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Your Link to Power

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Executive Summary

In April 2009, the California Independent System Operator implemented a major redesign of its day-ahead and real-time markets. This new market design includes a variety of features that are expected to increase the overall efficiency of California's wholesale market, including:

- Pricing and congestion management based on locational marginal pricing.
- Use of a full network model that includes all of the key market and physical constraints of the system.
- A day-ahead integrated forward market that includes simultaneous optimization of energy and ancillary services, and separate three-part bids for start-up costs, minimum loads and energy.
- An hour-ahead scheduling process for pre-dispatching and pricing of additional hourly imports and exports based on projected supply and demand conditions in the next operating hour.
- An enhanced real-time dispatch process for balancing loads and supplies within each operating hour on a 5-minute basis.
- Local market power mitigation provisions to protect against the potential for market power within transmission constrained load pockets, in which a few major suppliers own the bulk of generating resources needed to meet local reliability requirements.

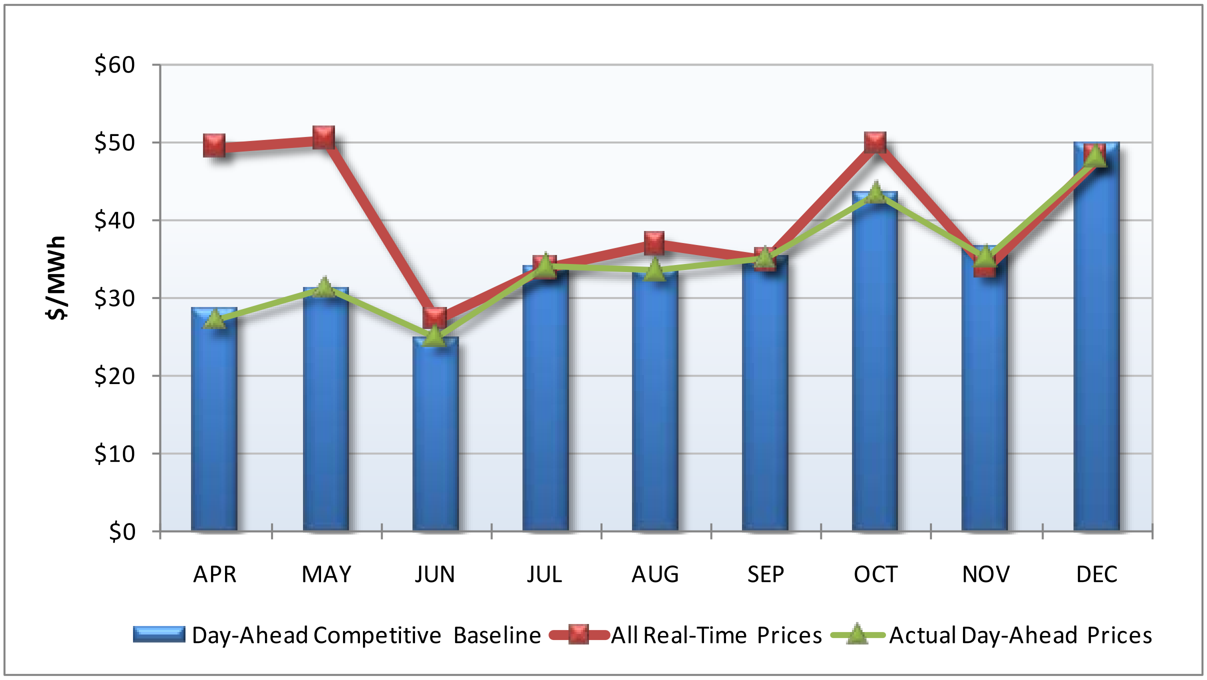
Chapter 1 provides a more detailed overview of the new market design, and how its various components are intended to increase the efficiency of California's wholesale market. The remaining chapters analyze the performance of these different market components in 2009.

Overall market performance

The overall performance of the new day-ahead and real-time markets in 2009 were highly efficient and competitive. Prices in the energy markets were approximately equal to competitive baseline prices that DMM estimates would result under highly competitive conditions. DMM calculates these competitive baseline prices by re-simulating the market using the actual day-ahead market software with bids reflecting the marginal cost of gas-fired units. Figure E.1 compares this competitive baseline price to average prices in the day-ahead and 5-minute real-time markets.

As shown in Figure E.1, prices in the day-ahead market during each month were consistently about equal to these competitive baseline prices. During the first two months of the new market, the real-time energy market was highly volatile, with periodic extreme price spikes driving up average prices. Real-time market performance improved quickly and consistently over the rest of the year. This improved performance can be attributed to a series of adjustments and enhancements in software and operating practices implemented by the ISO to address root causes of pricing anomalies and volatility.

Figure E.1 Comparison of competitive baseline price to actual day-ahead and real-time prices



Market prices soon followed patterns reflective of well-functioning competitive markets. Prices in the day-ahead and real-time energy markets began to converge and reflected marginal production costs. All prices have generally trended upward following the national price trend of natural gas, which is the most prevalent fuel for marginal resources in the system.

Comparisons of costs under the new market design with previous years must consider the significant differences between the new integrated energy market and the primarily bilateral market structure that was previously in place. Under the new market, total wholesale costs can be estimated directly from prices and quantities clearing in the day-ahead, hour-ahead and real-time markets. In prior years, more than 95 percent of total system load was met by energy schedules submitted by participants in the day-ahead and hour-ahead scheduling processes. To estimate the cost of this energy, DMM has relied upon bilateral price indices and other cost data. Because of these differences, the decrease in 2009 costs relative to costs for previous years reported by DMM should be viewed as an indication of the general magnitude and trend of changes in wholesale costs.

Total estimated wholesale costs for serving system load in 2009 were $8.8 billion, or $38/MWh. This compares with costs of $53/MWh of load served in 2008. Figure E.2 shows total estimated wholesale costs per MWh from 2005 to 2009 that are provided in nominal terms, as well as after a simple normalization for changes in average natural gas spot market prices.[1] Figure E.3 shows the contribution of different components of wholesale costs in terms of costs per MWh and the percentage of total 2009 costs.

[1] The dramatic changes in spot market gas prices from 2008 to 2009 make it difficult to compare prices over this period. While DMM normalizes wholesale electric prices based on the ratio of changes in average annual spot market gas prices, this approach assumes a direct correlation between electric and gas prices. In practice, electric prices do not change in fixed proportion to changes in spot market gas price.

Figure E.2 Total wholesale costs in $/MWh of load served: 2005-2009

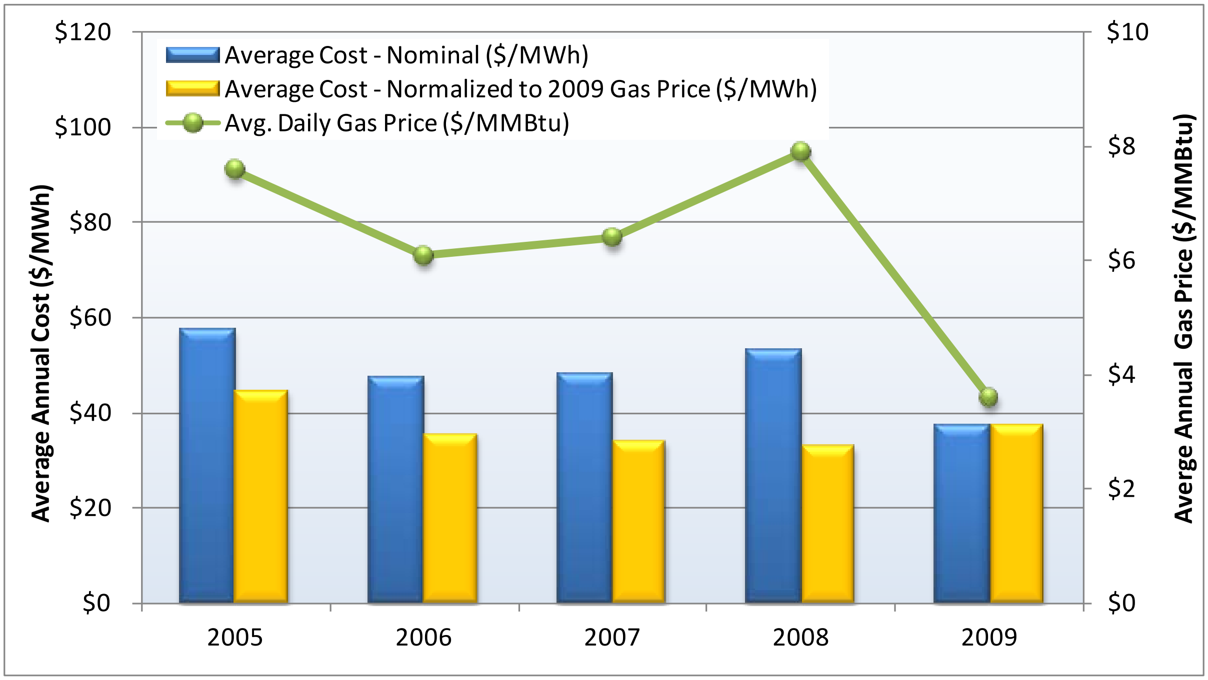
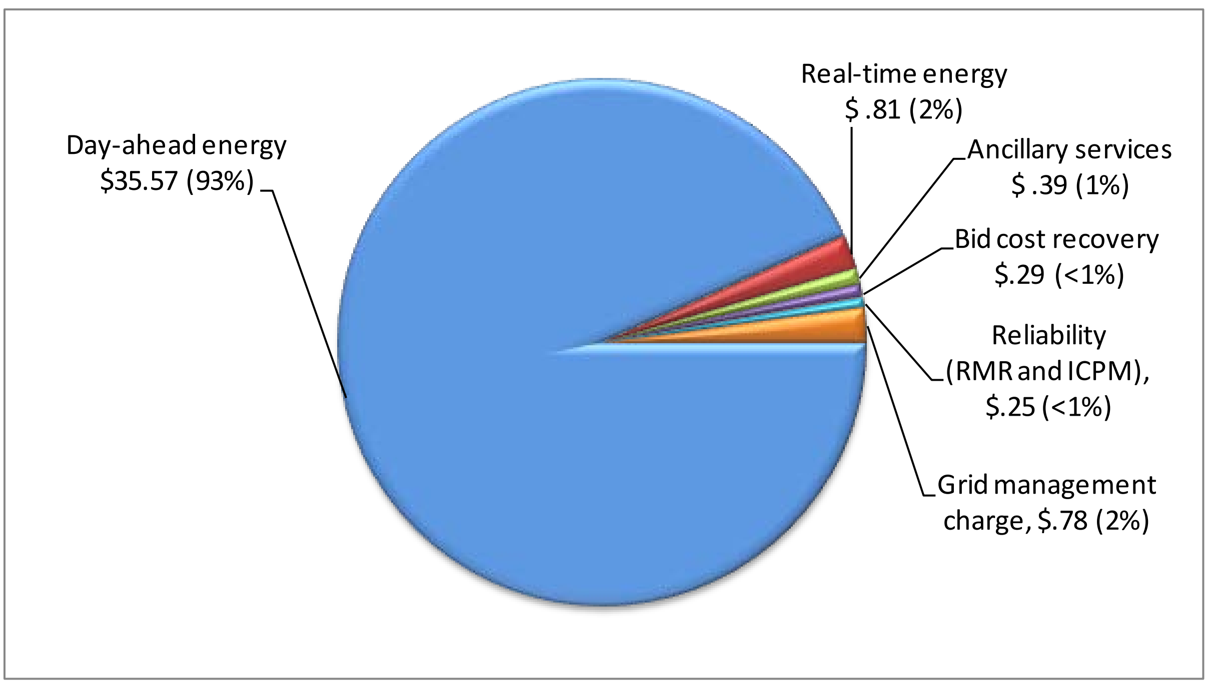


Figure E.3 Total wholesale costs in $/MWh of load served, 2009



Wholesale costs dropped significantly due to the lower spot market prices for natural gas, which averaged about 56 percent less in 2009 than in 2008.[2] Other factors contributing to the drop were lower loads and increased hydro availability in the summer months. The impact of congestion on costs was also low. This can be attributed to favorable load and supply conditions within the system and enhanced congestion management under the new market design.

Increased operational and market efficiencies under the new market design also contributed significantly to the decline in costs in 2009. Analysis of different market components provided in this report provides strong indications that this design increased market efficiency and reduced costs in a variety of ways.

- ***High day-ahead scheduling* —** The level of load and supply clearing the day-ahead market has consistently been very high. On average, almost 98 percent of total forecasted demand was scheduled in the day-ahead market. In the day-ahead market, the supply of resources that can be used to most meet load and manage congestion is typically much greater and more flexible than in real-time. Thus, high day-ahead scheduling allows for more efficient unit commitment, scheduling and congestion management. This also leaves a small volume of demand to be met by the residual unit commitment and real-time market processes.

- ***Convergence of day-ahead and real-time prices* —** In prior years, price indices for day-ahead bilateral markets tended to be higher than prices in the real-time imbalance market. Under the new market, prices in the day-ahead and real-time markets have converged closely, providing another indicator of the efficiency of the new market design. Price convergence in sequential energy markets indicates that day-ahead scheduling and dispatch patterns were accurate and efficient. This avoids the need for major adjustments as part of the re-optimization that occurs in the real-time market. As noted earlier, prices and dispatch patterns in the hour-ahead scheduling process used to adjust imports and exports often diverged significantly from the day-ahead and 5-minute real-time markets. This represents an area in which market efficiency can be further improved (See Chapter 3).

- ***Market competitiveness* —** Prices in the day-ahead and real-time energy markets have been extremely competitive. One of the key causes of the competitiveness of these markets is the high degree of forward contracting by load-serving entities. The high level of forward contracting significantly limits the ability and incentive for the exercise of market power in the day-ahead and real-time markets. In addition, bids for the additional supply needed to meet remaining demand in the day-ahead and real time energy markets have been highly competitive. Most additional supply needed to meet demand have been offered at prices close to default energy bids used in bid mitigation, which are designed to slightly exceed each unit's actual marginal or opportunity costs.

- ***Ancillary services* —** Ancillary service markets in 2009 performed well under the new market design. Costs declined from $0.74/MWh of load in 2008 to $0.39 in 2009. This represents a drop from 1.4 percent of wholesale energy costs in 2008 to only 1 percent in 2009. This compares favorably with ancillary service costs in other ISO markets with similar designs. In these markets, ancillary service costs have ranged from just under 1 percent to over 2 percent (See Chapter 6).

- ***Bid cost recovery payments* —** Under the new market design, generating units may submit three-part offers: start-up costs, minimum load costs, and bids for energy above minimum operating

[2] Average daily spot market prices for natural gas at the SoCal Border were about $3.9/mmBtu in 2009 compare to about $8.8/mmBtu in 2008.

levels. If a unit is started up or scheduled at minimum load during some hours through the day-ahead market, the unit is eligible for a bid cost recovery payment to ensure that it recovers the full cost of its start-up and minimum load costs, plus any energy bids that are dispatched. Three-part bidding and bid cost recovery may also increase the efficiency of the energy market by providing an incentive for suppliers to submit bids more closely to their marginal operating costs. Bid cost recovery payments averaged 1 percent of energy costs under the new market design. Equivalent uplift costs in other ISOs have also ranged from just under 1 percent to over 2 percent.

- ***Resource adequacy*** **—** The amount and location of capacity under resource adequacy contracts in 2009 also helped keep total costs low. Resource adequacy capacity has been used to meet almost all of residual unit commitment requirements under the new market design. Resource adequacy units are required to offer all available capacity into the residual unit commitment market at a price of $0/MW and do not receive an additional payment for capacity scheduled to meet residual unit commitment requirements. Resource adequacy capacity also helped reduce the amount and cost of capacity under reliability-must-run contracts, and was sufficient to meet local and system reliability requirements so that minimal additional capacity was procured through the interim capacity procurement mechanism in the tariff (see Section 7.6).

Energy markets

Since 2001, load serving entities have needed to procure energy through self-supply or bilateral arrangements, which was then scheduled in the day-ahead and hour-ahead congestion management processes. The CPUC has also encouraged the state's three major investor owned utilities to hedge a very large portion of their potential wholesale costs through a combination self-supply, forward bilateral contracting and other risk management vehicles.

Under the new market, self-scheduled and price-taking supply bids have accounted for about 70 to 80 percent of supply clearing the new day-ahead market. This means that the remaining 20 to 30 percent of supply is dispatched based on optimization of economic bids submitted by resource owners. As discussed in Chapter 3, the amount of supply clearing the market as a result of economic bids increased gradually over most of the months following implementation of the new market. This provides some evidence that as suppliers gain increased experience and confidence in the new market, they will offer an increasing portion of their supply into the ISO markets with price-sensitive bids.

Price convergence

A key measure of overall performance of the energy market is the degree of price convergence across the day-ahead, hour-ahead and real-time markets. In the first few months of the new market, average day-ahead prices tended to be lower than real-time prices. Average prices in the hour-ahead scheduling process were consistently lower than both day-ahead and real-time prices. Since then, price convergence in these three markets has improved substantially. By the fourth quarter of 2009, prices were similar across the energy markets when compared to previous quarters.

Figure E.4 shows average monthly prices in the three energy markets for the Southern California Edison load aggregation point during peak and off-peak hours, respectively. Price trends in the other major load aggregation points (Pacific Gas & Electric and San Diego Gas & Electric) are very similar to those depicted for the SCE area in Figure E.4.

Figure E.5 highlights the difference in average monthly prices in the hour-ahead and real-time markets for the PG&E area during peak and off-peak hours. As shown Figure E.5, prices in the hour-ahead scheduling process were systematically lower than prices in the 5-minute real time market, particularly during the first months of the new market. Although price convergence in these two markets improved toward the end of 2009, there was a tendency for prices in the hour-ahead process to be significantly lower than prices in the other markets. This remains an area for potential improvements in market performance. This issue is discussed in more detail in the following section.

Figure E.4 Comparison of peak hour prices (Southern California Edison)

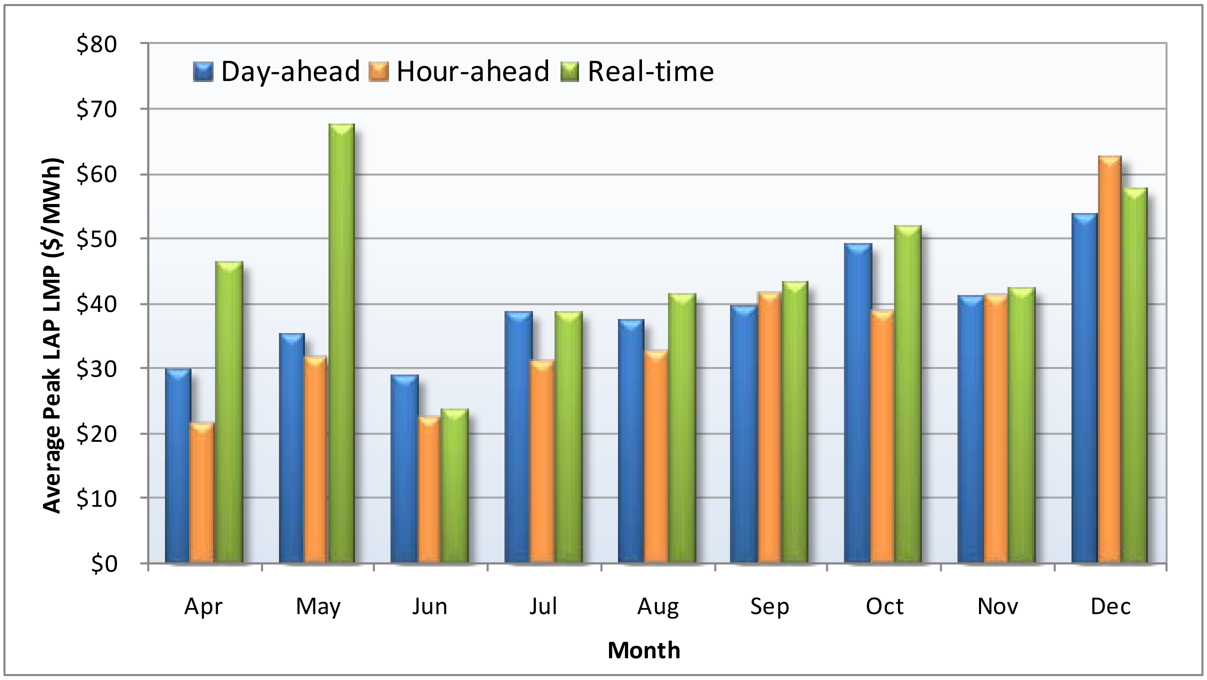
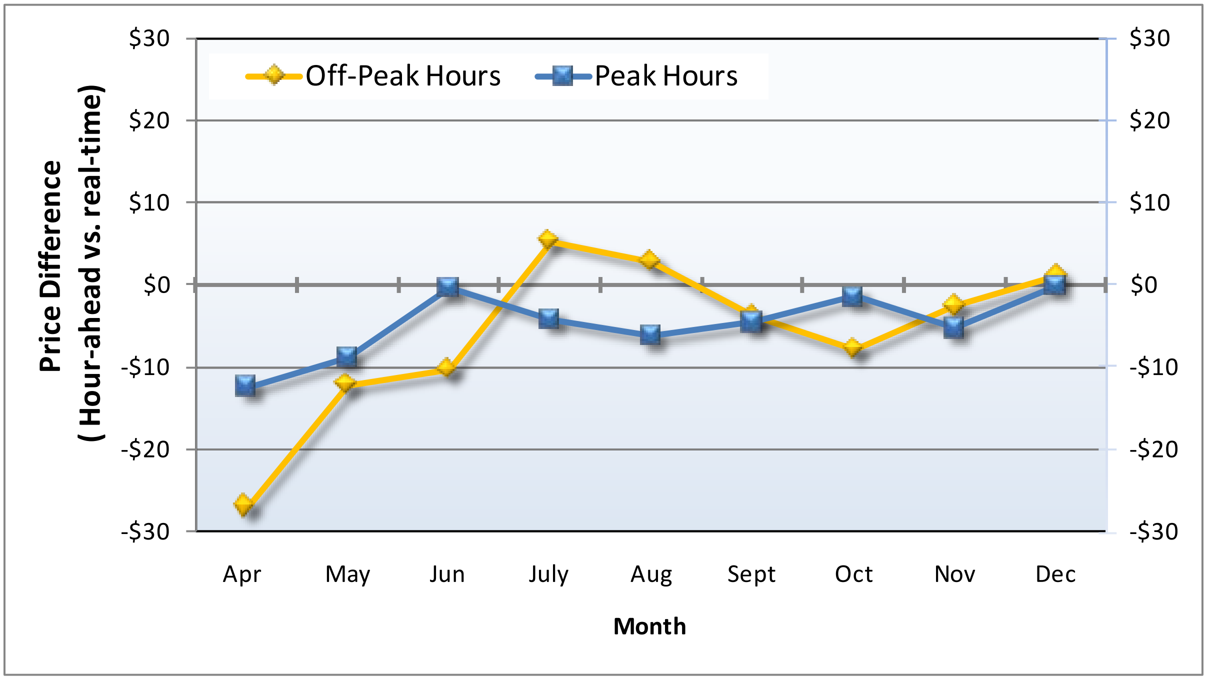


Figure E.5 Difference in hour-ahead versus real-time prices (Pacific Gas & Electric)



Hour-ahead scheduling process

During 2009, net import schedules clearing the hour-ahead scheduling process were systematically lower than net import schedules clearing the day-ahead market. As shown in Figure E.6, average monthly net imports clearing the hour-ahead process during peak hours were 500 MW to 1,000 MW lower than net day-ahead import schedules. This drop in net imports was due to a combination of a decrease in imports and an increase in exports in the hour-ahead market. Import schedules clearing in the hour-ahead decreased by an average of 200 MW, while exports increased by an average of 600 MW each hour.

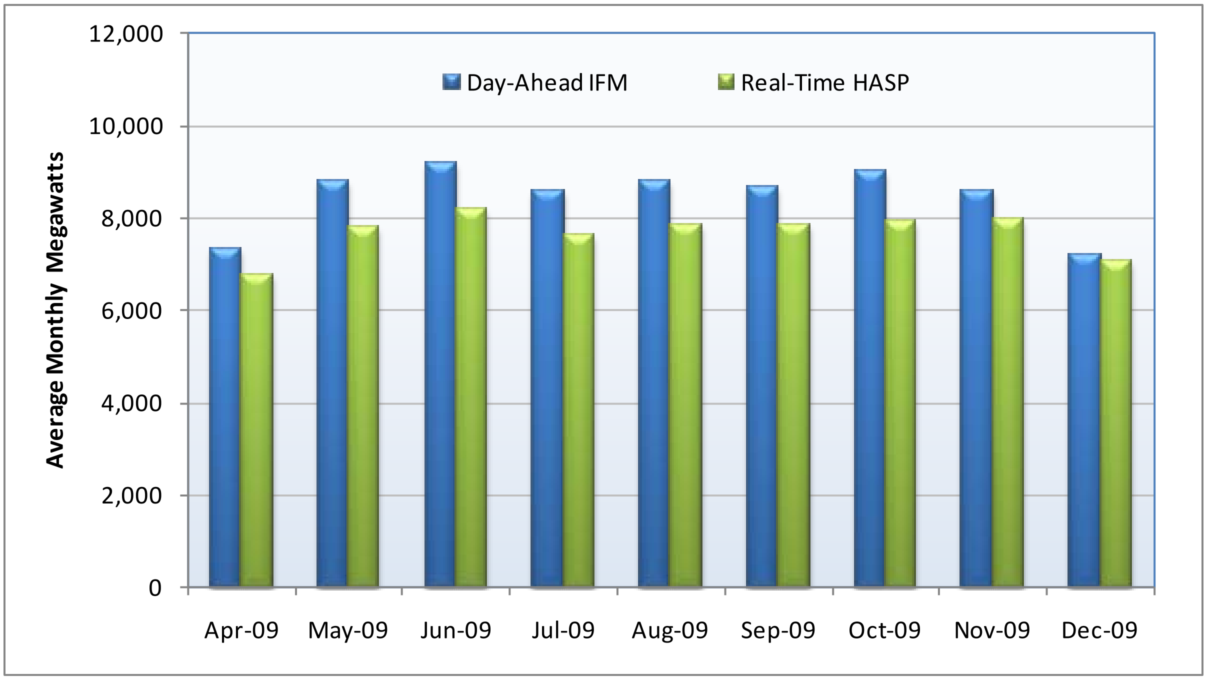
As noted earlier, prices in the hour-ahead market tended to be systematically lower than prices in both the day-ahead and 5-minute real-time markets. Regional marketers have responded to low hour-ahead prices by exporting power to other control areas and decreasing imports into the ISO. When net imports were decreased at low prices in the hour-ahead process, the ISO often needed to purchase additional energy to compensate for this at a higher price in the 5-minute real-time market. This pattern of selling low in the hour-ahead market and then buying high in the 5-minute real-time market has represented one of the most significant remaining sources of potential inefficiency under the new market.

This trend appears to be due to a combination of factors, as is discussed in greater detail in the DMM's quarterly report for the third quarter of 2009.[3] The low prices and decrease in net imports in the hour-ahead market appear to be due to systematic forecasting, modeling and optimization differences incorporated in the software used to clear the hour-ahead market and the software used for the 5-minute real-time market.

[3] *Quarterly Report on Market Issues and Performance,* Department of Market Monitoring, revised December 23, 2009. http://www.caiso.com/2457/2457987152ab0.pdf

This is one of the major areas of focus for modeling improvement in 2010. The ISO has implemented some improvements in the hour-ahead load forecasting process that appear to have improved performance of the hour-ahead scheduling process. The ISO is deploying several more significant forecasting and modeling improvements in 2010 that are intended to address some of the key causes of divergence between the hour-ahead and real-time prices and dispatch patterns.

Figure E.6 Net imports in day-ahead vs. hour-ahead market (peak hours)



Exceptional dispatch

Exceptional dispatches are manual instructions issued when the automated market optimization is not able to address a particular reliability requirement or constraint. Exceptional dispatches cause the ISO to serve load from specific generating resources, and can displace generation that otherwise would have been selected by the competitive energy and residual unit commitment market optimization processes. Thus, while exceptional dispatches are necessary for reliability, the ISO has made an effort to minimize exceptional dispatches by incorporating additional constraints into the market model that reflect reliability requirements that would otherwise need to be met by exceptional dispatches.

As shown in Figure E.7, total energy from exceptional dispatches ranged from 1 to 2 percent of total system energy from May to July, but decreased to less than 0.5 percent in the last three months of the year. Figure E.7 shows the hourly average energy from exceptional dispatches from three types of exceptional dispatches:

- ***Unit commitments*** — Exceptional dispatches for unit commitments instruct generators to operate at their minimum levels of output. The instructions typically occur one day in advance of actual operation, either before or after the running of the day-ahead energy and residual unit commitment processes. Minimum load energy from unit commitments accounts for the bulk of energy called upon by exceptional dispatches.

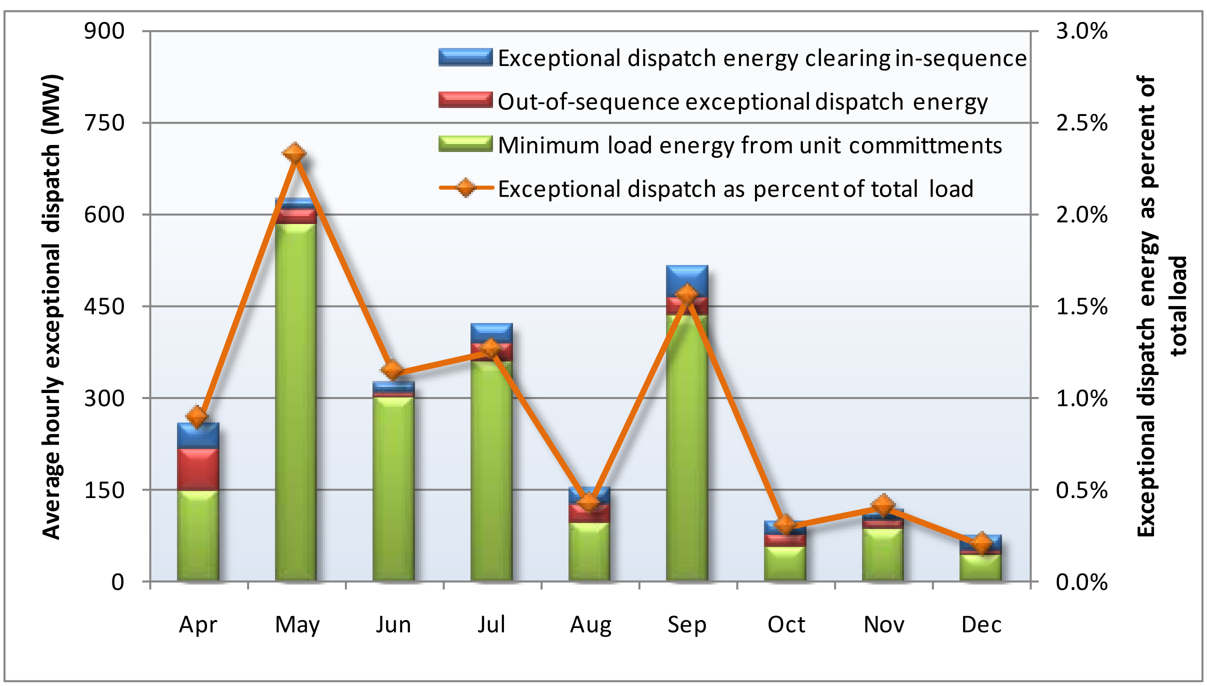
- ***In-sequence real-time energy*** — Exceptional dispatches are also issued to establish a minimum energy level for a unit above its minimum operating level. In this situation, the energy may be dispatched in-sequence by the real-time market software if the bid price clears the market. About half of exceptionally dispatched energy cleared in-sequence.

- ***Out-of-sequence real-time energy*** — Exceptional dispatches may also result in out-of-sequence real time energy if the bid price of a unit exceptionally dispatched is higher than the market price. Out-of-sequence real-time energy from exceptional dispatches was at its highest level in April, averaging approximately 68 MW per hour. Problems with the load forecasting software and other market features necessitated frequent market intervention through exceptional dispatches during this start-up period. By May, real-time exceptional dispatch energy dropped sharply to approximately 26 MW per hour, and remained below 30 MW on a monthly average basis through the end of the year.

The ISO continues to place a high priority on making improvements in modeling system and operating unit constraints, which should reduce the need for exceptional dispatches and any impact they may have on market prices.

Exceptional dispatches for energy may have had a significant impact on prices at some specific locations during limited time periods. However, is unlikely that exceptional dispatches for energy had a significant impact on overall real-time energy prices. As shown in Figure E.7, the bulk of energy from exceptional dispatches resulted from the minimum load energy from unit commitments. Minimum load energy would not be eligible to set the market clearing price, even if these units were committed through the market. As discussed in Chapter 3, operating logs also indicate a high portion of the out-of-sequence real-time energy from exceptional dispatches stemmed from unit operating constraints that would have made these dispatches ineligible to set market clearing prices.

Figure E.7 Average hourly energy from exceptional dispatches

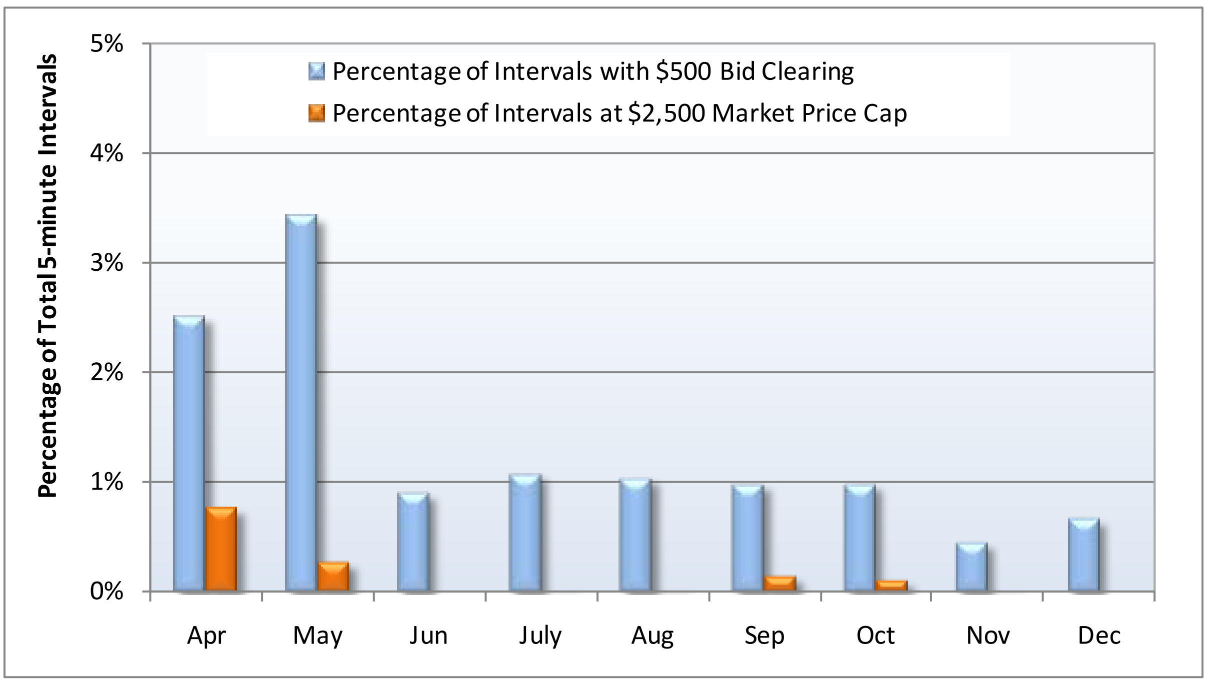


Market power mitigation

California's market design relies upon a high level of self-supply, forward-contracting and other portfolio risk management vehicles employed by load-serving entities to limit the potential for market power on a system-wide basis. The potential for market power on a system level basis is addressed through a $500/MWh bid cap. A $2,500 price cap was also in effect during the first year of the new market. However, these bid and price caps actually limited market prices in an extremely low portion of intervals. As shown in Figure E.8:

- Bids at the $500 energy bid cap were dispatched during an average of about 3 percent of intervals during April and May, but were dispatched during only about 1 percent of intervals over the remaining months of 2009. Overall, bids at the cap were dispatched in the 5-minute real-time market during about 1.3 percent of intervals from April to December 2009.
- The $2,500 market price cap was reached during about 0.76 percent of intervals in April and 0.27 percent of intervals in May, but was rarely reached during the remaining months of 2009. Overall, the price cap was reached in the real-time market during only 115 5-minute intervals or just 0.15 percent of intervals from April to December 2009.

Figure E.8 Frequency of $500/MWh bid cap and $2,500/MWh price cap binding in real-time market



Since ownership of generation resources within most transmission constrained load pockets of the system is highly concentrated under one or two major suppliers, the new market design includes more stringent provisions for mitigation of local market power. However, these have been triggered on a very limited basis due to the limited amount of congestion and highly competitive bidding that has occurred.

DMM has developed a variety of metrics to track and illustrate the frequency that bid mitigation is triggered and the impact this had on individual unit bids and dispatches. These metrics are described in Chapter 4 and Appendix A. Figure E.9 provides a monthly summary of three metrics showing the number of units impacted by mitigation in the day-ahead market:

- ***Units subject to bid mitigation* —** Mitigation is triggered if local market power procedures run prior to the day-ahead and if real-time markets indicate a unit may need to be dispatched at a higher level due to a non-competitive transmission constraint. During each month in 2009, an average of only one to three units per hour were subject to mitigation in the day-ahead market.

- ***Units with bids lowered* —** About 80 percent of units subject to mitigation in the day-ahead market actually had bids lowered as a result of mitigation. This reflects that market bids submitted by units are often lower than the default energy bids used to cap bids if a unit is subject to mitigation.

- ***Increased dispatches due to mitigation* —** About 30 percent of units subject to mitigation in the day-ahead market were dispatched at a higher level as a result of having their bid lowered by bid mitigation.

Figure E.10 shows the amount of energy dispatched from units within different local capacity areas because of bid mitigation in the day-ahead market. Section 2.1.1 of Chapter 2 provides a map and figures showing the location and amount of generation and peak load in each of these areas. As shown in Figure E.10:

- Over the entire nine-month period, an average of about 60 MW of additional energy may have been dispatched from mitigated units due to local market power mechanisms. This represents only 0.2 percent of system energy.

- Mitigation had the largest potential impact in September, when the total amount of additional energy that may have been dispatched from mitigated units averaged 134 MW per hour. This represents only 0.45 percent of system energy.

- The average hourly potential increase in energy dispatched from units due to mitigation was low and dispersed across different local areas.

- In the hour-ahead process, mitigation of real-time market bids was triggered a bit more frequently than in the day-ahead market.

The low frequency and impact of bid mitigation can be attributed to a combination of factors. As noted earlier, the need for mitigation was limited due to moderate loads and highly competitive bidding by supply resources. There was also limited congestion within the system. Mitigation may be triggered when congestion occurs on these paths in the market power mitigation runs made prior to the day-ahead and real-time markets. Bidding was also very competitive, with a large portion of supply needed to meet demand offered at prices just below or above marginal costs. In many cases, mitigation lowered a unit's bid market bid curve by a very small amount, so that this bid mitigation did not increase the level at which the unit was dispatched in the day-ahead market.

In 2010, DMM will pursue a number of potential changes in local market power mitigation procedures that may make them more efficient and may further reduce even further the low frequency with which mitigation is triggered. These are discussed in Chapter 4.

Figure E.9 Average number of units mitigated in the day-ahead market

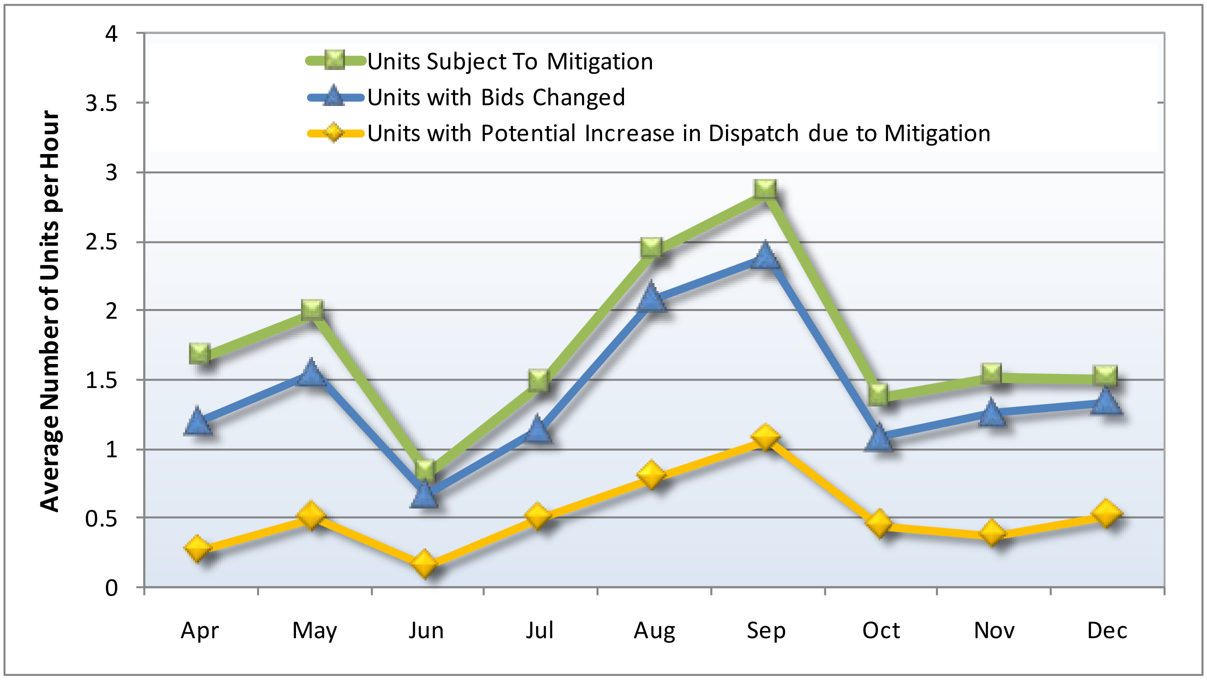
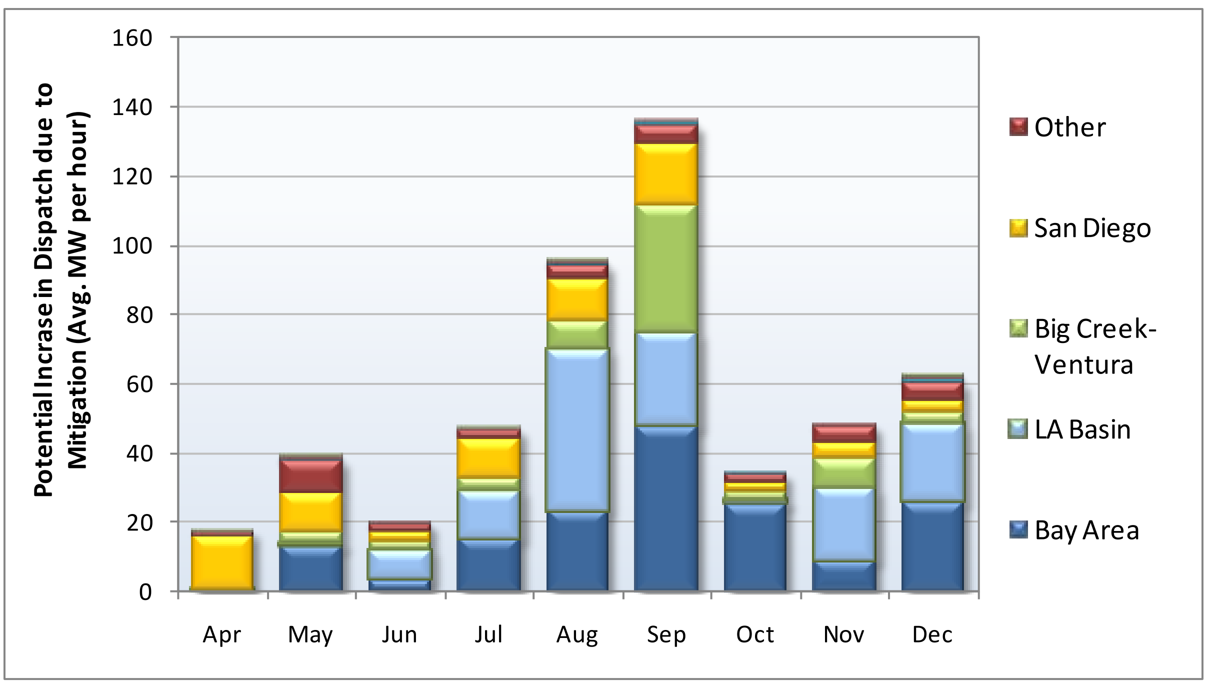


Figure E.10 Potential increase in day-ahead market dispatch due to mitigation: Hourly averages by local capacity area, April – December, 2009



Ancillary services

The new markets are designed to improve overall market efficiency through co-optimization of energy and ancillary services. With co-optimization, units are able to bid in all their capacity into both of these markets, and allow the market software to determine the most economical distribution of energy and ancillary service awards for each unit. This also increases the supply of bids available to both the energy and ancillary services markets.

Comparisons between ancillary services costs under the prior market and the new market designs must take into consideration a number of factors that affect these prices. Under the new market design, ancillary service costs have decreased based on measures that reflect each of the factors.

- As shown in Figure E.11, ancillary service costs decreased from $0.74/MWh of load in 2008 to $0.39/MWh in 2009. This represents a drop in ancillary service cost from 1.4 percent of estimated wholesale costs in 2008 to 1 percent in 2009.
- Monthly trends in ancillary service costs in 2009 before and after implementation of the new market also indicate that ancillary service costs have decreased under this design. As shown in Figure E.12, ancillary service costs increased in April, when the new market design was first implemented, but then decreased significantly over the rest of the year. Overall, ancillary service costs decreased from $0.49/MWh of load in the first quarter of 2009 to $0.36 in the remaining months of 2009 following the new market implementation.
- Seasonal trends also indicate that the new market design has resulted in lower ancillary service costs. These costs have historically increased in summer months when loads and prices are higher. However, as shown in Figure E.12, ancillary service costs decreased over the summer months in 2009 under the new market.

Figure E.11 Annual comparison of ancillary service cost as a percentage of wholesale energy costs

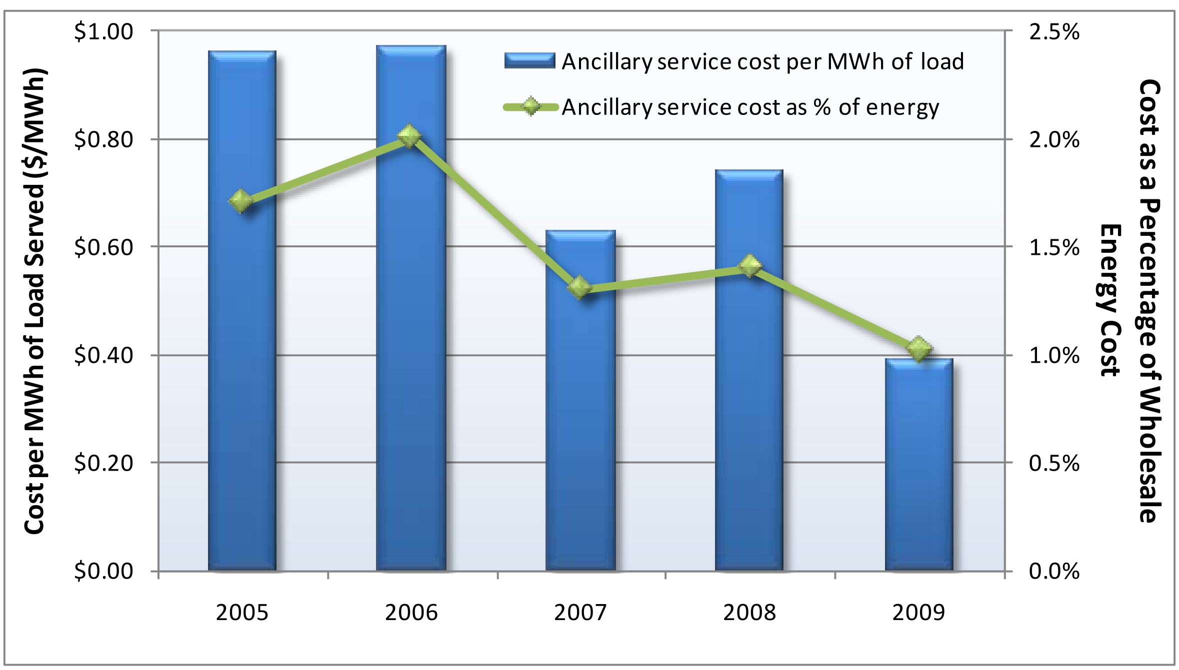
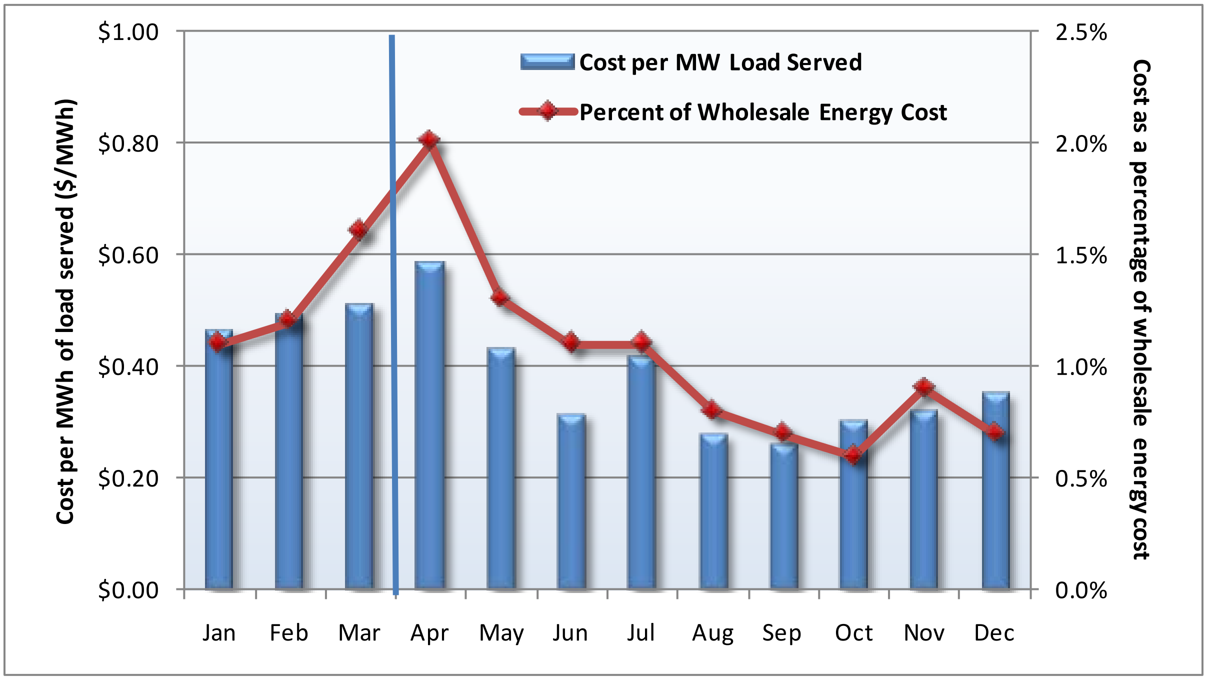


Figure E.12 2009 ancillary service costs by month



Residual unit commitment

The purpose of the residual unit commitment market is to ensure there is sufficient capacity online or reserved to meet load in real-time. The residual unit commitment market is run right after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of load that cleared in the day-ahead market and the day-ahead load forecast. Capacity procured in residual unit commitment, also called RUC availability, must be bid into the real-time market.

The direct cost of procuring through the RUC market for the first nine months of the new market was extremely low, totaling just $122,000. This is the result of two factors:

- First, the portion of load clearing the day-ahead market has consistently been high with an average of almost 98 percent of total forecast demand being scheduled in the day-ahead market. This left a small volume of demand to be met by the residual unit commitment processes.
- Second, virtually all capacity procured in RUC is from resource adequacy capacity. Resources providing resource adequacy capacity are required to offer all available capacity into RUC at a zero price and are not paid for any RUC capacity provided.

In addition to these direct RUC availability payments, about 13 percent (or $8.7 million) of bid cost recovery payments were associated with units committed in the RUC process. Thus, the combined cost of RUC availability payments plus these bid cost recovery payments is just over $8.8 million, or about 0.14% of total wholesale energy costs.

About 87 percent of bid cost recovery payments for units committed in RUC were incurred in August to November. During this period, additional capacity that was being committed in RUC increased due to capacity constraints that were added to reduce the need for committing units via exceptional dispatch. In January 2010, the ISO implemented these constraints in the day-ahead market and removed them from the RUC market. This should result in more efficient use and scheduling of any units committed to meet these constraints, because these units will have an opportunity to be scheduled for additional energy in the day-ahead market.

Resource adequacy program

Unlike other major ISOs, California's market design does not have a centralized capacity market. California relies on resource adequacy requirements placed on load serving entities to ensure that sufficient capacity is available to meet reliability planning requirements on a system-wide basis and within local areas.

- On a system-wide basis, load-serving entities must procure resource adequacy capacity equaling 115 percent of their projected peak demand requirements for each month under a 1-in-2 year forecast of peak demand.
- Local capacity requirements within specific areas of the grid total about 28,000 MW, as shown in Chapter 2, Figure 2.4 and in Table 2.2.

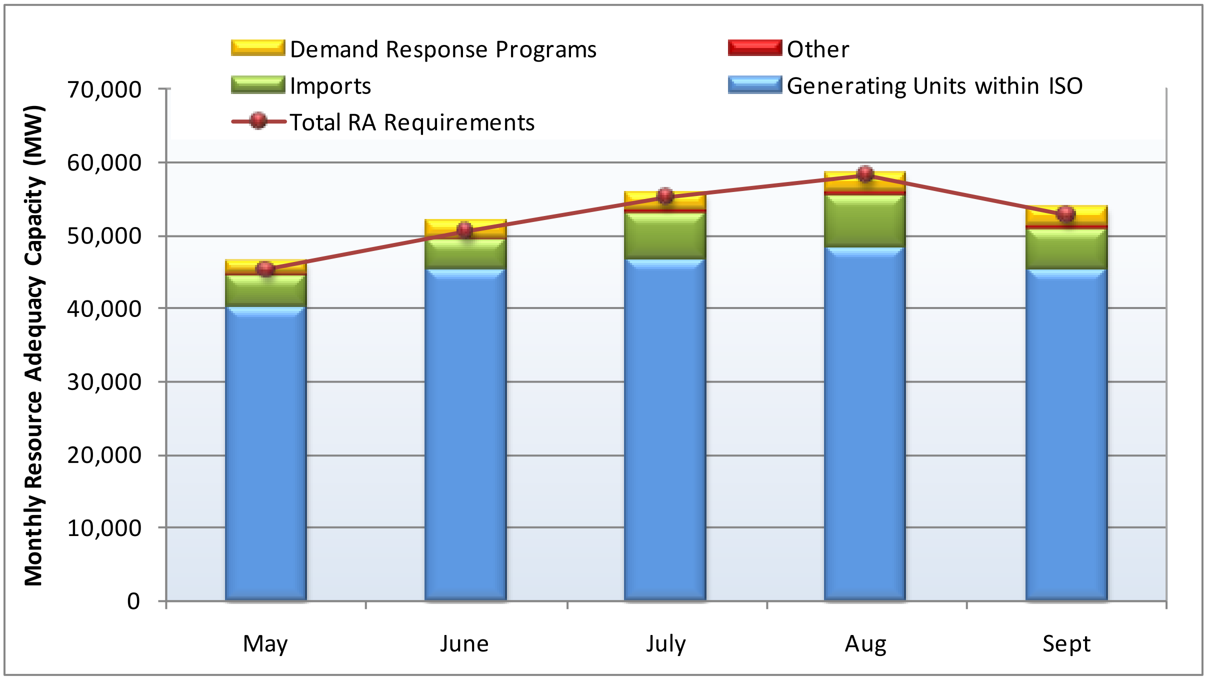
In 2009, resource adequacy capacity procured by load-serving entities in monthly showings met or exceeded their reliability requirements. As a result, the ISO did not need to procure any additional capacity to meet local capacity area requirements that were not met in the load-serving entities' year-ahead and month-ahead showings.[4] As shown in Figure E.13, about 3,000 MW of demand response capacity from utility programs were used by load-serving entities to meet nearly 5 percent of the total system-wide resource adequacy requirements during the summer months of 2009. Imports accounted for almost 10 percent of resource adequacy capacity during August.

Chapter 7 provides an analysis of the amount of resource adequacy supply actually bid or scheduled in the market during summer 2009. Our analysis shows that average availability of resource adequacy capacity to the market was high during the peak summer load hours, with about 91 percent of the overall capacity being available to the day-ahead market and about 88 percent to residual unit commitment. This represents an overall availability just slightly below the 93 percent level that is assumed in the resource adequacy program design.[5]

[4] A minor amount of capacity was procured under the interim capacity procurement mechanism provisions on a monthly basis due to minor changes in the amount of resource adequacy capacity available in some months and the issuance of exceptional dispatches to non-resource adequacy capacity.

[5] 115 percent resource adequacy requirements less 7 percent operating reserve = 108 percent. Thus, after accounting for operating reserve, about 93 percent of remaining resource adequacy capacity would be necessary to meet the 1-in-2 year peak load used in setting the requirement (93 percent x 108 percent = 100 percent).

Figure E.13 Resources used to meet resource adequacy requirements



Investment in new generation

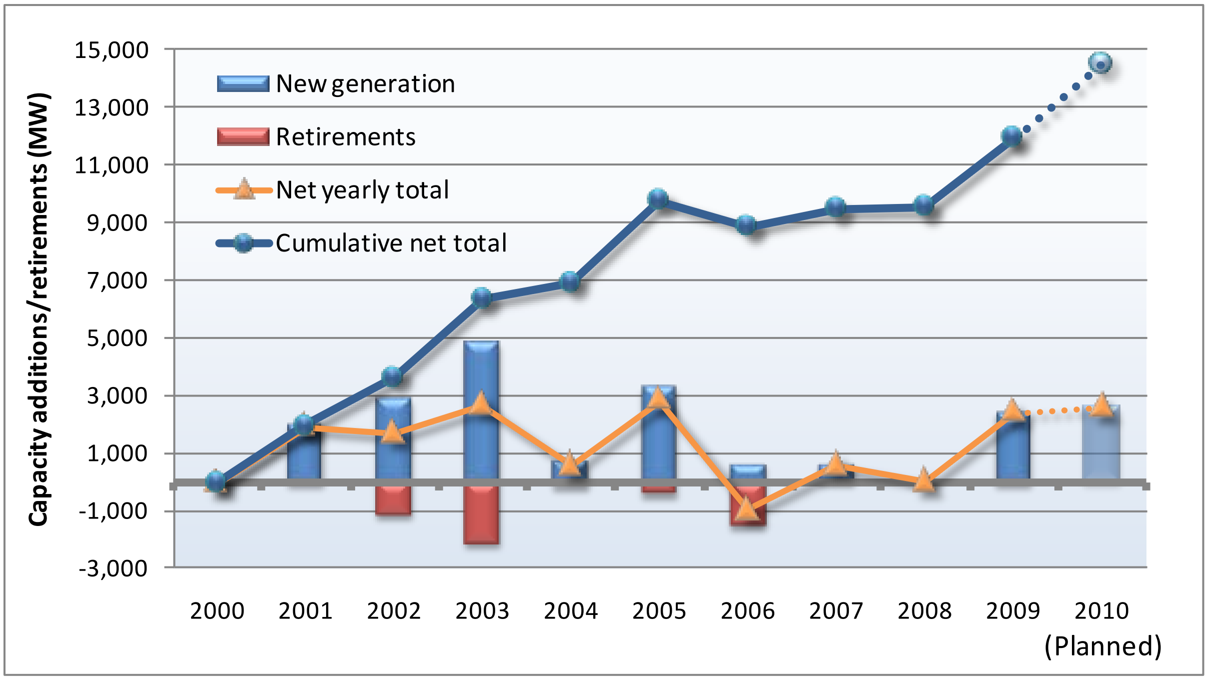
The amount of generation capacity being added and retired in the ISO each year provides an indication of the effectiveness of the California market and regulatory structure in bringing about new generation investment to replace older inefficient plants and meet load growth. Figure E.14 summarizes trends from 2000-2009, and planned capacity additions and retirements in 2010. Significant levels of new gas-fired generation were added in 2009 and are scheduled to be added in 2010. This provides some evidence that the state's resource adequacy program has been successful at stimulating some investment in new capacity.

DMM performs an annual assessment of the revenues that may be earned by a typical new generating unit from the market. This provides an indication of the extent to which the day-ahead, real-time energy and ancillary service markets may contribute to recovering the fixed costs in building new generating capacity. Annualized costs for new capacity critical for meeting reliability needs should be recoverable through a combination of long-term bilateral contracts and spot market revenues.

Results of this analysis for 2009 show a substantial decrease in net revenues for a typical new gas-fired combined cycle unit compared to 2008. As summarized in Chapter 2, estimated net revenues for typical new gas-fired generating units in 2009 would fall substantially below the annualized fixed cost of new generation. This analysis does not include revenues earned from resource adequacy contracts or other bilateral contracts. DMM does not have information on these revenues. However, these findings underscore the critical importance of long-term contracting as the primary means for facilitating new generation investment under the current market design.

The drop in net revenues for new gas combined cycle capacity is primarily attributed to the significant decrease in spot market gas prices and the associated drop in electricity prices. It may seem counterintuitive that lower gas prices would decrease net revenues for a new gas resource. However, since older less efficient gas units are often the marginal resources setting prices in the market, lower gas prices decrease the net revenues of new more efficient gas generation. This is illustrated in more detail in Section 2.3 of Chapter 2.

Figure E.14 Generation additions and retirements: 2000-2010



Recommendations

Short-term market improvements

DMM has provided recommendations for short-term market improvements in our quarterly reports. While the ISO has already taken steps responsive to these recommendations, follow-up on a number of these recommendations is warranted in 2010:

- ***Consistency of hour-ahead and real-time markets* —** Since the first few months of the new market, one of DMM's major recommendations has been to address the systematic divergence between dispatches and prices in the hour-ahead and real-time markets. DMM has worked with the ISO to identify several specific potential causes for this divergence. The ISO is taking steps to address these issues. The ISO has also identified a number of other modeling improvements that may address this issue and has made these initiatives a major focus in 2010. A more detailed discussion of these recommendations and initiatives is provided in Section 3.8 of Chapter 3.

- ***Exceptional dispatches* —** DMM has worked closely with the ISO to monitor and assess the volume and reasons for exceptional dispatches. This information was used to help identify ways to reduce the major causes of exceptional dispatch by incorporating additional constraints in the market model. As described in Section 3.5 of Chapter 3, the ISO has taken a number of steps to decrease exceptional dispatches. Because of this effort, the volume of day-ahead unit commitments has declined measurably. In 2010, the ISO continues to place a major emphasis on reducing the need for manual adjustments or intervention to supplement the automated market processes. DMM will continue to monitor the volumes and reasons for exceptional dispatches.

- ***Conforming transmission constraint limits based on actual flows* —** In our third quarterly report, DMM recommended that the ISO should continue to place a high priority on refining the practice of adjusting or conforming constraint limits in the market software. The ISO has taken a number of steps to reduce the need to conform constraint limits and provide more transparency of these adjustments to market participants. A more detailed discussion of these recommendations and actions taken by the ISO in this area is provided in Section 3.8 of Chapter 3 and Section 5.6 of Chapter 5.

- ***Compensating injections* —** This software feature automatically adjusts market flows in the hour-ahead market to reconcile the difference between modeled flows and actual flows observed at inter-ties with other control areas. As discussed in Section 3.8 of Chapter 3, DMM has recommended that prior to implementing this software feature, the ISO should develop metrics that can be used to monitor the impact of compensating injections on specific major constraints that are likely to be impacted by this feature.[6] DMM is working with the ISO to develop these metrics, and has recommended that the ISO provide participants with a technical paper and advance notice prior to re-implementing this feature.

New design initiatives

DMM has provided recommendations for new design initiatives developed in 2009 or that are under consideration.

Proxy demand resources

In May 2010, the ISO will implement a new product known as proxy demand resources. This product allows customers, utilities and third-party demand response providers to bid in load reductions as a demand-side resource in the market, similar to how a generator participates as a supply-side resource. This product is designed to increase participation in the energy and ancillary services markets.

DMM has offered recommendations to provide a reasonable level of assurance that demand reductions being paid for are actually occurring. We specifically suggested that program rules be further refined to establish more specific consequences for non-compliance with program requirements. In addition, the ISO should ensure it can quickly modify rules to address any identified measurement inaccuracies or gaming. These recommendations were incorporated in the final tariff filing on proxy demand resources.

Our other recommendations emphasized that effective administration of the proxy demand resource program will require significant attention, particularly for ongoing activities relating to verification, monitoring, assessment and potential rule modifications. The ISO has committed to develop a

[6] Modeled flows for constraints in the ISO provided by the market software do not differentiate between the portion of flow attributable to compensating injections and the portion of flow attributable to market schedules. Thus, the impact of compensating injections on constraints within the ISO must be calculated using data on the compensating injection values at each CNode outside of the ISO system, combined with shift factors for these CNodes relative to constraints within the ISO.

measurement and verification plan that addresses demand response performance, and has indicated that additional limitations may be placed on proxy demand resources in the future if necessary based on market analysis and participant behavior.[7]

The ISO expects participation by proxy demand resources to start at a low level in summer 2010 (e.g., 25 to 50 MW). This provides the opportunity to monitor and analyze initial program participation in 2010. Results of this monitoring and analysis can then be used to develop any modifications that might be appropriate before program participation ramps up in future years.

DMM continues to work with the ISO to ensure that effective monitoring and verification procedures are developed as part of the program implementation process. DMM plans on working with the ISO to assess the accuracy of the relatively simple method it will use to determine the baseline consumption that is used to measure load reductions when proxy demand resources are dispatched. If this approach systematically overestimates demand reductions, this will result in payments for demand reductions not achieved, as well as hinder further development of proxy demand resources.

Non-utility demand service providers

The state's resource adequacy program allows load-serving entities to use demand resources to meet their resource adequacy requirements. However, demand response providers are only able to earn capacity payments through utility managed retail demand response programs or through utility procurement contracts for demand response resources. Many stakeholders feel that without access to resource adequacy capacity payments, there will be insufficient incentive for aggregators to develop demand response resources able to participate directly in the market.[8]

This was identified as a significant potential barrier to demand response in a major report commissioned by the ISO on demand response in 2009.[9] One of the important steps to decrease the barriers to development of non-utility demand response is to define criteria or performance standards that must be met for proxy demand resources to meet resource adequacy requirement of another load-serving entity. Such criteria or standards would help make proxy demand resources a tradable product that demand service providers could sell to load serving entities in the bilateral market. Thus, we are recommending that the ISO begin to address this issue in 2010 to ensure that this does not hinder development of demand response resources by non-utility demand service providers.

Regulation energy management resources

The ISO is proposing tariff modifications that would encourage participation by non-generator resources in the ancillary services market. The proposal would open the ancillary service market to a broad range of non-generation technologies, including demand response and a variety of advanced energy storage technologies (e.g., batteries, flywheels, and compressed air). With greater access to the ancillary services market, these non-generation resources will have a broader range of revenue opportunities, and price signals for appropriate investment in these new technologies. The ISO will benefit from the

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[7] Memo to ISO Board of Governors, re: Decision on Proxy Demand Resource**,** September 2, 2009, p.7. http://www.caiso.com/241e/241eb5b844d0.pdf.

[8] See *California Independent System Operator Demand Response Barriers Study (per FERC Order 719*), April 29, 2009, prepared by Freeman, Sullivan & Co. and Energy and Environmental Economics, Inc. p. 29, http://www.caiso.com/2410/2410ca792b070.pdf.

[9] Ibid.

additional ancillary service resources provided and from how these non-generation resources will help to facilitate integration of renewable energy.

The ISO is considering a new resource category called regulation energy management. We identified numerous concerns with this approach as initially proposed. For example, the proposal would exempt regulation energy management resources from settlement of real-time energy. The efficiency of these resources in performing regulation services can range from 50 to 85 percent. Exempting these resources would not encourage development of more efficient demand response or storage technologies relative to less efficient storage technologies.

DMM believes it may be more appropriate to consider creating a separate regulation product tailored more specifically for regulation energy management resources, which also helps them aid the integration of renewable energy. The ISO has committed to re-examining this issue through the ancillary services market product review stakeholder process scheduled to begin in the second quarter of 2010.

Developing a comprehensive approach that addresses all long-run issues associated with regulation energy management resources may take significant time. However, we believe that it should be possible to develop an initial framework for the provision of regulation services by non-generation resources on a timeline that does not delay developing and testing of these new resources. For example, given the limited amount of these resources, pilot programs could be implemented while the details of any new market products are developed.

Market power mitigation

System level market power

The new market design relies upon a high level of self-supply and forward-contracting by load serving entities as a means of mitigating system-level market power. This is consistent with California Public Utilities Commission policies designed to ensure that the state's major utilities are hedged for a large portion of their energy supply needs. These policies have been effective and should be continued. A higher level of forward contracting and hedging will become increasingly important as the bid cap is raised from $500/MWh to $750/MWh and $1,000/MWh in the second and third years of the new market.

Local market power mitigation

The local market power mitigation provisions in the new market design have proven to be effective without imposing an excessive level of mitigation. Although these mitigation provisions have not had a significant direct impact on market results, this does not mean that these provisions are unneeded or did not have a significant indirect impact. Having effective market power mitigation provisions in the day-ahead and real-time markets encourage forward contracting and deters attempts to exercise market power.

These mitigation provisions should be maintained, while developing refinements. In 2010, DMM will pursue a number of potential changes that may make these provisions more efficient, and may reduce even further the low frequency with which mitigation is triggered. These potential modifications are discussed in more detail in Chapter 4.

As part of the process for developing the design for convergence bidding, DMM proposed modifications to market power mitigation procedures. These modifications are designed to ensure that local market power provisions are not undermined by bidding of virtual demand within transmission constrained load pockets.[10] The ISO indicated modifications to market power mitigation procedures proposed by DMM could not be implemented in conjunction with convergence bidding in February 2011, but committed to consider these modifications for implementation in April 2012.[11]

In 2010, DMM plans to further assess these proposed modifications to local market power mitigation with the ISO and stakeholders. We are recommending that the ISO and the Market Surveillance Committee perform further review of these proposed modifications, or other alternatives they may be considering, in 2010. This is necessary to ensure that any modification to these procedures that are ultimately preferred is not hindered by the time needed for implementation.

Competitive path assessment

The method used to designate constraints as competitive or non-competitive should be more dynamic. Starting in the second year of the new market, the competitiveness of constraints will be assessed four times a year. This analysis is time-consuming and must be performed based on a projection of potential system conditions several months in advance. Ideally, these designations can reflect current operating conditions, rather than being determined in advance based on assumptions of system and market conditions.

We are currently developing enhanced modeling tools that may allow much more dynamic designations. And we will also continue to develop alternative approaches for assessing market competiveness, such as the residual supply index used by other ISOs. We are also supporting development of potential approaches based on the residual demand curve facing individual suppliers, as suggested by the Market Surveillance Committee. Once tools for more dynamic assessment of the competitiveness of paths are in place, we intend to work with stakeholders to assess potential modifications to the current competitive path assessment methodology. Potential modifications to this methodology are discussed in more detail in Chapter 4.

Mitigation process quality improvements

In DMM's 2009 quarterly reports, we noted that there have been numerous hours in local market power mitigation procedures that were not reviewed for price impacts by the price correction team. DMM recommended that the ISO improve the process for ensuring that mitigation procedures in the hour-ahead scheduling process are thoroughly reviewed. We are continuing to work with the ISO to ensure the process for reviewing all aspects of the market power mitigation process is improved. The ISO has made this a priority in 2010. This is important to ensure the continued effectiveness of local market power mitigation procedures, and the confidence of market participants in market outcomes.

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10 *Local Market Power Mitigation Options Under Convergence Bidding*, Department of Market Monitoring, October 2, 2009 (http://www.caiso.com/243b/243bebe3228c0.pdf) and *Illustrative Examples of Alternative Local Market Power Mitigation*, Department of Market Monitoring, October 6, 2009 (http://www.caiso.com/243f/243fce76bf30.pdf).

11 The current day-ahead local market power mitigation procedures are based on the demand forecast. FERC has ordered the ISO to modify these bid mitigation procedures to be based on bid-in demand April 2012. The approach proposed by DMM would be based on bid-in demand, and would therefore provide a way for the ISO to comply with this FERC order.

Resource adequacy program

In March 2010, the CPUC issued a proposed order indicating that development of a centralized capacity market or a multi-year forward resource adequacy requirement may be deferred beyond 2010.[12] However, the current resource adequacy provisions of the ISO tariff and CPUC regulations will continue to be reviewed and modified.

Investment in new supply

As illustrated in Figure E.14, significant levels of new gas-fired generation were added in 2009 and are scheduled to be added in 2010. This provides some evidence that the state's resource adequacy program has been successful at stimulating some investment in new capacity. However, analysis of net revenues that would be earned by a typical new gas-fired generating plant in the market in 2009 shows a substantial decrease in net revenues compared to 2008 and would fall substantially below the annualized fixed cost of new generation.

This demonstrates one of the key trends in other ISOs with similar market designs. In highly competitive electricity markets, in which prices reflect generating costs of the marginal resources needed to meet demand, net operating revenues do not provide for recovery of the full fixed costs of new generation. These findings underscore the critical importance of long-term contracting as the primary means for facilitating new generation investment under our state's current resource program.

State policies designed to eliminate the use of once-through-cooling will complicate the challenge of ensuring sufficient new generation investment under the resource adequacy program. Most of the current capacity employing once-through-cooling is located within transmission constrained areas and is needed to meet local reliability requirements. California's current market design relies upon bilateral contracting by load-serving entities for the investment needed to ensure sufficient capacity remains within these areas to meet local resource adequacy requirements.

Integration of renewable energy and demand response

California has adopted policies to dramatically increase reliance on renewable energy and demand response. These policies are already simulating significant planning and investment in new renewable resources. New resources needed to meet these goals would meet the bulk of the state's requirements for new additional energy. However, the remote locations and intermittent nature of renewable resources is creating new and different investments in transmission, backup capacity and new types of ancillary services.

The ISO is placing a major emphasis on assessing how increased reliance on renewable energy and demand response will impact operational and reliability requirements. The ISO is also being proactive in planning transmission upgrades and modifying its market rules to spur development and integration of renewable energy and demand response.

There is considerable debate over whether overall market efficiency and California's goals for development and integration of renewable energy and demand response resources would best be achieved by continuing to base the state's resource adequacy program on bilateral contracting or to

[12] *Revised Proposed Decision: Adoption of a Preferred Policy for Resource Adequacy*, California Public Utilities Commission, May 30, 2010. http://docs.cpuc.ca.gov/efile/PD/115559.pdf

implement a centralized capacity market. Regardless of the approach California adopts, the ISO and CPUC face the challenge of refining capacity counting methods and performance standards for different resource types.

The availability of different resources can vary significantly, including during peak hours when they may be needed most for reliability. The availability and dispatchability of different resources also impacts how much backup capacity and new types of ancillary service the ISO may need to procure to ensure system reliability. Thus, improved methods are needed for quantifying the value of different resources in terms of their capacity value and impact on ancillary service requirements.

As part of the standard capacity product stakeholder process, the ISO has recently sought to develop forced outage standards for cogeneration, wind, solar and other non-conventional intermittent sources. The ISO's approach has used the framework established for forced outages of traditional dispatchable gas-fired units. This approach has proven problematic due to the diverse and fundamentally different nature of these intermittent resources. If forced outage standards are not tailored based on characteristics of different resource types, such standards may create an additional financial risk for these resources while providing minimal or no additional reliability benefit.

For many of these other resource types, DMM believes it may be more appropriate and effective to incorporate the reliability and operational characteristics of these resources, including forced outage rates, in the capacity value assigned to each resource under a resource adequacy or capacity market design. The costs of any additional ancillary services needed to integrate different resources should also be allocated in a way that reflects the reliability and operational characteristics of different resources. This will help ensure proper price signals for investment in different types of new resources. As increased reliance is placed on renewable energy and demand response resources, this will also ensure that the ISO maintains the necessary mix of resources to maintain reliability and market efficiency.

The ISO has a number of initiatives through which these issues can be further addressed in 2010. The CPUC and ISO have recently refined the criteria used to assess the amount of capacity from intermittent resources such as wind and solar that can be used to meet resource adequacy requirements. New criteria taking effect in 2010 should continue to be assessed and revised as necessary based on analysis of system needs as increased reliance is placed on renewable energy and demand response resources. The ISO is also initiating a stakeholder process in 2010 to review the potential need for new types of ancillary services that may be appropriate as increased reliance is placed on renewable energy and demand response resources.

1 Overview of California's wholesale electricity markets

In 2009, the ISO implemented a major redesign of California's wholesale energy markets as part of a multi-year project known as the market redesign and technology upgrade. This new market design has many of the same features in place at other ISOs and of those incorporated into the standard market design framework established by the Federal Energy Regulatory Commission. The new design includes a variety of features that should increase the overall efficiency of the wholesale market, including:

- Pricing and congestion management based on locational marginal pricing.
- Use of a full network model that includes all of the key market and physical constraints of the system.
- A day-ahead integrated forward market that includes simultaneous optimization of energy and ancillary services, and separate three-part bids for start-up costs, minimum loads and energy.
- A day-ahead residual unit commitment process for committing any additional resources and procuring sufficient additional capacity to meet the difference between the forecasted demand and demand scheduled in the day-ahead market.
- An hour-ahead scheduling process for pre-dispatching and pricing of additional hourly imports and exports based on projected supply and demand conditions in the next operating hour.
- An enhanced real-time dispatch process for balancing loads and supplies within each operating hour on a 5-minute basis.
- A must-offer requirement for all resources owned or contracted by load-serving entities to meet their resource adequacy obligations. These resource adequacy resources must offer all available capacity in the energy and residual unit commitment markets.
- Local market power mitigation provisions to protect against the potential for market power within transmission constrained load pockets, in which a few major suppliers own the bulk of generating resources needed to meet local reliability requirements.

This chapter provides an overview of the new market design and how its key components, examined in different sections of this report, are interconnected. The following sections also highlight how this new design varies from market rules in other ISOs that have implemented a nodal LMP-based market. The final section of the chapter summarizes key enhancements developed in 2009 that will be implemented over the second year of the new market operation.

1.1 Locational marginal pricing

The new market design is based on nodal locational marginal pricing. Locational marginal prices represent the cost (in $/MWh) of serving the next increment of demand at each point (or node) on the network, taking into account the bid prices of resources and transmission network constraints. Locational marginal prices are derived using a full network model that includes a detailed model of the physical power system network. Thus, the resulting prices reflect the physical system and market conditions and limitations.

Under locational marginal pricing, as congestion appears on the network, prices at each node adjust to reflect congestion costs or benefits from supply or demand at that particular location. Within areas where flows are constrained by limited transmission, higher cost generation is dispatched to meet demand. Outside of these transmission constrained areas, demand is met by lower cost generation. Hence, LMPs in congested regions are higher than the price in unconstrained regions.

Nodal LMP-based markets enable the ISO to more economically and efficiently manage congestion and provide price signals to market participants to self-manage congestion. Over the longer term, LMP markets also provide more efficient price signals to encourage development of new supply and demand-side resources within more constrained areas of the grid. LMP markets also help identify transmission upgrades that would be most cost-effective in terms of reduced congestion.

Because ownership of generation resources is highly concentrated within local transmission constrained areas (or load pockets), using LMP-based markets also heightens concern about the potential exercise and impacts of local market power. Consequently, the new market design includes provisions to mitigate local market power within transmission constrained load pockets. These provisions are described in Section 4.1 of Chapter 4.

Under the new market design, generating resources are paid based on LMPs for the specific node at which they are located. Meanwhile, load is bid and settled using load aggregation points, which represent aggregations of individual load nodes.[13] The three major load aggregation points in the system correspond to the service territories of the state's three major investor owned utilities: Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric.

This LAP-based approach for bidding and settlement of load was incorporated in the new nodal market design for a variety of reasons.[14]

- The use of load aggregation points for demand scheduling and bidding was designed to prevent unfair financial impacts to customers located in constrained areas of the grid that may result under nodal pricing.
- Scheduling and bidding of demand by load aggregation points was felt to be more practical and accurate, because each load-serving entity may have customers with load at hundreds or thousands of load nodes in the system.
- Finally, as explained in the filing for this new market design, "…there is general agreement among experts and those that operate markets based on LMP that the most important element in achieving the operational benefits of LMP is to settle supply resources at nodal prices, and that it is much less important to settle Demand at nodal prices."[15]

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[13] In the day-ahead market, scheduling coordinators submit bids for load at the load aggregation point where the load is located. The market software then automatically distributes load bids and forecasts at the load aggregation point level to individual nodes using load distribution factors. These load distribution factors represent the approximate portion of total load located at each node within the load aggregation point. In the real-time market, the market software forecasts real-time load at the load aggregation point level and automatically distributes this to individual nodes using load distribution factors.

[14] See Prepared Direct Testimony of Lorenzo Kristov (Exhibit ISO-1) submitted as Attachment F to the ISO's February 9, 2006 MRTU filing, (pp 27-36). http://www.caiso.com/1798/1798f5a45efa0.pdf

[15] The filing also noted that "… with regard to incentives for increasing Demand responsiveness, settlement based on time-varying prices is far more effective than settlement at spatially-varying prices," so that the ISO "therefore believes that it can

To promote demand response within higher price constrained areas, the ISO is implementing a proxy demand resource program in 2010 that will allow demand response to be settled based on LMPs that reflect the specific nodes at which load is being reduced.

1.2 Day-ahead market

Another major feature of the new market design is the day-ahead market for energy and ancillary services, known as the integrated forward market. California has not had a centrally cleared day-ahead market for energy since the January 2001 closure of the California Power Exchange, which forced load-serving entities to procure energy through self-supply or bilateral arrangements, and then schedule this energy in the ISO's day-ahead and hour-ahead congestion management processes. This lack of a day-ahead market has encouraged a very high level of self-supply and long-term forward bilateral contracting by the three major investor-owned utilities that serve the bulk of ISO load.

The California Public Utilities Commission also provided strong regulatory incentives for forward contracting and other portfolio risk management mechanisms. The state's three investor owned utilities procure electricity resources under long-term procurement plans based on guidelines developed by the CPUC. These plans are developed approximately every two years and include each utility's procurement strategy for the upcoming 10-year period. Under the currently-effective CPUC rules, these utilities are required to use hedging strategies that expose customers to a maximum rate increase looking 12 months into the future of no more than one cent per kWh (i.e., $10 per MWh).[16]

The high level of self-supply and forward contracting in California's wholesale markets has limited the incentive and ability for the exercise of market power by suppliers. This has been one of the primary factors contributing to the competiveness of California's wholesale energy market in recent years.

The addition of a centralized integrated day-ahead market under the new market design has created opportunities for increased market efficiencies in several ways:

- ***System-wide optimization of resources* —** In the absence of a centralized market, participants must rely heavily on self-scheduling of their own resource portfolios to meet their own demand. This may prevent efficiencies that can be gained by optimizing overall market supply to meet total system demand. The addition of a centralized day-ahead market has created the opportunity for more efficient commitment and scheduling of resources controlled by different participants on a day-ahead basis to meet expected system demand. Under this new market design, a relatively large portion of supply needed to meet demand has continued to be self-scheduled in the day-ahead market (i.e., bid as a price-taker so that it is automatically scheduled). However, the marginal supply needed to meet demand is determined by resources that are committed and scheduled through the market software. The new day-ahead market optimizes unit commitment and scheduling over a 24-hour period using a mixed integer programming algorithm (rather than the single-hour optimization used for most other ISOs). The objective function of this software is to minimize total bid costs of resources committed and scheduled by the market software.

- ***Co-optimization of energy and ancillary services* —** Another way in which the new market design can increase market efficiency is by co-optimizing procurement of energy and ancillary services from

implement LAP settlement and pricing for demand without compromising the effectiveness of the new LMP markets." Ibid., p 28.

[16] See http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/76979.htm,

resources that can provide either of these products. Co-optimization considers the energy and ancillary service capacity bids of each unit. In addition to receiving the market clearing price for ancillary services, resources providing ancillary services may also receive a payment to cover any opportunity cost of providing ancillary service capacity instead of being scheduled for energy. This opportunity cost payment reflects the difference between the energy bid price and the higher market clearing price for energy that a unit was unable to provide as a result of having capacity reserved for ancillary services. As with the prior market design, the optimization can substitute higher-quality ancillary services for lower quality products if this is a more economic way to meet the minimum requirements for each ancillary service (i.e., more upward regulation in place of spinning reserve, or more spinning reserve in place of non-spinning reserve). A more detailed description of the ancillary services market is provided in Chapter 6.

- ***Three-part bidding and bid cost recovery —*** Under the new market design, generating units may submit three-part offers: start-up costs, minimum load costs, and bids for energy (above minimum operating levels). If a unit is started up or scheduled at minimum load during some hours of a day through the day-ahead market, the unit is eligible for a bid cost recovery payment to ensure that it recovers the full cost of its start-up and minimum load costs, plus any energy bids that are dispatched. Units can earn revenues in excess of these bid costs during hours when market prices exceeded these bid prices. However, if market revenues earned over the course of an operating day are insufficient to recover the unit's start-up, minimum load and energy bids, the unit is "made whole" for the difference through a bid cost recovery payment. This can increase overall market efficiency by providing an incentive for suppliers to bid more closely to their actual marginal operating costs.

As discussed in Chapter 3, the amount of load scheduled in the day-ahead market has been extremely high, typically ranging from 96 to 100 percent of actual load. This high level of day-ahead scheduling also reduces the incentives to manipulate the real-time price, because the bulk of each supplier's final output is settled at day-ahead prices. Real-time market prices are only applicable to incremental adjustments to day-ahead schedules. Thus, suppliers who have scheduled large volumes in the day-ahead market have no incentive to increase the real-time price, unless their total net output in real time exceeds the amount of their supply scheduled in the day-ahead market.

1.3 Residual unit commitment

The residual unit commitment process is performed immediately after completion of the day-ahead energy market. This process is designed to allow the ISO to procure any additional unloaded capacity necessary to ensure that all projected energy requirements can be met in real time. The ISO uses final day-ahead market schedules as a starting point for the residual unit commitment process. It then determines if any additional capacity will be needed to meet forecasted loads on a system-wide basis or within any local transmission constrained areas. If necessary, additional resources may be started up or kept on-line through the residual unit commitment process to meet system-wide or local requirements.

The software minimizes the total cost of residual unit commitment bids for capacity (above minimum load) for each unit scheduled through this process, plus the start-up and minimum load costs of any additional units committed through this process. Generating units and imports under resource adequacy contracts are required to offer all available capacity at a zero-priced bid in the residual unit commitment process. Resource adequacy resources are not paid the RUC market clearing price for any capacity scheduled to meet RUC requirements, because these resources have already been contracted by load-serving entities to provide capacity. Non-resource adequacy resources may bid any available capacity at a price of up to $250/MW into the RUC market, and are paid the RUC market clearing price for any capacity scheduled to meet RUC requirements.

Given the high level of scheduling in the day-ahead market, the total amount of capacity committed or scheduled through the residual unit commitment process has been minimal in 2009. Moreover, because resource adequacy resources must offer all available capacity into RUC at a zero price and are not paid for any RUC capacity provided, the volume and cost of non-resource adequacy capacity scheduled through the RUC process has been minimal. This is discussed in more detail in Section 3.6.

1.4 Hour-ahead scheduling process

Resources within the ISO and dynamic resources in neighboring regions (or balancing authority areas) can be dispatched on a 5-minute basis within each operating hour to meet real-time loads. However, most imports and exports between the ISO and neighboring regions are non-dynamic, and must therefore be pre-dispatched about 45 minutes prior to the start of each operating hour. These imports and exports must also be scheduled at a fixed level for the entire hour. Because of the differences in these two types of resources, the new real-time market design includes two major sequential processes:

- The hour-ahead scheduling process is used to pre-dispatch non-dynamic imports or exports on inter-ties about 45 minutes prior to the start of each operating hour.

- The real-time dispatch is used to dispatch resources within the ISO and dynamic imports and exports during each 5-minute interval within each operating hour.

The hour-ahead scheduling optimization is performed using the same type of full network model and optimization algorithms used in the day-ahead market and 5-minute real-time dispatch markets. However, because most imports and exports need to be pre-dispatched for an entire operating hour, the hour-ahead scheduling optimization is performed 45 minutes prior to each operating hour, and is based on a forward-looking time horizon of 1 hour and 45 minutes (or seven 15-minute intervals).[17]

The hour-ahead scheduling optimization considers schedules and bids from imports and exports, as well as schedules and bids from resources within the ISO and dynamic imports/exports. All imports and exports scheduled in the day-ahead market are either self-scheduled or must re-submit economic bids to be used in hour-ahead scheduling process.[18] In addition, participants may self-schedule or bid additional imports and exports into the hour-ahead scheduling process.

The software clears this entire pool of supply and export bids against the forecast of total real-time demand. By re-clearing the entire market in this manner, the hour-ahead scheduling process is designed to identify the economically optimal mix of hourly imports and exports that should be pre-dispatched, given the projected supply of resources within the ISO and the forecast of real-time demand during the next operating hour.

Prices produced through the hour-ahead scheduling optimization are only used to settle additional hourly imports and exports that are pre-dispatched in the hour-ahead. The optimization considers all

[17] While the day-ahead market uses a 24-hour optimization based on hourly schedules, the real-time market optimizes based on 5-minute dispatch intervals over a one to two hour horizon.

[18] If a self-schedule or economic bid is not submitted in the hour-ahead scheduling process for an import or export schedule from the day-ahead market, the software automatically self-schedules this import or export in the hour-ahead.

real-time schedules and bids from resources within and outside of the ISO in order to identify an economically efficient mix of imports and exports that should be pre-dispatched in the hour-ahead. However, because these other resources are ultimately dispatched on a 5-minute basis during the real-time market based on actual real-time conditions, these resources are settled based on final dispatches and prices from the real-time market.

As noted above, participants with accepted day-ahead inter-tie transactions can either self-schedule these schedules in the hour-ahead process, or re-bid them at the same or different prices than were initially submitted in the day-ahead market. If a bid for an interchange transaction originally scheduled in the day-ahead market does not clear in the hour-ahead, the market participant essentially "buys-back" the import at the hour-ahead price (or "sells-back" an export at the hour-ahead price).

Day-ahead import schedules re-bid in the hour-ahead scheduling process may not clear due to either a change in bid price or a change in market prices. For example, a participant's day-ahead import schedule may not re-clear the hour-ahead process if the participant increases the bid price above the price at which the hour-ahead process clears. However, if the hour-ahead process clears at a lower price than the day-ahead market, a participant's hour-ahead import bid may not clear even if it is re-bid in the hour-ahead process at the same price as it was bid in the day-ahead market.

Participants are allowed to modify their bids between the day-ahead and hour-ahead markets in order to reflect changes in market or resources conditions, or manage their overall portfolio of market activity. The hour-ahead scheduling process is designed to allow the ISO to re-optimize the market given these changes, along with any changes in internal supply or demand conditions. Thus, the hour-ahead re-bidding process is designed to promote market efficiency by allowing participants and the ISO to re-optimize the interchange transactions given updated market bids and conditions.

1.5 Real-time dispatch

The real-time dispatch market uses final day-ahead schedules for resources within the ISO and final hour-ahead schedules for imports/exports as a starting point. It then re-dispatches resources every five minutes to balance generation and loads.

In the real-time market, supply and demand conditions may vary from those in the day-ahead market or hour-ahead scheduling process for a variety of reasons. First, actual load conditions often vary significantly from those forecasted on a day-ahead or hour-ahead basis. Also, supply in the real-time market is generally much more constrained than in the day-ahead market and hour-ahead scheduling process. This is because a variety of unit operating constraints tend to be more prevalent or binding in real-time. These constraints include:

- Start-up times for resources to be brought on-line.
- Ramp rate limitations.
- Forbidden regions (or levels of output) in which units may not operate.
- Minimum down times required after a unit has been brought offline or dispatched to a lower configuration.
- Unit outages and de-rates.

- Capacity providing contingency-only ancillary services (i.e., to be dispatched only if the ISO is facing a shortage of energy bids that threatens system reliability).

Real-time actual energy flows may also vary from modeled flows calculated (or predicted) from the real-time software due to loop flows, or discrepancies between modeled versus actual flows stemming from the limited ability of the full network model to correctly model actual flows. Discrepancies between modeled versus actual real-time flows can impact market operations in several ways:

- When modeled flows exceed actual flows, this can cause "phantom congestion," or congestion on transmission constraints in market software that is not actually occurring in real time. Operators may seek to compensate for this by raising transmission constraints in the market software, avoiding "phantom congestion" from occurring in the market.

- In other cases, actual flows monitored by system operators may exceed modeled flows, so that congestion actually occurring is not reflected in the market software. In this situation, operators may lower transmission constraint limits in the market software in order to compensate for the difference between actual and modeled flows. By lowering transmission limits in the real-time market software, the software begins to re-dispatch resources to relieve the congestion occurring in real-time. Under this scenario, LMPs increase at points of the grid where additional generation (or reduced demand) would help reduce this congestion to reflect the value of this congestion relief.

Prices resulting from the real-time market are only applicable to incremental adjustments (or deviations) relative to each resource's day-ahead schedule. As previously noted, a very high portion of total system load (e.g., at least 96 to almost 100 percent) has typically been scheduled in the day-ahead market since the new market design was implemented in 2009. Thus, suppliers that have scheduled large volumes in the day-ahead market have no incentive to increase the real-time price, unless their total net output in real-time exceeds the amount of their supply scheduled in the day-ahead market. The new market design does not include any penalties for uninstructed deviations, or deviations by generating units from their scheduled level of output.

1.6 Local market power mitigation

The new market design relies upon a high level of self-supply and forward-contracting by load-serving entities as the primary means of mitigating system-level market power. The potential for market power on a system level basis is addressed through a relatively high $500/MWh bid cap. This cap will increase to $750/MWh and $1,000/MWh in the second and third years after implementation of the new market design. The scheduled increase to a relatively high bid cap is also designed to serve as an additional incentive for load-serving entities to meet the bulk of their projected need through forward energy contracts.[19]

Because ownership of generation resources within most transmission constrained load pockets of the system is highly concentrated under one or two major suppliers, the new market design includes more stringent provisions for mitigation of local market power. The local market power mitigation provisions are similar to the approach employed by the PJM ISO. Under this approach:

[19] Physical withholding is addressed through a day-ahead and real-time must-offer obligation for resources contracted to meet any load-serving entity's resource adequacy requirements. Units not under resource adequacy contracts will not be required to offer into the markets.

- Units that must be dispatched to provide additional incremental energy to relieve transmission constraints deemed to be non-competitive may have their market bids lowered based on a default energy bid, which reflects the unit's actual marginal operating costs.
- Generation owners are allowed to select from among three options for setting their unit's default energy bid. Most gas-fired generating units have cost-based default energy bids, which reflect the unit's actual operating cost plus a 10 percent adder.
- These pre-market local market power mitigation procedures are performed prior to the day-ahead market and again prior to the real-time energy market.

These provisions are only applied to resources bid into the day-ahead and real-time markets. Thus, the effectiveness of these provisions could be undermined if the most economical supply needed to meet demand in transmission constrained load pockets could be withheld from the market. However, as discussed in the following section, California's resource adequacy program ensures that units with capacity sufficient to meet local reliability requirements are under contacts which include a must-offer obligation. Generating units under such contracts must bid this capacity into the day-ahead and real-time energy markets, and are then subject to the local market power mitigation provisions described above.

1.7 Resource adequacy program

Unlike many other major ISOs, the California ISO does not currently have a centralized capacity market. Instead, California's current market design includes a resource adequacy program, comprised of tariff provisions that work in conjunction with related requirements adopted by the CPUC and other provisions of California law applicable to non-CPUC jurisdictional entities, such as publicly-owned municipal utilities. California's resource adequacy program has two main goals:

- To ensure the capacity procured under the resource adequacy program by load-serving entities is sufficient to reliably operate the power system, on a system-wide and local level.
- To ensure that revenues from bilateral transactions necessary to meet resource adequacy requirements, in combination with other market opportunities, provides generation owners and developers with the opportunity to obtain sufficient revenue to compensate for their fixed costs and enable new projects to secure the financing needed for new construction.

Load-serving entities can meet these resource adequacy requirements by any combination of self-owned resources or bilateral contracts with owners of other supply resources. All supply resources that are used to meet any load-serving entity's resource adequacy requirements are then required to offer all available capacity into the day-ahead, residual unit commitment and real-time markets. However, the resource adequacy provisions of the tariff do not place any special limits on the price at which resource adequacy capacity is bid into the energy market.

While resource adequacy requirements can be met by capacity-only contracts, load-serving entities may also procure both capacity and energy jointly when contracting with generating resources to meet resource adequacy capacity requirements (e.g., through tolling agreements or strike prices for energy). In this way, the resource adequacy program may also help to mitigate market power by increasing incentives for forward contracting of energy.

The resource adequacy program includes capacity obligations for load-serving entities on a system-wide basis, as well as for local transmission constrained areas. On a system-wide basis, load-serving entities must procure resource adequacy capacity equaling 115 percent of their projected peak demand requirements for each month, based on a 1-in-2 year forecast of peak demand.[20] On a year-ahead basis, load-serving entities are required to designate specific resources that will meet 90 percent of these system-level resource adequacy requirements. Prior to each month, load-serving entities must then designate specific resources to meet 100 percent of their total requirements for that month.

On an annual basis, the ISO also performs technical studies to determine the minimum amount of capacity needed within transmission constrained load pockets, or local capacity areas, based on the ISO's 1-in-10 year forecast of peak demand. The ISO allocates responsibility for these local requirements to individual load-serving entities based on their share of load in the local capacity area. This allocation does not obligate any load-serving entity to procure capacity. Rather, the allocation is used to determine the its responsibility for the costs associated with any capacity that the ISO needs to procure to meet these local requirements. The ISO will procure resources within a local capacity area only if the portfolio of all resource adequacy capacity presented by all load-serving entities in their year-ahead resource adequacy showings is not sufficient to meet these local reliability requirements.

In 2009, the ISO did not need to procure any additional capacity to meet local capacity area requirements that were not met in the load-serving entity year-ahead showings.[21] However, the ISO has two main backstop options for procuring any additional capacity needed to meet RA requirement:[22]

- ***Reliability must-run contracts* —** The ISO has authority to designate units as reliability must-run resources, but exercises this authority only to renew existing must-run contracts for a relatively small amount of capacity (e.g., about 2,100 MW in 2009). For 2010, the ISO reduced capacity under must-run contracts by about 1,100 to only about 1,000 MW. Capacity under these contracts is used to meet resource adequacy requirements.

- ***Interim capacity procurement mechanism* —** The ISO can also procure capacity on a monthly or annual basis under the interim capacity procurement mechanism provisions of the tariff. Payments under these provisions are based on a capacity price of $41/kW-year.[23] This $41/kW-year price is likely to have played a key role in setting prices for resource adequacy capacity in local capacity areas, since this represents the price that unit owners may receive if they did not sign resource adequacy contracts and the ISO needed to procure capacity to meet reliability requirements in a local area.

[20] These resource adequacy provisions are designed to work in conjunction with resource adequacy requirements adopted by the CPUC and other provisions of California law applicable to non-CPUC jurisdictional entities, such as publicly-owned municipal utilities.

[21] A very minor amount of capacity was procured under the interim capacity procurement mechanism provisions on a monthly basis due to minor changes in the amount of resource adequacy capacity available in some months and the issuance of exceptional dispatches to non-resource adequacy capacity.

[22] The ISO can also take steps to procure additional capacity under its traditional out-of-market authority, including negotiating contracts, if it considers necessary to maintain system or local reliability. See Tariff Section 40.3.

[23] If a generating unit owner believes that the $41/kW-year interim capacity procurement mechanism price will not compensate a resource for its going forward costs, the unit owner may submit a filing at FERC to determine the just and reasonable capacity price for the going forward costs for the resource.

1.8 Future design enhancements

During 2009, the ISO completed the process of designing several significant market design enhancements scheduled for implementation during the second year of the new market design.

Scarcity pricing

In 2010 the ISO will implement scarcity pricing for ancillary services. This enhancement will allow the price of ancillary services to increase above the current $500 bid cap for ancillary services that will be in effect when the supply of ancillary services is insufficient to meet the ancillary service requirements. When such scarcity exists, the price of ancillary services will be based on an administratively set demand curve, plus any opportunity cost associated with providing ancillary service capacity instead of energy.[24] To ensure that scarcity pricing is triggered only when a scarcity of ancillary service capacity exists, all resource adequacy units will be required to offer all capacity certified to provide ancillary services into the ancillary service markets.

Participating load enhancements

The market currently allows major end-use loads that can be curtailed when directly dispatched in the real-time market (known as participating loads*)* to participate in the markets for real-time energy and ancillary service (non-spinning reserve). In practice, a relatively small amount of demand associated with the state water project participates in the market under these provisions of the tariff. To facilitate greater participation under these provisions, the ISO will implement a variety of software refinements in May 2010 that will provide greater flexibility for participating loads and allow these resources to be co-optimized for energy and ancillary services. These improvements will allow participating loads to provide additional details about the operating characteristics of the demand response resource such as their minimum megawatts of demand response and minimum demand response time.[25]

Proxy demand resources

In May 2010, the ISO will implement a new product – known as proxy demand resources. This product allows customers, utilities and other third-party demand response providers to bid in load reductions as a demand-side resource in the market, similar to how a generator participates as a supply-side resource. This new product is designed to facilitate increased participation in the energy and ancillary services market by demand response resources in several ways:

- To encourage demand response in locations where prices are highest, the proposal allows proxy demand resources to be paid for load reductions based on nodal prices where demand reductions occur, rather than based on prices for much broader load aggregation points used to settle load.
- The proxy demand resource product provides a way for demand response developed by non-utility, third-party demand service providers (sometimes referred to as curtailment service providers or CSPs) to participate in the energy and ancillary services markets.

[24] *Cal. Indep. Sys. Operator Corp.*, 127 FERC ¶ 61,268 (June 26, 2009).

[25] See *Update on Participating Load Functionality for Markets and Performance Initiative, April 27, 2000,* http://www.caiso.com/239e/239e704828350.pdf

- To facilitate participation by direct access customers and aggregation of customers by a demand response provider, end-use customers may enroll and participate in demand response programs with one entity (e.g., a demand response provider) and have their load served by a separate entity (e.g., a load-serving entity).
- To reduce operational barriers to participation, the product simplifies forecasting, scheduling and metering requirements.

The ISO expects participation by proxy demand resources to start at a relatively low level in summer 2010 (e.g., 25 to 50 MW), and then ramp up in the following years as utility demand response programs transition to this new product and new demand response capacity is developed by demand response providers. The CPUC indicated established specific targets and reporting requirements designed to ensure a gradual transition of utility demand response programs into the market as proxy demand resources or, in some cases, as participating loads.[26]

Third-party demand response providers

The state's resource adequacy program allows load serving entities to use demand resources to meet their resource adequacy requirements. However third-party demand response providers are only able to earn capacity payments through utility run retail demand response programs or through utility procurement contracts for demand response resources. Many stakeholders feel that without access to resource adequacy capacity payments, there will be insufficient incentive for third-party demand response providers to develop demand response resources that participate directly in the market.[27]

This was identified as a significant potential barrier to demand response in a major report commissioned by the ISO on demand response in 2009.[28] One of the key steps that may be taken to decrease the barriers to development of non-utility demand response is to develop performance standards for proxy demand resources that clearly define the service expected from these resources. Such standards would help make proxy demand resources a tradable product that curtailment service providers could sell to load-serving entities in the current bilateral market for resource adequacy capacity.

Many stakeholders believe that developing a forward capacity market is critical to increased participation by non-utility demand response in the market. A centralized capacity market would establish a transparent market price for demand response capacity and would provide non-utility demand service providers with a direct market in which to sell their capacity. The ISO has advocated development of a centralized forward capacity market, but a recent CPUC ruling suggests such a market will not be developed in the near term.[29]

[26] See *Decision Adopting Demand Response Activities and Budgets for 2009 through 2011,* CPUC Decision 09-08-02, August 20, 2009.

[27] See *California Independent System Operator Demand Response Barriers Study (per FERC Order 719)*, April 29, 2009, prepared by Freeman, Sullivan & Co. and Energy and Environmental Economics, Inc. p. 29, http://www.caiso.com/2410/2410ca792b070.pdf.

[28] Ibid.

[29] See Revised Proposed Decision, *Decision on Phase 2 – Track 2 Issues: Adoption of Preferred Policy for Resource Adequacy*, CPUC Rulemaking 05-12-013, March 30, 2010, http://docs.cpuc.ca.gov/efile/PD/115559.pdf

Multi-stage generation resources

This major software enhancement is designed to improve how operating characteristics and constraints of gas-fired generation – particularly combined cycle units – are incorporated in the market scheduling and dispatch software. This enhancement is designed to increase the efficiency and feasibility of dispatch instructions, and reduce manual dispatches needed to account for unit operating constraints not currently incorporated in the market software. Implementation of this enhancement is scheduled for October 2010.

Convergence bidding

The ISO is scheduled to implement convergence bidding (also known as virtual bidding) in February 2011. Convergence bids are financial bids to buy or sell energy in the day-ahead market, which are then automatically liquidated and settled at the real-time price. This capability is designed to encourage convergence of day-ahead and real-time prices as participants seek to arbitrage any price differences in these markets. This increase in price convergence has the potential to increase the efficiency of day-ahead unit commitment and energy schedules. Convergence bidding also allows generators to schedule in the day-ahead market and still earn the real-time price. This also allows generators to hedge the financial risk of forced outages after the day-ahead market that could cause a unit owner to pay high real-time energy prices for energy scheduled in the day-ahead market that cannot be delivered. Convergence bidding will be allowed at all locations, or nodes, within the system, including inter-ties with neighboring balancing areas.

Resource adequacy program

Another key aspect of the market design that will undergo enhancements in 2010 and beyond is California's resource adequacy program. In March 2010, the CPUC issued a proposed decision indicating that it may not move towards a centralized capacity market or a multi-year forward resource adequacy requirement, at least in the near future.[30] Nevertheless, the current resource adequacy provisions of the ISO tariff and CPUC regulations will continue to be reviewed and modified. Specific aspects of the resource adequacy program being refined include:

- ***Standard capacity product provisions —*** Numerous stakeholders have requested the ISO and CPUC collaborate to standardize obligations placed on generation units used to meet resource adequacy requirements, and incorporate these into the ISO tariff. The goal of such modifications is to facilitate bilateral contracting between load-serving entities and generators to meet resource adequacy requirements, and make resource adequacy contracts more tradable once they are signed. As part of this effort, performance standards for standard thermal generating resources were developed and incorporated in the ISO tariff for implementation in 2010. In 2010, the ISO and CPUC will continue to work with stakeholders to standardize other aspects of resource adequacy requirements, including provisions relating to replacement of capacity during planned outages and development of performance standards for intermittent resources (including cogeneration, wind and other renewables). Developing appropriate performance standards standard for these non-conventional resources has been problematic due to their diverse nature and characteristics. Regardless of whether a centralized capacity market is adopted, further refinements to the criteria used to determine the amount of resource adequacy capacity these resources can provide will pose a challenge that will continue to be addressed 2010.

[30] Ibid.

- ***Backstop provisions* —** The current interim capacity procurement mechanism provisions of the tariff that allow the ISO to procure capacity in the event of capacity deficiencies expire on March 31, 2011. If the CPUC does not move towards developing a centralized capacity market, and continues the current single-year bilateral approach, a replacement to the current interim capacity procurement mechanism will likely be of increased importance.

2 Load and supply conditions

This chapter provides an overview of system load and supply conditions during 2009. As discussed in this chapter:

- Load and supply conditions were relatively favorable in 2009. Peak system loads dropped and hydro availability in the summer months increased relative to 2008.

- The price of spot market gas dropped over 50 percent. This was the main cause of the lower wholesale costs in 2009.

- Significant levels of new gas-fired generation were added in 2009 and are scheduled to be added in 2010. This provides some evidence that the state's resource adequacy program and long-term procurement process may be stimulating some investment in new capacity, in addition to meeting short-term capacity needs.

- DMM performs an annual assessment of the revenues that may be earned by a typical new gas-fired generating unit from the market. This provides an indication of the extent to which the day-ahead and real-time energy and ancillary service markets may contribute to recovery of the fixed costs of investment in new generating capacity. Results for 2009 show a substantial decrease in net revenues compared to 2008. However, as explained Section 2.3 of this chapter, this can be primarily attributed to the drop in spot market gas prices and the associated decrease in electricity prices.

- The 2009 net revenue estimates for typical new gas-fired generation fall substantially below the annualized fixed cost of new generation. It is important to note that this analysis does not include revenues earned from resource adequacy contracts or other bilateral contracts. DMM does not have information on these revenues. However, these findings continue to underscore the critical importance of long-term contracting as the primary means for facilitating new generation investment under California's current market design.

2.1 Load conditions

2.1.1 System loads

Most key load indicators were lower in 2009 than in previous years. This is likely primarily attributable to moderate summer weather and slow or negative economic growth. Summer peak loads continued to decline moderately since the historic peak in 2006. Summer weather conditions have been generally mild since a record heat wave in 2006. Table 2.1 shows annual peak loads and energy use over the last four years.

In 2009, load peaked at 46,042 MW, on September 3, at 4:17 p.m. As shown in Figure 2.1, this exceeded the 1-in-2 year forecast of peak demand by about 663 MW, or 3.5 percent, but well below the 1-in-10 year peak forecast of 50,879 MW. The ISO sets system level resource adequacy requirements based on the 1-in-2 year forecast of peak demand. Resource adequacy requirements for local areas are set based on the 1-in-10 year peak forecast for each area.

Table 2.1 Annual system load statistics for 2006-2009[31]

Year	Avg. Load (MW)	% Chg.	Annual Total Energy (GWh)	Annual Peak Load (MW)	% Chg.
2006	27,432		241,019	50,270	
2007	27,644	0.8%	242,880	48,615	-3.3%
2008	27,526	-0.4%	241,128	46,897	-3.5%
2009	26,342	-4.3%	230,754	46,042	-1.8%

Figure 2.1 2009 peak load vs. planning forecasts

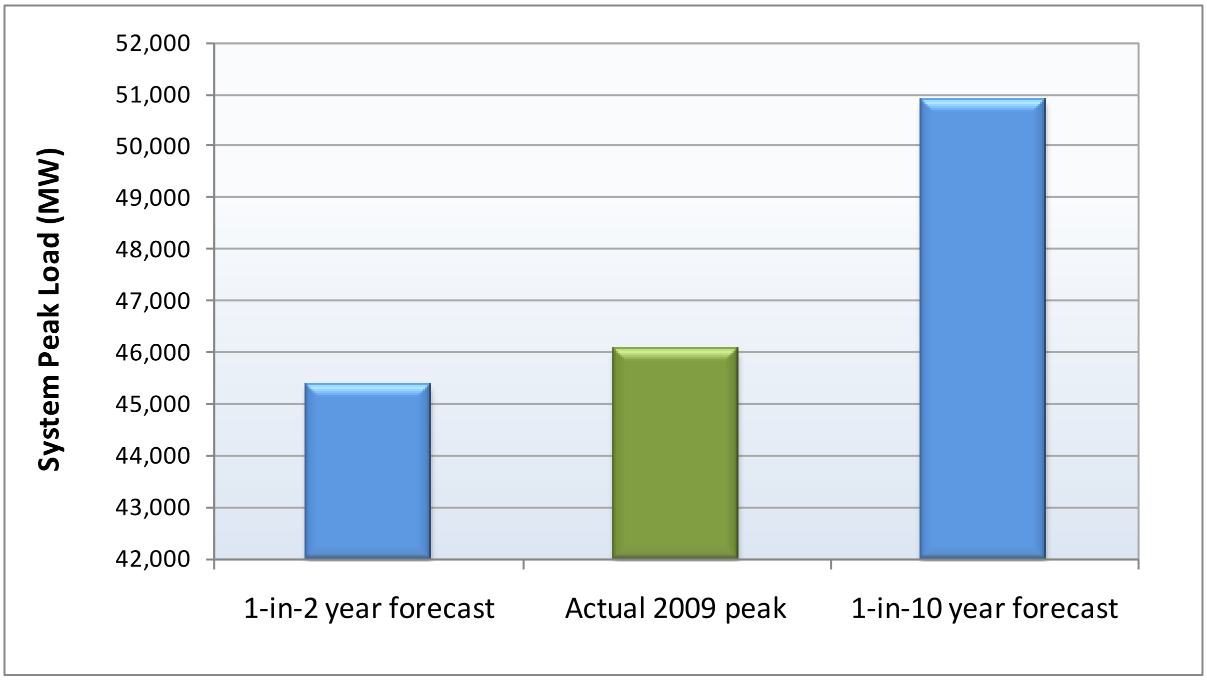


Figure 2.2 summarizes load peak hours (7-22) of the summer months of June to August from 1998 to 2009.[32] Average summer loads have been relatively flat since 2003, with the notable exception of 2006. However, as shown in Figure 2.2, system peak loads have been much more variable from year to year. These system peaks are driven by summer heat waves, which can drive system loads to extremely high levels for a very limited number of hours each summer. The potential for such peak loads drives many of the reliability planning requirements and always creates the potential for reliability problems under extreme weather conditions.

[31] This and all remaining tables, charts, and figures on load statistics are normalized to account for day of week and the 2008 leap year. Figures reported in this report will differ slightly from prior published figures.

[32] Loads prior to 2006 have been adjusted to remove demand associated with entities that are no longer part of the ISO balancing authority area (SMUD, WAPA and TID).

Figure 2.3 shows load duration curves for the years 2006 through 2009. Loads have been lower in 2009 than in other recent years. In 2009, loads exceeded 40,000 MW hours during 129 hours (1.5 percent of all hours), compared to 188 hours (2.1 percent) in 2008.

Figure 2.2 Summer loads condition: 1998 to 2009

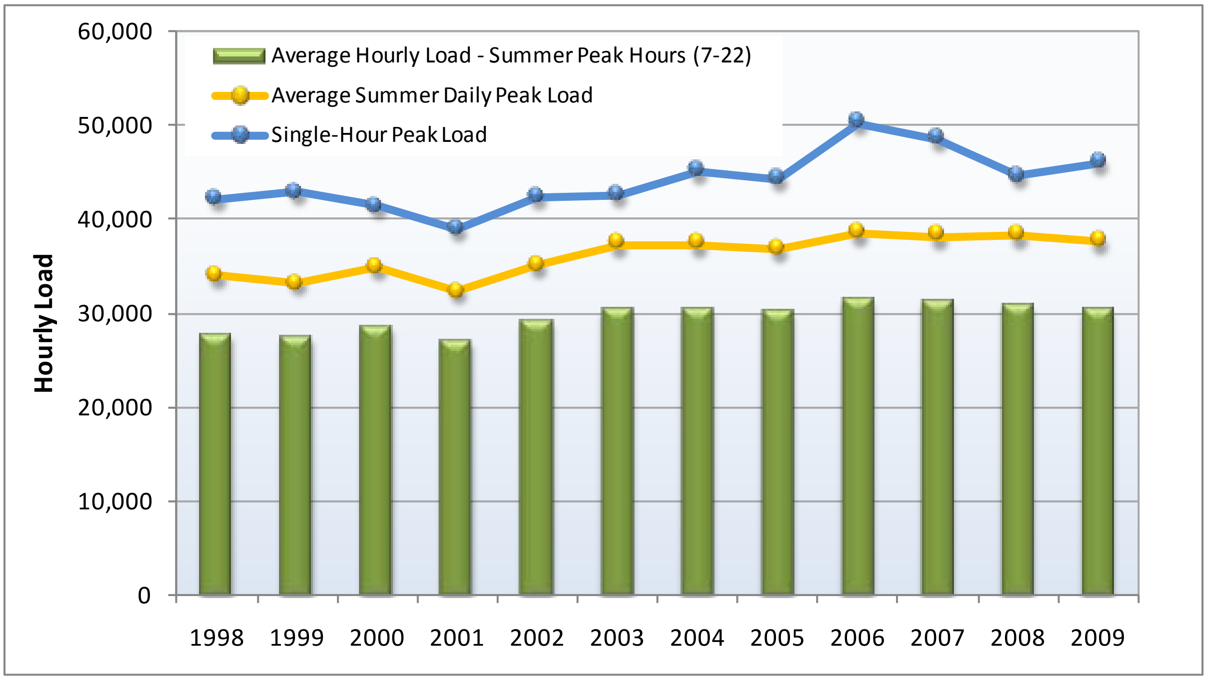
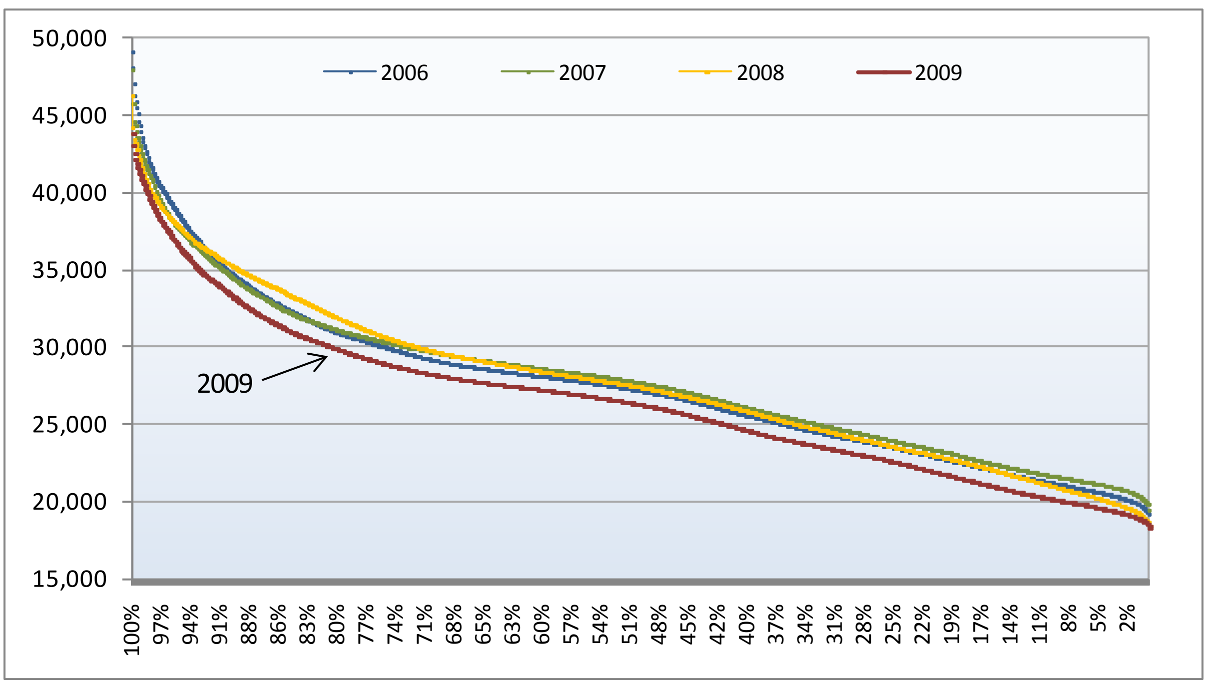


Figure 2.3 System load duration curves: 2006-2009



2.1.2 Local transmission constrained areas

Locational load and supply conditions play an important role under the new market design. As noted in Chapter 1, while generating resources are paid based on LMPs for the specific node at which they are located under the new market design, load is bid and settled using load aggregation points, which represent aggregations of individual load nodes.

The three major load aggregation points in the system correspond to the service territories of the state's three major investor owned utilities: PG&E, SCE, and SDG&E. Within each of these load aggregation points, most demand is concentrated within a limited number of transmission constrained load pockets. Under LMP markets, prices at nodes within these load pockets can often be higher, reflecting the need to dispatch higher cost resources to meet demand in these areas when transmission congestion occurs.

For purposes of establishing local reliability requirements that must be met under the state's resource adequacy program, the ISO has defined 10 local capacity areas, shown geographically in Figure 2.4. Virtually all of the load within the system is located within one of these local capacity areas. Table 2.2 and Figure 2.5 summarize the total amount of load within each of these local areas under the 1-in-10 year forecast:

- Local capacity areas within the PG&E load aggregation point account for about 40 percent of total local capacity area loads under the 1-in-10 year forecast, with loads in the Greater Bay Area accounting for about half of the potential peak load in the PG&E load aggregation point.
- The two local capacity areas within the SCE load aggregation point account for about 50 percent of total local capacity area loads under the 1-in-10 year forecast, with loads in the Los Angeles Basin accounting for about 80 percent the potential peak load in the SCE load aggregation point.
- The SDG&E load aggregation point is comprised of a single local capacity area, which accounts for about 10 percent of total local capacity area loads.

Table 2.2 also shows the total amount of generation located in each local capacity area and the total amount of capacity required for local reliability planning requirements in these areas. As shown in Table 2.2, a very high portion of the available capacity in most of these local capacity areas is needed to meet peak reliability planning requirements. Because one or two entities own the bulk of generation in each of these areas, the potential for locational market power in these load pockets is significant. This is discussed in detail in Chapters 4 and 8.

In later chapters of this report, we summarize a variety of market results for each of these load aggregation points and local capacity areas separately to provide an indication of key locational trends under the new nodal market design. The proportion of load and generation located within these areas provides an indication of the importance of results for different load aggregation points and local capacity areas in terms of the impact on overall market results.

Figure 2.4 Local capacity areas

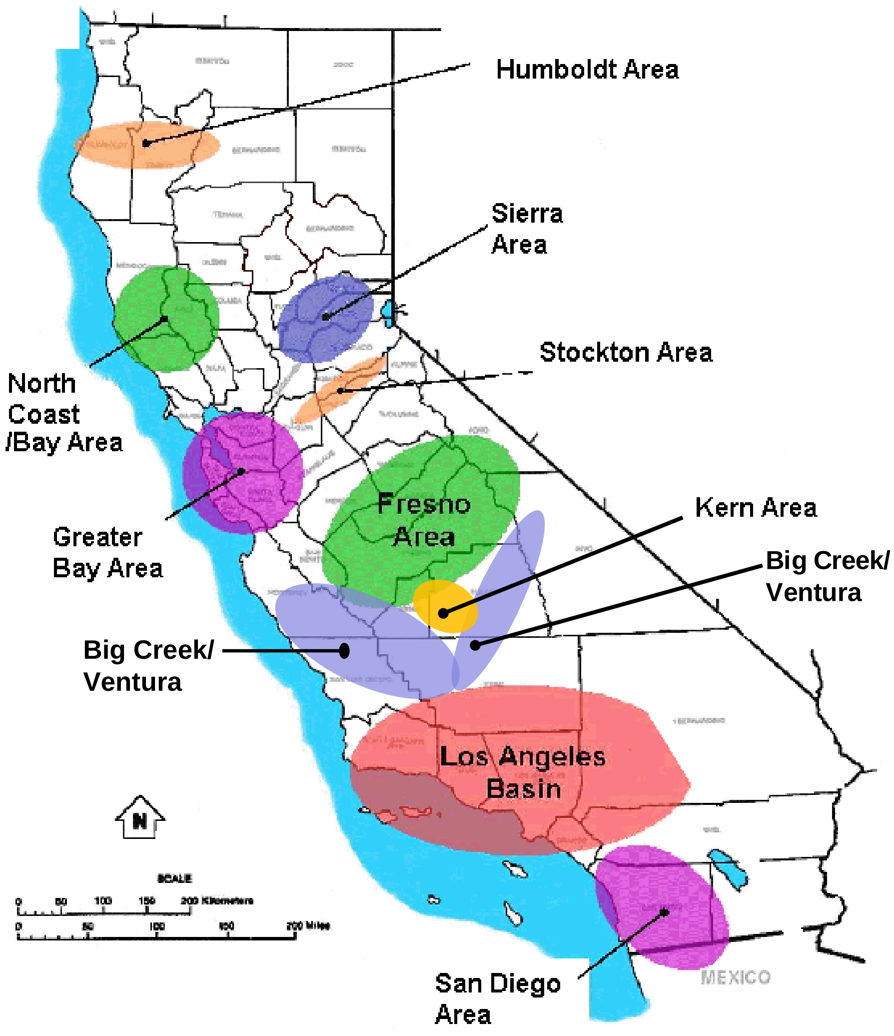
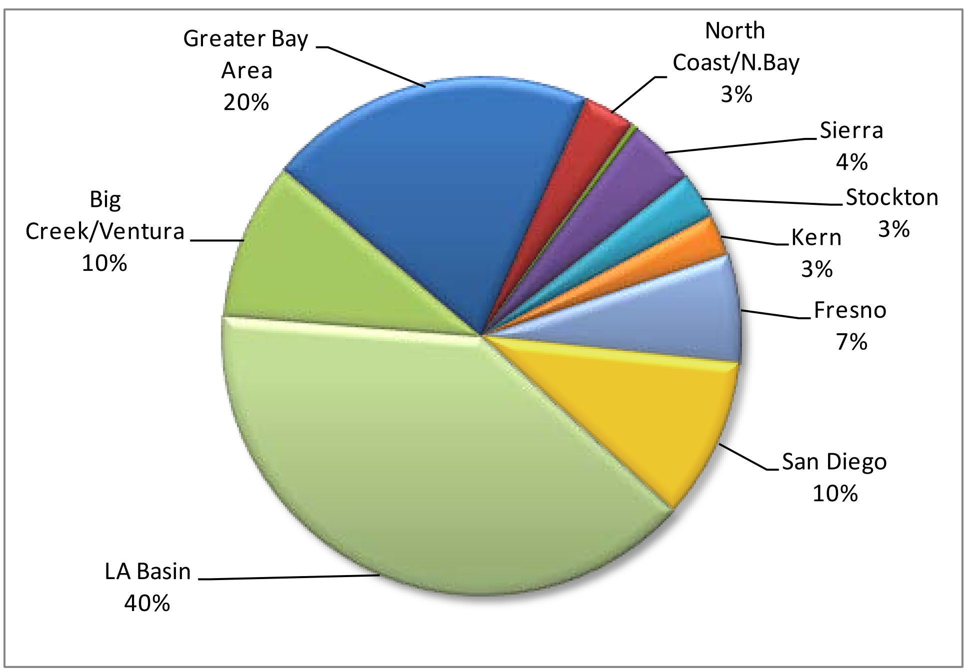


Table 2.2 Load and supply within local capacity areas

Local Capacity Area	LAP	Peak Load (1-in-10 year) MW	%	Dependable Generation (MW)	Local Capacity Requirement (MW)	Requirement as Percent of Generation
Greater Bay Area	PG&E	10,294	21%	6,773	4,791	71%
Fresno	PG&E	3,381	7%	2,829	2,680	95%
Sierra	PG&E	2,126	4%	1,780	2,320	130%**
North Coast/North Bay	PG&E	1,596	3%	945	766	81%
Stockton	PG&E	1,436	3%	541	726	134%**
Kern	PG&E	1,316	3%	677	422	62%**
Humbolt	PG&E	207	0.4%	183	177	97%
LA Basin	SCE	19,836	40%	12,164	9,728	80%
Big Creek/Ventura	SCE	4,937	10%	5,132	3,178	62%
San Diego	SDG&E	5,052	10%	3,663	3,127	85%**
Total		**50,181**		**34,687**	**27,915**	**80%**

Source: *2009 Local Capacity Technical Analysis: Final Report and Study Analysis*, May 1, 2008. http://www.caiso.com/1fba/1fbace9b2d170.pdf

Figure 2.5 Peak loads by local capacity area (based on 1-in-10 year forecast)



2.1.3 Demand response

Overview

Demand response plays an important role in meeting California's capacity planning requirements for peak summer demand. During the peak summer months, utility demand response programs met nearly five percent of overall system resource adequacy capacity requirements. However, direct participation by demand response in the wholesale energy market is currently limited to a relatively small amount of demand associated with water pumping loads. In 2010, the ISO will implement a proxy demand resource product that is designed to increase direct participation in the energy and ancillary service markets by utility demand response programs. The proxy demand resource product is also designed to increase demand response by allowing non-utility entities, such as independent curtailment service providers, to develop aggregations of end-use loads that can be reduced in response to market prices and bid these into the energy and ancillary service markets.

Participating loads

The market currently allows major end-use loads that can be curtailed when directly dispatched in the real-time market to participate in the real-time energy and ancillary service (non-spinning reserve) markets. In practice, a relatively small amount of demand, known as participating loads, participates in the market under these provisions of the tariff. To qualify as participating load, a demand response provider must be directly dispatchable and must meet specific telemetry and metering requirements in order to provide ancillary services.

Non-participating loads

Currently, the vast majority of demand response in California consists of programs for managing peak summer demands developed by the state's three major investor owned utilities. Loads that may be reduced through these programs are referred to as non-participating loads. These demand response programs are triggered based on criteria that are internal to the utility and not necessarily tied to market prices. The notification times required by the retail programs are also not well synchronized with market operations. This lack of integration lessens the ability of demand response to reduce electricity prices in the market because demand response cannot necessarily be called upon to reduce load at times of high prices or low reserve margins that do not result in an actual emergency.

These utility-managed demand response programs can be grouped into two general categories: reliability-based and price-based.

- ***Reliability-based programs* —** These consist primarily of large retail customers under interruptible tariffs and air conditioning cycling programs. These programs are primarily triggered by the ISO declaring a system emergency.

- ***Price responsive programs* —** These 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 2.3 summarizes total demand response capacity reported by the state's major utilities in monthly reports to the CPUC. Reliability-based programs account for about two-thirds of the capacity from utility-managed demand response programs, with price-responsive programs accounting for about one-third of this capacity, as illustrated in Figure 2.6.[33] In 2009, the CPUC established standard protocols for measurement and reporting of demand response programs for utilities under its jurisdiction.[34] In 2010, utilities will begin reporting demand response program capacity based on these new protocols. However, data based on these new protocols were not available for use in developing this report.

Table 2.3 Utility operated demand response programs (2007-2009)

Utility	Program		Aug-2007 Enrolled MW	Aug-2008 Enrolled MW	Aug-2009 Enrolled MW
SCE	Price-Responsive		256	381	498
PG&E	Price-Responsive		623	752	508
SDG&E	Price-Responsive		121	154	89
		Total	999	1,287	1,095
SCE	Reliability-Based		1,305	1,458	1,577
PG&E	Reliability-Based		323	466	533
SDG&E	Reliability-Based		98	83	62
		Total	1,726	2,007	2,172
	Combined Total		2,725	3,294	3,267

Although non-participating loads enrolled in these programs cannot be directly dispatched in response to market prices, expected load reductions from these programs can be used to meet the resource adequacy requirements of the load serving entities that manage these programs. As shown in Figure 2.7, demand programs were utilized by load-serving entities to meet nearly five percent of the total system-wide resource adequacy requirements during the summer months of 2009. When combined with imports and generation within the ISO, the capacity from these demand programs helped the total volume of resource adequacy capacity to exceed the total system requirements for each of the summer months.

[33] Data reported in the DMM's 2008 annual report were derived from monthly CPUC filings, which were not based on new measurement and reporting protocols. These data may overestimate demand response program capacity due to potential double-counting and other issues addressed by these new protocols. Thus, this report does not provide a comparison with data provided in previous DMM annual reports. See *2008 Annual Report: Market Issues and Performance*, Department of Market Monitoring, April 2008, p.2.4 http://www.caiso.com/2390/239087966e450.pdf

[34] *Load Impact Estimation for Demand Response: Protocols and Regulatory Guidance*, California Public Utilities Commission Energy Divisions, April 2008.

Figure 2.6 Utility operated demand response programs (2007-2009)

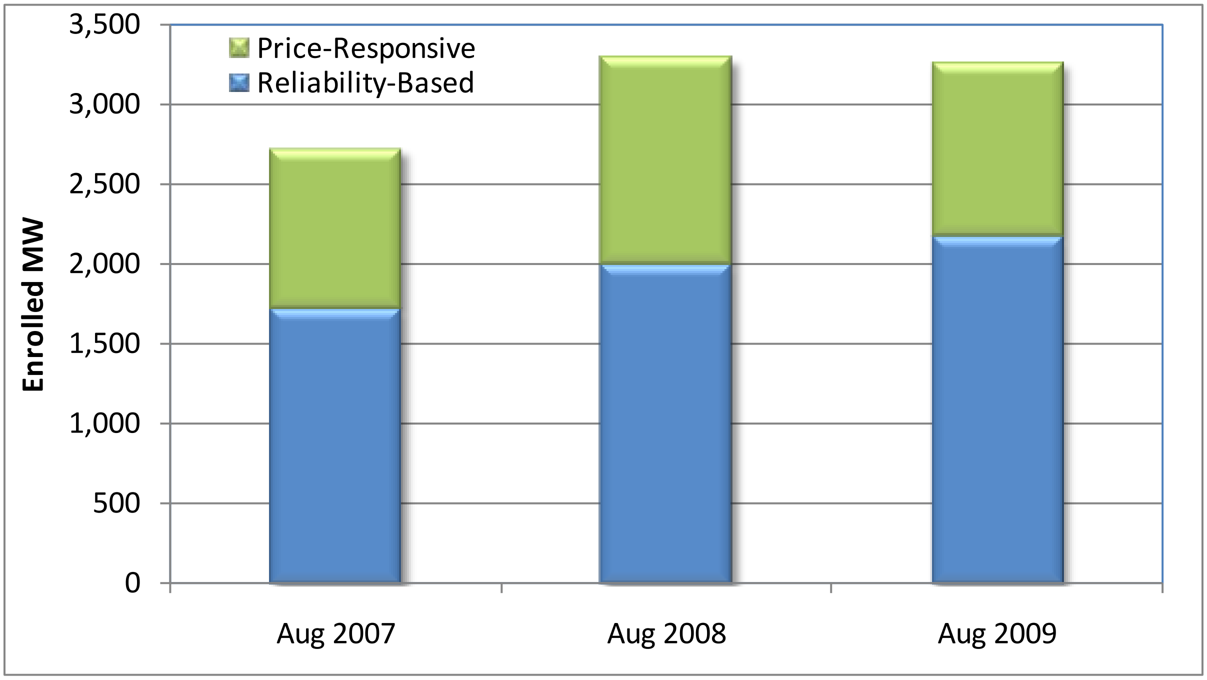
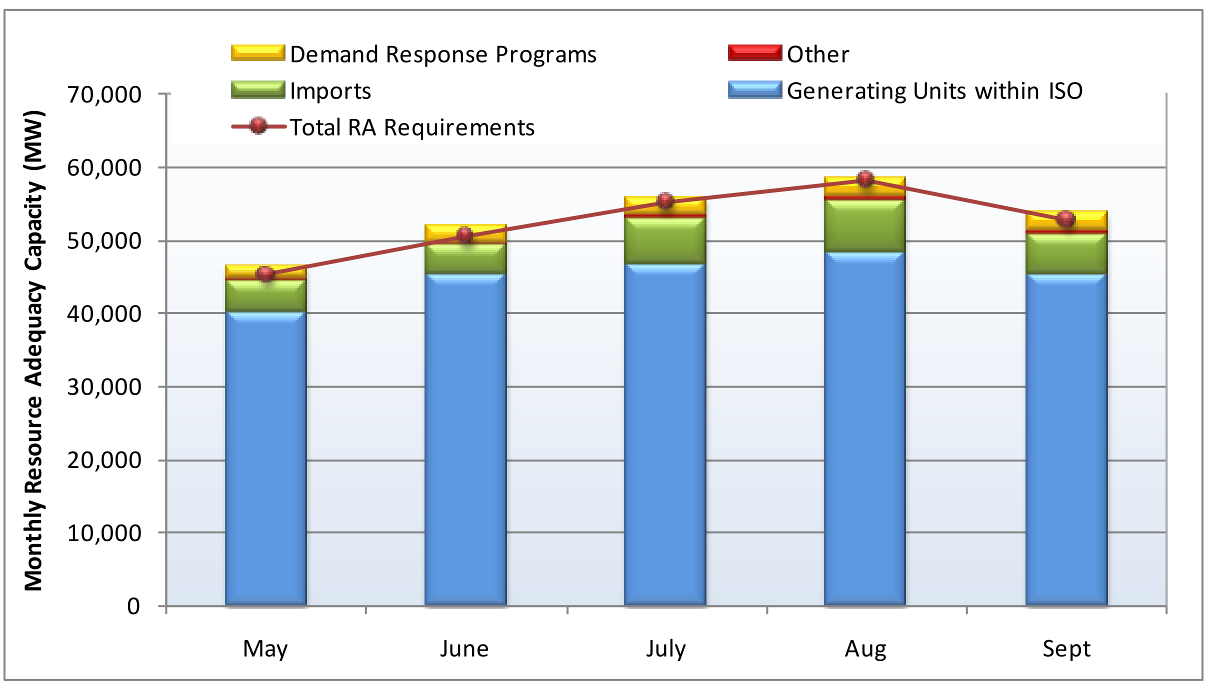


Figure 2.7 Demand response programs used to meet resource adequacy requirements



Proxy demand resources

In May 2010, the ISO will implement a new product – known as proxy demand resources – to encourage direct participation in the energy and ancillary services markets by end-use customers willing to curtail their demand in response to prices in the day-ahead and real-time energy markets. This product allows utilities or other entities, such as curtailment service providers, to develop aggregations of customers willing to curtail their demand and bid these potential load reductions into the market as proxy demand resources. To encourage demand response in locations where prices are highest, proxy demand resources will be paid based on nodal prices at locations where demand reductions occur, rather than prices for much broader load aggregation points used to settle all other load.

The ISO expects participation by proxy demand resources to start at a relatively low level in summer 2010 (e.g., 25 to 50 MW), and then ramp up in the following years as utility demand response programs transition to this new product and new demand response capacity is developed by curtailment service providers. The CPUC has indicated established specific targets and reporting requirements designed to ensure a gradual transition of utility demand response programs into the market as proxy demand resources or, in some cases, participating loads.[35]

2.2 Supply conditions

This section provides an overview of fundamental supply conditions for California's power market in 2009. In addition to examining the mix of different supply resources used to meet loads, the section provides an update on generation capacity additions and retirements occurring in 2009 and projected to occur in 2010.

2.2.1 Generation mix

Figure 2.8 provides a profile of monthly total energy supply by fuel type. Figure 2.9 provides an hourly profile of energy supply by fuel type for July through September. As shown in these figures, natural gas and hydroelectric production increase most during the higher load months of the year and the higher load hours of the day. These resources are most often marginal in the system. In 2009, natural gas and hydroelectric production supplied approximately 39 and 9 percent of supply, respectively.

Net imports represented approximately 26 percent of total supply in 2009, while base load nuclear production represented approximately 14 percent of supply. Renewables accounted for 8 percent of total energy. As shown in Figure 2.10, geothermal provided approximately half that amount, and wind provided approximately 25 percent of renewable energy. Biogas, biomass, and waste generation provided another 22 percent of renewable energy, while solar power provided 4 percent of renewable energy.

[35] See *Decision Adopting Demand Response Activities and Budgets for 2009 through 2011,* CPUC Decision 09-08-02, August 20, 2009.

Figure 2.8 Monthly generation by fuel type in 2009

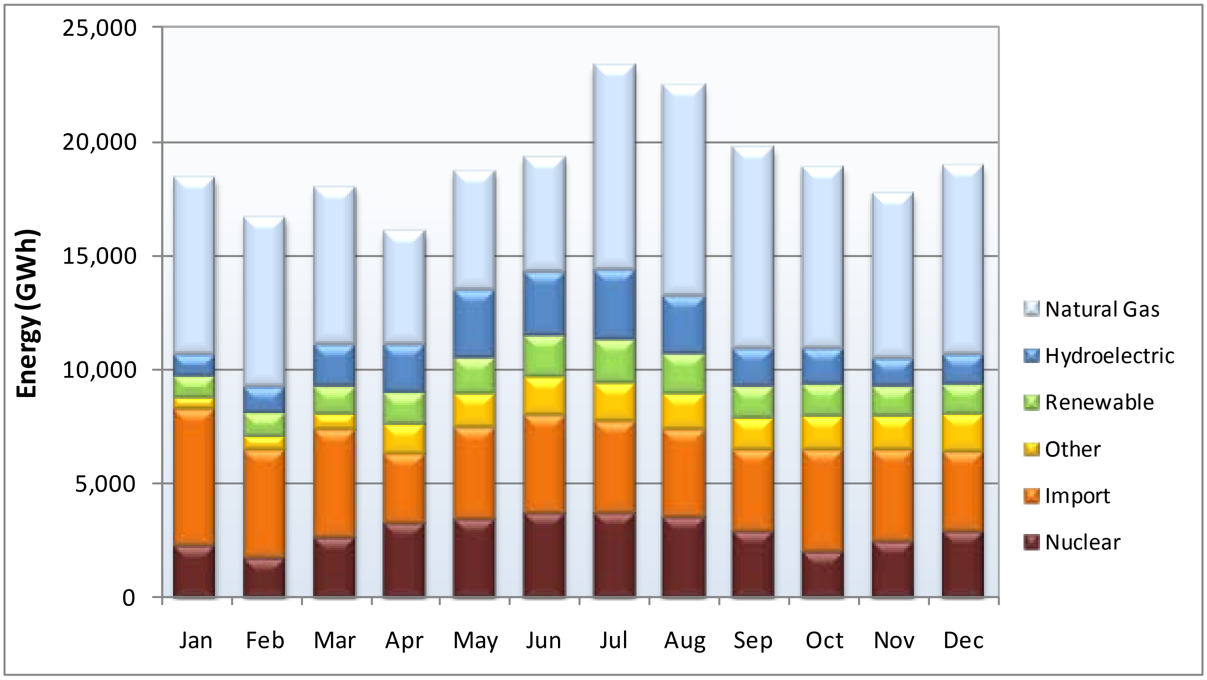


Figure 2.9 Hourly generation by fuel type in Q3 2009

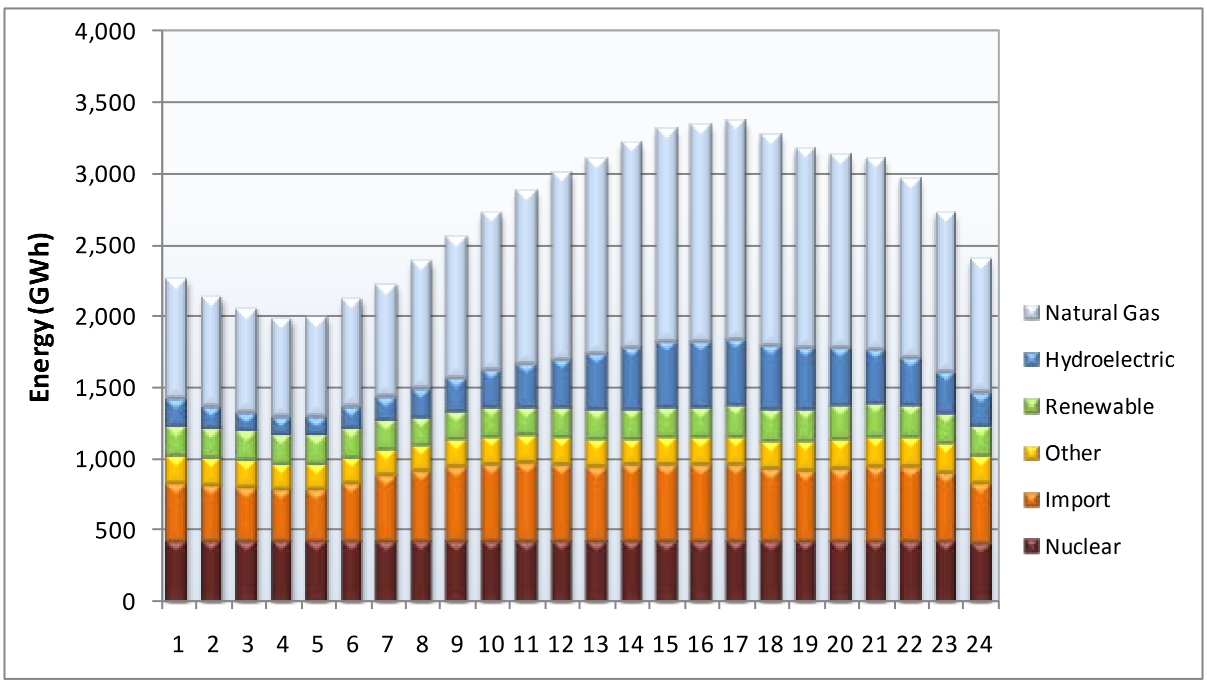
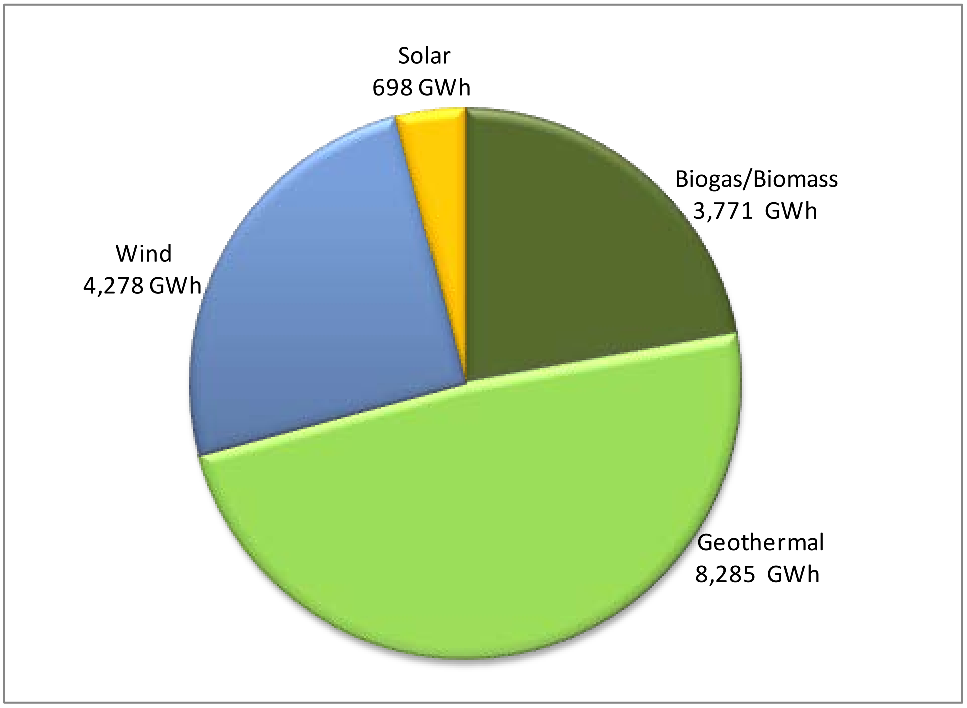


Figure 2.10 Total renewable generation by type in 2009



Hydroelectric supplies

Year-to-year variations in the supply of hydroelectric power in California can have a major impact on prices and the performance of the wholesale energy market. More abundant supplies of run-of-river hydroelectric power generally reduce the need for base load generation and imports. Hydro conditions also impact the amount of hydroelectric power and ancillary services available during peak hours from hydro units with reservoir storage. As noted in the previous section, these resources play a key role in meeting peak summer loads in the system. All hydro resources in the ISO are owned by load-serving entities that are net buyers of electricity, and therefore seek to manage these resources in a way that moderates overall energy and ancillary service prices.

From a long-term perspective, hydro conditions in California during 2009 continued a drought condition that has persisted since 2007, as shown in Figure 2.11. California snowpack was below 70 percent of average at the end of the season. As shown in Figure 2.12, hydroelectric output from units within the ISO during the summer months was slightly higher in 2009 than in the previous two years, but was significantly lower than in 2006.

Figure 2.11 Annual hydroelectric production (2002-2009)

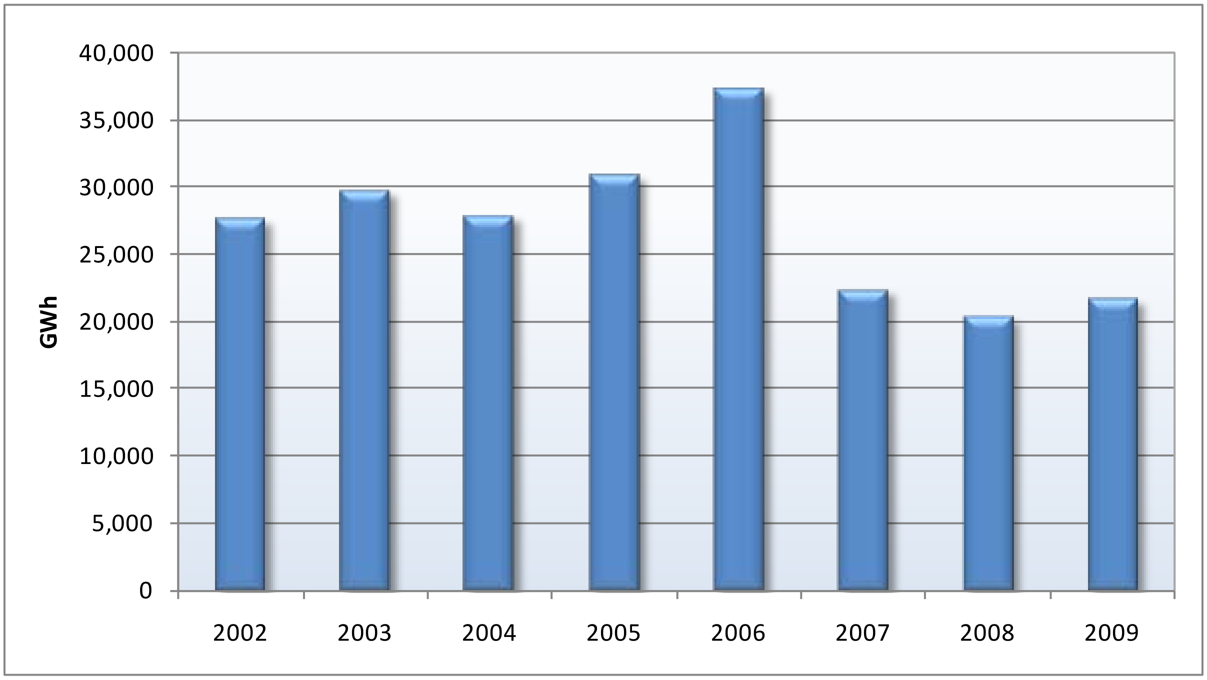


Figure 2.12 Average hourly hydroelectric production by month: 2006-2009

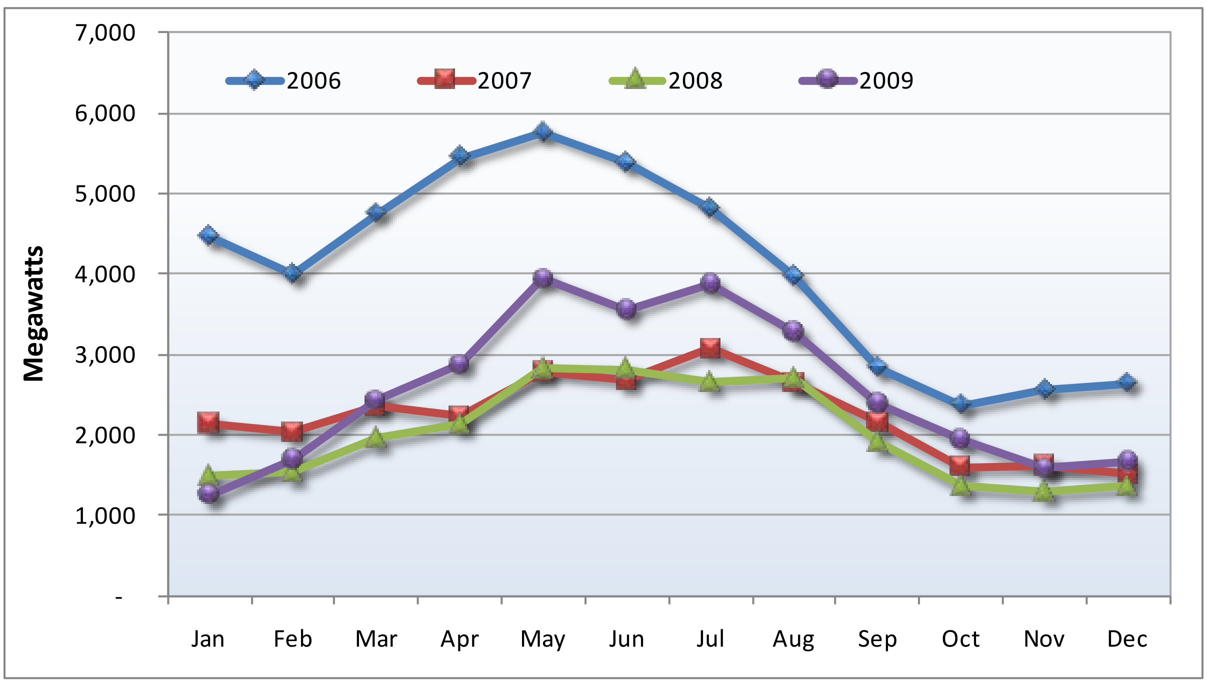
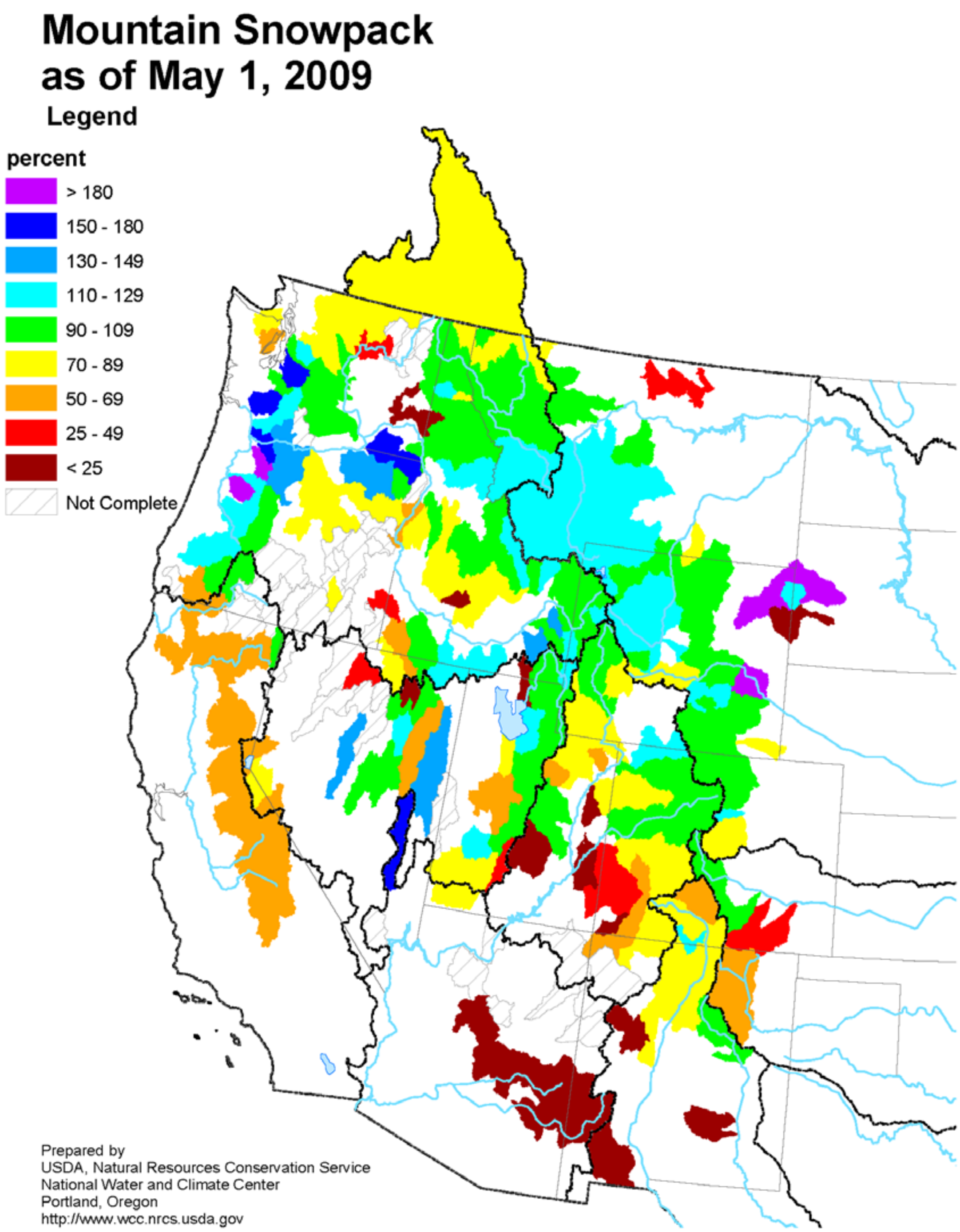


Figure 2.13 Mountain snowpack in the Western U.S., May 1, 2009



In 2009, cumulative precipitation in the Sierra began to exceed 2008 levels by March, and a late flurry in May ensured an enduring supply.[36] The mild weather resulted in moderate loads in the spring of 2009, and also provided for a longer melting period for California's snowpack that lasted through the summer. In comparison, the warm weather in the winter and spring of 2008 prevented accumulation of a lasting snowpack. This resulted in higher hydroelectric production during the summer months in 2009 compared to those in 2008, as shown in Figure 2.12.

Meanwhile, the Pacific Northwest experienced approximately average winter precipitation overall in 2009, as shown in Figure 2.13. British Columbia's snowpack was slightly below average, while Oregon and Washington enjoyed above-average snowpack. Despite these relatively favorable regional hydro conditions, imports from the Northwest dropped nearly 25 percent compared to 2008, as discussed in the following section.

Net imports

While hydroelectric production within the ISO was stronger in 2009 than in 2008, net imports decreased considerably. As noted in the previous section, the Pacific Northwest snowpack varied by region in the winter of 2009, whereas it had been consistently above average in 2008. Meanwhile, natural gas prices declined significantly in 2009 from levels seen in 2008, making California gas-fired generation more competitive with out-of-state generation. These factors combined to result in less intensive use of imports into California in 2009.

Figure 2.14 compares monthly net imports by region in 2009 and 2008. Overall net imports dropped about 13 percent. Net imports from the Southwest were about 10 percent lower, while imports from the Northwest were almost 25 percent lower.

2.2.2 Natural gas prices

The price of natural gas persisted at its lowest range in several years for most of 2009. This is the primary explanation for the low wholesale electric power prices seen in 2009. California natural gas prices ranged from $3 to $4 per mmBtu through the spring and summer. This range of gas prices results in marginal gas-fired power production costs in the range of $28 to $36/MWh for combined cycle resources, and $40 to $52/MWh for older peaking resources.[37]

Gas prices increased in the fall by approximately 43 percent above summer levels due to a cold snap that affected much of North America. California prices tend to follow national trends, with differences that reflect gas pipeline transportation congestion. Because Northern and Southern California are served by different gas producing regions and transportation systems, gas prices within California diverge frequently. Figure 2.15 shows weekly average natural gas prices for 2008 to 2009 at key delivery points in Northern California (PG&E Citygate) and in Southern California (SoCal Border), as well as at the national Henry Hub trading point.

[36] California Department of Water Resources, "Northern Sierra Precipitation: 8-Station Index, September 30, 2009," http://cdec.water.ca.gov/cgi-progs/products/PLOT_ESI.2009.pdf. Also "San Joaquin Precipitation: 5-Station Index, September 30, 2009," http://cdec.water.ca.gov/cgi-progs/products/PLOT_FSI.2009.pdf. Downloaded 3/17/2010.

[37] Based on heat rate of 9,000 Btu/kWh for combined cycle units and 13,000 Btu/kWh for older combustion turbines.

Figure 2.14 Net imports by region: 2008 and 2009

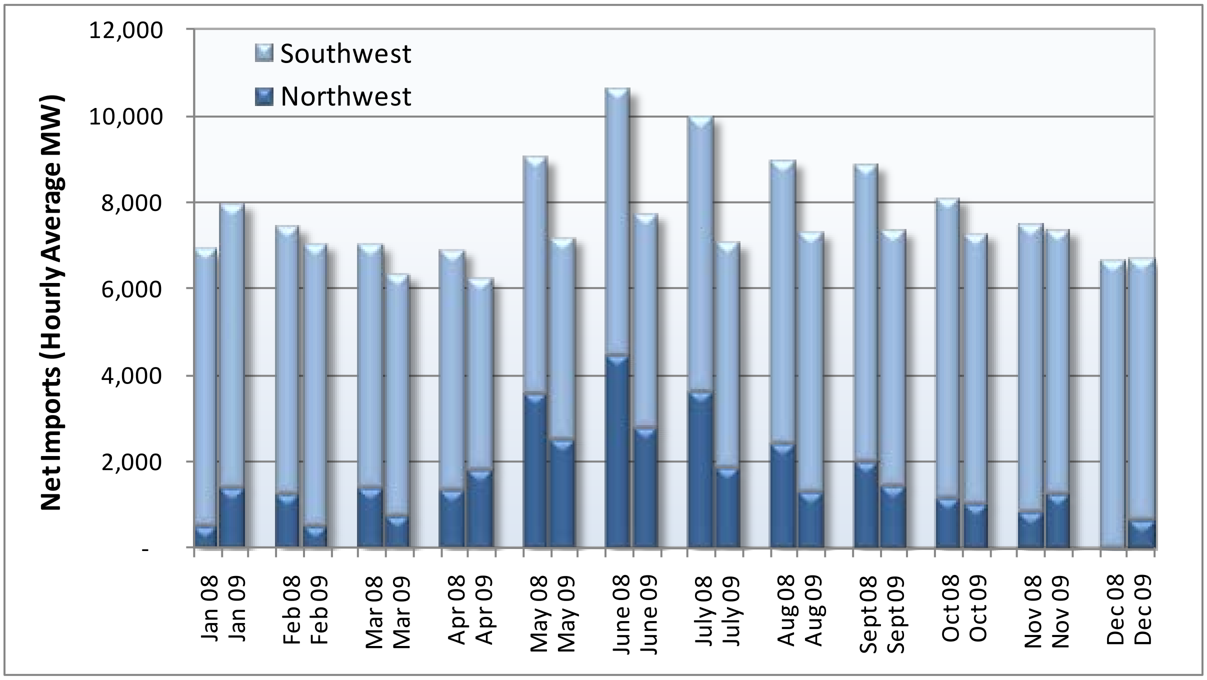
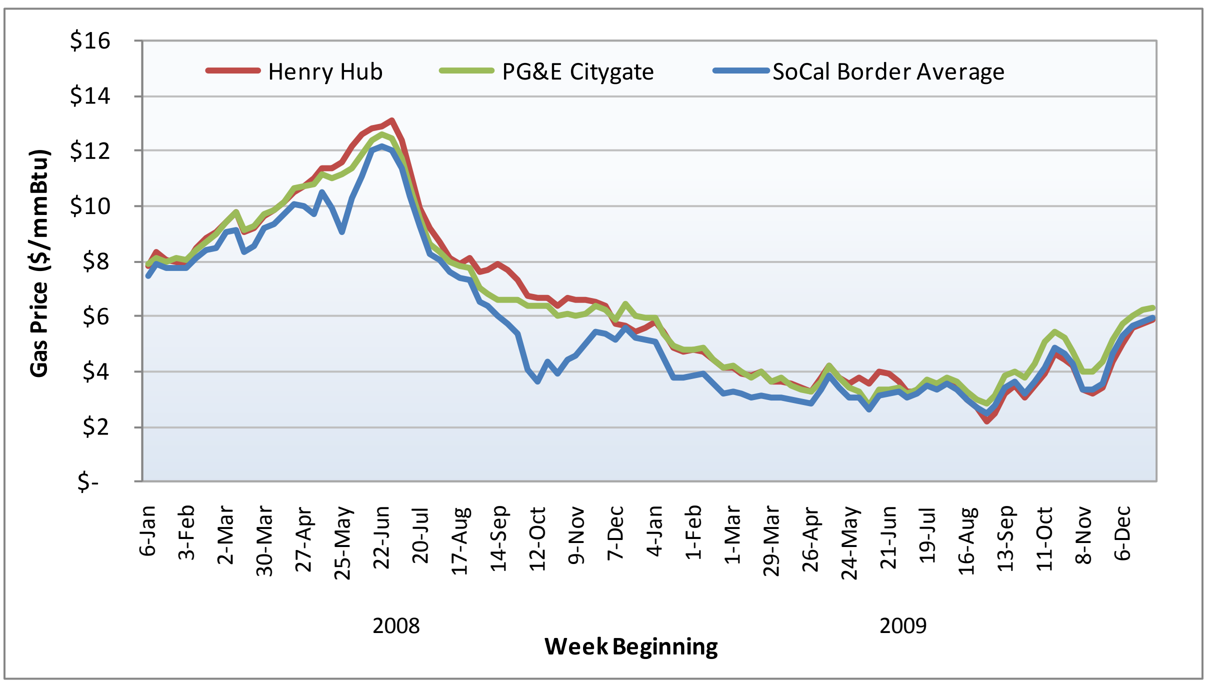


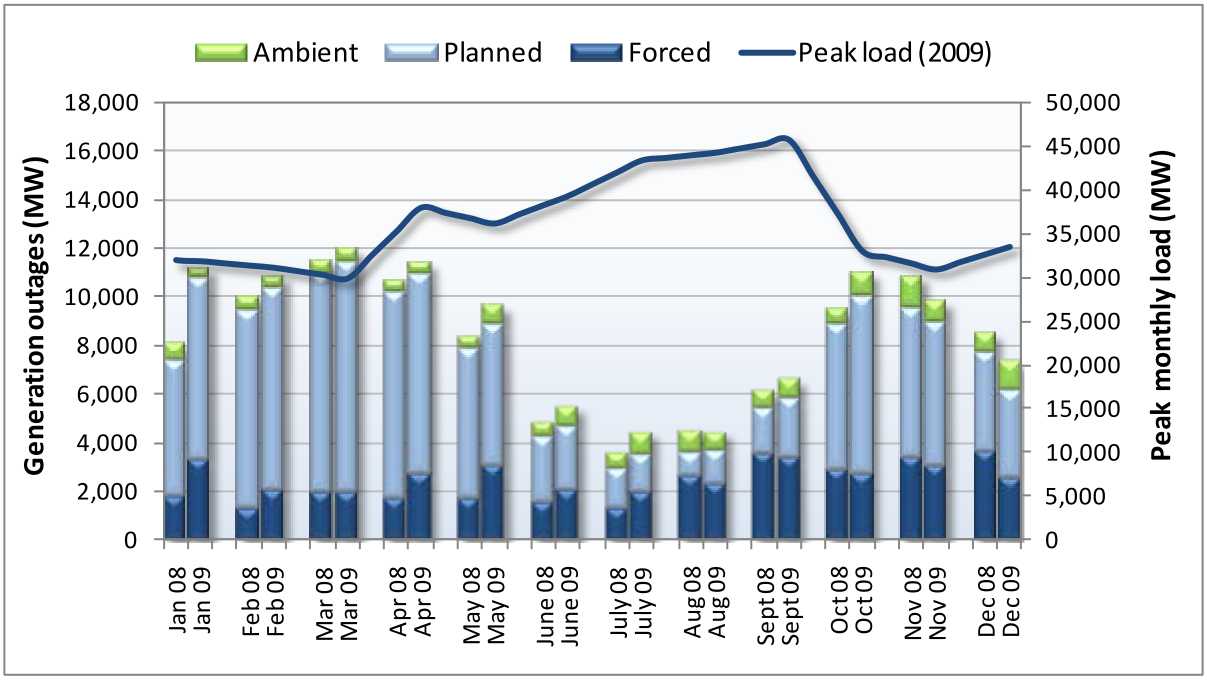
Figure 2.15 Weekly average natural gas prices in 2008-09



2.2.3 Generation outages

In 2009, generation outage volume followed a pattern similar to that in 2008. Figure 2.16 compares monthly average generation outages in 2008 and 2009. Forced outages were notably higher during the first four months of the new market design.

Figure 2.16 Monthly average outages: 2009 vs. 2008



2.2.4 Generation addition and retirement

As described in Chapter 1, California currently relies on resource adequacy requirements placed on load-serving entities to ensure that sufficient capacity is available to meet reliability planning requirements on a system-wide basis and within local areas. Trends in the amount of generation capacity being added and retired in the ISO each year provide important insight into the effectiveness of the California market and regulatory structure in bringing about new generation investment to replace the retirement of older inefficient plants and meet new load growth.

DMM also performs an annual assessment of the revenues that may be earned by a typical new generating unit from the market. This provides an indication of the extent to which the day-ahead and real-time energy and ancillary service markets may contribute to recovery of the fixed costs of investment in new generating capacity. Results of this analysis are provided in Section 2.3 of this chapter.

Figure 2.17 summarizes trends in addition and retirement of generation from 2000-2009, including planned capacity additions and retirements in 2010. Table 2.4 shows generation additions and retirements since 2001, with projected 2010 changes included along with totals across the 10-year period (2001-2010). The following sections provide a more detailed description of specific plant additions and retirements in 2009 and 2010.

Figure 2.17 Generation additions and retirements: 2000-2010

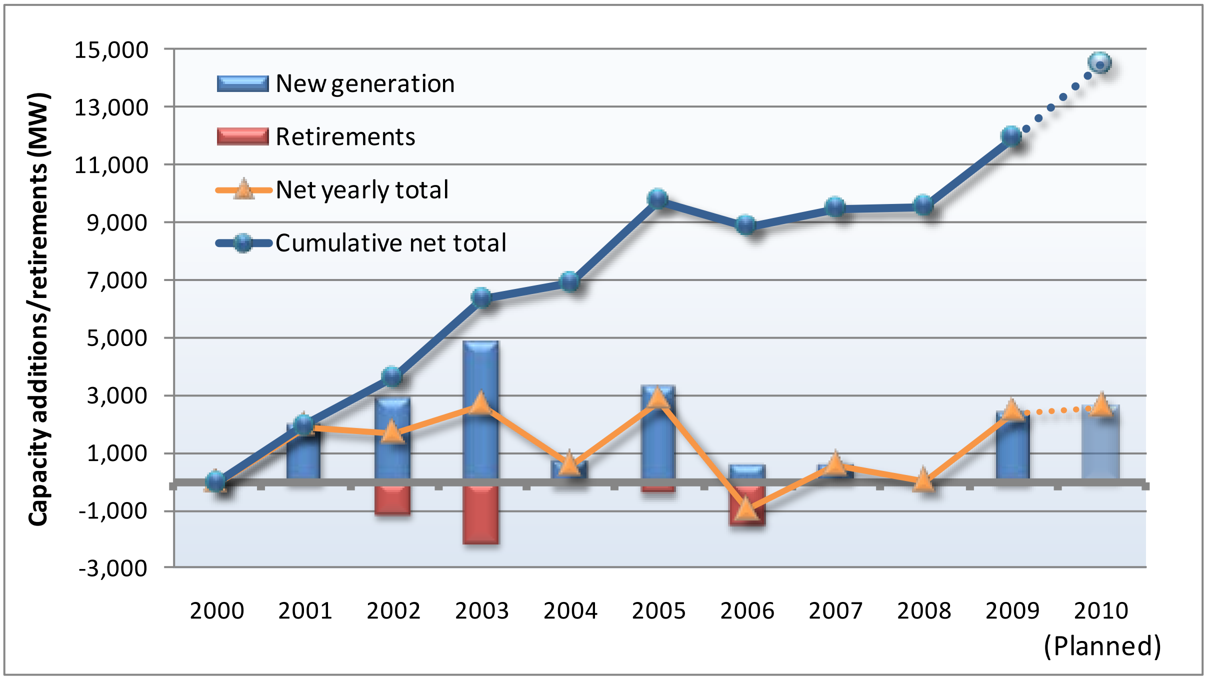


Table 2.4 Changes in generation capacity since 2001

	2001 - 2004	2005	2006	2007	2008	2009	Projected 2010	Total Through 2010
SP15								
New Generation	4,109	2,376	434	485	45	1,107	759	9,315
Retirements	(2,510)	(450)	(1,320)	0	0	0	0	(4,280)
Forecasted Load Growth*	2,022	531	542	553	564	575	587	5,374
Net Change	**(423)**	**1,395**	**(1,428)**	**(68)**	**(519)**	**531**	**172**	**(339)**
NP26								
New Generation	6,314	919	199	112	0	1,329	1,837	10,710
Retirements	(1,020)	0	(215)	0	0	(26)	0	(1,261)
Forecasted Load Growth*	1,604	422	430	439	447	456	465	4,264
Net Change	**3,690**	**497**	**(446)**	**(326)**	**(447)**	**847**	**1,372**	**5,186**
ISO System								
New Generation	10,423	3,295	633	598	45	2,435	2,596	20,025
Retirements	(3,530)	(450)	(1,535)	0	0	(26)	0	(5,541)
Forecasted Load Growth*	3,626	953	972	991	1,011	1,031	1,052	9,637
Net Change	**3,267**	**1,892**	**(1,874)**	**(394)**	**(966)**	**1,378**	**1,544**	**4,847**

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

Generation additions and retirements in 2009

Approximately 2,435 MW of new generation began commercial operation within the ISO in 2009. The new capacity was evenly split between the north and the south of Path 26, with 1,329 MW installed north of Path 26 (NP26) and 1,106 MW coming on-line south of Path 26 (SP26).

Table 2.5 shows the new generation projects that began commercial operation in 2009. Only 26 MW of generation was retired from service in 2009, while 2,435 MW of generation was added, resulting in a net capacity increase in the ISO control area of 2,410 MW.

Table 2.5 New generation facilities in 2009

Generating Unit	Resource Capacity (MW)		Commercial Operation 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
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
Vaca-Dixon Solar Station	2.0	*	24-Dec-09	NP26
NP26 Actual New Generation in 2009	***1,329***			
Inland Empire Energy Center Unit 1	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
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
Blythe Solar 1 Project	21.0	*	18-Dec-09	SP26
Chino RT Solar	2.0		12-Dec-09	SP26
SP26 Actual New Generation in 2009	***1,106.5***			
Total Actual New Generation in 2009	**2,435.1**			
*** Total Renewable Generation in 2009**	**186.5**			

Source: California ISO Grid Planning Department

Anticipated additions and retirements in 2010

The ISO projects construction of 1,837 MW of new generation in 2010.

Table 2.6 lists the changes expected for 2010. About 1,684 MW of this new capacity is expected to be commercially available prior to the anticipated summer peak season. Most significantly, Colusa Generating Station (715 MW) and Blythe Energy Project Phase II (520 MW) are expected before the summer peak. Currently, no megawatts of existing generation are planned to be retired in 2010.

Table 2.6 Planned generation additions in 2010

Generating Unit	Resource Capacity (MW)		Expected Operational Date	Zone ID
CalRENEW-1(A)	5.0	*	24-Feb-10	NP26
Blue Lake Power LLC Biomass Re-Power	13.8	*	1-Apr-10	NP26
Humboldt Bay Power Plant Repowering	162.0		1-Jun-10	NP26
CCSF Sunset Reservior PV Plant	4.5	*	1-May-10	NP26
Hatchet Ridge Wind, LLC Project	101.2	*	15-May-10	NP26
Western GeoPower Unit 1	38.5	*	1-Jun-10	NP26
Colusa Generating Station	715.0		1-Jun-10	NP26
Montezuma Wind Energy Center (High Winds III)	38.0	*	31-Oct-10	NP26
NP26 Planned New Generation in 2010	***1078.0***			
Orange Grove Energy Center	99.0		20-Jan-10	SP26
Rialto RT Solar/Southern California Edison	2.0	*	1-Feb-10	SP26
Chiquita Canyon Landfill	9.2	*	20-Jan-10	SP26
Calabasas Gas To Energy Facility	13.8	*	15-Feb-10	SP26
Blythe Energy Project Phase II	520.0		28-May-10	SP26
Olivenhain-Hodges Pumped Storage - Unit 1	20.0		31-Jul-10	SP26
Olivenhain-Hodges Pumped Storage - Unit 2	20.0		31-Jul-10	SP26
Copper Mountain Solar 1 Pseudo Tie PILOT	48.0	*	1-Nov-10	SP26
BME Otay Mesa Biomass Facility	27.0	*	1-Dec-10	SP26
SP26 Planned New Generation in 2010	***759.0***			
Total Planned New Generation in 2010	**1837.0**			
*** Total Renewable Generation in 2010**	**301.0**			

2.3 Net market revenues for typical new gas-fired generation

Although California has seen significant levels of new generation investment over the past several years, it is important that California has an adequate market and regulatory framework for facilitating investment in needed levels of new capacity. As discussed in Chapter 1, the state's resource adequacy program is the primary mechanism to ensure investment in new capacity when and where it is needed.

Annual fixed costs for existing and new units critical for meeting reliability needs should be recoverable through a combination of long-term bilateral contracts and spot market revenues. This section examines the extent to which revenues from the spot markets in 2009 would contribute to the annualized fixed cost of typical new gas-fired generating resources. This represents an important market metric tracked by all ISOs.

Key assumptions used in this analysis for a typical new combined cycle unit are shown in Table 2.7. A detailed description of the methodology and results of the analysis presented in this section is provided in Appendix A.

Table 2.7 Assumptions for typical new combined cycle unit[38]

Technical Parameters	
Maximum Capacity	500 MW
Minimum Operating Level	150 MW
Startup Gas Consumption	1,850 MMBtu/start
Heat Rates	
Maximum Capacity	7,100 MBTU/MW
Minimum Operating Level	7,700 MBTU/MW
Financial Parameters	
Financing Costs	$134.4 /kW-yr
Insurance	$7.2 kW-yr
Ad Valorem	$9.4 kW-yr
Fixed Annual O&M	$10.1 /kW-yr
Taxes	$29.6 kW-yr
Total Fixed Cost Revenue Requirement	**$190.7/kW-yr**
Variable O&M	$3.7/MWh

[38] The financing costs, insurance, ad valorem, fixed annual O&M and tax costs for a typical unit in this table were derived directly from the data presented in the CEC's 2010 Comparative Costs of California Central Station Electricity Generation Technologies report which can be found here: http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF

Hypothetical combined cycle unit

Results for a typical new combined cycle unit are shown in Table 2.8 and

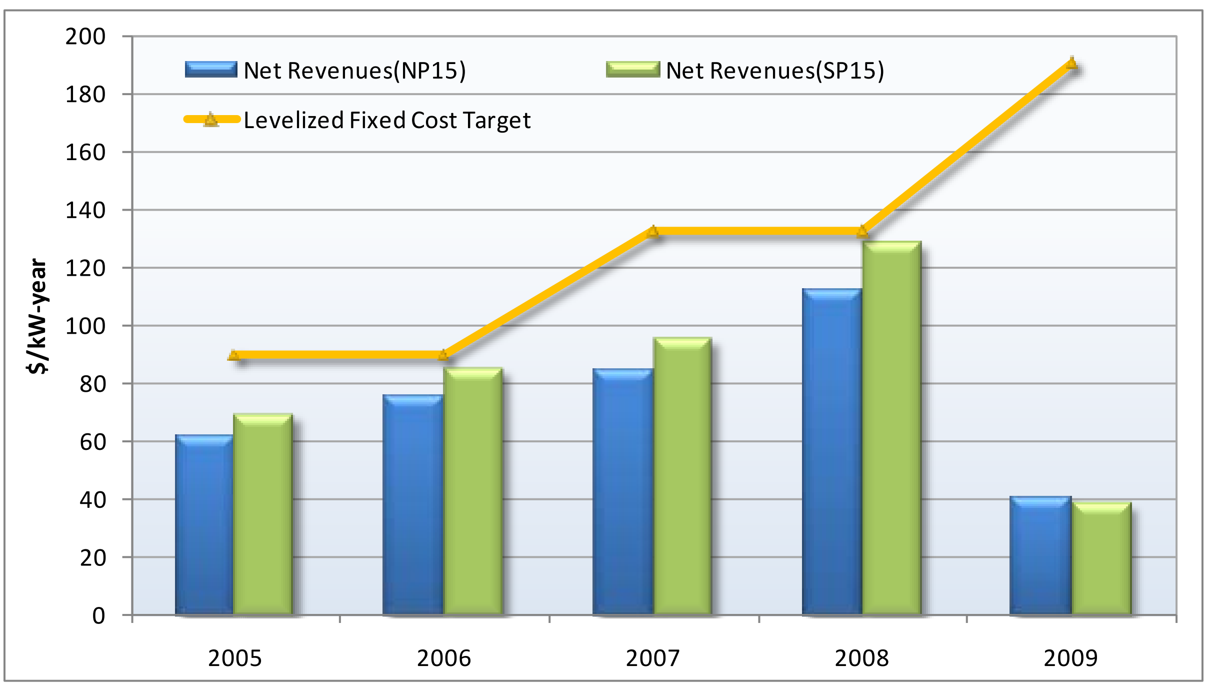
Figure 2.18. The significant increase in new generation costs in 2009 can be largely attributed to increases in capital and financing costs, and taxes. These cost estimates are based on surveys and third-party research reflecting a more current sampling of costs incurred by builders and investors in new generation compared to data from the California Energy Commission's *2007 Integrated Energy Policy Report* used in this analysis in prior years.

The 2009 results show a substantial decrease in net revenues compared to 2008 net revenues. The 2009 net revenue estimates for a hypothetical combined cycle unit in NP15 and SP15 both fall substantially below the $191/kW-yr annualized fixed cost estimated provided by the CEC.

Table 2.8 Financial Analysis of new combined cycle Unit (2006–2009)

Components	2006		2007		2008		2009	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	63%	75%	69%	76%	74%	81%	57%	57%
DA Energy Revenue ($/kW - yr	$319.65	$355.32	$369.59	$389.41	$489.17	$505.42	$172.67	$169.61
RT Energy Revenue ($/kW - yr)	$34.37	$50.02	$36.20	$41.98	$47.41	$51.98	$21.27	$15.50
A/S Revenue ($/kW – yr)	$1.01	$1.06	$0.37	$0.42	$0.41	$0.42	$0.76	$0.85
Operating Cost ($/kW - yr)	$279.50	$321.59	$321.86	$337.82	$425.16	$428.39	$154.57	$147.48
Net Revenue ($/kW – yr)	$75.53	$84.82	$84.30	$95.23	$111.82	$128.25	$40.14	$38.48
5-yr Average ($/kW – yr)	*$77.95*	*$86.70*						

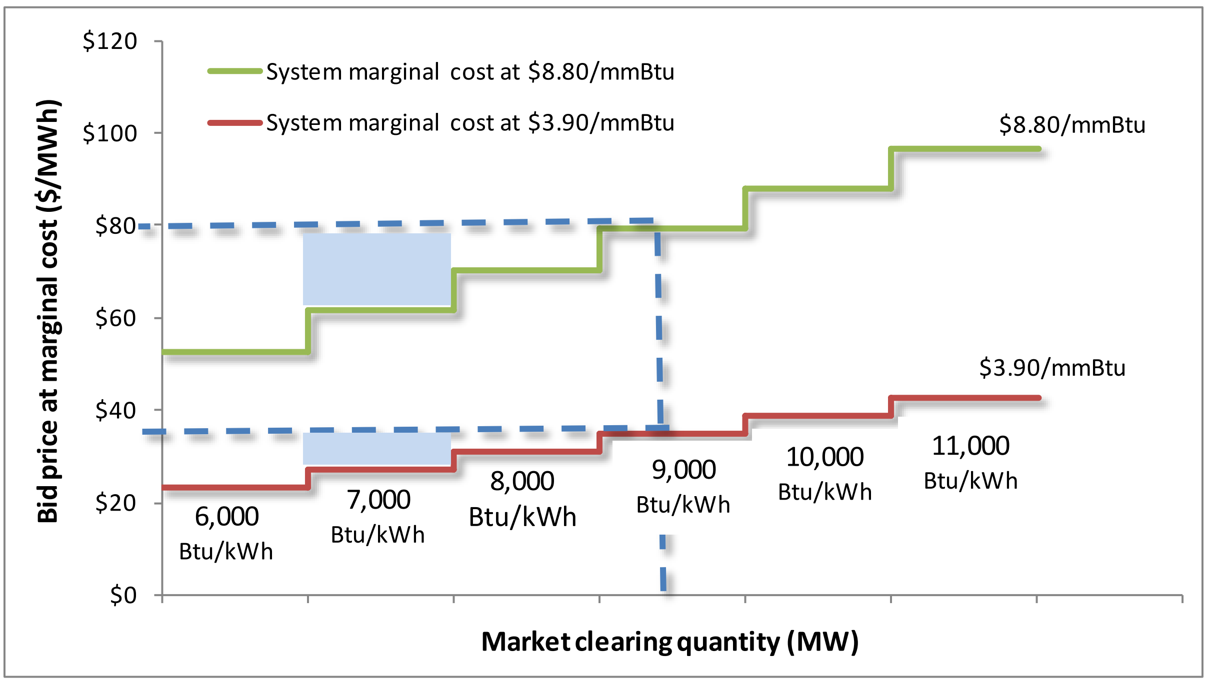
Figure 2.18 Estimated net revenue of hypothetical combined cycle unit



The decrease in net revenues for a new combined cycle can primarily be attributed to lower spot market gas prices and the corresponding drop in electricity market prices. It may seem counterintuitive that lower gas prices would decrease net revenues for a new gas resource. However, since older less efficient gas units are often the marginal resources setting prices in the market, lower gas prices decrease the net revenues of new more efficient generation. This is illustrated in Figure 2.19.

Figure 2.19 shows system marginal cost curves for the same set gas units at the average price of spot market gas in 2008 and 2009 ($8.80/mmBtu and $3.90/mmBtu, respectively). The example illustrates the market clearing at a market implied heat rate of 9,000 Btu/kWh, which is representative of the market in 2009.[39] The blue areas in Figure 2.19 show the net revenues earned by a new more efficient combined cycle unit with a heat rate of 7,000 Btu/kWh. As illustrated in Figure 2.19, the net revenues of a new combined cycle unit decrease by more than 50 percent due to the decrease in spot market gas prices from $8.80/mmBtu in 2008 to $3.90/mmBtu in 2009.

Figure 2.19 Impact of gas prices on net revenues of new gas-fired combined cycle unit



[39] The market implied heat rate refers to the forward power price divided by the gas price. For example, given a gas price of $4.00/mmBtu, a market clearing price of $36 corresponds to a market implied heat rate of 9,000 Btu/kWh.

Hypothetical combustion turbine unit

Key assumptions used in this analysis for a typical new combustion turbine are shown in Table 2.9. A detailed description of the methodology and results of the analysis presented in this section is provided in Appendix A. Table 2.10 and Figure 2.20 show the estimated net revenues that a hypothetical combustion turbine unit would have earned by participating in the real-time energy and non-spinning reserve market. It shows a relatively stable trend in the net revenues from all years in the study period. Estimated net revenues for a hypothetical combustion turbine also fell well short of the $212/kW-yr annualized fixed costs estimated by the California Energy Commission.

These findings continue to underscore the critical importance of long-term contracting as the primary means for facilitating new generation investment. Local requirements for new generation investment should be addressed through long-term bilateral contracting under the CPUC resource adequacy and long-term procurement framework. Under California's current market design, 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.

Table 2.9 Assumptions for typical new combustion turbine[40]

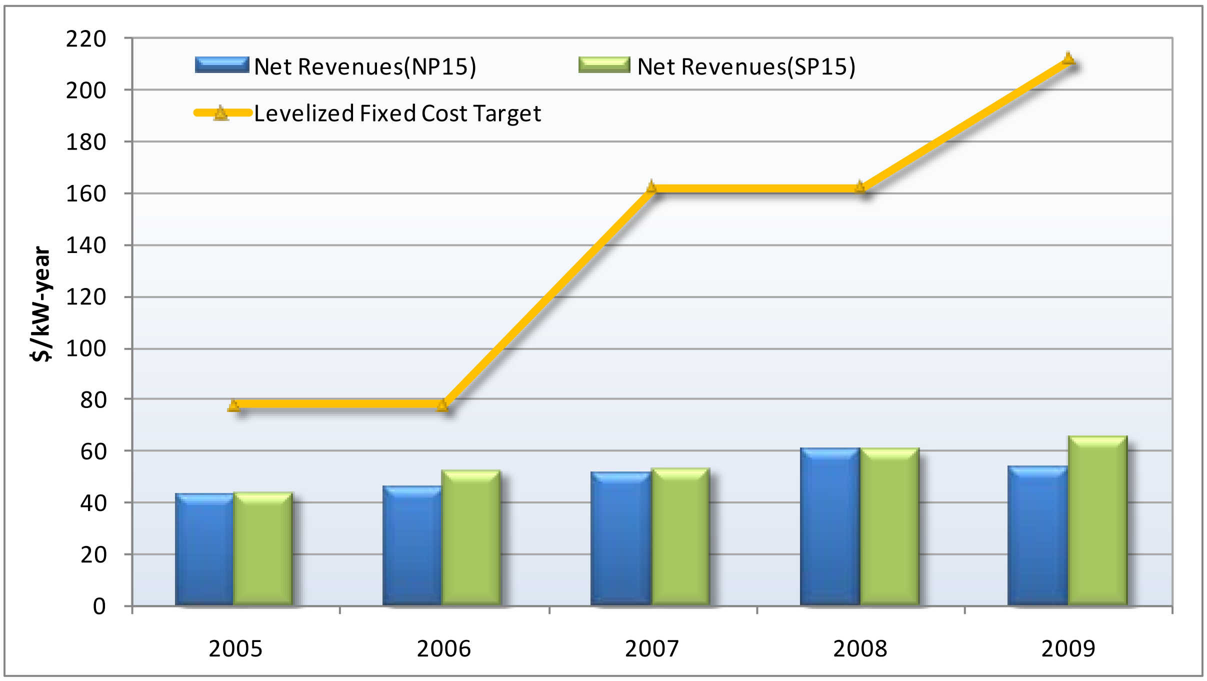
Technical Parameters	
Maximum Capacity	100 MW
Minimum Operating Level	40 MW
Startup Gas Consumption	180 MMBtu/start
Heat Rates (MBTU/MW)	
Maximum Capacity	9,300
Minimum Operating Level	9,700
Financial Parameters	
Financing Costs	$146.6 /kW-yr
Insurance	$7.9 kW-yr
Ad Valorem	$10.4 kW-yr
Fixed Annual O&M	$20.3 /kW-yr
Taxes	$26.5 kW-yr
Total Fixed Cost Revenue Requirement	**$211.7/kW-yr**
Variable O&M	$5.1/MWh

[40] See Footnote 38.

Table 2.10 Financial analysis of new combustion turbine (2006-2009)

Components	2006		2007		2008		2009	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	7%	10%	8%	9%	11%	12%	6%	6%
Energy Revenue ($/kW - yr)	$69.46	$99.77	$97.54	$104.99	$155.58	$158.98	$70.50	$84.62
A/S Revenue ($/kW - yr)	$22.67	$21.68	$13.30	$12.83	$5.50	$5.53	$8.64	$8.37
Operating Cost ($/kW - yr)	$46.04	$68.92	$59.18	$64.63	$100.12	$104.09	$25.85	$27.70
Net Revenue ($/kW - yr)	$46.10	$52.35	$51.66	$53.19	$60.96	$60.43	$53.29	$65.29
5-yr Average ($/kW - yr)	*$53.00*	*$57.82*						

Figure 2.20 Estimated net revenues of new combustion turbine



3 Energy market performance

3.1 Total wholesale market costs

Background

Since the start of the ISO market, the DMM has reported its estimate of annual wholesale energy costs. Under California's initial market design, the California Power Exchange's day-ahead market provided transparent prices that could be used to value energy scheduled prior to the real-time market. After the January 2001 closure of the California Power Exchange, there was not a transparent market price that could be used to value energy scheduled in the day-ahead and hour-ahead scheduling process, which has accounted for virtually all of the energy needed to meet loads since this time. Since 2001, DMM has estimated the total wholesale market costs based on a combination of estimated costs of utility-retained generation, bilateral forward contracts and spot market purchases by major load serving entities, and the cost of the very limited amount of energy purchased in the real-time energy market.

The new market design that started in April 2009 provides dramatically increased transparency of market clearing prices and quantities. This provides a basis for more accurately assessing wholesale energy costs. As a result, DMM modified its methodology for calculating total wholesale costs from the approach used in its seven prior annual reports.[41] The new method is based on the cost of serving load using the prices and quantities cleared in each of the three energy markets: day-ahead, hour-ahead and 5-minute real-time. The methodology also includes costs associated with ancillary service reserves, residual unit commitment, bid-cost recovery, reliability must-run contracts, the interim capacity procurement mechanism, and grid management charges. A more detailed description of the methodology used in calculating the total wholesale cost for 2009 is provided in Appendix A.

Total wholesale costs

Total estimated wholesale costs of serving load in 2009 were $8.8 billion, or $38/MWh. This compares with estimated wholesale costs of $53/MWh of load served in 2008. This decrease is attributable primarily to the drop in spot market prices for natural gas in 2009, which averaged about 56 percent less than in 2008.[42]

Natural gas fired resources are the marginal resource during most hours in the western U.S. electricity markets. This makes energy prices heavily influenced by the cost of natural gas. To account for year-to-year changes in gas prices, DMM also calculates an estimate of energy costs normalized to a fixed natural gas price.[43]

[41] Because the new market was in effect for only part of 2009 (April – December), the costs for the months prior to go-live (January – March) were calculated using a methodology similar to the one used in last year's annual report.

[42] For example, average daily spot market prices for natural gas at the SoCal Border in 2008 and 2009 were about $8.8/mmBtu and $3.9/mmBtu, respectively.

[43] The 2009 annual average of daily gas prices ($3.6/mmBtu) were used as the basis for normalization. Energy costs were normalized on an annual basis by multiplying the estimated portion of energy costs attributable to gas generation (both internal and external) by the ratio of applicable annual average gas price to the 2009 annual average gas price, and then adding in the non-energy cost components. The amount of gas generation assumed to normalize energy costs ranged between a low of 42 percent in 2005 and a high of 69 percent in 2008.

Figure 3.1 shows total estimated wholesale costs per MWh from 2005 to 2009. Wholesale costs are provided in nominal terms, as well as after a simple normalization for changes in average spot market prices for natural gas. A green line representing the annual average natural-gas price is included to illustrate the correlation between the cost of natural gas and the total wholesale cost estimate. Table 3.1 provides a monthly summary of 2009 nominal total wholesale costs by category. Table 3.2 provides annual summaries of nominal total wholesale costs by category for years 1998 through 2009.

Costs have been relatively stable from 2005 to 2008, with a noticeable decrease in costs in 2009. As previously noted, this was due primarily to the drop in spot market prices for natural gas. Other factors contributing to lower total wholesale costs in 2009 were lower total loads and increased hydro availability in the summer months, as highlighted in Chapter 2. During the peak summer hours, lower loads and increased hydro supply can have a major impact on moderating overall prices and avoiding extremely high prices.

Increased operational and market efficiencies under the new market design also appear to have contributed to the decline in costs in 2009. As outlined in Chapter 1, the new market incorporates a variety of features designed to increase the efficiency of California's wholesale market. Analysis of market performance in 2009 provided in this report provides strong indications that this new market design increased market efficiency and reduced costs in a variety of ways. For example:

- ***High day-ahead scheduling and low congestion* —** The very high level of load and supply scheduled in the new day-ahead market and the limited congestion occurring in 2009 provide indications of the efficiency of the new market design. On a day-ahead basis, the supply of resources that can be used to most efficiency meet load and manage congestion is typically much greater than in real time. Thus, when the bulk of load and suppliers are scheduled in the day-ahead market, this allows for more efficient unit commitment, scheduling and congestion management. High day-ahead scheduling also helps to keep the amount of capacity scheduled in the residual unit commitment market very low.

- ***Convergence of day-ahead and real-time prices* —** The relatively close convergence of prices in the day-ahead and real-time markets provides another indicator of the efficiency of the new market design. Price convergence in these sequential energy markets typically indicates that day-ahead scheduling and dispatch patterns were relatively accurate and efficient, so that major adjustments were not made as part of the re-optimization that occurs in the real-time market. As discussed in this chapter, prices and dispatch patterns in the hour-ahead scheduling process used to adjust imports and exports often diverged significantly from the day-ahead and 5-minute real-time markets. This represents areas in which the efficiency of the new market can be further improved.

- ***Market competitiveness* —** Prices in the day-ahead and real-time energy markets have been approximately equal to the competitive baseline prices DMM calculates by re-running the day-ahead market software with bids reflecting the marginal costs of gas-fired generation (see Chapter 4, Section 4.2). This indicates that actual overall energy market results are very close to this theoretical perfect dispatch. One of the key causes of the competitiveness of these markets is the high degree of forward contracting by load-serving entities. The high level of forward contracting significantly limits the ability and incentive for the exercise of market power in the day-ahead and real-time markets. In addition, bids for the additional supply needed to meet remaining demand in the day-ahead and real time energy markets have been highly competitive. Most additional supply needed to meet demand have been offered at prices close to default energy bids used in bid mitigation, which are designed to slightly exceed each unit's actual marginal or opportunity costs.

- ***Ancillary services* —** Ancillary service costs under the new market design dropped notably under a variety of different measures used to assess these costs (see Chapter 6). Ancillary service costs dropped from 1.4 percent of wholesale energy costs in 2008 to only 1 percent in 2009. This measure of ancillary service costs compares very favorably with ancillary service costs in other ISOs with similar market designs. In these markets, ancillary service costs have ranged from just under 1 percent to over 2 percent.

- ***Bid cost recovery payments* —** Bid cost recovery payments under the new market design were also lower than similar payments made under the prior market design, and compare very favorably with uplift costs in other ISO markets (see Section 3.7). Bid cost recovery payments under the new market design were about 25 percent lower than must-offer waiver denial costs in 2008 under the prior market design.[44] Bid cost recovery payments averaged 1 percent of energy costs under the new market design. Equivalent uplift costs in other ISOs have also ranged from just under 1 percent to over 2 percent.

- ***Resource adequacy* —** Another factor that indirectly helped keep total wholesale costs in the market relatively low is capacity under resource adequacy contracts utilized under the new market. As discussed in Section 3.6 of this chapter, resource adequacy capacity has been utilized to meet almost all residual unit commitment requirements under the new market design. Resource adequacy units are required to offer all available capacity into the residual unit commitment market at a price of $0/MW and do not receive an additional payment for capacity scheduled to meet residual unit commitment requirements. In addition, as discussed in Chapter 7, the amount of capacity available under the resource adequacy program helped reduce the amount and cost of capacity under reliability must-run contracts. Resource adequacy capacity was also sufficient to meet reliability requirements with very minimal reliance on additional capacity procured by the ISO through the interim capacity procurement mechanism.

The overall impact of various efficiency improvements under the new market design cannot be specifically quantified for several reasons. The dramatic changes in spot market gas prices from 2008 to 2009 make it difficult to compare prices over this period. While DMM normalizes wholesale electric prices based on changes in average annual spot market gas prices, this approach assumes a direct correlation between electric and gas prices. In practice, electric prices do not change directly in proportion to changes in spot market gas price.

In addition, as previously noted, forward costs were based on very limited data in prior years. The ISO did not have a formal day-ahead market, and prices paid by load-serving entities were not explicitly known. Under the new market, the settled prices and quantities are transparent and thus a more accurate total wholesale cost estimate can be calculated. For this reason, the 2009 estimate is a better estimate of total wholesale costs than in past years.

[44] Under the prior market design, must-offer waiver denial costs represented payments associated with start-up and minimum load cost of units required to be on-line for reliability reasons. These costs are not directly comparable to bid cost recovery payments under the new market design, but represent the most comparable component of the prior market to bid cost recovery payments.

Figure 3.1 Total wholesale costs in $/MWh of load served: 2005-2009

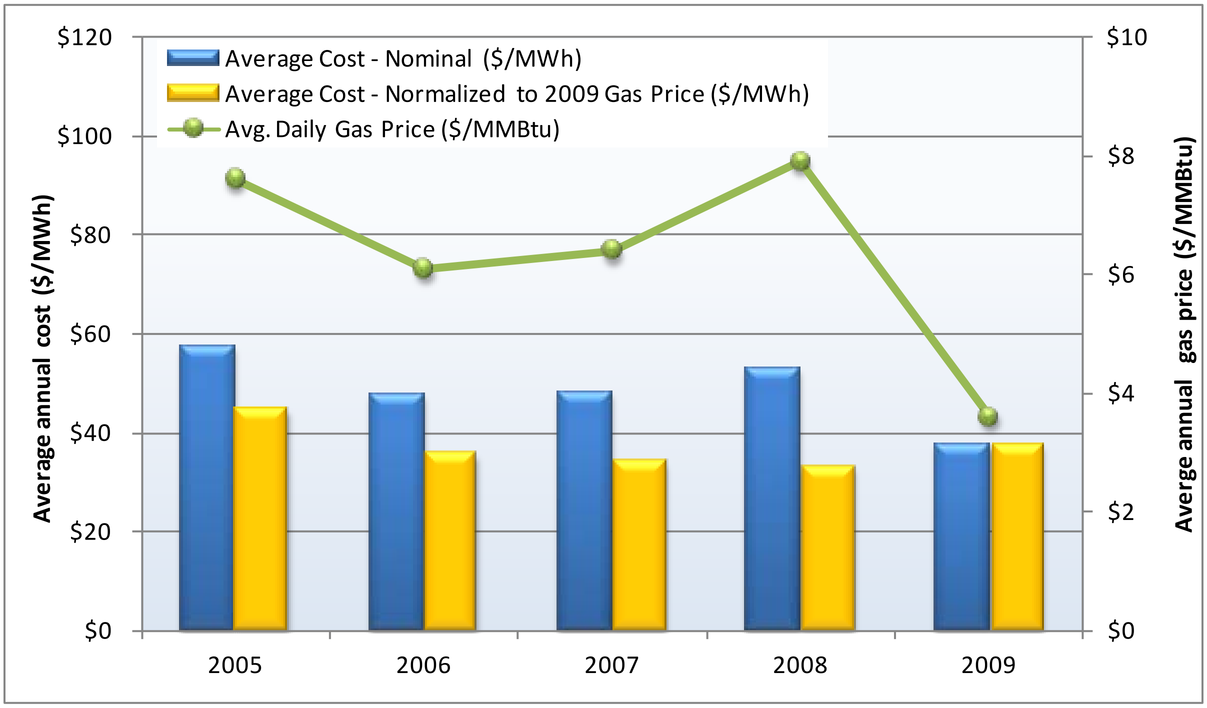


Table 3.1 Monthly wholesale costs: 2009

Month	ISO Load (GWh)	Total Est. Forward Costs ($MM)	RT Energy and Reliability Costs ($MM)	Reserve (AS + RUC) Costs ($MM)	Total Costs of Energy ($MM)	Total Costs of Energy and Reserves ($MM)	Avg Cost of Energy ($/MWh load)	Avg Cost of Reserves ($/MWh load)	Reserves as % of Wholesale Cost	Avg Cost of Energy & Reserves ($/MWh load)
Jan-09	18,308	$ 766	$ 26	$ 8	$ 793	$ 801	$ 43.30	$ 0.46	1.1%	$ 43.77
Feb-09	16,438	$ 622	$ 20	$ 8	$ 642	$ 650	$ 39.08	$ 0.49	1.2%	$ 39.56
Mar-09	17,850	$ 549	$ 21	$ 9	$ 570	$ 580	$ 31.96	$ 0.51	1.6%	$ 32.47
Apr-09	17,601	$ 483	$ 40	$ 10	$ 523	$ 534	$ 29.72	$ 0.60	2.0%	$ 30.31
May-09	19,349	$ 617	$ 30	$ 8	$ 647	$ 655	$ 33.41	$ 0.44	1.3%	$ 33.85
Jun-09	19,233	$ 523	$ 17	$ 6	$ 540	$ 547	$ 28.10	$ 0.32	1.1%	$ 28.42
Jul-09	22,889	$ 880	$ (0)	$ 10	$ 880	$ 889	$ 38.43	$ 0.42	1.1%	$ 38.85
Aug-09	22,343	$ 780	$ 8	$ 6	$ 788	$ 795	$ 35.29	$ 0.28	0.8%	$ 35.57
Sep-09	21,525	$ 802	$ 23	$ 6	$ 825	$ 831	$ 38.32	$ 0.26	0.7%	$ 38.59
Oct-09	18,688	$ 836	$ 49	$ 6	$ 885	$ 891	$ 47.37	$ 0.31	0.6%	$ 47.68
Nov-09	17,729	$ 636	$ 12	$ 6	$ 648	$ 654	$ 36.57	$ 0.33	0.9%	$ 36.90
Dec-09	18,804	$ 938	$ 17	$ 7	$ 955	$ 962	$ 50.81	$ 0.36	0.7%	$ 51.17
Total 2009	**230,754**	**$8,433**	**$265**	**$90**	**$8,698**	**$8,788**	**$37.69**	**$0.39**	**1.0%**	**$38.08**

Table 3.2 Estimated average wholesale energy costs per MWh (2005-2009)

	2005	2006	2007	2008	2009	Change '08-'09
Day-Ahead Energy Costs (excl. GMC)	$ 52.28	$ 43.01	$ 44.74	$ 47.48	$ 35.57	$ (11.91)
Real-Time Energy Costs	$ 0.82	$ 0.29	$ 0.25	$ 0.81	$ 0.81	$ (0.00)
Grid Management Charge	$ 0.84	$ 0.72	$ 0.76	$ 0.76	$ 0.78	$ 0.02
Bid Cost Recovery Costs	$ 0.55	$ 0.50	$ 0.23	$ 0.41	$ 0.29	$ (0.12)
Reliability Costs (RMR and ICPM)	$ 2.38	$ 2.07	$ 1.64	$ 2.80	$ 0.25	$ (2.55)
Average Total Energy Costs	**$ 56.86**	**$ 46.60**	**$ 47.62**	**$ 52.26**	**$ 37.69**	**$ (14.57)**
Reserve Costs (AS and RUC)	$ 0.96	$ 0.97	$ 0.63	$ 0.74	$ 0.39	$ (0.35)
Average Total Costs of Energy and A/S	**$ 57.83**	**$ 47.57**	**$ 48.25**	**$ 53.00**	**$ 38.08**	**$ (14.92)**

3.2 Day-ahead scheduling

A key factor contributing to the efficient performance of the new market design was the very high level of scheduling in the day-ahead market. The portion of load clearing the day-ahead market has consistently been very high. An average of 98 percent of total forecast demand was scheduled in the day-ahead market. This left a relatively small volume of demand to be met by the residual unit commitment and real-time market processes.

Under the prior market design, load-serving entities were required to schedule at least 95 percent of their load forecast in the day-ahead process during peak hours and 85 percent of forecasted load during off-peak hours.[45] Under the new market design, load-serving entities may be subject to significant charges if they do not schedule at least 85 percent of their actual load in the day-ahead market.[46] However, the portion of load being scheduled in the day-ahead market has consistently exceeded both the 95 percent requirement under the prior market design and the 85 percent threshold in the current market design.

Figure 3.2 shows the average load clearing the day-ahead market to the forecast of demand. The percentage of the forecast met in the day-ahead market has stayed relatively constant during each month under the new market, with day-ahead scheduled loads averaging about 97 to 99 percent of forecasted load.

This trend of a very high level of day-ahead scheduling has prevailed across all the hours of the day, as illustrated in Figure 3.3. During the early morning off-peak hours and morning ramping hours, load schedules tended to slightly exceed actual loads. This pattern reflects the fact that during off-peak and lower load peak hours, additional energy is available from minimum load generation requirements and imports for standard hourly blocks (i.e., all 8 off-peak hours or all 16 peak hours).

[45] Revision to ISO Tariff Amendment 72, September 11, 2006, http://www.caiso.com/docs/2005/09/23/2005092307580625192.html

[46] Section 11.14.

Figure 3.2 Day-ahead cleared volume versus forecast in 2009

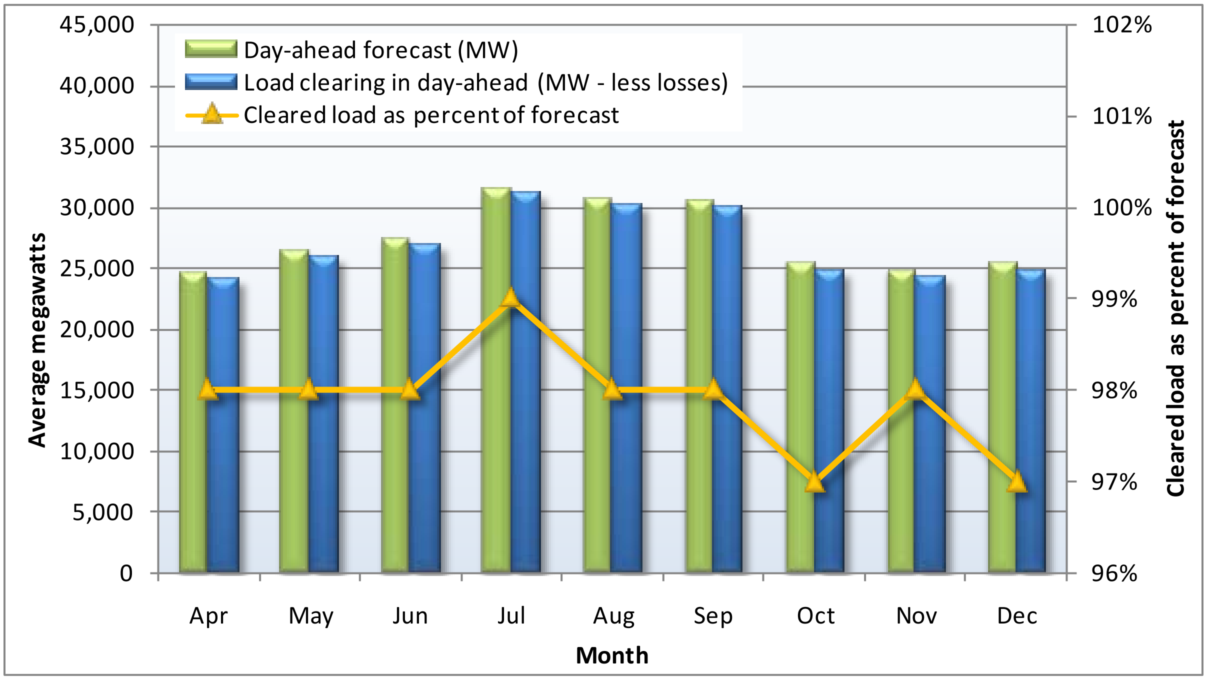
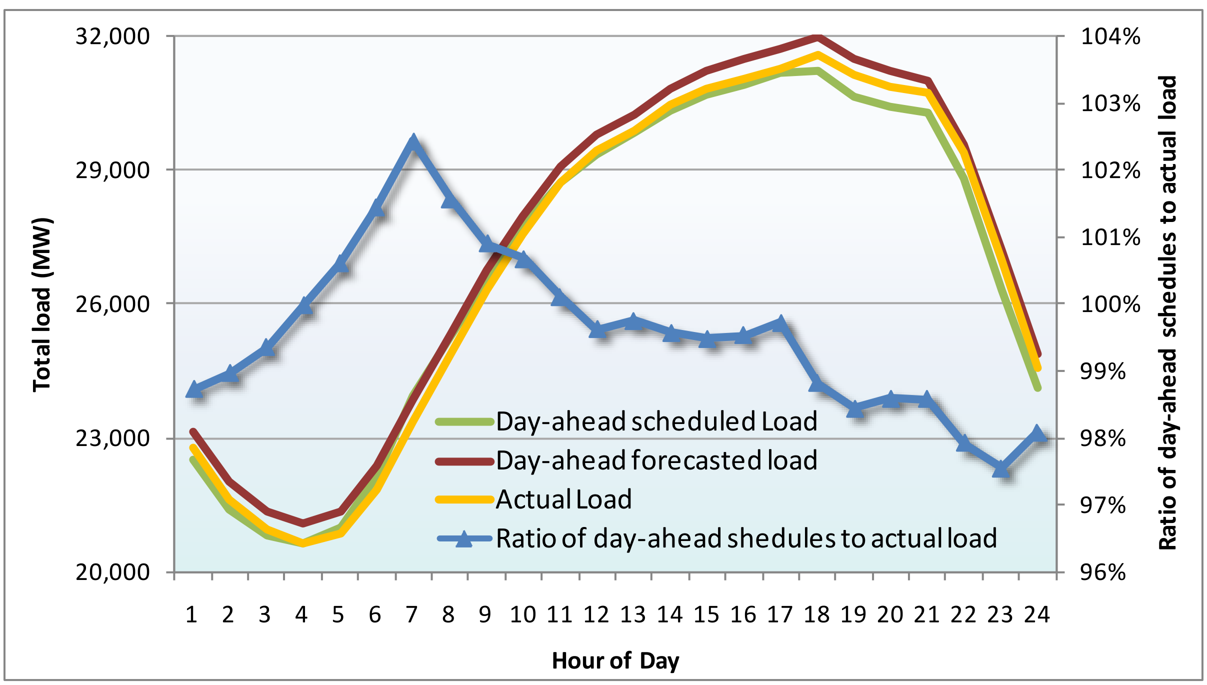


Figure 3.3 Day-ahead schedules, forecast and actual load, April- December 2009

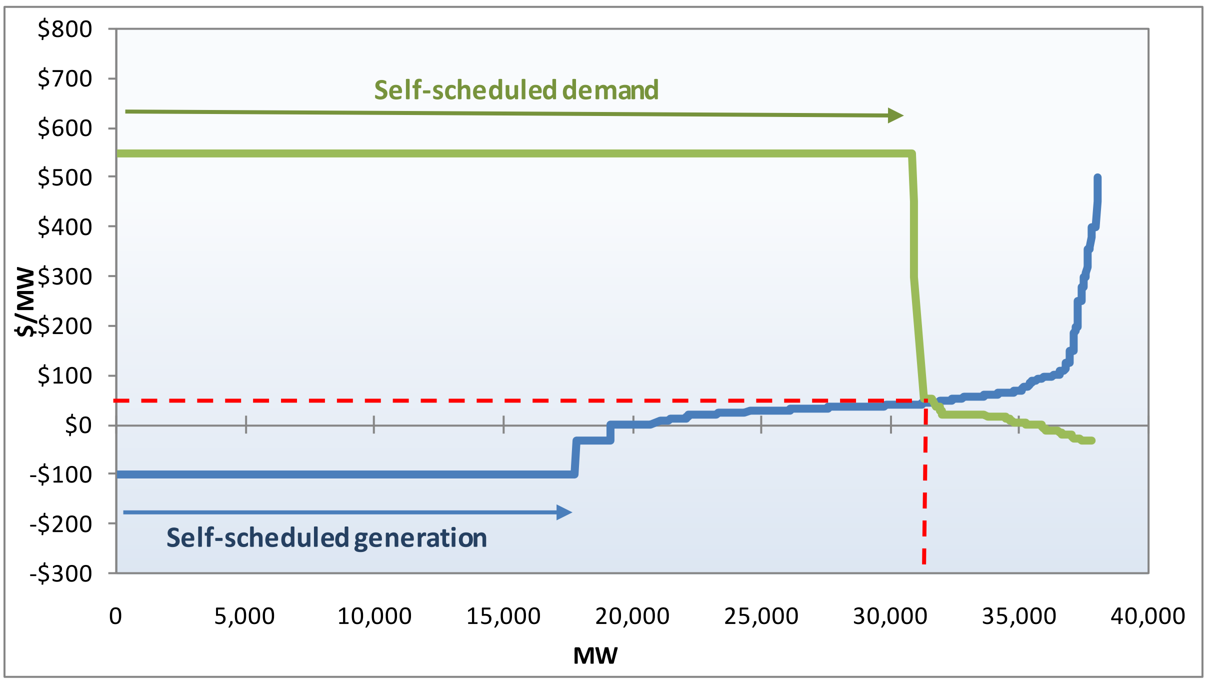


Self-scheduling of loads and generation

One of the factors underlying the high level of scheduling in the day-ahead market is a very high level of self-scheduling of loads and generation. Figure 3.4 shows an example of market supply and demand as bid into the day-ahead market on a midsummer day (August 15, 2009, Hour Ending 13). In this example, approximately 31,000 MW of load cleared with a system energy price of $34.56. This hour was selected for illustration purposes in part because there was no congestion this hour. Because there was no congestion, the aggregate system level bid curves for supply and demand intersect approximately price and quantity level corresponding to actual day-ahead market outcomes.

This chart highlights the proportion of load and generation that is self-scheduled in the day-ahead market. Demand depicted as bidding at $550/MWh and supply depicted as bidding at -$100/MWh are actually self-scheduled.[47] Figure 3.4 also shows the considerable degree of competitiveness in the day-ahead market. In this hour, approximately 5,000 MW of supply was available beyond the market clearing quantity before additional demand would have had a substantial impact on price. Competitive supply conditions encourage self-scheduling by demand, since load-serving entities can schedule as price takers and have confidence that their load will clear at a competitive price.

Figure 3.4 Supply and demand bids in day-ahead market: August 15, 2009, hour ending 13[48]



[47] In practice, the software represents self-scheduled load with much higher bid price and self-scheduled generation with a much lower bid price. The system energy losses were included in the demand self schedule segment and accounted for approximately 2.3 percent (711 MW) of the cleared demand (31 GW) on this hour.

[48] The system energy losses were included in the demand self schedule segment and accounted for approximately 2.3 percent (711 MW) of the cleared demand (31 GW) on this hour.

Figure 3.5 further illustrates the portion of load clearing the day-ahead market comprised of self-scheduling and price-taking demand bids, as opposed to price-sensitive demand bids. For purposes of this analysis, we have classified load bids between the maximum bid cap of $500 and $495/MW as price taking loads, because these bids are virtually certain to clear the market. As shown in Figure 3.5, self-scheduled and price-taking demand bids have accounted for an average of 96 to 98 percent of load clearing the new day-ahead market.

Figure 3.6 shows the portion of supply clearing the day-ahead market comprised of self-scheduling and price-taking bids. Again, for purposes of this analysis, we have classified supply bids between the lower bid limit of -$30 to $0 as price taking supply, because these bids are virtually certain to clear the market. As shown in Figure 3.5, self-scheduled and price-taking supply bids have accounted for an average of about 70 to 80 percent of supply clearing the new day-ahead market.

Under the new market design, extremely high levels of self-scheduled supply can decrease market efficiency by reducing the degree to which the market software is free to optimize different supply resources based on their bid costs. High levels of self-scheduled supply can also hinder the ability to manage congestion in the most cost-effective manner.

As shown in Figure 3.6, the total amount of self-scheduled and price-taking generation remained relatively constant over the first six months of the new market (April to September). However, because the total amount of supply clearing the market increased over these months, the portion of supply clearing the market due to self-scheduled and price-taking bids dropped from over 80 percent in April to under 70 percent in September. During the final three months of 2009, the portion of supply clearing the market due to self-scheduled and price-taking bids increased due to the drop in total supply clearing the market in these lower-load months.

These trends provide some evidence that as suppliers gain increased experience and confidence in the new market, they will bid an increasing portion of their supply with price-sensitive bids. However, given the limited duration of this trend, it is difficult to discern the degree to which the increase in price-sensitive bids by suppliers was due to seasonal trends versus increased experience and confidence in the new market.

Figure 3.5 Monthly average self-scheduled versus cleared load in day-ahead market

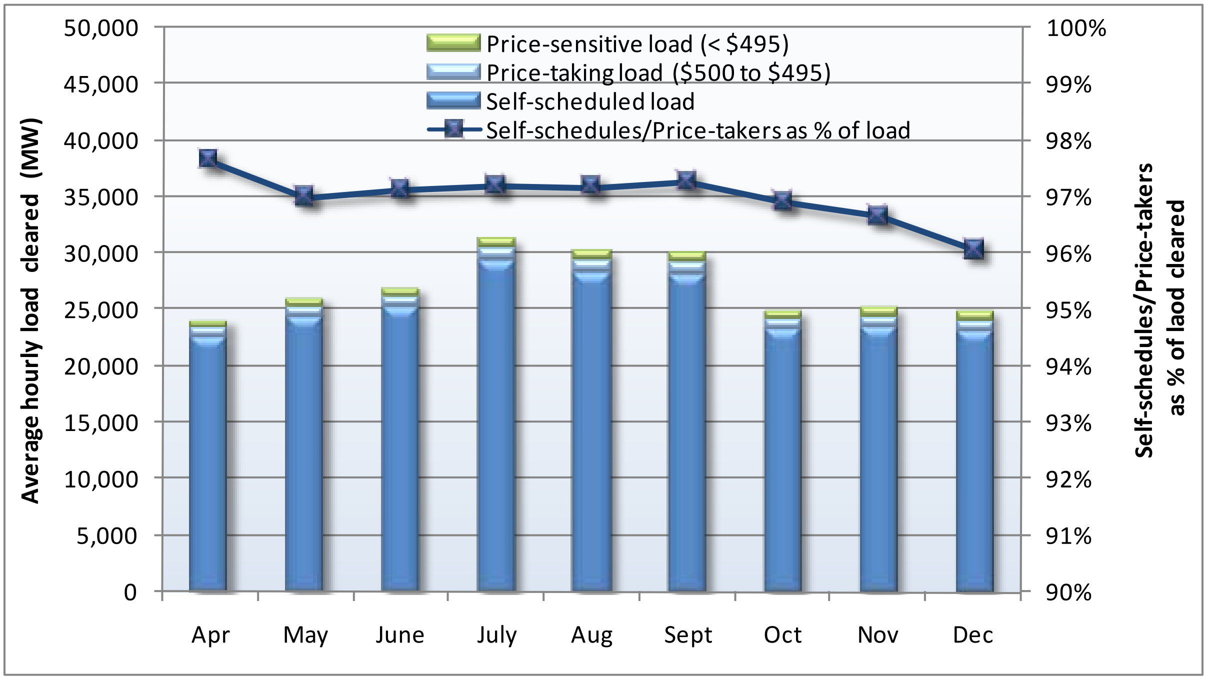
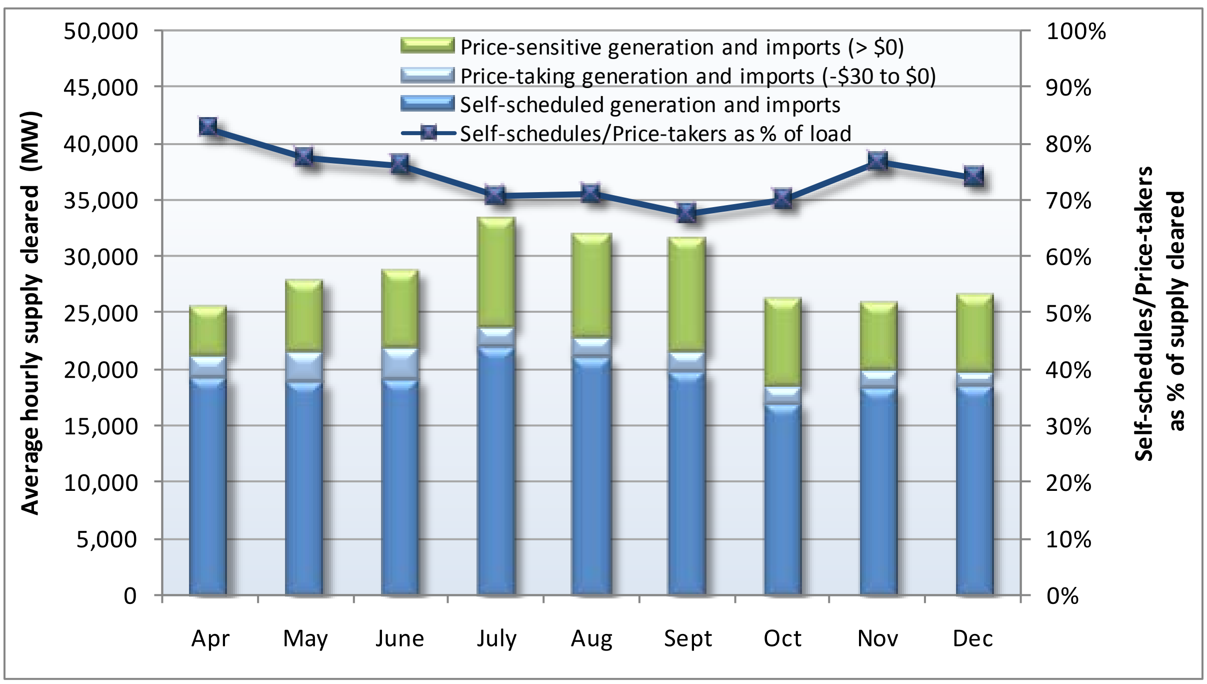


Figure 3.6 Monthly average self-scheduled versus cleared supply in day-ahead market



Hour-ahead scheduling process

The market design allows for day-ahead inter-tie schedules (imports and exports) to be modified through a re-clearing of the entire market in the hour-ahead scheduling process. Market participants with accepted day-ahead inter-tie transactions can either self-schedule these schedules in the hour-ahead scheduling process, or re-bid them at the same or different prices than were initially submitted in the day-ahead market. If a bid for an interchange transaction that was originally scheduled in the day-ahead market does not clear in this hour-ahead market, the market participant "buys-back" the import at the hour-ahead price (or "sells-back" an export at the hour-ahead price).

Day-ahead import schedules that are re-bid in the hour-ahead scheduling process may not clear this process due to either a change in their bid price or a change in market prices. For example, a participant's day-ahead import schedule may not re-clear if the participant increases the bid price above the price at which the hour-ahead market clears. However, even if a participant's hour-ahead import bid is equal to or lower than their bid price in the day-ahead market, the import bid may not clear if the hour-ahead process clears at a lower price than the day-ahead market. This illustrates how the hour-ahead re-bidding process is designed to promote market efficiency by allowing participants and the ISO to re-optimize the interchange transactions given updated market bids and conditions.[49]

During 2009, net import schedules clearing the hour-ahead scheduling process were systematically lower than net import schedules clearing the day-ahead market. As shown in Figure 3.7, average monthly net imports clearing the hour-ahead process during peak hours were 500 to 1,000 MW lower than net day-ahead import schedules. This drop in net imports was due to a combination of a drop in imports and an increase in exports in the hour-ahead market. Import schedules clearing in the hour-ahead decreased approximately 200 MW, while exports increased about 600 MW.

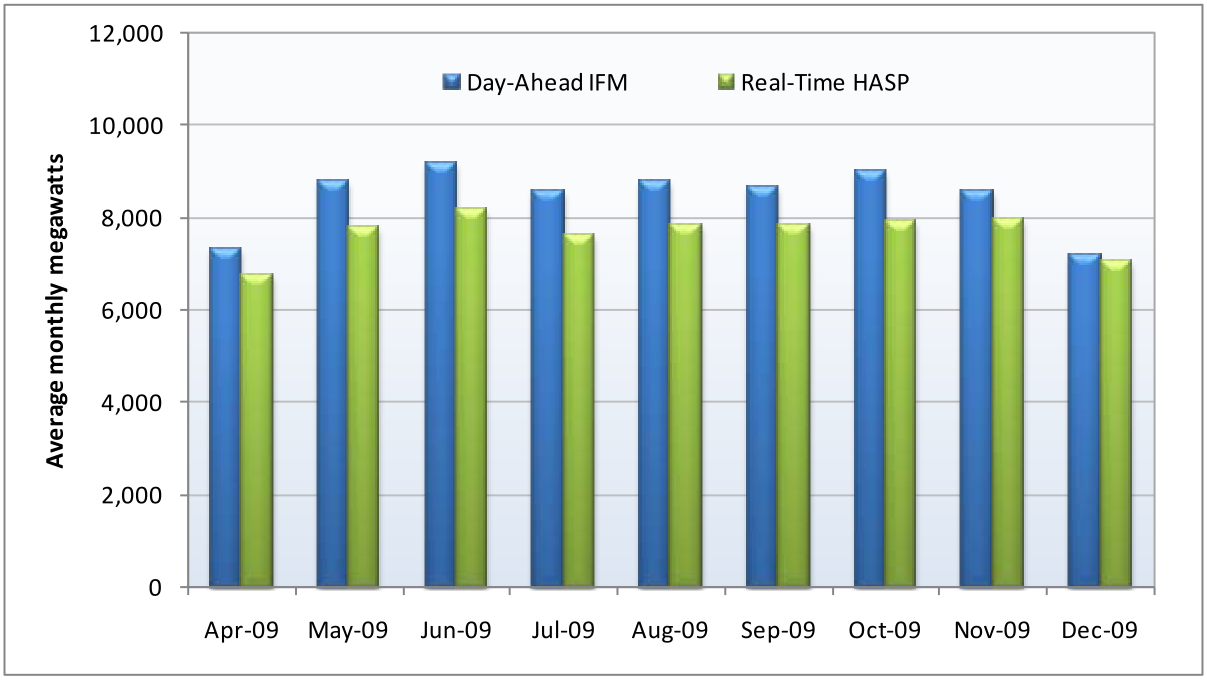
This trend appears to be due to a combination of factors, as is discussed in greater detail in the DMM's quarterly report for the third quarter of 2009.[50] The main cause of decreased net imports in the hour-ahead scheduling process is that prices in this market have tended to be systematically lower than prices in both the day-ahead and 5-minute real-time market. These lower prices appear to be due largely to systematic forecasting, modeling and optimization differences incorporated in the software used to clear the hour-ahead market and the software used for the 5-minute real-time market. Regional marketers have responded to low hour-ahead prices by exporting power to other control areas and/or decreasing imports into the ISO.

The divergence of prices between the hour-ahead scheduling process and the day-ahead and real-time markets is discussed further in Section 3.3.1. As noted in Section 3.3.1, when net imports are decreased at relatively low prices in the hour-ahead process, the ISO has often needed to purchase additional energy to compensate for this at a higher price in the 5-minute real-time market. This pattern of selling low in the hour-ahead market and then buying high in the 5-minute real-time market has represented one of the most significant sources of potential inefficiency under the new market.

[49] In 2009, this flexibility created some potential concerns about reliability and the potential for participants to engage in "implicit virtual bidding" in the day-ahead market. To address this concern, the ISO developed and filed tariff revisions that would prevent entities from profiting from any adjustments made in day-ahead inter-tie schedules unless these schedule's e-tags are submitted for day-ahead schedules prior to the hour-ahead process.

[50] *Quarterly Report on Market Issues and Performance,* http://www.caiso.com/2457/2457987152ab0.pdf

Figure 3.7 Day-ahead versus hour-ahead peak-hour net imports



3.3 Market prices

After an initial period of volatility following the introduction of the new market in April 2009, prices soon followed patterns reflective of well-functioning competitive markets. Average prices in the day-ahead and real-time energy markets began to converge, and reflected marginal production costs. This indicates that resource commitment and dispatch decisions are being optimized across the day-ahead and real-time markets. All prices have generally trended upward, following the national price trend of natural gas, which is the most prevalent fuel for marginal resources in the system.

3.3.1 Price convergence

One of the key measures of overall market performance is the degree of price convergence across the day-ahead, hour-ahead and real-time markets. Under the prior market design, price indices for day-ahead bilateral markets tended to be higher than prices in the real time imbalance market.

In the first few months of the new market, average day-ahead prices tended to be consistently lower than real-time prices. Average prices in the hour-ahead scheduling process were consistently lower than both day-ahead and real-time prices. Since then, price convergence in these three markets has improved substantially. By the fourth quarter of 2009, prices were relatively similar across the energy markets when compared to previous quarters.

Figure 3.8 and Figure 3.9 show average monthly prices in the three energy markets for the SCE load aggregation point during peak and off-peak hours, respectively. Monthly average price trends in the other major load aggregation points are very similar to those depicted for the SCE load aggregation point in Figure 3.8 and Figure 3.9.

In the first two months of the new market, problems with the short-term load forecasting application resulted in large discrepancies between the hour-ahead forecast and actual load. As this and other issues were resolved, prices in these three markets showed improved convergence. As shown in Figure 3.8 and Figure 3.9, peak-hour prices at the SCE load aggregation point in the day-ahead market have tracked well with real-time market prices since July, after diverging significantly during the first months of the new market design.

The tendency for real-time prices to be lower than day-ahead prices during off-peak hours may be explained by several factors. As previously illustrated in Figure 3.3, loads and generation scheduled during off-peak hours often tend to exceed actual loads. After the day-ahead market, additional generation also occurs during off-peak hours from the minimum load energy of units committed via the residual unit commitment market or units committed via exceptional dispatches for special reliability reasons. Additional generation from uninstructed energy also tends to be highest during off-peak hours, from wind resources and minimum load energy generation resources staying on-line.

By the fourth quarter of 2009, prices in the hour-ahead market also tracked much more closely with real-time prices, particularly during off-peak hours. This trend is highlighted in Figure 3.10, which shows the difference in average monthly prices in the hour-ahead scheduling process and the 5-minute real-time market, which represents the major area of price divergence between the three energy markets. Figure 3.10 shows data for the PG&E load aggregation point to illustrate the similarity with trends in the SCE load aggregation point.

By September, the most notable divergences between prices in the three energy markets were attributable to specific major events, rather than more systematic sources of price divergence:

- The very low average off-peak prices in the hour-ahead scheduling process in the SCE load aggregation point during September during off-peak hours were caused by an incorrect prediction by the market optimization of excess generation within Southern California on September 29 and 30.[51]
- The notably low average peak hour prices in the hour-ahead scheduling process in the SCE load aggregation point during October can be attributed to a few unrelated events over five noncontiguous days in October, involving transmission de-rates and outages on internal and import constraints.
- In December, there were several incidences of the SCE Import Limit binding in the hour-ahead scheduling process, which resulted in price spikes in excess of $1,000/MWh for the SCE area and drove average hour-ahead prices in the SCE load aggregation point above day-ahead and real-time prices that month.

As previously noted, low prices in the hour-ahead process have often been accompanied by a significant increase in exports and decrease in net imports in the hour-ahead process. During many of these hours, the ISO has then needed to purchase additional energy at a higher price in the 5-minute real-time market. This pattern of selling low in the hour-ahead market and then buying high in the 5-minute real-time market has represented one of the most significant sources of potential inefficiency under the new

[51] Prices on these days reached -$1100/MWh. Because they had no settlement impact, they were not corrected.

market. The ISO is taking a variety of steps to improve the consistency between prices and dispatches in the hour-ahead and real-time markets, as noted in DMM's prior quarterly reports.[52]

Figure 3.8 Comparison of monthly prices – SCE LAP, peak hours

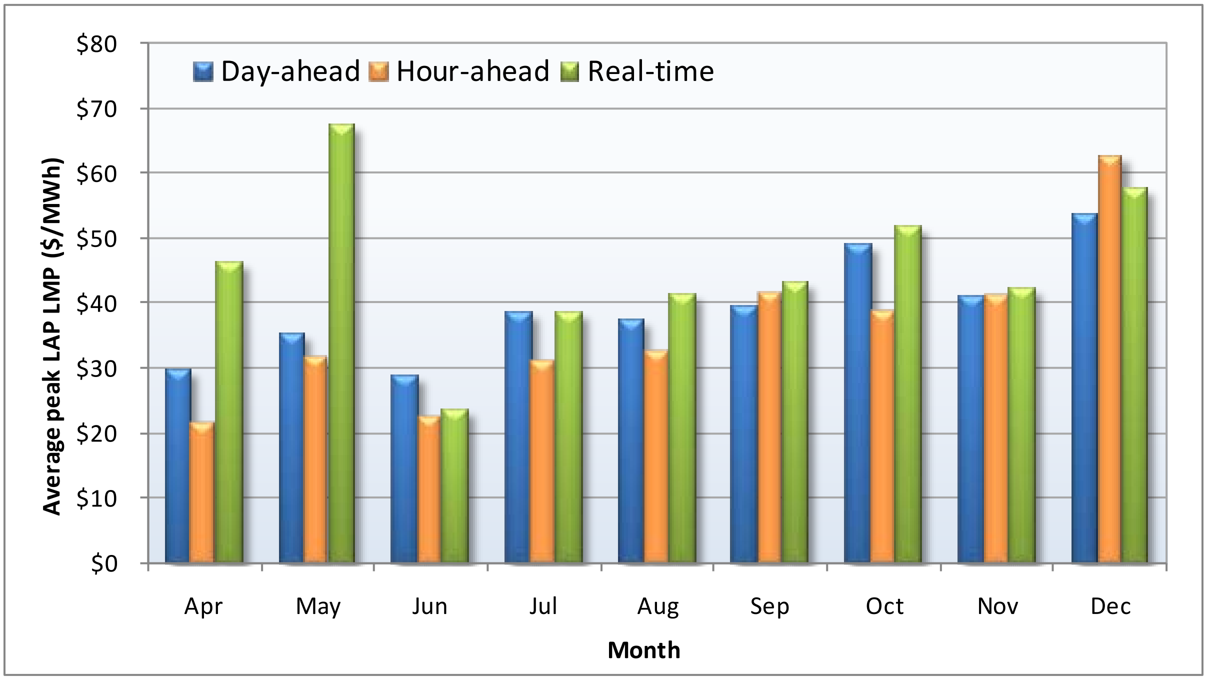
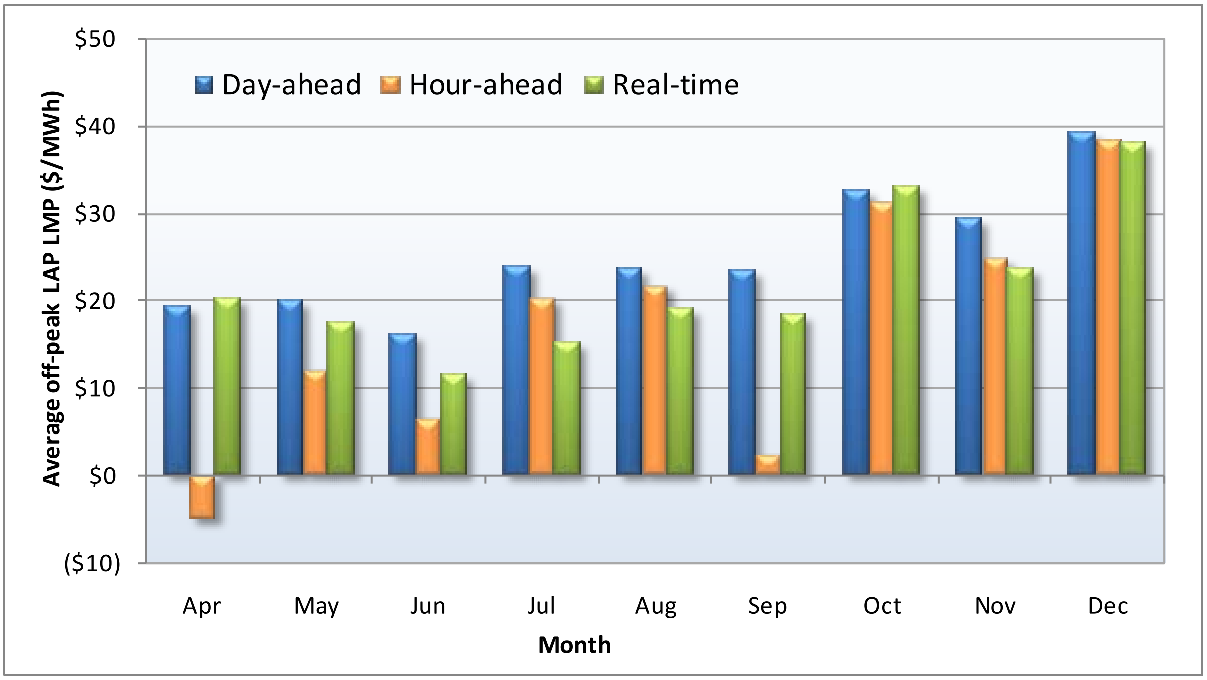
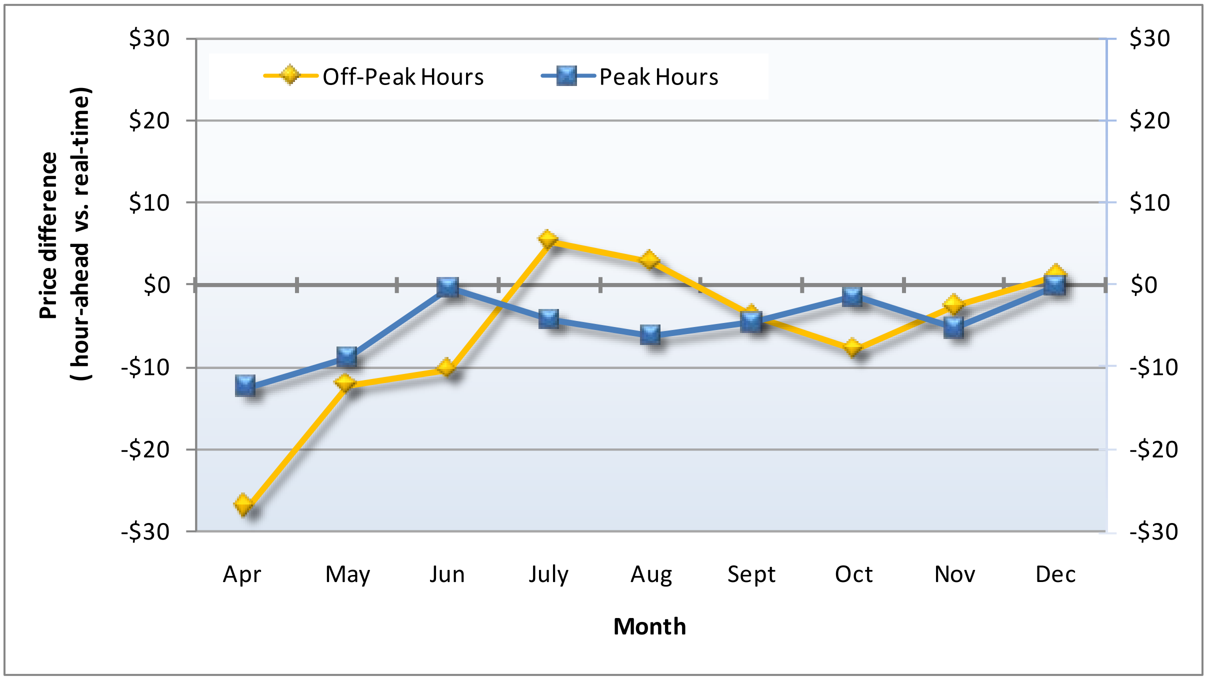


Figure 3.9 Comparison of monthly prices – SCE LAP, off-peak hours



[52] *Quarterly Report on Market Issues and Performance*, February 1, 2010, p.4 http://www.caiso.com/2730/2730ee1e71a10.pdf

Figure 3.10 Difference in hour-ahead and real-time prices, PG&E LAP



3.3.2 Locational prices

This section provides a more detailed analysis of locational price difference within the system in the day-ahead and real-time markets. Locations examined in this analysis represent the aggregation of all generation nodes within the local capacity areas and sub-areas used for determining local resource adequacy requirements (see Section 2.1.2 in Chapter 2). These areas have been identified as the major transmission constrained load pockets in the system.

Day-ahead price differences by local capacity area

Under California's market design, price signals for maintenance and development of transmission and resources must come from a combination of sources: nodal energy prices, regional ancillary service prices, local resource adequacy contract prices and bilateral energy contract prices. One of the benefits of a nodal energy market is to provide spot market energy price signals that better reflect when and where additional supply is needed, and transmission upgrades or demand response is most valuable.

In an LMP market, internal congestion is the main driver of locational price differences within the transmission system. When there is a congested transmission constraint, more costly supply must be procured to meet load on one side of the constraint. Less supply is needed on the other side of the constraint. This creates higher prices on the congested side of the constraint and lower prices on the uncongested side.

The frequency of congestion on internal constraints was low in 2009, particularly in the day-ahead energy market in which almost all of load and generation is scheduled.[53] This has resulted in only minor overall prices between local capacity areas.

The degree of locational price difference within the system can be measured based on the average LMP congestion component at generator nodes within each local capacity area. The average congestion component can be calculated as a percent of the average system energy price to measure locational price differences as a percentage of average prices. Table 3.3 shows this measure of locational price differences, along with average congestion LMP and system energy price for the local capacity areas within the system.

Table 3.3 Average congestion component as a percent of system LMP by local capacity area

		Average of Congestion LMP as Percent of System LMP											
LAP	LCA	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.	Avg. LMP (system)	Avg. LMP (congestion)
PG&E	Bay Area	3.1%	0.3%	0.1%	-0.1%	-0.2%	1.5%	0.3%	-2.0%	0.5%	0.3%	$33.86	$0.11
	Fresno	2.7%	0.0%	0.0%	0.0%	-0.2%	1.1%	0.1%	-2.0%	-0.7%	0.0%	$33.90	$0.00
	Humboldt	13.0%	0.3%	0.6%	1.4%	23.5%	9.7%	0.3%	8.3%	0.6%	5.9%	$33.74	$2.00
	Kern	2.4%	-1.8%	-0.1%	-0.1%	-0.3%	-0.9%	0.0%	-2.5%	-1.1%	-0.6%	$33.67	-$0.20
	NCNB	2.6%	0.4%	0.0%	-0.1%	-0.2%	1.4%	0.3%	-2.0%	0.4%	0.3%	$33.67	$0.09
	Sierra	1.8%	3.7%	0.1%	0.4%	-0.3%	1.4%	-1.3%	-3.0%	0.4%	0.2%	$33.64	$0.07
	Stockton	-1.0%	0.2%	-5.8%	-0.4%	-0.3%	1.3%	0.3%	-1.6%	0.4%	-0.5%	$33.63	-$0.18
SCE	Big Creek-Ventura	3.0%	-1.9%	0.5%	0.0%	0.1%	-0.9%	0.2%	2.5%	0.1%	0.3%	$33.76	$0.12
	LA Basin	2.9%	-2.2%	-0.1%	0.0%	0.2%	-0.5%	-0.4%	2.6%	0.1%	0.2%	$33.86	$0.08
SDG&E	San Diego	6.2%	-0.9%	-0.1%	0.3%	0.3%	-1.1%	-0.3%	-2.9%	-1.1%	-0.2%	$34.08	-$0.07

The average congestion component of the LMP for generation nodes in different local capacity areas was minimal in most months. There was more congestion with higher impacts on prices in the first two months of the new market, which resulted in higher congestion components in some local capacity areas in April and May. Beginning in June, the impact of congestion on price divergence was minimal. The Humboldt sub-region had the highest and most consistent congestion component due to congestion into this area.

The SCE percent import limit was introduced into the day-ahead market in November and was binding for several days, which caused a congestion component of about 2.5 percent within the SCE load aggregation point. This constraint increased the day-ahead price in the SCE load aggregation point and decreased the day-ahead price in both the PG&E and SDG&E load aggregation points.

Price divergence by local capacity area

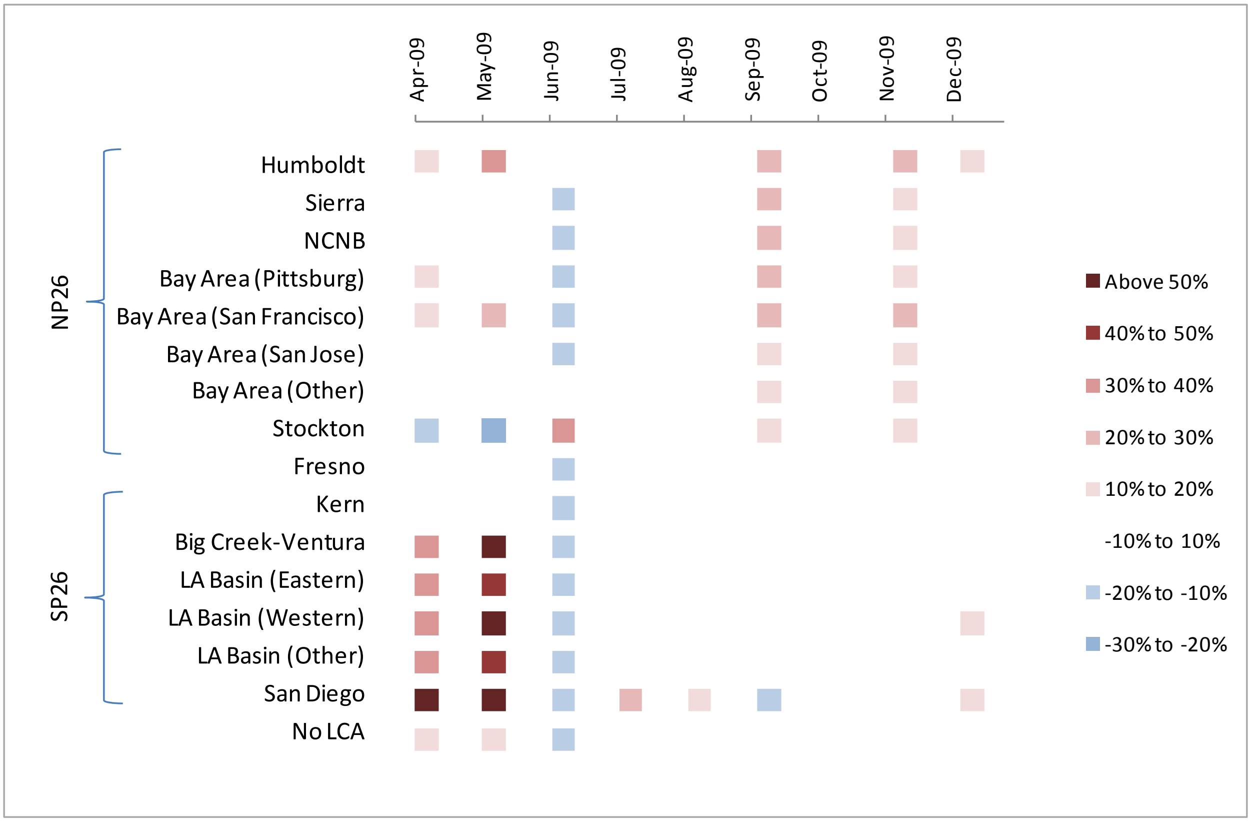
Differences in day-ahead and real-time markets for different locations within each of these local areas may provide an indication of systematic modeling discrepancies that could create inefficiencies in generation scheduling and dispatch.[54] Figure 3.11 shows monthly average peak-hour price differences

[53] The frequency of congestion and the impact of congestion on prices is covered in detail in Chapter 5.

[54] Suppliers with physical generation at nodes may be able to profit from differences at generation nodes at which their resources are located. However, the ISO only allows demand bidding at load aggregation point levels and does not provide for virtual bidding of demand or supply. Thus, there are currently very limited market mechanisms through which prices at a nodal level could be arbitraged by market participants.

by local capacity area. Price divergences for sub-regions within the San Francisco bay area and Los Angeles basin are also provided to show a more detailed level or price divergence. Various shades of red in Figure 3.11 indicate areas where average monthly real-time prices were higher than day-ahead prices, while various shades of blue indicate areas where average monthly real-time prices were lower than day-ahead prices.

Figure 3.11 Monthly average real-time versus day-ahead price difference category by local capacity area – peak hours



As shown in Figure 3.11, the differences in day-ahead versus real-time prices across the local capacity areas and sub-areas within each load aggregation point was very limited. Divergences in prices appear to be associated with specific grid and market conditions, rather than more systematic modeling discrepancies. For example:

- The higher levels of difference in April and May reflect the volatility following the introduction of the new market.
- Real-time prices were lower than day-ahead prices on average in June, a month with unseasonably cool weather in 2009. The exception to this rule occurred in the Stockton area, a small area skewed by a small number of intervals with high prices.

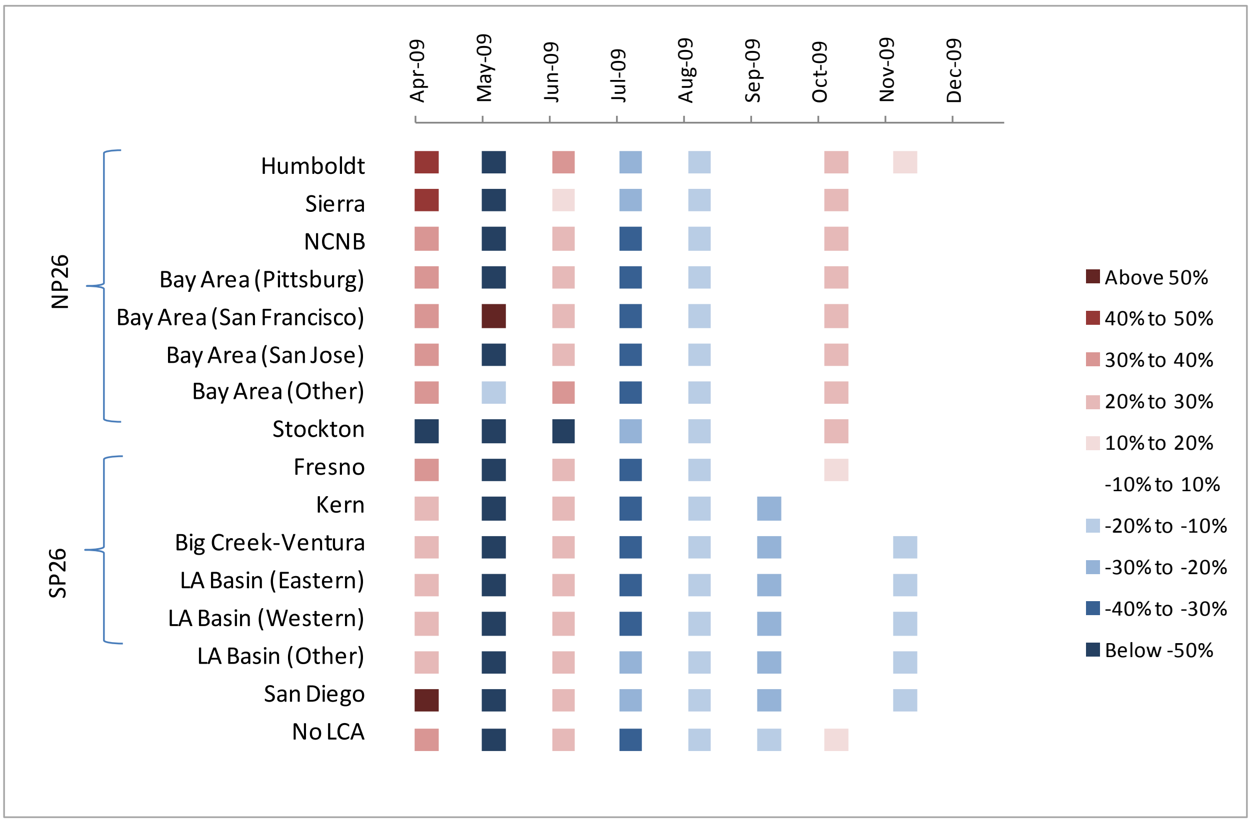
- Other notable periods of divergence include September and November, within the NP26 region. In both of these months, a few days of congestion on the Los Baños North branch group resulted in high real-time prices, causing spreads between real-time and day-ahead prices to be substantial. This branch group includes transmission between Path 15 and the Bay Area, and can impact PG&E area load aggregation point prices significantly when congested.
- In November, the ISO manually conformed flows on the Los Baños North branch group downward to manage unscheduled loop flows. This reliability procedure resulted in high shadow prices on the branch group. This procedure also triggered higher real-time congestion costs in late November, as its transmission capacity was reduced during a planned maintenance outage of the Tesla-Los Baños 500kV transmission corridor.
- In December, the La Fresa-Hinson 230kV line and other associated transmission lines in the western Los Angeles basin area were scheduled out for maintenance work. These outages resulted in frequent price spikes, and are described in greater detail in DMM's quarterly report for the fourth quarter of 2009. The spikes resulted in the monthly average real-time price being slightly greater than the average day-ahead price in that region.

Figure 3.12 shows a similar summary of monthly average peak-hour price differences by local capacity area for off-peak hours. In off-peak hours, day-ahead prices often were above real-time prices, as indicated by the shades of blue. Again, however, the divergences in prices appear to be associated with specific grid and market conditions, rather than more systematic modeling discrepancies.

- Off-peak real-time prices spiked occasionally in June, primarily due to scheduling errors, causing the difference metric to be positive on average. The exception to this pattern occurred in the Stockton local capacity area, which includes the Spring Gap hydroelectric system. This is an area of constrained generation, particularly during the spring runoff. Within the Stockton area, volatile and frequently negative prices in both the real-time and day-ahead markets on a relatively small number of days in the second quarter disproportionately impacted the percent average price statistic.
- In off-peak hours, average day-ahead prices in July and August were significantly higher than real-time prices across the system. Across the period, total day-ahead schedules were consistently higher than actual loads in most off-peak hours, as loads were unseasonably low. The ISO committed additional units through the exceptional dispatch procedure for local peak-period reliability reasons, primarily in July. These resources often remained online in off-peak hours, due to startup and shutdown time limitations. An unusual day-ahead high price spike also occurred on Sunday, July 26. These factors combined to cause the average off-peak price difference metric to be negative in July in all listed local capacity areas.
- In September, SP15 day-ahead prices usually exceeded real-time prices in off-peak hours. With the loss of transmission facilities due to the Station fire and an outage of the Hassayampa-North Gila portion of the Southwest Power Link, which brings power generated in Arizona to load in San Diego, many resources were committed through the exceptional dispatch process. This resulted in low real-time prices in the early morning hours. SP15 generation was further confined by the aforementioned Los Baños area outage, in addition to another outage that limited flow on Path 15, the principal electric transmission artery between Southern and Northern California. These outages put additional downward pressure on real-time prices in SP15, but pulled NP15 real-time prices upward, thereby limiting the significantly negative metric to SP15.

- October real-time prices averaged significantly higher than day-ahead prices in off-peak hours, due to anomalous events. Los Baños North outages in mid-October resulted in early-morning real-time price spikes on October 12 and 14. A mylar balloon caused the portion of the Southwest Power Link between Imperial Valley and Miguel to short circuit on October 25, forcing the line out and causing a price spike. Excluding these days, the system-wide average off-peak price spread was within the -$4 to $4 range.
- The November pattern of low real-time prices within the SCE load aggregation point was also driven by anomalies. On at least two days in November, loop flow activity outside the ISO control area caused Path 26 congestion in the south-to-north direction. The ISO manually conformed the path limit, causing the market software to post low real-time prices and decrease load within the SCE region.

Figure 3.12 Monthly average real-time versus day-ahead price difference category by local capacity area – off-peak hours



3.4 Price volatility

Overall prices were moderate in 2009, but trended upward near the end of the year, reflecting the escalating price of natural gas. The day-to-day volatility of prices – as measured by the overall range of prices – also increased somewhat in the fourth quarter, as more localized constraints were introduced and became binding into the software. In addition, outages, which typically are scheduled for the lower-load shoulder and winter months, resulted in congestion on transmission constraints that occasionally caused brief, localized price spikes, particularly within the SCE load aggregation point.

Figure 3.13 shows the frequency of different levels of prices spikes on a monthly basis under the new market design. During the first two months of the new market, a relatively high number of extreme price spikes occurred (i.e., in excess of the $500 bid cap). The frequency of these extreme price spikes decreased significantly in June and July. Starting in August, the frequency of price spikes remained relatively low and an increasing portion of price spikes were within a much lower range of $250 to $500/MWh. The lower frequency and more moderate levels of price spikes in the second half of 2009 can be attributed to a number of software and modeling improvements made to avoid extreme price spikes that were not reflective of actual real-time constraints and supply/demand conditions.

Figure 3.14 shows the top 10 percent of 5-minute real-time prices by quarter plotted as a price duration curve. The initial quarter of new the market (Q2) was particularly volatile, with prices in excess of $500/MWh during 1.5 percent of all 5-minute pricing intervals. In comparison, during Q3 and Q4, only .6 percent and .3 percent of real-time prices exceeded $500/MWh, respectively.

Figure 3.15 shows the lowest 10 percent of 5-minute real-time prices by quarter plotted as a price duration curve. In Q2, extremely low prices below the floor of -$30/MWh occurred in 4.2 percent of 5-minute pricing intervals. In Q3 and Q4, prices below the floor of -$30/MWh occurred in 1.9 and .9 percent of intervals, respectively.

Figure 3.13 Price spike frequency by month

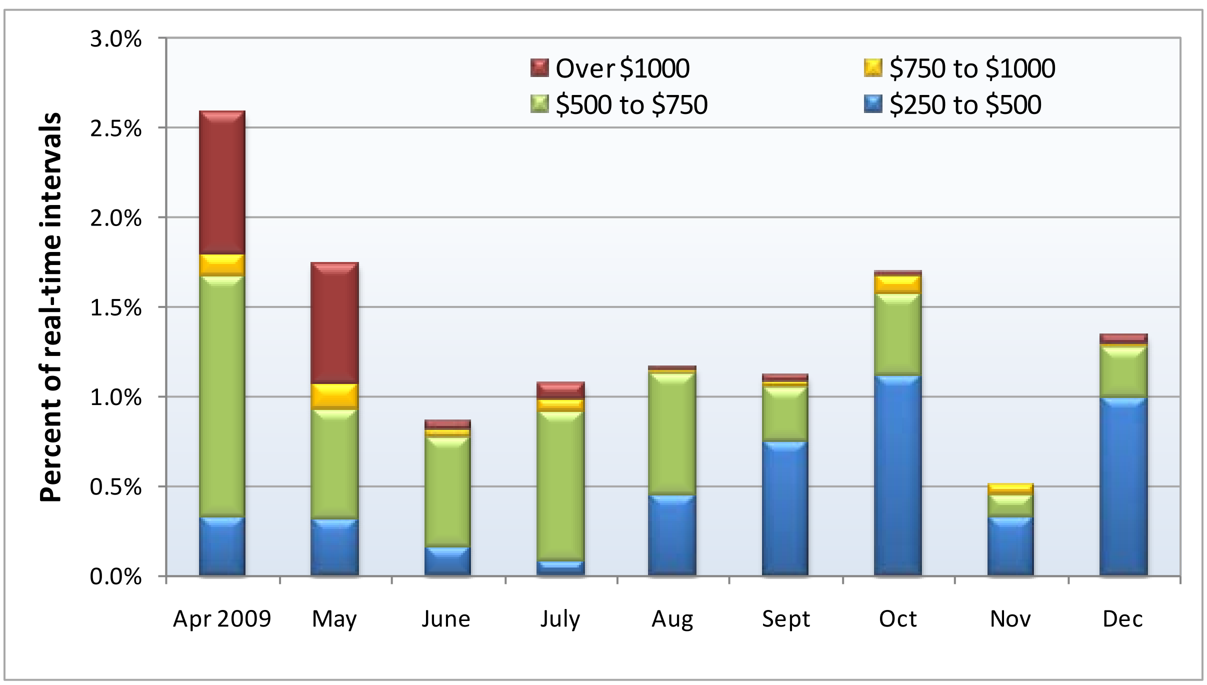


Figure 3.14 Real-time LMP duration curves by month: Top 10 percentile of LAP prices

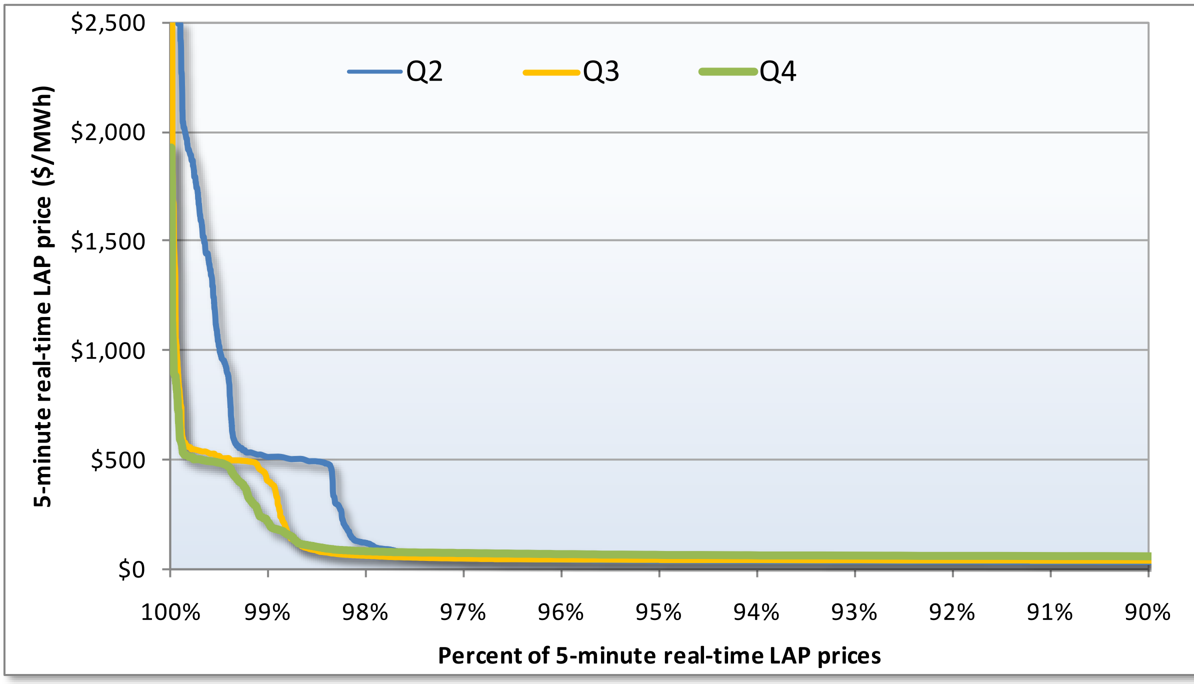
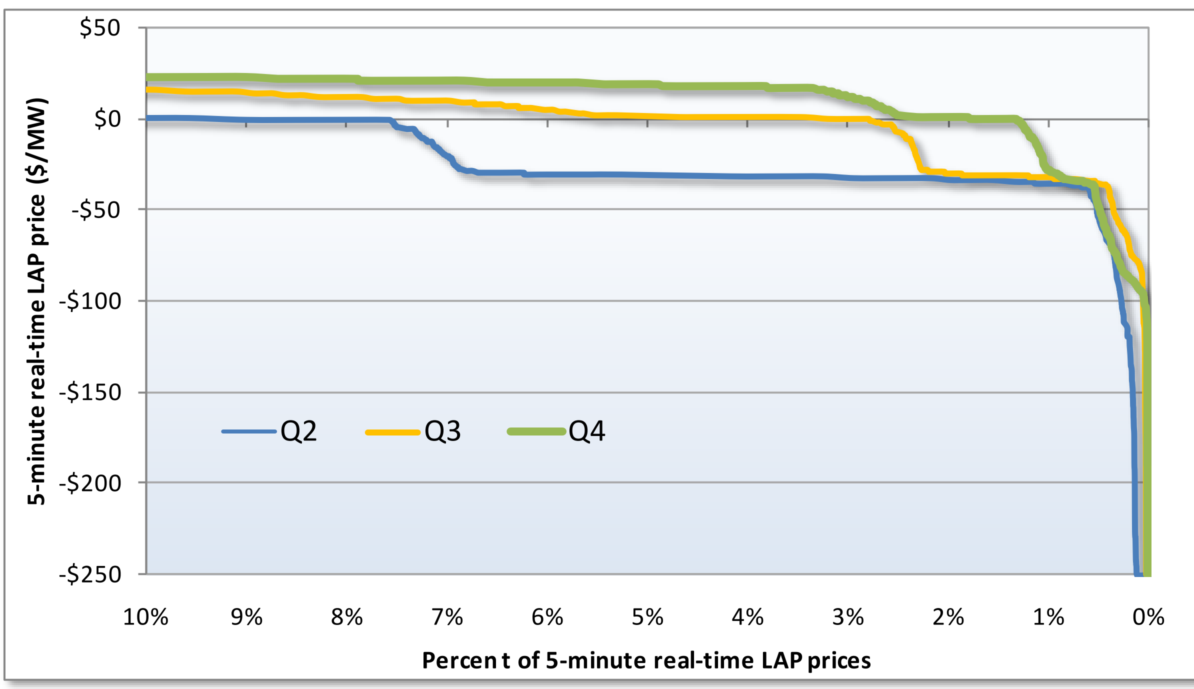


Figure 3.15 Real-time LMP duration curves by month: Bottom 10 percentile of LAP prices



As shown in Figure 3.16, price spikes in the real-time market were driven most frequently by the energy component of the LMP. This reflects the relatively limited role that congestion on transmission constraints into load pockets played in creating real-time price spikes. More frequently, real-time price spikes resulted from ramping limitation and other constraints.

In mid-April, unseasonably high loads contributed to both high loads in Southern California and congestion between Northern and Southern California, resulting in both energy and congestion-driven spikes. Congestion on Path 26 and the SDG&E Import Limit resulted in a relatively high level of congestion-driven spikes in May. In Q3, most price spikes were driven by high energy production costs within California, resulting from unit outages, the Station fire, and an outage of the Southwest Power Link lasting two weeks in September. In Q4, binding nomogram constraints were the primary drivers of congestion costs. Unseasonably cold weather in California caused several units to trip in early December, resulting in spikes in energy production costs.

Figure 3.16 Frequency of LMP energy and congestion components > $250 (SCE LAP)

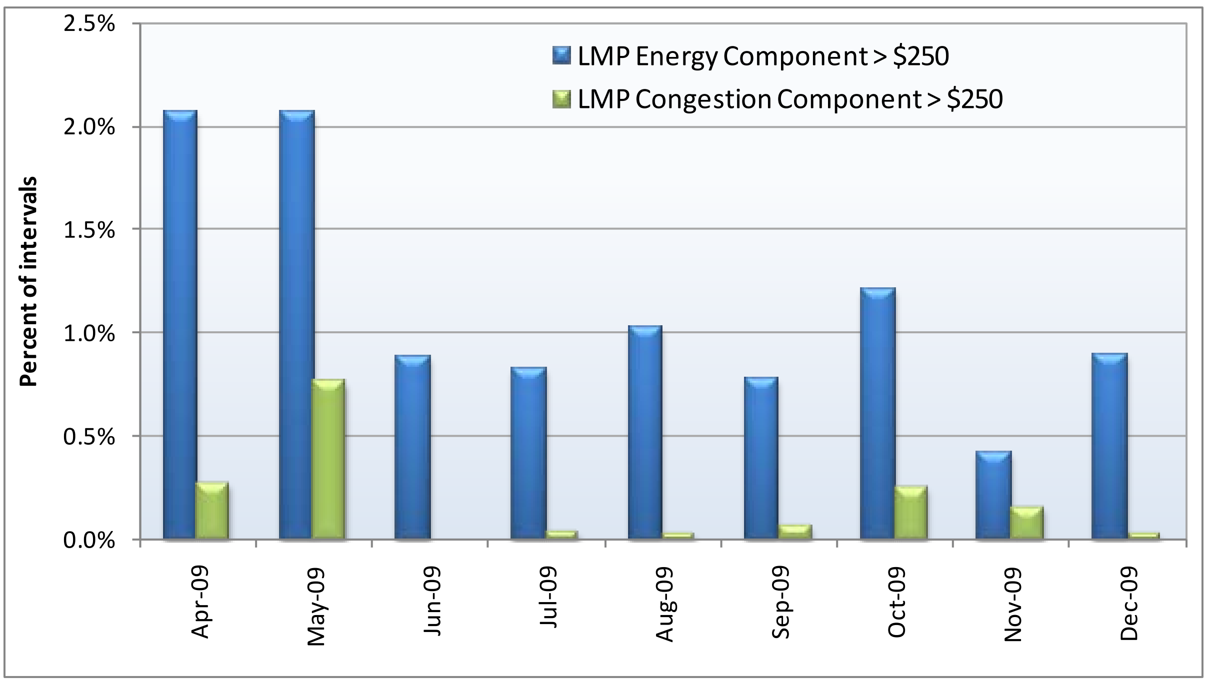


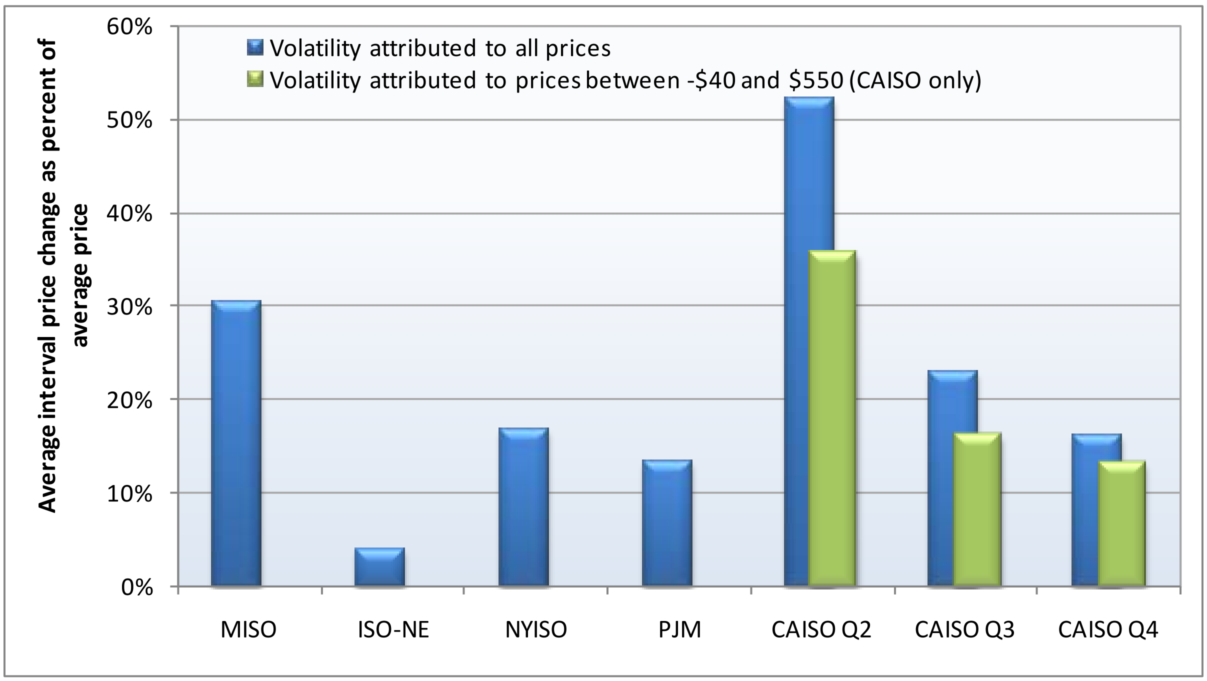
Figure 3.17 provides another measure of price volatility, which is based on the extent to which prices change from one 5-minute interval to the next in the real-time market.[55] As depicted in Figure 3.17, this measure has been calculated for several other ISOs with LMP markets in the United States. After an initial period of very high price volatility in the first few months of the new market, this measure of price volatility is now in a range similar to that of other U.S grid operators. The volatility metric for the California ISO is calculated in two ways. The blue bars reflect the entire set of prices, and thus are more

[55] This metric is a calculation of the average interval price change (in absolute value) expressed as a percentage of the average price. We calculate this metric by taking the arithmetic average of the three default load aggregation point prices (SCE, SDG&E, and PG&E) across all intervals in each quarter, and comparing it to the same metric for other ISOs with nodal pricing for all of 2007.

comparable to the metric used for other ISOs. The green bars denote the contribution to volatility when excluding extreme or outlier prices (i.e., only prices within the range of -$40/MWh to $550/MWh).

Differences across ISOs may be explained by variations in each ISO's design, market software and optimization features, and fundamental supply and demand conditions. In light of these factors, we do not necessarily view the comparison across ISOs as an apples-to-apples comparison. However, the trend of decreasing volatility for the California ISO market to levels within the range of that of other ISOs provides a clear indicator of improved and reasonable real-time market performance in terms of this aspect of price volatility.

Figure 3.17 Comparison of five-minute interval real-time LAP price volatility across ISOs



3.5 Exceptional dispatch

Exceptional dispatch is a process in which the ISO manually instructs a generator to change its level of output or start or shut down a resource. The exceptional dispatch process is used when the automated market optimization is not able to address a particular reliability requirement or constraint. Exceptional dispatches are sometimes necessary to commit resources for voltage support, which is not modeled in the market optimization. Exceptional dispatch unit commitments may also provide capacity support for complex nomograms or short-lived outages that are not modeled, or have yet to be modeled, in the market software. Capacity requirements specify the minimum number of resources needed in each local area to ensure that contingencies such as generation or transmission outages do not result in catastrophic power outages.

Exceptional dispatches for unit commitments instruct generators to operate at their minimum levels of output. They typically occur one day in advance of actual operation, either before or after the running of the day-ahead energy and residual unit commitment processes. If committed prior to the day-ahead energy market, units committed via exceptional dispatch can then be recognized by the market and scheduled to operate at higher levels of output. They can also be raised to higher output levels through real-time exceptional dispatch energy instructions, or combinations of real-time exceptional and market dispatches. Exceptional dispatch unit commitments have decreased due to new market software functionality, as explained below.

Exceptional dispatches cause the ISO to serve load from specific generating resources, and can displace generation that otherwise would have been selected by the competitive energy and residual unit commitment market optimization processes. Thus, while exceptional dispatches are necessary for reliability, the ISO has made an effort to minimize exceptional dispatches by incorporating additional constraints into the market model that reflect reliability requirements that would otherwise need to be met by exceptional dispatches.

Exceptional dispatches are governed by Tariff Section 34.9.[56] The ISO issues exceptional dispatches in accordance with Operating Procedure M-402 (Exceptional Dispatch), M-401 (Day-Ahead Market Operations), and M-403 (Real-Time Market Operations).[57] A detailed description of practices and rules for exceptional dispatches is provided in a *Technical Bulletin*.[58] Additional details of market trends and constraints that have required exceptional dispatches are provided in DMM's Q2 and Q3 reports.[59]

Exceptional dispatch unit commitments

Figure 3.20 shows monthly average energy volume from resources committed one day ahead of actual operation to operate at minimum output through exceptional dispatches in 2009. Transmission outages were the dominant reason for unit commitments through exceptional dispatch. Regional capacity constraints (G-206, G-217, and G-219) also required frequent unit commitments via exceptional dispatch.

Generation committed through day-ahead exceptional dispatches peaked in May, as extended transmission outages of the Devers-Palo Verde and Hassayampa-North Gila 500kV lines required capacity support in Southern California. The Southern California local capacity operating procedures also required multiple daily commitments in June and July. These procedures are:

- **G-206** — The San Diego area capacity requirement.
- **G-217** — The South of Lugo capacity requirement, which covers most of metropolitan Southern California.
- **G-219** — The Orange County capacity requirement.

[56] ISO Tariff Section 34.9, http://www.caiso.com/23d5/23d5ccbb9800.pdf.

[57] ISO Market Operating Procedures, http://www.caiso.com/thegrid/operations/opsdoc/marketops/index.html.

[58] ISO Technical Bulletin on Exceptional Dispatch, http://www.caiso.com/23ab/23abf0ae703d0ex.html.

[59] *Quarterly Reports on Market Issues and Performance,* http://www.caiso.com/2425/2425f4d463570.html.

Figure 3.18 Monthly average minimum-output energy volume by reason from day-ahead unit commitments via exceptional dispatch

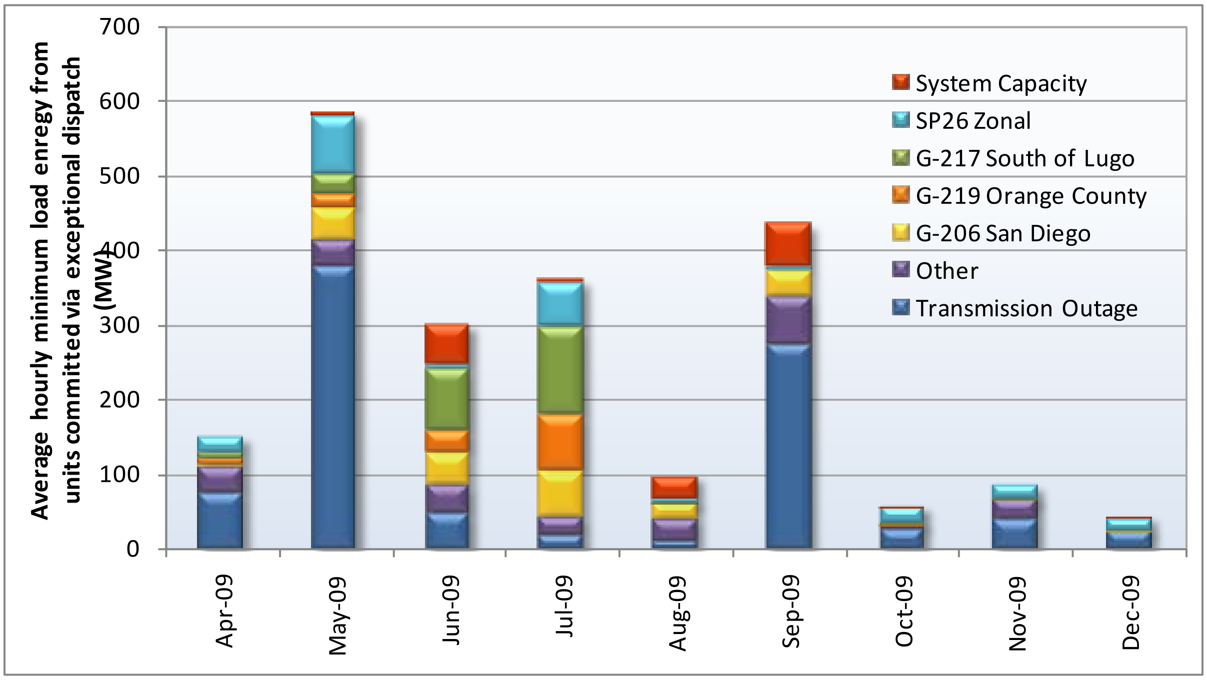
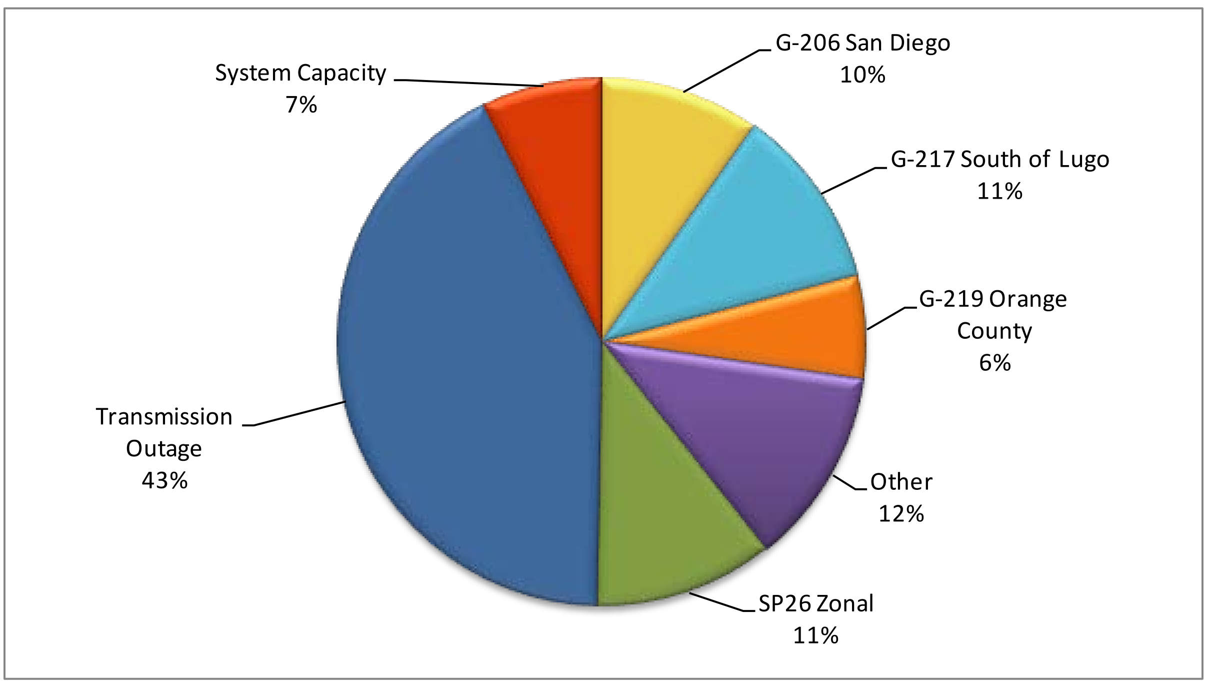


Figure 3.19 Minimum-output energy volume by reason from day-ahead exceptional dispatches



The G-217 and G-219 requirements were implemented via an automated capacity constraint in the residual unit commitment process on July 27, 2009. This eliminated the need to commit units via exceptional dispatch for these procedures after that date.[60]

In September, another extended outage of the Hassayampa-North Gila 500kV line and transmission damage caused by the Station fire required additional on-line capacity in Southern California. On-line capacity in the broader SP26 area was also required in multiple months throughout the year.

Exceptional dispatches for real-time energy

Real-time exceptional dispatches instruct resources to operate within particular levels until further notice. These instructions may specify minimum or maximum levels of operation.

- A minimum exceptional dispatch instruction directs a resource to move to a specific level of output, and maintain that level or higher, depending on market conditions. Because this minimum level is usually above the generator's current level of output when receiving the instruction, a minimum instruction effectively is an incremental, or upward, dispatch instruction. A unit receiving an exceptional dispatch for a minimum level may still clear the market in-sequence based on its bid price and set the real-time market price if its bid prices are equal to or lower than the market clearing price.
- A maximum exceptional dispatch instruction will maintain a resource no higher than a specified level, and effectively is a decremental, or downward instruction.
- Real-time exceptional dispatches may also start or shut down units on occasion.

Figure 3.20 shows the hourly average out-of-sequence real-time energy from upward exceptional dispatches by month in 2009. Figure 3.20 includes only minimum exceptional dispatch energy in excess of a unit's real-time market dispatch based on its market bid price (i.e., out-of-sequence real-time energy from exceptional dispatch). Analysis by DMM indicates that about half of real-time energy dispatched via exceptional dispatch clears the market in-sequence.

Real-time exceptional dispatch was at its highest level in April, averaging approximately 68 MW per hour. Problems with the load forecasting software and other market features necessitated frequent market intervention through exceptional dispatches during this start-up period. By May, real-time exceptional dispatch energy dropped sharply to approximately to 26 MW per hour, and remained below 30 MW on a monthly average basis through the end of the year.

[60] G-206 was not implemented into the market model. Unlike other areas, a significant portion of its local reliability requirements is met primarily through reliability must-run dispatch.

Figure 3.20 Hourly average out-of-sequence real-time energy due to exceptional dispatches by reason and month

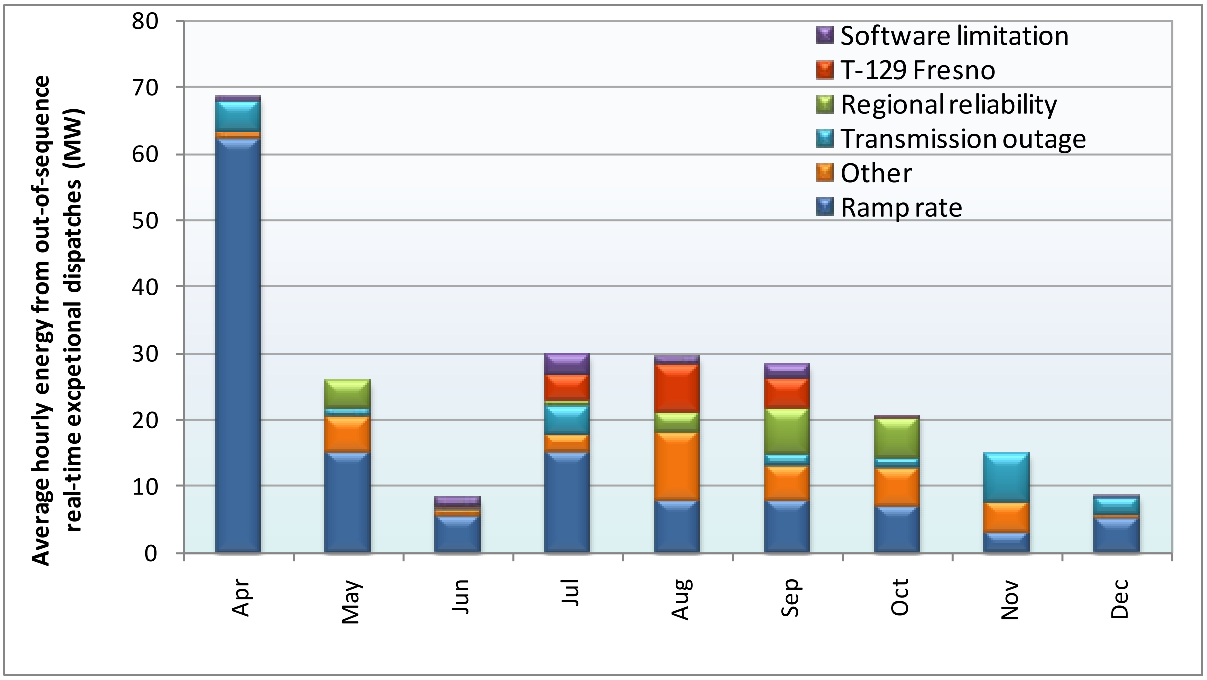


Figure 3.21 Summary of out-of-sequence real-time energy from exceptional dispatches by reason

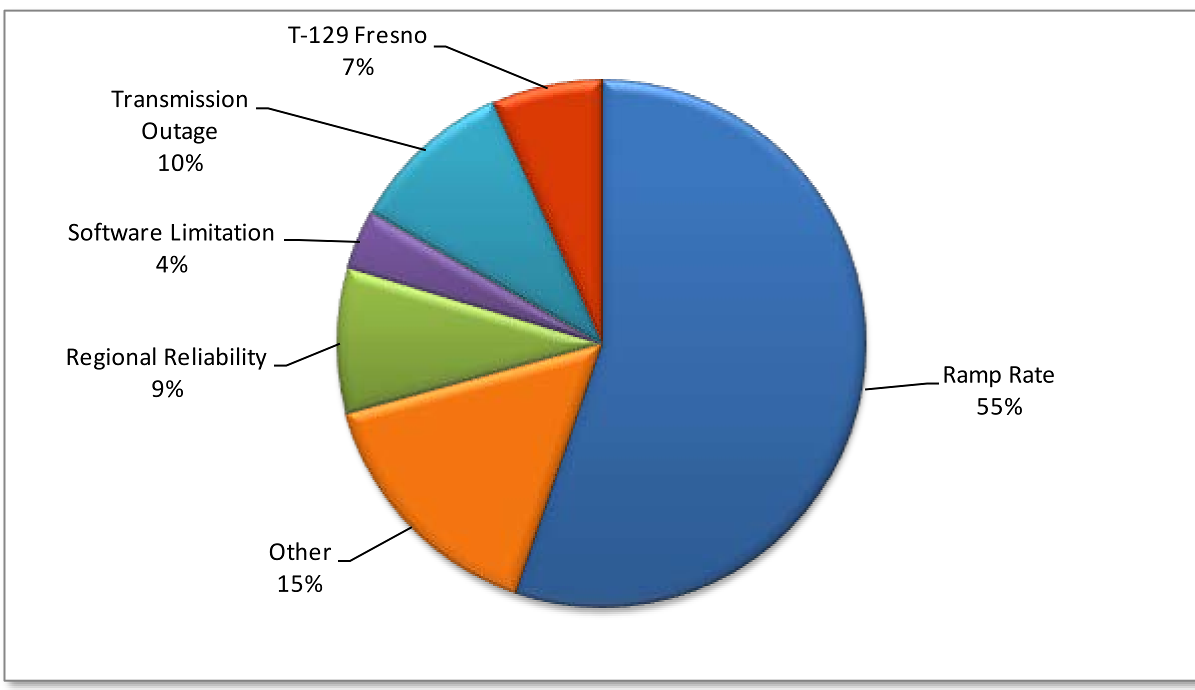


Figure 3.21 shows a summary of total volume of out-of-sequence real-time energy from exceptional dispatches for different reasons:

- ***Ramp rates —*** Exceptional dispatches logged as being made for ramp rate issues accounted for about 55 percent of total volume of out-of-sequence real-time energy from exceptional dispatches. These exceptional dispatch instructions are issued to move resources operating at minimum output to higher output levels where their ramp rates are greater. Operators sometimes deem this necessary to ensure units can be dispatched by the real-time market software as needed for reliability.

- ***Transmission outages —*** In several months, transmission outages have required frequent real-time congestion management. As shown in Figure 3.21, about 10 percent of the total volume of out-of-sequence real-time energy from exceptional dispatches have been logged under this category.

- ***Region reliability —*** This code was primarily used to log exceptional dispatches to manage issues relating to fires affecting transmission and local reliability issues. The category accounted for about 35 percent of exceptional dispatches energy volume between July and September, approximately half of which occurred on July 19. On that day, an inaccurate weather forecast coincided with a transmission outage that limited resources in a load pocket within Southern California.

- ***Software limitations —*** About 4 percent of out-of-sequence energy from exceptional dispatches was from exceptional dispatch instructions logged as being due a software limitation. These were interventions to manage a variety of market software issues. Most frequently, they were issued for the purpose of ensuring that market software properly recognized the operational status of resources. For example, in certain situations the market was not able to distinguish whether a pump storage resource was in generation mode or pump (load) mode. Exceptional dispatches were used to provide that information to the market optimization.

- ***T-129 Fresno —*** The T-129 nomogram required frequent real-time exceptional dispatches during the late spring and summer months. This operating procedure covers transmission in the Fresno area. T-129 dispatches were frequent but small, typically 5 MW or less.

- ***Other —*** Other reasons consist primarily of other local and regional transmission nomograms. These are typically frequent but low-volume dispatches for local transmission constraints. In 2009, the most prevalent transmission reasons were the T-103 (Southern California Import Transmission Limit) and T-138 (Humboldt County) constraints.

Actions to reduce exceptional dispatch

The ISO has taken steps to reduce the use of exceptional dispatch for day-ahead unit commitment and real-time energy dispatches, and to minimize its impact on the market:

- ***Unit commitment prior to the day-ahead run —*** When units are manually committed through exceptional dispatch in advance of the day-ahead market, their minimum load energy is included in the day-ahead market. This helps avoid duplicate commitment of capacity where possible and limits excess energy in the real-time market. Therefore, the ISO has sought to identify specific units that would need to be committed via exceptional dispatch not scheduled through the day-ahead market, and commit these units via exceptional dispatch prior to the day-ahead market.

- ***Capacity nomograms* —** The initial design of the market software did not include capacity commitment functionality in the day-ahead market. The ISO initially implemented this functionality in the residual unit commitment software. Capacity nomograms reflecting the G-217 and G-219 requirements were implemented in residual unit commitment software beginning trade date July 27, 2009. On trade date February 5, 2010, this minimum online commitment constraint functionality was implemented in the day-ahead energy market.[61] The ISO also included other nomograms in the residual unit commitment software when possible, and may include them in the day-ahead market in the future.

- ***Other modeling improvements* —** A variety of other market improvements implemented since the introduction of the market have also eased reliance on exceptional dispatches. These include simplified ramping, improvements in load distribution factor calculations, conforming of market-recognized transmission flow to actual flow, improvements in load forecasting, software fixes, and new transmission constraints. These are explained in greater detail in a white paper issued in December 2009.[62]

- ***Exceptional dispatch tools* —** The ISO has also developed new tools that enable operators to issue exceptional dispatch instructions to resources already covered by resource adequacy capacity contracts. Non-resource adequacy resources are entitled to compensation through the interim capacity procurement mechanism if selected for exceptional dispatches. Thus, selecting non-resource adequacy resources for an exceptional dispatch when a resource adequacy unit may be available results in additional costs to load. Because resource adequacy units already receive capacity compensation under their contract agreements, and are not entitled to additional capacity payments in the market, they are the preferred resources for any unit commitment needed via exceptional dispatch.

3.6 Residual unit commitment

This section summarizes the performance of the residual unit commitment market. The direct cost of procuring capacity through the residual unit commitment market for the first nine months of the new market was extremely low, totaling just $122,000. In addition, about 13 percent or $8.7 million of bid cost recovery payments were associated with units committed in the residual unit commitment process, as described in Section 3.7. When the direct residual unit commitment procurement costs are combined with bid cost recovery payments, this represents a combined cost of just over $8.8 million, or about 0.14 percent of total wholesale energy costs.

The extremely low costs for procuring residual unit commitment capacity in 2009 can be attributed to two factors:

- First, as described in Section 3.2, the portion of load clearing the day-ahead market has consistently been very high with an average of almost 98 percent of total forecast demand being scheduled in the day-ahead market. This left a very small volume of demand to be met by the residual unit commitment processes.

[61] ISO Market Notice, January 26, 2010, http://www.caiso.com/272a/272aac691c650.html, and ISO *Technical Bulletin on Minimum Online Capacity Constraint,* January 2, 2010, http://www.caiso.com/271d/271dedc860760.pdf.

[62] Exceptional Dispatch White Paper, December 2, 2009, http://www.caiso.com/2478/2478ead066f50.pdf, Chapter 3.

- Second, virtually all capacity procured in the residual unit commitment process is from resource adequacy capacity at a price of $0/MWh, as provided under the terms of the tariff for resource adequacy units.

Nearly all residual unit commitment procurement of non-resource adequacy capacity came from resources that were only partially contracted under resource adequacy. In these cases, residual unit commitment availability was procured from the resource beyond the capacity contracted under resource adequacy. After May, very little non-resource adequacy residual unit commitment was procured from resources with no resource adequacy contract. Most of non-resource adequacy capacity procured was from resources located in the LA Basin, Fresno, and other areas throughout the system that are not in local capacity areas.

Procurement of non-resource adequacy residual unit commitment increased beginning August, most notably in the LA Basin, due to implementation of two minimum online generation constraints in RUC. These capacity constraints enforced requirements for the South of Lugo and LA Basin areas (G-217 and G-219 respectively).

The bulk of bid cost recovery payments for units committed in residual unit commitment (87 percent) were incurred in the months of August to November when units were being committed as a result of these two capacity constraints. In January 2010, the ISO implemented these constraints in the day-ahead market and removed them from the residual unit commitment market. This should result in more efficient use and scheduling of any units committed to meet these constraints, because these units will have an opportunity to be scheduled for additional energy in the day-ahead market.

Background

The purpose of the residual unit commitment market is to ensure there is sufficient capacity online or reserved to meet load in real-time. The market is run right after the day-ahead market and procures capacity sufficient to bridge the gap between the amount of load that cleared in the day-ahead market and the day-ahead load forecast. Capacity procured in residual unit commitment, also called RUC availability, must be bid into the real-time market.

Prior to the new market, there was no formal reserve market to serve this purpose. Instead, the ISO evaluated online capacity after the day-ahead congestion management market was complete and manually committed additional resources to be online, if necessary, by enforcing the must-offer requirement that was imposed by FERC.

All capacity procured in residual unit commitment must be deliverable from the location where it is supplied. This is accomplished by running the residual unit commitment market on a nodal level using the same full network model used in the day-ahead energy market. Procuring capacity this way helps ensure that if the resource is called upon to provide energy in real-time, that energy is deliverable. In addition to procuring capacity from units within the ISO, the residual unit commitment market can also procure capacity from resource adequacy imports.

The market will also commit resources that were not scheduled in the day-ahead in order to procure capacity from those resources if necessary. When resources are committed in residual unit commitment, recovery of start-up and minimum load energy costs is guaranteed through bid cost recovery payments in the same fashion as units committed in the day-ahead and real-time markets.

Market prices for RUC availability are determined in the same way as energy prices, and the capacity is priced at the nodal level. Upper and lower bid price caps of $0/MW and $250/MW are imposed to address potential system market power. There is no local market power mitigation in the residual unit commitment market, despite the locational pricing of capacity procured. The local requirements placed on load-serving entities to procure and make available resource adequacy capacity help mitigate concerns about local market power in the residual unit commitment market given the availability, bidding, and settlement rules discussed below.

There is an important settlement rule in residual unit commitment that does not exist in the energy market. Resource adequacy capacity bid into residual unit commitment must be bid in at $0/MW and, regardless of the locational market price determined at that node, will be settled at $0/MW. Furthermore, all resource adequacy capacity must be made available in the residual unit commitment market (with limited exceptions). The settlement rule for residual unit commitment procurement from resource adequacy capacity recognizes that this capacity has already received a payment for availability via the resource adequacy contract. This capacity should not be paid a second time for the same availability. The bid price rule forces this capacity to be offered as a price taker, eliminating any positive impact that capacity may have on prices set for non-resource adequacy capacity procured. This section focuses on procurement of capacity that is not under resource adequacy contract. Analysis of capacity that is under resource adequacy contract is addressed in detail in Chapter 7.

RUC availability costs

The cost for RUC availability by month and local capacity area is presented in Figure 3.22. For the nine-month period, the total cost of RUC availability was roughly $122,000. The ISO procured RUC availability from non-resource adequacy capacity in several local capacity areas, although the cost in each was minimal. The local resource adequacy requirements on load-serving entities are lower in the spring. This results in less capacity contracted under resource adequacy and, consequently, a greater supply of capacity un-contracted and available in the residual unit commitment market.

Procurement from the LA Basin during August through December accounted for over half of the total cost. In late July, the ISO began enforcing the minimum online capacity requirements from operating procedures G-217 (South of Lugo) and G-219 (LA Basin / Orange County). As a result, the residual unit commitment market committed more resources in the LA Basin area and procured RUC availability capacity from these resources. In February 2010, the ISO moved enforcement of these constraints out of the residual unit commitment market and into the day-ahead market. Enforcement of these constraints in the residual unit commitment market is covered in more detail at the end of this section.

Monthly procurement and cost data are presented in Table 3.4. The first two data columns show megawatts procured from non-resource adequacy capacity and the resulting cost. The third column shows the total megawatts of under-scheduled load, calculated as the difference between the day-ahead forecast load less the load scheduled in the day-ahead market. The procurement target for RUC availability is derived from the amount of under-scheduled load after running the day-ahead market.

Figure 3.22 Cost of RUC availability procured from non-RA resources

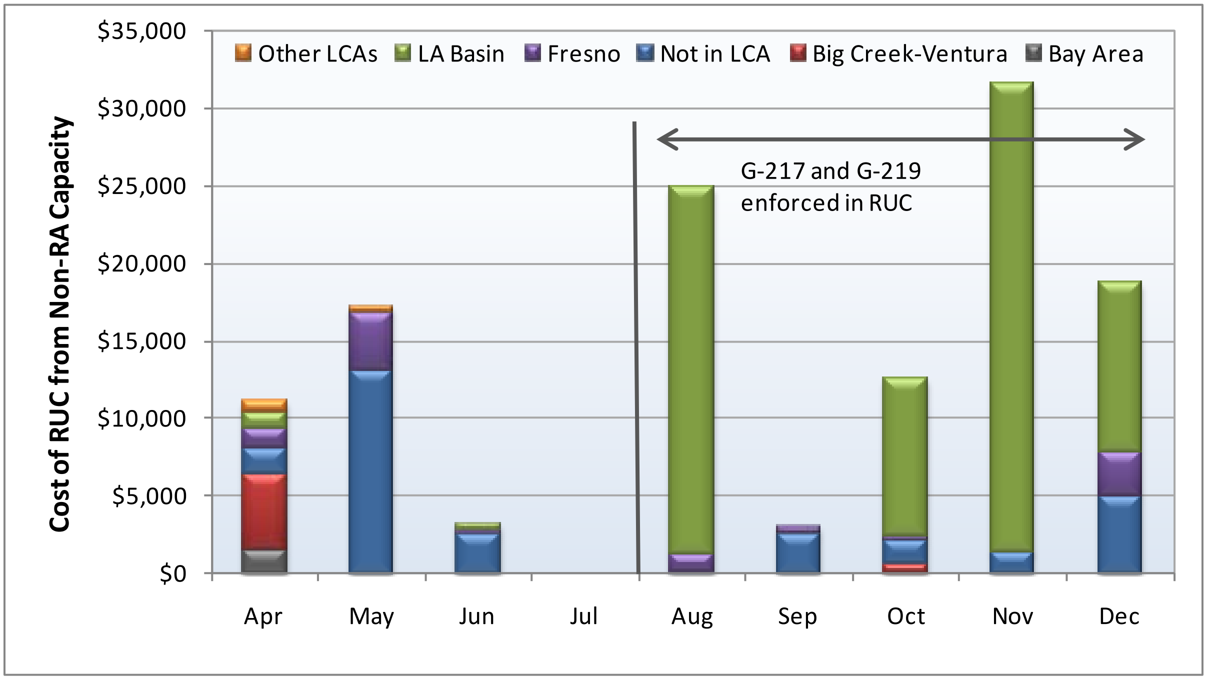


Table 3.4 RUC availability cost per MWh of net short

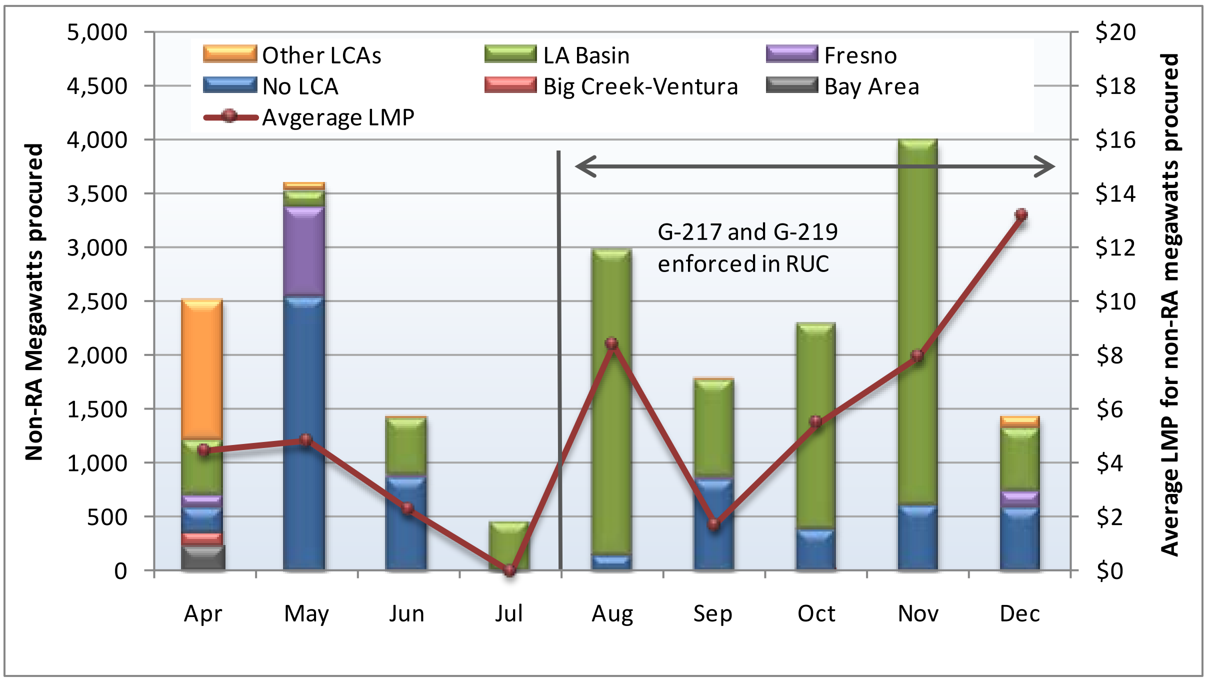
Month	RUC MW from Non-RA Capacity	Cost	MW of DA Underscheduling	Cost / MW of DA Underscheduling
April	2,510	$11,180	351,264	$0.03
May	3,573	$17,184	500,645	$0.03
June	1,415	$3,233	463,721	$0.01
July	447	$0	277,243	$0.00
August	2,971	$24,888	426,021	$0.06
September	1,770	$2,996	490,252	$0.01
October	2,288	$12,510	505,563	$0.02
November	3,970	$31,589	430,465	$0.07
December	1,428	$18,702	529,934	$0.04
Total	**20,372**	**$122,282**	**3,975,108**	**$0.03**

As noted above, resource adequacy capacity is bid into the residual unit commitment market at $0/MW and is settled at $0/MW regardless of the price set at the procurement location. This ensures that the resource adequacy capacity is procured first, where physically feasible, to meet the procurement target, minimizing the procurement of non-resource adequacy capacity that is bid in at prices above zero. The last column shows the average cost of RUC availability per megawatt of under-scheduled load. These figures are low, ranging from zero in July (all non-resource adequacy residual unit commitment procurement that was purchased cleared at $0/MW) to $0.07/MWh. Note that these costs are expressed per unit of under-scheduled load (which determines the demand for RUC availability). If normalized to load served, these figures would all be fractions of a cent.

Residual unit commitment procurement and prices

Figure 3.23 shows the volume of RUC availability procured from non-resource adequacy capacity within each local capacity area by month (see bars corresponding to left vertical axis). The line in Figure 3.23 shows average prices paid for this capacity, which reflects the residual unit commitment LMPs at locations where non-resource adequacy capacity was procured (see red line corresponding to right vertical axis). Over this period, the weighted average LMP for non-resource adequacy residual unit commitment procured was $6/MW, and was less than $10/MW in all months except for December. In July there was almost 500 MW procured at an average LMP of $0/MW resulting in zero cost in that month (as seen in Figure 3.22).

Figure 3.23 Non-resource adequacy capacity procured and average LMP



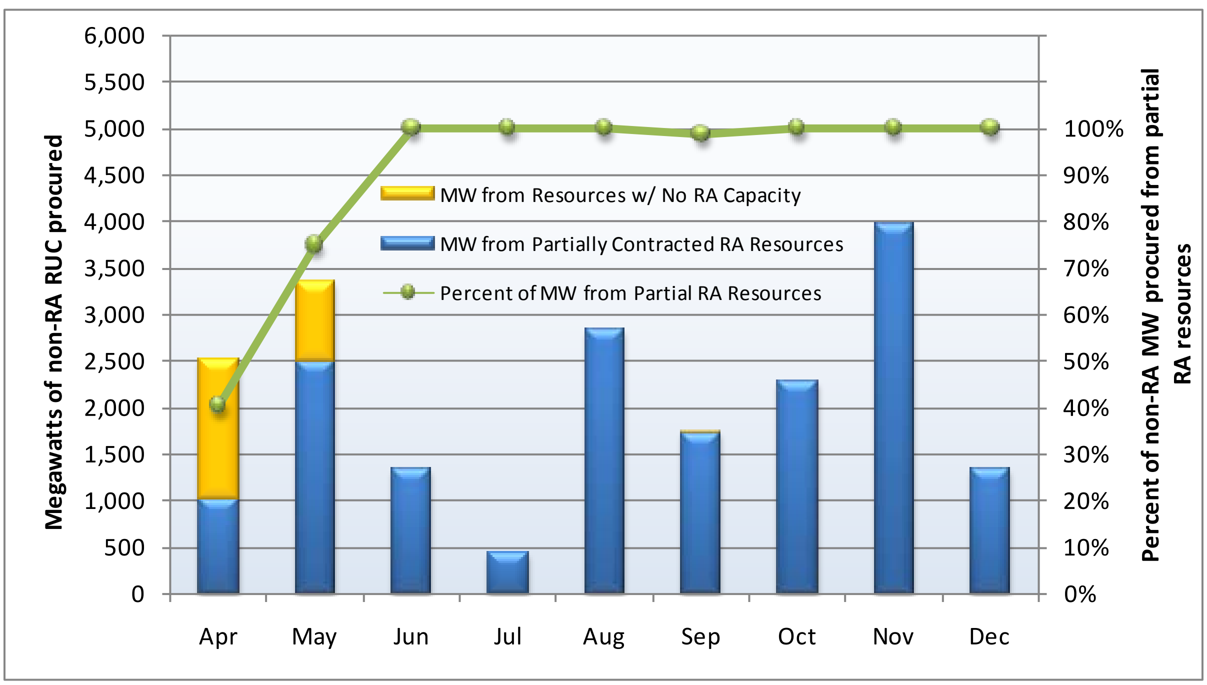
As shown in Table 3.5 in the following section of this report, the bulk of bid cost recovery payments for units committed in residual unit commitment (87 percent) were incurred in the months of August to November. This corresponds to the months when capacity being committed in residual unit commitment increased as a result of the capacity constraints for G-217 and G-219, as illustrated in Figure 3.23. In January 2010, the ISO implemented these constraints in the day-ahead market and removed them from the residual unit commitment market. This should result in more efficient use and scheduling of any units committed to meet these constraints, because these units will have an opportunity to be scheduled for additional energy in the day-ahead market.

Because only non-resource adequacy capacity can bid into the residual unit commitment market at prices above $0/MW and be settled at a price above $0/MW, the characteristic of resource adequacy capacity bid into the residual unit commitment market is interesting. Capacity can be non-resource adequacy for two reasons: it is bid in by a resource that does not have a resource adequacy contract for any of its capacity, or it is the un-contracted portion of capacity from a resource that is under resource adequacy contract. The latter case is referred to as a "partial resource adequacy" resource and describes most resource adequacy resources.

The amount of capacity a resource is allowed to sell under resource adequacy provisions is determined by the resource's net qualifying capacity. This is an estimate of deliverable energy that also accounts for availability and is generally less than the full nameplate capacity of the resource. This can result in capacity that is not contracted under the resource adequacy program but may be bid into the residual unit commitment market. In addition, some resources may have contracted an amount of capacity less than their full net qualifying capacity. This would also result in capacity from a resource adequacy-contracted resource available to be bid into the residual unit commitment market as non-resource adequacy capacity.

Figure 3.24 shows the procurement split between resources that were partially contracted and resources that had no capacity contracted under resource adequacy. The ISO procured all of the non-resource adequacy residual unit commitment capacity from partially contracted resources. Since June, the residual unit commitment market LMPs at locations where non-resource adequacy capacity was procured have been driven by resources under resource adequacy contract but not for their entire capacity. In April and May there was more RUC availability procured from resources with no resource adequacy contract. This was due to lower resource adequacy requirements in the spring resulting in more resources that did not have a resource adequacy contract for any portion of their capacity.

Figure 3.24 Non-resource adequacy capacity procured from partial-resource adequacy resources



3.7 Bid cost recovery payments

Under the new market design, units are eligible to receive bid cost recovery payments in the event that the total market revenues earned by a generating unit over the course of an operating day do not cover the sum of all bids accepted that day. The calculation of bid cost recovery payments includes bids for start-up, minimum load, ancillary services, residual unit commitment availability, and day-ahead and real-time energy.

If units started up or committed at minimum load are not dispatched for sufficient amounts of additional energy and/or do not earn sufficient revenues in excess of their bid costs, this may be reflected in higher bid cost recovery payments. Excessively high bid cost recovery payments can be indicative of inefficient unit commitment or dispatch. In other ISOs, high bid cost recovery payments for individual units have also been have associated with strategies for exercising local market power or gaming of market rules. Such strategies may involve submission of high start-up and minimum load bids, coupled with other bidding and scheduling behaviors to profit through high bid cost recovery payments.

Table 3.5 provides a summary of total bid cost recovery payments based on a query of settlement records at the beginning of January 2010.[63] The total amount of bid cost recovery payments over the first nine months of the new market has been about $66 million, or just about 1 percent of total energy costs. This indicates that bid cost recovery payments have been relatively low since the start of the new market. For example, in other markets, analogous payments (such as revenue sufficiency guarantees) have ranged from about 1 percent up to almost 3 percent of total energy costs.[64]

Table 3.5 Bid cost recovery payments

	BCR Payments (by Market)				BCR as Percent of
Month	IFM	RUC	Real Time	Total BCR	Energy and A/S
April	$1,276,054	$9,191	$2,722,231	$4,007,475	0.8%
May	$7,707,961	$35,145	$5,791,919	$13,535,026	2.1%
June	$4,433,919	$19,662	$3,364,600	$7,818,181	1.5%
July	$5,116,894	$862,463	$3,695,812	$9,675,168	1.2%
Aug	$1,286,996	$3,062,506	$1,684,784	$6,034,286	0.8%
Sept	$5,714,362	$1,182,056	$2,328,789	$9,225,207	1.2%
Oct	$3,059,812	$1,214,660	$632,801	$4,907,272	0.6%
Nov	$2,832,239	$2,140,493	$190,557	$5,163,290	0.8%
Dec	$5,641,226	$189,649	-$38,202	$5,792,672	0.6%
Total	**$37,069,463**	**$8,715,824**	**$20,373,291**	**$66,158,578**	**1.0%**

63 Since further adjustments are made to bid cost recovery settlement data over the longer settlement window, data in Table 3.5 represent a "snapshot" that may change somewhat, particularly for the more recent months. However, DMM does not expect the magnitude of such changes to be significant.

64 Based on data from 2008 annual reports for MISO, NYISO, PJM and ISO-NE.

Bid cost recovery payments under the new market design were also about 26 percent lower than must-offer waiver denial costs of $90 million in 2008. In the prior market, these must-offer waiver denial costs were the most analogous costs to bid cost recovery payments provided under the new markets.[65]

An analysis of start-up and minimum load bids is presented in Chapter 4. Results of this analysis provide further indication that bid cost recovery payments have not been driven up by excessively high start-up and minimum load bids.

3.8 Follow-up on prior recommendations

The ISO is taking steps to address several of the short-term recommendations in DMM's previous quarterly reports:

- ***Exceptional dispatch*** **—** DMM continues to monitor the volume and reasons for exceptional dispatch. The volume of day-ahead unit commitments has declined measurably. As described in Section 3.5, the ISO has taken a number of steps to decrease exceptional dispatches.

- ***Explore and implement options for incorporating into the market model the reliability constraints driving exceptional dispatch*** **—** As previously noted, the ISO implemented capacity nomograms in the residual unit commitment process in July 2009 that reflect capacity needs incorporated in two operating procedures (G-217 and G-219) that were driving a large portion of unit commitments via exceptional dispatches. DMM recommended that these constraints be incorporated in the day-ahead market model if possible. The ISO implemented minimum online commitment constraints for G-217 and G-219 on February 2, 2010.[66]

- ***Consistency of hour-ahead and real-time prices*** **—** Since the first month of the new market, one of DMM's major recommendations has been to address the systematic divergence between dispatches and prices in the hour-ahead and real-time markets.[67] As described below, DMM worked with the ISO to identify several specific potential causes for this divergence. The ISO is taking steps to address these issues. The ISO has also identified a number of other modeling improvements that may address this issue, and has made these initiatives a major focus in 2010. These initiatives include improvement of load distribution factors and improving how regulation energy is incorporated in the projection of demand in the real-time market.[68]

- ***Ramping of inter-tie schedules in hour-ahead market*** **—** As discussed in our Q3 report, a limitation of the hour-ahead scheduling process model is that it does not account for the fact that intra-hour changes in schedules of system resources (imports and exports) are ramped in over a 20-minute period each operating hour. This may cause the hour-ahead process to underestimate the actual ramping that will be needed in the 5-minute real-time market during this 20-minute ramping period. In Q4, the ISO initiated development of enhancements that would modify the hour-ahead process to

[65] Under the prior market design, must-offer waiver denial costs represented payments associated with start-up and minimum load cost of units required to be on-line for reliability reasons. These costs are not directly comparable to bid cost recovery payments under the new market design, but represent the most comparable component of the prior market to bid cost recovery payments.

[66] http://www.caiso.com/272a/272aac691c650.html

[67] For example, see *Review of April Market Performance*, Board of Governors Meeting, General Session, May 18, 2009. http://www.caiso.com/23b2/23b2769c69fe2.pdf

[68] See Market Performance and Planning Forum, February 4, 2010, presentation on Market Performance, Mark Rothleder, Director, Market Analysis and Development, pp. 7-22, http://www.caiso.com/2730/273095604690.pdf

account for the imbalance energy difference that arises due to this limitation. The ISO expects this modeling enhancement to be implemented in the second quarter of 2010.

- ***Load forecasting improvements —*** During 2009, DMM also identified a systematic difference in the load forecast used in the hour-ahead scheduling process and the real-time market. As discussed in our Q3 report, this may also contribute to systematic dispatch and price differences between the hour-ahead and real-time market. In January 2010, the ISO implemented a short-term modification that appears to have improved the hour-ahead demand forecast used in the hour-ahead market.[69] The ISO also has a new short-term forecasting tool under development that is designed to provide a more accurate and consistent forecast for both the hour-ahead and real-time market. This new forecast will be specifically designed to provide forecasts at the 15-minute and 5-minute level of granularity over the approximately two hour forecasting timeline needed for the hour-ahead and real-time market.[70] Implementation of this new forecasting tool is currently anticipated in the second quarter of 2010.

- ***Conforming transmission constraint limits based on actual flows —*** In our Q3 report, DMM recommended that the ISO should continue to place a high priority on refining the use of conforming constraint limits (referred to as "biasing" in our Q3 report). Specifically, DMM suggested that more automated statistical metrics that correlate the degree of conforming and congestion in the various sequential markets may be helpful in tracking trends and identifying potential areas for improvement as conditions change. DMM also noted that overall market transparency and the ability of participants to self-manage congestion can be improved by providing timely data to market participants on the application of conforming and the un-enforcement of constraints in market operations. In Q4, the ISO addressed this issue as part of a more comprehensive stakeholder process on public data release. The proposal for release of public data includes a provision to provide on a routine basis some of the same metrics that were provided by DMM in the Q3 report.[71] DMM is working with the ISO to facilitate development of the capability to provide these data on a routine basis. In addition, as reviewed in Chapter 5 of this report, the number of constraints that have been conformed in the real-time market decreased in the fourth quarter of 2009. In many cases, this reduction in conforming constraint limits can be attributed to improvements implemented at the end of Q3 aimed at modeling net rather than gross loads at nodes with significant amounts of self-generation.

- ***Compensating injections —*** These are positive or negative net power injections that can be automatically inserted into the network application portion of each real-time pre-dispatch run by a special algorithm incorporated in the real-time market software. The purpose of compensating injections is to reduce the difference between the modeled market flows and actual physical flows

[69] Ibid, pp. 17-19, http://www.caiso.com/2730/273095604690.pdf

[70] The automated load forecast system being used actually produces a 30-minute forecast, so that the more granular 15- and 5-minute forecasts needed for the hour-ahead and real-time market software are developed by interpolating from this 30-minute forecast.

[71] See pp. 91-95 in *Quarterly Report on Market Issues and Performance*, October 31, 2009, http://www.caiso.com/2425/2425f4d463570.html

over constraints near the inter-ties (e.g., due to loop flows), thereby reducing differences between modeled and actual flows throughout the network model.[72]

In October and November 2009, this software feature was turned on for testing. However, the ISO determined that during periods of high interchange ramping or inadvertent flows, these automated compensating injections were contributing to inaccuracies in the forward looking imbalance energy forecast and an increasing number of CPS2 violations. As a result, these automated compensating injections were turned off until further refinements could be made in this software feature. The ISO is currently testing enhancements to the compensating injection software and anticipates testing and then re-activating this feature in the actual market software in 2010.

DMM has recommended that prior to implementing this software feature, the ISO develop metrics that can be used to monitor the impact of compensating injections on specific major constraints within the ISO that are likely to be impacted by this feature.[73] DMM continues to work with the ISO to develop metrics to assess the impact of automated compensating injections. DMM has also recommended that the ISO provide participants with a technical paper and advance notice prior to re-implementing this feature.

[72] Thus, compensating injections are designed to be an automated, more accurate method of accounting for loop flows and other modeling discrepancies that would reduce the need for manual conforming or other actions operators may need to take to manage differences in modeled versus actual flows in real-time. When automated compensating injections are not being utilized, the ISO mitigates the congestion impact of loop flows manually by "circulating" energy between the NOB DC and PACI ties, and/or by manually conforming (biasing) the limits on major internal constraints within the ISO near the inter-ties.

[73] Modeled flows for constraints in the ISO provided by the market software do not differentiate between the portion of flow attributable to compensating injections and the portion of flow attributable to market schedules. Thus, the impact of compensating injections on constraints within the ISO must be calculated using data on the compensating injection values at each CNode outside of the system, combined with shift factors for these CNodes relative to constraints within the ISO.

4 Energy market competitiveness and mitigation

This chapter assesses the competitiveness of the energy market, along with the impact and effectiveness of market power mitigation provisions of the new market design. Key findings of this chapter include the following:

- The day-ahead integrated forward market has continued to be very stable and competitive, with virtually all loads and supply being scheduled in the day-ahead market. One of the key causes of the competitiveness of these markets is the high degree of forward contracting by load-serving entities. The high level of forward contracting significantly limits the ability and incentive for the exercise of market power in the day-ahead and real-time markets.

- Bids for the additional supply needed to meet remaining demand in the day-ahead and real time energy markets have been highly competitive. Most additional supply needed to meet demand have been offered at prices close to default energy bids used in bid mitigation, which are designed to slightly exceed each unit's actual marginal or opportunity costs.

- Prices in the day-ahead market during each month were consistently about equal to competitive baseline prices we estimate would result under perfectly competitive conditions. DMM estimates competitive baseline prices as a benchmark for assessing actual market prices by re-simulating the market using the day-ahead market software with bids reflecting the actual marginal cost of gas-fired units.

- Prices in the 5-minute real-time market exceeded this competitive baseline during the first few months of the new market due to extremely high price spikes during a relatively small percentage of 5-minute intervals. However, since June 2009, average prices in the 5-minute real-time market have also been approximately equal to this competitive baseline.

- The market power mitigation provisions of the new market design have been triggered on a very limited basis. During each month in 2009, an average of only 1 to 3 units per hour were subject to mitigation in the day-ahead market. Only about 30 percent of units subject to mitigation may have been dispatched at a higher level in the day-ahead market as a result of bid mitigation.

- The limited frequency and impact of bid mitigation can be attributed to a combination of factors, including relatively moderate loads and highly competitive bidding by supply resources. In many cases, the degree to which a unit's market bid curve is reduced by mitigation is relatively small, and did not have a significant impact on the level at which the unit is ultimately dispatched in the day-ahead market.

- Although these market power mitigation provisions have not had a significant direct impact on market results, this does not mean that these provisions are unneeded or did not have a more significant indirect impact. Having effective market power mitigation provisions in the day-ahead and real-time markets encourages forward contracting and deters attempts to exercise market power in the first place.

4.1 Market power mitigation

California's market design relies upon a high level of self-supply and forward-contracting by load-serving entities as a means of mitigating system-level market power. This is consistent with CPUC policies designed to ensure that the state's major utilities are hedged for a large portion of their energy supply needs.[74]

The potential for market power on a system level basis is addressed by a $500/MWh energy bid cap, which will increase to $750/MWh and $1,000/MWh in the second and third years of the new market design. During 2009, a $2,500/MWh cap on overall market prices was also in effect. This market price cap is eliminated starting in April 2010. Additional discussion and analysis of these bid and price caps is provided in Section 4.3 of this chapter. The scheduled increase to a relatively high bid cap is also designed to serve as an additional incentive for load-serving entities to meet the bulk of their projected need through forward energy contracts.[75]

Ownership of generation resources within most transmission constrained load pockets of the system is highly concentrated under one or two major suppliers. Therefore, the new market design includes more stringent provisions for mitigation of local market power. These local market power mitigation provisions are similar to the approach employed by the PJM ISO. Under this approach, units that must be dispatched to provide additional incremental energy to relieve transmission constraints deemed to be non-competitive may have their market bids lowered based on a default energy bid, which reflects the unit's actual marginal operating costs.

4.1.1 Bid mitigation inputs

The local market power mitigation process is applied in an automated manner by the market software as an integrated part of the daily and hourly operation of the day-ahead and real-time energy markets. However, key mitigation inputs are established well in advance:

- ***Competitiveness of transmission constraints —*** All network constraints (or paths) are first designated as competitive or non-competitive using the competitive path assessment. Under this methodology, a three-pivotal supplier test is used to assess the feasibility of meeting each transmission constraint with varying combinations of the suppliers' generation removed from the system. Constraints that cannot be met without the combined generation of any three suppliers are deemed non-competitive. Section 4.4.6 of this chapter provides a more detailed description of this methodology and analysis of the competiveness of congested constraints under actual operating conditions in 2009.[76]

- ***Default energy bid options —*** Units are subject to the automated bid mitigation process if needed to relieve congestion on a non-competitive constraint. Generation owners are allowed to select from among three options for setting the default energy bid used in the event their unit is subject to

[74] See discussion of Long-Term Procurement Plans in Section 1.2 in Chapter 1. Also see http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/76979.htm,

[75] Physical withholding is addressed through a day-ahead and real-time must offer obligation for resources contracted to meet any load-serving entity's resource adequacy requirements. Units not under resource adequacy contracts will not be required to offer into the market.

[76] A more detailed description of the competitive path assessment is also provided on the ISO website. For example, see *Competitive Path Assessment for MRTU: Final Results for MRTU Go-Live*, February 9, 2010. http://www.caiso.com/2365/23659ca314f0.pdf

bid mitigation. The most common option for gas-fired generating units is cost-based. Under this option, the default energy bid is based on the unit's incremental heat rate, spot market gas prices, and variable O&M costs. A 10 percent adder is applied to the unit's calculated marginal cost to cover any additional costs not incorporated in the formula and inputs used to calculate the cost-based option. Units can also opt to have a negotiated bid option which can provide a more customized calculation of a unit's marginal or opportunity costs. This option is currently implemented by a third party (Potomac Economics) under an ISO contract . Last, an LMP-based option is available under which the default energy bid is calculated based on LMPs during periods when the unit was dispatched during the prior 90 days. Section 4.4.3 of this chapter provides analysis of default energy bids used in mitigation.

- ***Start-up and minimum load bid caps —*** Generation owners are also allowed to select either a cost-based or bid-based option for determining start-up and minimum load bids used by the market software. If a unit is committed to operate, these bids are also used for determining any bid-cost recovery payments provided to ensure that each generator's market revenues cover the cost of bids accepted. Under the bid-based option, start-up and minimum load bids cannot exceed 200 percent of the unit's actual projected start-up and minimum load costs. Section 4.4.5 of this chapter provides a more detailed discussion and analysis of start-up and minimum load bidding rules and trends in 2009.

4.1.2 Bid mitigation process

Mitigation of a unit's market bids is triggered only when a unit is actually required to operate or run at a higher level due to network constraints previously deemed non-competitive. Units required to operate because of non-competitive constraints are identified by making two pre-market runs of the same market model used to operate the actual day-ahead and real-time energy markets.

- The first run, in which only competitive constraints are enforced, is known as the competitive-constraints run of the network model.
- The second run, in which all constraints are enforced, is known as the all-constraints run.

If a resource's dispatch level from the all-constraint run is greater than its dispatch level from the competitive-constraints run, this indicates that the unit is required to operate (or operate at a higher level) because of the non-competitive constraints being included in the all-constraints run. These units are then subject to an automated bid mitigation process before the actual energy market is run.

If a unit is subject to bid mitigation, the unit's original market bids are compared to its default energy bid and may be adjusted downwards, if necessary, so that the unit's bid curve does not exceed its default energy bid.[77] The unit's resulting mitigated bid curve is used in the final energy market run. Section 4.4.1 of this chapter provides an illustration of this bid mitigation process, along with an assessment of the impact of these procedures on the market bids and dispatches of units subject to mitigation.

[77] This mitigation is only applied to the portion of a unit's bid curve above the level at which the unit was dispatched in the competitive-constraints run. Also, if the unit was partially dispatched in the competitive-constraints run, the unit's highest-priced bid dispatched in this run forms a floor for mitigation of bids for the unit's remaining capacity. These limitations are designed to avoid mitigation of bids below levels that would have cleared the market with only competitive constraints enforced. This minimizes the potential impact of local market power mitigation on overall LMPs in the actual day-ahead or real-time energy markets.

These pre-market local market power mitigation procedures are performed prior to the day-ahead market and again prior to the real-time energy market. These pre-market runs are based on forecasted load to ensure that sufficient supply to meet demand is subject to bid mitigation.

Because these local market power mitigation provisions are only applied to resources bid into the day-ahead and real-time markets, the effectiveness of these provisions could be undermined if the most economical supply needed to meet demand in transmission constrained load pockets is withheld from the market. However, as discussed in Chapter 1, California's resource adequacy program is designed to ensure that capacity needed to meet local reliability requirements within transmission constrained load pockets is under contract to load-serving entities (or to the ISO under its backstop procurement mechanisms). Capacity under such contracts must bid this capacity into the day-ahead and real-time energy markets, and is then subject to the local market power mitigation provisions as described above.

4.2 Competitiveness benchmark

To assess the overall competitiveness of the energy market, DMM estimates competitive baseline prices as a benchmark for assessing actual market prices. This benchmark is calculated by re-simulating the market using the day-ahead market software with bids reflecting the actual marginal cost of gas-fired units. To calculate this baseline under the new market design, DMM replaces actual market bids submitted by gas-fired units with the default energy bids that would be used if a unit were subject to bid mitigation. A detailed description of the methodology is provided in previous quarterly reports filed in 2009.[78]

The percentage difference between actual market prices and prices resulting under this competitive baseline scenario represents the price-cost markup index. For example, if market prices averaged $55/MWh during a month, but the competitive baseline price was $50/MWh, this would represent a price-cost markup of 10 percent. DMM considers a market to be generally competitive if the price-cost markup index indicates no more than a 10 percent mark-up over the competitive baseline on a monthly and annual basis.

Figure 4.1 shows monthly summary results of this competitive baseline analysis for the SCE load aggregation point.

- The green bar (actual day-ahead price) represents the weighted average price for each load aggregation point for the days that were re-run using actual day-ahead market inputs (see left vertical axis).
- The blue bar (competitive baseline) shows the weighted average price for each load aggregation point for these same days based on the re-run performed using default energy bids for gas-fired generation (see left vertical axis).
- The orange line in each figure represents price-cost mark-up, or the percentage difference between actual prices and the prices under the competitive baseline (see right vertical axis).

Overall, the price-cost markup index indicates that monthly load aggregation point prices are well within competitive ranges through each of the first nine months of the new market. The markup is slightly negative for some months. This is because a significant number of generators bid slightly below their

[78] *Quarterly Report on Market Issues and Performance*, Department of Market Monitoring February 1, 2010, pp. 22-23. http://www.caiso.com/2730/2730ee1e71a10.pdf

default energy bids. Because cost-based default energy bids include a 10 percent bid-adder above fuel and variable costs, the small negative markups during some months does not indicate uncompetitively low prices. Rather, this reflects the fact that actual bids for many units are designed to cover fuel and variable costs, but do not include the additional 10 percent multiplier included in default energy bids.

Monthly results for the PG&E and SDG&E load aggregation points are approximately equal to results for SCE as shown in Figure 4.1. In each of these load aggregation points, monthly price-cost mark-up ranged from a low of about 5 percent to a high of about 1 percent. For the nine-month period from April through December 2009, the overall average price-cost mark-up for each load aggregation point was slightly negative (or about -1 percent).

Figure 4.1 Competitive baseline index, SCE load aggregation point (April – December, 2009)

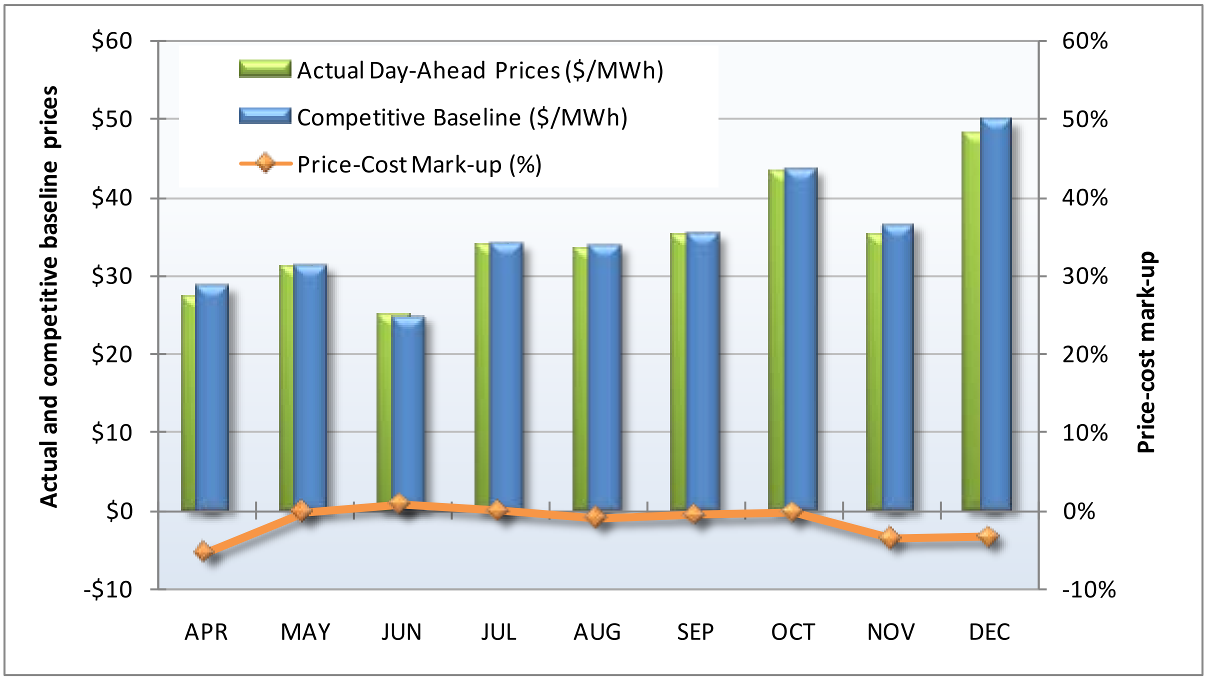
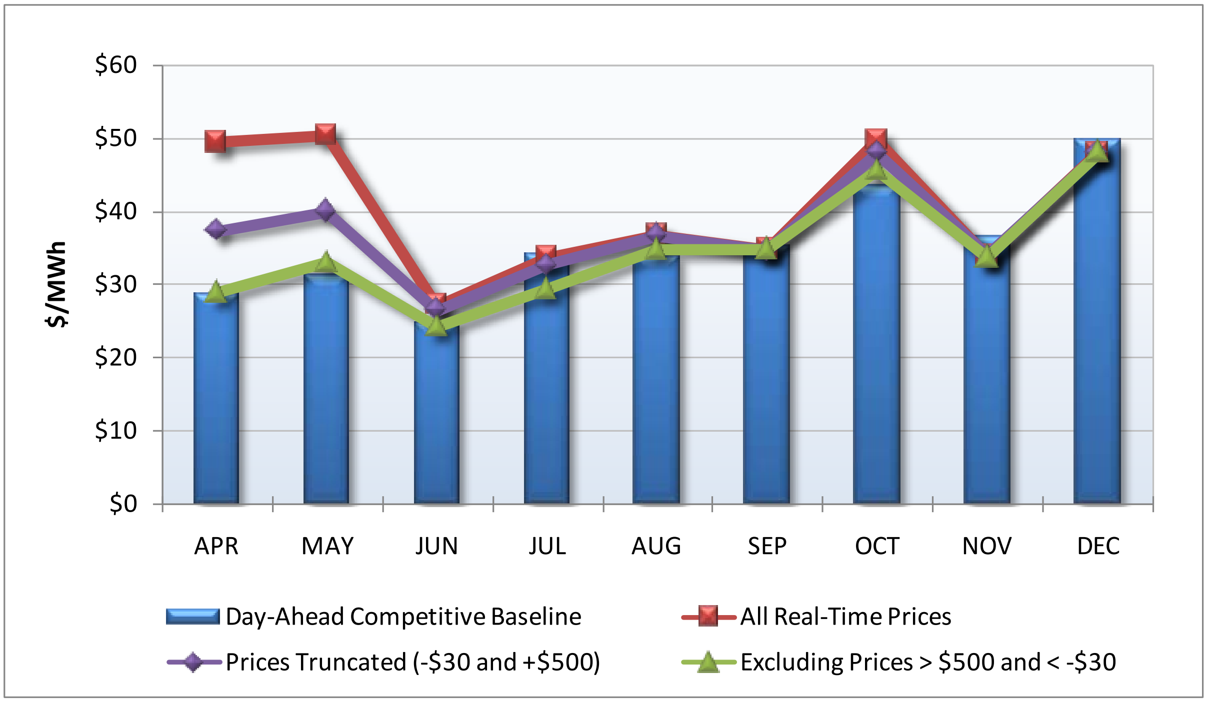


Figure 4.2 compares the competitive baseline price calculated by DMM using the day-ahead market software to three different averages of 5-minute real-time prices for the SCE area:

- The upper red line shows average real-time prices for all 5-minute intervals.
- The middle purple line shows average real-time prices with extreme prices above or below the bid caps for energy truncated at these minimum and maximum caps (-$30/MWh minimum and $500/MWh maximum).
- The lower green line shows average real-time prices with extreme prices above or below these caps excluded.

As shown in Figure 4.2, actual average real-time prices were significantly in excess of this competitive baseline during the first two months of the new market, but were equal to the competitive baseline from June to December. This reflects that there were much fewer extreme real-time prices in the June to December months. As shown in Figure 4.2, when prices outside of the bid caps are excluded, average prices were nearly equal to this competitive baseline during the first two months of the new market.

Figure 4.2 Comparison of competitive baseline to real-time prices (SCE LAP)



DMM has estimated the price-cost mark-up for California's wholesale market dating back to the start of the market in 1998. Figure 4.3 summarizes the results that have been published in DMM's prior annual reports. As shown in Figure 4.3, we have concluded that California's wholesale market has been competitive since 2002, with a price-cost mark-up generally ranging from 5 to 10 percent.

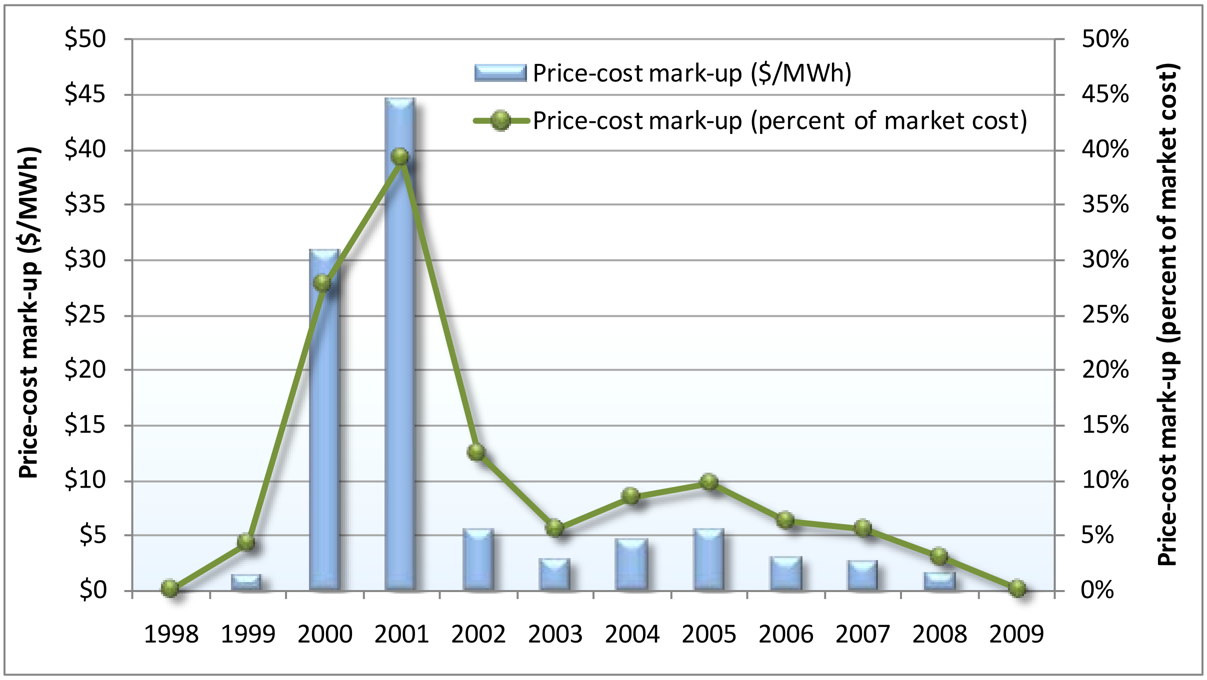
The price-cost markup and other analysis in this report indicate that prices under the new market design implemented in 2009 are extremely competitive. However, direct comparisons with the price-cost markups reported in previous years are difficult due to the dramatically different way in which DMM now calculates price-cost markup.

- As explained in Chapter 3, the method used to estimate total wholesale costs was very different in prior years because there was no formal forward energy market. From 2001 to 2008, DMM has estimated wholesale costs based on a combination of bilateral market price indices, bilateral contract costs, and operating costs of utility owned generation. Wholesale costs represent one of the two major components of the price-cost mark-up. To the extent that the prior method may have overestimated wholesale costs relative to the current method based on market prices, the price-cost mark-up would be higher in previous years.

- The method used to calculate the competitive baseline price under the new market design is modified and is more detailed compared to the method used in prior years.[79]

The extremely low price-cost mark-up calculated under the new methodology and market design may reflect increased efficiencies of this new market design, rather than increased competitiveness. On a going-forward basis, we believe this new competitive baseline methodology will provide a more accurate tool for assessing changes in market competitiveness or efficiency over time.

Figure 4.3 Price-cost mark-up: 1998-2009



4.3 Bid caps and market price caps

The bid and price limits in effect under the new market are summarized in Table 4.1. For the first year of the new market, energy bids were capped at $500/MWh and all prices were capped at $2,500/MWh. Bid caps and price limits both mitigate extreme prices, but they can serve different purposes:

- Bid caps were applied directly to market participants' offers for energy. They prevent participants from exercising market power through economic withholding, or offering capacity at exceptionally high prices to effectively remove that capacity from the market where it would clear at more normal prices.

- Price caps were also applied to market prices. In LMP markets, prices can exceed the bid cap when constraints are binding. For example, if transmission constraints are binding, in order to serve one

[79] For example, the current method uses default energy bids that include a 10 percent adder that was not included in bids for gas-fired units in prior years. This would tend to make the price-cost mark-up lower under the current market design. On the other hand, the prior method used bids based on average heat rates at each unit's maximum operating level, while the current method uses default energy bids based on incremental heat rates. This could tend to make the price-cost mark-up higher under the current market design.

extra megawatt of load at a certain location, the software may need to re-dispatch several megawatts to maintain energy balance and the transmission constraints simultaneously. This can cause LMPs several times above the bid prices.[80] In practice, the re-dispatch of resources made by the software may be so extreme and limited in duration that the resources being re-dispatched may not even be able to respond as modeled in the market software. The $2,500 price cap in effect during 2009 was designed to mitigate the impact to load-serving entities of more extreme pricing outcomes that could arise under such conditions.

Table 4.1 Price and bid limits

	Year 1	Year 2	Year 3
Energy Price Limits			
Maximum	$2,500	n/a	n/a
Minimum	-$2,500	n/a	n/a
Energy Bid Limits			
Maximum	$500	$750	$1,000
Minimum	-$30	-$30	-$30
Ancillary Services			
Maximum	$250	$250	$250
Minimum	$0	$0	$0
Residual Unit Commitment			
Maximum	$250	$250	$250
Minimum	$0	$0	$0

The 2009 bid and price caps had a limited impact on overall market prices, particularly after the first few months of the new market. Figure 4.4 shows the percentage of 5-minute real-time intervals in which at least some bids at the $500 energy bid cap cleared and the percentage of intervals that the $2,500 market price cap was reached. As shown in Figure 4.4:

- Bids at the $500 energy bid cap were dispatched during an average of about 3 percent of intervals during April and May, but were dispatched during only about 1 percent of intervals over the remaining months of the year. Overall, bids at the $500 energy bid cap were dispatched in the 5-minute real-time market during about 1.3 percent of intervals from April to December 2009.

[80] For example, assume transmission constraint A is binding, and there are only two generators with additional capacity (G1 and G2). G1 is operating at its lower limit, so its output cannot be decreased. G1 bids $200/MWh, and has shift factor .2 on constraint A. G2 bids $50/MWh, and has .25 shift factor on constraint. In order to meet one extra megawatt of load at the slack bus, the software will increment G1 up by 5 MW, and decrement G2 by 4 MW. This satisfies the energy balance requirement for one additional megawatt (4=1 MW). Transmission constraint A is satisfied (5 MW x .2 shift factor - 4 MW x .25 shift factor =0). In this case, the LMP at the slack bus is ($200 x 5 MW) – ($50 x 4 MW) = $800/MW.

- The $2,500 market price cap was reached during about 0.76 percent of intervals in April and 0.27 percent of intervals in May, but was rarely reached during the remaining months. Overall, the $2,500 price cap was reached in the real-time market during only 115 5-minute intervals or just 0.15 percent of intervals from April to December.

Figure 4.5 shows the portion of total supply bids in the real-time market submitted at the $500/MWh bid cap (see blue bars plotted on left axis scale). Figure 4.5 also shows the percentage of these $500/MWh bids that cleared the market (see orange line plotted on right axis scale). As shown in Figure 4.5:

- During the first month of the new market, only about 2.3 percent of supply bids in the real-time market were submitted at the $500/MWh bid cap. The amount of bids at the $500/MWh cap declined steadily each month thereafter, except in September, when they reached about 1.8 percent of real-time bids.

- An extremely small portion of bids submitted at the $500/MWh cap actually cleared in the real-time market (see orange line plotted on right axis scale). After the first three months of the new market, only about 0.0002 percent of capacity bid at the $500/MWh cap were dispatched.

As shown in Table 4.1, starting in April 2010, the $2,500/MWh energy price cap will end and the energy bid cap will rise to $750/MWh. Data and trends shown in Figure 4.4 and Figure 4.5 suggest that the impact of higher bid caps and the elimination of the price limit may be very limited. However, due to details of how constraints are represented and mitigated in the market software, there is a continued chance of extremely high LMPs that are more reflective of software modeling issues rather than actual operating limits or conditions. This could be particularly true when complex new features are added to the market software, such as multi-stage generation resources.

4.4 Local market power mitigation

Even with a competitive market, the frequency with which local market power mitigation provisions have been triggered and the impact of this mitigation on market bids and outcomes has been relatively low. This may be attributed to a combination of factors:

- A significant portion of supply is either owned by load-serving entities or under forward contracts to provide energy to load-serving entities or other entities.

- Load and supply conditions were very favorable and helped moderate the potential for high prices and market power during peak summer periods.

- Last, the existence of strong local market power provisions deters uncompetitive bidding by making it unprofitable to do so. This is particularly true when a significant portion of supply is owned or under contract to load-serving entities. Under such conditions, a supplier bidding in excess of marginal costs may simply reduce its market share and net revenues.

The following sections provide more detailed analysis of different aspects of the local market power mitigation provisions.

Figure 4.4 Frequency of $500/MWh bid cap and $2,500/MWh price cap binding in real-time market

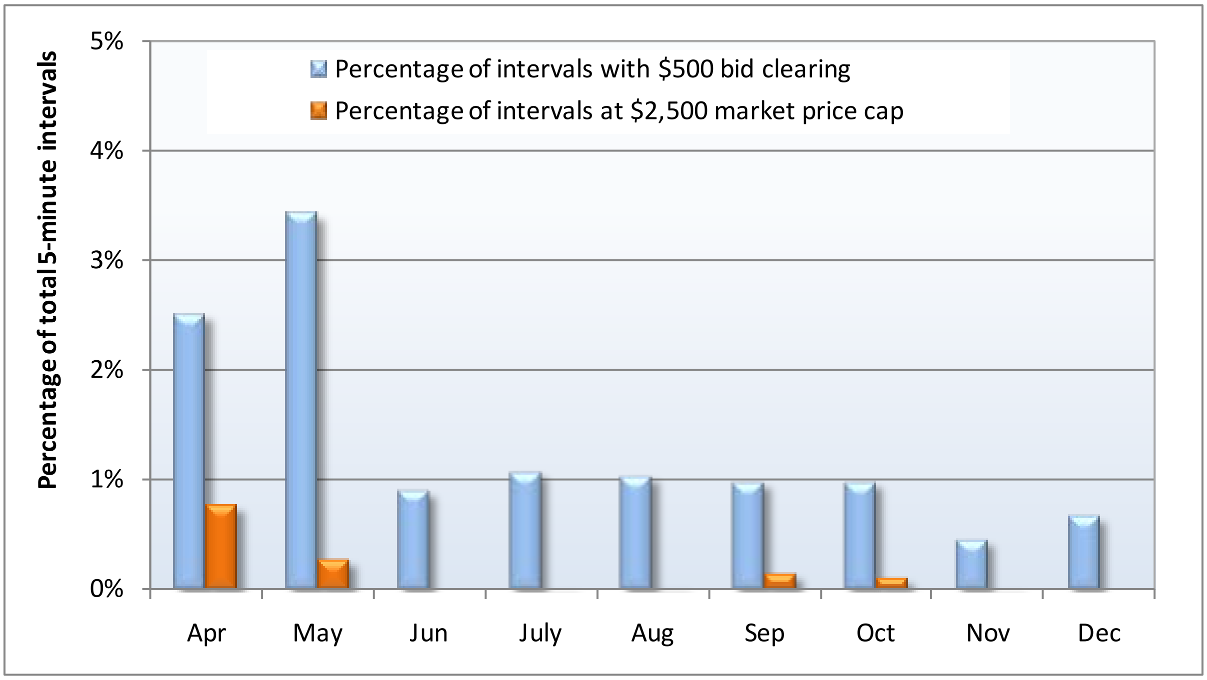
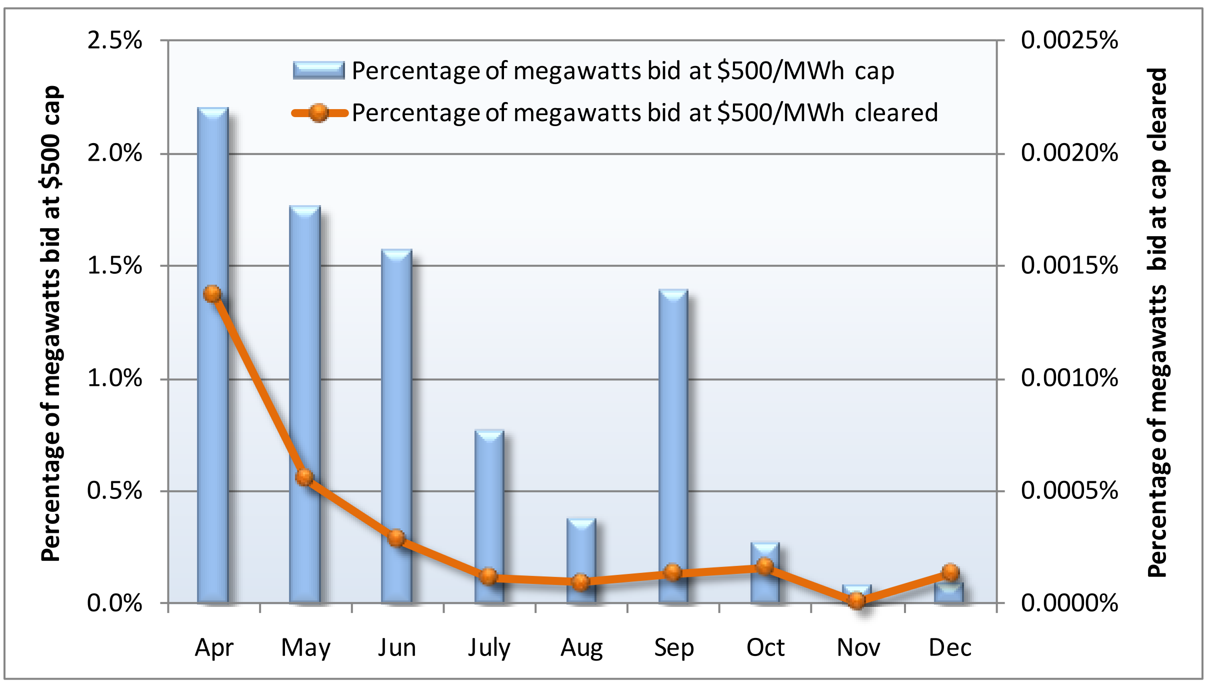


Figure 4.5 Percentage of capacity bid and cleared at $500/MWh bid cap in real-time market



4.4.1 Frequency and impact of bid mitigation

The impact of bid mitigation on actual market prices can only be assessed by re-running the market software *without* bid mitigation. However, the competitive baseline analysis presented in Section 4.2 provides an upper bound of the potential aggregate impact that bid mitigation may have on overall market prices. This competitive baseline is calculated by using default energy bids for all gas-fired units in place of their market bids. Therefore, this analysis provides an indication of prices that may occur if all gas-fired generators were always subject to bid mitigation. As discussed in Section 4.2, average monthly prices for this competitive baseline are nearly equal to actual market prices. This provides a clear indication that the competitiveness of market outcomes is primarily due to highly competitive bidding, and the direct impact of bid mitigation overall is relatively low.

Given the solution times for the current market software, this is not a practical approach for assessing impacts that mitigating bids of individual units or suppliers may have on market prices. However, we have developed a variety of metrics to measure the frequency with which local market power mitigation provisions have been triggered and the impact of this mitigation on each unit's energy bids and dispatch levels. The methodology used to calculate these metrics is illustrated in Section A.4 of Appendix A.

As shown in Figure 4.6:

- During each month in 2009, an average of only 1 to 3 units per hour were subject to mitigation in the day-ahead market. Units are considered subject to mitigation if their dispatch in the all-constraints run is higher than their dispatch in the competitive-constraints run of the market power mitigation process, as described in Section 4.1.2 of this chapter and Appendix A.

- About 80 percent of units subject to mitigation actually had market bids lowered as a result of mitigation. This reflects that in many cases a unit's market bid is below its default energy bid or the unit's highest priced bid clearing the competitive constraints run is higher than its default energy bid. In such cases, no modification of the unit's market bid occurs.

- Only about 30 percent of units subject to mitigation may have been dispatched at a higher level in the day-ahead market as a result of bid mitigation. As described in Section A.4 of Appendix A, DMM has developed a metric to approximate this impact based on where the actual market price intersects each unit's bid curve before and after mitigation. These findings reflect that the extent to which a unit's market bid curve is reduced by mitigation is often relatively small, and would not impact the level at which the unit is ultimately dispatched in the day-ahead market.

Figure 4.7 and Figure 4.8 provide a further indication of the impact of bid mitigation in the day-ahead market during different times and locations within the ISO. Both these figures show the average amount of additional capacity that may have been dispatched from units subject to bid mitigation as a result of having any of their bids lowered through the bid mitigation process.

- Figure 4.7 shows the potential increase in market dispatches in terms of the hourly average for each of the 24 operating hours of the day over the period of April to December 2009.

- Figure 4.8 shows the potential increase in market dispatches in terms of the monthly hourly average potential impact on the amount of energy dispatched from units within different local capacity areas as a result of bid mitigation.

Figure 4.6 Average number of units mitigated in day-ahead market

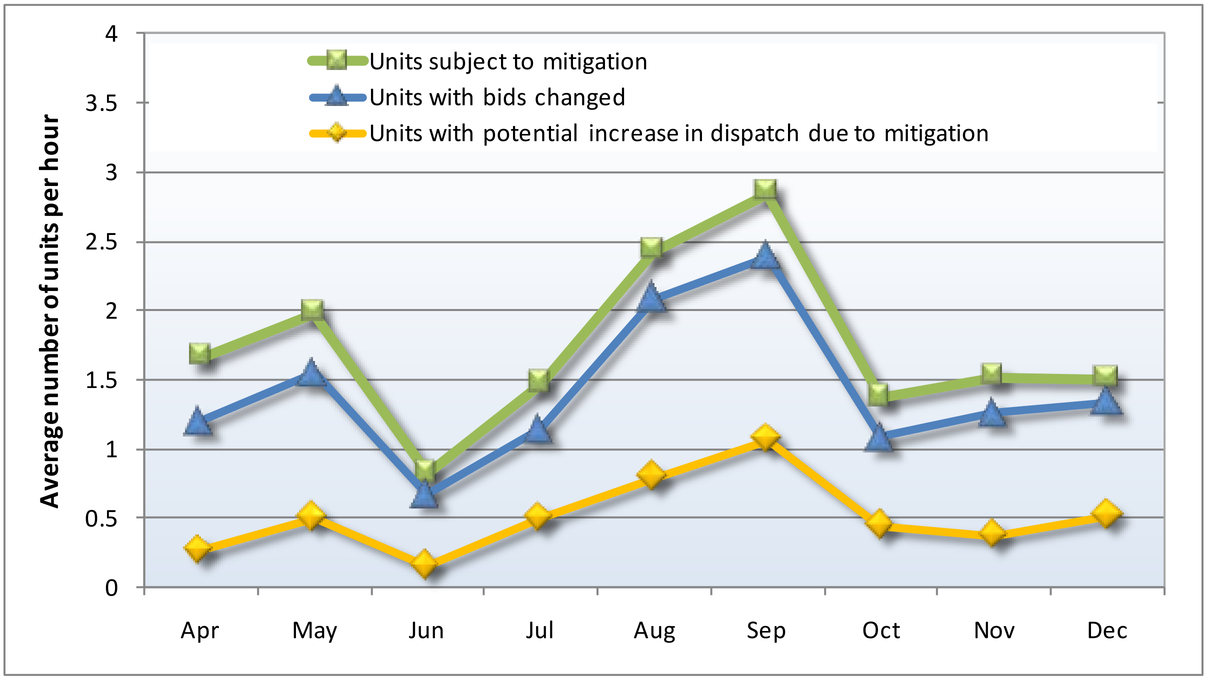
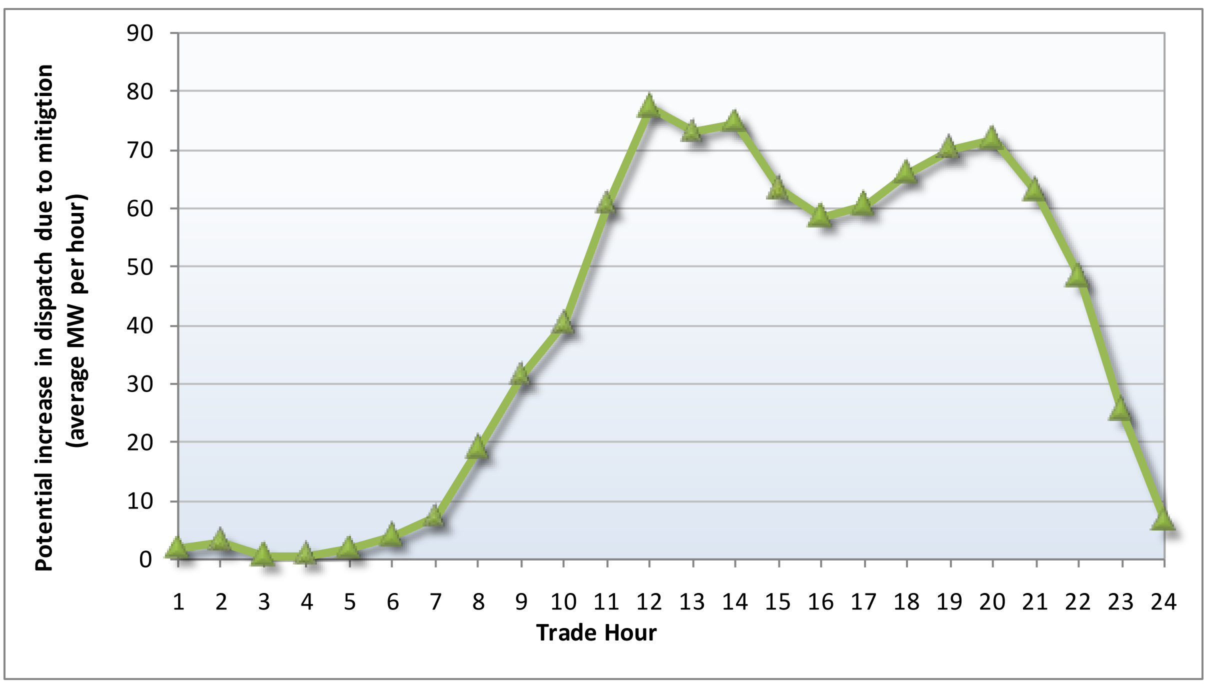


Figure 4.7 Potential increase in day-ahead market dispatch due to mitigation: Hourly averages, April – December, 2009



As shown in Figure 4.7, during the peak hours ending 12 to 20, the total aggregate increase in capacity from units subject to bid mitigation dispatched in the day-ahead market as a result of having their bids lowered in the mitigation process averaged about 67 MW. As shown in Figure 4.8:

- The Bay Area accounts for about 33 percent of the increase in capacity that may have been dispatched from units subject to bid mitigation. This represents an average of about 18 MW per hour.
- The Los Angeles Basin accounts for about 29 percent of the increase in capacity that may have been dispatched from units subject to bid mitigation. This represents an average of about 16 MW per hour.
- The San Diego area accounts for about 17 percent of the increase in capacity that may have been dispatched from units subject to bid mitigation. This represents an average of about 9 MW per hour.
- The Big Creek/Ventura area accounts for about 14 percent of the increase in capacity that may have been dispatched from units subject to bid mitigation. This represents an average of about 8 MW per hour.
- Other areas account for the remaining 8 percent of the increase in capacity that may have been dispatched from units subject to bid mitigation. This represents an average of about 4 MW per hour.

Local market power mitigation procedures for the real-time market are essentially the same as procedures for the day-ahead market. However, the determination of which bids should be mitigated in the 5-minute real-time market is made as part of the hour-ahead scheduling process. This requires that the mitigation be based on a forecast of supply and demand conditions during the following operating hour. In practice, actual supply and demand conditions can be significantly different than the projected conditions used to determine if bid mitigation is triggered.

In the hour-ahead process, mitigation of real-time market bids was triggered slightly more frequently than in the day-ahead market. As shown in Figure 4.9:

- Almost four units were subject to mitigation on average each hour in the real-time market. This compares to an average of less than two units that were subject to mitigation in the day-ahead market (see Figure 4.6).
- On average, less than two units had bids lowered each hour as a result of real-time bid mitigation procedures. This compares to an average of about 1.4 units that had bids lowered each hour in the day-ahead market as a result of bid mitigation procedures (see Figure 4.6).

The process for passing bids mitigated in the hour-ahead process into the 5-minute real-time market periodically failed to use the mitigated bids generated by the mitigation procedures from April to November due to a software problem. The software problem was triggered by the execution time of the hour-ahead scheduling process, and therefore occurred randomly. We have closely monitored the issue since it was discovered, and have not detected the same problem occurring again after the problem was fixed.

Figure 4.8 Potential increase in day-ahead market dispatch due to mitigation: Hourly averages by local capacity area, April – December, 2009

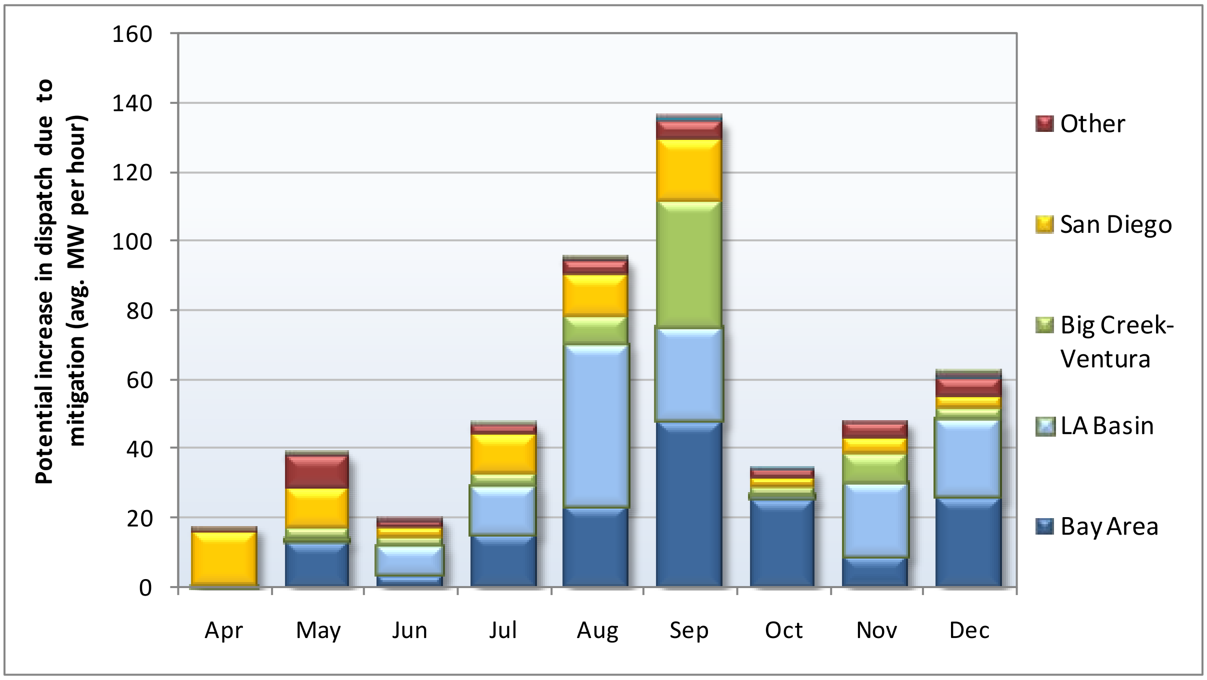
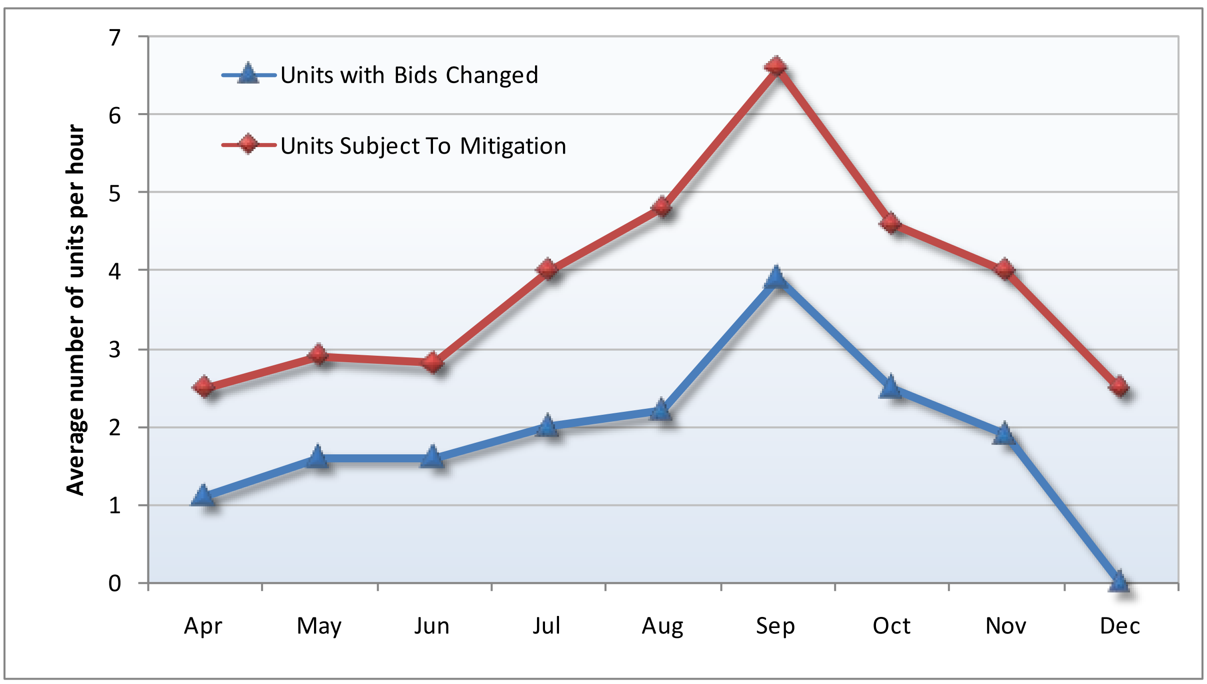


Figure 4.9 Average number of units mitigated in hour-ahead process



4.4.2 Mitigation of exceptional dispatches

If an exceptional dispatch is mitigated, the generator is paid the maximum of the LMP or the unit's default energy bid. Otherwise, exceptional dispatches are paid the maximum of the LMP or the unit's unmitigated bid price.

Under FERC's February 20, 2009 Order, all exceptional dispatches for energy were subject to mitigation for the first four months of the new nodal market (April through July 2009).[81] After this initial period, mitigation was only to be applied to exceptional dispatches that mitigate congestion on constraints deemed to be non-competitive under the competitive path analysis s.[82]

As noted in our Q2 report, we were concerned that if the ISO continued to issue exceptional dispatches for substantial volumes of energy for reasons that were not logged as being for a specific non-competitive constraint, there could be the potential for significant volumes of high cost exceptional dispatches. For example, exceptional dispatches logged for general reasons such as "Ramp Rate" or "Transmission Outage" are no longer subject to mitigation. As this more limited mitigation took effect in Q3, we worked closely with operations staff to clarify mitigation rules, to identify the potential cost implications of unmitigated exceptional dispatches, and to establish adequate logging practices for distinguishing between exceptional dispatches for competitive and non-competitive constraints.

Figure 4.10 shows the hourly average volumes of exceptional energy dispatches by month under the new market. As shown in Figure 4.10, the overall volumes of exceptionally dispatched energy have been relatively low since more relaxed mitigation rules took effect in August. Furthermore:

- After the first month of the new market, over half of exceptional dispatch energy cleared the market in-sequence, meaning that its bid price was less than or equal to the market clearing price for energy.
- Since August, when mitigation was limited to exceptional dispatches for non-competitive paths, only about 20 percent of exceptional dispatches were logged for non-competitive constraints.
- Finally, bid prices for exceptional dispatch energy that is out-of-sequence and not subject to mitigation have not been extremely high relative to each unit's default energy bid or the market clearing price for energy.

Figure 4.11 illustrates the relatively low above-market costs of exceptional dispatch energy. This chart shows the average price of out-of-sequence exceptional dispatch energy with and without mitigation. The lower blue line shows average prices if all exceptional dispatches were mitigated to the higher of the market price or the unit's default energy bid. This line provides a benchmark for assessing actual exceptional dispatch prices. The yellow line in Figure 4.11 shows the actual average prices to be paid for exceptional dispatch energy. The difference in these two prices reflects the degree to which energy bids for exceptionally dispatched energy exceed each unit's default energy bid and the market clearing price for energy.

[81] February 2009 Order, 126 FERC ¶ 61, 150.

[82] Exceptional dispatches relating to delta dispatch procedures were also subject to mitigation. February 2009 Order at P 74.

Starting in August, the difference in this benchmark price (blue line) and the average price for exceptional dispatches (yellow line) shows the limited degree to which the bid price of energy bids that were exceptionally dispatched exceeded this benchmark price. The rising prices in Figure 4.11 after August reflect the trend of higher spot market gas prices over these months. As shown in Figure 4.11:

- Since less stringent mitigation rules took effect in August, the average price of exceptionally dispatched energy has been about $60/MWh. This compares to an estimated average price of about $53/MWh over this time if all these exceptional dispatches had been mitigated. However, as noted above, only 20 percent of this energy was subject to bid mitigation.

- Given the relatively low volume of exceptionally dispatched energy illustrated in Figure 4.10, the overall above-market costs of exceptionally dispatched energy has been very limited. For example, we estimate that if mitigation were applied to all exceptionally dispatched energy since August, costs would have been only about $500,000 lower than the exceptional dispatch cost actually paid.

Figure 4.10 Exceptional dispatches for energy subject to bid mitigation

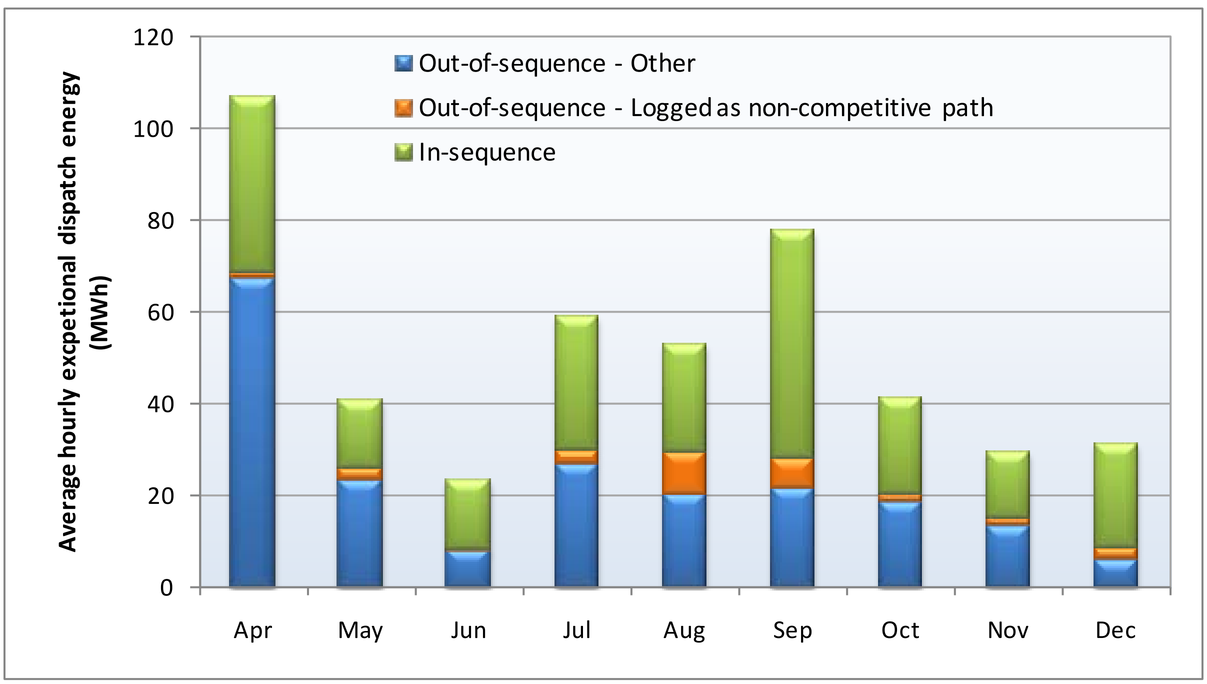
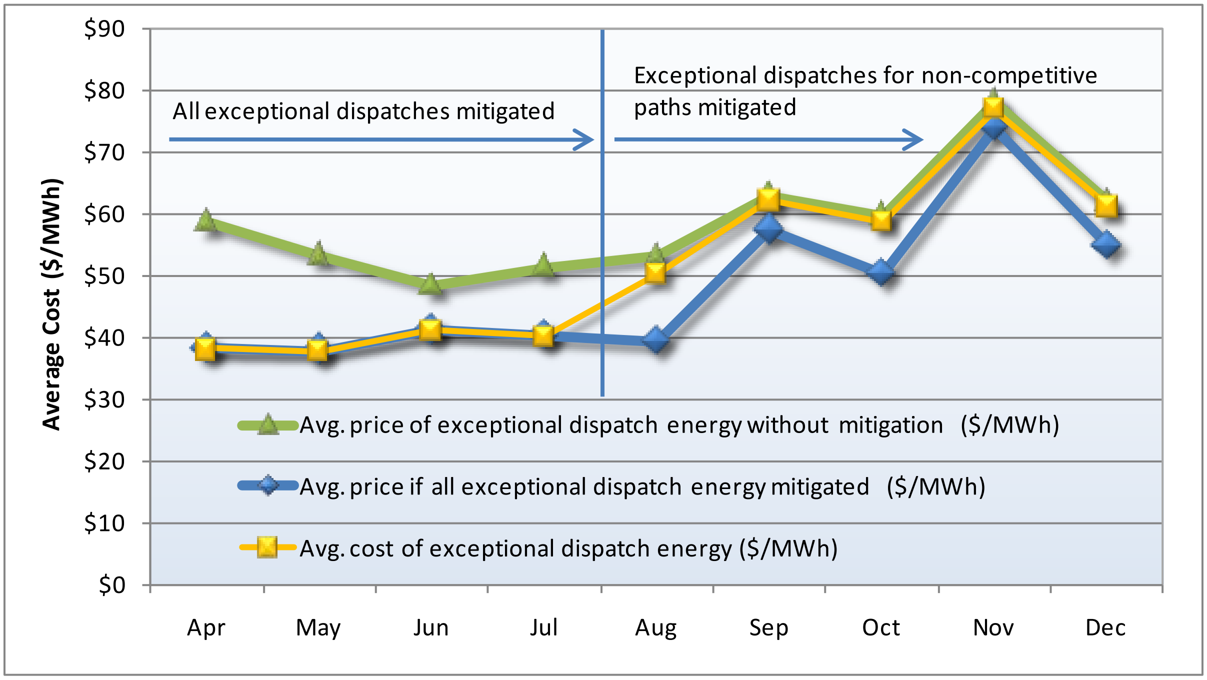


Figure 4.11 Average prices for out-of-sequence exceptional dispatch energy



4.4.3 Default energy bids

LMP-based default energy bids

Starting in July 2009, resources had the option of having their default energy bids calculated using an LMP-based approach. Default energy bids for units under this option are calculated by averaging the lowest quartile of LMPs for the time periods in which the unit was dispatched over the previous 90 days.[83] Dispatches and the corresponding LMPs during all peak hours are used to calculate the LMP-based default energy bid for peak hours. Dispatches and LMPs during other hours are used to calculate the LMP-based default energy bid for off-peak hours. The LMP-based default energy bid is calculated separately for the day-ahead and real-time markets. Thus, each unit under this option has a total of four default energy bid curves: day-ahead peak and off-peak, and real-time peak and off-peak.[84]

Figure 4.12 summarizes the amount of capacity by fuel type that selected and qualified for the LMP-based default energy bid option for July through December. When sufficient data first became available to calculate LMP-based default energy bids in July 2009, a total of 103 resources had selected the LMP-based default energy bid as their preferred option. Only 83 of these resources had been dispatched

[83] Pursuant to the ISO Tariff (39.7.1.6), the LMP-based default energy bid became available only after the first 100 days of the new market, since a history of LMP observations from the new market is required to calculate this default energy bid option.

[84] The Business Practice Manual on Market Instruments requires that in order to calculate an LMP-based default energy bid segment, the unit must have been dispatched a minimum number of hours during the previous 90 days. In the event that a unit selects the LMP-based option, but there is not sufficient dispatch data to calculate an LMP-based bid segment, the default energy bid for that segment is based on the other two default energy bid options (cost-based or negotiated) in the order of preference that was selected by the unit owners.

during a sufficient number of hours to quality for having their default energy bid set using the LMP-based option.[85] These resources represented nearly 10,000 MW generating capacity.

From September to November 2009, only one resource continued to select the LMP-based option. However, this resource had not been dispatched a sufficient number of times to qualify for having its default energy bid set using the LMP-based approach. The trend away from the LMP-based option starting in September 2009 can be attributed to the relatively low default energy bids that resulted under the LMP-based option for most units, reflecting the relatively low LMPs that have been observed in the market during many hours. In December 2009, a total of 22 hydro resources selected the LMP-based option, but only six of these resources qualified to have their default energy bids set using the LMP-based approach.

Figure 4.13 and Figure 4.14 summarize the LMP-based default energy bids by fuel type for the day-ahead and real-time markets by on and off peak in August 2009.[86]

- For gas-fired units, LMP-based default energy bids can be compared to each unit's default energy bid under the cost-based option. As shown in Figure 4.13 and Figure 4.14, LMP-based default energy bids for gas-fired units were generally lower than these unit's default energy bids under the cost-based option. An examination of each gas-fired unit individually shows that the LMP-based default energy bids for these units would generally be lower during off-peak hours in the day-ahead market, and lower for both peak and off-peak hours in the real-time market.[87] Because units selecting the LMP-based option are required to have default energy bids calculated using this option for both peak and off-peak hours in the day-ahead and real-time markets, this likely explains the shift away from using the LMP-based default energy bid as the primary option for these gas-fired units after August 2009.
- For non-gas units, DMM does not have cost data that can be directly compared to each unit's LMP-based default energy bid. However, a review of LMP-based default energy bids for these non-gas units suggests that the relatively low LMP-based default energy bids – particularly for off-peak hours and in the real-time market – also explains the shift away from using the LMP-based option after August 2009. As mentioned earlier, six hydro units qualified for the LMP-based option in December 2009. LMP-based default energy bids in December for these units were substantially higher than these units' LMP-based default energy bids in August.

[85] To be eligible for the LMP-based option a unit must have been dispatched in a minimum of about 2 percent of hours in the day-ahead and 1 percent in the real-time market under the current Business Practice Manual for Market Instruments.

[86] Because LMP-based default energy bids can change daily, this analysis was performed based on data for August 1, 2009.

[87] Unit level detail of this analysis can be found in section 2.2 of DMM's 3rd Quarter 2009 report, http://www.caiso.com/2457/2457987152ab0.pdf.

Figure 4.12 Capacity under LMP-based default energy bid option by fuel type

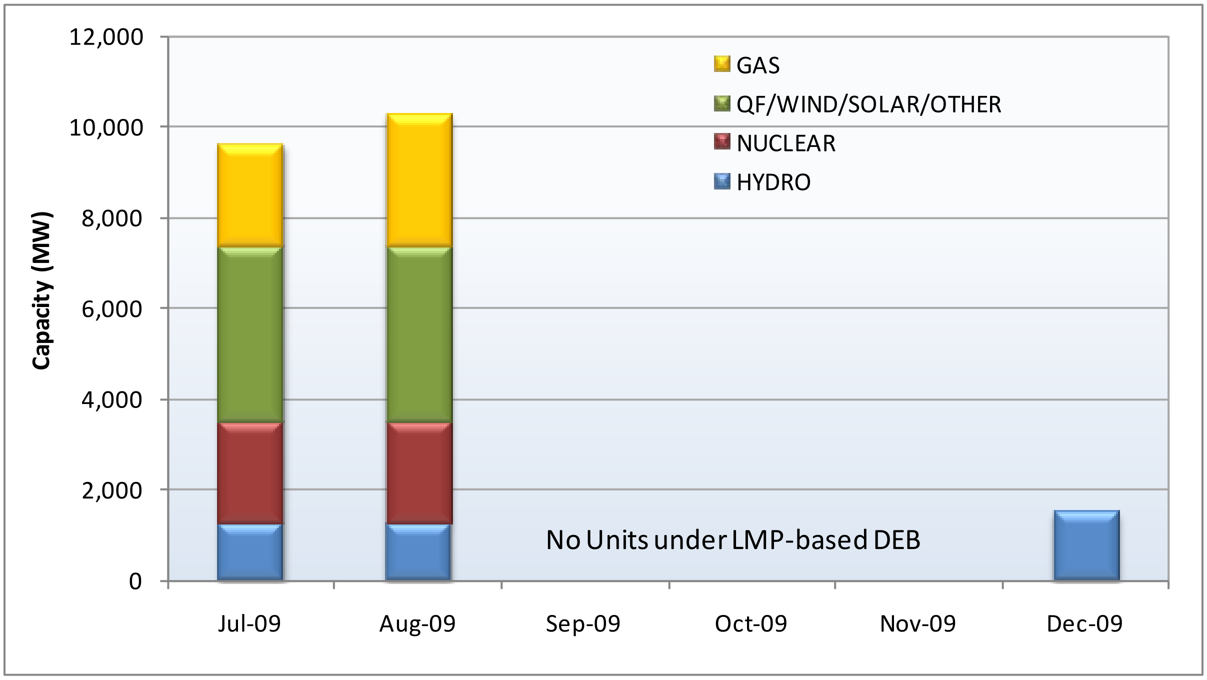


Figure 4.13 Average day-ahead LMP-based default energy bid by fuel type (non-gas units) August 2009

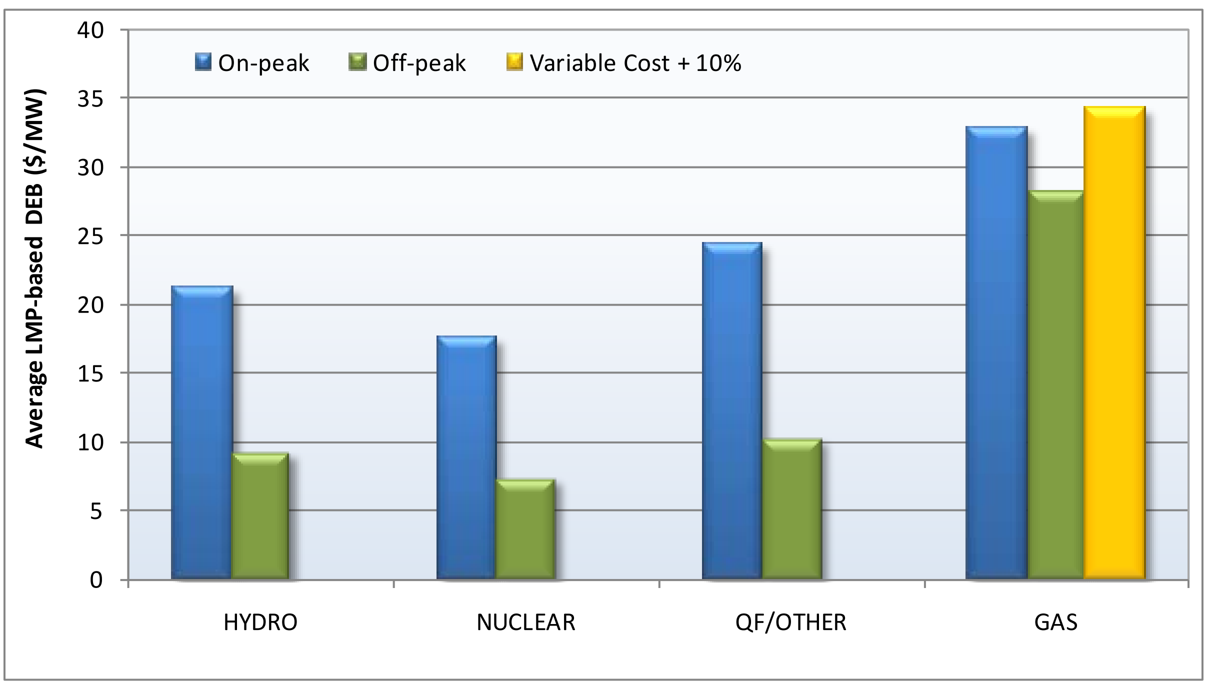
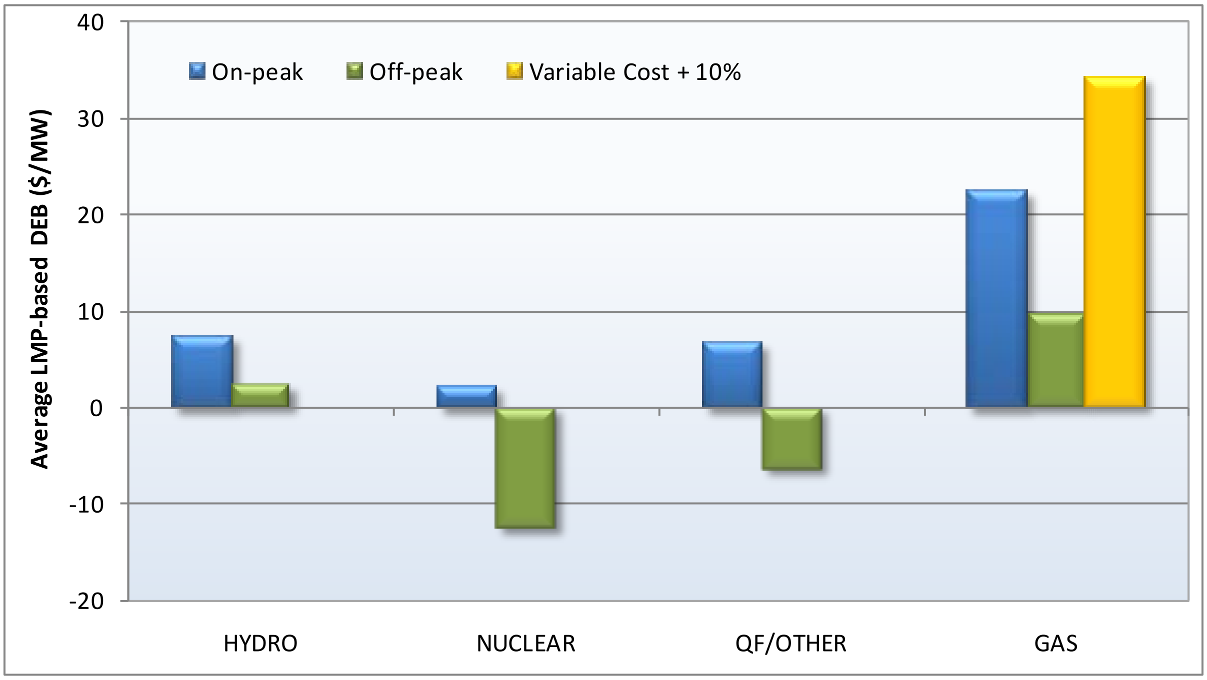


Figure 4.14 Average real-time LMP-based default energy bid by fuel type (non-gas units) August 2009



4.4.4 Frequently mitigated unit bid adder

The bid mitigation provisions also include the option for a bid adder to be included in cost-based default energy bids for resources that are frequently mitigated. Resources that are mitigated in greater than 80 percent of the hours in which they are running are deemed to be frequently mitigated units.

The purpose of the frequently mitigated unit bid adder is to provide opportunity for supplemental revenue for recovery of going-forward fixed costs for those resources that are frequently mitigated to their cost-based levels, which may be at or near their marginal cost of production. Resources with reliability must-run agreements or resource adequacy contracts receive revenues for recovery of going-forward fixed costs, so capacity under these reliability contracts is not eligible for the frequently mitigated unit bid adder.

Many gas-fired units are designated as resource adequacy capacity for most, but not all, of their maximum rated capacity (e.g., 95 percent). These are referred to as partial resource adequacy units. This allows a small portion of a unit's maximum nameplate capacity to be excluded from the must-offer requirement applicable to resource adequacy capacity. For the generation owner, this helps to limit the times when the unit is operated at the very upper range of its maximum rate capacity.[88] In addition, a unit that is designated as resource adequacy capacity most months of the year may not be designated as

[88] Many units are much less efficient in this upper operating range or require special operating measures. Wear-and-tear at this level may also be much higher. Also, many units may often not be able to achieve their maximum rated level due to ambient conditions.

resource adequacy during some months due to planned outages or simply because it is not needed to meet resource adequacy requirements during lower load months.

The default frequently mitigated unit bid adder is $24/MWh. This bid adder can only be added to their cost-based default energy bids. A negotiated option is available also for resources that believe the default of $24/MWh is not sufficient for recovering their going-forward fixed cost.[89] Units with a portion of their full nameplate capacity designated as resource adequacy capacity are eligible for a pro-rated bid adder if they meet the frequently mitigated unit criteria. For example, a frequently mitigated unit with 95 percent of its full rated capacity designated as resource adequacy capacity during a month would be eligible for a $1.20 default bid adder.[90]

Bid adder eligibility criteria

Eligibility for the bid adder is established on a monthly basis based on criteria in the tariff.[91] For purposes of calculating eligibility for the bid adder under the new market design, the frequency of mitigation has been calculated based on the number of hours when a unit was subject to mitigation in either the day-ahead or real-time markets. Units are considered subject to mitigation if their dispatch in the all-constraints run is higher than their dispatch in the competitive-constraints run of the market power mitigation process, as described in Section 4.1.2 of this chapter and illustrated in Section A.4 of Appendix A.[92]

Analysis presented in Section 4.4.1 shows about 80 percent of units subject to mitigation actually had their bids lowered and about 30 percent were dispatched at a higher level due to this mitigation (see Figure 4.6).[93] Thus, the method that the ISO currently uses to calculate the frequency of mitigation for purposes of determining eligibility significantly overstates the actual percentage of hours a unit's bid or dispatch is impacted by mitigation.

Frequently mitigated units in 2009

An extremely small number of units and capacity qualified for the frequently mitigated unit bid adder in 2009. All of these units were partial resource adequacy units that had most of their capacity designated as resource adequacy for most of the year. These units qualified for the adder because of relatively high rates of potential mitigation during the twelve months prior to the start of the new market.[94]

Figure 4.15 shows the frequency that individual units were subject to mitigation, as defined for determining eligibility for the bid adder, during the nine months of 2009 that the new market design

[89] Section 39.8 of the tariff at http://www.caiso.com/23d5/23d5cd07a480.pdf.

[90] 95 percent x $24/MWh = $1.20.

[91] Tariff Section 39.8.1.

[92] The percentage of hours a unit is mitigated is calculated by dividing the hours that a unit is subject to mitigation by the unit's total run hours. Run hours are those hours during which a generating unit has positive metered output.

[93] As previously noted, this analysis shows that only 80 percent of units subject to mitigation actually had market bids lowered as a result of mitigation. Only about 30 percent of units subject to mitigation may have been dispatched at a higher level in the day-ahead market as a result of bid mitigation.

[94] During the first twelve months after the start of the new market on April 1, 2009, the mitigation frequency used to determine eligibility for the bid adder was based on a rolling twelve month combination of data from the prior market design and this new market design. During the period prior to April 1, 2009, reliability must-run and out-of-sequence dispatches used to manage local congestion were used as a proxy for being subject to mitigation under the prior market design.

was in effect. Units are sorted in descending order of mitigation frequency to show the portion of units that were mitigated most frequently and their level of mitigation.

Figure 4.16 shows the frequency that capacity was subject to mitigation as defined for determining eligibility for the bid adder. This figure differs to reflect the size of each unit subject to potential mitigation in descending order of frequency. As shown in these two figures:

- ***Resource adequacy units —*** All of the nearly 30,000 MW of resource adequacy capacity was subject to mitigation less than 33 percent of run hours.[95] Reasons for the relatively low frequency of mitigation for most units were discussed in Section 4.4.1 of this chapter.

- ***Non-resource adequacy units —*** No non-resource adequacy units were subject to mitigation more than 20 percent of their run hours. Only three non-resource adequacy units, representing about 1,300 MW, were subject to mitigation between 10 to 20 percent of run hours. The remaining 3,300 MW of non-resource adequacy capacity was subject to mitigation less than 8 percent of hours.

  The low percentage of hours that non-resource adequacy units were subject to mitigation reflects the fact that most of this capacity is not located within transmission constrained local capacity areas. Units outside of local capacity areas are less likely to be needed by load-serving entities to meet local resource adequacy requirements. These units are also less likely to be dispatched to mitigate congestion on an uncompetitive constraint in the market power mitigation procedures.

- ***Reliability must-run units —*** Two reliability must-run units with a total capacity of about 400 MW were subject to mitigation about 70 percent of run hours. Another two units with a capacity of about 300 MW were subject to mitigation over 40 percent of hours.

The high percentage of hours that some reliability must-run units were subject to mitigation reflects the bids used for reliability must-run units in local market power mitigation procedures. Under the tariff, any market bids submitted by reliability must-run units are used in the competitive-constraints run of the local market power mitigation procedures. In the all-constraints run, cost-based bids derived using formulas specified in the reliability must-run contract are used. Even if a unit's market bids are just slightly over these cost-based contract bids, this makes it likely that the reliability must-run unit may be dispatched at a slightly higher level in the all-constraints run, which makes the unit subject to bid mitigation. For non-reliability must-run, both of these market power mitigation runs are made with market bids. This results in a lower rate of mitigation for non-reliability must-run units.

DMM and the ISO are reviewing options for reducing the frequency that reliability must-run units are mitigated as a result of the current bidding rules for these units. One option would be to utilize a software parameter that exists in the current software to adjust all bids dispatched in the competitive-constraints run downwards by some fixed amount (e.g., -$50/MWh) in the all-constraints run. This negative adjustment would tend to prevent units from being dispatched at a lower level in the all-constraints run unless this was needed to balance additional energy from units dispatched at a higher level in the all-constraints run to mitigate congestion on a constraint. Although this change may require a tariff modification, the parameter for applying this negative adjustment to bids dispatched in the competitive-constraints run already exists in the software.

[95] Data in this category include partial resource adequacy units because, as previously noted, all of these units were designated as resource adequacy for most of their capacity during most months.

Figure 4.15 Percent of hours subject to mitigation by unit (April – December 2009)

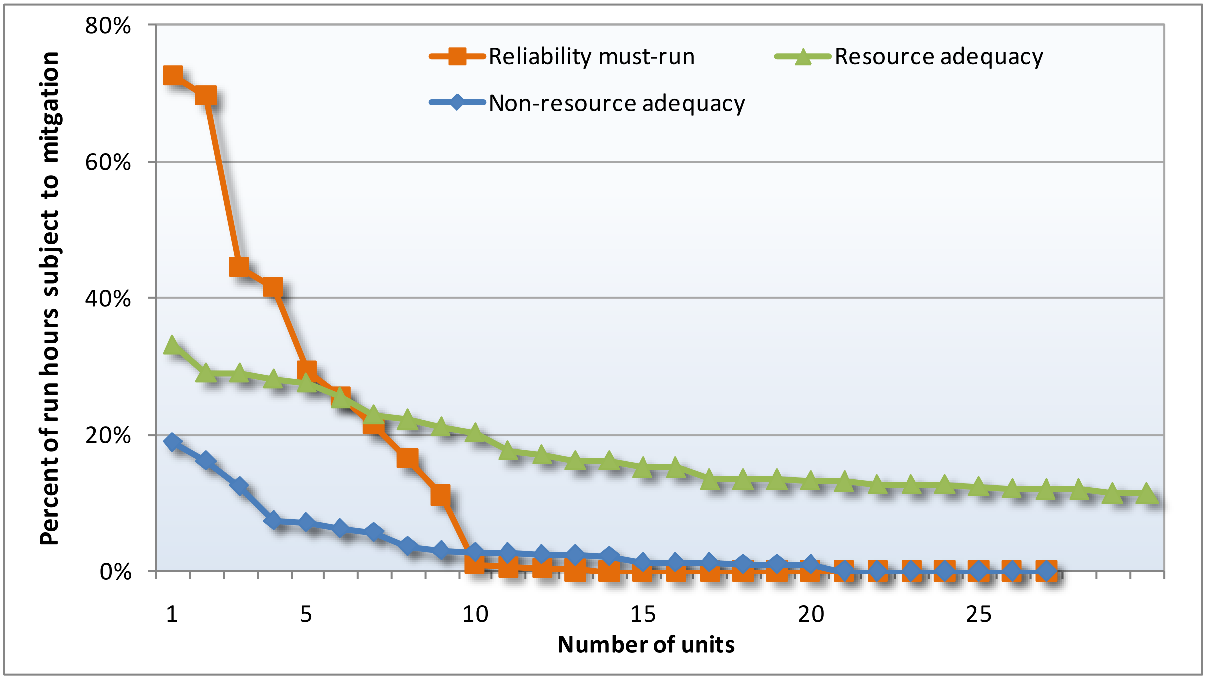
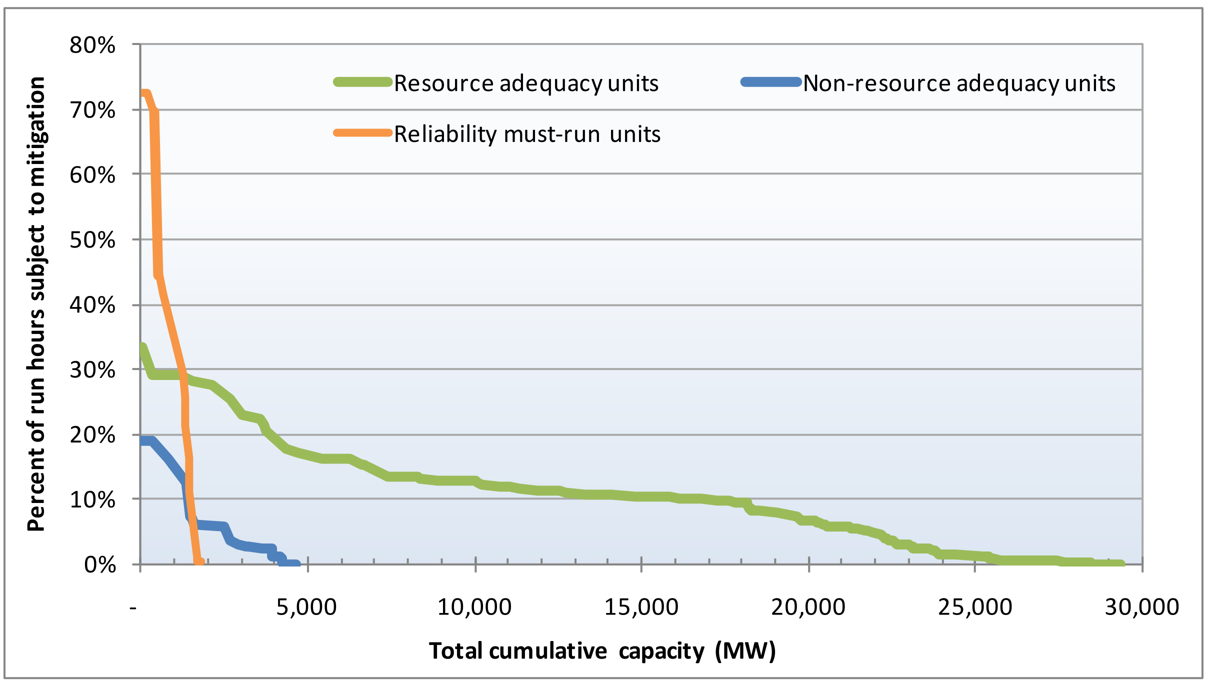


Figure 4.16 Percent of hours subject to mitigation by total capacity (April – December 2009)



4.4.5 Start-up and minimum load bids

Under the new market design, owners of gas-fired generation can choose either a cost-based proxy cost option or a bid-based registered cost option for their start-up and minimum load costs.

- Under the proxy cost option, each unit's start-up and minimum load costs are automatically calculated each day by the software based on an index of daily spot market gas prices, and the unit's start-up and minimum load fuel consumption, as reported through the master file.
- Unit owners selecting the registered cost option submit fixed bids for start-up and minimum load costs to the master file. These bids are then used by the market software. One of the key reasons for providing this bid-based option was to provide an alternative for generation unit owners who believed they had significant non-fuel start-up or minimum load costs that were not covered under the proxy cost option.

At the start of the new market, registered cost bids were capped as follows:

- For units outside of local capacity areas, registered cost bids could not exceed 400 percent of the unit's projected actual start-up and minimum load fuel costs.
- For units within local capacity areas, registered cost bids could not exceed 200 percent of the unit's projected actual start-up and minimum load fuel costs. The lower cap for units in local capacity areas reflected that these units would be more likely to have potential local market power that might be exercised by submission of excessively high start-up and minimum load bids under the registered cost option.

Two other key provisions relating to start-up and minimum load bids at the start of the new market include the following:

- Registered cost bids were initially required to be fixed for a six month period. Gas prices used to calculate the cap for each unit's registered cost bid were based on the maximum monthly gas futures prices over the forward looking six month period during which the bids would be fixed. The requirement that registered cost bids remain fixed for six months was included to provide an additional disincentive for owners selecting this option to bid excessively high, because they would then face the risk of pricing themselves out of the market during more competitive conditions.
- Under the tariff and master file design, the unit owner's selection of either the proxy or registered cost option is applied to both start-up and minimum load costs. In other words, a unit owner cannot select one of these options for start-up costs and the other option for minimum load costs.

After the first few months of the new market design, numerous participants raised concerns about the proxy and registered cost options. Some suppliers that selected the proxy cost option indicated that certain units were being turned off and on more frequently than under the former market, causing extra wear and tear on the generating units. For units with start-up and emissions limitations, this could also make it difficult for the owner to seek to optimize use of a unit over the time period of these constraints. Although the registered cost option allowed generation owners to incorporate non-fuel costs in their bids, numerous generation owners indicated the six month period that registered cost bids were required to remain fixed made it difficult to submit bids that accurately tracked changes in gas prices over this period.

As a short term response to these concerns, the ISO filed to modify these tariff provisions as follows:[96]

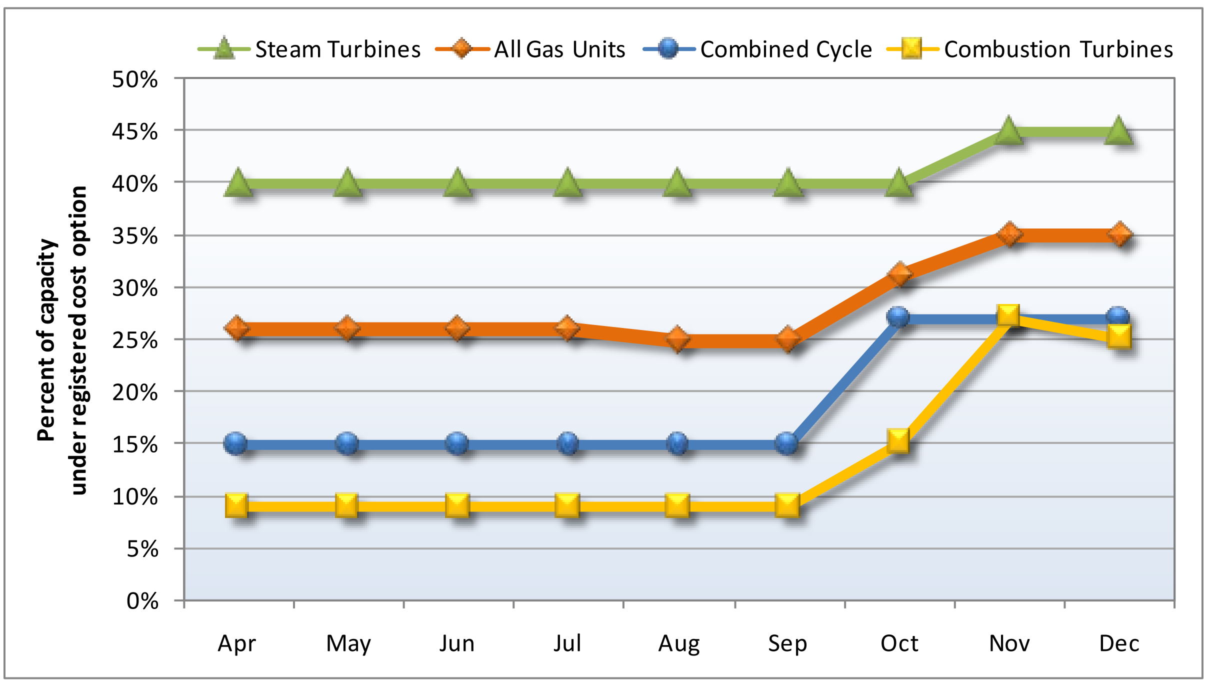
- The six month restriction on changing between the proxy and registered cost option or modifying registered cost bids was lowered to 30 days. This modification allows participants selecting the registered cost option to submit bids that would better represent their costs and help to more efficiently manage the way their units were being committed in the new markets.
- The cap for bids under the registered cost option for units outside of local capacity areas was also lowered from 400 percent to 200 percent of projected actual start-up and minimum load fuel costs.

The following sections summarize trends in the portion of capacity selecting the proxy and registered cost options since the start of the new market, and provide a summary of the general level of bids submitted under the registered cost option.

Capacity under registered cost option

At the start of the new market in April 2009, about 25 percent of gas-fired capacity elected the registered cost option for start-up and minimum load bids. As shown in Figure 4.17, following the Commission's September 29, 2009 Order accepting the proposed tariff revisions, the portion of gas-fired capacity selecting the registered cost option increased from about 25 percent to 35 percent.

Figure 4.17 Gas-fired capacity under registered cost option



[96] When filing these tariff revisions with FERC, the ISO requested a waiver of the Commission's 60-day prior notice requirement so that the modifications could become effective August 1, 2009, and unit owners wanting to switch from the proxy to registered cost option or modify registered cost bids could do so at that time. However, the Commission did not issue an order confirming acceptance of the ISO's July 30 filing until September 29, 2009. http://www.caiso.com/23fc/23fcb61b29f50.pdf

Bids submitted under registered cost option

After the election period for the registered cost option was reduced from six months to 30 days, a relatively limited portion of start-up and minimum load bids submitted for capacity under the registered cost option have been at or near the 200 percent cap in effect under this option. As shown in Figure 4.18 through Figure 4.21:

- The portion of capacity under the registered cost option submitting start-up bids at the 200 percent cap decreased significantly in December compared to April, as shown in Figure 4.18. However, in December approximately 72 percent of capacity was still bid at or greater than 180 percent of calculated costs.
- The portion of capacity under the registered cost option submitting minimum load bids above 100 percent of calculated minimum load costs increased significantly in December compared to April, as shown in Figure 4.19.
- Combined cycle and steam turbine units under the registered cost option tend to submit start-up bids at or near the 200 percent price cap, but submit minimum load bids at or near 100 percent of minimum load costs (see Figure 4.20 and Figure 4.21).
- Combustion turbine units under the registered cost option tend to submit start-up bids at or near 100 percent of cost, but tend to submit minimum load bids significantly above minimum load costs (see Figure 4.20 and Figure 4.21).

Figure 4.18 Registered cost start-up bids by month (April/December 2009)

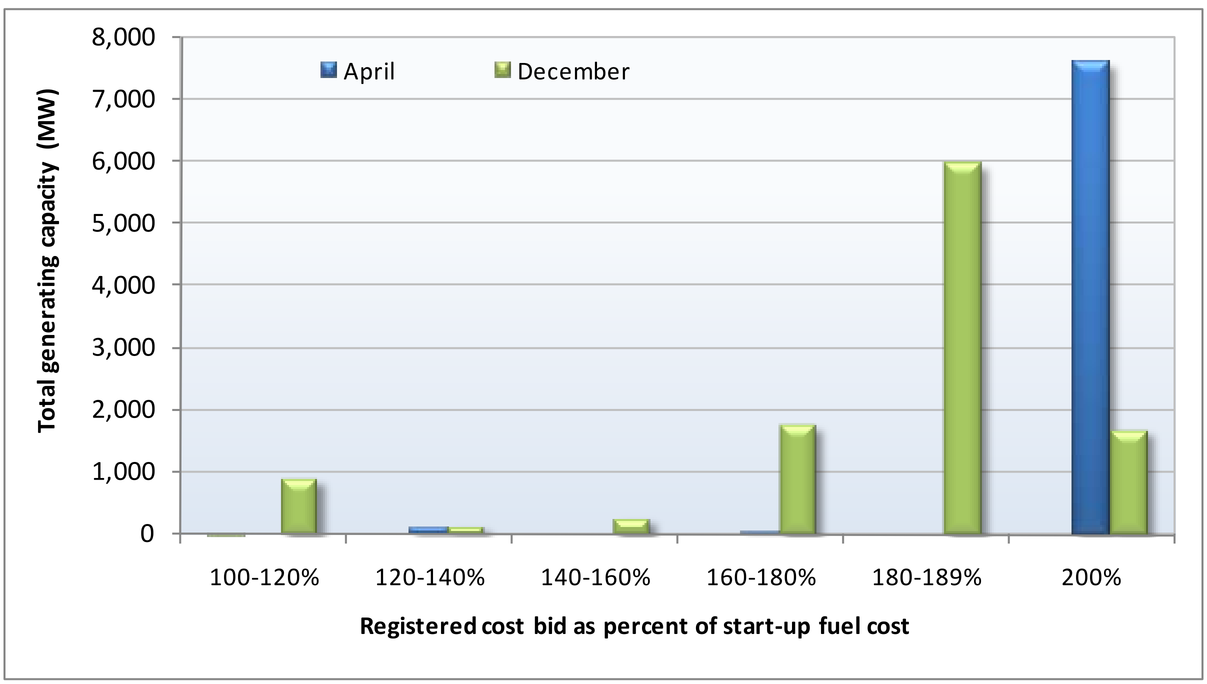


Figure 4.19 Registered cost minimum load bids by month (April/December 2009)

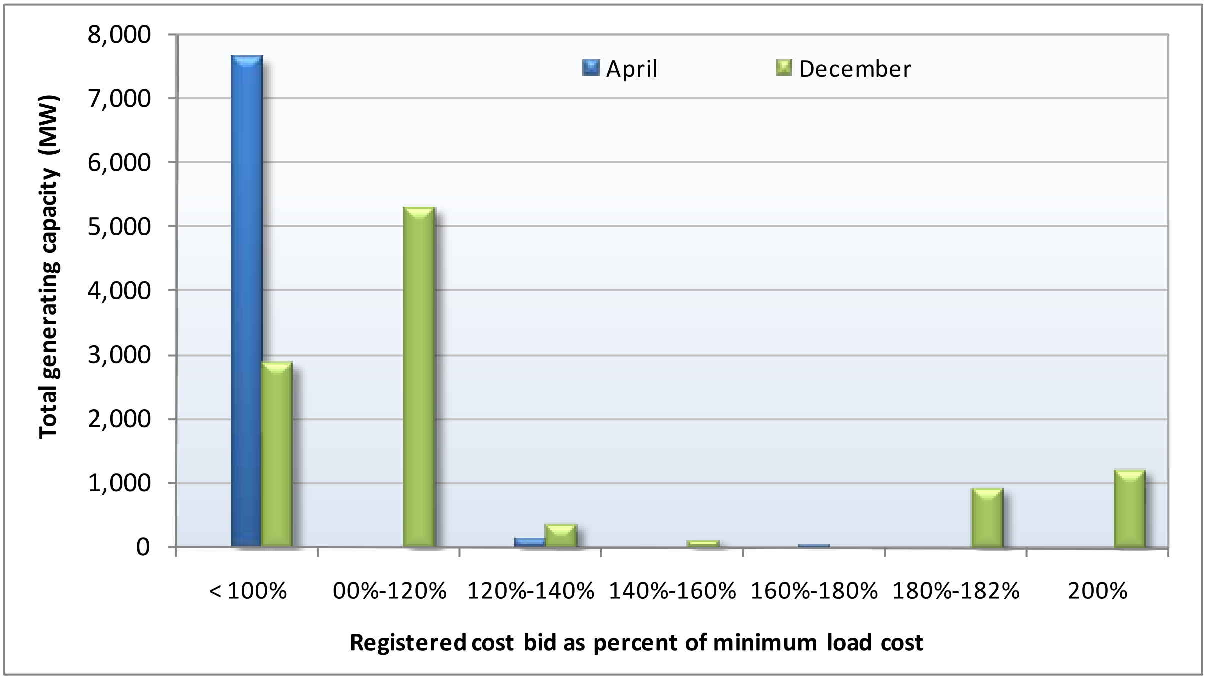


Figure 4.20 Registered cost start-up bids by generation type - December 2009

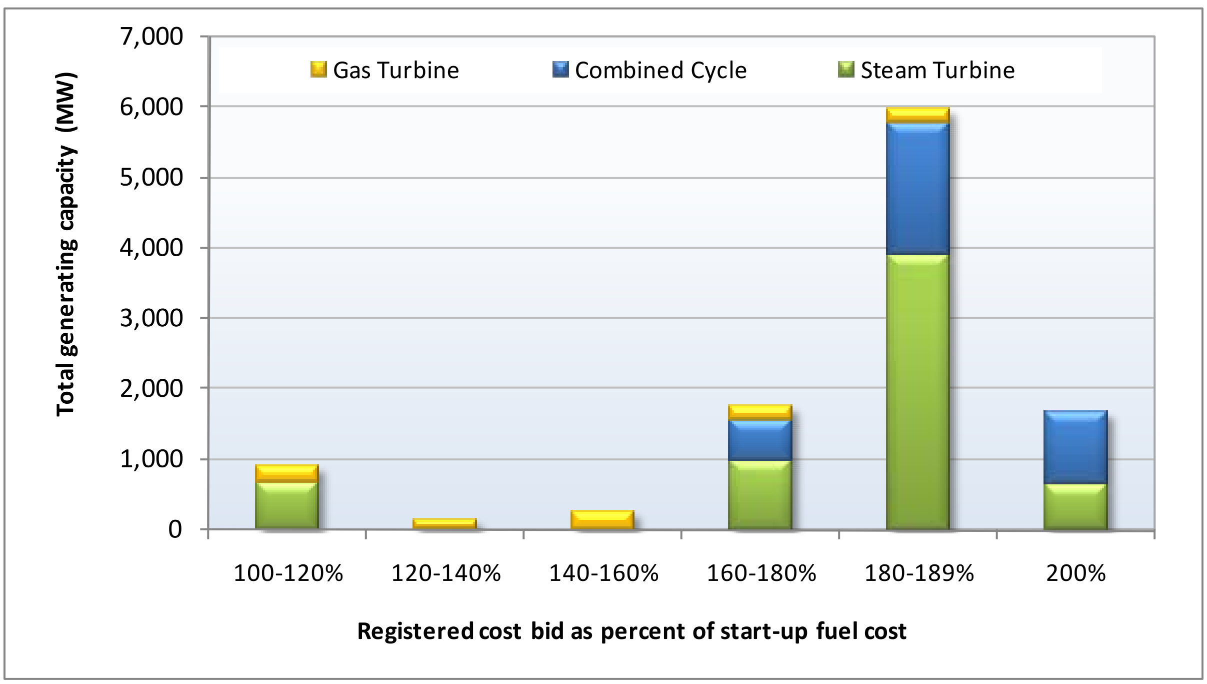
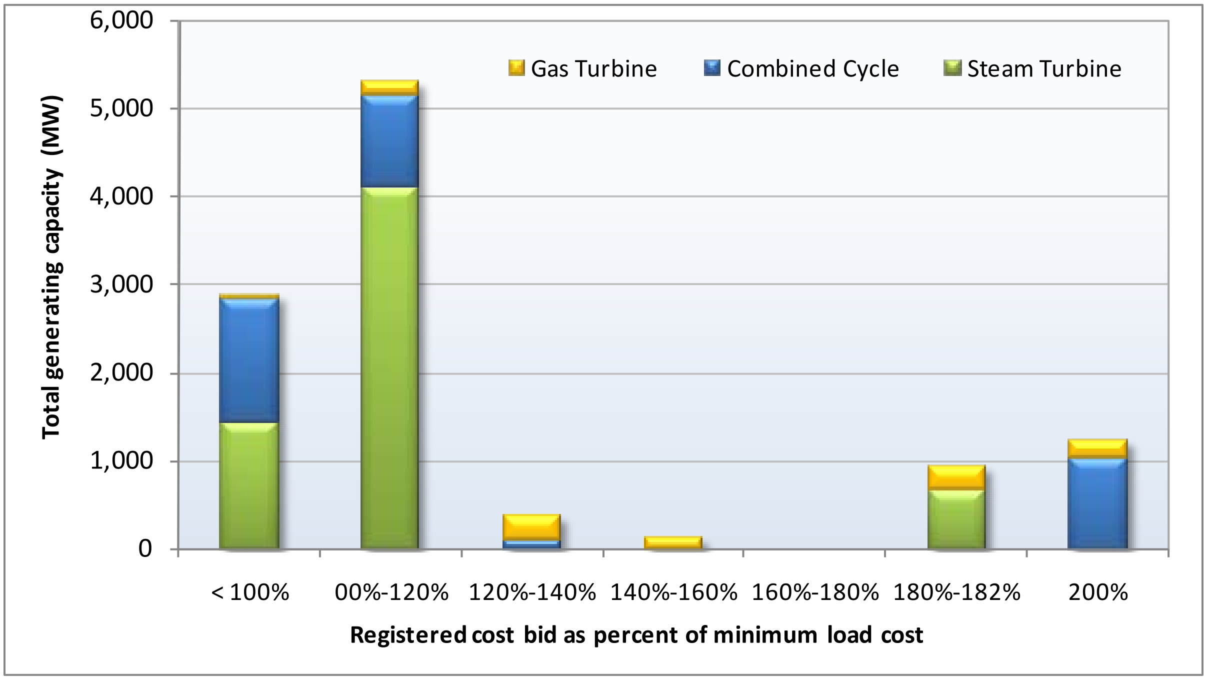


Figure 4.21 Registered cost minimum load bids by generation Type – December 2009



Conclusions

Overall, results of this analysis suggest that the current 200 percent cap on start-up and minimum load bids is not overly restrictive. Owners of most gas-fired capacity under the registered cost option appear to have been able to incorporate whatever non-fuel costs they may incur into bids within the 200 percent cap.

However, as shown in Figure 4.19 and Figure 4.21, a relatively high portion of units under the registered cost option submitted bids below or just slightly over their projected actual minimum load operating costs. This may reflect the fact that under the tariff and master file design, the unit owner must select either the proxy or registered cost option for both start-up and minimum load costs. A unit owner cannot select one of these options for start-up costs and the other option for minimum load costs.

This suggests that a significant portion of unit owners selecting the registered cost option may do so primarily to submit start-up bids that include additional non-fuel costs, and then submit minimum load bids at or near their projected actual minimum load costs. Numerous stakeholders have indicated this represents another aspect of the registered cost option they would like modified. Specifically, they have suggested that rules be modified to allow them to submit a fixed component for non-fuel costs associated with start-ups or perhaps minimum loads. This fixed component would then be added to fuel costs associated with start-up and minimum load costs, which would be calculated based on daily spot market gas prices.

This represents a future design modification that the ISO has indicated it will seek to address in 2010. DMM is supportive of such modifications provided a way is developed to reasonably limit any fixed component that would be added to start-up or minimum load cost bids.

4.4.6 Competitiveness of transmission constraints

Background

The ISO's new local market power mitigation provisions require that each network constraint (or path) be pre-designated as either competitive or non-competitive. Generation bids are subject to mitigation if that unit is dispatched up to relieve congestion on a transmission path pre-designated as non-competitive. Thus, for these provisions to be effective, it is important that constraints designated as competitive are in fact competitive under actual market conditions.

The methodology used to designate transmission constraints as competitive or non-competitive is the competitive path assessment.[97] The assessment is based on a 3-pivotal supplier feasibility test. The general concept is to exclude all supply resources of each combination of three suppliers, and then determine if the remaining suppliers' resources are sufficient to meet loads. This test applies all constraints in the full network model used by the market software being enforced. In effect, the competitive path assessment tests to see if a feasible solution exists with the supply of any three suppliers excluded from the market.[98]

During 2009, constraints were designated as competitive and non-competitive based on a study performed in February 2009 prior to the start of the new market in April.[99] Results of this first study were applied for the first 12 months of the new market. Starting in April 2010, the ISO will perform competitive path assessment studies on a seasonal basis four times per year and will update constraint designations based on these results. Under the current process, the competitiveness of constraints under actual market and operating conditions may vary from results of the study for a variety of reasons:

- The assessment must currently be performed on a network model developed and released as part of the congestion revenue rights auction process. This network model may differ from the model incorporated in the actual market software, which is frequently updated to reflect new constraints, transmission outages or ratings, or other adjustments.
- The assessment does not incorporate any generation or transmission outages.
- The assessment is run for a series of scenarios representing different load, hydroelectric and import conditions. Although these scenarios are based on historical data and are designed to cover a wide range of possible conditions, actual load and market conditions may vary from these scenarios.
- DMM currently uses the Plexos software to perform the assessment, rather than the actual market software.

[97] For a detailed description of this methodology, see *Competitive Path Assessment for MRTU Final Results for MRTU Go-Live,* Department of Market Monitoring, February, 2009, http://www.caiso.com/2365/23659ca314f0.pdf

[98] The competitive path assessment is performed with relatively high penalty prices assigned to any "overflow" conditions on paths being tested for competitiveness. Major paths deemed to be competitive are assigned much higher penalty prices. This ensures that if a feasible solution does not exist, flows on paths being tested will exceed transmission limits before any "overflow" occurs on paths not being tested. With this approach, if flows on any paths being tested exceed limits, the path is deemed to be non-competitive.

[99] See *Competitive Path Assessment for MRTU Final Results for MRTU Go*-Live*,* Department of Market Monitoring February, 2009 , http://www.caiso.com/2365/23659ca314f0.pdf

One of the drawbacks of the competitive path assessment is that the process is time-consuming given the DMM's current modeling tools. DMM is currently developing an enhanced modeling tool that will significantly reduce the time needed to perform the study.[100] This tool will also facilitate running the assessment using the actual network model and market inputs used by the market software.

DMM has also developed other metrics to assess actual market outcomes and determine whether one or more large suppliers may be pivotal for relieving congestion on specific constraints. The residual supply index for counterflow on congested constraints was developed by DMM based on similar metrics used by several other ISOs to assess the competitiveness of transmission constraints. The index is intended to supplement the competitive path designations and provide a tool that can be used to monitor and assess the competitiveness of constraints on a day-to-day basis under actual network and market conditions. A detailed description of the index is provided in Section A.5 of Appendix A.

Residual supply index analysis

The most common way to exercise market power is to withhold generation with a transmission constrained load pocket. In such circumstances, the availability of potential counterflows for congested paths is a key metric that can be used to assess the competitiveness of specific constraints. Potential counterflows on congested paths represent generation resources that may be used to relieve congestion by increasing their output.

The residual supply index measures how pivotal one or more suppliers may be in terms of controlling the supply of effective counterflow needed to relieve congestion of a specific transmission constraint. The index is the ratio of the demand for counterflow divided by the total residual supply of potential effective counterflow after removing the generation controlled by one or more of the largest suppliers. An index of less than 1 indicates that the residual supply of counterflow controlled by all other suppliers is insufficient to meet the demand for counterflow on a constraint. The index may be used to measure whether a single supplier is pivotal, or whether multiple suppliers are jointly pivotal.

One of the main strengths of the residual supply index is that it is calculated based on the actual supply and demand for counterflow during hours when congestion occurs. Results therefore reflect changes in system conditions not captured in the competitive path assessment. For example, if a transmission line is de-rated, this increases the demand for counterflow used in the test. If a unit effective at providing counterflow is unavailable due to an outage, this decreases the supply of counterflow used in the test.

Figure 4.22 and Table 4.2 summarize results of the hourly residual supply index for non-candidate paths on which day-ahead congestion occurred in 2009. These paths were deemed non-competitive because they did not meet the 500 hours criteria used to determine candidate paths in the competitive path analysis. As shown in Figure 4.22, of the hours when congestion occurred in the day-ahead market on most of these paths, a significant portion of hours were uncompetitive based on the residual supply index. The very limited number of paths that were competitive in all hours had extremely low congestion. As shown in the summary totals in the bottom row of Table 4.2:

- During 53 percent of the hours when congestion occurred on these paths, the RSI_1 was less than 1, indicating a single supplier was pivotal.

[100] The tool being developed is based on the PROBE software developed by PowerGem, which is currently in use at several other ISOs.

- During an additional 7 percent of the hours when congestion occurred on these paths, the RSI_2 was less than 1, indicating two suppliers were jointly pivotal. Thus, during a total of 60 percent of the hours when congestion occurred on these paths, two suppliers were jointly pivotal.
- During an additional 4 percent of the hours when congestion occurred on these paths, the RSI_3 was less than 1, indicating three suppliers were jointly pivotal. Thus, three suppliers were jointly pivotal a total of 64 percent of the hours when congestion occurred on these paths.

Figure 4.23 and Table 4.3 summarize results of the hourly residual supply index for paths that met the 500 hour criteria used to determine candidate paths and were found to be competitive in the competitive path analysis. As shown in these results, virtually all of these paths were competitive under the residual supply index.

Results of this analysis indicate that although the current method of designating paths as competitive or non-competitive is not highly dynamic, this approach is reasonably accurate:

- Most paths deemed as being uncompetitive under the competitive path assessment methodology were structurally uncompetitive during a significant portion of hours when congestion occurred on these paths based on the residual supply index (see Figure 4.22).
- A very limited number of paths deemed non-competitive based on the competitive path assessment were structurally competitive in most or all hours based on residual supply index results. All of these paths had extremely low hours of congestion (see Figure 4.22).
- Paths designated as competitive using the competitive path assessment methodology were structurally competitive in most or all hours under actual operating conditions based on residual supply index results (see Figure 4.23).

The reasonableness of the current competitive path assessment approach should consider the actual consequences of deeming competitive constraints as non-competitive (or false alarms), compared to deeming non-competitive constraints as competitive (or the miss rate of the methodology).[101]

- ***False alarm —*** If a constraint that is competitive under actual market conditions is deemed non-competitive, this should have no or minimal impact on actual market results. Unless congestion occurs on this constraint, no bid mitigation is triggered. If bid mitigation is triggered, units may have their market bids limited to their default energy bids. Under competitive conditions, suppliers should submit bids reflective of their actual marginal costs. Thus, unless the default energy bid for a unit is less than the unit's actual marginal costs, there would be no detrimental market impact of mitigating a unit under this scenario. To date, no generator has expressed a concern to DMM that their default energy bid is lower than their actual marginal cost.
- ***Miss rate —*** If a constraint that is non-competitive under actual market conditions is deemed competitive, this could have significant detrimental market results. Under this scenario, if congestion occurs on this constraint, no bid mitigation is triggered. This can obviously result in uncompetitively high prices. As shown in Figure 4.22 and Table 4.2, during 53 percent of the hours when congestion occurred on paths deemed as uncompetitive, residual supply index results indicate

[101] In this context, a false alarm is used to describe a Type I error or false positive. A false alarm would be equivalent of deeming a competitive constraint as non-competitive. A Type II error, or miss rate, would be equivalent to deeming a non-competitive constraint as competitive.

that a single supplier was pivotal. This provides strong evidence that path designations should err on the side of minimizing the miss rate, even if this means increasing the rate of false positives.

As previously noted, one of the drawbacks of the competitive path assessment is that the process is time-consuming given the DMM's current modeling tools. DMM is currently developing an enhanced modeling tool that will significantly reduce the time needed to perform the competitive path assessment. This tool will also facilitate running the assessment using the actual network model and market inputs used by the market software. DMM will also continue to develop alternative approaches for assessing market competiveness such as the residual supply index used by other ISOs. DMM is also supporting development of potential approaches based on the residual demand curve facing individual suppliers, being discussed by the Market Surveillance Committee.[102]

Once tools for more dynamic assessment of the competitiveness of paths are in place, DMM intends to work with stakeholders to assess potential modifications to the current competitive path assessment methodology. Potential modifications are discussed below.

- ***Threshold for hours of congestion* —** The original rationale of the 500 hour threshold was twofold. First, this threshold was designed to ensure that the assessment of competitiveness was focused on constraints that were congested a significant percentage of hours. If a path that was less frequently congested is deemed as non-competitive by default, this does not have any negative market impacts in the event of a false positive, but would avoid the potentially significant cost of a false miss, as described above. With tools to quickly perform more dynamic assessment of the competitiveness of paths under actual operating conditions, more paths could be designated as competitive without risk of incorrectly designating a path as competitive that is non-competitive under actual conditions.

- ***Actual market conditions* —** If path competitiveness could be re-assessed under actual operating conditions, this would allow inclusion of generation and transmission outages. Similarly, competitiveness could be assessed based on supply bids actually submitted to the market by resources not subject to automated must-offer requirements.

- ***Three-pivotal supplier test* —** Residual supply index results summarized in Figure 4.22 and Table 4.2 show that there is a minimal difference in using a 2-pivotal supplier test rather than a 3-pivotal supplier test in assessing path competitiveness. Again, with tools to quickly perform more dynamic assessment of the competitiveness of paths under actual operating conditions, it may be possible to base the test on a 2-pivotal supplier test.

- ***Multiple tests* —** Since different tests for market power have different strengths and weaknesses, it may be possible to utilize multiple tests to determine path competitiveness. For example, it may be possible to supplement the competitive path assessment methodology with other structural tests for assessing path competiveness such as the residual supply approaches used by several other ISOs, or the residual demand curve being discussed by the Market Surveillance Committee.

[102] *Review and Possible Revision of California's Local Market Power Mitigation Mechanism*, presentation by Frank A. Wolak, March 19, 2009 Market Surveillance Committee Meeting. http://www.caiso.com/275e/275e80143630.pdf

Figure 4.22 Residual supply index - Non-candidate paths in 2009

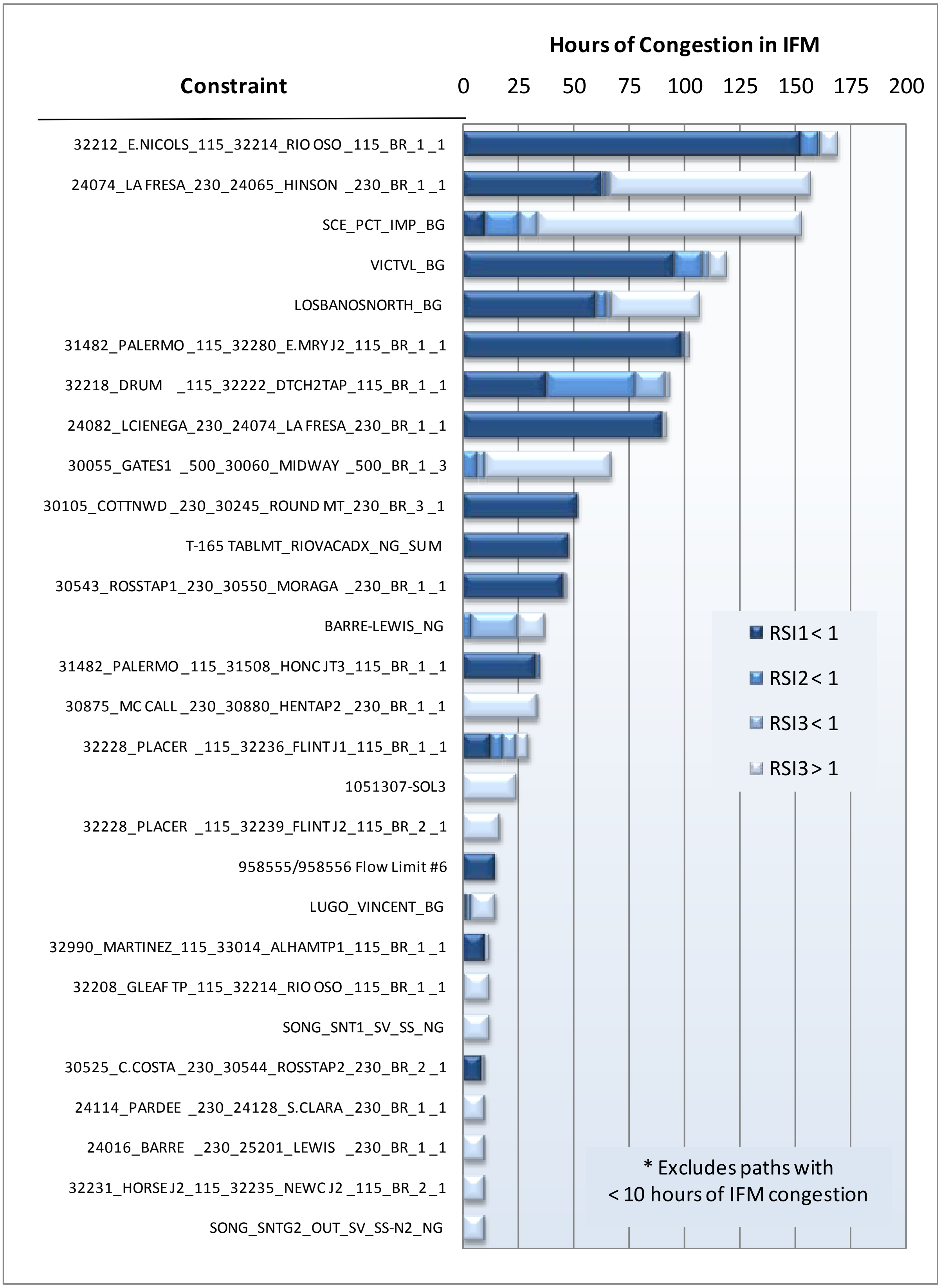


Table 4.2 Summary of RSI results - Non-candidate paths in 2009

Constraint_Name	Congest. Hours	$RSI_1 < 1$ Hours	%	$RSI_2 < 1$ Hours	%	$RSI_3 < 1$ Hours	%	$RSI_3 > 1$ Hours	%
32212_E.NICOLS_115_32214_RIO OSO _115_BR_1 _1	169	152	90%	8	5%	1	1%	8	5%
24074_LA FRESA_230_24065_HINSON _230_BR_1 _1	157	63	40%	2	1%	1	1%	91	58%
SCE_PCT_IMP_BG	153	10	7%	16	10%	8	5%	119	78%
VICTVL_BG	119	95	80%	13	11%	3	3%	8	7%
LOSBANOSNORTH_BG	107	60	56%	5	5%	2	2%	40	37%
31482_PALERMO _115_32280_E.MRY J2_115_BR_1 _1	102	99	97%	1	1%	0	0%	2	2%
32218_DRUM _115_32222_DTCH2TAP_115_BR_1 _1	93	38	41%	40	43%	13	14%	2	2%
24082_LCIENEGA_230_24074_LA FRESA_230_BR_1 _1	92	90	98%	0	0%	0	0%	2	2%
30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3	67		0%	7	10%	3	4%	57	85%
30105_COTTNWD _230_30245_ROUND MT_230_BR_3 _1	52	52	100%	0	0%	0	0%	0	0%
T-165 TABLMT_RIOVACADX_NG_SUM	48	48	100%	0	0%	0	0%	0	0%
30543_ROSSTAP1_230_30550_MORAGA _230_BR_1 _1	47	45	96%	1	2%	0	0%	1	2%
BARRE-LEWIS_NG	37		0%	4	11%	21	57%	12	32%
31482_PALERMO _115_31508_HONC JT3_115_BR_1 _1	35	33	94%	2	6%	0	0%	0	0%
30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1	34		0%	0	0%	0	0%	34	100%
32228_PLACER _115_32236_FLINT J1_115_BR_1 _1	30	13	43%	5	17%	6	20%	6	20%
1051307-SOL3	24		0%	0	0%	0	0%	24	100%
32228_PLACER _115_32239_FLINT J2_115_BR_2 _1	17		0%	0	0%	0	0%	17	100%
958555/958556 Flow Limit #6	15	15	100%	0	0%	0	0%	0	0%
LUGO_VINCENT_BG	15	1	7%	1	7%	2	13%	11	73%
32990_MARTINEZ_115_33014_ALHAMTP1_115_BR_1 _1	12	10	83%	0	0%	0	0%	2	17%
32208_GLEAF TP_115_32214_RIO OSO _115_BR_1 _1	12		0%	1	8%	0	0%	11	92%
SONG_SNT1_SV_SS_NG	12		0%	0	0%	0	0%	12	100%
30525_C.COSTA _230_30544_ROSSTAP2_230_BR_2 _1	10	9	90%	0	0%	0	0%	1	10%
24114_PARDEE _230_24128_S.CLARA _230_BR_1 _1	10		0%	0	0%	0	0%	10	100%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	10		0%	0	0%	0	0%	10	100%
32231_HORSE J2_115_32235_NEWC J2 _115_BR_2 _1	10		0%	0	0%	0	0%	10	100%
SONG_SNTG2_OUT_SV_SS-N2_NG	10		0%	0	0%	0	0%	10	100%
32200_PEASE _115_31506_HONC JT1_115_BR_1 _1	9	7	78%	0	0%	0	0%	2	22%
30005_ROUND MT_500_30015_TABLE MT_500_BR_1 _2	9	4	44%	2	22%	0	0%	3	33%
22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80	9		0%	0	0%	0	0%	9	100%
30550_MORAGA _230_30554_CASTROVL_230_BR_1 _1	8	8	100%	0	0%	0	0%	0	0%
35122_NWARK EF_115_35350_AMES BS _115_BR_2 _1	8	8	100%	0	0%	0	0%	0	0%
32990_MARTINEZ_115_33016_ALHAMTP2_115_BR_1 _1	8	2	25%	0	0%	0	0%	6	75%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	8		0%	0	0%	0	0%	8	100%
33010_SOBRANTE_115_30540_SOBRANTE_230_XF_1	7	4	57%	1	14%	0	0%	2	29%
24156_VINCENT _500_24155_VINCENT _230_XF_1 _P	7		0%	0	0%	0	0%	7	100%
30900_GATES _230_30970_MIDWAY _230_BR_1 _1	7		0%	0	0%	0	0%	7	100%
30525_C.COSTA _230_30565_BRENTWOD_230_BR_1 _1	7		0%	0	0%	1	14%	6	86%
24807_MIRAGE _115_24819_CONCHO _115_BR_1 _1	6	6	100%	0	0%	0	0%	0	0%
1030579_SONG_SNT2_OUT_NG	6	6	100%	0	0%	0	0%	0	0%
32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1	6		0%	0	0%	3	50%	3	50%
MARTIN_115KV_BUS_D_OUT_NG	6		0%	0	0%	0	0%	6	100%
1021973_SONGS_SNTG1_OUT_NG	6		0%	0	0%	0	0%	6	100%
30250_CARIBOU _230_30261_BELDENTP_230_BR_1 _1	5	1	20%	4	80%	0	0%	0	0%
VINCNT_BNKS_14_NG	5		0%	0	0%	0	0%	5	100%
958555/958556 Flow Limit #5	5		0%	0	0%	0	0%	5	100%
30970_MIDWAY _230_30060_MIDWAY _500_XF_13_S	5		0%	0	0%	0	0%	5	100%
32290_OLIVH J1_115_32214_RIO OSO _115_BR_1 _1	4	4	100%	0	0%	0	0%	0	0%
SC-VNCT_OUT_DA_NG	4		0%	0	0%	0	0%	4	100%
SOUTHLUGO_RV_BG	4		0%	0	0%	0	0%	4	100%
30525_C.COSTA _230_30543_ROSSTAP1_230_BR_1 _1	3	3	100%	0	0%	0	0%	0	0%
1030582_SONG_SNT1_SV_SS_NG	3		0%	0	0%	0	0%	3	100%
32950_PITSBURG_115_32970_CLAYTN _115_BR_4 _1	3		0%	0	0%	0	0%	3	100%
30790_PANOCHE _230_30900_GATES _230_BR_1 _1	2	1	50%	0	0%	1	50%	0	0%
24156_VINCENT _500_24155_VINCENT _230_XF_4 _P	2		0%	0	0%	0	0%	2	100%
31962_WDLND_BM_115_31970_WOODLD _115_BR_1 _1	2		0%	0	0%	0	0%	2	100%
SONG_SNT2_OUT_NG	2		0%	0	0%	0	0%	2	100%
30060_MIDWAY _500_24156_VINCENT _500_BR_3 _2	2		0%	0	0%	0	0%	2	100%
1042543 - NG1	2		0%	0	0%	0	0%	2	100%
34713_OGLE TAP_115_34784_CAWELO C_115_BR_1 _1	2		0%	0	0%	0	0%	2	100%
33310_SANMATEO_115_33315_RAVENSWD_115_BR_1 _1	1	1	100%	0	0%	0	0%	0	0%
30790_PANOCHE _230_30900_GATES _230_BR_2 _1	1	1	100%	0	0%	0	0%	0	0%
SONGS_SNTG2_OUT_NG	1		0%	0	0%	0	0%	1	100%
1030582_SONG_SNT1_OUT_NG	1		0%	0	0%	0	0%	1	100%
99106_SAN-MAR1_230_99104_MAR-SAN1_230_BR_1 _3	1		0%	0	0%	0	0%	1	100%
24155_VINCENT _230_24401_ANTELOPE_230_BR_1 _1	1		0%	0	0%	0	0%	1	100%
1030581_SONG_SNT1_OUT_NG	1		0%	0	0%	0	0%	1	100%
1031184_NG1	1		0%	0	0%	1	100%	0	0%
22430_SILVERGT_230_22466_MLMS3TAP_230_BR_1 _1	1		0%	0	0%	0	0%	1	100%
Totals	**1,680**	**889**	**53%**	**113**	**7%**	**66**	**4%**	**612**	**36%**

Figure 4.23 Residual supply index - Competitive paths in 2009

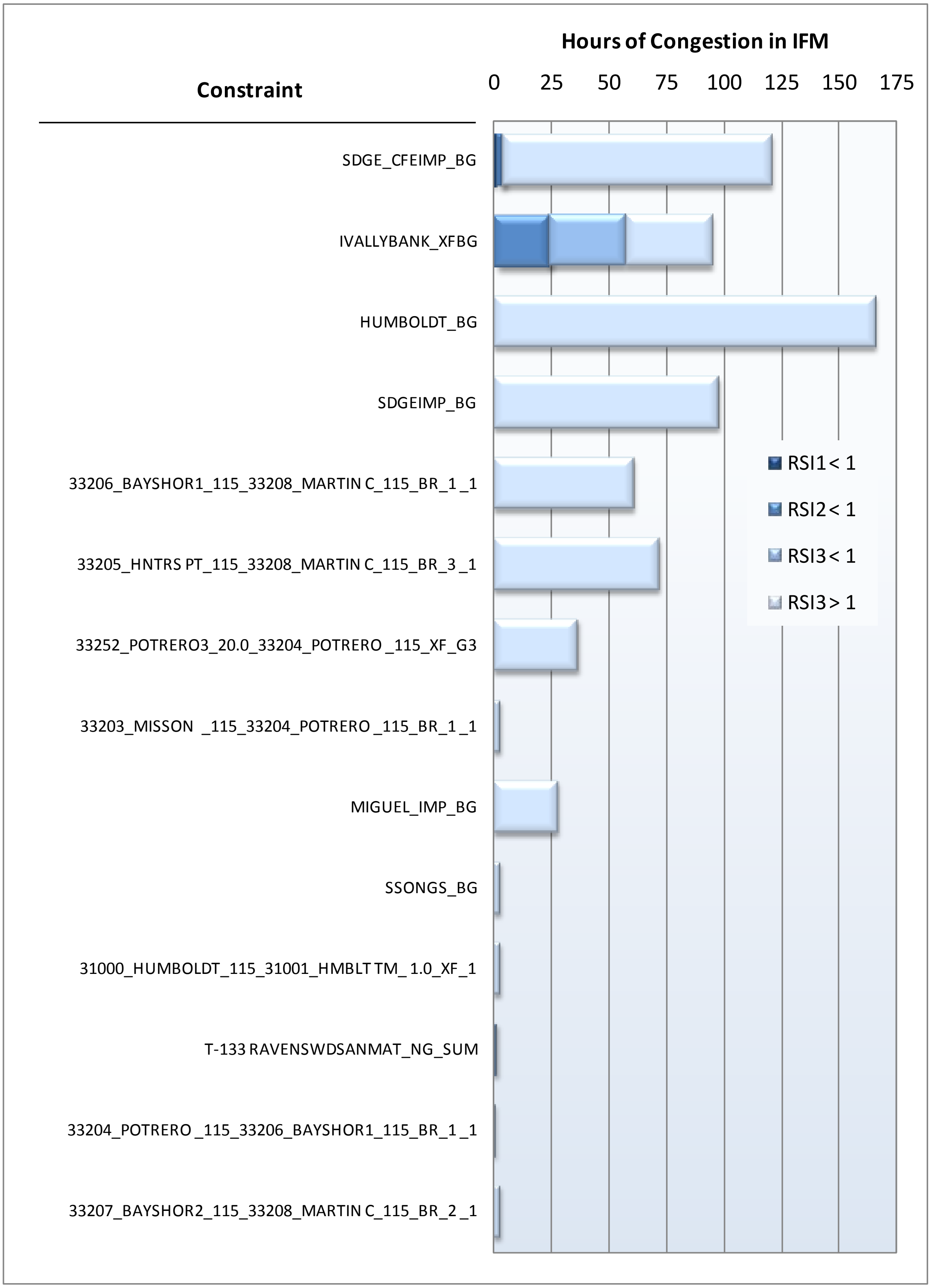


Table 4.3 Summary of RSI results - Non-candidate paths in 2009

Constraint Name	Congestion Hours	$RSI_1 < 1$		$RSI_2 < 1$		$RSI_3 < 1$		$RSI_3 > 1$	
		Hours	%	Hours	%	Hours	%	Hours	%
SDGE_CFEIMP_BG	121	1	1%	3	2%	0	0%	117	97%
IVALLYBANK_XFBG	95		0%	24	25%	33	35%	38	40%
HUMBOLDT_BG	166		0%	0	0%	0	0%	166	100%
SDGEIMP_BG	98		0%	0	0%	0	0%	98	100%
33206_BAYSHOR1_115_33208_MARTIN C_115_BR_1 _1	61		0%	0	0%	0	0%	61	100%
33205_HNTRS PT_115_33208_MARTIN C_115_BR_3 _1	72		0%	0	0%	0	0%	72	100%
33252_POTRERO3_20.0_33204_POTRERO _115_XF_G3	37		0%	0	0%	0	0%	37	100%
33203_MISSON _115_33204_POTRERO _115_BR_1 _1	3		0%	0	0%	0	0%	3	100%
MIGUEL_IMP_BG	28		0%	0	0%	0	0%	28	100%
SSONGS_BG	3		0%	0	0%	0	0%	3	100%
31000_HUMBOLDT_115_31001_HMBLT TM_ 1.0_XF_1	3		0%	0	0%	0	0%	3	100%
T-133 RAVENSWDSANMAT_NG_SUM	2		0%	0	0%	1	50%	1	50%
33204_POTRERO _115_33206_BAYSHOR1_115_BR_1 _1	1		0%	0	0%	0	0%	1	100%
33207_BAYSHOR2_115_33208_MARTIN C_115_BR_2 _1	3		0%	0	0%	0	0%	3	100%
Totals	**693**	**1**	**0%**	**27**	**4%**	**34**	**5%**	**631**	**91%**

5 Congestion management

This chapter provides a review of congestion in 2009 and examines major sources of congestion under the new market design, the impact of congestion on prices in the day-ahead market, and the consistency of congestion between the day-ahead and real-time markets. This chapter also reviews the market for congestion revenue rights.

5.1 Summary

The frequency of congestion and the impact of congestion on prices were relatively low in 2009 under the new market.

- ***Day-ahead congestion on inter-ties* —** The frequency of congestion on inter-ties with other regions was significantly lower in 2009 than in 2008. This is clearly attributable in part to the reduction in imports in 2009. Improved congestion management under the market design may have also contributed to decreased congestion. Figure 5.2 provides a comparison of the hours of day-ahead congestion during the months of April through December in 2008 and 2009.[103]
- ***Day-ahead congestion on internal constraints* —** The frequency of day-ahead congestion on constraints within the ISO was also relatively low under the new market design. In some cases, congestion had a significant impact on prices in the different load aggregation points during hours of congestion. However, since the frequency of this internal congestion was relatively low, this had a minimal impact on overall day-ahead energy prices over the nine months of the new market design. More detailed analysis of this issue is provided in Section 5.4 of this chapter.
- ***Real-time congestion* —** The frequency of congestion in the real-time market on many constraints tended to be higher than in the day-ahead market. This can occur for several reasons, ranging from increased demand in real-time, and discrepancies in modeled flows and actual flows observed in real-time due to loop flows and other sources of modeling inaccuracies. However, the overall frequency of real-time congestion was still relatively low on all internal and external constraints. While real-time congestion sometimes resulted in very high prices, the overall cost impact of this congestion was very low due to the high level of day-ahead scheduling. Section 5.5 of this chapter provides a detailed analysis of the consistency of congestion between the day-ahead and real-time markets. Section 5.6 provides an analysis of how constraint limits were adjusted or conformed by grid operators to account for differences in flows calculated by the market model and actual flows observed in real-time.

The relatively low level of congestion under the new market design may be attributable to a combination of factors. As discussed in previous chapters, internal load and supply conditions were generally favorable in 2009. Bidding of generation within transmission constrained load pockets was also highly competitive. Improved congestion management under the market design may have also contributed to the limited congestion. As noted in previous chapters, about 98 percent of total forecast demand was scheduled in the day-ahead market. In the day-ahead market, the supply of resources that

[103] It is difficult to make direct comparisons between the costs of congestion on these inter-ties under the prior congestion management process in 2008 and the new market design in 2009. Additional discussion and analysis of this is provided in Sections 5.1 and 5.3 of this chapter.

can be used to most efficiently meet load and manage congestion is typically much greater and more flexible than in real-time. Thus, high day-ahead scheduling allows for more efficient unit commitment, scheduling and congestion management.

5.2 Background

Congestion occurs when the physical limits of a constraint are binding and prohibit additional electricity to flow. This also prevents load from being served with the least cost energy. The impact analysis of congestion on energy prices identifies:

- Market signals for valuation of potential transmission enhancements that may have a significant effect on revenues earned by suppliers and costs paid by load-serving entities. These enhancements can mitigate the impact of the congestion on energy prices.
- Congestion constrained areas that may be uncompetitive in congested periods and possibly be impacted to a much greater degree by congestion in terms of market revenues and costs.

Prior congestion management process

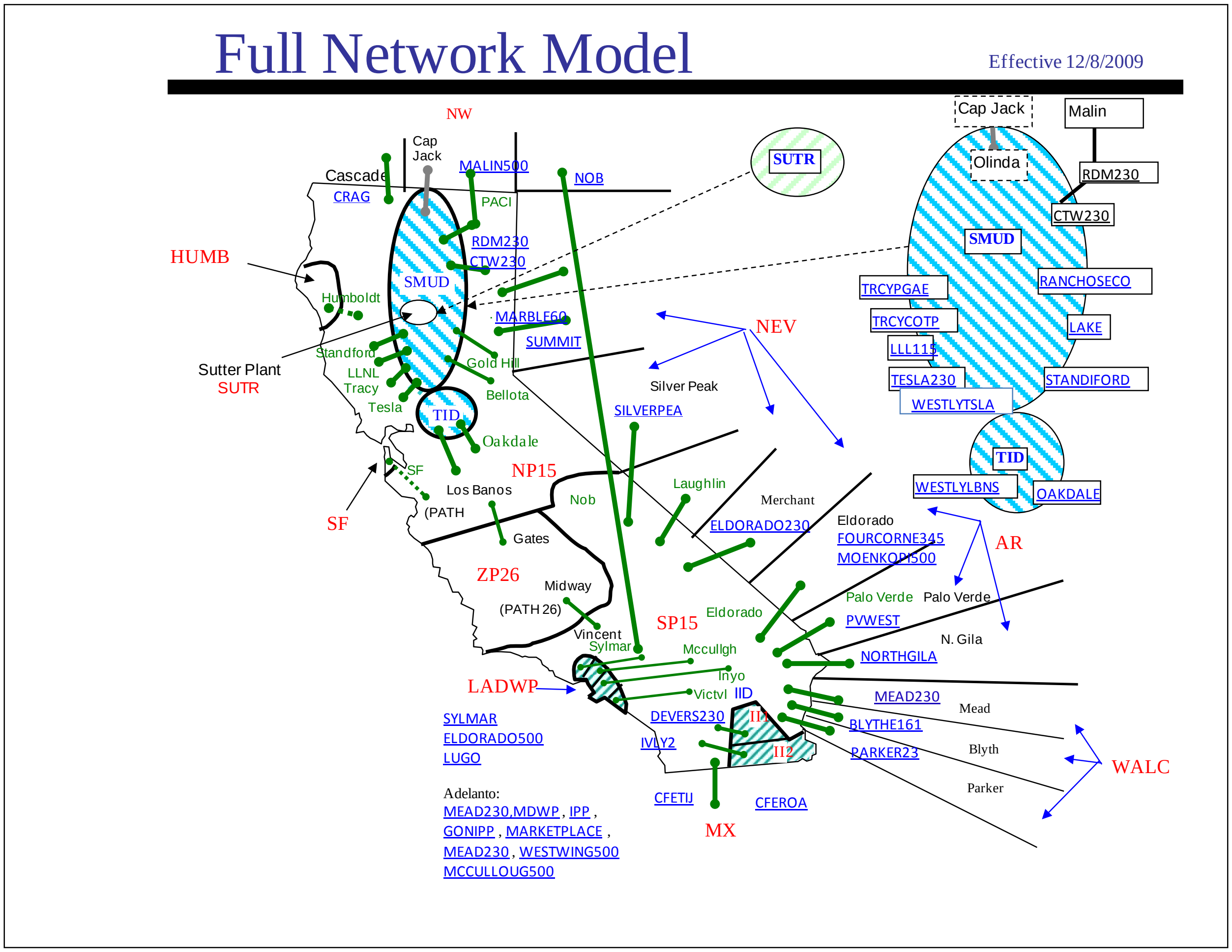
Prior to April 2009, the ISO employed a zonal market design to manage the grid, which distinguished between inter-zonal and intra-zonal congestion. Inter-zonal congestion refers to congestion that occurs between zones. Intra-zonal congestion refers to congestion within a zone. Under the prior zonal model, the ISO managed inter-zonal congestion in the day-ahead and hour-ahead processes only on major inter-ties and two large internal paths, Path 15 and Path 26. Figure 5.1 shows the active congestion zones and major inter-zonal pathways (branch groups) in the grid effective December 8, 2009. There were no operational changes in 2009.

The prior congestion management market used adjustment bids to mitigate congestion. The congestion management algorithm minimized the cost of adjustment bids accepted to manage congestion. However, any adjustment bids accepted from scheduling coordinators' portfolios were required to keep the loads and supply in the portfolio in balance. In other words, if an adjustment bid to reduce an import was accepted, this had to be balanced by accepting an adjustment bid to reduce the scheduling coordinator's load or exports by an equal amount. This constraint represented a significant source of potential inefficiency in the prior congestion management process.

Under the prior design, the usage charge for the inter-zonal interface was set by the marginal adjustment bids used to manage congestion on the inter-tie. When congestion occurred in the import direction, all import schedules were required to pay this explicit usage charge based on the final scheduled flow from their interface schedule. Schedules in the opposite direction of any congestion were paid the usage charge for this counterflow. The net collected amount of congestion charges was paid to the transmission owners and owners of firm transmission rights.

Under the prior market design, grid operators managed intra-zonal congestion within the ISO zones by manually dispatching resources to increase or decrease output. This was referred to as out-of-sequence dispatch. This form of congestion management was not priced in a transparent fashion, because intra-zonal congestion was managed outside the market.

Figure 5.1 Active congestion zones and branch groups



New congestion management process

Under the new nodal market design, congestion of inter-zonal and intra-zonal flowgates is managed in the day-ahead integrated forward market, hour-ahead scheduling process and 5-minute real-time dispatch market. With locational marginal pricing, the price attributed to congestion is implicit in the energy prices and applied to supply or load at the pricing point. The impact of all congestion during each pricing interval on the price of energy at a location is calculated and reported as a component of the overall price at that location.

When there is no physical limit on a transmission path the market software will dispatch energy to serve load using the least-cost energy bids system-wide. Limited transmission capacity (or congested constraints) prevent the market from moving electricity freely across the grid and requires dispatch of costlier energy to meet load.

When a constraint is binding, the market software produces a shadow price on that constraint that represents the system-wide cost savings that would occur if that constraint had one additional megawatt of transmission capacity available in the congested direction. However, this shadow price is not directly charged to participants. The shadow price is only an indication of the incremental impact on the objective function of the market software of the limited transmission on the binding constraint.

The additional cost of meeting load is also reflected in the congestion component of the LMP. The congestion component of locational marginal pricing is calculated and reported based on the aggregate impact of all binding constraints at that location. When multiple constraints are binding, this congestion component does not provide any indication of impact that any individual constraint is having on that LMP. In many cases, one or more binding constraints have a positive impact on the congestion component of the LMP, while one or more other constraints have a negative impact.

The impact of individual binding constraints on prices at any point can be determined by multiplying the shadow price of the binding constraint by the shift factor relating to the pricing point and the constraint. The methodology for this calculation for load aggregation points and prices within local capacity areas is presented in Appendix A. Section 5.4 of this report provides an analysis of the impact of different constraints on prices using this methodology.

Under the new market, constraints are categorized as either internal or external. Congestion on these constraints impact prices within the ISO area in different ways. The following sections provide an analysis of the frequency and impacts of congestion on external and internal constraints under the new market design.

5.3 External congestion

The congestion frequency on inter-ties with other regions was significantly lower in 2009 than in 2008. This may be largely attributable to the reduction in imports in 2009. Figure 5.2 provides a comparison of the hours of day-ahead congestion on major inter-ties during the months of April through December in 2008 and 2009. Table 5.1 provides a comparison of congested hours on a more complete list of inter-ties in the day-ahead market over this period.

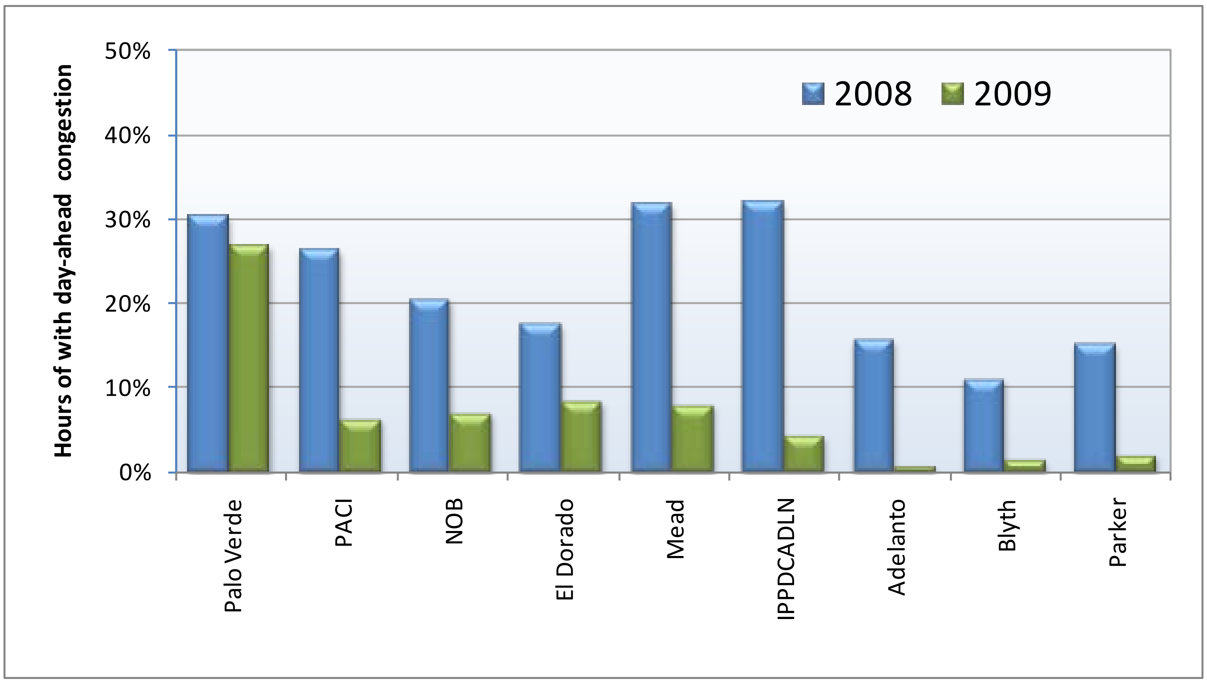
Another way of looking at the impact of congestion on the inter-ties is the difference between the price load pays inside the control area (the load aggregation point LMP) and the lower price paid for supply at the inter-tie. From the perspective of a load-serving entity seeking to import power over a congested tie point to meet load, this difference represents the increase in price incurred per megawatt hour due to congestion. From the perspective of a supplier, this price represents the decrease in the price received for any imports. The difference between the load aggregation point LMPs and the inter-tie price reflects the willingness to pay for additional transmission. This price difference most closely represents the congestion charge for imports under the prior congestion management process. However, it should be noted that this price difference may not be indicative of the impact of congestion on prices within the ISO and the cost to serve system load.[104]

[104] When an inter-tie is binding the import of less-expensive power is restricted. Higher-priced bids for imports across another non-congested inter-tie or internal resources will be dispatched. During many hours, there is a competitive pool of bids across the many inter-ties. Under this scenario, if a smaller subset of inter-ties is congested, similarly priced bids from the non-congested inter-ties may be dispatched. In this case, congestion on an inter-tie may have a relatively low impact on prices within the ISO.

Table 5.1 provides a comparison of this price difference under the new market design with the average congestion charge for imports under the prior day-ahead congestion management process. The inter-ties are arranged by the load aggregation point into which they are connected. For 2008, the average congestion charge category is the explicit charges from the day-ahead congestion management market under the prior market. The values for 2009 represent the average difference between the load aggregation point and the inter-tie LMPs in hours where there was congestion on that inter-tie. Each of these values reflects the average congestion charge or cost that would be incurred for importing 1 MW each hour on the tie point over the months of April to December.

As previously noted, the frequency of congestion at the inter-ties declined significantly compared to 2008. The average congestion charge during congested hours on major tie-points increased. The negative average difference for the Silver Peak inter-tie is attributable to a few hours of congestion in the external direction with extremely high prices.[105]

Figure 5.2 Hours of congestion on major inter-ties in 2008 and 2009 (April – December)



105 On August 6, there were several hours where this inter-tie was congested with an external LMP at the inter-tie of more than $400/MWh and an internal load aggregation point LMP less than $40/MWh. The difference during these few hours was significant enough to drive the annual average difference for this inter-tie to be negative (the inter-tie was only congested in one percent of hours). The average congestion charge, or price difference, in the non-extreme hours was about $30/MWh.

Table 5.1 Frequency of congestion and average congestion charge (April – December)

Import LAP	Inter-tie	Hours of congestion 2008	Hours of congestion 2009	Average congestion charge 2008	Average congestion charge 2009
PG&E	NOB	21%	7%	$15.0	$12.9
	PACI	26%	6%	$8.8	$9.7
	SILVERPK	1%	1%	$0.4	-$31.7
	SUMMIT	3%	6%	$6.0	$25.9
SCE	ADLANTOSP	16%	1%	$2.9	$9.5
	BLYTHE	11%	1%	$13.1	$15.4
	ELDORADO	18%	8%	$9.9	$13.1
	IID-SCE	1%		$4.6	$9.4
	IPPDCADLN	32%	4%	$9.2	N/A
	MEAD	32%	8%	$4.1	$15.1
	MERCHANT	3%		$0.9	
	MKTPCADLN	4%	0.1%	$5.4	N/A
	MONAIPPDC	1%	3%	-$0.3	N/A
	PALOVRDE	30%	27%	$4.0	$17.4
	PARKER	15%	2%	$21.1	$28.3
	TRACYCOTP	3%		$3.8	
	WSTWGMEAD	4%	0.4%	$7.4	N/A

5.4 Internal congestion

When an internal constraint is congested, resources on either side of the constraint are dispatched to maintain flows under the constraint limit and still meet load. This requires higher-priced bids to be dispatched on the constrained side of the transmission path where more power is needed and results in higher prices on that side of the constraint.

In these circumstances, there is a clear and direct relationship between the congested transmission constraint and the prices on either side of that constraint. The impact of individual binding constraints on prices at any point can be determined by multiplying the shadow price of the binding constraint by the shift factor relating to the pricing point and the constraint. The methodology for this calculation for both load aggregation points and prices within local capacity areas is presented in Appendix A.

Figure 5.3 shows the impact congestion on specific internal constraints had on average day-ahead LMPs for the three load aggregation points during the hours when congestion occurred. Constraints shown in Figure 5.3 include the most frequently congested internal flowgates and nomograms in the day-ahead market.

Table 5.2 provides a more detailed summary of this analysis calculated quarterly.[106] Table 5.3 includes the impact of congested constraints on LMPs at generation nodes within different local capacity areas in each load aggregation point. The average impact of a constraint on a price across all hours is also shown. This provides a better indication of the overall cost of congestion on load scheduled in the day-ahead market. When averaged across all hours, the impact of congestion is negligible because of the very low frequency of congestion in the day-ahead market.

As shown in Table 5.2 and Table 5.3, congestion on some constraints had a significant impact on prices in the different load aggregation points during hours of congestion. However, since the frequency of this internal congestion was relatively low, this had a minimal impact on overall day-ahead energy prices over the nine months of the new market design. Other findings include:

- Congestion on the Path 15 branch group had the highest impact on PG&E's load aggregation point prices. In Q2 2009, the impact was almost $4/MWh during congested hours. In Q3, the week-long outage on Los Baños-Midway #2 500 kV created congestion on Gates-Midway 500 kV line, which had an impact on the PG&E load aggregation point price of roughly $2.5/MWh in congested hours.

- Starting November 11, the ISO began enforcing the SCE import percent branch group limit. This is a constraint on the total volume of imports as a percentage of load into SCE territory.[107] The impact of this constraint on the SCE load aggregation point LMPs during hours this constraint was binding averaged $5.79/MWh.

- SDG&E CFE import branch group was congested heavily in April and May with monthly average shadow values of $19/MW and $5/MW, respectively. In Q2, the impact of this congestion on the SDG&E load aggregation point LMP was $7.57/MWh when the constraint was binding. The SDG&E import branch group also had significant impact on the SDG&E load aggregation point LMPs. These averaged $7.03/MWh and $2.55/MWh for the second and third quarters, respectively.

- In several of the local capacity areas within the PG&E area, the impact of the congestion is very localized and is measured on only a few generating nodes. Constraints generally have different impacts on local capacity areas within the load aggregation point in which the constraint is located. Constraints generally have the same impact on local capacity areas within a different load aggregation point.

- Congestion on some of the major flowgates physically separating the north zone from the south zone (such as Path 15, Path 26, and the Los Baños branch group) have direct impact on the energy prices in the north and south. For example, congestion on Path 26 from north-to-south results in constrained import into the south. This requires more expensive energy to be dispatched to meet load in the south. This also allows less expensive energy to be dispatched in the north since demand for energy from that zone decreased by the limited flows to the south on Path 26. This reflects an absolute impact on prices in the two zones.

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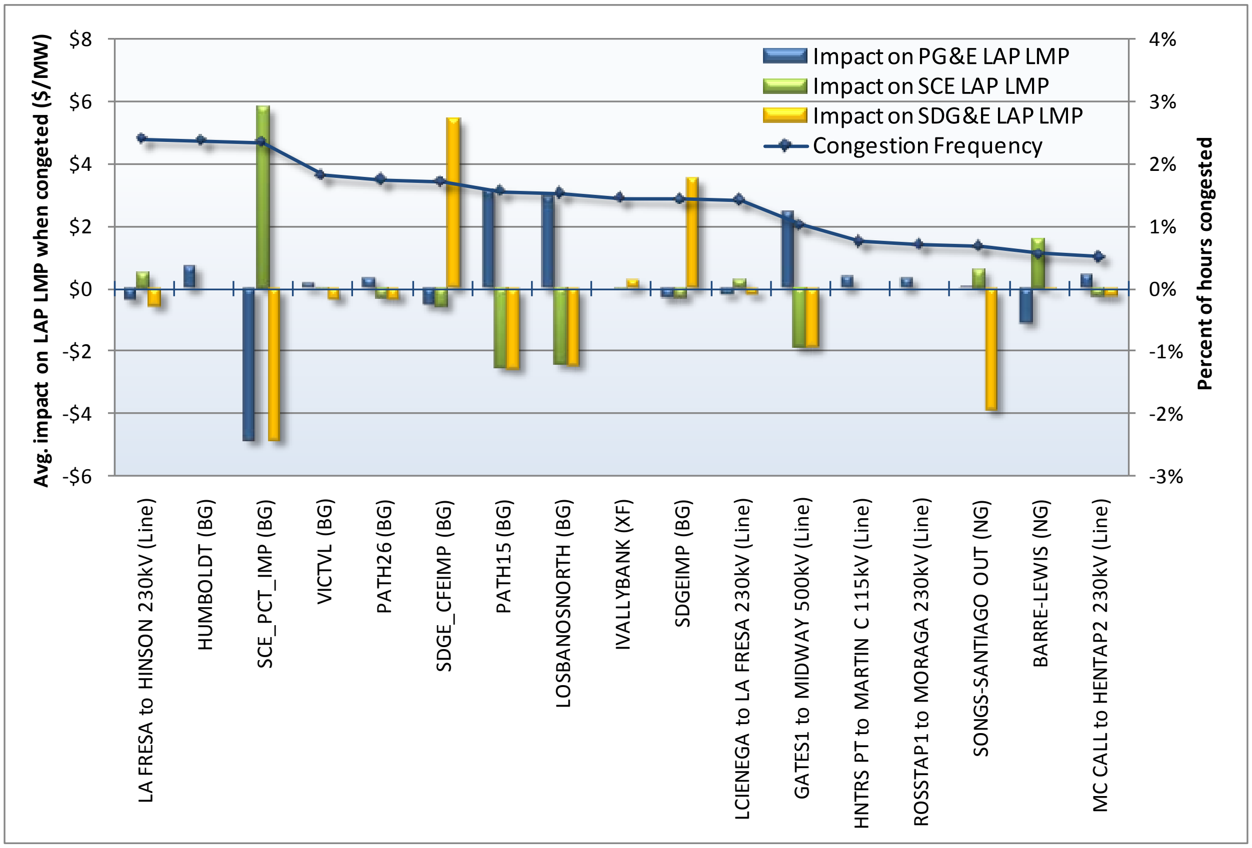
[106] Constraints listed in these tables are those that had a significant impact on load aggregation point LMPs. Specifically, these constraints were binding in the day-ahead market for at least 10 hours and the average impact on the load aggregation point LMP was at least $0.75.

[107] A technical bulletin was posted on December 1, 2009. See http://www.caiso.com/2479/247997c52e0f0.pdf.

Figure 5.3 Frequency of congestion on internal constraints (April – December 2009)



The calculations for the impact of congestion on both internal and inter-tie constraints have been represented in terms of impact on prices, rather than overall costs. Calculating the impact of congestion on cost to load requires selecting an accurate quantity that was exposed to the price impacts. Not all energy cleared in the market is exposed to these price impacts. In addition to financial hedges through congestion revenue rights, a significant portion of load is met through long-term and short-term forward contracts and generation owned by load-serving entities. In these cases it is not clear to what extent the price impacts from congestion have impacted the cost to serve this load. Using all load cleared at a price or all scheduled flow across an inter-tie without adjusting for these factors would grossly overstate the cost impact. For this reason, we have focused the analysis on the price impact during hours of congestion.

Table 5.2 Impact of congestion on day-ahead LMPs by load aggregation point

		Binding Hours			Q2			Q3			Q4		
Area	Constraint Name	Q2	Q3	Q4	PGAE	SCE	SDGE	PGAE	SCE	SDGE	PGAE	SCE	SDGE
PG&E	1051307-SOL3 (Potrero - Larkin 115 kV Outage) (NG)			24							$0.91		
	GATES1 to MIDWAY 500kV (Line)		64					$2.48	-$1.91	-$1.91			
	HUMBOLDT (BG)			29							$1.02		
	LOSBANOSNORTH (BG)	22	21	63	$0.47	-$2.90	-$2.90	$1.45	-$1.11	-$1.11	$3.93	-$3.30	-$3.30
	PATH15 (BG)	44	34	24	$3.97	-$3.36	-$3.36	$2.79	-$2.13	-$2.13	$2.16	-$1.75	-$1.75
	PATH26 (BG)	54		63	-$0.48	-$1.09	-$1.09				$1.97	-$1.67	-$1.67
SCE	BARRE-LEWIS (NG)			37							-$1.14	$1.56	-$0.19
	SCE_PCT_IMP (BG)			153							-$4.85	$5.79	-$4.85
	SONGS-SANTIAGO OUT (NG)		12					$0.32	$0.52	-$4.06			
SDGE	MIGUEL_IMP (BG)		19					-$0.32	-$0.17	$2.35			
	SDGE_CFEIMP (BG)	91	21		-$0.71	-$0.71	$7.57	-$0.17	-$0.17	$1.65			
	SDGEIMP (BG)	21	70		-$0.69	-$0.69	$7.03	-$0.27	-$0.27	$2.55			

Table 5.3 Impact of congestion on day-ahead LMPs in local capacity areas

Flowgate Name	Congested Hours	Average Shadow Value	PG&E Local Congested Area									SCE Local Congested Area				
			Bay Area	Stockton	Fresno	Humboldt	Kern	NCNB	Sierra	No LCA	PG&E LAP	Big Creek-Ventura	LA Basin	No LCA	SCE LAP	SDGE LAP
PG&E Constraints																
SPRNG GJ to MI-WUK 115kV (Line)	10.5%	$8		-$7.82												
HUMBOLDT (BG)	2.4%	$66				$71.38					$0.74					
E.NICOLS to RIO OSO 115kV (Line)	2.2%	$242		$2.10		-$10.20			$1.60	-$10.13	$0.06					
PATH15 (BG)	1.6%	$7	$4.02	$4.02	$3.34	$4.02	-$2.56	$4.02	$4.02	-$1.52	$3.15	-$2.57	-$2.57	-$2.57	-$2.57	-$2.57
PALERMO to E.MRY J2 115kV (Line)	1.5%	$77	$0.00	$1.98		-$4.60			$2.15	-$3.65	$0.16					
LOSBANOSNORTH (BG)	1.5%	$10	$4.65	$4.77	-$1.02	$5.03	-$2.39	$4.85	$4.78	-$1.21	$2.94	-$2.45	-$2.45	-$2.45	-$2.45	-$2.45
DRUM to DTCH2TAP 115kV (Line)	1.4%	$30							-$30.24		-$0.07					
GATES1 to MIDWAY 500kV (Line)	1.0%	$7	$3.00	$2.96	$2.50	$3.00	-$1.45	$3.00	$2.98	$0.04	$2.45	-$1.89	-$1.89	-$1.89	-$1.89	-$1.89
BAYSHOR1 to MARTIN C 115kV (Line)	0.9%	$11	$4.61								$0.15					
COTWDPGE to WHEELBR 115kV (Line)	0.8%	$59								-$59.09	-$0.03					
COTTNWD to ROUND MT 230kV (Line)	0.8%	$137				$3.55		$1.08	-$1.42	-$3.61	$0.05					
HNTRS PT to MARTIN C 115kV (Line)	0.8%	$30	$8.79								$0.40					
ROSSTAP1 to MORAGA 230kV (Line)	0.7%	$25	-$1.01	-$0.67		-$0.03		$0.79		-$0.59	$0.37					
MC CALL to HENTAP2 230kV (Line)	0.5%	$15			$2.65		-$0.35			-$0.33	$0.45	-$0.27	-$0.27	-$0.27	-$0.27	-$0.27
SCE Constraints																
LA FRESA to HINSON 230kV (Line)	2.4%	$16	-$0.36	-$0.36	-$0.36	-$0.36	-$0.36	-$0.36	-$0.36	-$0.36	-$0.36	-$0.30	-$0.06	-$0.42	$0.50	-$0.56
SCE_PCT_IMP (BG)	2.3%	$11	-$4.85	-$4.85	-$4.85	-$4.85	-$4.85	-$4.85	-$4.85	-$4.85	-$4.85	$5.79	$5.79	$5.79	$5.79	-$4.85
PATH26 (BG)	1.7%	$5	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	-$0.33	-$0.33	-$0.33	-$0.33	-$0.33
LCIENEGA to LA FRESA 230kV (Line)	1.4%	$8	-$0.19	-$0.19	-$0.19	-$0.19	-$0.19	-$0.19	-$0.19	-$0.19	-$0.19	-$0.19	-$0.14	-$0.19	$0.27	-$0.19
SONGS-SANTIAGO OUT (NG)	0.7%	$24			$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04	$0.47	-$1.18	-$0.13	$0.58	-$3.88
BARRE-LEWIS (NG)	0.6%	$24	-$1.09	-$1.09	-$1.09	-$1.09	-$1.09	-$1.09	-$1.09	-$1.09	-$1.09	$1.75	$1.25	-$2.62	$1.56	-$0.05
SDGE Constraints																
VICTVL (BG)	1.8%	$5	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	-$0.15	-$0.27	-$0.26	-$0.06	-$0.35
SDGE_CFEIMP (BG)	1.7%	$12	-$0.48	-$0.48	-$0.48	-$0.48	-$0.48	-$0.48	-$0.48	-$0.48	-$0.52	-$0.57	-$0.57	-$0.57	-$0.58	$5.45
IVALLYBANK (XF)	1.4%	$7											$0.15		-$0.01	$0.28
SDGEIMP (BG)	1.4%	$4	-$0.32	-$0.32	-$0.32	-$0.32	-$0.32	-$0.32	-$0.32	-$0.32	-$0.32	-$0.32	-$0.32	-$0.32	-$0.32	$3.53

5.5 Consistency of congestion

The coincidence of congestion between the day-ahead and real-time markets is a possible indicator of the degree to which the market and network model are reflecting similar conditions and efficiently managing congestion. For example, if a constraint is frequently not binding in the day-ahead market but is binding in the real-time market, this may warrant further review of how the constraint is being modeled in the day-ahead and real-time markets. Other factors such as loop flow and conforming of constraints may contribute to this trend.

The frequency of congestion in the real-time market on many constraints tended to be higher than in the day-ahead, as illustrated in Figure 5.4. This can occur for a variety of reasons, ranging from increased demand in real-time to discrepancies in modeled flows and actual flows observed in real-time. However, the overall frequency of real-time congestion was still relatively low on all internal and external constraints. Although real-time congestion sometimes resulted in very high prices, the overall cost impact of this congestion was very low due to the high level of day-ahead scheduling.

Figure 5.4 Consistency of congestion in day-ahead and real-time

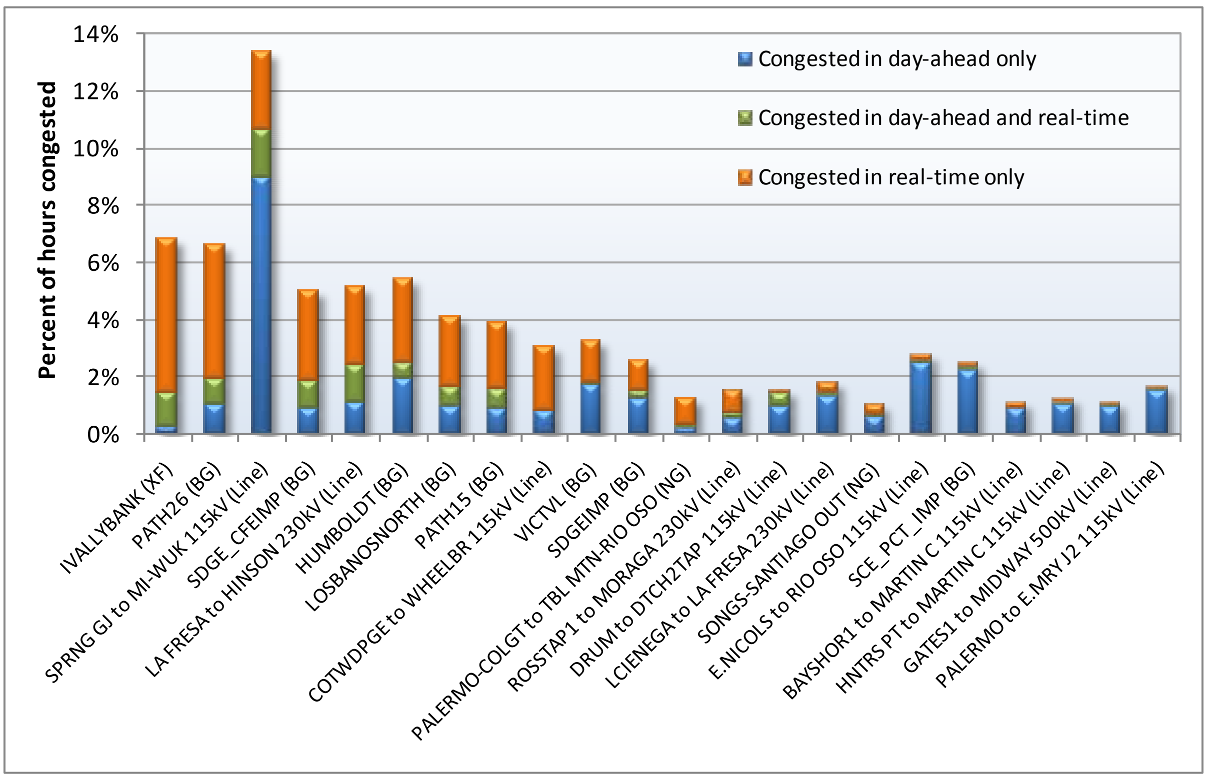


Table 5.4 and Table 5.5 provide a more detailed comparison of the frequency and consistency of congestion on various constraints during Q1 to Q4. Real-time congestion on inter-ties is based on congestion in the hour-ahead scheduling process. Real-time congestion for internal constraints is based on congestion in the 5-minute dispatch process. A constraint is considered congested in real-time for

the complete hour if it is congested for at least one interval. This is necessary to allow comparisons between the day-ahead market (an hourly market) and the two real-time markets that clear on a sub-hour level. Given this convention, the frequency of congestion reported below for the hour-ahead and real-time markets is overstated compared to a measure that counts congestion on a sub-hour basis.

As shown in Table 5.4 and Figure 5.5, there was not a high frequency of congestion on many internal constraints. For several of the most frequently congested constraints, congestion was often not consistent between the day-ahead and real-time market (e.g., congestion occurred in the day-ahead, but not in the real-time market, or vice versa).

- The IPPDCADLN_BG was the most frequently congested constraint. However, this particular branch group does not have a significant impact on electricity prices within the ISO or at the inter-ties.
- The SPRNG GJ to MI-WUK 115 kV line was frequently congested in April through early July. The line was binding an average of 98 MW in the day-ahead market. There are three hydro generation units connected to this line. This line can be congested on the hot summer days because of the dynamic rating and the limitation of the hydro units in the summertime.
- The SCE import limit was highly congested in the day-ahead market in November and December. The average shadow value in the day-ahead market was about $10/MWh. Congestion on this import limit was examined in detail in DMM's quarterly report for Q4 2009.[108]
- The Path 26 branch group had two major month-long de-rates: one from April 13 through May 19, and a second from October 19 through November 11. During these outages, Path 26 was frequently congested in both day-ahead and real-time.
- The SDG&E CFE import branch group was heavily congested on April and May in both day-ahead and real-time. This congestion was caused by a combination of daily de-rates due to scheduled outages and the level of conforming applied on transmission lines to maintain a safe operating limit. We provided a detailed review of congestion on this branch group in detail in the 2009 Q3 quarterly report.[109]
- The Path 15 and Los Baños North branch groups were congested more frequently in September. Congestion on these branch groups was exacerbated by an outage of three 500 kV lines: Los Baños-Midway #2, Gates-Midway and Diablo-Gates.

Figure 5.5 and Figure 5.6 shows the monthly day-ahead and real-time congestion frequencies of selected branch groups and inter-ties.

[108] *Quarterly Report on Market Issues and Performance*, February 1, 2010, http://www.caiso.com/2730/2730ee1e71a10.pdf
[109] *Quarterly Report on Market Issues and Performance*, December 23, 2009, http://www.caiso.com/2457/2457987152ab0.pdf

Table 5.4 Frequency of congestion and shadow values for the most congested flowgates and nomograms (IFM and RTD)[110],[111]

Constraint Name	Total Binding Frequency in IFM	Total Binding Frequency in RTD	Binding in IFM Only		Binding in RTD Only		Binding in Both IFM and RTD		
			Frequency of Congestion	Average Shadow Price	Frequency of Congestion	Average Shadow Price	Freq. of Cong.	Avg. SP IFM	Avg. SP RTD
IPPDCADLN (BG)	19.4%	6.2%	16.5%	$5	3.3%	$72	2.9%	$4	$66
SPRNG GJ to MI-WUK 115kV (Line)	10.6%	4.3%	9.0%	$9	2.7%	$47	1.7%	$3	$50
E.NICOLS to RIO OSO 115kV (Line)	2.6%	0.3%	2.5%	$287	0.2%	$383	0.1%	$96	$344
HUMBOLDT (BG)	2.5%	3.5%	2.0%	$64	2.9%	$208	0.6%	$88	$142
LA FRESA to HINSON 230kV (Line)	2.4%	4.0%	1.1%	$19	2.7%	$65	1.3%	$13	$94
SCE_PCT_IMP (BG)	2.3%	0.3%	2.2%	$10	0.2%	$141	0.1%	$19	$304
PATH26 (BG)	1.9%	5.5%	1.0%	$5	4.7%	$113	0.9%	$5	$50
SDGE_CFEIMP (BG)	1.8%	4.1%	0.9%	$6	3.2%	$159	0.9%	$18	$155
VICTVL (BG)	1.8%	1.5%	1.7%	$5	1.4%	$274	0.1%	$5	$347
LOSBANOSNORTH (BG)	1.6%	3.1%	1.0%	$15	2.5%	$92	0.7%	$9	$78
PALERMO to E.MRY J2 115kV (Line)	1.5%	0.1%	1.5%	$73	0.0%	$814	0.0%	$167	$135
PATH15 (BG)	1.5%	3.0%	0.9%	$6	2.3%	$88	0.7%	$7	$74
SDGEIMP (BG)	1.5%	1.4%	1.2%	$3	1.1%	$266	0.3%	$7	$493
IVALLYBANK (XF)	1.4%	6.6%	0.2%	$6	5.4%	$38	1.2%	$7	$42
LCIENEGA to LA FRESA 230kV (Line)	1.4%	0.5%	1.3%	$8	0.4%	$207	0.1%	$4	$2
DRUM to DTCH2TAP 115kV (Line)	1.4%	0.6%	1.0%	$30	0.1%	$51	0.5%	$30	$54
HNTRS PT to MARTIN C 115kV (Line)	1.1%	0.2%	1.0%	$28	0.1%	$500	0.1%	$20	$500
GATES1 to MIDWAY 500kV (Line)	1.0%	0.1%	0.9%	$7	0.0%	$253	0.1%	$6	$88
BAYSHOR1 to MARTIN C 115kV (Line)	0.9%	0.2%	0.9%	$11	0.2%	$474			
COTWDPGE to WHEELBR 115kV (Line)	0.8%	2.3%	0.8%	$59	2.3%	$49			
ROSSTAP1 to MORAGA 230kV (Line)	0.7%	1.0%	0.6%	$21	0.8%	$496	0.2%	$38	$542
SONGS-SANTIAGO OUT (NG)	0.7%	0.5%	0.6%	$25	0.4%	$699	0.1%	$18	$255
PALERMO-COLGT to TBL MTN-RIO OSO (NG)	0.3%	1.0%	0.2%	$150	1.0%	$699	0.1%	$256	$427

[110] The flowgates and nomograms which have been congested less than 1 percent of the time combined in the day-ahead and real-time markets have been eliminated from this analysis.

[111] On November 11, the ISO began enforcing the import limit in the market software, so that the ISO congestion related to this limit was managed by the market optimization. The binding frequency is calculated for November 11 through December 31.

Figure 5.5 Monthly congestion frequency of selected branch groups

Table 5.5 shows the frequency of congestion at the inter-ties in the day-ahead and hour-ahead markets. Figure 5.6 shows the monthly congestion frequencies of selected inter-ties. Congestion on several of the most frequently congested inter-ties was often consistent between the day-ahead and real-time market.

Table 5.5 Frequency of congestion and average shadow prices for the most frequently congested inter-ties in IFM and HASP[112,113]

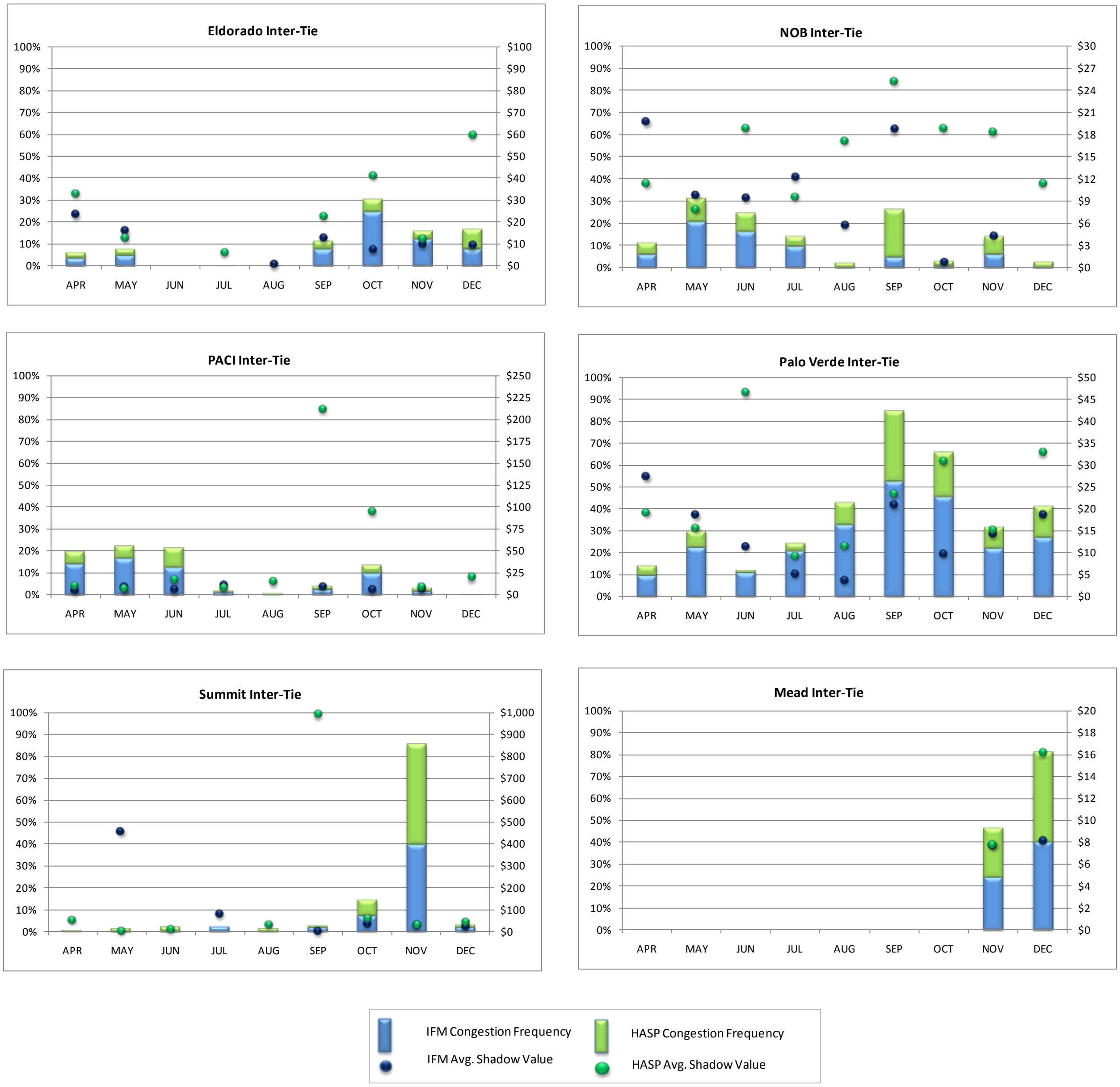
				Binding in IFM Only		Binding in HASP Only		Binding in IFM and HASP		
Inter-Tie name	Full (Import) Rating (MW)	Total Binding Frequency in IFM	Total Binding Frequency in HASP	Binding Frequency	Avg. Shadow Price	Binding Frequency	Avg. Shadow Price	Binding Frequency	Avg. SP IFM	Avg. SP HASP
PALOVRDE_ITC	3,427	26.9%	11.6%	17.3%	$12	2.0%	$37	9.6%	$17	$22
MEAD_ITC	1,460	7.1%	7.0%	1.1%	$5	0.9%	$24	6.1%	$9	$12
NOB_ITC	3,182	7.0%	7.1%	3.9%	$8	4.0%	$44	3.1%	$15	$11
ELDORADO_ITC	1,655	6.7%	3.1%	4.8%	$9	1.2%	$53	1.9%	$14	$28
PACI_ITC	3,200	6.3%	3.2%	4.4%	$5	1.3%	$63	1.8%	$8	$13
SUMMIT_ITC	160	5.8%	6.7%	1.1%	$35	2.0%	$184	4.7%	$37	$38
PARKER_ITC	440	1.8%	0.6%	1.5%	$26	0.3%	$62	0.3%	$20	$28
BLYTHE_ITC	218	1.4%	0.7%	1.2%	$13	0.5%	$22	0.3%	$6	$26
SILVERPK_ITC	34	0.9%	5.4%	0.3%	$193	4.8%	$24	0.6%	$4	$41
COTPISO_ITC	33	0.6%	0.7%	0.3%	$42	0.5%	$40	0.2%	$57	$21
IID-SCE_ITC	1,800	0.4%	0.1%	0.3%	$5	0.03%	$607	0.1%	$6	$71
CASCADE_ITC	600	0.08%	1.0%	0.02%	$18	1.0%	$116	0.1%	$0.38	$30

- The Palo Verde inter-tie was congested about 27 percent of the time in the day-ahead market. Most of this congestion occurred in September. On September 11, the North Gila-Hassayampa 500 kV line was forced out. This outage de-rated the Palo Verde inter-tie to 1,500 MW, or less than 50 percent of its normal capacity. This outage lasted until September 24.
- The Pacific DC inter-tie (North of Oregon) was congested about 11 percent of hours in the day-ahead market. Most of this congestion occurred during the spring and early summer months. The average shadow values of this inter-tie were $20, $10, $9 and $13/MWh in April, May, June and July, respectively.
- The Pacific DC inter-tie was also congested frequently in September due to a series of planned outages. This inter-tie was de-rated to less than 2,000 MW in the north-to-south (import) direction and 0 MW in the south-to-north (export) direction. During this period, the inter-tie was congested mostly in the export direction. The average monthly shadow prices were $19/MWh and $25/MWh in the day-ahead and hour-ahead markets, respectively.
- The Eldorado inter-tie was congested more than 24 percent of the time in October. The available capacity of this inter-tie was de-rated to 1,269 MW, down from its normal rating of 1,555 MW because of the month-long forced outage of the Eldorado-Moenkopi 500 kV line on September 29. This caused frequent congestion in October.

112 Starting November 13, 2009, the ISO created a new constraint, MEAD_ITC, as a companion to the combination of the two market scheduling limits MEAD_MSL and MEADTMEAD_MSL. This inter-tie constraint includes schedules for the following scheduling points MEAD230 and MEAD2MSCHD.

113 The inter-ties which have been congested less than 1 percent of the time have been eliminated from this analysis.

Figure 5.6 Monthly congestion frequency of selected inter-ties



Significant transmission events

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

- ***Devers-Valley 500 kV and Perkins-Mead 500 kV*** lines went out of service during the first several days of January for scheduled work, requiring de-rates on several branch groups, including Palo Verde. The total congestion costs on the Palo Verde inter-tie in January exceeded $3 million, which was about 68 percent of the total congestion costs for that month.

- ***Eldorado-Moenkopi 500 kV*** line was out from February 3 through March 3, and the capacity of the path was de-rated by half to 642 MW. As a result of this outage, the Eldorado inter-tie was congested frequently in the month of February.

- ***Diablo-Gates #1 500 kV*** line was out for scheduled maintenance from February 28 to March 7. The outage caused significant congestion on the Path 15 branch group.

- ***Devers-Palo Verde 500 kV*** line had scheduled maintenance from April 14 through April 17 that resulted in significant congestion on the Palo Verde inter-tie. The inter-tie was de-rated by almost half to 1,760 MW.

- ***Midway-Vincent # 3 500 kV*** line was out of service for more than a month, starting April 13, due to scheduled works on the line. The outage lasted until May 19. During this time the Path 26 branch group was de-rated to 2,000 MW, down from its normal rating of 4,000 MW.

- ***Palo Verde Inter-Tie*** was de-rated during the first half of May due to several scheduled maintenance outages. Devers-Palo Verde 500 kV line was out of service from May 2 to May 6. Then again from May 8 to May 11 and late evening hours of May 15 to early hours of May 18 after the Imperial Valley-North Gila 500 kV and Imperial Valley-Miguel 500 kV lines went out of service for scheduled maintenance, respectively.

- ***Los Baños-Tracy 500 kV and Diablo-Gates #1 500 kV*** lines were out of service in late May that caused de-rates on Path 15. Los Baños-Tracy was forced out on May 26 through June 6. Diablo-Gates #1 had scheduled work from May 28 through May 31.

- ***Celilo-Sylmar 1000 kV*** line was cleared for cold wash at Celilo & Sylmar on July 25 and July 26. The DC line of Path 65 was completely out in both directions as a result of the outage.

- ***Vincent 500 kV #4AA Bank*** was forced out on July 27 through August 2. The outage resulted in a significant de-rate of the Path 26 branch group to 2,000 MW in the north-to-south direction, which is half of its normal rating.

- ***North Gila-Hassayampa 500 kV*** line was forced out on September 11 until September 24. The outage resulted in significant de-rates on the Palo Verde inter-tie, to 1,500 MW, which is less than 50 percent of its normal rating. The Path 49 (East of River) and Path 46 (West of River) were de-rated as a result of this outage. The Palo Verde inter-tie was again de-rated in certain hours from September 25 through September 30 due to a combination of other planned and forced outages.

- ***Several Pacific Northwest 500/230 kV transmission lines*** were out of service during the second half of September through October 11 due to scheduled maintenance work. COI and NOB were de-rated as a result of these outages. From October 13 to October 24, PDCI was unavailable due to a planned outage on ***Celilo-Sylmar 1000kV DC line Poles 3 and 4.***

- ***Los Baños-Midway #2*** was taken out of service from September 8 through September 14. The planned outage resulted in a de-rate on the Path 15 branch group. Again from September 21 through September 27, and from September 29 to September 30, the Path 15 branch group was de-rated due to the planned outage of the ***Gates-Midway*** and the ***Diablo-Gates 500 kV*** lines, respectively.
- ***Drum-Rio Oso#2 115 kV*** line was out of service from October 28 through November 8. In addition, the ***Drum #1 Pump Hydro unit*** was undergoing scheduled work from November 3 through November 18. During the outages, the SUMMIT_ITC limit was de-rated to 0 MW only in the import direction. The export direction remained at its normal 100 MW capacity.
- ***Midway-Vincent No. 3 500 kV*** line was approved for planned maintenance work from October 19 through November 14. The outage resulted in a sharp de-rate on Path 26 branch group.
- ***Celilo-Sylmar 1000kV Converters 3 & 4*** were forced out on November 9. PDCI was de-rated significantly due to this outage and lasted until November 30 when the convertors returned to service.

5.6 Conforming constraint limits

Constraint limits in the market software are sometimes adjusted or conformed to account for differences in flows calculated by the market model and actual flows observed in real-time.[114] Operators conformed constraints to manage a small number of all transmission constraints, but during a significant number of hours. Constraints tended to be conformed in the upward direction in real-time, or increased. In such cases, the market limit was increased to reflect the true available capacity on the line. This avoids phantom congestion in real-time, which refers to congestion that occurs in the market model when the actual physical flows are below the limit in the market model.

Our analysis indicates that a total of about 200 flowgates were conformed or adjusted in Q2 through Q4. Only 20 of these flowgates were conformed in real-time more than 30 percent of the time. There was strong consistency in conforming between the hour-ahead and real-time markets in both frequency and level of adjustment.

The market limit of flowgates was conformed infrequently in the day-ahead market. Operation engineers reviewed the congestion in the day-ahead market on a regular basis to indicate any need for conforming the constraints' operating limits. They conformed the constraints' operating limits to either avoid phantom congestion in the day-ahead market or mitigate the potential for congestion that was occurring in the real-time market.

In the DMM Q3 report, we provided a detailed discussion of the practice of conforming transmission limits.[115] The two most common reasons for which operators make adjustments to transmission limits are to:

[114] This practice is referred to as "biasing" in DMM's Q3 report. The ISO now refers to this practice as conforming constraints.

[115] A July 13, 2009 technical bulletin on this topic can be found at http://www.caiso.com/23ea/23eae8aef980.pdf.

- Achieve greater alignment between the energy flows calculated by the market software and those observed or predicted in real-time operation across various paths.
- Set prudent operating margins consistent with good utility practice to ensure reliable operation under conditions of unpredictable and uncontrollable flow volatility.

Table 5.6 lists all flowgates and nomograms that were conformed in the real-time market, along with the percentage of hours that each were conformed, the average conformed limit, the percentage of hours in which it was binding while conforming was applied, and the average of the shadow price. The statistics presented in this table are calculated only for intervals in which the conforming action moved the effective limit from the actual limit. For most of these transmission lines, the conforming level was maintained at a relatively constant level during the period in which they were conformed.

As shown in Table 5.6, a small portion of all flowgates and nomograms were conformed in the real-time market during a significant percentage of hours in Q2 through Q4. Forty-six constraints were conformed over 10 percent of the hours, with only eight being conformed between 50 and 70 percent of the time.

Of the 46 constraints listed in Table 5.6, about 60 percent (27 constraints) were only conformed in the upward direction, to avoid congestion occurring in the market that was not actually occurring based on observed flows. Some of the major branch groups were conformed mostly downward (Path 16, Path 27, SDGE CFE import limit, SDGE import limit and Los Baños North branch group). Operators tend to conform down the operating limit of these major transmission lines to maintain an adequate reliability margin. The reliability margin ensures the flow on the grid line stays within the lines' operating limits even when sudden unpredictable changes in flows occur.

Table 5.6 shows conforming data for the real-time market and confirms that constraints were rarely congested during the time intervals that their operating limits were conformed upward. The congestion mostly occurred when downward conforming was applied. When ratings were conformed down, the actual real-time flows were approaching the constraint operating limit rapidly and in some cases even exceeded the limit. This suggests that operators had to adjust market limits downward to maintain an adequate reliability margin.

Our analysis indicates conforming performed in the hour-ahead and real-time markets is consistently applied across both markets. In Table 5.7, the consistency of conforming limits in real-time is compared to hour-ahead for every interval. However, for some of the major branch groups, such as Path 15 and Path 26, we observed less consistency of the applied conforming level in the real-time and hour-ahead markets. A different level of conforming may be required for enforcement of the same constraint in the day-ahead, hour-ahead and real-time markets depending on the condition of the transmission grid.[116]

[116] More information is available in Section 5.1.2 of DMM Q3 report: http://www.caiso.com/2457/2457987152ab0.pdf

Table 5.6 Real-time congestion frequencies and conforming limits for flowgates[117]

Flowgate Name	Conformed Intervals	Conformed Upward				Conformed Downward			
		Conformed Interval	Average Conformed Limit	Congested Intervals	Average Shadow Price	Conformed Interval	Average Conformed Limit	Congested Intervals	Average Shadow Price
MORAGA 1 (XF)	67.3%	67.2%	114	0.2%	$330				
MORAGA 2 (XF)	67.2%	67.2%	114	0.1%	$498				
TEMBLOR to PSEMCKIT 115kV (Line)	63.2%	63.2%	120	< 0.1%	$500				
LCIENEGA to LA FRESA 230kV (Line)	60.5%	60.0%	109	0.1%	$42	0.5%	97	< 0.1%	$424
HUMBOLDT (BG)	58.4%	46.0%	149	0.2%	$124	12.4%	83	1.5%	$217
C.COSTA to ROSSTAP1 230kV (Line)	56.8%	56.8%	116	< 0.1%	$500				
C.COSTA to ROSSTAP2 230kV (Line)	56.7%	56.7%	113						
ROSSTAP2 to MORAGA 230kV (Line)	56.7%	56.7%	113						
MARTINEZ to ALHAMTP1 115kV (Line)	44.5%	44.5%	122	0.1%	$334				
ALHAMTP1 to SOBRANTE 115kV (Line)	44.2%	44.1%	116	0.1%	$338				
HUMBOLDT 1 (XF)	43.8%	43.8%	110	0.1%	$458				
SDGE_CFEIMP (BG)	43.6%	0.0%	106			43.5%	94	2.5%	$146
IGNACIO to HMLT 115kV (Line)	39.8%	39.8%	110						
IVALLYBANK (XF)	37.5%	0.4%	103	< 0.1%	$22	37.1%	84	4.7%	$37
MC CALL to HENTAP2 230kV (Line)	36.8%	36.8%	112	0.1%	$10				
SSONGS (BG)	36.7%					36.7%	86	0.2%	$104
MIDWAY to VINCENT 500kV (Line)	36.0%	36.0%	114	< 0.1%	$500				
PATH26 (BG)	33.8%	0.4%	133	< 0.1%	$61	33.5%	78	3.3%	$100
SILVERGT to MLMS3TAP 230kV (Line)	33.2%	33.2%	120						
COTWDPGE to WHEELBR 115kV (Line)	31.1%	30.7%	110			0.4%	97	0.4%	$51
BARRE-LEWIS (NG)	27.9%	27.9%	105	< 0.1%	$1	< 0.1%	5		$0
LUGO_VINCENT (BG)	27.0%	27.0%	105	< 0.1%	$76	0.1%	95	0.1%	$50
ROSSTAP1 to MORAGA 230kV (Line)	24.4%	24.4%	125	< 0.1%	$166	< 0.1%	85		
VACA-DIX to LAMBIE 230kV (Line)	23.7%	23.7%	123	< 0.1%	$500				
LOSBANOSNORTH (BG)	23.1%	13.9%	105			9.2%	70	3.0%	$67
LA FRESA to HINSON 230kV (Line)	22.7%	0.1%	106			22.5%	93	0.7%	$393
SDGEIMP (BG)	21.4%	0.1%	107			21.4%	82	1.9%	$99
LAK-MOR1 to MORAGA 115kV (Line)	20.3%	20.3%	111	< 0.1%	$500				
LAKEWOOD to LAK-MOR1 115kV (Line)	20.1%	20.1%	111	< 0.1%	$500				
ALHAMTP2 to OLEUM 115kV (Line)	20.1%	20.1%	111						
OLIVH J1 to RIO OSO 115kV (Line)	19.2%	19.2%	112	< 0.1%	.				
GWFTRACY to LAMMERS 115kV (Line)	19.1%	19.1%	125						
PARDEE to VINCENT 230kV (Line)	18.9%	18.9%	150						
MIRAGE 4A (XF)	17.4%	17.4%	120						
SCE_PCT_IMP (BG)	17.1%	16.0%	112	< 0.1%	$201	1.1%	97	0.1%	$40
NEWARK to RAVENSWD 230kV (Line)	16.8%	16.7%	112	< 0.1%	$500				
T-165 PALERMO_COLGT (NG)	16.3%		102			16.3%	84		
E.NICOLS to RIO OSO 115kV (Line)	15.7%	15.7%	139	< 0.1%	$500				
HOLLISTR to LGNTSSW2 115kV (Line)	15.3%	15.3%	105						
GLEAF TP to RIO OSO 115kV (Line)	14.8%	14.8%	110	< 0.1%	$531				
TABLE MT to TESLA 500kV (Line)	14.5%	14.5%	110	< 0.1%	$57				
T-151 SOL-1 (NG)	13.6%	13.6%	150	< 0.1%	$1	0.1%	87		
WILSONAB 1 (XF)	13.5%	13.5%	105	< 0.1%	$82				
SANMATEO to RAVENSWD 115kV (Line)	13.3%	13.3%	110	0.1%	$500	< 0.1%	67		
BRDSLDNG to C.COSTA 230kV (Line)	13.0%	12.9%	107	< 0.1%	$172	< 0.1%	95	< 0.1%	$500
PATH15 (BG)	10.3%	0.0%	105	< 0.1%	$1	10.3%	84	1.8%	$70

[117] The time basis for the frequency statistics is based on all hours in the three-month range and does not account for periods where the constraint was not enforced and therefore would not be conformed. Consequently, the frequency statistics presented may understate the frequency for constraints that were not enforced throughout the period.

Table 5.7 Consistency of conforming limits in RTD and HASP

Flowgate Name	Conforming in RTD	Conforming Level Matches in RTD and HASP	Conforming Level *Does not* Matches in RTD and HASP	Avg. Conforming Level Match in RTD and HASP (in%)	Avg. Conforming Level Does not Match in RTD and HASP (in%)
MORAGA 1 (XF)	67.2%	65.6%	1.7%	114	106
MORAGA 2 (XF)	67.2%	65.6%	1.7%	114	106
TEMBLOR to PSEMCKIT 115kV (Line)	63.2%	61.6%	1.6%	120	110
LCIENEGA to LA FRESA 230kV (Line)	60.5%	60.3%	0.2%	109	106
HUMBOLDT (BG)	58.4%	56.9%	1.5%	136	92
C.COSTA to ROSSTAP1 230kV (Line)	56.8%	40.4%	16.4%	113	125
C.COSTA to ROSSTAP2 230kV (Line)	56.7%	56.7%	0.0%	113	113
ROSSTAP2 to MORAGA 230kV (Line)	56.7%	56.7%	0.0%	113	113
MARTINEZ to ALHAMTP1 115kV (Line)	44.5%	44.4%	0.1%	122	129
ALHAMTP1 to SOBRANTE 115kV (Line)	44.1%	43.7%	0.4%	116	117
HUMBOLDT 1 (XF)	43.8%	43.8%	0.0%	110	113
SDGE_CFEIMP (BG)	43.6%	36.1%	7.4%	94	94
IGNACIO to HMLT 115kV (Line)	39.8%	39.8%	0.0%	110	112
IVALLYBANK (XF)	37.5%	33.3%	4.2%	83	94
MC CALL to HENTAP2 230kV (Line)	36.8%	36.7%	0.1%	112	110
SSONGS (BG)	36.7%	36.4%	0.3%	86	93
MIDWAY to VINCENT 500kV (Line)	36.0%	36.0%	0.0%	114	112
PATH26 (BG)	33.8%	21.7%	12.1%	83	72
SILVERGT to MLMS3TAP 230kV (Line)	33.2%	33.2%	0.0%	120	120
COTWDPGE to WHEELBR 115kV (Line)	31.1%	31.1%	0.0%	110	107
BARRE-LEWIS (NG)	27.9%	27.6%	0.3%	105	103
LUGO_VINCENT (BG)	27.0%	27.0%	0.1%	105	105
ROSSTAP1 to MORAGA 230kV (Line)	24.4%	24.3%	0.2%	125	117
VACA-DIX to LAMBIE 230kV (Line)	23.7%	23.7%	0.0%	123	117
LA FRESA to HINSON 230kV (Line)	23.1%	22.2%	1.0%	92	63
SDGEIMP (BG)	22.7%	21.5%	1.1%	94	90
LOSBANOSNORTH (BG)	21.4%	18.0%	3.5%	82	86
LAK-MOR1 to MORAGA 115kV (Line)	20.3%	20.2%	0.0%	111	115
LAKEWOOD to LAK-MOR1 115kV (Line)	20.1%	20.1%	0.0%	111	116
ALHAMTP2 to OLEUM 115kV (Line)	20.1%	20.1%	0.0%	111	110
OLIVH J1 to RIO OSO 115kV (Line)	19.2%	19.1%	0.1%	125	112
GWFTRACY to LAMMERS 115kV (Line)	19.2%	19.1%	0.0%	112	112
PARDEE to VINCENT 230kV (Line)	18.9%	18.9%	0.0%	150	135
MIRAGE 4A (XF)	17.4%	17.4%	0.0%	120	114
SCE_PCT_IMP (BG)	17.1%	16.9%	0.2%	111	106
NEWARK to RAVENSWD 230kV (Line)	16.7%	16.7%	0.0%	112	111
T-165 PALERMO_COLGT (NG)	16.3%	16.0%	0.3%	84	84
E.NICOLS to RIO OSO 115kV (Line)	15.7%	15.7%	0.0%	139	124
HOLLISTR to LGNTSSW2 115kV (Line)	15.3%	15.3%	0.0%	105	105
GLEAF TP to RIO OSO 115kV (Line)	14.8%	14.7%	0.0%	110	115
TABLE MT to TESLA 500kV (Line)	14.5%	14.5%	0.0%	110	116
T-151 SOL-1 (NG)	13.6%	13.4%	0.3%	150	146
WILSONAB 1 (XF)	13.5%	13.5%	0.0%	105	113
SANMATEO to RAVENSWD 115kV (Line)	13.3%	13.3%	0.0%	110	90
BRDSLDNG to C.COSTA 230kV (Line)	13.0%	12.9%	0.1%	107	114
PATH15 (BG)	10.3%	8.6%	1.8%	85	80

Table 5.8 lists all flowgates and nomograms that were conformed in day-ahead market, along with the percentage of hours that each flowgate or nomogram was conformed, the average conformed limit, the percentage of hours in which it was binding while conforming was applied, and the average of the shadow price.

As shown in Table 5.8, almost half of the constraints that were conformed in the day-ahead market tended to be "conformed up." In such cases, the market model experienced phantom congestion in real-time (i.e., congestion in the market model when actual physical flows were below limits), so conforming was used to reflect the true available capacity on the line. Operating engineers evaluated the validity of the congestion in the day-ahead market and recommended conforming or un-enforcing a constraint, as appropriate.

SDG&E CFE import limit and SDG&E import limit branch groups were frequently conformed down to 95 percent of their operating limit, mostly to sustain a safe reserve margin. Path 26, T-165 Palermo to Colgate nomogram and La Fresa to Hinson 230 kV line were conformed downward during transmission outages. This was usually needed to maintain appropriate operating margin for flowgates impacted directly or indirectly by adverse operating conditions.

Table 5.8 Conforming limits and congestion frequencies for flowgates in day-ahead[118]

Flowgate Name	Conformed Hours	Average Conformed Limit	Congested Intervals	Average Shadow Price
SDGE_CFEIMP (BG)	65.5%	95	0.8%	$4
SDGEIMP (BG)	61.1%	95	1.2%	$3
VICTVL (BG)	36.4%	112	0.7%	$5
MIRAGE 4A (XF)	17.5%	120		
IVALLYBANK (XF)	16.4%	111		
T-165 PALERMO_COLGT (NG)	16.0%	84	0.4%	$25
PATH26 (BG)	13.1%	86	0.6%	$6
COTWDPGE to WHEELBR 115kV (Line)	9.1%	109		
LUGO_VINCENT (BG)	7.3%	110	0.1%	$2
CARIBOU to BELDENTP 230kV (Line)	6.2%	106	0.2%	$188
LA FRESA to HINSON 230kV (Line)	4.9%	68	1.8%	$17

118 The time basis for the frequency statistics is based on all hours in the three month range and does not account for periods where the constraint was not enforced and therefore would not be conformed. Consequently, the frequency statistics presented may understate the frequency for constraints that were not enforced throughout the period.

5.7 Congestion under prior zonal market design (Q1 2009)

Table 5.9 shows the congestion frequencies and average congestion charges by branch group, direction (import or export), and market type (day-ahead or hour-ahead) in the first quarter of 2009.

- 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 Palo Verde, Mead, Eldorado and Adelanto SP branch groups were congested in at least 15 percent of hours.
- The most frequently congested branch groups in Q1 2009 were the Palo Verde and Mead branch groups, each of which were congested 38 percent of hours in the day-ahead market.
- Eldorado, Adelanto SP and Blythe branch groups were also congested 26, 15 and 19 percent of hours, respectively, in the hour-ahead market, with all of the congestion in the import direction.

Table 5.9 Inter-zonal congestion frequencies (2009 Q1)[119]

	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_BG	15	0	$2	$0	2	0	$39	$0
BLYTHE_BG	13	0	$2	$0	1	0	$8	$0
CASCADE_BG	0	0	$0	$0	0	0	$3	$0
ELDORADO_BG	26	0	$14	$0	11	0	$26	$0
IID-SCE_BG	1	0	$1	$0	0	0	$0	$0
IID-SDGE_BG	4	0	$0	$0	0	0	$0	$0
IPPDCADLN_BG	8	0	$2	$0	3	0	$27	$0
MEAD_BG	38	0	$1	$0	37	0	$6	$0
MERCHANT_BG	0	0	$0	$0	1	0	$1	$0
MKTPCADLN_BG	5	0	$0	$0	1	0	$30	$0
NOB_BG	0	3	$0	$2	0	2	$4	$6
PACI_BG	2	0	$0	$0	3	0	$16	$0
PALOVRDE_BG	38	0	$2	$0	13	0	$10	$0
PARKER_BG	7	0	$2	$0	0	0	$40	$0
PATH15_BG	6	0	$8	$0	4	0	$21	$0
PATH26_BG	1	0	$1	$0	1	0	$10	$8
TRACYCOTP_BG	0	0	$0	$0	0	0	$15	$0
WSTWGMEAD_BG	2	0	$7	$0	1	0	$2	$0

[119] 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."

Table 5.10 shows the total annual congestion charges for the major ISO branch groups in Q1 2009. Total congestion charges system-wide were about $13 million in Q1 2009 compared to $17 million in Q1 2008.

Figure 5.7 compares congestion charges in Q1 2008 and Q1 2009 on selected major paths. The planned outage of the Devers-Valley 500 kV and Perkins-Mead 500 kV lines resulted in high congestion frequency of the Palo Verde branch group in the month of January. This branch group was congested 38 percent and 13 percent of the time in Q1 in the day-ahead and hour-ahead markets, respectively. Average day-ahead congestion charges were only $2/MWh compared to $10/MWh in the hour-ahead market. The total congestion charges on this branch group ($4 million) were about 30 percent of the total congestion charges in Q1 2009, which were similar to the congestion charges in Q1 2008.

Average day-ahead and hour-ahead congestion charges on the Eldorado branch group were $14/MWh and $26/MWh, respectively. The high congestion frequency on the Eldorado branch group was mostly due to a month-long scheduled outage of the Eldorado-Moenkopi 500 kV line. This line was out from February 3 through March 3. Congestion frequency on the Mead branch group in the day-ahead market was 26 percent. Thirty eight percent of total congestion charges ($5 million) were incurred on the Eldorado branch group, all in the import direction in the day-ahead. The congestion charges on this inter-tie in Q1 increased significantly compared to $2 million in congestion charges in Q1 2008.

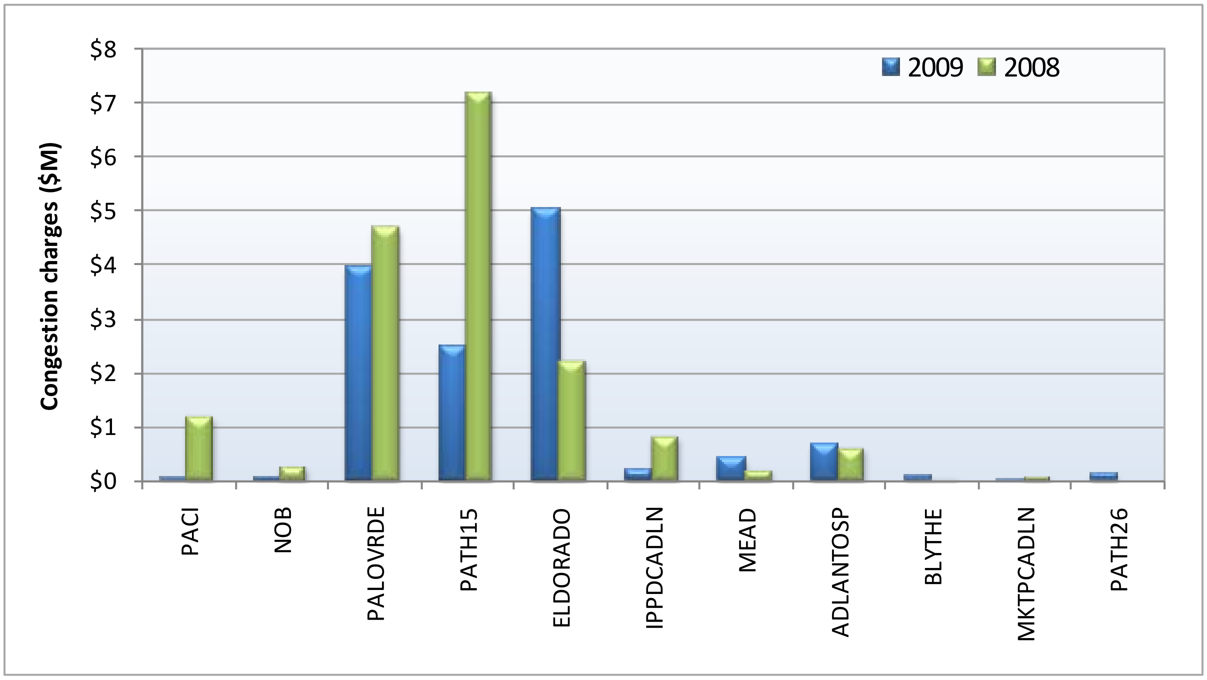
Mead was congested 38 percent of the hours in the day-ahead market in the import direction. However, the average congestion charge was only $1/MWh. The total congestion charges on this inter-tie were less than half a million dollars, about 3 percent of the total congestion charges in Q1 2009.

The total congestion charges on Path 15 were about $2.5 million, or about 19 percent of the total congestion charges in Q1 2009. This amount was significantly lower compared to the $7 million congestion charges in Q1 2008.

Table 5.10 Inter-zonal congestion charges (2009)

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	$660,920	$0	$723	$0	$661,642	$0	$660,920	$723	$661,642	5%
BLYTHE	$76,383	$0	$456	$0	$76,839	$0	$76,383	$456	$76,839	1%
CASCADE	$0	$0	$590	$0	$590	$0	$0	$590	$590	0%
ELDORADO	$5,016,058	$0	$745	$0	$5,016,803	$0	$5,016,058	$745	$5,016,803	38%
IID-SCE	$8,116	$0	$0	$0	$8,116	$0	$8,116	$0	$8,116	0%
IID-SDGE	$104	$0	$0	$0	$104	$0	$104	$0	$104	0%
IPPDCADLN	$187,185	$0	$9,090	$0	$196,276	$0	$187,185	$9,090	$196,276	1%
LAUGHLIN	$0	$0	$0	$2	$0	$2	$0	$2	$2	0%
MEAD	$370,301	$0	$52,086	$0	$422,387	$0	$370,301	$52,086	$422,387	3%
MERCHANT	$0	$0	$4,689	$0	$4,689	$0	$0	$4,689	$4,689	0%
MKTPCADLN	$21,549	$0	$2,504	$0	$24,053	$0	$21,549	$2,504	$24,053	0%
NOB	$0	$24,894	$9,207	$24,595	$9,207	$49,489	$24,894	$33,801	$58,696	0%
PACI	$20,572	$0	$26,668	$0	$47,241	$0	$20,572	$26,668	$47,241	0%
PALOVRDE	$3,932,576	$0	$14,435	$0	$3,947,011	$0	$3,932,576	$14,435	$3,947,011	30%
PARKER	$43,680	$0	$53	$0	$43,733	$0	$43,680	$53	$43,733	0%
PATH15	$2,472,894	$0	$8,259	$0	$2,481,152	$0	$2,472,894	$8,259	$2,481,152	19%
PATH26	$22,895	$0	$35,622	$55,912	$58,518	$55,912	$22,895	$91,535	$114,430	1%
WSTWGMEAD	$34,214	$0	$505	$0	$34,718	$0	$34,214	$505	$34,718	0%
Total	**$12,867,447**	**$24,894**	**$165,632**	**$80,509**	**$13,033,080**	**$105,403**	**$12,892,342**	**$246,141**	**$13,138,482**	**100%**

Figure 5.7 Congestion charges on selected paths (Q1 2008 vs. Q1 2009)



5.8 Transmission infrastructure changes

Several transmission projects were completed in 2009. Upgrades associated with individual lines or equipment are listed below in Table 5.11. The more significant of these upgrades are described in detail below:

- ***Rancho Vista Substation 500/230 kV Project –*** This project was justified based on reliability needs of San Bernardino and Riverside counties. The project provides additional transformer capacity to serve growing load demand in the eastern LA basin and bank relief to the Mira Loma Substation. This is sponsored by SCE.
- ***Antelope-Pardee Transmission 500 kV Project –*** This 26.5 mile 500 kV transmission line (initially energized at 220 kV) from Santa Clarita to Lancaster will relieve overloads on the Antelope-Vincent 220 kV line. This is sponsored by SCE.
- ***Antelope-Vincent No. 2 220 kV Line Project (TRTP segment 2) –*** This project, formerly known as the Tehachapi Renewable Transmission Project, involves a new 500 kV line but was initially energized at 220 kV.

Table 5.11 2009 transmission projects

Transmission Project	Net Capacity Increase	In-Service Date
Monta Vista 60 kV Upgrade	200	Feb-09
Midway Sub - Emergency replacement of Bank 1 with 420 MVA (230/115 kV)	300	Apr-09
Los Banos: Repl Bank 1 (500/230 kV 4 x 374 MVA, 1-Ph)	374	Apr-09
Repl 230/115kV, 420 MVA, Midway Bk 1	313	Apr-09
Martin-Hunters Point 115 kV Underground HP4 Cable	187	Apr-09
Humboldt - Harris 60 kV Reconductoring	16	May-09
Brighton 230/115 kV Transformer Replacement	287	May-09
Kern PP Bank #1 115/70kV Replacement	80	May-09
Kern PP - replace 115/70 kV Bank 1	80	May-09
Bellota - replace 230/115 kV Bank 2 w/ 3-ph 200 MVA	80	May-09
Gold Hill-Placer 115 kV Rein-Prj	160	Jun-09
Santa Maria -Sisquoc 115 kV Reconductoring Project	108	Jun-09
Contra Costa-Lone Tree 230 kV Reconductor	330	Jun-09
Contra Costa-Las Positas 230 kV Line	330	Aug-09
West Sacramento - Brighton 115 kV Reconductor	99	Jun-09
Rancho Vista 500/230kV Substation Project	1,344	Mar-09
Antelope-Oasis-Palmdale-Quartz Hill and Antelope-Shuttle 66kV Line Reconductor Project	125	Mar-09
Antelope-Pardee (TRTP Segment 1) 500kV transmission line from Santa Clarita to Lancaster	1,287	Oct-09
New Antelope-Quartz Hill#2 66 kV Line	125	Oct-09
Buck Blvd-Julian Hinds 220kV line	356	Oct-09
Antelope-Vincent No.2 220 kV Line (ATP)(TRTP segment 2)	1,505	Dec-09
Antelope-Windhub 500kV (initially energized at 220kV), Windhub-Highwind 220kV (segment 3A & 3B	1,505	Dec-09
13824 (Los Coches - South Bay) uprating	110	Mar-09
New Division - Naval Station Metering 69 kV line TL6950	143	May-09
Naval Station - upgrade existing TL606	46	May-09
SH-NCM-ES (13811) and BQ-CC (13825) step 1 of Encina reconfig.	63	Oct-09
Rebundle 13815 with old 13813	37	Nov-09
Total	**9,590**	

5.9 Congestion revenue rights

Background

In the new market, LMPs are comprised of three components: energy, congestion, and losses. The congestion component varies depending on the transmission line and can therefore be volatile. The new market allows market participants to acquire congestion revenue rights as a means to hedge against volatile congestion costs. Congestion revenue rights are financial instruments used to hedge against congestion costs in the day-ahead integrated forward market. They are defined by five elements:

- ***Megawatt quantity*** —This is the volume of CRRs per hour for each hour of the CRR life term.
- ***Life term*** — Each CRR has one of three categories of life term: a month, one calendar season of a one year, or one calendar season for 10 years.
- ***Time-of-use*** — Each CRR is defined as being for either the peak or off-peak hours as defined by WECC guidelines.
- ***Sink*** — The sink of a CRR can be an individual node, load aggregation point, or a group of nodes. The amount received or paid by the CRR holder each hour is the LMP of the sink of the CRR minus the LMP of the source of the CRR.

- ***Source* —** The source of a CRR can be an individual node, load aggregation point or a group of nodes. The amount received or paid by the CRR holder each hour is the LMP of the sink of the CRR minus the LMP of the source of the CRR.

The CRR market is organized into annual and monthly programs that include an allocation and auction process. In the annual program, the rights are allocated and auctioned for long-term and short-term calendar seasons. The long-term rights are valid for 10 years. A short-term right is valid for one year. The monthly program is an auction for rights that are valid for one calendar month for one year. A more detailed explanation of the CRR processes is provided in the ISO report *2009 Market Performance of CRRs.*[120]

Market results

Figure 5.8 and Figure 5.9 show the amount of megawatts awarded for peak and off-peak hours by month, market term, and process. In both figures, the long-term and short-term rights are valid for a three-month period, so there is no variation within a calendar season in the amount of rights awarded in these processes. There is some variability because the allocation processes are based on historical load. Therefore, the awarded CRRs follow the seasonal load patterns, increasing during the peak load seasons.

There is no maximum limit on the amount of CRRs awarded in the auction processes. This is because the physical constraints (such as transmission limits) used in the CRR model can continually be offset by counter-flow rights. Therefore, rights awarded in the short-term and monthly auction processes have the most variability in the two figures below. In the last three months, the amount of rights auctioned off increases as a result of more counter-flow rights being bid and cleared in the market.

CRRs are awarded and settled based on a market clearing price. Market participants that take a counter-flow position are paid a dollar amount per megawatt of CRRs. This reflects the expectation that these CRRs will most likely lose money in the day-ahead energy market.

Figure 5.10 and Figure 5.11 show the awarded megawatt amount at market clearing prices grouped into price bins. The price bins represent the price per megawatt hour for each CRR. This is equal to the market clearing price divided by the total hours for which that right is valid. This allows the seasonal rights to be grouped with, and compared to, the monthly rights. The line represents the total number of rights awarded in each month, including seasonal and monthly rights.

The same general trends occur for rights for both peak and off-peak hours. In both Figure 5.10 and Figure 5.11, there is an increase in the total number of rights awarded, reflected by the upward trend of the line. As previously mentioned, this is mostly due to an increase in the amount of counter-flow rights awarded and therefore also an increase in the amount of non-counter-flow rights.

For peak hour CRRs, 82 percent in the positive direction and 82 percent in the counter-flow direction were auctioned off at a price between $0 and $0.50/MW. For off-peak hour CRRs, 92 percent in the positive direction and 90 percent in the counter-flow direction were auctioned off at a price between $0 and $0.50/MW. More detailed analysis of the CRR market is provided in the ISO report *2009 Market Performance of CRRs.*[121]

[120] http://www.caiso.com/272b/272b8a1623070.html

[121] Ibid.

Figure 5.8 Allocated and awarded congestion revenue rights (peak)

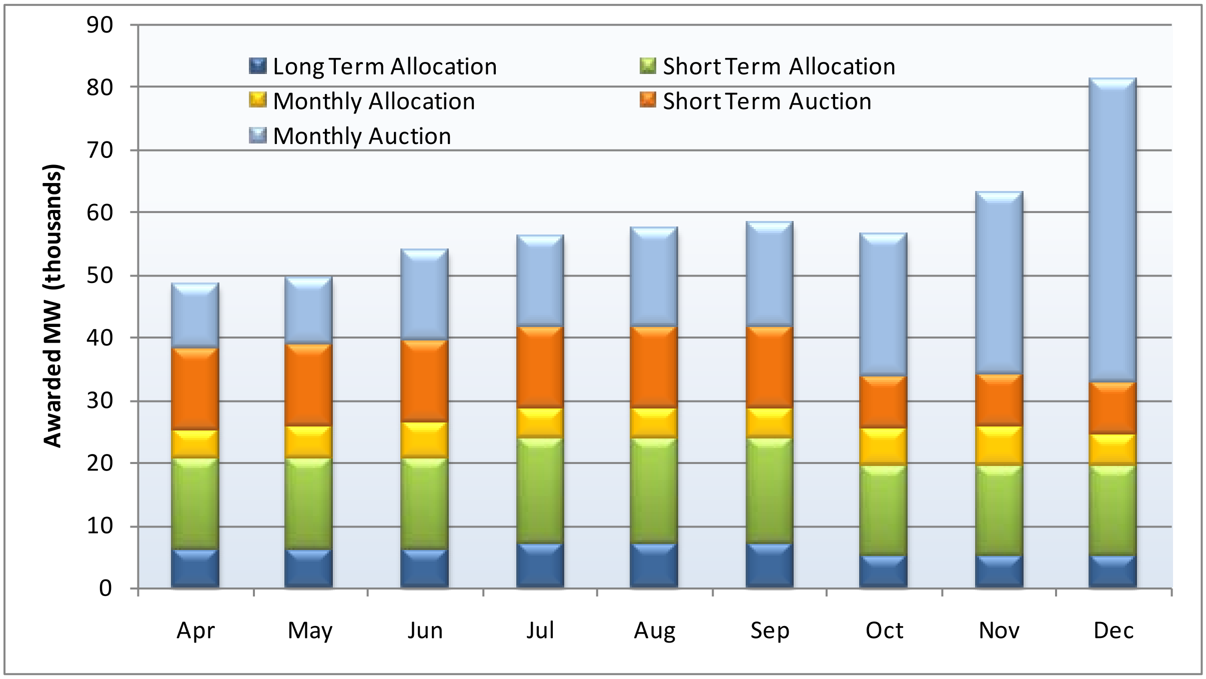


Figure 5.9 Allocated and awarded congestion revenue rights (off-peak)

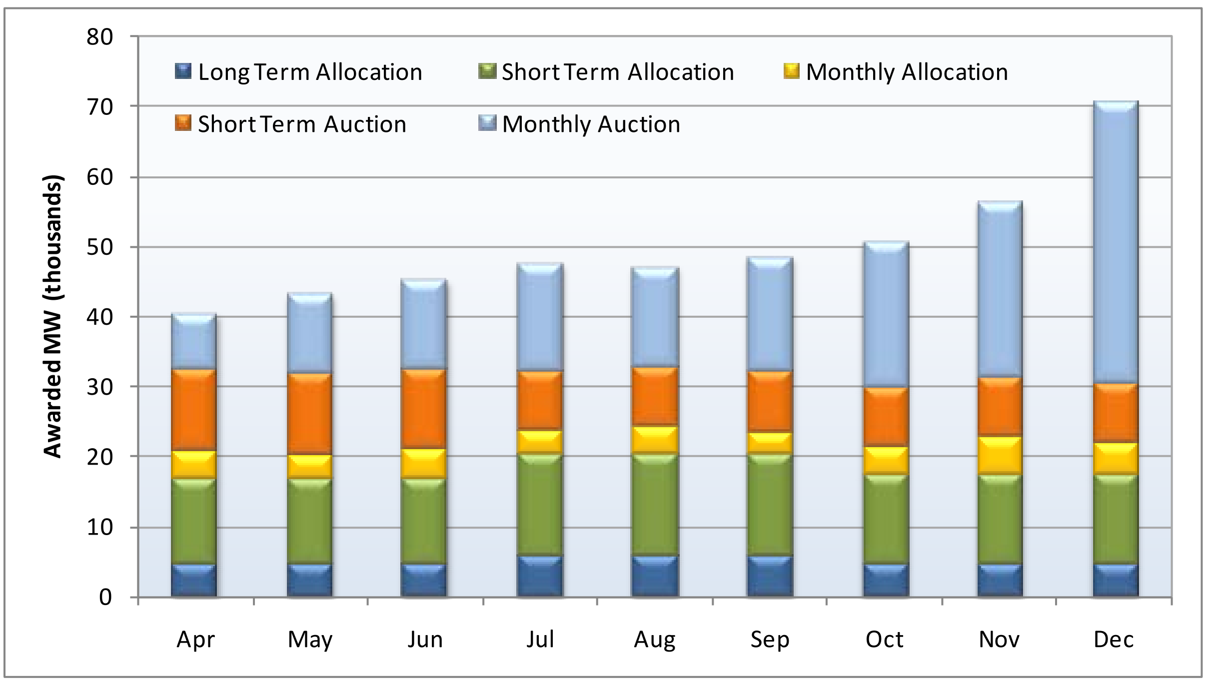


Figure 5.10 Auctioned congestion revenue rights by price bin (peak hours)

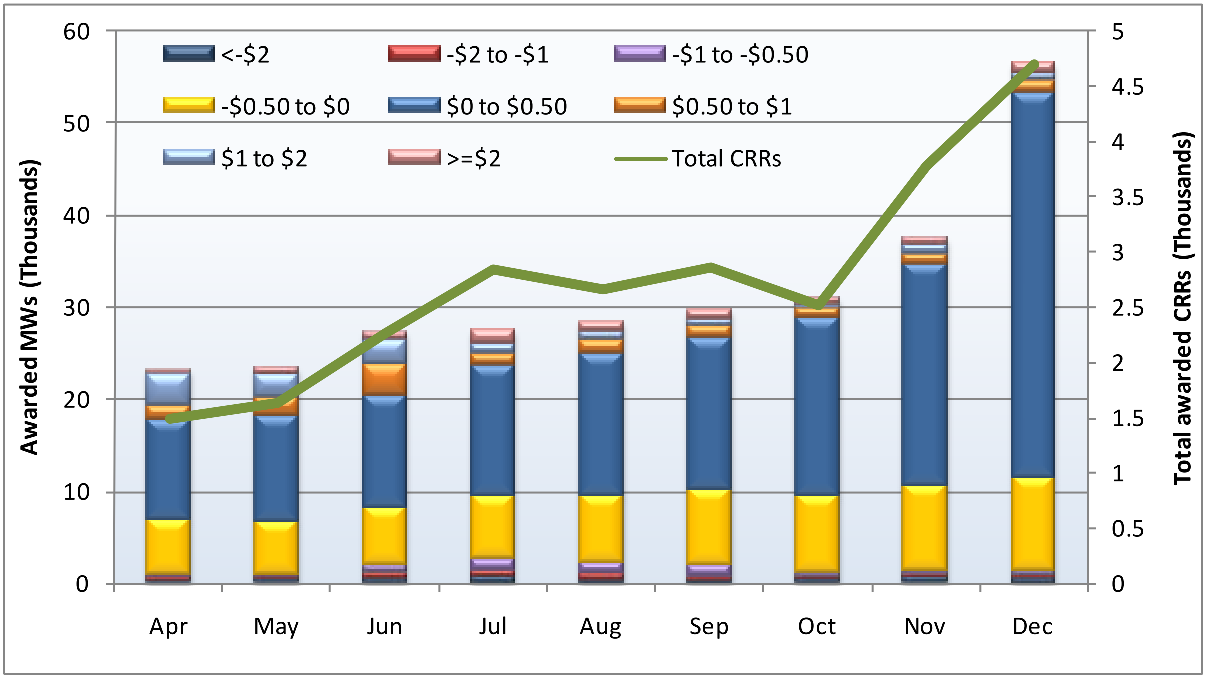
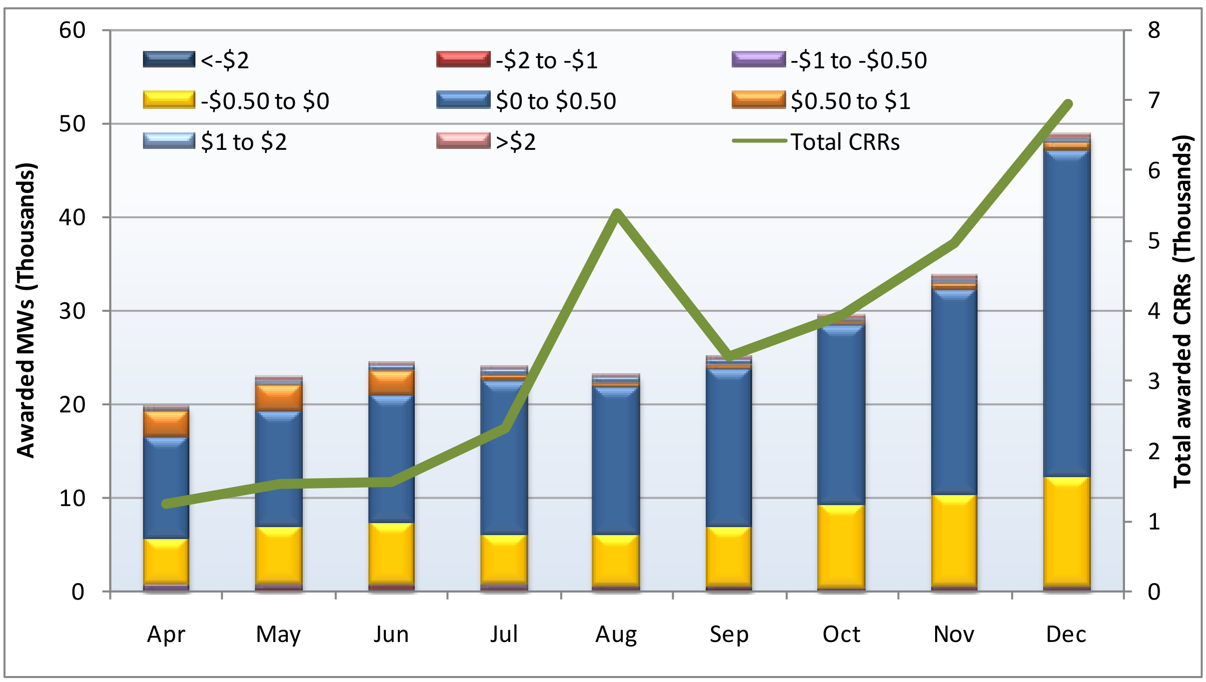


Figure 5.11 Auctioned congestion revenue rights by price bin (off-peak hours)



CRR revenue adequacy

The ISO limits the number of CRRs released to maintain revenue adequacy. In other words, the amount of congestion rents collected from the day-ahead energy market is sufficient to cover all the revenue right entitlements. Under certain assumptions and system conditions, revenue adequacy may be guaranteed when using a simultaneous feasibility test when releasing rights in the annual and monthly process.[122]

A balancing account is maintained to track the programs' revenue adequacy. Congestion charges collected from the day-ahead energy market are paid into the balancing account, from which rights entitlements are debited. Although a simultaneous feasibility test, theoretically, guarantees revenue adequacy, under actual market conditions, events such as unforeseen outages and de-rates can create revenue deficiencies and surpluses. Therefore, in addition to congestion charges, all revenues from the annual and monthly auction processes are included in the account to help supplement CRR entitlement payments, if needed. Any shortfall or surplus in the balancing account at the end of each month is allocated to measured demand.

This section provides an overview of the CRR revenue adequacy on a monthly and annual basis from two perspectives: one including the auction revenues and one without. The analyses show that the ISO was revenue deficient in seven of the nine months when solely considering congestion charges collected from the day-ahead energy market. When supplementing CRR entitlements with auction revenues, the ISO was only deficient in three of the nine months with an overall revenue surplus at the end of the year.

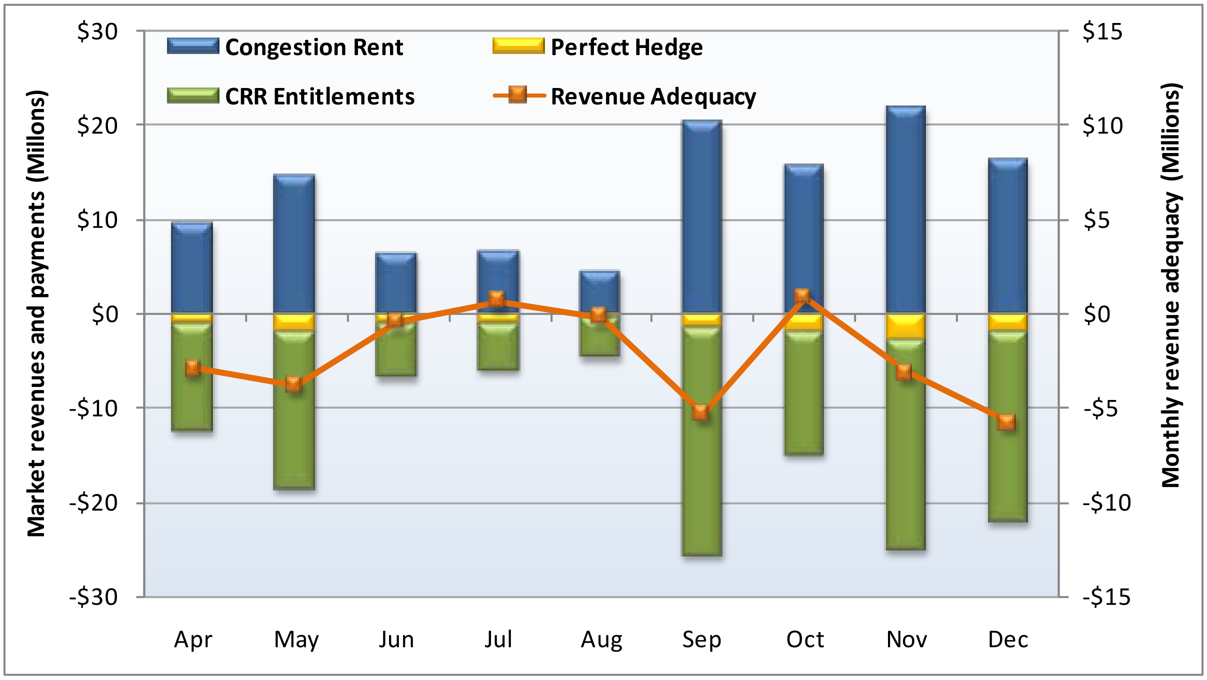
Figure 5.12 shows the revenue adequacy by month broken down into revenues and costs to the ISO. The congestion rent (blue bars) is the only source of revenues to the ISO in this figure. The yellow bars represent the amount of congestion charges collected from market participants with existing rights (existing transmission contract, transmission ownership right, and converted rights). These rights make market participants exempt from any congestion charges, so that these costs are a debit from the account. Entitlements paid to CRR holders are represented by the green bars. The monthly revenue adequacy is shown by the orange line, which is equal to the congestion rent, minus perfect hedge and entitlements for each month.

As seen in Figure 5.12, the ISO was revenue deficient in seven of the nine months, indicating congestion charges collected were not sufficient to fund the entitlements. This is mostly a result of unforeseen outages and de-rates on inter-ties that were not accounted for in the CRR network model during the annual and monthly processes.

The Palo Verde inter-tie and SCE_PCT_IMP_BG were the two major contributors to revenue deficiencies throughout the year. In April, Palo Verde was de-rated to 1,760 MW due to a planned outage. In May, Palo Verde was de-rated again to levels of 1,661 MW to 2,176 MW. In both instances, the inter-tie became congested, increasing payments to CRR holders that was funded by a lower amount of scheduled energy in the day-ahead market, thus creating a revenue deficiency.

[122] For a more detailed explanation of CRR revenue adequacy and the simultaneous feasibility test, please see the 2009 Market Performance Report on CRRs at http://www.caiso.com/272b/272b8a1623070.html.

Figure 5.12 Monthly revenue adequacy



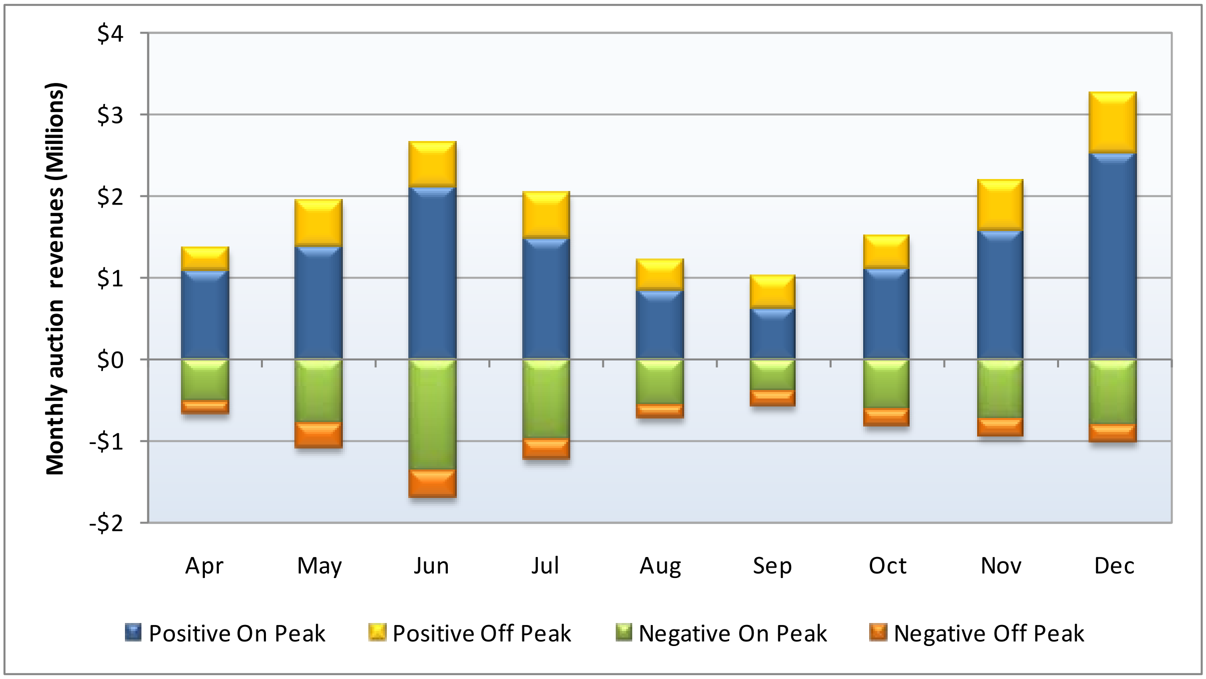
In September, one of the most deficient months of the year, Palo Verde was de-rated to 1,505 MW when the North Gila to Hassayampa line was forced out. The revenue deficiency in November was due to a de-rate on Palo Verde, as well as congestion on the SCE_PCT_IMP_BG in the day-ahead energy market. The North Gila-Hassayampa line was forced out again, de-rating Palo Verde to 2,794 MW then further to 1,442 MW. The SCE_PCT_IMP_BG was initially modeled on November 11, 2009, in the day-ahead energy market, and became frequently binding at high shadow prices.

As previously noted, the CRR balancing account also includes revenues generated from the annual and monthly auctions. While the simultaneous feasibility test theoretically guarantees revenue adequacy, revenue deficiencies can occur due to unforeseen events as previously described. Therefore, revenue adequacy can also be analyzed with auction revenues.

Figure 5.13 provides the monthly auction revenues by direction and time of use. A positive direction indicates the CRRs are sourced and sinked at locations that generally are congested in that direction (congestion at the sink is expected to be on average greater than that at the source). Therefore, market participants are willing to pay for these rights because they expect to collect entitlements through the day-ahead energy market. Negative direction rights indicates the congestion typically is in the opposite direction and market participants are paid to take these rights due to the expectation they will lose money on them. Thus, these market participants are willing to take the risk of losing CRR revenues through the day-ahead market for a price.

Overall, the ISO collected a net of $8.4 million through the monthly auctions. A total of $17.1 million was collected from positive direction rights. $8.7 million of these revenues were used to fund the negative direction rights. Most of the revenues collected and the CRRs funded were for peak hours.

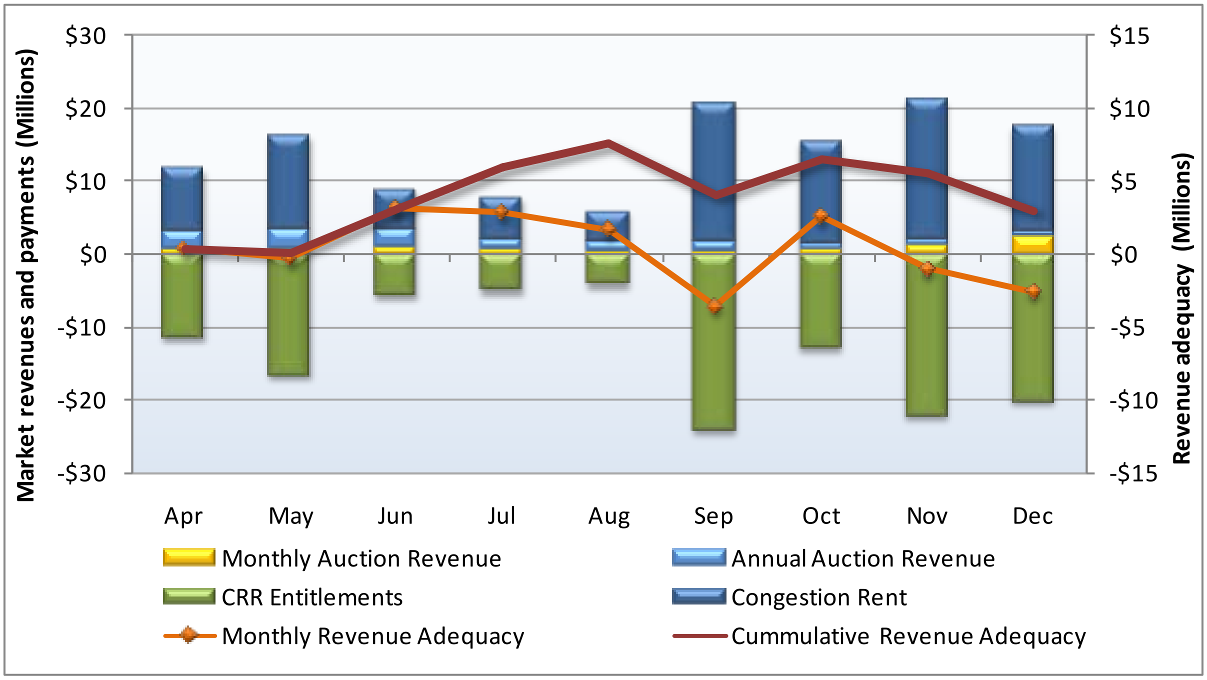
Figure 5.13 Monthly auction revenues by direction and time of use



The net revenues collected from the monthly and annual auctions are credited to the balancing account to help offset any deficiencies. Figure 5.14 shows the revenue adequacy by month including the auction revenues. The light blue bars represent revenues from the annual auction while revenues from the monthly auctions are represented by the yellow bars. The annual auction revenues are allocated pro-rata to each month for which the right was valid based on the time of use and hours in each month. Congestion rent is already net of the perfect hedge represented in Figure 5.12.

The annual and monthly auctions generated enough revenues to make four of the seven deficient months revenue adequate. The three months that were still revenue deficient (September, November, and December) were months in which major unforeseen events took place as previously discussed. Overall, the cumulative revenue adequacy, represented by the line, shows the ISO having a $3 million surplus at the end of the year. This is mainly due to having surpluses from June to August and then again in September. These revenues were sufficient to offset the deficient months.

Figure 5.14 Monthly revenue adequacy with auction revenues



CRRs as a financial instrument

For market participants using CRRs as strictly financial instruments to hedge against day-ahead congestion, the expectation is that the CRR profitability is $0. The profitability is defined as the CRR payments minus the cost to obtain the CRRs through the auction process. Each market participant participating in the auction processes reveals their own expectation of each CRR's predicted entitlements through bid prices. Therefore, those CRRs that were extremely profitable or extremely costly indicate either an under- or over-valuation, respectively.

Figure 5.15 through Figure 5.18 show the profitability distribution of CRRs by life term, seasonal or monthly, and time of use, on or off peak hours. These data only include CRRs acquired through the auction process since these CRRs were acquired and valued through a market process. The CRR profitability represents the profit per mega-watt hour.[123] A negative profit indicates either the market revenues were less than the auction cost, or in the case of counter-flow CRRs, a negative profit indicates the auction price paid was less than the revenues earned.

A large percentage of the profits are centered near $0/MWh indicating a well performing market for CRRs as a financial hedge. However, in each case there are some CRRs with extremely high profits or costs mostly attributable to unforeseen forced outages that resulted in congestion in the day-ahead

[123] The CRR profit is defined as the total CRR revenues minus auction cost, divided by the quantity MW and number of hours for which that CRR is valid. For example, assume a 10 MW monthly on-peak CRR cost of $100 in the auction (10 MW x $10/MW). If this CRR received $900 in revenues this would represent a net profit of $800 over the life of the CRRs. Since the CRR is valid for 400 hours and was for 10 MW, the profit per megawatt hour would be $0.20/MWh ($800/400hrs/10MW = $.20/MWh).

market and counter-flow CRRs being over-valued in the auction. Overall, the weighted average profit per MWh in each CRR grouping is slightly positive.

Figure 5.15 shows the profitability of CRRs auctioned in the annual process that are valid for one calendar season during peak hours.

- Only CRRs with profits between +/- $2 per MWh are shown, which represents 84 percent of all seasonal peak CRRs.
- Eleven percent of CRRs had profits at least $2/MWh and 5 percent at or below -$2/MWh.
- The average profitability of the CRRs represented in Figure 5.15 was $0.10/MWh.
- The most profitable CRRs tended to be sourced at load aggregation points and were intended to provided counter-flow as indicated by the negative market clearing price. Due to minimal congestion in the day-ahead market, the auction price paid to these CRR holders was more than CRR revenues, which were expected to be negative.

Figure 5.16 shows the profitability of CRRs auctioned in the annual process that are valid for one calendar season during off-peak hours.

- Only CRRs with profits between +/- $2/MWh are included in Figure 5.16. These represent 93.5 percent of all seasonal off peak CRRs.
- Six percent of CRRs had profits at least $2/MWh and less than 1 percent at or below -$2/MWh.
- The average profitability of the CRRs represented in Figure 5.16 was $0.10/MWh, similar to seasonal peak CRRs.
- The most profitable CRRs during off-peak hours were also the most profitable during peak hours.

Figure 5.15 Profitability of congestion revenue rights - seasonal CRRs, peak hours

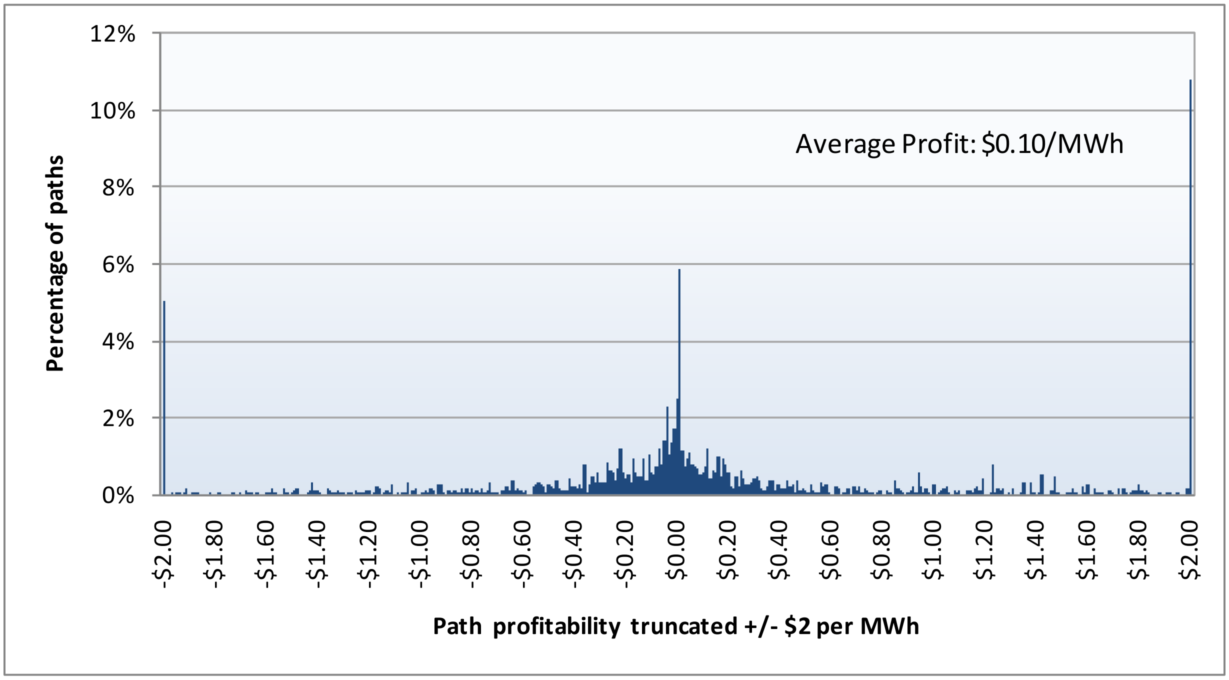


Figure 5.16 Profitability of congestion revenue rights - seasonal CRRs, off-peak hours

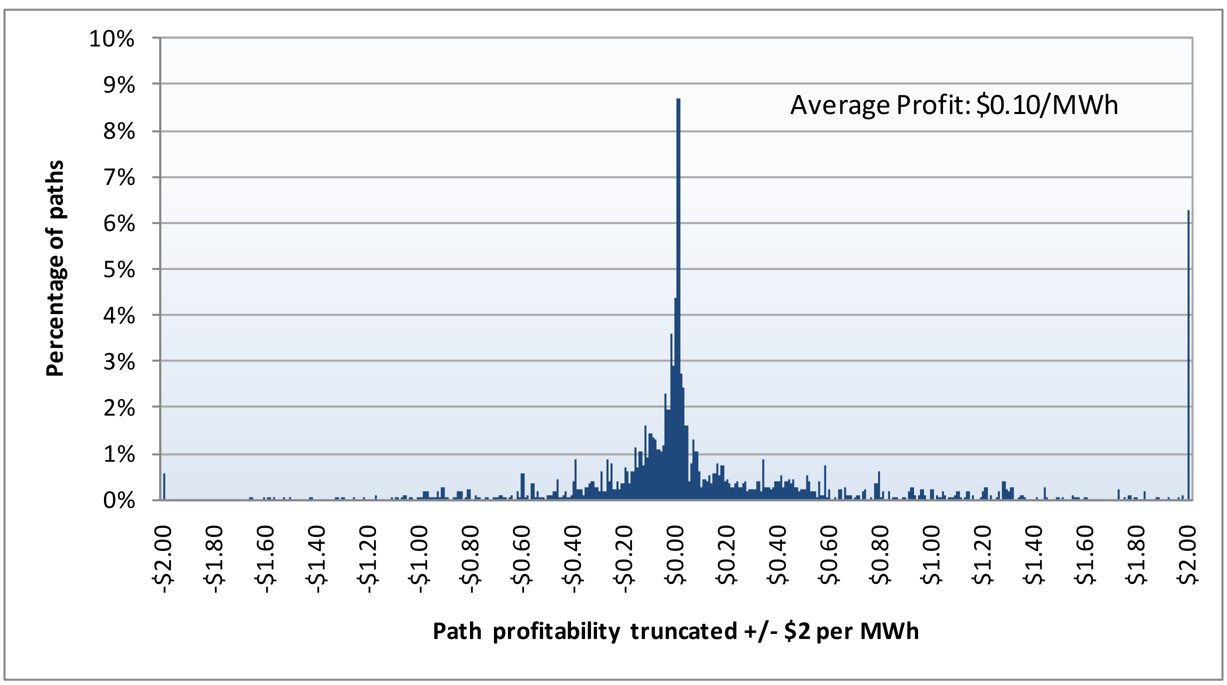


Figure 5.17 shows the profitability of CRRs auctioned in the monthly processes that are valid for one calendar month during peak hours.

- Only CRRs with profits of +/- $2/MWh are shown. This represents 90 percent of all seasonal peak CRRs.
- Seven percent of CRRs had profits over $2/MWh and 3 percent had profits below -$2/MWh.
- The average profitability of the CRRs represented in Figure 5.17 was $0.18/MWh, making this the most profitable CRR grouping.
- While there were still a few extremely profitable and unprofitable CRRs, 65 percent had a profit between -$0.50/MWh and $0.50/MWh.
- The CRRs that were most profitable and most costly are those that were impacted by unforeseen outages and de-rates that caused major congestion in the day-ahead markets.

Figure 5.18 shows the profitability of CRRs auctioned in the monthly processes that are valid for one calendar month during off-peak hours.

- Only CRRs with profits of +/- $2/MWh are shown. This represents 90 percent of all seasonal off-peak CRRs.
- Less than one percent of CRRs had profits over $2/MWh and less than 1 percent had profits below -$2/MWh.
- The average profitability of the CRRs represented in Figure 5.17 was $0.07/MWh.
- Eighty-five percent had a profit between -$0.50/MWh and $0.50/MWh.
- The monthly off-peak CRRs that were most profitable and most costly are those that were impacted by unforeseen outages and de-rates that caused major congestion in the day-ahead markets.

Figure 5.17 Profitability of congestion revenue rights - monthly CRRs, peak hours

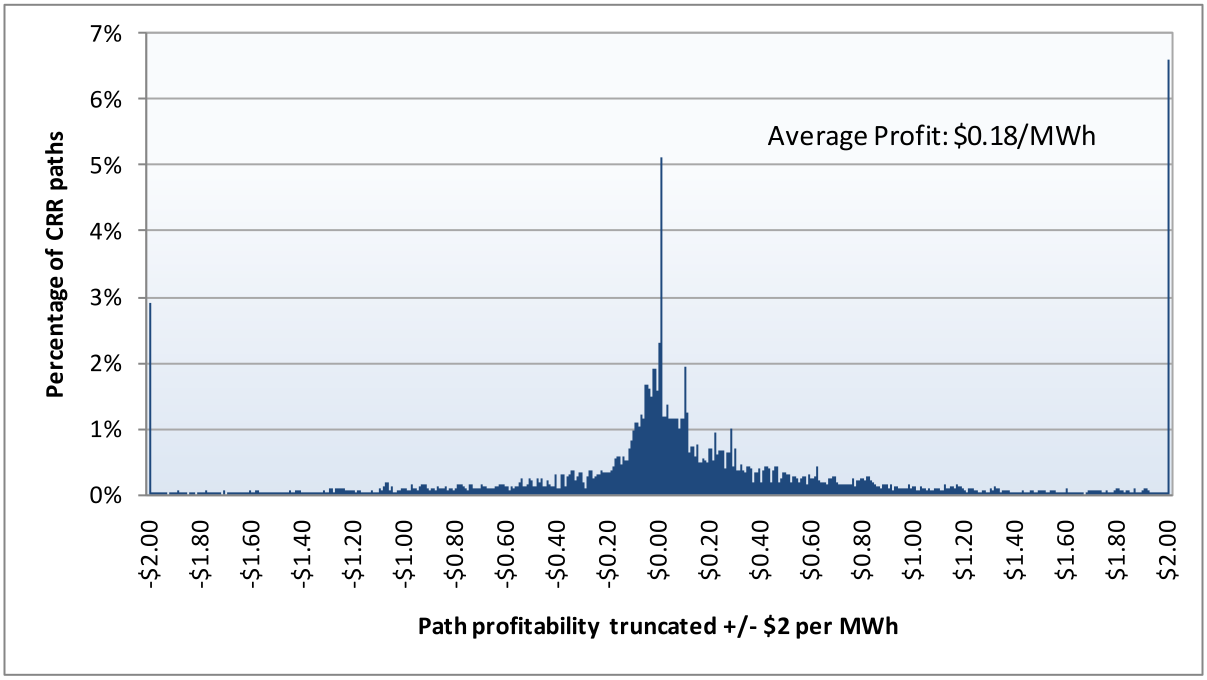
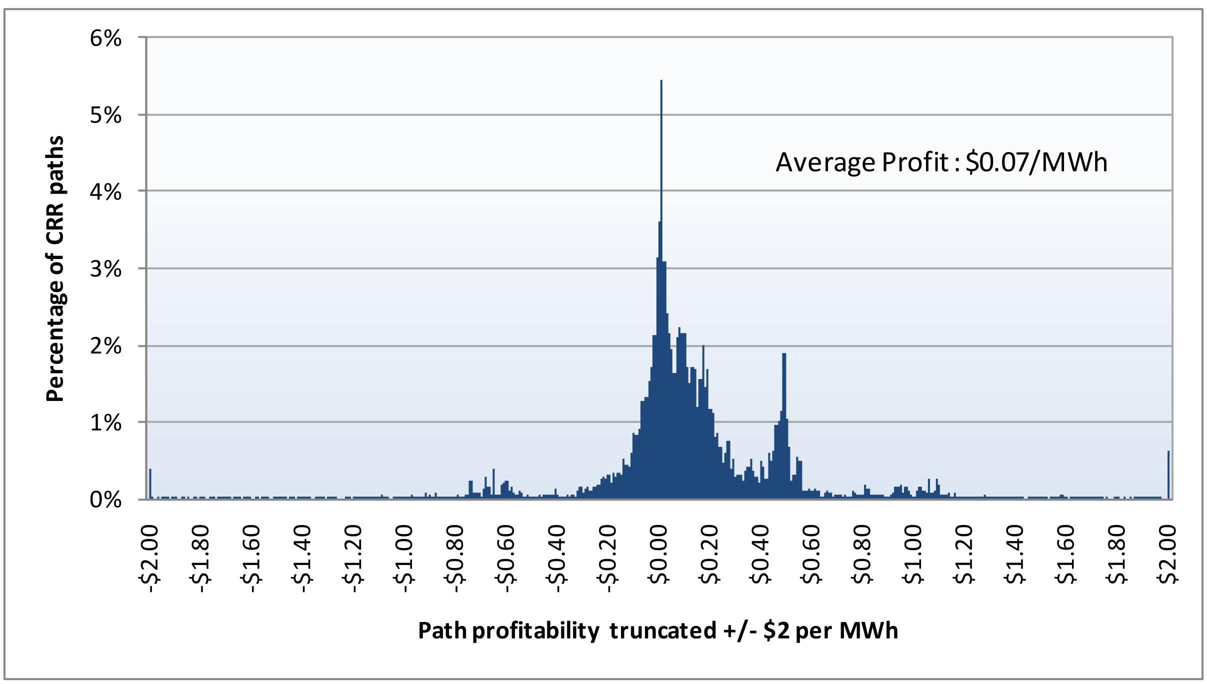


Figure 5.18 Profitability of congestion revenue rights - monthly CRRs, off-peak hours



6 Ancillary services

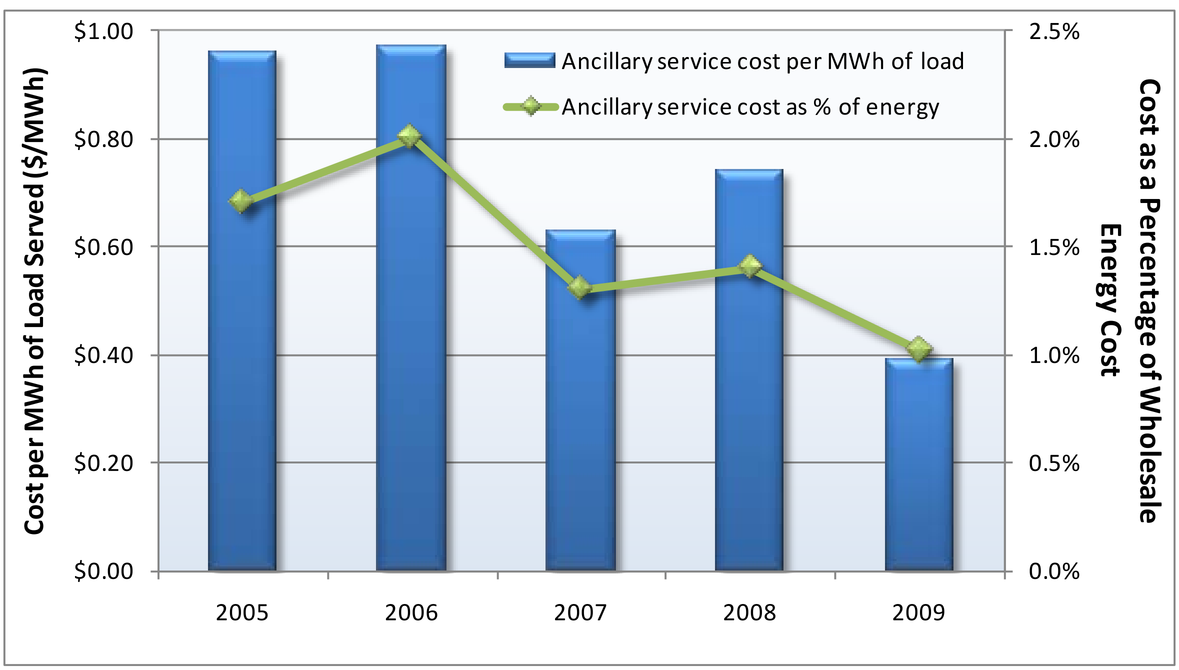
Ancillary service markets performed extremely well in 2009, showing an overall decrease of 50 percent in total costs from 2008. There were no hours in which the supply of ancillary services was insufficient to meet the ISO's requirements.

The more significant changes in prices and costs occurred after the implementation of the new market, when co-optimization of energy and ancillary services greatly improved the efficiency of the market. With co-optimization, units are able to bid in all their capacity into both the energy and ancillary service markets without risk of losing revenue in one market by having their capacity sold in the other market. This increases the supply of bids and allows the market software to determine the most efficient use of each unit's capacity for energy and ancillary services.

Under the new market design, 100 percent of the forecasted requirement for ancillary series is procured in the day-ahead market. This also contributed to lower costs by ensuring that the demand for incremental capacity in real-time was minimal. This made ancillary service cost less exposed to higher real-time ancillary service prices, which sometimes resulted from high prices in the real-time energy market.

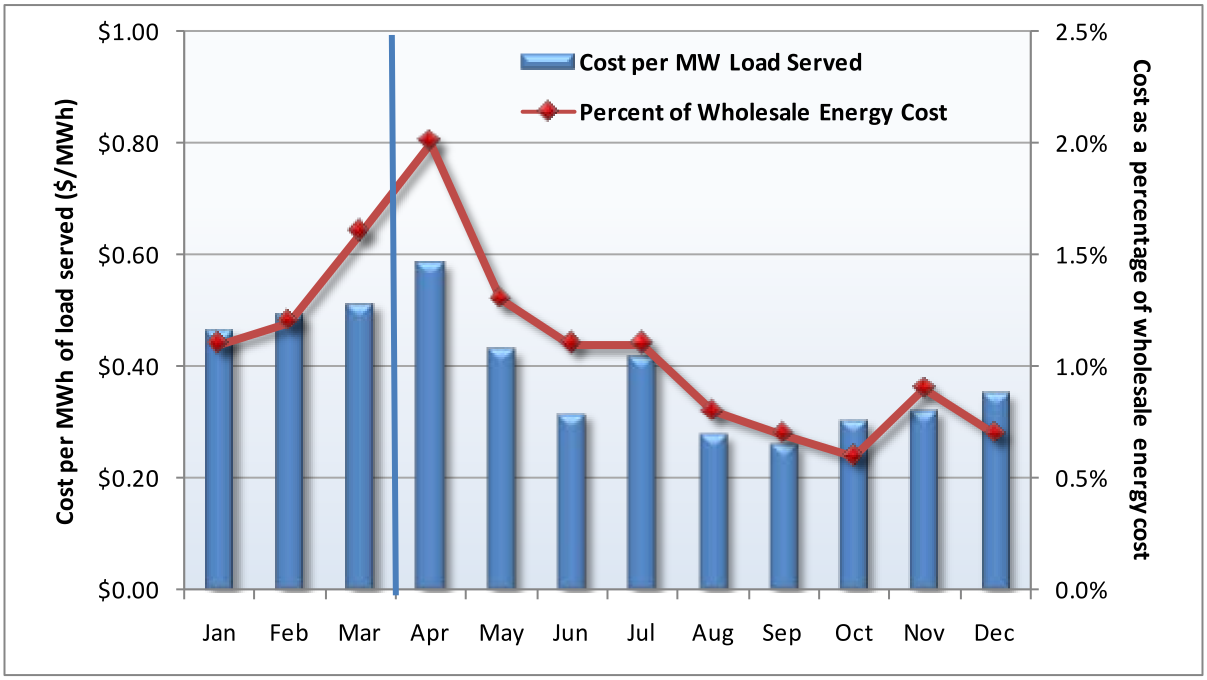
Under the new market, ancillary service costs have decreased as indicated by measures that reflect different load levels and the cost of energy (and, indirectly, natural gas prices) between years as well as seasonal variations. As shown in Figure 6.1, ancillary service costs decreased from $0.74/MWh of load in 2008 to $0.39 in 2009. Ancillary service costs also dropped from 1.4 percent of estimated wholesale costs in 2008 to 1 percent in 2009.

Figure 6.1 Ancillary service cost as a percentage of wholesale energy cost (2005 – 2009)



Monthly trends in ancillary service costs in 2009 before and after implementation of the new market design also indicate costs have decreased under the new market design, as shown in Figure 6.2. Overall, ancillary service costs decreased from $0.49/MWh of load in the first quarter of 2009 to $0.36 in the remaining months of the year following the new market implementation. Ancillary service costs dropped from 1.3 percent of estimated wholesale costs during the first quarter of 2009 to 0.9 percent after the new market implementation.

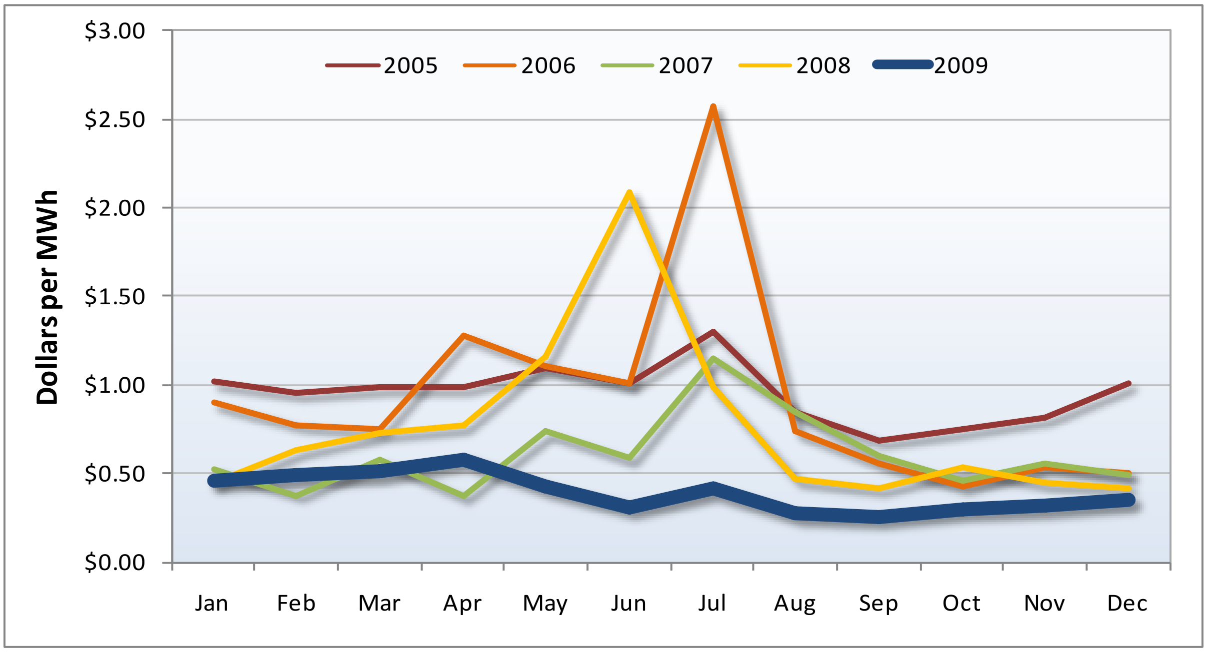
Figure 6.2 2009 ancillary service cost by month



Seasonal trends also indicate that the new market design has resulted in lower ancillary service costs. As shown in Figure 6.3, those costs have historically increased in summer months, when both loads and prices are higher. However, they decreased over the summer months in 2009 under the new market design.

An enhancement to the function and pricing of the ancillary service market, scarcity pricing, will be implemented in 2010. Scarcity pricing is a design mechanism intended to trigger higher prices for ancillary services and energy when the level of operating reserve drops below an administrative threshold, indicating scarcity in the market. The primary trigger is in the ancillary services market; however, through co-optimization of energy and ancillary services the scarcity price in ancillary services (when triggered) may also be reflected in the energy price and vice versa. Scarcity pricing will be triggered in the day-ahead and real-time ancillary service markets when there is not enough capacity to meet requirements by region and product, resulting in higher prices influenced by an administratively determined scarcity price schedule.

Figure 6.3 Ancillary service cost per MWh of load (2005 – 2009)



6.1 Market overview[124]

Ancillary service types

The California ISO procures four ancillary services in the day-ahead and real-time markets:

- ***Regulation up*** — Units providing regulation up must be able to move quickly above their scheduled operating point in response to automated signals from the ISO to maintain the frequency of the system by balancing generation and demand and they must be synchronized to the grid.
- ***Regulation down*** — Units providing regulation down must be able to move quickly below their scheduled operating point in response to automated signals from the ISO and synchronized to the grid.
- ***Spinning reserve*** — Resources providing spinning reserves must be synchronized with the grid (i.e., on-line or "spinning") and be able to ramp over a specified range within 10 minutes.
- ***Non-spin*** — Resources providing non-spinning reserves must be able to synchronize with the grid and ramp over a specified range within 10 minutes. Combustion turbines that can start-up and become synchronized to the grid within 10 minutes can provide non-spinning reserves. Demand response resources can also provide non-spin capacity if they are telemetered and meet the ramping requirements.

[124] The following market overview will focus on ancillary services in the new markets. For a more detailed explanation of the prior markets, refer to *2008 Annual Report on Market Issues and Performance*, Department of Market Monitoring, http://www.caiso.com/2390/2390818c3bc40.html.

Regulation up and regulation down are used on a continual basis to maintain system frequency by balancing generation and demand. Spinning and non-spinning resources are used to maintain system frequency stability during emergency operating conditions and major unexpected variations in load. Spinning and non-spinning resources are often referred to collectively as operating reserves.

The ISO also allows for cascading of higher quality for lower quality reserves. Regulation up is considered the highest upward quality reserve, followed by spin, then non-spin. When economical, the market software will procure more of a higher quality reserve to meet the requirement of a lower quality reserve.

Ancillary service requirements

The ISO sets system-wide requirements for each ancillary service to meet or exceed WECC's minimum operating reliability criteria and NERC's control performance standards.

- The regulation requirement prior to October 2009 was set at 350 MW for both regulation up and down. Currently, the requirement is based on inter-hour changes in scheduled generation, inter-tie schedules, forecasted demand, and the number of units starting up or shutting down. Therefore, the requirement can vary each hour depending on the hour of operation, and is set for regulation up and down independently.
- The operating reserve requirement is set by the maximum of 5 percent of forecasted demand met by hydroelectric resources plus 7 percent of forecasted demand met by thermal resources, or the largest single contingency.

In the prior market design, a portion of the ancillary service requirement could be deferred to the hour-ahead market. Under the new market, 100 percent of the expected requirement for each of the four types of ancillary services is procured in the day-ahead market. All reserve requirements can be increased or decreased in the real-time pre-dispatch market based on updated system conditions. Additional capacity may be procured in the real-time pre-dispatch to either replace capacity that is no longer available due to outages and de-rates, or to meet an increase in market requirement (e.g., because of an increase in the demand forecast). Units with day-ahead awards that are unable to provide the capacity in real-time are charged for the unavailable capacity at the average of the four real-time pre-dispatch prices.

Contingency-only ancillary services

In the day-ahead market, spinning and non-spinning capacity can be bid in as either non-contingent or contingency-only operating reserves. Non-contingent operating reserves can be economically dispatched as energy in real-time. Contingency reserves can only be dispatched to avoid, or respond to, a system contingency. This may occur because of the sudden loss of internal generation or transmission, or whenever an operator determines that additional energy is needed on an emergency basis to protect local or system reliability.

Additional capacity procured in the real-time market is automatically flagged as contingency-only. Also, if any additional capacity is procured in real-time from a unit already scheduled to provide non-contingent capacity in the day-ahead market, that unit's day-ahead capacity is also converted to contingency-only. Currently, there is no limitation on the percent of procured operating reserves that is flagged as contingency-only.

Co-optimization of ancillary services

One of the major enhancements of the new nodal market design is co-optimization of the procurement of energy and ancillary services. Co-optimization considers the lost opportunity cost of providing one product (energy or ancillary service) rather than the other when determining prices.[125] With co-optimization, market outcomes more closely reflect the cost of producing one product in lieu of the other. This results in a more efficient least cost procurement of both products.

The day-ahead market co-optimizes energy and ancillary services over a 24-hour period and is financially binding for both energy and ancillary services. The real-time pre-dispatch market also co-optimizes energy and ancillary services. The real-time pre-dispatch market is run every 15 minutes, about 22 minutes in advance of each 15-minute operating period.

Ancillary service procurement

Under the prior market design, the ISO procured ancillary services in the day-ahead and hour-ahead markets from within three zones. Under the new market, the ISO can procure ancillary services in the day-ahead and real-time pre-dispatch markets from 10 pre-defined regions. Only four of these regions were enforced in 2009:

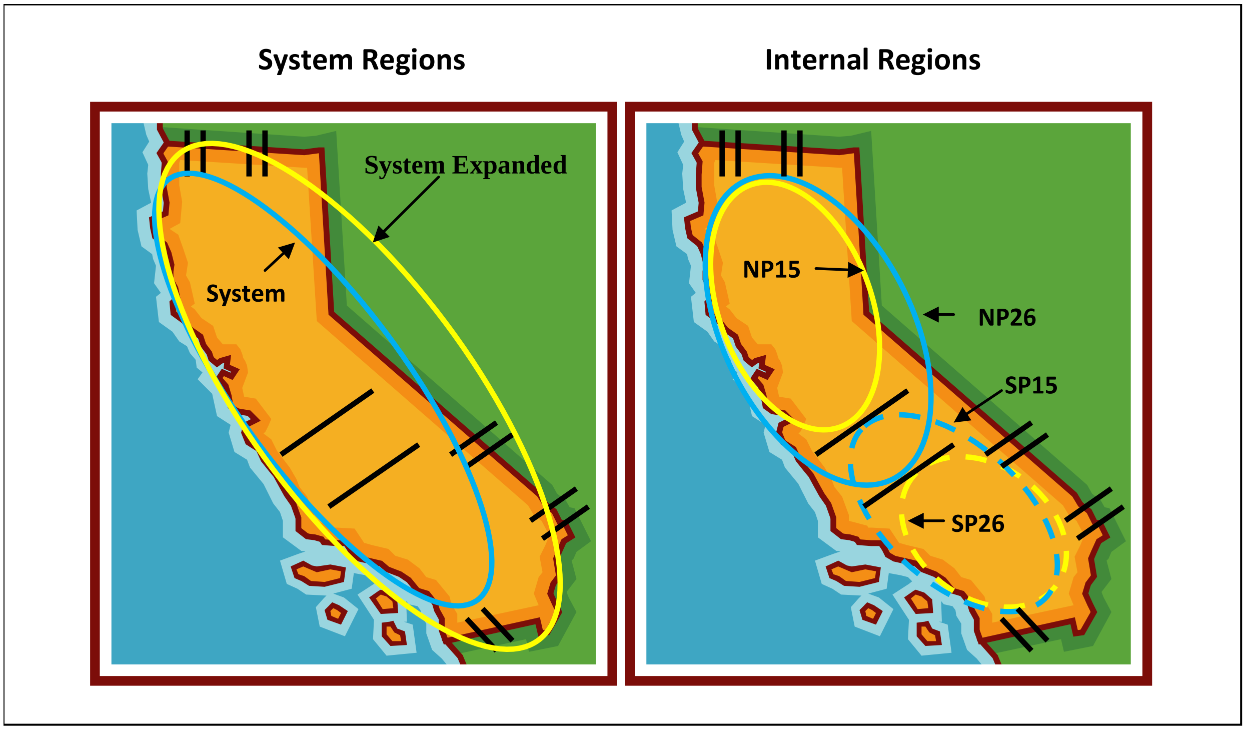
- System
- System Expanded
- South of Path 26
- South of Path 26 Expanded

Figure 6.4 illustrates the new market procurement regions in terms of system and internal regions. The system region map includes both the system region and the system expanded region. The internal regions are all nested within the system regions. The far right map only shows the unexpanded internal regions simply for illustrative purposes. In all cases, the expanded regions are identical to the inner regions but include any inter-ties with one end in the unexpanded region.

The system minimum requirement for each service is distributed as minimum sub-regional requirements for each enforced sub-region. Because of the nesting of regions in the new markets, capacity procured in a more granular region also counts toward meeting the minimum requirement of the outer region.

[125] For example, take a 100 MW unit that bid in 90 MW of energy at $20/MW and 20 MW of spin at $5/MW. If the unit is awarded 90 MW of energy and 10 MW of spin, there is no opportunity cost because the unit did not forgo any bid in energy for spin capacity. However, if the unit was awarded 80 MW of energy with an energy LMP of $50 and 20 MW of spin, there would be a $30 opportunity cost equal to the difference of the energy LMP at that unit's PNode and its energy bid price ($30=$50-$20). Furthermore, assuming this unit was marginal for spin, the spin market clearing price would be $35 = $5(marginal spin bid price)+$30(opportunity cost).

Figure 6.4 Ancillary services old market zones and new market regions



In addition to the minimum regional requirements, the new market also enforces the following procurement requirements in both the day-ahead and real-time pre-dispatch markets.

- ***Upward ancillary service maximum requirement*** **—** The total procurement of regulation up, spin, and non-spin cannot exceed a maximum value. This requirement is to ensure the market does not hold unnecessary capacity from the energy market.
- ***Spin operating reserve minimum requirement*** **—** At least 50 percent of total operating reserves must be met by spinning reserves.
- ***Internal generation operating reserve minimum requirement*** **—** At least 50 percent of total operating reserves must be met by internal resources.

Ancillary service pricing

The pricing of ancillary services changed significantly with the implementation of the new nodal markets. In the old market, the clearing price was set by the bid price of the marginal unit. Furthermore, all resources providing the same service received the same price despite being located in different zones. The new markets provide regional pricing signals for each service in two manners:

- ***Regional ancillary service shadow prices* —** These prices reflect the cost of having to procure one additional megawatt from within a given region for a given service.[126] Regional ancillary service shadow prices are non-zero when the regional minimum or maximum requirement constraint is binding, and are always zero when the regional minimum and maximum requirement constraints are not binding.

- ***The ancillary service market clearing price* —** The market clearing price received by each unit for each service sold is the summation of the regional ancillary service shadow prices for that service across the regions in which the unit resides. For example, the ancillary service market clearing price of a unit that sold regulation up in the SP26 region is equal to the summation of the regulation up regional ancillary service shadow prices for SP26, SP26 Expanded, System, and System Expanded regions. Thus, units within the most granular region will always receive the highest market clearing price for a given service. It also follows that, because of cascading of higher quality reserves for lower quality reserves, the highest quality reserve, regulation up, will always have the highest market clearing price. Furthermore, all units belonging to the same set of regions, for the same service, will receive the same market clearing price.

6.2 Procurement

The ISO procures four ancillary services in the day-ahead and real-time markets: regulation up, regulation down, spin, and non-spin. System-wide requirements are set for each ancillary service to meet or exceed WECC's minimum operating reliability criteria and NERC's control performance standards. The system-wide requirements are distributed as zonal requirements in the old markets, or regional requirements in the new markets, covering the ISO control area. This section will provide an overview of procurement trends in 2009 by market type as well as by region. A discussion of various market mechanisms and caveats are also provided. The analyses will show that most procurement patterns remained relatively consistent between the old and new markets with a few exceptions:

- Day-ahead requirements and procurement increased with the new markets.
- Regulation requirement varies under the new markets.
- Substitution tends to occur more between spin and non-spin in the new markets where it occurred more between regulation up and spin in the previous markets.

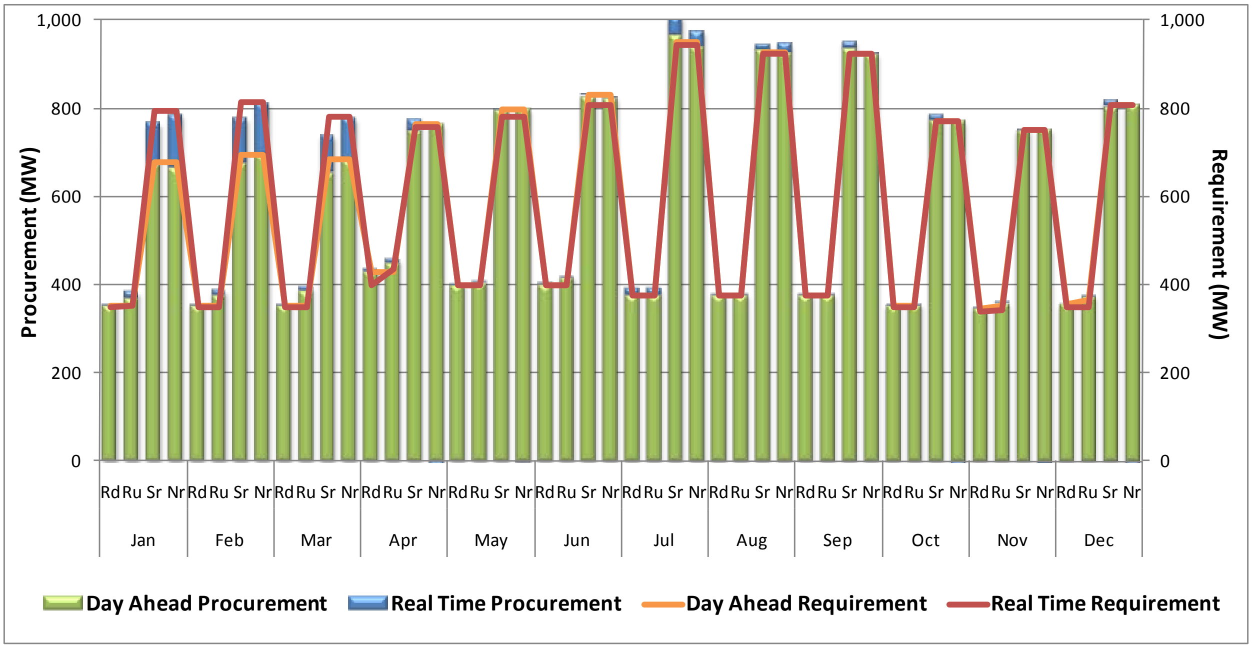
Figure 6.5 shows the monthly average hourly procurement and requirement by market type for all four services. The change in requirements is one of the most noticeable differences in procurement trends under the new market. Day-ahead requirements increased substantially for all four products in the new market, most notably for spin and non-spin. This is because in the prior markets, the ISO deferred a small percentage of ancillary service requirements to the real-time market. Therefore, the day-ahead requirement in the prior markets reflects a percentage of the estimated requirement. In the new markets, the ISO does not defer a percentage to the real-time; therefore, the day-ahead requirement reflects 100 percent of the estimated requirement.

Overall, the average hourly operating reserve requirement, referring to spin and non-spin collectively, is 1,641 MW, representing a 5 percent decrease from 2008. The operating reserve requirement is typically set by 5 percent of forecasted demand met by hydroelectric resources plus 7 percent of forecasted

[126] A regional ancillary service shadow price is produced for each enforced region and each service.

demand met by thermal resources.[127] Therefore, operating reserve requirements follow a seasonal load pattern as evident by the slightly higher requirement during the peak load months.

Figure 6.5 Procurement by market type



The requirement for regulation up and down was consistently 350 MW in both the day-ahead and hour-ahead markets in the prior market. When the new markets were implemented, the requirement for regulation up and down was initially 350 MW in both the day-ahead and real-time markets, but varied thereafter. The requirement was increased 150 MW in April to minimize the number of control performance standards 2 violations and was gradually lowered over subsequent months. In October, an algorithm was implemented that more accurately determined reliable regulation requirements based on inter-hour forecast and schedule changes.

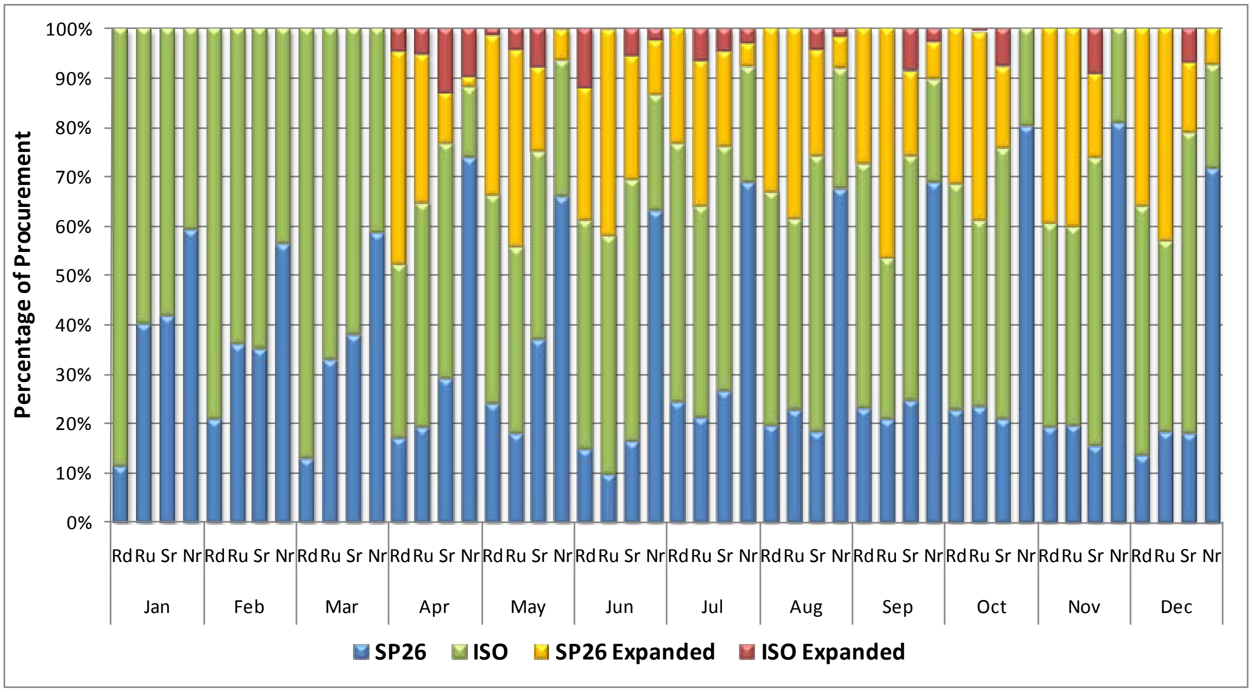
Under the prior market design, higher quality ancillary service products could be substituted for lower quality reserves. A similar mechanism exists in the new market and is referred to as product substitution or cascading. The effect of these mechanisms is reflected in Figure 6.5 by the amount of procured capacity above the requirement of one product, followed by procurement less than the requirement of a lower quality product. For example, in January, approximately 40 MW of additional regulation up was procured, represented by the procured megawatts above the requirement. The additional capacity was procured to meet spin requirement as shown by the difference in spin requirement and procurement.

Ancillary services were to meet only a system-level requirement in the prior market and four regions in the new markets. Procuring to regional requirements ensures spatial procurement of ancillary services

[127] Because of the magnitude of demand, the five and seven percent is typically larger than the single largest contingency, which can also set the requirement.

across the control area. Although regional requirements were not enforced in the prior market, the capacity procured in the first quarter is reflected in Figure 6.6.

Figure 6.6 Procurement by ancillary service region



In the new markets, the system minimum requirement was consistently distributed as minimum requirements to the four regions. Because of the nested nature of the regions, the requirements listed below for larger regions are inclusive of more granular regions.

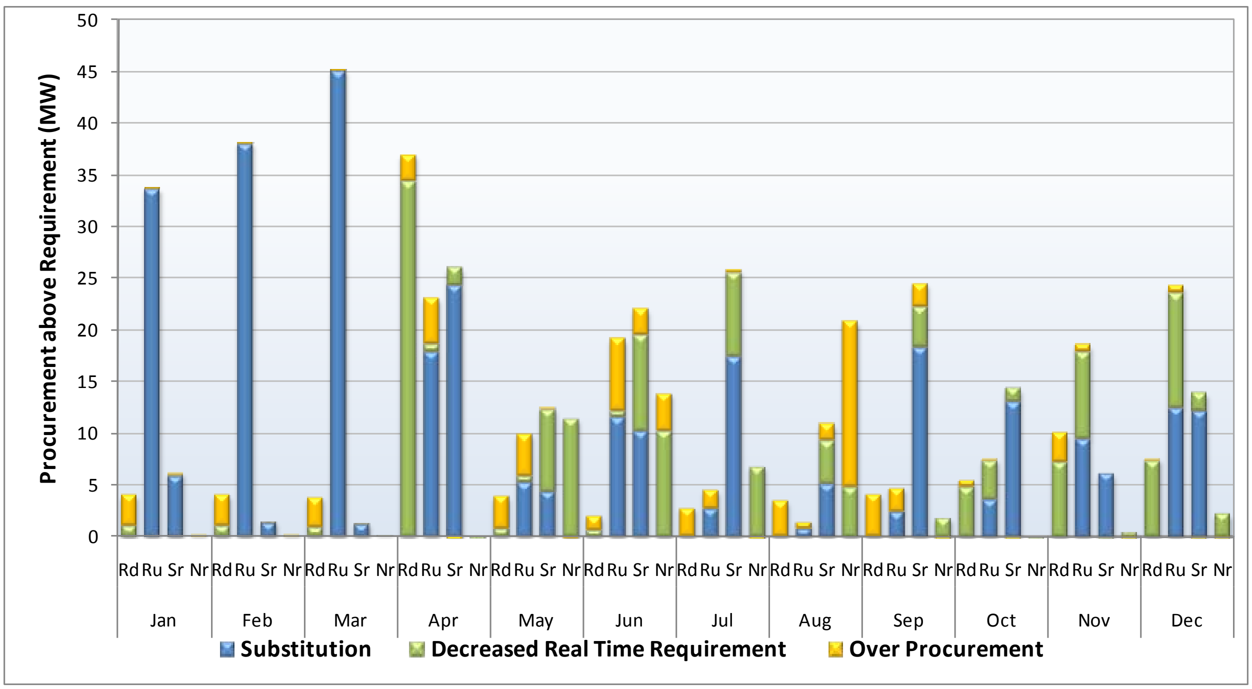
- Regulation
  - 10 MW[128] minimum in the SP26 and ISO regions.
  - 35 percent of total requirement from SP26 Expanded region.
  - 100 percent of total requirement from ISO Expanded region.
- Operating Reserves
  - 17.5 percent of total requirement from the SP26 region.
  - 35 percent of total requirement from the SP26 Expanded.
  - 50 percent of total requirement from the ISO region.
  - 100 percent of total requirement from the ISO Expanded region.

[128] Regulation requirement is reported in megawatts rather than percentage because the requirement in percentage varied to keep the minimum requirement at 10 MW.

Figure 6.6 above shows the average regional procurement of each commodity by month as a percentage of the total procurement. The percentages reported for the larger regions under the new markets are incremental to the percentages of the nested regions. Despite the absence of regional requirements in the prior market, spatial procurement of capacity has remained relatively unchanged between the two markets in 2009.

Capacity procured in the new markets across the ties is distinguished from internal capacity as represented by the procurement in the two expanded regions. Ancillary services bid across the ties have to compete with energy for transmission capacity. If a tie becomes congested, the scheduling coordinator awarded ancillary services will be charged the congestion rate. On average, only 16 percent of operating reserve capacity came from ties.

Figure 6.7 Ancillary service procurement breakdown



There were no hours or intervals with procurement deficiency in ancillary services. However, there were several instances where more than the minimum requirement was procured as a result of several factors including substitution between services, changes in requirements from day-ahead to real-time, and procuring at no additional cost from $0 priced bids. Figure 6.7 focuses on the capacity procured in excess of the total market requirement by commodity. The chart provides a summary of procurement above the requirement under the following categories:

- ***Substitution* —** Capacity procured above the requirement for a given commodity and region that was procured to meet the requirement of a lower quality product because of the rational buyer algorithm (January through March) or cascading (April through December). This capacity was used to meet the requirement of a different service and is not considered “over-procurement.”

- ***Decreased real-time requirement* —** Capacity procured in the day-ahead but also cleared in real-time despite a lower real-time requirement.

- ***Over-procurement* —** Capacity procured, after accounting for substitution and changes in the requirement, because of being self-scheduled or bid in at a zero dollar price.

In the first three months of 2009, the majority of capacity procured above the requirement was due to substitution. On average, an additional 40 MW of regulation up and 3 MW of spin was procured to substitute for non-spin in the old markets. From April through December, there were some significant changes in the distribution of, and reasons for, procuring above the requirement. Capacity procured for substitution came from both regulation up and spin for non-spin requirement.

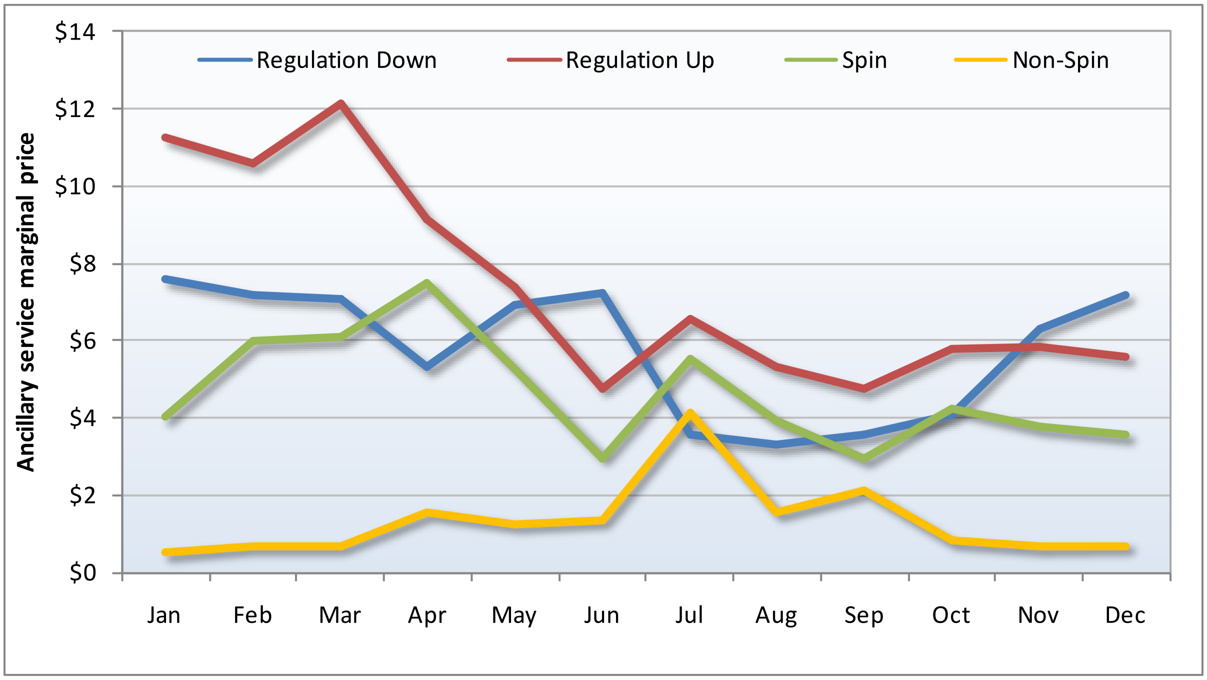
After April, procurement of regulation above the (real-time) requirement because of a decreased requirement was minimal until October, when the new regulation requirement tool was implemented. Often, the day-ahead requirement for regulation up and/or down reached 500-600 MW, especially during ramping hours, compared to 375 MW prior to the new tool. In real-time, operators would adjust the requirement down if it became apparent that less regulation was required. In these circumstances all of the available day-ahead capacity will remain procured (no sell-back to suppliers), even if there is a decreased requirement in real-time. This often results in procurement above the new, decreased, requirement.

The market also procured capacity above the minimum requirement as long as the additional capacity did not increase the overall production cost. The additional capacity was procured if it was self-scheduled (no bid-cost of procurement) and at a location with no lost opportunity cost. This issue was identified in late July and early August, when the market was consistently procuring capacity over the required amount, often in excess of 100 MW. As seen in Figure 6.7, over procured capacity drastically decreased in October because of a new total upward ancillary service maximum constraint implemented in late September.

6.3 Ancillary service pricing

Resources providing ancillary services receive a capacity payment, or market clearing price, in both the day-ahead and real-time markets. Capacity payments in the real-time market are only for incremental capacity above the day-ahead award. Figure 6.8 and Figure 6.9 below show the weighted average market clearing prices for each ancillary service product by month in the day-ahead and real-time markets respectively.

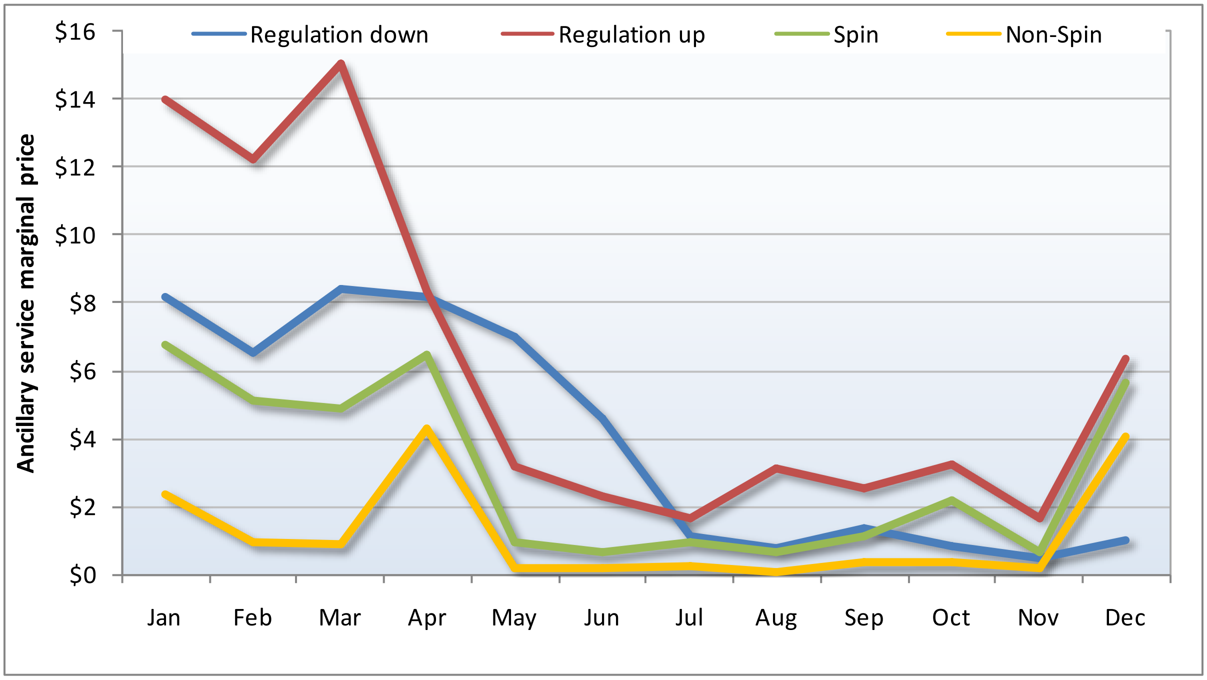
Figure 6.8 Day-ahead ancillary service market clearing prices



Overall, the day-ahead prices ranged from approximately $0.50/MW to $13/MW but significantly decreased one month after the new market was implemented. From May through December, day-ahead prices ranged from $0.50/MW to $7/MW. This is most likely attributable to the following factors:

- Supply in the new market significantly increased because scheduling coordinators could bid in all certified capacity into both energy and ancillary service markets. Previously, total capacity bid into energy plus ancillary services could not exceed the certified capacity.
- Bid prices tended to decrease in the new market because the co-optimization in the new market compensates a supplier for their lost opportunity cost of selling ancillary services in lieu of energy. Suppliers no longer have to forecast their lost opportunity cost and include that in their ancillary service bid.
- Suppliers no longer needed to account for commitment cost (start up and minimum load) in their bid prices. The new market, through market revenue or bid cost recovery, will compensate suppliers for these costs.

Figure 6.9 Real-time ancillary service marginal prices



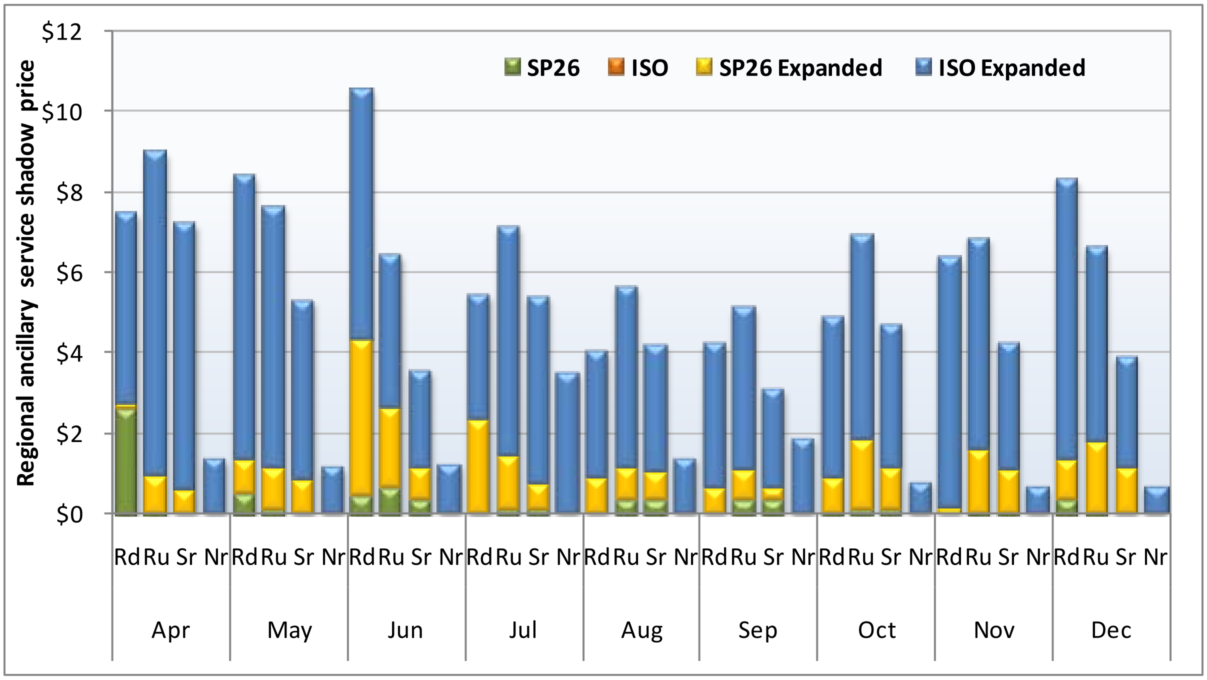
Real-time ancillary service prices, shown in Figure 6.9, generally reflect the same pricing trends as in the day-ahead. Prices decreased for all products one month after the new market was implemented. The range of observed prices also decreased, initially ranging from approximately $1/MW to $15/MW in the old market to $0.10/MW to $6/MW in the new one. However, the decrease in real-time prices is also attributable to the smaller amount of capacity procured in that market.

Real-time prices in December increased significantly for the three upward products. The increase in prices was event driven where there were several generating units and transmission lines being forced out of service due to weather conditions. Prices for all three services for four intervals on December 7 and two on December 8 were greater than $1,500/MW. The system conditions from these events led to higher energy prices, which were then reflected in the ancillary service prices.

The ISO procured ancillary services from four of the 10 pre-defined zones under the new market.[129] As previously mentioned, each region is enforced with a minimum requirement for all products. Because of the nested nature of the regions, any procurement from a more granular region is also applied to meeting the requirement of the larger region. Figure 6.10 and Figure 6.11 show the average regional ancillary service shadow prices by commodity for the day-ahead and real-time markets, respectively. Across all products and months, the ISO expanded region produced the highest regional shadow prices on average, followed by the SP26 expanded region.

[129] Regional ancillary service shadow prices are only relevant to the new markets, therefore only prices for April through December are provided.

Figure 6.10 Day-ahead regional shadow prices



The two internal regions, the SP26 and ISO, were rarely binding due to the low minimum requirements set in both regions for all four products. The minimum requirement for both regulation products in both regions was 10 MW. When more than 10 MW was procured, the minimum constraint was non-binding and resulted in a zero dollar shadow price. In addition, if more than 10 MW was procured from SP26, then the ISO region also becomes non-binding. This is because they both had the same minimum requirement and any capacity procured in SP26 region helped meet the ISO requirement because SP26 is nested within the ISO region. The expanded regions had higher requirements and became binding more frequently than the internal regions.

The same holds true for spin and non-spin; however, the minimum requirements were 17.5 percent and 50 percent of the total requirement for the SP26 and ISO regions, respectively. The expanded regions were binding more often than the internal regions because of the low minimum requirements for the SP26 and ISO regions. Typically, more than the minimum amount of capacity was procured from the internal regions.

Despite the low minimum requirements in SP26, the region was binding a few times during the nine months. When SP26 became binding, it was an indication that capacity in the north or expanded regions was more economical. This can occur for a couple reasons:

- Energy prices in the south were higher and therefore most units with bid in capacity also had a higher lost opportunity cost. Therefore, capacity in the north or expanded regions was more economical.
- Capacity in the south was bid in at higher prices than in the north. If the bid price spread was large enough, it would be more economical to create a non-zero shadow price in the south and procure capacity in the north.

Figure 6.11 Real-time regional shadow prices

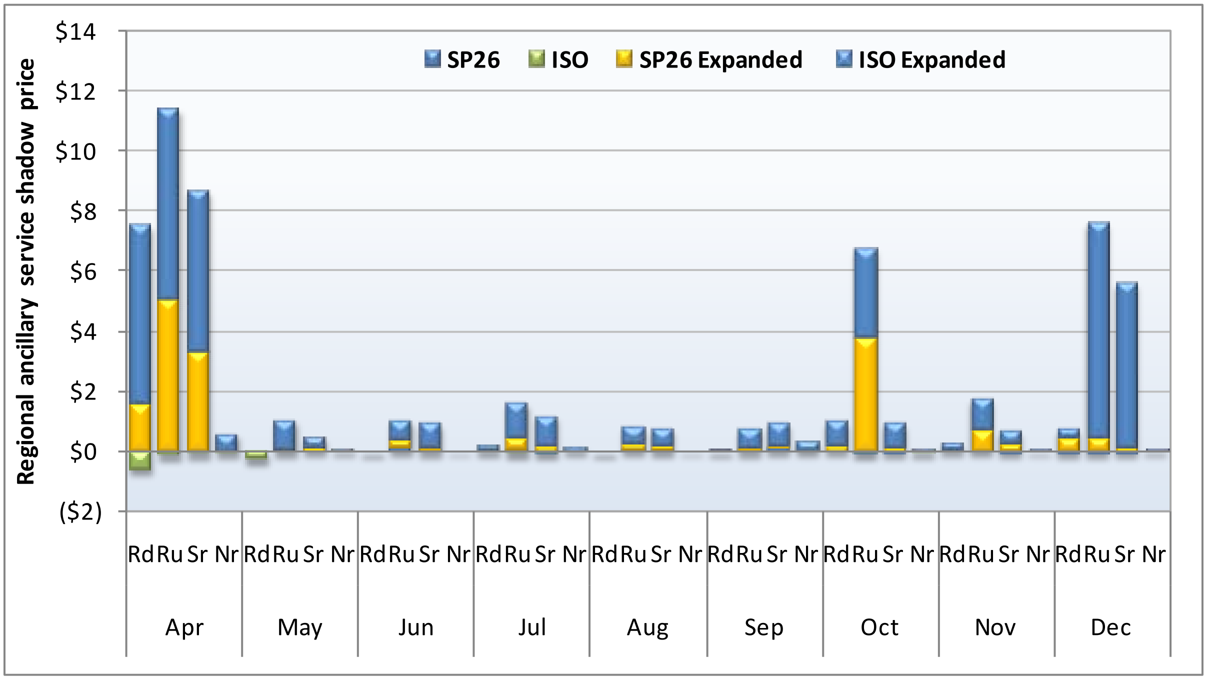
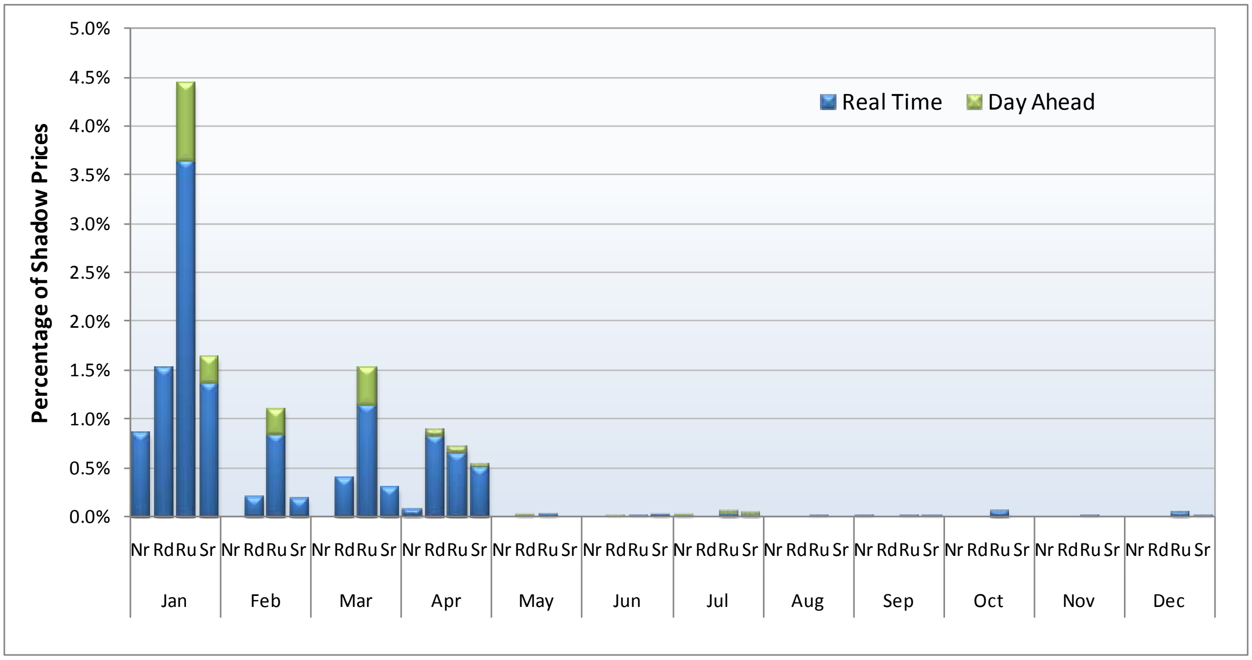


Figure 6.11 shows the real-time shadow prices for all four products from April through December. There are two main differences between shadow prices in the day-ahead compared to real-time. First, real-time prices are, on average, significantly lower than day-ahead. This is due to the small amount of incremental capacity needed in the real-time. One hundred percent of estimated requirement is met in the day-ahead. Therefore, the day-ahead market inherently clears higher up the supply curve. In real-time, all day-ahead awarded capacity is submitted as self-schedules. The only incremental capacity awarded in real-time is to replace day-ahead capacity that is no longer available and make up for any increases in requirements from the day-ahead.

Second, there were a few negative shadow prices in the ISO region during April and May. These were the result of over-procurement where a maximum constraint in the ancillary service market becomes binding. In the first two months, a large amount of capacity was being self-scheduled in the ISO region and was not able to be backed down. This created over-procurement and negative shadow prices. Note that even though negative shadow prices were created in the ISO region, there was a larger off-setting positive shadow price for the ISO expanded region. Because the market price received by units is the summation of shadow prices for the regions in which it resides, no unit had to pay the ISO to provide ancillary services.

Figure 6.12 Ancillary service price spike frequency



Throughout this chapter, each metric has shown a decrease in costs and prices of ancillary services since the implementation of the new nodal markets. Figure 6.12 highlights the significant difference in ancillary service prices since the start of the new markets in April. Figure 6.12 shows the percentage of prices greater than $50/MW for each month and commodity by market type. Overall, there were few instances where prices reached beyond $50/MW in either market and most of those instances occurred in the real-time market. That said, the times when prices did reach above $50/MW were concentrated in the first four months. Again, the month of April was an adjustment period and therefore did have higher prices than the remaining months in the new market.

6.4 Ancillary service costs

Ancillary service costs in 2009 totaled $89.9 million, representing a 50 percent decrease from 2008. Figure 6.13 shows the total cost[130] of procuring all four products by region and month. The line represents the average cost per MWh of load served in the prior market design versus the new market. In the new market, regional cost is incremental to the cost incurred from nested regions.[131] For example, the ISO region cost is incremental relative to the SP26 region cost.

Twenty-nine percent of the annual cost was incurred during the first three months of the year, representing $0.49 per megawatt hour of load served. Approximately 73 percent of total cost in the old markets (first quarter of 2009) was incurred from North of Path 26, compared to 27 percent from South of Path 26. Spin and regulation up contributed the most to cost during the old markets, representing 37

[130] The total cost figures from April through December account for day-ahead capacity that is unavailable in real-time, and charged back to the specific unit(s) at the average of the real-time price.

[131] Figure 6.4 provides a map comparing the ancillary service regions in the old and new markets.

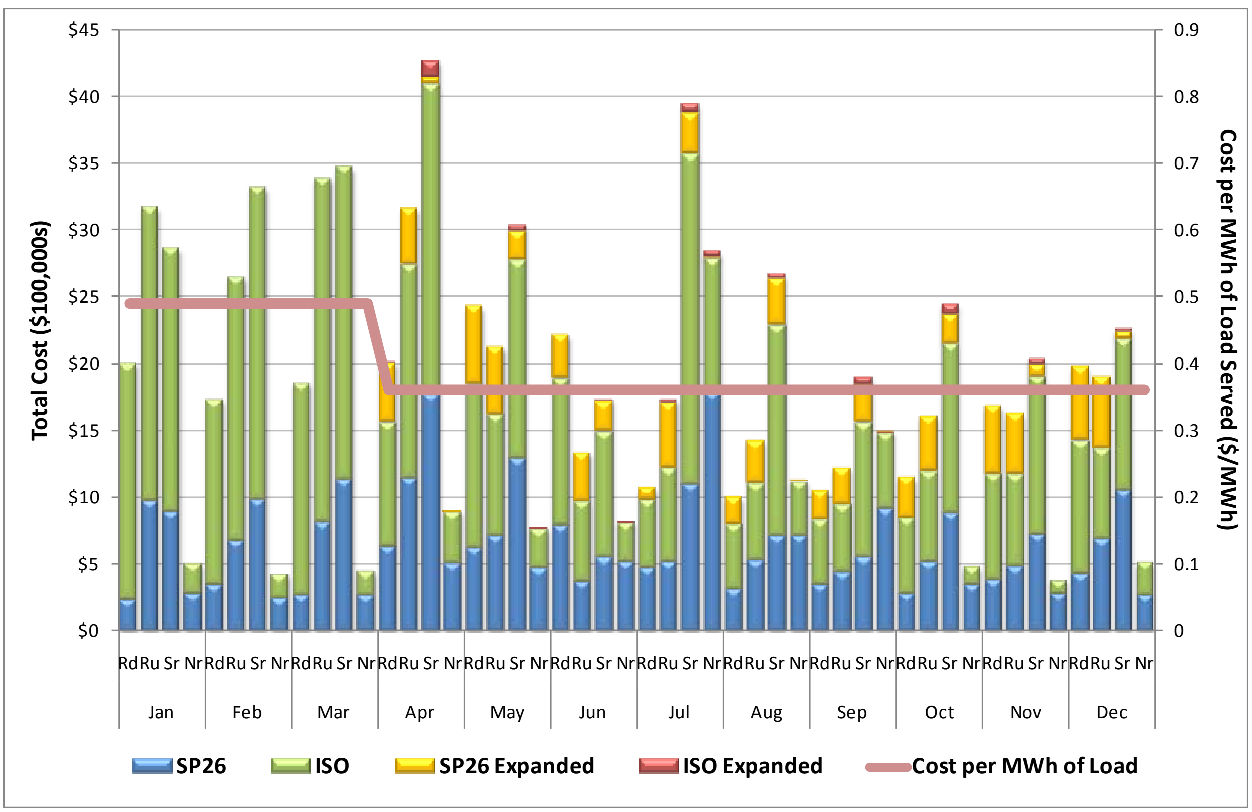
and 36 percent, respectively. Next was regulation down at 22 percent. Non-spin accounted for only 5 percent of the total cost in the first three months, most likely because of the rational buyer algorithm.

Ancillary services in the new market (April through December) have been procured from four of the 10 pre-defined regions, System, System Expanded, South of Path 26, and South of Path 26 Expanded regions, in the day-ahead and real-time pre-dispatch markets. In the remaining nine months, the total cost of ancillary services accounted for 71 percent of the annual cost, which translates to $0.36/MWh of load served. April was the highest cost month of the year, which can mostly be attributed to the following factors:

- The first month of the new markets proved to be a period of adjustment for market participants, the software, and operators.
- Regulation requirements were increased from 350 MW to 500 MW within the first few days and then gradually brought back down during subsequent months; higher requirements tend to be positively correlated with higher prices.
- Average prices for regulation down, spin, and non-spin increased by, on average, $2/MW for the month.

July was also a high cost month because of one incident that increased day-ahead ancillary service prices well above previously observed prices in the new markets. The event will be discussed in more detail in Section 6.3.

Figure 6.13 Ancillary service cost by region

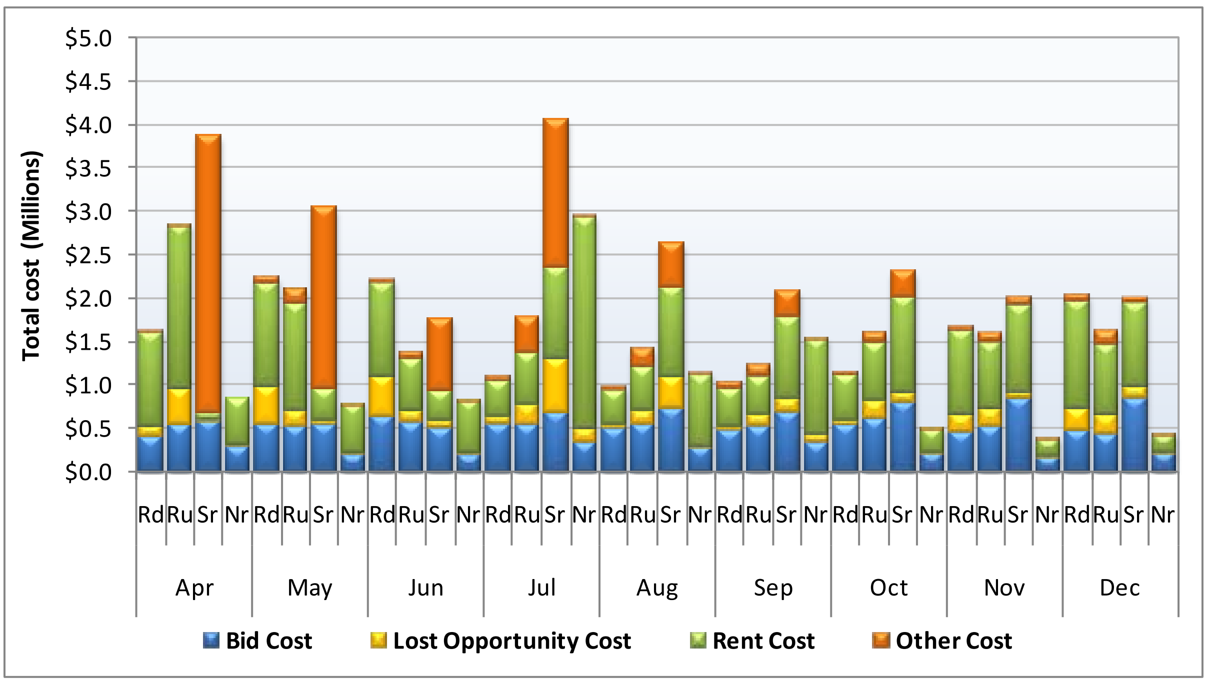


Ancillary service cost components

Figure 6.14 below shows the day-ahead total procurement costs de-constructed into the following four cost categories:

- ***Bid cost —*** This represents the cost of ancillary services from submitted capacity bids; the product of each unit's capacity bid price and awarded capacity. If the capacity bid price was higher than the market clearing price, the market cleared price was used.
- ***Lost opportunity cost —*** This reflects the net revenue that could have been earned by selling energy but was foregone because that capacity was procured as ancillary service instead.
- ***Rent cost —*** This represents the cost of ancillary services because of a unit receiving a market clearing price above its bid and lost opportunity cost. The product of the difference of the market clearing price minus bid and lost opportunity cost and awarded capacity.
- ***Other cost —*** This includes ancillary service costs that cannot be distinguished between rent and lost opportunity cost. Because of the complexity of the co-optimization and various factors that determine lost opportunity cost, it is not always easily determined if the price is due to a lost opportunity cost, rent, or other factors.

Figure 6.14 Day-ahead ancillary service cost de-construction



In the day-ahead market, most ancillary service prices are set by bid prices. These hours account for 28 percent of the total costs. Because most clearing prices are set by bid prices, most of the cost falls into either the bid or rent cost category. When the marginal bid sets the market price, it is usually higher[132]

[132] The day-ahead co-optimization minimizes the cost over a 24-hour period. Therefore, even though the market clearing price is less than a bid price, the market determines it less costly to award that unit capacity and make the difference up in bid cost recovery than procure from another unit that may have a high lost opportunity cost.

than all other accepted bids. Therefore, all other units receive a market price higher than their bid price, with the difference going into the rent cost category, which comprised 45 percent of total cost.

Lost opportunity cost represents 27 percent of total day-ahead cost. This is due to ample amount of capacity bid in the day-ahead market such that capacity is rarely awarded to a unit with lost opportunity cost unless:

- The bid price and lost opportunity cost is less than the bid price of the next economical unit.
- The unit setting the market price has lost opportunity cost.

Lost opportunity cost can arise from capacity constraints, ramping constraints, regional substitution, product substitution, and congested inter-ties. The day-ahead market has observed very few ancillary service bids being set by lost opportunity cost, accounting for 9 percent of the total cost. However, it is not always straightforward to determine why a market clearing price is above any accepted bid price because of several factors that interplay in determining the marginal unit. In such situations, cost that cannot be determined as lost opportunity cost or rent is collectively stated as other costs. This category totals 18 percent and is comprised of either lost opportunity cost or rent. Most of the decrease in cost in 2009 is attributed to the efficiency from co-optimization in the new market and, to a lesser extent, lower loads.

6.5 Special issues

Since the start of the new ancillary service market, several issues and concerns have been identified. Following is a brief explanation of each issue and how the ISO addressed them. A more detailed explanation and market analyses for all three issues can be found in our *Quarterly Report on Market Issues and Performance* for the third quarter of 2009.[133]

- ***Contingency-only procurement* —** Operating reserves can be flagged as either non-contingent or contingency-only. Scheduling coordinators can specify contingency-only or not in the day-ahead bid; all incremental capacity procured in real-time is contingency-only. Furthermore, if a unit with day-ahead non-contingent capacity is awarded incremental capacity in real-time, all of the awarded capacity for that unit is converted to contingency-only. The ISO does not impose a maximum constraint on the amount of contingency-only capacity procured. Contingency-only capacity can only be dispatched as energy in real-time during a contingency run or at operator's discretion. This reduced the amount of capacity available for dispatch in real-time and could result in higher prices unnecessarily. While there has not been a significant amount of market impact, this may become an issue during higher loads and stressed conditions when there has not been an actual contingency, but that capacity is needed in real-time to meet demand.
- ***Over-procurement* —** In some instances, the market software procured capacity beyond the requirement which made that capacity unavailable for dispatch in the real-time market. The market co-optimizes ancillary services and energy to minimize overall costs. When more than the minimum requirement of ancillary services was submitted though self-schedules, and this capacity was at a location with no lost opportunity cost, the market would procure the capacity at no

[133] See Chapter 3, *Quarterly Report on Market Issues and Performance*, December 23, 2009. http://www.caiso.com/2457/2457987152ab0.pdf.

additional cost. Since a large portion of ancillary service capacity is bid as contingency only, this over-procurement of ancillary series could decrease the supply of real-time energy. To address this issue, a new total upward maximum constraint was implemented that capped the total procured of all three upward services so that the market would not over procure capacity. The maximum constraint is set at two megawatts above the higher of day-ahead awards and real-time requirement summed across all three products.

- ***Scarcity pricing* —** Scarcity pricing is scheduled to be implemented in 2010. Scarcity pricing will be triggered in the day-ahead and real-time ancillary service markets when there is not enough capacity to meet requirements by region and product, resulting in higher prices reflecting the administratively set scarcity price schedule. The design for this mechanism does not have a direct linkage between the ancillary service market and the energy market in real-time. This weakens the relationship between prices of these two products and limits the impact the scarcity pricing mechanism can have on real-time energy prices. The high ancillary service prices may be reflected in high energy prices when the marginal capacity was needed for, and could have been used for, either energy or ancillary services as a result of the co-optimization. In the day-ahead market, when awards and prices are financially binding for both products, scarcity pricing will be reflected in all prices. In real-time, ancillary services are procured and priced in the real-time pre-dispatch market run while energy is awarded and priced in the real-time market run. The co-optimization and scarcity pricing will take place in the real-time pre-dispatch market run. The disconnect of financially binding market runs for both products in the real-time may result in ancillary service prices reflecting true scarcity but energy prices at the same locations that are not impacted by the high ancillary service prices. The linkage between ancillary service prices and energy prices in the context of scarcity pricing will be revisited in the stakeholder process on ancillary market review to be conducted in 2010.

7 Resource adequacy

Unlike most other major ISOs, the California ISO does not have a centralized capacity market. California's current market design includes a resource adequacy program, comprised of tariff provisions that work in conjunction with related requirements adopted by the California Public Utilities Commission. California's resource adequacy program has two main goals:

- To ensure the capacity procured by load-serving entities under the resource adequacy program is sufficient to reliably operate the power system, on a system-wide and local level.
- To ensure that revenues from bilateral transactions necessary to meet resource adequacy requirements, in combination with other market opportunities, provide generation owners and developers with the opportunity to obtain sufficient revenues to compensate for their fixed costs and to enable developers secure the financing needed for new construction.

In 2009, capacity procurement under the resource adequacy program was sufficient to meet virtually all of the ISO system-wide and local area reliability requirements. As a result, the ISO placed very limited reliance on the two alternative capacity procurement mechanisms provided under the tariff: reliability must-run contracts and the interim capacity procurement mechanism.

This section also analyzes the availability of resource adequacy supply since the start of the new markets in April 2009. Our analysis shows that the overall availability of resource adequacy capacity was relatively high in each month, with somewhat better availability during the summer months. The overall average availability of resource adequacy capacity to the ISO market was relatively high during the peak summer load hours, with about 91 percent of the overall capacity being available to the day-ahead market and about 88 percent to the residual unit commitment process. This represents an overall availability just slightly below the 92 percent level that is assumed in the resource adequacy program design.[134]

7.1 Background

The resource adequacy program is designed to ensure there will be sufficient generation capacity to meet demand, particularly under high peak load conditions. Load-serving entities generally must arrange enough resource adequacy generation and demand response capacity to meet 115 percent of their forecast peak demand in each month (based on a 1-in-2 year peak forecast). The 115 percent requirement is designed to include the additional operating reserve needed above peak load (about 7 percent), plus an allowance for outages and other resource limitations (about 8 percent).

About half of the generation resources counted toward this resource adequacy requirement must bid into the market for each hour of the month that the resource is physically available. Most gas-fired generation is subject to this all-hours must-offer obligation. These units must bid the full amount of their resource adequacy contract obligation except when this capacity is unavailable due to a reported planned or forced outage.

[134] 115 percent resource adequacy requirements less 7 percent operating reserve = 108 percent. Thus, after accounting for operating reserve, about 93 percent of remaining resource adequacy capacity would be necessary to meet the 1-in-2 year peak load used in setting the requirement (108 percent x 93 percent = 100 percent).

The other half of the generation resources counted towards the resource adequacy requirement do not have to offer the market in all hours of the month. These resources are to be made available to the market consistent with their operating limitations. These include hydro resources, non-dispatchable intermittent resources (such as cogeneration, wind, and solar) and use-limited thermal resources.

Use-limited thermal resources generally have environmental or regulatory restrictions on the hours they can operate, such as a maximum number of operating hours in a month or year. For instance, many peaking units within more populated and transmission constrained areas are only allowed to operate 360 hours per year under air permitting regulations. Market participants submit plans for use-limited resources to the ISO that describe these restrictions and outline their planned operation.

Market participants make resource adequacy units available to the market by submitting economic bids or self-schedules to the day-ahead integrated forward market. Some resources must also submit bids to the residual unit commitment process and to the real-time market.

- ***Day-ahead market and residual unit commitment process —*** For just under half of resource adequacy capacity (including over 23,000 MW of non-use-limited gas-fired generation), the ISO automatically creates the required day-ahead energy or residual unit commitment bids if a bid or self-schedule is not submitted by the market participant.[135] The ISO does not create bids for any capacity that is unavailable due to a scheduled outage, forced outage or de-rate, as reported through the outage reporting system SLIC.

- ***Committed in day-ahead or residual unit commitment process —*** If the day-ahead market or residual unit commitment process commits a resource adequacy unit, the market participant has an obligation to offer this resource adequacy capacity to the real-time market and the ISO will automatically create the required real-time market energy bid if not bid or self-scheduled by the participant.

- ***Short-start units not committed in day-ahead market or residual unit commitment process —*** In addition, market participants must bid or self-schedule all non-use-limited short-start units that are resource adequacy capacity in the real-time market. The ISO automatically creates the required real-time market energy bid if the capacity is not bid or scheduled by the participant.

However, for the other half of the resource adequacy capacity fleet, the ISO does not create a bid if one is not submitted by a market participant.

- The ISO does not create bids for about 6,400 MW of hydro resources and over 900 MW of use-limited thermal units because the resource adequacy program assumes that market participants will manage availability of these resources and submit bids and self-schedules to make them available consistent with their operating restrictions.

- The ISO also does not create bids for about 10,000 MW of non-dispatchable generators, which include nuclear, qualifying facilities, wind, solar and other miscellaneous resources.

[135] The total resource adequacy capacities listed in this section are based on the capacity during summer months.

- The ISO does not currently create bids for import resources, which account for over 4,000 MW of resource adequacy capacity. The ISO plans to start doing so in the future.[136]

7.2 Monthly resource adequacy availability

Figure 7.1 summarizes the amount of resource adequacy capacity made available to the day-ahead, residual unit commitment and real-time markets during each month since the start of the new markets in April 2009.

- The red line shows the total amount of resource adequacy capacity for each month.

- The colored horizontal bars show the amounts of resource adequacy capacity that was made available to the day-ahead, residual unit commitment, and real-time markets, respectively. These amounts are calculated as the average total amount of bids and schedules made available to each of these markets during the resource adequacy Standard Capacity Product "Availability Assessment Hours" during each month.[137]

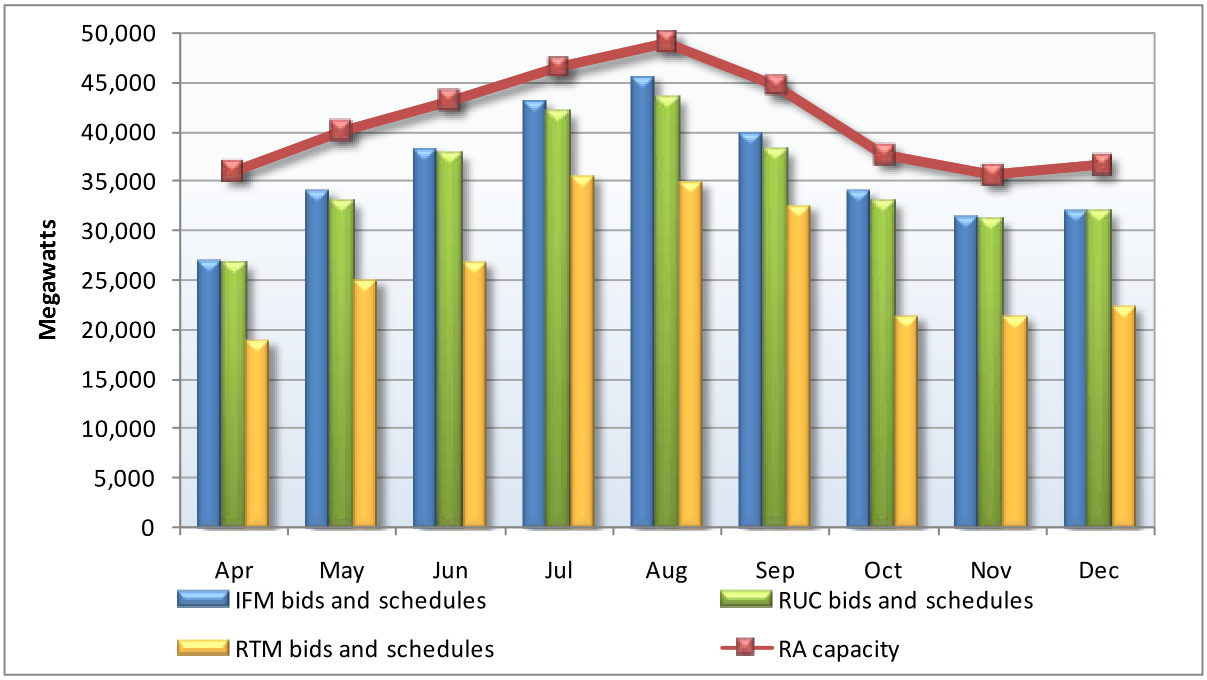
Figure 7.1 shows that a high portion of resource adequacy capacity was available to the market in each month, and that the best availability was over the summer. For example, about 46,000 MW out of about 49,000 MW of resource adequacy capacity (93 percent) was available on average to the day-ahead market during August 2009. On the other hand, during December, a somewhat smaller proportion of resource adequacy capacity was available to the day-ahead market, 87 percent. Over all these months, slightly fewer resources were available to residual unit commitment than were available to the day-ahead market. Figure 7.1 also shows that a smaller portion of resource adequacy capacity was available to the real-time market. This reflects that long-start units are not available to the real-time market if the day-ahead market or residual unit commitment processes do not commit them.

The resource adequacy capacity included in this analysis excludes as much as 9,700 MW of resource adequacy capacity for which this analysis cannot be performed or is not highly meaningful. This includes: resource adequacy resources representing some import and "liquidated damages" contracts, resource adequacy capacity from reliability must-run resources, resource adequacy requirements met by demand response programs, and load-following metered subsystem resources.

[136] The ISO is conducting a stakeholder initiative to resolve the methodology to create bids for resource adequacy import capacity when not submitted by market participants, and plans to implement system functionality to do this.

[137] These are operating hours 14-18 during April through October and operating hours 17-21 during the reminder of the year.

Figure 7.1 Monthly resource adequacy capacity and resources scheduled or bid in day-ahead, RUC and real-time markets



7.3 Resource adequacy availability during summer peak hours

Although the availability of resource adequacy capacity is important during all times of the year, it is especially important during summer peak hours. While the previous section of this report examined resource adequacy capacity availability during all of the standard capacity product availability assessment hours over each month of the year, this section examines resource adequacy capacity availability during the highest summer peak load hours.

Under California Public Utilities Commission rules, a resource must be available at least 210 hours over the summer months of May through September to be counted as resource adequacy.[138] The resource adequacy program presumes that market participants will manage use-limited generators to make them available during the peak load hours. We have evaluated the availability of resource adequacy generation during the 210 hours during May through September with the highest peak loads (i.e., all hours with peak load over 38,700 MW).

While CPUC requirements do not require that resource adequacy capacity be available during these specific 210 peak hours and participants do not have perfect foresight about which hours will have the highest loads over the summer, we have chosen to assess resource adequacy availability during these peak 210 hours in order to provide results that are – in aggregate – roughly comparable to basic market design assumptions that appear to underlie the 210 hour requirement incorporated in the CPUC's resource adequacy requirements (i.e., that this 210 hour requirement will provide a high level of availability during peak hours when most resource adequacy capacity is needed to ensure reliability).

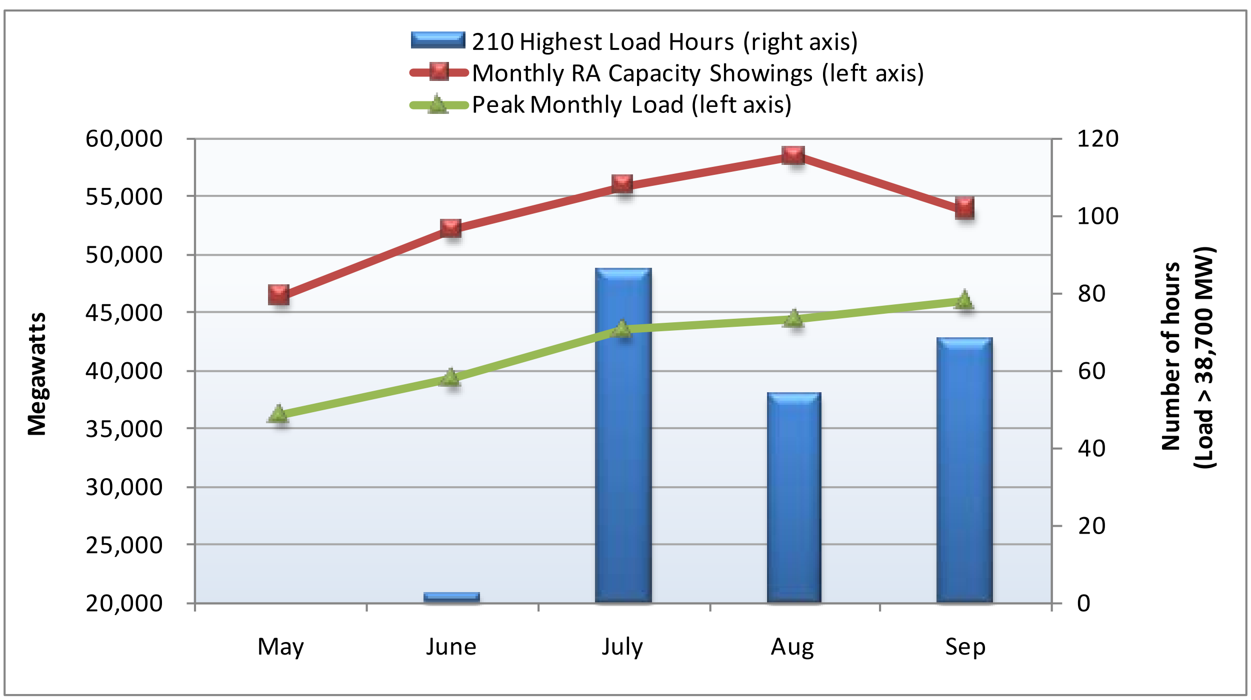
[138] The CPUC requires that resource adequacy capacity be available at least 210 hours during the months of May through September based on the resources being available 30, 40, 40, 60, and 40 hours during each of these months, respectively.

Figure 7.2 provides an overview of monthly resource adequacy requirements, monthly peak load and the frequency of the 210 highest load hours (with load over 38,000 MW) that occurred during May through September 2009. The red and yellow lines (plotted against the left axis) compare the monthly resource adequacy capacity with the peak load that actually occurred during each of these months. As shown in Figure 7.2:

- Total resource adequacy capacity was 46,000 to 58,500 MW during these months, which exceeded the monthly peak load in May through August by about 28 to 32 percent, and the monthly peak load in September by about 17 percent.
- The high margins in May through August reflect that resource adequacy requirements are designed to meet 115 percent of a 1-in-2 year load forecast, and that peak loads in these months in 2009 were not unusually high.
- The lower margin in September reflects that highest peak load occurred in this month when resource adequacy requirements were actually lower than in August, the forecasted peak load month.

The bars in Figure 7.2 show the number of the top 210 load hours that occurred during each of these months, which represent the specific hours upon which the analysis in this chapter presented below are based. As illustrated by the blue bars in Figure 7.2, the actual summer peak and a high portion of the highest load hours each summer may not occur in the month with the most resource adequacy capacity. This underscores the need for all resource adequacy capacity to be made available to the market, particularly in these peak load hours.

Figure 7.2 Summer monthly resource adequacy capacity, peak load, and peak load hours May-September 2009



To provide an indication of the actual availability of resource adequacy capacity over these 210 peak hours, Figure 7.3 summarizes the amount of capacity for which bids and self-schedules were available to the day-ahead market, residual unit commitment and real-time market. Figure 7.3 presents this information as a *duration curve* of availability, representing the portion of resource adequacy capacity available to the market during the 2010 highest load hours.

- The left vertical axis of Figure 7.3 shows the total resource adequacy capacity available over the 210 highest load hours between May and September (ranked in descending order of total resource adequacy megawatt bid or scheduled in each of these three markets).[139]

- Tight vertical axis of Figure 7.3 shows the resource adequacy capacity available as a percentage of the average overall resource adequacy capacity over these peak hours.

- The horizontal axis of Figure 7.3 shows the number of hours that the resource adequacy capacity listed on the left and right vertical axes was available to the day-ahead, residual unit commitment, and real-time market.

- The day-ahead bids and self-schedule amounts shown include bids and self-schedules for energy and ancillary services for resource adequacy capacity.

- The residual unit commitment bid amounts shown include bids for resource adequacy capacity, as well as the amounts of energy or ancillary services from resource adequacy capacity that cleared in the day-ahead market.

- The real-time bid amounts shown include energy bids and self-schedules for energy from resource adequacy capacity submitted to the real-time market and included in a day-ahead energy schedule.

Figure 7.3 shows that a high proportion of resource adequacy capacity was available to these markets on average during the 210 summer peak load hours, although the amounts available vary significantly:

- ***Day-ahead energy —*** Bids and self-schedules for resource adequacy capacity averaged about 91 percent of the overall resource adequacy capacity in the day-ahead market, ranging in individual hours from approximately 83 to 100 percent during these peak load hours.

- ***Residual unit commitment —*** The amount of resource adequacy capacity available averaged 90 percent of the overall resource adequacy capacity in residual unit commitment during these peak hours, ranging from approximately 82 to 94 percent in individual hours. The slightly lower amount of resource adequacy capacity available to residual unit commitment than the day-ahead market reflects that market participants did not submit residual unit commitment bids for some resources that they bid or scheduled in the day-ahead market.

- ***Real-time market —*** Bids and self-schedules for resource adequacy capacity averaged approximately 79 percent of resource adequacy capacity in the real-time market, and varied from 72 to 87 percent in individual hours. As previously described, the relatively lower amount of resource adequacy capacity available to the real-time market, as compared to the day-ahead market and

[139] Figure 7.3 does not include approximately 9,700 MW of the overall ISO resource adequacy capacity for which this analysis cannot be performed or is not highly meaningful, as previously described.

residual unit commitment, is due to not all resource adequacy capacity being committed in the day-ahead market or residual unit commitment process. As discussed below, bids and self-schedules were submitted for a relatively high proportion of the resource adequacy capacity that was available in the real-time dispatch timeframe.

Figure 7.3 Resource adequacy bids and self-schedules available to the IFM, RUC, and RTM: 210 highest peak load hours (May-Sep 2009)

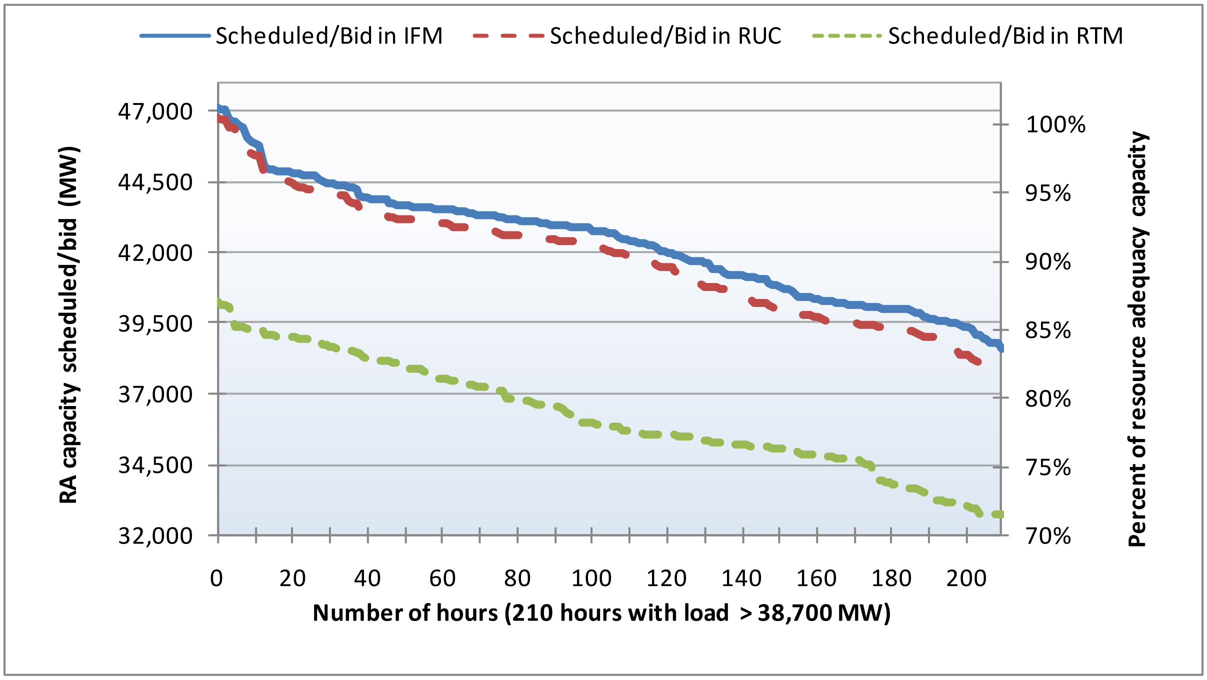


Table 7.1 provides a different look at the resource adequacy capacity examined in Figure 7.3 over the 210 summer peak load hours, breaking out the overall resource adequacy capacity by generation technology, and showing the outage-adjusted resource adequacy capacity and the amounts available to the various markets for each types of generation. Table 7.1 also shows sub-totals for these amounts for two categories: (1) resources for which the ISO creates bids if market participants do not submit a bid or self-schedule, and (2) resources for which the ISO does not create bids. Table 7.1 presents this information as follows:

- ***Resource adequacy capacity after reported outages and de-rates —*** The first three numerical columns of Table 7.1 list the approximately 46,600 MW of resource adequacy capacity examined in this analysis as well as the capacity remaining after adjusting for reported outages and de-rates (in megawatts and as a percent of total resource adequacy capacity). After adjusting for reported outages and de-rates, the remaining capacity was about 95 percent of the overall resource adequacy capacity. This represents an outage rate of about 5 percent during the summer peak load hours. For the 23,000 MW of gas-fired generators for which the ISO creates bids if not submitted by market participants, about 93 percent of the overall capacity remained after adjusting for reported outages and de-rates. This represents an outage rate of about 7 percent during summer peak load hours.

- ***Day-ahead market availability —*** Table 7.1 also lists the average amount of bids and self-schedules actually scheduled or bid in the day-ahead market (in megawatts and as a percent of total resource adequacy capacity). For the approximately 24,000 MW of resource adequacy capacity for which the ISO submits bids based on their reported availability, day-ahead availability was virtually the same as the total resource adequacy capacity after adjusting for outages and de-rates, 92 percent. For the approximately 22,400 MW of resource adequacy capacity for which the ISO does not create bids, the total capacity scheduled or bid in the day-ahead market averaged only 90 percent. This is much less than the 97 percent of the total maximum capacity of these resources after accounting for reported de-rates and outages.[140] This brings the total average availability of all resource adequacy capacity in the day-ahead market examined in this analysis down a little, to about 91 percent, somewhat less than the 95 percent of resource adequacy capacity available after adjusting for outages and de-rates.

  Table 7.1 shows that the shortfall in the amount of resource adequacy capacity scheduled in the day-ahead market, as compared to the outage-adjusted resource adequacy capacity, is primarily attributable to use-limited gas resources, hydro, wind, solar generators, QFs, other non-dispatchable generators, and imports. Hydro and other non-dispatchable resources were likely scheduled in amounts less than their resource adequacy capacity because they are not dispatchable and the energy deliveries needed from these resources was likely down due to relatively light summer load conditions. Outages that may have affected the availability of import resources are not reflected in Table 7.1 because market participants cannot report outages affecting imports in the ISO outage reporting system. The availability of wind, solar and QF resources is discussed in more detail in section 7.4.

- ***Residual unit commitment availability —*** Table 7.1 then lists the average amount of bids and self-schedules actually scheduled or bid in the residual unit commitment process. The overall percentage of resource adequacy capacity made available in the residual unit commitment process decreases slightly to 90 percent compared to the 91 percent of capacity available in the day-ahead market. As shown in Table 7.1, the major reason for this is that market participants apparently did not submit residual unit commitment bids for all use-limited gas and QF resources that they scheduled or bid in the day-ahead market.[141]

- ***Real-time market availability —*** The last three columns of Table 7.1 compare the total resource adequacy capacity potentially available in the real-time market timeframe with the actual amount of capacity that was available to the real-time market. The resource adequacy capacity available in the real-time market timeframe is calculated as the remaining resource adequacy capacity from resources with a day-ahead or residual unit commitment schedule plus the resource adequacy capacity from uncommitted short-start units (not adjusted for outages or derates). On average, about 92 percent of the resource adequacy capacity that was potentially available to the real-time market was actually available, slightly more than 91 percent of resource adequacy capacity available to the day-ahead market.

[140] Some of this difference may also have been due to outages of import resources, for which market participants cannot report outages or de-rates through the ISO outage reporting system SLIC. This difference is also due to hydro and other non-dispatchable resources being scheduled in amounts less than their resource adequacy capacity which this is likely attributable to less energy being scheduled from these non-dispatchable resources because of relatively light summer load conditions.

[141] These shortfalls are most likely not because of resources not being physically available. If a resource is available for a given day and a bid or self-schedule is submitted to the day-ahead market, then that resource should presumably be available for the same day in the residual unit commitment process.

Table 7.1 Average resource adequacy capacity and availability to IFM, RUC, and RTM: 210 Highest Load Hours (May-Sep 2009)

Resource Type	Total RA Capacity (MW)	Net Outage Adjusted RA Capacity		IFM Bids and Self-Schedules		RUC Bids		Total RTM RA Capacity (MW)	RTM Bids and Self-Schedules	
		MW	% of Total RA Cap.	MW	% of Total RA Cap.	MW	% of Total RA Cap.		MW	% of RTM RA Cap.
ISO Creates Bids:										
Gas-Fired Generators	23,173	21,436	93%	21,415	92%	21,415	92%	17,028	16,228	95%
Other Generators	993	918	92%	917	92%	917	92%	990	913	92%
Subtotal	24,166	22,354	93%	22,332	92%	22,332	92%	18,018	17,141	95%
ISO Does Not Create Bids:										
Use-Limited Gas Units	915	904	99%	849	93%	746	82%	890	804	90%
Hydro Generators	6,444	6,276	97%	5,811	90%	5,790	90%	6,444	5,437	84%
Nuclear Generators	4,901	4,756	97%	4,690	96%	4,690	96%	4,901	4,727	96%
QF Generators	4,504	4,354	97%	3,907	87%	3,783	84%	4,486	3,870	86%
Wind/Solar Generators	658	655	100%	384	58%	384	58%	658	498	76%
Other (Non-Dispachable)	737	569	77%	537	73%	537	73%	737	530	72%
Imports	4,261	4,261	100%	3,906	92%	3,862	91%	3,858	3,799	98%
Subtotal	22,420	21,775	97%	20,084	90%	19,792	88%	21,974	19,665	89%
Total	46,586	44,129	95%	42,416	91%	42,124	90%	39,992	36,806	92%

7.4 Resource adequacy capacity intermittent resources

Analysis in Table 7.1 shows that a relatively smaller portion of resource adequacy capacity from wind, solar and QF generators, as compared to other types of resource adequacy capacity, was generally available to the market in the summer peak load hours. Although only about 76 percent of the resource adequacy capacity of wind and solar resources was scheduled in the real-time market, their actual output was approximately the same as their resource adequacy capacity in the peak hours. The actual output of QFs, which provided about 4,500 MW of resource adequacy capacity, only averaged about 86 percent of this capacity in the peak hours. The following section discusses the availability of wind, solar and QF resources in more detail.

Because the output of these resources is variable and cannot be dispatched, the amount of resource adequacy capacity that these resources can provide is based on past output, rather than nameplate capacity. This is called the resource's net qualifying capacity. The net qualifying capacity of intermittent resources for 2009 was based on their average output during the hours of noon to six on non-holiday weekdays during the same month in the previous three years. The CPUC has revised the methodology for determining the net qualifying capacity of wind and solar resources for 2010. The net qualifying capacity for these resources is now based on the output that they can exceed in 70 percent of certain peak hours, adjusted for a factor that reflects the benefit of the covariance of the output of many individual intermittent generators.

Since the output of resources can vary year-to-year, and also because their output in the actual peak load hours could conceivably be much different than their net qualifying capacity, Figure 7.4 and Figure 7.5 compare the resource adequacy capacity of wind, solar and QF generation, respectively, to their actual output over July through September 2009. Their actual output is shown as their average output during two different time periods during these months:

- Noon to six, non-holiday weekdays, which are the hours of the day used in the net qualifying capacity calculation.
- The highest 210 load hours during summer 2009 that occurred in the months of July through September.

Figure 7.4 shows that the actual output of wind and solar resources in July through August 2009 during the hours used in the net qualifying capacity calculation ("the NQC hours") during the hours from noon to six in July and August was more than their average output in the same hours over the previous three years. In September, wind and solar resources' actual output during the net qualifying capacity hours was slightly lower than their resource adequacy capacity. Figure 7.4 also shows that the actual output of wind and solar in the 210 hours summer peak load hours that occurred in these months was a little less than it was in the net qualifying capacity hours in these months. This output in the 210 peak hours was more than these resources' resource adequacy capacity in July, while it was a little less than the resource adequacy capacity in August and September. Overall the output of wind and solar resources averaged 107 percent of their resource adequacy capacity in these 210 peak hours, as opposed to the only 76 percent of their capacity that was scheduled in the real-time market (as shown in Table 7.1).

Figure 7.4 Resource adequacy capacity available from wind/solar resources (July-September 2009)

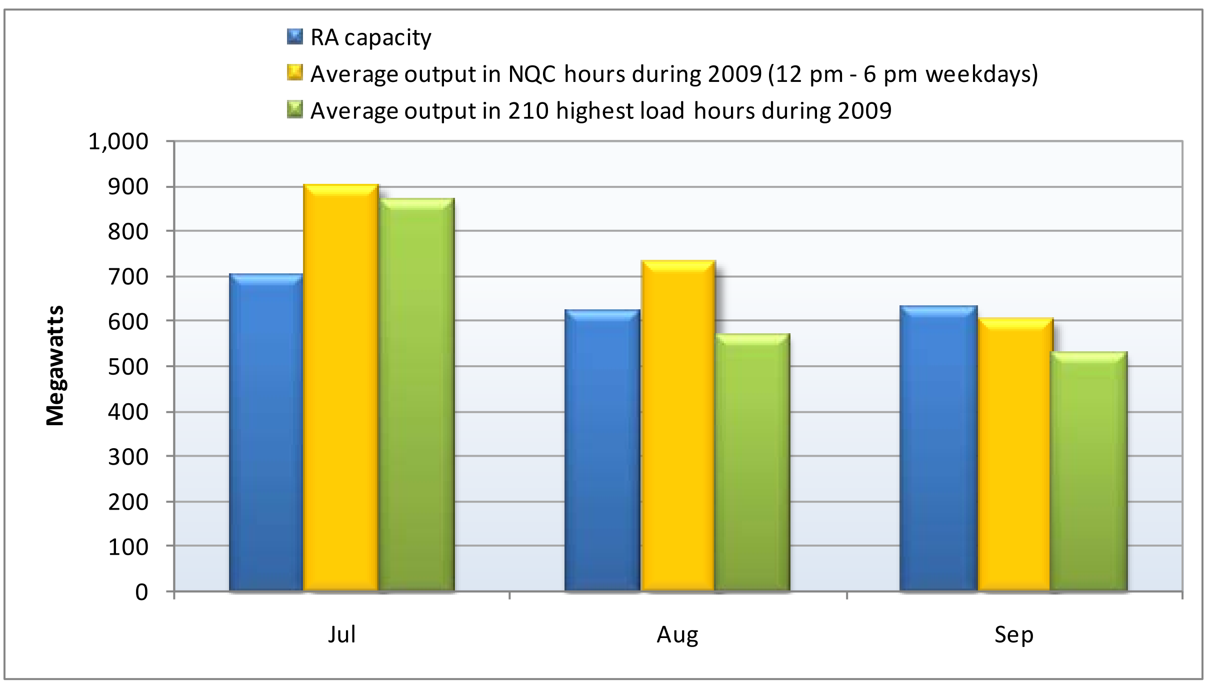
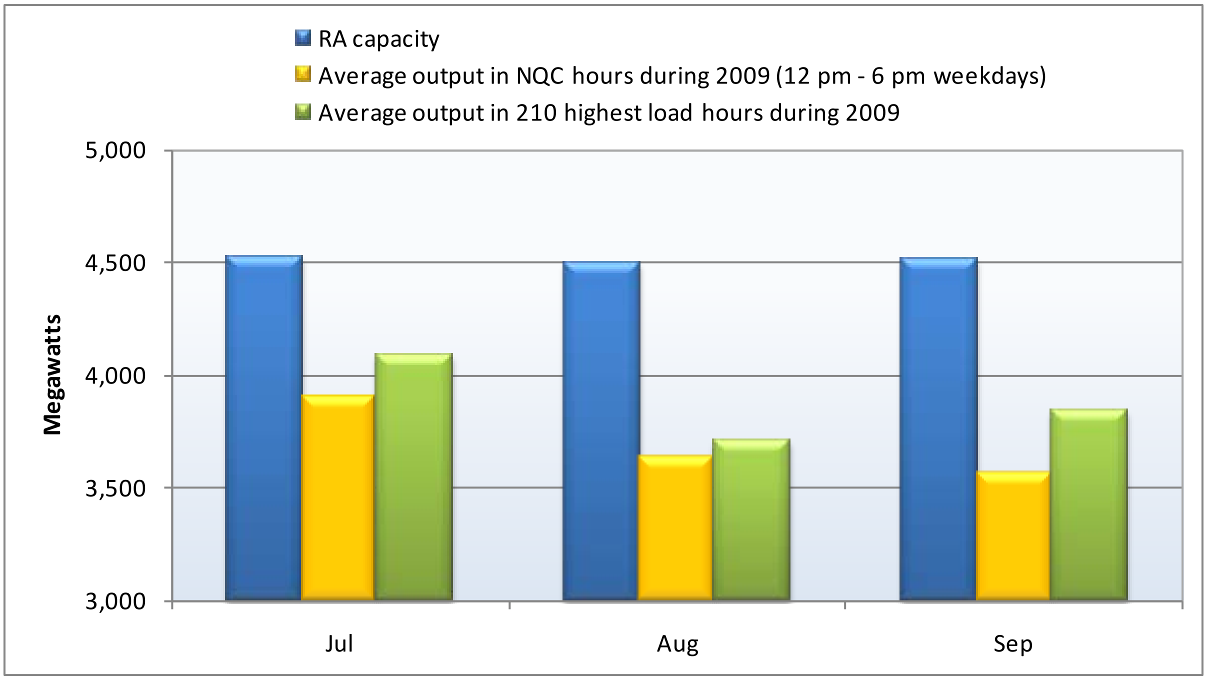


Figure 7.5 shows that the actual output of QF generation in July through September 2009 during the net qualifying capacity hours was significantly less than these resources' resource adequacy capacity. Figure 7.4 also shows that the actual output of QF generation in the 210 summer peak load hours that occurred in these months was a little more than it was in the net qualifying capacity hours during the same period, but still significantly less than these resources' resource adequacy capacity. Overall during these

hours, these resources output averaged only 86 percent of their resource adequacy capacity. The reason for this shortfall is not clear, but it could be because of reduced activity due to the economic slowdown at QF's host facilities.

Figure 7.5 Resource adequacy capacity available from qualifying facility resources (July-September 2009)



7.5 Resource adequacy import bid prices

Figure 7.6 and Figure 7.7 summarize the bid prices and degree of self-scheduling of resource adequacy import resources in the day-ahead market during peak and off-peak periods, respectively.

Because import resources are often backed by contracts to deliver energy, in contrast to being backed by the output of a specific generator, import bid prices and the degree with which market participants self-schedule imports presumably indicate the amount of available resources to back imports. Reasonably priced bids for resource adequacy import resources, or a high-degree of scheduling, potentially indicates that a market participant can easily obtain resources (energy and transmission) to deliver imports. Conversely, participants may bid higher and self-schedule less if they anticipate it will be harder to deliver imports.

Figure 7.6 and Figure 7.7 summarize resource adequacy import resources' bid prices and the amount by which they were self-scheduled, as explained below:

- The green line (plotted against the left axis) shows the weighted average of the maximum bid price for each resource adequacy import resource for which market participants submitted economic bids to the day-ahead market.

- The blue bars (plotted against the right axis) show the average percentage of resource adequacy import capacity that market participants self-scheduled in the day-ahead market.

Figure 7.6 Resource adequacy import bid prices and self-schedule quantities peak periods

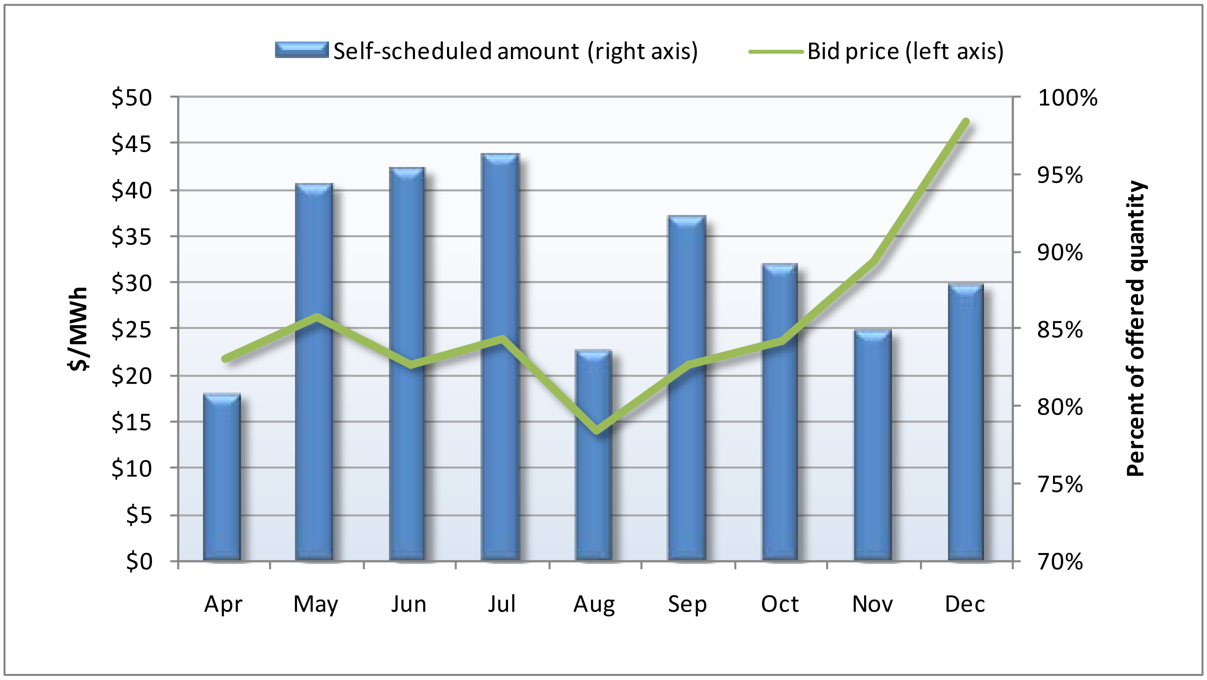


Figure 7.7 Resource adequacy import bid prices and self-schedule quantities off-peak periods

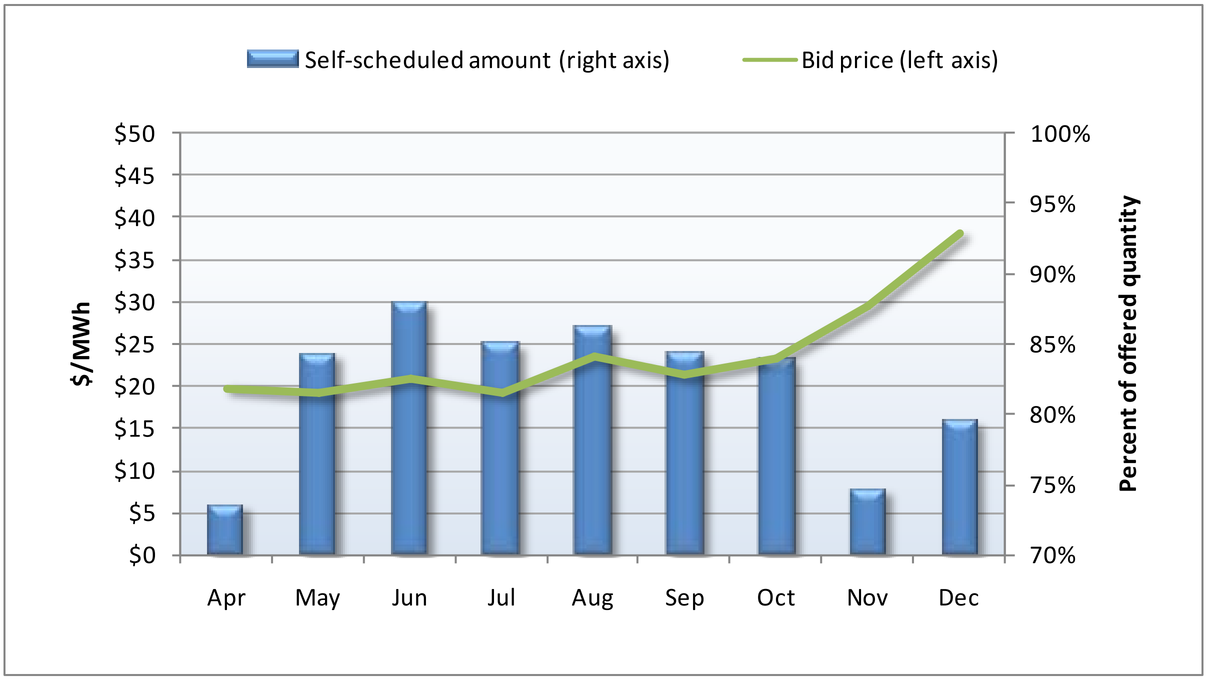


Figure 7.6 and Figure 7.7 show that market participants self-scheduled a large proportion of resource adequacy imports in the day-ahead market – approximately 90 percent during peak hours and approximately 82 percent during off-peak hours, on average across the various months. The bid prices were reasonable for the portion that they did not self-schedule, ranging from an average of approximately $20/MWh to $50/MWh during peak hours and from approximately $20/MWh to $35/MWh during off-peak hours. The month-to-month increase in bid prices beginning in October is generally consistent with the market-wide increase in energy prices.

7.6 Backup capacity procurement

If the capacity procured under the resource adequacy program was not sufficient to meet the ISO system-wide and local are reliability requirements, the cost of alternative capacity procurement mechanisms could increase significantly. Thus, another indicator the success of the resource adequacy program is the extent to which alternative capacity procurement mechanisms are utilized to supplement or replace resource adequacy as means of meeting.

- ***Reliability must-run contracts —*** The amount of capacity under reliability must-run contracts and the costs associated with these contracts dropped substantially over the last few years, as shown in Figure 7.8. Part of this reduction is due to transmission system upgrades. Local capacity requirements placed on load-serving entities under the resource adequacy program has also reduced reliance on reliability must-run contracts. Much of the capacity needed to meet local reliability requirements is now procured under the resource adequacy program rather than through reliability must-run contracts. The drop in net pre-dispatch and net real-time costs for reliability must-run units in 2009 may be attributed to a combination of lower congestion, lower gas prices and enhanced congestion management under the new market design.

- ***Interim capacity procurement mechanism —*** A minimal amount of incremental capacity (315 MW) was procured for a one month basis under the interim capacity procurement mechanism of the ISO tariff. This bulk of this capacity was procured due to transmission outages that created additional needs for capacity in specific parts of the grid. The total cost of this capacity was $1.1 million. As shown in Figure 7.9, the bulk of this procurement occurred due to a forced outage of Moss Landing-Los Banos 500 kV line in October 2009. All units from which some capacity was procured under the interim provisions were designated as resource adequacy units for the bulk of their capacity in other months. Interim procurement designations were minimal in 2009.

Thus, under 2009 conditions, procurement of capacity under the resource adequacy program was sufficient to meet virtually all of the ISO system-wide and local are reliability requirements, and the cost of procurement under these alternative capacity procurement mechanisms was very limited.

Figure 7.8 Reliability must-run costs: 2007-2009

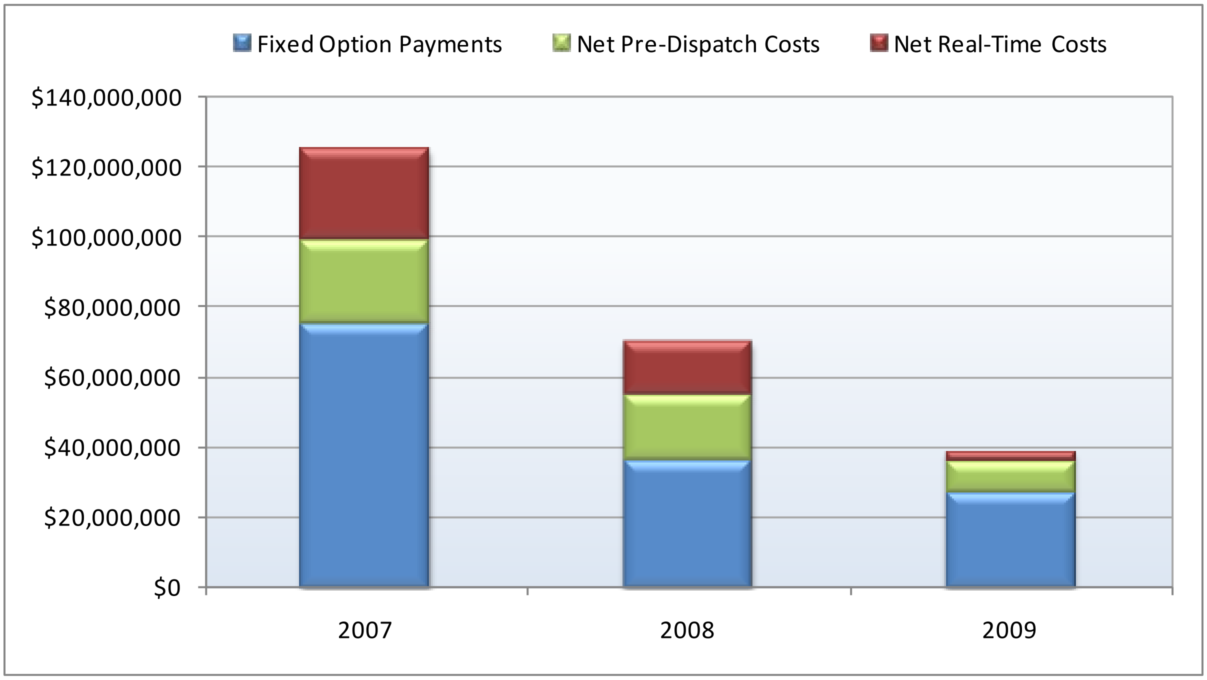


Figure 7.9 Interim capacity procurement mechanism costs (2009)

Resource	LCA	ICPM Designation (MW)	Estimated Cost	ICPM Designation Dates
Yuba City Energy Center [1]	Sierra	1	$3,417	4/21 - 5/20
Humbolt Mobile #2 2	Humbolt	15	$21,403	6/20 - 6/30
Moutainview #3	LA Basin	2	$3,892	8/2 - 8/31
Moutainview #4	LA Basin	2	$3,892	8/2 - 8/31
Humbolt Mobile #2	Humbolt	15	$21,403	8/7 - 9/7
Balch #3	Fresno	1.5	$5,837	8/20 - 9/18
Creed Energy Center #1	Bay Area	48	$186,796	10/13 - 11/11
Feather River Energy Center #1	Sierra	1	$3,892	10/13 - 11/11
Gilroy Energy Center #3	Bay Area	46	$179,013	10/13 - 11/11
Goose Haven Energy Center #1	Bay Area	48	$186,796	10/13 - 11/11
King City Energy Center #1		44.6	$173,565	10/13 - 11/11
Lambie Energy Center #1	Bay Area	48	$186,796	10/13 - 11/11
Wolfskill Energy Center #1	Sierra	46	$179,013	10/13 - 11/11
		318	**$1,155,714**	

[1] Manual Dispatch 1 MW beyond 45 MW RMR contract limit
[2]Outage of other RA units required additional on-line capacity
[3] Local transmission outages
[4] Forced outage of Moss Landing-Los Banos 500kV line

7.6.1 Conclusion and recommendations

In 2009, procurement of capacity under the resource adequacy program was sufficient to meet virtually all of the ISO system-wide and local are reliability requirements. At the same time, analysis provided in this report reinforces the need for the ISO, CPUC and local regulatory agencies to continue to consider future refinements in the resource adequacy program.

Short-term recommendations for standard capacity product stakeholder process

During the peak hours examined in this analysis, the overall average availability of resource adequacy capacity was relatively high — about 91 percent in the day-ahead market and 90 percent in the residual unit commitment process. This represents an overall availability just slightly below the 93 percent level assumed in the design of the resource adequacy program.[142] Under higher loads that equal or exceed the 1-in-2 year peak forecast used in setting resource adequacy requirements, this difference could potentially have a significant impact on ISO market performance and system reliability.

We believe the following recommendations and findings should be considered in developing future refinements to standard capacity product provisions being developed for resource adequacy units:

- ***Actual availability of use-limited gas units —*** The availability of internal use-limited gas-fired generators used to calculate the performance incentive under the standard capacity product provision should potentially be based on the amount of bids or schedules actually submitted to the ISO market, rather than based just on the unit's forced outage rates. As shown in Table 7.1, while market participants reported that 99 percent of the 915 MW of use-limited gas units were available after adjusting for outages and de-rates, they submitted bids or schedules for an average of 93 percent of this capacity to the day-ahead market, 82 percent of this capacity to the residual unit commitment process, and 90 percent of this capacity to the real-time market. Thus, the amount of these resources actually available to the market is not necessarily reflected in their forced outage rates. Consequently, it may be appropriate to base the standard capacity product availability incentive for these resources on bids and schedules submitted to the market as compared to the units' use-plans.

- ***Use-plan review —*** Because the amount of capacity bid or scheduled for use-limited gas-fired generators was less than the amount of capacity that should have been available after adjusting for outages, and because the availability of use-limited resources during peak hours was generally less than their planned resource adequacy capacity, this reinforces the need for the ISO to thoroughly review the use-plans submitted for use-limited resources. The initial operation of the new market during summer conditions provides historical data that can be used to evaluate these use-plans in the future.

- ***Actual availability of qualifying facilities —*** During the 210 highest load hours examined in this analysis, the overall actual output of qualifying facilities was about 88 percent of the amount of these resources' capacity that was counted to meet resource adequacy requirements. The capacity of these resources that may be used to meet resource adequacy requirements is based on their historical average output. However, as shown by these results, the actual output of these resources can be significantly less in individual years. This may indicate that further revisions to the counting rules for qualifying facilities may be appropriate and also illustrates that it is important for other

[142] See footnote 1.

types of resource adequacy resources to be fully available to the market to compensate for these types of shortfalls.

We recommend that the ISO incorporate the following into its process for reviewing use-plans for resources that are granted use-limited status:

- The ISO should review use-plans for the upcoming year against the actual availability of a unit over this past summer to ensure that the availability delineated in a use-plan is consistent with the past availability of a unit.

- Market participants should be asked to include a description in their use-plans as to how they will bid and schedule a use-limited resource to maximize the resource's availability to market during the hours of highest load. For example, a use-limited gas resource could be bid as non-spinning reserve flagged as contingency-only dispatch to make the unit available if the capacity is needed, while limiting the actual hours dispatched.

- The availability described in use-plans should be compared to how the resource is counted as resource adequacy capacity. For example, load-serving entities under CPUC jurisdiction can count resource adequacy capacity up to maximum amounts in several "buckets," determined by the hours in a month a resource is available. The availability of use-limited resources described in use-plans submitted to the ISO should be compared to how these resources are counted as resource adequacy capacity to ensure they are consistent.

Investment in new supply

As illustrated discussed in Chapter 2, significant levels of new gas-fired generation were added in 2009 and are scheduled to be added in 2010. This provides some evidence that the state's resource adequacy program has been successful at stimulating some investment in new capacity. However, analysis of net revenues that would be earned by a typical new gas-fired generating plant in the ISO market in 2009 shows a substantial decrease in net revenues compared to 2008. Estimated net revenues for typical new gas-fired generating units in 2009 would fall substantially below the annualized fixed cost of new generation.

This demonstrates one of the key trends in other ISOs with similar market designs. In highly competitive electricity markets, in which prices reflect generating costs of the marginal resources needed to meet demand, net operating revenues do not provide for recovery of the full fixed costs of new generation. These findings underscore the critical importance of long-term contracting as the primary means for facilitating new generation investment under the state's current resource program.

Integration of renewable energy and demand response

California has adopted policies to dramatically increase reliance on renewable energy and demand response. These policies are already simulating significant planning and investment in new renewable resources. New resources needed to meet these goals would meet the bulk of the state's requirements for new additional energy. However, the remote locations and intermittent nature of renewable resources is creating new and different investments in transmission, backup capacity and new types of ancillary services.

The ISO is placing a major emphasis on assessing how increased reliance on renewable energy and demand response will impact operational and reliability requirements. The ISO is also being proactive in planning transmission upgrades and modifying its market rules to spur development and integration of renewable energy and demand response.

There is considerable debate over whether overall market efficiency and California's goals for development and integration of renewable energy and demand response resources would best be achieved by continuing to base the state's resource adequacy program on bilateral contracting or to implement a centralized capacity market. Regardless of the approach California adopts, the ISO and CPUC face the challenge of refining capacity counting methods and performance standards for different resource types.

The availability of different resources can vary significantly, including during the peak hours when they may be needed most for reliability. The availability and dispatchability of different resources also impacts how much backup capacity and new types of ancillary service the ISO may need to procure to ensure system reliability. Thus, improved methods are needed for quantifying the value of different resources in terms of their capacity value and impact on ancillary service requirements.

As part of the standard capacity product stakeholder process, the ISO has recently sought to develop forced outage standards for cogeneration, wind, solar and other non-conventional intermittent sources. The ISO's approach has used the framework established for forced outages of traditional dispatchable gas-fired units. This approach has proven problematic due to the diverse and fundamentally different nature of these intermittent resources. If forced outage standards are not tailored based on characteristics of different resources types, such standards may create an additional financial risk for these resources while providing minimal or no additional reliability benefit.

For many of these other resource types, DMM believes it may be more appropriate and effective to incorporate the reliability and operational characteristics of these resources, including forced outage rates, in the capacity value assigned to each resource under a resource adequacy or capacity market design. The costs of any additional ancillary services needed to integrate different resources should also be allocated in a way that reflects the reliability and operational characteristics of different resources. This will help ensure proper price signals for investment in different types of new resources. As increased reliance is placed on renewable energy and demand response resources, this will also ensure that the ISO maintains the necessary mix of resources to maintain reliability and market efficiency.

The ISO has a number of initiatives through which these issues can be further addressed in 2010. The CPUC and ISO have recently refined the criteria use to assess the amount of capacity from intermittent resources such as wind and solar can be used to meet resource adequacy requirements. New criteria taking effect in 2010 should continue to be assessed and revised as necessary based on analysis of ISO system needs as increased reliance is placed on renewable energy and demand response resources. The ISO is also initiating a stakeholder initiative in 2010 to review the potential need for new types of ancillary services that may be appropriate as increased reliance is placed on renewable energy and demand response resources.

8 Market Surveillance Committee

8.1 Role of the Market Surveillance Committee

Historically, the California Independent System Operator Market Surveillance Committee has served as an impartial voice while commenting on a wide array of wholesale energy market issues. Management and the Federal Energy Regulatory Committee have adopted a number of their recommendations since its inception. The MSC is consistently recognized by the industry and the public as useful and effective, due largely to the stature of its members as nationally recognized experts as well as their perceived independence. Both characteristics have led by state and federal regulators to show the MSC being considerable deference when offering opinions.

8.2 Member biographies

In 2009, the Committee was comprised of the following members: Frank Wolak of Stanford University, Benjamin Hobbs of Johns Hopkins University and James Bushnell of Iowa State University. Frank Wolak served as the Committee Chair. The following is a brief description of each member's background.

Since April of 1998, Dr. Frank Wolak has been the MSC chairman. In this capacity, he has testified numerous times at FERC and before various committees of the US Senate and House of Representatives on issues relating to market monitoring and market power in electricity markets. Some of these topics include: FERC's role in the design of the California electricity market, the factors leading to the California electricity crisis, the role of the Enron trading strategies in the California electricity crisis, and lessons from the California electricity crisis and Enron bankruptcy for the design of effective regulatory oversight of wholesale energy markets.

Dr. Wolak is the Holbrook Working Professor of Commodity Price Studies in the Economics Department and the Director of the Program on Energy and Sustainable Development at Stanford University. He received his undergraduate degree from Rice University, and awarded a Master of Science in Applied Mathematics and doctorate 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 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 the Theodore & Kay Schad Professor of Environmental Management in the Whiting School of Engineering, at Johns Hopkins University, where he has been since 1995. He also holds a joint appointment in the Department of Applied Mathematics and Statistics. He is a former Professor of Systems Engineering and Civil Engineering at Case Western Reserve University. He has previously held positions at Brookhaven National Laboratory and Oak Ridge National Laboratory. He is a member of the Public Interest Advisory Committee for the Gas Technology Institute. During 2009-2010, he was a Senior Research Associate in the Electricity Policy Research Group in the Department of Economics and Judge Business School at the University of Cambridge, UK. His research interests include stochastic electric power planning models, including transmission planning; power systems operations and economics; multi-objective and risk analysis; ecosystem management; and mathematical programming models for simulating imperfect energy markets. Dr. Hobbs has published numerous journal and magazine articles on these topics and has co-authored two books. Dr. Hobbs has a doctorate 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 an Associate Professor and Cargill Chair in Energy Economics at the Department of Economics at Iowa State University. Also at ISU, he is the Director of Bio-based Industry Center and a Research Associate of the National Bureau of Economic Research. Dr. Bushnell received a doctorate in Operations Research from U.C. Berkeley in 1993. In addition, he served as a member of the Market Monitoring Committee of the California Power Exchange before it collapsed in the wake of the California energy crisis of 2000-2001. He has written extensively on the regulation, organization, and competitiveness of energy markets. Dr. Bushnell has testified on regulatory and competition policy issues before numerous state and federal regulatory and legislative institutions and consulted on energy issues throughout the U.S. and internationally.

8.3 Accomplishments

In 2009, the MSC was involved in discussions with ISO staff and the Department of Market Monitoring on several issues and provided opinions on several market design policy issues that included the following:

- *Proxy Demand Resource Proposal* – May 1, 2009
- *Comments on Barriers to Demand Response and the Symmetric Treatment of Supply and Demand Resources* – June 30, 2009
- *Comments on Changes to Bidding Start-Up and Minimum Load* – July 16, 2009
- *Opinion on Convergence Bidding* – October 16, 2009
- *Opinion on Reserve Scarcity Pricing Design* – December 2, 2009

MSC opinions can be found at: http://www.caiso.com/docs/2000/09/14/200009141610025714.html

8.4 Market Surveillance Committee meetings

The MSC held several public meetings and teleconferences in 2009 to hear and discuss various market design issues with stakeholders and interested parties. In preparation for the start of the new market, the MSC was involved in assisting the Department of Market Monitoring with refining the market monitoring protocols and reviewing the results of market simulation.

Appendix A Methodologies and detailed results

A.1 Net market revenues for new gas-fired generation

This section examines the extent to which revenues from the ISO spot markets in 2009 would contribute to the annualized fixed cost of typical new gas-fired generating resources. This represents an important market metric tracked by all ISOs.

The methodology used for the 2009 analysis is similar to the one used in DMM's *Annual Report on Market Issues and Performance* in previous years. The analysis is based on a hypothetical combined cycle and combustion turbine unit as described in Table A.1 and Table A.2. Net revenues for the combined cycle unit are estimated based on the generator's participation in the day-ahead energy and ancillary services market, and in the real-time energy market while net revenues for the combustion turbine are based on its participation in the real-time energy market and the ancillary services market.

DMM's last two annual reports were based on cost estimates published in the California Energy Commission's *2007 Integrated Energy Policy Report.* For our 2009 report, cost estimates were based on survey and third-party research sponsored by the CEC, which reflected a more current sampling of costs incurred by builders and investors in building new generation. Updated annualized capacity costs for combined cycle units rose from $132/kW-yr in the CEC's 2007 study to $191/kW-yr. For simple cycle units, annualized costs increased from $162/kW-yr to $212/kW-yr. The significant increase in new generation costs in 2009 can be largely attributed to increases in capital and financing costs and taxes.

Table A.1 Assumptions for typical new combined cycle unit[143]

Technical Parameters	
Maximum Capacity	500 MW
Minimum Operating Level	150 MW
Startup Gas Consumption	1,850 MMBtu/start
Heat Rates	
Maximum Capacity	7,100 MBTU/MW
Minimum Operating Level	7,700 MBTU/MW
Financial Parameters	
Financing Costs	$134.4 /kW-yr
Insurance	$7.2 kW-yr
Ad Valorem	$9.4 kW-yr
Fixed Annual O&M	$10.1 /kW-yr
Taxes	$29.6 kW-yr
Total Fixed Cost Revenue Requirement	**$190.7/kW-yr**
Variable O&M	$3.7/MWh

[143] The financing costs, insurance, ad valorem, fixed annual O&M and tax costs in this table were derived directly from the data presented in the CEC's 2010 *Comparative Costs of California Central Station Electricity Generation Technologies* report which can be found here: http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF

Table A.2 Assumptions for typical new combustion turbine unit[144]

Technical Parameters	
Maximum Capacity	100 MW
Minimum Operating Level	40 MW
Startup Gas Consumption	180 MMBtu/start
Heat Rates (MBTU/MW)	
Maximum Capacity	9,300
Minimum Operating Level	9,700
Financial Parameters	
Financing Costs	$146.6 /kW-yr
Insurance	$7.9 kW-yr
Ad Valorem	$10.4 kW-yr
Fixed Annual O&M	$20.3 /kW-yr
Taxes	$26.5 kW-yr
Total Fixed Cost Revenue Requirement	**$211.7/kW-yr**
Variable O&M	$5.1/MWh

A.1.1 Net revenue methodology

New combined cycle unit

The net revenues earned by the hypothetical combined cycle unit described in Table A.1 are based on market participation in the day-ahead, real-time energy and ancillary services markets. The hypothetical combined cycle unit was evaluated against both NP15 and SP15 prices, independently. The specific methods used for these approaches are described below.

1) An initial operating schedule for the day-ahead energy market was determined based on the hourly prices of the ISO northern and southern generation hubs (NP15 and SP15), and the unit's marginal operating cost plus a 10 percent adder. Operating costs were based on daily spot market gas prices, combined with the heat rates and variable O&M cost assumptions listed in Table A.1. The unit was scheduled up to full output when hourly prices exceed variable operating costs subject to 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 plus the bid adder. The algorithm compared operating losses during these hours to the cost of shutting down and re-starting the unit; if operating losses exceeded these shutdown and 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 plus the bid adder exceeded day-ahead bilateral energy prices.

[144] See Footnote 143.

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. The scheduling logic was the same as in the day-ahead market except that the average hourly real-time market trading hub prices were used. 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 and the output was smaller than its maximum stable level. The spinning reserve ancillary service prices were based on actual day-ahead prices.

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

6) If the unit did not recover its start-up costs during the period for which it was committed or dispatched, it was assumed the unit would receive an uplift payment equal to the negative net revenue amount.

7) A combined forced and planned outage rate of 5 percent was simulated by decreasing total annual net operating revenues by 5 percent.

New combustion turbine

The net revenues earned by the hypothetical combustion turbine unit described in Table A.2 are based on participation in the real-time energy[145] and ancillary services market. The hypothetical combustion turbine was evaluated against both NP15 and SP15 prices, independently. 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 trading hub energy price exceeded the unit's marginal operating costs plus a 10 percent bid adder. Operating costs were based on daily spot market gas prices, combined with the heat rates and variable O&M cost assumptions listed in Table A.2. The unit was scheduled up to full output when the average hourly real-time market trading hub prices exceeded variable operating costs plus 10 percent 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 trading hub prices fall below the variable operating costs plus the bid adder. The algorithm compared operating losses during these hours to the cost of shutting down and re-starting the unit; if operating losses exceeded the shutdown and 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 plus the bid adder exceeded real-time energy prices.

3) Ancillary service revenues were calculated by assuming the unit could provide up to 80 MW of non-spinning reserve each hour if it was committed during the hour. The non-spinning service prices were based on actual day-ahead ancillary service prices.

[145] Real-time market prices were used for the combustion turbine revenue analysis because this is a more likely market for fast-start units to be called upon to provide energy.

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

5) If the unit did not recover its start-up costs during the period for which it was committed or dispatched, it was assumed the unit would receive an uplift payment equal to the negative net revenue amount.

6) 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.

Changes to methodology in 2009

The following points outline the changes to inputs or assumptions that affected the net revenue estimates in this report compared to previous reports.

- ***Input prices —*** In previous years, the revenue analysis was based heavily on spot market prices as reported by Powerdex, an independent energy information company. In 2009, revenue analysis was based on actual market prices produced under the new nodal market. Index prices, such as those reported by Powerdex, are based on surveyed transactions and can be skewed by volumes and clearing prices and do not reflect the prices that all generators were paid. In the 2009 revenue analysis, actual trading hub prices from the new market were used to reflect actual prices that generators were paid.

- ***Fixed-costs requirements —*** As stated earlier, the most recent fixed cost targets for a new combined cycle unit and a new combustion turbine unit provided by the CEC were markedly higher than the targets used in the 2008 revenue analysis. The increase in fixed cost estimates are due to higher financing and capital costs, and taxes.

- ***New market design —*** Another change that inherently affects the revenue analysis results is that the analysis is based solely on the prices that resulted from the new market. The new market, which started in April 2009, impacts the prices used in this analysis. For example, in the new market, energy and ancillary services are co-optimized. In past years, energy and ancillary services were procured independently.

A.1.2 Results

Hypothetical combined cycle unit

The net revenue results for a combined cycle unit participating in the energy and ancillary service markets are summarized in Table A.3. Results for 2009 show a substantial decrease in net revenues compared to 2008. This decrease in estimated net revenues can largely be attributed to the decrease in spot market gas and electricity prices.

For comparison, during the months April through December, average day-ahead peak spot electricity prices for northern California were almost 55 percent lower in 2009 than in 2008 ($84/MWh in 2008 and $38/MWh in 2009). The decrease in electricity prices are explained largely by the decrease in natural gas prices in 2009 relative to 2008.

Table A.3 compares the net revenue estimates for the hypothetical combined cycle unit with the annualized fixed costs requirements for the past five years. The 2009 net revenue estimates for a hypothetical combined cycle unit in NP15 and SP15 both fall substantially below the $191/kW-yr annualized fixed cost estimate provided by the CEC. While 2008 showed an increase in annualized fixed cost recovery based on energy and ancillary service sales, 2009 net revenue estimates revealed a larger gap between the annualized fixed cost target and net revenues from energy and ancillary services.

Table A.3 Financial analysis of new combined cycle unit (2006-2009)

Components	2006		2007		2008		2009	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	63%	75%	69%	76%	74%	81%	57%	57%
DA Energy Revenue ($/kW - yr)	$319.65	$355.32	$369.59	$389.41	$489.17	$505.42	$172.67	$169.61
RT Energy Revenue ($/kW - yr)	$34.37	$50.02	$36.20	$41.98	$47.41	$51.98	$21.27	$15.50
A/S Revenue ($/kW – yr)	$1.01	$1.06	$0.37	$0.42	$0.41	$0.42	$0.76	$0.85
Operating Cost ($/kW - yr)	$279.50	$321.59	$321.86	$337.82	$425.16	$428.39	$154.57	$147.48
Net Revenue ($/kW – yr)	$75.53	$84.82	$84.30	$95.23	$111.82	$128.25	$40.14	$38.48
5-yr Average ($/kW – yr)	*$77.95*	*$86.70*						

Given the considerable change in 2009 results, further analysis was performed to benchmark results for the hypothetical combined cycle unit against actual combined cycle units. This analysis included actual scheduled and generation data for nine merchant-owned combined cycle units of similar size. Results of this benchmarking are summarized below:

- ***Capacity Factors —*** Figure A.1 and Figure A.2 shows on-peak and off-peak capacity factors of the hypothetical combined cycle unit (in green) and the surveyed merchant-owned combined cycle units (in blue) during the first nine months of the new market. The hypothetical combined cycle unit had an average all-hours capacity factor of 57 percent while the capacity factor for the group of merchant-owned units averaged 61 percent (with a range of 40 to 78 percent). The hypothetical unit’s capacity factor of 76 percent for peak hours is very close to the group average capacity factor of 71 percent (with a range of 55 percent to 88 percent). This unit’s capacity factor of 39 percent for off-peak hours is significantly lower than that of the merchant-owned units’ average capacity factor of 50 percent (with a range of 22 to 73 percent). [146]

- ***Self-scheduling of energy —*** On average, the nine merchant-owned combined cycle units self-scheduled 71 percent of their cleared energy (or 44 percent of total possible energy) into the day-ahead market. This indicates that these resources are engaging in forward bilateral contracting as a means of meeting their fixed cost requirement. This net revenue analysis does not include an estimate of revenues associated with forward bilateral contracting (energy or resource adequacy capacity) because the details of such agreements are not publicly available. Figure A.3 shows self-scheduled energy as a percent of total cleared energy for the surveyed merchant-owned units during the first nine months of the new market.

[146] This difference may be attributed to two factors. First, in modeling the hypothetical combined cycle, a minimum down time constraint was not enforced, so the unit shuts down during off-peak hours and restarts during on-peak hours if economic to do so. Second, some combined cycle units may operate at minimum load during off-peak hours instead of completely shutting them down because frequent shut-downs and restarts create wear and tear on units and increases maintenance costs.

Figure A.1 Comparison of capacity factors for peak hours

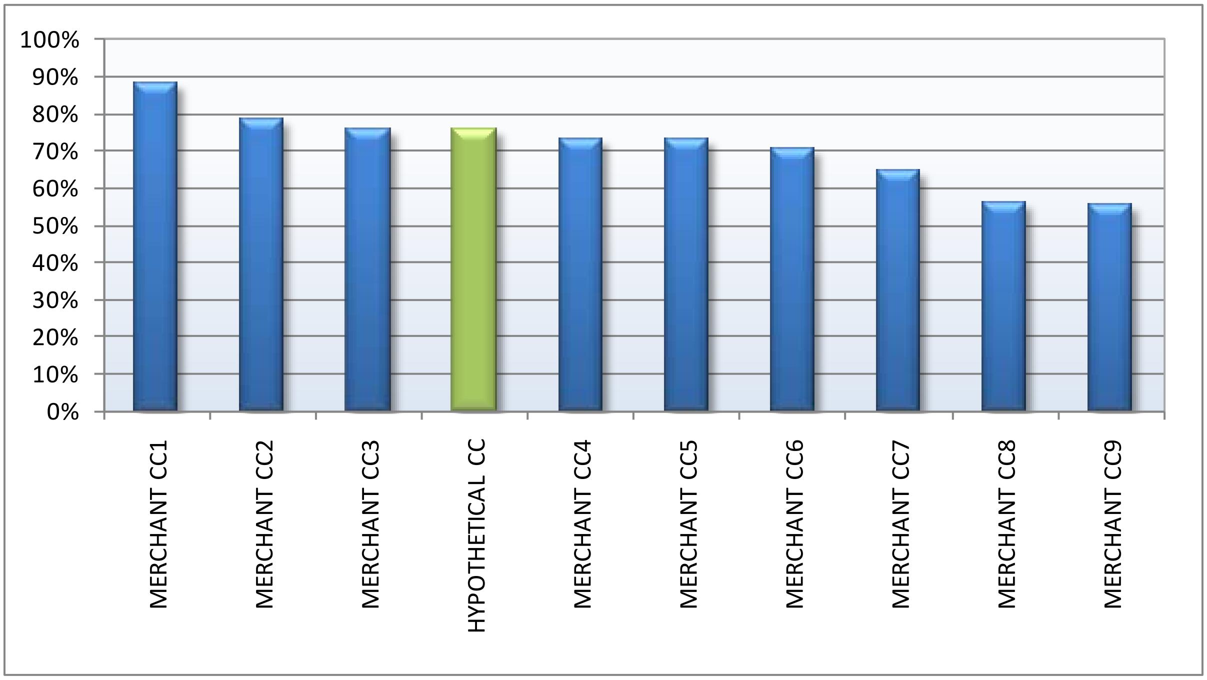


Figure A.2 Comparison of capacity factors for off-peak hours

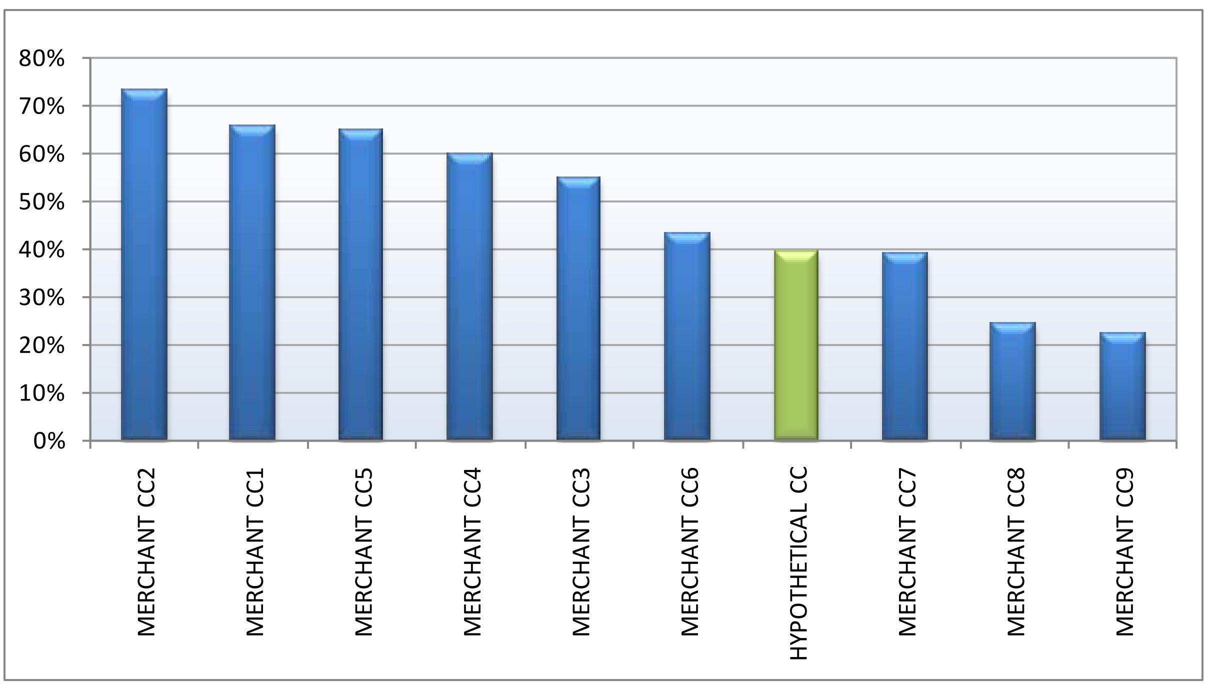
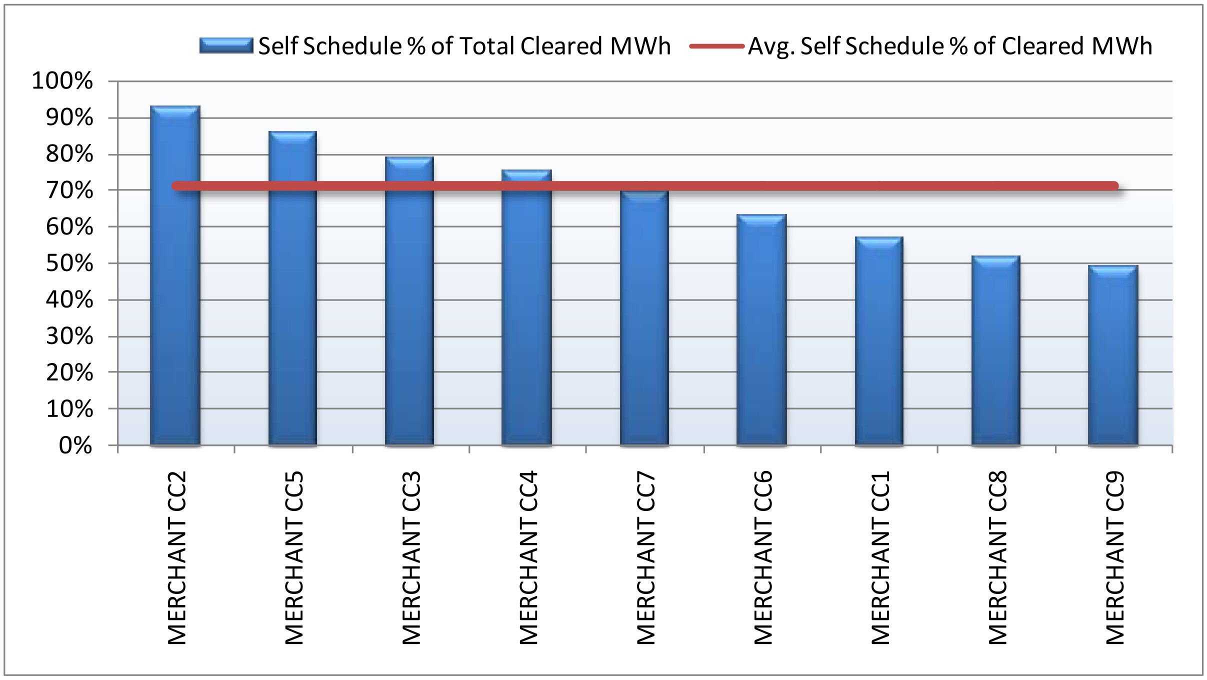


Figure A.3 Self-scheduled energy as a percent of total cleared energy for combined cycle units



Hypothetical combustion turbine

Table A.4 shows the estimated net revenues that a hypothetical combustion turbine unit would have earned by participating in the day-ahead ancillary services and real-time market. Estimated spot market revenues for a hypothetical unit in NP15 or SP15 fell well short of the $211.7/kW-yr annualized fixed costs of new capacity as reported by the CEC for all years (2006-2009). Table A.4 compares the net revenue estimate for the unit against the annualized fixed costs requirements for the past five years.

Table A.4 Financial analysis of new combustion turbine unit (2006-2009)

Components	2006		2007		2008		2009	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	7%	10%	8%	9%	11%	12%	6%	6%
Energy Revenue ($/kW - yr)	$69.46	$99.77	$97.54	$104.99	$155.58	$158.98	$70.50	$84.62
A/S Revenue ($/kW - yr)	$22.67	$21.68	$13.30	$12.83	$5.50	$5.53	$8.64	$8.37
Operating Cost ($/kW - yr)	$46.04	$68.92	$59.18	$64.63	$100.12	$104.09	$25.85	$27.70
Net Revenue ($/kW - yr)	$46.10	$52.35	$51.66	$53.19	$60.96	$60.43	$53.29	$65.29
5-yr Average ($/kW - yr)	*$53.00*	*$57.82*						

A.2 Total wholesale costs

Since 1999, the DMM has reported its estimate of annual wholesale energy costs that is compared across years. In prior years, the total wholesale market costs were estimated by considering costs related to utility-retained generation, forward bilateral contracts, real-time energy, and ancillary service reserves. Given the new market design and the resulting availability and transparency of market clearing prices and quantities, we were compelled to create a new methodology of calculating a total wholesale cost estimate.[147]

It is also important to note that in prior years, forward costs were primarily based on limited data since the ISO did not have a formal day-ahead market and thus the prices load-serving entities were paying were not explicitly known. Under the new market, the settled prices and quantities are transparent and thus a more accurate total wholesale cost estimate can be calculated. For this reason, the 2009 estimate may be a better estimate of total wholesale costs than in past years.

A.2.1 Methodology

The new method of estimating total cost focuses on the cost of serving load using the prices and quantities cleared at the load aggregation points in the IFM and RTD energy markets, while also taking into account the net import settlements at the interties during HASP. In addition, the costs associated with ancillary service reserves, residual unit commitment, bid-cost recovery, reliability must-run contracts, the interim capacity payment mechanism, and grid management charges are included in the new total wholesale cost estimate. The estimate does not include resource adequacy procurement costs, a regulatory requirement for bilateral capacity arrangements between generator and load serving entities that has been in place since June 2006.[148]

For the 2009 months under the old market, January through March, the total cost estimate was calculated using a methodology similar to the one used in the DMM's 2008 annual report. The following briefly describes the new methodology used in estimating the costs.

- ***Day-ahead energy costs*** — These costs were calculated by taking the product of the hourly price and quantities at each local aggregation point and summing the hourly products to equal the total day ahead energy costs for the period.

- ***Residual unit commitment costs —*** These costs were calculated for non-resource adequacy RUC awards. The non- resource adequacy RUC costs were calculated by summing the hourly non-resource adequacy RUC awards and RUC LMPs for each generator providing non- resource adequacy RUC capacity.

- ***Net hour-ahead import costs —*** Costs of net imports (or a decrease in net imports) were calculated by taking the difference in the day ahead market and the hour ahead scheduling process net import quantities at each intertie PNode on each hour multiplied by the hour ahead scheduling process intertie LMP[149].

[147] Because the new market was in effect for only part of 2009 (April – December), the costs for the months prior to go-live (January – March) were calculated using a methodology similar to the one used in last year's annual report.

[148] In years prior to 2009, resource adequacy costs were also excluded in the total wholesale cost estimate. DMM has excluded resource adequacy cost estimates since it is difficult to estimate these costs as contract details are not known to the ISO.

[149] Since the day ahead market is run on an hourly basis and the hour ahead scheduling process is run in 15 minute increments, a weighted average hour ahead scheduling process LMP and average hour ahead scheduling process net import MW was calculated for each intertie PNode so that the data for hour-ahead scheduling process was of equal granularity to the day ahead data.

- ***Real-time energy costs*** — The real-time energy cost calculation builds on the day ahead market and the hour ahead scheduling process calculations to isolate only the cost associated with the incremental portion of real-time dispatched energy. First, an hourly weighted average local aggregation point energy price was calculated by summing the product of prices and quantities at each local aggregation point and dividing by the sum of quantities. The weighted average price was used in costing the incremental real-time dispatched energy. Next, the incremental real-time dispatched energy was calculated by summing the hourly real-time dispatched energy, then subtracting the integrated forward market energy and hour ahead scheduling process net import energy.[150] Finally, the hourly incremental real-time dispatched energy cost was calculated by multiplying the incremental real-time dispatched energy by the weighted average local aggregation point price.

- ***Day-ahead ancillary services costs*** — Day-ahead ancillary services costs were calculated by summing the product of the hourly day-ahead ancillary services schedule and the relevant ancillary service marginal price for each generator for each ancillary services commodity (spinning reserve, non-spinning reserve, regulation up, and regulation down).

- ***Real-time ancillary services costs* —** Real-time ancillary services costs were calculated at each 15 minute real-time pre-dispatch interval for each contributing generator for each ancillary services commodity and dependent upon if the real-time ancillary services award was greater or less than its day ahead ancillary services award. If the real-time ancillary services award was greater than the day ahead ancillary services award for a particular resource, the incremental real-time ancillary services award was multiplied by the relevant 15 minute interval ancillary service marginal price and divided by four (to equal a quarter hour's cost). This calculation represents the additional real-time ancillary services cost to the ISO. If the real-time ancillary services award was less than the day ahead ancillary services award for a particular generator on a particular interval, the difference of the two awards was multiplied by the hourly average ancillary service marginal price and divided by four. This calculation represents revenue collected by the ISO for a day ahead ancillary services award that was not available from the particular generator in real time. Finally, the costs and buyback revenues at each hour are summed to equal the total hourly real-time ancillary services cost (net of buybacks).

- ***Bid cost recovery costs* —** Bid cost recovery payments were obtained from settlements data and were simply summed to get total recovery costs for the period.

- ***Reliability must-run costs* —** Reliability must-run payments were obtained from settlements data and were simply summed to get total must-run costs for the period.

- ***Interim capacity payment mechanism costs* —** These costs were obtained from the interim capacity payment mechanism designation reports available on the ISO website.

- ***Grid management charge* —** GMC costs to market participants were estimated by multiplying the 2009 bundled GMC rate of $0.776 with the total energy transacted.

[150] Similar to the point made in footnote 149, an hourly average real-time dispatch energy total and a weighted average energy price was calculated from 5 minute interval data so that the real-time dispatch data was of equal granularity to the day ahead data.

A.2.2 Results

Table A.5 provides a component breakdown of contributing factors to nominal energy costs on a per-unit basis. This table serves as a useful benchmark of ISO and market performance, excluding the costs of resource adequacy contracting. This table has changed slightly from previous years due to the change in market design and the resulting change in reporting categories. Using the new market categories provided in Table A.5, the pre-new market categories have been integrated in the following manner:

- ***Day-ahead energy costs (excluding GMC)*** contains the pre-new market categories: forward-scheduled energy costs, excluding inter-zonal congestion costs and GMC.
- ***Real-time energy costs*** contains the pre-new market categories: incremental in-sequence real-time energy costs, out-of-sequence real-time energy re-dispatch premium, less in-sequence decremental real-time energy savings.
- ***Grid management charge*** contains the pre-new market category of GMC.
- ***Bid cost recovery costs*** contains the pre-new market category of explicit minimum load cost compensation costs (uplift).
- ***Reliability costs (RMR and ICPM)*** contains the pre-new market categories of: inter-zonal congestion costs, reliability capacity services tariff and transitional capacity procurement mechanism costs, and reliability must-run net costs.
- ***Reserve costs (AS and RUC)*** contains the pre-new market category: ancillary service costs (self-provided ancillary services valued at market prices).

As shown in this table, the decrease in non-normalized costs is evident between 2008 and 2009 with the bulk of the difference attributable to a decrease in day-ahead energy costs in 2009.

Table A.5 Contributions to estimated average wholesale energy costs per MWh of load served, 2005-2009

	2005	2006	2007	2008	2009	Change '08-'09
Day-Ahead Energy Costs (excl. GMC)	$ 52.28	$ 43.01	$ 44.74	$ 47.48	$ 35.57	$ (11.91)
Real-Time Energy Costs	$ 0.82	$ 0.29	$ 0.25	$ 0.81	$ 0.81	$ (0.00)
Grid Management Charge	$ 0.84	$ 0.72	$ 0.76	$ 0.76	$ 0.78	$ 0.02
Bid Cost Recovery Costs	$ 0.55	$ 0.50	$ 0.23	$ 0.41	$ 0.29	$ (0.12)
Reliability Costs (RMR and ICPM)	$ 2.38	$ 2.07	$ 1.64	$ 2.80	$ 0.25	$ (2.55)
Average Total Energy Costs	**$ 56.86**	**$ 46.60**	**$ 47.62**	**$ 52.26**	**$ 37.69**	**$ (14.57)**
Reserve Costs (AS and RUC)	$ 0.96	$ 0.97	$ 0.63	$ 0.74	$ 0.39	$ (0.35)
Average Total Costs of Energy and A/S	**$ 57.83**	**$ 47.57**	**$ 48.25**	**$ 53.00**	**$ 38.08**	**$ (14.92)**

Table A.6 Annual wholesale costs: 1998 to 2009

Month	ISO Load (GWh)	Total Est. Forward Costs ($MM)	RT Energy and Reliability Costs ($MM)	Reserve (AS + RUC) Costs ($MM)	Total Costs of Energy ($MM)	Total Costs of Energy and Reserves ($MM)	Avg Cost of Energy ($/MWh load)	Avg Cost of Reserves ($/MWh load)	Reserves as % of Wholesale Cost	Avg Cost of Energy & Reserves ($/MWh load)
1998 (9mo)	169,239	$ 4,704	$ 1,061	$ 638	$ 5,765	$ 6,403	$ 34.07	$ 3.77	10.0%	$ 37.83
Total 1999	227,533	$ 6,848	$ 562	$ 404	$ 7,410	$ 7,814	$ 32.57	$ 1.78	5.2%	$ 34.34
Total 2000	237,543	$ 22,890	$ 3,446	$ 1,720	$ 26,336	$ 28,056	$ 110.87	$ 7.24	6.1%	$ 118.11
Total 2001	227,024	$ 21,248	$ 4,586	$ 1,346	$ 25,834	$ 27,180	$ 113.79	$ 5.93	5.0%	$ 119.72
Total 2002	232,011	$ 9,865	$ 532	$ 157	$ 10,397	$ 10,554	$ 44.81	$ 0.68	1.5%	$ 45.49
Total 2003	230,668	$ 10,814	$ 696	$ 199	$ 11,510	$ 11,709	$ 49.90	$ 0.86	1.7%	$ 50.76
Total 2004	239,788	$ 11,832	$ 1,099	$ 184	$ 12,931	$ 13,115	$ 53.93	$ 0.77	1.4%	$ 54.70
Total 2005	236,449	$ 12,526	$ 830	$ 228	$ 13,356	$ 13,584	$ 56.49	$ 0.96	1.7%	$ 57.45
Total 2006	240,260	$ 10,563	$ 633	$ 234	$ 11,196	$ 11,430	$ 46.60	$ 0.97	2.0%	$ 47.57
Total 2007	241,990	$ 11,260	$ 260	$ 152	$ 11,520	$ 11,672	$ 47.61	$ 0.63	1.3%	$ 48.23
Total 2008	241,552	$ 12,257	$ 366	$ 178	$ 12,623	$ 12,802	$ 52.27	$ 0.74	1.4%	$ 53.01
Total 2009	**230,754**	**$ 8,433**	**$ 265**	**$ 90**	**$ 8,698**	**$ 8,788**	**$ 37.69**	**$ 0.39**	**1.0%**	**$ 38.08**

A.3 Reliability must-run costs

Table A.7 Reliability must-run monthly contract and energy costs in 2009

Month	Pre-Dispatched Energy (GWh)	Real-Time Energy (GWh)	Fixed Option Payments ($MM)	Net Day-Ahead Costs ($MM)	Net Real-Time Costs ($MM)	Total RMR Costs ($MM)
Jan-09	54	46	$ 2.5	$ 1.2	$ 0.8	$ 4.6
Feb-09	38	24	$ 2.3	$ 0.7	$ 0.3	$ 3.3
Mar-09	36	6	$ 2.5	$ 0.6	$ 0.2	$ 3.3
Apr-09	73	12	$ 2.3	$ 1.0	$ 0.2	$ 3.5
May-09	34	7	$ 1.3	$ 0.6	$ 0.4	$ 2.2
Jun-09	47	9	$ 2.4	$ 0.5	$ 0.0	$ 2.9
Jul-09	104	4	$ 2.5	$ 0.2	$ 0.0	$ 2.7
Aug-09	108	9	$ 2.5	$ 1.1	$ 0.2	$ 3.8
Sep-09	131	11	$ 2.4	$ 0.9	$ (0.0)	$ 3.3
Oct-09	81	10	$ 2.5	$ 0.9	$ 0.3	$ 3.7
Nov-09	48	5	$ 2.1	$ 0.9	$ 0.0	$ 3.1
Dec-09	63	8	$ 1.8	$ 0.7	$ 0.1	$ 2.6
Total	**815**	**153**	**$ 27.2**	**$ 9.4**	**$ 2.5**	**$ 39.1**
% Chg from 2008	33%	-70%	-18%	-49%	-84%	-41%

A.4 Frequency and impact of bid mitigation

The impact of bid mitigation on actual market prices can only be assessed by re-running the market software without bid mitigation. Given the solution times for the current market software, this is not a practical approach for assessing impacts that bid mitigation of individual units or suppliers may have on market prices. However, we have developed metrics to measure the frequency with which local market power mitigation provisions have been triggered, and the impact of mitigation on each unit's market bids and market dispatch level.

Figure A.4 and Figure A.5 illustrate three of these metrics using an hypothetical example of how a unit's bids may be mitigated and dispatched as a result of the local market power process. These metrics are described below.

- ***Units subject to mitigation* —** Units dispatched at a higher level in the all-constraints run than in the competitive constraints run are subject to bid mitigation. As illustrated in Figure A.4, a unit's initial market bid is subject to mitigation if its dispatch in the all constraints run (Q_{AC}) is greater than its dispatch in the competitive run (Q_{CC}). This indicates more generation is needed in areas constrained by the non-competitive paths, compared with the level of generation needed with only competitive constraints enforced.

- ***Units with bids lowered* —** Units subject to mitigation may not actually have their market bids mitigated or lowered. The unit's highest market bid cleared in the competitive constraints run is used as a floor for its mitigated bid. The unit's bid cannot be mitigated below this floor, even if this exceeds the unit's default energy bid.[151] The ISO bid mitigation procedures only affect the portion of the unit's bid curve beyond the level at which the unit is dispatched in the competitive constraints run. If any part of this bid curve above this level exceeds this bid floor or the unit's default energy bid, this portion of the bid curve is mitigated to the higher of this bid floor or the default energy bid. Figure A.4 provides an example of this situation, as the unit's highest bid dispatched in the competitive constraints run (P_{CC}) is used as a floor for the red line representing the unit's final mitigated bid.

- ***Potential increase in dispatch due to bid mitigation* —** As shown in Figure A.5, if a unit's bid is lowered because of mitigation, the unit may be dispatched at a higher level in the market. The potential increase in the unit's dispatch due to bid mitigation can be measured by the difference (if any) between the unit's actual market dispatch and its estimated dispatch level if its bid had not been mitigated. In Figure A.5, the unit's actual market dispatch is denoted by Q_{IFM}, and the unit's dispatch based on its unmitigated bid is denoted by Q_U. Q_U is estimated by the point where the actual market-clearing price intersects the unit's unmitigated bid curve. Thus, $Q_{IFM} - Q_U$ represents the unit's potential increase in dispatch due to bid mitigation.[152]

[151] For an example of this floor, see the unit's final mitigated bid for capacity up to Q_{CC} in Figure A.4.

[152] In practice, the unit's bid price at its actual dispatch level in the integrated forward market (Q_{IFM}) can be lower than the unit's bid price because the integrated forward market is a 24-hour optimization. This could also create situations where the amount of the unit's unmitigated bid curve below the integrated forward market price was less than the unit's dispatch in the competitive constraints run. To avoid any overestimation of the impacts of mitigation that could result from these conditions, the estimated dispatch of the unit with unmitigated bids was constrained to be not less than its dispatch in the competitive constraints run ($Q_U \geq Q_{CC}$). The net effect of this constraint is to simply prevent the measure of the increase in dispatch due to mitigation during any hour (Q_{IFM} - Q_U) from exceeding the actual increase in the unit's final integrated forward market schedule over the unit's dispatch in the competitive constraints run based on its unmitigated bids (Q_{IFM} - Q_{CC}).

Figure A.4 Bid mitigation

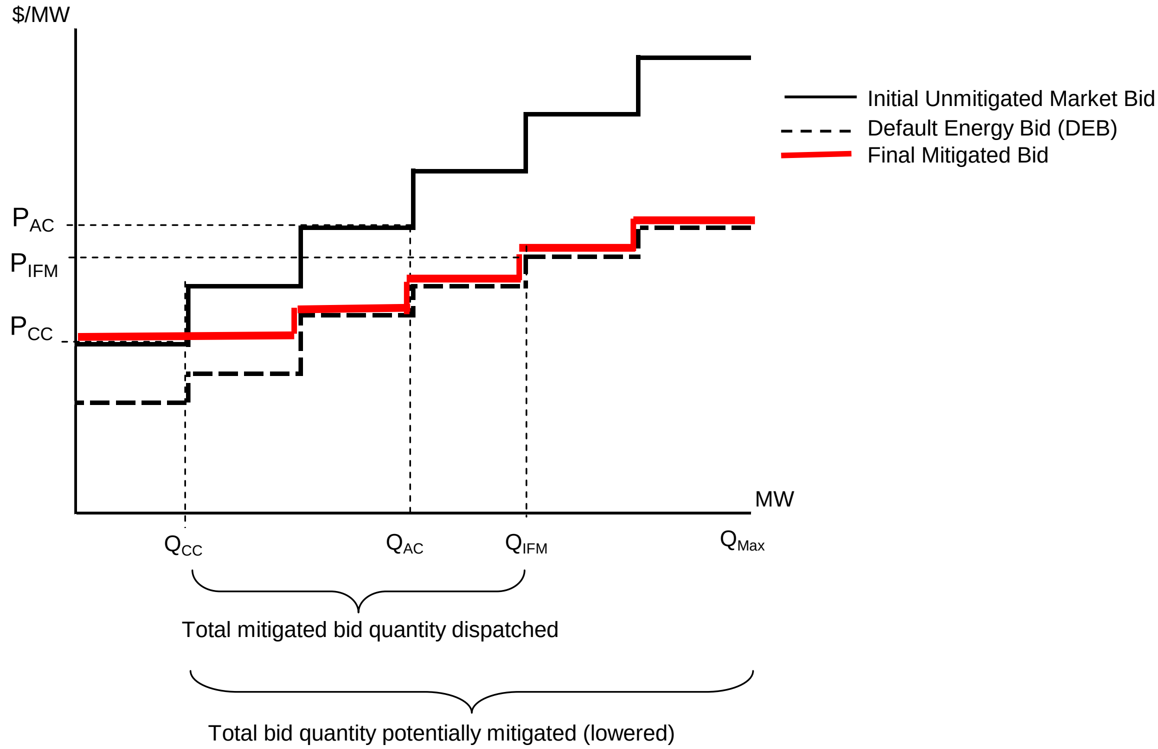
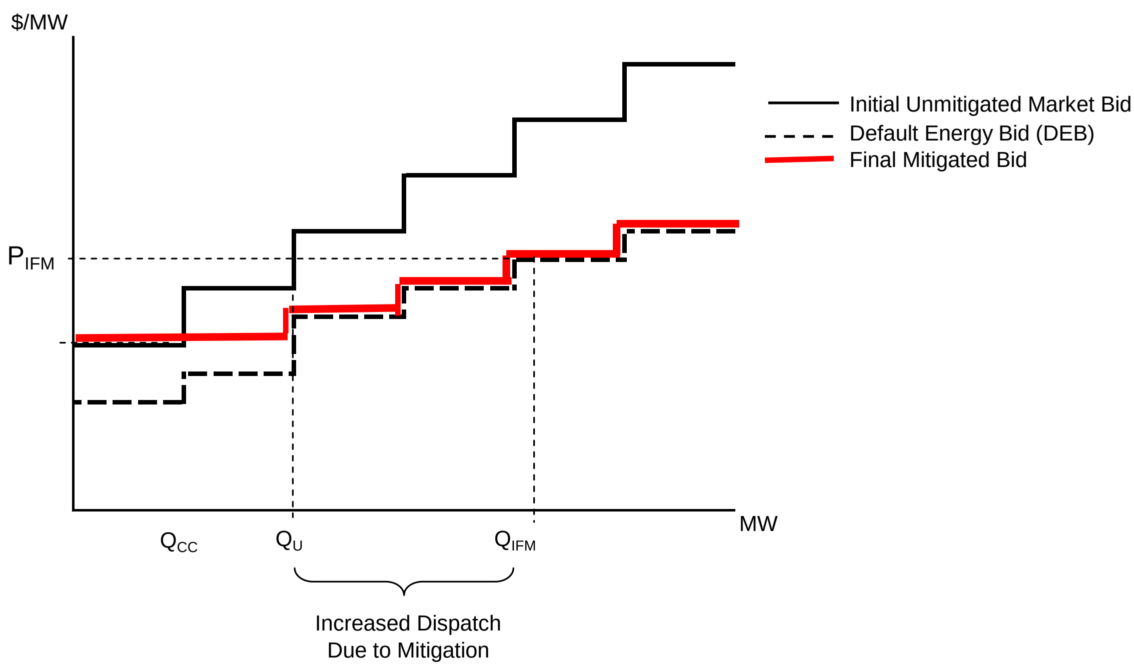


Figure A.5 Measuring impact of bid mitigation



A.5 Residual supply index for counterflow

The most common way to exercise market power is to withhold generation within a transmission constrained load pocket. In such circumstances, the availability of potential counterflows for congested paths is a key metric that can be used to assess the competitiveness of specific constraints. Potential counterflows on congested paths represent generation resources that may be used to relieve congestion by increasing their output.

The residual supply index for counterflow on congested constraints was developed by DMM based on similar metrics used by several other ISOs to assess the competitiveness of transmission constraints. The index supplements the competitive path designations and provide a tool that can be used to monitor and assess the competitiveness of constraints on a day-to-day basis under actual network and market conditions.

The index for each congested constraint can be defined as follows.

Shift Factor SF(*k*,*i*) represent resource *k*'s shift factor on *i*-th congested constraint

Schedule MW(*k*) represent resource *k*'s output (MW)

Pmax(*k)* equal resource *k*'s maximum output

The dispatched counterflow of resource *k* for SF(*k*,*i*) < 0 is:

D_CFlow(*k*) = SF(*k*,*i*)*MW(*k*)

The supply of potential counter flow of resource *k* for SF(*k*,*i*) < 0 is:

S_CFlow(*k*) = SF(*k*,*i*)*Pmax(*k*)

The total dispatched counterflow from resources controlled by market participant P is:

D_CFlow(P) = ∑D_CFlow(*k*) where *k* belongs to P

The total dispatched counter flow from all resources is:

Total_D_CFlow = ∑D_CFlow(*k*) for all *k*

The total supply of potential counter from all resources is defined as:

Total_S_CFlow = ∑S_CFlow(*k*) for all *k*

An index representing the ratio of total supply of potential counter from all resources (before removing any supplier) relative to the total demand for counterflow, or RSI (0), can then be calculated as follows:

$$RSI(0) = \frac{Total\_S\_CFlow}{Total\_D\_CFlow} = \frac{\sum_k S\_CFlow(k)}{\sum_k D\_CFlow(k)}$$

The index with the single largest supplier removed (RSI_1) is calculated as follows:

$$RSI(1) = \frac{Total\_S\_CFlow - S\_CFlow(P1)}{Total\_D\_CFlow}$$

The index with the two largest suppliers removed (RSI_2) is calculated as follows:

$$RSI(2) = \frac{Total\_S\_CFlow - S\_CFlow(P1) - S\_CFlow(P2)}{Total\_D\_CFlow}$$

The index with the three largest suppliers removed (RSI_3) is calculated as follows:

$$RSI(3) = \frac{Total\_S\_CFlow - S\_CFlow(P1) - S\_CFlow(P2) - S\_CFlow(P3)}{Total\_D\_CFlow}$$

Important aspects of the index for counterflow on congested paths include the following:

- One of the main strengths of the index is that it is calculated based the actual supply and demand for counterflow during hours when congestion occurs. Results, therefore, reflect changes in system conditions not captured in the competitive path assessment. For example, if a transmission line is de-rated, this increases the demand for counterflow used in the test. If a unit effective at providing counterflow is unavailable due to an outage, this decreases the supply of counterflow used in the test. Thus, the residual supply index may vary significantly for a given constraint, reflecting different dispatch patterns at different time.
- A second major advantage of the index is that it computationally simpler. Once automated metrics are developed, the index can be quickly calculated for each congested constraint by combining readily available market data with each unit's shift factors.
- The residual supply index is analyzed individually for each binding constraint, ignoring potential interaction among multiple constraints. For instance, available counter flow for one constraint may not be fully dispatched because these counter flows may worsen the congestion in the other constraint. Such factors among multiple congestions are not revealed in index, while competitive path assessment results reflect the complex network effect by simultaneous constraint modeling.
- Available counter-flow in index calculation depends on maximum capacity of the unit, which may not be fully available due to operating constraints such as ramping.
- The index can only be calculated once a constraint is binding (and actual flow may be equal to or greater than the limit). Meanwhile, the competitive path assessment designates non-competitiveness based on overflow criterion. Under the competitive path assessment methodology, a constraint that is binding but not violated (i.e. without overflow) is still considered competitive regardless of its shadow price.
- The index is for counter-flow only and ignores positive flow. When two constraints have similar index values, actual market outcome such as transmission shadow prices may be different because of different positive flows.

- The index of counter-flow should not be treated or categorized absolutely by a fixed threshold (such as 1). Since the index does not consider positive flow, operating constraints such as ramping, interaction among multiple constraints, the calculated values should be treated as a supplementary tool to analyze market competitiveness.

A.6 Calculating the impact of binding constraints on LMP at load aggregation points and local capacity areas

When a constraint is congested, the market produces a shadow price. This price represents the system-wide bid cost savings that would occur if that constraint had one additional megawatt of transmission capacity in the congested direction.

When there is no physical limit on a transmission path, transmission is not scarce. So the market software will dispatch energy to serve load, using the least-cost energy bids system-wide. In contrast, congestion occurs when physical constraints limit the capacity of a transmission line preventing the market from moving electricity freely across the grid. Therefore, the market software chooses the costlier energy that is topologically closer to the load. This additional cost is known as congestion costs, which is determined by the shadow price of the constraint and the real shift factor on the constraint to serve load.

- The shadow price on a transmission path is the savings in total system production cost, if that constraint had one additional megawatt of transmission capacity in the congested direction.

- Shift factor is the sensitivity of the power flow change on a transmission line, if the injection at the bus changes by one megawatt. To define shift factor, consider a power injection of one megawatt at one bus and a withdrawal at another bus. A shift factor to a particular line is the ratio of a change in flow on a line to the change in injection and withdrawal at a pair of buses.

Although the market produces a shadow price for a congested constraint, this price is not directly charged to participants. Neither does it pay for counter-flow schedules in the opposite direction of congestion. The shadow price is only an indication of the additional production cost because of the binding constraint.

Transmission congestion does affect the generation dispatch pattern required to meet load at the various load points. Consequently, this congestion has an indirect impact on the price of energy at different nodes. The market software calculates and publishes the impact of congestion on the energy price at any location, as the congestion component of the LMP for all locations where energy is priced. Thus, in the new nodal market, the cost of congestion is implicit in the energy prices directly used in settlement. This relationship makes congestion frequency and shadow prices important in the new market.

For any time interval and in any location where energy is priced, the shadow price and shift factor of congested constraints and the LMP congestion component will have the following relationship:

$$-\sum_{n=1}^{N} \text{Shift Factor}_n * \text{Shadow Price}_n = \text{LMP}_{\text{Congestion Component}}$$

Where:

N is the total number of the constraints on the grid.

Shift $Factor_n$ represents the proportion of the power flowing in the n_{th} constraint when one megawatt of power is injected in the given location.

Uncongested lines have a shadow price of zero, since an additional unit of scheduled energy will not overflow the line and thus will not require substitution.

The following example in Table A.8 helps to show the impact of congestion on local aggregation point energy prices more clearly. On November 25, trade hour ending 7, two internal constraints were binding in the integrated forward market; La Fresa – Hinson 230 kV line and Los Banos North branch group.

Table A.8 Congestion component (day-ahead market, November 25, 2009, Hour Ending 7)

Flowgate Name	Shift Factor	Shadow Price	Congestion Price	LMP	LMP Congestion	LMP Energy + Loss
LA FRESA to HINSON 230 kV (Line)	0.03800	$14.27	-$0.54	$36.75	$2.08	$34.67
LOSBANOSNORTH (BG)	-0.23351	$11.24	$2.62	$36.75	$2.08	$34.67
LA FRESA to HINSON 230 kV (Line)	-0.06119	$14.27	$0.87	$30.48	-$1.41	$31.89
LOSBANOSNORTH (BG)	0.20300	$11.24	-$2.28	$30.48	-$1.41	$31.89
LA FRESA to HINSON 230 kV (Line)	0.03800	$14.27	-$0.54	$28.55	-$2.82	$31.37
LOSBANOSNORTH (BG)	0.20300	$11.24	-$2.28	$28.55	-$2.82	$31.37

As the table shows, PG&E LMP price was $36.75. This price combines the $34.67 for producing energy and an additional $2.08 because of binding constraints. We use the formula explained above to deconstruct the $2.08 LMP congestion component:

- La Fresa – Hinson 230 kV line congestion decreased the PG&E LMP price by $0.54.
  (-1)* (0.038 * $14.27) = -$0.54

- Los Banos North branch group congestion increased the PG&E LMP price by $2.62.
  (-1)*(-0.23351 * $11.24) = $2.62

These two congestion prices add up to $2.08, which is the PG&E LMP congestion component.

From this example, one can see the higher shadow price of a binding constraint cannot be an indication of a higher congestion cost because the shift factor associated with the binding constraint has an important effect. In our example, let's assume that the shadow prices for both La Fresa – Hinson 230 kV and Los Banos North branch group are $100. The congestion cost derived by La Fresa – Hinson 230 kV is only -$3.80, compared to $23.40 of congestion cost caused by on the Los Banos North branch group.

In the same method, the LMP congestion components of SCE and SDGE can be deconstructed.

- The La Fresa – Hinson 230 kV line congestion increased the SCE LMP price by $0.87. In contrast, the Los Banos North branch group congestion decreased the SCE LMP prices by $2.28. Overall, the SCE LMP congestion component was -$1.41.

Unlike PG&E and SCE, congestion on La Fresa – Hinson line and Los Banos North branch group both decreased the SDGE LAP price by $2.82. Only $0.54 was contributed by La Fresa – Hinson congestion, compared to $2.28 contributed by the Los Banos North branch group congestion.