

California ISO

**2009 Annual Report on
Market Issues and Performance**

Special Revised Executive Summary – June 30, 2010

Prepared by: Department of Market Monitoring

Executive Summary

This is a special revised Executive Summary of the *2009 Annual Report on Market Issues and Performance* released by the Department of Market Monitoring (DMM) in April 2010.¹ This revised Executive Summary contains additional information and discussion of market conditions, performance, and costs from 2009 dating back to the start of the ISO market in 1998.

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

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

A more detailed overview of the new market design, and how its various components are intended to increase the efficiency of California's wholesale market, is provided in Chapter 1 of DMM's *2009 Annual Report on Market Issues and Performance*. The remaining chapters of the report analyze the performance of these different market components in 2009.

Overall market performance

Market Competitiveness

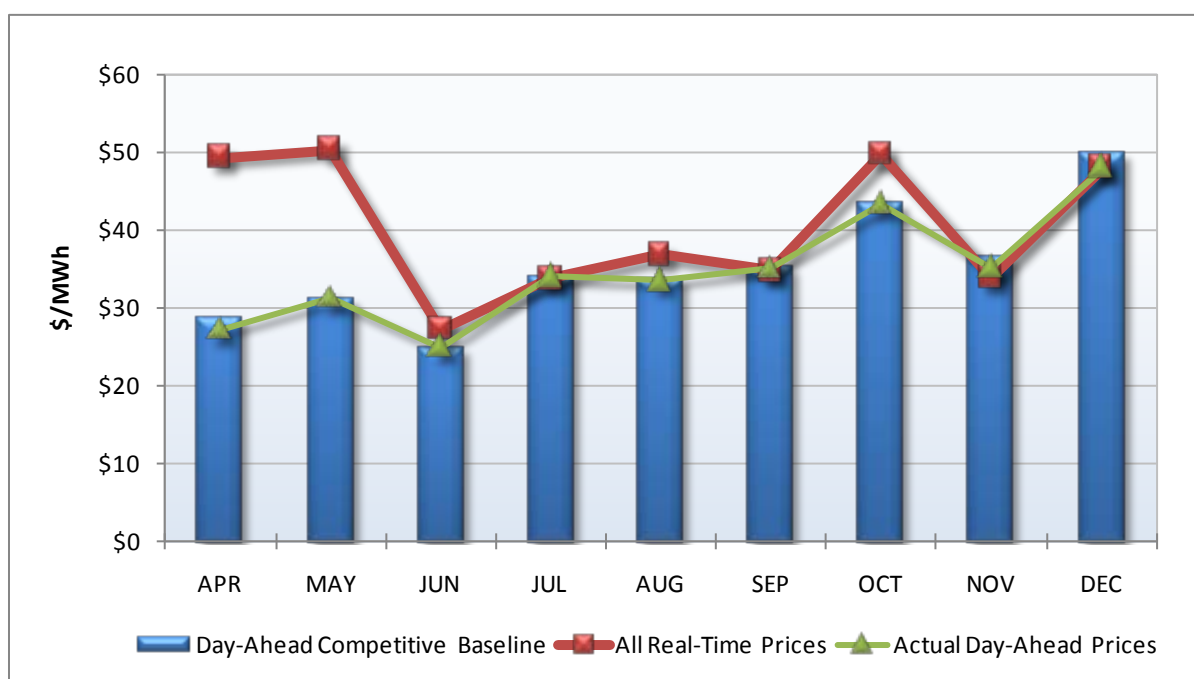
The new day-ahead and real-time markets in 2009 were highly efficient and competitive. Prices in the ISO's energy markets were approximately equal to competitive baseline prices that DMM estimates would result under highly competitive conditions. DMM calculates these competitive baseline prices by re-simulating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

¹ <http://www.caiso.com/2777/27778a322d0f0.pdf>

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

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

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

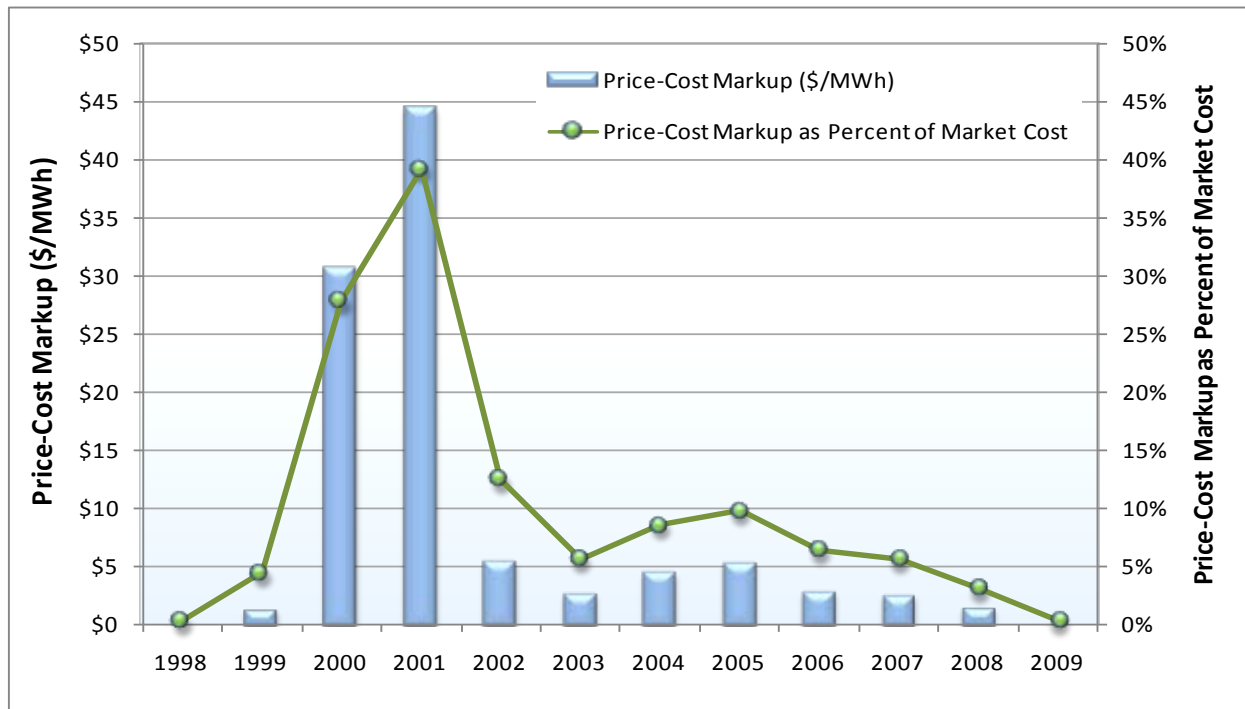


DMM has compared overall wholesale market prices to its estimate of competitive baseline prices dating back to the start of the market in 1998. The degree to which wholesale market prices exceed DMM's estimate of competitive baseline prices is known as the *price-cost markup*. Figure E.2 summarizes the results of the *price-cost markup* analysis that have been published in DMM's prior annual reports dating back to 1998. As shown in Figure E.2:

- California's wholesale market was highly competitive during its first two years (1998 to 1999), with a price-cost mark-up of less than 1 percent.
- During the energy crisis of 2000 to 2001, prices in California's wholesale markets were highly uncompetitive, with a price-cost mark-up ranging from almost 30 to 40 percent.
- California's wholesale market has been relatively competitive from 2002 to 2008, with a price-cost mark-up generally ranging from 5 to 10 percent.

- Under the new market design implemented in 2009, prices in California’s wholesale market reflect extremely competitive and efficient conditions, with prices approximately equal to a perfectly competitive baseline.

Figure E.2 Overall wholesale market price-cost markup, 1998-2009



The price-cost markup and other analysis in this report indicate that prices under the new market design implemented in 2009 are extremely competitive. However, direct comparisons with the price-cost markups reported in previous years are difficult due to the different way in which DMM has needed to calculate the price-cost markup over the 12 years that the ISO has been in operation. Specifically, DMM has needed to modify the data and method used to calculate total wholesale costs as California’s wholesale market has changed since the ISO began operation in 1998.

- **1998 to 2000.** From 1998 through 2000, under California’s initial market design, the California Power Exchange’s day-ahead market provided transparent prices that could be used to value energy scheduled prior to the ISO’s real-time market. During this period, DMM estimated wholesale costs for all energy scheduled on a day-ahead and hour-ahead basis based on prices in the California Power Exchange’s day-ahead market. DMM calculated the cost of the remaining energy needed to meet demand based on prices in the ISO’s real-time market and costs of real-time energy procured out-of-market by the ISO.
- **2001 to 2008.** From closure of the California Power Exchange in January 2001 to 2008, there was no centralized market for energy scheduled on a day-ahead and hour-ahead basis with the ISO. During this period, most energy needed to meet demand was scheduled on a day-ahead or hour-ahead basis with the ISO. DMM estimated wholesale costs for energy scheduled on a day-ahead or hour-ahead basis with the ISO based on a combination of (1) estimated operating costs of generation owned by the state’s investor owned utilities (IOUs) scheduled with the ISO, (2) costs of bilateral contracts signed by the State of California and the state’s major IOUs available to DMM, and (3)

bilateral cost indices for any remaining generation scheduled on a day-ahead or hour-ahead basis with the ISO. DMM calculated the cost of the remaining energy needed to meet demand based on prices in the ISO's real-time market and costs of real-time energy procured out-of-market by the ISO.

- **2009.** The new market design that started in April 2009 provides dramatically increased transparency of market clearing prices and quantities. This provides a basis for more accurately assessing wholesale energy costs. As a result, DMM modified its methodology for calculating total wholesale costs from the approach used in its seven prior annual reports.² The new method is based on the cost of serving load using the prices and quantities cleared in each of the ISO's three energy markets: day-ahead, hour-ahead and 5-minute real-time.

In addition, the method used to calculate the competitive baseline price under the new market design is also modified and is more detailed compared to the method used in prior years.³ Thus, the extremely low price-cost mark-up calculated under the new methodology and market design may largely reflect increased efficiencies of this new market design, rather than increased competitiveness. On a going-forward basis, we believe this new competitive baseline methodology will provide a more accurate tool for assessing changes in market competitiveness or efficiency over time.

Total wholesale costs

Figure E.3 shows total estimated wholesale costs per MWh from 1998 to 2009. Wholesale energy costs during different years are calculated as described in the preceding section. Total wholesale costs in each year include energy costs, as well as costs associated with ancillary service reserves, various forms of uplift payments (must-offer waiver denials costs, residual unit commitment, bid-cost recovery) and reliability costs (such as reliability must-run contracts and interim capacity procurement). Costs do not include any capacity payments made under the resource adequacy program.

Wholesale costs are provided in nominal terms, as well as after a simple normalization for changes in average spot market prices for natural gas. Natural gas fired resources are the marginal resource during most hours in the western U.S. electricity markets. This makes energy prices heavily influenced by the cost of natural gas. To account for year-to-year changes in gas prices, DMM also calculates an estimate of energy costs normalized to a fixed natural gas price.⁴ The green line in Figure E.3 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.

As shown in Figure E.3, costs were stable in 1998 and 1999, before spiking dramatically during the energy crisis of 2000 to 2001. Since 2002, costs have been relatively stable, despite significant

² Because the new market was in effect for only part of 2009 (April – December), the costs for the months prior to go-live (January – March) were calculated using a methodology similar to the one used in last year's annual report.

³ For example, the current method uses default energy bids that include a 10 percent adder that was not included in bids for gas-fired units in prior years. This would tend to make the price-cost mark-up lower under the current market design. On the other hand, the prior method used bids based on average heat rates at each unit's maximum operating level, while the current method uses default energy bids based on incremental heat rates. This could tend to make the price-cost mark-up higher under the current market design.

⁴ The 2009 annual average of daily gas prices (\$3.60/mmBtu) was used as the basis for normalization. Energy costs were normalized on an annual basis by multiplying the estimated portion of energy costs attributable to gas generation (both internal and external) by the ratio of applicable annual average gas price to the 2009 annual average gas price, and then adding in the non-energy cost components. The amount of gas generation assumed to normalize energy costs ranged between a low of 42 percent in 2005 and a high of 69 percent in 2008.

fluctuations in spot market gas prices. Prices decreased noticeably in 2009. Total estimated wholesale costs of serving load in 2009 were \$8.8 billion, or \$38/MWh. This compares with estimated wholesale costs of \$53/MWh of load served in 2008. Figure E.4 shows the contribution of different components of wholesale costs in terms of costs per MWh and the percentage of total 2009 costs.

Figure E.3 Total wholesale costs in \$/MWh of load served: 1998-2009

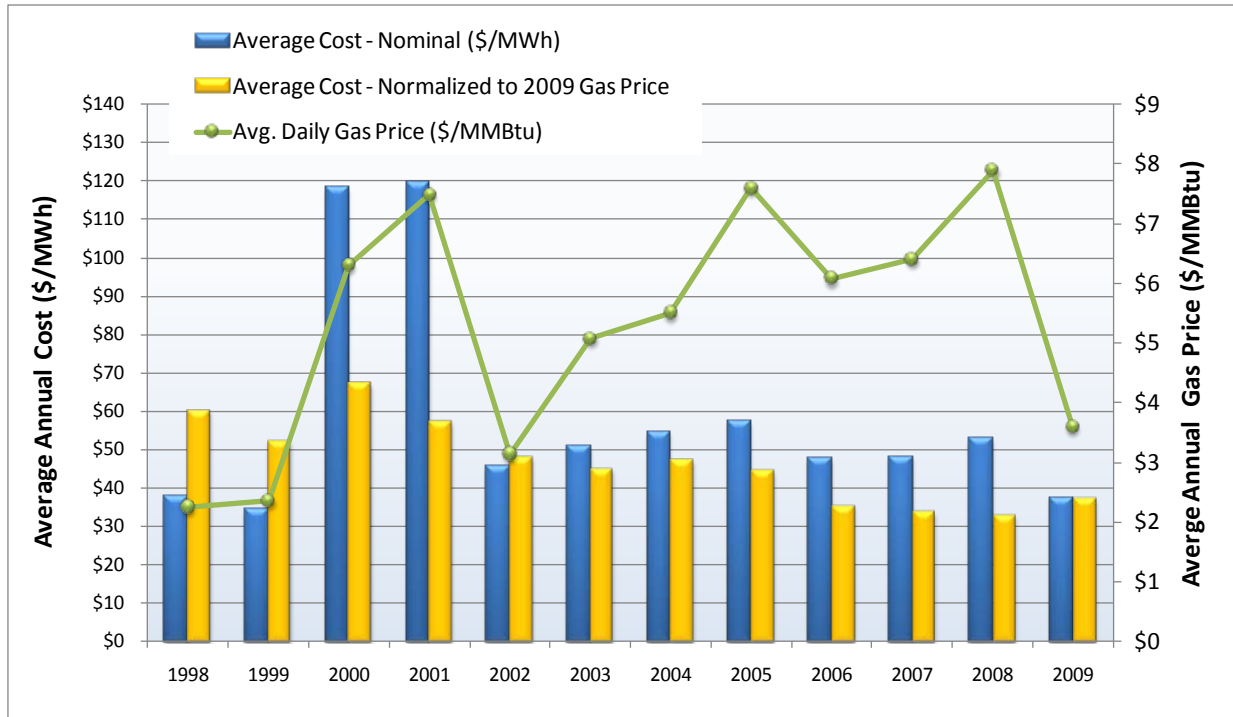
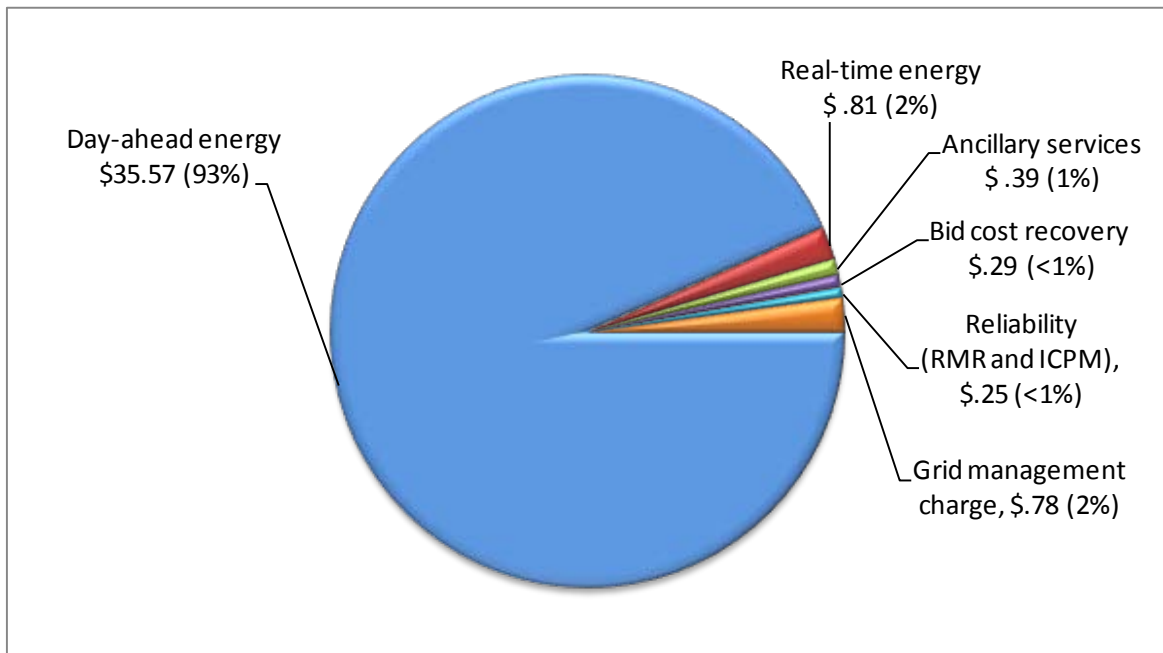


Figure E.4 Total wholesale costs in \$/MWh of load served, 2009



The decrease in wholesale cost in 2009 is attributable primarily to the drop in spot market prices for natural gas in 2009, which averaged about 56 percent less than in 2008.⁵ Other factors contributing to lower total wholesale costs in 2009 were lower total loads and increased hydro availability in the summer months. During the peak summer hours, lower loads and increased hydro supply can have a major impact on moderating overall prices and avoiding extremely high prices.

Comparisons of costs under the new market design with previous years must consider the significant differences between the new integrated energy market and the primarily bilateral market structure that was previously in place, as described in the previous section. Because of these differences, the decrease in 2009 costs relative to costs for previous years reported by DMM should be viewed only as a general indication of a downward trend in wholesale costs.

However, analysis of different market components provided in this report provide strong indications that the new market design implemented in 2009 increased market efficiency and reduced costs in a variety of ways.

- **High day-ahead scheduling** — The level of load and supply clearing the day-ahead market has consistently been very high. On average, almost 98 percent of total forecasted demand was scheduled in the day-ahead market. In the day-ahead market, the supply of resources that can be used to most meet load and manage congestion is typically much greater and more flexible than in real-time. Thus, high day-ahead scheduling allows for more efficient unit commitment, scheduling and congestion management. This also leaves a small volume of demand to be met by the residual unit commitment and real-time market processes.
- **Convergence of day-ahead and real-time prices** — In prior years, price indices for day-ahead bilateral markets tended to be higher than prices in the real-time imbalance market. Under the new market, prices in the day-ahead and real-time markets have converged closely, providing another indicator of the efficiency of the new market design. Price convergence in sequential energy markets indicates that day-ahead scheduling and dispatch patterns were accurate and efficient. This avoids the need for major adjustments as part of the re-optimization that occurs in the real-time market. As noted earlier, prices and dispatch patterns in the hour-ahead scheduling process used to adjust imports and exports often diverged significantly from the day-ahead and 5-minute real-time markets. This represents an area in which market efficiency can be further improved (See Chapter 3).
- **Market competitiveness** — Prices in the day-ahead and real-time energy markets have been extremely competitive. One of the key causes of the competitiveness of these markets is the high degree of forward contracting by load-serving entities. The high level of forward contracting significantly limits the ability and incentive for the exercise of market power in the day-ahead and real-time markets. In addition, bids for the additional supply needed to meet remaining demand in the day-ahead and real time energy markets have been highly competitive. Most additional supply needed to meet demand have been offered at prices close to default energy bids used in bid mitigation, which are designed to slightly exceed each unit's actual marginal or opportunity costs.
- **Ancillary services** — Ancillary service markets in 2009 performed well under the new market design. Costs declined from \$0.74/MWh of load in 2008 to \$0.39 in 2009. This represents a drop from 1.4 percent of wholesale energy costs in 2008 to only 1 percent in 2009. This compares favorably with

⁵ For example, average daily spot market prices for natural gas at the SoCal Border in 2008 and 2009 were about \$8.8/mmBtu and \$3.9/mmBtu, respectively.

ancillary service costs in other ISO markets with similar designs. In these markets, ancillary service costs have ranged from just under 1 percent to over 2 percent (See Chapter 6).

- **Bid cost recovery payments** — Under the new market design, generating units may submit three-part offers: start-up costs, minimum load costs, and bids for energy above minimum operating levels. If a unit is started up or scheduled at minimum load during some hours through the day-ahead market, the unit is eligible for a bid cost recovery payment to ensure that it recovers the full cost of its start-up and minimum load costs, plus any energy bids that are dispatched. Three-part bidding and bid cost recovery may also increase the efficiency of the energy market by providing an incentive for suppliers to submit bids more closely to their marginal operating costs. Bid cost recovery payments averaged 1 percent of energy costs under the new market design. Equivalent uplift costs in other ISOs have also ranged from just under 1 percent to over 2 percent.
- **Resource adequacy** — The amount and location of capacity under resource adequacy contracts in 2009 also helped keep total costs low. Resource adequacy capacity has been used to meet almost all of residual unit commitment requirements under the new market design. Resource adequacy units are required to offer all available capacity into the residual unit commitment market at a price of \$0/MW and do not receive an additional payment for capacity scheduled to meet residual unit commitment requirements. Resource adequacy capacity also helped reduce the amount and cost of capacity under reliability-must-run contracts, and was sufficient to meet local and system reliability requirements so that minimal additional capacity was procured through the interim capacity procurement mechanism in the tariff (see Section 7.6).

System loads

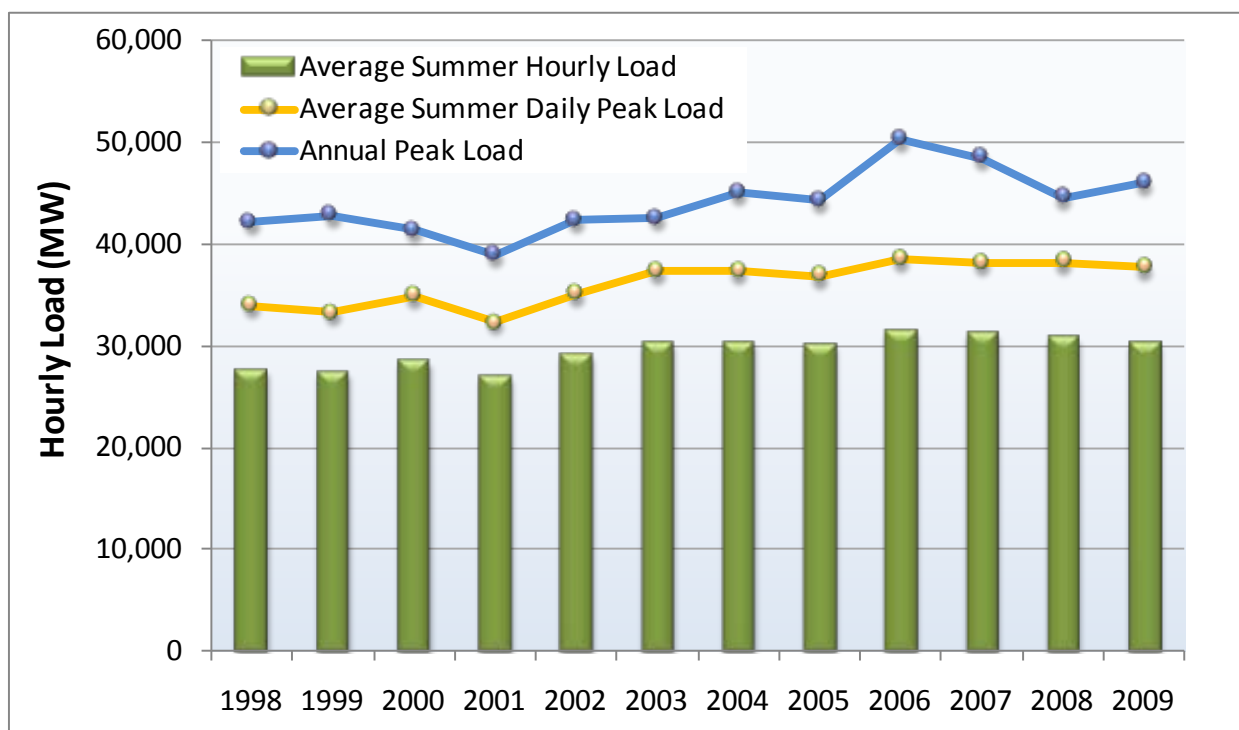
Most key load indicators were lower in 2009 than in previous years. This is likely primarily attributable to moderate summer weather and slow or negative economic growth. Summer peak loads continued to decline moderately since the historic peak in 2006. Summer weather conditions have been generally mild since a record heat wave in 2006. Figure E.5 shows annual peak loads and energy use over the last four years.

In 2009, load peaked at 46,042 MW, on September 3, at 4:17 p.m. As shown in Figure E.5, this exceeded the 1-in-2 year forecast of peak demand by about 663 MW, or 3.5 percent, but well below the 1-in-10 year peak forecast of 50,879 MW. The ISO sets system level resource adequacy requirements based on the 1-in-2 year forecast of peak demand. Resource adequacy requirements for local areas are set based on the 1-in-10 year peak forecast for each area.

Figure E.5 summarizes load peak hours (7-22) of the summer months of June to August from 1998 to 2009.⁶ Average summer loads have been relatively flat since 2003, with the notable exception of 2006. However, as shown in Figure E.5, system peak loads have been much more variable from year to year. These system peaks are driven by summer heat waves, which can drive system loads to extremely high levels for a very limited number of hours each summer. The potential for such peak loads drives many of the reliability planning requirements and always creates the potential for reliability problems under extreme weather conditions.

⁶ 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 E.5 System loads: Summer months, 1998-2009



Self-scheduling

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

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

Price convergence

A key measure of overall performance of the energy market is the degree of price convergence across the day-ahead, hour-ahead and real-time markets. In the first few months of the new market, average day-ahead prices tended to be lower than real-time prices. Average prices in the hour-ahead scheduling process were consistently lower than both day-ahead and real-time prices. Since then, price

convergence in these three markets has improved substantially. By the fourth quarter of 2009, prices were similar across the energy markets when compared to previous quarters.

Figure E.6 shows average monthly prices in the three energy markets for the Southern California Edison load aggregation point during peak and off-peak hours, respectively. Price trends in the other major load aggregation points (Pacific Gas & Electric and San Diego Gas & Electric) are very similar to those depicted for the SCE area in Figure E.6.

Figure E.7 highlights the difference in average monthly prices in the hour-ahead and real-time markets for the PG&E area during peak and off-peak hours. As shown Figure E.7, prices in the hour-ahead scheduling process were systematically lower than prices in the 5-minute real time market, particularly during the first months of the new market. Although price convergence in these two markets improved toward the end of 2009, there was a tendency for prices in the hour-ahead process to be significantly lower than prices in the other markets. This remains an area for potential improvements in market performance. This issue is discussed in more detail in the following section.

Figure E.6 Comparison of peak hour prices (Southern California Edison)

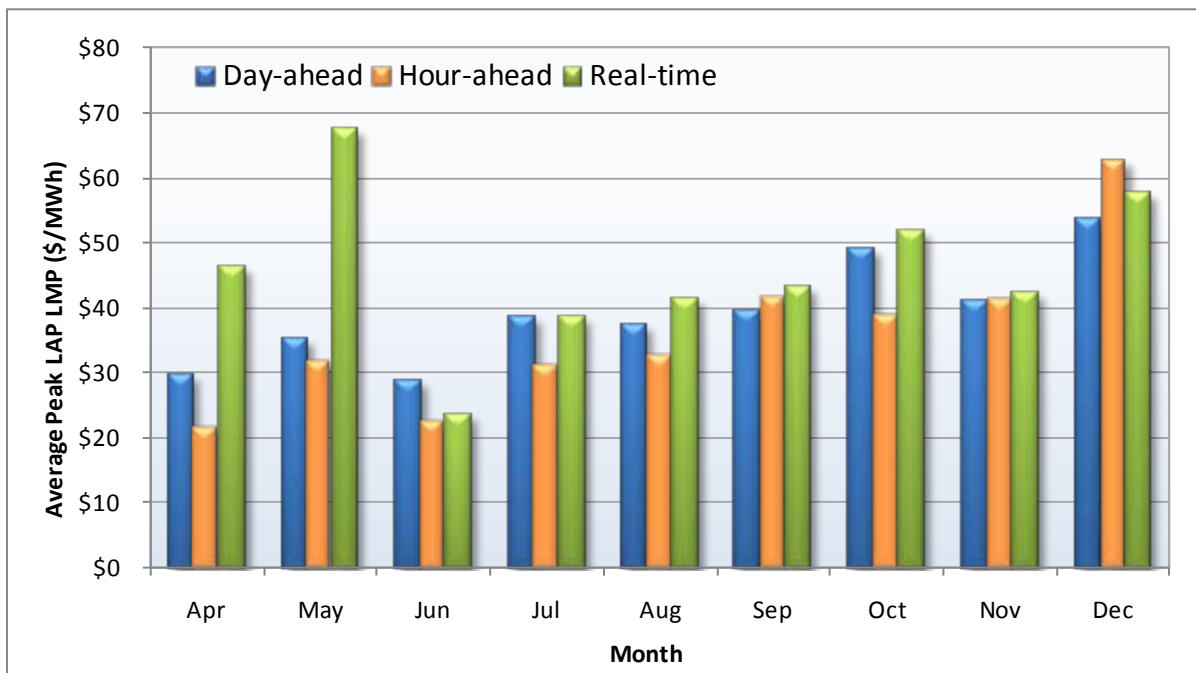
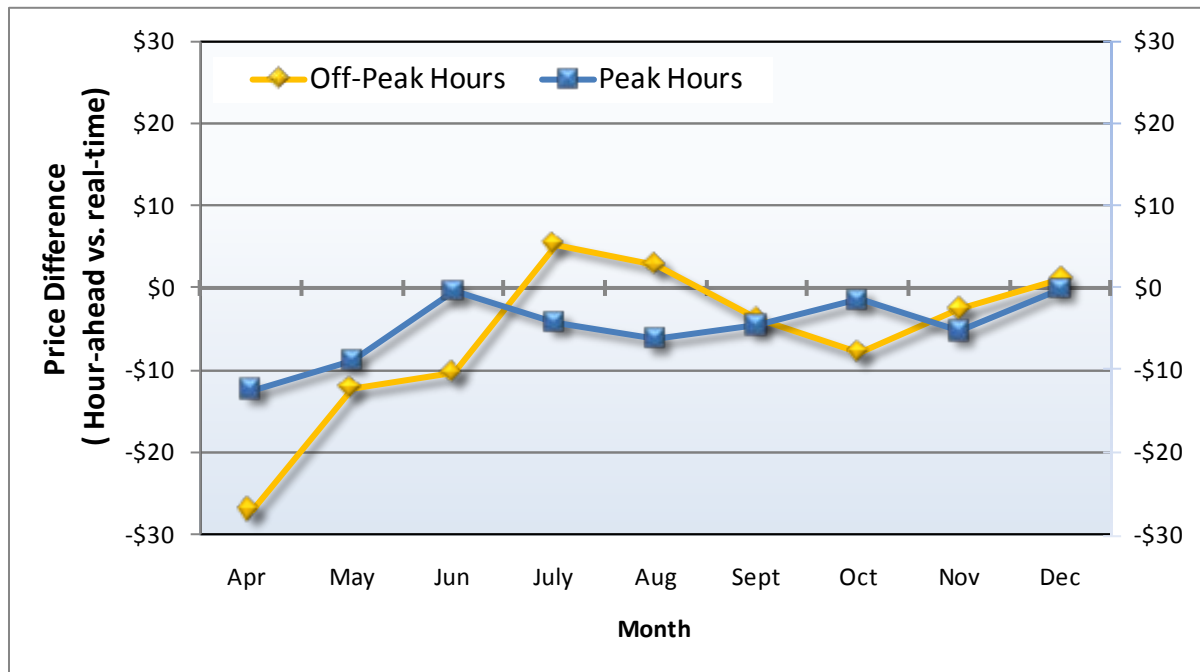


Figure E.7 Difference in hour-ahead versus real-time prices (Pacific Gas & Electric)

Hour-ahead scheduling process

During 2009, net import schedules clearing the hour-ahead scheduling process were systematically lower than net import schedules clearing the day-ahead market. As shown in Figure E.8, average monthly net imports clearing the hour-ahead process during peak hours were 500 MW to 1,000 MW lower than net day-ahead import schedules. This drop in net imports was due to a combination of a decrease in imports and an increase in exports in the hour-ahead market. Import schedules clearing in the hour-ahead decreased by an average of 200 MW, while exports increased by an average of 600 MW each hour.

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

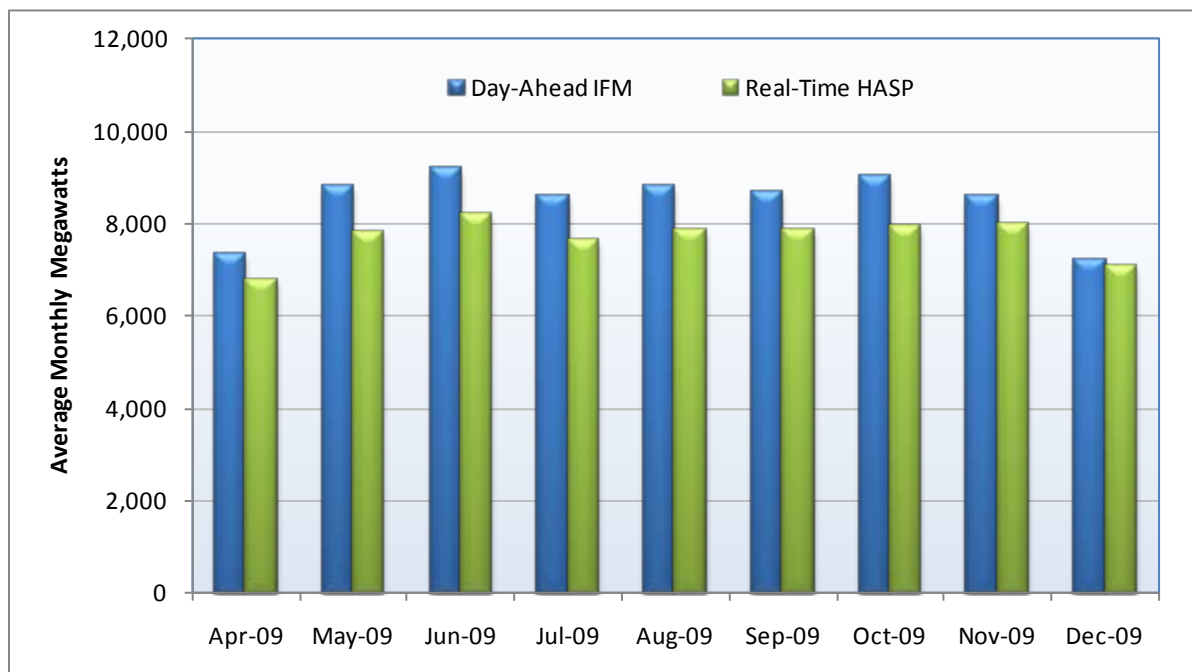
This trend appears to be due to a combination of factors, as is discussed in greater detail in the DMM's quarterly report for the third quarter of 2009.⁷ The low prices and decrease in net imports in the hour-ahead market appear to be due to systematic forecasting, modeling and optimization differences

⁷ *Quarterly Report on Market Issues and Performance*, Department of Market Monitoring, revised December 23, 2009. <http://www.caiso.com/2457/2457987152ab0.pdf>

incorporated in the software used to clear the hour-ahead market and the software used for the 5-minute real-time market.

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

Figure E.8 Net imports in day-ahead vs. hour-ahead market (peak hours)



Exceptional dispatch

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

As shown in Figure E.9, total energy from exceptional dispatches ranged from 1 to 2 percent of total system energy from May to July, but decreased to less than 0.5 percent in the last three months of the year. Figure E.9 shows the hourly average energy from exceptional dispatches from three types of exceptional dispatches:

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

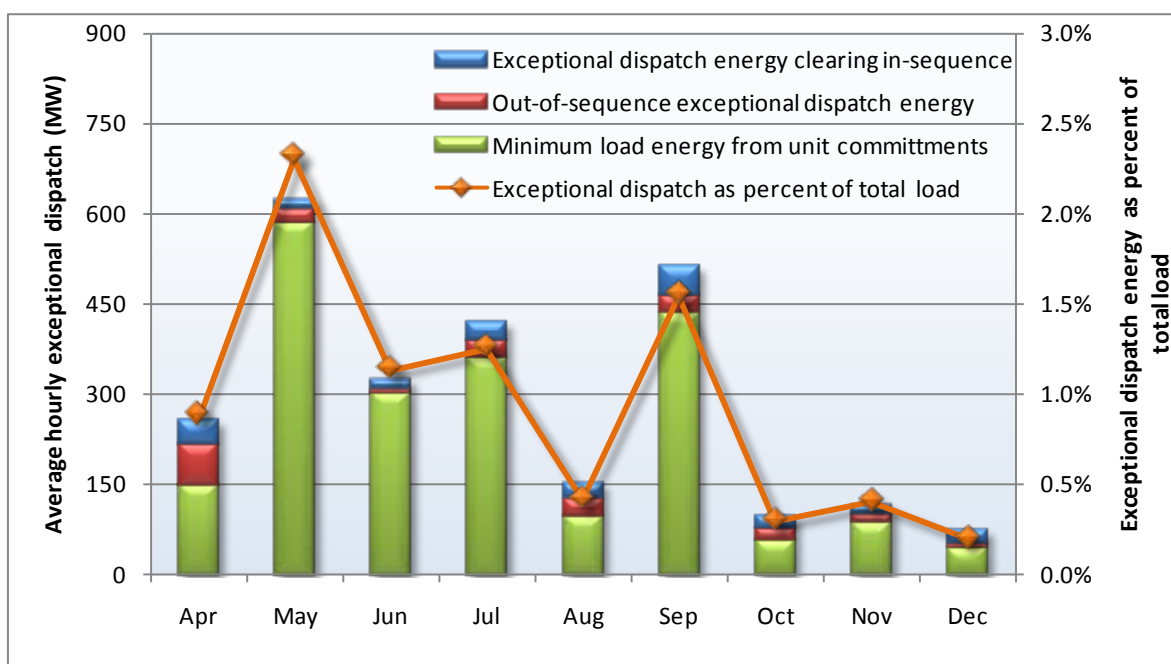
processes. Minimum load energy from unit commitments accounts for the bulk of energy called upon by exceptional dispatches.

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

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

Exceptional dispatches for energy may have had a significant impact on prices at some specific locations during limited time periods. However, is unlikely that exceptional dispatches for energy had a significant impact on overall real-time energy prices. As shown in Figure E.9, the bulk of energy from exceptional dispatches resulted from the minimum load energy from unit commitments. Minimum load energy would not be eligible to set the market clearing price, even if these units were committed through the market. As discussed in Chapter 3, operating logs also indicate a high portion of the out-of-sequence real-time energy from exceptional dispatches stemmed from unit operating constraints that would have made these dispatches ineligible to set market clearing prices.

Figure E.9 Average hourly energy from exceptional dispatches

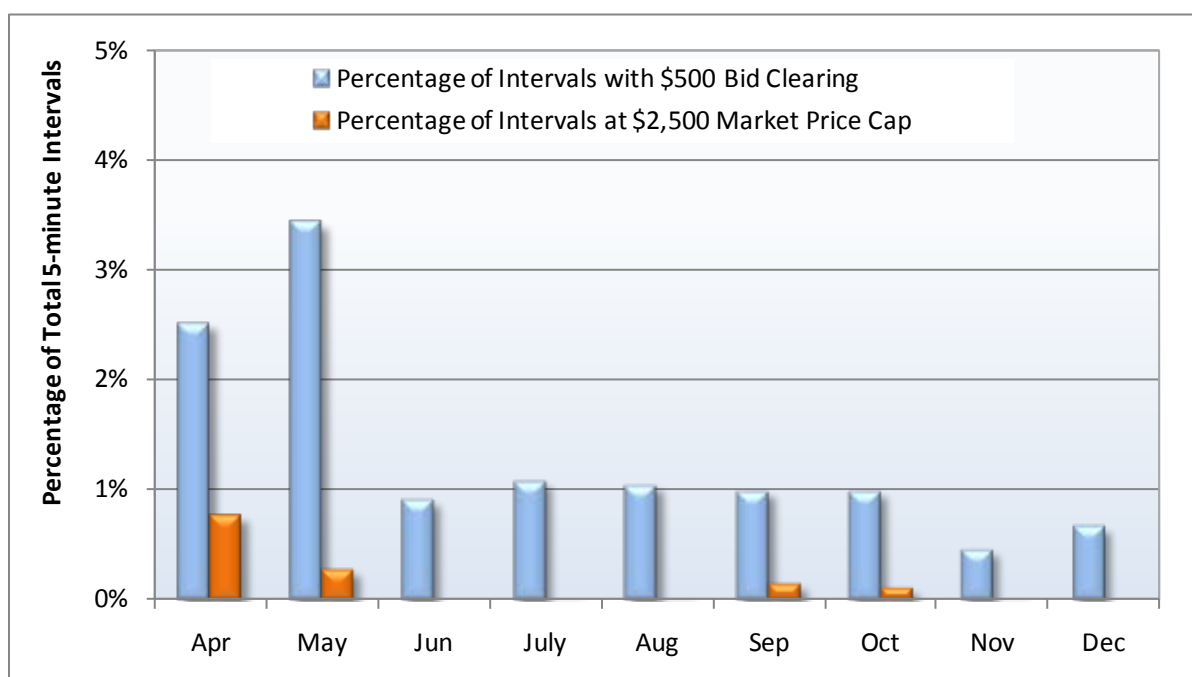


Market power mitigation

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

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

Figure E.10 Frequency of \$500/MWh bid cap and \$2,500/MWh price cap binding in real-time market



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

DMM has developed a variety of metrics to track and illustrate the frequency that bid mitigation is triggered and the impact this had on individual unit bids and dispatches. These metrics are described in Chapter 4 and Appendix A. Figure E.11 provides a monthly summary of three metrics showing the number of units impacted by mitigation in the day-ahead market:

- **Units subject to bid mitigation** — Mitigation is triggered if local market power procedures run prior to the day-ahead and if real-time markets indicate a unit may need to be dispatched at a higher level due to a non-competitive transmission constraint. During each month in 2009, an average of only one to three units per hour were subject to mitigation in the day-ahead market.
- **Units with bids lowered** — About 80 percent of units subject to mitigation in the day-ahead market actually had bids lowered as a result of mitigation. This reflects that market bids submitted by units are often lower than the default energy bids used to cap bids if a unit is subject to mitigation.
- **Increased dispatches due to mitigation** — About 30 percent of units subject to mitigation in the day-ahead market were dispatched at a higher level as a result of having their bid lowered by bid mitigation.

Figure E.12 shows the amount of energy dispatched from units within different local capacity areas because of bid mitigation in the day-ahead market. Section 2.1.1 of Chapter 2 provides a map and figures showing the location and amount of generation and peak load in each of these areas. As shown in Figure E.12:

- Over the entire nine-month period, an average of about 60 MW of additional energy may have been dispatched from mitigated units due to local market power mechanisms. This represents only 0.2 percent of system energy.
- Mitigation had the largest potential impact in September, when the total amount of additional energy that may have been dispatched from mitigated units averaged 134 MW per hour. This represents only 0.45 percent of system energy.
- The average hourly potential increase in energy dispatched from units due to mitigation was low and dispersed across different local areas.
- In the hour-ahead process, mitigation of real-time market bids was triggered a bit more frequently than in the day-ahead market.

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

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

Figure E.11 Average number of units mitigated in the day-ahead market

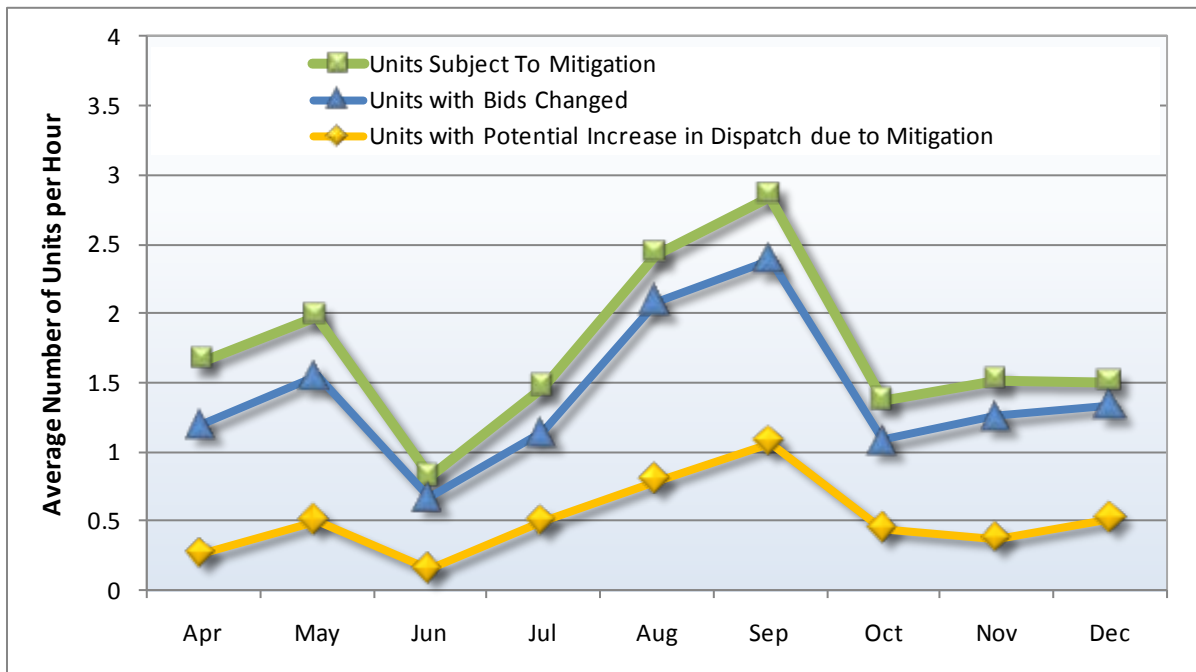
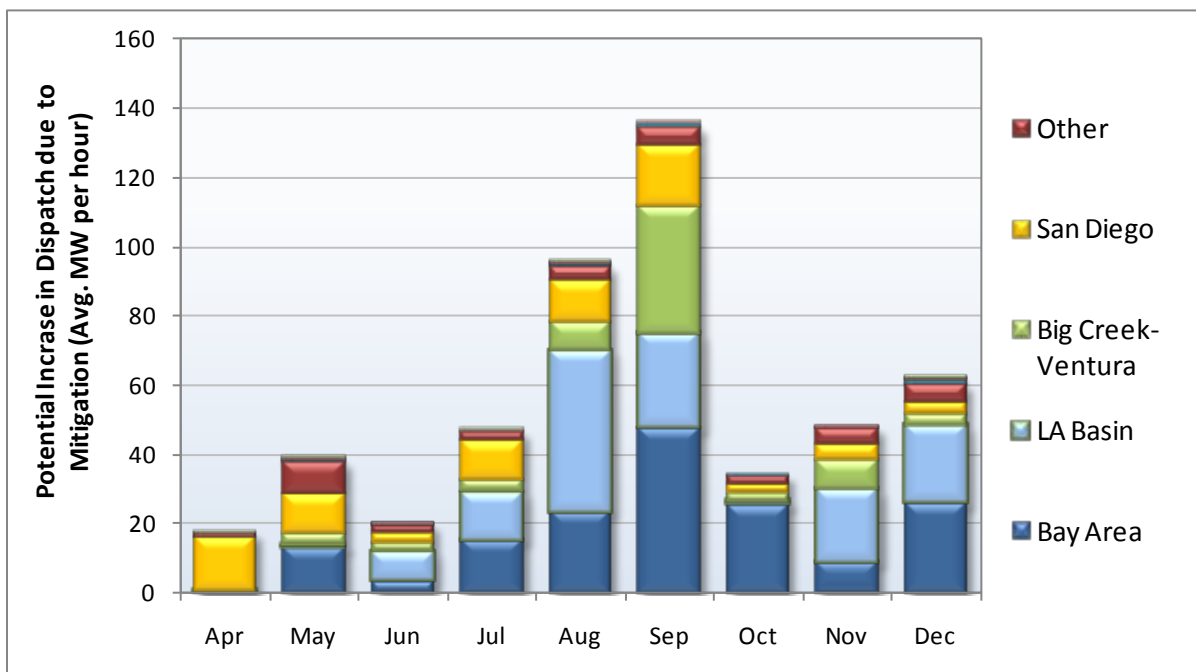


Figure E.12 Potential increase in day-ahead market dispatch due to mitigation: Hourly averages by local capacity area, April – December, 2009



Ancillary services

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

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

- As shown in Figure E.13, ancillary service costs decreased from \$0.74/MWh of load in 2008 to \$0.39/MWh in 2009. This represents a drop in ancillary service cost from 1.4 percent of estimated wholesale costs in 2008 to 1 percent in 2009.
- Monthly trends in ancillary service costs in 2009 before and after implementation of the new market also indicate that ancillary service costs have decreased under this design. As shown in Figure E.14, ancillary service costs increased in April, when the new market design was first implemented, but then decreased significantly over the rest of the year. Overall, ancillary service costs decreased from \$0.49/MWh of load in the first quarter of 2009 to \$0.36 in the remaining months of 2009 following the new market implementation.
- Seasonal trends also indicate that the new market design has resulted in lower ancillary service costs. These costs have historically increased in summer months when loads and prices are higher. However, as shown in Figure E.14, ancillary service costs decreased over the summer months in 2009 under the new market.

Figure E.13 Annual comparison of ancillary service cost as a percentage of wholesale energy costs

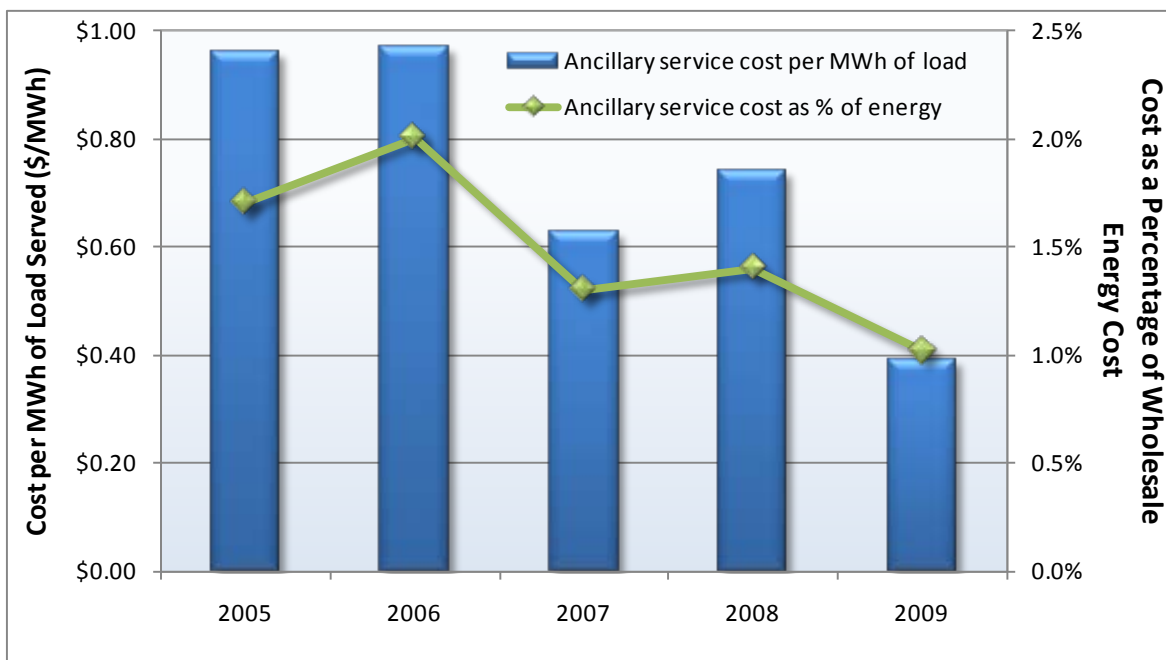
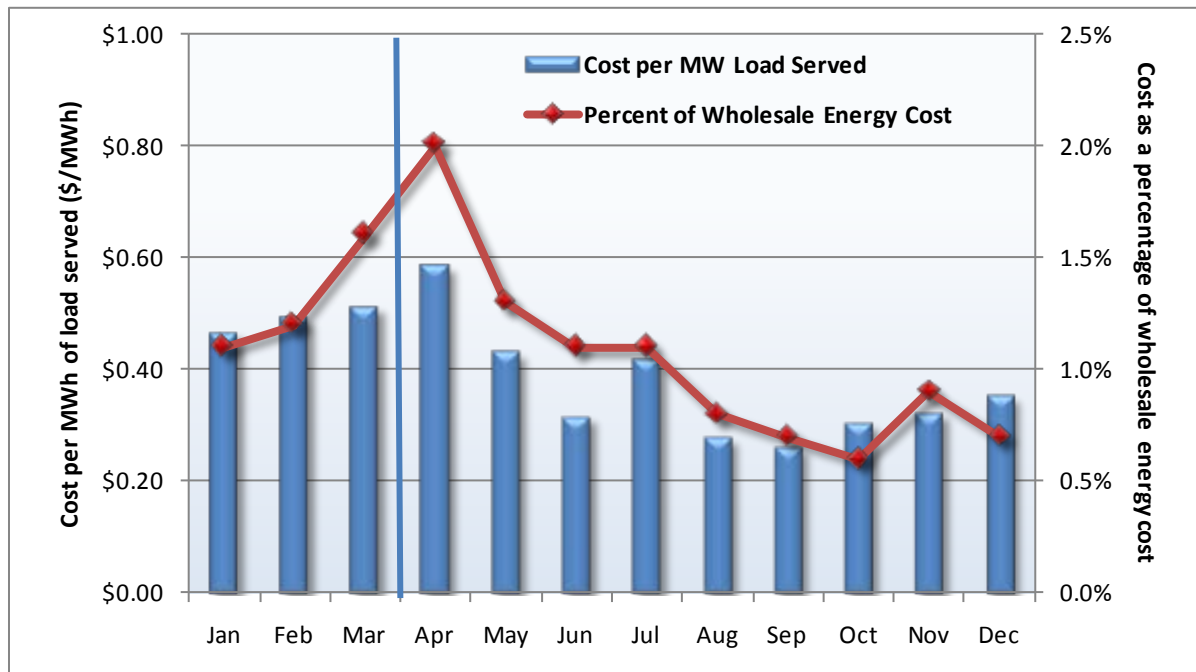


Figure E.14 2009 ancillary service costs by month

Residual unit commitment

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

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

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

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

About 87 percent of bid cost recovery payments for units committed in RUC were incurred in August to November. During this period, additional capacity that was being committed in RUC increased due to

capacity constraints that were added to reduce the need for committing units via exceptional dispatch. In January 2010, the ISO implemented these constraints in the day-ahead market and removed them from the RUC market. This should result in more efficient use and scheduling of any units committed to meet these constraints, because these units will have an opportunity to be scheduled for additional energy in the day-ahead market.

Resource adequacy program

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

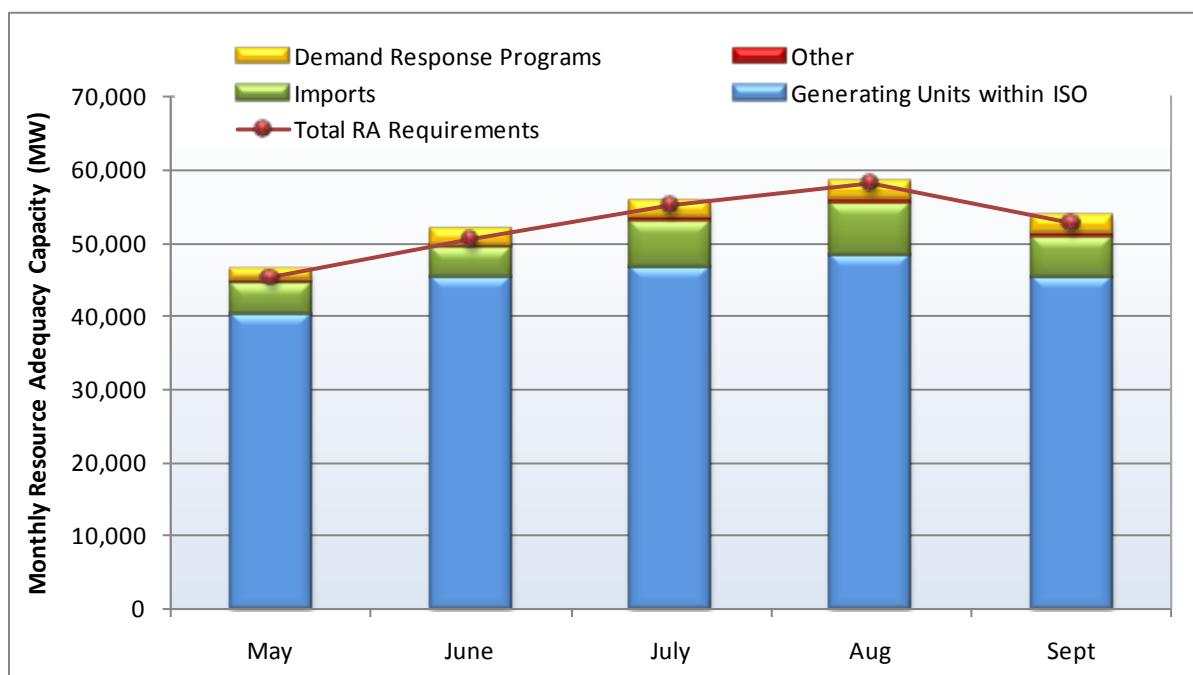
- On a system-wide basis, load-serving entities must procure resource adequacy capacity equaling 115 percent of their projected peak demand requirements for each month under a 1-in-2 year forecast of peak demand.
- Local capacity requirements within specific areas of the grid total about 28,000 MW, as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

In 2009, resource adequacy capacity procured by load-serving entities in monthly showings met or exceeded their reliability requirements. As a result, the ISO did not need to procure any additional capacity to meet local capacity area requirements that were not met in the load-serving entities' year-ahead and month-ahead showings.⁸ As shown in Figure E.15, about 3,000 MW of demand response capacity from utility programs were used by load-serving entities to meet nearly 5 percent of the total system-wide resource adequacy requirements during the summer months of 2009. Imports accounted for almost 10 percent of resource adequacy capacity during August.

Chapter 7 provides an analysis of the amount of resource adequacy supply actually bid or scheduled in the market during summer 2009. Our analysis shows that average availability of resource adequacy capacity to the market was high during the peak summer load hours, with about 91 percent of the overall capacity being available to the day-ahead market and about 88 percent to residual unit commitment. This represents an overall availability just slightly below the 93 percent level that is assumed in the resource adequacy program design.⁹

⁸ 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.

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

Figure E.15 Resources used to meet resource adequacy requirements

Investment in new generation

The amount of generation capacity being added and retired in the ISO each year provides an indication of the effectiveness of the California market and regulatory structure in bringing about new generation investment to replace older inefficient plants and meet load growth. Figure E.16 summarizes trends from 2000-2009, and planned capacity additions and retirements in 2010. Significant levels of new gas-fired generation were added in 2009 and are scheduled to be added in 2010. This provides some evidence that the state's resource adequacy program has been successful at stimulating some investment in new capacity.

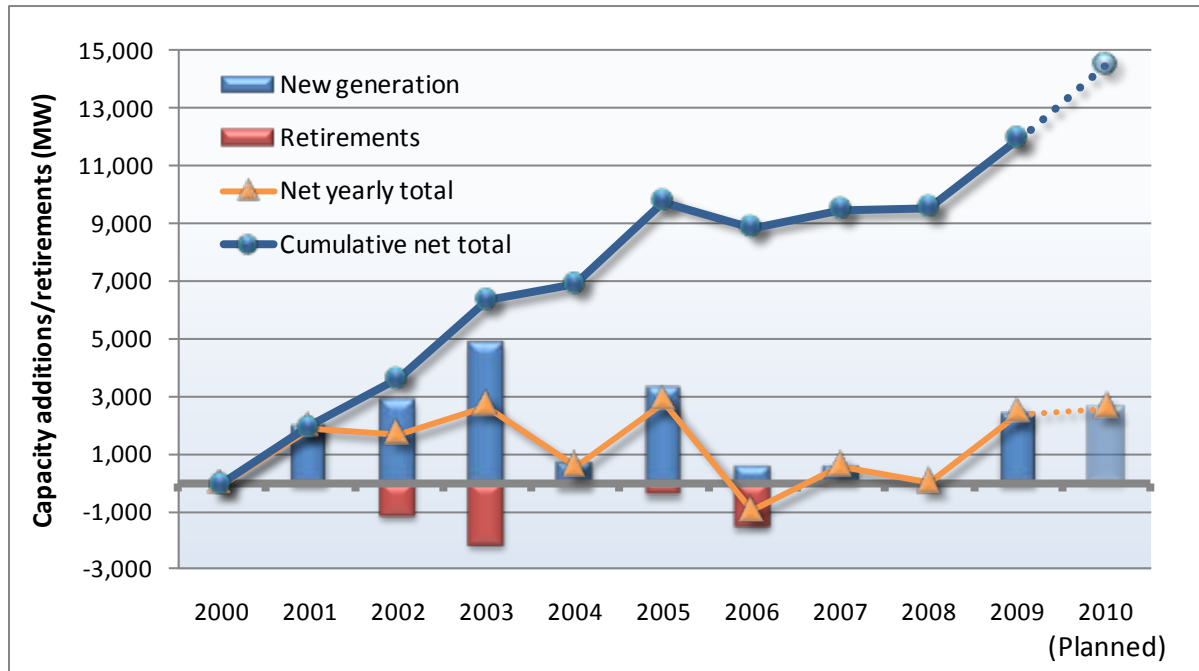
DMM performs an annual assessment of the revenues that may be earned by a typical new generating unit from the market. This provides an indication of the extent to which the day-ahead, real-time energy and ancillary service markets may contribute to recovering the fixed costs in building new generating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

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

The drop in net revenues for new gas combined cycle capacity is primarily attributed to the significant decrease in spot market gas prices and the associated drop in electricity prices. It may seem

counterintuitive that lower gas prices would decrease net revenues for a new gas resource. However, since older less efficient gas units are often the marginal resources setting prices in the market, lower gas prices decrease the net revenues of new more efficient gas generation. This is illustrated in more detail in Section 2.3 of Chapter 2.

Figure E.16 Generation additions and retirements: 2000-2010



Recommendations

Short-term market improvements

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

- Consistency of hour-ahead and real-time markets** — Since the first few months of the new market, one of DMM's major recommendations has been to address the systematic divergence between dispatches and prices in the hour-ahead and real-time markets. DMM has worked with the ISO to identify several specific potential causes for this divergence. The ISO is taking steps to address these issues. The ISO has also identified a number of other modeling improvements that may address this issue and has made these initiatives a major focus in 2010. A more detailed discussion of these recommendations and initiatives is provided in Section 3.8 of Chapter 3.
- Exceptional dispatches** — DMM has worked closely with the ISO to monitor and assess the volume and reasons for exceptional dispatches. This information was used to help identify ways to reduce the major causes of exceptional dispatch by incorporating additional constraints in the market model. As described in Section 3.5 of Chapter 3, the ISO has taken a number of steps to decrease

exceptional dispatches. Because of this effort, the volume of day-ahead unit commitments has declined measurably. In 2010, the ISO continues to place a major emphasis on reducing the need for manual adjustments or intervention to supplement the automated market processes. DMM will continue to monitor the volumes and reasons for exceptional dispatches.

- **Conforming transmission constraint limits based on actual flows** — In our third quarterly report, DMM recommended that the ISO should continue to place a high priority on refining the practice of adjusting or conforming constraint limits in the market software. The ISO has taken a number of steps to reduce the need to conform constraint limits and provide more transparency of these adjustments to market participants. A more detailed discussion of these recommendations and actions taken by the ISO in this area is provided in Section 3.8 of Chapter 3 and Section 5.6 of Chapter 5.
- **Compensating injections** — This software feature automatically adjusts market flows in the hour-ahead market to reconcile the difference between modeled flows and actual flows observed at inter-ties with other control areas. As discussed in Section 3.8 of Chapter 3, DMM has recommended that prior to implementing this software feature, the ISO should develop metrics that can be used to monitor the impact of compensating injections on specific major constraints that are likely to be impacted by this feature.¹⁰ DMM is working with the ISO to develop these metrics, and has recommended that the ISO provide participants with a technical paper and advance notice prior to re-implementing this feature.

New design initiatives

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

Proxy demand resources

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

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

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

¹⁰ Modeled flows for constraints in the ISO provided by the market software do not differentiate between the portion of flow attributable to compensating injections and the portion of flow attributable to market schedules. Thus, the impact of compensating injections on constraints within the ISO must be calculated using data on the compensating injection values at each CNode outside of the ISO system, combined with shift factors for these CNodes relative to constraints within the ISO.

measurement and verification plan that addresses demand response performance, and has indicated that additional limitations may be placed on proxy demand resources in the future if necessary based on market analysis and participant behavior.¹¹

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

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

Non-utility demand service providers

The state's resource adequacy program allows load-serving entities to use demand resources to meet their resource adequacy requirements. However, demand response providers are only able to earn capacity payments through utility managed retail demand response programs or through utility procurement contracts for demand response resources. Many stakeholders feel that without access to resource adequacy capacity payments, there will be insufficient incentive for aggregators to develop demand response resources able to participate directly in the market.¹²

This was identified as a significant potential barrier to demand response in a major report commissioned by the ISO on demand response in 2009.¹³ One of the important steps to decrease the barriers to development of non-utility demand response is to define criteria or performance standards that must be met for proxy demand resources to meet resource adequacy requirement of another load-serving entity. Such criteria or standards would help make proxy demand resources a tradable product that demand service providers could sell to load serving entities in the bilateral market. Thus, we are recommending that the ISO begin to address this issue in 2010 to ensure that this does not hinder development of demand response resources by non-utility demand service providers.

Regulation energy management resources

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

¹¹ Memo to ISO Board of Governors, re: Decision on Proxy Demand Resource, September 2, 2009, p.7. <http://www.caiso.com/241e/241eb5b844d0.pdf>.

¹² See *California Independent System Operator Demand Response Barriers Study (per FERC Order 719)*, April 29, 2009, prepared by Freeman, Sullivan & Co. and Energy and Environmental Economics, Inc. p. 29, <http://www.caiso.com/2410/2410ca792b070.pdf>.

¹³ Ibid.

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

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

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

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

Market power mitigation

System level market power

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

Local market power mitigation

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

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

As part of the process for developing the design for convergence bidding, DMM proposed modifications to market power mitigation procedures. These modifications are designed to ensure that local market power provisions are not undermined by bidding of virtual demand within transmission constrained load pockets.¹⁴ The ISO indicated modifications to market power mitigation procedures proposed by DMM could not be implemented in conjunction with convergence bidding in February 2011, but committed to consider these modifications for implementation in April 2012.¹⁵

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

Competitive path assessment

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

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

Mitigation process quality improvements

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

¹⁴ *Local Market Power Mitigation Options Under Convergence Bidding*, Department of Market Monitoring, October 2, 2009 (<http://www.aiso.com/243b/243bebe3228c0.pdf>) and *Illustrative Examples of Alternative Local Market Power Mitigation*, Department of Market Monitoring, October 6, 2009 (<http://www.aiso.com/243f/243fce76bf30.pdf>).

¹⁵ The current day-ahead local market power mitigation procedures are based on the demand forecast. FERC has ordered the ISO to modify these bid mitigation procedures to be based on bid-in demand April 2012. The approach proposed by DMM would be based on bid-in demand, and would therefore provide a way for the ISO to comply with this FERC order.

Resource adequacy program

In March 2010, the CPUC issued a proposed order indicating that development of a centralized capacity market or a multi-year forward resource adequacy requirement may be deferred beyond 2010.¹⁶ However, the current resource adequacy provisions of the ISO tariff and CPUC regulations will continue to be reviewed and modified.

Investment in new supply

As illustrated in Figure E.16, significant levels of new gas-fired generation were added in 2009 and are scheduled to be added in 2010. This provides some evidence that the state's resource adequacy program has been successful at stimulating some investment in new capacity. However, analysis of net revenues that would be earned by a typical new gas-fired generating plant in the market in 2009 shows a substantial decrease in net revenues compared to 2008 and would fall substantially below the annualized fixed cost of new generation.

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

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

Integration of renewable energy and demand response

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

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

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

¹⁶ *Revised Proposed Decision: Adoption of a Preferred Policy for Resource Adequacy*, California Public Utilities Commission, May 30, 2010. <http://docs.cpuc.ca.gov/efile/PD/115559.pdf>

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

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

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

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

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