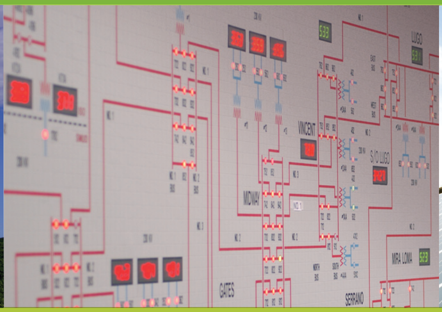
Market Issues & Performance
2008 Annual Report

Department of Market Monitoring
California Independent System Operator Corporation


California ISO
Your Link to Power

ACKNOWLEDGEMENT

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Executive Summary

Overview

Each year the Department of Market Monitoring (DMM) publishes a report on the performance of markets administered by the California Independent System Operator (CAISO). This report covers the period of January 1, 2008 through December 31, 2008.

For the seventh consecutive year (2002-2008), California's wholesale energy markets remained stable and competitive in 2008. This trend is predominantly due to a high level of forward energy contracting by the state's investor owned utilities, which limits their exposure to spot market price volatility, enhances competition, and facilitates new generation investment. Over the past eight years (2001-2008), approximately 15,000 MW of new generation has been added to the CAISO Control Area, enabling the retirement of 5,500 MW of older inefficient generation, resulting in a net increase of 9,500 MW of new generation. Though only 45 MW of new generation was added in 2008,[1] approximately 3,141 MW of new generation is projected to be operational in 2009, 216 MW of which are renewable energy projects.[2]

While California experienced a second consecutive year of below normal rainfall and snow pack, which raised concerns about hydroelectric supply availability during the critical summer months, relatively moderate summer temperatures mitigated this concern and produced generally competitive conditions with no major reliability issues. California experienced only one major heat wave in 2008. It occurred from June 18-21 with the annual peak load set on June 20th at 46,897 MW, well below the all-time record summer peak load of 50,270 MW set in 2006 and unusually early for an annual peak, which typically occurs in July or August. The June 2008 heat wave was managed without any significant market or reliability issues.

From a grid operations standpoint, the most notable event of the year was the California wildfires that raged through large portions of Central and Northern California in June and July. During the June heat wave, dry lightning strikes ignited numerous wildfires across Central and Northern California. With spring 2008 being the driest on record for many parts of the state, the fires quickly spread to catastrophic proportions, resulting in more than 2,000 wildfires burning across the state and over 1.3 million acres burned. With many fires burning near major transmission facilities, grid conditions were challenging, requiring numerous de-rates of generation and transmission facilities, market interventions such as real-time Out-of-Sequence dispatches, and commitment of generation units at specific locations. Despite the challenging conditions, no major reliability events occurred during the wildfires. Most of the wildfires were contained by mid-July.

Grid operators also had to manage an unusually high level of unscheduled flows across the grid through much of the spring and early summer of 2008. These flows were driven primarily by high demand for abundant hydroelectric energy from the Pacific Northwest, high natural gas prices, and below normal hydroelectric supplies in California and other southwestern states.

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[1] Though approximately 1,660 MW of new generation was at some point on-line and tested in 2008, only 45 MW actually became commercially operable in 2008 with another 770 MW becoming commercially operable in the first quarter of 2009.

[2] The 216 MW figure is nameplate capacity. The net qualifying capacity of these resources is approximately 28 MW.

Unscheduled flows are largely managed through real-time redispatches at the inter-ties and from internal resources and can result in significant market costs.

The most notable market event in 2008 was a dramatic increase in congestion costs, particularly on the major inter-ties with the Pacific Northwest. Total inter-zonal congestion cost was approximately $176 million in 2008, compared to $85 million in 2007. Most of the increase occurred in the spring and early summer, as a combination of abundant hydroelectric supplies in the Northwest and high natural gas prices increased demand and willingness to pay for using the major transmission facilities between California and the Pacific Northwest (i.e., the Pacific AC and DC Inter-ties). Congestion costs also increased significantly on a major transmission link between Southern and Northern California (Path 15) and was due primarily to one of the three 500 kV lines that comprise this path being taken out of service for scheduled maintenance during October 14 to November 7.

In terms of the general performance of the wholesale energy markets during the entire year, one of the primary metrics that DMM uses to gauge overall market competitiveness is a 12-month Market Competitiveness Index (MCI), which represents a 12-month rolling average of the estimated hourly price-cost mark-ups (i.e., the difference between actual energy prices and estimated "competitive" prices derived from cost-based simulations). MCI values below $10/MWh are considered to be reflective of a workably competitive market. The monthly MCI values estimated for 2008 were well below this level for all months of the year.

The average estimated cost of wholesale energy in 2008 was $53.01/MWh of load compared to $48.23/MWh in 2007.[3] Costs include the following components: forward scheduled energy, inter-zonal congestion, real-time imbalance energy, real-time out-of-sequence (OOS) energy redispatch premium, net Reliability Must Run (RMR) costs, ancillary services, and CAISO-related costs (transmission, reliability, and grid management charges). The increase in the costs in 2008 was primarily due to greater reliance on fossil fueled generation – due to limited hydroelectric supplies – and to increased congestion costs on major importing paths to California. The cost of natural gas historically has had a strong influence on the total energy cost estimate. To control for that exogenous factor, DMM also calculates an estimate of energy costs normalized to a fixed natural gas price. Costs normalized to a fixed gas price were slightly lower in 2008 than in 2007. This decline is due in part to lower peak loads during the critical summer months of July and August, which reduced the need to utilize more inefficient thermal generation.

One significant positive trend that has been reported in prior annual reports has been the sharp reduction in intra-zonal congestion costs. This trend did not continue in 2008 as intra-zonal congestion costs increased from $96 million in 2007 to $174 million in 2008. Intra-zonal congestion costs are comprised of three components: 1) Minimum Load Cost Compensation (MLCC) for units denied must-offer waivers, 2) real-time RMR costs, and 3) real-time redispatch costs. The increase is primarily attributable to higher MLCC payments and real-time redispatch costs. MLCC costs increased by $46 million in 2008, mainly due to the need to commit units in the summer months to relieve a transmission constraint in Southern California. The cost of real-time redispatch costs increased by $39 million in 2008. This increase was due in large part to the increased need to move resources committed at minimum load to higher dispatchable output levels where they have faster ramping capabilities. These dispatchability payments resulted in costs of approximately $12.3 million in 2008. Humboldt-area redispatches resulted in costs of nearly $23 million. Additionally, the Victorville-Lugo nomogram, which often requires

[3] The 2007 estimate has been recalculated based upon the most recently available information.

the out-of-sequence dispatch of a costly steam resource in Southern California, incurred approximately $9.5 million in redispatch costs.

The RMR costs noted above only pertain to the cost of real-time RMR energy dispatches. The total cost of RMR units, which includes both fixed cost payments and variable cost payments for day-ahead and real-time dispatches, declined, from approximately $121 million in 2007 to $71 million in 2008, a reduction of approximately $50 million. This reduction is predominantly due to the reduction in the amount of capacity under RMR contracts, from approximately 3,400 MW in 2007 to 2,400 MW in 2008.

Another reliability management cost, which is relatively new, is the capacity payments made to generation units that are neither RMR units nor Resource Adequacy (RA) units. These capacity payments were made pursuant to the Reliability Capacity Services Tariff (RCST) and provide for both a daily capacity payment for non-RA units that are committed by the CAISO and potentially monthly capacity payments if a non-RA unit is designated by the CAISO as RCST. Because the CAISO's new market design was delayed beyond the expiration of the RCST, a Transitional Capacity Procurement Mechanism (TCPM) was developed and approved by FERC with an effective date of June 1, 2008. The TCPM serves as a bridge between the expired RCST and the Interim Capacity Procurement Mechanism (ICPM), which the CAISO intends to implement simultaneously with MRTU. In 2007, the CAISO did not make any forward RCST designations but did make numerous daily capacity payments to non-RA units, amounting to approximately $26 million. In 2008, RCST and TCPM payments were considerably less, amounting to approximately $3.4 million, of which $1.5 million were RCST payments and $1.9 million were TCPM payments.

In comparing the sum of the reliability management costs discussed above (intra-zonal congestion, other RMR costs, and RCST/TCPM payments) to last year, the total for 2008 is approximately 5% higher than 2007 ($232 million in 2008 compared to $221 million in 2007). Higher intra-zonal congestion costs in 2008 were largely offset by the above noted reduction in RMR costs and RCST/TCPM payments.

Another important market performance metric that DMM reports on each year is the extent to which spot market revenues for the entire year cover the annualized fixed cost of new generation facilities. The DMM's financial assessment of the potential revenues a new generation facility could have earned in California's spot market in 2008 indicates estimated spot market revenues fell short of the unit's annual fixed costs. This marks the sixth straight year that the DMM's analysis found that estimated spot market revenues did not provide sufficient fixed cost recovery for new generation investment. However, the analysis for the past four years (2005-2008) does show a positive trend of net revenues increasing for a new combined cycle unit, with estimated net-market revenues in 2008 of approximately $112/kW-year and $128/kW-year for Northern and Southern California, respectively, which is approaching the estimated annualized fixed costs of $132.6/kW-year.

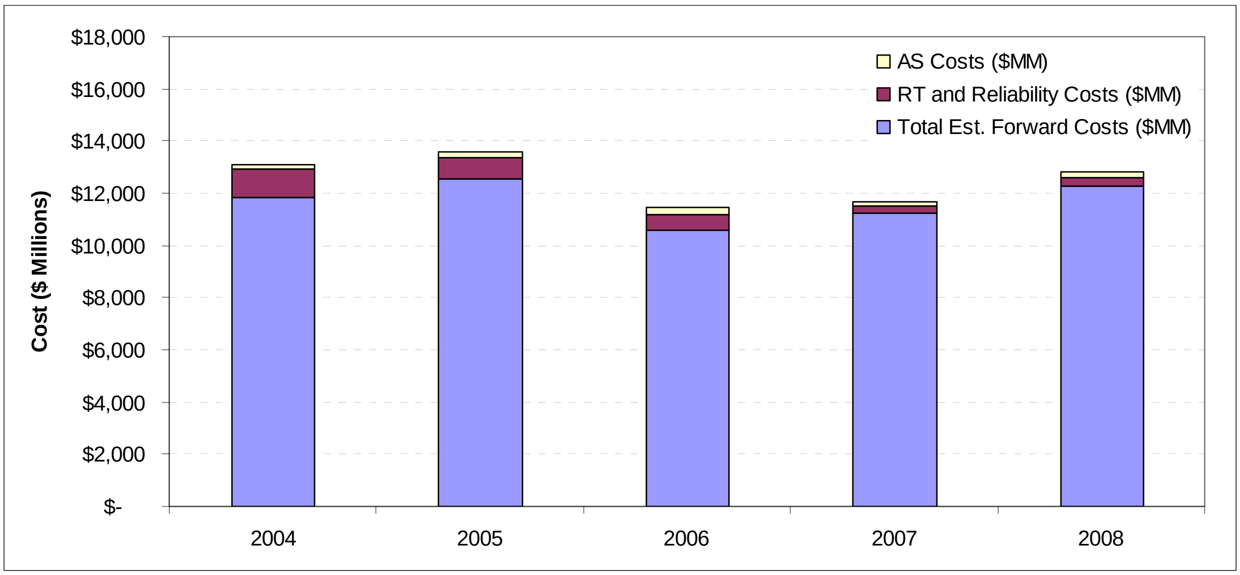
These and other key findings are discussed in greater detail below.

Total Wholesale Energy and Ancillary Service Costs

Since 1999, the DMM has reported its estimate of annual wholesale energy costs. This provides an estimate of total wholesale market costs to load served that can be compared across years. It includes estimates of utility-retained generation costs, forward bilateral contract costs, real-time energy costs, and ancillary service reserve costs. The real-time component of costs also includes reliability costs (minimum-load compensation, out-of-sequence redispatch premiums, and fixed and variable RMR costs). These estimates do *not* include resource adequacy procurement costs, as these costs are not available to the CAISO.

As shown in Figure E.1, estimated total wholesale energy costs increased in 2008, to approximately $12.8 billion (compared to $11.7 billion in 2007). The increase is due primarily to significantly higher natural gas prices during the first half of the year and greater reliance on fossil-fuel generation due to less availability of hydroelectric energy. Total costs may have been even higher in 2008 but for a significant decline in natural gas prices during the second half of the year.

Figure E.1 2004 – 2008 Wholesale Energy Costs



General Market Conditions

Demand

Annual average hourly load in 2008 was slightly lower than in 2007 (Table E.1). Monthly average hourly load was lower in most months of 2008, except for June, September, and October. The average hourly load in June 2008 was 2.2 percent above the monthly average for June 2007 primarily because of a heat wave during the third week of June 2008. Average hourly loads in September and October 2008 were significantly higher than the same months in 2007, 4 percent and 3.7 percent, respectively. Higher September loads were due to more summer-like temperature patterns through much of the month, particularly during the first and last week of September, both of which experienced daily peak loads above 40,000 MW. Similarly, a heat wave during the first week of October 2008 pushed average daily loads higher than the same month last year. Average hourly loads during the peak summer months of July and August 2008 were down from last year by 1.6 percent and 3 percent, respectively.

Table E.1 Load Statistics for 2004 – 2008*

Year	Avg. Load (MW)	% Chg.	Annual Total Energy (GWh)	Annual Peak Load (MW)	% Chg.
2004 Actual	27,311		239,957	45,597	
2005 Actual	26,985	-1.2%	237,063	45,562	-0.1%
2006 Actual	27,432	1.6%	241,019	50,270	10.3%
2007 Actual	27,644	0.8%	242,880	48,615	-3.3%
2008 Actual	27,498	-0.5%	241,594	46,897	-3.5%
2004 Adjusted	26,443		232,327	44,209	
2005 Adjusted	26,475	0.1%	232,586	44,260	0.1%
2006 Adjusted	27,432	3.5%	241,019	50,198	11.8%
2007 Adjusted	27,644	0.8%	242,880	48,535	-3.4%
2008 Adjusted	27,498	-0.5%	241,594	46,897	-3.5%

* Adjusted figures are normalized to account for day of week, changes in the CAISO Control Area footprint, and the 2004 and 2008 leap years.

Supply

Only 45 MW of new generation became commercially operation within the CAISO Control Area in 2008, consisting of a single wind generation projected added in southern California. This figure is significantly below the 1,800 MW that was projected for 2008 in last year's report. New generation projects are complicated and costly, and consequently can be subject to significant delays. Most of the projects projected to become commercial in 2008 were delayed, with only the 45 MW Dillon Wind Project making it to commercial production during 2008.[4]

Table E.2 below shows an annual accounting of generation additions and retirements since 2001, with projected 2009 changes included along with totals across the nine year period (2001-2009). Including estimates for 2009, the total net increase in installed generation in the CAISO Control Area over the nine years spanning 2001-2009 is projected to be approximately 12,600 MW. When accounting for an estimated 2 percent load growth over the same seven year period of approximately 8,600 MW, the net supply margin increased by roughly 4,000 MW since the energy crisis. Interestingly, Table E.2 indicates that generation additions in Southern California are projected to just keep pace with load growth and unit retirements, resulting in a minor net-increase of approximately 30 MW, but in Northern California (NP26) there was approximately a 4,000 MW increase in new generation after accounting for load growth and generation retirement.

[4] Though approximately 1,660 MW of new generation was at some point on-line and tested in 2008, only 45 MW actually became commercially operable in 2008 with another 770 MW becoming commercially operable in the first quarter of 2009.

Table E.2 CAISO Generation Additions and Retirements

	2001	2002	2003	2004	2005	2006	2007	2008	Projected 2009	Total Through 2009
SP15										
New Generation	639	478	2,247	745	2,376	434	485	45	1,650	9,099
Retirements	0	(1,162)	(1,172)	(176)	(450)	(1,320)	0	0	0	(4,280)
Forecasted Load Growth*	491	500	510	521	531	542	553	564	575	4,787
Net Change	**148**	**(1,184)**	**565**	**48**	**1,395**	**(1,428)**	**(68)**	**(519)**	**1,075**	**32**
NP26										
New Generation	1,328	2,400	2,583	3	919	199	112	0	1,491	9,035
Retirements	(28)	(8)	(980)	(4)	0	(215)	0	0	(26)	(1,261)
Forecasted Load Growth*	389	397	405	413	422	430	439	447	456	3,798
Net Change	**911**	**1,995**	**1,198**	**(414)**	**497**	**(446)**	**(326)**	**(447)**	**1,009**	**3,976**
ISO System										
New Generation	1,967	2,878	4,830	748	3,295	633	598	45	3,141	18,135
Retirements	(28)	(1,170)	(2,152)	(180)	(450)	(1,535)	0	0	(26)	(5,541)
Forecasted Load Growth*	880	897	915	934	953	972	991	1,011	1,031	8,585
Net Change	**1,059**	**811**	**1,763**	**(366)**	**1,892**	**(1,874)**	**(394)**	**(966)**	**2,084**	**4,008**

*Assumes 2% peak load growth.

Imports continue to play a key role in meeting demand. Figure E.2 shows average annual gross imports, exports, and net imports for the five-year period covered by 2004-2008. Average hourly gross imports increased significantly in 2008. This was primarily due to the reduced availability of hydroelectric generation within California and high natural gas prices during the first half of the year, which resulted in more imports from the Pacific Northwest and the Southwest. These same factors likely accounted for the reduction in annual exports also observed in 2008. Overall, hourly net-imports in 2008 averaged about 9,000 MWh, the highest level observed over this five year period.

Figure E.2 Average Annual Imports, Exports, and Net Imports (2004-2008)

Generation Outages

Figure E.3 depicts monthly average planned and forced outages between 2005 and 2008. Similar to previous years, planned outages were high during the first five months of the year, lower during the peak summer months, and high again in the fall months. Monthly averages of planned and forced outages in 2008 were generally higher than 2007, with the exception of June and July. Higher planned outages during the January to May 2008 timeframe are primarily attributable to (1) a large combined cycle unit that was shutdown for a compete overhaul of its turbines and (2) a nuclear unit shut down for refueling. The higher rate of forced outages observed in the September to December 2008 time frame is due primarily to a 1,125 MW nuclear unit outage in September, several hydro resources derated throughout the fall, and up to 1,500 MW of combined cycle generation out for much of the fall.

Figure E.3 Monthly Average Planned and Forced Outages (2005 – 2008)

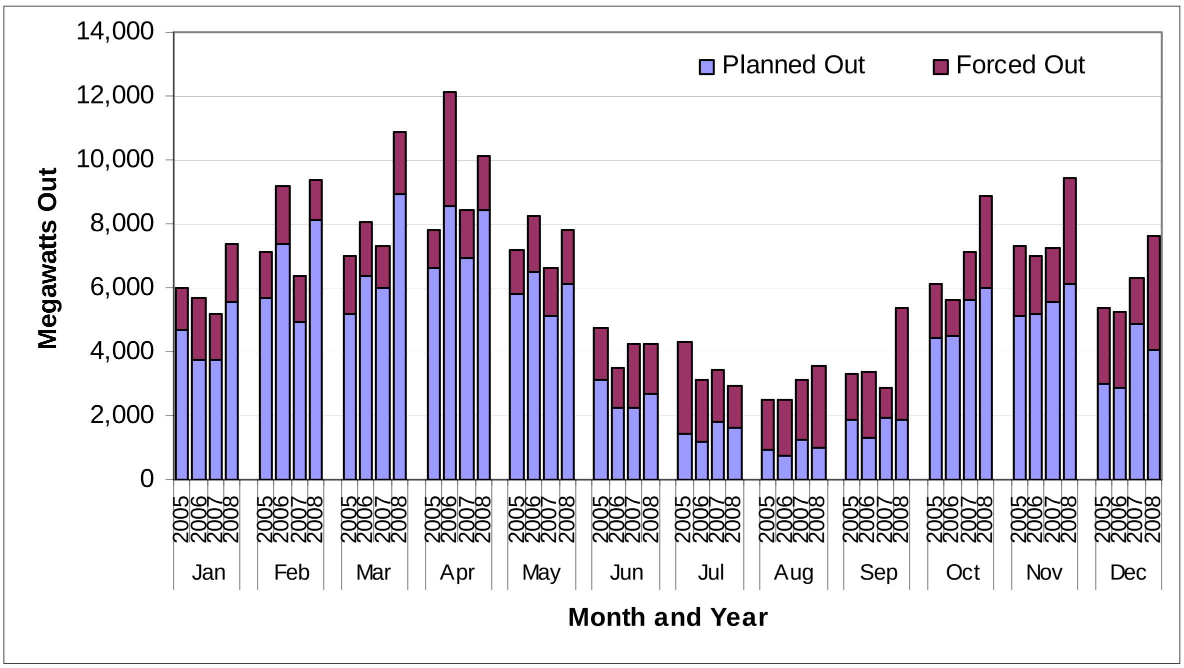
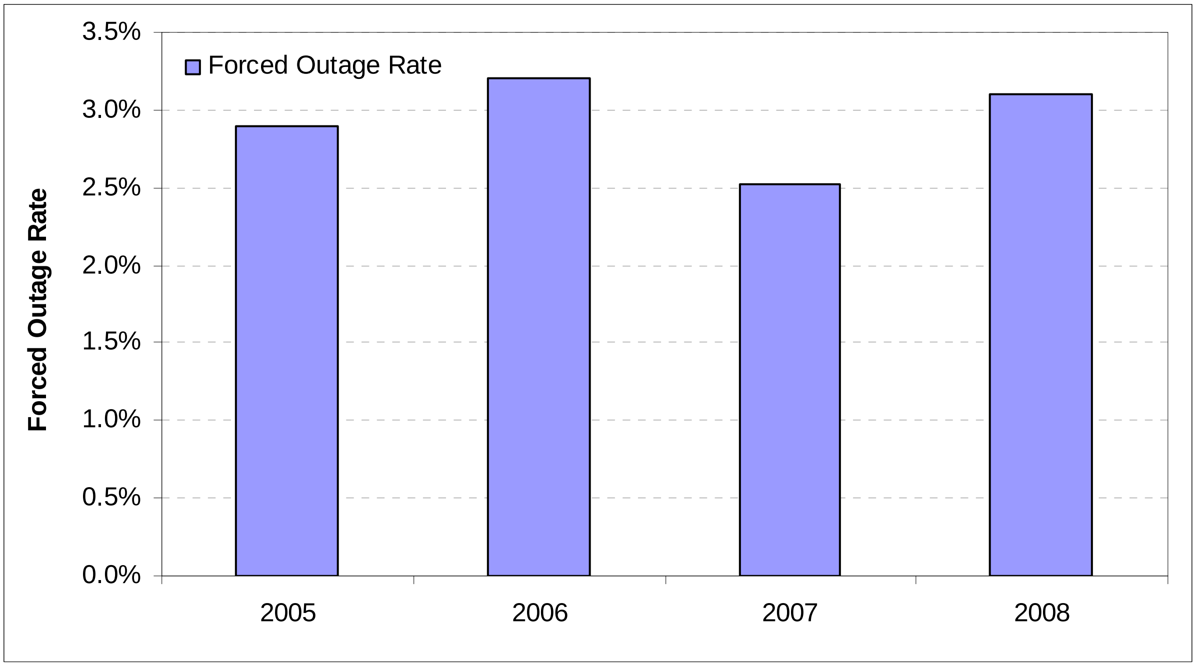


Figure E.4 compares annual forced outage rates since 2005. The annual forced outage rate in 2008 was approximately 3.1 percent, which is a slight increase from 2007. The increase is mainly due to the higher level of forced outages observed in the latter part of the year (September – December), which as noted above was due to a combination of nuclear, hydro, and large combined cycle resource outages.

Figure E.4 Annual Forced Outage Rates (2005 – 2008)



Short-term Energy Market Performance

The significant number of long- to medium-term contracts entered into by the state of California in 2001, and by LSEs since then, combined with the large amount of new generation added to the Western energy markets, provided effective market power mitigation in the 2008 short-term energy markets. When LSEs are substantially hedged by longer-term fixed price energy arrangements, they substantially reduce their exposure to market power in the spot market and, more generally, high spot market prices. Adequate long-term energy contracting also reduces incentives for supply resources to try to elevate spot prices. Market power mitigation measures are in place to reduce the risk of market manipulation and opportunistic exploitation of contingencies and extreme circumstances. However, mitigation should not excessively dampen spot market volatility, as that may encourage LSEs to reduce their forward contract coverage and rely more on the spot markets.

Estimated Mark-up of Short-term Bilateral Transactions

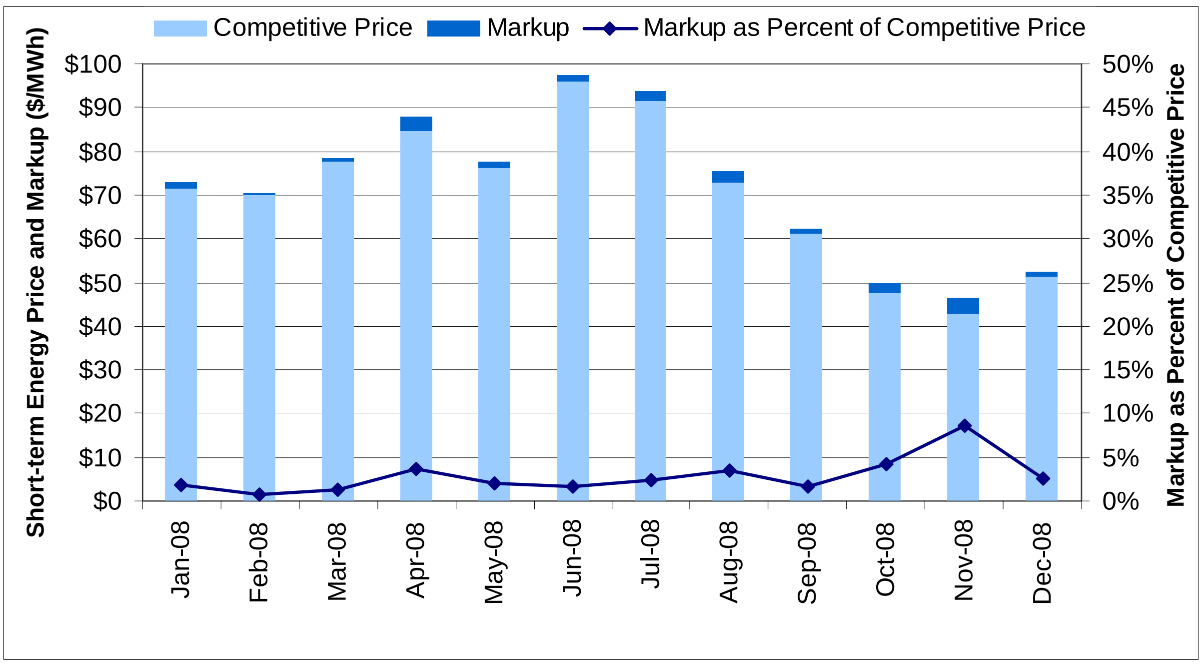
Having no formal forward energy market makes a comprehensive review of competitiveness difficult due to the lack of reporting on transactions in the short-term bilateral energy market. The CAISO has estimated mark-ups for short-term spot market transactions based on data collected from Powerdex, Inc.,[5] an independent energy information company that provides hourly wholesale power indexes in the WECC, as well as short-term purchase cost information provided by the state's three investor owned utilities. The competitive benchmark prices are calculated using a production cost model that determines the hourly system marginal cost by

[5] http://www.powerdexindexes.com/.

incorporating detailed generation unit and system cost information. Figure E.5 shows the monthly average of estimated hourly mark-ups for short-term bilateral transactions. A detailed description of the methodology and assumptions used in the analysis can be found in Chapter 2.

For 2008, monthly short-term mark-ups ranged from 1 to 9 percent, compared to 2 to 11 percent in the prior year, but were below 5 percent in all months except November. Overall, 2008 short-term forward markets functioned competitively. Though mark-ups were higher in November at 9 percent, they appear to have had minimal cost impacts to California LSEs due to the high level of hedging, which minimized spot market exposure.

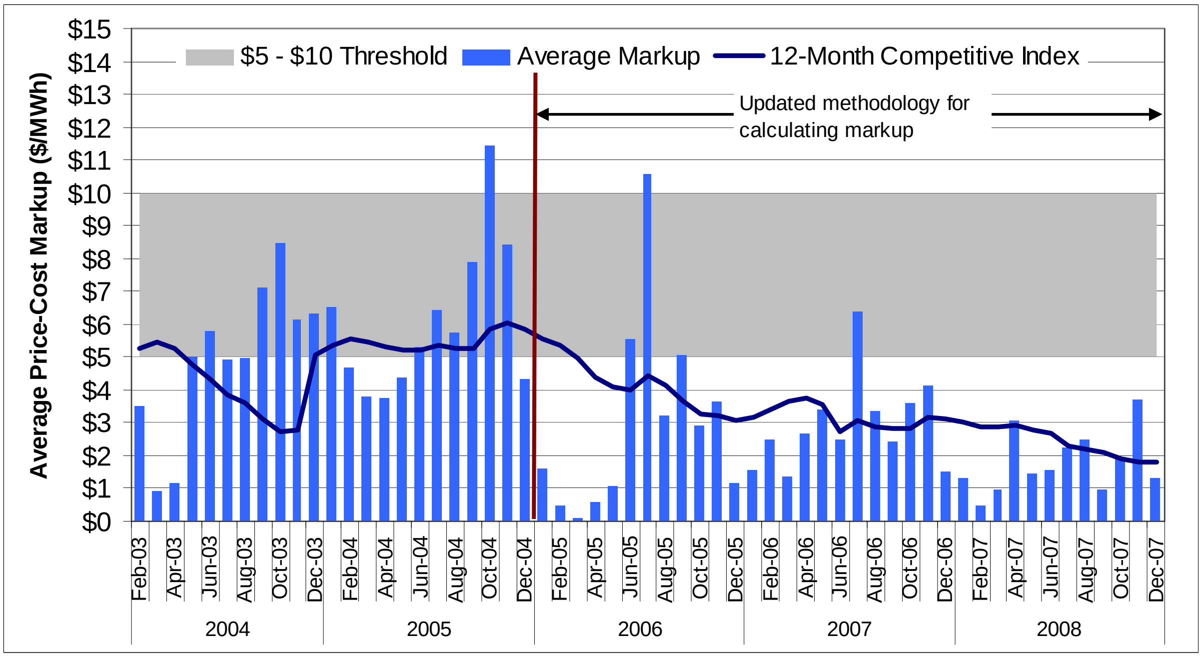
Figure E.5 Short-term Price-Cost Mark-up Index (2008)



Twelve-Month Market Competitiveness Index

Another index the CAISO uses to evaluate market competitiveness is the 12-month competitiveness index. The CAISO developed the index to measure market outcomes over a longer period of time. The index is a volume-weighted twelve-month rolling average of the short-term energy mark-up above estimated competitive baseline cost. The index provides a benchmark to measure the degree of market power exercised in the California short-term energy market during a 12-month period. Experience has shown that the market is workably competitive when the index is within a range of approximately $5 to $10/MWh or below. The index, which crossed this threshold in May 2000 and remained very high during the California energy crisis, served as a barometer for uncompetitive market conditions. The index moved back into the competitive range in May 2002 and has remained in that range through 2008. This indicates that the short-term energy market in California stabilized in late 2001 and has produced fairly competitive results over the past seven years. Figure E.6 below shows the market competitiveness index values for the past five years (2004-2008).

Figure E.6 Twelve-Month Market Competitiveness Index (2004-2008)



Revenue Adequacy of New Generation

Another benchmark often used for assessing the competitiveness of markets is the degree to which spot prices support the cost of investment in new supply needed to meet growing demand and replace existing capacity that is no longer economical to operate. Typically, new generation projects would not go forward without having the output of the plant secured through long-term contractual arrangements that would cover most, if not all, of the plant's fixed costs. However, given the lack of information on prices paid in the current long-term bilateral energy and capacity markets, our analysis examined the extent to which spot markets contributed to the economics of investment in new supply capacity given observed prices over the last four years. Clearly a plant would not be built on the expectation of full cost recovery by selling solely into the CAISO's real-time imbalance energy and ancillary service markets. However, this analysis does show the trend in the level of contribution towards a new unit's fixed costs that could have been recovered in these markets over the year. Chapter 2 includes a detailed explanation of the costs and assumptions used in the analysis.

The assessment of the potential revenues a new generation facility (combined cycle or combustion turbine) could have earned in California's spot market in 2008 indicates that potential spot market revenues fell short of a new unit's annual fixed costs (Figure E.7 and Figure E.8). However, the revenue gap for a combined cycle unit was much smaller in 2008, and has continued to trend down over the five year period shown in Figure E.7. Specifically, the combined cycle analysis shows a trend of net spot market revenues increasing for both Southern (SP15) and Northern (NP15) California with estimated net revenues in 2008 of approximately $111/kW-year and $128/kW-year for Northern and Southern California, respectively, short of the estimated annualized fixed costs of $132.6/kW-year. While estimated net spot market revenues also increased in 2008 for a new combustion turbine (Figure E.8), net revenues were still well below the $162.1/kW-year estimated break-even point.

Figure E.7 Financial Analysis of New CC Unit (2004-2008)

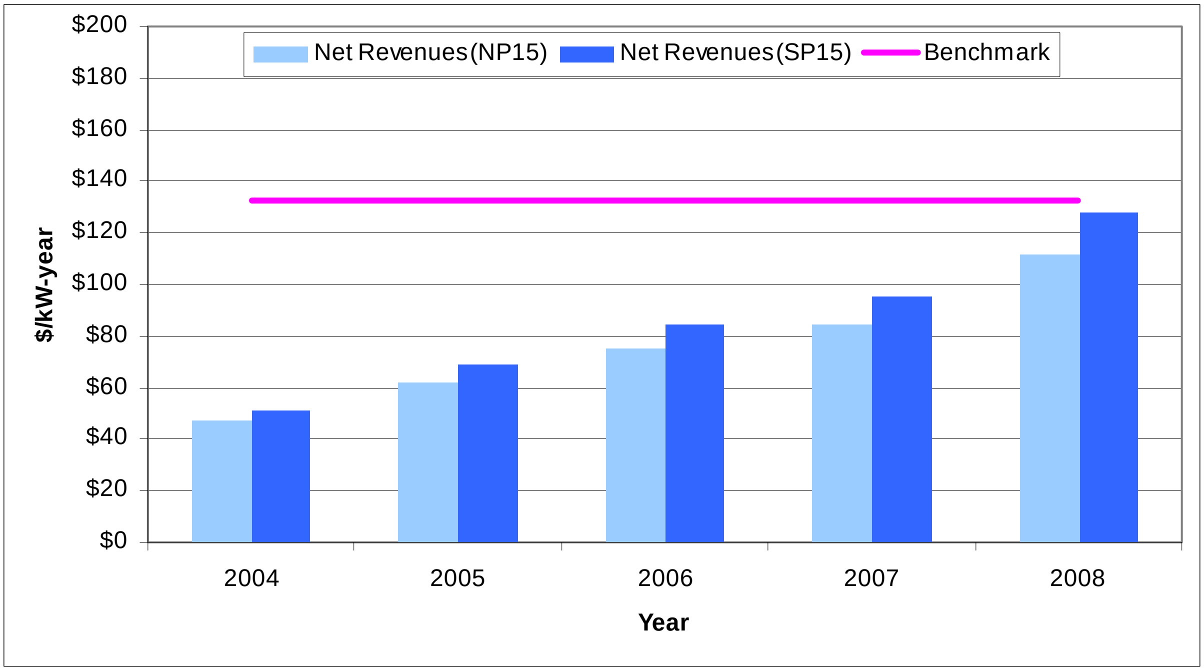
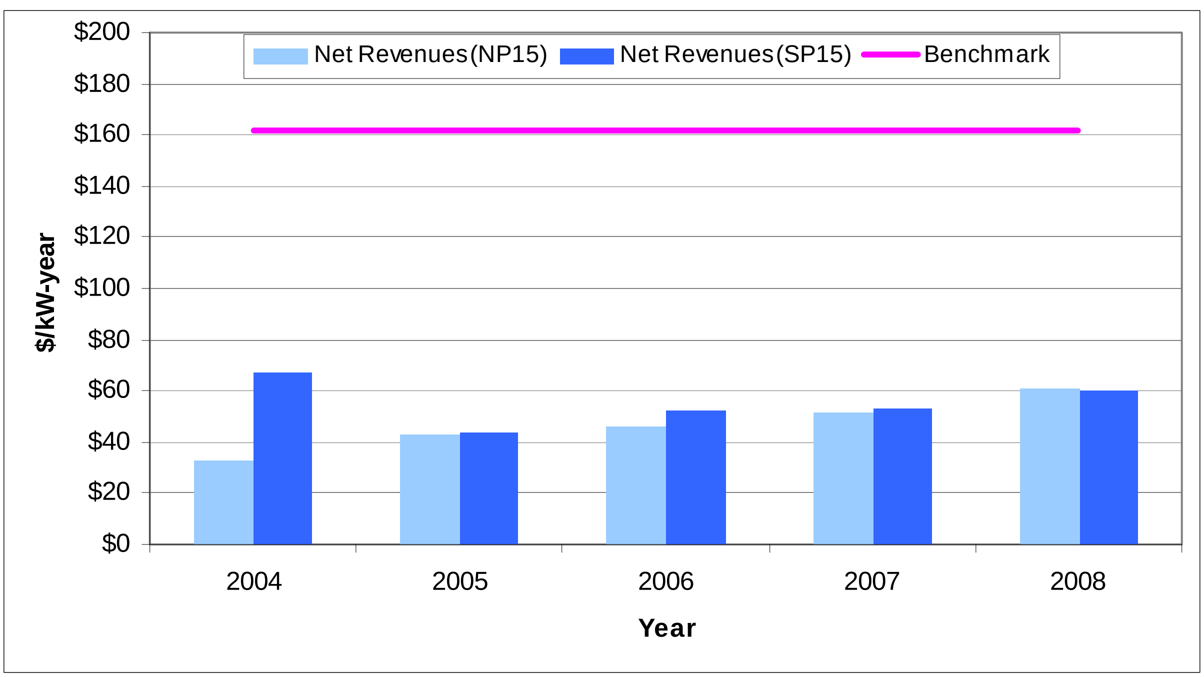


Figure E.8 Financial Analysis of New CT Unit (2004-2008)



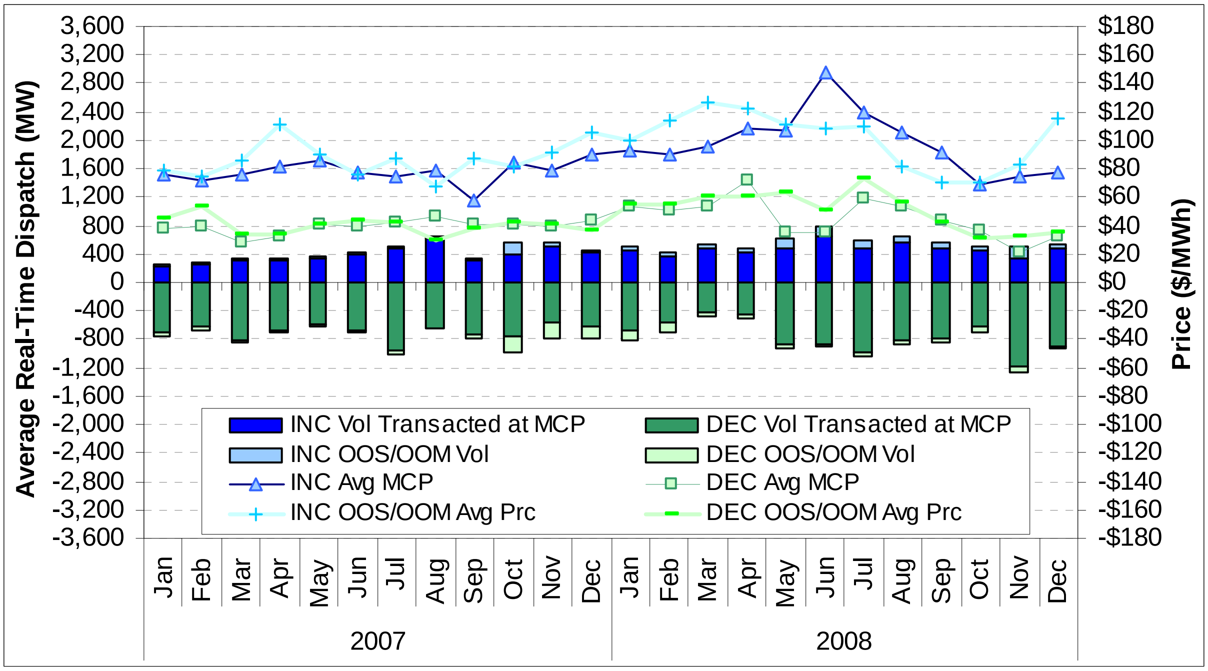
The finding that estimated spot market revenues do not provide for fixed cost recovery underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. It also suggests that there are deficiencies in the current spot market design that are limiting market revenue opportunities – although it could be alternatively argued that the spot market design is adequate and sending the right investment signal for the current market year (i.e., the generation level from a market efficiency standpoint was adequate in 2008) but the net revenues earned in 2008 are not indicative of future market revenue opportunities, which are the primary driver for new investment. In any case, future market design features that could provide better price signals for new investment include: locational marginal pricing (LMP) for spot market energy, local scarcity pricing during operating reserve deficiency hours, and possibly monthly and annual local capacity markets. The CAISO Market Redesign and Technology Upgrade (MRTU), which was implemented on April 1, 2009, will provide some of these elements (LMP, some degree of scarcity pricing). Other design options (formal reserve shortage scarcity pricing mechanism and/or local capacity markets) are being considered for future adoption. In the meantime, local requirements for new generation investment should be addressed through long-term bilateral contracting under the CPUC Resource Adequacy and long-term procurement framework and similar programs for non-CPUC jurisdictional entities.

Real Time Energy Market

For the seventh year in a row, significant forward scheduling by LSEs resulted in low imbalance energy volumes throughout 2008 (Figure E.9). Real-time balancing energy was again overwhelmingly in the decremental direction as a high level of forward scheduling plus unscheduled energy from units committed under the must-offer obligation resulted in frequent over-generation in the real-time imbalance energy market. As shown in Figure E.9, the average hourly levels of decremental dispatches were fairly consistent throughout each month of 2007, averaging close to 900 MWh.

Monthly average prices in 2008 for periods when the CAISO was issuing incremental energy dispatches were higher in the first half of the year, compared to 2007, and peaked in June at approximately $145/MWh. This pattern is consistent with the observed price pattern for natural gas prices, which also peaked in June at approximately $12/MMBTU. Similarly, monthly average prices for incremental energy declined during the second half of the year following the same declining pattern as natural gas prices. Average monthly prices for periods when the CAISO was issuing decremental dispatches were significantly lower, generally averaging between $60/MWh and $40/MWh.

Figure E.9 Monthly Average Real-time Prices and Volumes (2007-2008)



Competitiveness of Real-time Energy Market

The CAISO uses a real-time price-to-cost mark-up index to measure market performance in the Real Time Market. This index compares Real Time Market prices to estimates of real-time system marginal costs. It excludes resources or certain portions of resources that were unable to respond to dispatch instructions for reasons such as physical operating constraints.[6] It is important to note that an index based upon the extremely small volume of transactions in the Real Time Market is not indicative of overall wholesale market competitiveness.[7] Nonetheless, it provides a useful metric for Real Time Market performance.

Throughout 2008, estimated monthly average mark-ups in the Real Time Market were generally higher in the off-peak months than in the peak summer months. For example, during the spring (March-June), average monthly mark-ups were in the 30-60 percent range, but declined steadily through the summer to approximately 10 percent during the peak summer months of August and September, then increased back to the 20-30 percent range in the fall. Mark-ups were generally lower in the summer months because there were typically more units on-line to provide real-time energy, particularly thermal units with greater ramping capability than are

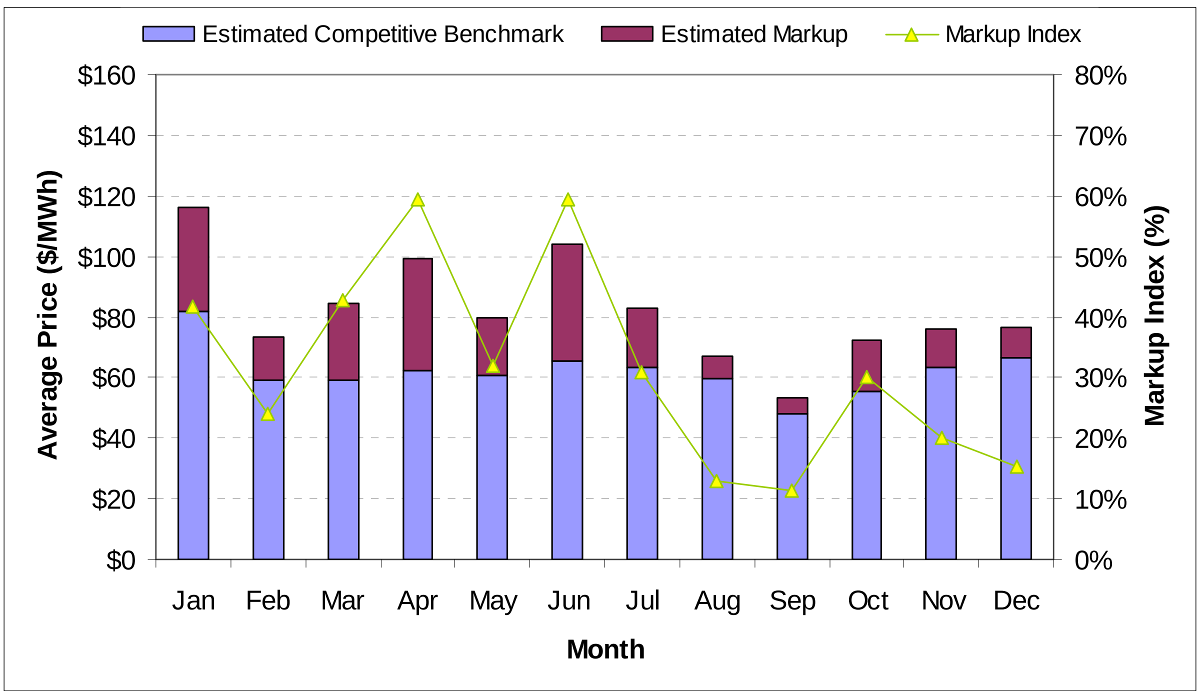
[6] The original real-time price-cost mark-up index used system marginal cost based on all resources available for day-ahead scheduling. That competitive benchmark is more applicable to measure competitiveness of day-ahead and short-term energy markets. Only a subset of those resources is used in the calculation of the real-time mark-up.

[7] Volumes and prices in the Real Time Market are sensitive to a number of factors (i.e., uninstructed deviations, Grid Operator activities taken to mitigate local or zonal reliability issues, unscheduled flows from neighboring control areas, brief perturbations in load) that are outside of fundamental supply and demand conditions that drive market prices. For this reason, and the fact that volumes in the Real Time Market are overall quite small, we look to the spot bilateral market for more meaningful indicators of competitiveness in the wholesale market.

available in the off-peak months. Additionally, peak loads during the summer months in 2008 were fairly moderate, which in turn moderated imbalance energy demands.

While the unusually high mark-ups for the Real Time Market suggest a lack of market competition, it is important to note that the extremely small volumes of energy clearing this market (typically less than 2 percent of the load) coupled with a limited supply of 5-minute dispatchable bids makes this market extremely volatile.[8] High volatility of both price and dispatch quantities coupled with overall low market clearing volumes serve as disincentives for additional supply to enter the market. Given the very small market volumes and high volatility observed in the CAISO Real Time Market, the competitiveness of the day-ahead spot bilateral market is a much more indicative measure of overall spot market competitiveness, and, as reported above, the estimated mark-ups in the day-ahead spot market were much lower, indicating that the spot market was workably competitive in 2008.

Figure E.10 Monthly Estimated Mark-up for Real Time Incremental Imbalance Energy Market (2008)



Real-time Congestion (Intra-Zonal)

Intra-zonal congestion occurs when power flows overload the transfer capability of grid facilities within the congestion zones that are modeled and managed in the CAISO day-ahead and hour-ahead congestion management market. Intra-zonal congestion most frequently occurs in load pockets, or areas where load is concentrated with insufficient transmission to allow access to

[8] It is important to note that real-time imbalance energy markets are inherently volatile and thus the volatility observed in the CAISO Real Time Market is not necessarily an indication of market design deficiencies.

lower priced energy. Intra-zonal congestion can also occur due to generation pockets in which generation is clustered together with insufficient transmission to allow the energy to flow out of the pocket area. In both cases, the absence of sufficient transmission access to an area means that the CAISO has to resolve the problem locally, either by incrementing generation within a load pocket or by decrementing it in a generation pocket.

One significant positive trend that has been reported in prior annual reports has been the sharp reduction in intra-zonal congestion costs. This trend did not continue in 2008 as intra-zonal congestion costs increased from $96 million in 2007 to $174 million in 2008. Intra-zonal congestion costs are comprised of three components: 1) Minimum Load Cost Compensation (MLCC) for units denied must-offer waivers, 2) real-time RMR costs, and 3) real-time redispatch costs. Costs for all three of these components are shown in Table E.3. The increase is primarily attributable to higher MLCC payments and real-time redispatch costs. MLCC costs increased by $46 million in 2008, mainly due to the need to commit units in the summer months to relieve a transmission constraint in Southern California (Lugo substation). The cost of real-time redispatch costs increased by $39 million in 2008. This increase was caused primarily by the increased need for uplift to move resources committed at minimum load to higher real-time dispatchable regions. Humboldt-area local OOS dispatches incurred significant redispatch costs as well. The cost increases for the MLCC and redispatch components of intra-zonal congestion costs were partially offset by a decrease in the third component, real-time RMR cost, of $6 million.

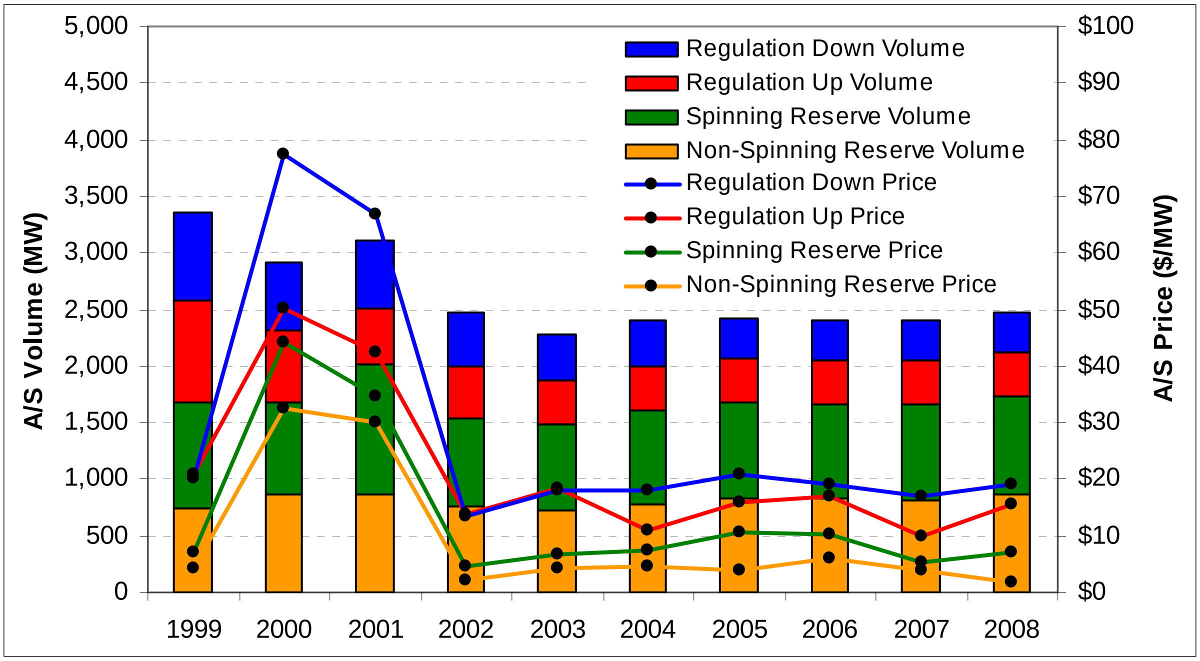
Table E.3 Monthly Intra-Zonal Congestion Costs by Category ($ Million)

	MLCC Costs			RT RMR Costs			RT Redispatch Costs			Total		
Month	2006	2007	2008	2006	2007	2008	2006	2007	2008	2006	2007	2008
Jan	$ 10	$ 3	$ 7	$ 13	$ 2	$ 2	$ 4	$ 2	$ 6	$ 27	$ 6	$ 15
Feb	$ 8	$ 2	$ 4	$ 15	$ 1	$ 2	$ 2	$ 2	$ 6	$ 25	$ 4	$ 11
Mar	$ 11	$ 2	$ 5	$ 13	$ 1	$ 1	$ 3	$ 1	$ 4	$ 27	$ 4	$ 10
Apr	$ 27	$ 2	$ 4	$ 8	$ 2	$ 2	$ 6	$ 2	$ 3	$ 41	$ 6	$ 10
May	$ 12	$ 2	$ 12	$ 3	$ 1	$ 2	$ 1	$ 2	$ 7	$ 16	$ 4	$ 21
Jun	$ 15	$ 3	$ 13	$ 4	$ 1	$ 0	$ 0	$ 1	$ 6	$ 19	$ 5	$ 19
Jul	$ 14	$ 7	$ 10	$ 2	$ 1	$ 1	$ 0	$ 2	$ 7	$ 17	$ 10	$ 18
Aug	$ 5	$ 2	$ 9	$ 3	$ 1	$ 1	$ 0	$ 1	$ 6	$ 8	$ 4	$ 16
Sep	$ 3	$ 2	$ 8	$ 2	$ 0	$ 1	$ 0	$ 1	$ 4	$ 5	$ 4	$ 13
Oct	$ 1	$ 10	$ 3	$ 3	$ 7	$ 1	$ 1	$ 8	$ 5	$ 5	$ 25	$ 9
Nov	$ 1	$ 5	$ 9	$ 6	$ 3	$ 1	$ 0	$ 4	$ 11	$ 7	$ 12	$ 21
Dec	$ 2	$ 5	$ 6	$ 7	$ 3	$ 1	$ 0	$ 4	$ 4	$ 9	$ 12	$ 12
Total	**$ 109**	**$ 44**	**$ 90**	**$ 80**	**$ 22**	**$ 16**	**$ 17**	**$ 30**	**$ 69**	**$ 207**	**$ 96**	**$ 174**

Ancillary Service Markets

In the Ancillary Service (A/S) Markets, prices were stable in 2008 but average prices were higher for most services, particularly Regulation. Higher prices for Regulation occurred primarily during the spring and early summer as a majority of thermal units that usually provide regulation services were off-line due to lower cost hydroelectric produced energy being imported from the Pacific Northwest. This contributed to fewer supply bids for Regulation, resulting in sharply higher prices. Average annual price for Non-Spinning Reserve declined in 2008 from $3.98/MW in 2007 to $1.74/MW in 2008. Overall, A/S prices increased 12 percent from a weighted average price of $7.41/MW in 2007 to $8.27/MW in 2008 but were still below the average annual prices reported for 2003-2006. The average volume of each ancillary service purchased was quite similar to previous years (Figure E.11).

Figure E.11 Annual A/S Prices and Volumes (1999-2008)



The A/S markets also experienced a 39 percent increase in the total number of hours of bid insufficiency in 2008 compared to the previous year (Table E.4). Regulation Up experienced the greatest increase in number of hours of bid insufficiency at 62 hours (compared to 11 in 2007), most of which occurred during the months of May and June 2008, and can be generally attributed to less thermal generation being on line due to high natural gas prices, relatively low load levels (May through mid-June) and abundance of hydroelectric energy from the Pacific Northwest. As load levels increased beginning in the third week of June, more thermal units came on-line and more unloaded capacity was available to provide regulation services. Table E.4 also shows the average level of bid insufficiency, expressed as a percentage of the requirement level. The average level of bid insufficiency declined from 8 percent in 2007 to 7 percent in 2008. However, the average level of bid insufficiency for Regulation Up increased from 7 percent in 2007 to 14 percent in 2008.

Table E.4 Ancillary Service Bid Insufficiency

	Number of Hours With Shortage				
	Regulation Down	Regulation Up	Spinning Reserve	Non-Spinning Reserve	All Services
2007	20	11	35	36	102
2008	5	62	45	30	142
Percent Δ	-75%	464%	29%	-17%	39%

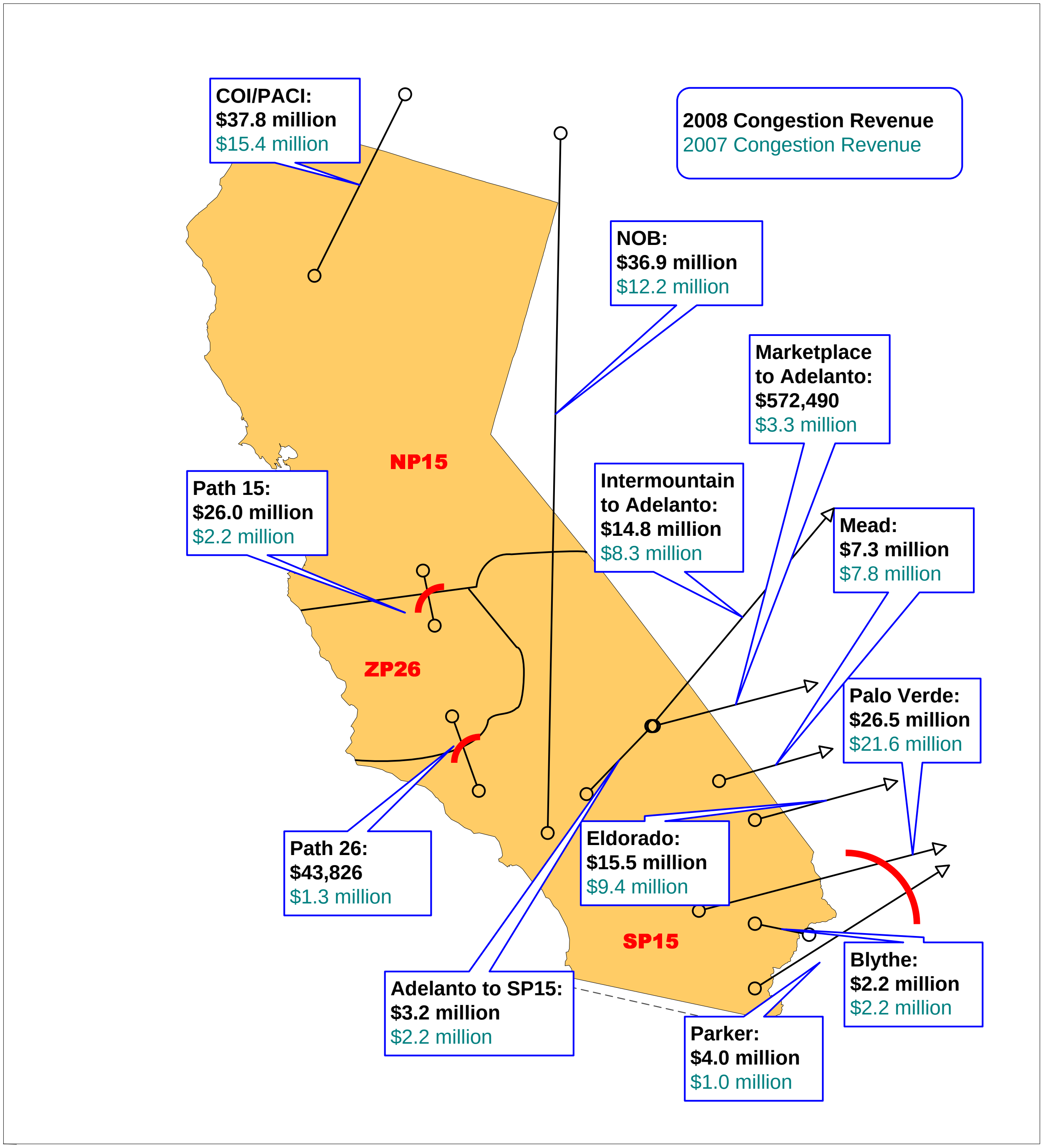
	Average Percent of Requirement Short				
	Regulation Down	Regulation Up	Spinning Reserve	Non-Spinning Reserve	All Services
2007	15%	7%	6%	8%	8%
2008	9%	14%	4%	7%	7%

Inter-Zonal Congestion Market

The CAISO Inter-Zonal Congestion Management Market was also generally stable and competitive in 2008, but inter-zonal congestion did increase significantly from 2007. Total inter-zonal congestion cost in 2008 was $176 million, significantly higher than the $85 million in 2007.

Figure E.12 shows the total annual congestion costs for the most commonly congested paths in 2007 and 2008. The most dramatic increases occurred on three major transmission paths, Path 15 and the two major inter-ties with the Pacific Northwest (Pacific AC Inter-tie or PACI), and the Pacific DC Inter-tie (PDCI – also known as NOB). Congestion costs on Path 15 increased from $2.2 million in 2007 to $26.1 million in 2008. This ten-fold increase was due primarily to one of the three 500 kV lines that comprise this path being taken out of service for scheduled maintenance during October 14 to November 7. Congestion costs on PACI increased to $37.8 million in 2008, compared to $15.4 million in 2007. Similarly, congestion costs on PDCI increased to $37 million, compared to $12.2 million in 2007. The substantial increase in congestion costs on these two paths can be attributed to a combination of abundant hydroelectric supplies in the Northwest and high natural gas prices, which increased demand and willingness to pay for using the major transmission facilities between California and the Pacific Northwest. Additionally, the PACI was derated on June 29, 2008, due to wildfires, resulting in almost $6 million in congestion costs for that single day. Palo Verde continued to have significant congestion costs in 2008, at $26.5 million, compared to $21.6 million in 2007.

Figure E.12 Major Congested Inter-ties and Congestion Costs



Summary and Conclusions

Overall, the CAISO markets and short-term bilateral energy markets were stable and competitive in 2008. This performance reflects the significant strides that California has made since the energy crisis both in terms of infrastructure enhancements (transmission and generation) as well as in forward energy contracting. Medium- to long-term forward energy contracting provides a number of critical benefits to the market. First, it protects LSEs from spot market volatility (i.e., it is an important hedging tool). Second, it shifts spot market risk to the supply side of the market, and, in so doing, largely reduces incentives for suppliers to exercise market power. Finally, it provides a means for facilitating new generation investment. When load is effectively hedged, periodic price spikes impose manageable costs to load and provide important market benefits such as incentives to avoid generation forced outages, revenues for generation fixed cost recovery, and market prices that encourage demand response programs.

In terms of the spot market signals being provided for new generation investment, the spot markets continue to produce net-market revenues that are short of what would be needed to cover the annualized costs of new generation facilities. Typically, new generation projects would not go forward without having the output of the plant secured through long-term contractual arrangements that would cover most, if not all, of the plant's fixed costs. Nonetheless, this analysis does show the trend in the level of contribution towards a new unit's fixed costs that could have been recovered in the spot markets over the year. The fact that California's spot markets do not provide sufficient market revenues for fixed cost recovery six years in a row underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. It also suggests that there are deficiencies in the current spot market design that are limiting market revenue opportunities – although it could be alternatively argued that the spot market design is adequate and sending the right investment signal for the current market year, but the net revenue earned in 2008 is not indicative of future market revenue opportunities, which are the primary driver for new investment. In any case, future market design features that could provide better price signals and revenue opportunities for new investment include: locational marginal pricing (LMP) for spot market energy, local scarcity pricing during operating reserve deficiency hours, and possibly monthly and annual local capacity markets. The CAISO Market Redesign and Technology Upgrade (MRTU), which was implemented on April 1, 2009, will provide some of these elements (LMP, some degree of scarcity pricing). Other design options (formal reserve shortage scarcity pricing mechanism and/or local capacity markets) are being seriously considered for future adoption.

While seven consecutive years of stable and competitive market performance is encouraging, the industry must remain vigilant in addressing its ever growing infrastructure needs, particularly for Southern California. Though approximately 7,500 MW of new generation has been added to Southern California since the energy crisis, which enabled the retirement of 4,300 MW of older inefficient generation, net generation additions for that region have only just kept pace with load growth. Consequently, reliability needs for that region continue to be met, in part, by older, less efficient generation, which cannot be sustained indefinitely. Moreover, major state environmental policies, such as greenhouse gas reductions, Renewable Portfolio Standards (RPS), and a potential ban on once-through cooling systems, will call for even more aggressive and coordinated action on addressing infrastructure issues.

1 Market Structure and Design Changes

1.1 Introduction and Background

This chapter reviews some of the major market design and infrastructure changes that impacted market performance in 2008. Unlike prior years, there were no significant market design changes implemented in 2008, so the focus of this chapter for this year's report is on changes to generation and transmission infrastructure. The infrastructure changes discussed below include changes in generation retirements and additions, various transmission upgrades implemented in 2008, and potential future projects.

1.2 Generation Additions and Retirements

Trends in the net-generation capacity being added to the CAISO Control Area each year provide important insight into the effectiveness of the California market and regulatory structure in bringing about new generation investment and facilitating the retirement of older inefficient plants. The Department of Market Monitoring tracks changes in the portfolio of installed capacity in the CAISO Control Area and conducts revenue analysis for new generation investment to determine the extent to which the California market is providing sufficient incentives for new generation investment.[9]

1.2.1 Generation Additions and Retirements in 2008

Only 45 MW of new generation began commercial operation within the CAISO Control Area in 2008. This additional capacity came from a new wind facility, Dillon Wind Project, in Southern California. This figure is significantly below the 1,800 MW that was projected for 2008 in last year's report. New generation projects are complicated and costly, and consequently are subject to significant delays. Most of the projects projected to become commercial in 2008 were delayed, with only the Dillon Wind Project making it to commercial production during 2008[10]. Table 1.1 shows the new generation projects that began commercial operation in 2008.

[9] Generator revenue analysis is provided in Chapter 2.

[10] Though approximately 1,660 MW of new generation was at some point on-line and tested in 2008, only 45 MW actually became commercially operable in 2008 with another 770 MW becoming commercially operable in the first quarter of 2009.

Table 1.1 New Generation Facilities in 2008

Generating Unit	Net Dependable Capacity (MW)	Commercial Operation Date	Zone ID
--- None ---			NP 26
NP26 New Generation in 2008	***0.0***		
Dillon Wind Project	45.0	18-Apr-08	SP26
SP26 New Generation in 2008	***45.0***		
Total New Generation in 2008	**45.0**		

No generation capacity was retired from service in 2008. Therefore, the net capacity increase in the CAISO Control Area was 45 MW.[11] Table 1.2 summarizes the net change in installed generation by region.

Table 1.2 Generation Capacity Change in 2008 by Region

Region	Generation Additions (MW)	Generation Reductions (MW)	Net Change in Generation (MW)
NP26	0	0	0
SP26	45	0	45
CAISO Control Area	**45**	**0**	**45**

1.2.2 Anticipated New and Retired Generation in 2009

The CAISO projects construction of 3,414 MW of new generation in 2009, of which roughly 1,404 MW are expected to be commercially available prior to the anticipated summer peak season. Table 1.3 below lists the changes expected for 2009. Most significantly, there are two 405 MW resources, the Inland Empire units, and the 615 MW Otay Mesa unit, that are expected to be operational in October 2009. Additionally, the 619 MW Gateway unit went commercial in January 2009.

[11] Though approximately 1,660 MW of new generation was at some point on-line and tested in 2008, only 45 MW actually became commercially operable in 2008 with another 770 MW becoming commercially operable in the first quarter of 2009.

Table 1.3 Planned Generation Additions in 2009

Generating Unit	Resource Capacity (MW)		Expected Operational Date	Zone ID
Gateway Generating Station	619.0		04-Jan-09	NP26
Shiloh Wind Farm II	150.0	*	27-Jan-09	NP26
Ox Mountain Landfill Gas Generation	11.4		01-Apr-09	NP26
Keller Canyon Landfill Generating Facility	3.8		01-May-09	NP26
GV1 / Green Volts, Inc.	2.0	*	01-Jun-09	NP26
G2 Energy, Ostrom Road LLC	1.6		28-Jan-09	NP26
Starwood Power Midway	139.8		01-Jun-09	NP26
Panoche Energy Center	401.0		01-Jun-09	NP26
Humboldt Bay Power Plant Repowering	162.0		01-Dec-09	NP26
NP26 Planned New Generation in 2009	***1,491***			
Inland Empire Energy Center Unit 1	405.0		01-Oct-09	SP26
Inland Empire Energy Center Unit 2	405.0		01-Oct-09	SP26
Fontana RT Solar	2.0	*	01-May-09	SP26
Garnet Energy Center	3.0	*	15-May-09	SP26
Garnet Energy Center Expansion	3.5	*	01-Jun-09	SP26
Chiquita Canyon Landfill	9.2			SP26
Kittyhawk Renewable Energy Facility	2.2		01-Jun-09	SP26
Sierra Solar Generating Station	5.0	*	01-Jun-09	SP26
Toland Landfill G-T-E Project	1.0		01-Jun-09	SP26
Otay Mesa Energy Center	615.0		01-Oct-09	SP26
Miramar Energy Facility II	49.0		31-Jul-09	SP26
Orange Grove	99.0		01-Nov-09	SP26
Coram Brodie Wind Project	51.0	*	01-Dec-09	SP26
SP26 Planned New Generation in 2009	***1,650***			
Total Planned New Generation in 2009	**3,141**			
*** Total Renewable Generation in 2009**	**217**			

Currently only 26 MW of existing generation is planned to be retired in 2009, all in NP15. Unlike the lengthy process for constructing a new resource and bringing it online, a generation owner can retire an existing resource 90 days after notifying the CAISO.

Table 1.4 Planned Generation Retirements in 2009

Generating Unit	Resource Capacity (MW)	Zone ID
MMC Mid-Sun	22.5	NP15
Wheelabrator Shasta Unit 4	3.0	NP15
Total Planned Retired Generation in 2009	**26**	

Table 1.5 below shows an annual accounting of generation additions and retirements since 2001, with projected 2009 changes included along with totals across the nine year period (2001-2009).

Table 1.5 Changes in Generation Capacity Since 2001

	2001	2002	2003	2004	2005	2006	2007	2008	Projected 2009	Total Through 2009
SP15										
New Generation	639	478	2,247	745	2,376	434	485	45	1,650	9,099
Retirements	0	(1,162)	(1,172)	(176)	(450)	(1,320)	0	0	0	(4,280)
Forecasted Load Growth*	491	500	510	521	531	542	553	564	575	4,787
Net Change	**148**	**(1,184)**	**565**	**48**	**1,395**	**(1,428)**	**(68)**	**(519)**	**1,075**	**32**
NP26										
New Generation	1,328	2,400	2,583	3	919	199	112	0	1,491	9,035
Retirements	(28)	(8)	(980)	(4)	0	(215)	0	0	(26)	(1,261)
Forecasted Load Growth*	389	397	405	413	422	430	439	447	456	3,798
Net Change	**911**	**1,995**	**1,198**	**(414)**	**497**	**(446)**	**(326)**	**(447)**	**1,009**	**3,976**
ISO System										
New Generation	1,967	2,878	4,830	748	3,295	633	598	45	3,141	18,135
Retirements	(28)	(1,170)	(2,152)	(180)	(450)	(1,535)	0	0	(26)	(5,541)
Forecasted Load Growth*	880	897	915	934	953	972	991	1,011	1,031	8,585
Net Change	**1,059**	**811**	**1,763**	**(366)**	**1,892**	**(1,874)**	**(394)**	**(966)**	**2,084**	**4,008**

* Forecasted load growth is based on an assumed 2 percent peak load growth rate applied each year.

There was a 45 MW net increase in installed generation in the CAISO Control Area in 2008 with no unit retirements. Although this net change in installed capacity was positive, adjusted for projected load growth of 1,011 MW, the net incremental change (i.e., net of load growth) was a negative 966 MW. The total net increase in installed generation in the CAISO Control Area over the nine years spanning 2001-2009 is projected to be roughly 12,600 MW (including projected net growth in 2009 which, as highlighted with 2008 projections, are subject to significant revision after the fact). When adjusted for estimated annual load growth, the net increase in installed generation drops from 12,594 MW to just over 4,008 MW over this nine year period.

1.3 Transmission System Enhancements

There were several transmission projects completed in 2008. The various upgrades associated with individual lines or equipment are listed below in Table 1.6. Some of the more significant of these upgrades are described in greater detail below:

Vaca-Dixon 500/230 kV - PG&E added Transformer Bank 12 at Vacaville-Dixon 500/230 kV to operate in parallel with Bank 11.

New Westley-Rosemore 230 kV lines were constructed by PG&E. Also, two new 230/115 kV transformers were extended by PG&E at Westley Substation.

Tiffany Substation 115 kV was connected to the Dillon Wind Generation Project by SCE.

New Barren Ridge 230kV substation - SCE looped existing Inyo-Rinaldi 230kV line through new Barren Ridge Substation forming two new 230kV lines named Barren Ridge-Rinaldi and Inyo-Barren Ridge. Also added new Pine Tree-Barren Ridge 230kV line. All three lines are controlled by LDWP, but interface with SCE at Control through existing phase shifter.

Silvergate - New 230/69 kV Substation - SDGE decommissioned Main Street Substation and commissioned Silvergate. The 69kV portion of Silvergate was energized in November followed by the 230kV portion, which was energized on December 2008.

Table 1.6 Transmission Projects Completed in 2008

Transmission Project	In-Service Date
New Vaca Dixon 500/230 kV transformer	Jan-08
Lake Hodges pump station loop-in 69kV line; Building a new substation	Jan-08
2 New 230/115 kV transformers in Westley substation	Jan-08
New Vermont Substation - City of Anaheim	Jan-08
Wintec VI (Tiffany Substation); new 115kV switching station	Feb-08
Nations Petroleum 70 kV Interconnection	Mar-08
Connecting generation Dillion Wind to Tiffany 115 kV	Mar-08
El Cajon - 69kV capacitor reactor replacement	Mar-08
San Joaquin Valley RAS is an infrastructure replacement	Apr-08
Del Monte 115/60 kV transformer replacement	Apr-08
Drum-Bell 115 kV line; replacement of line breakers and upgrading switches	Apr-08
Herndon - Bullard 115 kV reconductoring	Apr-08
Kasson-Lammers 115 kV reconductoring	Apr-08
Mc Call 230 /115 kV transformer replacement	May-08
Merced 115 kV Bus reconductoring	May-08
Install new distribution Hughson substation in the Tuolumne - Taylor 115 kV line	May-08
Newark-Fremont 115 kV line reconductoring	May-08
Installing SPS at Atwater	May-08
Installing new transformer in Palermo Substation 230/115 kV	May-08
Chowchilla-LeGrand 115kV reconductoring	May-08
Install new Rogers Substation in the Westley - Walnut 115 kV line	May-08
New Westley-Rosemore 230 kV lines	May-08
Connecting Lone Tree Substation 230 kV to the transmission grid	Jun-08
Interconnect new load to Oleum 115 kV bus and extend two 115 kV lines	Jun-08
MONOLITH new bus tie breaker	Jun-08
Stagg 230/60 kV transformer upgrade	Jun-08
New transformer at Vierra	Jun-08
Templeton - Atascadero 70 kV reconductoring	Jun-08
Metcalf-El Patio 115 kV lines reconductoring	Jun-08
Humboldt - Harris 60 kV reconductoring	Jun-08
Installing SPS at Antelope	Jul-08
Weber #1 60 kV line reconfiguration	Aug-08
New Barren Ridge 230kV substation	Sep-08
Davis 115 kV Circuit Breaker	Sep-08
Transmission interconnection for Otay Mesa Generation Project	Sep-08
Hicks Station 230kV - Installing Bank #5	Sep-08
Otay (Mesa) Metro Powerloop (OMEC) - Miguel Tap; installing 2 breakers	Sep-08
Metcalf-Moss Landing 230 kV line reconductoring	Oct-08
Rerate North City West (NCW) from 138kV to 69kV	Oct-08
Goleta Bank 3A & 4A; replacement with a single bank	Oct-08
Gateway Generation Station interconnection to Contra Costa PP substation 230 kV bus	Oct-08
Antelope 280 MVA 230/66 kV Transformer Bank #3A uprate	Nov-08
San Luis Rey 230 kV rearrangement	Nov-08
Silvergate - New 230/69 kV Substation	Nov-08
SOUTH BAY upgrade 138kV bank #50	Dec-08
Increasing Plainfield substation capacity (Transmission)	Dec-08
Ox Mountain interconnection to the transmission grid (60kV)	Dec-08
Expanding Mountainview(MVPP) RAS	Dec-08

2 Summary of Energy Market Performance

2.1 Demand Conditions

2.1.1 Actual Loads

System peak loads in 2008 declined nominally since 2007, due to relatively mild weather and perhaps a slowing economy. Overall, load averaged 0.5 percent below that of 2007. Summer weather conditions have been generally mild since a record heat wave in 2006.

Load peaked in 2008 on Friday, June 20, at 46,897 megawatts (MW), amid a four-day heat wave. This peak was below the 1-in-2 peak estimate of 48,900 MW, a benchmark used as a minimum grid planning reliability target. Load exceeded 45,000 MW in only four hours in 2008 – all on June 20 – compared with 19 hours over four days in 2007, and 62 hours over 11 days in 2006.

Table 2.1 shows nominal annual peak load and total energy for the last 5 years, as well as peak load and total energy adjusted for the 2004 and 2008 leap years and changes in load footprint that occurred in 2004 and 2005. Table 2.2 shows same-month comparisons of load statistics in 2007 and 2008.

Table 2.1 CAISO Annual Load Statistics for 2004-2008

Year	Avg. Load (MW)	% Chg.	Annual Total Energy (GWh)	Annual Peak Load (MW)	% Chg.
2004 Actual	27,311		239,957	45,597	
2005 Actual	26,985	-1.2%	237,063	45,562	-0.1%
2006 Actual	27,432	1.6%	241,019	50,270	10.3%
2007 Actual	27,644	0.8%	242,880	48,615	-3.3%
2008 Actual	27,498	-0.5%	241,594	46,897	-3.5%
2004 Adjusted	26,443		232,327	44,209	
2005 Adjusted	26,475	0.1%	232,586	44,260	0.1%
2006 Adjusted	27,432	3.5%	241,019	50,198	11.8%
2007 Adjusted	27,644	0.8%	242,880	48,535	-3.4%
2008 Adjusted	27,498	-0.5%	241,594	46,897	-3.5%

Table 2.2 Rates of Change in Load: Same Months in 2008 vs. 2007

	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
January-08	-1.3%	-1.3%	-2.1%	-2.5%
February-08	-1.2%	-1.3%	-2.0%	-2.5%
March-08	-3.0%	-3.0%	-3.1%	-6.2%
April-08	-0.9%	-0.1%	-0.4%	7.9%
May-08	-1.2%	-1.3%	0.3%	8.6%
June-08	2.2%	3.1%	0.8%	13.1%
July-08	-1.6%	-1.9%	-0.4%	0.0%
August-08	-3.0%	-2.9%	-1.7%	-8.1%
September-08	4.0%	7.8%	1.8%	-1.0%
October-08	3.7%	5.6%	1.1%	24.0%
November-08	-1.7%	-1.5%	-1.6%	-1.0%
December-08	-2.2%	-1.7%	-3.8%	0.4%

The relatively sharp changes in monthly peaks in June and October reflect the fact that peaks occur in different months from year to year. June and October were unseasonably warm in 2008, whereas annual peaks in previous years typically have occurred in July, August, and September. Figure 2.1 shows CAISO loads in June 2008 compared to those in 2007, and depicts the June 2008 peak compared to the same period in 2007. Similarly, a brief heat wave the first week of October 2008 saw a peak of 41,597 MW, compared to the October 2007 peak of 34,959 MW.

Figure 2.1 California ISO System-wide Actual Loads: June 2008 vs. June 2007

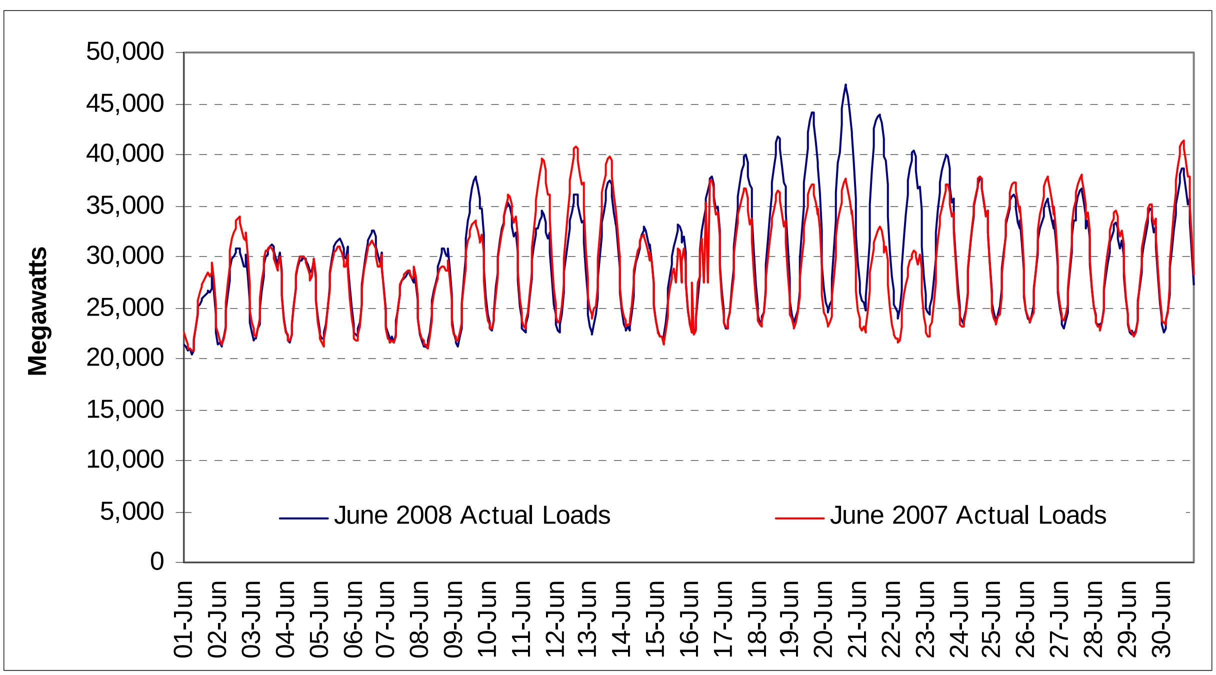


Figure 2.2 depicts load duration curves for each of the last five years, and shows that loads in 2008 were generally within the 5-year average range. Note that in 2008, there were 188 hours

(2.1 percent of all hours) with loads in excess of 40,000 MW, compared to 228 hours (2.6 percent) in 2007.

Figure 2.2 CAISO System-wide Actual Load Duration Curves: 2004-2008

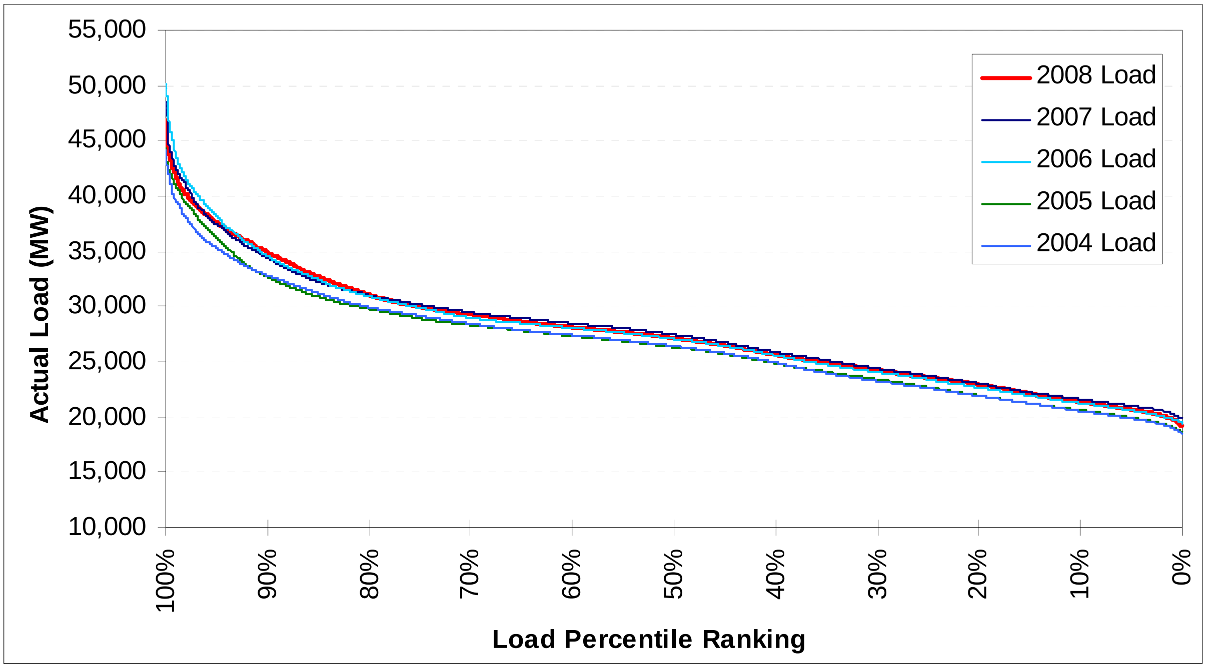


Table 2.3 shows annual load changes between 2007 and 2008 for NP26, SP15, and the entire control area. Average hourly loads declined slightly in 2008 in both Northern and Southern regions. Daily trough load, which is generally less sensitive to weather than average or peak loads, declined nearly 1 percent system-wide.

Table 2.3 CAISO Annual Load Change: 2008 vs. 2007

Zone	Avg. Hourly Load	Daily Peak Load	Daily Trough Load	Annual Peak
NP26	-0.4%	0.3%	-1.3%	2.8%
SP15	-0.7%	-0.1%	-0.7%	-6.0%
CAISO Control Area	-0.5%	0.1%	-0.9%	-3.6%

2.1.2 Role of Demand Response

Various demand response programs operating in California play an important role in meeting peak summer energy demands. This section provides a brief overview of the various demand response programs available for meeting peak summer demand in 2008.

The vast majority of demand programs available for managing peak summer demands are managed by California's three investor owned utilities (Southern California Edison (SCE), Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E)). However, the CAISO markets also provide an opportunity for certain demand resources (Participating Loads) to directly participate in the Ancillary Service (Non-Spinning Reserve) and Real Time Markets.

Currently, Participating Loads are comprised of pumped-hydroelectric facilities and water pumping facilities that in aggregate amount to approximately 4,380 MW of demand response capability. However, because pumped-hydroelectric facilities typically pump water (i.e., consume energy) only during off-peak hours, their contribution to peak demand management is limited. The CAISO is currently conducting a stakeholder process for enhancing the current Participating Load program for implementation in 2010.

The utility-managed demand programs can be grouped into two general categories: "reliability-based" and "price-based". Reliability-based programs consist primarily of large retail customers under interruptible tariffs and air conditioning cycling programs. These programs are primarily triggered by the CAISO declaring a system emergency. Price responsive programs include Critical Peak Pricing retail tariffs in which program participants are charged significantly higher rates for peak hours of declared critical peak days. They also include various price-based programs where customers are paid to reduce consumption when certain market conditions are triggered. Table 2.4 provides a summary of the total megawatts enrolled in each of these categories by utility for July and August of 2007 and 2008. The total megawatts enrolled in price-responsive demand programs increased significantly for all three utilities and increased in total by approximately 30 percent for each month. There was also a significant increase in reliability-based programs for SCE and PG&E, which in total amounted to approximately a 16% increase for each month.

Table 2.4 Summary of Utility Operated Demand Programs[12]

Utility	Program	Jul-07 Enrolled MW	Jul-08 Enrolled MW	Aug-07 Enrolled MW	Aug-08 Enrolled MW
SCE	Price-Responsive	240	369	256	381
PG&E	Price-Responsive	608	735	623	752
SDG&E	Price-Responsive	117	150	121	154
	Total	964	1,254	999	1,287
SCE	Reliability-Based	1,283	1,436	1,305	1,458
PG&E	Reliability-Based	322	451	323	466
SDG&E	Reliability-Based	93	89	98	83
	Total	1,698	1,976	1,726	2,007
	Combined Total	2,662	3,230	2,725	3,294

2.2 Supply Conditions

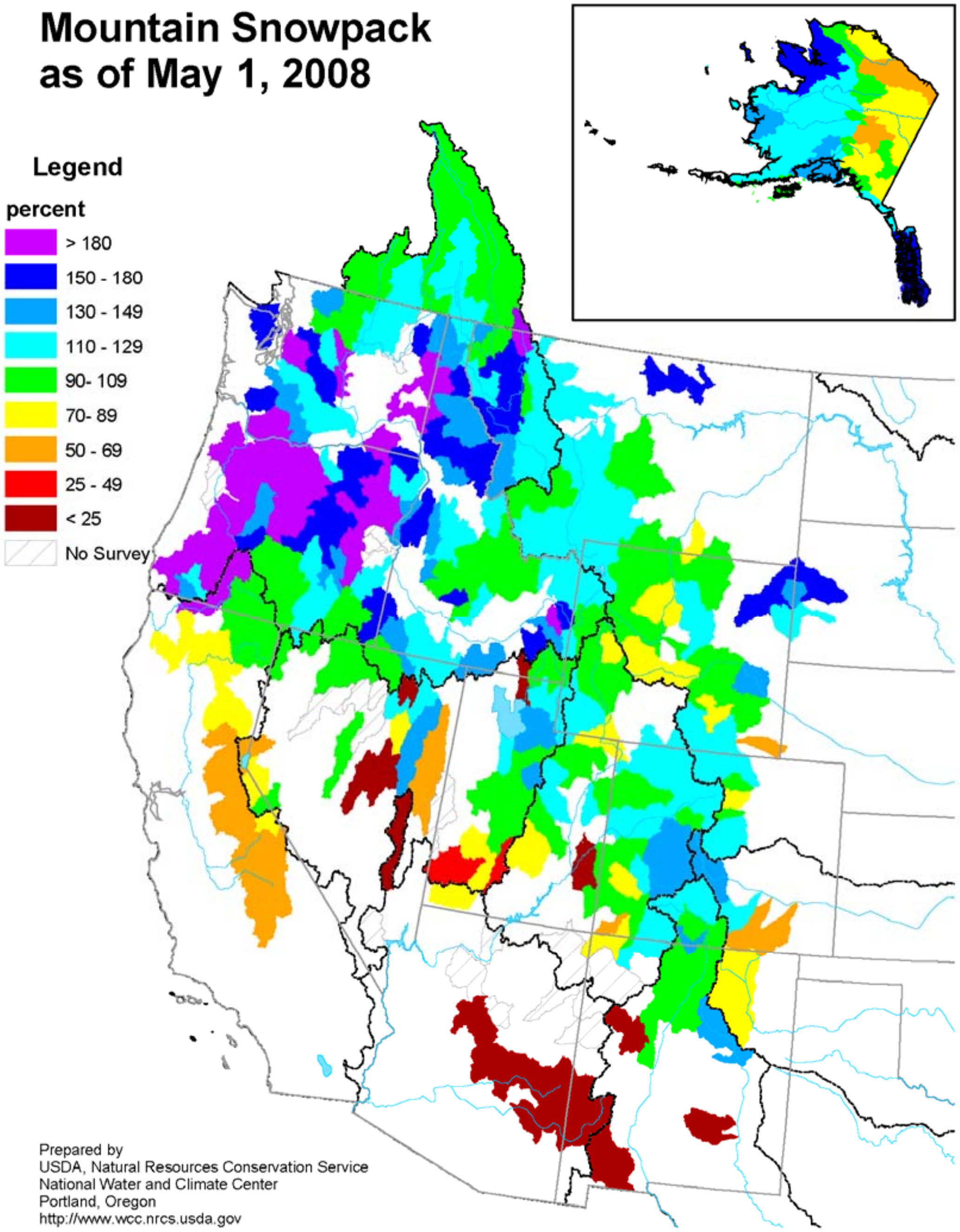
The worldwide spike in oil prices that peaked in July 2008 also caused a substitution-induced spike in natural gas prices. These higher natural gas prices, coincident with low hydroelectric production in California and constrained transmission, resulted in high production costs of electric power in 2008.

[12] Data reported in Table 2.4 are based primarily on utility monthly reports to the CPUC on the operation of interruptible and demand response programs.

2.2.1 Hydroelectric

Drought conditions continued into 2008 within California, as had been the case since 2007, although the Pacific Northwest enjoyed average to above-average precipitation. Oregon in particular had a robust snow pack, nearly twice its historic average in some areas, enabling it to provide electric power exports to California through the summer. This had the side effect of exacerbating congestion on the PACI and PDCI transmission corridors, as discussed in Chapter 5.

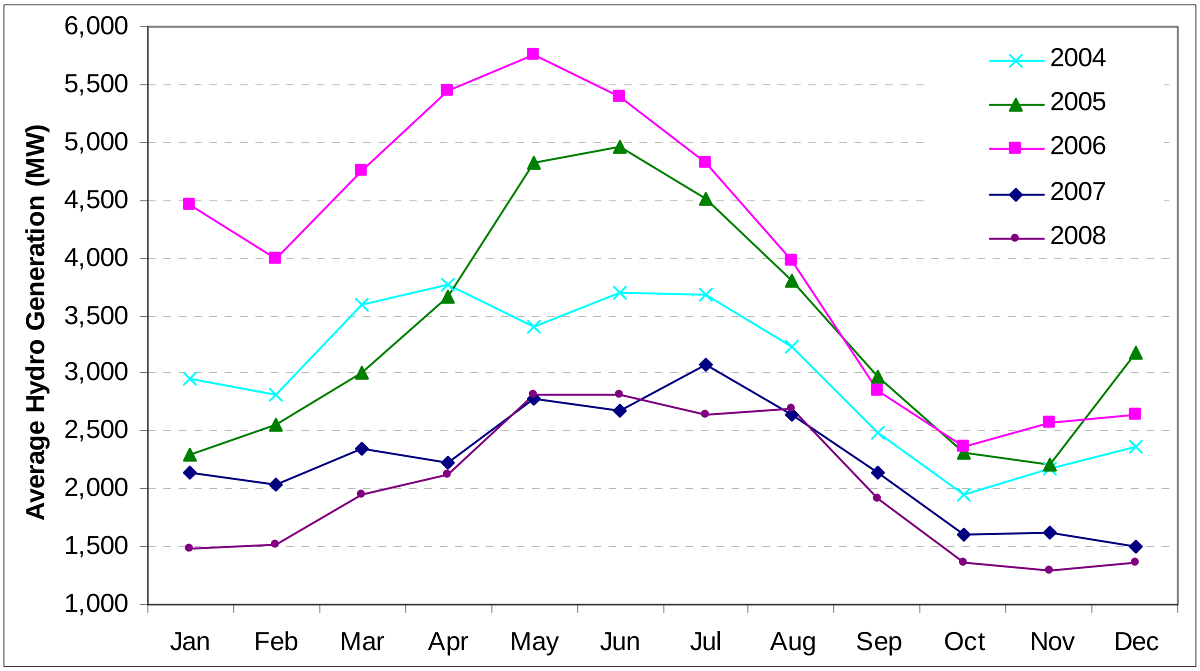
Figure 2.3 Mountain Snowpack in the Western U.S., May 1, 2008[13]



[13] Source: USDA Natural Resources Conservation Service, http://www.wcc.nrcs.usda.gov/cgibin/westsnow.pl

Figure 2.4 highlights the California drought condition in 2008. Monthly average hydroelectric production in 2008 was below 2007 levels for most months and well below the monthly production levels for 2004 to 2006. The only month in which 2008 hydro production exceeded the 2007 level more than marginally was June, which experienced the peak load for the year during a week-long heat wave that resulted in a high rate of both snow melt and loads.

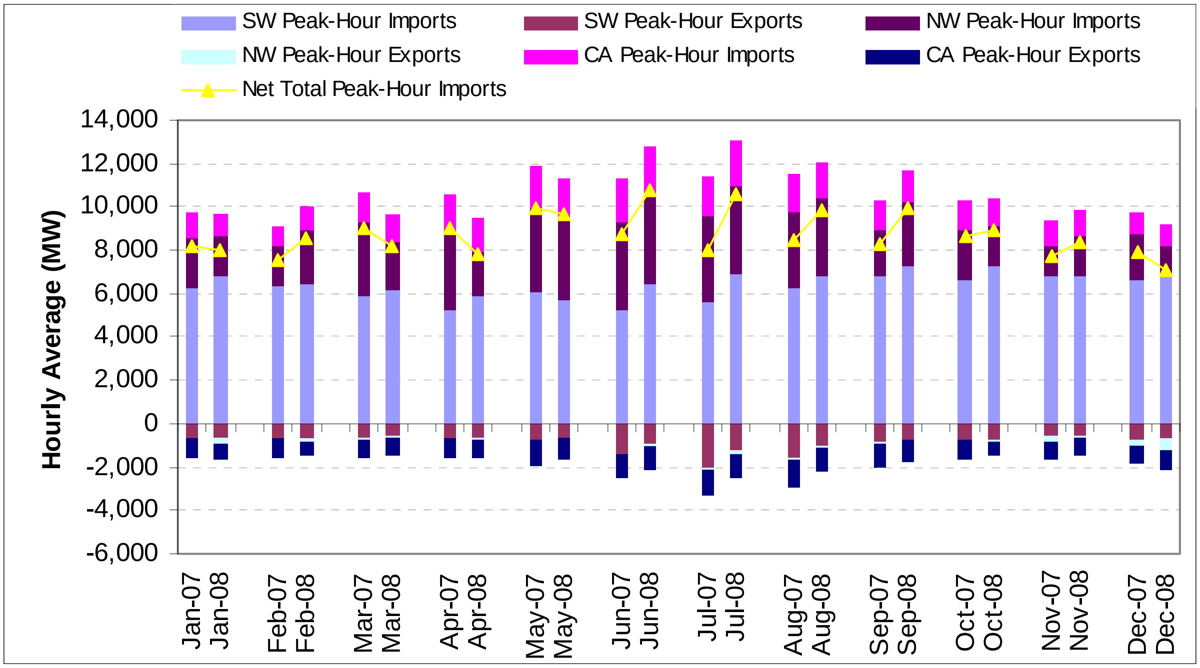
Figure 2.4 Average Hourly Hydroelectric Production by Month: 2004-2008



2.2.2 Imports and Exports

Figure 2.5 compares 2007 and 2008 monthly average imports and exports by neighboring region, and total net imports (import less export). Average hourly net imports during peak hours were significantly higher in 2008 during the months of June through September. Most of this increase came from reduced exports and higher imports from the Southwest. While the Northwest enjoyed energy surpluses during June and July due to its strong hydro conditions and non-peaking summer load, transmission constraints limited the amount of energy imports to California. Thus, California drew higher imports during the summer of 2008 from the Southwest.

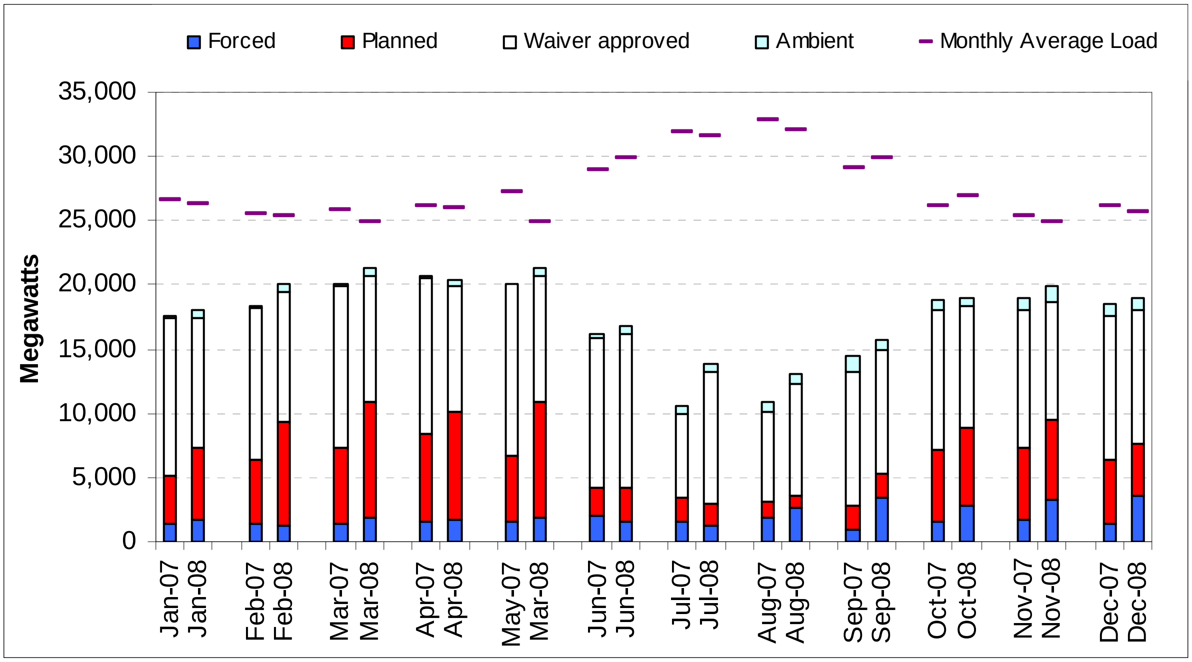
Figure 2.5 Year-to-Year Comparison of Hourly Average Scheduled Imports and Exports by Month: 2008 vs. 2007



2.2.3 Generation Outages

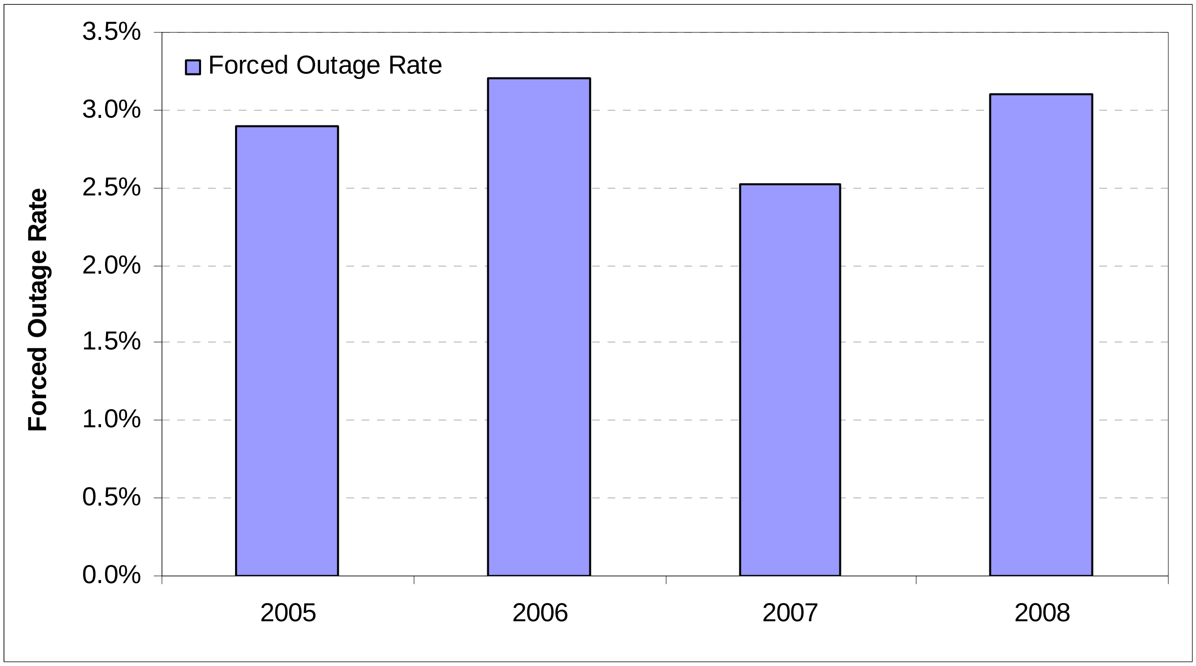
Figure 2.6 compares 2007 and 2008 average monthly outages by type (planned, forced, waiver-approved, or ambient). The relatively high volume of planned resource outages between January and May 2008, when compared to outages in the previous year, can interchangeably be attributed to (1) a large combined cycle resource that was shut down for a complete overhaul of its turbines; (2) a nuclear resource that was shut for refueling; and (3) a hydroelectric resource that was derated due to low water conditions. The higher rate of forced outages observed in August through December 2008 can be attributed to a week-long nuclear unit outage in September of 1,125 MW, up to 800 MW of hydro power out at various times during the fall, and three large combined cycle units that were out for much of the fall, accounting for as much as 1,500 MW of forced out. One of the larger combined cycle units had significant forced outages beginning in August and extending through the end of the year.

Figure 2.6 Year-to-Year Comparison of Hourly Average Outages by Month 2008 vs. 2007



The official rate of forced outages increased in 2008 to 3.1 percent. A few large outages accounted for most of the difference: A nuclear unit was out for most of late August, and a large hydroelectric resource was derated for most of the year due to low water conditions, which was classified as forced. Excluding the hydroelectric resource derate, the forced outage rate would have been 2.7%.

Figure 2.7 Year-to-Year Comparison of Forced Outage Rates: 2005-2008[14]



2.2.4 Natural Gas Prices

The primary driver of higher electricity prices in 2008 was the spike in worldwide fossil fuel costs. Natural gas, the primary fuel for California's energy supply, and the fuel that is almost always on the margin, reached its highest level since Hurricanes Katrina and Rita impacted much natural gas infrastructure in 2005. This price movement closely tracked the spike in worldwide oil prices around the same time.

Another notable trend in gas prices has been the occasional but extended price separation between Northern and Southern California regions. Northern California's natural gas primarily comes from the Rocky Mountains and Canada, whereas Southern California is supplied largely from the San Juan Basin in New Mexico. Thus, gas prices in Northern and Southern California tend to move in step with their own markets' supply-demand conditions. At the current time, there are only small transportation facilities between Northern and Southern California, so products are not substitutable and thus prices may move separately due to their respective supply-demand conditions.

Figure 2.8 depicts weekly average natural gas prices in 2008.

[14] Methodology is similar to one used by the California Energy Commission to count generation in the CAISO Control Area since 2001. Typically, additions and retirements of generation are taken from the CAISO *Summer Loads and Resources Assessment* for the relevant year. However, in 2008, a few large unit additions listed in the *Assessment* were not active on the grid until very late in the year, if at all, and thus were excluded from the forced outage rate calculation. These units, Inland Empire 1 and 2, would appropriately be included in the 2009 calculation.

Figure 2.8 Weekly Average Natural Gas Prices in 2008

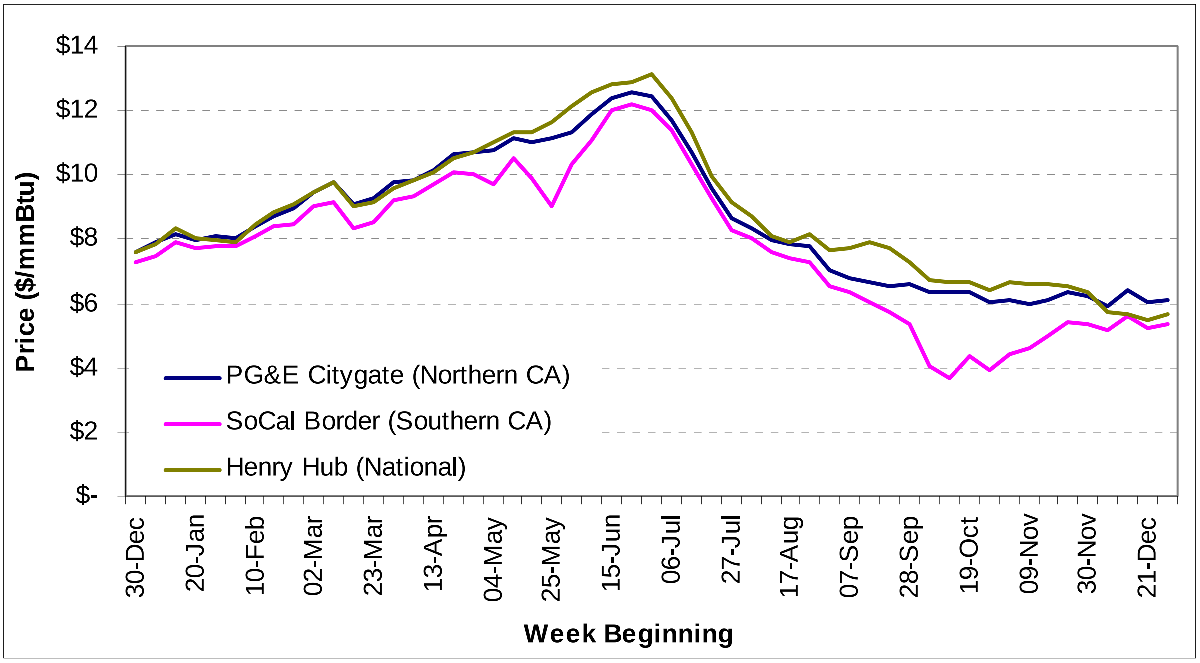
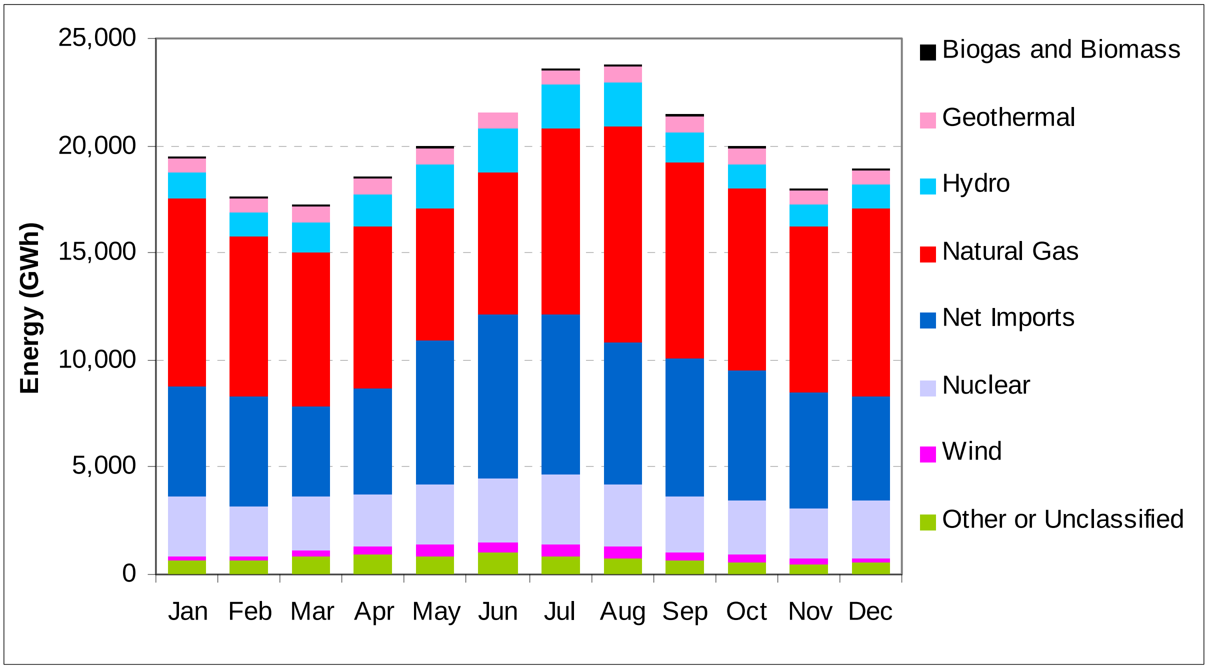


Figure 2.9 shows a monthly average profile of generation by fuel type in 2008. Net imports displaced some natural gas production in the early summer of 2008 when compared to the same period in 2007, as strong hydroelectric conditions in the Northwest, combined with high natural gas-fired production costs in California, provided a strong incentive to import power. As natural gas prices declined in the peak summer months of July through September and average loads increased, energy production from natural gas fueled facilities increased.

Figure 2.9 Monthly Energy Generation by Fuel Type in 2008



2.3 Periods of Market Stress

In 2008, the CAISO markets saw very little in terms of market stress. Summer loads were moderate and there were no major grid or market events that had a significant impact. However, there were the two notable events in 2008 that bear mention. Congestion costs on the Pacific AC and DC Interties hit historic levels during the spring, due in large part to transfer limit derates from maintenance further north and mitigation of unscheduled flows. Also, there were major wildfires in the northern part of the state that did threaten grid reliability but most of the direct impact to the grid was on the lower-voltage system.

2.3.1 High Congestion Costs and Un-scheduled Flow

The CAISO incurred significant costs to mitigate congestion in two distinct categories this spring - forward congestion on paths used to import power from the Pacific Northwest into California and near real-time mitigation of seasonal unscheduled flow from the Pacific Northwest.

For a three week period on two major branch groups connecting to the Pacific Northwest, the forward congestion costs totaled over $25 million, due largely to a recurring maintenance outage in the Pacific Northwest that impacted the transfer capacity of the Pacific AC Intertie. The $25 million in forward congestion costs for the three week period surpassed the historical annual total congestion costs for those two branch groups.

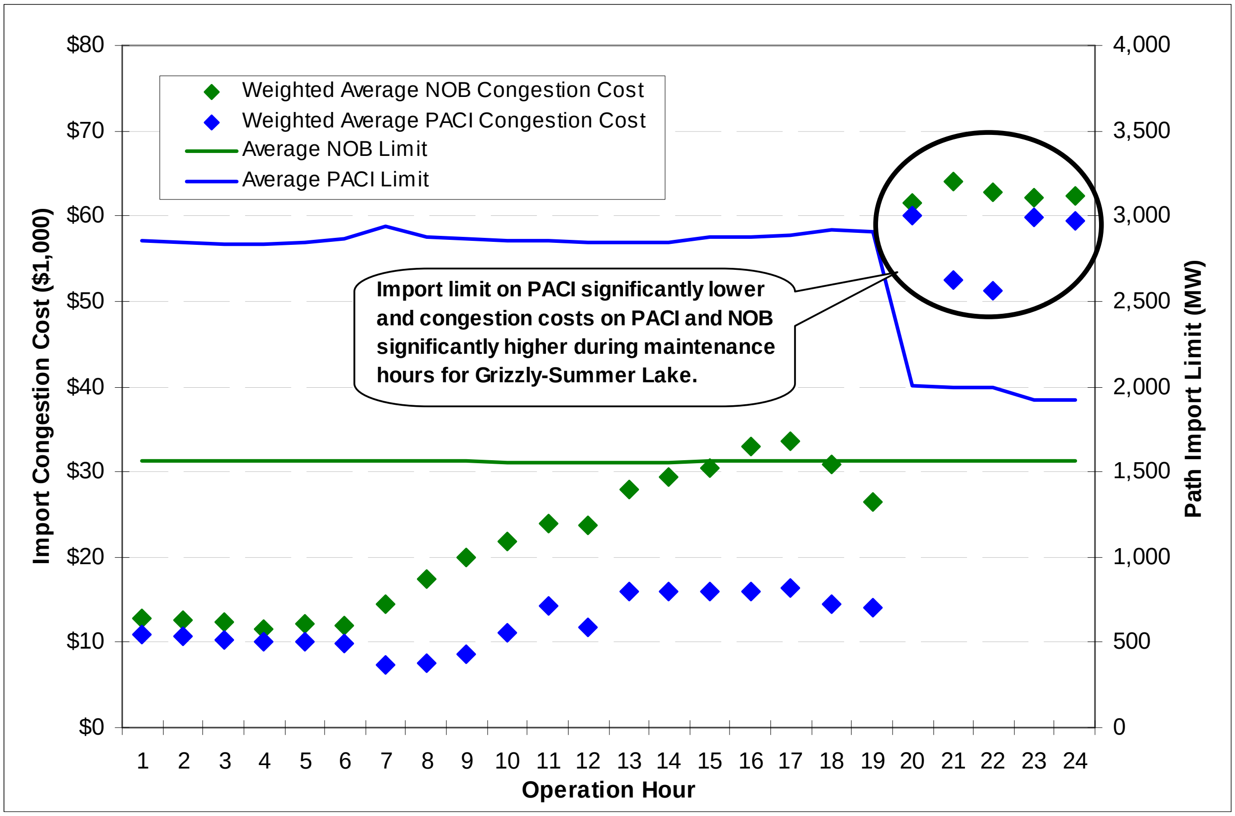
There were also significant costs incurred as a result of unscheduled loop flow through the CAISO Control Area which, unabated, could cause the northwest interties to overload. Seasonal unscheduled flow is the result of high hydroelectric output in the Pacific Northwest. The CAISO used imbalance market export bids to mitigate these seasonal unscheduled flows and, during some periods, balanced those exports with higher-cost internal gas-fired resources. Estimated cost for mitigating unscheduled flow for May and the first half of June alone was over $8 million.

High Inter-zonal Congestion Costs from Pacific Northwest

Each spring the CAISO must manage reliability issues stemming from seasonal maintenance outages as well as high output levels from hydroelectric generation in Northern California and the Pacific Northwest. This year, congestion management charges for the Pacific AC Intertie (PACI) and the Pacific DC Intertie (PDCI) totaled over $25 million for the period May 23 through June 13. Congestion on these paths was impacted by maintenance work on the Grizzly-Summer Lake lines in the Bonneville Power Administration (BPA) control area. While the Grizzly-Summer Lake lines are not in the CAISO Control Area, this work resulted in BPA reducing the available capacity on PACI in the north-to-south direction during hours ending 20 through 24, when the work was being performed.

Figure 2.10 below shows the average hourly line rating (in the import direction) and congestion cost for PACI and NOB for the period May 23 through June 13. While PACI and NOB both had congestion across all hours of the day, most congestion charges occurred between hours ending 20 through 24 where the PACI line was derated by roughly 1,000 MW to accommodate the Grizzly-Summer Lake line work in the BPA control area. Interestingly, congestion costs on NOB also increased significantly during those hours, despite no change in the NOB path rating, as importers shifted their schedules from PACI to NOB.

Figure 2.10 Average Congestion Cost and Average Path Limit by Hour May 23 – June 13, 2008



These two paths were also frequently congested during hours when no derates were applied. We can explain congestion across all hours and the increased willingness to pay for transmission capacity resulting in considerably higher costs during derate hours, at least in part, by the disparity between the price of hydroelectric power from the Pacific Northwest and the cost of gas-fired generation in California. During the spring hydro run-off period, hydroelectric power is often offered at very low prices since those suppliers will have to "spill" water to accommodate more snow runoff in the hydro system and are willing to accept a lower price for that energy rather than spill the water without any electricity revenues. At the same time, natural gas prices have been ranging between $9/MMBtu and $12/MMBtu, historically very high compared to prior summers. This natural gas price range implies a $90/MWh to $120/MWh electricity price, valued at the marginal cost of a relatively efficient gas fired resource with a 10,000 heat rate. Because of the spread between gas-fired costs at the higher gas prices and inexpensive hydroelectric power generated during the spring run-off period, we find greater willingness to pay for transmission for importing inexpensive Pacific Northwest power into California to meet load.

The impact of the Grizzly-Summer Lake outage on the PACI rating began on May 27 and ended on Friday, June 13, after which congestion costs on both PACI and NOB have declined significantly. While it is not possible to know what the congestion costs on PACI and NOB would have been absent the late evening derates on PACI, we can provide a ball-park estimate of the additional congestion costs resulting from this outage. The additional cost is estimated by taking the difference between average hourly congestion price in hours with and without the PACI derate and applying that difference to the affected hours across the 19 days where the derate was in effect. Using this approach, we estimate that roughly \$12.3 million of the \$26.1 million in congestion cost on PACI and NOB during this period can be attributed to the Grizzly-Summer Lake outage impact on PACI path limits, with the remainder attributed to seasonal import patterns and the increased willingness to pay for transmission resulting from low prices for Pacific Northwest hydro and high natural gas prices. Importantly, some Scheduling Coordinators (SCs) are hedged against these congestion costs through ownership of Firm Transmission Rights (FTRs). For imports on PACI and NOB during this period, roughly 33% of schedules that were subject to import congestion charges were hedged through FTRs, leaving SCs who scheduled imports across these lines about 67% exposed (collectively) to these high congestion charges.

Figure 2.11 Daily Total Congestion Cost for PACI and NOB
May 12 – June 15, 2008

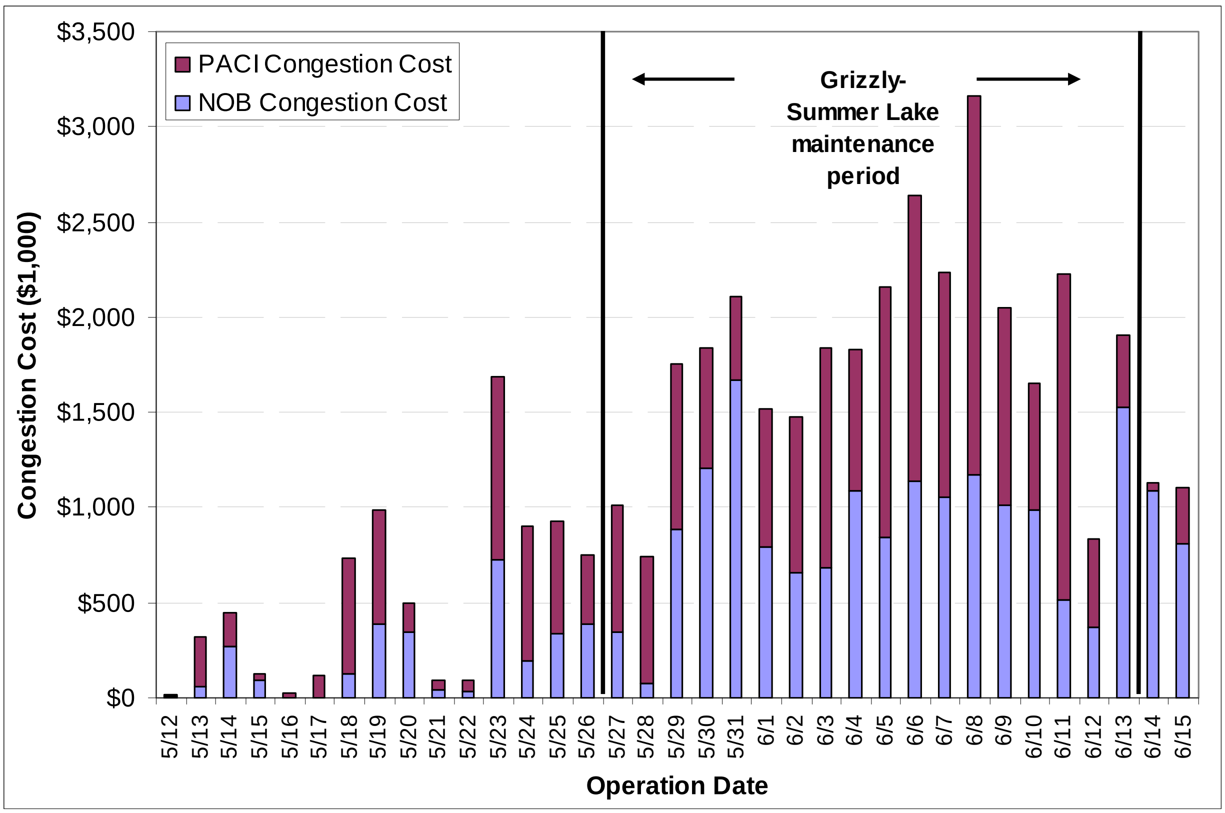


Figure 2.11 shows daily congestion costs for PACI and NOB from May 12 through June 15. Note that daily congestion costs were relatively low until May 23. The Grizzly-Summer Lake outage began the evening of May 27, and persistent high congestion costs on PACI and NOB began occurring the following day, largely tapering off on June 14.

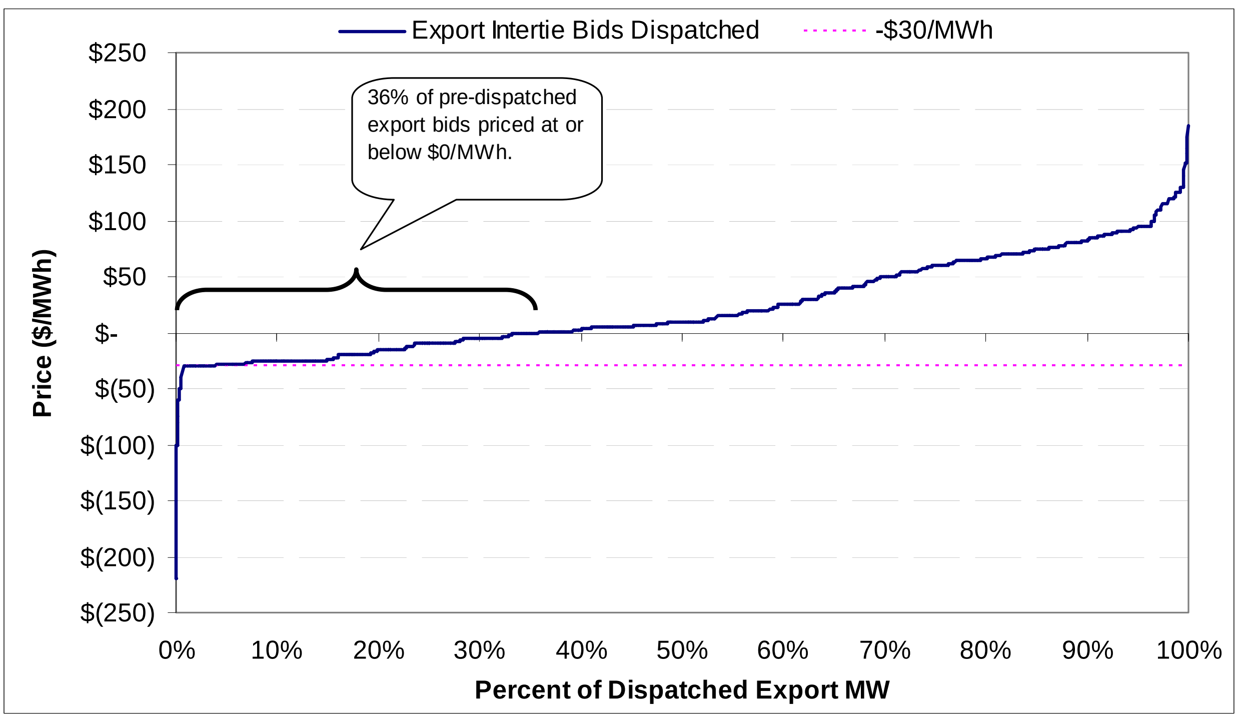
Managing Seasonal Unscheduled Flow

Another related seasonal pattern that the CAISO must manage is Unscheduled Flow (USF), generally in the north-to-south direction from the Pacific Northwest through the CAISO Control Area and out to the Southwest. As the market software does not explicitly manage USF, CAISO operators must do this and require uneconomic dispatch of energy bids. Inefficiency associated with uneconomic dispatch caused significant cost in spring 2008, with estimates totaling over $8 million for May through the first half of June.

Most prevalent in the spring, USF is driven by high hydroelectric production in the Pacific Northwest, varies in magnitude from hour to hour, and must be managed in order to avoid overloading of interties and internal paths. The CAISO is not the only control area impacted by USF. Neighboring control areas and utilities, as well as those within California (i.e., SMUD, TID, LADWP) have to manage their system to accommodate USF.

The CAISO has several tools available to manage USF, including relying on the WECC procedure for managing USF and dispatching imbalance market energy bids to provide counter flow on PACI. As a preventative measure for managing USF, the CAISO often chooses to dispatch export bids from the imbalance market to provide additional counter flow (exports) on the PACI Branch Group. In doing so, the CAISO often must dispatch very low-priced, and even negative-priced, export bids to resolve USF. A low-priced bid indicates an SC is not willing to pay much for energy exported to them from the ISO, and a negative-priced bid indicates an SC is unwilling to take energy from the CAISO unless they are paid to do so. Figure 2.12 shows the price distribution of export bids dispatched in the imbalance market during May 2008. To highlight the low prices at which the CAISO is selling this energy to export, bids priced at or below $0/MWh represent roughly 36 percent of the quantity dispatched.

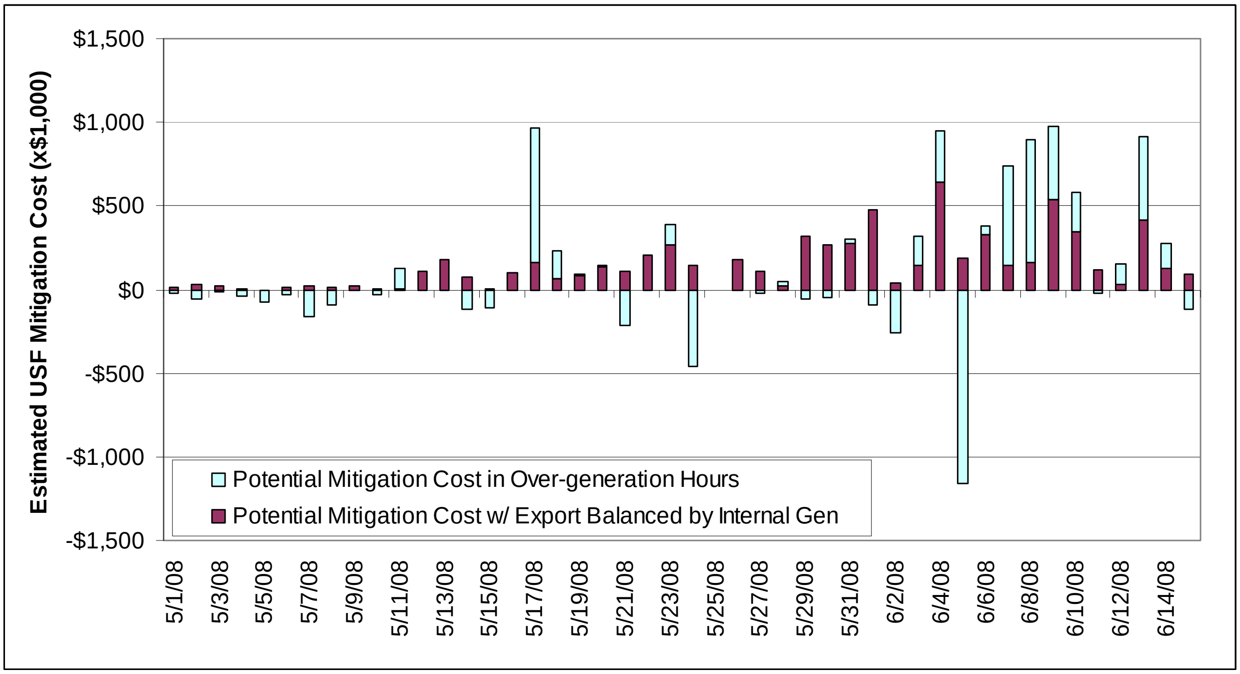
Figure 2.12 Price Distribution of Imbalance Export Bids Dispatched in May 2008



In general, the CAISO must procure additional energy in the imbalance market to balance the energy exported from the control area up PACI to manage USF. Some of this energy may come from pre-dispatch import bids from, for example, the Southwest. However, often the CAISO procures the energy needed to balance these exports from internal resources, forcing the CAISO to move further up the supply curve, dispatching higher-priced bids.

This practice of selling energy at low prices for export and making up that imbalance through buying internal generation at higher prices results in increased uplift cost. Figure 2.13 below shows the estimated daily cost of hourly mitigating USF through the pre-dispatch of export energy bids for the period May 1 through June 15. The data used to create this figure were limited to hours where there was a net pre-dispatch export to help isolate the instances where USF was being mitigated.

Figure 2.13 Daily Average Estimated Cost of Uneconomic Dispatch Associated with Pre-dispatch Exports for May 1, 2008 to June 14, 2008



Daily cost is minimal for the first half of May and begins to increase mid-May as hydroelectric production in the Pacific Northwest increases, increasing USF and requiring the CAISO to mitigate it. Estimates of potential mitigation cost are broken out into two metrics. The first measure, represented by red bars in Figure 2.13, measures the cost of uneconomic dispatch when the CAISO must balance mitigating export dispatches with incremental dispatch of higher-cost internal generation. The second measure, represented by the light blue bars, represents the cost of uneconomic export dispatch when the CAISO anticipates USF but is also in over-generation and needs to further back-down internal resources.[15] Together, these measures will likely over-estimate the cost directly attributable to mitigating USF but do provide an upper bound.

The estimated potential cost associated with mitigation of USF for May and the first half of June is roughly $8.1 million. With these high costs resulting from the need to manage USF within the

[15] The formulas for calculating the two cost metrics both use the difference between the price of internal dispatch and the price of pre-dispatched export bids and apply this price difference to an appropriate quantity reflecting the mitigation action. In the case where the CAISO was balancing the export with increased internal generation, the quantity is determined by the lesser of the net pre-dispatch export and the net internal incremental dispatch. In the case where the CAISO is exporting and dispatching internal resources downward, the quantity is calculated as the net pre-dispatch exports.

CAISO, and the fact that this unscheduled power flow issue will persist in coming years, including MRTU, the CAISO should explore whether there are more cost effective means to manage USF. For example, enacting mitigation measures from the WECC process more proactively, or incorporating USF estimates into the forward markets (e.g., day-ahead) so as to reduce the amount of redispatch required in the real-time market. Whether a more forward approach to managing USF is possible will depend in part on how accurately USF can be forecasted in advance of real-time.

2.3.2 Early Summer Wildfires in the North

2008 was the second below-average hydro year in a row, and this year's spring was the driest on record which resulted in the fire season starting earlier than usual. The first few fires began in early June with the Humboldt fire, and a set of dry lightning storms from June 19 - 21 ignited some additional major fires (Butte, Mendocino and Shasta-and-Trinity) in Northern California. The effort to bring these fires under control involved firefighters from across the state, and continued well into July. As various fires moved closer to the high-voltage transmission system, lower flow limits on the Pacific AC Inter-tie (PACI) were enacted during June to mitigate potential threats to grid reliability. In addition, due to higher summer loads and as a precaution against the fires, the CAISO issued Restricted Maintenance Operations notices on five days in June.

The direct impact of these fires on CAISO markets was minimal. While congestion costs in the north, ancillary service costs, and imbalance energy prices all increased in June (compared with May or July), these changes were primarily due to other factors. As discussed in the prior section, higher congestion costs for this period are the result of transmission outages in the BPA control area and mitigation of unscheduled flow. Higher ancillary service prices, specifically in regulating reserves, are common in the spring as hydro resources are not available to move in their regulation range due to high water flows and there are fewer gas-fired resources on during this time of year to provide ancillary services. Lastly, the higher imbalance prices in June were observed primarily beginning mid-month, coinciding with a mild heat wave that increased load and placed pressure on the imbalance market.

2.4 Wholesale Energy and Ancillary Services Costs

Since 1999, the DMM has reported its estimate of annual wholesale energy costs. This provides an estimate of total wholesale market costs to load served that can be compared across years. It includes estimates of utility-retained generation costs, forward bilateral contract costs, real-time energy costs, and ancillary service reserve costs. The real-time component of costs also includes reliability costs (must-offer payments and minimum-load compensation, out-of-sequence redispatch premiums, and fixed and variable RMR costs). These estimates do *not* include resource adequacy procurement costs, a regulatory requirement for bilateral capacity arrangements between generators and LSEs that has been in place since June 2006. Costs associated with these bilateral capacity contracts are not visible to the CAISO.

The estimated total wholesale energy and ancillary service cost for 2008 was approximately \$12.8 billion, or \$53.01 per megawatt-hour (MWh) of load served, compared to 48.23/MWh of load served in 2007. These estimates reflect not only CAISO market prices, but also estimated costs of spot market transactions, long-term contracts entered into during the 2001 energy crisis, production of utility-owned generation, and other cost components, all of which are described in the notes accompanying Table 2.6.

The increase in costs between 2007 and 2008 is explained largely by a spike in fossil fuel prices, during the peak months of June and July, 2008, and continued drought conditions in California that prevented substitution of low-cost hydroelectric generation for natural-gas-fired generation. (These phenomena are noted above in Sections 2.2.1 and 2.2.4.) In addition, the routine congestion of transmission lines due to the high demand in California caused the delivered costs of power transmitted from the Northwest to be similar to expensive marginal (gas-fired) production costs in California. High costs may have been offset somewhat by the continued expiration of long-term contracts and subsequent replacement of them by new short- or long-term contracts.

Table 2.5 Monthly Wholesale Energy Costs: 2008 and Previous Years

Month	ISO Load (GWh)	Total Est. Forward Costs ($MM)	RT and Reliability Costs ($MM)	AS Costs ($MM)	Total Costs of Energy ($MM)	Total Costs of Energy and A/S ($MM)	Avg Cost of Energy ($/MWh load)	Avg Cost of A/S ($/MWh load)	A/S as % of Wholesale Cost	Avg Cost of Energy & A/S ($/MWh load)
Jan-08	19,574	$ 994	$ 23	$ 9	$ 1,017	$ 1,026	$ 51.98	$ 0.45	0.9%	$ 52.43
Feb-08	17,602	$ 910	$ 18	$ 11	$ 927	$ 939	$ 52.68	$ 0.63	1.2%	$ 53.32
Mar-08	18,455	$ 951	$ 31	$ 13	$ 982	$ 995	$ 53.19	$ 0.73	1.3%	$ 53.92
Apr-08	18,733	$ 1,121	$ 22	$ 14	$ 1,142	$ 1,156	$ 60.96	$ 0.77	1.2%	$ 61.73
May-08	19,994	$ 1,126	$ 45	$ 23	$ 1,171	$ 1,195	$ 58.59	$ 1.16	1.9%	$ 59.75
Jun-08	21,466	$ 1,377	$ 73	$ 37	$ 1,450	$ 1,487	$ 67.54	$ 1.73	2.5%	$ 69.27
Jul-08	23,469	$ 1,445	$ 26	$ 23	$ 1,472	$ 1,495	$ 62.70	$ 0.99	1.5%	$ 63.69
Aug-08	23,784	$ 1,188	$ 33	$ 11	$ 1,221	$ 1,232	$ 51.32	$ 0.48	0.9%	$ 51.80
Sep-08	21,473	$ 937	$ 25	$ 9	$ 962	$ 971	$ 44.79	$ 0.41	0.9%	$ 45.21
Oct-08	20,005	$ 752	$ 21	$ 11	$ 773	$ 784	$ 38.63	$ 0.54	1.4%	$ 39.17
Nov-08	17,950	$ 688	$ 28	$ 8	$ 716	$ 724	$ 39.88	$ 0.45	1.1%	$ 40.33
Dec-08	19,047	$ 769	$ 22	$ 8	$ 791	$ 799	$ 41.53	$ 0.42	1.0%	$ 41.95
Total 2008	**241,552**	**$ 12,257**	**$ 366**	**$ 178**	**$ 12,623**	**$ 12,802**	**$ 52.27**	**$ 0.74**	**1.4%**	**$ 53.01**
Total 2007	241,990	$ 11,260	$ 260	$ 152	$ 11,520	$ 11,672	$ 47.61	$ 0.63	1.3%	$ 48.23
Total 2006	240,260	$ 10,563	$ 633	$ 234	$ 11,196	$ 11,430	$ 46.60	$ 0.97	2.0%	$ 47.57
Total 2005	236,449	$ 12,526	$ 830	$ 228	$ 13,356	$ 13,584	$ 56.49	$ 0.96	1.7%	$ 57.45
Total 2004	239,788	$ 11,832	$ 1,099	$ 184	$ 12,931	$ 13,115	$ 53.93	$ 0.77	1.4%	$ 54.70
Total 2003	230,668	$ 10,814	$ 696	$ 199	$ 11,510	$ 11,709	$ 49.90	$ 0.86	1.7%	$ 50.76
Total 2002	232,011	$ 9,865	$ 532	$ 157	$ 10,397	$ 10,554	$ 44.81	$ 0.68	1.5%	$ 45.49
Total 2001	227,024	$ 21,248	$ 4,586	$ 1,346	$ 25,834	$ 27,180	$ 113.79	$ 5.93	5.0%	$ 119.72
Total 2000	237,543	$ 22,890	$ 3,446	$ 1,720	$ 26,336	$ 28,056	$ 110.87	$ 7.24	6.1%	$ 118.11
Total 1999	227,533	$ 6,848	$ 562	$ 404	$ 7,410	$ 7,814	$ 32.57	$ 1.78	5.2%	$ 34.34
1998 (9mo)	169,239	$ 4,704	$ 1,061	$ 638	$ 5,765	$ 6,403	$ 34.07	$ 3.77	10.0%	$ 37.83

Notes to Wholesale Costs Table:

CAISO load is total energy consumed in GWh. Cost totals are in millions of dollars. Averages are in dollars per MWh of load served.

1998-2000:

Forward costs include estimated California Power Exchange (PX) and bilateral energy costs.

Estimated PX Energy Costs include UDC owned supply sold in the PX, valued at PX prices.

Estimated Bilateral Energy Cost based on the difference between hour-ahead schedules and PX quantities, valued at PX prices.

Beginning November 2000, CAISO Real-time Energy Costs include OOM Costs.

1998-2001:

RMR costs were not available and are not included. Must-Offer costs were not applicable.

2001 and 2002:

Sum of hour-ahead scheduled costs. Includes UDC (cost of production), estimated and/or actual CDWR costs, and other bilaterals priced at hub prices.

RT energy includes OOS, OOM, dispatched real-time paid MCP, and dispatched real-time paid as-bid.

2002 through 2006:

RT and reliability costs include real-time incremental balancing costs, decremental balancing savings, minimum-load compensation costs for resources committed per Must Offer Obligation, OOS/OOM costs, RMR fixed and variable costs.

2007 and 2008:

RT and reliability costs include real-time incremental balancing costs, decremental balancing savings, minimum-load compensation costs for resources committed per Must Offer Obligation, OOS/OOM costs, RMR fixed and variable costs, and RCST and TCPM payments.

2003:

Loads are unadjusted. CAISO included SMUD through 6/18/02. Load Jan-03 through Jun-03 may be lower than in 2002 due to SMUD exit.

2003 through 2008:

Forward energy costs revised slightly upward using a methodology developed for the 2006 Annual Report to include: utility-retained generation at estimated production costs; long-term contract (formerly managed by CDWR/CERS) estimated using 2002 delivery volumes; and short-term bilateral procurement estimated at utility-supplied procurement prices, when available, or Powerdex hour-ahead prices.

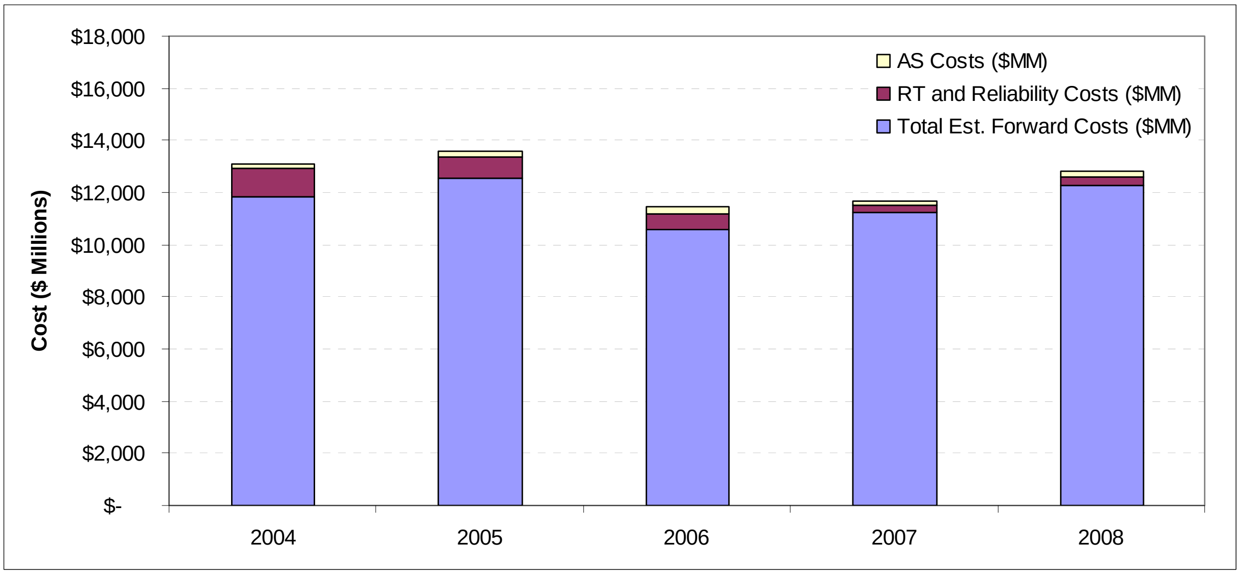
2006 through 2008 figures do not include RA capacity payments, which are not visible to the CAISO.

All years:

A/S costs include CAISO purchased and self-provided A/S priced at corresponding A/S market price for each hour, less Replacement Reserve refund, if any.

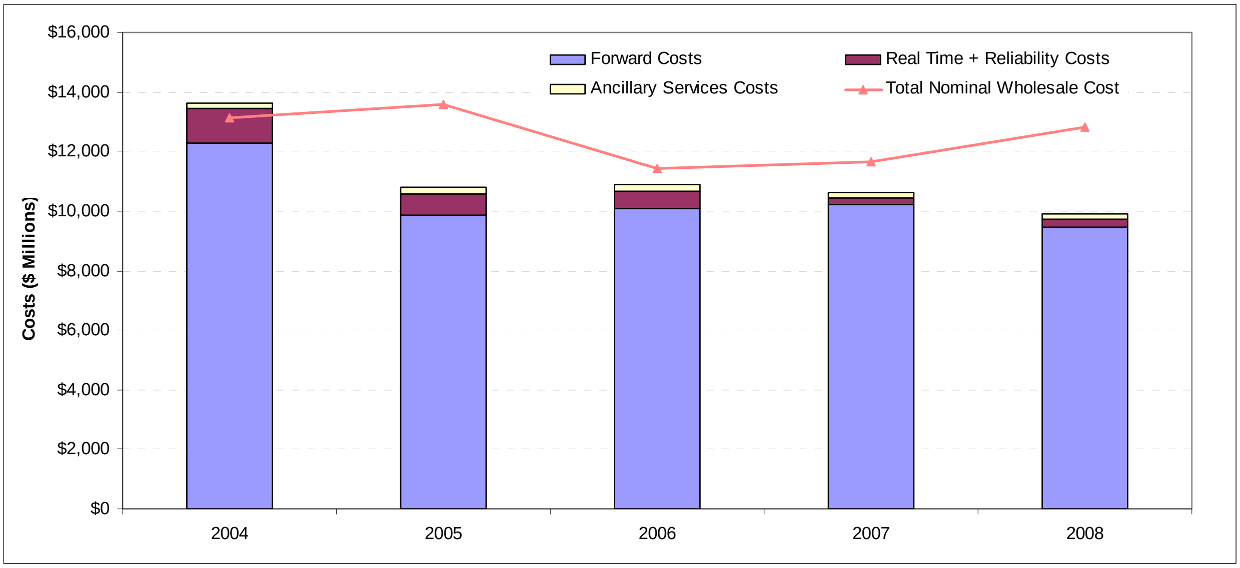
Figure 2.14 shows total wholesale costs from 2004 to 2008. Costs have been relatively stable since 2003. Many of the costliest contracts lingering from the 2001 energy crisis have expired, and transmission upgrades and new generation have both contributed to stabilizing energy costs. Reliability costs, which had decreased dramatically between 2006 and 2007 due in large part to transmission upgrades within Southern California and the substitution of resource adequacy (RA) and out-of-sequence dispatches for RMR contracting, increased in 2008. Reliability management costs are discussed in greater detail in Chapter 6.

Figure 2.14 Total Wholesale Costs: 2004-2008



The cost of natural gas historically has had a strong influence on the total energy cost estimate, and this has certainly been the case since 2006. To control for that exogenous factor, DMM also calculates an estimate of energy costs normalized to a fixed natural gas price, again excluding the costs of RA contracts, the costs of which are not known to the CAISO. As shown in Figure 2.15 and below in Figure 2.16, costs normalized to a fixed gas price were slightly lower in 2008 than in 2007, on both total and per-megawatt-served bases. This decline is due in part to lower peak loads during the critical summer months of July and August, which reduced the need to utilize more inefficient thermal generation.

Figure 2.15 Total Wholesale Costs Normalized to Fixed Gas Price: 2004-2008[16]



The aforementioned increase in non-normalized costs is evident in Table 2.6, which provides a component breakdown of contributing factors to energy costs on a per-unit basis. This table serves as a useful benchmark of CAISO and market performance, but again excludes the costs of RA contracting. Note that inter-zonal congestion costs increased by approximately 144 percent between 2007 and 2008; this was incurred largely during the period of high natural gas prices (May through early July), when transmission congestion charges for transporting lower-cost hydroelectric power in the Northwest into California exceeded $100/MWh.

Table 2.6 Contributions to Estimated Average Wholesale Energy Costs per Unit of Load Served in CAISO, 2004-2008[17]

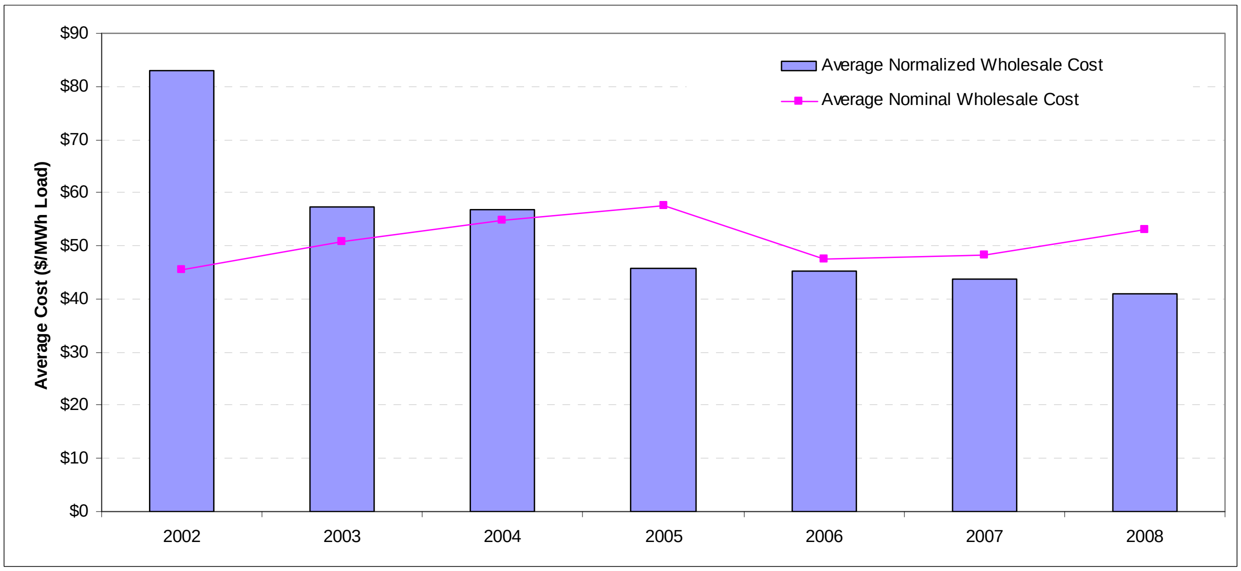
	2004	2005	2006	2007	2008	Change '07-'08
Forward-Scheduled Energy Costs, excl. Interzonal Congestion and GMC	$ 48.21	$ 52.28	$ 43.01	$ 44.74	$ 47.48	$ 2.74
Interzonal Congestion Costs	$ 0.23	$ 0.23	$ 0.23	$ 1.03	$ 2.50	$ 1.48
GMC	$ 0.90	$ 0.84	$ 0.72	$ 0.76	$ 0.76	$ -
Incremental In-Sequence RT Energy Costs	$ 0.86	$ 1.55	$ 1.04	$ 1.06	$ 1.71	$ 0.66
Explicit MLCC Costs (Uplift)	$ 1.21	$ 0.55	$ 0.50	$ 0.23	$ 0.41	$ 0.19
RCST/TCPM Costs			$ 0.06	$ 0.11	$ 0.01	$ (0.09)
Out-of-Sequence RT Energy Redispatch Premium	$ 0.43	$ 0.14	$ 0.10	$ 0.15	$ 0.29	$ 0.14
RMR Net Costs (Include adjustments from prior periods)	$ 2.67	$ 2.14	$ 1.78	$ 0.50	$ 0.29	$ (0.21)
Less In-Sequence Decremental RT Energy Savings	$ (0.59)	$ (0.87)	$ (0.85)	$ (0.96)	$ (1.19)	$ (0.23)
Average Total Energy Costs	**$ 53.93**	**$ 56.86**	**$ 46.60**	**$ 47.61**	**$ 52.27**	**$ 4.67**
A/S Costs (Self-Provided A/S valued at ISO Market Prices)	$ 0.77	$ 0.96	$ 0.97	$ 0.63	$ 0.74	$ 0.11
Average Total Costs of Energy and A/S	**$ 54.70**	**$ 57.83**	**$ 47.57**	**$ 48.23**	**$ 53.01**	**$ 4.78**

16 July 2004 gas price ($5.70/mmBtu) is used as the basis for normalization. Energy costs were normalized separately on a monthly basis by dividing the monthly nominal energy costs by the ratio of the applicable monthly gas price to the July 2004 indexed gas price, and then adding the non-energy cost components. Total costs include all actual or estimated energy costs adjusted for differences in natural gas price, along with unadjusted costs of grid management, ancillary services, TCPM charges, and fixed RMR payments. Total costs do not include RA capacity payments, which are not visible to the CAISO.

17 Figures reported in this table for the prior reporting year have been adjusted to reflect the most current and accurate data and therefore are slightly different from those reported last year.

Figure 2.16 shows average total annual wholesale cost of energy and ancillary services ($/MWh of load) for 2002 through 2008, expressed in both nominal terms and normalized to a fixed gas price, again exclusive of RA costs. The nominal average cost has followed the trend of gas prices, with the exception of 2006, when an unusually strong hydroelectric supply displaced costlier gas-fired generation. The apparent decrease in normalized costs in 2008 again is likely the result of lower peak loads relative to 2007 during the peak summer months of July and August, which resulted in more efficient thermal generation being on the margin.

Figure 2.16 Average Total Wholesale Cost per Unit of Load: 2002-2008



2.5 Market Competitiveness Indices

2.5.1 Price-to-Cost Mark-up for Short Term Energy Purchases

The Department of Market Monitoring uses the price-to-cost mark-up to measure market performance in the California wholesale electricity markets. This is the difference between the actual price paid in the market for wholesale electricity and an estimate of the production cost of the most expensive, or marginal, unit of energy needed to serve load. The ratio of the volume-weighted average mark-up to marginal cost is a metric that can be used to identify market performance trends over time.

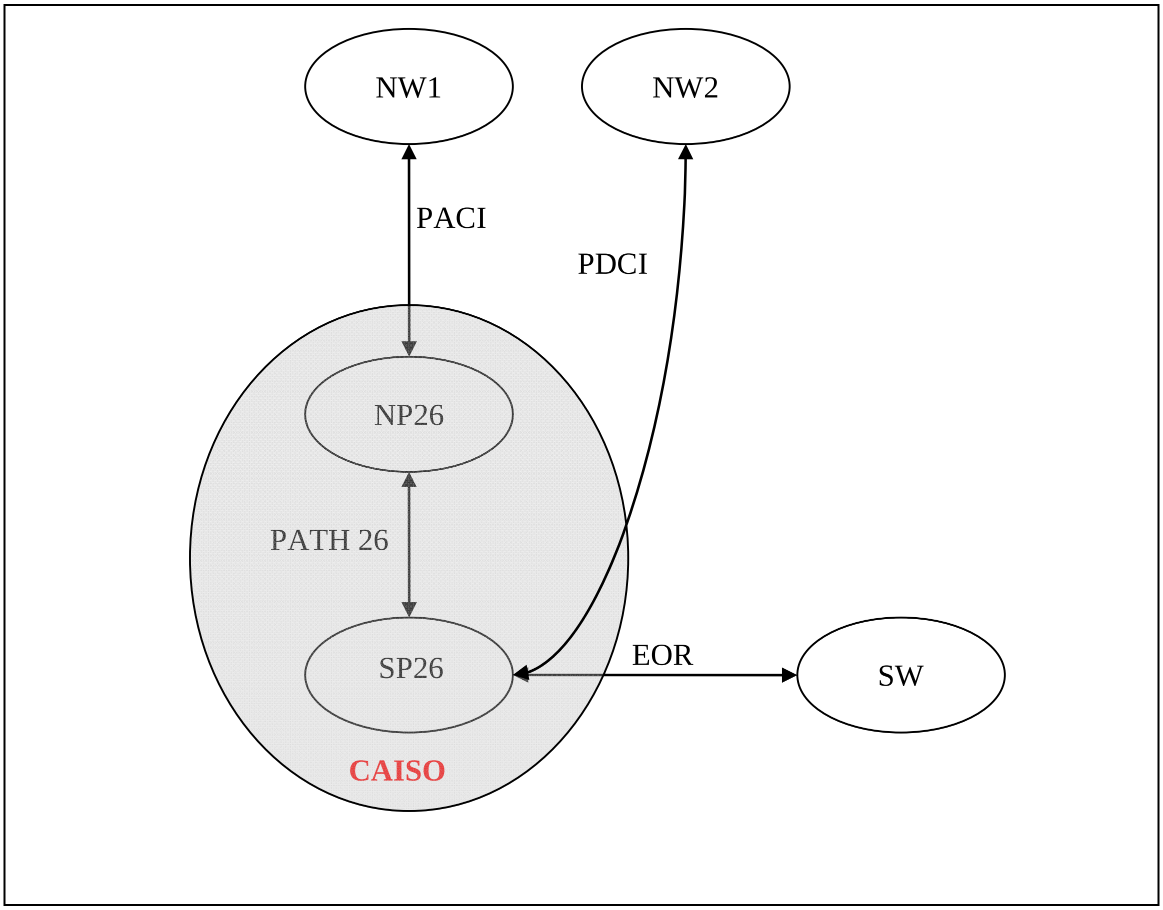
Previous Annual Reports have implemented several index constructs yielding measures of market competitiveness in the short-term energy markets. Those indices have been based on several price sources ranging from CAISO market data and information from bilateral forward contracts to prices from the Department of Water Resources' California Energy Resources Scheduler (CERS) energy procurement deals. The methodology used here has been updated to include data sources that were previously not available. However, there are still periods in calendar year 2004 for which short-term energy procurement information is not available. During these periods, hourly short-term forward price data purchased from Powerdex is used as a substitute. For 2005 through 2008, the actual short-term prices paid were obtained from confidential bilateral transactions data of three major utilities that participate in the CAISO markets. Only the transactions that occurred 24 hours prior to the operating day were considered in the analysis to be short-term.

The simulation of competitive benchmark prices considers a single-price auction framework consistent with the current CAISO imbalance market design and clears offers against hour-ahead scheduled load subject to the following assumptions:

- Simplified five node, four line zonal model.
- Import and export bids are fixed in quantity at observed hour-ahead scheduled import levels, and priced at the regional spot trading hub reported price reported from Powerdex, with the California-Oregon Border (COB) as Northwest and Palo Verde (PV) as Southwest pricing points.
- Internal thermal generators with heat rate data bid in at marginal cost as determined by their incremental heat rate, hourly natural gas price, and variable operating and maintenance costs.
- Internal hydroelectric units, nuclear units and the rest of thermal units without heat rate data bid in zero as price and hour-ahead schedule as quantity.
- All the remaining internal generators, including biomass, geothermal, Qualified Facility, wind, etc., bid in zero as price and metered output as quantity.
- Unit commitment decisions are based on historical hour-ahead schedules and metered output.

Figure 2.17 shows the simplified zonal radial network model used in the simulation.

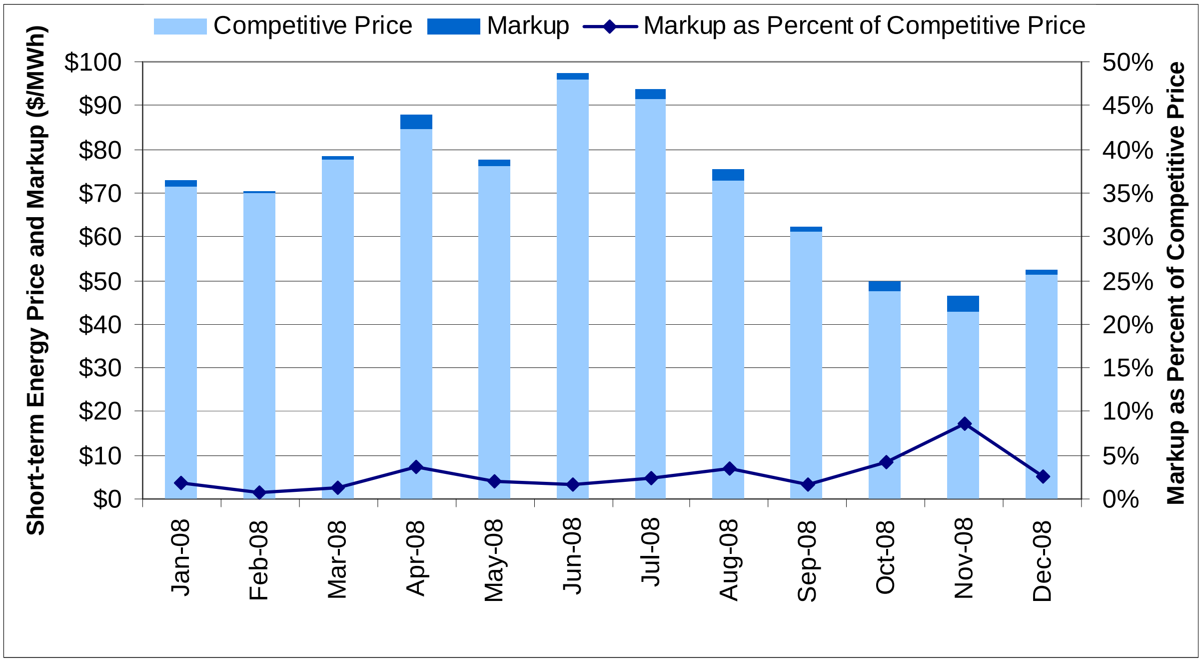
Figure 2.17 Simplified Network Topology Used in Competitive Price Simulation



The CAISO market model utilizes PLEXOS for Power Systems as the market simulation tool. PLEXOS employs a linear programming-based production cost minimization model, which allows for co-optimization with ancillary service markets.

For calendar year 2008, the CAISO observed monthly short-term mark-ups ranging from 1 to 8 percent, compared to 2 to 11 percent in the prior year. Figure 2.18 summarizes competitiveness in the short-term forward energy markets. Overall, 2008 short-term forward markets functioned effectively, leading largely to competitive pricing in the CAISO Control Area.

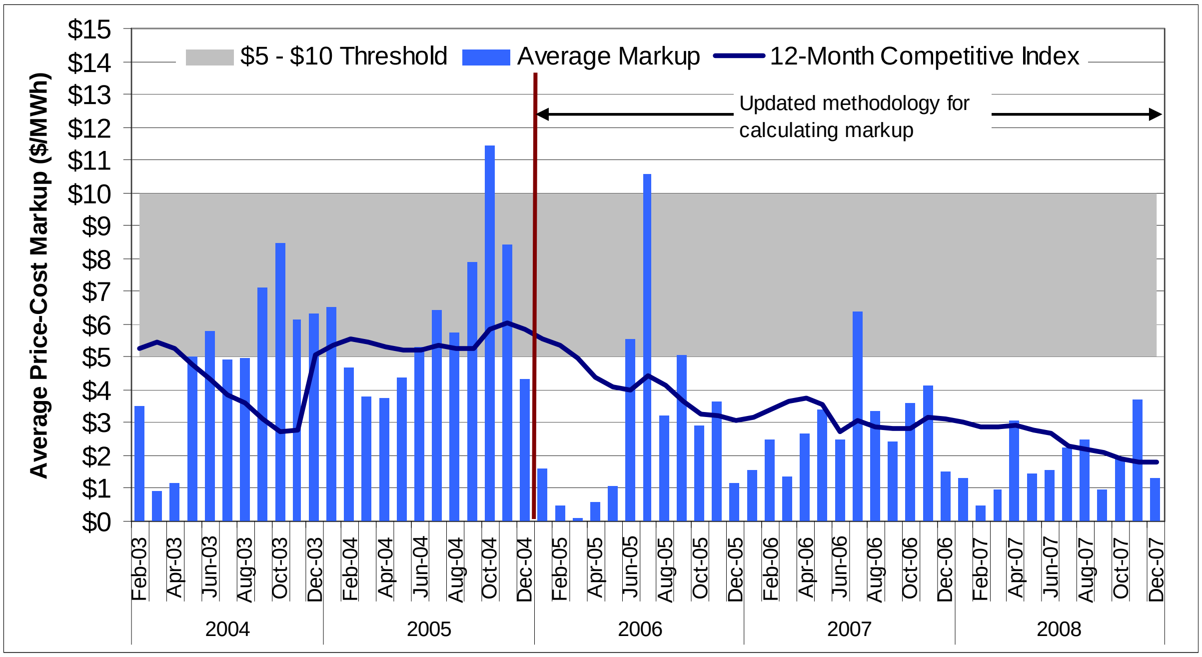
Figure 2.18 2008 Short-term Forward Market Index



2.5.2 Twelve-Month Competitiveness Index

The CAISO employs several indices to assess market competitiveness. The index in Figure 2.19 serves to measure market outcomes over extended time periods against estimated perfectly competitive market outcomes. The 12-Month Competitiveness Index is a rolling average of the short-term energy mark-up above simulated competitive prices during a twelve month period. The CAISO assumes that the short-term energy market is subject to little or no exercise of market power when the index is within or below a $5 to $10 per MWh range. In 2008, the index was well below this range and generally within $2-3/MWh.

Figure 2.19 Twelve-Month Competitiveness Index



2.5.3 Price-to-Cost Mark-up for Imbalance Energy

The real-time price-to-cost mark-up index is designed to measure real-time imbalance market performance. This index detects trends in the price-to-cost ratio. Sporadic price spikes due to operational constraints such as shortage of ramping capability have limited impact on this real-time mark-up. This index is a somewhat conservative measure of a competitive baseline price since it only takes into account generation units that were dispatched by the CAISO. By only including dispatched units in determining the competitive baseline price, this metric does not account for any possible economic withholding of units that bid higher than the market clearing price. This methodology assumes that high-priced bids above the market clearing price correspond to high costs, which will usually produce a higher estimated competitive baseline price (and lower mark-up). The methodology also discounts physical withholding by assuming that units that are forced out of service are not available for legitimate reasons and that generators that do not bid in all of their available capacity will have that capacity bid in for them by the CAISO under the must-offer obligation.

Figure 2.20 and Figure 2.21 show the monthly average mark-up for incremental and decremental real-time energy dispatched in 2008, respectively. As shown in these figures, the incremental Real Time Market mark-ups are above 20 percent for the lower-load months, when the imbalance market was primarily decremental and incremental energy dispatches were relatively infrequent and moderate. The mark-ups were lowest during the summer months, when incremental energy dispatches traditionally are more frequent, and were particularly low for incremental dispatches in September. Mark-ups were generally lower in the summer months because there were typically more units on-line to provide real-time energy, particularly thermal units with greater ramping capability than are available in the off-peak months. Additionally, peak loads during the summer months were fairly moderate, which in turn moderated imbalance energy demands. This is discussed in further detail below.

It is important to note that this market is prone to some degree of market power because of the very low volumes that clear this market and the fact that demand for 5-minute energy is very volatile and price inelastic. A generator submitting a bid at a very high price for the last few megawatt-hours of its unit's capacity will likely have those bids taken periodically, as the total supply of bids in this market can be very thin, thus requiring periodic dispatching of most or all of the available energy. The low volume and highly volatile nature of this market make it unattractive for new supply to enter to "compete away" high energy prices. It is also important to note that the impact of market power in the Real Time Market is relatively minor given the low market volumes and the fact that some of the generation earning the high market prices is owned or under operational control of LSEs. In addition, during the mild load months, a relatively large number of units were out on planned maintenance, and relatively few units were committed at minimum load, pursuant to the FERC Must-Offer Obligation (MOO) and/or under resource adequacy contracts. This, along with unseasonably low availability of inexpensive hydroelectric supply, resulted in relatively few units available for balancing services during this period, which resulted in somewhat thinner imbalance supply. Consequently, during short periods where the imbalance requirement was high (in either the incremental or decremental direction), the thinner supply resulted in more frequent intervals where higher priced bids (lower priced bids for decremental intervals) were required to meet imbalance, resulting in higher price-cost mark-ups in those intervals.

Figure 2.20 Average Hourly Real-time Incremental Energy Mark-up above Competitive Baseline Price by Month for 2008

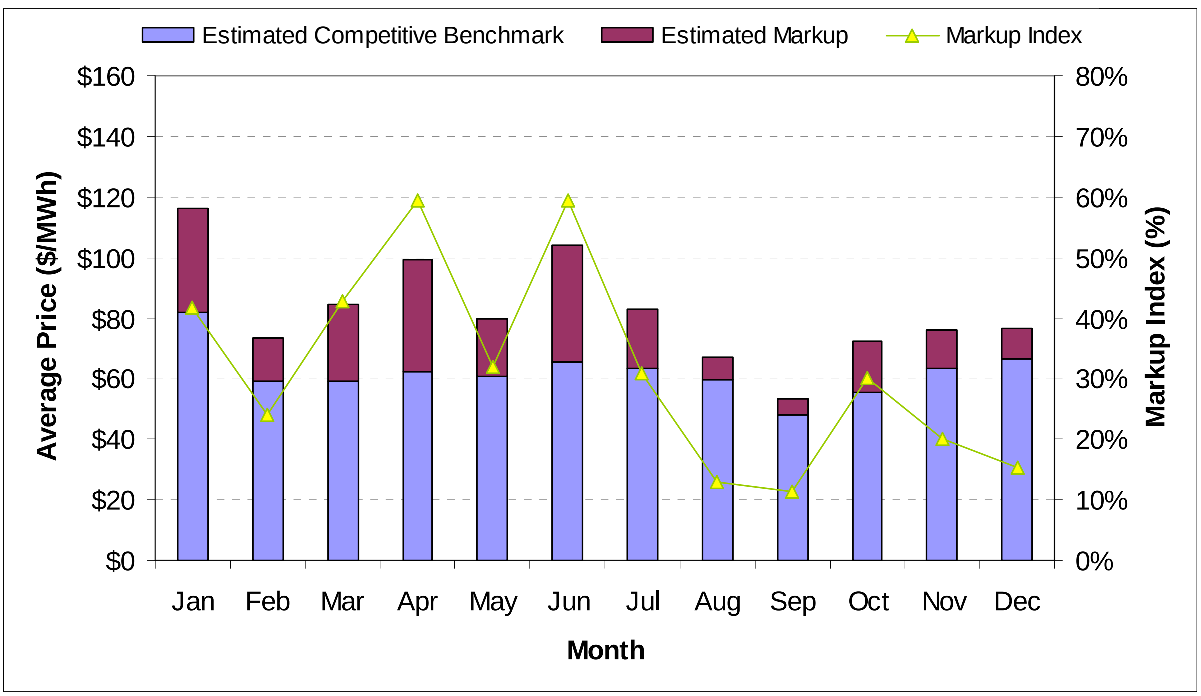
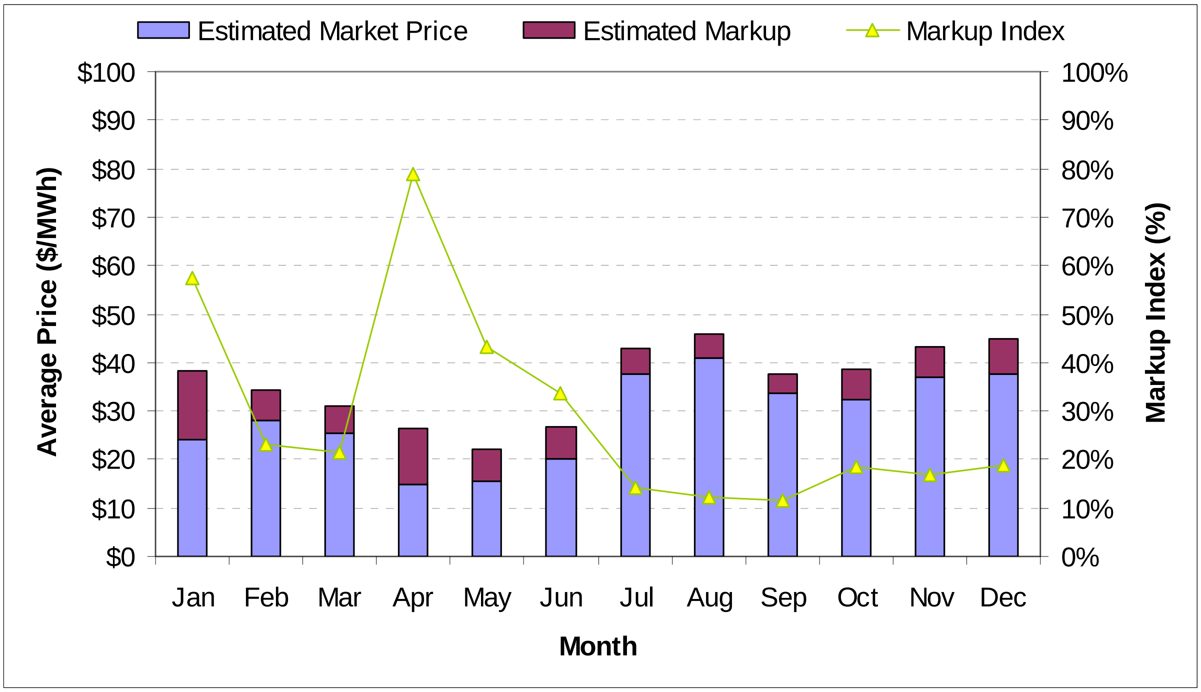


Figure 2.21 Average Hourly Real-time Decremental Energy Mark-up below Competitive Baseline Price by Month for 2008



2.6 Incentives for New Generation Investment

Though California has seen significant levels of new generation investment over the past several years, the relationship between grid reliability, new investment, the retirement of aged plants, and price signals remains an important focus of the CAISO. In recent years, there has been a declining but continued reliance on very old and inefficient generation to meet Southern California reliability needs. Going forward, it is imperative that California has an adequate market/regulatory framework for facilitating new investment in the critical areas of the grid where it is needed, particularly Southern California. This section begins with an assessment of the extent to which spot market revenues in 2008 were sufficient to cover the annualized fixed cost of new generation. A review of the generation additions and retirements for 2002 through 2008 and projections for 2009 is provided at the end of this section, along with a review of the continued reliance on older generation facilities.

2.6.1 Revenue Adequacy for New Generation Investment

This section examines the extent to which the current spot markets operated by CAISO provide sufficient revenues to cover the annualized fixed costs of two types of generating units (combined cycle and combustion turbine). It is important to note that spot markets are inherently volatile and as such never guarantee fixed cost recovery, particularly if the market is over-supplied. Moreover, given the lead-time needed for new generation investment, current spot market prices may not be the best indicator for new investment. Expectations on future spot market prices – based on expectations of future supply and demand conditions – are likely to be a stronger driver for long-term contracting, which is the primary means for facilitating new investment. To the extent existing units are critical to meeting reliability needs, their annual fixed costs should be recoverable through a combination of long-term bilateral contracts and/or capacity markets and spot market revenues. Nonetheless, examining the extent to which current spot market prices alone can contribute to annual recovery of fixed costs for new investment has proven to be an important market metric that all ISOs measure.

The annualized fixed costs used in this analysis are obtained from the 2007 California Energy Commission (CEC) report on Comparative Costs of California Central Station Electricity Generation Technologies,[18] which estimates the annualized fixed cost for a new combined cycle unit and a new combustion turbine to be $132.6/kW-year and $162.1/kW-year, respectively. The costs of new generation estimates are based substantially on empirical survey data collected from power plant developers in California who built power plants between 2001 and 2006. The cost estimates based on these survey results reflect a more current sampling of costs incurred by builders / investors in new generation compared to the $90/kW-yr for combined cycle and $78/kW-yr for simple cycle units published in the CEC 2003 Integrated Energy Policy Report and used in this study in prior years. The large increase in new generation costs in 2007 can be attributed to increases in material costs, siting and environmental costs, the availability and cost of investment capital, changes to the specific taxes that are included in the cost estimate, and increases in O&M costs. In addition, the higher cost figures reported in the 2007 report are based on empirical survey data from recent plant builders while the figures reported in the 2003 report were based largely on constructed costs. The specific operating characteristics of the two unit types that these cost estimates are based on are provided in Table 2.7 and Table 2.8.

Table 2.7 Analysis Assumptions: Typical New Combined Cycle Unit[19]

Technical Parameters	
Maximum Capacity	550 MW
Minimum Operating Level	150 MW
Startup Gas Consumption	1,850 MMBtu/start
Heat Rates	
Maximum Capacity	7,100 MBTU/MW
Minimum Operating Level	8,200 MBTU/MW
Financial Parameters	
Financing Costs	$90.2 /kW-yr
Insurance	$6.2 kW-yr
Ad Valorem	$4.9 kW-yr
Fixed Annual O&M	$11.2 /kW-yr
Taxes	$20.1 kW-yr
Total Fixed Cost Revenue Requirement	**$132.6/kW-yr**
Variable O&M	$2.4/MWh

[18] The CEC report can be found here: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF.

[19] The Financing Costs, Insurance, Ad Valorem, Fixed Annual O&M and Taxes costs for a typical unit in this table were derived directly from the data presented in the CEC report referenced in footnote 18, which also can be found in this presentation posted to the CAISO website: http://www.caiso.com/1c75/1c75c8ff34640ex.html.

Table 2.8 Analysis Assumptions: Typical New Combustion Turbine Unit[20]

Technical Parameters	
Maximum Capacity	50 MW
Minimum Operating Level	20 MW
Startup Gas Consumption	180 MMBtu/start
Heat Rates (MBTU/MW)	
Maximum Capacity	9,300
Minimum Operating Level	9,700

Financial Parameters	
Financing Costs	$107.7 /kW-yr
Insurance	$7.3 kW-yr
Ad Valorem	$5.8 kW-yr
Fixed Annual O&M	$20.8 /kW-yr
Taxes	$20.5 kW-yr
Total Fixed Cost Revenue Requirement	**$162.1/kW-yr**
Variable O&M	$10.9/MWh

2.6.2 Methodology

To provide a longer-term perspective, the net revenue analysis provided in this year's Annual Report was conducted over a 4-year period (2005-2008). The methodology used this year is identical to the one used in the 2006 Annual Report on Market Issues and Performance. The net revenues earned by the hypothetical combined cycle described in Table 2.7 is based on the generator's participation in all possible markets: the Real Time Market and Ancillary Services Market operated by CAISO and the day-ahead bilateral energy markets. The specific methods used for the approach are described below.

Combined Cycle – Net Revenue Methodology

The operational and scheduling assumptions used to assess the potential revenues that could be earned by a typical new combined cycle unit are summarized below:

1) An initial operating schedule for day-ahead bilateral energy markets was determined based on the hourly spot market price index published by Powerdex and the unit's marginal operating costs. Operating costs were based on daily spot market gas prices, combined with the heat rates and variable O&M cost assumptions listed in Table 2.7. The unit was scheduled up to full output when hourly prices exceed variable operating costs subject to observing the ramping limitations.

2) The initial schedule was modified by applying an algorithm to determine if it would be more economical to shut down the unit during hours when day-ahead prices fall below the variable operating costs. The algorithm compared operating losses during these hours to the cost of shutting down and re-

[20] See Footnote 19

starting the unit; if operating losses exceeded these shut-down/start-up costs, the unit was scheduled to go off-line over this period. Otherwise, the unit was ramped down to its minimum operating level during hours when its variable costs exceeded day-ahead bilateral energy prices.

3) If the unit was scheduled to stay off-line in the Day Ahead Market, it may be turned on in the Real Time Market operated by CAISO. The scheduling logic was the same as in the Day Ahead Market except that the Real Time Market clearing prices in both NP15 and SP15 were used instead of the Powerdex prices. The unit was scheduled up to full output when hourly real-time prices exceeded variable operating costs while observing the ramping limits.

4) Ancillary Service revenues were calculated by assuming the unit could provide up to 50 MW of spinning reserve each hour if it was committed in either the Day Ahead Market or Real Time Market for the hour and the output was smaller than its max stable level. The spinning reserve service prices were based on actual CAISO Day Ahead Market prices.

5) All start-up gas costs associated with the simulated operation of the unit were included in the calculation of operating costs.

6) Finally, a combined forced and planned outage rate of 5 percent was simulated by decreasing total annual net operating revenues by 5 percent.

In prior years, the results for SP15 also included possible Minimum Load Cost Compensation (MLCC) payments. The hours when the generator was committed under must-offer waiver denials were obtained from 2002 data. A more recent empirical study shows that the must-offer waiver denial hours for combined cycle units have reduced dramatically since then.[21] Moreover, when combined cycle units were denied waivers, it was typically due to specific local and zonal reliability reasons and most qualified units were very old. Since our study was focused on incentive for new generation and only revenues from normal competitive market conditions were considered, such uplifts were not included in this year's analysis.

Combustion Turbine – Net Revenue Methodology

The net revenues earned by the hypothetical combustion turbine unit described in Table 2.8 were based on market participation limited to the Real Time Market[22] and Ancillary Services Market. The specific methods used for these approaches are described below.

1) For each hour, it was assumed the unit would operate if the average hourly real-time price exceeded the unit's marginal operating costs. Operating costs were based on daily spot market gas prices, combined with the heat rates and variable O&M cost assumptions listed in Table 2.8. The unit was scheduled up

[21] For the 2004-2007 period, the total must-offer waiver denial hours for the combined cycle units in the CAISO Control Area ranged from 100 to 300.

[22] Real Time Market prices were used for the Combustion Turbine revenue analysis because this is a more likely market for fast-start units. However, the fact that the CAISO Real Time Market prices were often below prevailing day-ahead and day-of spot market prices, particularly during peak summer periods, makes the use of Real Time Market prices a somewhat conservative measure of potential energy market revenues.

to full output when Real Time Market hourly prices exceeded variable operating costs while observing the ramping limits.

2) The initial schedule was modified by applying an algorithm to determine if it would be more economical to shut down the unit during hours when Real Time Market prices fall below the variable operating costs. The algorithm compared operating losses during these hours to the cost of shutting down and re-starting the unit; if operating losses exceeded these shut-down/start-up costs, the unit was scheduled to go off-line over this period. Otherwise, the unit was ramped down to its minimum operating level during hours when its variable costs exceeded real-time energy prices.

3) Ancillary service revenues were calculated by assuming the unit could provide up to 40 MW of non-spinning reserve each hour if it was committed during the hour. The non-spinning service prices were based on actual CAISO Day Ahead Market prices.

4) All start-up gas costs associated with the simulated operation of the unit were included in the calculation of operating costs.

5) Finally, a combined forced and planned outage rate of 5 percent was simulated by decreasing total annual net operating revenues from real-time energy and non-spinning reserve sales by 5 percent.

2.6.3 Results

As noted in the previous methodology section, given the often significant differences between day-ahead bilateral prices and the CAISO real-time energy prices, particularly when the CAISO is decrementing resources in real-time, this year’s revenue analysis follows the same methodology as last year’s which includes the analysis that examines potential net revenues for a hypothetical combined cycle unit if it participated in both energy markets. The above methodologies also assume that the unit could be dispatched based on perfect foresight of market prices in all participated markets, which is not possible in practice. Therefore, the results may overestimate the net revenues, and, thus, may be considered the upper limits of potential revenues.

The results for a combined cycle unit are summarized in Table 2.9. It shows a relatively increasing trend in the net revenues from 2005 to 2008. The total capacity factor varies somewhat, but in general remains relatively constant throughout the evaluation periods while the revenues from the Day Ahead Market increased in recent years, mainly due to higher prices in the short-term bilateral market. However, the estimated net revenues in both zones have been substantially below the $132.6/kW-yr annualized fixed cost of the unit indicated in the CEC report, with 2008 estimates coming much closer to the level required to recover annualized fixed costs.

Table 2.10 shows the estimated net revenues that a hypothetical combustion turbine unit would have earned by participating in the CAISO Real Time Market as well as Ancillary Services Market. It shows a relatively stable trend in the net revenues from all years in the study period. Similar to the combined cycle analysis, the estimated revenues for a hypothetical combustion turbine unit fell well short of the $162.1/kW-yr annualized fixed costs indicated in the CEC report for all years (2005-2008) under all scenarios.

Table 2.9 Financial Analysis of New Combined Cycle Unit (2005–2008)

Components	2005		2006		2007		2008	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	65%	72%	63%	75%	69%	76%	74%	81%
DA Energy Revenue ($/kW - yr)	$372.39	$386.31	$319.65	$355.32	$369.59	$389.41	$489.17	$505.42
RT Energy Revenue ($/kW - yr)	$51.29	$63.83	$34.37	$50.02	$36.20	$41.98	$47.41	$51.98
A/S Revenue ($/kW – yr)	$1.41	$1.76	$1.01	$1.06	$0.37	$0.42	$0.41	$0.42
Operating Cost ($/kW - yr)	$363.06	$382.79	$279.50	$321.59	$321.86	$337.82	$425.16	$428.39
Net Revenue ($/kW – yr)	$62.04	$69.12	$75.53	$84.82	$84.30	$95.23	$111.82	$128.25
4-yr Average ($/kW – yr)	*$83.42*	*$94.35*						

Table 2.10 Financial Analysis of New Combustion Turbine Unit (2005-2008)

Components	2005		2006		2007		2008	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	8%	10%	7%	10%	8%	9%	11%	12%
Energy Revenue ($/kW - yr)	$87.50	$107.50	$69.46	$99.77	$97.54	$104.99	$155.58	$158.98
A/S Revenue ($/kW - yr)	$19.30	$18.50	$22.67	$21.68	$13.30	$12.83	$5.50	$5.53
Operating Cost ($/kW - yr)	$63.70	$82.00	$46.04	$68.92	$59.18	$64.63	$100.12	$104.09
Net Revenue ($/kW - yr)	$43.10	$44.10	$46.10	$52.35	$51.66	$53.19	$60.96	$60.43
4-yr Average ($/kW - yr)	*$50.45*	*$52.52*						

2.6.4 Discussion

The results shown in Table 2.9 and Table 2.10 indicate that net revenues appear to be sufficient to cover a unit's fixed operating and maintenance (O&M) costs on an annual basis. These fixed O&M costs are the fixed costs that a unit owner would be able to avoid incurring if the unit were not operated for the entire year (i.e., mothballed). Note that variable (fuel) costs (including start-up costs) are automatically covered since the simulation nets these costs against revenues to calculate net revenue. Fixed O&M costs, as reported by the CEC, are $11.2/kW-year for a combined cycle unit and $20.8/kW-year for a combustion turbine unit. If net revenues are expected to exceed fixed O&M costs, it should be sufficient to keep an existing unit operating from year to year. However, in order to provide an incentive for new generation investment, expected net revenues over a multi-year timeframe would need to exceed the total fixed costs of a unit (e.g., $162.1/kW-year for a combustion turbine unit).

The results above show that total fixed cost recovery, fixed O&M cost plus the cost of capital, was not achieved for either generation technology in any of the four years. In the case of the combustion turbine unit, net revenues were generally well below the total fixed cost estimate of $162.1/kW-year. The estimated net revenues ranged from $43/kW-yr to $61/kW-yr in the NP15 area and $44/kW-yr to $60/kW-yr in the SP15 area. The four year averages were $50/kW-yr in the NP15 area and $53/kW-yr in the SP15 area. However, as previously noted, basing potential energy market revenues solely on CAISO Real Time Market prices may tend to understate potential revenues given that real-time prices are generally below the day-ahead and day-of market prices. The same result is true for combined cycle units, where the total fixed cost of $132.6/KW-year is never fully reached, even when all potential revenues are accounted for. However, revenue analysis for combined cycle units does reveal a favorable trend over the past four years (2005-2008) with estimated net revenues increasing in both zones over this period. Higher short-term bilateral market prices accounted for much of this increase. The annual net revenues ranged from $62/kW-yr to $112/kW-yr in the NP15 area and $69/kW-yr to $128/kW-yr in the SP15 area. The four year averages were $83/kW-yr in the NP15 area and $94/kW-yr in the SP15 area.

The finding that estimated spot market revenues did not provide for fixed cost recovery underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. It also suggests that there are deficiencies in the current spot market design that are limiting market revenue opportunities – although it could be alternatively argued that the spot market design is adequate and sending the right investment signal for the current market year (i.e., the generation level from a market efficiency standpoint was adequate in 2008) but the net revenue earned in 2008 is not indicative of future market revenue opportunities, which is the primary driver for new investment. In any case, future market design features that could provide better price signals and revenue opportunities for new investment include: locational marginal pricing (LMP) for spot market energy, local scarcity pricing during operating reserve deficiency hours, and possibly monthly and annual local capacity markets. The CAISO Market Redesign and Technology Upgrade (MRTU), implemented in April 2009, provides some of these elements (LMP, some degree of scarcity pricing). Other design options (formal reserve shortage scarcity pricing mechanism and/or local capacity markets) are being seriously considered for future adoption.

In the meantime, local requirements for new generation investment should be addressed through long-term bilateral contracting under the CPUC Resource Adequacy and long-term procurement framework and similar programs for non-CPUC jurisdictional entities. These programs can provide additional revenue for new generation and cover the gap between annualized capital cost and the simulated net spot market revenues provided in the previous section.

While a broader range of market and contracting opportunities are being developed that could provide additional incentives for new generation, the continued reliance on an aging pool of generating units in California remains a concern. Though there has been a favorable and persistent trend over the past six years of reduced reliance on these units, they are still relied on in a significant number of hours. Clearly, California cannot continue indefinitely to rely on the existing pool of aging resources, which tend to be less economically efficient, more environmentally harmful, and less reliable. Table 2.11 shows generation additions and retirements, with a load growth trend figure. The total estimated net change in supply margins through 2008 is negative 262 MW for SP15, indicating that new generation has not quite kept pace with unit retirements and load growth in this region.[23] One of the consequences of this is the continued reliance on older generation facilities.

[23] It is important to note that this table only shows part of the supply picture in SP15. Numerous transmission upgrades have also occurred within SP15 to improve generation deliverability within the zone; however, despite these improvements, meeting summer peak load demands in SP15 remains more challenging than in Northern California.

Table 2.11 Generation Additions and Retirements by Zone

	2001	2002	2003	2004	2005	2006	2007	2008	Projected 2009	Total Through 2009
SP15										
New Generation	639	478	2,247	745	2,376	434	485	45	1,650	9,099
Retirements	0	(1,162)	(1,172)	(176)	(450)	(1,320)	0	0	0	(4,280)
Forecasted Load Growth*	491	500	510	521	531	542	553	564	575	4,787
Net Change	**148**	**(1,184)**	**565**	**48**	**1,395**	**(1,428)**	**(68)**	**(519)**	**1,075**	**32**
NP26										
New Generation	1,328	2,400	2,583	3	919	199	112	0	1,491	9,035
Retirements	(28)	(8)	(980)	(4)	0	(215)	0	0	(26)	(1,261)
Forecasted Load Growth*	389	397	405	413	422	430	439	447	456	3,798
Net Change	**911**	**1,995**	**1,198**	**(414)**	**497**	**(446)**	**(326)**	**(447)**	**1,009**	**3,976**
ISO System										
New Generation	1,967	2,878	4,830	748	3,295	633	598	45	3,141	18,135
Retirements	(28)	(1,170)	(2,152)	(180)	(450)	(1,535)	0	0	(26)	(5,541)
Forecasted Load Growth*	880	897	915	934	953	972	991	1,011	1,031	8,585
Net Change	**1,059**	**811**	**1,763**	**(366)**	**1,892**	**(1,874)**	**(394)**	**(966)**	**2,084**	**4,008**

* Forecasted load growth is based on an assumed 2 percent peak load growth rate applied each year.

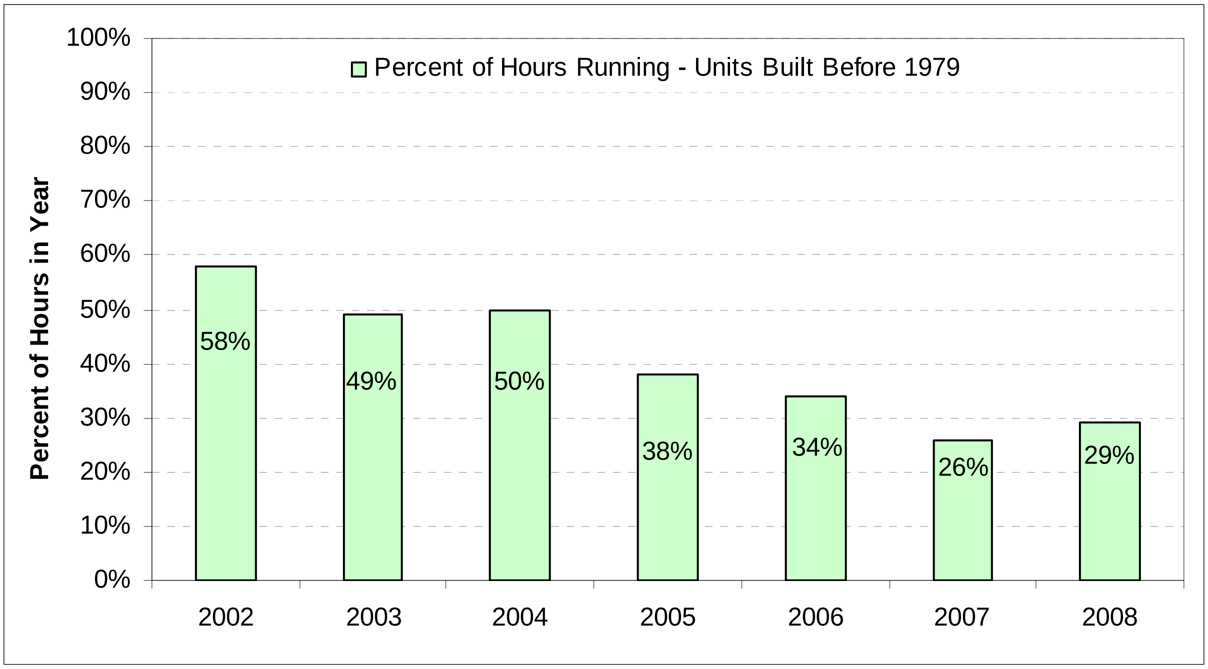
Despite the significant amount of older generation capacity that has been retired in recent years, there remains a large pool of aging units in California, with 46 units built before 1979 having an average age of 45 years, as seen in Table 2.12. Figure 2.22 shows the percent of hours in a year that units built before 1979 are running, and indicates a clear trend of declining utilization of these older units. However, this older pool of units was still relied upon, to provide either energy or reliability services, for roughly 29 percent of the hours in 2008. Because of the age and relative inefficiency of these units, they are likely to have net revenues below those reported above, and have less ability to recover even fixed O&M costs through spot market revenues. For these units, long-term contracting is especially necessary to ensure continued operation in the short-run and re-powering of these facilities in the longer-run if new investment is insufficient to provide replacement capacity.

Table 2.12 Characteristics of California's Aging Pool of Resources

	Number of Units	Unit Capacity[1]	Average Unit Age (Years)[2]	Capacity Factor[3]	Percent of Hours Running[4]
North of Path 26	13	4,642	46	13%	28%
South of Path 26	33	9,304	44	11%	30%
Total	**46**	**13,946**	**45**	**12%**	**29%**

[1] Total active unit capacity as of date of publication.
[2] Based on build date.
[3] Based on 2008 data. Does not adjust for unit outages.
[4] Based on 2008 data. Percent of all hours in year where unit showed positive metered generation.

Figure 2.22 Percent of Hours Running for Units Built Before 1979



3 Real Time Market Performance

3.1 Overview

2008 marked the fourth full year of operation under the Real Time Market Application (RTMA) software. The RTMA software was designed to address significant shortcomings in the prior real-time dispatch and pricing application (Balancing Energy and Ex-Post Pricing or BEEP).

The RTMA software uses a 120-minute time horizon to compare the load forecast, current and expected telemetry of resources in the CAISO Control Area, current and expected telemetry of transmission links to other control areas, and the current status of resources on Automatic Generation Control (AGC). From this information, RTMA sets generation levels for resources participating in the CAISO Real Time Market using an optimization that achieves least-cost dispatch while respecting generation and inter-zonal constraints.

A complementary software application, Security Constrained Unit Commitment (SCUC), determines the optimum short-term (i.e., one to two hours, the time from the current interval through the end of the next hour based on the current and next hour's bids) unit commitment of resources used in the RTMA. The SCUC software commits off-line resources with shorter start-up times into the Real Time Market for RTMA to dispatch, or, conversely, the SCUC software de-commits resources as required to prevent over-generation in real-time. The SCUC program runs prior to the beginning of the operating hour and performs an optimal hourly pre-dispatch for the next hour to meet the forecast imbalance energy requirements while minimizing the bid cost over the entire hour. The SCUC software also pre-dispatches (i.e., dispatches prior to the operating hour) hourly inter-tie bids.

This chapter reviews the performance of the CAISO Real Time Market in 2008. Section 3.2 provides a general review of RTMA prices and dispatch volumes compared to prior years. One significant driver of Real Time Market volumes is the level of forward energy scheduling, which is influenced by the CAISO 95 Percent Day-Ahead Scheduling Requirement (Amendment 72). Section 3.3 provides a review of load scheduling practices.

3.2 Real-Time Market Trends

3.2.1 Prices and Volumes

Figure 3.1 shows monthly average prices and volumes for both incremental and decremental energy and both in- and out-of-sequence (OOS) dispatches for 2007 and 2008. Monthly prices for incremental energy in 2008 were volatile, consistent with the steady rise of natural gas prices in the first half of the year and subsequent drop through the second half, with average incremental energy prices peaking at approximately $147/MWh in June, compared to a low in October of $70.61/MWh. Average monthly prices for decremental energy, which suppliers pay to avoid generating to their hour-ahead energy schedules, peaked in April, at $71.63/MWh, compared to a low in November of $21.27/MWh. In-sequence dispatch volumes were predominantly decremental in most months of 2008. The preponderance of decremental dispatches can be attributed in part to high levels of forward energy scheduling, which may be driven by the CAISO day-ahead load scheduling requirement (Amendment 72), and Load

Serving Entities' (LSEs) aversion to volatile Real Time Market prices. The spike in the average cost of incremental OOS dispatches in December is due to periods where additional local reliability support was required from less efficient resources in Northern California (please see Chapter 6 for additional details), for a small overall volume of energy.

Figure 3.1 Monthly Average Dispatch Prices and Volumes (2007-2008)[24]

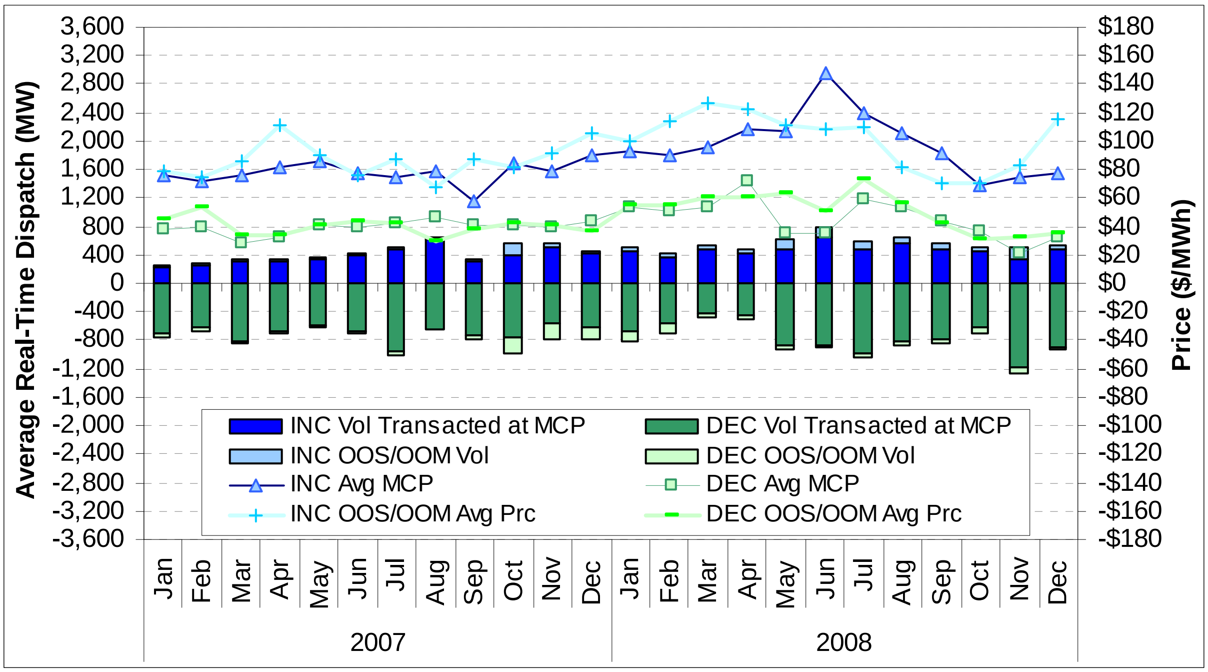


Figure 3.2 and Figure 3.3 show the same metrics presented in Figure 3.1, but separately for peak and off-peak hours, respectively. As can be seen in these figures, the average monthly market volume trends across the two years are fairly similar for peak and off-peak hours. As expected, average monthly prices were generally higher in the peak hours.

[24] Charts reflect latest available data and thus may differ for periods that had been previously reported.

Figure 3.2 Monthly Average Dispatch Prices and Volumes, 2007-2008 Peak Hours

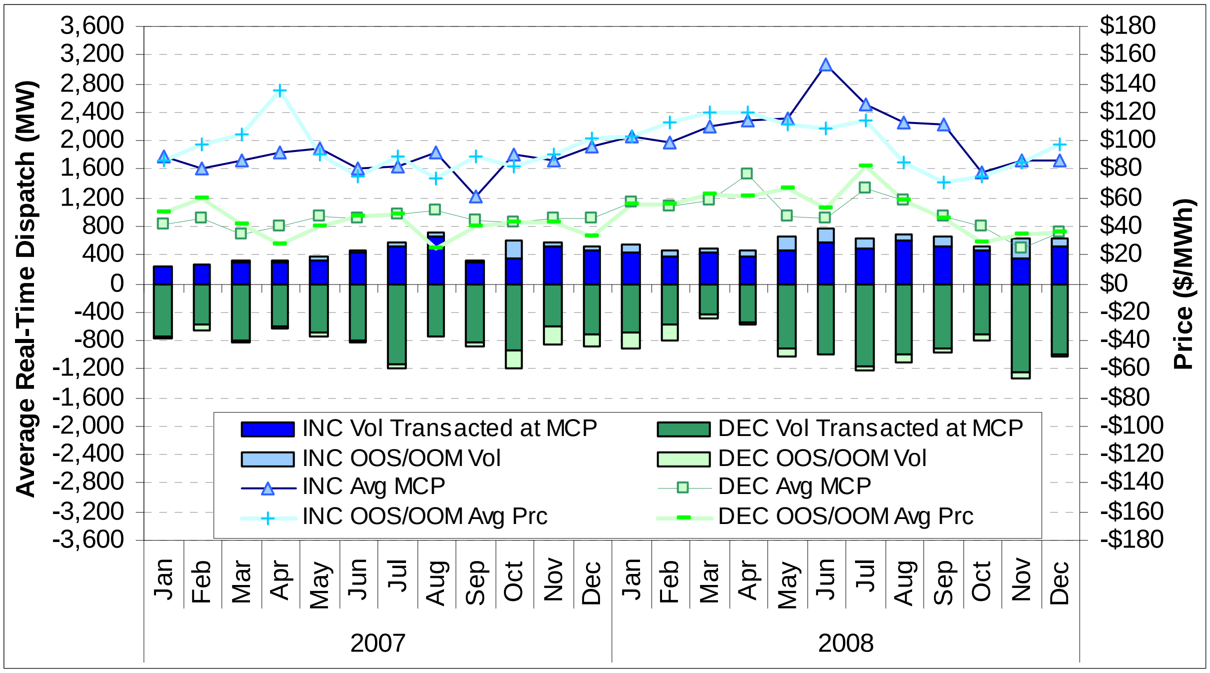


Figure 3.3 Monthly Average Dispatch Prices and Volumes, 2007-2008 Off-Peak Hours

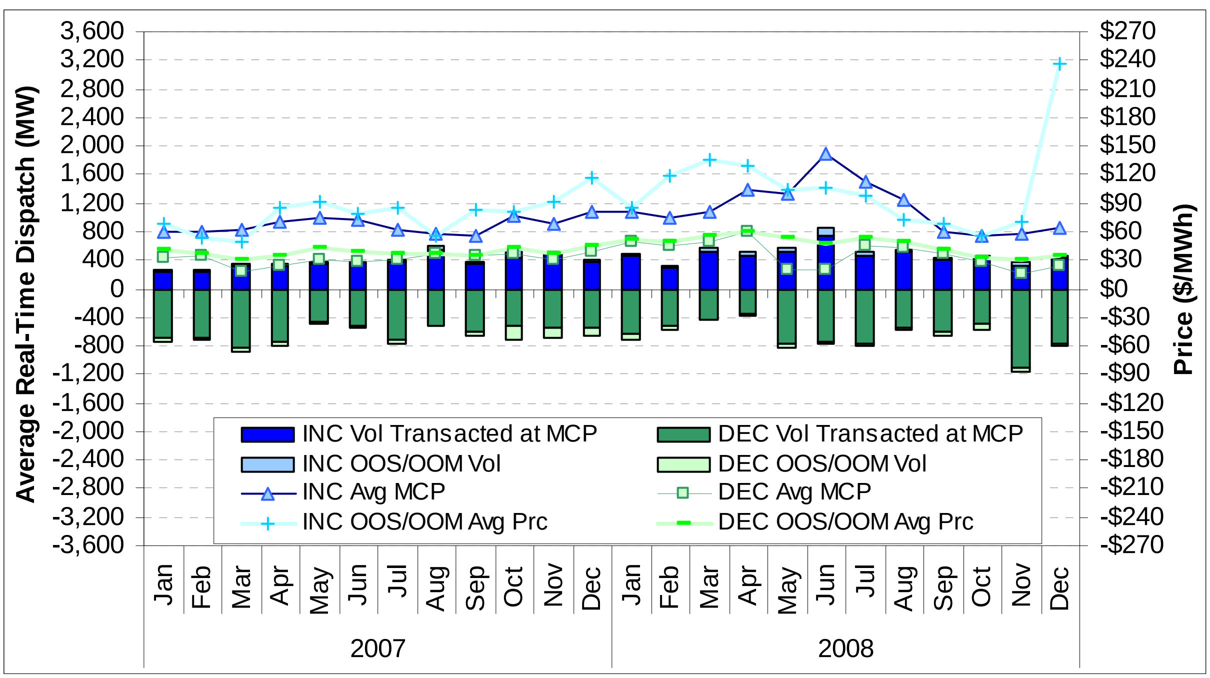


Figure 3.4 compares average annual Real Time Market prices by zone (NP26, SP15) for 2005 through 2008. Congestion on Path 26 in the north-to-south direction has resulted in consistently higher prices in SP15 than in NP26. However, this trend has decreased in recent years, as the Southern California grid has been upgraded, and atypical weather patterns have caused relatively mild weather in Southern California and extreme weather in Northern California in 2008, particularly in December. The general upward trend in average prices in 2008 can be explained by higher natural gas prices, combined with lower levels of hydroelectric production compared to prior years, resulting in higher reliance on more costly natural gas generation.

Figure 3.4 Average Annual Real-Time Prices by Zone, 2005-2008

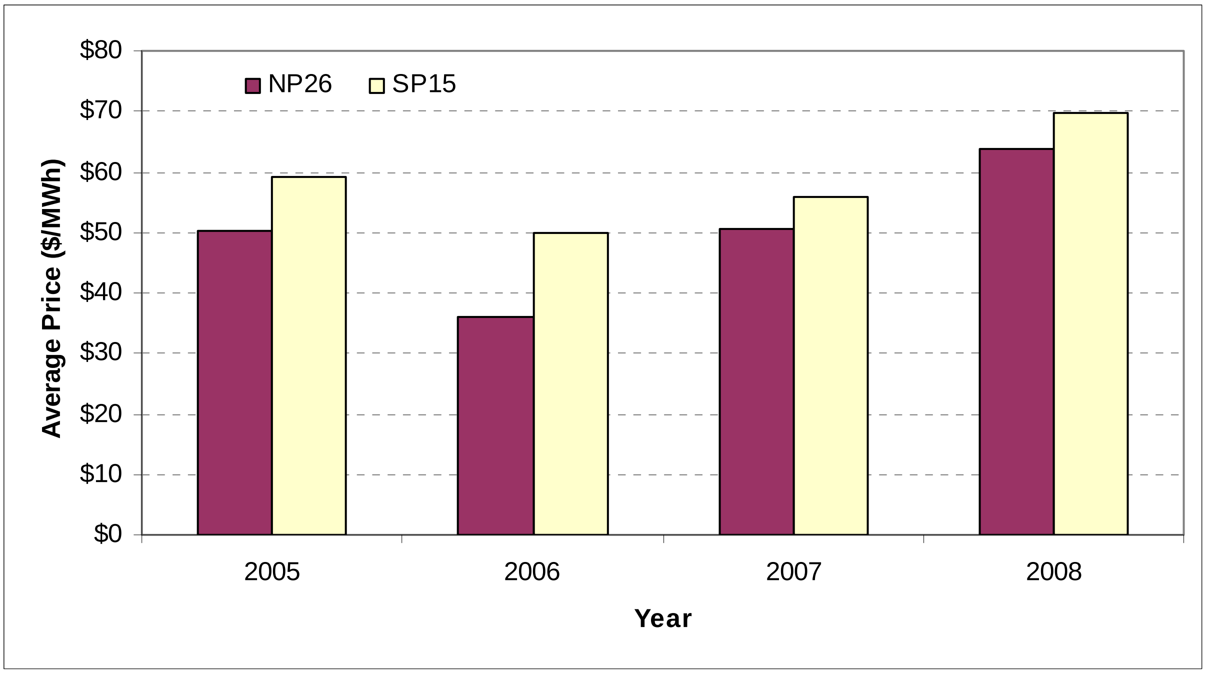
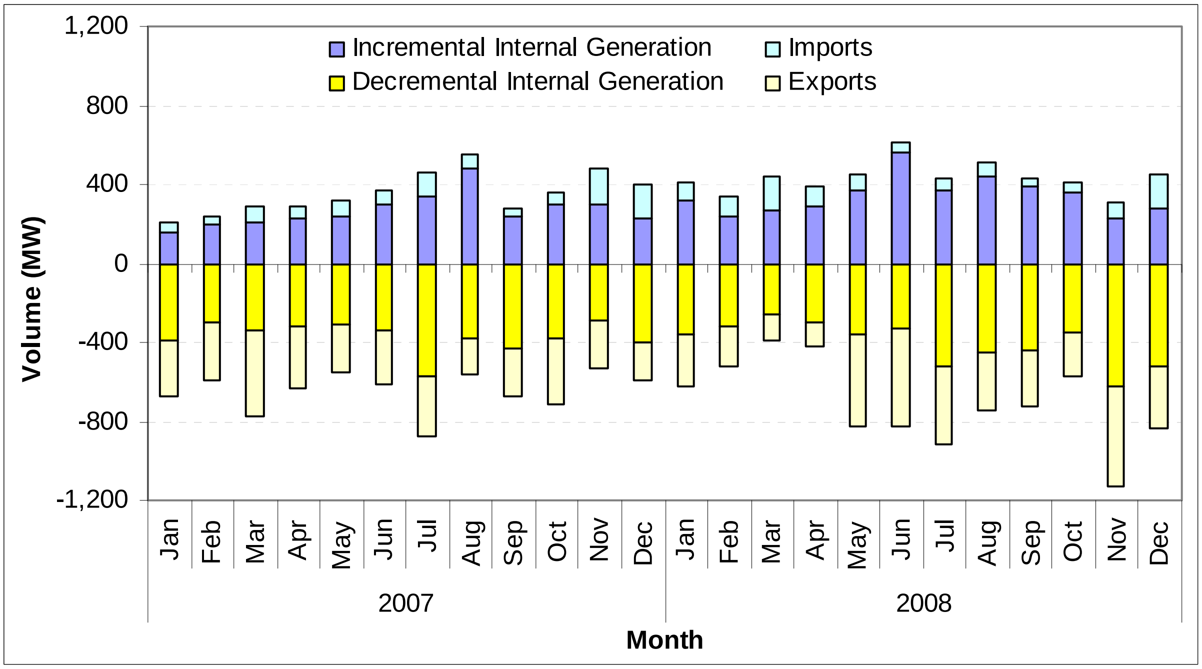


Figure 3.5 shows the monthly average dispatch volumes for internal generation, imports and exports for 2007 and 2008. Since the implementation of Amendment 72, LSEs have been conservative in meeting the 95 percent forward scheduling requirement and often have forward scheduled generation and imports in excess of the requirement. Consequently, real-time balancing in the decremental direction has typically been more prevalent than in the incremental direction.

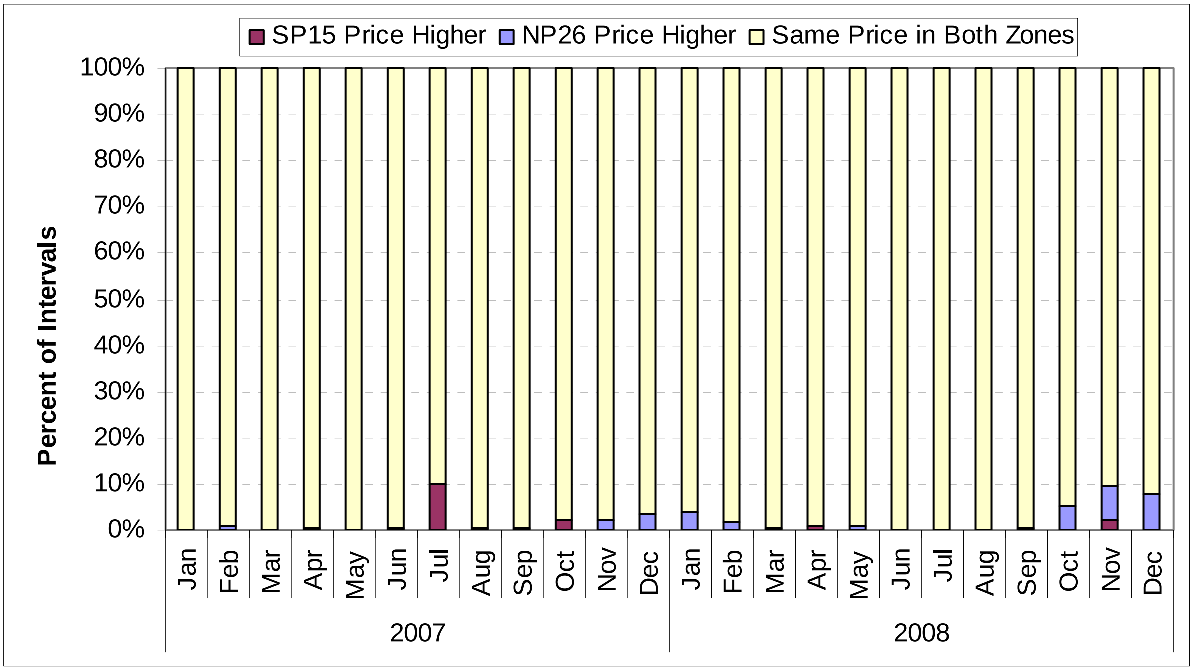
Figure 3.5 Monthly Average Dispatch Volumes for Internal Generation, Imports, and Exports (2007-2008)



3.2.2 Real-Time Inter-Zonal Congestion

Figure 3.6 depicts the proportion of market splits in 2007 and 2008. Real-time inter-zonal congestion, which causes market price splits, increased in frequency to 2.6 percent of hours in 2008, compared to 1.8 percent of hours in 2007. However, splits with the higher price in SP15, indicating congestion in the north-to-south direction, have decreased in frequency relative to splits with the higher price in NP26. Of the 2,721 intervals with price splits in 2008, 2,460 had higher NP26 prices. In comparison, of the 1,845 intervals with splits in 2007, 638 had higher NP26 prices. This can be explained in part by a derate of Path 15 due to transmission work on the Los Baños-Midway 500 kV line, intermittent derates of the Pacific DC Intertie, and ongoing work in the Moss-Metcalf transmission corridor, which constrained transmission from several large generators in the Monterey area to Bay Area load. Unusual weather patterns in 2008 were another factor, with a mild summer and a cold late fall, skewing energy consumption toward Northern California. These factors, along with minimal hydro resources within Northern California, combined to result in clockwise loop flow, effectively creating a vacuum of power within Northern California that was mitigated by dispatching costly Bay Area resources upward and less expensive Southern California and Southwestern units downward, resulting in Real Time Market price separations. For further details on this phenomenon, please see the discussion of the Victorville-Lugo Nomogram in Chapter 6.

Figure 3.6 NP26-SP15 Market Price Splits (2007-2008)



3.3 Forward Scheduling

Under the current CAISO market structure, there is no organized Day Ahead Market for energy. Instead, all day-ahead scheduling is based on bilateral contracts and supply resources directly owned or controlled by LSEs. In addition, each SC must submit balanced load and supply schedules. The amount of load and supply scheduled on a day-ahead basis can have a significant impact on CAISO operations. To the extent the amount of load and supply scheduled is insufficient to meet the CAISO's forecast of load and other system conditions, the CAISO may commit additional supply resources on a day-ahead basis through the must-offer waiver denial process. In real-time, significant under-scheduling can also require the CAISO to dispatch additional incremental energy resources through the Real Time Market.

During 2008, the level of forward scheduling was similar to that in 2007, closely aligned with actual load. Figure 3.7 compares the average hourly values of day-ahead and hour-ahead schedules with actual load during 2008. This high level of scheduling can be attributed to a number of factors.

- In October 2005, the CAISO filed and FERC subsequently approved Tariff Amendment 72, which required Scheduling Coordinators (SCs) to submit day-ahead schedules equal to at least 95 percent of their forecast demand for each hour of the next day. The 95 percent day-ahead scheduling requirement was designed to enhance reliability and reduce the need for the CAISO to take actions to protect against under-scheduling, such as requiring additional capacity to be on-line through MOW denials and dispatching additional energy in the real-time. In February 2007, the CAISO filed and FERC subsequently approved, with modifications, a Tariff amendment to relax the existing minimum load scheduling requirement during off-peak hours from 95 percent to 75 percent of each Scheduling Coordinator's demand forecast, effective April 26, 2007.

- In addition, the amount of forward scheduling in 2008 was affected by a variety of CPUC procurement guidelines which have had the effect of encouraging the state's major Investor Owned Utilities (IOUs) to forward contract for most or all of their projected energy needs.

- Finally, while Resource Adequacy requirements in effect for 2008 require only that available RA capacity be made available to the CAISO, it is likely that many RA capacity contracts are coupled with energy contracts – such as energy tolling agreements – which allow LSEs to schedule energy from RA resources on a day-ahead basis.

Several patterns of load scheduling have persisted in recent years:

- A prevalent pattern at night, generally between hours ending 2:00 and 6:00 a.m., is the heavy over-scheduling of load. This is the pattern that motivated the reduction of the off-peak scheduling requirement to 75 percent of forecast load. This has been characteristic of the load pattern across seasons.

- Since the record peak summer of 2006, schedules have generally been more than sufficient to meet summer peak loads. Since then, summer peaks have declined, as shown in Table 2.1. In the presence of the 95 percent scheduling requirement, scheduling short of load has been limited to days in which forecast load has been substantially short of actual load, usually due to unforeseen weather conditions. More commonly, schedules exceed load, often resulting in the decremental dispatch discussed above in Section 3.2.1.

- From late fall to early spring, the weekday load pattern exhibits a very sharp load ramp in the early evening, due to household cooking, heating, and lighting load. This load ramp reaches its highest rate in late December due to holiday lighting, and can approach 2,700 MW per hour, generally between hours ending 16:00 and 18:00 (from 3:00 to 6:00 p.m.), but varying considerably due to weather and the time of year. Daily peak loads in this period may range from 28,000 to 35,000 MW, so the load pull can approach five to 10 percent of the daily total in a single hour. Since hourly generation schedules have specific ramping periods, from ten minutes before the end of one hour until ten minutes after the beginning of the next, schedules cannot possibly match a much smoother load pull, which does not occur in hourly blocks. In addition, if load ramps mid-hour, rather than in concert with hourly generation schedules, the resulting imbalance can be 1,000 MW or more.

During peak hours (and, in particular, hour ending 16:00), day-ahead schedules often exceeded the 95 percent scheduling requirement established under Amendment 72, as illustrated in Figure 3.9. This trend suggests that factors in addition to the 95 percent scheduling requirement – such as CPUC supply procurement guidelines, and the bundling of capacity and energy contracts with RA resources – were primarily responsible for the high degree of forward scheduling seen throughout 2008, as has also been the case in recent years. Another factor may simply be that LSEs are risk averse and therefore want to minimize their exposure to volatile Real Time Market prices.

Figure 3.8 shows, by month for all hours, average actual load together with day-ahead and hour-ahead under-scheduling. Even in July and August when average load peaked, the percent under-scheduled was still less than two percent of actual load. Figure 3.9 similarly depicts the percentage of under-scheduling for all hours ending 16:00 (between 3:00 and 4:00 p.m.) by month for 2008. This chart highlights the fact that during the peak hours of 2008, the extent of aggregate under-scheduling was slightly less than three percent of actual load.

As discussed in Section 3.2, high levels of scheduling or over-scheduling required the CAISO to reduce or decrement additional generation in the Real Time Market during many hours in 2008. Even if energy and net import schedules submitted by SCs are approximately equal to actual CAISO system loads, the CAISO may need to decrement significant amounts of energy due to various sources of unscheduled energy that appear in real-time under the current market design. Major sources of unscheduled energy include:

- Minimum load energy from units committed through the MOW process.
- Positive uninstructed energy from resources within the CAISO, including steam generating units operating at minimum load during off-peak hours, cogeneration resources, and intermittent resources such as wind energy.
- Additional net incremental energy from real-time out-of-sequence (OOS) dispatches due to intra-zonal congestion and local reliability requirements.
- Loop flows creating net positive energy from neighboring control areas.

In 2008, as in previous years, the limited amount of under-scheduling that did occur did not detrimentally impact system reliability or significantly increase MOW commitment costs. This is largely explained by the fact that the CAISO was largely decrementing energy in real-time due to various sources of unscheduled energy. For example, Figure 3.10 shows the percent of hours during the year in which the CAISO was decrementing energy along with the average levels of under-scheduling for each of the 24 operating hours of the day. The red portions of the bars depict the MWh by which aggregate day-ahead schedules fell below 95 percent of the CAISO day-ahead forecast. As depicted in Figure 3.10, the bulk of under-scheduling occurred during hours in which the CAISO was, on average, decrementing energy. Thus, under-scheduling did not create a need for additional incremental energy in real-time and, in fact, under conditions such as these, additional forward scheduling may have only increased the need to decrement energy in real-time.

Figure 3.7 Average Actual Load Relative to Hour Ahead and Day Ahead Schedules by Operating Hour for 2008

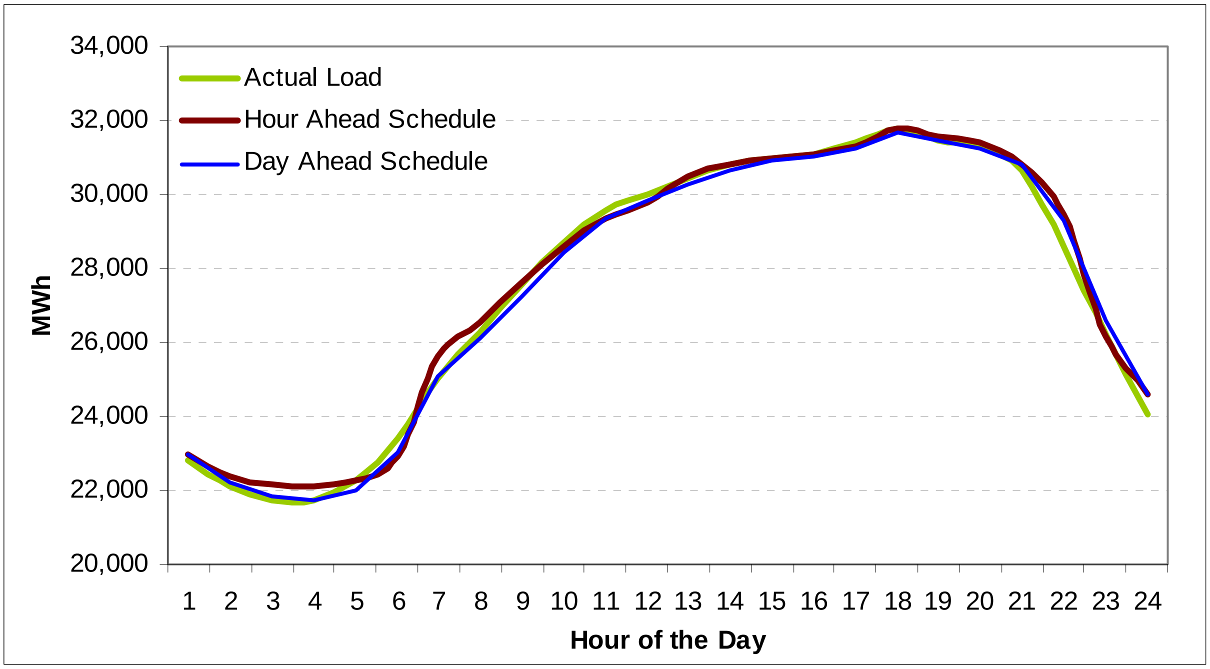


Figure 3.8 Average Hourly Actual Load Relative to Under-Scheduling for 2008 by Month for All Hours

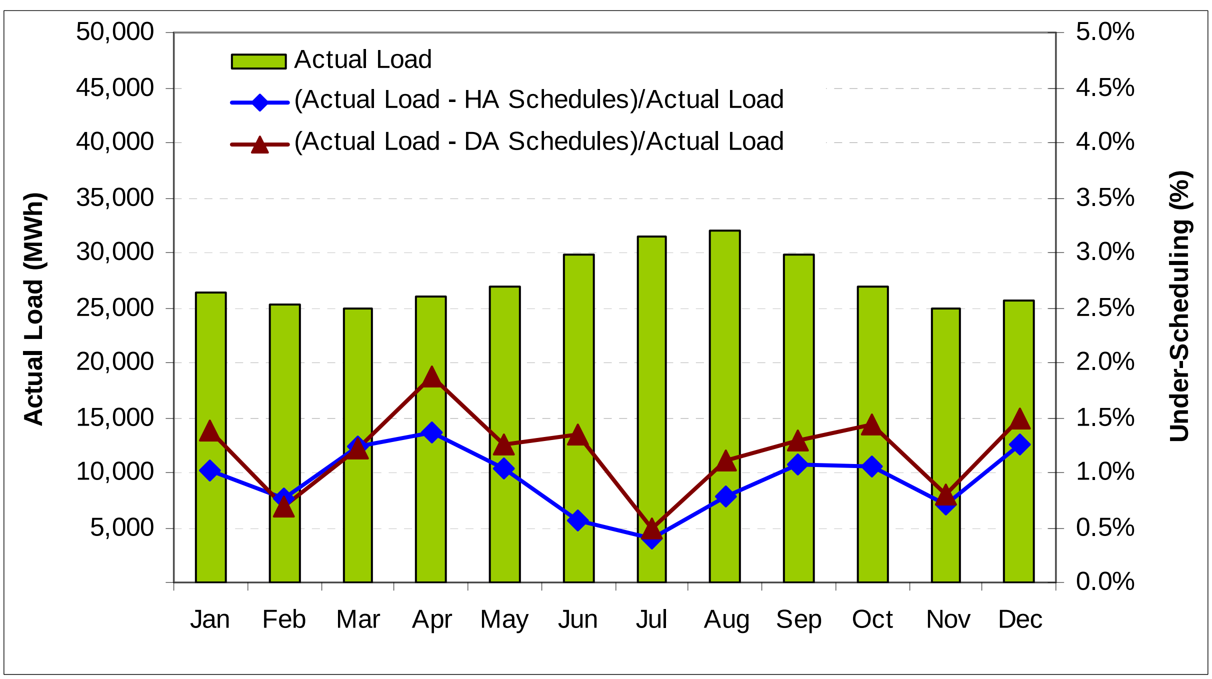


Figure 3.9 Average Hourly Actual Load Relative to Under-Scheduling for 2008 by Month for Hours Ending 16:00 only

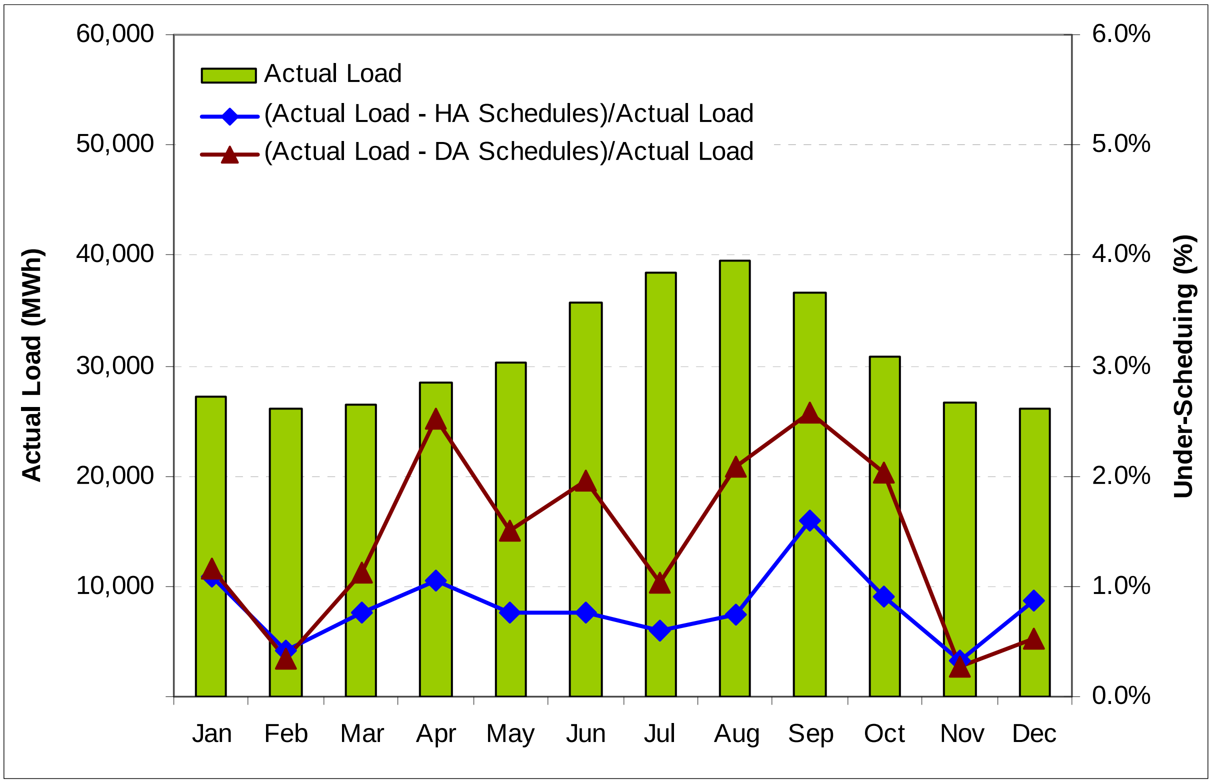
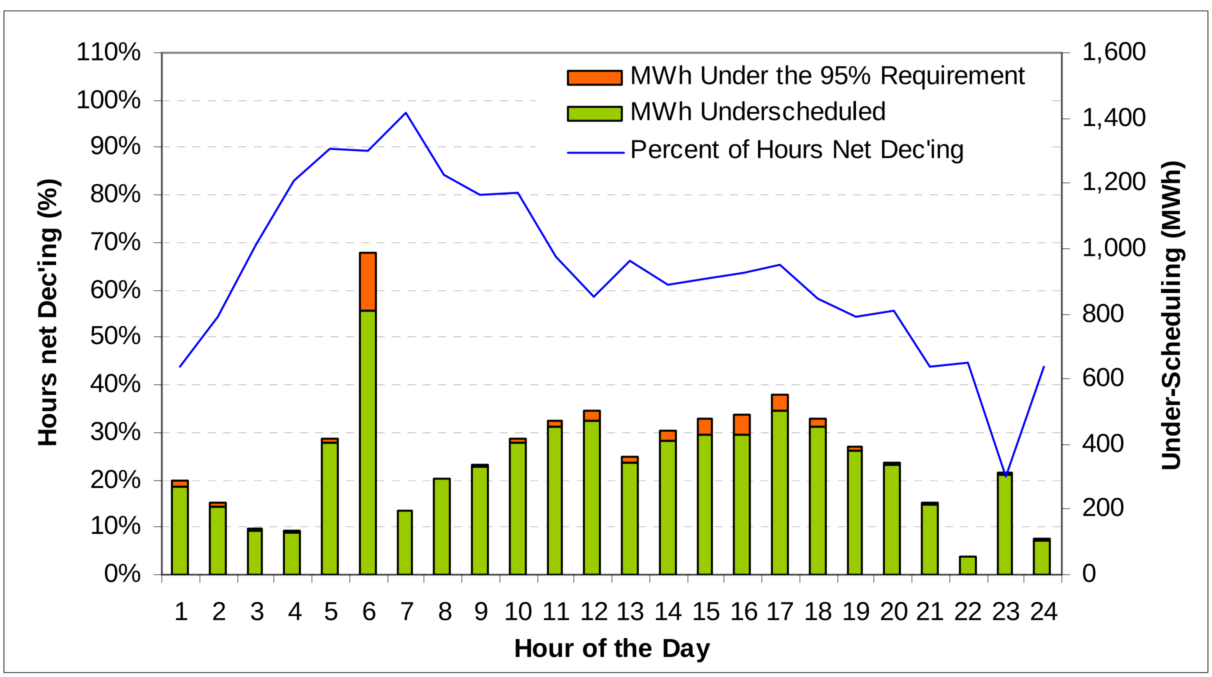


Figure 3.10 Average Under-Scheduling by Hour Relative to Net Decremental Energy in 2008



4 Ancillary Service Markets

4.1 Summary of Performance in 2008

Overall, average Ancillary Service (A/S) prices increased by 12 percent in 2008 compared to prevailing prices in 2007. The total procurement cost also increased at roughly the same rate while the total procurement volumes of the four A/S products stayed almost at the same level as in 2007. The increase in the aggregate A/S price resulted from average price increases in all services except for Non-Spinning Reserve. Overall, total cost to load increased 16 percent to $0.73/MWh, still under $1.00/MWh in total as well as across each of the four services.

4.2 Ancillary Service Market Background

The CAISO procures Regulation Reserve, Spinning Reserve and Non-Spinning Reserve in the Day Ahead and Hour Ahead Markets such that the total procurement volumes plus self-provision volumes meet or exceed the Western Electricity Coordinating Council's (WECC) Minimum Operating Reliability Criteria (MORC) and North American Electricity Reliability Council (NERC) Control Performance Standards (CPS). The CAISO procures A/S at the lowest overall cost while maintaining the reliability of the system and the competitiveness of the markets. The combination of a single-price auction pricing mechanism across the control area and the Rational Buyer algorithm, which allows for economic substitution of less expensive bids in place of more expensive bids across services, facilitates a least-cost procurement approach to meeting reliability requirements.

The definitions for the actively procured Ancillary Services are:

6) Regulation Reserves: Reserved capacity provided by generating resources that are running and synchronized with the CAISO controlled grid, so that the operating levels can be increased (incremented) or decreased (decremented) instantly through Automatic Generation Control (AGC) to allow continuous balance between generating resources and demand. The CAISO operates two distinct capacity markets for this service, upward and downward Regulation Reserve.

7) Spinning Reserves: Reserved capacity provided by generating resources that are running (i.e., "spinning") with additional capacity that is capable of ramping over a specified range within 10 minutes and running for at least two hours. The CAISO needs Spinning Reserve to maintain system frequency stability during emergency operating conditions and unanticipated variations in load.

8) Non-Spinning Reserves: Generally, reserved capacity provided by generating resources that are available but not running. These generating resources must be capable of being synchronized to the grid and ramping to a specified level within 10 minutes, and then be able to run for at least two hours. Curtailable demand can also supply Non-Spinning Reserve provided that it is telemetered and capable of receiving dispatch instructions and performing accordingly

within 10 minutes. The CAISO needs Non-Spinning Reserve to maintain system frequency stability during emergency conditions.

9) Requirement: The CAISO maintain minimum amounts of Regulation, Spinning, and Non-Spinning Reserves to meet WECC and NERC control performance criteria. The quantity of Regulation Reserve capacity needed for each Settlement Period of the Day Ahead Market and the Hour Ahead Market shall be determined as a percentage of the aggregate scheduled demand for that Settlement Period. The quantity of Spinning Reserve and Non-Spinning Reserve is calculated as (a) 5 percent of the Demand (except the Demand covered by firm purchases from outside the CAISO Control Area) to be met by Generation from hydroelectric resources plus 7 percent of the Demand (except the Demand covered by firm purchases from outside the CAISO Control Area) to be met by Generation from other resources, or (b) the single largest Contingency, if this is greater or (c) by reference to such more stringent criteria as the CAISO may determine from time to time.

CAISO market participants can self-provide any or all of these A/S products, bid them into the CAISO markets, or purchase them from the CAISO. The CAISO procures two other ancillary services on a long-term basis: voltage support and black start. Reliability Must Run (RMR) contracts serve as the primary procurement vehicle for these services. Through the remainder of this chapter, the term “ancillary services” (A/S) will be used only to refer to the three reserved-capacity products defined above.

Scheduling Coordinators (SCs) simultaneously submit bids to supply any or all three products to the CAISO in conjunction with their preferred day-ahead and hour-ahead schedules. Submitted A/S bids must be associated with specific resources (system generating units, import interchange location, load, or curtailable export) and must contain a capacity component and an energy component. The CAISO selects resources to provide A/S capacity based only on their capacity bid prices and deliverability. Thereafter, the CAISO uses the energy bid prices to dispatch units to provide real-time energy.

4.3 Prices and Volumes of Ancillary Services

Overall, A/S prices increased 12 percent from a weighted average price of $7.41/MW in 2007, which was the lowest annual average price since 2002, to $8.27/MW in 2008. Increases in the average price of three of the four Ancillary Services outweighed the decrease in average price of Non-Spinning Reserve and contributed to the overall price increase. The prices of Regulation Down, Regulation Up, and Spinning Reserve increased 57 percent, 13 percent, and 30 percent, respectively, while the price of Non-Spinning Reserve decreased 56 percent. Despite the overall price increase in 2008, prices across all four services were within the normal range of historical prices and were generally still below the average prices reported for 2003 through 2006, as indicated in Table 4.1.

Procurement volumes, in total, were slightly higher than in 2007, with the largest increase in hourly average volume procured in Non-Spinning Reserve. Table 4.1 compares prices and volumes from previous operating years.

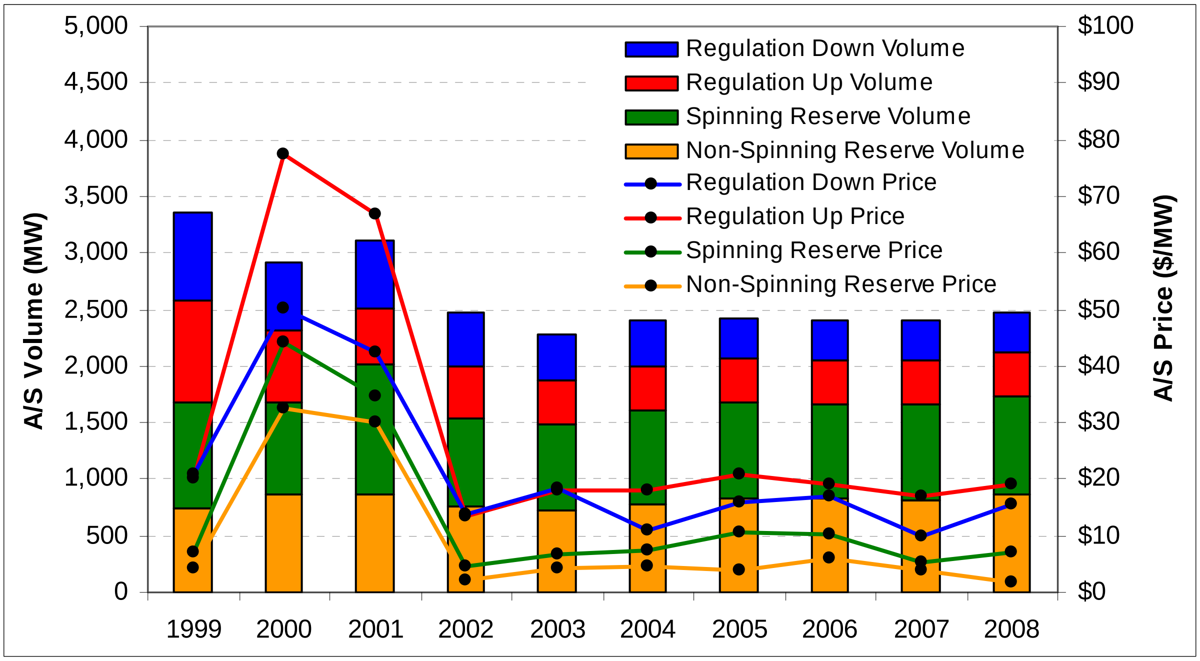
Table 4.1 Annual Hourly Average A/S Prices and Volumes

	Year	Regulation Down	Regulation Up	Spinning Reserve	Non-Spinning Reserve	Average A/S Price
Price ($/MW)	1999	$20.84	$20.22	$7.07	$4.35	$11.97
	2000	$50.15	$77.28	$44.07	$32.46	$41.03
	2001	$42.33	$66.72	$34.69	$30.03	$36.42
	2002	$13.76	$13.41	$4.66	$2.15	$7.08
	2003	$18.43	$18.08	$6.62	$4.20	$9.81
	2004	$10.95	$17.95	$7.25	$4.43	$8.63
	2005	$16.05	$20.94	$10.45	$3.98	$10.72
	2006	$17.01	$18.94	$10.11	$5.96	$11.12
	2007	$9.97	$16.81	$5.42	$3.98	$7.41
	2008	$15.67	$18.94	$6.99	$1.74	$8.27

	Year	Regulation Down	Regulation Up	Spinning Reserve	Non-Spinning Reserve	Total Volume
Volume (MW)	1999	769	903	942	735	3,349
	2000	594	633	818	861	2,907
	2001	614	492	1,148	862	3,117
	2002	469	460	775	763	2,466
	2003	416	381	767	722	2,286
	2004	408	395	817	782	2,403
	2005	363	386	841	839	2,428
	2006	354	389	831	831	2,405
	2007	361	379	849	815	2,403
	2008	357	387	865	869	2,478

Figure 4.1 depicts the historical pattern of prices and volumes since 1999 and indicates that A/S prices and volumes have been relatively stable over the past seven years (2002-2008) as compared to the period from 1999 to 2001. As a result of cost-minimizing economic substitution of less expensive bids for higher quality services in place of more expensive bids for lower quality services, prices of upward A/S reserves generally display a decreasing pattern in the order of Regulation, Spinning Reserve, and Non-Spinning Reserve.

Figure 4.1 Annual Average A/S Prices and Volumes



Monthly day-ahead reserve prices tend to vary with seasonal load levels, as seen in Figure 4.2. In contrast to 2007, the volatility in monthly average A/S prices is higher in 2008. Higher prices for Regulation occurred primarily during the spring and early summer of 2008, as a majority of thermal units that usually provide regulation services were off-line due to lower cost hydroelectric produced energy being imported from the Pacific Northwest. This contributed to fewer supply bids for Regulation, which resulted in sharply higher prices.

Figure 4.2 Monthly Weighted Average A/S Prices

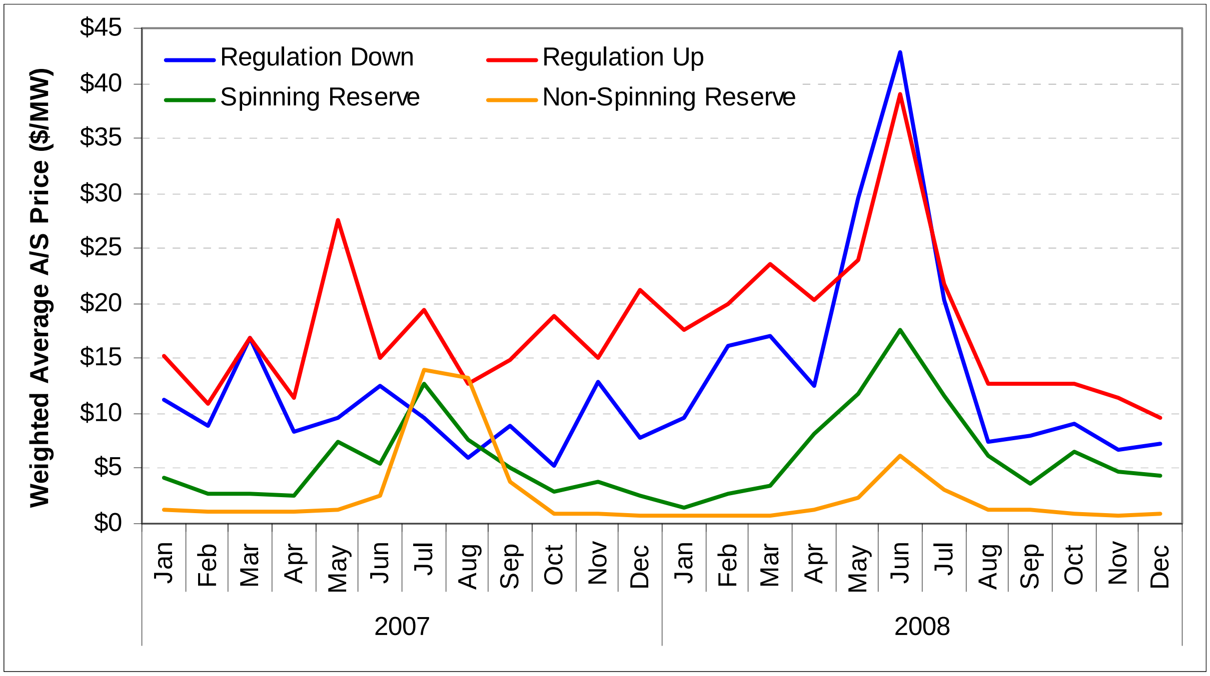


Figure 4.3 shows the variation of A/S prices across different operating hours. Prices of Upward Regulation and Operating Reserves generally follow the load pattern, with higher prices in peak load hours. However, Regulation Down Reserve prices observe an opposite trend, with high prices in the early morning hours when the load is low. These high prices for Downward Regulation Reserve are especially prominent during the spring morning hours, as fewer resources are operating in a range where they can back generation down to provide regulating energy, and hydro-electric resources are reluctant to reduce output due to the spill conditions that occur during the spring runoff period, as illustrated in Figure 4.4. Similarly, price patterns for Operating Reserves are shown in Figure 4.5 which also shows the seasonal variation in prices. The highest hourly average prices for Operating Reserves were observed in the peak hours of the spring. This was due to fewer thermal resources being on-line because of higher fuel costs and an abundance of hydroelectric energy from the Pacific Northwest. Less thermal resources online reduced the available supply on ancillary service bids and put upward pressure on prices. As loads increased beginning in the third week of June 2008, more thermal resources came on-line and average Operating Reserve prices declined. As more resources are operating at high output levels in the summer peak hours, the supply of Operating Reserve is limited, resulting in higher prices. This effect is more prominent in Spinning Reserve. Higher energy prices in the summer peak hours also contributed to the price spikes of Operating Reserves by driving up the opportunity cost of reserving generation capacity.

Figure 4.3 Day Ahead Hourly Average A/S Prices (2008)

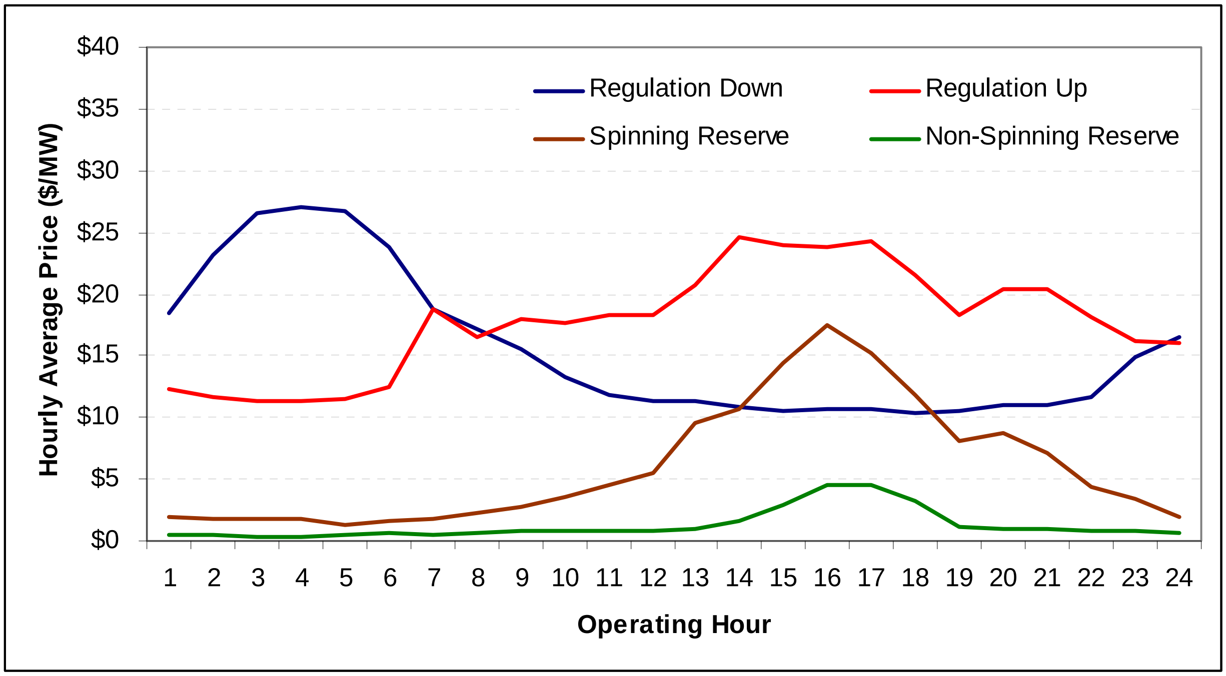


Figure 4.4 Hourly Average Regulation Down Prices by Season (2008)

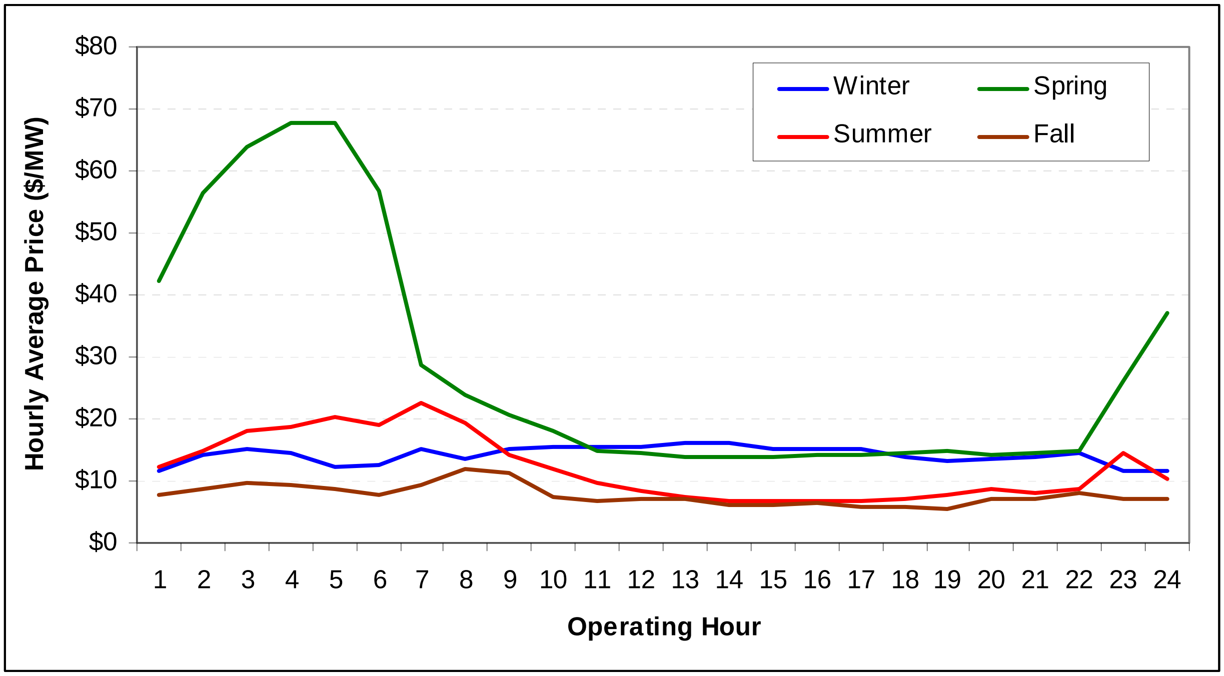
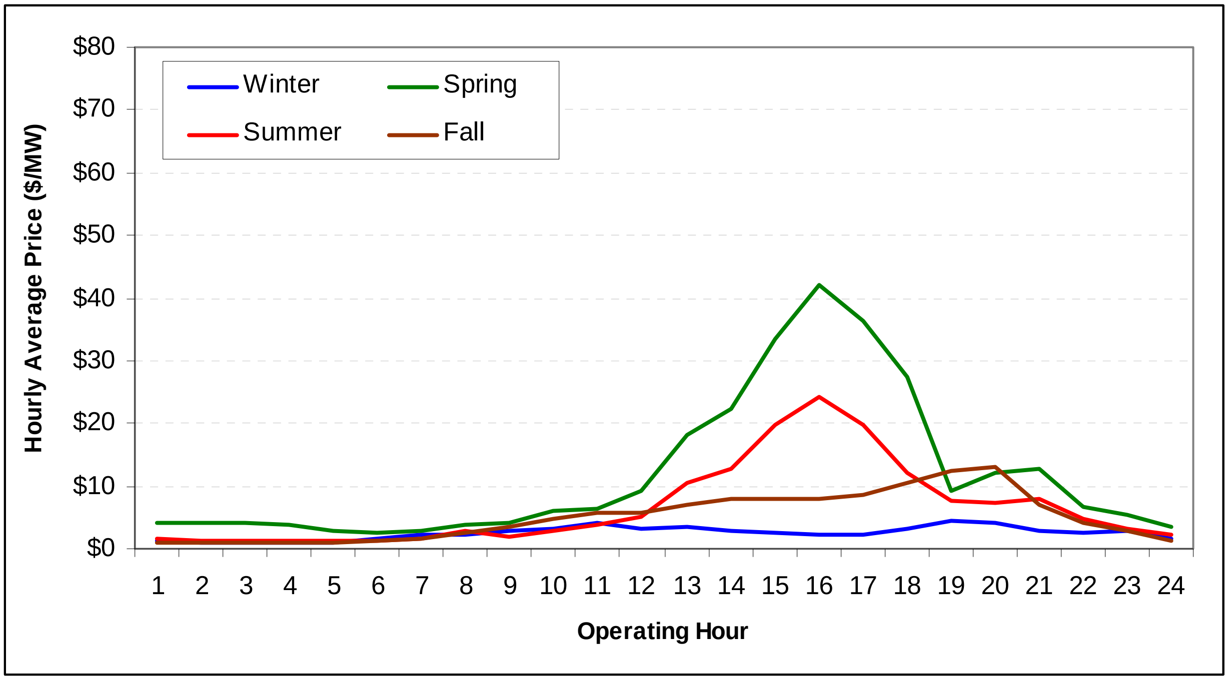
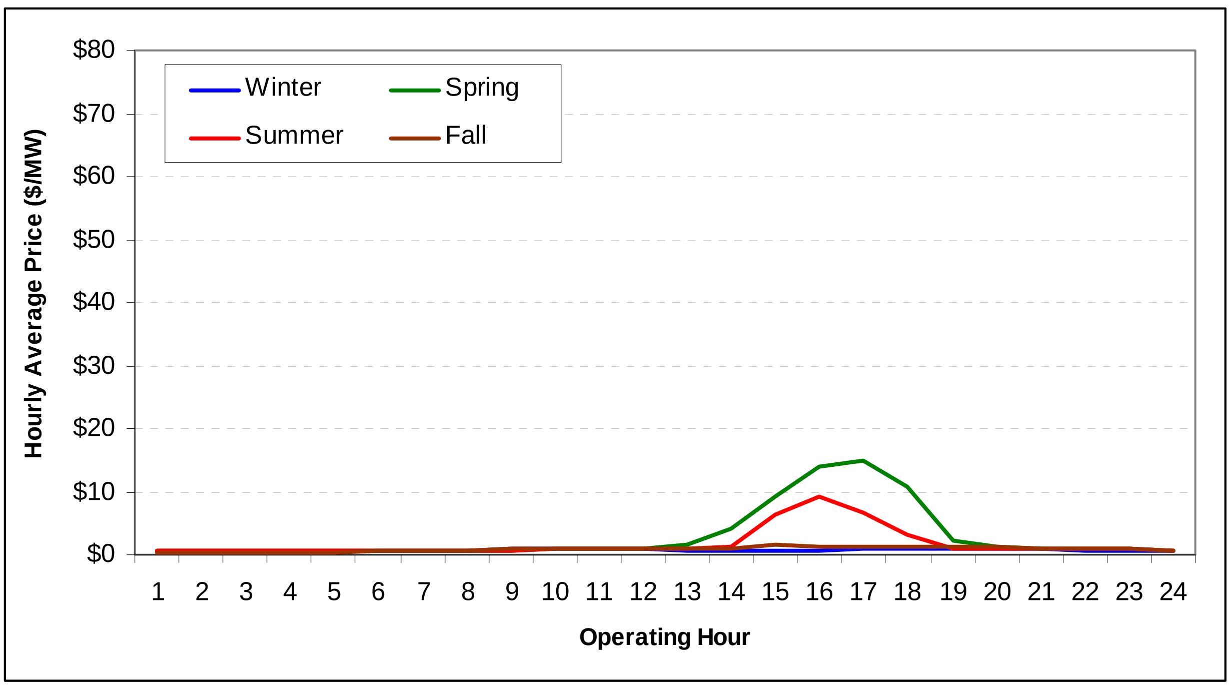


Figure 4.5 Hourly Average Operating Reserve Prices by Season (2008)
Spinning Reserve (Top) & Non-Spinning Reserve (Bottom)





The price duration curves for the A/S Day Ahead Market, shown in Figure 4.6 and Figure 4.7, reflect generally expected price behavior with the higher quality products exhibiting the highest sustained prices in general. Overall, Operating Reserve prices were at price levels above $25 in fewer than five percent of the operating hours in 2008, up from about two percent in the preceding year. At the same time the percentage hours with Regulation Reserve prices over $25 stayed at about ten percent in 2008, similar to what was observed in 2007.

Figure 4.6 Price Duration Curves for Regulation Reserve Markets (2008)

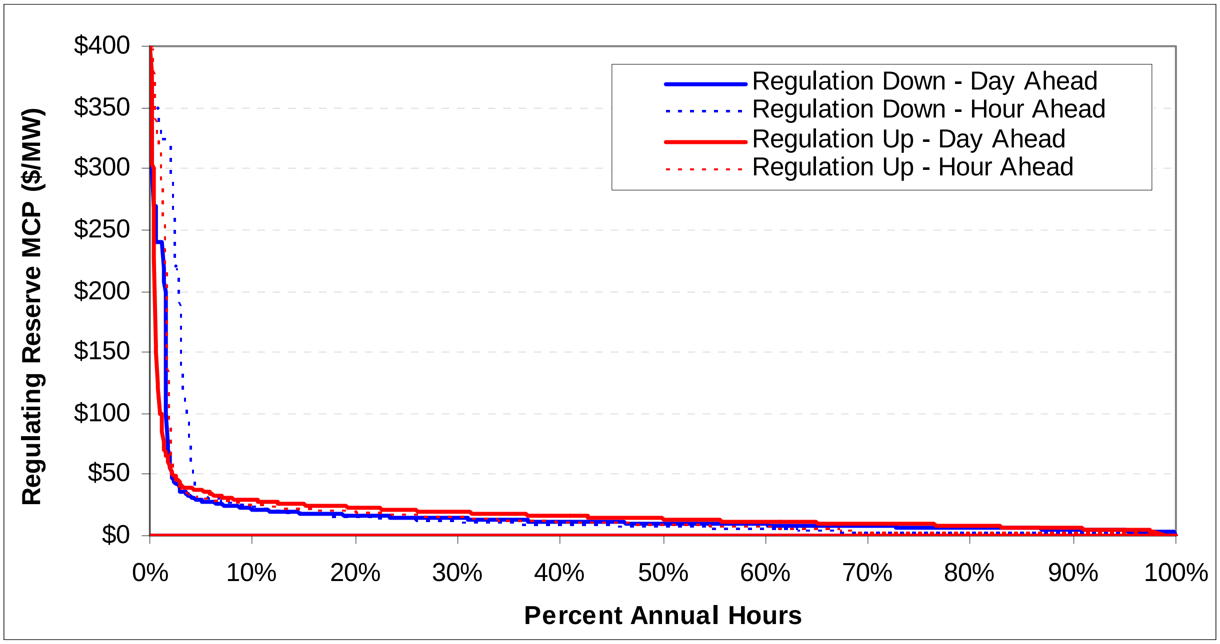
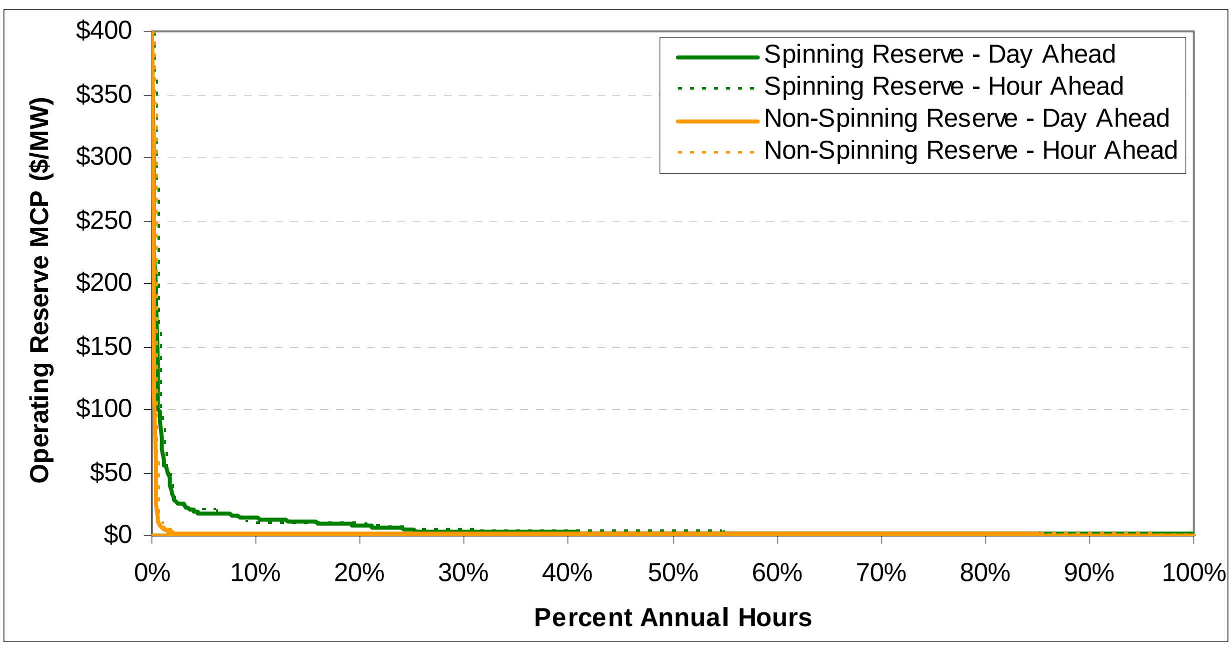


Figure 4.7 Price Duration Curves for Operating Reserve Markets (2008)

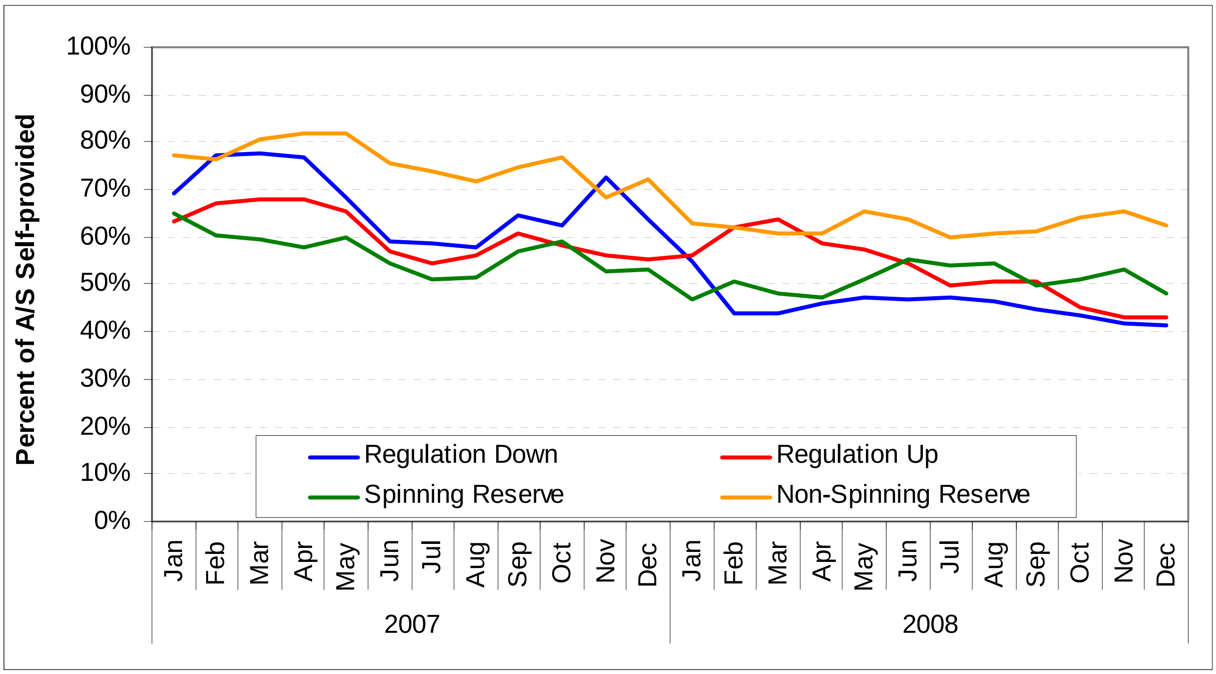


4.4 Ancillary Services Supply

4.4.1 Self-Provision of Ancillary Services

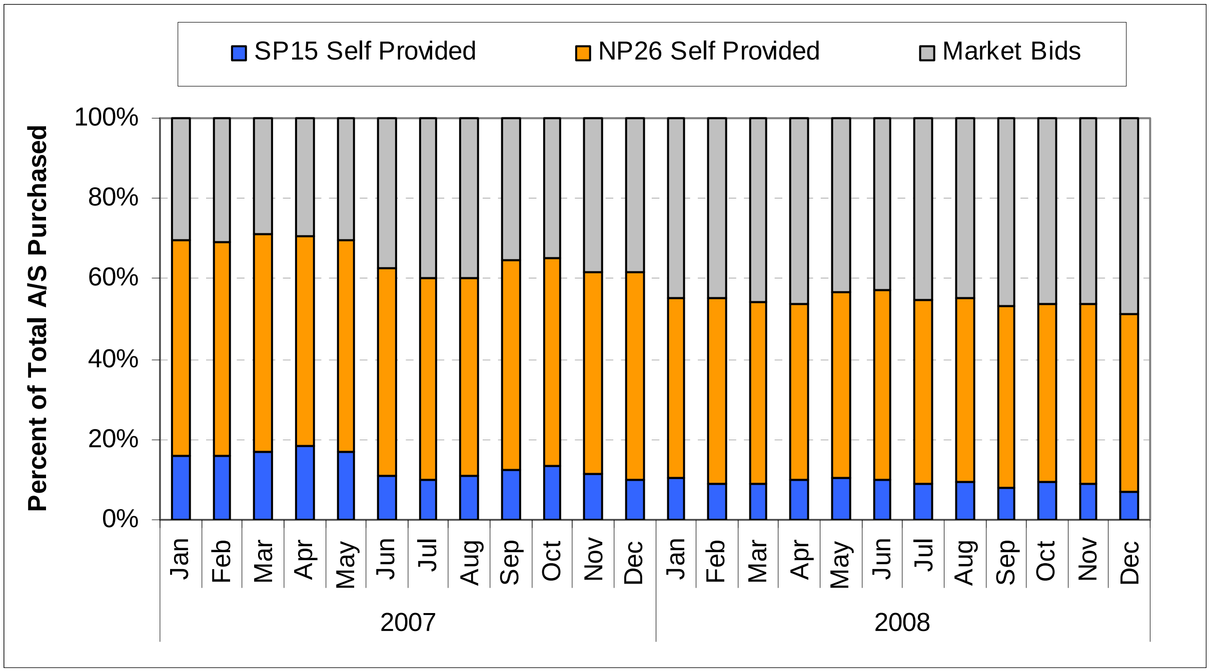
Self-provided ancillary services declined as a share of the total supply in 2008, ranging between 40 and 70 percent (Figure 4.8). Summer months exhibited a relatively lower percentage of self-provision of Regulation Up and Non-Spinning Reserve, while self provision of Regulation Down and Spinning Reserve increased.

Figure 4.8 Average Hourly Self-Provision of A/S



It is also interesting to view self-provision by zone. Figure 4.9 shows the breakout of total A/S procured by source (market bid, self-provided in NP26, and self-provided in SP15). During 2007 and 2008, the CAISO purchased A/S on a system-wide basis and did not practice zonal procurement. Consistent with this practice, the percentages shown in this figure are with respect to total system-wide A/S procurement. Note that hourly average self-provision in NP26 ranged from 43 percent to 47 percent during 2008 while the corresponding figure in SP15 was much lower, between 7 percent and 11 percent. The 2008 self-provision percentages in both NP26 and SP15 declined compared to 2007 levels. Typically, due to the distribution of load between the North and South, the calculated A/S requirement in SP15 is higher than that of NP26. Although not shown in this chapter, historically roughly 70 percent of A/S has been procured in NP26 with the remainder in SP15. However, as shown in Figure 4.9, combined procurement from resources in SP15 (procurement from market bids and self-provided A/S) is usually significantly lower than the calculated zonal A/S requirement. This disparity between the North and South is facilitated by transmission capability on Path 15 and Path 26, along which energy from A/S can be transferred from north-to-south to provide reliability support in the event of a contingency.

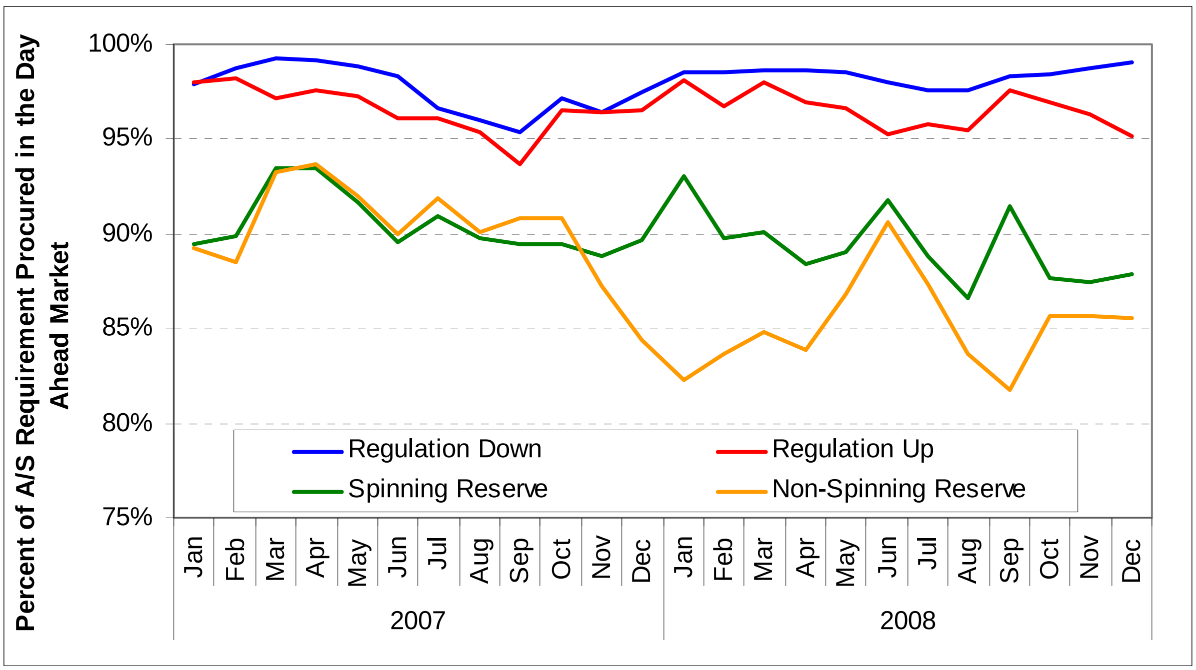
Figure 4.9 Average Hourly Self-Provision of A/S as a Percent of Total Procurement, by Zone, for All Services Combined



4.4.2 Day-ahead vs. Hour-ahead Procurement

The percent of Regulating Reserves requirement procured in the Day Ahead Market remained relatively stable between 95 percent and 100 percent, while the day-ahead procurement of Operating Reserves declined compared to 2007, especially Non-Spinning Reserve, which was below 85 percent for most of the year (Figure 4.10).

Figure 4.10 Hourly Average Day-Ahead Procurement



4.4.3 Bid Sufficiency

Bid insufficiency occurs when there is not enough available capacity bid into the markets to meet the procurement requirements. In addition to potentially creating reliability issues, bid insufficiency in the A/S markets can result in market power concerns as essentially any supplier to the A/S market in bid deficient hours is pivotal. Additionally, market power concerns can arise if bid sufficiency exists but only marginally so. In these cases, certain suppliers may also be pivotal in the sense that the A/S requirements could not be met absent their supply. The CAISO employs several measures of bid sufficiency. Volumes of capacity shortages convey information about the magnitude of the deficiency events and the count of operating hours where bid-in capacity falls short of requirements represent commonly used metrics that provide insight into the frequency and severity of shortage events. Table 4.2 provides these two metrics for the past two operating years.

Table 4.2 Ancillary Service Bid Insufficiency[25]

	Number of Hours With Shortage				
	Regulation Down	Regulation Up	Spinning Reserve	Non-Spinning Reserve	All Services
2007	20	11	35	36	102
2008	5	62	45	30	142
Percent ∆	-75%	464%	29%	-17%	39%

	Average Percent of Requirement Short				
	Regulation Down	Regulation Up	Spinning Reserve	Non-Spinning Reserve	All Services
2007	15%	7%	6%	8%	8%
2008	9%	14%	4%	7%	7%

The change in frequency of bid insufficiency from 2007 to 2008 was mixed across services, with Regulation Down and Non-Spinning Reserve less frequent and Regulation Up and Spinning Reserve more frequent. Overall, the average percent of requirement that was short in hours of insufficiency was relatively low and for all services combined roughly the same in 2008 as in 2007. The following figures (Figure 4.11 through Figure 4.14) show the frequency of hourly bid deficiencies and the average amount of deficiency (expressed as a percentage of the total requirement) by month and by service, for the past two years.

[25] The figures in this table in the Annual Report on 2007 Market Issues and Performance for Regulation Up and Regulation Down were mistakenly reversed. The figures shown for Regulation Up should have been placed in the Regulation Down column and vice versa.

Figure 4.11 Frequency of Bid Insufficiency in the Hour-Ahead Market and Average Capacity Short – Regulation Down

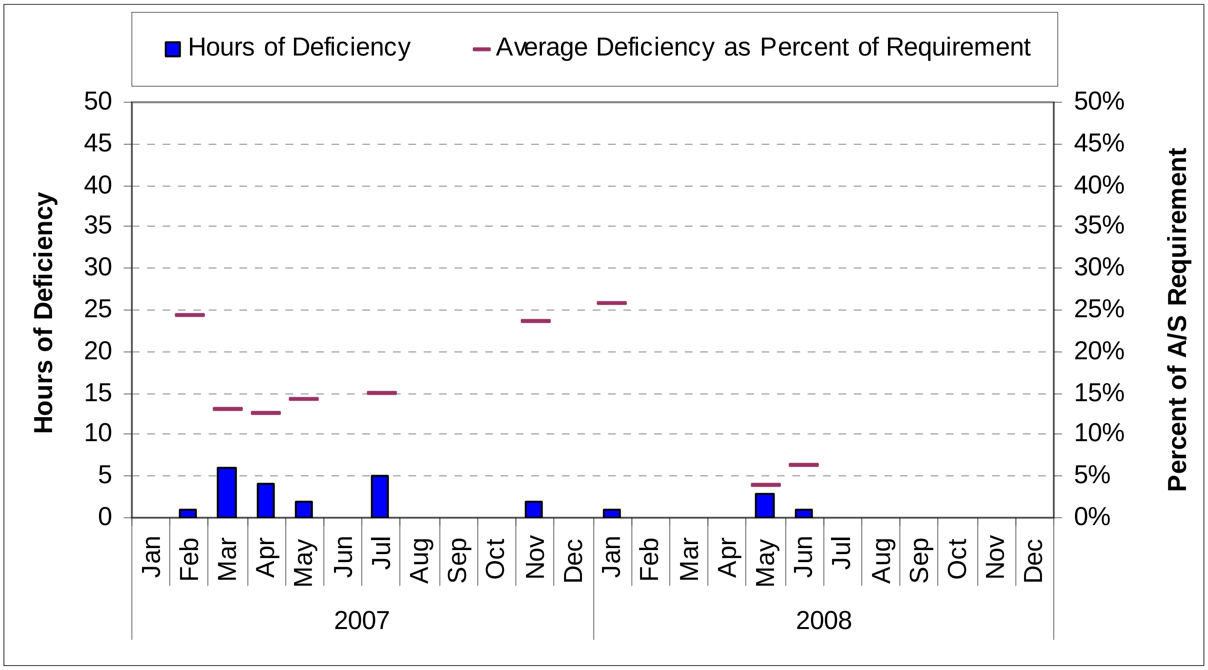


Figure 4.12 Frequency of Bid Insufficiency in the Hour-Ahead Market and Average Capacity Short – Regulation Up

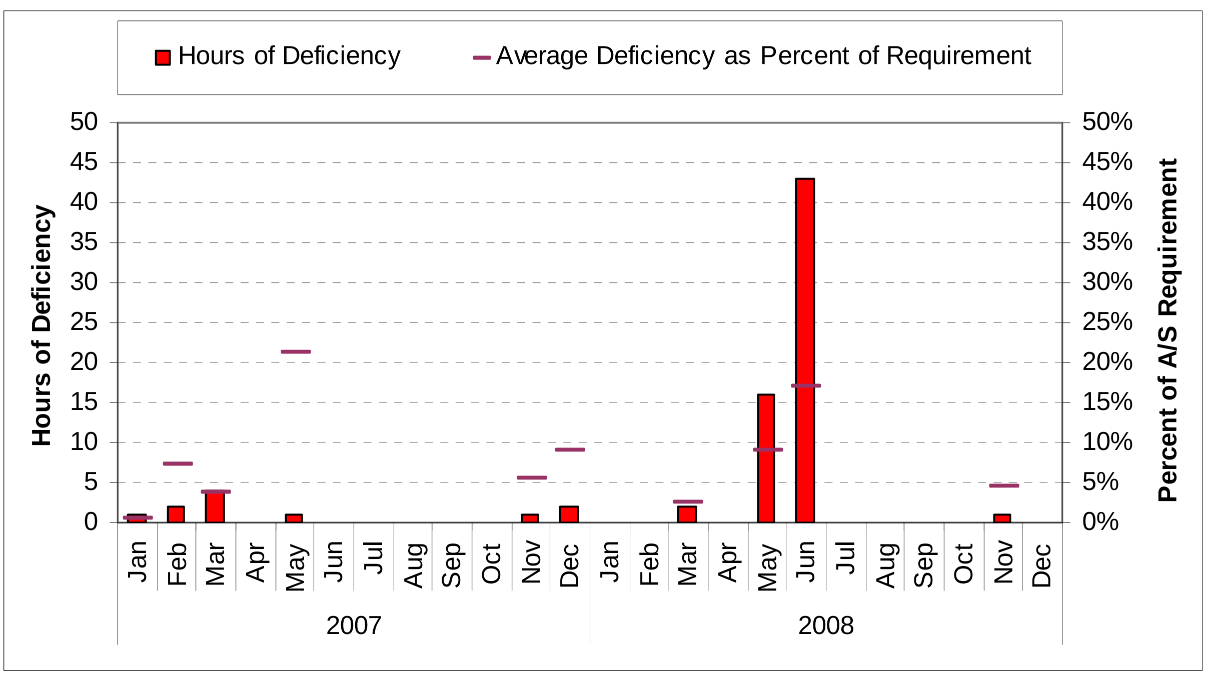


Figure 4.13 Frequency of Bid Insufficiency in the Hour-Ahead Market and Average Capacity Short – Spinning Reserve

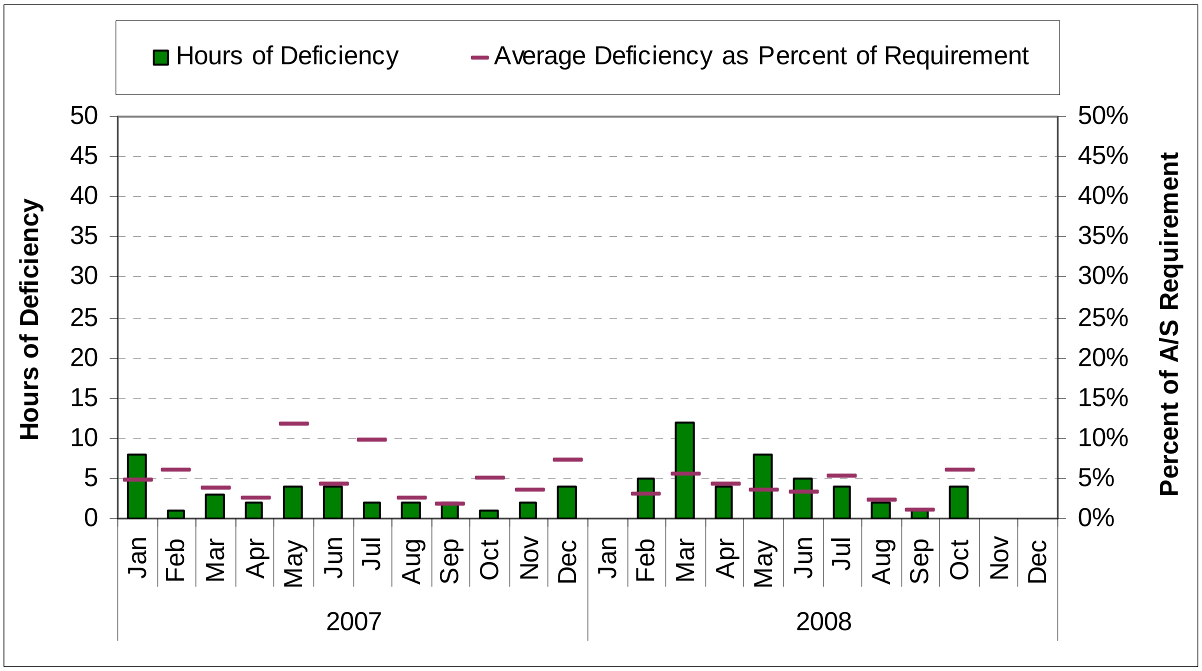
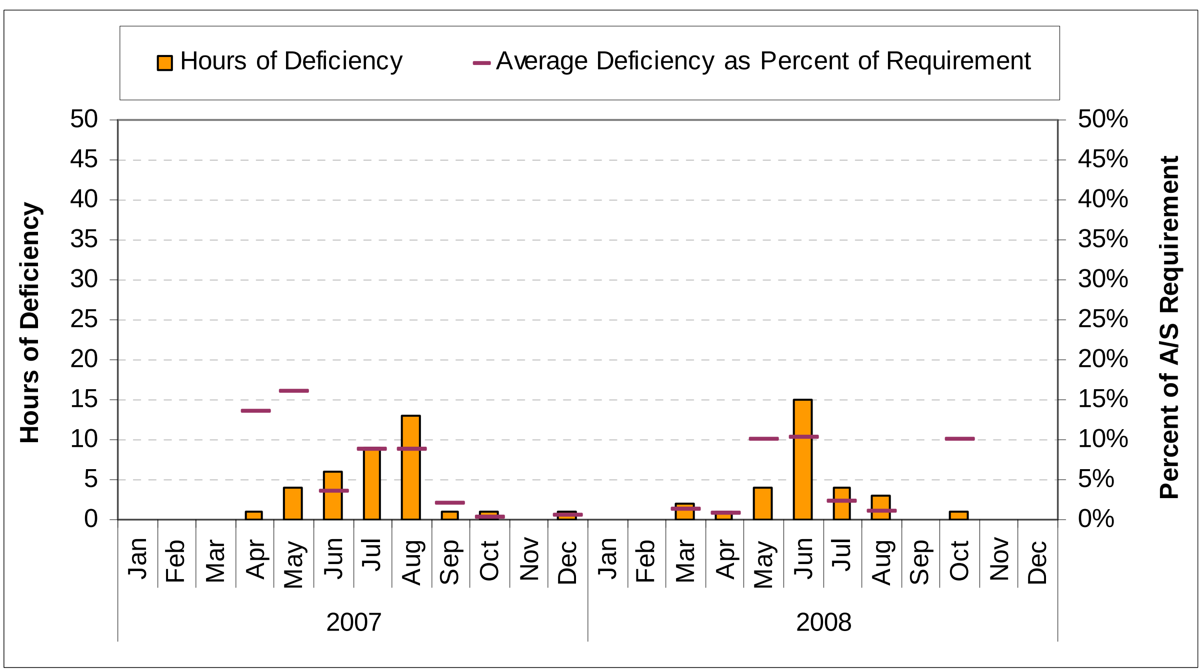


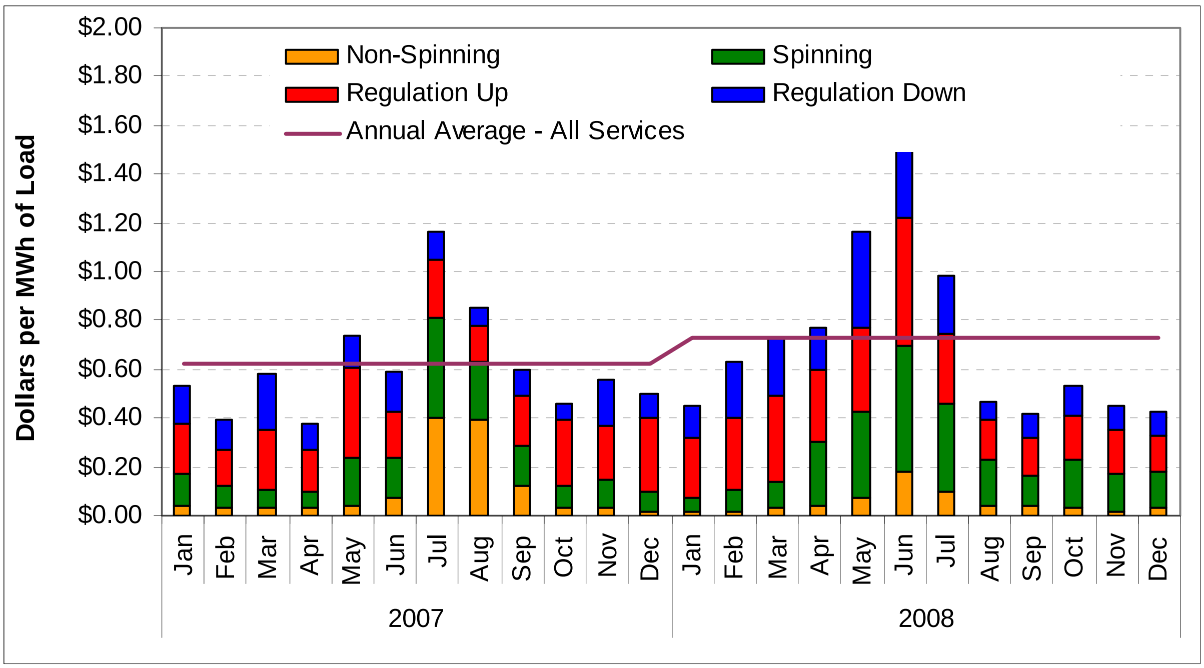
Figure 4.14 Frequency of Bid Insufficiency in the Hour-Ahead Market and Average Capacity Short – Non-Spinning Reserve



4.5 Costs

The total cost of A/S capacity per unit of MWh load increased in 2008 compared to 2007. The A/S procurement cost to load in 2008 averaged $0.73/MWh, which is 16 percent higher than the $0.63/MWh average the year before. Figure 4.15 provides the monthly details on these costs. With the exception of April through July, all monthly total cost of A/S capacity per unit of MWh load remained under $1.00/MWh in 2008.

Figure 4.15 Monthly Cost of A/S per MWh of Load



5 Inter-Zonal Congestion Management Markets

5.1 Inter-Zonal Congestion Management

Congestion occurs when the physical limits of a line, or inter-tie, prohibit load from being served with the least cost energy. The current zonal market distinguishes between inter- and intra-zonal congestion. Inter-zonal congestion refers to congestion that occurs between zones; intra-zonal congestion refers to congestion within a zone, which is discussed in the next chapter. Inter-zonal congestion is managed in forward markets on major inter-ties and two large internal paths (Path 15 and Path 26). Scheduling Coordinators (SCs) submit adjustment bids, which are dispatched to alleviate congestion while maintaining a balanced portfolio and minimizing congestion charges. The marginal adjustment bid dispatched to relieve congestion sets the congestion charge on the interface for the given period. Each SC pays a congestion charge depending on scheduled, accepted flows on the congested interface to the CAISO, which is then distributed back to holders of Firm Transmission Rights (FTRs) and Transmission Owners (TOs).

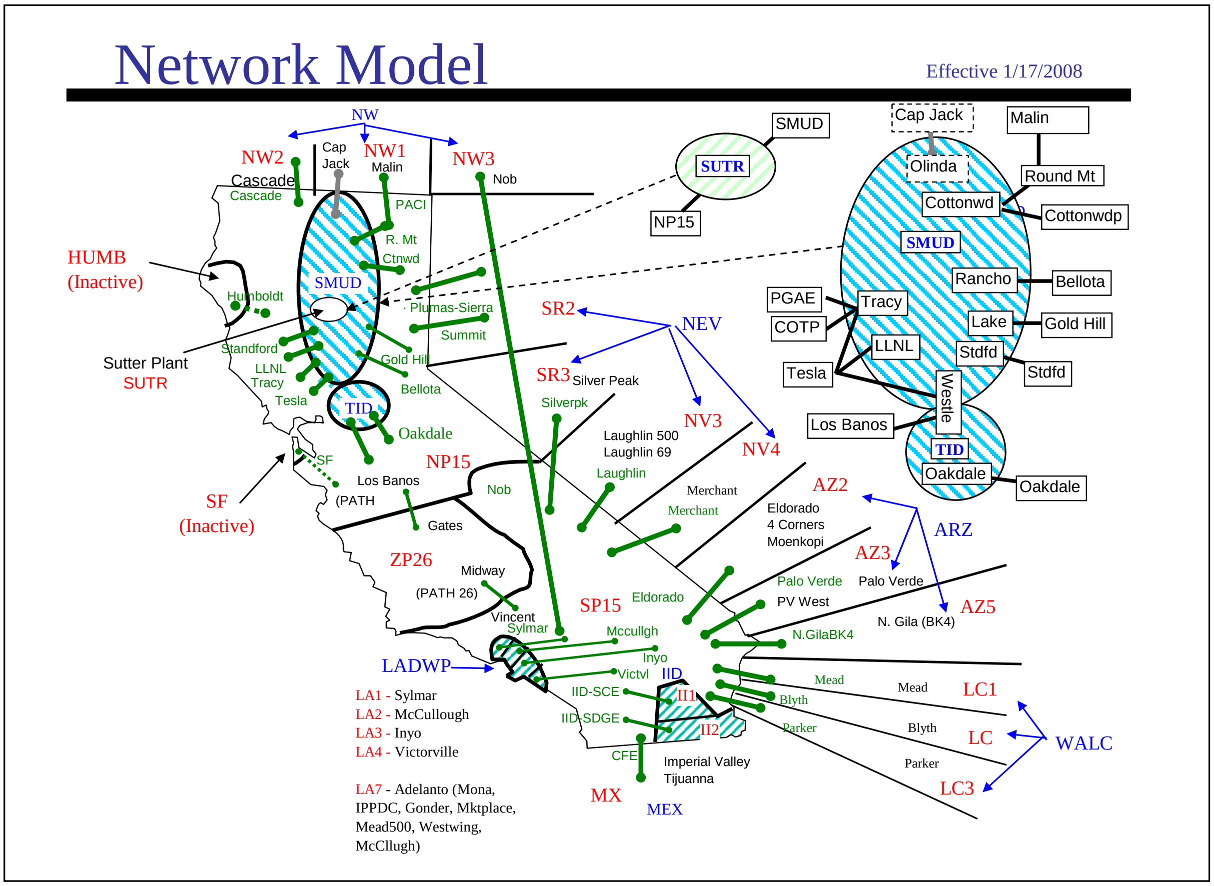
Congestion in 2008 increased in frequency and charges among almost all branch groups and inter-ties from 2007. The increase in congestion frequency and charges system-wide is mostly attributed to high north-to-south flows during the spring and early summer months coupled with transmission outages throughout the year and a few distinct events in the fall. Total congestion charges increased from $85 million in 2007 to $176 million in 2008, the first year since 2001 with charges over $100 million. The Pacific AC Inter-tie (PACI) and Pacific DC Inter-tie (PDCI or Nevada-Oregon Border (NOB) as referred to in the tables) branch groups had the highest congestion charges, each accounting for 21 percent of total charges; June was the most costly month in 2008 at near $53 million. The most frequently congested paths in 2008 were the IPP (DC)-Adelanto (IPPDCADLN) and Mead inter-ties, each at 32 percent of total annual hours. The spring and early summer months' congestion charges were concentrated on PACI and NOB as hydro electricity was imported from the Northwest to meet California load. The pattern of congestion transitioned to Palo Verde and Path 15 in the winter and fall months as Northwest hydro went into the re-charge season and California shifted to rely more heavily on gas, nuclear, and coal generation from the Southwest.

Scheduling Coordinators can own FTRs to mitigate congestion charges they incur during the year. A FTR is both a financial instrument and a physical right to transmission. On the financial side, owners share in the distribution of Usage Charge revenues received by the CAISO due to inter-zonal congestion during the period for which the FTR was issued. The physical right is the priority given to FTR holders when scheduling energy across congested interfaces. FTRs are distributed to SCs through assignment, auction, secondary sales or trades, and transfers. Total revenues from the 2008-2009 FTR primary auction was $102 million, a 16 percent decrease from the 2007-2008 FTR primary auction.

5.1.1 Overview

Under the current zonal model, the CAISO manages congestion in the forward market only on major inter-ties and two large internal paths (Path 15 and Path 26). It uses adjustment bids to mitigate congestion while minimizing the cost of schedule adjustments and keeping each SC's schedule in balance. The marginal SC establishes the usage charge for the inter-zonal interface. All SCs pay this charge based on their accepted, scheduled flow on the interface. The CAISO pays the net amount of congestion charges it collects to the Transmission Owners (TOs) and owners of FTRs. Figure 5.1 shows the active congestion zones and major inter-zonal pathways (branch groups) in the CAISO grid effective by January 17, 2008. There were no operational changes in 2008.

Figure 5.1 Active Congestion Zones and Branch Group



Total inter-zonal congestion charges for the Day Ahead and Hour Ahead Markets in 2008 were $176 million, which is roughly double the 2007 total. Table 5.1 shows the historical annual total inter-zonal congestion charges since the year 2001. The majority of 2008 inter-zonal congestion charges (72 percent) can be attributed to 4 branch groups (PACI, NOB, Palo Verde and Path 15), with PACI and NOB constituting the largest share. The next section provides a more detailed breakdown of congestion frequency and charges by individual branch group.

Table 5.1 Historical Inter-Zonal Congestion Charges

Year	Total Inter-Zonal Congestion Charges ($ M)
2001	$107
2002	$42
2003	$26
2004	$56
2005	$55
2006	$56
2007	$85
2008	$176

5.1.2 Inter-Zonal Congestion Frequency and Magnitude

This section summarizes frequencies and average congestion charges for major inter-zonal interfaces (branch groups) in 2008. Table 5.2 shows annual congestion frequencies and average congestion charges by branch group, direction (import or export), and market type (day-ahead or hour-ahead). The frequency of congestion in 2008 was highest on several of the main branch groups between the CAISO and neighboring control areas outside California. In the Day Ahead Market, the Mead, Palo Verde, Eldorado, Adelanto, Parker, Blythe, NOB, PACI, and the IPP(DC)-Adelanto branch groups all were congested in at least 10 percent of hours. In the Hour Ahead Market, the Mead, Palo Verde, Eldorado, PACI, and NOB branch groups were also congested in at least 10 percent of hours. The most frequently congested branch groups in 2008 were the Mead branch group and the IPP(DC)-Adelanto branch group, each at 32 percent in the Day Ahead Market, up from 10 percent and 29 percent respectively in 2007. Mead and PACI were also congested 20 and 19 percent of hours, respectively, in the Hour Ahead Market in 2008, with all of the congestion in the import direction.

Higher congestion costs on PACI and NOB in 2008 are attributed to a combination of very favorable hydro conditions in the Pacific Northwest and unfavorable hydro conditions in California coupled with very high natural gas prices. With limited hydroelectric supplies within California and the high cost of natural gas, imported power from the Pacific Northwest was very attractive, resulting in high north-to-south flows across PACI and NOB into the CAISO Control Area during the spring and early summer months and high congestion usage charges. Congestion usage charges on PACI averaged $10/MWh in the Day Ahead Market and $57/MWh in the Hour Ahead Market (compared to $3/MWh and $17/MWh, respectively, in 2007). Similar price changes were observed on the Pacific DC (NOB) branch group. On June 29th PACI was sharply derated due to wildfires burning in its vicinity. This derate occurred during the weekend when scheduling coordinators were unable to re-route their import schedules from other resources, which resulted in almost $6 million in congestion costs.

Average day-ahead congestion charges on two major Southwest branch groups (Palo Verde and Eldorado) were comparable to the Northwest, averaging $5/MWh and $14/MWh, respectively. The increased congestion on Eldorado branch group was mostly due to a month-long scheduled outage from mid-November to mid-December. Congestion frequency on the Mead branch group in the Day Ahead Market increased significantly from 18 percent in 2007 to 32 percent in 2008, which occurred mostly during October and December. Congestion frequency on the Parker branch group in the Day Ahead Market increased significantly from 8 percent in 2007 to 15 percent in 2008. Congestion frequency on Path 15 in the Day Ahead Market increased to 5 percent in 2008 compared with 0 percent in 2007. The congestion mostly occurred in March, October, November and December as a result of forced and planned outages.

Table 5.2 Inter-Zonal Congestion Frequencies (2008)[26]

	Day-Ahead Market				Hour-ahead Market			
	Percentage of Congested Hours (%)		Average Congestion Price ($/MWh)		Percentage of Congested Hours(%)		Average Congestion Price ($/MWh)	
Branch Group	Import	Export	Import	Export	Import	Export	Import	Export
ADLANTOSP	16	0	$3	$0	3	0	$48	$0
BLYTHE	11	0	$12	$0	1	0	$60	$0
CASCADE	0	0	$0	$0	0	0	$3	$8
ELDORADO	18	0	$14	$0	10	0	$24	$0
GONDIPPDC	0	0	$0	$0	0	0	$5	$66
IID-SCE	1	0	$5	$0	0	0	$11	$0
IID-SDGE	0	0	$0	$0	0	0	$0	$0
IPPDCADLN	32	0	$8	$0	5	0	$64	$0
MEAD	32	0	$4	$0	20	0	$11	$0
MERCHANT	3	0	$1	$0	2	0	$6	$0
MKTPCADLN	4	0	$4	$0	1	0	$55	$0
MONAIPPDC	1	1	$0	$0	0	1	$52	$57
NOB	20	1	$15	$1	15	1	$63	$25
PACI	26	0	$10	$0	19	0	$57	$0
PALOVRDE	30	0	$5	$0	11	0	$18	$0
PARKER	15	0	$22	$0	1	0	$85	$0
PATH15	5	0	$19	$0	2	0	$20	$0
PATH26	0	0	$0	$0	0	0	$0	$40
SILVERPK	1	0	$0	$0	1	0	$18	$0
SUMMIT	3	0	$8	$0	2	0	$50	$41
TRACYCOTP	3	0	$4	$30	1	0	$10	$0
WSTWGMEAD	4	0	$8	$0	1	0	$34	$0

5.1.3 *Inter-Zonal Congestion Usage Charges and Revenues*

Table 5.1 shows the total annual congestion charges for the major CAISO branch groups in 2008. Total congestion charges system-wide of $176 million represents a 108 percent increase above the 2007 total. Forty two (42) percent of total congestion charges were incurred on the Pacific AC Inter-tie (PACI) and the Pacific DC Inter-tie (PDCI, or NOB); each 21 percent, all in the import direction, compared to 18 and 14 percent of total congestion charges incurred in 2007. Another 15 percent was incurred on the Path 15 (south-to-north direction) and another 15 percent on the Palo Verde (import direction) branch groups, compared to the 3 percent and 25 percent respectively in 2007. Though Palo Verde had $4.9 million in higher congestion costs in 2008, its share of total congestion charges declined. Other branch groups with significant increases in congestion charges over 2007 include: the Eldorado branch group with a 65 percent increase; the IPP(DC)-to-Adelanto (IPPDCADLN) branch group with an 80 percent

[26] In all tables, north-to-south congestion on Path 26 and Path 15 is represented as “Exports” and south-to-north congestion on these paths is represented as “Imports”.

increase; the Mead branch group with more than a 50 percent increase; and finally the Parker branch group with congestion charges three times higher than congestion charges in 2007. The branch groups that experienced a decline in congestion charges from 2007 were Market Place-Adelanto (MKTPCADLN) and Path 26, which decreased by 83 percent and 97 percent, respectively.

Table 5.3 Inter-Zonal Congestion Charges (2008)

Branch Group	Day-ahead		Hour-ahead		Total Congestion Charges		Total Congestion Charges		Total Congestion Charges	Total Charges Percent
	Import	Export	Import	Export	Import	Export	Day-ahead	Hour-ahead		
ADLANTOSP	$3,103,048	$0	$101,175	$0	$3,204,223	$0	$3,103,048	$101,175	$3,204,223	2%
BLYTHE	$2,107,804	$30	$44,663	$0	$2,152,467	$30	$2,107,834	$44,663	$2,152,497	1%
CASCADE	$0	$0	$1,305	$1,499	$1,305	$1,499	$0	$2,804	$2,804	0%
ELDORADO	$15,233,808	$0	$236,869	$0	$15,470,677	$0	$15,233,808	$236,869	$15,470,677	9%
GONDIPPDC	$0	$0	$15	$4,749	$15	$4,749	$0	$4,764	$4,764	0%
IID-SCE	$187,539	$0	$468	$0	$188,007	$0	$187,539	$468	$188,007	0%
IID-SDGE	$43	$0	$4	$0	$47	$0	$43	$4	$47	0%
IPPDCADLN	$14,711,883	$0	$55,107	$0	$14,766,990	$0	$14,711,883	$55,107	$14,766,990	8%
MEAD	$7,041,184	$0	$281,717	$0	$7,322,901	$0	$7,041,184	$281,717	$7,322,901	4%
MERCHANT	$158,567	$0	$44,657	$0	$203,223	$0	$158,567	$44,657	$203,223	0%
MKTPCADLN	$529,389	$0	$43,101	$0	$572,490	$0	$529,389	$43,101	$572,490	0%
MONAIPPDC	$998	$11	$1,635	$47,256	$2,633	$47,267	$1,009	$48,891	$49,899	0%
NOB	$37,392,658	$53,327	-$525,537	$46,408	$36,867,121	$99,735	$37,445,986	-$479,129	$36,966,856	21%
PACI	$40,320,811	$0	-$2,563,499	$0	$37,757,312	$0	$40,320,811	-$2,563,499	$37,757,312	21%
PALOVRDE	$26,193,624	$0	$326,458	$0	$26,520,082	$0	$26,193,624	$326,458	$26,520,082	15%
PARKER	$4,013,738	$0	$25,369	$0	$4,039,106	$0	$4,013,738	$25,369	$4,039,106	2%
PATH15	$25,920,668	$0	$130,969	$0	$26,051,637	$0	$25,920,668	$130,969	$26,051,637	15%
PATH26	$0	$0	$0	$43,826	$0	$43,826	$0	$43,826	$43,826	0%
SILVERPK	$506	$0	$3,040	$0	$3,545	$0	$506	$3,040	$3,545	0%
SUMMIT	$27,165	$0	$29,389	$7,008	$56,554	$7,008	$27,165	$36,398	$63,563	0%
SYLMAR-AC	$0	$0	$0	$17,306	$0	$17,306	$0	$17,306	$17,306	0%
TRACYCOTP	$28,073	$18,967	$14,710	-$18,967	$42,783	$0	$47,040	-$4,257	$42,783	0%
WSTWGMEAD	$379,727	$0	$2,933	$0	$382,660	$0	$379,727	$2,933	$382,660	0%
Total	**$177,351,231**	**$72,335**	**-$1,745,453**	**$149,085**	**$175,605,778**	**$221,421**	**$177,423,567**	**-$1,596,368**	**$175,827,199**	**100%**

Exports from the CAISO Control Area resulted in only $177,600 in congestion charges – 56 percent of which was on NOB and 27 percent on Mona-IPP (DC) branch group, which connects to the Intermountain Power Project and is physically located in Utah.

The hour-ahead congestion typically occurs when SCs make adjustments to their day-ahead schedules or as the result of changes in line ratings after the closure of the Day Ahead Market. Only incremental schedule changes in the Hour Ahead Markets are subject to hour-ahead congestion charges. Thus, the volume of transactions in the Hour Ahead Market is much lower than that in the Day Ahead Market.

Significant Transmission Events

There were several significant transmission events, forced outages, and scheduled outages that contributed to congestion charges on one or more major inter-ties or internal paths. Following is a brief description of selected major events that may have had a significant impact on congestion charges.

YAVAPAI-WESTWING 500kV line de-energized for scheduled work on January 22nd to January 24th, which led to heavy congestion on the Palo Verde and El Dorado branch groups.

Palo Verde-Devers 500kV line was out for scheduled work on February 2nd. The outage de-rated all Southwest inter-ties, which could have contributed to almost $1 million in congestion charges on Palo Verde on that day.

DIABLO-GATES #1 500kV was cleared for scheduled work from March 13th to March 23rd, de-rating Path 15 by almost 2,500 MW north-to-south. The outage led to the heavy congestion on Path 15 throughout these days.

Imperial Valley-Miguel 500kV line was cleared for scheduled work on April 12 and 13. The Pale Verde branch group was de-rated and heavily congested as a result of this outage, which resulted in high congestion costs on the Pale Verde branch group during these two days.

Round Mountain-Table Mountain #1and #2 500kV Series Capacitors were forced out of service on June 26 and 27 respectively due to wild fires. As a result, PACI was severely de-rated. Even though the lines were returned to service on late June 28, the CAISO de-rate remained in effect for the rest of the next two days due to the fires in the area. The total congestion costs on PACI reached $8.6 million from June 27th until June 30th, possibly due to the de-rate on PACI coupled with favorable hydro conditions in the Pacific Northwest.

LUGO-MIRA LOMA #2 and #3 500kV lines relayed on June 23rd, due to fires reported outside of Lugo substation. The de-rate on the lines led to the intra-zonal congestion at South of Lugo for several hours in the afternoon. However, the lines were restored later that day.

Diablo Canyon #2 Nuclear Power Unit tripped in the early minutes of Sunday, August 17th, while carrying 1,137 MW. The unit was offline till September 6th. During this period, the outage of Diablo Canyon #2, combined with other factors, resulted in flows in excess of the Victorville-Lugo nomogram (T-135).

SONGS unit #3 came offline in the afternoon of September 1st, due to problems with B Train diesel generator. This outage led to the loss of 1,100 MW of generation capacity. The unit came back on September 13.

PALO VERDE 500kV CB 998 was forced out on August 27th, and caused heavy congestion on Victorville-Lugo throughout that day and the following day. High congestion costs were observed on August 27 and 28.

McCullough-Victorville #2 500kV line, the Perkins-Mead 500kV line, and the Victorville-Rinaldi 500kV line were out of service on September 6, causing de-rates on Palo Verde and IPPDCADLN, which created heavy congestion.

DIABLO-GATES #1 500kV line cleared for a forced outage on September 12. The outage de-rated Path 15 in the Day Ahead Market for September 13 which led to high congestion costs on that day. The line was restored on the evening of September 13.

Los Banos-Midway #2 500kV line was out on October 13th for a scheduled service. The congestion costs on Path 15 spiked to $4 million on that day, possibly as a result of this outage. This line was subsequently taken fully out of service for scheduled work from October 14th through November 7th, contributing to consistent congestion costs on Path 15 for during this time.

Eldorado-Moenkopi 500 kV and Yavapai-Westwing 500 kV lines de-energized on November 12th for scheduled work, de-rating the Palo Verde tie, East of River, and West of River transfer capabilities. On that day high congestion costs were observed on the Palo Verde, Eldorado and IPPDCADLN branch groups. Yavapai-Westwing 500 kV line was not available until December 20th.

Celilo-Sylmar 1,000 kV line was out of service for maintenance work from October 5 to October 25, de-rating PDCI. The transfer capabilities of PDCI ranged from 570 MW to 0 MW during this period. From October 19 to October 25, the line was completely out for annual service. Again, starting November 15, Celilo-Sylmar 1,000 kV line was forced out due to fire in the area which made PDCI unavailable. The PDCI was restored to full capacity by December 8.

Sylmar Station was damaged by the Sayre fire which started on November 13. The fire started inside the Sylmar converter station and caused multiple transmission outages, including the PDCI, which was already de-energized, and all the lines emerging from the Sylmar station, mostly serving LADWP. The repair was completed on November 26th.

Significant Changes in Congestion Cost

Due to the major transmission events and other system conditions (e.g., hydroelectric availability, regional energy demands), congestion charges on almost all major inter-ties and paths increased from 2007. Figure 5.2 compares congestion charges in 2007 and 2008 on selected major paths. Congestion charges increased on the Pacific AC Inter-tie (PACI) and the Pacific DC Inter-tie (NOB), which was due to a combination of very favorable hydro conditions in the Pacific Northwest and unfavorable hydro conditions in California coupled with very high natural gas prices. With limited hydroelectric supplies within California and the high cost of natural gas, imported power from the Pacific Northwest was very attractive, resulting in high north-to-south flows across PACI and NOB into the CAISO Control Area during the spring and early summer months and high congestion usage charges. Congestion charges also increased sharply on Path 15, due primarily to a planned outage of the Los Banos-Midway #2 500kV line from October 13th through November 7th. Congestion charges on the Mead, Eldorado, Palo Verde and IPPDCADLN branch groups were higher in 2008 as well. Mead was congested heavily on October 13th, most of which can be attributed to the outage of other transmission lines on that day. High congestion costs on the Eldorado, Palo Verde and IPPDCADLN branch groups were driven by scheduled maintenance, outages, and over-scheduling, as discussed below.

Figure 5.3 shows the seasonal pattern of congestion charges on major paths. High monthly congestion charges on several of the branch groups correspond with the timing of several major transmission events previously discussed. The highest cost month was June, due primarily to high north-to-south congestion on PACI and NOB. Total congestion cost for June was approximately $53 million, almost as much as the total annual congestion costs for all of 2007. October through December also had notably high congestion charges on Path 15, Palo Verde and Eldorado, primarily due to the transmission de-rates, and increased reliance on Southwest imports. Following is a brief discussion of events that led to increased congestion charges by branch group.

Figure 5.2 Congestion Charges on Selected Paths (2007 vs. 2008)

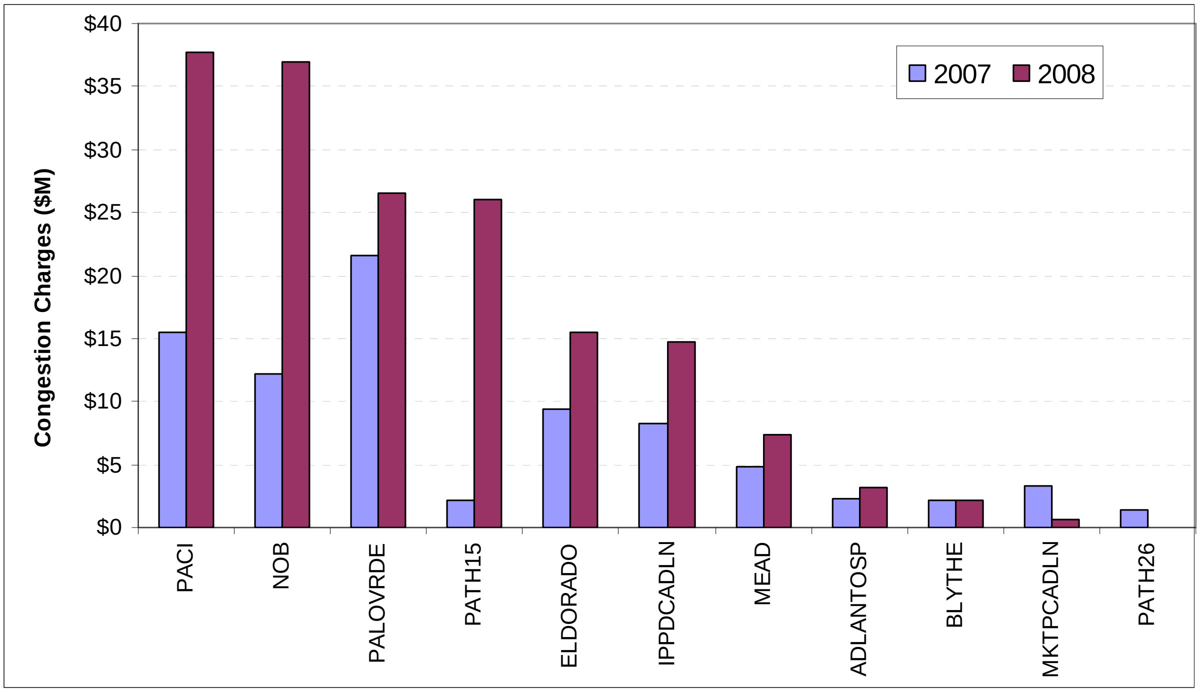
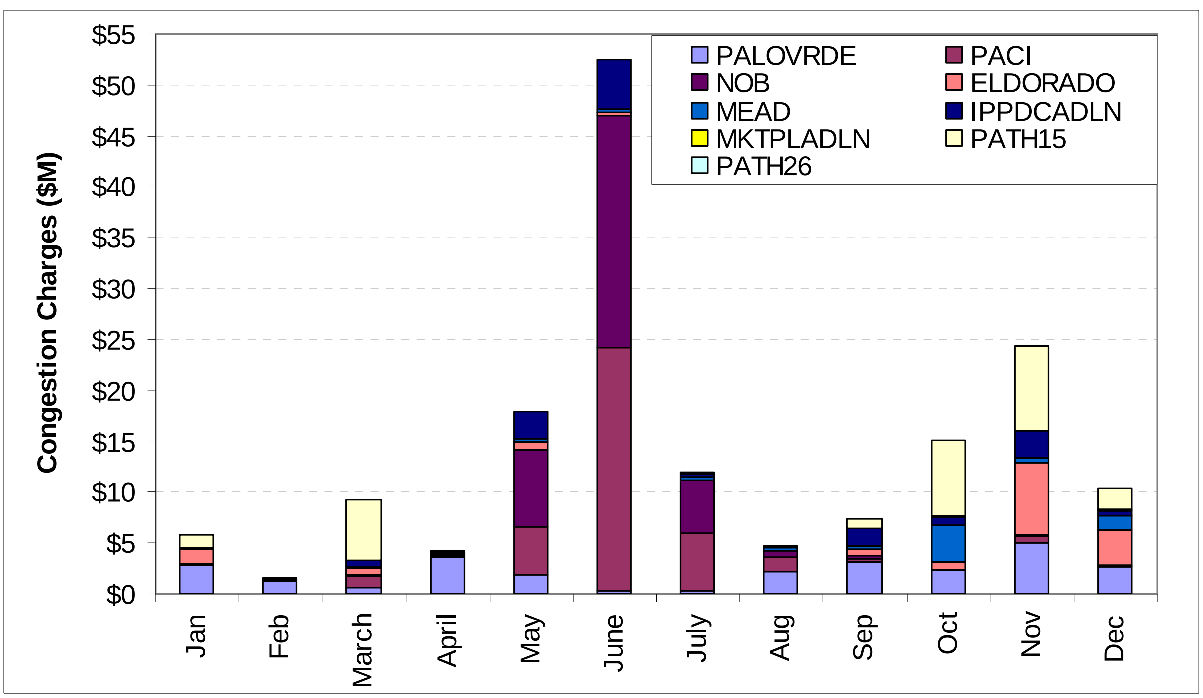


Figure 5.3 Monthly Congestion Charges on Selected Major Paths (2008)



Pacific AC Inter-tie (PACI) congestion charges increased $22.3 million from 2007, most of which can be attributed to high north-to-south flows motivated by the cheap hydro power during May, June and July due to a higher than usual snow fall and a delayed spring runoff. On June 29th PACI was sharply de-rated due to wildfires burning in its vicinity. This de-rate occurred during the weekend when scheduling coordinators were unable to re-route their import schedules from other resources, resulting in almost $6 million in congestion costs.

Pacific DC Inter-tie (PDCI or NOB as in the table) congestion charges nearly tripled from 2007, reaching $37 million, most of which occurred during the late spring and early summer months. Congestion charges can be attributed almost entirely to competition amongst in-state importers for inexpensive hydro power from the Pacific Northwest.

Path 15 congestion charges increased sharply in 2008 by $23.9 million from 2007 reaching $26 million, most of which can be attributed to planned outages in October and November. On October 13th congestion costs on Path 15 spiked to about $4 million due to the planned outage of the Los Banos-Midway #2 500kV line. The Los Banos-Midway #2 500kV line was subsequently taken fully out of service for scheduled work from October 14th through November 7th contributing to consistent congestion costs on Path 15 during these two months. On November 3rd congestion costs on Path 15 jumped to around $6.7 million. On this day in the Day Ahead Market, the path was uncharacteristically overscheduled by over 1,000 MW resulting in high congestion prices for several hours of the day.

Eldorado congestion charges increased to $15.5 million from $9.4 million in 2007, most of which was incurred during the last two months of the year. Eldorado-Moenkopi 500 kV line was de-rated for most of November and December, which led to the de-rate of the Eldorado branch group. The $1.5 million in congestion charges which were incurred from January 22nd to 24th was the result of the Eldorado branch group de-rate for scheduled maintenance on the Yavapai-Westwing 500 kV line.

Intermountain Power Project DC to Adelanto (IPPDCADLN) congestion charges reached $14.6 million in 2008, nearly $6.5 million higher than previous year. More than one third of the congestion charges occurred in June, which was driven by over-scheduling.

5.2 Firm Transmission Rights Market Performance

A Firm Transmission Right (FTR) is a right that has both financial and physical transmission right attributes. FTRs entitle their owners to share in the distribution of Usage Charge revenues received by the CAISO (in the Day Ahead and Hour Ahead Markets) in connection with inter-zonal congestion during the period for which the FTR is issued. FTRs also entitle registered FTR Holders to certain scheduling priorities (in the Day Ahead Market) for the transmission of energy across a congested inter-zonal interface.

The CAISO does not require that FTR owners be CAISO Scheduling Coordinators (SCs). FTRs may be purchased by any qualified bidder purely as an investment to enable the owner to receive a stream of income from the congestion usage revenues. In order to be used in scheduling, however, an FTR must be assigned to one of the SCs. In addition, an owner may resell the FTR, or the scheduling rights may be unbundled from the revenue rights and sold or transferred to another party. All these sales, transfers or assignments are considered “secondary market transactions” and must be recorded in the CAISO Secondary Registration System (SRS). Due to the delay of the Market Redesign and Technology Upgrade (MRTU) implementation date, current FTRs were extended until the start of MRTU through secondary auctions.

5.2.1 Primary Auction Results

The CAISO creates a primary market for FTRs by auctioning them each year for a 12-month period beginning in April and ending in March. Due to the several delays in the start of the Market Redesign and Technology Upgrade (MRTU), the 2008-2009 FTR primary auctions took place for the 1-month, 3-month, and 4-month periods from April 1, 2008, to March 30, 2009.[27] The FTR Auction is a simultaneous, multi-round clearing price auction conducted separately and independently across specified CAISO inter-zonal interfaces. The FTR Auction proceeds are distributed to Participating Transmission Owners (PTOs), based upon their respective ownership interest in each auctioned path. Owners of FTRs can use their FTRs as a hedge against congestion costs.

Table 5.4 provides a summary of the 2008-2009 FTR primary auction results. In the 2008-2009 primary auction, FTRs on 32 directional branch groups were auctioned. Total revenue earned in the 2008-2009 primary auction was approximately $102 million for the 12-month period. The 2007-2008 primary auction, which spanned a 10-month period, generated $121 million in revenue. Auction results for the 2007-2008 primary auction can be found in the 2007 Annual Report on Market Issues and Performance.

The FTR auction results are listed independently for each branch group by direction in Table 5.4.

[27] The 1-month periods were for the months of April, May, October, November and December 2008. The 4-month period was for June 1-September 30, 2008. The 3-month period was for January 1-March 31, 2009.

Table 5.4 Summary of 2008-2009 FTR Auction Results (April 1, 2008 through March 31, 2009)[28]

Branch Group	Direction	Total FTRs Sold (MW) 1 Month Term	Total FTRs Sold (MW) 3 Month Term	Total FTRs Sold (MW) 4 Month Term	Auction Clearing Price ($/MW) 1 Month Term	Auction Clearing Price ($/MW) 3 Month Term	Auction Clearing Price ($/MW) 4 Month Term	Auction Revenue ($)
BLYTHE	Export	116	116	116	$8	$25	$33	$11,598
BLYTHE	Import	180	180	180	$1,303	$708	$1,455	$1,562,335
CFE	Export	390	363	408	$8	$25	$33	$38,917
CFE	Import	400	400	400	$8	$25	$33	$39,992
CTNWDRDMT_BG	Export	320	320	320	$8	$25	$33	$31,994
CTNWDRDMT_BG	Import	320	320	320	$8	$25	$33	$31,994
CTNWDWAPA_BG	Export	646	646	646	$8	$25	$33	$64,587
CTNWDWAPA_BG	Import	726	646	846	$8	$25	$33	$74,585
ELDORADO	Export	295	295	739	$8	$25	$33	$44,293
ELDORADO	Import	739	739	739	$1,565	$3,728	$2,398	$10,308,769
IID-SCE	Import	600	600	600	$12	$31	$42	$80,724
IID-SDGE	Export	57	57	57	$8	$25	$33	$5,699
IID-SDGE	Import	24	24	24	$8	$25	$33	$2,400
MEAD	Export	347	267	669	$8	$25	$42	$48,998
MEAD	Import	598	598	598	$525	$421	$812	$2,307,951
NOB	Export	418	418	418	$11	$34	$33	$50,152
NOB	Import	418	418	418	$1,619	$824	$14,809	$9,919,040
PACI	Export	947	961	961	$9	$25	$33	$100,321
PACI	Import	883	883	883	$1,076	$493	$16,305	$19,584,031
PALOVRDE	Export	760	680	1,355	$8	$25	$33	$93,816
PALOVRDE	Import	1,943	1,943	1,943	$3,168	$5,316	$6,492	$53,718,393
PARKER	Import	160	160	160	$767	$1,659	$663	$985,336
PATH15	Import	3,283	3,330	3,330	$53	$56	$35	$1,174,706
PATH26	Export	2,127	2,127	2,127	$32	$33	$288	$1,027,128
RNCHLAKE	Export	585	585	585	$8	$25	$33	$58,488
RNCHLAKE	Import	497	417	617	$8	$25	$33	$51,690
SILVERPK	Export	10	10	10	$8	$25	$50	$1,167
SILVERPK	Import	10	10	10	$13	$38	$88	$1,913
TRACYPGAE_BG	Export	657	657	657	$8	$25	$33	$65,687
TRACYPGAE_BG	Import	697	657	857	$8	$25	$33	$74,019
VICTVL	Export	424	424	560	$8	$25	$33	$46,924
VICTVL	Import	962	842	862	$8	$25	$33	$89,848
Total								**$101,697,492**

5.2.2 2008-2009 FTR Market Performance

FTR Revenue

The 2008-2009 FTR market cycle began on April 1, 2008, and ended on March 31, 2009. Table 5.5 summarizes the FTR revenues from the current market cycle through the end of December 2008. The primary auction price for those directional Branch Groups that were auctioned off in three time blocks, as noted in Table 5.4, is a quantity weighted average price. FTR market revenues for the 2007-2008 FTR Auction can be found in the 2007 Annual Report.

During the current FTR cycle, with the exception of three paths (Blythe (export), IID-SDGE (import), and Path 26 (North-to-South)), the remainder had total pro-rated FTR revenue greater than their auction prices. This is not surprising. As discussed in section 5.1.3, the observed congestion charges in 2008 were significantly higher than the previous year. These sharp increases are also reflected on the pro-rated FTR revenues compared to the auction prices. As

[28] The 1-month term represents the months of April, May, October, November and December of 2008. The 4-month term represents the FTR auction for June 1-September 30, 2008. The 3-month term represents the FTR auction for January 1-March 31, 2009.

mentioned earlier, the FTR holders of major paths are also transmission owners. The FTR auction revenues are used to reduce the Transmission Revenue Requirement (TRR). As a result, the FTR purchase cost for these entities is to a large extent offset by a corresponding reduction in the TRR. Also, the FTR provides additional benefits to the holders beyond FTR revenue. Schedules with FTR rights are entitled to scheduling priority in the Day Ahead Market, and FTRs can serve as insurance to hedge against possible high congestion charges.

Table 5.5 below compares the price of FTRs at the time of auction and the revenues from those FTRs from the current market cycle. These figures represent data for the first nine months of the cycle, through the end of 2008 (April-08 to Dec-08). A calculated average price over this period is used for comparison.

Table 5.5 FTR Revenue Statistics ($/MW) (April 2008 – December 2008)

Branch Group	Direction	2008 Monthly FTR Market Revenues ($MW) Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Cum. Net $MW FTR Rev.	Prorated Net $MW FTR Rev.	Primary Auction Price	Value Ratio
ADLANTOSP	Import	$ 39	$ 126	$ 83	$ 132	$ 140	$ 180	$ 514	$ 17	$ 41	$ 1,272	$ 1,696	N/A	N/A
BLYTHE	export	$ -	$ -	$ -	$ -	$ (0)	$ -	$ -	$ -	$ -	$ (0)	$ (0)	$ 21	-2%
BLYTHE	Import	$ 344	$ 43	$ 0	$ 28	$ 41	$ 75	$ 1,031	$ 4,239	$ 50	$ 5,851	$ 7,802	$ 1,379	566%
ELDORADO	Import	$ 129	$ 589	$ 6	$ 156	$ 2	$ 374	$ 499	$ 4,769	$ 2,410	$ 8,933	$ 11,911	$ 1,982	601%
GONDIPPDC	export	$ 634	$ -	$ -	$ -	$ -	$ 126	$ 16	$ -	$ -	$ 776	$ 1,035	N/A	N/A
GONDIPPDC	Import	$ -	$ -	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ 2	$ 2	N/A	N/A
IID-SCE	Import	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 66	$ 105	$ 171	$ 228	$ 27	846%
IID-SDGE	Import	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0	$ 0	$ 1	$ 21	2%
IPPDCADLN	Import	$ 39	$ 2,101	$ 176	$ 3,850	$ 98	$ 1,354	$ 706	$ 2,021	$ 430	$ 10,775	$ 14,367	N/A	N/A
MEAD	Import	$ 95	$ 273	$ 225	$ 231	$ 203	$ 173	$ 2,870	$ 469	$ 987	$ 5,526	$ 7,368	$ 669	1101%
MKTPCADLN	Import	$ 98	$ 0	$ 270	$ 0	$ 47	$ 3	$ 41	$ -	$ 195	$ 653	$ 871	N/A	N/A
MONAIPPDC	export	$ -	$ -	$ 201		$ 18	$ -	$ -	$ -	$ -	$ 218	$ 291	N/A	N/A
MONAIPPDC	Import	$ 3	$ 1	$ 0	$ 1	$ 0	$ 1	$ 0	$ -	$ -	$ 7	$ 9	N/A	N/A
NOB	export	$ -	$ -	$ -	$ -	$ -	$ -	$ 18	$ 46	$ 31	$ 95	$ 127	$ 22	578%
NOB	Import	$ 14	$ 4,942	$ 3,627	$ 14,886	$ 524	$ 280	$ 4	$ -	$ 6	$ 24,282	$ 32,376	$ 8,214	394%
PACI	Import	$ 36	$ 2,188	$ 2,444	$ 11,713	$ 563	$ 149	$ 9	$ 422	$ 13	$ 17,536	$ 23,381	$ 8,691	269%
PALOVRDE	Import	$ 944	$ 503	$ 76	$ 89	$ 575	$ 822	$ 598	$ 1,303	$ 705	$ 5,615	$ 7,487	$ 4,830	155%
PARKER	Import	$ 500	$ 78	$ 4,296	$ 6,051	$ 15	$ 154	$ 1,571	$ 146	$ 72	$ 12,882	$ 17,176	$ 715	2402%
PATH15	South-to-North	$ -	$ -	$ 7	$ -	$ -	$ 168	$ 1,244	$ 1,374	$ 339	$ 3,132	$ 4,176	$ 44	9491%
PATH26	North-to-South	$ 11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11	$ 15	$ 160	9%
SILVERPK	Import	$ -	$ 6	$ 125	$ 77	$ -	$ -	$ -	$ -	$ -	$ 207	$ 277	$ 51	542%
TRACYCOTP	Import	$ 2	$ 51	$ 1	$ 153	$ 11	$ 0	$ -	$ -	$ -	$ 218	$ 291	$ 22	1321%
WSTWGMEAD	Import	$ 3	$ 17	$ 40	$ 4	$ 45	$ 0	$ 4	$ 460	$ 736	$ 1,310	$ 1,746	N/A	N/A

FTR Trades in the Secondary Markets

In California, the successful bidders in the FTR primary auctions are allowed to conduct further FTR trades in the secondary markets. The FTR transactions in the secondary markets have been minimal, as shown in Table 5.6.

One notable exception was trades from the City of Vernon back to CAISO on April 21, 2008. Apparently, the City of Vernon executed FTR trades with Startrans IO for Mead-Adelanto Project and the Mead-Phoenix Project. Since Startrans IO was not a load entity, it could not hold FTRs. As a result, the City of Vernon FTR contracts were adjusted on April 2008. In a separate event, the FTRs on TRACYCOTP_BG were adjusted since certain capacity on this Branch Group was under contract for sale by the City of Vernon to Transmission Agency of Northern California (TANC).

The other exchanges occurred between Southern Participating Transmission Owners (SPTOs) (i.e., the City of Pasadena, the City of Anaheim, the City of Azusa, and the City of Riverside) and the CAISO, due to either the transfer of FTRs owned by SPTOs to CAISO, or the revision of SPTOs entitlements.

Table 5.6 FTR Trades in the Secondary Market (April 2008 – March 2009)

Branch Group	Direction	Date of Trade	Buyer	Seller	Quantity Sold (MW)	First Effective Date	Last Effective Date
GONDIPPDC	Import	28-Mar-08	PASA	CISO	5	25-Sep-08	30-Sep-08
GONDIPPDC	Export	28-Mar-08	PASA	CISO	8	25-Sep-08	30-Sep-08
GONDIPPDC	Export	2-Sep-08	PASA	CISO	7	25-Sep-08	30-Sep-08
GONDIPPDC	Export	15-Sep-08	ANHM	CISO	7	25-Sep-08	30-Sep-08
MCCLMKTPC	Import	21-Apr-08	CISO	VERN	156	23-Apr-08	30-Apr-08
MCCLMKTPC	Export	21-Apr-08	CISO	VERN	156	23-Apr-08	30-Apr-08
MCCLMKTPC	Import	21-Apr-08	CISO	VERN	156	1-May-08	30-Sep-08
MCCLMKTPC	Export	21-Apr-08	CISO	VERN	156	1-May-08	30-Sep-08
MEAD	Import	20-Mar-08	FMTX	SEPC	200	12-Apr-08	31-May-08
MEAD	Import	28-Mar-08	FMTX	CITI	225	1-Sep-08	30-Sep-08
MEAD	Import	2-Sep-08	AZUA	CISO	17	1-Oct-08	31-Dec-08
MEAD	Import	2-Sep-08	AZUA	CISO	19	1-Jan-09	31-Jan-09
MEAD	Import	12-Jan-09	AZUA	CISO	19	1-Feb-09	31-Mar-09
MEADMKTPC	Import	21-Apr-08	CISO	VERN	105	23-Apr-08	30-Apr-08
MEADMKTPC	Export	21-Apr-08	CISO	VERN	105	23-Apr-08	30-Apr-08
MEADMKTPC	Import	21-Apr-08	CISO	VERN	105	1-May-08	30-Sep-08
MEADMKTPC	Export	21-Apr-08	CISO	VERN	105	1-May-08	30-Sep-08
MEADTMEAD	Import	21-Apr-08	CISO	VERN	47	23-Apr-08	30-Apr-08
MEADTMEAD	Export	21-Apr-08	CISO	VERN	47	23-Apr-08	30-Apr-08
MEADTMEAD	Import	21-Apr-08	CISO	VERN	47	1-May-08	30-Sep-08
MEADTMEAD	Export	21-Apr-08	CISO	VERN	47	1-May-08	30-Sep-08
MKTPCADLN	Import	21-Apr-08	CISO	VERN	81	23-Apr-08	30-Apr-08
MKTPCADLN	Export	21-Apr-08	CISO	VERN	81	23-Apr-08	30-Apr-08
MKTPCADLN	Import	21-Apr-08	CISO	VERN	81	1-May-08	30-Sep-08
MKTPCADLN	Export	21-Apr-08	CISO	VERN	81	1-May-08	30-Sep-08
MONAIPPDC	Import	28-Mar-08	ANHM	CISO	153	25-Sep-08	30-Sep-08
MONAIPPDC	Export	28-Mar-08	ANHM	CISO	161	25-Sep-08	30-Sep-08
MONAIPPDC	Import	28-Mar-08	PASA	CISO	48	25-Sep-08	30-Sep-08
MONAIPPDC	Export	28-Mar-08	PASA	CISO	50	25-Sep-08	30-Sep-08
MONAIPPDC	Import	28-Mar-08	RVSD	CISO	80	25-Sep-08	30-Sep-08
MONAIPPDC	Export	28-Mar-08	RVSD	CISO	84	25-Sep-08	30-Sep-08
MONAIPPDC	Import	2-Sep-08	PASA	CISO	49	25-Sep-08	30-Sep-08
MONAIPPDC	Export	2-Sep-08	PASA	CISO	58	25-Sep-08	30-Sep-08
MONAIPPDC	Import	2-Sep-08	RVSD	CISO	63	25-Sep-08	30-Sep-08
MONAIPPDC	Export	2-Sep-08	RVSD	CISO	74	25-Sep-08	30-Sep-08
NOB	Import	20-Mar-08	RVSD	CISO	31	1-Apr-08	30-Apr-08
NOB	Import	20-Mar-08	RVSD	CISO	83	1-May-08	31-May-08
NOB	Export	20-Mar-08	RVSD	CISO	83	1-Apr-08	31-May-08
NOB	Import	28-Mar-08	RVSD	CISO	83	1-Jun-08	30-Sep-08
NOB	Export	28-Mar-08	RVSD	CISO	83	1-Jun-08	30-Sep-08
NOB	Import	2-Sep-08	AZUA	CISO	20	1-Nov-08	30-Nov-08
NOB	Import	2-Sep-08	AZUA	CISO	21	1-Dec-08	31-Dec-08
NOB	Import	2-Sep-08	RVSD	CISO	83	1-Oct-08	31-Oct-08
NOB	Import	2-Sep-08	RVSD	CISO	3	1-Oct-08	31-Jan-09
NOB	Export	2-Sep-08	RVSD	CISO	83	1-Oct-08	31-Jan-09
NOB	Import	2-Sep-08	RVSD	CISO	31	1-Nov-08	31-Jan-09
NOB	Import	8-Sep-08	AZUA	CISO	3	1-Oct-08	31-Jan-09
NOB	Import	12-Jan-09	RVSD	CISO	31	1-Feb-09	31-Mar-09
NOB	Export	12-Jan-09	RVSD	CISO	83	1-Feb-09	31-Mar-09
PACI	Import	10-Jul-08	SCE1	CITI	112	13-Jul-08	30-Sep-08
TRACYCOTP	Import	3-Apr-08	CISO	VERN	121	8-Apr-08	30-Sep-08
TRACYCOTP	Export	3-Apr-08	CISO	VERN	121	8-Apr-08	30-Sep-08
WSTWGMEAD	Import	21-Apr-08	CISO	VERN	28	23-Apr-08	30-Apr-08
WSTWGMEAD	Export	21-Apr-08	CISO	VERN	28	23-Apr-08	30-Apr-08
WSTWGMEAD	Import	21-Apr-08	CISO	VERN	28	1-May-08	30-Sep-08
WSTWGMEAD	Export	21-Apr-08	CISO	VERN	28	1-May-08	30-Sep-08

5.2.3 Adjustments to the FTR Quantities from the Primary Auction

According to Tariff section 36.3, the proposed FTR release quantity for the primary auction should be computed by subtracting any converted rights - i.e., the converted Existing Transmission Contract (ETC) amounts turned over to the CAISO from New Participating Transmission Owners (NPTO) - from the Available Transmission Contract (ATC) values at the 99.5 percent confidence level for each branch group.

However, for the 2008-2009 FTR auction, the CAISO produced proposed FTR quantities based on FTR quantities from the 2007-2008 FTR auction and postponed the necessary adjustments until after the primary auction. The initial FTR quantities, which were approved by the CAISO Board of Governors, are shown in Table 5.4.

Table 5.7 represents the converted rights that were returned to the CAISO by the New PTOs, Anaheim, Azusa, Banning, Pasadena, Riverside and Vernon, for the 2008-2009 cycle. Pursuant to current (pre-MRTU) CAISO Tariff section 36.4.3, the New PTOs will receive FTRs for these converted rights. As it was explained earlier, for any branch group on which FTRs are to be released, if there are NPTO converted rights, CAISO removes these from the calculated release amounts prior to making them available in the primary FTR auction. However, for 2008-2009 FTR auction, these adjustments were made after the primary auction took place.

Table 5.7 Converted Rights Released to the CAISO by the New PTOs (2008 Auction Year)

Branch Group	Direction	Quantity Sold (MW)	First Effective Date	Last Effective Date
ADLANTOSP	Import	1,036	01-Apr-08	31-Mar-09
ADLANTOSP	Export	502	01-Apr-08	31-Mar-09
GONDIPPDC	Import	3	01-Apr-08	30-Sep-08
GONDIPPDC	Import	5	01-Oct-08	31-Mar-09
GONDIPPDC	Export	5	01-Apr-08	30-Sep-08
GONDIPPDC	Export	15	01-Oct-08	31-Mar-09
IPPDCADLN	Import	647	01-Apr-08	31-Mar-09
IPPDCADLN	Export	471	01-Apr-08	31-Mar-09
MCCLMKTPC	Import	731	01-Apr-08	30-Apr-08
MCCLMKTPC	Import	575	01-May-08	31-Mar-09
MCCLMKTPC	Export	731	01-Apr-08	30-Apr-08
MCCLMKTPC	Export	757	01-May-08	31-Mar-09
MEAD	Import	34	01-Apr-08	31-Mar-09
MEAD	Export	70	01-Apr-08	30-Sep-08
MEAD	Export	58	01-Oct-08	31-Mar-09
MEADMKTPC	Import	369	01-Apr-08	30-Apr-08
MEADMKTPC	Import	264	01-May-08	31-Mar-09
MEADMKTPC	Export	369	01-Apr-08	30-Apr-08
MEADMKTPC	Export	264	01-May-08	31-Mar-09
MEADTMEAD	Import	182	01-Apr-08	30-Apr-08
MEADTMEAD	Import	135	01-May-08	31-Mar-09
MEADTMEAD	Export	182	01-Apr-08	30-Apr-08
MEADTMEAD	Export	135	01-May-08	31-Mar-09
MKTPCADLN	Import	423	01-Apr-08	30-Apr-08
MKTPCADLN	Import	342	01-May-08	31-Mar-09
MKTPCADLN	Export	423	01-Apr-08	30-Apr-08
MKTPCADLN	Export	342	01-May-08	31-Mar-09
MONAIPPDC	Import	189	01-Apr-08	30-Sep-08
MONAIPPDC	Import	281	01-Oct-08	31-Mar-09
MONAIPPDC	Export	188	01-Apr-08	30-Sep-08
MONAIPPDC	Export	295	01-Oct-08	31-Mar-09
NOB	Import	73	01-Apr-08	30-Sep-08
NOB	Import	70	01-Oct-08	31-Jan-09
NOB	Import	73	01-Feb-09	31-Mar-09
NOB	Export	73	01-Apr-08	31-Mar-09
SYLMAR-AC	Import	10	01-Apr-08	31-Mar-09
SYLMAR-AC	Export	0	01-Apr-08	31-Mar-09
TRACYCOTP	Import	121	01-Apr-08	31-Mar-09
TRACYCOTP	Export	121	01-Apr-08	31-Mar-09
WSTWGMEAD	Import	126	01-Apr-08	30-Apr-08
WSTWGMEAD	Import	98	01-May-08	31-Mar-09
WSTWGMEAD	Export	126	01-Apr-08	30-Apr-08
WSTWGMEAD	Export	98	01-May-08	31-Mar-09

6 Reliability Costs

Intra-zonal congestion management costs – Minimum Load Cost Compensation (MLCC), Reliability Must Run (RMR) real-time dispatch costs, and Out-of-Sequence (OOS) redispatch – increased 81 percent in 2008 to $174 million, from a total in 2007 of $96 million (revised)[29]. The significant increase is primarily attributable to the following grid management issues: 1) Congestion in the Humboldt County area near the Oregon border and the Lugo area northeast of Los Angeles and 2) various derates and clearances for transmission work impacting the Moss-Metcalf corridor south of the Bay Area, the San Onofre area north of San Diego, the Southwest Power Link corridor east of San Diego, and the Victorville-Lugo Nomogram.

The increase in intra-zonal congestion costs in 2008 was largely offset by a reduction in other RMR costs and in RCST/TCPM payments. In comparing the sum of the reliability management costs (intra-zonal congestion, other RMR costs, and RCST/TCPM payments) to last year, the total for 2008 is approximately 5 percent higher than 2007 ($232 million in 2008 compared to $221 million in 2007).

6.1 Overview

Scheduling Coordinators (SCs) submit day-ahead/hour-ahead generation and load schedules to the CAISO. Due to differences in the price and availability of power in different locations, these schedules vary daily and, collectively, may exceed the transfer capability of grid facilities within the congestion zones. However, the CAISO's Day Ahead and Hour Ahead Congestion Management Markets only manage congestion between zones, not within zones. This allows SCs to submit day-ahead/hour-ahead schedules that require transmission within a zone that is not physically feasible, and, as a consequence, creates the need for CAISO operators to have to manage intra-zonal congestion in real-time. Managing large amounts of intra-zonal congestion in real-time creates operational and reliability challenges and can result in significant costs.

Intra-zonal congestion costs are comprised of three components:

10) Minimum Load Cost Compensation (MLCC).[30] These costs result from generating units that are committed to operate on a day-ahead basis under the provisions of the Must-Offer Obligation in order to mitigate anticipated intra-zonal congestion.[31]

11) Costs from Reliability Must Run (RMR) real-time dispatches that are the first response to intra-zonal congestion.

12) Costs of Out-of-Sequence (OOS) dispatches.

[29] These costs do not include Reliability Capacity Service Tariff (RCST) or Transitional Capacity Procurement Mechanism (TCPM) charges or capacity payments to meet Resource Adequacy (RA) requirements.

[30] MLCC payments are cost-based and are calculated as variable cost for providing the minimum load energy plus a $6/MWh O&M adder.

[31] Pursuant to Amendment 60 to the CAISO Tariff, MLCC costs are categorized into three categories (system, zonal and local), which reflect the primary reason the unit was denied a must-offer waiver. Both zonal and local MLCC costs are included as the MLCC component of intra-zonal costs.

Intra-zonal congestion most frequently occurs in load pockets, or areas where load is concentrated, where transmission within the zone is not sufficient to allow access to lower-priced energy. In some cases, the CAISO must also decrement generation outside the load pocket to balance the incremental generation dispatched within it. Intra-zonal congestion can also occur due to pockets in which generation is clustered together, without the transmission necessary for the energy to flow out of that pocket to load. In both cases, the absence of sufficient transmission access to an area means that the CAISO has to resolve the problem locally, either by incrementing generation within a load pocket or by decrementing it in a generation pocket. Such congestion is inefficient if the market costs due to the transmission congestion (i.e., the cost imposed by the fact that load cannot be served by the lowest-cost supplier(s), and instead must be served by higher-cost suppliers) exceed the cost of a transmission upgrade that could alleviate the congestion.

Typically, there is limited competition within load or generation pockets, since the bulk of generation within such pockets is owned by just one or two suppliers. As a result, intra-zonal congestion is often coupled with locational market power. Consequently, methods to resolve intra-zonal congestion are designed to limit the ability of suppliers to exercise local market power.

The CAISO's current method for dealing with incremental intra-zonal congestion involves a combination of steps and operating procedures. On a day-ahead basis, the CAISO often constrains-on or commits long-start thermal units through the must-offer waiver (MOW) process in return for minimum load cost payments and/or RA capacity payments. This forward unit commitment process helps to mitigate intra-zonal congestion that may be anticipated based upon day-ahead schedules submitted by market participants. Units required to operate under the MOW process are typically dispatched at minimum load levels. They are then required to bid all unloaded capacity into the CAISO Real Time Market.[32] In real-time, the CAISO dispatches real-time energy bids in merit order (based on bid price) in order to balance overall system or zonal loads and generation. If dispatch of in-sequence bids does not resolve intra-zonal congestion in real-time, the CAISO can mitigate intra-zonal congestion in three ways:

- First, the CAISO may dispatch available RMR capacity to mitigate congestion;
- Second, should energy from RMR units be insufficient, the CAISO may dispatch other units by calling real-time energy bids OOS;[33]
- Finally, if insufficient market bids exist to mitigate intra-zonal congestion, the CAISO may call units Out-of-Market (OOM).

Units incremented OOS to mitigate intra-zonal congestion are paid the higher of their bid price or the zonal market clearing price (MCP). They do not set the real-time market clearing price. Units decremented OOS to mitigate intra-zonal congestion are charged the lower of their decremental reference price or the zonal market-clearing price. They also do not set the real-time market clearing price. Inter-tie bids taken OOS are settled on an as-bid basis.

[32] Available thermal units within the CAISO Control Area are subject to the Must-Offer Obligation (MOO) whereby incremental energy bids are automatically inserted for them if they fail to do so themselves. There is no MOO for decremental energy bids.

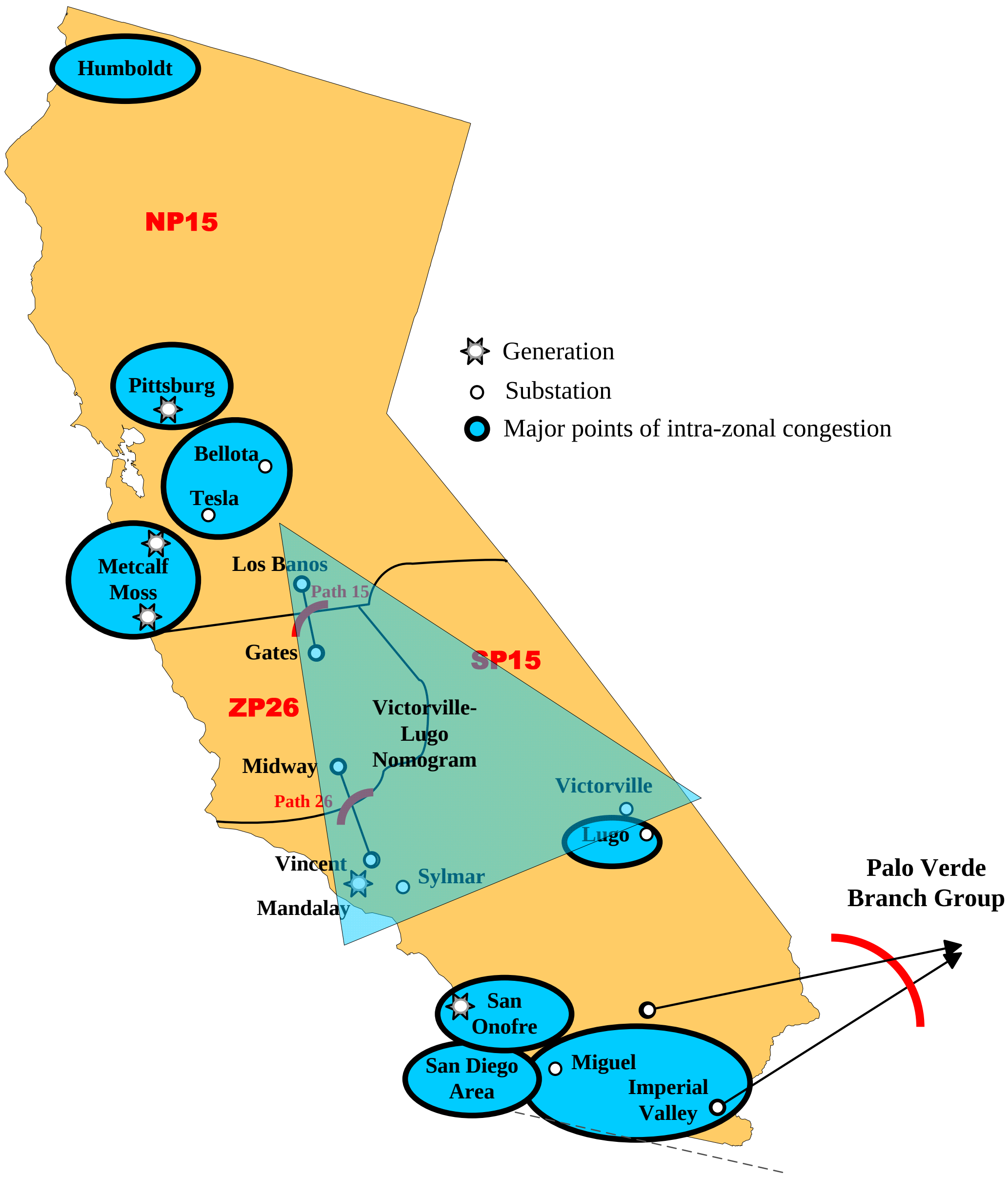
[33] The term "out-of-sequence" refers to the fact that such dispatches require the CAISO, when incrementing (or decrementing) generation, to bypass lower (or higher) priced, in-sequence, real-time bids to find a unit whose grid location enables it to mitigate a particular intra-zonal congestion problem.

6.2 Points of Intra-Zonal Congestion

Both NP26 and SP15 experienced intra-zonal congestion in 2008. The largest congestion point within NP26 again was the Humboldt County area on the North Coast of California. Upgrades to the Moss Landing-Metcalf and Tesla-Bellota transmission corridors also created significant intra-zonal congestion and redispatch costs. Sources of intra-zonal congestion within Southern California included the Southwest Power Link corridor, which includes the Imperial Valley and Miguel transmission stations; the area near the San Onofre Nuclear Generation Station (SONGS), where transmission upgrades occurred while one of the generation units was shut down for refueling; and the Lugo area, which continues to be a transmission choke point between Nevada generation and Southern California load.

A new challenge this year was the Victorville Lugo Nomogram (VLN), a technical constraint on power flows into California and between areas served by the CAISO and the Los Angeles Department of Water and Power (LADWP). The reliability costs were due to management of flows that violated the nomogram, which is distinct from management of congestion in either the Victorville or Lugo areas. High Northern California loads and low hydroelectric conditions during the summer of 2008 effectively created significant power flows from the Pacific DC Intertie and the Southwest, through the LADWP at the Sylmar substation, and up Path 26 to Northern California that violated the VLN. The VLN also became an issue when the Sayre fire destroyed connection facilities in October, effectively removing the Sylmar substation from the grid. In this case, a special version of the VLN was used to manage flows around Sylmar. Operators mitigated the violations by dispatching generation that feeds into the Sylmar substation. Most of this generating capacity consists of aged and costly resources located in or near Ventura County.

Figure 6.1 Key Points of Intra-Zonal Congestion



6.3 Reliability Management Costs

Intra-zonal congestion costs increased 81 percent in 2008 to $174 million, from a total in 2007 of $96 million,[34] excluding Resource Adequacy (RA) contract payments and RCST/TCPM payments. Measurable intra-zonal congestion management costs include three components: 1) MLCC for intra-zonal (non-system) reasons, 2) RMR variable costs associated with real-time congestion management, and 3) OOS redispatch costs. These components are reported separately in Table 6.1 along with the totals.

The increase in 2008 costs is primarily attributable to higher MLCC payments and real-time redispatch costs. MLCC costs increased by $46 million in 2008, mainly due to the need to commit units in the summer months to relieve a transmission constraint in Southern California. The cost of real-time redispatch costs increased by $39 million in 2008. The increase in OOS redispatch costs in 2008 was due in large part to the increased need to move resources committed at minimum load to real-time dispatchable regions, as they are no longer covered by RMR contracts. These dispatchability payments resulted in costs of approximately $12.3 million in 2008. Humboldt-area local OOS dispatches, which also have replaced discontinued RMR contracts, resulted in costs of nearly $23 million. The aforementioned Victorville-Lugo nomogram, which often requires the out-of-sequence dispatch of a costly steam resource in Southern California, incurred approximately $9.5 million in redispatch costs. Congestion at the Miguel and Imperial Valley stations resulted in approximately $7.8 million in redispatch costs.

Table 6.1 Monthly Total Estimated Intra-Zonal Congestion Costs for 2006-2008 ($MM)

	MLCC Costs			RT RMR Costs			RT Redispatch Costs			Total		
Month	**2006**	**2007**	**2008**	**2006**	**2007**	**2008**	**2006**	**2007**	**2008**	**2006**	**2007**	**2008**
Jan	$ 10	$ 3	$ 7	$ 13	$ 2	$ 2	$ 4	$ 2	$ 6	$ 27	$ 6	$ 15
Feb	$ 8	$ 2	$ 4	$ 15	$ 1	$ 2	$ 2	$ 2	$ 6	$ 25	$ 4	$ 11
Mar	$ 11	$ 2	$ 5	$ 13	$ 1	$ 1	$ 3	$ 1	$ 4	$ 27	$ 4	$ 10
Apr	$ 27	$ 2	$ 4	$ 8	$ 2	$ 2	$ 6	$ 2	$ 3	$ 41	$ 6	$ 10
May	$ 12	$ 2	$ 12	$ 3	$ 1	$ 2	$ 1	$ 2	$ 7	$ 16	$ 4	$ 21
Jun	$ 15	$ 3	$ 13	$ 4	$ 1	$ 0	$ 0	$ 1	$ 6	$ 19	$ 5	$ 19
Jul	$ 14	$ 7	$ 10	$ 2	$ 1	$ 1	$ 0	$ 2	$ 7	$ 17	$ 10	$ 18
Aug	$ 5	$ 2	$ 9	$ 3	$ 1	$ 1	$ 0	$ 1	$ 6	$ 8	$ 4	$ 16
Sep	$ 3	$ 2	$ 8	$ 2	$ 0	$ 1	$ 0	$ 1	$ 4	$ 5	$ 4	$ 13
Oct	$ 1	$ 10	$ 3	$ 3	$ 7	$ 1	$ 1	$ 8	$ 5	$ 5	$ 25	$ 9
Nov	$ 1	$ 5	$ 9	$ 6	$ 3	$ 1	$ 0	$ 4	$ 11	$ 7	$ 12	$ 21
Dec	$ 2	$ 5	$ 6	$ 7	$ 3	$ 1	$ 0	$ 4	$ 4	$ 9	$ 12	$ 12
Total	**$ 109**	**$ 44**	**$ 90**	**$ 80**	**$ 22**	**$ 16**	**$ 17**	**$ 30**	**$ 69**	**$ 207**	**$ 96**	**$ 174**

6.3.1 Minimum Load Cost Compensation

Pursuant to a FERC Order issued May 25, 2001,[35] and subsequent Orders, the CAISO provides Minimum Load Cost Compensation to generators that apply for waivers of the Must-Offer

[34] The $96 million figure for 2007 is a revision to the $101 million figure reported in the 2007 Annual Report on Market Issues and Performance. The number was revised based on more accurate RMR settlement information for the months of November and December 2007.

[35] 95 FERC 61,275; 95 FERC 61,418, etc. (2001).

Obligation but are denied, and thus are required to be on-line at minimum load for the following operating day. In such cases, the CAISO compensates the generators for their minimum load costs, based upon unit operating costs and natural gas prices, where applicable. In addition, generators that are neither RA nor RCST resources, and whose waiver requests are denied, are also entitled to receive the real-time price for energy supplied while operating at minimum load. Units subject to the Must-Offer Obligation are required to bid all unloaded capacity into the CAISO Real Time Market. To encourage units subject to must-offer to bid into the Ancillary Services Market, the CAISO filed and FERC approved Amendment 60. This tariff change enables generators to keep both ancillary services revenues and MLCC.

Table 6.2 shows average must-offer and RA waiver denial capacity and total monthly costs in 2007 and 2008, as well as the imbalance energy payments that these generators received for their minimum-load energy based on real-time market prices. The costs shown also include MLCC costs for "system" reliability reasons in addition to intra-zonal reasons; these system commitments account for the differences among the totals in Table 6.1 and Table 6.2. Note that all costs exclude resource adequacy contract payments, which are negotiated bilaterally between utilities and generation owners, and thus are not visible to the CAISO.

Table 6.2 Must-Offer Waiver Denial Capacity and Costs

	2007			2008		
Month	**Average MW***	**MLCC ($MM)**	**Imbalance ML Energy Payments ($MM)**	**Average MW***	**MLCC ($MM)**	**Imbalance ML Energy Payments ($MM)**
Jan	1,053	$3.3	$0.5	1,440	$7.2	$0.1
Feb	848	$1.9	$0.2	991	$3.9	$0.0
Mar	796	$2.3	$0.5	1,111	$5.1	$0.1
Apr	845	$2.5	$0.2	1,138	$5.0	$0.1
May	697	$1.7	$0.0	2,352	$14.5	$0.2
Jun	1,541	$5.6	$1.1	2,305	$14.3	$0.0
Jul	1,951	$8.8	$2.2	1,769	$12.6	$0.0
Aug	1,483	$4.0	$0.5	2,113	$9.9	$0.0
Sep	1,119	$3.7	$0.5	2,145	$8.4	$0.0
Oct	1,844	$10.7	$3.3	1,255	$3.2	$0.0
Nov	1,312	$5.1	$0.4	2,546	$9.7	$0.0
Dec	1,092	$5.0	$0.1	1,621	$5.2	$0.2
Annual Total	1,215	$54.6	$9.6	1,732	$99.2	$0.6

CAISO operators issued unit commitments for a variety of reasons in 2008. The different reasons and associated commitment costs are shown in Figure 6.2.

- The single largest cost-contributing reason for commitments was congestion at the Lugo substation, a key choke point for transmission of generation from the Las Vegas and Hoover Dam region to load in Southern California. Most of the $22.4 million in commitment costs for congestion at the Lugo substation were incurred during the summer months, and are apportioned zonally to SP26 load. Lugo-area congestion also resulted in another $7 million in locally-allocated commitment costs.

- The Southern California Import Transmission nomogram (SCIT), a technical constraint on the amount of power that can instantaneously be imported into SP26, incurred $10.5 million in zonally-apportioned commitment costs, distributed approximately uniformly throughout the year.

- Congestion at the Miguel substation, a choke point in the transmission of generation in Mexico and Arizona to load in Southern California, incurred approximately $9.4 million in costs apportioned zonally.

- Transmission work near the San Onofre Nuclear Generation Station (SONGS), located north of San Diego, required unit commitments in the San Diego area, at a cost of approximately $8 million apportioned locally. Other unit commitments for localized reliability needs in the San Diego area cost approximately $5.1 million.

- Costs to commit units to mitigate violations of the aforementioned Victorville-Lugo Nomogram totaled approximately $5.4 million.

Figure 6.2 Annual MLCC Costs by Reason, 2007-2008

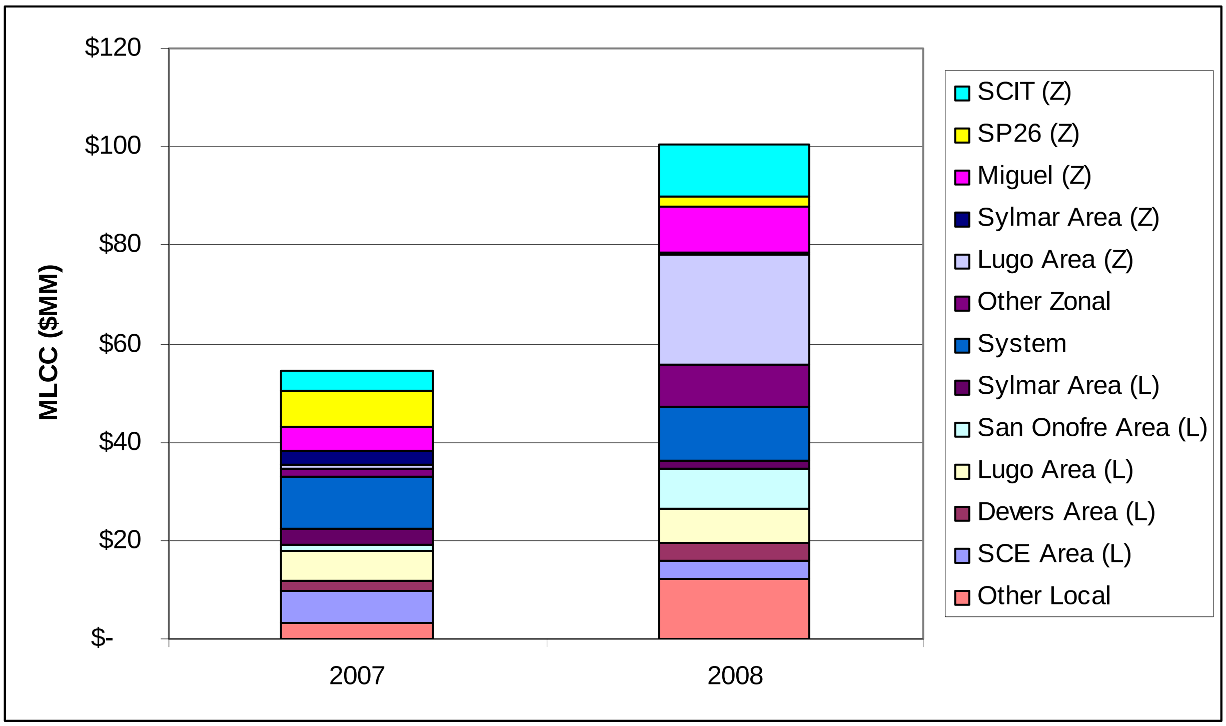


Figure 6.3 provides a monthly breakdown of 2008 MLCC costs by reason. MLCC costs for the Lugo area were primarily incurred during the June to September timeframe, whereas zonally allocated MLCC costs for the Victorville-Lugo Nomogram occurred in November after a fire destroyed the Sylmar substation. MLCC costs for the Miguel constraint occurred primarily in the months of January through April.

Figure 6.3 Monthly MLCC Costs by Reason, 2008

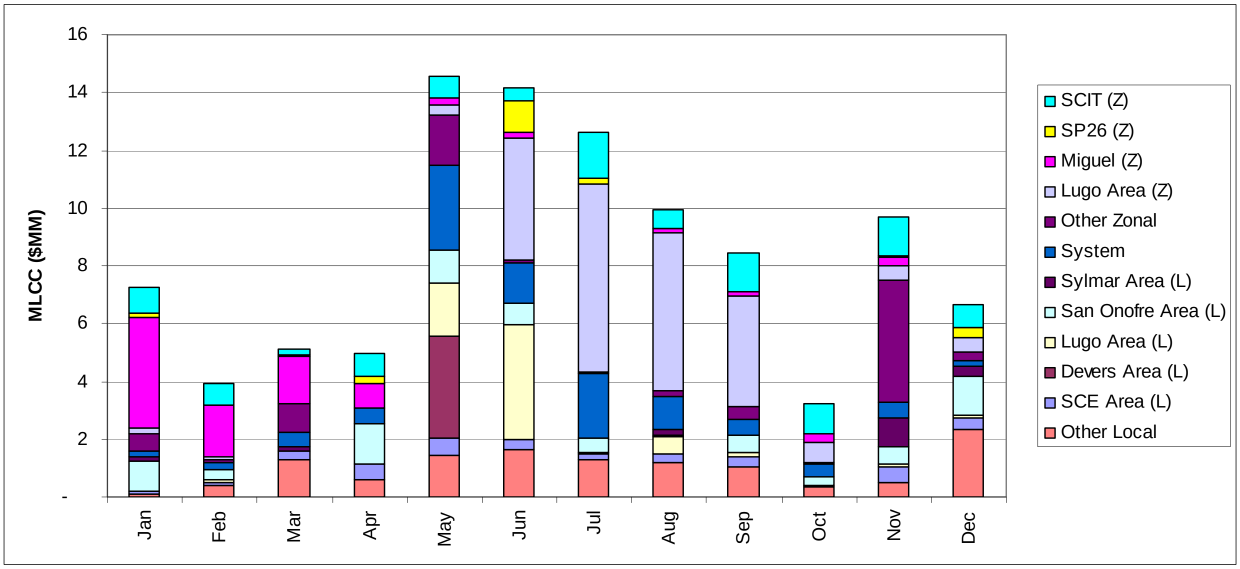
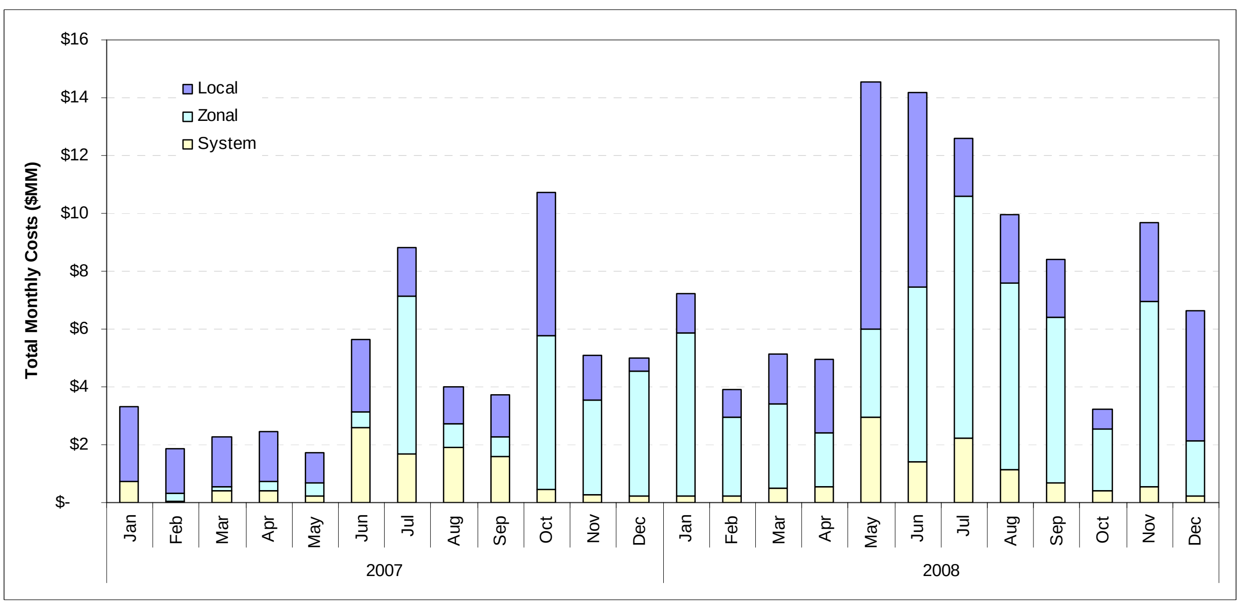


Figure 6.4 shows average daily capacity cost of waiver denials by commitment charge type (local, zonal, and system). The monthly totals of all three reason categories equal the values shown in Table 6.2 and Figure 6.3. No single reason explains the increase in costs beginning in May 2008; rather, multiple reasons, as shown above in Figure 6.3, all contribute to the total.

Figure 6.4 Total Monthly MLCC Payments for All Reasons (Local, Zonal, and System), 2007-2008

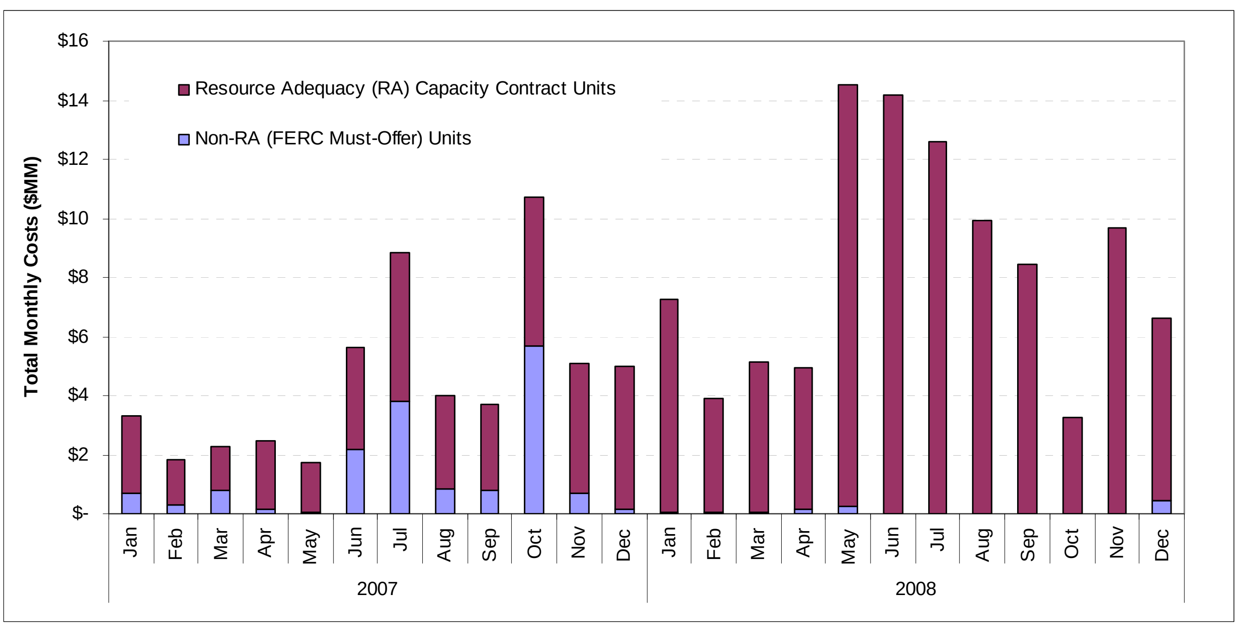


In 2006, the Resource Adequacy (RA) programs developed by the CPUC became effective. This program requires that LSEs procure sufficient resources to meet their peak load along with appropriate reserves. In addition to the CPUC RA program, non-CPUC jurisdictional LSEs have also instituted similar capacity reserve margins. RA programs support system and local grid reliability by creating a framework intended to promote new generation investment in California by providing generation resources a revenue source to contribute towards fixed cost recovery. The CAISO facilitates implementation of these RA programs through its Interim Reliability Requirements Program (IRRP), which defines the way RA resources are made available to the CAISO prior to the implementation of MRTU.

Beginning in June 2006, the CPUC directed its jurisdictional LSEs to procure sufficient resources to cover 100 percent of their forecasted load for each month, plus a 15 percent margin for operating and planning reserves. The California Energy Commission determined for each CPUC-jurisdictional LSE load forecast based on an allocation of each LSE's coincident share of the forecasted CAISO system peak for each month. Before applying the 15 percent reserve margin, each LSE's forecast load was adjusted downward based on its administratively determined share of demand response resources (i.e., load that can be curtailed) available in the utility service territory in which their load is located. LSEs not under CPUC jurisdiction, mainly local publicly-owned utilities, meet roughly similar requirements determined by their respective LRAs.

The implementation of the RA program in June 2006 has significantly reduced reliance on the FERC-directed Must-Offer Obligation. Most frequently-committed units are now covered under RA capacity contracts. Non-RA units were committed under the Must-Offer Obligation in 2008 occasionally, usually to meet system requirements and when needed in unusual circumstances. A total of 17 units were committed under the Must-Offer Obligation, at a total cost just short of $1 million. A single high-cost steam unit in Southern California was committed in December for a series of local line clearances, at a cost of $450,000. The other Must-Offer committed resources primarily were quick-start generating units located primarily in or near the Bay Area.

Figure 6.5 Total Monthly MLCC Payments to Must-Offer vs. RA-Contracted Units in 2007-2008



6.3.2 Reliability Capacity Service Tariff and Transitional Capacity Procurement Mechanism Charges

Beginning June 1, 2006, the CAISO implemented a Reliability Capacity Services Tariff (RCST) under which any non-RA unit committed by the CAISO through the must-offer waiver process for reliability needs would be compensated with a daily capacity payment. The RCST also provides the CAISO with the authority to designate non-RA units to provide services under the RCST tariff as a "backstop" in the event that the CAISO determined that RA resources procured by LSEs did not meet projected reliability needs.

The purpose of the RCST, which was ultimately approved by the FERC, was to provide a mechanism by which the reliability needs of the CAISO were met and that ensured generators providing reliability services would be appropriately compensated, thereby reducing the likelihood that units critical for reliability will be mothballed or shut down.

Because the Market Redesign Technology Upgrade (MRTU) has been delayed beyond the expiration of the RCST, the Transitional Capacity Procurement Mechanism (TCPM) was approved by the Federal Energy Regulatory Commission in an order issued on May 30, 2008, effective June 1, 2008, until implementation of MRTU. The TCPM enables the CAISO to acquire generation capacity to maintain grid reliability if load serving entities fail to meet resource adequacy requirements; procured resource adequacy resources are insufficient; or unexpected conditions, i.e., "Significant Events," create the need for additional capacity. The TCPM serves as a bridge between the Reliability Capacity Services Tariff and the proposed Interim Capacity Procurement Mechanism (ICPM) which the CAISO intends to implement simultaneously with MRTU.

Key provisions of the RCST include the following:

- **RCST Capacity Payments.** In addition to receiving minimum load costs, non-RA units designated as RCST are eligible to receive an RCST capacity payment. The capacity payments are equal to $73/kW-year, less a variable Peak Energy Rent (PER) amount that is calculated each month based on the potential net energy and ancillary services revenues that could be earned by a new peaking unit given actual CAISO market prices. The net payment was designed to reflect a reasonable price for "backstop" capacity and encourage LSEs and generators to engage in longer term contracting and not rely on the must-offer mechanism. This net RCST capacity payment is calculated on a monthly basis by allocating these annual fixed costs to each month using monthly percentages, which allocate a higher portion of annual fixed costs to summer months relative to other months of the year.

- **RCST Designations.** Any non-RA units designated as RCST units by the CAISO for one or more months are eligible for the monthly capacity payment described above. The RCST settlement also provides that if any non-RA unit is committed under the must-offer waiver process for four separate days in any year, the CAISO would evaluate whether a significant change in grid operations had occurred that warrants making additional RCST designations.

- **Daily RCST Capacity Payments**. Any non-RA units committed through the CAISO's must-offer process are eligible for a daily RCST capacity payment equal to 1/17th of the monthly capacity payment described above. However, daily RCST capacity payments for any month may not exceed the total monthly capacity payment described above. As discussed below, approximately $10.6 million in daily RCST capacity payments under this provision occurred in 2006 due to non-RA units being committed through the must-offer waiver process, with more than 75 percent of these costs occurring during periods of extremely high system loads in June through August.

- **Real Time Energy Mitigation Adder.** The RCST tariff provisions also include a potential $40/MWh payment adder for certain units that are mitigated under the CAISO's current local market power mitigation (LMPM) measures more than four 10-minute intervals in one day.[36]

The TCPM modifies the RCST by blending it with provisions of the ICPM, and includes the following provisions:

- **Higher Capacity Payments.** The TCPM increases the current RCST Target Annual Capacity Price from $73/kW-year to $86/kW-year, less PER. The $86/kW-year price is between the fixed costs of existing units and the cost on new entry.

- **Higher Daily Capacity Payments.** The TCPM also increases the current daily MOO capacity payment that is in the RCST from a factor of 1/17 to a factor of 1/8. The additional compensation recognizes, inter alia, that the commitment of a FERC MOO unit to provide reliability services is essentially a daily designation of capacity as opposed to a monthly or longer designation.

- **Significant Event Designations.** TCPM incorporates the improvements made in the ICPM to the process for designating resources to respond to TCPM Significant Events, but with an objective benchmark for designation of capacity resources. Resources receive a minimum 30-day capacity designation upon first commitment, and then may be subject to extensions of 30 to 90 days if deemed necessary.

- **Stringent Reporting Requirements.** The CAISO must issue notification of any TCPM designation within two business days and post a designation report by the earlier of 30 days after procuring the resource or 10 days after the end of the month.

- **Local Deficiencies.** TCPM adds tariff language from the ICPM to address how the CAISO would backstop for RA deficiencies relative to local requirements, and how the CAISO would address a collective deficiency relative to the local RA requirement.

- **Utilities' RA Quantification.** TCPM adds tariff language from the ICPM to address allowing LSEs to "count" or "credit" certain TCPM procurement in RA showings. However, as with the ICPM proposal, the CAISO will not permit TCPM Significant Event designations to "count" toward RA showings.

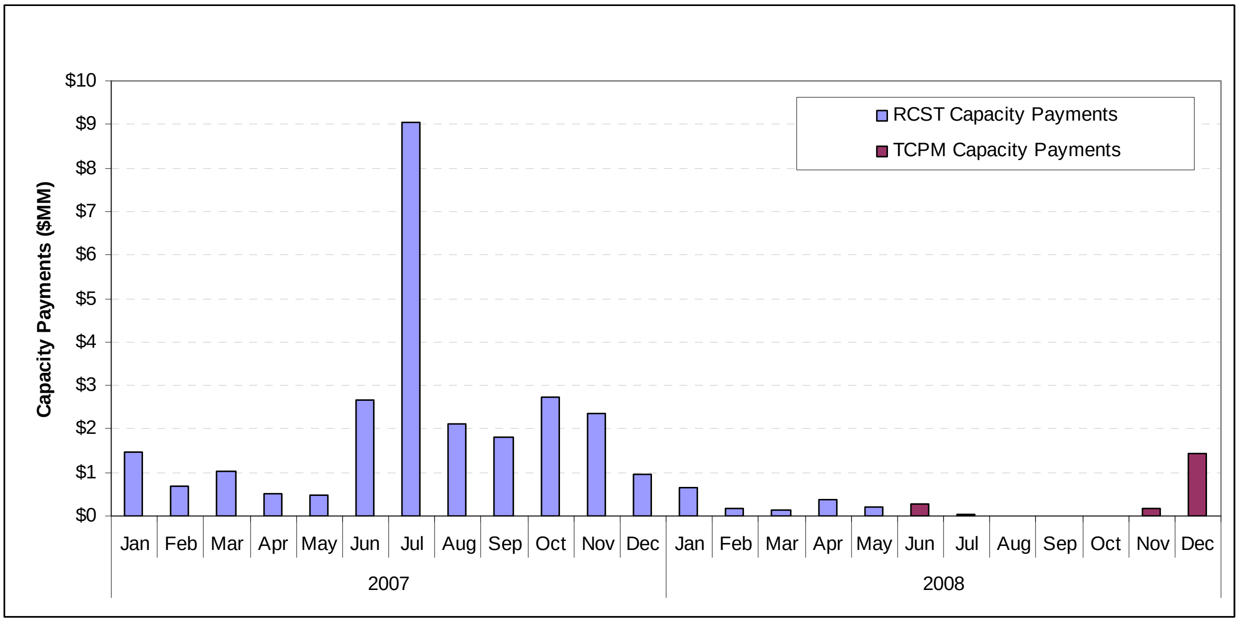
- **Cost Allocation Methodology.** TCPM incorporates the ICPM cost allocation methodology for TCPM Significant Events, which is based on Market Participants' actual

[36] Under current LMPM measures, bids dispatched out-of-sequence for intra-zonal congestion or local reliability needs which are in excess of $50 or 200 percent of the interval MCP are mitigated to their reference price and settled on the greater of the mitigated bid or the interval MCP. Under the RCST tariff provisions, bids mitigated under these LMPM provisions may have up to $40/MWh added to their mitigated price if the unit is subject to LMPM more than four 10-minute intervals in one day. However, the $40/MWh adder is reduced if necessary so that the total price paid under LMPM does not exceed the original bid price.

usage of the CAISO Controlled Grid during the period of the TCPM Significant Event, rather than costs based on the prior year peak load.

Figure 6.6 depicts RCST and TCPM capacity payments in 2007 and 2008. The 2008 total amounted to $3.4 million, of which $1.5 million were RCST payments for trade dates January through May, and $1.9 million were TCPM payments for June through December. In comparison, the 2007 RCST payments totaled $25.9 million. These figures are not included in the total reliability management costs, but *are* included in the total energy cost index discussed in Chapter 2.

Figure 6.6 RCST and TCPM Capacity Payments, 2007-2008



6.3.3 Reliability Must-Run (RMR) Costs

To mitigate local market power and to ensure that local reliability requirements are met, California's current market design relies upon RMR contracts with units located at known congested locations on the transmission grid. Through an annual planning process, the CAISO designates specific generating units as RMR units, based on the potential need for these units to be on-line and/or generate at sufficient levels to provide voltage support, adequate local generation in the event of system contingencies, and meet other system requirements related to local reliability. RMR contracts provide a mechanism for compensating unit owners for the costs of operating when units are needed for local reliability but may not be economical to operate based on overall energy and ancillary service market prices. RMR units are either pre-dispatched for local reliability needs (prior to real-time), or incremented in real-time either for local reliability or for intra-zonal congestion. RMR units cannot be pre-dispatched for intra-zonal congestion.

All RMR units receive two basic forms of compensation: (1) a Fixed Option Payment (FOP) that provides a contribution to each unit's fixed costs, and (2) a variable cost payment for energy provided under the RMR contract option, which is paid as the difference (if any) between the unit's variable operating costs and market revenues received for energy provided in response to an RMR requirement.[37]

Since 2006, the CAISO has significantly reduced its portfolio of RMR resources. This has resulted in a decline in total RMR costs of approximately 42 percent since 2007, and 83 percent between 2006 and 2008. Table 6.3 shows fixed and variable RMR costs by month in 2008, and further divides variable cost payments into costs associated with pre-dispatch RMR energy for local reliability, and additional real-time RMR energy dispatches for any remaining intra-zonal congestion.[38] Generators providing energy in response to a real-time RMR dispatch are paid based on their variable operating costs, with the responsible Transmission Owner (TO) receiving a credit back for the value of this energy at the real-time price. Thus, the net cost of real-time RMR dispatches for intra-zonal congestion or other local reliability requirements is equal to the difference between the RMR unit's variable operating cost and the real-time price of energy.

Table 6.3 Monthly RMR Contract Energy and Costs in 2008*

Month	Pre-Dispatched Energy (GWh)	Real-Time Energy (GWh)	Fixed Option Payments ($MM)	Net Pre-Dispatch Costs ($MM)	Net Real-Time Costs ($MM)	Total RMR Costs ($MM)
Jan	41	92	$ 3	$ 1	$ 2	$ 6
Feb	40	48	$ 2	$ 1	$ 2	$ 6
Mar	14	13	$ 2	$ 1	$ 1	$ 5
Apr	27	21	$ 2	$ 1	$ 2	$ 5
May	51	22	$ 3	$ 3	$ 2	$ 8
Jun	52	11	$ 3	$ 1	$ 0	$ 5
Jul	54	24	$ 3	$ 3	$ 1	$ 7
Aug	55	36	$ 3	$ 1	$ 1	$ 5
Sep	65	51	$ 3	$ 1	$ 1	$ 5
Oct	69	72	$ 3	$ 1	$ 1	$ 6
Nov	75	56	$ 4	$ 2	$ 1	$ 7
Dec	70	60	$ 3	$ 1	$ 1	$ 6
2008 Total	**611**	**505**	**$ 36**	**$ 19**	**$ 16**	**$ 71**
% Chg from 2007	**-9%**	**-27%**	**-52%**	**-19%**	**-28%**	**-42%**

* Includes only dispatches under contract option.

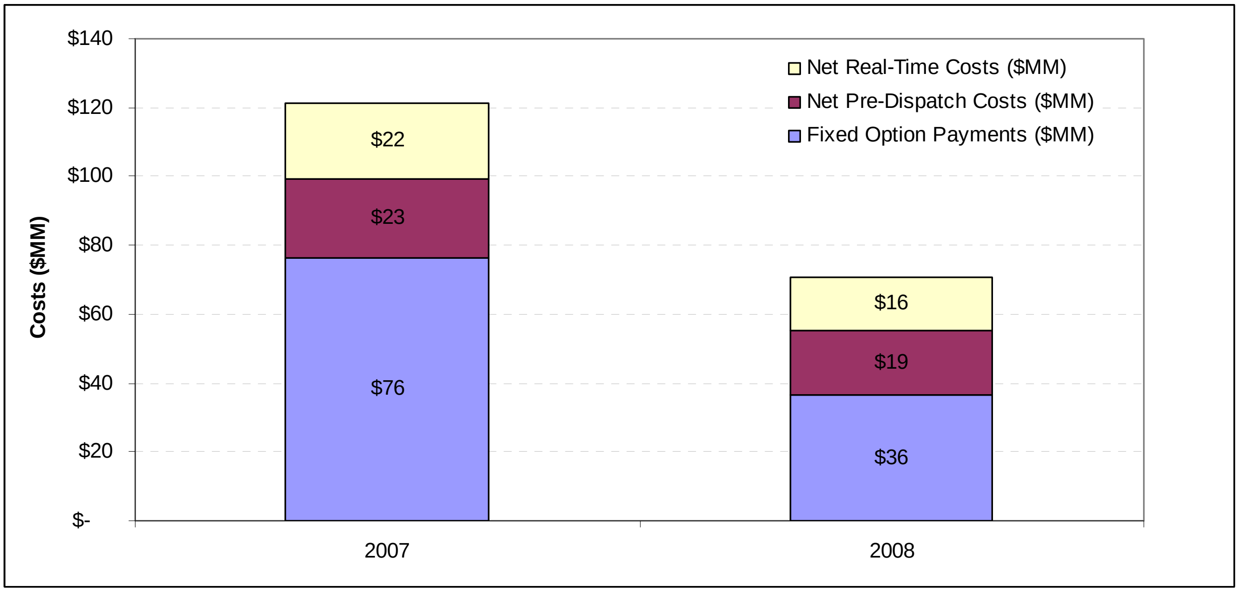
Most of the savings in RMR contract costs is attributable to a large reduction in the amount of generation capacity under RMR contracts, from approximately 3,400 MW in 2007 to approximately 2,400 MW in 2008. The significant decline in the amount of generation capacity under RMR contracts was brought about through the introduction of Local Resource Adequacy requirements. With more local resources being procured through Resource Adequacy contracts, the CAISO was able to significantly decrease its RMR designations, which in turn resulted in a significant decrease in RMR fixed option payments, from approximately $76 million in 2007 to $36 million in 2008. In addition, the reduction in RMR contracted units resulted in substantially lower RMR variable cost payments (pre-dispatch and real-time dispatch). RMR variable costs totaled approximately $35 million in 2008, compared to $45 million in 2007. In

[37] Units under Condition 1 of the RMR contract are free to select the "Market Option" when receiving an RMR dispatch on a day-ahead or hour-ahead basis, in which case they keep all revenues from sales of this energy and do not receive any reimbursement for variable operating costs.

[38] Since selection of RMR units and pre-dispatch of RMR units is based on local reliability requirements, these costs are not specifically associated with intra-zonal congestion. While annual designation of RMR units and pre-dispatch of RMR units to meet local area reliability requirements may reduce intra-zonal congestion in real-time, these costs would be incurred even if intra-zonal congestion did not occur in real-time. Thus, it is more appropriate to exclude costs associated with the FOP and pre-dispatch of RMR units from intra-zonal congestion costs.

sum, total RMR costs decreased in 2008 to approximately $71 million, from approximately $121 million in 2007 (Figure 6.7). This continued a trend of declining RMR costs that has persisted since 2004.

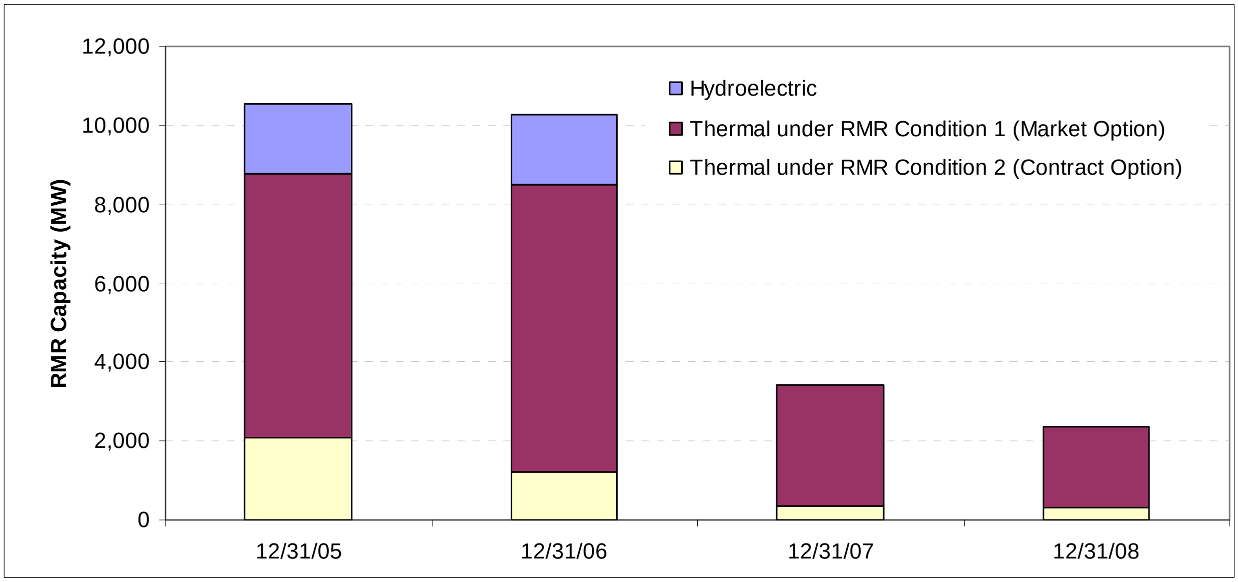
Figure 6.7 Total RMR Costs, 2007-2008



The portion of RMR unit capacity selecting Condition 2 (non-market) of the pro forma RMR contract continued to decrease, which also contributed to lower variable cost payments. RMR-providing generation owners may select either Condition 1 or 2 contracts. Condition 1 designations entitle the generation owner to participate in the market, and, if dispatched for RMR, to select on a daily basis whether to collect variable contract-based rates (Contract Path) or market revenues (Market Path). Because Condition 1 units have market opportunities, they receive a lower monthly FOP.[39] Condition 2 effectively is a tolling agreement between the CAISO and the generation owner, where the owner receives a higher FOP, but receives cost-based payments for its energy and cannot participate in the market unless given an RMR dispatch. Condition 2 unit capacity accounted for approximately 13.6 percent of total RMR-contracted unit capacity by the end of 2008, compared to 10.3 percent at the end of 2007, as shown below in Figure 6.8.

[39] RMR Condition 1 revenues from dispatch under the Market Path are not included in the calculation of reliability costs, but are included as real-time market costs in the calculation of total wholesale market costs in Chapter 2.

Figure 6.8 RMR Capacity by Resource and Contract Type, 2005-2008



6.3.4 Out-of-Sequence (OOS) Costs

The costs of Out-Of-Sequence (OOS) dispatches for mitigating real-time intra-zonal congestion is measured in terms of the redispatch cost, which is the incremental cost incurred from having to dispatch some resources up and other resources down to alleviate the congestion. For incremental energy bids dispatched OOS, the redispatch cost is the difference between the price paid to the resource for OOS energy (generally, their bid price) less the market clearing price (the cost of balancing the OOS energy). For decremental energy bids dispatched OOS, the redispatch cost is based on the market clearing price for incremental energy less the reference price for decremental OOS energy.[40]

As shown in Table 6.4, net redispatch costs to load of incremental dispatches, or the costs in excess of real-time market prices, were approximately $49.8 million in 2008, compared to $20.8 million in 2007. In all, the CAISO procured 878 GWh of incremental OOS energy at an average price of $116.37/MWh, or $56.66/MWh above market.

Table 6.5 shows decremental OOS statistics. Decremental redispatch costs, or the amount of money below the market price that resources save when the CAISO reduces their output in order to avoid intra-zonal congestion, totaled approximately $19.3 million in 2008, compared to $9.7 million in 2007. In all, the CAISO decremented 635.8 GWh of OOS energy at an average price of $52.74/MWh, or $30.33/MWh below market.

[40] This discussion excludes OOS and OOM dispatches for system conditions, which totaled approximately $5.1 million in redispatch costs in 2008. These dispatches were largely incremental dispatches to RMR Condition 2 units during the summer heat wave, which under the RMR contract are not permitted to bid into the market without prior instruction to do so, and decremental dispatches to pump storage units to offset over-generation during the spring months.

Table 6.4 Incremental OOS Congestion Costs in 2008

	GWh	Gross Cost ($MM)	Redispatch Premium ($MM)	Mitigation Savings ($)	Average Price	Average Net Cost ($/MWh)
Jan	63.1	$ 6.9	$ 3.1	$ 735,456	$ 109.59	$ 49.61
Feb	47.9	$ 6.3	$ 3.3	$ 175,123	$ 130.99	$ 67.94
Mar	33.9	$ 4.9	$ 2.6	$ 27,192	$ 146.08	$ 78.16
Apr	45.6	$ 6.0	$ 2.3	$ 8,712	$ 131.44	$ 51.09
May	109.1	$ 12.7	$ 5.4	$ 252,943	$ 116.49	$ 49.84
Jun	111.6	$ 13.5	$ 5.4	$ 964,495	$ 120.83	$ 47.98
Jul	89.8	$ 11.6	$ 5.3	$ 338,577	$ 129.49	$ 59.25
Aug	67.4	$ 6.9	$ 2.9	$ 295,001	$ 102.24	$ 42.71
Sep	79.1	$ 6.9	$ 2.6	$ 938,236	$ 87.54	$ 32.29
Oct	41.2	$ 5.9	$ 4.1	$ 119,850	$ 143.40	$ 100.40
Nov	134.8	$ 14.5	$ 9.2	$ 149,157	$ 107.82	$ 67.98
Dec	54.4	$ 5.9	$ 3.5	$ 16,801	$ 109.29	$ 64.96
2008 Total	**878.1**	**$ 102.2**	**$ 49.8**	**$ 4,021,543**	**$ 116.37**	**$ 56.66**

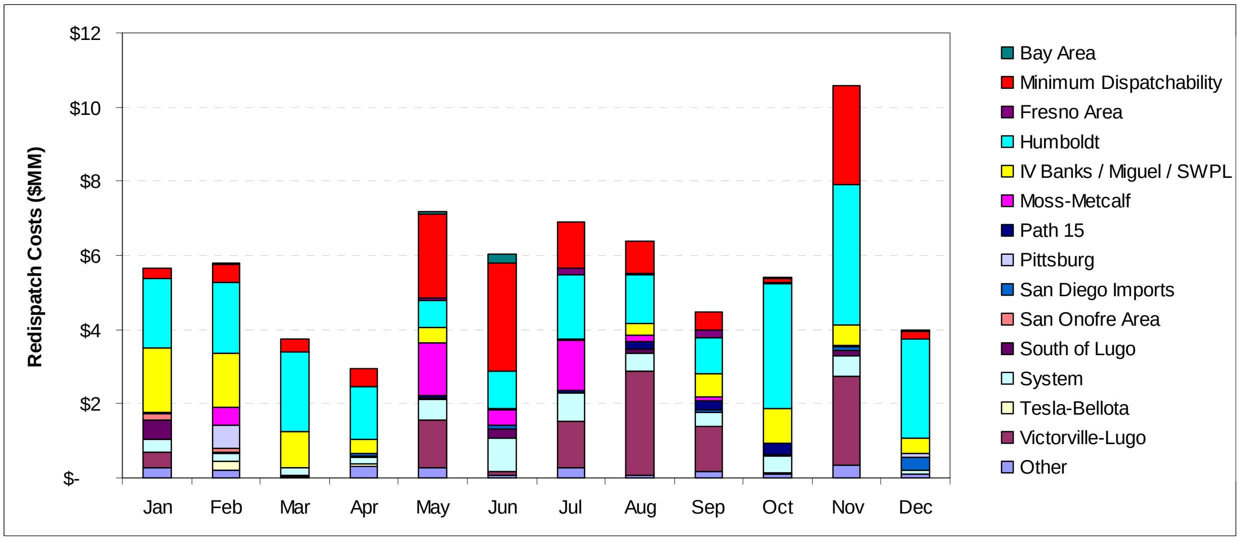
Table 6.5 Decremental OOS Congestion Costs in 2008

	GWh	Gross Cost ($MM)	Redispatch Premium ($MM)	Average Price	Average Net Cost ($/MWh)
Jan	(116.5)	$ (6.7)	$ 2.5	$ 57.25	$ 21.55
Feb	(107.1)	$ (5.9)	$ 2.5	$ 54.76	$ 23.79
Mar	(36.6)	$ (2.3)	$ 1.1	$ 61.48	$ 30.14
Apr	(23.7)	$ (1.5)	$ 0.6	$ 61.76	$ 25.61
May	(52.4)	$ (3.4)	$ 1.7	$ 64.08	$ 33.25
Jun	(13.9)	$ (0.9)	$ 0.7	$ 61.42	$ 48.71
Jul	(38.1)	$ (2.9)	$ 1.6	$ 75.65	$ 41.30
Aug	(52.3)	$ (3.1)	$ 3.5	$ 58.96	$ 67.00
Sep	(47.8)	$ (2.4)	$ 1.9	$ 49.47	$ 39.76
Oct	(70.4)	$ (2.1)	$ 1.3	$ 30.48	$ 18.11
Nov	(53.8)	$ (1.8)	$ 1.4	$ 33.15	$ 26.02
Dec	(23.2)	$ (0.8)	$ 0.4	$ 35.09	$ 19.03
2008 To	**(635.8)**	**$ (33.5)**	**$ 19.3**	**$ 52.74**	**$ 30.33**

The increase in OOS redispatch costs in 2008 over the 2007 level was due in large part to the increased need to move resources committed at minimum load to real-time dispatchable regions, as they are no longer covered by RMR contracts. These dispatchability payments resulted in costs of approximately $12.3 million in 2008. Humboldt-area local OOS dispatches, which also have replaced discontinued RMR contracts, resulted in costs of nearly $23 million. The aforementioned Victorville-Lugo nomogram, which often requires the out-of-sequence dispatch of a costly steam resource in Southern California, incurred approximately $9.5 million in redispatch costs. Congestion at the Miguel and Imperial Valley stations, which occurs due to a generation pocket in Mexicali, Mexico, which is connected to the CAISO-managed grid to serve San Diego-area load, resulted in approximately $7.8 million in redispatch costs. Other

OOS dispatches were due primarily to outages for transmission upgrades, most notably the Moss-Metcalf #1 and #2 230 kV lines, which incurred approximately $4 million in redispatch costs.

Figure 6.9 Monthly Contribution to Intra-Zonal Congestion OOS Redispatch Costs by Reason in 2008



7 Market Surveillance Committee

7.1 Market Surveillance Committee

Historically, the Market Surveillance Committee (MSC or Committee) has served as an impartial voice on a wide array of wholesale energy market issues. CAISO management and the FERC have adopted a number of Committee recommendations since its inception. The MSC has been recognized consistently by the industry and the public as useful and effective, due in large part to the stature of its members as nationally recognized experts as well as their perceived independence. Both characteristics have led to the MSC being shown considerable deference by state and federal regulators.

7.1.1 Current Members

In 2008, the Committee was comprised of the following members: Frank Wolak of Stanford University, Benjamin Hobbs of Johns Hopkins University and James Bushnell of the University of California Energy Institute at Berkeley. Frank Wolak served as the chairman of the Committee.[41] The following is a brief description of each member's background.

Since April of 1998, Dr. Wolak has been Chairman of the MSC. In this capacity, he has testified numerous times at the FERC and at various Committees of the US Senate and House of Representatives on issues relating to market monitoring and market power in electricity markets. Dr. Wolak has also worked on the design and regulatory oversight of the electricity markets internationally, including markets in Europe, Australia/Asia, Latin America, and the US (CAISO, NYISO, PJM, ISO-NE). He lectures internationally on issues related to electricity market monitoring and regulatory oversight. He has contributed to the design of market monitoring and regulatory oversight protocols in a number of electricity markets.

Dr. Frank Wolak is a Professor of Economics at Stanford University. He received his undergraduate degree from Rice University, and an S.M. in Applied Mathematics and Ph.D. in Economics from Harvard University. His fields of research are industrial organization and empirical economic analysis. He specializes in the study of privatization, competition and regulation in network industries such as electricity, telecommunications, water supply, natural gas and postal delivery services. He is the author of numerous academic articles on these topics. He is a Research Associate of the National Bureau of Economic Research and a Visiting Researcher at the University of California Energy Institute in Berkeley. Professor Wolak has served as a consultant to the California and U.S. Departments of Justice on market power issues in the telecommunications, electricity, and natural gas markets. He has also served as a consultant to the Federal Communications Commission and Postal Rate Commission on issues relating to regulatory policy in network industries.

Dr. Benjamin F. Hobbs, a member of the MSC since 2002, is a Professor of Geography & Environmental Engineering and Applied Mathematics & Statistics in the Whiting School of Engineering, at Johns Hopkins University since 1995. He is a former Professor of Systems Engineering and Civil Engineering at Case Western Reserve University. He has previously held

[41] More information is available at http://www.caiso.com.

positions at Brookhaven National Laboratory and Oak Ridge National Laboratory. He is presently Scientific Advisor to The Energy Research Centre of the Netherlands and a member of the Public Interest Advisory Committee for the Gas Technology Institute. His research interests include stochastic electric power planning models, environmental and energy systems analysis and economics, multi-objective and risk analysis, ecosystem management, and mathematical programming models of imperfect energy markets. Dr. Hobbs has published numerous journal articles and magazine articles on these topics and has co-authorized two books. Dr. Hobbs has a Ph.D. in Environmental Systems Engineering from Cornell University, and is a Fellow of the IEEE.

Dr. James Bushnell, a member of the MSC since 2002, is currently the Research Director of the University of California Energy Institute at Berkeley. He also serves as Lecturer at the Haas School of Business at UC Berkeley. He is a former member of the Market Monitoring Committee of the California Power Exchange (CALPX). His research interests include industrial organization and regulatory economics, energy policy, and environmental economics. He has published numerous articles on the economics of electricity deregulation and has testified extensively on energy policy issues. Much of research has focused on examining market incentives in particular; market rules and structures created; and in developing empirical methods for measuring the impact of market power on deregulated electricity markets. Dr. Bushnell has a Ph.D. in Industrial Engineering and Operations Research with a B.S. in Economics and Industrial Engineering.

7.1.2 Accomplishments

In 2008 the MSC was involved in discussions with CAISO staff on several issues and provided opinions on several market design policy issues.

- Refinements to the MRTU Interim Capacity Payment Mechanism.
- Market power mitigation mechanisms for Exceptional Dispatch under MRTU.
- Implementation of policies to reduce California's greenhouse gas emissions.
- Cost allocation rules for convergence bids.
- Relaxing the decremental bidding rule under MRTU.
- Demand response functionality in Market Release 1A.
- Modeling and pricing Integrated Balancing Authority Areas under MRTU.
- Pricing logic under flexible modeling of constrained-on generation units.
- Design of the ancillary services procurement process under MRTU.
- MRTU parameter tuning process and reserve scarcity pricing.
- Uneconomic adjustment in the MRTU market optimizations.

7.1.3 MSC Meetings

In 2008 the MSC conducted several combined joint stakeholder meetings and teleconferences. The MSC also met in executive session meetings with the Department of Market Monitoring (DMM) to discuss refining the market monitoring protocols for the start of MRTU.