California ISO

Shaping a Renewed Future

2010

# Market Issues & Performance Annual Report

Department of Market Monitoring

**ACKNOWLEDGEMENT**

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# Executive Summary

In April 2009, the ISO implemented a major redesign of California's wholesale energy markets. In 2010, this new design continued to effectively facilitate efficient and competitive market performance:

- Despite a significant increase in the price of natural gas, total wholesale electric prices rose only about 5 percent. This represents a 7 percent decrease in electricity prices after adjusting for higher natural gas prices.
- About 98 percent of system load was scheduled in the day-ahead energy market, which continued to be highly efficient and competitive. Day-ahead prices continued to be approximately equal to prices we estimate would result under perfectly competitive conditions.
- Price spikes in the 5-minute real-time market increased and drove average real-time prices well above day-ahead and hour-ahead market prices during many months. However, the impact of these prices on total wholesale costs was limited because of the high level of day-ahead scheduling.
- Ancillary service costs dropped slightly to less than 1 percent of total energy costs.
- Bid cost recovery payments were less than 1 percent of total energy costs in 2010, which is approximately equal to the level of these costs in 2009.
- Out-of-market unit commitments and energy dispatches to meet constraints not reflected in the market software decreased substantially. This was achieved by efforts to improve the accuracy of market models and to incorporate additional constraints in these models to represent more complex reliability requirements.
- Over 1,500 MW of new gas-fired generation came online in 2010, along with about 500 MW of renewable generation.
- Capacity made available through the state's resource adequacy program continues to meet reliability planning requirements and virtually all operational needs.

Several important aspects of market performance have not improved or have shown signs of worsening toward the end of 2010.

- The frequency and magnitude of real-time price spikes increased starting in spring 2010. In most cases, these price spikes lasted for only a few 5-minute intervals. These price spikes generally reflect short-term modeling and forecasting limitations, rather than fundamental underlying supply and demand conditions.
- Prices in the hour-ahead market have been systematically lower than prices in the day-ahead and real-time markets. This has led to significant reductions in net imports in the hour-ahead market. In most cases, the ISO has needed to re-purchase this energy in the real-time market at higher prices.

This pattern of selling low in the hour-ahead market and buying high in real-time creates substantial revenue imbalances that are allocated to load-serving entities. In 2010, we estimate these costs totaled at least $81 million or almost 1 percent of total day-ahead and real-time energy costs.

Since 2009, the ISO Department of Market Monitoring (DMM) has expressed concern that these trends are attributable to systematic differences in the inputs and models used in the different markets and may persist unless specifically addressed though enhanced modeling and operational practices. If systematic price differences continue to occur after implementation of convergence bidding in February 2011, this may create substantial additional revenue imbalances that must be allocated to load-serving entities. These price trends may be further exacerbated by the April 2011 increase in the bid cap from $750 to $1,000/MWh.

The ISO is developing and implementing software and modeling enhancements aimed at addressing the fundamental causes of real-time price spikes and price divergence. In addition to these enhancements, DMM has recommended that the ISO more aggressively address this problem by developing and implementing operating practices and procedures specifically designed to result in better convergence of hour-ahead and real-time prices. Addressing the underlying causes of real-time price spikes and price divergence in these markets should be one of the ISO's highest priorities in 2011.

## Total wholesale market costs

Total estimated wholesale costs of serving load in 2010 were $8.6 billion or about $40/MWh. This represents an increase of about 5 percent from a cost of $38/MWh in 2009. However, gas prices increased substantially in 2010, with spot market gas prices increasing by about 17 percent.[1] After accounting for higher gas prices, total wholesale energy costs decreased from $38/MWh in 2009 to $35/MWh in 2010, representing a decrease of over 7 percent in gas-normalized prices.

Figure E.1 shows total estimated wholesale costs per MWh from 2006 to 2010. Wholesale costs are provided in nominal terms, as well as after a simple normalization for changes in average spot market prices for natural gas. The 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.

A combination of factors contributed to lower gas-normalized total wholesale costs in 2010. As highlighted in Chapter 2, fundamental demand and supply conditions favorable to lower prices in 2010 included:

- Lower loads, especially during the peak summer hours.
- Increased hydro availability.
- The addition of over 1,500 MW of new gas-fired generation.

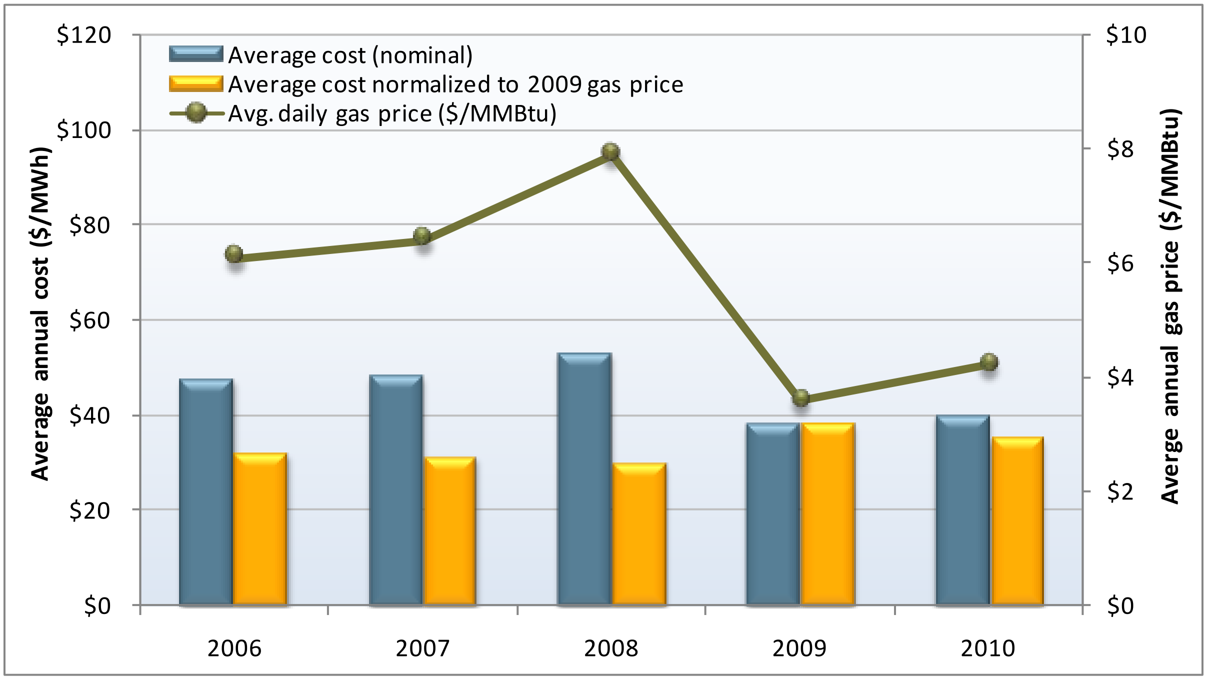
Other market conditions also contributed to lower prices:

- Loads clearing the day-ahead market averaged 98 percent of total forecast demand in 2010. This left a relatively small volume of demand to be met by the real-time energy market.
- Most suppliers continue to bid very competitively in the day-ahead and real-time energy markets. This may be attributable to a high level of forward contracting for energy and the high level of available supply relative to demand.

[1] In this report, we calculate average annual gas prices by weighting daily spot market prices by the total daily ISO system loads. This results in a price that is more heavily weighted based on gas prices during summer months rather than winter months, when natural gas prices are often highest.

- Overall, congestion was lower in 2010, particularly on constraints within the ISO. This is partly attributable to lower loads and more favorable supply conditions. Enhancements in how market constraints and flows are modeled may have also contributed to lower congestion. Improvements have also been made in how operators manually adjust constraint limits in the hour-ahead and real-time markets based on the difference in actual observed flows and flows calculated by the market model.

**Figure E.1 Total annual wholesale costs per MWh of load: 2006-2010**




## Energy market prices

A key measure of overall market performance is the degree of price convergence between the day-ahead, hour-ahead and real-time markets. Price convergence is an indicator of market efficiency, as it suggests that resource commitment and dispatch decisions are being optimized across the day-ahead and real-time markets. Price divergence can also create revenue imbalances that must be allocated to load-serving entities.

Figure E.2 shows average hourly prices in the three energy markets by quarter for the Pacific Gas and Electric area.[2] Price convergence in these three markets improved substantially from the third quarter of 2009 until the first quarter of 2010. However, prices in these three markets diverged significantly in the second quarter of 2010. Price divergence trends shown in Figure E.2 were even more pronounced during the peak load hours.

[2] The PG&E average prices were often similar to prices at the other load aggregation points (Southern California Edison and San Diego Gas and Electric). However, there were times when the other points were more congested than the PG&E price, and therefore were less representative of overall system conditions than the PG&E price.

**Figure E.2 Comparison of monthly prices – PG&E load aggregation point (all hours)**

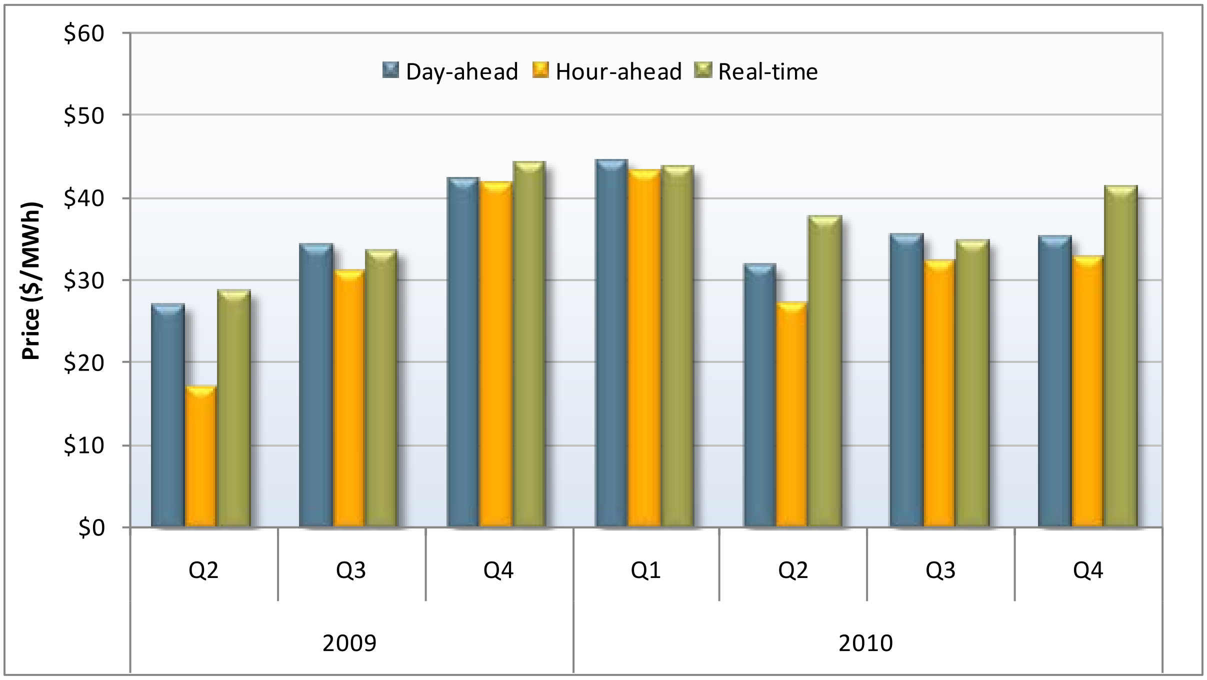
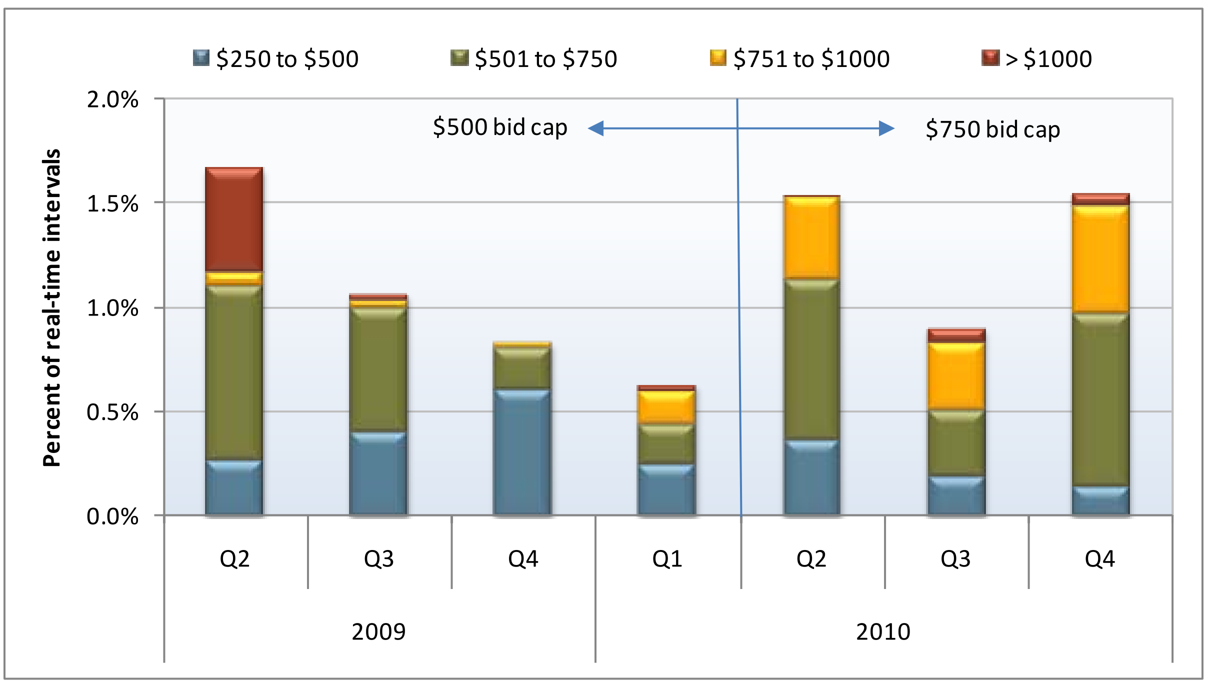



**Figure E.3 Price spike frequency by quarter**




Much of the divergence in energy market prices has been driven by relatively short but extreme price spikes in the 5-minute real-time market. Figure E.3 shows the frequency of different levels of price spikes on a quarterly basis since the nodal market was implemented in 2009. In most cases, these price spikes lasted for only a few 5-minute intervals. These price spikes generally reflect short-term modeling limitations, rather than fundamental underlying supply and demand conditions. The severity of these price spikes increased after the price cap was raised from $500/MWh to $750/MWh in April 2010. This cap was raised to $1,000/MWh on April 1, 2011.

As previously shown in Figure E.2, prices in the hour-ahead market have been systematically lower than prices in the day-ahead and real-time markets. This has led to significant reductions in net imports in the hour-ahead market relative to the day-ahead market. In most cases, the ISO has needed to re-purchase this energy in the real-time market at higher prices. This pattern of selling low in the hour-ahead market and buying high in the real-time market creates substantial revenue imbalances that are allocated to load-serving entities.

In 2010, we estimate that these costs totaled about $81 million. While this represents less than 1 percent of total day-ahead and real-time energy costs, these costs represent the most significant source of inefficiency under the new market design that should be addressed by the ISO. Since 2009, DMM has expressed concern that these trends are attributable to systematic differences in the inputs and models used in the different market models and may persist unless specifically addressed though enhanced modeling and operational practices.

If these systematic price differences continue to occur after implementation of convergence bidding in February 2011, this may create even higher revenue imbalances that must be allocated to load-serving entities.

## Market competitiveness and mitigation

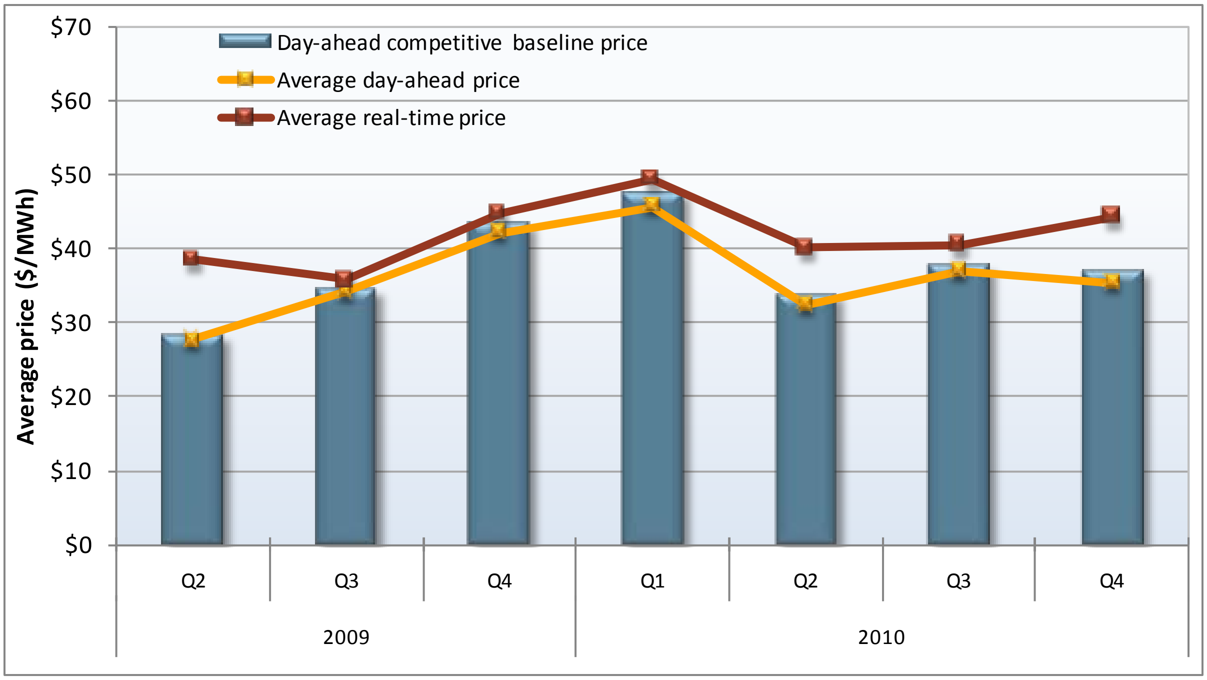
Overall wholesale energy prices were approximately equal to competitive baseline prices that DMM estimates would result under perfectly competitive conditions. DMM calculates these competitive baseline prices by re-simulating the market using the actual day-ahead market software with bids reflecting the marginal cost of gas-fired units. Figure E.4 compares this competitive baseline price to average system-wide prices in the day-ahead and 5-minute real-time markets.

As shown in Figure E.4, prices in the day-ahead market have consistently been about equal to these competitive baseline prices since the start of the nodal market design. In 2010, average system-wide real-time prices exceeded this competitive baseline by about 12 percent. Real-time prices in the SCE area exceeded this competitive baseline by an even higher level of 17 percent due to congestion.

Most of the difference in real-time prices and this competitive baseline were caused by extremely high price spikes during a small portion of the total 5-minute intervals. As previously noted, these price spikes generally reflect short-term modeling limitations, rather than fundamental underlying supply and demand conditions. These real-time price spikes are not attributable to uncompetitive bidding or other anti-competitive behavior. Despite higher average real-time prices, the total weighted average prices of energy transactions in all ISO energy markets was approximately equal to competitive baseline prices estimated by DMM. This reflects the fact that most energy is scheduled in the day-ahead market.

A key cause driving 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 generally been highly competitive. Most additional supply needed to meet demand has 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.

**Figure E.4 Comparison of competitive baseline with day-ahead and real-time prices**



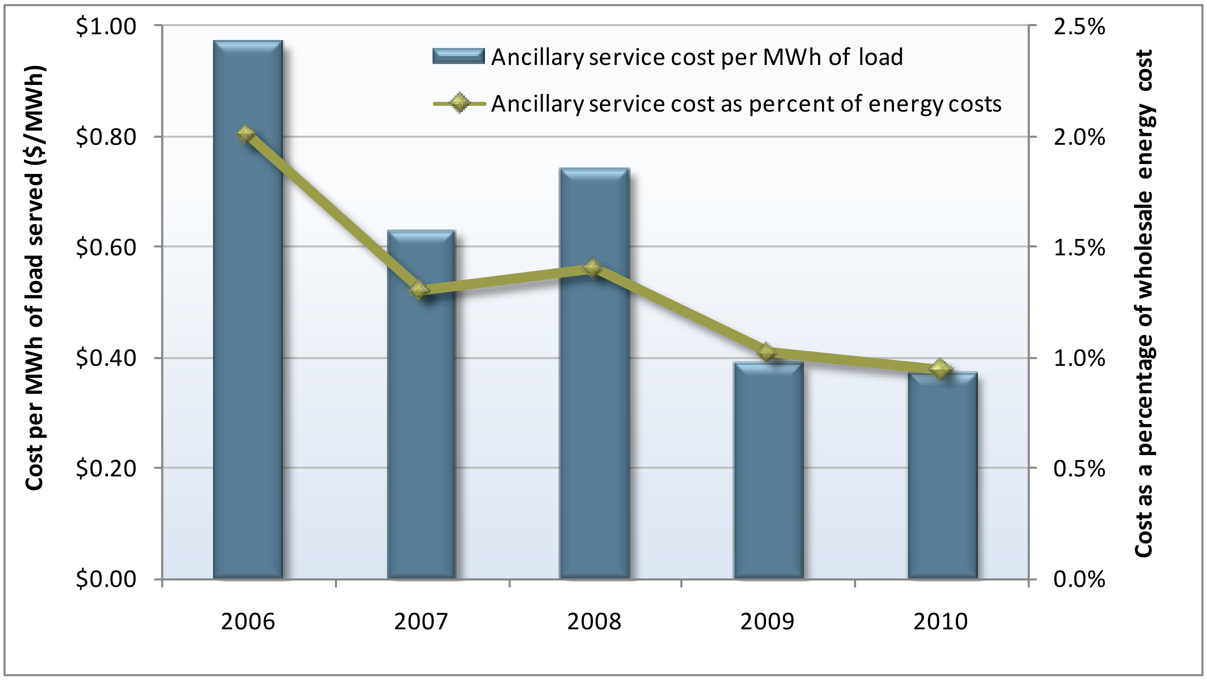

The local market power mitigation provisions in the new market design have proven to be effective without imposing an excessive level of mitigation. During each quarter in 2010, an average of less than one unit per hour was subject to mitigation in the day-ahead market. When units are subject to mitigation, they are often not dispatched at a higher level as a result of this mitigation. This occurs since mitigation often results in a minor change in bids and market prices often exceed a unit's unmitigated bid.

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 all of these markets.

## Ancillary services

Ancillary service markets continued to perform well and even improved in 2010. Total ancillary service costs totaled $84 million, representing a 6 percent decrease from 2009. As shown in Figure E.5, ancillary service costs decreased from $0.93/MWh of load in 2006 to $0.37 in 2010. This represents a decrease in ancillary service costs to less than 1 percent in 2010 from 2 percent of total energy cost in 2006.

**Figure E.5 Ancillary service cost as a percentage of wholesale energy cost (2006 – 2010)**



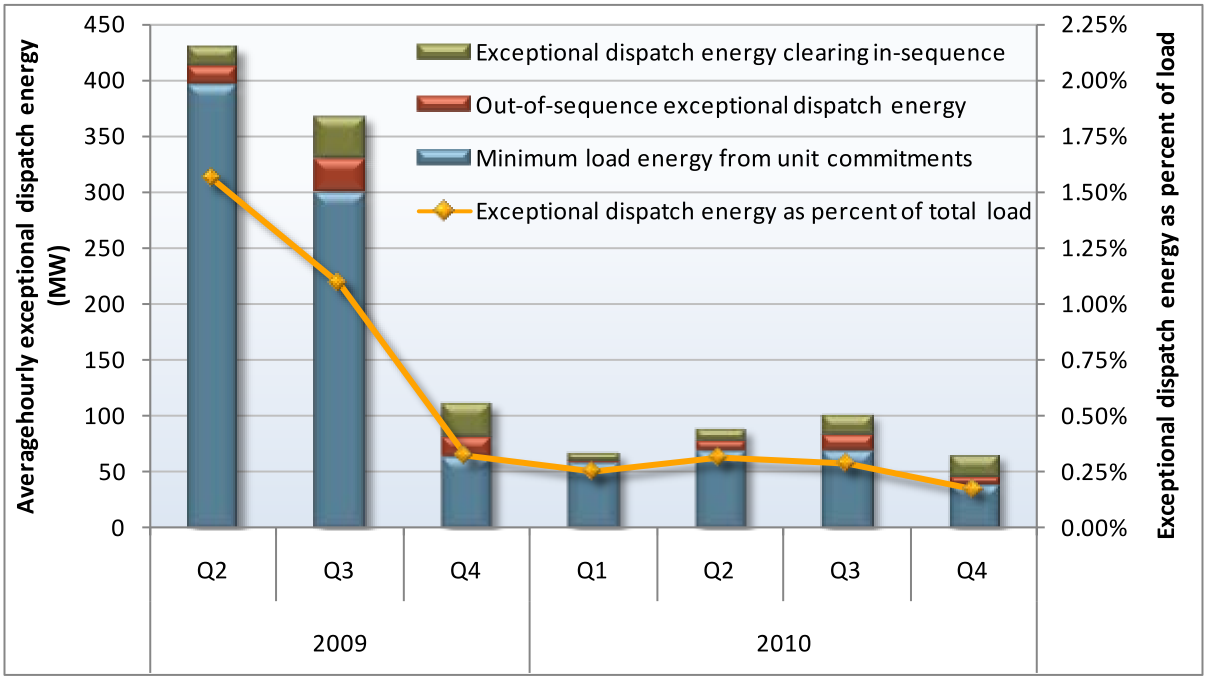

## Exceptional dispatches

Exceptional dispatches (also known as out-of-market dispatches) are instructions issued by system operators when the automated market optimization is not able to address a particular reliability requirement or constraint. The ISO has made an effort to reduce exceptional dispatches by incorporating additional constraints into the market model that reflect these reliability requirements.

Total energy from all exceptional dispatches was significantly lower in 2010, dropping to 0.3 percent from 0.9 percent of system load in 2009. As shown in Figure E.6:

- Most energy from exceptional dispatches represents minimum load energy from units committed to operate by exceptional dispatches. This minimum load energy averaged just 58 MW per hour in 2010.
- Over half of the energy above minimum load from exceptional dispatches cleared in-sequence, meaning that its bid price was less than the market clearing price.
- Exceptional dispatches resulting in out-of-sequence real-time energy with a bid price higher than the market price accounted for an average of only 8 MW per hour in 2010.

**Figure E.6 Average hourly energy from exceptional dispatches**




## Bid cost recovery payments

Generating units are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all bids accepted by the ISO. This calculation includes bids for start-up, minimum load, ancillary services, residual unit commitment availability and day-ahead and real-time energy.

Units committed by the market software or exceptional dispatches may have higher bid cost recovery payments if they have very high bid costs or are not dispatched for significant amounts of additional energy above minimum load. Thus, excessively high bid cost recovery payments can be indicative of inefficient unit commitment or dispatch.

Figure E.7 provides a summary of total estimated bid cost recovery payments in 2010.[3] These payments in 2010 are projected to total $68 million or about 0.8 percent of total energy costs. Bid cost recovery payments averaged also about 0.8 percent of total energy costs during the first nine months of the new market in 2009. This represents a relatively low level for such payments. For example, analogous payments in other ISO markets have ranged from about 1 percent up to almost 3 percent of total energy costs.[4]

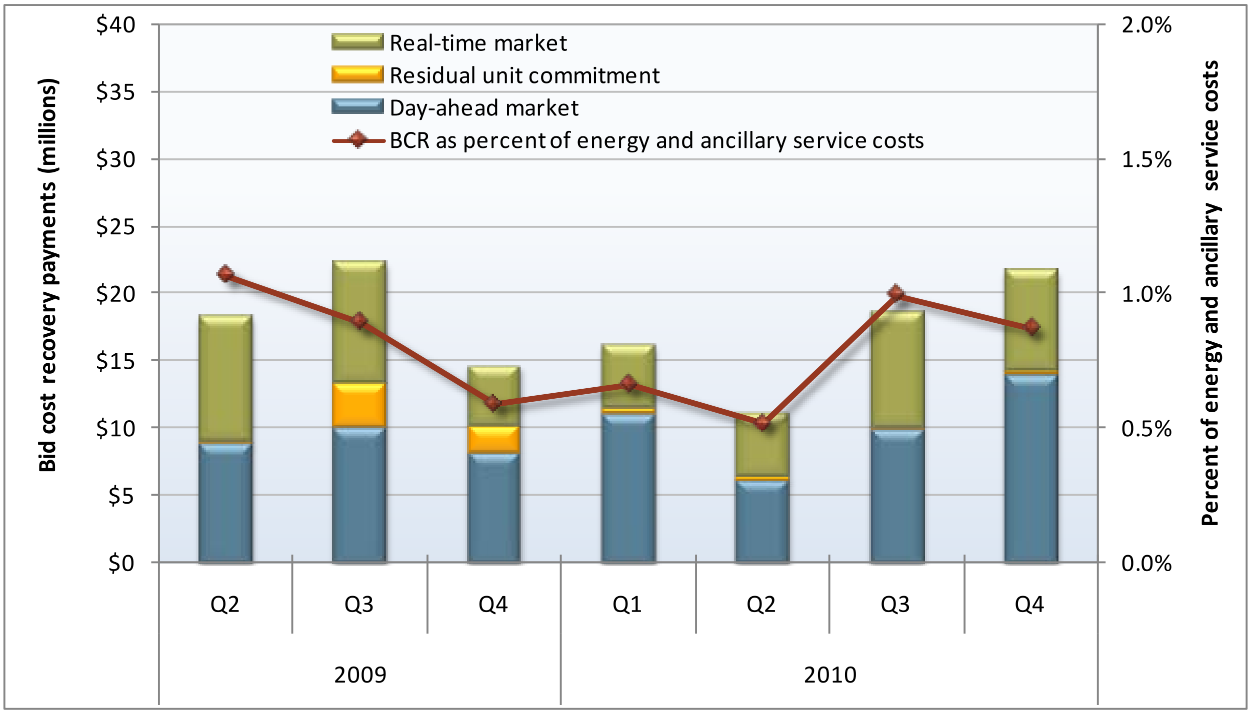
Even though overall bid cost recovery payments remained relatively low in 2010, the quarterly trend in Figure E.7 shows that these payments increased notably in the fourth quarter of the year. Most of this

[3] Estimates in this report include estimated adjustments to bid cost recovery data still pending in the settlement system.

[4] Based on data from 2008 annual reports for MISO, NYISO, PJM and ISO-NE. In some other markets, analogous payments are referred to as revenue sufficiency guarantees.

increase can be attributed to an increase in a specific bidding practice that resulted in over-payment of bid cost recovery to resources scheduled in the day-ahead market that were then subsequently dispatched below their day-ahead schedule in real-time. In March 2011, the ISO filed with the Federal Energy Regulatory Commission to modify the bid cost recovery mechanism to eliminate this over-payment.[5] Multi-state generating unit deployment issues added to real-time payments in December.

**Figure E.7 Bid cost recovery payments**




## Generation addition and retirement

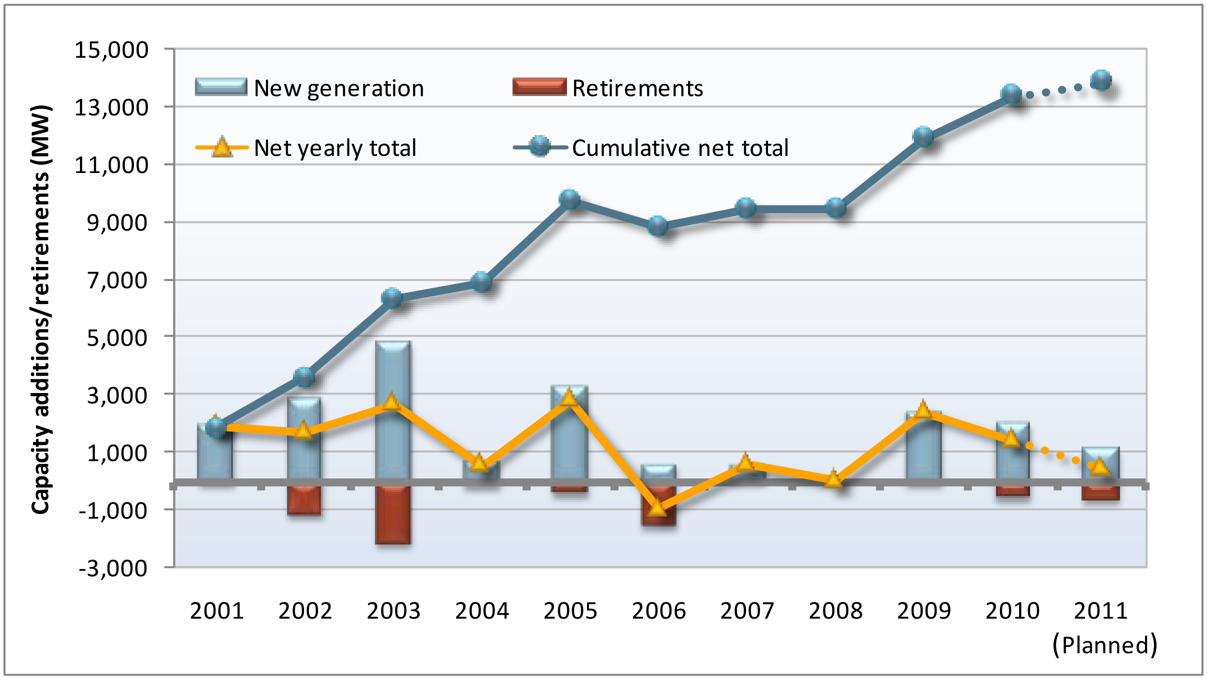
California currently relies on long-term procurement planning and resource adequacy requirements placed on load-serving entities by the California Public Utilities Commission to ensure that sufficient capacity is available to meet system and local reliability requirements. Trends in the amount of generation capacity being added and retired each year provide an indication of the effectiveness of the California market and regulatory structure in incenting new generation investment.

Figure E.8 summarizes trends in the addition and retirement of generation from 2001 to 2010. It also includes planned capacity additions and retirements in 2011. Over 2,000 MW of new generation began commercial operation within the ISO system in 2010. This included about 1,500 MW of new gas-fired capacity and about 500 MW of renewable generation.

[5] California Independent System Operator Corporation, Tariff Revision and Request for Expedited Treatment, March 18, 2011, http://www.caiso.com/2b45/2b45d10069e0.pdf.

The ISO is anticipating construction of 1,147 MW of new generation in 2011, with almost two-thirds coming from renewable resources. The ISO also anticipates 683 MW of existing generation to be retired in 2011.

**Figure E.8 Generation additions and retirements: 2001-2011**




Under California's market design, annual fixed costs for existing and new units critical for meeting reliability needs can be recovered through a combination of long-term bilateral contracts and spot market revenues. Each year DMM analyzes the extent to which revenues from the spot markets in 2010 would contribute to the annualized fixed cost of typical new gas-fired generating resources. This represents a market metric tracked by all ISOs and FERC.

Results of this analysis using 2010 prices for gas and electricity show a slight decrease in net operating revenues for hypothetical new gas units compared to 2009. The 2010 net revenue estimates for a hypothetical combined cycle and combustion turbine both fall substantially below the estimates of the annualized fixed costs for these technologies developed by the California Energy Commission. For a new combined cycle unit, net operating revenues earned from the markets in 2010 are estimated at about $31 to $36/kW, compared to estimated annualized fixed costs of $191/kW.

Under current market conditions additional new generic gas-fired capacity does not appear to be needed. However, a substantial portion of the state's 15,000 MW of older gas-fired units will need to be maintained and retrofitted in the coming years to meet local reliability requirements and to provide the ramping and backup capacity needed to integrate large volume of renewable generation. Virtually all of this capacity is located in transmission constrained load pockets and will need to be retrofitted to eliminate once-through-cooling over the next decade to continue in operation.

Investment necessary to maintain and retrofit this capacity can be addressed through long-term bilateral contracting under the CPUC long-term procurement and resource adequacy proceedings.

However, this capacity is located in areas where one or two entities own most of the generation needed to meet the local reliability requirements. Potential competition from new generation and transmission in these areas is severely limited because of siting and other regulatory limitations. Thus, DMM has continued to emphasize the need for a mechanism to mitigate local market power that may be exercised in the bilateral market for local capacity.[6]

### Resource adequacy

Resource adequacy provisions of the ISO tariff require load-serving entities to procure adequate generation capacity to meet 115 percent of their monthly forecast peak demand. The amount of this capacity offered into the market each day depends on the actual availability of resources being used to meet these requirements. For example, the availability of thermal generation depends on forced and planned outages. The availability of hydro, cogeneration and renewable capacity depends on their actual available energy. The amount of capacity from these energy-limited resources that can be used to meet resource adequacy requirements is based on their actual output during peak hours over the previous three years.

Chapter 7 of this report provides an analysis of the amount of resource adequacy capacity actually available in the ISO market during peak hours of 2010. This analysis shows that the availability of resource adequacy capacity was relatively high during the highest load hours of each month. During the peak summer load hours, about 92 percent of resource adequacy capacity was available to the day-ahead energy market. This is approximately equal to the target level of availability incorporated in the resource adequacy program and represents a slight improvement in availability compared to 2009.

Capacity under the resource adequacy program in 2010 was sufficient to meet virtually all 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.

## Recommendations

DMM works closely with ISO staff and stakeholders to provide recommendations on new market design initiatives on an ongoing basis. DMM has provided a variety of specific recommendations for short-term market improvements in our prior quarterly reports. While the ISO has already taken steps responsive to many of these recommendations, continued emphasis on these issues is warranted in 2011. The remainder of this section highlights DMM recommendations on several key issues and initiatives in 2011.

### Real-time price spikes and price divergence

Most importantly, DMM has noted two related aspects of the market performance that have not improved or shown signs of worsening toward the end of 2010.

- The frequency and magnitude of real-time price spikes increased starting in spring 2010. In most cases, these price spikes lasted for only a few 5-minute intervals. These price spikes generally

[6] Memorandum to ISO Board of Governors, from Eric Hildebrandt, Director, Market Monitoring, October 26, 2010, re: Market Monitoring Report http://www.caiso.com/283c/283c759f32380.pdf.

reflect short-term modeling and forecasting limitations, rather than fundamental underlying supply and demand conditions.

- Prices in the hour-ahead market have been systematically lower than prices in the day-ahead and real-time markets. This has led to a pattern of selling low in the hour-ahead market and buying high in the real-time market that creates substantial revenue imbalances that are allocated to load-serving entities.

Addressing these two related issues should represent the highest priority for the ISO in terms of improving current market performance. If these trends continue after implementation of convergence bidding in February 2011, even higher revenue imbalances may occur that must be allocated to load-serving entities. DMM has expressed concern that these trends are attributable to systematic differences in the inputs and models used in the hour-ahead and 5-minute real-time market and may persist unless specifically addressed though enhanced modeling and operational practices.

The ISO is developing and implementing software and modeling enhancements aimed at addressing the fundamental causes of real-time price spikes and price divergence. A more detailed discussion of these recommendations and initiatives is provided in our quarterly report for the fourth quarter of 2010.[7] While implementation of changes already identified by the ISO may improve price convergence, the ISO should continue to identify other potential causes of price spikes and price divergence and how these may be addressed. There are a variety of options that may achieve the fundamental goal of having average hour-ahead prices equilibrate with average real-time prices.

In addition to expediting these enhancements, DMM has recommended that the ISO place a higher priority on developing and implementing more systematic procedures and guidelines for adjusting the load forecasts used in the hour-ahead and 5-minute real-time markets to achieve better price convergence in these markets. Until other modeling enhancements are made, these adjustments represent the main mechanism available for getting better convergence of hour-ahead and real-time prices.

### San Diego congestion

DMM is supportive of modeling enhancements that would prevent the type of extreme prices that periodically occur in the San Diego area. Although the conditions that cause such high prices have been very infrequent, such modeling enhancements would allow prices to increase significantly when congestion occurs but would produce prices that are more reflective of actual underlying system conditions and congestion relief being provided. A more detailed discussion of this issue and options, recommendations and initiatives is provided in our quarterly report for the fourth quarter of 2010.[8]

### Local market power mitigation

The local market power mitigation provisions of the new energy market design have proven to be effective without imposing an excessive level of mitigation. However, with the implementation of virtual bidding in February 2011, DMM is recommending that current local market power mitigation procedures be modified to ensure that virtual bids do not undermine the effectiveness of these procedures. The ISO has proposed an approach that may achieve these goals, while also reducing the

[7] See *Quarterly Report on Market Issues and Performance*, February 8, 2011, pp. 27-32, http://www.caiso.com/2b1f/2b1f838819910.pdf.

[8] Ibid, pp. 7-8.

computational time currently required to implement these procedures. DMM is supportive of this approach because it would allow for additional enhancements that would make the current process more dynamic in two ways:

- Bid mitigation for the real-time dispatch could be determined in the real-time pre-dispatch process run every 15-minutes, rather than in the hour-ahead scheduling process.
- The competitiveness of binding constraints could be determined by the market software based on actual system conditions, rather than based on studies performed up to four months in advance.[9]

These modifications would allow the mitigation process to more accurately reflect actual market and system conditions in the day-ahead and real-time markets.

### New market products

One of the ISO's major initiatives in 2010 was to begin to review new types of ancillary services or other products that may be appropriate as increased reliance is placed on intermittent renewable energy resources. The ISO completed additional technical studies needed as the foundation for this initiative. However, limited progress was made translating these technical results into potential new market products and requirements. The ISO will continue to address this issue in 2011.

DMM notes that the type of new ramping products being discussed by the ISO may help to mitigate the price spikes that are currently occurring in the real-time market. The majority of these price spikes do not appear to be attributable to the current levels of intermittent generation in the real-time market. As reliance on intermittent renewables increases, the need for additional ramping flexibility and backup capacity will become more acute for both system reliability and market performance.

Increased production from renewable energy will also decrease the overall demand for energy from more reliable and flexible generation technologies needed to meet the operational challenges created by higher levels of renewable energy. Additional products can provide these traditional resources compensation for the additional reliability and flexibility they provide. These products may provide significant revenue opportunities for these flexible resources. However, under California's current market design, resource characteristics needed for renewable integration will need to be explicitly procured and compensated through the long-term planning and resource adequacy processes.

As noted in DMM's 2009 annual report, the costs of any additional products 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. For example, if new ancillary services or other products are specifically procured to mitigate the impacts of intermittent renewable resources, the cost of these additional products should be allocated to these intermittent resources. Currently, the cost of all ancillary services is allocated to load.

[9] Currently, the competitiveness of constraints is determined in advance on a quarterly basis using the competitive path assessment methodology.

### Forward capacity procurement

One of the most challenging and controversial market design issues facing the ISO and state regulators continues to be the question of whether to adopt a more formal longer-term capacity market and what backstop authority the ISO will have to procure any additional capacity needed for reliability.

The ISO has been supportive of a centralized capacity market in lieu of the current bilateral approach. However, the ISO has acknowledged the complexities of designing a capacity market that satisfies the highly specific resource preferences embodied in state energy and environmental policy. The ISO has indicated that it would be premature for the CPUC to specify many of the details of the centralized capacity market design at this time.

As discussed in Chapter 1, the CPUC issued an order in June 2010 indicating the state will not proceed with development of a centralized capacity market or to modify the resource adequacy process to include longer-term requirements at this time. The CPUC's order noted that while a centralized capacity market may be effective at incenting development of new generic capacity, designing a capacity market that includes local reliability requirements and resource characteristics needed for renewable integration is more difficult.

DMM has consistently expressed concerns about the complexity of incorporating all the state's local reliability requirements in a centralized capacity market. None of the capacity market proposals developed to date have addressed this issue. DMM has specifically noted that a variety of local reliability requirements exist within the local capacity areas for which resource adequacy requirements are currently based. To date, these sub-area requirements have fortunately been met by the specific units contracted by the state's major load-serving entities to meet their overall local area requirements. However, these sub-area requirements would need to be explicitly incorporated in a centralized capacity market design to ensure that capacity procured through such a market would be sufficient to meet actual reliability requirements.

More recently, the complexities of incorporating resource needs and preferences driven by the state's energy and environmental policy are also becoming increasingly apparent. The ISO is currently working to identify the characteristics and quantity of dispatchable generation flexibility needed to facilitate renewable integration. These characteristics include start-up times, ramp rates and more complicated operating limitations associated with combined cycle units. These characteristics and needs must be more specifically defined and quantified by the ISO before further assessment can be made of how these might be incorporated in a central capacity market. Under a forward capacity market, requirements for these resource characteristics would need to be quantified at least four years in advance. Day-to-day performance obligations of capacity capable of meeting these special characteristics would also need to be defined.[10]

Another key issue is how to count capacity from demand response and renewable resources. The availability of these different resources can vary significantly, especially during peak hours when they may be needed most for reliability. The characteristics of these resources impact how much backup capacity and new types of ancillary service the ISO may need to ensure system reliability. Thus, improved methods are needed for quantifying the value of different resources in terms of their capacity

[10] For instance, if a unit is counted toward meeting a resource adequacy obligation or capacity market requirement for specific operational characteristics – such as fast ramping capability – rules must be established to ensure that this ramping flexibility is actually made available in the real-time market. Current market rules allow participants to self-schedule units or bid in lower ramp rates so that this fast ramping capability is not actually available in the markets.

value and impact on the need for additional ancillary services or other new products designed to mitigate the impact of intermittent resources.

Once these issues are addressed with greater detail and certainty, this may provide the necessary basis for proceeding with a more centralized or formal market for forward capacity procurement. However, DMM believes it would be premature to commit to a central capacity market until additional work has been done on these issues.

## Organization of report

The remainder of this report is organized as follows:

- **Overview of California's wholesale electric markets.** Chapter 1 provides an overview of the market design and how key components examined in different sections of this report are interconnected. This chapter provides a summary of key market enhancements implemented in 2010 and additional modifications to be implemented in 2011 or beyond.
- **Loads and resources.** Chapter 2 summarizes load and supply conditions impacting market performance in 2010. This chapter includes an analysis of net operating revenues earned by hypothetical new gas-fired generations from the ISO's energy and ancillary services markets.
- **Overall market performance.** Chapter 3 provides an analysis of overall market performance in 2010.
- **Market competitiveness and mitigation.** Chapter 4 assesses the competitiveness of the energy market, along with the impact and effectiveness of market power mitigation provisions of the new market design.
- **Congestion.** Chapter 5 provides a review of congestion and the market for congestion revenue rights.
- **Ancillary services.** Chapter 6 reviews the performance of the ancillary service markets.
- **Resource adequacy.** Chapter 7 reviews the short-term performance of California's resource adequacy program in 2010.
- **Real-time market issues.** Chapter 8 provides a more detailed analysis of factors driving real-time market prices.

# 1 Overview of California's wholesale electricity markets

In April 2009, the ISO implemented a major redesign of California's wholesale energy markets. This chapter provides an overview of the market design and how key components examined in different sections of this report are interconnected. The chapter highlights a variety of state policies and requirements closely linked to design and performance of these markets. A summary is provided of key market enhancements implemented in 2010 and additional modifications to be implemented in 2011 or beyond.

The new market implemented in 2009 has many of the same features in place at other ISOs and included in the standard market design framework established by the Federal Energy Regulatory Commission. These include:

- Pricing and congestion management based on locational marginal pricing – also known as nodal pricing.
- 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.

## 1.1 Locational marginal pricing

The market design is based on locational marginal pricing, or nodal pricing. Locational marginal prices represent the additional cost 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 are designed to reflect the physical system and market conditions and limitations.

Under locational marginal pricing, as congestion appears on the network, prices at each node area are adjusted to reflect congestion costs or benefits from supply or demand. 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, nodal prices in congested regions are higher than the price in unconstrained regions.

Locational marginal pricing enables the ISO to more economically and efficiently manage congestion and provide price signals to market participants to self-manage congestion. Over the longer term, these nodal prices also provide more efficient price signals to encourage development of new supply and demand-side resources within more constrained areas of the grid. Nodal pricing also helps identify transmission upgrades that would be most cost-effective in reducing congestion.

Because ownership of generation resources is highly concentrated within local transmission constrained areas (or load pockets), nodal pricing heightens concern about the potential exercise and impacts of local market power. Consequently, the market design includes provisions to mitigate local market power within transmission constrained load pockets.

While generators are paid at the node, load is bid and settled using *load aggregation points* (referred to as LAPs) which represent aggregated load nodes.[11] The major 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.

## 1.2 Day-ahead market

Another major feature of the market design is the day-ahead market for energy and ancillary services, known as the integrated forward market. The addition of a centralized integrated day-ahead market has created opportunities for increased market efficiencies in several ways.

### System-wide optimization of resources

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 market design, a large portion of supply needed to meet demand has continued to be self-scheduled as price-takers so that it is automatically scheduled in the day-ahead market. However, the marginal supply needed to meet demand is provided by resources that are bid into and scheduled through the market software. The day-ahead market optimizes unit commitment and scheduling over a 24-hour period using a mixed integer programming algorithm. The objective function of this software is to minimize total bid costs of resources committed and scheduled by the market software.

[11] 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.

### Co-optimization of energy and ancillary services

The market design also increases efficiency by co-optimizing procurement of energy and ancillary services from resources that can provide both of these products. Co-optimization considers the energy and ancillary service capacity bids of resources providing ancillary services. These resources receive the market clearing price for ancillary services and 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. 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. For example, more upward regulation may be procured 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

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 exceed 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.

### Forward bilateral contracting

For the eight years prior to implementation of this new day-ahead market, load-serving entities needed to procure energy through self-supply or bilateral arrangements, and then schedule this energy in the day-ahead and hour-ahead congestion markets. As discussed in Section 1.8, the CPUC also provides strong regulatory incentives for forward contracting and other portfolio risk management mechanisms. This has encouraged a very high level of self-supply and long-term forward bilateral contracting by the three major investor-owned utilities. Together these three utilities serve about 90 percent of total ISO load.

The high level of self-supply and forward contracting in California's wholesale markets has limited the incentive and ability for suppliers to exercise market power. This has been one of the primary factors contributing to the competiveness of California's wholesale energy market in recent years. As discussed in Chapter 3, the amount of load scheduled in the day-ahead market has been high, typically ranging from 96 to over 100 percent of actual load. This high level of scheduling reduces the incentives for suppliers to increase real-time prices, because the bulk of suppliers' 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 allows 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 system loads or within any local transmission constrained areas. If necessary, additional resources may be started up or kept online through the residual unit commitment process to meet system 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 cost of start-up and minimum load bids 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 residual unit commitment market clearing price for any capacity scheduled to meet these 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 residual unit commitment process and receive the market clearing price for any bids accepted in this market.

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 and 2010. Moreover, because resource adequacy resources must offer all available capacity into this process at a zero price and are not paid for any capacity provided, the volume and cost of non-resource adequacy capacity scheduled for residual unit commitment has also been minimal.

## 1.4 Hour-ahead scheduling process

Resources within the ISO and dynamic resources in neighboring regions or balancing authorities can be dispatched on a 5-minute basis within each operating hour to meet real-time loads. However, most imports and exports are non-dynamic and must 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 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).[12]

The hour-ahead scheduling optimization considers schedules and bids from imports and exports, as well as schedules and bids from resources within the ISO. All imports and exports scheduled in the day-ahead market are either self-scheduled or participants must re-submit economic bids to be used in the hour-ahead scheduling process.[13] In addition, participants may self-schedule or bid additional imports and exports into the hour-ahead scheduling process.

The hour-ahead market software re-optimizes this entire pool of supply and export bids against the forecast of total real-time demand. The optimization considers all real-time schedules and bids from resources inside and outside of the ISO. This 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.

As noted above, participants with accepted day-ahead inter-tie transactions can either self-schedule in the hour-ahead market or re-bid their day-ahead transactions. 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 because of 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 to reflect changes in market or resources conditions, or to manage their overall portfolio of market activity. The hour-ahead scheduling process is designed to promote market efficiency by allowing re-optimization of the market given these changes, along with any changes in internal supply or demand 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 and exports as a starting point. It then re-dispatches resources every five minutes to balance generation and loads.

Supply and demand conditions in the real-time market may vary from those in the day-ahead market or hour-ahead scheduling process for a variety of reasons. Actual load conditions often vary from those forecasted on a day-ahead or hour-ahead basis. Supply in the real-time market is also generally much more constrained than in the day-ahead market and hour-ahead scheduling process.

[12] 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.

[13] 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 actual energy flows may also vary from modeled flows calculated (or predicted) by the real-time software. This occurs because of the full network model's limited ability to correctly model actual flows because of loop flows, other details of the ISO system and conditions in the surrounding regions outside the ISO. 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, preventing 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 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, nodal prices 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 dispatches or uninstructed deviations relative to each supply resource's day-ahead schedule. The market design does not include any penalties for uninstructed deviations by generating units from their scheduled level of output. If a participant's actual real-time load is higher or lower than their day-ahead load schedule, the difference is settled at the real-time price. In 2009 and 2010, load-serving entities scheduling less than 85 percent of their actual real-time load in the day-ahead market could be subject to an additional under-scheduling charge. However, as previously noted, nearly all total system load has typically been scheduled in the day-ahead market since the new market design launched in 2009. The load under-scheduling charge has never been triggered.

## 1.6 Market power mitigation

The ISO market 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. 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.[14]

The potential for market power on a system level basis is addressed through a relatively high bid cap. This cap was increased from $500/MWh to $750/MWh on April 1, 2010. This cap was increased to $1,000/MWh on April 1, 2011. This scheduled increase to a 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.

Because generation ownership within most transmission constrained load pockets is highly concentrated under one or two major suppliers, the market includes more stringent provisions for mitigating local market power. With this approach:

[14] See discussion of long term procurement plans in Section 1.8 in Chapter 1.

- Prior to clearing the day-ahead and real-time markets, the market software is run to identify units that may be dispatched to provide additional incremental energy to relieve transmission constraints deemed to be non-competitive.
- These units 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 units' default energy bids. Most gas-fired generating units have cost-based default energy bids, which reflect their actual operating cost plus a 10 percent adder.

Bid mitigation provisions are only applied to resources bid into the day-ahead and real-time markets. Thus, mitigation effectiveness 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 contract, which includes a must-offer obligation. Generating units 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

Reliable and efficient wholesale electric markets require mechanisms to ensure:

- Availability of sufficient and dependable supply on a day-to-day basis to support reliable operation of the transmission system.
- Timely and efficient investment needed to maintain existing generation and develop new supply.

Unlike the three eastern ISOs, the California ISO does not have a centralized capacity market to meet these requirements. Instead, California's wholesale market relies on a resource adequacy program and long term procurement planning process adopted by the CPUC to provide sufficient capacity to ensure reliability. The resource adequacy program includes ISO tariff requirements that work in conjunction with state regulatory requirements and processes adopted by the CPUC.

The resource adequacy provision of the ISO tariff requires load-serving entities to bilaterally procure adequate generation capacity to meet 115 percent of their 1-in-2 year forecast of peak demand in each month. 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). This capacity must then be bid into the ISO market through a must-offer requirement. Load-serving entities provide these resource adequacy showings to the ISO on a year-ahead basis.

The ISO also performs technical studies to determine the minimum amount of capacity needed within transmission constrained load pockets, or local capacity areas, under 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.[15] The ISO will procure resources within a local

[15] This allocation does not obligate any load-serving entity to procure capacity. Rather, the allocation is used to determine each load-serving entity's responsibility for the costs associated with any capacity that the ISO needs to procure to meet these local requirements.

capacity area only if the portfolio of all resource adequacy capacity presented by all load-serving entities in their year-ahead showings is not sufficient to meet these local reliability requirements.

Load-serving entities can meet resource adequacy requirements by any combination of self-owned resources or bilateral contracts with owners of other supply resources. All supply resources used to meet resource adequacy requirements are 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 limit the price at which resource adequacy capacity is bid into the energy markets.

While resource adequacy requirements can be met by capacity-only contracts, load-serving entities may also procure capacity and energy jointly when contracting with generating resources. For example, a load-serving entity may procure capacity through tolling agreements or contracts providing the option to procure energy at specific prices. In this way, the resource adequacy program may also help to mitigate market power by increasing incentives for forward contracting of energy.

## 1.8 Long term procurement plans

Under California's market design, investment needed to maintain existing generation and develop new supply is achieved through a combination of resource adequacy requirements and other state policies and requirements. The CPUC's long-term procurement planning proceedings play a key role in driving this investment.[16] Under this process, investor-owned utilities are responsible for submitting procurement plans for meeting their customers' projected needs over a ten-year horizon. Procurement plans include a mix of short-, medium- and long-term contracts. Under current 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).[17]

The state has explicitly adopted a hybrid market structure that includes new utility-owned generation as well as long-term contracts for investment in new supply by merchant generators. By approving procurement plans, the CPUC establishes up-front standards for the utilities' procurement activities and cost recovery. This avoids the need for after-the-fact reasonableness review by the CPUC of the resulting utility procurement decisions.

The long-term procurement proceedings are also utilized as a forum for comparing different resource portfolios in terms of criteria such as cost, risk, reliability, and environmental impact. This ensures that plans are consistent with state requirements and policies established through other proceedings and regulations. For example, plans currently being developed must be designed to meet the state's aggressive renewable portfolio standards and requirements to phase out use of once-through-cooling for over 18,000 MW of existing thermal generation.

California's climate change laws also require that preference be given to clean fossil-fuel technologies. In addition to price risk, procurement plans are required to consider the carbon risk associated with investments in fossil resources to avoid crowding out preferred resources or incurring stranded costs by purchasing technology that may become obsolete.

[16] Documents relating to the CPUC's long-term procurement planning process are provided at http://www.dra.ca.gov/DRA/energy/LTTP.htm.

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

## 1.9 Backstop capacity procurement options

In 2009 and 2010, the ISO did not need to procure any additional capacity to meet local capacity area requirements that were not met in year-ahead showings by load-serving entities.[18] However, the ISO has two main backstop options for procuring any additional resource capacity needed:[19]

- ***Reliability must-run contracts* —** The ISO has authority to designate any unit as a reliability must-run resource. However, the ISO currently exercises this authority only to renew existing must-run contracts for a relatively small amount of capacity. In 2009, about 2,100 MW of capacity was under reliability must-run contracts. In 2010, the ISO reduced capacity under these contracts to only about 1,000 MW.

- ***Interim capacity procurement mechanism* —** In 2009 and 2010, ISO also had the authority to procure capacity on a monthly or annual basis under its interim capacity procurement mechanism provisions. Payments under these provisions are based on a capacity price of $41/kW-year.[20] This price likely played a key role in setting prices for resource adequacy capacity in local capacity areas, because this represents the price that unit owners may receive if they did not sign resource adequacy contracts and the ISO needed to procure capacity.

## 1.10 Market design and software enhancements

### Compensating injections

The ISO re-implemented a software feature in July 2010 known as *compensating injections* to manage unscheduled flows along the inter-ties in an automated manner.[21] This feature calls for scheduling injections and withdrawals in the market software at locations external to the ISO that minimize unscheduled flows on inter-ties. The injections are determined in the real-time pre-dispatch run made every 15 minutes, and are then included in the hour-ahead and 5-minute real-time markets. The performance of this new software feature was reviewed in our quarterly report for the fourth quarter of 2010.[22]

### Hourly inter-tie ramping

Most imports and exports between the ISO and neighboring balancing authorities are scheduled in fixed hourly amounts. The net total of all imports and exports scheduled each hour is referred to as the net

[18] 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.

[19] 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.

[20] 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.

[21] Technical Bulletin 2010-07-01, *Compensating Injection in the ISO Real-time Market*, July 16, 2010, http://www.caiso.com/27d4/27d4e73124db0.pdf. As noted in prior DMM reports, the ISO initially implemented compensating injections in October 2009, but turned off this feature in November 2009 until further refinements were made.

[22] See *Quarterly Report on Market Issues and Performance*, February 8, 2011, pp. 30-32, http://www.caiso.com/2b1f/2b1f838819910.pdf.

hourly inter-tie schedule. In practice, changes in the net inter-tie schedule between the ISO and neighboring balancing authorities from one hour to the next are made over a 20 minute period. This ramping period begins ten minutes before the start of the next operating hour, and ends ten minutes after it starts.

When the market software was implemented in 2009, changes in net imports during this 20 minute ramping period were only modeled in the 5-minute market software. In 2010, a new hourly inter-tie ramping feature was developed to more accurately account for this 20-minute inter-tie ramping in the hour-ahead scheduling process used to dispatch imports and exports. This feature helps reduce the price and dispatch inconsistencies that have occurred between the hour-ahead and real-time markets by making the hour-ahead dispatch process more consistent with actual conditions in the 5-minute real-time market.

This feature was initially implemented from December 3 until December 23, 2010. It was suspended to refine the rules for how this ramping constraint affects prices used to settle imports and exports when it is binding. The ISO reactivated this feature on January 27, 2011.[23]

### Scarcity pricing of ancillary services

The ISO implemented scarcity pricing for ancillary services on December 14, 2010. This enhancement allows prices to increase above the $250/MW bid cap when the supply of ancillary services is insufficient to meet operating resource requirements. When such scarcity exists, ancillary services prices are based on an administratively set demand curve, plus any opportunity cost associated with providing such capacity instead of energy.[24] To ensure that scarcity pricing is triggered only during true scarcity, all resource adequacy units are required to offer into these markets all capacity certified to provide ancillary services.

This market enhancement will impact prices for ancillary services procured in the real-time pre-dispatch process that is run every 15 minutes. However, energy prices produced in this process are not binding for energy dispatched in the subsequent 5-minute real-time market. Thus, any ancillary service scarcity pricing in the 15-minute process will not be directly reflected in energy prices in the 5-minute real-time market. For any scarcity of ancillary services to be reflected in these 5-minute energy prices, the market software would need to be modified to perform procurement and co-optimization of energy and ancillary services on a 5-minute basis. This represents a significant market design change that is not currently under consideration given higher priority enhancements likely to provide greater benefits relative to implementation costs and complexity.

### Proxy demand resources

In August 2010, the ISO implemented a new product known as proxy demand resources. This allows participants to provide bids for load reductions from demand response actions and technologies. These bids are then dispatched by the ISO market software in the same manner as generating units that participate as supply-side resources.

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[23] As noted in a December 2 market notice, this feature "will not be visible to market participants; however, future market reports will provide information about how this feature is working to improve HASP to RTD price convergence." *Market Notice, December 2, 2010, Hourly Intertie Ramping Production Deployment* 12/03/10.

[24] *California Independent System Operator Corp.*, 127 FERC ¶ 61,268 (June 26, 2009).

Although this enhancement began in August 2010, a negligible amount of proxy demand resource capacity was registered in 2010 and no bids from these resources were dispatched. Participation in proxy demand resources was very limited in part because of a June 2010 CPUC decision. This order allowed utilities to implement proxy demand resource pilot programs, but "prohibit[ed] further participation by IOU retail customers until the CPUC develops ratepayer protections and other relevant rules and protocols pursuant to the Commission's existing jurisdiction."[25]

The CPUC decision also temporarily prohibited demand response providers from bidding demand reductions from customers served by utilities until settlement rules for such arrangements are developed. The decision did not prohibit participation by direct access customers and energy service providers. However, the potential for proxy demand resources offered by non-utility entities appears limited at this time because these resources do not receive a capacity payment under the ISO market design unless occurring through a bilateral contract selling resource adequacy capacity to a load-serving entity.

In the near term, most proxy demand resource capacity is expected to come from existing utility demand response programs. Utility filings in March 2011 indicated that as much as 10 percent of their demand response capacity may be offered as proxy demand resources by summer 2011. This would represent over 200 MW of demand response during peak summer months.

### Multi-stage generation resources

This major software enhancement improves how operating characteristics and constraints of gas-fired generation – particularly combined cycle units – are incorporated in the market scheduling and dispatch software. It is aimed at increasing the efficiency and feasibility of dispatch instructions. This should also reduce the need for manual dispatches to account for unit operating constraints not currently incorporated in the market software. This feature was implemented on December 7, 2010.

## 1.11 Future market design and software enhancements

The ISO completed designing several significant market design enhancements during 2010 that are scheduled for implementation in 2011 or later.

### Convergence bidding

In February 2011, the ISO implemented convergence bidding – also known as virtual bidding. 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 intended to promote convergence of day-ahead and real-time prices as participants seek to arbitrage any price differences in these markets. 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. In addition, generators can 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 is allowed at all supply and demand nodes including inter-ties with neighboring balancing areas.

[25] *Decision on Phase Four Direct Participation Issues,* CPUC Decision 10-06-002, June 3, 2010, p. 2, http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/118962.htm.

### Real-time ramping flexibility

The ISO is intending to implement a flexible ramping constraint in the hour-ahead and 15-minute pre-dispatch processes in early 2011. This requires the software optimization results include a pre-specified amount of additional ramping capacity beyond levels needed to simply meet the energy forecast. This constraint is to ensure that sufficient upward and potentially downward[26] ramping capability from 5-minute dispatchable resources is committed and available to balance loads and supply. When applied in the hour-ahead market, this constraint may cause the level of net imports to better align with internal ramping energy needs. This constraint will also help deal with supply and demand variability and uncertainty that may arise in real-time from forecasted conditions. When applied in the 15-minute pre-dispatch process, this constraint may trigger commitment of fast start units when additional upward ramping capacity is needed.

### Capacity procurement mechanism

As previously noted, the market design implemented in 2009 included the interim capacity procurement mechanism, which expired on March 31, 2011. The ISO developed and filed with federal regulators in 2010 for approval of a more permanent capacity procurement mechanism.[27] This proposal retains most of the interim provisions, but raised the annualized price used to determine payments from $41/kW-year to $55/kW-year. This pricing is designed to equal or exceed the going-forward fixed costs of existing generation. DMM provided comments supporting these changes to the ISO, stakeholders and Board.[28]

FERC issued an order in March 2011 accepting the key provisions of this filing, pending the outcome of a technical conference. Given the long-term nature of these provisions, the Commission indicated that "it is critical to evaluate not only whether the [mechanism] appropriately compensates non-resource adequacy resources for short-term transitory events but also whether it provides a just and reasonable long-term backstop to the CPUC's ongoing resource adequacy program."[29]

### Dynamic transfers

Renewable portfolio standards for load-serving entities in California are increasing interest in market design modifications that would allow greater amounts of renewable resource imports. One way to accommodate more imports is to allow increased use of dynamic transfers between the ISO and neighboring balancing authorities. Dynamic transfers require that scheduled flows between adjacent balancing areas be adjusted on a 5-minute basis, rather than hourly.

A key issue with such dynamic transfers involves how transmission capacity should be reserved or allocated in advance given the uncertainty associated with how much capacity will actually be needed for these intermittent resources. Allowing greater capacity reservations may promote more renewables development destined for ISO use. However, the intermittent nature of these resources may increase

[26] Initially, the downward constraint will not be enforced. Enforcing the downward constraint may exacerbate over-generation conditions by committing and loading a resource higher to allow for more downward ramping capability.

[27] *Revised Draft Final Proposal Capacity Procurement Mechanism, and Compensation and Bid Mitigation for Exceptional Dispatch*, September 15, 2010, http://www.caiso.com/2812/281211a4d4cf70.pdf.

[28] Memorandum to ISO Board of Governors, from Eric Hildebrandt, Director, Market Monitoring, October 26, 2010, re: Market Monitoring Report http://www.caiso.com/283c/283c759f32380.pdf.

[29] 134 FERC ¶ 61,211, March 17, 2011,P. 56. http://www.caiso.com/2b44/2b44c8174d090.pdf.

the need for balancing services within the ISO and in some cases prevent more efficient use of all available transmission capacity.

The ISO recently completed a comprehensive proposal for a variety of tariff modifications and policies to address these issues.[30] In addition, the ISO will monitor any related operational issues and will coordinate with other balancing authorities to study regional issues affecting dynamic transfer capabilities. Should a need arise to limit dynamic transfers of intermittent resources, the ISO will identify appropriate solutions, including limiting new dynamic transfers of intermittent resources. However, the ISO would not limit dynamic transfers that would have already been established. If approved by the ISO Board of Governors, these provisions could become effective in 2011.

### Reliability demand response product

A stakeholder process completed in 2010 yielded a new product that enables emergency-triggered demand response resources, such as interruptible load programs and air-conditioning cycling, to bid into the ISO market.[31] The reliability demand response product is based on the proxy demand response product implemented in 2010. However, reliability demand response resources will only be dispatched by the ISO in event of a system or local emergency. This enhancement is scheduled for implementation in the spring of 2012.

The reliability demand response product was developed as part of a 2007 settlement agreement with the CPUC requiring the transition of many of the current reliability-based and emergency-triggered demand response programs into price-responsive demand response products. In addition, the settlement reduces the amount of reliability-based and emergency-triggered demand response programs that count for resource adequacy from the current 3.5 percent of system peak to 2 percent of system peak in 2014.[32]

### Regulation energy management

In early 2011, the ISO also completed work on a new resource category known as regulation energy management, which allows advanced energy storage technologies, such as batteries and flywheels, to provide regulation in the ISO market.[33] Over the next few years, the ISO expects limited amounts of these new technologies to be available for participation in the markets. However, these new technologies may represent valuable system resources as increased reliance is placed on intermittent renewable resources. The ISO proposal provides an initial framework that will allow the ISO and developers to gain valuable experience operating these resources for regulation services.

DMM has noted in previous reports that key details of how energy-limits of these technologies will be managed in the real-time market still need to be developed and refined.[34] This includes the extent to

[30] *Dynamic Transfers: Revised Draft Final Proposal*, February 18, 2011, http://www.caiso.com/2b29/2b29c05056f10.pdf. Also see Second Supplement to Dynamic Transfer Revised Draft Final Proposal, http://www.caiso.com/2b53/2b53bc392e8c0.pdf.

[31] *Reliability Demand Response Product Revised Draft Final Proposal*, Version 2.0. Prepared for The Reliability Demand Response Product Stakeholder Initiative, October 14, 2010, http://www.caiso.com/281a/281abd55ec00.pdf.

[32] The CPUC final decision approving the settlement agreement can be found at: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/119815.htm.

[33] *Regulation Energy Management: Draft Final Proposal*, January 13, 2011, http://www.caiso.com/2b05/2b05e7075f6d0.pdf.

[34] Memorandum to ISO Board of Governors, from Eric Hildebrandt, Director, Market Monitoring, January 27, 2011, re: Market Monitoring Report, http://www.caiso.com/2b14/2b1492a55b00.pdf.

which these resources may be dispatched differently than conventional regulation resources and decision rules for re-charging these resources with energy from the real-time energy market. The ISO has indicated it will closely monitor the development and performance of regulation energy management resources and modify their requirements as appropriate. This will allow the ISO and stakeholders to review and refine various market and operational elements as appropriate before the amount of regulation energy management capacity reaches higher levels.

### Load aggregation points

As previously noted above, under the ISO nodal market design load is bid and settled using load aggregation points, which represent aggregations of individual load nodes located in the service territories of the state's three utilities.[35] FERC approved this approach, but ordered the ISO to disaggregate the three major load aggregation points within three years from the start of the nodal market design, which began in April 2009.

In 2010, the ISO examined options for complying with this directive by April 2012 through a stakeholder process. Virtually all stakeholders requested that the ISO either delay or indefinitely defer disaggregation of the existing load aggregation points on the grounds that the costs of any further disaggregation outweigh potential benefits. In addition, under the nodal market design, overall price differences within the current load aggregation points have been minimal. In light of this, the ISO intends to file a motion with FERC to extend the timeline for further disaggregation of load scheduling points until 2013.[36]

### Resource adequacy program

The current resource adequacy provisions of the ISO tariff and CPUC regulations will continue to be reviewed and modified in 2011 and beyond. Specific aspects of the resource adequacy program being refined include:

- **Standard capacity product.** The standard capacity product provisions of the ISO tariff went into effect in 2010. These create a financial incentive to minimize outages of generation that provide resource adequacy capacity. The initial standard capacity product provisions only applied to conventional generators in 2010. Provisions applicable to wind, solar and cogeneration units became effective in January 2011. In 2011, the ISO will work with stakeholders to determine how to apply the standard capacity product provisions to demand response resources.
- **Integrating renewables.** In 2010 the ISO proposed that the CPUC modify resource adequacy requirements for load-serving entities under the CPUC's jurisdiction to consider operational characteristics of generation needed to support increased amounts of intermittent renewable generation such as wind and solar. This includes fast ramping and start-up capabilities and the ability to provide regulation. The CPUC deferred ruling on the ISO's proposal in time for any of these modifications to be included in resource adequacy requirements for 2012. Load-serving entities

[35] 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.

[36] *Interim Proposal: Load Granularity Refinements*, December 9, 2010, http://www.caiso.com/2867/2867c62170920.pdf.

must procure capacity to meet these requirements in 2011. However, the ISO plans to provide additional information on the needed operational characteristics of the resource adequacy fleet needed to integrate renewables so that load-serving entities can incorporate this information in their procurement decisions.

- **Demand-response.** The state's major utilities will submit applications in 2011 for their 2012-2014 demand response programs. The CPUC has indicated that these programs should be designed to be compatible with resource adequacy requirements to the extent feasible. For example, in some cases the hours that demand response programs may be triggered may be expanded to better coincide with hours used in determining capacity available to meet resource adequacy requirements. This is intended to improve the consistency and comparability between demand response resources and supply-side resources in the resource adequacy process.[37]

In June 2010, the CPUC issued a final decision on a four-year proceeding examining several potential fundamental modifications to the resource adequacy program.[38] The first issue was whether to require a multi-year forward commitment of capacity resources as part of the resource adequacy process. The CPUC found that this has the potential to provide important reliability and market benefits by advance knowledge of impending reliability problems and resource needs. This information could be used by planners and market participants to address resource needs in a more timely and cost effective manner.

However, the CPUC decided not to proceed with a multi-year forward procurement mandate at this time. The CPUC determined that the development of new generating capacity was being effectively met by the resource adequacy program in conjunction with the CPUC's long-term procurement planning process and renewable portfolio standards. The CPUC also expressed concern that requiring all load-serving entities to meet resource adequacy requirements several years in advance could be detrimental to retail competition since this could be more burdensome for non-utility load-serving entities.

### Capacity market

A second major issue addressed in the CPUC's June 2010 decision was whether to adopt a centralized capacity auction mechanism administered by the ISO. During this four-year proceeding, a variety of proposals for a centralized capacity auction administered by the California ISO were developed and considered. The CPUC noted the potential benefits of a capacity market, but expressed several major concerns about implementing such a mechanism at this time.

- The CPUC expressed concern about the compatibility of a capacity market with the state's aggressive goals for renewable energy development and greenhouse gas reductions. As noted in this decision, the underlying premise of a centralized auction is to promote investment in generic capacity.[39] The CPUC expressed concern that this creates the potential for a capacity market to result in development of new capacity, but fail to bring about investment in specialized capacity needed to meet the state's environmental goals and satisfy the ISO's operational needs.

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[37] *Administrative Law Judge's Rules Providing Guidance for the 2012-2014 Demand Response Applications*, August 27, 2010, http://docs.cpuc.ca.gov/efile/RULINGS/122575.pdf.

**[38]** *Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program, Decision on Phase 1 – Track 2 Issues: Adoption of a Preferred Policy for Resource Adequacy*, Decision 10-06-018 June 3, 2010.

[39] Ibid, p. 59.

- The CPUC also noted that "while a centralized auction approach may be well-suited to achieving system reliability, it is less clear that this is true for satisfying local reliability across multiple local capacity areas."[40] The CPUC expressed concern that this could result in unnecessary and costly duplication of capacity investment. DMM has expressed concern about this aspect of a capacity market design and has noted the need for local market power mitigation given the concentrated ownership of capacity needed to meet local capacity requirements.[41]

- Finally, the CPUC noted that problems have been observed with capacity market in other ISOs. Since "a decision to move to a centralized auction in California would not be an easily reversible choice, there would be a clear benefit to observing the PJM experience (as well as that of the ISO-NE and NYISO markets) play out further before determining whether a centralized auction operated by the CAISO is the best solution for California."[42]

In light of these concerns, the CPUC declined to proceed with development of a centralized capacity market at this time. As previously noted, the ISO is working with the CPUC to identify the characteristics of more flexible conventional generation needed to facilitate renewable integration and ensure that these needs are incorporated in the procurement decisions of the state's major load-serving entities.

[40] Ibid, p. 59.

[41] *Potential Effectiveness of the Demand Curve Approach for Mitigation of Local Market Power in Capacity Markets*, May 20, 2009, http://www.caiso.com/2747/2747edae27b70.pdf.

[42] *Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program, Decision on Phase 1 – Track 2 Issues: Adoption of a Preferred Policy for Resource Adequacy*, Decision 10-06-018 June 3, 2010. p. 62-63.

# 2 Load and supply conditions

Overall load and supply conditions were favorable in 2010. This helped reduce the impact of higher natural gas prices on electricity market costs. Other trends highlighted in this chapter include the following:

- Although the peak system load during a single hour increased almost 3 percent, average loads during peak hours declined about 2.5 percent.
- Hydro production and availability increased relative to 2009, particularly in the summer months.
- In 2010, the load-weighted average price of natural gas in the daily spot markets increased about 17 percent from 2009.[43] This was the primary driver of an increase of about 5 percent in the annual wholesale energy cost per MWh of load served in 2010.
- Over 1,500 MW of new gas-fired generation and approximately 500 MW of renewable generation were added in 2010. Another 733 MW of renewable generation is planned in 2011.
- DMM performs an annual assessment of revenues that may be earned by a typical new gas-fired generating unit from the energy and ancillary service markets. This provides an indication of the extent to which these market revenues may contribute to recovery of the fixed costs of investment in new generating capacity. The 2010 results show a slight decrease in net revenues compared to 2009. This decrease in net operating revenues reflects the fact that energy market prices increased less than prices for natural gas in the daily spot markets.
- The estimated net operating revenues for typical new gas-fired generation in 2010 fell substantially below the annualized fixed cost of new generation. This analysis does not include revenues earned from resource adequacy contracts or other bilateral contracts. However, these findings continue to emphasize 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

System loads were generally lower in 2010 than in previous years. This is likely attributable to a combination of moderate summer weather and general economic conditions. Despite these moderate conditions, peak demand during the highest load hour of 2010 was higher than the previous two years.

Table 2.1 shows annual peak loads and energy use over the last five years. Summer weather conditions have been generally mild since a record heat wave in 2006. In 2010, load peaked at 47,350 MW on August 25 at 4:20 p.m. Although peak demand during this single hour was almost 3 percent higher than in 2009, average loads during all peak summer hours declined about 2.5 percent.

[43] In this report, we calculate average annual gas prices by weighting daily spot market prices by the total ISO system loads. This results in a price that is more heavily weighted based on gas prices during summer months when system loads are higher than winter months, during which gas prices are often highest.

**Table 2.1 Annual system load: 2006 to 2010[44]**

| Year | Annual total energy (GWh) | Average load (MW) | % change | Annual peak load (MW) | % change |
|---|---|---|---|---|---|
| 2006 | 241,019 | 27,432 | | 50,270 | |
| 2007 | 242,880 | 27,644 | 0.8% | 48,615 | -3.3% |
| 2008 | 241,128 | 27,526 | -0.4% | 46,897 | -3.5% |
| 2009 | 230,754 | 26,342 | -4.3% | 46,042 | -1.8% |
| 2010 | 224,922 | 25,676 | -2.5% | 47,350 | 2.8% |

Figure 2.1 summarizes load conditions during peak hours 7 to 22 of June to August since 2000.[45] Average loads during these peak hours have remained relatively flat since 2003, with the notable exception of 2006. However, system demand during the single highest load hour has varied substantially from year to year. These system peaks are driven by heat waves, which can push system loads to extremely high levels for a limited number of hours each summer. The potential for such peak loads drives many of the reliability planning requirements and can create reliability problems under extreme weather conditions.

Figure 2.2 shows load duration curves for the years 2008 through 2010. These data further illustrate how overall loads have been lower, while peak demand in the higher load hour of the year has continued to increase over the last two years. In 2010, loads exceeded 40,000 MW during 88 hours, or about 1 percent of all hours. In 2009, load exceeded 40,000 MW during 129 hours, or about 1.5 percent of all hours.

As shown in Figure 2.3, the 2010 summer peak demand exceeded the 1-in-2 year forecast of peak demand by about 211 MW, or 0.45 percent. This was well below the 1-in-10 year peak forecast of 49,455 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 based on the 1-in-10 year peak forecast for each area.

[44] 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 may differ slightly from prior published figures.

[45] 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 2.1 Summer load conditions (2000 to 2010)**

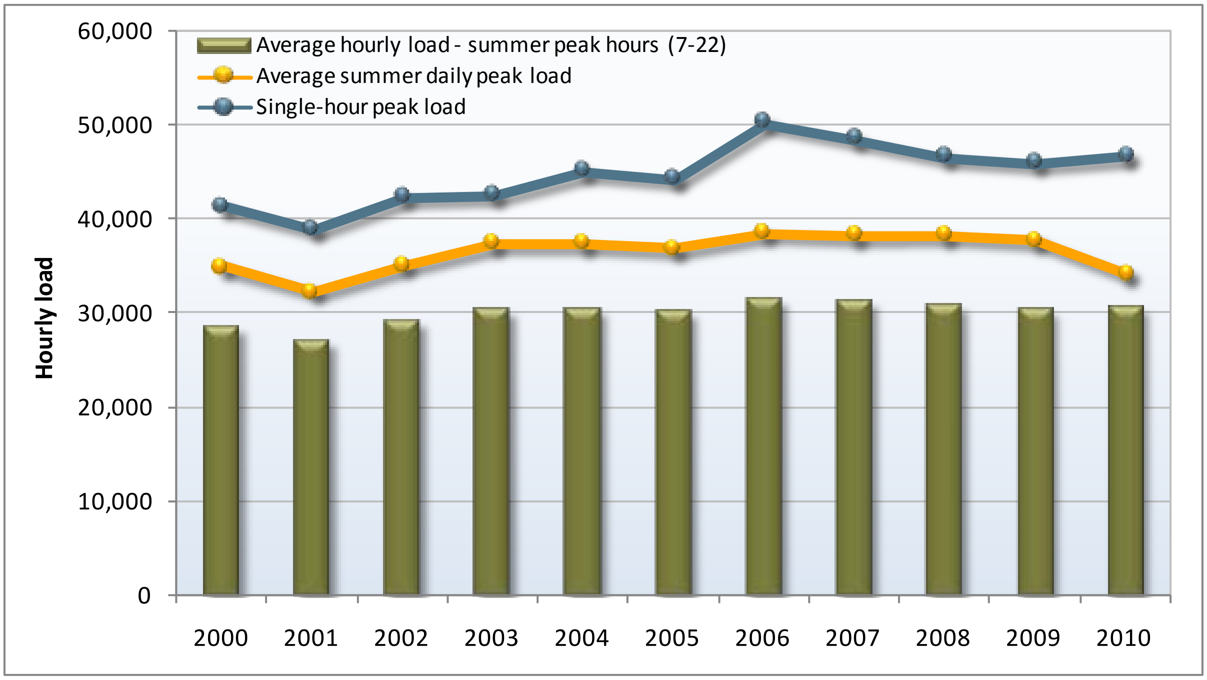



**Figure 2.2 System load duration curves (2008 to 2010)**

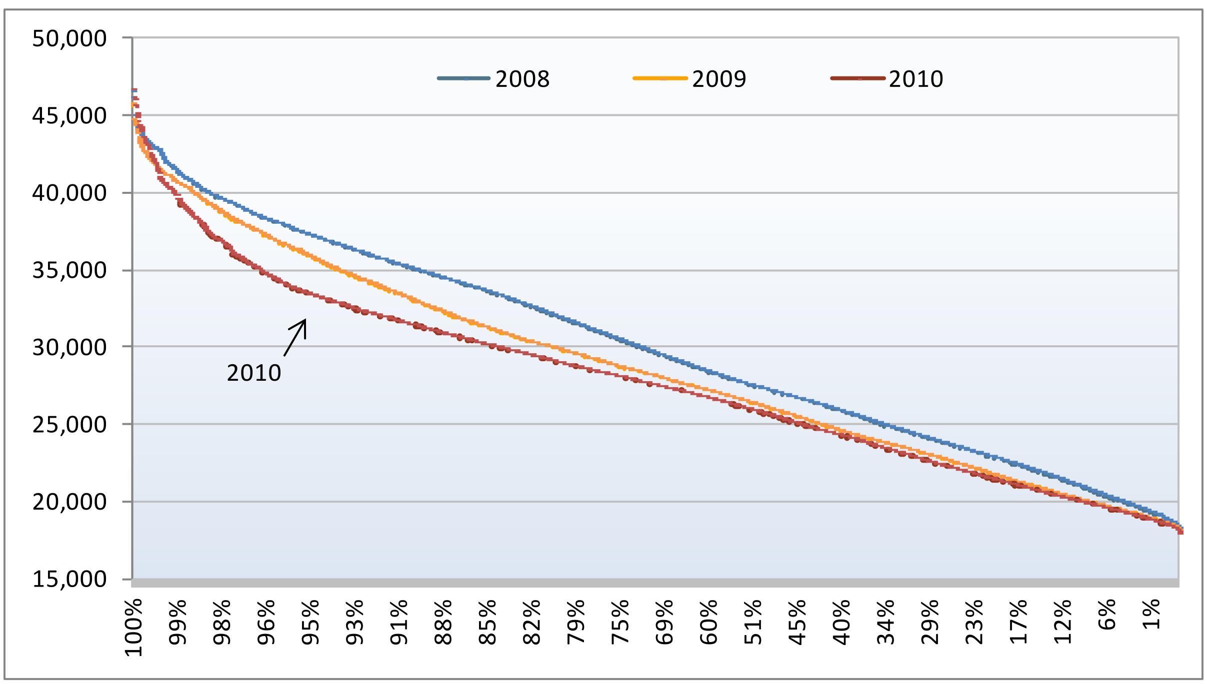
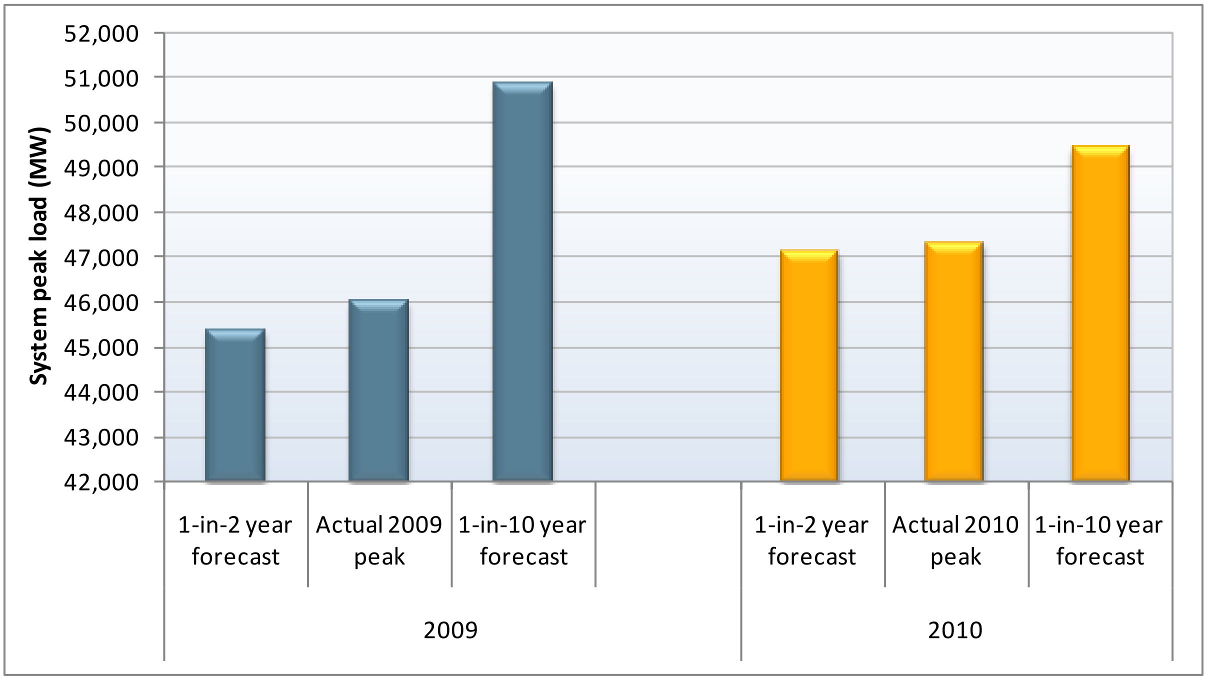


**Figure 2.3 Peak load vs. planning forecasts (2009 vs. 2010)**




## 2.1.2 Local transmission constrained areas

The ISO has defined ten local capacity areas for use in establishing local reliability requirements under the state's resource adequacy program, as shown in Figure 2.4. Most of the total system demand 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 used to set local reliability requirements

- Local capacity areas within the PG&E area account for about 40 percent of total local capacity area loads under the 1-in-10 year forecast. Loads in the Greater Bay Area account for about half of the potential peak load in the PG&E load aggregation point.
- The two local capacity areas within the SCE area account for about 50 percent of total local capacity area loads under the 1-in-10 year forecast. Loads in the Los Angeles Basin account for about 80 percent of 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.

In the following chapters of this report, we summarize a variety of market results for each of these load aggregation points and local capacity areas separately. This provides an indication of key locational trends under the nodal market design. The proportion of load and generation located within these areas provides an indication of the relative 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**

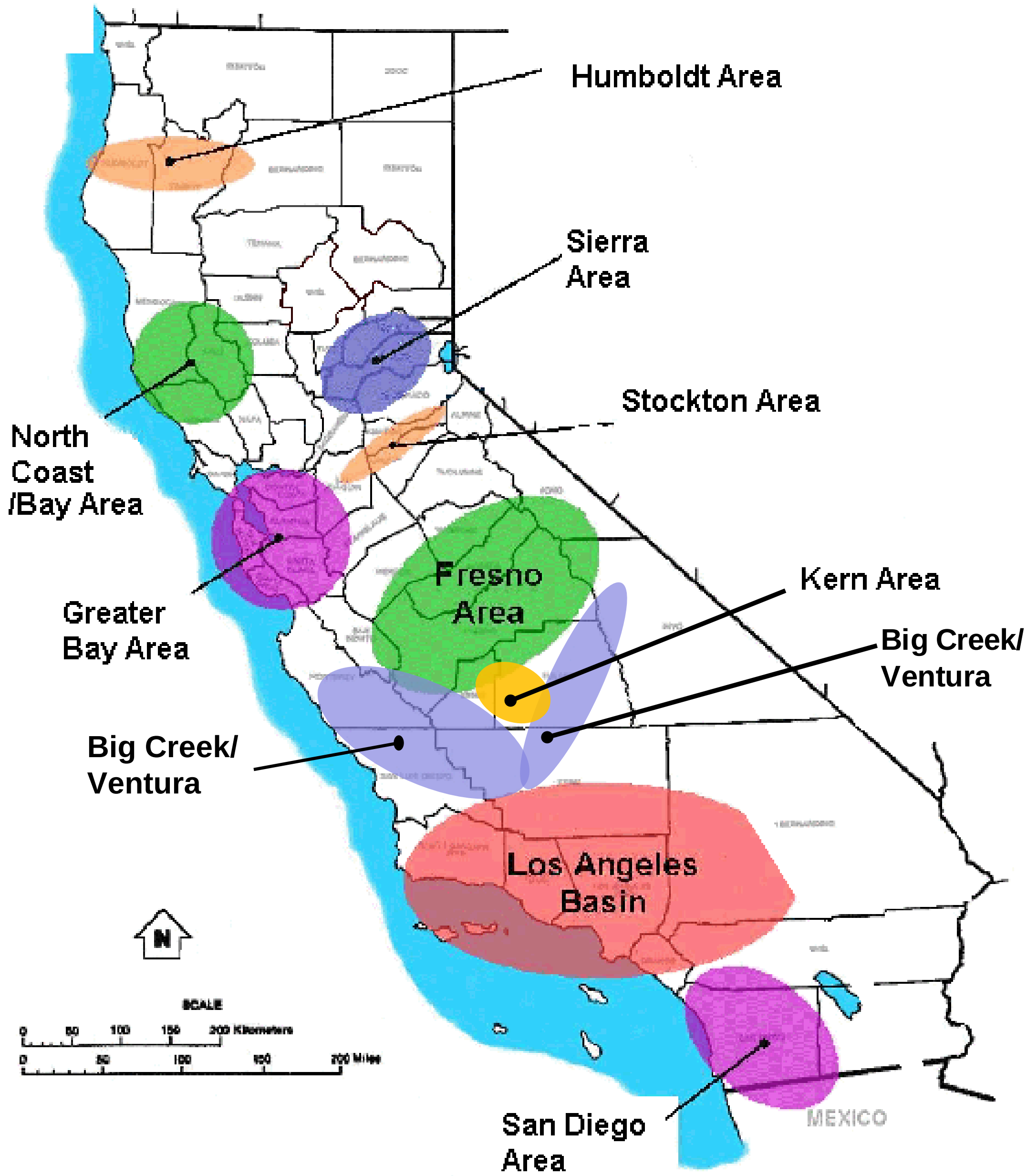


**Table 2.2 Load and supply within local capacity areas**

| 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 | 10,276 | 21% | 6,704 | 4,651 | 69% |
| Fresno | PG&E | 3,377 | 7% | 2,941 | 2,640 | 90% |
| Sierra | PG&E | 2,126 | 4% | 1,835 | 2,102 | 115%* |
| North Coast/North Bay | PG&E | 1,614 | 3% | 885 | 790 | 89%* |
| Stockton | PG&E | 959 | 2% | 495 | 681 | 138%* |
| Kern | PG&E | 1,240 | 2% | 665 | 404 | 61%* |
| Humbolt | PG&E | 203 | 0.4% | 183 | 176 | 96% |
| LA Basin | SCE | 20,058 | 40% | 12,130 | 9,735 | 80% |
| Big Creek/Ventura | SCE | 5,033 | 10% | 5,093 | 3,334 | 65% |
| San Diego | SDG&E | 5,127 | 10% | 3,707 | 3,214 | 87%* |
| **Total** | | **50,013** | * | **34,638** | **27,727** | **80%** |

Source: *2010 Local Capacity Technical Analysis: Final Report and Study Analysis*, May 1, 2009. http://www.caiso.com/23a1/23a186dd41f50.pdf

*Indicates local capacity area or sub-area with insufficient capacity to meet requirements. This implies that if 1-in-10 year peak loads did occur, load would need to be shed immediately after the first contingency to comply with reliability criteria.

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

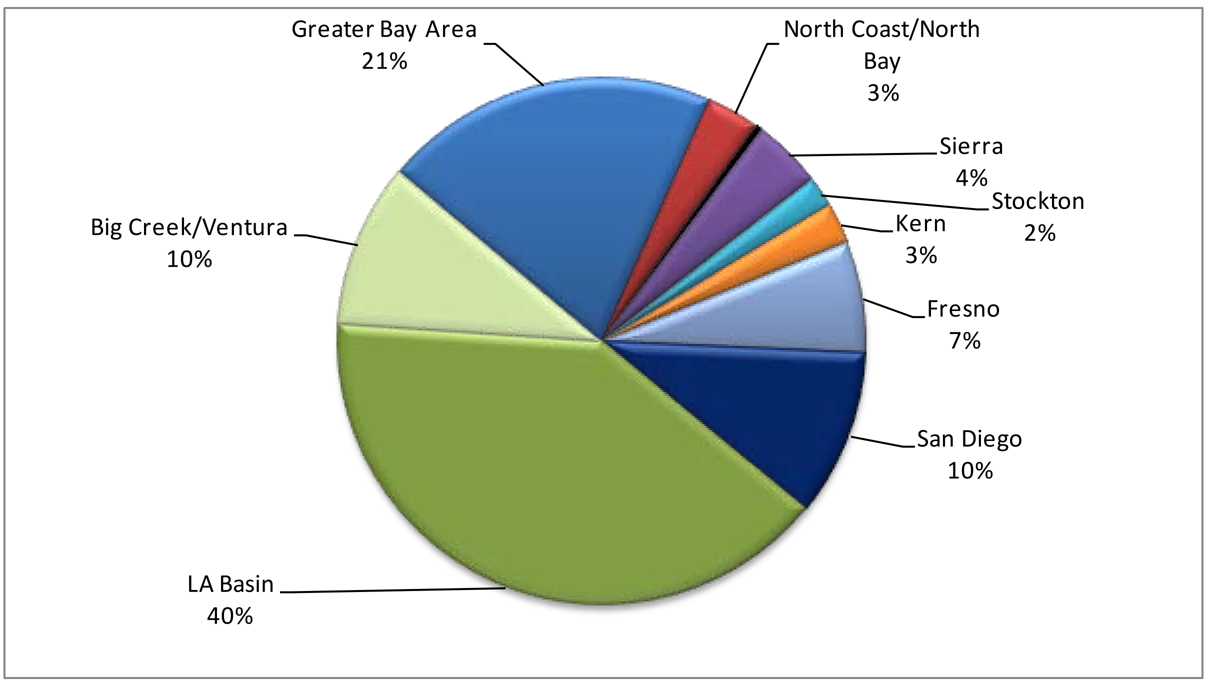


Table 2.2 also shows the total amount of generation located in each local capacity area along with the total amount of capacity required for local reliability planning requirements in these areas. Table 2.2 shows that a very high portion of the available capacity in most of these local capacity areas is needed to meet peak reliability planning requirements. One or two entities own the bulk of generation in each of these areas. As a result, the potential for locational market power in these load pockets is significant.

### 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, demand response programs operated by the state's three investor-owned utilities met about 4.5 percent of overall system resource adequacy capacity requirements. Non-utility entities, such as independent curtailment service providers, can provide demand response by participating in utility sponsored programs. Demand response provided directly to the ISO by non-utility entities is currently limited primarily to demand associated with water pumping loads.

In August 2010, the ISO implemented a proxy demand resource product designed to increase direct participation in the energy and ancillary service markets by utility demand response programs. This market enhancement also allows aggregators of end-use loads to bid into the ancillary service market. However, a negligible amount of proxy demand resource capacity was registered in 2010 and no bids from these resources were dispatched.

#### Participating loads

The market allows curtailable end-use loads, or participating loads, to participate in the real-time energy and non-spinning reserve markets. To qualify as participating load, a demand response provider must be directly dispatchable and must meet specific telemetry and metering requirements. In practice, a limited amount of demand from pumping loads participates in the market. The ISO does not release information on the amount of participating loads since virtually all this capacity is operated by one market participant – the California Department of Water Resources.

#### Non-participating loads

The vast majority of demand response now in California consists of load management programs operated by the state's three investor-owned utilities, known as non-participating loads. These demand response programs are triggered based on criteria set by the utility and not necessarily tied to market prices. Notification times required by the retail programs are also not well synchronized with market operations. This lack of integration lessens the programs' ability to reduce electricity prices in the market, because these demand response resources cannot necessarily be called upon to reduce load at times of high prices or low reserve margins that do not result in an actual system emergency.

Utility-managed demand response programs can be grouped into two general categories:

- ***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 in declaring a system reliability threat.

- ***Price responsive programs —*** These are programs in which participants are charged higher rates for critical peak hours. 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 during the peak summer month of August as reported to the CPUC. Until 2009, demand response capacity was reported based on potential load reductions from total loads enrolled under each program. In 2009, the CPUC established standard protocols for measuring and reporting demand response programs for utilities under its jurisdiction.[46] As a result, estimated values reported for 2010 are lower relative to capacity reported in previous years based on enrolled loads.

The bottom two rows of Table 2.3 show the amount of capacity from utility demand response programs used to meet resource adequacy requirements. The amount of capacity from utility operated demand response programs that may be used to meet resource adequacy requirements is determined by the CPUC based on its estimate of demand response capacity that can be expected during peak summer conditions.

As shown in Table 2.3, demand response capacity used to meet 2010 resource adequacy requirement tracked closely with estimates of actual demand response capacity reported in 2010 under the more advanced protocols for measurement and reporting of these programs. The decrease in demand response used to meet resource capacity requirements in 2010 reflects the lower values resulting from use of standard protocols for measuring and reporting demand response programs.

The CPUC allows a 15 percent adder to be applied to demand response capacity used to meet resource adequacy requirements. This accounts for the fact that demand reductions reduce the amount of capacity needed to meet the 15 percent supply margin used in setting resource adequacy requirements.

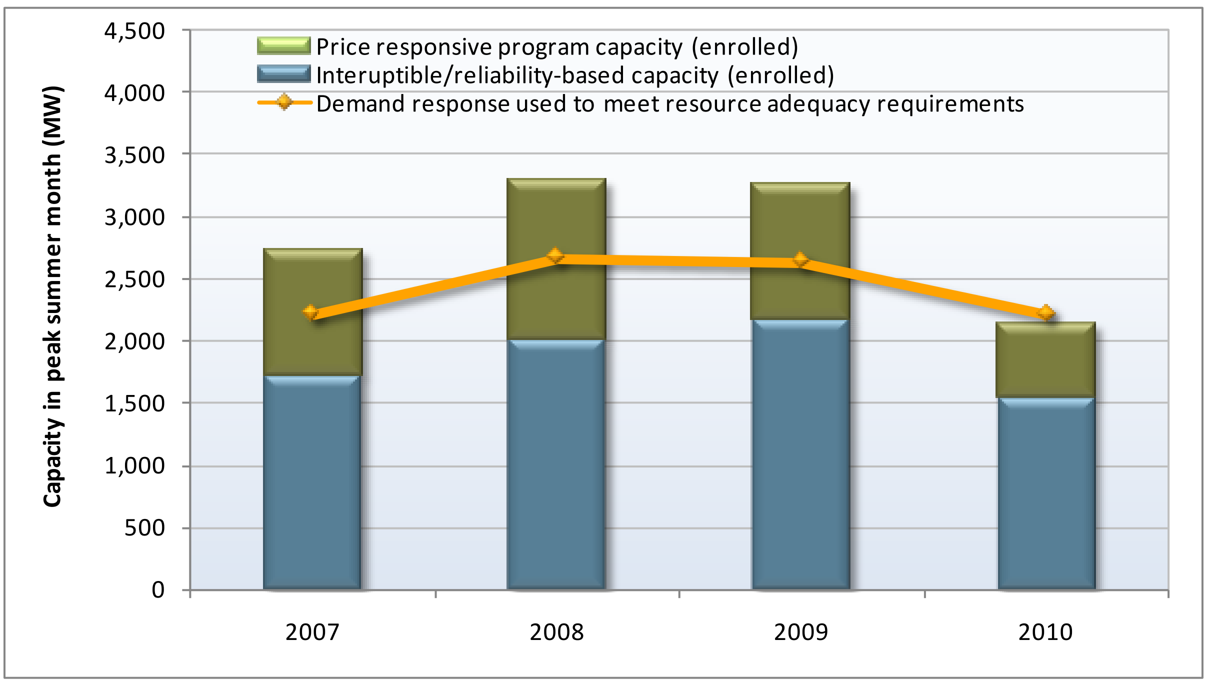
Figure 2.6 provides a graphical summary of data in Table 2.3. As illustrated in Figure 2.6, reliability-based programs account for about three-quarters of the capacity from utility-managed demand response programs, with price-responsive programs accounting for about one-quarter of this capacity. Data in Figure 2.6 do not include the 15 percent adder.

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

**Table 2.3 Utility operated demand response programs (2007-2010)**

| Utility | Program type | 2007 Enrolled MW | 2008 Enrolled MW | 2009 Enrolled MW | 2010 Estimated MW |
|---|---|---|---|---|---|
| SCE | Price-responsive | 256 | 381 | 498 | 214 |
| PG&E | Price-responsive | 623 | 752 | 508 | 304 |
| SDG&E | Price-responsive | 121 | 154 | 89 | 72 |
| | ***Total price -responsive*** | 999 | 1,287 | 1,095 | 590 |
| SCE | Reliability-based | 1,305 | 1,458 | 1,577 | 1,245 |
| PG&E | Reliability-based | 323 | 466 | 533 | 291 |
| SDG&E | Reliability-based | 98 | 83 | 62 | 9 |
| | ***Total reliability-based*** | 1,726 | 2,007 | 2,172 | 1,545 |
| | ***Total enrolled/estimated*** | 2,725 | 3,294 | 3,267 | 2,135 |
| | ***Resource adequacy capacity*** | 2,226 | 2,670 | 2,637 | 2,221 |
| | ***With 15 percent adder*** | 2,560 | 3,071 | 3,033 | 2,554 |

**Figure 2.6 Utility operated demand response programs (2007-2010)**



## 2.2 Supply conditions

### 2.2.1 Generation mix

Figure 2.7 provides a profile of average hourly generation by month and fuel type. Figure 2.8 shows an hourly average profile of energy supply by fuel type for July through September. These figures show the following:

- 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 2010, natural gas and hydroelectric production supplied approximately 35 and 12 percent of supply, respectively.
- Net imports represented around 26 percent of total supply in 2010, while base load nuclear production represented around 14 percent of supply.
- Non-hydro renewable generation accounted for 9 percent of total supply.

Figure 2.9 provides a more detailed breakdown of non-hydro renewable generation in 2009 and 2010.[47]

- Geothermal provided approximately 42 percent of renewable energy.
- Wind provided approximately 30 percent of renewable energy.
- Biogas, biomass, and waste generation provided another 23 percent of renewable energy.
- Solar power accounted for 5 percent of total renewable generation.

Generation from wind and solar resources slightly increased in 2010 while generation from the other two resources slightly decreased.

[47] This year we have improved our methodology and used metered generation and therefore obtained more accurate results.

**Figure 2.7 Average hourly generation by month and fuel type in 2010**

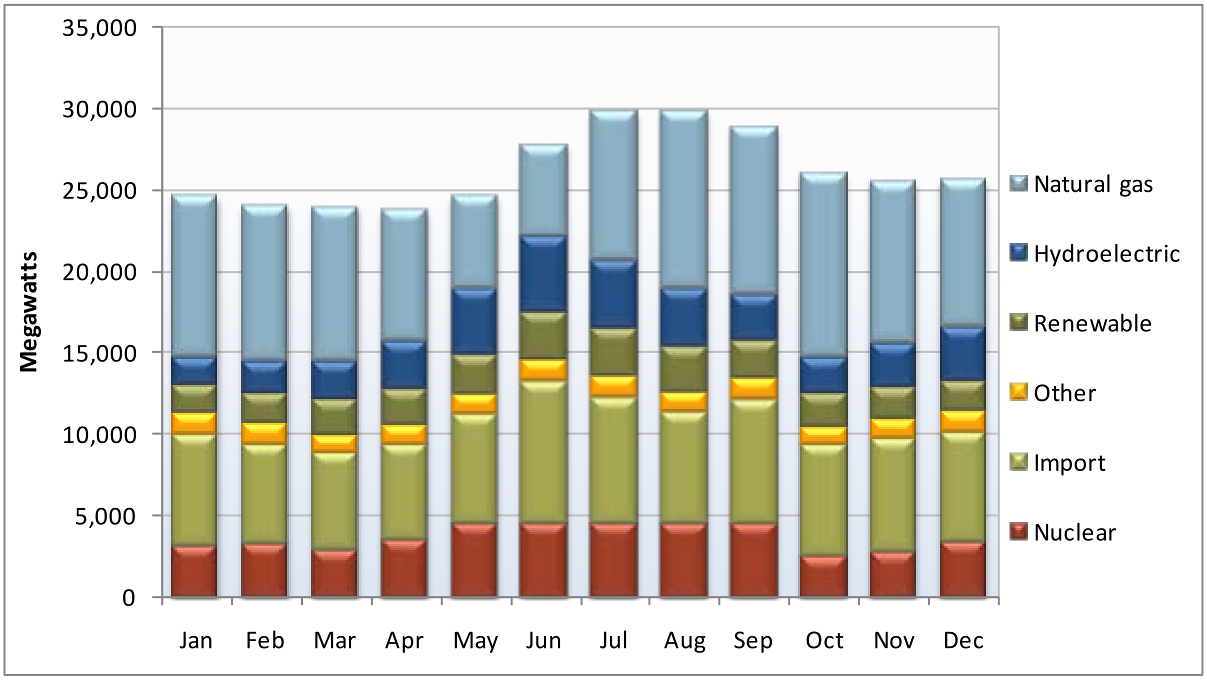



**Figure 2.8 Average hourly generation by fuel type in Q3 2010**

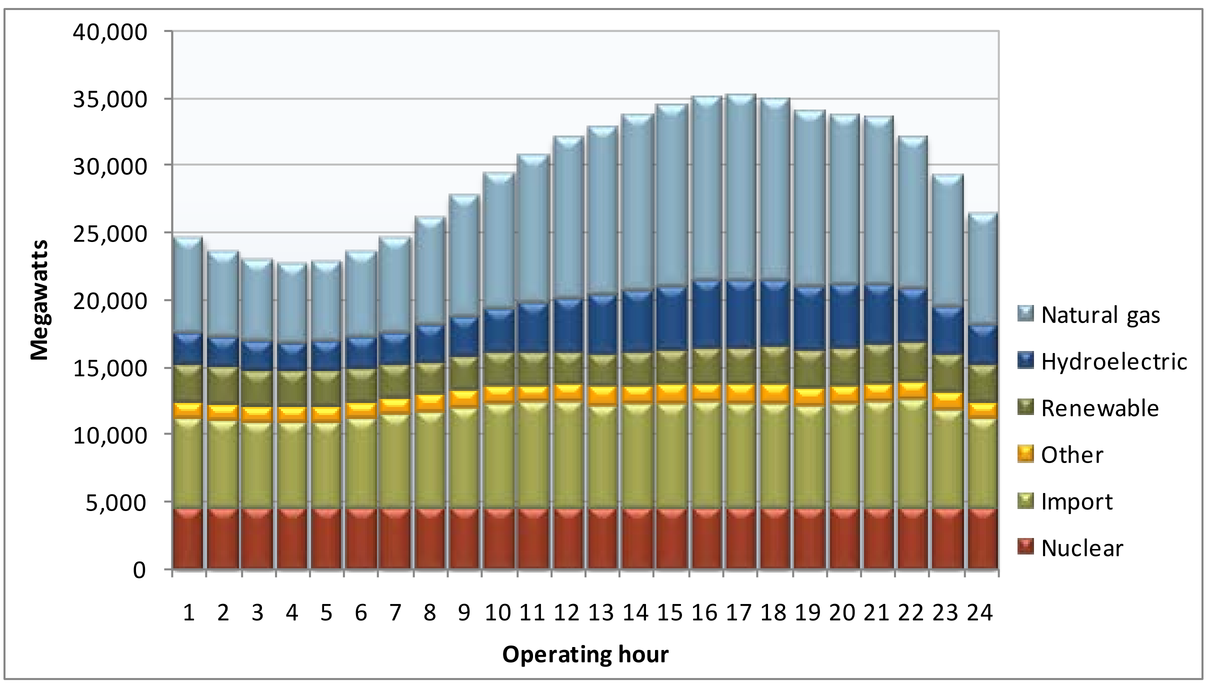
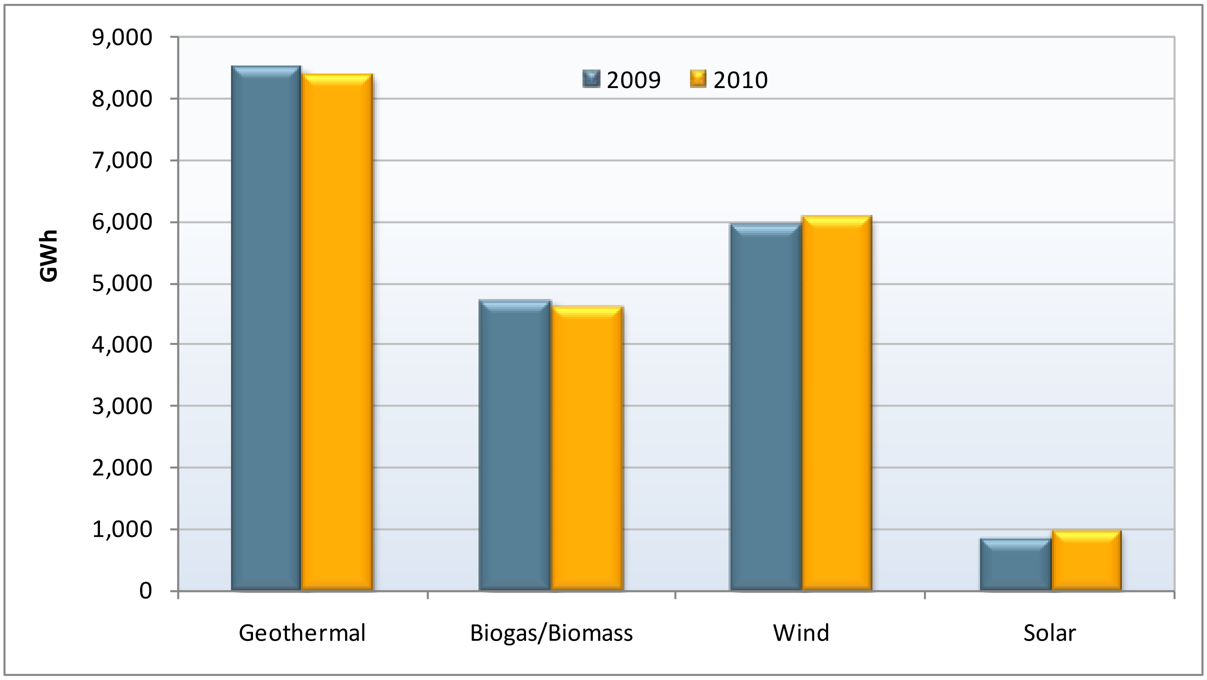


**Figure 2.9 Total renewable generation by type in 2009 and 2010**




## Hydroelectric supplies

Year-to-year variations in hydroelectric power supply 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 units with reservoir storage. 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.

As shown in Figure 2.10, overall hydroelectric production in 2010 was higher than in the previous three years, but still lower than in 2006 and earlier years. Overall snowpack in the Sierras on May 1, 2010, was about 148 percent of the long term average, indicating better-than-average hydro conditions.

Figure 2.11 compares monthly hydroelectric output from units within the ISO for each of the last three years. In 2010, hydro production was significantly higher than 2009 during the month of June and again in November and December. During the peak load months of July and August, hydro production was about 7 percent higher than in 2009.

**Figure 2.10 Annual hydroelectric production (2002-2010)**

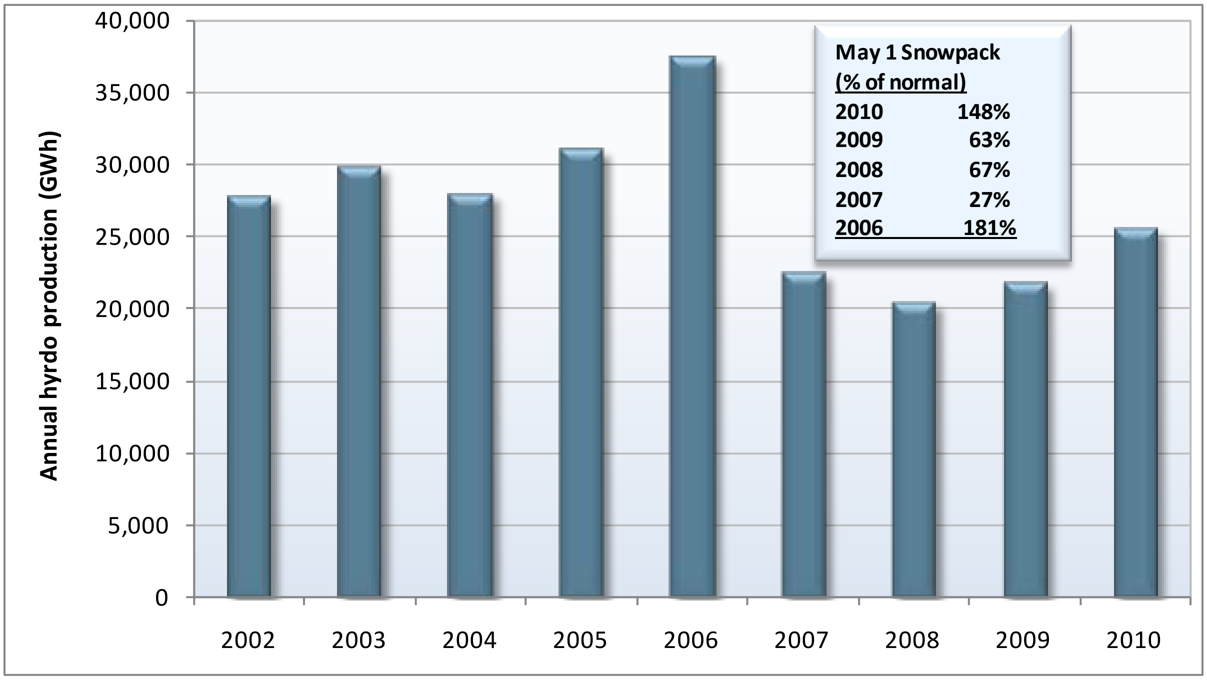
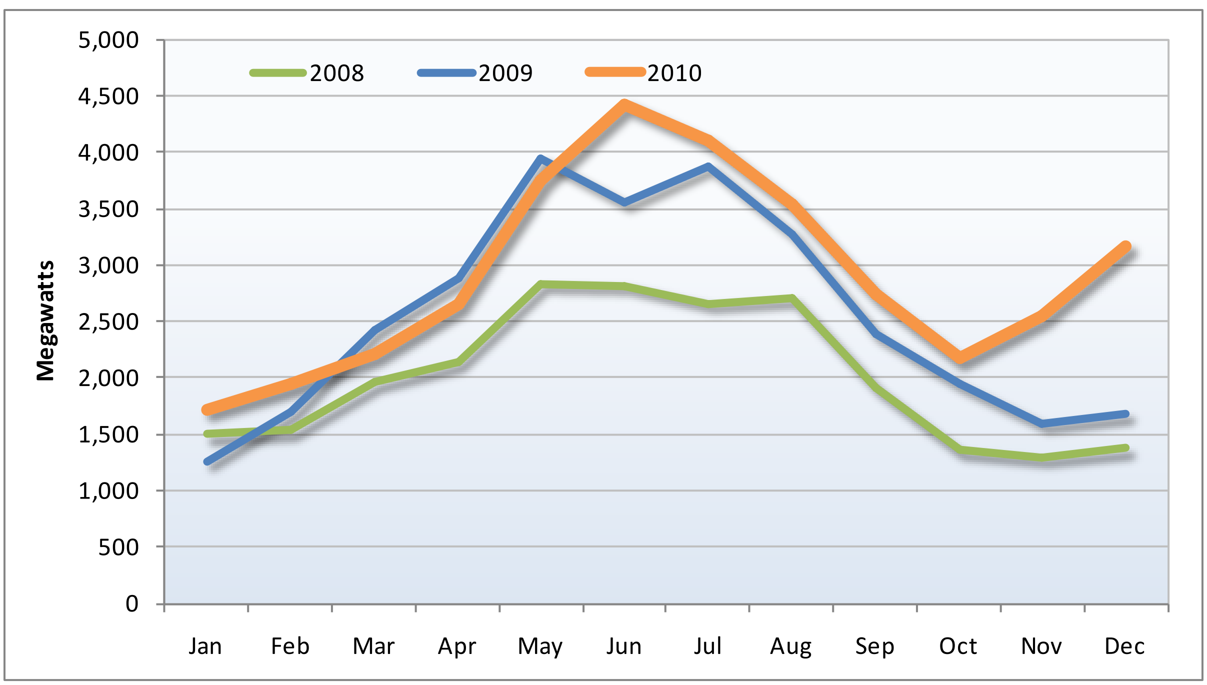



**Figure 2.11 Average hourly hydroelectric production by month: 2008-2010**

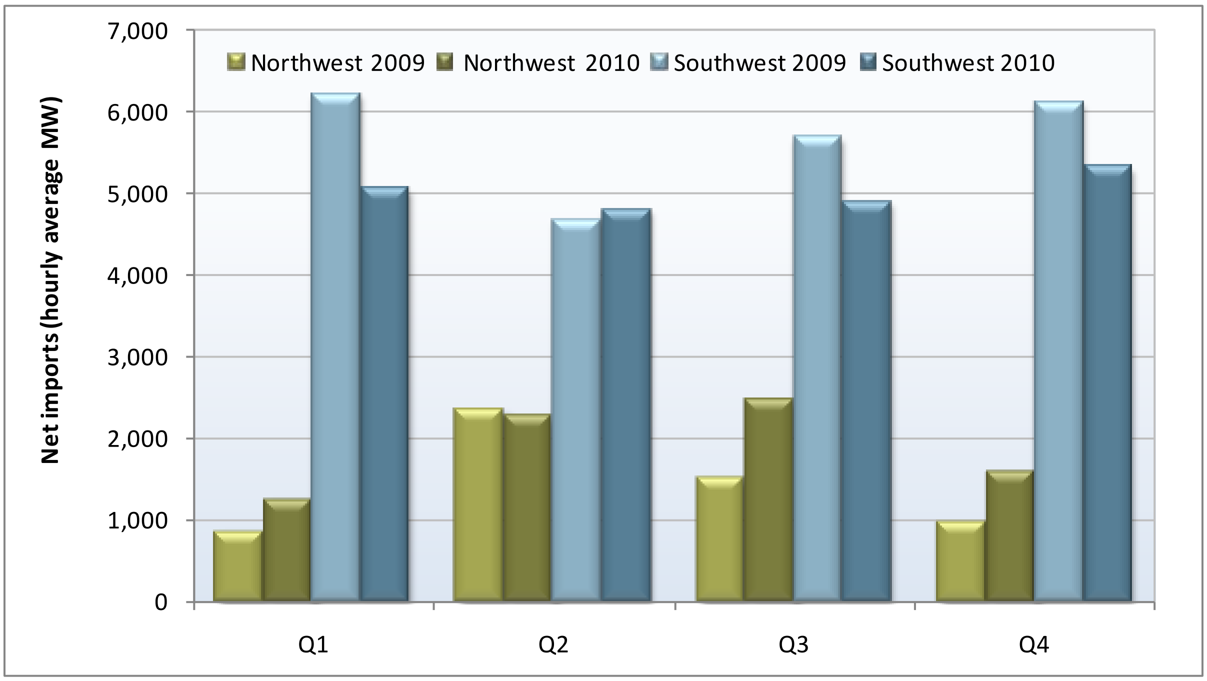


### Net imports

Figure 2.12 compares final net imports after the hour-ahead market by region for each quarter of 2010 and 2009. Overall, net imports dropped about 3 percent in 2010 from 2009. Net imports from the Southwest dropped about 12 percent, while imports from the Northwest increased about 33 percent.

This change likely occurred as a result of changes in the relative price differentials between California and the Northwest and Southwest. The price differential between the SP15 and the Palo Verde trading hub prices fell in both on-peak and off-peak periods in 2010 when compared to 2009. In the Northwest, the 2010 price differential between the NP15 and Mid-Columbia trading hub prices increased in on-peak periods and fell slightly in off-peak periods when compared to 2009.

**Figure 2.12 Net imports by region: 2009 and 2010**




## 2.2.2 Natural gas prices

Electric prices in the western states typically follow natural gas price trends because natural gas units are frequently the marginal source of generation in California and other regional markets. In 2010, the load-weighted average price of natural gas in the daily spot markets increased about 17 percent from 2009.[48] This was the primary driver of an increase of about 5 percent in the annual wholesale energy cost per MWh of load served in 2010.

48 In this report, we calculate average annual gas prices by weighting daily spot market prices by the total ISO system loads. This results in a price that is more heavily weighted based on gas prices during summer months when system loads are higher than winter months, during which gas prices are often highest.

Figure 2.13 shows monthly average natural gas prices for 2008 through 2010 at key delivery points in Northern California (PG&E Citygate) and in Southern California (SoCal Border). Prices for the national Henry Hub trading point are also provided as a point of reference.[49]

- In 2010, the price of natural gas increased substantially from the low prices observed in 2009, but still remained relatively low compared to previous years.
- Natural gas prices peaked at the beginning of the year, during the winter heating season, and were lowest in the fall at the end of the natural gas injection season.
- Through the spring and summer, California's monthly average natural gas prices ranged from $3.82 to $4.55/MMBtu. This range of gas prices resulted in marginal gas-fired power production costs in the range of $34 to $40/MWh for combined cycle resources, and $50 to $59/MWh for older peaking resources.[50]

Natural gas prices in California 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, natural gas prices within California periodically diverge, with prices in Northern California tending to be higher than in Southern California. However, the difference between natural gas prices in Northern and Southern California continued to decline in 2010.

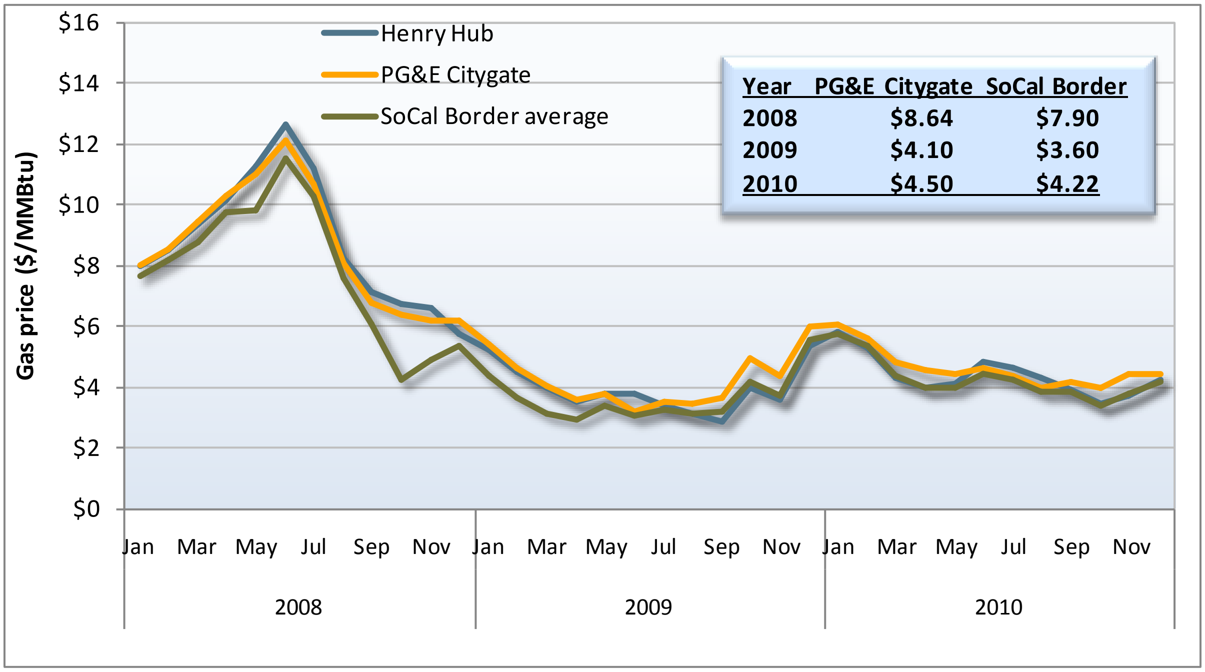
- In 2010, average daily natural gas prices in Northern California exceeded prices in Southern California by about $0.29/MMBtu, or 7 percent.
- In 2009, natural gas prices in Northern California exceeded prices in Southern California by about $0.52/MMBtu, or 14 percent.
- In 2008, natural gas prices in Northern California exceeded prices in Southern California by about $0.75/MMBtu, or 10 percent.

This decline was a result of changes in increased production and transportation capacity and lower costs from sources in the northern Rocky Mountain area and Canada to Northern California.

[49] In practice, gas delivered to California is produced in areas of the Rocky Mountains and southwest. However, prices at Henry Hub provide an indication of the degree to which prices in these regional markets periodically diverge due to regional rather than national market conditions.

[50] This is based on a heat rate of 9,000 Btu/kWh for combined cycle units and 13,000 Btu/kWh for older combustion turbines.

**Figure 2.13 Monthly weighted average natural gas prices in 2008-2010**




## 2.2.3 Generation outages

DMM tracks generation outages based on data from the ISO outage management system. DMM cannot use their data to accurately differentiate between the duration and type of outages (i.e., planned, forced or ambient). This process requires substantial time and can require subjective judgments to be made about how to interpret data in order to quantify the duration and type of outages. Therefore, DMM is not including data on generation outages in this report, as we have in prior years.

## 2.2.4 Generation addition and retirement

California currently relies on long-term procurement planning and 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 system each year provide important insight into the effectiveness of the California market and regulatory structure in incenting new generation investment.

Figure 2.14 summarizes trends in the addition and retirement of generation from 2001-2010. It also includes planned capacity additions and retirements in 2011. Table 2.4 also shows generation additions and retirements since 2001. It includes projected 2011 changes and totals across the 11-year period (2001-2011).

### Generation additions and retirements in 2010

Approximately 2,044 MW of new generation began commercial operation within the ISO system in 2010. About 1,002 MW were installed north of Path 26 (NP26) and 1,042 MW came online south of Path 26 (SP26). A more detailed listing of these is provided in Table 2.5.

### Anticipated additions and retirements in 2011

The ISO is anticipating construction of 1,147 MW of new generation in 2011, with almost two-thirds coming from renewable resources. Table 2.6 provides more detailed information on these projects. The ISO expects about 946 MW of this new capacity to be commercially available before the anticipated summer peak season. The ISO also anticipates 683 MW of existing generation to be retired in 2011. A more detailed listing of this capacity is provided in Table 2.6.

**Figure 2.14 Generation additions and retirements: 2001-2011**

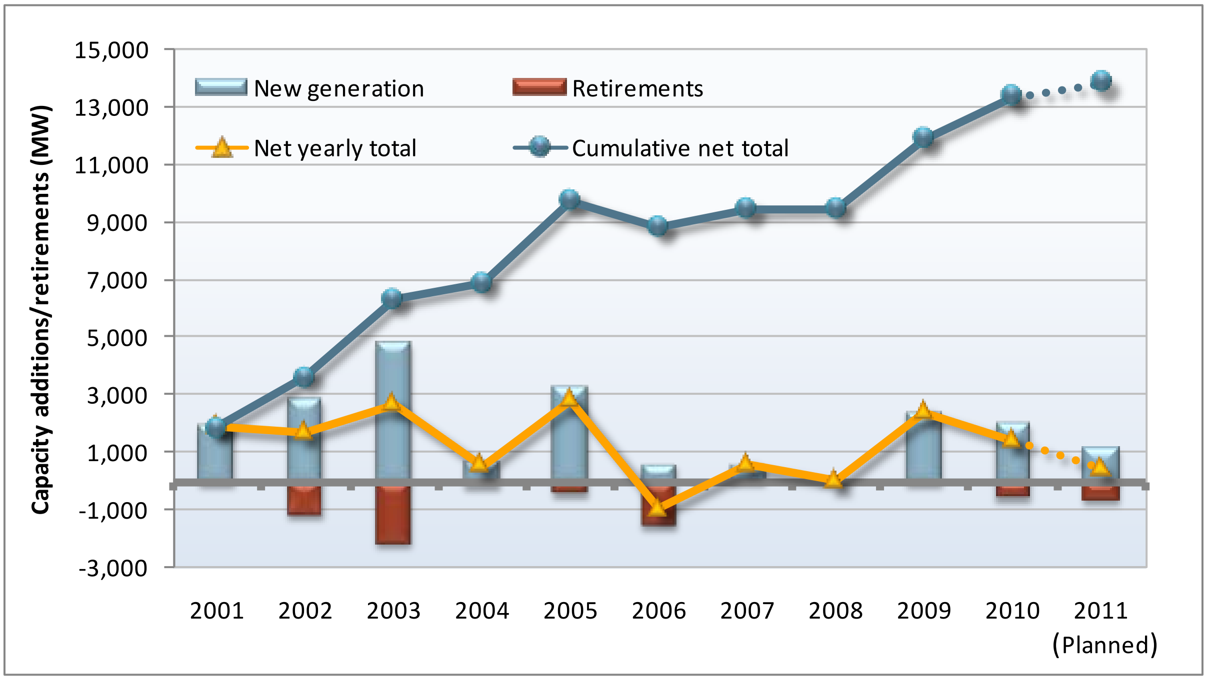



**Table 2.4 Changes in generation capacity since 2001**

| | 2001 - 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | Projected 2011 | Total Through 2011 |
|---|---|---|---|---|---|---|---|---|
| ***SP15*** | | | | | | | | |
| New Generation | 6,485 | 434 | 485 | 45 | 1,107 | 1,042 | 1,023 | 10,620 |
| Retirements | (2,960) | (1,320) | 0 | 0 | 0 | (414) | (321) | (5,015) |
| **Net Change** | **3,525** | **(886)** | **485** | **45** | **1,107** | **628** | **702** | **5,605** |
| ***NP26*** | | | | | | | | |
| New Generation | 7,233 | 199 | 112 | 0 | 1,329 | 1,002 | 124 | 9,998 |
| Retirements | (1,020) | (215) | 0 | 0 | (26) | (175) | (362) | (1,797) |
| **Net Change** | **6,213** | **(16)** | **112** | **0** | **1,303** | **827** | **(238)** | **8,201** |
| ***ISO System*** | | | | | | | | |
| New Generation | 13,718 | 633 | 598 | 45 | 2,435 | 2,043 | 1,147 | 20,619 |
| Retirements | (3,980) | (1,535) | 0 | 0 | (26) | (589) | (683) | (6,812) |
| **Net Change** | **9,738** | **(902)** | **598** | **45** | **2,410** | **1,455** | **464** | **13,807** |

**Table 2.5 New generation facilities in 2010**

| Generating unit | Resource capacity (MW) | | Commercial operation date | Zone ID |
|---|---|---|---|---|
| CalRENEW-1(A) | 5.0 | * | 30-Apr-10 | NP26 |
| Blue Lake Power LLC Biomass Re-Power | 13.8 | * | 10-Sep-10 | NP26 |
| Humboldt Bay Power Plant Repowering (New Humboldt Bay Generating Station) | 162.0 | | 30-Sep-10 | NP26 |
| CCSF Sunset Reservior PV Plant | 4.5 | * | 1-Nov-10 | NP26 |
| Hatchet Ridge Wind,LLC Project | 101.2 | * | 19-Nov-10 | NP26 |
| Colusa Generating Station | 715.0 | | 23-Dec-10 | NP26 |
| ***NP26 Actual New Generation in 2010*** | ***1,002*** | | | |
| Orange Grove Energy Center | 99.0 | | 17-Jun-10 | SP26 |
| Rialto RT Solar/Southern California Edison | 2.0 | * | 1-Feb-10 | SP26 |
| Chiquita Canyon Landfill | 9.2 | * | 23-Nov-10 | SP26 |
| Calabasas Gas To Energy Facility | 13.8 | * | 24-Sep-10 | SP26 |
| Blythe Energy Project Phase II | 520.0 | | 11-Jun-10 | SP26 |
| El Cajon Energy Center, LLC. | 49.5 | | 16-Jun-10 | SP26 |
| Copper Mountain Solar 1 Pseudo Tie PILOT | 48.0 | * | 30-Apr-10 | SP26 |
| CPC West - Alta Wind 1 | 150.0 | * | 29-Dec-10 | SP26 |
| CPC West - Alta Wind II | 150.0 | * | 29-Dec-10 | SP26 |
| ***SP26 Actual New Generation in 2010*** | ***1,042*** | | | |
| **Total Actual New Generation in 2010** | **2,044** | | | |
| *** Total Renewable Generation in 2010** | **498** | | | |

Source: California ISO Grid Planning Department

### Table 2.6 Planned generation additions in 2011

| Generating unit | Resource capacity (MW) | | Expected operational date | Zone ID |
|---|---|---|---|---|
| Wind Energy Center | 36.8 | * | 25-Jan-11 | NP26 |
| Biomass Re-Power | 22.5 | * | 1-Mar-11 | NP26 |
| Biomass Re-Power | 6 | * | 1-Apr-11 | NP26 |
| Run-of-the-river Hydro Re-power | 5.0 | * | 1-Apr-11 | NP26 |
| Wastewater Treatment Gas Turbine | 4.5 | * | 15-Apr-11 | NP26 |
| 19 MW Solar Photovoltaic Project | 19.0 | * | 1-May-11 | NP26 |
| 20 MW Solar Photovoltaic project | 20.0 | * | 1-May-11 | NP26 |
| 6 MW Solar Photovoltaic Project | 6.0 | * | 1-Jun-11 | NP26 |
| 4 MW Sodium Sulfide Battery Project | 4.0 | | 1-Jun-11 | NP26 |
| ***NP26 Planned New Generation in 2011*** | ***124*** | | | |
| Wind Project | 150.0 | * | 11-Feb-11 | SP26 |
| Clean Diesel Generators | 23.5 | | 21-Feb-11 | SP26 |
| Pumped Storage Resource - Unit 1 | 20.0 | | 28-Feb-11 | SP26 |
| Pumped Storage Resource - Unit 2 | 20.0 | | 28-Feb-11 | SP26 |
| Solar Photovoltaic Project | 1.0 | * | 28-Feb-11 | SP26 |
| Solar Photovoltaic Project | 5.0 | * | 26-Feb-11 | SP26 |
| Wind Project | 102.0 | * | 1-Apr-11 | SP26 |
| Solar Photovoltaic Project | 7.5 | * | 26-Feb-11 | SP26 |
| Solar Photovoltaic Project | 1.5 | * | 29-Mar-11 | SP26 |
| Solar Photovoltaic Project | 5.0 | * | 31-Mar-11 | SP26 |
| Landfill Gas Project | 1.9 | * | 31-Mar-11 | SP26 |
| Landfill Gas Expansion | 4.0 | * | 1-Apr-11 | SP26 |
| Solar Photovoltaic Project | 8.0 | * | 1-Apr-11 | SP26 |
| Landfill Gas Project | 2.0 | * | 1-Apr-11 | SP26 |
| Solar Photovoltaic Project | 2.5 | * | 8-Apr-11 | SP26 |
| Wind Project | 168.0 | * | 1-May-11 | SP26 |
| Solar Photovoltaic Project | 3.5 | * | 19-Apr-11 | SP26 |
| Peaker Unit 3-4 | 99.0 | | 1-Mar-11 | SP26 |
| Peaker Unit 1-2-3-4 | 198.0 | | 1-Jun-11 | SP26 |
| Peaker Project | 49.5 | | 1-Aug-11 | SP26 |
| Wind Project | 151.0 | * | 1-Sep-11 | SP26 |
| ***SP26 Planned New Generation in 2011*** | ***1,023*** | | | |
| **Total Planned New Generation in 2011** | **1,147** | | | |

## 2.3 Net market revenues of new gas-fired generation

It is important that California have an adequate market and regulatory framework for facilitating investment in needed levels of new capacity. As discussed in Chapter 1, the CPUC's long-term procurement process and resource adequacy program is currently the primary mechanism to ensure investment in new capacity when and where it is needed. Given this regulatory framework, 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.

Each year, DMM examines the extent to which revenues from the spot markets in 2010 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. Costs used in the analysis are based on a 2010 report by the California Energy Commission.[51]

**Table 2.7 Assumptions for typical new combined cycle unit[52]**

| | |
|---|---|
| **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 |

[51] A more detailed description of the methodology and results of the analysis presented in this section are provided in Appendix A.1 of DMM's *2009 Annual Report on Market Issues & Performance,* April 2010, which can be found at http://www.caiso.com/2777/27778a322d0f0.pdf.

[52] 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 at: http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF.

### Hypothetical combined cycle unit

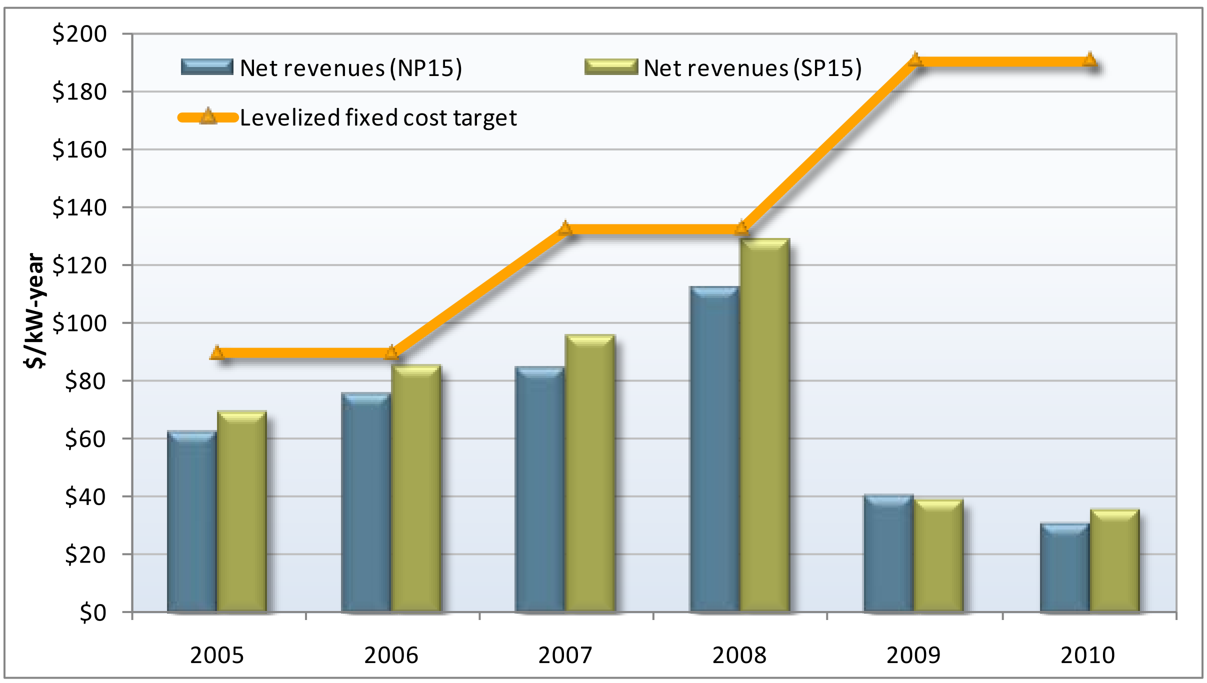
Results for a typical new combined cycle unit are shown in Table 2.8 and Figure 2.15. The increase in new generation costs in 2009 are primarily attributable to increases in capital and financing costs and taxes, according to the California Energy Commission report used in this analysis.

The 2010 net revenue results show a slight decrease in net revenues compared to 2009. The 2010 net revenue estimates for a hypothetical combined cycle unit in NP15 and SP15 both fall substantially below the $191/kW-yr estimate of annualized fixed costs provided in the CEC report.

**Table 2.8 Financial Analysis of new combined cycle unit (2006–2010)**

| Components | 2006 | | 2007 | | 2008 | | 2009 | | 2010 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | NP15 | SP15 | NP15 | SP15 | NP15 | SP15 | NP15 | SP15 | NP15 | SP15 |
| Capacity Factor | 63% | 75% | 69% | 76% | 74% | 81% | 57% | 57% | 67% | 74% |
| DA Energy Revenue ($/kW - yr) | $319.65 | $355.32 | $369.59 | $389.41 | $489.17 | $505.42 | $172.67 | $169.61 | $137.95 | $142.65 |
| RT Energy Revenue ($/kW - yr) | $34.37 | $50.02 | $36.20 | $41.98 | $47.41 | $51.98 | $21.27 | $15.50 | $34.89 | $37.31 |
| A/S Revenue ($/kW – yr) | $1.01 | $1.06 | $0.37 | $0.42 | $0.41 | $0.42 | $0.76 | $0.85 | $1.01 | $1.25 |
| Operating Cost ($/kW - yr) | $279.50 | $321.59 | $321.86 | $337.82 | $425.16 | $428.39 | $154.57 | $147.48 | $143.25 | $145.69 |
| Net Revenue ($/kW – yr) | $75.53 | $84.82 | $84.30 | $95.23 | $111.82 | $128.25 | $40.14 | $38.48 | $30.60 | $35.52 |
| *5-yr Average ($/kW – yr)* | *$68.48* | *$76.46* | | | | | | | | |

**Figure 2.15 Estimated net revenue of hypothetical combined cycle unit**



### Hypothetical combustion turbine unit

Key assumptions used in this analysis for a typical new combustion turbine are shown in Table 2.9.[53] Table 2.10 and Figure 2.16 show estimated net revenues that a hypothetical combustion turbine unit would have earned by participating in the real-time energy and non-spinning reserve markets.

These results show 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 estimate of annualized fixed costs in the CEC report.

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[54]**

| **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 |

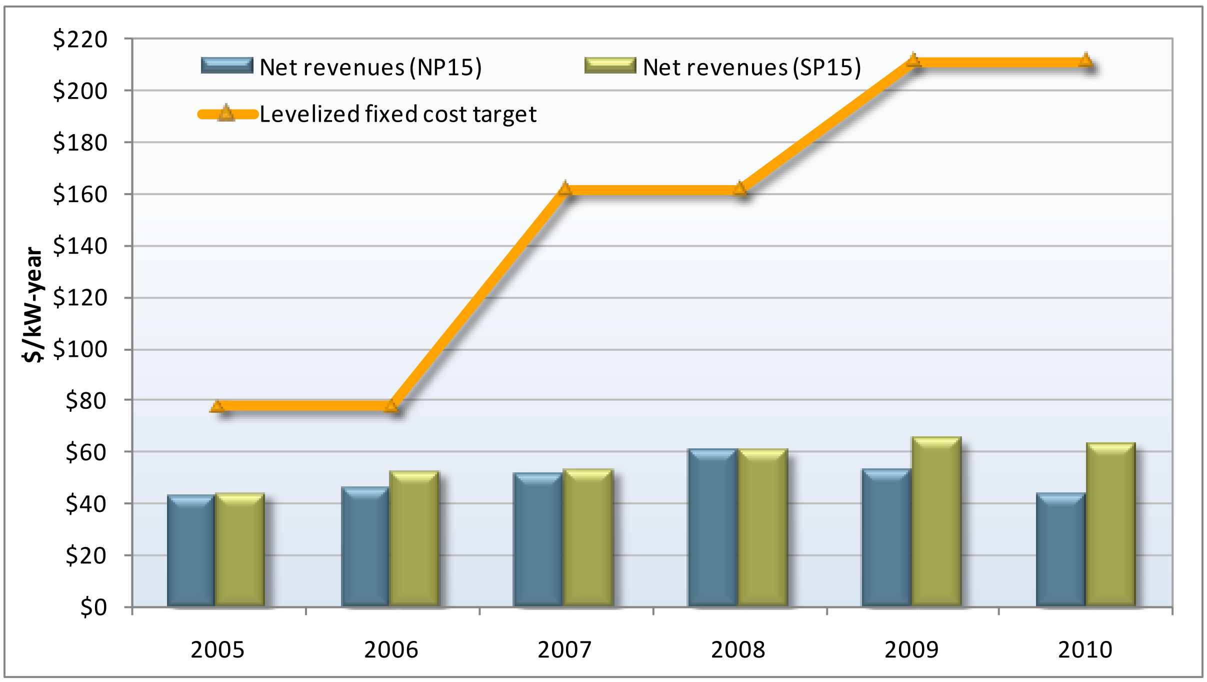
[53] See Footnote 51.

[54] See Footnote 52.

**Table 2.10 Financial analysis of new combustion turbine (2006-2010)**

| Components | 2006 | | 2007 | | 2008 | | 2009 | | 2010 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | NP15 | SP15 | NP15 | SP15 | NP15 | SP15 | NP15 | SP15 | NP15 | SP15 |
| Capacity Factor | 7% | 10% | 8% | 9% | 11% | 12% | 6% | 6% | 7% | 10% |
| Energy Revenue ($/kW - yr) | $69.46 | $99.77 | $97.54 | $104.99 | $155.58 | $158.98 | $70.50 | $84.62 | $64.97 | $95.94 |
| A/S Revenue ($/kW - yr) | $22.67 | $21.68 | $13.30 | $12.83 | $5.50 | $5.53 | $8.64 | $8.37 | $3.36 | $2.97 |
| Operating Cost ($/kW - yr) | $46.04 | $68.92 | $59.18 | $64.63 | $100.12 | $104.09 | $25.85 | $27.70 | $24.80 | $35.60 |
| Net Revenue ($/kW - yr) | $46.10 | $52.35 | $51.66 | $53.19 | $60.96 | $60.43 | $53.29 | $65.29 | $43.54 | $63.32 |
| *5-yr Average ($/kW - yr)* | *$51.11* | *$58.92* | | | | | | | | |

**Figure 2.16 Estimated net revenues of new combustion turbine**



# 3 Overall market performance

In April 2009, the ISO implemented a major redesign of California's wholesale energy markets. In 2010, this nodal market design continued to perform well overall.

- Despite a significant increase in the price of natural gas, total wholesale electric prices rose only about 5 percent. This represents a 7 percent decrease in electricity prices after adjusting for higher natural gas prices.
- About 98 percent of system load was scheduled in the day-ahead energy market, which continued to be highly efficient and competitive. Day-ahead prices continued to be approximately equal to prices we estimate would result under perfectly competitive conditions.
- Price spikes in the 5-minute real-time market increased and drove average real-time prices well above day-ahead and hour-ahead market prices during many months. However, the impact of these prices on total wholesale costs was limited because of the high level of day-ahead scheduling.
- Reliance on out-of-market unit commitments and dispatches to meet constraints not reflected in the market software decreased substantially. This was achieved primarily by improvements in the accuracy of day-ahead and real-time market models to incorporate additional constraints that represent more complex reliability requirements.
- Ancillary service costs dropped slightly to less than 1 percent of total energy costs.
- Bid cost recovery payments were less than 1 percent of total energy costs in 2010, while 2009 figures were revised downward from about 1 percent to less than 1 percent due to changes in the ISO's methodology for calculating these payments.

Several aspects of the market performance have not improved or have shown signs of worsening toward the end of 2010.

- **Real-time price spikes.** The frequency and magnitude of real-time price spikes increased starting in spring 2010. In most cases, these price spikes lasted for only a few 5-minute intervals. These price spikes generally reflect short-term modeling limitations, rather than fundamental underlying supply and demand conditions. The severity of these price spikes increased after the price cap was raised from $500/MWh to $750/MWh in April 2010. This cap was raised to $1,000/MWh on April 1, 2011.
- **Divergence of hour-ahead and real-time prices.** Prices in the hour-ahead scheduling process have been systematically lower than prices in the day-ahead and real-time markets. This has led to significant reductions in net imports in the hour-ahead market. In most cases, the ISO has needed to re-purchase this energy in the real-time market at higher prices. This pattern of selling low in the hour-ahead market and buying high in the real-time market creates substantial revenue imbalances that are allocated to load-serving entities.

DMM has expressed concern that these trends are attributable to systematic differences in the inputs and models used in the different market models and may persist unless specifically addressed through enhanced modeling and operational practices. If systematic price differences continue to occur after implementation of convergence bidding in February 2011, this may create substantial additional revenue imbalances that must be allocated to load-serving entities.

## 3.1 Total wholesale market costs

Total estimated wholesale costs of serving load in 2010 were $8.6 billion or about $40/MWh. This represents an increase of about 5 percent from a cost of $38/MWh in 2009. However, gas prices increased substantially in 2010, with spot market gas prices increasing by about 17 percent.[55] After accounting for higher gas prices, total wholesale energy costs decreased from $38/MWh in 2009 to $35/MWh in 2010, representing a decrease of over 7 percent in gas-normalized prices.

A variety of factors contributed to the decrease in gas-normalized total wholesale costs in 2010. As highlighted in Chapter 2, fundamental demand and supply conditions favorable to lower prices in 2010 included:

- Lower loads, especially during the peak summer hours
- Increased hydro availability
- The addition of over 1,500 MW of new gas-fired generation[56]

Other factors contributing to lower prices discussed in the following sections and chapters of this report include the following:

- High day-ahead scheduling
- Competitive bidding in the day-ahead and real-time energy markets
- Lower congestion

Figure 3.1 shows total estimated wholesale costs per MWh from 2006 to 2010. Wholesale costs are provided in nominal terms, as well as after a simple normalization for changes in average spot market prices for natural gas. The 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 annual summaries of nominal total wholesale costs by category for years 2006 through 2010. Under the new market design, our estimate of total wholesale market costs uses the prices and quantities cleared in each of the three energy markets: day-ahead, hour-ahead and 5-minute real-time. Our estimate also includes costs associated with ancillary services, residual unit commitment, bid-cost recovery, reliability must-run contracts, the interim capacity procurement mechanism, and grid management charges.[57]

Prior to implementation of the new market design in 2009, the ISO did not have a day-ahead energy market. Virtually all supply was provided through self-supply or bilateral trading and supply arrangements. This required DMM to estimate wholesale energy costs on various sources of bilateral market data and estimated costs of self-supply. Thus, as noted in our 2009 annual report, comparisons of costs in 2009 and 2010 under the new market design with previous years should be viewed with caution given the different sources of data used to estimate wholesale costs in prior years.

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[55] In this report, we calculate average annual gas prices by weighting daily spot market prices by the total ISO system loads. This results in a price that is more heavily weighted based on gas prices during summer months when system loads are higher than winter months, during which gas prices are often highest.

[56] Over 1,500 MW of new gas-fired generation and approximately 500 MW of renewable generation were added in 2010, as noted in section 2.2.4 of Chapter 2.

[57] A more detailed description of the methodology used to calculate the wholesale costs is provided in Appendix A of DMM's *2009 Annual Report on Market Issues and Performance*, April 2010, http://www.caiso.com/2777/27778a322d0f0.pdf.

**Figure 3.1 Total annual wholesale costs per MWh of load: 2006-2010**

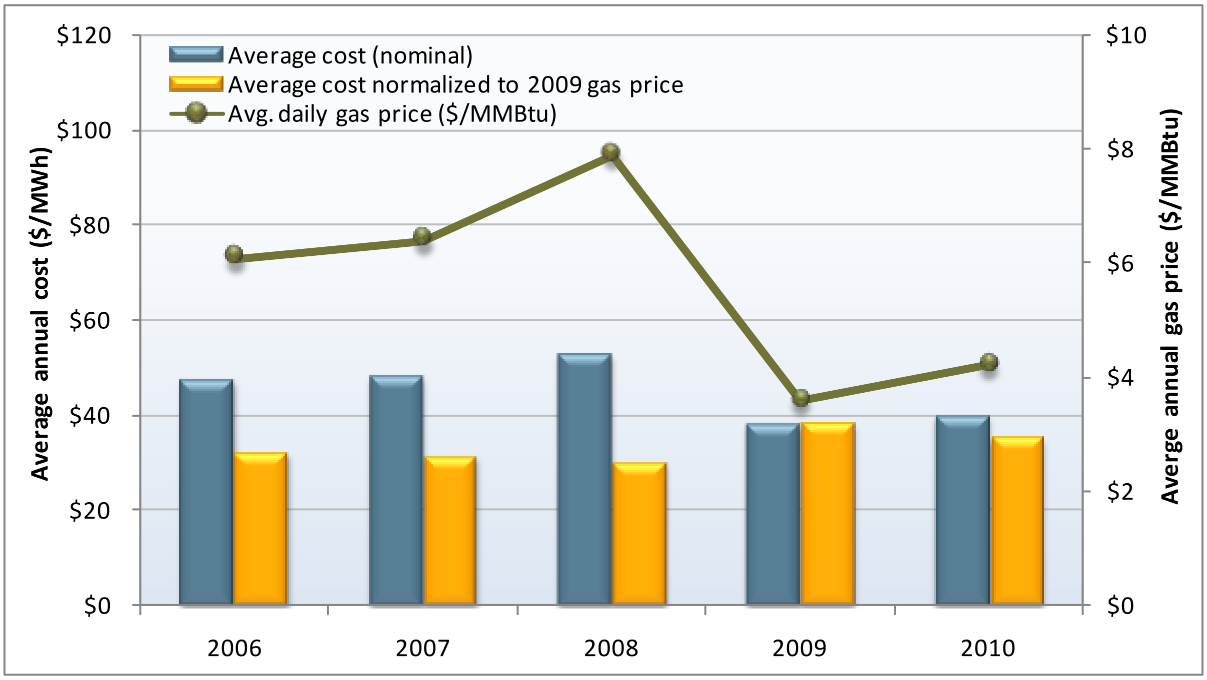



**Table 3.1 Estimated average wholesale energy costs per MWh (2006-2010)**

| | 2006 | 2007 | 2008 | 2009 | 2010 | Change '09-'10 |
|---|---|---|---|---|---|---|
| Day-Ahead Energy Costs (excl. GMC) | $ 43.01 | $ 44.74 | $ 47.48 | $ 35.57 | $ 37.37 | $ 1.80 |
| Real-Time Energy Costs | $ 0.29 | $ 0.25 | $ 0.81 | $ 0.81 | $ 0.73 | $ (0.08) |
| Grid Management Charge | $ 0.72 | $ 0.76 | $ 0.76 | $ 0.78 | $ 0.79 | $ 0.01 |
| Bid Cost Recovery Costs | $ 0.50 | $ 0.23 | $ 0.41 | $ 0.29 | $ 0.37 | $ 0.08 |
| Reliability Costs (RMR and ICPM) | $ 2.07 | $ 1.64 | $ 2.80 | $ 0.25 | $ 0.27 | $ 0.02 |
| **Average Total Energy Costs** | **$ 46.60** | **$ 47.62** | **$ 52.26** | **$ 37.70** | **$ 39.53** | **$ 1.83** |
| | | | | | | |
| Reserve Costs (AS and RUC) | $ 0.97 | $ 0.63 | $ 0.74 | $ 0.39 | $ 0.38 | $ (0.01) |
| **Average Total Costs of Energy and A/S** | **$ 47.57** | **$ 48.25** | **$ 53.00** | **$ 38.08** | **$ 39.91** | **$ 1.83** |

## 3.2 Day-ahead scheduling

The portion of load clearing the day-ahead market has consistently been very high, averaging 98 percent of total forecast demand in 2010. This left a relatively small volume of demand to be met by the residual unit commitment process and real-time market.

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

This trend of very high 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 and imports that are purchased in standard multi-hour blocks (i.e., all 8 off-peak hours or all 16 peak hours).

**Figure 3.2 Day-ahead cleared load versus forecast in 2009 and 2010**

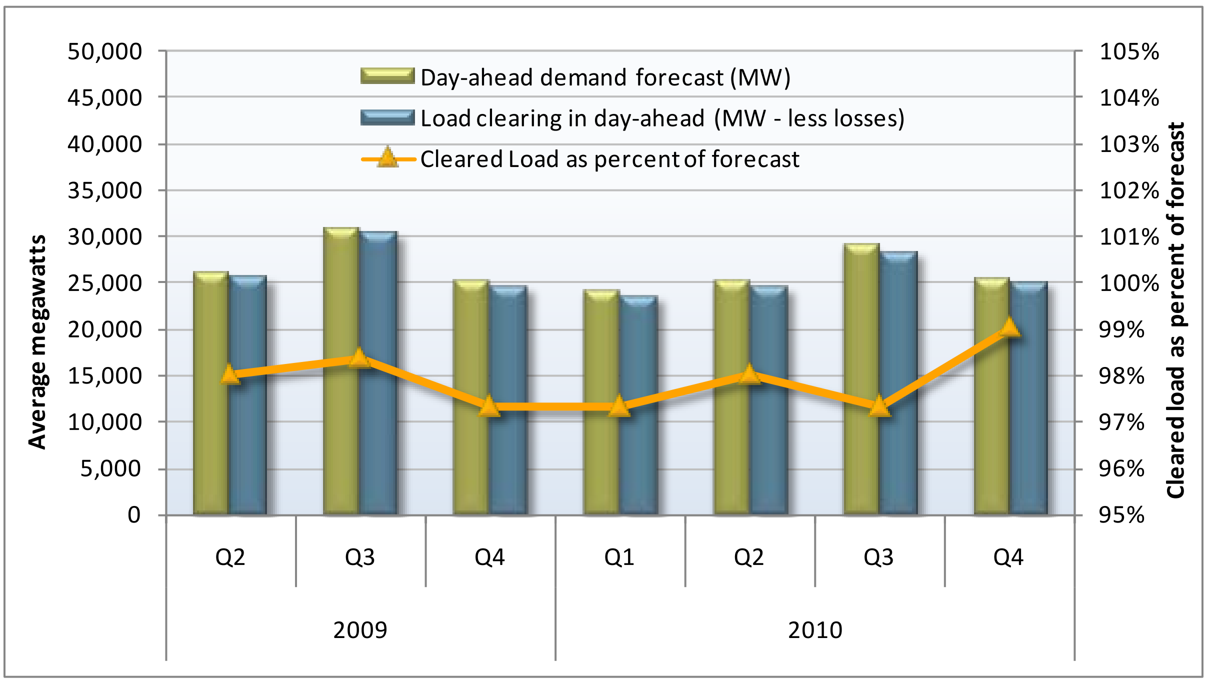
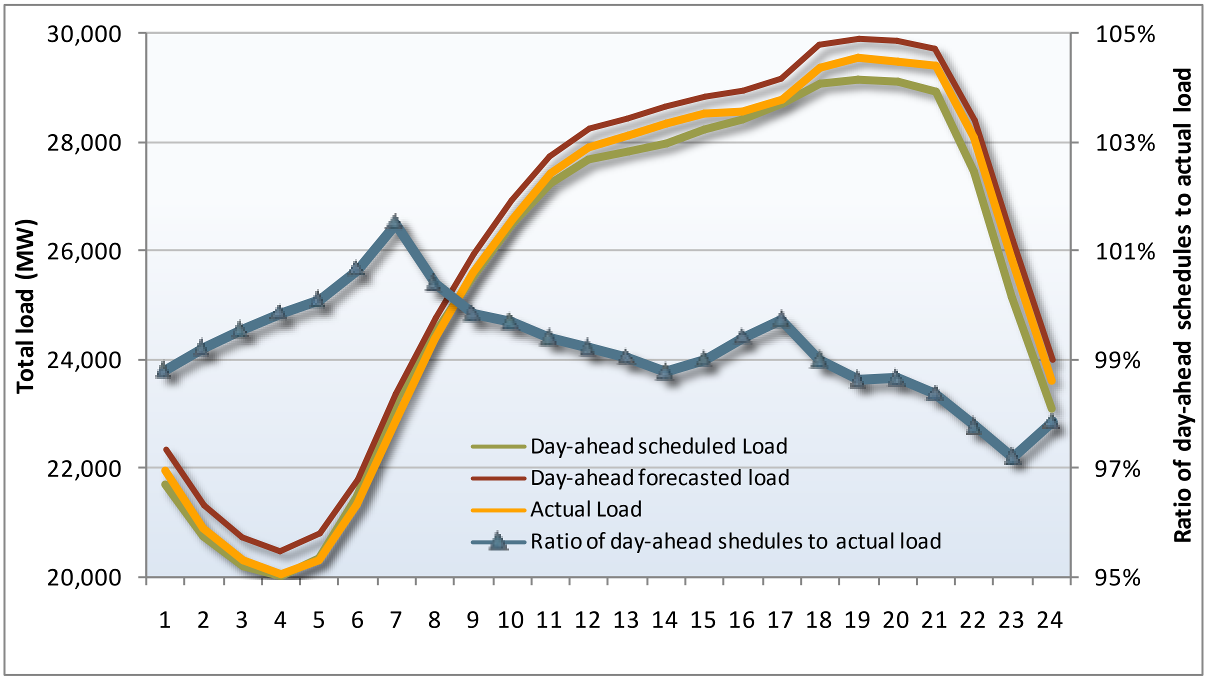


**Figure 3.3 Day-ahead schedules, forecast and actual load 2010**




### Self-scheduling of loads and generation

The high level of scheduling in the day-ahead market is due largely to a very high level of self-scheduling of loads and generation. Figure 3.4 illustrates the portion of load clearing the day-ahead market comprised of self-schedules and price-taking demand bids, as opposed to price-sensitive demand bids.[58] As shown in Figure 3.4, self-scheduled and price-taking demand bids have accounted for an average of 96 to 98 percent of load clearing the day-ahead market.

Figure 3.5 shows the portion of supply clearing the day-ahead market comprised of self-scheduling and price-taking bids.[59] 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 day-ahead market.

Extremely high levels of self-scheduled supply can decrease market efficiency by reducing the degree to which the market software is free to optimize supply resources based on their bid costs. These levels also hinder the ability to manage congestion in the most cost-effective manner. As shown in Figure 3.5, the total amount of self-scheduled and price-taking generation and supply remained relatively constant.

[58] For purposes of this analysis, we have classified load bids within $5/MWh of the maximum bid cap because these bids are virtually certain to clear the day-ahead market. The energy bid cap was $500/MWh April 1, 2009 to March 31, 2010 and $750/MWh after April 1, 2010.

[59] For purposes of this analysis, we have classified supply bids between the energy bid floor and $0/MWh as price taking supply because these bids are virtually certain to clear the day-ahead market. The energy bid floor is -$30/MWh for 2009 and 2010.

**Figure 3.4 Quarterly average self-scheduled versus cleared load in day-ahead market**

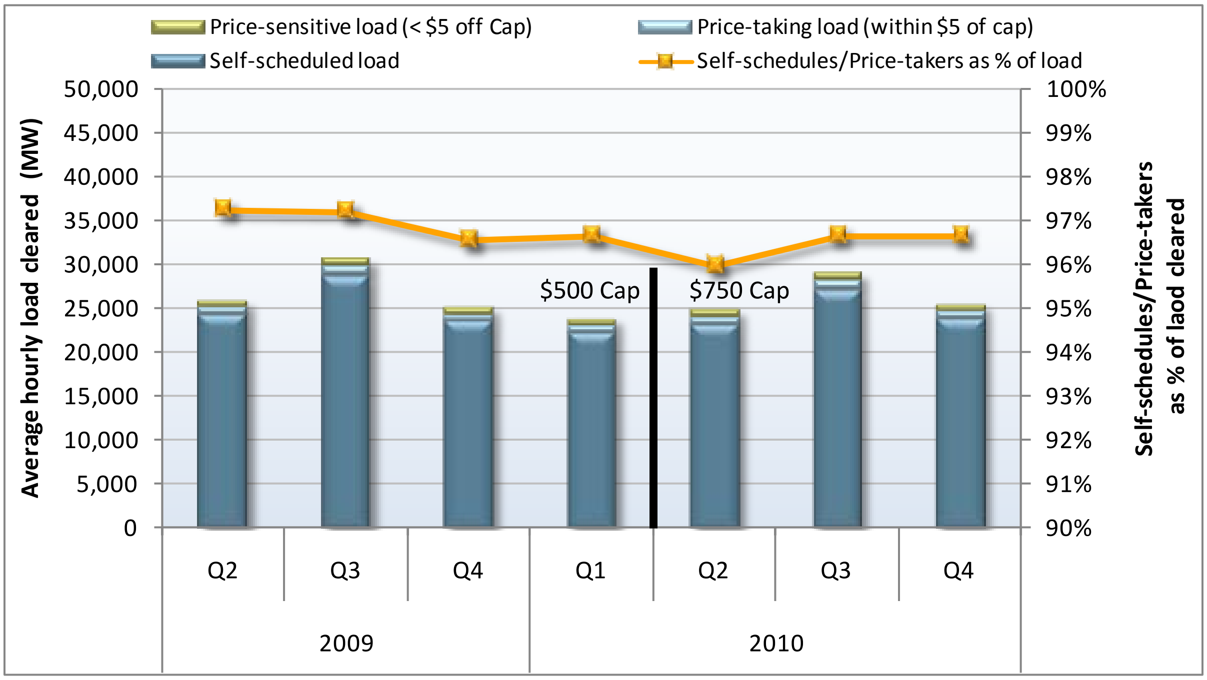
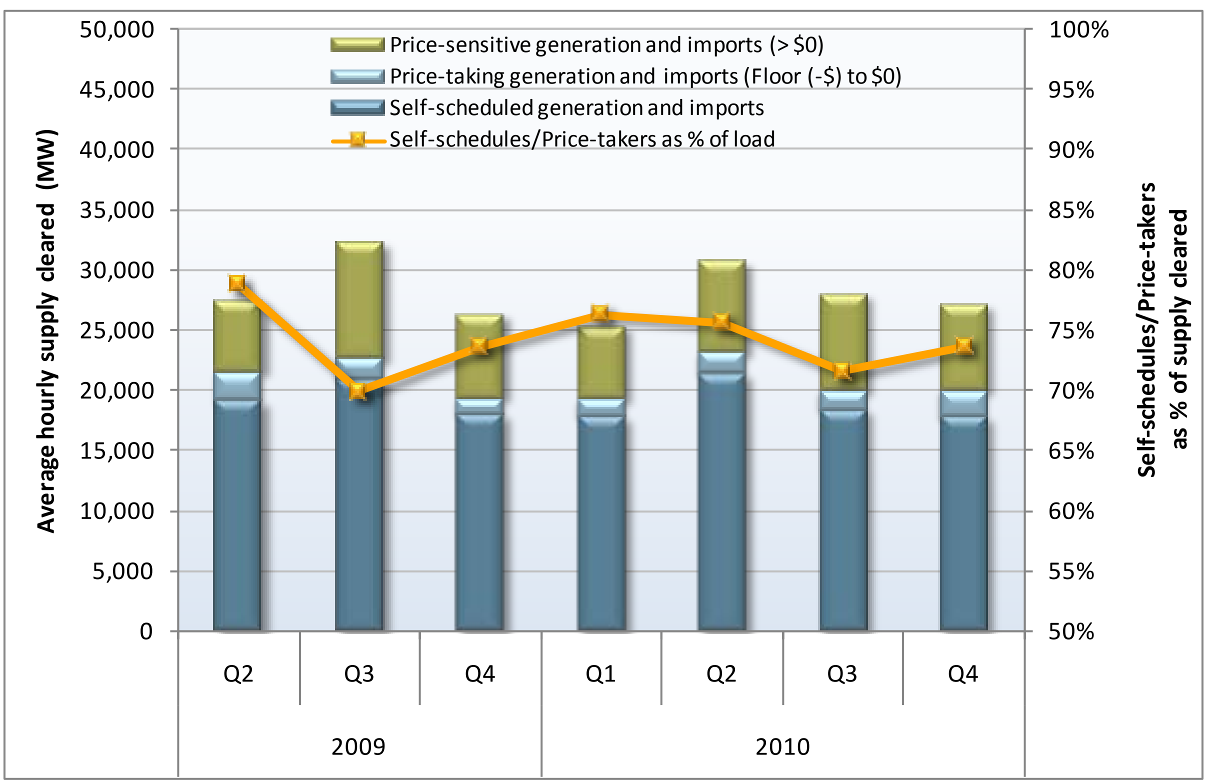



**Figure 3.5 Quarterly average self-scheduled versus cleared supply in day-ahead market**



### Hour-ahead scheduling process

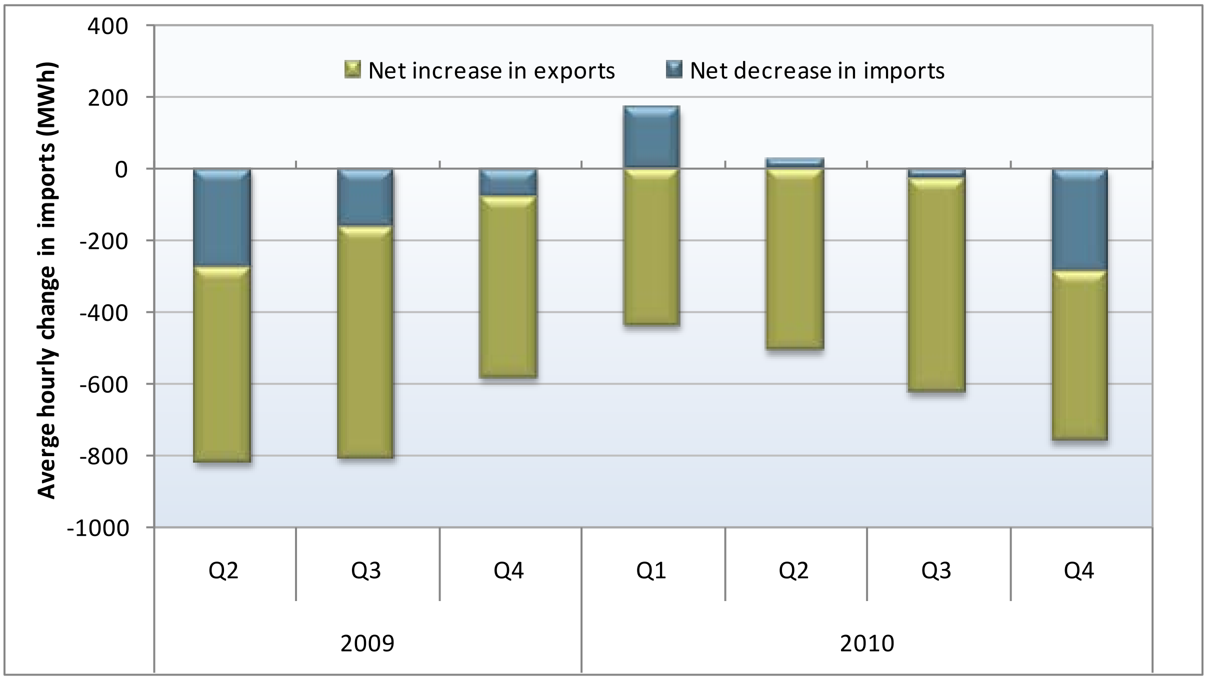
The hour-ahead scheduling process allows day-ahead inter-tie schedules to be modified through a re-optimization of the entire market. Market participants with accepted day-ahead imports or export bids can either self-schedule their energy in the hour-ahead scheduling market, or re-bid their day-ahead transactions at the same or different prices. If an import scheduled in the day-ahead market does not clear in the hour-ahead market, the market participant buys back the import at the hour-ahead price. Exports scheduled in the day-ahead market that do not clear in the hour-ahead market are sold back at the hour-ahead price.

In 2009 and 2010, net import schedules clearing the hour-ahead market were systematically lower than net import schedules clearing the day-ahead market. Figure 3.6 shows that during each quarter since the start of the new market design, net imports clearing the hour-ahead market averaged 250 to 800 MW less than net day-ahead import schedules. This drop in net imports was mainly a result of increased exports in the hour-ahead market, but also because of decreased imports in some quarters. In 2010, import schedules clearing in the hour-ahead decreased approximately 30 MW from day-ahead import schedules, while exports increased by an average of 500 MW in the hour-ahead market.

The main cause of decreased net imports in the hour-ahead market is that prices in this market have tended to be systematically lower than prices in the day-ahead and 5-minute real-time market. These lower prices are discussed in further detail in Section 3.3. Regional load-serving entities and marketers have taken advantage of these low hour-ahead prices by exporting power to other control areas and decreasing imports into the ISO system.

As noted in Section 3.3.1, when net imports are decreased in the hour-ahead market, the ISO has usually 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 represents one of the most significant sources of potential inefficiency under the new market design.

**Figure 3.6 Change in day-ahead net imports after hour-ahead market**




## 3.3 Energy market prices

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. Figure 3.7 shows average quarterly prices in the three energy markets for the PG&E load aggregation point for all hours.[60] Figure 3.8 highlights the difference in prices in these markets.

Price convergence in these three markets improved substantially from the third quarter of 2009 until the first quarter of 2010. However, price divergence increased significantly in the second quarter of 2010, and prices remained divergent through the rest of the year among the three markets. Price convergence improved early in the third quarter of 2010, but, starting in September and continuing through the fourth quarter, prices again diverged in the three markets. Divergence in this period was concentrated more around the peak load hours than the late evening ramp down hours. The divergence is particularly noticeable in the real-time market.

Much of the divergence in energy market prices has been driven by relatively short but extreme price spikes in the 5-minute real-time market. Figure 3.9 shows the frequency of different levels of prices spikes on a quarterly basis since the nodal market design was implemented in 2009.

[60] The PG&E average prices were often similar to prices at the other load aggregation points. However, there were times when the other points were more congested than the PG&E price, and therefore were less representative of overall system conditions than the PG&E price.

**Figure 3.7 Comparison of monthly prices – PG&E load aggregation point (all hours)**

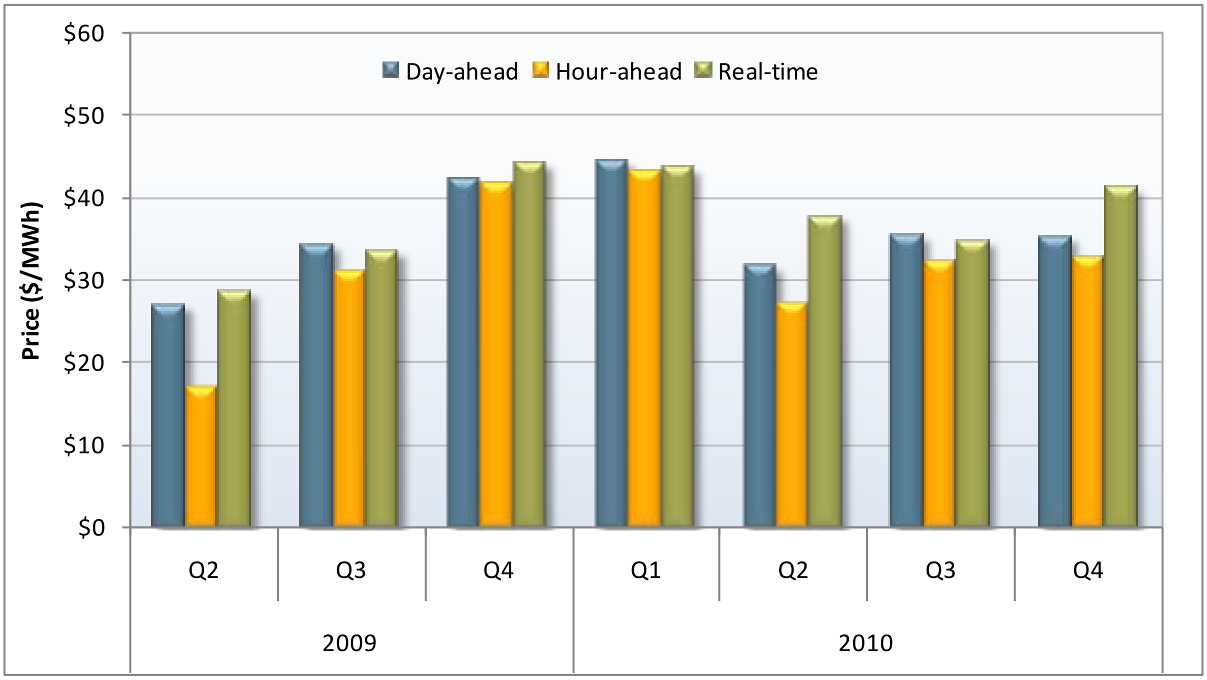



**Figure 3.8 Difference in hour-ahead and real-time prices compared to day-ahead prices PG&E area (all hours)**

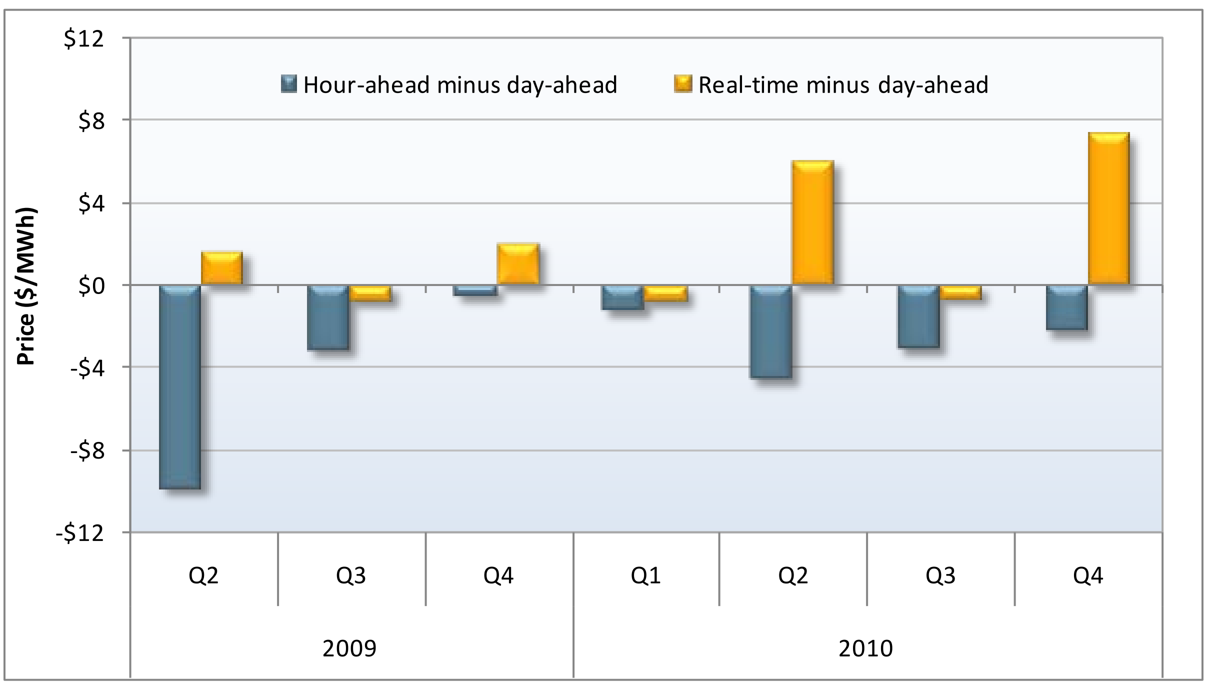
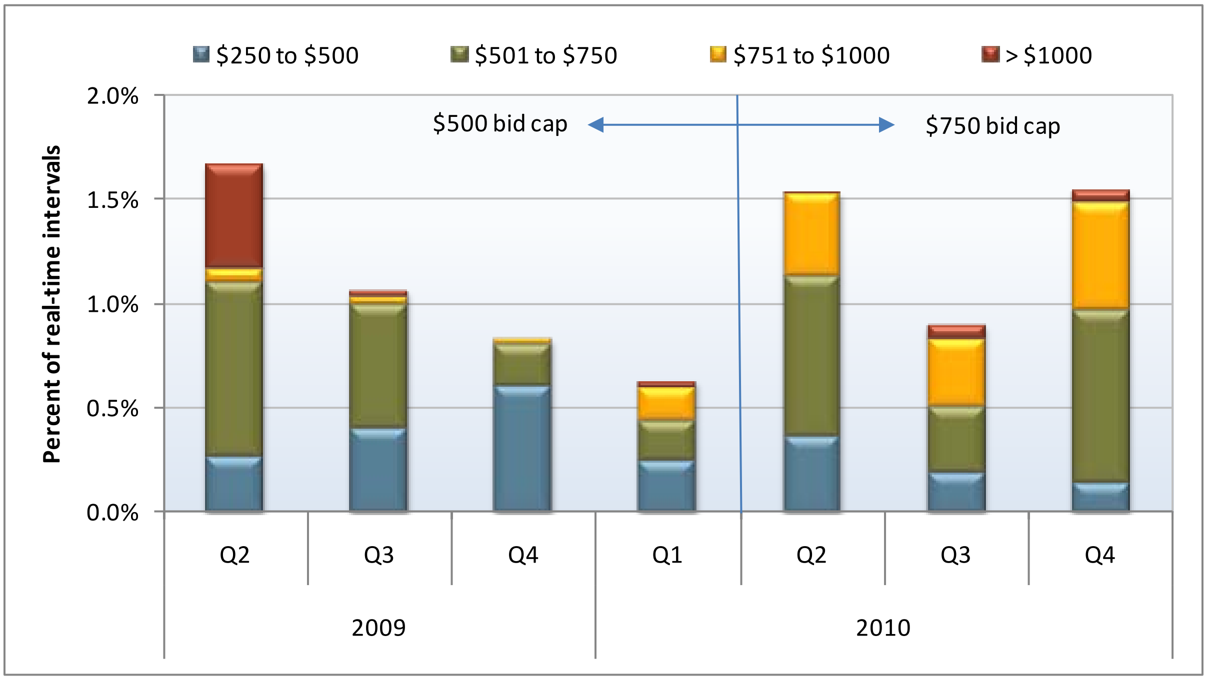


**Figure 3.9 Price spike frequency by quarter**




As shown in Figure 3.9:

- The frequency of price spikes declined steadily over the first year, falling from roughly 1.7 percent of intervals in the second quarter of 2009 to just over 0.6 percent of intervals in the first quarter of 2010. However, the frequency of price spikes increased significantly starting in the second quarter of 2010.
- In addition, the overall level of price spikes also increased. Only a small number of these price spikes have been caused by high priced bids, with most price spikes being caused by the need to relax a transmission or energy constraint in the market model. However, penalty prices used when a market constraint is relaxed are set at or above the bid cap. Thus, raising the bid cap to $750/MWh from $500/MWh on April 1, 2010, has indirectly increased the level of price spikes in the real-time market. This is reflected in the yellow bar in Figure 3.9, which shows how prices between $751 and $1,000/MWh have increased and account for a larger share of price spikes.

A more detailed analysis and explanation of the causes of price spikes in the real-time market is provided in Chapter 8.

Figure 3.10 shows the top five percent of 5-minute real-time prices by year plotted as a price duration curve. While the overall frequency of positive price spikes is comparable between 2009 and 2010, the price levels have two distinct shapes. The 2010 price curve has more prices around $750/MWh, whereas the 2009 curve has more prices around the $500/MWh level. As discussed earlier, this pattern is related to the change in the bid cap from $500/MWh to $750/MWh.

**Figure 3.10 High real-time prices by year: Top 5th percentile of prices**

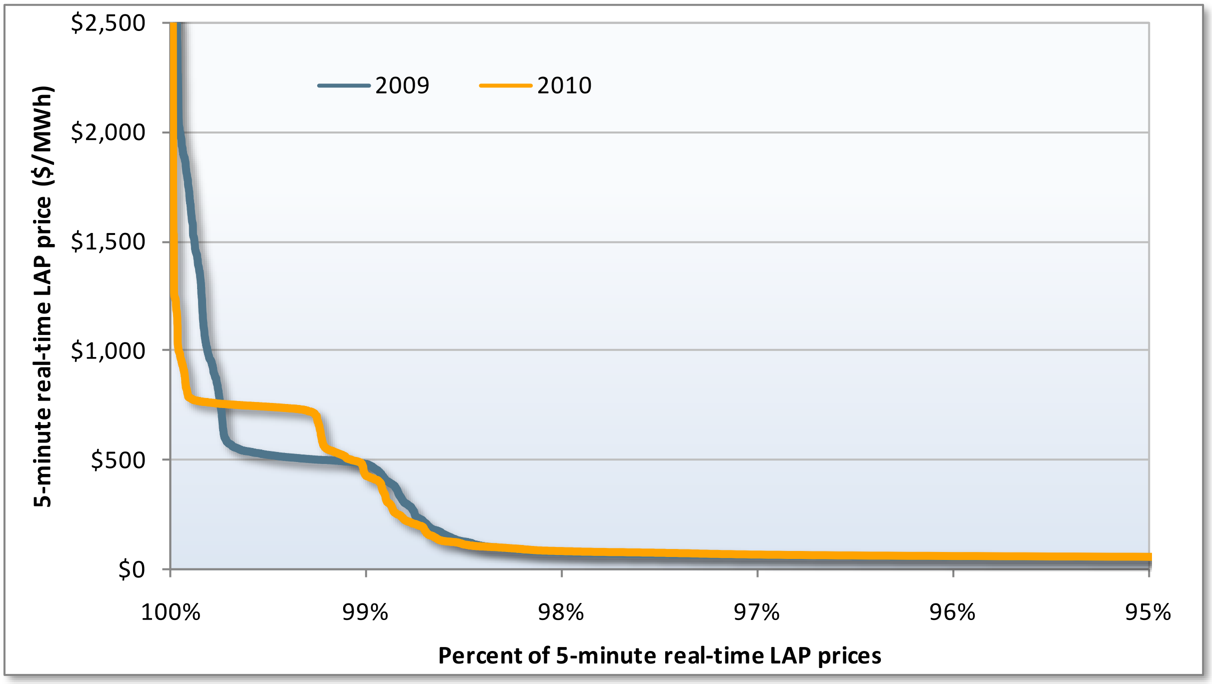



**Figure 3.11 Low real-time prices by year: Bottom 5th percentile of prices**

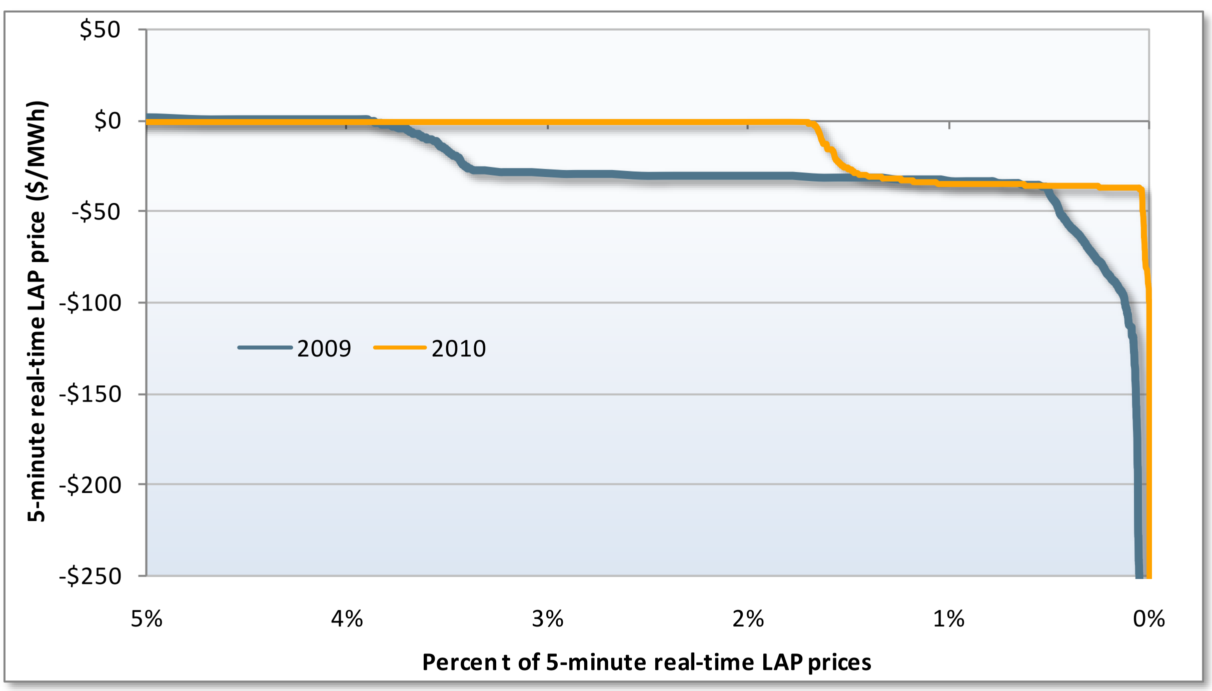


Figure 3.11 shows the lowest five percent of 5-minute real-time prices by year plotted as a price duration curve. As seen in the graph, there were fewer negative price spikes in 2010 compared to 2009. Moreover, the frequency of extreme negative price occurrences also fell in 2010. There were only 10 real-time price intervals for one of the load aggregation points between -$100/MWh and -$386/MWh. In 2009 there were almost 300 intervals with prices in one of these areas between -$100/MWh and -$2,500/MWh.

### 3.3.1 Costs associated with price divergence

Divergence in prices can pose additional inefficiencies and costs on the system. When net imports decrease in the hour-ahead market, but real-time imbalance energy increases, the decrease in net imports may be inefficient.[61] Such reductions are inefficient if hour-ahead prices are systematically lower than real-time prices, so that the ISO is selling energy in the hour-ahead at a low price and then dispatching additional energy in real-time at a higher price. This can also create substantial uplifts that must be recovered from load-serving entities through the real-time imbalance energy offset charge.[62]

The green bars in Figure 3.12 show DMM's estimate of the average hourly decrease in hour-ahead net imports that were subsequently re-procured by the 5-minute real-time market by month. The lower red line shows the weighted average prices at which this decrease in net imports was settled in the hour-ahead market. The blue line is the weighted average prices for additional energy procured in the 5-minute real-time market during each month.[63]

Together, the hourly decrease in hour-ahead net imports and the difference in hour-ahead and real-time prices produce the estimated imbalance energy costs. The total costs are ultimately determined by the quantity that is reduced in the hour-ahead process and then re-procured in real-time, combined with the difference in prices in these two markets.

As shown in Figure 3.12, the estimated quantities of reduced imports resulting in higher real-time energy purchases declined from the beginning of the new market in the second quarter of 2009 through the first quarter of 2010, and increased through the remainder of 2010.[64] Average weighted price differences between the hour-ahead and real-time markets were largest in the second quarters of 2009 and 2010.

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[61] The inter-tie prices are relative to prices in neighboring systems. If prices outside of the ISO system are higher, it makes economic sense for net imports to decrease in the hour-ahead market. This can be accomplished by either reducing imports or increasing exports.

[62] More information about the real-time imbalance energy offset charge can be found on the ISO website at http://www.caiso.com/2406/2406e2a640420.html.

[63] DMM estimates the hourly decrease in hour-ahead net imports that were subsequently re-procured by the real-time dispatch by month based on the difference between the decrease in net imports each hour with the amount of energy dispatched in the 5-minute market during that hour. For instance, if the net imports were decreased by 500 MW in the hour-ahead, and 700 MW of net incremental energy was dispatched in the 5-minute market that hour, the entire 500 MW decrease of net imports in hour-ahead was re-procured in the 5-minute market. If net imports were decreased by 500 MW in the hour-ahead, but only 200 MW of net incremental energy was dispatched in the 5-minute market that hour, then only 200 MW of the decrease of net imports in hour-ahead was counted as being re-procured in the 5-minute market.

[64] Some DMM metrics were affected by undocumented changes made to data table structures when the multi-stage generator project was launched in early December. The results for December have been estimated for these metrics until they can be correctly calculated.

**Figure 3.12 Net import reductions in hour-ahead scheduling process creating an increase in real-time energy dispatched**

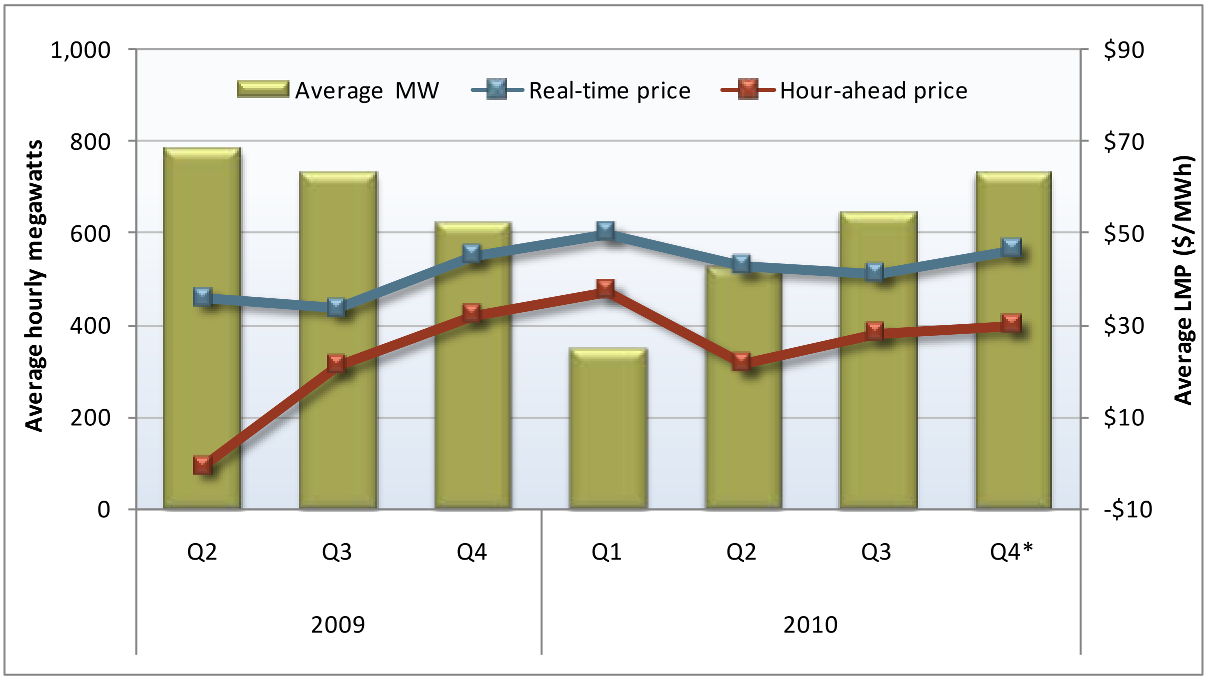


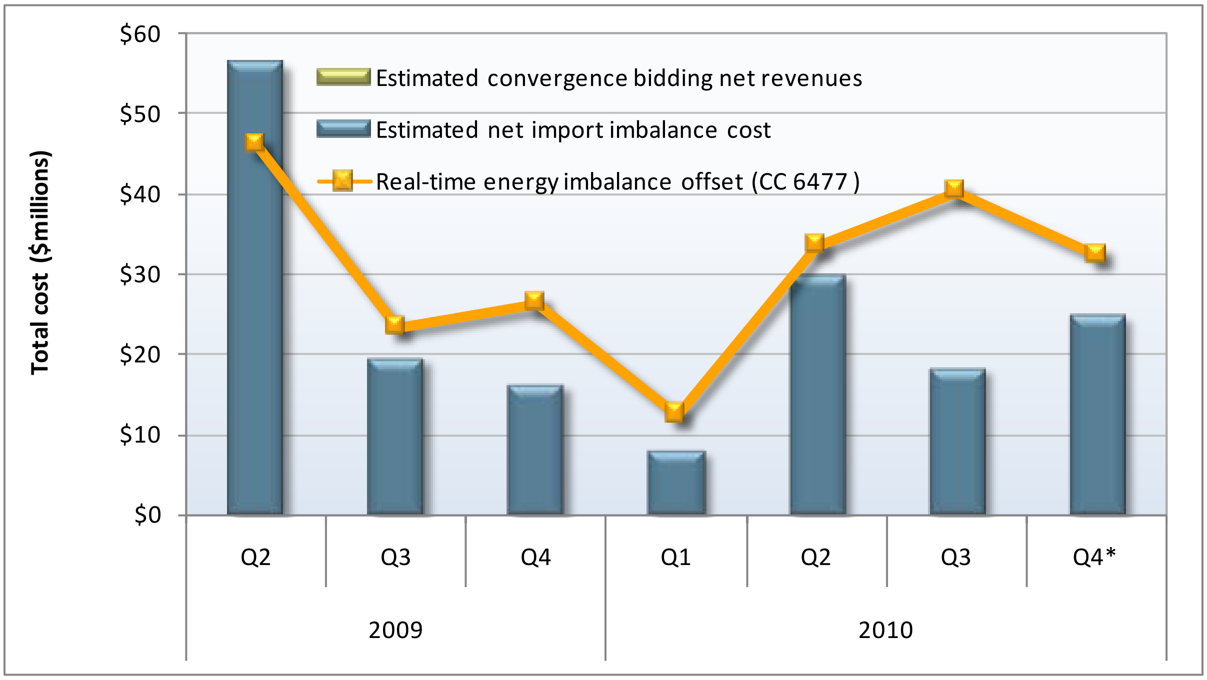

Figure 3.13 shows the estimated costs of additional imbalance energy because of decreasing net imports in the hour-ahead and increasing procurement of imbalance energy in real-time at higher prices.[65] This estimated cost remains the single largest component of the real-time energy imbalance charge. The largest values were at the very start of the new market and again in the second quarter of 2010.

The real-time energy imbalance charge totaled over $118 million in 2010, up from roughly $95 million for the three quarters of 2009.[66] These charges represent uplifts roughly 75 percent higher than the bid cost recovery payments outlined in Section 3.7.

[65] DMM estimates these costs based on (1) the decrease in hour-ahead net imports that were subsequently re-procured in real-time, and (2) the difference in hour-ahead versus real-time prices during the corresponding hour. This estimate is only one element of the real-time imbalance energy offset charge and, therefore, will differ from the total value of the charge for various reasons. Further detail on the different elements contained within the charge can be found in the following report: http://www.caiso.com/2416/2416e7a84a9b0.pdf.

[66] The real-time energy imbalance offset charge was greater than $750,000 on 33 days in 2010. The charges on these days accounted for over 40 percent of the total real-time energy offset charges for the year.

**Figure 3.13 Estimated imbalance costs from decreased net hour-ahead imports**[67]




## 3.4 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 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. These constraints reflect reliability requirements that would otherwise need to be met by exceptional dispatches.

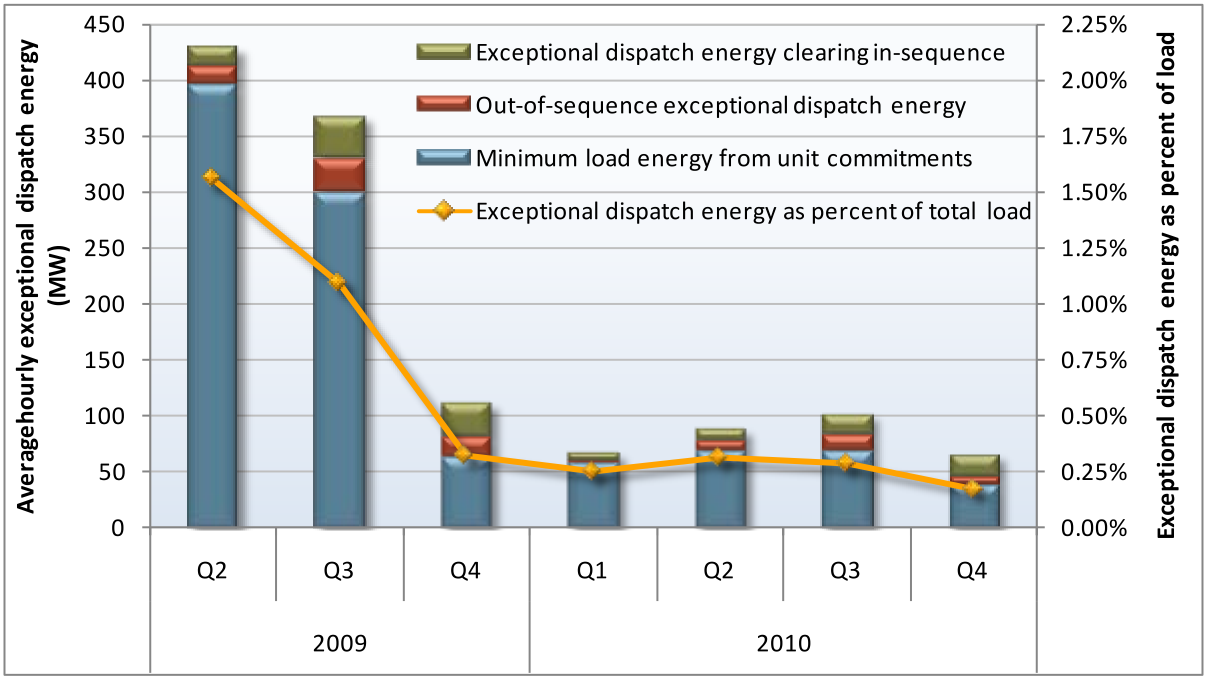
Exceptional dispatches can be grouped into three distinct categories:

- ***Unit commitments*** — Exceptional dispatches for unit commitments instruct generators to operate at their minimum levels of output. Minimum load energy from unit commitments accounts for the bulk of exceptional dispatch energy.
- ***In-sequence real-time energy*** — Exceptional dispatches are also issued to establish a minimum power 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.
- ***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.

[67] See footnote 64 for explanation of December results.

As shown in Figure 3.14, total energy from all exceptional dispatches was significantly lower in 2010 than 2009.[68] Total energy from all exceptional dispatches dropped from 0.9 percent of system load in 2009 to 0.3 percent in 2010.

**Figure 3.14 Average energy from exceptional dispatches**




### Exceptional dispatches for unit commitment

Figure 3.15 and Figure 3.16 provide a summary of the amount of minimum load energy from units committed by exceptional dispatches for various reasons. Measures taken to reduce exceptional dispatches are described in multiple ISO whitepapers.[69] Much of the drop in minimum load energy from exceptional dispatches depicted in Figure 3.15 can be attributed to minimum online constraints that have been incorporated in the day-ahead energy market model.[70] A more detailed discussion of these minimum online constraints and the impact these have had on unit commitments is assessed in Section 3.5.

[68] All exceptional dispatch numbers and figures in this report exclude April 2009 data due to issues with the availability and reliability of that data.

[69] The December 2, 2009 *Exceptional Dispatch Whitepaper* is available at http://www.caiso.com/2478/2478ead066f50.pdf. The June 10, 2010 *Exceptional Dispatch Review and Assessment Whitepaper* is available at http://www.caiso.com/27b1/27b1ec8436300.pdf.

[70] See *Technical Bulletin 2010-01-02: Minimum Online Commitment Constraint*, January 11, 2010, http://www.caiso.com/271d/271dedc860760.pdf.

**Figure 3.15 Average minimum load energy from exceptional dispatch unit commitments**

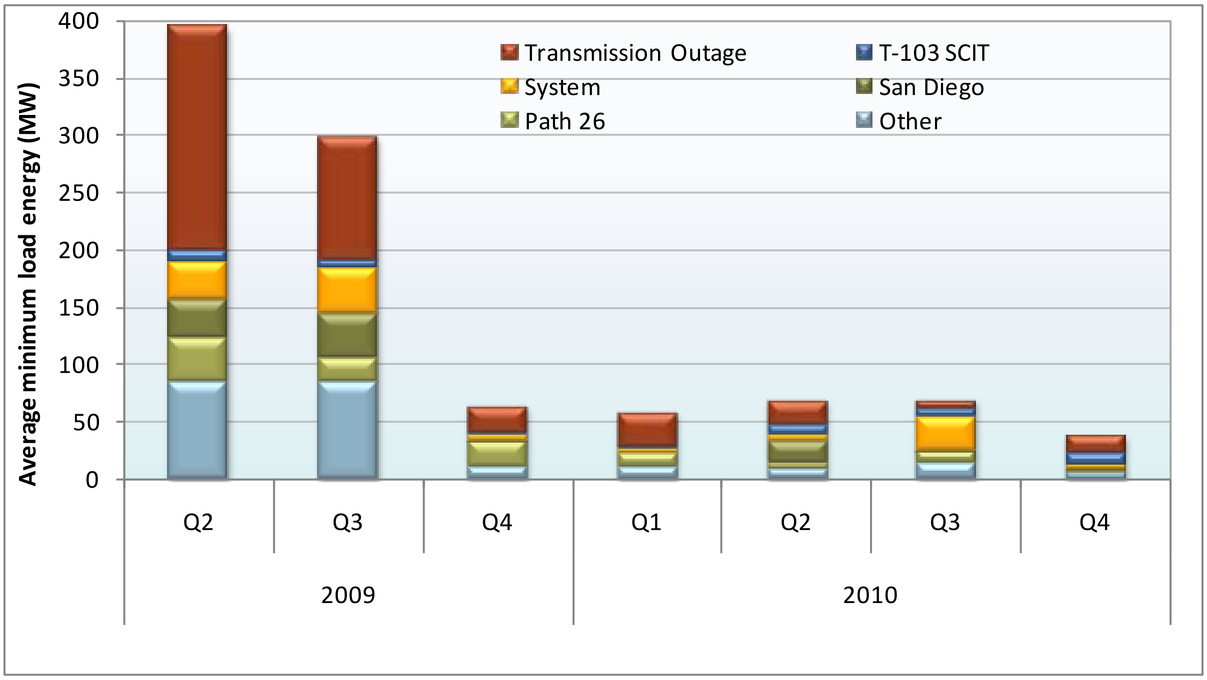
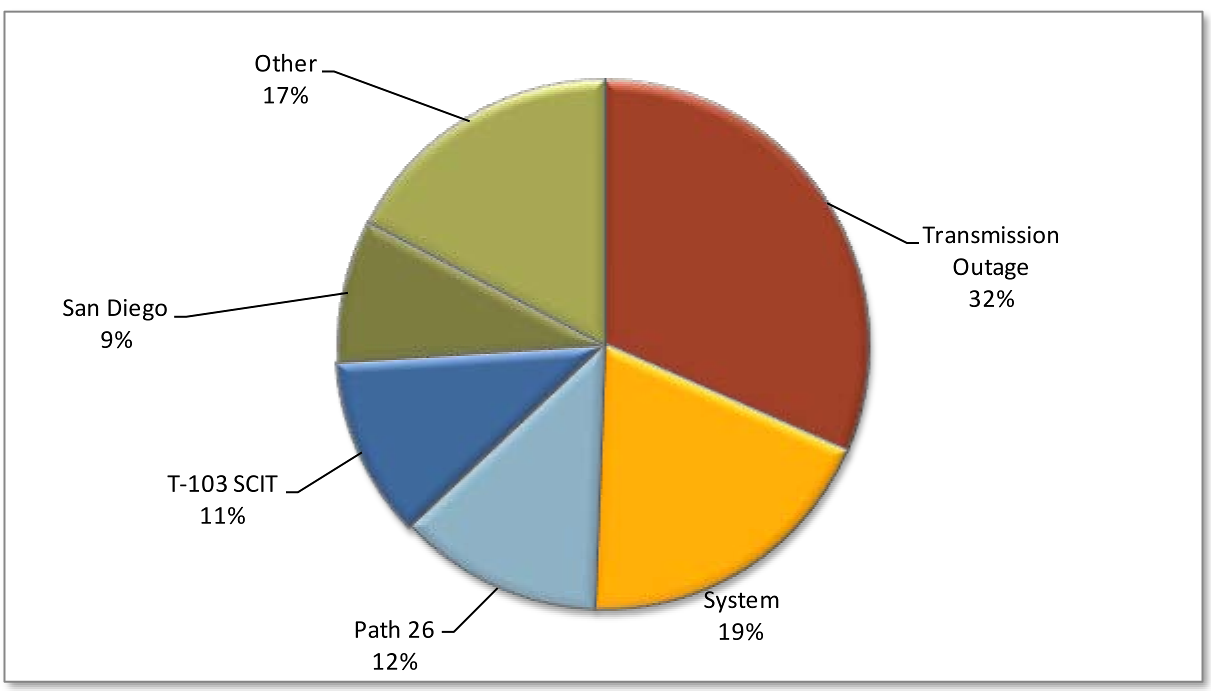



**Figure 3.16 Summary of 2010 minimum load energy from exceptional dispatch unit commitments**



### Exceptional dispatches for energy

Exceptional dispatches for additional real-time energy also dropped dramatically in 2010. Average out-of-sequence energy from exceptional dispatch dropped from 22 MW in 2009 to 8 MW in 2010. The ISO improved its modeling of constraints and market flows, which contributed to the reduction in out-of-sequence energy for transmission outages, ramp rate and system capacity.

Figure 3.17 and Figure 3.18 summarize the amount of out-of-sequence energy from exceptional dispatches for various reasons.

- About half of the out-of-sequence energy stems from exceptional dispatches to move units to output levels where the units have optimal ramping capabilities.
- Isolated incidents accounted for most of the other categories of out-of-sequence energy from exceptional dispatches in Figure 3.17 and Figure 3.18.

### Continuing need for exceptional dispatches

The ISO successfully reduced exceptional dispatch energy through the incorporation of new constraints into the model and the implementation of market enhancements. However, several challenges remain.

- Operators continue to issue commitment exceptional dispatches for system capacity and reliability. They issue the bulk of these dispatches when the system load approaches its annual peaks in the second and third quarters. These exceptional dispatches protect the system from voltage collapse should worst-case contingencies occur. They also protect crucial interties from potential thermal overload in the event of worst-case contingencies. Operators issue most system capacity exceptional dispatches after they see the results of the day-ahead market. They can then assess the location and quantity of additional capacity required to support system reliability.
- Despite improvements, the ISO software does not accurately model flows over the inter-ties nor does the optimization model generation contingencies or uncertainty in load.[71] The optimization also cannot commit units for voltage stability. The ISO has successfully defined capacity constraints translating these reliability requirements into minimum quantities of required online capacity in local areas. However, complications remain in mathematically defining the location and quantity of online capacity required for protecting the broader system from worst-case contingencies during peak conditions.
- Furthermore, the model cannot account for unit commitment requirements for maintaining system inertia.[72] The Southern California import transmission nomogram defines the maximum allowed flows on key transmission corridors as a function of inertia in the south. Difficulties remain in incorporating forecasts for required inertia into the model. Therefore, protecting this nomogram from violation continues to require the commitment of units via exceptional dispatch.

[71] For a more detailed description of these issues, please see section 3.5 of DMM's *Quarterly Report on Market Issues and Performance*, July 30, 2009, at http://www.caiso.com/23fb/23fbed164b6bo.pdf.

[72] Inertia is the tendency of a moving object to continue moving. The spinning generators and load in a power system provide the inertia for a power system. The tendency of these spinning components to not change their frequency of rotation supports the power system's frequency during power supply-demand imbalances. The more generators spinning and providing inertia to the power system, the less sensitive system frequency is to power supply-demand imbalances. Therefore, a power system requires an adequate amount of large, spinning generators to protect the system from rapid frequency collapse following contingencies.

**Figure 3.17 Average out-of-sequence energy from exceptional dispatches by reason**

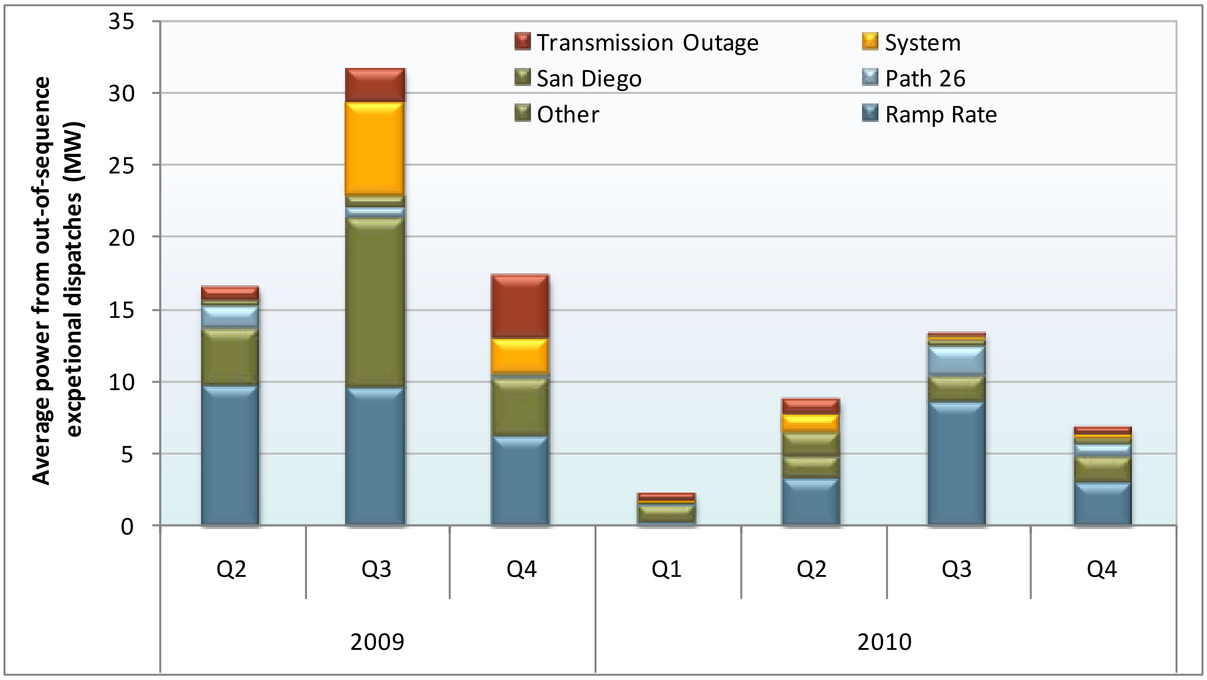
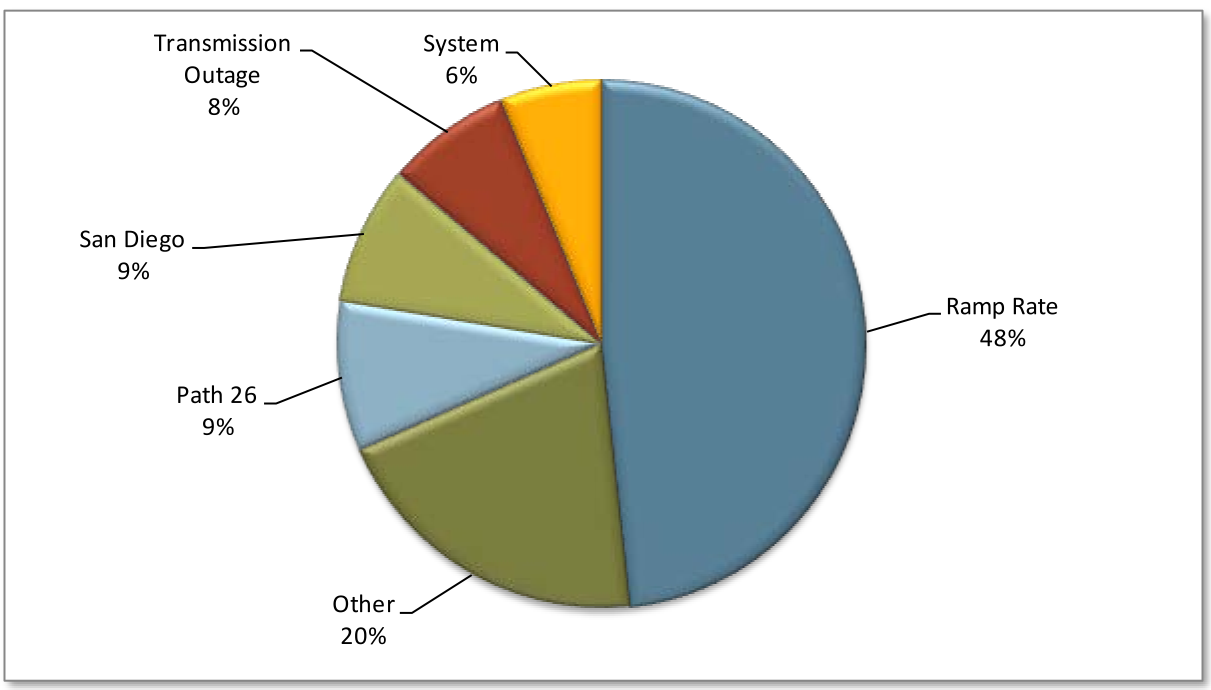



**Figure 3.18 Summary of 2010 out-of-sequence energy from exceptional dispatches by reason**



- Finally, the market does not model the loss of the Pacific DC inter-tie. Therefore, operators have to continue to issue unit commitment exceptional dispatches to ensure adequate online capacity for protecting Path 26 from the loss of this inter-tie.

## 3.5 Minimum online constraints

As noted in the prior section, the ISO has reduced exceptional dispatches significantly by incorporating additional constraints into the market model. Most of the reduction in exceptional dispatch unit commitments has resulted from incorporation of minimum online constraints in the day-ahead energy market model.

These constraints are based on existing operating procedures that require a minimum quantity of online capacity from a specific group of resources in a defined area.[73] If a unit is online, its full available capacity can be used to meet these requirements. Thus, capacity helping to meet this requirement can also be scheduled to provide energy. In some cases, capacity from different units is multiplied by different effectiveness factors that reflect each units' effectiveness at meeting the constraint. The effectiveness of different units can vary based on their location and ability to provide VAR support.

The ISO implemented minimum online constraints for a variety of reliability requirements in 2010:

- The ISO implemented minimum online capacity constraints based on the G-217 and G-219 procedures in the day-ahead market in February 2010. These replaced nomograms for the procedures that were incorporated in the residual unit commitment model in the third quarter of 2009. These constraints have eliminated almost all exceptional dispatches to commit units for LA Basin and South of Lugo stability.

- The ISO implemented a minimum online capacity constraint based on the G-206 procedure in the second quarter of 2010. This eliminated almost all unit commitments for San Diego stability made through exceptional dispatches.

- The ISO also implemented the ability to create special minimum online capacity constraints for other local area reliability requirements and transmission outages in the second quarter of 2010. These constraints significantly decreased commitment exceptional dispatches for planned transmission outages. These constraints will not be able to eliminate all commitment exceptional dispatches for transmission outages because some time is typically required to determine how to model these special constraints given a change in network topology or other system conditions.

Precisely determining whether any additional capacity is committed due to minimum online constraints requires that the market software be re-run with and without these constraints.[74] However, DMM has developed an approach for estimating when specific units may have been committed to meet these constraints based on market results. This approach builds on the fact that units committed specifically to meet minimum online constraints would typically receive some bid cost recovery in the day-ahead market. With this approach, a test is applied to identify hours when a minimum online constraint would

[73] See *Technical Bulletin 2010-01-02: Minimum Online Commitment Constraint*, January 11, 2010, http://www.caiso.com/271d/271dedc860760.pdf.

[74] See discussion in DMM's quarterly report for the first quarter of 2010. The software does not flag specific units committed due to these constraints. Also, since units are committed in large discrete increments of capacity, final market results do not produce shadow prices or even show these constraints as being binding such as when a transmission constraint is congested.

not be met except for units receiving bid cost recovery for the day-ahead market on that operating day.[75]

Monthly results of this analysis are summarized in Figure 3.19. Based on this analysis, we estimate that:

- An average of about 224 MW of capacity was committed due to minimum online constraints from February through December 2010.
- Minimum load energy from this capacity averaged about 54 MW. As previously shown in Figure 3.14, total minimum load energy from units committed using exceptional dispatch also average about 50 MW or about 0.3 percent of total system loads. Thus, total minimum load energy from units committed by both these mechanisms accounts for just over 100 MW or 0.6 percent of total system loads.
- Over 40 percent of capacity above minimum load of units committed to meet these constraints was scheduled for energy in the day-ahead market. This reflects the fact that once a unit is committed at minimum load, a substantial portion of its energy is often economic in the day-ahead market. Minimum online constraints provide a way of determining the most economically efficient mix of units for meeting these constraints taking into account these units' minimum load and energy bid costs.
- Capacity committed to meet these constraints was much higher in August and September due to high system loads. Commitments were also high in December, when capacity from specific units was needed due to transmission and unit outages. During these three months, an average of about 470 MW of capacity was committed due to minimum online constraints

Figure 3.20 summarizes results of this analysis based on the category of minimum online constraint leading to the commitment of additional capacity. As shown in Figure 3.20:

- An average of about 150 MW of capacity was committed due to minimum online constraints based on transmission and generation operating procedures for the SCE area. These include G-217, G-219 and requirements for smaller sub-areas within the SCE area. This accounts for about two-thirds of the total estimated capacity committed due to minimum online constraints.
- An average of just over 40 MW of capacity was committed due to minimum online constraints based on local reliability requirement for the San Diego area. This represents about 20 percent of the total estimated capacity committed due to minimum online constraints.
- An average of about 33 MW of capacity was committed due to minimum online constraints for other local reliability requirements. Many of these occurred in December due to temporary transmission outages. This represents about 15 percent of the total estimated capacity committed due to minimum online constraints.

Based on this analysis, we estimate that units committed to meet minimum online constraint accounted for about $17 million or about 25 percent of bid cost recovery payments in 2010.

[75] This test identifies the largest unit receiving bid cost recovery that is effective at meeting each minimum online constraint (if any), and subtracts this capacity from the total capacity scheduled to be online in the day-ahead market that is effective at meeting the constraint. If the constraint could not have been met without this unit, the constraint is deemed to have been binding that hour and all units effective at meeting the constraint receiving bid cost recovery in the day-ahead market that day are assumed to have been committed to meet the constraint.

**Figure 3.19 Estimated impact of minimum online constraints by month**

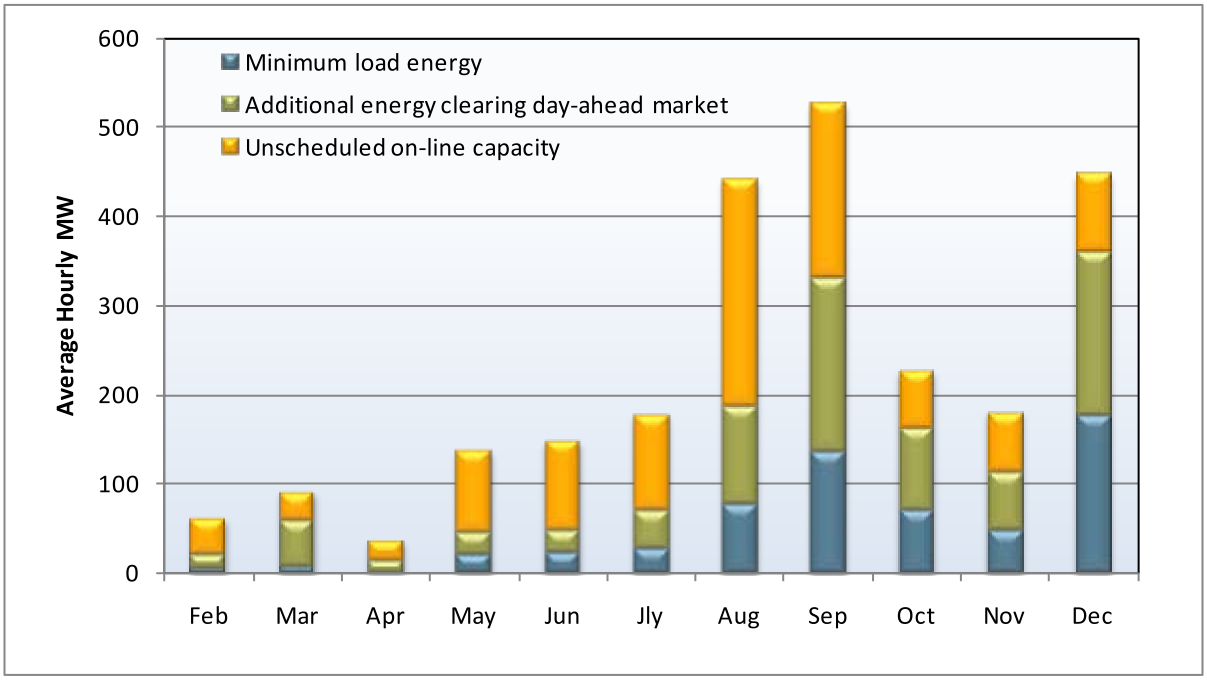
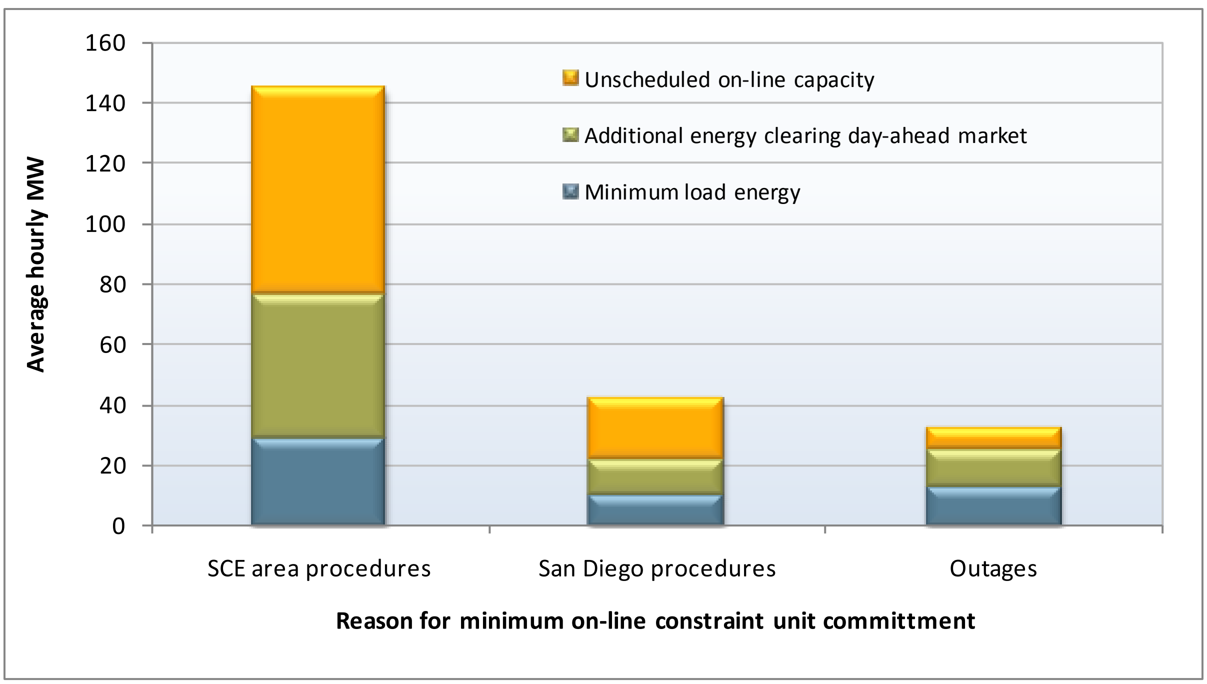



**Figure 3.20 Estimated impact of minimum online constraints by category**



## 3.6 Residual unit commitment

In 2010, the direct cost of procuring capacity through the residual unit commitment market was extremely low, totaling just $83,000. This compares to a cost of $122,000 in 2009. The extremely low costs for procuring residual unit commitment capacity in 2010 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 process.
- Second, most of the capacity procured in the residual unit commitment process is from resource adequacy capacity at a price of $0/MW, as required under the ISO tariff.

In addition to this direct cost, units committed in the residual unit commitment process accounted for $1.4 million in bid cost recovery payments or about 1.7 percent of total bid cost recovery payments in 2010. In just nine months of 2009, residual unit commitments accounted for $8.7 million in bid cost recovery payments or about 13 percent of total bid cost recovery payments.

The much higher bid cost recovery costs in 2009 were incurred after August 2009, when the ISO implemented two minimum online generation constraints in the residual unit commitment process. These capacity constraints enforced requirements for the South of Lugo and LA Basin areas (G-217 and G-219, respectively). In February 2010, the ISO started to implement these constraints in the integrated forward market. As explained in Section 3.5, incorporating these constraints in the day-ahead market allows the market software to determine the most economically efficient mix of units for meeting these constraints taking into account these units' minimum load and energy bid costs.

## 3.7 Bid cost recovery payments

Generating units are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all the unit's accepted bids that day. This calculation includes bids for start-up, minimum load, ancillary services, residual unit commitment availability and day-ahead and real-time energy.

If units that are started up or committed at minimum load are not dispatched for sufficient amounts of additional energy 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.

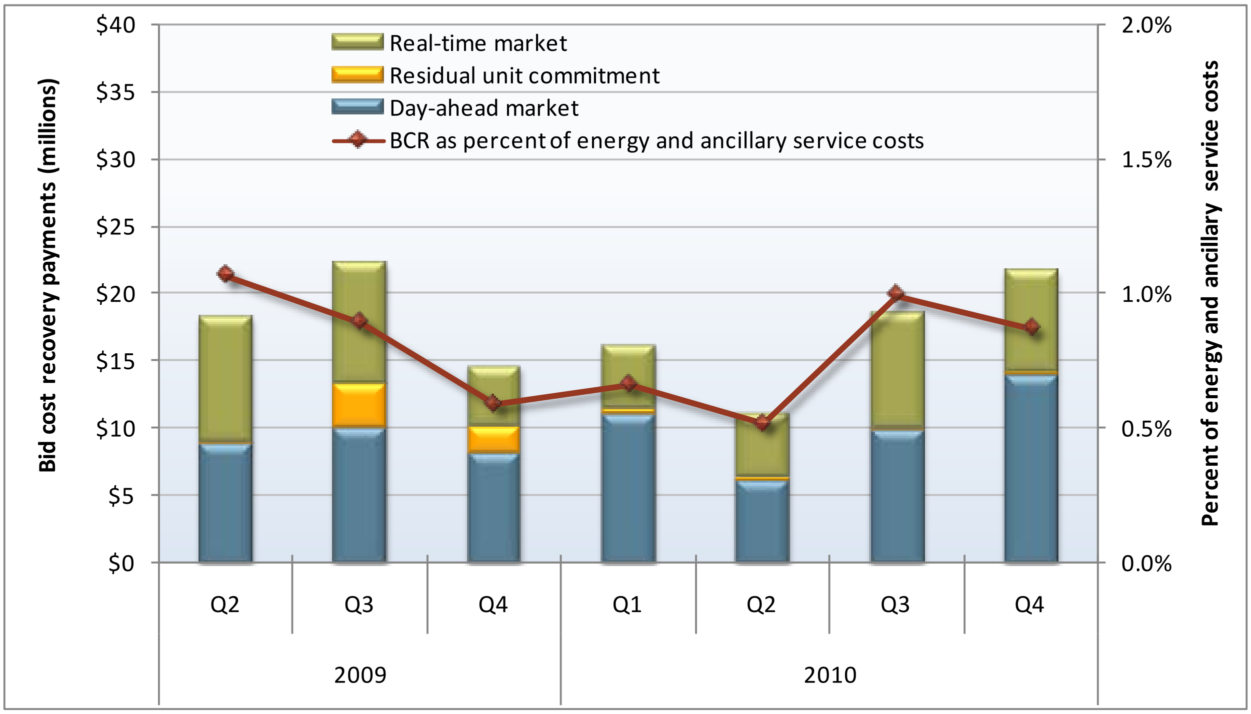
Figure 3.21 provides a summary of total estimated bid cost recovery payments in 2010.[76] In 2010 these payments are projected to total $68 million or about 0.8 percent of total energy costs. In 2009, these costs also averaged about 0.8 percent of total energy costs.[77] This represents a relatively low amount

[76] Estimates provided in this report include estimated adjustments to bid cost recovery data which are still pending in the ISO settlement system.

[77] The 2009 number differs from earlier reported numbers due to revisions to the ISO's bid cost recovery settlement data. The most current bid cost recovery numbers are reflected in this analysis.

for such payments. For example, in other ISO markets, analogous payments have ranged from about 1 percent up to almost 3 percent of total energy costs.[78]

**Figure 3.21 Bid cost recovery payments**




Even though overall bid cost recovery payments remained relatively low in 2010, the quarterly trend in Figure 3.21 shows that these payments increased notably in the fourth quarter of the year. Most of this increase can be attributed to an increase in a specific bidding practice that resulted in over payment of bid cost recovery to resources scheduled in the day-ahead market. In March 2011, the ISO filed with FERC to modify bid cost recovery mechanism to eliminate this over payment.[79] Multi-state generating unit deployment issues added to real-time payments in December.

[78] Based on data from 2008 annual reports for MISO, NYISO, PJM and ISO-NE. In some other markets, analogous payments are referred to as revenue sufficiency guarantees.

[79] California Independent System Operator Corporation, Tariff Revision and Request for Expedited Treatment, March 18, 2011, http://www.caiso.com/2b45/2b45d10069e0.pdf.

# 4 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 market design. Key findings include the following:

- The day-ahead integrated forward market has continued to be stable and competitive with virtually all loads and supply being scheduled in the day-ahead market.
- A key driver of the market competitiveness is the high degree of forward contracting by load-serving entities. This significantly limits the ability and incentive to exercise market power in the day-ahead and real-time markets.
- Bids for additional supply needed to meet remaining demand in the day-ahead and real-time markets have generally been highly competitive. Most additional supply needed to meet demand has 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 quarter 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 the competitive baseline by about 10 percent in 2010. This difference was caused by extremely high price spikes during a small portion of total 5-minute intervals, which is discussed in more detail in Chapter 8. These real-time price spikes are not attributable to uncompetitive bidding or other anti-competitive behavior.
- Despite these higher average real-time prices, the total weighted average prices of energy transactions in all of the markets was approximately equal to the competitive baseline prices. This reflects that most energy is scheduled in the day-ahead market.
- Under current load and supply conditions, the system-wide energy market is structurally competitive. However, since ownership of resources within different areas of the ISO grid is highly concentrated, local reliability requirements and transmission limitations give rise to local market power in many areas of the system.
- The local market power mitigation provisions of the nodal market have continued to be triggered on a very limited basis. During each quarter in 2010, an average of less than one unit per hour was subject to mitigation in the day-ahead market. In the real-time market, bids for an average of about 2.5 units were lowered as a result of mitigation.
- When units are subject to mitigation, they are often not dispatched at a higher level as a result of this mitigation. This occurs since mitigation often results in a minor change in bids and market prices often exceed a unit's unmitigated bid.

- Although the 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. Effective local market power mitigation provisions in the day-ahead and real-time markets encourage forward contracting and deter attempts to exercise market power in all of these markets.

## 4.1 Overall market competitiveness

To assess the overall competitiveness of the energy market, DMM estimates competitive baseline prices as a benchmark for assessing actual market prices. DMM calculates this benchmark by re-simulating the day-ahead market using bids that reflect the actual marginal cost of gas-fired units. A detailed description of the methodology is provided in prior quarterly reports.[80]

Figure 4.1 compares this competitive baseline price to average system-wide prices in the day-ahead and 5-minute real-time markets. As shown in Figure 4.1:

- Prices in the day-ahead market have consistently been slightly lower than these competitive baseline prices since the start of the nodal market design. Competitive baseline prices can be lower than day-ahead prices because some generators bid slightly below their default energy bids used in calculating this competitive baseline. Default energy bids include a 10 percent adder above fuel and variable costs.

- In 2010, average system-wide real-time prices exceeded this competitive baseline by about 12 percent. Real-time prices in the SCE area exceeded this competitive baseline by an even higher level of 17 percent due to congestion.

Most of the difference in real-time prices and this competitive baseline was caused by extremely high price spikes during a small portion of total 5-minute intervals. As discussed in Chapter 3 and Chapter 8, these price spikes generally reflect short-term modeling limitations, rather than fundamental underlying supply and demand conditions. These real-time price spikes are not attributable to uncompetitive bidding or other anti-competitive behavior.

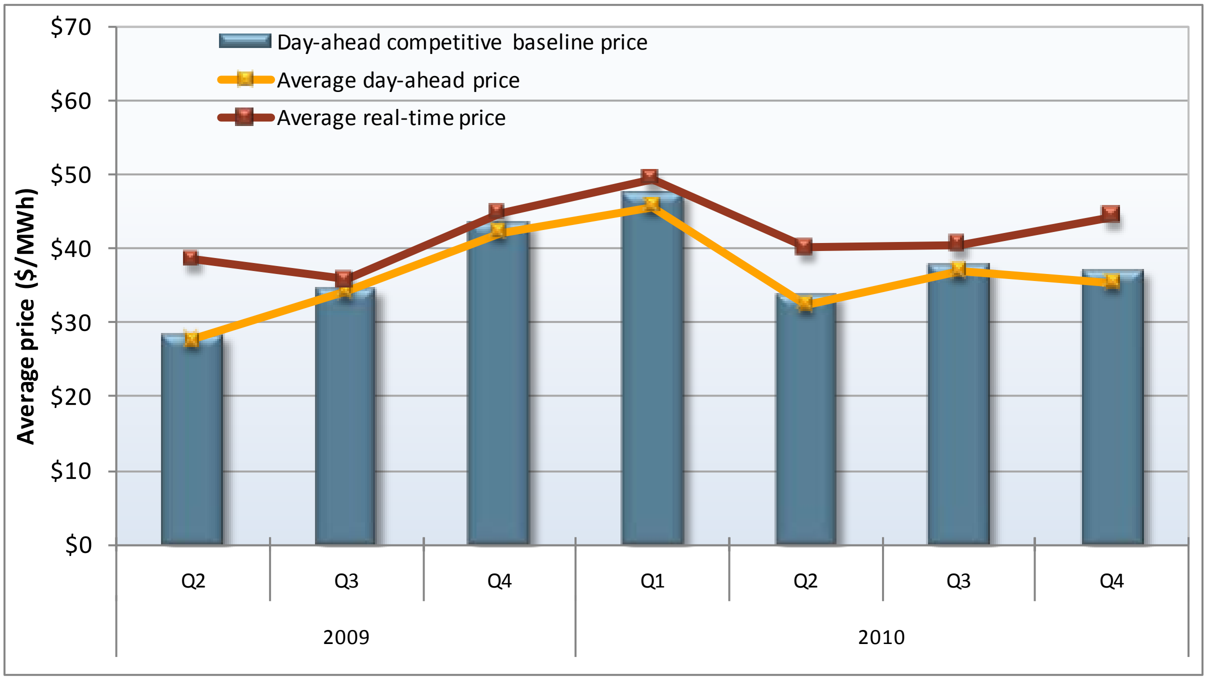
DMM also calculates an overall price-cost markup by comparing competitive baseline prices to total average wholesale energy costs.[81] Total costs used in this analysis represent a weighted average of all energy transactions in the day-ahead, hour-ahead and real-time markets.[82] Thus, this analysis includes energy procured at higher prices in the real-time market, as well as net energy sales in the hour-ahead market at lower prices.

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

[81] DMM calculates the price-cost markup index as the percentage difference between actual market prices and prices resulting under this competitive baseline scenario. 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 this index is no more than a 10 percent mark-up over the competitive baseline on a monthly and annual basis.

[82] These costs are based on the same data and methodology used in the analysis of total wholesale energy costs provided in Chapter 3.

**Figure 4.1 Comparison of competitive baseline with day-ahead and real-time prices**



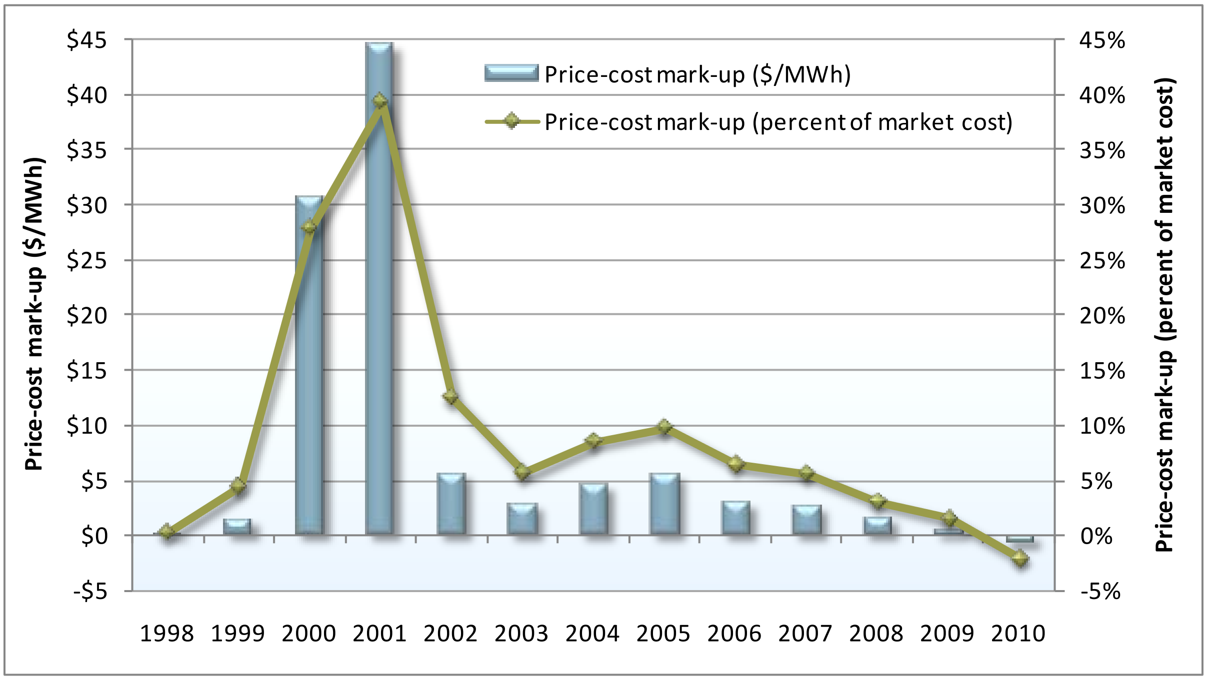

In 2010, the overall price-cost mark-up was slightly negative, or about -2 percent. Thus, even after taking higher real-time prices into account, overall market prices are approximately equal to prices under perfectly competitive conditions. In 2009, DMM estimated the overall price-cost mark-up to be about 1.5 percent. The lower price-cost mark-up in 2010 can be attributed to day-ahead market prices that were somewhat lower in 2010 relative to the competitive baseline prices calculated using the day-ahead market software.

DMM has analyzed the price-cost mark-up for California's wholesale market since the beginning of the ISO in 1998. Figure 4.2 summarizes the results published in DMM's prior annual reports. As shown in Figure 4.2, DMM has 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 mark-up and other analysis in this report indicate that prices under the nodal market design in 2009 and 2010 are extremely competitive. However, as discussed in our 2009 annual report, direct comparisons reported in previous years are difficult due to the significantly different way in which DMM calculated price-cost mark-up.[83]

[83] See *2009 Annual Report on Market Issues and Performance*, April 2010, pp 3.1-3.3 and 4.46-4.47 http://www.caiso.com/2777/27778a322d0f0.pdf.

**Figure 4.2 Price-cost mark-up: 1998-2010**




## 4.2 Structural measures of competitiveness

Market structure refers to the ownership of supply available in the market. The structural competitiveness of electric markets is often assessed using two related quantitative measures: the pivotal supplier test and residual supply index. Both of these measures assess the sufficiency of supply available to meet demand after removing the capacity owned or controlled by one or more entities.

- **Pivotal supplier test**. If supply is insufficient to meet demand with the supply of the largest supplier removed, then this supplier is pivotal. This is referred to as a single pivotal suppler test. The two-pivotal supplier test is performed by removing supply owned or controlled by the two largest suppliers. For the three-pivotal test, supply of the three largest suppliers is removed.

- **Residual supply index.** The residual supply index is the ratio of remaining supply divided compared to demand after the supply owned or controlled by the largest suppliers is removed.[84] If the residual supply index is less than 1.0, this indicates the largest suppliers whose supply is excluded when calculating the index are pivotal.

In the electric industry, measures based on two or three suppliers in combination are often used because of the potential for potential for oligopolistic bidding behavior by multiple suppliers. The potential for such behavior is high in the electric industry because the demand for electricity is highly

[84] For instance, assume demand equals 100 MW and the total available supply equals 120 MW. If one supplier owns 30 MW of this supply, the residual supply index equals .90, or (120 – 30)/100.

inelastic, and competition from new sources of supply is limited by long lead times and regulatory barriers to siting of new generation.

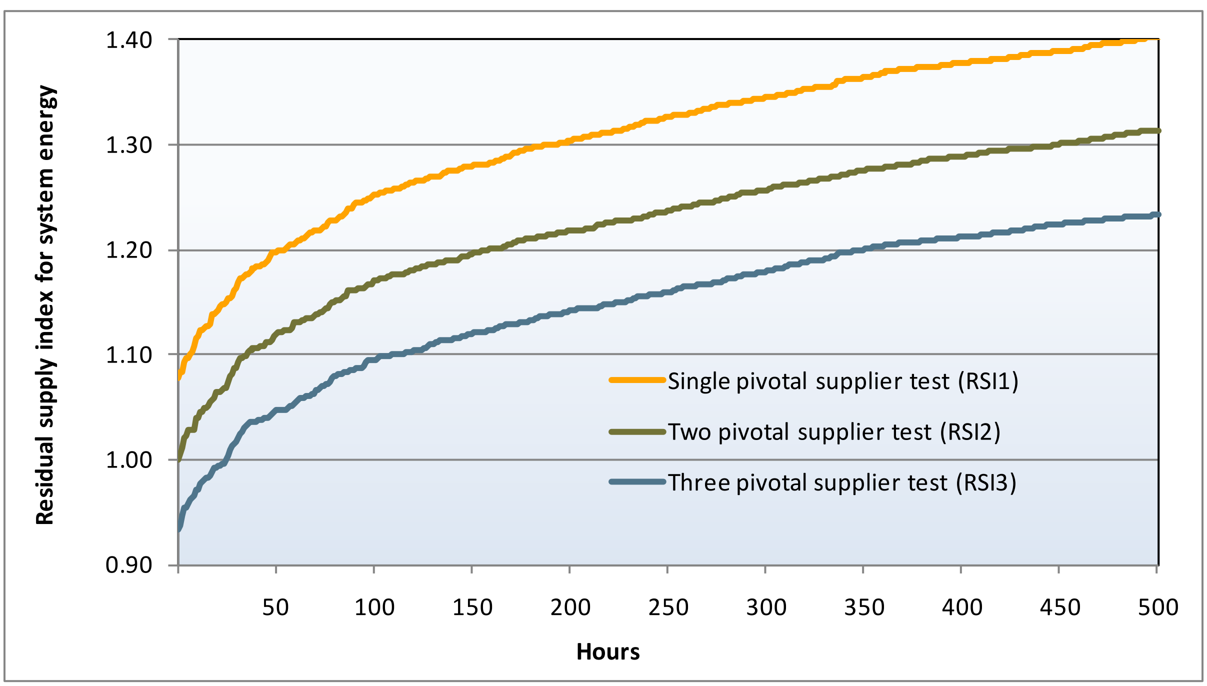
In this report, when the residual supply index is calculated by excluding the largest supplier, we refer to this measure as the $RSI_1$. With the two or three largest suppliers excluded, we refer to these results as the $RSI_2$ and $RSI_3$, respectively. A detailed description of the residual supply index was provided in Appendix A of DMM's 2009 annual report.

### 4.2.1 Day-ahead system energy

Figure 4.3 shows the hourly residual supply index for the day-ahead energy market in 2010. This analysis is based on system energy only and ignores potential limitations due to transmission limitations.[85] Results are only shown for the 500 hours when the residual supply index was lowest. These hours generally correspond to the highest load hours. As shown in Figure 4.3, the residual supply index with the three largest suppliers removed ($RSI_3$) was less than 1.0 during only 22 hours.

These findings reflect the favorable overall system supply and moderate load conditions discussed in Chapter 2. Under these conditions, the underlying structure of the overall energy market fosters competitive behavior and outcomes in the system-wide energy market. However, as discussed in the following sections, since ownership of resources within different areas of the ISO grid is highly concentrated, local reliability requirements and transmission limitations give rise to local market power in many areas of the system.

**Figure 4.3 Residual supply index for day-ahead energy market**




[85] All internal supply bid into the day-ahead market is used in this calculation. Imports are assumed to be limited to 12,000 MW. Demand includes actual system loads plus ancillary services.

### 4.2.2 Local capacity requirements

As shown in Chapter 2, the ISO has defined ten local capacity areas for which separate local reliability requirements are established under the state's resource adequacy program.[86] In most of these areas a high portion of the available capacity is needed to meet peak reliability planning requirements. One or two entities own most of the generation needed to meet local capacity requirements in each of these areas.

Table 4.1 provides a summary of the residual supply index for major local capacity areas. The demand in this analysis represents the local capacity requirements set by the ISO. Load-serving entities meet these requirements through a combination of self-owned generation and capacity procured though bilateral contracts. For this analysis, we assume that all capacity owned by load-serving entities will be used to meet these requirements with the remainder procured from the other entities that own the remaining resources in the local area.

As shown in Table 4.1, the total amount of supply owned by non-load-serving entities meets or exceeds the additional capacity needed by load-serving entities to meet these requirements. However, in each area, one or two suppliers are individually pivotal for meeting the remainder of the capacity requirement. In other words, some portion of these suppliers' capacity is needed to meet local requirements. This is indicated by $RSI_1$ values less than 1.0 and $RSI_2$ values of .33 or lower in each of these areas.

**Table 4.1 Residual supply index for major local capacity areas based on resource adequacy requirements**

| Local capacity area | Net non-LSE capacity requirement (MW) | Total non-LSE capacity (MW) | Total residual supply ratio | $RSI_1$ | $RSI_2$ | $RSI_3$ | Number of individually pivotal suppliers |
|---|---|---|---|---|---|---|---|
| **PG&E area** | | | | | | | |
| Greater Bay | 3,605 | 4,338 | 1.20 | 0.55 | 0.08 | 0.04 | 2 |
| North Coast/North Bay | 652 | 652 | 1.00 | 0.02 | 0.01 | 0.00 | 1 |
| **SCE area** | | | | | | | |
| LA Basin | 4,949 | 6,815 | 1.38 | 0.51 | 0.33 | 0.20 | 1 |
| Big Creek/Ventura | 811 | 2,938 | 1.76 | <1.00 | 0.11 | 0.07 | 1 |
| **San Diego** | 1,622 | 2,027 | 1.25 | 0.54 | 0.11 | 0.05 | 2 |

In addition to the capacity requirements for each local capacity area used in this analysis, additional reliability requirements exist for numerous sub-areas within each local capacity area. Some of these require that capacity be procured from specific individual generating plants. Others involve complex combinations of units which have different levels of effectiveness at meeting the reliability requirements. These sub-area requirements are not formally included in local capacity requirements

[86] Table 2.2 shows the amount of generation located in each local capacity area along with the total amount of capacity required for local reliability planning requirements in these areas.

incorporated in the state's resource adequacy program. However, these additional sub-area requirements represent an additional source of local market power. The specific units needed to meet these sub-area requirements are not included in the mix of units contracted by load-serving entities to meet area level requirements; the ISO would need to procure these units using its backstop procurement authority.

As discussed in Chapter 7, in 2010 load-serving entities continued to procure all capacity needed to meet local resource adequacy requirements through bilateral contracts. As a result, the ISO has not needed to procure capacity through reliability must-run contracts or the capacity procurement mechanism in the ISO tariff. However, having this authority in the tariff serves as a backstop that mitigates the potential for local market power in bilateral markets for this capacity.

In the energy markets, the potential for local market power is mitigated through bid mitigation procedures, as discussed in Section 4.3. These procedures require that each transmission constraint be pre-designated as either competitive or non-competitive based on seasonal planning studies performed several months in advance. The following section examines the actual structural competiveness of transmission constraints when congestion has occurred in the day-ahead and real-time markets.

### 4.2.3 Competitiveness of transmission constraints

#### Background

The ISO's local market power mitigation provisions require that each constraint be pre-designated as either competitive or non-competitive. Generation bids are subject to mitigation if that unit is committed or dispatched to relieve congestion on a constraint pre-designated as non-competitive. 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. This methodology incorporates a 3-pivotal supplier test.[87] The competitive path assessment tests to see if a feasible power flow solution of a full network model can be reached with the supply of any three suppliers excluded from the market.[88]

Starting in April 2010, the ISO performs competitive path assessment studies on a seasonal basis four times per year and updates constraint designations based on these results.[89] 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:

[87] 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.

[88] 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.

[89] 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 2009. Results of this first study were applied for the first 12 months of the new market. 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.

- 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 simulation software to perform the assessment, rather than the actual market software.

One of the drawbacks of the competitive path assessment is that the process is time-consuming given DMM's current modeling tools. Thus, DMM is currently proposing to modify the market rules and software so that the determination of constraint competitiveness is performed within the market software each day as part of the mitigation process.[90] This approach will allow this analysis to more closely reflect actual market and system conditions.

### Residual supply index for counterflow

The approach being proposed by DMM for assessment of the competitiveness of constraints is referred to as the residual supply index for counterflow on congested constraints. This approach was developed by DMM based on similar metrics used by several other ISOs to assess the competitiveness of transmission constraints. DMM has used this index to monitor the competitiveness of constraints on a day-to-day basis and assess the accuracy of the competitive path assessment methodology under actual network and market conditions.[91]

The residual supply index measures how pivotal one or more suppliers are based on their ownership or control of the supply of effective counterflow capable of relieving 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.

[90] *Proposed Modifications to Methodology for Competitive Path Designations for Local Market Power Mitigation,* Department of Market Monitoring, March 2011, http://www.caiso.com/2b45/2b45e56d50fb0.pdf.

[91] The methodology used to calculate these metrics is illustrated in Section A.5 of Appendix A of DMM's *2009 Annual Report on Market Issues & Performance*, April 2010, http://www.caiso.com/2777/27778a322d0f0.pdf.

### Day-ahead market results

Figure 4.4 and Table 4.2 summarize results of the hourly residual supply index for non-candidate constraints on which day-ahead congestion occurred in 2010. These constraints were deemed non-competitive because they did not meet the criteria used to determine candidate paths eligible to be analyzed and deemed competitive as part of the competitive path analysis studies. Under these criteria, most constraints are only eligible to be studied and deemed to be competitive if congestion on these constraints has been managed during at least 500 hours over the previous 12 months.

As shown in Figure 4.4, the frequency of congestion on these constraints was relatively low in 2010. During hours when congestion occurred in the day-ahead market, the residual supply index indicates that these constraints were uncompetitive a relatively small portion of the time. These findings are significantly different than results from 2009, which indicated that congested constraints deemed uncompetitive were in fact uncompetitive a high portion of the time.[92]

As shown in the summary totals in the bottom row of Table 4.2:

- During 5 percent of the hours when congestion occurred on constraints deemed to be non-competitive, the $RSI_1$ was less than 1, indicating a single supplier was pivotal. This compares to 53 percent of hours with a single pivotal supplier in 2009.
- During an additional 1 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 6 percent of the hours when congestion occurred on these paths, two suppliers were jointly pivotal. This compares to 60 percent of hours with two jointly pivotal suppliers in 2009.
- The $RSI_3$ was less than 1 during very few additional hours, indicating that use of a 3-pivotal supplier test yields results very similar to a 2-pivotal supplier test. This is consistent with 2009 results.

Figure 4.5 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. These findings are consistent with results of analysis of competitive constraints in 2009.

[92] Ibid, pages 4.29 – 4.36.

**Figure 4.4 Residual supply index - Non-candidate paths in 2010 for day-ahead market**

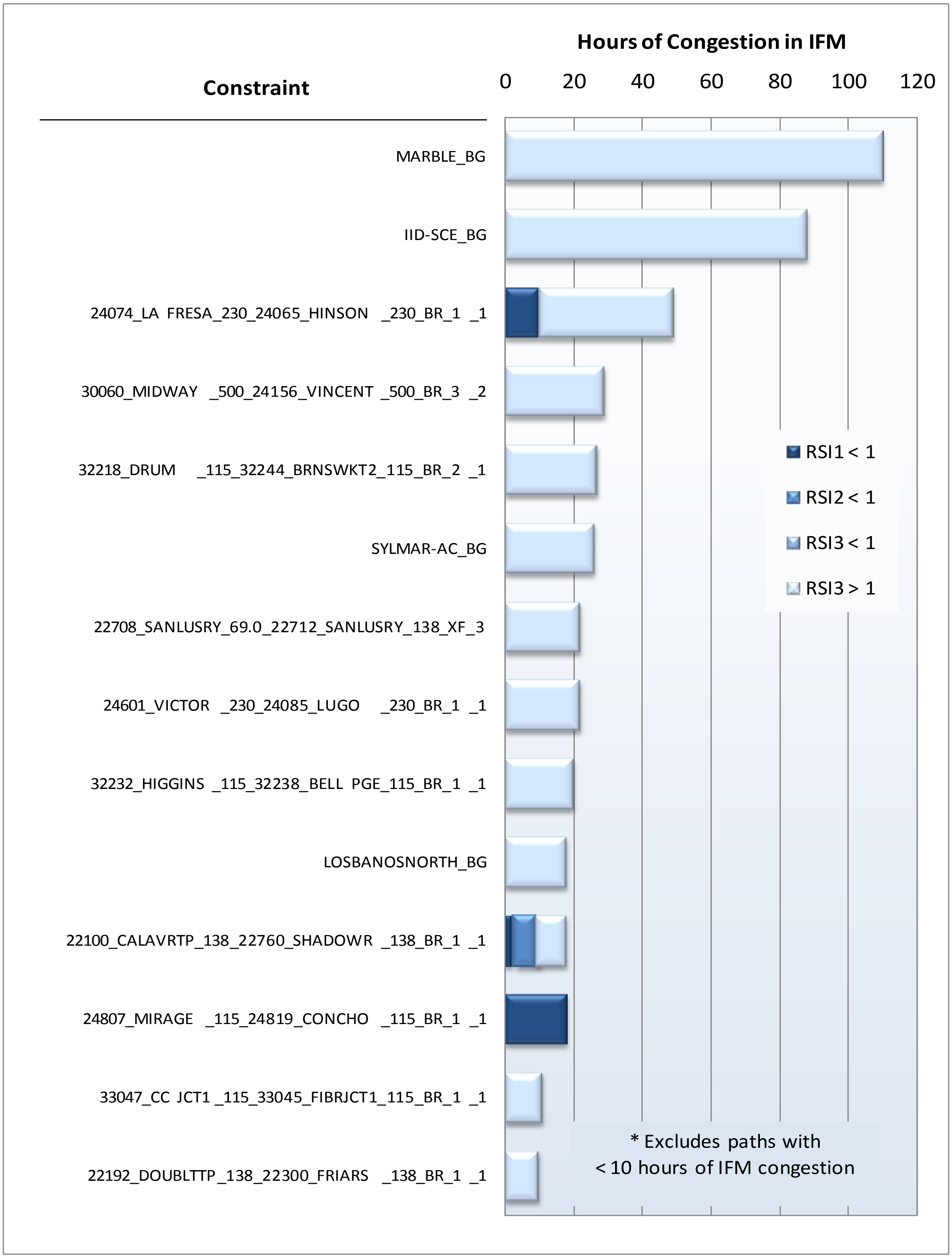


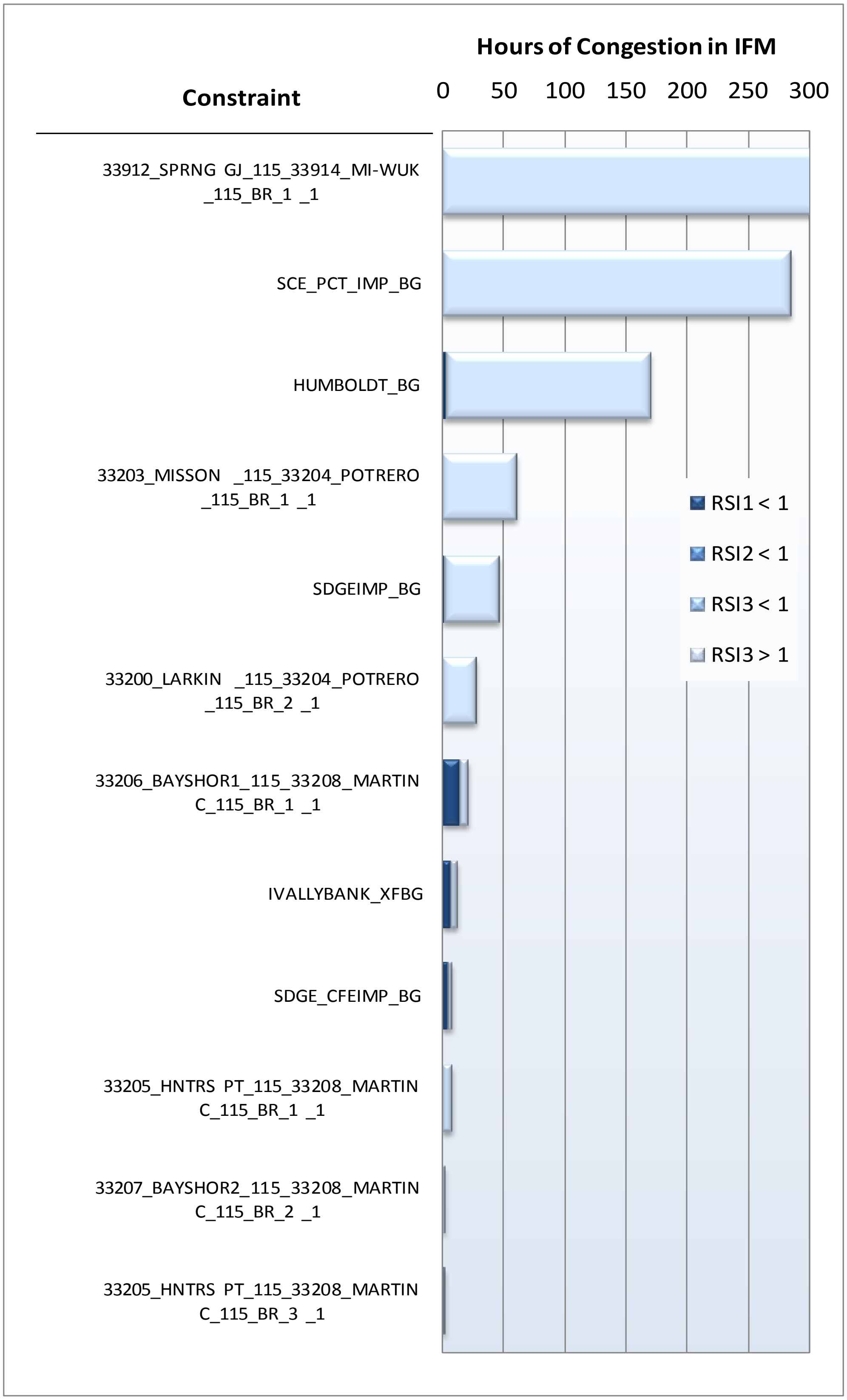
**Table 4.2 Summary of RSI results - Non-candidate paths in 2010 for day-ahead market**

| Constraint_Name | Congest. Hours | $RSI_1 < 1$ Hours | $RSI_1 < 1$ % | $RSI_2 < 1$ Hours | $RSI_2 < 1$ % | $RSI_3 < 1$ Hours | $RSI_3 < 1$ % | $RSI_3 > 1$ Hours | $RSI_3 > 1$ % |
|---|---|---|---|---|---|---|---|---|---|
| MARBLE_BG | 110 | 0 | 0% | 0 | 0% | 0 | 0% | 110 | 100% |
| IID-SCE_BG | 88 | 0 | 0% | 0 | 0% | 0 | 0% | 88 | 100% |
| 24074_LA FRESA_230_24065_HINSON _230_BR_1 _1 | 49 | 10 | 20% | 0 | 0% | 0 | 0% | 39 | 80% |
| 30060_MIDWAY _500_24156_VINCENT _500_BR_3 _2 | 29 | 0 | 0% | 0 | 0% | 0 | 0% | 29 | 100% |
| 32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1 | 27 | 0 | 0% | 0 | 0% | 0 | 0% | 27 | 100% |
| SYLMAR-AC_BG | 26 | 0 | 0% | 0 | 0% | 0 | 0% | 26 | 100% |
| 22708_SANLUSRY_69.0_22712_SANLUSRY_138_XF_3 | 22 | 0 | 0% | 0 | 0% | 0 | 0% | 22 | 100% |
| 24601_VICTOR _230_24085_LUGO _230_BR_1 _1 | 22 | 0 | 0% | 0 | 0% | 0 | 0% | 22 | 100% |
| 32232_HIGGINS _115_32238_BELL PGE_115_BR_1 _1 | 20 | 0 | 0% | 0 | 0% | 0 | 0% | 20 | 100% |
| LOSBANOSNORTH_BG | 18 | 0 | 0% | 0 | 0% | 0 | 0% | 18 | 100% |
| 22100_CALAVRTP_138_22760_SHADOWR _138_BR_1 _ | 18 | 2 | 11% | 7 | 39% | 0 | 0% | 9 | 50% |
| 24807_MIRAGE _115_24819_CONCHO _115_BR_1 _1 | 18 | 18 | 100% | 0 | 0% | 0 | 0% | 0 | 0% |
| 33047_CC JCT1 _115_33045_FIBRJCT1_115_BR_1 _1 | 11 | 0 | 0% | 0 | 0% | 0 | 0% | 11 | 100% |
| 22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1 | 10 | 0 | 0% | 0 | 0% | 0 | 0% | 10 | 100% |
| 30487_ELECTRA _230_30500_BELLOTA _230_BR_1 _1 | 9 | 0 | 0% | 0 | 0% | 0 | 0% | 9 | 100% |
| 34778_FELLOWS _115_34800_MORGAN _115_BR_1 _1 | 9 | 0 | 0% | 0 | 0% | 0 | 0% | 9 | 100% |
| 22228_ENCINA _138_22052_BATIQTP _138_BR_1 _1 | 8 | 0 | 0% | 0 | 0% | 0 | 0% | 8 | 100% |
| NOB_BG | 8 | 0 | 0% | 0 | 0% | 0 | 0% | 8 | 100% |
| 31464_COTWDPGE_115_31463_WHEELBR _115_BR_1 _ | 7 | 0 | 0% | 0 | 0% | 0 | 0% | 7 | 100% |
| 30261_BELDENTP_230_30300_TABLMTN _230_BR_1 _: | 7 | 0 | 0% | 0 | 0% | 0 | 0% | 7 | 100% |
| 32290_OLIVH J1_115_32214_RIO OSO _115_BR_1 _1 | 7 | 0 | 0% | 0 | 0% | 0 | 0% | 7 | 100% |
| SOUTHLUGO_RV_BG | 6 | 0 | 0% | 0 | 0% | 0 | 0% | 6 | 100% |
| 32212_E.NICOLS_115_32214_RIO OSO _115_BR_1 _1 | 5 | 0 | 0% | 0 | 0% | 0 | 0% | 5 | 100% |
| SSONGS_BG | 5 | 0 | 0% | 0 | 0% | 0 | 0% | 5 | 100% |
| 24804_DEVERS _230_24806_MIRAGE _230_BR_1 _1 | 4 | 0 | 0% | 0 | 0% | 0 | 0% | 4 | 100% |
| 30900_GATES _230_30970_MIDWAY _230_BR_1 _1 | 4 | 0 | 0% | 0 | 0% | 0 | 0% | 4 | 100% |
| 30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3 | 4 | 0 | 0% | 0 | 0% | 0 | 0% | 4 | 100% |
| 30015_TABLE MT_500_30030_VACA-DIX_500_BR_1 _3 | 4 | 0 | 0% | 0 | 0% | 0 | 0% | 4 | 100% |
| 31482_PALERMO _115_32280_E.MRY J2_115_BR_1 _1 | 3 | 0 | 0% | 0 | 0% | 0 | 0% | 3 | 100% |
| 32218_DRUM _115_32222_DTCH2TAP_115_BR_1 _1 | 2 | 0 | 0% | 0 | 0% | 0 | 0% | 2 | 100% |
| 32208_GLEAF TP_115_32214_RIO OSO _115_BR_1 _1 | 2 | 0 | 0% | 0 | 0% | 0 | 0% | 2 | 100% |
| SCIT_BG | 1 | 0 | 0% | 0 | 0% | 0 | 0% | 1 | 100% |
| 38605_BUENAVJ2_230_30970_MIDWAY _230_BR_1 _1 | 1 | 0 | 0% | 0 | 0% | 0 | 0% | 1 | 100% |
| 33008_GRIZLYJ2_115_32780_CLARMNT _115_BR_2 _1 | 1 | 0 | 0% | 0 | 0% | 0 | 0% | 1 | 100% |
| **Totals** | **565** | **30** | **5%** | **7** | **1%** | **0** | **0%** | **528** | **93%** |

**Table 4.3 Summary of RSI results - Competitive paths in 2010 for day-ahead market**

| Constraint Name | Congestion Hours | $RSI_1 < 1$ Hours | $RSI_1 < 1$ % | $RSI_2 < 1$ Hours | $RSI_2 < 1$ % | $RSI_3 < 1$ Hours | $RSI_3 < 1$ % | $RSI_3 > 1$ Hours | $RSI_3 > 1$ % |
|---|---|---|---|---|---|---|---|---|---|
| 33912_SPRNG GJ_115_33914_MI-WUK _115_BR_1 _: | 690 | 0 | 0% | 0 | 0% | 0 | 0% | 690 | 100% |
| SCE_PCT_IMP_BG | 286 | 0 | 0% | 0 | 0% | 0 | 0% | 286 | 100% |
| HUMBOLDT_BG | 170 | 3 | 2% | 0 | 0% | 0 | 0% | 167 | 98% |
| 33203_MISSON _115_33204_POTRERO _115_BR_1 _ | 61 | 0 | 0% | 0 | 0% | 0 | 0% | 61 | 100% |
| SDGEIMP_BG | 47 | 2 | 4% | 0 | 0% | 0 | 0% | 45 | 96% |
| 33200_LARKIN _115_33204_POTRERO _115_BR_2 _1 | 28 | 0 | 0% | 0 | 0% | 0 | 0% | 28 | 100% |
| 33206_BAYSHOR1_115_33208_MARTIN C_115_BR_1 | 21 | 14 | 67% | 0 | 0% | 0 | 0% | 7 | 33% |
| IVALLYBANK_XFBG | 12 | 7 | 58% | 0 | 0% | 0 | 0% | 5 | 42% |
| SDGE_CFEIMP_BG | 8 | 5 | 63% | 0 | 0% | 0 | 0% | 3 | 38% |
| 33205_HNTRS PT_115_33208_MARTIN C_115_BR_1 _ | 8 | 0 | 0% | 0 | 0% | 0 | 0% | 8 | 100% |
| 33207_BAYSHOR2_115_33208_MARTIN C_115_BR_2 | 2 | 0 | 0% | 0 | 0% | 0 | 0% | 2 | 100% |
| 33205_HNTRS PT_115_33208_MARTIN C_115_BR_3 _ | 2 | 1 | 50% | 0 | 0% | 0 | 0% | 1 | 50% |
| **Totals** | **1,335** | **32** | **2%** | **0** | **0%** | **0** | **0%** | **1,303** | **98%** |

**Figure 4.5 Residual supply index - Competitive paths in 2010 for day-ahead market**



### Real-time market results

Figure 4.6 and Table 4.4 summarize results of the residual supply index for non-candidate paths on which real-time congestion occurred in 2010. As shown in Figure 4.6, during hours when congestion occurred in the real-time market, the residual supply index indicates that these constraints were uncompetitive a relatively high portion of the time.

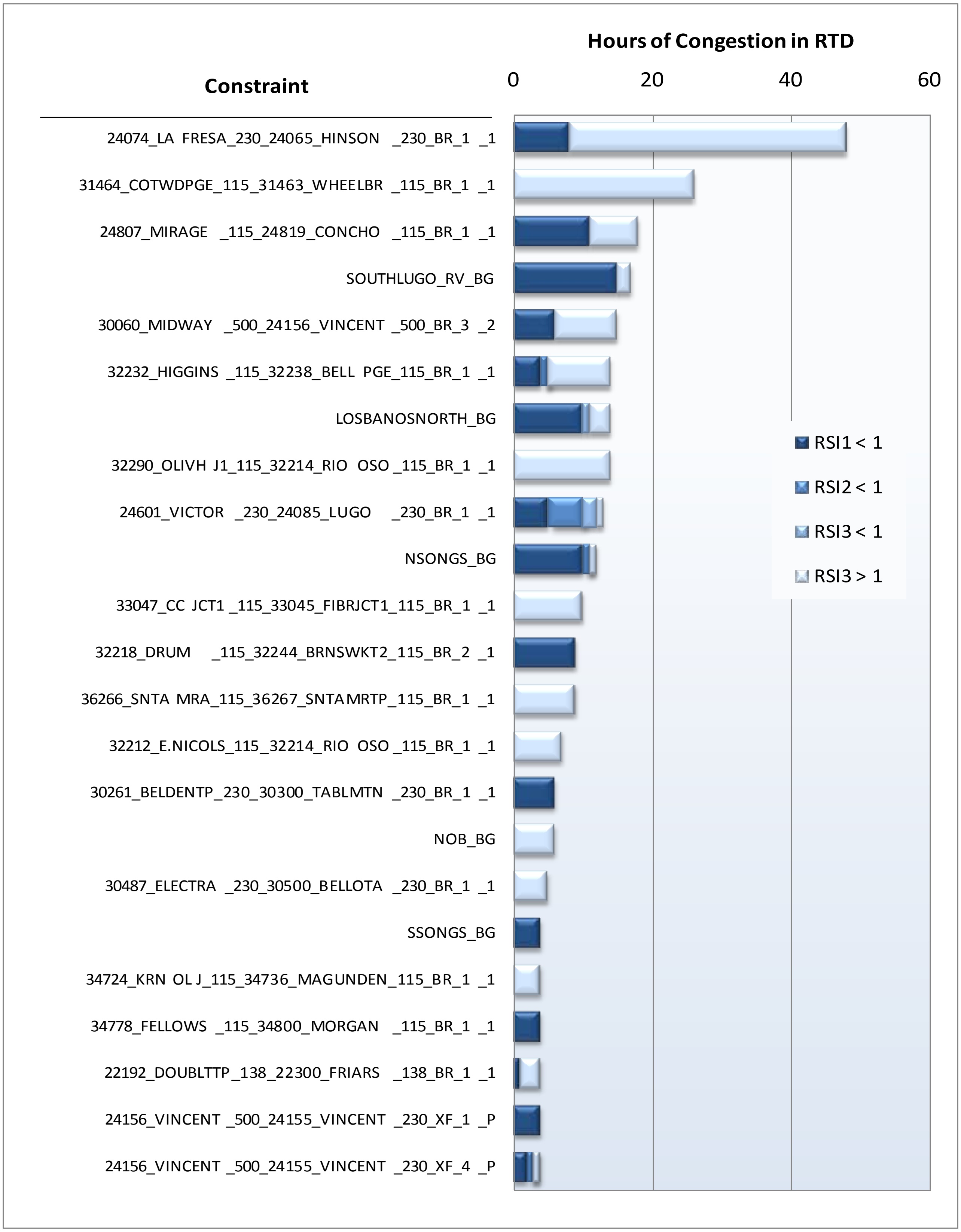
As shown in the summary totals in the bottom row of Table 4.4:

- During 37 percent of the hours when congestion occurred on these paths, the $RSI_1$ was less than 1, indicating a single supplier was pivotal.
- During an additional 3 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 40 percent of the hours when congestion occurred on these paths, two suppliers were jointly pivotal.
- As with analysis of the day-ahead congestion in 2009 and 2010, the $RSI_3$ was less than 1 during very few additional hours, indicating that use of a 3-pivotal supplier test yields results very similar to a 2-pivotal supplier test.

Figure 4.7 and Table 4.5 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, most of these paths were competitive under the residual supply index. Overall, these real-time analysis results indicate that although the current method of designating paths as competitive or non-competitive is not highly dynamic, this approach is reasonably accurate:

- Paths deemed non-competitive under the competitive path assessment methodology were structurally uncompetitive a much higher portion of the time in the real-time market than in the day-ahead market (compare Figure 4.4 and Figure 4.6). This reflects the fact that in real-time, the available supply of effective counterflow is much more limited by ramping constraints and that longer-start units that are not online cannot be used to relieve congestion.
- Paths deemed uncompetitive were structurally uncompetitive during about 40 percent of hours in the real-time market when congestion occurred on these paths based on the residual supply index (see Figure 4.6 and Table 4.3).
- 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 in both the day-ahead and real-time markets (see Figure 4.5 and Figure 4.7).

**Figure 4.6 Residual supply index - Non-candidate paths in 2010 for real-time market**



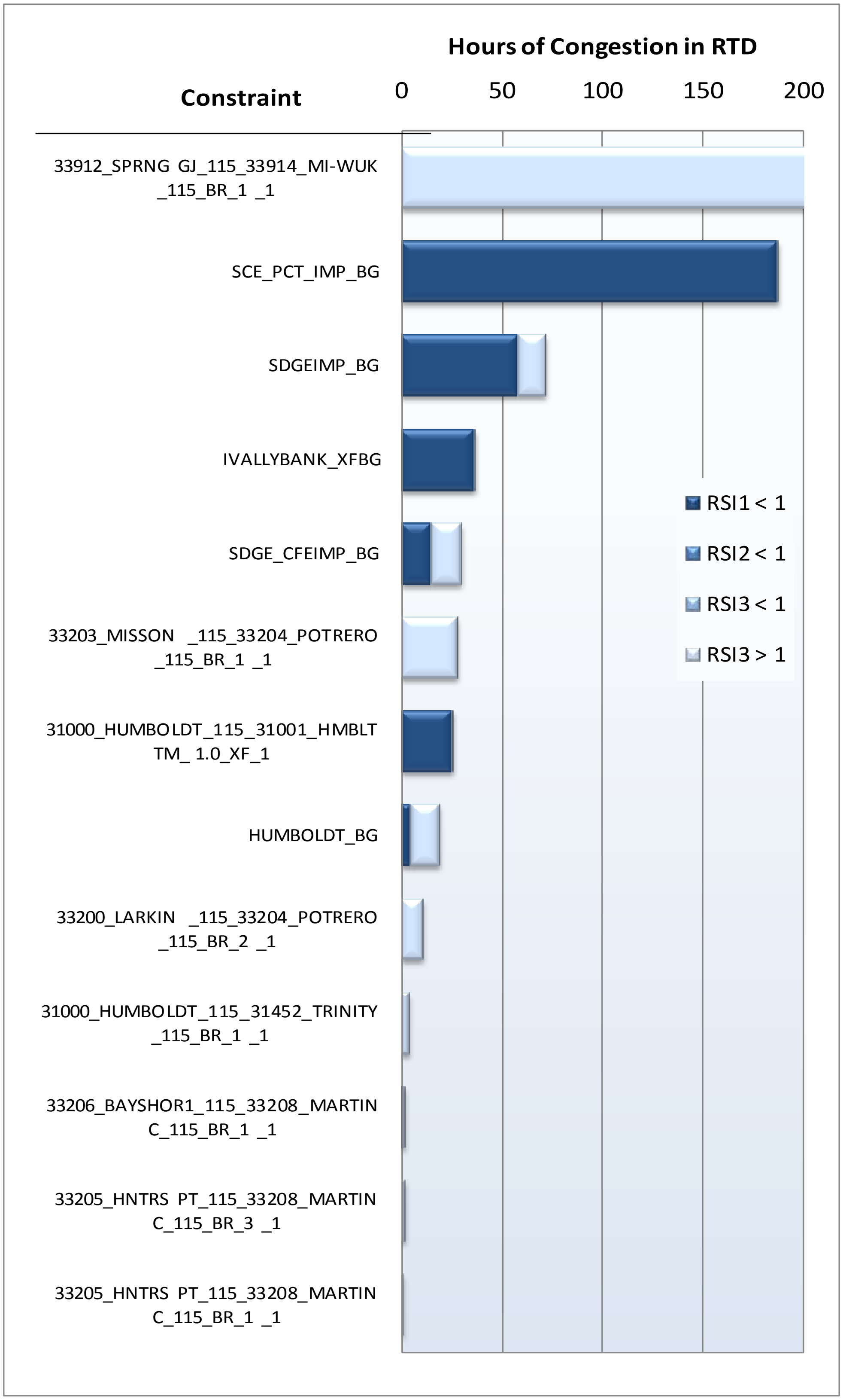
## Table 4.4 Summary of RSI results - Non-candidate paths in 2010 for real-time market

| Constraint_Name | Congest. Hours | $RSI_1 < 1$ Hours | $RSI_1 < 1$ % | $RSI_2 < 1$ Hours | $RSI_2 < 1$ % | $RSI_3 < 1$ Hours | $RSI_3 < 1$ % | $RSI_3 > 1$ Hours | $RSI_3 > 1$ % |
|---|---|---|---|---|---|---|---|---|---|
| 24074_LA FRESA_230_24065_HINSON _230_BR_1 _1 | 48 | 8 | 17% | 0 | 0% | 0 | 0% | 40 | 83% |
| 31464_COTWDPGE_115_31463_WHEELBR _115_BR_1 _1 | 26 | 0 | 0% | 0 | 0% | 0 | 0% | 26 | 100% |
| 24807_MIRAGE _115_24819_CONCHO _115_BR_1 _1 | 18 | 11 | 61% | 0 | 0% | 0 | 0% | 7 | 39% |
| SOUTHLUGO_RV_BG | 17 | 15 | 88% | 0 | 0% | 0 | 0% | 2 | 12% |
| 30060_MIDWAY _500_24156_VINCENT _500_BR_3 _2 | 15 | 6 | 40% | 0 | 0% | 0 | 0% | 9 | 60% |
| 32232_HIGGINS _115_32238_BELL PGE_115_BR_1 _1 | 14 | 4 | 29% | 1 | 7% | 0 | 0% | 9 | 64% |
| LOSBANOSNORTH_BG | 14 | 10 | 71% | 0 | 0% | 1 | 7% | 3 | 21% |
| 32290_OLIVH J1_115_32214_RIO OSO _115_BR_1 _1 | 14 | 0 | 0% | 0 | 0% | 0 | 0% | 14 | 100% |
| 24601_VICTOR _230_24085_LUGO _230_BR_1 _1 | 13 | 5 | 38% | 5 | 38% | 2 | 15% | 1 | 8% |
| NSONGS_BG | 12 | 10 | 83% | 1 | 8% | 0 | 0% | 1 | 8% |
| 33047_CC JCT1 _115_33045_FIBRJCT1_115_BR_1 _1 | 10 | 0 | 0% | 0 | 0% | 0 | 0% | 10 | 100% |
| 32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1 | 9 | 9 | 100% | 0 | 0% | 0 | 0% | 0 | 0% |
| 36266_SNTA MRA_115_36267_SNTAMRTP_115_BR_1 _1 | 9 | 0 | 0% | 0 | 0% | 0 | 0% | 9 | 100% |
| 32212_E.NICOLS_115_32214_RIO OSO _115_BR_1 _1 | 7 | 0 | 0% | 0 | 0% | 0 | 0% | 7 | 100% |
| 30261_BELDENTP_230_30300_TABLMTN _230_BR_1 _1 | 6 | 6 | 100% | 0 | 0% | 0 | 0% | 0 | 0% |
| NOB_BG | 6 | 0 | 0% | 0 | 0% | 0 | 0% | 6 | 100% |
| 30487_ELECTRA _230_30500_BELLOTA _230_BR_1 _1 | 5 | 0 | 0% | 0 | 0% | 0 | 0% | 5 | 100% |
| SSONGS_BG | 5 | 4 | 80% | 0 | 0% | 0 | 0% | 0 | 0% |
| 34724_KRN OL J_115_34736_MAGUNDEN_115_BR_1 _1 | 4 | 0 | 0% | 0 | 0% | 0 | 0% | 4 | 100% |
| 34778_FELLOWS _115_34800_MORGAN _115_BR_1 _1 | 4 | 4 | 100% | 0 | 0% | 0 | 0% | 0 | 0% |
| 22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1 | 4 | 1 | 25% | 0 | 0% | 0 | 0% | 3 | 75% |
| 24156_VINCENT _500_24155_VINCENT _230_XF_1 _P | 4 | 4 | 100% | 0 | 0% | 0 | 0% | 0 | 0% |
| 24156_VINCENT _500_24155_VINCENT _230_XF_4 _P | 4 | 2 | 50% | 1 | 25% | 0 | 0% | 1 | 25% |
| 38600_BUENAVJ1_230_30970_MIDWAY _230_BR_1 _1 | 3 | 0 | 0% | 0 | 0% | 0 | 0% | 3 | 100% |
| 34778_FELLOWS _115_34779_MIDSUN _115_BR_1 _1 | 2 | 0 | 0% | 1 | 50% | 1 | 50% | 0 | 0% |
| 32786_OAKLAND _115_32790_STATIN X_115_BR_2 _1 | 2 | 1 | 50% | 0 | 0% | 0 | 0% | 1 | 50% |
| 30055_GATES1 _500_30060_MIDWAY _500_BR_1 _3 | 2 | 0 | 0% | 0 | 0% | 0 | 0% | 2 | 100% |
| 30015_TABLE MT_500_30030_VACA-DIX_500_BR_1 _3 | 2 | 2 | 100% | 0 | 0% | 0 | 0% | 0 | 0% |
| 31482_PALERMO _115_32280_E.MRY J2_115_BR_1 _1 | 2 | 0 | 0% | 0 | 0% | 0 | 0% | 2 | 100% |
| 35901_GRN VALY_115_35922_MOSSLD _115_BR_1 _1 | 2 | 2 | 100% | 0 | 0% | 0 | 0% | 0 | 0% |
| 34774_MIDWAY _115_34804_BELRIDGE_115_BR_1 _1 | 1 | 0 | 0% | 1 | 100% | 0 | 0% | 0 | 0% |
| 24016_BARRE _230_24044_ELLIS _230_BR_1 _1 | 1 | 1 | 100% | 0 | 0% | 0 | 0% | 0 | 0% |
| 32782_STATIN D_115_32788_STATIN L_115_BR_1 _1 | 1 | 0 | 0% | 0 | 0% | 0 | 0% | 1 | 100% |
| 22228_ENCINA _138_22052_BATIQTP _138_BR_1 _1 | 1 | 1 | 100% | 0 | 0% | 0 | 0% | 0 | 0% |
| 24086_LUGO _500_24085_LUGO _230_XF_2 _P | 1 | 0 | 0% | 0 | 0% | 0 | 0% | 1 | 100% |
| 34752_KERN PWR_115_30945_KERN PP _230_XF_3 | 1 | 0 | 0% | 0 | 0% | 0 | 0% | 1 | 100% |
| 32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1 | 1 | 1 | 100% | 0 | 0% | 0 | 0% | 0 | 0% |
| 32224_CHCGO PK_115_32232_HIGGINS _115_BR_1 _1 | 1 | 1 | 100% | 0 | 0% | 0 | 0% | 0 | 0% |
| 32208_GLEAF TP_115_32214_RIO OSO _115_BR_1 _1 | 1 | 0 | 0% | 0 | 0% | 0 | 0% | 1 | 100% |
| **Totals** | **292** | **108** | **37%** | **10** | **3%** | **4** | **1%** | **169** | **58%** |

## Table 4.5 Summary of RSI results - Competitive paths in 2010 for real-time market

| Constraint Name | Congestion Hours | $RSI_1 < 1$ Hours | $RSI_1 < 1$ % | $RSI_2 < 1$ Hours | $RSI_2 < 1$ % | $RSI_3 < 1$ Hours | $RSI_3 < 1$ % | $RSI_3 > 1$ Hours | $RSI_3 > 1$ % |
|---|---|---|---|---|---|---|---|---|---|
| 33912_SPRNG GJ_115_33914_MI-WUK _115_BR_1 _1 | 1897 | 0 | 0% | 0 | 0% | 0 | 0% | 1897 | 100% |
| SCE_PCT_IMP_BG | 188 | 187 | 99% | 0 | 0% | 0 | 0% | 1 | 1% |
| SDGEIMP_BG | 72 | 58 | 81% | 0 | 0% | 0 | 0% | 14 | 19% |
| IVALLYBANK_XFBG | 37 | 36 | 97% | 0 | 0% | 0 | 0% | 1 | 3% |
| SDGE_CFEIMP_BG | 30 | 15 | 50% | 0 | 0% | 0 | 0% | 15 | 50% |
| 33203_MISSON _115_33204_POTRERO _115_BR_1 _1 | 28 | 0 | 0% | 0 | 0% | 0 | 0% | 28 | 100% |
| 31000_HUMBOLDT_115_31001_HMBLT TM_ 1.0_XF_1 | 26 | 25 | 96% | 0 | 0% | 0 | 0% | 1 | 4% |
| HUMBOLDT_BG | 19 | 5 | 26% | 0 | 0% | 0 | 0% | 14 | 74% |
| 33200_LARKIN _115_33204_POTRERO _115_BR_2 _1 | 11 | 0 | 0% | 0 | 0% | 0 | 0% | 11 | 100% |
| 31000_HUMBOLDT_115_31452_TRINITY _115_BR_1 _1 | 4 | 0 | 0% | 0 | 0% | 0 | 0% | 4 | 100% |
| 33206_BAYSHOR1_115_33208_MARTIN C_115_BR_1 _1 | 2 | 1 | 50% | 0 | 0% | 0 | 0% | 1 | 50% |
| 33205_HNTRS PT_115_33208_MARTIN C_115_BR_3 _1 | 2 | 0 | 0% | 0 | 0% | 0 | 0% | 2 | 100% |
| 33205_HNTRS PT_115_33208_MARTIN C_115_BR_1 _1 | 1 | 0 | 0% | 0 | 0% | 0 | 0% | 1 | 100% |
| **Totals** | **2,317** | **327** | **14%** | **0** | **0%** | **0** | **0%** | **1,990** | **86%** |

**Figure 4.7 Residual supply index - Competitive paths in 2010 for real-time market**



## 4.3 Local market power mitigation

### 4.3.1 Frequency and impact of bid mitigation

The competitive baseline analysis presented in Section 4.1 is calculated by using default energy bids for all gas-fired units in place of their market bids. This analysis provides an indication of prices that would result if all gas-fired generators were always subject to bid mitigation. As discussed in Section 4.1, 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.

The impact of bids that are actually mitigated on market prices can only be assessed by re-running the market software without bid mitigation. Given the solution times for the 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, DMM has developed a variety of metrics to measure the frequency with which bid mitigation provisions have been triggered and the impact of this mitigation on each unit's energy bids and dispatch levels.[93]

As shown in Figure 4.8 and Figure 4.9, the frequency and impact of mitigation in the day-ahead market dropped significantly in 2010.

- An average of less than one unit was subject to mitigation each hour, with an average of less than 0.5 units having their bid actually lowered due to mitigation. In 2009, bids were lowered for an average of about 1.4 units per hour in the day-ahead market.
- The estimated increase in energy dispatched in the day-ahead market from these units averaged less than 5 MW per hour. This compares to an estimated impact from mitigation of about 31 MW in 2009.

Two major factors contributed to the decrease in day-ahead mitigation:

- Congestion on uncompetitive constraints within the ISO system was significantly lower in 2010. This causes less frequent mitigation.
- As described in our 2009 annual report, bidding rules for reliability must-run units selecting the Condition 1 contract type tend to trigger local market power mitigation.[94] In 2009, these reliability must-run units accounted for almost half of the frequency and impact of bid mitigation. Five units under Condition 1 reliability must-run contracts in 2009 were not under this type of contract in 2010. Thus, these units were subject to mitigation much less frequently in 2010.

[93] The methodology used to calculate these metrics is illustrated in Section A.4 of Appendix A of DMM's *2009 Annual Report on Market Issues & Performance*, April 2010, http://www.caiso.com/2777/27778a322d0f0.pdf.

[94] Market bids submitted by reliability must-run units selecting the Condition 1 contract option 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. See page 4.22 of DMM's *2009 Annual Report on Market Issues and Performance*, April 2010, http://www.caiso.com/2777/27778a322d0f0.pdf.

In the real-time market, bid mitigation frequency in 2010 was comparable to that of 2009, as shown in Figure 4.10. However, as shown in Figure 4.11, the impact of bid mitigation increased notably:

- In 2010, bids for an average of about 2.5 units were lowered as a result of the hour-ahead mitigation process. This compares to an average of about 3.6 units per hour in 2009.
- An average of about 0.7 units per hour were dispatched at a higher level in the real-time market as a result of bid mitigation in both 2009 and 2010.
- The estimated increase in real-time dispatches from these units because of bid mitigation averaged about 60 MW in 2010 compared to about 20 MW in 2009.

Thus, while the impact of mitigation on real-time dispatches increased in 2010, the overall impact of bid mitigation remains low in the real-time market.

Some of the increased impact of bid mitigation in 2010 can be attributed to problems with the bid mitigation process in 2009 that prevented mitigated bids from being used in the real-time market. As noted in our 2009 annual report, the process for passing bids mitigated in the hour-ahead process to the 5-minute real-time market failed periodically because of a software problem.[95] DMM monitored this issue in 2010 and worked with the ISO price validation team to ensure this problem did not reoccur.

[95] See *2009 Annual Report on Market Issues and Performance*, April 2010, http://www.caiso.com/2777/27778a322d0f0.pdf Data on the frequency that bids were lowered as a result of mitigation in Figure 4.11 and Figure 4.12 are based on mitigated bids from the hour-ahead software and do not reflect the frequency that these bids were not actually passed to the real-time market software. However, the data on the impact of mitigation in Figure 4.11 and Figure 4.12 reflect the actual bids used in the real-time market software.

**Figure 4.8 Average number of units mitigated in day-ahead market**

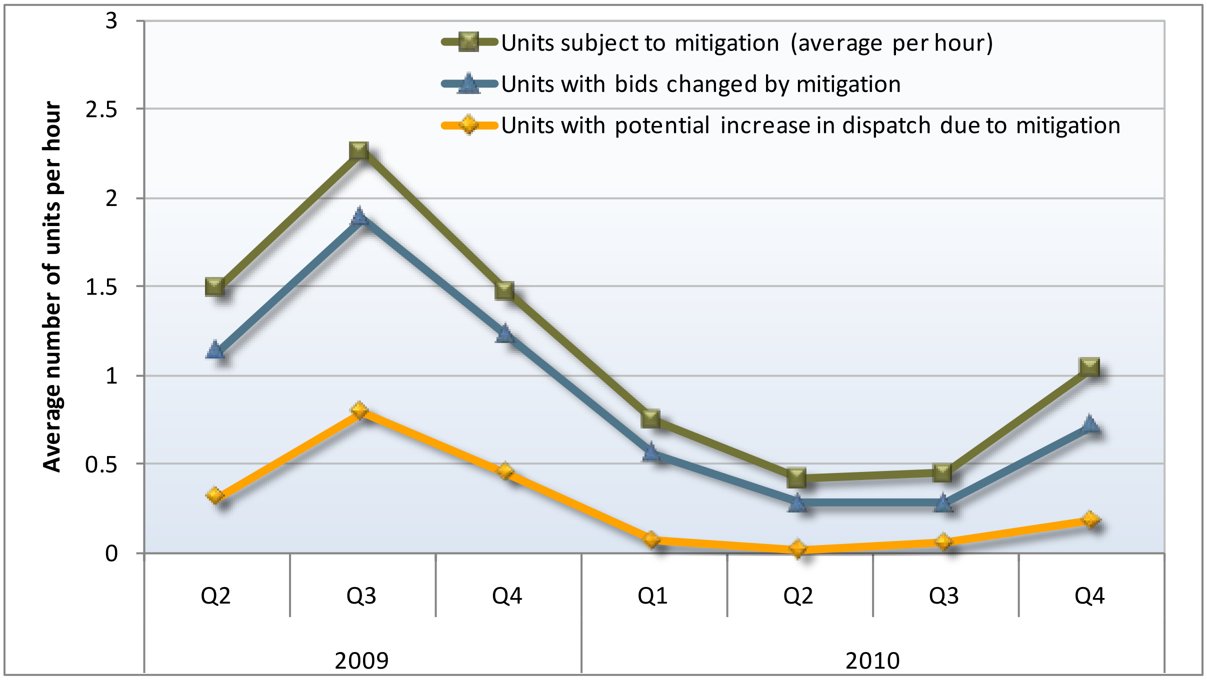



**Figure 4.9 Potential increase in day-ahead energy dispatch due to mitigation: Hourly averages, 2009 and 2010**

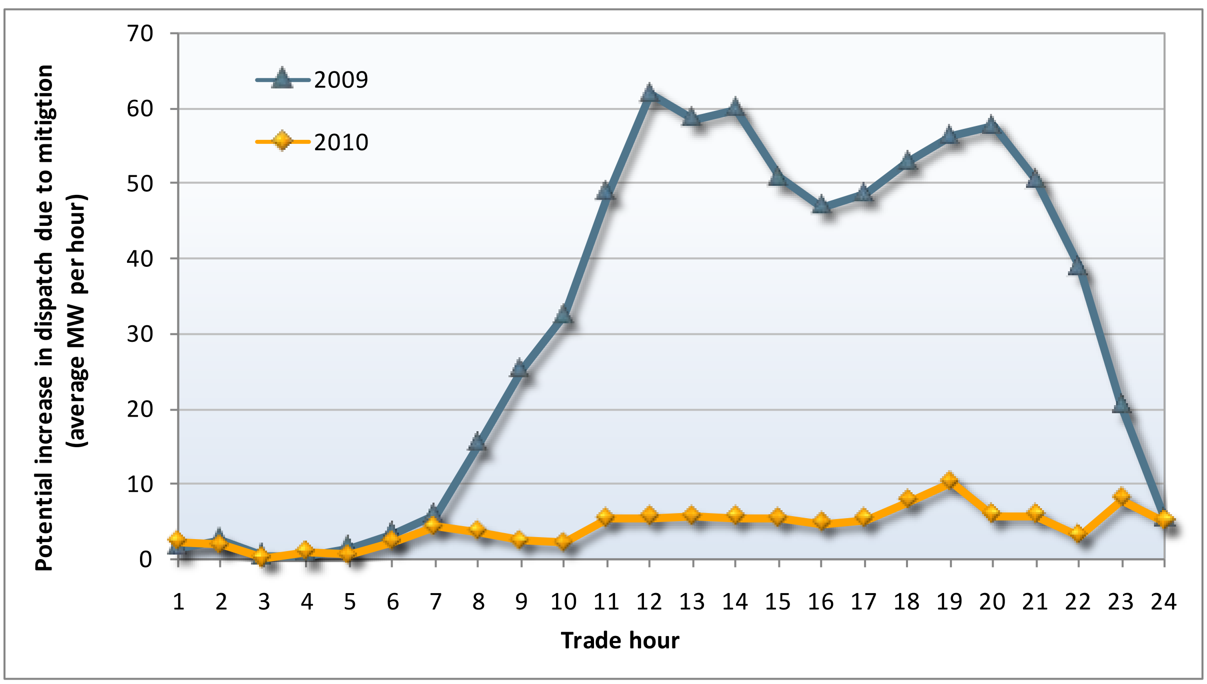


**Figure 4.10 Average number of units mitigated in real-time market**

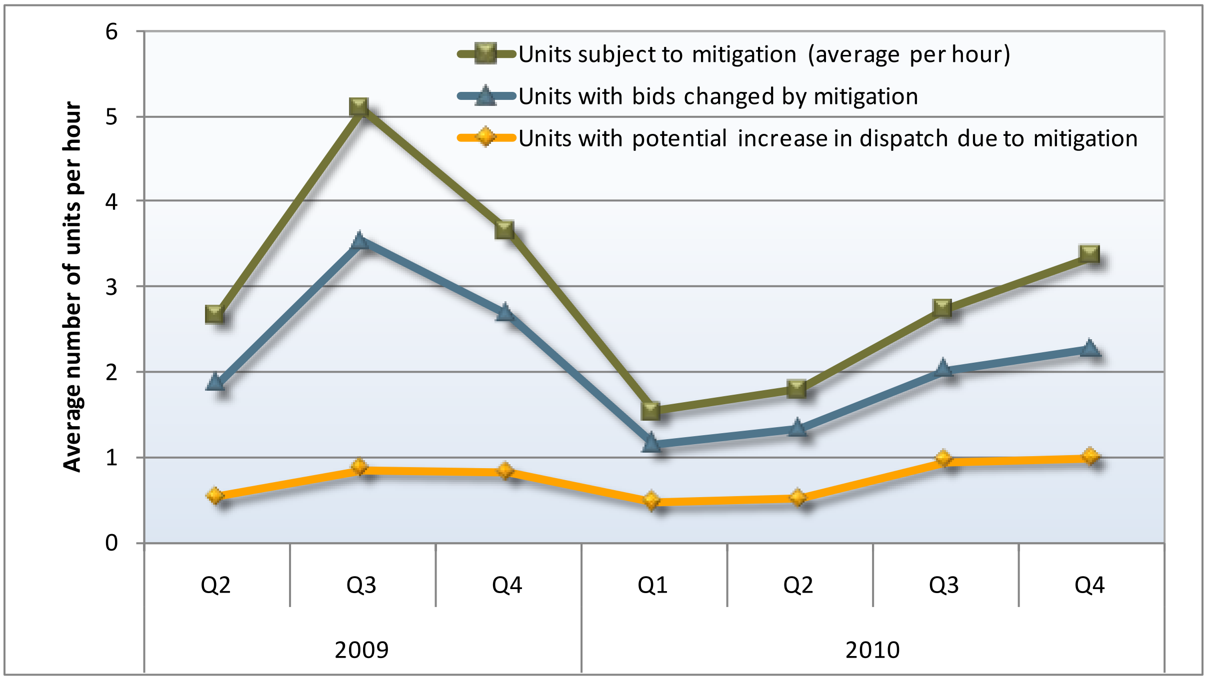
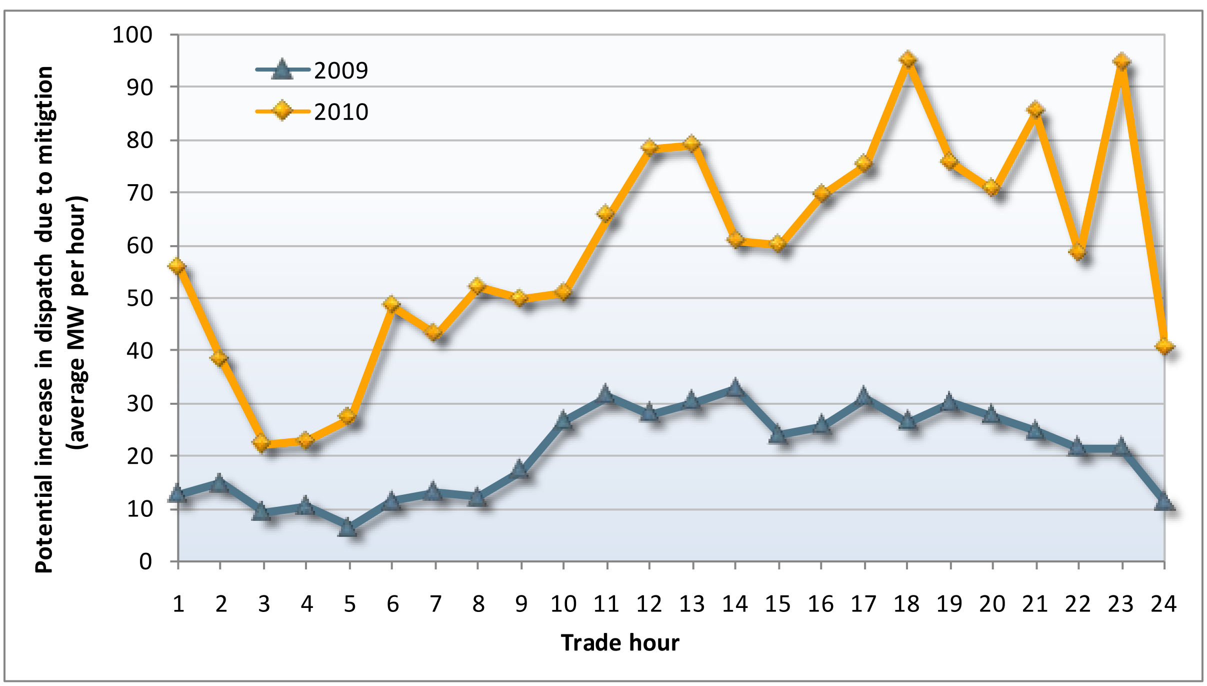



**Figure 4.11 Potential increase in real-time energy dispatch due to mitigation: Hourly averages, 2009 and 2010**



### 4.3.2 Mitigation of exceptional dispatches

Exceptional dispatches are manual instructions issued when the automated market optimization is not able to address a particular reliability requirement or constraint. A more detailed discussion of exceptional dispatches is provided in Section 3.4 of Chapter 3.

Exceptional dispatches for energy above a unit's minimum operating level are subject to mitigation if operator logs indicate the dispatch was issued to mitigate congestion on a designated non-competitive constraint. If an exceptional dispatch is mitigated, the generator is paid the greater of the unit's nodal price or default energy bid. Otherwise, all exceptional dispatches are paid the greater of the nodal price or the unit's unmitigated bid price.

As shown in Figure 4.12, the volume of total exceptional dispatch energy and the portion of this energy subject to mitigation decreased substantially in 2010:[96]

- Over half of exceptional dispatch energy cleared the market in-sequence, meaning that bid prices were below the market clearing price for energy.
- An average of less than 8 MW of energy per hour was exceptionally dispatched out-of-sequence in 2010.
- Only about 9 percent of this out-of-sequence exceptional dispatch energy in 2010 was logged as being related to a non-competitive constraint and therefore subject to mitigation. This is down from 19 percent in 2009.

The total volume and portion of out-of-sequence energy logged as being for non-competitive constraints dropped in 2010 for several reasons:

- Exceptional dispatches for ramp rate issues comprised the bulk of out-of-sequence energy, particularly in the third and fourth quarters of 2010. Exceptional dispatches logged as being for unit ramp rate issues are not treated as being associated with non-competitive constraints and therefore are not subject to mitigation.
- Exceptional dispatches for mitigating congestion on Path 26 increased in the third and fourth quarters of 2010. Path 26 is one of the major constraints that are deemed to be a competitive constraint by default.

[96] All exceptional dispatch numbers and figures in this report exclude April 2009 data due to lack of availability and reliability of that data.

**Figure 4.12 Exceptional dispatches subject to bid mitigation**

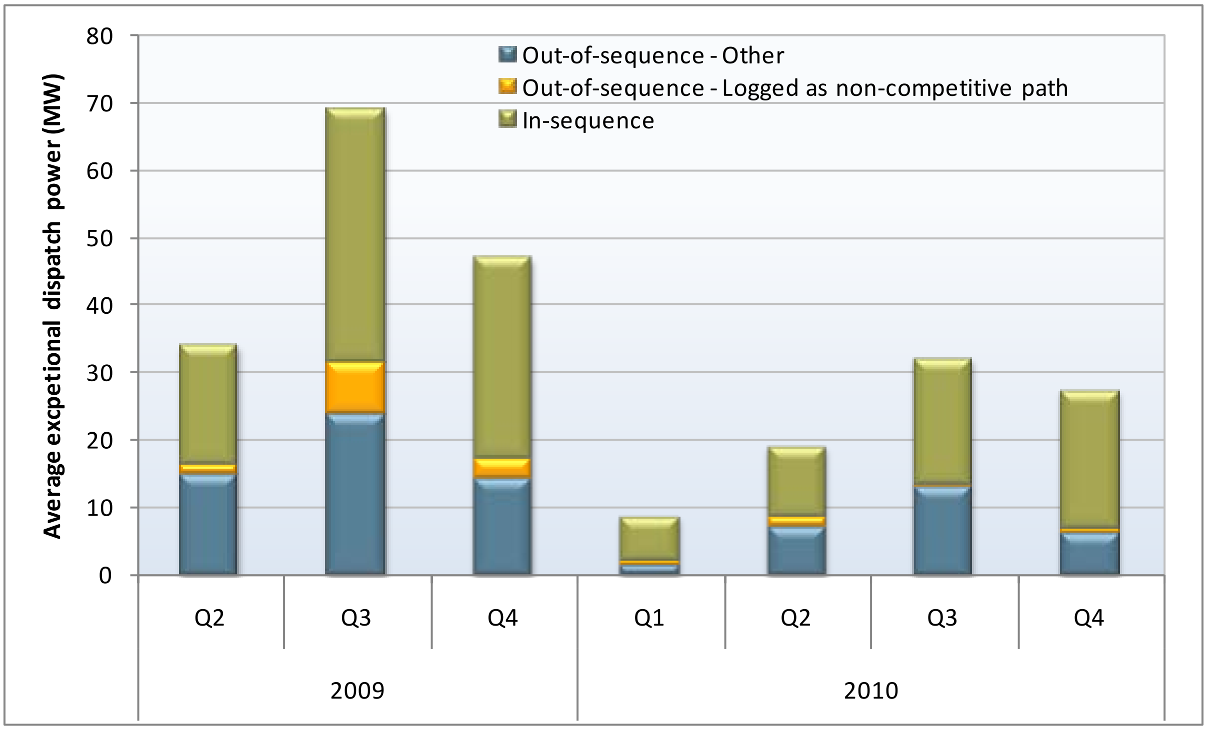
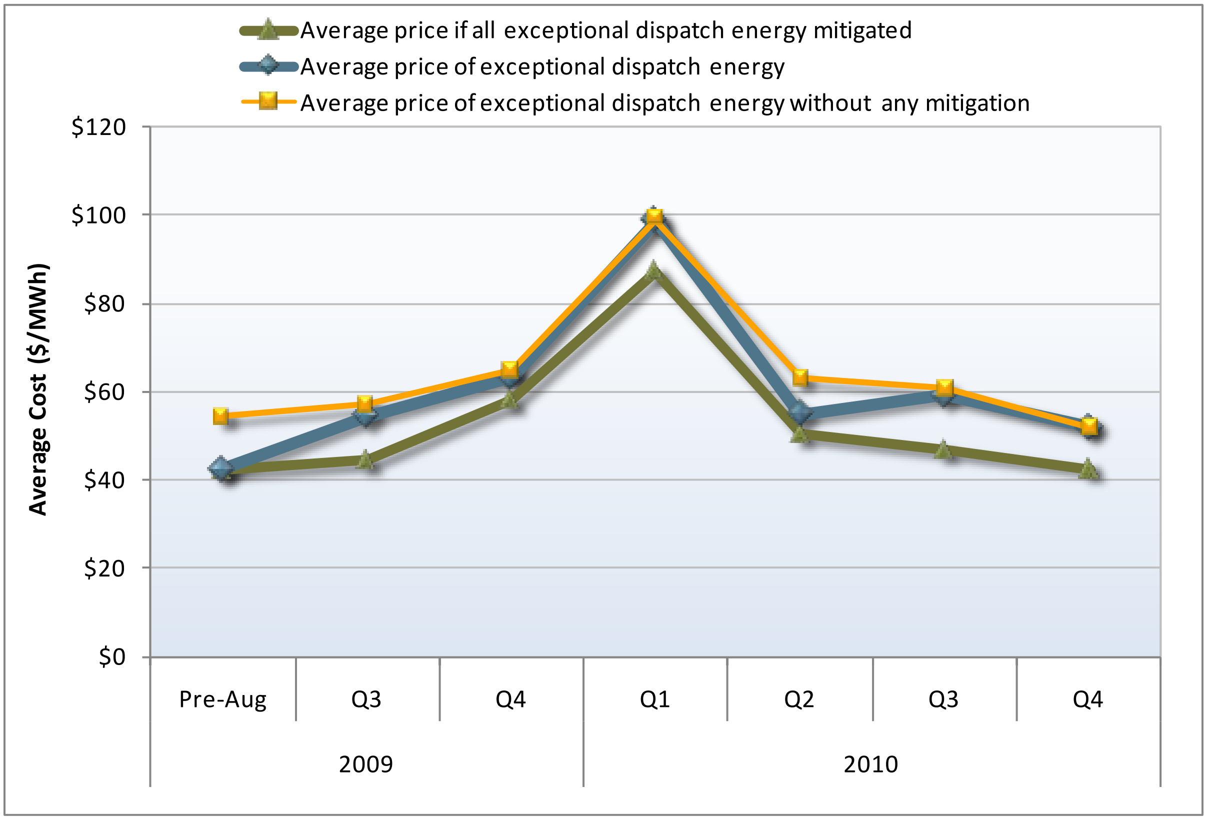



Figure 4.13 shows the average price of out-of-sequence exceptional dispatch energy with and without mitigation.

- The higher yellow line shows average prices if no exceptional dispatches were mitigated.
- The blue line shows the actual average prices paid for exceptional dispatch energy. The difference between this line and the higher yellow line shows the impact of mitigation on the overall price of exceptional dispatch energy.
- The lower green 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 difference in this line and the higher yellow line reflects the degree to which energy bids for exceptional dispatch energy exceed each unit's default energy bid and the market clearing price for energy.

As reflected in Figure 4.13, units receiving out-of-sequence exceptional dispatches received an average of $69/MWh or about $12/MWh (21 percent) above what they would receive if subject to mitigation. Given the low volume of out-of-sequence exceptional dispatch energy, the above-market cost of this exceptional dispatch energy was limited. We estimate that if mitigation were applied to all exceptional dispatch energy in 2010, costs would have been only about $650,000 lower than the exceptional dispatch cost actually paid.

**Figure 4.13 Average prices for out-of-sequence exceptional dispatch energy**




## 4.3.3 Start-up and minimum load bids

Owners of gas-fired generation can choose from two options for their start-up and minimum load bid costs:

- **Proxy costs**. Under this option, each unit's start-up and minimum load costs are automatically calculated each day based on an index of daily spot market gas price and the unit's start-up and minimum load fuel consumption as reported in the master file.[97]
- **Registered costs**. Unit owners selecting this option submit fixed monthly bids for start-up and minimum load costs, which are then used by the daily market software. Registered cost bids are capped at 200 percent of projected costs as calculated under the proxy cost option. One of the reasons for providing this bid-based option was to provide an alternative for generation unit owners

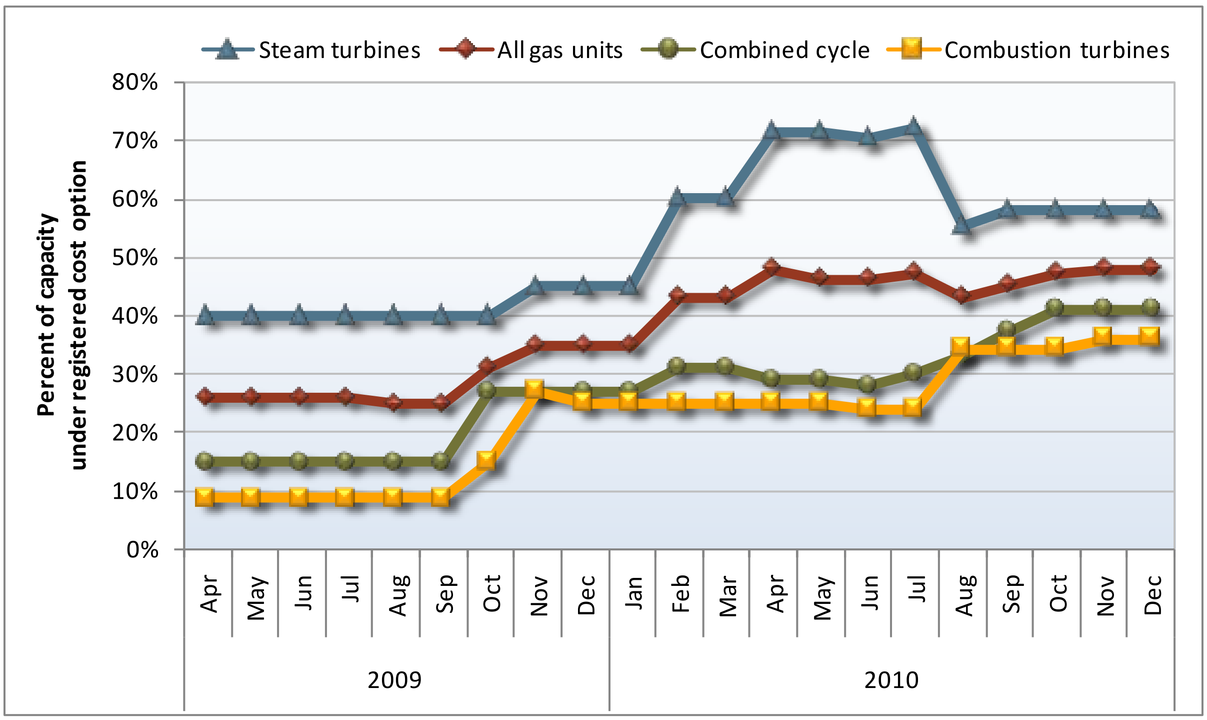
[97] An additional $2 to $6/MW are added to minimum load costs for non-fuel variable O&M costs.

who believed they had significant non-fuel start-up or minimum load costs not covered under the proxy cost option. This option has been revised once since the beginning of the nodal market.[98]

### 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 4.14, this was an increase from about 25 percent to 48 percent by the end of 2010. The increase followed tariff modifications that allow changing registered cost bids every month rather than only every six months.

**Figure 4.14 Gas-fired capacity under registered cost option**




### Bids submitted under registered cost option

After the initial six month period after the start of the new market, the overall level of start-up and minimum load bids have remained relatively stable.

- The portion of capacity at or near the bid cap for start-up costs has remained large and stable, as shown in Figure 4.15. Over 70 percent of the start-up bids are submitted greater than 180 percent of the cap during each quarter of 2010.

[98] The six month restriction on changing between the proxy and registered cost option or modifying registered cost bids was lowered to 30 days to allow participants selecting the registered cost option to submit bids that would better represent their costs. 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. FERC filing September 29, 2009, http://www.caiso.com/23fc/23fcb61b29f50.pdf.

- Registered cost bids for minimum load capacity tend to be much lower and range more widely relative to actual minimum load fuel costs, as shown in Figure 4.16. About 70 percent of minimum load bids are less than 120 percent of the bid cap.
- Combined cycle and steam turbine units tend to submit start-up bids at or near the 200 percent price cap, as shown in Figure 4.17. However, these units submit minimum load bids that tend to be much lower and range more widely, as illustrated in Figure 4.18.
- Gas turbine units tend to submit the higher start-up and minimum load bids relative to their fuel costs (see Figure 4.17 and Figure 4.18).

**Figure 4.15 Registered cost start-up bids by quarter**

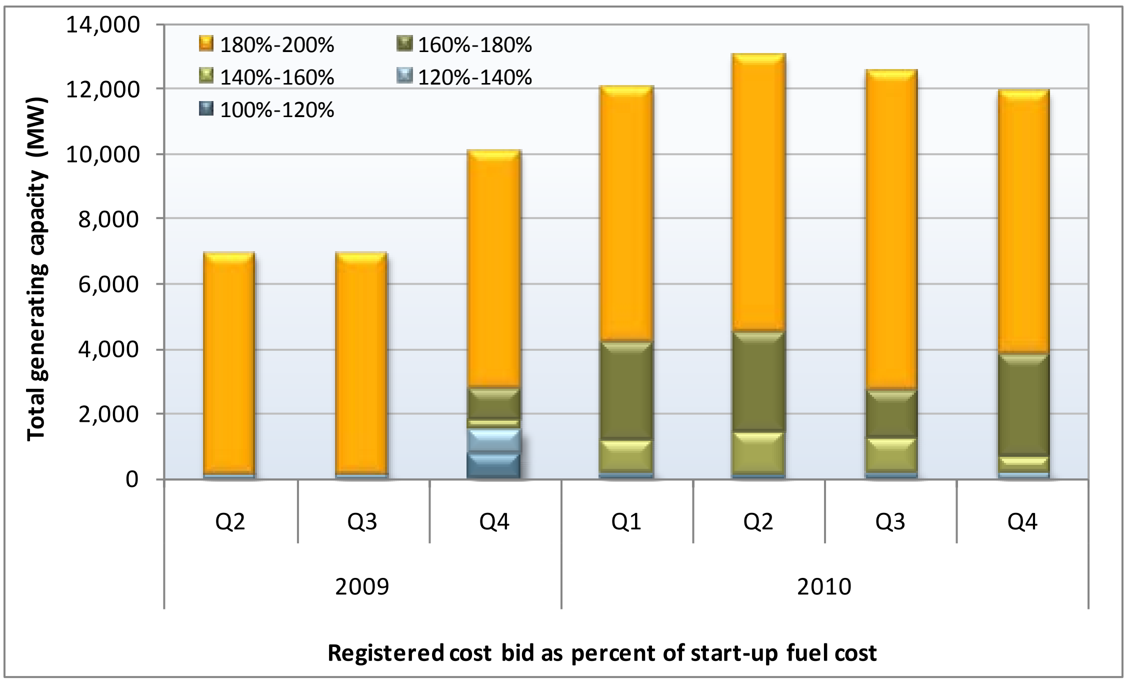


**Figure 4.16 Registered cost minimum load bids by quarter**

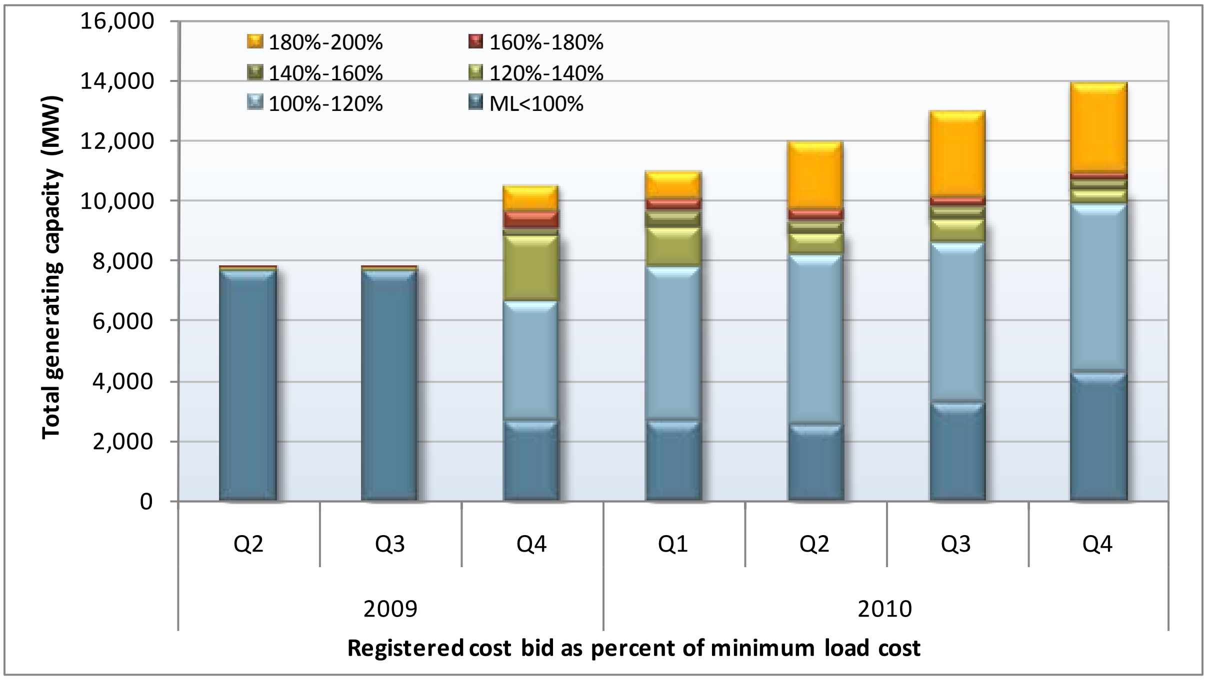



**Figure 4.17 Registered cost start-up bids by generation type - December 2010**

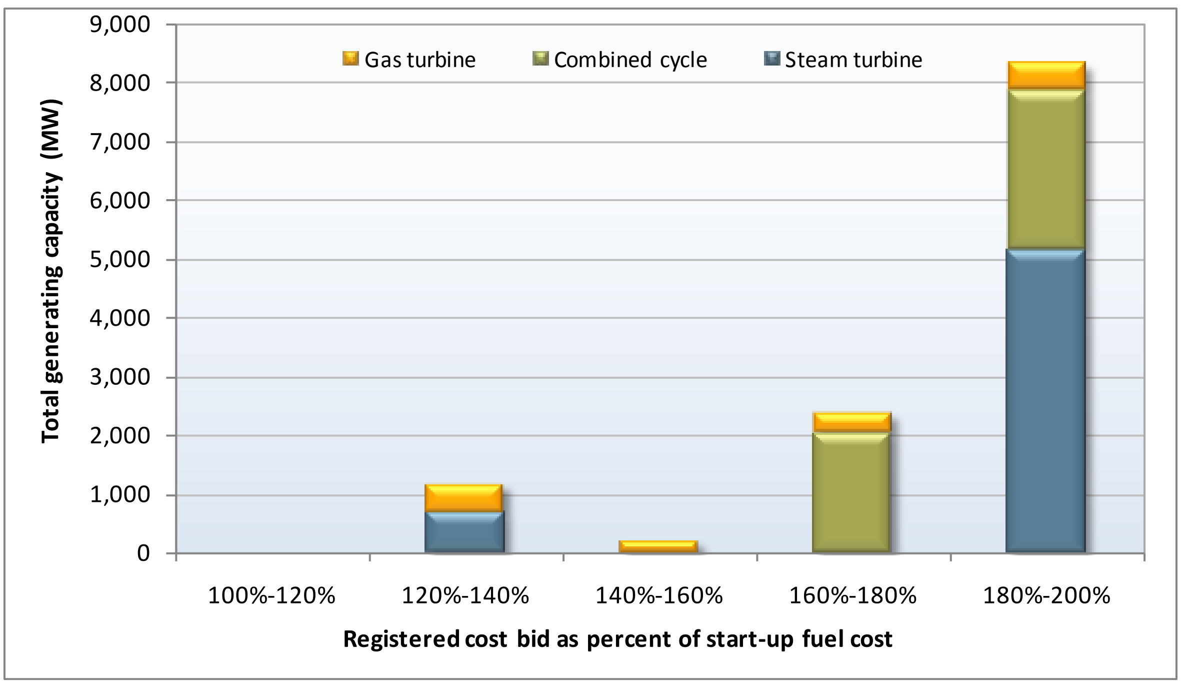
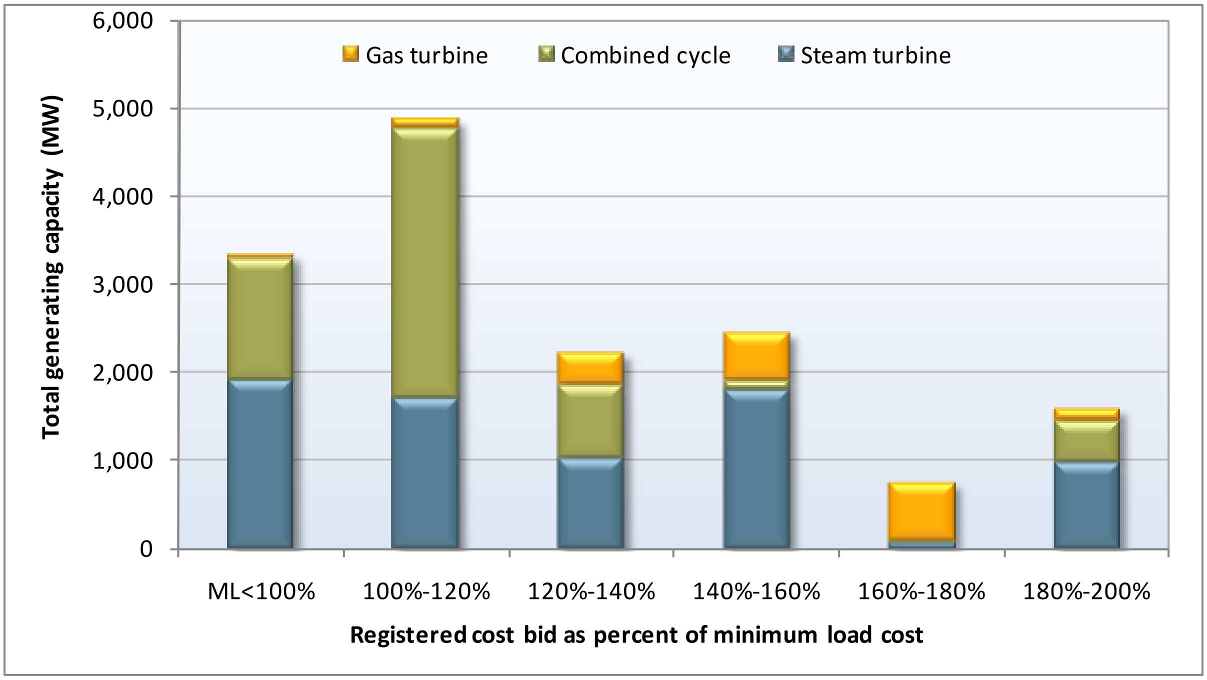


**Figure 4.18 Registered cost minimum load bids by generation Type – December 2010**




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 non-fuel costs they may incur into bids within the cap.

However, as shown in Figure 4.17 and Figure 4.18, a large portion of units under the registered cost option submitted high start-up bids, but submitted minimum load bids close to their minimum load operating 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. Under the 2010 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.

The ISO conducted a stakeholder process in 2010 to consider options for providing further flexibility in the rules for start-up and minimum load bids. In January 2011, the ISO filed to amend its tariff to permit participants to select between the proxy and registered cost option separately for start-up and minimum load costs. The ISO also proposed allowing participants selecting the proxy cost option to bid lower than their daily proxy cost.[99] These modifications were implemented in April 2011.

As noted in DMM's 2009 annual report, numerous stakeholders have also 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. DMM

[99] Start-Up Minimum Load Tariff Amendment in Docket Number ER11-2760-000, January 26, 2011, http://www.caiso.com/2b12/2b12b6a22ed60.pdf.

continues to be supportive of such modifications provided a practical and effective way is developed to assess and limit any fixed component that would be added to start-up or minimum load cost bids.

# 5 Congestion

This chapter provides a review of congestion and the market for congestion revenue rights in 2010. Findings include:

- The frequency and impact of congestion within the ISO system on prices was lower in 2010 than during the first year of the nodal market design in 2009. Internal load and supply conditions were favorable. No major or prolonged transmission outages or contingencies occurred that triggered significant congestion longer than a few days.
- Congestion on inter-ties with other balancing authorities was mixed. This may be attributed to a drop in imports and fewer transmission outages on major inter-ties.
- Net overall profits on congestion revenue rights purchased in the seasonal and monthly markets was minimal, or about $0.01/MWh for all congestion rights.
- Revenues from congestion revenue rights in the predominant direction of congestion were notably less than auction prices, suggesting that congestion was lower than anticipated by market participants.
- Meanwhile, auction prices for congestion revenue rights in the opposite direction of congestion tended to be less than actual congestion, making most of these counterflow congestion revenue rights profitable.

## 5.1 Background

Congestion in a nodal energy market occurs when the market model estimates flows on the transmission network have reached or exceeded the limit of a transmission constraint. This often occurs because of differences in bid prices for different generation resources. The objective of the market software is to minimize the cost of accepted supply bids dispatched to meet demand, and as such electricity flows tend to be high on transmission paths connecting low priced resources with higher-priced load centers. When congestion occurs, resources must be re-dispatched to keep flows of electricity within transmission limits. Congestion can also occur or be exacerbated by outages of a key generation resource or transmission line.

As congestion appears on the network, locational marginal prices at each node area 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. This results in higher prices within congested regions and lower prices in unconstrained regions.

The impact of congestion is included in the total locational marginal price for each node. However, the ISO also calculates and reports on the congestion impact at each pricing location for each pricing interval. This is known as the marginal congestion component of the locational marginal price. Prices at two nodes that differ significantly are often driven by the congestion component. Smaller but more systematic ongoing differences in nodal prices occur when the differences in estimated transmission losses associated with each node are factored into locational marginal prices.

When a constraint is binding, the market software produces a shadow price on that constraint. This represents the 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; it only indicates an incremental cost on the objective function of the market software of the limited transmission on the binding constraint.

There are three major types of transmission constraints that are enforced in the market model and may impact prices when they become binding:

- Flowgates represent single transmission lines or paths with a single maximum limit.
- Branch groups represent multiple transmissions lines with a limit on the total combined flow on these lines.
- Nomograms are more complex constraints that represent interdependencies and interactions between multiple transmission system limitations that must be met simultaneously.

Locational marginal pricing enables the ISO to more economically and efficiently manage congestion and provide price signals to market participants to self-manage congestion. Over the longer term, nodal prices also provide efficient signals that encourage development of new supply and demand-side resources within more constrained areas. Nodal pricing also helps identify transmission upgrades that would be most cost-effective in terms of reduced congestion.

## 5.2 Congestion on inter-ties

Overall congestion on inter-ties connecting the ISO with other regions was generally comparable in 2010 to congestion in 2009, with associated congestion charges somewhat lower in 2010. Congestion charges on ties linking the ISO to supplies in the southwest decreased considerably, while congestion charges on ties with the northwest increased.

Figure 5.1 compares the percentage of hours that major inter-ties were congested in the day-ahead market in 2009 and 2010. Congestion increased on the two major inter-ties linking the ISO with the northwest – Nevada / Oregon Border (NOB) and Pacific A/C Intertie (PACI). The frequency of congestion increased notably on the Inter-mountain Power Project DC Adelanto branch group[100] and the Mead inter-tie, while decreasing significantly on the other major inter-ties with the southwest, Palo Verde and El Dorado.

Table 5.1 provides a summary of the frequency of congestion on these inter-ties along with average and total congestion charges from the day-ahead market. Figure 5.2 provides a graphical comparison of total congestion charges on major inter-ties in 2009 and 2010.

The congestion price reported in Table 5.1 is the shadow price for the binding inter-tie constraint. For a load-serving entity trying to import power over a congested tie point, this congestion price reflects the increase in price incurred per megawatt-hour of load served due to a limitation on the ability to import less expensive energy from a neighboring control area. For a supplier of import energy, congestion represents the decrease in the price they receive for imports sold to the ISO.

[100] The IPP DC Adelanto branch group is not an inter-tie, but is reported in this section because it is imposed in the market model to manage imports into the ISO from the Adelanto area and has been frequently congested in both 2009 and 2010.

As shown in Table 5.1 and Figure 5.2, total congestion charges for imports on the two major inter-ties linking the ISO with the southwest – Palo Verde and El Dorado – fell from $60 million in 2009 to about $22 million in 2010. Congestion on the Palo Verde inter-tie was driven up in 2009 when this path was de-rated on several occasions to accommodate transmission maintenance and upgrades. As shown in Chapter 2, overall imports from the southwest decreased in 2010.

Total congestion on the two major inter-ties linking the ISO with the northwest – Nevada / Oregon Border (NOB) and Pacific A/C Intertie (PACI) – increased from $13 million in 2009 to about $32 million in 2010. As shown in Chapter 2, overall imports from the northwest increased in 2010.

Table 5.1 also includes congestion charges for the Inter-mountain Power Project DC branch group (IPP DC Adelanto). Congestion charges for this constraint increased from $3.8 million in 2009 to $7.9 million in 2010. Outages on this branch group occurred in the second and fourth quarters of 2010 and accounted for the increase in congestion charges over the prior year.

**Figure 5.1 Percent of hours with congestion on major inter-ties in 2009 and 2010**

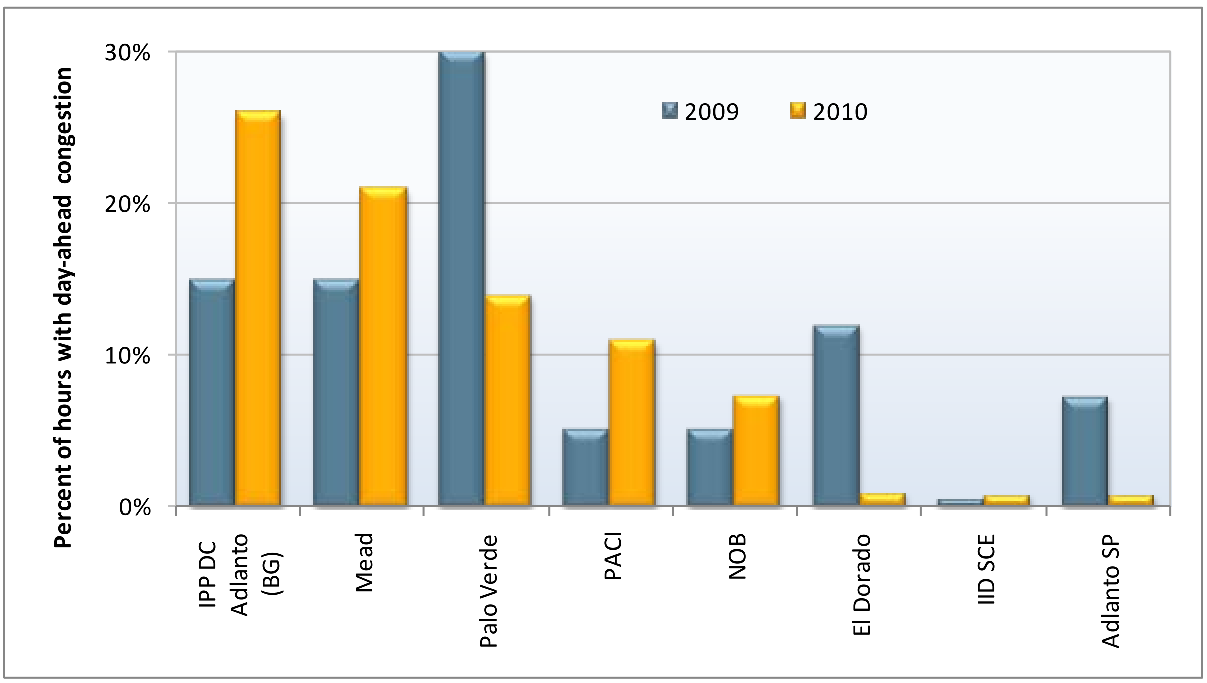
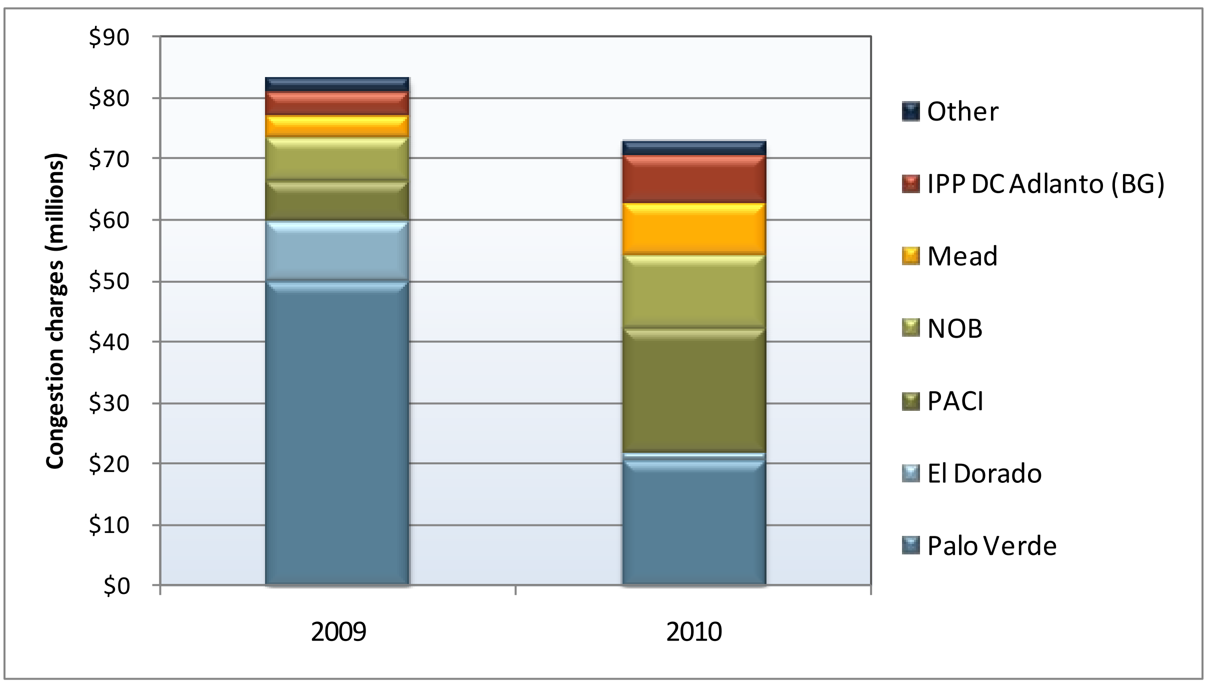


**Table 5.1 Summary of import congestion in 2009 and 2010**

| Import region | Inter-tie | Frequency of import congestion | | Average congestion charge ($/MW) | | Import congestion charges (thousands) | |
|---|---|---|---|---|---|---|---|
| | | 2009 | 2010 | 2009 | 2010 | 2009 | 2010 |
| Northwest | PACI | 5% | 11% | $5.9 | $9.2 | $6,370 | $20,194 |
| | NOB | 5% | 7% | $11.0 | $12.7 | $7,078 | $12,253 |
| | Cascade | 0% | 2% | $15.5 | $6.8 | $1 | $78 |
| Southwest | Palo Verde | 30% | 14% | $8.1 | $7.0 | $49,586 | $20,712 |
| | Mead | 15% | 21% | $3.8 | $5.1 | $3,728 | $8,433 |
| | IPP DC Adlanto (BG) | 15% | 26% | $4.9 | $5.9 | $3,822 | $7,859 |
| | IID - SCE | 1% | 1% | $2.9 | $34.0 | $85 | $1,377 |
| | El Dorado | 12% | 1% | $11.1 | $11.4 | $10,126 | $1,222 |
| | Adlanto SP | 7% | 1% | $2.4 | $5.0 | $1,312 | $389 |
| | Other | | | | | $1,009 | $312 |
| ***Total*** | | | | | | ***$83,118*** | ***$72,829*** |

**Figure 5.2 Import congestion charges on major inter-ties for 2009 and 2010**



## 5.3 Internal congestion

When a constraint within the ISO system is congested, resources on both sides of the constraint are re-dispatched to maintain flows under the constraint limit. In this case, congestion has a clear and direct impact on prices. Congestion at each pricing point is determined by summing the product of the shadow price of each binding constraint and the shift factor relating to the pricing point for each constraint. Appendix A of DMM's 2009 annual report provides a detailed description of this calculation for both load aggregation points and prices within local capacity areas.

Figure 5.3 and Figure 5.4 show the impact that congestion on specific internal constraints had during the congested hours on average day-ahead prices at the system's three load aggregation points. As shown in these figures, most of the constraints were congested for only a small percentage of total hours. Figure 5.3 shows these data for constraints located within Northern California, while Figure 5.4 shows constraints located in Southern California. As shown in these figures, congestion on constraints within Northern California increases prices within the PG&E area, but decreases prices in the SCE and SDG&E areas. Similarly, congestion on constraints within Southern California increases prices within that area and decreases prices in Northern California.

Table 5.2 provides a more detailed analysis by quarters.[101] Table 5.3 shows the impact of congested constraints on average prices for all generation nodes within different local capacity areas. As shown in the tables, congestion on some constraints significantly affected prices. However, since this internal congestion occurred infrequently, it had a minimal impact on overall day-ahead energy prices. Other findings include:

- Congestion on the Midway - Vincent 500 kV line had the highest impact on prices in the PG&E area. In the third quarter of 2010, the impact was over $6/MWh during congested hours. In the fourth quarter, a week-long outage on the Moss Landing - Los Baños-Midway 500 kV line created congestion of roughly $3/MWh in the PG&E load aggregation point price.
- The SCE import branch group was heavily congested in the first quarter of 2010. Enforcement of this constraint began in November 2009. This is a constraint on the total volume of imports as a percentage of load into SCE territory.[102] When this constraint was binding overall prices in the SCE area increased by almost $4/MWh.
- The SDG&E import branch group was derated in the fourth quarter of 2010 for maintenance work on the Otay Mesa - Tijuana 230 kV line. During the period when this constraint was congested in the day-ahead market, prices in the SDG&E area increased by about $2.50/MWh.

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

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

**Figure 5.3 Frequency and impact of congestion on northern internal constraints**

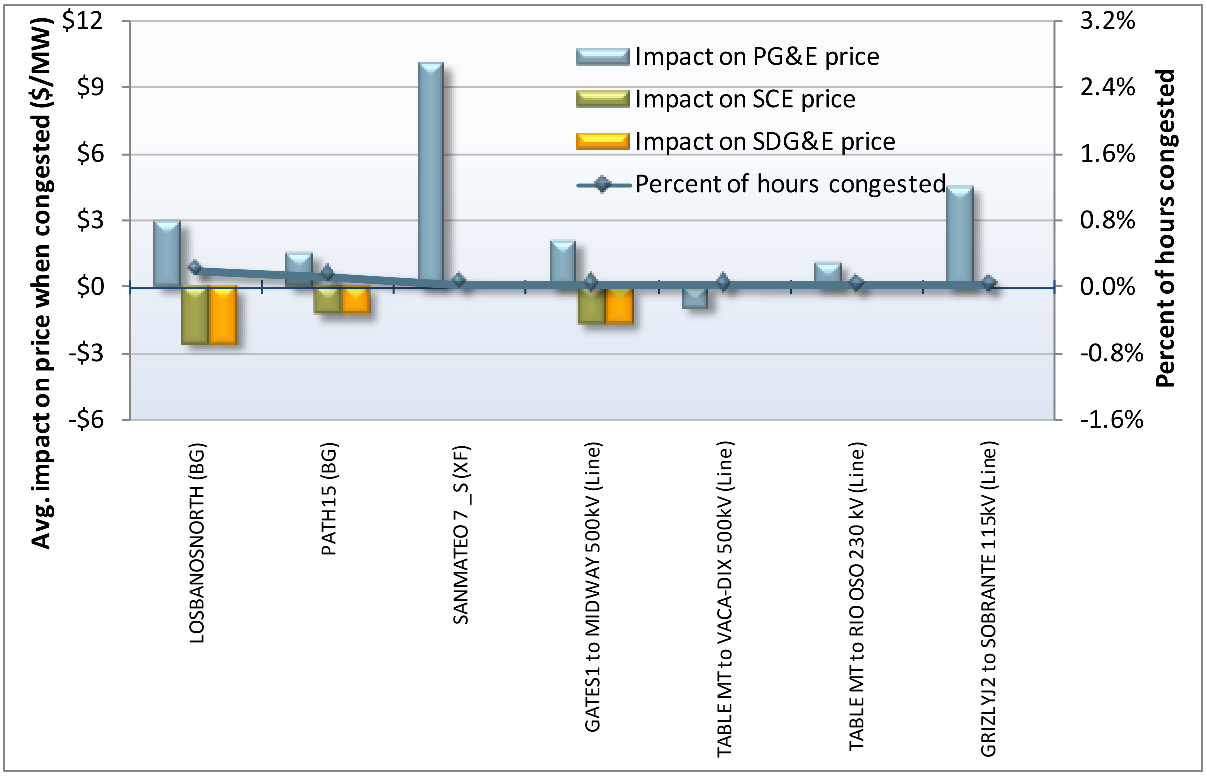



**Figure 5.4 Frequency and impact of congestion on southern internal constraints**

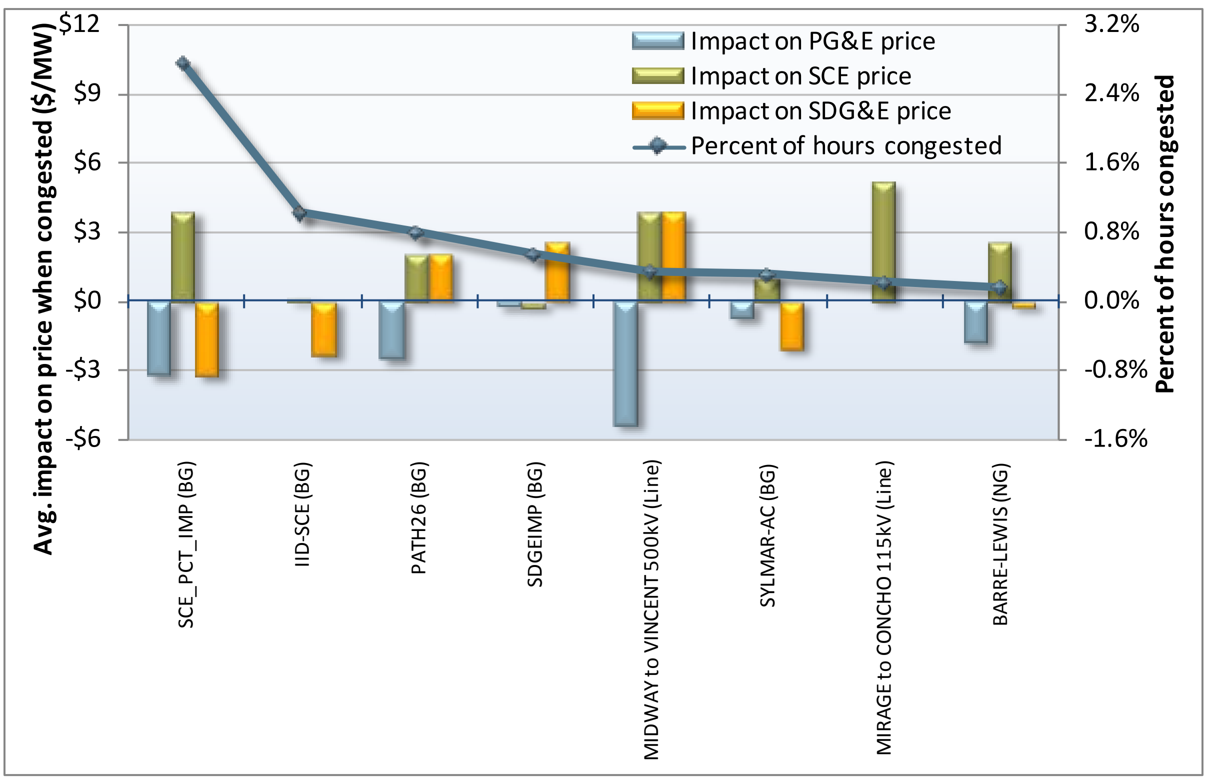


**Table 5.2 Impact of congestion on day-ahead locational marginal prices by load aggregation point**

| Area | Constraint | Congested hours | | | | Q1 | | | Q2 | | | Q3 | | | Q4 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Q1 | Q2 | Q3 | Q4 | PGAE | SCE | SDGE | PGAE | SCE | SDGE | PGAE | SCE | SDGE | PGAE | SCE | SDGE |
| PG&E | HUMBOLDT (BG) | 13 | 136 | 17 | | $1.99 | | | $0.39 | | | $0.21 | | | | | |
| | LOSBANOSNORTH (BG) | | | | 18 | | | | | | | | | | $2.98 | -$2.54 | -$2.54 |
| | MIDWAY to VINCENT 500kV (Line) | | | 23 | | | | | | | | -$6.22 | $4.41 | $4.41 | | | |
| | PATH26 (BG) | 20 | | 43 | | -$2.57 | $2.05 | $2.05 | | | | -$3.33 | $2.62 | $2.62 | | | |
| | SLIC 1108011 VINCNT (NG) | 12 | | | | -$4.34 | $4.20 | $1.27 | | | | | | | | | |
| SCE | BARRE-LEWIS (NG) | | | | 11 | | | | | | | | | | -$2.13 | $2.92 | -$0.03 |
| | SCE_PCT_IMP (BG) | 226 | | | | -$3.30 | $3.93 | -$3.30 | | | | | | | | | |
| SDGE | SDGEIMP (BG) | | | | 42 | | | | | | | | | | -$0.28 | -$0.28 | $2.51 |
| | SYLMAR-AC (BG) | | | | 26 | | | | | | | | | | -$0.78 | $0.99 | -$2.07 |

**Table 5.3 Impact of congestion on day-ahead location marginal prices by local capacity areas**

| Constraint | 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) | 3.4% | $10 | | -$10.28 | | | | | | | $0.00 | | | | $0.00 | $0.00 |
| 1213702-MARTIN (NG) | 1.1% | $14 | $6.89 | | | | | | | | $0.23 | | | | $0.00 | $0.00 |
| **SCE Constraints** | | | | | | | | | | | | | | | | |
| SCE_PCT_IMP (BG) | 3.2% | $7 | -$3.27 | -$3.27 | -$3.27 | -$3.27 | -$3.27 | -$3.27 | -$3.27 | -$3.27 | -$3.27 | $3.79 | $3.79 | | $3.89 | -$3.27 |
| ELNIDO-LAFRESA (NG) | 2.4% | $12 | -$0.29 | -$0.29 | -$0.29 | -$0.29 | -$0.29 | -$0.29 | -$0.29 | -$0.29 | | -$0.29 | -$0.05 | | | |
| PATH26 (BG) | 0.8% | $6 | -$2.58 | -$2.58 | -$2.58 | -$2.58 | -$2.58 | -$2.58 | -$2.58 | -$2.58 | -$2.58 | $2.55 | $2.55 | | $2.03 | $2.03 |
| HUMBOLDT (BG) | 0.6% | $64 | | | | $63.82 | | | | | $0.50 | | | | $0.00 | $0.00 |
| MISSON to POTRERO 115kV (Line) | 0.5% | $6 | -$1.36 | | | | | | | | $0.01 | | | | $0.00 | $0.00 |
| **SDGE Constraints** | | | | | | | | | | | | | | | | |
| SDGEIMP (BG) | 0.5% | $3 | -$0.28 | -$0.28 | -$0.28 | -$0.28 | -$0.28 | -$0.28 | -$0.28 | -$0.28 | -$0.28 | -$0.28 | -$0.28 | | -$0.28 | $2.56 |

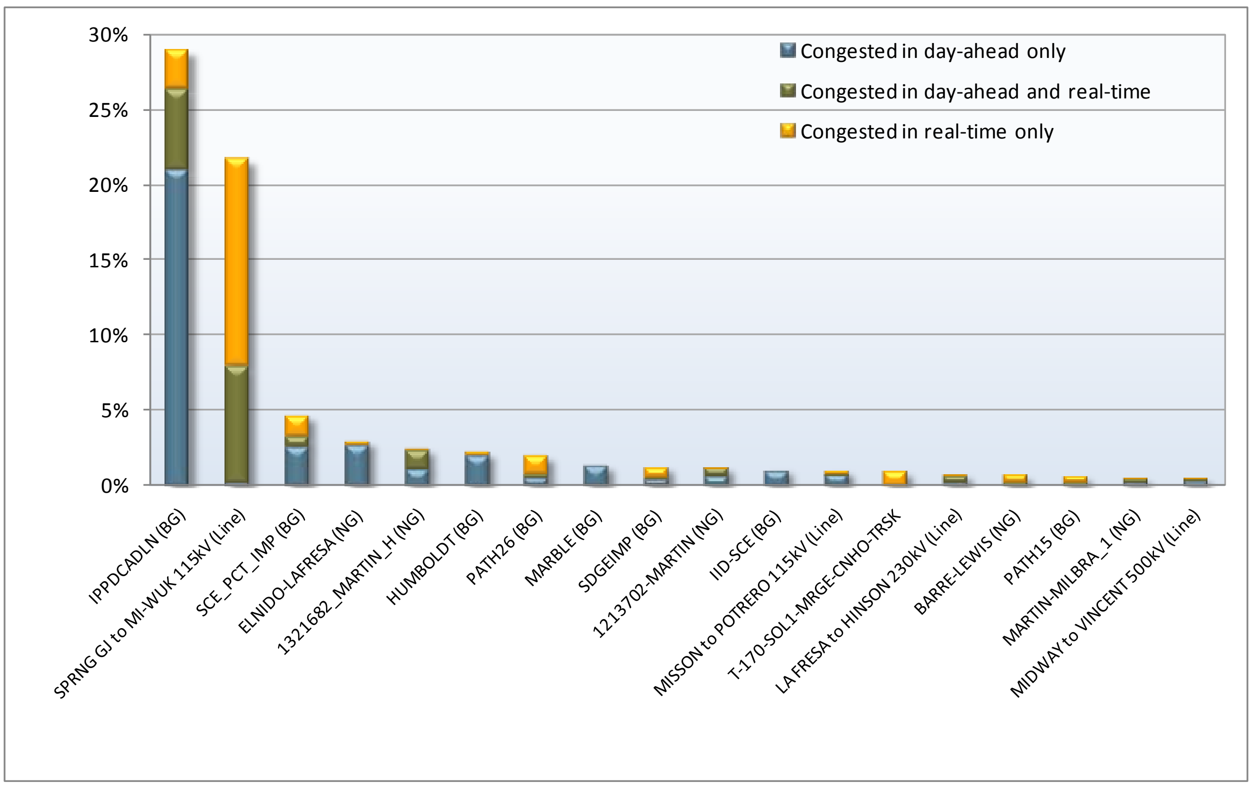
## 5.4 Consistency of congestion

Because most load and generation is scheduled in the day-ahead market, congestion in this market has the greatest overall market impact. Congestion revenue rights are also settled based on day-ahead prices. When real-time congestion occurs, it sometimes results in very high prices because the ability to re-dispatch resources in real-time to relieve congestion is much more limited. However, the overall cost impact of this real-time congestion was very low because of the high level of day-ahead scheduling.

There are many reasons why congestion in the day-ahead market may be different than it is in the hour-ahead and real-time markets. However, the consistency of day-ahead congestion with congestion in the hour-ahead and real-time energy markets provides a potential indicator of the degree to which the market and network model efficiently model and manage similar conditions and congestion. For example, if a constraint is frequently not binding in the day-ahead market but is in the real-time market, this may warrant further review of how the constraint is modeled in the day-ahead and real-time markets. Other factors such as loop flow and conforming of constraints may contribute to this trend.

Figure 5.5 compares the frequency and consistency of congestion on the most frequently binding constraints in 2010. Table 5.4 provides a more detailed comparison.

**Figure 5.5 Consistency of congestion in day-ahead and real-time markets**



As shown in Figure 5.5, congestion in the day-ahead or the real-time markets was extremely low on most internal constraints. Systematic differences in day-ahead and real-time congestion were limited to three constraints:

- The IPP DC Adelanto branch group was the most frequently congested constraint because of line outages. As the location of this constraint is near the ISO interface with neighboring control areas, congestion on this particular branch group does not have a significant impact on electricity prices within the ISO system 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 at an average of 96 MW in the day-ahead market. Three hydro generation units are connected to this line, which can be congested during the spring hydro run-off period as the hydroelectric generation can more easily approach the line limit, particularly in real-time. Because this constraint is located between a small generation pocket and the rest of the ISO system, congestion on this constraint has minimal impact on overall prices for the PG&E area.
- The SCE import limit was highly congested in the day-ahead market in the first quarter of 2010. The average shadow value in the day-ahead market was about $7/MWh. We provided a detailed review of congestion on this branch group in DMM's first quarter report for 2010.[103]

Table 5.5 provides a more detailed comparison of the frequency and consistency of congestion on inter-ties with neighboring control areas in the day-ahead and hour-ahead markets, including:[104]

- The Mead inter-tie was congested 21 percent of the time in the day-ahead market. Even when day-ahead congestion occurred, there were often significant quantities of unused capacity associated with existing transmission rights.[105] Some of this capacity becomes available in the hour-ahead market, which tends to result in less congestion in the hour-ahead market.
- The Palo Verde inter-tie was congested about 14 percent of the time in the day-ahead market, primarily because of planned outages and line maintenance.
- The Pacific AC inter-tie was congested about 11 percent of the hours in the day-ahead market, again primarily because of planned outages and line maintenance.

On many constraints, the overall frequency of congestion in the day-ahead market tended to be slightly higher than in the real-time. This may reflect the fact that in real-time, operators can adjust constraint limits upwards to avoid congestion if actual real-time flows are observed to be lower than flows calculated by the market software. This is discussed in more detail in Section 5.6.

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[103] *Quarterly Report on Market Issues and Performance*, June 2, 2010, http://www.caiso.com/27a9/27a9742b51210.pdf.

[104] Real-time congestion on inter-ties is based on congestion in the hour-ahead market. Real-time congestion for internal constraints is based on congestion in the 5-minute dispatch market. 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 congestion frequency for hour-ahead and real-time markets reported in Table 5.5 is overstated, compared to a measure that counts congestion on a sub-hour basis.

[105] Capacity is reserved for existing transmission contracts (ETCs) and transmission ownership rights (TORs). These transmission rights are reserved until after the completion of the hour-ahead market, unless they are released by the participant prior to the running of the market. The participant may choose to schedule or not schedule power on the reserved transmission. This reduces the amount of transmission capacity available for the market, regardless of whether the capacity is used by the participant or not.

**Table 5.4 Summary of day-ahead and real-time congestion on internal constraints**

| Constraint Name | Average Binding Limit (MW) | 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) | 580 | 26.3% | 8.0% | 20.9% | $7 | 2.6% | $75 | 5.4% | $8 | $68 |
| SPRNG GJ to MI-WUK 115kV (Line) | 96 | 7.9% | 21.5% | 0.2% | $7 | 13.8% | $48 | 7.7% | $8 | $62 |
| SCE_PCT_IMP (BG) | 6,588 | 3.3% | 2.1% | 2.5% | $7 | 1.4% | $205 | 0.8% | $9 | $165 |
| ELNIDO-LAFRESA (NG) | 639 | 2.6% | 0.3% | 2.6% | $12 | 0.3% | $103 | 0.0% | | |
| 1321682_MARTIN_H (NG) | 193 | 2.3% | 1.3% | 1.1% | $24 | 0.1% | $289 | 1.2% | $14 | $187 |
| HUMBOLDT (BG) | 43 | 1.9% | 0.2% | 1.9% | $46 | 0.2% | $338 | 0.0% | | |
| MARBLE (BG)* | 0 | 1.3% | 0.0% | 1.3% | $273 | 0.0% | | 0.0% | | |
| 1213702-MARTIN (NG) | 193 | 1.1% | 0.6% | 0.7% | $14 | 0.1% | $256 | 0.5% | $14 | $122 |
| IID-SCE (BG) | 535 | 1.0% | 0.0% | 1.0% | $95 | 0.0% | | 0.0% | | |
| PATH26 (BG) | 1,495 | 0.8% | 1.5% | 0.5% | $4 | 1.2% | $149 | 0.3% | $8 | $80 |
| MISSON to POTRERO 115kV (Line) | 133 | 0.7% | 0.3% | 0.7% | $5 | 0.3% | $571 | 0.0% | $6 | $500 |
| LA FRESA to HINSON 230kV (Line) | 845 | 0.6% | 0.6% | 0.2% | $20 | 0.2% | $180 | 0.4% | $14 | $130 |
| SDGEIMP (BG) | 1,879 | 0.5% | 0.8% | 0.4% | $2 | 0.7% | $329 | 0.1% | $4 | $171 |
| BARRE-LEWIS (NG) | 1,470 | 0.2% | 0.6% | 0.1% | $33 | 0.5% | $822 | 0.1% | $43 | $763 |
| PATH15 (BG) | 3,050 | 0.1% | 0.6% | 0.1% | $4 | 0.5% | $40 | 0.1% | $2 | $16 |

* Marble (BG) has stranded load and therefore always rated non-zero in the import limit and 0 MW in the export limit. When bids are submitted in the 0 MW rated direction, but do not clear, the branch group can be considered congested because a 0MW flow is equal to a 0MW limit.

**Table 5.5 Summary of day-ahead and hour-ahead congestion on inter-ties**

| Inter-Tie name | Full (Import) Rating (MW) | Total Binding Frequency in IFM | Total Binding Frequency in HASP | Binding in IFM Only | | Binding in HASP Only | | Binding in IFM and HASP | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Binding Frequency | Avg. Shadow Price | Binding Frequency | Avg. Shadow Price | Binding Frequency | Avg. SP IFM | Avg. SP HASP |
| MEAD_ITC | 1460 | 21.1% | 24.7% | 6.6% | $4 | 10.1% | $8 | 14.6% | $6 | $10 |
| PALOVRDE_ITC | 3328 | 13.7% | 8.6% | 8.1% | $6 | 2.9% | $15 | 5.6% | $10 | $12 |
| PACI_ITC | 3200 | 10.5% | 8.6% | 4.9% | $7 | 3.0% | $11 | 5.6% | $11 | $18 |
| SILVERPK_ITC | 17 | 9.4% | 7.4% | 7.1% | $15 | 5.2% | $27 | 2.3% | $14 | $20 |
| NOB_ITC | 1564 | 7.4% | 6.0% | 3.1% | $9 | 1.6% | $18 | 4.3% | $15 | $20 |
| CASCADE_ITC | 100 | 2.3% | 2.9% | 1.2% | $10 | 1.8% | $21 | 1.1% | $7 | $24 |
| SUMMIT_ITC | 120 | 1.7% | 1.6% | 1.2% | $31 | 1.1% | $27 | 0.5% | $29 | $20 |
| ELDORADO_ITC | 1655 | 1.0% | 0.6% | 0.9% | $10 | 0.5% | $9 | 0.1% | $8 | $6 |
| COTPISO_ITC | 33 | 0.9% | 0.7% | 0.6% | $10 | 0.4% | $24 | 0.3% | $12 | $21 |
| ADLANTO-SP_ITC | 1218 | 0.8% | 0.4% | 0.5% | $6 | 0.2% | $10 | 0.2% | $3 | $14 |
| PARKER_ITC | 220 | 0.3% | 0.6% | 0.2% | $37 | 0.5% | $22 | 0.1% | $11 | $28 |
| BLYTHE_ITC | 194 | 0.3% | 0.6% | 0.3% | $21 | 0.5% | $32 | 0.0% | $25 | $13 |

## 5.5 Impact of congestion on prices

This section provides a more detailed analysis of locational price differences in the day-ahead and real-time markets because of congestion. 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

Price differences because of congestion between different areas of the ISO system are based on the congestion component of the locational marginal prices as a percent of the total system energy price.

This approach captures price differences caused by congestion without including price differences that result from differences in transmission losses at different locations.

Table 5.6 shows this measure of locational price differences, along with the average congestion component and the system energy price for the local capacity areas within the system. The average congestion component for generation nodes in different local capacity areas was minimal in most quarters. There was more congestion with higher impacts on prices in the first months of the new market, which resulted in higher congestion components in some local capacity areas in April and May 2009.

In 2010, congestion has remained low in most areas but was highest in the first quarter of 2010. The Humboldt sub-region remained the highest and most consistently congested region. For part of 2010, exceptional dispatches were used to manage constraints in the Humboldt area. As new resources were added, congestion in the Humboldt sub-region declined. Overall, the average congestion component increased in 2010 compared to 2009 in most sub-regions.

In PG&E, the average congestion component was negative in all regions but Humboldt. This reflects that congestion on major constraints in Southern California reduce prices in the PG&E area, as shown previously in Figure 5.4. The overall frequency and impact of several of these constraints – such as Path 26, the SCE import branch group and the Midway - Vincent 500kV line – was relatively high and outweighed the overall impact of congestion on other constraints that raise prices in the PG&E area.

**Table 5.6 Congestion as a percent of total system energy price by local capacity area**

| | | Average of Congestion LMP as Percent of System LMP | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LAP | LCA | 2009 Q2 | 2009 Q3 | 2009 Q4 | 2010 Q1 | 2010 Q2 | 2010 Q3 | 2010 Q4 | 2009 Avg. | 2010 Avg. | 2009 Avg. LMP (congestion) | 2010 Avg. LMP (congestion) |
| PG&E | Bay Area | 1.2% | 0.4% | -0.4% | -0.9% | -0.2% | -0.1% | 0.1% | 0.3% | -0.3% | $0.11 | -$0.12 |
| | Fresno | 0.9% | 0.3% | -0.9% | -0.9% | -0.2% | -0.2% | -0.1% | 0.0% | -0.4% | $0.00 | -$0.16 |
| | Humboldt | 4.6% | 11.5% | 3.1% | 1.0% | 6.8% | 0.0% | 0.0% | 5.9% | 1.7% | $2.00 | $0.60 |
| | Kern | 0.2% | -0.4% | -1.2% | -0.9% | -0.5% | -0.2% | -0.1% | -0.6% | -0.5% | -$0.20 | -$0.19 |
| | North Coast North Bay | 1.0% | 0.4% | -0.4% | -1.1% | -0.2% | -0.3% | 0.0% | 0.3% | -0.5% | $0.09 | -$0.19 |
| | Sierra | 1.9% | 0.5% | -1.3% | -0.9% | -0.7% | 0.2% | 0.4% | 0.2% | -0.4% | $0.07 | -$0.15 |
| | Stockton | -2.2% | 0.2% | -0.3% | -0.9% | -1.9% | -0.2% | 0.0% | -0.5% | -0.9% | -$0.18 | -$0.34 |
| SCE | Big Creek-Ventura | 0.5% | -0.3% | 0.9% | 1.1% | 0.2% | 0.4% | 0.2% | 0.3% | 0.5% | $0.12 | $0.18 |
| | LA Basin | 0.2% | -0.1% | 0.8% | 1.1% | 0.2% | 0.1% | 0.0% | 0.2% | 0.5% | $0.08 | $0.18 |
| SDG&E | San Diego | 1.7% | -0.2% | -1.4% | -0.7% | -0.2% | -0.3% | -0.2% | -0.2% | -0.3% | -$0.07 | -$0.11 |

## Price differences by local capacity area

As noted above, day-ahead and real-time prices in local capacity areas can diverge as a result of differences in congestion between these two markets. Table 5.7 and Table 5.8 show quarterly average peak hour and off-peak hour price differences by local capacity area, and also include the results for different sub-regions within the San Francisco bay area and Los Angeles local capacity areas. Various shades of red in the tables 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.

**Table 5.7 Average difference between real-time and day-ahead price by local capacity area – peak hours**

| | | 2009 | | | 2010 | | | |
|---|---|---|---|---|---|---|---|---|
| Region | LCA (Sub-Area) | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| NP26 | Humboldt | 20% | 5% | 11% | -1% | -3% | -5% | 19% |
| | Sierra | 3% | 8% | 5% | -1% | 6% | -1% | 17% |
| | North Coast North Bay | 2% | 7% | 5% | -1% | 8% | -1% | 17% |
| | Bay Area (Pittsburg) | 3% | 7% | 4% | -1% | 10% | -1% | 17% |
| | Bay Area (San Francisco) | 5% | 8% | 4% | 0% | 11% | 6% | 29% |
| | Bay Area (San Jose) | 2% | 7% | 5% | -1% | 12% | -1% | 18% |
| | Bay Area (Other) | 7% | 8% | 6% | -1% | 12% | -1% | 17% |
| | Stockton | -6% | 7% | 5% | -1% | -13% | -13% | 17% |
| | Fresno | 0% | 2% | 2% | -1% | 7% | -1% | 17% |
| SP26 | Kern | -2% | -2% | 2% | -2% | 7% | -1% | 18% |
| | Big Creek-Ventura | 34% | 4% | 3% | 19% | 8% | 18% | 22% |
| | LA Basin (Eastern) | 34% | 4% | 0% | 16% | 7% | 23% | 12% |
| | LA Basin (Western) | 34% | 5% | 2% | 17% | 8% | 21% | 26% |
| | LA Basin (Other) | 34% | 6% | 6% | 17% | 8% | 21% | 29% |
| | San Diego | 79% | 11% | 3% | 3% | 10% | 16% | 46% |
| | No LCA | 6% | 5% | 4% | 2% | 7% | 3% | 18% |

**Table 5.8 Average difference between real-time and day-ahead price by local capacity area – off-peak hours**

| | | 2009 | | | 2010 | | | |
|---|---|---|---|---|---|---|---|---|
| Region | LCA (Sub-Area) | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| NP26 | Humboldt | 24% | -17% | 13% | -5% | 36% | -7% | 20% |
| | Sierra | 17% | -14% | 9% | -4% | 55% | -5% | 16% |
| | North Coast North Bay | 16% | -14% | 10% | -4% | 55% | -4% | 17% |
| | Bay Area (Pittsburg) | 16% | -14% | 9% | -4% | 55% | -5% | 16% |
| | Bay Area (San Francisco) | 17% | -14% | 9% | -4% | 55% | -4% | 17% |
| | Bay Area (San Jose) | 16% | -14% | 9% | -4% | 55% | -4% | 17% |
| | Bay Area (Other) | 18% | -14% | 9% | -4% | 56% | -5% | 16% |
| | Stockton | 16% | -14% | 9% | -4% | 30% | -20% | 16% |
| | Fresno | 16% | -18% | 4% | -4% | 55% | -4% | 16% |
| SP26 | Kern | 7% | -22% | 3% | -4% | 53% | -4% | 17% |
| | Big Creek-Ventura | 5% | -22% | -2% | 0% | 52% | -2% | 18% |
| | LA Basin (Eastern) | 5% | -22% | -2% | 0% | 52% | -1% | 18% |
| | LA Basin (Western) | 5% | -22% | -2% | 0% | 53% | -2% | 19% |
| | LA Basin (Other) | 5% | -22% | -1% | 1% | 53% | -2% | 19% |
| | San Diego | 39% | -19% | -1% | -4% | 54% | -2% | 23% |
| | No LCA | 14% | -16% | 7% | -3% | 55% | -4% | 17% |

As shown in Table 5.7 and Table 5.8, differences in day-ahead and real-time prices between local capacity areas and sub-areas within each load aggregation point were very limited in 2010. This reflects that divergences in day-ahead and real-time prices have been primarily driven by specific grid and market conditions rather than congestion, as outlined in Section 3.3. However, there are specific examples of congestion related differences impacting the peak and off-peak hours:

- In SP26 the Kern local capacity area experienced price divergence in the first and third quarters of 2010, particularly because of high demand in Southern California (north-to-south flows) and line outages.[106]
- The limit on the Humboldt branch group was conformed for grid reliability reasons and conditions. This issue was addressed in a November technical bulletin.[107]
- In the San Francisco Bay area, the divergence in the fourth quarter is associated with the MARTIN_H_NG nomogram. This nomogram was enforced for the scheduled outage at Martin "H" station near San Francisco.
- The Stockton local capacity area, which includes the Spring GAP hydroelectric system, is an area of constrained generation, particularly during the spring hydro run-off. The SPRNG GJ to MI-WUK 115 kV line was frequently congested in the second and third quarters of 2010, leading to divergent day-ahead and real-time market prices.
- In November and December, price divergence occurred in the eastern LA Basin, primarily because of congestion on the Barre-Lewis nomogram. This congestion was a result of outages on the Mira Loma-Olinda and Mira Loma-Walnut 230 kV lines. Maintenance on Palo Verde 500 kV in late October and beginning of November also contributed to the price divergence.
- Throughout the fourth quarter of 2010, the San Diego branch group was adjusted down to maintain reliability margins. This was a result of a combination of outages.[108] Section 5.6 provides a more detailed discussion of adjusting and conforming transmission limits.

## 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. The two most common reasons to adjust transmission limits are to:

- Achieve greater alignment between the energy flows calculated by the market software and those observed or predicted in real-time operation across various paths. For example, operators sometimes adjust operating limits upward to avoid phantom congestion in the day-ahead or real-

[106] The Midway-Vincent 500 kV line rating was impacted by fires in August and scheduled maintenance in September.

[107] *Technical Bulletin 2010-11-01 Minimum Generation Online Commitment in Humboldt Area*, November 24, 2010, http://www.caiso.com/2858/2858789a3c1c0.pdf.

[108] The San Onofre Nuclear Unit #3 was off line for refueling from October through December. Outages occurred In October, November and December for the Imperial Valley 500 kV line, Imperial Valley-La Rosita 230 kV line, Lugo-Victor 230 kV line and the San Luis Rey - San Onofre 230 kV lines. Outages occurred for the IVALLYBANK_XFBG and the Imperial Valley 500 kV line in October and November respectively. Also, in November there was a loss of CFE Generation and, as a result, the import limit reached its max.

time market. Phantom congestion refers to cases when congestion occurs in the market model when the actual physical flows are below the limit in the market model. In other cases, operators adjust constraints in the day-ahead market to mitigate the potential for congestion occurring in the real-time market.

- Set prudent operating margins, consistent with good utility practice, to ensure reliable operation under conditions of unpredictable and uncontrollable flow volatility.

Table 5.9 lists all constraints conformed in the real-time market. This table only presents the statistics calculated for intervals in which the conforming action moved the effective limit from the actual limit. As shown in Table 5.9:

- A total of 21 constraints were conformed greater than 5 percent of the time. Only eight of these constraints were conformed in real-time more than 20 percent.
- There was strong consistency in conforming between the hour-ahead and real-time markets in both frequency and level of adjustment.
- A small portion of all constraints were conformed in the real-time market during a significant percentage of hours. Only 14 constraints were conformed over 10 percent of the hours, with only eight being conformed between 20 and 97 percent of the time.
- Of the 15 constraints listed in Table 5.9, about 27 percent – or 4 constraints – were conformed only in the upward direction to avoid congestion that was not actually occurring based on observed flows.
- The SCE percent import branch group was mostly conformed upward.
- In September, the ISO automated the enforcement of an under-frequency import limit in the market model to meet the 25 percent minimum generation requirement for the local San Diego area.[109]
- The SDG&E CFE import limit and the SDG&E import limit were the major branch groups conformed mostly downward. Operators tend to conform down the operating limit of these major transmission lines to maintain an adequate reliability margin. The margin ensures the flows stay within the lines' operating limits, even when sudden unpredictable flow changes occur in real-time.

Table 5.10 compares the consistency of conforming limits in real-time to hour-ahead for every interval. This analysis indicates conforming performed in the hour-ahead and real-time markets is consistently applied across both markets.

[109] *Technical Bulletin 2010-09-03: Local San Diego Area 25% Minimum Generation Requirement*, http://www.caiso.com/2818/281883a449830.pdf.

## Table 5.9 Real-time congestion and conforming of limits by constraint

| 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 |
| LUGO_VINCENT (NG) | 97.7% | 97.6% | 135 | | | 0.1% | 74 | | |
| SCE_PCT_IMP (BG) | 53.0% | 48.9% | 115 | 0.14% | $224 | 4.1% | 98 | 0.55% | $173 |
| HUMBOLDT (BG) | 49.0% | 43.4% | 156 | 0.03% | $89 | 5.6% | 80 | 0.04% | $457 |
| SSONGS (BG) | 26.0% | 0.0% | 105 | | | 26.0% | 85 | 0.03% | $94 |
| T-165 TABLMT_RIOVACADX (NG) | 25.3% | 25.3% | 115 | <0.1% | $2,139 | <0.1% | 83 | | |
| SDGE_CFEIMP (BG) | 23.5% | 0.4% | 144 | | | 23.1% | 94 | 0.14% | $494 |
| SPRNG GJ to MI-WUK 115kV (Line) | 22.9% | 0.1% | 101 | 0.01% | $5 | 22.9% | 93 | 17.97% | $57 |
| HUMBOLDT 1 (XF) | 20.4% | 20.2% | 110 | 0.01% | $619 | 0.2% | 47 | | |
| SILVERGT to MLMS3TAP 230kV (Line) | 19.9% | 19.9% | 120 | | | | | | |
| ORO LOMA to EL NIDO 115kV (Line) | 19.0% | 19.0% | 110 | | | | | | |
| SDGEIMP (BG) | 18.7% | 0.1% | 102 | <0.1% | $8 | 18.6% | 88 | 0.33% | $236 |
| MISSON to POTRERO 115kV (Line) | 17.9% | 17.9% | 111 | 0.05% | $609 | | | | |
| ELNIDO-LAFRESA (NG) | 16.1% | 14.1% | 107 | 0.01% | $5 | 2.1% | 97 | 0.21% | $79 |
| BARRE-LEWIS (NG) | 12.9% | 12.2% | 104 | <0.1% | $21 | 0.7% | 94 | 0.34% | $927 |
| STANISLS to RVRBK J2 115kV (Line) | 9.9% | 9.9% | 110 | | | | | | |
| HIGGINS to BELL PGE 115kV (Line) | 9.5% | 9.5% | 110 | <0.1% | $896 | | | | |
| SANMATEO to RAVENSWD 115kV (Line) | 9.0% | 9.0% | 112 | 0.03% | $380 | | | | |
| 1304243_1304282_SOL_3 | 8.6% | 0.0% | 102 | | | 8.6% | 75 | 0.03% | $641 |
| LARKIN to POTRERO 115kV (Line) | 7.4% | 7.4% | 117 | <0.1% | $750 | | | | |
| VICTVL (BG) | 6.9% | 6.9% | 115 | | | | | | |
| VINCENT 4 _P (XF) | 5.1% | 5.1% | 110 | 0.01% | $677 | | | | |

## Table 5.10 Conforming of constraint limits in hour-ahead and real-time markets

| Flowgate Name | Conforming in RTD | Conforming Level Match in RTD and HASP | Conforming Level Does not Match in RTD and HASP | Avg. Conforming Level Match in RTD and HASP (in%) | Avg. Conforming Level Does not Match in RTD and HASP (in%) |
|---|---|---|---|---|---|
| SCE_PCT_IMP (BG) | 53.0% | 51.7% | 1.3% | 114 | 100 |
| HUMBOLDT (BG) | 49.0% | 48.9% | 0.2% | 147 | 103 |
| ADLANTOSP (MSL) | 48.6% | 48.3% | 0.3% | 100 | 100 |
| MKTPCADLN (MSL) | 48.6% | 48.3% | 0.3% | 100 | 100 |
| SUTTEROBANION (BG) | 48.6% | 48.3% | 0.3% | 100 | 100 |
| IPP-IPPGEN (MSL) | 48.6% | 48.3% | 0.3% | 100 | 100 |
| MONAIPPDC (MSL) | 48.6% | 48.3% | 0.3% | 100 | 100 |
| POTRERO (MSL) | 36.6% | 36.6% | 0.0% | 100 | 100 |
| IPPDCADLN (BG) | 31.4% | 30.6% | 0.8% | 100 | 100 |
| SSONGS (BG) | 26.0% | 26.0% | 0.0% | 85 | 73 |
| SDGE_CFEIMP (BG) | 23.5% | 23.3% | 0.2% | 95 | 92 |
| SPRNG GJ to MI-WUK 115kV (Line) | 22.9% | 22.2% | 0.7% | 93 | 92 |
| HUMBOLDT 1 (XF) | 20.3% | 20.2% | 0.2% | 110 | 87 |
| SILVERGT to MLMS3TAP 230kV (Line) | 19.9% | 19.9% | | 120 | |
| ORO LOMA to EL NIDO 115kV (Line) | 19.0% | 19.0% | 0.0% | 110 | 110 |
| SDGEIMP (BG) | 18.7% | 18.3% | 0.4% | 88 | 87 |
| MISSON to POTRERO 115kV (Line) | 17.9% | 15.8% | 2.1% | 110 | 115 |
| STANISLS to RVRBK J2 115kV (Line) | 9.9% | 9.9% | 0.0% | 110 | 110 |
| HIGGINS to BELL PGE 115kV (Line) | 9.3% | 9.3% | 0.0% | 110 | 115 |
| LARKIN to POTRERO 115kV (Line) | 7.4% | 7.1% | 0.4% | 115 | 157 |
| VICTVL (BG) | 6.9% | | 6.9% | | 115 |
| VINCENT 4 _P (XF) | 5.1% | 5.1% | 0.0% | 110 | 113 |

Congestion in the day-ahead market is reviewed on a regular basis to determine the need for conforming the constraints' operating limits. However, the market limit of constraints was rarely conformed in the day-ahead market. Table 5.11 lists all internal constraints conformed in the day-ahead market.

- The San Bernardino to Devers 230 kV line was conformed downward during transmission outages.
- 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.

**Table 5.11 Conforming of internal constraints in day-ahead market**

| Constraint | Conformed hours | Average conformed limit | Congested intervals | Average shadow price |
|---|---|---|---|---|
| SANBRDNO to DEVERS 230kV (Line) | 2.7% | 93 | | |
| SDGE_CFEIMP (BG) | 1.1% | 95 | | |
| SDGEIMP (BG) | 1.1% | 95 | | |
| COTWDPGE to WHEELBR 115kV (Line) | 0.8% | 107 | | |
| MIDWAY to VINCENT 500kV (Line) | 0.5% | 228 | | |
| T-170-SOL1-MRGE-CNHO-TRSK DA | 0.5% | 108 | | |
| MISSON to POTRERO 115kV (Line) | 0.3% | 120 | | |
| GLEAF TP to RIO OSO 115kV (Line) | 0.3% | 103 | | |
| BARRE to ELLIS 230kV (Line) | 0.3% | 115 | | |
| SN LS OB to SNTA MRA 115kV (Line) | 0.3% | 110 | | |
| AMES DST to NWARK EF 115kV (Line) | 0.3% | 92 | | |
| BAYSHOR1 to MARTIN C 115kV (Line) | 0.3% | 110 | | |
| POTRERO to BAYSHOR1 115kV (Line) | 0.3% | 110 | | |
| BRNSWKT1 to DTCH2TAP 115kV (Line) | 0.3% | 110 | | |
| MIRAGE to CONCHO 115kV (Line) | 0.3% | 110 | 0.07% | $678 |
| DRUM to BRNSWKT2 115kV (Line) | 0.3% | 110 | 0.15% | $11 |
| Miguel_TL13826_OUT | 0.2% | 87 | 0.11% | $6 |

## 5.7 Transmission infrastructure changes

A variety of notable transmission infrastructure changes occurred in 2010. The more significant upgrades or additions are described below:

- Steel River Infrastructure Fund North America built the Trans Bay Cable, a 400 MW, 53 mile, high voltage direct current transmission cable that connects PG&E's Pittsburg and Potrero substations. It began commercial operations on November 23, 2010. This upgrade improved the reliability of service in the San Francisco area and was instrumental in allowing the ISO to release the Potrero power plant from its reliability must-run designation, which was effective December 31, 2010.
- The Oakland Underground Cable Project was completed in May 2010, adding an additional 115 kV underground cable. This project is expected to reduce reliability must-run requirements and congestion in the Bay Area.

- The Southern Transmission System was upgraded in December from 1,920 MW to 2,400 MW. The system is comprised of the Intermountain-Adelanto 500 kV direct current transmission line, which extends between the Intermountain Power Project, near Delta, Utah, and the Adelanto Switching Station in Southern California.
- The Redondo-La Fresa 230 kV line and the Barre-Ellis 230 kV line were upgraded for reliability and to mitigate line overloads.

## 5.8 Congestion revenue rights

Congestion revenue rights are financial instruments offered as part of the nodal design to allow participants to hedge against congestion costs in the day-ahead market. This section provides an overview of congestion revenue market results and trends. Our analyses show:

- A significant increase in the number of congestion revenue rights and amount of megawatts awarded in 2010 when compared to 2009.
- A revenue deficiency in only two of the twelve months, with a $33 million surplus at the end of 2010 that will be allocated to measured demand.
- Average profitability close to $0/MWh in 2010 compared to about $0.11/MWh in 2009, indicating that congestion revenue rights were an efficient financial hedge instrument.

### Background

Locational marginal prices are composed of three components: energy, congestion, and transmission losses. The congestion component can vary widely depending on the location and severity of congestion, and it can be volatile. Market participants can acquire congestion revenue rights as a financial hedge against volatile congestion costs. As a market product, congestion revenue rights are defined by five elements:

- ***Life term —*** Each congestion revenue right has one of three categories of life term: one month, one calendar season, and one calendar season for 10 years. There are four calendar seasons corresponding to the four quarters of the calendar year.
- ***Time-of-use —*** Each congestion revenue right is defined as being for either the peak or off-peak hours as defined by Western Electricity Coordinating Council guidelines.[110]
- ***Megawatt quantity —*** This is the volume of congestion revenue rights allocated or purchased. For instance, one megawatt of congestion revenue rights with a January 2010 monthly life term and on-peak time-of-use represents one megawatt of congestion revenue rights during each of the 400 peak hours during this month.
- ***Sink —*** The sink of a congestion revenue right can be an individual node, load aggregation point, or a group of nodes.

[110] Peak hours are defined as hours ending 7 through 22 excluding Sundays and WECC holidays. All other hours are off-peak hours.

- ***Source* —** The source of a congestion revenue right can be an individual node, load aggregation point or a group of nodes.

The amount received or paid by the congestion revenue right holder each hour is the day-ahead locational market price of this sink minus the locational market price for the source. Prices used to settle congestion revenue rights involving load aggregation points or a group of nodes represent the weighted average of prices at individual nodes.

The congestion revenue rights market is organized into annual and monthly allocation and auction processes.

- In the annual program, rights are allocated and auctioned separately for each of the four calendar seasons. Long-term rights are valid for one calendar season for 10 years. A short-term right is valid for one calendar season of one specific year.
- The monthly program is an auction for rights that are valid for one calendar month of one specific year.

A more detailed explanation of the congestion revenue right processes is provided in the ISO's *2010 Annual Market Performance CRR Report.*[111]

### Market results

Figure 5.6 and Figure 5.7 show the monthly average amount of the various types of congestion revenue rights awarded within a quarter since 2009 for peak and off-peak hours, respectively. As shown in these figures:

- The total volume of congestion revenue rights increased significantly in 2010, primarily because of an increase in the rights purchased in the short term auction. This auction was conducted in November 2009, while the auction for short-term rights for 2009 was conducted in 2008 prior to the start of the nodal market. Thus, the increase in short-term rights purchased for 2010 may reflect a reduction in uncertainty about the value of congestion revenue rights once the nodal market was successfully implemented.
- During 2009, rights purchased through the monthly auction increased each quarter. All other processes for acquiring congestion revenue rights for 2009 were completed in 2008. Therefore, market participants wanting to increase participation in the congestion revenue rights market for 2009 had to do so through the monthly processes.
- In 2010, rights purchased through the monthly auction decreased compared to the fourth quarter of 2009. This reflects the fact that participants wanting to procure rights for 2010 relied much more heavily on the short-term auction for seasonal congestion revenue rights conducted in November 2009.
- Congestion revenue rights awarded through the allocation process do not vary significantly from quarter to quarter. The small variation between calendar seasons reflects that the allocation process is based on historical load.

[111] http://www.caiso.com/2b44/2b44c6c4383b0.pdf.

**Figure 5.6 Allocated and awarded congestion revenue rights (peak)**

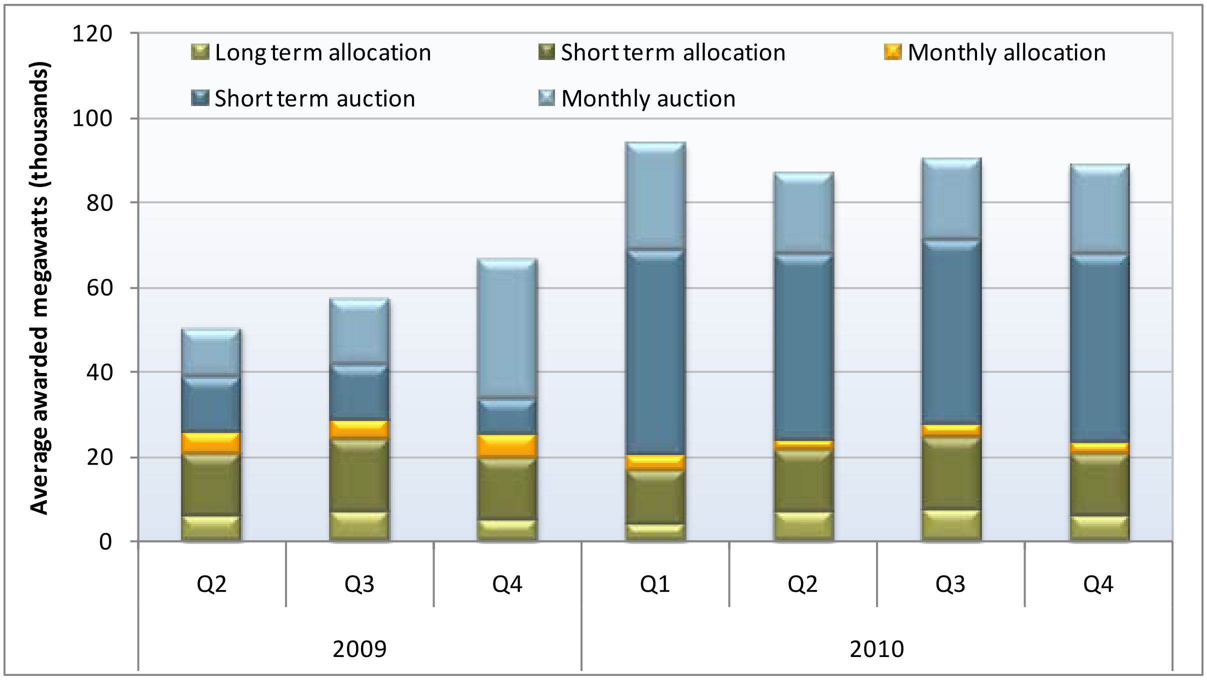



**Figure 5.7 Allocated and awarded congestion revenue rights (off-peak)**

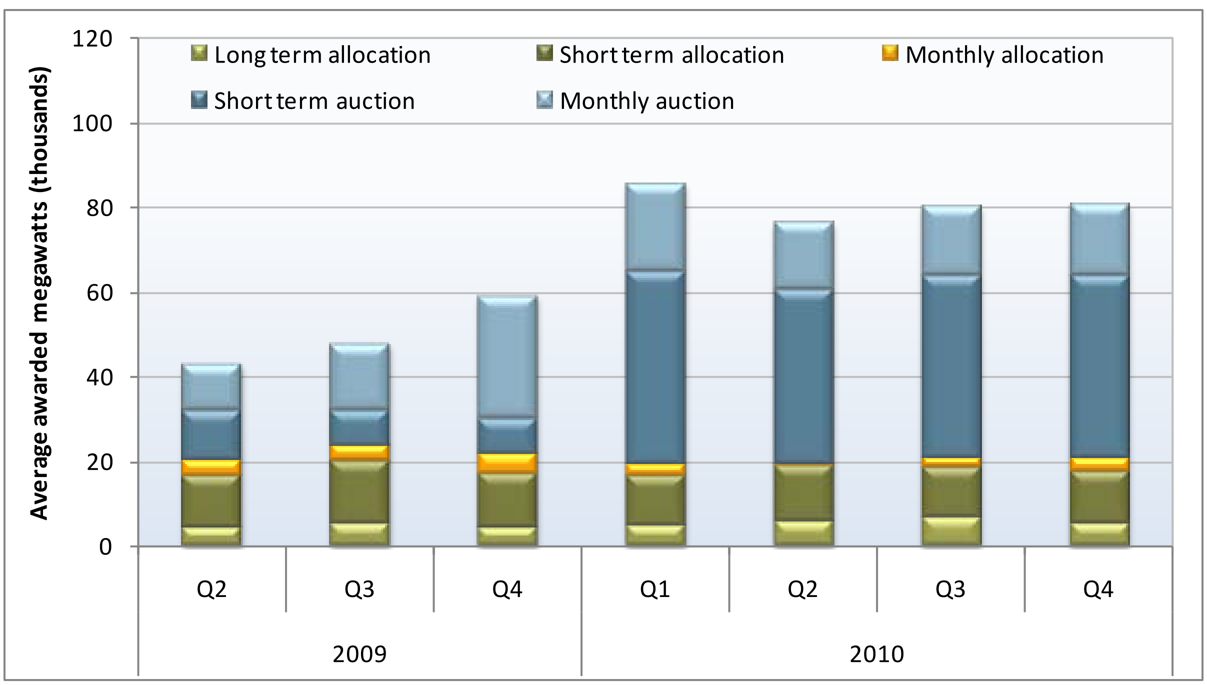


Figure 5.8 and Figure 5.9 provide a high level summary of the market clearing quantities and prices in the auctions for seasonal and monthly congestion revenue rights for each quarter of 2009 and 2010. Prices in these figures represent the price per megawatt-hour for each congestion revenue right. This is equal to the market clearing price divided by the total hours for which the right is valid. This allows the seasonal rights to be grouped and compared with monthly rights.

The same general trends occur for both peak and off-peak hours. On average, almost 60 percent of 2010 awarded megawatts had a clearing price of between \$0/MWh and \$0.10/MWh. Figure 5.8 and Figure 5.9 show there is a significant increase in the average number of awarded congestion revenue rights and average awarded megawatts from 2009 to 2010. The average monthly megawatts awarded between \$0 and \$0.10/MWh more than doubled from 2009 to 2010 for both on and off-peak congestion revenue rights. There were two main reasons for this increase:

- An increase in bids submitted for the short-term auction process resulted in more awarded congestion revenue rights and cleared megawatts, most notably priced between \$0/MWh and \$0.10/MWh.
- More congestion revenue rights in a counter-flow direction cleared, thus allowing more congestion revenue rights in a positive direction to also clear.

Although the price of different congestion revenue rights varies widely, the price of most rights has been within ±\$0.10 MWh.

**Figure 5.8 Auctioned congestion revenue rights by price bin (peak hours)**

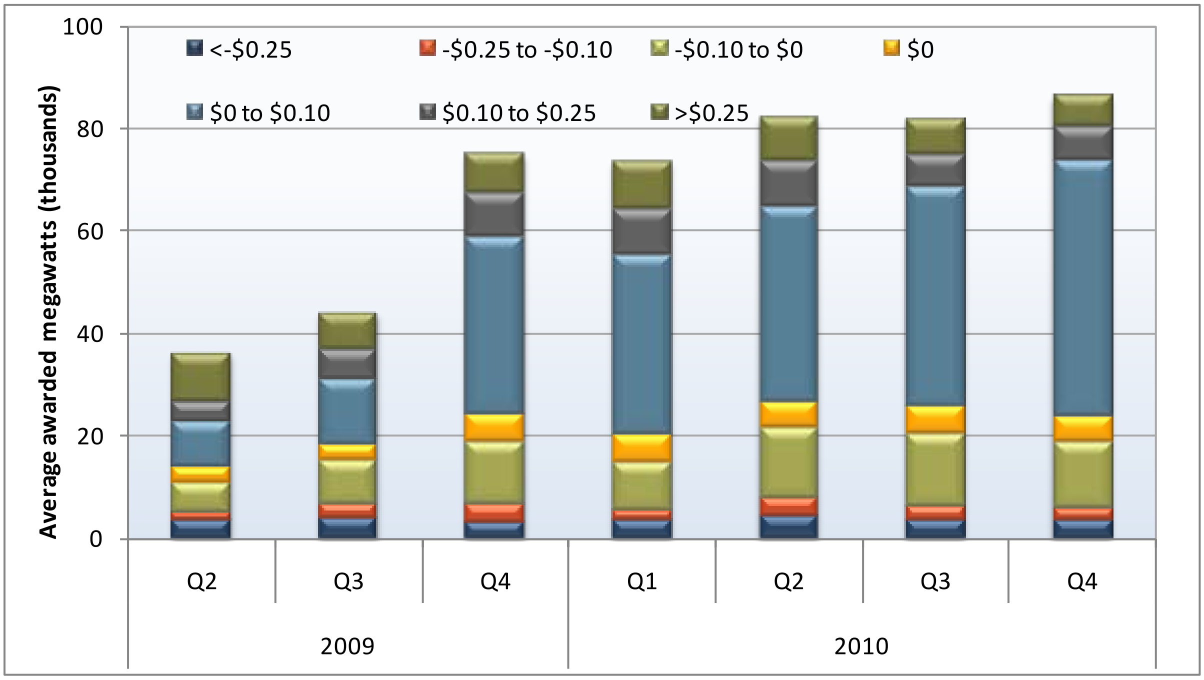
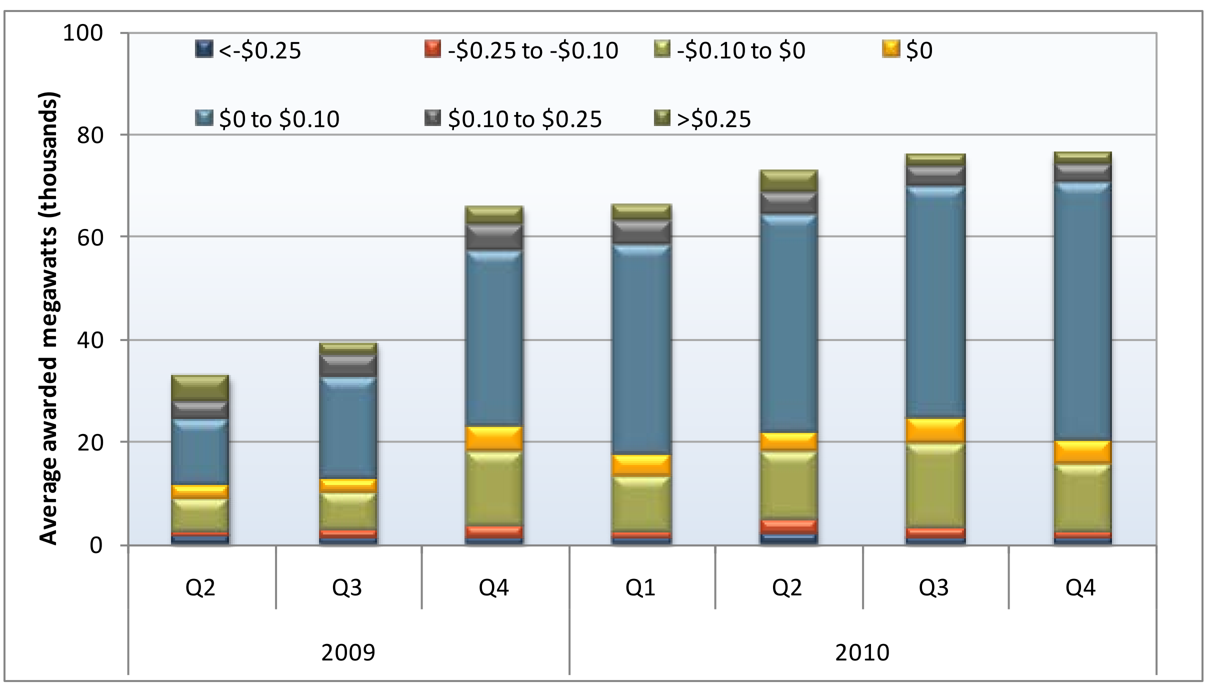



**Figure 5.9 Auctioned congestion revenue rights by price bin (off-peak hours)**



### Congestion revenue right revenue adequacy

The market for congestion revenue rights is designed so that the amount of congestion rents collected from the day-ahead energy market is sufficient to cover all the payments to rights holders. This is referred to as revenue adequacy.

The ISO limits the number of congestion revenue rights available in the allocation and auction processes between various sources and sinks to help maintain overall revenue adequacy.[112] However, under actual market conditions, events such as transmission outages and derates can create revenue deficiencies and surpluses even when the congestion expectations in the auction and in the day-ahead market are identical. Therefore, all revenues from the annual and monthly auction processes are included in the account to help ensure revenue adequacy if needed. Any shortfall or surplus in the balancing account at the end of each month is allocated to measured demand.

Figure 5.10 shows the revenues, payments and overall revenue adequacy of the congestion revenue rights market by quarter in 2009 and 2010.

- The dark blue bars represent congestion rent, which account for the main source of revenues in the balancing account.
- Light blue bars show net revenues from the annual and monthly auctions for congestion revenue rights corresponding to each quarter. This includes revenues paid for positively priced congestion revenue rights in the direction of expected prevailing congestion, less payment made to entities purchasing negatively priced counter flow congestion revenue rights.
- Dark green bars show net payments made to holders of congestion revenue rights. This includes payments made to holders of rights in the prevailing direction of congestion plus revenues collected from entities purchasing counter flow congestion revenue rights.
- The orange line shows the sum of monthly total revenue adequacy for the three months in each quarter before revenues from the auction are included.
- The red line shows total quarterly revenue adequacy after auction revenues are included.

As seen in Figure 5.10, revenue deficiency occurred for the first four quarters of the new nodal market before taking into account auction revenues. This is mostly a result of unforeseen outages and derates on inter-ties that were not accounted for in the congestion revenue right network model during the annual and monthly processes.[113] However, with auction revenues included, revenues from the congestion revenue rights program were slightly positive over this period.

Revenue adequacy during the first quarter of 2010 dropped for several reasons, including:

- In January 2010, the SCE percent import branch group was consistently congested and contributed heavily to revenue deficiencies. This constraint started being enforced in the day-ahead market in November 2009 but was not enforced in the congestion revenue rights process until January 2010. Thus, more congestion revenue rights were awarded than would have been if the constraint was also active in the congestion revenue right process.

[112] For a more detailed explanation of congestion revenue rights revenue adequacy and the simultaneous feasibility test, please see the ISO's *2009 Market Performance Report on CRRs* at http://www.caiso.com/272b/272b8a1623070.html.

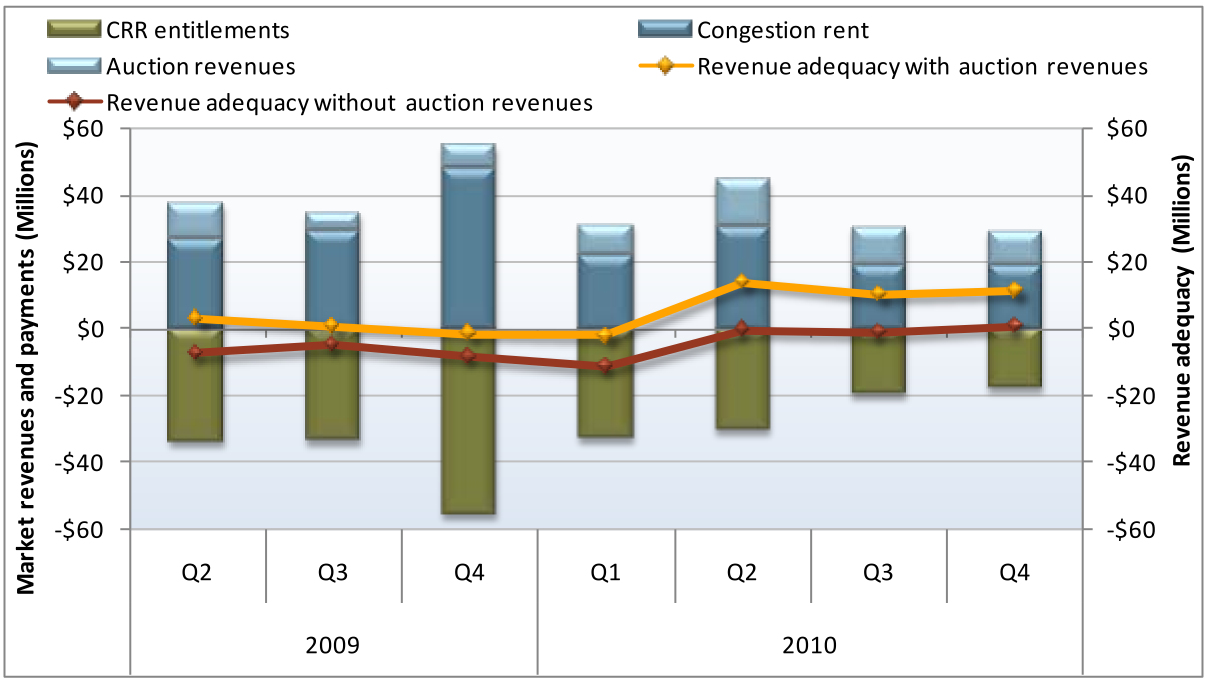
[113] For a detailed explanation of 2009 deficiencies, refer to Chapter 5 in *DMM's 2009 Annual Report on Market Issues and Performance*, April 2010, http://www.caiso.com/2777/277789c42ac70.html.

- The Palo Verde inter-tie was derated in March and April of 2010, contributing to revenue deficiencies during those months.

For the last three quarters of 2010, revenues from the congestion revenue rights program were approximately neutral before taking into account auction revenues. With auction revenues included, revenues from the congestion revenue rights program were positive each quarter over the last three quarters of 2010.

The total cumulative revenue adequacy of the congestion revenue rights balancing account for 2010 was about $33 million, a $30 million increase from 2009. This represents about 74 percent of total net revenues from the annual and monthly auctions for 2010.

**Figure 5.10 Quarterly revenue adequacy**




### Profitability of congestion revenue rights

Each entity participating in the congestion revenue rights auction reveals its expectation of congestion costs through bid prices. Participants with actual generation, load or contracts tied to nodal market prices may assign an additional value to congestion revenue rights as a hedge against extremely high congestion costs. These participants may be willing to pay a premium above the expected value of congestion to mitigate this risk.

- **Profitability of prevailing flow congestion revenue rights.** For prevailing flow congestion revenue rights, profitability depends on the initial purchase price, minus revenues received over the term of the right as the result of any congestion that occurs between the source and sink of the right. As previously noted, these rights are typically purchased by participants seeking a hedge against congestion costs associated with their expected energy deliveries, purchases or financial contracts. Therefore, these rights may tend to be slightly unprofitable on average.

- **Profitability of counter flow congestion revenue rights.** For counter flow congestion revenue rights, profitability is determined by the payment received from the auction, minus payments made over the term of the right as the result of any congestion between the source and sink of the right. These counter flow rights are typically purchased by financial traders willing to take the risk associated with the obligation to pay unknown amounts based on actual congestion in return for the initial fixed payment they receive for these rights. Given the higher risk that may be associated with these rights, these rights may tend to be slightly profitable on average.

Figure 5.11 through Figure 5.14 show the profitability distribution of congestion revenue rights for peak and off-peak hours in 2010.[114] The figures only include congestion revenue rights acquired through the auction process since these rights were valued through a market process. Each chart distinguishes between prevailing flow and counter flow congestion revenue rights.

Results of these figures suggest that congestion in 2010 was less than anticipated by market participants.

- About 16 percent of prevailing flow rights were profitable. Overall, profits for prevailing flow congestion revenue rights averaged about -$0.02/MWh.
- About 93 percent of all counter flow rights had positive profits. Profits for all counter flow rights averaged $0.05/MWh.

The least profitable seasonal congestion revenue rights were sourced and sinked in the prevailing flow direction where heavy congestion occurred in 2009. Day-ahead congestion between these sources and sinks did not materialize in 2010 as it did in 2009. Therefore, congestion revenues paid to entities purchasing these congestion revenue rights exceeded auction prices paid for these rights.

The most profitable paths were counter flow rights sourced at locations that were highly congested in 2009. Auction clearing prices for these rights were highly negative, indicating the expectation of a continuation of high day-ahead congestion in 2010. However, congestion was much lower in 2010. Therefore, the auction price paid to purchasers of these congestion revenue rights exceeded day-ahead congestion rent charged to entities.

In the monthly auction, the most profitable and unprofitable congestion revenue rights were those impacted by unforeseen outages and derates. Congestion on major transmission constraints in June and October caused congestion in the day-ahead markets. This made some prevailing flow rights highly unprofitable and some counter flow rights highly profitable.

[114] 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. The same profit is represented for each awarded megawatt on the same path. For example, assume a 10 MW monthly on-peak CRR cost $100 in the auction (10 MW x $10/MW). If this CRR received $900 in day-ahead congestion 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). This profit would be shown with a frequency of 10, representing each awarded megawatt.

**Figure 5.11 Profitability of congestion revenue rights - seasonal CRRs, peak hours**

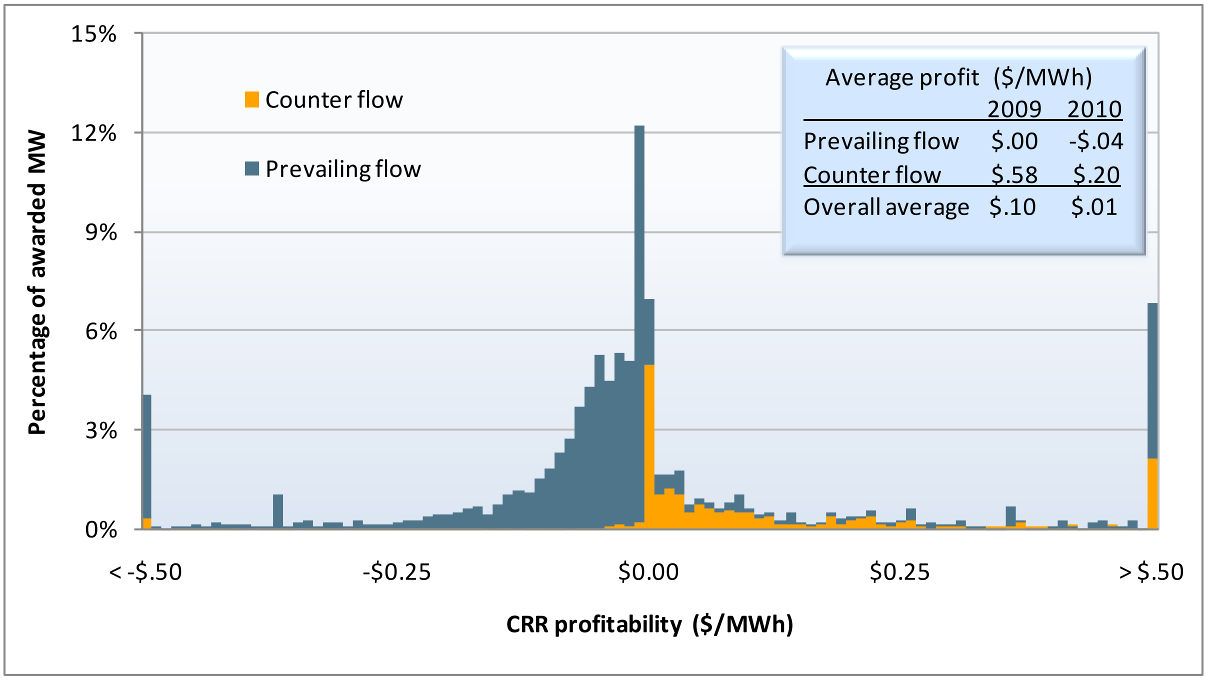



**Figure 5.12 Profitability of congestion revenue rights - seasonal CRRs, off-peak hours**

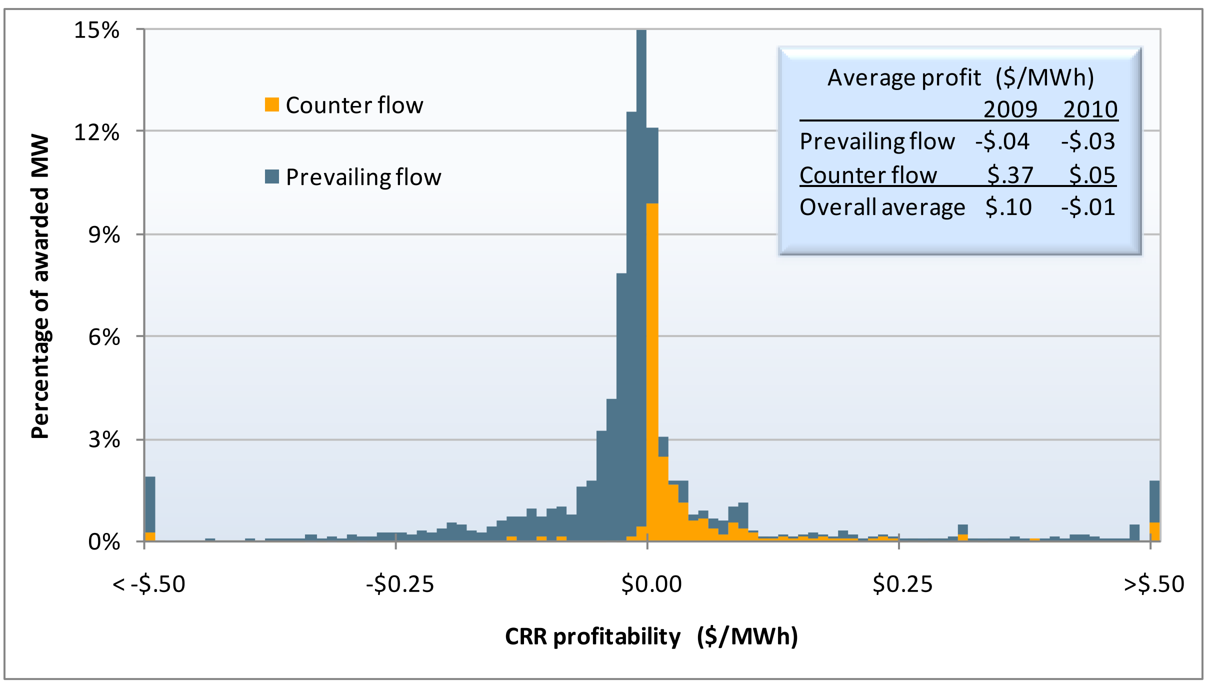


**Figure 5.13 Profitability of congestion revenue rights - monthly CRRs, peak hours**

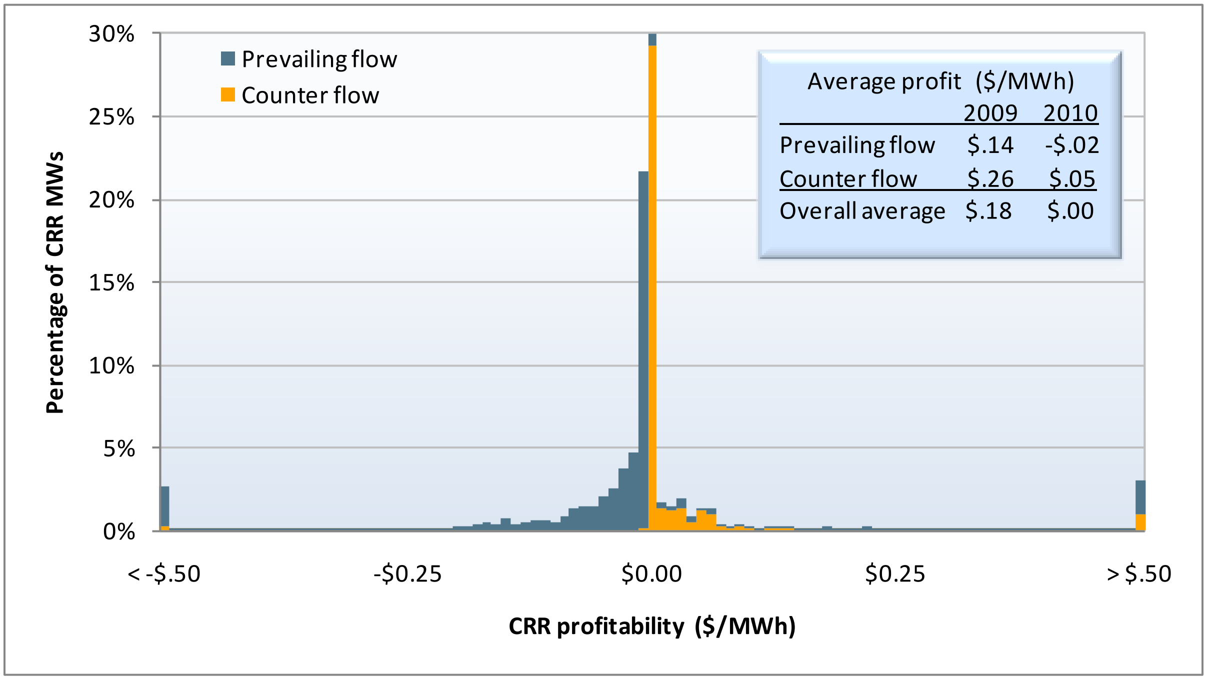
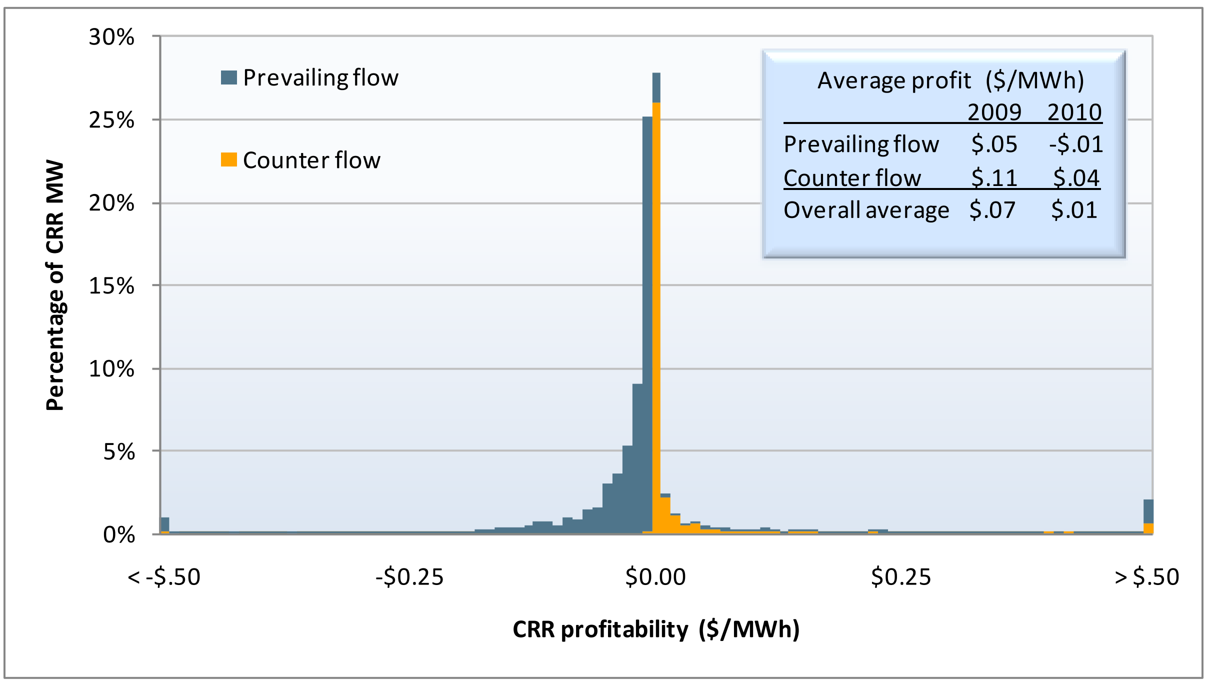



**Figure 5.14 Profitability of congestion revenue rights - monthly CRRs, off-peak hours**



# 6 Ancillary services

Ancillary service markets continued to perform well and even improve in 2010. Total ancillary service costs totaled $84 million, representing a 6 percent decrease over 2009. As shown in Figure 6.1, ancillary service costs decreased from $0.93/MWh of load in 2006 to $0.37 in 2010. This represents a decrease in ancillary service costs to less than 1 percent in 2010 from 2 percent of total energy cost in 2006.

**Figure 6.1 Ancillary service cost as a percentage of wholesale energy cost (2006 – 2010)**

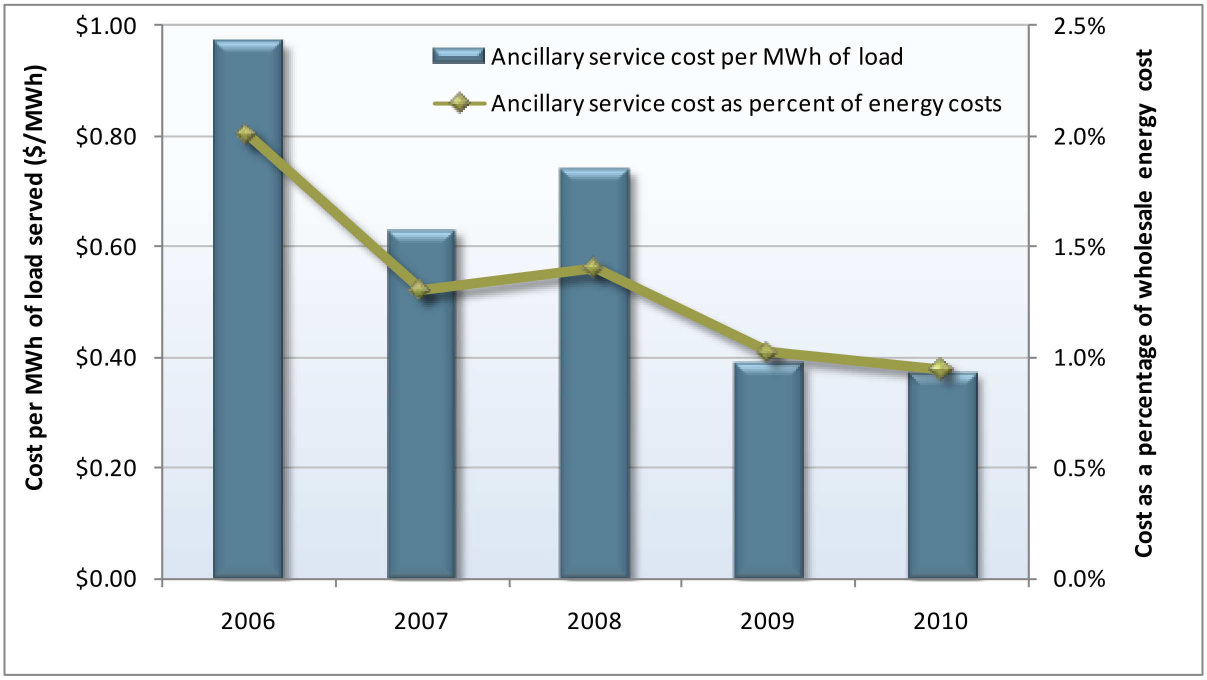



Figure 6.2 further illustrates the cost decreases under the nodal market design. From a level of $0.49/MWh of load in the first quarter of 2009, these costs fell to $0.36 for the rest of 2009 before rising to $0.37 in 2010. These costs went from 1.3 percent of estimated wholesale costs during the first quarter of 2009 to 0.9 percent for the rest of the year and into 2010.

Ancillary service costs peaked around $0.50/MWh in the second quarter of 2010 as hydroelectric generation produced electricity rather than reserves during the spring run-off period. By the fourth quarter, the costs fell to $0.33/MWh, representing less than 0.9 percent of total wholesale energy costs.

Historically, ancillary service costs have peaked in the spring and summer months. Figure 6.3 shows that spring and summer costs in 2009 and 2010 were notably lower than the average summer costs between 2006 and 2008.

**Figure 6.2 Ancillary service cost by quarter**

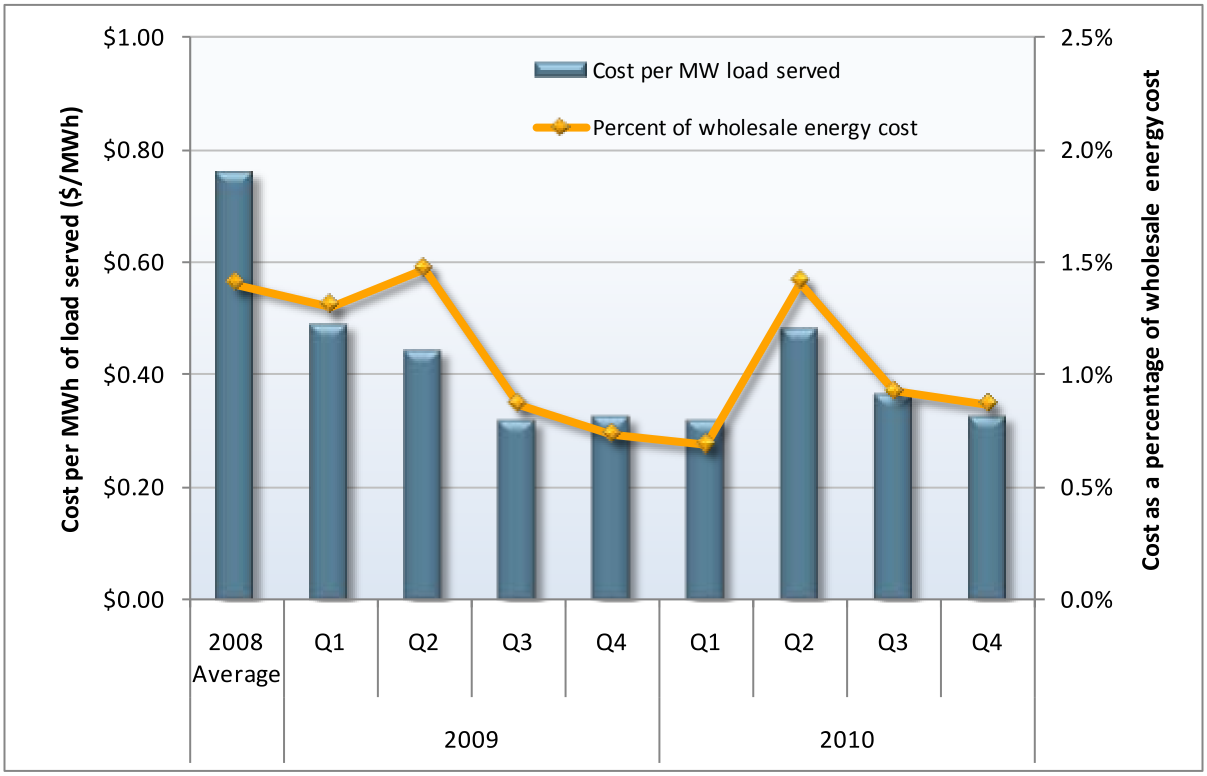
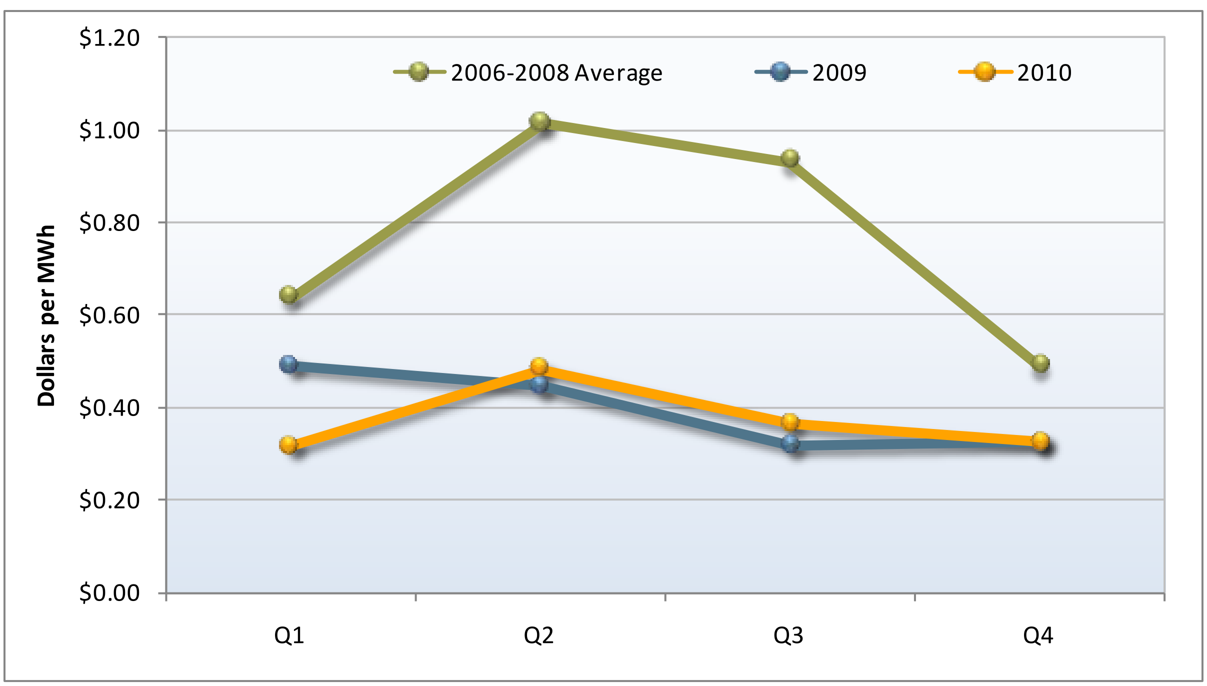



**Figure 6.3 Ancillary service cost per MWh of load (2006 – 2010)**



## 6.1 Market overview

### Ancillary service types

The California ISO procures four ancillary services in the day-ahead and real-time markets:

- ***Regulation up —*** Units providing this service must be synchronized to the grid and able to move quickly above their scheduled operating level after receiving automated signals from the ISO.
- ***Regulation down —*** Units providing regulation down must be synchronized to the grid and able to move quickly below their scheduled operating level in response to automated signals from the ISO.
- ***Spinning reserve —*** These resources must be online or spinning and be able to ramp over a specified range within 10 minutes.
- ***Non-spinning reserve —*** Resources providing this energy must be able to ramp to capacity and synchronize with the grid within 10 minutes. Demand response resources can also provide non-spin capacity if they meet telemetering and ramping requirements.

The ISO uses regulation up and regulation down to maintain system frequency by balancing generation and demand. Spinning and non-spinning resources, collectively known as operating reserves, are used to maintain system frequency stability during emergency operating conditions and major unexpected variations in load. When economical, the market software will procure more of a higher quality reserve, such as regulation, to meet the requirement of a lower quality reserve such as the operating reserves.

### 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 capacity 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 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.

Under the nodal 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 replace capacity that is no longer available because of outages and derates. Also capacity may be procured to meet a market requirement increase resulting from 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 real-time price for ancillary services.

### 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. 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

Co-optimization considers the lost opportunity cost of providing one product (energy or ancillary service) over the other when determining prices.[115] This creates market outcomes that more closely reflect the cost of producing one product in lieu of the other and 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. It runs about 22 minutes in advance of each 15-minute operating period.

### Ancillary service procurement

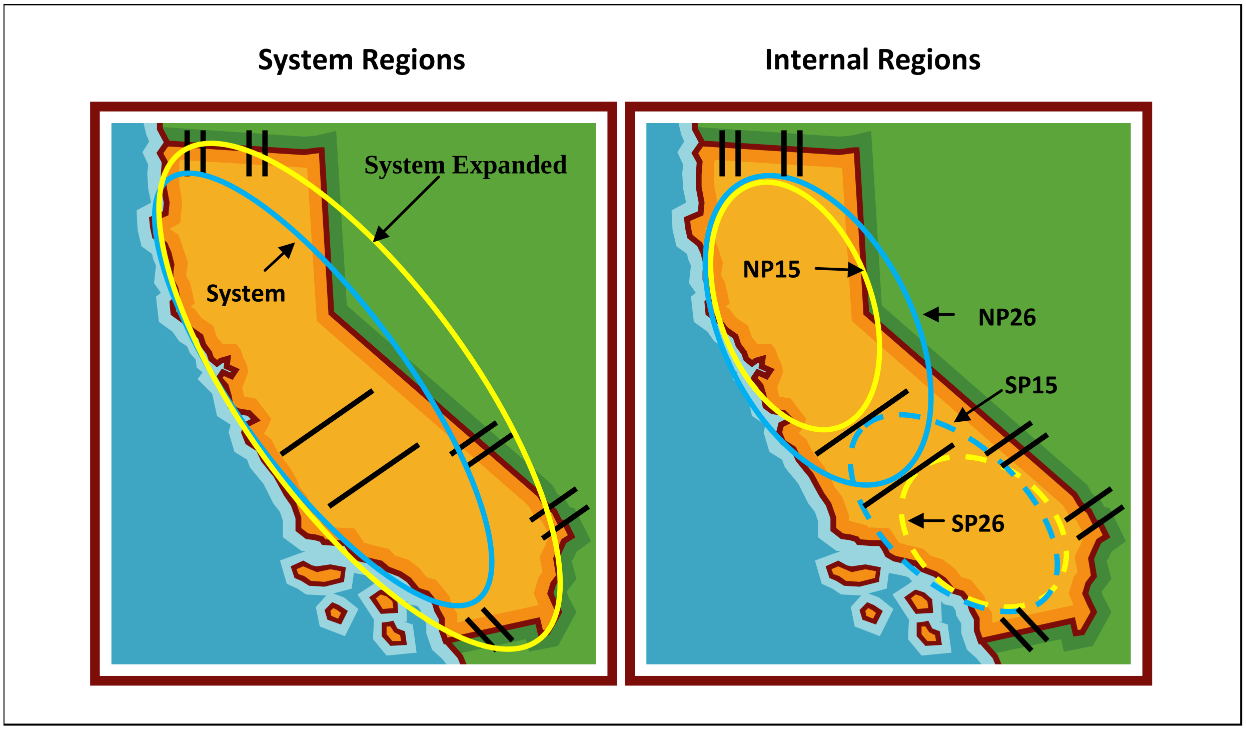
Under the new market, the ISO can procure ancillary services in the day-ahead and real-time pre-dispatch markets from 10 pre-defined regions. Only four of these regions were utilized in 2010:

- System
- System Expanded
- South of Path 26
- South of Path 26 Expanded

Figure 6.4 illustrates these procurement regions. The system region map includes the system 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. The expanded regions are identical to the inner regions but include any inter-ties with one end in the unexpanded region. Capacity procured in a region nested within another region also counts toward meeting the minimum requirement of the outer region.

[115] 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 price of $50 and 20 MW of spin, there would be a $30 opportunity cost equal to the difference of the energy price 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 market regions**




In addition to the minimum regional requirements, the market also enforces the following procurement requirements in the day-ahead and real-time pre-dispatch markets.

- ***Upward ancillary service maximum requirement* —** The total procurement of regulation up, spinning, and non-spinning reserves cannot exceed a predetermined cap. This is to ensure the market does not hold unused capacity from the energy market.
- ***Spinning 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 ancillary services pricing changed significantly with the nodal market implementation. The new market provides regional pricing signals for each service in two ways:

- ***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.[116] These shadow prices are non-

[116] A regional ancillary service shadow price is produced for each enforced region and each service.

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.[117]

### Scarcity pricing of ancillary services

The ISO implemented scarcity pricing of ancillary services in both the day-ahead and real-time pre-dispatch processes on December 14, 2010. This mechanism administratively sets the ancillary service price in the case of ancillary services deficiencies. The price level accounts for both the quality and location of the reserve and sets the price for each ancillary service product and region accordingly.

Scarcity pricing only indirectly affects energy market pricing outcomes in real-time. Ancillary services are procured and priced in the real-time pre-dispatch market run every 15 minutes while energy is awarded and priced in the 5-minute real-time market.

The real-time pre-dispatch process also commits quick-start units and schedules inter-tie resources. The real-time pre-dispatch, however, does not set real-time prices for internal energy resources. Therefore, to the extent there are tradeoffs affecting the commitment of quick-start units and inter-tie resources, these results will only indirectly influence the energy market prices for internal resources in the 5-minute real-time market.

## 6.2 Procurement

The ISO procures four ancillary services in the day-ahead and real-time markets: regulation up, regulation down, spinning, and non-spinning. 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. Under the nodal market, the day-ahead requirement is set equal to 100 percent of the estimated requirement, so that most ancillary services are procured in the day-ahead market.

The average hourly real-time operating reserve requirement was 1,641 MW in 2009 and 1,617 MW in 2010, which was about a 5 percent decrease from the 2008 level. This requirement is typically set by 5 percent of forecasted demand met by hydroelectric resources plus 7 percent of forecasted demand met by thermal resources.[118] Thus, the requirements follow a seasonal load pattern with higher requirements during the peak load months.

The requirement for regulation up and down is implemented by an algorithm based on inter-hour forecast and schedule changes. The average hourly real-time regulation down requirement was 330 MW in 2010, whereas the average hourly real-time regulation up requirement was 356 MW. The respective 2009 values were 367 MW and 370 MW. The 2009 regulation procurement levels were

[117] 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 the SP26, SP26 expanded, system and system expanded regions.

[118] Because of the magnitude of demand, the 5 and 7 percent are typically larger than the single largest contingency, which can also set the requirement.

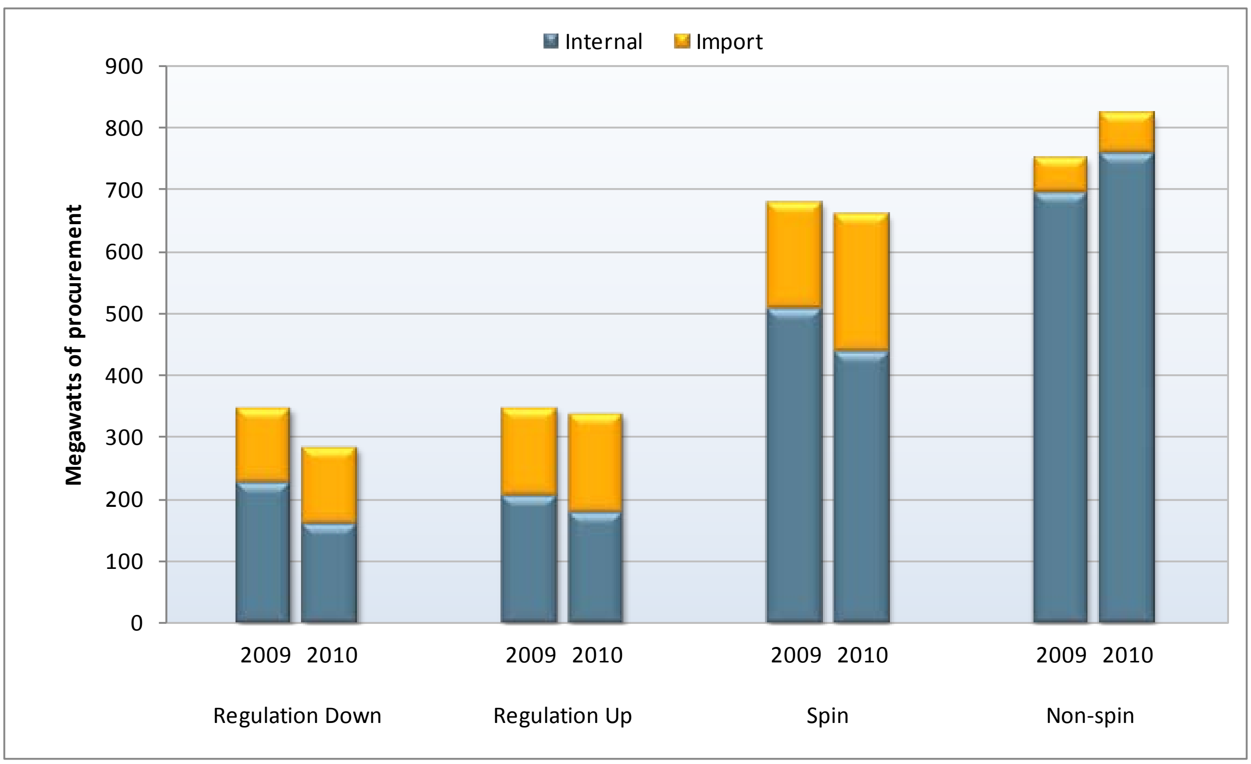
higher because of increased procurement to address violations of the control performance standards (CPS2) at the beginning of the new market.

Ancillary services requirements are met internally and externally as the market includes both internal and expanded system regions. As seen in Figure 6.5, imports are playing a larger role in providing ancillary services for the ISO market.

- Imports of all ancillary services increased from 490 MW in 2009 to 569 MW in 2010.[119] This represents an increase from 23 percent of total ancillary services in 2009 to 27 percent in 2010.
- In 2010, 48 percent of the regulation up resources came from imports, up from 41 percent in 2009.
- Imports accounted for 19 percent of spinning and non-spinning reserve capacity in 2010, compared to 16 percent in 2009.

Ancillary services bid across the inter-ties have to compete for transmission capacity with energy. If a tie becomes congested, the scheduling coordinator awarded ancillary services will be charged the congestion rate. As noted above, the requirements put limitations on ancillary services procurement levels from imports. Thus, most ancillary services requirements are met by ISO resources.

**Figure 6.5 Procurement by internal resources and imports**

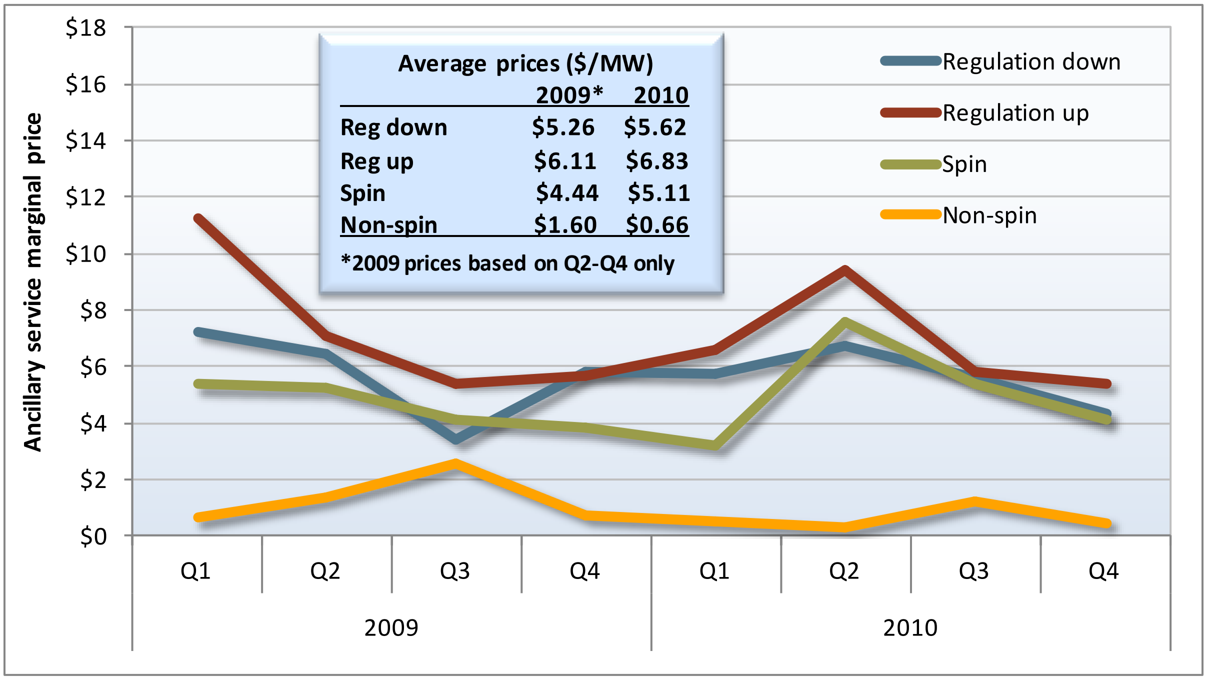



[119] In 2009, data from the final three quarters are used in the calculations.

## 6.3 Ancillary services pricing

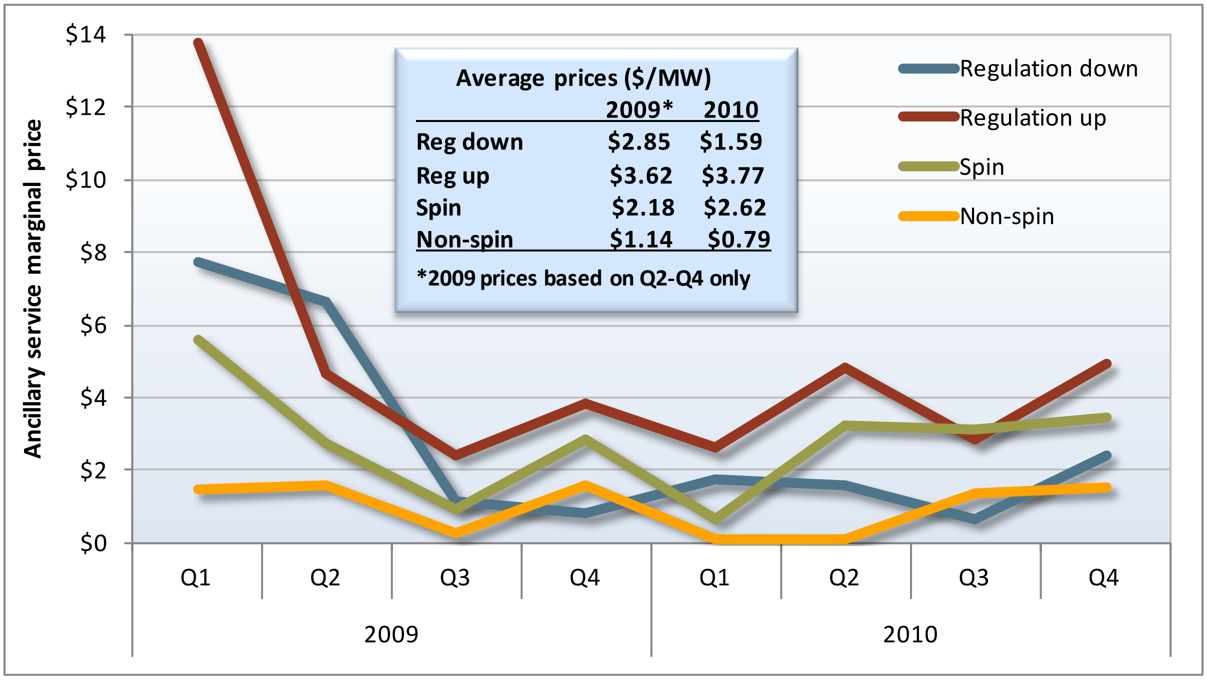
Resources providing ancillary services receive a capacity payment, or market clearing price, in both the day-ahead and real-time markets. Capacity payments in the real-time market are only for incremental capacity above the day-ahead award. Figure 6.6 and Figure 6.7 below show the weighted average market clearing prices for each ancillary service product by quarter in the day-ahead and real-time markets respectively in 2009 and 2010.

**Figure 6.6 Day-ahead ancillary service market clearing prices**




Overall, 2010 average quarterly day-ahead prices ranged from approximately $0.30/MW to $9.40/MW, peaking in June. For the most part, favorable hydroelectric conditions caused the high prices from April to July. This occurred as upward reserve capacities from hydro units that typically would bid relatively low prices were reduced when hydro units provided energy. Therefore, more ancillary service capacity needed to be procured from other units at a higher price.

**Figure 6.7 Real-time ancillary service market clearing prices**



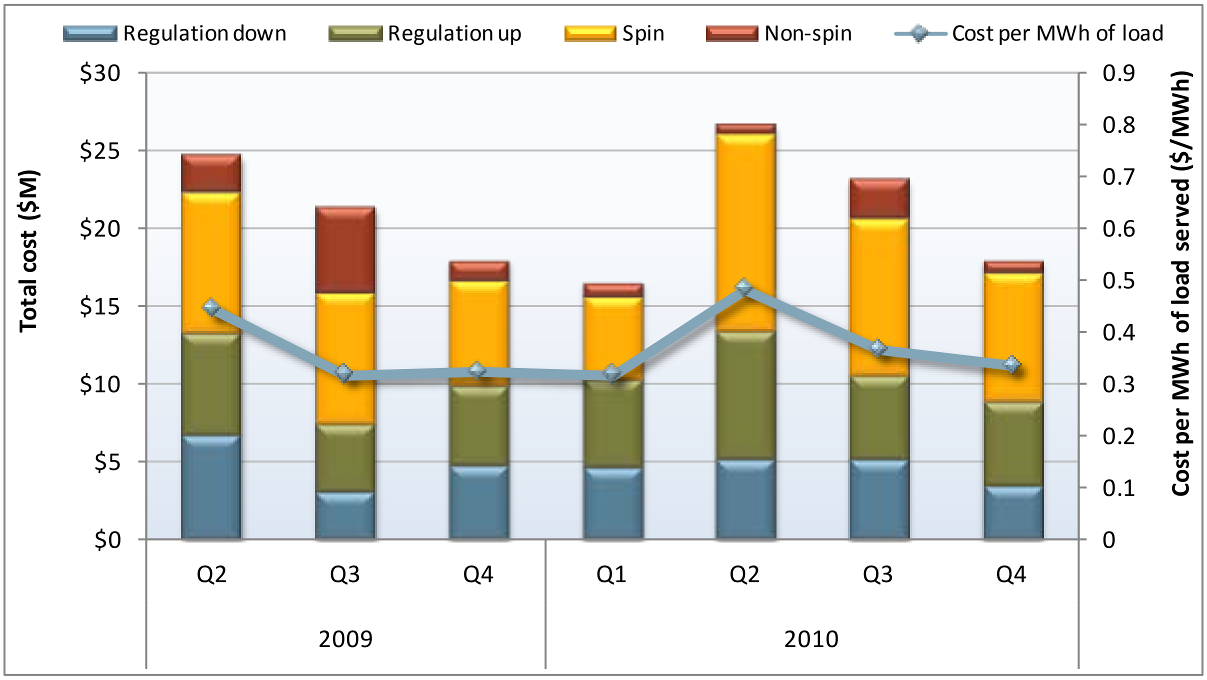

In Figure 6.7, real-time ancillary service prices generally reflect similar pricing trends to the day-ahead. Real-time prices ranged from $0.10/MW to $7.40/MW. The volume of procurement in the real-time market is very limited, accounting for less than 1 percent of the total procurement. In November, real-time prices increased significantly for all of the products because of price spikes above $600/MW. These ancillary services price spikes mostly resulted from high opportunity costs from real-time energy price spikes in November, especially on November 29. Since the real-time ancillary services market is small in volume, such price spikes affect average prices significantly.

## 6.4 Ancillary service costs

Ancillary service costs in 2010 totaled $84.5 million, a 6 percent decrease from 2009. Spinning reserve costs were also larger in these months because of higher seasonal requirements.

Figure 6.8 shows the total cost of procuring all four ancillary service products by quarter. The line represents the average cost per megawatt-hour of load served. May, June and July were the highest cost months in 2010. These higher costs were mainly caused by higher ancillary services prices. Spinning reserve costs were also larger in these months because of higher seasonal requirements.

**Figure 6.8 Ancillary service cost by region**




## 6.5 Special issues

In 2010, the ISO did experience some issues with ancillary service market outcomes. The following is a brief explanation of each issue.

- ***Instances where ancillary services requirements were not met*** — On two occasions in 2010, the supply of ancillary services was insufficient to meet ISO requirements. In July, the minimum reserve requirement was manually set above the maximum reserve limit and therefore the minimum requirement was not met. This resulted in several intervals of negative prices for the ISO expanded region for regulation down. In November, there was a software patch implementation problem that caused ramping issues and an unexpected deficiency in the system. There were a few intervals where ancillary services prices for regulation were above the ancillary services bid cap of $250/MW. Had scarcity pricing of ancillary services been implemented at the time, it is likely that the scarcity pricing mechanism would have triggered.

- ***Scarcity pricing activated inappropriately*** — Scarcity pricing of ancillary services in the pre-dispatch process was activated inappropriately on December 19 and 23 although no shortage of ancillary services existed.[120] Both instances occurred because of separate software patch installations, and for December 23, the published ancillary service prices were reverted back to the day-ahead results. No further instances of false scarcity pricing have occurred since December 23.

[120] Ancillary service scarcity pricing was triggered incorrectly on December 19 in multiple intervals in the real-time market runs during hour ending 18 and for multiple intervals in hours ending 1 and 2 on December 23.

# 7 Resource adequacy

Unlike the three eastern ISOs, the California ISO does not have a centralized capacity market. Instead, California's wholesale market relies on a resource adequacy program and long term procurement planning process adopted by the California Public Utilities Commission to provide sufficient capacity to ensure reliability. The resource adequacy program includes ISO tariff requirements that work in conjunction with state regulatory requirements and processes adopted by the CPUC.

This chapter analyzes the amount of resource adequacy capacity made available in the ISO market during 2010. Our analysis shows that the availability of resource adequacy capacity was relatively high in each month and that there was adequate available capacity during the peak summer hours. During the peak summer load hours, about 92 percent of resource adequacy capacity was available to the day-ahead energy market and the residual unit commitment process. This is approximately equal to the target level of availability incorporated in the resource adequacy program design and represents a slight improvement in availability compared to 2009.

Capacity under the resource adequacy program in 2010 was sufficient to meet virtually all 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.

## 7.1 Background

The resource adequacy provisions of the ISO tariff require load-serving entities to procure adequate generation capacity to meet 115 percent of their forecast peak demand in each month. 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). This capacity must then be bid into the market through a must-offer requirement. Load-serving entities provide these resource adequacy showings to the ISO on a year-ahead basis.

About 60 percent of generation resources counted toward resource adequacy requirements must be bid into the market for each hour of the month except when it is unavailable because of outages. This includes most gas-fired generation with a total capacity of over 23,000 MW. The ISO automatically creates bids for these resources if they are not submitted by the market participant.[121]

The other 40 percent of generation resources counted toward the resource adequacy requirement do not have to offer their full resource adequacy capacity in all hours of the month. These resources are required to be made available to the market consistent with their operating limitations. These include:

- Hydro resources;
- Non-dispatchable generators, which include nuclear, qualifying facilities, wind, solar and other miscellaneous resources; and
- Use-limited thermal resources.

[121] An exception is import resources. The ISO does not currently create bids for resource adequacy imports although it is scheduled to begin doing so by early next year.

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 use plans for these resources to the ISO that describe their restrictions and outline their planned operation.

All resource adequacy capacity that is available must be offered in the ISO market through economic bids or self-schedules as follows:

- **Day-ahead energy and ancillary services market** — All available resource adequacy capacity must be either self-scheduled or bid into the day-ahead energy market. Resources certified for ancillary services must offer this capacity in the ancillary services markets.
- **Residual unit commitment process** — Market participants are also required to submit bids priced at $0/MWh into the residual unit commitment process for all resource adequacy capacity.
- **Real-time market** — All resource adequacy resources committed in the day-ahead market or residual unit commitment process must also be made available to the real-time market. Short-start units providing resource adequacy capacity must also be offered in the real-time energy and ancillary services markets.

Long-start units and imports providing resource adequacy capacity that are not scheduled in the day-ahead market or residual unit commitment process do not need to be offered in the real-time market.

## 7.2 Overall resource adequacy availability

Even though generation capacity is especially important to meet the peak loads of the summer months, it is important that the full amount of resource adequacy capacity be made available to the market throughout the year. For example, significant amounts of generation can be out for maintenance during the non-summer months, making resource adequacy capacity instrumental in meeting even moderate loads.

Figure 7.1 summarizes the average amount of resource adequacy capacity made available to the day-ahead, residual unit commitment and real-time markets in each quarter of 2010.

- The red line shows the total amount of resource adequacy capacity.[122]
- The bars show the amount of resource adequacy capacity that was made available to the day-ahead, residual unit commitment, and real-time markets, respectively.[123]

Figure 7.1 shows that a high portion of resource adequacy capacity was available to the market throughout the year. The highest availability was during the third quarter, which includes the summer

[122] The resource adequacy capacity included in this analysis excludes as much as 6,300 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.

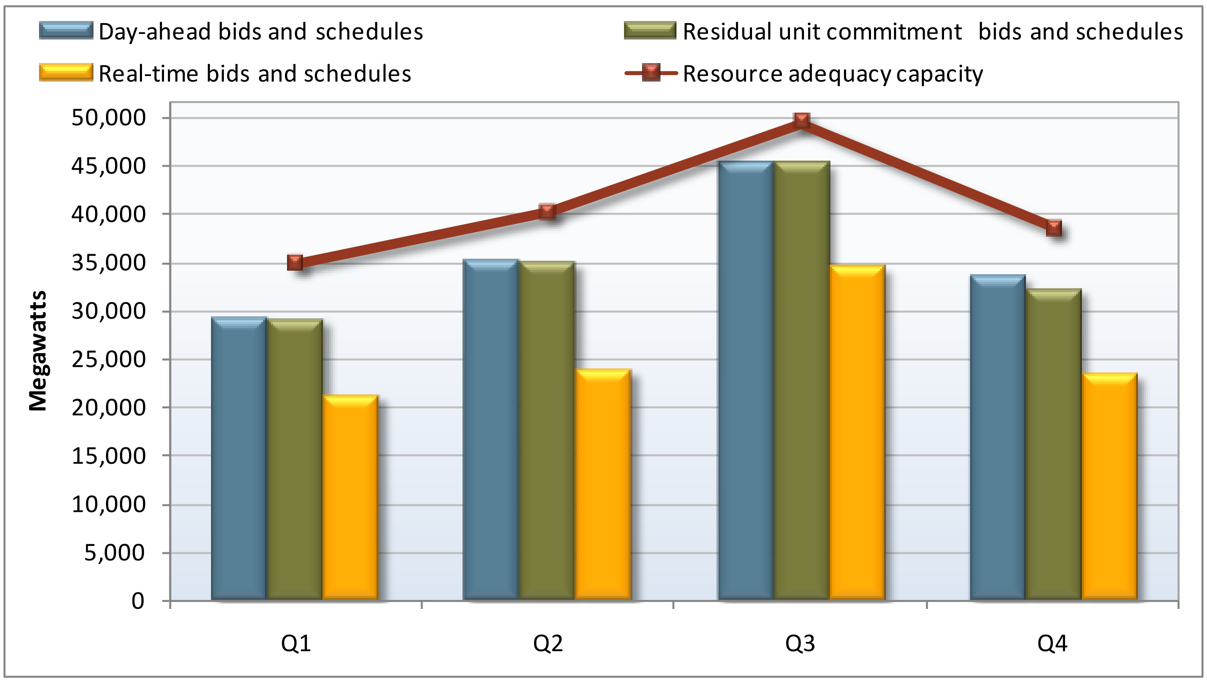
[123] These amounts are calculated as the average total amount of bids and schedules made available to each of these markets during the resource adequacy standard capacity product “availability assessment hours” during each month. These are operating hours 14-18 during April through October and operating hours 17-21 during the remainder of the year.

months of July through September. During these months, an average of 45,300 MW out of about 49,400 MW of resource adequacy capacity (92 percent) was available in the day-ahead market.

During the first quarter, about 84 percent of resource adequacy capacity was available to the day-ahead market. Over all these months, virtually all capacity offered in the day-ahead energy market was also available in the residual unit commitment process.

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 they are not committed in the day-ahead energy market or residual unit commitment process.

**Figure 7.1 Quarterly resource adequacy capacity scheduled or bid into ISO markets**




## 7.3 Summer peak hours

California's resource adequacy program recognizes that a portion of the state's generation is only available during limited hours. To accommodate this, load-serving entities are allowed to meet a portion of their resource adequacy requirements with generation that is available only a portion of the time. This element of the resource adequacy program reflects the assumption that this generation will generally be available and used during hours of the highest peak loads.

Resource adequacy program rules are designed to ensure that the highest peak loads are met by requiring that all resource adequacy capacity be available at least 210 hours over the summer months of May through September.[124] The rules do not specify that these hours must include the hours of the highest load or most critical system conditions. Acknowledging that market participants do not have perfect foresight when the highest loads will actually occur, the program assumes that they will manage these use-limited generators so that they are available during the peak load hours.

[124] The CPUC requires the resources be available 30, 40, 40, 60, and 40 hours during each of these months, respectively.

The availability of resource adequacy capacity during the 210 peak hours is an important indication of how well the program meets actual peak loads. Thus, as in our 2009 annual report, DMM has evaluated the availability of resource adequacy generation during the 210 hours of the months May through September with the highest peak loads. In 2010, this includes all hours with peak load over 39,817 MW.

Figure 7.2 provides an overview of monthly resource adequacy capacity, monthly peak load, and the frequency of the 210 highest load hours that occurred during the period. The red and green 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 about 45,000 to about 57,000 MW during May through August 2010. This exceeded the respective peak loads in each month by about 14 to 53 percent.
- The summer peak load occurred in August. Resource adequacy capacity in this month exceeded this peak load by 21 percent.
- The high capacity margins in May through August reflect that resource adequacy requirements are designed to meet 115 percent of a 1-in-2 year load forecast. However, peak loads in the same period in 2009 were not unusually high.
- The lower margin in September reflects that the peak load in this month was almost as high in August. Since peak loads are historically lower in September, the resource adequacy requirement for September is substantially less than for August.

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, both the peak load and the largest number of the top 210 load hours were in August. This is not the case every year. A higher portion of peak load hours can also occur in other months. This underscores the need for market participants to consistently make resource adequacy capacity 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 2010**

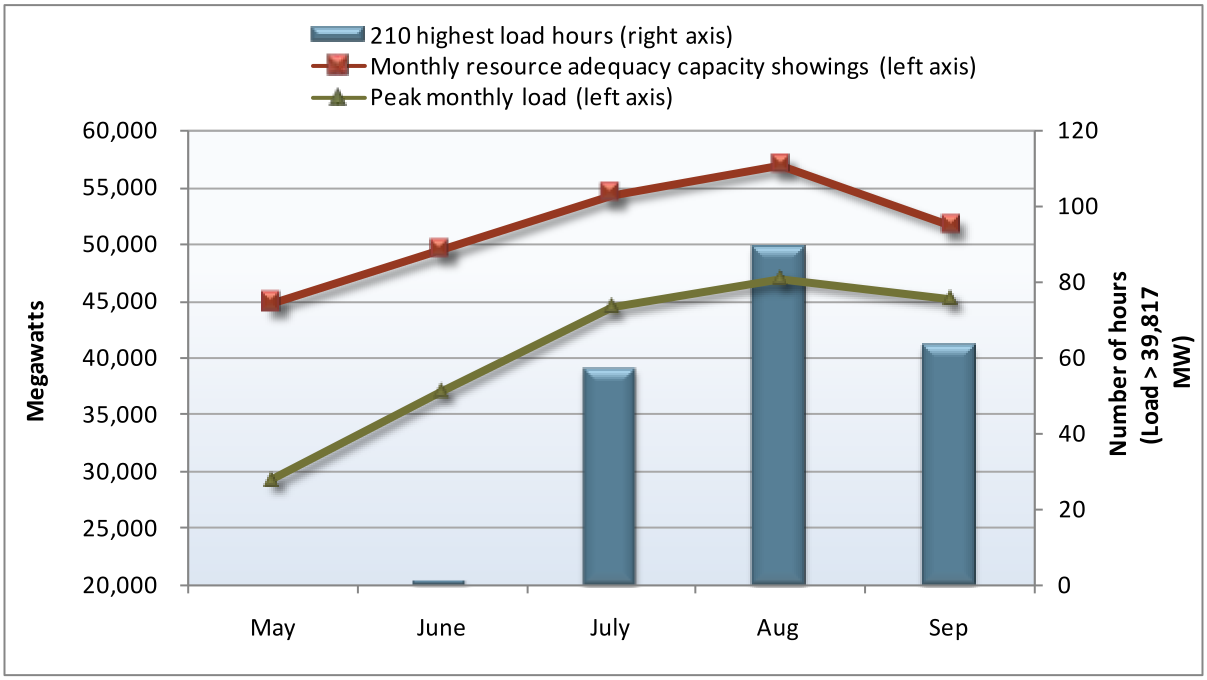



Figure 7.3 shows the amount of capacity scheduled or bid in the day-ahead and real-time market during these 210 peak hours. These results are ranked in descending order of total resource adequacy megawatts bid or scheduled in each of the three markets listed below.[125] As shown in Figure 7.3, a high portion of resource adequacy capacity was available to these markets during the 210 summer peak load hours:

- ***Day-ahead market*** **—** Bids and self-schedules for resource adequacy capacity in this market averaged about 91 percent of overall resource adequacy capacity, varying in individual hours from about 83 to 100 percent of resource adequacy capacity.
- ***Residual unit commitment*** **—** Resource adequacy capacity available to this process was 90 percent of overall resource adequacy capacity, just slightly less than the amount available to the day-ahead market.
- ***Real-time market*** **—** Bids and self-schedules for resource adequacy capacity in the real-time market averaged about 77 percent of overall resource adequacy capacity, varying in individual hours from about 63 to 91 percent. As previously noted, the lower amount of resource adequacy capacity available to the real-time market results from not all resource adequacy capacity was committed in the day-ahead market or residual unit commitment process. As discussed below, bids and self-

[125] Figure 7.3 does not include approximately 7,700 MW of the overall ISO resource adequacy capacity for which this analysis cannot be performed or is not highly meaningful, as previously described. 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.

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 during 210 highest peak load hours**

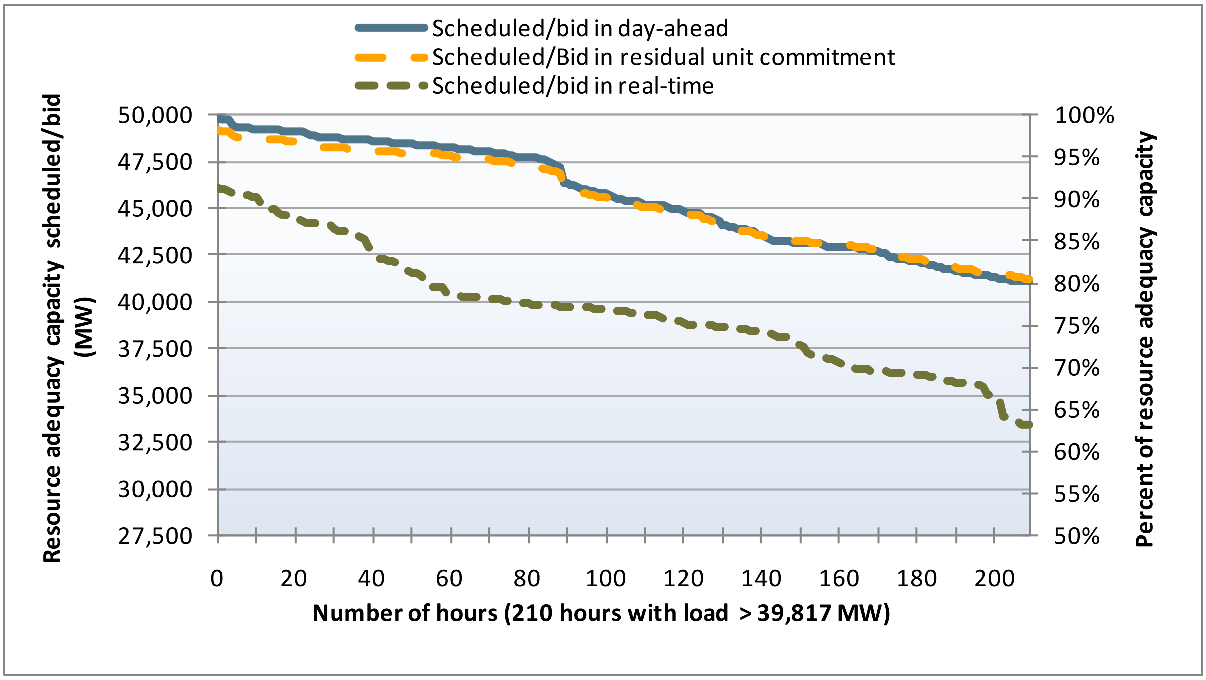



Table 7.1 provides a more detailed summary of the availability of resource adequacy capacity over the 210 summer peak load hours for each type of generation. Separate sub-totals are provided for resources for which the ISO creates bids if market participants do not submit a bid or self-schedule, and resources for which the ISO does not create bids. Table 7.1 presents this information as follows:

- ***Resource adequacy capacity after reported outages and derates —*** The first three numerical columns of Table 7.1 list the approximately 49,700 MW of resource adequacy capacity examined in this analysis, along with the capacity available after adjusting for reported outages and derates. After adjusting for outages and derates, the remaining capacity equals about 95 percent of the overall resource adequacy capacity. This represents an outage rate of about 5 percent during the 210 highest load hours in 2010.

- ***Day-ahead market availability —*** For the 23,827 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 88 percent of the available capacity of these resources after accounting for reported derates and outages. This reduces the total average availability of all resource adequacy capacity in the day-ahead market to about 91 percent. As shown in Table 7.1, this is attributable to a lower level of resource adequacy capacity being scheduled or bid in the day-ahead market by use-limited gas resources, hydro, wind, solar generators, qualifying facilities and imports. Hydro, qualifying facilities and other non-dispatchable resources may be scheduled at lower levels because of 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, qualifying facilities, and other non-dispatchable resources is discussed in more detail in Section 7.4.

- ***Residual unit commitment availability —*** The overall percentage of resource adequacy capacity made available in the residual unit commitment process was just slightly less, one percent, than that available to the day-ahead market.

- ***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 scheduled or bid in the real-time market. An average of about 90 percent of the resource adequacy capacity that was potentially available to the real-time market was scheduled or bid in the real-time market.

**Table 7.1 Average resource adequacy capacity and availability during 210 highest load hours**

| Resource type | Total resource adequacy capacity (MW) | Net outage adjusted resource adequacy capacity | | Day-ahead bids and self-schedules | | Residual unit commitment bids | | Total real-time market resource adequacy capacity (MW) | Real-time market bids and self-schedules | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | MW | % of total RA Cap. | MW | % of total RA Cap. | MW | % of Total RA Cap. | | MW | % of real-time RA Cap. |
| ISO Creates Bids: | | | | | | | | | | |
| Gas-Fired Generators | 23,344 | 21,990 | 94% | 21,906 | 94% | 21,900 | 94% | 16,589 | 15,598 | 94% |
| Other Generators | 1,111 | 1,001 | 90% | 999 | 90% | 999 | 90% | 1,086 | 971 | 89% |
| Subtotal | **24,455** | **22,991** | **94%** | **22,905** | **94%** | **22,899** | **94%** | **17,674** | **16,568** | **94%** |
| ISO Does Not Create Bids: | | | | | | | | | | |
| Use-Limited Gas Units | 3,112 | 2,865 | 92% | 2,734 | 88% | 2,422 | 78% | 1,514 | 1,354 | 89% |
| Hydro Generators | 6,795 | 6,318 | 93% | 5,821 | 86% | 5,726 | 84% | 6,795 | 5,655 | 83% |
| Nuclear Generators | 4,699 | 4,581 | 97% | 4,565 | 97% | 4,565 | 97% | 4,699 | 4,530 | 96% |
| Wind/Solar Generators | 563 | 563 | 100% | 358 | 64% | 358 | 64% | 563 | 424 | 75% |
| Qualifying Facilities | 3,951 | 3,787 | 96% | 3,352 | 85% | 3,335 | 84% | 3,934 | 3,270 | 83% |
| Other Non-Dispachable | 355 | 355 | 100% | 330 | 93% | 330 | 93% | 355 | 305 | 86% |
| Imports | 4,354 | 4,354 | 100% | 3,856 | 89% | 3,851 | 88% | 4,107 | 3,755 | 91% |
| Subtotal | **23,827** | **22,822** | **96%** | **21,017** | **88%** | **20,588** | **86%** | **21,966** | **19,291** | **88%** |
| Total | **48,282** | **45,813** | **95%** | **43,922** | **91%** | **43,487** | **90%** | **39,640** | **35,860** | **90%** |

## 7.4 Intermittent resources

Intermittent resources include wind, solar, qualifying facilities and other miscellaneous non-dispatchable resources. Unlike conventional generation, the output of these resources is variable and cannot be dispatched. Consequently, the amount of resource adequacy capacity that these resources can provide is based on past output rather than nameplate capacity. The amount of resource adequacy capacity that each individual resource can provide is known as its net qualifying capacity.

The net qualifying capacity of wind and solar resources is based on the output that they exceed in 70 percent of peak hours (1:00 p.m. to 6:00 p.m.) during each month over the previous three years. These amounts are adjusted for a factor that reflects the benefit of the low covariance between the outputs of many individual intermittent generators. This is a change from the previous year, when net qualifying capacity for these resources was based on average output during these peak hours. This change recognizes that wind output is highly variable and can be substantially less than average during peak hours, when resource adequacy capacity is most important.

Figure 7.4 and Figure 7.5 illustrate analysis of wind and solar resources, respectively. Wind and solar combined currently account for only about 650 MW of resource adequacy capacity in the peak summer month August. However, the amount of resource adequacy requirements met by these renewable resources will increase significantly as the total amount of installed wind and solar capacity increases.

As shown in Figure 7.4, output from wind resources in July exceeded their resource adequacy capacity. In August, although the output from wind resources was more than their resource adequacy capacity in the hours used to calculate new qualifying capacity, their actual output in the 210 highest load hours was much less than their resource adequacy capacity. In September, wind resources' output in both the hours used to calculate net qualifying capacity and the 210 highest load hours were less than their resource adequacy capacity. However, actual wind output fell short of their resource adequacy capacity in August and September. This illustrates the variability of wind resources and that wind output can be much lower in the highest peak load hours than in the hours used to determine the net qualifying capacity.

Figure 7.5 shows a comparison of the same data for solar resources in July through September. Solar output in hours used to calculate net qualifying capacity was greater than the output in the 210 highest summer peak load hours during these months. Overall, actual solar output in the 210 highest summer peak load hours equaled about 89 percent of the output in the hours used to calculate net qualifying capacity during these months, and about 79 percent of solar resource adequacy capacity during these months.

Figure 7.6 provides a similar analysis for qualifying facilities and other miscellaneous non-dispatchable resources. The net qualifying capacity of qualifying facilities and other non-dispatchable resources is based on their average output during peak hours over the previous three years. An annual net qualifying capacity value is calculated based on their output during the summer months. Thus, this analysis shows the average actual output of these resources during these hours.

As shown in Figure 7.6, the actual output of these resources in July through September 2010 during hours used to calculate net qualifying capacity was about the same as their output in the 210 highest load hours. However, their average output during these hours was significantly lower than their resource adequacy capacity in August and September. Overall, output in the 210 highest load hours was about 91 percent of resource adequacy capacity.

**Figure 7.4 Resource adequacy capacity available from wind resources**

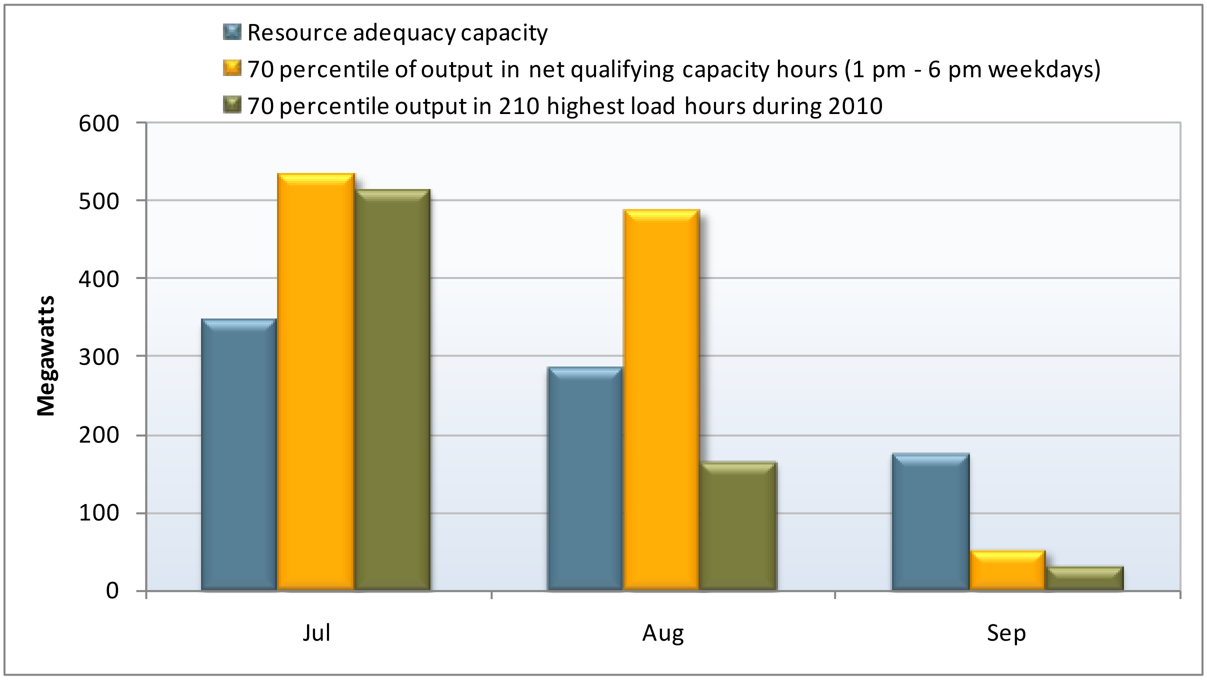



**Figure 7.5 Resource adequacy capacity available from solar resources**

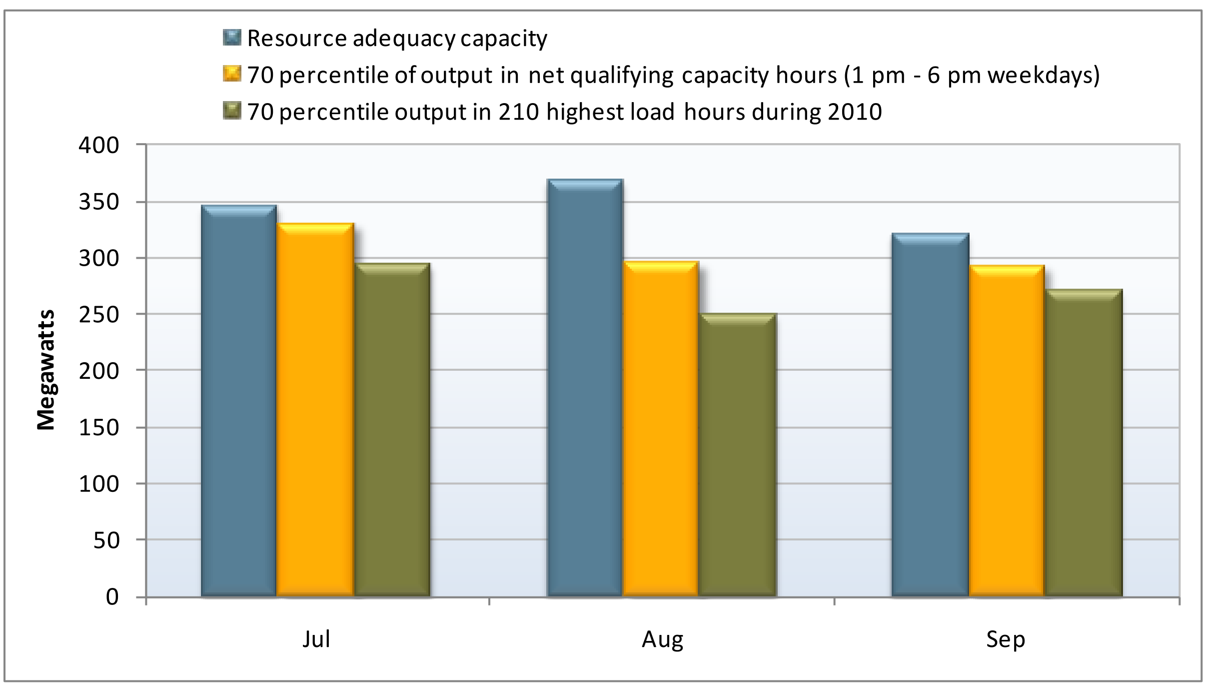
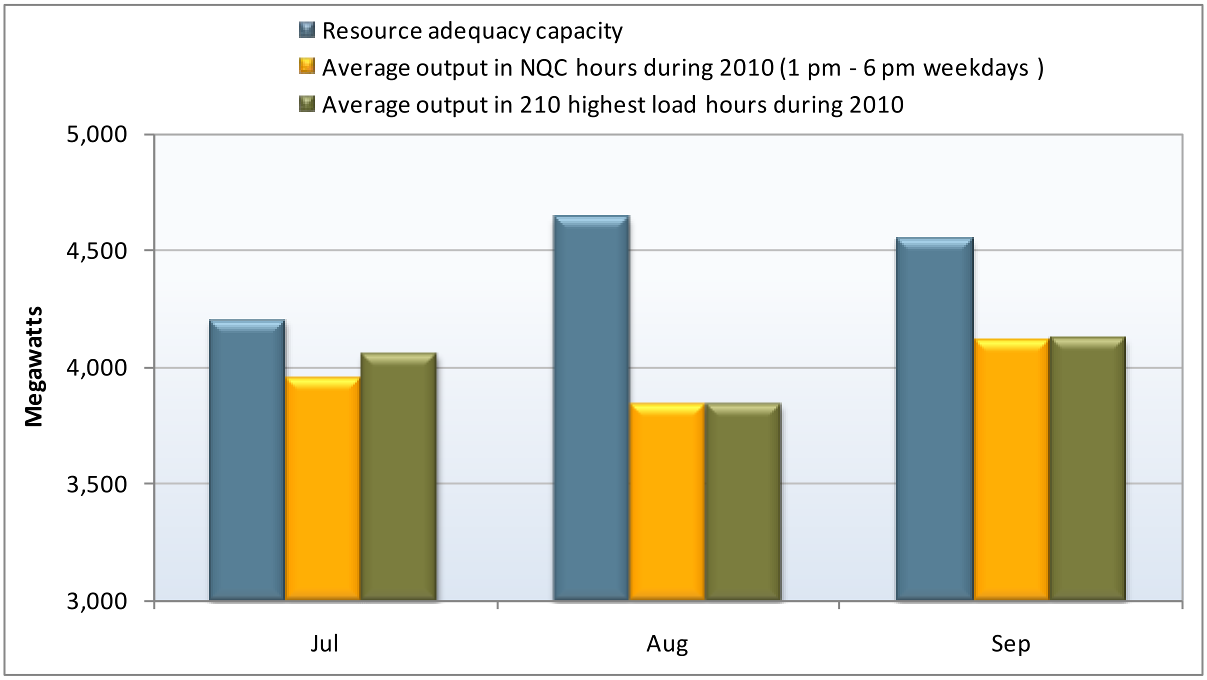


**Figure 7.6 Resource adequacy capacity available from qualifying facility resources**




## 7.5 Imports

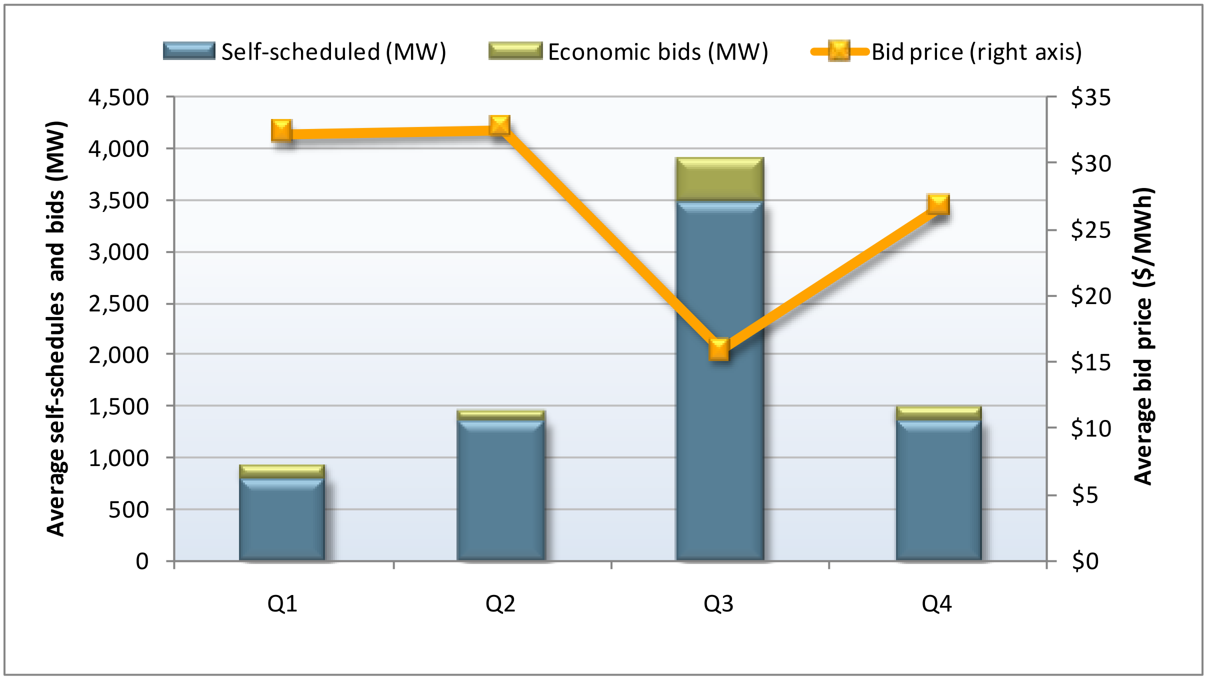
Load-serving entities can utilize imports to meet a limited amount of their resource adequacy requirement. A very large portion of resource adequacy imports are self-scheduled in the day-ahead market and most of the remainder is bid at relatively low prices. This suggests that resource adequacy imports are supported by a relatively high degree of commitments for energy and transmission.

Figure 7.7 summarizes the bid prices and volume of self-schedules and economic bids for resource adequacy import resources in the day-ahead market during peak periods throughout the year.

- The blue and green bars (plotted against the left axis) show the respective average amounts of resource adequacy import capacity that market participants either self-scheduled or economically bid in the day-ahead market.

- The gold line (plotted against the right axis) shows the average maximum bid prices for resource adequacy import resources for which market participants submitted economic bids to the day-ahead market.

**Figure 7.7 Resource adequacy import self-schedules and bids (peak hours)**




As shown in Figure 7.7, market participants self-scheduled a large proportion of resource adequacy imports in the day-ahead market. For example, during the peak summer months (third quarter), they self-scheduled an average of 3,477 MW of resource adequacy imports in the day-ahead market while they submitted additional energy bids for an average of 418 MW. An even larger proportion of resource adequacy imports were self-scheduled during the rest of the year.

Figure 7.7 also shows that market participants submitted relatively low-priced energy bids for the portion of resource adequacy imports not self-scheduled. During the peak summer months (third quarter), the average maximum economic bid was only about $16/MWh. Bid prices averaged about $30/MWh during the other quarters, but the volume of resource adequacy capacity economically bid averaged only 119 MW per hour in the non-summer periods.

## 7.6 Backup capacity procurement

If the capacity procured under the resource adequacy program was not sufficient to meet system-wide and local reliability requirements, the cost of alternative capacity procurement mechanisms could increase significantly. Thus, another indicator of the success of the resource adequacy program is the extent to which alternative capacity procurement mechanisms are used to supplement or replace resource adequacy as a means of meeting capacity requirements.

- ***Reliability must-run contracts —*** The amount of capacity under reliability must-run contracts and the costs associated with these contracts were lower in 2009 and 2010 compared to previous 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 have also reduced reliance on reliability must-run contracts with most of the needed capacity procured under the resource adequacy program. The drop in net pre-dispatch and net real-time costs for reliability must-run units in 2009 and 2010 compared to previous years 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* —** Minimal amounts of incremental capacity were procured for short periods of time under the interim capacity procurement mechanism of the ISO tariff. As shown in Table 7.2, only 371 MW of capacity was procured under this mechanism and all of this capacity was procured for the minimum duration of one month. The bulk of this capacity was procured because of problems with remedial action schemes or transmission outages that created additional needs for capacity in specific parts of the grid. The total cost of this capacity was $1.4 million.

Thus, in 2010 procurement of capacity under the resource adequacy program was sufficient to meet virtually all of the ISO system-wide and local area reliability requirements, and the cost of procurement under these alternative capacity procurement mechanisms was very limited.

**Figure 7.8 Reliability must-run costs: 2007-2010**

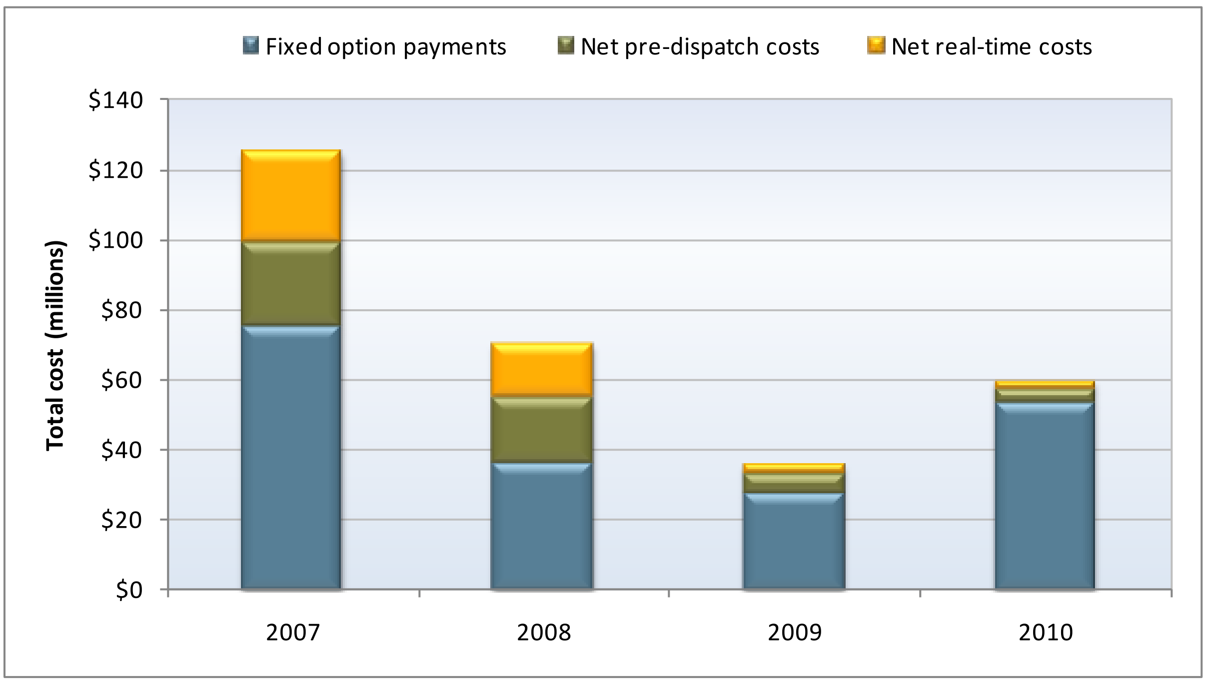


**Table 7.2 Interim capacity procurement mechanism costs (2010)**

| Resource | Local capacity area | ICPM designation (MW) | Estimated cost | ICPM designation dates |
|---|---|---|---|---|
| El Segundo #4 [1] | LA Basin | 20 | $77,832 | 1/5 - 2/3 |
| Delta Energy Center [2] | Bay Area | 127 | $494,192 | 4/30 - 5/29 |
| Yuba City Energy Center [3] | Sierra | 1 | $3,892 | 7/18 - 8/16 |
| Huntington Beach #3 and #4 [2] | LA Basin | 182 | $708,268 | 8/17 -9/22 |
| Mindalay #1 and #2 [4] | BC - Ventura | 40 | $155,664 | 9/27 - 10/26 |
| CalPeak - Enterprise and Border [1] | San Diego | 0.7 | $2,723 | 10/12 - 11/10 |
| | | **371** | **$1,442,571** | |

[1] Dispatched for local transmission reliability.

[2] Dispatched for remedial action scheme failure.

[3] Manual dispatch 1 MW beyond 45 MW reliability must run capacity.

[4] Dispatched for system capacity

## 7.6.1 Conclusion

Procurement of capacity under the resource adequacy program in 2010 was sufficient to meet virtually all system-wide and local 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.

# 8 Real-time market issues

As discussed in Chapters 3 and 4, prices in the day-ahead energy market have been highly stable and competitive since the start of the nodal market in 2009. However, prices in the 5-minute real-time market have remained highly volatile. Price spikes in this market have tended to drive average real-time prices significantly above day-ahead and hour-ahead prices during many months. This chapter provides a more detailed analysis of factors driving this price divergence.

## 8.1 Background

Supply and demand conditions in the real-time market may vary from those in the day-ahead market or hour-ahead scheduling process for a variety of reasons. Actual load conditions often vary from those forecasted on a day-ahead or hour-ahead basis. The actual supply in the 5-minute real-time market is also generally much more constrained than in the day-ahead market and hour-ahead scheduling process. This is due to a variety of unit operating characteristics tending to be more constrained and/or binding during individual 5-minute intervals in real-time than is assumed in the day-ahead and hour-ahead markets. These resource characteristics include:

- Start-up times for resources to be brought online
- Ramp rate limitations
- Forbidden regions, or ranges of output at which units may not operate for a sustained period
- Minimum down times required after a unit has been brought offline or dispatched to a lower configuration
- Unit outages and derates
- Capacity providing contingency-only ancillary services, which is dispatched only during a shortage of energy bids that threatens system reliability

All of these factors create differences in the inputs used in the hour-ahead and 5-minute markets. In addition, there is a fundamental difference between the models used in the hour-ahead and 5-minute markets. The hour-ahead market forecasts demand and optimizes projected supply using 15-minute intervals. In real-time, demand and supply are balanced on a 5-minute basis. Thus, various system constraints and limitations – such as unit ramping capabilities – tend to become binding much more frequently in the real-time market. When these limitations become binding in real-time, high price spikes, often near the bid cap, occur which drive real-time prices well above hour-ahead prices.

As discussed in this chapter, most of the price spikes in the 5-minute market generally last only a few 5-minute intervals and reflect short-term modeling limitations, rather than fundamental underlying supply and demand conditions.

## 8.2 Congestion

As shown in Figure 8.1, price spikes in the PG&E load aggregation point in the 5-minute real-time market were driven most frequently by the energy component of the total price, rather than by congestion.[126] This reflects the relatively limited role that congestion on transmission constraints into load pockets played in creating real-time price spikes in PG&E.

Figure 8.2 shows that congestion played a larger role for the SCE load aggregation point, accounting for up to 40 percent of the price in the first quarter of 2010. Even so, the energy component was still the largest component of the price during price spikes. This relationship also held for the SDG&E load aggregation point prices, with congestion accounting for up to 35 percent of the price in the fourth quarter of 2010. The next section examines why the energy component is the largest factor driving real-time price spikes.

## 8.3 System power balance constraint

When energy that can be dispatched is insufficient to meet estimated demand during any 5-minute interval, the system-wide power balance constraint of the market software is relaxed. This constraint requires dispatched supply to meet estimated load on a system-wide level during all 5-minute intervals. The power balance constraint is relaxed under two different conditions:

- When insufficient incremental energy is available for 5-minute dispatch, the real-time software relaxes this constraint in the scheduling run using penalty prices of $750/MW for the first 350 MW and $6,500/MW thereafter. In the pricing run, a penalty price of $750/MW is used. This causes prices to spike to the $750/MWh bid cap or above.[127]
- When insufficient decremental energy is available for 5-minute dispatch, the software relaxes this constraint in the scheduling run using a penalty price of -$35/MW for the first 350 MW. After this, different types of self-scheduled energy may be curtailed at penalty prices beginning at -$825/MW. In the pricing run, a penalty price of -$35/MW is used. This causes prices to drop down to or below the soft floor for energy bids set at -$30/MWh.

When brief insufficiencies of energy bids that can be dispatched to meet the power balance software constraint occur, the actual physical balance of system loads and generation is not impacted significantly nor does it pose a reliability problem.[128] This is because the real-time market software is not a perfect representation of actual 5-minute conditions. To the extent an imbalance in loads and generation actually does exist during these intervals, units providing regulation service provide any additional energy needed to balance loads and generation.

[126] Load aggregation point prices above $250/MWh were considered for this analysis.

[127] If a significant level of relaxation has occurred, the resulting prices are approximately equal to the bid cap ($500/MWh prior to April 2010 and $750/MWh afterwards). If relatively minor relaxation has occurred, prices in the pricing run may fall below the bid cap and would be set by marginal bids actually dispatched. This occurs from the fact that in the pricing run, a number of other constraints are relaxed slightly and other extremely high or low penalty prices enforced in the scheduling run are replaced with the bid cap and -$30/MWh bid floor.

[128] Large or extended imbalance shortages can potentially pose a reliability concern. However, for the most part, power balance constraint relaxations occur for short instances.

**Figure 8.1 Real-time prices by component during hours when PG&E area price > $250/MWh**

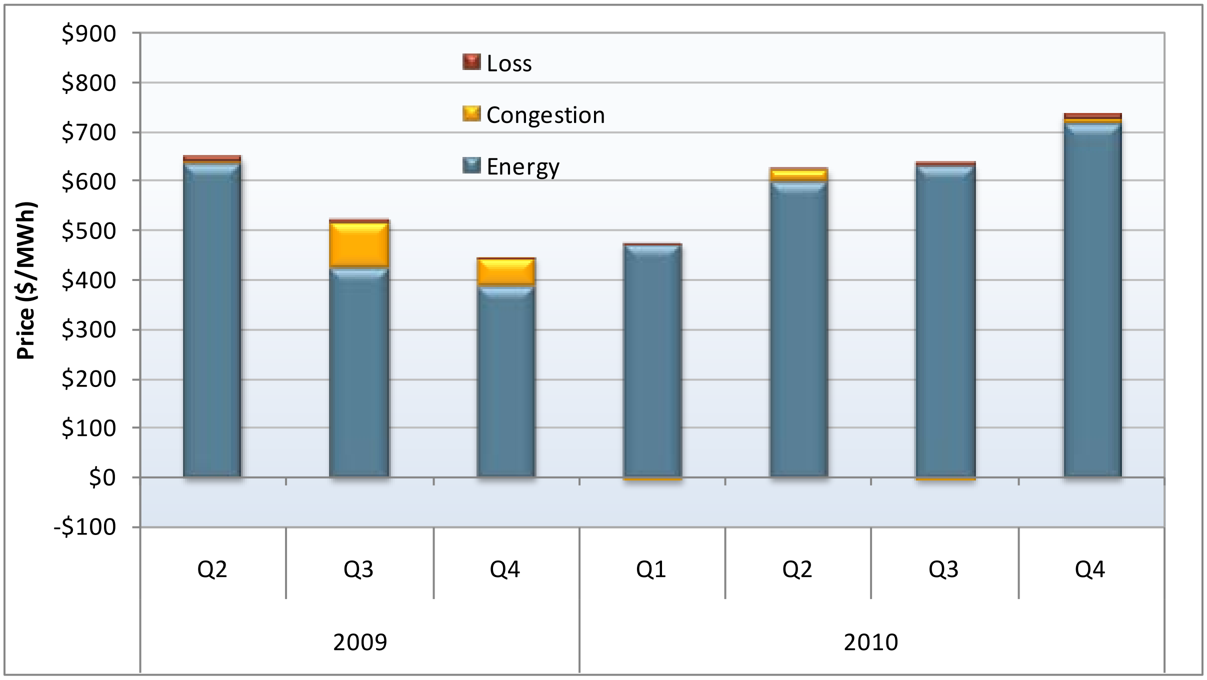



**Figure 8.2 Real-time prices by component during hours when SCE area price > $250/MWh**

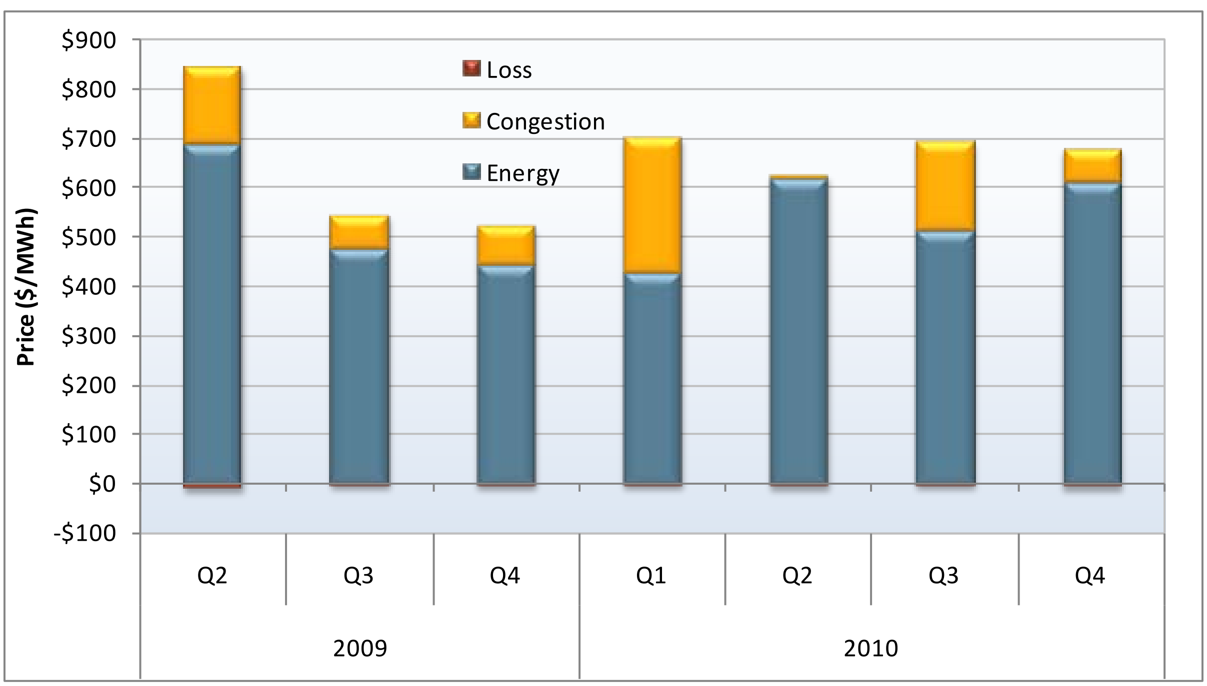


Figure 8.3 and Figure 8.4 show the frequency with which the power balance constraint was relaxed in the 5-minute real-time market software since the beginning of the nodal market. This constraint has never been relaxed in the day-ahead or the hour-ahead markets.

- As shown in Figure 8.3, this constraint was relaxed because of insufficient incremental energy in about 1 percent of the 5-minute intervals starting in the third quarter of 2009 through the third quarter of 2010. However, the frequency increased to about 1.5 percent of all 5-minute intervals during the fourth quarter of 2010.
- As shown in Figure 8.4, this constraint was relaxed due to insufficient decremental energy less consistently but more frequently than for upward insufficiencies. When the constraint is relaxed under these conditions, the downward impact on average prices is also less significant because prices only drop towards or to the -$30/MWh bid floor.

The ISO recently proposed lowering this bid floor to -$500/MWh in 2012 and even lower in the following years. DMM has expressed concern about this proposal, due in part to the impact this would have when the power balance constraint was relaxed because of short-term insufficiencies of dispatchable downward energy bids that can be created by software modeling issues.[129]

Figure 8.5 and Figure 8.6 provide more detailed information on the intervals in which the power balance constraint was relaxed. Figure 8.5 shows the percentage of intervals that the power balance constraint was relaxed by hour in 2010. As shown in Figure 8.5:

- Shortages of upward ramping capacity caused the constraint to be relaxed most frequently during peak hours when system loads were highest and changing at a relatively high rate.[130]
- Overall, the constraint was relaxed because of shortages of upward ramping in about 1.1 percent of intervals during 2010. However, during the system peak load hours of 18 through 21, prices spiked because of shortages of upward ramping in around 2.3 percent of intervals, more than double the average for all hours.

Figure 8.6 shows the number of consecutive 5-minute intervals that shortages of upward ramping capacity existed in 2009 and 2010. As shown in Figure 8.6:

- Over 75 percent of price spikes persist for only one to three 5-minute intervals (or 5 to 15 minutes) in both 2009 and 2010.
- During intervals when price spikes occurred, system energy prices averaged $381/MWh when the bid cap was $500/MWh. This compares to an average system energy price of only $91/MWh in the intervals before and after these price spikes.
- After the bid cap was raised to $750/MWh on April 1, 2010, prices averaged $646/MWh during intervals when this constraint was relaxed. This compares to an average system energy price of only $102/MWh in the intervals before and after these price spikes.

[129] See DMM comments on Phase 1 of the integration market initiative at http://www.caiso.com/2b11/2b11a5a872c80.pdf.

[130] During off-peak hours, the power balance constraint has been binding due to shortages of downward ramping capacity. However, shortages of downward ramping do not create prices lower than the -$30/MWh bid floor that is in effect for real-time energy bids.

**Figure 8.3 Relaxation of power balance constraint due to insufficient upward ramping capacity**

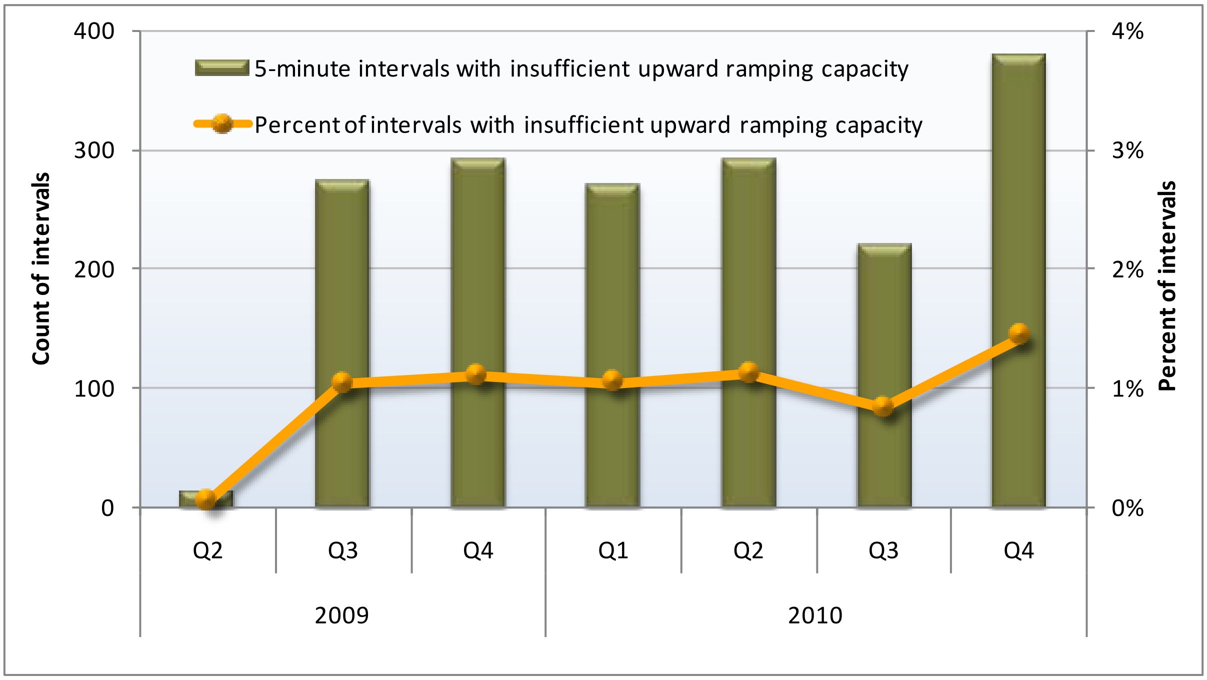



**Figure 8.4 Relaxation of power balance constraint because of insufficient downward ramping capacity**

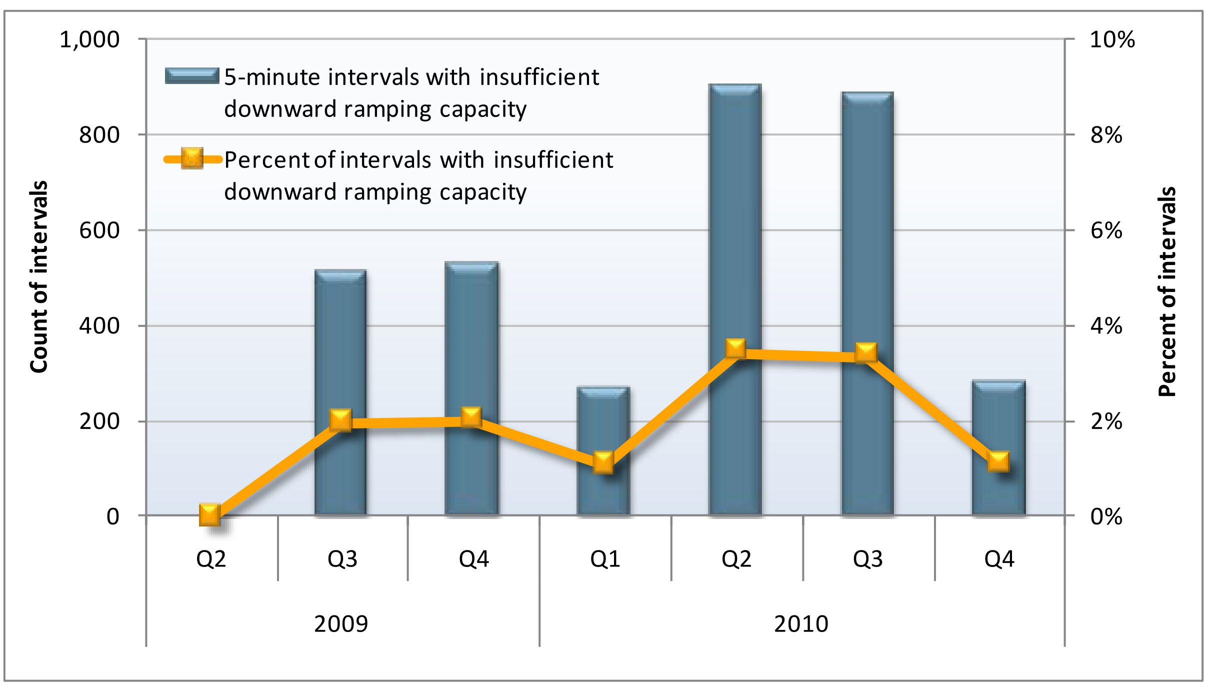


**Figure 8.5 Relaxation of power balance constraint by hour in 2010**

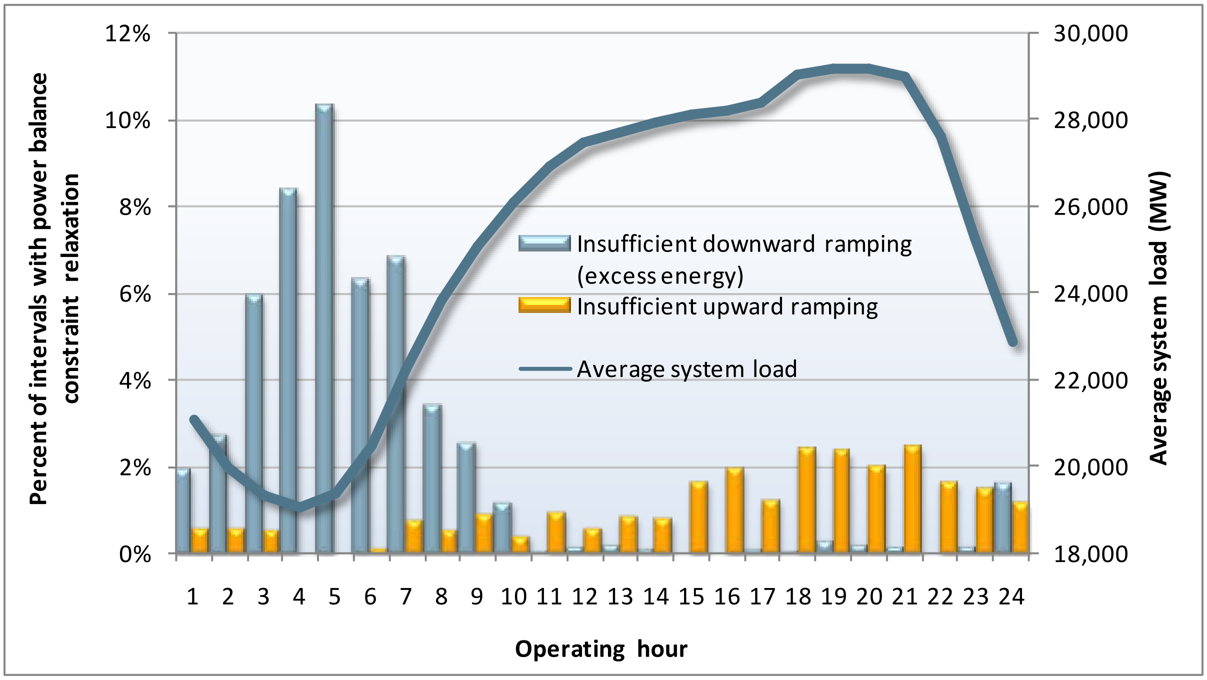
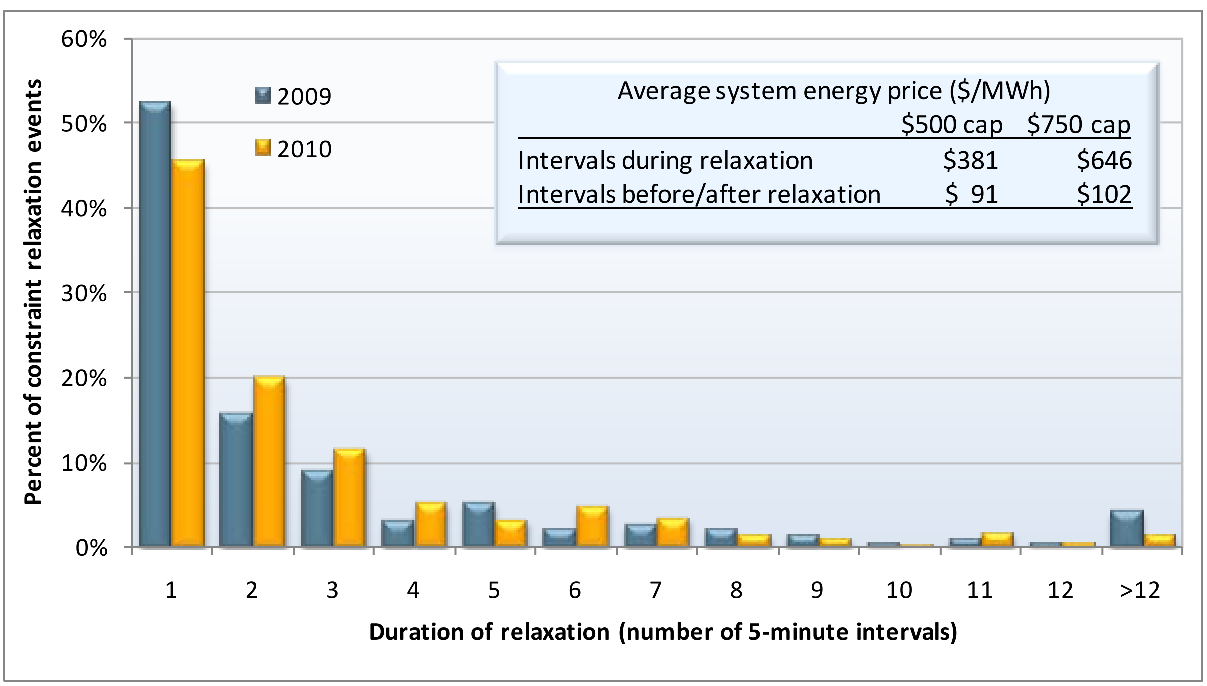



**Figure 8.6 Duration of energy balance constraint relaxation events**



## 8.4 Reasons for prices near caps

The ISO implemented an energy bid cap and floor to diminish the effect volatile energy prices may have on market participants. That is because these limits impact prices directly and indirectly:

- Dispatching a generator with a bid at or near the bid cap or floor will directly impact the system energy cost and prices.
- Penalty prices for relaxing various constraints are set based on the bid caps and floors. When one of these constraints is relaxed, prices can reach the energy price cap or floor.

Prices have rarely reached the bid cap or floor because of the market dispatching energy bids at these bid limits. Most prices that have hit these limits are caused by relaxing the power balance or transmission capacity constraints.

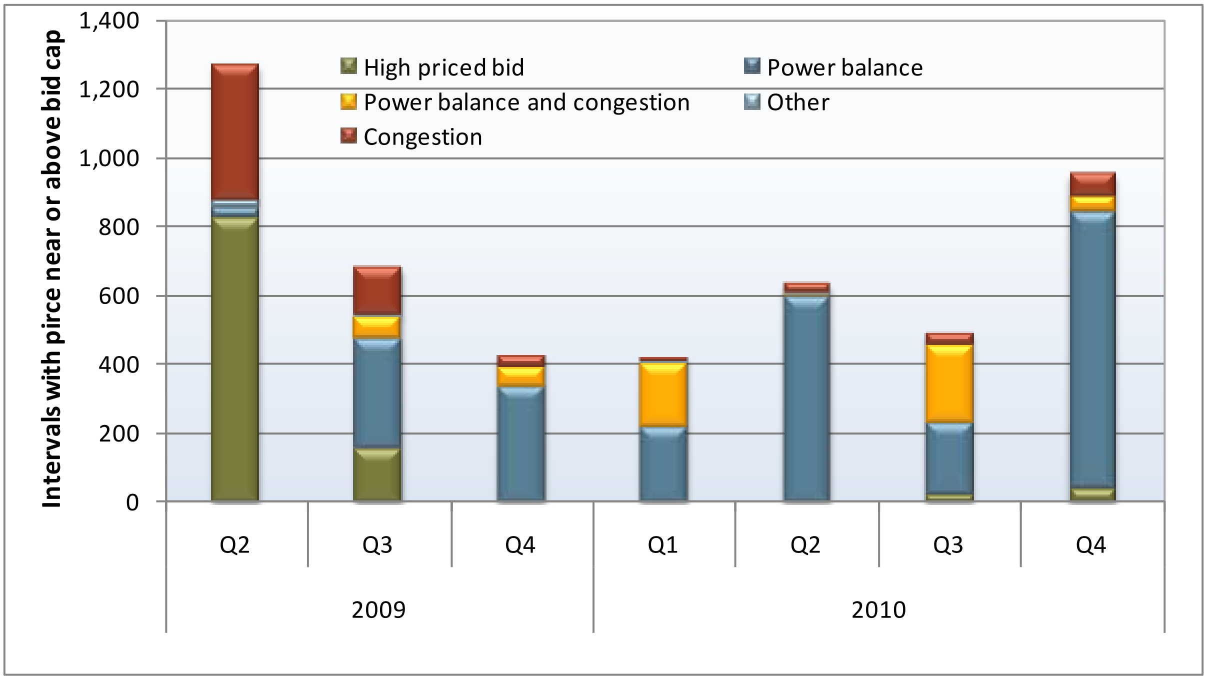
### High prices near energy bid cap

Figure 8.7 summarizes an analysis of the frequency of different factors driving high real-time prices for each load aggregation point. The analysis categorizes each high priced interval as follows:

- **Power balance constraint** – the power balance constraint was relaxed and the congestion component was less than $200/MWh.
- **Power balance constraint and congestion** – the power balance constraint was relaxed and the congestion component was greater than $200/MWh.
- **Congestion** – the power balance constraint was not relaxed and the congestion component was greater than $200/MWh.
- **High priced bid** – the power balance constraint was not relaxed, the congestion component was less than $200/MWh, and a high priced bid was dispatched during the interval.
- **Other** – the high price was not caused by any of the above categories.

Results of this analysis show that most of the high prices in the real-time market were driven by relaxation of the power balance constraint or binding transmission constraints. There were very few instances where the dispatch of high priced bids could have caused a high load aggregation point price.

**Figure 8.7 Factors causing high real-time prices**




As shown in Figure 8.7:

- Over 50 percent of all high prices at load aggregation points in 2009 and 2010 were due to relaxing the power balance constraint during an interval when congestion did not have a significant impact on price. Starting in the third quarter of 2009, this category has accounted for the largest percentage of the price events.[131] About 15 percent of all high price events were due to pure congestion and 12 percent to a combination of congestion and the power balance constraint.

- From the fourth quarter of 2009 through 2010, significant congestion often occurred during intervals when the power balance constraint was relaxed. This combination of conditions was highest in the third quarter of 2010 as a result of wildfire related derates of Path 26 during periods of high loads.

- During the first two quarters of 2009, over 25 percent of the high real-time load aggregation point prices were primarily attributable to congestion. However, congestion played a much reduced role in high prices thereafter.

- About 63 percent of the price spikes in the first four months of the new market were a result of high priced bids. During this period, the power balance constraint threshold was extremely high. After the first four months of the new nodal market in 2009, only 0.02 percent of the high prices are likely to have been a result of dispatching a high priced bid.

[131] The threshold used to determine when the power balance constraint was relaxed was set to $6,500 prior to August 2009. At this level, the market rarely relaxed the power balance constraint in the first four months of the new market.

Overall, the frequency of high priced intervals did not significantly increase when the energy bid cap changed in April 2010. Rather, the higher bid cap increased the magnitude of price spikes. Relaxation of the power balance constraint before April 1, 2010, would have resulted in an energy cost component at or near $500/MWh. Relaxation of this constraint after April 1, 2010, would result in an energy cost component at or near $750/MWh because of the increase in the cap.

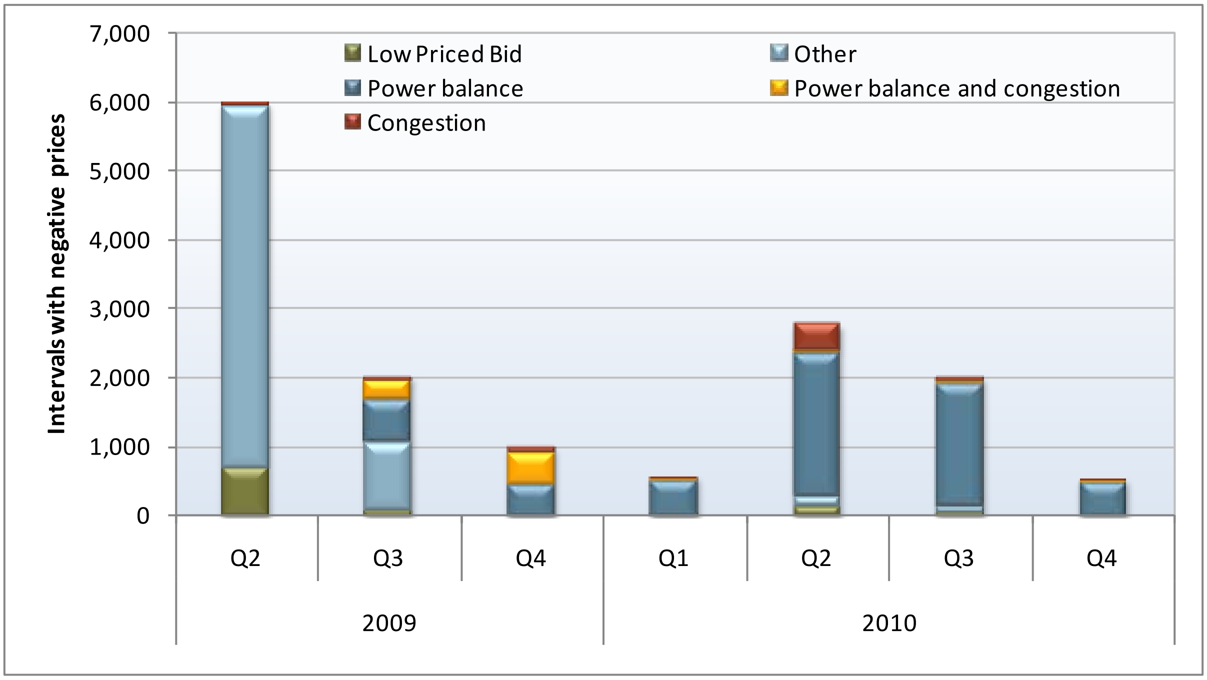
### Low prices near energy bid floor

The ISO implemented an energy bid floor of -$30/MWh at the start of the nodal markets. Real-time energy prices become negative for various reasons. Figure 8.8 summarizes an analysis of the causes of real-time prices less than $0/MWh at load aggregation points. The causes for low prices are categorized as follows:

- **Power balance constraint** – the power balance constraint was relaxed and the congestion component was less than 50 percent of the price.
- **Power balance constraint and congestion** – the power balance constraint was relaxed and the congestion component was more than 50 percent of the price.
- **Congestion** – the power balance constraint was not relaxed and the congestion component was more than half the price.
- **Low priced bid** – the energy component was between -$30/MWh and $0/MWh, the congestion component was less than 50 percent of the price, and a negatively priced bid was dispatched;
- **Other** – the energy component was less than -$30/MWh but the power balance constraint was not relaxed.

Results of this analysis show that most negative prices occur when the power balance constraint is relaxed due to a shortage of bids that can be dispatched downward.

**Figure 8.8 Factors causing negative prices**




As seen in Figure 8.8:

- In the second and third quarters of 2009, almost 70 percent of negative prices were due to other model parameters. Most of these negative prices had energy components between -$30 and -$35, but the power balance constraint was not relaxed. At the start of the nodal market, the penalty price associated with violating the power balance constraint was more negative in the first two quarters than its current level. Therefore, this constraint was not relaxed during the initial months of the new market. Prices below -$30/MWh were caused by other model parameters.
- The penalty price for the power balance constraints was modified at the beginning of July 2009 to be less negative. Low prices caused by relaxing the power balance constraint occurred more frequently in 2010 compared to 2009. About 80 percent of negative prices in 2010 occurred when the power balance constraint was relaxed. Most of these negative prices occurred in June and July 2010.
- Only about 5 percent of negative prices for load aggregation points were caused by congestion.
- About 6 percent of these negative prices were caused by a combination of congestion and relaxation of the power balance constraint.
- Negative bids directly caused only about 6 percent of negative prices.

Excess supply conditions that cause the power balance constraint to be relaxed generally occur in the early morning hours. During those hours, most of the online capacity is inflexible because of being self-scheduled or at minimum operating points. If there were sufficient negatively priced bids, the price would be set by a less negative bid rather than the penalty price.

## 8.5 Load forecasting and manual adjustments

One of the primary contributing factors to divergence of prices in the hour-ahead and 5-minute real-time markets involves the difference in load forecasts used in these two markets. For example, if system demand is under-forecasted in the hour-ahead market, the market software may dispatch imports and exports in a way that decreases the supply of available upward ramping capacity within the ISO during the 5-minute market. Similarly, if the load forecast is suddenly increased in the 5-minute real-time market, this can create a brief shortfall in the upward ramping energy available to meet the increased load forecast.

Some of the differences in these forecasts may be due to changing conditions between the execution of the hour-ahead market and the 5-minute real-time market. These changing conditions can include deviations in both load and supply. Supply deviations can occur as a result of uninstructed deviations, non-modeled unit start-up and shut down generation, changes in variable resource output, and tagging issues related to imports and exports. Together, these deviations can affect units providing ancillary services, most notably regulation, and the system frequency as measured by the area control error.

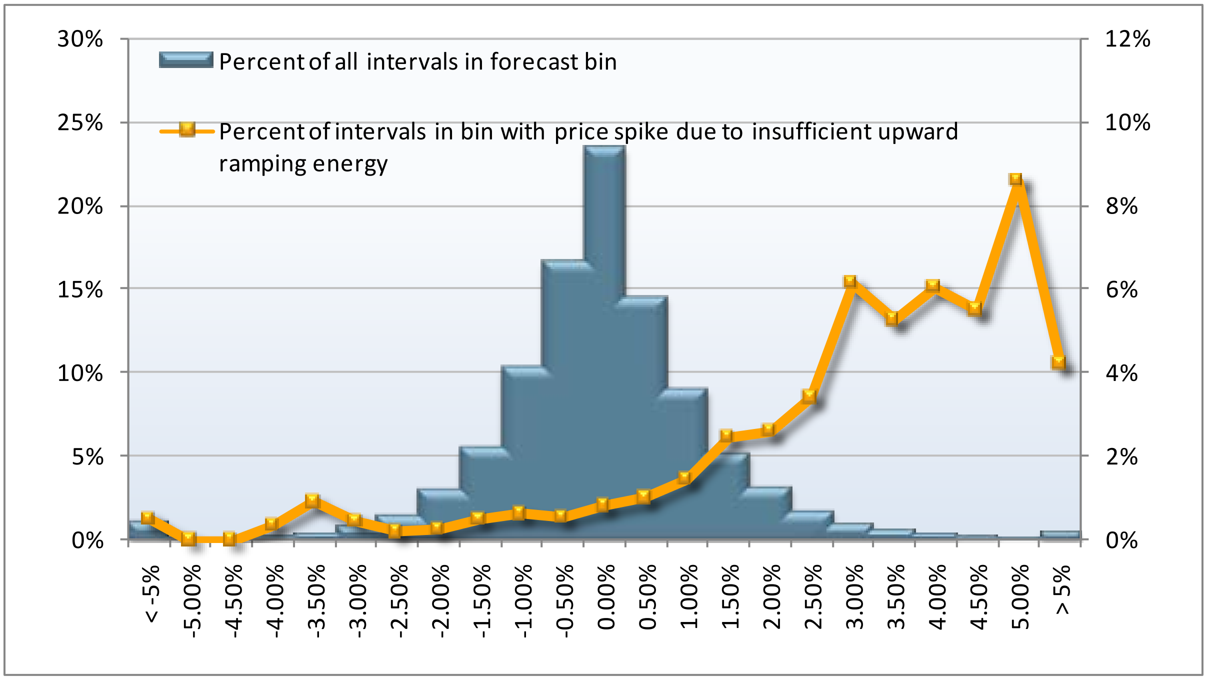
As a result, operators can manually adjust load forecasts used in the software to account for these load and supply deviations. This is known as a load adjustment. Load adjustment levels are not necessarily consistent between the hour-ahead and real-time forecasts. This can contribute to differences in price results between the hour-ahead market and the 5-minute real-time market, and short but extreme price spikes in the 5-minute market.

Figure 8.9 provides a histogram of the difference in the load forecast used in the hour-ahead market and the 5-minute load forecast in 2010. The bins represented by the blue bars show the distribution of this difference as a percentage of the real-time forecast. The line shows the percentage of intervals within each of these bids that the energy balance constraint was relaxed due to insufficient upward ramping energy. Load forecast data include manual adjustments. As shown in Figure 8.9:

- During 84 percent of hours, the load forecast used in the hour-ahead market was within ±1.5 percent of the 5-minute load forecast. During these hours, shortages of upward ramping capacity rarely occurred.
- A higher percentage of upward ramping capacity shortages occurred when the 5-minute load forecast exceeded the load forecast used in the hour-ahead scheduling process by 1.5 percent or more.
- As the degree to which real-time loads were under-forecasted in the hour-ahead market increases, the incidence of price spikes due to shortages of upward ramping capacity also increases.

DMM has identified some cases in which it appears that manual load adjustments may have contributed to the shortages of upward energy resulting in relaxation of the power balance constraint and extreme price spikes. For example, this can occur when the hour-ahead load forecast is adjusted significantly downwards, and when the real-time forecast is suddenly adjusted upwards. The more extreme differences in the hour-ahead and real-time forecasts in Figure 8.9 likely reflect cases in which such adjustments occurred.

**Figure 8.9 Difference in hour-ahead and real-time forecast in 2010**




Based on these observations, DMM has recommended that the ISO seek to improve how and when to adjust the load forecasts used in the hour-ahead and 5-minute real-time markets. The ISO is developing a more systematic procedure that gives operators additional guidance to determine whether a load adjustment should be removed or continued.

The ISO is also continuing development of a new short-term forecasting tool that would provide a more accurate and consistent forecast for the hour-ahead and real-time markets. This tool will provide forecasts at the 15-minute and 5-minute levels. The current load forecasting tool provides 30-minute forecasts, from which more granular forecasts are developed by simple interpolation. This new forecasting tool was expected in 2010, but implementation is now scheduled in 2011.

When the ISO implements this tool, DMM recommends that the ISO keep a database of manual adjustments made to this forecast in the hour-ahead and real-time software.[132] DMM believes this data may provide a basis for more systematic analysis and improvements of manual load adjustment practices and perhaps the load forecasting tool itself. Also, these data will be needed to determine the extent to which any new load forecasting tool reduces the need for manual adjustments and its accuracy prior to any such adjustments.

[132] At the time this report was developed, only a portion of the manual load adjustments are saved in the software database. Other manual adjustments are made to the forecast, but are recorded only in a separate spreadsheet format that cannot be readily used for analysis.

## 8.6 Impact of power balance constraint

The power balance constraint was relaxed due to insufficient incremental energy during only about 1.1 percent of intervals in 2010. However, price spikes during these intervals had a significant impact on overall average real-time prices due to the bid cap and penalty prices used in the pricing run when this relaxation occurs.

Figure 8.10 and Figure 8.11 highlight the degree to which the divergence of average quarterly real-time prices was caused by extreme prices during the small percentage of hours when power balance constraint relaxations occur.[133] With these hours excluded, real-time prices were approximately equal to hour-ahead prices. As shown in these figures, the impact of hours when the power balance constraint needed to be relaxed became especially high in the second and fourth quarters of 2010. This reflects the increased frequency this constraint was relaxed and the higher magnitude of price spikes when this occurs because of the higher $750/MWh bid cap that took effect in April 2010.

Figure 8.10 also shows that in every quarter except for the first one, the day-ahead market prices were higher than both the hour-ahead and real-time market prices when power balance constraint relaxations were excluded. This indicates the possible likelihood of a day-ahead price premium.

[133] This analysis excludes high prices at the price cap as well as priced near the price floor during hours when the power balance constraint was relaxed.

**Figure 8.10 Average prices excluding hours when power balance constraint relaxed (PG&E LAP, all hours)**

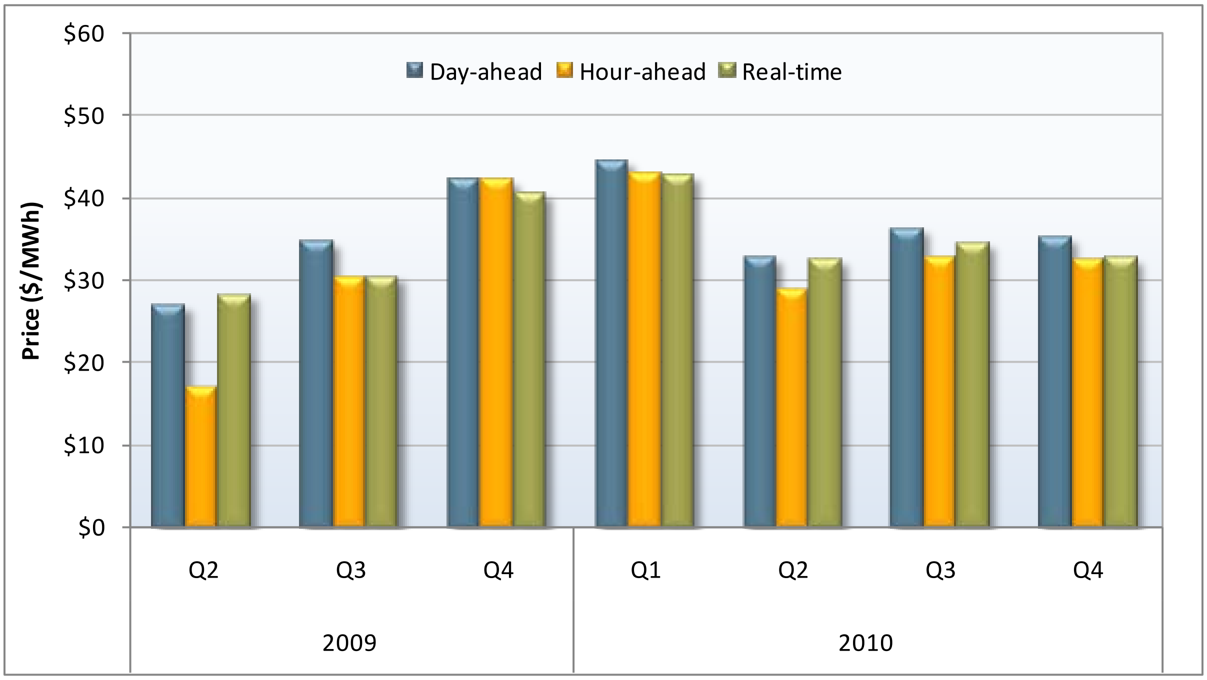



**Figure 8.11 Difference in average prices excluding hours when power balance constraint was relaxed (PG&E LAP, all hours)**