Market Performance Report November 2006

December 22, 2006

ISO Market Services

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Executive Summary

Highlights for November 2006:

- The average load in November 2006 was 25,507 MW – about 250 MW or 1 percent below the average for October 2006.
- Natural gas prices rose slightly during November from October's $7.00 to around $7.50 by month's end.
- Bilateral electricity prices also increased, following the increasing gas prices.
- Scheduled outages increased to an average of 5,200 MW, up slightly from October's 4,500 MW.
- Average real-time energy price increased slightly by 3% from $47.78/MWh to 49.25$/MWh over the past month. Incremental price increased 4% and decremental price increased 3%.
- The frequency of five-minute interval prices exceeding $250 remained relatively unchanged (88 in November vs. 87 in October).
- Re-dispatch volumes and costs of incremental OOS dispatch increased while decremental re-dispatch volumes and costs decreased.
- The average total cost of Ancillary Services increased 26% from October's $0.43/MWh to $0.54/MWh in November. The number of bid insufficiency hours increased from October's 3 to 14 in November.
- Total unit commitment costs reversed a 3-month decline, increasing by 32% from October's $700,000 to $925,000 in November.
- Total inter-zonal congestion costs increased to $5 million in November from $3.4 million in October.

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Market Characteristics

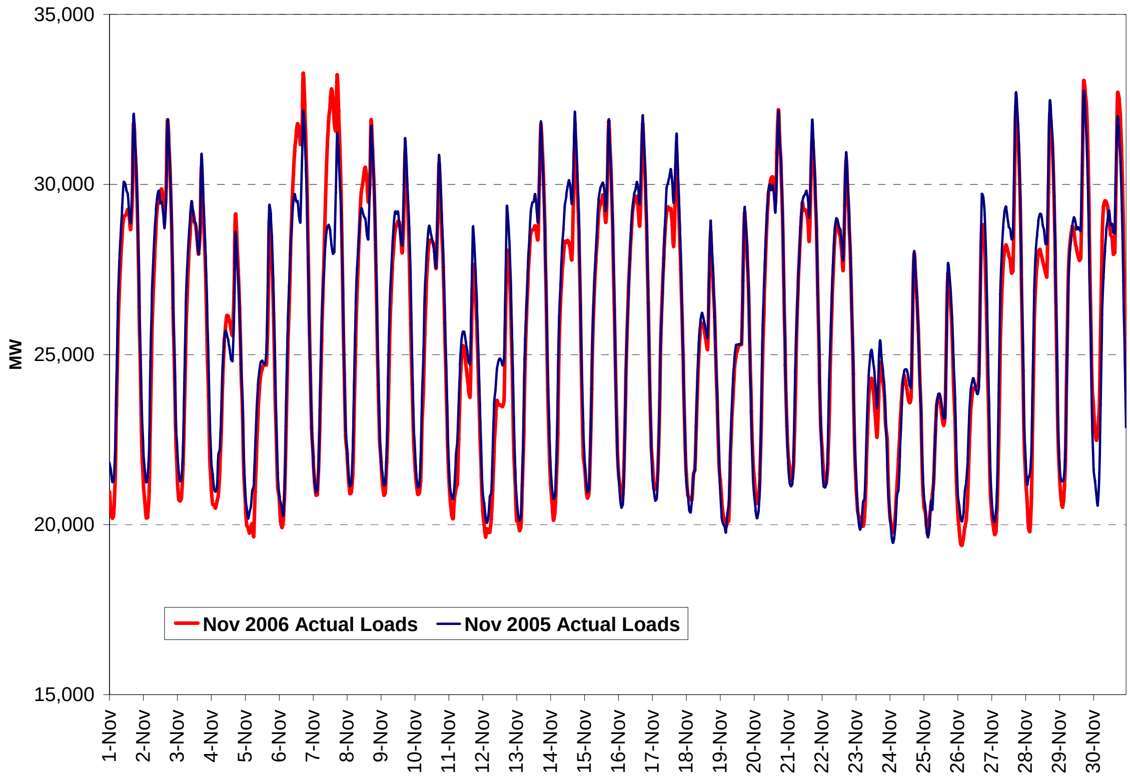
Loads

The average hourly load pattern for the CAISO control area during November 2006 was typical for this time of year. The peak load for the month was 33,249 MW (32,430 MW in October), while the average load was 25,507 MW (25,748 MW in October). Overall, the month was slightly cooler than November 2005 as seen in Table 1 below. This month's average load was about 250 MW or 1 percent below the average for the preceding month of October. Figure 1 below provides a graphical comparison of the load pattern in November 2006 vs. November 2005.

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

	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
December-05	-2.7%	-1.8%	-4.3%	-1.5%
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%
Yearly Average	-4.9%	-3.0%	-3.5%	-26.5%

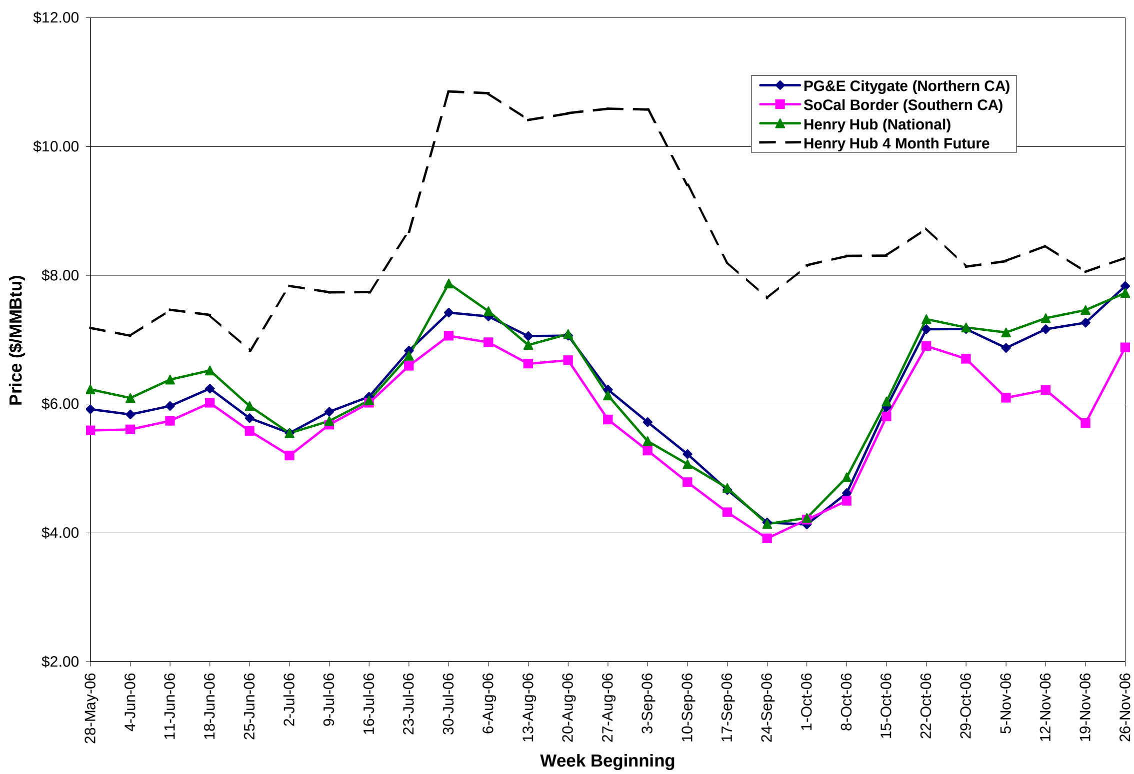
Figure 1: System Load Comparison - November 2006 v. November 2005



Natural Gas Storage and Prices*

Natural gas prices rose slightly during November in Northern California and across the U.S. consistent with unseasonably cold weather in Canada and rising crude oil prices, as seen in Figure 2 below. At the same time, prices declined sharply at the Southern California border as milder autumn temperatures endured in much of the Pacific Southwest. High inventories on the PG&E pipeline system prevented gas traders from taking advantage of an obvious arbitrage opportunity by moving additional gas from South to North. Inter-regional trades where prohibited throughout the month as PG&E declared numerous system-wide, high-inventory operational flow orders, which imposed financial penalties on shippers who didn't adhere to their scheduled deliveries. As of Friday, November 24, natural gas in storage across the continental U.S. was 3,417 Bcf or 7.2 percent above the 5-year average.

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

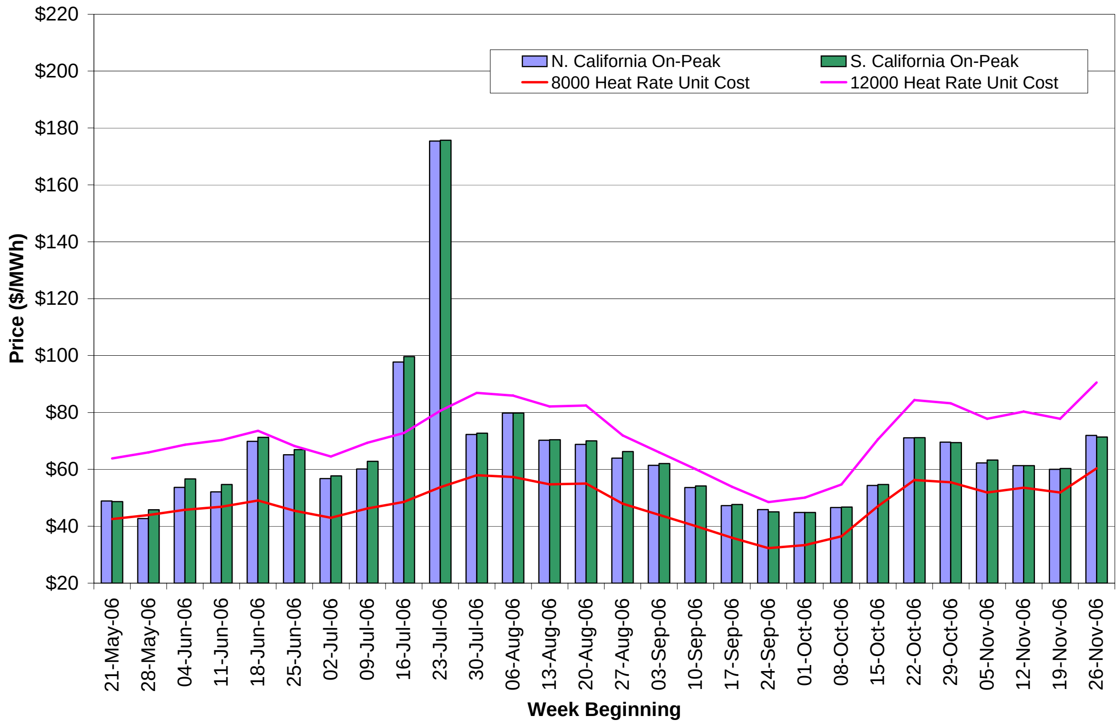


* Natural gas prices are important to the market as much of the capacity in the West, especially the newer units, are gas-fired. These units are also often marginal, meaning that they set the price levels in bilateral markets. The four-month futures price is an indication of market expectations of pricing 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. With no other discernable market forces to act upon them, bilateral electricity prices in November closely followed the pattern of natural gas prices in Figure 2.

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

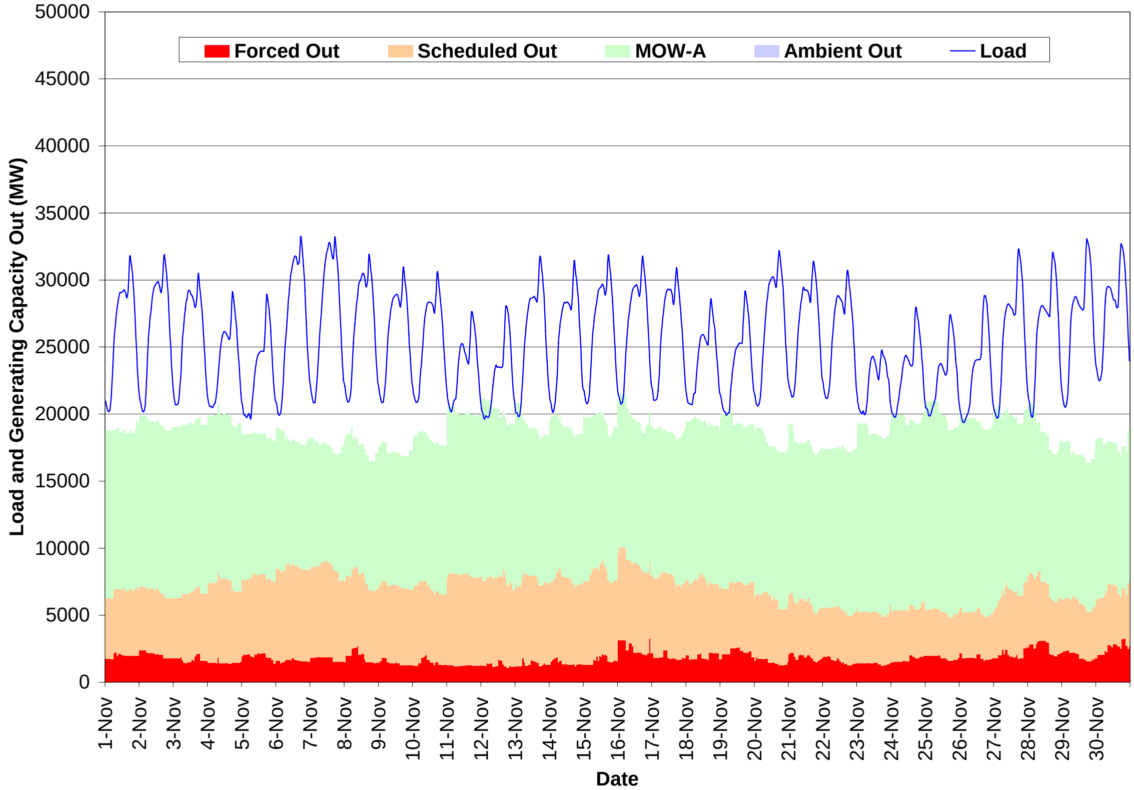


* Bilateral electricity prices indicate the general level of prices at which electricity is being traded in California. The ISO's Real-Time Market is a balancing market and generally serves only a fraction of total load, seldom more than 5 percent.

Generator Outages*

Figure 4 below contrasts cumulative system outages with the system load for the month of November. Outage levels were relatively stable throughout the month with no significant trend. The average level of scheduled outages was 5,200 MW – up slightly from October's average of about 4,500 MW. The average level of forced outages also climbed to 1,800 MW from October's unusually low average of 1,200 MW. The average level of must-offer waivers increased marginally from 10,000 MW in October to 12,000 in November consistent with the decline in daily load peaks.

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.

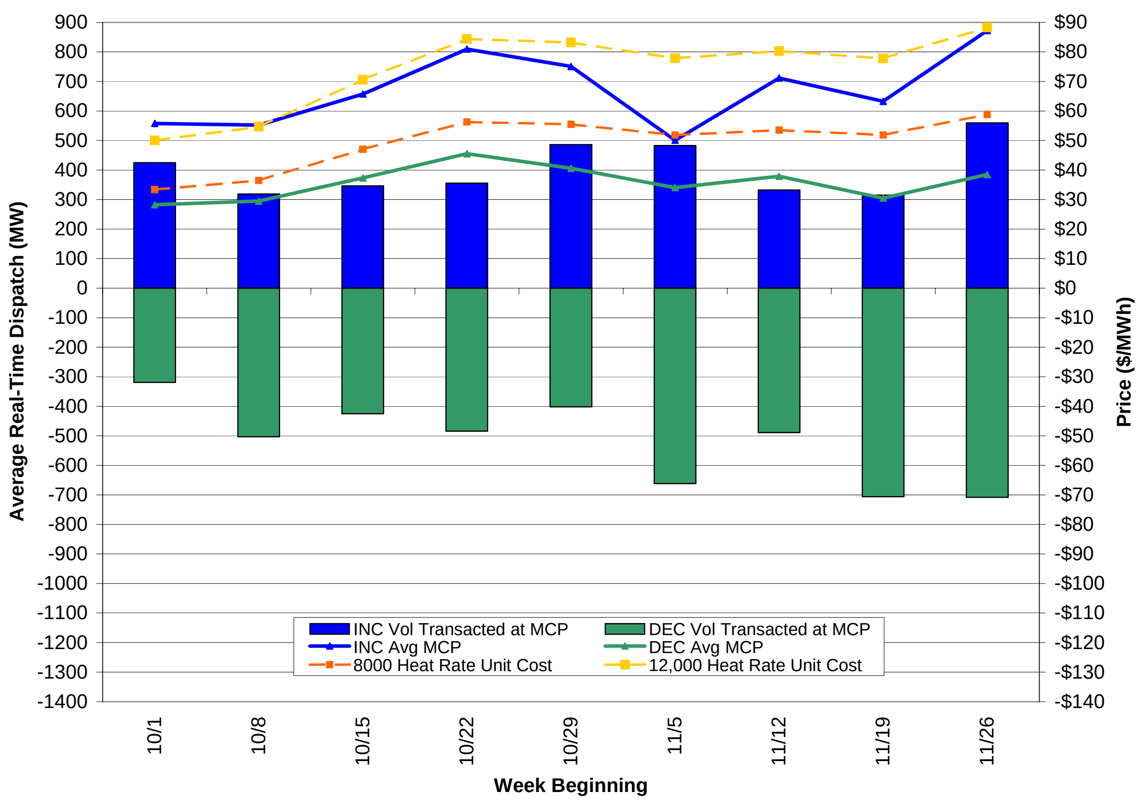
Market Performance Metrics

Real-Time Energy Market

Prices and Volumes*

Real-time dispatch prices were more volatile in November as compared to October, as Figure 5 illustrates. Incremental dispatch prices trended higher throughout November while the decremental dispatch prices remained nearly unchanged. The dispatch prices trend is consistent with the trend observed in natural gas prices over the same timeframe.

Figure 5: Weekly Average Real-time Price and Volume for In-Sequence and Out-of-Sequence Energy – October and November 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.

Table 2 presents the 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 October, net incremental dispatch volume increased by about 17% to 322.04 GWh in November, while net decremental dispatch volume increased by 21% to -469.58 GWh. Weighted average real-time prices increased for incremental energy increased moderately in November relative to October by approximately 4%, while decremental prices for incremental energy decreased by 3%.

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	$72.33/MWh 195.75 GWh	$36.99/MWh -264.8 GWh	$61.66/MWh 3.96 GWh	$53.8/MWh -33.08 GWh	$72.12/MWh 199.72 GWh	$38.85/MWh -297.88 GWh
OFFPEAK	$60.8/MWh 113.49 GWh	$33.08/MWh -162.56 GWh	$47.82/MWh 8.81 GWh	$34.01/MWh -9.15 GWh	$59.87/MWh 122.3 GWh	$33.13/MWh -171.71 GWh
ALL	$68.1/MWh 309.24 GWh	$35.5/MWh -427.35 GWh	$52.11/MWh 12.78 GWh	$49.51/MWh -42.23 GWh	$67.47/MWh 322.02 GWh	$36.76/MWh -469.58 GWh

Five-Minute Energy Prices[*]

Five-minute dispatch interval prices and ten-minute settlement interval prices are plotted in Figure 6 and Figure 7.[1] As compared to October, real-time dispatch price volatility remained about the same in November, exceeding $250 on 88 occasions as compared to 87 occasions in October.

There were three significant periods of high prices: the first on November 27th, the second on November 28th and the third on November 29th. On these days, the system demand ran significantly higher than the day ahead forecast. As a result, an insufficient number of slow-start resources were committed in the day prior. As schedules fell short of demand due to the forecast error, real-time market demand increased along with the potential for exhausted bid stacks and associated high prices. The situation was exacerbated on November 27th by a loss of 760MW generation due to operational problems and on November 29th by a loss of 560MW along with the simultaneous loss of EMS. Contributing factors also occurred on November 28th when instances of real-time, south-to-north congestion on Path 26 caused the market to split, with prices in NP15 elevated above those in SP15.

[*] 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 6: NP15 Real Time Dispatch and Settlement Prices

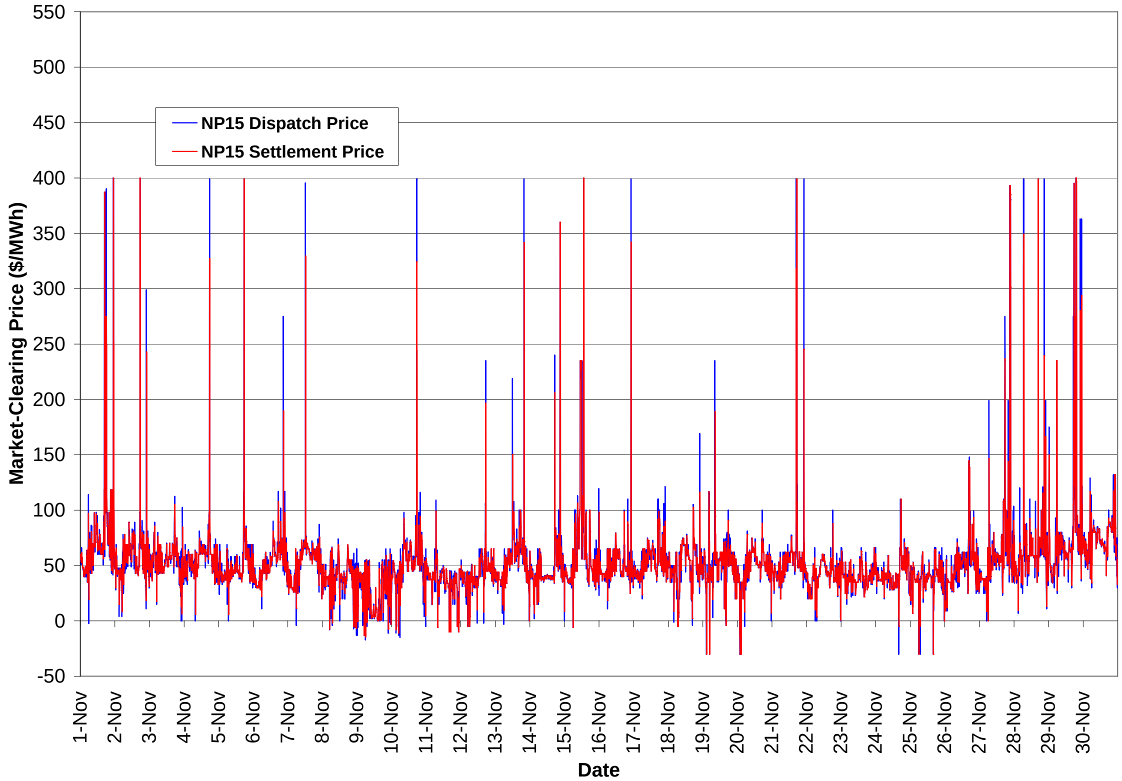
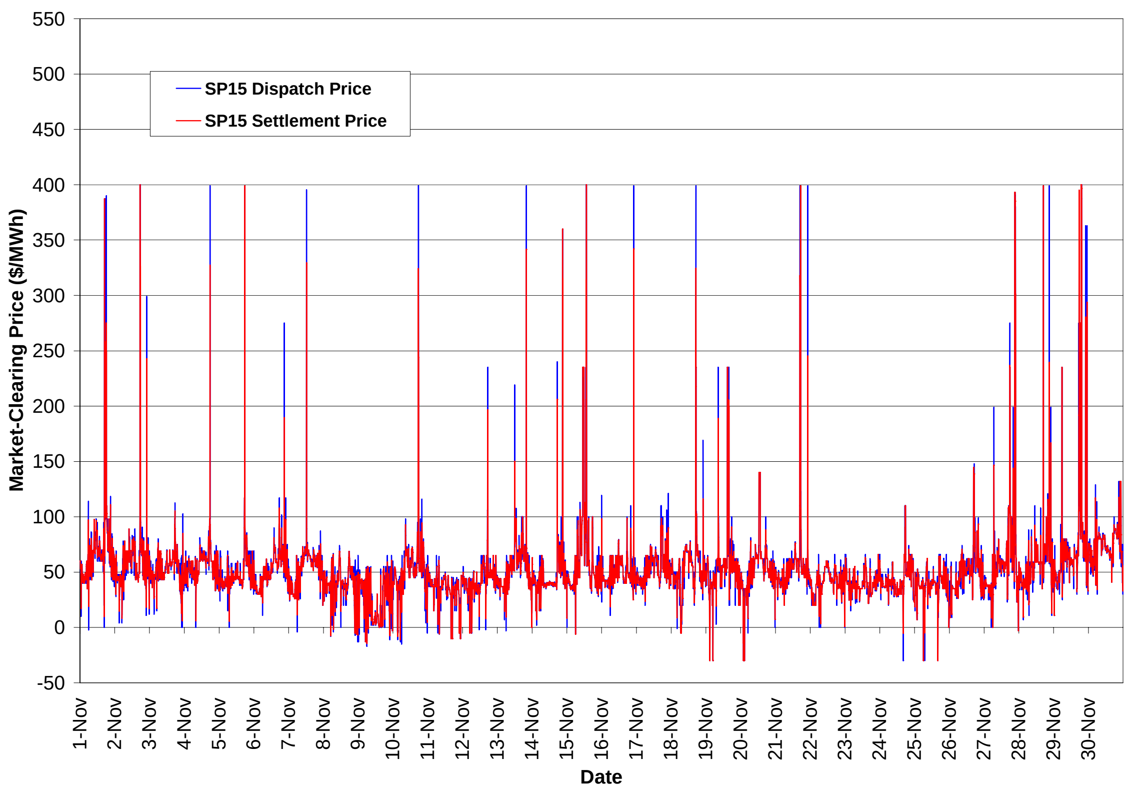


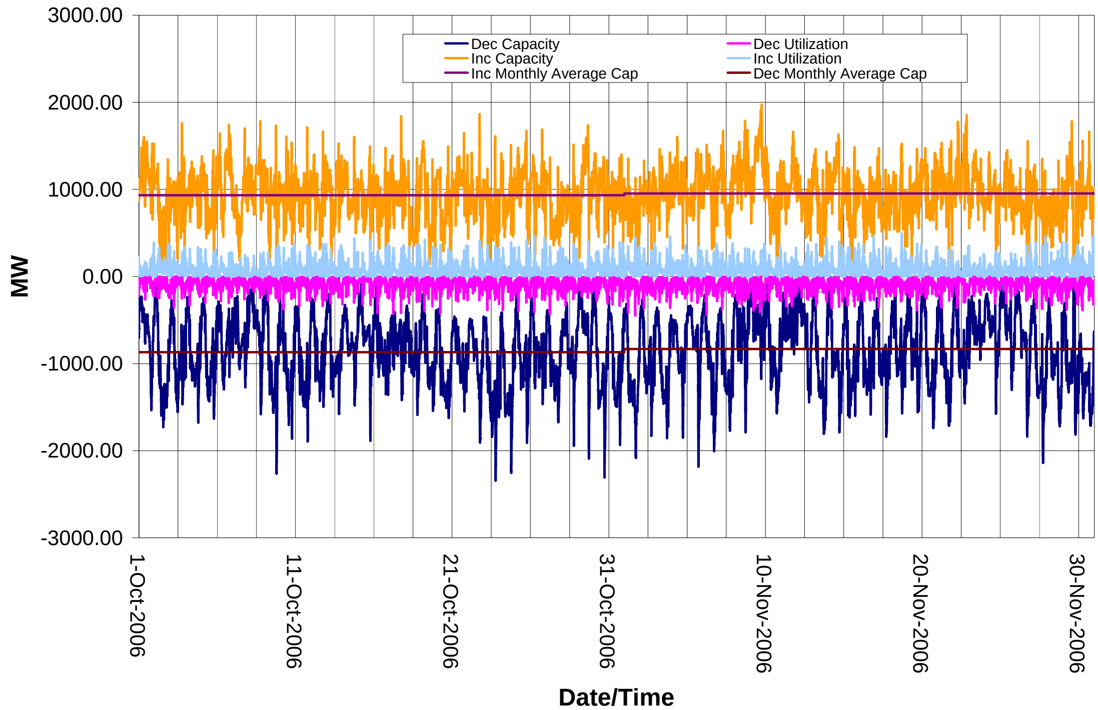
Figure 7: SP15 Real Time Dispatch and Settlement Prices



Five-Minute Bid Stack Utilization*

As peak loads declined from the summer peaks, fewer generating units were being scheduled to operate. As a result, there was less incremental generating capacity available to be bid into the real-time market during the months of October and November. The declining trend in five-minute incremental and decremental bid stack capacity that were seen in October subsided in November and remained about constant, as illustrated in Figure 8 below.

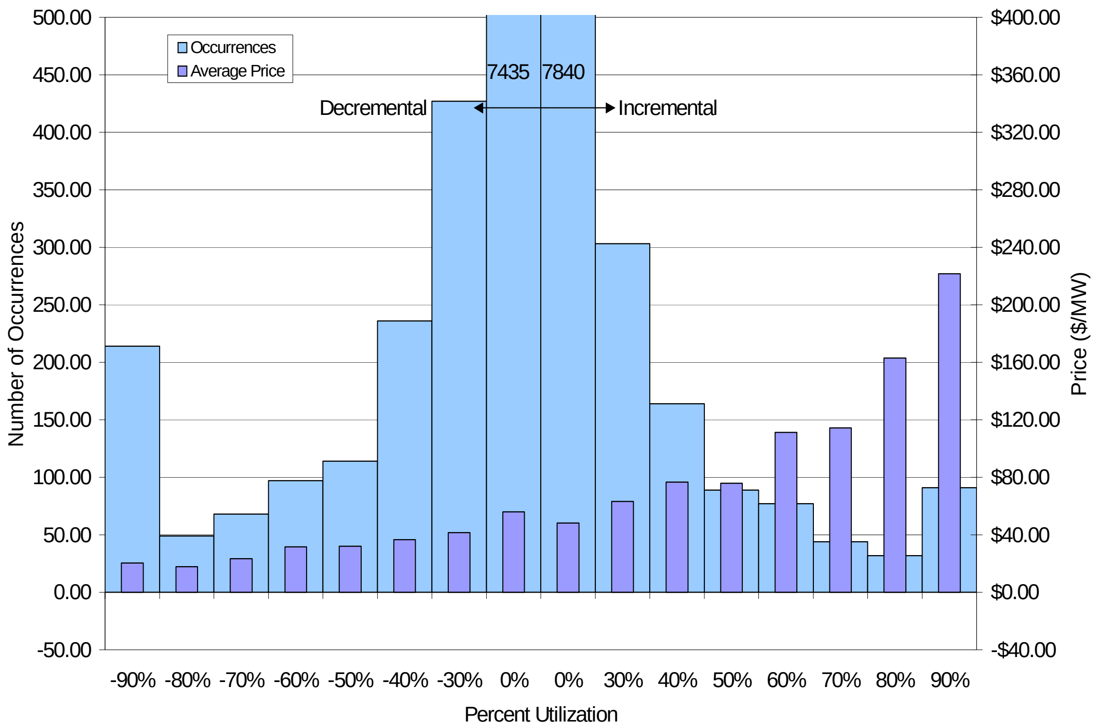
Figure 8: Five-Minute Stack Capacity and Utilization – 6-Interval Moving Average



* 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.

The utilization histogram in Figure 9 indicates an increase in incremental bid stack capacity utilization. In November there were 91 instances of five-minute intervals with over 90% incremental stack utilization, compared with 49 in October. At the same time, the frequency of over 90% decremental stack utilization was about 214 instances in November compared with 100 in October.

Figure 9: Five-Minute Stack Utilization Histogram – November 2006 6-Interval Moving Average

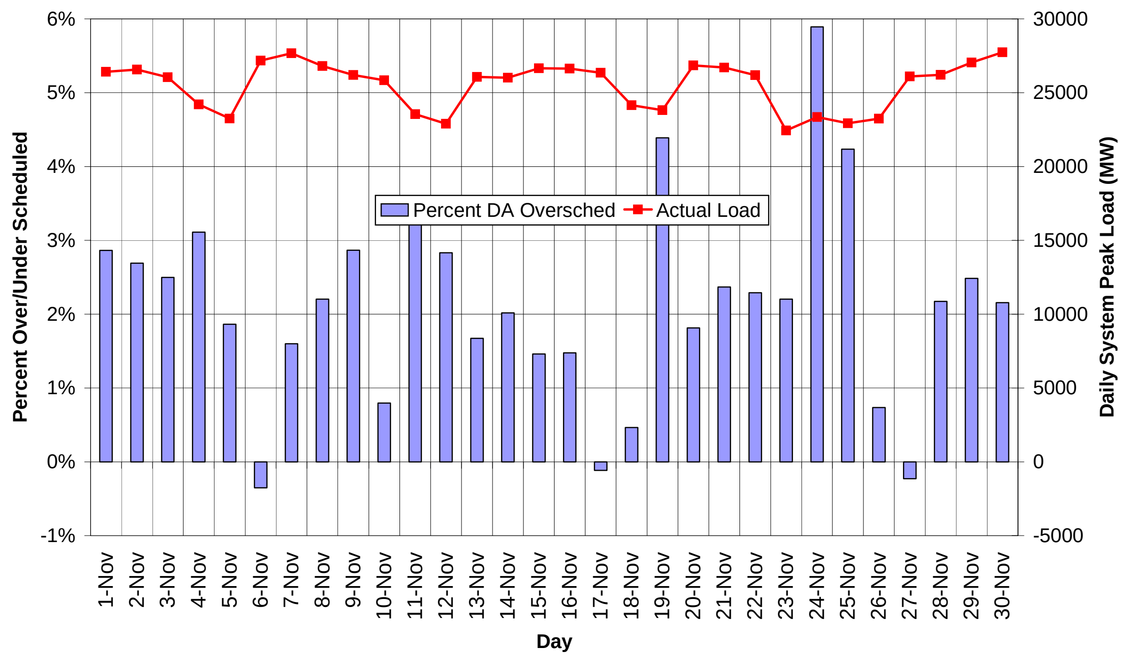


Over- and Under-Scheduling

Day-Ahead Scheduling Deviations*

As shown in Figure 10, the daily average SC load schedules continued to be consistently above the SC day-ahead forecasts during November with the exception of three days. On November 6th, November 17th and November 27th, the daily average SC load schedules fell below the SC day-ahead forecasts although the maximum under-scheduling deviation was below 0.4%.

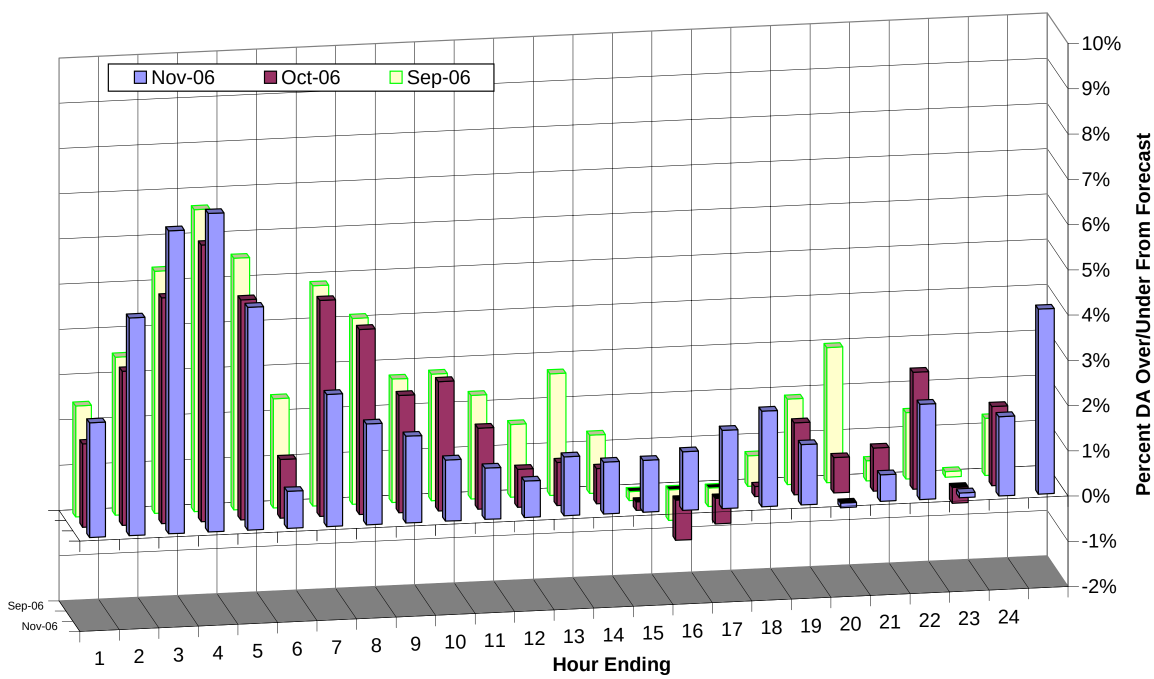
Figure 10: SC Day-Ahead Average Scheduling Deviation compared to SC Forecast – November 2006



* 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.

Figure 11 below indicates that while scheduling coordinators always schedule above their forecast load by about two percent on average, the breakdown by hour displays an uneven pattern. When measured against their own forecasts, scheduling coordinators tend to over-schedule during all hours of the day. This pattern is consistent with the presence of block contracts. Note particularly how the change in schedule error between Hour-Ending 6, Hour-Ending 7, Hour-Ending 22 and Hour-Ending 23 coincides with the delivery of on-peak blocks beginning at 0600 and ending at 2300.

Figure 11: SC hourly Average Day Ahead Scheduling Deviation Compared to SC Day Ahead Forecast – Sep 2006 through Nov 2006



Hour-Ahead Scheduling Deviations*

In November, scheduling coordinators were under-scheduling the load in the Hour-Ahead for about 40% of the time while over-scheduling the load for about 60% of the time. Still, the scheduling error was quite small – typically well under two percent deviation as Figure 12 illustrates.

Figure 12: Average Scheduling Deviation Percentages By Day* - November 2006

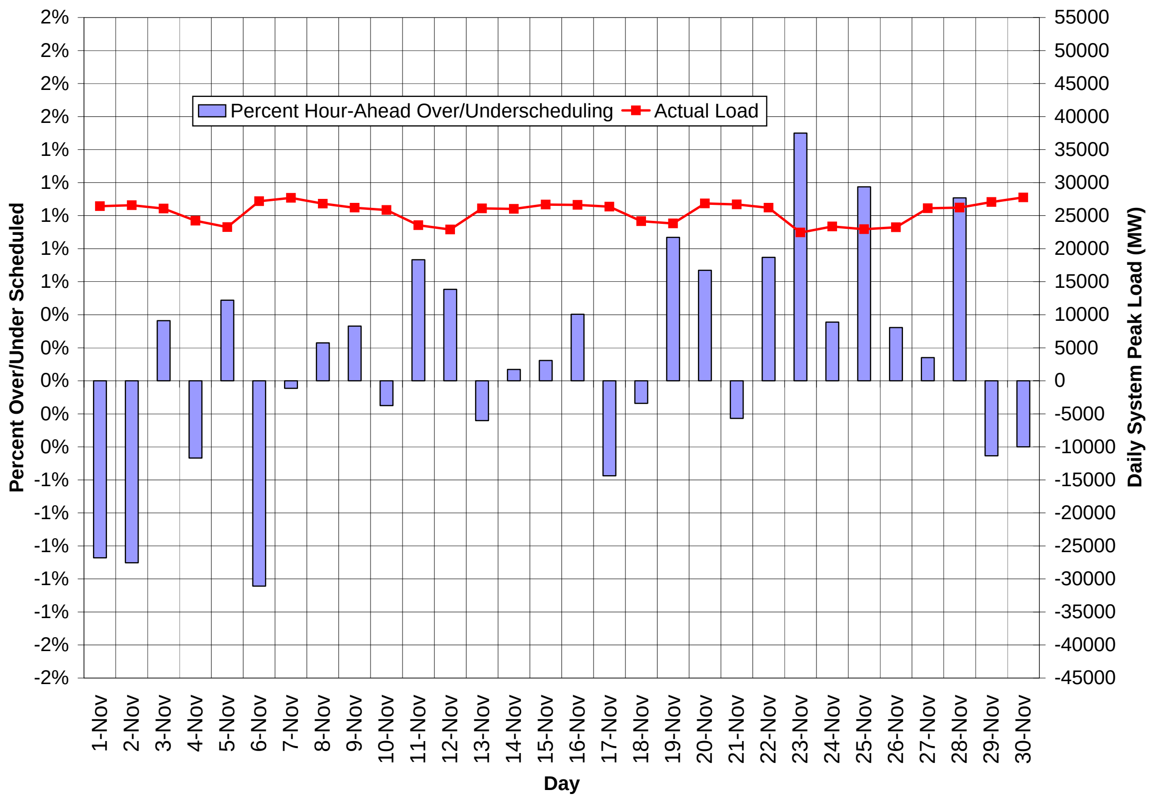
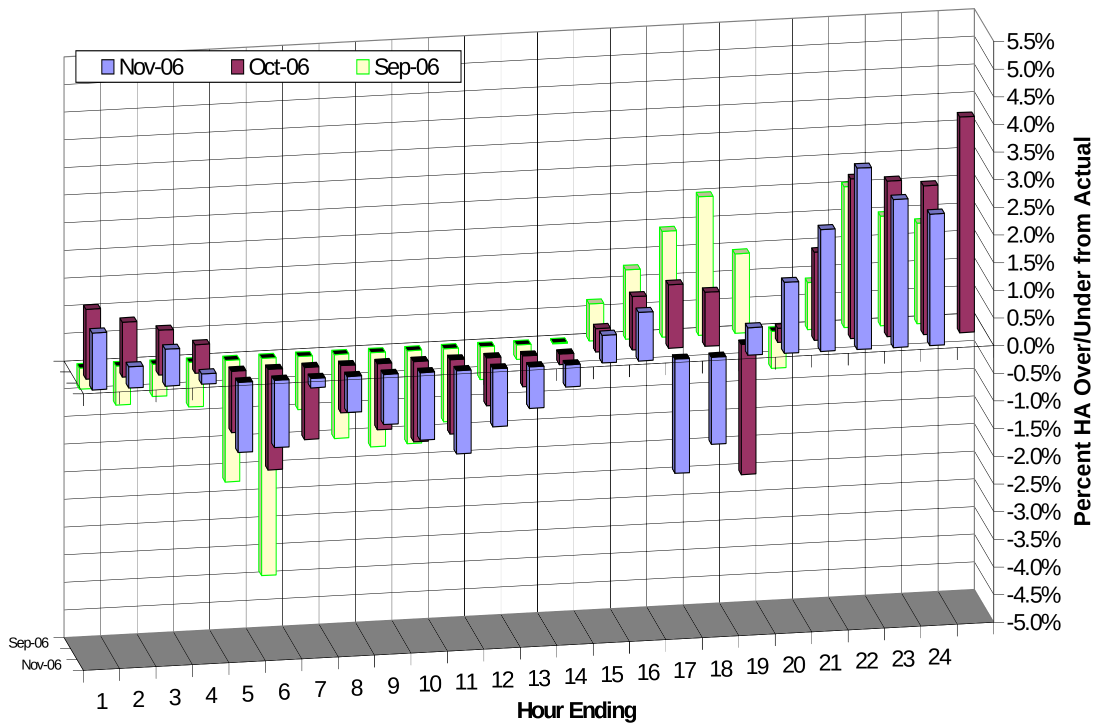


Figure 12 show the hourly averages for scheduling deviation for November, where the tendency to over-schedule during the late evening and early morning ramp-down, and under-schedule at the start of the morning load pick-up, remains apparent. Also apparent in Figure 13 is that during the month of November it becomes increasingly more difficult to accurately schedule load around the peak Hours Ending 17, 18, and 19 as the evening load ramps become steeper. This is reflected in the increased error margins during these late evening hours.

* In the hour-ahead framework under and over-scheduling indicates the extent to which LSEs schedule resources to meet their load. Figure 12 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: Hour-Ahead Over- And Under-Scheduling Percentages Averaged By Hour* – Sep 2006 through Nov 2006

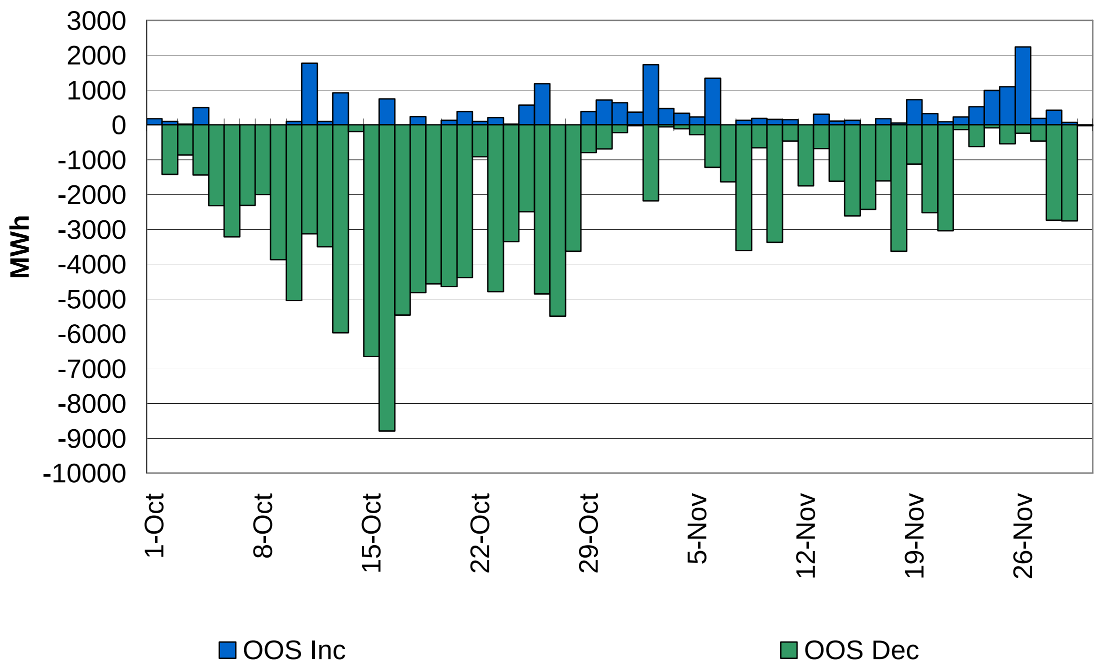


Note: Positive values reflect over-scheduling and negative values reflect under-scheduling.

Out-of-Sequence Dispatches*

Daily MWh dispatch volumes for incremental and decremental Out-of-Sequence (OOS) dispatches are shown in Figure 14. Decremental volumes decreased significantly in November as compared to October, dropping by 59 percent to 44,000 MWh. Incremental OOS dispatch rose by 41 percent to 13,000 MWh, however still a very low volume compared to the decremental dispatch.

Figure 14: Daily OOS MWh – October and November 2006



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*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 15 displays cumulative daily incremental re-dispatch costs (the premium in excess of the Market Clearing Price) for October and November, broken out by the associated reason for the OOS dispatch. The incremental re-dispatch costs increased by 71 percent to $190,000 in November, up from October's costs of $111,000. The dominant proportion of the costs (58 percent) was related to management of pumping load and system energy.

Figure 15: Daily Incremental OOS Re-Dispatch Costs by Reason October and November 2006

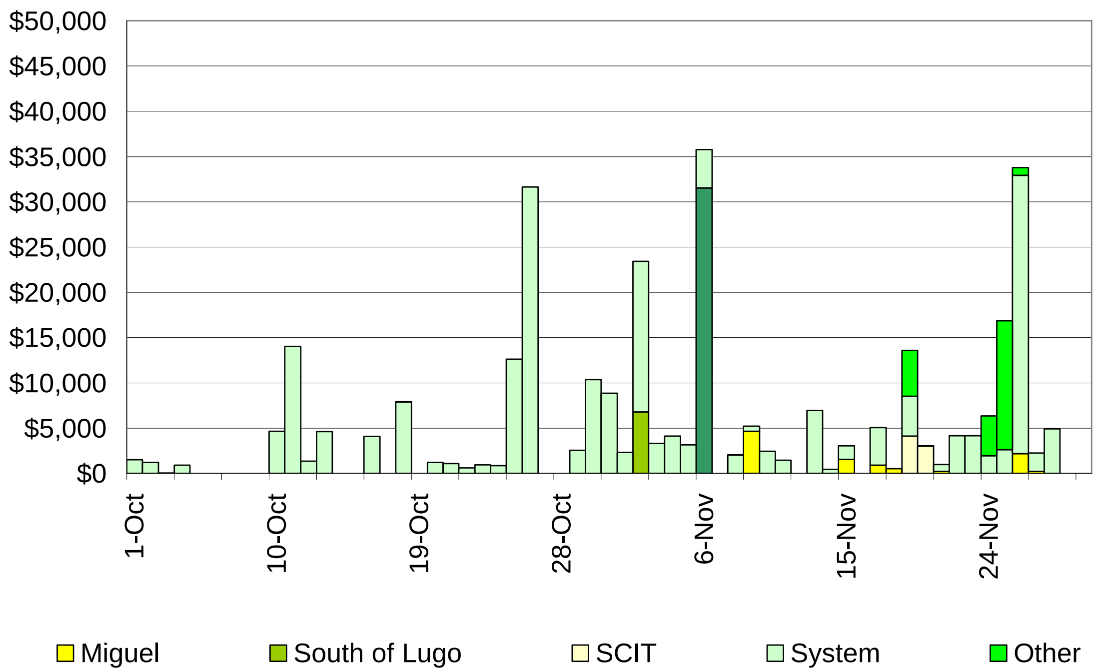
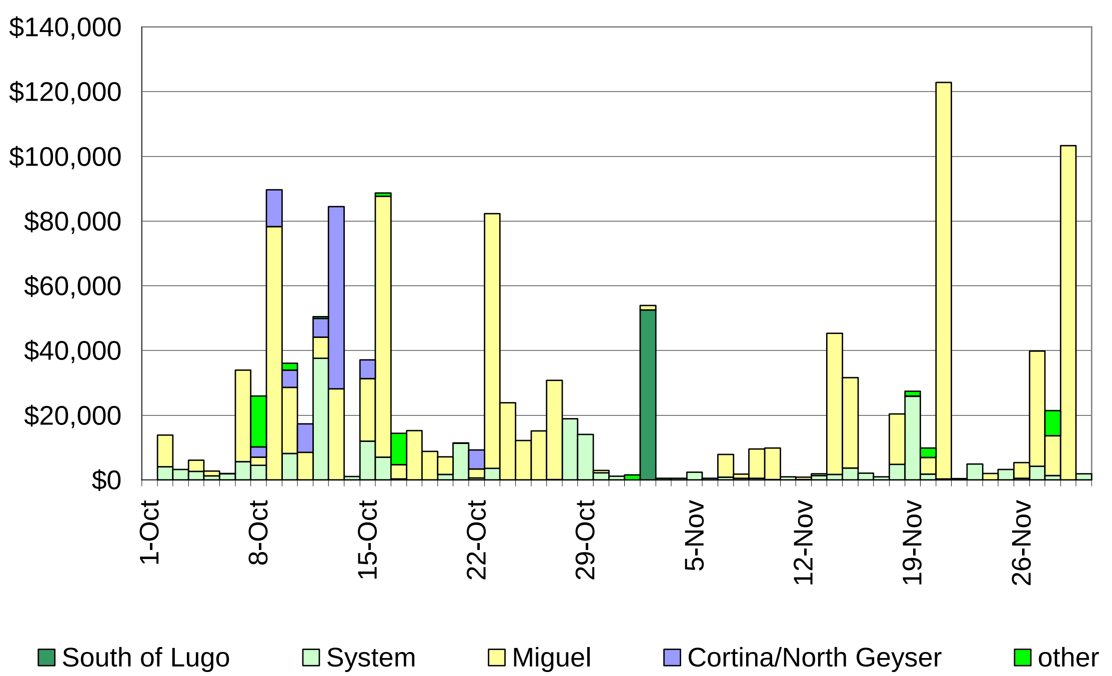


Figure 16 shows cumulative daily decremental re-dispatch costs for October and November, again broken out by the associated reason for the OOS dispatch. Decremental costs decreased 30 percent to $540,000 from October's value of $760,000. Mitigation of intra-zonal congestion on Miguel was the major contribution (75 percent) to the decremental re-dispatch costs.

Figure 16: Daily Decremental OOS Re-Dispatch Costs by Reason October and November 2006

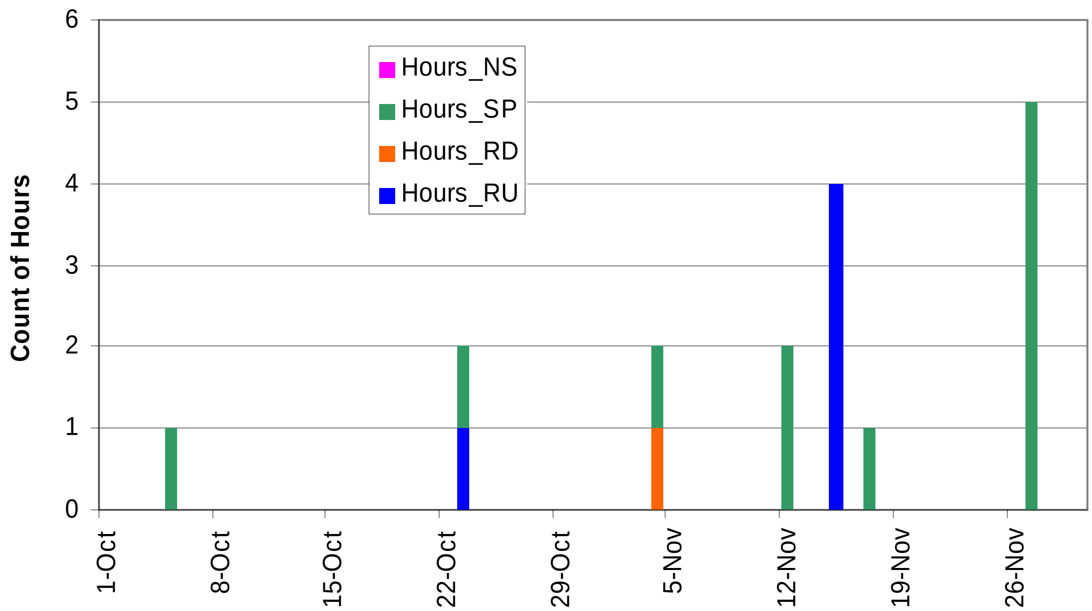


Availability of Ancillary Services[2*]

Bid Insufficiency

The frequency of bid-insufficient hours increased to 14 in November from 3 in October. The daily breakdown of bid-insufficient hours for the months of October and November is shown in Figure 17 below. The main reason for bid-insufficiency in November was inter-zonal congestion on the Mead branch group, which resulted ancillary service bids from dynamic system resources becoming unavailable during certain hours.

Figure 17: Count of Bid-Insufficient Hours – October and November 2006

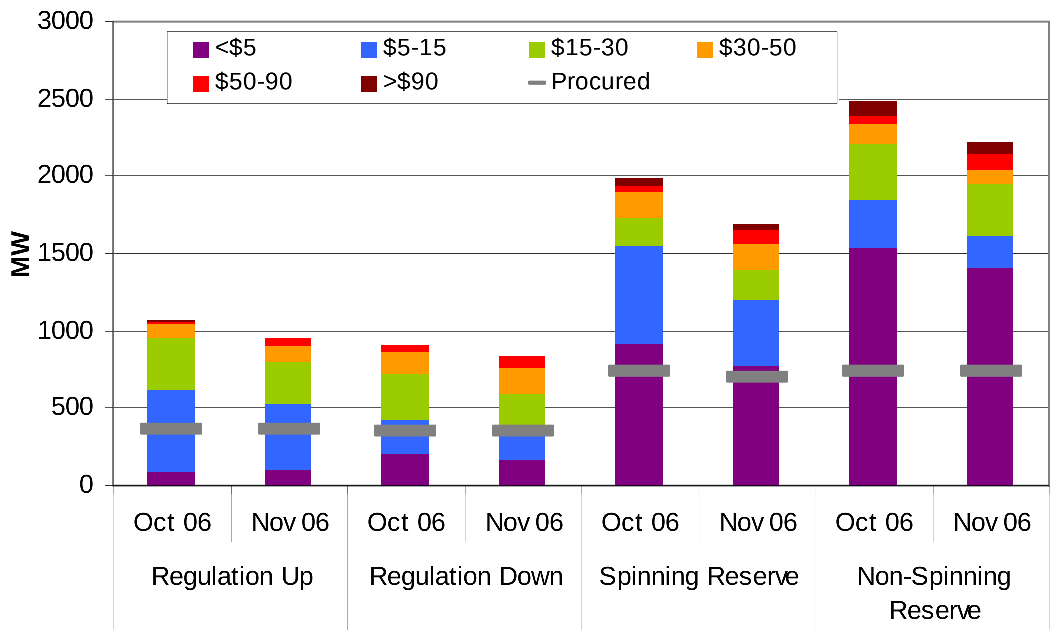


[*] The availability of Ancillary Services (AS) is important as an insufficient supply of AS can increase the cost to load. The availability of AS is also an indication of the relative incentive to use capacity to supply AS or produce energy.

Ancillary Service Supply

Figure 18 below shows the total volume and bid ranges of Ancillary Services that were bid into the market during October and November 2006, as well as the total amount of Ancillary Services ultimately procured by the CAISO. Consistent with decreasing system demand in November due to milder temperatures, both the Ancillary Services capacity requirements and bid-in capacity declined for all services.

Figure 18: Ancillary Service Day-Ahead Average Bid Volume by Price Bin – October and November 2006



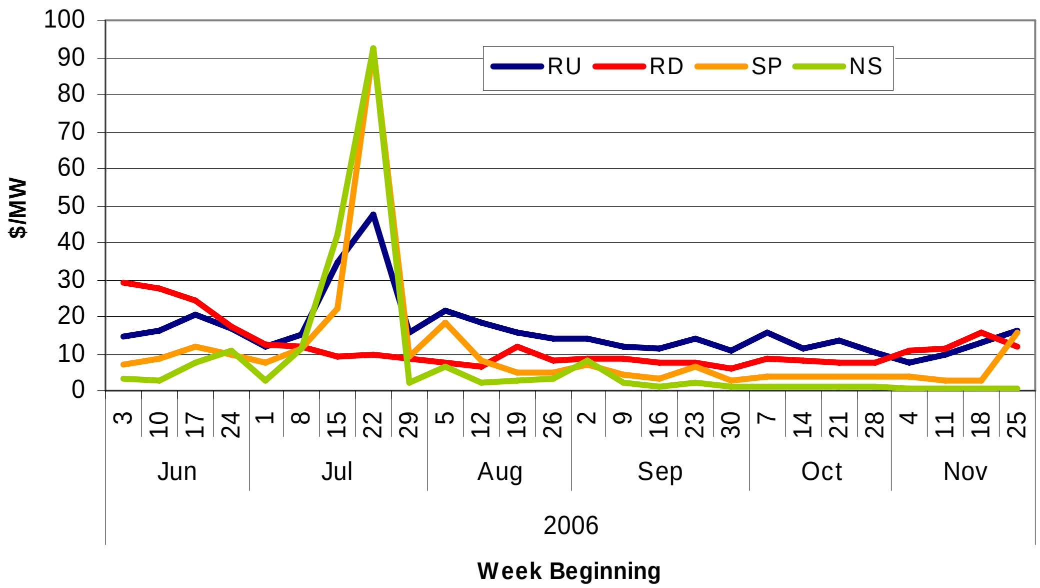
Ancillary Services Market Prices*

As compared to October, weighted average Ancillary Services prices increased sharply for Regulation Down and Spinning Reserve in November, while average prices declined slightly for Regulation Up and Non-Spinning Reserve. Table 3 shows the price breakout for each service separately. Figure 19 below displays the six-month price trend on a weekly average basis.

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

	Average Required (MW)				Weighted Average Price ($/MW)			
	RU	RD	SP	NS	RU	RD	SP	NS
Oct 06	368	356	829	836	$ 12.75	$ 7.69	$ 3.56	$ 0.86
Nov 06	387	354	777	809	$ 11.31	$ 11.93	$ 5.89	$ 0.71
%Diff	5.1%	-0.5%	-6.3%	-3.2%	-11.3%	55.1%	65.3%	-17.1%

Figure 19: Weekly Weighted Average Ancillary Service Prices – 2006

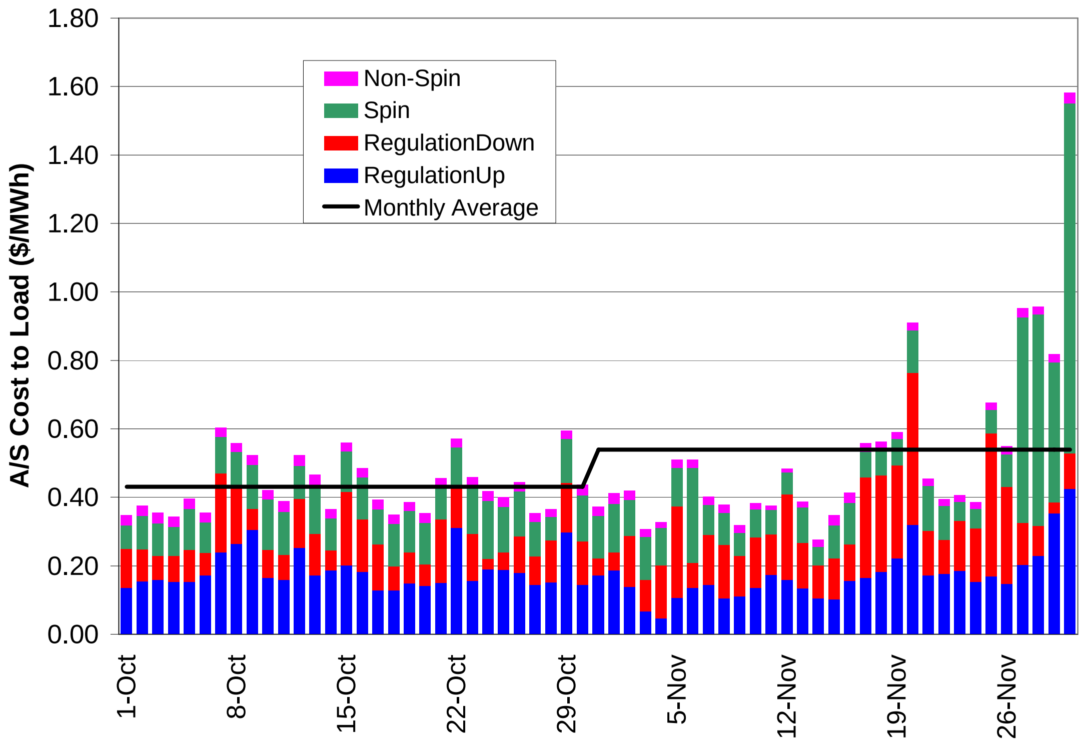


* AS Market prices are important not only as indicators of the cost to load, but also because high AS prices often indicate system stresses.

Cost to Load[3]

Total costs of Ancillary Services per MWh of load for the months of October and November are presented in Figure 20. The average total costs increased to $0.54 in November from October's $0.43. The increase in average total costs for Ancillary Services can be attributed primarily to a declining availability of Ancillary Services capacity.

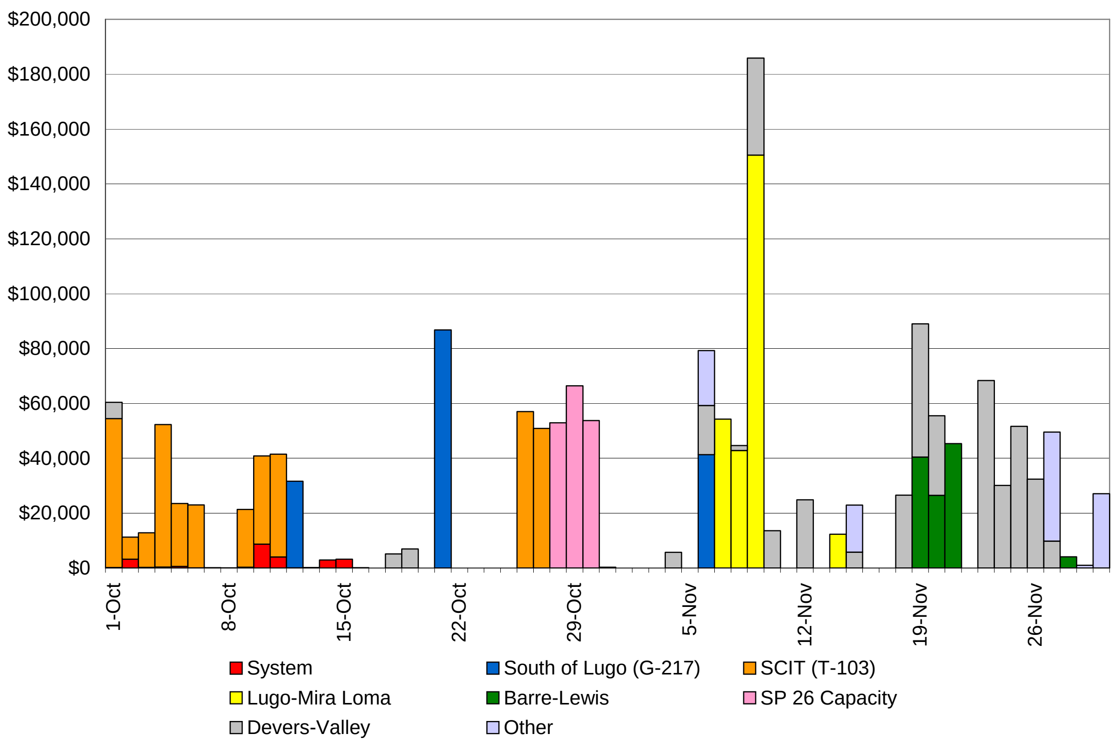
Figure 20: Monthly Ancillary Service Cost to Load – October and November 2006



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

Total unit commitment costs reversed a three-month decline as November's total came in at $925,000 – a slight increase over October's total of $700,000. Unlike recent months, however, the vast majority of unit commitment costs in November (almost 85 percent) were driven by transmission line maintenance in Southern California (Lugo-Mira Loma, Devers-Valley and Barre-Lewis). Figure 21 shows unit commitment costs by reason for those units that were committed under Resource Adequacy (RA) rules. As was the case in the previous month, no FERC must-offer units were committed in the Day-Ahead during November.

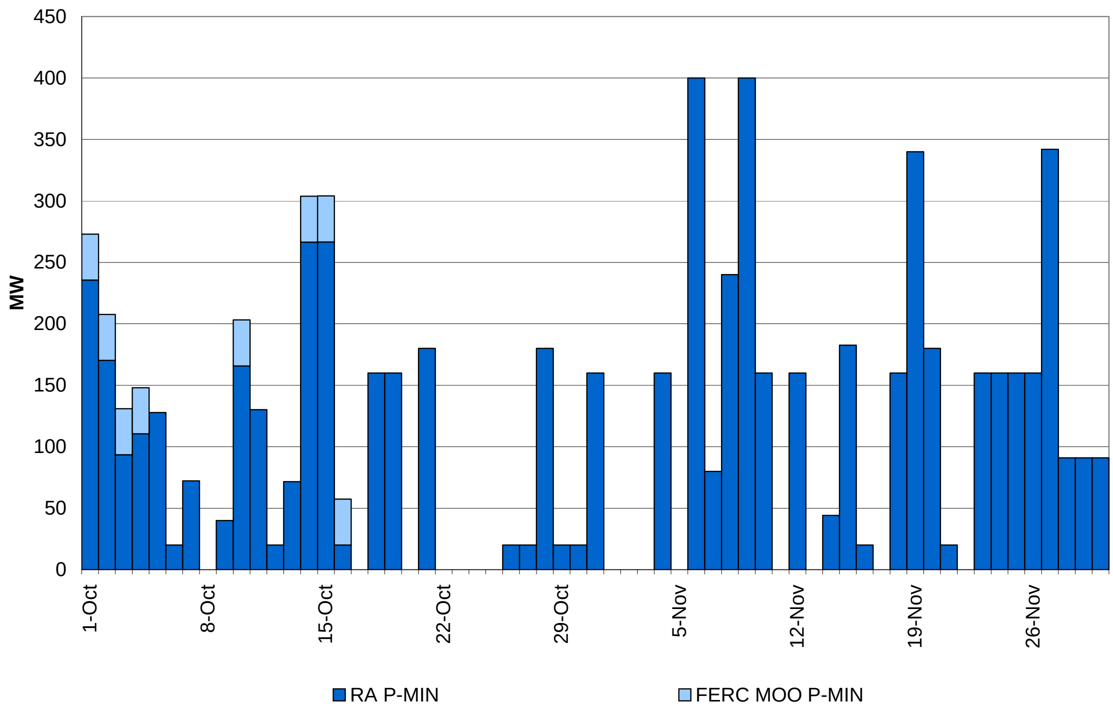
Figure 21: Resource Adequacy Costs by Reason – October and November 2006



[*] 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.

Figure 22 shows the daily cumulative unit minimum loads (p-mins) of the committed RA and FERC must-offer units for October and November.* The total for the month of November was just under 4,000 MW, or about 130 MW per day on average.

Figure 22: 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 simply 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 $5 million in November from $3.4 million in October. This is slightly below the average cost over the past 12 months of $5.4 million, and sharply below the November 2005 total of $9.3 million. Congestion costs by branch group for the month of November are depicted in Table 4. Over half the congestion costs occurred on the Palo Verde branch group and were driven almost exclusively by over-scheduling during on-peak hours. The remaining congestion costs listed in Table 4 also resulted largely from over-scheduling.

Table 4: Inter-Zonal Congestion Costs – November 2006

Branch Group	Day-ahead		Hour-ahead		Import/Export Total Congestion Cost		DA/HA Total Congestion Cost		Total Congestion Cost	Total Cost Percent
	Import	Export	Import	Export	Import	Export	Day-ahead	Hour-ahead		
ADLANTOSP	$543,542	$0	$7,586	$0	$551,128	$0	$543,542	$7,586	$551,128	11%
BLYTHE	$59,371	$0	-$986	$0	$58,385	$0	$59,371	-$986	$58,385	1%
ELDORADO	$235,332	$0	-$11,500	$0	$223,832	$0	$235,332	-$11,500	$223,832	5%
IID-SCE	$0	$0	$241	$0	$241	$0	$0	$241	$241	0%
IPPDCADLN	$467,473	$0	-$3,072	$0	$464,401	$0	$467,473	-$3,072	$464,401	9%
MEAD	$442,670	$0	$9,085	$0	$451,755	$0	$442,670	$9,085	$451,755	9%
MKTPCADLN	$49,917	$0	-$399	$0	$49,519	$0	$49,917	-$399	$49,519	1%
NOB	$0	$0	$1	$14,703	$1	$14,703	$0	$14,704	$14,704	0%
PACI	$0	$0	$8,011	$0	$8,011	$0	$0	$8,011	$8,011	0%
PALOVRDE	$2,548,259	$0	$9,192	$0	$2,557,451	$0	$2,548,259	$9,192	$2,557,451	52%
PARKER	$130,503	$0	-$152	$0	$130,351	$0	$130,503	-$152	$130,351	3%
PATH15	$365,534	$0	-$8,970	$0	$356,564	$0	$365,534	-$8,970	$356,564	7%
PATH26	$0	$0	$23,679	$0	$23,679	$0	$0	$23,679	$23,679	0%
WSTWGMEAD	$2,752	$0	$2,473	$0	$5,225	$0	$2,752	$2,473	$5,225	0%
Total	$4,845,353	$0	$35,188	$14,703	$4,880,541	$14,703	$4,845,353	$49,891	$4,895,244	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 – November 2006

	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	19	0	$4		11	0	$34	
BLYTHE _BG	14	0	$3		0	0	$0	
ELDORADO _BG	11	0	$3		5	0	$6	
IID-SCE _BG	0	0			0	0	$30	
IPPDCADLN_BG	20	0	$5		8	0	$27	
MEAD _BG	15	0	$6		11	0	$33	
MKTPCADLN_BG	10	0	$2		6	0	$1	
NOB _BG	0	0			0	1	$0	$5
PACI _BG	0	0			4	0	$1	
PALOVRDE _BG	29	0	$5		18	0	$16	
PARKER _BG	11	0	$10		0	0		
PATH15 _BG	3	0	$5		2	0	$6	
PATH26 _BG	0	0			1	0	$22	
WSTWGMEAD_BG	1	0	$3		5	0	$5	

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, 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.