Market Performance Report
December 2006

January 23, 2007

ISO Market Services

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Executive Summary

Highlights for December 2006:

- The average load in December was 26,229 MW, approximately 2.8 percent above November's average load of 25,507 MW.
- Natural gas prices declined steadily during December from $7.50/MMBtu to under $6.00/MMBtu by month's end.
- Bilateral electricity prices also declined consistent with the fall in gas prices.
- Average real-time energy price increased slightly over the prior month from $49.25/MWh to $50.79/MWh. Average volumes of incremental and decremental energy remained relatively unchanged.
- The volume of scheduled outages declined by about half during the month as the volume of Must-Offer-Waivers-Allowed increased accordingly.
- Consistent with the increase in on-line capacity, the frequency of five-minute interval prices exceeding $250 declined from 88 in November to 59 in December.
- Out-of-Sequence re-dispatch volumes increased by 60 percent while re-dispatch costs increased from $610,000 to $830,000, or about 36 percent. Most of these costs were due to intra-zonal congestion, which was driven by transmission line maintenance during December.
- The average total cost of Ancillary Services declined in December from $0.55/MWh to $0.49/MWh. The number of bid insufficient hours fell from 14 in November to 7 in December.
- Total unit commitment costs increased sharply to $2.3 million in December, up from $975,000 in November. The increase was driven primarily by Southern California Import Transmission (SCIT) nomogram generation requirements, because a significant amount of base load generation was off-line for maintenance through the first two-thirds of the month.
- Total inter-zonal congestion costs increased marginally from $5 million in November to $6 million in December. Two thirds of these costs occurred on the Palo Verde branch group and were driven by transmission line maintenance.

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Market Characteristics

Loads

At 26,229 MW, average loads where up slightly in December from one year ago, and 2.8 percent above November's average load of 25,507 MW. The average daily peak was also up slightly over December 2006, as shown in Table 1. Figure 1 below provides a graphical comparison of the load pattern in December 2006 vs. December 2005.

Figure 1: System Load Comparison - December 2006 v. December 2005

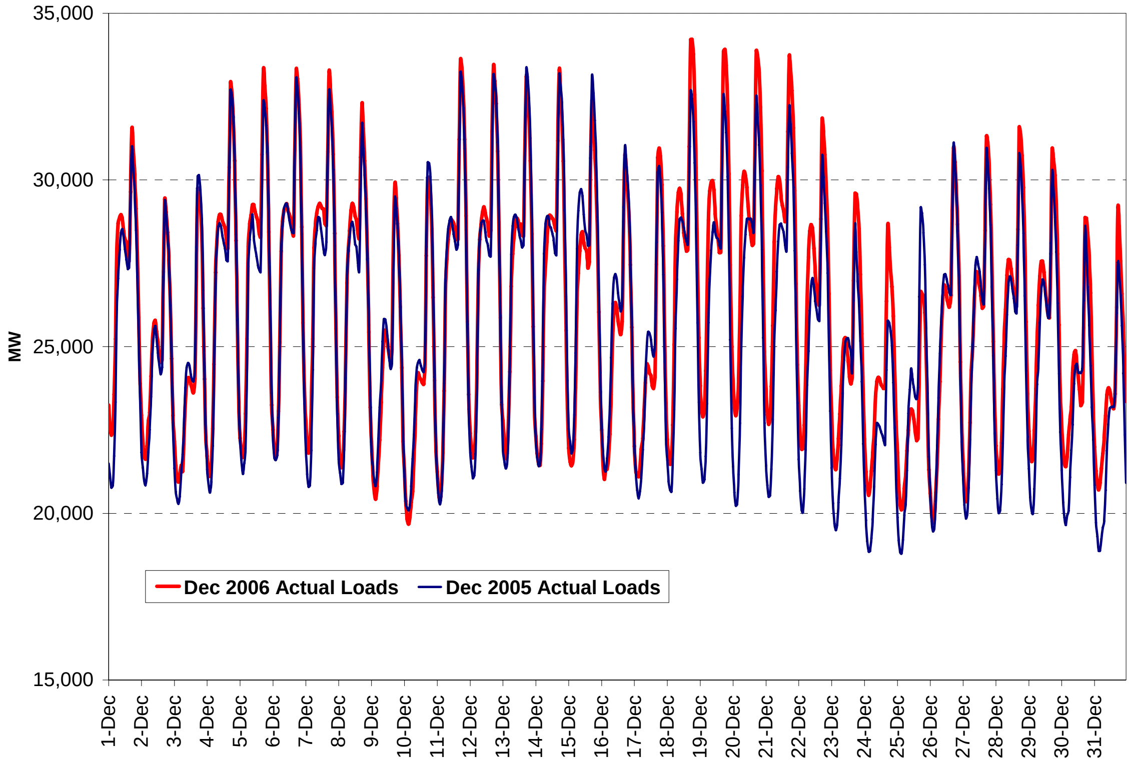


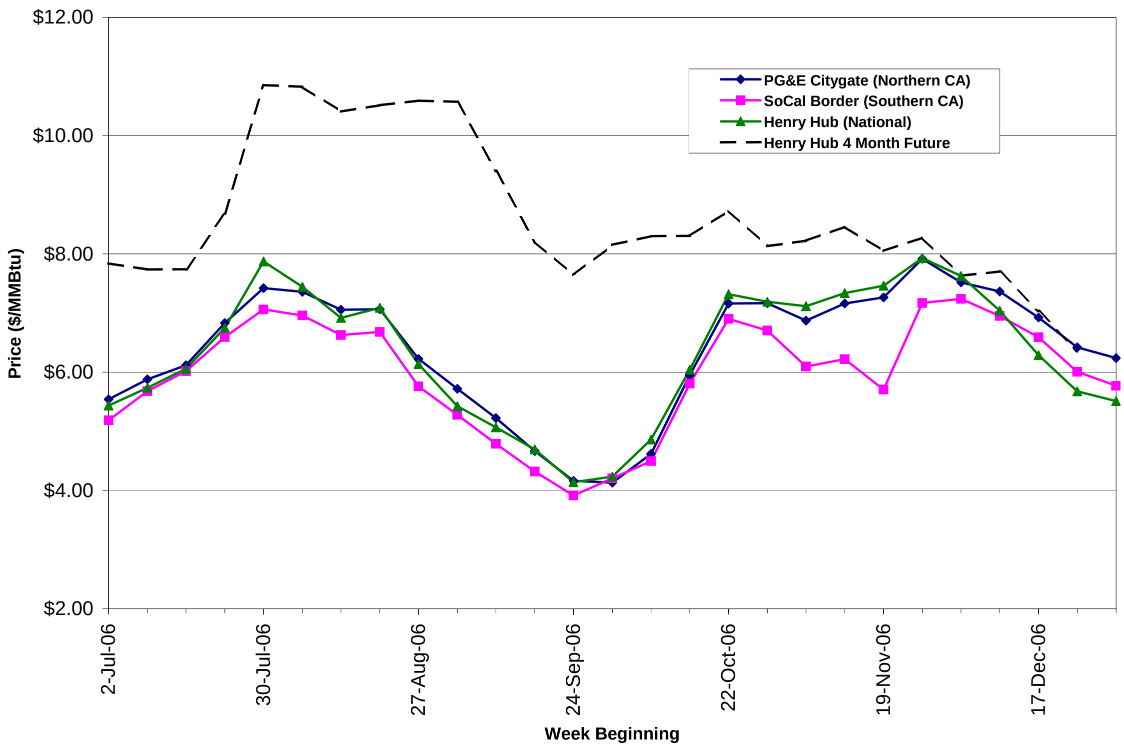
Table 1: System Load Changes Compared to Same Months in Prior Year

	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
January-06	0.2%	-0.2%	0.7%	-2.5%
February-06	1.6%	1.4%	3.2%	1.1%
March-06	3.3%	2.9%	6.7%	3.0%
April-06	-1.8%	-1.7%	0.3%	-1.9%
May-06	1.1%	1.4%	-0.4%	-3.5%
June-06	10.3%	14.7%	5.1%	13.0%
July-06	5.8%	6.2%	5.0%	10.6%
August-06	-3.3%	-4.9%	-0.5%	0.2%
September-06	3.6%	5.3%	2.9%	12.4%
October-06	-2.5%	-2.8%	-2.0%	-7.8%
November-06	-1.0%	-0.6%	-1.0%	1.6%
December-06	1.5%	1.1%	4.0%	2.6%
Yearly Average	1.6%	1.9%	2.0%	10.6%

Natural Gas Storage and Prices*

Warmer-than-normal December temperatures across the country led to steady declines in natural gas spot prices this month as seen in Figure 2 below. By December 29, the Henry Hub price reached $5.51, which is the lowest it's been since this year's heating season began (November 1). The California Composite Average Price finished the month slightly higher at $5.93. Nation-wide natural gas in storage as of Friday, December 29, was 3,074 Bcf, or 15.3 percent above the 5-year average.

Figure 2: Weekly Average Natural Gas Spot Prices – June 2006 to November 2006

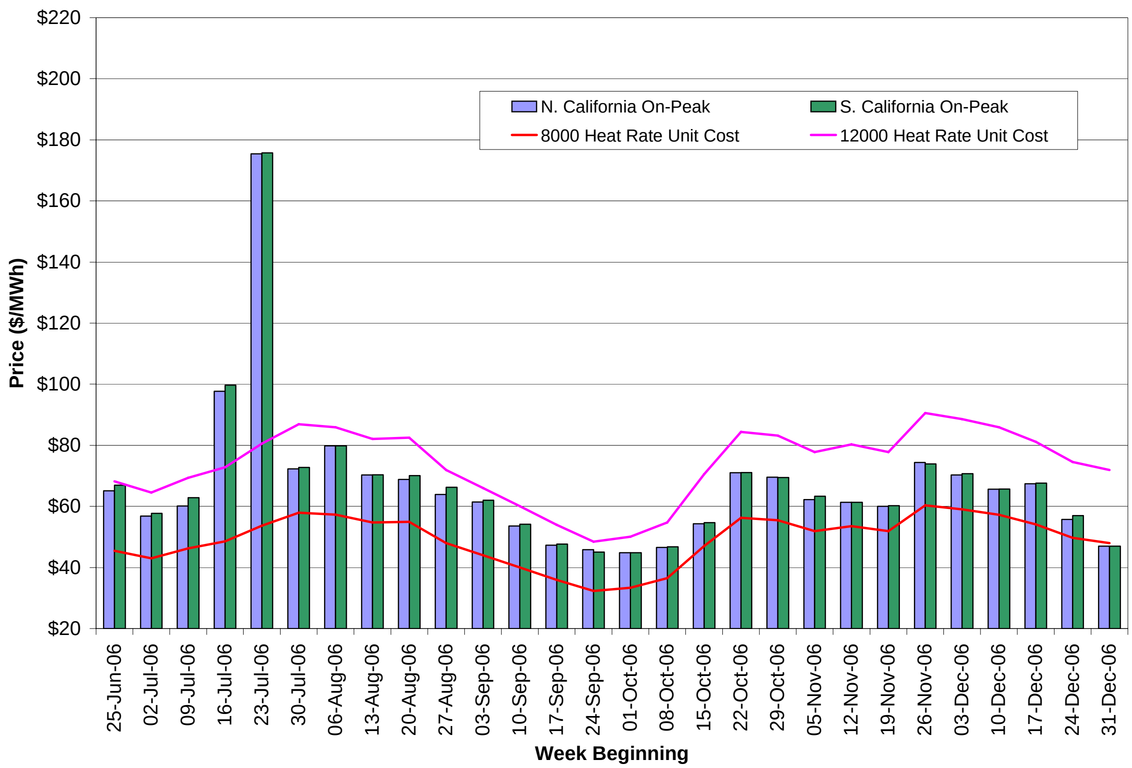


* Natural gas prices are important to the market as much of the capacity in the West, especially the newer units, are gas-fired. These units are also often marginal, meaning that they set the price levels in bilateral markets. The four-month futures price is an indication of market expectations of pricing levels in four months time.

Bilateral Electricity Prices*

Figure 3 compares weekly average on-peak prices for Northern and Southern California with the nominal gas costs for two reference gas turbine generators. The sharp decline in average prices from the mid-$70 range in late November to $47 during the last week of December parallels the decline in gas prices. Contract prices where further depressed during the last few days of the month by storm impacts in the Bay Area, mild weather in the Pacific Northwest and light trading volume.

Figure 3: Daily Peak-Hour Bilateral Contract Prices – Weekly Averages

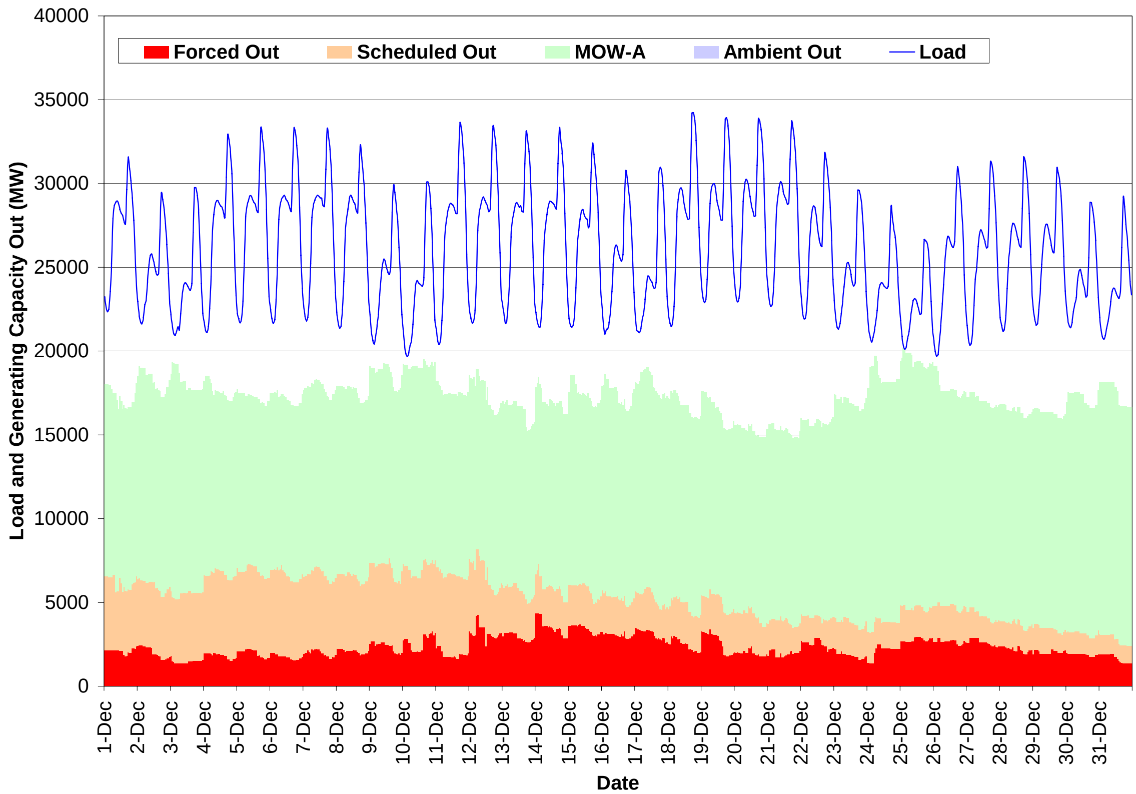


* Bilateral electricity prices indicate the general level of prices at which electricity is being traded in California. The ISO's Real-Time Market is a balancing market and generally serves only a fraction of total load, seldom more than 5 percent.

Generator Outages*

Figure 4 below contrasts cumulative system outages with the system load for the month of December. The average level of planned outages was slightly over 4,000 MW through the first half of the month and fell to under 2,000 MW during the second half as a large amount of base-load generation came back on-line after scheduled maintenance. Accordingly, the level of must-offer waivers increased over this time frame from about 11,000 to 13,000 MW. Forced outages were up on average to 2,300 MW from November's level of 1,800 MW.

Figure 4: Daily Outages by Type v. Load



* As a rule, the level of outages is less important as long as loads are well below peak. Individual outages may affect prices for short periods of time.

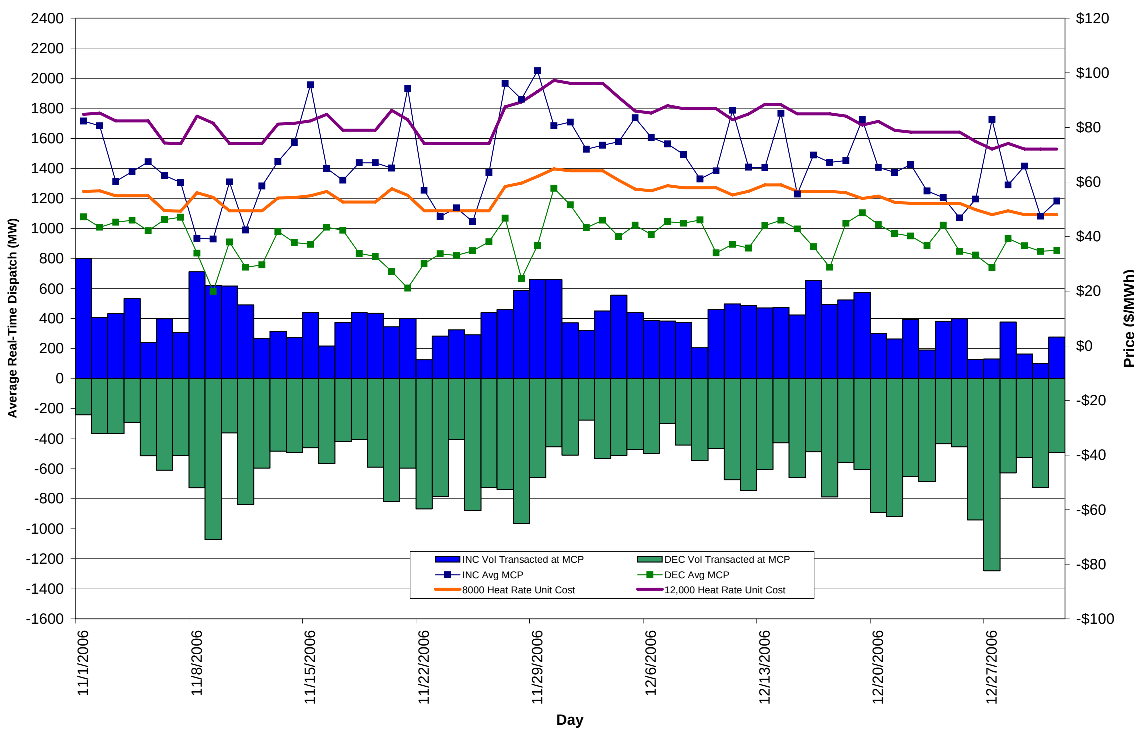
Market Performance Metrics

Real-Time Energy Market

Prices and Volumes*

Real-time dispatch prices were less volatile in December as compared to November, as shown in Figure 5 below. Figure 6 indicates that, on average, both incremental and decremental dispatch prices were slightly higher in December than in November, which is consistent with the trend observed in natural gas prices over the same timeframe.

Figure 5: Daily Average Real-time Price and Volume for In-Sequence Energy – November and December 2006



* Real-time prices and volumes in the balancing energy market are important as they indicate the extent to which load is scheduled in the forward scheduling periods. Unlike the bilateral markets, where pricing is primarily driven by the underlying costs of production and unit efficiency, pricing in the real-time balancing market is strongly influenced by the accuracy of scheduling, load forecasts, and unit commitment decisions.

Figure 6: Monthly Average Real-time Price and Volume for In-Sequence Energy – Jan to Dec 2006

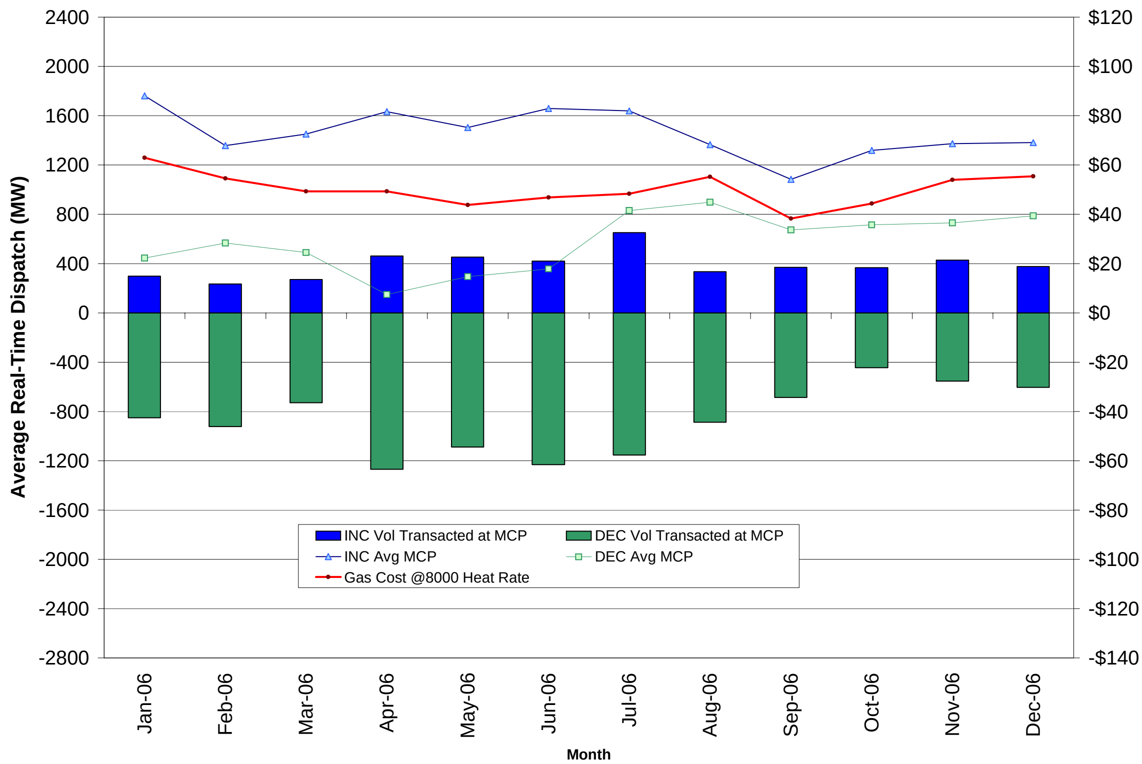


Table 2 presents monthly total dispatch volumes and average prices broken out for on-peak and off-peak energy, incremental and decremental energy, and in-sequence and out-of-sequence energy. Compared to November, total incremental dispatch volume decreased by about 7 percent to 299 GWh in December, while total decremental dispatch volume increased by 10 percent to 517 GWh. Weighted average real-time prices for incremental energy increased moderately by approximately 1.5 percent in December relative to November, while weighted average prices for decremental energy increased by 10 percent.

Table 2: Average Real-Time Dispatch and Prices – November 2006

	In-Seq. RT Dispatch		OOS/OOM RT Dispatch		Total RT Dispatch	
	Inc	Dec	Inc	Dec	Inc	Dec
PEAK	$71.27/MWh 153.82 GWh	$41.41/MWh -261.91 GWh	$62.65/MWh 4.43 GWh	$52.91/MWh -50.54 GWh	$71.03/MWh 158.25 GWh	$43.27/MWh -312.45 GWh
OFFPEAK	$66.46/MWh 125.86 GWh	$36.58/MWh -187.61 GWh	$58.01/MWh 15.16 GWh	$41.1/MWh -16.74 GWh	$65.55/MWh 141.02 GWh	$36.95/MWh -204.35 GWh
ALL	$69.1/MWh 279.68 GWh	$39.4/MWh -449.52 GWh	$59.06/MWh 19.59 GWh	$49.97/MWh -67.29 GWh	$68.45/MWh 299.27 GWh	$40.77/MWh -516.8 GWh

Five-Minute Energy Prices[*]

Five-minute dispatch interval prices and ten-minute settlement interval prices for NP15 and SP15 are plotted in Figure 7 and Figure 8.[1] Real-time dispatch prices were less volatile in December exceeding $250 on only 59 occasions as compared to 88 occasions in November. The majority of these price events (31 out of 59) occurred in the first dispatch interval of the late evening/early morning hours while loads were declining steeply. Since the hourly schedules necessarily decline more sharply than actual load during the first few intervals of these hours, there is usually a large demand for incremental imbalance energy to balance the schedule with the load. Price spikes occurred when the demand for imbalance energy exceeded the bid stack capacity during these intervals. The remaining price spikes in December generally occurred during peak-load hours when the Hour Ahead schedule fell short of actual load demands.

[*] Five-minute energy prices are important as they provide an indication of the extent to which the real time market is strained by either load patterns or system events.

Figure 7: NP15 Real Time Dispatch and Settlement Prices

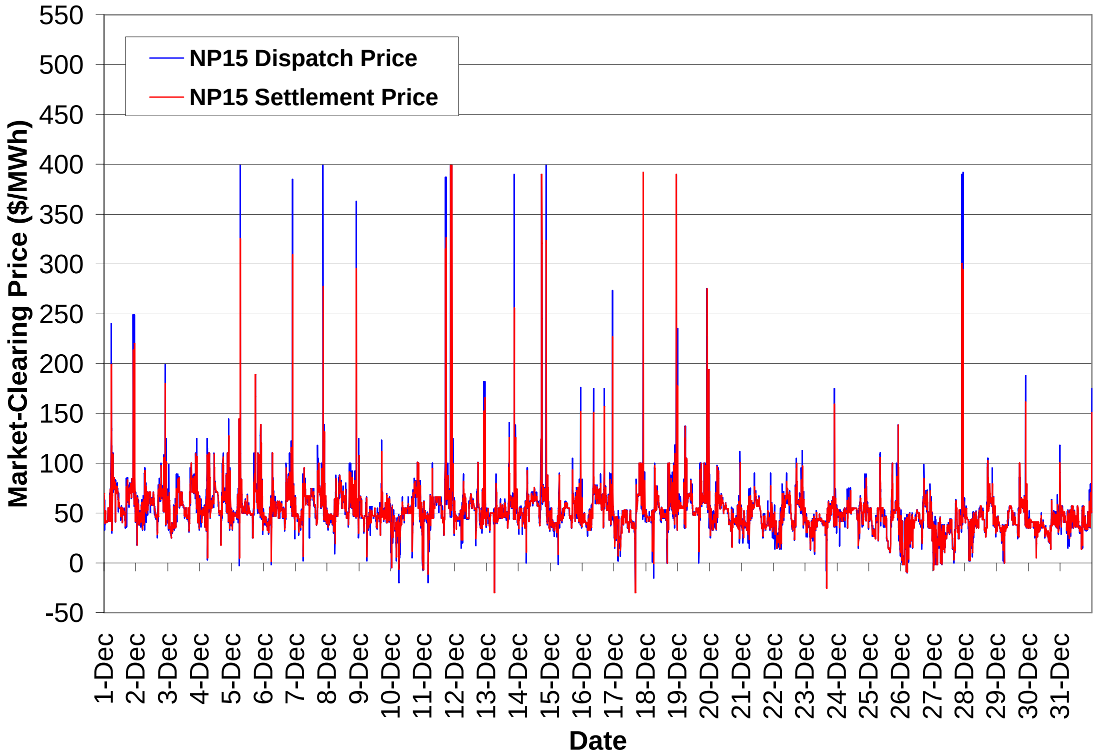
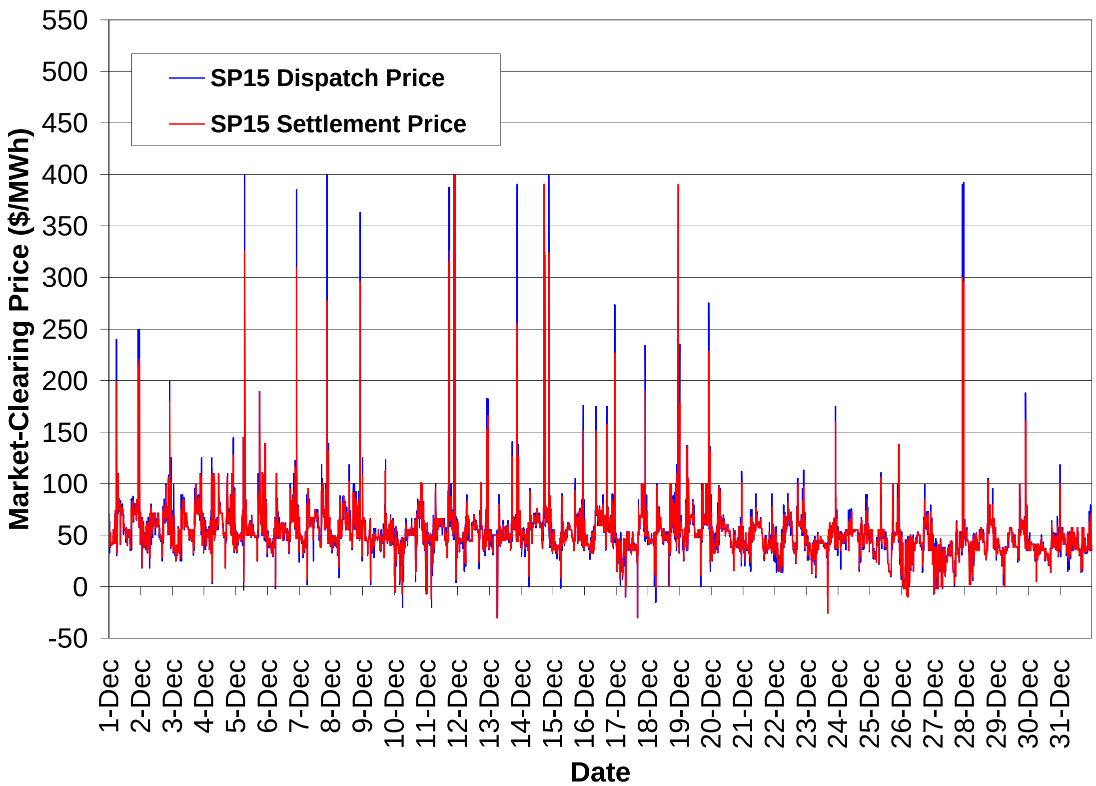


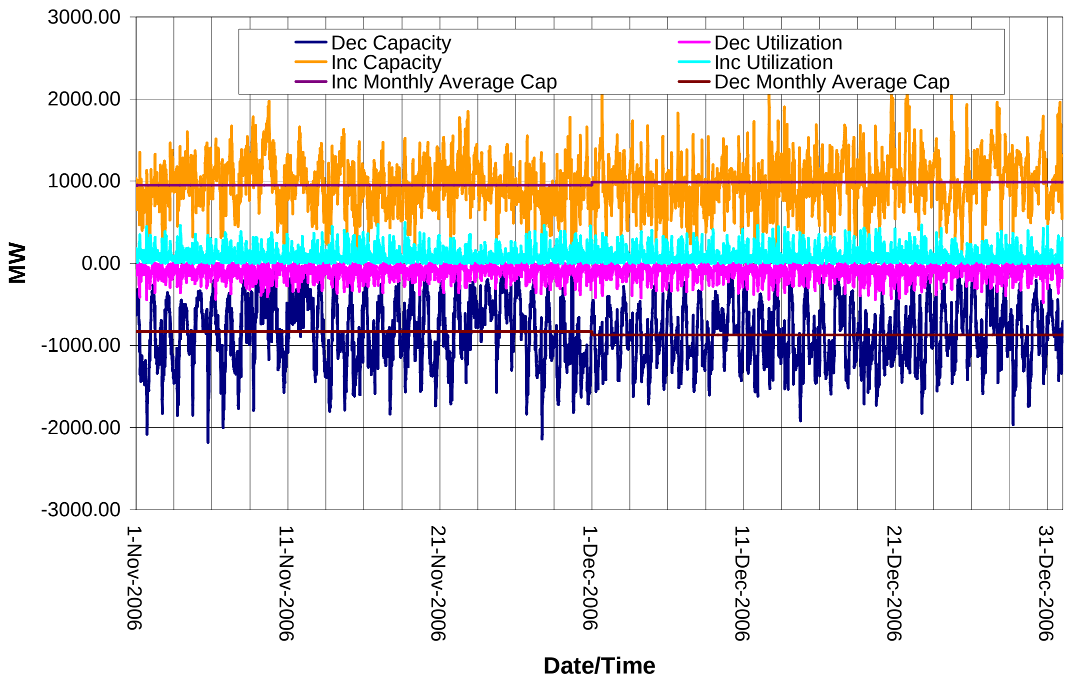
Figure 8: SP15 Real Time Dispatch and Settlement Prices



Five-Minute Bid Stack Utilization*

Five-minute incremental and decremental bid stack capacity and utilization for November and December are illustrated in Figure 9 below. Both the average incremental and decremental bid stack capacities increased slightly in December, while average bid stack utilization decreased. The larger margin between bid stack capacity and utilization in December is consistent with observed decline in prices exceeding $250.

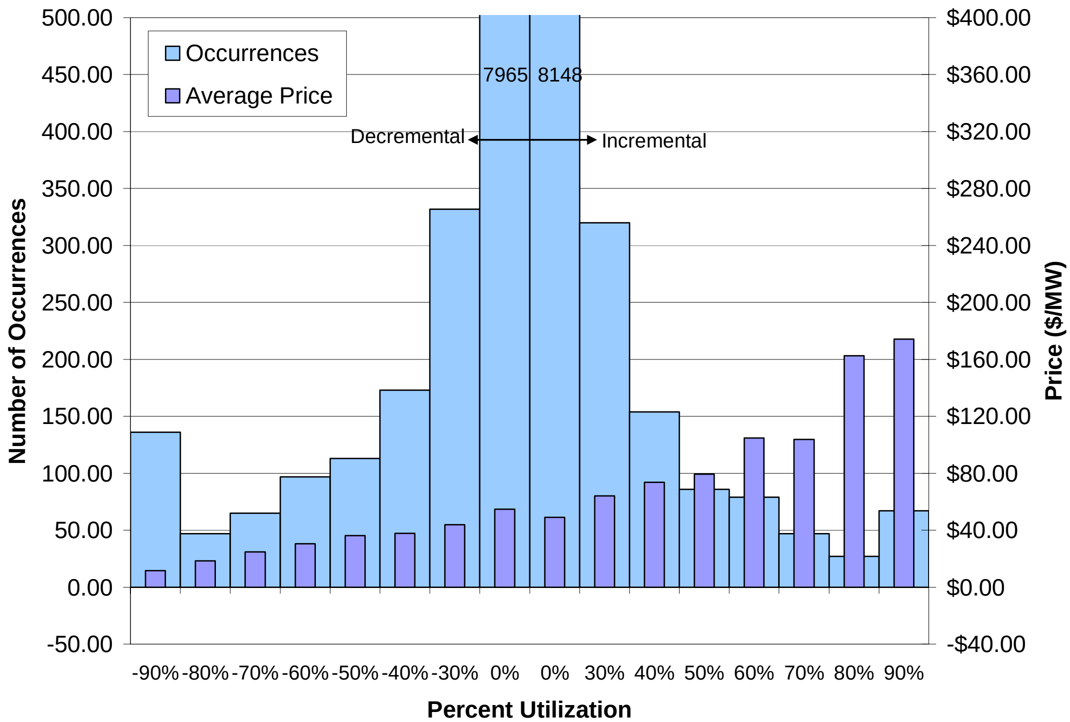
Figure 9: Five-Minute Stack Capacity and Utilization – 6-Interval Moving Average



* The five-minute bid stack utilization is important as it is highly correlated with price spikes and likewise indicates system stresses on the grid, such as ramping periods, and occasionally grid events as well, such as forced outages of major transmission lines or generators.

Relative to November, the bid stack utilization histogram in Figure 10 reflects a decline in incremental capacity utilization. There were 67 instances of five-minute intervals with over 90 percent incremental stack utilization in December compared to 91 in November. At the same time, the frequency of over 90 percent decremental stack utilization was 136 instances in December compared with 214 in November.

Figure 10: Five-Minute Stack Utilization Histogram – November 2006 6-Interval Moving Average

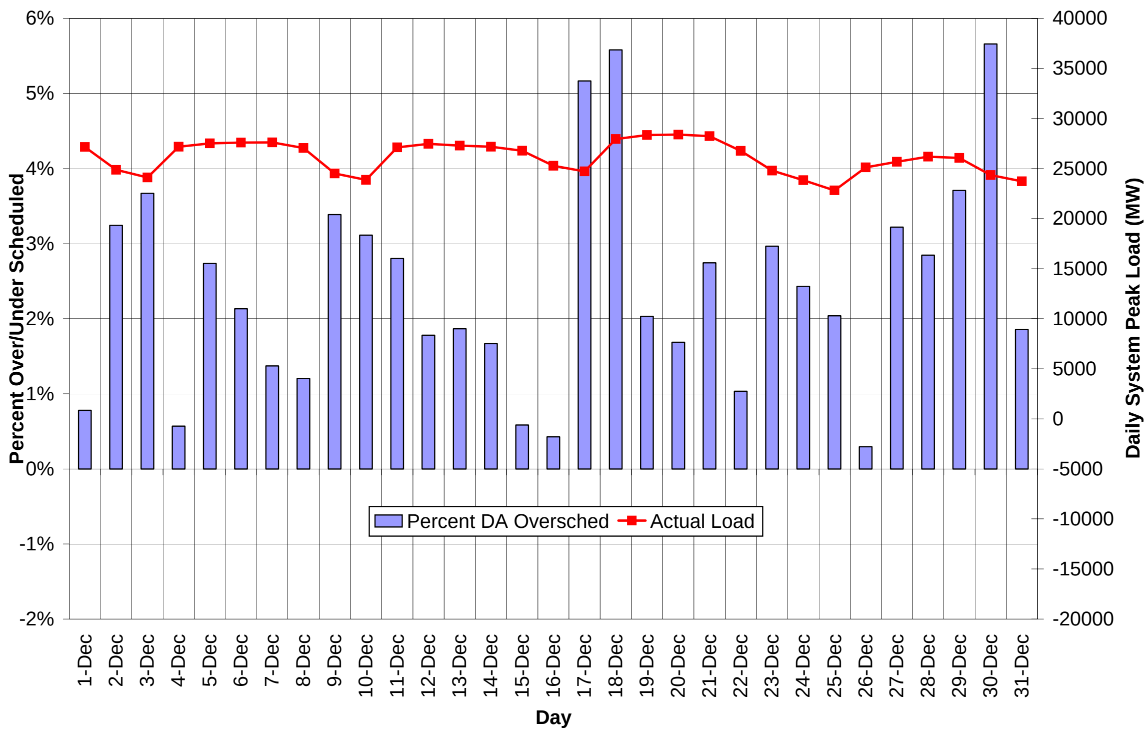


Over- and Under-Scheduling

Day-Ahead Scheduling Deviations*

Figure 11 displays the aggregate deviation between Day-Ahead schedules and Day-Ahead forecasts for all Schedule Coordinators (SCs) in the CAISO control area. As has been the trend over recent months, on an average daily basis SCs continue to consistently over schedule relative their forecasts.

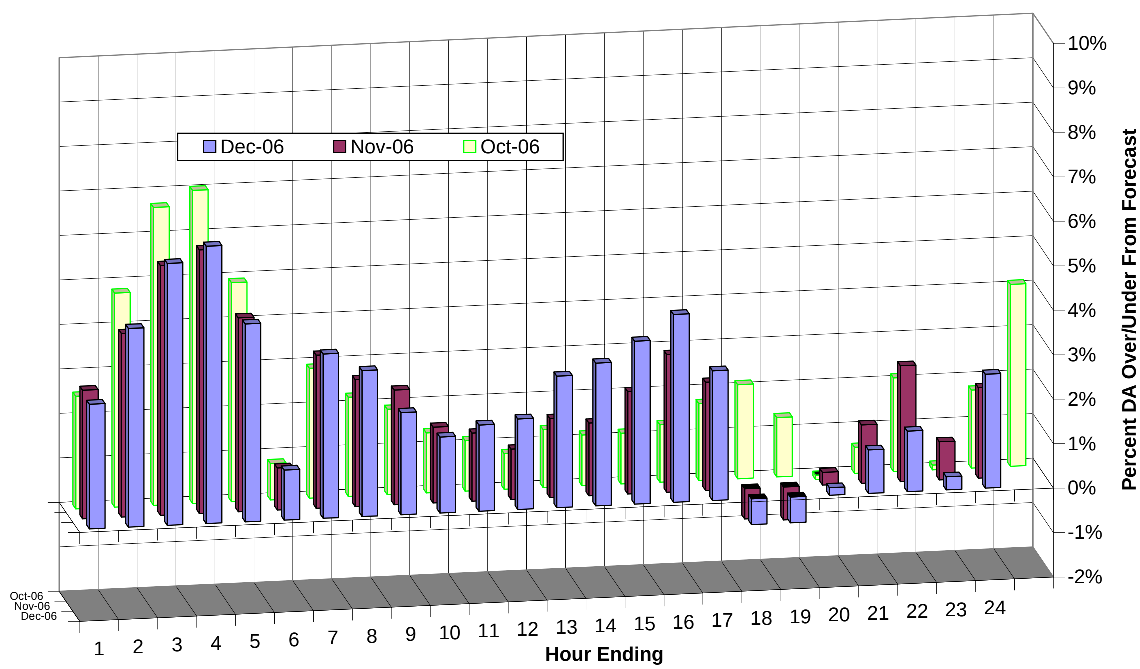
Figure 11: SC Day-Ahead Average Scheduling Deviation compared to SC Forecast – December 2006



* In the Day-Ahead framework SCs jurisdictional entities are required to schedule 95 percent of their forecast load day-ahead in accordance with Amendment 72 of the CAISO Tariff. Besides the tariff compliance aspects the day-ahead scheduling deviations are important in that an SC that accurately schedules to meet its load forecast will thereby be more likely to commit long-start resources to serve its load. This reduces the need for California ISO to utilize Resource Adequacy or Must Offer commitments to assure adequate generation capacity to serve the load.

While SCs may consistently schedule above their forecast load by about two percent on a daily basis, the breakdown by hour displays an uneven pattern. Figure 12 below indicates that during December SC schedules primarily targeted the forecast peak between Hours Ending 18 and 20 where, on net, the tendency was to underschedule slightly.

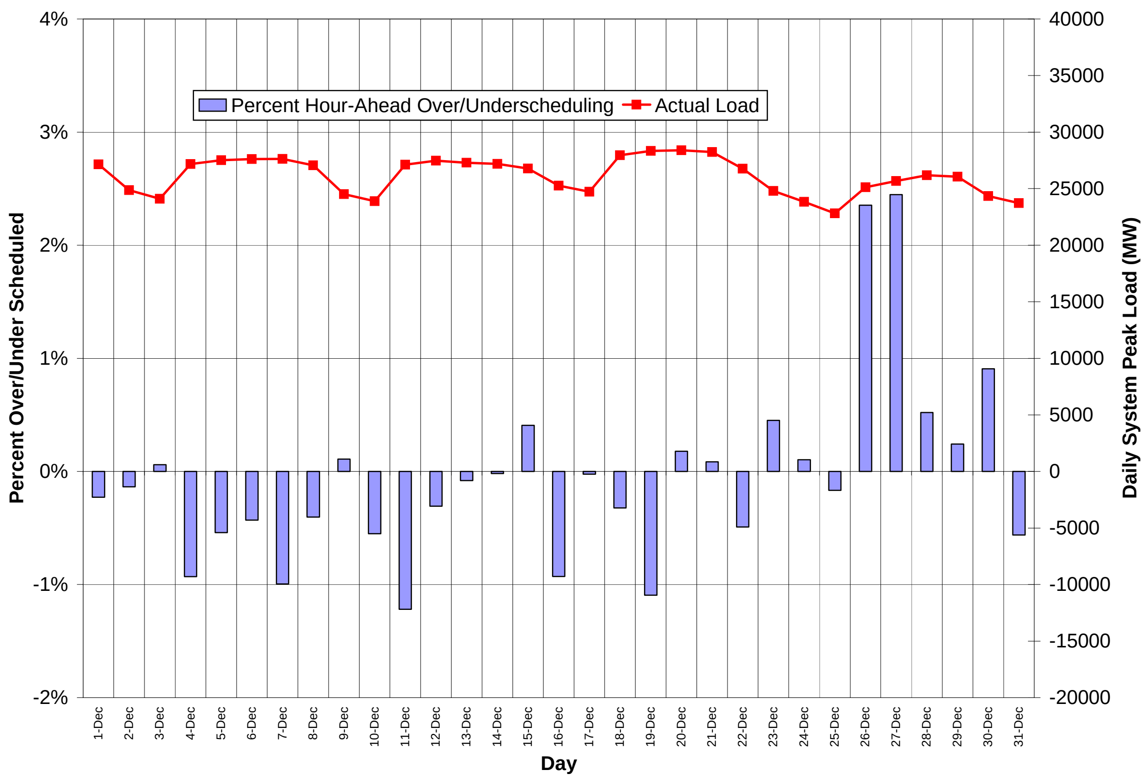
Figure 12: SC hourly Average Day Ahead Scheduling Deviation Compared to SC Day Ahead Forecast – Sep 2006 through Nov 2006



Hour-Ahead Scheduling Deviations*

On average, there was a slight tendency for scheduling coordinators to underschedule relative to actual load in the Hour Ahead, although the deviations were quite small and rarely exceeded one percent. The sharp spike in overscheduling on December 26th and 27th reflect the difficulty in accurately forecasting load demand in the days immediately preceding and subsequent to major holidays like Christmas.

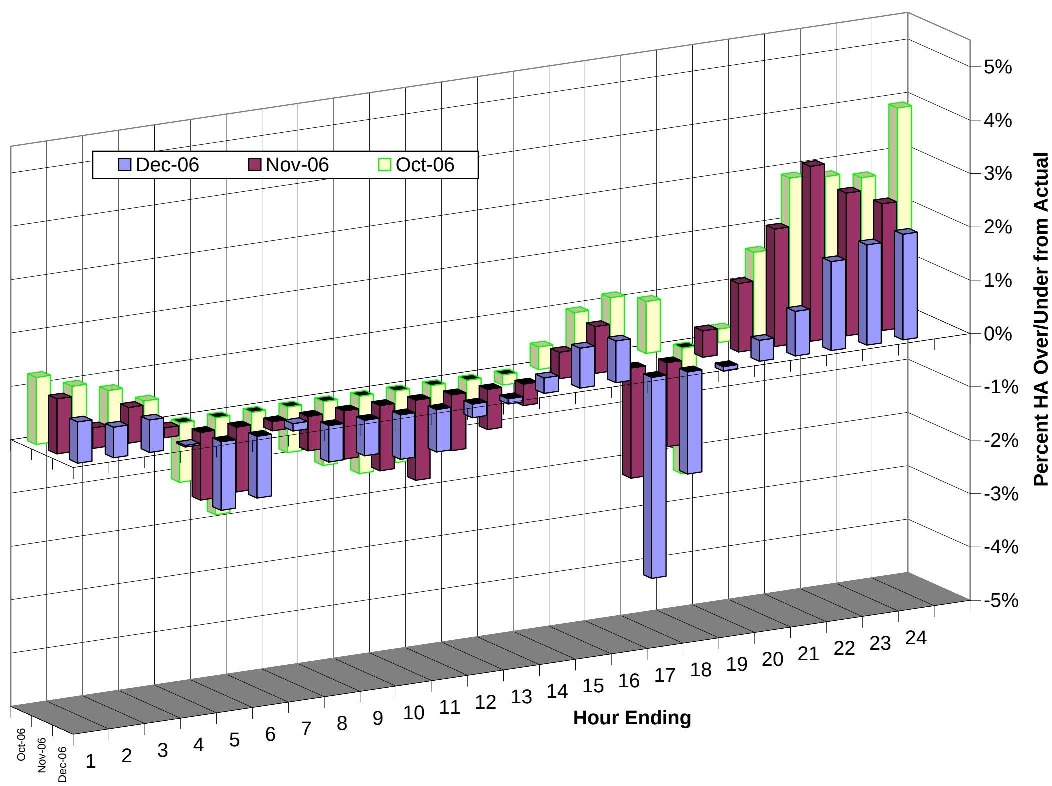
Figure 13: Average Scheduling Deviation Percentages By Day*



* In the hour-ahead framework under and over-scheduling indicates the extent to which LSEs schedule resources to meet their load. Figure 13 shows scheduling deviation percentages between actual load and final Hour-Ahead schedules. These percentages are most directly associated with the volume of dispatch and consequently price in the real time energy markets.

Figure 13 show the hourly averages for scheduling deviation for December, where the tendency to over-schedule during the late evening and early morning ramp-down, and under-schedule at the start of the morning load pick-up, remains apparent. Also apparent in Figure 14 is that during the month of December it becomes increasingly more difficult to accurately schedule load around the peak Hours Ending 17 and 18 as the evening load ramps become steeper. This is reflected in the increased error margins during these late evening hours.

Figure 14: Hour-Ahead Over- And Under-Scheduling Percentages Averaged By Hour* – Sep 2006 through Nov 2006

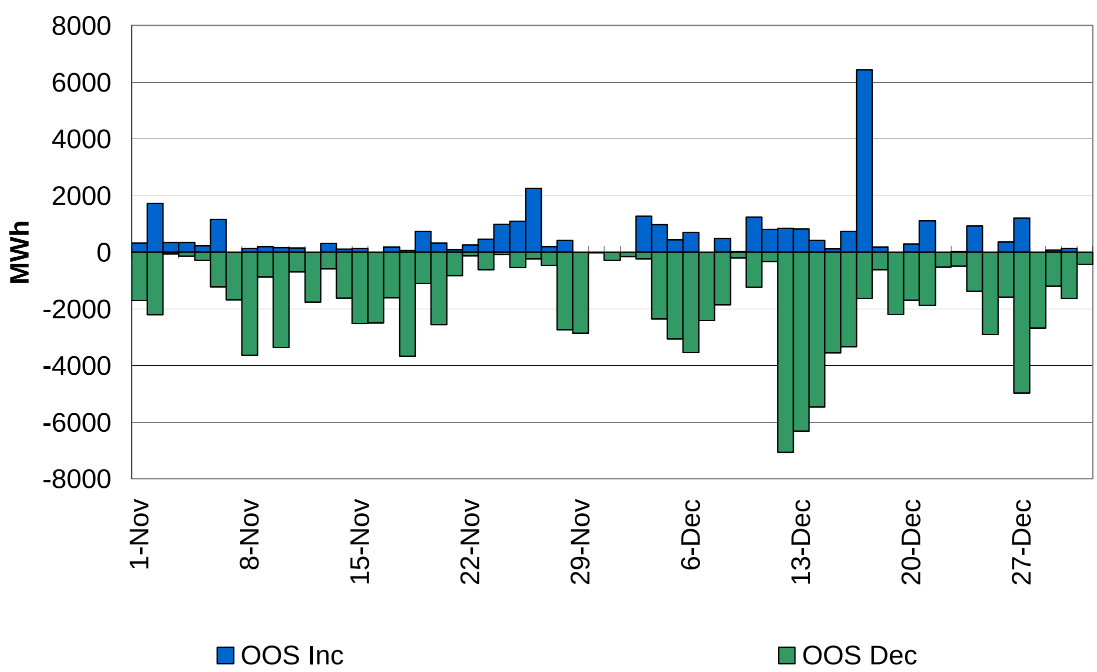


Note: Positive values reflect over-scheduling and negative values reflect under-scheduling.

Out-of-Sequence Dispatches*

Daily MWh dispatch volumes for incremental and decremental Out-of-Sequence (OOS) dispatches are shown in Figure 15. Both incremental and decremental volumes increased by 59 percent in December as compared to November. In December the Incremental OOS dispatch rose to 20,000 MWh and decremental OOS dispatch rose to 57,000 MWh.

Figure 15: Daily OOS MWh – November and December 2006



*OOS dispatches are used to reduce intra-zonal congestion and thus the volume and cost of OOS dispatches indicates the magnitude of transmission constraints on the grid within the CAISO Control Area and how expensive they are to mitigate in real-time. These graphs represent the most accurate data available at the time of publication and these quantities may be significantly adjusted during the settlements process.

Figure 16 displays cumulative daily incremental re-dispatch costs (the premium in excess of the Market Clearing Price) for November and December, broken out by the associated reason for the dispatch. Incremental re-dispatch costs more than doubled to $410,000 in December, up from November's costs of $190,000. The dominant proportion of the costs (60 percent) were driven by system energy reasons. System reasons include intra-zonal congestion related to system reliability and pump load management. For example, a significant proportion of the OOS cost incurred on December 3rd were motivated by concerns of possible transmission losses due to the Ventura County wild fires. And on December 17th, pumps were shut down to avoid a conflict with a nomogram. Incremental re-dispatch costs accounted for 20 percent of the total and were attributed to the mitigation of intra-zonal congestion at West of Devers.

Figure 16: Daily Incremental OOS Re-Dispatch Costs by Reason November and December 2006

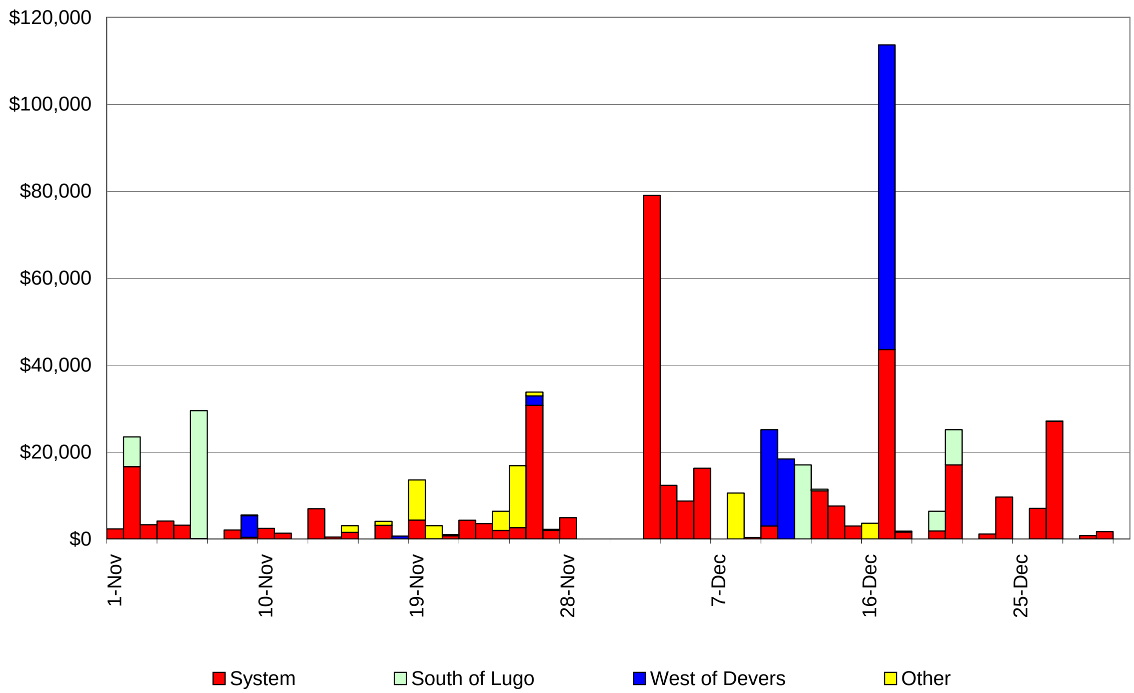
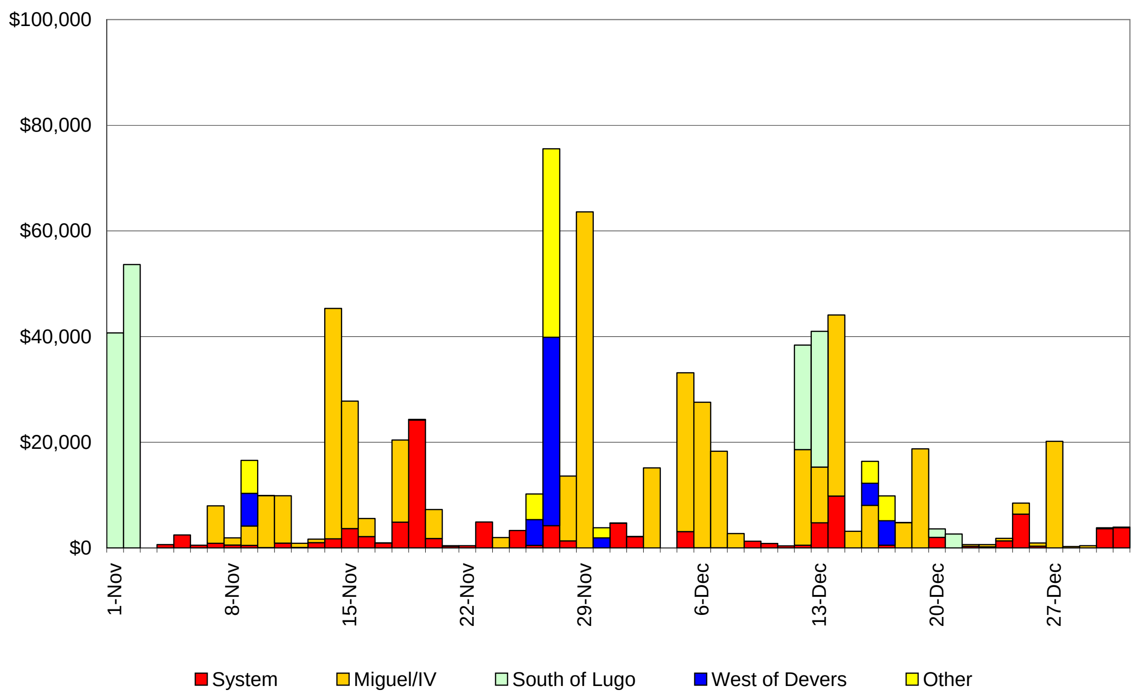


Figure 17 shows cumulative daily decremental re-dispatch costs for November and December, again broken out by the associated reason for the OOS dispatch. While the volume of decremental OOS dispatch in December rose 60 percent above November's level, the re-dispatch costs were almost unchanged at a level of $420,000. Half of the decremental re-dispatch costs were attributed to mitigation of intra-zonal congestion on Miguel and Imperial Valley Banks.

Figure 17: Daily Decremental OOS Re-Dispatch Costs by Reason November and December 2006

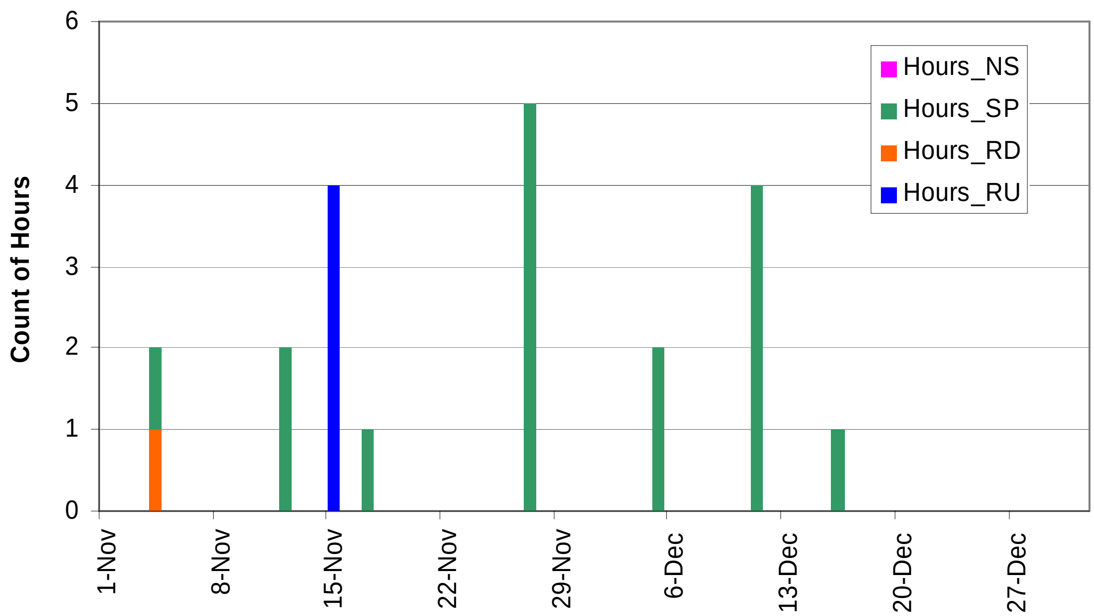


Availability of Ancillary Services[2*]

Bid Insufficiency

The frequency of bid-insufficient hours decreased to 7 in December from 14 in November. The daily breakdown of bid-insufficient hours for the months of November and December is shown in Figure 18 below. The main reasons for bid-insufficiency in December were inter-zonal congestion on the Mead branch group, which caused Ancillary Service bids from dynamic system resources to become unavailable during certain hours. In addition, several units were operated near their maximum operating limits, which prevented them from providing previously bid spinning reserve.

Figure 18: Count of Bid-Insufficient Hours – November and December 2006

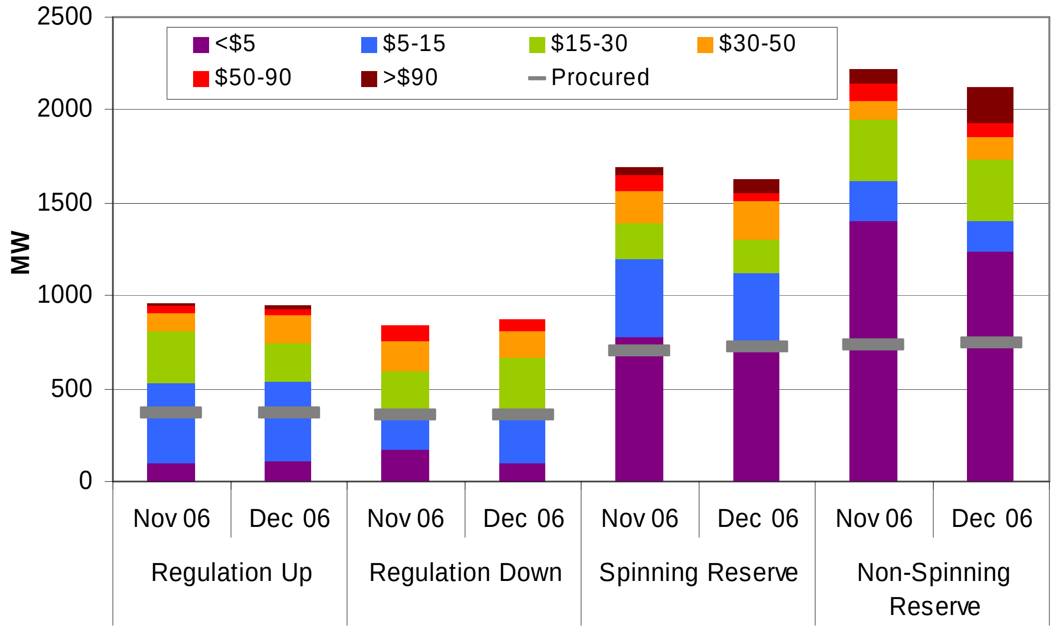


[*] The availability of Ancillary Services (AS) is important as an insufficient supply of AS can increase the cost to load. The availability of AS is also an indication of the relative incentive to use capacity to supply AS or produce energy.

Ancillary Service Supply

Figure 19 below shows the total volume and bid ranges of Ancillary Services that were bid into the market during November and December 2006, as well as the total amount of Ancillary Services ultimately procured by the CAISO. Both the Ancillary Services capacity requirements and bid-in capacity for Regulation Up and Regulation down remained relatively unchanged in December. However, the requirements for Spin and Non-Spin reserves have increased slightly while the bid-in capacities for Operating Reserves have declined slightly in December.

Figure 19: Ancillary Service Day-Ahead Average Bid Volume by Price Bin – November and December 2006



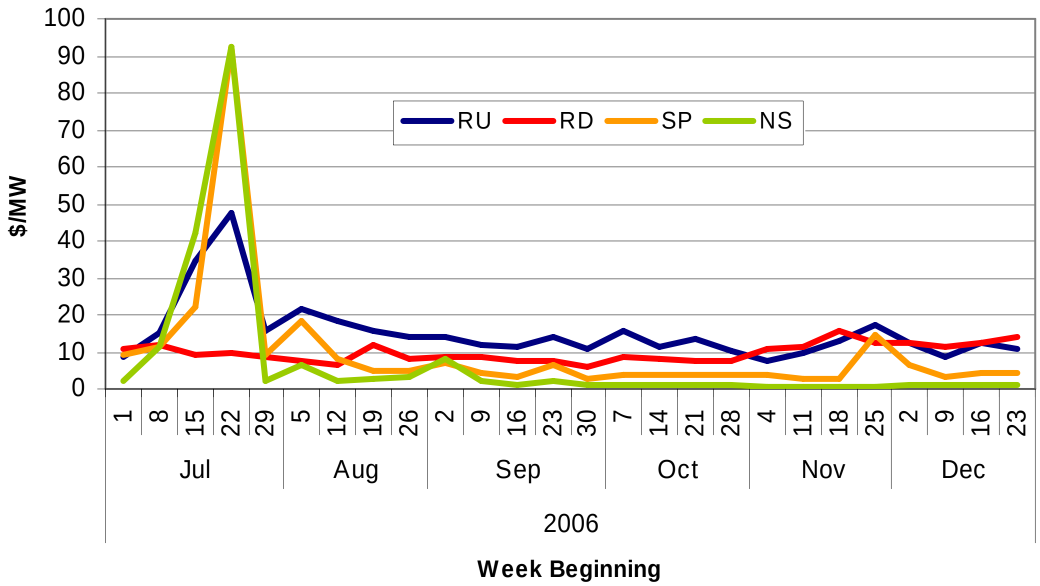
Ancillary Services Market Prices*

As compared to November, weighted average Ancillary Services prices for Non-Spinning Reserve increased sharply in December, but declined significantly for Spinning Reserve. Table 3 shows the price breakout for each service separately, while Figure 20 below displays the six-month price trend on a weekly average basis.

Table 3: Average Ancillary Service Requirements and Prices - November and December 2006

	Average Required (MW)				Weighted Average Price ($/MW)			
	RU	RD	SP	NS	RU	RD	SP	NS
Nov 06	387	354	777	809	$ 11.31	$ 11.93	$ 5.89	$ 0.71
Dec 06	381	356	808	831	$ 11.20	$ 12.34	$ 4.48	$ 1.05
%Diff	-1.4%	0.6%	3.9%	2.7%	-0.9%	3.5%	-23.9%	47.6%

Figure 20: Weekly Weighted Average Ancillary Service Prices – 2006

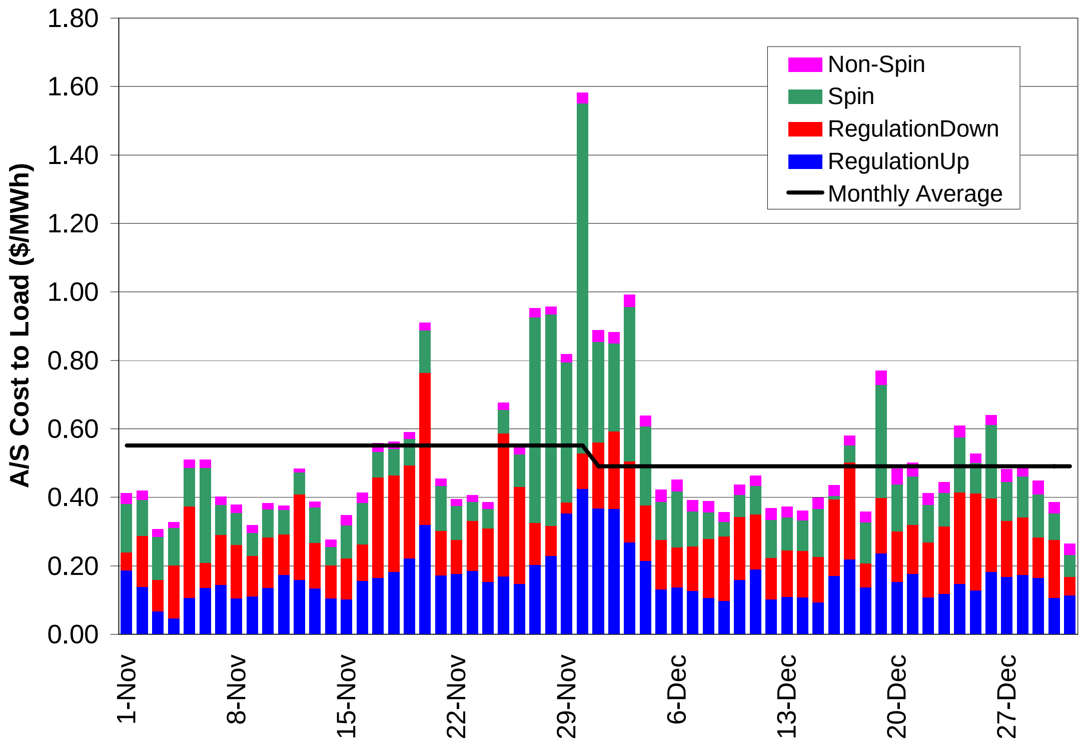


* AS Market prices are important not only as indicators of the cost to load, but also because high AS prices often indicate system stresses.

Cost to Load[3]

The daily total costs of Ancillary Services per MWh of load are presented in Figure 21 for the months of November and December. The average total cost decreased to $0.49 in December from November's $0.55. The decrease in average total costs for Ancillary Services can be attributed primarily to a declining Spin price.

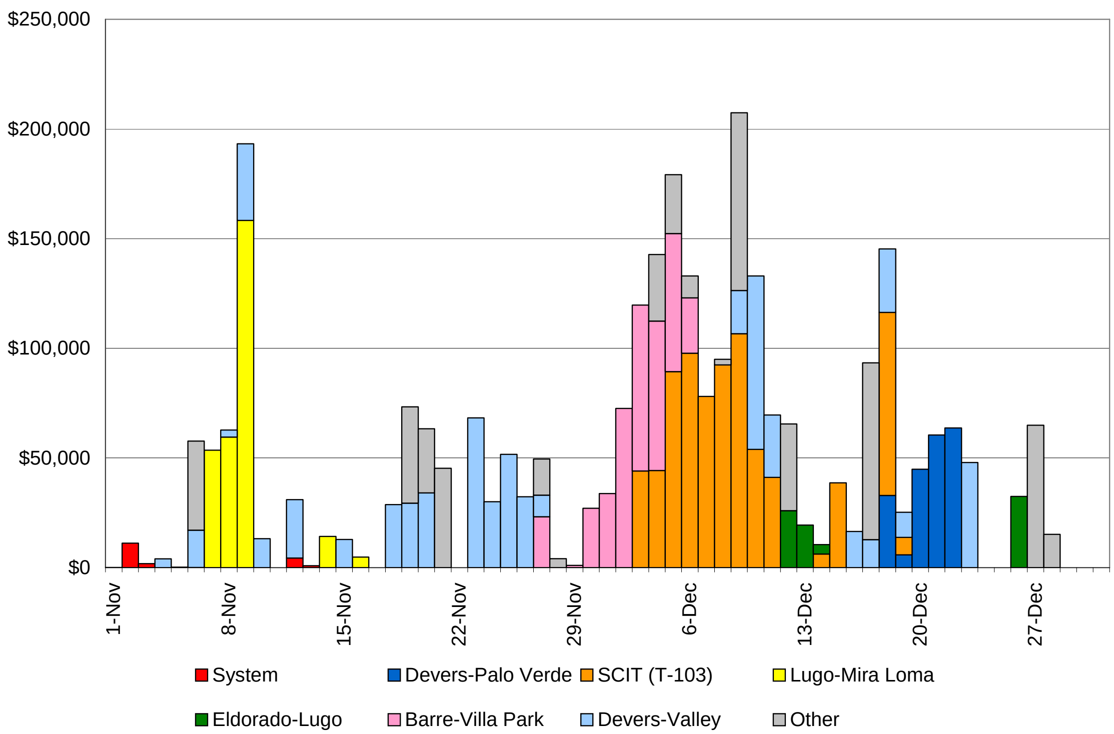
Figure 21: Monthly Ancillary Service Cost to Load – November and December 2006



Resource Adequacy and FERC Must-Offer Unit Commitment [4*]

Total unit commitment costs increased sharply to $2.3 million in December, up from $975,000 in November. The increase in cost was driven primarily by the SCIT nomogram generation requirements, as a significant amount of base load generation in Southern California was off-line for maintenance through the first two-thirds of the month. The remaining 60 percent of unit commitment costs were driven by transmission line maintenance in Southern California. Figure 22 shows unit commitment costs by reason for those units that were committed under Resource Adequacy (RA) rules during November and December.

Figure 22: Resource Adequacy Costs by Reason – November and December 2006



[*] Resource Adequacy and FERC must-offer metrics are important as they indicate the extent to which the CAISO has to rely on backstop procedures to ensure grid reliability. Ideally, the CAISO would not rely on must-offer commitments at all. It would prefer to rely on Resource Adequacy unit commitment rather than FERC must-offer commitments.

Unlike the prior months of October and November, there were a small number of FERC must-offer unit commitments in the Day-Ahead this December, as displayed in Figure 23. Concerns over the possible loss of transmission lines due to wild fires in Ventura County motivated the commitment of specific units under the FERC Must-Offer rules on December 4th and 5th. Later in the month, maintenance on the Devers-Palo Verde transmission lines also required several unit commitments. The total cost for unit commitments in accordance with the FERC Must-Offer rules in December was approximately $300,000.

Figure 23: FERC Must Offer Costs by Reason – November and December 2006

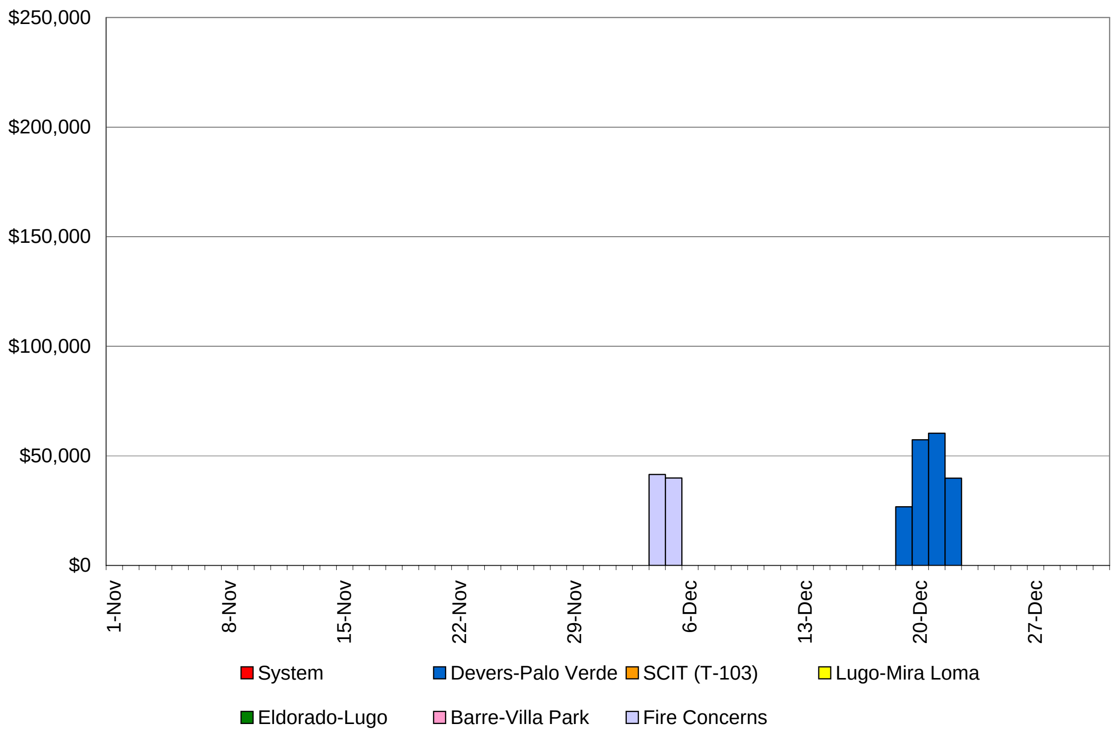
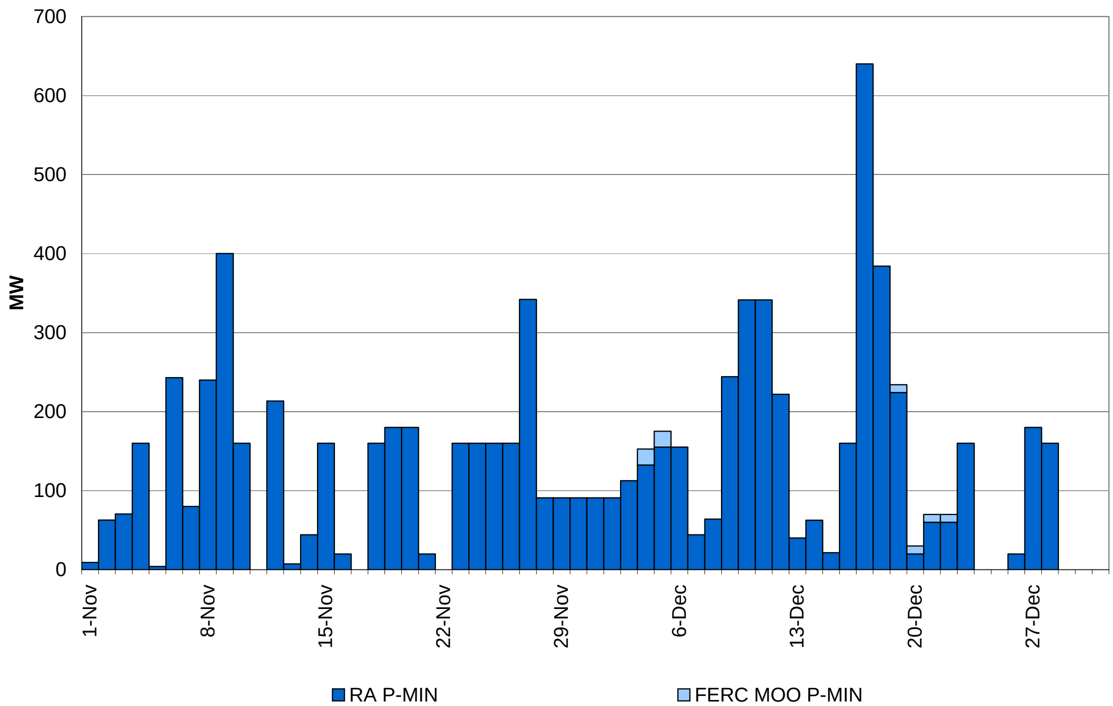


Figure 24 shows the daily minimum load values (p-mins) of the RA and FERC must-offer units committed in the Day Ahead during November and December.* The average daily minimum load for the month of December was approximately 140 MW.

Figure 24: RA and FERC MOO P-MIN – September and October 2006



* The cumulative p-mins are important as this energy spills into the Real-Time Market and can exacerbate the off-peak over-generation problems. Ideally one would want the cumulative p-mins to be as low as possible. The p-min MW numbers are calculated by summing the p-min MW values of all committed units for each day.

Inter-Zonal Markets

Congestion Costs[*]

Total inter-zonal congestion costs rose to $6 million in December from $5 million in November which is just about average for the past 12 months, and well below the December 2005 total of $8.5 million. Congestion costs by branch group for the month of December are depicted in Table 4. Over two-thirds of the congestion costs occurred on the Palo Verde branch group, and most of this congestion occurred between the dates of December 19 and 22 while the Palo Verde-Devers transmission line was removed from service to complete construction of a transmission tower. The remaining congestion costs listed in Table 4 resulted largely from over-scheduling.

Table 4: Inter-Zonal Congestion Costs – December 2006

Congestion Cost by Branch Group: 01-Dec-06 to 31-Dec-06

Branch Group	Day-ahead		Hour-ahead		Total Congestion Cost		Total Congestion Cost		Total Congestion	Total Cost Percent
	Import	Export	Import	Export	Import	Export	Day-ahead	Hour-ahead		
ADLANTOSP	$49,919	$0	-$2,331	$0	$47,588	$0	$49,919	-$2,331	$47,588	1%
BLYTHE	$3,283	$0	-$5	$0	$3,277	$0	$3,283	-$5	$3,277	0%
ELDORADO	$157,356	$0	$27,369	$0	$184,725	$0	$157,356	$27,369	$184,725	3%
IID-SCE	$1,338	$0	$3,010	$0	$4,348	$0	$1,338	$3,010	$4,348	0%
IPPDCADLN	$172,729	$0	-$8	$0	$172,722	$0	$172,729	-$8	$172,722	3%
MEAD	$193,862	$0	-$15,980	$0	$177,882	$0	$193,862	-$15,980	$177,882	3%
MELONPLNT	$0	$0	$0	$451	$0	$451	$0	$451	$451	0%
MKTPCADLN	$25,382	$0	-$748	$0	$24,634	$0	$25,382	-$748	$24,634	0%
NOB	$0	$0	$11,097	$0	$11,097	$0	$0	$11,097	$11,097	0%
PACI	$484	$0	$39,554	$0	$40,038	$0	$484	$39,554	$40,038	1%
PALOVRDE	$4,114,352	$0	-$49,366	$0	$4,064,986	$0	$4,114,352	-$49,366	$4,064,986	67%
PARKER	$6,190	$0	$502	$0	$6,692	$0	$6,190	$502	$6,692	0%
PATH15	$1,461,872	$0	-$162,916	$0	$1,298,955	$0	$1,461,872	-$162,916	$1,298,955	22%
WSTWGMEAD	$630	$0	$40	$0	$670	$0	$630	$40	$670	0%
Total	$578,487	$0	$12,056	$0	$590,543	$0	$578,487	$12,056	$6,038,066	100%

[*] Inter-zonal congestion costs are important as they indicate which transmission lines are a bottleneck into or out of the CAISO system, and often which lines suffered forced outages, which is one of the main causes of increased costs.

Table 5 below provides a breakout of average congestion prices and percentage of time congested by branch group.

Table 5: Inter-Zonal Congestion Prices and Frequencies – December 2006

Congestion Price and Frequency by Branch Group: 01-Dec-0631-Dec-06

	Day-Ahead Market				Hour-ahead Market			
	Percentage of Hours Being Congested (%)		Average Congestion Price ($/MWh)		Percentage of Hours Being Congested (%)		Average Congestion Price ($/MWh)	
	Import	Export	Import	Export	Import	Export	Import	Export
ADLANTOSP_BG	1	0	$5		1	0	$41	
BLYTHE _BG	6	0	$1		0	0	$0	
ELDORADO _BG	7	0	$2		1	0	$25	
IID-SCE _BG	0	0	$2		0	0	$70	
IPPDCADLN_BG	33	0	$1		10	0	$55	
MEAD _BG	13	0	$3		6	0	$31	
MELONPLNT_BG	0	0			0	0		$30
MKTPCADLN_BG	2	0	$4		0	0	$0	
NOB _BG	0	0			0	0	$33	
PACI _BG	3	0	$0		4	0	$10	
PALOVRDE _BG	33	0	$10		13	0	$20	
PARKER _BG	1	0	$3		0	0	$136	
PATH15 _BG	4	0	$17		1	0	$6	
SUMMIT _BG	0	0	$0		0	0		
WSTWGMEAD_BG	1	0	$1		0	0	$1	

Endnotes

[1] Five-minute prices are the clearing prices calculated by the ISO real time market application (RTMA) every five minutes. Ten-minute settlement prices are calculated as the average of the two relevant dispatch interval prices, weighted by the dispatch volume in each dispatch interval. Settlement interval prices are significant in that they are the prices used to settle load deviations for real time energy. The ten-minute prices are calculated as a weighted average of two five-minute dispatch interval prices.

[2] Ancillary service requirements for spinning and non-spinning reserve are determined as a percentage of the system demand forecast – normally the higher of 7 percent of forecast demand or the largest system contingency.

[3] The costs to load values are calculated by summing up total A/S costs for the month and dividing by the cumulative monthly system load. The resulting values show the cost contribution of A/S per megawatt-hour.

[4] On June 1st, 2006 the California ISO implemented new Resource Adequacy (RA) rules as directed by the California Public Utilities Commission. These rules require load-serving entities to contract for most of their power needs a year in advance, and to have 115 percent of their requirements contracted for one month in advance. The additional planning reserve is intended to ensure that sufficient generating capacity is available to maintain an operating reserve of approximately seven percent in real time. RA unit commitment works similarly to the FERC Must Offer unit commitment process, which is still in effect. Based on Day-Ahead forecasts and other information, the ISO determines whether additional generating capacity is required for the following day's market. Under the new program, the ISO must first call on "RA units" during the unit commitment process, because their capacity has already been procured through RA contracts. If additional units are required, the ISO can still call on units in accordance with the FERC Must-Offer procedures.