2014 ANNUAL REPORT ON MARKET ISSUES & PERFORMANCE

California ISO

Department of Market Monitoring

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Executive summary

This report focuses on the performance of the markets in the ISO balancing area, and finds that they continued to perform efficiently and competitively overall in 2014.[1] Key highlights of market performance in this report by the Department of Market Monitoring (DMM) include the following:

- Total wholesale electric costs increased by 13 percent. This increase was primarily driven by a 17 percent increase in natural gas prices in 2014 compared to 2013. After controlling for the natural gas and greenhouse gas price changes, wholesale electric costs increased by about 3 percent.
- Despite record low hydro-electric conditions, moderate loads and the addition of new solar generation with over 1,700 MW of peak summer capacity helped to keep market prices low and highly competitive.
- Overall prices in the ISO energy markets in 2014 were highly competitive, averaging close to what DMM estimates would result under highly efficient and competitive conditions, with most supply being offered at or near marginal operating costs.
- Average real-time prices tended to be lower than average day-ahead prices, continuing a trend that began in 2013. This trend is partly attributable to a drop in high real-time price spikes compared to prior years. This trend also reflects additional unscheduled generation in real time, particularly from wind and solar units.
- Under the real-time market redesign implemented in May 2014, most real-time energy and all virtual bids are settled based on prices from the 15-minute market. Prices in this 15-minute market tracked relatively close to day-ahead prices, particularly after initial implementation in the second quarter. Average 15-minute prices were only about $1/MWh less than day-ahead prices over the second half of the year.
- While the 15-minute real-time market design is working well overall, the volume of 15-minute dispatchable bids on inter-ties has been very low on most tie-points. This suggests that major barriers to participation in the 15-minute market remain on a regional level outside the ISO system despite the Federal Energy Regulatory Commission's requirement that all balancing areas allow 15-minute scheduling on inter-ties.

Other aspects of the ISO markets performed well and helped keep overall wholesale costs low:

- Ancillary service costs totaled $69 million, or about 21 percent more than in 2013. The increase is related to a decrease in ancillary services from hydro-electric generators compared to 2013 and an increase in natural gas prices.
- Bid cost recovery payments totaled $95 million, or less than 1 percent of total energy costs in 2014, compared to about $108 million of total energy costs in 2013. Payments for units scheduled by the residual unit commitment process accounted for $5 million of these costs, compared to $23 million in 2013. This decrease was driven in large part by changes implemented in early 2014 to better

[1] The performance of the energy imbalance market, which was launched in November 2014, is addressed separately in Section 3.4. All remaining analyses and calculations in this report are for the ISO balancing area only.

account for forecasted renewables in the residual unit commitment as opposed to bid-in renewables.

- Exceptional dispatches, or *out-of-market* unit commitments and energy dispatches issued by ISO grid operators to meet constraints not incorporated in the market software, decreased from 2013 and remained relatively low. Total energy from all exceptional dispatches totaled about 0.16 percent of total system energy in 2014 compared to 0.26 percent in 2013. The above-market costs resulting from these exceptional dispatches decreased 40 percent from $18 million in 2013 to $11 million in 2014.

- Congestion within the ISO system decreased in 2014 compared to prior years and had a lower impact on average overall prices across the system. The reduction in real-time congestion can be attributed partly to improved ISO procedures that better align day-ahead line limits with real-time limits. This allows for better commitment of resources to resolve anticipated congestion in real time.

- Real-time market revenue imbalance charges allocated to load-serving entities increased slightly from $183 million in 2013 to $188 million in 2014. While imbalance offset charges associated with congestion fell from $126 million in 2013 to $106 million in 2014, charges related to real-time energy imbalance costs increased from $57 million in 2013 to $81 million in 2014. However, energy imbalance offset charges include several components that are offset by reductions in other settlement charges allocated to load-serving entities. Thus, this component does not fully reflect net uplift costs actually assessed to load-serving entities.

- On an annual basis, congestion revenue rights had a net revenue shortfall of about $95 million in 2014. This was a substantial reduction from the $23 million and $3 million surpluses in 2012 and 2013, respectively, and the first annual shortfall since the nodal market began in 2009. Multiple issues contributed to this shortfall including: 1) low hydro conditions exacerbating local congestion and 2) modeling differences in transmission between the day-ahead market and the congestion revenue rights model.

This report also highlights key aspects of market performance and issues relating to longer-term resource investment, planning and market design.

- About 1,900 MW of summer peak generating capacity was added in 2014 with about 93 percent of the new capacity coming from new solar generation.

- Energy from new solar resources is expected to continue to increase at a high rate in the next few years as a result of projects under construction to meet the state's renewable portfolio standards. This will increase the need for flexible and fast ramping capacity that can be dispatched by the ISO to integrate increased amounts of variable energy efficiently and reliably.

- Only 25 MW of natural gas-fired generation was added in 2014.

Net operating revenues for many – if not most – older existing gas-fired generating units are likely to be lower than the going-forward costs of these units. A substantial portion of this existing capacity is located in transmission constrained areas and is needed to meet local reliability requirements and to ensure enough flexible capacity exists to integrate the influx of new intermittent resources. Most of this capacity will also need to be replaced or repowered to comply with the state's restrictions on use of once-through cooling. This investment is likely to require some form of longer-term capacity payment or contracting.

DMM is highly supportive of the initiatives to increase the efficiency of the state's capacity procurement process and to address key gaps in the state's current market design. More detailed recommendations concerning capacity procurement initiatives are provided in the final section of this executive summary.

Total wholesale market costs

The total estimated wholesale cost of serving load in 2014 was $12.1 billion or just over $52/MWh. This represents an increase of about 13 percent from a cost of over $46/MWh in 2013. The increase in electricity prices was mostly due to a 17 percent increase in wholesale natural gas prices.[2] After normalizing for higher natural gas prices and greenhouse gas compliance costs, DMM estimates that total wholesale energy costs were stable, increasing slightly from $43.50/MWh in 2013 to just under $45/MWh in 2014, which is an increase of about 3 percent.[3]

The stability of normalized prices is remarkable given the extent of the market changes this year. A variety of factors had the effect of raising prices. As highlighted elsewhere in this report, conditions that contributed to higher prices include the following:

- Lower in-state hydro-electric generation; and
- Continued reduction in imports that began in mid-2013 and continued through 2014.

Other factors had the effect of lowering prices. These factors are discussed in the following sections and chapters of this report and include the following:

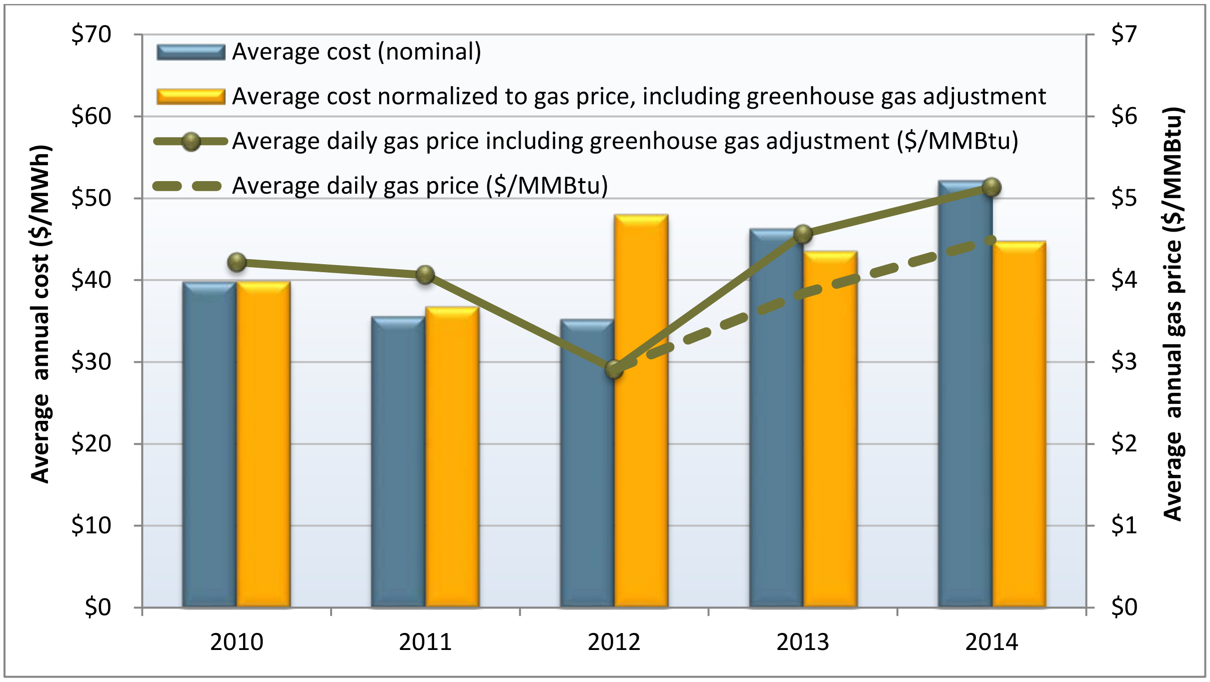
- Moderate loads;
- Addition of new generation capacity, particularly solar;
- Decreased regional congestion; and
- Increased net virtual supply, which lowered day-ahead prices and brought them closer to real-time prices.

Figure E.1 shows total estimated wholesale costs per MWh from 2010 to 2014. Wholesale costs are provided in nominal terms (blue bar), as well as after normalization for changes in average spot market prices for natural gas (yellow bar). The green line, representing the annual average of daily natural gas prices including greenhouse gas compliance, is included to illustrate the correlation between the cost of natural gas and the total wholesale cost estimate. The dashed green line excludes greenhouse gas compliance costs and is included for reference in 2013 and 2014.

[2] 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, when gas prices are often highest.

[3] Greenhouse gas compliance costs are calculated by multiplying a load weighted annual average greenhouse gas allowance price by an emission factor that is a measure of the greenhouse gas content of natural gas. Derivation of the emission factor used here, 0.531148, is discussed in further detail in Section 1.2.4. Gas prices are normalized to 2010 prices. In previous reports, DMM normalized to 2009 prices.

Figure E.1 Total annual wholesale costs per MWh of load (2010-2014)



Market competitiveness

Overall wholesale energy prices were about equal to competitive baseline prices DMM estimates would result under perfectly competitive conditions. DMM calculates 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.2 compares this price to actual average system-wide prices in the day-ahead, 15-minute and 5-minute real-time markets. When comparing these prices, it is important to note that baseline prices are calculated using the day-ahead market software, which does not reflect all system conditions and limitations that impact real-time prices.

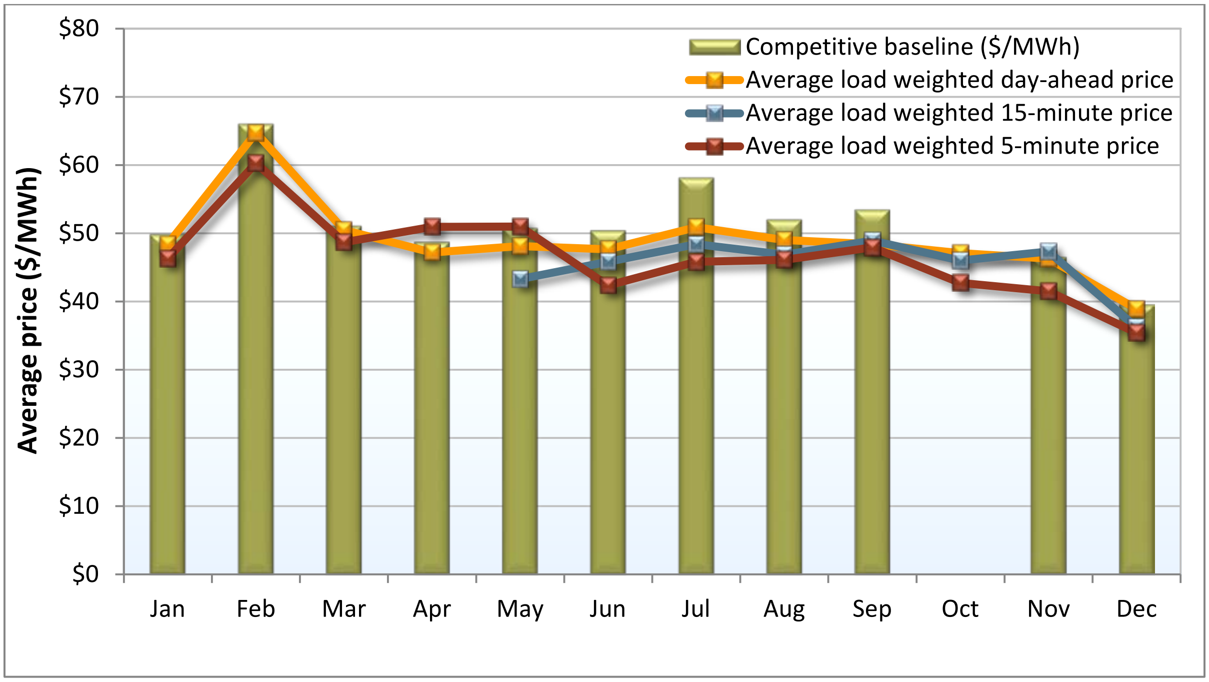
As shown in Figure E.2, prices in the day-ahead market were about equal to the competitive baseline prices in most months in 2014.[4] Day-ahead prices were noticeably lower than the competitive benchmark in July and September.

In the 5-minute real-time market, average prices were lower than the competitive baseline in 2014 in most months except for April and May. Average prices for the 15-minute market were lower in all months except for November. A major factor contributing to these lower real-time prices was the substantial amount of real-time energy that was not scheduled in the day-ahead market.[5]

[4] For October, DMM was unable to calculate the competitive baseline because of implementation issues with transitioning the systems to the fall market software version.

[5] This unscheduled energy was the combined result of a variety of factors, rather than being driven by any single source. Various sources of additional real-time energy included minimum load energy from units committed after the day-ahead market through the residual unit commitment process and exceptional dispatches, additional must-take energy from thermal generating resources, and unscheduled energy from variable renewable energy.

Figure E.2 Comparison of competitive baseline prices with day-ahead and real-time prices



Energy market prices

Energy market prices were higher in 2014 than 2013, as seen in Figure E.3 and Figure E.4.

- This increase was attributed primarily to a more than 17 percent increase in natural gas prices in 2014, compared to 2013. Gas prices were especially high in February 2014 as tight supply conditions outside of California affected both supply and demand increased price levels. Gas prices remained higher in 2014 than 2013 for most of the rest of the year.
- Another factor causing upward pressure on electricity prices was a decrease in hydro-electric generation in 2014. Overall, hydro production in 2014 was about 70 percent of production in 2013 and 60 percent of production in 2012.

Figure E.3 Comparison of system energy prices (peak hours)

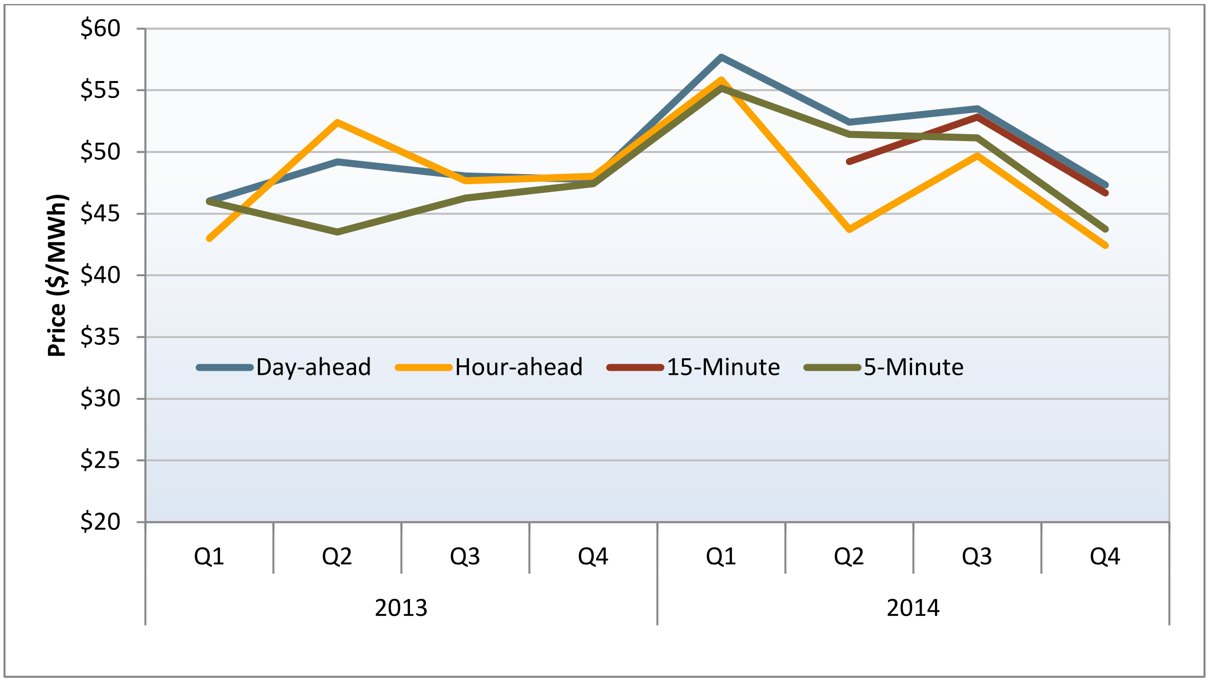


Figure E.4 Comparison of system energy prices (off-peak hours)

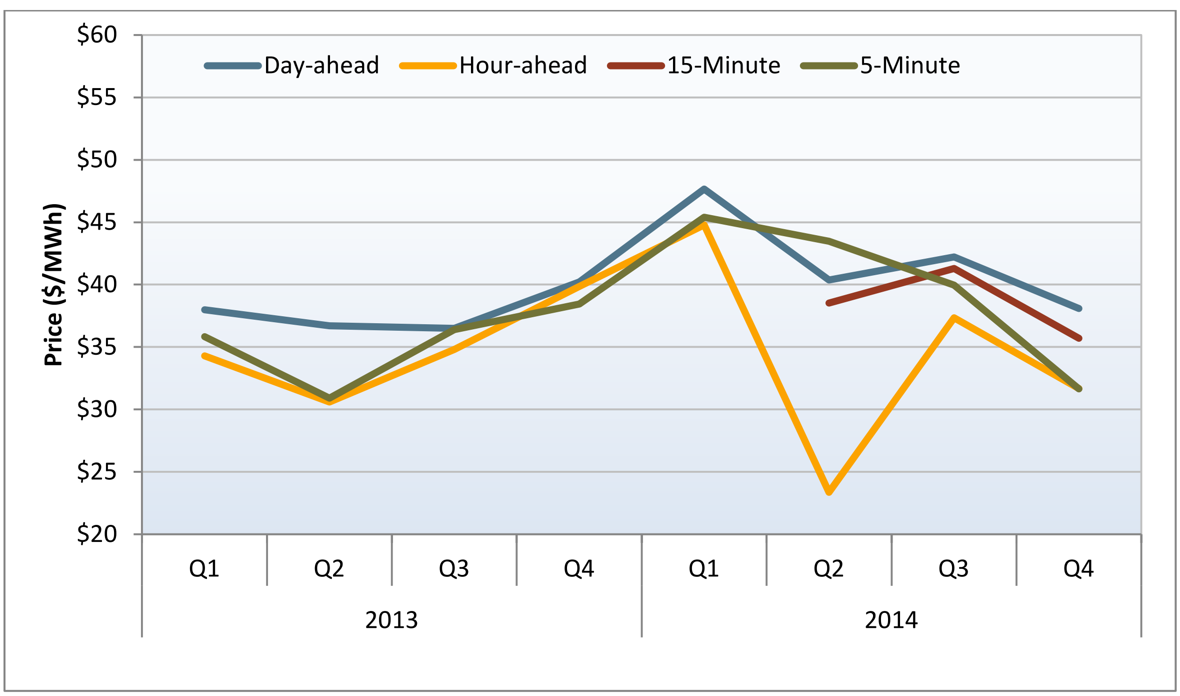


Figure E.3 and Figure E.4 also show prices for the new 15-minute market implemented in May and highlight the following:

- Real-time prices tended to be lower than average day-ahead prices during most periods, thus continuing a trend that began in 2013. This can partly be attributed to additional generation available in real-time, including significant volumes of renewable energy that is not included in day-ahead schedules and may not be offset completely by virtual bids.
- Average prices for the new 15-minute market, upon which most real-time energy is settled financially, were lower than the day-ahead market prices. Prices in the 15-minute market averaged about $1.60/MWh lower than day-ahead prices for the year and $1.10/MWh for the second half of the year after the initial implementation period in the spring.
- Prices in the new 15-minute market tracked more closely with day-ahead prices during peak hours during the last half of 2014. Over the last six months of 2014, average 15-minute prices during peak hours were just $0.70 (or about 1.4 percent) less than day-ahead prices.
- Prices in both the hour-ahead and 5-minute markets were lower than day-ahead prices for much of the year. Beginning in May, hour-ahead prices are not used in financial settlement of any inter-tie or other resources, but are only used for inter-tie scheduling purposes. Also, as a result of the market changes related to implementation of FERC Order No. 764, the 5-minute market had a lower impact on settlement as less imbalance now occurs against the 5-minute real-time price.

Convergence bidding

Virtual bidding is a part of the Federal Energy Regulatory Commission's standard market design and is in place at all other ISOs with day-ahead energy markets. In the California ISO market, virtual bidding is formally referred to as *convergence bidding*, which was implemented in February 2011.

Convergence bidding allows participants to place purely financial bids for supply or demand in the day-ahead energy market. These virtual supply and demand bids are treated similar to physical supply and demand in the day-ahead market. However, all virtual bids clearing the day-ahead market are removed from the real-time markets, which are dispatched based only on physical supply and demand.

When convergence bids are profitable, they may increase market efficiency by improving day-ahead unit commitment and scheduling. Convergence bidding also provides a mechanism for participants to hedge or speculate on price differences at different locations due to congestion or between the day-ahead and real-time markets.

In 2014, convergence bidders continued a shift from virtual demand to virtual supply, which began in the latter half of 2013. Average hourly virtual supply clearing in the day-ahead market exceeded virtual demand by about 450 MW per hour in 2014, compared to an average of about 380 MW of net virtual supply last year. This trend reflects the change in prices that began in 2013, when average real-time prices began to be consistently lower than average day-ahead prices during most periods.

The increase in virtual supply was driven in large part by an increase in net virtual supply bids submitted by load-serving entities, which increased from 156 MW per hour in 2013 to 265 MW per hour in 2014. One reason the state's main load-serving entities are authorized by the California Public Utilities Commission (CPUC) to engage in virtual bidding is to offset renewable energy that is not scheduled in the day-ahead market for contractual reasons. However, the total amount of net virtual supply clearing the day-ahead market still fell short of the total amount of renewable and other generation not scheduled in the day-ahead market.

Total net revenues paid to entities engaging in convergence bidding, including bid cost recovery charges allocated to virtual bids, were around $26 million in 2014, compared to about $17 million in 2013. Most of these net revenues resulted from virtual supply bids. However, financial entities and marketers also continued to place large volumes of offsetting virtual demand and supply bids at different locations during the same hour. This type of offsetting bids, which are designed to hedge or profit from congestion, represented about 65 percent of all accepted virtual bids in 2014.

Table E.1 compares the distribution of convergence bidding volumes and revenues among different groups of convergence bidding participants. These data show that most convergence bidding activity is conducted by entities engaging in pure financial trading that do not serve load or transact physical supply. These entities accounted for just over $17 million (almost 58 percent) of the total convergence bidding revenues in 2014.

About half of this $9 million year-over-year increase in net revenues received by convergence bidders resulted from a decline in bid cost recovery payments resulting from residual unit commitment costs allocated to virtual supply. The portion of these costs allocated to virtual supply dropped from about $9 million in 2013 to $5 million in 2014. This decrease was driven in large part by changes in how forecasted renewable schedules are accounted for in the residual unit commitment process, which resulted in a significant drop in residual unit commitment bid cost recovery.[6]

Table E.1 Convergence bidding volumes and revenues by participant type (2014)

Trading entities	Average hourly megawatts			Revenues\Losses ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	964	1,008	1,972	-$2.9	$20.3	$17.3
Marketer	294	362	656	-$0.5	$6.2	$5.7
Physical generation	150	226	376	-$0.6	$4.2	$3.7
Physical load	2	267	269	-$0.1	$3.4	$3.3
Total	**1,409**	**1,863**	**3,273**	**-$4.0**	**$34.1**	**$30.1**

Local market power mitigation

In 2013, the ISO implemented the second phase enhancement of the new transmission competitiveness evaluation and mitigation mechanism to address local market power in the real-time market. Together with the first phase implemented in April 2012, this completed the transition to the new procedure in both the day-ahead and real-time markets.

[6] In early 2014, the ISO began adjusting renewable schedules in the residual unit commitment process to forecasted levels. This resulted in several hundred megawatts of additional supply in the residual unit commitment, which reduced the amount of capacity and commitment procured by that process. See Section 2.4 for further detail.

This local market power mitigation procedure requires that each constraint be designated as either *competitive* or *non-competitive* prior to the actual market run. This is determined through a test, known as *dynamic path assessment*, which determines the competitiveness of transmission constraints based on actual system and market conditions for each interval. Generation bids are subject to mitigation if mitigation procedures indicate generators are effective to relieve the congestion on constraints that are structurally uncompetitive.

For these provisions to be effective, it is important that constraints designated as competitive are in fact competitive under actual market conditions. The new dynamic path assessment approach uses actual market conditions and produces a more accurate and less conservative assessment of transmission competitiveness.

Most resources subject to mitigation submitted competitive offer prices, so that many bids were not lowered as a result of the mitigation process. The number of units in the day-ahead market that had bids changed by mitigation averaged about 1.3 per hour in 2014, compared to 0.5 units per hour in 2013. The estimated impact of bid mitigation on the amount of additional energy clearing in the day-ahead market from units with mitigated bids was about 11 MW per hour in 2014 compared to about 6 MW per hour in 2013.

The frequency of bid mitigation in the real-time market in 2014 was lower when compared to 2013, averaging 0.5 units with bids mitigated per hour in 2014 compared to 1 unit per hour in 2013. The estimated impact of bid mitigation on the amount of additional real-time energy dispatched as a result of bid mitigation fell from about 26 MW per hour in 2013 to about 23 MW per hour in 2014.

Mitigation provisions that apply to exceptional dispatch for energy above minimum load reduced costs to $144,000 in 2014, down from $450,000 in 2013. This reflects the fact that exceptional dispatches were relatively low and bids mitigated were not significantly in excess of competitive levels.

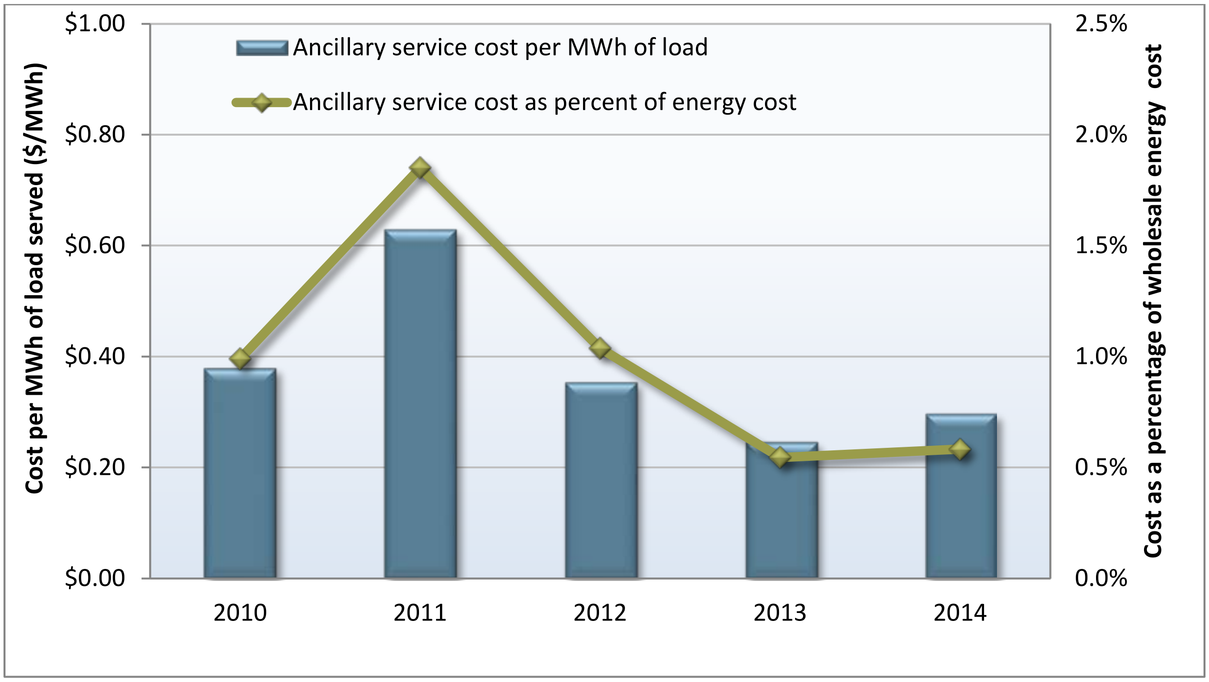
Ancillary services

Ancillary service costs totaled $69 million in 2014, representing a 21 percent increase from $57 million in 2013. The increase is related to a decrease in ancillary services from hydro-electric generators compared to 2013 and an increase in natural gas prices.

As shown in Figure E.5, ancillary service costs increased to $0.30/MWh of load served in 2014 from $0.25/MWh in 2013. Ancillary service costs represent 0.6 percent of wholesale energy costs, up slightly from 0.5 percent in 2013. Even though the 2014 numbers include a full year of regulation pay-for-performance payments, which began in June 2013, mileage costs remained low, representing just over 1 percent of total ancillary service costs compared to just under 1 percent in 2013.

Beginning October 1, 2014, the ISO modified its operating reserve requirement calculations to be compliant with FERC Order No. 789. These modifications result in somewhat lower average procurement levels of operating reserves than before the change.

Figure E.5 Ancillary service cost as a percentage of wholesale energy cost



Exceptional dispatches

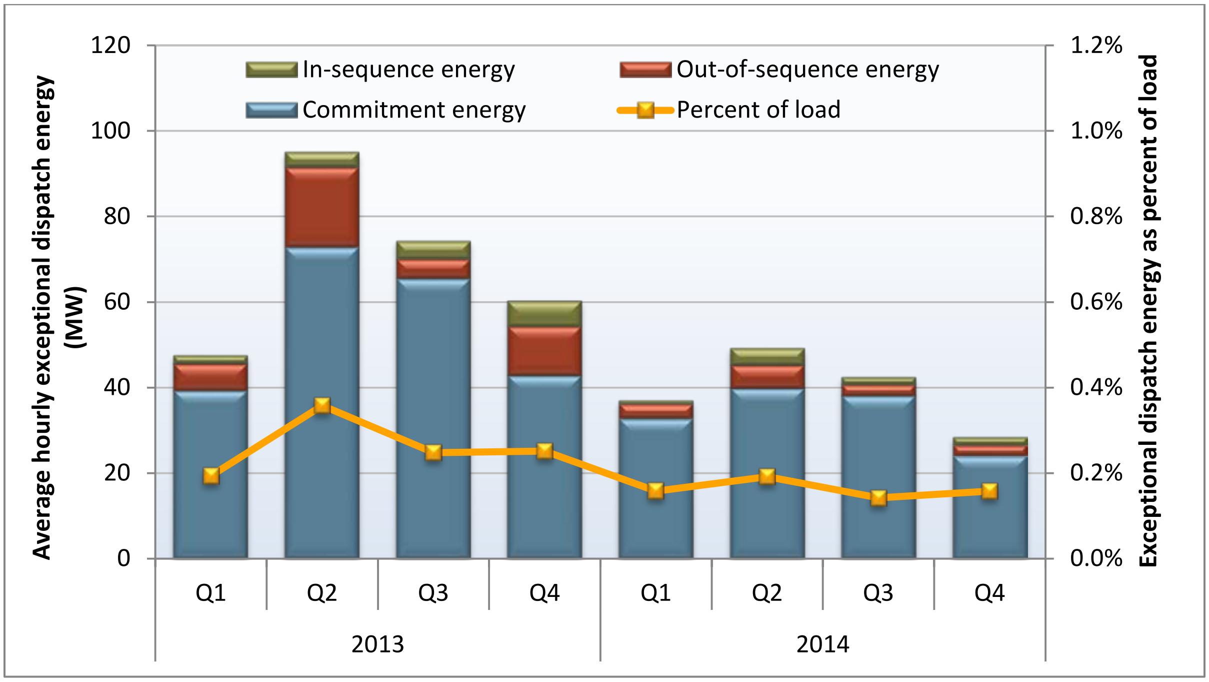
Exceptional dispatches are instructions issued by grid operators when the automated market optimization is not able to address particular reliability requirements or constraints. These dispatches are sometimes referred to as *manual* or *out-of-market* dispatches. The ISO has made an effort to reduce exceptional dispatches by refining operational procedures and incorporating additional constraints into the market model that reflect reliability requirements.

Total energy from all exceptional dispatches decreased in 2014, falling from 0.26 percent in 2013 to 0.16 percent of system load in 2014. The following is shown in Figure E.6:

- Minimum load energy from units committed through exceptional dispatches averaged about 30 MW per hour in 2014, down from about 50 MW in 2013. The minimum load energy represents about 86 percent of energy from exceptional dispatches in 2014.
- Exceptional dispatches resulting in out-of-sequence real-time energy with bid prices higher than the market prices accounted for an average of about 4 MW per hour in 2014, down from 10 MW in 2013. This decrease was driven primarily by a reduction in exceptional dispatches for unit testing and exceptional dispatches related to the Southern California import transmission (SCIT) limit.
- About 40 percent of the energy above minimum load from exceptional dispatches cleared in-sequence, meaning that their bid prices were less than the market clearing prices and were ultimately not classified as exceptional dispatches by the ISO.

The above-market costs of all exceptional dispatches, including commitment and energy, decreased from $18 million in 2013 to $11 million in 2014. Of these costs, approximately $1 million was related to exceptional dispatch energy above minimum load in 2014, compared to about $1.4 million in 2013.

Figure E.6 Average hourly energy from exceptional dispatches



Out-of-market costs

There are multiple forms of out-of-market costs incurred in the ISO markets that are not directly paid to generators or collected from load-serving entities through market clearing prices. Most of these costs are ultimately allocated to load-serving entities through various charges, sometimes referred to as *uplifts*. These costs include the following categories:

- Bid cost recovery payments;
- Real-time imbalance offset costs;
- Real-time exceptional dispatch costs; and
- Other reliability costs including reliability must-run and capacity procurement mechanism costs.

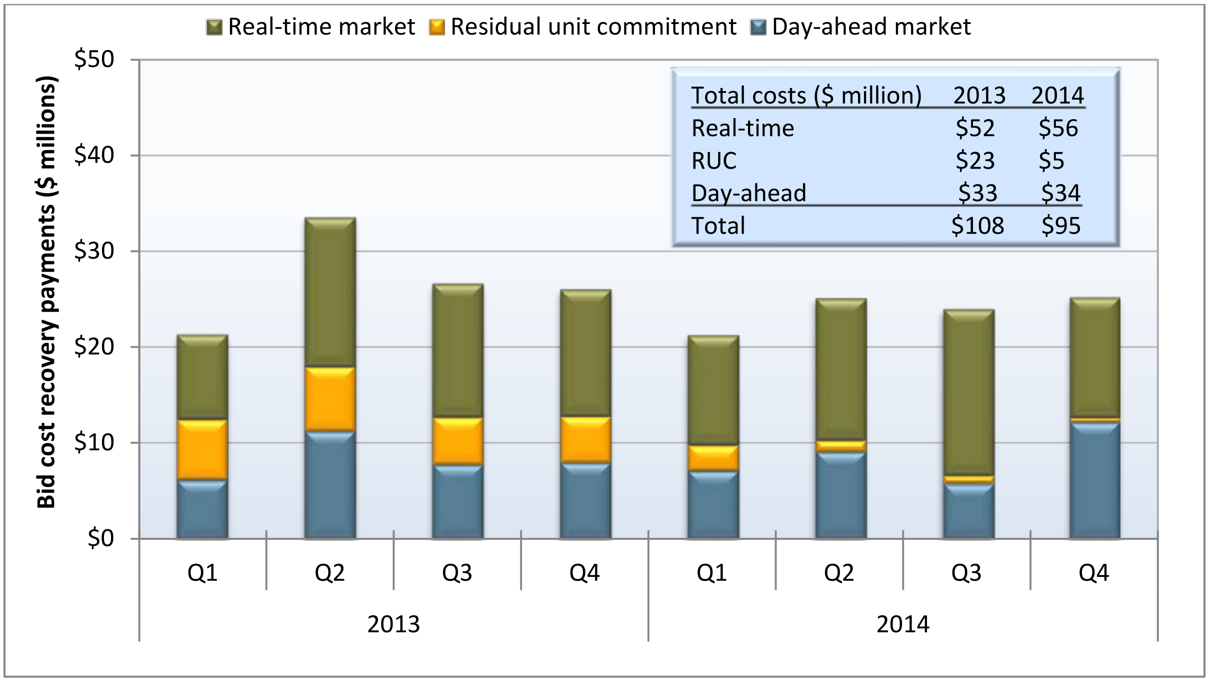
Bid cost recovery payments

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. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch.

Figure E.7 provides a summary of total estimated bid cost recovery payments in 2014. These payments totaled around $95 million or about 1 percent of total energy costs. This compares to a total of

$108 million of total energy costs in 2013, which is a decrease of about 12 percent from 2013 to 2014 and was driven by a decrease in bid cost recovery payments due to residual unit commitment from $23 million in 2013 to $5 million in 2014.

Figure E.7 Bid cost recovery payments



This decrease in bid cost recovery payments associated with units committed through the residual unit commitment process can be partially attributed to decreases in the residual unit commitment procurement levels driven by reliability related adjustments made by ISO operators.[7] This change can also be attributed to the introduction of a new automatic adjustment process that accounts for differences between the day-ahead schedules of resources in the participating intermittent resource program and the forecast output of these renewable resources. This adjustment can reduce residual unit commitment procurement targets and therefore decrease the potential for unit commitments.[8]

Real-time imbalance offset costs

The real-time imbalance offset charge is the difference between the total money paid out by the ISO and the total money collected by the ISO for energy settled at real-time prices. The charge is allocated as an uplift to load-serving entities and exporters based on measured system demand.

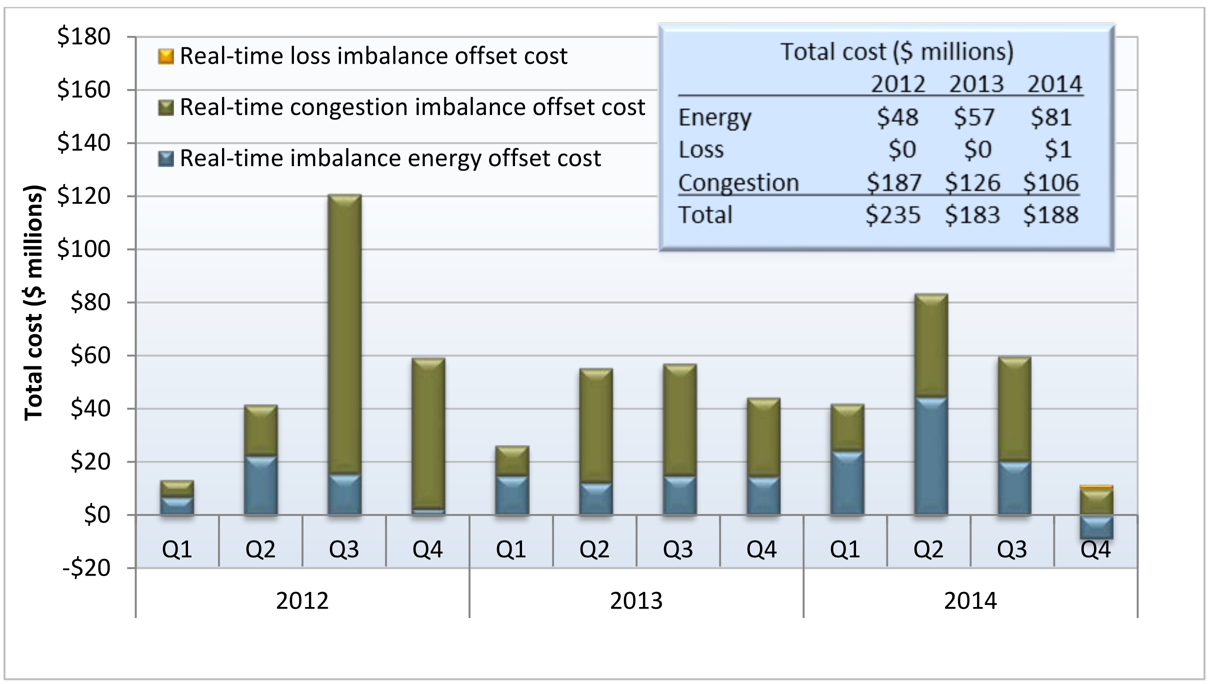
[7] ISO operators can make adjustments to the system or regional residual unit commitment requirements to mitigate potential contingencies. These changes are concentrated primarily in the peak hours. Occasionally, units are committed in the residual unit commitment process to meet these system needs. However, these units are at times uneconomic in real time, requiring recovery of their bid costs through bid cost recovery payments.

[8] See Sections 2.4 and 8.6 for further detail on this new adjustment feature.

The real-time imbalance offset charge consists of three components. Any revenue imbalance from the energy and loss components of hour-ahead, 15-minute and 5-minute real-time energy settlement prices is collected through the *real-time imbalance energy offset charge* (RTIEO). Any revenue imbalance from just the congestion component of these real-time energy settlement prices is recovered through the *real-time congestion imbalance offset charge* (RTCIO). Until October 1, the ISO aggregated real-time loss imbalance offset costs with real-time energy imbalance costs. Following October 1, any revenue imbalance from the loss component of real-time energy settlement prices is collected through the *real-time loss imbalance offset charge*.

Total real-time imbalance costs for energy and congestion were about $188 million in 2014, compared to $183 million in 2013. As shown in Figure E.8, real-time imbalance congestion offset costs fell to $106 million in 2014 from $126 million in 2013. The increase in total imbalance offset costs was primarily attributable to an increase in the real-time energy imbalance offset costs, which increased from $57 million in 2013 to $81 million in 2014. These energy imbalance offset costs include several components that are offset by reductions in other settlement charges allocated to load-serving entities. Thus, these energy imbalance offset costs do not reflect total net uplift costs assessed to load-serving entities.

Figure E.8 Real-time imbalance offset costs



Real-time exceptional dispatch costs

Real-time exceptional dispatch costs, also known as out-of-sequence costs, decreased from about $1.4 million in 2013 to around $1 million in 2014. Lower above-market costs from exceptional dispatch in 2014 generally reflect the overall decrease in volume of exceptional dispatches. ISO goals to decrease the frequency and volume of exceptional dispatches appear to have influenced and sustained the drop in out-of-sequence energy costs.

Other reliability costs

Other reliability costs include reliability must-run and capacity procurement mechanism costs. Because load-serving entities procure most local capacity requirements through the resource adequacy program, the amount of capacity and costs associated with reliability must-run contracts have been relatively low over the past few years. However, these costs increased to $25 million in 2014 from $21 million in 2013. These costs were primarily the result of a reliability must-run agreement that placed synchronous condensers at Huntington Beach Units 3 and 4 into service in late June 2013. This agreement was put into place due to the outages and retirement of the San Onofre Nuclear Generating Station units.

In addition to the notable increase in reliability must-run payments, capacity payments related to the capacity procurement mechanism also increased from $2.7 million in 2013 to $8 million in 2014. In total, there were only two capacity procurement contracts in 2014. One of the contracts was related to natural gas scarcity events in early February and the second was the result of transmission related reliability concerns.

Congestion

Congestion on transmission constraints within the ISO system decreased compared to prior years and had a lower impact on average overall prices across the system.

- Prices in the SDG&E area were impacted the most by internal congestion, which increased average day-ahead and real-time prices in the SDG&E area above the system average by about $0.60/MWh (1.2 percent) and $1.20/MWh (2.6 percent), respectively.
- Congestion increased average day-ahead prices in the SCE area above the system average by about $0.23/MWh or 0.5 percent. Real-time congestion did not have a significant impact on overall average prices because multiple constraints had offsetting effects, with some increasing congestion and others decreasing congestion.
- The overall impact of congestion on prices in the PG&E area reduced prices below the system average by about 1.3 percent in the day-ahead and just under 1 percent in the 15-minute market.

Congestion on most major inter-ties connecting the ISO with other balancing authority areas was higher in 2014 compared to 2013, particularly for inter-ties connecting the ISO to the Pacific Northwest because of both outages and economic conditions. However, congestion on inter-ties does not typically have a significant effect on market prices within the ISO system compared to congestion within the ISO system.

Congestion revenue rights

Congestion revenue rights payments created a net revenue shortfall of about $95 million in 2014. This was a substantial reduction from the $23 million and $3 million surpluses in 2012 and 2013, respectively, and the first annual shortfall since the nodal market began in 2009. This revenue shortfall was primarily allocated to load-serving entities.

In the first half of the year, inter-tie constraints played a significant role in revenue adequacy. In the second half of the year, internal constraints exacerbated by the low hydro conditions played a major role in revenue shortfalls. More than half of the revenue shortfall resulted from differences between the network transmission model used in the congestion revenue rights process and the day-ahead market model on just three constraints.[9]

Revenue inadequacy was mainly due to unexpected or non-modeled outages and unsettled flows in the day-ahead market. The ISO took steps to address the revenue inadequacy by accounting for more constraints in the congestion revenue right model for future auctions. This essentially limits the amount of congestion revenue rights that are allocated or auctioned off going forward.

The total volume of all congestion revenue rights both allocated and auctioned increased by 39 percent in 2014. This increase was driven by a trend of increased volumes clearing in the seasonal and monthly auctions that began in 2013. Much of this increase stemmed from increased participation by financial entities and an increase in the amount of congestion revenue rights clearing at $0/MW.

Financial participants received the largest share of net revenues, collecting net revenues of $74 million of the $94 million in net revenues paid out by the ISO in 2014. These financial entities bid heavily in the seasonal and monthly auctions, speculating on and responding to congestion trends.

Load-serving entities collected net revenues of $34 million in 2014. Most of these revenues resulted from allocations made based on load served and auction revenues from counter-flow positions. In 2014, load-serving entities used counter-flow positions to sell allocated rights back to the market.

Resource adequacy

The CPUC's resource adequacy provisions require load-serving entities to procure adequate generation capacity to meet 115 percent of their monthly forecast peak demand. The capacity amount offered into the market each day depends on the actual availability of resources being used to meet these requirements. For example, thermal generation availability depends on forced and planned outages. Hydro, cogeneration and renewable capacity availability 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 9 in this report provides an analysis of the amount of resource adequacy capacity actually available in the ISO market during peak hours. This analysis shows that resource adequacy capacity availability was relatively high during the highest load hours of each month. During the peak summer load hours, about 95 percent of resource adequacy capacity was available to the day-ahead energy market. This is approximately equal to the target availability level incorporated in the resource adequacy program and similar to the results in prior years.

The state's resource adequacy program continued to work well as a short-term capacity procurement mechanism. Capacity made available under the resource adequacy program in 2014 was mostly sufficient to meet system-wide and local area reliability requirements. However, because of the San Onofre Nuclear Generating Station (SONGS) outages and retirement as well as local voltage concerns, the ISO continued to rely on reliability must-run contracts to meet local reliability requirements.

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[9] The Magunden to Vestal and Helms pump nomograms, and the Warnerville to Wilson transmission line.

With the active support of the ISO, the CPUC has adopted requirements for California's investor-owned utilities to procure flexible capacity in order to help meet the system net load changes. This represents a wider focus of the resource adequacy program from simply meeting peak system and local capacity needs to also include flexible capacity needs during ramping periods when renewable generation drops off. These requirements were non-binding in 2014, but have become binding and enforced in 2015.

To complement these new CPUC requirements, the ISO continues to develop protocols for: determining requirements for flexible capacity, counting flexible resource adequacy showings, determining must-offer requirements, and curing any shortfalls through backstop procurement. Specifically, the ISO has completed, in part or in full, stakeholder processes on the following initiatives:

- **Flexible resource adequacy.** This initiative was conditionally approved by FERC in 2014 and recognizes the important contributions made by other resource characteristics that contribute to the flexible response needed to integrate large quantities of renewable generation. This program also includes a specific must-offer obligation for flexible capacity that further differentiates it from generic resource adequacy capacity.

- **Reliability services initiative.** This initiative streamlines rules for replacement and substitute capacity should a resource adequacy unit become unavailable, clarifies definitions and qualifying criteria for new technology resources, and includes a compliance measurement mechanism for resource adequacy and flexible resources. The ISO Board of Governors approved this initiative in early 2015.

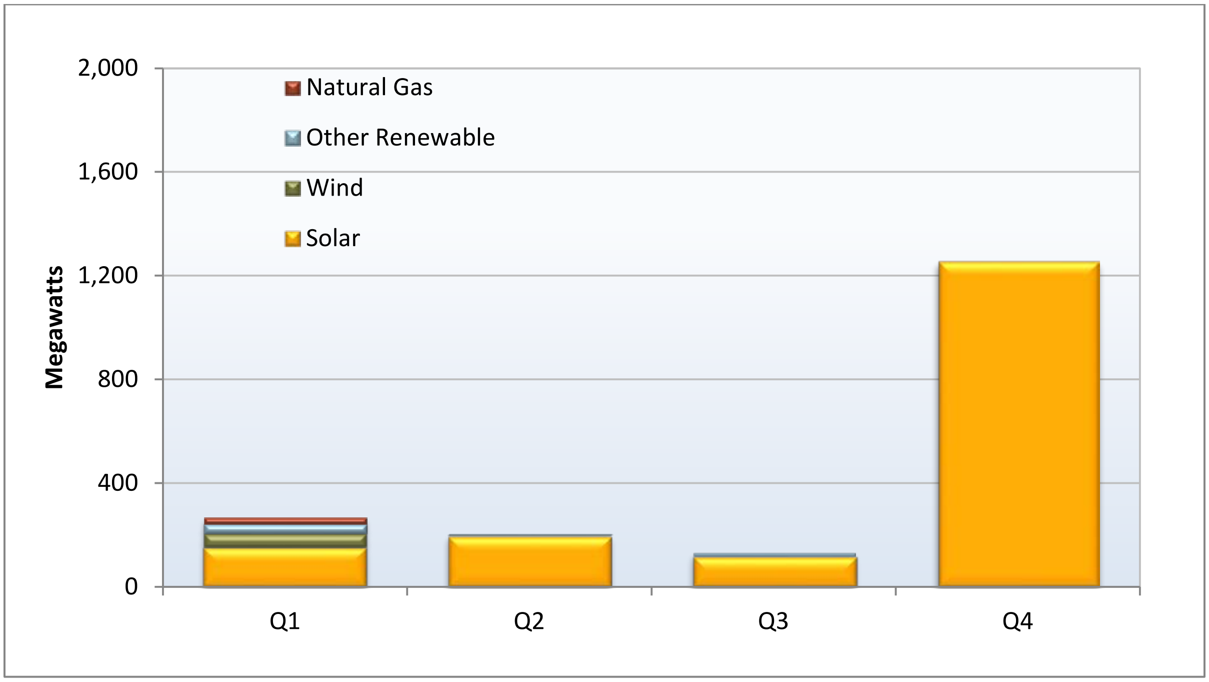
- **Capacity procurement mechanism replacement.** Also approved by the ISO Board in early 2015, this new program allows resources to submit bids for capacity, and will look to those bids first, when possible, to fulfill procurement needs. The new program is expected to function very similarly to the existing capacity procurement mechanism, but it is now designed to allow for competition.

Generation addition and retirement

California currently relies on long-term procurement planning and resource adequacy requirements placed on load-serving entities by the CPUC 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.9 summarizes the quarterly trends in summer capacity additions in 2014. Almost 2,900 MW of new nameplate generation began commercial operation within the ISO system in 2014, contributing to almost 1,900 MW of additional summer capacity. Almost all of the new generation capacity was from renewable resources, primarily solar.

Figure E.9 Generation additions by resource type (summer peak capacity)



The ISO anticipates a continued increase in new nameplate renewable generation in the coming years to meet the state's 33 percent renewable goals. There was little natural gas-fired capacity added or retired in 2014. Going forward, significant reductions in total gas-fired capacity are possible beyond 2014 due to the state's restrictions on using once-through cooling technology. The ISO has highlighted the need to back up and balance renewable generation with the flexibility of conventional generation resources to maintain reliability as more renewable resources come online.

Under the ISO 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 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 2014 prices for gas and electricity show an increase in net operating revenues for hypothetical new combined cycle units, compared to prior years, and mixed results in net operating revenues for hypothetical new combustion turbine gas units as net revenues increased in Northern California and decreased in Southern California. In both cases, however, the 2014 net revenue estimates for hypothetical combined cycle and combustion turbine units continued to fall substantially below the estimates of the annualized fixed costs for these technologies. For a new combined cycle unit, net operating revenues earned from the markets in 2014 increased to an estimated $61/kW-year in Southern California, compared to potential annualized fixed costs of $176/kW-year.

Under current market conditions, additional new generic gas-fired capacity does not appear to be needed at this time. Net operating revenues for many – if not most – older existing gas-fired generators are likely to be lower than their going-forward costs. However, a substantial portion of the state's 15,000 MW of older gas-fired capacity is located in transmission constrained load pockets and is needed to meet local reliability requirements. Much of this existing capacity is also needed to provide the operational flexibility required to integrate the large volume of intermittent renewable resources coming online. However, this capacity must be retrofitted or replaced over the next decade to eliminate use of once-through cooling technology. This investment is likely to require some form of longer-term capacity payment or contracting.

Recommendations

DMM works closely with the ISO to provide recommendations on current market issues and market design initiatives on an ongoing basis. A detailed discussion of DMM's comments and recommendations are provided in Chapter 10 of this report.

Full network model

In October 2014, the ISO implemented an expanded network model that includes more topology and inputs from other balancing areas. This expanded network model is designed to allow the day-ahead and real-time models to more accurately project actual power flows.

DMM has provided specific recommendations relating to more detailed metrics and analysis that we propose be used by the ISO to assess the impacts of the expanded modeling functionality.[10] DMM recommends that more detailed, automated metrics focus on the following:

- The impact that the full network model is having on specific constraints which are at or near their limits in the day-ahead and real-time markets based on estimated or actual flows.
- Constraints on which congestion costs are highest and differ between the day-ahead and 15-minute markets, as measured by total modeled flows and congestion prices.
- All internal constraints, as well on the inter-ties and select internal constraints, which are currently included in the ISO's metrics.

Automation of these metrics is important so that they can be used to quickly identify issues and allow resources to be focused on modeling improvements or adjustments that have the highest value in terms of reliability and market benefits.

DMM has also recommended that as the ISO gains experience with the full network model and unscheduled flows caused by other balancing areas, this information should be analyzed and adjustments should be incorporated back into the congestion revenue rights auction to avoid selling rights to transmission capacity that may not be available in the day-ahead market.

DMM continues to work with the ISO and the Market Surveillance Committee toward developing such metrics.

[10] Memorandum from Eric Hildebrandt to ISO Board of Governors, re: Market Monitoring Report, January 30, 2014: http://www.caiso.com/Documents/DepartmentMarketMonitoringReport-Memo-Feb2014.pdf.

Congestion revenue rights

In 2014, the congestion revenue rights process resulted in a net revenue shortfall of $95 million. The ISO currently allocates any congestion revenue rights revenue inadequacy uplift to load-serving entities based on measured demand. Such revenue inadequacy decreases the total revenues received by load-serving entities for the congestion revenue rights that they made available to the auction.

The revenue inadequacy is generally due to differences between the network transmission model used in the congestion revenue rights process and the final day-ahead market model. In general, the day-ahead model may be more restrictive than the congestion revenue rights model. This is because transmission changes that are unanticipated at finalization of the congestion revenue rights model are more likely to reduce available transmission capacity than to increase it as transmission flows are de-rated to account for unplanned outages and other unanticipated conditions. In addition, new constraints not in place when the congestion revenue rights full network model is finalized may impose limits on transmission capacity in the day-ahead market.

The ISO has taken steps to address the revenue inadequacy by accounting for more constraints in the congestion revenue rights model in future auctions. This essentially limits the amount of congestion revenue rights that are auctioned off going forward. DMM recommends that the ISO continue these efforts and notes that this must represent an on-going process and effort, rather than being a onetime project.

DMM has also noted there are a variety of unavoidable modeling issues that can create discrepancies in the network transmission model used in the congestion revenue rights process and the final day-ahead market model. These include planned and unexpected transmission outages and de-rates that occur after the congestion revenue rights model is finalized.

In 2014, DMM proposed a general methodology that could be used to allocate congestion revenue rights revenue inadequacy costs back to holders of congestion revenue rights on an interval and constraint specific basis. This alternative allocation approach would limit the total amount of revenues that can be transferred from load-serving entities to congestion revenue rights holders through uplift. Moreover, this allocation method would reduce the incentive for entities purchasing congestion revenue rights to target the modeling differences that create revenue inadequacy costs.[11]

The ISO included modifications to the congestion revenue rights process for potential stakeholder initiatives in 2015. However, the ISO ultimately excluded any initiative on congestion revenue rights due to resource limitations and the ISO assessment that this would involve a complicated stakeholder process.

DMM has also recommended that as the ISO gains experience with the full network model and unscheduled flows caused by other balancing areas, this information should be used to inform the congestion revenue rights auction process to improve how the ISO rates transmission capacity.

[11] *Allocating CRR Revenue Inadequacy by Constraint to CRR Holders*, Department of Market Monitoring, October 6, 2014: https://www.caiso.com/Documents/AllocatingCRRRevenueInadequacy-Constraint-CRRHolders_DMMWhitePaper.pdf.

Virtual bidding

Virtual bidding on inter-ties was scheduled to be re-implemented in May 2015 – one year after implementation of the new 15-minute real-time market design. In April 2015, the ISO requested a waiver for the requirement to re-implement virtual bidding on inter-ties for up to an additional 12-month period. The basis of the ISO request was the concern that reintroducing inter-tie virtual bidding in light of the observed lack of liquidity in economic bidding in the ISO's 15-minute market would decrease economic efficiency, based on a supplemental report completed by DMM analyzing the connection between 15-minute market economic bids at the inter-ties and inter-tie virtual bidding.[12]

During the period of the waiver, the ISO will explore the causes underlying the lack of liquidity at the inter-ties in the 15-minute market. The ISO will also seek stakeholder input as to whether there are feasible solutions to the liquidity issues and identify what level of liquidity is sufficient, from a market efficiency perspective, to reinstitute inter-tie virtual bidding.

DMM supports the continued suspension of virtual bidding on inter-ties given the current lack of liquidity on most inter-ties in the 15-minute market. DMM will work with the ISO and stakeholders to explore the reasons for this lack of liquidity, along with other options that might be feasible to increase liquidity or otherwise mitigate the potential inefficiencies that may be created if virtual bidding was re-implemented on inter-ties under current market conditions and rules.

DMM has also cautioned that virtual bidding on inter-ties could inflate real-time congestion revenue imbalances in the event that constraint limits need to be adjusted downward in the 15-minute market to account for unscheduled flows not incorporated in the day-ahead market model. The expanded full network model implemented in fall of 2014 is designed to account for unscheduled flows in the day-ahead market model. DMM's recommendations on the expanded full network model are provided in Section 10.1.

Start-up and minimum load bids

In 2014 and early 2015, the ISO developed several changes to how start-up and minimum load bid costs are calculated. These changes were aimed primarily at making sure start-up and minimum load bids used by the ISO software reflect the prevailing spot market prices of natural gas. This is necessary to avoid inefficient unit commitments, as well as potential revenue inadequacy for some units.

DMM supported these changes as representing a reasonable balance between the need to allow participants to submit start-up and minimum load bids incorporating expected gas and opportunity costs, while continuing to mitigate locational market power and potentially manipulative behavior designed to recover excessive start-up and minimum load bid costs through bid cost recovery payments.

As noted in prior annual reports, DMM is very supportive of the concept of including opportunity costs in start-up and minimum load bids, and is supportive of the ISO's general approach to calculating opportunity costs. We recommend that the ISO continue further refining and developing their current prototype model and continue to engage stakeholders in developing and refining the opportunity cost methodology and model.

[12] *Potential market inefficiencies from convergence bidding at interties with insufficient liquidity of fifteen-minute bids*, Department of Market Monitoring, April 3, 2015: http://www.caiso.com/Documents/DMMReport-ConvergenceBiddingonInterties.pdf.

In early 2015, DMM expressed concerns that this important market enhancement has been deferred again, and that given the current status of this project, it may be very difficult for the ISO to complete the development, testing and stakeholder review of an opportunity cost model and rules in time for consideration of this issue by the ISO Board meeting in September 2015 as planned.

Bidding rules initiative

The ISO started a new initiative in 2015 to consider a range of modifications to bidding rules. Included within the potential scope of this initiative is consideration of the natural gas prices used in development of the start-up, minimum load, and energy bids used as bid caps and for cost-based bids used in bid mitigation.

In this new stakeholder initiative, DMM is working with the ISO and stakeholders to consider how gas prices and other inputs used to limit start-up, minimum load and energy bids may be made more flexible and accurate. However, DMM emphasizes that current limits on all these inputs play an important role in mitigating local market power and gaming of bid cost recovery rules. In addition, any new rule modifications must take into consideration the ongoing effort and resources that may be needed for some ISO business units to verify and administer the new changes.

Flexible ramping product

The ISO continues to develop a flexible ramping product that would replace the flexible ramping constraint currently incorporated in the real-time market software. The ISO's most recent proposal will use a demand curve derived from forecast uncertainty to economically procure both upward and downward flexible capacity in the 15-minute market and the 5-minute real-time dispatch. This proposal also appears to have been modified so that payments for this product would be based on opportunity costs rather than separate bid prices that could be submitted for flexible ramping capacity up to a cap of $250/MW. As noted in our 2013 annual report, DMM has recommended eliminating these bidding provisions since no specific short-term marginal costs have been demonstrated or described that these bids would be used to cover.[13]

With these modifications, DMM is highly supportive of this most recent proposal as a more effective way of ensuring operational ramping flexibility than the current flexible ramp constraint. However, the proposed design would procure capacity to meet five minute ramping uncertainty. Deviations from forecasts can occur over consecutive 5-minute intervals. Extending the flexible ramping design to capacity products with durations greater than five minutes (i.e., 15 minutes, 30 minutes, or longer) could better position the markets to respond to increased uncertainty as the grid transitions to a future of increased renewable generation and variable demand.[14] DMM would be supportive of exploring such an extension or policy that meets similar goals. DMM is also supportive of further policy development that could allow the flexible ramping products to be incorporated into the day-ahead market.

[13] *2013 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2013, pp. 252: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

[14] This is further described in DMM's comments on the Draft Final Proposal: http://www.caiso.com/Documents/DMMComments_FlexibleRampingProduct-DraftFinalProposal.pdf.

Reliability services initiative

In early 2015, the ISO completed the first phase of this initiative, which included the following: 1) enhancements to further integrate preferred resources into the grid; 2) a new availability incentive mechanism to encourage greater availability from resource adequacy resources including demand response and use-limited resources; and 3) revisions to resource adequacy outage rules to streamline ISO processes and provide a platform for flexible resource adequacy outage rules.[15]

DMM is supportive of the ISO's proposal under the first phase of this initiative as a step toward improving and streamlining resource adequacy requirements and processes to meet the need for increased operational flexibility to integrate new renewable energy resources. DMM has provided recommendations on follow-up actions on two aspects of the ISO's final proposal.

Under the ISO's final proposal, until the ISO completes the work needed to include opportunity cost estimates in start-up and minimum load bids, use-limited resources can exempt themselves from the availability standards by submitting special outages. Therefore, as noted above, DMM continues to urge the ISO to commit the resources necessary to develop and implement the opportunity cost estimation method.

The ISO is proposing to set the penalty price for not meeting availability standards at 60 percent of the soft offer cap for the capacity procurement mechanism. As noted in DMM's last annual report and its comments in this stakeholder initiative, if the cost of replacement capacity approaches the soft offer cap, it will be less costly for generating unit owners to pay the penalty rather than provide substitute capacity. DMM believes this scenario could occur precisely when supply conditions are tightest and options for capacity that can be procured bilaterally by participants or by the ISO through the capacity procurement mechanism is most limited and non-competitive.

DMM recommends that the ISO monitor this issue once the new incentive mechanism has been implemented. If the initial level of this penalty appears to be insufficient to incent participants to meet availability standards, the penalty price may need to be raised closer to the soft cap for the backstop procurement mechanism that the ISO may need to employ to procure additional capacity as the result of any failure to meet availability standards.

Flexible capacity procurement requirements

DMM is supportive of a multi-year capacity procurement that includes flexible capacity requirements. The ISO and the CPUC continue working toward consideration of multi-year resource adequacy requirements and the incorporation of more detailed flexible capacity needs.

The ISO is developing several short-term products that may provide additional market revenues for resources providing flexibility in real time. These include the flexible ramping product and the contingency modeling enhancements discussed in Sections 10.9 and 10.10. However, it is unclear how often these constraints will be binding and, therefore, provide significant market revenues. DMM believes it is prudent to continue development of a market design that includes provisions to ensure sufficient flexible capacity is built or maintained in advance of the timeline needed to bring new flexible capacity online.

[15] The proposal considered by the ISO Board can be found at: http://www.caiso.com/Documents/DraftFinalProposalAddendum-ReliabilityServices.pdf.

Energy imbalance market

Since implementation of the energy imbalance market in the PacifiCorp balancing areas, DMM has collaborated with the ISO to monitor market performance and identify actions that may be taken to improve market performance. Analysis and recommendations by DMM concerning the current EIM performance and design are included in special reports being submitted to FERC pursuant to the Commission's December 1, 2014, and March 16, 2015, orders on the ISO's energy imbalance market.[16]

[16] While this annual report covers the energy imbalance market in Section 3.4, much more detail is provided in our quarterly reports and our regular reports to FERC pursuant to the December 1 and March 16 orders. The rest of the metrics contained within this annual report focus on the ISO balancing area only, excluding any impacts from the energy imbalance market.

Organization of report

The remainder of this report is organized as follows:

- **Loads and resources.** Chapter 1 summarizes load and supply conditions impacting market performance in 2014. This chapter includes an analysis of net operating revenues earned by hypothetical new gas-fired generation from the ISO markets.
- **Overall market performance.** Chapter 2 summarizes overall market performance in 2014.
- **Real-time market performance.** Chapter 3 provides an analysis of real-time market performance, and includes information on market enhancements related to 15-minute scheduling and pricing as well as the energy imbalance market.
- **Convergence bidding.** Chapter 4 analyzes the convergence bidding feature and its effects on the market.
- **Ancillary services.** Chapter 5 reviews performance of the ancillary service markets.
- **Market competitiveness and mitigation.** Chapter 6 assesses the competitiveness of the energy market, along with impact and effectiveness of market power and exceptional dispatch mitigation provisions.
- **Congestion.** Chapter 7 reviews congestion and the market for congestion revenue rights.
- **Market adjustments.** Chapter 8 reviews the various types of market adjustments made by the ISO to the inputs and results of standard market models and processes.
- **Resource adequacy.** Chapter 9 assesses the short-term performance of California's resource adequacy program in 2014.
- **Recommendations.** Chapter 10 highlights DMM recommendations on current market issues and new market design initiatives on an ongoing basis.

1 Load and resources

This chapter reviews key aspects of demand and supply conditions that affected overall market prices and performance. In 2014, wholesale electricity prices were driven higher by a significant increase in gas prices and the lowest level of hydro-electric production since the ISO began operation in 1998. However, the upward pressure on prices due to these factors was offset in large part by moderate loads and a significant increase in supply from new solar generation.

More specific trends highlighted in this chapter include the following:

- The average price of natural gas in the daily spot markets in California increased over 17 percent from 2013.[17] This was the main driver in the 13 percent increase in the nominal annual wholesale energy cost per MWh of load served in 2014.
- Summer loads peaked at 45,090 MW, or a 7 MW decrease from 2013 and the lowest peak load observed in several years.
- Hydro-electric generation provided approximately 5 percent of total supply in 2014, a decrease from 8 percent in 2013 and the lowest level since the ISO began operation in 1998.
- Net imports decreased by about 1 percent in 2014 compared to 2013. Lower priced imports from the Northwest increased by 6 percent, while imports from the Southwest decreased by 6 percent.
- About 1,900 MW of summer peak generating capacity was added in 2014, with about 93 percent of the new capacity coming from solar generation.
- Energy from wind and solar resources directly connected to the ISO grid provided more than 10 percent of system energy, compared to about 8 percent in 2013. Solar energy production more than doubled compared to 2013 and produced almost the same amount of energy as wind.
- Demand response programs operated by the major utilities continued to meet about 5 percent of the ISO's overall system resource adequacy capacity requirements. Activation of these programs increased in 2014, but overall participation remains limited.
- The estimated net operating revenues for typical new gas-fired generation in 2014 remained 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 investment in any new generation or retrofit of existing generation needed under the ISO's current market design.

[17] 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, when gas prices are typically highest.

1.1 Load conditions

1.1.1 System loads

System loads remained almost the same in 2014 compared to 2013. Table 1.1 summarizes annual system peak loads and energy use over the last five years.

Table 1.1 Annual system load: 2010 to 2014

Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2010	224,922	25,676	-2.5%	47,350	2.8%
2011	226,087	25,791	0.4%	45,545	-3.8%
2012	234,882	26,740	3.7%	46,847	2.9%
2013	231,800	26,461	-1.0%	45,097	-3.7%
2014	231,610	26,440	-0.1%	45,090	0.0%

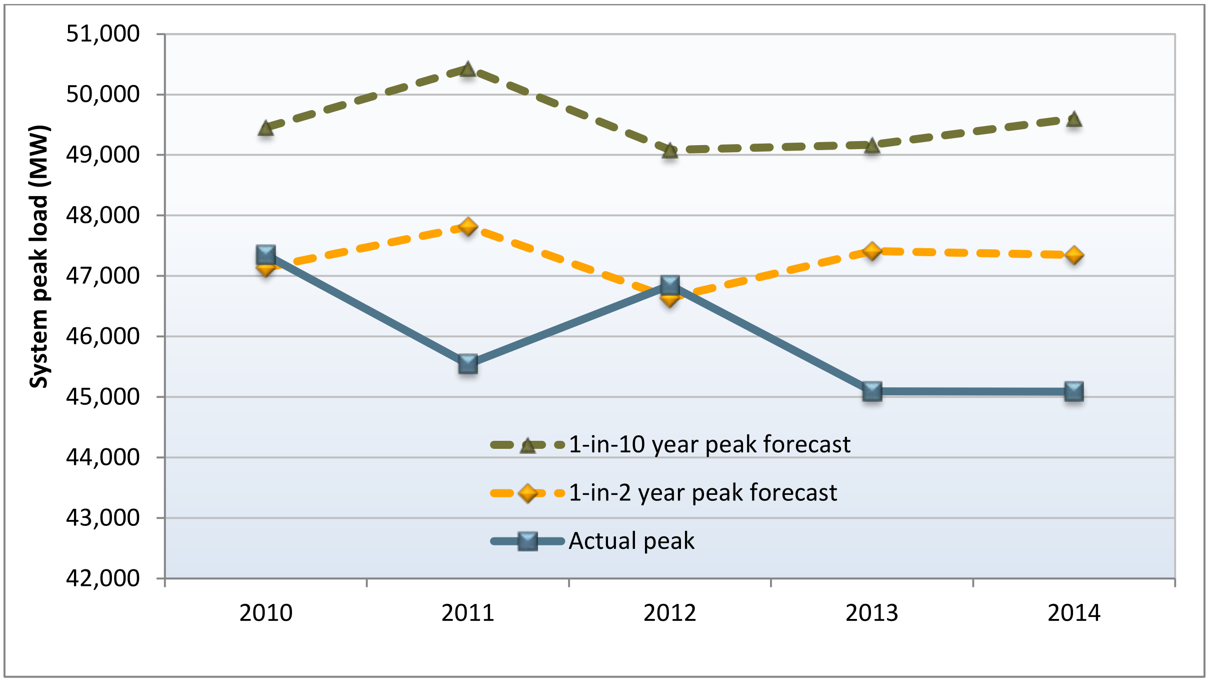
In 2014, annual, average and peak load measures all remained at similar levels compared to 2013.

- Annual total energy reached 231,610 GWh, a 0.1 percent decrease from 2013.
- Summer loads peaked at 45,090 MW on September 15 at 4:53 p.m., a 7 MW drop from 2013 and the lowest peak load observed in the last five years.

System demand during the single highest load hour often varies substantially year to year because of summer heat waves. The potential for heat-related peak loads creates a continued threat of operational reliability problems and drives many of the ISO's reliability planning requirements.

Peak load in 2014 was significantly lower than both the ISO's 1-in-2 year and 1-in-10 year forecasts as shown in Figure 1.1. In coordination with the CPUC and other local regulatory authorities, the ISO sets system level resource adequacy requirements based on the *1-in-2 year*, or median year, forecast of peak demand. Resource adequacy requirements for local areas are based on the *1-in-10 year*, or 90th percentile year, peak forecast for each area. The instantaneous peak load (45,090 MW) was about 5 percent below the 1-in-2 year forecast (47,351 MW) and 9 percent below the 1-in-10 year forecast (49,601 MW).

Figure 1.1 Actual load compared to planning forecasts



1.1.2 Local transmission constrained areas

The ISO has defined 10 local capacity areas for use in establishing local reliability requirements for the state's resource adequacy program (see Figure 1.2). Table 1.2 summarizes the total amount of load within each of these local areas under the 1-in-10 year forecast used to set local reliability requirements. Most of the total peak system demand is located within two areas: the Los Angeles Basin (40 percent) and the Greater Bay Area (21 percent).

The three investor-owned utility (IOU) areas may be characterized as follows:

- The Southern California Edison area accounts for 49 percent of total local capacity area loads under the 1-in-10 year forecast. Loads in the Los Angeles Basin account for 81 percent of the potential peak load in this area.
- The Pacific Gas and Electric area accounts for 40 percent of total local capacity area loads under the 1-in-10 year forecast. Loads in the Greater Bay Area account for 53 percent of the potential peak load in the PG&E area.
- The San Diego Gas and Electric area is comprised of a single local capacity area, which accounts for 11 percent of the total local capacity area load forecast.

In the following chapters of this report, we summarize a variety of market results for each of these three main load areas – also known as *load aggregation points* or LAPs. In some cases, we provide results for specific local capacity areas. These results provide insight into key locational trends under the nodal market design. The proportion of load and generation located within the areas is shown in Table 1.2

and is an indication of the relative importance of results for different aggregate load and local capacity areas on overall market results.

In addition to local capacity area load forecasts, Table 1.2 shows the total amount of generation in each local capacity area and the proportion of that capacity required to meet local reliability requirements established in the state resource adequacy program. In most areas, a very high proportion of the available capacity 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. This issue is examined in Chapter 6 of this report.

In addition, California's once-through cooling (OTC) regulations affect a significant proportion of capacity needed to meet local capacity requirements in four areas: Greater Bay Area, Los Angeles Basin, Big Creek/Ventura and San Diego. Further discussion of this issue is available in DMM's 2011 annual report.[18]

Table 1.2 Load and supply within local capacity areas in 2014

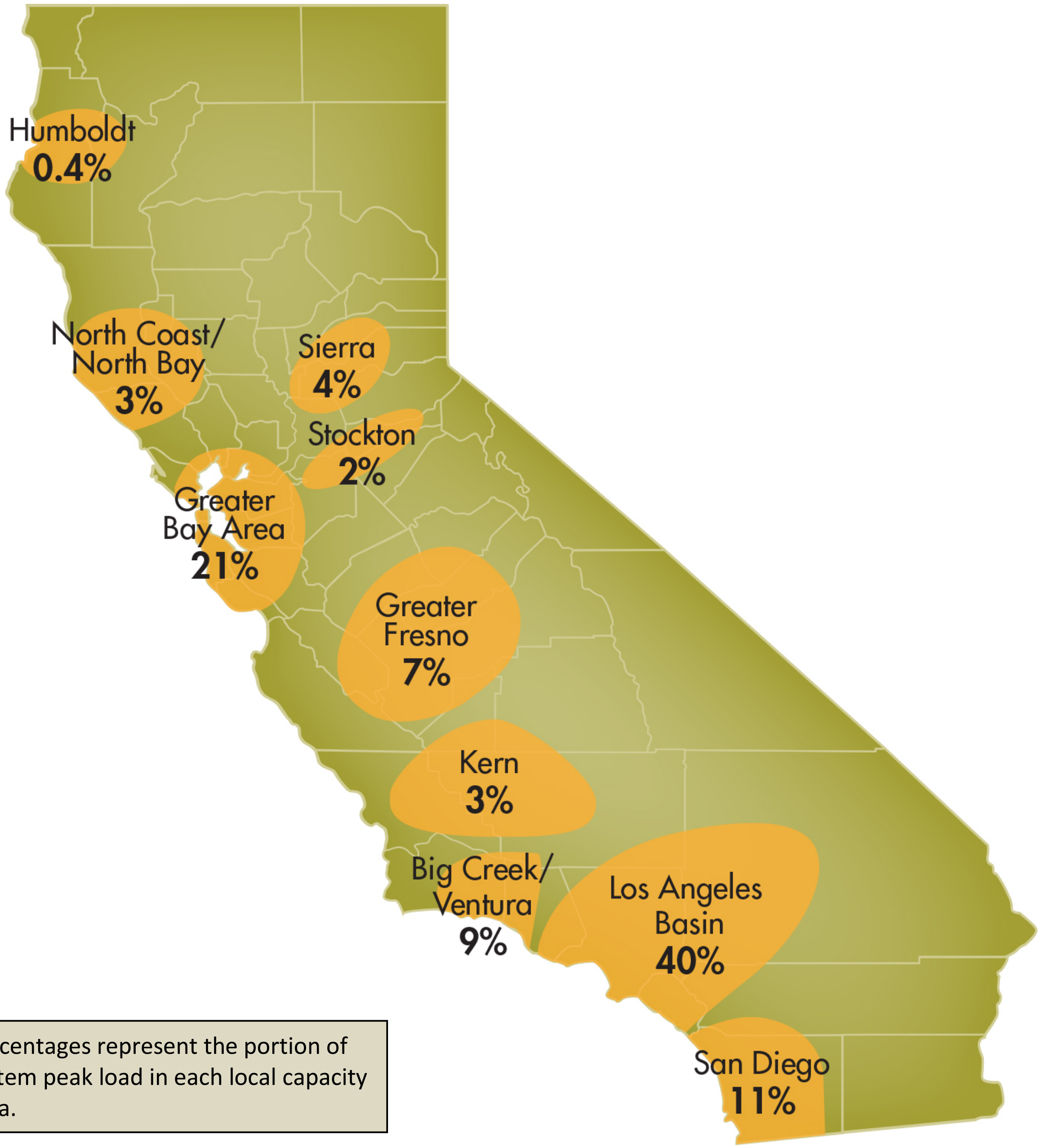
		Peak Load (1-in-10 year)		Dependable Generation	Local Capacity Requirement	Requirement as Percent of
Local Capacity Area	**LAP**	**MW**	**%**	**(MW)**	**(MW)**	**Generation**
Greater Bay Area	PG&E	10,419	21%	7,616	4,638	61%*
Greater Fresno	PG&E	3,246	7%	2,828	1,857	66%
Sierra	PG&E	1,958	4%	2,050	2,088	102%*
North Coast/North Bay	PG&E	1,465	3%	921	623	68%
Stockton	PG&E	1,163	2%	604	701	116%*
Kern	PG&E	1,281	3%	677	462	68%*
Humboldt	PG&E	195	0.4%	243	195	80%
LA Basin	SCE	19,694	40%	11,789	10,430	88%
Big Creek/Ventura	SCE	4,580	9%	5,318	2,250	42%
San Diego	SDG&E	5,200	11%	4,706	4,063	86%*
Total		**49,201**		**36,752**	**27,307**	

Source: *2015 Local Capacity Technical Analysis: Final Report and Study Results*, April 30, 2014. See Table 6 on page 22. http://www.caiso.com/Documents/Final2015LocalCapacityTechnicalStudyReportApr30_2014.pdf

* Generation deficient LCA (or with sub-area that is deficient). Deficient area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.

[18] *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, p. 27: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

Figure 1.2 Local capacity areas



Percentages represent the portion of system peak load in each local capacity area.

1.1.3 Demand response

Overview

Demand response continues to play a role in meeting California's capacity planning requirements for peak summer demand. These programs are operated by the state's three investor-owned utilities and meet about 5 percent of total ISO system resource adequacy capacity requirements.

Demand response is a resource that allows consumers to adjust electricity use in response to forecast or actual market conditions, including high prices and reliability signals. By providing capacity to help meet demand on extremely high load days, demand response could decrease demand in high use periods enough to lower market prices for energy and ancillary services and increase transmission reliability.

Demand response programs are currently dispatched and administered by the utilities that sponsor these programs, rather than by the ISO. These programs are overseen by the CPUC. Independent demand response providers offer this resource through utility-sponsored programs, as do other non-utility entities. Currently, the vast majority of demand response provided directly to the ISO is pumping load, which is not associated with the utility demand response programs.[19]

In 2010, the ISO implemented a proxy demand resource product. This allows aggregators of end-use loads to bid directly into the energy and ancillary service markets. This product was implemented to increase direct participation in the energy and ancillary service markets by utility demand response programs, as well as aggregated end-use or independent demand response providers.

The capacity of proxy demand resources grew from 6 MW in 2013 to 47 MW in 2014. These resources were also dispatched several times in 2014. These resources were not dispatched in 2013 and were only dispatched at a minimal level in 2012. A revised demand response registration system implemented in 2015 is expected to facilitate further growth in proxy demand resource capacity.

Starting in May 2014, the ISO also enabled reliability demand response resources to be dispatched as part of the market optimization during a system emergency. When an emergency condition is declared, reliability demand response resources can now enter the bid stack at prices between $950/MWh to $1,000/MWh. No reliability demand response resources were registered or available for dispatch in the ISO market during 2014. However, the revised registration system is also expected to facilitate further growth in these resources.

In addition to the utility demand response programs, the ISO issues flex alerts when system conditions are expected to be particularly high. Flex alerts urge consumers to voluntarily reduce demand through broadcast press releases, text messages and other means. The program is funded by the utilities under the authority of the CPUC. The only flex alert issued by the ISO in 2014 was a state-wide alert issued on February 6 in response to significant reliability concerns related to natural gas pipeline supply issues.[20]

[19] 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.

[20] See: http://www.caiso.com/Documents/ISOIssuesStatewideFlexAlert.pdf.

Utility demand response programs

Much of California's current demand response consists of load management programs operated by the state's three investor-owned utilities. These programs have been triggered by criteria set by the utilities and are not necessarily tied to wholesale market prices. Notification times required by the retail programs have historically not been not well coordinated with ISO market operations, which has limited the programs' use and usefulness in the ISO markets.

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

- ***Reliability-based programs.*** These programs consist primarily of large retail customers under interruptible tariffs and air conditioning cycling programs. These demand resources are primarily triggered only when the ISO declares a system reliability threat or for a local transmission emergency.[21]

- ***Day-ahead price-responsive programs***. These programs are triggered on a day-ahead basis in response to market or system conditions that indicate relatively high market prices. Specific indicators used by utilities to trigger these programs include forecasts of temperatures or unit heat rates that may be scheduled given projected real-time prices. This category also includes *critical peak pricing* programs under which participating customers are alerted that they will pay a significantly higher rate for energy during peak hours of the following operating day.

- ***Day-of price-responsive programs***. These programs are referred to as *day-of* demand response programs since they can be dispatched during the same operating day for which the load reduction is needed. These resources include capacity from air conditioning cycling programs dispatched directly by the utilities and much of the load reduction capacity procured through curtailment service providers. These programs can also be triggered on a day-ahead basis in response to market or system conditions.

Although any demand response impact on load can provide value to the market, from the perspective of overall market performance and system reliability, day-of price responsive demand programs are most valuable to the ISO system. These programs provide capacity that is able to respond to rapidly changing market conditions and can provide flexibility in real time without being reserved a day in advance.

Table 1.3 summarizes total demand response capacity for each of the three major utilities during the peak summer month of August, as reported to the CPUC since 2010.[22] Protocols in effect since 2010 require utilities to report two measures of demand response capacity: *ex ante* and *ex post*.[23] *Ex post* values are calculated by multiplying total program enrollment by the average customer impact for customers enrolled in the previous year. *Ex ante* values are calculated by multiplying total program enrollment by the estimated average load impact that would occur under expected weather and load conditions on the peak day of the month between 1:00 p.m. and 6:00 p.m. The *ex ante* values form the

[21] In early 2014, FERC accepted the ISO's modification to the reliability demand response program. The change allows reliability demand response to be dispatched as part of the market optimization during a system emergency. Bid prices will range between $950 and $1,000/MWh. The change was effective May 2014. For more information, see: http://www.caiso.com/Documents/Mar28_2014_OrderAcceptingTariffRevisions-ReliabilityDemandResponse_ER11-3616_ER13-2192.pdf.

[22] The monthly reports are available at http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Monthly+Reports/index.htm.

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

basis for the remaining discussion in this section because they are most representative of actual available demand response capacity during 2014.

Each investor-owned utility uses demand response capacity to meet resource adequacy requirements. As shown in the bottom two rows of Table 1.3, demand response capacity used to meet resource adequacy requirements from 2010 to 2014 has tracked closely with estimates of actual demand response capacity reported in these years under the more advanced reporting protocols.

In 2014, estimated demand response capacity available in August was approximately equal to the resource adequacy requirements that the CPUC allowed these resources to meet. The decrease in demand response used to meet resource capacity requirements since 2010 reflects the use of the more stringent protocol for measuring and reporting demand response programs that took effect in 2010. 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 response reduces the amount of load used to calculate the 15 percent supply margin used in setting resource adequacy requirements.

Table 1.3 Utility operated demand response programs (2010-2014)

Utility/type	2010 Estimated MW*	2011 Estimated MW*	2012 Estimated MW*	2013 Estimated MW*	2014 Estimated MW*
Price-responsive					
SCE	214	287	962	706	790
PG&E	304	469	340	404	418
SDG&E	72	58	118	54	61
Sub-total	589	814	1,420	1,164	1,269
Reliability-based					
SCE	1,245	1,167	727	684	733
PG&E	291	253	282	332	313
SDG&E	9	8	2	0	0
Sub-total	1,544	1,428	1,010	1,016	1,047
Total	2,134	2,270	2,430	2,180	2,316
Resource adequacy allocation	2,221	2,421	2,598	2,582	2,299
With 15 percent adder	2,554	2,784	2,987	2,970	2,644

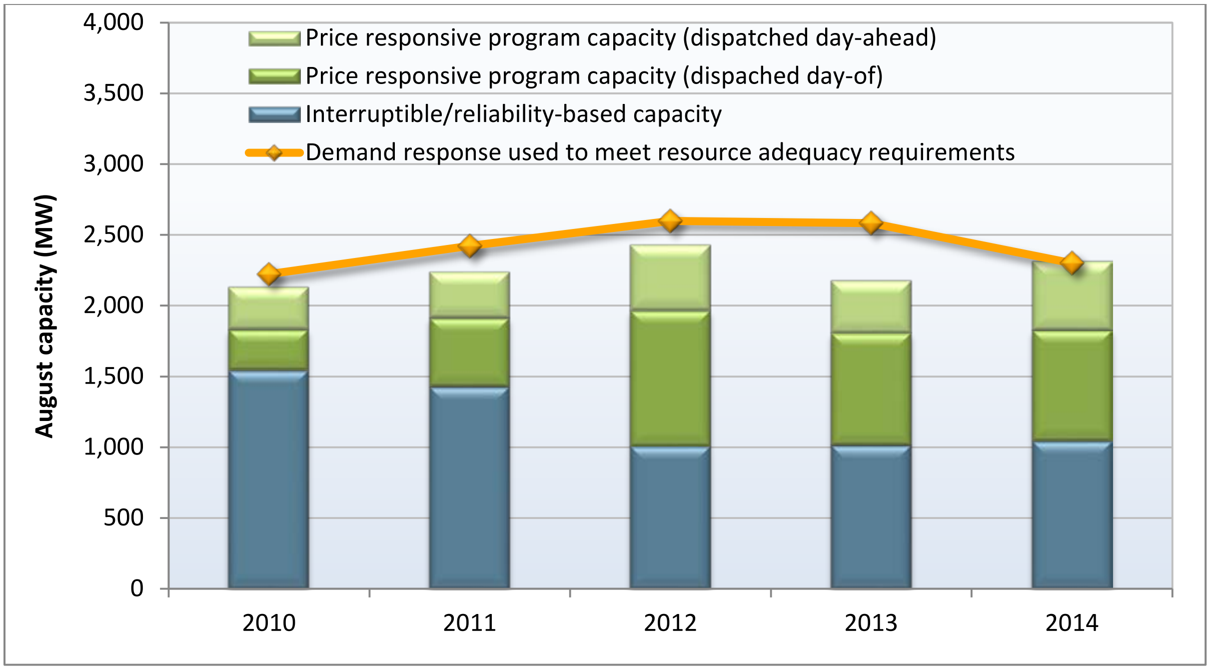
* Capacity based on ex ante assessment of program enrollment and impacts in August.

Figure 1.3 summarizes data in Table 1.3, but provides a further breakdown of the portion of price-responsive capacity that can be dispatched on a day-ahead and day-of basis since 2010. As shown in Figure 1.3:

- Price-responsive programs accounted for 55 percent of this capacity in 2014, which is a major increase from 2010 and 2011 levels, and a slight increase over the 2013 value (53 percent).
- Reliability-based programs accounted for 45 percent of the capacity from utility-managed demand response resources in 2014. Historically, reliability programs have been a larger component of demand response capacity.

- In 2014, price-responsive programs that can be dispatched on a day-of basis fell to 34 percent of all demand response capacity, down slightly from about 35 percent in 2013.

Figure 1.3 Utility operated demand response programs (2010-2014)



Use of demand response programs

Demand response resources continue to be dispatched by utilities on a limited but growing basis. In 2014, these programs were dispatched about 60 percent more than in 2013, as measured by post event estimates of energy reductions provided seven days after the event and then re-estimated at year end. However, the total estimated impact of these demand response events represents a very small portion of total ISO system energy – approximately 0.02 percent.

While demand response dispatch volume was small in 2014, these resources were dispatched during the hours that have historically seen the highest demand or when they would likely have the most impact on system reliability. For example, demand response resources were activated on February 6 in response to significant reliability concerns related to natural gas pipeline supply issues. Over the course of 2014, dispatch was concentrated in the hours between 2:00 p.m. and 6:00 p.m., often the peak ramping hours in the day. About 40 percent of demand response was dispatched on a day-ahead basis. The remaining 60 percent was dispatched on a day-of or emergency basis.

In 2014, most demand response was dispatched in response to market or system conditions, rather than to evaluate or measure the demand response program itself. The percent of demand response dispatch for testing fell substantially from 2013 as the total volume of demand response dispatch increased. In 2014, dispatch of demand response for measurement or evaluation accounted for less than 1 percent of dispatch for day-ahead programs and about 5 percent of dispatch for day-of programs. In 2013, approximately 1 percent of day-ahead dispatch and 30 percent of day-of dispatch was for testing purposes.

Demand response issues

While use of demand response increased in 2014, several challenges remain before this capacity can be better integrated into the market and ISO operational decisions. These challenges include refinements to software and market functionality both on the ISO and demand response provider side, the timing and quality of demand response data through metering and telemetry, and limited integration of available demand response data into ISO market and operations.

While the ISO implemented a proxy demand resource product in 2010, few bids from these resources were dispatched in 2014 and none were dispatched in 2013. Although proxy demand resource product participation in the ISO markets has been approved by FERC, the CPUC has limited bundled utility customer participation in this program to pilot programs.[24] Thus, while the utilities' programs were triggered more by price than for reliability purposes, the integration of these programs with the ISO markets is still poor, as commitment and dispatch decisions continue to occur outside the market optimization.

Except for the small amount of demand response bid into the market, daily forecasts of scheduled demand response sent to the ISO by the major investor-owned utilities are the only source of information directly available to the ISO on utility operated demand response resources. However, these forecasts are provided on a spreadsheet to the ISO and are, therefore, not well integrated with market operations and systems at this time.

1.2 Supply conditions

1.2.1 Generation mix

In 2014, natural gas and imports continued to be the largest sources of energy to meet ISO load. Due to low levels of precipitation and snowpack, hydro-electric generation continued to decrease in 2014 compared to the already low levels observed in 2013. Solar generation from resources directly connected to the ISO grid more than doubled in 2014 compared to 2013, increasing its overall share of generation to about 5 percent.

Figure 1.4 provides a profile of average hourly generation by month and fuel type. Figure 1.5 illustrates the same data on a percentage basis. These figures show the following:

- Nuclear generation provided about 7 percent of supply in 2014, down from about 8 percent in 2013.
- Hydro-electric generation provided approximately 5 percent of supply in 2014, a decrease from almost 8 percent in 2013.
- Natural gas generators provided approximately 41 percent of supply in 2014, up from 40 percent in 2013. Natural gas generators produced the most during September and October. These resources were most often marginal and price setting in the ISO system.

[24] For further detail see CPUC Decision 10-06-002, issued in Proceeding R.07-01-041. More information on this decision can be found here: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/118962.htm. A broader discussion of regulatory issues is available in the ISO's 5th Annual Demand Response report in docket no. ER06-615-000: http://www.caiso.com/Documents/2012-01-17_ER06-615_5thAnnualDR_Report_CY2011.pdf.

Figure 1.4 Average hourly generation by month and fuel type in 2014

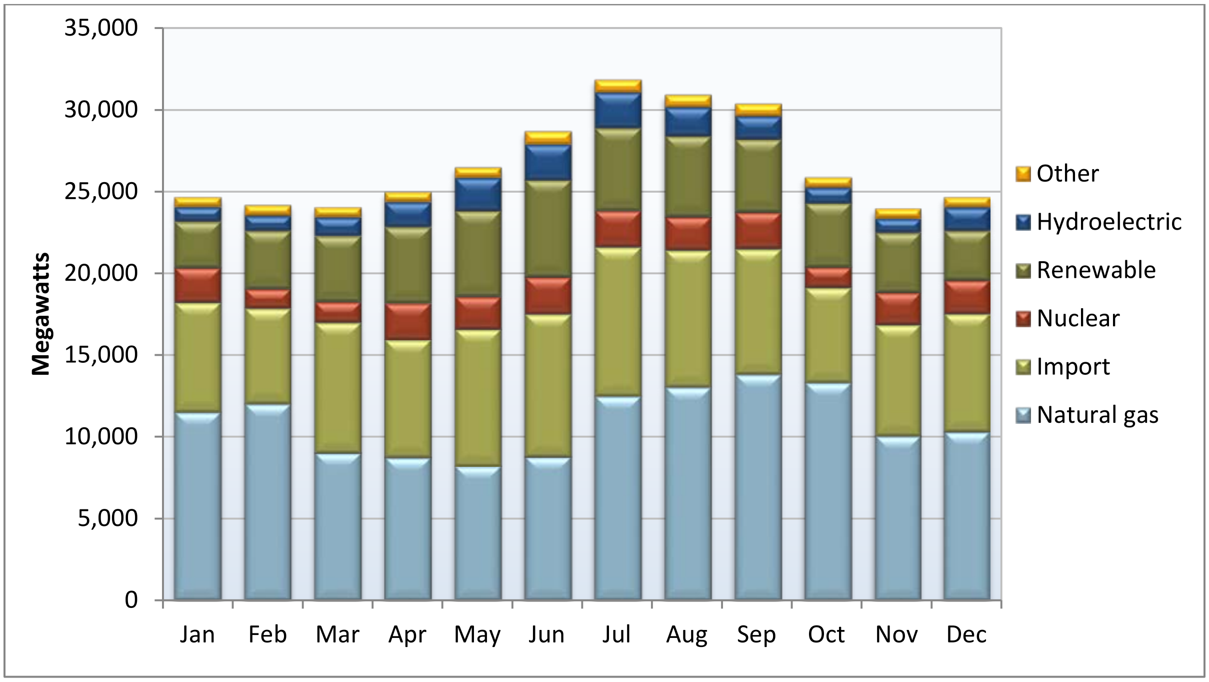
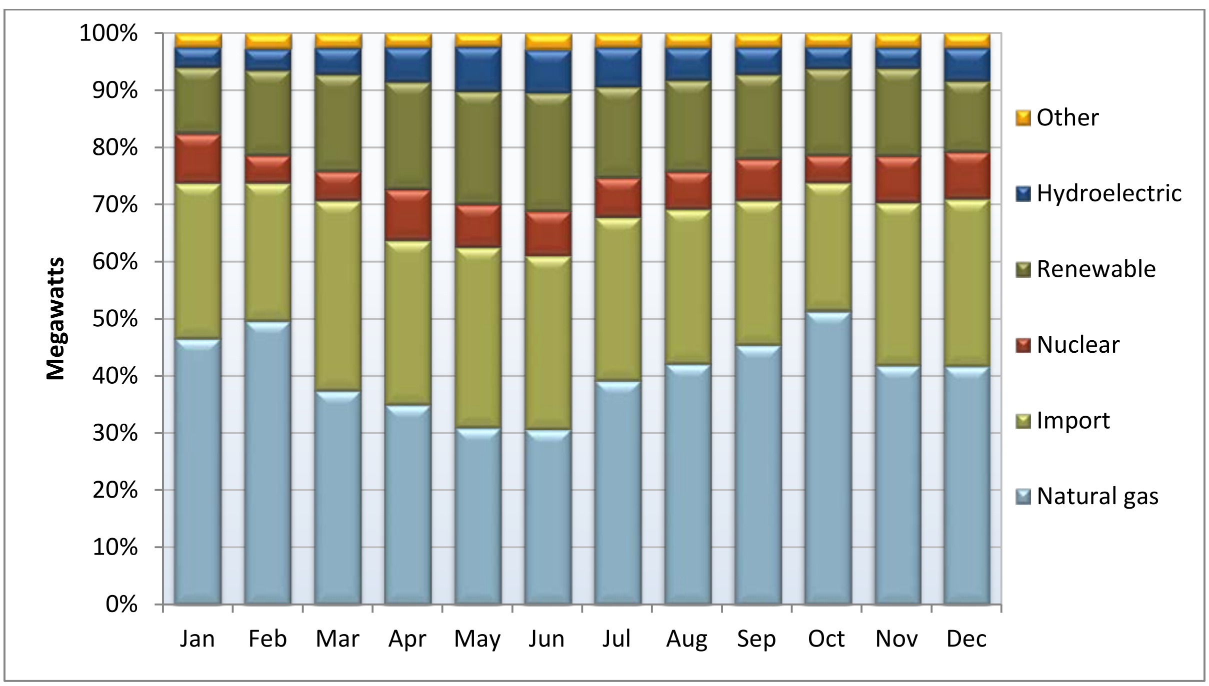


Figure 1.5 Average hourly generation by month and fuel type in 2014 (percentage)



- Net imports were down slightly compared to 2013 and represented approximately 28 percent of generation.
- Non-hydro renewable generation directly connected to the ISO system accounted for 16 percent of total supply.[25] Total non-hydro renewable generation was up 21 percent from 2013, driven primarily by growth in generation from solar resources.

Figure 1.6 provides a detailed breakdown of non-hydro renewable generation directly connected to the ISO grid from 2011 through 2014. The following is shown in Figure 1.6:

- Generation from wind resources remained the largest source of renewable generation directly connected to the ISO grid.
- Wind resources provided 33 percent of renewable energy, down from 40 percent in 2013. Wind provided 5.6 percent of overall system energy in 2014.
- Solar power from resources directly connected to the ISO system increased dramatically in 2014. Overall output from solar more than doubled from 5,500 GWh in 2013 to 11,500 GWh, and provided just under 5 percent of system energy. The portion of renewable energy provided by solar increased from 17 percent in 2013 to 29 percent in 2014.
- Geothermal provided approximately 23 percent of renewable energy in 2014, or just under 4 percent of overall system energy.
- Biogas, biomass, and waste generation contributed 14 percent of renewable energy, or about 2.4 percent of total system energy.

Wind production peaked in the spring months when system loads are moderate, hydro-electric generation is relatively more abundant, and the supply portfolio is limited due to outages. The combination of these conditions contributes to the potential for negative prices reflecting near over-generation conditions during this period.

Figure 1.7 compares average monthly generation from hydro, wind and solar resources. Because of the dramatic increase in solar generation and simultaneous decrease in hydro-electric generation, the amounts of energy produced by hydro, wind and solar were similar throughout the year. On a monthly basis, solar generation exceeded both wind and hydro-electric generation in September, October and November. Wind exceeded solar and hydro from February through June. Going forward, solar is expected to increase its portion of new renewable supply.

[25] In this analysis, non-hydro renewables do not include imports or behind the meter generation such as rooftop solar. DMM has very limited access to this information. Thus, this analysis may differ from other reports of total renewable generation.

Figure 1.6 Total renewable generation by type (2011-2014)

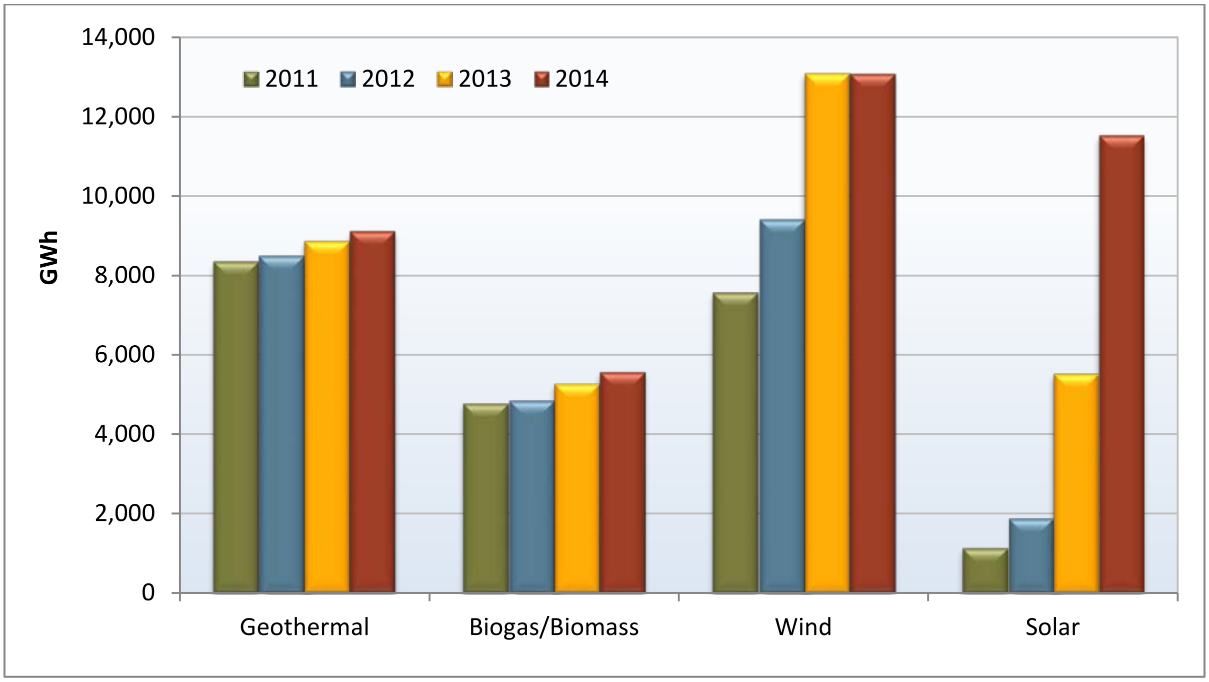
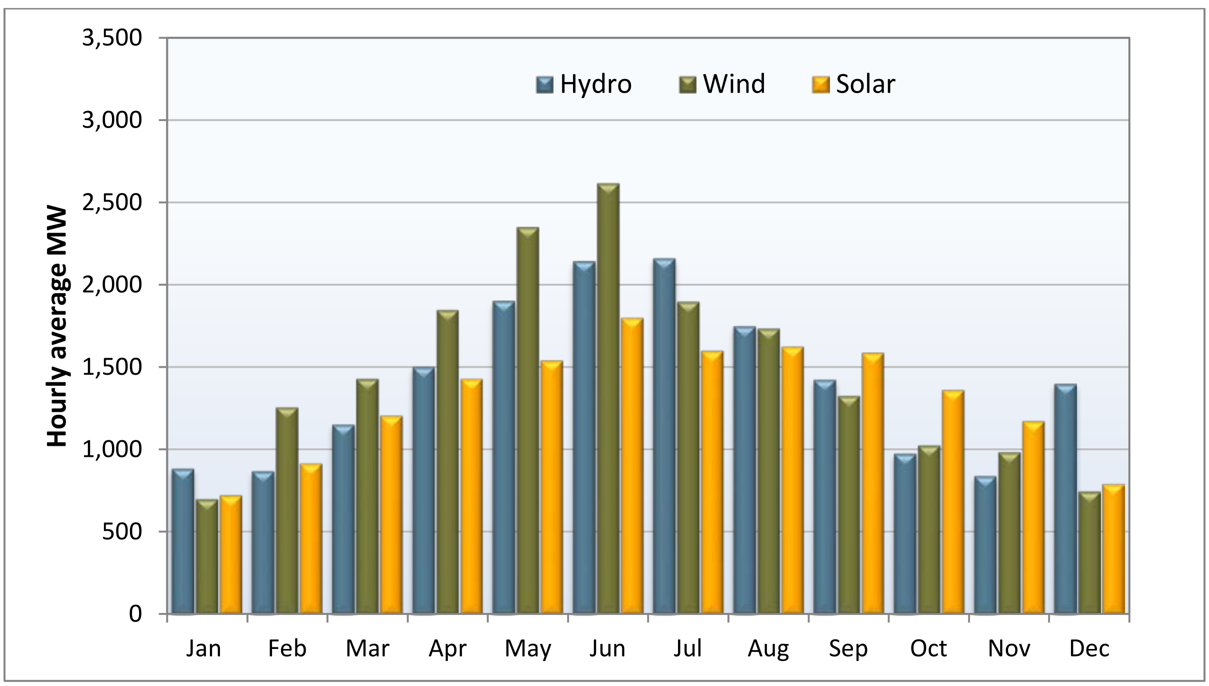


Figure 1.7 Monthly comparison of hydro, wind and solar generation (2014)

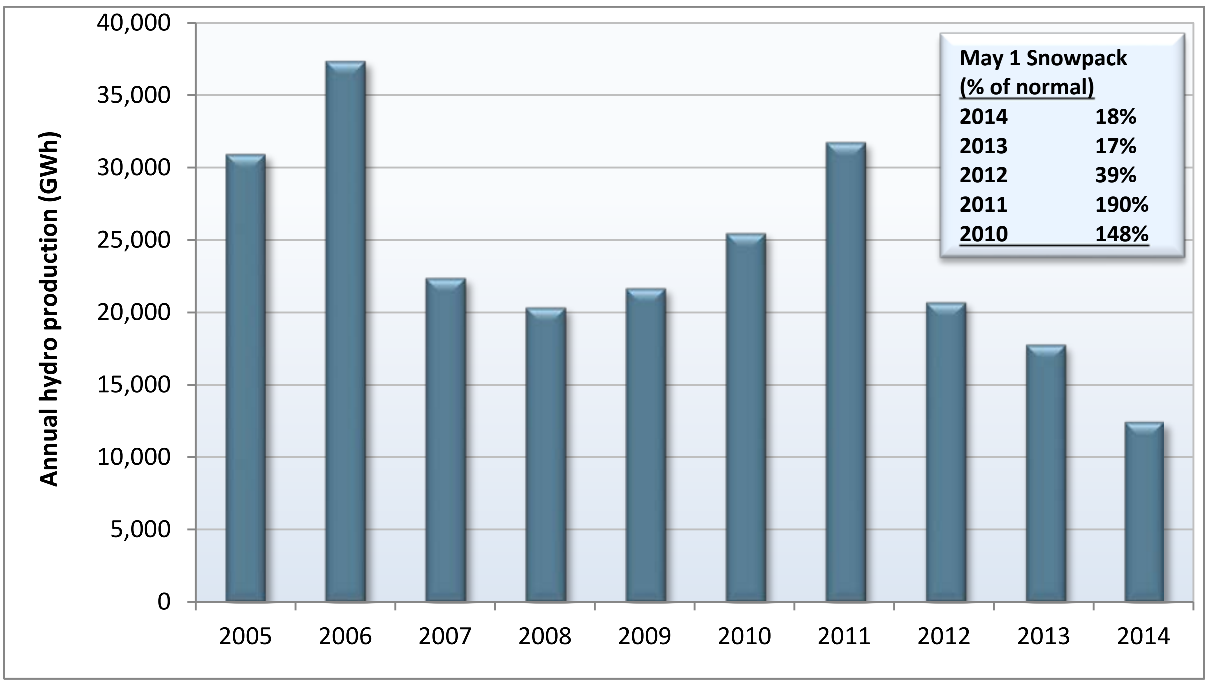


Hydro-electric supplies

Year-to-year variation in hydro-electric power supply in California has a major impact on prices and the performance of the wholesale energy market. More abundant supplies of run-of-river hydro-electric power generally reduce the need for baseload generation and imports. Hydro conditions also impact the amount of hydro-electric power and ancillary services available during peak hours from units with reservoir storage. Almost all hydro-electric resources in the ISO are owned by load-serving entities that are net buyers of electricity. They therefore seek to manage these resources in a way that moderates overall energy and ancillary service prices.

Overall hydro-electric production in 2014 was low, falling about 30 percent below production in 2013, which is the lowest annual hydro-electric production since the ISO began operation in 1998. Snowpack in the Sierra Nevada mountains, as measured on May 1, 2014, was only 18 percent of the long-term average, indicating much lower than average hydro conditions.[26] Figure 1.8 illustrates overall production over the last decade.

Figure 1.8 Annual hydro-electric production (2005-2014)



[26] For snowpack information, please see: California Cooperative Snow Surveys' Snow Water Equivalents (inches), California Department of Water Resources: http://cdec.water.ca.gov/cdecapp/snowapp/sweq.action.

Figure 1.9 Average hourly hydro-electric production by month (2012-2014)

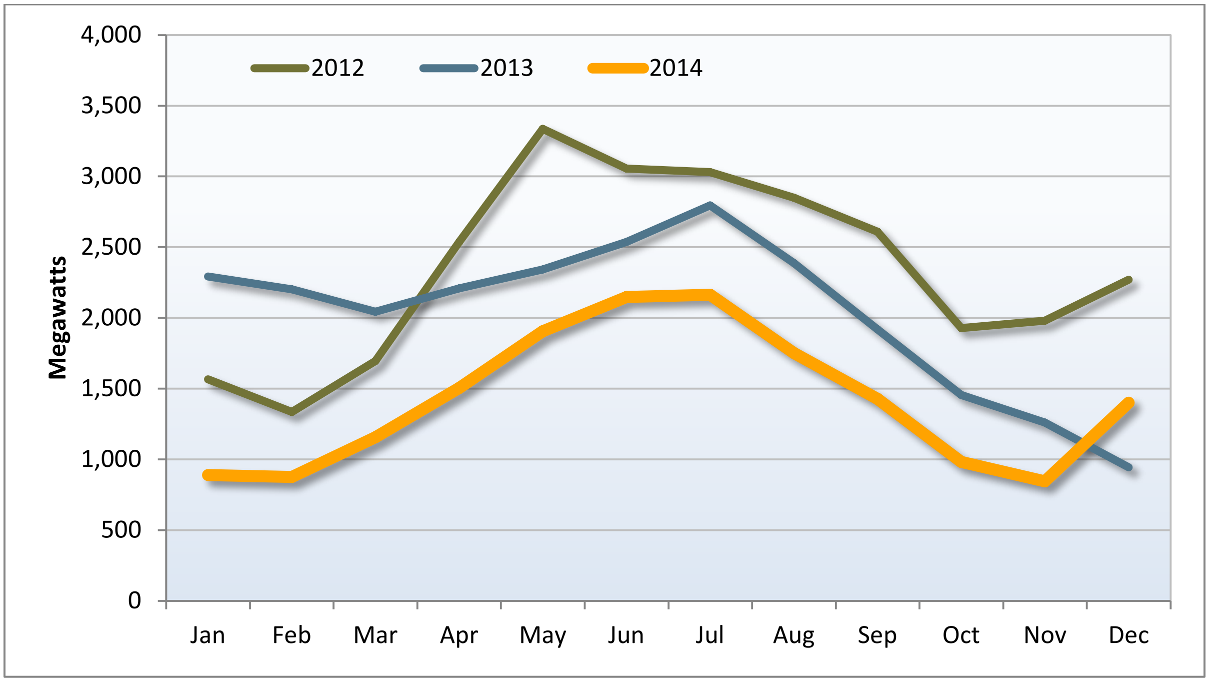


Figure 1.9 compares monthly hydro-electric output from resources within the ISO system for each of the last three years. For every month except December, hydro production in 2014 was at least 15 percent lower compared to the corresponding month in 2013. Overall, hydro production in 2014 was about 70 percent of production in 2013 and 60 percent of production in 2012. During the summer months of June to August, hydro production was 79 percent of production during the same period of 2013 and 68 percent of the same period in 2012. In the final quarter of the year, hydro production was about 88 percent of the same period in 2013.

Net imports

Net imports decreased by about 1 percent in 2014 from 2013.[27] Total net imports from lower priced sources in the Northwest increased by more than 6 percent, while net imports from the Southwest decreased by almost 6 percent.

Figure 1.10 compares net imports by region for each quarter of 2013 and 2014. Net imports from the Southwest were lower than the previous year in all but the first quarter of 2014. Net imports from the Northwest were lower than the previous year in the first two quarters and higher in the third and fourth quarters.

[27] Net imports are equal to scheduled imports minus scheduled exports in any period.

Figure 1.10 Net imports by region (2013-2014)

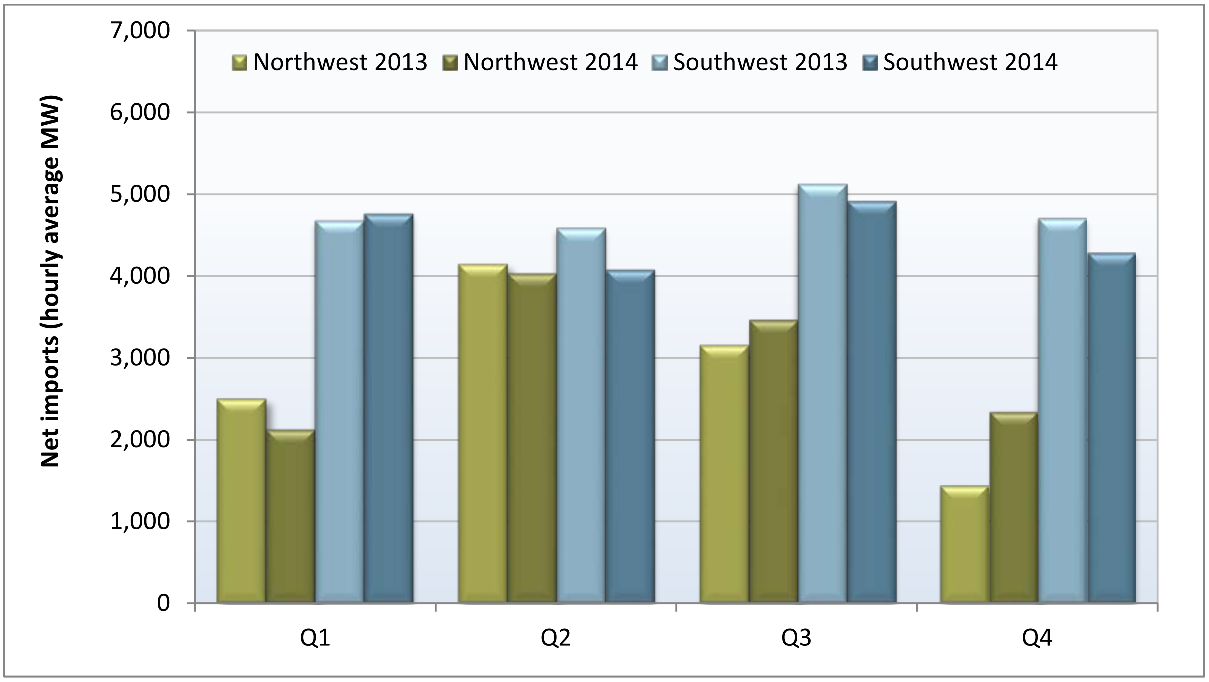
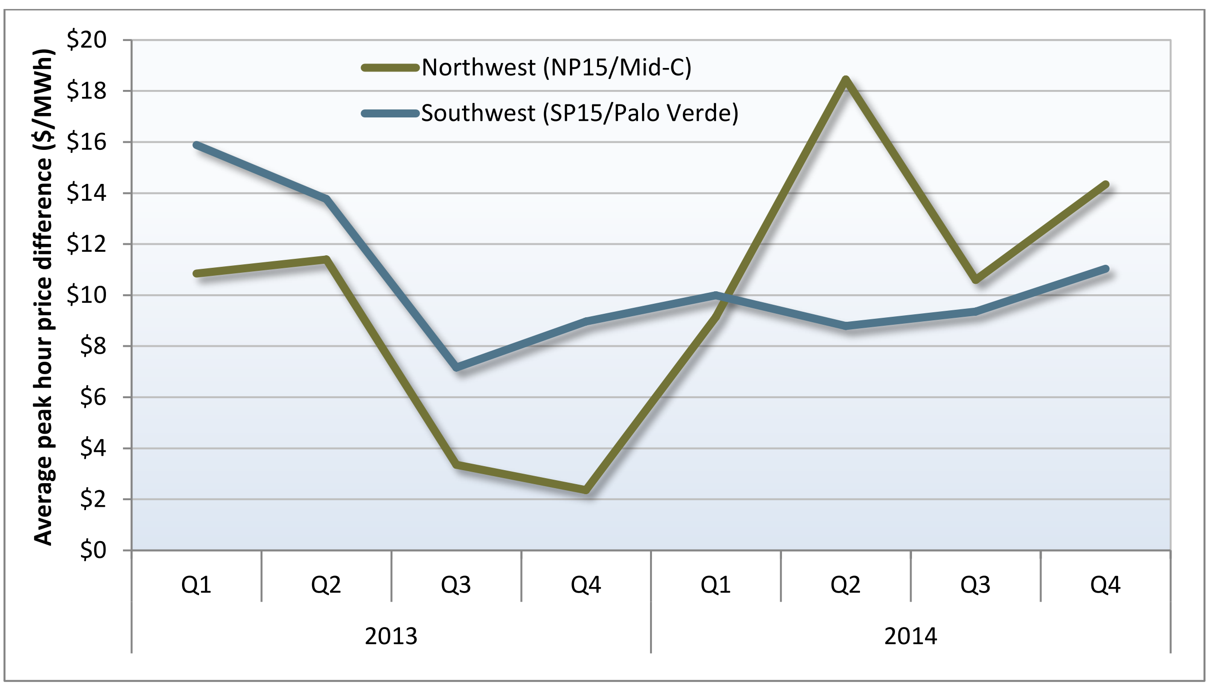


Figure 1.11 Average price difference by import region – peak hours



These changes in imports were likely driven by demand and supply conditions in the Pacific Northwest and the Southwest. Figure 1.11 shows the quarterly average day-ahead price difference for peak hours between Northern California (NP15) and the Northwest (Mid-C) as well as between Southern California (SP15) and the Southwest (Palo Verde). The overall increase of imports from the Northwest generally reflects that prices in the Northwest were lower than prices in Northern California, and that the difference in price was larger in 2014 compared to 2013. Imports were likely limited from the Northwest in the second quarter as a result of congestion. While prices in the Southwest remained lower than prices in Southern California, the average difference in price was smaller in 2014 compared to 2013.

1.2.2 Generation outages

Generation outage levels, including partial unit derates, fell by 5 percent in 2014.

The ISO groups generation outages into four categories:

- ***Planned outages*** — Reductions in available capacity for scheduled maintenance that are submitted by October 15 of the preceding year and are updated quarterly.
- ***Forced outages*** — Unplanned reductions in capacity due to equipment failure, unforeseen required maintenance or other exigent circumstances.
- ***Ambient outages*** — Reductions in available capacity due to external conditions such as temperature or air quality restrictions.
- ***Normal outages*** — Reductions in available capacity where a planned, forced, or ambient designation is not appropriate, such as the inability to respond to dispatch instructions due to other physical limitations.[28]

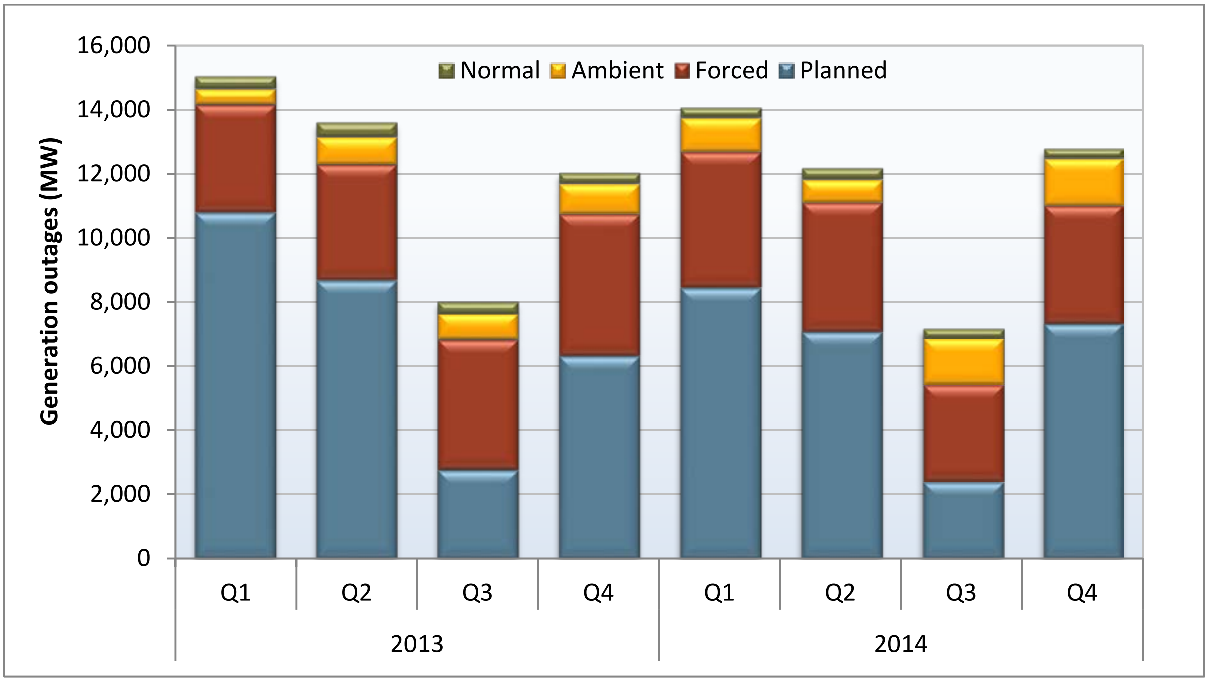
Figure 1.12 shows the quarterly averages of maximum daily outages broken out by type during peak hours.[29] Overall generation outages follow a seasonal pattern with the majority taking place in the non-summer months. This pattern is primarily driven by planned outages, as maintenance is performed outside the higher summer load period. Total outages averaged about 11,500 MW in 2014 down from 12,200 MW in 2013.

Forced outages averaged about 3,700 MW in 2014, down from 3,900 MW in 2013. Planned outages also decreased to 6,300 MW in 2014 from 7,200 MW in 2013. Ambient outages increased by more than 50 percent to 1,200 MW in 2014 from 800 MW in 2013. This increase was primarily driven by outages related to insufficient amounts of water for hydro-electric generation. Average normal outages fell to 310 MW in 2014 from 380 MW in 2013.

[28] These are referred to as normal outages because they are submitted to the ISO using a normal card in the ISO's outage management system.

[29] Data are estimated from outage data in the outage management system.

Figure 1.12 Average of maximum daily generation outages by type – peak hours



1.2.3 Natural gas prices

Electric prices in western states typically follow natural gas price trends because natural gas units are usually the marginal source of generation in the ISO and other regional markets. In 2014, the average weighted price of natural gas in the daily spot markets increased by about 17 to 21 percent from 2013 levels in the main trading hubs in California. The increase in natural gas prices was the main driver causing the annual wholesale energy cost per MWh of load served in 2014 to increase relative to 2013.

Natural gas prices in 2014 were higher than 2013 prices for most of the year. Figure 1.13 shows monthly average natural gas prices for 2011 through 2014 at key delivery points in Northern California (PG&E Citygate) and in Southern California (SoCal Citygate and SoCal Border) as well as for the Henry Hub trading point, which acts as a point of reference for the national market for natural gas.

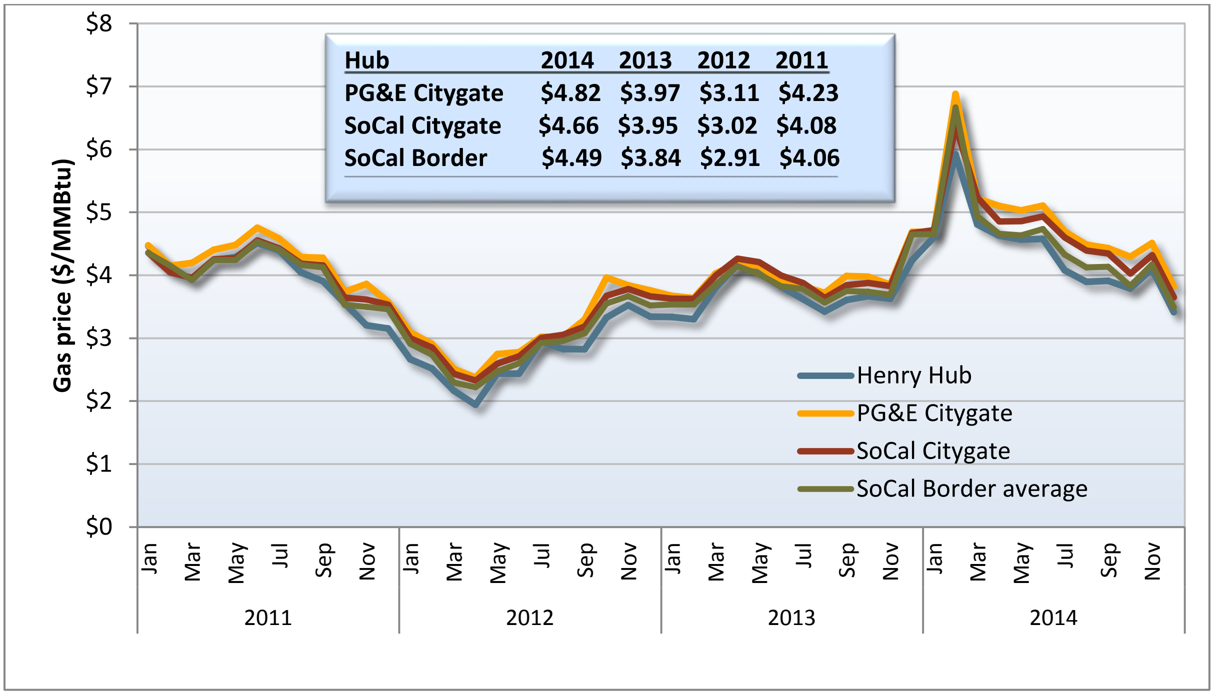
The winter heating season in 2013/2014 experienced record low temperatures throughout much of the country and natural gas storage levels dipped to lows not experienced since 2003. In particular, multiple severe cold snaps significantly stressed the natural gas system throughout the country during the winter. As a result, both regional and national natural gas markets were highly volatile.

This volatility spilled over into western markets in early February. Although California was not experiencing severe weather during this period, severe cold weather conditions and supply restrictions outside of California caused western natural gas market hubs to experience large increases in prices on multiple days.

Natural gas prices began the month of February trading at a little over $5/MMBtu. On February 4, gas prices increased by about $1/MMBtu and then increased to about $7.50/MMBtu on February 5. On

February 6 the Southern California Gas Citygate hub price increased to almost $13/MMBtu and the Pacific Gas and Electric Citygate hub price increased to almost $25/MMBtu, an increase of over 300 percent from the prior day's price. On February 7, natural gas prices decreased to around $8/MMBtu. Natural gas prices at California trading hubs had not experienced such high levels, or volatility, in several years.[30]

Figure 1.13 Monthly weighted average natural gas prices (2011-2014)



While natural gas prices in California tend to follow national trends, differences can occur that reflect gas pipeline 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.

The load weighted average price at the PG&E Citygate in 2014 was about $0.16/MMBtu higher than the price at the SoCal Citygate. This year the SoCal Citygate price was about midway between the PG&E Citygate price and the SoCal Border price. In 2013, the PG&E Citygate and the SoCal Border prices were almost the same. On average in 2014, SoCal Border prices were lower than SoCal Citygate and PG&E Citygate prices by about 7 percent and 4 percent, respectively.

[30] In contrast, Northeastern gas market trading hubs typically exhibit this type of behavior during most winters due to limited pipeline capacity and high flows into their region.

1.2.4 California's greenhouse gas allowance market

This section provides background on California's greenhouse gas allowance market under the state's cap-and-trade program, which was applied to the wholesale electric market beginning in 2013, and the impacts that greenhouse gas costs have on wholesale electric prices. A more detailed description of the cap-and-trade program and its impact on wholesale electric prices in 2013 was provided in DMM's 2013 annual report.[31]

Background

California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006, directs the California Air Resources Board (CARB) to develop regulations to reduce greenhouse gas emissions to 1990 levels by 2020. The cap-and-trade program is one of a suite of regulatory measures adopted by CARB to achieve this goal.

The cap-and-trade program covers major sources of greenhouse gas emissions including power plants.[32] The program includes an enforceable emissions cap that declines over time. Under the program, California directly distributes and auctions allowances, which are tradable permits equal to the emissions allowed under the cap.

Sources with compliance obligations are required to procure and then surrender allowances and offsets equal to their emissions at the end of each compliance period, but with a partial annual surrender in the interim years. Imports from unspecified sources and electric generation resources emitting more than 25,000 metric tons of greenhouse gas annually, either within California or as imports into California, are covered under the first phase of the cap-and-trade program. Emissions compliance obligations began being enforced on January 1, 2013.

Allowances are associated with a specific year, known as the *vintage*. Allowances are *bankable*, meaning that an allowance may be submitted for compliance in years subsequent to the vintage of the allowance.[33] Generators and importers covered by the regulations are required to submit allowances covering 30 percent of emissions in each year and the remainder of their emissions in the final year of each three year compliance period. In addition to allowances, covered generators and importers may submit emissions offsets to cover up to 8 percent of their emissions.[34] The total cap on emissions declined 2 percent annually through 2014 and will continue to decline 3 percent annually through 2020.

[31] *2013 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2014, pp. 123-136: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

[32] The cap-and-trade program covers major sources of greenhouse gas emissions in California such as refineries, power plants, industrial facilities, and transportation fuels. For the electricity sector, the covered entity is the first deliverer of electricity. The first deliverer is defined in the regulation as the operator of an in-state electricity generator, or an electricity importer. The compliance obligation for first deliverers is based on the emissions that are a result of the electricity they place on the grid. The threshold for inclusion in the program for electricity generated from an in-state facility, and for imported electricity from a specified source, is 25,000 metric tons of annual greenhouse gas emissions. For imported electricity from unspecified sources, there is no threshold and all emissions are covered.

[33] For example, a vintage 2013 allowance may be used for compliance during either the first (2013-2014), second (2015-2017), or third (2018-2020) compliance periods.

[34] See the ARB offset credit issuance table for a list of projects that have been issued ARB offset credits: http://www.arb.ca.gov/cc/capandtrade/offsets/issuance/arb_offset_credit_issuance_table.pdf.

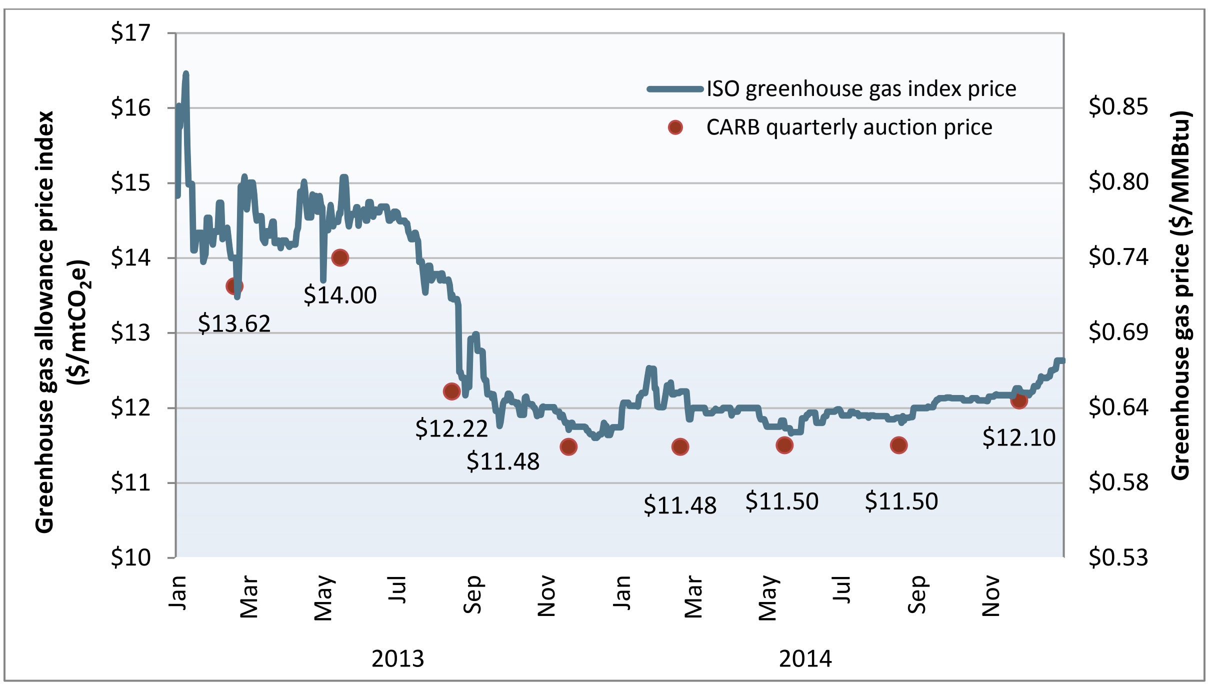
Allowances are available at quarterly auctions held by CARB and may also be traded bilaterally. In addition, contracts for future delivery of allowances are traded on public exchanges such as the InterContinental Exchange (ICE). The cap-and-trade program affects wholesale electricity market prices in two ways. First, market participants covered by the program will presumably increase bids to account for the incremental cost of greenhouse gas allowances. Second, the ISO amended its tariff, effective January 1, 2013, to include greenhouse gas compliance cost in the calculation of each of the following:

- resource commitment costs (start-up and minimum load costs);
- default energy bids (bids used in the automated local market power mitigation process); and
- generated bids (bids generated on behalf of resource adequacy resources and as otherwise specified in the ISO tariff).[35]

Greenhouse gas allowance prices

When calculating various cost-based bids used in the ISO market software, the ISO uses a calculated greenhouse gas allowance index price as a daily measure of the cost of greenhouse gas allowances. The index price is calculated as the average of two market based indices.[36] Daily values of the ISO greenhouse gas allowance index are plotted in Figure 1.14.

Figure 1.14 ISO's greenhouse gas allowance price index



[35] Details on each of the calculations may be found in the ISO Business Practice Manual for Market Instruments, Appendix K: http://bpmcm.caiso.com/BPM Document Library/Market Instruments/BPM_for_Market_Instruments_v26_clean.doc.

[36] The indices are ICE and ARGUS Air Daily. As the ISO noted in a market notice issued on May 8, 2013, the ICE index is a settlement price but the ARGUS price was updated from a settlement price to a volume weighted price in mid-April of 2013. For more information, see the ISO notice: http://www.caiso.com/Documents/GreenhouseGasAllowancePriceSourcesRevisedMay8_2013.htm.

Figure 1.14 also shows market clearing prices in CARB's quarterly auctions of emission allowances that can be used for the 2013 or 2014 compliance year. The values displayed on the right axis convert the greenhouse gas allowance price into an incremental gas price adder, dollars per MMBtu, by multiplying the greenhouse gas allowance price by an emissions factor that is a measure of the greenhouse gas content of natural gas.[37] Thus, the blue line can be read from both the left and right hand axes.

As shown in Figure 1.14, the cost of greenhouse gas allowances in bilateral markets fell over the course of 2013. In 2014, allowance costs were stable at about \$12/mtCO_2e throughout most of the year. Allowance costs rose following the first joint auction with Quebec, held on November 20, 2014, in advance of the second compliance period, ending the year at \$12.63/mtCO_2e.

The cost of greenhouse gas allowances in bilateral markets averaged about \$12.04/mtCO_2e in 2014, a more than 10 percent decrease from the average of \$13.55/mtCO_2e in 2013. The ISO's greenhouse gas allowance price index generally exceeded clearing prices in the CARB's quarterly allowance auctions, but varied in a similar pattern, reflecting current market conditions.

The greenhouse gas compliance cost expressed in dollars per MMBtu in 2014 ranged from \$0.62/MMBtu to \$0.67/MMBtu. This represents almost 15 percent of the average cost of gas during this period.

Impact of greenhouse gas program

A detailed analysis of the impact of the state's cap-and-trade program on wholesale electric prices in 2013 was provided in DMM's 2013 annual report.[38] Based on statistical analysis for changes in prices after the cap-and-trade program was implemented in January 2013, DMM estimated that greenhouse gas costs increased electric prices in the ISO market by about \$6/MWh in 2013.

DMM no longer uses this statistical approach for estimating the impact of greenhouse gas cost due to the difficulty of controlling for changes in other factors that also affect wholesale electric prices since the cap-and-trade obligations for electric generators went into effect in January 2013.

However, as noted above, greenhouse gas compliance costs in 2014 decreased by about 11 percent relative to 2013, and averaged almost 15 percent of the cost of gas. The \$12.04/mtCO_2e would represent an additional cost of about \$4.25/MWh for a relatively efficient gas unit.[39] The average price in 2013, \$13.55/mtCO_2e, would represent an additional cost of about \$5.75/MWh for the same relatively efficient gas resource.

[37] The emissions factor, 0.0531148 mtCO_2e/MMBtu, is the sum of the product of the global warming potential and emission factor for CO_2, CH_4 and N_2O for natural gas. Values are reported in tables A-1, C-1 and C-2 of Title 40 – Protection of Environment, Chapter 1 – Environmental Protection Agency, Subchapter C – Air Programs (Continued), Part 98-Mandatory Greenhouse Gas Reporting, available here: http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&tpl=/ecfrbrowse/Title40/40cfr98_main_02.tpl.

[38] *2013 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2014, pp. 123-136: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

[39] DMM calculates this cost by multiplying the average index price by the heat rate of a relatively efficient gas unit (8,000 Btu/kWh) and an emissions factor for natural gas: 0.0531148 mtCO_2e/MMBtu derived in footnote 37.

1.2.5 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 new generation development.

Figure 1.15 summarizes trends in the addition and retirement of generation from 2005 through 2014.[40] Table 1.4 also shows generation additions and retirements since 2005, including totals across the 10 year period (2005 through 2014).

Figure 1.16 and Figure 1.17 show additional generation capacity by generator type. As the figures indicate, most of the additional generation capacity in 2014 was from solar generation.

Generation additions and retirements in 2014

Almost 1,900 MW of new summer peak capacity began commercial operation within the ISO system in 2014. About 400 MW of this capacity was installed in the PG&E area and over 1,400 MW came online in the SCE and SDG&E areas. In 2014, on a nameplate basis, more than 200 MW of wind capacity and more than 2,500 MW of additional solar capacity came online. A more detailed listing of units added in 2014 is provided in Table 1.5.

There were no retirements within the ISO system in 2014.

[40] Starting in 2011, capacity values are calculated summer peak values. The values in 2010 and before are nominal capacity values. For 2012 through 2014, DMM used capacity factors calculated by the ISO for generation of each fuel type on the basis of actual performance over the prior three year period. These factors may change year to year.

Figure 1.15 Generation additions and retirements (2005-2014)

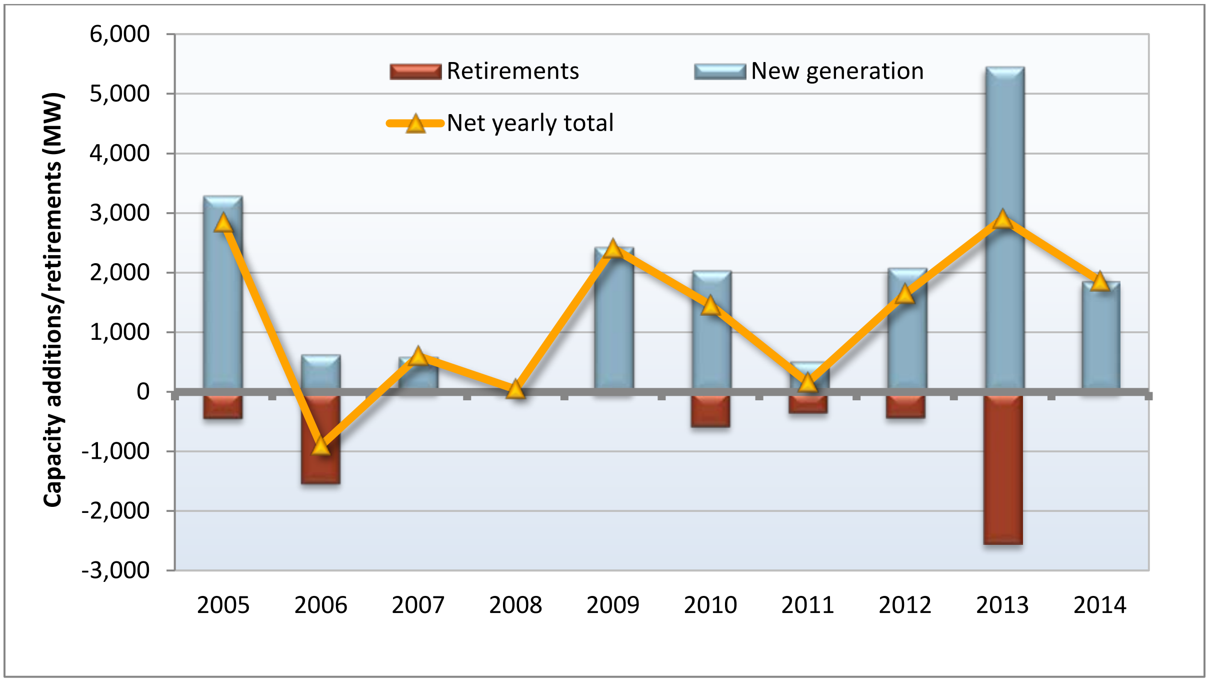


Table 1.4 Changes in generation capacity since 2005

	2005-2009	2010	2011	2012	2013	2014	Total through 2014
SCE and SDG&E							
New Generation	4,447	1,042	401	1,054	3,045	1,431	11,421
Retirements	(1,770)	(414)	0	(440)	(1,883)	0	(4,507)
Net Change	2,677	**628**	**401**	**614**	**1,163**	**1,431**	**6,914**
PG&E							
New Generation	2,559	1,002	115	1,033	2,411	426	7,546
Retirements	(241)	(175)	(362)	0	(674)	0	(1,452)
Net Change	2,318	**827**	**(247)**	**1,033**	**1,737**	**426**	**6,094**
ISO System							
New Generation	7,007	2,044	516	2,087	5,456	1,858	18,967
Retirements	(2,011)	(589)	(362)	(440)	(2,557)	0	(5,959)
Net Change	4,996	**1,455**	**154**	**1,647**	**2,899**	**1,858**	**13,009**

Figure 1.16 Generation additions by resource type (nameplate capacity)

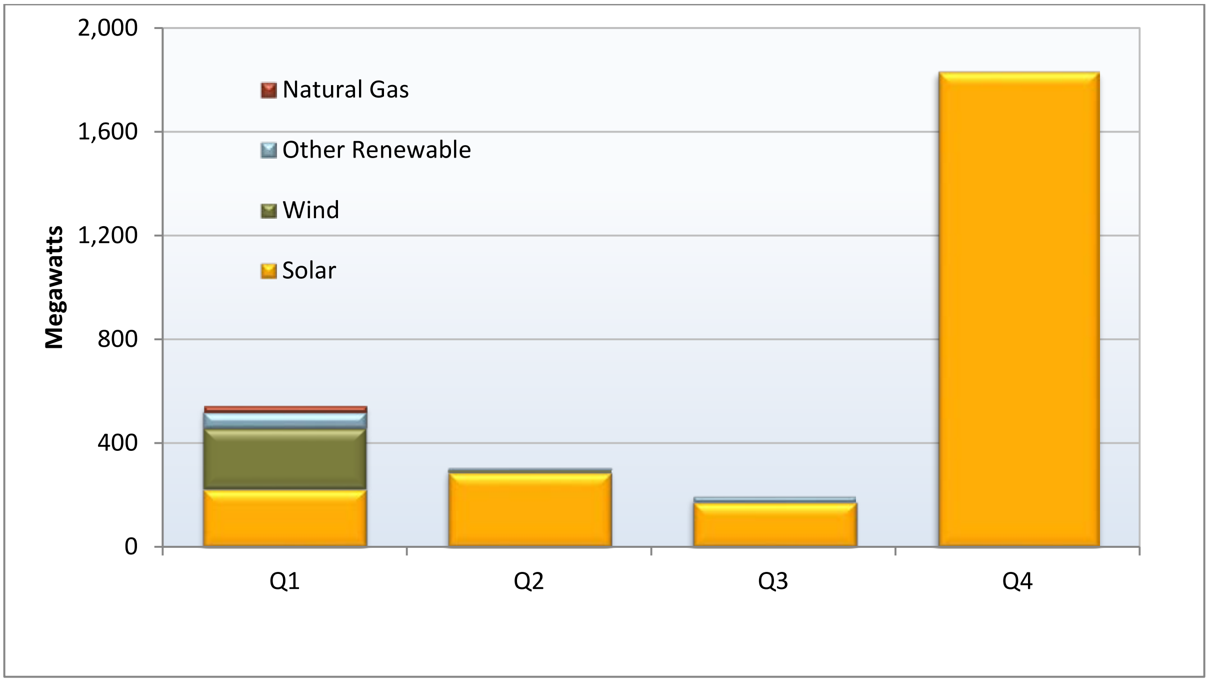


Figure 1.17 Generation additions by resource type (summer peak capacity)

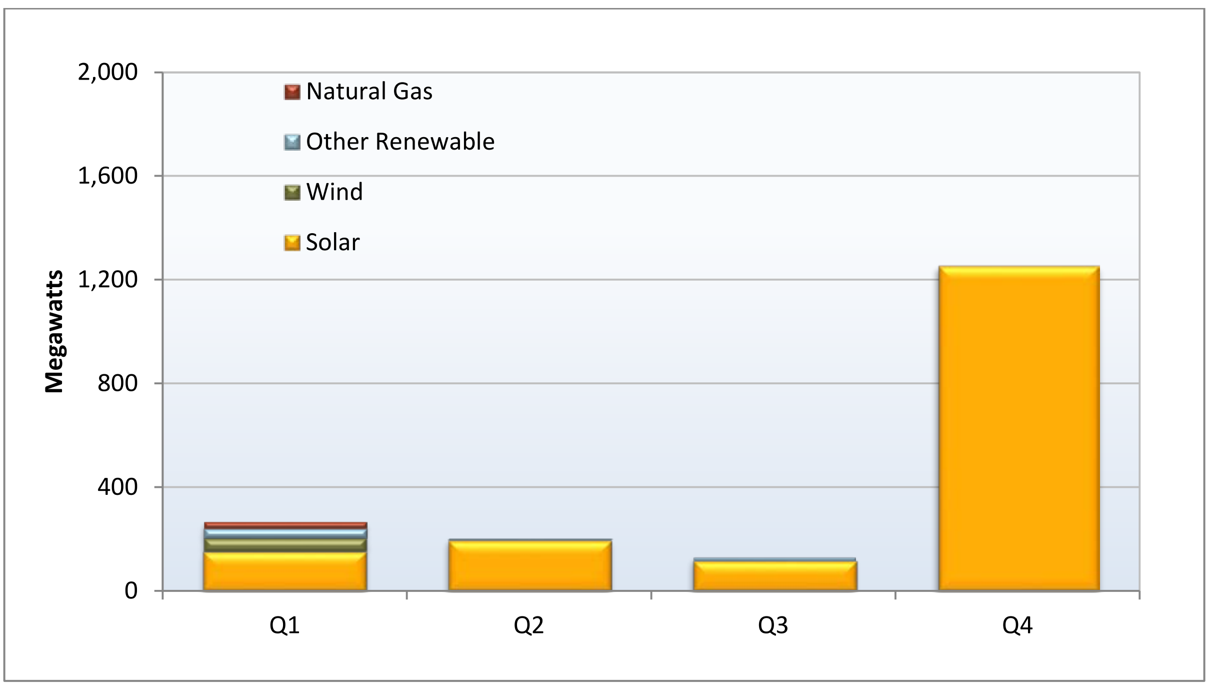


Table 1.5 New generation facilities in 2014

Generating unit	Unit type	Resource capacity (MW)	Summer capacity (MW)	Commercial operation date	Area
Vasco Road Landfill Generating Station*	Biogas	4	3	5-Feb-14	PG&E
Bear Creek Solar*	Solar	2	1	5-Feb-14	PG&E
Forward*	Biogas	4	3	5-Feb-14	PG&E
Stockton Biomass*	Biomass	48	29	12-Feb-14	PG&E
Westlands Solar Farm PV 1*	Solar	18	12	18-Feb-14	PG&E
Fall River Mills Project A*	Solar	2	1	5-Mar-14	PG&E
Fall River Mills Project B*	Solar	2	1	5-Mar-14	PG&E
Vintner Solar*	Solar	2	1	6-Mar-14	PG&E
Bidart Old River 1*	Biogas	2	1	10-Mar-14	PG&E
Central Valley Ag Power Oakdale*	Biogas	1	1	11-Mar-14	PG&E
Kettleman Solar*	Solar	1	1	14-Mar-14	PG&E
Amedee Geothermal Venture 1*	Geothermal	2	1	1-Apr-14	PG&E
Ameresco San Joaquin*	Biogas	4	3	24-Apr-14	PG&E
Adobe Solar*	Solar	20	14	21-May-14	PG&E
Windland Refresh 1*	Wind	7	2	3-Jun-14	PG&E
San Benito Smart Park*	Solar	2	1	16-Jun-14	PG&E
Terzian*	Solar	1	1	17-Jun-14	PG&E
Orion Solar 1*	Solar	12	8	26-Jun-14	PG&E
Orion Solar 2*	Solar	8	5	26-Jun-14	PG&E
Cloverdale Solar 1*	Solar	2	1	26-Jun-14	PG&E
Sunshine Gas Producers*	Biogas	20	12	1-Sep-14	PG&E
White River West*	Solar	20	14	1-Oct-14	PG&E
Topaz Solar Farms (Phase II)*	Solar	313	214	27-Oct-14	PG&E
Regulus Solar*	Solar	60	41	11-Nov-14	PG&E
Harris*	Solar	1	1	27-Nov-14	PG&E
Adams East*	Solar	19	13	13-Dec-14	PG&E
Kansas*	Solar	20	14	18-Dec-14	PG&E
Putah Creek Solar Farm*	Solar	2	1	19-Dec-14	PG&E
Kent South*	Solar	20	14	24-Dec-14	PG&E
Old River One*	Solar	20	14	30-Dec-14	PG&E
PG&E Actual New Generation in 2014		**637**	**426**		

Table continues on next page.

Generating unit	Unit type	Resource capacity (MW)	Summer capacity (MW)	Commercial operation date	Area
Zephyr Park*	Wind	4	1	7-Feb-14	SCE
Silver Ridge Mount Signal*	Solar	200	137	4-Mar-14	SDG&E
CP Kelco Cogeneration Facility	Gas Unit	25	25	5-Mar-14	SDG&E
Otay 5*	Biogas	2	1	14-Mar-14	SDG&E
Otay 6*	Biogas	2	1	14-Mar-14	SDG&E
Alta Wind 10*	Wind	138	30	17-Mar-14	SCE
Alta Wind 11*	Wind	90	20	17-Mar-14	SCE
Expressway Solar A*	Solar	2	1	7-May-14	SCE
Expressway Solar B*	Solar	2	1	7-May-14	SCE
Antelope Valley Solar Ranch 1*	Solar	242	165	19-Jun-14	SCE
Centinela Solar Energy 1*	Solar	127	87	30-Jul-14	SDG&E
Hesperia*	Solar	2	1	8-Aug-14	SCE
Centinela Solar Energy 2*	Solar	46	31	15-Aug-14	SDG&E
Solar Star 1 (Phase I)*	Solar	177	121	22-Oct-14	SCE
Western Antelope Blue Sky Ranch A*	Solar	20	14	7-Nov-14	SCE
Antelope West Solar*	Solar	20	14	13-Nov-14	SCE
Dry Farm Ranch B*	Solar	5	3	14-Nov-14	SCE
Lone Valley Solar Park 1*	Solar	10	7	19-Nov-14	SCE
Lone Valley Solar Park 2*	Solar	20	14	20-Nov-14	SCE
Desert Green Solar Farm*	Solar	7	4	26-Nov-14	SDG&E
Mojave Solar*	Solar	250	171	4-Dec-14	SCE
Desert Sunlight 300*	Solar	300	205	5-Dec-14	SCE
Desert Sunlight 250*	Solar	250	171	5-Dec-14	SCE
Columbia Two*	Solar	15	10	10-Dec-14	SCE
Camelot*	Solar	45	31	11-Dec-14	SCE
Solar Star 2 (Phase I)*	Solar	236	161	18-Dec-14	SCE
Garnet Solar Power Generation Station 1*	Solar	4	3	23-Dec-14	SCE
SCE and SDG&E Actual New Generation in 2014		**2,237**	**1,431**		
Total Actual New Generation in 2014		**2,874**	**1,858**		
Total Renewable Generation in 2014*		**2,849**	**1,833**		

Source: California ISO Interconnection Resources Department

1.3 Net market revenues of new gas-fired generation

Every wholesale electric market must have an adequate market and regulatory framework for facilitating investment in needed levels of new capacity. 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 would contribute to the annualized fixed cost of typical new gas-fired generating resources. This represents an important market metric tracked by all ISOs.[41] Costs used in the analysis are based on a study by the California Energy Commission (CEC).

Hypothetical combined cycle unit

Key assumptions used in this analysis for a typical new combined cycle unit are shown in Table 1.6. Results for a typical new combined cycle unit are shown in Table 1.7 and Figure 1.18. The 2014 net revenue results show an increase in net revenues compared to 2013. However, while there was an increase in net revenues from 2013 levels, the 2014 net revenue estimates for a hypothetical combined cycle unit in NP15 and SP15 both fall substantially below the $176/kW-year estimate of annualized fixed costs based on the CEC data.

Table 1.6 Assumptions for typical new combined cycle unit[42]

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	$96.7 /kW-yr
Insurance	$7.3 /kW-yr
Ad Valorem	$9.6 /kW-yr
Fixed Annual O&M	$43.7 /kW-yr
Taxes	$18.5 /kW-yr
Total Fixed Cost Revenue Requirement	**$175.8/kW-yr**

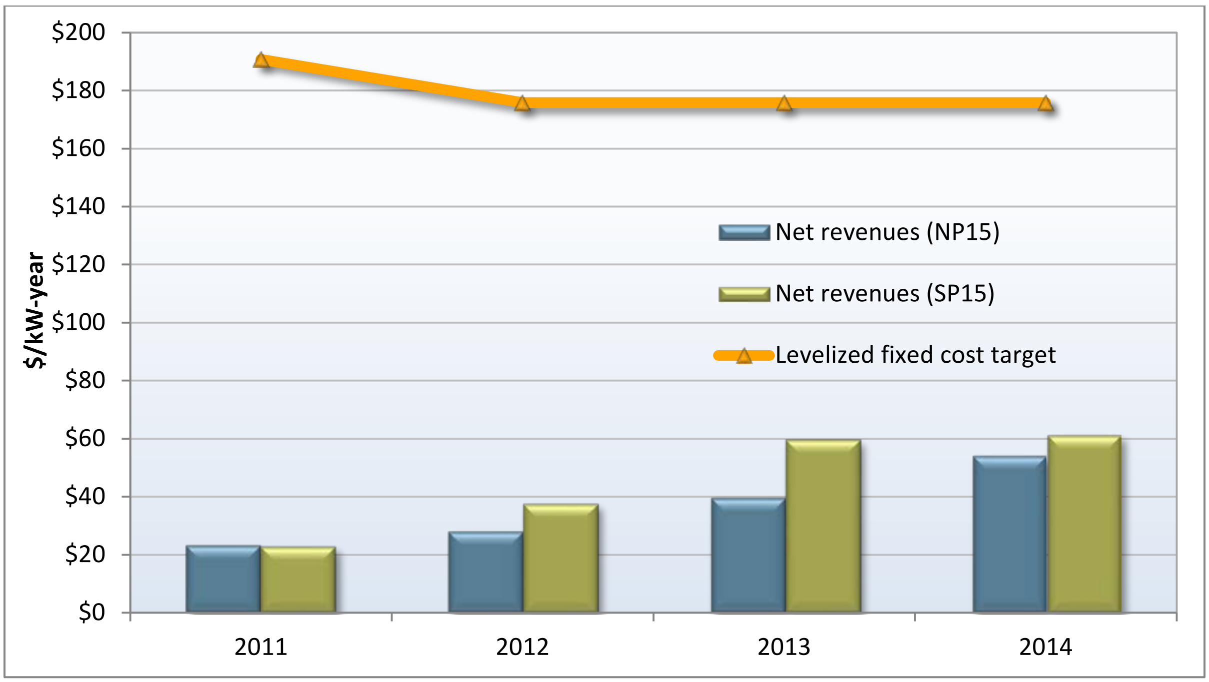
41 A more detailed description of the methodology and results of the analysis presented in this section are provided in Appendix A.1 of DMM's *2009 Annual Report on Market Issues & Performance,* April 2010, which can be found at http://www.caiso.com/2777/27778a322d0f0.pdf.

42 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 March 2013 CEC Workshop on the Cost of New Renewable and Fossil-Fueled Generation in California: http://www.energy.ca.gov/2013_energypolicy/documents/index.html#03072013. The cost of actual new generators varies significantly due to factors such as ownership, location and environmental constraints. More detailed information can be found in the CEC documents.

Table 1.7 Financial analysis of new combined cycle unit (2011-2014)

Components	2011		2012		2013		2014	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	53%	66%	70%	75%	84%	83%	83%	84%
DA Energy Revenue ($/kW - yr)	$101.62	$94.27	$118.95	$134.59	$286.19	$315.53	$325.36	$326.07
RT Energy Revenue ($/kW - yr)	$28.62	$30.84	$11.70	$11.62	$10.17	$10.14	$23.62	$22.08
A/S Revenue ($/kW – yr)	$1.71	$2.29	$0.37	$0.39	$0.03	$0.06	$0.08	$0.09
Operating Cost ($/kW - yr)	$108.65	$104.41	$103.01	$108.96	$256.78	$266.00	$295.03	$287.00
Net Revenue ($/kW – yr)	$23.30	$22.99	$28.02	$37.64	$39.62	$59.73	$54.02	$61.23
5-yr Average ($/kW – yr)	*$36.24*	*$45.40*						

Figure 1.18 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 1.8. Table 1.9 and Figure 1.19 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 decrease in the SP15 area and an increase in the NP15 areas in 2014 compared to prior years.

This change is likely a result of differences in congestion patterns in 2014 compared to 2013. In particular, there was less separation between Northern and Southern California prices. Much of the congestion in 2013 in the SP15 area was due to limits on the percentage of load in the SCE area that can be met by total flows on all transmission paths into the SCE area (i.e., SCE_PCT_IMP_BG). This constraint was removed in October 2013. As a result, there was less separation of SP15 prices in 2014, decreasing the differences in net revenues between the two areas.

Estimated net revenues for a hypothetical combustion turbine also fell well short of the $190/kW-year estimate of annualized fixed costs in the CEC study.

Table 1.8 Assumptions for typical new combustion turbine[43]

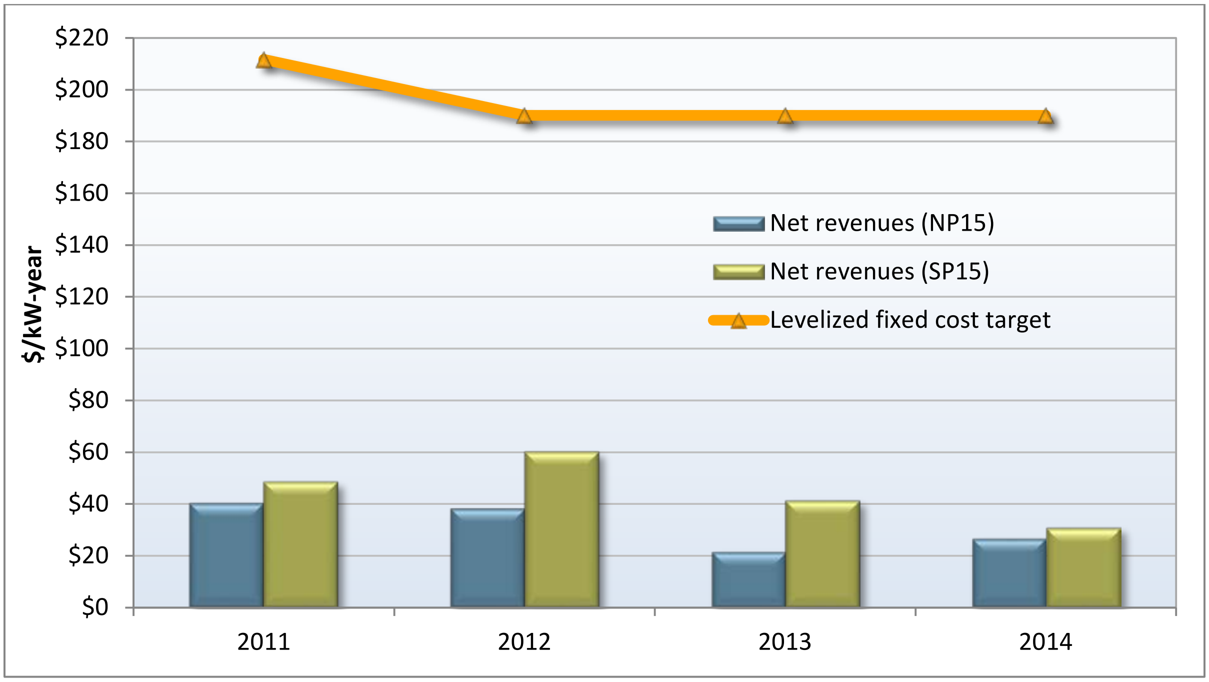
Technical Parameters	
Maximum Capacity	100 MW
Minimum Operating Level	40 MW
Startup Gas Consumption	180 MMBtu/start
Heat Rates (MBTU/MW)	
Maximum Capacity	9,300
Minimum Operating Level	9,700
Financial Parameters	
Financing Costs	$116.2 /kW-yr
Insurance	$8.8 /kW-yr
Ad Valorem	$11.6 /kW-yr
Fixed Annual O&M	$34.7 /kW-yr
Taxes	$18.8 /kW-yr
Total Fixed Cost Revenue Requirement	**$190.1/kW-yr**

Table 1.9 Financial analysis of new combustion turbine (2011-2014)

Components	**2011**		**2012**		**2013**		**2014**	
	NP15	**SP15**	**NP15**	**SP15**	**NP15**	**SP15**	**NP15**	**SP15**
Capacity Factor	6%	7%	5%	8%	8%	9%	10%	10%
Energy Revenue ($/kW - yr)	$57.60	$69.57	$48.78	$78.89	$58.48	$82.95	$85.48	$87.31
A/S Revenue ($/kW - yr)	$6.06	$5.98	$4.29	$5.04	$1.14	$1.34	$0.71	$0.86
Operating Cost ($/kW - yr)	$23.23	$26.88	$14.82	$23.62	$38.03	$42.85	$59.46	$57.26
Net Revenue ($/kW - yr)	$40.43	$48.67	$38.26	$60.32	$21.59	$41.45	$26.73	$30.91
5-yr Average ($/kW - yr)	*$31.75*	*$45.34*						

[43] 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 March 2013 CEC Workshop on the Cost of New Renewable and Fossil-Fueled Generation in California: http://www.energy.ca.gov/2013_energypolicy/documents/index.html#03072013. The cost of actual new generators varies significantly due to factors such as ownership, location and environmental constraints. More detailed information can be found in the CEC documents.

Figure 1.19 Estimated net revenues of new combustion turbine



Conclusion

Overall, the findings in this section 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.

A more detailed discussion of issues relating to capacity procurement, investment in new and existing generating capacity, and longer-term resource adequacy is provided in Chapter 9 of this report.

2 Overview of market performance

The ISO markets continued to perform efficiently and competitively overall in 2014.

- Total wholesale electric costs increased by 13 percent, driven primarily by a 17 percent increase in natural gas prices in 2014 compared to 2013. After controlling for the higher natural gas costs and changes in greenhouse gas prices, wholesale electric costs increased by about 3 percent.
- Overall prices in the ISO energy markets over the course of 2014 were highly competitive, averaging close to what DMM estimates would result under highly competitive conditions.
- Real-time prices tended to be lower than average day-ahead prices during most periods, continuing a trend that began in 2013. However, real-time prices began tracking more closely with day-ahead prices in the second half of the year following implementation of the new 15-minute market in May. Most real-time energy and all virtual bids are settled at 15-minute prices, with the remainder of real-time energy settled at 5-minute market prices.
- In the second half of 2014, average 15-minute prices during peak hours were only about $0.70/MWh lower than day-ahead prices. During off-peak hours, average 15-minute prices were about $1.70/MWh lower than day-ahead prices, driven in part by excess energy from renewables and thermal units being kept online at minimum operating levels during the late morning and early afternoon hours.
- Since implementation of FERC Order No. 764, there was an increase in self-scheduling on the inter-ties in both the day-ahead and, in particular, the real-time markets. Real-time liquidity on the inter-ties has been limited in both the hour-ahead and especially in the 15-minute markets.

Other aspects of the ISO markets performed well and helped keep overall wholesale costs low.

- Ancillary service costs totaled $69 million, or about 21 percent more than in 2013. The increase is related to a decrease in ancillary services from hydro-electric generators compared to 2013 and an increase in natural gas prices.
- Bid cost recovery payments totaled $95 million, or less than 1 percent of total energy costs in 2014, compared to about $108 million of total energy costs in 2013. Payments for units scheduled by the residual unit commitment process accounted for $5 million of these costs, compared to $23 million in 2013. This decrease was driven in large part by changes implemented in early 2014 to better account for forecasted renewables in the residual unit commitment as opposed to bid-in renewables.
- Exceptional dispatches, or *out-of-market* unit commitments and energy dispatches issued by ISO grid operators to meet constraints not incorporated in the market software, decreased from 2013 and remained relatively low. Total energy from all exceptional dispatches totaled about 0.16 percent of total system energy in 2014 compared to 0.26 percent in 2013. The above-market costs resulting from these exceptional dispatches decreased 40 percent from $18 million in 2013 to $11 million in 2014.
- Congestion within the ISO system decreased in 2014 compared to prior years and had a lower impact on average overall prices across the system. The reduction in real-time congestion can be

attributed partly to improved ISO procedures that better align day-ahead line limits with real-time limits. This allows for better commitment of resources to resolve anticipated congestion in real time.

- Real-time market revenue imbalance charges allocated to load-serving entities increased slightly from $183 million in 2013 to $188 million in 2014. While charges associated with congestion fell from $126 million in 2013 to $106 million in 2014, charges related to real-time energy imbalance costs increased from $57 million in 2013 to $81 million in 2014. This charge includes several components that are offset by settlement values elsewhere in the market and, thus, are not true uplift costs, which partly contributed to the increase in real-time energy imbalance offset costs in 2014.

2.1 Total wholesale market costs

The total estimated wholesale cost of serving load in 2014 was $12.1 billion or just over $52/MWh. This represents an increase of about 13 percent from a cost of over $46/MWh in 2013. The increase in electricity prices was mostly due to a 17 percent increase in wholesale natural gas prices.[44] After normalizing for higher gas prices and greenhouse gas compliance costs, DMM estimates that total wholesale energy costs were stable, increasing slightly from $43.50/MWh in 2013 to just under $45/MWh in 2014, an increase of about 3 percent.[45]

The stability of total gas-normalized costs is remarkable given the extent of market changes this year. A variety of factors had the effect of raising prices. As highlighted elsewhere in this report, conditions that contributed to higher prices include the following:

- Historically low in-state hydro-electric generation; and
- Continued reduction in imports that began in mid-2013 and continued through 2014.

Other factors had the effect of lowering prices. These factors are discussed in the following sections and chapters of this report and include the following:

- Additions of new generation capacity, particularly solar;
- Decreased regional congestion; and
- Increased net virtual supply, which lowered average day-ahead prices and brought them closer to average real-time prices.

Figure 2.1 shows total estimated wholesale costs per MWh of system load from 2010 to 2014. Wholesale costs are provided in nominal terms (blue bar), as well as after normalization for changes in average spot market prices for natural gas and greenhouse gas compliance costs (gold bar). The greenhouse gas compliance cost is added to natural gas prices in 2013 and 2014 to account for the

[44] 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, when gas prices are often highest.

[45] Greenhouse gas compliance costs are calculated by multiplying a load weighted annual average greenhouse gas allowance price by an emission factor that is a measure of the greenhouse gas content of natural gas. Derivation of the emission factor used here, 0.531148, is discussed in further detail in Section 1.2.4. Gas prices are normalized to 2010 prices. In previous reports, DMM normalized to 2009 prices.

estimated cost of compliance with California's greenhouse gas cap-and-trade program. The green line, representing the annual average of daily natural gas prices including greenhouse gas compliance, is included to illustrate the correlation between the cost of natural gas and the total wholesale cost estimate. The dashed green line excludes greenhouse gas compliance costs and is included for reference in 2013 and 2014.

Figure 2.1 Total annual wholesale costs per MWh of load (2010-2014)

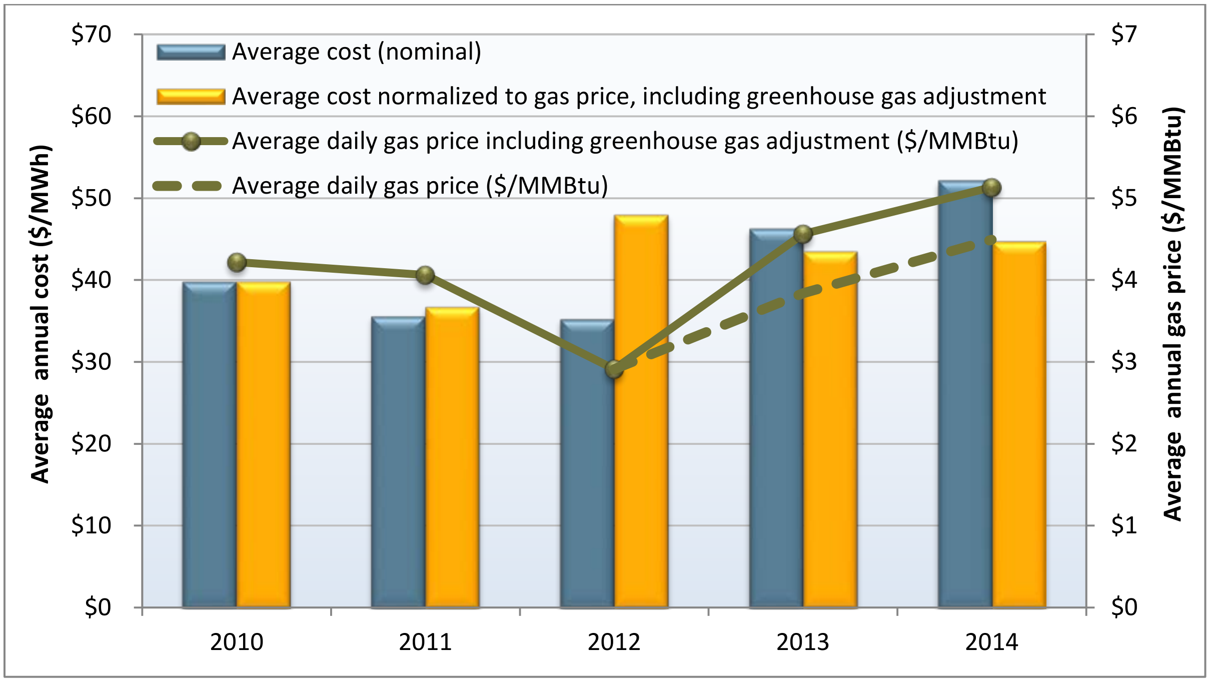


Table 2.1 provides annual summaries of nominal total wholesale costs by category from 2010 through 2014. Starting in May 2014, total wholesale market costs are estimated based on prices and quantities cleared in each of the three energy markets: day-ahead, 15-minute and 5-minute real-time markets, which reflects the new market design implemented at that time. Prior to May 2014, costs were estimated based on prices and quantities cleared in the day-ahead, hour-ahead and 5-minute markets. This estimate also includes costs associated with ancillary services, convergence bidding, residual unit commitment, bid cost recovery, reliability must-run contracts, the capacity procurement mechanism, the flexible ramping constraint and grid management charges.[46]

As seen in Table 2.1, the increase in cost in 2014 was primarily due to the increase of day-ahead energy costs, which represents by far the largest component of wholesale energy costs. Real-time energy costs also increased while both reliability and reserve costs remained stable, relative to 2013. Ancillary

[46] A description of the basic 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. This methodology was modified to include costs associated with the flexible ramping constraint and convergence bidding. Flexible ramping costs are added to the real-time energy costs. This calculation was also updated to reflect the substantial market changes implemented on May 1, 2014. Following this period, both 15-minute and 5-minute real-time prices are used to calculate real-time energy costs.

service costs increased slightly, but remained constant as a percent of total wholesale energy costs (0.58 percent in 2014 compared to 0.56 percent in 2013). Reliability costs remained low as reliability needs associated with the outage and retirement of the SONGS units were addressed through mechanisms other than the capacity procurement mechanism, including synchronous condensers.

Table 2.1 Estimated average wholesale energy costs per MWh (2010-2014)

	2010	2011	2012	2013	2014	Change '14-'13
Day-ahead energy costs (excl. GMC)	$ 37.37	$ 32.88	$ 32.57	$ 44.14	$ 48.57	$ 4.43
Real-time energy costs (incl. flex ramp)	$ 0.73	$ 0.80	$ 0.99	$ 0.57	$ 1.98	$ 1.41
Grid management charge	$ 0.79	$ 0.79	$ 0.80	$ 0.80	$ 0.80	$ (0.00)
Bid cost recovery costs	$ 0.37	$ 0.56	$ 0.45	$ 0.47	$ 0.41	$ (0.06)
Reliability costs (RMR and CPM)	$ 0.27	$ 0.03	$ 0.14	$ 0.10	$ 0.14	$ 0.04
Average total energy costs	**$ 39.53**	**$ 35.06**	**$ 34.96**	**$ 46.08**	**$ 51.90**	**$ 5.82**
Reserve costs (AS and RUC)	$ 0.38	$ 0.62	$ 0.37	$ 0.26	$ 0.30	$ 0.04
Average total costs of energy and reserve	**$ 39.91**	**$ 35.68**	**$ 35.33**	**$ 46.34**	**$ 52.20**	**$ 5.86**

2.2 Overall market competitiveness

To assess the competitiveness of the ISO energy markets, DMM compares actual market prices to competitive benchmark prices we estimate would result under highly competitive conditions. DMM estimates competitive baseline prices by re-simulating the market using the day-ahead market software with bids reflecting the actual marginal cost of gas-fired units, no convergence bids, and actual load.[47]

Figure 2.2 compares this competitive baseline price to load weighted prices in the day-ahead, 15-minute and 5-minute real-time markets. When comparing these prices, it is important to note that baseline prices are calculated using the day-ahead market software under highly competitive conditions, which do not reflect all of the system conditions and limitations that impact real-time prices.

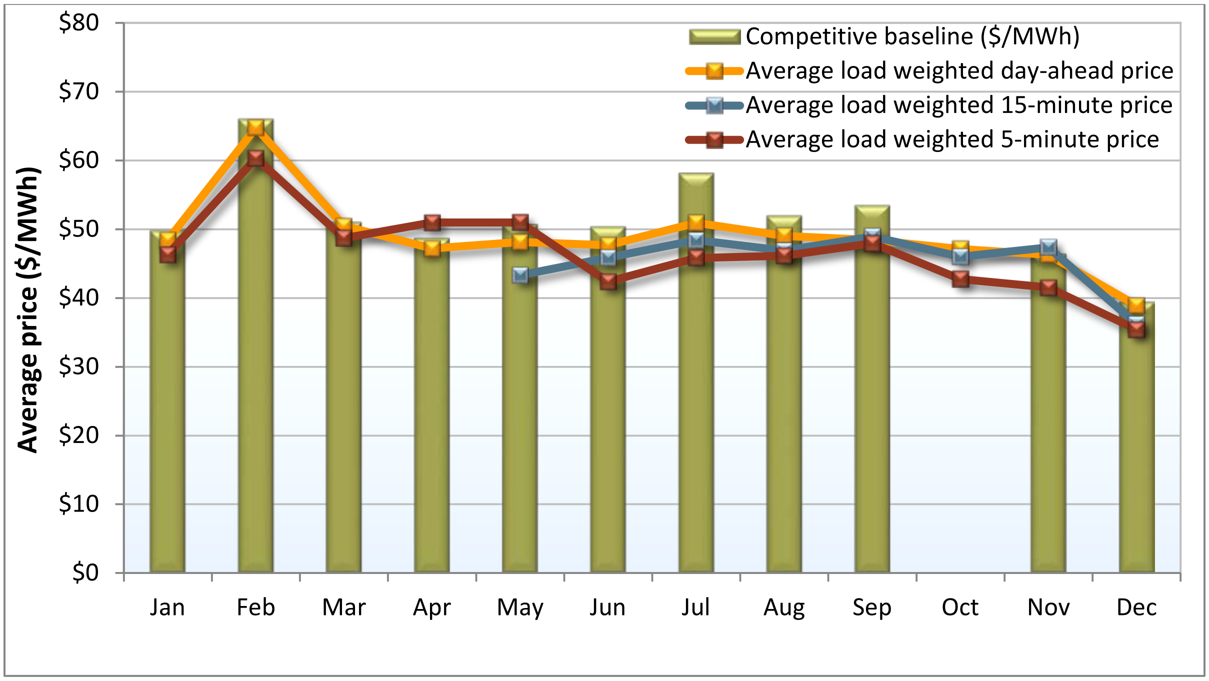
As shown in Figure 2.2, prices in the day-ahead market were similar to competitive baseline prices in most months in 2014. Day-ahead prices were slightly lower than the competitive benchmark in all months, and were about $7/MWh lower in July.

In the 5-minute real-time market, average prices were lower than the competitive baseline in 2014 in most months except for April and May. Average prices for the 15-minute market were lower in all

[47] The competitive baseline is a scenario setting the bids for gas-fired generation equal to default energy bids (DEBs), removing convergence bids and setting system demand to actual system load. This scenario represents the combination of perfect load forecast along with physical and competitive bidding of price-setting resources, and is calculated using DMM's version of the actual market software. Beginning in November 2013, default energy bids now include a grid management charge component, which can create a slightly higher competitive baseline as compared with previous periods. For October, DMM was unable to calculate the competitive baseline because of implementation issues with transitioning the systems to the fall market software version.

months except for November. A major factor contributing to these lower real-time prices was the amount of real-time energy that was not scheduled in the day-ahead market.[48]

Figure 2.2 Comparison of competitive baseline price with day-ahead and real-time prices



DMM also calculates an overall *price-cost mark-up* by comparing competitive baseline energy prices to total average wholesale energy prices.[49] Total wholesale energy prices used in this analysis represent a load-weighted average price of all energy transactions in the day-ahead, hour-ahead and real-time markets.[50] Thus, this analysis combines energy procured at higher day-ahead prices, as well as net energy sales in the hour-ahead, 15-minute and 5 minute real-time market at lower prices.

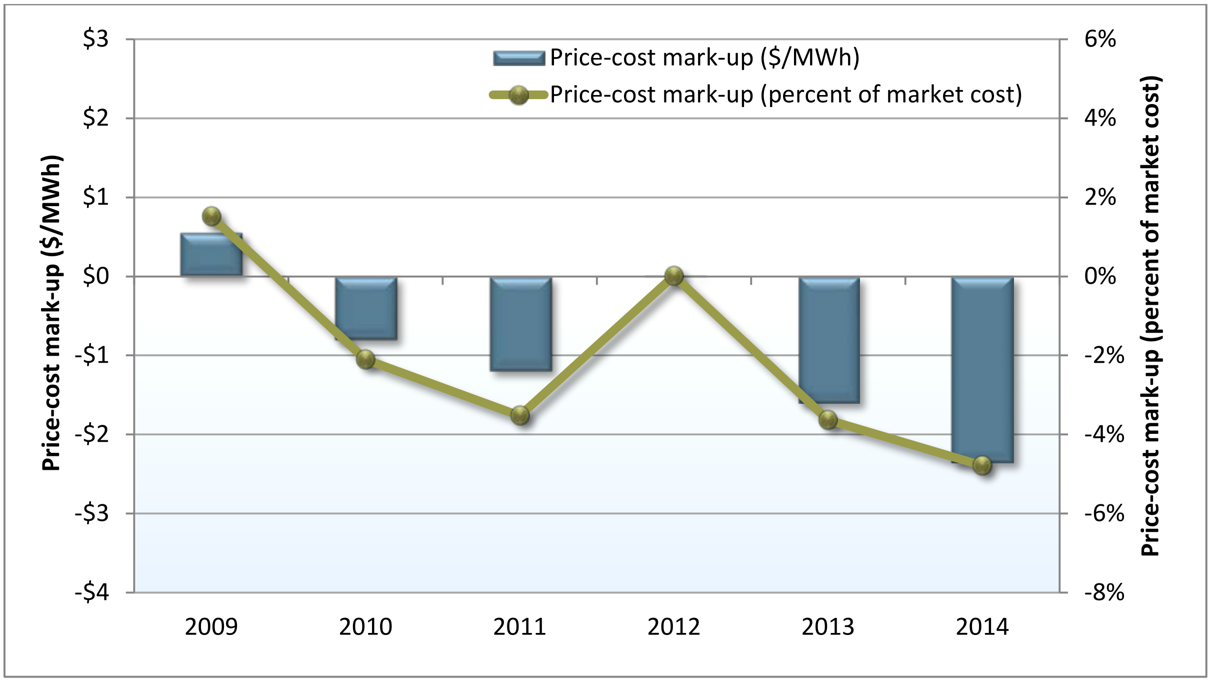
As shown in Figure 2.3, the overall combined average of day-ahead and real-time prices was about $2.35/MWh or about 4.8 percent lower than the competitive baseline price. The price-cost mark-up and other analyses in this report indicate that prices have been extremely competitive, overall, since implementation of the nodal market.

48 This unscheduled energy was the combined result of a variety of factors, rather than being driven by any single source. Various sources of additional real-time energy included minimum load energy from units committed after the day-ahead market through the residual unit commitment process and exceptional dispatches, additional must-take energy from thermal generating resources, and unscheduled energy from variable renewable energy.

49 DMM calculates the price-cost mark-up 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 and the competitive baseline price was $50/MWh, this would represent a price-cost mark-up of 10 percent.

50 The wholesale costs of energy are pro-rated calculations of the day-ahead, hour-ahead and real-time prices weighted by the corresponding forecasted load. Beginning in May 2014, the calculation pro-rates day-ahead, 15-minute and 5-minute prices weighted by the corresponding forecasted load. The month of October 2014 has been excluded from this calculation because of implementation issues with transitioning the systems to the fall market software version.

Figure 2.3 Price-cost mark-up (2009-2014)



As shown in Figure 2.3, this represents a slight drop in the price-cost mark-up in 2014 compared to 2013 and is consistent with the slightly negative price-cost mark-ups observed in the last several years. Slightly negative price-cost mark-ups can reflect the fact that some suppliers bid somewhat lower than their default energy bids – which include a 10 percent adder above estimated marginal costs.

The methodology for calculating total energy costs was modified in 2014 to account for changes in data availability and to better account for real-time energy. While DMM believes these changes provide a more accurate method of estimating total wholesale costs, the effect of these changes, under current market price trends, was to contribute to the drop in the 2014 mark-up by increasing total estimates of wholesale costs relative to prior years.

Going forward, DMM will also seek to enhance the way the competitive baseline cost is calculated using the day-ahead market software by incorporating actual or forecasted renewables rather than only renewables scheduled or bid into the day-ahead market. DMM believes that using only scheduled or bid in renewables may make the competitive baseline price higher, contributing to a lower price-cost mark-up. It does this by underestimating the actual supply of renewable generation, which increases the degree to which the competitive baseline calculation is higher than actual market costs.

2.3 Energy market prices

This section reviews energy market prices by focusing on a few key elements: price levels and convergence, and real-time price volatility. Key points highlighted in this section include the following:

- Average energy market prices were higher in 2014 than 2013.

- Real-time market prices in both the 15-minute and 5-minute markets tended to be lower than day-ahead market prices during most periods in 2014.
- Over the second half of 2014, price convergence improved significantly between the day-ahead market and the 15-minute market implemented in May. Most real-time energy is settled based on prices in this new 15-minute market.

Energy market prices were higher in 2014 than 2013, as seen in Figure 2.4 and Figure 2.5.

- This increase was attributed primarily to a more than 17 percent increase in gas prices in 2014, compared to 2013. In particular, gas prices spiked in early February due to scarcity conditions (see Section 1.2.3 for further detail) driving up ISO prices in the first quarter.
- Another factor causing upward pressure on electricity prices was a decrease in hydro-electric generation in 2014. Overall, hydro production in 2014 was about 70 percent of production in 2013 and 60 percent of production in 2012.

Figure 2.4 and Figure 2.5 also show the following:

- Real-time prices tended to be lower than average day-ahead prices during most periods, continuing a trend that began in 2013. This can be partly attributed to additional generation in real time that is not included in the day-ahead market, primarily from renewable resources.
- Average prices for the new 15-minute market implemented in May, upon which most real-time energy is settled financially, were lower than the day-ahead market prices. Prices in the 15-minute market averaged about $1.60/MWh lower than day-ahead prices for the year and $1.10/MWh for the second half of the year after the initial implementation period in the spring.
- Prices in the new 15-minute market tracked even more closely with day-ahead prices during peak hours during the last half of 2014. Over the last six months of 2014, average 15-minute prices during peak hours were just $0.70 (or about 1.4 percent) less than day-ahead prices.
- Average quarterly 5-minute market off-peak prices in the second quarter were greater than the day-ahead market by about $3/MWh. Historically, the 5-minute market prices have been highly volatile, experiencing periods of both extreme positive and negative price spikes. High volatility occurred in April prior to the implementation of the new 15-minute market in May. Beginning in May, price variability in the 5-minute market had a lower impact as less settlement now occurs against the 5-minute real-time price.
- Beginning in the second quarter, hour-ahead market prices diverged much lower than day-ahead prices, and remained lower throughout the year. In 2013, hour-ahead market prices were higher than the real-time market prices. Lower hour-ahead price levels were most likely affected by increases in unscheduled wind and solar generation, as well as large volumes of self-scheduled inter-tie schedules after implementation of the 15-minute market in May. Under the new real-time market design implemented in 2014, hour-ahead prices are not used in financial settlement of any inter-tie or other resources, but are only used for inter-tie scheduling purposes.

Figure 2.4 Comparison of quarterly prices – system energy (peak hours)

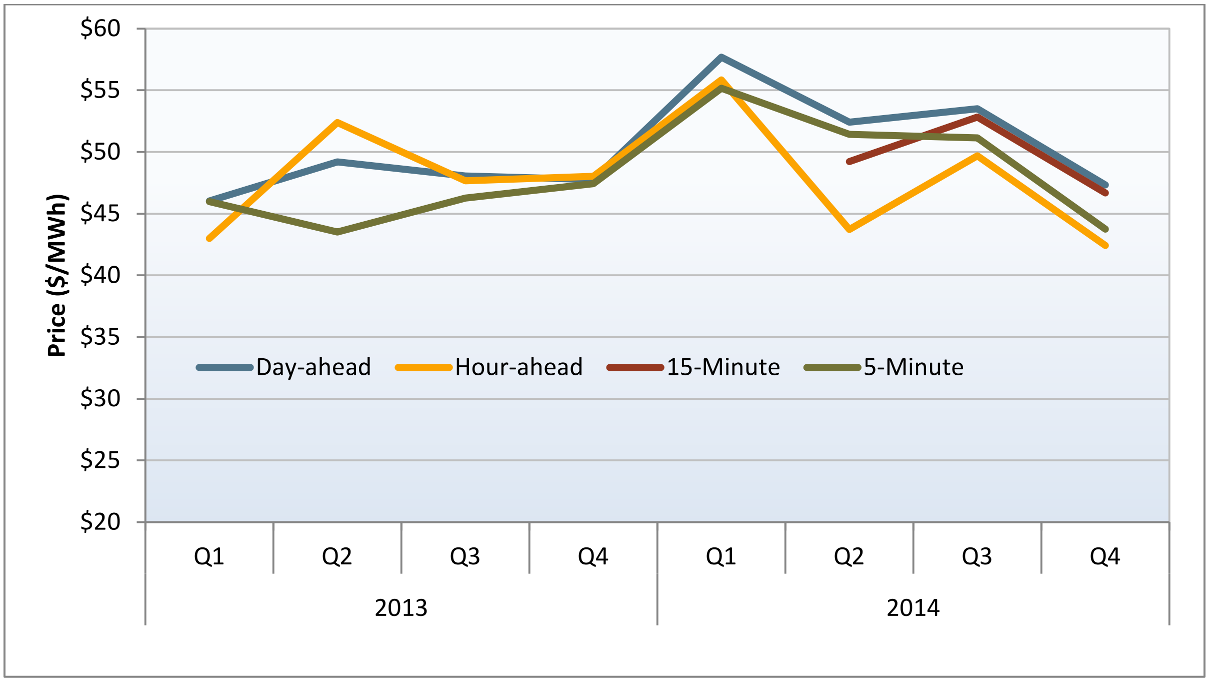
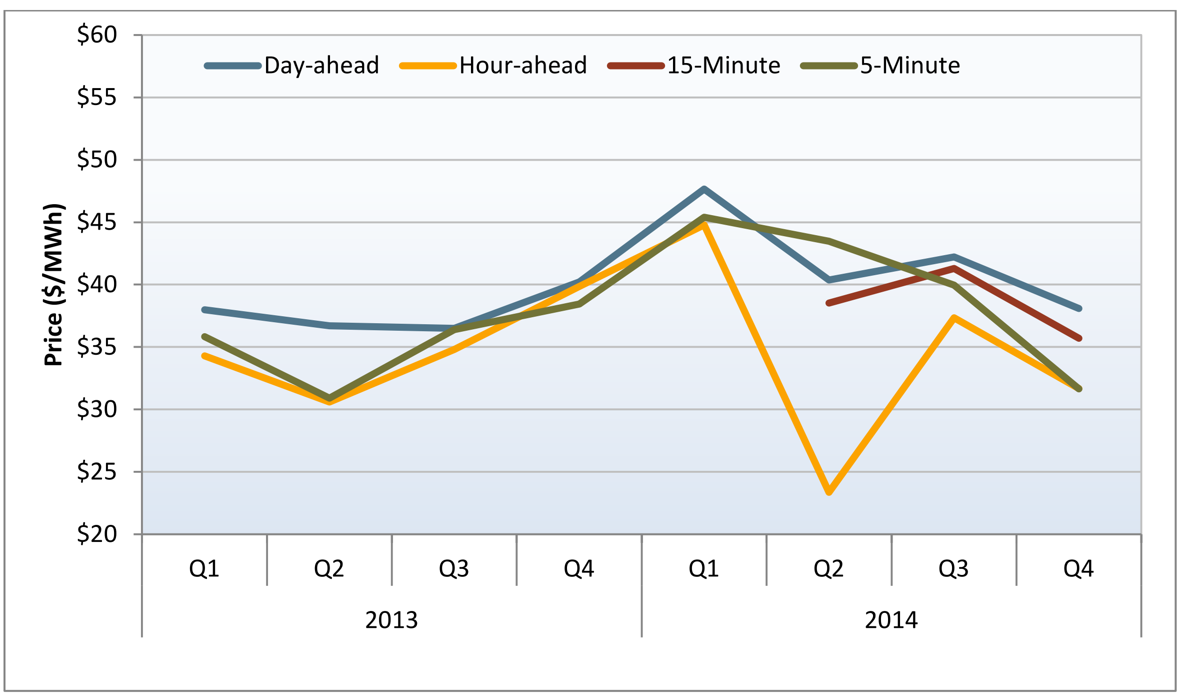


Figure 2.5 Comparison of quarterly prices – system energy (off-peak hours)



2.4 Residual unit commitment

The purpose of the residual unit commitment market is to ensure that there is sufficient capacity online or reserved to meet actual 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 physical supply cleared in the day-ahead market and the day-ahead forecast load. Capacity procured in the residual unit commitment must be bid into the real-time market.

The ISO in 2014 introduced an automatic adjustment to residual unit commitment schedules to account for differences between the day-ahead schedules of participating intermittent resource program (PIRP) resources and the forecast output of these renewable resources. This adjustment reduces residual unit commitment procurement targets by the estimated under-scheduling of renewable resources in the day-ahead market. In addition, ISO operators are able to increase the amount of residual unit commitment requirements for reliability purposes. This tool was used far less frequently in 2014 than in 2013.[51] In addition, when the market clears with net virtual supply, residual unit commitment capacity is needed to replace the net virtual supply with physical supply.

Total residual unit commitment volume decreased in the fourth quarter of 2013 and continued at moderate levels through 2014.[52] Figure 2.6 shows quarterly average hourly residual unit commitment procurement, categorized as either non-resource adequacy or resource adequacy and minimum load. Total residual unit commitment procurement fell from an average of 932 MW per hour in 2013 to 398 MW per hour in 2014.

While capacity procured in residual unit commitment must be bid into the real-time market, only a fraction of this capacity is committed to be online by the residual unit commitment process.[53] Most of the capacity procured in the residual unit commitment process is from units which are already scheduled to be online through the day-ahead market or from short-start units that do not need to be started up unless actually needed in real time.

Although the total average hourly volume of residual unit commitment capacity was over 200 MW in each quarter of 2014, the capacity committed to start up and operate at minimum load averaged just 21 MW each hour. Moreover, only a small fraction of this capacity was from long-start units which are committed to be online by the residual unit commitment process.[54]

Most of the capacity procured in the residual unit commitment market does not incur any direct costs from residual unit capacity payments because only non-resource adequacy units committed in the residual unit commitment receive capacity payments.[55] As shown by the very small green segment of each bar in Figure 2.6, the non-resource adequacy residual unit commitment was low in 2014, averaging

[51] See Section 8.6 for further discussion on operator adjustments in the residual unit commitment process.

[52] Values reported for 2014 exclude two days when market data was unavailable: October 15, 2014, and November 1, 2014.

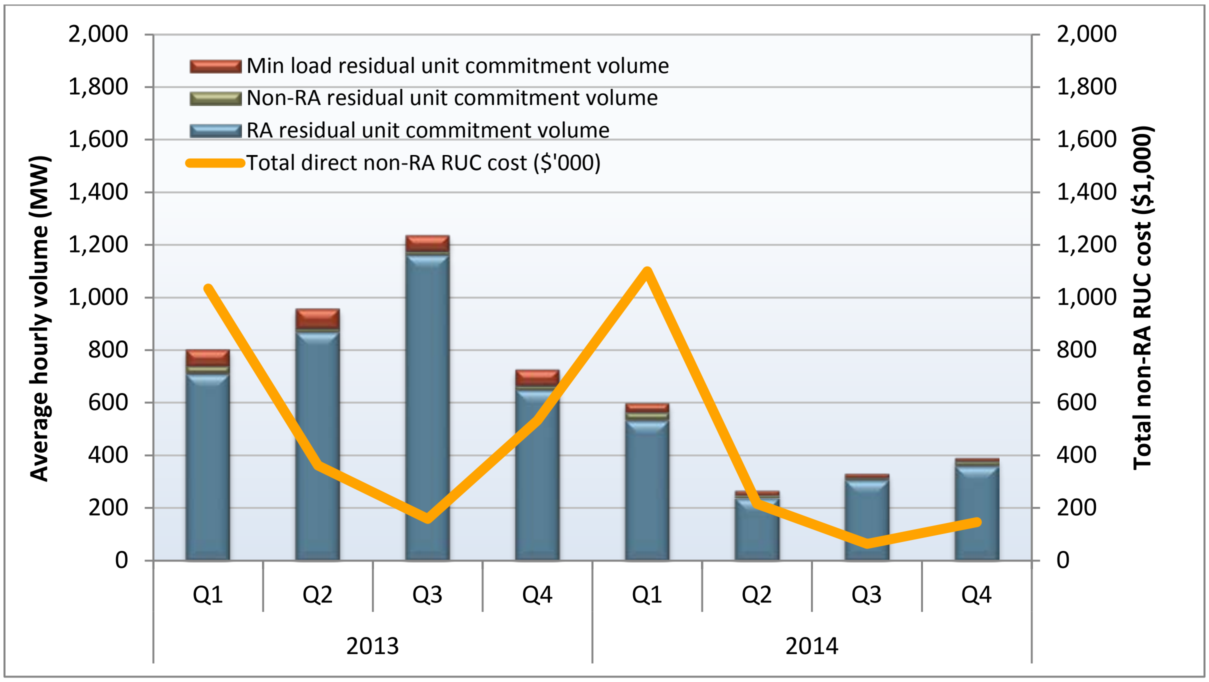
[53] Only the small portion of minimum load capacity from *long-start units*, units with start-up times greater than or equal to five hours, is committed to be online in real-time by the residual unit commitment process. In 2014, only 7 percent of minimum load residual unit commitment was provided by long-start resources.

[54] Long-start commitments are resources that require 300 or more minutes to start up. These resources receive binding commitment instructions from the residual unit commitment process. Short-start units receive an advisory commitment instruction in the residual unit commitment process, whereas the actual unit commitment decision for these units occurs in real time.

[55] Resource adequacy units receive bid cost recovery payments as well as payments through the resource adequacy process.

only 15 MW per hour. This was a slight decrease from 17 MW per hour in 2013. The total direct cost of residual unit commitment, represented by the gold line in Figure 2.6, was about $1.6 million in 2014, about 75 percent of the direct cost of $2.1 million in 2013.

Figure 2.6 Residual unit commitment costs and volume



Some of the capacity committed to meet residual unit commitment results in additional bid cost recovery payments, as discussed in Section 2.5. In 2013, units committed in this process accounted for around $23 million in bid cost recovery payments, or about 21 percent of total bid cost recovery payments. In 2014, these costs fell to $5 million, or just over 5 percent of total bid cost recovery payments. Units committed by the residual unit commitment can be either long- or short-start units. Long-start unit commitment accounted for $6.9 million or just over 80 percent of the residual unit commitment bid cost recovery payment before netting with other bid cost recovery payment components. Short-start units accounted for $1.6 million.

The decrease in residual unit commitment bid cost recovery payments is primarily due to decreased commitment driven by reduced operator adjustments and the automatic adjustments to renewable schedules in the residual unit commitment requirements. The next section explains bid cost recovery in further detail.

2.5 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. This calculation includes bids for start-up, minimum load, ancillary services, residual unit commitment availability and day-ahead and real-time energy. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch.

Bid cost recovery rules were modified in May 2014. Before the changes, bid cost recovery payments were calculated by netting all daily bid costs and revenues from the day-ahead, residual unit commitment and real-time markets. For instance, if a unit was committed in the day-ahead market and required bid cost recovery payments, these payments would be adjusted by any positive net revenues received in the real-time market.

Beginning in May 2014, the ISO no longer nets the costs and revenues between the day-ahead and real-time markets.[56] Instead, the ISO calculates the costs and revenues for day-ahead and real-time markets separately for each day. These changes were made to reduce incentives to self-schedule and increase incentives for suppliers to submit bids in the real-time market that reflected their actual marginal operating costs. DMM has not observed any increase in bid cost recovery payments as a result of this change.

Figure 2.7 provides a summary of total estimated bid cost recovery payments in 2014 by quarter and by market. Bid cost recovery payments totaled around $95 million or less than 1 percent of total energy costs. This compares to a total of $108 million or about 1 percent of total energy costs in 2013, a decrease of about 12 percent from 2013 to 2014. The decline in bid cost recovery payments resulted from a decrease in bid cost recovery associated with residual unit commitment, declining from $23 million in 2013 to $5 million in 2014.

Bid cost recovery payments for units committed in the day-ahead energy market totaled $34 million in 2014. DMM estimates that units committed due to minimum online constraints incorporated in the day-ahead energy market accounted for about $16 million or around 17 percent of total bid cost recovery payments in 2014. These constraints are used to meet special reliability issues that require having units online to meet voltage requirements and in the event of a contingency.[57]

Bid cost recovery payments associated with real-time market dispatches accounted for $56 million in 2014. Bid cost recovery payments resulting from units committed though exceptional dispatches also played an important role in real-time bid cost recovery payments. DMM estimates that approximately $10 million of the real-time bid cost recovery payments in 2014 was for units committed through exceptional dispatches.

Bid cost recovery payments associated with units committed through the residual unit commitment process totaled about $5 million in 2014, a significant decrease from $23 million in 2013. This decrease can be partially attributed to decreases in the residual unit commitment procurement levels driven by reliability related adjustments made by ISO operators.[58] This decrease can also be attributed to introduction of a new automatic adjustment tool that accounts for differences between the day-ahead schedules of participating intermittent resource program resources and the forecast output of these

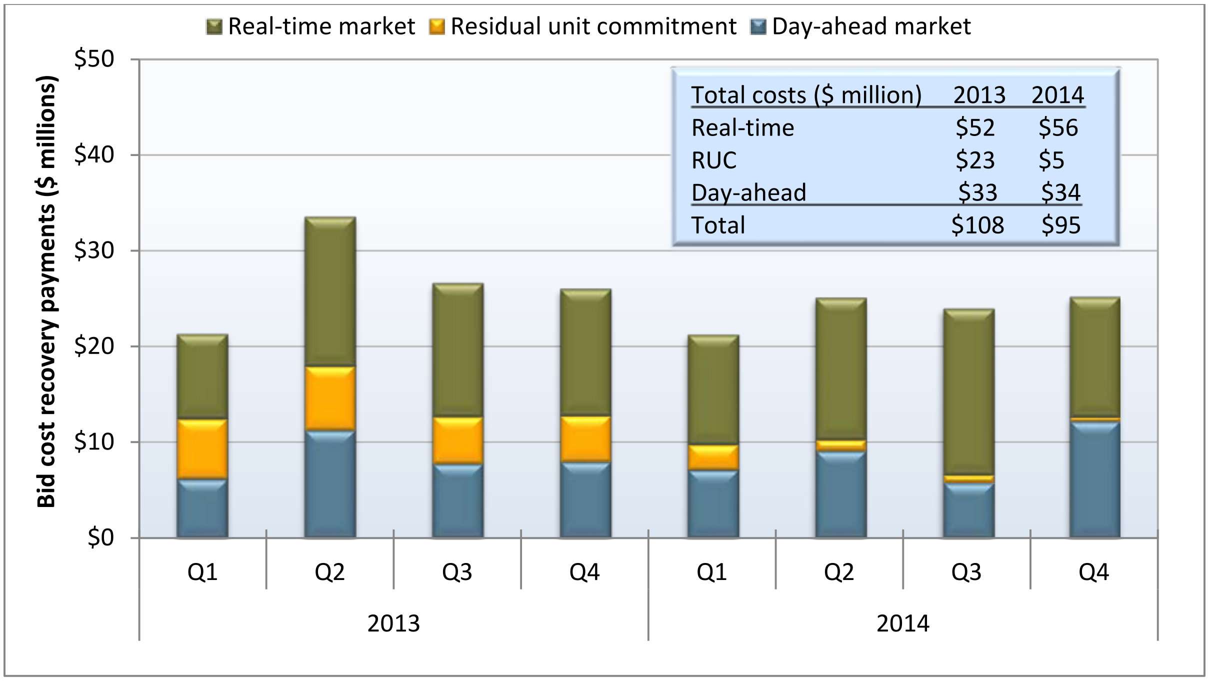
[56] The residual unit commitment and real-time markets are netted together.

[57] Minimum online 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. These constraints make sure that the system has enough longer-start capacity online to meet locational voltage requirements and respond to contingencies that cannot be directly modeled.

[58] ISO operators can make adjustments to the system or regional residual unit commitment requirements to mitigate potential contingencies. These changes are concentrated primarily in the peak hours. Occasionally, units are committed in the residual unit commitment process to meet these system needs. However, these units are at times uneconomic in real time requiring recovery of their bid costs through bid cost recovery payments.

renewable resources. This adjustment can reduce residual unit commitment procurement targets and therefore decrease the potential for unit commitments.[59]

Figure 2.7 Bid cost recovery payments



2.6 Real-time imbalance offset costs

The real-time imbalance offset charge is the difference between the total money paid out by the ISO and the total money collected by the ISO for energy settled in the real-time energy markets. Historically, this included energy settled at hour-ahead and 5-minute prices. On May 1, the ISO implemented market changes related to FERC Order No. 764, which included a financially binding 15-minute market. Following May 1, real-time imbalance offsets include energy settled at 15-minute and 5-minute prices. Within the ISO system, the charge is allocated as an uplift to measured demand (i.e., physical load plus exports).

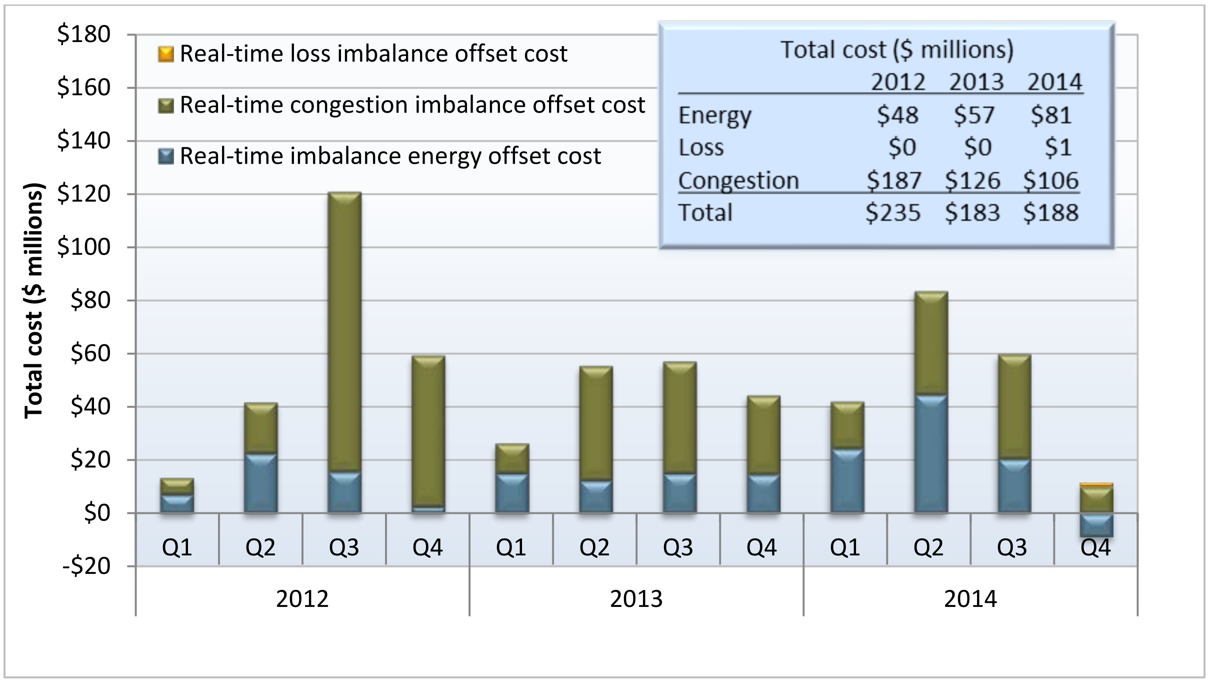
The real-time imbalance offset charge consists of three components. Any revenue imbalance from the energy components of real-time energy settlement prices is collected through the *real-time imbalance energy offset charge* (RTIEO). Any revenue imbalance from the congestion component of these real-time energy settlement prices is recovered through the *real-time congestion imbalance offset charge* (RTCIO). Until October 1, the ISO aggregated real-time loss imbalance offset costs with real-time energy imbalance costs. Following October 1, any revenue imbalance from the loss component of real-time energy settlement prices is collected through the *real-time loss imbalance offset charge*.

[59] See Sections 2.4 and 8.6 for further detail on this new adjustment feature.

Real-time imbalance costs for energy, losses and congestion totaled $188 million in 2014, compared to $183 million in 2013. As seen in Figure 2.8, the increase in total imbalance offset costs was primarily attributable to an increase in the real-time energy imbalance offset costs, which increased from $57 million in 2013 to $81 million in 2014. Real-time imbalance congestion offset costs fell to $106 million in 2014 from $126 million in 2013.

Values reported here are the most current reported settlement imbalance charges, but are subject to change. In addition to the routine causes for recalculation, the ISO has determined that a metering error resulted in under-metering of actual power flow over a handful of inter-ties. The ISO has resolved the inter-tie metering issue and offset costs calculated on the basis of under-metered flow will be corrected. Revised settlements will reflect this change following the normal settlements timeline.

Figure 2.8 Real-time imbalance offset costs



Total cost ($ millions)	2012	2013	2014
Energy	$48	$57	$81
Loss	$0	$0	$1
Congestion	$187	$126	$106
Total	$235	$183	$188

Real-time congestion offset costs

In 2014, real-time congestion offset costs, totaling $106 million, were primarily the result of unpredictable real-time conditions rather than systematic and predictable congestion patterns stemming from unscheduled flows and market modeling differences that drove congestion offset costs in prior periods.[60] Congestion offset costs incurred on 24 days accounted for over $33 million, more than one-third of the annual total cost. Congestion offset costs are caused by deviations between the congestion component of prices at which real-time load and generation are settled. Decreases in power flow limits between the day-ahead and the hour-ahead or, following May 1, the 15-minute real-time market can lead to real-time congestion offset costs as the ISO buys power at higher price locations and

[60] For further details, see *2012 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2013, Section 3.4: pp. 90-99: http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf.

sells power at lower price locations in order to schedule power to meet the lower real-time power flow limit on a constraint.

The ISO's efforts to address systematic modeling differences between the day-ahead and real-time markets, including better alignment of day-ahead and real-time transmission limits and modification of the constraint relaxation parameter, contributed to reducing real-time congestion imbalance costs in 2014 compared to previous periods. However, as the 2014 results show, the possibility of high real-time imbalance offset costs continues to exist as random and unexpected events occur.

Real-time imbalance energy offset costs

In 2014, real-time energy offset costs were $81 million, accounting for less than half of total real-time imbalance offset costs. A substantial portion of these costs occurred on a relatively small number of days as a result of specific unanticipated events.

The settlement values reported for the real-time energy imbalance offset include several components that are offset by settlement values elsewhere in the market and thus are not true uplift costs. For example, transmission loss obligation charges for transmission loss paybacks are currently allocated to measured demand through a separate settlements process. When a scheduling coordinator schedules imports involving certain transmission access outside of the ISO, losses associated with these imports are paid back to the appropriate balancing authority area in the form of energy. Transmission loss obligation charges to the scheduling coordinator reflect the amount paid to ISO generators to provide the transmission loss payback energy.[61]

Real-time energy offset costs incurred on February 6 totaled over $6.7 million, about 8 percent of the annual total. As discussed in Section 1.2.3 there were significant electric reliability issues related to gas pipeline concerns on this day. ISO operators adjusted hour-ahead market loads and exceptionally dispatched significant volumes of generation on the inter-ties in order to maintain reliability. The high real-time imbalance energy offset costs on this date were driven by the substantial volume of imports settled at hour-ahead prices which were substantially higher than real-time prices. For instance, hour-ahead prices in hours ending 18 and 19 exceeded real-time average prices by over $800/MWh. Real-time energy offset costs incurred on 9 additional days totaling $12.6 million accounted for over 15 percent of the annual total.

Real-time loss offset costs

Beginning on October 1, the ISO settled any revenue imbalance from the loss component of real-time energy settlement prices through the real-time loss imbalance offset charge. Previously, these offset charges were aggregated as part of the real-time energy imbalance costs. The real-time loss offset costs totaled about $1 million in the fourth quarter.

[61] Further details of the role of transmission loss obligation charges and other potential causes of real-time imbalance energy offset are outlined in the following DMM white paper: http://www.caiso.com/Documents/ReviewofReal-TimeImbalanceEnergyOffset-DMMWhitePaper.pdf.

2.7 Full network model expansion

Background

The ISO implemented what is referred to as a *full network model* in the day-ahead and real-time markets beginning October 15. This software enhancement is designed to improve ISO system modeling by expanding the topology and inputs used to project actual power flows in the day-ahead and real-time market models. By expanding the market model to include other balancing areas, the ISO will also be able to reflect outages and other reliability parameters on those external systems and analyze how they may affect the ISO market. This provides the opportunity for substantial reliability benefits under scenarios such as that which led to the major Southwest blackout on September 8, 2011.

These modeling enhancements may also improve market efficiency by allowing better management of congestion. This expanded model is designed to model the unscheduled electrical flows that occur within the ISO balancing area caused by the load, generation and interchanges forecast for other balancing areas in the western interconnection. The goal of this is to produce day-ahead and real-time schedules and prices that more accurately reflect actual system constraints and the impact schedules have on these constraints. Expanding the ISO network model to a regional level that includes other balancing authority areas is also a key component needed to ensure the efficiency and future expansion of the energy imbalance market.

As noted in DMM's memo to the ISO Board on this initiative, the accuracy with which unscheduled flows can be projected will depend on a variety of other modeling assumptions that must be made, such as which generation schedules in other balancing areas are ultimately increased or decreased as a result of imports or exports within the ISO system.[62] Consequently, DMM has noted that monitoring the impact that this has on projections of unscheduled flow and congestion in the day-ahead and real-time market models – and modifying these models in response to this monitoring – is critical.

Recommendations and analysis

The ISO has performed some impact assessments of the full network model enhancements before and after implementation. DMM has provided specific recommendations to the ISO for more detailed and targeted metrics for assessing the impact of the full network model. Metrics recommended by DMM include the following enhancements to those currently used by the ISO:

- DMM recommends that the ISO full network model metrics include all internal constraints, as well on the inter-ties and select internal constraints, which are currently included in the ISO's metrics;
- Unless the estimated or actual flow on a line is actually near a limit in the day-ahead or real-time market, there may be little or no consequences of any improvement of projected flows in terms of reliability or market costs. Therefore, DMM recommends that these automated metrics focus on the impact that the full network model is having on estimated flows on specific constraints which are at or near their limits in the day-ahead and real-time markets based on estimated or actual flows; and

[62] See http://www.caiso.com/Documents/DepartmentMarketMonitoringReport-Memo-Feb2014.pdf.

- DMM also recommends that the ISO metrics and analysis focus on constraints on which the actual market impact of congestion is highest. As identified in prior reports by DMM, the bulk of real-time energy congestion offset costs that have been incurred in the past are associated with a relatively small number of constraints in any given period. Automated metrics can be used to quickly identify these constraints and allow resources to focus on modeling improvements or adjustments that have the highest value in terms of reliability and market benefits.

DMM has performed limited analysis of the full network model performance based on this general approach. Based on this analysis, DMM identified that discrepancies between day-ahead and real-time base injections and line conformances contributed to some significant differences between congestion in the day-ahead and real-time markets. DMM's analysis contributed to identifying the following modeling issues:

- **Table Mountain nomogram in October.** ISO operators alleviated inaccurate flow during most real-time intervals by conforming the real-time limit of the Table Mountain nomogram constraint upwards. However, the ISO did not correspondingly conform the day-ahead limit of the nomogram upwards. As a result, there was heavy day-ahead congestion but mild real-time congestion. Base injection flow impact and incorrect network modeling were contributing factors to the heavy day-ahead congestion.

- **No day-ahead base injections over Pacific DC Intertie.** Real-time base injections over the Pacific DC Intertie contributed to significant real-time congestion over the Victorville – Lugo 500 kV line in the first few weeks of December. Because of an implementation error related to time stamps dating back to the initial full network model implementation, the ISO was not including any base injections over the Pacific DC Intertie in the day-ahead market. Omitting these PDCI base injections from the day-ahead market contributed to Victorville – Lugo 500 kV having significantly higher congestion in real-time than day-ahead over the first few weeks of December. In the coming weeks, the ISO is expecting to publish a technical bulletin with thorough analysis of the PDCI modeling issues from the fourth quarter of 2014.

DMM continues to work with the ISO and the Market Surveillance Committee in developing more automated and enhanced metrics and other analysis to assess and improve the full network model.

3 Real-time market performance

The ISO made two major changes to the real-time market in 2014.

- In May, the ISO implemented a new real-time market design that includes 15-minute dispatch and settlement of both internal generation and inter-tie resources.
- In November, the real-time market was also expanded to include the PacifiCorp balancing areas through implementation of the energy imbalance market (EIM).

This chapter provides additional background and analysis of these major market changes, along with key trends related to performance of the real-time market. Highlights in this chapter include the following:

- Upon implementing the new 15-minute market in May, price variability in the 5-minute market now has a lower impact because most real-time energy is settled at the 15-minute price. In addition, the 15-minute market is much less volatile, because it is less susceptible to ramping limitations that can cause the need to dispatch extremely high priced bids or relax the power balance constraint to balance load and supply.
- In 2014, prices in both the 15-minute and 5-minute markets were fairly stable, with the overall frequency of extremely high and low prices dropping somewhat compared to 2013. Negative price variability was more frequent in both markets than positive price variability.
- Total imports and exports clearing in the day-ahead and real-time markets have not changed considerably after implementing 15-minute scheduling on the inter-ties in May. However, the amount of price sensitive import and export bids offered into the real-time market has decreased dramatically, with most imports and exports being self-scheduled in the real-time market.
- The lack of liquidity on inter-ties in the real-time market is especially acute in the 15-minute market, with no 15-minute dispatchable bids being submitted on many inter-ties. This lack of liquidity has created the need to manage real-time congestion based on *pro rata* scheduling cuts rather than economic bids during some hours.
- Flexible ramping payments were about $6.5 million for the year, compared to about $26 million in 2013. This decrease is partly attributable to a decrease in the maximum flexible ramping requirement in January from 900 MW to 600 MW. As a result of this change, the average requirement during the morning and evening ramping hours decreased from over 600 MW in 2013 to about 450 MW in 2014.
- Prices in the EIM during most intervals have been highly competitive and have been set by bids closely reflective of the marginal operating cost of the highest cost resource dispatched to balance loads and generation. However, during a relatively small portion of intervals in the EIM balancing areas, energy or flexible ramping constraints have had to be relaxed for the market software to balance modeled supply and demand.
- Shortly after EIM implementation, the ISO gained approval to use a special price discovery mechanism to allow prices under shortage conditions to be set based on the last economic price, rather than the $1,000/MWh penalty price otherwise applied when the power balance constraint is relaxed. This special price mitigation feature has kept overall EIM prices about equal to bilateral

market prices used to set imbalance energy charges in the PacifiCorp areas before EIM implementation.

3.1 15-minute real-time market

The ISO implemented 15-minute scheduling on inter-ties on May 1, consistent with FERC Order No. 764. Along with this change, the ISO revamped its real-time market to include 15-minute settlement of both internal generation and inter-tie resources, while retaining the 5-minute market for balancing purposes. This section provides a brief background of this change and highlights key market observations related to this change.

Background

FERC Order No. 764 required the ISO to establish 15-minute intra-hour schedule changes along inter-ties to facilitate the integration of large amounts of renewable variable energy resources. The ISO went beyond the minimum requirements outlined in the order to implement a number of other market changes aimed at achieving other benefits that included the following:

- Allowing more granular scheduling of resources, which was intended to accommodate scheduling variable energy resources over the inter-ties as well as allowing all resources to be scheduled more effectively with shortened forecast lead times.
- Reducing settlement uplift charges attributed to settling inter-tie resources at hourly prices while settling internal resources at 5-minute prices. Inter-tie and internal resources are now scheduled and settled in the same 15-minute market run in real time.
- Complying with FERC Order No. 764 requirements to allow for 15-minute inter-tie scheduling, while including provisions for hourly inter-tie transactions to remain.
- Correcting the problems that led to suspension of convergence bidding at the inter-ties.[63]

The new real-time market includes both 15-minute and 5-minute financially binding schedules and settlement. The 15-minute market produces schedules and prices for all resources, including internal and inter-tie transactions. Differences between 15-minute schedules and day-ahead schedules settle at the 15-minute market prices.

The real-time market maintains the 5-minute dispatch for internal resources, participating load and dynamically scheduled inter-tie transactions. Differences between 5-minute market dispatches and 15-minute market schedules settle at the 5-minute price.

Results from the 15-minute market produce schedules and prices 37 minutes before the applicable interval, compared to 75 minutes prior to the change. This is designed to incorporate the most current forecast for renewable generation and reduce lead time and forecast error.

[63] While convergence bidding at the inter-ties was scheduled to be re-implemented in May 2015, the ISO requested a waiver for the requirement in April 2015 on the concern that reintroducing inter-tie virtual bidding would decrease economic efficiency in light of the observed lack of liquidity in economic bidding in the ISO's 15-minute market. The FERC granted a temporary waiver delaying implementation pending further review. For more information, see the following link: http://www.caiso.com/Documents/Apr29_2015_OrderGrantingWaiverRequest_IntertieVirtualBidding_ER15-1451_ER14-480.pdf.

The real-time market continues to include an hour-ahead scheduling process. However, it is only used to schedule inter-tie transactions that must be fixed for the hour. These fixed hourly schedules are no longer guaranteed the price projected by the hour-ahead scheduling process. Rather, they are paid the price in each of the 15-minute settlement intervals during the hour they are scheduled.

The ISO continues to settle load in the real-time market at load aggregation point prices, which are now calculated using an average of the 15-minute and 5-minute prices. The prices are weighted by the respective load forecasts used by the 15-minute and 5-minute market runs. Load continues to be metered hourly but is settled on a 5-minute basis.

A variety of options for scheduling inter-tie transactions were implemented to accommodate the 15-minute market structure, including:

- **15-minute economic bid:** Market participants have the option to submit economic bids that the ISO can schedule in 15-minute intervals based on price. These transactions are settled at the 15-minute price.
- **Fixed hourly self-schedules:** Market participants can submit fixed self-schedules for the hour. These transactions are settled at the average 15-minute price over the operating hour.
- **Fixed hourly economic bid:** Market participants can submit economic bids for inter-tie transactions that are a fixed quantity for the hour and that the ISO schedules in the hour-ahead scheduling process based on price. These transactions are settled at the average 15-minute price over the operating hour.
- **Fixed hourly economic bid with single intra-hour schedule change:** Similar to the fixed hourly economic bid option above, market participants can submit economic bids for inter-tie transactions that are a fixed quantity for the hour and that the ISO schedules based on price. However, this option allows for the schedule to be changed once per hour during the 15-minute market. These transactions are settled against 15-minute market prices.
- **Dynamic transfer:** Market participants continue to be able to establish dynamic transfer arrangements that enable 5-minute dispatch and settlement of inter-tie transactions. These are settled similar to internal generation.

A penalty is applied if a variable energy resource routinely submits high forecasts to the hour-ahead process because these would displace other inter-tie resources. This penalty or the 5-minute price, depending on the circumstances, is also applied to other inter-tie schedules that are not delivered.

Market performance

The amount of inter-tie imports and exports cleared between the day-ahead and real-time markets has not changed considerably after implementing 15-minute scheduling on the inter-ties in May. However, there was a significant decrease in the amount of inter-tie bids offered into the real-time market and a corresponding increase in the volume of self-scheduled inter-tie transactions. While this overall trend continued into the fourth quarter, there was an uptick in the volume of price sensitive bids in real time in December for both hourly and 15-minute transactions.

Figure 3.1 and Figure 3.2 show the level of self-scheduled imports and exports compared to the total offered imports and exports in the day-ahead and real-time markets, respectively. Initially, the quantity of self-scheduled inter-tie import bids in both the day-ahead and real-time markets increased following the new inter-tie rules implemented in May. In the second part of the year, especially in the fourth quarter, the quantity and share of self-scheduled imports in the day-ahead market decreased while self-scheduled exports increased slightly.

However, in the real-time market most of the inter-tie import bids remained self-scheduled. Around 85 percent of import bids and 53 percent of export bids in the hour-ahead market were self-schedules between May and December. In the first four months of 2014, 51 percent of import bids and 8 percent of export bids were self-scheduled in the hour-ahead market.

Economic import bidding increased in December by about 50 percent in the hour-ahead market and 30 percent in the 15-minute market compared to October and November. This increase may be related to the Bonneville Power Administration's implementation of 15-minute scheduling on October 21 or other potential factors.

Since May 2014, the majority of price sensitive bids on the inter-ties were in the hour-ahead market. In the fourth quarter, around 85 percent of all import and 62 percent of all export bids were hourly blocks, as shown in Figure 3.3. Only about 15 percent of priced import bids and 38 percent of priced export bids were 15-minute dispatchable bids. The hourly economic bid block option with a single intra-hour economic schedule change accounts for an extremely small portion of inter-tie bids, with an average of only 3 MW of imports and 3 MW of exports per hour bid under this option from May to December 2014. Due to the very small volume of these bids they are not visible in Figure 3.3.

Figure 3.1 Volume of self-schedules and price-sensitive bids in the day-ahead market

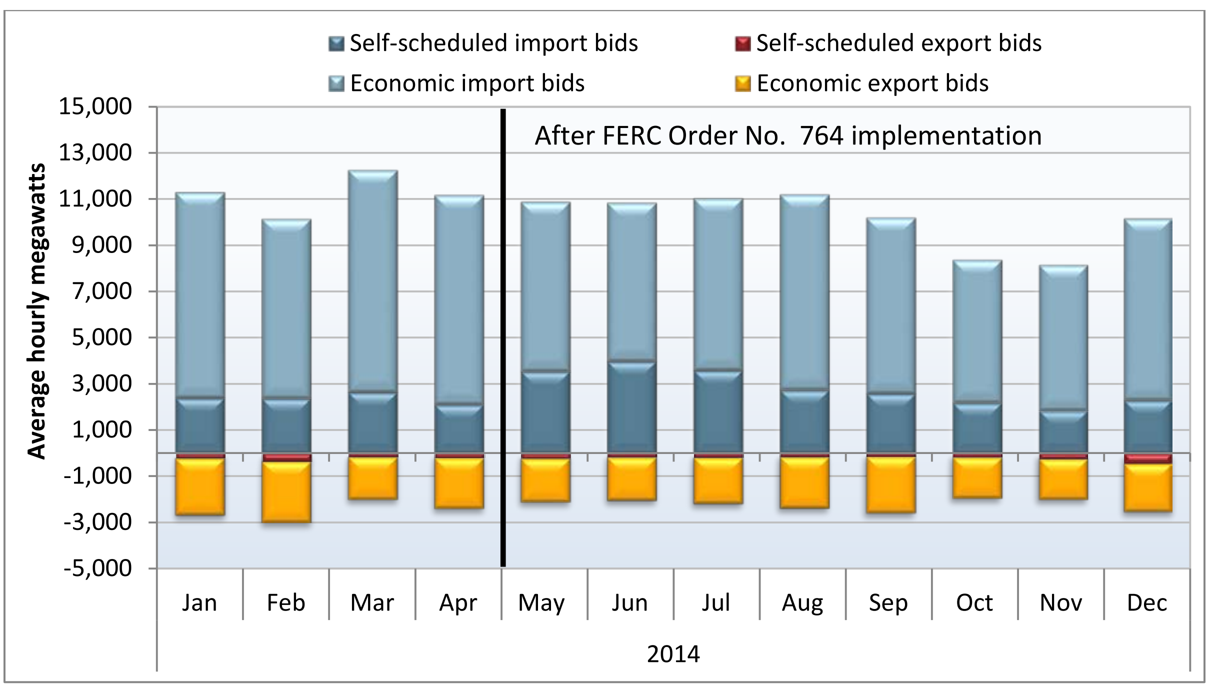


Figure 3.2 Volume of self-schedules and price sensitive bids in the real-time market

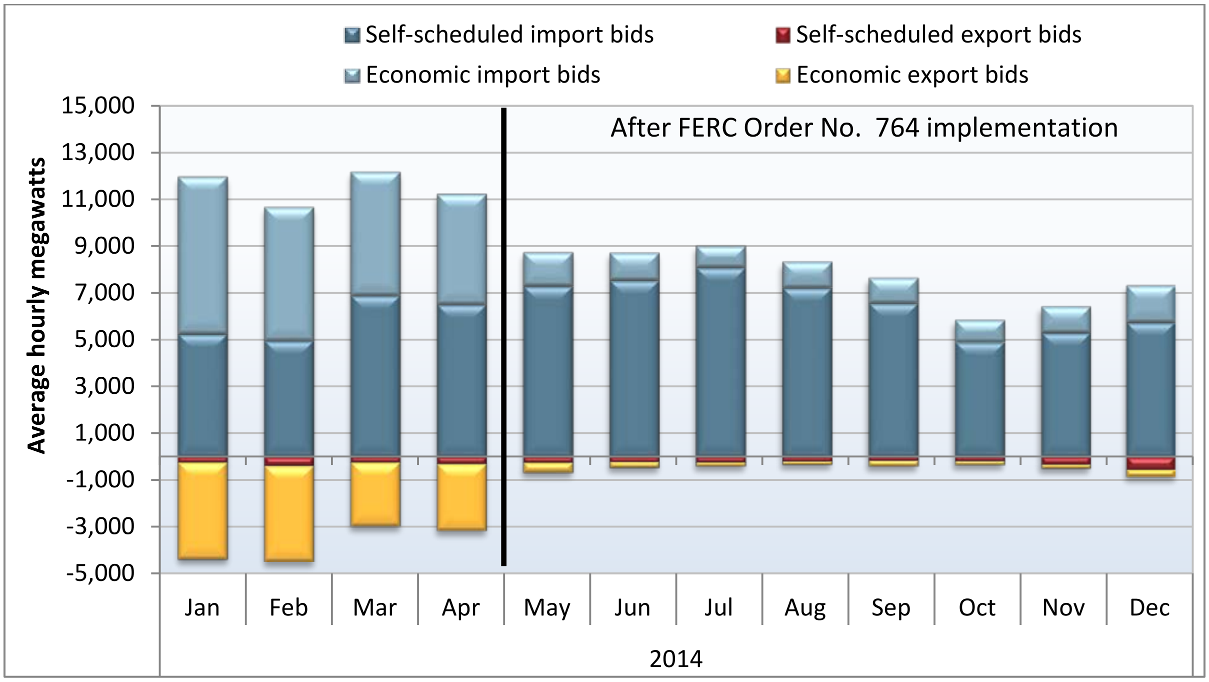
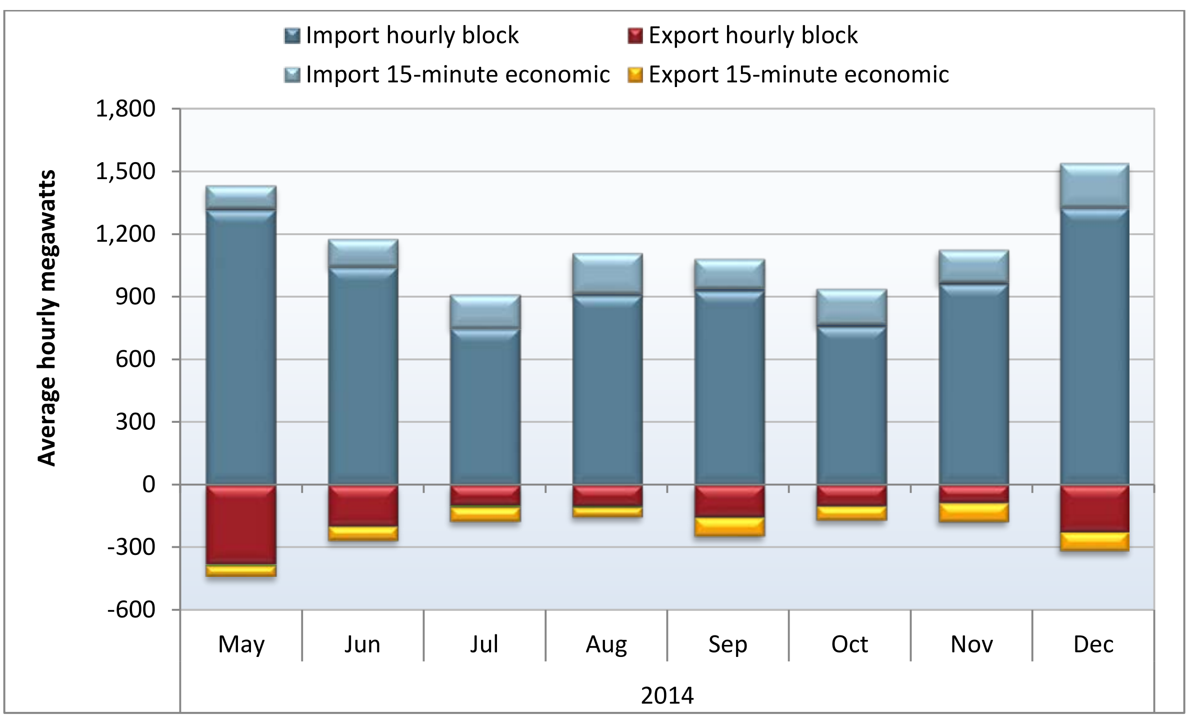


Figure 3.3 Price sensitive import and export bids by bidding option



3.2 Real-time price variability

Prices in the 5-minute real-time market since implementation of the nodal market in 2009 have been highly volatile with periods of brief but extremely high and low prices. In many instances, this price variability resulted from various modeling issues, causing the need to relax the power balance constraint to balance load and supply in the real-time market model, rather than underlying supply and demand conditions.

Upon implementing the new 15-minute market in May, price variability in the 5-minute market now has a lower impact because most real-time energy is settled at the 15-minute price. In addition, the 15-minute market is much less volatile, because it is less susceptible to modeling issues that can cause the need to dispatch extremely high priced bids or relax the power balance constraint to balance load and supply.

In 2014, prices in both the 15-minute and 5-minute markets were fairly stable, with the overall frequency of extremely high and low prices dropping somewhat compared to 2013. This trend was particularly notable in the second half of 2014, after issues with the new 15-minute market were resolved in the two months following implementation in May.

Prices in the 15-minute market rose above $250/MWh in around 0.4 percent of all intervals, and 5-minute market prices reached above $250/MWh in around 0.7 percent of all intervals.[64] In 2013, prices in the 5-minute market exceeded $250/MWh during 0.6 percent of all intervals

Figure 3.4 shows the frequency of positive price spikes above $250/MWh that occurred in the 15-minute market beginning in May 2014. The frequency of price spikes above $750/MWh increased as the year progressed, most notably in the fourth quarter when price spikes over $1,000/MWh represented about 0.15 percent of 15-minute intervals.

Figure 3.5 shows the frequency of positive price spikes above $250/MWh that occurred in the 5-minute market in 2013 and 2014. The slight increase in prices over $250/MWh in 2014 was driven by an increase in price spikes between $250/MWh to $500/MWh in the second quarter, which includes the first two months of the new 15-minute market. The overall frequency of 5-minute price spikes above $750/MWh was lower in 2014 than the previous year.

The relatively high frequency of positive spikes in the spring was partly due to ramping limitations resulting from rapid decline of solar generation during the late afternoon hours and unexpected drops in wind generation. The increased availability of ramping resources in the higher load summer months decreased the frequency of positive price spikes caused by sudden changes in renewable generation.

During 2014, negative prices occurred in the 15-minute market during 1.9 percent of intervals. Figure 3.6 shows the quarterly frequency of negative price spikes after May in the 15-minute market. The frequency decreased significantly after the second quarter from 4 percent to 0.6 percent in the third quarter and 1.2 percent in the fourth quarter. Most of the negative prices in the 15-minute market were between -$30/MWh and $0/MWh.

[64] The 15-minute market prices in this analysis were between May and December 2014 while the 5-minute market prices were for the entire year of 2014.

Figure 3.4 Frequency of positive 15-minute price spikes (all LAP areas)

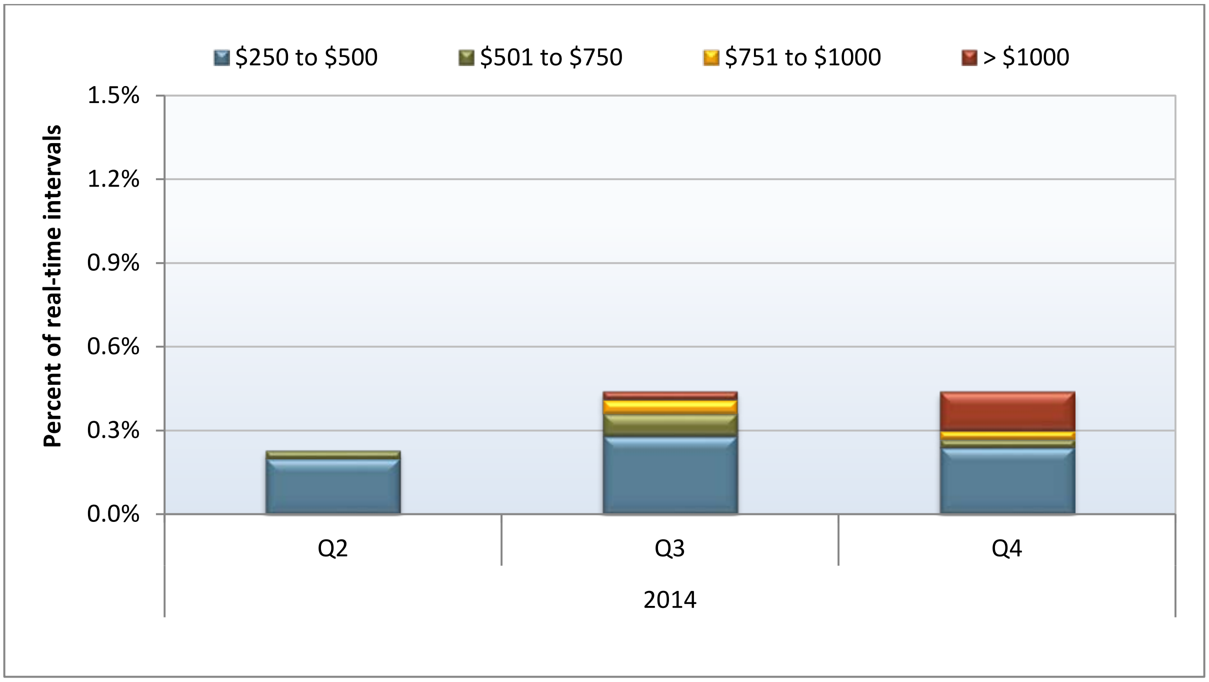


Figure 3.5 Frequency of positive 5-minute price spikes (all LAP areas)

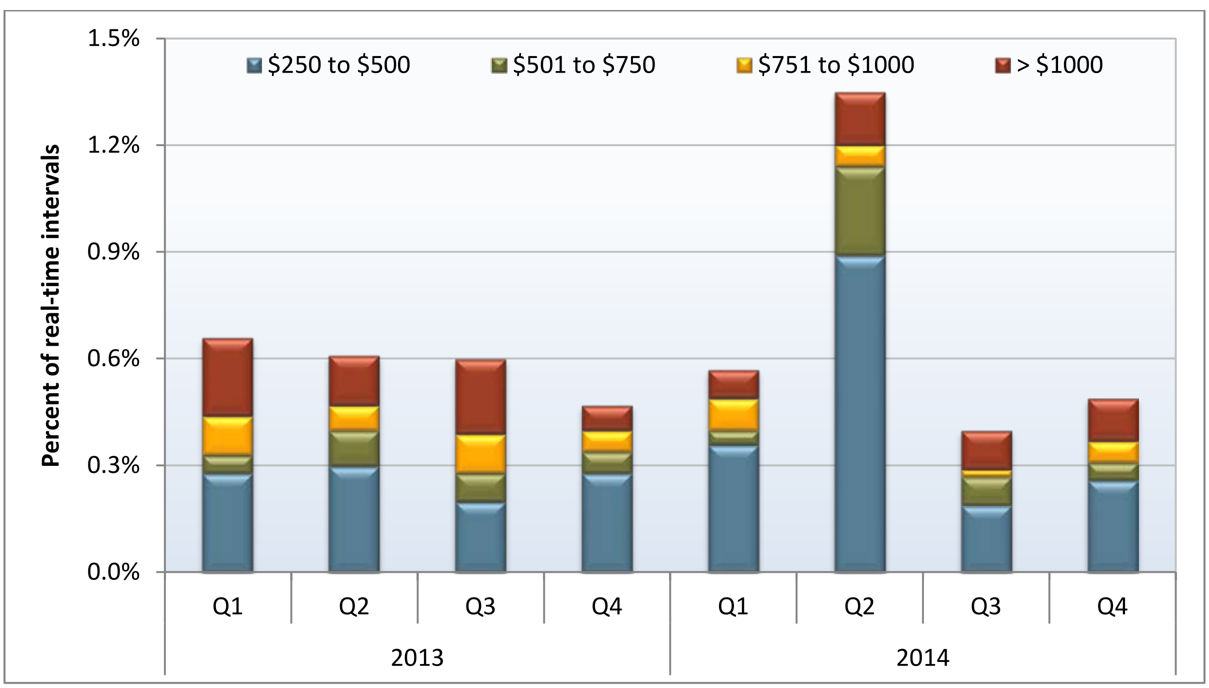


Figure 3.6 Frequency of negative 15-minute price spikes (all LAP areas)

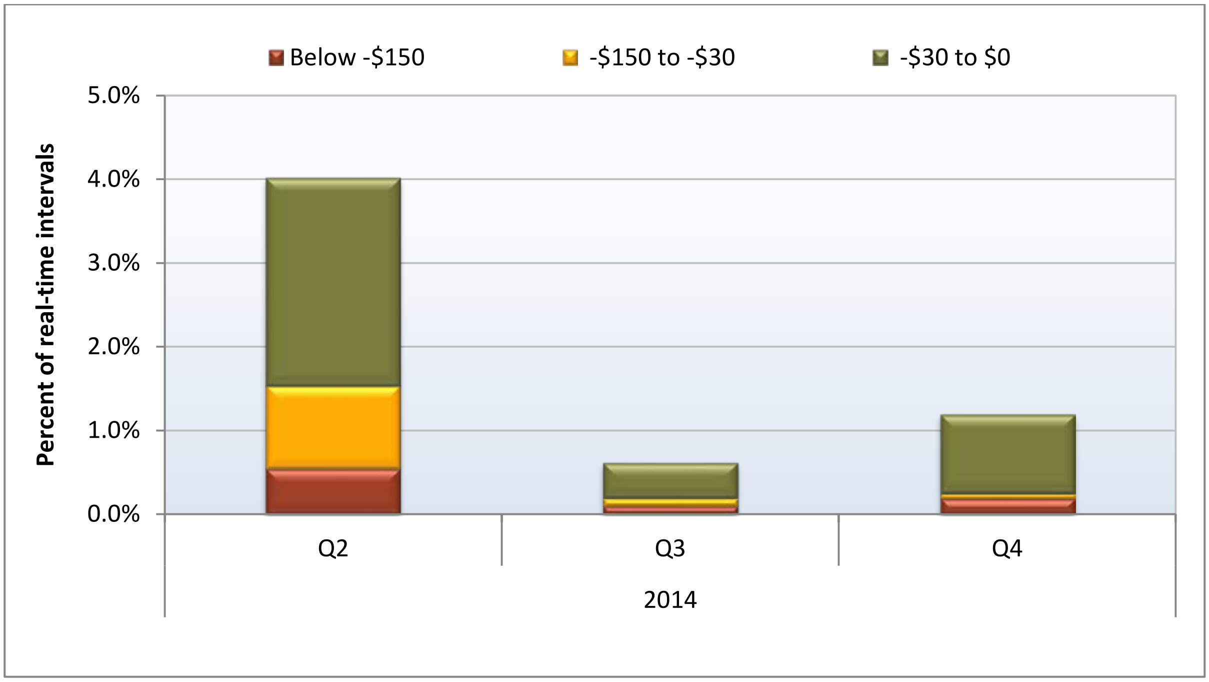


Figure 3.7 Frequency of negative 5-minute price spikes (all LAP areas)

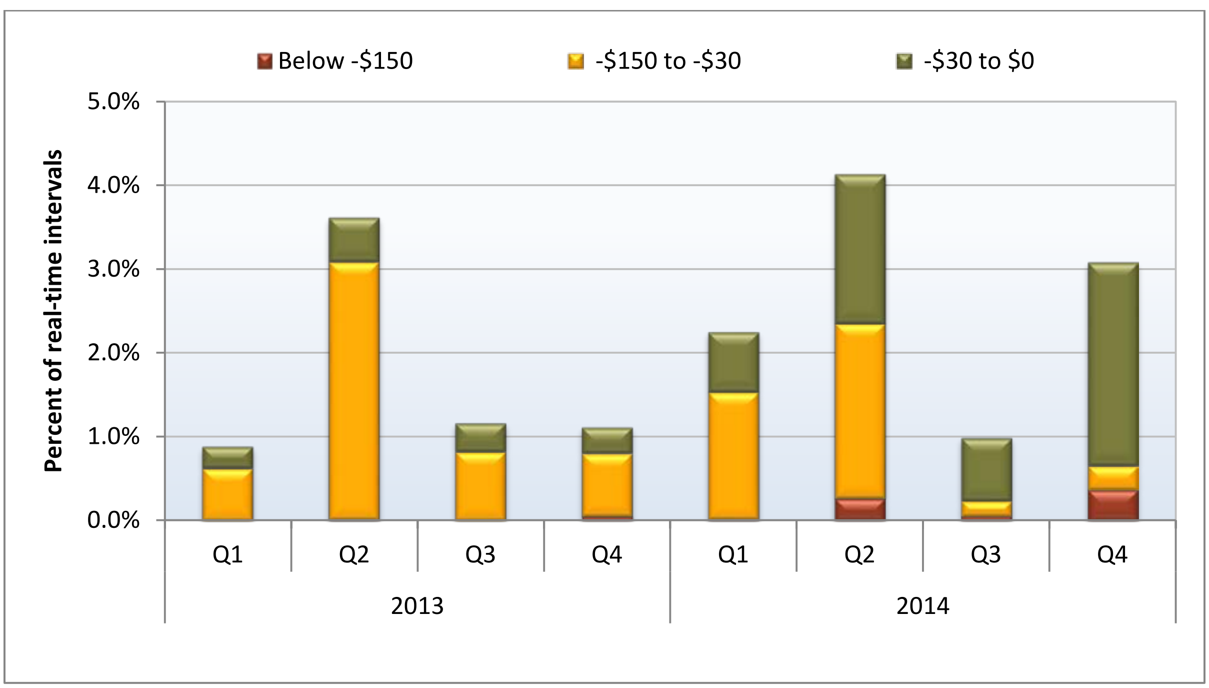


Figure 3.7 shows the quarterly frequency of negative price spikes in the 5-minute market in 2013 and 2014. The frequency of negative prices in the 5-minute market was 2.6 percent in 2014, compared to 1.7 percent in 2013. However, following implementation of the 15-minute market, most negative prices ranged from $0/MWh to -$30/MWh, while most negative prices in the 5-minute market during 2013 were between -$30/MWh to -$150/MWh.

Negative prices in the second quarter were partly due to periods of over-generation resulting from unscheduled wind and solar generation. Specifically, unscheduled solar generation resulted in situations of over-generation during the rapid ramping periods during morning hours. Negative prices in the fourth quarter were especially common in periods of relatively low load prior to the steep evening load ramp as solar generation peaked for the day and other generation resources remained available to meet the ramp. Most negative prices in 2014 were the result of negative bids.

3.2.1 System power balance constraint

Background

The ISO market includes an energy bid cap and bid floor to limit the effect that short-term constraints, modeling issues or market power may have on market outcomes. Currently, the bid cap is set at $1,000/MWh and the bid floor is set at -$150/MWh.[65] The bid cap and floor affect 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 energy and transmission constraints incorporated in the market software are also set based relative to the bid cap and floor. When one of these constraints is relaxed, prices can reach the energy bid cap or floor, as described below.

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

When energy that can be dispatched in the real-time market 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 real-time dispatch, this constraint is relaxed in the scheduling run of the real-time software. In the scheduling run, the software assigns

[65] On May 1, 2014, the bid floor was lowered to a hard bid floor of -$150/MWh from a soft bid floor of -$30/MWh. This change was primarily intended to provide incentives for renewable generation to bid downward dispatch into the market economically. This change was also intended to eliminate inconsistencies between the scheduling run and the pricing run. Since the bid floor was lowered in May, DMM has not identified a significant change in bidding below -$30/MWh in the real-time market. DMM has observed an increase in bids below -$30/MWh in the day-ahead market. Thus, the benefits of this change appear to be minimal as there were relatively few negative prices in the day-ahead market and more negative prices in the real-time market in 2014.

a penalty price of $1,100/MW for the first 350 MW that this constraint is relaxed.[66] After this, load and export schedules may be reduced at a penalty price of $6,500/MW in the scheduling run. In the pricing run, a penalty price of $1,000/MW is used. This causes prices to spike to the $1,000/MWh bid cap or above.

- When insufficient decremental energy is available for 5-minute real-time dispatch, the software relaxes this constraint in the scheduling run using a penalty price of -$155/MW for the first 350 MW. After this, day-ahead self-scheduled energy may be curtailed at a penalty price of -$1,000/MW. In the pricing run, a penalty price of -$155/MW is used. This causes prices to drop down to or below the -$150/MWh floor for energy bids.

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 necessarily pose a reliability problem. This is because the real-time market software is not a perfect representation of actual 5-minute conditions. To the extent power balance relaxations occur more frequently or last for longer periods of time, an imbalance in loads and generation actually does exist during these intervals, resulting in units providing regulation service to provide additional energy needed to balance loads and generation. To the extent that regulation service and spinning reserve capacity are exhausted, the ISO may begin relying on the rest of the interconnection to balance the system, which may affect the reliability performance of the ISO system.

Sometimes extreme congestion on constraints within the ISO system can limit the availability of significant amounts of supply. This can cause system-wide limitations in ramping capacity, and thus cause relaxations in the power balance constraint. In these cases, the cost of relaxing the system power balance constraint is less expensive than the cost of relaxing the internal constraint. Therefore, the system power balance constraint is relaxed to deal with the ramping limitation in the congested portion of the ISO system.[67]

Load bias limiter

Power balance constraint relaxation is modeled differently in the pricing run than in the scheduling run. Prior to the pricing run, the ISO software performs an additional test to see if operator load adjustments caused relaxation of the power balance constraint in the scheduling run. This functionality is called the *load bias limiter*. Specifically, the software compares the magnitude of the power balance relaxation to the size of the operator load adjustment for both shortage and excess events. If the operator load adjustments exceeded the quantity of the relaxation, the size of the load adjustment is automatically reduced in the pricing run by a value slightly larger than the power balance relaxation.

For instance, assume the grid operator had entered a 100 MW upward load bias for an interval. The load bias limiter adjustment is triggered if the power balance constraint is relaxed less than 100 MW during this interval. For instance, if the power balance constraint is relaxed by 70 MW in the scheduling run with the 100 MW upward load bias in effect, the load used in the pricing run is adjusted to reflect only a 30 MW upward load bias. This effectively limits the upward load bias in the pricing run to the

[66] The scheduling run parameter was increased in 2012 from $1,000/MW to ensure that all economic bids were exhausted before the penalty was imposed.

[67] This is primarily true for large regional constraints. For very small local constraints, the opposite is true. In the case of local constraints, the cost of relaxing the local constraint is less expensive than the cost of relaxing the system constraint. Thus, the regional constraint is relaxed instead of the power balance constraint.

amount of supply bids actually available to the market software given ramping and other constraints (100 MW bias – 70 MW relaxation = 30 MW of available supply).[68]

This results in a feasible market solution in the pricing run, so that the price is set by the highest priced supply dispatched rather than the $1,000/MWh penalty price for the power balance constraint.[69] The resulting price is often less than the $1,000/MWh bid cap as the last economic bid sets the price instead.

The ISO implemented this real-time market software enhancement in December 2012. The purpose of this tool was to assist operators by automating adjustments to avoid extreme unintended market effects due to operator load adjustments that did not increase or decrease the actual supply of system energy. This tool was operational in the 5-minute real-time market in the ISO balancing area, but not in the EIM balancing areas, in 2014.

Figure 3.8 through Figure 3.11 highlight the frequency with which this mechanism resolved power balance relaxations in the ISO balancing area. The load bias limiter resolved almost 80 percent of the upward power balance relaxations that occurred in the scheduling runs in the 5-minute market during 2014, compared to about 50 percent in 2013. In 2014, this feature resolved about 50 percent of the downward power balance relaxations that occurred in the scheduling runs in the 5-minute market, compared to about 80 percent in 2013.

The ISO has extended this tool to both the 15-minute and 5-minute markets for the EIM balancing areas in 2015. However, the current special price discovery feature in effect makes the application of this duplicative in terms of the final price impact.

DMM has provided the ISO with a recommendation on how the load bias limiter feature might be enhanced to better reflect the impact of excessive load bias adjustment changes on creating power balance shortages. Specifically, DMM has recommended considering the adjustment based on the *change* in load bias from one interval to the next instead of on the *absolute value* of any positive load bias.

Power balance constraint relaxations

Before accounting for the load bias limiter, the frequency of power balance constraint relaxations due to insufficient upward ramping capacity increased and relaxations due to insufficient downward ramping capacity were about the same in 2014 compared to the previous year. After accounting for the load bias limiter, relaxations due to insufficient upward ramping decreased and relaxations due to insufficient downward ramping increased in 2014 compared to 2013. Congestion-related power balance constraint infeasibilities in 2014 decreased compared to 2013.

Figure 3.8 and Figure 3.9 show the frequency with which the power balance constraint was relaxed in the 5-minute real-time market software in each quarter since 2013. The power balance constraint has never been relaxed in the day-ahead or 15-minute markets in the ISO system.[70]

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[68] If the relaxation exceeds the load bias or the load bias is in the opposite direction of the relaxation, the limiter feature does not apply in the pricing run.

[69] Because congestion usually happens on local or regional constraints, the load bias limiter feature may not be able to resolve the infeasibility. Thus, congestion-related power balance relaxations were not considered resolved by the load bias limiter in this analysis.

Figure 3.8 Relaxation of power balance due to insufficient upward ramping capacity

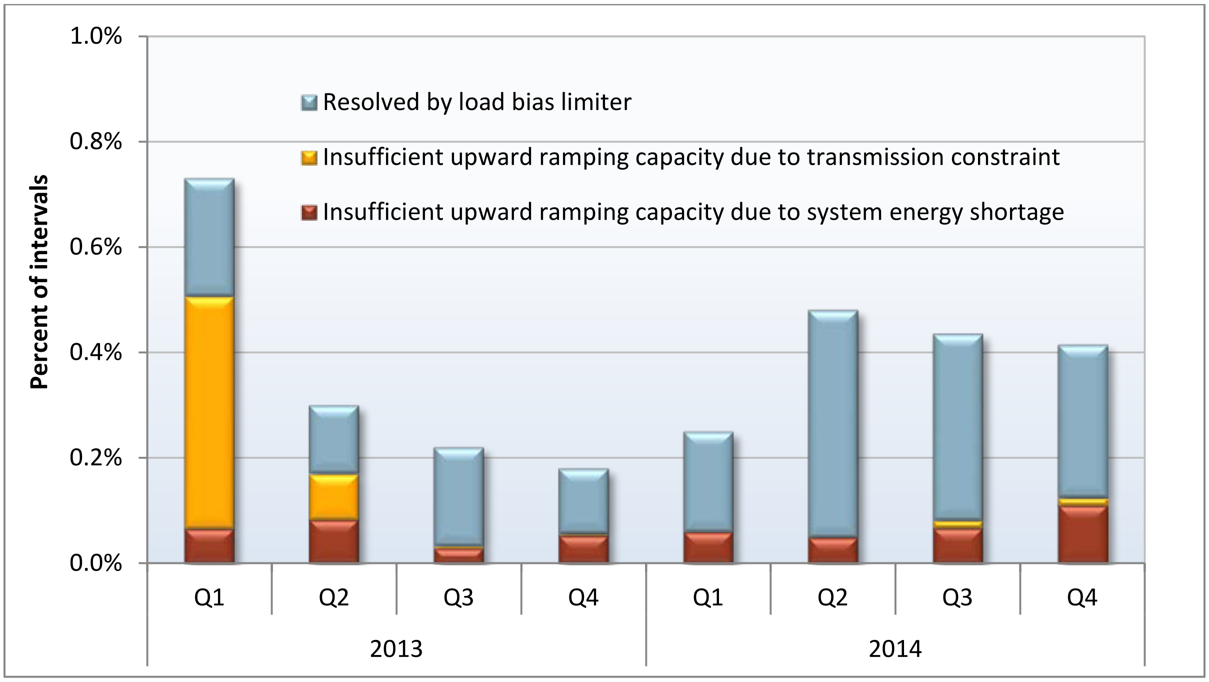
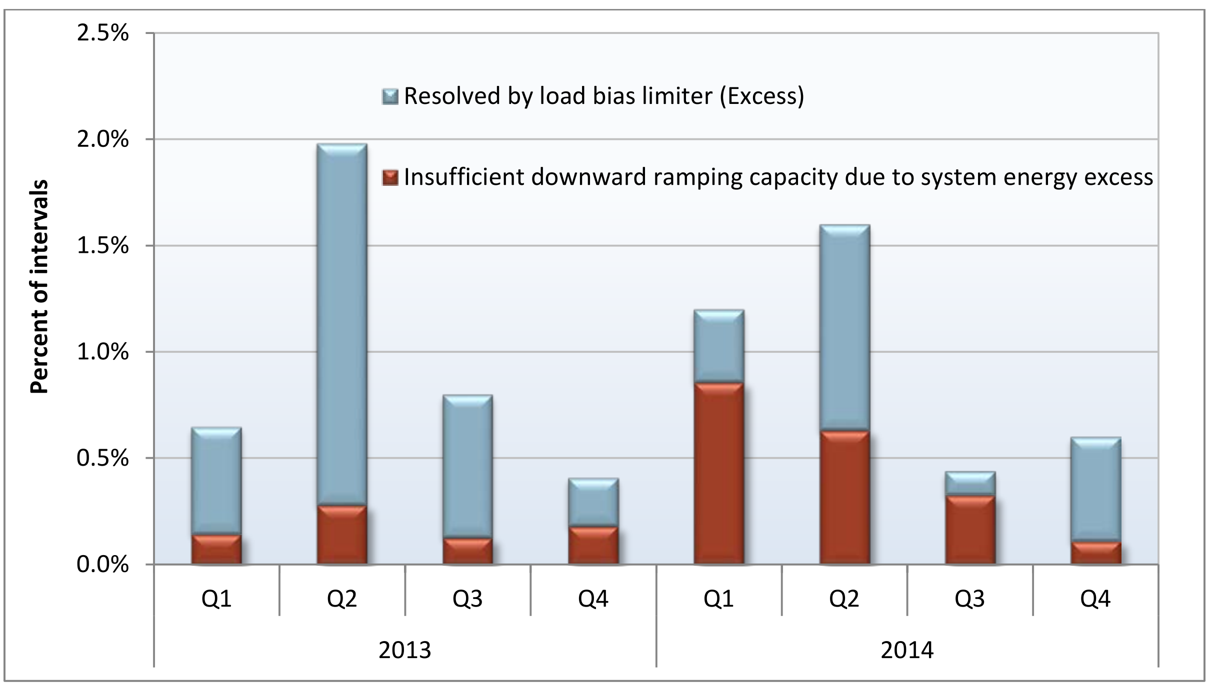


Figure 3.9 Relaxation of power balance due to insufficient downward ramping capacity



[70] In the energy imbalance market, power balance constraint relaxations have also occurred in the 15-minute market in both the PacifiCorp East and West balancing areas, but not in the ISO balancing area.

As shown in Figure 3.8, the constraint was relaxed because of insufficient incremental energy in about 0.4 percent of the 5-minute intervals in 2014, a slight increase from about 0.36 percent of the 5-minute intervals in 2013. In 2014, around 2 percent of the upward ramping capacity relaxations (shown in Figure 3.8) resulted from extreme congestion compared to about 37 percent in 2013.

The frequency of relaxations due to insufficient downward ramping capacity was similar in 2014 compared to 2013. As in previous years, power balance constraint relaxations due to insufficient downward decremental capacity occurred more frequently than insufficient upward capacity. As shown in Figure 3.9, the constraint was relaxed due to insufficient decremental capacity in about 1 percent of intervals in 2014. There were no insufficient downward ramping relaxations caused by transmission constraints in 2014, down from 6 intervals in 2013.

Negative power balance constraint relaxations were likely a result of increased solar generation, particularly in the late morning and early afternoon hours. When the constraint is relaxed under these conditions, the downward impact on average prices is less significant because prices only drop towards or to the bid floor of -$150/MWh.[71] As in previous years, congestion was not a driving factor causing downward ramping infeasibilities.

Figure 3.10 shows the percentage of intervals that the power balance constraint was relaxed in the scheduling run due to shortages of upward ramping during each operating hour in 2014. This figure also shows the average net load in each hour and the percentage of intervals the power balance relaxation was and was not resolved by the load bias limiter feature.

As shown in Figure 3.10, shortages of upward ramping capacity caused the system power balance constraint to be relaxed most frequently during the late evening ramping and peak load hours of the day (16 through 20). During these hours, shortages of upward ramping occurred in around 1.2 percent of intervals, up from about 0.9 percent in 2013.[72] This was more than six times more frequent than all other hours.

Figure 3.11 shows the percentage of intervals that the power balance constraint was relaxed in the scheduling run due to shortages of downward ramping during each operating hour in 2014. This figure shows that the system power balance constraint was relaxed due to shortages of downward ramping capacity or excess energy primarily during off-peak hours, and in the late morning and early afternoon hours when solar generation peaks.

Downward power balance relaxations occurred in almost 2.2 percent of intervals in the late morning and early afternoon hours (10 through 13). This is a significant increase from 2013 when these hours only had power balance relaxations in about 0.3 percent of intervals. Excess energy often occurs in these hours as generation from solar units reaches higher levels while generation is on to meet the evening ramping and peak generation needs.

As in prior years, most of the upward and downward ramping shortages were very short-lived. In 2014, about 79 percent of shortages of upward ramping capacity persisted for only one to three 5-minute intervals (or 5 to 15 minutes). About 63 percent of shortages of downward ramping capacity lasted for only one to three 5-minute intervals. This was a decrease from about 95 percent in 2013.

[71] Before May 2014, the price floor was -$30/MWh.

[72] The number in 2013 was based on hours ending 18 through 21.

Figure 3.10 Relaxation of power balance constraint due to insufficient upward ramping capacity by hour (2014)

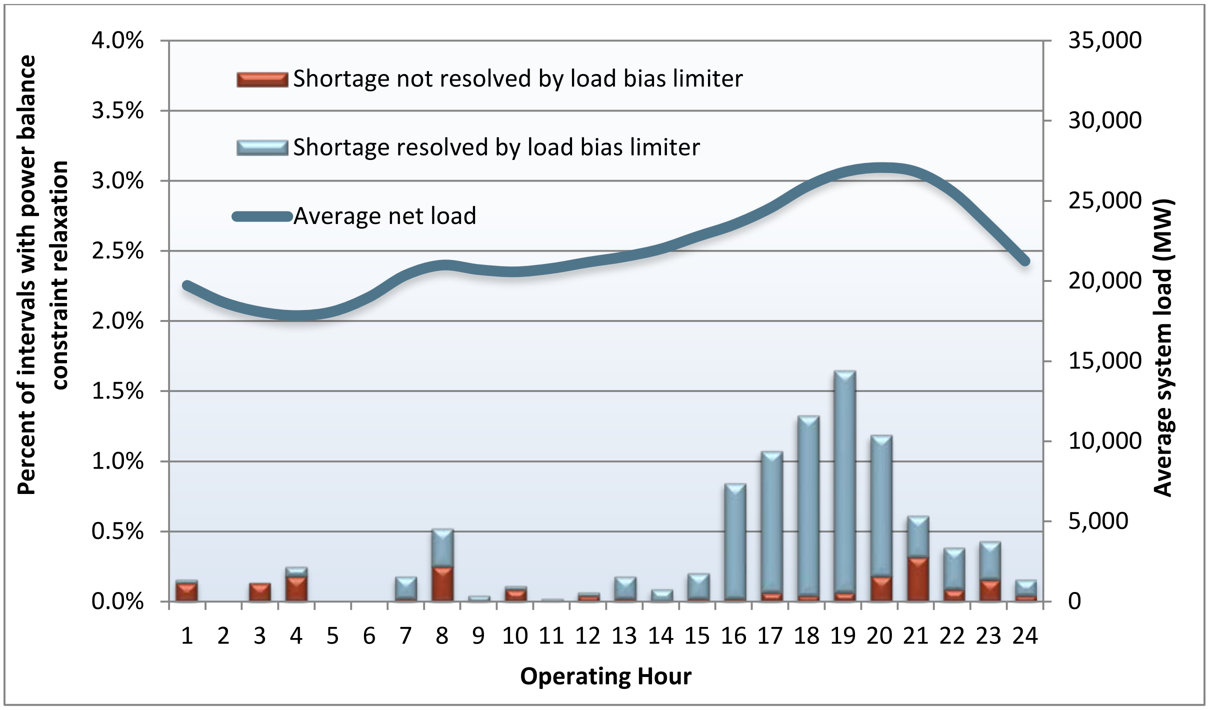
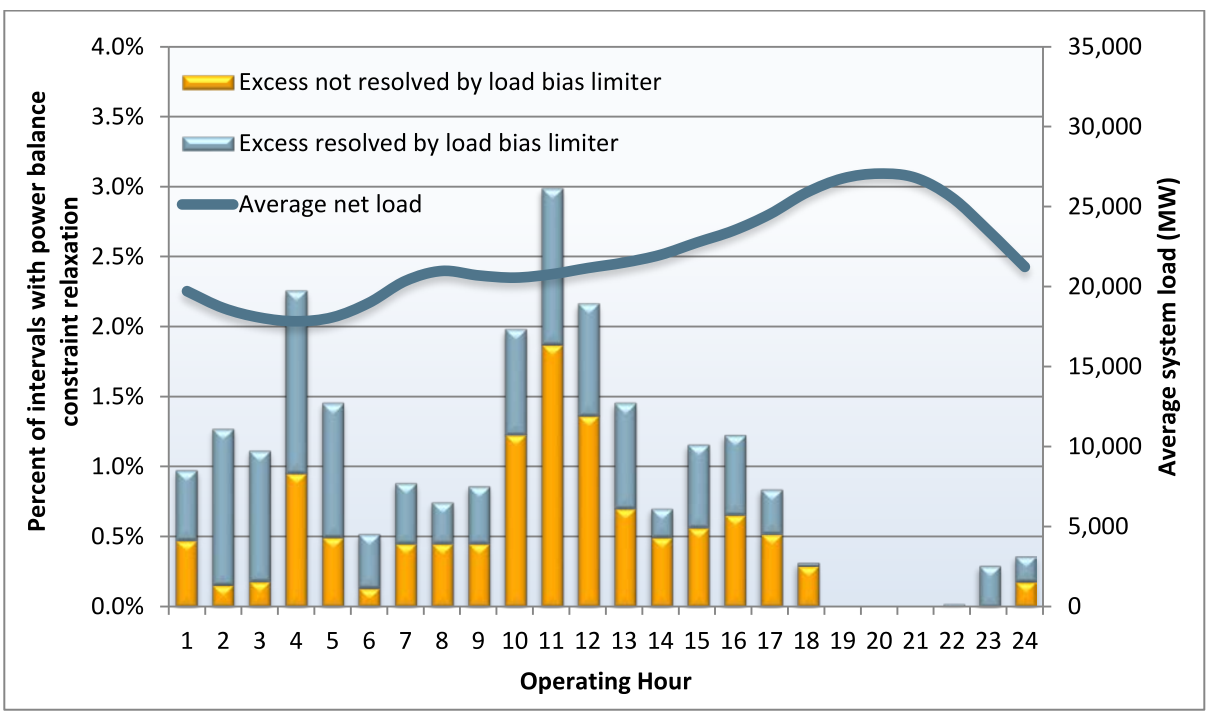


Figure 3.11 Relaxation of power balance constraint due to insufficient downward ramping capacity by hour (2014)



3.3 Flexible ramping constraint

This section provides background of the flexible ramping constraint and highlights key performance measures. These include the following:

- Flexible ramping payments were about $6.5 million for the year, compared to about $26 million in 2013. For the sake of comparison, costs for spinning reserves totaled about $35 million in 2014.
- Hydro-electric capacity accounted for about 52 percent of these payments with natural gas-fired capacity accounting for 39 percent.
- On average, the flexible ramping requirement was set to around 330 MW in the late evening and early morning hours and around 450 MW in the morning and evening load-ramping hours.
- With the implementation of the energy imbalance market, the flexible ramping constraint is now applied to each EIM balancing authority area, as group combinations of balancing authority areas, and for the entire EIM footprint.

Background

ISO enforces the flexible ramping constraint in the upward ramping direction in the 15-minute real-time market.[73] Application of the constraint in the 15-minute market is intended to ensure that enough capacity is procured to meet the flexible ramping requirement.

The ISO balancing area default requirement was set to 300 MW, but was frequently adjusted up to 450 MW, typically in the morning and evening ramping hours.[74] The ISO operators have the ability to adjust the requirement depending on system conditions. Over the course of the year, ISO operators frequently adjusted the requirement to different levels to better prepare for potential ramping shortages, particularly during the steep morning and evening ramping periods.

If there is sufficient capacity already online, the constraint does not commit additional resources in the system, which often leads to a low (or often zero) shadow price for the procured flexible ramping capacity. Otherwise, additional flexible ramping capacity is increased to supplement the existing non-contingent spinning reserves in the system in managing these variations.

Units committed to meet the flexible ramping requirement can be eligible for bid cost recovery payments in real time. A procurement shortfall of flexible ramping capacity will occur when there is a shortage of available supply bids to meet the flexible ramping requirement or when there is energy scarcity in the 15-minute real-time market.

Since December 2011, the penalty price associated with procurement shortfalls was set to $247/MW. This penalty price remained through 2014. However, as part of its analysis of upcoming market changes

[73] The flexible ramping constraint is also binding in the second, but not the first, interval of the real-time dispatch market.

[74] On January 31, 2014, the ISO lowered the recommended maximum adjustment of the flexible ramping requirement from 900 MW to 600 MW. For further detail, see the following market notice: http://www.caiso.com/Documents/Notification-RevisedCaliforniaISO_OperatingProcedures2250-2330-2540-4410-5730.htm.

in the spring of 2014, the ISO determined that $60/MW was a more appropriate penalty price.[75] The FERC approved this change, and, accordingly, the ISO lowered the penalty price on January 15, 2015.[76]

Modeling the flexible ramping constraint in the energy imbalance market

Before EIM implementation in November, the flexible ramping constraint was applied to internal generation, dynamic inter-ties and proxy demand response resources within the ISO. After EIM implementation, the flexible ramping constraint is now also applied to each EIM balancing authority area, as group combinations of balancing authority areas, and for the entire EIM footprint. In total there are seven flexible ramping constraints used in the model.

The flexible ramping requirement for each EIM balancing authority area is determined using a similar methodology to that which has been historically used for the ISO area. The market operator calculates the amount of 5-minute flexibility required for each individual area and then again for the entire EIM footprint.

Individual balancing authority areas before each operating hour need to meet the flexible ramping requirement to ensure enough upward ramping capacity is available prior to the 15-minute market run. Before the market runs the ISO performs a test, called the flexible ramping sufficiency test, to ensure sufficient capacity in each balancing area.

Market operators calculate the flexible ramping requirement values used in the flexible ramping constraint sufficiency test for each area. For instance, the ISO calculates the requirement for the ISO balancing area and PacifiCorp calculates the requirement for the PacifiCorp East and West balancing areas. The final requirement value for each area reflects the pro rata share of the EIM diversity benefit and the flexible ramping requirement credit of each balancing area.[77]

The diversity benefit is the difference between the sum of individual balancing authority area flexible ramp requirements and the flexible ramping requirement for the combined balancing areas as a whole.[78] Should an EIM balancing area fail the hourly flexible ramping sufficiency test, it cannot increase imports from any other area for that hour. This rule was designed to ensure that a balancing

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75 For the ISO analysis, see: http://www.caiso.com/Documents/TechnicalBulletin-FlexibleRampingConstraintPenaltyPrice-FifteenMinuteMarket.pdf.

76 For more information, see: http://www.caiso.com/Documents/Dec18_2014_OrderAcceptingFlexibleRampingConstraintParameterAmendment_ER15-50.pdf.

77 For example, if a balancing authority area has a flexible ramping requirement of 300 MW without diversity benefit or credit, and the pro rata diversity benefit for that balancing authority area is 20 MW, and the balancing authority area also has a 30 MW requirement credit, then the final requirement value for the balancing authority area in the flexible ramping sufficiency test will be 300 - 20 - 30 = 250 MW. Other factors can also affect the final value of the flexible ramping requirement used in the sufficiency test. Details of the calculation methodology can be found in the Business Practice Manual for Energy Imbalance Market, Section 10.3.2.1: http://bpmcm.caiso.com/BPM Document Library/Energy Imbalance Market/BPM_for_Energy Imbalance Market_V2_clean.docx.

78 For example, if the flexible ramping requirement for the two balancing authority areas in the EIM is 400 MW and 200 MW, and the entire EIM footprint has a requirement of 450 MW, then the EIM diversity benefit is equal to 150 MW (600 MW - 450 MW). This diversity benefit of 150 MW will be distributed among the balancing authority areas in proportion to their individual requirements. In this case, the first balancing authority area will receive 100 MW and the other will receive 50 MW of the diversity benefit.

area is not leaning on the flexibility of another area.[79] If all the areas pass the test, the market optimizes the flexible ramping requirement for each area to meet each of the flexible ramping constraints. Should an area fail the sufficiency test, it is excluded from the combined constraint optimization.

As discussed in DMM's fourth quarter report, flexible ramping constraint results in the ISO and EIM appeared inconsistent with the EIM design and market conditions.[80] DMM referred these results to the ISO for further review. The ISO determined that a variety of software and design errors drove these results and took steps to mitigate these issues in February 2015.

Performance of the flexible ramping constraint

Total payments for flexible ramping resources in 2014 were around $6.5 million, compared to about $26 million in 2013. For the sake of comparison, costs for spinning reserves totaled about $35 million in 2014. There are also secondary costs, such as those related to bid cost recovery payments to cover the commitment costs of the units committed by the constraint and additional ancillary services payments. Assessment of these costs are complex and beyond the scope of this analysis.

Table 3.1 provides a summary of the monthly flexible ramping constraint activity in the 15-minute real-time market in 2014.[81] The table highlights the following:

- For the year, the flexible ramping constraint was binding in 5 percent of 15-minute intervals. The frequency that the flexible ramping constraint was binding varied over the year. Aside from December, the frequency was highest in March and April (12 percent) and lowest in November (1 percent).
- The portion of intervals during which the ISO was unable to procure the targeted level of flexible ramping capacity was 0.2 percent of all 15-minute intervals in 2014, compared to 1.3 percent of intervals in 2013.
- The average shadow price when binding, excluding December, varied between $25/MWh and $74/MWh.
- The constraint did not bind in December as a result of EIM implementation issues.

[79] As stated in the Business Practice Manual for Energy Imbalance Market, Section 10.3.2.1; for details see: http://bpmcm.caiso.com/BPM Document Library/Energy Imbalance Market/BPM_for_Energy Imbalance Market_V2_clean.docx.

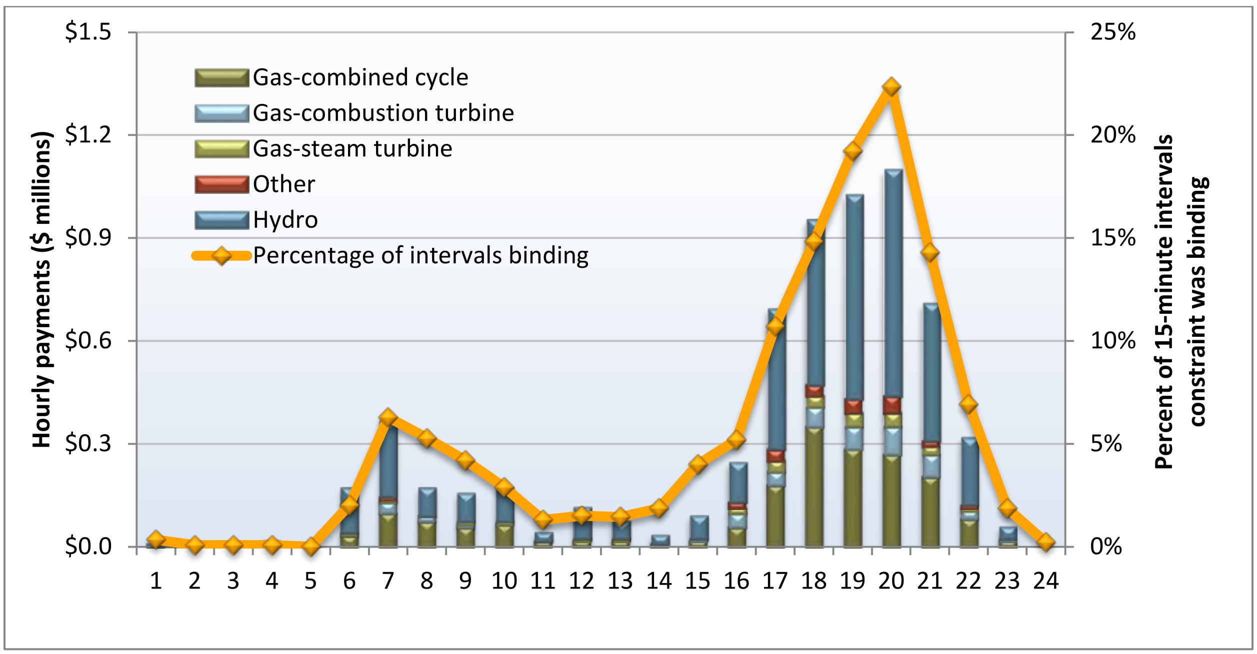
[80] For further details, see *Q4 2014 Report on Market Issues and Performance*, Department of Market Monitoring, March 2015, Section 3.2.1: pp. 35-40: http://www.caiso.com/Documents/2014FourthQuarterReport_MarketIssuesandPerformance_March2015.pdf.

[81] DMM had problems with data availability between October 16 and October 30, and thus did not include the data from that period in the calculation.

Table 3.1 Flexible ramping constraint monthly summary

Year	Month	Total payments to generators ($ millions)	15-minute intervals constraint was binding (%)	15-minute intervals with procurement shortfall (%)	Average shadow price when binding ($/MWh)
2014	Jan	$1.27	10%	0.1%	$28.37
2014	Feb	$0.56	4%	0.4%	$45.68
2014	Mar	$1.17	12%	0.3%	$34.37
2014	Apr	$1.32	11%	0.8%	$44.59
2014	May	$0.72	7%	0.1%	$28.96
2014	Jun	$0.25	4%	0.1%	$25.97
2014	Jul	$0.25	3%	0.1%	$49.23
2014	Aug	$0.11	3%	0.1%	$25.06
2014	Sep	$0.21	4%	0.1%	$33.10
2014	Oct	$0.42	4%	0.4%	$41.84
2014	Nov	$0.19	1%	0.2%	$74.48
2014	Dec	$0.02	0%	0.0%	$0.00

Figure 3.12 Hourly flexible ramping constraint payments to generators (January – December)



On an hourly basis, DMM estimates that most payments for ramping capacity occurred during the evening peak hours and that most payments were for hydro-electric resources. Figure 3.12 shows the hourly flexible ramping payment distribution during the entire year broken down by technology type.[82] As shown in the graph, the highest payment periods were during hours ending 7 and 17 through 22.

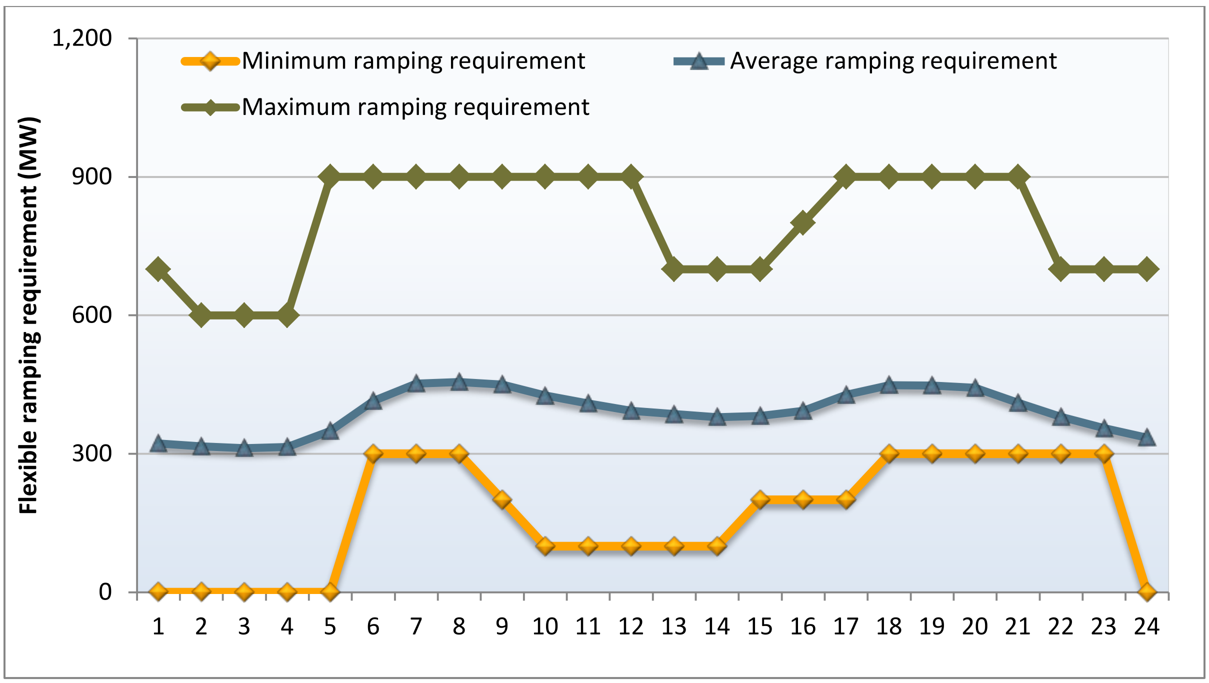
[82] Due to a data issue, the data from November 2, 2014 was not included in the calculation.

Natural gas-fired capacity accounted for about 39 percent of these payments with hydro-electric capacity accounting for 52 percent.

Procurement of flexible ramping capacity

The ISO continues its efforts to decrease the frequency and volume of exceptional dispatch. As a result, ISO operators use market tools such as the flexible ramping constraint to deal with reliability concerns. Figure 3.13 shows the hourly average flexible ramping requirement values in 2014. The hourly ramping requirement ranged from a minimum of 0 MW to a maximum of 900 MW.[83] On average, the requirement was set to around 330 MW in the late evening and early morning hours and around 450 MW in the morning and evening load-ramping hours, which was down from an average of over 600 MW in 2013 in the morning and evening load-ramping hours.

Figure 3.13 Hourly average flexible ramping requirement values (January – December)



3.4 Energy imbalance market

Background

The energy imbalance market became financially binding with its first participant on November 1. Balancing authority areas outside of the ISO balancing authority area can now voluntarily take part in

[83] On January 31, 2014, the ISO lowered the recommended maximum adjustment of the flexible ramping requirement from 900 MW to 600 MW. For further detail, see the following market notice: http://www.caiso.com/Documents/Notification-RevisedCaliforniaISO_OperatingProcedures2250-2330-2540-4410-5730.htm.

the ISO's real-time market. The energy imbalance market is expected to achieve benefits for customers and facilitate integration of higher levels of renewable generation.[84]

The EIM includes both 15-minute and 5-minute financially binding schedules and settlement. Energy imbalances between 15-minute schedules and base (pre-market) schedules settle at the 15-minute market prices, and energy imbalances between 15-minute schedules and 5-minute schedules settle at 5-minute market prices. With the EIM, the ISO also modified the flexible ramping constraint construct as outlined in further detail in Section 3.3.

During the initial EIM implementation, the amount of capacity available through the market clearing process was restricted and imbalance needs were not reflective of actual economic and operational conditions. This caused the need to relax ramping and system energy balance constraints in the market software more frequently than expected to enable the market to clear. When relaxing the power balance constraint for an EIM area, prices could be set based on the $1,000/MWh penalty price for this constraint used in the pricing run of the market model.

After review, the ISO determined that many of these outcomes were inconsistent with actual conditions. Consequently, on November 13, 2014, the ISO filed a request for tariff waiver and FERC approved the waiver providing special *price discovery* measures to set prices based on the last dispatched bid price rather than penalty prices for various constraints.[85] FERC approved the filing on December 1 with an effective date of November 14, 2014. In addition, FERC ordered that the ISO and the Department of Market Monitoring provide informational reports every 30 days during the period of the waiver, outlining the issues driving the need for the EIM tariff waiver.[86]

Energy imbalance market performance

Prices in the EIM during most intervals have been highly competitive and have been set by bids closely reflective of the marginal operating cost of the highest cost resource dispatched to balance loads and generation. However, during a relatively small portion of intervals, energy or flexible ramping constraints have had to be relaxed for the market software to balance modeled supply and demand.

Figure 3.14 and Figure 3.15 provide a weekly summary of the frequency of constraint relaxation, average prices with and without price discovery, and bilateral market prices, for PacifiCorp East and PacifiCorp West, respectively, in the 15-minute market.

As shown in Figure 3.14, the frequency of constraint relaxations in the 15-minute market in PacifiCorp East was relatively high during the first month of EIM, and then declined significantly through most of December. As shown in Figure 3.15, the frequency of constraint relaxations in the 15-minute market in

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[84] For more information see: *Benefits for Participating in EIM* report, February 11, 2015: http://www.caiso.com/Documents/PacifiCorp_ISO_EIMBenefitsReportQ4_2014.pdf.

[85] For further details, see http://www.caiso.com/Documents/Nov13_2014_PetitionWaiver_EIM_ER15-402.pdf.

[86] The two ISO filings and the two DMM filings for November and December can be found at the following links:
http://www.caiso.com/Documents/Dec15_2014_EnergyImbalanceMarketPerformanceReport_ER15-402.pdf
http://www.caiso.com/Documents/Jan15_2015_EnergyImbalanceMarket_REPORT_ER15-402.pdf
http://www.caiso.com/Documents/Dec18_2014_DMMReport_EIMPerformance_November2014_ER15-402.pdf
http://www.caiso.com/Documents/Jan23_2015_DMMAssessment_December2014EIMPerformance.pdf.

PacifiCorp West dropped substantially during November and remained relatively low through the end of December.

These two figures also show average daily prices in the 15-minute market with and without the special price discovery mechanism being applied to mitigate prices in PacifiCorp East and PacifiCorp West, respectively. These figures also provide a comparison of EIM prices to bilateral market price indices that were used to set prices in the PacifiCorp areas prior to EIM implementation.[87] These figures show that without the price discovery provisions being applied in EIM, average daily prices would consistently exceed the bilateral market price index reflective of prices for imbalance energy in the PacifiCorp areas prior to EIM. However, with price discovery, EIM prices track very closely with this bilateral price index.

Figure 3.16 and Figure 3.17 provide the same weekly summary for the 5-minute market. As shown in these figures, the need to relax the power balance constraint in the 5-minute market has also remained relatively high in both PacifiCorp East and PacifiCorp West since EIM implementation. This reflects the fact that in the 5-minute market the supply of ramping capacity within PacifiCorp is more constrained. This also reflects that incremental transfers into PacifiCorp from the ISO in the 5-minute market have been essentially prevented during almost all intervals. The dynamic transfer constraint (DTC), which constrains the extent to which transfers between PacifiCorp and the ISO scheduled in the 15-minute market can change in the 5-minute market, was set to a limit of less than 0.003 MW during more than 92 percent of 5-minute market intervals between November 1 and December 31.[88]

As shown in Figure 3.14 through Figure 3.17, the price discovery mechanism approved under FERC's December 1 order has effectively mitigated the impact of constraint relaxation on market prices beginning on November 14. Currently, prices before November 14 are not subject to price discovery and diverged significantly from the bilateral market prices.

[87] The bilateral market index represents a daily average of peak and off-peak prices for four major western trading hubs (California Oregon Border, Mid-Columbia, Palo Verde and Four Corners). Prior to EIM implementation, DMM identified this bilateral price index to stakeholders and regulators as a benchmark DMM would use to assess the competitiveness and overall performance of EIM.

[88] On February 4, 2015, the ISO started to adjust the dynamic transfer constraint between PacifiCorp and the ISO.

Figure 3.14 Frequency of constraint relaxation and average prices by week PacifiCorp East - 15-minute market

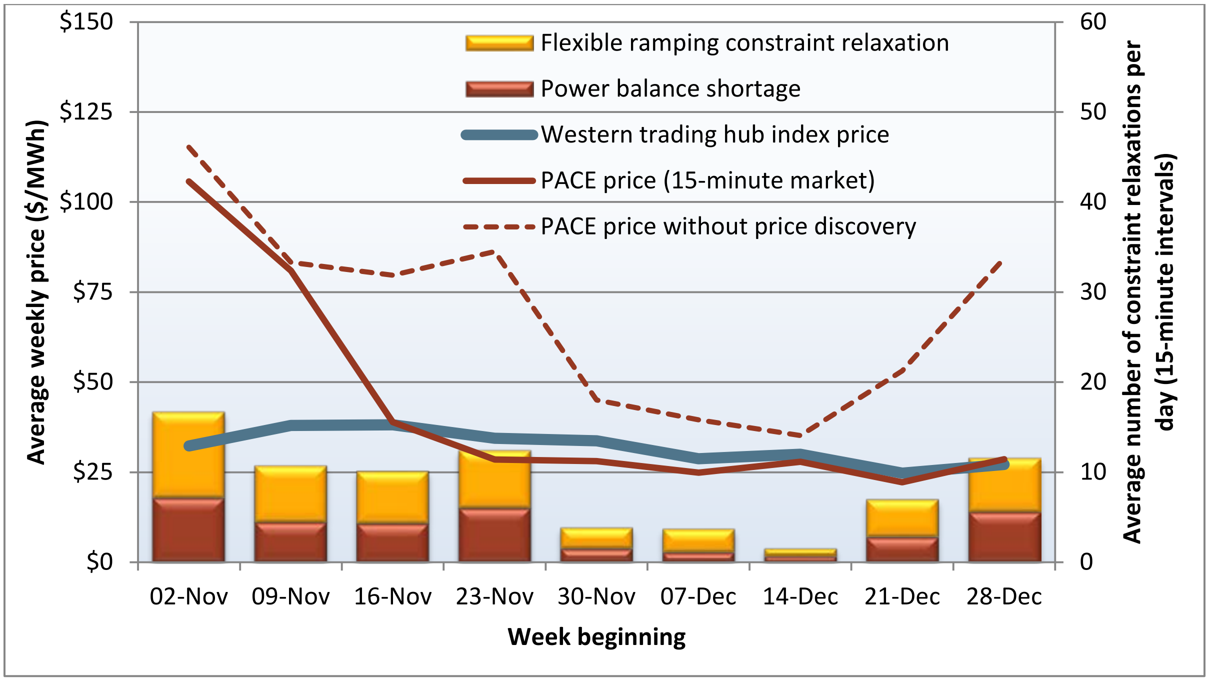


Figure 3.15 Frequency of constraint relaxation and average prices by week PacifiCorp West - 15-minute market

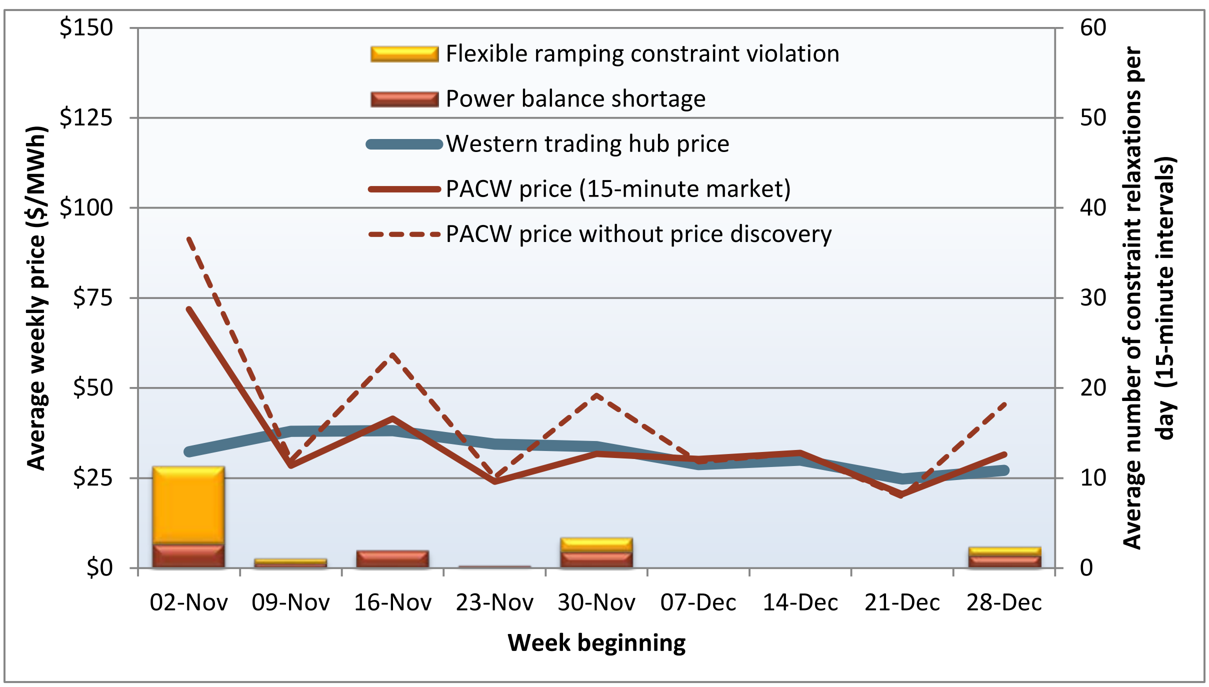


Figure 3.16 Frequency of constraint relaxation and average prices by week PacifiCorp East - 5-minute market

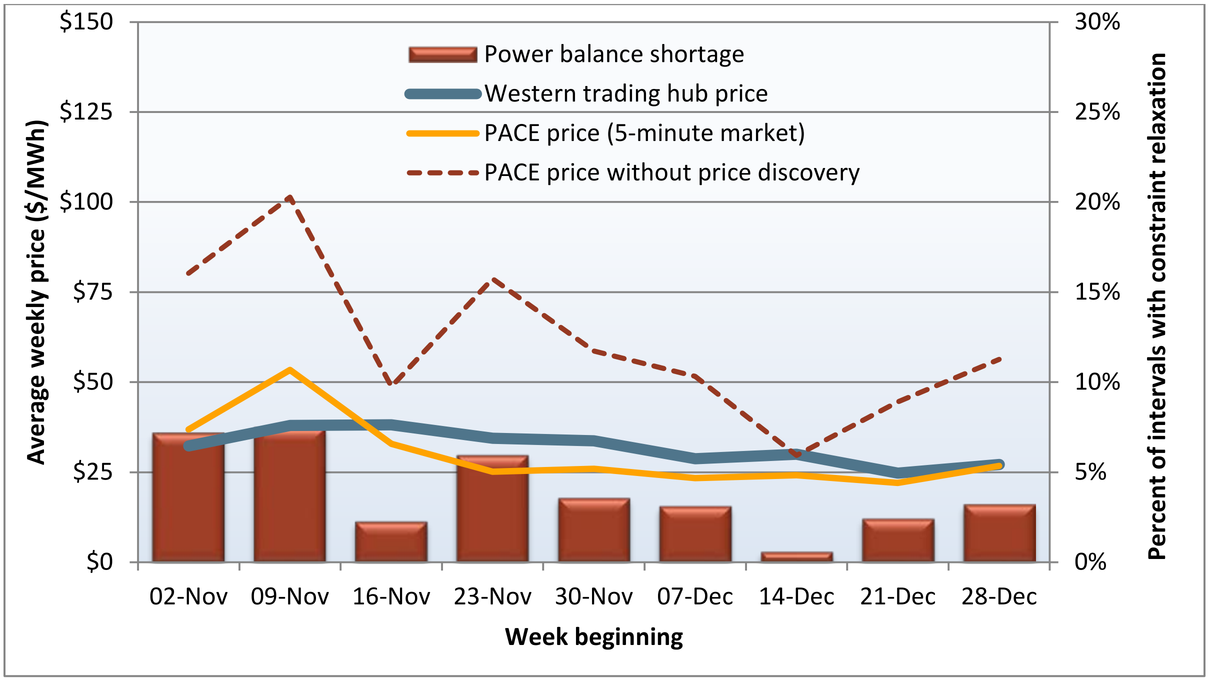
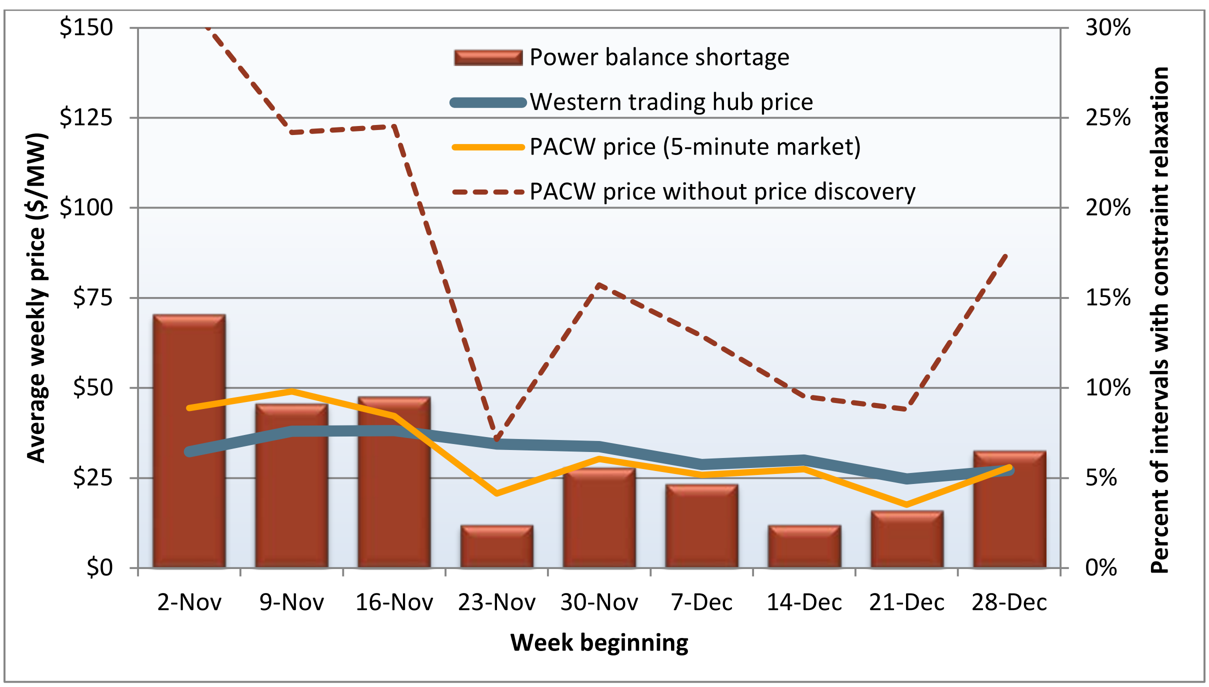


Figure 3.17 Frequency of constraint relaxation and average prices by week PacifiCorp West - 5-minute market



4 Convergence Bidding

Convergence bidders in 2014 continued a shift from virtual demand to virtual supply that began in the latter half of 2013. Average hourly virtual supply clearing in the day-ahead market exceeded virtual demand by about 450 MW per hour in 2014, compared to an average of about 380 MW of net virtual supply last year. This trend reflects the change in prices that began in 2013, when average real-time prices began to be consistently lower than average day-ahead prices during most periods.

The increase in virtual supply was driven in large part by an increase in net virtual supply bids submitted by load-serving entities, which increased from 156 MW per hour in 2013 to 265 MW per hour in 2014. One reason the state's main load-serving entities are authorized by the CPUC to engage in virtual bidding is to offset renewable energy that is not scheduled in the day-ahead market for contractual reasons. However, the total amount of net virtual supply clearing the day-ahead market still fell short of the total amount of renewable and other generation not scheduled in the day-ahead market.

Total net revenues paid to entities engaging in convergence bidding, including bid cost recovery charges allocated to virtual bids, totaled around $26 million in 2014, compared to about $17 million in 2013. Most of these net revenues resulted from virtual supply bids. However, financial entities and marketers also continued to place large volumes of offsetting virtual demand and supply bids at different locations during the same hour. This type of offsetting bids, which are designed to hedge or profit from congestion, represented about 65 percent of all accepted virtual bids in 2014.

Over 57 percent of these net revenues were paid to financial entities which only participate in virtual bidding and congestion revenue rights in the ISO markets. About 20 percent of these net revenues were received by marketers who also engaged in scheduling of imports and exports, with physical generators and load-serving entities each receiving slightly over 10 percent of net revenues.

About half of this $9 million increase in net revenues received by convergence bidders resulted from a decline in bid cost recovery payments resulting from residual unit commitment costs allocated to virtual supply. The portion of these costs allocated to virtual supply dropped from about $9 million in 2013 to $5 million in 2014. This decrease was driven in large part by changes in how forecasted renewable schedules are accounted for in the residual unit commitment process, which resulted in a significant drop in residual unit commitment bid cost recovery.[89]

Background

Virtual bidding is a part of the Federal Energy Regulatory Commission's standard market design and is in place at all other ISOs with day-ahead energy markets. In the California ISO markets, virtual bidding is formally referred to as *convergence bidding*. The ISO implemented convergence bidding in February 2011.

Convergence bidding allows participants to place purely financial bids for supply or demand in the day-ahead energy market. These virtual supply and demand bids are treated similar to physical supply and

[89] In early 2014, the ISO began adjusting renewable schedules in the residual unit commitment process to forecasted levels. This resulted in several hundred megawatts of additional supply in the residual unit commitment, which reduced the amount of capacity and commitment procured by that process. See Section 2.4 for further detail.

demand in the day-ahead market. However, all virtual bids clearing the day-ahead market are removed from the real-time markets, which are dispatched based only on physical supply and demand. Virtual bids accepted in the day-ahead market are liquidated financially in the real-time market as follows:

- Participants with virtual demand bids accepted in the day-ahead market pay the day-ahead price for this virtual demand. Virtual demand at points within the ISO is then paid the real-time price for these bids.
- Participants with accepted virtual supply bids are paid the day-ahead price for this virtual supply. Virtual supply at points within the ISO is then charged the real-time price.

Virtual bidding allows participants to profit from any difference between day-ahead and real-time prices. In theory, as participants take advantage of opportunities to profit through convergence bids, this activity should tend to make prices in these different markets closer, as illustrated by the following:

- If prices in the real-time market tend to be higher than day-ahead market prices, convergence bidders will seek to arbitrage this price difference by placing virtual demand bids. Virtual demand will raise load in the day-ahead market and thereby increase prices. This increase in load and prices could also lead to the commitment of additional physical generating units in the day-ahead market, which in turn could tend to reduce average real-time prices. In this scenario, virtual demand could help improve price convergence by increasing day-ahead prices and reducing real-time prices.
- If real-time market prices tend to be lower than day-ahead market prices, convergence bidders will seek to profit by placing virtual supply bids. Virtual supply will tend to lower day-ahead prices by increasing supply in the day-ahead market. This increase in virtual supply and decrease in day-ahead prices could also reduce the amount of physical supply committed and scheduled in the day-ahead market.[90] This would tend to increase average real-time prices. In this scenario, virtual supply could help improve price convergence by reducing day-ahead prices and increasing real-time prices.

Convergence bidding also provides a mechanism for participants to hedge or speculate against price differences in the two following circumstances:

- price differences between the day-ahead and real-time markets; and
- congestion at different locations.

However, the degree to which convergence bidding has actually increased market efficiency by improving unit commitment and dispatches has not been assessed. In some cases, virtual bidding may be profitable for some market participants without increasing market efficiency significantly or even decreasing market efficiency.[91]

[90] This will not create a reliability issue as the residual unit commitment process occurs after the integrated forward market run. The residual unit commitment process removes convergence bids and re-solves the market to the ISO forecasted load. If additional units are needed, the residual unit commitment process will commit more resources.

[91] A recent report reviewing the effectiveness of virtual bidding indicates that under certain conditions, virtual bidding may be parasitic to the market rather than adding value and improving efficiency. The report focused on issues that had been identified and noted in the California ISO markets. For more information see:

Virtual bidding on inter-ties was temporarily suspended in November 2011 due to issues with settlement of virtual bids at inter-ties that tended to lead to high revenue imbalance costs and reduced the potential benefits of virtual bids at nodes within the ISO system.[92] Virtual bidding on inter-ties was scheduled to be re-implemented in May 2015 – one year after implementation of the new 15-minute real-time market design.

However, in April 2015, the ISO requested a waiver for the requirement to re-implement virtual bidding on inter-ties for up to an additional 12-month period. The basis of the ISO request was the concern that reintroducing inter-tie virtual bidding in light of the observed lack of liquidity in economic bidding in the ISO's 15-minute market would decrease economic efficiency, based on a supplemental report completed by DMM analyzing the connection between 15-minute market economic bids at the inter-ties and inter-tie virtual bidding.[93] FERC granted a temporary waiver delaying implementation of convergence bidding on the inter-ties pending further review and a subsequent order.[94]

Beginning in May 2014, virtual bids at internal points within the ISO system accepted in the day-ahead market began to be settled based on prices in the 15-minute market rather than 5-minute market prices. All numbers reported in this section reflect the prevailing settlement rules at the time the market ran.

4.1 Convergence bidding trends

Convergence bidding volumes were relatively stable throughout the year and continued the shift to net virtual supply which began in the latter half of 2013. Figure 4.1 shows the quantities of both virtual demand and supply offered and cleared in the market. Figure 4.2 shows the average net cleared virtual positions for each operating hour.

Key convergence bidding trends include the following:

- On average, 50 percent of virtual supply and demand bids offered into the market cleared in 2014, a decrease from about 57 percent in 2013.

Parsons, John E., Cathleen Colbert, Jeremy Larrieu, Taylor Martin and Erin Mastrangelo. 2015. Financial Arbitrage and Efficient Dispatch in Wholesale Electricity Markets. MIT Center for Energy and Environmental Policy Research, Working Paper, February.

Retrieved from http://www.mit.edu/~jparsons/publications/20150300_Financial_Arbitrage_and_Efficient_Dispatch.pdf.

92 As described in DMM's 2011 annual report, this problem was created by the fact that virtual bids at inter-ties were settled on hour-ahead prices, while virtual bids at internal locations were settled at 5-minute prices. For further detail see the *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, pp. 77-79: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

93 *Potential market inefficiencies from convergence bidding at interties with insufficient liquidity of fifteen-minute bids*, Department of Market Monitoring, April 3, 2015: http://www.caiso.com/Documents/DMMReport-ConvergenceBiddingonInterties.pdf.

94 See: http://www.caiso.com/Documents/Apr29_2015_OrderGrantingWaiverRequest_IntertieVirtualBidding_ER15-1451_ER14-480.pdf.

Figure 4.1 Quarterly average virtual bids offered and cleared

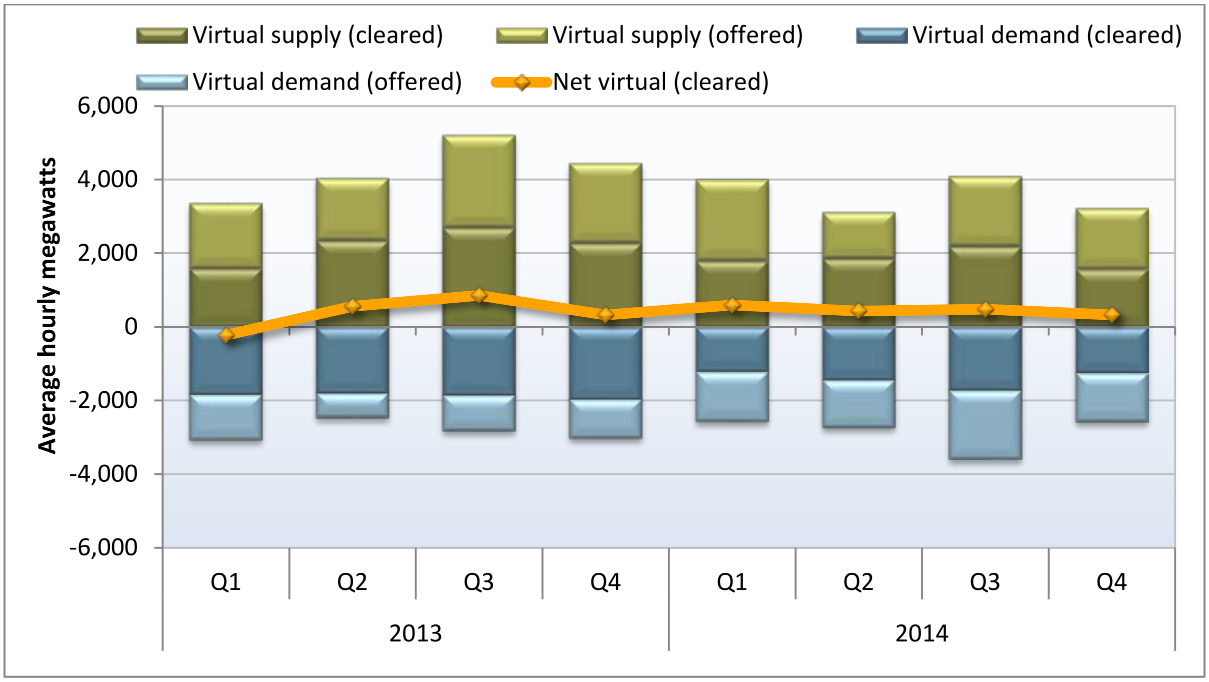
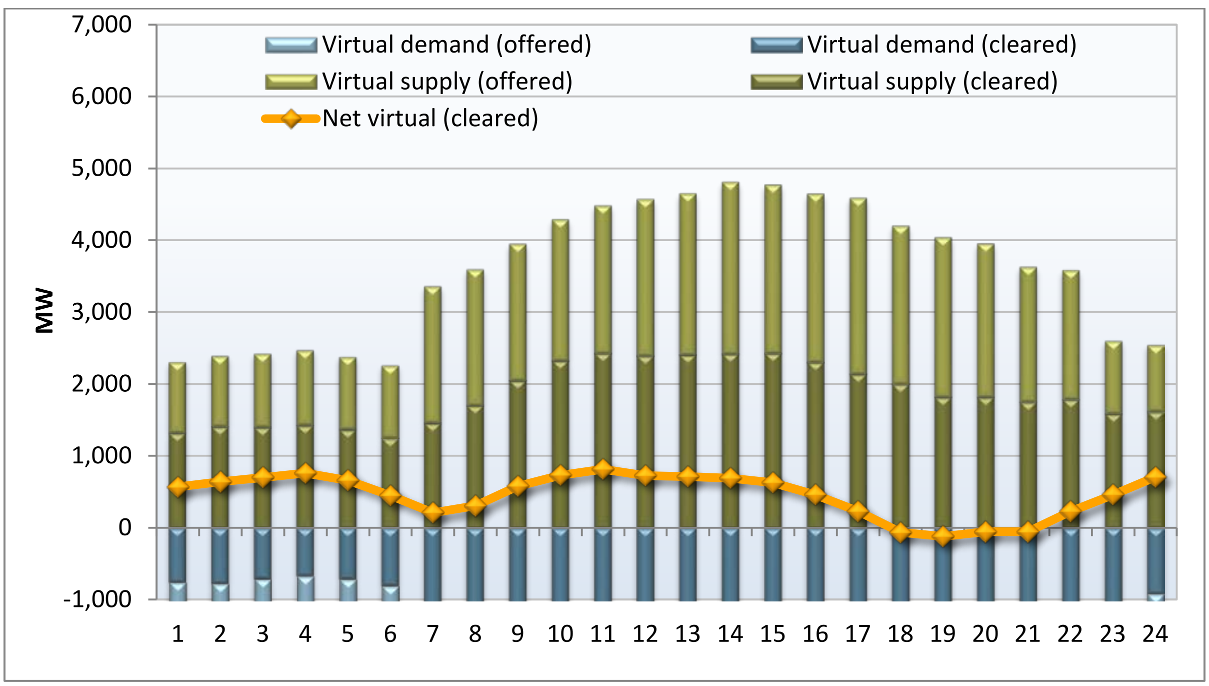


Figure 4.2 Average net cleared virtual bids in 2014



- The average hourly cleared volume of virtual supply outweighed virtual demand during every quarter. For the year, average hourly cleared virtual supply outweighed virtual demand by about 450 MW per hour. This is an increase from last year when the average hourly cleared virtual supply outweighed virtual demand by about 380 MW in each hour. The increase in net virtual supply volumes may be due to periods of lower prices between the real-time markets and the day-ahead markets in 2014 (see Section 2.3).

- The shift to virtual supply positions that began in 2013 continued in 2014. The net position of all cleared virtual bids remained virtual supply in all but four hours (hours ending 18 through 21).

- About 60 percent of cleared virtual positions were held by pure financial trading entities that do not serve load or transact physical supply. In 2013, about 78 percent of cleared virtual positions were held by pure financial trading entities.

Offsetting virtual supply and demand bids

Market participants can also hedge congestion costs or seek to profit from differences in congestion between different points within the ISO by placing equal quantities of virtual demand and supply bids at different locations during the same hour. These virtual demand and supply bids offset each other in terms of system energy. However, the combination of these offsetting bids can be profitable if there are differences in congestion in the day-ahead and real-time markets between these two locations.

The majority of cleared virtual bids in 2014 were related to these bids and remained relatively stable throughout the year. Figure 4.3 shows the average hourly volume of offsetting virtual supply and demand positions. The dark blue and dark green bars represent the average hourly overlap between demand and supply by the same participants. The light blue bars represent the remaining portion of virtual demand that was not offset by virtual supply by the same participants. The light green bars represent the remaining portion of virtual supply that was not offset by virtual demand by the same participants.

As shown in Figure 4.3:

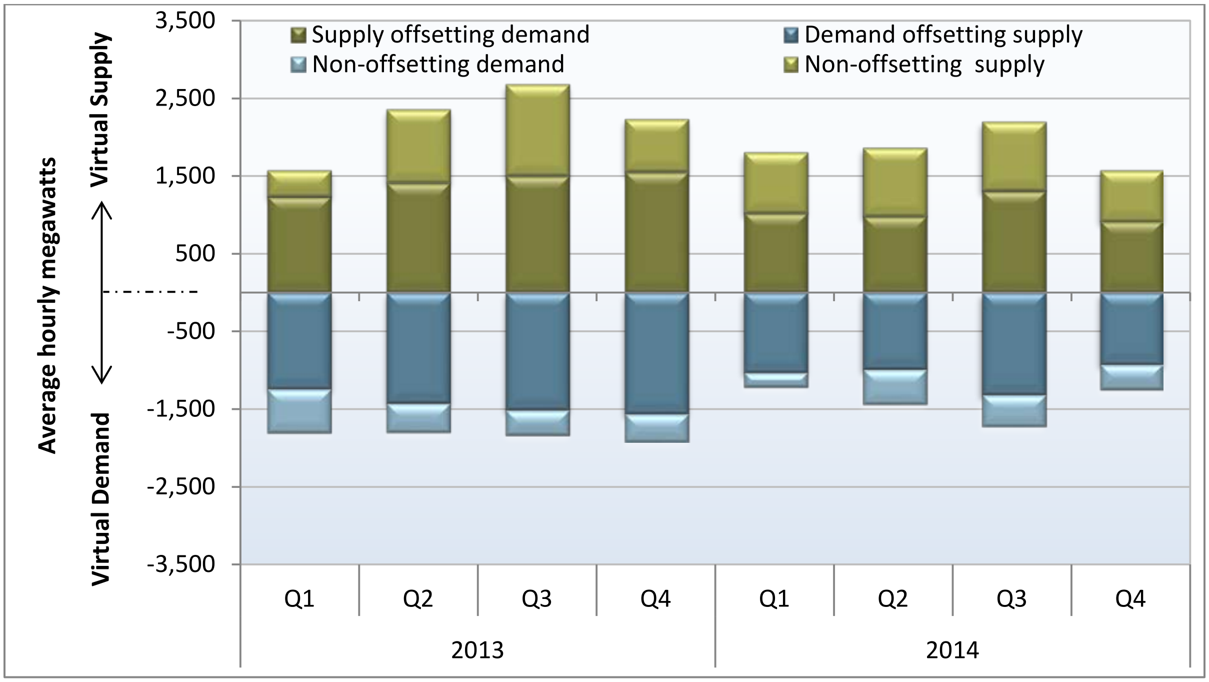
- Offsetting virtual positions accounted for an average of about 1,100 MW of virtual demand offset by 1,100 MW of virtual supply in each hour of the year. These offsetting bids represent about 65 percent of all cleared virtual bids in 2014, down from over 70 percent of bids in 2013. This suggests that virtual bidding continues to be used to hedge or profit from congestion.

- Over the course of the year, the amount of offsetting virtual bidding positions taken by participants fluctuated somewhat in volume and as a share of total virtual bids. The share of offsetting virtual positions was between 60 percent and 68 percent throughout the year.

- As discussed later in this chapter, virtual demand bids tended to be placed in selected peak hours during periods when average real-time prices tended to be higher than average day-ahead prices, coincident with real-time price spikes.

- Virtual supply bids were the dominant bid type and tended to be placed in all off-peak hours and in many peak hours during periods when average real-time prices tended to be lower than average day-ahead prices.

Figure 4.3 Average hourly offsetting virtual supply and demand positions



Consistency of price differences and volumes

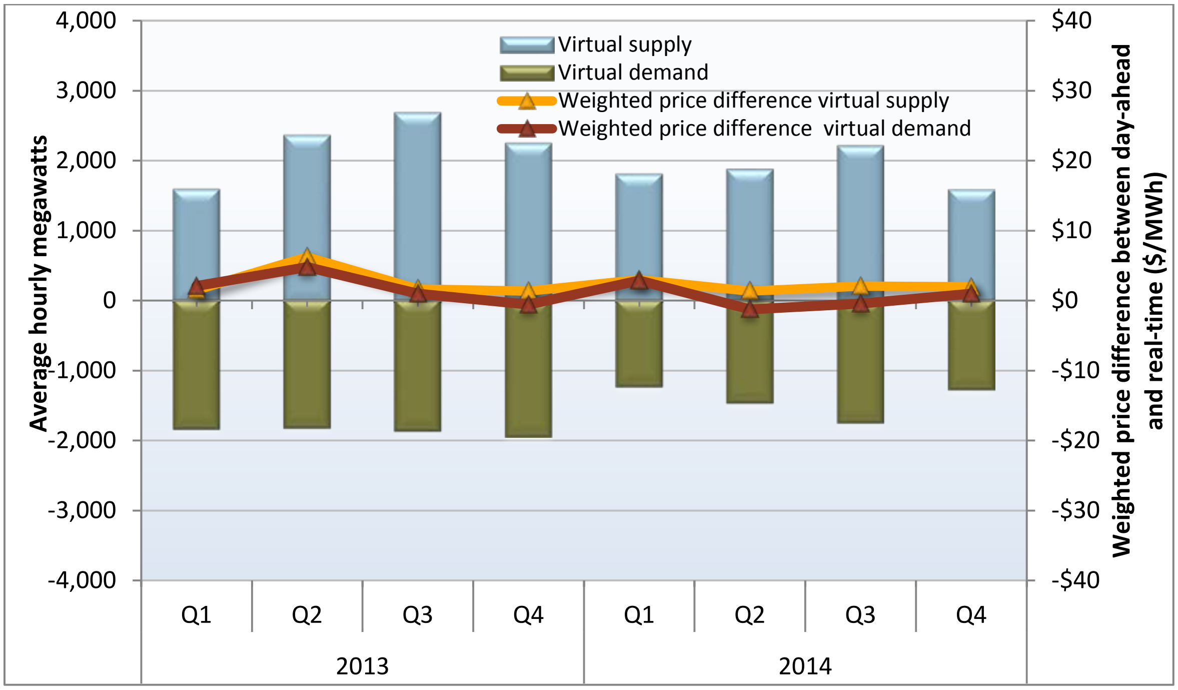
Convergence bidding is designed to bring together day-ahead and real-time prices when the net market virtual position is directionally consistent (and profitable) with the price difference between the two markets. Net convergence bidding volumes were generally consistent with price differences in all quarters of 2014, with the exception being the third quarter where convergence bids were only consistent in 13 hours. Compared to the previous year, the 2014 net convergence bidding volumes, on average, were more consistent with price differences between the day-ahead and real-time markets.

Figure 4.4 compares cleared convergence bidding volumes with the volume weighted average price differences at which these virtual bids were settled. The difference between day-ahead and real-time prices shown in this figure represents the average price difference weighted by the amount of virtual bids clearing at different locations.

Periods when the red line is negative indicates that the weighted average price charged for virtual demand in the day-ahead market was lower than the weighted average real-time price paid for this virtual demand. In 2014, virtual demand positions were not profitable in the first and fourth quarters and profits in the second and third quarters were a result of a few days with large price differences. In 2013, virtual demand volumes were not profitable in most quarters, with the exception of the fourth quarter.

Quarters when the yellow line is positive indicates that the weighted average price paid for virtual supply in the day-ahead market was higher than the weighted average real-time price charged when this virtual supply was liquidated in the real-time market. As with 2013, virtual supply was consistently profitable in all quarters in 2014.

Figure 4.4 Convergence bidding volumes and weighted price differences



As noted earlier, a large portion of the virtual supply clearing the market was paired with demand bids at different locations by the same market participant. Such offsetting virtual supply and demand bids are likely used as a way of hedging or speculating from congestion within the ISO. When virtual supply and demand bids are paired in this way, one of these bids may be unprofitable independently, but the combined bids may break even or be profitable due to congestion.

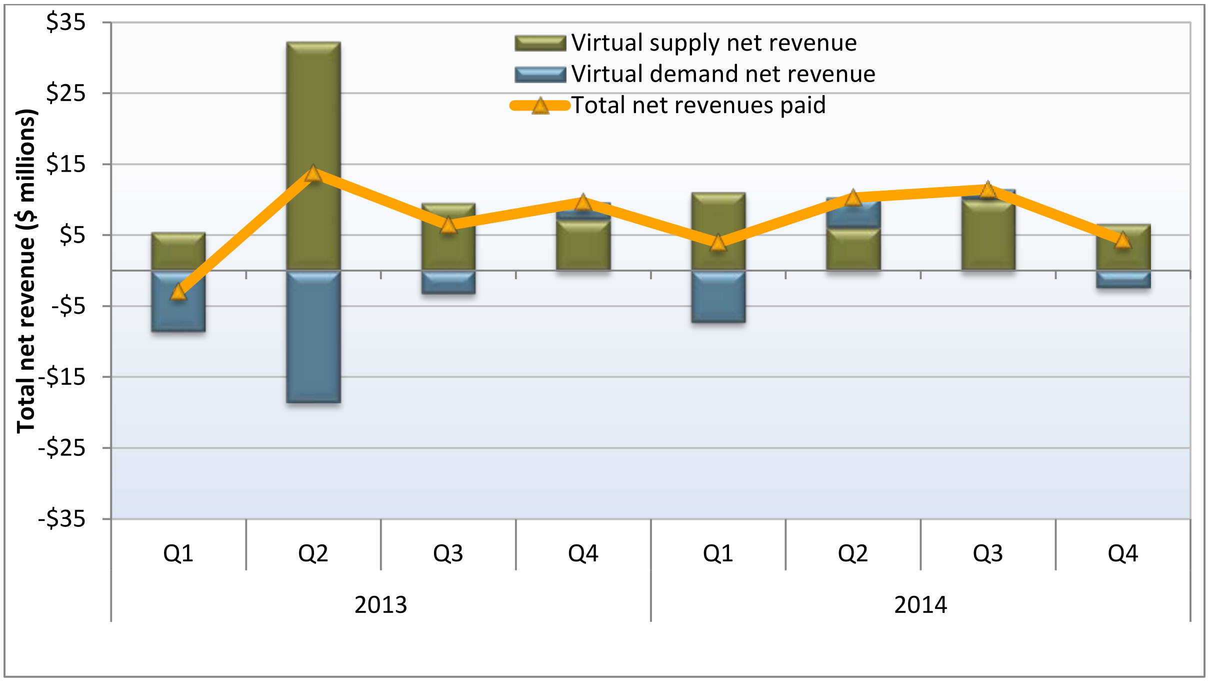
4.2 Convergence bidding payments

Net revenues paid to convergence bidders (prior to any allocation of bid cost recovery payments) totaled about $30 million in 2014, up from about $26 million in 2013, or an increase of about 15 percent. The majority of these profits were associated with virtual supply. Figure 4.5 shows total quarterly net profits paid for accepted virtual supply and demand bids. As shown in this figure:

- All net revenues ($34 million) came from virtual supply. About $4 million in losses were received by virtual demand.
- Virtual supply positions were profitable in all quarters in 2014. This trend reflects that revenues on virtual supply bids placed in nearly all hours are less volatile, and negative price spikes are smaller in magnitude and typically last longer.
- In the first and fourth quarters virtual demand positions were unprofitable with losses totaling over $9 million. Second and third quarter revenues totaled about $5 million and were associated with specific events that caused real-time prices to spike above day-ahead prices, in turn driving virtual demand revenues up and resulting in high profits on a few days. Overall, these results reflect that real-time prices were lower than day-ahead prices for most of the year.

- Total net revenues paid to virtual bidders peaked in the third quarter at $11.5 million which was slightly larger than the second quarter revenues of a little over $10 million. Total net revenues were lowest in the first and fourth quarters at $4 million in each quarter.

Figure 4.5 Total quarterly net revenues from convergence bidding



Net revenues and volumes by participant type

DMM's analysis finds that most convergence bidding activity is conducted by entities engaging in pure financial trading that do not serve load or transact physical supply. These entities accounted for over $17 million (about 58 percent) of the total convergence bidding revenues in 2014.

Table 4.1 compares the distribution of convergence bidding volumes and revenues among different groups of convergence bidding participants. The trading volumes show cleared virtual positions along with the corresponding revenues in millions of dollars.

Table 4.1 Convergence bidding volumes and revenues by participant type (2014)

Trading entities	Average hourly megawatts			Revenues\Losses ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	964	1,008	1,972	-$2.9	$20.3	$17.3
Marketer	294	362	656	-$0.5	$6.2	$5.7
Physical generation	150	226	376	-$0.6	$4.2	$3.7
Physical load	2	267	269	-$0.1	$3.4	$3.3
Total	**1,409**	**1,863**	**3,273**	**-$4.0**	**$34.1**	**$30.1**

DMM has defined financial entities as participants who own no physical power and participate in only the convergence bidding and congestion revenue rights markets. Physical generation and load are represented by participants that primarily participate in the ISO as physical generators and load-serving entities, respectively. Marketers include participants on the inter-ties and participants whose portfolios are not primarily focused on physical or financial participation in the ISO markets.

As shown in Table 4.1, financial participants represent the largest segment of the virtual market, accounting for about 60 percent of volumes and about 58 percent of revenues. Generation owners and load-serving entities represent about 23 percent of the revenues but only about 20 percent of volumes. Marketers represent about 20 percent of the trading volumes and revenues.

4.3 Bid cost recovery charges to virtual bids

As previously noted, virtual supply and demand bids are treated similarly to physical supply and demand in the day-ahead market. However, virtual bids are excluded from the day-ahead market processes for price mitigation and grid reliability (local market power mitigation and residual unit commitment). This impacts how physical supply is committed in both the integrated forward market and in the residual unit commitment process.[95] When the ISO commits units, it may pay market participants through the bid cost recovery mechanism to ensure that market participants are able to recover start-up costs, minimum load costs, transition costs, and energy bid costs.[96]

Because virtual bids can influence unit commitment, they share in the associated costs. Specifically, virtual bids can be charged for bid cost recovery payments under two charge codes.[97]

- Integrated forward market bid cost recovery tier 1 allocation addresses costs associated with situations when the market clears with positive net virtual demand.[98] In this case, virtual demand leads to increased unit commitment in the day-ahead market, which may not be economic.
- Day-ahead residual unit commitment tier 1 allocation relates to situations where the day-ahead market clears with positive net virtual supply.[99] In this case, virtual supply leads to decreased unit commitment in the day-ahead market and increased unit commitment in the residual unit commitment, which may not be economic.

The day-ahead residual unit commitment tier 1 allocation charge associated with virtual bids continued a general decline from the previous year. In the first half of the year, about 8 percent of total bid cost recovery charges were attributed to the day-ahead residual unit commitment tier 1 allocation charge.

95 If physical generation resources clearing the day-ahead energy market are less than the ISO's forecasted demand, the residual unit commitment process ensures that enough additional physical capacity is available to meet the forecasted demand. Convergence bidding increases unit commitment requirements to ensure sufficient generation in real time when the net position is virtual supply. The opposite is true when virtual demand exceeds virtual supply.

96 Generating units, pumped-storage units, or resource-specific system resources are eligible for receiving bid cost recovery payments.

97 Both charge codes are calculated by hour and charged on a daily basis.

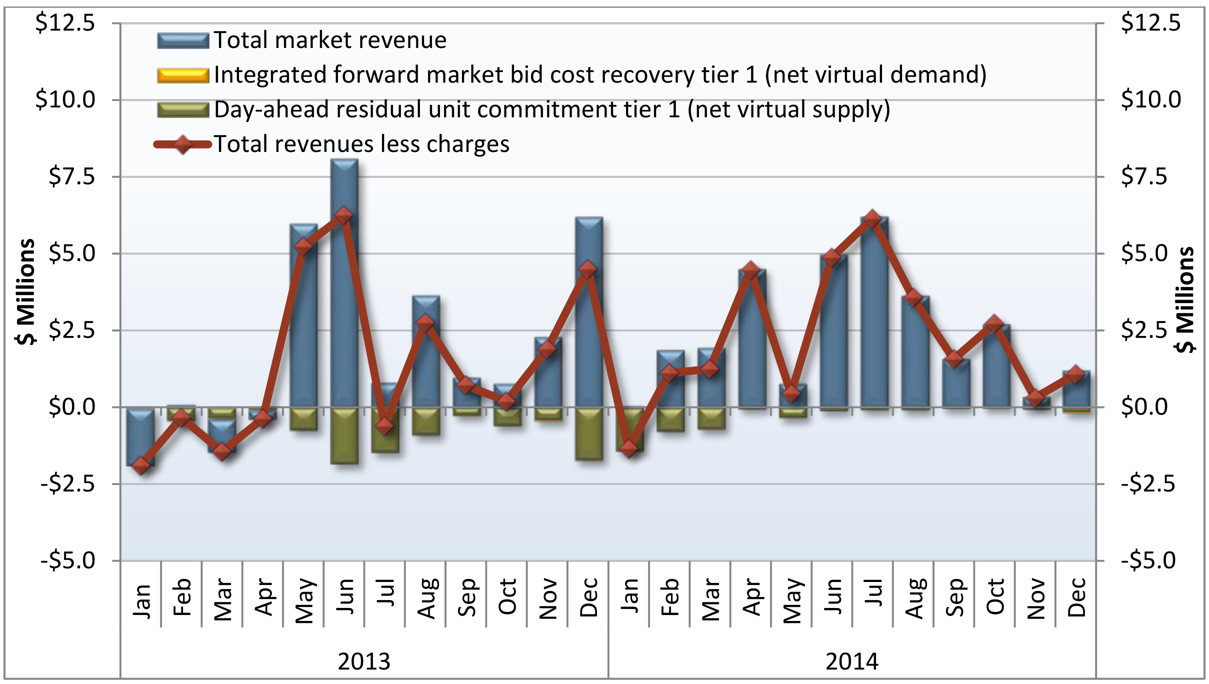
98 For further detail, see Business Practice Manual configuration guides for charge code (CC) 6636, IFM Bid Cost Recovery Tier1 Allocation_5.1a: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

99 For further detail, see Business Practice Manual configuration guides for charge code (CC) 6806, Day Ahead Residual Unit Commitment (RUC) Tier 1 Allocation_5.5: http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing.

Charges were highest in January when this charge accounted for around 24 percent of total bid cost recovery charges. In the second half of the year, only 1 percent of total bid cost recovery charges were attributed to the day-ahead residual unit commitment tier 1 allocation charge. Much of this decline can be attributable to reductions in residual unit commitment procurement in 2014. The residual unit commitment procurement declined in early 2014 as the ISO began adjusting renewable schedules in the residual unit commitment to account for forecasted schedules as opposed to bid-in schedules.[100]

Figure 4.6 shows estimated total convergence bidding revenues, total revenues less bid cost recovery charges and costs associated with the two bid cost recovery charge codes. The total convergence bidding bid cost recovery costs for the year were about $4 million, a reduction from nearly $9 million in 2013. As noted earlier, the total 2014 estimated net revenue for convergence bidding was around $30 million. Total convergence bidding revenue adjusted for bid cost recovery costs was around $26 million.

Figure 4.6 Convergence bidding revenues and costs associated with bid cost recovery tier 1 and RUC tier 1



100 For further detail, see Section 2.4.

5 Ancillary services

The ancillary service market continued to perform efficiently and competitively in 2014. The cost of ancillary services increased, driven primarily by an increase in prices driven by more procurement from natural-gas fired generation and higher natural gas prices. Key trends highlighted in this chapter include:

- Ancillary service costs increased to $69 million in 2014, representing a 21 percent increase from $57 million in ancillary service costs in 2013.
- Costs were about 0.6 percent of total energy costs in 2014, slightly higher than in 2013. The annual cost of $0.30 per MWh was higher than the $0.25 per MWh cost in 2013.
- Ancillary service prices were higher in 2014, driving the increase in overall cost. The increase was driven by a decrease in ancillary services from hydro-electric generators compared to 2013 and an increase in natural gas prices.
- The value of self-providing ancillary services accounted for about $7 million of total ancillary service costs in 2014, or about 10 percent.[101] By using their own resources to meet ancillary service requirements, load-serving entities are able to hedge against the risk of higher costs in the ISO market. In 2013, self-provided ancillary services accounted for about 8 percent of total ancillary service costs, or about $4.6 million.
- The average hourly day-ahead requirement for operating reserves was 1,702 MW. This is down 1 percent from 1,717 MW in 2013. The average hourly real-time operating reserve requirement was 1,664 MW in 2014, a 6 percent increase from 1,566 MW in 2013. The average hourly day-ahead regulation down requirement was 326 MW in 2014, roughly equal to the 325 MW requirement in 2013. The average hourly day-ahead regulation up requirement was 341 MW, a small increase compared to the 338 MW requirement in 2013. The real-time regulation requirement remained unchanged at 300 MW for both regulation up and regulation down.
- The ISO modified its operating reserve requirement calculations to be compliant with FERC Order No. 789 beginning October 1, 2014. These modifications result in somewhat lower average procurement levels of operating reserves than before the change.
- Ancillary service scarcity pricing events occurred in February, April and December 2014. Scarcity pricing was in place for a total of two intervals in the hour-ahead market and 14 intervals in the 15-minute real-time market. In 2013, the ISO experienced a single ancillary service scarcity event for three intervals in the 15-minute real-time market.
- The ISO began ancillary service compliance testing in late 2012 and continued the program through 2013 and to a lesser degree in 2014. DMM anticipates that the ISO will revise and clarify the ancillary service compliance testing procedures in 2015 in response to implementation challenges. Ancillary service compliance testing will continue to be an important part of maintaining reliability.

[101] Load-serving entities reduce their ancillary service requirements by self-providing ancillary services. While this is not a direct cost to the load-serving entity, economic value exists.

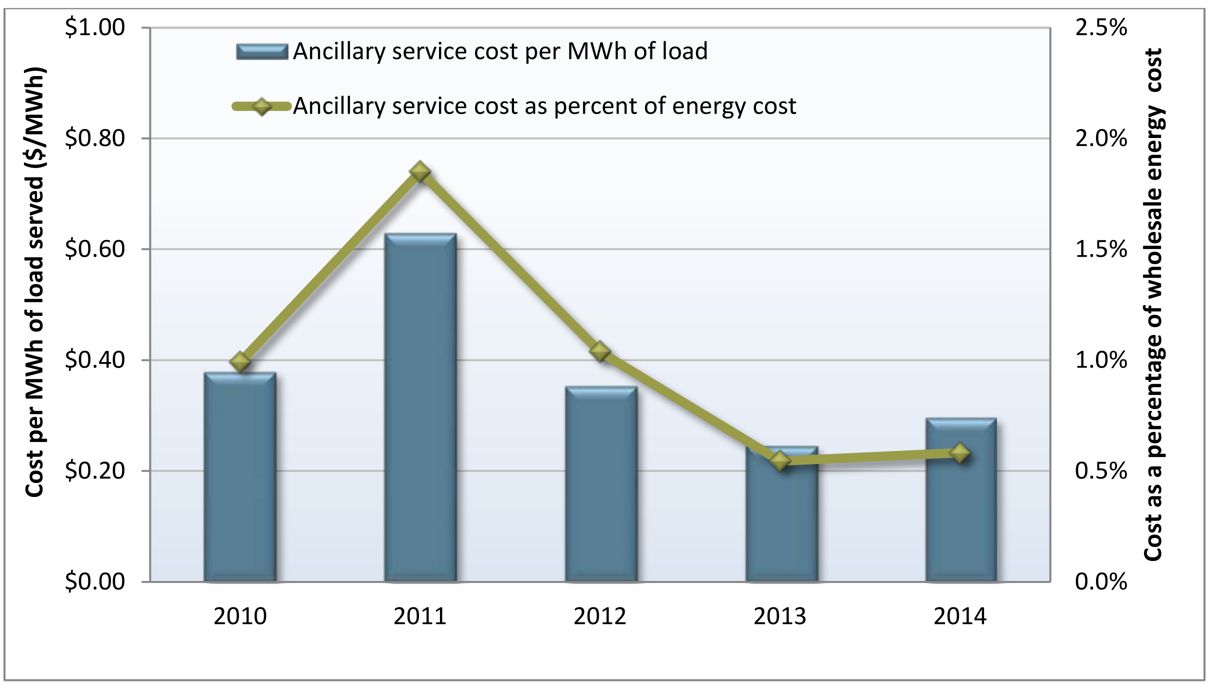
A detailed description of the ancillary service market design, implemented in 2009, is provided in DMM's 2010 annual report.[102] This market design includes co-optimizing energy and ancillary service bids provided by each resource. With co-optimization, units are able to bid all of their capacity into the energy and ancillary service markets without risking the loss of revenue in one market when their capacity is sold in the other. Co-optimization allows the market software to determine the most efficient use of each unit's capacity for energy and ancillary services.

5.1 Ancillary service costs

Ancillary service costs increased to $0.30/MWh of load served in 2014 from $0.25/MWh in 2013. While the ancillary service costs increased compared to 2013, they were still lower than in many of the previous years since the ISO nodal market implementation in 2009. Ancillary service costs represent 0.6 percent of wholesale energy costs, a slight increase from just over 0.5 percent in 2013. Figure 5.1 illustrates ancillary service costs both as a percentage of wholesale energy costs and per MWh of load from 2010 through 2014.

Ancillary service costs were highest during the fourth quarter of 2014. Figure 5.2 shows the cost of ancillary services by quarter, measured both as a percentage of wholesale energy costs and per MWh of load served. Costs per MWh were lowest in the first quarter ($0.24/MWh) and highest in the fourth quarter ($0.34/MWh).

Figure 5.1 Ancillary service cost as a percentage of wholesale energy costs (2010-2014)



[102] *2010 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2011, pp. 139-142: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

Figure 5.2 Ancillary service cost by quarter

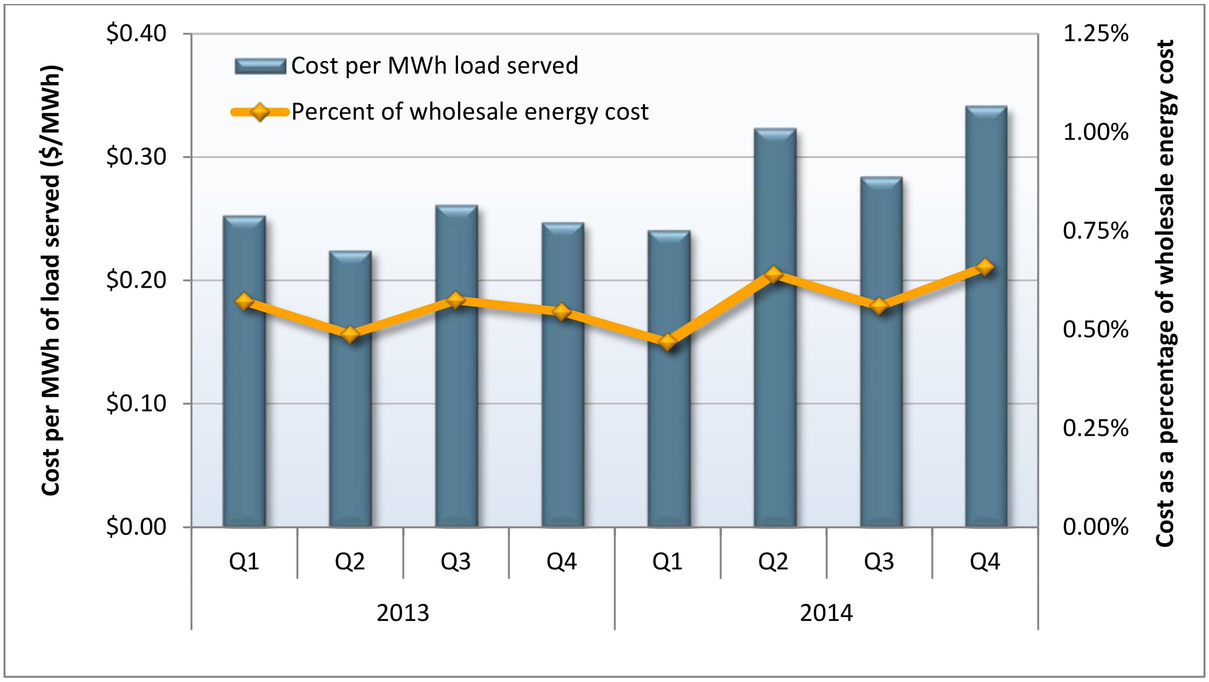
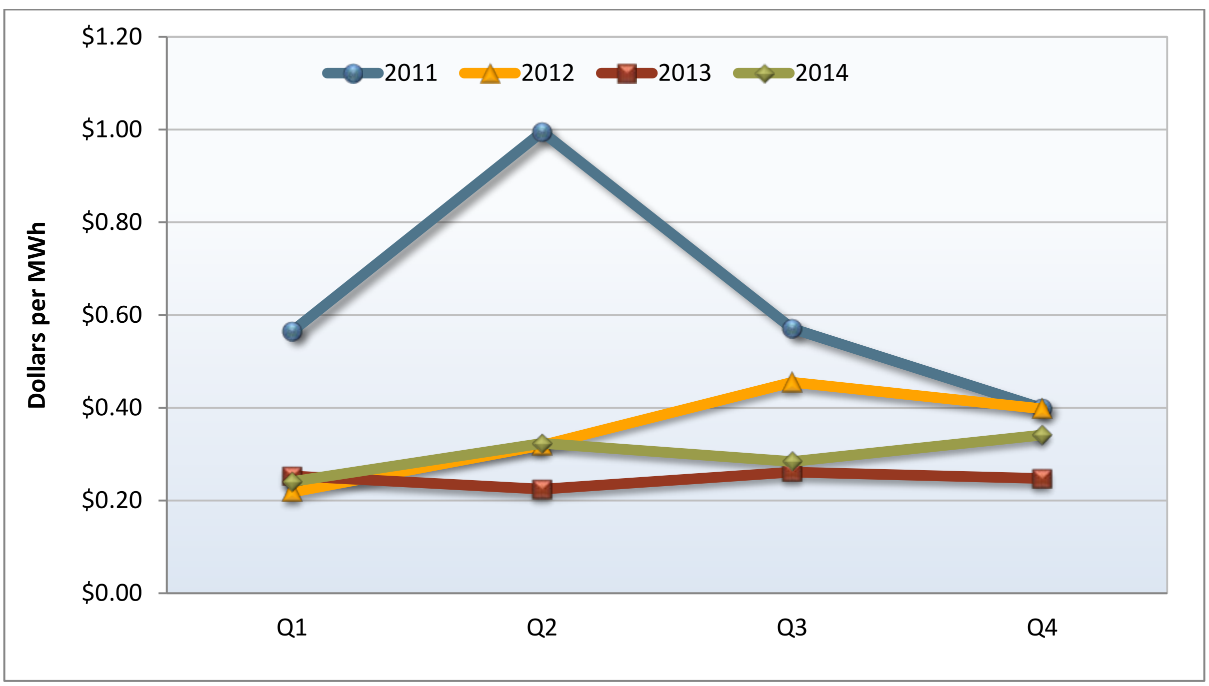


Figure 5.3 Ancillary service cost per MWh of load (2011-2014)



While this pattern is similar to 2012 and 2013, this represents a departure from typical seasonal patterns. Historically, ancillary service costs have peaked in the spring and early summer months, when the snowmelt in the Sierra Nevada mountains creates high levels of hydro runoff that require hydro-electric resources to produce electricity rather than ancillary services. This change was likely a result of low hydro conditions in recent years.

Ancillary service costs measured as a percentage of wholesale energy costs were less than 0.5 percent in the first quarter and increased to reach almost 0.7 percent in the fourth quarter. As a percent of wholesale energy costs, the first quarter of 2014 had the lowest ancillary service costs of any quarter since the nodal market began in 2009.

5.2 Ancillary service procurement

The ISO procures four ancillary services in the day-ahead and real-time markets: regulation up, regulation down, spinning, and non-spinning.[103] Ancillary service procurement requirements are set for each ancillary service to meet or exceed Western Electricity Coordinating Council's minimum operating reliability criteria and North American Electric Reliability Corporation's control performance standards. 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 day-ahead requirement for operating reserves was 1,702 MW, down 1 percent from 1,717 MW in 2013. The average hourly real-time operating reserve requirement was 1,664 MW in 2014, a 6 percent increase from 1,566 MW in 2013.

Beginning October 1, the ISO modified its operating reserve requirement calculations to be compliant with new operating reserve standards. A description of these modifications is provided in Section 5.5. Both before and after the modifications, the ISO appears to procure more operating reserves than required by the regional reliability standard in the day-ahead market. Using different requirement methodologies between the day-ahead and real-time markets has caused differences in procurement of ancillary services. In 2014, the real-time market procured an average of 38 MW fewer operating reserves compared to the day-ahead market. This difference is considerably smaller than the 151 MW average difference in 2013.

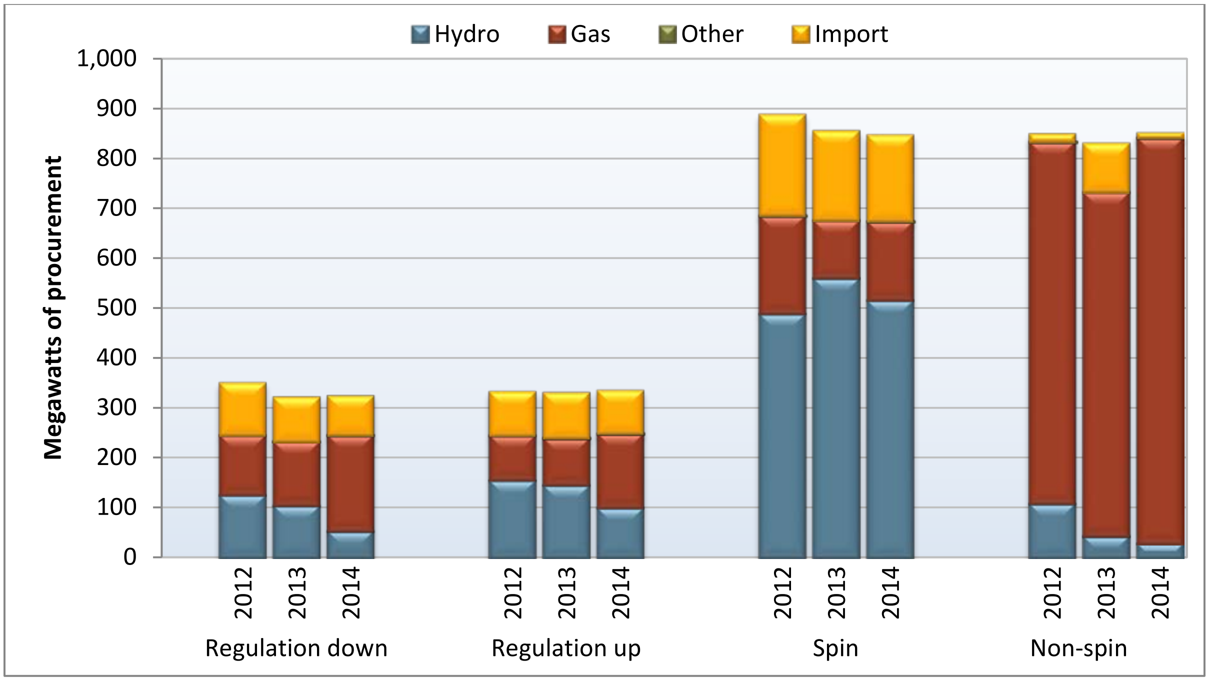
The average hourly real-time requirements for both regulation down and regulation up were 300 MW in 2014, unchanged from 2013. The requirement for regulation up and down is implemented by running an algorithm based on inter-hour forecast and schedule changes. The average hourly day-ahead regulation down requirement was 326 MW in 2014, an increase from 325 MW in 2013. The average hourly day-ahead regulation up requirement was 341 MW, an increase from 338 MW in 2013.

Figure 5.4 shows the portion of ancillary services procured by fuel type. Ancillary service requirements are met by both internal resources and imports. Ancillary service imports are indirectly limited by minimum requirements set for procurement of ancillary services from within the ISO system. In addition, ancillary services bid across the inter-ties have to compete for transmission capacity with energy. If an inter-tie becomes congested, the scheduling coordinator awarded ancillary services will be

[103] In addition, in June of 2013 the ISO added a performance payment to the regulation up and regulation down markets, separate from the existing capacity payment system. This product is often referred to as mileage.

charged the congestion rate. Thus, most ancillary service requirements continue to be met by ISO resources.

Figure 5.4 Procurement by internal resources and imports



Total procurement of ancillary services in 2014 was similar to the amount procured in 2013, a pattern consistent with the small average changes in ancillary service requirements discussed above. Compared to 2013, gas-fired resources provided a larger proportion of all ancillary services. The composition of ancillary service resources is characterized as follows:

- Average hourly provision of ancillary services from hydro-electric resources decreased in 2014 to 697 MW. This is an 18 percent decrease from 853 MW in 2013 and is likely due to lower hydro-electric generation conditions in 2014. Hydro-electric resources provided less of each ancillary service type.
- Total ancillary service imports decreased from 457 MW in 2013 to 348 MW in 2014 on an average hourly basis. Imports provided 24 percent of regulation down capacity, 26 percent of regulation up capacity, 20 percent of spinning reserves and 1 percent of non-spinning reserves.
- Gas-fired reserves provided 1,310 MW, up 28 percent from 1,026 MW in 2013. These resources provide the vast majority of non-spinning reserves as in previous years.

For the procurement of mileage, the breakdown between different fuels differs from the procurement of regulation. While hydro-electric resources provided 30 percent of procured regulation up and 16 percent of procured regulation down, it provided 43 percent and 42 percent of procured mileage up and mileage down, respectively. Correspondingly, gas resources and imports provided smaller proportions of the quantity of mileage procured compared to their proportions of regulation procurement.

5.3 Ancillary service pricing

Resources providing ancillary services receive a capacity payment, or market clearing price, in both the day-ahead and real-time markets. Capacity payments in the real-time market are only for incremental capacity above the day-ahead award. Figure 5.5 and Figure 5.6 show the quantity weighted average market clearing prices for each ancillary service product by quarter in the day-ahead and real-time markets in 2013 and 2014.

Except for non-spinning reserve, 2014 weighted average day-ahead prices increased from 2013, as seen in Figure 5.5. Quarterly weighted average prices ranged from approximately $0.15 per MW for non-spinning reserve in the second quarter to $6.53 per MW for regulation up in the second quarter. Day-ahead prices were generally lower than real-time prices, on a weighted quarterly average basis. Prices were generally highest for regulation up and lowest for non-spin resources, as they were in 2013.

Real-time weighted average ancillary service prices were lower in 2014 for all services except non-spinning reserve, as illustrated in Figure 5.6. Most ancillary service procurement occurs in the day-ahead market, so the real-time market prices have a relatively small impact on overall ancillary service costs.

The real-time weighted average ancillary service prices are to a large extent determined by the frequency and magnitude of price spikes. In the third quarter, there were very few large spikes in real-time ancillary service prices resulting in low average prices for all four services. The weighted average prices for the fourth quarter were significantly impacted by price spikes occurring on October 6 when a combination of factors including higher than forecast loads, transmission limitations and inter-tie schedule cuts created high prices for real-time energy and ancillary services. These price spikes had an especially large impact on the average price for non-spinning reserves given both the quantity of non-spinning reserves procured as well as the high prices on this day.

The quantity weighted average market clearing prices for mileage up and mileage down remained low throughout 2014 in both the day-ahead and real-time markets. The day-ahead annual weighted average price for mileage up decreased from $0.09 per unit of mileage in 2013 to $0.06 per unit in 2014. For mileage down, the day-ahead average price decreased from $0.12 per unit in 2013 to $0.09 per unit in 2014. In the real-time market, weighted average mileage prices were even lower, averaging $0.03 for mileage up and $0.01 for mileage down in 2014. One reason for the low average prices of mileage is that the least-cost regulation resources are often able to supply a sufficient amount of mileage resulting in a non-binding mileage requirement and a $0 market clearing price.

Figure 5.5 Day-ahead ancillary service market clearing prices

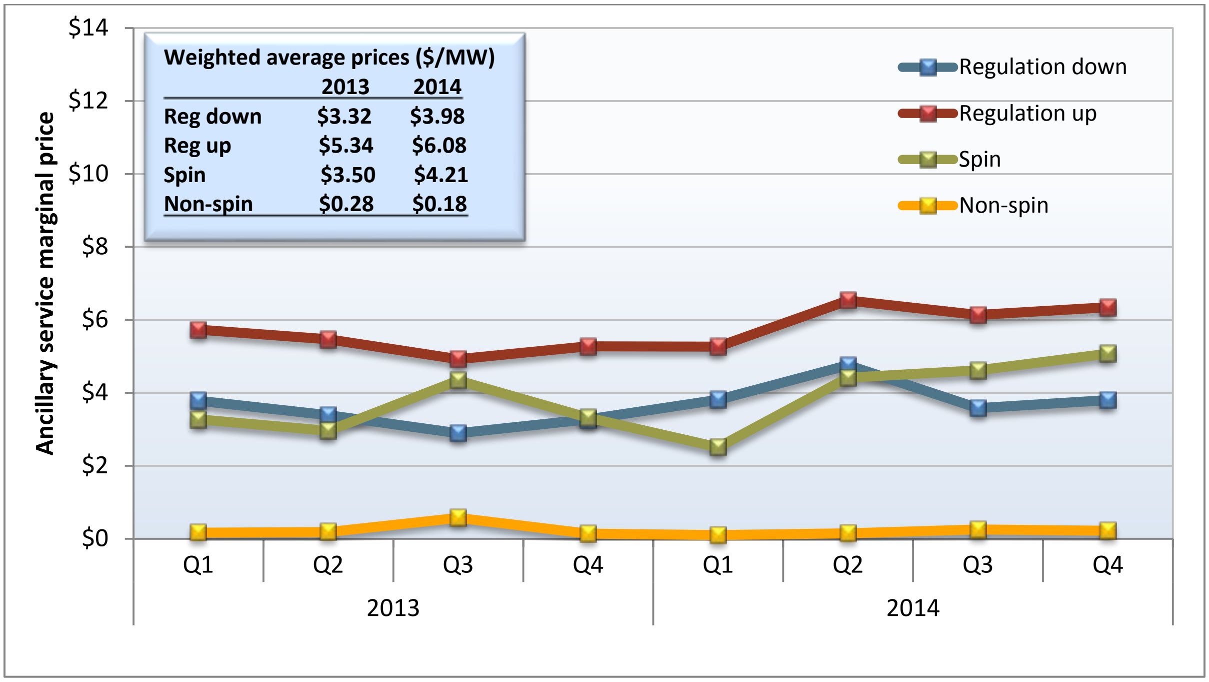
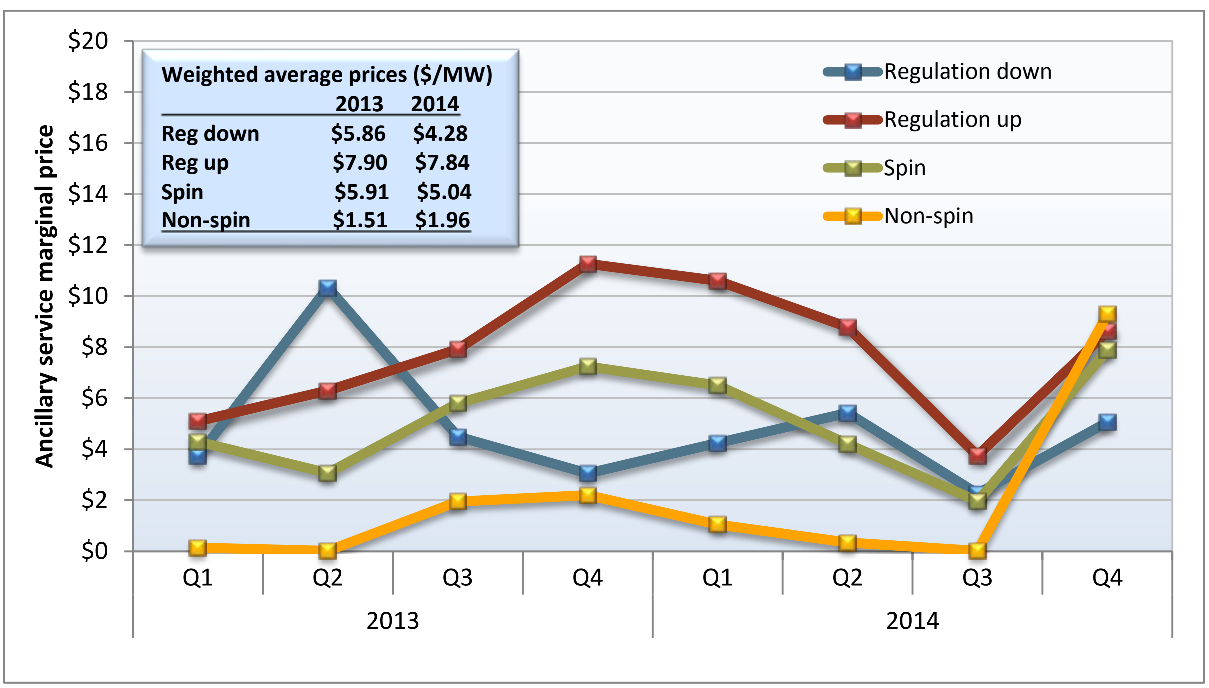


Figure 5.6 Real-time ancillary service market clearing prices

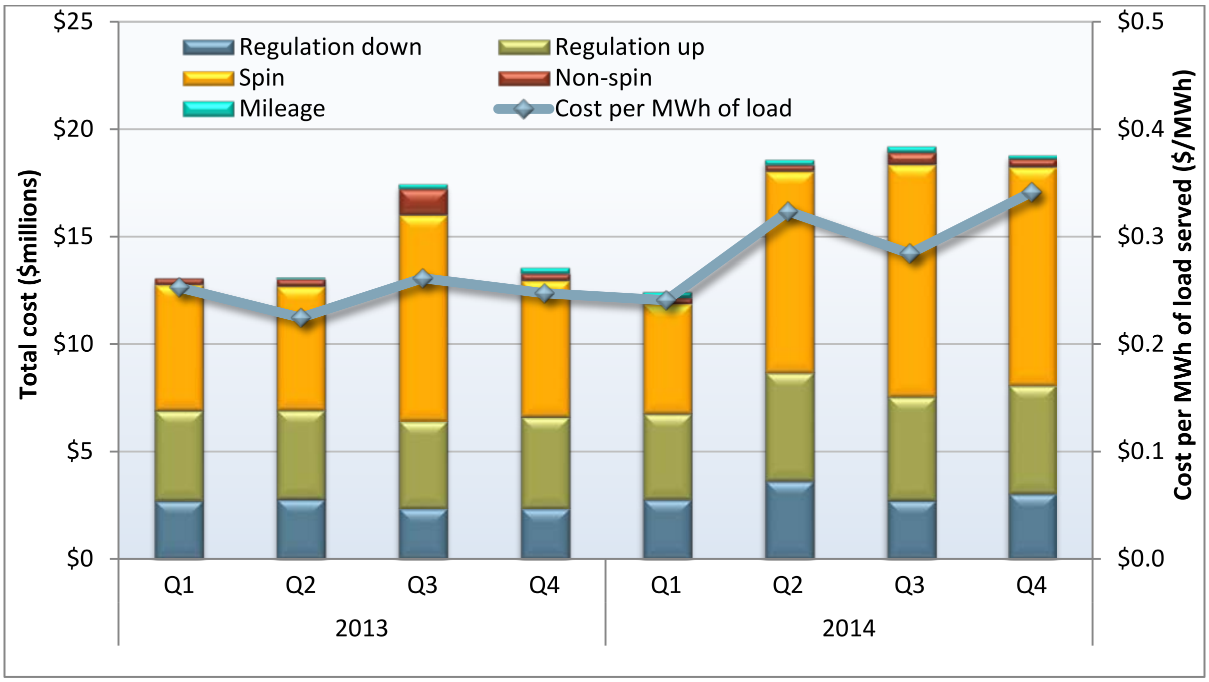


5.4 Ancillary service costs

Ancillary service costs totaled $69 million, an increase of 21 percent from 2013. The value of self-provided ancillary services by load-serving entities was $7.1 million of this amount, or about 10 percent.

Figure 5.7 shows the total cost of procuring ancillary service products by quarter along with the total ancillary service cost for each MWh of load served. Total ancillary service cost peaked during the third quarter of the year. The increase in total cost was primarily driven by an increase in day-ahead prices for spinning and regulation up reserves as more natural gas resources provided reserves in 2014 and as gas prices increased by about 17 percent.

Figure 5.7 Ancillary service cost by product



5.5 Special issues

This section highlights additional features of the ancillary service market:

- scarcity pricing;
- compliance testing, which began in late 2012; and
- FERC Order No. 789.

Ancillary service scarcity pricing

Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. Under the ancillary service scarcity price mechanism, implemented in December 2010, the ISO pays a pre-determined scarcity price for ancillary services procured during scarcity interval events. The scarcity prices set during these events in 2014 were either $500/MWh or $600/MWh.

Ancillary service scarcity pricing events occurred in February, April and December 2014. Scarcity pricing was in place for a total of two intervals in the hour-ahead market and 14 intervals in the 15-minute real-time market. There was a single ancillary service scarcity event in 2012 and only three 15-minute intervals in 2013 in which ancillary services requirements were not met.

The first set of scarcity events in 2014 occurred on February 6. As discussed in detail in Chapter 1, natural gas prices spiked to unusually high levels on this date due to weather and supply conditions outside of California. The ISO experienced significant reliability concerns related to natural gas pipeline supply issues. ISO operators took numerous actions to protect electric system reliability and help manage gas pipeline limitations. Despite these actions, ancillary services scarcity pricing was triggered in the 15-minute real-time market run for non-spin in three intervals of hour ending 17 and for regulation down in all four intervals of hour ending 17. Ancillary service scarcity pricing was also triggered in the hour-ahead market for non-spin in hour ending 18 and 19 and for regulation down in hour ending 18. The maximum shortfall was for non-spin in the hour-ahead market for hour ending 18 when procurement fell 208 MW below the requirement.[104]

Ancillary service scarcity pricing was again triggered on April 8 and April 12 by ancillary service procurement falling short of requirements.[105] An unexpectedly large shortfall in imports on April 8 between the hour-ahead and 15-minute real-time market required that resources that had been providing ancillary service provide energy instead, reducing capacity available for ancillary services. A non-spin scarcity occurred in the 15-minute real-time market in hour ending 19, interval 3, in the SP26 expanded sub region. The procurement shortfall was 15 MW. A non-spin scarcity also occurred for hour ending 20, intervals 3 and 4, in the ISO expanded system region. The procurement shortfall was 128 MW in interval 3 and 106 MW in interval 4.

A regulation down scarcity occurred on April 12 in the real-time market for hour ending 13, interval 3, in the ISO expanded system region. Prevailing over-generation conditions, due in part to real-time renewable schedules substantially above day-ahead schedules, contributed to a situation in which procuring regulation down would require increasing generation that would have exacerbated over-generation. The procurement shortfall was 5 MW.

Ancillary service scarcity pricing was triggered in late December on two days when outages and telemetry issues for two resources providing substantial ancillary service capacity forced those resources out of the real-time market. The real-time market was not able to procure the full amount of capacity backed down in all intervals. Ancillary service scarcity pricing was triggered for regulation down on December 23 in hour ending 22, interval 4, when procurement fell 6 MW short of the requirement in the SP26 region. Regulation down scarcity pricing was triggered again on December 24 in hour ending 4, interval 3, when procurement fell 3 MW short of the requirement in the ISO system expanded region.

[104] For further detail, see: http://www.caiso.com/Documents/Notification-AncillaryServicesScarcityEventFeb14_2014.htm and http://www.caiso.com/Documents/UpdatedAncillaryServiceRegionNamesDue-ScarcityEvent-Feb6_2014.htm.

[105] For further detail, see: http://www.caiso.com/Documents/Notification-AncillaryServicesScarcityEventApr21_2014.htm and http://www.caiso.com/Documents/Notification-AncillaryServicesScarcityEventApr14_2014.htm.

Regulation down scarcity pricing was triggered a third time in this period when procurement in the SP26 region fell 6 MW short of the requirement in hour ending 12, interval 2.[106]

Ancillary service compliance testing

In response to concerns that resources did not perform up to their rated ancillary service level during real-time ancillary service contingency events, the ISO announced that it would begin ancillary service compliance testing in November 2012.[107] The ISO used its verifications procedures in 2014 to test whether or not resources that were committed to providing ancillary services were able to deliver when called upon.[108] The ISO audited the performance of more than 50 resources providing ancillary services during a single contingency dispatch. Of the resources tested, more than 10 percent failed to pass the performance audit and were sent warning notifications.

Most resources that are subject to testing go through two stages: a performance audit and a compliance test. A performance audit occurs when a resource is flagged for failing to meet dispatch during a contingency run. The compliance test is an unannounced test in which a resource is called upon to produce energy at a time when it is scheduled to hold reserves. Failing either or both of these tests can result in disqualification of the resource for ancillary services and rescission of payments that were made to the resource. The ISO also has the authority to initiate a compliance test without the resource first experiencing a contingency related performance audit.

DMM anticipates that the ISO will continue to rely on ancillary service compliance testing as an important part of maintaining reliability.

Implementation of FERC Order No. 789

The ISO modified its operating reserve requirement calculations beginning October 1 to be compliant with new operating reserve standards.[109] Under the previous standard, the ISO calculated total operating reserve requirements as the maximum of the single most severe contingency and the sum of 7 percent of load served by hydro-electric resources and 5 percent of remaining load. Under the new standard, the total operating reserve requirement is calculated as the maximum of the single most severe contingency and 3 percent of the sum of load, internal generation and net pseudo and dynamic imports. To the extent that the ISO relies on static imports to serve load, this would result in lower operating reserve requirements under the new standard.

Figure 5.8 illustrates average hourly operating reserve requirements in the fourth quarter of 2014, along with a comparison of the difference between the 2014 and 2013 fourth quarter requirements. The ISO procures operating reserves in both the day-ahead and real-time market. As was the case under the preexisting requirement, the ISO appears to procure more operating reserves than required by the

[106] For further detail, see: http://www.caiso.com/Documents/NotificationofAncillaryServicesScarcityEvent010915.htm.

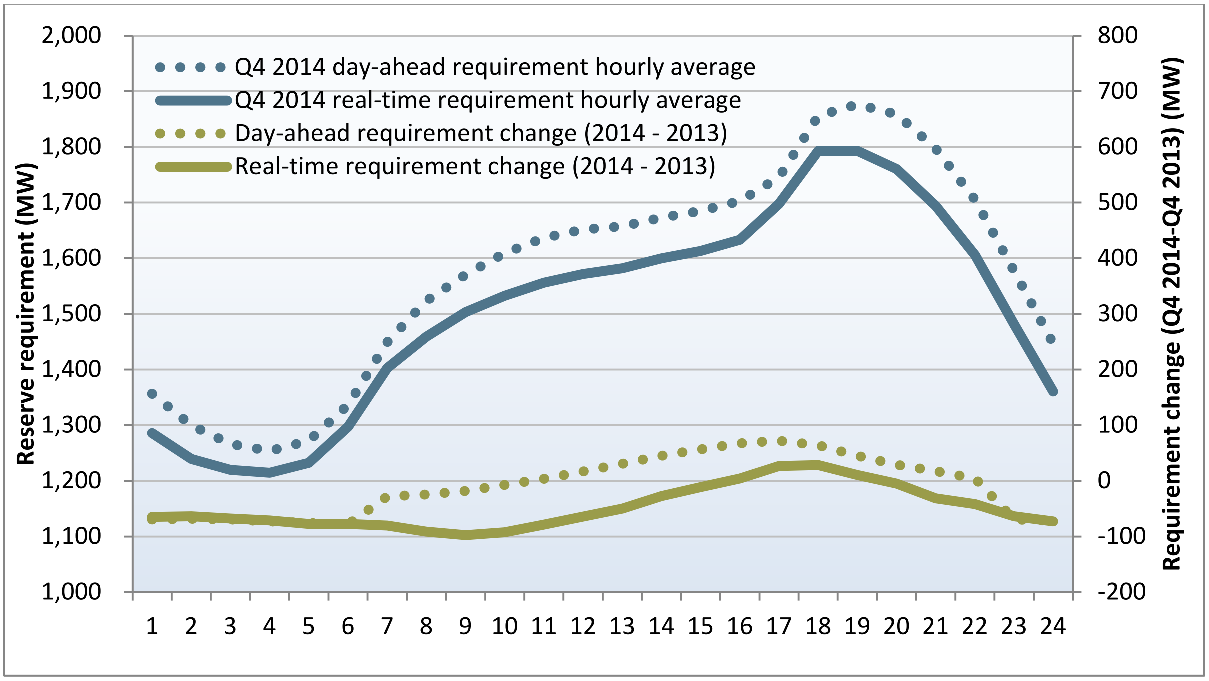
[107] See the following market notice for more information: http://www.caiso.com/Documents/CaliforniaISOConductUnannouncedComplianceTesting.htm.

[108] The documentation can be found here: http://www.caiso.com/Documents/5370.pdf.

[109] Specifically, the new procedures are consistent with the Western Electricity Coordinating Council (WECC) regional reliability standard on contingency resources (BAL-002-WECC-2). BAL-002-WECC-2 was approved by FERC under Order No. 789 http://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Order789_BAL-002-WECC-2_RM13-13_20131121.pdf, which became effective on January 28, 2014. The ISO implemented changes consistent with this requirement on October 1, 2014.

regional reliability standard in the day-ahead market.[110] As illustrated in Figure 5.8, the lowest average requirements are in the real-time market under the new requirements.

Figure 5.8 Hourly average spinning and non-spinning reserve requirements (Q4)



Implementing FERC Order No. 789 also included new e-tagging requirements for import resources providing ancillary services in the 15-minute real-time market. Beginning October 1, resources providing ancillary services in the real-time market are required to have a valid e-tag for the operating reserve awarded in the day-ahead market (real-time awards are capped at the e-tagged quantity). Submitted e-tags are validated to assure that the resource is qualified to provide ancillary services, the transmission and generation are firm, and the e-tag appropriately specifies the nature of the transaction is providing ancillary services.

[110] On October 1, 2014, the ISO began to calculate day-ahead operating reserve requirements as 6 percent of forecast load including pumping load. The ISO intends to refine the day-ahead operating reserve requirement setting tool to calculate the day-ahead requirement based on the expected value of the real-time ancillary service requirement rather than as a fixed percent of forecast load alone.

6 Market competitiveness and mitigation

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

- The day-ahead energy market remained structurally competitive on a system-wide level in almost all hours.
- The supply of capacity owned by non-load-serving entities meets or exceeds the additional capacity that load-serving entities need to procure to meet local resource adequacy requirements in most areas. However, in some areas, one supplier is individually pivotal, because some portion of this supplier's capacity is needed to meet local requirements.
- The dynamic path assessment, which is part of the enhanced local market power mitigation procedures implemented in 2013, is an automated test incorporated in the market software used to determine competitiveness of transmission constraints based on actual system and market conditions in each interval. This automated test effectively identified non-competitive constraints in the day-ahead and real-time markets in 2014.
- Most resources subject to bid mitigation to manage congestion on non-competitive constraints submitted competitive offer prices, so that many bids were not lowered as a result of the mitigation process. The number of units in the day-ahead market that had bids changed by mitigation remained very low, but increased from an average of about 0.5 units per hour in 2013 to an average of about 1.3 units per hour in 2014.
- The frequency of bid mitigation in the real-time market dropped from about one unit per hour in 2013 to about 0.5 units per hour in 2014. The estimated impact of bid mitigation on the amount of additional real-time energy dispatched as a result of bid mitigation decreased in 2014 to about 23 MW per hour from about 26 MW per hour in 2013.
- Mitigation provisions that apply to exceptional dispatch for energy above minimum load reduced costs to $144,000 in 2014, down from $450,000 in 2013. This reflects the fact that the volume of exceptional dispatches was relatively low and bids mitigated were not significantly in excess of competitive levels.
- Gas-fired capacity opting for the registered cost option for start-up and minimum load costs declined considerably in 2014 compared to 2013. Under this registered cost option, bids may exceed cost-based levels but are fixed for one month. The decrease in capacity under this option appears to have been driven primarily by a sudden spike in spot natural gas prices in early February. The volume of natural gas-fired capacity opting for the registered cost option continued to drop through the remainder of the year, particularly for start-up costs.

6.1 Structural measures of competitiveness

Market structure refers to the ownership of the available supply in the market. The structural competitiveness of electric markets is often assessed using two related quantitative measures: the *pivotal supplier test* and the *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 any individual supplier removed, then this supplier is pivotal. This is referred to as a single pivotal supplier 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 supply from non-pivotal suppliers to the demand.[111] A residual supply index less than 1.0 indicates an uncompetitive level of supply when the largest suppliers' shares are excluded.

In the electric industry, measures based on two or three suppliers in combination are often used because of the potential for oligopolistic bidding behavior. The potential for such behavior is high in the electric industry because the demand for electricity is highly 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.[112]

6.1.1 Day-ahead system energy

Figure 6.1 shows the hourly residual supply index for the day-ahead energy market in 2014. This analysis is based on system energy only and ignores potential limitations due to transmission limitations.[113] Results are only shown for the 500 hours when the residual supply index was lowest. As shown in Figure 6.1, the residual supply index with the three largest suppliers removed (RSI_3) was less than 1 in about 80 hours and about 10 hours with the two largest suppliers removed (RSI_2). The hourly RSI_3 value was as low as 0.91 in 2014 compared to about 0.86 in 2013.

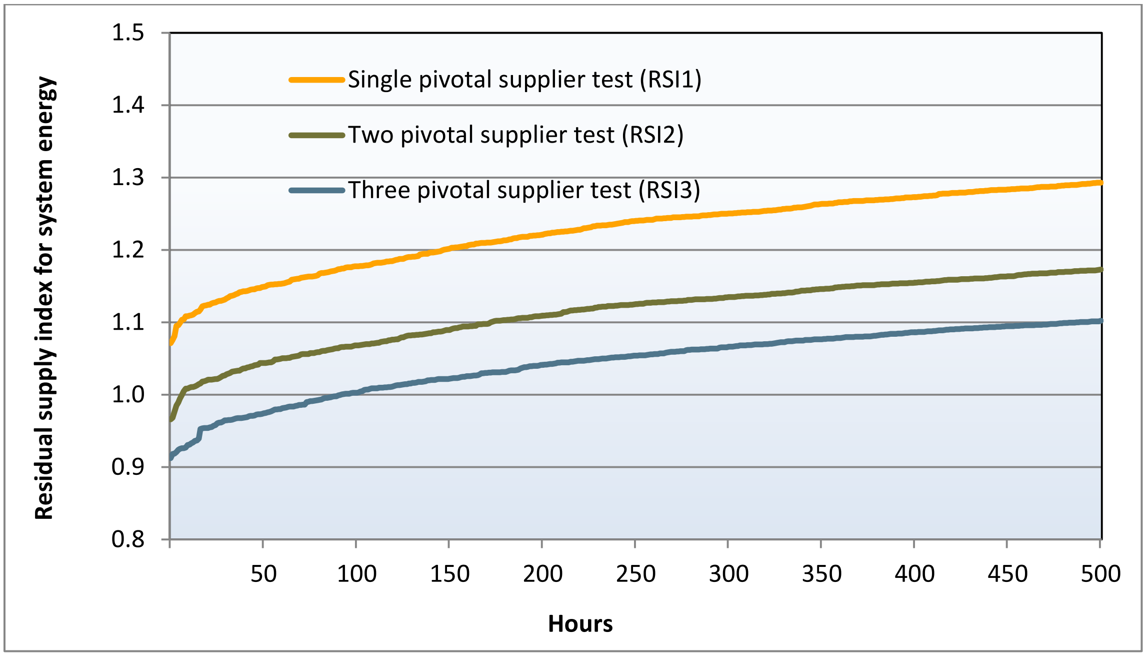
The residual supply index values reflect load conditions and generation availability, as well as resource ownership or control. Some generating units have tolling contracts, which transfer the control from unit owners to load-serving entities. These tolling contracts improve overall structural competitiveness in the operating period versus the study period. However, as discussed in the following sections, because 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.

[111] 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 0.90, or (120 – 30)/100.

[112] A detailed description of the residual supply index was provided in Appendix A of DMM's 2009 annual report.

[113] 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.

Figure 6.1 Residual supply index for day-ahead energy



6.1.2 Local capacity requirements

The ISO has defined 10 local capacity areas for which separate local reliability requirements are established under the state's resource adequacy program. 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 6.1 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 6.1, 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 in most areas. However, in some areas, one or more 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.

Table 6.1 Residual supply index for major local capacity areas based on net qualifying capacity

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	2,250	5,081	2.26	1.08	0.15	0.08	0
North Coast/North Bay	476	722	1.52	0.01	0.01	0.00	1
SCE area							
LA Basin	6,345	6,747	1.06	0.46	0.22	0.12	2
Big Creek/Ventura	99	2,919	29.58	7.99	0.75	0.27	0
San Diego/Imperial Valley	1,331	2,465	1.85	0.99	0.54	0.11	1

In addition to the capacity requirements for each local 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 incorporated in the state's resource adequacy program. However, these additional sub-area requirements represent an additional source of local market power. If a unit needed for a sub-area requirement is not procured in the resource adequacy program and that resource does not make itself available to the ISO in the spot market, the ISO may need to procure capacity from the unit using the backstop procurement authority under the capacity procurement mechanism of the ISO tariff. Section 6.2 describes these provisions and changes made in these tariff provisions in 2014.

In the day-ahead and real-time energy markets, the potential for local market power is mitigated through bid mitigation procedures. These procedures require that each congested transmission constraint be designated as either competitive or non-competitive. This designation is based on established procedures for applying a pivotal supplier test in assessing the competitiveness of constraints. Section 6.3 examines the actual structural competitiveness of transmission constraints when congestion occurred in the day-ahead and real-time markets.

6.2 Capacity procurement mechanism

The capacity procurement mechanism within the ISO tariff provides backstop procurement authority to ensure that the ISO will have sufficient capacity available to maintain reliable grid operations. This backstop authority also helps to mitigate the potential for exercise of locational market power by units that are needed to meet local reliability requirements by establishing a reasonable price under which the ISO could procure this capacity if load-serving entities did not meet local resource adequacy capacity requirements through bilateral purchases. However, to date this mechanism has rarely been used as essentially all local capacity requirements are being procured in the bilateral market by load-serving entities.

The current ISO capacity procurement mechanism tariff authority will expire on February 16, 2016. In a 2011 Order, FERC instructed the ISO to develop enhanced backstop provisions that would 1) procure capacity at a price that accounts for market conditions that change over time; 2) provide a reasonable opportunity for suppliers to recover fixed costs; and 3) support incremental investment by existing resources to perform long-term maintenance or make improvements that are necessary to satisfy environmental requirements or address reliability needs associated with renewable resource integration.

In response, the ISO is proposing to replace the current administrative rate with a competitive solicitation process to determine the backstop capacity procurement price under the capacity procurement mechanism.[114] The ISO's proposal was developed through a stakeholder process that garnered widespread support.

The proposal includes a soft offer cap initially set at the California Energy Commission (CEC) estimated levelized going-forward fixed costs for a mid-cost 550 MW combined cycle with duct firing resource in 2013 plus 20 percent. This equals $75.68/kW-year (or $6.31/kW-month). A supplier may go to FERC to cost-justify a price higher than the soft offer cap prior to offering the resource into the competitive solicitation process or after receiving a capacity procurement mechanism designation by the ISO.

The ISO will monitor the use of the capacity procurement mechanism to ensure that load-serving entities are not relying on this mechanism as an alternative to bilateral procurement as a means of capacity procurement to meet resource adequacy obligations. If the specific levels of procurement under this mechanism are made to meet resource adequacy requirements of a load-serving entity, the ISO will open a stakeholder initiative to explore the reasons for use of this mechanism for capacity procurement.

DMM is supportive of this proposal as a means of continuing to balance the need for the ISO to have a means of procuring capacity to meet reliability requirements and mitigate potential local market power with the goal of continuing to provide an incentive for most or all capacity needs to be met by resource adequacy capacity procured in the bilateral market.

6.3 Competitiveness of transmission constraints

On May 1, 2013, the ISO completed the transition to the new market power assessment and mitigation procedure. This section reviews the performance of this method for determining the competitiveness of transmission constraints.

Background

Local market power is created by insufficient or concentrated control of supply within a local area. These supply conditions include the amount and control of supply within the area, and the availability of transmission to move supply into the local area from outside.

[114] Memo to ISO Board of Governors from Keith Casey, Vice President, Market and Infrastructure Development, February 4, 2015, *Re: Decision on capacity procurement mechanism replacement framework*: http://www.caiso.com/Documents/DecisionCapacityProcurementMechanismReplacementFramework-UpdatedMemo-Feb2015.pdf.

The ISO local market power mitigation provisions require that each transmission constraint be designated as either *competitive* or *non-competitive* prior to the binding market run. The methodology used to designate transmission constraints as competitive or non-competitive is called the *dynamic competitive path assessment*, or DCPA. This assessment evaluates 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.[115] The evaluation uses a pre-market mitigation run to clear supply and demand with un-mitigated bids. If any internal transmission constraints are binding in the pre-market run they are assessed for competitiveness of supply of counter-flow.

The assessment uses a residual supply index based on supply and demand of counter-flow from internal resources for each binding constraint. If there is sufficient supply of counter-flow for the binding constraint after removing the three largest net suppliers, then the constraint is deemed competitive. Otherwise, it is deemed non-competitive. A non-competitive supply of counter-flow is considered to be indicative of local market power and resources in this pool of supply may subsequently be subject to bid mitigation.

Competitiveness results

The results of the three-pivotal residual supply index reflect the changing competitiveness of transmission constraints in the day-ahead and real-time markets. Figure 6.2 and Figure 6.3 show the distribution of the three-pivotal residual supply index for the most frequently congested transmission facilities for the day-ahead and real-time market, respectively. The green bars in the chart indicate the range of the 25^{th} to 50^{th} percentile of these values, while the blue bars show the range of the 50^{th} to 75^{th} percentile of the distributions. The horizontal lines represent the remaining range, with the vertical lines showing the minimum and maximum values.

As is shown in these figures, for most constraints the residual supply index tends to be greater than 1 for most of the hours when congestion occurs, so that the constraints are deemed competitive and no units are subject to mitigation. This is true in both the day-ahead and real-time markets. Only a few constraints are consistently found to be uncompetitive when congestion occurs. A significant number of constraints tend to be competitive under some conditions and uncompetitive under other conditions. These results highlight one of the key advantages of the dynamic competitive path assessment implemented in 2012 and 2013, which is the ability to test and designate the competitiveness of constraints based on actual system conditions.

[115] The static competitive path assessment is performed with relatively high penalty prices assigned to any overflow conditions on paths being tested for competitiveness.

Figure 6.2 Transmission competitiveness in 2014 for the day-ahead market

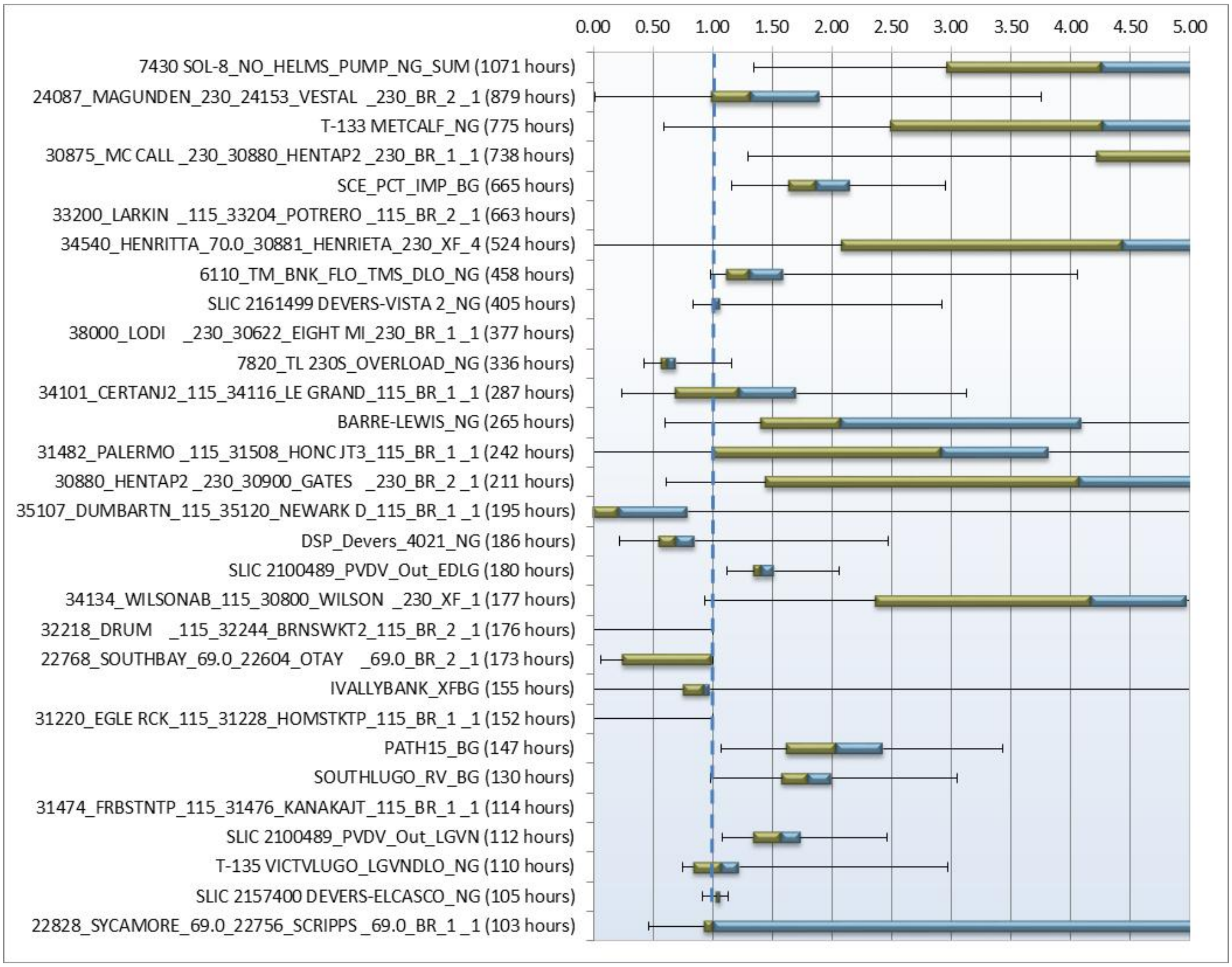
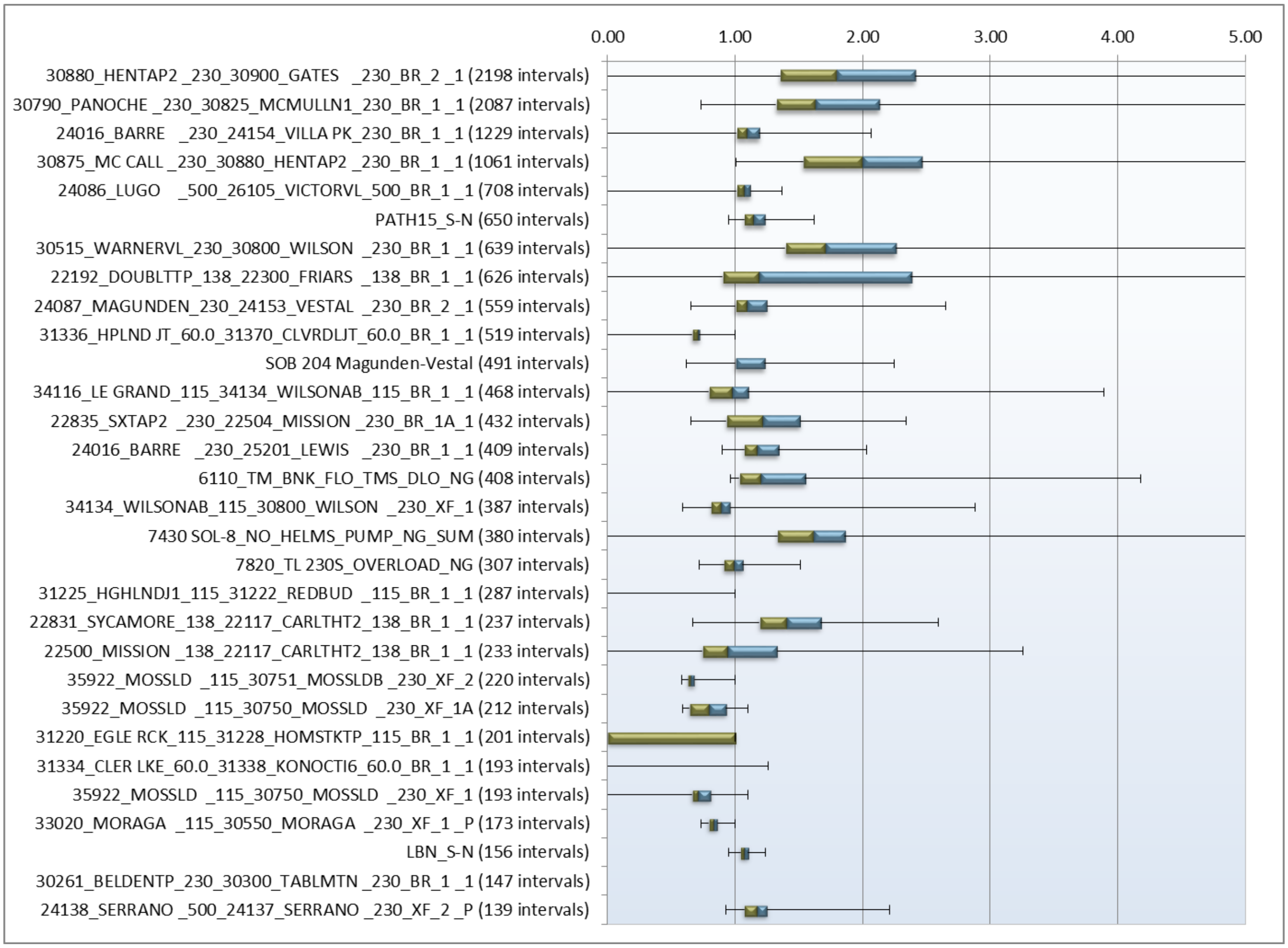


Figure 6.3 Transmission competitiveness in 2014 for the real-time market



Accuracy of transmission competitiveness assessment

Evaluating the performance of the dynamic competitive path assessment involves examining two factors, the accuracy with which the mitigation run predicts congestion in the market run and the portion of constraints congested in the mitigation or market run which are non-competitive. The way in which DMM has used this framework to assess the overall accuracy of new mitigation procedures is shown graphically in Table 6.2.

As shown in Table 6.2, when congestion is *over-identified*, or is projected to occur in the mitigation run but does not occur in the market, mitigation is only applied when the congested constraint is deemed to be non-competitive. As described later in this section, the frequency of such seemingly unnecessary mitigation has been extremely low in both the day-ahead and real-time markets under the new mitigation procedures. The frequency of this occurrence in 2014 was of a similar magnitude to the frequency of the relevant part of 2013.

When congestion is *under-identified*, or is not projected to occur in the mitigation run but then occurs in the market, inaccurate mitigation only results when the congested constraint would have been deemed non-competitive. In these cases, mitigation should be applied but is not. This is referred to as *under-mitigation*. Because the dynamic competitive path assessment procedure does not evaluate uncongested constraints, we do not know exactly how many of these under-identified constraints would have been deemed competitive or uncompetitive. However, as discussed in the following sections, other analysis by DMM indicates that constraints on which congestion occurs are competitive a very high portion of the time.

Table 6.2 Framework for analysis of overall accuracy of transmission competitiveness

Congestion prediction (mitigation run vs. market)	Dynamic competitive path assessment results	
	Competitive	Non-competitive
Consistent (congested in mitigation and market runs)	No mitigation	Correct mitigation
Over-identified (congestion in mitigation run, but not market)	No mitigation	**Mitigation applied, but not needed**
Under-identified (no congestion in mitigation run, but market congestion)	No mitigation	**Mitigation needed, but not applied**

The unit of measurement for the analysis below is a constraint-interval. Each time a constraint is congested for a given interval that counts as one constraint-interval. A total of 100 constraint-intervals, then, could include 100 constraints each congested for 1 interval, or 1 constraint congested for 100 intervals, or 50 constraints each congested for 2 intervals and so on. For day-ahead results, we refer to the constraint-intervals as constraint-hours, as the intervals in the day-ahead market each represent one hour.

Day-ahead market

In the day-ahead market, the mitigation run is performed immediately before the actual market run and uses the same initial input data – except for bids that are mitigated as a result of the market power mitigation run. DMM has found that the congestion predicted in the day-ahead mitigation run is highly consistent with actual congestion that occurs in the subsequent day-ahead market.

Table 6.3 categorizes each of the constraint-hours during 2014 in which congestion occurred in the market power mitigation run and/or the final day-ahead market run. As shown in the first row of Table 6.3, congestion occurred in both the day-ahead mitigation and market runs in about 88 percent of these constraint-hour instances. Constraints that were congested in both runs were deemed competitive about 73 percent of the time, which counts for 65 percent of total congested constraint-hours.[116] Bid mitigation was applied to resources that could relieve this congestion in only about 27 percent of these hours, or 24 percent of total congested hours.

[116] 18,422 ÷ 25,109 = 73 percent.

As shown in the second row of Table 6.3, during about 5 percent of the congested constraint-hours, constraints were congested in the day-ahead mitigation run but not in the day-ahead market run. These congested constraints were deemed competitive 60 percent of the time, so that bid mitigation was applied when no congestion occurred in the day-ahead market run in only about 2 percent of the total constraint-hours in which congestion occurred. Over-identification of congestion does not necessarily subject resources to bid mitigation unnecessarily. In some cases, lowering of bids through bid mitigation prior to the market run may prevent congestion in the day-ahead market run.

Table 6.3 Consistency of congestion and competitiveness of constraints in the day-ahead local market power mitigation process[117]

	Competitive		Non-competitive		Total	
Congestion prediction	**# constraint hours**	**%**	**# constraint hours**	**%**	**# constraint hours**	**%**
Consistent	18,422	65%	6,687	24%	25,109	88%
Over-identified	893	3%	670	2%	1,563	5%
Under-identified	---	---	---	---	1,747	6%
					28,419	**100%**

Congestion prediction:
Consistent = Congestion in mitigation and market runs.
Over-identified = Congestion in mitigation run, but no congestion in market.
Under-identified = No congestion in mitigation run, but congestion in market.

As shown in the third row of Table 6.3, during about 6 percent of the constraint-hours in which congestion occurred, constraints were congested in the day-ahead market run but not in the day-ahead mitigation run. As previously noted, when congestion is not identified in the mitigation run but then occurs in the market run, the market software does not provide results of the three pivotal supplier test that can be used to determine if the constraint was competitive or non-competitive. However, data from other hours when congestion occurs in the day-ahead market during the mitigation run indicate that congested constraint intervals are non-competitive only about 28 percent of the time.[118] This suggests that the frequency of under-mitigation is extremely low and is less than 2 percent of intervals when congestion occurs.[119]

Real-time market

As part of the new 15-minute market implemented in May 2014, some details of the dynamic competitive path assessment and local market power mitigation procedure were enhanced. Path

[117] The mitigation run consistently predicts no congestion in the market run in a very large number of instances.

[118] Based on percent of constraint-hours in first two rows of Table 6.3 in which constraints congested in mitigation run were found to be non-competitive.

[119] 28 percent x 6 percent < 2 percent.

assessment and bid mitigation happen as part of the 15-minute market, as before. Now, however, results from this mitigation process apply to both the 15-minute market and the 5-minute market.

The timing of the dynamic competitive path assessment also changed with this implementation. Until May 2014, the real-time local market power mitigation procedures were performed about 35 minutes before the 5-minute real-time market run. These procedures now take place about 50 minutes before the 5-minute real-time market run.

The dynamic competitive path assessment is performed in an advisory interval of a 15-minute market run. For example, the market run that determines binding dispatch schedules for the first interval of the first hour of each day also encompasses the path assessment and mitigation protocol for the second interval of the first hour of the 15-minute market.

The accuracy of congestion prediction is notably lower in the real-time local market power mitigation process than in the day-ahead. Because of the delay between the dynamic competitive path assessment run and the market runs, there may be differences in the model inputs such as load, generation output, transmission limits, generation and transmission outages, and other factors. The differences in inputs can cause differences in congestion between the predictive assessment run and the final, binding market run. However, because most congested constraints are deemed competitive in the real time, the overall impact of less accurate congestion prediction is still very low in the real-time market.

15-minute market

Beginning on May 1, the results of the dynamic competitive path assessment were applied to bids in the new 15-minute market. Consistency of the 15-minute assessment run with the binding 15-minute market run is not as close as that of the day-ahead runs, but is closer than the relationship of the 15-minute assessment run with the 5-minute market.

The results in Table 6.4 show the accuracy of the 15-minute dynamic competitive assessment process in predicting congestion in the binding run of the 15-minute market. Of all of the constraint-intervals that were congested in either the assessment run, the 15-minute market run, or both, the assessment run predicted congestion consistently with the 15-minute market run on about 69 percent of those constraint-intervals. Overall, about 81 percent of constraint-intervals that were congested in the assessment run were competitive. If a similar ratio of competitive to non-competitive holds for the under-identified constraint-intervals, this suggests that under-mitigation occurred in only about 2 percent of the total number of congested constraint-intervals.

Table 6.4 Consistency of congestion and competitiveness in the 15-minute market local market power mitigation process

Congestion prediction	Competitive # constraint intervals	%	Non-competitive # constraint intervals	%	Total # constraint intervals	%
Consistent	12,777	55%	3,139	14%	15,916	69%
Over-identified	3,795	16%	777	3%	4,572	20%
Under-identified	---	---	---	---	2,687	12%
					23,175	**100%**

Congestion prediction:
Consistent = Congestion in mitigation and market runs.
Over-identified = Congestion in mitigation run, but no congestion in market.
Under-identified = No congestion in mitigation run, but congestion in market.

5-minute market

The binding 5-minute market run happens further still from the dynamic competitive path assessment run in the 15-minute market that predicts congestion. There is less consistency between these runs than between the relevant runs for the other markets, but our estimates of the impact suggest that the inconsistencies are only relevant on a very small number of constraint-intervals.

For this analysis, the comparison is made between 15-minute intervals for the assessment run and the set of three 5-minute intervals for the 5-minute real-time market. If congestion occurs on a constraint in one, two, or all three of the 5-minute intervals that correspond to a 15-minute interval, we count that as a single constraint-interval of congestion.

As shown in the first row of Table 6.5, congestion occurred in both the 15-minute real-time mitigation and 5-minute market runs in about 56 percent of all constraint-intervals in which congestion occurred in the 5-minute real-time process. As shown in the second row of Table 6.5, about 24 percent of the congested constraint-intervals were congested in the real-time mitigation run but not in the real-time market. However, bid mitigation was applied when no congestion occurred in the real-time market run in only the non-competitive intervals, or about 4 percent of the total congested constraint-intervals of the 5-minute market.

As shown in the third row of Table 6.5, in about 21 percent of the congested constraint-intervals, constraints were congested in the real-time market run but not in the real-time mitigation run. As previously noted, the market software does not provide results of the three pivotal supplier test for these intervals, so data are not available to determine if the constraint was competitive or non-competitive. However, data from other hours when congestion occurs in the real-time market during the mitigation run indicate that constraints in the 5-minute market are competitive around 82 percent of the time. This suggests that the frequency of under-mitigation is extremely low and occurs in about 3.8 percent of intervals when congestion occurs.

Table 6.5 Consistency of congestion and competitiveness in the 5-minute market local market power mitigation process

Congestion prediction	Competitive # constraint intervals	Competitive %	Non-competitive # constraint intervals	Non-competitive %	Total # constraint intervals	Total %
Consistent	14,117	45%	3,237	10%	17,354	56%
Over-identified	6,018	19%	1,320	4%	7,338	24%
Under-identified	---	---	---	---	6,411	21%
					31,103	**100%**

Congestion prediction:
Consistent = Congestion in mitigation and market runs.
Over-identified = Congestion in mitigation run, but no congestion in market.
Under-identified = No congestion in mitigation run, but congestion in market.

6.4 Local market power mitigation

This section provides an assessment of the frequency and impact of the automated local market power mitigation procedures described earlier. The section also provides a summary of the volume and impact of non-automated mitigation procedures that are applied for some exceptional dispatches, or additional dispatches issued by grid operators to meet reliability requirements issues not met by results of the market software.

6.4.1 Frequency and impact of automated bid mitigation

The ISO's automated local market power mitigation procedures were enhanced in April 2012 to more accurately identify and mitigate resources with the ability to exercise local market power in the day-ahead and hour-ahead markets. The real-time mitigation procedures were enhanced in May 2013. As part of these changes, the ISO adopted a new, in-line dynamic approach to the competitive path assessment. This new approach uses actual market conditions and produces a more accurate and less conservative assessment of transmission competitiveness.

In the real-time market, the number of units subject to mitigation, the number of units mitigated, and the estimated increase in dispatch were lower in 2014 than in 2013. In the day-ahead market, the number of units subject to mitigation, the number of units mitigated and the amount of megawatts scheduled were higher in 2014 compared to 2013. Day-ahead mitigation was similar to 2012 and remained low overall.

The competitive baseline analysis presented in Section 2.2 is calculated by using default energy bids for all gas-fired units in place of their market bids. Thus, this competitive baseline analysis provides an indication of prices that would result if all gas-fired generators were always subject to bid mitigation. As discussed in Section 2.2, the competitive baseline prices are nearly equal to or higher than the actual market prices for most months. This indicates that under most conditions enough capacity was offered at competitive prices to allow demand to be met at competitive prices.

The impact on market prices of bids that are actually mitigated can only be assessed precisely by re-running the market software without bid mitigation. This is not a practical approach because it would take an extreme amount of time to re-run the market software for every day-ahead and real-time market run. However, DMM has developed a variety of metrics to estimate the frequency with which mitigation was triggered and the effect of this mitigation on each unit's energy bids and dispatch levels. These metrics identify units which actually have their bids lowered as a result of mitigation each hour and also estimate the increase in energy dispatched from these units as a result of this decrease in bid price.[120]

Both the frequency (as shown in Figure 6.4) and the estimated change in schedules (as shown in Figure 6.5) increased in the day-ahead market in 2014:

- An average of 18 units in each hour were subject to day-ahead mitigation in 2014, slightly higher than an average of 16 units in 2013.
- An average of 1.3 units had day-ahead bids changed in 2014. This was up from an average of only 0.5 units with day-ahead bids changed in 2013.
- The estimated increase in energy dispatched in the day-ahead market from these units averaged about 11 MW per hour in 2014. This compares to an estimated impact from mitigation of 6 MW in 2013.
- While the number of units subject to mitigation, units mitigated with a bid change and volume of megawatts mitigated all increased in 2014 compared to 2013 in the day-ahead market, these numbers were still lower than in 2012.

Unlike day-ahead mitigation, the frequency of real-time mitigation decreased in 2014 compared to 2013. Figure 6.6 highlights the frequency of real-time mitigation, whereas Figure 6.7 highlights the volume of real-time mitigation:

- Bids for an average of 0.5 units per hour were lowered as a result of the real-time mitigation process in 2014. This compares to an average of about 1 unit in 2013.
- On average, 0.4 and 0.2 units per hour were dispatched at a higher level in the real-time market as a result of bid mitigation in 2013 and 2014, respectively.
- The estimated increase in real-time dispatches from these units because of bid mitigation averaged about 23 MW in 2014, compared to about 26 MW in 2013.

[120] 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 and Performance*, April 2010, http://www.caiso.com/2777/27778a322d0f0.pdf.

Figure 6.4 Average number of units mitigated in day-ahead market

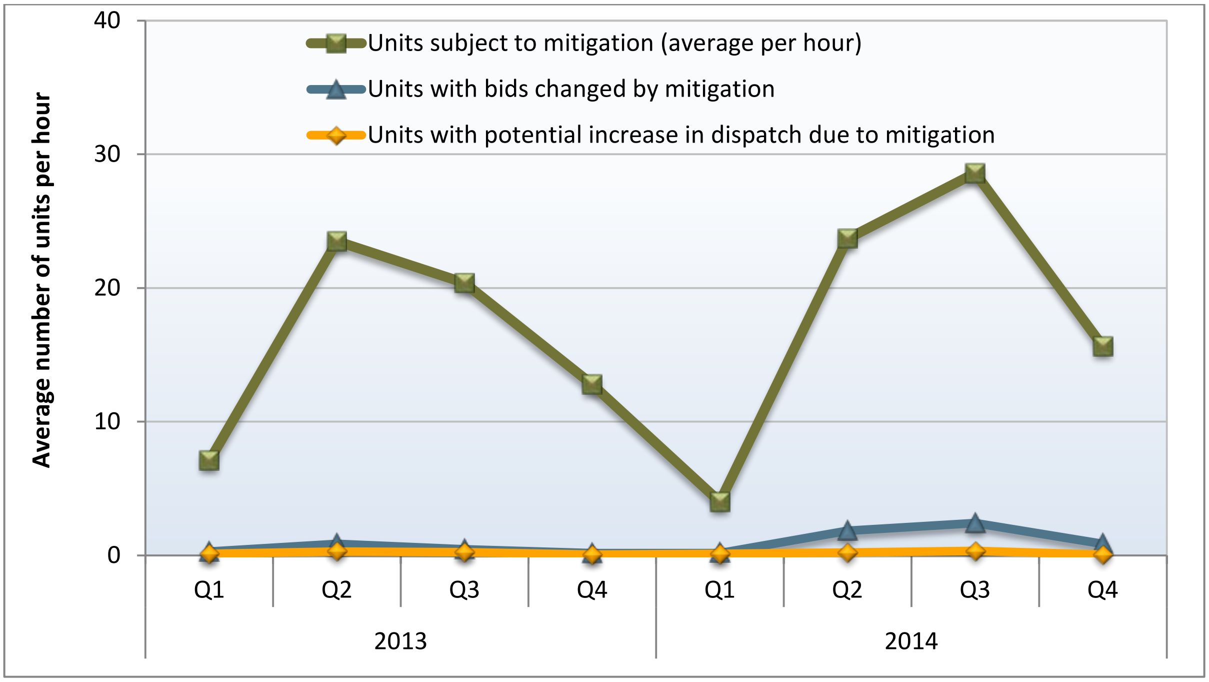


Figure 6.5 Potential increase in day-ahead dispatch due to mitigation (hourly averages)

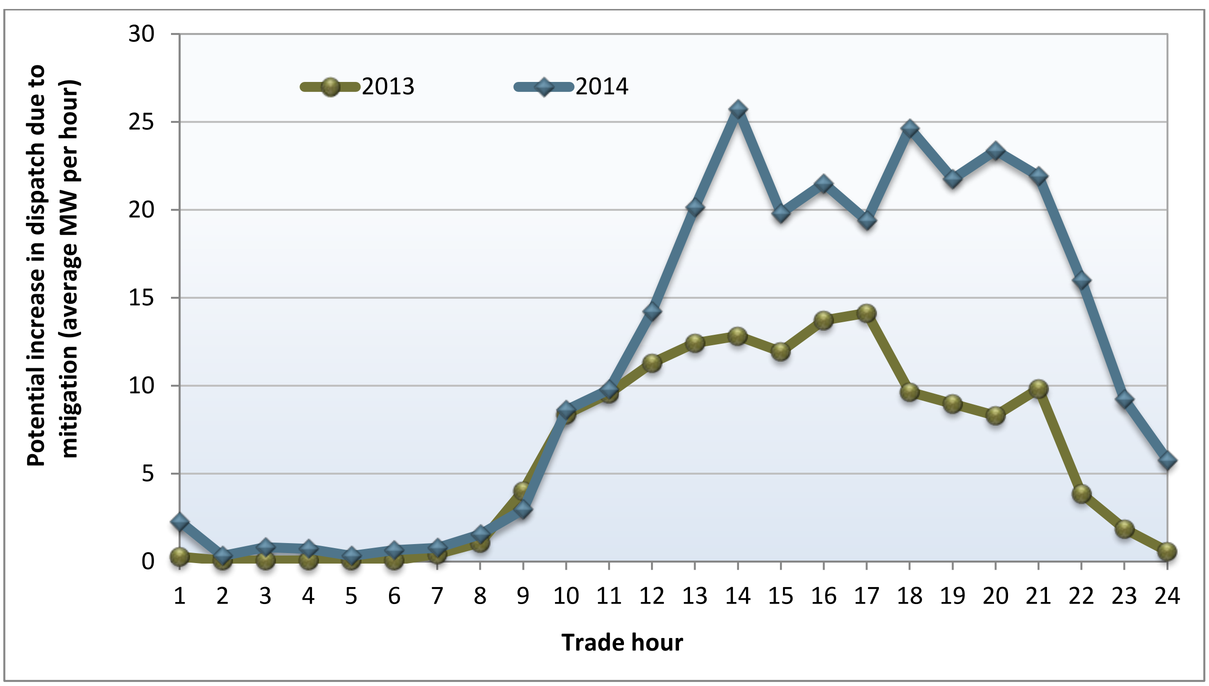


Figure 6.6 Average number of units mitigated in real-time market

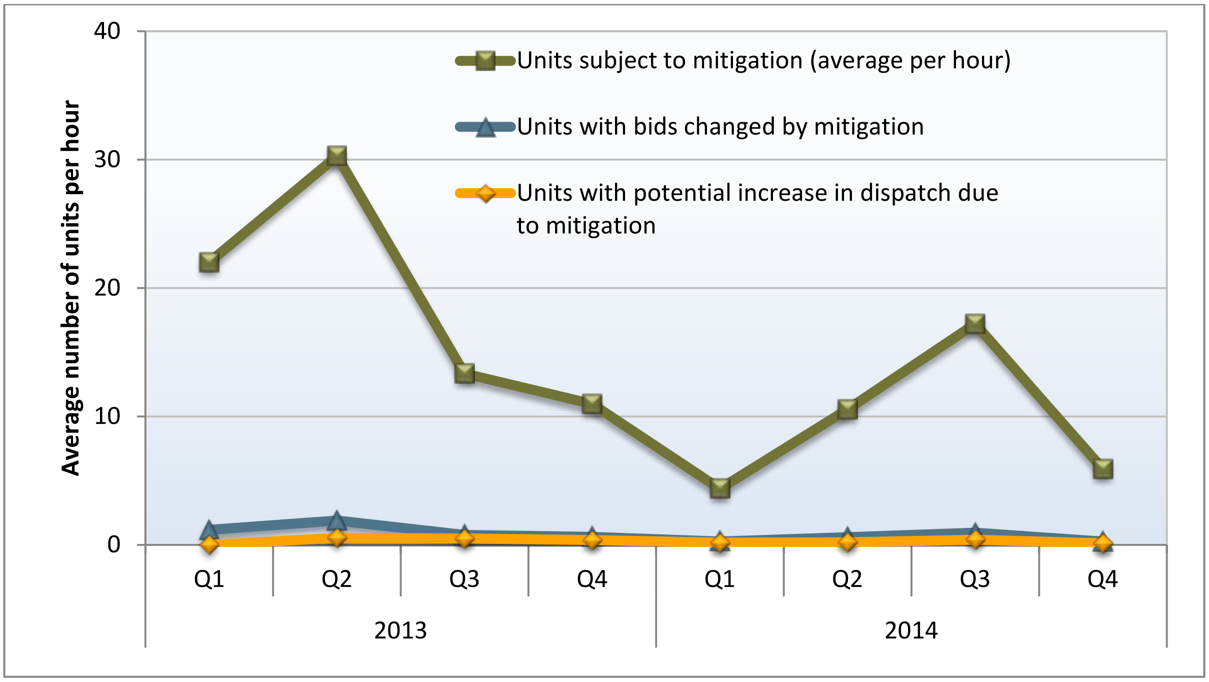
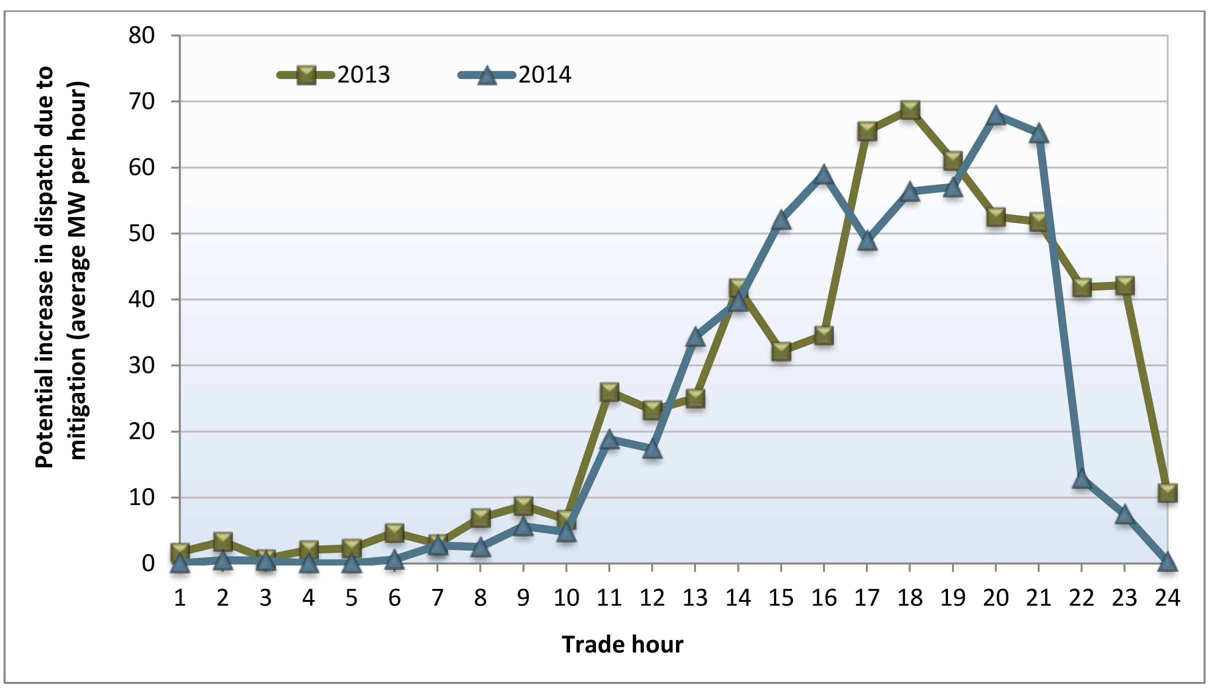


Figure 6.7 Potential increase in real-time dispatch due to mitigation (hourly averages)



6.4.2 Mitigation of exceptional dispatches

Overview

Exceptional dispatches are instructions issued by grid operators when the automated market optimization is not able to address a particular reliability requirement or constraint.[121] Total energy from exceptional dispatches decreased in 2014, with the associated above-market costs dropping from $18 million in 2013 to $11 million in 2014. This decrease in costs, in large part, reflects the decrease in volume of exceptional dispatches. Local market power mitigation of exceptional dispatches also played a role in limiting above-market costs, although this role was smaller than in prior years.

Exceptional dispatches are subject to mitigation if the commitment or dispatch is made for any of the following reasons:

- Address reliability requirements related to non-competitive transmission constraints;
- Ramp resources with ancillary services awards or residual unit commitment capacity to a dispatch level that ensures their availability in real time;
- Ramp resources to their minimum dispatchable level in real time, allowing the resource to be more quickly ramped up if needed to manage congestion or meet another reliability requirement; or
- Address unit-specific environmental constraints not incorporated into the model or the ISO's market software that affect the dispatch of units in the Sacramento Delta, which is commonly known as *Delta Dispatch*.

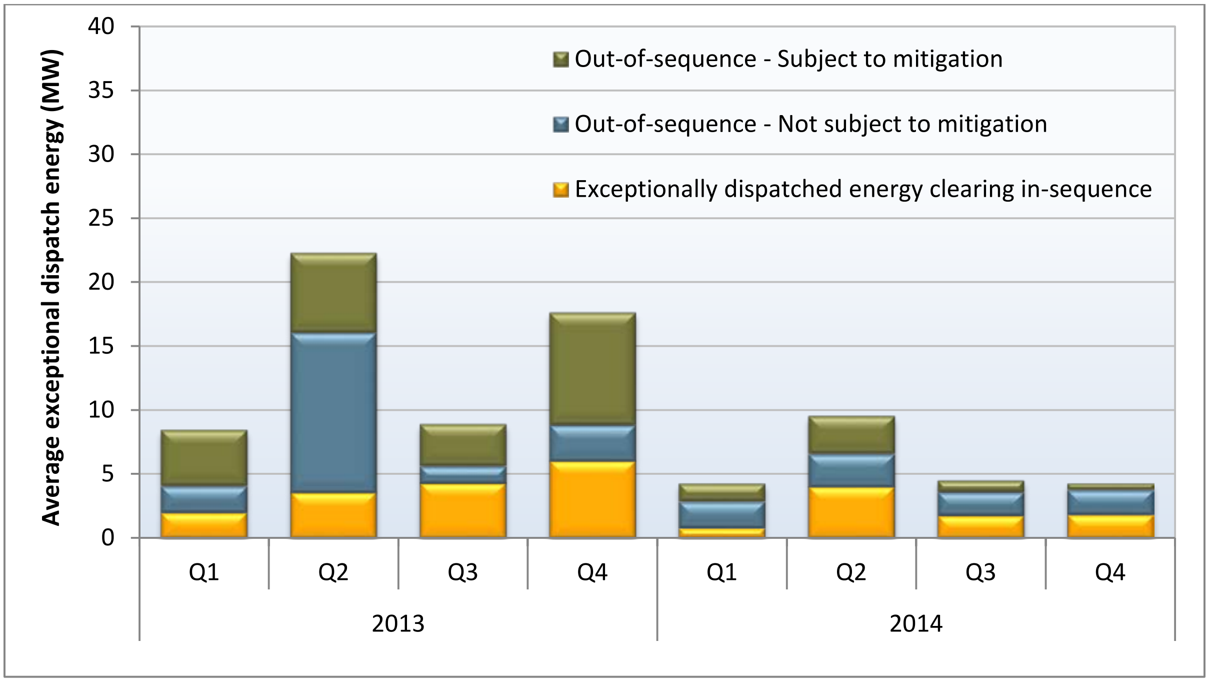
In 2013, the ISO committed to reducing the frequency and volume of exceptional dispatches, where possible, through the use of other tools for reliability management. This reduced the overall level of exceptional dispatch in 2013 and continued to reduce exceptional dispatch levels in 2014. In addition, scheduling coordinators bid a greater amount of energy at prices below the locational marginal price in 2013 and 2014. This further reduced the need for exceptional dispatch energy and related mitigation. Although the ISO expanded market power mitigation provisions applicable to exceptional dispatches in 2012 and 2013, these factors resulted in a decreased volume and percentage of exceptional dispatches as well as those subject to mitigation.

Volume and percent of exceptional dispatches subject to mitigation

As shown in Figure 6.8, the volume of total exceptional dispatch energy decreased in 2014 when compared to 2013. Figure 6.8 also shows that the greatest reduction in exceptional dispatch energy occurred in out-of-sequence energy subject to mitigation, which fell 75 percent in 2014 compared to 2013. Out-of-sequence energy is energy with bid prices above the market clearing price. ISO goals to decrease the frequency and volume of exceptional dispatches, as well as an increase in energy bid below the locational marginal price, influenced the drop in out-of-sequence energy subject to mitigation.

[121] A more detailed discussion of exceptional dispatches is provided in Section 8.1.

Figure 6.8 Exceptional dispatches subject to bid mitigation



Impact of exceptional dispatch energy mitigation

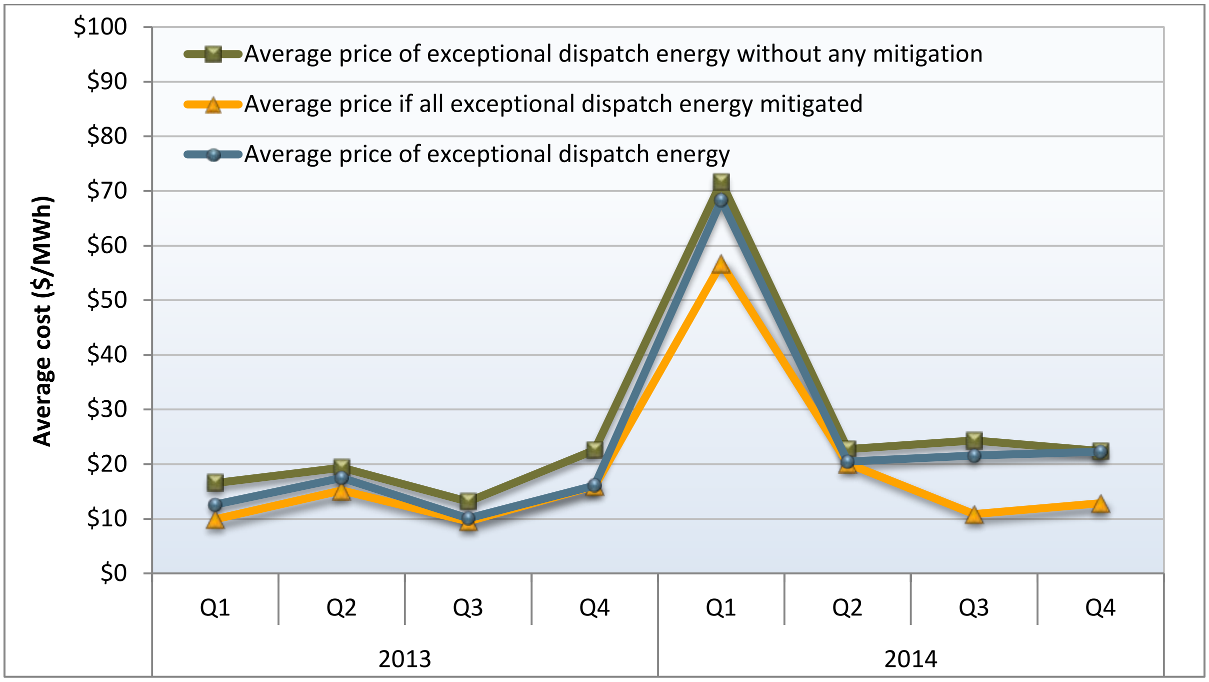
Figure 6.9 shows the difference in the average price for exceptional dispatch energy under three scenarios. The distance between the green and blue lines in Figure 6.9 illustrates the impacts of exceptional dispatch mitigation. The distance between these lines is the difference between the settled average price of exceptional dispatch energy (blue line) and the average price of exceptional dispatch energy in the absence of mitigation (green line). Greater distance between these two lines implies a larger overall impact of mitigation. As Figure 6.9 shows, this impact was relatively low in 2013 and remained low in 2014.

The yellow line in Figure 6.9 shows the average price of exceptional dispatch energy if all exceptional dispatch energy had been subject to mitigation. A greater distance between the green line and the yellow line is indicative of lower quantities of exceptional dispatch energy subject to mitigation. The distance between these lines is greatest in the third and fourth quarters of 2014, which is consistent with the lower levels of out-of-sequence energy subject to mitigation previously shown in Figure 6.8.

The average price of exceptional dispatch energy increased in 2014 to $33/MWh from $14/MWh in 2013. The first quarter of 2014 saw the highest average price for exceptional dispatch energy at $68/MWh. This value was significantly influenced by a significant volume of exceptional dispatch on February 6 and 7 during a period of tightness of natural gas supply and extreme natural gas prices. Overall market prices increased on these dates and local market power mitigation generally played a small role.[122]

[122] For further discussion of the February 2014 gas issues and related exceptional dispatch, see *Q1 2014 Report on Market Issues and Performance*, Department of Market Monitoring, May 2014, p. 41-48: http://www.caiso.com/Documents/2014FirstQuarterReport-MarketIssues_Performance-May2014.pdf.

Figure 6.9 Average prices for out-of-sequence exceptional dispatch energy



Mitigation of exceptional dispatches averted excess cost of about $144,000 in 2014, down from $450,000 in avoided out-of-sequence costs in 2013. The amount that was ultimately paid to exceptional dispatch generation in excess of the market price totaled $1 million in 2014, down from $1.4 million in 2013.[123] A greater amount of energy bid at prices below the locational marginal price combined with the overall reduction in the volume of out-of-sequence energy resulted in lower out-of-sequence costs in 2014.

6.5 Start-up and minimum load bids

In 2014, owners of gas-fired generation could choose from two options for their start-up and minimum load bid costs: proxy costs and registered costs.[124] Prior to April 2011, owners electing the registered

123 Exceptional dispatch is discussed in more detail in Section 8.1 of this report.

124 Under the proxy cost option, each unit's start-up and minimum load costs are automatically calculated each day based on an index of a daily spot market gas price and the unit's start-up and minimum load fuel consumption as reported in the master file. Unit owners selecting the registered cost option submit fixed monthly bids for start-up and minimum load costs, which are then used by the daily market software. Registered cost bids were at 150 percent of projected costs as calculated under the proxy cost option beginning in November 2013, whereas registered costs were capped at 200 percent before. One of the reasons for providing this bid-based registered cost option was to provide an alternative for generation unit owners who believed they had significant non-fuel start-up or minimum load costs not covered under the proxy cost option. See the following filing for more information: http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/CommitmentCostsRefinement2012.aspx. Furthermore, at the very end of 2014, the FERC accepted ISO proposed changes limiting eligibility of the registered cost option to resources with use limitations. Moreover, resources on the proxy cost option were allowed to bid-in up to 125 percent of proxy costs, whereas before they were capped at bidding in up to 100 percent of proxy costs. For further details see: http://www.caiso.com/Documents/Dec302014_OrderAcceptingCommitmentCostEnhancementsTariffRevision_ER15-15-001.pdf.

cost option were required to submit costs for both minimum load and start-up. Beginning in April 2011, participants could elect any combination of proxy or registered minimum load and start-up costs.[125]

Natural gas markets experienced significant price volatility in February 2014, with gas prices at the PG&E Citygate hub increasing over 300 percent on February 6.[126] These events appear to have had a significant impact on how participants viewed the proxy and registered cost options. Specifically, the data show a steep and sustained drop in the number of resources choosing the registered cost option as about half of the resources choosing the registered cost option for minimum load switched to the proxy cost option during February and did not switch back after the gas markets stabilized.

In addition, a change to proxy and registered costs in November 2013 may have also impacted the election choice. Beginning in November 2013, suppliers were allowed to include marginal costs associated with major maintenance and the grid management charge. Coincident with the inclusion of the additional major maintenance adder, the cost cap under the registered cost option was reduced from 200 percent of the projected proxy cost to 150 percent.[127]

Capacity under registered cost option

Gas-fired capacity opting for the registered cost option declined considerably in 2014 compared to 2013. As shown in Figure 6.10 through Figure 6.13, major changes occurred in the amount of capacity under the registered cost option for both start-up and minimum load costs in 2014. As shown in these figures:

- The portion of all gas-fired capacity selecting registered costs for both start-up and minimum load decreased in the first quarter of 2014, particularly for steam turbine units. This appears to be a result of the natural gas price spike events in early February 2014.
- In December 2014, about 44 percent of all natural gas-fueled capacity,[128] or approximately 12,000 MW, elected the registered cost start-up option. In December 2013, about 78 percent or 23,000 MW elected the registered cost start-up option.
- Natural gas-fueled minimum load capacity also decreased in December 2014 to about 15,000 MW compared to 27,000 MW in 2013, which represents 33 percent and 63 percent, respectively.
- By the end of 2014, around 20 percent of all natural gas-fueled capacity chose the registered cost option for start-up costs only, an increase from 13 percent in 2013. Approximately 54 percent of natural gas-fueled capacity solely elected the registered cost minimum load option, which is about twice the percentage as 2013.
- The portion of capacity at or near or below the floor (proxy cost) for start-up costs and minimum load costs decreased compared to 2013, as shown in Figure 6.12 and Figure 6.13. This change

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

[126] See Section 1.2.3 for further detail.

[127] See 145 FERC ¶ 61,082, order accepting tariff revisions, issued October 29, 2013: http://www.ferc.gov/CalendarFiles/20131029160035-ER13-2296-000.pdf.

[128] Some resources are registered as multi-stage generating (MSG) resources, which means for reasons related to the resource's technical characteristics it can be operated in various discrete configurations. In some cases, these resources can start up in only a subset of the configurations. This analysis excludes the "non-startable" configurations.

primarily occurred after the natural gas spike in February 2014 which may have prompted a review of the registered cost option for market participants.

Figure 6.10 Gas-fired capacity under registered cost option for start-up cost bids

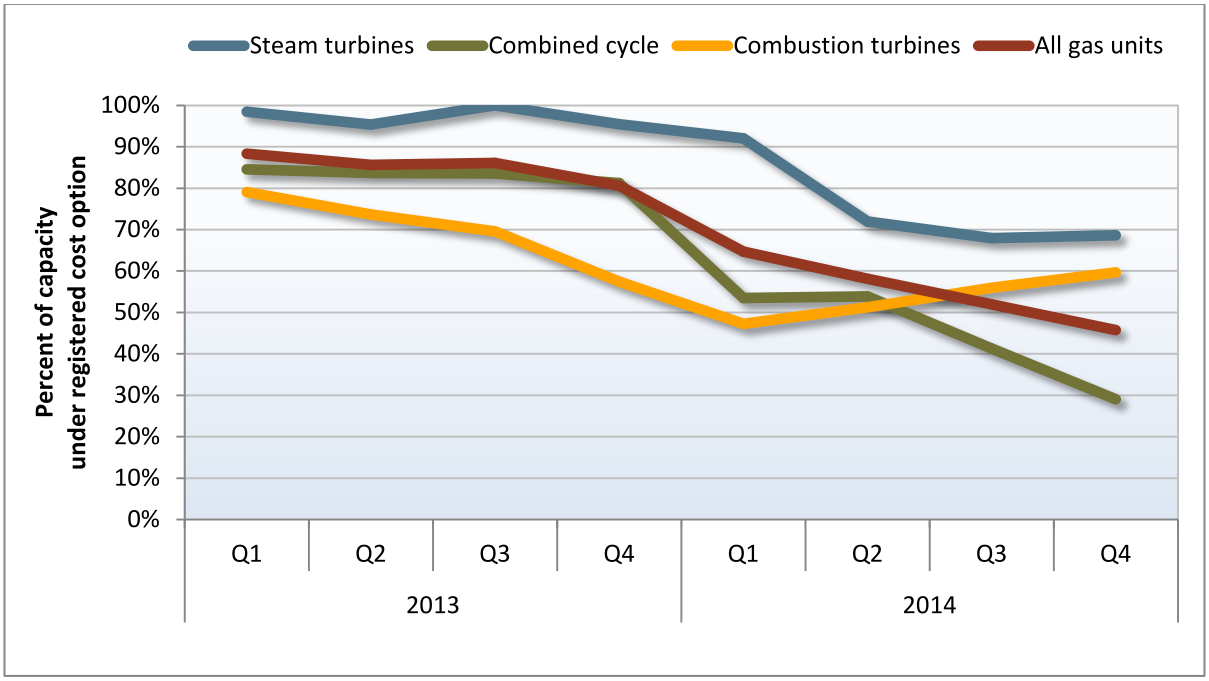


Figure 6.11 Gas-fired capacity under registered cost option for minimum load bids

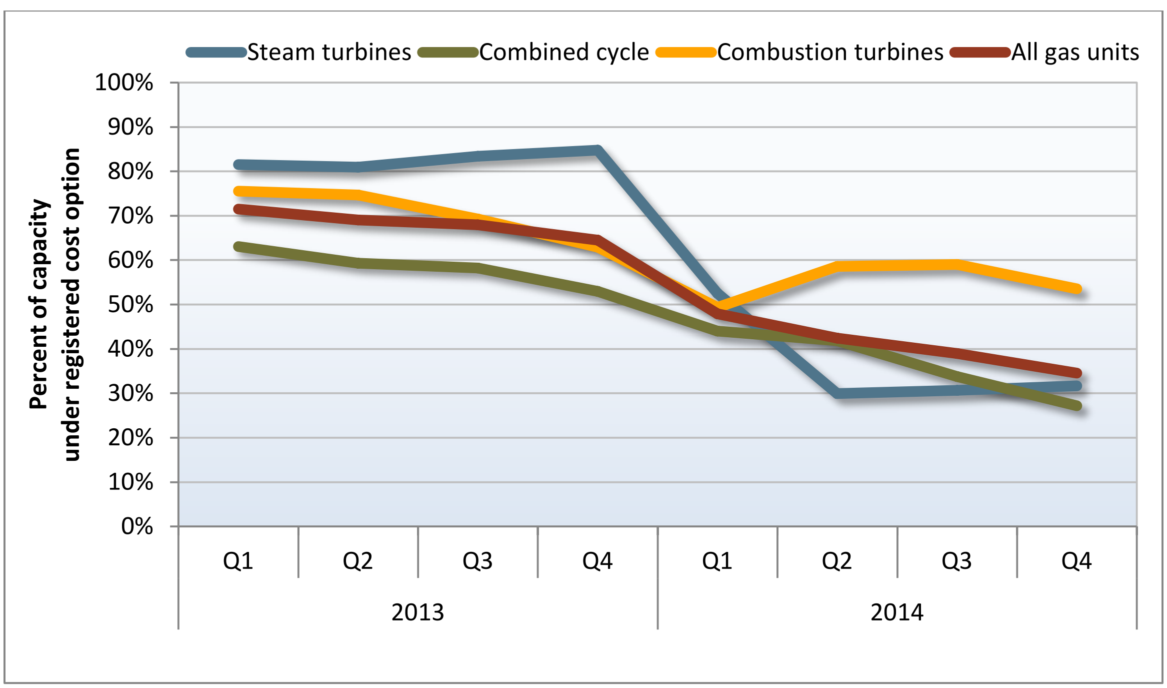


Figure 6.12 Registered cost start-up bids

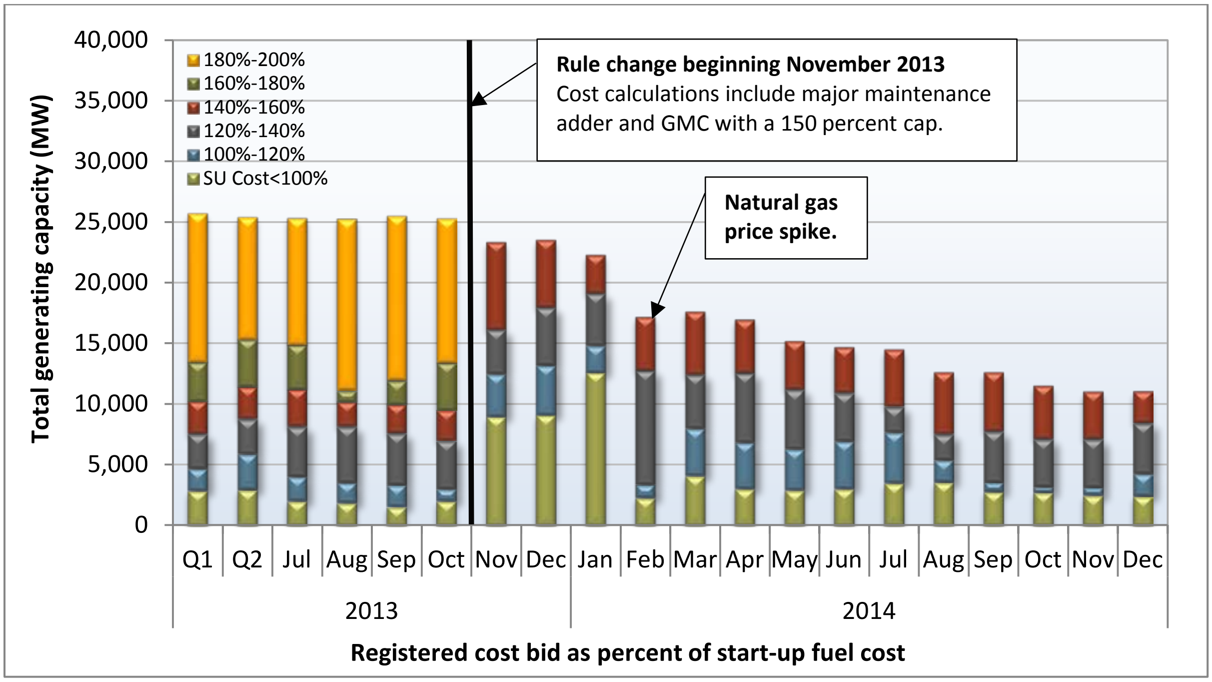


Figure 6.13 Registered cost minimum load bids

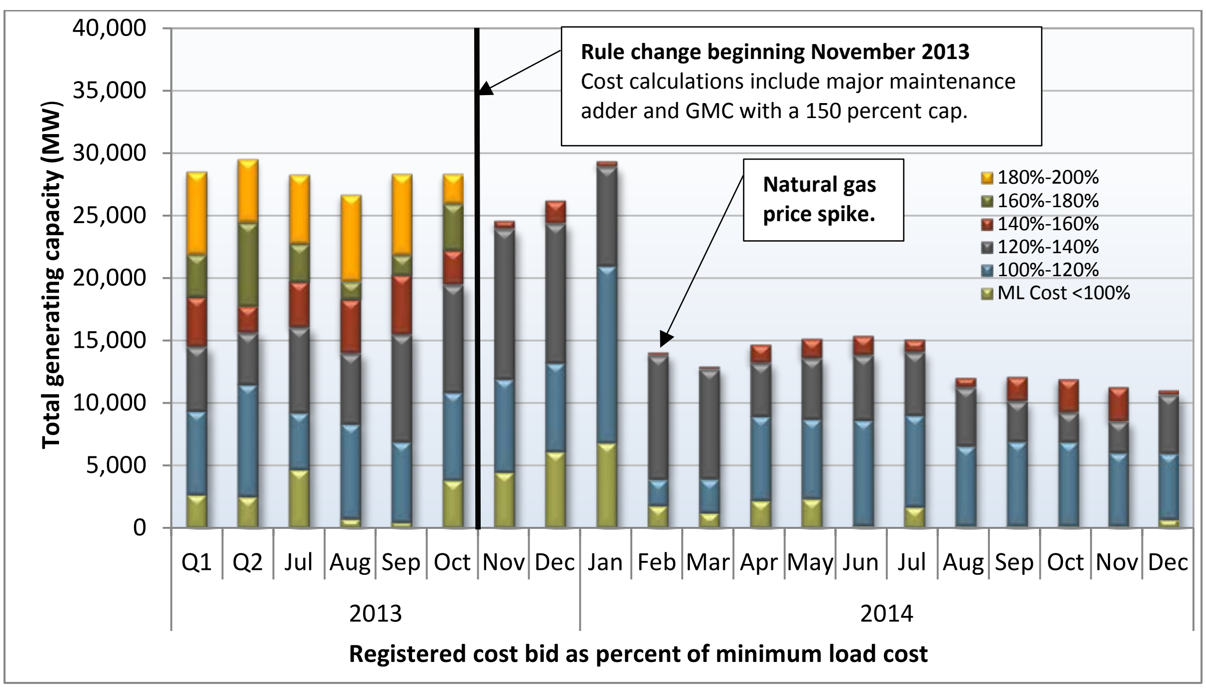


Figure 6.14 and Figure 6.15 show the amount of capacity under the registered cost option bidding at different levels by technology.[129] As illustrated in these figures:

- Of total natural gas capacity in December 2014, the registered cost start-up option was chosen by over 69 percent of steam turbines, 28 percent of combined cycles, and about 56 percent of gas turbines. With the exception of gas turbines, these percentages were significantly less than December 2013 levels when steam turbines, combined cycles and gas turbines had 93 percent, 79 percent and 60 percent, respectively.
- Of total natural gas capacity in December 2014, the registered cost minimum load option was chosen by nearly 30 percent of steam turbines, about 27 percent of combined cycles, and about 49 percent of gas turbines. In December 2013, the registered cost minimum load option was chosen by nearly 84 percent of steam turbines, about 55 percent of combined cycles, and about 61 percent of gas turbines.
- Most capacity under the start-up registered cost bid option submitted bids near the bid cap. This is a change from what was observed in previous periods. In December, start-up bids within 10 percent of the bid cap constituted about 40 percent of total capacity under the registered cost option, as shown in Figure 6.14. About 37 percent of capacity bid registered minimum load costs within 10 percent of the maximum costs for minimum load.
- Capacity electing the start-up registered cost option was unevenly distributed towards the outside ranges with the exception of steam turbines, which represented a small fraction of the maximum range. The range with the largest capacity was from 140 percent to 150 percent and accounted for about 41 percent of total start-up capacity on the registered cost option.
- Capacity electing the minimum load registered cost option was more heavily weighted toward the higher ranges. The two largest ranges with the largest capacity were from 120 percent to 130 percent and 140 percent to 150 percent which accounted for about 40 percent and 37 percent of total minimum load capacity on the registered cost option, respectively.

Compared to previous years, these results show a shift downward in the total capacity electing the start-up and minimum load registered option as well as a capacity shift towards bidding in closer to the cap.

[129] Generation technology consists of steam turbines, gas turbines and combined cycles.

Figure 6.14 Registered cost start-up bids by generation type – December 2014

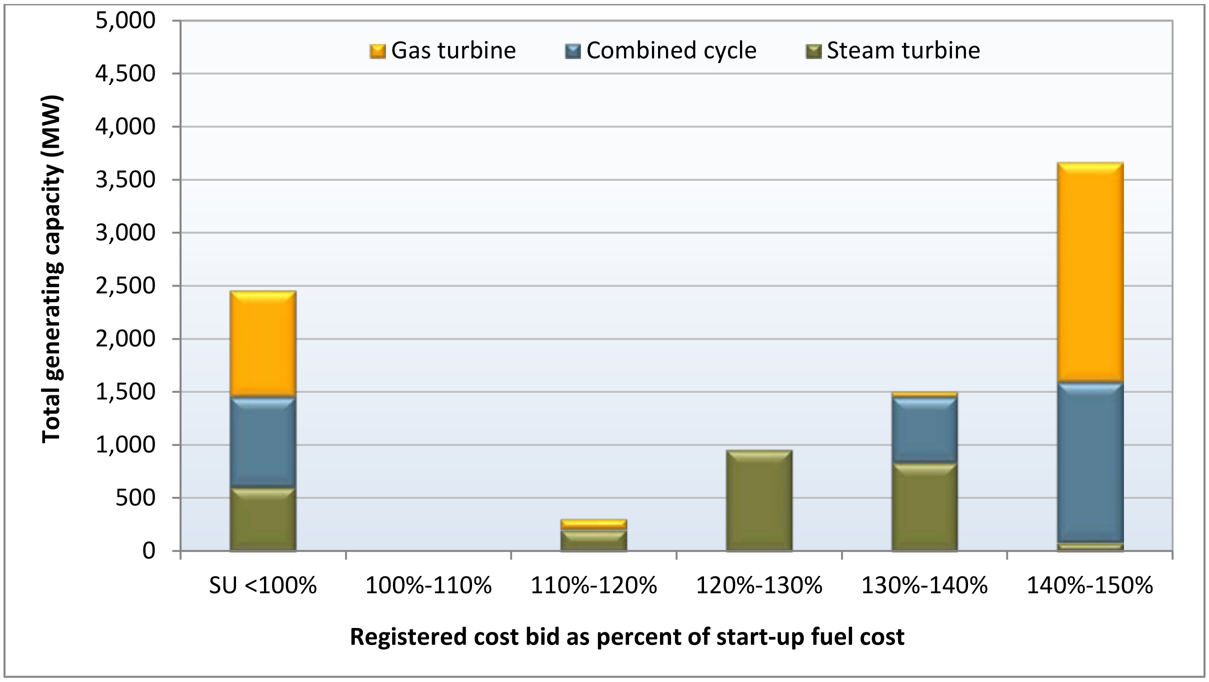
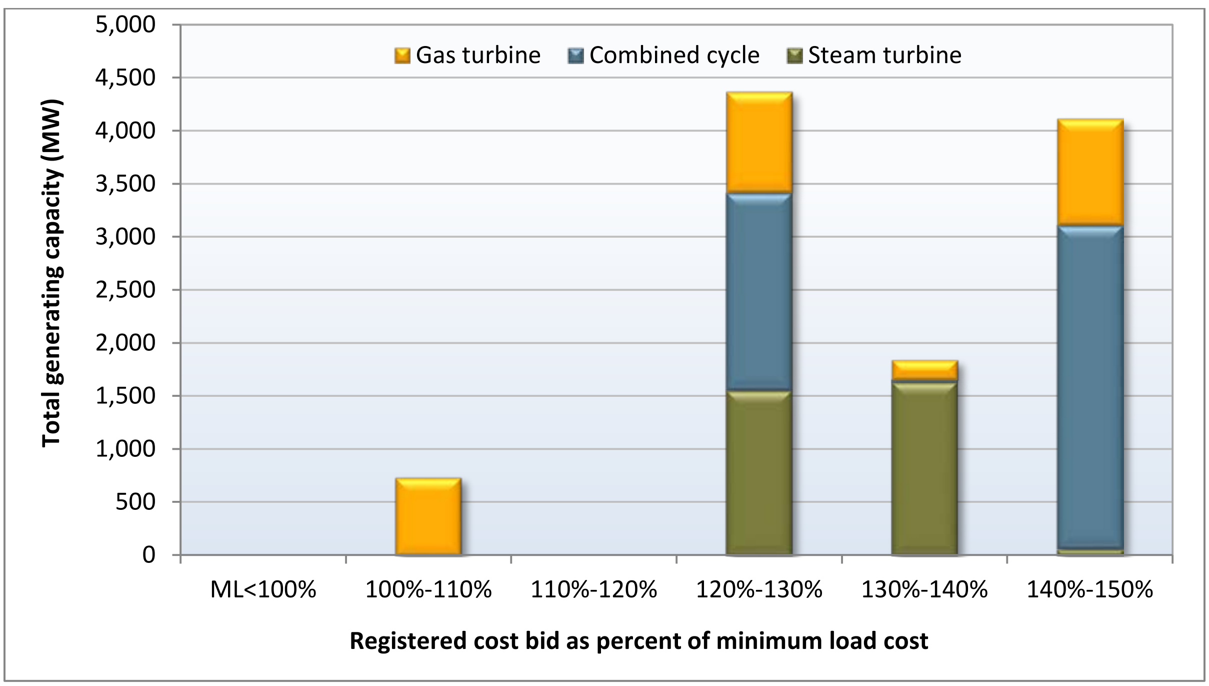


Figure 6.15 Registered cost minimum load bids by generation type – December 2014



7 Congestion

This chapter provides a review of congestion and the market for congestion revenue rights in 2014. The findings include the following:

- Congestion on transmission constraints within the ISO system decreased compared to prior years and had a lower impact on average overall prices across the system.
- Prices in the SDG&E area were impacted the most by internal congestion, which increased average day-ahead and real-time prices in the SDG&E area above the system average by about $0.60/MWh (1.2 percent) and $1.20/MWh (2.6 percent), respectively.
- Congestion increased average day-ahead prices in the SCE area above the system average by about $0.23/MWh or 0.5 percent. Real-time congestion did not have a significant impact on overall average prices because multiple constraints had offsetting effects, with some increasing congestion and others decreasing congestion.
- The overall impact of congestion on prices in the PG&E area reduced prices below the system average by about 1.3 percent in the day-ahead and just under 1 percent in the 15-minute market.
- Congestion on most major inter-ties connecting the ISO with other balancing authority areas was higher in 2014 compared to 2013, particularly for inter-ties connecting the ISO to the Pacific Northwest.
- The total volume of all congestion revenue rights both allocated and auctioned increased by 39 percent in 2014. This increase was driven by a trend of increased volumes clearing in the seasonal and monthly auctions that began in 2013. Much of this increase stemmed from increased participation by financial entities and an increase in the amount of congestion revenue rights clearing at $0/MW.
- Congestion revenue rights payments created a net revenue shortfall of about $95 million in 2014. This was a substantial reduction from the $23 million and $3 million surpluses in 2012 and 2013, respectively, and the first annual shortfall since the nodal market began in 2009.
- Financial participants received the largest share of net revenues of congestion revenue rights, collecting net revenues of $74 million of the $94 million in net revenues paid out by the ISO in 2014. These financial entities bid heavily in the seasonal and monthly auctions, speculating on and responding to congestion trends.
- Load-serving entities collected net revenues of congestion revenue rights of $34 million in 2014. Most of these revenues resulted from allocations made based on load served and auction revenues from counter-flow positions. In 2014, load-serving entities used counter-flow positions to sell allocated rights back to the market.

7.1 Background

Locational marginal pricing enables the ISO to more efficiently manage congestion and provide price signals to market participants to self-manage congestion. Over the longer term, nodal prices are intended to 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.

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. As congestion appears on the network, locational marginal prices at each node reflect marginal 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.

When a constraint is binding, the market software produces a shadow price on that constraint. This generally represents the cost savings that would occur if that constraint had one additional megawatt of transmission capacity available in the congested direction. 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 transmission 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.

Congestion on inter-ties between the ISO and other balancing areas decreases the price received for imports. This congestion also affects payments for congestion revenue rights. However, this congestion has generally had minimal impact on prices for loads and generation within the ISO system. This is because when congestion has limited additional imports on one or more inter-ties, additional supply from other inter-ties or from within the ISO has been available at a relatively small increase in price.

7.2 Congestion on inter-ties

The frequency and financial impacts of congestion on most inter-ties connecting the ISO with other balancing authority areas was higher in 2014 than in the previous year, particularly for inter-ties connecting the ISO to the Pacific Northwest as well as to Palo Verde.

Table 7.1 provides a detailed summary of the frequency of congestion on inter-ties along with average and total congestion charges from the day-ahead market. The congestion price reported in Table 7.1 is the shadow price for the binding inter-tie constraint. For a supplier or load-serving entity trying to import power over a congested inter-tie, this congestion price represents the decrease in the price for imports into the ISO. This congestion charge also represents the amount paid to owners of congestion revenue rights that are sourced outside of the ISO at points corresponding to these inter-ties.

Figure 7.1 compares the percentage of hours that major inter-ties were congested in the day-ahead market over the last three years. Figure 7.2 provides a graphical comparison of total congestion charges on major inter-ties in each of the last three years.

The table and figures highlight the following:

- Congestion increased substantially from the previous year on the two major inter-ties linking the ISO with the Pacific Northwest: the Nevada/Oregon Border (NOB) and the Pacific A/C Intertie (PACI). The latter inter-tie, PACI, is identified as PACI/Malin 500 in the table due to the PACI ITC constraint being replaced by the MALIN 500 inter-tie scheduling limit with implementation of the full network model on October 15.[130] Total congestion on these two inter-ties increased from about $61 million in 2013 to about $147 million in 2014. This is likely driven by greater hydro-electric generation availability in the Northwest and relative price differences between the Northwest and Northern California, most notably in the late portion of the first quarter and the second quarter of 2014.
- Congestion increased on Palo Verde, which is the largest inter-tie linking the ISO system with the Southwest. Congestion charges on Palo Verde increased from about $26 million in 2013 to over $36 million in 2014.

Table 7.1 Summary of import congestion (2012-2014)

Import region	Inter-tie	Frequency of import congestion			Average congestion charge ($/MW)			Import congestion charges (thousands)		
		2012	2013	2014	2012	2013	2014	2012	2013	2014
Northwest	PACI/Malin 500	42%	21%	25%	$10.5	$8.6	$17.0	$84,657	$34,026	$88,731
	NOB	39%	24%	37%	$11.6	$9.8	$12.7	$59,236	$27,823	$58,902
	COTPISO	8%		1%	$16.5		$17.8	$271		$37
	Summit	2%	1%	1%	$19.6	$10.6	$16.4	$195	$38	$57
	Cascade	20%	14%	6%	$14.8	$13.5	$10.6	$2,086	$1,280	$490
	Tracy 230	2%		0.1%	$232.4		$72.5	$1,164		$17
	Tracy 500		2%	3%		$21.3	$27.3		$1,292	$2,262
Southwest	Palo Verde	11%	14%	17%	$10.3	$13.2	$15.1	$19,177	$26,438	$36,551
	Mead	18%	3%	1%	$9.2	$7.7	$8.5	$15,248	$2,181	$1,206
	IPP DC Adelanto (BG)	11%		5%	$3.0		$8.5	$1,195		$1,727
	IPP Utah			7%			$7.2			$879
	West Wing Mead			1%			$30.1			$280
	Market Place Adelanto			0.3%			$16.6			$261
	Sylmar AC			0.4%			$9.7			$251
	IID - SCE	1%	3%	0.5%	$53.8	$49.8	$53.0	$1,646	$5,735	$1,005
	El Dorado	6%	3%		$10.1	$6.3		$5,695	$1,639	
	Mona IPP DC (MSL)	6%			$2.7			$285		
	IID-SDGE_ITC	0.2%			$963.6			$1,095		
	Other							$905	$169	$142
Total								***$192,855***	***$100,621***	***$192,797***

* The IPP DC Adelanto branch group is not an inter-tie, but is included here because of the function it serves in limiting imports from the Adelanto region and the frequency with which it was binding.

130 California ISO Technical Bulletin 'Pricing Logic for Scheduling Point – Tie Combination' March 2, 2015: http://www.caiso.com/Documents/TechnicalBulletin_PricingLogicforSchedulingPoint-TieCombination.pdf.

Figure 7.1 Percent of hours with congestion on major inter-ties (2012-2014)

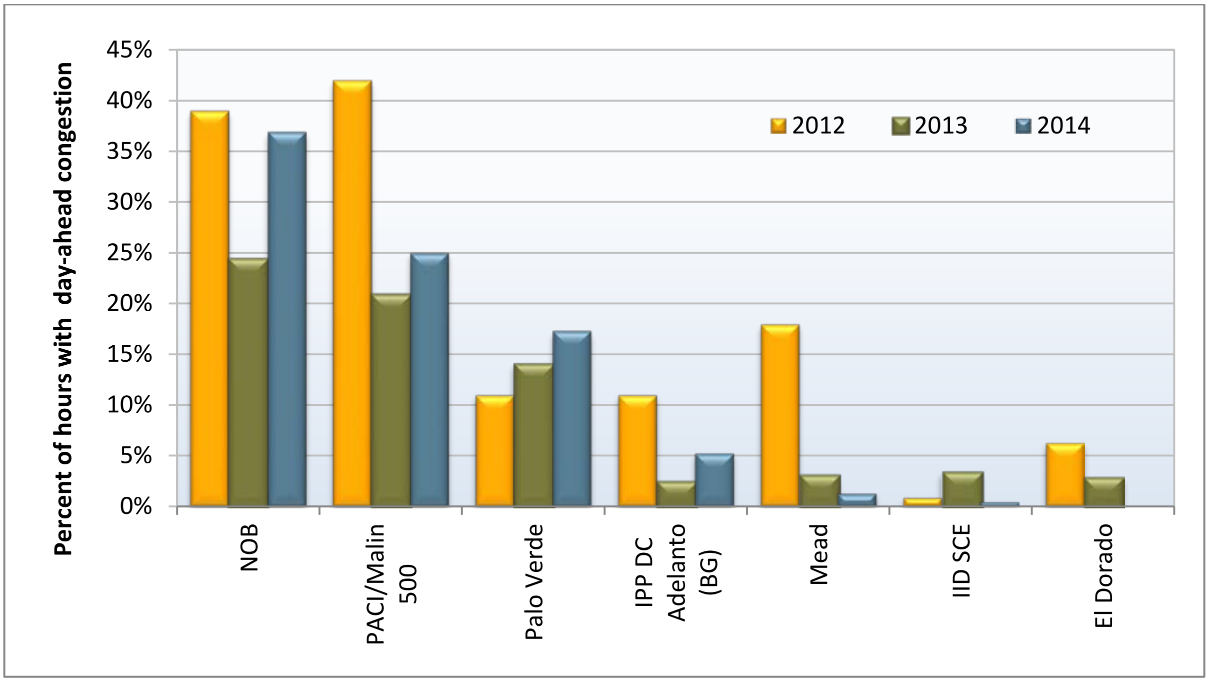
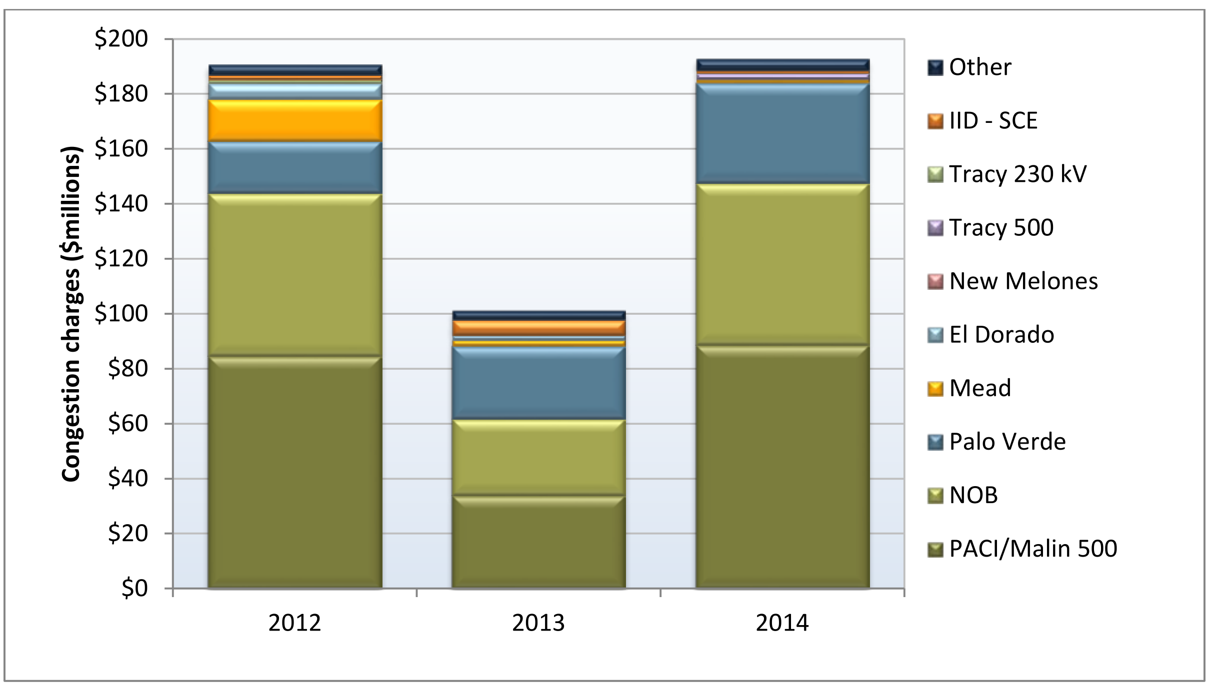


Figure 7.2 Import congestion charges on major inter-ties (2012-2014)



7.3 Congestion impacts on internal constraints

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 within the ISO system.

The impact of congestion on any constraint on each pricing node in the ISO system can be calculated by summing the product of the shadow price of that constraint and the shift factor for that node relative to the congested constraint. This calculation can be done for individual nodes, as well as groups of nodes that represent different load aggregation points or local capacity areas.[131]

Congestion on constraints within Southern California generally increases prices within the SCE and SDG&E areas, but decreases prices in the PG&E area. Likewise, congestion within Northern California typically increases prices in the PG&E area, but decreases prices in Southern California. Constraints are grouped by price impact within each utility area, which, depending on system topography, may not always correspond to the physical location of the constraint.

7.3.1 Day-ahead congestion

Table 7.2 shows the impact of congestion on specific internal constraints during congested hours on average day-ahead prices at the system's three aggregate load areas.

The most congested constraint in the ISO system in 2014 was in the PG&E area and was the constraint limiting imports into the Fresno area (e.g., 30880_HENTAP2_230_30900_GATES_230_BR_2_1), which is heavily dependent on imports from the 230 kV system through the McCall, Herndon and Henrietta banks, and local hydro generation. These constraints are adjusted to protect for thermal overload from the contingency loss of the Gates – Gregg 230 kV line. The 30880_HENTAP2_230_30900_GATES _230_BR_2_1 constraint was congested in the day-ahead market about 30 and 22 percent of the hours in the second and third quarters, respectively, and about 11 percent and 4 percent of the hours in the first and fourth quarters, respectively. When congestion occurred on this constraint in the second quarter, day-ahead prices in the PG&E area increased about $1.84/MWh with negligible change in SDG&E and SCE area prices. In the third quarter, PG&E area prices increased about $2/MWh when congestion occurred on this constraint, while SDG&E and SCE area prices decreased about $0.50/MWh.

In the SCE area, the Barre – Villa 230 kV line and the Barre – Lewis constraints together were the most frequent binding constraints in 2014. These constraints were used by the ISO to manage contingencies at a more granular level than in years past, where the ISO previously applied the Barre – Lewis nomogram. The Barre – Villa 230 kV line was congested in all quarters, but was highest in the third quarter at about 17 percent of hours. The Barre – Lewis 230 kV line was congested due to contingencies in the first and second quarters in about 7 percent and 4 percent of hours, respectively. When the Barre – Lewis and Barre – Villa lines were binding in the second quarter, prices in the SCE area increased by about $1.50/MWh because of each constraint. Also, in the second quarter these constraints increased prices in the SDG&E area by $0.87/MWh and $1.98/MWh, and decreased prices in the PG&E area by about $1.00/MWh and $1.28/MWh, respectively.

131 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.

Table 7.2 Impact of congestion on day-ahead prices during congested hours

		Frequency				Q1			Q2			Q3			Q4		
Area	Constraint	Q1	Q2	Q3	Q4	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	6110_TM_BNK_FLO_TMS_DLO_NG		11.9%	14.8%	8.5%				$0.71	-$0.89	-$0.89	$0.45	-$0.50	-$0.50	$3.17	$1.83	$1.70
	30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	10.5%	29.9%	21.6%	3.8%	$0.36	-$0.27	-$0.27	$1.84			$2.01	-$0.56	-$0.56	$0.50	-$0.36	-$0.36
	35922_MOSSLD _115_30751_MOSSLDB _230_XF_1				3.5%										$0.87	-$1.36	-$2.41
	35922_MOSSLD _115_30751_MOSSLDB _230_XF_2				2.5%										$1.11		
	33020_MORAGA _115_30550_MORAGA _230_XF_1 _P	2.5%	7.6%		1.4%	$0.33	-$0.24	-$0.24	$0.80	-$0.70	-$0.70				$1.37		
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1				1.1%										$4.28	-$3.92	-$3.92
	SLIC 2512269 SOL1				0.6%										$0.88		-$1.07
	30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1			34.1%								$1.82	-$1.56	-$1.56			
	35922_MOSSLD _115_30750_MOSSLD _230_XF_1A		5.0%	5.7%					$0.78			$0.61	-$0.56	-$0.56			
	30915_MORROBAY_230_30916_SOLARSS _230_BR		0.4%	1.3%					$4.69	-$4.08	-$4.08	$7.70	-$3.52	-$3.52			
	SLIC 2412157 PARDEE-SYLMAR2_NG			0.5%								$0.58		-$2.71			
	PATH15_BG	1.6%	9.4%	0.3%		$4.56	-$3.65	-$3.65	$3.67	-$3.07	-$3.07	$3.86	-$3.25	-$3.25			
	SLIC 2249785 ELDORADO-LUGO_1_NG		3.8%						$0.62	-$0.43	-$1.01						
	SLIC 2237207 TL50002 DVRB		2.1%						$0.75	-$0.92	$0.71						
	T-135 VICTVLUGO_DVRB_NG	6.1%	2.0%			$0.62	-$0.48	-$0.78	$1.23	-$1.02	-$1.46						
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1		1.6%						$2.74	-$2.30	-$2.30						
	LOSBANOSNORTH_BG		1.1%						$3.75	-$3.16	-$3.16						
	SLIC 2206489_PVCR_Out_EDLG		0.8%						$0.74	-$0.52	-$1.38						
	30750_MOSSLD _230_30790_PANOCHE _230_BR_1 _1		0.3%						$2.21	-$1.87	-$1.87						
	30790_PANOCHE _230_30900_GATES _230_BR_1 _1		0.2%						$2.20	-$1.70	-$1.70						
	SLIC 2207662 NGila-HWD PVDV	1.7%				$0.43	-$0.45	$0.26									
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	5.1%	2.0%	16.7%	12.2%	-$2.59	$2.98	$0.54	-$1.00	$1.49	$0.87	-$0.75	$0.91	$0.51	-$0.89	$1.91	$0.18
	7500_SOL1_NG				1.1%										-$0.57	$0.54	-$0.57
	SLIC 2285023 PATH 15 N-S SOL				0.4%										-$2.53	$1.81	$1.81
	SLIC 2319206 HDW-HASS_SCIT				0.4%										-$4.14	$3.62	$3.69
	24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1		2.9%	15.5%						$0.85			$3.34				
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	0.2%		1.5%		-$2.17	$1.69	$1.67				-$1.37	$0.93	$0.90			
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	6.6%	4.3%			-$1.48	$1.80	$0.96	-$1.28	$1.52	$1.98						
	PATH26_BG	1.4%				-$2.18	$1.69	$1.69									
	25201_LEWIS _230_24137_SERRANO _230_BR_1 _1	0.4%				-$4.54	$4.07	-$1.10									
SDG&E	7820_TL 230S_OVERLOAD_NG	1.6%	5.7%	3.0%	4.2%	-$0.11		$1.89	-$1.25		$6.68	-$0.29		$2.68	-$0.27	$0.22	$3.32
	IVALLY-ELCNTO_230_BR_1_1				3.2%										-$0.06		$2.98
	22356_IMPRLVLY_230_20118_ROA-230 _230_BR_1 _1				2.7%												$5.37
	6510 SOL1_NG				2.6%										-$4.55	$3.70	$5.05
	22208_EL CAJON_69.0_22408_LOSCOCHS_69.0_BR_1 _1				1.9%												$0.50
	22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1			3.2%	1.7%												$3.57
	SLIC 2300985 Hoodoo_H.Gila_S-Lin				1.6%												$2.04
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	2.2%	3.0%	0.7%	1.0%			$1.90			-$2.79			-$1.61			-$0.95
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P				1.3%										-$1.11	$0.59	$2.64
	IID-SCE_BG				1.1%												-$1.51
	SLIC 2422498 TL50001_NG				0.5%										-$0.62		$10.61
	SLIC 2474810 CFE ROA-HRA_NG				0.3%											$0.81	$16.51
	SLIC 2474667 CFE MEP-TOY_NG				0.2%											$1.09	$24.02
	SLIC 2474777 CFE_HRA-MEP_NG				0.2%											$0.90	$19.38
	SLIC 2481747 CFE MEP-TOY_NG				0.2%											$0.25	$5.21
	SLIC 2481748 CFE HRA-MEP_NG				0.2%											$0.46	$9.06
	22597_OLDTWNTP_230_22504_MISSION _230_BR_1 _1			0.4%	0.2%												$12.94
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	3.2%	26.8%	10.1%		-$0.06	-$0.21	$0.87	-$0.80	$0.51	$1.12	-$0.61	$0.31	$0.57			
	22835_SXTAP2 _230_22504_MISSION _230_BR_1A_1		0.3%	7.9%							$4.90			$3.74			
	22831_SYCAMORE_138_22124_CHCARITA_138_BR_1 _1			1.4%										$1.57			
	22768_SOUTHBAY_69.0_22772_SOUTHBAY_138_XF_1			0.4%										$4.18			
	22500_MISSION _138_22117_CARLTHT2_138_BR_1 _1		1.2%	0.2%							$6.00			$6.48			
	22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1	1.5%	4.2%					$4.85			$6.65						
	22448_MESAHGTS_69.0_22496_MISSION _69.0_BR_1 _1		1.4%								$2.08						
	22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1		0.7%						-$0.47		$3.43						
	SDGE_CFEIMP_BG		0.7%						-$1.02	-$1.02	$10.16						
	22636_PARADISX_69.0_22456_MIGUEL _69.0_BR_1 _1		0.4%								$10.92						
	MIGUEL_BKs_MXFLW_NG		0.4%								$7.94						
	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P		0.4%						-$7.10	$3.95	$14.39						
	24138_SERRANO _500_24137_SERRANO _230_XF_1 _P		0.3%						-$4.89	$2.86	$9.28						
	24084_LITEHIPE_230_24091_MESA CAL_230_BR_1 _1		0.3%						-$5.84	$4.14	$8.54						
	SOUTHLUGO_RV_BG	2.1%	0.1%			-$2.60	$1.80	$2.70	-$5.08	$3.44	$4.44						
	SLIC 2157511 LUG0-MIRA LOMA 3	4.1%				-$1.74	$1.28	$1.57									
	22136_CLAIRMNT_69.0_22140_CLARMTTP_69.0_BR_1 _1	0.5%						$3.52									
	SLIC 2196141 MIDWAY SOL1	0.4%				-$1.26	$1.04	$1.04									
	24155_VINCENT _230_24126_RIOHONDO_230_BR_1 _1	0.2%				-$4.14	$3.22	$3.57									

While the San Diego area had the greatest quantity of congested constraints throughout the year, the percentage of hours each constraint was congested was rather low. The 7820_TL230S_OVERLOAD_NG constraint, which protects the Imperial Valley – El Centro 230 kV line for a loss of the Imperial Valley – North Gila 500 kV line, was binding in all quarters in 2014. The second quarter experienced the highest percentage of congested hours, at about 5.7 percent, which increased SDG&E area prices by about $6.68/MWh, decreased PG&E area prices by $1.25/MWh and had negligible impact on the SCE area prices. The 22192_DOUBLTTP_138_22300_FRIARS_138_BR_1_1 constraint was also binding in all quarters in 2014 and typically decreased prices in the SDG&E area with negligible price impact on the SCE and PG&E areas.

As shown in these figures and tables, congestion on some constraints significantly affected prices during hours when congestion occurred. The frequency and magnitude of congestion on transmission constraints within the ISO system was somewhat consistent to prior years and had a smaller impact on average overall prices in the different load areas. Additional analysis and discussion of the impact of congestion on average annual prices for different areas within the ISO is provided in the following section of this chapter.

Overall day-ahead price impacts

This section provides an assessment of differences on overall average prices caused by congestion between different areas of the ISO system. Unlike the analysis provided in the previous section, this assessment is made based on the average congestion component of the locational marginal prices as a percent of the total average system energy price during all hours – including both congested and non-congested hours. This approach shows the impact of congestion taking into account the frequency that congestion occurs as well as the magnitude of the impact of congestion during hours when it occurs.[132]

Table 7.3 shows the overall impact of congestion on different constraints on average prices in each load aggregation area in 2014. These results show that:

- The overall impact of congestion on prices in the PG&E area increased prices above the system average by about $0.62/MWh, an increase of about 1.3 percent. The constraints with the largest impacts were Hentap to Gates at $0.26/MWh (0.5 percent) and McCall to Hentap at $0.17 (0.3 percent). These constraints are designed to protect for thermal overload from the contingency loss of the Gates – Gregg 230 kV line.
- Internal constraints had the greatest impact on prices in the San Diego area. The combined effect increased average prices above the system average by about $0.59/MWh or about 1.2 percent. The 7820_TL230S_OVERLOAD_NG constraint, which protects the Imperial Valley – El Centro 230 kV line for a loss of the Imperial Valley – North Gila 500 kV line, had the largest impact at $0.16/MWh (0.3 percent).
- Congestion drove prices in the SCE area above the system average prices by about $0.23/MWh or almost 0.5 percent. This was a large decrease from the prior year when the SCE area was congested by $1.72/MWh (3.8 percent), which was related to limits on the percentage of load in the SCE area to meet total flows on all transmission paths into the SCE area (i.e., SCE_PCT_IMP_BG).[133]

[132] In addition, this approach identifies price differences caused by congestion without including price differences that result from differences in transmission losses at different locations.

[133] The ISO un-enforced this constraint starting October 1, 2013. The ISO found greater reliability benefits could be achieved from modifying the physical Under Frequency Load Shedding Relay scheme and removing this constraint.

Table 7.3 Impact of constraint congestion on overall day-ahead prices during all hours

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1	$0.17	0.34%	-$0.08	-0.17%	-$0.08	-0.17%
PATH15_BG	$0.11	0.22%	-$0.09	-0.19%	-$0.09	-0.18%
30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	$0.26	0.53%	-$0.01	-0.02%	-$0.01	-0.02%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.09	-0.17%	$0.14	0.29%	$0.01	0.02%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	-$0.07	-0.14%	$0.04	0.08%	$0.09	0.18%
7820_TL 230S_OVERLOAD_NG	-$0.01	-0.01%			$0.16	0.32%
6110_TM_BNK_FLO_TMS_DLO_NG	$0.11	0.22%	$0.03	0.05%	$0.02	0.04%
24087_MAGUNDEN_230_24153_VESTAL _230_BR_2 _1			$0.14	0.29%		
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.04	-0.08%	$0.05	0.10%	$0.01	0.03%
22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1					$0.09	0.18%
6510 SOL1_NG	-$0.03	-0.06%	$0.02	0.05%	$0.03	0.07%
22835_SXTAP2 _230_22504_MISSION _230_BR_1A_1					$0.08	0.16%
7430 SOL-2_NO_HELMS_PUMP_NG_SUM	$0.06	0.11%				
22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1					$0.05	0.11%
7500_SOL1_NG	-$0.01	-0.03%	$0.02	0.04%	-$0.01	-0.03%
30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1	$0.02	0.04%	-$0.01	-0.03%	-$0.01	-0.03%
T-135 VICTVLUGO_DVRB_NG	$0.02	0.03%	-$0.01	-0.03%	-$0.02	-0.04%
SLIC 2157511 LUG0-MIRA LOMA 3	-$0.02	-0.04%	$0.01	0.03%	$0.02	0.03%
33020_MORAGA _115_30550_MORAGA _230_XF_1 _P	$0.02	0.04%	-$0.01	-0.02%	-$0.01	-0.02%
SOUTHLUGO_RV_BG	-$0.02	-0.03%	$0.01	0.02%	$0.02	0.03%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.01	-0.02%	$0.01	0.01%	$0.02	0.04%
22356_IMPRLVLY_230_20118_ROA-230 _230_BR_1 _1					$0.04	0.07%
7430_SOL_15_DA_NG_SUM	$0.03	0.06%				
30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
LOSBANOSNORTH_BG	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
IVALLY-ELCNTO_230_BR_1_1					$0.02	0.05%
22500_MISSION _138_22117_CARLTHT2_138_BR_1 _1					$0.02	0.05%
SDGE_CFEIMP_BG					$0.02	0.04%
SLIC 2249785 ELDORADO-LUGO_1_NG	$0.01	0.01%	$0.00	-0.01%	-$0.01	-0.02%
SCIT_BG	-$0.01	-0.02%	$0.01	0.01%	$0.01	0.01%
PATH26_BG	-$0.01	-0.02%	$0.01	0.01%	$0.01	0.01%
35922_MOSSLD _115_30750_MOSSLD _230_XF_1A	$0.02	0.04%				
30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.01	-0.01%	$0.01	0.01%	$0.01	0.01%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.02	-0.03%
SLIC 2422498 TL50001_NG					$0.02	0.03%
22597_OLDTWNTP_230_22504_MISSION _230_BR_1 _1					$0.02	0.03%
SLIC 2474810 CFE ROA-HRA_NG					$0.01	0.03%
24138_SERRANO _500_24137_SERRANO _230_XF_1 _P					$0.01	0.02%
24084_LITEHIPE_230_24091_MESA CAL_230_BR_1 _1					$0.01	0.01%
SLIC 2474667 CFE MEP-TOY_NG					$0.01	0.02%
22636_PARADISX_69.0_22456_MIGUEL _69.0_BR_1 _1					$0.01	0.02%
SLIC 2237207 TL50002 DVRB			-$0.01	-0.01%		
Other	$0.10	0.20%	-$0.01	-0.02%	$0.08	0.16%
Total	$0.62	1.26%	$0.23	0.48%	$0.59	1.19%

7.3.2 Real-time congestion

Congestion in the 15-minute and 5-minute real-time markets differs from congestion in the day-ahead market. Real-time congestion typically occurs less frequently overall, but often occurs on a larger number of constraints and has a bigger impact on prices when it occurs.

15-minute market congestion

The congestion effect on price was larger in the 15-minute market, but overall congestion occurred less frequently than in the day-ahead market. Table 7.4 shows the frequency and magnitude of congestion by quarter from the implementation of the 15-minute market in May 2014.

Overall, the 30880_HENTAP2_230_30900_GATES_230_BR_2_1 and the 30875_MCCALL_230 _30880_HENTAP2_BR_1_1 constraints were the most frequently binding constraints after the implementation of the 15-minute market. These Fresno area constraints are heavily dependent on imports from the 230 kV system through the McCall, Herndon and Henrietta banks, and local hydro generation. The constraints are adjusted to protect for thermal overload from the contingency loss of the Gates – Gregg 230 kV line.

During the second quarter, the 30880_HENTAP2_230_30900_GATES_230_BR_2_1 constraint increased prices in the PG&E area by about $5.50/MWh and decreased prices by about $8/MWh in the SDG&E and SCE areas. The price impact in the PG&E area in the third quarter was similar to the second quarter, but the SDG&E and SCE areas prices decreased by about $3/MWh instead of $8/MWh. The 30875_MCCALL_230_30880_HENTAP2_BR_1_1 constraint was primarily binding in the third quarter, increasing prices in the PG&E area by about $4.50/MWh and decreasing prices in the SDG&E and SCE areas by about $3.70/MWh.

Congestion occurred most consistently in the San Diego area on 24138_SERRANO_500_24137_ SERRANO_230_XF_2_P, with the greatest frequency occurring in the fourth quarter at about 0.4 percent of intervals. This constraint increased prices in the SDG&E and SCE areas by about $5.21/MWh and $5.16/MWh, respectively. This constraint decreased prices in the PG&E area by about $3.29/MWh in the fourth quarter. The most frequently binding constraint in the SDG&E area was 22835_SXTAP2_230_ 22504_MISSION_230_BR_1A_1, which was caused by planned outages in the San Diego area. This constraint affected the SDG&E prices by about $18/MWh and $15/MWh for the second and third quarters, respectively. With the exception of the 7820_TL 230S_OVERLOAD_NG, 6510 SOL1_NG and the 30060_MIDWAY_500_29402_WIRLWIND_500_BR_1_2 constraints, other congestion occurred infrequently and typically had a minimal impact on overall 15-minute energy prices.

In the SCE area, the 24016_BARRE_230_24154_VILLA PK_230_BR_1_1 and the 24086_LUGO_500_ 26105_VICTORVL_500_BR_1_1 constraints were binding throughout all time periods, with the highest frequency of binding intervals occurring in the fourth quarter affecting around 2 percent and 1 percent of intervals, respectively.

In the fourth quarter, the 24016_BARRE_230_24154_VILLA PK_230_BR_1_1 constraint was binding in roughly 12 percent of hours in the day-ahead market compared to around 2 percent of intervals in the 15-minute market. While this constraint increased day-ahead prices in the SCE area by about $2/MWh, it increased prices by about $7.80/MWh in the 15-minute market. Differences in congestion in the day-ahead and real-time markets occur as system conditions change, virtual bids liquidate and constraints are adjusted to account for discrepancies between market and actual flows and to provide a reliability margin.

Table 7.4 Impact of congestion on 15-minute prices by load aggregation point in congested intervals

		Frequency			Q2			Q3			Q4		
Area	Constraint	Q2	Q3	Q4	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
PG&E	30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	2.4%	3.1%	0.3%	$5.56	-$8.32	-$8.32	$5.37	-$2.94	-$2.94	$10.09	-$10.95	-$11.64
	PATH15_S-N	0.6%		0.1%	$37.94	-$30.37	-$30.37				$37.78	-$33.75	-$31.82
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1			0.1%							$14.67	-$7.20	-$7.20
	30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1	0.1%	3.4%		$5.64	-$4.85	-$4.85	$4.50	-$3.68	-$3.68			
	6110_TM_BNK_FLO_TMS_DLO_NG	1.5%	0.7%		$3.43	-$5.02	-$5.02	$5.42	-$7.56	-$7.56			
	30915_MORROBAY_230_30916_SOLARSS _230_BR_1 _1		0.1%					$19.69	-$7.51	-$7.51			
	30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1		0.1%					$17.28	-$15.22	-$15.22			
	33020_MORAGA _115_30550_MORAGA _230_XF_1 _P	0.4%			$13.14	-$8.17	-$8.17						
	T-135 VICTVLUGO_DVRB_NG	0.3%			$3.26	-$2.42	-$4.01						
	SLIC 2249785 ELDORADO-LUGO_1_NG	0.3%			$4.27	-$3.19	-$6.88						
SCE	24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	0.2%	1.5%	1.8%	-$7.04	$4.50	$10.32	-$4.19	$4.75	$1.71	-$3.47	$7.82	$0.97
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	1.3%	0.6%	1.2%	-$0.95	$0.91	-$0.28	$5.14	-$3.84	-$3.34	$2.14	$2.30	-$0.05
	SLIC 2319206 HDW-HASS_SCIT			0.3%							-$3.76	$12.32	$12.23
	PATH26_N-S			0.1%							-$32.16	$28.88	$27.34
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1		0.6%					-$4.81	$5.81	$2.11			
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2		0.2%					-$23.39	$17.59	$17.17			
SDG&E	24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	0.1%	0.1%	0.4%	-$16.35	$5.74	$29.86	-$14.44	$10.70	$37.31	-$3.29	$5.16	$5.21
	6510 SOL1_NG			0.4%							-$4.44	$10.79	$12.66
	IVALLY-ELCNTO_230_BR_1_1			0.1%							-$10.37	-$10.43	$60.75
	SLIC 2474808 CFE ROA-HRA_NG			0.1%								$2.09	$46.34
	22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1	0.5%		0.1%	-$2.42		$17.09						$64.91
	22835_SXTAP2 _230_22504_MISSION _230_BR_1A_1	0.5%	1.4%				$17.69			$14.58			
	7820_TL 230S_OVERLOAD_NG	0.5%	0.7%		-$9.17		$47.97	-$4.80	-$2.86	$49.17			
	22835_SXTAP2 _230_22504_MISSION _230_BR_1 _1		0.5%							$9.01			
	SCIT_BG		0.3%					-$55.33	$32.00	$35.33			
	SLIC 2377852 TL50001_NG		0.1%							$22.88			
	22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1	0.9%					$16.02						
	22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1	0.5%					-$17.84						
	24084_LITEHIPE_230_24091_MESA CAL_230_BR_1 _1	0.2%			-$8.01	$5.48	$11.00						
	22708_SANLUSRY_69.0_22712_SANLUSRY_138_XF_3	0.1%					-$25.41						
	SOUTH_OF_LUGO	0.1%			-$11.81	$8.33	$11.45						

Overall 15-minute price impacts

Table 7.5 shows the overall impact of 15-minute congestion in 2014 on average prices in each load area by constraint.[134] The overall impact of congestion increased the SDG&E area price by about $1.22/MWh (2.6 percent), PG&E area prices by about $0.41/MWh (1 percent) and SCE area prices by about $0.06/MWh (0.1 percent).

In the SDG&E area, the constraint with the greatest impact on real-time prices was 7820_TL 230S_OVERLOAD_NG at $0.18/MWh (0.40 percent). Also the 22835_SXTAP2_230_22504 _MISSION_230_BR_1A_1 constraint had a large impact at $0.09 (0.20 percent). The *other* category has the largest impact in the SDG&E area and is a collection of constraints below a very low price threshold where data collection and presentation is limited.

In the PG&E area, the constraints with the greatest impact on real-time prices were 30880_HENTAP2_230_30900_GATES_230_BR_2_1 at $0.11/MWh (0.23 percent), PATH15_S-N at $0.08/MWh (0.18 percent) and SCIT_BG at -$0.07/MWh (-0.14 percent).

The constraints in the SCE area with the greatest impact on real-time prices were PATH15_S-N with about -$0.07/MWh (-0.15 percent) and 24016_BARRE_230_24154_VILLA PK_230_BR_1_1 with $0.08/MWh (0.18 percent). These constraints, along with all other constraints, combined to have a minimal overall congestion impact in the SCE area at $0.06/MWh.

134 Due to data issues, details on specific constraints below a very low price impact could not be calculated and were included in the *other* category.

Table 7.5 Impact of constraint congestion on overall 15-minute prices during all hours

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
PATH15_S-N	$0.08	0.18%	-$0.07	-0.15%	-$0.07	-0.14%
7820_TL 230S_OVERLOAD_NG	-$0.01	-0.03%			$0.18	0.40%
SCIT_BG	-$0.07	-0.14%	$0.04	0.08%	$0.04	0.09%
30880_HENTAP2 _230_30900_GATES _230_BR_2 _1	$0.11	0.23%	-$0.02	-0.03%	-$0.01	-0.03%
24016_BARRE _230_24154_VILLA PK_230_BR_1 _1	-$0.04	-0.09%	$0.08	0.18%	$0.01	0.02%
30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1	$0.06	0.13%	-$0.03	-0.08%	-$0.03	-0.07%
22835_SXTAP2 _230_22504_MISSION _230_BR_1A _1					$0.09	0.20%
6110_TM_BNK_FLO_TMS_DLO_NG	$0.03	0.07%	-$0.03	-0.06%	-$0.03	-0.06%
PATH26_N-S	-$0.02	-0.05%	$0.02	0.04%	$0.02	0.04%
24138_SERRANO _500_24137_SERRANO _230_XF_2 _P	-$0.01	-0.03%	$0.01	0.03%	$0.03	0.06%
22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1					$0.04	0.09%
30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.02	-0.04%	$0.01	0.03%	$0.01	0.03%
6510 SOL1_NG	-$0.01	-0.01%	$0.02	0.03%	$0.02	0.04%
22831_SYCAMORE_138_22117_CARLTHT2_138_BR_1 _1					$0.04	0.08%
24016_BARRE _230_25201_LEWIS _230_BR_1 _1	-$0.01	-0.03%	$0.02	0.04%		
IVALLY-ELCNTO_230_BR_1_1					$0.03	0.06%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.02	0.04%			-$0.01	-0.02%
30915_MORROBAY_230_30916_SOLARSS _230_BR_2 _1	$0.02	0.03%	-$0.01	-0.02%	-$0.01	-0.02%
22192_DOUBLTTP_138_22300_FRIARS _138_BR_1 _1					-$0.03	-0.06%
SLIC 2319206 HDW-HASS_SCIT			$0.01	0.03%	$0.01	0.03%
33020_MORAGA _115_30550_MORAGA _230_XF_1 _P	$0.01	0.02%	-$0.01	-0.02%	-$0.01	-0.02%
Other	$0.29	0.64%	$0.01	0.03%	$0.90	1.93%
Total	$0.41	0.90%	$0.06	0.13%	$1.22	2.64%

5-minute market congestion

After implementing the 15-minute market in May, 5-minute market congestion has had a reduced impact on overall settlements. Even so, congestion in the 5-minute market is still important and is outlined below.

As with the day-ahead and 15-minute markets, the most congested constraint in the 5-minute market was in the PG&E area and was associated with constraints limiting imports into the Fresno area (e.g., 30880_HENTAP2_230_30900_GATES_230_BR_2_1). This particular constraint was congested in the 5-minute market by about 4 percent and 8 percent of the hours in the second and third quarters, respectively, and about 1 percent of the hours in the first and fourth quarters. When congestion occurred on this constraint in the second quarter, 5-minute prices in the PG&E area increased about $6/MWh and prices in SDG&E and SCE areas decreased by over $8/MWh. In the third quarter, PG&E area prices increased about $5.60/MWh when congestion occurred on this constraint, while SDG&E and SCE area prices decreased about $5.50/MWh and $4.60/MWh.

The second most congested constraint was 24016_BARRE_230_24154_VILLA PK_230_BR_1_1 in the SCE area. This constraint had the highest frequency of binding intervals in the third and fourth quarters at around 4 percent and 5 percent, respectively. When congestion occurred on this constraint in the third quarter, 5-minute prices increased in the SCE and SDG&E areas by about $3.60/MWh and $2.64/MWh respectively, while prices in the PG&E area decreased by about $3.60/MWh. In the fourth quarter, it increased SCE and SDG&E area prices by about $5.50/MWh and $2.00/MWh, respectively, while it decreased prices in the PG&E area by about $3.16/MWh.

In the San Diego area, the 22835_SXTAP2_230_22504_MISSION_230_BR_1A_1 and 22835_SXTAP2_230_22504_MISSION_230_BR_1_1 constraints were the highest frequently binding constraints and were congested primarily in the third quarter with over 3 percent and about 1 percent of the hours, respectively. When congestion occurred on these constraints in the third quarter, the 5-minute prices increased in the SDG&E area by over $9/MWh, and had a negligible impact on the SCE and PG&E prices.

Overall 5-minute price impacts

The overall impact of 5-minute congestion in 2014 on average prices in each load area by constraint was similar to 15-minute congestion price impacts. The overall impact of congestion increased the SDG&E area price by about $0.78/MWh (1.7 percent), PG&E area prices by about $0.37/MWh (1 percent) and SCE area prices by about $0.04/MWh (0.1 percent).

In the SDG&E area, as with the 15-minute market, the constraint with the greatest impact on 5-minute prices was 7820_TL 230S_OVERLOAD_NG at $0.18/MWh (0.4 percent). Also similar to the 15-minute market, the 22835_SXTAP2_230_22504_MISSION_230_BR_1A_1 constraint had a large price impact at $0.14 (0.31 percent).

In the PG&E area, the constraints with the greatest impact on 5-minute prices were PATH15_S-N at $0.41/MWh (0.88 percent), 30880_HENTAP2_230_30900_GATES_230_BR_2_1 at $0.22/MWh (0.48 percent) and 30875_MCCALL_230_30880_HENTAP2_BR_1_1 at $0.12/MWh (0.26 percent).

The two constraints in the SCE area with the greatest impact on 5-minute prices were PATH26_N-S at about $0.19/MWh (0.41 percent) and 24016_BARRE_230_24154_VILLA PK_230_BR_1_1 at $0.14/MWh (0.30 percent).

7.4 Congestion revenue rights

Congestion revenue rights are financial instruments that allow participants to speculate on congestion trends or 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 the following:

- The total volume of all congestion revenue rights both allocated and auctioned increased by 39 percent in 2014. This increase mainly resulted from a 50 percent increase in congestion revenue rights awarded in short-term and monthly auctions.
- A $95 million revenue shortfall existed at the end of 2014, which will be allocated to measured demand.

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 the following five elements:

- ***Life term —*** Each congestion revenue right has one of two categories of life term: one month or one calendar season. The long-term allocation process extends seasonal congestion revenue rights awarded in the annual allocation for an additional 9 years to provide a hedge for a total of 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 peak or off-peak hours as defined by Western Electricity Coordinating Council guidelines.[135]

- ***Megawatt quantity —*** This is the volume of congestion revenue rights allocated or purchased. For instance, one megawatt of congestion revenue rights with a January 2014 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.

- ***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 congestion price of the sink minus the congestion 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.[136]

- In the annual process, 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 and are only available through the allocation process. A short-term right is valid for one calendar season of one specific year.

- The monthly process is an allocation and auction for rights that are valid for one calendar month of one specific year.

Figure 7.3 and Figure 7.4 show the monthly average amount of the various types of congestion revenue rights awarded within a quarter since 2012 for peak and off-peak hours, respectively. The following is shown in these figures:

- The total volume of congestion revenue rights increased by 39 percent in 2014 compared to 2013. This was in part the result of increases in cleared megawatts in the counter-flow direction and cleared megawatts from $0/MWh bids in the monthly auctions. The short-term auction for 2014 was conducted in November 2013.

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

[136] A more detailed explanation of the congestion revenue right processes is provided in the ISO's *2014 Annual CRR Market Results Report*. See: http://www.caiso.com/Documents/2014AnnualCRRMarketResultsReport.pdf.

Figure 7.3 Allocated and awarded congestion revenue rights (peak hours)

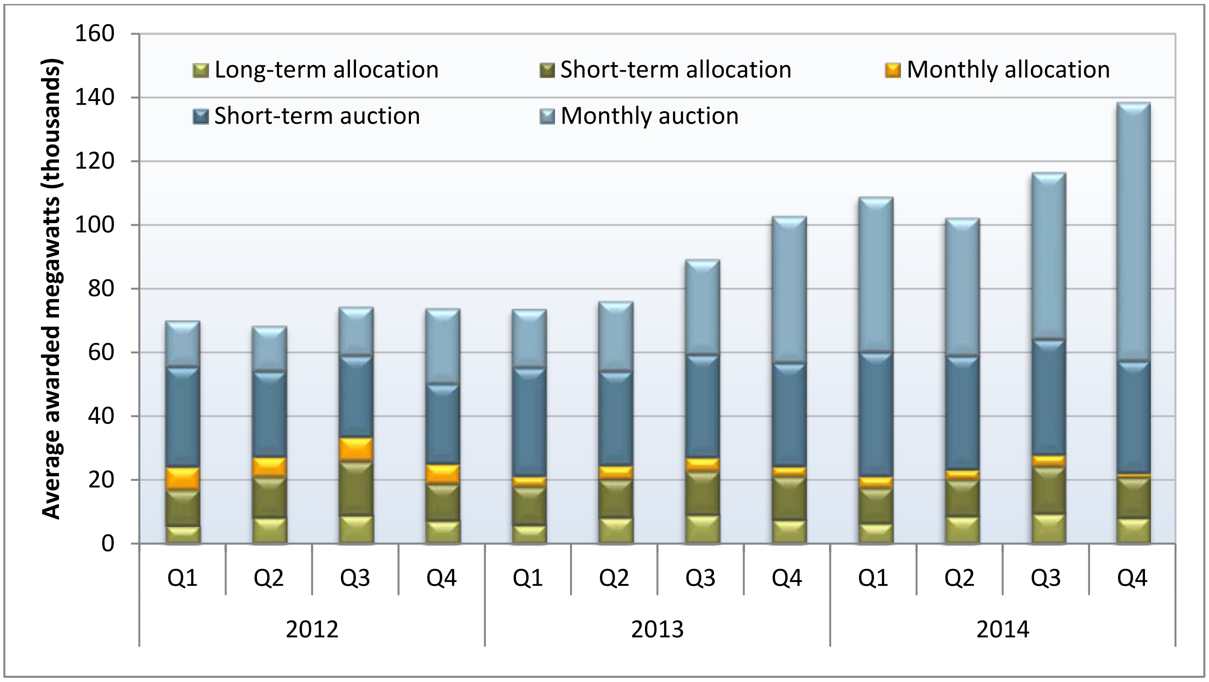
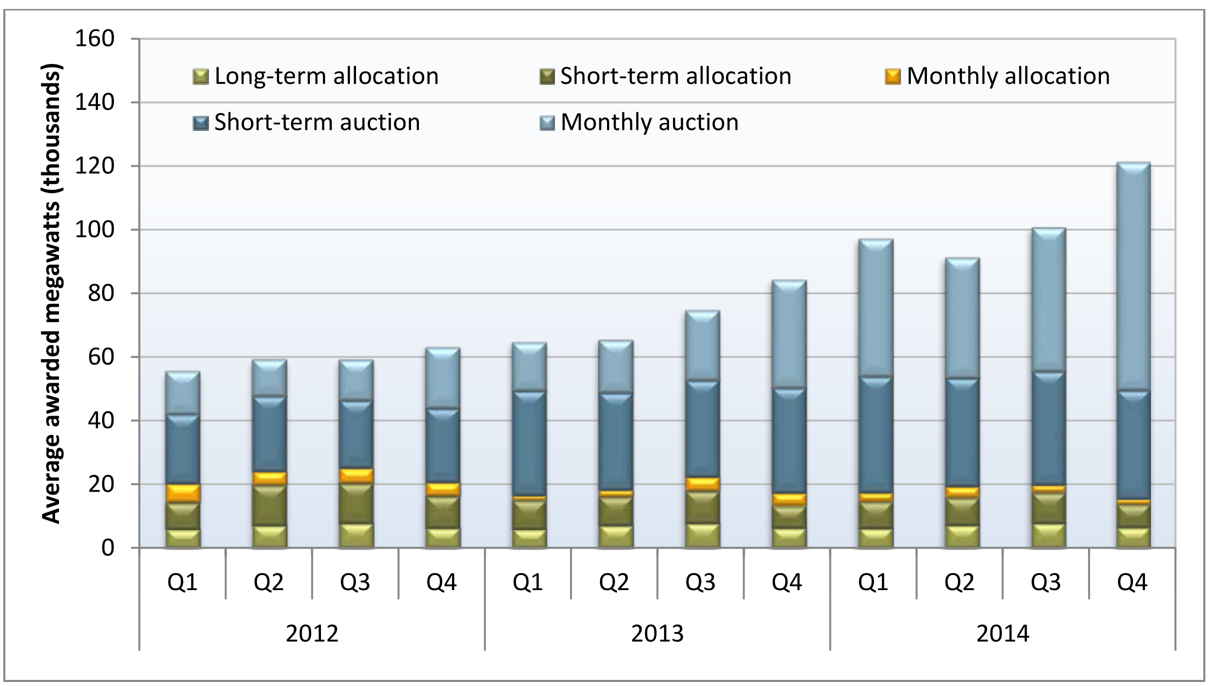


Figure 7.4 Allocated and awarded congestion revenue rights (off-peak hours)



- Rights purchased for 2014 through the monthly auctions increased notably in the second half of the year. All other processes for acquiring congestion revenue rights for 2014 were completed in 2013. Therefore, market participants wanting to increase participation in the congestion revenue rights market for 2014 had to do so through the monthly processes.

- 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.

Figure 7.5 and Figure 7.6 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 over the last three years. 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.[137] This allows the seasonal rights to be grouped and compared with monthly rights.

Different general trends occurred for peak and off-peak hours in 2014. During peak hours, about 33 percent of awarded megawatts had a clearing price above $0.25/MWh, whereas during off-peak hours around 18 percent of 2014 awarded megawatts had a clearing price above $0.25/MWh.

Figure 7.5 and Figure 7.6 show that the average awarded megawatts increased by around 50 percent in 2014 compared to previous years. There were several main reasons for the overall increase in the monthly megawatts awarded:

- An increase in bids submitted for the short-term and particularly the monthly auction processes resulted in more awarded congestion revenue rights, most notably priced above $0/MWh.

- Average monthly megawatts awarded with $0/MWh bids tripled in 2014 compared to 2013. This trend began in 2013 and continued through 2014.

- More congestion revenue rights in the counter-flow direction cleared. This allowed more congestion revenue rights in the positive prevailing direction to also clear.

Although the price of different congestion revenue rights varies widely, about 43 percent of peak rights prices were greater than $0.10/MWh, as shown in Figure 7.5. About 19 percent of peak congestion revenue rights cleared at $0/MWh in 2014. The volume of peak congestion revenue rights clearing at prices greater than $0.25/MWh increased in 2014 but its share in total cleared peak congestion revenue rights decreased to 33 percent compared to 38 percent in 2013.

As shown in Figure 7.6, the amount of congestion revenue rights for off-peak hours has also been growing, driven in large part by an increase in low priced congestion revenue rights. About 15 percent of off-peak rights prices cleared at a price of $0/MWh in 2014.

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137 Auction price is defined as auction cost, divided by the quantity megawatts and number of hours for which that right is valid. The same cost is represented for each awarded megawatt on the same path. For example, assume a monthly auction and a 10 MW monthly on-peak congestion revenue right is cleared with $20/MW price in the auction (total cost is $200=10 MW x $20/MW). If there are 400 peak hours in the month and the congestion revenue right was for 10 MW, the auction cost per megawatt-hour would be $0.05/MWh ($200/400hrs/10MW = $0.05/MWh). This auction cost would be shown with a frequency of 10, representing each awarded megawatt.

Figure 7.5 Auctioned congestion revenue rights by price (peak hours)

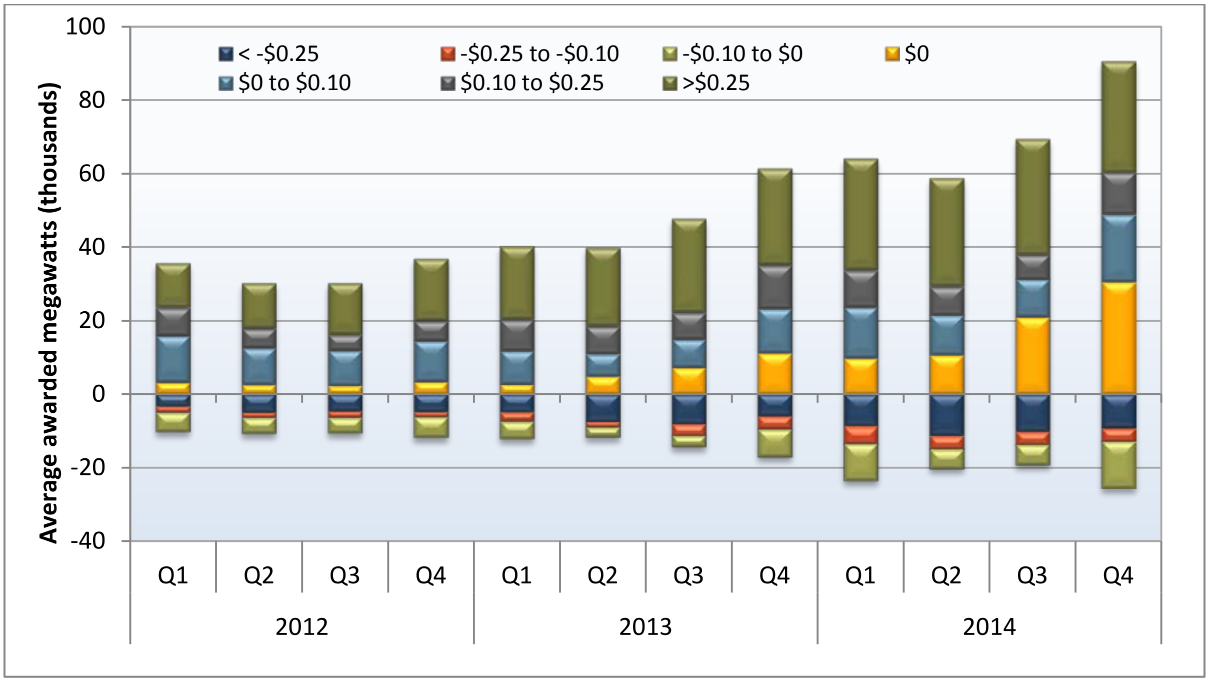
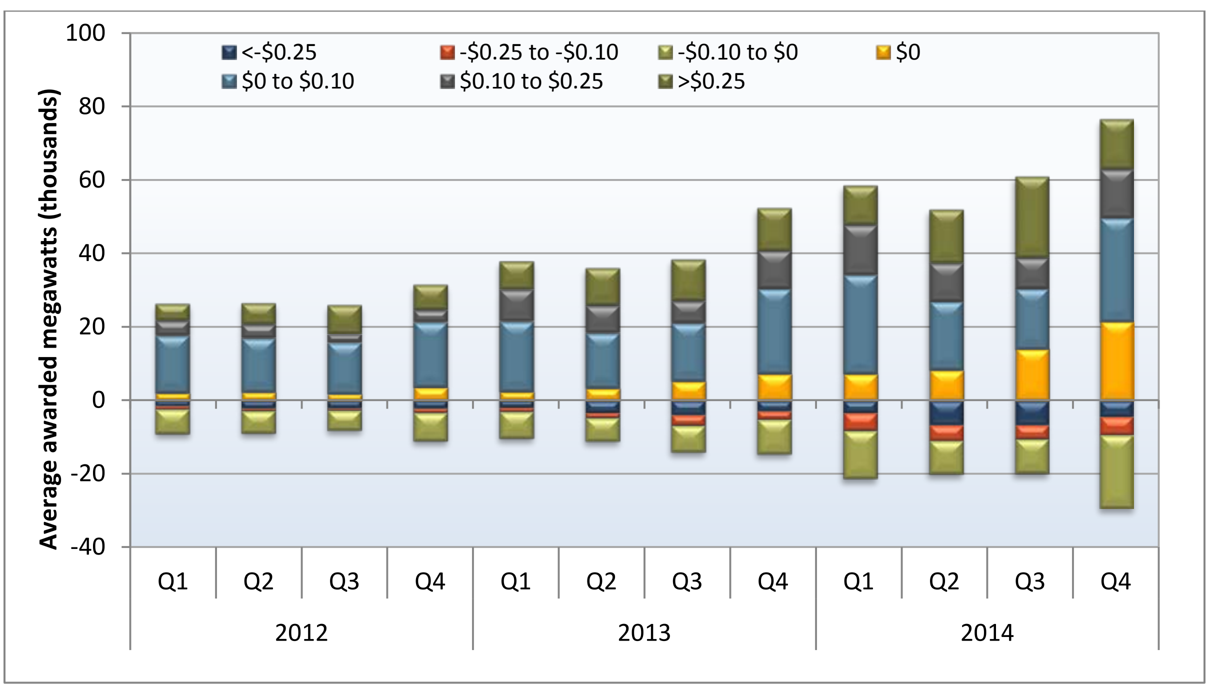


Figure 7.6 Auctioned congestion revenue rights by price (off-peak hours)



Congestion revenue right revenue adequacy

On an annual basis, the congestion revenue rights process generated a $95 million net revenue shortfall in 2014, a substantial reduction from the $23 million and $3 million surpluses in 2012 and 2013. By far the largest revenue inadequacy in the past few years occurred in the third quarter of 2014 when revenue shortfalls before accounting for auction revenues reached $88 million. Auction revenues decreased the shortfall in the balancing account in the third quarter to around $53 million**.** This section analyzes the reasons behind the decline in revenue adequacy in 2014.

Background

The market for congestion revenue rights is designed such that congestion rent collected from the day-ahead energy market is sufficient to cover payments to congestion revenue rights holders. This is referred to as revenue adequacy.[138] The day-ahead congestion rents and congestion revenue right payments are placed in a balancing account. All revenues from the annual and monthly auction processes are added to the balancing account to offset deficits due to revenue inadequacy, if needed. Any shortfall or surplus in the balancing account at the end of each month is allocated to measured demand.

Congestion rents collected in the day-ahead market may not be sufficient to cover payments to congestion revenue rights holders. Revenue inadequacy is generally due to differences between the network transmission model used in the congestion revenue rights process and the final day-ahead market model. In general, the day-ahead model may be more restrictive than the congestion revenue rights model. This is because transmission changes unanticipated at finalization of the congestion revenue rights model are more likely to reduce available transmission capacity than to increase it, as transmission flows are derated to account for unplanned outages and other unanticipated conditions. In addition, new nomograms not in place when the congestion revenue rights full network model is finalized may impose limits on transmission capacity in the day-ahead market. Therefore, the quantity of congestion revenue rights released in the monthly and annual congestion revenue rights processes for a path may be higher than the actual transmission capacity available in the day-ahead market, increasing the potential for revenue inadequacy.

Potential causes of revenue imbalances[139]

- **Unexpected or non-modeled outages:** Any forced outages during the congestion revenue rights settlement month, or outages that become known before the settlement month but after the deadline for inclusion in the congestion revenue rights model, can create negative revenue imbalances. Outages reported after the congestion revenue rights model deadline on transmission lines not controlled by participating transmission owners in the ISO can also affect the available transmission capacity within the ISO.

[138] For a more detailed explanation of congestion revenue rights revenue adequacy and the simultaneous feasibility test, please see the ISO's 2014 reports on congestion revenue rights at: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=6E3E0602-9DF9-4F7F-8557-3D7C99DCCBE8.

[139] These causes are explained in greater detail in DMM's white paper "Allocating CRR Revenue Inadequacy by Constraint to CRR Holders," available at: http://www.caiso.com/Documents/AllocatingCRRRevenueInadequacy-Constraint-CRRHolders_DMMWhitePaper.pdf.

The timing of the congestion revenue rights auction process creates opportunities for entities to target reported outages and modeling discrepancies between the congestion revenue rights network model and the day-ahead market model. Outages reported after a certain deadline cannot be included in the congestion revenue rights model. However, these outages will be included in the day-ahead market model. Therefore, any outages reported during the roughly month-long period after the outage reporting deadline but before the congestion revenue rights auction closes will create modeling discrepancies that can be actively targeted by congestion revenue rights auction participants.

- **Granularity differences:** Congestion revenue rights are issued for monthly (or greater) terms, while the day-ahead market runs daily. Transmission outages may last days or hours. Therefore, constraints can be modeled to precisely reflect the timeframe of outages in the day-ahead market, with different limits during different days and hours. However, constraints must be modeled with one single limit for the entire month (or longer) in the congestion revenue rights model. This difference in modeling granularity can create revenue imbalances. Due to these inherent differences in modeling granularity, revenue adequacy cannot be guaranteed. This is because the surpluses in some days and hours will not necessarily cover the deficits in other days and hours.

- **General modeling discrepancies and errors:** There is always the possibility of discrepancies and errors between the congestion revenue rights and day-ahead models. This creates the possibility that congestion revenue rights awards based on the congestion revenue rights model will create settled flows larger than day-ahead market settled flows.

  Also, modeling errors and discrepancies can create situations where a large or unconstrained quantity of congestion revenue rights can be purchased at or near zero cost. Consider two nodes that are electrically located in the same spot except for one constraint between them. If this constraint is not included in the congestion revenue rights model, congestion revenue rights that source and sink at the two nodes will have no effect on other constraints (as net injections would be zero). Their price in the congestion revenue rights market will be $0/MWh because any binding constraint in the congestion revenue rights market will have the same price impact on both the source and sink. If the two nodes are not the same but very similar, the net flows created by congestion revenue rights at the nodes will be very close to zero, and the effects of binding constraints on congestion revenue rights prices will be small. For example, congestion revenue rights purchased at a price of $0/MWh received about $7.4 million of revenue from the Palo Verde ITC in March 2014.

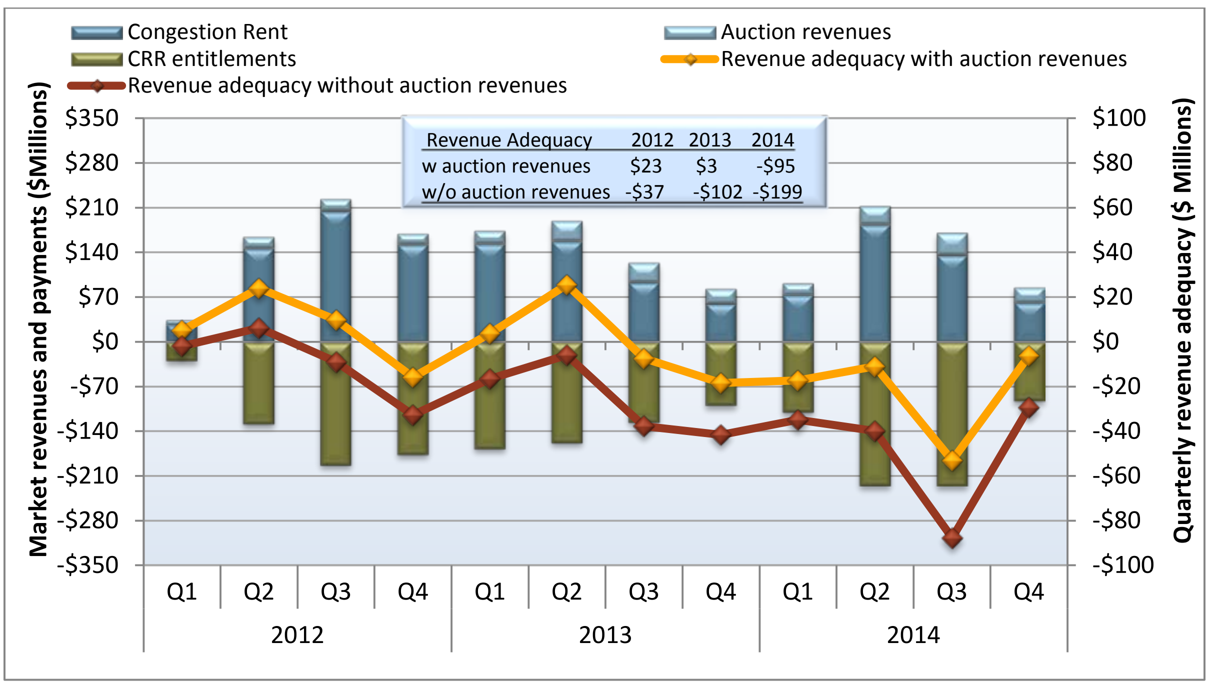
- **Unsettled flows in the day-ahead market:** Ideally all day-ahead market flows over a constraint would settle at the shadow value of the constraint. However, unsettled flows might occupy space on transmission constraints reducing the day-ahead market congestion rent used to pay congestion revenue right holders. Unsettled flows can occur for several reasons, including: differences in actual AC flows and calculated flows from linearized DC shift factors; the use of lossless shift factors; threshold levels on shift factors for inclusion in the day-ahead optimization; and non-settled injections or withdrawals.

Revenue adequacy

Figure 7.7 shows the revenues, payments and overall revenue adequacy of the congestion revenue rights market by quarter for the last three years.

- The dark blue bars represent congestion rent, which accounts 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 when revenues from the auction are included.
- The red line shows total quarterly revenue adequacy when auction revenues are excluded.

Figure 7.7 Quarterly revenue adequacy



As seen in Figure 7.7, congestion revenue rights before accounting for auction revenues had significant levels of revenue shortfall in the first half of 2014. Shortfalls were due, in part, to the following differences between the network transmission model used in the congestion revenue rights process and the day-ahead market model:[140]

[140] The ISO market performance metric catalog for 2014 provides greater detail, see: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=5520CF84-6265-4155-8E03-FD91F3495C08.

- PACI inter-tie constraint;
- Palo Verde inter-tie constraint; and
- Tracy 500 inter-tie constraint.

Congestion revenue rights before auction revenues also had significant levels of revenue shortfall in the second half of 2014. By far the largest revenue inadequacy in the past several quarters occurred in the third quarter of 2014 when revenue shortfalls before accounting for auction revenues reached $88 million. Auction revenues decreased the shortfall in the balancing account in the third quarter to around $53 million.

In contrast to the first half of the year, internal constraints played a major role in revenue shortfalls in the second half. More than half of the revenue shortfall resulted from differences between the network transmission model used in the congestion revenue rights process and the day-ahead market model on the following three constraints:

- Magunden to Vestal nomogram area constraints;
- Helms Pump nomogram constraint; and
- Warnerville to Wilson transmission line.

Revenue inadequacy that occurred on these six constraints was mainly due to unexpected or non-modeled outages and unsettled flows in the day-ahead market. The ISO has taken steps to address the revenue inadequacy by accounting for more constraints in the congestion revenue right model in future auctions. This limits the amount of congestion revenue rights that are auctioned off going forward.

The total cumulative revenue inadequacy of the congestion revenue rights balancing account for 2014 was about $95 million, approximately a $98 million decrease from 2013.

Components of congestion revenue rights balancing account by market participant type

Table 7.6 compares the distribution of individual components of congestion revenue rights balancing account among different groups of congestion revenue rights holders and shows the final balance of revenue adequacy account for each participant type.[141] The columns include the following:

- **Net day-ahead congestion rents:** Represents the net collection of congestion in the day-ahead market from market participants.
- **CRR settlement rule:** Refers to the charges from the congestion revenue rights settlement rule mechanism.[142]
- **CRR auction revenues:** Represents the net revenues from the annual and monthly congestion revenue rights auctions.

[141] ISO's final account balance in the table shows the difference between payments to the ISO and payments by the ISO. A negative balance means that the ISO paid more to the market participants than it received from them.

[142] If a market participant's convergence bidding positions impact the power flow and congestion on a constraint by a certain percentage and increase the value of the congestion revenue rights for the market participant, the ISO adjusts the payment by reducing the value of the congestion revenue rights.

- **CRR entitlements:** Refers to net payments made to holders of congestion revenue rights, which include payments made to holders of rights in the prevailing direction of congestion plus revenues collected from entities purchasing counter-flow congestion revenue rights.
- **Final CRR account balance**: Is the sum of the first three columns, which represent collections made by the ISO, minus CRR entitlements which are paid out by the ISO.

For purposes of this analysis, congestion revenue rights holders are categorized as follows:

- Balancing authority areas outside the ISO system.
- Financial entities that own no physical power in the ISO system and participate in only the convergence bidding and congestion revenue rights markets.
- Marketers that participate by scheduling imports or exports on inter-ties and whose portfolios are not primarily focused on physical or financial participation in the ISO markets.
- Physical generators who primarily participate in the ISO as physical generators.
- Physical load or entities who primarily participate in the ISO as load-serving entities.

As shown in Table 7.6, financial participants received the largest share of net revenues, collecting net revenues of $74 million of the $94 million in net revenues paid out by the ISO in 2014. These financial entities bid heavily in the monthly auctions, speculating on and responding to congestion trends.

Load-serving entities collected net revenues of $34 million in 2014. Most of these revenues resulted from allocations made based on load served and auction revenues from counter-flow positions.[143] Load-serving entities used counter-flow positions to sell allocated rights back to the market in 2014.

Table 7.6 Components of CRR balancing account by market participant type

Trading entities	Payments to the ISO ($ millions)			Payments by the ISO ($ millions)	
	Net day-ahead congestion rents	CRR settlement rule	CRR auction revenues	CRR entitlements	Final CRR account balance
Balancing authority	$7.9			$5.7	$2.2
Financial	$21.4	$0.1	$24.7	$120.3	-$74.0
Marketer	$110.7	$0.1	$89.9	$193.9	$6.9
Physical generation	$83.9	$0.1	$14.2	$93.6	$4.6
Physical load	$233.5	$0.0	-$24.4	$243.7	-$34.5
Total	**$457.5**	**$0.4**	**$104.4**	**$657.3**	**-$95.0**

[143] Negative auction revenues in Table 7.6 represent ISO payments for the cleared counter-flow positions. 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 often 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.

Congestion revenue right settlement rule

The ISO has a settlement rule that limits the opportunity for a participant's congestion revenue rights holdings to be increased by their convergence bidding activity in the day-ahead market. If a market participant's portfolio of convergence bids affects the flows on a congested constraint by more than 10 percent, then an automated procedure incorporated in the ISO settlement system compares the constraint's impact on the value of the market participant's congestion revenue rights.[144] If the impact on the constraint increases the value of the congestion revenue rights for a market participant, the ISO adjusts the payment by reducing the value of the congestion revenue rights. This settlement rule is not applied to convergence bids that affect load aggregation points or trading hubs as the ISO deems the impact of a single market participant on congestion at the load aggregation point or trading hub level to be limited.

In total, the settlement rule rescinded congestion revenue rights payments of only around $300,000 in 2014, compared to $2.9 million in 2013. This decline resulted from several errors in the automated procedure incorporated in the ISO settlement system, which led to underestimation of the congestion revenue right settlement rule amounts. DMM identified several of these issues in 2014 and has been working with the ISO to correct them. The ISO has been working on fixing these issues and has indicated it plans to correct settlement statements retroactively.

[144] For detailed information, see the ISO Tariff section 11.2.4.6 on Adjustment of CRR Revenue.

8 Market adjustments

Given the complexity of market models and systems, all ISOs make some adjustments to the inputs and outputs of their standard market models and processes.[145] Market model inputs – such as transmission limits – may sometimes be modified to account for potential differences between modeled power flows and actual real-time power flows. Load forecasts may be adjusted to account for potential differences in modeled versus actual demand and supply conditions, including uninstructed deviations by generation resources.

In this chapter, DMM reviews the frequency of and reasons for a variety of key market adjustments, including:

- exceptional dispatches;
- modeled load adjustments;
- transmission limit adjustments;
- blocked dispatch instructions;
- aborted and blocked pricing runs in the real-time market; and
- residual unit commitment adjustments.

Over the last few years, the ISO has placed a priority on reducing various market adjustments and continues to work toward reducing market adjustments in 2015.

8.1 Exceptional dispatch

Exceptional dispatches are unit commitments or energy dispatches issued by operators when they determine that the market optimization results may not sufficiently address a particular reliability issue or constraint. This type of dispatch is sometimes referred to as an out-of-market dispatch. While exceptional dispatches are necessary for reliability, they create uplift costs not fully recovered through market prices, can affect market prices, and can create opportunities for the exercise of temporal market power by suppliers.

Exceptional dispatches can be grouped into three distinct categories:

- **Unit commitments** — Exceptional dispatches can be used to instruct a generating unit to start up or continue operating at minimum operating levels. Almost all of these unit commitments are made after the day-ahead market to resolve reliability issues not met by unit commitments resulting from the day-ahead market model optimization.
- **In-sequence real-time energy** — Exceptional dispatches are also issued in the real-time market to ensure that a unit generates above its minimum operating level. This report refers to energy that

[145] At the California ISO, these adjustments are sometimes made manually based entirely on the judgment of operators. Other times these adjustments are made in a more automated manner using special tools developed to aid ISO personnel in determining what adjustments should be made and making these adjustments into the necessary software systems.

would likely have cleared the market without an exceptional dispatch (i.e., that has an energy bid price below the market clearing price) as *in-sequence* real-time energy.

- **Out-of-sequence real-time energy** — Exceptional dispatches may also result in *out-of-sequence* real-time energy. This occurs when exceptional dispatch energy has an energy bid priced above the market clearing price. In cases when the bid price of a unit being exceptionally dispatched is subject to local market power mitigation provisions of the ISO tariff, this energy is considered out-of-sequence if the unit's default energy bid used in mitigation is above the market clearing price.

Decreased total energy from exceptional dispatch

Total energy resulting from all types of exceptional dispatches decreased by approximately 40 percent in 2014 from 2013, as shown in Figure 8.1.[146] The percentage of total exceptional dispatch energy from minimum load energy accounted for about 86 percent of all energy from exceptional dispatches in 2014. About 9 percent of energy from exceptional dispatches in 2014 was from out-of-sequence energy, with the remaining 5 percent from in-sequence energy. These proportions are comparable to the distribution of exceptional dispatch energy in 2013.

Total energy from exceptional dispatches, including minimum load energy from unit commitments, equaled 0.16 percent of system loads in 2014, compared to 0.26 percent in 2013. Thus, total energy from exceptional dispatches continues to account for a relatively low portion of total system loads.

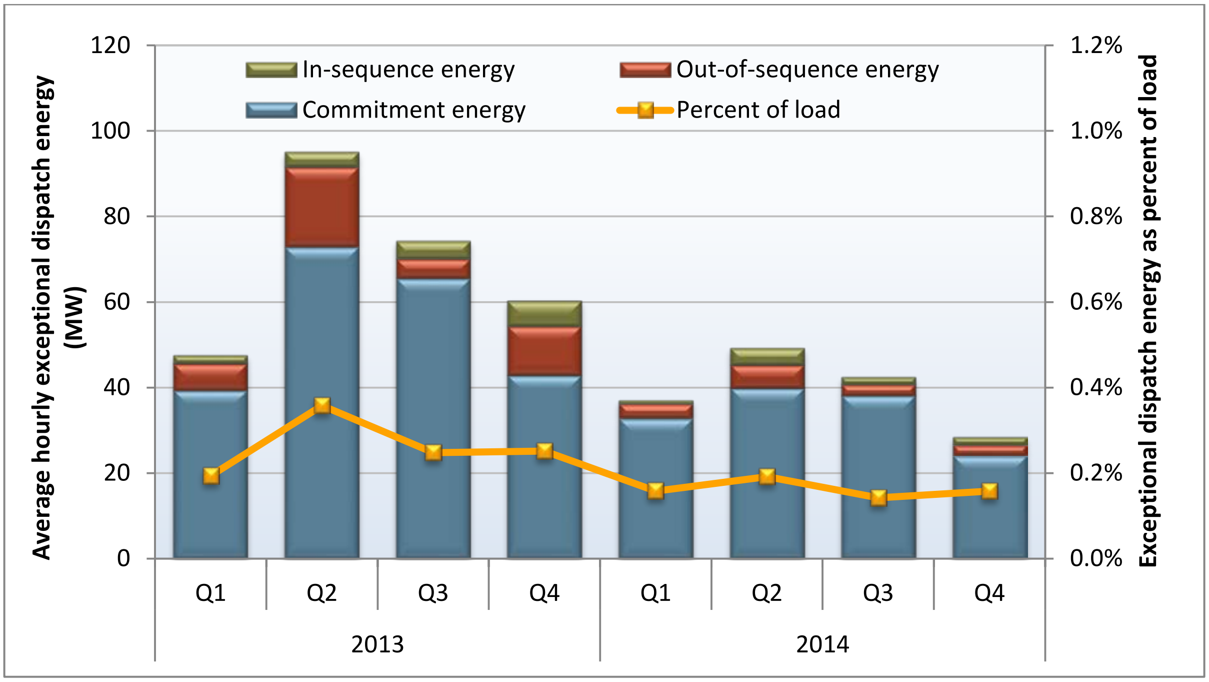
Much of the decrease in total energy from exceptional dispatches was driven by a decrease in minimum load energy, particularly in the second and third quarters of 2014. The second and fourth quarters also saw a decline in out-of-sequence energy above minimum load. The overall decrease in exceptional dispatch energy largely reflects a decrease in minimum load energy from unit testing, as well as an overall decrease in exceptional dispatch energy related to the management of the Southern California import transmission limit (SCIT). Relatively low levels of exceptional dispatch energy continue to reflect the broader effort by the ISO to decrease the frequency and volume of exceptional dispatch through the use of other market tools where possible to address reliability concerns.

Although exceptional dispatches are priced and paid outside of the market, they can have an effect on the market clearing price for energy. Energy resulting from exceptional dispatch effectively reduces the remaining load to be met by the rest of the supply. This can reduce market prices relative to a case where no exceptional dispatch was made. However, most exceptional dispatches appear to be made to resolve specific constraints that would make energy from these exceptional dispatches ineligible to set the market price for energy even if these constraints were incorporated in the market model.

For instance, as discussed later in this section, the bulk of energy from exceptional dispatches is minimum load energy from unit commitments. Energy from this type of exceptional dispatch would not be eligible to set market prices even if incorporated in the market model. In addition, because exceptional dispatches occur after the day-ahead market, energy from these exceptional dispatches primarily affects the real-time market. If energy needed to meet these constraints was included in the day-ahead market, prices in the day-ahead market would be lower.

[146] All exceptional dispatch data are estimates derived from Market Quality System (MQS) data, market prices, dispatch data, bid submissions, and default energy bid data. DMM's methodology for calculating exceptional dispatch energy and costs has been revised and refined since previous reports. Exceptional dispatch data reflected in this report may differ from previous annual and quarterly reports as a result of these enhancements.

Figure 8.1 Average hourly energy from exceptional dispatch



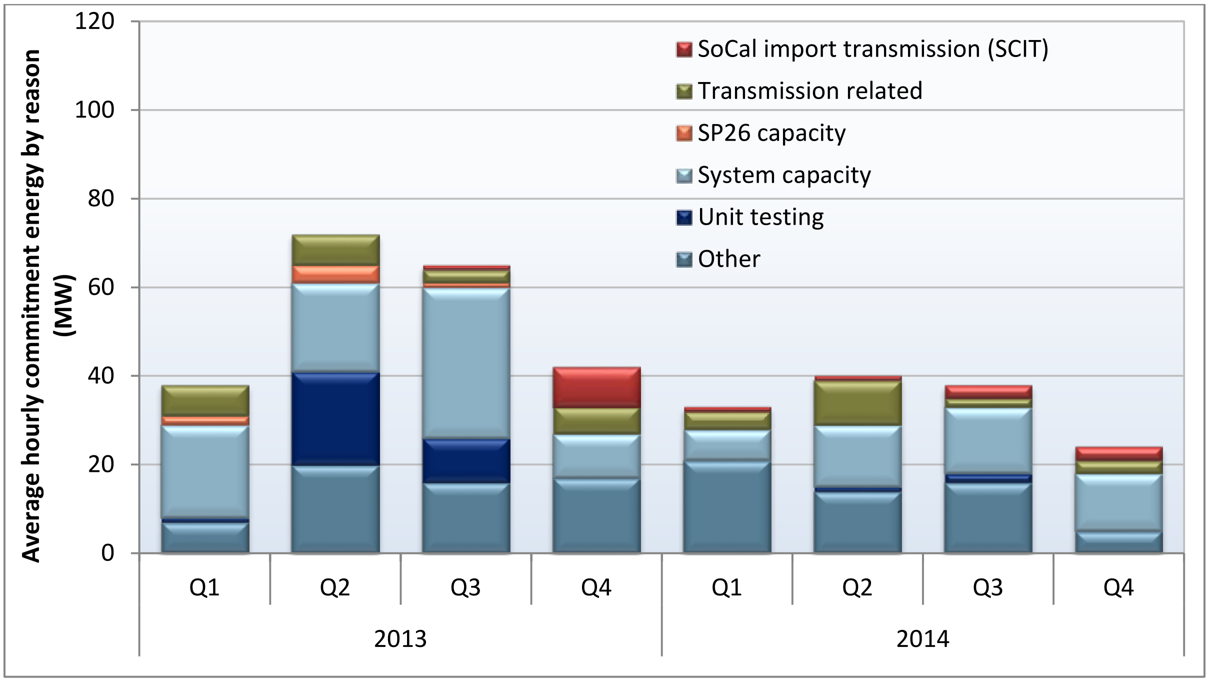
Exceptional dispatches for unit commitment

The ISO sometimes finds instances where the day-ahead market process did not commit sufficient capacity to meet certain reliability requirements not directly incorporated in the day-ahead market model. Alternatively, a scheduling coordinator may wish to operate a resource out-of-market for purposes of unit testing. In these instances, the ISO may commit additional capacity by issuing an exceptional dispatch for resources to come online and operate at minimum load.

Minimum load energy from exceptional dispatch unit commitments fell by over 35 percent in 2014 compared to 2013. As shown in Figure 8.2, reduction in minimum load energy from exceptional dispatch unit commitments occurred throughout the year. Levels fell in the second and third quarters due to reductions in unit testing and a reduced need for extra system capacity. Fourth quarter levels fell from a decreased need to manage potential contingencies associated with the Southern California import transmission limit (SCIT).

As noted above, reductions in minimum load energy related to unit testing contributed significantly to the overall decline in 2014 exceptional dispatch unit commitment. This category of exceptional dispatch minimum load energy was inflated in 2013 by repeated testing of one large unit in the second quarter and testing of several new generation resources throughout the spring and summer. No large resources tested excessively in 2014 and the number of new resources fell. These conditions led to the reduction of related exceptional dispatch in 2014. While overall minimum load energy from exceptional dispatch fell in 2014, a significant amount of remaining minimum load energy continued to result from unit commitments made for more general system contingencies and load uncertainty. Unit commitments related to SCIT accounted for about 13 percent of minimum load energy in the fourth quarter of 2014.

Figure 8.2 Average minimum load energy from exceptional dispatch unit commitments

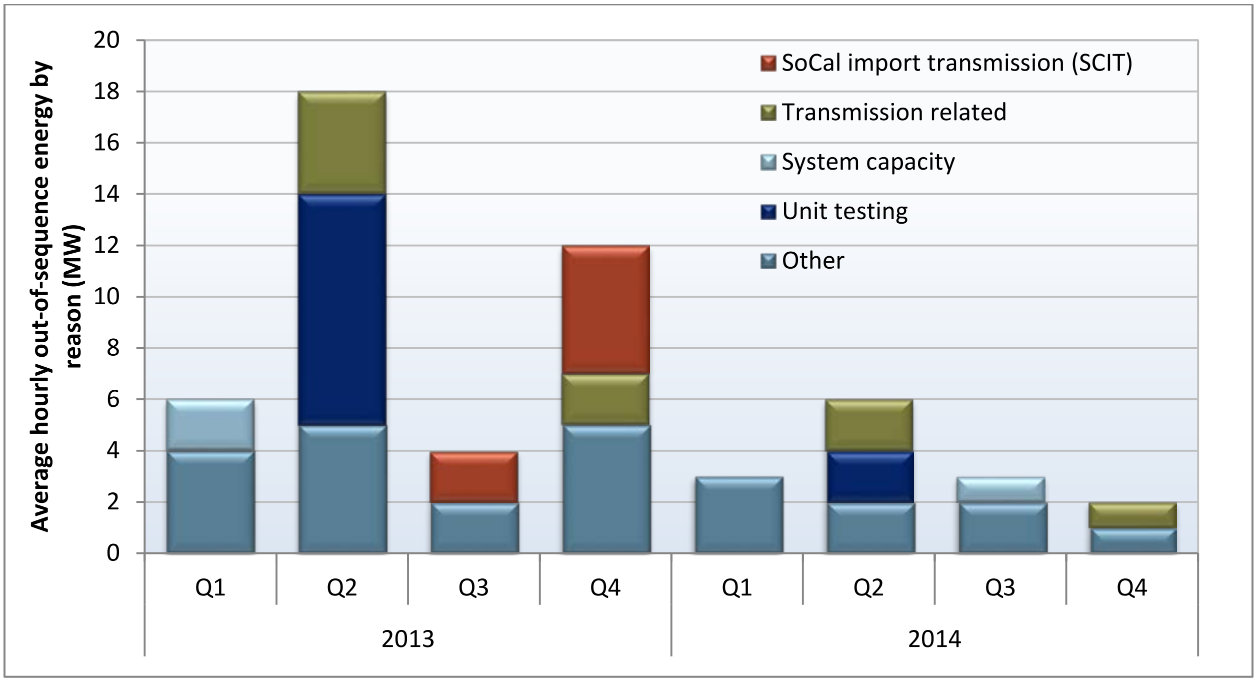


Exceptional dispatches for energy

Energy from real-time exceptional dispatches to ramp units up above minimum load or their regular market dispatch level decreased by about 65 percent in 2014. As previously illustrated in Figure 8.1, much of this exceptional dispatch energy (about 60 percent) was out-of-sequence, meaning the bid price was greater than the locational market clearing price. This represents a 10 percent decline from 2013.

Figure 8.3 shows the decrease in out-of-sequence exceptional dispatch energy over the year in 2014. The decrease in out-of-sequence energy, as compared to 2013, was driven primarily by a reduction in exceptional dispatches for unit testing and exceptional dispatches to protect against contingencies related to the Southern California import transmission limit. Levels of out-of-sequence energy from unit testing in 2013 reflect repeated testing of one unit and testing of several new generation resources. No large resources tested excessively in 2014 and the number of new resources fell. This led to an overall reduction in exceptional dispatch for unit testing, as well as a reduction in out-of-sequence energy for unit testing. The volume of out-of-sequence exceptional dispatch energy related to SCIT fell from an average hourly level of 2 MW in 2013 to a negligible level in 2014.

Figure 8.3 Out-of-sequence exceptional dispatch energy by reason



Exceptional dispatch costs

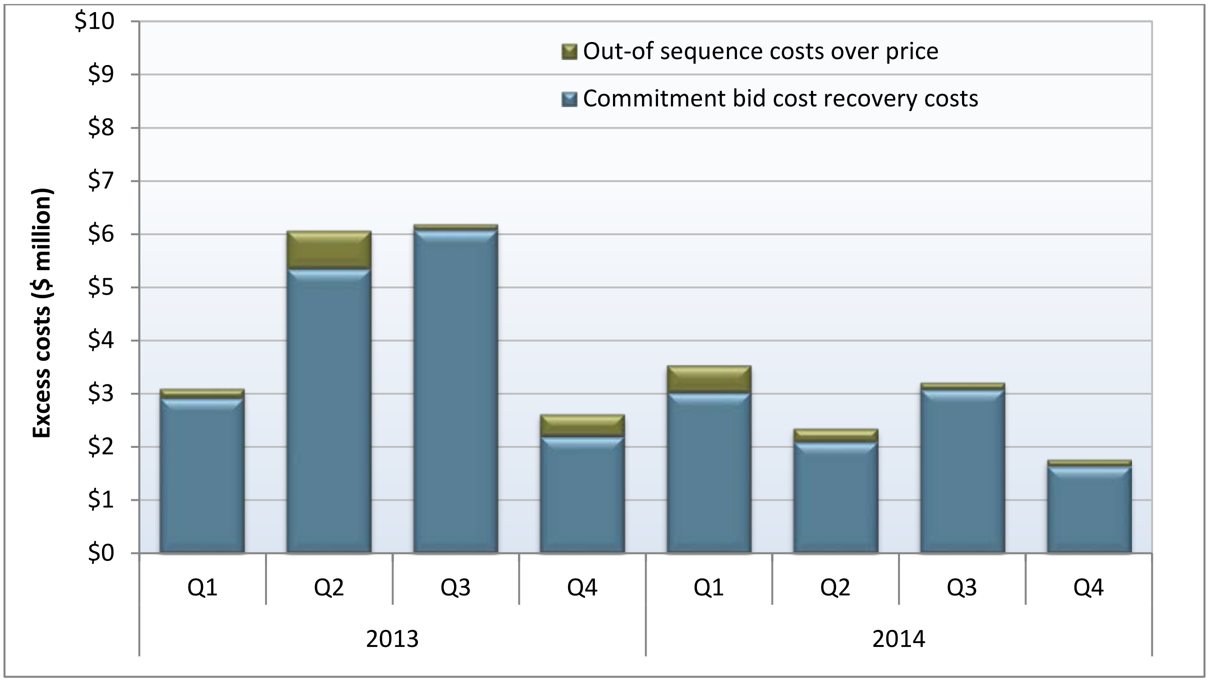
Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy.

- Units committed through exceptional dispatch that do not recover their start-up and minimum load bid costs through market sales can receive bid cost recovery for any start-up and minimum load bid costs.
- Units being exceptionally dispatched for real-time energy out-of-sequence may be eligible to receive an additional payment to cover the difference in their market bid price and their locational marginal energy price.

Figure 8.4 shows the estimated costs for unit commitment and additional energy resulting from exceptional dispatches in excess of the market price for this energy. Commitment costs for exceptional dispatch paid through bid cost recovery decreased from $17 million to $10 million, while out-of-sequence energy costs decreased from $1.4 million to $1 million.[147] Overall, these above-market costs decreased 40 percent from $18 million in 2013 to $11 million in 2014.

[147] The out-of-sequence costs are estimated by multiplying the out-of-sequence energy by the bid price (or the default energy bid if the exceptional dispatch was mitigated) minus the locational price for each relevant bid segment. Commitment costs are estimated from the real-time bid cost recovery associated with exceptional dispatch unit commitments.

Figure 8.4 Excess exceptional dispatch cost by type



Lower above-market costs from exceptional dispatch in 2014 generally reflect the overall decrease in volume of exceptional dispatches. Local market power mitigation for exceptional dispatches also played a role in limiting above-market costs, although this role was smaller than in prior years. Additional discussion of local market power mitigation for exceptional dispatch is included in Section 6.4.2.

8.2 Load adjustments

The ISO frequently adjusts real-time loads in the hour-ahead and real-time markets to account for potential modeling inconsistencies or inaccuracies. Some of these inconsistencies are due to changing system and market conditions, such as changes in load and supply, between the execution of the hour-ahead market and the real-time market.

Operators can manually adjust load forecasts used in the software through a *load adjustment*. These adjustments are sometimes made manually based entirely on the judgment of the operator informed by actual operating conditions. Other times, these adjustments are made in a more automated manner using special tools developed to aid ISO operators in determining what adjustments should be made and making these adjustments into the necessary software systems.

In December 2012, the ISO enhanced the real-time market software to limit load forecast adjustments made by operators to only the available amount of system ramp. Beyond this level of load adjustment, a shortage of ramping energy occurs that triggers a penalty price through the relaxation of the power balance constraint without achieving any increase in actual system energy. With this software enhancement, known as the *load bias limiter* (see Section 3.2.1 for further detail), load adjustments made by operators are less likely to have an extreme effect on market prices.

Figure 8.5 shows the average hourly load adjustment profile for the hour-ahead, 15-minute and 5-minute real-time markets during the first four months of 2014 (January through April). Figure 8.6 shows the average load adjustments for each operating hour in these markets during the last eight months of the year (May through December). The following is shown in these figures:

- During the first four months of the year, hour-ahead market adjustments exceeded the 15-minute market adjustments for most hours of the day, especially by more than 100 MW during the morning and evening ramping periods. The 5-minute adjustments also exceeded the 15-minute adjustments during most hours. The 5-minute adjustments were higher than both hour-ahead and 15-minute adjustments between hours ending 12 and 18.
- During the last eight months of the year, load adjustments decreased in all three markets. The load adjustment amounts were close among all three markets during most hours of the day. The largest deviation was observed between hours ending 19 and 24, when both the hour-ahead and 15-minute adjustments exceeded the 5-minute adjustments by about 100 MW or more.
- A potential reason for the change in load adjustment patterns was because of the implementation of FERC Order No. 764. This order allowed for changes in energy and inter-tie schedules in the 15-minute market in addition to changes in hourly schedules on inter-ties. As a result, there was increased flexibility to deal with real time variations in generation and supply.

Figure 8.7 highlights how load adjustments changed during peak hour ending 18 from month-to-month over the course of 2014.

- The use of load adjustments in all markets decreased in March and April, but increased gradually since May with the exception of load adjustments in the 5-minute real-time dispatch, which decreased by more than 200 MW in November.
- The load adjustments were highest in February for hour-ahead and 5-minute real-time markets, while the 15-minute adjustment peaked in December. The load adjustments in February were related to the extreme weather outside of California which led to a higher gas price and volatility in California.
- On average, no month in 2014 had negative load adjustments in any of the three markets.

Figure 8.5 Average hourly load adjustments (January through April)

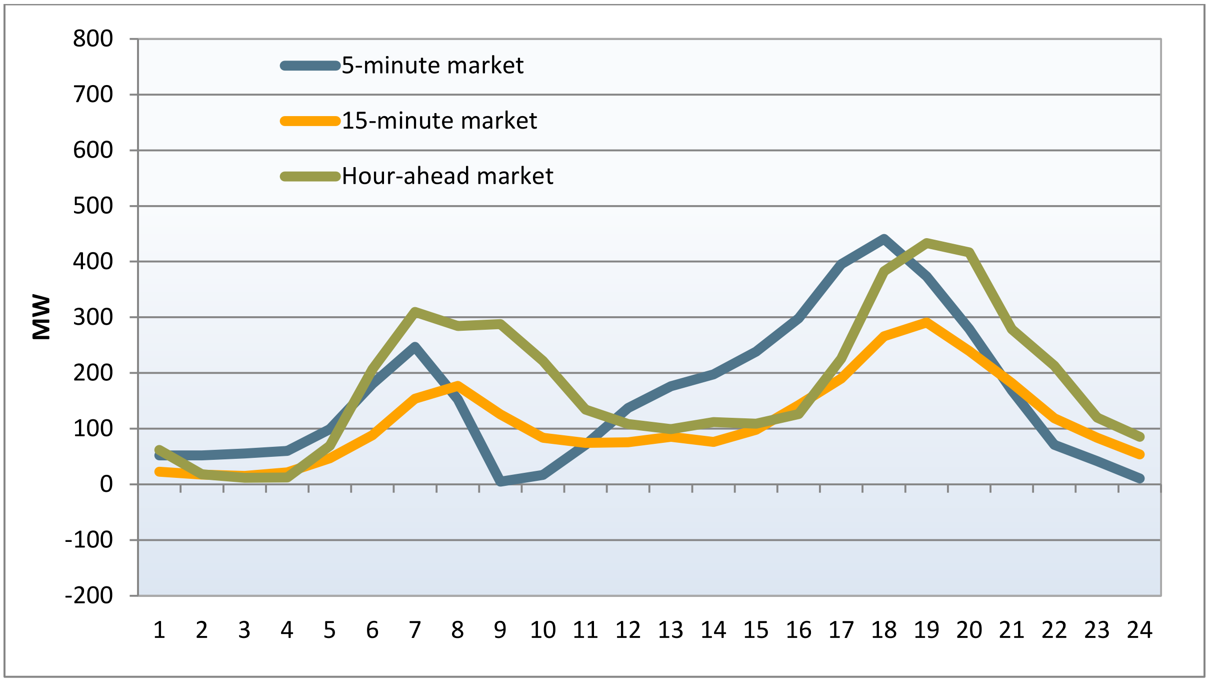


Figure 8.6 Average hourly load adjustments (May through December)

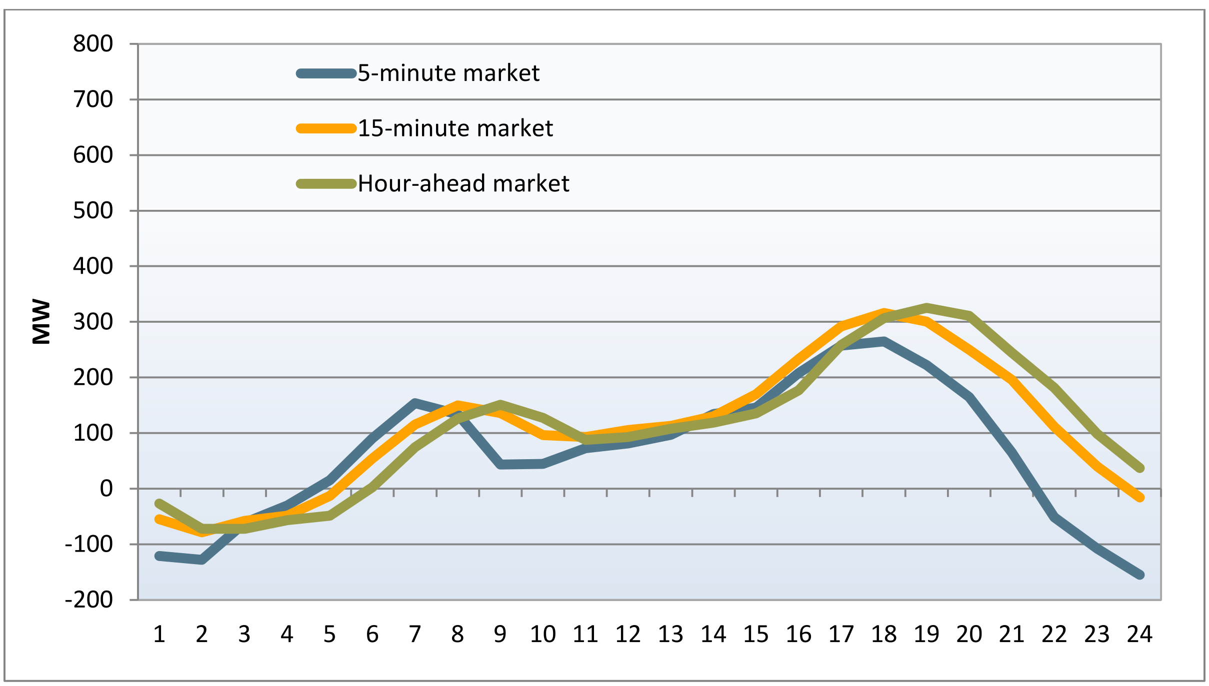
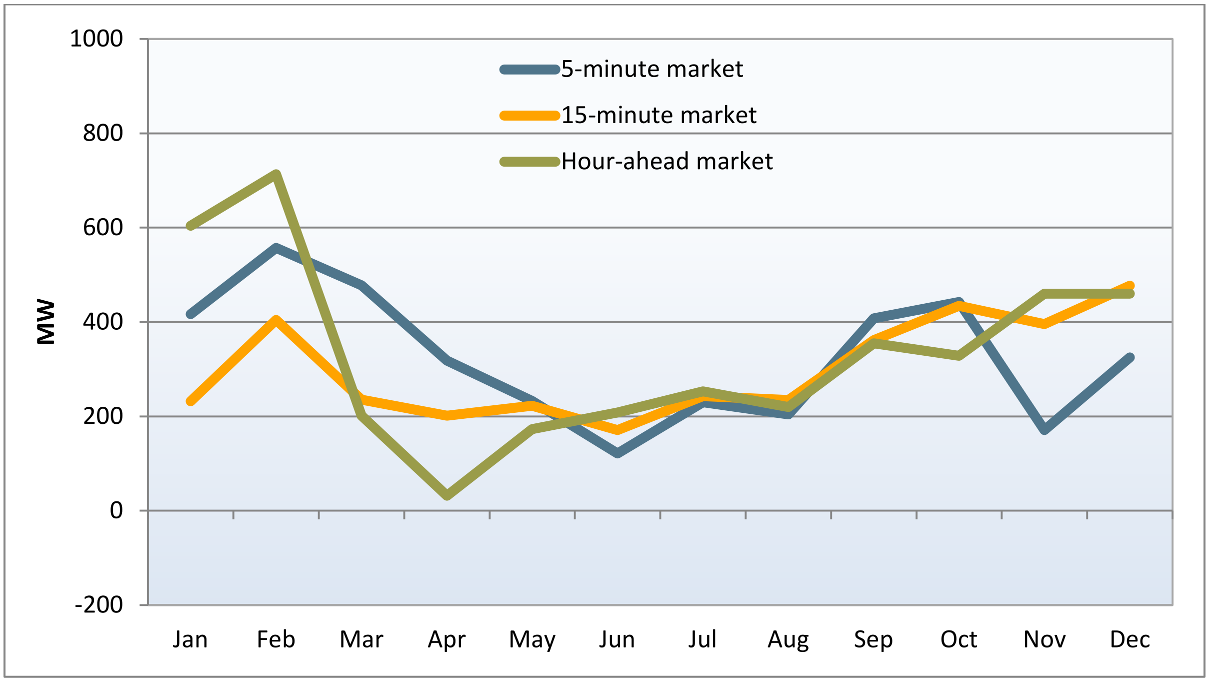


Figure 8.7 Average monthly load adjustments (hour ending 18)



8.3 Transmission limit adjustments

Actual flows on transmission lines can sometimes vary significantly from flows predicted by the network model. In the real-time market, operators track actual transmission line flows and may determine that the market model is not accurately reflecting the actual system flows. There are a variety of causes for these modeling inaccuracies. Unscheduled flows on major transmission paths – also known as *loop flows* – can originate due to differences in scheduled and actual power flows outside the ISO system.[148] Within the ISO system, differences in line flows can result from demand forecast errors and generating units deviating from their schedules, known as uninstructed deviations.[149]

In the real-time market, operators track actual transmission line flows and may determine that the market model is not accurately reflecting the actual flows. The ISO model may overestimate or underestimate transmission line flows. The operators will adjust the transmission limit incorporated in the market model depending on the nature of the inconsistency.

- There are times when the estimated power flow on a transmission line reaches the constraint limit incorporated in the market model. As a result, price congestion occurs on the line. After reviewing actual metered line flows, the operators may determine that the price congestion is not reflective of actual system conditions, and will therefore increase the line limit incorporated in the market model upwards to eliminate the inaccurate market congestion.

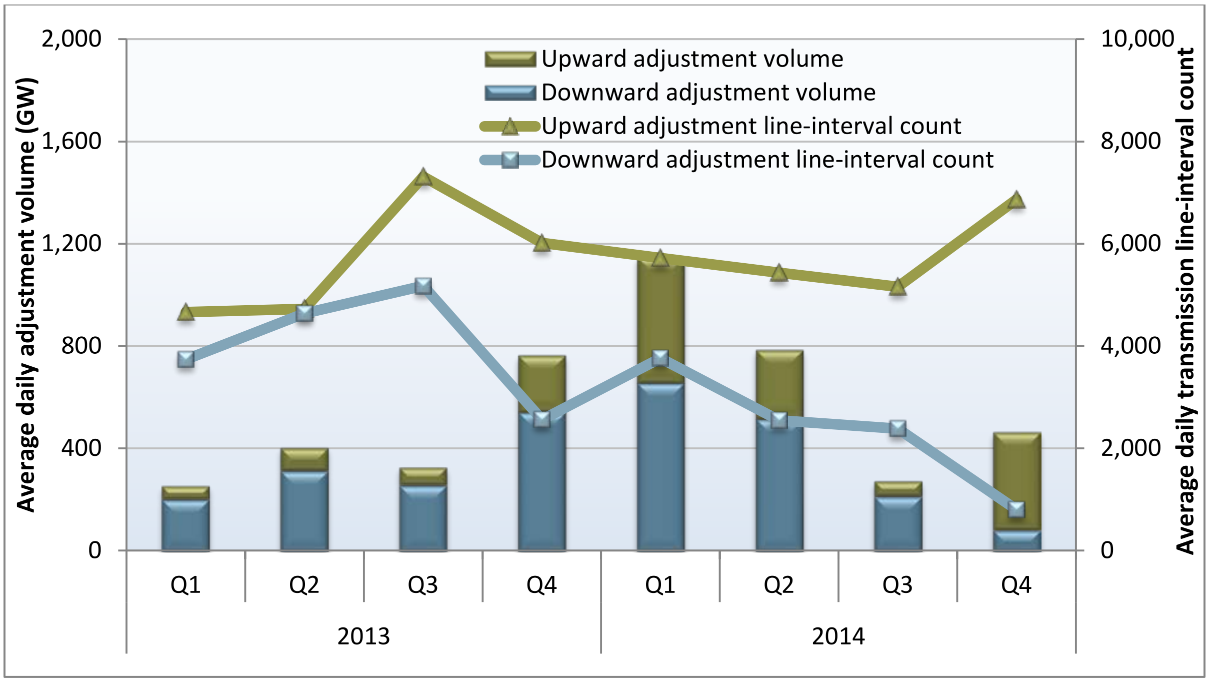
[148] The ISO attempts to model these flows at the inter-ties through the expansion of the full network model (see Section 2.7).

[149] Differences also occur as a result of units generating below their minimum operating level due to start-up or shut-down profiles being left out of the market optimization.

- Alternatively, there are times when the estimated flow on a transmission line is below the constraint limit, but the operators may determine that the actual metered loads are indeed approaching or at the transmission limit. In this situation, operators will decrease the line limit in the market model downwards to force the model to account for the actual congestion. This triggers price congestion and causes the market model to manage the congestion by re-dispatching resources based on their bid prices and effectiveness at reducing congestion.

The ISO refers to such adjustments as *conforming* of transmission limits since the goal is to conform the limits in the market model to the actual level of flow being observed. Figure 8.8 shows the frequency operators have conformed transmission in either an upward[150] or downward direction, along with the average volume of these transmission adjustments.[151]

Figure 8.8 Average daily frequency and volume of internal transmission adjustments by quarter



The frequency of transmission adjustments decreased by around 16 percent in 2014 compared to 2013. The volume of transmission adjustments increased in the upward direction and decreased in the

150 Upward adjustments of 200 percent are excluded from these calculations. These adjustments were implemented as a business practice to un-enforce the nomograms in the market model beginning in the fourth quarter of 2012.

151 The frequency of transmission adjustments is measured by counting the number of intervals that each different line is adjusted. The ISO reports on transmission conforming in its monthly performance metric catalogue. Monthly transmission conforming information in 2014 can be found in the later sections of the monthly performance metric catalogue reports: http://www.caiso.com/Documents/Market%20performance%20metric%20catalog%202014.

downward direction in 2014 compared to 2013.[152] This increase in the upper direction was primarily driven by the increase in the number of transmission constraints modeled in the ISO markets. As part of the ISO's efforts to reduce exceptional dispatches, the ISO has increased the number of constraints in the network model. When a transmission constraint is loaded at a point that is increasingly closer to its system operating limit, the ISO operators can conform the transmission constraint down to prevent the line from exceeding that limit.

8.4 Blocked instructions

The ISO's real-time market functions using a series of processes. During each of these processes, the market model occasionally issues commitment or dispatch instructions that are inconsistent with actual system or market conditions. In such cases, operators may cancel or *block* commitment or dispatch instructions generated by the market software.[153] This can occur for a variety of reasons, including the following:

- **Data inaccuracies.** Results of the market model may be inconsistent with actual system or market conditions as a result of a data systems problem. For example, the ISO takes telemetry data and feeds the telemetry into the real-time system. If the telemetry is incorrect, the market model may try to commit or de-commit units based on the bad telemetry data. The operators may act accordingly to stop the instruction from being incorrectly sent to market participants.
- **Software limitations of unit operating characteristics.** Software limitations can also cause inappropriate commitment or dispatch decisions. For example, some unit operating characteristics of certain units are also not completely incorporated in the real-time market models. For instance, the ISO software has problems with dispatching pumped storage units as the model does not reflect all of its operational characteristics.
- **Information systems and processes.** In some cases, problems occur in the complex combination of information systems and processes needed to operate the real-time market on a timely and accurate basis. In such cases, operators may need to block commitment or dispatch instructions generated by the real-time market model.

While the overall number of blocked instructions increased in 2014 compared to 2013, blocked instructions increased on the inter-ties and decreased slightly for internal units. The volume of blocked instructions was down in 2014 compared to 2013 on inter-ties, but up for internal units, which was driven by a big increase in the fourth quarter. Figure 8.9 shows the frequency and volume of blocked dispatches on inter-ties. Figure 8.10 shows the frequency of blocked real-time commitment start-up and shut-down and multi-stage generator transition instructions for internal generators.

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[152] When adjusting transmission constraints in the upward direction, the goal is to alleviate false binding of a constraint. When adjusting transmission constraints in the downward direction the goal is to true up market flows to the actual flows in real-time. The magnitude of the transmission adjustment is an indication of the modeling error between the market flows and the actual system flows.

[153] The ISO reports on blocked instructions in its monthly performance metric catalogue. Blocked instruction information can be found in the later sections of the monthly performance metric catalogue report: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=5520CF84-6265-4155-8E03-FD91F3495C08.

Figure 8.9 Frequency and volume of blocked real-time inter-tie instructions

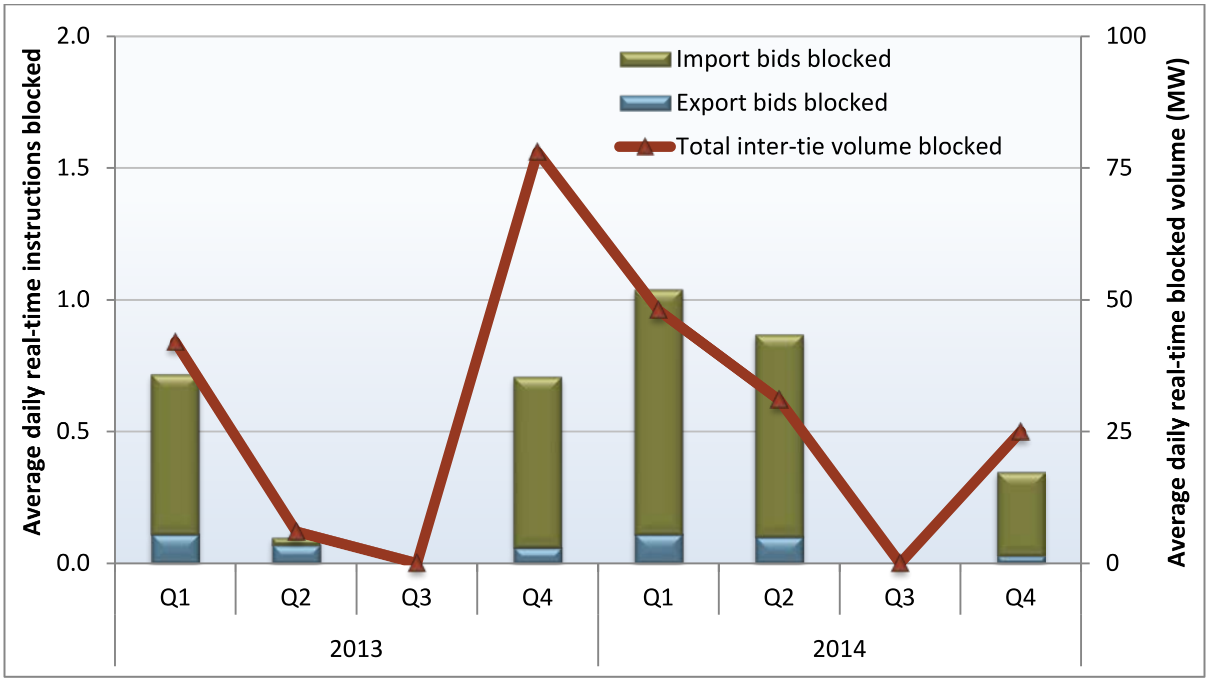
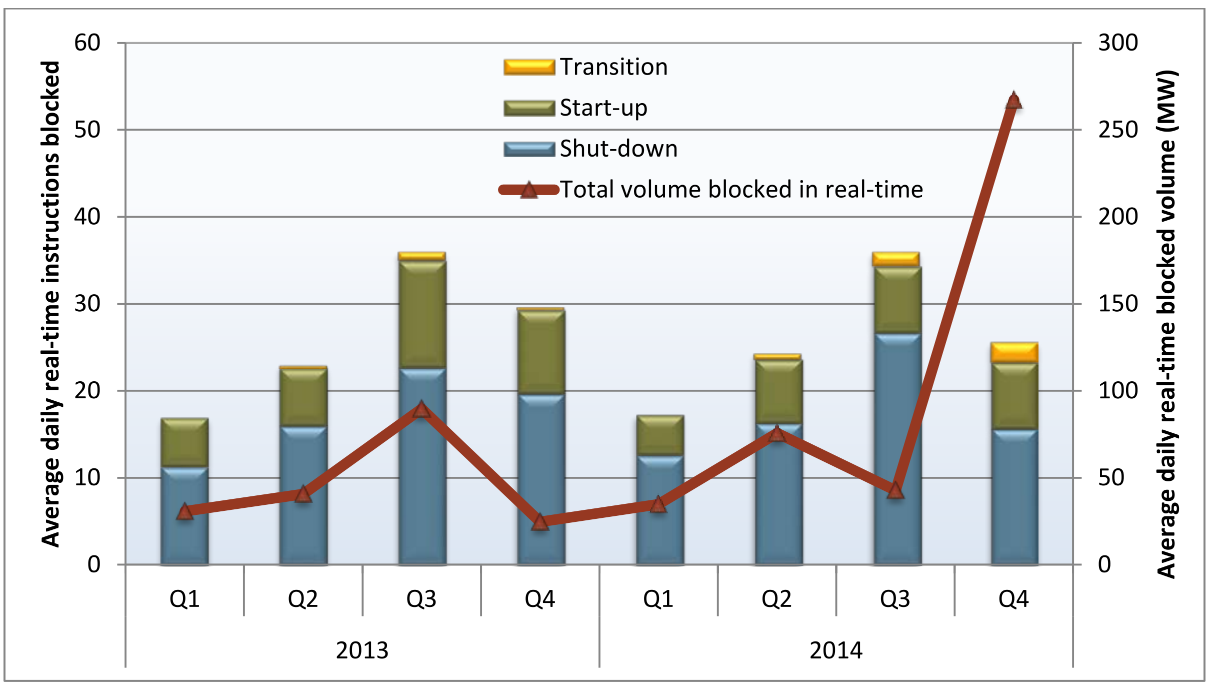


Figure 8.10 Frequency and volume of blocked real-time internal instructions



The average number of daily blocked inter-tie instructions in 2014 increased by about 50 percent compared to 2013. Blocked instructions for internal resources only decreased slightly in 2014 compared to 2013. Moreover, blocked shut-down instructions were the most common reason for blocked instructions at about 69 percent in 2014. Blocked start-up instructions accounted for about 26 percent of blocked instructions within the ISO in 2014, while blocked transition instructions to multi-stage generating units accounted for only 5 percent for the same period.

Increases in transmission adjustments primarily resulted in an increase in blocked instructions for internal resources in 2014. This occurred because transmission adjustments sometimes caused the market software to dispatch additional units not needed to address actual system conditions. In these cases, the ISO operators blocked the start-up of these units that are not needed. In many cases following blocked start-ups, ISO operators subsequently conformed the transmission limit on the constraint that caused the inappropriate start-up. In addition, the ISO software continued to have problems with dispatching pumped storage units as the model does not reflect all of its operational characteristics.

The ISO has been working on measures to decrease the need for blocked instructions. The ISO operating engineers enhanced the granularity of existing nomograms in 2013. This enhancement included breaking down the nomograms into separate contingencies to better address certain planned outages. This change allowed ISO operators to better adjust transmission limits more accurately in accordance with current system conditions. This is intended to result in fewer exceptional dispatches and fewer blocked dispatches in real time.

8.5 Blocked dispatches

Operators review dispatches issued in the real-time market before these dispatch and price signals are sent to the market. If the operators determine that the 5-minute dispatch results are inappropriate, they are able to block the entire real-time dispatch instructions and prices from reaching the market.

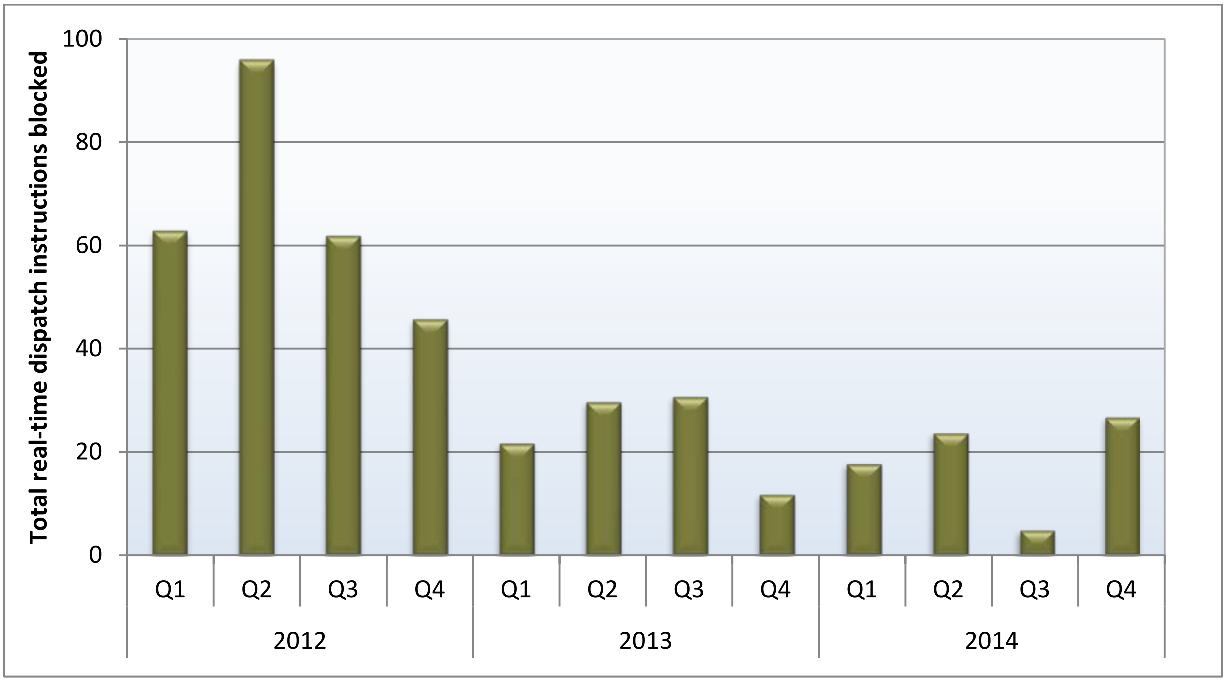
The ISO began blocking dispatches in 2011 as both market participants and ISO staff were concerned that inappropriate price signals were being sent to the market even when they were known to be problematic. These inappropriate dispatches would often cause participants to act inappropriately when considering actual and not modeled system conditions. Quite frequently, many of the blocked intervals eliminated the need for a subsequent price correction.

Operators can choose to block the entire market results to stop dispatches and prices resulting from a variety of factors including incorrect telemetry, inter-tie scheduling information or load forecasting data. Furthermore, the market software is also capable of automatically blocking the solution when the market results exceed threshold values.[154]

Figure 8.11 shows the frequency that operators blocked price results in the real-time dispatch from 2012 through 2014. The total number of blocked intervals in 2014 dropped by about 22 percent from 2013 levels. This change is driven by the decrease in blocked dispatches triggered by ISO operators due to improved market software functionality.

[154] For example, if the load were to drop by 50 percent in one interval, the software can automatically block the results.

Figure 8.11 Frequency of blocked real-time dispatch intervals



8.6 Residual unit commitment adjustments

As noted in Section 2.4, the purpose of the residual unit commitment market is to ensure that there is sufficient capacity online or reserved to meet actual 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 forecast load. ISO operators are able to increase the amount of residual unit commitment requirements for reliability purposes, a practice which became fairly common in 2013. Use of this procedure declined substantially by the end of 2013 and continued to decline through 2014.

As illustrated in Figure 8.12, residual unit commitment procurement appears to be driven in large part by the need to replace cleared net virtual supply bids, which can offset physical supply in the integrated forward market. On average, cleared virtual supply (green bar) was more prevalent in 2014 than in 2013 (see Chapter 4 for further detail).

The ISO introduced an automatic adjustment to residual unit commitment schedules to account for differences between the day-ahead schedules of participating intermittent resource program (PIRP) resources and the forecast output of these renewable resources.[155] This adjustment, called the eligible intermittent resource adjustment, went into effect in February 2014 and is represented by the yellow bar in Figure 8.12. In the future, this adjustment may be expanded to include adjustments for forecasts

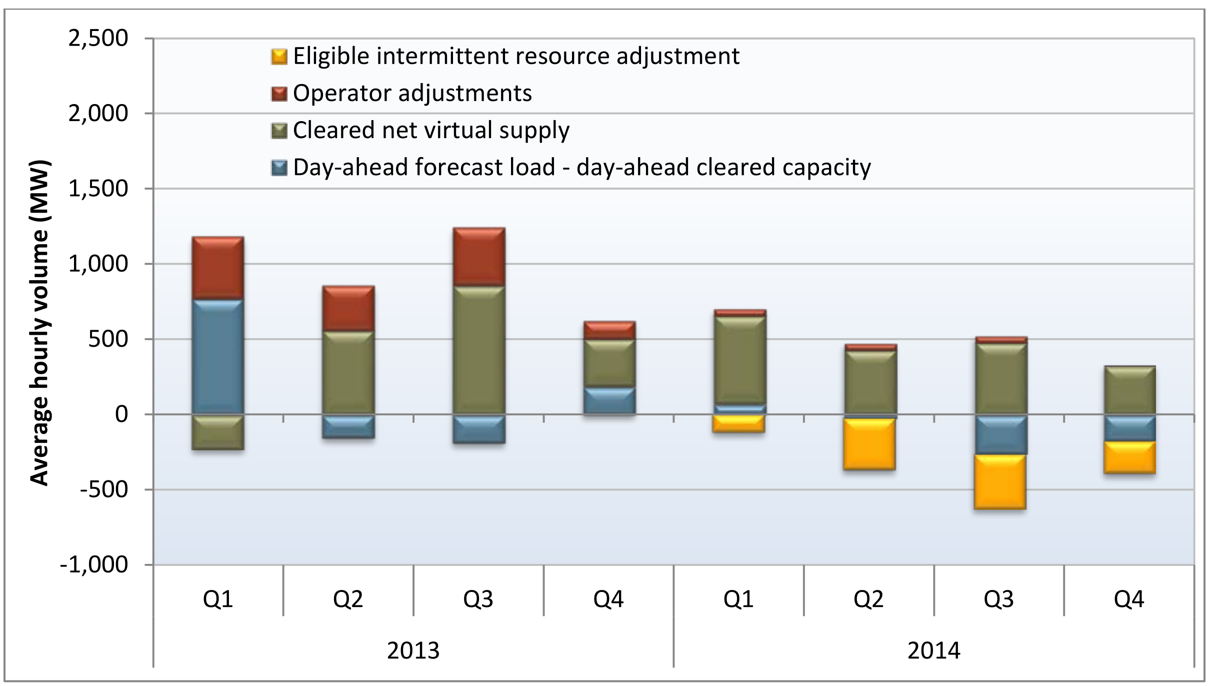
[155] Specifically, the adjustment is only made for PIRP resources that have positive schedules in the day-ahead market. PIRP resources that are not scheduled in the day-ahead market are not adjusted at this time.

of participating intermittent resource program renewables without day-ahead schedules. DMM supports this change.

The day-ahead forecasted load versus cleared day-ahead capacity (blue bar) represents the difference in cleared supply (both physical and virtual) compared to the ISO's load forecast.[156] On average, this factor increased residual unit commitment in the first quarter, but was not a significant factor in any month except for February. This effect was significantly smaller in the first quarter of 2014 than in the first quarter of 2013. Operator adjustments to the residual unit commitment process (red bar) played a minimal role in the residual unit commitment procurement in 2014 compared to previous periods, averaging less than 40 MW per hour.

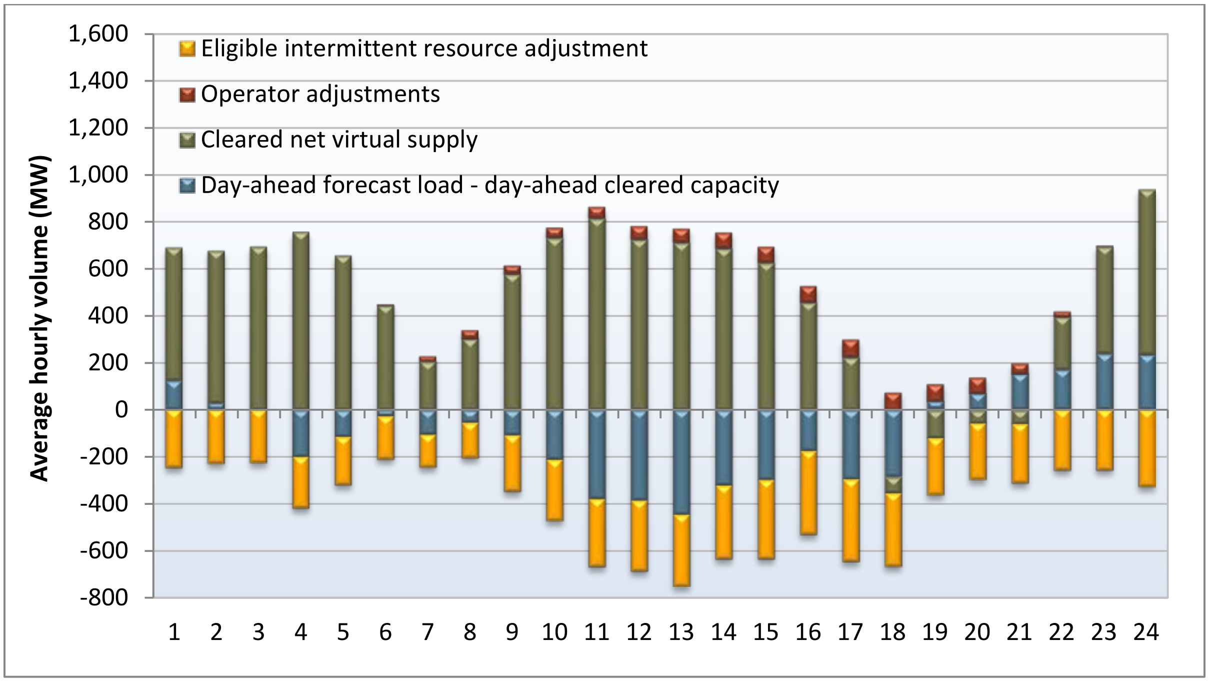
Figure 8.13 illustrates the average hourly determinants of residual unit commitment procurement. Operator adjustments were concentrated in the peak load hours of the day, peaking in hours ending 15 to 21. While adjustments were low in the off-peak hours, net virtual supply was a major driver of residual unit commitment procurement in these periods. Load differences were most pronounced in the evening hours. Intermittent resource adjustments were greatest in hours ending 12 to 18 and hour ending 24.

Figure 8.12 Determinants of residual unit commitment procurement



[156] Due to the loss of source data, DMM estimated the values reported in the blue bar by subtracting price sensitive load including losses from the sum of forecast load, day-ahead exports and pumped storage load.

Figure 8.13 Average hourly determinants of residual unit commitment procurement (2014)



9 Resource adequacy

California's wholesale market relies heavily on a long-term procurement planning process and resource adequacy program adopted by the CPUC to provide sufficient capacity to ensure reliability. The resource adequacy program includes ISO tariff requirements that work in conjunction with regulatory requirements and processes adopted by the CPUC and other local regulatory authorities.

This chapter analyzes the short-term effectiveness of the resource adequacy program in terms of the availability of resource adequacy capacity in the ISO market in 2014. This analysis focuses on the availability of these resources during the 210 hours with the highest system loads to provide an indication of how well program requirements are meeting actual peak loads. This includes all hours in 2014 with peak load over 38,629 MW. Key findings of this analysis include the following:

- During the 210 hours with the highest loads, about 95 percent of resource adequacy capacity was available to the day-ahead energy market and the residual unit commitment process. This is about equal to the target level of availability incorporated in the resource adequacy program design and a slight improvement to the 94 percent availability in 2013.

- Capacity made available under the resource adequacy program in 2014 was mostly sufficient to meet system-wide and local area reliability requirements. However, due to the outage and retirement of the two SONGS units, the ISO continued to rely on reliability must-run contracts with synchronous condensers at Huntington Beach units 3 and 4 to improve local reliability.

With the active support of the ISO, the CPUC has adopted requirements for California's investor-owned utilities to procure flexible capacity in order to help meet the system net load changes. This represents a wider focus of the resource adequacy program from simply meeting peak system and local capacity needs to also include flexible capacity needs during ramping periods when renewable generation drops off.

To complement these new CPUC requirements, the ISO continues to develop protocols for determining requirements for flexible capacity, counting flexible resource adequacy showings, determining must-offer requirements, and curing any shortfalls through backstop procurement. Specifically, the ISO has completed, in part or in full, stakeholder processes on the following initiatives:

- **Flexible resource adequacy.** This initiative was conditionally approved by FERC in 2014 and recognizes the important contributions made by other resource characteristics that contribute to the flexible response needed to integrate large quantities of renewable generation. This program also includes a specific must-offer obligation for flexible capacity that further differentiates it from generic resource adequacy capacity.

- **Reliability services initiative.** This initiative streamlines resource adequacy rules for replacement and substitute capacity should a resource adequacy unit become unavailable, clarifies definitions and qualifying criteria for new technology resources, and includes a compliance measurement mechanism for resource adequacy and flexible resource adequacy resources. The ISO Board approved this initiative in early 2015.

- **Capacity procurement mechanism replacement.** Also approved by the ISO Board in early 2015, this new program allows resources to submit bids for capacity, and will look to those bids first, when possible, to fulfill procurement needs. The new program is expected to function very similar to the existing capacity procurement mechanism, but is designed to allow competition between different resources that may meet any capacity needs when possible.

9.1 Background

The CPUC resource adequacy provisions require load-serving entities to procure generation capacity to meet 115 percent of their forecast peak demand in each month.[157] 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 markets through a must-offer requirement. Load-serving entities meet these requirements by providing resource adequacy showings to the ISO on a year-ahead basis due in October and provide twelve month-ahead filings during the compliance year.

Around half of the generating capacity counted toward resource adequacy requirements must be bid into the market for each hour of the month except when this capacity is reported to the ISO as being unavailable because of outages. This includes most gas-fired generation and imports, with a total capacity of around 30,500 MW. If the market participant does not submit bids, the ISO automatically creates bids for these resources.

Imports represent around 8 percent of resource adequacy capacity. Beginning in January 2012, the ISO began to automatically create energy bids for imports in the day-ahead market when market participants fail to submit bids for this capacity and have not declared this capacity as unavailable. If an import is not scheduled in the day-ahead market, the importer is not required to submit a bid for this capacity in the real-time market. If an import clears the day-ahead market and is not self-scheduled or re-bid in the real-time market, the ISO submits a self-schedule for this capacity.

The remaining generation resources that are 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 the following:

- Hydro resources, which represent 13 percent of resource adequacy capacity.
- Use-limited thermal resources, such as combustion turbines subject to use limitations under air emission permits, which represent 8 percent of resource adequacy capacity.[158]
- Non-dispatchable generators, which include nuclear, qualifying facilities, wind, solar and other miscellaneous resources. These resources account for about 17 percent of capacity.

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

[157] As noted in Section 40.3 of the ISO tariff, load-serving entities are also required to procure generation capacity to meet capacity requirements for local capacity areas.

[158] Use-limited thermal resources generally have environmental, regulatory or technical restrictions on the hours they can operate, such as a maximum number of operating hours or a maximum number of start-ups and shutdowns in a month or a year. Market participants submit use plans to the ISO for these resources. These plans describe their restrictions and outline their planned operation.

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

9.2 Overall resource adequacy availability

Generation capacity is especially important to meet the peak loads of the summer months. However, it is also important that sufficient 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. With more intermittent renewable generation coming online, the need for sufficient ramping capacity is also becoming increasingly important throughout the year during many non-peak load hours.

In 2014, a high portion of resource adequacy capacity was available to the market throughout the year. Figure 9.1 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 2014. The red line shows the total amount of this capacity used to meet resource adequacy requirements.[159] The bars show the amount of this resource adequacy capacity that was made available during critical hours in the day-ahead, residual unit commitment, and real-time markets.[160]

Key findings of this analysis include the following:

- The highest availability was during the third quarter, from July through September. During these months, out of around 50,500 MW of resource adequacy capacity included in this analysis, an average of around 43,000 MW (or about 85 percent) was available in the day-ahead market.

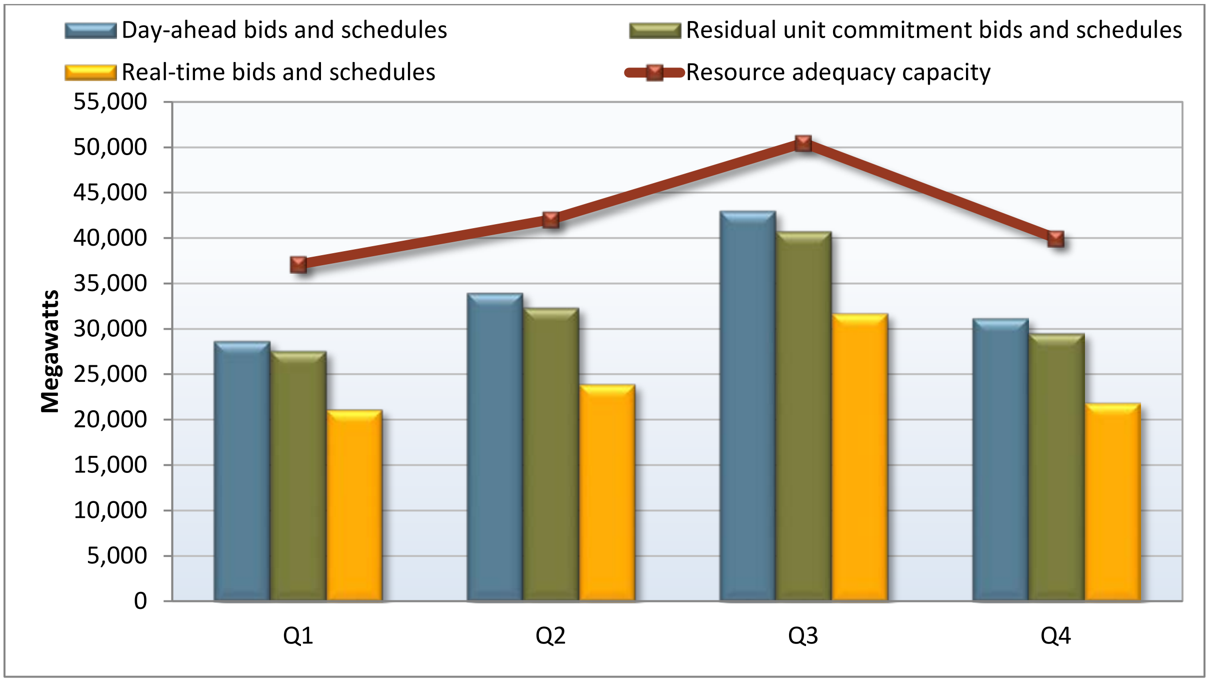
- The lowest level of availability was during the first quarter, during which about 78 percent of resource adequacy capacity was available to the day-ahead market.

[159] The resource adequacy capacity included in this analysis excludes as much as a few thousand megawatts of resource adequacy capacity for which this analysis cannot be performed or is not highly meaningful. This includes resource adequacy resources representing some imports and firm import 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.

[160] These amounts are calculated as the hourly average of total 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 through 18 during April through October and operating hours 17 through 21 during the remainder of the year.

- Over all months, almost all capacity offered in the day-ahead energy market was also available in the residual unit commitment process.
- Figure 9.1 also shows that a smaller portion of resource adequacy capacity was available to the real-time market. This is primarily because many long-start gas-fired 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 9.1 Quarterly resource adequacy capacity scheduled and bid into ISO markets (2014)



9.3 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.[161] The rules do not specify that these hours must include the hours of the highest load or most critical system conditions. Because participants do not have perfect foresight when the highest loads will actually occur, the program assumes that they will manage these use-limited

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

generators so that they are available during the peak load hours. In 2014, this included all hours with peak load over 38,629 MW.

Figure 9.2 provides an overview of monthly resource adequacy capacity, monthly peak load, and the number of hours with loads over 38,629 MW during that period. Many of the highest load hours occurred during heat waves in July and September. 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. The yellow line adjusts the resource adequacy capacity by demand response capacity.

Figure 9.2 Summer monthly resource adequacy capacity, peak load, and peak load hours (May through September 2014)

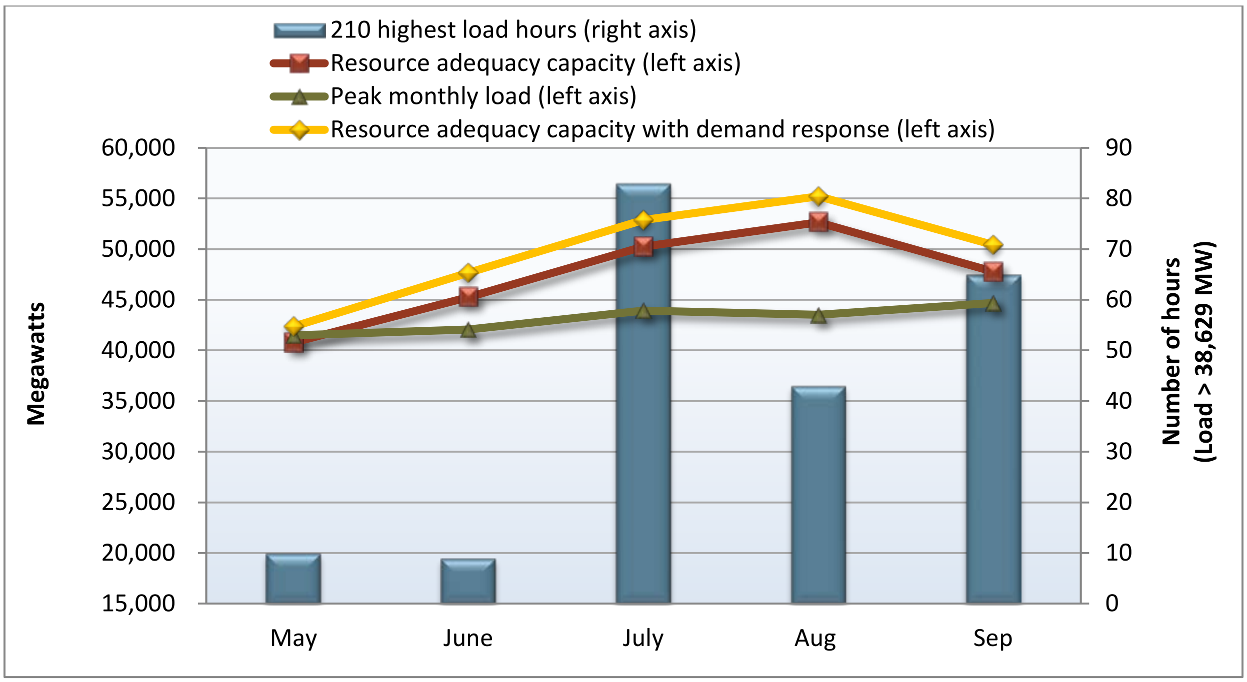


Table 9.1 provides a detailed summary of the availability of resource adequacy capacity over the 210 summer peak load hours for each type of generation. Separate sub-totals are provided for resources for which the ISO creates bids if market participants do not submit a bid or self-schedule, and resources for which the ISO does not create bids. As shown in Table 9.1:

- ***Resource adequacy capacity after reported outages and derates*** — Average resource adequacy capacity was around 49,700 MW during the 210 highest load hours in 2014. 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 these hours.

- ***Day-ahead market availability*** — For the 19,000 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 around 80 percent of the available capacity of these resources. This compares to the 95 percent of the available capacity from the resources for which the ISO creates bids.

- ***Residual unit commitment availability*** — The overall percentage of resource adequacy capacity made available in the residual unit commitment process was just slightly less than that available to the day-ahead market.
- ***Real-time market availability*** — The last three columns of Table 9.1 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. The resource adequacy capacity available in the real-time market timeframe is calculated as the remaining resource adequacy capacity from resources with a day-ahead or residual unit commitment schedule plus the resource adequacy capacity from uncommitted short-start units (not adjusted for outages or derates). An average of about 84 percent of the resource adequacy capacity that was potentially available to the real-time market was scheduled or bid in the real-time market. This bid-in capacity has been adjusted for outages and derates.
- ***Use-limited gas units*** — Around 4,200 MW of use-limited gas resources are used to meet resource adequacy requirements. Most of these resources are peaking units within more populated and transmission constrained areas that are only allowed to operate 360 hours per year under air permitting regulations. Market participants submit to the ISO use plans for these resources, but are not actually required to make them available during peak hours. About 91 percent of this capacity was available in the day-ahead market during the highest 210 load hours. In real time, about 2,700 MW of this 4,200 MW of capacity was scheduled or bid into the real-time market.
- ***Nuclear units*** — Around 5,000 MW of nuclear capacity were used to meet resource adequacy requirements in 2011. Both San Onofre Nuclear Generating Station units have been unavailable since early 2012 and retired in June 2013. This is reflected in Table 9.1 which shows that the nuclear resource adequacy capacity was around 2,800 MW in 2014.
- ***Imports*** — Around 3,800 MW of imports were used to meet resource adequacy requirements. About 98 percent of this capacity was scheduled or bid in the day-ahead market during the 210 highest load hours. Most of this capacity was self-scheduled or bid at competitive prices in the day-ahead market. About 94 percent of real-time capacity was scheduled or bid into the real-time market. The availability of imports is discussed in more detail in Section 9.4.

Table 9.1 Average resource adequacy capacity and availability (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	25,224	24,281	96%	24,225	96%	23,596	94%	18,912	18,331	97%
Other Generators	1,549	1,449	94%	1,108	72%	1,080	70%	1,531	1,184	77%
Imports	3,803	3,803	100%	3,713	98%	3,628	95%	3,220	3,043	94%
Subtotal	**30,576**	**29,533**	**97%**	**29,046**	**95%**	**28,304**	**93%**	**23,663**	**22,558**	**95%**
ISO Does Not Create Bids:										
Use-Limited Gas Units	4,220	3,921	93%	3,841	91%	3,764	89%	2,991	2,668	89%
Hydro Generators	6,384	5,464	86%	4,518	71%	4,411	69%	6,384	4,463	70%
Nuclear Generators	2,834	2,818	99%	2,818	99%	2,818	99%	2,834	2,791	98%
Wind/Solar Generators	2,809	2,789	99%	1,673	60%	1,609	57%	2,765	2765*	100%
Qualifying Facilities	2,773	2,688	97%	2,457	89%	2,457	89%	2,773	2,440	88%
Other Non-Dispachable	104	103	99%	53	51%	53	51%	104	97	93%
Subtotal	**19,124**	**17,782**	**93%**	**15,360**	**80%**	**19,073**	**100%**	**17,850**	**12,459**	**70%**
Total	**49,700**	**47,316**	**95%**	**44,406**	**89%**	**47,377**	**95%**	**41,514**	**35,017**	**84%**

* Actual wind/solar generation is used as a proxy for real-time bids.

9.4 Imports

Load-serving entities are allowed to use imports to meet their resource adequacy requirement. There are roughly 11,000 MW of total import capability into the ISO system and net imports averaged about 8,400 MW during the peak summer months. Utilities used imports to meet around 3,800 MW, or about 8 percent, of the resource adequacy requirements during the 210 highest load hours. This reflects a 16 percent decrease in the resource adequacy capacity from imports compared to 2013 and a 30 percent decrease compared to 2012. This reduction in resource adequacy capacity from imports appears to have been replaced by higher levels of resource adequacy capacity from use-limited gas units as well as wind and solar generation.

Imports used to meet resource adequacy requirements are not required to originate from specific generating units or be backed by specific portfolios of generating resources. In addition, resource adequacy imports are only required to be bid into the day-ahead market. These imports can be bid at any price and do not have any further obligation if not scheduled in the day-ahead energy or residual unit commitment process.

DMM has expressed concern that these rules could in theory allow a significant portion of resource adequacy requirements to be met by imports that may have limited availability and value during critical system and market conditions. For example, resource adequacy imports could be routinely bid well above projected prices in the day-ahead market to ensure they do not clear and would then have no further obligation to be available in the real-time market.

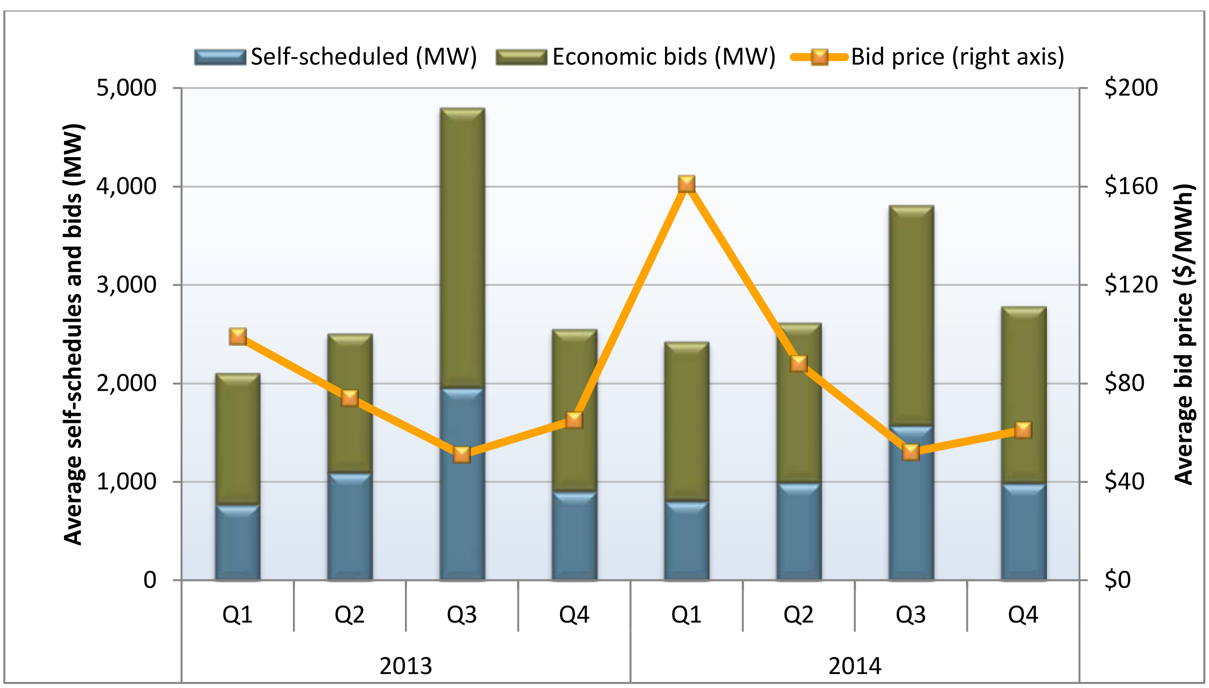
The quantity and prices of economic bids for some resource adequacy imports started to increase in 2013. Self-scheduled imports constituted around 39 percent of total bids in 2013 compared to 64 percent in 2012. This economic bidding trend continued in 2014 as self-scheduled imports only constituted around 38 percent of total bids in the day-ahead market.

Figure 9.3 summarizes the bid prices and volume of self-scheduled and economic bids for resource adequacy import resources in the day-ahead market, during peak hours, 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 (blue bar) or economically bid (green bar) in the day-ahead market. The gold line (plotted against the right axis) shows the average weighted bid prices for resource adequacy import resources for which market participants submitted economic bids to the day-ahead market.

The quantity of imports with economic bids in 2014 was similar to the level in 2013. The quantity of economic bids was greater than the quantity of self-scheduled bids in every quarter.

Figure 9.3 also shows that market participants submitted higher-priced economic bids in the first quarter of 2014. The weighted average of bid prices increased from $65/MWh in the final quarter of 2013 to $160/MWh in the first quarter of 2014. In the first quarter of 2012, imports averaged about $180/MWh. Overall, weighted average bid prices were higher in 2014 compared to 2013, averaging $87/MWh in 2014 compared to $68/MWh in 2013.

Figure 9.3 Resource adequacy import self-schedules and bids (peak hours)



9.5 Backup capacity procurement

The ISO tariff includes provisions allowing the ISO to procure any resources needed if capacity procured by load-serving entities under the resource adequacy program is not sufficient to meet system-wide and local reliability requirements. These provisions include both reliability must-run contracts and the capacity procurement mechanism.

Because load-serving entities procure most of the needed local capacity requirements through the resource adequacy program, the amount of capacity and costs associated with reliability must-run contracts have been relatively low over the past few years. However, these costs increased to $25 million in 2014 from $21 million in 2013. Most of these costs resulted from the reliability must-run agreement that placed synchronous condensers at Huntington Beach units 3 and 4 into service in late June 2013. This agreement was put into place due to the outage and subsequent retirement of the SONGS units in June 2013.

Capacity payments related to the capacity procurement mechanism also increased in 2014. Capacity procurement mechanism costs increased from $2.7 million in 2013 to $7.7 million on two contracts in 2014. The High Desert Power Project received capacity procurement mechanism payments to help meet operating reserve requirements and avoid a Stage 1 emergency in the case of extreme natural gas supply scarcity events in Southern California in early February 2014.[162] Moss Landing 2 received capacity procurement payments in the fall to address transmission related reliability concerns.

Table 9.2 Capacity procurement mechanism costs (2014)

Resource	Local capacity area	CPM designation (MW)	Estimated cost	CPM designation dates
High Desert Power Project Aggregate	CAISO System	181	$1,159,644	2/6 - 3/7
Moss Landing 2	CAISO System	490	$6,593,139	10/2 - 12/1
		671	**$7,752,783**	

9.6 Resource adequacy developments

Flexible resource adequacy

In 2014, FERC conditionally approved the ISO's proposal to institute requirements for flexible resource adequacy capacity.[163] These requirements were placed to help the ISO manage integration of high levels of renewable energy, and for the most part mirror similar requirements recently approved by the CPUC for its jurisdictional entities.[164] While the established resource adequacy program ensures that the grid has access to a total amount of capacity, the flexible resource adequacy program recognizes the

[162] For more information on the gas scarcity events, please see Section 1.2.3.

[163] For more information on FERC's acceptance: http://www.caiso.com/Documents/Oct16_2014_OrderConditionallyAcceptingTariffRevisions-FRAC-MOO_ER14-2574.pdf.

[164] A description of this policy can be found at: http://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRACriteriaMustOfferObligation-Clean.pdf.

important contributions made by other resource characteristics that contribute to the flexible response needed to integrate large quantities of renewable generation. The new program also includes a specific must-offer obligation for flexible capacity that further differentiates it from generic resource adequacy capacity.

Reliability services initiative

The reliability services initiative streamlines resource adequacy rules for replacement and substitute capacity should a resource adequacy unit become unavailable, clarifies definitions and qualifying criteria for new technology resources, and includes a compliance measurement mechanism for resource adequacy and flexible resource adequacy resources. The new mechanism is intended to replace the existing standard capacity product (SCP) mechanism, which measures compliance with resource adequacy must-offer obligations.

The basic concept of the must-offer obligation is that a resource must be available to the market. Under the standard capacity product, a resource was considered available unless it had submitted an outage. The new mechanism, known as the resource adequacy availability incentive mechanism, improves upon the standard capacity product by defining availability through submission of bids. This change allows for evaluation of the must-offer obligation of flexible resource adequacy resources. Other changes from the standard capacity product include lowering the penalty price and making more resources subject to potential compliance penalties. The first stage of this feature was approved by the ISO Board of Governors on March 2015.[165]

Under the ISO's final proposal, until the ISO completes the work needed to include opportunity cost estimates in start-up and minimum load bids, use-limited resources can exempt themselves from the availability standards by submitting special outages. Therefore, DMM continues to urge the ISO to commit the resources necessary to develop and implement the opportunity cost estimation method which will allow use-limited resources to bid into all hours.

The ISO's final proposal also sets the penalty price for not meeting availability standards at 60 percent of the soft offer cap for the capacity procurement mechanism. As noted in DMM's last annual report and its comments in this stakeholder initiative, if the cost of replacement capacity approaches the soft offer cap, it will be less costly for generating unit owners to pay the penalty rather than provide substitute capacity. DMM believes this scenario could occur precisely when supply conditions are tightest and options for capacity that can be procured bilaterally by participants or by the ISO through the capacity procurement mechanism is most limited and non-competitive.

DMM recommends that the ISO monitor this issue once the new incentive mechanism has been implemented. If the initial level of this penalty appears to be insufficient to incent participants from meeting availability standards, the penalty price may need to be raised closer to the soft cap for the backstop procurement mechanism that the ISO may need to employ to procure additional capacity as the result of any failure to meet availability standards.

[165] The proposal considered by the ISO Board can be found at: http://www.caiso.com/Documents/DraftFinalProposalAddendum-ReliabilityServices.pdf.

Capacity procurement mechanism replacement

The ISO's existing capacity procurement mechanism is set to expire in 2016. The capacity procurement mechanism is a tool that the ISO can use to ensure that it has enough capacity available to operate the grid. It is primarily used to overcome unexpected situations, although it could also come into play if there was a shortcoming in the resource adequacy program. In order to replace this tool, a new program was designed in 2014 and approved by the ISO Board in early 2015.[166] The new program is expected to function very similar to the existing capacity procurement mechanism, but is designed to allow competition between different resources that may meet any capacity needs when possible. The new program allows resources to submit bids for capacity, and will look to those bids first when possible to fulfill procurement needs.

[166] The proposal can be found at: http://www.caiso.com/Documents/RevisedStrawProposal-CapacityProcurementMechanismReplacement.pdf.

10 Recommendations

DMM works closely with the ISO to provide recommendations on current market issues and new market design initiatives on an ongoing basis. This chapter summarizes DMM recommendations on the following market design initiatives and issues.

- Expansion of network model to regional level
- Congestion revenue rights
- Virtual bidding on inter-ties
- Real-time imbalance offset costs
- Start-up and minimum load costs
- Transition costs
- Bidding rules initiative
- Scheduling of variable energy resources
- Flexible ramping product
- Contingency modeling enhancements
- Forward procurement of flexible capacity
- Reliability services initiative
- Energy imbalance market

10.1 Network model expansion

Background

In October 2014, the ISO implemented an expanded network model that includes more topology and inputs from other balancing areas. This expanded network model is designed to allow the day-ahead and real-time models to more accurately project actual power flows. By expanding the full network model to include other balancing areas, the ISO will also be able to reflect outages and other reliability parameters on those external systems and analyze how they may affect the ISO market.

Recommendations

DMM strongly supported the ISO's final proposal to expand its network model. The final proposal was the result of significant input from DMM, the Market Surveillance Committee and stakeholders.

As noted in DMM's last annual report, creating and testing an expanded network model is a difficult and complex task. Other ISOs have experienced serious challenges in improving the accuracy of their estimates of unscheduled flows. Consequently, DMM, the Market Surveillance Committee and stakeholders recommended that the ISO analyze, validate, and benchmark the full network model before and after implementation to ensure it provides the intended benefits.

The ISO has developed metrics for assessing the performance of the expanded full network model. These metrics are designed to assess whether day-ahead estimates of unscheduled flows created by loads and schedules in other balancing areas produced by this new network model improved the accuracy of total estimated day-ahead flows compared to a scenario without any estimate of unscheduled flows.[167]

DMM provided specific recommendations relating to more detailed metrics and analysis that the ISO may use to assess the impacts of the expanded modeling functionality. As summarized in DMM's memo to the ISO Board on this topic: [168]

- Unless the estimated or actual flow on a line is actually near a limit in the day-ahead or real-time market, there may be little or no consequences of any improvement of projected flows in terms of reliability or market costs. Therefore, DMM recommends that the ISO's automated metrics focus on the impact that the full network model is having on estimated flows on specific constraints which are at or near their limits in the day-ahead and real-time markets based on estimated or actual flows.
- DMM also recommends that the ISO's metrics and analysis focus on constraints on which the actual market impact of congestion is highest. As identified in prior reports by DMM, the bulk of real-time energy congestion offset costs that have been incurred in the past are associated with a relatively small number of constraints in any given period. Automated metrics can be used to quickly identify these constraints and allow the ISO to focus its resources on modeling improvements or adjustments that have the highest value in terms of reliability and market benefits.
- The ISO's metrics and analysis focus primarily on inter-ties. DMM recommends implementing the type of more detailed automated metrics described above for a larger range of internal constraints as well.
- DMM recommends the ISO develop a variety of automated metrics that it can use to assess the impact that modeling inputs and assumptions have on market congestion in the day-ahead and real time. Automation of metrics that can flag the most critical aspects of performance is critical due to the massive amount of data involved in assessing unscheduled flows.

[167] DMM has noted that even if the model provides a better estimate of unscheduled flows crated by non-ISO schedules compared to not estimating unscheduled flows at all, this does not ensure that the model is providing a better estimate of actual congestion. For example, assume a constraint has a 1,000 MW limit, +800 MW of flow created by ISO market schedules, and +150 MW of unscheduled flow created by non-ISO market schedules. If the model estimated +225 MW of unscheduled flow created by non-ISO market schedules, this would be a much more accurate estimate of actual unscheduled flow (+150 MW) than the alternative of not estimating unscheduled flows. However, in this scenario the overestimation of unscheduled flows would lead to +25 MW of false congestion in the market model.

[168] Memorandum from Eric Hildebrandt to ISO Board of Governors, re: Market Monitoring Report, January 30, 2014: http://www.caiso.com/Documents/DepartmentMarketMonitoringReport-Memo-Feb2014.pdf.

DMM is continuing to work closely with the ISO and the Market Surveillance Committee toward developing more detailed and automated metrics for monitoring and enhancing the full network model functionality.

10.2 Congestion revenue rights

When transmission constraints are congested in the day-ahead market, the revenue collected by the ISO from scheduled load exceeds revenues paid to generation. Congestion revenue rights are designed to try to return this excess revenue to the investor-owned utilities and other load-serving entities that own the transmission.

In 2014, the congestion revenue rights process resulted in a net revenue shortfall after accounting for auction revenues of $95 million compared to surpluses of $23 million and $3 million in 2012 and 2013, respectively. The ISO currently allocates any congestion revenue rights revenue inadequacy uplift to load-serving entities based on measured demand. Such revenue inadequacy decreases the total revenues received by load-serving entities for the congestion revenue rights that they made available to the auction.

As discussed in Section 7.4, such revenue inadequacy is generally due to differences between the network transmission model used in the congestion revenue rights process and the final day-ahead market model. In general, the day-ahead model may be more restrictive than the congestion revenue rights model. This is because transmission changes unanticipated at finalization of the congestion revenue rights model are more likely to reduce available transmission capacity than to increase it, as transmission flows are de-rated to account for unplanned outages and other unanticipated conditions. In addition, new nomograms not in place when the congestion revenue rights full network model is finalized may impose limits on transmission capacity in the day-ahead market.

The ISO has taken steps to address the revenue inadequacy by accounting for more constraints in the congestion revenue rights model in future auctions. This essentially limits the amount of congestion revenue rights that are auctioned off going forward.

However, DMM has noted that there are a variety of modeling issues that can tend to create discrepancies in the network transmission model used in the congestion revenue rights process and the final day-ahead market model. In 2014, DMM provided a general methodology that could be used to allocate congestion revenue rights revenue inadequacy costs back to holders of congestion revenue rights on an interval and constraint specific basis. This alternative allocation approach would limit the total amount of revenues that can be transferred from load-serving entities to congestion revenue rights holders through uplift. Moreover, this allocation method would reduce the incentive for entities purchasing congestion revenue rights to target the modeling differences that create revenue inadequacy costs.[169]

Consideration of options for modifying the method for allocating congestion revenue rights revenue imbalances was identified as a high priority for numerous market participants as part of the 2014 market initiative issue ranking process. However, the ISO did not include this in its list of initiatives that would

[169] *Allocating CRR Revenue Inadequacy by Constraint to CRR Holders*, Department of Market Monitoring, October 6, 2014: https://www.caiso.com/Documents/AllocatingCRRRevenueInadequacy-Constraint-CRRHolders_DMMWhitePaper.pdf.

be pursued in 2015 due to resource limitations and the ISO assessment that this would involve a complicated stakeholder process.

10.3 Virtual bidding on inter-ties

Under the new real-time market implemented in 2014, the ISO would settle virtual bids on inter-ties and internal locations within the ISO based on differences between day-ahead and 15-minute prices. Under the prior market design, the ISO market settled virtual bids at internal nodes based on 5-minute prices while it settled virtual bids on inter-ties using prices from the hour-ahead market. Settling all virtual bids on the 15-minute prices would eliminate the problem that led to high revenue imbalance costs and the suspension of virtual bidding on inter-ties in late 2011.[170]

Virtual bidding on inter-ties was scheduled to be re-implemented in May 2015 – one year after implementation of the new 15-minute real-time market design. In April 2015, the ISO requested a waiver for the requirement to re-implement virtual bidding on inter-ties for up to an additional 12-month period. The basis of the ISO request was the concern that reintroducing inter-tie virtual bidding in light of the observed lack of liquidity in economic bidding in the ISO's 15-minute market would decrease economic efficiency, based on a supplemental report completed by DMM analyzing the connection between 15-minute market economic bids at the inter-ties and inter-tie virtual bidding.[171]

During the period of the waiver, the ISO and stakeholders will explore the causes underlying the lack of liquidity at the inter-ties in the 15-minute market and related inter-tie pricing issues. They will seek to identify ways to improve liquidity and any appropriate inter-tie pricing improvements, as well as to identify the sufficient level of liquidity, from a market efficiency perspective, to reinstitute inter-tie virtual bidding.

DMM supports the continued suspension of virtual bidding on inter-ties given the current lack of liquidity on most inter-ties in the 15-minute market. DMM will work with the ISO and stakeholders to explore the reasons for this lack of liquidity and how to improve it. In addition, DMM and the ISO will also explore potential inter-tie pricing improvements and/or other options that might be feasible to increase liquidity or otherwise mitigate the potential inefficiencies that may be created if virtual bidding was re-implemented on inter-ties under current market conditions and rules.

As noted above, DMM has also cautioned that virtual bidding on inter-ties could inflate real-time congestion revenue imbalances in the event that constraint limits need to be adjusted downward in the 15-minute market to account for unscheduled flows not incorporated in the day-ahead market model. The expanded full network model implemented in the fall of 2014 is designed to account for unscheduled flows in the day-ahead market model. DMM's recommendations on the expanded full network model are provided in Section 10.1.

[170] As described in DMM's 2011 annual report, this problem was created by the fact that virtual bids at inter-ties were settled on hour-ahead prices, while virtual bids at internal locations were settled at 5-minute prices. For further detail see the *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, pp. 77-79: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

[171] *Potential market inefficiencies from convergence bidding at interties with insufficient liquidity of fifteen-minute bids*, Department of Market Monitoring, April 3, 2015: http://www.caiso.com/Documents/DMMReport-ConvergenceBiddingonInterties.pdf.

10.4 Real-time imbalance offset costs

The real-time imbalance offset charge consists of three components:

- Any revenue imbalance from the energy and loss components of hour-ahead, 15-minute and 5-minute market real-time energy settlement prices is collected through the *real-time imbalance energy offset charge* (RTIEO).
- Any revenue imbalance from just the congestion components of these real-time energy settlement prices is recovered through the *real-time congestion imbalance offset charge* (RTCIO).
- Until October 1, the ISO aggregated real-time loss imbalance offset costs with real-time imbalance energy offset costs. Beginning October 1, any revenue imbalance from the loss component of real-time energy settlement prices is collected through the *real-time loss imbalance offset charge*.

The new real-time market design implemented in May 2014 has reduced revenue imbalances allocated to load through real-time imbalance energy offset charges formerly caused by the difference in hour-ahead prices used to settle inter-tie transactions and 5-minute prices used to settle energy from resources within the ISO system.

DMM continues to caution that large real-time congestion imbalance revenue charges could still occur if the ISO adjusts transmission limits downward after the day-ahead market to account for unscheduled flows. This creates congestion offset costs by reducing the volume of energy flows in the real-time market over congested constraints.[172] Thus, it will remain important for the ISO to continue efforts to improve modeling of flows in the day-ahead and 15-minute markets, so that the need to reduce flows in real time by adjusting constraint limits downward is reduced.

As noted in our last annual report, re-implementation of virtual bidding on inter-ties could inflate real-time revenue imbalances if constraint limits need to be adjusted downward in the 15-minute market to account for unscheduled flows not incorporated in the day-ahead market model. The expanded full network model implemented in the fall of 2014 is designed to account for unscheduled flows in the day-ahead market model. DMM's recommendations on the expanded full network model are provided in Section 10.1.

Since the ISO needs to adjust constraint limits downward in the 15-minute market below levels incorporated in the day-ahead market model due to reasons such as transmission de-rates, DMM has also suggested the ISO implement a settlement rule that would allocate a portion of congestion offset costs back to convergence bidders based on the level by which these virtual bids directly contributed to these offset costs.[173]

[172] See *Real-time Revenue Imbalance in CAISO Markets,* Department of Market Monitoring, April 24, 2013: http://www.caiso.com/Documents/DiscussionPaper-Real-timeRevenueImbalance_CaliforniaISO_Markets.pdf.

[173] Ibid.

10.5 Start-up and minimum load bids for natural gas units

Background

In 2014, owners of gas-fired generation could choose from two options for setting their start-up and minimum load bid costs: the proxy cost option and the registered cost option.

- The proxy cost option is a cost-based option, under which each unit's start-up and minimum load costs are automatically calculated each day based on an index of a daily spot market gas price and the unit's start-up and minimum load fuel consumption as reported in the master file.
- The registered cost option is a bid-based option under which scheduling coordinators submit fixed monthly bids for start-up and minimum load costs, which are then used by the daily market software. Beginning in November 2013, registered cost bids were capped at 150 percent of projected costs as calculated under the proxy cost option. This option was provided as an alternative for generation unit owners who believed they had significant non-fuel start-up or minimum load costs not covered under the proxy cost option.

Starting in November 2013, scheduling coordinators could also apply for major maintenance adders to be included in start-up and minimum load bids to reflect any incremental maintenance costs incurred as a result of additional start-ups or run hours.

A cold weather event on February 6, 2014, led to a rapid increase in gas prices and highlighted the potential market impacts of the gas prices used by the ISO to calculate bids under the proxy cost option, which are based on gas prices traded two days prior to the operating day. This event also highlighted the potential impact of monthly fixed start-up and minimum load bids under the registered cost option, which was selected by most gas-fired capacity at the time, in cases when a rapid increase in gas prices occurs.

Both these market features caused start-up and minimum load bids used by the ISO software to be significantly lower than the prevailing market prices of natural gas. As a result, the ISO's market systems made resource commitments that reflected prices for minimum load energy from some units that may have been well below actual costs. In addition to less efficient unit commitments, this created potential revenue inadequacy for some units.

To address this issue, the ISO requested, and the FERC granted, temporary waivers of its tariff in March 2014 to allow it to incorporate a more recent gas price forecast into its day-ahead market solution and settlement practices under certain conditions. The waiver also allowed units on the registered cost option to switch to the proxy cost option in the event of a sudden increase in the price of natural gas.

In late 2014, the ISO gained FERC approval to make these changes permanent, along with two modifications.

- First, resources on the proxy cost option were allowed to bid in up to 125 percent of proxy costs, whereas before they were capped at bidding in up to 100 percent of proxy costs. This additional flexibility was provided to allow resources to submit proxy cost bids that reflect any additional gas and other costs not accurately reflected in the methodology for calculating proxy cost bids.
- Second, only resources with use limitations were eligible for the registered cost option. This provision was designed to allow use-limited resources to continue to submit higher bids that reflect

the potential opportunity costs of the use limitations. The ISO plans to eliminate the registered cost option once it develops and implements a methodology and tool to explicitly calculate opportunity costs for units with start-up or run hour limits and incorporate these in start-up and minimum load bids.

DMM supported these changes as representing a reasonable balance between the need to allow participants to submit start-up and minimum load bids incorporating expected gas and opportunity costs, while continuing to mitigate locational market power and potentially manipulative behavior designed to recover excessive start-up and minimum load bid costs through bid cost recovery payments.

Use-limited status

As part of another stakeholder initiative completed in early 2015, the ISO clarified that under current market rules resources can only be deemed use-limited based on physical, environmental or regulatory limits, and that units cannot be eligible for use-limited status based on contract-based limitations or economic operating costs. This has important implications since units deemed to be use-limited will continue to be exempted from key bidding limits and availability standards established through other market rules and initiatives aimed at making sure capacity is available for dispatch to meet the growing operational need for flexible capacity.

DMM has noted that the ISO's efforts to limit the number of resources with exemptions due to actual physical or regulatory use limits may be undermined if scheduling coordinators can use other unit operating constraints in the market model to limit unit usage and flexibility. One key model input currently used by participants to limit unit operation is the limit on start-ups per day set by each unit's scheduling coordinator.

DMM has also expressed concerns that daily start limits entered by participants do not reflect the actual physical limits of generating units. In 2014, the ISO started a process to examine this issue. Under the flexible resource adequacy program requirements being implemented by the ISO and CPUC, units will be required to enter at least two start-ups per day in order to meet requirements for this most flexible category of resources. DMM encourages the ISO to continue to review and clarify rules regarding daily start limits and other unit operating constraints submitted by scheduling coordinators that can also have a major impact on unit availability and flexibility.

Opportunity cost bid adder

As noted in prior annual reports, DMM is very supportive of the concept of including opportunity costs in start-up and minimum load bids, and is supportive of the ISO's general approach to calculating opportunity costs. We recommend that the ISO continue further refining and developing their current prototype model and continue to engage stakeholders in developing and refining the opportunity cost methodology and model.

In early 2015, DMM expressed concerns that this important market enhancement has been deferred again, and that given the current status and resources being applied to this project, it may be very difficult for the ISO to complete the development, testing and stakeholder review of an opportunity cost model and rules in time for consideration of this issue by the ISO Board in September 2015 as planned.[174]

For ISO staff to actually implement opportunity costs in the market, this software must also be highly automated and allow for opportunity cost to be updated as necessary based on changes in market prices or actual generating units. DMM has also recommended that a version of the model be made available to market participants so that they may perform their own analysis and request updates or modifications to their opportunity cost bids as appropriate.

DMM continues to look forward to working closely with the ISO and stakeholders on the details of this important market enhancement and implementing this functionality in the market.

Major maintenance adders

Beginning in late 2013, resources are eligible to apply to have a major maintenance adder included in their start-up and minimum load bids. This adder is designed to cover the incremental maintenance costs incurred from major maintenance actions that periodically occur based on the number of times a unit has started up and/or the number of hours it has run. Including these additional costs in start-up and minimum load bids can reduce the frequency that units get cycled on and off, and ensure that generators recover these costs whenever they are dispatched to operate.

Although the process for implementing major maintenance adders was initially problematic, the ISO, in consultation with DMM, assumed responsibility for this process in mid-2014. Because of changes in late 2014, fewer units were allowed to bid up to 150 percent of costs under the registered cost option as a result of changes made under the first phase of the commitment cost initiative. This led many participants with resources that did not previously have a major maintenance adder to avail themselves of this bidding option.

DMM believes further refinements to the tariff provisions regarding the major maintenance adder could be made. These changes would make this market feature even more effective at ensuring that unit commitments reflect actual marginal unit commitment costs and that resource owners recover the additional costs associated with starting up and operating flexible generating units more frequently to meet the ISO’s growing need for operational flexibility.

10.6 Transition cost bids

In early 2015, the ISO Board gave approval to the ISO to file with FERC a proposal to modify the manner in which transition cost bids for multi-stage generating units are calculated. The ISO wants to simplify the calculation of multi-stage generating resource transition costs and treats these costs similar to generator start-up costs. Scheduling coordinators will be allowed to bid transition costs in the same manner that proxy and registered costs are currently bid into the market, so that transition cost bids may be submitted up to 125 or 150 percent of cost-based calculations.[175]

[174] Memorandum from Eric Hildebrandt to ISO Board of Governors, re: Market Monitoring Report, March 19, 2015: http://www.caiso.com/Documents/Department_MarketMonitoringReport-Mar2015.pdf.

[175] For more detailed examples and description, see *Commitment Cost Enhancements Phase 2 Draft Final Proposal*, California ISO, February 9, 2015, pp. 20-27: http://www.caiso.com/Documents/DraftFinalProposal_CommitmentCostEnhancementsPhase2.pdf.

DMM is highly supportive of these enhancements that address recommendations that have been reiterated by DMM in each of our last three annual reports. These enhancements greatly simplify the current calculation of transition costs, provide more clarity for market participants and provide a basis for the ISO to review and verify these costs.

10.7 Bidding rules initiative

The ISO intends to undertake a new initiative to consider a range of modifications to bidding rules in 2015. Issues within the potential scope of this initiative include the natural gas prices used in development of start-up, minimum load, and energy bids used as bid caps and for cost-based bids used in bid mitigation.

Review of gas costs

Some stakeholders have suggested that participants should be allowed to submit their own estimates of gas costs for start-up, minimum load and energy bids without any specific limits, and then only apply mitigation through some form of *ex post* review of gas costs.

DMM opposes this type of fundamental modification in the current process for limiting start-up and minimum load bids for a variety of reasons.

- First, in 2013 the ISO completed a process to lower the limit on start-up and minimum load bids in order to limit potential gaming or manipulative practices aimed at profiting from high bid cost recovery payments. The ISO has adopted rules to address specific practices by one participant aimed at profiting from high minimum load bids under the registered cost option.[176] The lower 150 percent limit implemented in 2013 is seen as an important protective measure against other such practices.[177]

- Second, the current framework for limiting these bids has worked well under almost all conditions over the five year period since the nodal market began in 2009. The specific problems occurring due to the very extreme conditions on February 6, 2014, have been addressed in a targeted manner by two recent rule changes implemented in 2014.[178] DMM believes that issues which arise under very extreme and infrequent conditions can continue to be addressed effectively in a targeted manner through additional refinements, if necessary.

- Finally, DMM notes that if rules are modified to allow participants to submit their own start-up and minimum load bids without any specific limits, some form of mitigation will still be needed. After the fact review of bids would be very administratively burdensome, and would not mitigate the distortion in the market that would have already occurred due to use of the unmitigated bids.

[176] For more information, see: http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/CommitmentCostsRefinement2012.aspx.

[177] Part of the reason for this rule change was to protect against any new practices that might become profitable given changes that the ISO made to bid cost recovery rules in 2013. Under these new rules, bid cost recovery payments are now calculated separately for the day-ahead and real-time markets, rather than netting any net revenues from one market against any bid cost recovery shortfall in another market.

[178] For further information, see Section 6.5.

Dynamic mitigation of start-up and minimum load bids

Another option that has been discussed in the past has been to automatically apply mitigation only when it is determined that a unit may have local market power – such as the ISO's automated procedures for energy bid mitigation. In prior stakeholder processes, the ISO has referred to this as *dynamic mitigation* of start-up and minimum load bids.

In practice, however, units may have market power as a result of various capacity constraints that require units to be committed and operating at least at minimum load. These constraints include the minimum online constraints (MOCs) and new constraints being added as a result of the flexible ramping product and contingency modeling enhancements. Unlike transmission constraints used to determine if energy bid mitigation should be triggered, these other constraints are much more complex and may not be binding when market power may occur.

The ISO market software also includes a variety of unit level operating characteristics and constraints that can cause a unit to be committed on or kept in operation at a particular configuration. The timeframe of some of these constraints (such as minimum operating times) can go beyond the time horizon of the real-time optimization. In many cases, ISO operators also override the market optimization through exceptional dispatches or software scripts. These situations can prevent consideration of start-up and minimum load bid costs submitted for each unit or mitigation of unit-level market power using automated tools and criteria.

If the ISO pursues this type of approach, DMM recommends that the ISO carefully consider all these factors, along with the complexity and reliability of any automated tools and criteria for mitigating start-up and minimum load bids that would need to be developed to implement this approach.

10.8 Scheduling of variable energy resources

Under the new real-time market design implemented in 2014, all variable energy resources are allowed to schedule based on their own forecast of their expected output. DMM recommended that the ISO retain the authority to use its own forecast of the output of a variable energy resource if schedules submitted by these resources appear to be systematically inaccurate and create detrimental market impacts. The ISO included this recommendation in its initial compliance filing for FERC Order No. 764. However, FERC's March 20, 2014, order on this filing required the ISO to either delete the tariff clause granting the ISO this authority or to establish specific criteria for triggering the automatic use of the ISO's forecast for a variable energy resource that has submitted inaccurate forecasts.

In the months following implementation of the 15-minute market, the ISO's forecast was used as the forecast for all variable energy resources. Recently, the forecast submitted by scheduling coordinators has begun to be used for some variable energy resources. However, the ISO has not yet begun to archive the data necessary to compare the accuracy of the scheduling coordinator's forecast with the accuracy of the ISO's load forecast relative to each resource's actual output. DMM recommends that the ISO complete the work necessary to collect the information required to assess the accuracy of scheduling coordinator forecasts.

DMM believes that developing specific criteria for triggering the use of the ISO's forecast may alleviate some reliability concerns related to inaccurate variable energy resource forecasts. However, DMM does not believe this approach will effectively address the potential for variable energy resources to profit from strategically inaccurate forecasts intended to profit from systematic differences between the 15-minute and 5-minute markets.

Therefore, DMM has also recommended that the ISO create a new settlement rule to prevent variable energy resources from profiting from inaccurate forecasts. The rule would calculate the net revenues a resource received from inaccuracies in its 15-minute market forecast over an appropriately long period of time (e.g., several weeks or months). If a resource has positive net revenues from its forecast inaccuracies over this period the ISO should rescind payment of the net revenues.

DMM believes this type of settlement rule is more equitable and beneficial for all participants. This settlement rule would also avoid reliance on subjective determinations of whether forecast errors that are profitable for participants are intentional or not. Without such a settlement rule, the only course of action for the ISO is to rely on DMM to refer cases to FERC under behavioral market rules. FERC would then need to make a determination of whether forecast errors that are profitable for participants are intentional and violate FERC rules prohibiting false information and market manipulation.

10.9 Flexible ramping product

Background

The ISO continues to work on development of a flexible ramping product that would replace the flexible ramping constraint currently incorporated in the real-time market software. The ISO's most recent flexible ramping product proposal discussed in an April 2015 stakeholder call will use a demand curve derived from forecast uncertainty to economically procure both upward and downward flexible capacity in the 15-minute market and the 5-minute real-time dispatch. The most recent proposal also appears to have been modified so that payments for this product would be based on opportunity costs rather than separate bid prices that could be submitted for flexible ramping capacity up to a cap of $250/MW. As noted in our 2013 annual report, DMM has recommended eliminating these bidding provisions because no specific short-term marginal costs have been demonstrated or described that these bids would be used to cover.[179]

Recommendations

Given these modifications, DMM is highly supportive of this most recent proposal as a more effective way of ensuring operational ramping flexibility than the current flexible ramp constraint. However, the current flexible ramping product design would procure capacity to meet five minute ramping uncertainty. Deviations from forecasts can occur over consecutive intervals. Extending the flexible ramping design to capacity products with durations greater than five minutes could better position the markets to respond to increased uncertainty as the grid transitions to a future of increased renewable generation and variable demand.[180] DMM would be supportive of exploring such an extension or policy that meets similar goals. DMM is also supportive of further policy development that could allow the flexible ramping products to be incorporated into the day-ahead market.

[179] *2013 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2013, pp. 252: http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

[180] This is also described in DMM's comments on the Draft Final Proposal: http://www.caiso.com/Documents/DMMComments_FlexibleRampingProduct-DraftFinalProposal.pdf.

10.10 Contingency modeling enhancements

Background

After a real-time transmission or major generation outage, flows on other transmission paths may begin to exceed their *system operating limit*. Under North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards, the ISO is required to return flows on critical transmission paths to their system operating limits (SOL) within 30 minutes when a real-time contingency leads to the system being in an insecure state. Under some conditions, the ISO currently uses exceptional dispatch and minimum online capacity constraints to position resources so that the ISO would have the ability to return critical paths to their operating limits within 30 minutes in the event of such a contingency.

The ISO has proposed an alternative modeling approach aimed at reducing the use of exceptional dispatches and minimum online capacity constraints. The modeling enhancements proposed by the ISO include the modeling of post-contingency preventive-corrective constraints and generation contingencies in the market optimization so the need to position units to meet applicable reliability criteria would be incorporated into the market model.[181] The ISO has noted that incorporating constraints in the market model should reduce exceptional dispatches, replace some minimum online constraints, provide greater compensation through locational marginal clearing prices, and may result in a separate capacity payment for resources (both generation and demand response) that help meet the reliability standards.

Recommendations

DMM is supportive of this initiative. DMM believes one of the main additional benefits of this approach is that it will allow these reliability requirements to be met more efficiently because they will be met by explicit constraints incorporated in the market model. This will allow requirements to be calculated in a more automated manner based on actual system conditions and then met by the least cost mix of resources as determined by the market software optimization.

DMM has worked with the ISO to incorporate these flow-based corrective constraints into the current local market power mitigation process. Completion of this has been deferred pending further analysis of the impacts of this modeling feature based on simulations using the actual ISO software. DMM is supportive of this approach given the complexity of this market feature.

10.11 Forward procurement of flexible capacity

Background

Under current market conditions, additional new gas-fired capacity does not appear to be needed to meet system-level capacity requirements at this time. However, a substantial portion of the state's older gas-fired capacity is located in transmission constrained load pockets and is needed to meet local reliability requirements. Much of this capacity (or other new flexible capacity) may also be needed to

[181] *Contingency Modeling Enhancements Issue Paper*, March 11, 2013, http://www.caiso.com/Documents/IssuePaper-ContingecyModelingEnhancements.pdf.

provide the operational flexibility needed to integrate and back up the large volume of intermittent renewable resources coming online.

Investment necessary to maintain, retrofit or replace this existing capacity could be addressed through long-term bilateral contracting under the CPUC's long-term procurement and resource adequacy proceedings. To date, this process has proven effective at meeting system and local capacity requirements set by the ISO. However, a potential gap exists between the state's current long-term procurement planning and the one-year-ahead timeframe of the state's resource adequacy program. Specifically:

- Until recently, neither of these processes incorporated any specific capacity or operational requirements for the flexible capacity characteristics that will be needed to integrate the large volume of intermittent renewable resources coming online in the next few years. The CPUC has taken the first step toward establishing flexible capacity requirements by establishing non-binding flexible capacity requirements for 2014 and mandatory requirements for 2015.
- The resource adequacy program and the capacity procurement mechanism in the ISO tariff are based on procurement of capacity only one year in advance. This creates a gap between the existing system and the multi-year timeframe over which some units at risk of retirement may need to be kept online to meet future system flexibility or local reliability requirements.

The ISO continues to work with the CPUC, other local regulatory authorities and stakeholders to take a variety of steps to address this issue on a more comprehensive and longer-term basis.

Flexible capacity procurement requirements

In early 2014, the ISO completed a flexible capacity procurement proposal to establish requirements for flexible capacity and set the criteria for counting the amount of flexible capacity that can be provided by different resources toward meeting these requirements. The proposal also gives the ISO the authority to procure additional capacity in the event these requirements are not met by load-serving entities. The FERC conditionally approved this proposal in October 2014.[182]

The current flexible capacity system is widely viewed as an interim solution and will provide the ISO and CPUC with additional experience and time to develop a more comprehensive set of provisions. The current flexible capacity system is also part of an overall package of initiatives designed to ensure procurement and availability of sufficient flexible capacity to meet system needs. Other elements include the following:

- Development of a flexible capacity product and contingency modeling enhancements that may provide additional market revenues to resources that are available and provide flexibility and reliability benefits in real time.
- In 2014, the ISO also developed a new more market-based backstop procurement mechanism, still known as the capacity procurement mechanism, designed to provide a more efficient way of procuring any additional capacity needs and facilitating increased participation by smaller resources and non gas-fired alternatives.

[182] For more information, see: http://www.caiso.com/Documents/Oct16_2014_OrderConditionallyAcceptingTariffRevisions-FRAC-MOO_ER14-2574.pdf.

The ISO and the CPUC continue working toward consideration of multi-year resource adequacy requirements and the incorporation of more detailed flexible capacity needs. Phase 2 of the ISO's reliability services initiative will start in 2015 with a goal of considering more detailed quantification of flexible capacity needs. At the CPUC, the joint reliability plan proceeding has been in the process of addressing flexible capacity needs, the possibility of multi-year forward procurement, and other issues related to the evolving framework of resource adequacy in the state.[183]

Recommendations

DMM is supportive of a multi-year capacity procurement that includes flexible capacity requirements. The current process underway between the ISO and the CPUC provides a process for further defining flexible capacity requirements and incorporating these into the portfolio requirements of the major load-serving entities.

The ISO is developing several short-term products that may provide additional market revenues for resources providing flexibility in real time. These include the flexible ramping product and the contingency modeling enhancements discussed in Sections 10.9 and 10.10. However, it is unclear how often these constraints will be binding and, therefore, whether they will provide significant market revenues. As noted above, DMM has not identified any incremental costs beyond opportunity costs of providing these products and is recommending that the market design not include separate capacity bids for these products until or unless any such costs have been quantified.

DMM does not believe that at this time it is possible to project the level of net revenues any unit may receive in an efficient spot market for flexible capacity and whether this would cover any incremental fixed cost of flexible capacity. However, DMM believes that the marginal costs of providing flexibility may in fact be relatively low, particularly relative to any additional fixed costs necessary to install flexible capacity. Under this scenario, it is entirely likely that efficient spot market prices would not cover these fixed costs – just as efficient competitive spot market energy revenues typically do not cover the fixed costs of new investment in energy capacity. Therefore, DMM believes it is prudent to continue development of a market design that includes provisions to ensure sufficient flexible capacity is built or maintained in advance on the timeline needed to bring new flexible capacity online.

In prior reports and as part of other ISO initiatives, DMM has emphasized two major recommendations relating to this issue:

- **Flexible capacity requirements should be directly linked with operational ramping needs.** As previously noted in this chapter, the ISO is developing a 5-minute flexible ramping product and corrective capacity constraint. The ISO is also developing new model constraints that will result in resources being scheduled and compensated to help ensure sufficient additional capacity is available to respond to contingencies within 30 minutes. Any flexible capacity requirement established for a multi-year forward resource adequacy process or capacity market should ensure that day-to-day market requirements for these resource flexibility needs can be consistently met by the flexible capacity procured.

- **Flexible capacity procurement should be directly linked with a must-offer obligation for operational ramping products.** The ISO tariff should also include must-offer provisions ensuring

[183] For more information on the CPUC's joint reliability plan (JRP) see: http://www.cpuc.ca.gov/PUC/energy/Procurement/The_Joint_Reliability_Plan_Proceeding.htm.

that flexible capacity procured to meet forward requirements are actually made available in the ISO markets to meet operational and market needs. In some cases, market power mitigation or other economic provisions may be appropriate to ensure this capacity can be utilized to meet requirements for ISO market products or operational constraints developed to meet flexibility and reliability needs.

10.12 Reliability services initiative

The reliability services initiative is a two-phase, multi-year effort to address the ISO's rules and processes surrounding resource adequacy resources. The initiative is part of the ISO's overall effort to work with the CPUC to ensure that sufficient resources with the right capabilities are available and offered into the ISO market to meet local, flexible, and system needs.

In early 2015, the ISO completed the first phase of this initiative, which included enhancements to further integrate preferred resources into the grid; a new availability incentive mechanism to encourage greater availability from resource adequacy resources including demand response and use-limited resources; and finally, revisions to resource adequacy outage rules to streamline ISO processes and provide a platform for flexible resource adequacy outage rules.[184]

DMM is supportive of the ISO's proposal under the first phase of this initiative as a step forward toward improving and streamlining resource adequacy requirements and processes to meet the need for increased operational flexibility to integrate new renewable energy resources. DMM has provided recommendations on follow-up actions on two aspects of the ISO's final proposal.

Exemption for use-limited resources

Under the ISO's final proposal, until the ISO completes the work needed to include opportunity cost estimates in start-up and minimum load bids, use-limited resources can exempt themselves from the availability standards by submitting special outages. Therefore, as noted above, DMM continues to urge the ISO to commit the resources necessary to develop and implement the opportunity cost estimation method.

Penalty for non-compliance

The ISO is proposing to set the penalty price for not meeting availability standards at 60 percent of the soft offer cap for the capacity procurement mechanism. As noted in DMM's last annual report and its comments in this stakeholder initiative, if the cost of replacement capacity approaches the soft offer cap, it will be less costly for generating unit owners to pay the penalty rather than provide substitute capacity. DMM believes this scenario could occur precisely when supply conditions are tightest and options for capacity that can be procured bilaterally by participants or by the ISO through the capacity procurement mechanism is most limited and non-competitive.

DMM recommends that the ISO monitor this issue once the new incentive mechanism has been implemented. If the initial level of this penalty appears to be insufficient to incent participants to meet availability standards, the penalty price may need to be raised closer to the soft cap for the backstop

[184] The proposal considered by the ISO Board can be found at: http://www.caiso.com/Documents/DraftFinalProposalAddendum-ReliabilityServices.pdf.

procurement mechanism that the ISO may need to employ to procure additional capacity as the result of any failure to meet availability standards.

10.13 Energy imbalance market

Background

In November 2014, the ISO implemented an energy imbalance market in the two balancing authority areas operated by PacifiCorp with a total of about 10,000 MW of peak load located primarily in Oregon and Utah. NV Energy has also announced plans to participate in the EIM in October 2015 with about 7,500 MW of peak load in Nevada. Puget Sound Energy has also announced plans to enter the EIM in the fall of 2016 with about 2,700 MW of peak load in the state of Washington. Most recently, Arizona Public Service, based in Phoenix, will begin participating in the EIM in late 2016.

DMM worked closely with the ISO and members of its Market Surveillance Committee to ensure that this new market will offer benefits for current participants within the ISO, as well as entities outside the ISO, that will be participating in this new market as sellers or relying on it to meet their imbalance energy needs. DMM supports the general design, which includes numerous features made to protect current ISO market participants from potential uplift costs associated with the energy imbalance market.[185]

Market power mitigation

In 2014, DMM recommended that the ISO consider additional market power mitigation provisions beyond those incorporated in the ISO's draft and final proposals. Specifically, DMM recommended the rules be modified so that bid mitigation tests and procedures would be triggered when congestion occurred into an EIM balancing authority area on an EIM scheduling constraint from the ISO or another EIM balancing area.

In June 2014, DMM completed a study of the potential structural competitiveness of the PacifiCorp balancing areas.[186] The report concluded that based on currently available information, DMM could not conclude that the two PacifiCorp balancing authority areas will be structurally competitive and, therefore, recommended that market power mitigation procedures be applied when scheduling constraints into either of these balancing areas become binding.

Based on this study, the ISO filed to extend market power mitigation so that bid mitigation tests and procedures would be triggered when congestion occurred into the PacifiCorp balancing areas from the ISO or another EIM balancing area. FERC accepted these proposed revisions prior to implementation of the energy imbalance market in November 2014.

[185] Memorandum from Eric Hildebrandt to ISO Board of Governors, re: Market Monitoring Report, October 31, 2013: http://www.caiso.com/Documents/DecisionEnergyImbalanceMarketDesign-DMM%20Memo-Nov2013.pdf.

[186] *Assessment of Potential Market Power in Energy Imbalance Market*, Department of Market Monitoring, Updated June 30, 2014: https://www.caiso.com/Documents/UpdatedAssessment-PotentialMarketPower-EnergyImbalanceMarket_corrected.pdf.

Energy imbalance market performance

Since implementation of the energy imbalance market in the PacifiCorp balancing areas, DMM has collaborated with the ISO to monitor market performance and identify actions that may be taken to improve performance. Analysis and recommendations by DMM concerning the current EIM performance and design are included in special reports being submitted to FERC pursuant to the Commission's December 1, 2014, and March 16, 2015, orders on the ISO's energy imbalance market.

Year one enhancements

DMM has also worked with the ISO and stakeholders to develop a series of key enhancements scheduled for implementation in October 2015 as part of the ISO's initiative on EIM Year 1 Enhancements.

EIM transfer limits constraints

DMM believes the most important element of the ISO's proposal for enhancing the EIM design involves how transfer limit constraints between EIM balancing authority areas will be modeled. The approach proposed by the ISO is designed to maximize the use of transmission rights made available in the EIM on different inter-ties while avoiding any inappropriate impact this has on locational prices within EIM areas. DMM believes this approach can effectively balance these objectives, but recommends that the details of this approach be carefully tested and adjusted as necessary based on market simulation prior to implementation, as described in the ISO's Board memo on this issue.[187]

DMM has closely reviewed the proposed approach for modeling EIM transfer limit constraints based on the level of detail provided in the ISO's final proposal, and submitted a detailed summary of DMM's analysis.[188] Based on this analysis, DMM concurs with the ISO and the Market Surveillance Committee that if the transfer cost used in the market software is set at a relatively low value, the proposed approach should allow the ISO to efficiently make use of EIM transfer capacity while limiting the impact of the transfer cost on locational market prices.

The final proposal outlined by the ISO specifies that the transfer cost used in the market software will be determined by the ISO. If an EIM entity has multiple EIM internal inter-ties, the ISO will consult with the EIM entity to determine the appropriate transfer costs to balance the goals of maximizing use of transmission made available in EIM while minimizing impacts of the transfer cost on prices. This clarification addresses concerns that an EIM entity could be subject to scrutiny by DMM if the transfer cost was set by the EIM entity rather than by the ISO. DMM is prepared to work closely with the ISO and EIM entities to determine the level at which transfer costs should be set based on pre-implementation market simulation results and actual market results after implementation.

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[187] Memorandum from Keith Casey to ISO Board of Governors, re: Decision on EIM year 1 enhancements phase 1, March 19, 2015: http://www.caiso.com/Documents/Decision_EnergyImbalanceMarketYear_1EnhancementsPhase1-Memo-Mar2015-.pdf.

[188] Comments on Energy Imbalance Market Year 1 Enhancements Draft Final Proposal, Department of Market Monitoring, March 17, 2015: http://www.caiso.com/Documents/DMMComments_EnergyImbalanceMarketYear1Enhancements-DraftFinalProposal.pdf.

Greenhouse gas bidding rules

DMM supports proposed changes involving greenhouse gas bidding rules. These changes would implement recommendations made by DMM during the initial EIM design to encourage EIM participation and address stakeholder concerns.[189] FERC's June 19 order on the initial EIM design directed the ISO to include these provisions in the future EIM design.

One detail involved in complying with FERC's June 19 order was the degree of flexibility that will be provided to participants in terms of "flagging" resources' bids that could be deemed delivered to the ISO versus being available only to meet demand within other EIM balancing authority areas not subject to California's cap-and-trade program compliance obligations. The ISO's proposal seeks to provide flexibility by allowing the portion of each resource's bid quantity eligible for delivery to the ISO to vary from hour-to-hour, rather than requiring each resource to "opt in" or "out" of being potentially subject to California's greenhouse gas program on a daily or longer-term basis.

DMM appreciates that this flexibility is being provided in response to requests from some stakeholders and to encourage participation in EIM. Some stakeholders have expressed concerns about the need for this flexibility and requested that DMM review this market design feature for potential gaming or other detrimental market impacts. DMM has reviewed this issue, and, while we see limited value or need for this additional flexibility, we also do not have any significant concerns about potential gaming or other detrimental impacts of this bidding flexibility. Nonetheless, DMM will monitor any bidding behavior that may indicate an attempt to detrimentally affect market outcomes by hourly changes in greenhouse gas bidding.

[189] Memorandum from Eric Hildebrandt to ISO Board of Governors, re: Market Monitoring Report, March 19, 2015, p. 3: http://www.caiso.com/Documents/Department_MarketMonitoringReport-Mar2015.pdf.