high when compared to those granted to other ISOs. Table 2 below shows that since AMP LMPM was instituted at the end of October 2002 there has been a total of approximately $8 million of gross OOS costs. The current mitigation structure has provided about $200,000 in cumulative savings through mitigation.

Table 2. Effect of AMP on OOS Incremental Dispatches

Month	MWh	Redispatch Cost @ MCP	Actual Cost w/Mitigation	Original Cost w/o Mitigation	Mitigated Dollars (Original Cost - Actual Cost)
Nov-02	9,732	$ 340,442	$ 648,586	$ 707,990	$ 59,404
Dec-02	1,402	78,644	99,017	102,383	3,366
Jan-03	10,234	423,685	708,734	716,168	7,434
Feb-03	163	9,504	12,482	12,482	0
Mar-03	33,872	1,735,419	2,561,223	2,563,396	2,173
Apr-03	54,654	1,344,311	3,353,006	3,475,300	122,294
May-03	5,290	323,426	359,053	368,565	9,512
Jun-03	3,833	184,577	235,459	239,610	4,152
Total	119,181	4,440,007	7,977,560	8,185,895	208,335

In the month of June there was comparatively little mitigation activity. Two units were OOS mitigated, both early in the month. Gross OOS costs for June were $235,459, and the mitigation procedure provided $4,152 of cumulative mitigation, or 7.5% of the difference between the bid price gross cost and the equivalent market clearing price cost.

Price Spikes. The three notable price spikes in June had a modest impact on imbalance energy costs, when compared to spikes in recent months.

On June 7, the real-time INC price ranged between $115 and $135.74/MWh between 8:50 and 10:40 p.m., as a resource tripped and a line was out. The cost impact of this spike was approximately $110,000.[1]

On June 10, the INC price hit $120/MWh for two intervals, as the output from a large unit in Southern California was curtailed due to a malfunction. The cost impact of this spike was approximately $11,000.

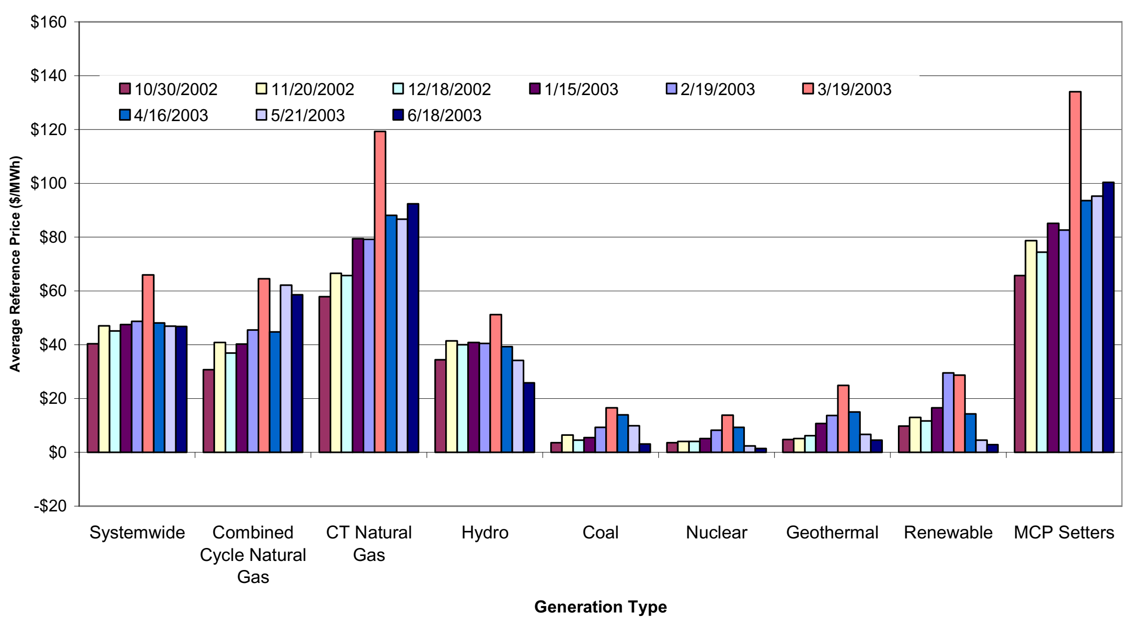
On June 15, between 8:50 and 9:40 p.m., the INC price ranged between $100 and $125/MWh, as a unit tripped, causing a frequency disturbance and interrupting its delivery of awarded reserves. The cost impact of the spike was approximately $45,000.

[1] Cost impact is estimated as the volume of the spike multiplied by the difference in cost between the market-clearing price(s) during the spike and the weekly average cost for incremental energy.

AMP Performance. To date, the AMP Impact Test has yet to be triggered. Bidders into the BEEP Stack failed the AMP Conduct test in only 6 hours in June, a reversal from the trend leading to 131 hours in May.

Previous Market Analysis Reports have shown trends in reference levels for peak-hour reference levels. The May report included the peak-hour trend through June. DMA also monitors trends in off-peak reference levels, which have been significantly influenced by the price spikes seen in Hour Ending 23:00 (10:00 to 11:00 p.m.). Non-normalized average reference levels for off-peak hours spiked in March, following the spike in natural gas prices at that time. However, the portfolio of off-peak MCP-setters' reference levels continued to trend upward in the range of $90 to $100/MWh after retreating from spike-period levels. This was due almost exclusively to the series of price spikes in HE 23:00 between March and early May. The following chart shows average off-peak-hour reference levels for all generation types, not normalized for the price of natural gas. In addition, the average reference level of a small portfolio of units that consistently were able to set the BEEP market-clearing price at least 10 times between April and June is shown in the chart below as the "MCP Setters".

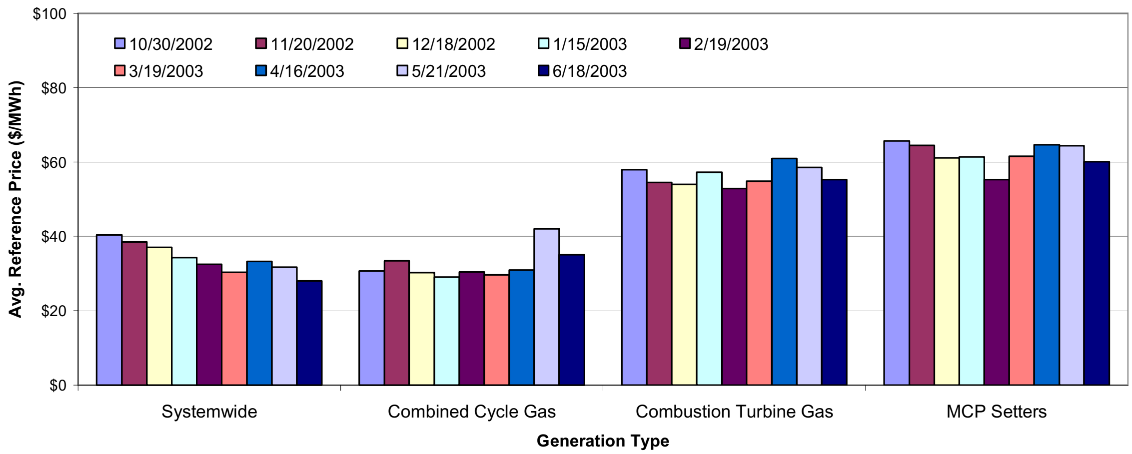
Figure 7. Average Off-Peak-Hour Reference Levels by Generation Type[2]



The aforementioned HE 23:00 price spikes caused the off-peak MCP setters' portfolio average reference level, deflated to the October 2002 gas price, to crest in April at $64.34/MWh, and to remain nearly at that level through the first half of May. The HE 23:00 spikes largely dissipated by late May, due to the shift in load to the summer pattern where the daily peak occurs in the late-afternoon hours. This was a considerable increase from its low in February of $55.21/MWh. The following chart shows gas-normalized off-peak average reference levels.

[2] Bars in different colors show average reference levels for different months. Since each reference level is constructed as a 90-day rolling average index, monthly reference levels are taken from Hour Ending 4:00 on the third Wednesday of each month. This is the case for both normalized and non-normalized reference levels.

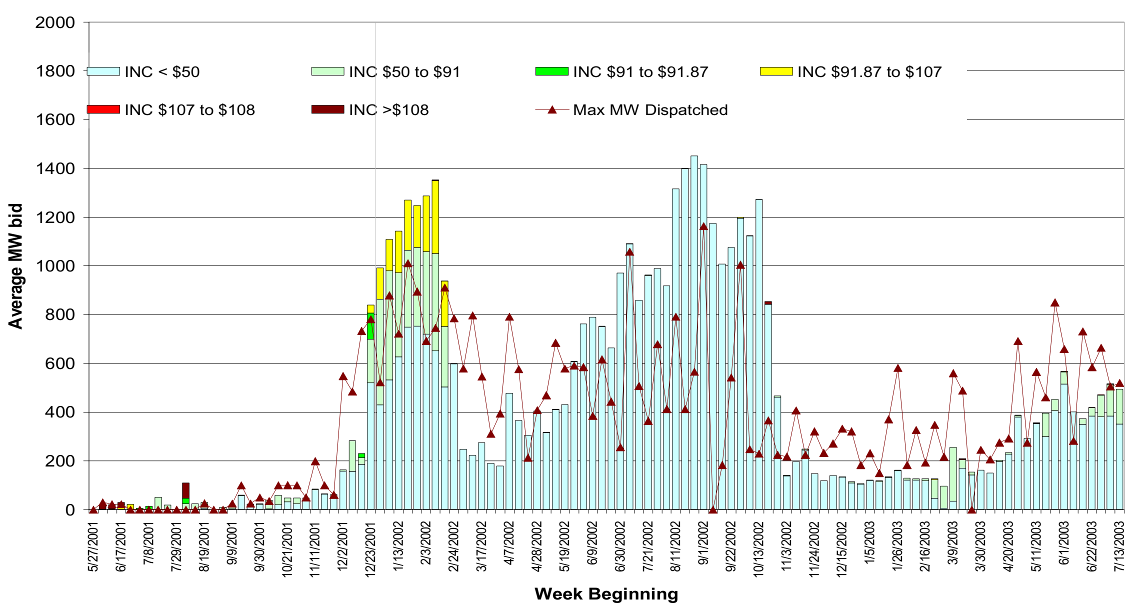
Figure 8. Average Off-Peak Reference Levels for Gas-Fired Generation Types, Normalized for Changes in the Price of Natural Gas



The increase in reference prices is largely explained by the change in the price of natural gas. In addition, units that were not able to set the price regularly often saw their reference prices increase anyway, due to the fact that the reference level for a particular unit is calculated as a rolling average of the BEEP market-clearing price when the unit is on and generating, whether or not it is dispatched in the real-time energy market.

Effect of Amendment 52. As noted earlier, importers have been eligible to submit prices they are willing to accept (pay) to provide incremental (decremental) energy in the real-time market since June 24. While it is premature to draw conclusions in regard to the effect of this rule change at the time of this writing, the following chart suggests that imports have been increasingly willing to provide balancing energy.

Figure 9. Weekly Average Incremental Import Bid Volume into the BEEP Stack through early July



III. Ancillary Services Markets

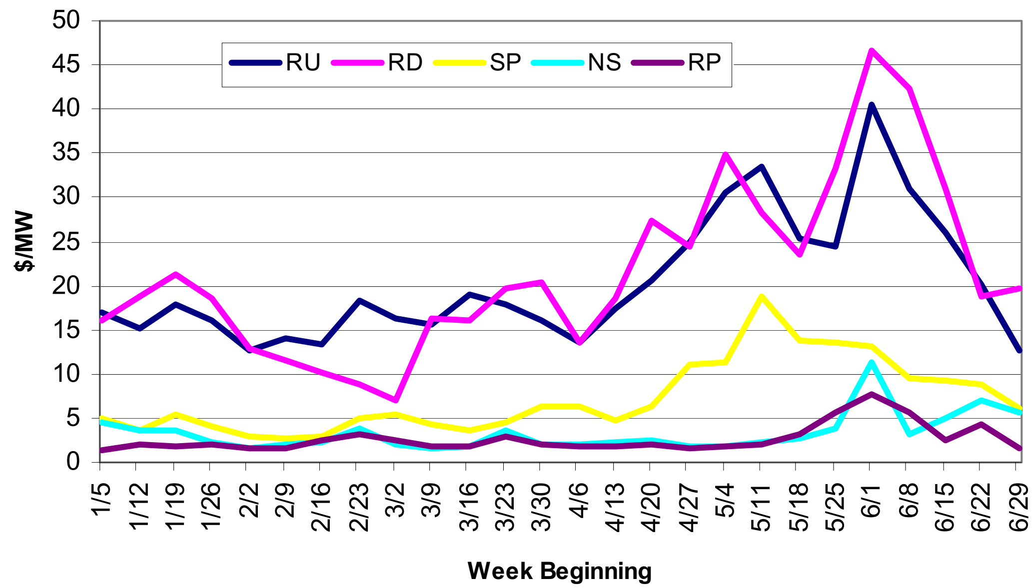
The monthly quantity-weighted average price of ancillary service products increased in June when compared to the average May price. The average price of spinning reserves (SP) decreased substantially, while the average prices of non-spinning reserves (NS) and downward regulation (RD) increased substantially. The average price of upward regulation (RU) increased somewhat from May to June. Although prices in June were greater on average than those in May (and April), the latter half of June trended toward lower prices.

There were several periods during which ancillary service prices were high in June. In particular, during June 1-4 prices for RU, SP and NS were greater than $75/MW in the day-ahead market.

Despite the monthly average increase in ancillary service products excluding SP, the intra-monthly trend at the end of June was toward decreases in price of all products other than NS. The week beginning June 22 had average regulation prices that were similar to prices seen in the early months of the year. Increasing average load brought more generating units capable of supplying these services online, improving bid sufficiency. Increasing average load also increased the requirement for operating reserves. Non-spin bid sufficiency did not benefit from the increase in load, so NS prices increased with increasing load.

The following chart shows quantity-weighted weekly average AS prices through June.

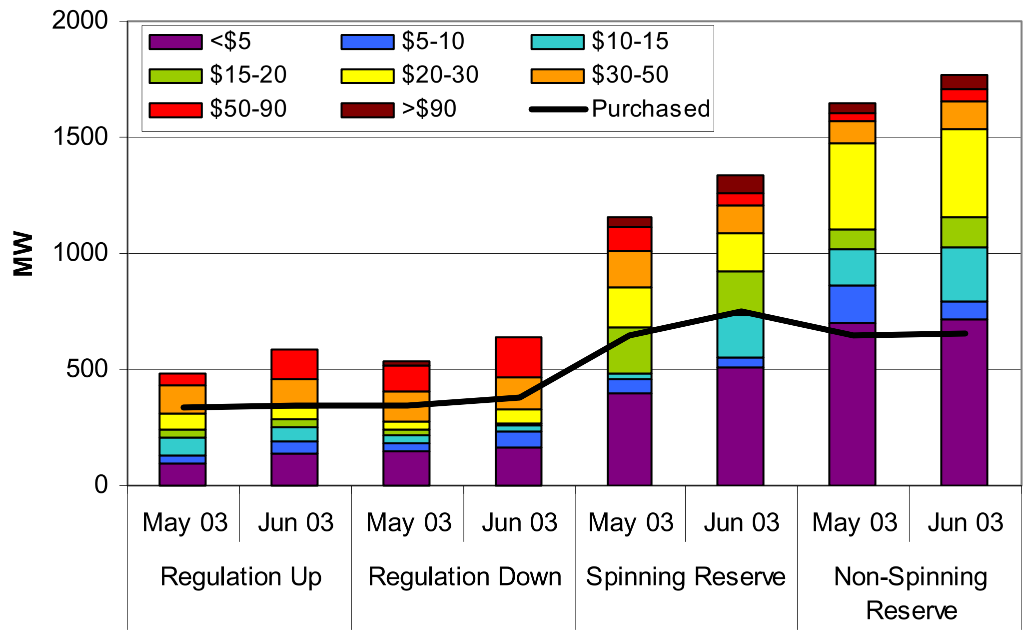
Figure 10. Ancillary Service Weekly Average Prices 2003



Regulation prices tended to be lower during peak hours, with RU averaging $23.84/MW and $38.04/MW in peak and off-peak hours, respectively; and RD averaging $30.37/MW and $40.77/MW in peak and off-peak hours, respectively. This is due to the fact that regulation-enabled units tend to come online during the morning ramp and shut off during the evening ramp. Consequently, relatively few of them are available in off-peak hours, reducing bid sufficiency and making the market less competitive at that time.

The decrease in average price of SP from May to June is accompanied by a fairly substantial shift in bid composition. Overall bid sufficiency improved, and suppliers into the reserves market offered SP at lower prices. This is due to the fact that more generators were online and available to provide spin, since load in June was on average greater than load in May. Meanwhile,the increase in average price of NS from May to June was due mostly to on-peak price increases, as was seen during the same period in 2002. Increases in NS prices are attributable to increasing peak load: the majority of hours cleared at moderate prices, while the hours surrounding the peak load for the day typically cleared at prices high enough to have a substantial impact on the daily average. The chart below shows monthly average bid composition four RU, RD, SP and NS.

Figure 11. Monthly Average Day-Ahead Bid Composition



IV. Interzonal Congestion Markets

Congestion costs totaled approximately $1 million in June, significantly lower than the $4 million that occurred in May. Of the $1 million in congestion costs, nearly half was incurred due to congestion on Path 26 in the north-to-south direction. Other congestion costs mainly occurred on COI, and to a lesser extent on the Pacific DC Intertie (NOB), in the import (north-to-south) direction.

Similar to May, the congestion costs totaling $0.47 million on Path 26 were incurred during peak hours throughout the month. The combination of abundant hydro energy in the Northwest area and high demand in Southern California and in the Southwest resulted in congestion through California in the north-to-south direction in many peak hours. Nonetheless, congestion prices were moderate, with the price peaking at approximately $10/MWh in the day-ahead market. In general, Path 26 was available at its full capacity, except on June 17, when it was derated in the north-to-south direction.

In addition, COI and NOB experienced some derates in June. Derates on COI were associated with scheduled annual maintenance. Congestion prices on COI were positively correlated with the magnitudes of derates on the path. However, in general, congestion prices on COI and NOB were mild, with the highest day-ahead congestion prices around $10/MWh. Most congestion costs on NOB occurred in the last few days of the month, also partially related to line derates. The highest day-ahead congestion price on NOB was reported on May 29, when the congestion price reached $11/MWh.

Finally, one notable incidence of congestion was related to Silver Peak. Silver Peak was congested the entire day of June 30 in the export direction, with a constant congestion price of $30/MWh. In contrast, Silver Peak experienced relatively little congestion in the first half of 2003. This congestion was caused by a sharp increase of an export schedule by a particular SC well beyond the line's total capacity of 17 MW. We are currently investigating the facts involved with this event.

Table 3. Interzonal Congestion Frequencies and Prices

			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)**
BLYTHE	import	OFF-PEAK				2	0%	235.83
CASCADE	import	ON-PEAK	54	8%	0.00	15	2%	0.00
COI	import	OFF-PEAK	3	0%	0.01	6	1%	1.34
COI	import	ON-PEAK	244	34%	1.22	130	18%	11.03
ELDORADO	import	OFF-PEAK				2	0%	67.70
ELDORADO	import	ON-PEAK				1	0%	10.00
LUGO-MONA	import	OFF-PEAK	7	1%	1.00			
MEAD	import	ON-PEAK	1	0%	20.04	1	0%	29.87
NOB	import	ON-PEAK	141	20%	0.35	51	7%	18.45
PALO VERDE	import	OFF-PEAK				1	0%	5.00
PALO VERDE	import	ON-PEAK	3	0%	1.45	1	0%	2.00
PATH15	S->N	OFF-PEAK				3	0%	74.13
PATH 26	S->N	OFF-PEAK				2	0%	31.94
PATH 26	N->S	ON-PEAK	115	16%	0.00	21	3%	0.00
SILVER PEAK	Export	ON-PEAK	16	2%	30.00			
SILVER PEAK	Export	OFF-PEAK	8	1%	30.00			

Table 4. Inter-zonal Congestion Costs

Branch Group	Day-ahead		Hour-ahead		Total Congestion Cost		Total Congestion Cost		Total Congestion Cost
	Import	Export	Import	Export	Export	Import	Day-ahead	Hour-ahead	
BLYTHE	$0	$0	$45,294	$0	$45,294	$0	$0	$45,294	$45,294
COI	$344,387	$0	$307	$0	$344,694	$0	$344,387	$307	$344,694
ELDORADO	$0	$0	$941	$0	$941	$0	$0	$941	$941
LUGO-MONA	$1,120	$0	$0	$0	$1,120	$0	$1,120	$0	$1,120
MEAD	$12,966	$0	$0	$0	$12,966	$0	$12,966	$0	$12,966
NOB	$86,775	$0	$35,671	$0	$122,446	$0	$86,775	$35,671	$122,446
PALO VERDE	$9,035	$0	$611	$0	$9,646	$0	$9,035	$611	$9,646
PATH 26	$0	$458,917	$8,118	$2,845	$8,118	$461,762	$458,917	$10,963	$469,881
SILVER PEAK	$0	$12,262	$0	$0	$0	$12,262	$12,262	$0	$12,262
Grand Total	**$454,283**	**$471,179**	**$90,942**	**$2,845**	**$545,226**	**$474,024**	**$925,462**	**$93,787**	**$1,019,250**

V. Firm Transmission Rights Market

FTR scheduling. On some paths, FTRs were used to establish scheduling priority in the day-ahead markets. As shown in the following table, a high percentage of FTRs was scheduled on certain paths (88% on Eldorado, 88% on LOGOIPPDC, 86% on Palo Verde, 100% on Silver Peak in the import direction, and 51% on Path 26, in the North-to-South direction). FTRs on those paths are mainly owned by Southern California Edison Company (SCE1) and municipal utilities. Also, FTR scheduling on Path26 was higher in May and June compared to earlier months in the year. FTR owners may have used their FTRs for their hedging feature, thereby avoiding paying the high congestion costs on these paths.

Table 5. FTR Scheduling Statistics for June, 2003

Direction	Branch Group	MW FTR Auctioned	Avg MW FTR Sch	Max MW FTR Sch	Max Single SC FTR Scheduled	% FTR Schedule
IMP	COI	745	173	588	500	23%
IMP	ELDORADO	510	449	510	510	88%
IMP	IID-SCE	600	467	480	460	78%
IMP	LUGOIPPDC **	370	324	364	231	88%
IMP	LUGO-MONA **	167	89	94	54	53%
IMP	LUGOWSTWG **	93	26	30	12	28%
IMP	MEAD	516	46	196	150	9%
IMP	NOB	686	172	324	100	25%
IMP	PALO VERDE	627	541	620	600	86%
IMP	SILVER PEAK	10	10	10	10	100%
IMP	VICTORVILLE	991	13	50	50	1%
EXP	MEAD	464	22	200	125	5%
EXP	NOB	664	6	23	23	1%
EXP	PATH 26	1,425	730	1,311	560	51%

*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 June. Because congestion prices and costs were significantly lower in June than in the previous several months, FTR revenue for most paths was also lower. For instance, FTR revenue on Path 26 was only $226 per MW, much lower than the $1,500 per MW reported in May. The exception was the FTR for Silver Peak in the export direction, with a congestion price of $30/MWh on June 30.

Table 6. FTR Revenue Per MW ($/MW)

Branch Group	direction	Net $/MW FTR Rev Apr - Imp	Net $/MW FTR Rev May - Imp	Net $/MW FTR Rev Jun - Imp	Cumm Net $/MW FTRREV - Imp	Pro Rated NET $/MW FTRREV - Imp	FTR Auction Price
BLYTHE	IMPORT	$69	$0	$231	$300	$1,199	$5,460
COI	IMPORT	$723	$536	$299	$1,558	$6,233	$19,828
ELDORADO	IMPORT	$0	$0	$1	$1	$2	$16,944
LUGOIPPDC**	IMPORT	$272	$0	$0	$272	$1,087	N/A
LUGO-MONA**	IMPORT	$0	$715	$7	$722	$2,887	N/A
LUGOWSTWG**	IMPORT	$3	$0	$0	$3	$13	N/A
MEAD	IMPORT	$166	$0	$14	$179	$717	$7,820
NOB	IMPORT	$249	$203	$68	$520	$2,081	$12,245
PALO VERDE	IMPORT	$233	$15	$5	$254	$1,014	$88,167
PATH 26	IMPORT	$0	$0	$5	$5	$19	$254
SUMMIT	IMPORT	$108	$0	$0	$108	$434	$650
IID-SDGE	EXPORT	$0	$480	$0	$480	$1,920	$182
PATH 15**	EXPORT	$0	$5	$0	$5	$20	N/A
PATH 26	EXPORT	$1,147	$1,500	$224	$2,872	$11,486	$8,602
SILVER PEAK	EXPORT	$0	$0	$720	$720	$2,880	$100

*Pro-rate 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.

** FTRs on these paths were awarded to municipal utilities that converted their lines to the ISO, and thus were not released in the primary auction.

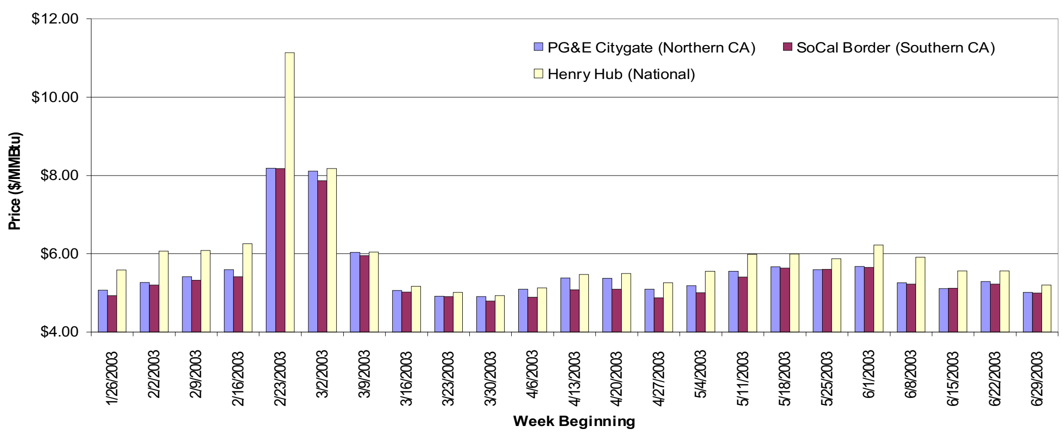
FTR Concentration There were no trades in the secondary FTR market in June. Therefore, the FTR owner concentration table reported in April remains valid.

VI. Natural Gas Markets

The relatively cool weather with intermittent heat waves affected natural gas prices. High temperatures in the Southeast kept Henry Hub gas prices high for much of the first two weeks of June, typically in excess of $5.90/MMBtu. High temperatures in the West also resulted in California prices approaching $6.00/MMBtu and Malin prices at $5.50/MMBtu between June 2 and 4, although prices fell sharply after that point to $5.00 to $5.50/MMBtu. California prices spiked to $5.75/MMBtu on 8 June, but returned to $5.00/MMBtu by June 12.

High linepack in the West helped to drive California and Malin prices down to $4.50/MMBtu, but high cooling load driven by very high temperatures in California drove natural gas prices back to $5.50/MMBtu. Temperatures cooled off for a few days again, followed by another hot spell between 22 and 26 June, driving gas prices to $5.50/MMBtu. Henry Hub prices for the latter half of June remained between $5.50 and $5.75/MMBtu. The following chart shows weekly average gas prices at California delivery points and the Henry Hub national trading point through June.

Figure 12. Weekly Average Natural Gas Prices through June



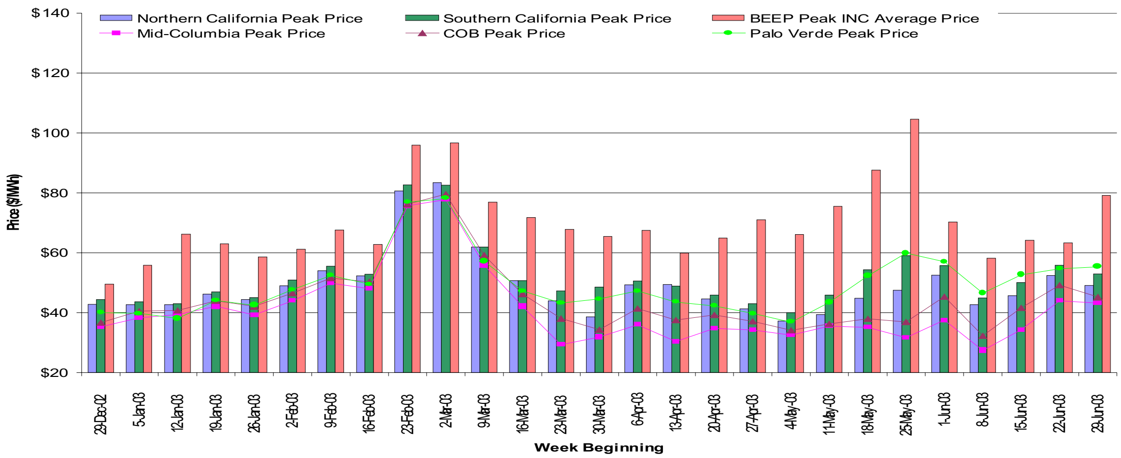
VII. Regional Bilateral Electric Markets

A pattern of periodic high cooling demand in California manifested itself during June, with sharp early to mid-week price highs each week in June. High cooling demand driven by high temperatures and concomitant high natural gas prices drove California and Palo Verde prices to around $70/MWh on June 2. Prices rapidly returned to the $45/MWh level by the end of the first week, however, as temperatures and gas prices subsided. Temperatures increased again to around $55/MWh on June 9, but returned to the $45/Mwh level by the end of the second week.

During the third week of June, Palo Verde prices exceeded Southern California prices by over $5/MWh, with prices on June 18 and 19 exceeding $60/MWh, compared to $55/MWh in Southern California. The remainder of June produced electricity prices that were at least $55/MWh, with a

California price spike on June 26 of $64/MWh. The following chart shows weekly average hub prices and the ISO real-time INC price through June.

Figure 13. Weekly Average Regional Electric Bilateral Contract Prices and ISO real-time incremental Prices through June



VIII. Issues under Review

On March 31, 2003, the ISO filed a petition for Tariff Amendment 50 with the FERC, requesting stronger locational market power mitigation measures (LMPM). The requested LMPM measures included a provision for mitigation of decremental bids in intra-zonal congestion situations that arise from generation over-scheduling in generation pockets. On May 30, 2003, FERC issued an Order on the ISO's Amendment 50, which rejected proposed changes to INC bid mitigation but approved, subject to modification, DEC bid mitigation. Specifically, the Order "require[s] that the CAISO use reference prices for DEC bids to be administered by an independent entity, and applied to all generators – thermal and non-thermal." The CAISO has since worked with Potomac Economics, its vendor that calculates INC reference prices, to develop a DEC reference price methodology. The mitigation was put into effect July 1, 2003. The ISO will continue to monitor the DEC reference prices and the impact of the new mitigation.