2012 ANNUAL REPORT ON MARKET ISSUES & PERFORMANCE

Department of Market Monitoring

California ISO

Shaping a Renewed Future

ACKNOWLEDGEMENT

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Executive summary

The ISO's markets continued to perform efficiently and competitively overall in 2012. Key highlights of market performance noted in this report by the Department of Market Monitoring (DMM) include the following:

- Total wholesale electric costs fell by 2 percent. However, natural gas prices dropped almost 30 percent, so that ISO prices were higher after accounting for lower gas prices. This increase was driven by a combination of higher loads, lower hydro-electric supply, over 2,000 MW of nuclear generation outages and increased congestion.
- Overall prices in the ISO energy markets over the course of 2012 were about equal to what DMM estimates would result under highly competitive conditions. About 97 percent of system load was scheduled in the day-ahead energy market, which continued to be highly efficient and competitive.
- Average real-time prices were driven higher than day-ahead market prices during some periods by relatively infrequent but high price spikes. Real-time prices spiked over $250/MWh in about 1 percent of 5-minute intervals, with many of these spikes being driven by congestion.

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

- The ISO implemented new automated local market power mitigation procedures in the day-ahead and real-time software that mitigated local market power very effectively and accurately. This helped keep prices at competitive levels during most peak summer load periods.
- Ancillary service costs totaled $84 million, or about 1 percent of total energy costs compared to about 2 percent in 2011. This decrease was partly driven by the decrease in natural gas prices and increased use of limited hydro supplies to provide spinning reserves rather than energy.
- Bid cost recovery payments totaled $104 million, or about 1.3 percent of total energy costs in 2012, compared to 1.5 percent in 2011. About half of these payments resulted from units committed to operate to meet special capacity related reliability requirements.
- 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, increased from 2011 but remained relatively low. Energy from exceptional dispatches totaled about 0.53 percent of total system energy in 2012 compared to 0.40 percent in 2011.
- Although the volume of energy from exceptional dispatches increased, the above-market costs resulting from these dispatches decreased from $43 million in 2011 to $34 million in 2012. These costs decreased because more of these exceptional dispatches were made to manage congestion on uncompetitive constraints and were therefore subject to local market power provisions in the ISO tariff.

Congestion increased significantly in 2012, largely as the result of new reliability constraints incorporated in the market models and outages of the San Onofre Nuclear Generating Station (SONGS) units. This congestion impacted market performance in numerous ways:

- Congestion within the ISO system resulted in an increase in price divergence between overall locational market prices in the day-ahead, hour-ahead and real-time markets. Real-time congestion was typically higher than in the day-ahead market as a result of reductions in transmission constraint limits made in response to power flows observed in real-time.
- Congestion also drove real-time market revenue imbalance charges allocated to load-serving entities higher. These charges increased from $28 million in 2011 to $186 million in 2012, or about 2 percent of total wholesale costs.
- Convergence (or virtual) bidding inflated these real-time congestion imbalances by increasing the volume of transactions settled at higher real-time congestion prices.
- Almost all of the $56 million in net profits received by virtual bidders resulted from divergences of day-ahead and real-time congestion associated with changes in reductions in transmission flow limits after the day-ahead market. In 2011, most profits received by virtual bidders resulted from divergence in system energy prices between the day-ahead, hour-ahead and real-time markets.

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

- About 700 MW of peak generating capacity from renewable generation was added in 2012. Energy from wind and solar resources directly connected to the ISO grid provided slightly more than 5 percent of system energy, compared to 3.9 percent in 2011.
- Energy from new wind and solar resources is expected to increase at a much higher 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 intermittent energy efficiently and reliably.
- Over 1,300 MW of new gas-fired generation was added in 2012. However, the estimated net operating revenues for typical new gas-fired generation – excluding revenues from resource adequacy contracts or other bilateral contracts – remained substantially below the annualized fixed cost of new generation.

Net operating revenues for many – if not most – older existing gas-fired generation 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.

The state's resource adequacy program continued to work well as a short-term capacity procurement mechanism. However, it has become increasingly apparent that the state's current one-year ahead resource adequacy process is not sufficient to ensure that sufficient flexible generation will be kept online over the next few years to reliably integrate the increased amount of intermittent renewable energy coming online.

The ISO and the California Public Utilities Commission (CPUC) continued to address these resource adequacy issues through several initiatives in 2012. One initiative involves development of specific requirements for flexible generating capacity needed to integrate increasing amounts of intermittent renewable generation into the ISO system. The ISO and CPUC are also collaborating on a process and discussions that could lead to incorporation of these flexibility requirements into a multi-year ahead resource adequacy process or centralized capacity market.

DMM is highly supportive of these initiatives as ways of increasing the efficiency of the state's capacity procurement process and addressing these key gaps in the state's current market design. Three key recommendations provided by DMM on these capacity procurement initiatives are highlighted below.

- Flexible capacity requirements incorporated in the longer term procurement process should ensure that sufficient flexible capacity is procured to meet the ISO's different market and operational needs. This includes needs being addressed though the 5-minute flexible ramping product and 30-minute contingency response constraint being developed by the ISO. Flexible capacity requirements used in long-term procurement should be directly based on the ISO's projected market requirements for these different dimensions of resource flexibility.
- ISO rules should include must-offer and market power mitigation provisions ensuring that flexible capacity procured several years in advance is available and can be effectively utilized to meet the ISO's day-to-day market or operational requirements. These tariff provisions should explicitly include future market requirements for the flexible ramping product and 30-minute contingency response constraint being developed by the ISO.
- A well-designed centralized capacity market may offer several advantages compared to continued reliance on the state's resource adequacy program. A capacity market may provide a more reliable and efficient mechanism for procuring portfolios of resources that cover the different attributes of flexibility needed to meet the ISO's market and operational needs, and may be more efficient and easier to coordinate in a centralized market. A capacity market may also provide a more efficient mechanism to encourage demand response and other options for meeting local reliability requirements in transmission constrained areas, in which a large portion of existing gas-fired capacity must be replaced or retrofitted to meet the state's restrictions on once-through-cooling.

Total wholesale market costs

Total estimated wholesale costs of serving load in 2012 were $8.4 billion or just under $36/MWh. This represents a decrease of about 2 percent per megawatt-hour from a cost of over $36/MWh in 2011.

While electricity prices decreased slightly, natural gas prices decreased almost 30 percent in 2012.[1] Much of this decrease occurred in the first half of the year. After accounting for lower gas prices, DMM estimates that total wholesale energy costs increased from $33/MWh in 2011 to over $42/MWh in 2012, representing an increase of over 28 percent in gas-normalized prices.[2]

[1] 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.

[2] Gas prices are normalized to 2009 prices.

A variety of factors contributed to the increase in gas-normalized total wholesale costs in 2012. As highlighted in this report, major factors that contributed to higher prices include:

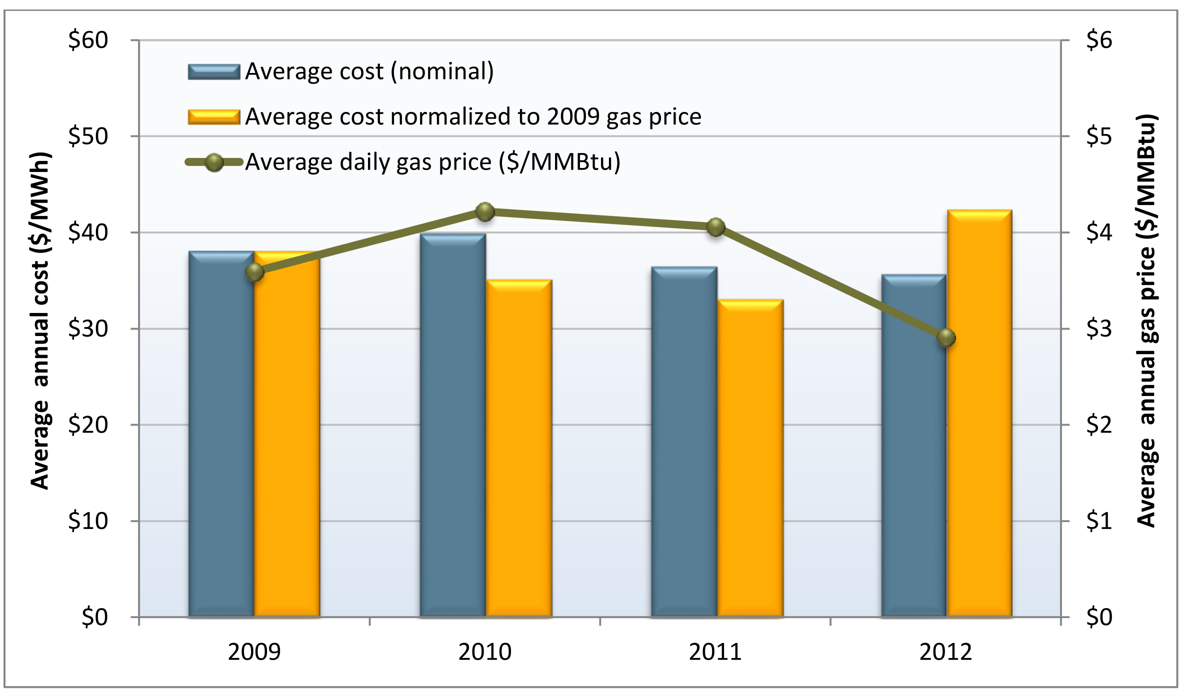
- higher average and peak summer loads;
- lower in-state hydro-electric generation;
- outages of over 2,000 MW of nuclear generation; and
- increased congestion within the ISO.

In addition to lower natural gas prices, several other factors helped keep prices lower. These include:

- increased imports from the Southwest and the Northwest;
- additions of over 2,000 MW of new generation capacity;
- high day-ahead scheduling relative to actual loads; and
- more effective mitigation of local market power during high load periods.

Figure E.1 shows total estimated wholesale costs per MWh from 2009 to 2012. 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 represents the annual average natural gas price and shows the correlation between the cost of natural gas and the total wholesale costs.

Figure E.1 Total annual wholesale costs per MWh of load (2009-2012)



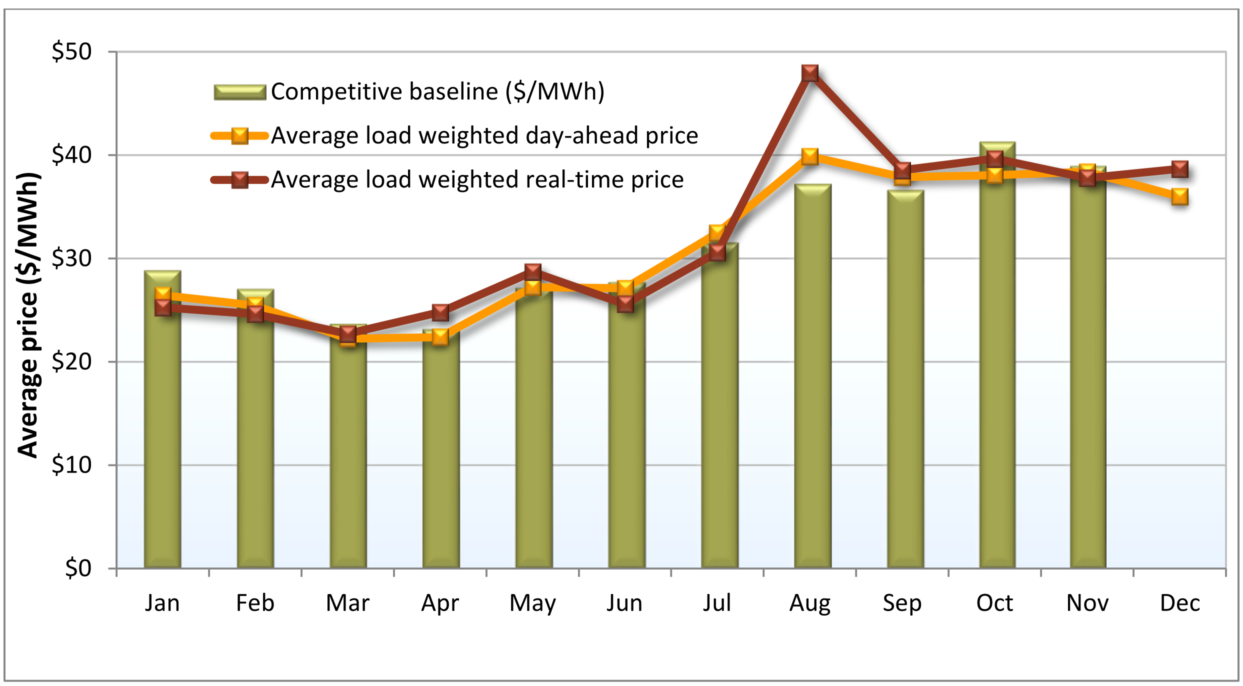
Market competitiveness

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 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, but exceeded this baseline price by about 7 percent in the peak load month of August. High prices in August were driven by high congestion on constraints in Southern California, along with peak loads and uncompetitive bidding by some market participants. Under these conditions, high prices can result since a limited set of resources are available to resolve transmission conditions.

In the real-time market, average system-wide prices were lower than the competitive baseline in 2012 in most months except for April, May, August and September. In the peak month of August, high real-time prices were driven by congestion impacting Southern California prices related to peak loads, unscheduled flows and wildfires. In the real-time market, congestion typically causes prices to rise more sharply than in the day-ahead market because there is a much more limited set of resources available to resolve the transmission conditions.

Figure E.2 Comparison of competitive baseline with day-ahead and real-time prices[3]



[3] DMM was unable to rerun most save cases in December due to software system limitations.

As discussed in sections of this report on market power mitigation, new local market power bid mitigation procedures implemented in 2012 helped keep prices competitive by very effectively mitigating the exercise of local market power. In August, the ISO also gained approval from the Federal Energy Regulatory Commission (FERC) to expand market power mitigation provisions applicable to exceptional dispatches issued to units needed to meet special reliability requirements not incorporated in the real-time market model.[4] This expansion of mitigation for exceptional dispatches further deters uncompetitive bidding in the day-ahead and real-time energy markets by units frequently needed to meet these special reliability requirements.[5]

Energy market prices

System energy prices were lower in the first half of the year and rose notably during the second half of the year. This is primarily attributable to the increase in natural gas prices during the year. Higher loads and lower hydro supplies also contributed to higher prices in the last half of the year. Figure E.3 and Figure E.4 show average quarterly system energy prices in the three energy markets for peak and off-peak hours, respectively.[6] Except for peak hours in the second quarter, differences in average day-ahead and real-time prices in 2012 were low, indicating an improvement in system energy price convergence compared to 2011. Average prices in the hour-ahead market continued to diverge from day-ahead and real-time prices for sustained periods in 2012.

One of the key factors driving divergence between average prices in the ISO's different energy markets has been the occurrence of relatively infrequent but extremely high real-time price spikes. Figure E.5 shows the frequency of different levels of price spikes in aggregate load area prices by quarter, over the past two years. The frequency of real-time price spikes has been similar over the last two years, with about 1 percent of real-time prices exceeding $250/MWh. In the fourth quarter of 2012, the frequency of price spikes remained high, but the level of these prices decreased.

While system energy price convergence improved between day-ahead and real-time prices in 2012, congestion increased significantly. This resulted in a continued divergence in the total locational marginal prices between the day-ahead, hour-ahead and real-time markets. Almost all profits received by convergence bidding positions in 2012 were associated with congestion. In 2011, almost all profits received by virtual bidders resulted from divergence in system energy prices.

[4] See "Exceptional Dispatch and Residual Imbalance Energy Mitigation Tariff Amendment" in FERC Docket No. ER12-2539-000, August 28, 2012, at: http://www.caiso.com/Documents/August282012ExceptionalDispatch-ResidualImbalanceEnergyMitigationTariffAmendment-DocketNoER12-2539-000.pdf.

[5] Additional discussion of this issue is provided in Section 6.3.2 of this report.

[6] In previous reports, DMM used the Pacific Gas and Electric area price to highlight price trends. However, since congestion increased in 2012, DMM has switched its price analysis to the system marginal energy price, which is not affected by congestion or losses.

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

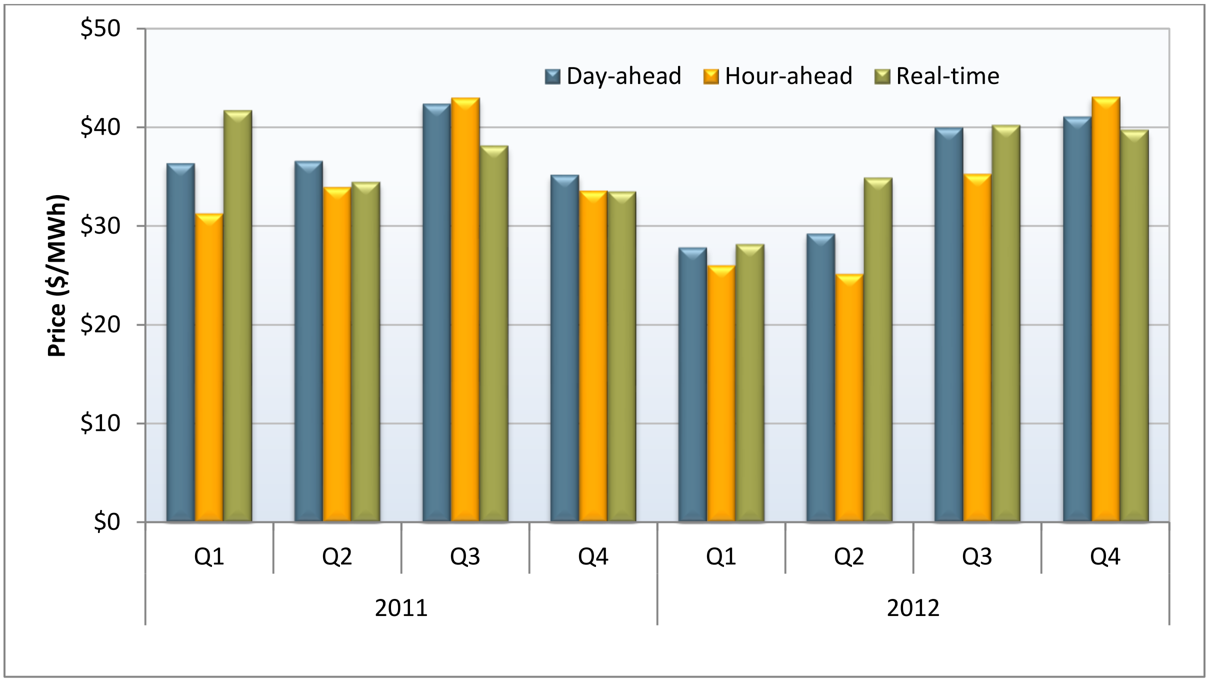


Figure E.4 Comparison of system energy prices (off-peak hours)

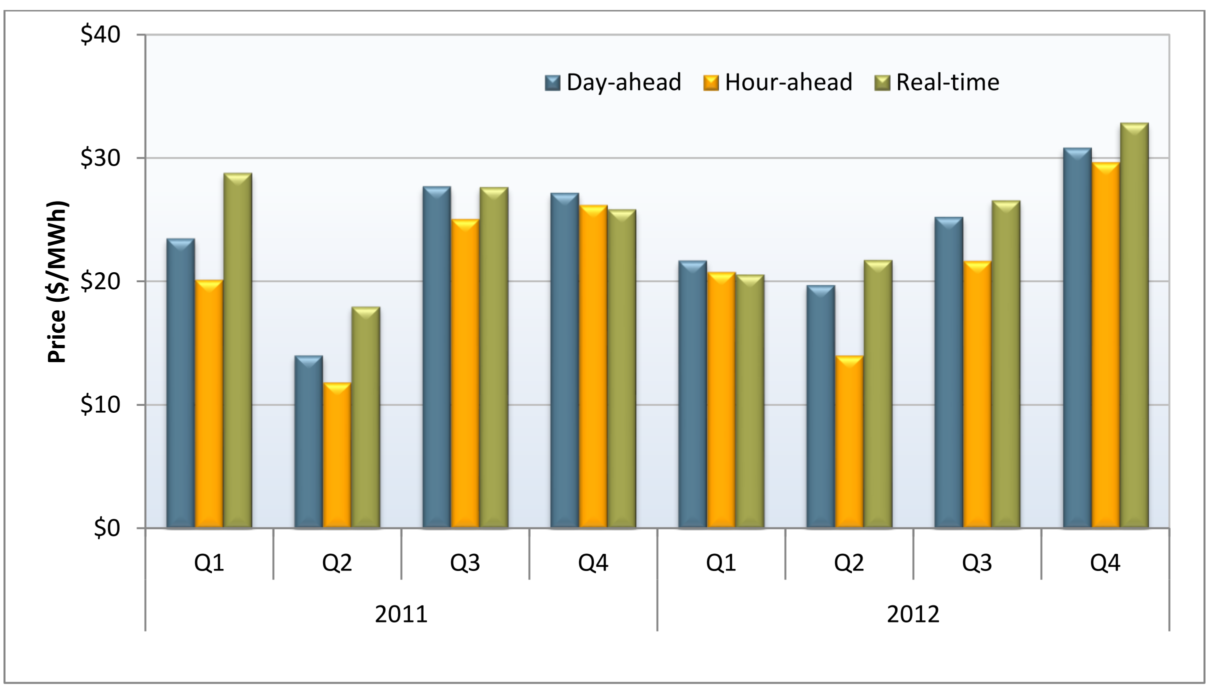
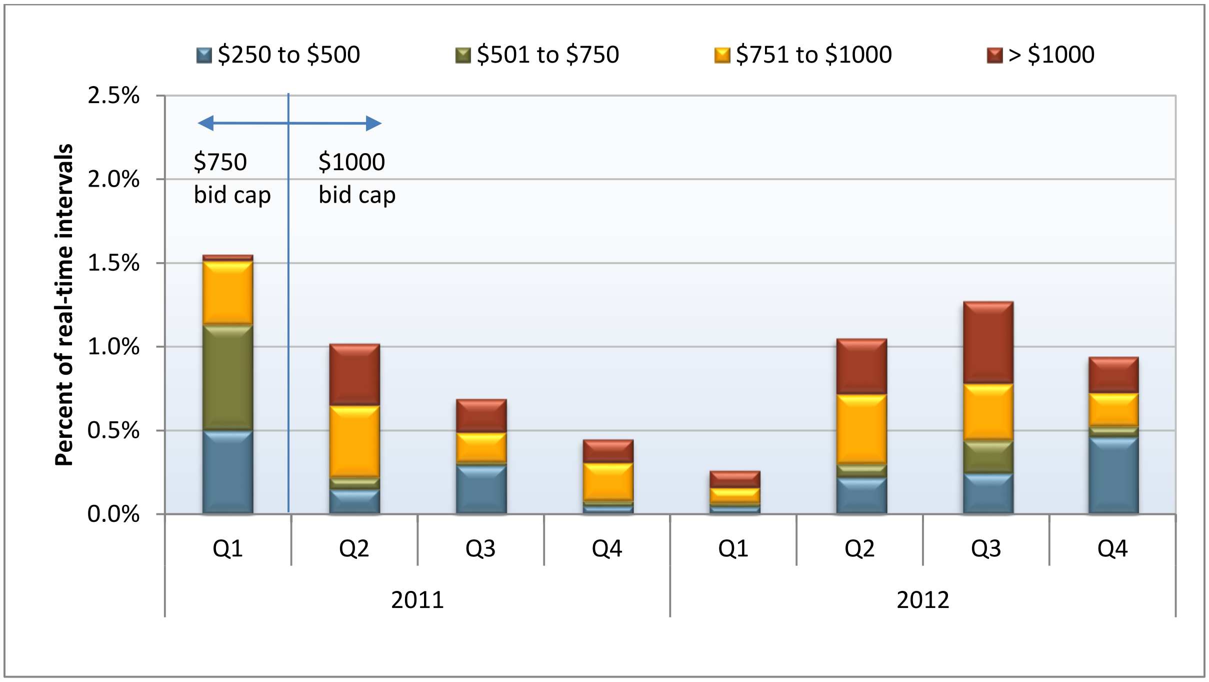


Figure E.5 Price spike frequency by quarter



Convergence bidding

Virtual bidding is a part of the FERC 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*. The ISO implemented convergence bidding in the day-ahead market on February 1, 2011. Virtual bidding on inter-ties was suspended on November 28, 2011.[7] Thus, 2012 represents a full year with virtual bidding within the ISO system but not at the inter-ties.

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 against average price differences in the two following circumstances:

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

Total net revenues paid to entities engaging in convergence bidding totaled over $56 million in 2012. Most of these net revenues resulted from offsetting virtual demand and supply bids placed by participants at different internal locations that are designed to profit from higher congestion between these locations in real-time.

This type of offsetting internal supply and demand bids placed by the same participant represented over 55 percent of all accepted virtual bids in 2012, up from 35 percent in 2011. The increase in both the

[7] See 137 FERC ¶ 61,157 (2011) accepting and temporarily suspending convergence bidding at the inter-ties subject to the outcome of a technical conference and a further commission order. More information can also be found under FERC docket number ER11-4580-000.

quantity and net revenues of offsetting internal virtual bids likely stems from the increased differences in congestion between the day-ahead and real-time markets in 2012. Frequently, these offsetting bids were placed at points that increased market flows on transmission paths which had limits reduced in real-time relative to the day-ahead market. As a result, these virtual bids substantially contributed to increasing real-time congestion revenue imbalance paid by load-serving entities.

DMM's analysis indicates that most convergence bidding activity was conducted by entities engaging in pure financial trading that do not serve load or transact physical supply. These entities accounted for almost $50 million (90 percent) of the total net profits received by virtual bidders in 2012. Table E.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.

For this analysis, DMM has defined financial entities as participants who control no physical power, do not serve any load, and participate in only the convergence bidding and congestion revenue rights markets. Entities included in the physical generation and physical load categories 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 either physical or purely financial participation in the ISO market.

As shown in Table E.1, financial participants represent the largest segment of the virtual market, accounting for about 64 percent of volumes and about 90 percent of net revenues. Marketers represent about 30 percent of the trading volumes and 11 percent of the net revenues. Generation owners and load-serving entities represent a small segment of the virtual market both in terms of volumes and in terms of net revenues (less than 5 percent).

Table E.1 Convergence bidding volumes and revenues by participant type (2012)

Trading entities	Average hourly megawatts			Revenues ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	1,049	757	1,807	31.2	18.7	49.9
Marketer	467	374	841	6.8	-0.3	6.5
Physical Generation	61	70	131	1.8	0.0	1.8
Physical Load	8	36	45	-1.1	-0.5	-1.6
Total	**1,586**	**1,238**	**2,823**	**38.7**	**17.8**	**56.5**

Local market power mitigation

In April 2012, the ISO implemented a new method for mitigating local market power in the day-ahead and real-time markets. These new market power mitigation procedures were put to the test under challenging market and system conditions in 2012.

During the summer months, the potential for the exercise of local market power in Southern California increased substantially due to relatively tight supply and demand conditions, frequent congestion and an increase in the portion of capacity offered at uncompetitively high bid prices. The new mitigation procedures limited local market power effectively and accurately. Four specific indicators of the effectiveness of the performance of these new procedures are discussed below.

The new mitigation procedures helped keep prices significantly lower in high load hours, when the potential for local market power was highest. During the highest load days of the summer months, mitigation was frequently triggered by congestion into the Southern California Edison and San Diego Gas & Electric areas. When mitigation was triggered in the SCE area, average peak hour prices remained below $100/MWh or about 10 to 35 percent less than would have resulted without mitigation.

The new mitigation procedures resulted in more accurate projection of congestion in the day-ahead market. This is important since mitigation is triggered only when congestion is projected to occur in this pre-market process. This new method predicted congestion in the day-ahead market with over 90 percent accuracy, compared to 45 percent under the previous method. This improvement reflects the fact that these new pre-market procedures incorporate all bids used in the day-ahead market, including convergence (or virtual) supply and demand bids.

These new procedures also resulted in more accurate classification of non-competitive constraints. Under the ISO's prior mitigation approach, the structural competitiveness of transmission constraints was assessed based on planning studies done months in advance and many constraints were not eligible to be deemed competitive. With the new method, this assessment is performed automatically by the market software based on actual system and market conditions. Using this approach, the accuracy with which constraints are classified as either competitive or uncompetitive has increased from about 30 percent to 90 percent.

The new mitigation approach essentially eliminates unnecessary mitigation, or bid mitigation when structural local power market does not exist. The new mitigation approach applies bid mitigation only to resources that can directly relieve congestion on a constraint found to be non-competitive. As noted above, the new pre-market mitigation procedures identify very accurately when congestion would occur and when transmission constraints were uncompetitive under actual market conditions. Thus, the new method has almost completely eliminated the triggering of bid mitigation when the potential for local market power does not exist.

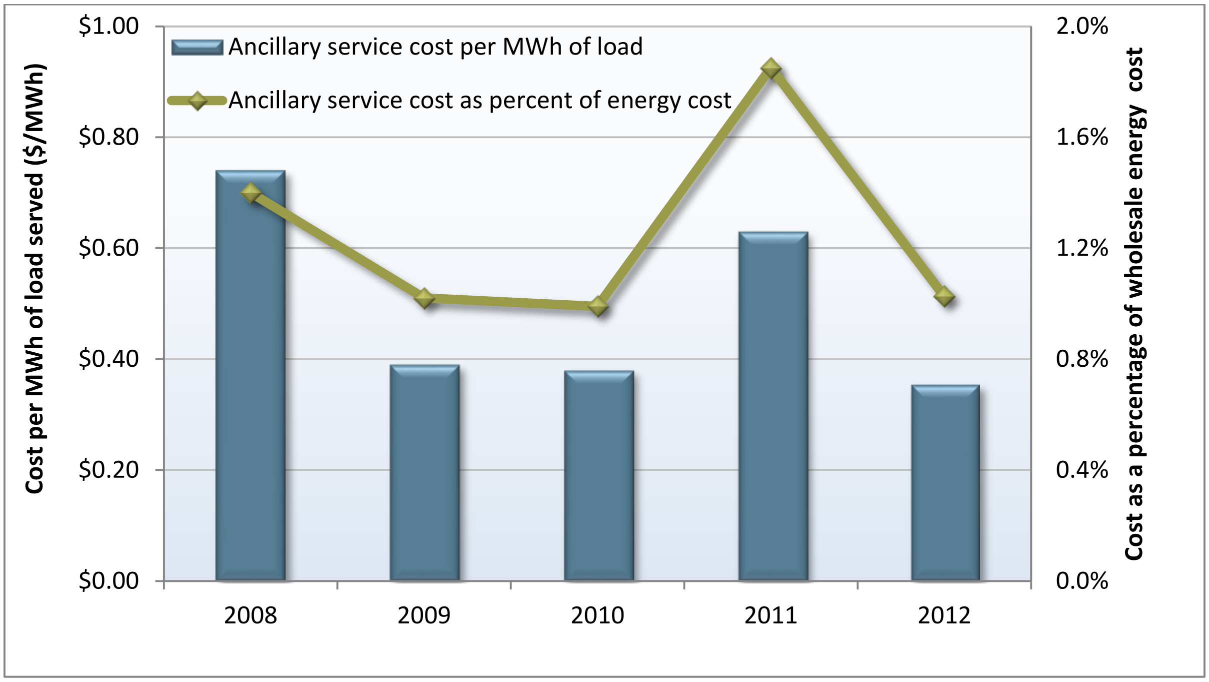
As discussed in other sections of this report, local market power provisions applicable to exceptional dispatches were also highly effective in mitigating local market power by resources needed to meet special non-modeled reliability requirements.

Ancillary services

Ancillary service costs totaled about $84 million in 2012, representing a 40 percent decrease from 2011. Ancillary service prices were lower in 2012, driving the decrease in overall cost. This price decrease is likely due to relatively low natural gas costs and an increase in the provision of spinning reserves from hydro-electric generators, compared to 2011.

As shown in Figure E.6, ancillary service costs decreased to $0.36/MWh of load in 2012 from $0.63/MWh in 2011. This represents a decrease in ancillary service costs to about 1 percent of total energy costs in 2012 from 1.9 percent of total energy cost in 2011.

Figure E.6 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.

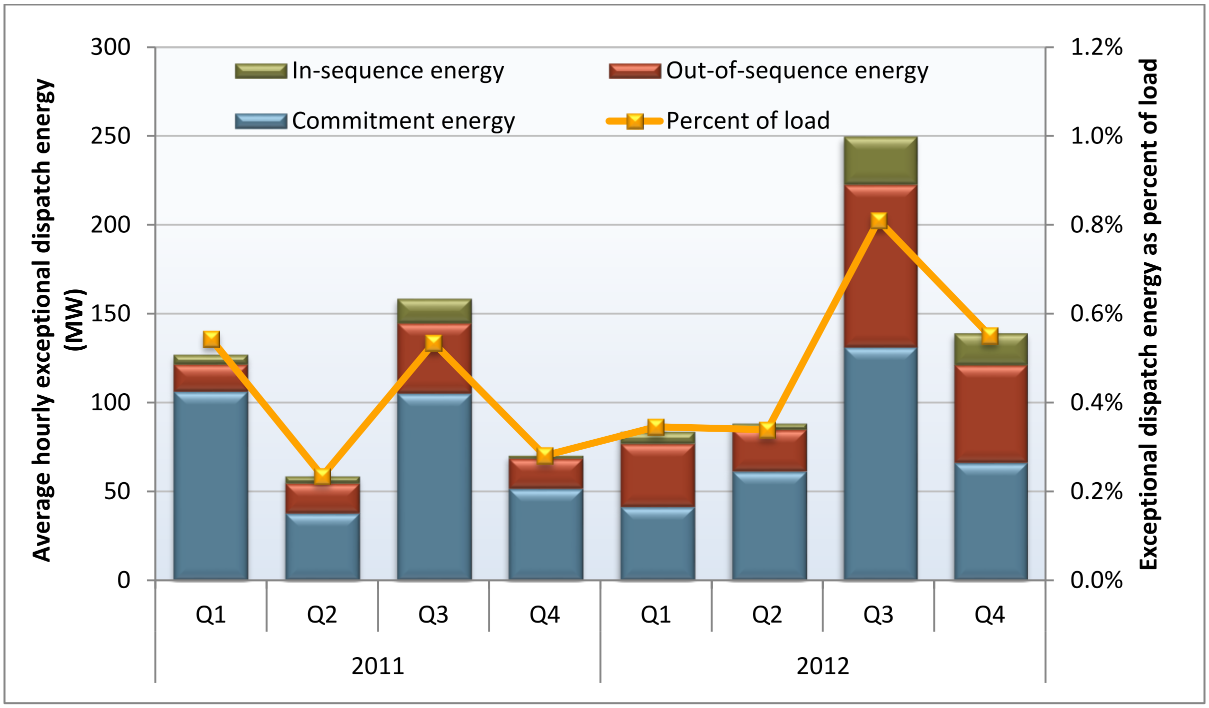
Total energy from all exceptional dispatches increased in 2012, rising from 0.40 percent in 2011 to 0.53 percent of system load in 2012. The following is shown in Figure E.7:

- Minimum load energy from units committed through exceptional dispatches averaged about 75 MW per hour in both 2012 and 2011. This represents about 55 percent of energy from exceptional dispatches in 2012.
- Exceptional dispatches resulting in out-of-sequence real-time energy with bid prices higher than the market prices accounted for an average of about 52 MW per hour in 2012, up from 22 MW in 2011. This increase was primarily the result of more exceptional dispatches made to position units at a level where they could provide more upward ramping capacity.
- About 20 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.

Although energy from exceptional dispatches increased, the above-market costs of all exceptional dispatches decreased from $43 million in 2011 to $34 million in 2012. This decrease in costs reflects the fact that a much larger portion of exceptional dispatch energy in 2012 was to manage congestion for non-competitive constraints and therefore subject to local market power mitigation provisions.

As discussed in Chapter 6, these mitigation provisions mitigated about $227 million of costs that would have otherwise resulted from the need to dispatch extremely high priced bids in the real-time market to meet special reliability requirements not incorporated in the market software. As noted in Chapter 10, the ISO has an initiative underway to incorporate these requirements in the market software and provide compensation for resources helping to meet these requirements.

Figure E.7 Average hourly energy from exceptional dispatches



Out-of-market costs

There are multiple forms of out-of market costs incurred in the ISO markets, which 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*. While some of these costs are incurred for reliability purposes, some of these costs have been the result of inappropriate participant behavior or inconsistencies between the day-ahead and real-time market models. 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

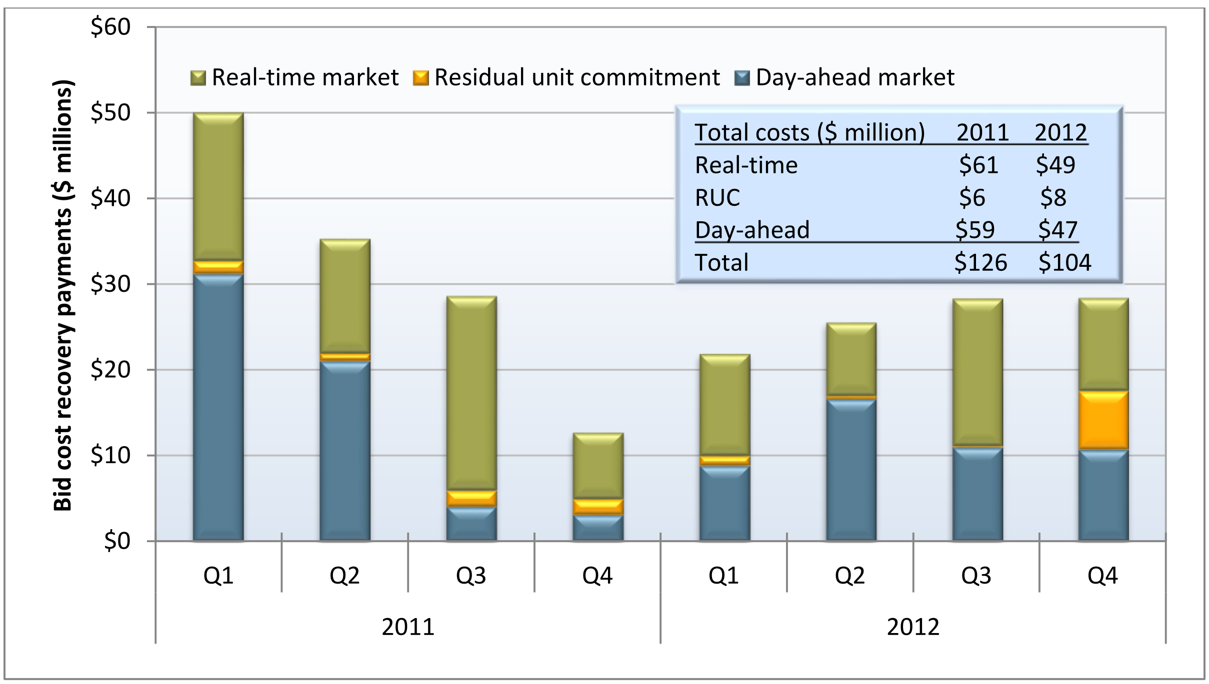
Generating units are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all the unit's accepted bids. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch. However, as described below, a large portion of bid cost recovery payments in 2012 were incurred in order to meet special reliability issues that require having units on-line and ready to ramp up in the event of a contingency.

Figure E.8 provides a summary of total estimated bid cost recovery payments in 2012. These payments totaled around $104 million or about 1.2 percent of total energy costs. This compares to a total of $126 million or about 1.5 percent of total energy costs in 2011, or a decrease of about 17 percent from 2011.

DMM estimates that units committed due to minimum online constraints incorporated in the day-ahead energy market to meet special capacity-based reliability requirements accounted for $22 million or over 20 percent of total bid cost recovery payments in 2012.

Approximately $26 million or about 25 percent of the real-time bid cost recovery payments in 2012 stemmed from units committed through exceptional dispatches to meet other special capacity-based reliability requirements.

Figure E.8 Bid cost recovery payments



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 hour-ahead and 5-minute market prices.

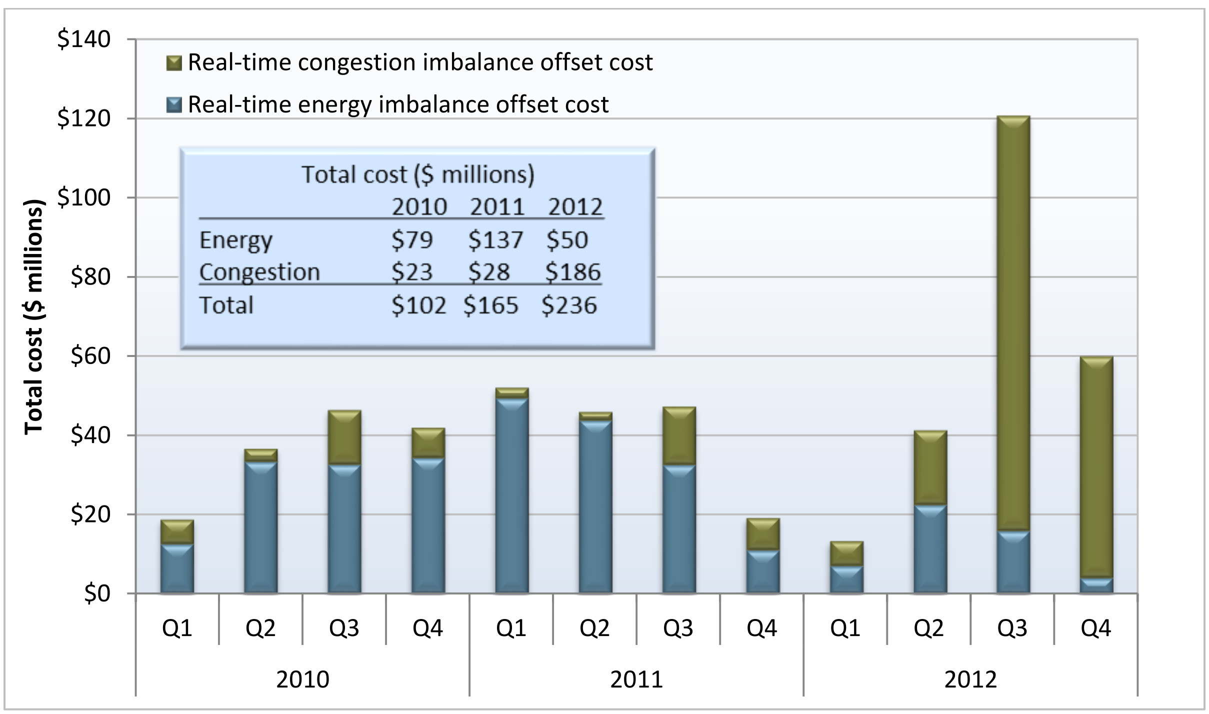
The charge is allocated as an uplift to load-serving entities and exporters based on measured system demand.

The real-time imbalance offset charge consists of two components. Any revenue imbalance from the energy and loss components of hour-ahead and 5-minut 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).

Total real-time imbalance costs for energy and congestion were about $236 million in 2012, compared to $165 million in 2011. As shown in Figure E.9 this was primarily attributable to increases in the real-time congestion imbalance offset costs, which rose from $28 million to $186 million. This increase was driven primarily by high real-time congestion prices on constraints whose flow limits were reduced after the day-ahead market. In most cases, these limits were reduced to account for unscheduled flows observed in real-time. In Chapter 3 of this report, DMM describes a method that might be used as a framework for allocating these revenue imbalances more equitably.

Real-time imbalance energy offset costs decreased from $137 million in 2011 to $50 million in 2012, the lowest yearly value since the nodal market began in 2009. The decrease in real-time imbalance energy costs in 2012 was primarily driven by the suspension of virtual bidding on inter-ties in December 2011.

Figure E.9 Real-time imbalance offset costs



Total cost ($ millions)

	2010	2011	2012
Energy	$79	$137	$50
Congestion	$23	$28	$186
Total	$102	$165	$236

Real-time exceptional dispatch costs

Real-time exceptional dispatch costs, also known as out-of-sequence costs, decreased from just under $12 million in 2011 to around $8 million in 2012. Although the amount of exceptional dispatch energy increased in 2012, the above-market cost of this energy decreased because a larger portion resulted from dispatches to manage congestion on uncompetitive constraints and was therefore subject to mitigation.

In August, the ISO also amended its tariff to expand mitigation of payments for exceptional dispatches to include all real-time exceptional dispatches needed to ensure that a resource is operating at its minimum dispatchable level.[8] As previously noted, these mitigation provisions avoided about $227 million in above-market costs that would have otherwise been incurred as a result of the need to dispatch extremely high priced bids in the real-time market to meet special non-modeled reliability requirements.

Other reliability costs

Other reliability costs include reliability must-run and capacity procurement mechanism costs. 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 reduced notably in 2011 and 2012, compared to the previous years. These costs totaled around $7 million and $6 million in 2011 and 2012, respectively.

However, while reliability must-run payments remained low, capacity payments related to the capacity procurement mechanism increased. The increase in the capacity procurement mechanism payments in 2012 were directly related to the outages of San Onofre Nuclear Generating Station units 2 and 3, which were offline for almost all of 2012 due to a combination of planned and forced outages as well as for testing of critical systems.

These combined outages created local reliability concerns. In response to the SONGS outages, the ISO used its capacity procurement mechanism to procure a total capacity of 966 MW at a cost of about $26 million in 2012. In 2011, capacity procurement mechanism payments totaled around $1.5 million.

Resource adequacy

The ISO tariff'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 2012 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 91 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.

[8] See "Exceptional Dispatch and Residual Imbalance Energy Mitigation Tariff Amendment" in FERC Docket No. ER12-2539-000, August 28, 2012, at http://www.caiso.com/Documents/August282012ExceptionalDispatch-ResidualImbalanceEnergyMitigationTariffAmendment-DocketNoER12-2539-000.pdf.

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 2012 was mostly sufficient to meet system-wide and local area reliability requirements. However, because of the two SONGS unit outages and potential local contingencies in certain areas, the ISO increased reliance on meeting local reliability requirements through the ISO capacity procurement mechanism provisions.

However, it has become increasingly apparent that the state's current one-year ahead resource adequacy process is not sufficient to ensure that sufficient flexible generation will be kept online over the next few years to reliably integrate the increased amount of intermittent wind and solar energy coming online. This issue is discussed further in the following section and in the sections in this report summarizing DMM's recommendations.

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.

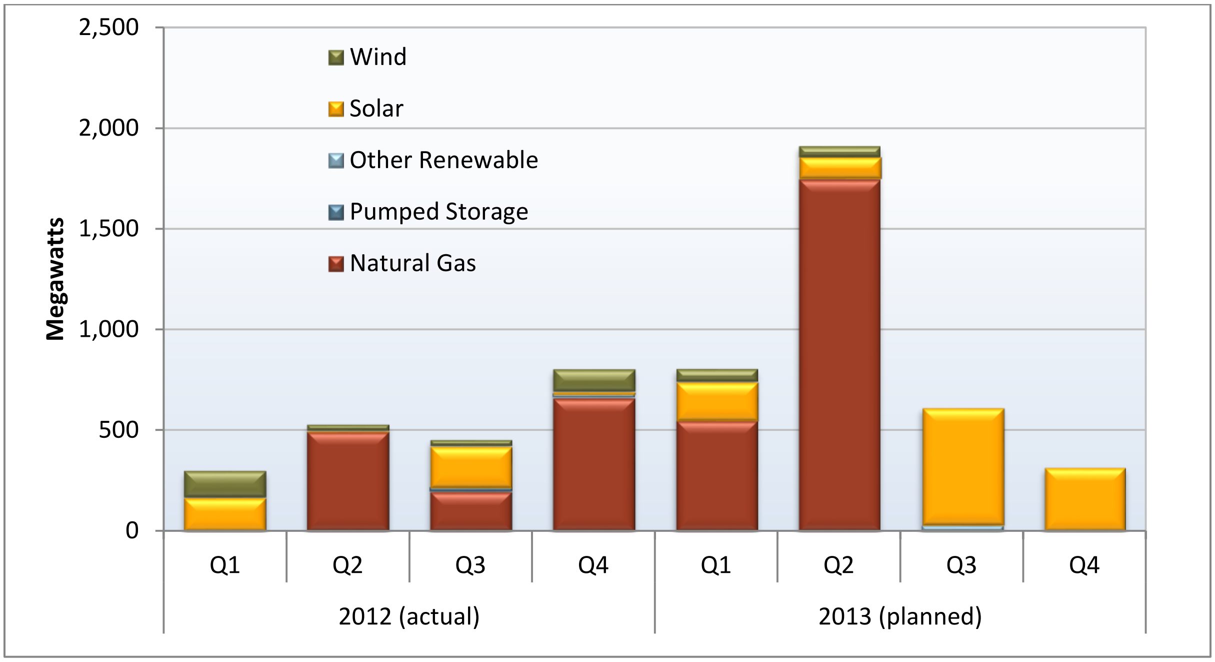
Figure E.10 summarizes the quarterly trends in summer capacity additions in 2012 and planned additions in 2013. Over 3,000 MW of new nameplate generation began commercial operation within the ISO system in 2012, contributing to over 2,000 MW of additional summer capacity. This included over 1,300 MW of new gas-fired capacity and about 2,000 MW of nameplate renewable generation, which added about 700 MW of summer capacity.

In the coming years, the ISO anticipates construction of several thousand megawatts of new nameplate renewable generation to meet the state's 33 percent renewable goals. While over 1,300 MW of gas generation came online in 2012 and over 2,000 MW is anticipated in 2013, much of the generation expected going forward will be renewable. As more renewable generation comes online, the ISO has highlighted the need to backup and balance renewable generation with the flexibility of conventional generation resources to maintain reliability.[9]

Under the California ISO's market design, annual fixed costs for existing and new units critical for meeting reliability needs can be recovered through a combination of long-term bilateral contracts and spot market revenues. Each year DMM analyzes the extent to which revenues from the spot markets 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.

[9] More information on renewable integration can be found here: http://www.caiso.com/informed/Pages/StakeholderProcesses/IntegrationRenewableResources.aspx.

Figure E.10 Generation additions by resource type (summer peak capacity)



Results of this analysis using 2012 prices for gas and electricity show a decrease in net operating revenues for hypothetical new gas units compared to 2010. The 2012 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 2012 are estimated to be about $38/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. 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 to eliminate use of once-through cooling technology over the next decade.

For many existing resources, net operating revenues may not even cover the unit's going forward fixed costs. This capacity is increasingly uneconomic to keep available or retrofit without some form of capacity payment. This highlights several key limitations of the state's current long-term procurement planning and resource adequacy programs.

- Neither of these processes incorporates any specific capacity or operational requirements for the flexible capacity characteristics that will be needed from a large portion of gas-fired resources to integrate the large volume of intermittent renewable resources coming online in the next few years.
- 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 these

procurement mechanisms 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.

In 2012, the ISO completed a stakeholder process to develop an interim mechanism in the ISO tariff to ensure the ISO has sufficient backstop procurement authority to procure any capacity at risk of retirement not contracted under the resource adequacy program that the ISO identifies as needed up to five years in the future to maintain system flexibility or local reliability. However, in early 2013, FERC rejected the ISO's tariff filing to establish this backstop procurement authority.[10]

The ISO is also taking the following steps to address this issue on a more comprehensive and longer-term basis:

- Working with the CPUC and stakeholders to integrate requirements for new categories of flexible resource characteristics into the current resource adequacy program.[11]
- Proposing that the CPUC establish a multi-year resource adequacy requirement, including flexibility requirements, in the next resource adequacy proceeding that would establish resource adequacy requirements starting in 2014.

DMM's comments and recommendation on this issue are summarized in the following section.

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.

Re-design of the real-time market

The ISO is proposing major changes to its real-time market as part of its effort to comply with FERC Order No. 764, which requires all balancing areas to offer 15-minute scheduling on transactions between balancing areas. The ISO's proposed changes are designed to better integrate the process for dispatching and settling transactions between the ISO and other balancing areas with the 5-minute process used to dispatch and settle resources within the ISO.

DMM worked closely with the ISO and stakeholders in developing these market design changes, which include several key modifications made to address concerns identified by DMM. We are very supportive of the final proposal and believe it represents a major improvement over the current market structure. DMM's more specific comments on these proposed design changes include the following:

- The proposed changes should significantly reduce revenue imbalances allocated to load through real-time imbalance offset charges by decreasing the difference in prices used to settle inter-tie transactions and 5-minute prices currently used to settle energy from resources within the ISO. However, as discussed in Chapter 3, DMM cautions that large real-time revenue imbalances could

[10] For further details see *Flexible Capacity Procurement Market and Infrastructure Policy Straw Proposal*, March 7, 2012: http://www.caiso.com/Documents/StrawProposal-FlexibleCapacityProcurement.pdf.

[11] For further details see the Flexible Capacity Procurement stakeholder process site: http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleCapacityProcurement.aspx.

still occur if transmission limits are adjusted downward after the day-ahead market to account for unscheduled flows and congestion.

- Under the ISO's proposal, bid cost recovery will not be paid if these 15-minute prices fail to cover the bid price of fixed hourly transactions. DMM supports this approach because it creates appropriate price signals that more closely reflect the value of fixed hourly-block resources and provide an incentive to transition to providing 15-minute scheduling flexibility.
- The ISO is proposing to re-implement virtual bidding on inter-ties in conjunction with these market design changes. DMM cautions that virtual bidding on inter-ties could inflate real-time revenue imbalances in the event that constraint limits need to be adjusted downward in the 15-minute process to account for unscheduled flows not incorporated in the day-ahead market model, as noted above. Thus, DMM recommends the ISO carefully consider this issue and that virtual bidding on inter-ties be re-implemented in a very limited and gradual manner that is contingent on the observed performance of this new market design. In Chapter 3 of this report, DMM describes a method that might be used as a framework for allocating these revenue imbalances more equitably.

The ISO is currently planning on filing this proposal with FERC in late 2013 for implementation in spring 2014.

Flexible ramping product

The ISO is proposing to replace the flexible ramping constraint with a flexible ramping product, to be implemented in late 2014 in conjunction with the real-time market re-design stemming from FERC Order No. 764. DMM is supportive of this product as a more effective way of ensuring operational ramping flexibility than the current flexible ramp constraint.

The ISO's flexible ramping product proposal also includes a provision that ensures all energy bid into the day-ahead and real-time markets is available to meet market requirements for this product. However, these provisions do not prevent the exercise of market power by bidding up to the $250/MW bid cap. Since this product will be procured to a system-wide requirement, DMM does not view additional mitigation measures as necessary. However, the ISO has left open the potential to procure flexible ramping product regionally, which would require further assessment of competitiveness and potentially additional mitigation measures.

Contingency modeling enhancements

As part of an initiative to reduce the need for exceptional dispatches, the ISO has proposed an alternative modeling approach aimed at reducing the use of exceptional dispatches and minimum-online capacity constraints.[12] The 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.

DMM is highly supportive of this initiative. The initiative directly addresses one of the recommendations in our 2011 annual report, in which we recommended that the ISO monitor and seek to limit exceptional dispatches related to needs for online capacity and ramping capability to meet overall system and south

[12] *Contingency Modeling Enhancements Issue Paper*, March 11, 2013, http://www.caiso.com/Documents/IssuePaper-ContingecyModelingEnhancements.pdf.

of Path 26 needs.[13] From DMM's perspective, one of the main additional benefits of this approach is that it will allow these reliability requirements to be met more efficiently, since they will be met by explicit constraints incorporated in the market model. This will allow the requirements to be calculated in a more automated manner based on actual system conditions and then met by the least cost mix of resources.

In some cases, requirements that can only be met by resources controlled by a limited number of suppliers would give rise to local market power. In the real-time market, temporal market power may also exist in cases when only a limited number of resources capable of meeting requirement are committed to operate. Once additional information is available on these requirements and how they will be modeled, DMM will work with the ISO to determine if market power mitigation provisions are needed and, if so, how these might be incorporated into the market process in the most automated manner possible.

Forward procurement of flexible capacity

In DMM's last few annual reports, we have expressed support for a multi-year capacity procurement that includes multi-dimensional flexible requirements. In these reports and as part of other ISO initiatives, DMM has emphasized two major recommendations:

- **Flexible capacity requirements should be directly linked with operational ramping needs.** The ISO is developing a 5-minute flexible ramping product to be implemented in 2014. 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 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 that flexible capacity procured to meet forward requirements is 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.

In 2011, the ISO proposed three different types of flexible capacity requirements (regulation, load following and maximum continuous ramping), and continues to indicate that this type of multi-dimensional flexibility requirement will be needed. The CPUC and some stakeholders expressed concern that this approach was overly complex to incorporate into the resource adequacy requirements at this time. The current interim proposal being considered in the first phase of a CPUC resource adequacy process to address this issue includes the same one-year time period as the current resource adequacy program, and would establish a single 3-hour continuous ramping requirement for the 2014 compliance year.

[13] *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, p. 200: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

DMM believes this interim proposal is a step in the right direction, but recommends that the ISO and CPUC should continue to work toward a multi-year ahead flexibility requirement, which ensures that all operational and market flexibility requirements can be met by capacity procured to meet these requirements. This first phase has highlighted the challenges in quantifying flexible resource capacity, specifying requirements and defining appropriate must-offer obligations linking flexible capacity procured with the ISO's operational and market needs.

For example, DMM is concerned that a single 3-hour continuous ramping requirement may not ensure that shorter-term ramping requirements are met. These shorter-term requirements include those associated with the 5-minute flexible ramping product to be implemented in 2014, as well as new model constraints being developed to ensure sufficient additional capacity is available to respond to contingencies within 30 minutes.

Forward capacity market

The ISO has suggested that a new capacity paradigm is needed in California due to the dramatic change in net load predicted to begin in 2015.[14] DMM is supportive of efforts to begin a detailed design of a multi-year capacity market, such as a five year-ahead market. In prior annual reports and other comments, we have noted the difficulties of incorporating local requirements in a capacity market, defining and quantifying flexibility characteristics of different resource types, and linking forward procurement of flexible capacity to ISO operational and market needs through must-offer and price mitigation provisions.[15] These complexities must be specifically addressed well in advance of the start of a multi-year capacity market.[16] As noted above, the ISO and stakeholders are engaged in a variety of initiatives in conjunction with the CPUC in which these issues are being addressed.

Given California's current ownership of resources, environmental regulations and ISO operational requirements, a centralized capacity market may offer several significant benefits relative to the option of further modifying the state's current resource adequacy program.

- Mitigation of local market power could be incorporated into the capacity market design itself.
- Procurement of multiple flexible capacity requirements may be more reliably and efficiently met through a centralized market than through bilateral procurement of each flexible attribute separately.
- A capacity market may help enable a more cost-effective way of ensuring that enough capacity is maintained to meet local capacity requirements while meeting once-through-cooling restrictions applicable to much of the capacity located within these local areas.

[14] See the *Comprehensive Forward Capacity Procurement Framework*, CAISO, February 26, 2013: http://www.caiso.com/Documents/CaliforniaISO-BriefingPaper-LongTermResourceAdequacySummit.pdf.

[15] *2010 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2011, pp. 14-15: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

[16] For instance, if a resource is counted toward meeting a specific flexible requirement — such as load following — then rules must be established in advance to ensure that this ramping flexibility is made available in the real-time market. Current market rules allow resources to self-schedule or bid in lower ramp rates so any fast ramping capacity procured may not actually be available to the real-time market.

- Experience in other ISOs suggests that a capacity market may result in increased development of energy efficiency and demand response, which are preferred resources under California state regulatory policy guidelines.

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 2012. 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 2012.
- **Real-time market performance.** Chapter 3 provides an analysis of real-time market performance, including reasons for real-time imbalance uplifts.
- **Convergence bidding.** Chapter 4 analyzes the convergence bidding feature that was added in 2011 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 2012.
- **Recommendations.** Chapter 10 highlights DMM recommendations on current market issues and new market design initiatives on an ongoing basis as well as follow up on a variety of specific recommendations for market improvements made in our prior annual and quarterly reports.

Chapter 1 of DMM's 2010 annual report provides a summary of the nodal market design implemented in 2009 and key design enhancements that have been added in 2010 and 2011.[17] This chapter of our 2010 annual report also highlights various state policies and requirements closely linked to the design and performance of the ISO markets.

[17] *2010 Annual Report on Market Issues and Performance*, April 2011, pp. 17-32. http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

1 Load and resources

Both load and supply conditions were challenging in 2012. Peak loads reached levels not seen in several years, hydro-electric generation was down significantly and over 2,000 MW of important nuclear generation was on outage. Key trends highlighted in this chapter include the following:

- The load-weighted average price of natural gas in the daily spot markets decreased almost 30 percent from 2011.[18] This was the main driver in the slight decrease in the nominal annual wholesale energy cost per MWh of load served in 2012.
- Summer loads peaked at 46,847 MW, a 2.9 percent jump from 2011 and the highest peak load observed since 2008.
- Hydro-electric generation provided approximately 9 percent of total supply in 2012, a decrease from 14 percent in 2011. The drop in hydro-electric energy was concentrated in the summer months from June to August, during which hydro energy was 35 percent lower than in 2011.
- Net imports increased by 7 percent in 2012 over 2011, driven by a 9 percent increase in imports from the Southwest compared to 2011.
- About 700 MW of peak generating capacity from renewable generation was added in 2012. Energy from wind and solar currently provides slightly more than 5 percent of system energy, compared to 3.9 percent in 2011. Energy from new wind and solar resources is expected to increase at a much higher rate in the next few years as a result of projects under construction to meet the state's renewable portfolio standards.
- 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 continued to be limited in 2012, despite more than doubling from 2011 levels.
- Price responsive demand response capacity surpassed reliability based demand response capacity for the first time. Price responsive capacity accounted for 58 percent of demand response in 2012. This capacity can be dispatched during the operating day in response to real-time market conditions or on a day-ahead basis in response to expected market conditions. Reliability-based programs that can only be activated under extreme system conditions made up the remaining 42 percent.
- Over 1,300 MW of new gas-fired generation was added in 2012. The estimated net operating revenues for typical new gas-fired generation in 2012 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.

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

1.1 Load conditions

1.1.1 System loads

System loads were significantly higher in 2012, approaching levels not seen since 2008. The increase is likely due to a combination of high temperatures in peak demand months and a recovering economy. Table 1.1 summarizes annual system peak loads and energy use over the last five years.

Table 1.1 Annual system load: 2008 to 2012

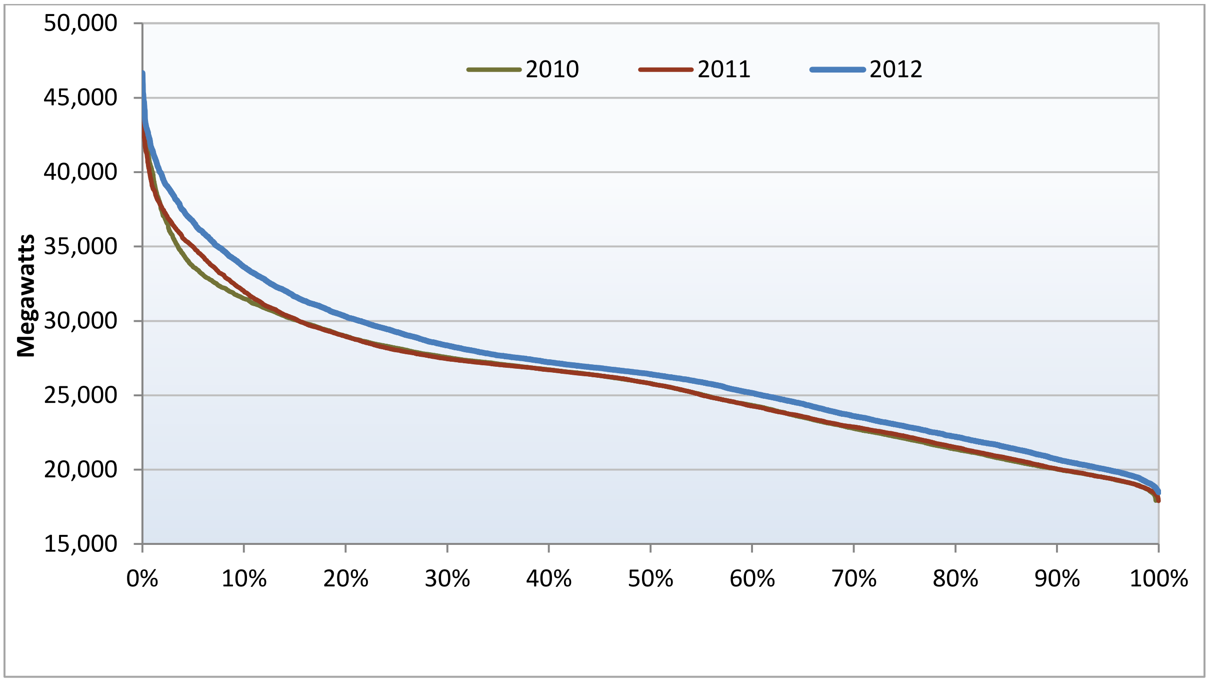
Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2008	241,128	27,526	-0.4%	46,897	-3.5%
2009	230,754	26,342	-4.3%	46,042	-1.8%
2010	224,922	25,676	-2.5%	47,350	2.8%
2011	226,087	25,791	0.4%	45,545	-3.8%
2012	234,882	26,740	3.7%	46,847	2.9%

Annual, average and peak load measures all increased in 2012.

- Annual total energy reached 234,882 GWh, a 3.9 percent increase over 2011.
- Average loads during all hours increased by 3.7 percent.
- Summer loads peaked at 46,847 on August 13 at 3:53 p.m., a 2.9 percent jump from 2011 and the highest peak load observed since 2008.

Demand was especially high during peak hours compared to 2011 (see Figure 1.2 for load duration curves for 2010 through 2012). System load exceeded 40,000 MW in 151 hours in 2012 compared to 61 hours in 2011, an increase from 0.6 percent to 1.7 percent.

Figure 1.1 System load duration curves (2010 to 2012)



Other measures of peak load served in 2012 also increased. System demand during the single highest load hour varies substantially year to year because of summer heat waves. The potential for such heat-related peak loads creates a continued threat of operational reliability problems and drives many of the ISO's reliability planning requirements.

Figure 1.1 summarizes load conditions during summer peak hours.

- Average hourly summer peak load was 32,603 MW, higher than any observed since 2002.[19]
- Average daily peak load grew 5 percent to 36,438 MW.
- The single hour peak load grew about 3.8 percent to 46,664 MW.[20]

Peak load was slightly higher than the ISO's 1-in-2 year forecast. 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.

Summer peak demand in 2012 was slightly higher than the 1-in-2 year forecast and well below the 1-in-10 year forecast, as demonstrated in Figure 1.3. The instantaneous peak load (46,847 MW) was only 0.4 percent above 46,639 MW, the 1-in-2 year forecast.

[19] Summer peak hours included in this calculation are from June to August, hours ending 7 to 22.

[20] This value is lower than the instantaneous peak reported earlier because DMM calculates the hourly peak load as the average of twelve 5-minute intervals.

Figure 1.2 Summer load conditions (2002 to 2012)

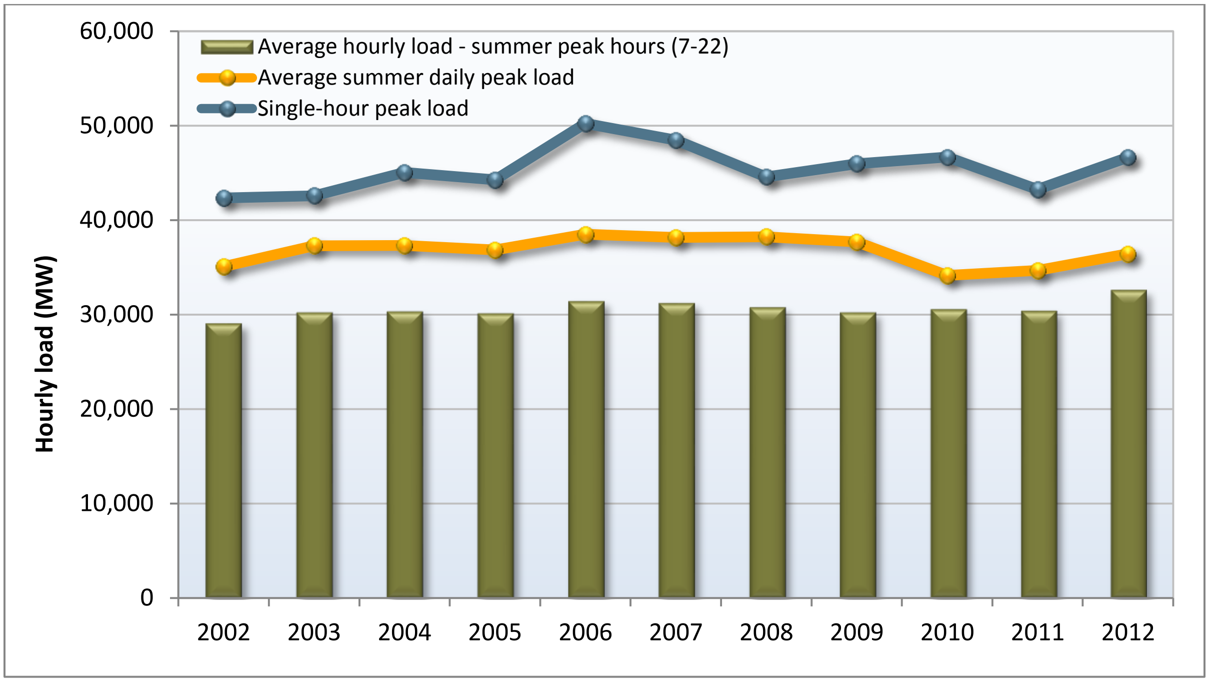
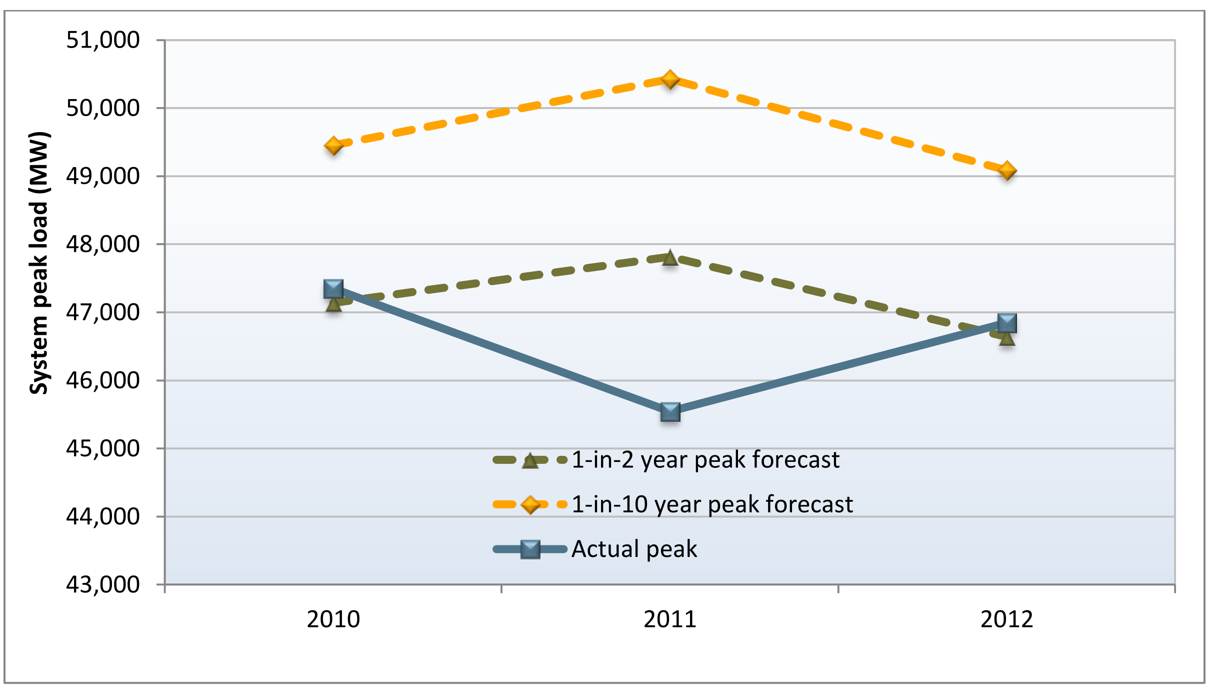


Figure 1.3 Actual load compared to planning forecasts



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 1.4). Table 1.2 and Figure 1.5 summarize the total amount of load within each of these local areas under the 1-in-10 year forecast used to set local reliability requirements. Most of the total peak system demand is located within two areas: the Los Angeles Basin (41 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 51 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 39 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 10 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 shown in Table 1.2 and Figure 1.5 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.

The available supply in Table 1.2 for the Los Angeles Basin includes over 2,000 MW of generation from the San Onofre nuclear plant that is not expected to be available in 2013. As shown in Table 1.2, without this generation, all of the available supply within the Los Angeles Basin is needed to meet local capacity requirements.

In addition, California's once-through-cooling (OTC) regulations affect a significant proportion of capacity needed to meet local capacity requirements in four local capacity 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.[21]

[21] *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 1.4 Local capacity areas

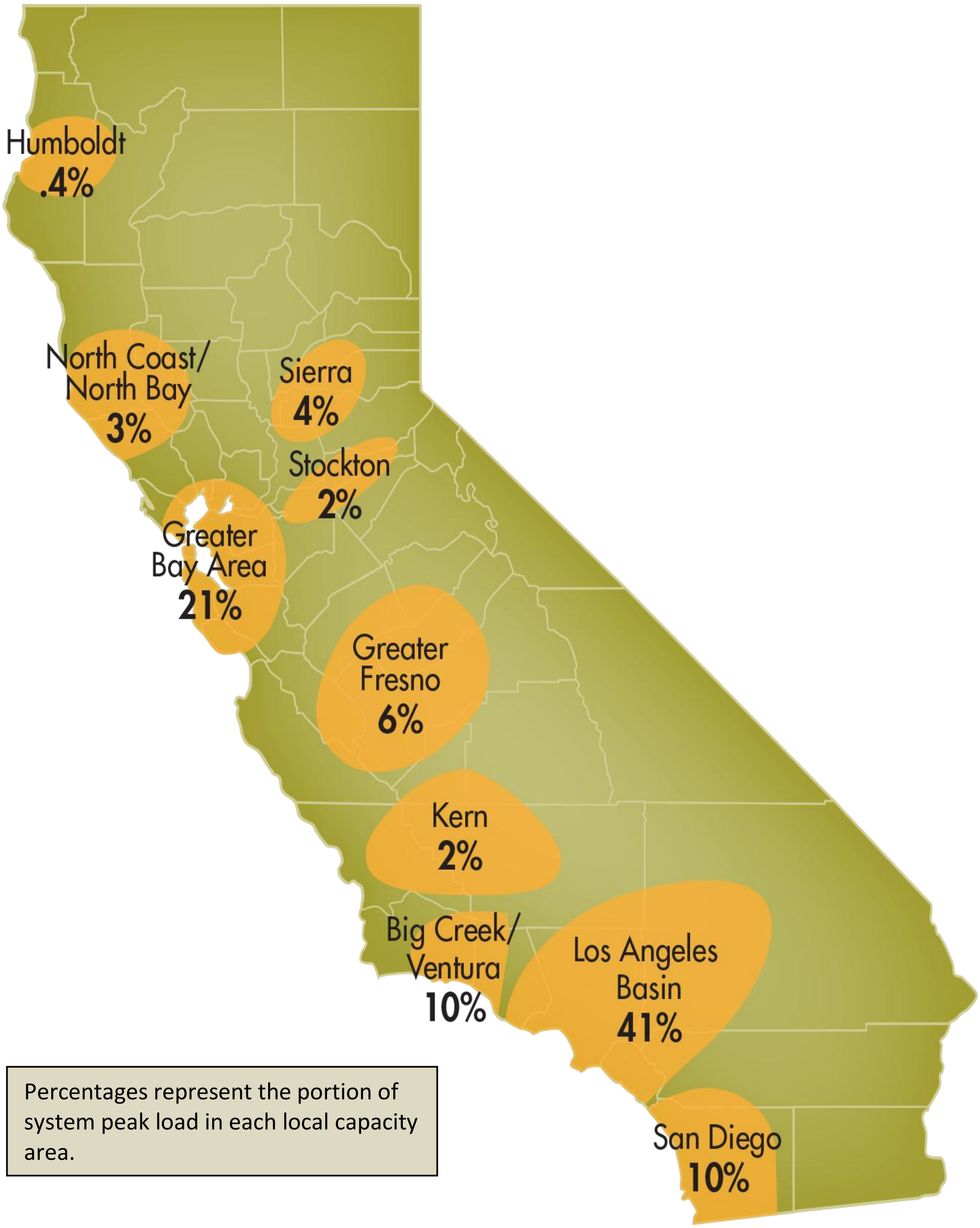


Table 1.2 Load and supply within local capacity areas in 2012

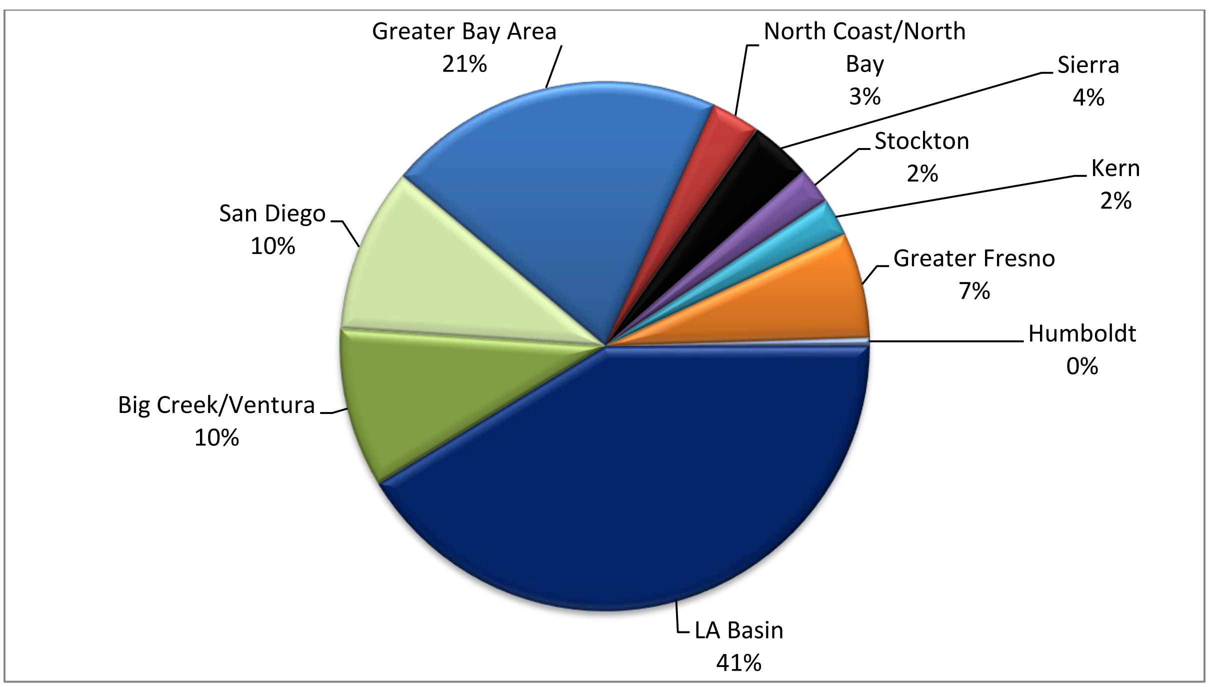
Local Capacity Area	LAP	Peak Load (1-in-10 year) MW	%	Dependable Generation (MW)	Local Capacity Requirement (MW)	Requirement as Percent of Generation
Greater Bay Area	PG&E	9,954	21%	6,588	4,278	65%
Greater Fresno	PG&E	3,120	6%	2,770	1,907	69%*
Sierra	PG&E	1,816	4%	2,037	1,974	97%*
North Coast/North Bay	PG&E	1,420	3%	859	613	71%
Stockton	PG&E	1,086	2%	505	567	112%*
Kern	PG&E	1,110	2%	611	325	53%*
Humboldt	PG&E	210	0.4%	222	212	95%*
LA Basin	SCE	19,931	41%	12,083**	10,865	90%
Big Creek/Ventura	SCE	4,693	10%	5,232	3,093	59%
San Diego	SDG&E	4,844	10%	3,087	2,944	95%*
Total		**48,184**		**33,994**	**26,778**	**79%**

Source: *2013 Local Capacity Technical Analysis: Final Report and Study Analysis*, April 30, 2012. See Table 6 on page 24. http://www.caiso.com/Documents/April302012LCTStudyReport2013indocketnoR1110023.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.

** Includes over 2,000 MW of generation from the San Onofre nuclear plant that is not expected to available in 2013.

Figure 1.5 Peak loads by local capacity area (based on 1-in-10 year forecast)



1.1.3 Demand response

Overview

Demand response plays an increasingly important 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 almost 5 percent of total ISO system resource adequacy capacity requirements.

Demand response is a resource that allows consumers to reduce 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 generally dispatched and administered by the utilities that sponsor these programs, rather than by the ISO. These programs are overseen by the CPUC. Independent curtailment service providers offer demand response by participating in utility sponsored programs, as do other non-utility entities. Currently, demand response provided directly to the ISO is primarily limited to water pumping loads.[22]

In August 2010, the ISO implemented a proxy demand resource product. This market enhancement 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 curtailment service providers. However, less than 6 MW of proxy demand resource capacity were registered when load peaked in 2012, down from about 12 MW in 2011. No bids from these resources were dispatched in 2012, so that no payments were made by the ISO for any demand reductions.

In addition to the utility demand response programs discussed in detail below, the ISO issues flex alerts when system conditions are expected to be particularly high. Flex alerts urge consumers to voluntarily reduce demand through broadcast process releases, text messages and other means. The program is funded by the utilities under the authority of the CPUC. The ISO issued a state-wide flex alert on August 10, 2012, and an alert for Southern California on August 14, 2012, during the peak summer hours.

Utility demand response programs

Almost all of California's current demand response consists of load management programs operated by the state's three investor-owned utilities. These programs are triggered by criteria set by the utilities and are not necessarily tied to market prices. Notification times required by the retail programs are also not well synchronized with ISO market operations. This limits the programs' ability to be dispatched during periods of the highest loads and prices.

[22] 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.

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.

- ***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.

From the perspective of overall market performance and system reliability, day-of price responsive demand programs are significantly more valuable than price-responsive programs that can only be triggered on a day-ahead basis.

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 2008.[23] As shown in Table 1.3, there is a notable drop in reported demand response capacity from 2009 to 2010. This was due to a change in the way that demand response capacity is assessed and reported.

Through 2009, demand response capacity was reported based on total controllable load enrolled in each program. Protocols in effect since 2010 require utilities to report two measures of demand response capacity: *ex ante* and *ex post*.[24] *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. in 2012. The *ex ante* values form the basis for the remaining discussion in this section because they are most representative of actual available demand response capacity during 2012.

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 2012 has tracked closely with estimates of actual demand response capacity reported in these years under the more advanced reporting protocols. The amount of this capacity used to meet resource adequacy requirements is determined by the CPUC, based on its estimate of demand response capacity that can be expected under peak summer conditions.

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

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

In 2012, *ex ante* estimates of demand response capacity available in August equaled approximately 95 percent of 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 standard protocols 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 reductions reduce the amount of capacity needed to meet the 15 percent supply margin used in setting resource adequacy requirements.

Table 1.3 Utility operated demand response programs (2008-2012)

Utility/type	2008 Enrolled MW	2009 Enrolled MW	2010 Estimated* MW	2011 Estimated* MW	2012 Estimated* MW
Price-responsive					
SCE	381	498	214	287	962
PG&E	752	508	304	469	340
SDG&E	154	89	72	58	118
Sub-total	1,287	1,095	589	814	1,420
Reliability-based					
SCE	1,458	1,577	1,245	1,167	727
PG&E	466	533	291	253	282
SDG&E	83	62	9	8	2
Sub-total	2,007	2,172	1,544	1,428	1,010
Total	3,294	3,267	2,134	2,270	2,430
Resource adequacy allocation	2,670	2,637	2,221	2,421	2,598
With 15 percent adder	3,071	3,033	2,554	2,784	2,987

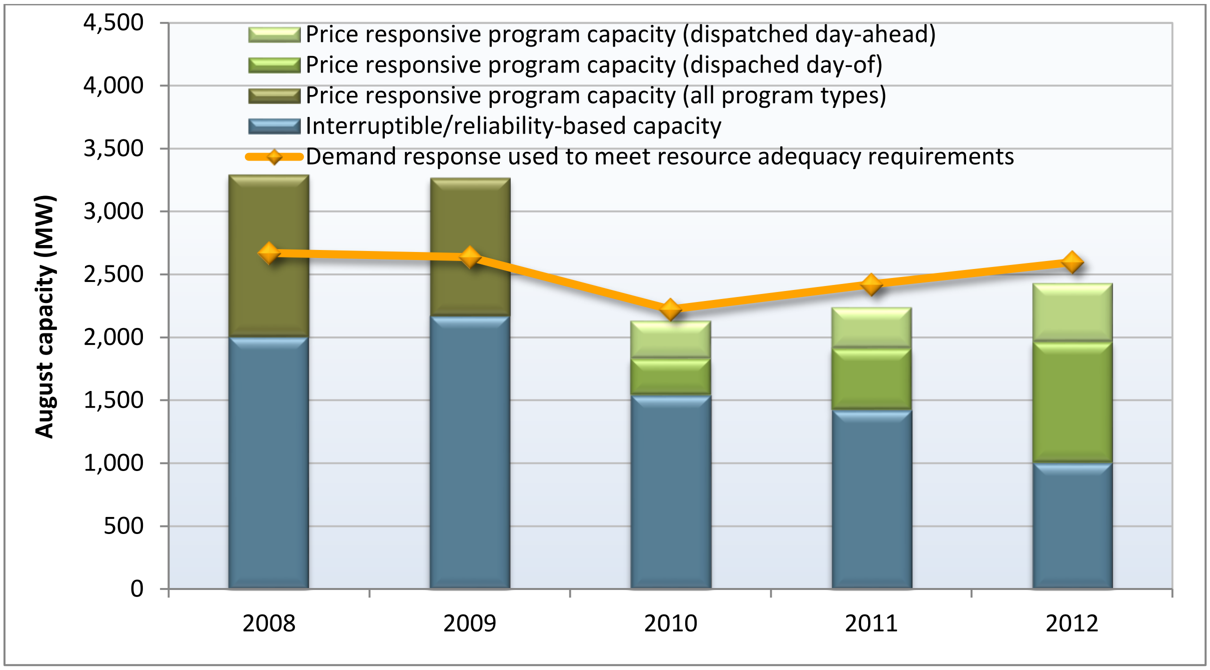
* Capacity for 2008-2009 based on planning projections of program enrollment and impacts.
Capacity for 2010-2012 based on *ex ante* assessment of program enrollment and impacts.

Figure 1.6 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.[25] The following is shown in Figure 1.6:

- Price-responsive programs accounted for 58 percent of this capacity in 2012, which is a major increase from prior years as reliability programs were historically larger.
- Reliability-based programs accounted for 42 percent of the capacity from utility-managed demand response resources in 2012.
- In 2012, price-responsive programs that can be dispatched on a day-of basis grew to 39 percent of all demand response capacity, compared to about 14 percent in 2010 and 22 percent in 2011.

[25] Prior to 2010, data provided in the monthly reports are not sufficient to differentiate between price-responsive demand response that can be dispatched on a day-ahead and day-of basis.

Figure 1.6 Utility operated demand response programs (2008-2012)



From the perspective of overall market performance and system reliability, price-responsive demand response, which can be dispatched on the same day that high market prices or critical system conditions occur are significantly more valuable than programs that can only be triggered on a day-ahead basis or in response to a system reliability emergency.

Use of demand response programs

Demand response resources continue to be dispatched by utilities on a limited basis. These programs were dispatched at more than twice the volume in 2012 as in 2011, as measured by post event estimates provided 7 days after the event. However, the total estimated impact of these demand response events represents a very small portion of total energy in the market – approximately 0.01 percent.

While demand response dispatch volume was small in 2012, these resources were dispatched during the peak months and peak hours of the year, when they are likely to have the most impact. Figure 1.7 shows the annual total amount of demand response activated by the three largest utilities in 2012 by operating hour. Dispatch was concentrated in the hours between 3:00 p.m. and 6:00 p.m., often the peak load hours in the day. As demonstrated in Figure 1.7 , about 62 percent of demand response was dispatched on a day-ahead basis. The remaining 38 percent was dispatched on a day-of or emergency basis.

Figure 1.8 shows the total amount of demand response dispatched by month and utility. Demand response resources were not dispatched outside of the peak period (June through October), with the majority of this dispatch occurring during the peak summer month of August.

Figure 1.9 shows the hourly demand response dispatch on the ISO's peak load day (August 13) and the day after the peak day (August 14). This figure demonstrates that demand response dispatch was activated during high load conditions, but varied substantially day-to-day. During most hours on these peak load days, about 100 MW of demand response were activated. However, during hour 16 of August 14, demand response topped 500 MW, or 1.1 percent of system load.

Figure 1.7 Total amount of demand response programs dispatched in 2012 by hour

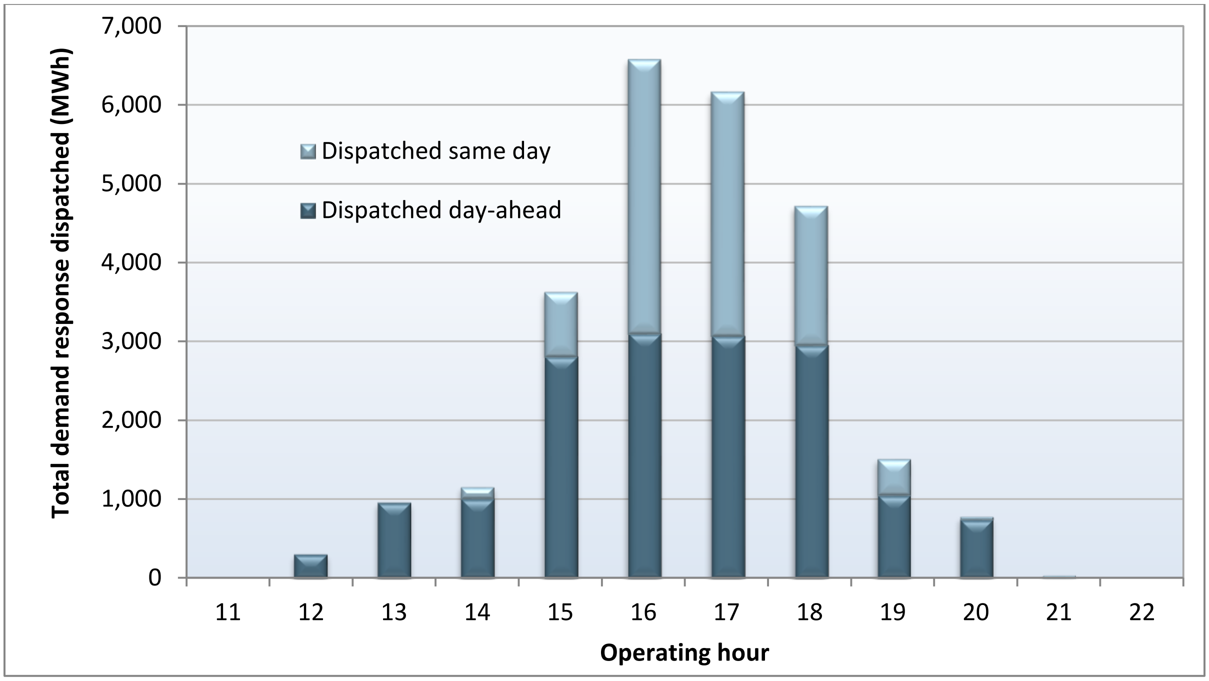


Figure 1.8 Total amount of demand response programs dispatched in 2012 by month

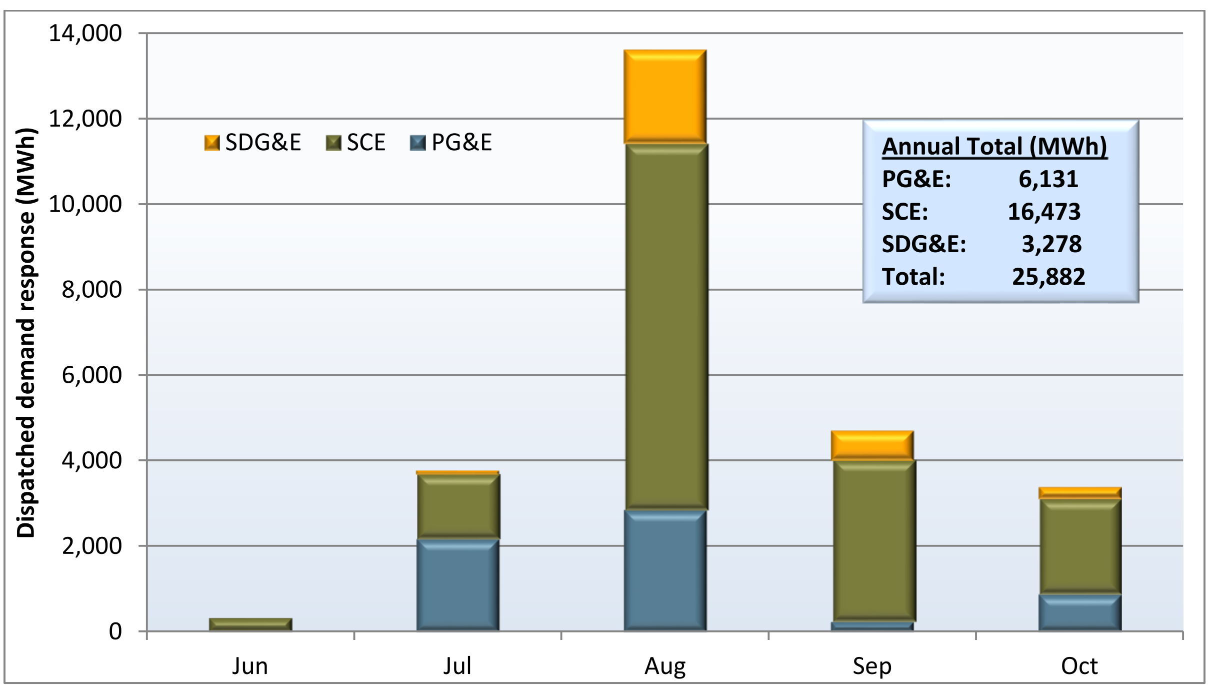
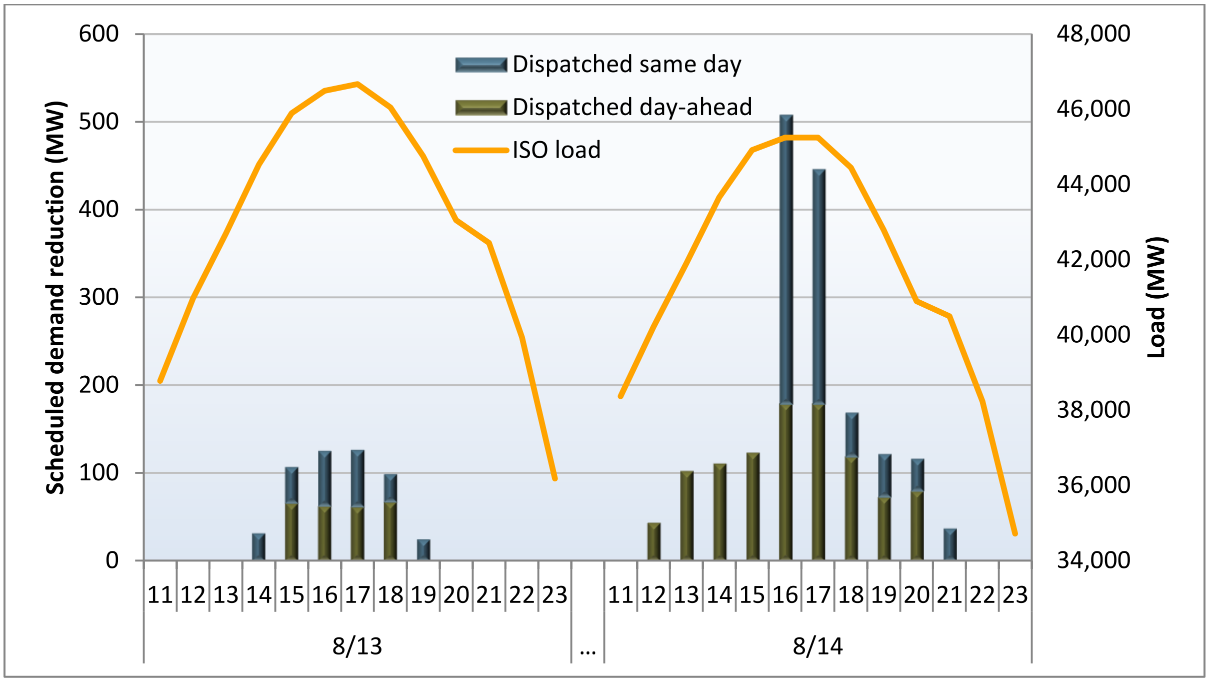


Figure 1.9 Demand response dispatched on August 13 and 14, 2012



In 2012, most demand response was dispatched in response to market or system conditions, rather than measurement or evaluation. Dispatch for measurement or evaluation accounted for approximately 1 percent of dispatch for day-ahead programs and 22 percent of dispatch for day-of programs in 2012. In 2011, dispatch for measurement and evaluation accounted for a greater portion – 5 percent of day-ahead dispatch and about 80 percent of same day dispatch.

Demand response issues

While use of demand response increased in 2012, several challenges remain before this capacity is well integrated into the market and ISO operational decisions. These challenges include limited use of the ISO's proxy demand resource program, the timing and quality of demand response data, and limited integration of available demand response data into ISO operations.

While the ISO implemented a proxy demand resource product in 2010, no bids from these resources were dispatched in 2012. 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.[26] Thus, while the utilities' programs were triggered more by price than for reliability purposes, the integration of these programs with the market is still poor as commitment and dispatch decisions continue to occur outside the market optimization.

[26] 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.

Daily forecasts of scheduled demand response sent to the ISO by the major investor owned utilities are the only source of information for the ISO on utility operated demand response resources. However, these forecasts are not well integrated with market operations for several reasons.

First, the timing of the forecast reports makes it difficult for these to be included in actual ISO resource commitment decisions. In preparation for the extended outage of SONGS units 2 and 3, the three major utilities agreed to provide the ISO with a daily forecast schedule for demand response programs. This hourly forecast is updated by 8:00 a.m. of the day on which the demand response programs are dispatched and then updated again by the end of day on which the demand response event occurred. Thus, the ISO receives the updated forecast information shortly before or sometimes after the activation of the event, thus making it difficult to incorporate demand response expectations into actual market operations.

Second, measuring the impact of dispatched demand response in a timely fashion remains a challenge. As noted earlier, the utilities provide forecast estimates the day before and the day of operation. Seven days after a demand response event, the utilities provide the ISO with post event estimates of dispatched demand response capacity. Under the CPUC monitoring and evaluation protocols, the actual performance of demand response is re-assessed on an annual basis using final metered data and sophisticated econometric estimates of load without demand response. However, these results are not available until the spring of the following year.[27]

Last, demand response forecast schedules have also been difficult to integrate into ISO operations because they can differ substantially from actual load reductions achieved. The performance of demand response programs – as measured by the difference between forecasted impacts and after the fact estimates of actual impacts – has been the subject of concern for both the ISO and CPUC. This may be particularly true of new programs without a long history of measured performance which rely heavily on consumer behavior and price responsiveness.[28]

The ISO has developed explicit procedures to incorporate forecasted demand response into the day-ahead market. These procedures were updated in May 2012 to include the day-ahead demand response schedules in manual operator adjustments of the load forecast used in the day-ahead market. While operators reviewed this information and included these numbers in their evaluation of the day-ahead market, this rarely resulted in reductions in load projections. Although the ISO received more timely notice of demand response than in prior periods, forecast demand response was often low relative to total system load and an inconsistent predictor of final estimated demand response values. As a result, the full benefits of demand response in terms of unit commitment decisions may not be realized in the market at this time given current procedures and quality of information.

[27] Values summarized above are based on post event summaries provided by the utilities to the ISO. Because measuring the quantity of demand response dispatched requires estimating what load would have been in the absence of these programs, data used for this report may differ from values submitted to the CPUC.

[28] In response to CPUC information requests, SCE and SDG&E provided data with their applications for Approval of Demand Response Program Augmentations and Associated Funding for the Years 2013 through 2014. These include data on demand response program performance by program and date and explanations for average daily program performance deviations greater than 10 percent. SCE's response is publicly posted at the following address: http://www3.sce.com/sscc/law/dis/dbattach11.nsf/0/C630953A78996EB688257B250001C3E7/$FILE/A.12-12-017+et+al-+SCEs+APPLICATION+RE+ADDITIONAL+DR+FOR+2013+AND+2014+-SCE+Response+to+ALJ+2-21-2013+Ruling+.pdf. SDG&E provides information on the proceeding but does not post the response itself (http://www.sdge.com/regulatory-filing/3973/sdge-2013-—-2014-demand-response-programs).

Under the current market design, the ISO does not have the data or responsibility for assessing the performance of these utility programs. When these programs are bid and dispatched directly in the ISO market as proxy demand resources, the ISO will play a role in assessing the impact of these resources based on metering data as part of its settlement process.

1.2 Supply conditions

1.2.1 Generation mix

As in previous years, most generation in 2012 came from natural gas and imports. Hydro-electric generation was lower in 2012 due to low levels of precipitation and snowpack. A growing share was produced by other renewable energy resources such as wind and solar.

Figure 1.10 provides a profile of average hourly generation by month and fuel type. Figure 1.11 illustrates the same data on a percentage basis. Figure 1.12 shows an hourly average profile of energy supply by fuel type for the peak summer months, July through September. This information is illustrated on a percentage basis in Figure 1.13.

These figures show the following:

- Total generation within the ISO rose by less than 1 percent in 2012.
- Nuclear generation was down 49 percent in 2011, following the extended outages of the San Onofre Nuclear Generating Station units 2 and 3.
- Hydro-electric generation provided approximately 9 percent of supply in 2012, a substantial decrease from 14 percent in 2011. The drop in hydro-electric generation was concentrated in the summer months from June to August when it was 38 percent lower than the same period in 2011.
- The gap in supply created by falling hydro-electric and nuclear generation was filled, in large part, by natural gas. Natural gas generators provided approximately 39 percent of supply in 2012, up from 28 percent in 2011.
- Combined, natural gas and hydro-electric generation produced the most during the higher load months (August and September) of the year and in the higher load hours of the day (7 through 22). These resources were most often marginal in the system.
- Imports represented approximately 30 percent of capacity, a slight increase in percentage terms from 2011 (29 percent). Overall, energy from imports increased by 7 percent. These values do not net out exports. Net import values do remove exports and are discussed in further detail later in this section.
- Non-hydro renewable generation directly connected to the ISO system accounted for 10 percent of total supply. Total renewable generation was up 13 percent from 2011.[29] This increase was due to growth in energy from wind and solar resources.

[29] In this analysis, non-hydro renewables do not include imports or behind the meter generation such as rooftop solar.

Figure 1.10 Average hourly generation by month and fuel type in 2012

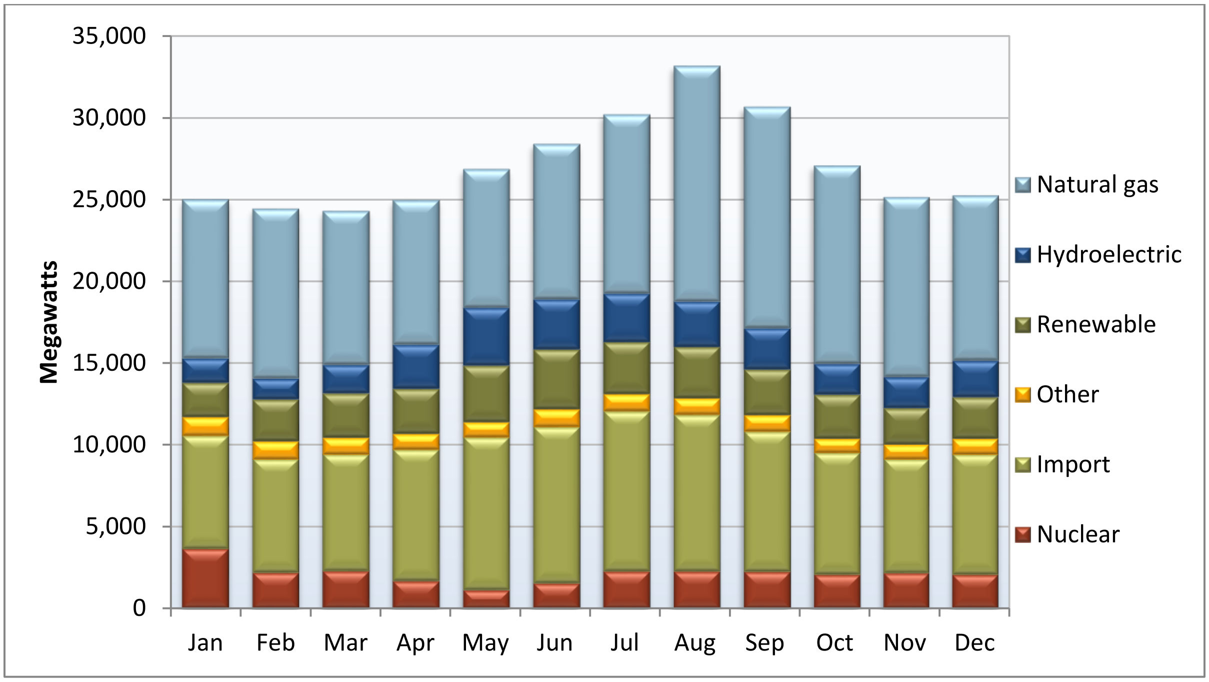


Figure 1.11 Average hourly generation by month and fuel type in 2012 (percentage)

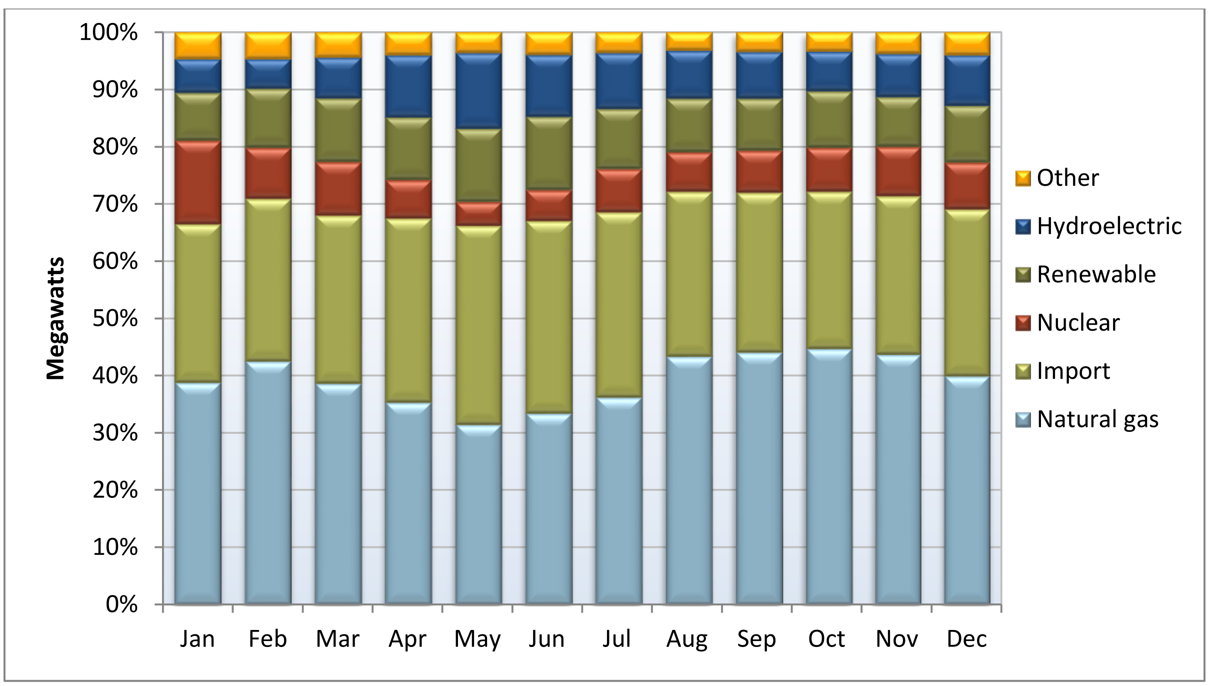


Figure 1.12 Average hourly generation by fuel type in Q3 2012

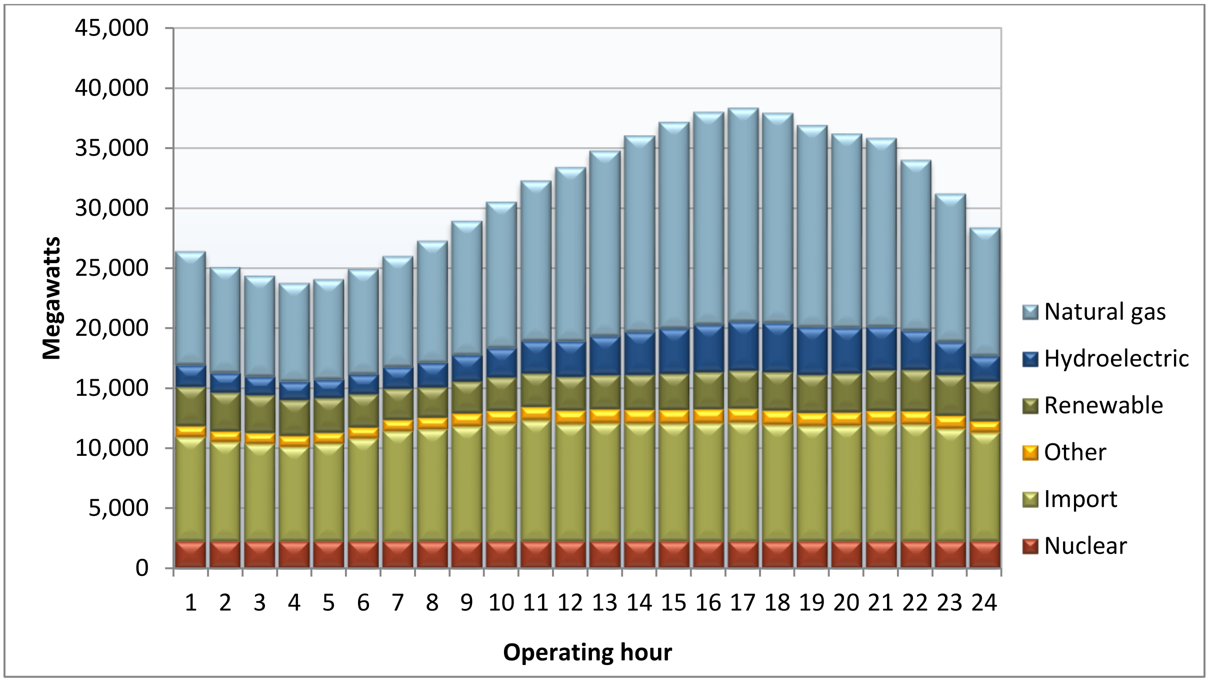
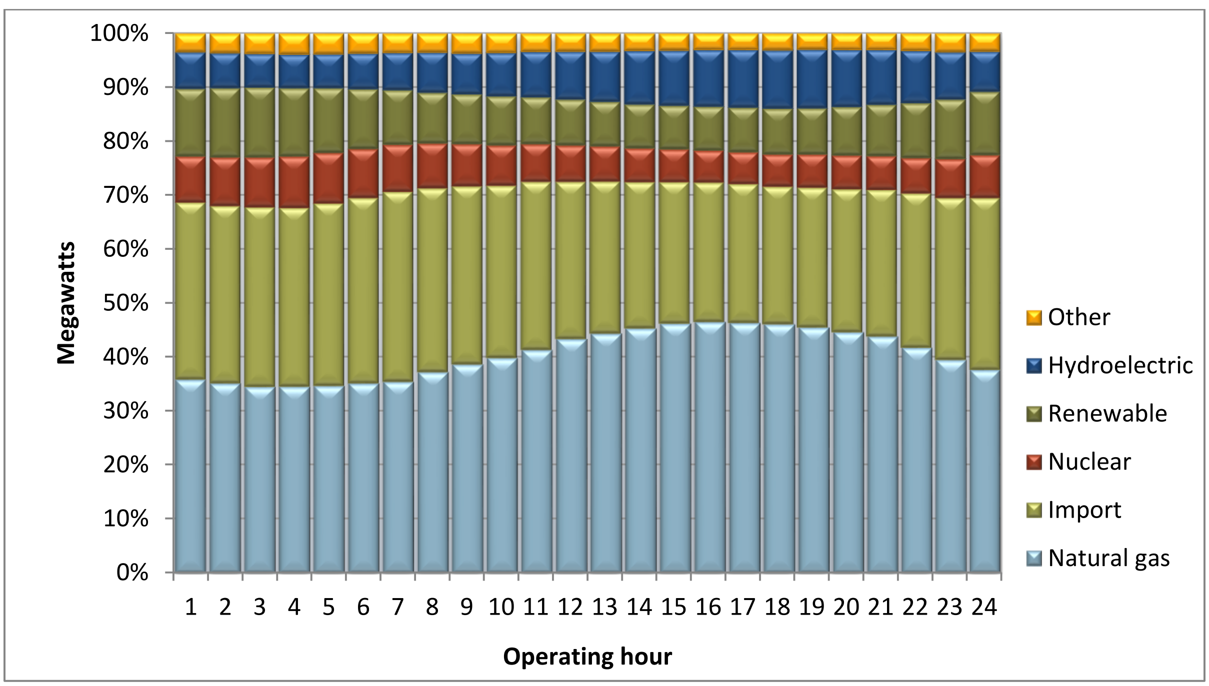


Figure 1.13 Average hourly generation by fuel type in Q3 2012 (percentage)



Increased non-hydro renewable generation within the ISO came predominately from wind, but solar generation also grew rapidly in 2012. Figure 1.14 provides a detailed breakdown of non-hydro renewable generation from 2009 through 2012.

- For the first time, generation from wind resources directly connected to the ISO grid exceeded that from geo-thermal, becoming the largest source of renewable generation inside California.
- Wind resources provided 38 percent of renewable energy, up from 35 percent in 2011. Wind provided 4 percent of overall system energy in 2012.
- Geothermal provided approximately 34 percent of renewable energy in 2012, or about 4 percent of overall system energy.
- Biogas, biomass, and waste generation contributed 20 percent of renewable energy, or about 2 percent of total system energy.
- Solar power from resources directly connected to the ISO system increased from about 5 percent to 8 percent of total renewable generation. Solar represented about 1 percent of overall system energy in 2012.

Both hydro-electric and wind generation peaked in the second quarter (April through June), when system loads are moderate and the supply portfolio is limited due to outages. The combination of these conditions contributes to the potential for negative price spikes due to over-generation during these months. Figure 1.15 compares average monthly generation from hydro, wind and solar resources. Currently, the share of generation from solar resources is low, relative to the hydro and wind resources. However, solar is expected to provide an increasing portion of supply from new renewable resources.

Figure 1.14 Total renewable generation by type (2009-2012)

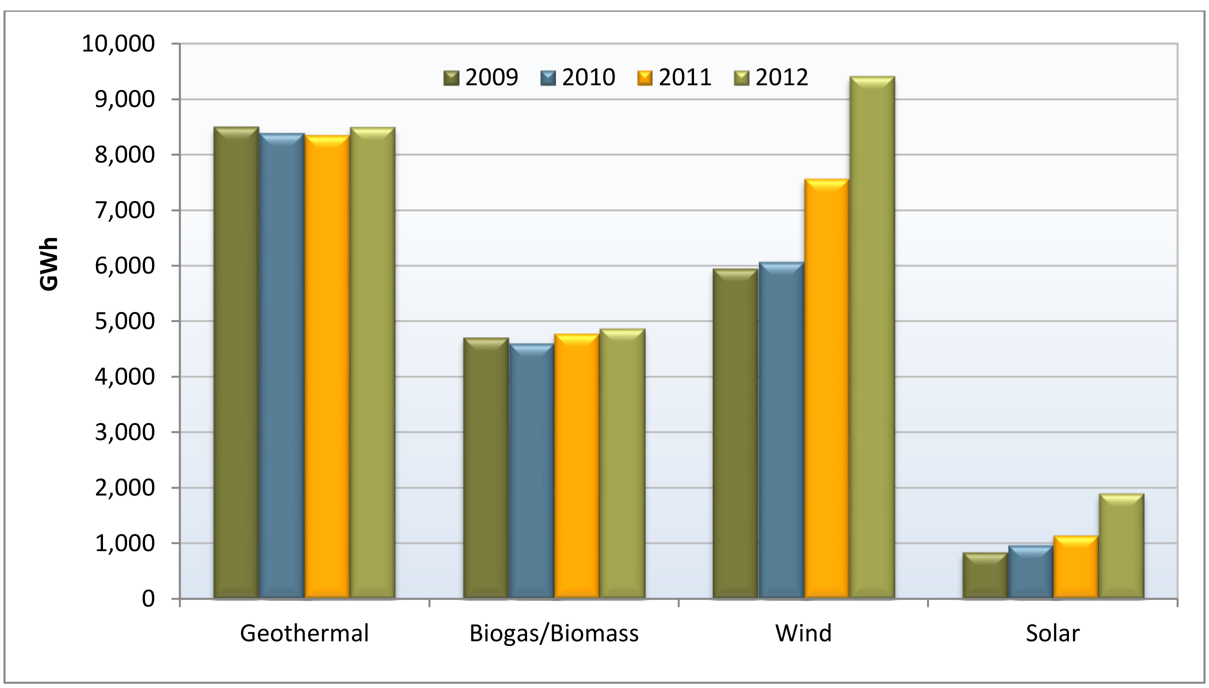
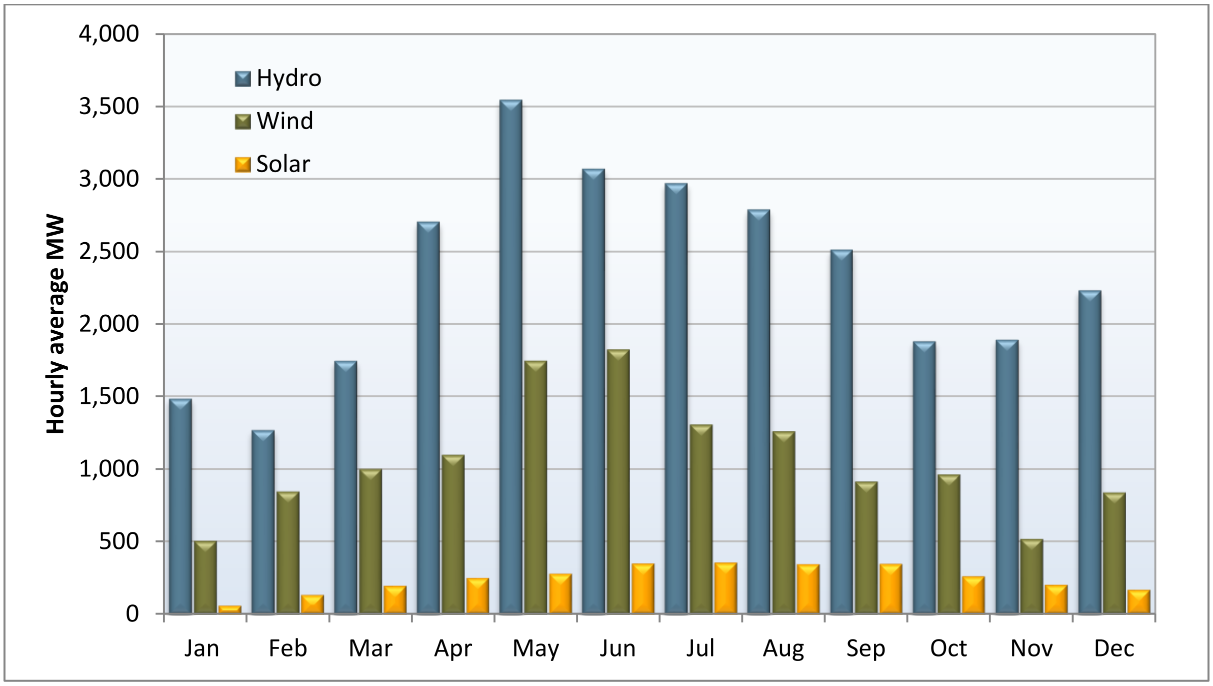


Figure 1.15 Monthly comparison of hydro, wind and solar generation (2012)



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 2012 was low, only slightly higher than production in 2008 – the year with the lowest hydro-electric production in the past decade. Snowpack in the Sierra Nevada Mountains, as measured on May 1, 2012, was only 39 percent of the long-term average, indicating much lower than average hydro conditions.[30] Figure 1.16 illustrates overall production over the last decade.

Figure 1.17 compares monthly hydro-electric output from resources within the ISO for each of the last three years. Hydro production in 2012 was 65 percent of production in 2011 and 81 percent of 2010. During the summer months of June to August, hydro production was only 62 percent of production during the same period of 2011.

[30] 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 1.16 Annual hydroelectric production (2003-2012)

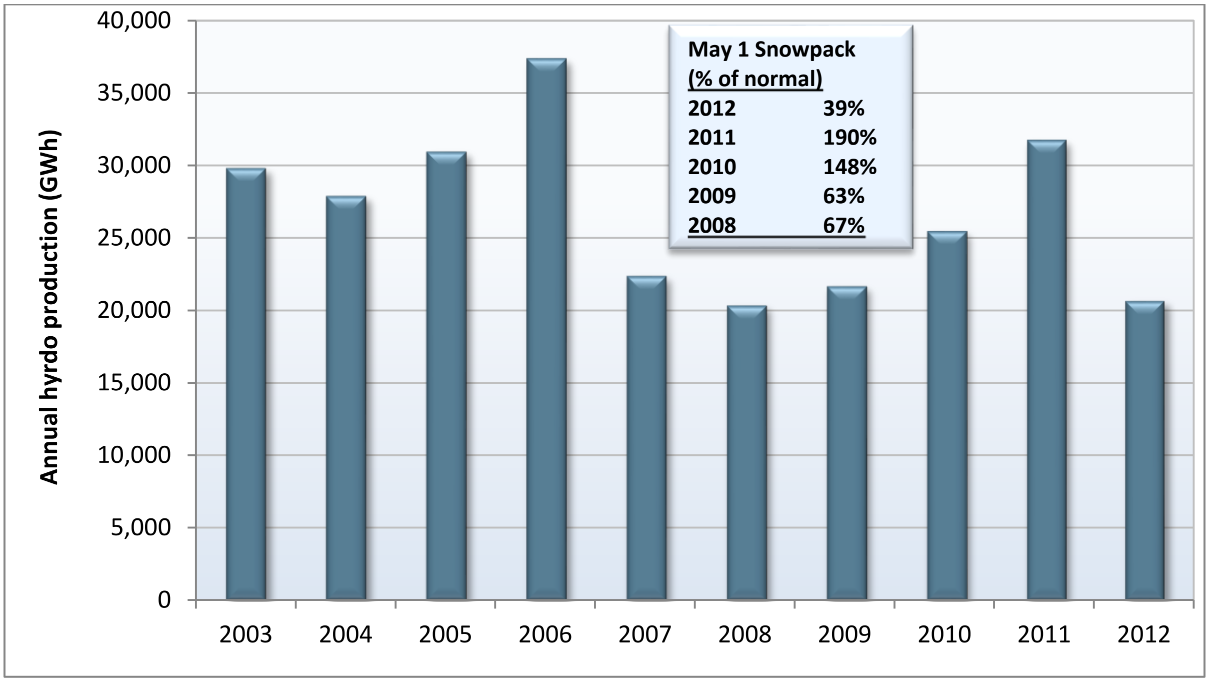
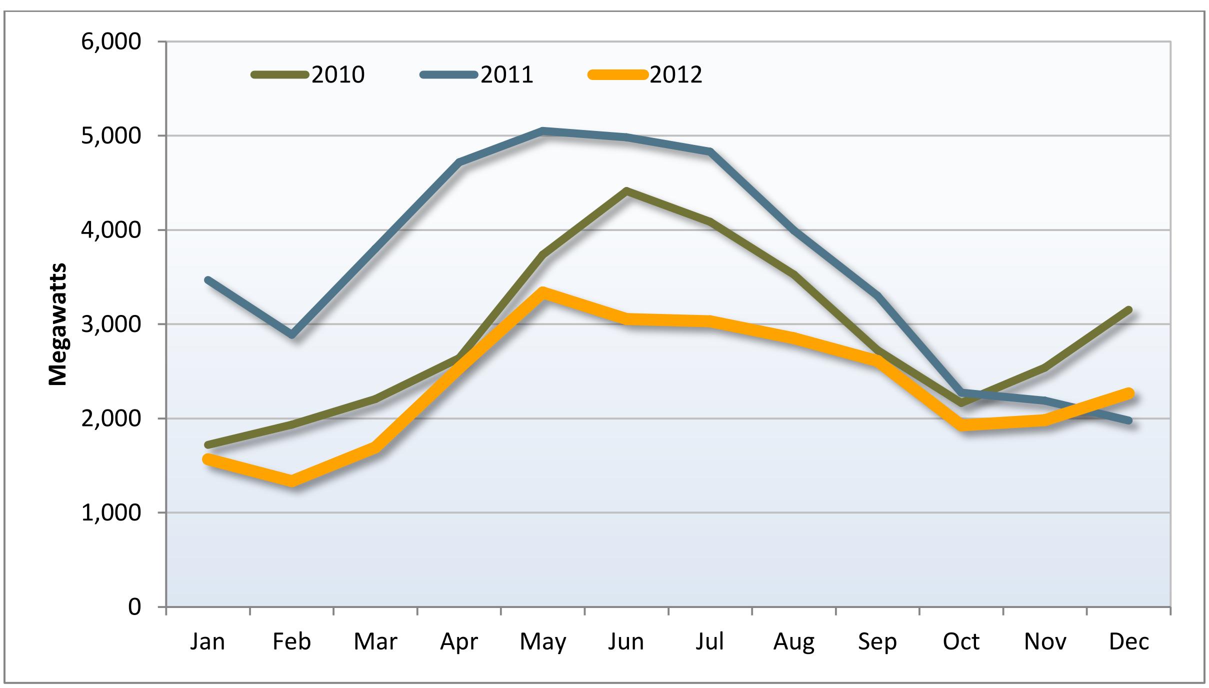


Figure 1.17 Average hourly hydroelectric production by month (2010-2012)

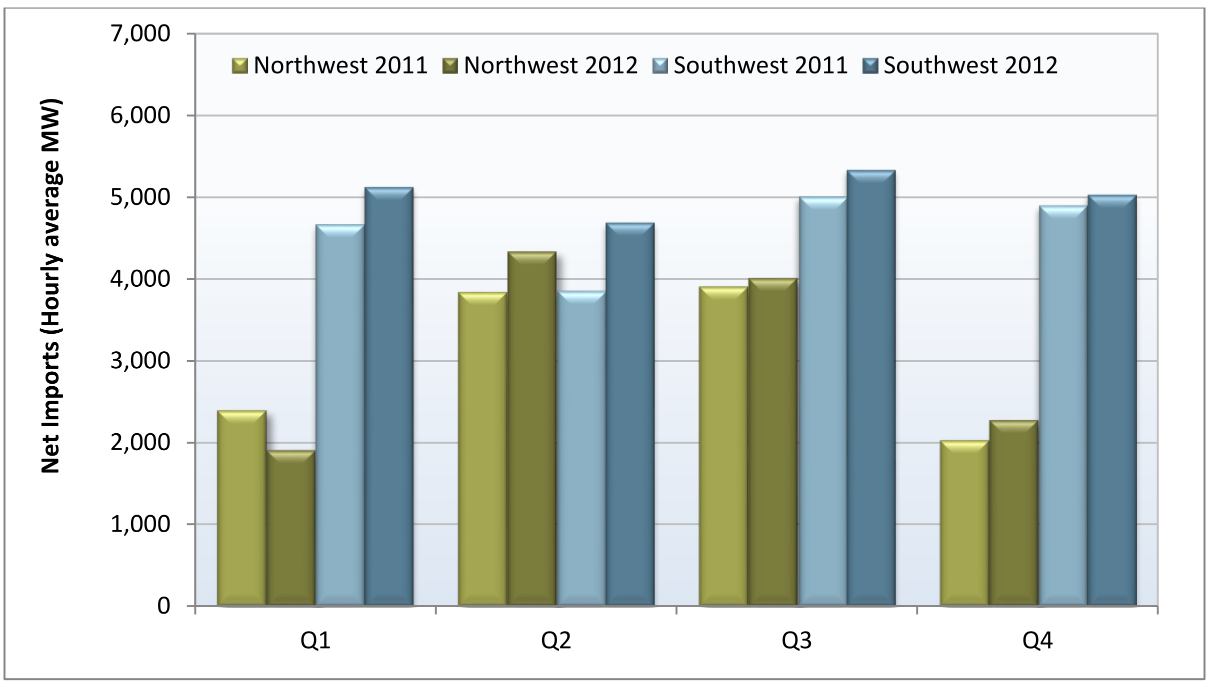


Net imports

Net imports increased by 7 percent in 2012 over 2011.[31] Net imports from the Northwest increased by 3 percent, while net imports from the Southwest increased by 9 percent. Figure 1.18 compares net imports by region for each quarter of 2011 and 2012. This increase in imports was a combination of increasing load, decreased baseload generation availability due to the SONGS outages (see Section 1.2.2) and a substantial decrease in hydro-electric generation within the ISO.

Price differentials between California and adjacent trading hubs reflect these conditions. Falling on-peak prices in the Mid-Columbia trading hub led to increased price differentials between Mid-Columbia and NP15. On-peak prices at the Palo Verde trading hub also decreased substantially in 2012 leading to a relatively large price differential between Palo Verde and SP15 prices. The growth of net imports into the ISO system reflects the changes in the relative price of electricity both within and outside of the ISO system.

Figure 1.18 Net imports by region (2011-2012)



1.2.2 Generation outages

Generation outage levels increased significantly in 2012, due primarily to outages at the San Onofre Nuclear Generating Station. Generation outages are reductions in available capacity from generating units. 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.

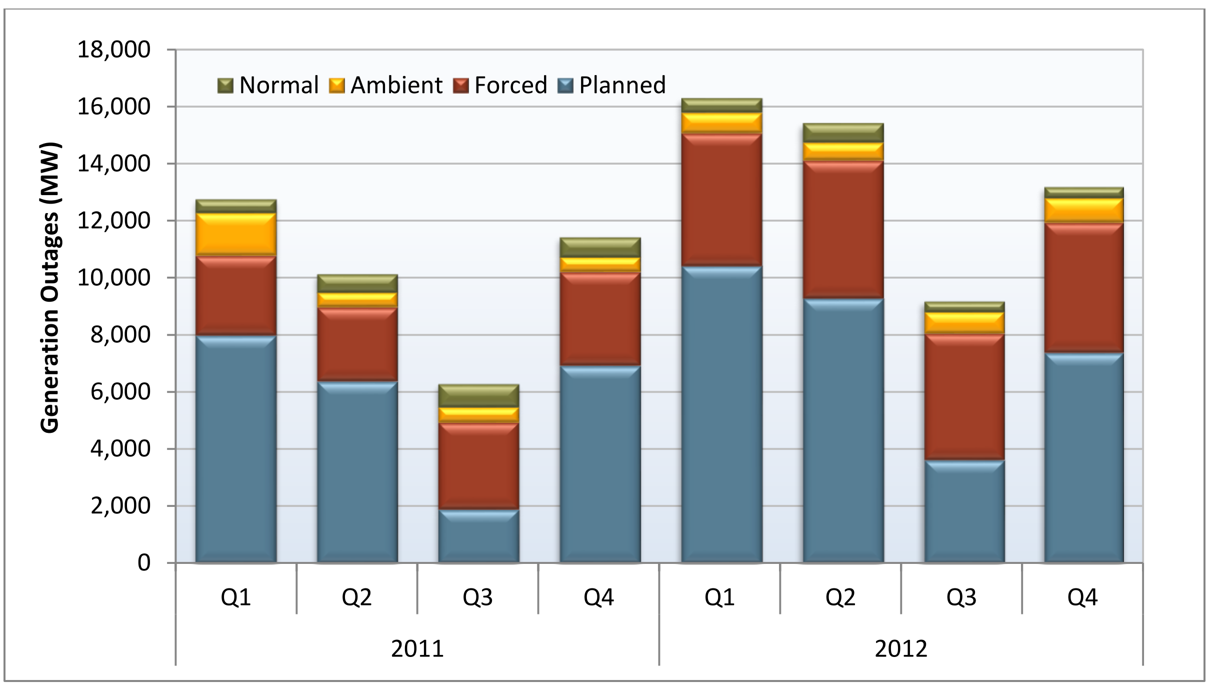
[31] Net imports are equal to scheduled imports minus scheduled exports in any period. The import values discussed in the previous section are total import values.

- ***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.[32]

Figure 1.19 shows the quarterly averages of maximum daily outages broken out by type during peak hours.[33] 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 13,500 MW in 2012 up from 10,200 MW in 2011. The SONGS outages at both units 2 and 3 — totaling 2,250 MW — were the primary driver of increased outages.

Forced outages remained fairly consistent across all quarters in 2012 averaging about 4,600 MW in 2012 up from 2,900 MW in 2011. SONGS unit 3 accounted for the majority of this increase. Planned outages also increased to almost 7,700 MW in 2012 from 5,800 MW in 2011. SONGS unit 2 accounted for the majority of this increase. Ambient outages fell to 750 MW in 2012 from 775 MW in 2012 and normal outages fell to 490 MW in 2012 from 660 MW in 2011.

Figure 1.19 Average of maximum daily generation outages by type – peak hours



[32] 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, SLIC.

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

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 2012, the average weighted price of natural gas in the daily spot markets decreased almost 30 percent from 2011. This was the main driver causing the annual wholesale energy cost per MWh of load served in 2012 to decrease relative to 2011.

Natural gas prices at California trading hubs followed the decrease in prices at the national level. Overall, prices fell in 2012 as the amount in storage was high following a mild winter, and as hydraulic fracturing continues to play a larger role in increasing natural gas supplies. Figure 1.20 shows monthly average natural gas prices for 2009 through 2012 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.

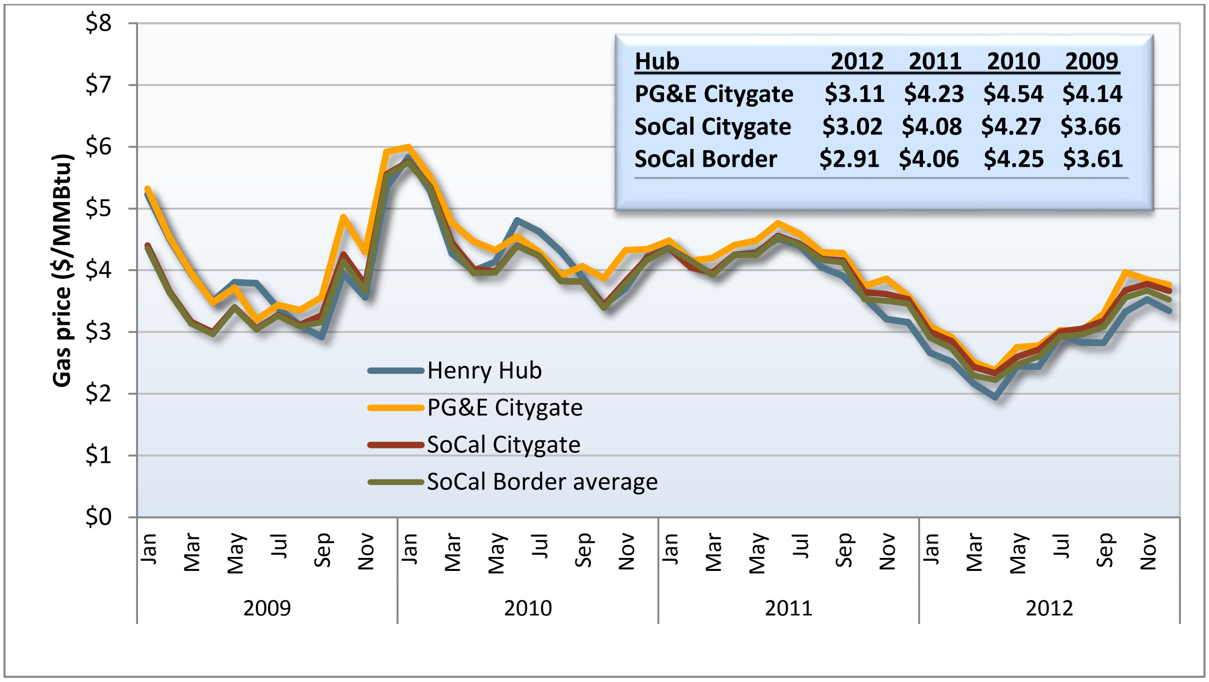
While natural gas prices in California tend to follow national trends, differences can occur that reflect gas pipeline congestion. Because Northern and Southern California are served by different gas producing regions and transportation systems, natural gas prices within California periodically diverge, with prices in Northern California tending to be higher than in Southern California. While the Northern California gas prices remained higher in 2012 compared to Southern California gas prices, the difference in price between the PG&E Citygate and the SoCal Citygate decreased whereas the price difference between the PG&E Citygate and SoCal Border increased.

The SoCal Citygate price, which had historically been closer to the SoCal Border price, was closer to the PG&E Citygate price in 2012. The trend began in the fourth quarter of 2011 and continued through 2012 (as seen in Figure 1.20).

- In 2012, average daily natural gas prices in Northern California exceeded prices at the SoCal Citygate by about $0.09/MMBtu, or 3 percent. In 2011, natural gas prices in Northern California exceeded prices in SoCal Citygate by about $0.15/MMBtu, or 4 percent.
- In 2012, average daily natural gas prices in Northern California exceeded prices at the SoCal Border by about $0.20/MMBtu, or 6 percent. In 2011, natural gas prices in Northern California exceeded prices in SoCal Border by about $0.18/MMBtu, or 4 percent.

While relatively small price differences remain between the northern and southern gas hubs, the overall stabilization of price differences between Northern and Southern California prices was a result of structural changes in the gas markets. These changes include increased production and transportation capacity and lower costs from sources in the northern Rocky Mountain area and Canada to Northern California. The effects of the Ruby Pipeline coming into service in late July 2011 also had a significant effect on reducing the overall price differences. The pipeline takes low cost natural gas from the Rockies to the Northwest.

Figure 1.20 Monthly weighted average natural gas prices (2009-2012)



1.2.4 Generation addition and retirement

California currently relies on long-term procurement planning and resource adequacy requirements placed on load-serving entities to ensure that sufficient capacity is available to meet reliability planning requirements on a system-wide basis and within local areas. Trends in the amount of generation capacity being added and retired in the ISO system each year provide important insight into the effectiveness of the California market and regulatory structure in incenting new generation investment.

Figure 1.21 summarizes trends in the addition and retirement of generation from 2003 through 2012. It also includes planned capacity additions and retirements in 2013.[34] Table 1.4 also shows generation additions and retirements since 2003. It includes projected 2013 changes and totals across the 11-year period (2003 through 2013).

Figure 1.22 and Figure 1.23 show additional generation capacity by generator type. As the figures indicate, most of the additional generation capacity is from wind, solar and natural gas units. The vast majority of the new renewable capacity is expected to come from wind and solar generators.

Generation additions and retirements in 2012

Over 2,000 MW of new generation began commercial operation within the ISO system in 2012. About 1,000 MW of this capacity was installed in the PG&E area and over 1,000 MW came online in the SCE and SDG&E areas. Five major natural gas units were added with 1,350 MW of combined capacity. This

[34] Capacity values in 2011, 2012 and 2013 are calculated summer peak capacity values. The values in 2010 and before are nominal capacity values. For 2012, 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.

additional capacity is offset, in part, by the retirement of units with combined capacity of 440 MW in early 2013.[35] A more detailed listing of units is provided in Table 1.5.

Anticipated additions and retirements in 2013

The ISO anticipates almost 3,650 MW of new generation in 2013.[36] Around 1,350 MW of this capacity is anticipated to come from renewable resources. Table 1.6 provides more detailed information on these projects. The ISO expects about 2,700 MW of this new capacity to be commercially available before the anticipated summer peak season. The ISO expects 440 MW of natural gas capacity to retire before the peak summer months of 2013.

Over the past two years, much of the new gas-fired generation has been offset by the retirement of older gas-fired generation. As a result, non-renewable generation capacity has not grown significantly in the last few years, while renewable generation increases to meet the state's renewable requirements. Both 2012 and 2013 may prove to be exceptions. Beyond 2013, significant reductions in total gas-fired capacity are possible due to the state's restrictions on use of once-through cooling technology.

Meanwhile, the amount of new renewable generation has begun to increase dramatically. As more renewable generation comes online, the ISO has highlighted the need to backup and balance renewable generation with the flexibility of conventional generation resources to maintain reliability.[37]

The state's resource adequacy program continued to work well as a short-term capacity procurement mechanism. However, in 2012 it became increasingly apparent that the state's current process for longer-term procurement may not ensure the investment and revenues needed to support sufficient new or existing gas-fired capacity to integrate the increased amount of intermittent renewable energy coming online. The ISO, CPUC and stakeholders have been working through this issue as a part of several initiatives in 2012, with many continuing into 2013. This represents a major market design challenge facing the ISO and state policy makers.

[35] In 2013, the only units expected to retire are Huntington Beach units 3 and 4. The California Energy Commission approved the conversion of both of these units from energy generators to synchronous condensers supplying voltage support in December 2012. FERC issued an order in Docket No. ER13-351-000 which states, in part, that "Huntington Beach Units 3 and 4, as synchronous condensers, will only produce reactive power to provide voltage support, not energy or other ancillary services, and will not participate in market transactions." http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13148012, page 7.

[36] Capacity values reported in this section are estimated summer capacity, unless otherwise noted.

[37] More information on renewable integration can be found here: http://www.caiso.com/informed/Pages/StakeholderProcesses/IntegrationRenewableResources.aspx.

Figure 1.21 Generation additions and retirements (2003-2013)

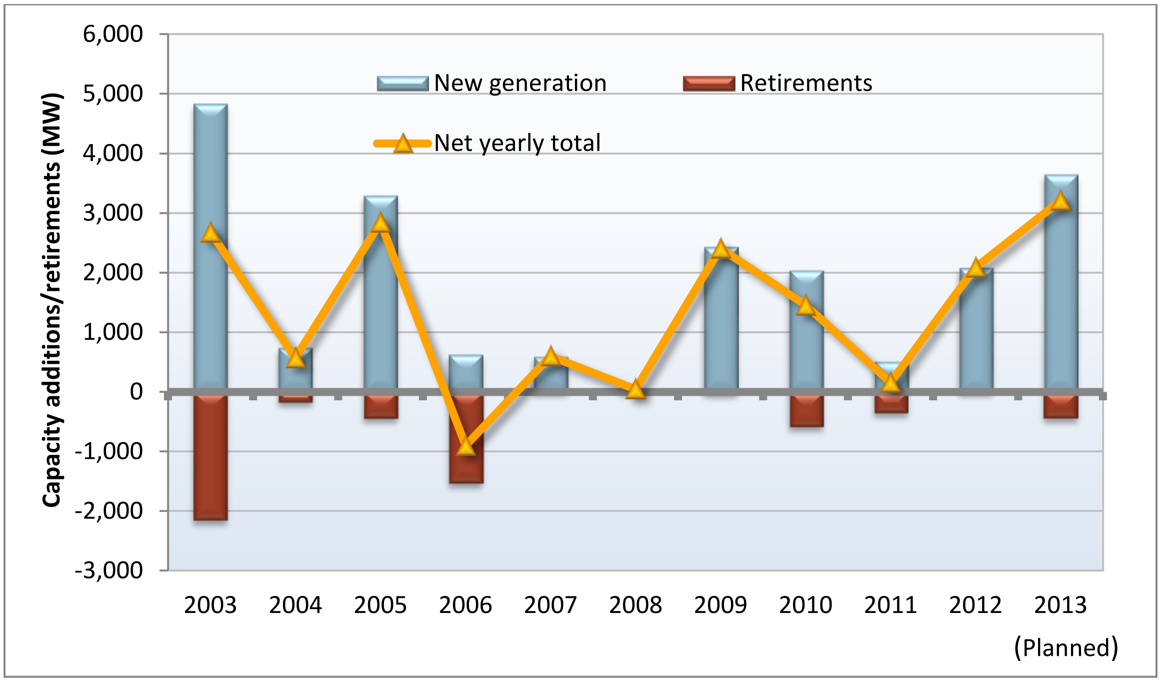


Table 1.4 Changes in generation capacity since 2003

	2003-2007	2008	2009	2010	2011	2012	Projected 2013	Total through 2013
SCE and SDG&E								
New Generation	6,287	45	1,107	1,042	401	1,054	2,410	12,346
Retirements	(3,118)	0	0	(414)	0	0	(440)	(3,972)
Net Change	**3,169**	**45**	**1,107**	**628**	**401**	**1,054**	**1,970**	**8,374**
PG&E								
New Generation	3,816	0	1,329	1,002	115	1,033	1,238	8,533
Retirements	(1,199)	0	(26)	(175)	(362)	0	0	(1,762)
Net Change	**2,617**	**0**	**1,303**	**827**	**(247)**	**1,033**	**1,238**	**6,771**
ISO System								
New Generation	10,104	45	2,436	2,044	516	2,087	3,649	20,880
Retirements	(4,317)	0	(26)	(589)	(362)	0	(440)	(5,734)
Net Change	**5,787**	**45**	**2,410**	**1,455**	**154**	**2,087**	**3,209**	**15,146**

Figure 1.22 Generation additions by resource type (nameplate capacity)

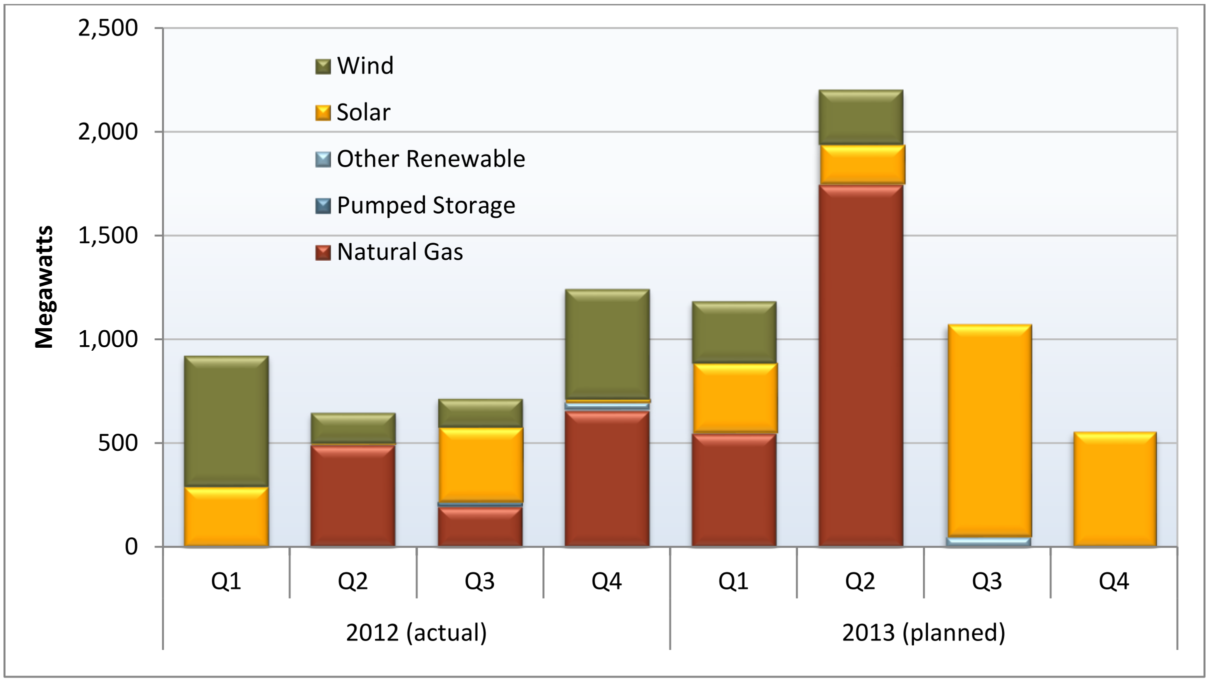


Figure 1.23 Generation additions by resource type (summer peak capacity)

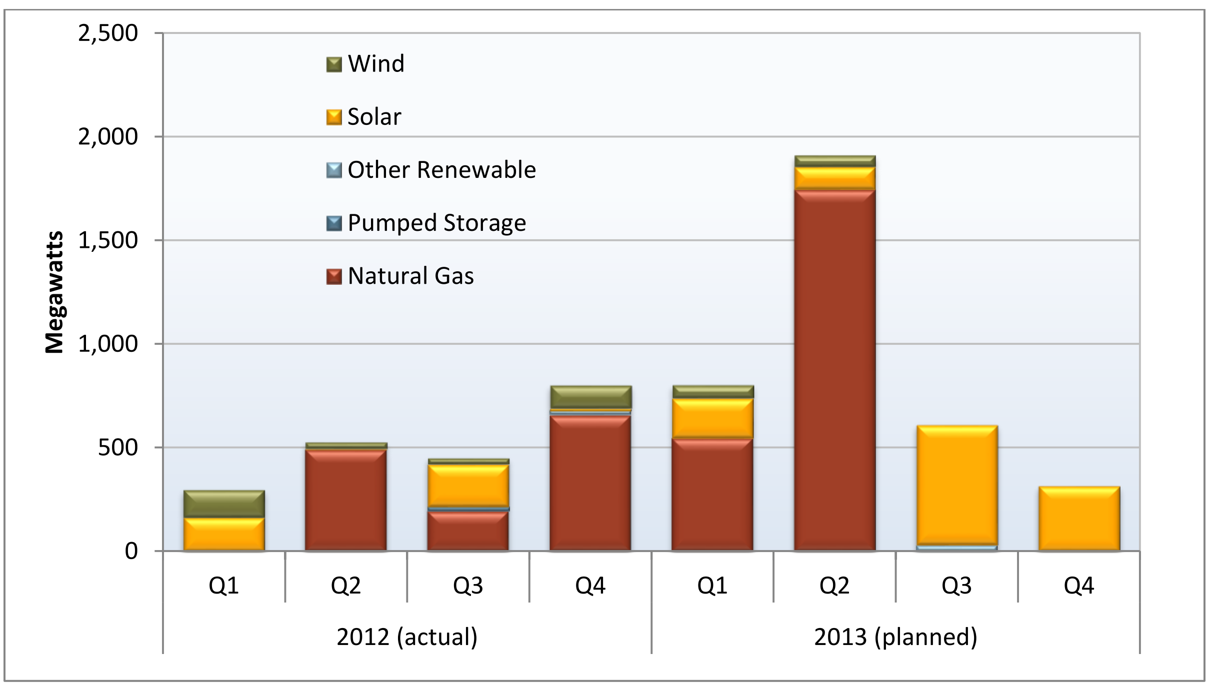


Table 1.5 New generation facilities in 2012

Generating unit	Unit type	Resource capacity (MW)	Summer capacity (MW)	Commercial operation date	Area
Montezuma II *	Wind	78	16	1-Feb-12	PG&E
Solano Wind Project - Phase 3 (230KV) *	Wind	128	27	5-Mar-12	PG&E
Cantua Solar Station *	Solar	20	11	25-Jul-12	PG&E
Giffen Solar Station *	Solar	19	11	25-Jul-12	PG&E
Huron Solar Station *	Solar	20	11	30-Aug-12	PG&E
Gridly 6 Solar*	Solar	3	1	1-Aug-12	PG&E
Mariposa Energy Project	Gas Unit	196	196	4-Sep-12	PG&E
California Valley Solar Ranch-Phase A *	Solar	210	120	19-Sep-12	PG&E
Tracy Combined Cycle Power Plant	Gas Unit	332	332	1-Nov-12	PG&E
Northern California Power Agency	Gas Unit	280	280	27-Nov-12	PG&E
Nickel 1 ("NLH1") *	Solar	2	1	28-Nov-12	PG&E
Shiloh IV Wind Project *	Wind	100	21	8-Dec-12	PG&E
Kiara Anderson *	Biomass	7	4	12-Dec-12	PG&E
Joya Del Sol *	Solar	2	1	21-Dec-12	PG&E
PG&E Actual New Generation in 2012		**1,396**	**1,033**		
Agua Caliente Solar *	Solar	290	165	22-Jan-12	SDG&E
Windstar I *	Wind	120	25	28-Jan-12	SCE
CPC East - Alta Wind VIII *	Wind	150	32	1-Feb-12	SCE
Golden Springs Building C1 *	Solar	1	1	10-Feb-12	SCE
Mountain View IV Wind *	Wind	49	10	23-Feb-12	SCE
NZWIND 6 CALWND*	Wind	9	2	24-Mar-12	SCE
Coram Brodie Wind Project *	Wind	102	21	29-Mar-12	SCE
Golden Solar Building D *	Solar	1	1	2-Apr-12	SCE
North Palm Springs 1 *	Solar	2	1	2-Apr-12	SCE
Industry MetroLink PV1 *	Solar	2	1	3-Apr-12	SCE
SS San Antonio West *	Solar	2	1	4-May-12	SCE
CPC West - Alta Wind 6 *	Wind	150	32	9-May-12	SCE
Desert Star Energy Center	Gas Unit	495	495	18-Jun-12	SCE
Pacific Wind Project *	Wind	140	29	19-Jul-12	SDG&E
Copper Mountain Solar 2 *	Solar	92	52	3-Aug-12	SCE
Lake Hodges Pumped Storage-Unit2	Pumped Storage	20	20	27-Aug-12	SDG&E
Brea Power II *	Biogas	28	17	1-Nov-12	SCE
McGrath Beach Peaker	Gas Unit	47	47	1-Nov-12	SCE
North Palm Springs 4A Solar*	Solar	4	2	2-Nov-12	SCE
SPVP005 Redlands RT Solar *	Solar	3	1	24-Nov-12	SCE
SPVP007 Redlands RT Solar *	Solar	3	1	24-Nov-12	SCE
SPVP018 Fontana RT Solar *	Solar	2	1	24-Nov-12	SCE
SPVP042 Porterville Solar *	Solar	5	3	24-Nov-12	SCE
North Sky River Wind Project *	Wind	160	34	7-Dec-12	SCE
JAWBNE 2 SRWND *	Wind	77	16	11-Dec-12	SCE
Manzana Wind *	Wind	189	40	20-Dec-12	SCE
WKN Wagner, LLC *	Wind	6	1	21-Dec-12	SCE
SPVP044 *	Solar	3	1	30-Dec-12	SCE
SCE and SDG&E Actual New Generation in 2012		**2,150**	**1,054**		
Total Actual New Generation in 2012		**3,546**	**2,087**		
Total Renewable Generation in 2012*		**2,175**	**716**		

Source: California ISO Interconnection Resources Department

Table 1.6 Planned generation additions in 2013

Generating unit	Number of projects	Resource capacity (MW)	Summer capacity (MW)	Commercial operation date	Area
Solar Project *	1	40	23	Jan-13	PG&E
Solar Project *	1	90	51	Mar-13	PG&E
Gas Project (Net Replacement)	1	126	126	May-13	PG&E
Solar Project *	1	20	11	May-13	PG&E
Gas Project	2	940	940	Jun-13	PG&E
Solar Project *	5	34	19	Jun-13	PG&E
Solar Project *	3	41	24	Jul-13	PG&E
Biogas-Biomass Project *	1	50	30	Sep-13	PG&E
Solar Project *	1	2	1	Sep-13	PG&E
Solar Project *	1	20	11	Oct-13	PG&E
Biogas-Biomass Project *	1	2	1	Oct-13	PG&E
PG&E Total New Generation in 2013		**1,365**	**1,238**		
Gas Project	1	49	49	Jan-13	SCE
Solar Project *	4	73	42	Jan-13	SCE
Wind Project *	2	300	63	Jan-13	SCE
Solar Project *	2	136	78	Feb-13	SDG&E
Gas Project	1	501	501	Mar-13	SCE
Solar Project *	1	137	78	Apr-13	SCE
Gas Project	1	800	800	May-13	SCE
Gas Project (Net Replacement)	1	-120	-120	Jun-13	SCE
Wind Project *	1	265	56	Jun-13	SDG&E
Solar Project *	1	18	10	Jul-13	SCE
Solar Project *	3	809	461	Aug-13	SCE
Solar Project *	1	5	3	Sep-13	SCE
Solar Project *	1	150	86	Sep-13	SDG&E
Solar Project *	1	133	76	Oct-13	SCE
Solar Project *	3	384	219	Oct-13	SDG&E
Solar Project *	1	19	11	Nov-13	SCE
SCE and SDG&E Total New Generation in 2013		**3,658**	**2,410**		
Total Planned New Generation in 2013		**5,023**	**3,649**		
Total New Renewable Generation in 2013*		**2,727**	**1,353**		

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.[38] Costs used in the analysis are based on a preliminary 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 1.7. Results for a typical new combined cycle unit are shown in Table 1.8 and Figure 1.24. The 2012 net revenue results show an increase in net revenues compared to 2011. The 2012 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 provided in the CEC workshop.

Table 1.7 Assumptions for typical new combined cycle unit[39]

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**

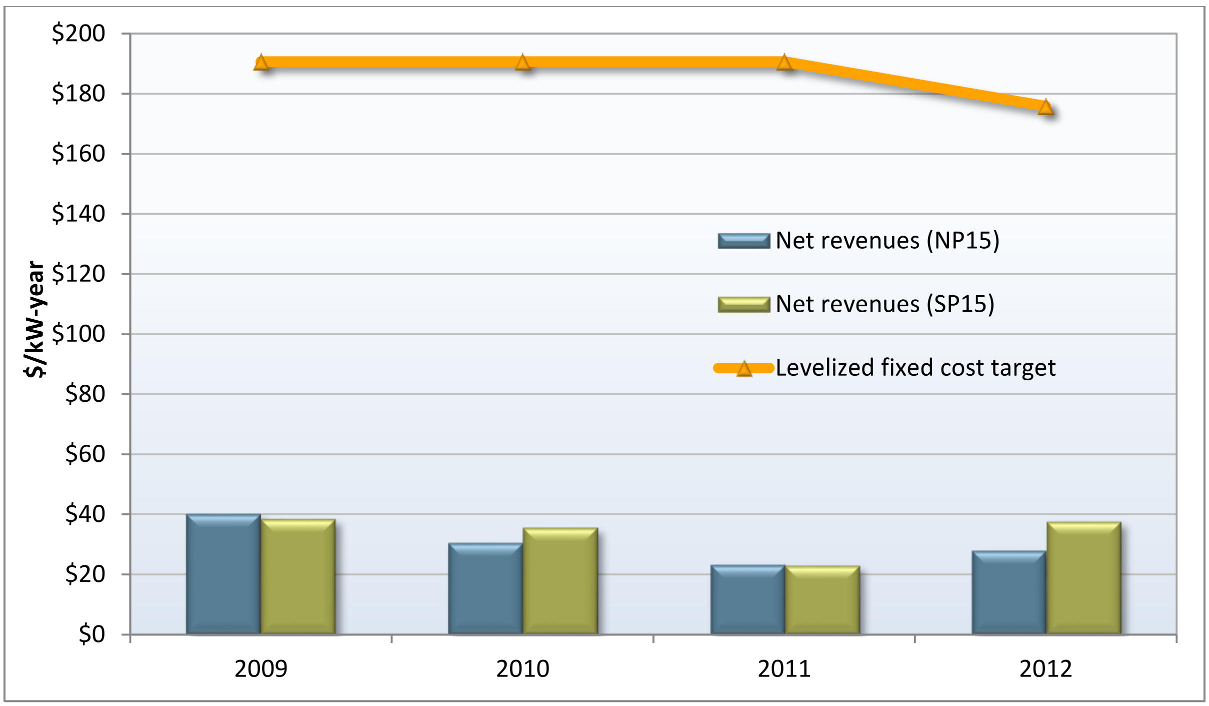
[38] A more detailed description of the methodology and results of the analysis presented in this section are provided in Appendix A.1 of DMM's *2009 Annual Report on Market Issues & Performance,* April 2010, which can be found at http://www.caiso.com/2777/27778a322d0f0.pdf.

[39] 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 numbers reported in the workshop are preliminary numbers. 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 1.8 Financial analysis of new combined cycle unit (2009-2012)

Components	2009		2010		2011		2012	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	57%	57%	67%	74%	53%	66%	70%	75%
DA Energy Revenue ($/kW - yr)	$172.67	$169.61	$137.95	$142.65	$101.62	$94.27	$118.95	$134.59
RT Energy Revenue ($/kW - yr)	$21.27	$15.50	$34.89	$37.31	$28.62	$30.84	$11.70	$11.62
A/S Revenue ($/kW – yr)	$0.76	$0.85	$1.01	$1.25	$1.71	$2.29	$0.37	$0.39
Operating Cost ($/kW - yr)	$154.57	$147.48	$143.25	$145.69	$108.65	$104.41	$103.01	$108.96
Net Revenue ($/kW – yr)	$40.14	$38.48	$30.60	$35.52	$23.30	$22.99	$28.02	$37.64
5-yr Average ($/kW – yr)	*$30.51*	*$33.66*						

Figure 1.24 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 1.9. Table 1.10 and Figure 1.25 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 an increase in the net revenues in the SP15 area and a slight decrease in the net revenues in the NP15 area in 2012. 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 1.9 Assumptions for typical new combustion turbine[40]

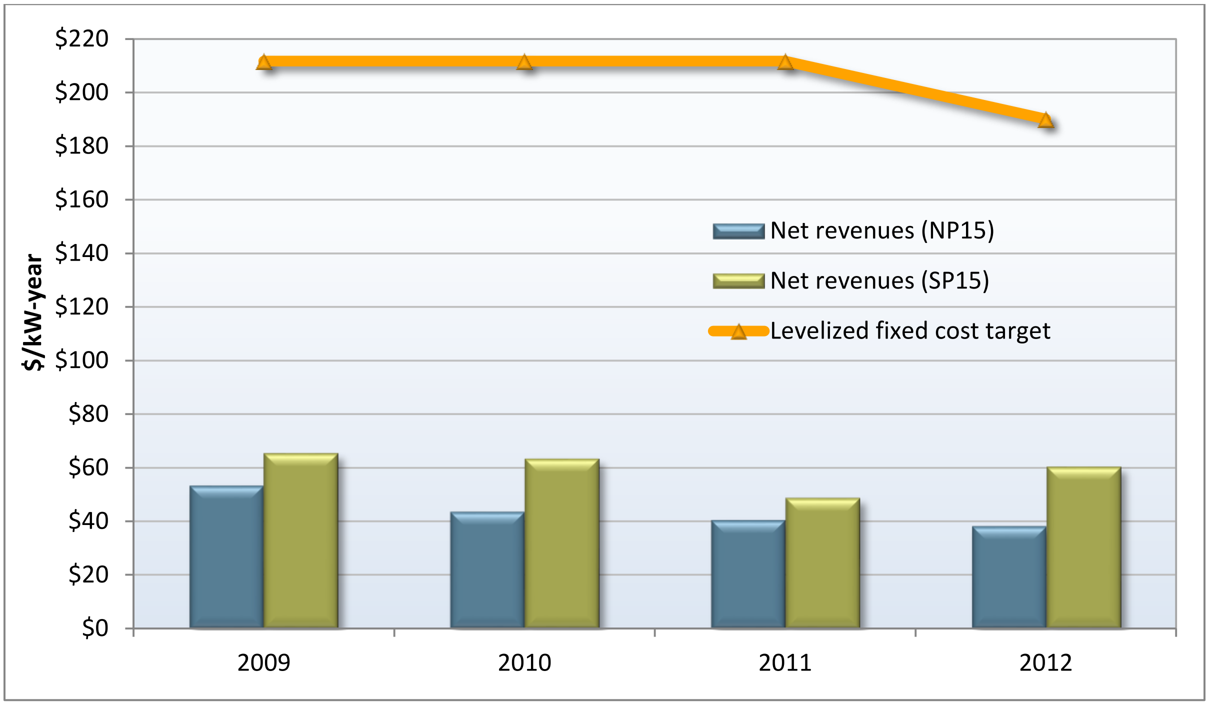
Technical Parameters	
Maximum Capacity	100 MW
Minimum Operating Level	40 MW
Startup Gas Consumption	180 MMBtu/start
Heat Rates (MBTU/MW)	
Maximum Capacity	9,300
Minimum Operating Level	9,700
Financial Parameters	
Financing Costs	$116.2 /kW-yr
Insurance	$8.8 /kW-yr
Ad Valorem	$11.6 /kW-yr
Fixed Annual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

Table 1.10 Financial analysis of new combustion turbine (2009-2012)

Components	2009		2010		2011		2012	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	6%	6%	7%	10%	6%	7%	5%	8%
Energy Revenue ($/kW - yr)	$70.50	$84.62	$64.97	$95.94	$57.60	$69.57	$48.78	$78.89
A/S Revenue ($/kW - yr)	$8.64	$8.37	$3.36	$2.97	$6.06	$5.98	$4.29	$5.04
Operating Cost ($/kW - yr)	$25.85	$27.70	$24.80	$35.60	$23.23	$26.88	$14.82	$23.62
Net Revenue ($/kW - yr)	$53.29	$65.29	$43.54	$63.32	$40.43	$48.67	$38.26	$60.32
5-yr Average ($/kW - yr)	*$43.88*	*$59.40*						

[40] 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 numbers reported in the workshop are preliminary numbers. 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 1.25 Estimated net revenues of new combustion turbine



These findings continue to underscore the critical importance of long-term contracting as the primary means for facilitating new generation investment. Local requirements for new generation investment should be addressed through long-term bilateral contracting under the CPUC resource adequacy and long-term procurement framework. Under California's current market design, these programs can provide additional revenue for new generation and cover the gap between annualized capital cost and the simulated net spot market revenues provided in the previous section.

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 Section 9.7 and Chapter 10 of this report.

2 Overview of market performance

The ISO's markets continued to perform efficiently and competitively overall in 2012.

- Total wholesale electric costs fell by 2 percent. However, natural gas prices dropped almost 30 percent, so that ISO prices were higher after accounting for lower gas prices. This increase was driven by a combination of higher loads, lower hydro-electric supply, over 2,000 MW of nuclear generation outages and increased congestion.
- Overall prices in the ISO energy markets over the course of 2012 were about equal to what DMM estimates would result under highly competitive conditions. About 97 percent of system load was scheduled in the day-ahead energy market, which continued to be highly efficient and competitive.
- Average real-time prices were driven higher than day-ahead market prices by relatively infrequent but high price spikes during some periods. Real-time prices spiked over $250/MWh in about 1 percent of 5-minute intervals, with many of these spikes being driven by congestion.

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

- The ISO implemented new automated local market power mitigation procedures in the day-ahead and real-time software that mitigated local market power very effectively and accurately. This helped keep prices at competitive levels during most peak summer load periods.
- Ancillary service costs totaled $84 million, or about 1 percent of total energy costs compared to about 2 percent in 2011. This decrease was partly driven by the decrease in natural gas prices and increased use of limited hydro supplies to provide spinning reserves rather than energy.
- Bid cost recovery payments totaled $104 million, or about 1.3 percent of total energy costs in 2012, compared to 1.5 percent in 2011.
- 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, increased from 2011 but remained relatively low. Energy from exceptional dispatches totaled about 0.53 percent of total system energy in 2012 compared to 0.40 percent in 2011.
- Although the volume of energy from exceptional dispatches increased, the above-market costs resulting from these exceptional dispatches decreased from $43 million in 2011 to $34 million in 2012. These costs decreased because more of these dispatches were made to manage congestion on uncompetitive constraints and were therefore subject to local market power provisions in the ISO tariff.

Congestion increased significantly in 2012, largely as the result of new reliability constraints incorporated in the market models and outages of the SONGS nuclear generating units. This congestion impacted market performance in numerous ways:

- Congestion within the ISO system resulted in an increase in price divergence between overall locational market prices in the day-ahead, hour-ahead and real-time markets. Real-time congestion was typically higher than in the day-ahead market as a result of reductions in transmission constraint limits made in response to power flows observed in real-time.

- High real-time congestion drove real-time market revenue imbalance charges allocated to load-serving entities higher. These charges increased from $28 million in 2011 to $186 million in 2012, or about 2 percent of total wholesale costs.
- Almost all of the $56 million in net profits received by convergence (or virtual) bidders was the result of differences in day-ahead and real-time congestion. In 2011, most profits received by virtual bidders resulted from divergence in system energy prices between the day-ahead, hour-ahead and real-time markets.

2.1 Total wholesale market costs

The total estimated wholesale costs of serving load in 2012 were $8.4 billion or just under $36/MWh. This represents a decrease of about 2 percent per megawatt hour from a cost of over $36/MWh in 2011. While electricity prices decreased slightly, natural gas prices decreased significantly in 2012 (almost 30 percent).[41] Much of this decrease occurred in the first half of the year. After accounting for lower gas prices, DMM estimates that total wholesale energy costs increased from $33/MWh in 2011 to over $42/MWh in 2012, representing an increase of over 28 percent in gas-normalized prices.[42]

A variety of factors contributed to the increase in gas-normalized total wholesale costs in 2012. As highlighted elsewhere in this report, conditions that contributed to higher prices include the following:

- Higher average loads and higher summer peak loads;
- Lower in-state hydro-electric generation;
- Outages of over 2,000 MW of nuclear generation for most of the year (SONGS units 2 and 3); and
- Increased regional congestion.

While there were several factors contributing to higher prices, there were other factors in addition to lower natural gas prices contributing to driving prices lower. These factors are discussed in the following sections and chapters of this report and include the following:

- Increased imports from the Southwest and the Northwest;
- Additions of new generation capacity;
- Relatively high day-ahead scheduling of load relative to actual loads; and
- More effective local market power mitigation on uncompetitive constraints.

Figure 2.1 shows total estimated wholesale costs per MWh of system load from 2009 to 2012. Wholesale costs are provided in nominal terms, as well as after normalization for changes in average spot market prices for natural gas. The green line representing the annual average of daily natural gas prices is included to illustrate the correlation between the cost of natural gas and the total wholesale cost estimate.

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

[42] Gas prices are normalized to 2009 prices.

Figure 2.1 Total annual wholesale costs per MWh of load (2009-2012)

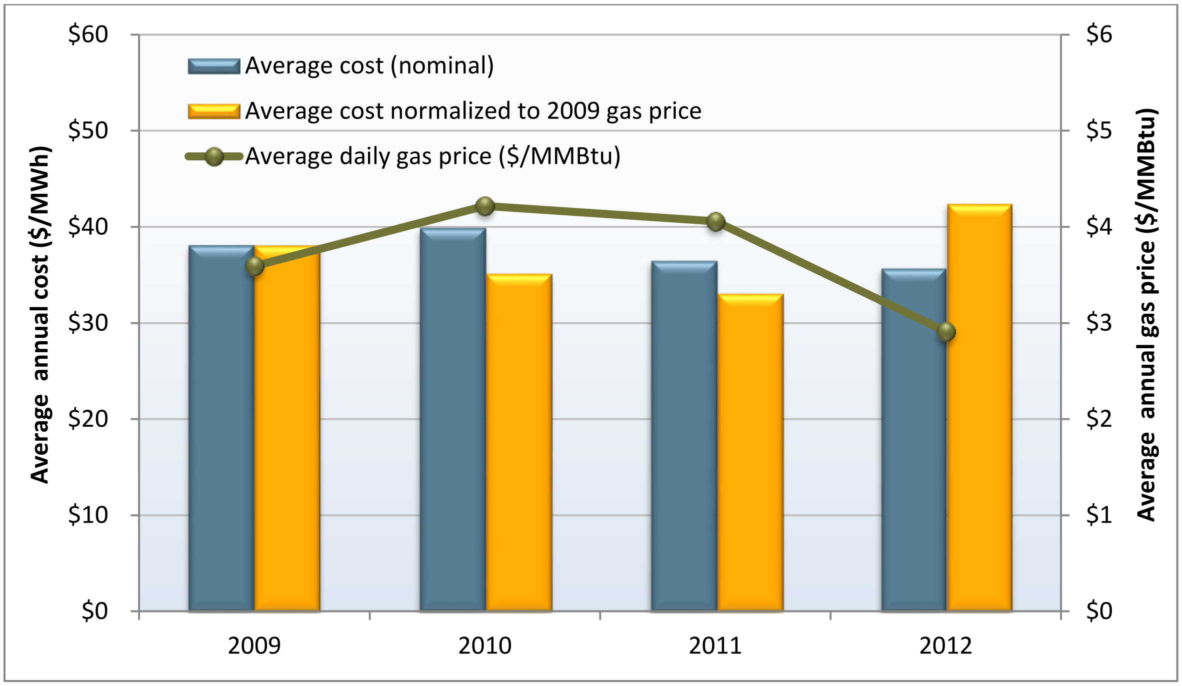


Table 2.1 provides annual summaries of nominal total wholesale costs by category for years 2009 through 2012. Under the nodal market design, which began in 2009, total wholesale market costs are estimated based on prices and quantities cleared in each of the three energy markets: day-ahead, hour-ahead and 5-minute real-time 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, and the flexible ramping constraint and grid management charges.[43]

As seen in Table 2.1, most cost categories decreased in 2012 relative to 2011. The decrease in nominal wholesale costs is mostly due to a decrease in day-ahead and real-time energy costs. The primary factor causing this decrease was the significant decrease in natural gas prices. The majority of the decrease in day-ahead and real-time energy costs occurred in the first half of 2012. Ancillary service costs decreased, compared to 2011, due to decreases in gas prices and increased usage of limited hydro-electric supplies to provide spinning reserves. Reliability costs increased to address local reliability concerns related to the outage of SONGS units 2 and 3.

[43] 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. In last year's report, DMM broke out net convergence bidding costs as its own category. This year, DMM has enhanced the methodology to include the gross convergence bidding revenues and costs as part of both the day-ahead and real-time market costs for both 2011 and 2012. As a result of this change and other minor adjustments, the wholesale numbers in 2011 changed slightly.

Table 2.1 Estimated average wholesale energy costs per MWh (2009-2012)

	2009	2010	2011	2012	Change '11-'12
Day-Ahead Energy Costs (excl. GMC)	$ 35.57	$ 37.37	$ 32.88	$ 32.57	$ (0.30)
Real-Time Energy Costs (incl. Flex Ramp)	$ 0.81	$ 0.73	$ 1.60	$ 1.35	$ (0.25)
Grid Management Charge	$ 0.78	$ 0.79	$ 0.79	$ 0.80	$ 0.01
Bid Cost Recovery Costs	$ 0.29	$ 0.37	$ 0.56	$ 0.45	$ (0.11)
Reliability Costs (RMR and CPM)	$ 0.25	$ 0.27	$ 0.03	$ 0.14	$ 0.11
Average Total Energy Costs	**$ 37.70**	**$ 39.53**	**$ 35.86**	**$ 35.32**	**$ (0.55)**
Reserve Costs (AS and RUC)	$ 0.39	$ 0.38	$ 0.62	$ 0.37	$ (0.24)
Average Total Costs of Energy and Reserve	**$ 38.09**	**$ 39.91**	**$ 36.48**	**$ 35.69**	**$ (0.79)**

2.2 Overall market competitiveness

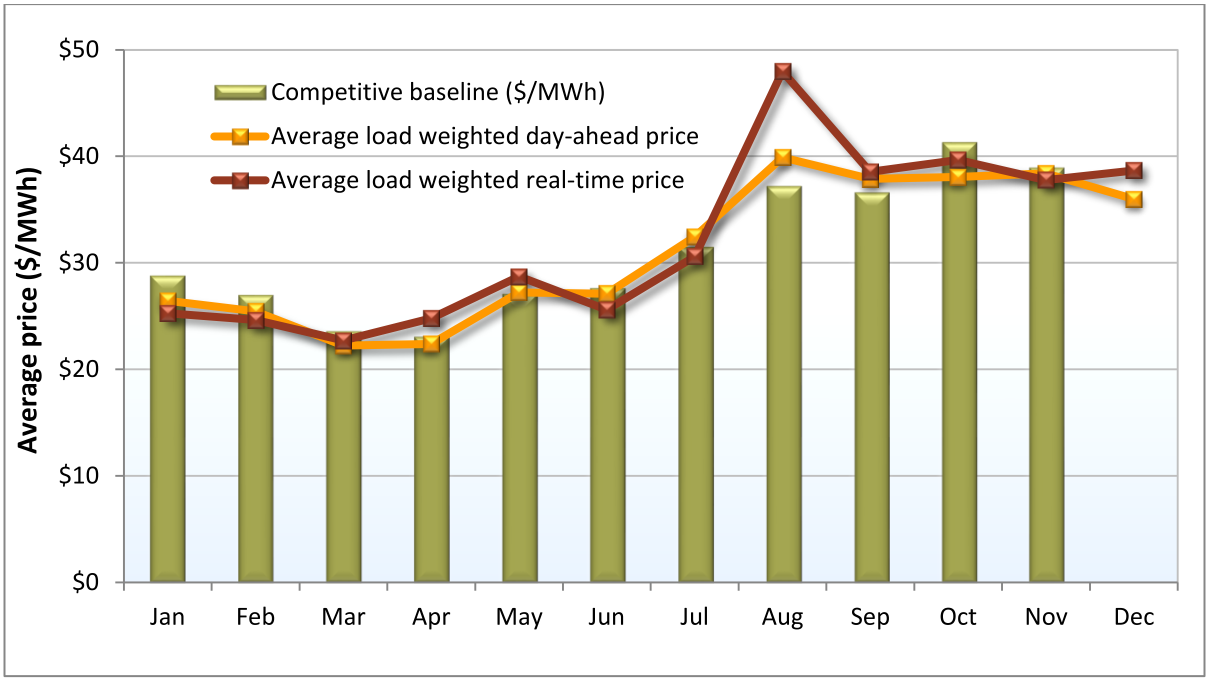
To assess the competitiveness of the ISO energy markets, DMM compares actual market prices to competitive benchmark prices we estimate would result under highly competitive conditions. DMM estimates competitive baseline prices by re-simulating the market using the day-ahead market software with bids reflecting the actual marginal cost of gas-fired units.[44] Figure 2.2 compares this competitive baseline price to average system-wide prices in the day-ahead 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 of the system conditions and limitations that impact real-time prices.

As seen in Figure 2.2, prices in the day-ahead market were about equal to the competitive baseline prices in most months, but exceeded this baseline price by about 7 percent in the peak load month of August. High prices in August were driven by high congestion on constraints in Southern California, along with peak loads and uncompetitive bidding by some market participants. Under these conditions, high prices can occur because a limited set of resources are available to resolve transmission conditions.

In the real-time market, average system-wide prices were lower than the competitive baseline in 2012 in most months except for April, May, August and September. In the peak month of August, high real-time prices were driven by congestion impacting Southern California prices related to peak loads, unscheduled flows and wildfires. In the real-time market, congestion typically causes prices to rise more sharply than in the day-ahead market because there is a much more limited set of resources available to resolve the transmission conditions.

[44] A more detailed description of the methodology used to estimate competitive baseline prices and the price-cost mark-up is provided in DMM's *Quarterly Report on Market Issues and Performance*, February 13, 2012, p. 14, http://www.caiso.com/Documents/QuarterlyReport_Market%20Issues_Performance-February2012.pdf. Due to technical limitations, DMM was unable to rerun the day-ahead model with actual load starting in May. For the remaining months of the year, DMM calculated the competitive baseline by setting bids for gas-fired generation to their default energy bids (DEBs), including convergence bids and running the day-ahead market with bid-in load. With this approach, the combination of cleared virtual demand and physical demand was very close to actual and forecast load. Thus, DMM believes that this is a reasonable approach to calculate the overall competitive baseline given these rerun limitations.

Figure 2.2 Comparison of competitive baseline with day-ahead and real-time load weighted prices[45]



As discussed in Chapter 6 of this report, new local market power bid mitigation procedures implemented in 2012 helped keep prices competitive by effectively mitigating the exercise of local market power. In August, the ISO also gained approval from FERC to expand market power mitigation provisions applicable to exceptional dispatches issued to units needed to meet special reliability requirements not incorporated in the real-time market model.[46] This expansion of mitigation for exceptional dispatches further deters uncompetitive bidding in the day-ahead and real-time energy markets by units frequently needed to meet these special reliability requirements. Additional discussion of this is provided in Section 6.3.2 of this report.

DMM also calculates an overall price-cost mark-up by comparing competitive baseline prices to total average wholesale energy costs.[47] Total costs used in this analysis represent a load-weighted average of all energy transactions in the day-ahead, hour-ahead and real-time markets.[48] Thus, this analysis includes energy procured at higher prices in the real-time market, as well as net energy sales in the hour-ahead market at lower prices.

[45] DMM was unable to rerun most save cases in December due to technical difficulties. We will replicate the December runs when we begin analysis of 2013 results.

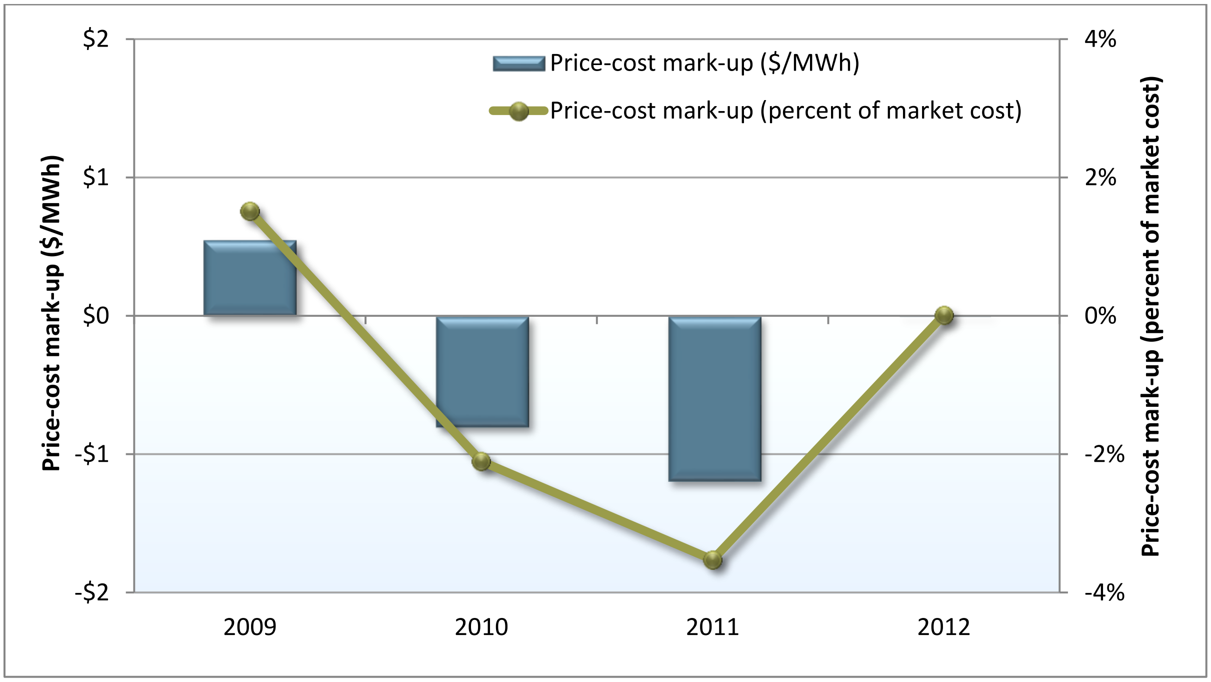
[46] See "Exceptional Dispatch and Residual Imbalance Energy Mitigation Tariff Amendment" in FERC Docket No. ER12-2539-000, August 28, 2012, at: http://www.caiso.com/Documents/August282012ExceptionalDispatch-ResidualImbalanceEnergyMitigationTariffAmendment-DocketNoER12-2539-000.pdf.

[47] 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, but the competitive baseline price was $50/MWh, this would represent a price-cost markup of 10 percent.

[48] These costs are based on the same data and methodology used in the analysis of total wholesale energy costs provided in Section 2.1.

In 2012, DMM estimated the overall price-cost mark-up to be about 0.01 percent, as seen in Figure 2.3. In 2010 and 2011, the overall price-cost mark-up was slightly negative, about -2 percent and -4 percent, respectively.[49] The higher price-cost mark-up in 2012 was driven by increases in the summer peak load months relative to other months. The price-cost mark-up and other analysis in this report indicate that prices under the nodal market design have been very competitive, overall.

Figure 2.3 Price-cost mark-up (2009-2012)



2.3 Day-ahead scheduling

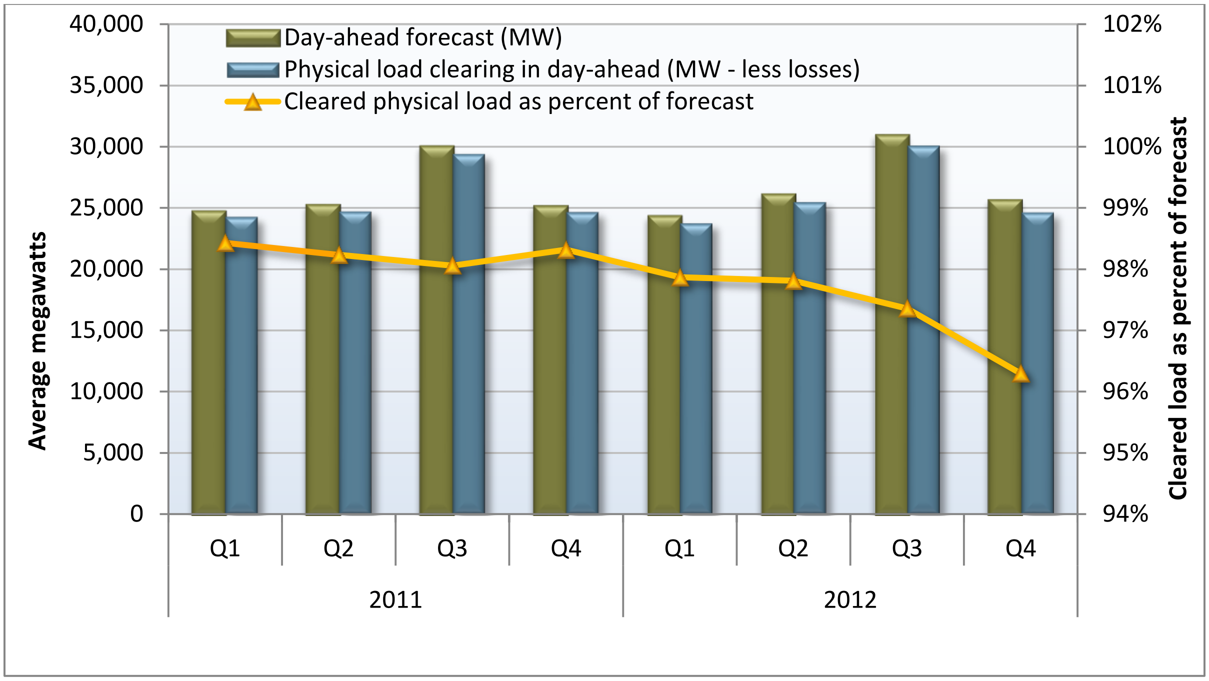
The level of physical load bids clearing the day-ahead market continued to be high in 2012, averaging about 97 percent of total forecast demand and actual loads. Although a relatively small volume of physical demand is settled in the real-time market, this represents a change from previous years, when about 99 percent of physical load had been scheduled in the day-ahead market. However, when net virtual demand resulting from convergence bids is added to the scheduled physical load, total demand clearing the day-ahead market has continued to match the day-ahead load forecast very closely, especially during peak hours. Figure 2.4 compares the average level of physical load clearing in the day-ahead market to the forecast of demand. In the third and fourth quarters, physical load as a percentage of forecasted load clearing the day-ahead market began to trend downward. In the fourth quarter, physical load clearing the day-ahead market averaged about 96 percent of the load forecast, the lowest point in over two years.

While the ISO's load forecast tended to match the actual load for most of the day, physical load clearing the day-ahead market was often lower than the forecast during the peak hours. However, during peak

49 As previously noted, DMM was unable to rerun most save cases in December due to technical difficulties. We will replicate the December runs when we begin analysis of 2013 results.

hours virtual demand tended to drive total load clearing the day-ahead market up to levels about equal to or above actual and forecasted system loads.

Figure 2.4 Physical load clearing day-ahead market compared to load forecast

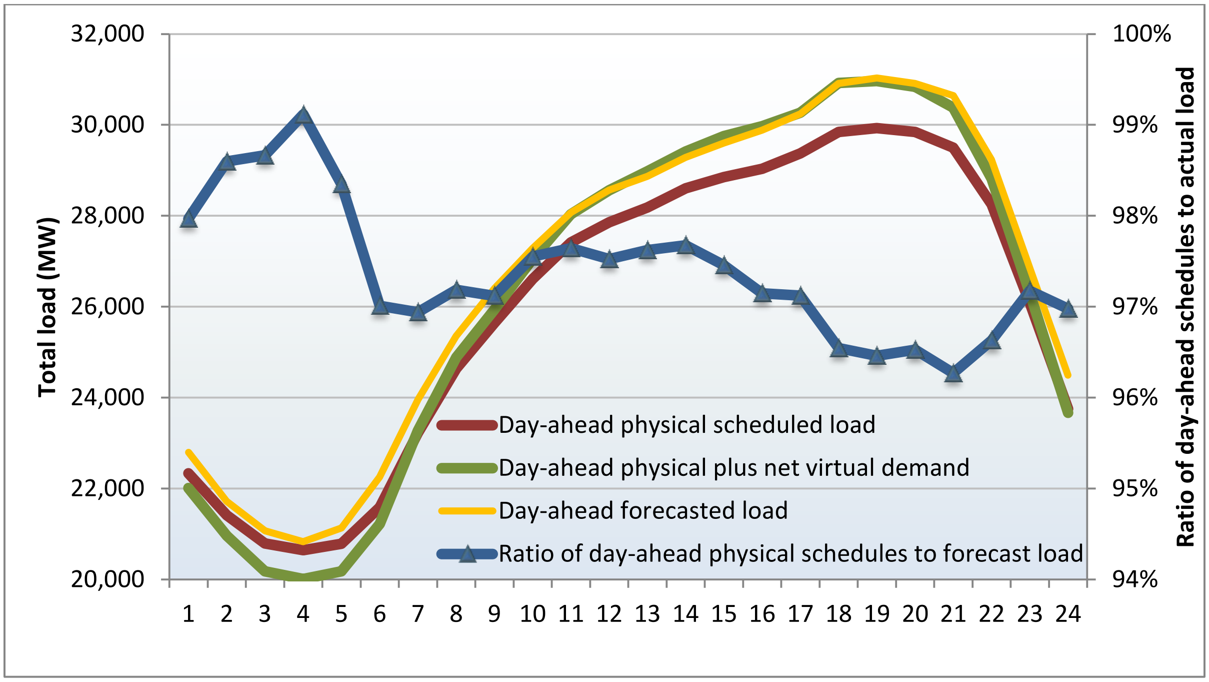


As shown in Figure 2.5, average physical load clearing the day-ahead market over the course of 2012 (red line) was less than the load forecast (yellow line) during many hours of the day, with the greatest differences falling in the evening peak hours. During the late evening off-peak hours and morning ramping hours, the load schedules tended to be close to forecast loads. In previous years, average physical load scheduled in the day-ahead market equaled about 99 percent of forecast load, particularly in the peak hours.

However, as also shown in Figure 2.5, the average total amount of demand, including net virtual demand from all convergence bids, clearing the day-ahead market (green line) matched the day-ahead forecast load (yellow line) very closely in the peak hours, while falling below the forecast of load in the off-peak hours. This reflects an average net virtual bidding position of net demand in the peak hours and net supply during the off-peak hours. The lower scheduling of physical load in peak hours reflects a substitution of price sensitive bids for physical demand by convergence bids.

Virtual bidding trends are discussed in more detail in Chapter 4 (Section 4.1) of this report. As noted in Chapter 4, during many peak hours of the summer months when average real-time prices exceeded average day-ahead prices, virtual demand pushed total demand clearing the day-ahead market an average of about 1,000 MW over actual and forecasted loads.

Figure 2.5 Day-ahead schedules, forecast and actual load (2012)



Self-scheduling of loads and generation

The high level of scheduling in the day-ahead market is due largely to a very high level of self-scheduling of loads and generation.

Figure 2.6 shows the portion of load clearing the day-ahead market comprised of self-schedules and price-taking demand bids, as opposed to price-sensitive demand bids.[50] Self-scheduled and price-taking demand bids accounted for an average of 95 to 96 percent of load clearing the day-ahead market in 2012, up just slightly from 2011. This self-scheduled or price-taking load also equaled about 96 percent of the forecast of actual load in both 2011 and 2012. This indicates that load-serving entities continue to be price takers for a very high level of their actual load, while submitting price sensitive bids for the remainder. As noted above, a lower portion of these price sensitive physical demand bids cleared the day-ahead market in 2012, while additional higher priced virtual demand bids cleared the market.

Figure 2.7 shows the portion of supply clearing the day-ahead market comprised of self-scheduling and price-taking bids.[51] Extremely high levels of self-scheduled supply can decrease market efficiency by reducing the degree to which the market software is free to optimize supply resources based on their bid costs. High levels of self-scheduling can also hinder the ability to manage congestion in the most cost-effective manner. The total amount of self-scheduled and price-taking supply has decreased each quarter since the second quarter of 2011.

[50] In this analysis, DMM classified load bids within $5/MWh of the maximum bid cap as price-taking because these bids are virtually certain to clear the day-ahead market. The energy bid cap was $750/MWh from April 1, 2010 to March 31, 2011. The energy bid cap increased to $1,000/MWh on April 1, 2011.

[51] In this analysis, DMM classified supply bids between the energy bid floor and $0/MWh as price-taking supply because these bids are virtually certain to clear the day-ahead market. The energy bid floor was -$30/MWh in 2011 and 2012.

Figure 2.6 Average self-scheduled load as a percent of total load cleared in day-ahead market

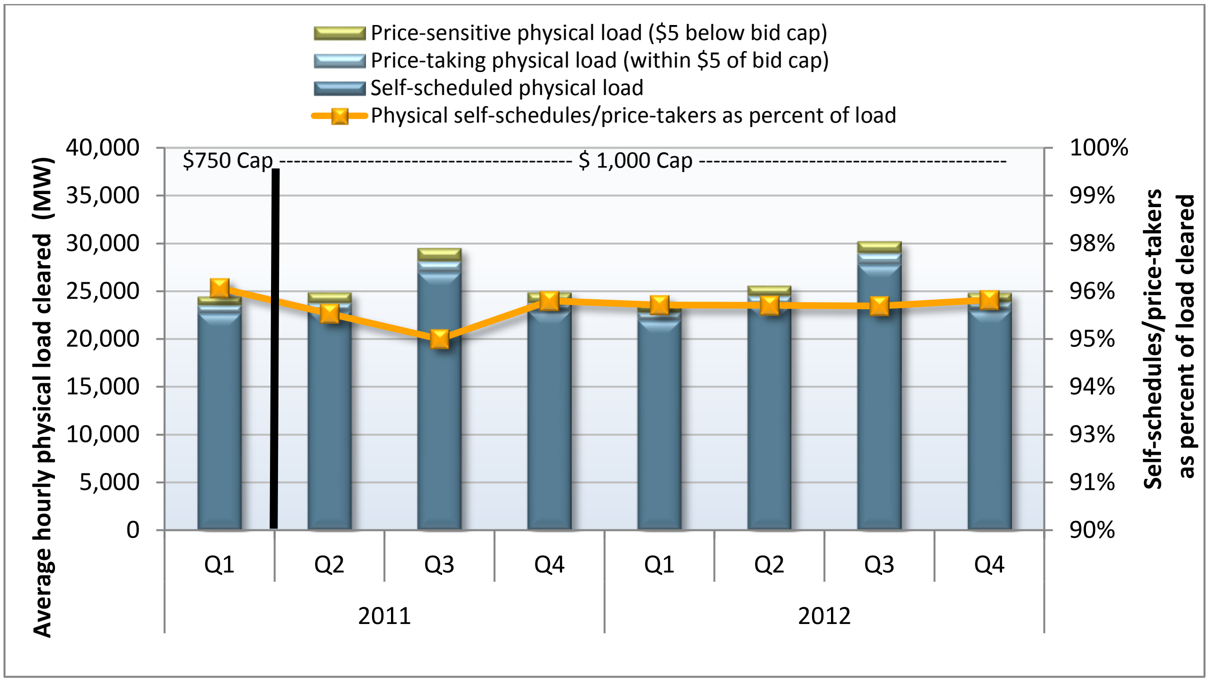
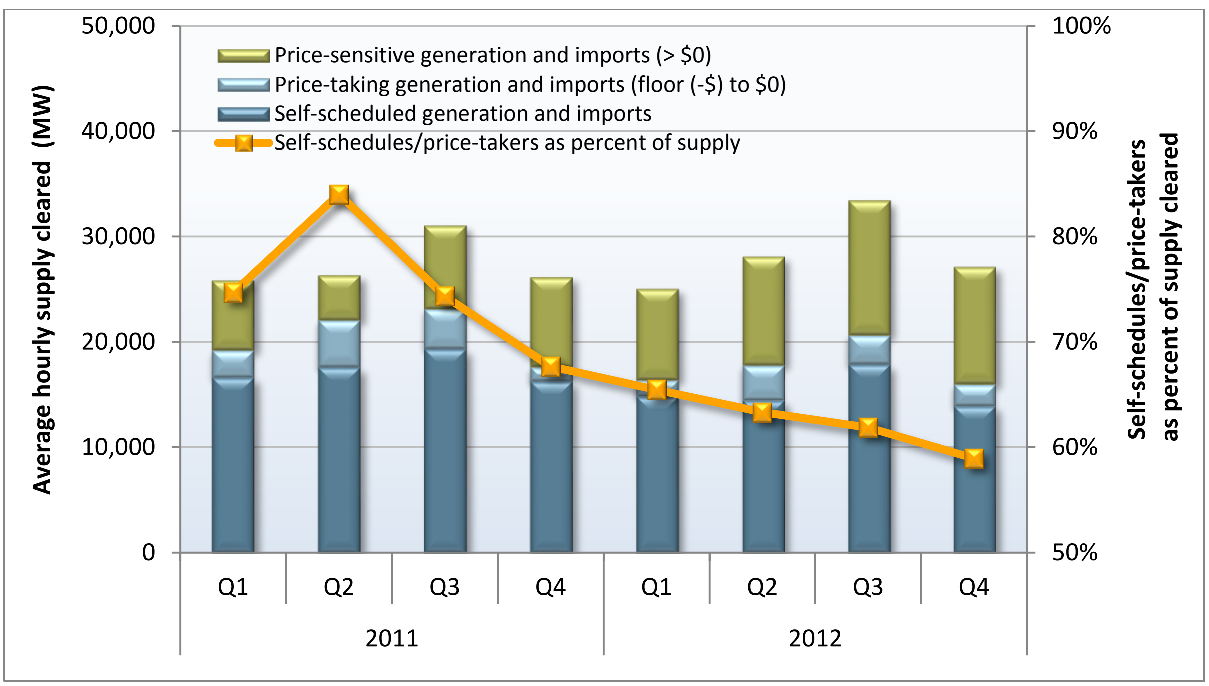


Figure 2.7 Average self-scheduled supply as a percent of total supply cleared in day-ahead market



In 2012, self-scheduled and price-taking supply bids have accounted for an average of about 59 to 65 percent of supply clearing the day-ahead market. Self-scheduling of supply has trended downward in all quarters of 2012. A large portion of this reduction in self-scheduled supply reflects the outage of SONGS units 2 and 3, which represents about half of the self-scheduled nuclear power in California. Also, compared to 2011, self-scheduled hydro generation was also down between 40 and 50 percent during the summer months due to a reduction in hydro-electric availability due to low precipitation. Finally, since loads were higher in 2012, this tended to decrease the percentage of self-supply as a portion of total load.

Hour-ahead market

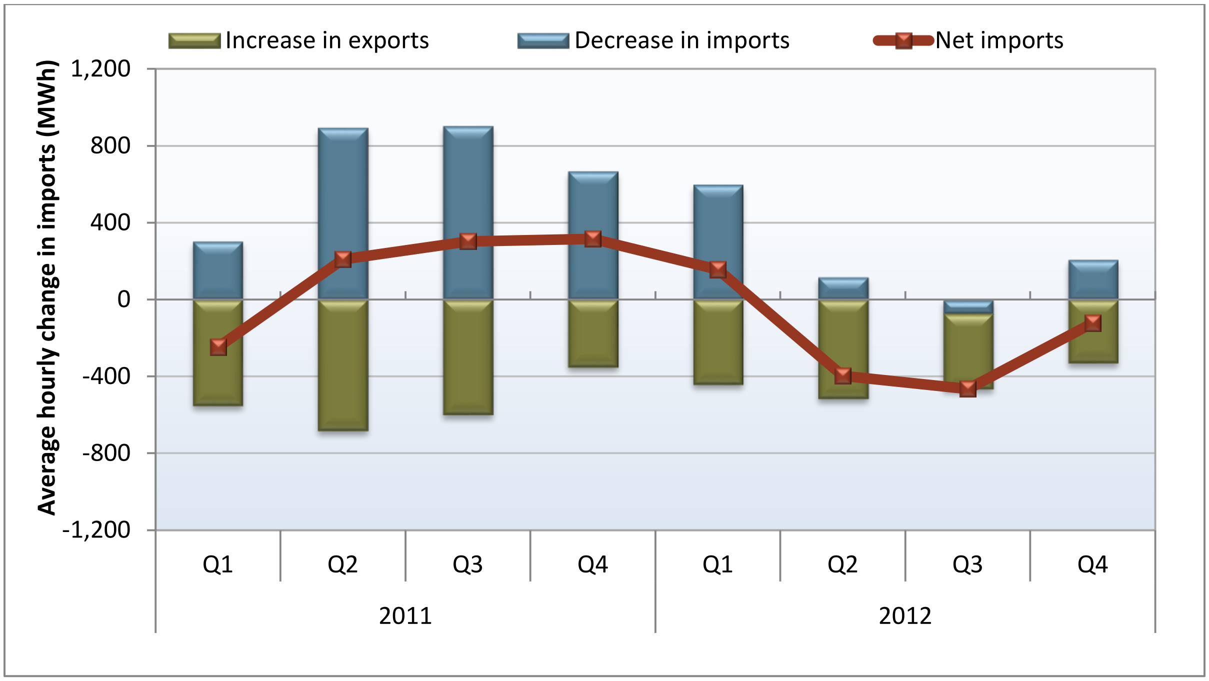
The hour-ahead market allows day-ahead inter-tie schedules to be modified through a re-optimization of the entire market. Market participants with accepted day-ahead imports or export bids can either self-schedule their energy in the hour-ahead market, or re-bid day-ahead scheduled quantities at the same or different prices. If an import scheduled in the day-ahead market does not clear in the hour-ahead market, the market participant buys back the import at the hour-ahead price. Exports scheduled in the day-ahead market that do not clear in the hour-ahead market are sold back at the hour-ahead price.[52]

For most of 2012, net import schedules clearing the hour-ahead market were systematically lower than net imports clearing the day-ahead market (as seen in Figure 2.8). This was a reversal of the trend that existed in most of 2011, and a reversion back to the pattern that existed in previous years.

The trend of reduced net imports in the hour-ahead market during the second and third quarters of 2012 can be attributed largely to the fact that hour-ahead prices remained systematically lower relative to day-ahead and real-time prices in these months, as shown in Figure 2.9 and Figure 2.10. This change may also be partly attributable to the elimination of convergence bids on the inter-ties in late 2011 (see Chapter 4), as physical imports no longer compete with virtual imports for transmission availability in the day-ahead market. This may result in scheduling of more physical imports in the day-ahead market in 2012 relative to 2011, when virtual imports were allowed on inter-ties in the day-ahead market.

[52] In order to receive positive buy back revenues for imports or positive sell back revenues for exports, participants must have submitted a valid e-Tag in the day-ahead market. Otherwise, any positive revenues received by buying or selling back the transaction in the hour-ahead market will be rescinded.

Figure 2.8 Change in net day-ahead imports resulting from hour-ahead market (hour-ahead minus day-ahead schedules)



2.4 Energy market prices

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

- Energy market prices were slightly lower in 2012 than 2011, on average.
- Price convergence improved between the day-ahead and real-time markets in 2012.
- Price convergence remained an issue between the hour-ahead and real-time markets.
- Congestion increased significantly in 2012 compared to 2011.
- Real-time price spikes occurred as frequently in 2012 as in 2011, but the overall level of the price spikes was lower by the end of the year.

Price levels and convergence

Energy market prices were slightly lower in 2012 than 2011, and price convergence improved between the day-ahead and real-time markets in 2012. Price convergence between the hour-ahead and real-time markets was mixed, depending on the metric used to assess price convergence, but remained fairly consistent overall with levels seen in 2011.

Figure 2.9 and Figure 2.10 show average quarterly system energy prices in the three energy markets for peak and off-peak hours, respectively.[53] The following is shown in these figures:

- Prices were lower in the first half of the year and higher during the second half of the year. This is primarily attributable to natural gas prices which were lower in the first half of the year and higher during the second half of the year.
- With the exception of peak hours in the second quarter of 2012, average day-ahead and real-time price differences in 2012 were small, about $2/MWh or less. This was an improvement in price convergence from 2011.
- Price divergence increased between hour-ahead and real-time markets in 2012 compared to 2011. After the first quarter of 2012, prices diverged on average by $3/MWh or more between the hour-ahead and real-time markets in both peak and off-peak hours.
- Hour-ahead market prices were higher than real-time market prices, on average, in the fourth quarter of 2012. This was the result of a few instances of extreme prices in the hour-ahead market that drove average hour-ahead prices higher than average real-time prices.

While average prices indicate that price convergence has improved between the day-ahead and 5-minute real-time markets in 2012, this improvement is a result of averaging differences over a period of time. For instance, Figure 2.12 shows that average hour-ahead and real-time price differences appeared to improve in the third quarter as they decreased relative to the second quarter. However, the absolute average difference increased, indicating that prices differed by more on an hourly basis.

When the absolute price difference is taken, price convergence between the day-ahead and real-time markets improved in 2012 compared to 2011.[54] In addition, price convergence improved slightly when comparing the absolute average price differences between the hour-ahead and real-time markets. However, in both instances, the improvement in the absolute differences was driven by improvements in absolute price convergence in the first quarter (see Figure 2.11 and Figure 2.12). After the first quarter, the absolute price differences averaged over $16/MWh between day-ahead and real-time market prices and almost $19/MWh between hour-ahead and real-time market prices.

[53] In previous reports, DMM used the PG&E area price to highlight overall price trends. However, since congestion increased in 2012, DMM has switched its price analysis to the system marginal energy price, which is not affected by congestion or losses.

[54] By taking the absolute value, the direction of the difference is eliminated, leaving only the magnitude of the difference. Mathematically, this measure will always exceed the simple average price differences if both negative and positive price differences occur. If the magnitude decreases, that would indicate that price convergence was improving. If the magnitude increases, that would indicate that price convergence was getting worse. DMM does not anticipate that the average absolute price convergence should be zero. This metric is considered supplementary to the simple average metrics and helps to further interpret price convergence.

Figure 2.9 Comparison of quarterly prices – system energy (peak hours)

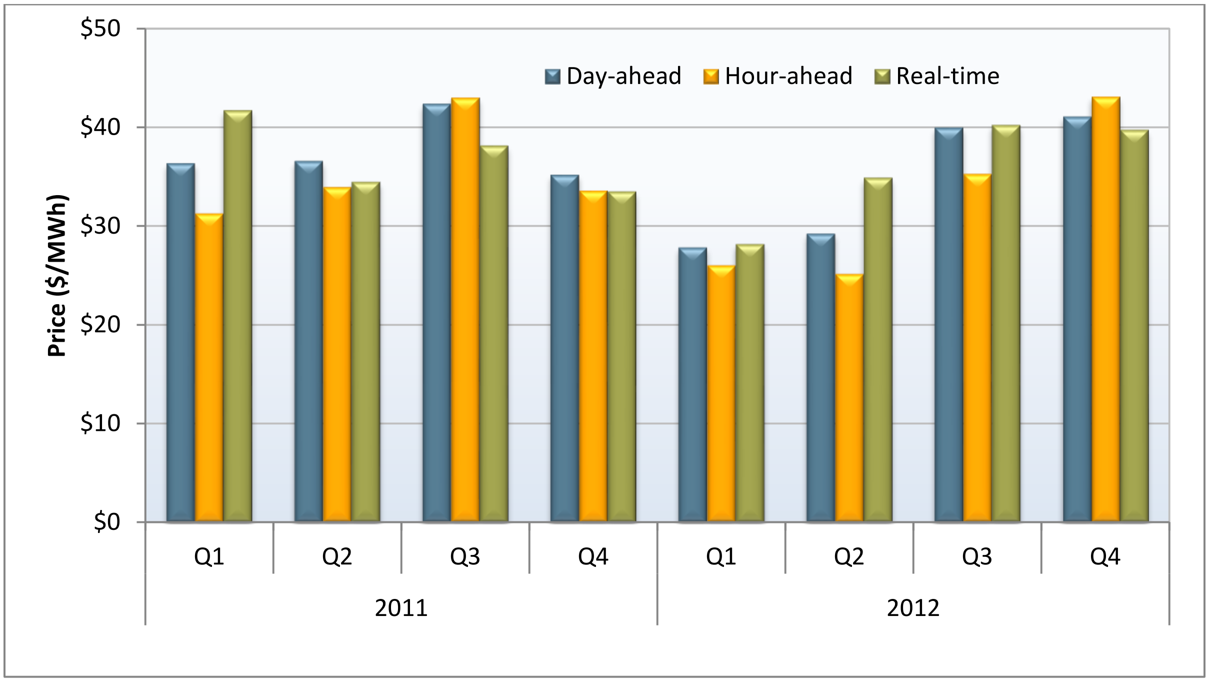


Figure 2.10 Comparison of quarterly prices – system energy (off-peak hours)

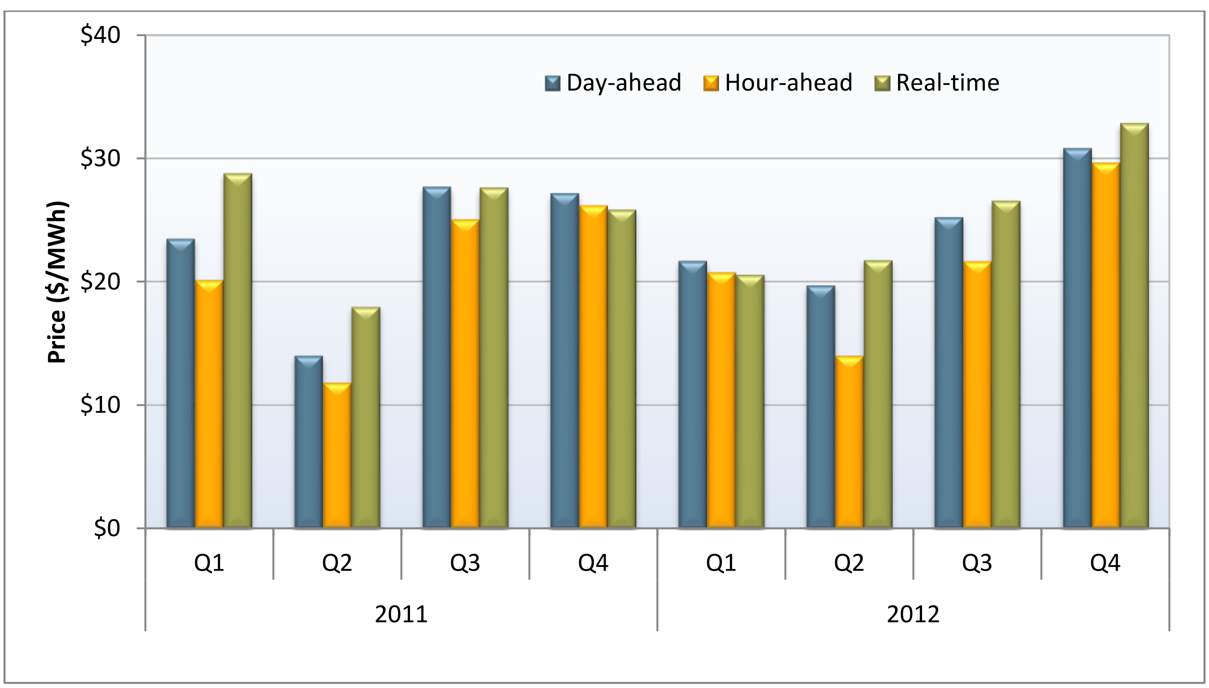


Figure 2.11 Difference in day-ahead and real-time prices – system energy (all hours)

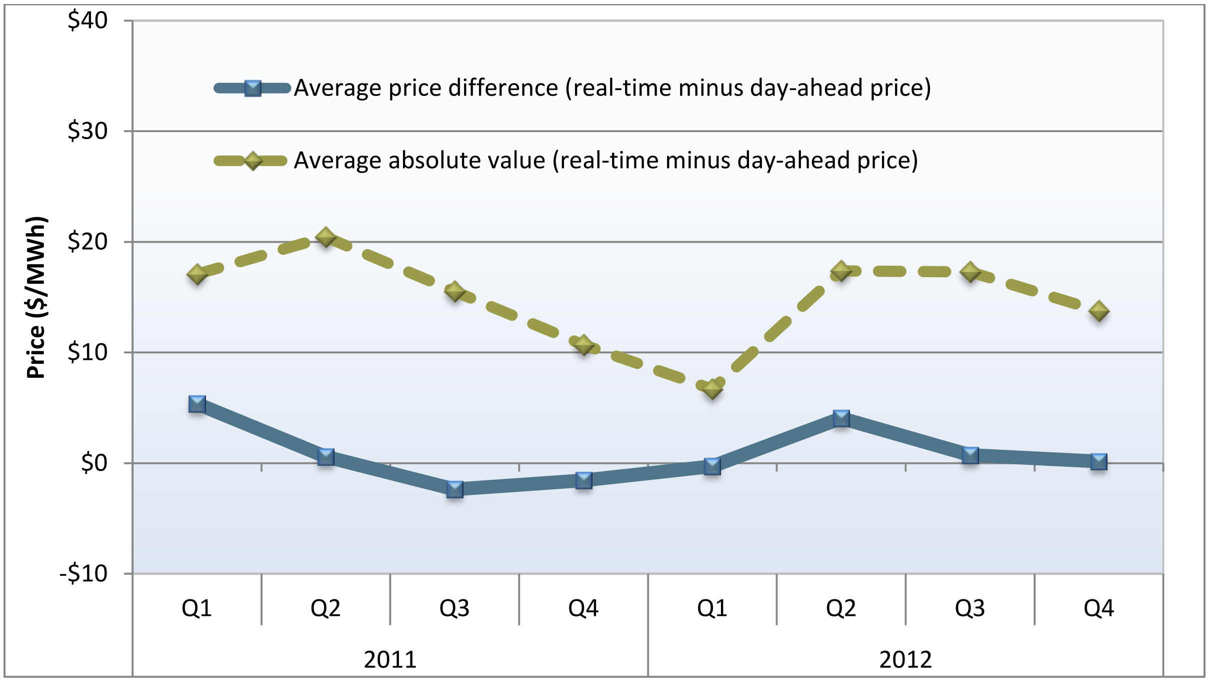
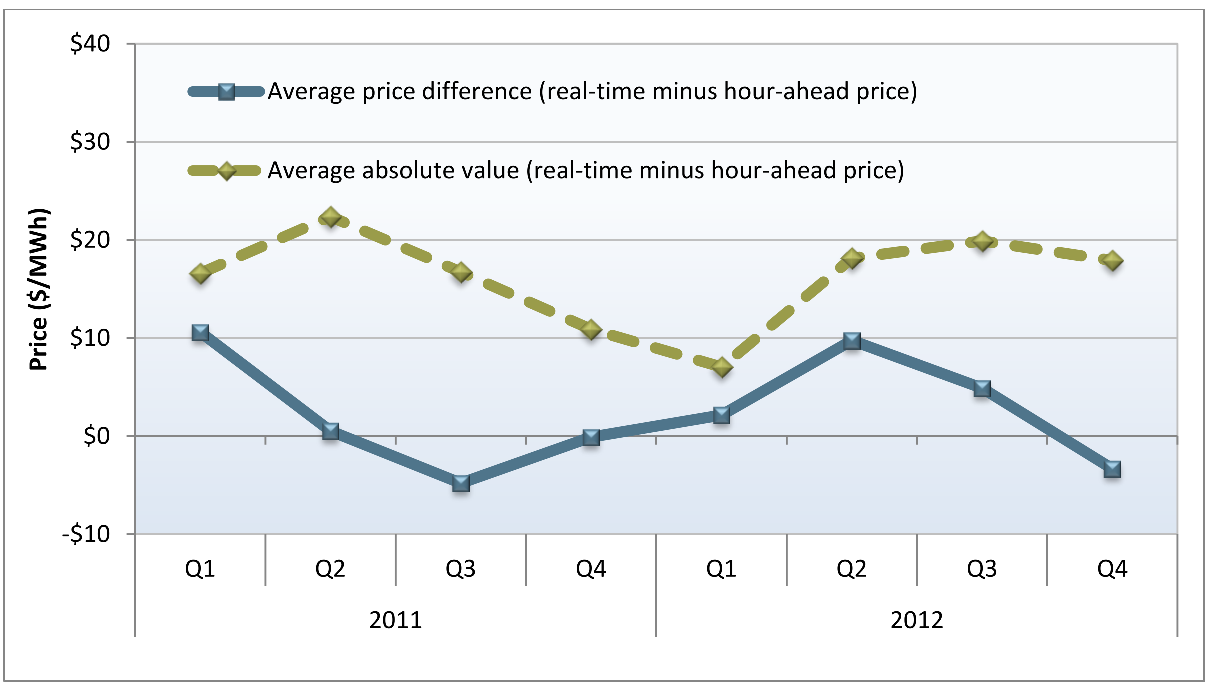


Figure 2.12 Difference in hour-ahead and real-time prices – system energy (all hours)



Congestion

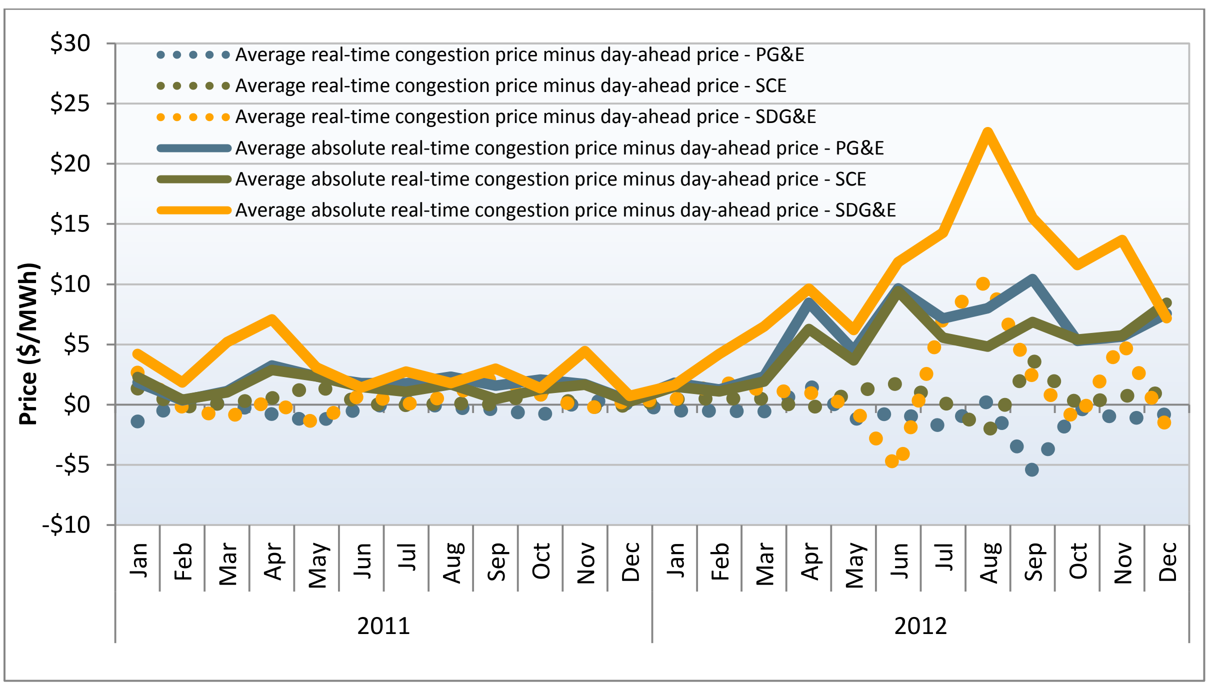
This section compares the congestion price differences between the day-ahead, hour-ahead and real-time markets as both a simple and absolute average over time. These metrics show that congestion increased significantly in 2012 compared to 2011.

Figure 2.13 shows the monthly average and absolute congestion price differences between the day-ahead and real-time markets since January 2011 for each load area. Figure 2.14 shows the monthly average and absolute congestion price difference between the day-ahead and hour-ahead markets by load area for the same period.

The simple average (dashed line) and absolute average (solid line) measures of price divergence between the day-ahead and the other markets were relatively small in 2011, with one exception.[55] This trend continued into early 2012. However, beginning in February and continuing through the rest of the year, day-ahead market congestion differed significantly from both real-time and hour-ahead congestion measured as both a simple average and, to an even greater degree, as an absolute average.[56]

For example, in November 2012, the absolute difference between the day-ahead and the real-time prices in the SDG&E area was just under $15/MWh, while the simple average difference was approximately $5/MWh. The price differences were also significant between the day-ahead and hour-ahead market in November 2012, about $7.30/MWh and $4/MWh for absolute and simple averages, respectively.

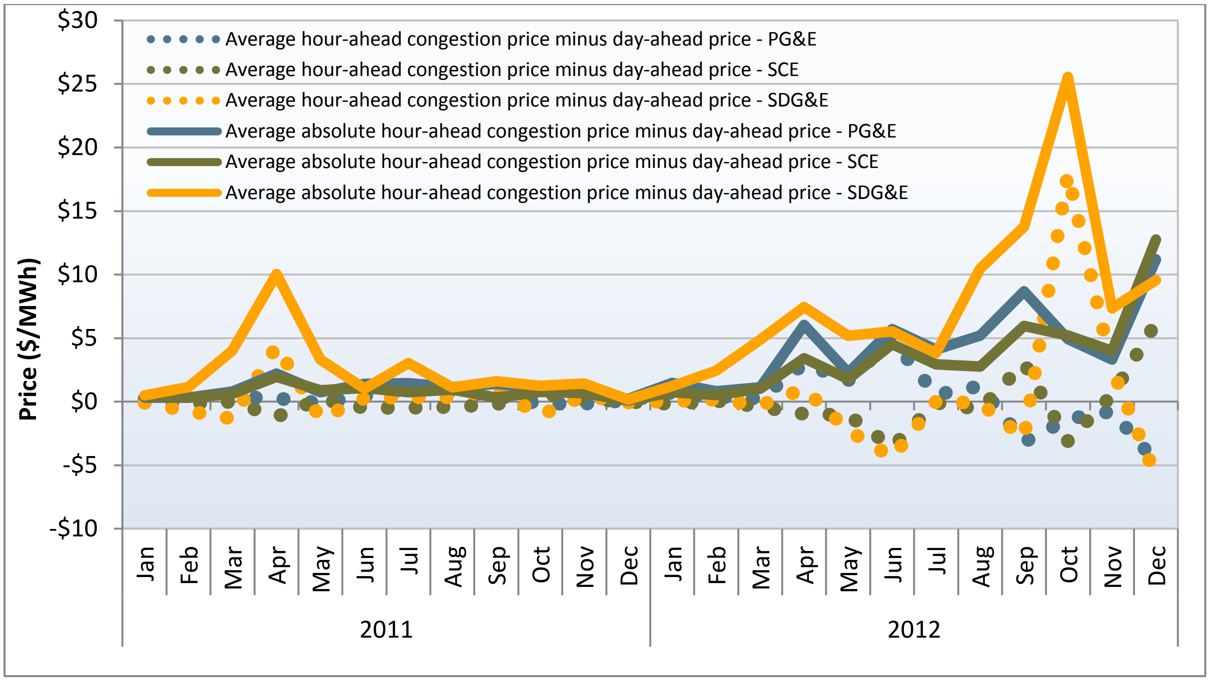
Figure 2.13 Monthly average and absolute congestion price differences between the day-ahead and real-time markets



[55] There were short periods of congestion differences in the SDG&E area in early 2011.

[56] This roughly coincides with the outage of SONGS units 2 and 3. While these outages directly played a role in increasing congestion in 2012, other factors also increased congestion (see Section 7.3 for further detail).

Figure 2.14 Monthly average and absolute congestion price differences between the day-ahead and hour-ahead markets



Convergence bidders have been able to profit from the congestion price differences between the day-ahead and real-time markets. Real-time imbalance congestion costs occurred as a result (see Section 3.4). These congestion differences were related to differences in system conditions including line ratings and outages.

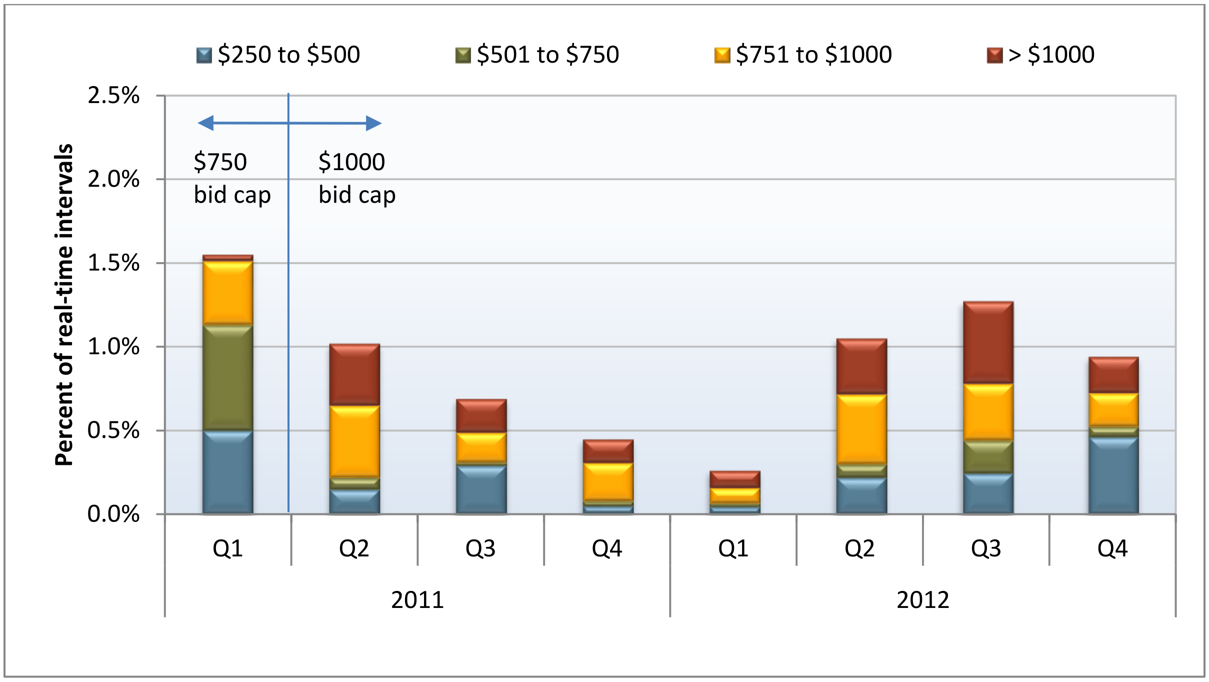
Price spikes

One of the key factors that historically drove price divergence was the small frequency of extreme real-time price spikes. Figure 2.15 shows the frequency of different levels of price spikes on a quarterly basis over the past two years for aggregate load prices. The frequencies shown in Figure 2.15 can be affected by spikes in the system-wide price of energy and prices spikes caused by high congestion.

The frequency of real-time price spikes was similar in the two years, with about 1 percent of real-time prices being extremely high. However, the improvement in day-ahead and real-time price convergence is partly due to the decrease in the frequency of real-time price spikes in the first quarter and decrease in the price-spike levels in the fourth quarter. The frequency of real-time price spikes decreased at the end of 2011 and continued into the first quarter of 2012. However, beginning in the second quarter of 2012 and continuing through the rest of the year, the frequency of price spikes was around 1 percent of real-time intervals.

The total frequency of price spikes at or above $1,000/MWh increased in the third quarter of 2012, primarily as a result of congestion. In the fourth quarter, the overall level of price spikes dropped, with the majority of price spikes falling within the $250 to $500/MWh range. This change was likely attributed to two factors. First, ISO operators began to increase the flexible ramping requirement more consistently during the evening ramping hours. Second, the ISO implemented load and congestion adjustment functionality that limits the chance of ISO operator adjustments creating brief modeling infeasibilities that result in very high prices.

Figure 2.15 Real-time price spike frequency by quarter



2.5 Residual unit commitment

The purpose of the residual unit commitment market is to ensure 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. Capacity procured in residual unit commitment must be bid into the real-time market.

The direct cost of procuring capacity through the residual unit commitment process was around $2.5 million in 2012 compared to $1.1 million in 2011 and $83,000 in 2010. After implementing convergence bidding in February 2011, the direct residual unit commitment costs increased notably. When the market clears with net virtual supply, residual unit commitment capacity is needed to replace the net virtual supply with physical supply. For most of 2012, the market cleared net virtual demand. Therefore, the impact of virtual positions was limited on both the direct capacity procurement costs and bid cost recovery payments associated with residual unit commitment.

Around 85 percent of the total $2.5 million costs occurred in the fourth quarter. This was a result of two factors:

- A major transmission outage created reliability issues with 30-minute ramping capacity in the PG&E area. The ISO addressed these issues by setting higher regional residual unit commitment requirements.

- The ISO operators also set higher requirements for the system during steep ramping hours to meet system ramping needs.

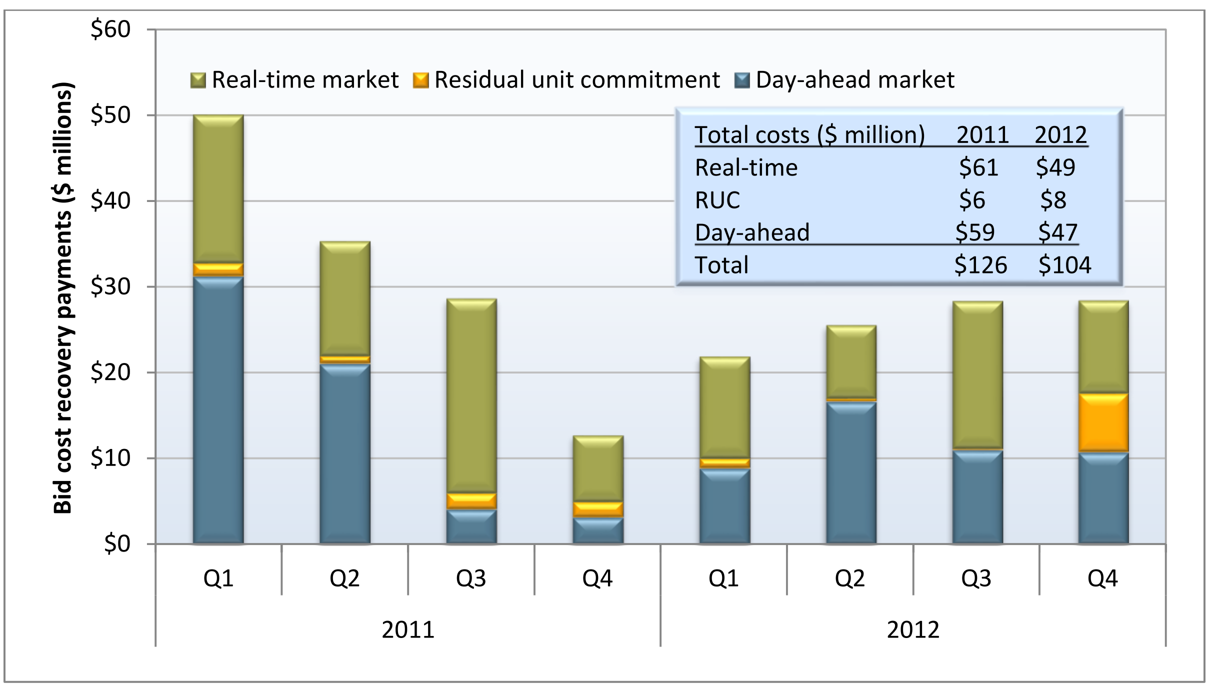
In 2012, units committed in the residual unit commitment process accounted for around $8 million in bid cost recovery payments, or about 8 percent of total bid cost recovery payments. In 2011, these costs were $6 million or about 5 percent of total bid cost recovery payments. The increase is primarily because of the transmission outage that affected 30-minute ramping needs in the fourth quarter. The next section explains this issue in further detail.

2.6 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. However, as described below, a large portion of bid cost recovery payments in 2012 were incurred to meet special reliability issues that require having units online and ready to ramp up in the event of a contingency.

Figure 2.16 provides a summary of total estimated bid cost recovery payments in 2012 by quarter and by market. Bid cost recovery payments totaled around $104 million or about 1.3 percent of total energy costs. This compares to a total of $126 million or about 1.5 percent of total energy costs in 2011, a decrease of about 17 percent from 2011 to 2012.

Figure 2.16 Bid cost recovery payments



Bid cost recovery payments for units committed in the day-ahead energy market totaled $47 million in 2012. DMM estimates that units committed due to minimum online constraints incorporated in the day-ahead energy market accounted for $22 million or over 20 percent of total bid cost recovery payments in 2012. 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 $49 million or almost half of all bid cost recovery payments in 2012. As shown in Figure 2.16, these payments increased notably in the third quarter, reaching around $17 million, with $11 million in August. A sustained heat wave and the resulting increases in load in August required the ISO to commit extra units after the day-ahead market by exceptional dispatch to protect the system from potential system or local contingencies.

Bid cost recovery payments resulting from units committed though exceptional dispatches played a significant role in the increases in the real-time bid cost recovery payments. These payments are driven primarily by minimum load bid costs, which can equal up to 200 percent of units' actual fuel cost of operating at minimum load. DMM estimates that approximately $26 million of the real-time bid cost recovery payments in 2012 stemmed from units committed through exceptional dispatches.

Bid cost recovery payments associated with units committed through the residual unit commitment process totaled about $8 million, with most of these costs occurring in the fourth quarter of 2012. The increase resulted from an increase in residual unit commitment requirements for Northern California to protect reliability in the event of a contingency. These requirements were increased due to a de-rate of the major transmission path into Northern California from the Northwest (California Oregon Intertie).

This increase in residual unit commitment requirements began in mid-October and continued for about a month. The ISO then began to model the capability in case of contingency need as a minimum online constraint north of Path 15. After the addition of the new constraint, residual unit commitment bid cost recovery payments fell. However, residual unit commitment bid cost recovery payments still remained moderate afterwards because ISO operators continued to make adjustments to the system residual unit commitment requirements to address system reliability during the steep evening ramp periods.

[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.

3 Real-time market issues

This chapter highlights changes in factors that caused and changed the nature of extreme positive and negative prices in 2012. In addition, this chapter highlights the performance of the flexible ramping constraint and the underlying causes of real-time uplifts known as real-time energy and congestion imbalance offset costs.

- While shortages of upward ramping capacity continued to play a role in setting high prices, the frequency of such price spikes decreased over the course of the year as a result of improvements in market software and procedures. The frequency of positive real-time price spikes as a result of upward ramping infeasibilities decreased from 0.8 percent of intervals in 2011 to 0.6 percent of intervals in 2012.
- Congestion began to play a major role in extreme positive real-time prices in 2012, accounting for over half of all price spikes due to shortage of upward ramping capacity in 2012.
- The frequency of negative real-time prices decreased to 1 percent of intervals in 2012, down from 1.8 percent in 2011. This decrease was likely the result of less inflexible self-scheduled hydro-electric generation availability in 2012. Most negative prices in 2012 occurred when the power balance constraint needed to be relaxed in the market software due to shortages of downward ramping capacity. In 2011, most negative real-time prices were set by negative priced bids dispatched by the ISO.
- Payments to generating resources resulting from the flexible ramping constraint payments were relatively low, totaling about $20 million for the year. For the sake of comparison, spinning reserve costs were about $35 million for the year.
- While the flexible ramping constraint likely contributed to the decrease in system-wide real-time price spikes, this constraint is less capable of addressing congestion-related real-time price spikes.
- Real-time imbalance offset costs totaled about $236 million in 2012, up from $165 million in 2011. The increase was primarily a result of increases in real-time congestion imbalance offset costs from $28 million in 2011 to $186 million in 2012.
- The increase in real-time congestion imbalance offset costs was primarily the result of reductions in transmission limits between the day-ahead and real-time markets. In many instances, ISO operators adjusted these limits downward in real-time to better account for unscheduled flows observed in real-time.
- Virtual bidding increased real-time congestion imbalance offset costs. This occurred as virtual bidding increased the volume of transactions contributing to the revenue imbalance allocated through the real-time congestion imbalance offset charge when flows were decreased between the day-ahead and real-time markets due to transmission limitations.

3.1 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; the bid floor is set at -$30/MWh.[58] 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 on 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 dispatch, this constraint is relaxed in the scheduling run of the real-time software. In the scheduling run, the software assigns a penalty price of $1,100/MW for the first 350 MW that this constraint is relaxed.[59] 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 dispatch, the software relaxes this constraint in the scheduling run using a penalty price of -$35/MW for the first 350 MW. After this, self-scheduled energy may be curtailed at a penalty price of -$1,800/MW. In the pricing run, a penalty price of -$35/MW is used. This causes prices to drop down to or below the -$30/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 insufficiencies 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 providing any additional energy needed to balance loads and generation. To the extent that regulation service and spin 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.

[58] The -$30/MWh bid floor is really a “soft floor.” Bids below -$30/MWh can be submitted, but do not set the market price. Also, bids below -$30/MWh are subject to cost justification if the participant seeks to be paid more than -$30/MWh.

[59] 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.

Sometimes extreme congestion on constraints within the ISO system can limit availability of significant amounts of supply. This can cause system-wide limitations in the upward 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 upward ramping limitations in the congested portion of the ISO system.[60]

3.2 System power balance constraint

The frequency of power balance constraint relaxations due to insufficient upward or downward ramping capacity decreased in 2012 compared to previous years. However, congestion played a larger role contributing to power balance constraint infeasibilities in 2012.

Figure 3.1 and Figure 3.2 show the frequency with which the power balance constraint was relaxed in the 5-minute real-time market software each quarter since 2011. The power balance constraint has never been relaxed in the day-ahead or the hour-ahead markets as self-schedules are cut first.

As shown in Figure 3.1, the constraint was relaxed because of insufficient incremental energy in about 0.6 percent of the 5-minute intervals in 2012. In 2011, the power balance constraint was relaxed in about 0.8 percent of the 5-minute intervals. Even though the total frequency was down, more power balance relaxations occurred as a result of congestion in 2012. In 2012, around 54 percent of the upward ramping capacity relaxations shown in Figure 3.1 resulted from extreme congestion compared to about 10 percent in 2011.

As in previous years, the power balance constraint was relaxed more frequently due to insufficient downward decremental capacity than upward insufficiencies in 2012. As shown in Figure 3.2, the constraint was relaxed due to insufficient decremental capacity just over 1 percent of intervals in 2012. This was a decrease in frequency compared to 2011, where the power balance was relaxed as the result of downward ramping insufficiencies during almost 2 percent of intervals. Thus, there was a significant decrease in the frequency of relaxations due to insufficient downward ramping capability. When the constraint is relaxed under these conditions, the downward impact on average prices is also less significant because prices only drop towards or to the bid floor of -$30/MWh.

[60] 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.

Figure 3.1 Relaxation of power balance constraint due to insufficient upward ramping capacity

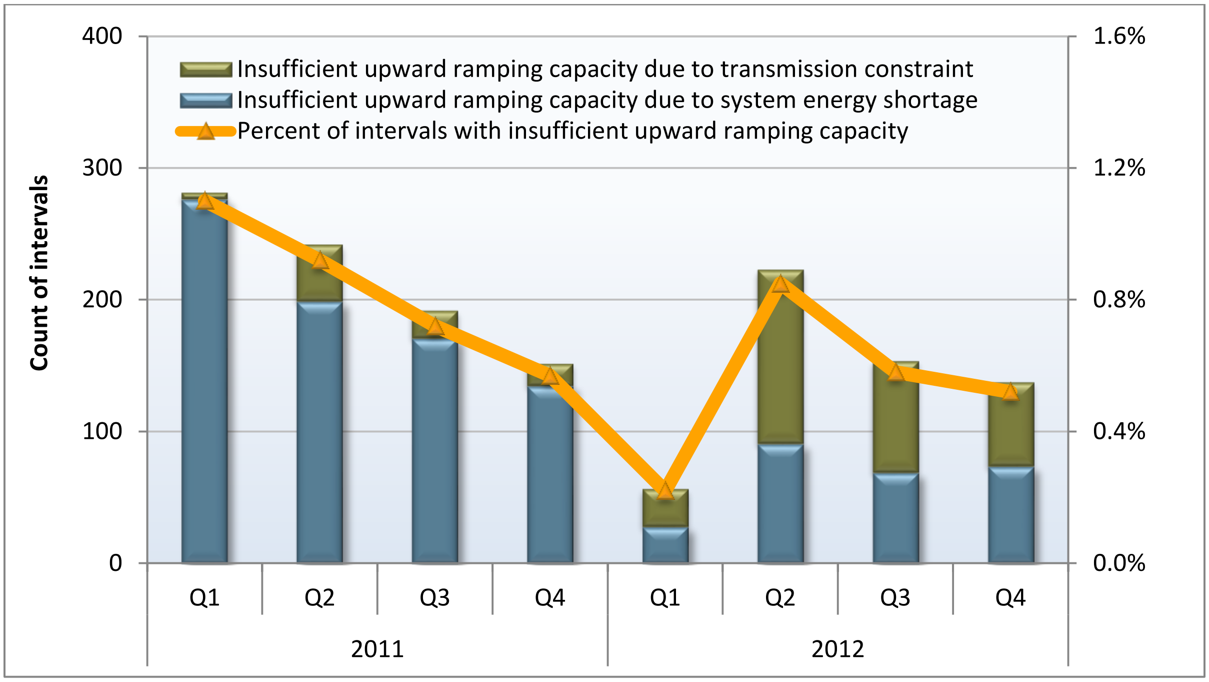


Figure 3.2 Relaxation of power balance constraint due to insufficient downward ramping capacity

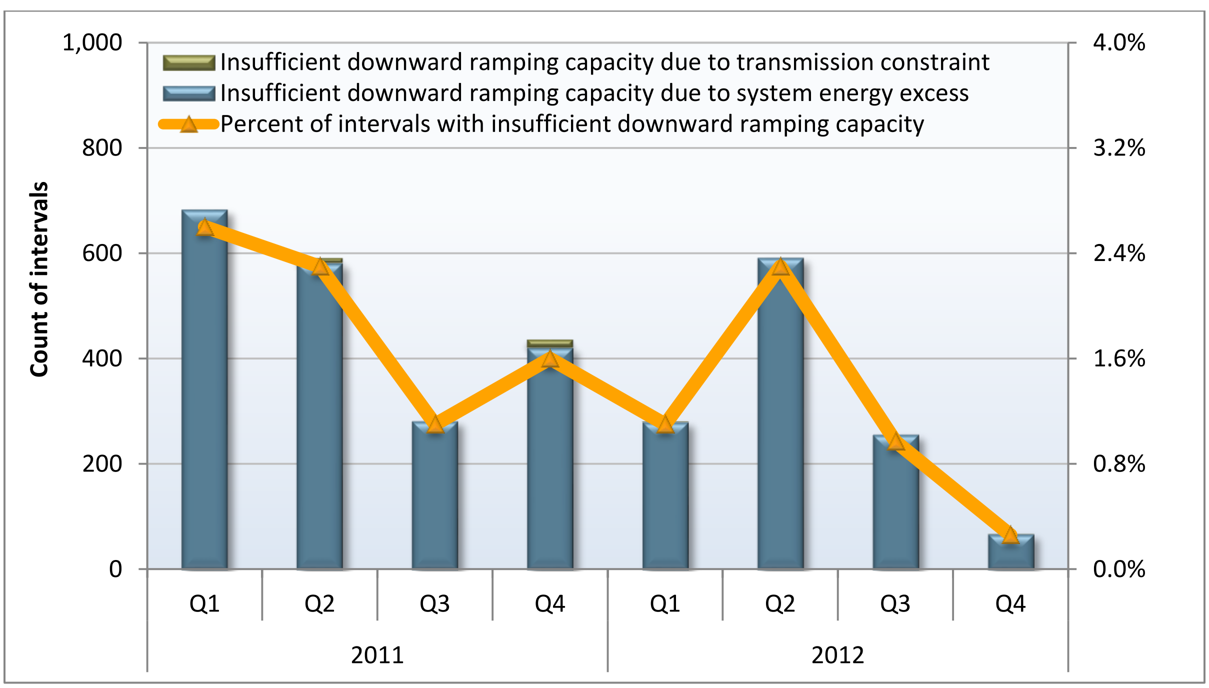


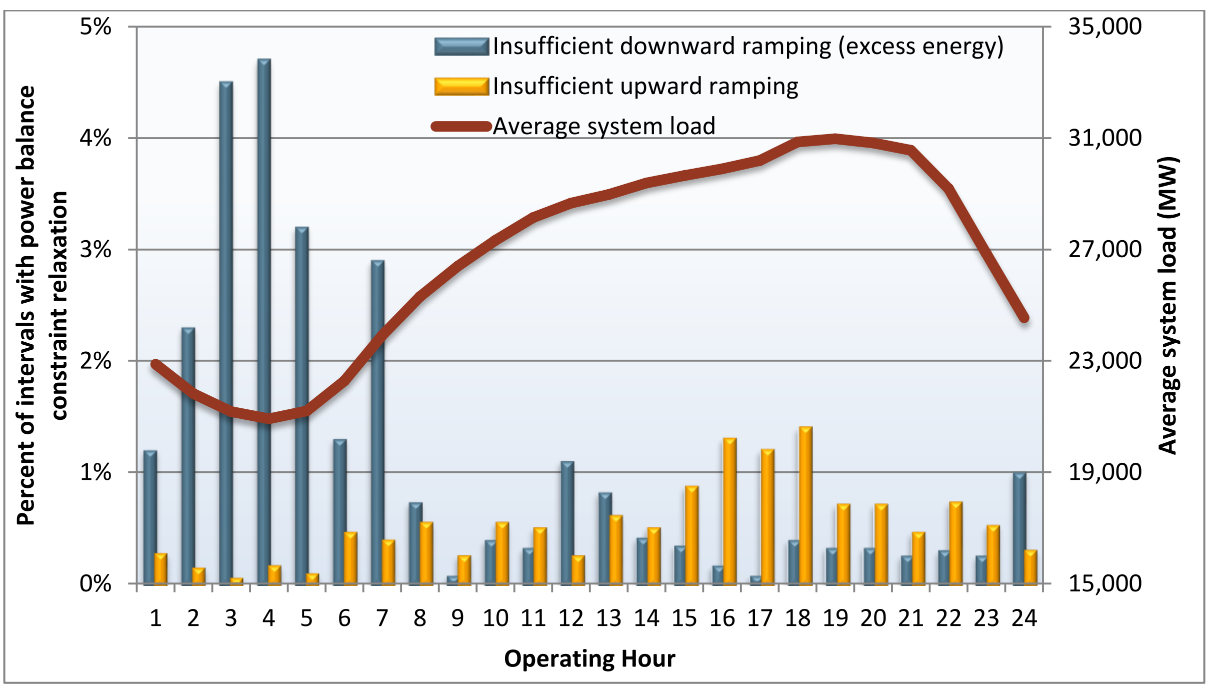
Figure 3.3 shows the percentage of intervals that the power balance constraint was relaxed during each operating hour in 2012. The following is shown in this figure:

- Shortages of upward ramping capacity (yellow bar) caused the system power balance constraint to be relaxed most frequently during the evening load ramping hours (16 through 19) when system loads were changing at a relatively high rate. During these hours, prices spiked because of shortages of upward ramping in around 1.2 percent of intervals, almost double the average for all hours for the year (0.6 percent).

- The system power balance constraint was relaxed due to shortages of downward ramping capacity (blue bar) primarily during the off-peak hours, especially early morning hours, when periods of excess energy tend to occur. About 76 percent of these intervals occurred in hours ending 1 through 8, during which the constraint was relaxed about 2.5 percent of the time. Excess energy often occurs in these hours as generation from wind units reaches higher levels, and as units and inter-tie schedules ramp up from off-peak levels to peak levels.

Most of these shortages were very short-lived. About 89 percent of shortages of upward ramping capacity persisted for only one to three 5-minute intervals (or 5 to 15 minutes). About 72 percent of shortages of downward ramping capacity lasted for only one to three 5-minute intervals.

Figure 3.3 Relaxation of power balance constraint by hour (2012)

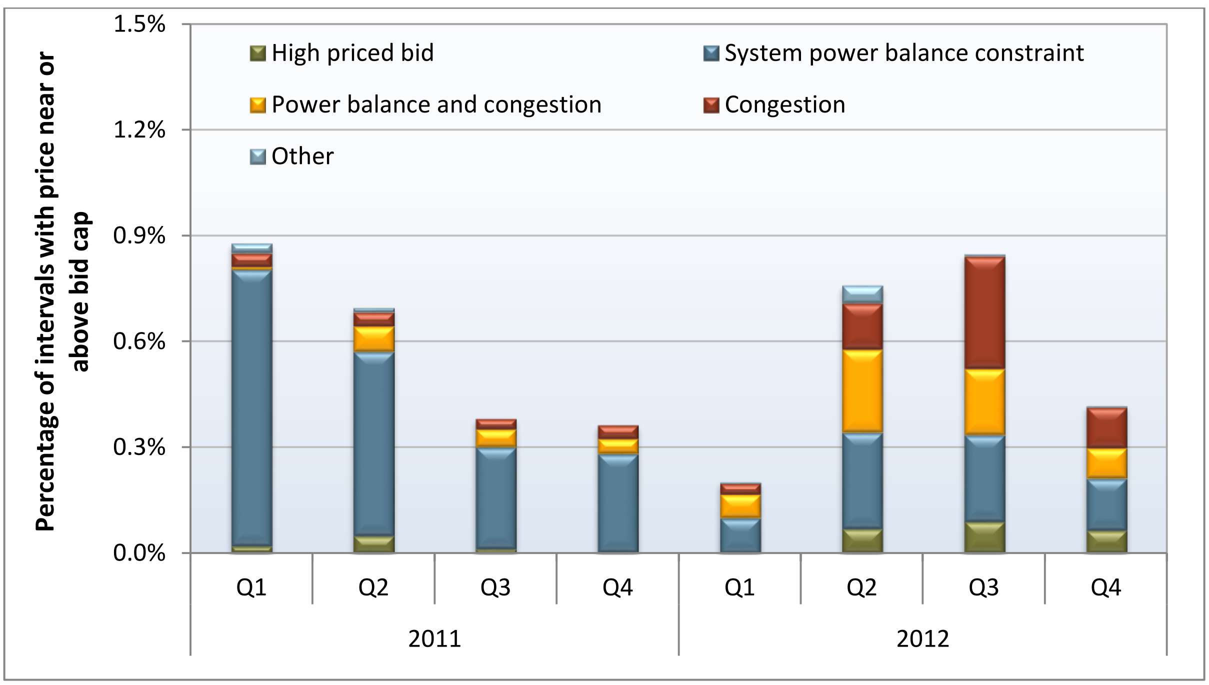


Causes of extremely high prices

As noted earlier, congestion has played a larger role in high prices in the real-time market in 2012. Figure 3.4 shows the approximate frequency of different factors driving high real-time prices for each load aggregation point. For purposes of this analysis, high prices are defined as including all intervals in which the real-time price for a load aggregation point was at or near the bid cap.[61] The primary reasons for each of these high load aggregation point prices are identified based on the following categories:

- **System power balance constraint** – During these intervals the power balance constraint was relaxed and the congestion component was less than $200/MWh.
- **Power balance constraint and congestion** – These prices occurred in intervals when the power balance constraint was relaxed and the congestion component was greater than $200/MWh.
- **Congestion** – These prices occurred in intervals when the power balance constraint was not relaxed and the congestion component was greater than $200/MWh.
- **High priced bid** – These prices occurred when the power balance constraint was not relaxed and the congestion component was less than $200/MWh, but a high priced bid was dispatched during the interval.
- **Other** – The high price was not caused by any of the above categories.

Figure 3.4 Factors causing high real-time prices



Results of this analysis show that the factor causing extremely high prices in the real-time market continued to be the power balance constraint either by itself or in combination with congestion. The following is shown in Figure 3.4:

- Around 34 percent of all high prices at load aggregation points in 2012 were due to relaxing the power balance constraint during an interval when congestion did not have a significant impact on price. This is down from 78 percent of the high prices in 2011.

[61] The analysis behind this figure reviews price spikes above $700/MWh.

- Starting in the first quarter of 2012, congestion played a higher role in causing high load aggregation point prices. In 2012, about 27 percent of all high price events were due to pure congestion, compared to 6 percent in 2011. About 26 percent of the high price events were due to a combination of congestion and the system power balance constraint in 2012, compared to 8 percent in 2011.
- There were relatively few instances where the dispatch of high priced bids could have caused a high load aggregation point price. Overall, these intervals represented about 10 percent of all high price events during the year, compared to 7 percent in 2011. This increase mainly resulted from high bids from a small group of units.

Causes of negative prices

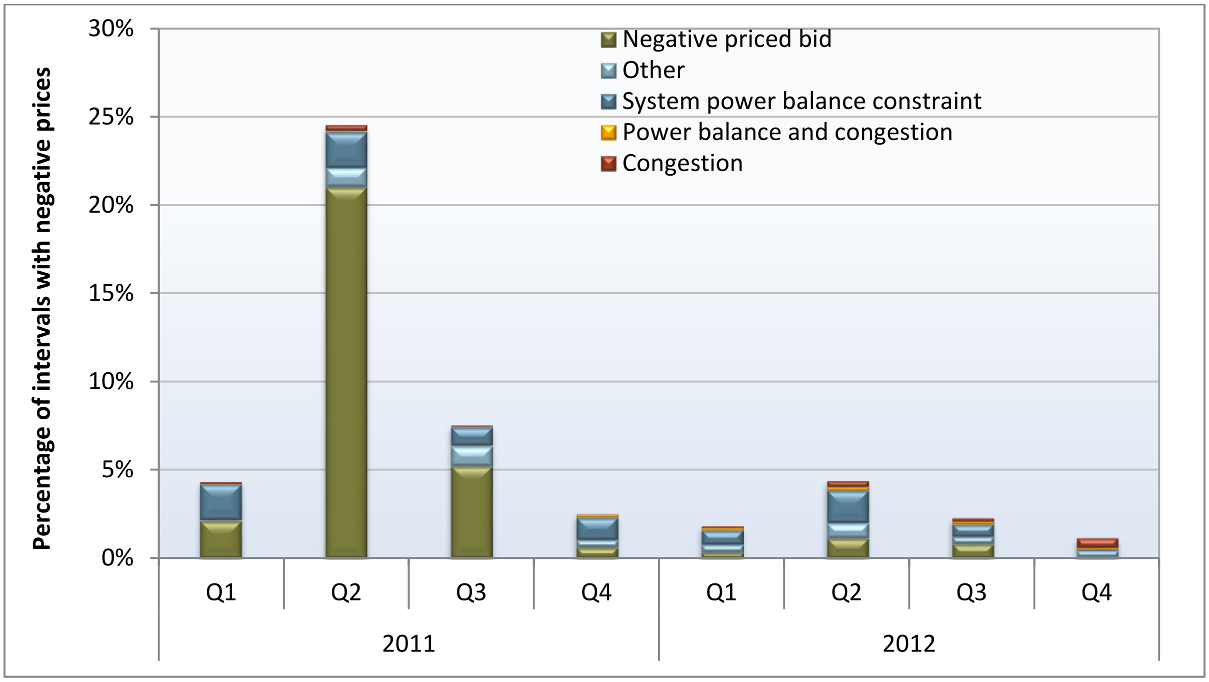
The frequency of negative prices decreased notably in 2012 compared to 2011. This is likely due to decreases in hydro-electric generation. Real-time energy prices become negative for various reasons. Figure 3.5 summarizes an analysis of the causes of real-time prices less than $0/MWh at load aggregation points. The causes for low prices are categorized as follows:

- **Power balance constraint** – During these intervals the power balance constraint was relaxed and the congestion component was less than 50 percent of the price.
- **Power balance constraint and congestion** – These prices occurred when the power balance constraint was relaxed and the congestion component was more than 50 percent of the price. In these cases, the congestion component was negative.
- **Congestion** – These negative prices occurred when the power balance constraint was not relaxed and the negative congestion component accounted for more than half the negative price.
- **Low priced bid** – During these intervals, the energy component was between -$30/MWh and $0/MWh, the congestion component accounted for less than 50 percent of the negative price, and a negatively priced bid was dispatched.
- **Other** – The negative price was not caused by any of the conditions described above.

Results of this analysis show that negatively priced bids play a much smaller role in determining the negative prices in 2012 compared to 2011. As seen in Figure 3.5:

- In 2012, around 25 percent of negative prices were due to the dispatch of negatively priced bids, compared to 86 percent of the negative prices in 2011.
- About 36 percent of negative prices in 2012 occurred when the power balance constraint was relaxed, up from about 16 percent in 2011.
- About 21 percent of negative prices were due to other model parameters. Most of these negative prices had energy components between -$30/MWh and -$35/MWh, but the power balance constraint was not relaxed.
- Congestion started to play a more important role in determining the negative prices in 2012. It caused about 18 percent of negative prices for load aggregation points compared to 2 percent in 2011.

Figure 3.5 Factors causing negative real-time prices



3.3 Real-time flexible-ramping constraint

This section provides background of the flexible ramping constraint, highlights key performance measures, and makes recommendations for further review. While it is difficult to benchmark the performance of this constraint with other products, DMM highlights several performance factors and makes recommendations on how to better understand its effect on the market.

The key highlights include the following observations:

- Flexible ramping payments were about $20 million for the year. For the sake of comparison, spinning reserve costs were about $35 million for the year.
- Almost half of flexible ramping constraint payments were during intervals when the system was unable to procure enough flexible ramping capacity to meet the requirement.
- The ISO operators began to increase the flexible ramping requirement more consistently during the evening ramping periods of the day in the fourth quarter after being static for much of the year.
- Just over half of the flexible ramping capacity was in the northern part of the ISO system. When congestion occurs in the southern part of the system, this capacity can be *stranded* or unavailable for dispatch to help relieve congestion and meet system energy requirements in Southern California.

DMM continues to recommend that the ISO review how the flexible ramping constraint has affected the unit commitment decisions made in real-time.[62]

Background

In mid-December 2011, the ISO began enforcing the flexible ramping constraint in the upward ramping direction in the 15-minute real-time pre-dispatch and the 5-minute real-time dispatch markets. The constraint is only applied to internal generation and proxy demand response resources and not to external resources. Application of the constraint in the 15-minute real-time pre-dispatch market ensures that enough capacity is procured to meet the flexible ramping requirement.

The default requirement is currently set to around 300 MW, down from the original default of 700 MW. The ISO operators have the ability to adjust the requirement depending on system conditions. For most of the year, the default requirement was applied over the day with little adjustment. However, by the end of the year, ISO operators adjusted the requirement more frequently to better prepare for potential ramping shortages during steep evening ramping periods. These adjustments generally took place between hours ending 16 and 20 and were up to 800 MW during these hours.

The flexible ramping constraint was implemented to account for the non-contingency based variations in supply and demand between the 15-minute real-time pre-dispatch and the 5-minute real-time dispatch. The additional flexible ramping capacity is designed to supplement the existing non-contingent spinning reserves in the system in managing these variations.

The ISO procures the available 15-minute dispatchable capacity from the available set of resources in the 15-minute real-time pre-dispatch run. If there is sufficient capacity already online, the ISO 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. During intervals when there is not enough 15-minute dispatchable capacity available among the committed units, the ISO can commit additional resources (mostly short-start units) for energy to free up capacity from the existing set of resources. The short-start units can be eligible for bid cost recovery payments in real-time.[63] A procurement shortfall of flexible ramping capacity will occur where 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 pre-dispatch.[64]

Performance of the flexible ramping constraint

Total payments for flexible ramping resources in 2012 were around $20 million.[65] For the sake of comparison, costs for spinning reserves have totaled about $35 million in 2012. There are also secondary costs, such as those related to bid cost recovery payments to cover the commitment costs of

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[62] The ISO is planning to add new model functionality that will indicate which units were added by the flexible ramping constraint.

[63] Further detailed information on the flexible ramping constraint implementation and related activities can be found here: http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/FlexibleRampingConstraint.aspx.

[64] The penalty price associated with procurement shortfalls is set to just under $250.

[65] In November 2012, the ISO implemented changes to the settlement rules for the flexible ramping constraint. These changes have been incorporated in the revenue calculations for November and December. See the following document for further details: http://www.caiso.com/Documents/October242012Amendment-ImplementFlexibleRampingConstraint-DocketNoER12-50-000.pdf.

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 the monthly flexible ramping constraint activity in the 15-minute real-time market in 2012. The table highlights the following:

- The frequency that the flexible ramping constraint was binding varied widely, being highest in the spring (23 percent) and lowest in the fourth quarter (4 percent).
- The portion of intervals during which the ISO was unable to procure the targeted level of flexible ramping capacity fell to around 1 percent of all 15-minute intervals in the fourth quarter, compared to approximately 2 percent in the first nine months.
- The average shadow prices when binding varied between $32/MWh and $80/MWh.

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)
2012	Jan	$2.45	17%	1.0%	$38.44
2012	Feb	$1.46	8%	1.3%	$77.37
2012	Mar	$1.90	12%	1.0%	$42.75
2012	Apr	$3.37	22%	1.5%	$39.86
2012	May	$4.11	23%	6.0%	$79.48
2012	Feb	$1.49	13%	2.3%	$77.37
2012	Mar	$1.01	8%	1.4%	$42.75
2012	Apr	$0.77	7%	1.2%	$39.86
2012	May	$1.03	13%	0.8%	$79.48
2012	Oct	$0.95	9%	1.0%	$39.19
2012	Nov	$0.23	4%	0.5%	$53.34
2012	Dec	$1.09	9%	1.6%	$61.84

Almost half of flexible ramping payments to generators in 2012 (48 percent) occurred during intervals when the system was unable to procure enough flexible ramping capacity to meet the requirement. Figure 3.6 shows the monthly flexible ramping payments to generators. The green bar shows the payments made during intervals with procurement shortfalls and the blue bar shows the payments in all other periods.

On an hourly basis, most payments for ramping capacity occurred during the evening peak hours. In addition, most payments were for natural gas-fired resources. Figure 3.7 shows the hourly flexible ramping payment distribution during the fourth quarter broken down by technology type. As shown in the graph, the highest payment periods were during hours ending 17 through 21. Also seen in the figure, natural gas-fired capacity accounted for about 65 percent of these payments with hydro-electric capacity accounting for 33 percent.

Figure 3.6 Monthly flexible ramping constraint payments to generators

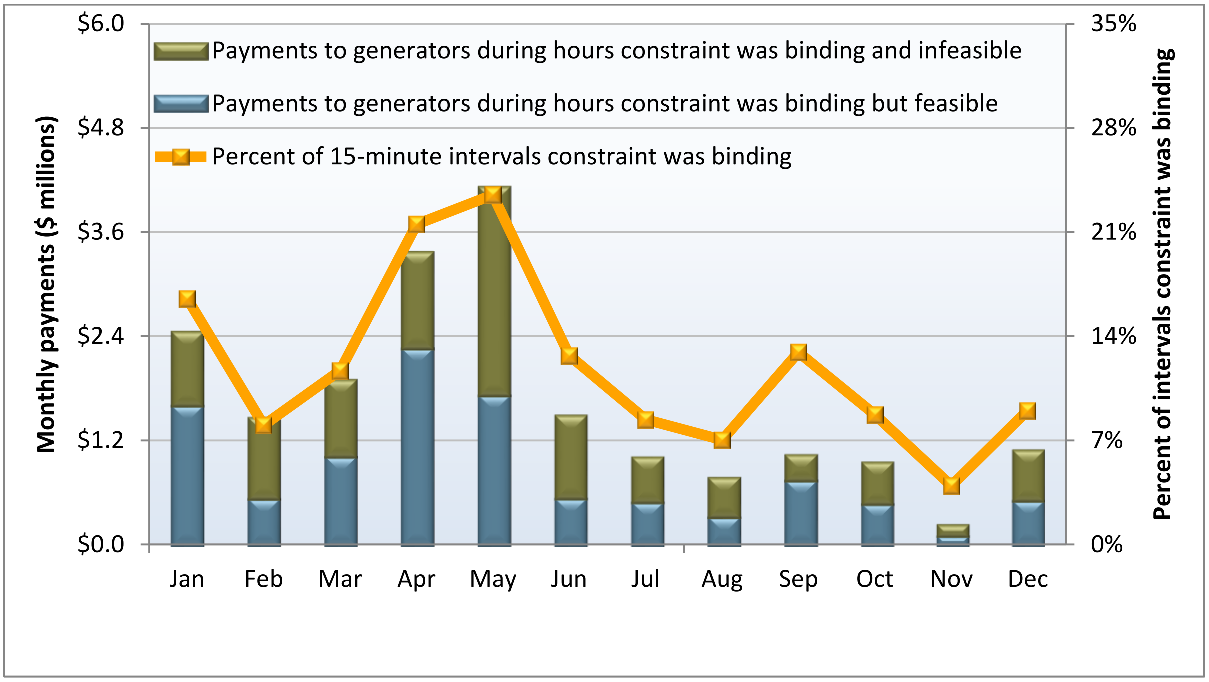
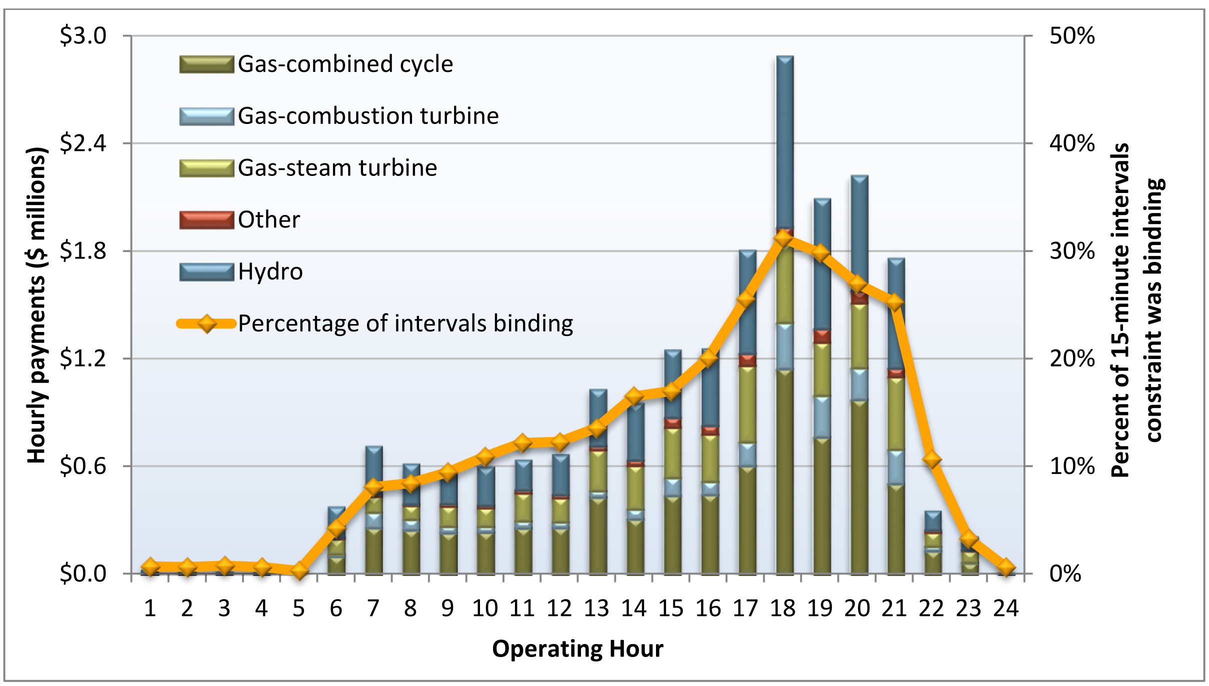


Figure 3.7 Hourly flexible ramping constraint payments to generators (January – December)

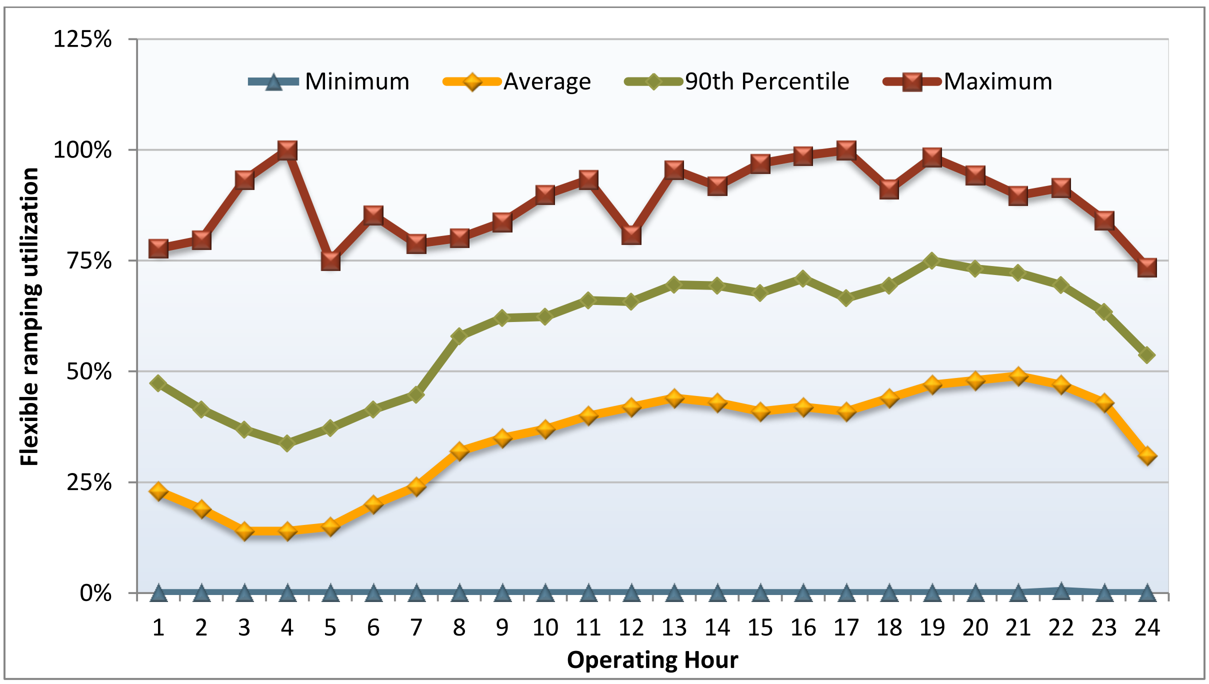


Real-time use of flexible ramping capacity

The ISO's primary metric to determine how effective the flexible ramping constraint is at procuring ramping capacity when needed is to determine how much of the ramping is utilized in real-time. The ISO has used the results of this metric to adjust the default flexible ramping capacity requirement. The metric determines how much of the procured flexible ramping capacity in the 15-minute real-time pre-dispatch was utilized in the 5-minute real-time dispatch. The utilization is a function of prevailing system conditions, including load and generation levels and generation and transmission availability.[66]

Figure 3.8 shows the minimum, average, 90th percentile and maximum hourly utilization of procured flexible ramping capacity in the 5-minute real-time dispatch in 2012. Overall, average hourly utilization was around 35 percent, ranging from 14 percent in the early mornings to 49 percent in the late evening hours. Utilization at the 90th percentile ranged from 34 percent in the early morning hours to 75 percent in the evening peak hour. Utilization was at 100 percent at individual 5-minute intervals during load ramping hours and during peak periods.

Figure 3.8 Flexible ramping utilization by hour (January – December)



Procurement of flexible ramping by region

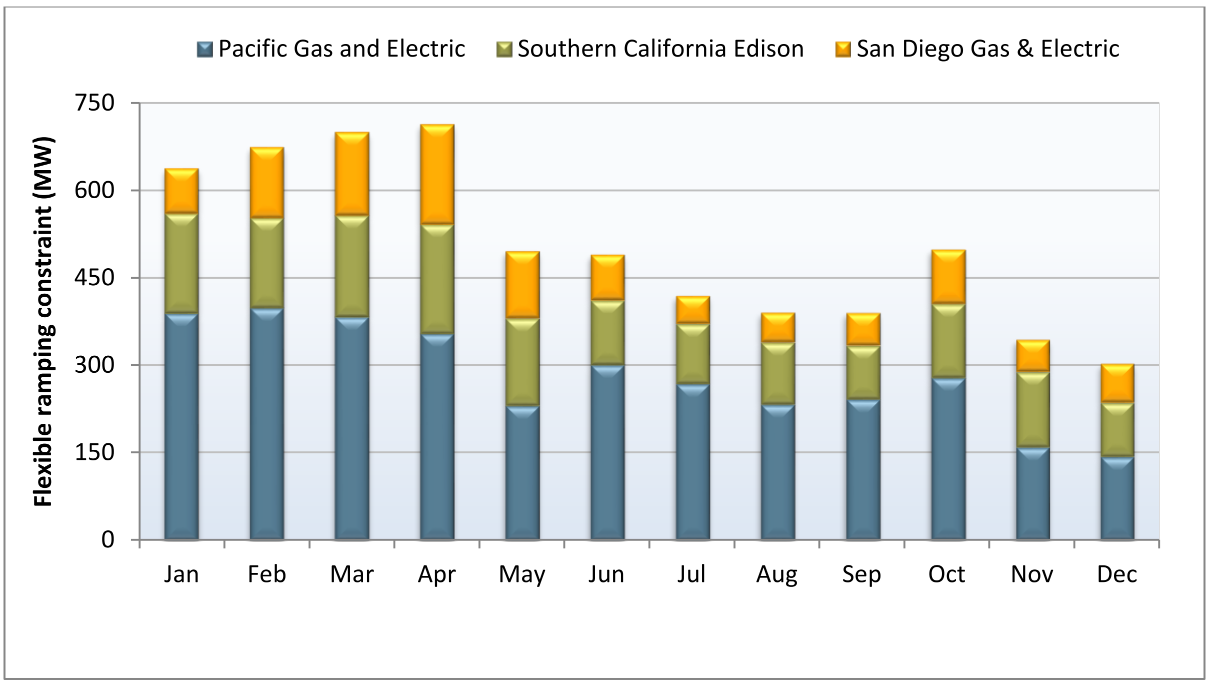
The flexible ramping constraint is designed to address system ramping needs. However, to the extent that flexible ramping capacity is procured in transmission constrained areas, the flexible ramping constraint can also help to resolve ramping needs within transmission constrained areas in the ISO system.

[66] For the most part, DMM replicates the ISO's methodology in this analysis. The one exception is that DMM uses settlement information to calculate the flexible ramping capacity utilization. Because of this difference, DMM's results may differ slightly from the ISO's results.

Figure 3.9 shows the procurement of flexible ramping capacity by investor-owned utility area. During the year, around 56 percent of the capacity procured for the flexible ramping constraint was in the Pacific Gas and Electric area. Because flexible capacity is deployed during tight system-wide conditions, the majority of this capacity cannot be used when there is congestion in the southern part of the state, which occurred more frequently in 2012 (see Section 7.3).

For example, in the second half of the year, around 62 MW of flexible ramping capacity was procured in the San Diego area, on average. Thus, only a small amount of dispatchable flexible ramping capacity was available to resolve ramping conditions in 5-minute real-time intervals with San Diego congestion. Also in the second half of the year, average flexible ramping capacity procurement was around 109 MW and 221 MW in the SCE and PG&E areas, respectively. Considering the congestion that occurred in the SCE area, particularly in the third and fourth quarters, the procured flexible ramping capacity had a limited role in resolving 5-minute congestion-related ramping issues in this region.

Figure 3.9 Flexible ramping constraint by investor-owned utility area



Recommendation

As noted in previous reports, DMM recommends that the ISO review how the flexible ramping constraint has affected the unit commitment decisions made in the 15-minute real-time pre-dispatch. DMM believes that evaluating commitment decisions is an important measure of the overall effectiveness of the constraint. In addition, identifying commitment changes caused by the flexible ramping constraint will help in calculating secondary costs related to the flexible ramping constraint. These secondary costs include additional ancillary services payments and additional real-time bid cost recovery payments paid to short-term units committed to deliver energy and displace capacity on other units to provide flexible ramping capacity. In 2013, the ISO is planning to perform sensitivity analysis to gauge the impact of the flexible ramping constraint on unit commitment and explore the feasibility of adding new model functionality that will indicate which units were committed by the constraint.

3.4 Real-time imbalance offset costs

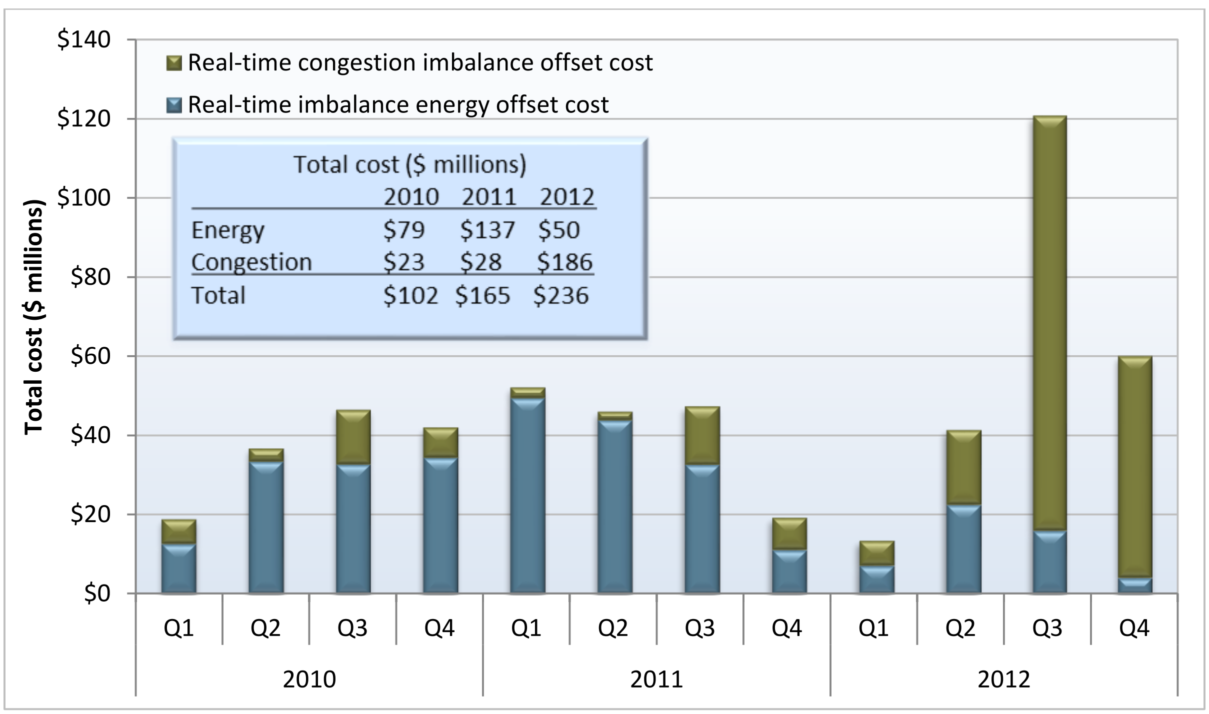
The real-time imbalance offset charge is the difference between the total money paid out by the ISO and the total money collected by the ISO for energy settled at hour-ahead and 5-minute market prices. The charge is allocated as an uplift to measured demand.

The real-time imbalance offset charge consists of two components. Any revenue imbalance from the energy and loss components of hour-ahead 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 components of these real-time energy settlement prices is recovered through the *real-time congestion imbalance offset charge* (RTCIO).

Real-time imbalance costs for energy and congestion totaled about $236 million in 2012, compared to $165 million in 2011. As seen in Figure 3.10, this was primarily attributable to increases in the real-time congestion imbalance offset costs, which rose from $28 million to $186 million. As explained later in this chapter, the increase in real-time imbalance costs for congestion was driven primarily by high real-time congestion prices on constraints whose flow limits were reduced in real-time. In most cases, these limits were reduced to account for unscheduled flows observed in real-time.

Real-time imbalance energy offset costs decreased from $137 million in 2011 to $50 million in 2012, the lowest yearly value since the nodal market began in 2009. As explained in the following sections, the decrease in real-time imbalance energy costs in 2012 was primarily driven by the suspension in virtual bidding on inter-ties in December 2011.[67]

Figure 3.10 Real-time imbalance offset costs



[67] For more detail on the analysis contained in section 3.4 see the discussion paper "Real-time Revenue Imbalance in California ISO Markets," by Ryan Kurlinski at: http://www.caiso.com/market/Pages/MarketMonitoring/MarketMonitoringReportsPresentations/Default.aspx.

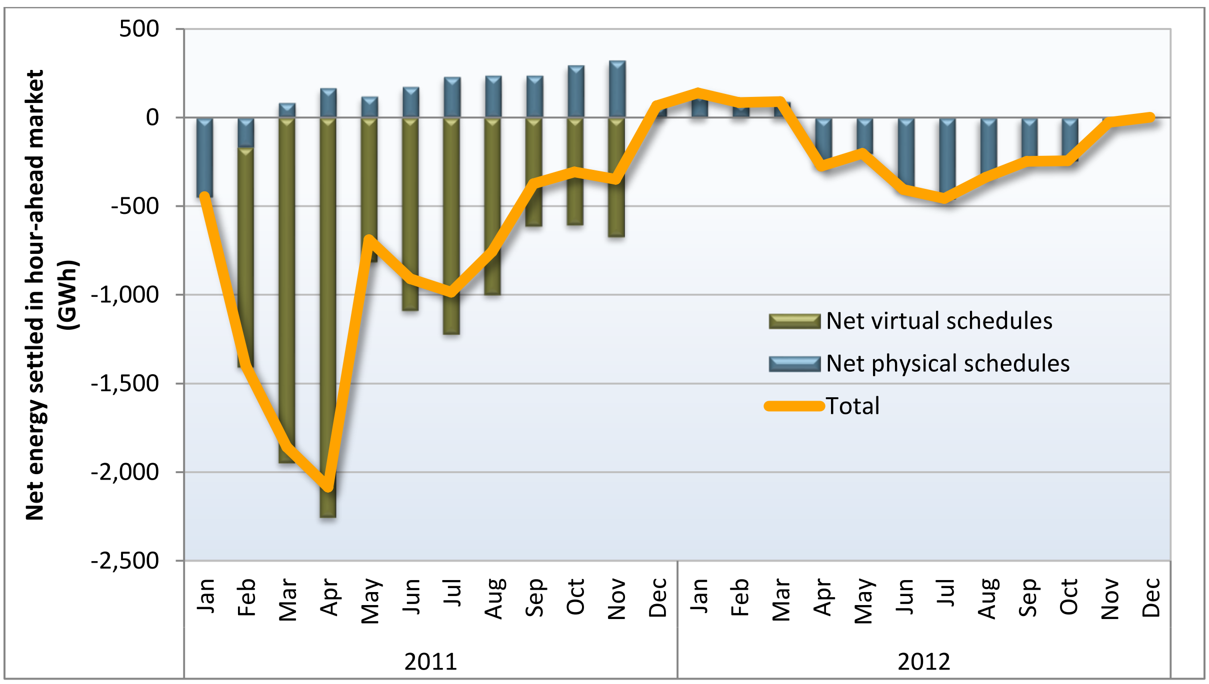
3.4.1 Real-time imbalance energy offset

Real-time imbalance energy offset charges are primarily a function of two factors: the quantity of net import and export energy, including liquidated inter-tie virtual schedules, which the ISO buys (or sells) in the hour-ahead market in a given hour; and the difference between system energy prices in the hour-ahead and 5-minute real-time markets. The quantity of net inter-tie energy bought (or sold) by the ISO at the hour-ahead market price must be subsequently offset by the ISO at the 5-minute market prices. When the ISO sells net exports (including liquidated inter-tie virtual supply) in the hour-ahead market and then purchases additional supply in the 5-minute market at a higher price, this creates a revenue shortfall that is recovered through the imbalance energy offset charge.[68]

The ISO can therefore reduce the magnitude of the uplift (positive or negative) in any given hour by either (1) reducing the quantity of net inter-tie energy it acquires that hour, or (2) reducing the system energy price difference between the hour-ahead and 5-minute markets.

As discussed in Section 2.4 of this report, the difference between prices in the hour-ahead and 5-minute markets did not decrease significantly in 2012. However, the quantity of net energy sold in the hour-ahead market was significantly lower in 2012, as shown in Figure 3.11.

Figure 3.11 Physical and virtual energy settled in hour-ahead market



[68] For instance, if the ISO has net exports of 100 MW in the hour-ahead market (through a combination of liquidated inter-tie virtual supply, reductions to day-ahead imports, and increases to day-ahead exports), this will be offset by a 100 MW net injection increase at internal nodes (through a combination of liquidated internal virtual demand, increases in internal and dynamic generation, and decreases in load). If this 100 MW of net export is sold at an hour-ahead price of $30/MWh, and the additional 100 MW of supply is purchased in the 5-minute market at a price of $40/MWh, this results in a real-time revenue shortfall of $1,000 (100 MW x $30/MWh - 100 MW x $40/MWh).

Suspension of virtual bids at the inter-ties in November of 2011 contributed significantly to the reduction in this volume. This played a major role in decreasing the real-time imbalance energy offset charge down to $50 million in 2012 from $137 million in 2011.

3.4.2 Real-time congestion imbalance offset

This section presents an analysis performed to estimate the contribution to real-time congestion imbalance offset from various factors. The analysis estimates each constraint's contribution to these costs and divides causation into four separate categories:

- Decreases in power flow limits between day-ahead and hour-ahead markets;
- Decreases in power flow limits between hour-ahead and 5-minute markets;
- Differences in constraint shadow prices in the hour-ahead and 5-minute markets; and
- Changes to inter-tie resources' hour-ahead schedules in the 5-minute market.

As shown in Figure 3.12 and Figure 3.13, results of this analysis indicate that reductions in power flow limits of constraints between day-ahead and real-time caused about $155 million of the $185 million of real-time congestion imbalance offset charges in 2012.

Figure 3.13 illustrates that changes to these power flow limits between markets was consistently the main cause of the real-time congestion imbalance offset costs, accounting for the bulk of the cost in every month. A more detailed description of these four contributing factors and results of this analysis are provided below.

Figure 3.12 Causes of real-time congestion imbalance offset costs by year

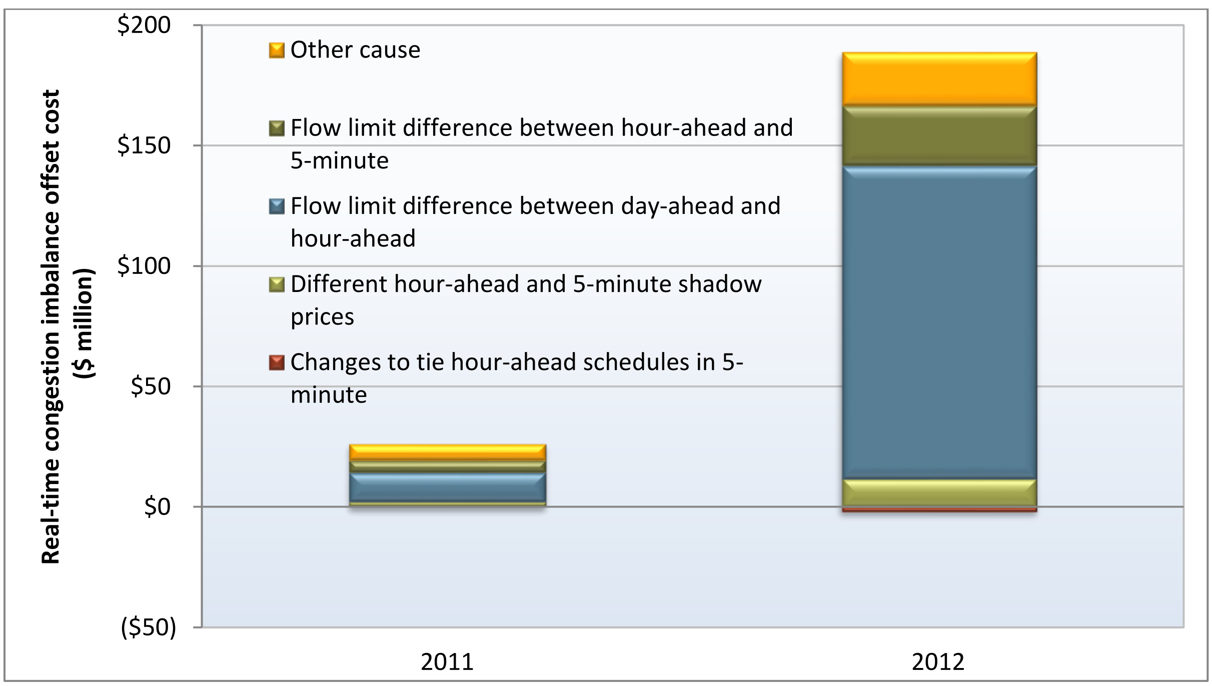
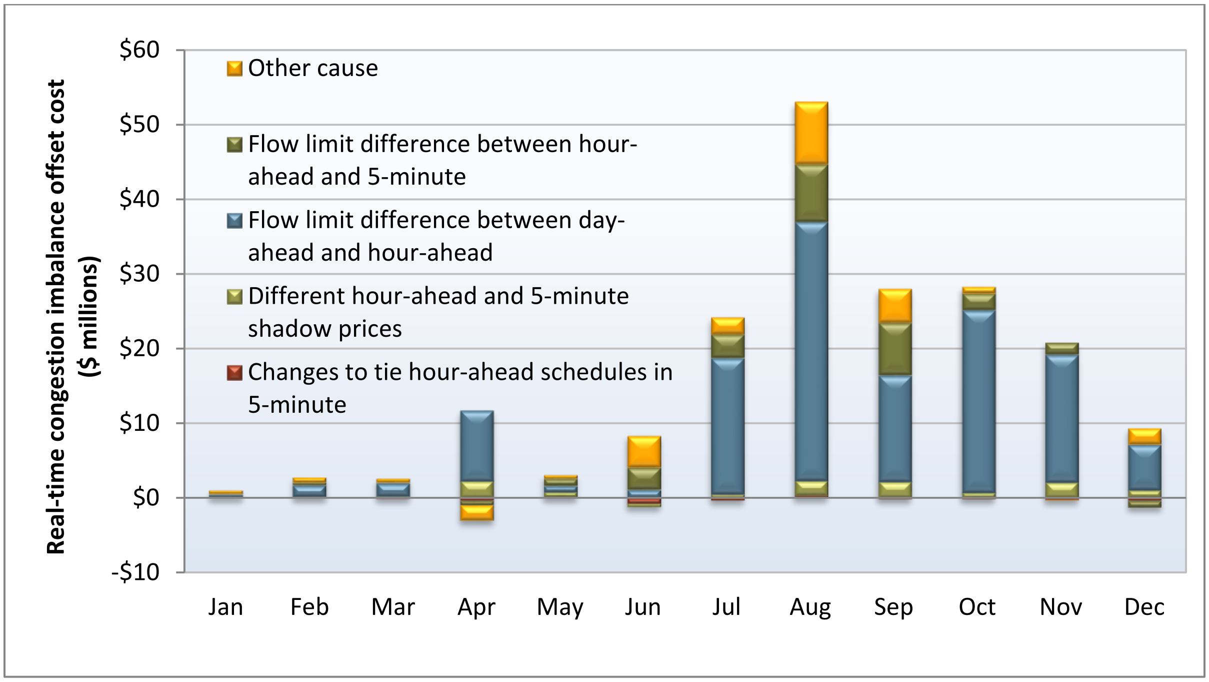


Figure 3.13 Causes of real-time congestion imbalance offset by month in 2012



Decrease in power flow limits between day-ahead and hour-ahead markets

When the scheduled power flow over a constraint decreases between the day-ahead and hour-ahead markets, this change in power flow must be accomplished by an increase in net power injections at some nodes, and an equal quantity of decreased net power injections at other nodes.[69] Net power injections must increase at nodes where an injection has a relatively high effectiveness at reducing power flows over the constraint. Net power injections must decrease at nodes where a withdrawal has a relatively high effectiveness at reducing power flows over the constraint.

The constraint's impact on the real-time price of each injection or withdrawal is directly proportional to the effectiveness of the injection or withdrawal in impacting flow on the constraint. A constraint's congestion price will have a positive impact on the price at locations where an injection would reduce flow on the constraint. Conversely, it will have a negative impact on the price at nodes where a withdrawal would reduce flow on the constraint.

To reduce the day-ahead flow on the constraint to the lower hour-ahead limit, the extra hour-ahead injections must be at locations with higher overall prices than the equal quantity of withdrawals.

[69] The changes in flow limits discussed throughout the real-time congestion imbalance offset sections of this report refer specifically to the changes between the linearized real-power flow quantities that settle on the constraint's shadow price. The changes to these real-power flow limits may be caused by manual adjustments to the constraint's alternating current power flow limit used in the markets. Other structural differences between the markets may cause differences in the amount of constraint capacity available for real-power settled in the markets. These other structural differences include reactive power flow differences between markets; different impacts from compensating injections in the different markets; and topography changes between markets (such as an outage of line X after the day-ahead market that causes the shift factors for constraint Y to be different between the day-ahead and real-time).

Reducing flow limits on constraints between the day-ahead and hour-ahead markets therefore causes the ISO to buy power at a high price in real-time while simultaneously selling the same quantity of power back at a relatively low price in real-time. This creates the real-time revenue imbalance.

This decrease in flow between the day-ahead and hour-ahead markets is accomplished by a combination of changes to day-ahead schedules at internal nodes and inter-tie nodes. The changes to day-ahead schedules of internal nodes that contribute to meeting this flow change contribute to real-time congestion imbalance offset based on the 5-minute market shadow price of the constraint. The changes to day-ahead schedules of inter-tie nodes that contribute to meeting this flow change contribute to the real-time congestion imbalance offset based on the hour-ahead market shadow price of the constraint.

Decreases in power flow limits between hour-ahead and 5-minute markets

A constraint's power flow can also be decreased between an hour's hour-ahead market and 5-minute market runs. This incrementally increases the real-time congestion imbalance offset through the same dynamic described above. The main difference is that the decrease in flow between the hour-ahead and 5-minute markets is almost entirely accomplished by changes to the hour-ahead schedules of internal nodes.[70] The changes to hour-ahead schedules of internal nodes that contribute to meeting this flow change contribute to real-time congestion imbalance offset based on the 5-minute market shadow price of the constraint.

Differences in hour-ahead and 5-minute market shadow prices

For any given hour, the impact on the constraint's hour-ahead market flows from changes to day-ahead schedules of *internal* nodes may be in the opposite direction as the flow impact from changes to day-ahead schedules of *inter-tie* nodes. Therefore, some of the flow impact on the constraint from internal nodes *offsets* the flow impact from inter-tie nodes. In such an hour, the amount of the internal node flow impact and inter-tie node flow impact that is offsetting does not contribute to decreasing the day-ahead market flow down to the lower hour-ahead market flow level. However, the flow impact from internal nodes settles on the constraint's 5-minute market shadow price while the offsetting amount of flow impact from inter-tie nodes settles on the constraint's hour-ahead market shadow price. As a result, each MWh of offsetting internal/inter-tie flow impact contributes to the real-time congestion imbalance offset. The dollar per MWh contributed to the real-time congestion imbalance offset is the difference between the hour-ahead and 5-minute market shadow prices.

Changes to inter-tie resources' hour-ahead schedules in the 5-minute market

The hour-ahead schedules of non-dynamic inter-tie resources settle on the resource's hour-ahead market price. While the settlement quantity of such resources does not deviate from the hour-ahead schedule,[71] the 5-minute market will change the unpublished schedule of these resources to account for issues such as inter-hour ramp. Similar to the dynamic described in the section immediately above, for

[70] Inter-tie resources for the most part have the same schedules in the hour-ahead and 5-minute markets. The contribution to real-time congestion imbalance offset from non-dynamic system resources that have different schedules in the 5-minute market than in the hour-ahead market is discussed in the final two descriptions of the causes of real-time congestion imbalance offset immediately below.

[71] This is true unless there are operational adjustments, which are discussed on the following page in the "other causes" section.

any given interval, the impact on the constraint's 5-minute market flows from changes to hour-ahead schedules of *internal* nodes may be in the opposite direction as the flow impact from changes to hour-ahead schedules of *inter-tie* nodes. In such an interval, the amount of the internal node flow impact that is offset by inter-tie flow impact does not contribute to decreasing the hour-ahead market flow down to the lower 5-minute market flow level. We therefore attribute the real-time congestion imbalance offset contribution from this quantity of internal node flow impact to the fact that the market design allows unsettled changes to inter-tie hour-ahead market schedules in the 5-minute market.

Other causes not specifically identified in our analysis

Our analysis accounts for most causes of real-time congestion imbalance offset that are related to scheduled market quantities and prices. The analysis does not account for manual changes to market awards and prices (with the exception of some shadow price corrections that are included in the analysis). The causes of real-time congestion imbalance offset quantified in the "other causes" category therefore include some price corrections to shadow prices, uninstructed and unaccounted-for energy, and operational adjustments to system resources' hour-ahead schedules that settle on 5-minute market prices.

Results by constraint

Results of this analysis show that a large portion of the high uplift charges caused by reductions in power flow limits after the day-ahead market was driven by a handful of constraints. Table 3.2 illustrates that the top 7 constraints contributed about 60 percent of the real-time congestion offset costs caused by reducing constraints' power flow limits after the day-ahead market in 2012. However, about 30 other constraints each contributed more than $500,000 to these costs, and over 40 more constraints each contributed more than $100,000 to this uplift.

Inter-tie system resources significantly impacted the congestion on the top seven constraints in Table 3.2. Reducing the power flow limits of such constraints down after the start of the hour-ahead market run prevents the 15-minute pre-dispatch and 5-minute real-time dispatch optimizations from re-dispatching some of the resources that are most effective at reducing the constraints' flows. As a result, reducing the power flow limits of constraints down after the start of the hour-ahead market run can significantly increase the magnitude of the congestion price of these constraints in the 5-minute market.

This can amplify the impacts of even small reductions in the constraint's power flow limit after the hour-ahead market. This is because it is not just the additional changes to internal nodes' 5-minute market schedules relative to the internal nodes' hour-ahead schedules that contribute to real-time congestion imbalance offset based on the constraint's 5-minute market shadow price. As explained above, all changes to internal nodes' day-ahead schedules in either the hour-ahead or 5-minute markets (including all internal virtual schedules that liquidate in the hour-ahead market) contribute to the real-time congestion imbalance offset based on the 5-minute market shadow price of the constraint.

Table 3.2 Real-time congestion imbalance offset caused by changes to constraints' power flow limits (Top 30 constraints of 2012)

Constraint	2012 RTCIO caused by differences between DA and RT flow limits
6110_TM_BNK_FLO_TMS_DLO_NG	$37,900,000
22342_HDWSH _500_22536_N.GILA _500_BR_1 _1	$14,800,000
SLIC 2042305 ELD-LUGO PVDV	$10,700,000
SOUTHLUGO_RV_BG	$9,500,000
14013_HDWSH _500_22536_N.GILA _500_BR_1 _1	$8,600,000
SLIC 2023497 TL50003_CFERAS	$8,200,000
T-135 VICTVLUGO_EDLG_NG	$8,000,000
SCIT_BG	$6,400,000
SDGE_CFEIMP_BG	$6,100,000
BARRE-LEWIS_NG	$5,200,000
PACI_ITC	$4,100,000
SLIC 1953261 ELD-LUGO PVDV	$2,800,000
SCE_PCT_IMP_BG	$2,700,000
SLIC 1902749 ELDORADO_LUGO-1	$2,700,000
7820_TL 230S_OVERLOAD_NG	$2,400,000
SLIC 1356092 Serrano Valley OUT	$2,200,000
SLIC 1884984 Gould-Sylmar	$2,100,000
NOB_ITC	$2,000,000
24137_SERRANO _230_24154_VILLA PK_230_BR_1 _1	$1,900,000
PATH26_N-S	$1,900,000
230S overload for loss of PV	$1,800,000
T-167 SOL 2_NG_SUM	$1,700,000
T-165 SOL-12_NG_SUM	$1,600,000
SLIC 1956086_ELD-MCCUL HDW	$1,600,000
22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80	$1,600,000
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$1,400,000
PATH15_S-N	$1,300,000
30550_MORAGA _230_33020_MORAGA _115_XF_3 _P	$1,200,000
MEAD_ITC	$1,100,000
T-165 SOL-4_NG_SUM	$1,100,000

Virtual bidding and real-time congestion imbalance offset costs

As discussed above, real-time congestion imbalance offset is caused by underlying differences between ISO markets. The main structural cause of the real-time congestion imbalance offset is differences in power flow limits between the day-ahead and hour-ahead markets, and between the hour-ahead and 5-minute markets. Therefore, virtual schedules increase real-time congestion imbalance offset to the extent that they cause day-ahead power flows to exceed real-time power flows on constraints that bind in real-time.

Analysis designed to assess the real-time congestion imbalance offset charge caused by virtual schedules will be inadequate if the analysis does not appropriately account for the amount of physical day-ahead schedules, and consequently flows, displaced by the cleared virtual schedules. Virtual schedules are cleared in the day-ahead market along with physical schedules and do displace physical schedules to a greater or lesser extent. In the absence of cleared virtual bids, an additional amount of physical schedules would clear and contribute to the real-time congestion imbalance offset. A causal analysis would therefore be difficult without re-running the day-ahead market and assessing real-time congestion imbalance offset costs using day-ahead market flows both with and without virtual bids in the market.

Data from completed market runs, however, can be used to quantify the extent to which cleared virtual schedules, as opposed to cleared physical schedules, contributed to (and benefited from) the real-time congestion imbalance offset that actually occurred. For this report, DMM used the analytical framework described above to develop a quantitative method for analyzing virtual schedules' contribution to real-time congestion imbalance offset in 2012.

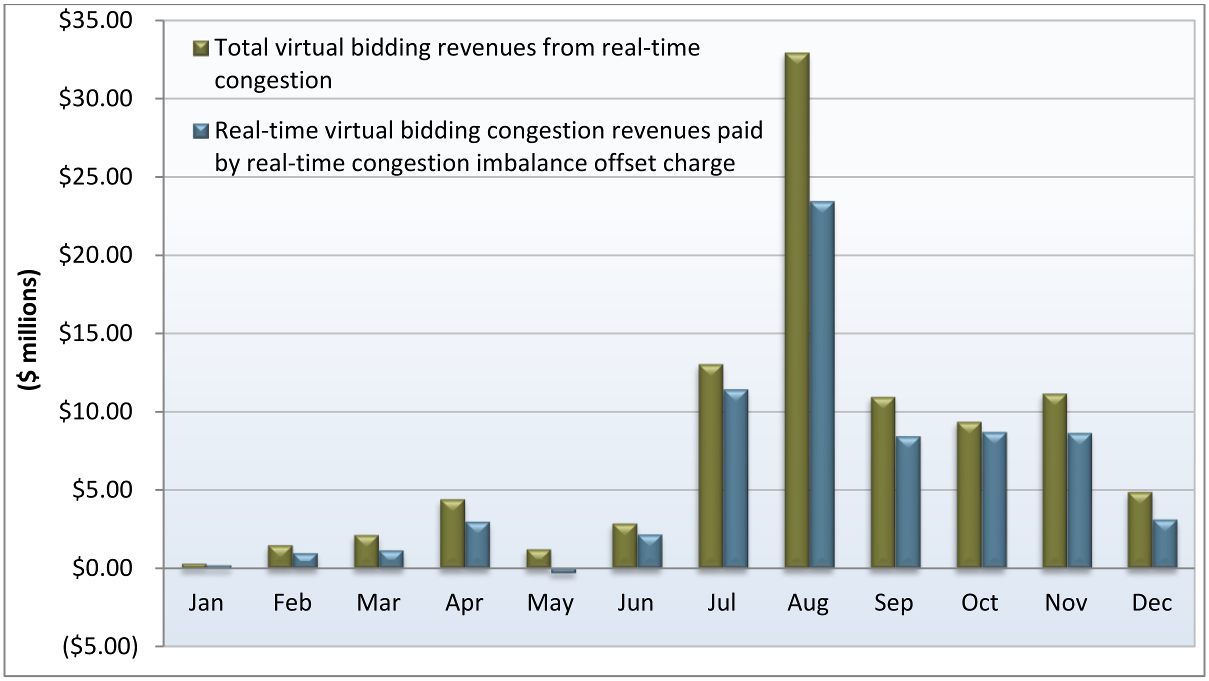
The method starts by calculating the amount of power flow from virtual schedules over constraints that have different power flows in the day-ahead and real-time markets. However, virtual schedules' contribution to the real-time congestion imbalance offset is not based on this total virtual flow. The total virtual flow on a constraint simply identifies the virtual schedule flow quantity that settles on the constraint's real-time shadow price.[72]

The difference between a constraint's day-ahead and real-time power flow contributes to a charge or credit to the real-time congestion imbalance offset. The extent to which virtual schedules contributed to (and benefited from) real-time congestion imbalance offset payments is therefore limited by the amount the day-ahead market power flow actually exceeded the real-time market power flow of the constraint. This method identifies the amount that virtual schedules contributed to real-time congestion imbalance offset charges (and credits) by only considering the difference between the day-ahead and real-time power flows on each constraint binding in the real-time market.

Based on this approach, DMM estimates that about $70 million out of $95 million of real-time congestion revenues paid to virtual positions in 2012 resulted from excess day-ahead power flow on constraints whose power flow limits were reduced between the day-ahead and real-time markets. As a result, about 80 percent of net real-time congestion revenues paid to virtual bidders in 2012 were ultimately recovered from load-serving entities through real-time congestion imbalance offset charges. Figure 3.14 illustrates the monthly estimates of these payments and highlights that the contribution of real-time virtual bidding to the real-time imbalance offset cost accounted for most of the real-time virtual bidding congestion settlement in each month.

[72] The total virtual real-time congestion revenues are what is reported as the "virtual" portion of the real-time congestion imbalance offset settlement charge codes. This is not related to how much virtual positions actually contributed to real-time congestion imbalance offset costs, besides through the possible coincidence of the bulk of virtual schedule real-time congestion revenues coming from constraints whose power flow limits are lower in real-time than in the day-ahead. This relationship is graphed below.

Figure 3.14 Virtual bidding revenues from real-time congestion paid by real-time congestion imbalance offset charge



Discussion of results

In a market without structural differences between the day-ahead and real-time market models, money paid by the ISO to virtual schedules for their real-time settlement would be funded by real-time market payments to the ISO from counterparties that took the opposite position of the virtual schedules in the day-ahead market. However, money paid by the ISO to virtual schedules that benefit from structural differences between day-ahead and real-time markets is not covered by in-market real-time payments to the ISO from schedules taking the opposite position. This revenue imbalance results in an uplift charge.

This analysis reveals the significant extent to which virtual schedules were submitted and cleared to leverage constraints modeled with power flow limits that were higher in the day-ahead market than they were in the real-time markets. As a result, the vast majority of real-time congestion revenues paid to virtual schedules were charged to metered demand as uplift. Uplift caused by structural differences between ISO markets has accounted for most real-time virtual bidding revenues in California.

In 2011, differences between system energy prices in the hour-ahead and 5-minute real-time markets accounted for most real-time virtual bidding revenues. However, in 2012 most real-time virtual bidding revenues stemmed from differences in constraint flow limits between day-ahead and real-time markets.

An alternative allocation of the real-time congestion imbalance offset uplift cost could allocate the cost to both physical and virtual schedules. The alternative allocation could utilize a decomposition methodology similar to the one used in this analysis. This allocation may be more appropriate than charging metered demand.

This uplift is caused by underlying structural differences between the ISO energy markets. Most of the uplift therefore cannot be allocated to the market participant that caused the uplift. However, in the absence of an ability to allocate uplift by causation, it may be appropriate to assign uplifts to the market participants that benefit from the uplift. This approach may better align virtual bidding profits with their potential contribution to converging the day-ahead and real-time markets.

4 Convergence Bidding

Convergence 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 the day-ahead market on February 1, 2011. Virtual bidding on inter-ties was suspended on November 28, 2011.[73] Thus, 2012 represents a full year with virtual bidding within the ISO system but not at the inter-ties.

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 against price differences in the two following circumstances:

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

Total net revenues paid to entities engaging in convergence bidding totaled around $56 million in 2012. Most of these net revenues resulted from offsetting virtual demand and supply bids at different internal locations designed to profit from higher congestion between these locations in real-time.

This type of offsetting internal bids represented over 55 percent of all accepted virtual bids in 2012, up from 35 percent in 2011. The increase in both the quantity and net revenues of offsetting internal virtual bids likely stems from the increased differences in congestion between the day-ahead and real-time markets in 2012.

Most of these net profits ($39 million) came from virtual demand on internal nodes, which are settled based on the difference in real-time and day-ahead prices. For the year, virtual demand outweighed virtual supply by an average of almost 350 MW per hour. Virtual demand averaged 1,585 MW per hour, while virtual supply averaged only 1,240 MW per hour.

Background

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 hour-ahead and 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.

[73] See 137 FERC ¶ 61,157 (2011) accepting and temporarily suspending convergence bidding at the inter-ties subject to the outcome of a technical conference and a further commission order. More information can also be found under FERC docket number ER11-4580-000.

- 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.

Thus, 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.[74] 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.

However, the degree to which convergence bidding has actually increased market efficiency by improving unit commitment and dispatches has not been assessed.

4.1 Convergence bidding trends

Convergence bidding volumes increased steadily over the year, with net cleared volumes shifting from net virtual supply to net virtual demand beginning in the second quarter of 2012. 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 at internal locations for each operating hour.

Key convergence bidding trends include the following:

- On average, 52 percent of virtual supply and demand bids offered into the market cleared in 2012.
- The cleared volume of virtual demand outweighed virtual supply during each of the last three quarters. For the year, cleared virtual demand outweighed virtual supply by almost 350 MW.
- The net position of all cleared virtual bids was typically virtual demand in the peak hours and virtual supply in the off-peak hours.
- About 64 percent of cleared virtual positions were held by pure financial trading entities that do not serve load or transact physical supply.

[74] 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.

Figure 4.1 Quarterly average virtual bids offered and cleared[75]

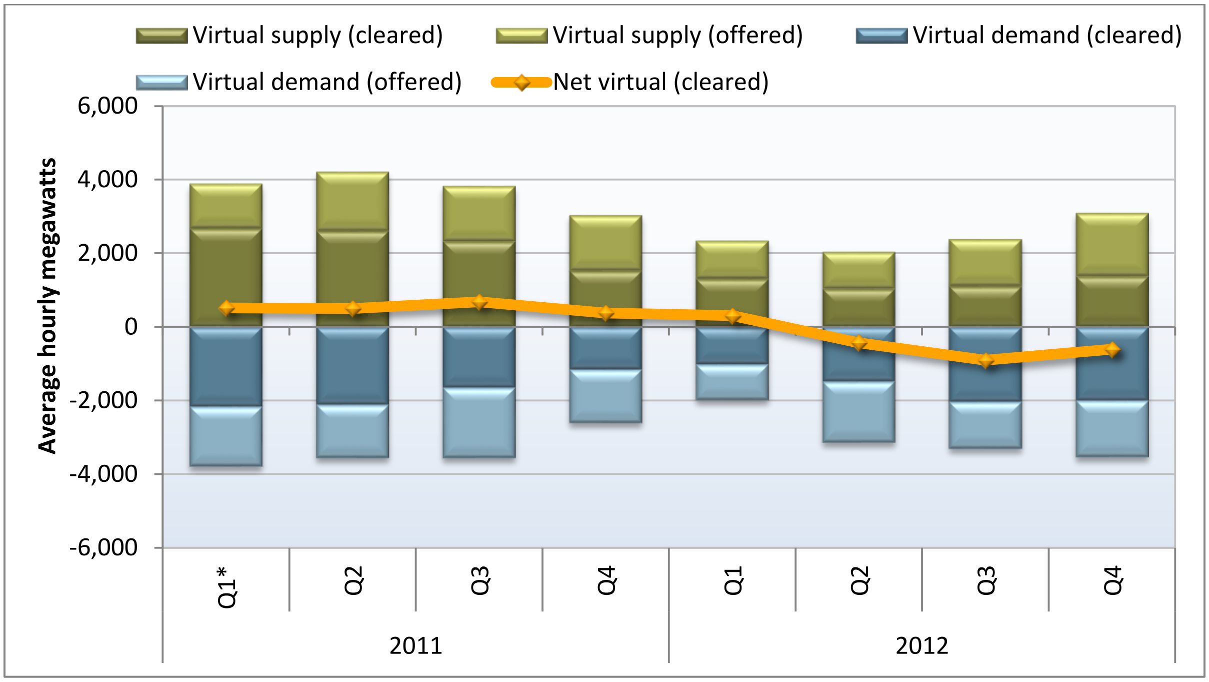
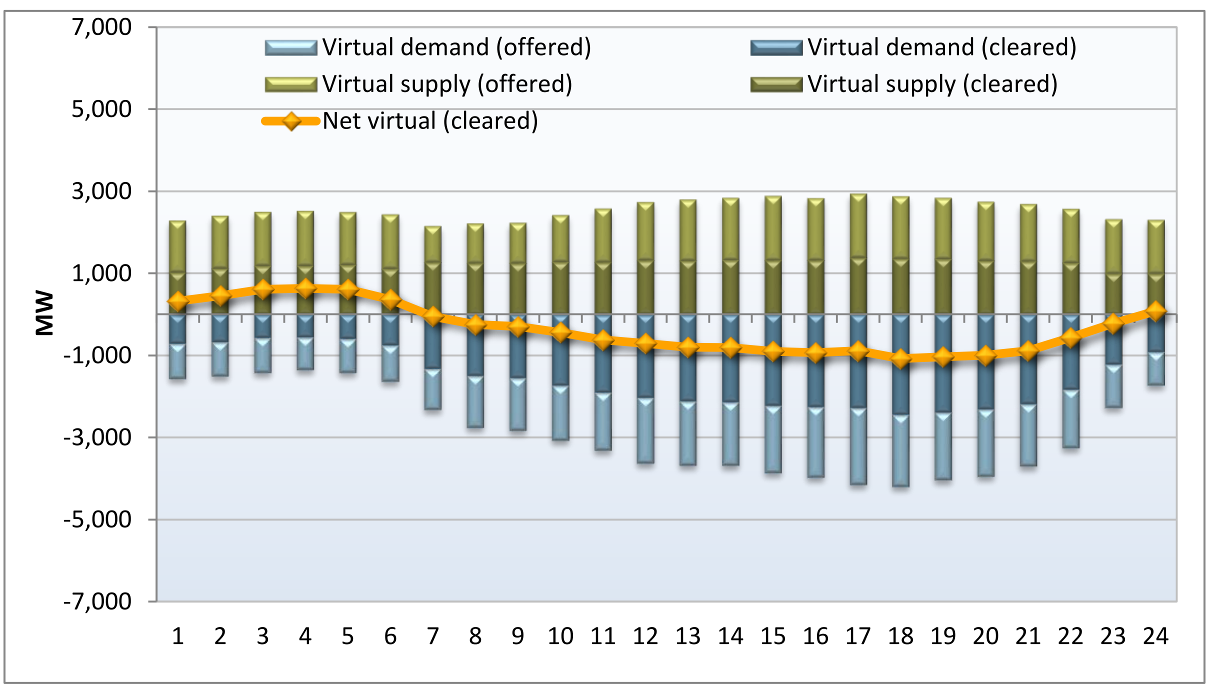


Figure 4.2 Average net cleared virtual bids at internal points in 2012



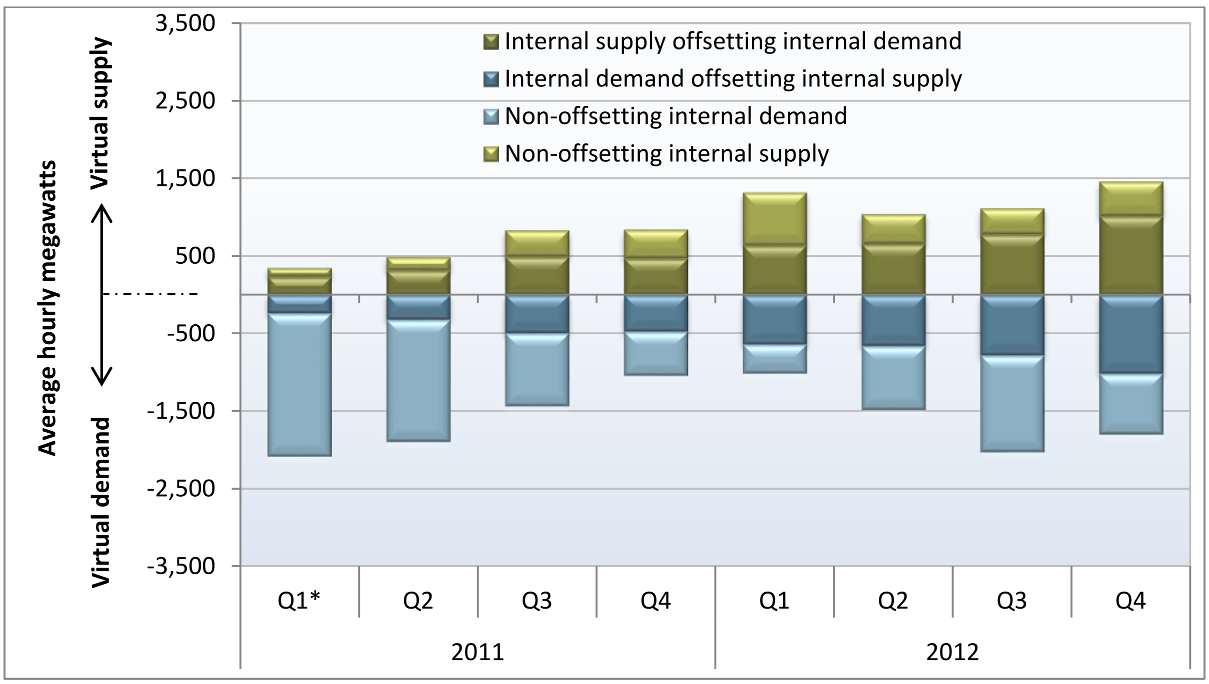
[75] Since convergence bidding began in February 2011, all convergence bidding figures that include the first quarter of 2011 only include records for February and March.

Offsetting virtual supply and demand bids at internal points

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 internal 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 market between these two locations.

The majority of cleared virtual bids in 2012 were related to such offsetting bids. Figure 4.3 shows the average hourly volume of offsetting virtual supply and demand positions at internal locations. The dark blue and dark green bars represent the average hourly overlap between internal demand and internal supply by the same participants.[76] The light blue bars represent the remaining portion of internal virtual supply that was not offset by internal virtual demand by the same participants. The light green bars represent the remaining portion of internal virtual demand that was not offset by internal virtual supply by the same participants.

Figure 4.3 Average hourly offsetting virtual supply and demand positions at internal points



As shown in Figure 4.3:

- Offsetting virtual positions at internal locations accounted for an average of about 770 MW of virtual demand offset by 770 MW of virtual supply in each hour of the year. These offsetting bids represent over 55 percent of all cleared internal virtual bids in 2012, up from 35 percent of bids in 2011. This suggests that since the suspension of virtual bidding on inter-ties, virtual bidding has been increasingly used to hedge or profit from internal congestion.

[76] When calculating the overlap between each participant's accepted virtual supply and demand bids at internal points, we did not include the portion of the participant's internal virtual demand bids that were offset by imports in 2011.

- Over the course of the year, the amount of offsetting internal virtual bidding positions taken by participants grew in volume and as a share of total internal virtual bids. By the fourth quarter, the share of offsetting internal virtual positions had increased to over 60 percent of cleared bids.
- As discussed later in this chapter, the remaining virtual demand bids tended to be placed in peak hours during periods when average real-time prices tended to be higher than average day-ahead prices due to real-time price spikes.
- The remaining virtual supply bids tended to be placed in off-peak hours during periods when average real-time prices tended to be lower than average day-ahead prices.

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 consistent with price differences in many hours early in 2012. However, beginning in the third quarter and continuing into the fourth quarter, net convergence bidding volumes, on average, were consistent with price differences between the day-ahead and real-time markets in only about half of the hours.

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 internal locations.

For the intervals when the red line is negative, this indicates that the weighted average price charged for internal virtual demand in the day-ahead market was lower than the weighted average real-time price paid for this virtual demand.

Internal virtual demand volumes were consistent with weighted average price difference for the hours in which this virtual demand cleared the market in all quarters of 2012. On average, these virtual demand positions were particularly profitable in the second and the third quarters.

During months when the yellow line is positive, this indicates that the weighted average price paid for internal 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. Except for the second quarter, virtual supply at internal locations was consistently profitable.

As noted earlier, a large portion of the internal virtual supply clearing the market was paired with internal demand bids at different internal locations by the same market participant. Such offsetting virtual supply and demand bids are likely used as a way of hedging or speculating from internal 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.

Figure 4.4 Convergence bidding volumes and weighted price differences at internal locations

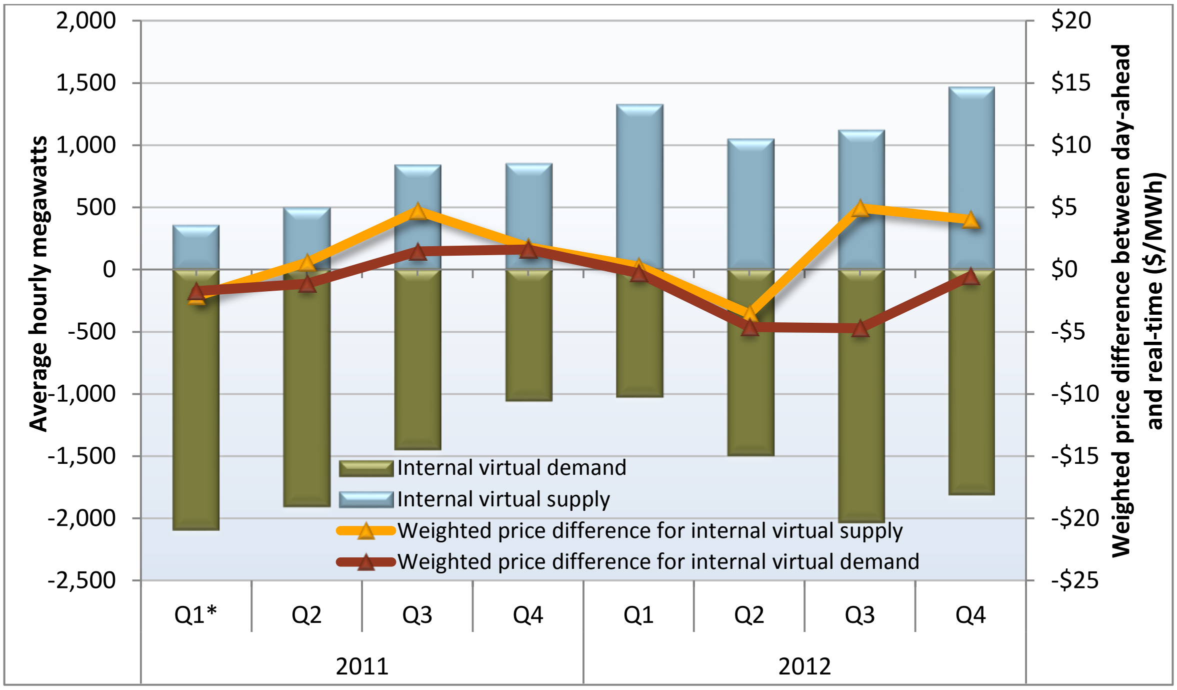


Figure 4.5 through Figure 4.8 show average hourly net cleared convergence bidding volumes compared to the difference in the day-ahead and real-time system marginal energy prices in each quarter of the year. The blue bars represent the net cleared internal virtual position, whereas the green line represents the difference between the day-ahead and real-time system marginal energy prices.

In anticipation of real-time price spikes, market participants often bid virtual demand in peak hours. Even though these spikes do not occur often, the revenues received outweigh losses that happened otherwise in every quarter of the year (see Section 4.2 below for further detail).

- As shown in Figure 4.5, convergence bidding volumes in the first quarter were consistent in 19 of the hours with price convergence at internal locations. Consistency was best in the off-peak hours and in the later afternoon hours.
- In the second quarter, as seen in Figure 4.6, convergence bidding volumes were also directionally consistent with differences between day-ahead and real-time prices in most hours of the day. The consistency of the net cleared convergence bidding positions improved from the first quarter.
- Figure 4.7 shows that convergence bidding volumes in a majority of hours in the third quarter were not consistent with price convergence at internal locations. In total, there were only 11 hours where net convergence bidding volumes were consistent with day-ahead and real-time price differences.
- As shown in Figure 4.8, virtual net positions were consistent in half of the hours in the fourth quarter. The consistency improved in the peak hours and decreased in the off-peak hours as compared to the third quarter.

Figure 4.5 Hourly convergence bidding volumes and prices (January – March)

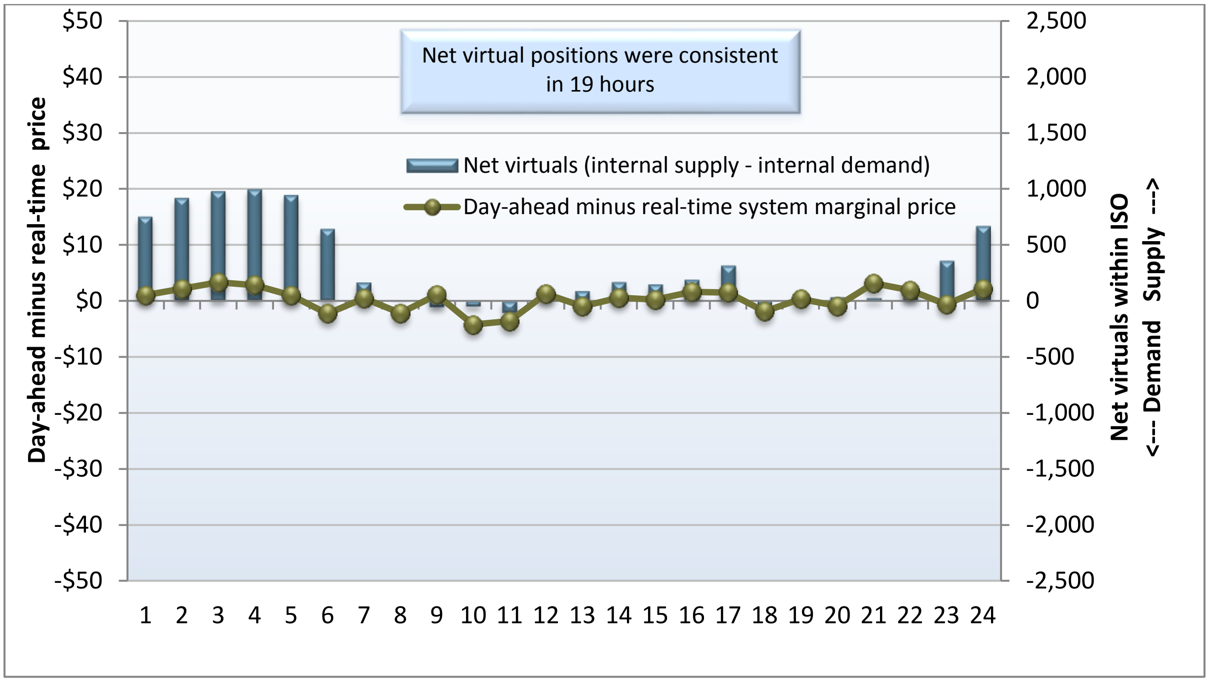


Figure 4.6 Hourly convergence bidding volumes and prices (April – June)

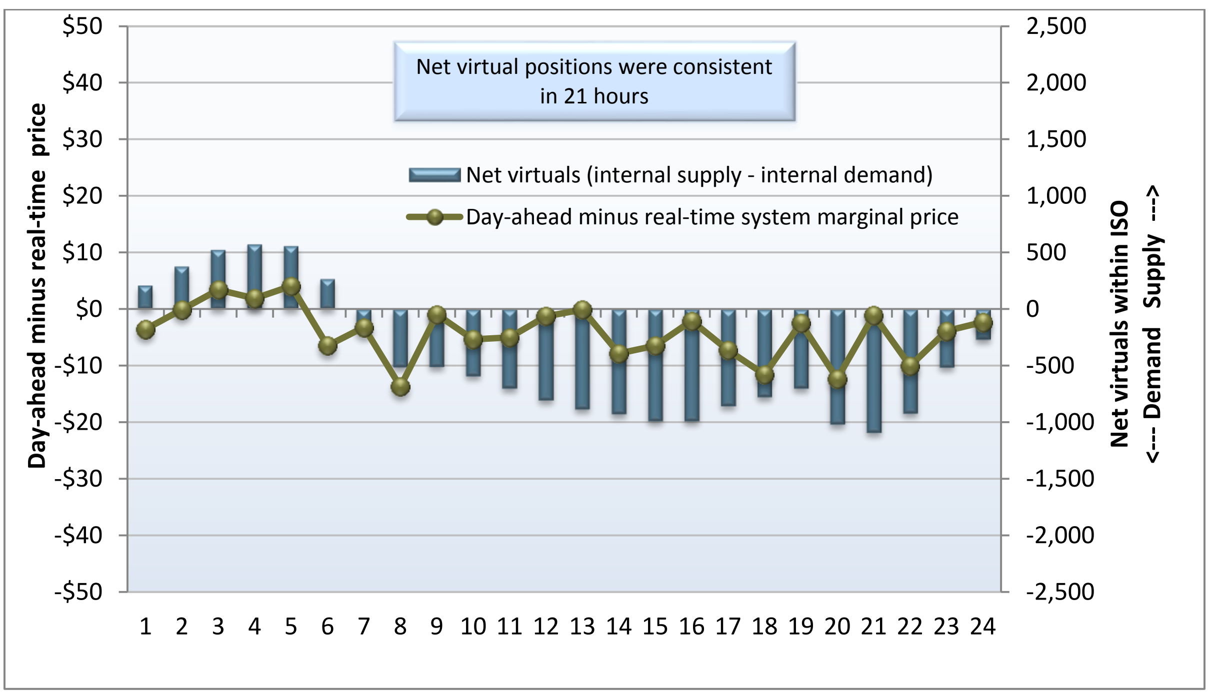


Figure 4.7 Hourly convergence bidding volumes and prices (July – September)

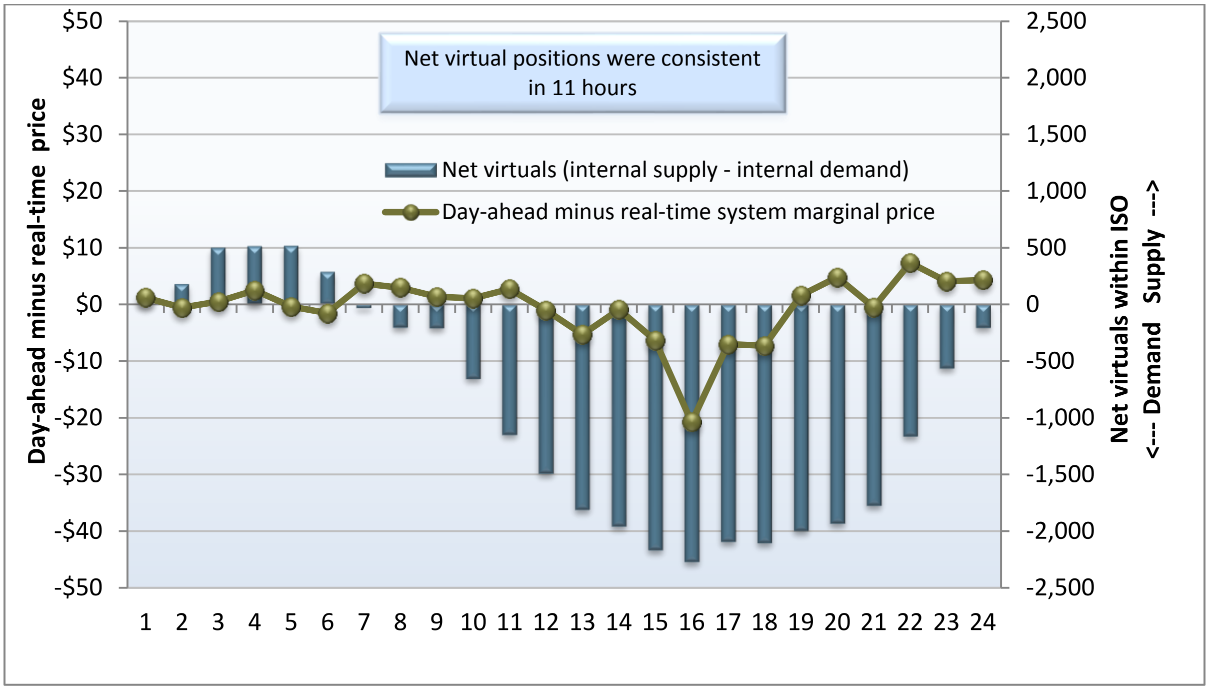
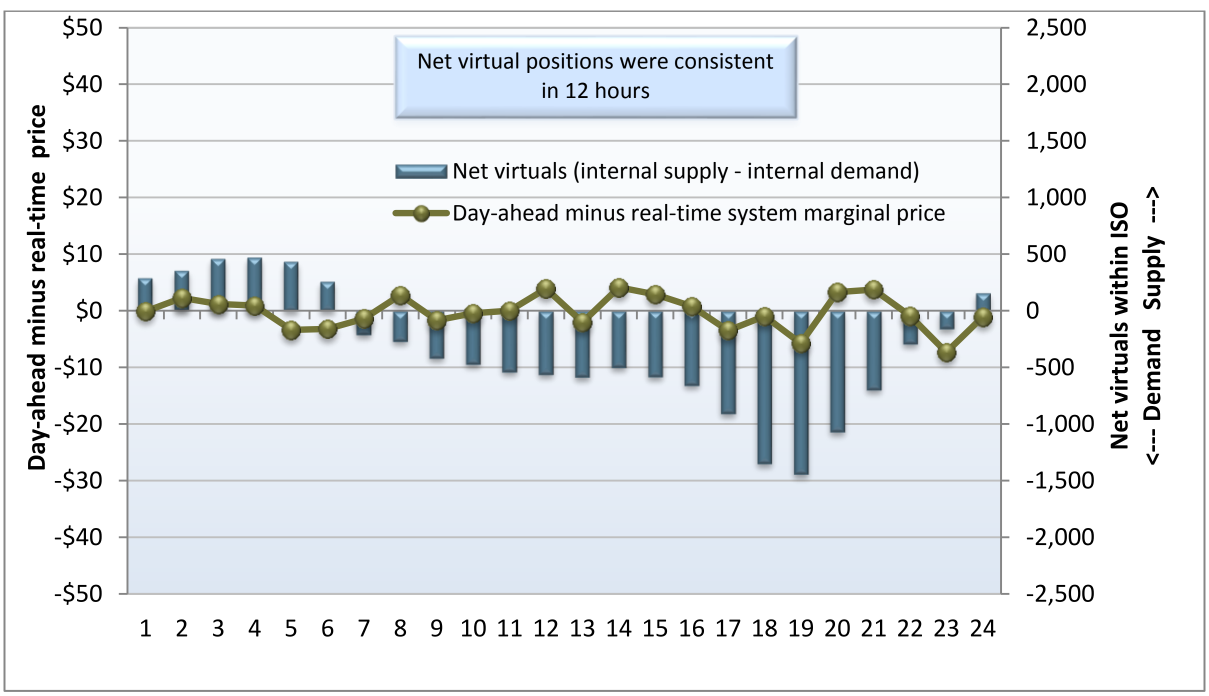


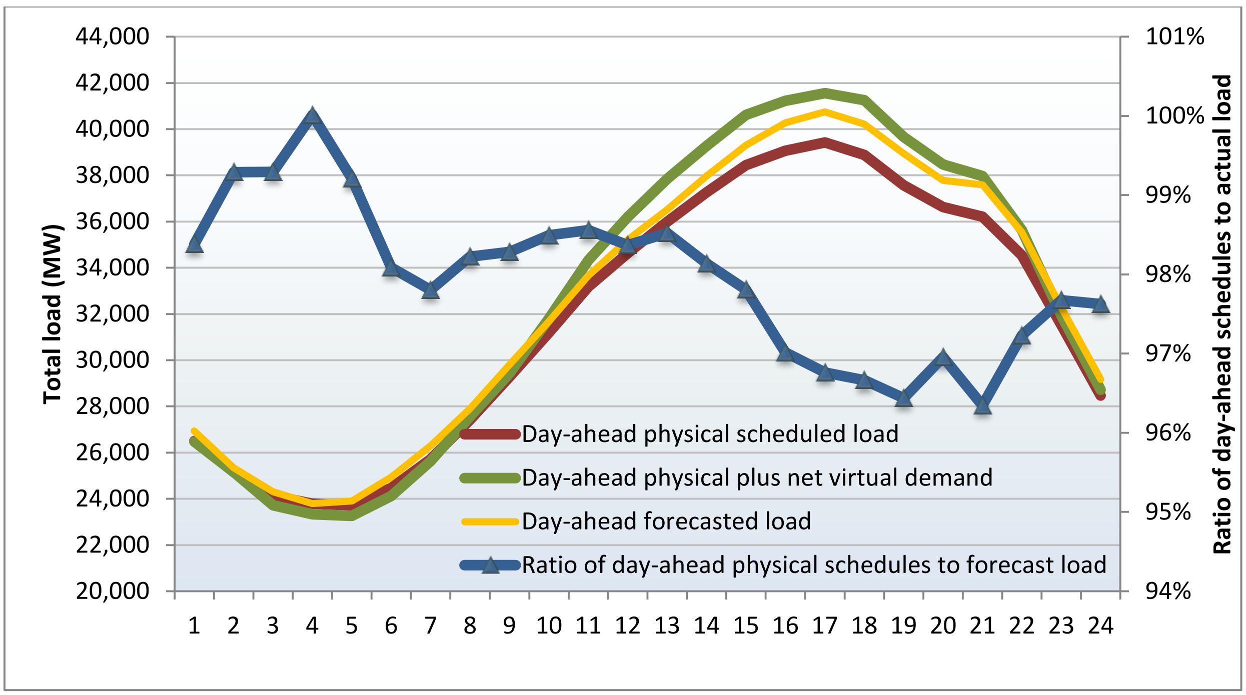
Figure 4.8 Hourly convergence bidding volumes and prices (October – December)



As discussed in Section 2.3 of this report, over the course of 2012, the average total amount of demand (including net virtual demand) clearing the day-ahead market matched the day-ahead forecast load very closely in the peak hours, while falling below the forecast of load in the off-peak hours. However, as shown in Figure 4.9, during many peak hours of the summer months virtual demand pushed total demand clearing the day-ahead market an average of about 1,000 MW over actual and forecasted loads.

During these periods, virtual demand bids were profitable during many peak hours since average real-time prices tended to exceed average day-ahead prices. When combined with physical demand bids, this virtual demand pushed the total quantity of demand clearing the day-ahead market above forecasted and actual system demand. While this helped converge day-ahead and real-time prices, it also helped drive day-ahead prices above levels that would result if total demand clearing the day-ahead market equaled actual or forecasted demand. This illustrates how factors driving up average real-time prices can ultimately drive up day-ahead prices as well.

Figure 4.9 Day-ahead schedules, forecast and actual load (August 2012)



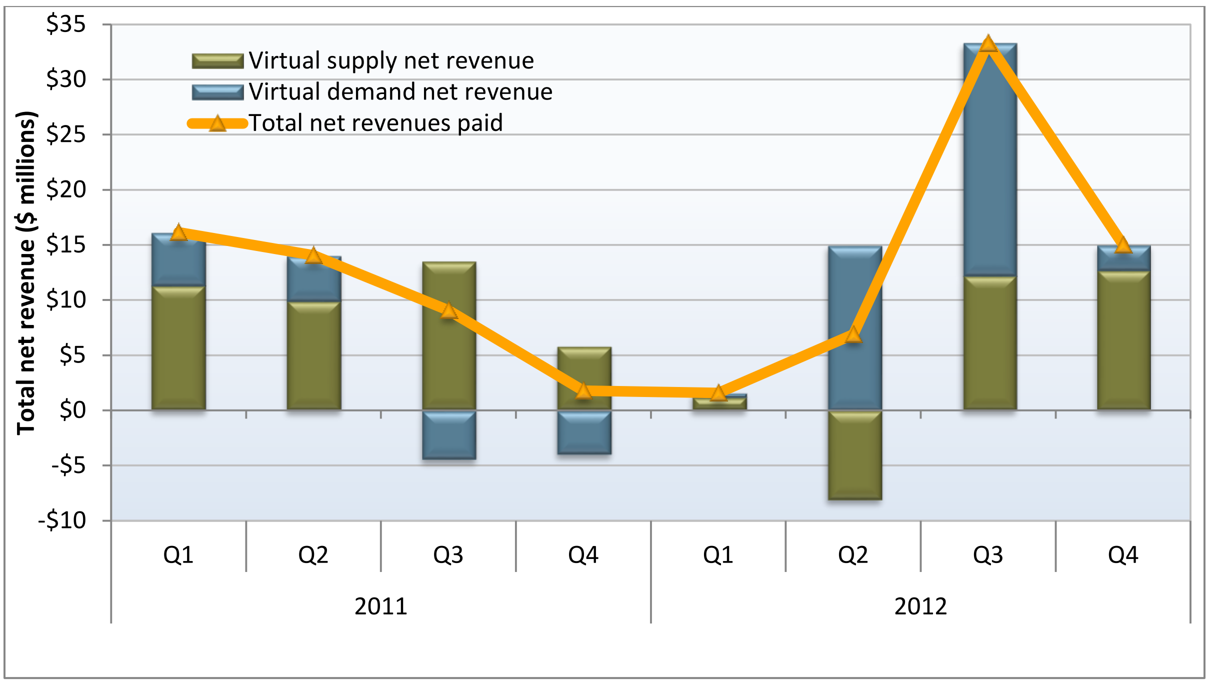
4.2 Convergence bidding payments

Net revenues paid to convergence bidders totaled over $56 million in 2012, up from $41 million in 2011, or an increase of 37 percent. The majority of these profits were associated with congestion. Figure 4.10 shows total monthly net profits paid for accepted virtual supply and demand bids. As shown in this figure:

- Most of the net revenues ($39 million) came from virtual demand. About $18 million in profits were received by virtual supply at internal locations.
- Most of the net revenues were attributed to congestion-related price differences.

- In 2012, virtual supply positions were profitable in all periods but the second quarter. This trend reflects that revenues on virtual supply bids placed in the off-peak hours are less volatile, since negative price spikes are smaller in magnitude and typically last longer.
- Virtual demand positions were consistently profitable in every quarter, while monthly revenues varied from being profitable or unprofitable from one month to the next. This trend reflects that real-time prices were predictably higher than day-ahead prices in summer months, but were much more consistent with day-ahead prices for the rest of the year.
- Total net revenues paid to virtual bidders peaked in the third quarter, exceeding $33 million. Total net revenues were near zero in the first quarter and reached $7 million and $15 million in the second and fourth quarters, respectively.

Figure 4.10 Total monthly net revenues from convergence bidding



Net revenues at internal scheduling points

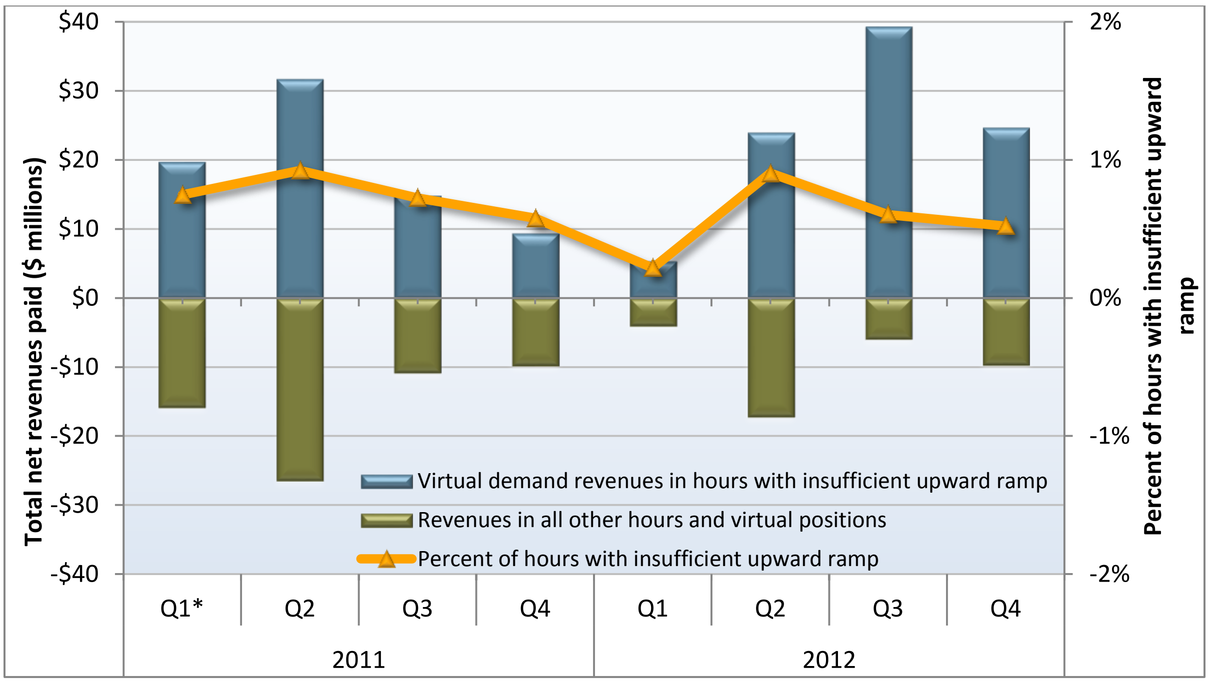
In 2012, virtual demand accounted for about 57 percent of cleared bids at internal locations, compared to 44 percent in 2011. Virtual demand bids at internal nodes are profitable when real-time prices spike in the 5-minute real-time market. Almost all profits from these internal virtual demand positions have resulted from a relatively small portion of intervals when the power balance constraint was relaxed as a result of insufficient ramp either on a system or regional basis (see Section 3.2).

Figure 4.11 compares total revenues from internal virtual bids during hours when the power balance constraint was binding due to short-term shortages of upward ramping capacity with the overall net revenues of internal virtual bids during all other hours. As shown in Figure 4.11:

- Although upward ramping capacity was insufficient during less than 1 percent of hours each quarter, these hours accounted for all net revenues for virtual demand. Net revenues from virtual demand during these brief but extreme price spikes can be high enough to outweigh losses when the day-ahead price exceeds the real-time market price. In fact, having a single 5-minute interval price spike can yield enough aggregate income to compensate for losses in the remaining hours of the day.

- During the other 99 percent of hours when sufficient ramping capacity was available, virtual demand bids were highly unprofitable. In the first quarter, the frequency of real-time price spikes was the lowest in the year. Consequently, the net revenues of internal virtual bids decreased to near zero.

Figure 4.11 Convergence bidding net revenues from internal scheduling points



These price spikes are typically associated with brief shortages of ramping capacity. Virtual demand at internal scheduling points can potentially result in additional capacity being committed and available in the real-time market. In practice, however, the impact of internal virtual demand on real-time price spikes appears to have been limited by a number of factors:

- As discussed in prior sections of this chapter, the impact of virtual internal demand in the day-ahead market was offset significantly by virtual supply.

- Any additional capacity potentially made available by convergence bidding may not be enough to address the short-term ramping limitations in the real-time market.

Also, in the event of over-generation, real-time prices can be negative, but rarely fall below the bid floor of -$30/MWh. This diminishes the risk of market participants losing substantial money by bidding virtual demand as well as reduces the potential benefits to virtual supply bids at internal nodes.

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 almost $50 million (almost 90 percent) of the total convergence bidding revenues in 2012.

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.

DMM has defined financial entities as speculators 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 64 percent of volumes and about 90 percent of revenues. Marketers represent about 30 percent of the trading volumes and 11 percent of the revenues. Generation owners and load-serving entities represent a small segment of the virtual market both in terms of volumes and in terms of revenues (less than 5 percent).

Table 4.1 Convergence bidding volumes and revenues by participant type (2012)

Trading entities	Average hourly megawatts			Revenues ($ millions)		
	Virtual demand	Virtual supply	Total	Virtual demand	Virtual supply	Total
Financial	1,049	757	1,807	31.2	18.7	49.9
Marketer	467	374	841	6.8	-0.3	6.5
Physical Generation	61	70	131	1.8	0.0	1.8
Physical Load	8	36	45	-1.1	-0.5	-1.6
Total	**1,586**	**1,238**	**2,823**	**38.7**	**17.8**	**56.5**

4.3 Changes in unit commitment

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

In the last three quarters of 2012, cleared virtual demand consistently exceeded virtual supply in the day-ahead market. This had the potential effect of reducing residual unit commitment costs as this could contribute to more generation commitment in the price setting integrated forward market run of the day-ahead market.[77]

In the fourth quarter, the ISO committed additional generating capacity to mitigate a major outage that created reliability concerns in the northern part of the state. This increased both the direct capacity procurement costs and bid cost recovery payments associated with residual unit commitment. Convergence bids were less likely to contribute to these costs as the net position was primarily net virtual demand for much of this period.

As noted in Section 2.5, total direct residual unit commitment costs reached $2.5 million in 2012, up from $1.1 million in 2011 and $83,000 in 2010. Bid cost recovery payments for capacity committed in the residual unit commitment process were also up in 2012 totaling $8 million, up from $6.1 million in 2011 and $1.4 million in 2010. A detailed explanation for the increases in residual unit commitment is provided in Section 2.6.

[77] Unfortunately, neither DMM nor the ISO have been able to do a comprehensive study to determine how convergence bidding may have influenced unit commitment in the integrated forward market.

5 Ancillary Services

The ancillary service market continued to perform efficiently and competitively in 2012. The cost of ancillary services fell substantially, driven by a decrease in ancillary service prices. The supply of ancillary services was sufficient to meet the ISO's requirements in all but one 15-minute interval in one sub-region. Key trends highlighted in this chapter include:

- Ancillary service costs decreased to $84 million in 2012. This is a 40 percent decrease from $139 million of ancillary service costs in 2011.
- Costs decreased from 1.9 percent of total energy costs in 2011 to 1 percent in 2012. The annual cost of $0.36 per MWh was the lowest value since the nodal market began in 2009.
- Ancillary service prices were lower in 2012, driving the decrease in overall cost. The decrease is likely due to relatively low natural gas costs and an increase in provision of spinning reserves from hydro-electric generators compared to 2011.
- The value of self-providing ancillary services accounted for $14 million of total ancillary service costs in 2012, or about 17 percent.[78] By using their own resources to meet ancillary service requirements, load-serving entities are able to hedge against the risk of higher ancillary costs in the ISO market. In 2011, self-provided ancillary services accounted for about 24 percent of total ancillary service costs, or about $33 million in 2011.
- Only one ancillary service scarcity event occurred in 2012. The scarcity was limited to 15 MW of spinning reserves during one 15 minute interval and had a total estimated incremental cost of $391.
- The ISO implemented an updated algorithm for determining the operating reserve requirement in the real-time market in August. After implementation of this feature, the ISO has procured an average of about 95 MW less spinning and non-spinning reserves in the real-time market than in the day-ahead market. In 2013, the ISO plans to enhance and then implement this feature in the day-ahead market to better align the procurement of ancillary services between the day-ahead and real-time markets.
- The ISO announced that it will begin ancillary service compliance testing starting in November 2012. DMM worked to ensure that this process included specific resources that did not previously meet their full ancillary service obligations, as well as random samples of all resources. Results should become available in 2013.

A detailed description of the ancillary service market design, implemented in 2009, is provided in DMM's 2010 annual report.[79] 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

[78] 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.

[79] *2010 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2011, pp. 139-142: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

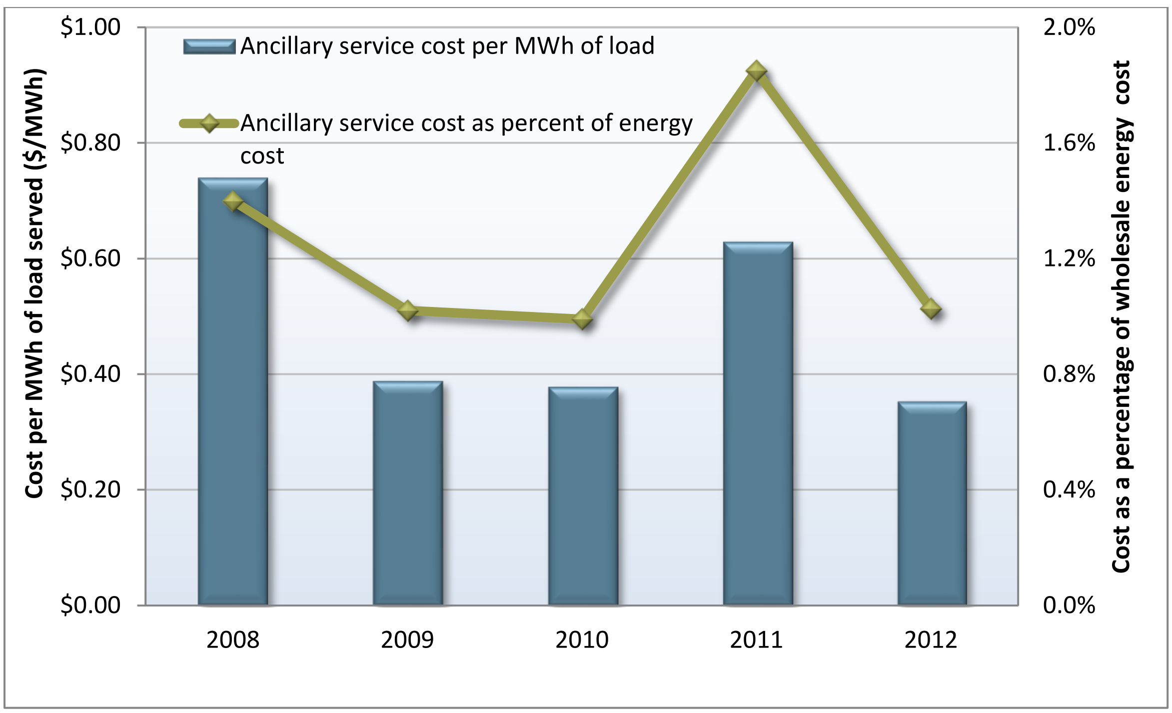
capacity is sold in the other. Co-optimization allows the market software to determine the most efficient use of each unit's capacity for energy and ancillary services.

5.1 Ancillary service costs

Ancillary service costs decreased to $0.36/MWh of load served in 2012 from $0.63/MWh in 2011. Costs returned to a level comparable to those in 2010 ($0.37/MWh). This cost represents 1 percent of wholesale energy costs, down from 1.9 percent in 2011 and close to the 1 percent range for the two previous years following the ISO's nodal market implementation in 2009.

Figure 5.1 illustrates ancillary service costs both as a percentage of wholesale energy costs and per MWh of load from 2008, the year preceding the nodal market design, through 2012. Ancillary service costs per MWh were lower in 2012 than in any other year in the last five years.

Figure 5.1 Ancillary service cost as a percentage of wholesale energy costs (2008 – 2012)



Ancillary service costs were highest during the third quarter of 2012. 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 ($0.22/MWh) and highest in the third quarter ($0.45/MWh).

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 likely occurred as a result of low hydro-electric generation in 2012. Ancillary service costs measured as a percentage of wholesale energy costs peaked in the second quarter at 1.12 percent and remained relatively high in the third quarter at 1.11 percent.

On a quarterly basis, ancillary service costs per MWh were lower than those in both 2011 and the average quarterly cost for 2006 through 2009. As illustrated in Figure 5.3, quarterly costs were lower than 2010 in the first two quarters of the year and slightly higher in the third and fourth quarter.

Figure 5.2 Ancillary service cost by quarter

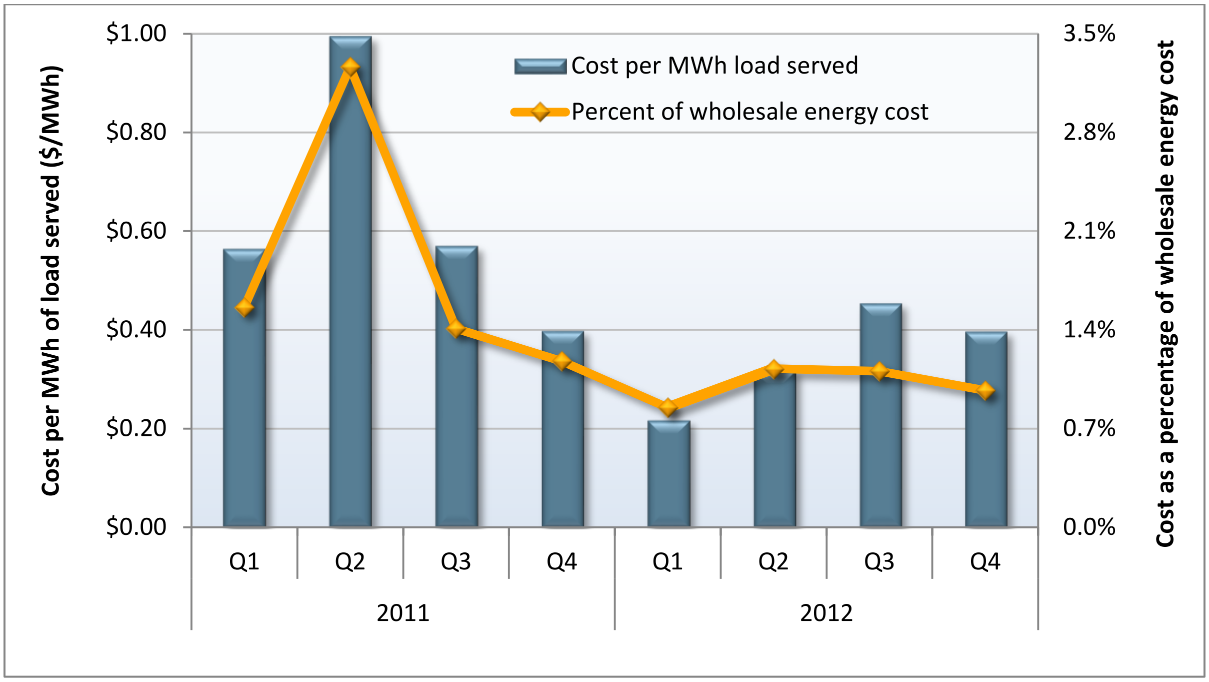
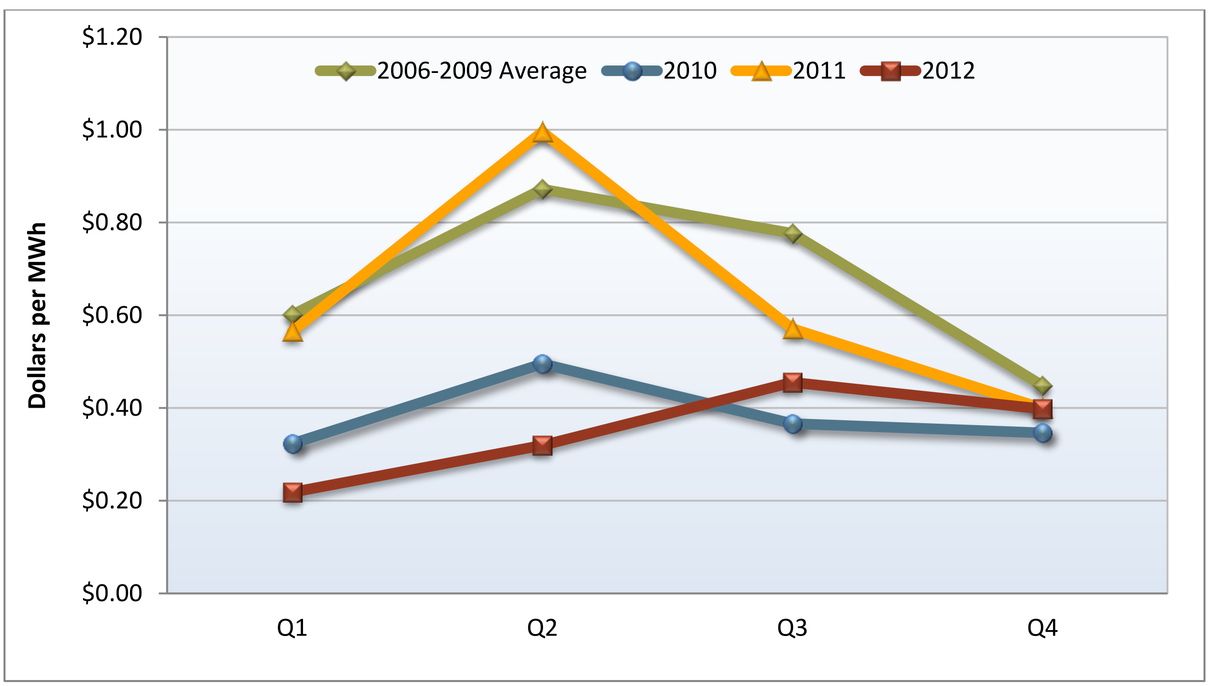


Figure 5.3 Ancillary service cost per MWh of load (2006 – 2012)



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. 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 1,757 MW in 2012, up 2.5 percent from 1,715 MW, the average in 2011. The average hourly real-time operating reserve requirement was 1,686 MW in 2012, a 1.6 percent decrease from 1,713 MW in 2011. The hourly day-ahead requirement applies to operating reserves (spinning and non-spinning) and is typically set by 5 percent of forecasted demand met by hydro-electric resources plus 7 percent of forecasted demand met by thermal resources.[80] Thus, the requirements follow a seasonal load pattern with higher requirements during the peak load months. Real-time operating reserve requirements were set using the same algorithm until the implementation of a new requirement setter, discussed in further detail below.

The average hourly requirement for regulation down increased and the requirement for regulation up decreased in 2012 compared to 2011. The requirement for regulation up and down is implemented by running an algorithm based on inter-hour forecast and schedule changes. The average hourly real-time regulation down requirement was 349 MW in 2012, compared to 341 MW in 2011. The average hourly real-time regulation up requirement was 327 MW, compared to 338 MW in 2011.

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

Procurement of ancillary services increased in 2012, in a pattern consistent with the changes in ancillary service requirements discussed above. Average hourly procurement of regulation down increased 2 percent to 350 MW in 2012. Procurement of regulation up resources decreased 6 percent to 333 MW. Spinning reserve procurement increased 4 percent to 887 MW and non-spinning reserve procurement increased 1 percent to 848 MW.

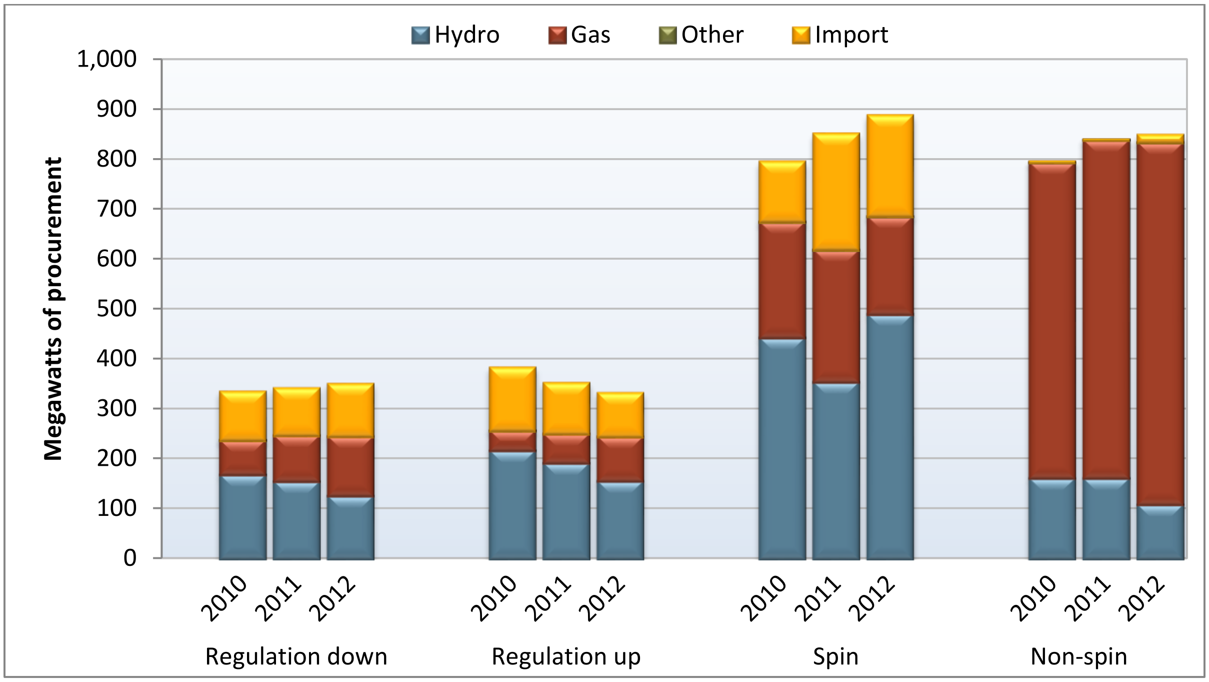
The fuel type of resources providing ancillary services was very similar to 2011 with a slight shift from imports to natural gas. The composition of ancillary service providers is characterized as follows:

- Average hourly provision of ancillary services from hydro-electric resources increased in 2012 to 878 MW. This is a 2 percent increase from 860 MW in 2011 and was primarily a result of hydro providing more spinning reserves.

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

- Total imports decreased from 430 MW in 2011 to 410 MW in 2012 on an average hourly basis. Imports provided 30 percent of regulation down capacity, 26 percent of regulation up, 23 percent of spinning reserves and 2 percent of non-spinning reserves.
- Gas-fired reserves provided 1,129 MW, up 3 percent from 1,093 MW in 2011. These resources provide the vast majority of non-spinning reserves as in years past.

Figure 5.4 Procurement by internal resources and imports



5.3 Ancillary services pricing

Resources providing ancillary services receive a capacity payment, or market clearing price, in both the day-ahead and real-time markets. Capacity payments in the real-time market are only for incremental capacity above the day-ahead award. Figure 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 2011 and 2012.

Overall, 2012 average quarterly day-ahead prices decreased from 2011. In 2012, monthly weighted average prices ranged from approximately $0.15 per MW to $8.84 per MW. Relatively low gas prices may have reduced the cost of ancillary services provided by natural gas units. Prices were generally highest for regulation up and lowest for non-spin resources.

Real-time ancillary service prices decreased significantly in 2012 compared to 2011, as illustrated in Figure 5.6. Monthly weighted average real-time prices ranged from $0.04 per MW to $30.25 per MW. Real-time ancillary service prices were lower as a result of multiple factors including lower natural gas prices, decreased requirements related to the implementation of the ancillary service requirement setter, and the dynamic ramp rates of ancillary services in the day-ahead market, which was implemented in August 2011.[81]

Figure 5.5 Day-ahead ancillary service market clearing prices

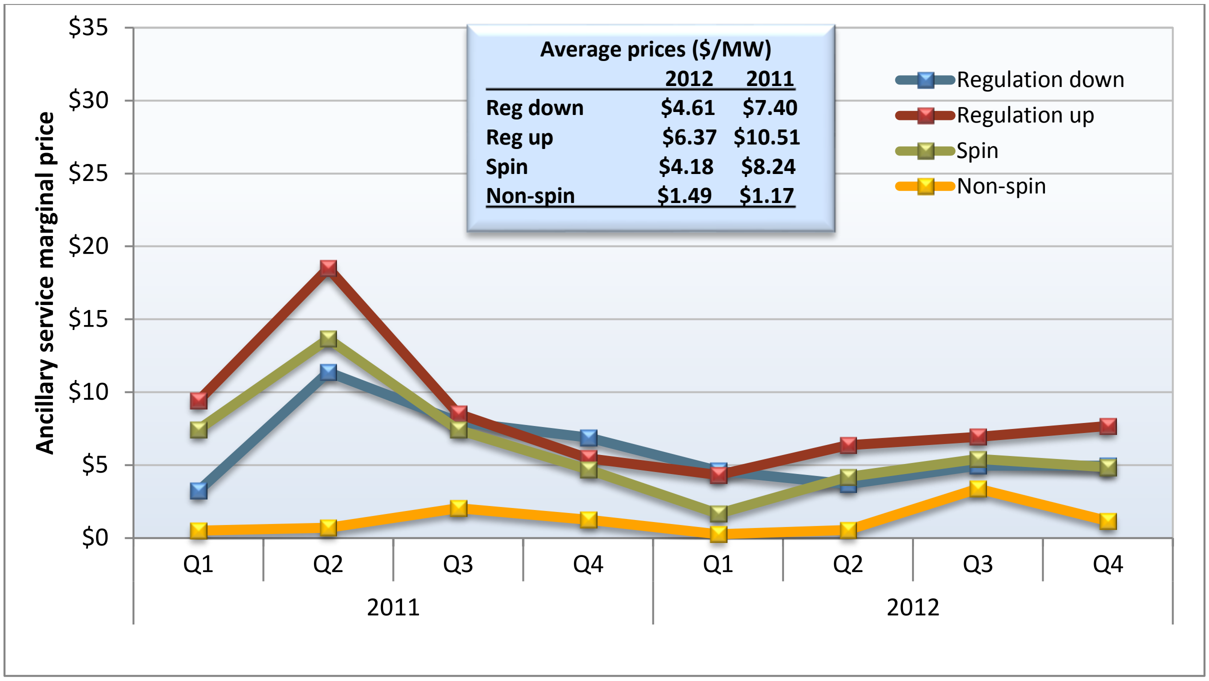
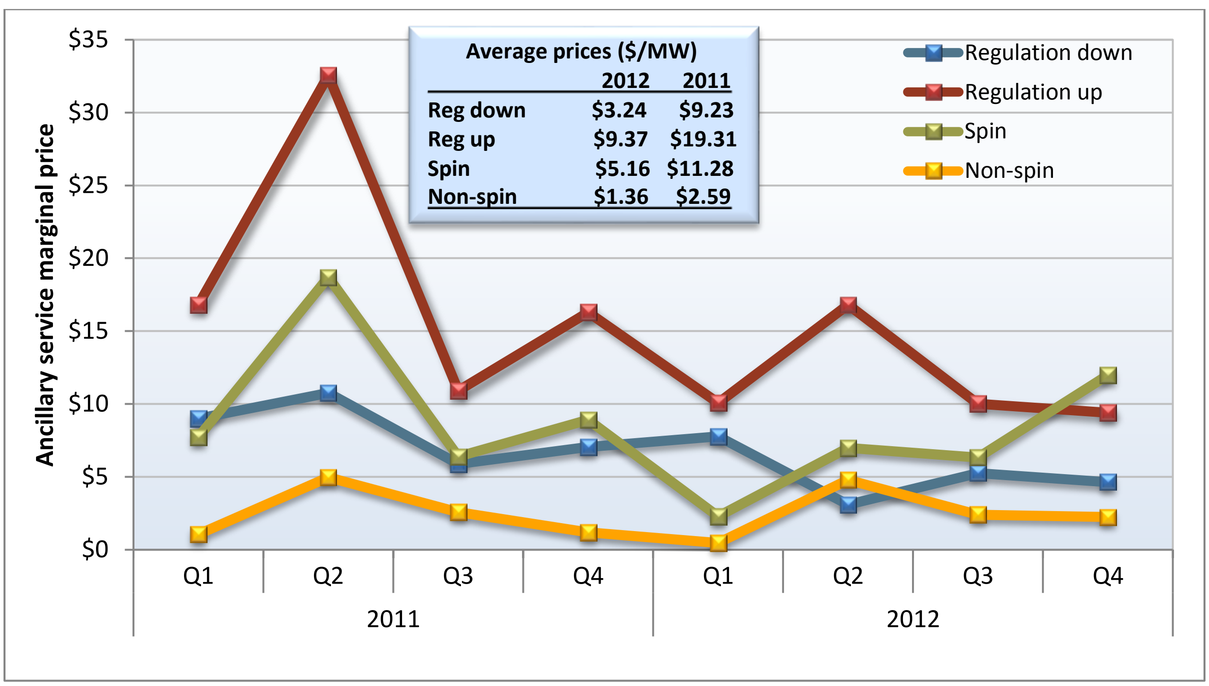


Figure 5.6 Real-time ancillary service market clearing prices



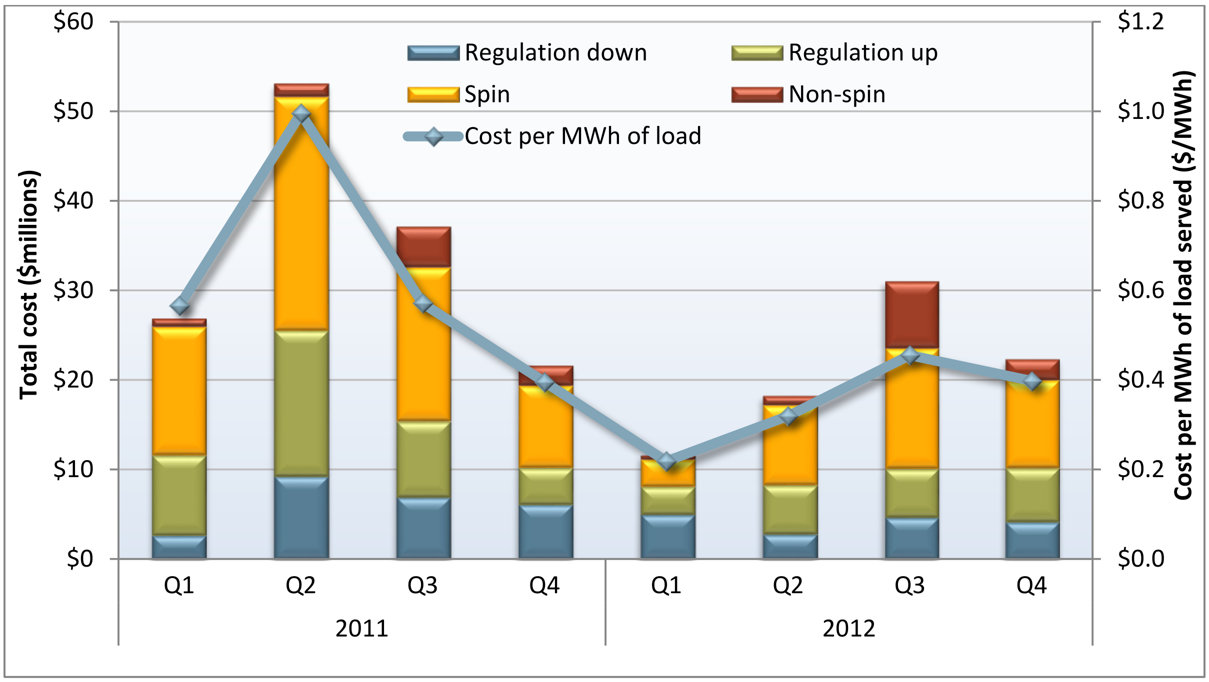
[81] *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, pp. 100-102.

5.4 Ancillary service costs

Ancillary service costs totaled $84 million, a decrease of 40 percent from 2011. The value of self-provision of ancillary service by load-serving entities was $14 million of this amount, or about 17 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. As discussed previously, lower prices due to lower natural gas prices and increased hydro-electric availability for spinning reserves contributed to this decrease in cost.

Figure 5.7 Ancillary service cost by product



5.5 Special issues

This section highlights additional features of the ancillary service market:

- scarcity pricing;
- requirements setter, introduced in August 2012; and
- compliance testing, which began in late 2012.

Ancillary service scarcity pricing

Scarcity pricing of ancillary services occurs when there is insufficient supply to meet reserve requirements. Under the ISO's 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.

In 2012, there was only one 15-minute interval in which the ancillary service requirements were not met in either the hour-ahead or real-time markets. This scarcity event occurred on September 9 for spinning reserves in the 15-minute real-time pre-dispatch in the last interval of hour ending 14 for the SP26 expanded sub-region.

The scarcity event occurred because of an insufficiency of generation within Southern California. ISO operators responded by exceptionally dispatching a single external unit that had been providing ancillary services to zero megawatts. In addition, the total import capacity decreased causing internal resources that had been providing ancillary services to provide energy instead. These factors, in addition to a simultaneous increase in the load forecast, combined to create a situation in which spinning reserve capacity was just over 15 MW short of the spinning reserve requirements in the SP26 expanded region.

The incremental cost of this event to the market was $391.[82] This figure is down from last year when 24 ancillary service scarcity events had an estimated market impact of approximately $60,000.

Ancillary service requirement setter

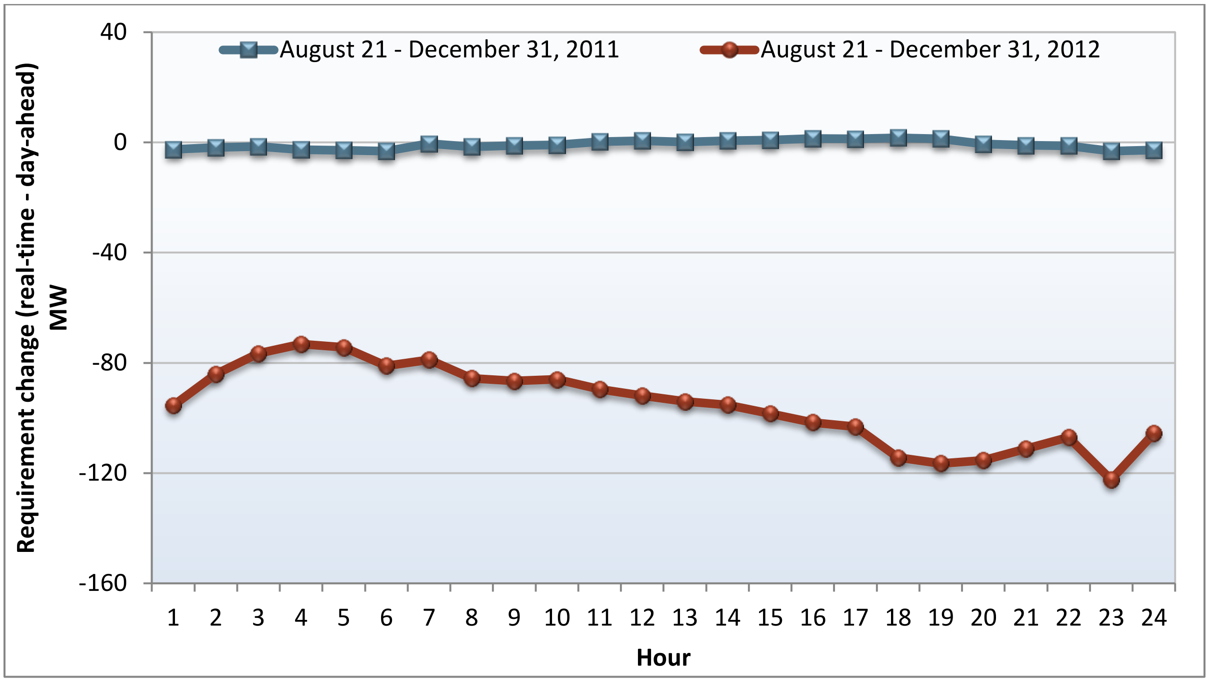
On August 21, 2012, the ISO implemented an automated feature known as the *ancillary service requirement setter.* This feature first calculates the ancillary services requirement based on the three following measures: resource mix, single largest contingency in the system, and percentage of load forecast (between 5 and 5.7 percent in real-time depending on system conditions). The final requirement is typically the largest of these three calculated values. The operator has the ability to override the requirement setter if necessary by setting the ancillary service requirement as a fixed percentage of the load forecast.

This automated feature has been utilized to assess the requirement for spinning and non-spinning reserves in the 15-minute real-time pre-dispatch market. The process to set the day-ahead requirements has not changed as the new feature has not been used to set the requirement in the day-ahead market.

Using different requirement methodologies between the two markets has caused systematic differences in procurement of ancillary services. The real-time market procured an average of 95 MW fewer spinning and non-spinning reserves after implementation of the setter on August 21 through the end of the year. Figure 5.8 illustrates the average difference in procurement by hour, comparing 2011 to 2012. DMM has recommended that the ISO use this new feature in the day-ahead market in order to better align the procurement of ancillary services between the day-ahead and real-time markets. The ISO plans to enhance and then implement this feature in the day-ahead market.

[82] The ISO calculates the incremental cost by multiplying the incremental capacity acquired by the difference between the price for the scarcity interval and the price that occurred in the preceding interval without scarcity. In this case, the incremental reserve capacity procured during this event was 380 MW.

Figure 5.8 Spinning and non-spinning reserves requirement change



Ancillary service compliance testing

The ISO announced in mid-October that it would begin ancillary service compliance testing in November 2012.[83] Earlier in the year, DMM identified concerns with participant performance during real-time ancillary service contingency events. Specifically, some resources did not perform up to their rated ancillary service level. DMM worked with the ISO to ensure that a compliance testing process was in place to test market participant ancillary service compliance. DMM worked to ensure that this process included specific resources that did not previously meet their full ancillary service obligations, as well as a random sample of all resources. Results should become available in 2013.

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

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 very competitive on a system-wide level. There were only about 50 hours with three jointly pivotal suppliers, compared to only 2 hours in 2011.
- Supply of local capacity owned by non-load-serving entities meets or exceeds the additional capacity needed to meet local requirements in most areas. However, in most areas, one supplier is individually pivotal, since some portion of this supplier's capacity is needed to meet local requirements.
- In 2012, the ISO implemented a new approach for determining the competiveness of transmission constraints in the day-ahead market software based on actual system and market conditions each hour. This new approach, known as *dynamic path assessment*, improved the accuracy with which constraints are deemed competitive or non-competitive from roughly 45 percent to over 90 percent. Since the ISO's local market power bid mitigation process is only triggered when congestion is projected to occur on uncompetitive constraints, this reduces both instances of inadvertent over- and under-mitigation.
- The number of units subject to bid mitigation in the day-ahead market increased significantly as a result of the combination of the new local market power mitigation approach and an increase in day-ahead congestion.
- Most resources subject to mitigation submitted competitive offer prices, so that their bids were not lowered as a result of the mitigation process. Only 1.4 units on average per hour actually had their bid price lowered in the day-ahead market as a result of mitigation.
- The frequency of bid mitigation in the real-time market in 2012 was higher when compared to 2011. However, estimated impact of bid mitigation on the amount of additional real-time energy dispatched as a result of bid mitigation was about the same as 2011.
- Uncompetitive bidding increased in both the day-ahead and real-time markets during summer months. However, local market power mitigation provisions effectively limited the impact of uncompetitive bids on market prices in both the day-ahead and real-time markets.
- Mitigation provisions that apply to exceptional dispatch reduced excess costs that would have resulted from attempted exercise of market power from a small number of units by about $227 million.

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

6.1.1 Day-ahead system energy

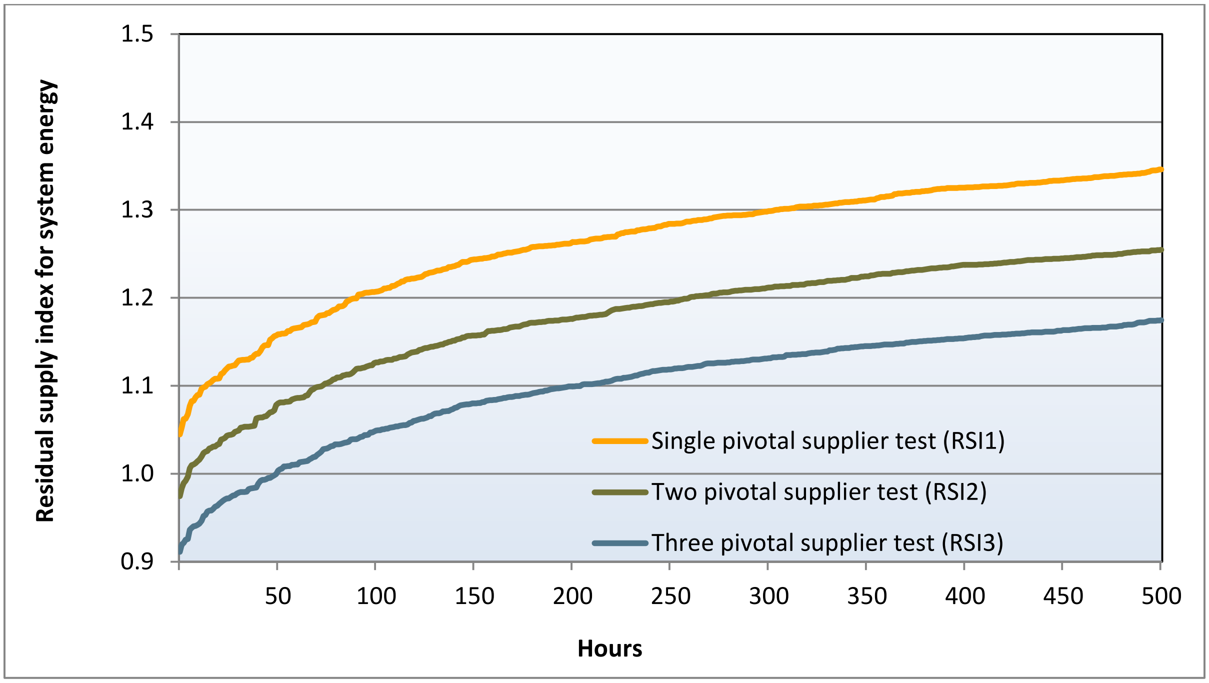
Figure 6.1 shows the hourly residual supply index for the day-ahead energy market in 2012. This analysis is based on system energy only and ignores potential limitations due to transmission limitations.[85] Results are only shown for the 500 hours when the residual supply index was lowest. These hours generally correspond to the highest load hours. As shown in Figure 6.1, the residual supply index with the three largest suppliers removed (RSI_3) was less than 1 in less than 50 hours and less than 5 hours with the two largest suppliers removed (RSI_2).

While this is an increase in the number of instances observed in 2011 (only 2 hours with an RSI_3 less than 1) these findings reflect the favorable overall system supply and moderate load conditions. Under these conditions, the underlying structure of the overall energy market fosters competitive behavior and outcomes in the system-wide energy market. However, as discussed in the following sections, since ownership of resources within different areas of the ISO grid is highly concentrated, local reliability requirements and transmission limitations give rise to local market power in many areas of the system.

[84] For instance, assume demand equals 100 MW and the total available supply equals 120 MW. If one supplier owns 30 MW of this supply, the residual supply index equals 0.90, or (120 – 30)/100.

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

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 most 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. This is indicated by RSI_1 values less than 1.0 and RSI_2 values of 0.24 or lower in each of these areas.

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	2,762	4,851	1.76	0.87	0.15	0.09	1
North Coast/North Bay	480	736	1.53	0.04	0.01	0.00	1
SCE area							
LA Basin	5,900	7,196	1.22	0.50	0.34	0.22	1
Big Creek/Ventura	831	2,917	3.51	0.95	0.09	0.03	1
San Diego	1,221	1,421	1.16	0.22	0.06	0.01	1

The analysis in Table 6.1 includes over 2,000 MW of SCE's SONGS nuclear units in the calculation of the net local area capacity requirements for the Los Angeles Basin that must be met from capacity not owned by load-serving entities. Without the SONGS units, all remaining capacity within this area is needed to meet local area requirements.

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 (the capacity procurement mechanism).

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. The following section examines the actual structural competiveness of transmission constraints when congestion has occurred in the day-ahead and real-time markets.

6.2 Competitiveness of transmission constraints

On April 11, 2012, the ISO implemented a new local market power mitigation methodology in the day-ahead and hour-ahead markets. Part of this new methodology implemented in the day-ahead market was a new method for identifying which constraints are considered structurally uncompetitive, so that bids may be subject to mitigation to prevent the exercise of local market power.

This section reviews the performance of this new method for determining the structural competitiveness of constraints. Other key components of these new local market power mitigation procedures are discussed in Section 6.3.

Background

The ISO local market power mitigation provisions require that each constraint be designated as competitive or non-competitive prior to the actual market run. Generation bids are subject to mitigation if certain conditions 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 methodology used to designate transmission constraints as competitive or non-competitive is the competitive path assessment. This methodology incorporates a 3-pivotal supplier test that has historically been performed in an off-line study.[86] The competitive path 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.[87] Beginning April 11, 2012, the ISO implemented a new dynamic in-line competitive path assessment and mitigation trigger within the day-ahead market software and discontinued application of the off-line study for day-ahead path assessments.[88]

The dynamic competitive path assessment and new local market power mitigation trigger mechanism work as follows. In the pre-market mitigation run, the market software clears supply and demand using 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.

Next, the impact of congested non-competitive constraints on the energy price at each resource is evaluated. If there is a positive impact on the price then the resource could benefit from exercising local market power and consequently is subject to bid mitigation. Bid mitigation lowers the bid price to the higher of the resource's default energy bid or a calculated competitive price. The calculated competitive price is effectively the price at the resource less the contribution to that price from congested non-competitive constraints. The mitigated bids are then used in the actual market run.

This in-line dynamic approach to competitive path assessment has several advantages over the static off-line study approach. First, it uses actual market conditions to evaluate the transmission

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[86] For a detailed description of the methodology for the static off-line methodology, see *Competitive Path Assessment for MRTU Final Results for MRTU Go-Live,* Department of Market Monitoring, February 2009, http://www.caiso.com/2365/23659ca314f0.pdf. See the 2009 through 2011 editions of the *Annual Report on Market Issues and Performance* at http://www.caiso.com/market/Pages/MarketMonitoring/MarketIssuesPerfomanceReports/Default.aspx for analysis of the prior approach to local market power mitigation in the day-ahead market. Path designations prior to April 2010 were based on a study performed in February 2009.

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

[88] For a detailed description of the methodology for the in-line dynamic approach see: http://www.caiso.com/Documents/DraftFinalProposal-LocalMarketPowerMitigationEnhancements.pdf.

competitiveness. In contrast, the static competitive path assessment studies included a large number of hypothetical scenarios with high, medium, and low anticipated conditions for demand, imports, and generation output levels. Using actual market conditions produces more accurate and less conservative results.

Second, the new mitigation trigger is based directly on the impact of specific resources on prices due to congestion on structurally uncompetitive constraints. The previous mitigation trigger was based on a change in dispatch between a pre-market run without uncompetitive constraints and a second pre-market run with uncompetitive constraints added. While the prior approach was theoretically a very accurate way of identifying units that could relieve congestion on uncompetitive constraints, in practice this approach was subject to error from various modeling issues that could create changes in congestion and unit dispatch between these pre-market runs and the actual day-ahead market.

The new dynamic competitive path assessment and mitigation trigger will be fully implemented in the real-time market in May 2013.

Day-ahead market results

Following implementation of this new dynamic approach, DMM monitored the accuracy of this method by performing after-the-fact off-line calculations of day-ahead market competitiveness designations and then comparing these to the final market results. The market software determines these designations based on the pre-market run, which may not be exactly the same as the final day-ahead market results. For this analysis, DMM re-constructs the residual supply index using the day-ahead market output and uses this as the benchmark to compare the market software designations from the pre-market run.

Figure 6.2 shows the comparisons between these pre-market and final day-ahead competitiveness designations. For a given transmission constraint, the competiveness designation varies. Some constraints are competitive all the time, while others show the mixture of competitiveness and non-competitiveness. In general, the pre-market designations are very similar to the designations re-calculated using final day-ahead results.

Real-time market results

Figure 6.3 compares the static competitiveness designation and competitiveness designations re-calculated using final market data. These calculations are done on a 5-minute interval basis, since the dynamic competitive path is not yet implemented in the real-time market. This analysis shows that transmission constraints tend to be less competitive in real-time compared to the day-ahead market. For a given transmission constraint, the competiveness designation varies, similar to that in the day-ahead market. Results of the static competitive path assessment are conservative, in that most constraints on which congestion occurred were deemed non-competitive in all hours, but were competitive many hours. However, the static approach also correctly designates constraints as non-competitive when these constraints are indeed non-competitive in real-time.

Figure 6.2 Transmission competitiveness in 2012 for the day-ahead market

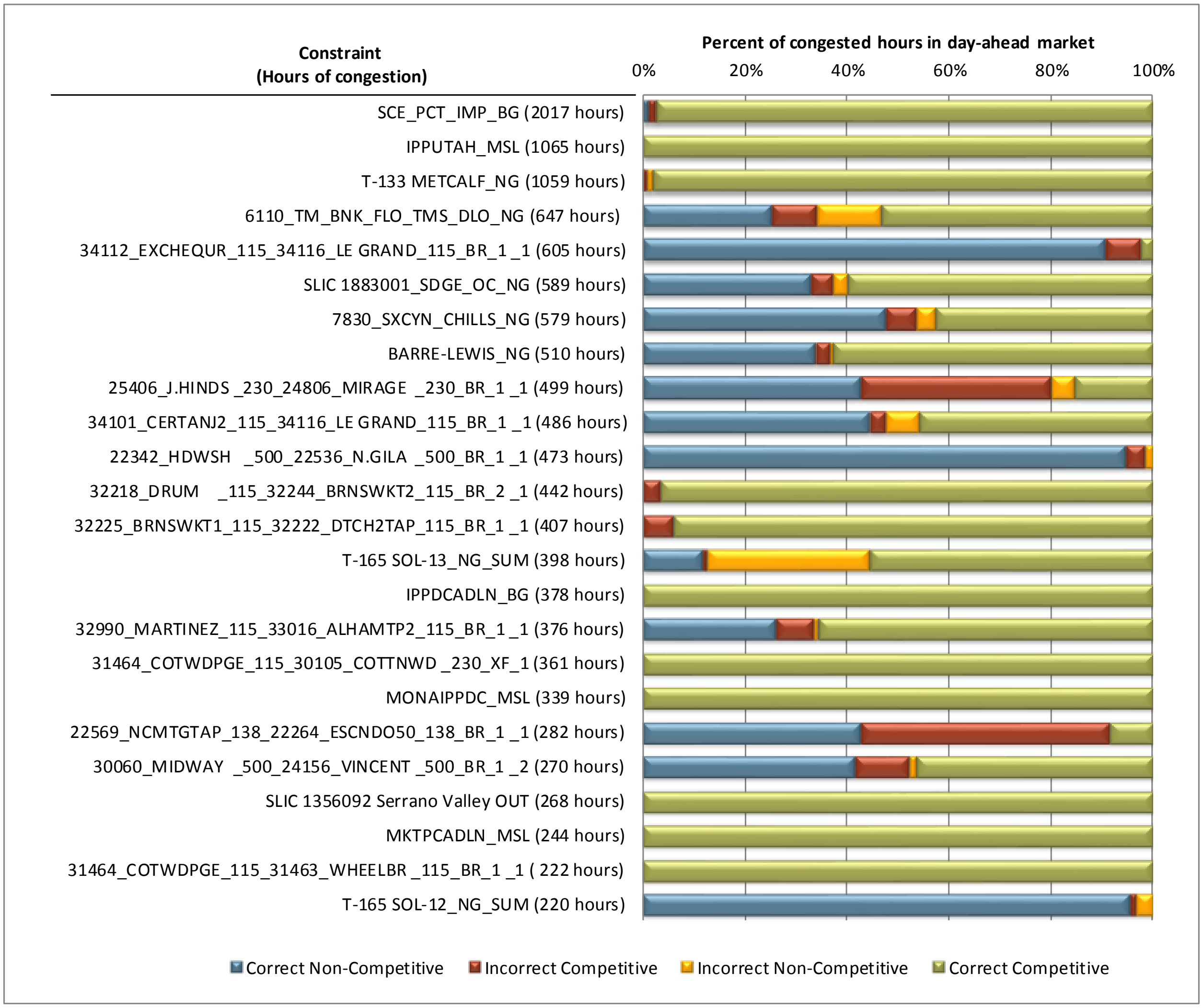
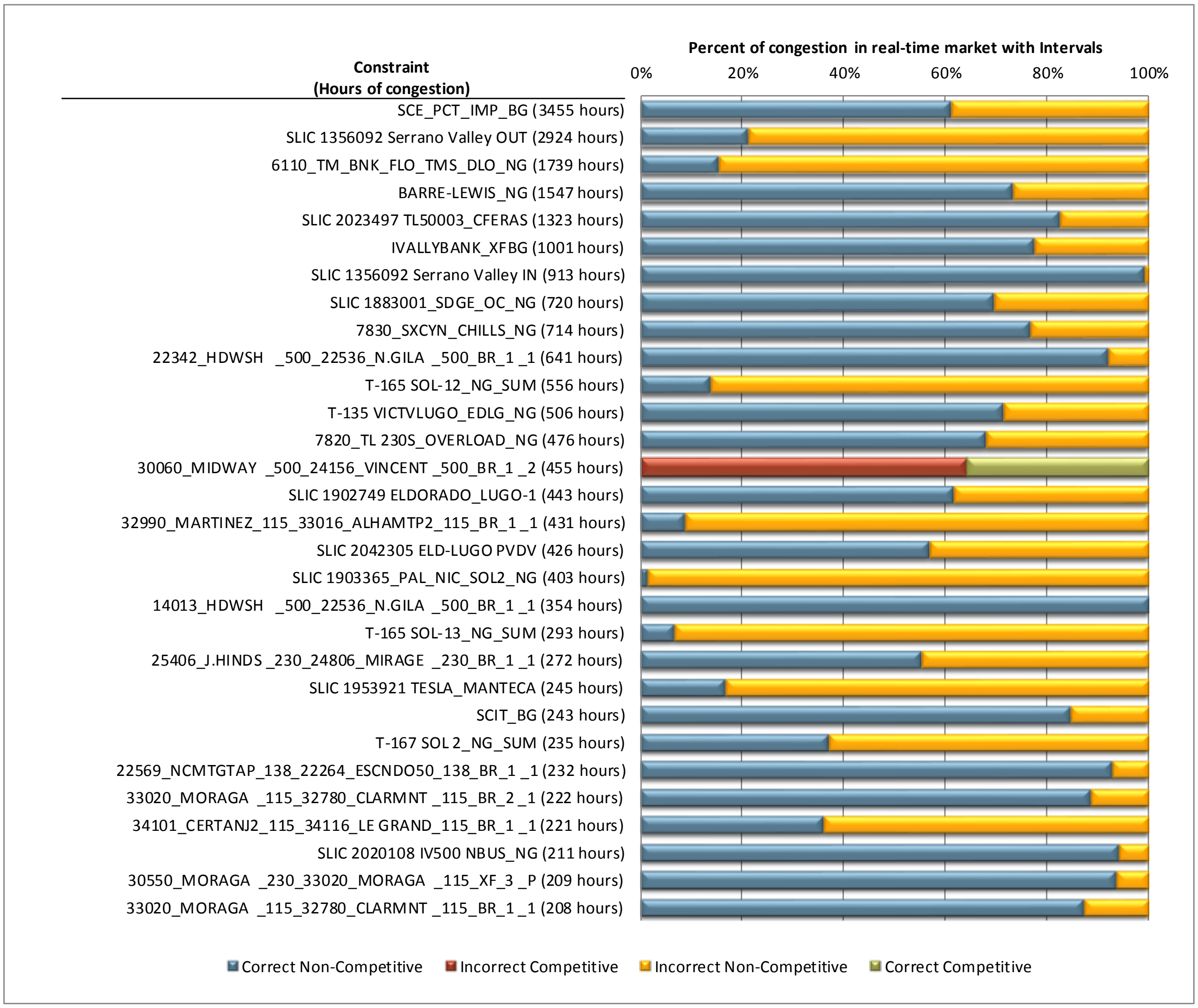


Figure 6.3 Transmission competitiveness in 2012 for the real-time market



6.3 Local market power mitigation

On April 11, 2012, the ISO implemented a new local market power mitigation methodology in the day-ahead and hour-ahead markets. Resources subject to mitigation are now identified by the resources' physical ability to relieve congestion. The new method of mitigation increased the number of resources subject to mitigation in 2012, but is more accurate in identifying those that have the ability to exercise local market power. More discussion on the application of the new mitigation method is provided in Section 6.2.

6.3.1 Frequency and impact of bid mitigation

The ISO's 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. While there was an increase in the number of resources subject to mitigation as a result of these changes, the number of resources having bids lowered remained about the same compared to 2011.

In the day-ahead market, the amount of additional energy, which DMM estimates was dispatched from units as a result of bid mitigation, increased significantly. This reflects two factors: more frequent congestion and increased dispatches from a small set of resources whose bids were lowered significantly as a result of mitigation.

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, average monthly prices for this competitive baseline are nearly equal to actual market prices for all months except August. This indicates that under most conditions enough capacity was offered at competitive prices to allow demand to be met at competitive prices.

The impact of bids that are actually mitigated on market prices can only be assessed 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. Alternatively, DMM has developed a variety of metrics to estimate the frequency of when mitigation was triggered and the effect of this mitigation on each unit's energy bids and dispatch levels.[89]

As shown in Figure 6.4 and Figure 6.5:

- The number of units eligible for mitigation in the day-ahead market increased significantly starting in the second quarter of 2012. This increase in mitigation activity is mostly attributable to the change in the mitigation method implemented in mid-April and an increase in day-ahead congestion from the previous two years.
- An average of 31 units in each hour were subject to day-ahead mitigation under the new mitigation method. This is compared to an average of 3.4 units subject to day-ahead mitigation from 2010 through the first quarter of 2012.

[89] 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.

- An average of 1.4 units had bids changed both before and after the change in mitigation methodology, despite the significant increase in units subject to mitigation.
- The estimated increase in energy dispatched in the day-ahead market from these units averaged about 35 MW per hour. This compares to an estimated impact from mitigation of just under 7 MW in 2011.
- Approximately half of the estimated increase in energy dispatched in the day-ahead market is from a small subset of units (red line in Figure 6.4) bidding at or greater than $200/MWh.

Several factors contributed to the increase in day-ahead mitigation. These factors include the following:

- Day-ahead congestion on uncompetitive constraints within the ISO system was significantly higher in 2012.
- The change in mitigation methodology in mid-April, by definition, increased the resources subject to mitigation. Any resource effective in relieving congestion on an uncompetitive constraint was subject to mitigation. Prior to the change, only a few resources may have been subject to mitigation based on changes in dispatch between the competitive constraints and all constraints market runs.
- There was a significant increase in high-priced energy bids (over $200/MWh) in the day-ahead market, as indicated by the difference between the red and green lines in Figure 6.5. Therefore, the increase in energy dispatched from these units when these bids were mitigated was greater.

The frequency of bid mitigation in the real-time market in 2012 was also higher when compared to 2011, as shown in Figure 6.6. However, as shown in Figure 6.7, the hourly megawatt impact of bid mitigation was about the same when compared to 2011:

- In 2012, bids for an average of about 2 units per hour were lowered as a result of the hour-ahead mitigation process. This compares to an average of about 4.2 units per hour in the previous two years.
- On average, less than 1 unit per hour was dispatched at a higher level in the real-time market as a result of bid mitigation in 2012, compared to about 1.5 units per hour in the previous two years.
- The estimated increase in real-time dispatches from these units because of bid mitigation averaged about 40 MW in 2012 compared to about 39 MW in 2011.

Thus, while the units subject to real-time mitigation in 2012 increased as a result of the new mitigation method, the overall impact of bid mitigation was lower in the real-time market when compared to the previous two years.

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

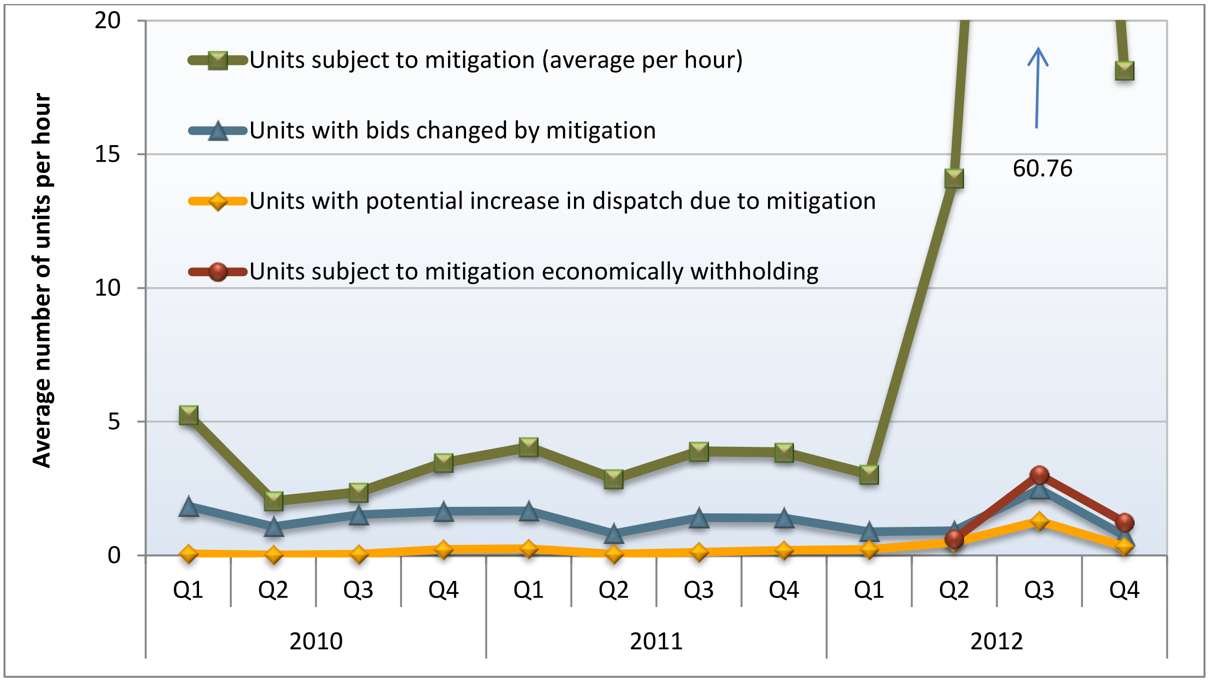


Figure 6.5 Potential increase in day-ahead dispatch due to mitigation (hourly averages)

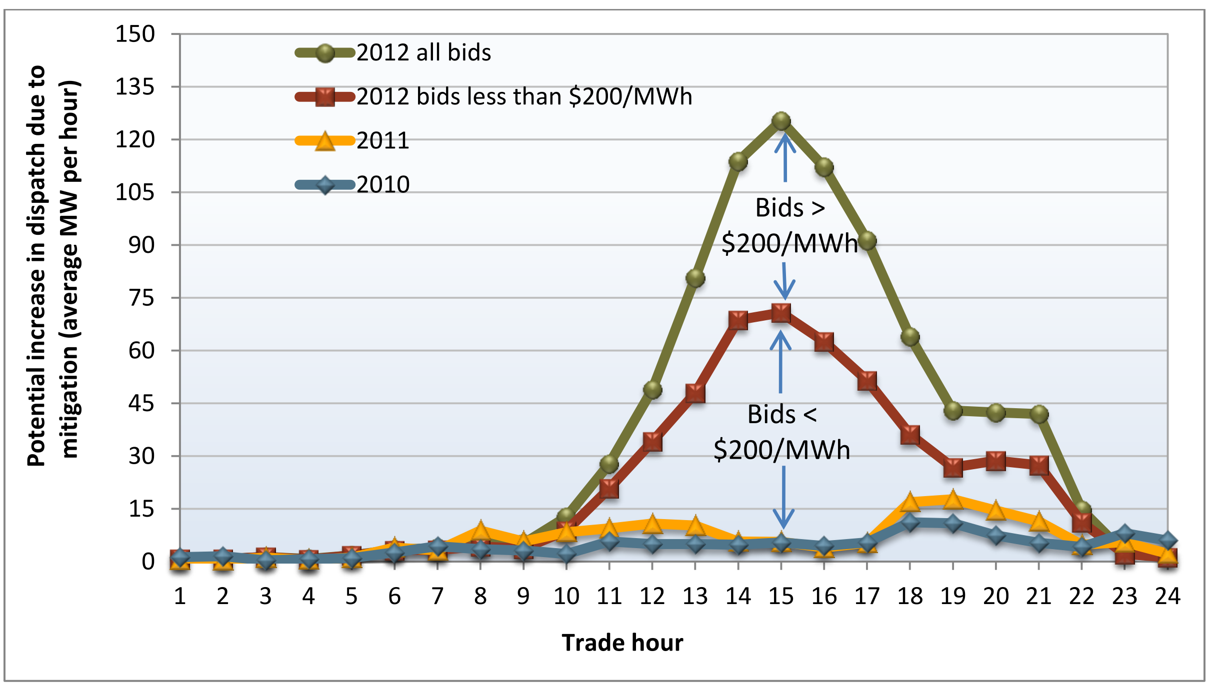


Figure 6.6 Average number of units mitigated in real-time market

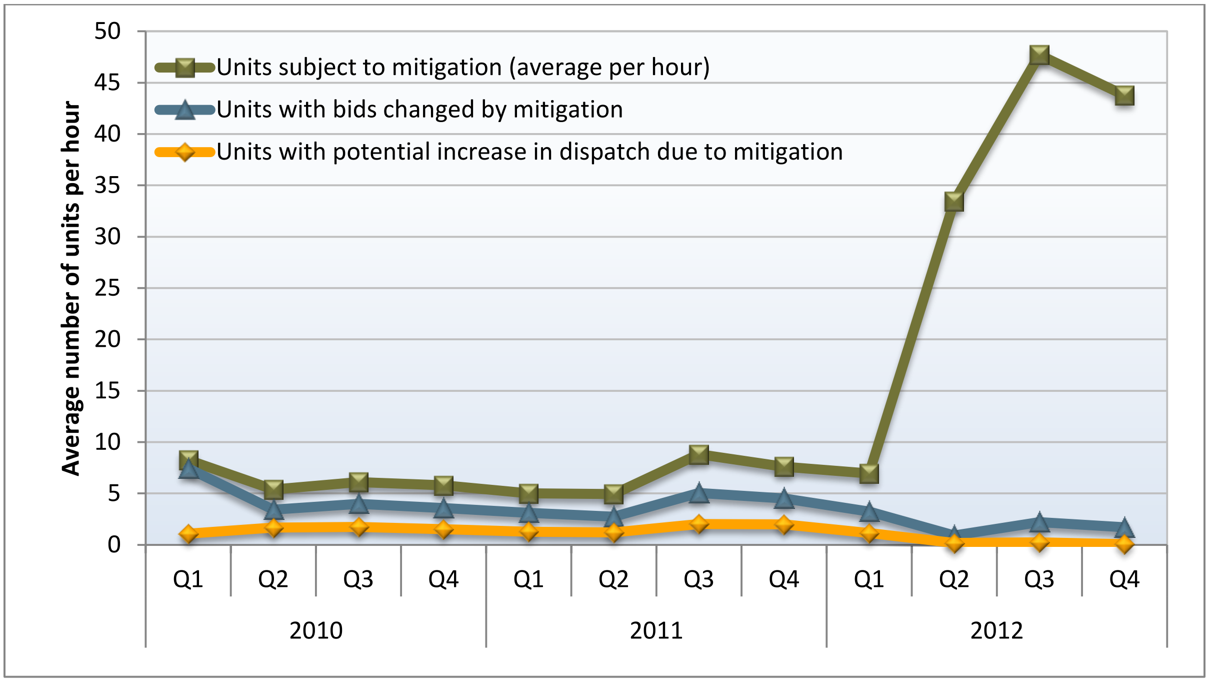
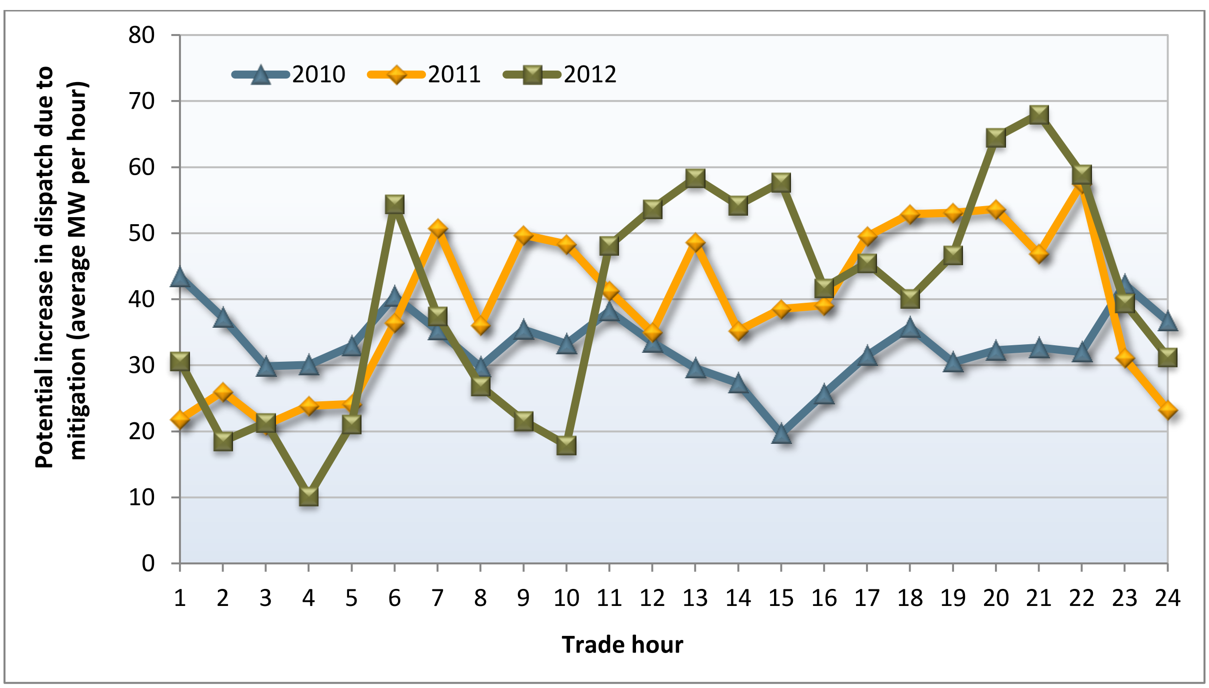


Figure 6.7 Potential increase in real-time dispatch due to mitigation (hourly averages)



6.3.2 Mitigation of exceptional dispatches

Exceptional dispatches are manual instructions issued when the automated market optimization is not able to address a particular reliability requirement or constraint.[90] Although total energy from exceptional dispatches increased in 2012, the above-market costs resulting from exceptional dispatches decreased from $43 million in 2011 to $34 million in 2012. This decrease in costs, in large part, reflects the fact that a much larger portion of exceptional dispatch energy in 2012 was to manage congestion for non-competitive constraints and was therefore subject to local market power mitigation provisions.

Exceptional dispatches issued to ensure units operate at some level above their minimum operating level are subject to mitigation if the dispatch was issued to manage congestion on a non-competitive constraint. In August, the ISO also gained approval from FERC to expand market power mitigation provisions applicable to exceptional dispatches.[91] With this tariff amendment, exceptional dispatches are also subject to market power mitigation if the resource was dispatched from its minimum operating level to its minimum dispatchable level. The minimum dispatchable level is the operating level for a resource where they can achieve their highest ramp rate. This allows a unit to be more quickly ramped up if needed to manage congestion or meet another reliability requirement in the event of a contingency such as a major generation or transmission outage.

Without mitigation, units being exceptionally dispatched by the ISO for additional real-time energy are paid the higher of their bid price or the market clearing price. This can create an incentive to submit extremely high priced bids with the expectation they may be paid this bid price when needed to meet these special reliability requirements. When subject to mitigation, units being exceptionally dispatched are paid the higher of the market clearing price or a default bid reflective of actual operating costs. This deters uncompetitive bidding in the day-ahead and real-time energy markets.

The expansion of mitigation for exceptional dispatches in August provided further deterrent to uncompetitive bidding in the day-ahead and real-time energy markets by units frequently needed to meet these special reliability requirements.

The volume of total exceptional dispatch energy significantly increased in 2012 when compared to 2011, most notably in the third and fourth quarters. As also shown in Figure 6.8:

- The percentage of energy dispatched in-sequence (with bid prices below the market clearing price) remained consistent from 2011 to 2012 at approximately 21 percent.
- The percentage of out-of-sequence energy (with bid prices above market clearing price) not subject to mitigation decreased from 72 percent in 2011 to only 25 percent in 2012.
- The percentage of out-of-sequence energy subject to mitigation increased from 7 percent in 2011 to 54 percent in 2012.

The total volume and proportion of out-of-sequence energy increased in 2012 for several reasons:

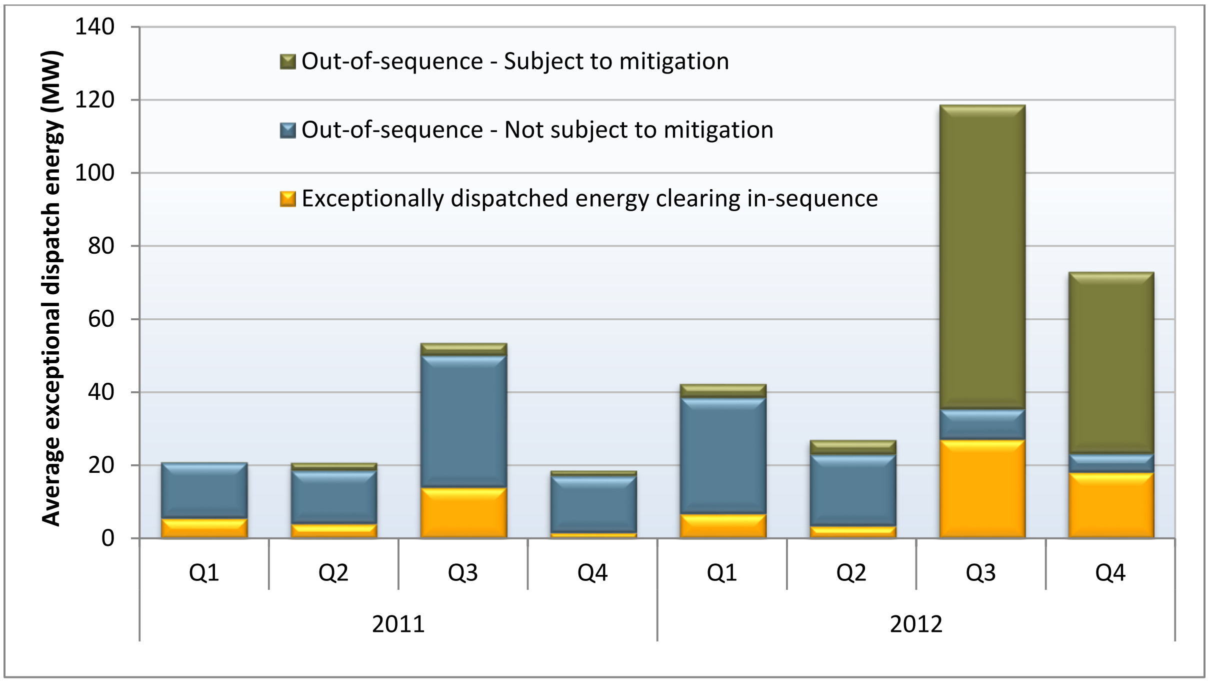
- The SONGS outages in Southern California created system conditions that required resources within this area to be exceptionally dispatched.

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

[91] See "Exceptional Dispatch and Residual Imbalance Energy Mitigation Tariff Amendment" in FERC Docket No. ER12-2539-000, August 28, 2012, at: http://www.caiso.com/Documents/August282012ExceptionalDispatch-ResidualImbalanceEnergyMitigationTariffAmendment-DocketNoER12-2539-000.pdf.

- More exceptional dispatches were needed to ensure units operated at minimum dispatchable levels, at which they could be ramped up more quickly to manage congestion in the event of a contingency not incorporated in the market software. Many of these were issued to meet non-modeled reliability requirements associated with the need to manage congestion associated with the Southern California Import Transmission or SCIT constraint in the event of a contingency.
- Some units frequently needed to operate at minimum dispatchable levels to meet non-modeled reliability requirements submitted extremely high priced energy bids, so that the units were scheduled through the market at their minimum load operating levels. In this situation, exceptional dispatches were issued to ensure units operated at higher levels.

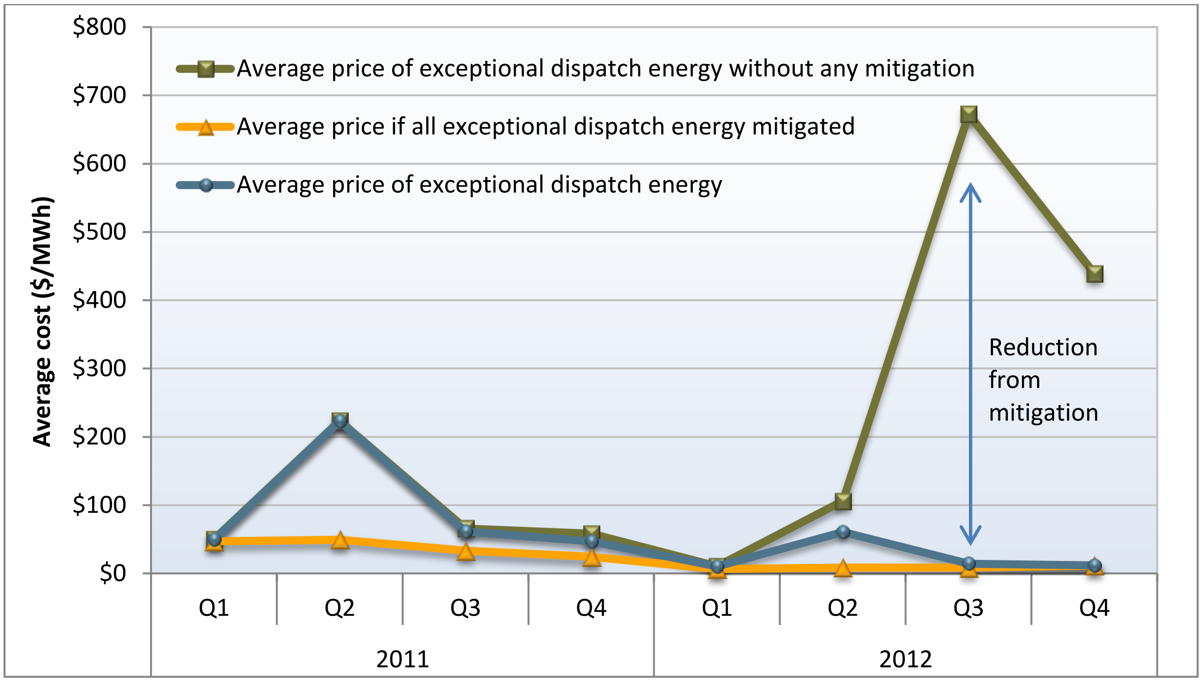
Figure 6.8 Exceptional dispatches subject to bid mitigation



Mitigation substantially decreased the cost of exceptional dispatch particularly in the second half of 2012, as seen in Figure 6.9. The three lines in Figure 6.9 show the difference in average price for exceptional dispatch energy under three scenarios if no mitigation was applied, with actual mitigation applied, and if mitigation had been applied to all exceptional dispatches.

The green line in Figure 6.9 shows the average price of exceptional dispatch energy without mitigation. The blue line shows the actual average prices paid for exceptional dispatch energy after mitigation was applied. Thus, the difference between the blue line and the green line shows the impact mitigation had on the overall price of exceptional dispatch energy.

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



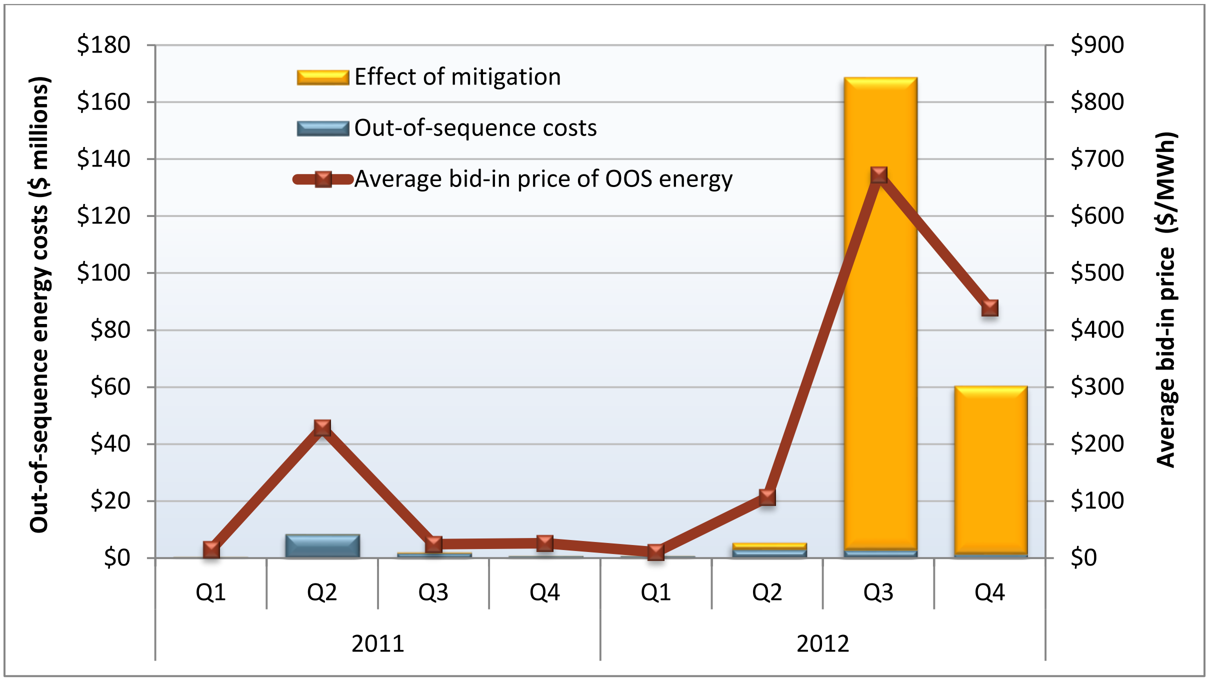
The yellow line shows average prices if all exceptional dispatches were mitigated to the higher of the market price or the unit's default energy bid. Thus, the difference in the yellow line and the green line reflects the degree to which energy bids for exceptional dispatch energy exceed each unit's default energy bid and the market clearing price for energy. This provides a benchmark for assessing actual exceptional dispatch prices and the effectiveness of mitigation.

The large increase in the average price of exceptional dispatch energy before mitigation (green line) in the second half of 2012 resulted from extremely high bid prices from a small set of units. However, as seen by the small difference between the blue and yellow lines, most of the exceptional dispatch energy was mitigated.

The impact of mitigation of exceptional dispatches in terms of mitigating excessive costs are shown in Figure 6.10 by the orange bar segments. Mitigation for exceptional dispatch was effective during this period and averted significant excess cost of $227 million in 2012. The amount that was ultimately paid to exceptional dispatch that was in excess of the market price (blue bar segment) totaled just over $8 million.[92] The large impact of exceptional dispatch mitigation reflects the fact that bids subject to mitigation were primarily from resources offering at or near the $1,000/MWh offer cap. The average *as-bid* price of out-of-sequence energy was over $670/MWh in the third quarter compared to $50/MWh in other periods in 2012 and throughout 2011.

[92] Exceptional dispatch is discussed in more detail in Section 8.1 of this report.

Figure 6.10 Out-of-sequence cost for real-time exceptional dispatch and averted cost due to mitigation



6.4 Market power mitigation in Southern California during July and August 2012

This section reviews market competitiveness and the effectiveness of market power mitigation in the Southern California region during the peak summer months of July and August, 2012.

During these months, the potential for local market power in Southern California increased substantially compared to prior years for a number of reasons:

- Tighter supply and demand conditions existed due to the loss of 2,000 MW of baseload generation from the SONGS units, coupled with higher peak loads.
- Congestion was more frequent and severe on transmission constraints into the SCE and SDG&E areas.
- An increased portion of capacity within Southern California was offered at uncompetitively high bid prices.

In the day-ahead market, there was a significant amount of internal generation with offer prices well in excess of variable cost during the summer months, as shown in Figure 6.11. Although there was more capacity offered at uncompetitive prices in October and November of 2012, these are relatively low-load months where there is often sufficient available capacity to meet demand at competitive prices.

Figure 6.12 provides a detailed daily summary of uncompetitive offers in the day-ahead market during July and August of 2012. A large quantity of capacity was offered at uncompetitive prices during two heat waves during these months that resulted in high load: July 9 through 13 and August 6 through 21.

Figure 6.11 Southern California capacity with high offer price in the day-ahead market (peak hours 13 to 20)

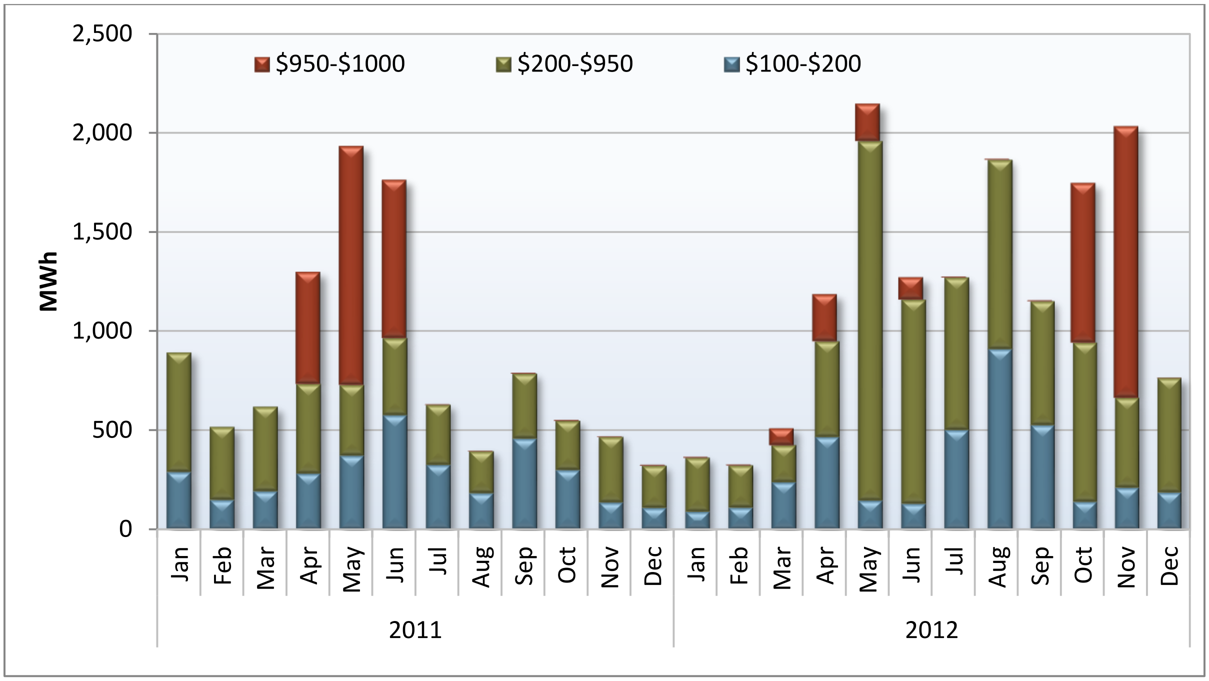
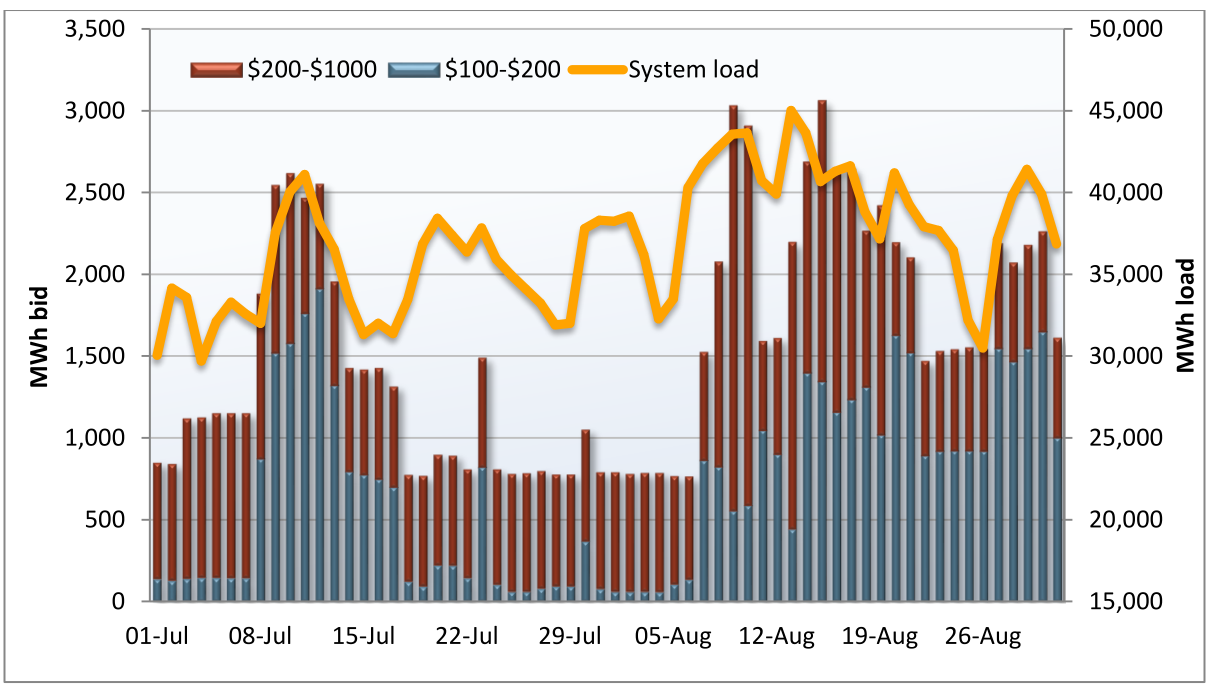
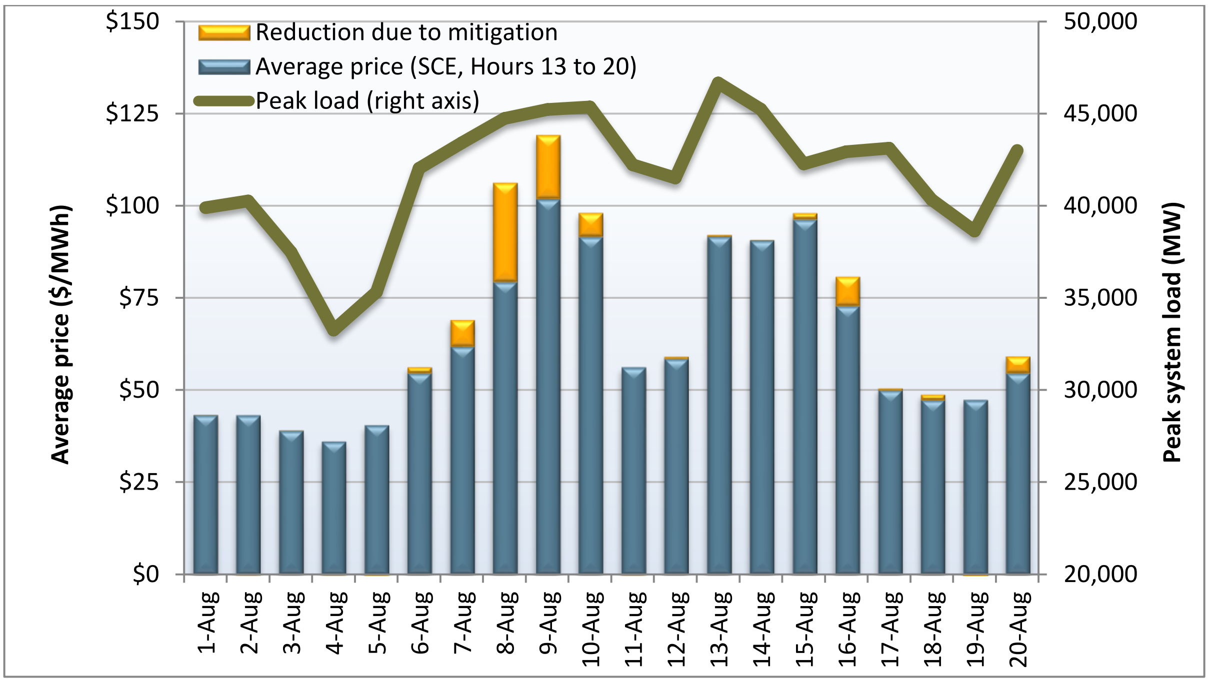


Figure 6.12 Southern California capacity with high offer price in the day-ahead market, July and August 2012 (peak hours 13 to 20)



During the highest load days of the summer, mitigation was frequently triggered by congestion into the SCE and San Diego areas. Figure 6.13 shows the impact of local market power mitigation on the SCE area price during peak hours ending 13 through 20 during August 1 to 20, 2012. The yellow bar segment indicates the increase in price that would have occurred had mitigation not been applied.[93] On these days, mitigation generally kept average peak hour prices below $100/MWh, or about 10 to 35 percent lower than prices that would have resulted without mitigation. The impact of mitigation on prices in the SDG&E area was even greater during this period.

Figure 6.13 Impact of local market power mitigation on day-ahead prices in SCE area (peak hours, 13 to 20)



While mitigation rules were very effective in identifying and mitigating local market power, large volumes of high energy bids during periods of very high demand can raise system energy prices. California's market design includes a relatively high bid cap of $1,000/MWh to mitigate system market power, and therefore relies on a high level of forward contracting and hedging by load-serving entities to mitigate potential system-wide market power.

As discussed in Chapter 2 (Section 2.2), overall prices in the day-ahead market were about equal to the competitive baseline prices in most months, but exceeded levels DMM estimates would result under highly competitive conditions by about 7 percent in the peak load month of August. As noted in Chapter 2, high prices in August were driven by high congestion on constraints in Southern California, along with peak loads and uncompetitive bidding by some market participants.

[93] The impact of local market power mitigation is measured as the difference between the price from the mitigation run and the price from the actual market run. The mitigation run clears the market using clean bids which are bids that conform to bidding rules but have not been subject to mitigation. The market run clears the market using bids that have been subject to mitigation (when mitigation is triggered by the mitigation run). The two runs are otherwise identical. Comparing the resulting prices provides an accurate measure of the impact of mitigation on price.

6.5 Start-up and minimum load bids

Owners of gas-fired generation can choose from two options for their start-up and minimum load bid costs: proxy costs and registered costs.[94] Prior to April 2011, owners electing the registered 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 they preferred.[95]

Capacity under registered cost option

Gas-fired capacity opting for the registered cost option for start-up and minimum load bids has increased since the start of the nodal market. This increase has continued to approximately 75 percent by December 2012. As shown in Figure 6.14 and Figure 6.15, a noticeable upward shift in the amount of capacity under the registered cost option for both start-up and minimum load occurred after the April 2011 tariff modifications.

The following is shown in these figures:

- In December 2012, the portion of natural gas fueled capacity for start-up costs under the registered cost option increased approximately 78 percent from December 2011, while minimum load capacity increased over 48 percent.
- In December 2012, about 77 percent of all natural gas fueled capacity, or approximately 29,000 MW, was on the registered cost start-up option. About 60 percent, approximately 22,000 MW, was on the registered cost option for minimum load bids.
- By the end of 2012, less than 4 percent of natural gas fueled capacity solely elected the registered cost minimum load option. Over 21 percent of natural gas fueled capacity chose the registered cost option for start-up costs only.
- The portion of capacity at or near the cap for start-up costs has remained large but decreased compared to 2011, as shown in Figure 6.16. In the fourth quarter of 2012, about 60 percent of the registered cost start-up bids were greater than 180 percent of the calculated fuel costs.
- Registered cost bids for minimum load capacity tend to be lower and range more widely relative to actual minimum load fuel costs, as shown in Figure 6.17. In the fourth quarter, about 16 percent of minimum load bids were less than 120 percent of the bid cap, compared to 12 percent in the same period in 2011. Also in the fourth quarter, about 48 percent of the minimum load bids were greater than 180 percent of the cap, compared to 60 percent in 2011.

[94] Under the proxy cost option, each unit's start-up and minimum load costs are automatically calculated each day based on an index of daily spot market gas price and the unit's start-up and minimum load fuel consumption as reported in the master file. 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 are capped at 200 percent of projected costs as calculated under the proxy cost option. One of the reasons for providing this bid-based option was to provide an alternative for generation unit owners who believed they had significant non-fuel start-up or minimum load costs not covered under the proxy cost option. See FERC filing September 29, 2009: http://www.caiso.com/23fc/23fcb61b29f50.pdf.

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

Figure 6.14 Start-up gas-fired capacity under registered cost option

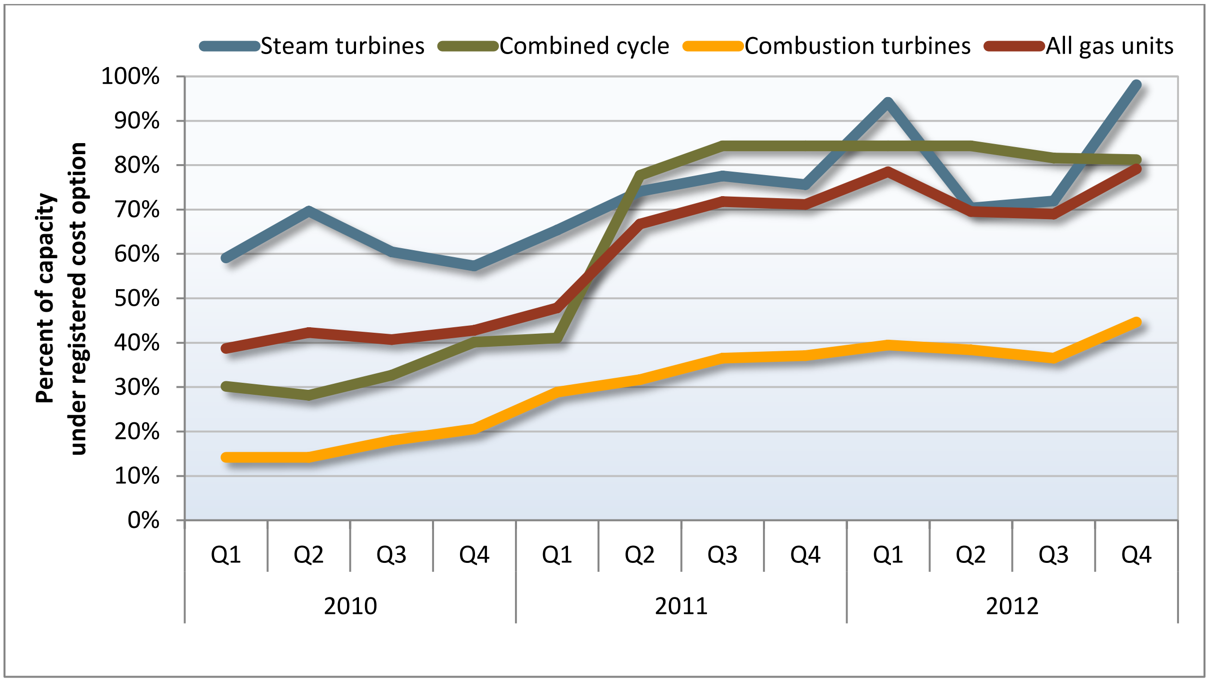


Figure 6.15 Minimum load gas-fired capacity under registered cost option

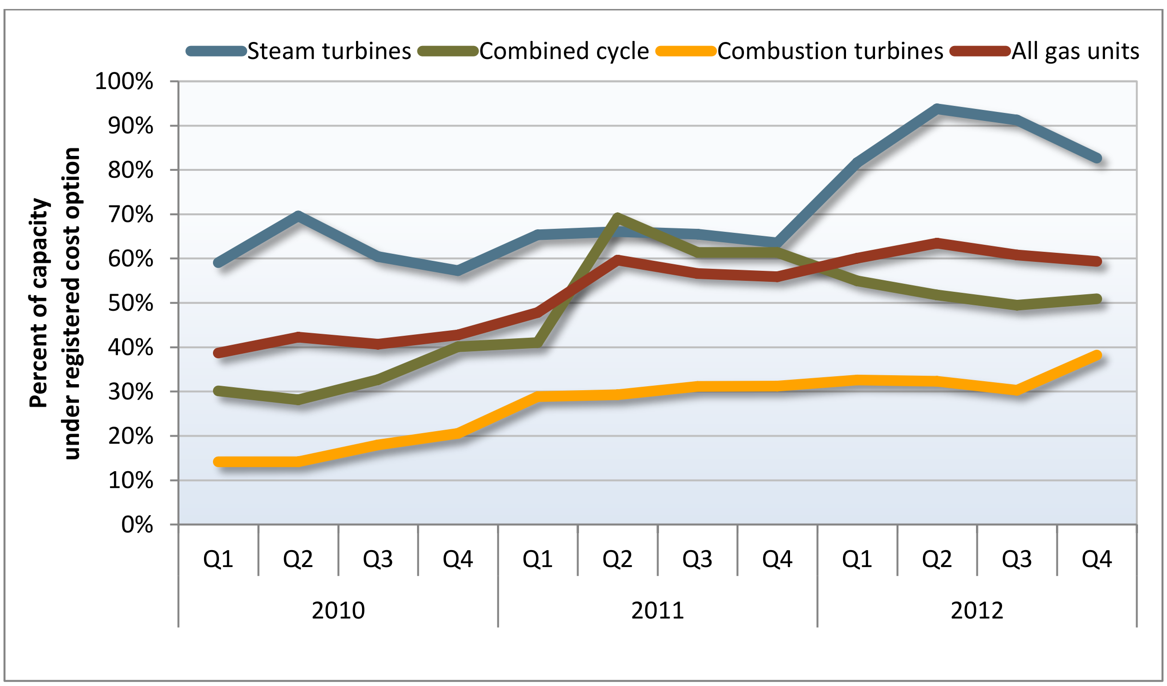


Figure 6.16 Registered cost start-up bids by quarter

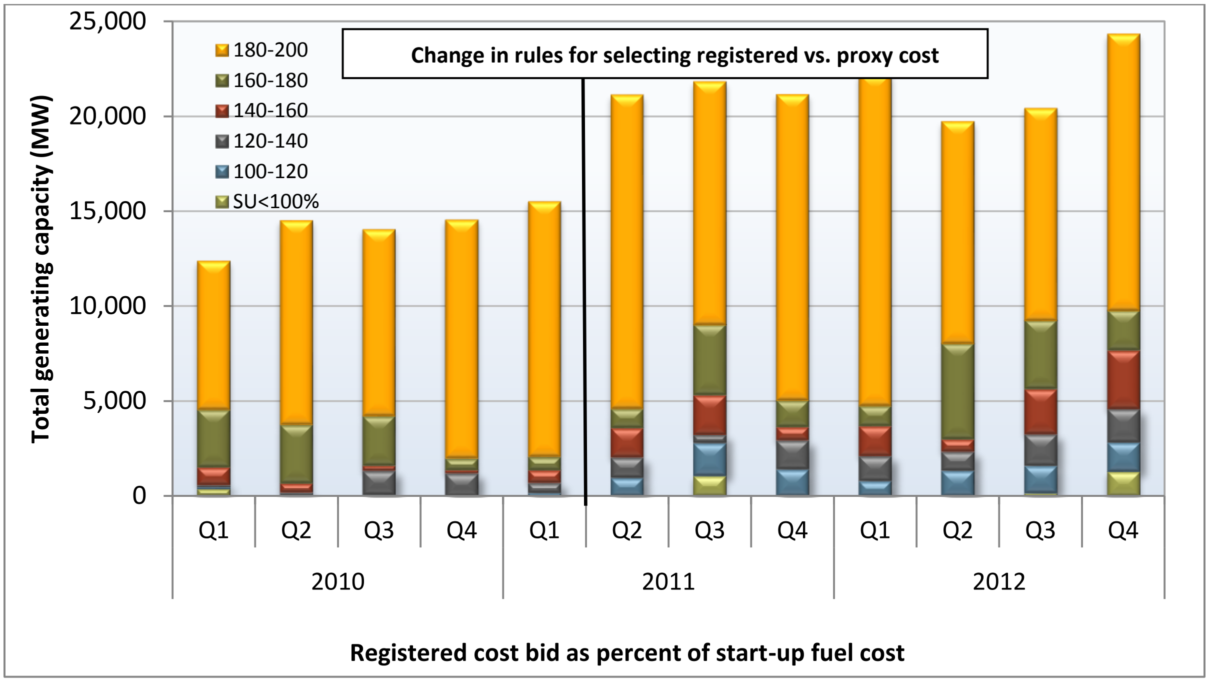
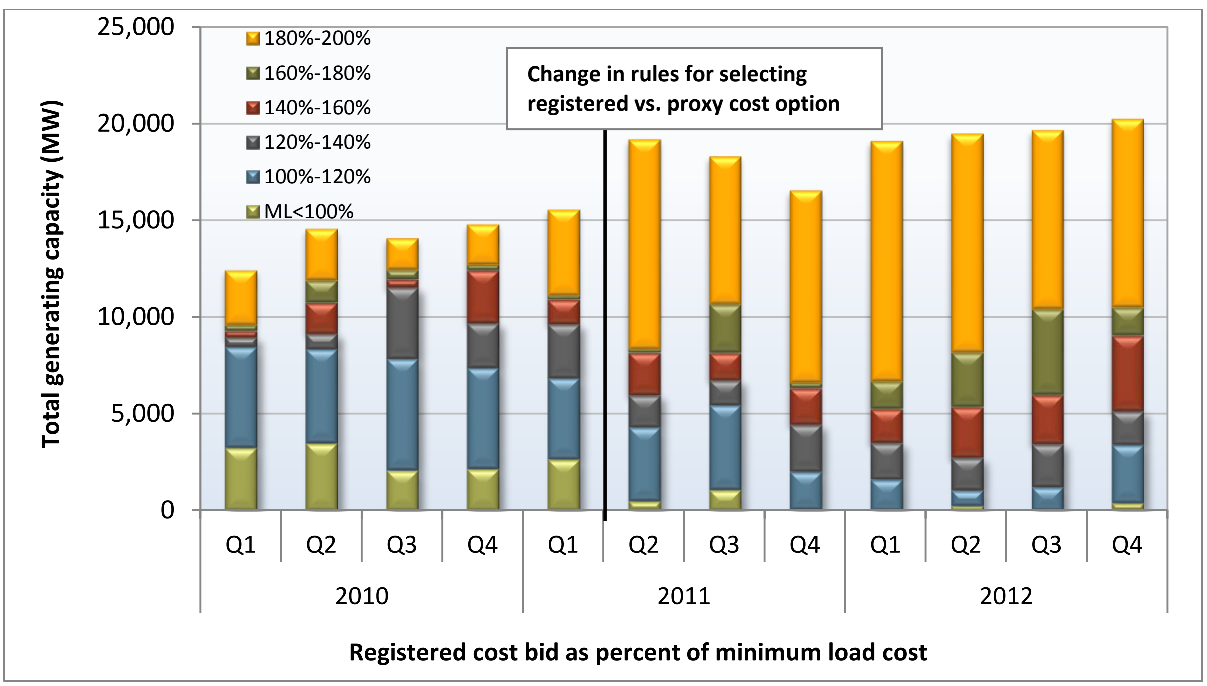


Figure 6.17 Registered cost minimum load bids by quarter



DMM also examined the amount of capacity under the registered cost option by technology,[96] as shown in Figure 6.18 and Figure 6.19:

- Of total natural gas capacity in December 2012, the registered start-up option was chosen by over 98 percent of steam turbines and 76 percent of combined cycles. Only 51 percent of gas turbines elected this option.
- Of total natural gas capacity in December 2012, the registered minimum load option was chosen by over 46 percent of steam turbines and 37 percent of combined cycles. Only 17 percent of gas turbines elected this option.
- Most capacity under the start-up registered cost bid option submitted bids at or near the bid cap. This trend began in December 2010. As shown in Figure 6.18, nearly 65 percent of capacity under the registered cost option submitted start-up bids greater than 180 percent of actual start-up fuel costs.
- Minimum load registered cost bid capacity has a wider range of bid costs than start-up costs. Nearly 30 percent of the bids were less than 140 percent of the actual minimum load proxy costs.
- Generally, steam turbines bid close to the bid cap for both start-up and minimum load costs. Bid costs for gas turbines and combined cycles had a wider range.
- Overall, results of this analysis suggest that the registered cost option for start-up and minimum load bids are heavily skewed toward the 200 percent cap. This is especially true for steam turbine capacity. The cap is expected to decrease from 200 percent to 150 percent in the fall of 2013.[97] Since most participants opt for bid costs greater than 150 percent, the majority of bids are likely to be near or at the new cap.

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

[97] See ISO Board Memorandum, May 9, 2012, 'Decision on Commitment Costs Refinements': http://www.caiso.com/Documents/DecisionCommitmentCostsRefinements-Memo-May2012.pdf.

Figure 6.18 Registered cost start-up bids by generation type – December 2012

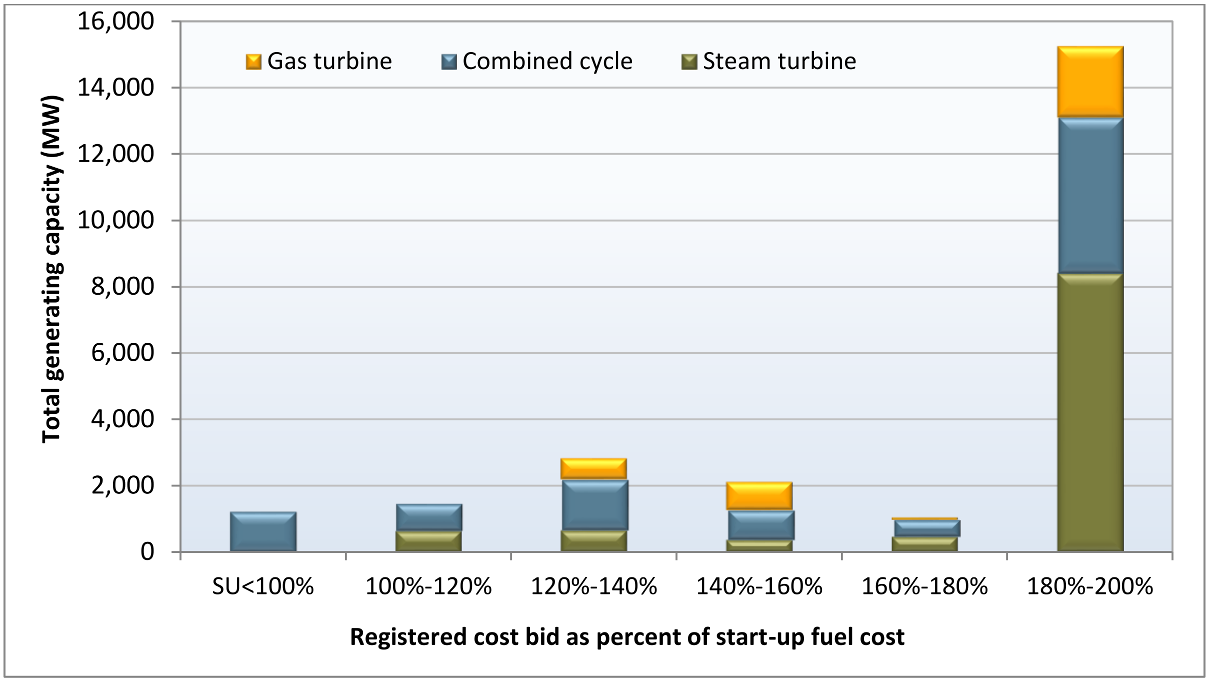
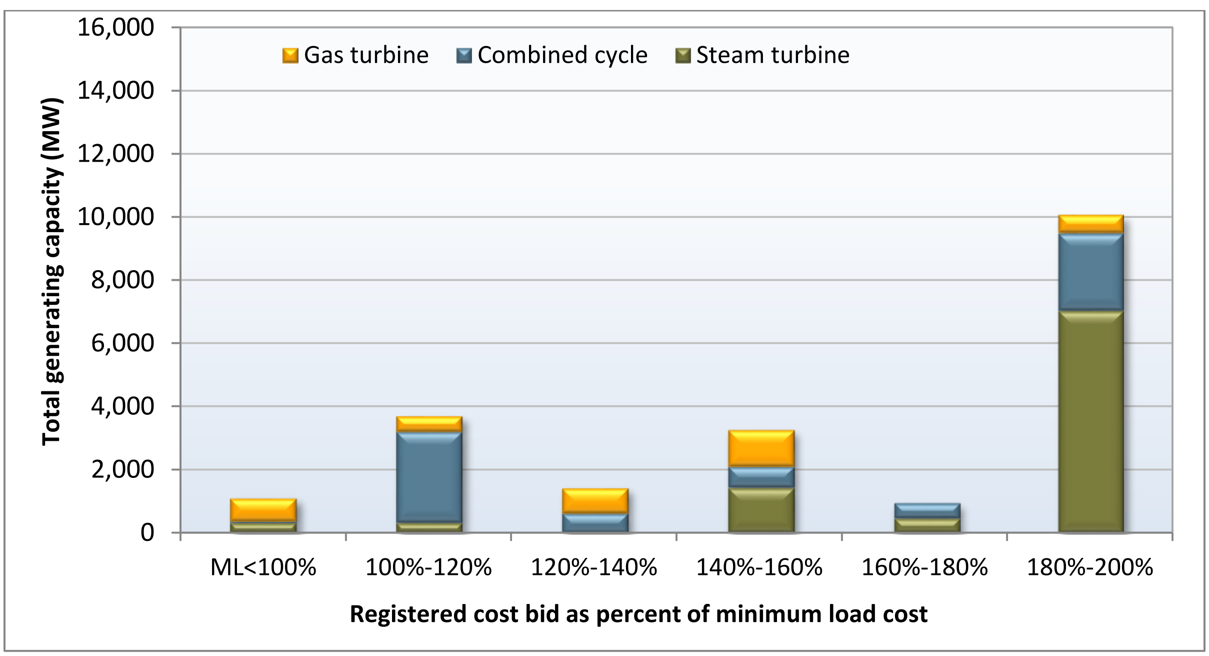


Figure 6.19 Registered cost minimum load bids by generation type – December 2012



7 Congestion

This chapter provides a review of congestion and the market for congestion revenue rights in 2012. The findings include the following:

- Congestion on transmission constraints within the ISO increased compared to prior years and had a greater impact on average overall prices across the ISO system.
- Congestion in 2012 increased largely as a result of incorporation of new reliability constraints in the market models, combined with outages of over 2,000 MW of nuclear generation (SONGS units 2 and 3).
- Prices in the San Diego area were impacted the most by internal congestion, which increased average prices in the San Diego area above the system average by about $2/MWh or 6 percent. Nearly all of this increase is due to congestion on import limits directly into the SDG&E area.
- Congestion drove prices in the SCE area above the system average prices by about $1/MWh or 3.3 percent. About 80 percent of this increase 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.[98]
- The overall impact of congestion on prices in the PG&E area was to reduce prices below the system average by about $1/MWh or 3 percent. This results from the fact that prices in the PG&E area are lowered when congestion occurs on the constraints that limit flows into the SCE and SDG&E areas.
- Congestion on most major inter-ties connecting the ISO with other balancing authority areas was higher in 2012, particularly for inter-ties connecting the ISO to the Pacific Northwest. This appears primarily due to major generation and transmission outages within the ISO system, combined with abundant supplies of relatively low-priced energy from hydro-electric and wind resources in the Northwest in the first half of the year.
- Average profitability of all congestion revenue rights was about $0.40/MW in 2012, compared to about $0.07/MW in 2011. This increase was driven largely by higher levels of congestion associated with the SONGS outages. Overall, rights in the prevailing flow of congestion were more profitable than rights in the opposite, or counter-flow, direction of the prevailing flow. This is a change from what had occurred in previous years.

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.

[98] This constraint is designed to ensure that enough generation is being supplied from units within SCE area in the event of a contingency that significantly limit imports into SCE or decreases generation within the SCE area.

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 energy 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 2012 than in previous years, particularly for inter-ties connecting the ISO to the Pacific Northwest.

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 point, this congestion price represents the decrease in the price they receive 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.

Table 7.1 Summary of import congestion (2010 - 2012)

Import region	Inter-tie	Frequency of import congestion			Average congestion charge ($/MW)			Import congestion charges (thousands)		
		2010	2011	2012	2010	2011	2012	2010	2011	2012
Northwest	PACI	11%	11%	42%	$9.2	$9.1	$10.5	$20,194	$48,903	$84,657
	NOB	7%	8%	39%	$12.7	$9.2	$11.6	$12,253	$25,471	$59,236
	COTPISO	1%	13%	8%	$10.9	$24.7	$16.5	$20,968	$629	$271
	Summit	0%	1%	2%	$10.0	$46.9	$19.6	$14,884	$317	$195
	Cascade	2%	32%	20%	$6.8	$12.0	$14.8	$78	$2,481	$2,086
	New Melones	0%	17%		$0.0	$33.4		$0	$6,788	$0
	Tracy 230	0%	1%	2%	$0.0	$669.4	$232.4	$0	$3,841	$1,164
Southwest	Palo Verde	14%	19%	11%	$7.0	$10.2	$10.3	$20,712	$25,885	$19,177
	Mead	21%	13%	18%	$5.1	$7.1	$9.2	$8,433	$8,287	$15,248
	IPP DC Adlanto (BG)	26%	0%	11%	$5.9	$11.7	$3.0	$7,859	$186	$1,195
	IID-SDGE_ITC			0%			$963.6			$1,095
	IID - SCE	1%	4%	1%	$34.0	$9.8	$53.8	$1,377	$1,579	$1,646
	El Dorado	1%	2%	6%	$11.4	$8.4	$10.1	$1,222	$2,183	$5,695
	Mona IPP DC (MSL)	0%	14%	6%	$0.0	$3.9	$2.7	$0	$631	$285
	BLYTHE_ITC			1%			$62.0			$749
	Adlanto SP	1%	0%		$5.0	$0.2		$389	$0	$0
	Other							$312	$205	$156
Total								***$108,681***	***$127,386***	***$192,855***

* The IPP DC Adlanto branch group and the Mona IPP DC market scheduling limit are not inter-ties, but is included here because of their function in limiting imports from the Adlanto / Mona regions and the frequency with which they were binding.

Figure 7.1 Percent of hours with congestion on major inter-ties (2010 – 2012)

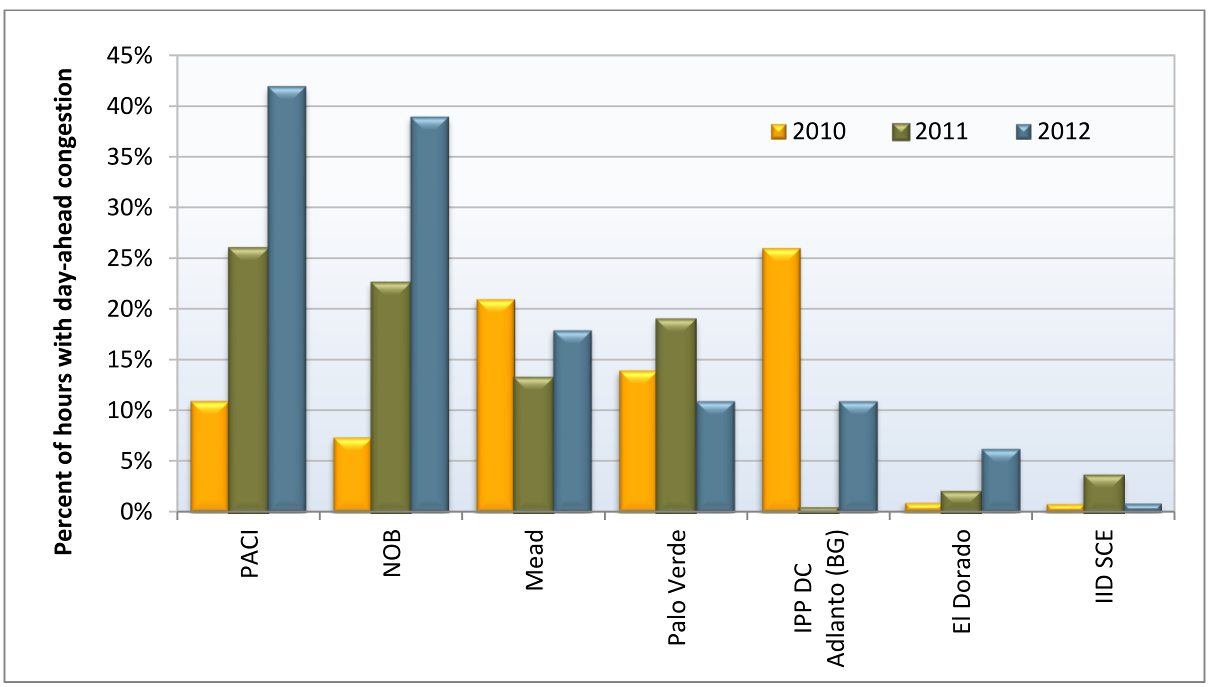
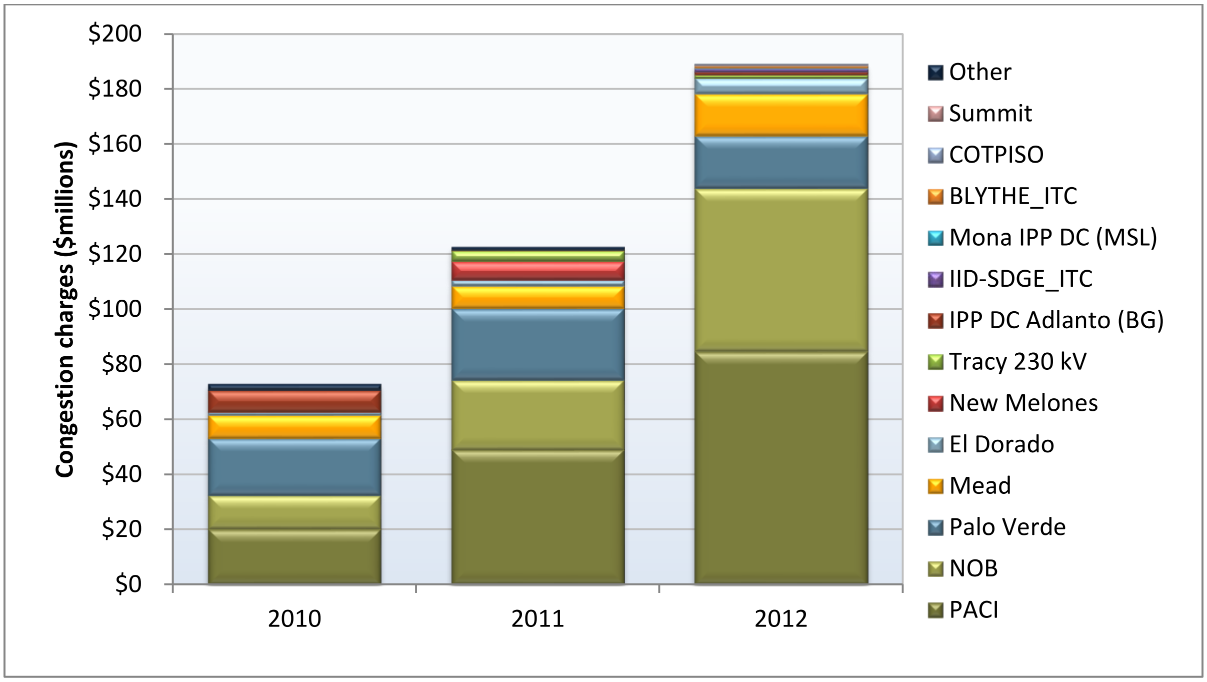


Figure 7.2 Import congestion charges on major inter-ties (2010 – 2012)



Congestion increased substantially 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). Total congestion on these two inter-ties increased from $74 million in 2011 to about $144 million in 2012. This reflects the increase in imports from the Northwest resulting from seasonal supplies of energy from hydro and wind resources and periods of forced outages and scheduled maintenance.

Congestion decreased significantly on Palo Verde, which is the largest inter-tie linking the ISO with the Southwest. Congestion charges on Palo Verde decreased from $26 million in 2011 to about $19 million in 2012. The decrease in congestion on this inter-tie appears related to the completion of transmission maintenance and upgrades in 2012.

The frequency of congestion on the Mead inter-tie linking the ISO to the Southwest increased from 13 percent in 2011 to 18 percent in 2012, and congestion charges almost doubled to about $15 million in 2012 from $8 million in 2011. This congestion was associated with planned and forced outages.

Congestion charges on the El Dorado inter-tie more than doubled in 2012 to $5.6 million, compared to $2.2 million in 2011. This appears to be related to forced outages and transmission maintenance.

No congestion occurred on the New Melones inter-tie in 2012. Congestion charges for this inter-tie were $6.7 million in 2011 and were zero in 2012. This change is the result of the removal of virtual bidding on fully encumbered inter-ties.[99]

[99] See the ISO market notice on August 22, 2011, indicating Virtual Bidding Not Allowed at Fully Encumbered Inter-ties. The ISO noted that "with the adoption of a recent Business Practice Manual change, virtual bidding will no longer be allowed on inter-tie scheduling points that are fully encumbered by existing rights where the available transfer capacity is 0 MW. This change will be effective trade date August 29, 2011." For more information see the following link: http://www.caiso.com/Documents/VirtualBiddingNotAllowed-FullyEncumberedInter-tiesAug_22_2011.htm.

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. In 2012, congestion on numerous internal constraints significantly affected prices during hours when congestion occurred, particularly in the SDG&E area.

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.[100]

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.

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.

In 2012, the most congested constraint in the ISO system was the constraint limiting imports into the SCE area (SCE_PCT_IMP_BG). This constraint was congested in the day-ahead market about 37 percent of time in the second and fourth quarters and 24 percent of the time in the third quarter. During the second quarter, when congestion occurred on this constraint, day-ahead prices in the SCE area increased about $3.40/MWh and decreased for SDG&E and PG&E areas of just under $2.90/MWh. In the fourth quarter, SCE prices increased about $3.90/MWh when congestion occurred on this constraint and decreased in the SDG&E and PG&E areas about $3.20/MWh.

In the PG&E area, the most congested constraint was the Table Mountain nomogram (6110_TM_BNK_TMS_DLO_NG). In the third quarter, congestion on this nomogram occurred in 23 percent of hours. During these hours, prices in the PG&E area increased by $1.80/MWh and prices in the SCE and SDG&E areas decreased by about $1.51/MWh. This congestion was mainly due to maintenance, unscheduled flows on the California-Oregon Intertie (COI) and the Caribou (Chips) Fire.

In the SDG&E area, the following three constraints were frequently binding and had a significant impact on prices:

- The SLIC 1883001_SDGE_OC_NG nomogram was directly related to the outage of the SONGS units and ended with the addition of the Sunrise Powerlink in mid-June.[101] This nomogram was constrained in the first and second quarters in about 14 percent and 32 percent of hours, respectively. In the second quarter, this constraint increased the prices in the SDG&E area by

[100] 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.

[101] The Sunrise Powerlink transmission project constructed a 117-mile long 500 kV power line to bring 1,000 MW of renewable energy from the Imperial Valley to the San Diego area. It was one of the most important transmission additions in the ISO system in 2012. This addition increased SDG&E import capabilities and was important for improving reliability in the San Diego area with the outage of SONGS units 2 and 3.

$6.46/MWh in congested hours and SCE by $0.28/MWh while decreasing prices in the PG&E area by $0.71/MWh.

- The 7830_SXCYN_CHILLS_NG nomogram protects the system for the potential loss of the Imperial Valley to Miguel 500 kV line. This nomogram increased SDG&E area prices in congested hours by $7.43/MWh, but had no impact on PG&E and SCE area prices.

- The 23242_HDWSH_500_22536_N.GILA_500_BR_1_1 constraint is associated with the Hoodoo Wash to North Gila 500 kV line. This is a segment of the Southwest Powerlink (SWPL), which is a major transmission corridor (500 kV) that runs from the Palo Verde/Hassayampa Substation in Arizona to the Miguel Substation in San Diego County, California. It is jointly owned by San Diego Gas & Electric Company (SDG&E), Arizona Public Service Company (APS) and Imperial Irrigation District (IID). In the third quarter, this constraint was binding about 16 percent of hours. During these hours, SDG&E prices increased $9.20/MWh due to congestion on this constraint, while PG&E prices dropped by $1.47/MWh and SCE prices dropped about $0.34/MWh.

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	PATH15_BG				9.1%										$1.80	-$1.45	-$1.45
	SLIC 1356082_PVDV-ELDLG_NG				1.6%										$0.52		-$1.44
	SLIC 2040200 Goodrich PVD EM out				1.5%										$0.30		-$1.26
	SLIC 2040200 Goodrich PVD out				2.7%										$0.47		-$2.05
	6110_TM_BNK_FLO_TMS_DLO_NG		6.3%	23.4%					$0.80	-$0.85	-$0.85	$1.80	-$1.51	-$1.51			
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	8.6%				$1.24	-$0.97	-$0.97									
SCE	SCE_PCT_IMP_BG	4.6%	35.6%	24.3%	38.0%	-$1.31	$1.62	-$1.31	-$2.87	$3.40	-$2.87	-$2.15	$2.43	-$2.13	-$3.21	$3.90	-$3.17
	BARRE-LEWIS_NG			5.7%	15.7%							-$0.54	$0.61	$0.37	-$1.86	$2.25	$1.12
	SLIC 1356092 Serrano Valley OUT				11.5%										$0.27	-$0.36	$0.18
	SLIC 1356092 Serrano Valley IN				1.5%										-$0.64	$0.57	-$0.64
	24138_SERRANO _500_24151_VALLEYSC_500_BR_1 _1				1.0%										$5.81	-$9.43	$5.81
	30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1				0.5%										$1.70	-$2.60	-$2.60
	24137_SERRANO _230_24154_VILLA PK_230_BR_1 _1				0.4%										-$6.88	$6.78	
	PATH26_BG	4.8%	3.6%	0.4%	0.2%	-$1.63	$1.39	$1.39	-$1.41	$1.16	$1.16	-$3.05	$1.80	$1.80	-$4.80	$3.80	$3.80
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2		0.7%	11.3%					-$3.22	$2.39	$2.44	-$5.24	$3.47	$3.57			
	30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2			0.7%								-$4.00	$2.37	$2.28			
	SLIC1852244PATH26LIOSN2S	4.7%				-$1.98	$1.66	$1.66									
	SLIC1883001 MIGUEL BKS	1.4%				-$0.14		$5.01									
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1	1.0%				-$1.15	$1.65	-$1.93									
	SLIC 1848345_23021_Outage	0.5%				-$1.17		$7.79									
SDG&E	22342_HDWSH _500_22536_N.GILA _500_BR_1 _1			15.9%	5.3%							-$1.47	-$0.34	$9.20	-$1.60	-$3.81	$9.75
	SLIC 2023497 TL50003_CFERAS				4.3%												$18.08
	22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80				4.8%												$0.54
	SLIC 1956086_ELD-MCCUL HDW				4.3%										$0.16	-$0.28	$0.46
	IVALLYBANK_XFBG				3.3%												$0.74
	SOUTHLUGO_RV_BG				2.6%										-$3.69	$2.36	$3.94
	7830_SXCYN_CHILLS_NG			23.3%	2.4%									$7.43	-$48.17		$44.23
	SDGE_PCT_UF_IMP_BG		1.1%	0.4%	1.3%				-$0.40	-$0.40	$4.27	-$0.47	-$0.47	$4.70	-$0.55	-$0.55	$5.19
	SLIC 2020109 IV500 SBUS_NG				1.2%										-$0.36		$3.68
	22831_SYCAMORE_138_22116_CARLTHTP_138_BR_1 _1				1.1%												$9.74
	SDGE_CFEIMP_BG	9.0%	2.4%		1.0%	-$0.45	-$0.45	$4.19	-$0.56	-$0.56	$5.64				-$0.88	-$0.88	$7.84
	SLIC 2023497 TL50003_CFERAS_DAM				0.8%												$6.03
	SLIC 2040601 TL23050_NG				0.7%												$3.18
	SLIC 2040600 TL23050_NG				0.5%												$11.57
	22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1				0.5%										-$1.55		$10.99
	SLIC 2040598 TL23050_NG				0.4%												$9.69
	SLIC 2046458 TL23050_NG				0.4%												$4.71
	SDGEIMP_BG			4.4%								-$0.71	-$0.71	$7.19			
	SOUTHLUGO_RV_BG			3.6%								-$9.02	$5.25	$8.15			
	14013_HDWSH _500_22536_N.GILA _500_BR_1 _1			1.4%								-$0.40		$2.91			
	22831_SYCAMORE_138_22116_CARLTHTP_138_BR_1 _1			0.4%										$9.93			
	SLIC 2034755 TL23040_NG			0.6%										$7.36			
	SLIC 1883001_SDGE_OC_NG	14.2%	31.7%			-$0.65	-$0.06	$6.27	-$0.71	$0.28	$6.46						
	SLIC 1883001 Miguel_BKS_NG_2	2.4%	0.9%			-$0.07		$3.08	-$0.45		$6.79						
	SLIC 1977036 Barre-Ellis NG		0.5%						-$0.75		$6.90						
	22832_SYCAMORE_230_22828_SYCAMORE_69.0_XF_2	0.1%						$24.09									

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 increased compared to prior years and had a greater 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 that congestion has when it occurs.[102]

Table 7.3 shows the overall impact of congestion on different constraints on average prices in each load aggregation area in 2012. These results show that:

- Prices in the San Diego area were impacted the most by internal congestion and increased average prices in the San Diego area above the system average by just about $2/MWh or about 6 percent. Nearly all of this increase is due to congestion on import limits directly into the SDG&E area.
- Congestion drove prices in the SCE area above the system average prices by about $1/MWh or around 3 percent. About 80 percent of this increase 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.[103] About 15 percent of this increase was from a compilation of smaller constraints throughout the time period and about 5 percent of this increase was due to congestion in the north-to-south direction on Path 26.
- The overall impact of congestion on prices in the PG&E area was to reduce prices below the system average by about $1/MWh or a decrease of 3 percent. This results from the fact that prices in the PG&E area are lowered when congestion occurs on the constraints that limit flows into the SCE and SDG&E areas.

Table 7.4 shows the overall impact of congestion on day-ahead prices within each of the local capacity areas within the ISO system during 2011 and 2012. These data show that the impact of congestion on day-ahead prices in almost all of these areas increased in 2012. In addition, these results show that the impact of congestion did not vary widely between major local capacity areas in the SCE and PG&E areas. The difference in the average congestion component for generation nodes within these local capacity areas was minimal.

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

[103] This constraint is designed to ensure that enough generation is being supplied from units within SCE area in the event of a contingency that significantly limit imports into SCE or decreases generation within the SCE area.

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
SCE_PCT_IMP_BG	-$0.69	-2.35%	$0.82	2.65%	-$0.68	-2.11%
SLIC 1883001_SDGE_OC_NG	-$0.08	-0.27%			$0.73	2.25%
7830_SXCYN_CHILLS_NG	-$0.03	-0.09%			$0.70	2.15%
22342_HDWSH _500_22536_N.GILA _500_BR_1 _1	-$0.08	-0.26%	$0.00	-0.01%	$0.47	1.46%
30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2	-$0.15	-0.50%	$0.10	0.32%	$0.10	0.31%
SOUTHLUGO_RV_BG	-$0.11	-0.36%	$0.06	0.20%	$0.10	0.31%
6110_TM_BNK_FLO_TMS_DLO_NG	$0.12	0.40%	-$0.07	-0.22%	-$0.07	-0.21%
SLIC 2023497 TL50003_CFERAS					$0.20	0.61%
BARRE-LEWIS_NG	-$0.08	-0.25%	$0.09	0.30%	$0.01	0.04%
SDGE_CFEIMP_BG	-$0.02	-0.05%	-$0.02	-0.05%	$0.15	0.45%
PATH15_BG	$0.04	0.13%	-$0.03	-0.10%	-$0.03	-0.10%
PATH26_BG	-$0.04	-0.13%	$0.03	0.10%	$0.03	0.09%
SDGEIMP_BG	-$0.01	-0.03%	-$0.01	-0.03%	$0.08	0.25%
30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.03	0.09%	-$0.02	-0.07%	-$0.02	-0.06%
SLIC1852244PATH26LIOSN2S	-$0.02	-0.08%	$0.02	0.06%	$0.02	0.06%
24138_SERRANO _500_24151_VALLEYSC_500_BR_1 _1	$0.02	0.05%	-$0.03	-0.08%	$0.02	0.05%
SDGE_PCT_UF_IMP_BG	-$0.003	-0.01%	-$0.003	-0.01%	$0.03	0.10%
22831_SYCAMORE_138_22116_CARLTHTP_138_BR_1 _1					$0.04	0.11%
SLIC 1883001 Miguel_BKS_NG_2					$0.03	0.10%
SLIC 1356092 Serrano Valley OUT	$0.01	0.02%	-$0.01	-0.03%	$0.01	0.01%
SLIC1883001 MIGUEL BKS					$0.02	0.05%
SLIC 2040200 Goodrich PVD out	$0.003	0.01%			-$0.01	-0.04%
22886_SUNCREST_230_22832_SYCAMORE_230_BR_1 _1	-$0.002	-0.01%			$0.02	0.04%
30060_MIDWAY _500_29402_WIRLWIND_500_BR_1 _2	-$0.01	-0.02%	$0.004	0.01%	$0.004	0.01%
Other	$0.15	0.51%	$0.02	0.06%	$0.05	0.14%
Total	-$0.94	-3.2%	$0.96	3.1%	$1.98	6.1%

Table 7.4 Day-ahead congestion by local capacity area[104]

		Average of Congestion LMP as Percent of System LMP			
LAP	LCA	2011 Avg. LMP (congestion)	2011 Avg.	2012 Avg. LMP (congestion)	2012 Avg.
PG&E	Bay Area	-$0.34	-1.1%	-$1.12	-3.7%
	Fresno	-$0.49	-1.6%	-$1.23	-4.1%
	Humboldt	$0.12	0.2%	-$1.78	-5.9%
	Kern	-$0.42	-1.4%	-$1.44	-4.8%
	North Coast North Bay	-$0.48	-1.6%	-$1.35	-4.5%
	Sierra	-$0.28	-1.2%	-$0.72	-2.4%
	Stockton	-$1.40	-4.7%	$0.34	1.1%
SCE	Big Creek-Ventura	$0.23	0.8%	$0.70	2.3%
	LA Basin	$0.14	0.5%	$0.88	2.9%
SDG&E	San Diego	$0.72	2.5%	$2.03	6.7%

104 Unlike the prices in Table 7.3, which are load weighted, prices in Table 7.4 are generation weighted.

7.3.2 Real-time congestion

Congestion in the real-time market differs from congestion in the day-ahead market. Real-time congestion typically occurs less frequently overall, but often occurs on a wider number of constraints and has a larger impact on prices when it occurs. A more detailed discussion of differences in day-ahead and real-time congestion is provided in Section 7.4.

Table 7.5 shows the frequency and average shadow prices of real-time congestion by quarter. The SCE_PCT_IMP_BG constraint was also the most congested constraint in the real-time market during 2012. This constraint was directly affected by the San Onofre outages and was binding in 4 percent of the intervals in the third quarter and 6 percent of the intervals in the fourth quarter. During these intervals, the constraint increased prices in the SCE area by $27/MWh in the third quarter and $44/MWh in the fourth quarter. During these periods, this constraint decreased prices in the SDG&E and PG&E areas almost as much as it increased prices in the SCE area.

During the fourth quarter, two constraints in the SCE area associated with a planned outage of the Devers to Valley 500 kV Line in November were frequently binding in real-time and had a major impact on prices. The SLIC 1356092 Serrano Valley OUT constraint was binding in real-time in approximately 11 percent of intervals. During these intervals, this constraint decreased prices by $1.43/MWh in the SCE area and increased prices by $0.78/MWh in the PG&E and SDG&E areas. Another constraint representing flows in the opposite direction of this constraint (SLIC 1356092 Serrano Valley IN) was also congested in over 4 percent of the real-time intervals in the fourth quarter. This increased prices during these intervals in the SCE area by $0.34/MWh and decreased the PG&E and SDG&E area prices by $0.21/MWh.

In the SCE area, congestion on the Barre-Lewis_NG was also exacerbated by the San Onofre outages and occurred in about 4 percent of hours in the fourth quarter. This increased prices in the SCE area by $8.66/MWh in congested hours and decreased prices in the PG&E and SDG&E areas by about $13.19/MWh and $1.93/MWh, respectively.

In the San Diego area, real-time congestion and prices were affected by multiple constraints during the year. The 1883001_SDGE_OC_NG nomogram, which was associated with the SONGS outages, had the most significant impact on real-time congestion. This nomogram was congested in the first and second quarters at 5.3 and 2.7 percent, respectively. During intervals of congestion in the second quarter, this increased costs in the San Diego area by about $68/MWh, while decreasing PG&E prices by $8/MWh and having a negligible effect on SCE prices. Other significant binding constraints were Imperial Valley-Miguel (TL50003), Hoodoo-Wash and Sycamore Canyon.

PG&E area prices in the real-time market were most influenced by congestion on the Table Mountain nomogram (6110_TM_BNK_TMS_DLO_NG) in the third quarter.[105] This constraint occurred mainly because of maintenance, unscheduled flows on COI and the Caribou (Chips) fire. Congestion occurred in 5 percent of intervals in the third quarter, causing prices in the PG&E area to increase $29/MWh in congested intervals while decreasing prices in the SCE and SDG&E areas by about $27/MWh.

Real-time prices in the PG&E area were also affected by congestion on the Midway-Gates transmission line, which occurred during 3.2 percent of intervals in the first quarter, and on Path 15, which occurred in 3.5 percent of intervals in the fourth quarter.

[105] This constraint is discussed in further detail in Section 7.6.

Table 7.5 Impact of congestion on real-time prices during congested intervals

		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	PATH15_S-N		0.1%		3.5%				$59.14	-$50.27	-$50.27				$26.15	-$21.81	-$21.81
	SLIC 2042305 ELD-LUGO PVDV				1.6%										$17.75	-$9.26	-$32.63
	30750_MOSSLD _230_30790_PANOCHE _230_BR_1 _1				0.3%										$2.53	-$2.47	-$2.47
	24086_LUGO _500_26105_VICTORVL_500_BR_1 _1				0.2%										$52.24	-$36.93	-$92.17
	SLIC 2040200 Goodrich PVD EM out				0.1%										$10.33		-$39.71
	SLIC 2040200 Goodrich PVD out				0.1%										$13.89		-$63.87
	SLIC 1956086_ELD-MCCUL EL-LU				0.1%										$7.21		-$15.37
	SLIC 2041811 PNOCHE-KERNEY SOL1				0.1%										$16.95	-$11.07	-$11.07
	SLIC 1356082_PVDV-ELDLG_NG				0.1%										$9.18		-$23.17
	SLIC 2077489 SOL3				0.1%										$17.62		-$25.95
	30630_NEWARK _230_30703_RAVENSWD_230_BR_1 _1				0.1%											-$32.00	-$32.00
	SLIC 1953261 ELD-LUGO PVDV				0.1%										$64.76	-$28.61	-$126.57
	6110_TM_BNK_FLO_TMS_DLO_NG		1.7%	4.9%					$20.04	-$25.77	-$25.77	$28.95	-$27.11	-$27.11			
	T-135 VICTVLUGO_EDLG_NG			1.8%								$13.62	-$8.51	-$18.09			
	30055_GATES1 _500_30900_GATES _230_XF_11_P			0.3%								$3.63	-$3.04	-$3.04			
	30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2			1.3%								-$69.86	$46.78	$48.06			
	TRACY230_BG			0.1%								$33.26	-$21.89	-$21.89			
	SLIC 1902749 ELDORADO_LUGO-1	1.1%	1.7%			$3.30	-$2.36	-$3.96	$12.43	-$8.32	-$14.48						
	LBN_S-N	0.02%	0.5%			$1.59	-$1.29	-$1.29	$228.26	-$199.05	-$199.05						
	LOSBANOSNORTH_BG	0.0%	0.1%			$3.22	-$2.74	-$2.74	$179.78	-$142.40	-$142.40						
	SLIC 1977990 SYL_PAR_NG		0.03%						$26.58	-$20.03	-$98.65						
	PATH26_S-N	0.3%	0.02%			$30.46	-$25.84	-$25.84	$1.63	-$1.41	-$1.41						
	SLIC 1902748 ELDORADO_LUGO-1	1.1%				$4.29	-$2.98	-$6.43									
	30900_GATES _230_30970_MIDWAY _230_BR_1 _1	3.2%				$4.76	-$3.65	-$3.65									
SCE	SLIC 1356092 Serrano Valley OUT				11.0%										$0.78	-$1.43	$0.78
	SCE_PCT_IMP_BG	0.2%	2.2%	4.4%	6.1%	-$63.37	$79.72	-$63.37	-$69.78	$86.32	-$69.66	-$24.70	$27.25	-$23.63	-$36.29	$44.37	-$35.85
	SLIC 1356092 Serrano Valley IN				4.1%										-$0.21	$0.34	-$0.21
	BARRE-LEWIS_NG			1.7%	3.8%							-$7.84	$5.16	$190.44	-$13.19	$8.66	-$1.93
	24137_SERRANO _230_24154_VILLA PK_230_BR_1 _1				0.4%										-$19.36	$15.09	-$18.45
	24016_BARRE _230_25201_LEWIS _230_BR_1 _1				0.1%										-$25.97	$23.66	
	P26_NS_LOWLIMIT				0.03%										-$192.09	$156.75	$156.75
	PATH26_N-S	2.8%	2.1%	0.2%		-$17.37	$14.65	$14.65	-$59.99	$48.95	$48.95	-$51.51	$33.76	$33.76			
	PATH15_N-S		1.7%						-$38.79	$29.03	$29.03						
	SLIC-1832324-SOL7		0.7%						-$26.50	$17.82	$17.82						
	SLIC 1832324_SOL7_REV1		0.4%						-$8.11	$5.52	$5.52						
	7680 Sylmar_1_NG	0.1%	0.1%					-$60.31	-$11.98	$6.19	-$29.41						
	PATH26_BG		0.1%						-$66.41	$50.25	$50.25						
	24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1	0.02%	0.1%			-$18.58	$22.52	-$70.75	-$10.86	$9.51	-$45.44						
SDG&E	SLIC 2023497 TL50003_CFERAS				4.4%												$59.76
	IVALLYBANK_XFBG				2.0%												$1.53
	22342_HDWSH _500_22536_N.GILA _500_BR_1 _1			1.3%	0.9%							-$47.85		$311.05	-$17.60		$107.78
	SLIC 2020108 IV500 NBUS_NG				0.8%												$10.59
	7830_SXCYN_CHILLS_NG			2.4%	0.6%									$37.61			$14.13
	7820_TL 230S_OVERLOAD_NG	0.2%	1.1%	0.2%	0.5%			$3.64			$50.51			$146.81			$40.48
	SLIC 1956086_ELD-MCCUL HDW				0.5%										$9.50		$20.16
	22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80				0.4%												$4.91
	SLIC 2020109 IV500 SBUS_NG				0.3%												$14.50
	SLIC 2049607 TL23050_NG_2				0.3%												$7.42
	SLIC 2023351 TL50002_PV				0.3%											-$11.59	$22.70
	SDGE_PCT_UF_IMP_BG				0.2%										-$6.88	-$6.88	$68.79
	SDGE_CFEIMP_BG	0.7%	0.1%		0.2%	-$3.91	-$3.91	$36.83	-$5.16	-$5.16	$54.25				-$57.41	-$57.41	$517.89
	SLIC 2041286 TL50003_NG				0.2%										-$3.37		$22.36
	SOUTHLUGO_RV_BG	0.1%	0.05%	0.5%	0.1%	-$74.07	$59.77	$80.34	-$5.40	$3.82	$6.26	-$192.73	$125.29	$177.63	-$107.67	$77.25	$97.26
	SCIT_BG			0.8%	0.1%							-$77.70	$50.96	$55.22	-$208.38	$142.81	$154.42
	14013_HDWSH _500_22536_N.GILA _500_BR_1 _1			1.3%								-$32.03		$231.77			
	SLIC 2034755 TL23040_NG			0.4%										$38.15			
	SLIC 1953261 ELD-LUGO PVDV			0.3%								$34.59	-$20.15	-$67.32			
	SDGE IMPORTS			0.2%								-$68.23	-$68.23	$646.45			
	HASYAMPA-NGILA-NG1		0.1%	0.2%					-$20.22		$141.43	-$27.71		$227.22			
	22844_TALEGA _230_22840_TALEGA _138_XF_1			0.1%										$78.25			
	SLIC 1883001_SDGE_OC_NG	5.3%	2.7%			-$2.64	-$0.08	$24.17	-$8.17		$68.55						
	SLIC 1884984 Gould-Sylmar		0.5%								-$57.35						
	230S overload for loss of PV		0.5%								-$51.27						
	SDGEIMP_BG		0.1%						-$17.03	-$17.03	$172.81						
	SLIC 1883001 Miguel_BKS_NG_2	1.2%	0.02%					$14.54			$3.77						
	SLIC1852244PATH26LIOSN2S	2.8%				-$7.22	$6.02	$6.02									
	SLIC1883001 MIGUEL BKS	1.4%						$20.10									
	SLIC 1883001 Miguel_BKS_NG	1.0%						$14.23									
	SOUTHEAST_IMPORTS	1.0%						$8.73									
	SLIC 1846936_23021_Outage	0.4%				-$1.78		$12.45									
	SLIC 1908221_22_23028-9_NG	0.2%						-$33.54									

Table 7.6 shows the overall impact of real-time congestion on average prices in each load area for 2012 by constraint.

Prices in the San Diego area were above the system average by about $3.73/MWh or about 11 percent. While numerous constraints drove SDG&E congestion up, congestion in other areas drove the SDG&E area prices down. For instance, the SCE_PCT_IMP_BG drove down the SDG&E area price by $1.23/MWh or 3.5 percent. However, the overall net impact of congestion caused average real-time prices in the San Diego area to be the highest of all load aggregation points within the ISO in 2012.

Congestion drove overall prices in the SCE area above system average prices by about $1.55/MWh or about 5 percent. Most of this increase 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 (SCE_PCT_IMP_BG). Two other major drivers of congestion were on constraints that had offsetting effects. The north-to-south congestion on Path 26 increased prices by about $0.38/MWh (1 percent), while congestion on the Table Mountain constraint in the PG&E area (6110_TM_BNK_FLO_TMS_DLO_NG) decreased prices by $0.38/MWh (1 percent).

Average prices in the PG&E area were lowered by congestion within the ISO system by about $1.84/MWh or 6 percent. This resulted in lower prices in the PG&E area when congestion occurred on the major constraints that limit flows in the north-to-south direction (Path26_N-S) and on constraints limiting flows into the SCE and SDG&E areas. The impact of these constraints lowered prices in the PG&E area outweighed the offsetting impact of the Table Mountain constraint (6110_TM_BNK_TMS_DLO_NG), which increased overall annual prices in the PG&E area by $0.44/MWh or about 1.5 percent.

Table 7.6 Impact of constraint congestion on overall real-time prices during all hours

	PG&E		SCE		SDG&E	
Constraint	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
SCE_PCT_IMP_BG	-$1.25	-4.23%	$1.51	4.62%	-$1.23	-3.52%
22342_HDWSH _500_22536_N.GILA _500_BR_1 _1	-$0.20	-0.67%			$1.27	3.61%
PATH26_N-S	-$0.46	-1.57%	$0.38	1.16%	$0.38	1.08%
6110_TM_BNK_FLO_TMS_DLO_NG	$0.44	1.48%	-$0.35	-1.08%	-$0.35	-1.00%
14013_HDWSH _500_22536_N.GILA _500_BR_1 _1	-$0.11	-0.36%			$0.78	2.22%
SLIC 1883001_SDGE_OC_NG	-$0.09	-0.31%			$0.78	2.24%
SOUTHLUGO_RV_BG	-$0.31	-1.03%	$0.20	0.62%	$0.28	0.81%
LBN_S-N	$0.28	0.94%	-$0.24	-0.74%	-$0.24	-0.69%
SLIC 2023497 TL50003_CFERAS					$0.67	1.90%
PATH15_S-N	$0.25	0.83%	-$0.21	-0.63%	-$0.21	-0.58%
30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2	-$0.22	-0.75%	$0.15	0.46%	$0.15	0.44%
SCIT_BG	-$0.21	-0.72%	$0.14	0.44%	$0.15	0.44%
PATH15_N-S	-$0.16	-0.55%	$0.12	0.37%	$0.12	0.35%
SDGE_CFEIMP_BG	-$0.04	-0.12%	-$0.04	-0.11%	$0.32	0.91%
SDGE IMPORTS	-$0.03	-0.11%	-$0.03	-0.10%	$0.31	0.88%
BARRE-LEWIS_NG	-$0.16	-0.55%	$0.11	0.33%	$0.01	0.01%
7820_TL 230S_OVERLOAD_NG					$0.27	0.76%
7830_SXCYN_CHILLS_NG					$0.25	0.72%
SLIC 2042305 ELD-LUGO PVDV	$0.07	0.24%	-$0.03	-0.10%	-$0.13	-0.38%
HASYAMPA-NGILA-NG1	-$0.02	-0.07%			$0.16	0.45%
T-135 VICTVLUGO_EDLG_NG	$0.06	0.21%	-$0.04	-0.11%	-$0.08	-0.23%
SLIC 1902749 ELDORADO_LUGO-1	$0.06	0.21%	-$0.04	-0.13%	-$0.07	-0.20%
PGE_IMPORT	$0.05	0.18%	-$0.05	-0.14%	-$0.05	-0.13%
SLIC1852244PATH26LIOSN2S	-$0.05	-0.17%	$0.04	0.13%	$0.04	0.12%
SLIC 1953261 ELD-LUGO PVDV	$0.04	0.12%	-$0.02	-0.06%	-$0.07	-0.20%
LOSBANOSNORTH_BG	$0.04	0.15%	-$0.04	-0.11%	-$0.04	-0.10%
SLIC-1832324-SOL7	-$0.05	-0.15%	$0.03	0.09%	$0.03	0.09%
30900_GATES _230_30970_MIDWAY _230_BR_1 _1	$0.04	0.13%	-$0.03	-0.09%	-$0.03	-0.08%
24086_LUGO _500_26105_VICTORVL_500_BR_1 _1	$0.03	0.09%	-$0.02	-0.06%	-$0.05	-0.14%
SLIC 1649002 VINCENT BANK	-$0.03	-0.12%	$0.03	0.09%	$0.02	0.06%
SLIC 1884984 Gould-Sylmar					-$0.08	-0.21%
SLIC1883001 MIGUEL BKS					$0.07	0.20%
230S overload for loss of PV					-$0.07	-0.19%
SDGE_PCT_UF_IMP_BG	-$0.01	-0.02%	-$0.01	-0.02%	$0.06	0.16%
SLIC 1356092 Serrano Valley OUT	$0.01	0.05%	-$0.04	-0.12%	$0.01	0.04%
PATH26_S-N	$0.02	0.08%	-$0.02	-0.06%	-$0.02	-0.06%
SDGEIMP_BG	-$0.01	-0.02%	-$0.01	-0.01%	$0.05	0.13%
SLIC 1883001 Miguel_BKS_NG_2					$0.04	0.13%
PATH26_BG	-$0.02	-0.06%	$0.01	0.04%	$0.01	0.04%
24137_SERRANO _230_24154_VILLA PK_230_BR_1 _1	-$0.02	-0.07%	$0.02	0.05%		
SLIC 1902748 ELDORADO_LUGO-1	$0.01	0.04%	-$0.01	-0.02%	-$0.02	-0.05%
SLIC 2034755 TL23040_NG					$0.04	0.10%
SLIC 1883001 Miguel_BKS_NG					$0.04	0.10%
SLIC 1956086_ELD-MCCUL HDW	$0.01	0.03%			$0.03	0.07%
P26_NS_LOWLIMIT	-$0.01	-0.04%	$0.01	0.03%	$0.01	0.03%
7680 Sylmar_1_NG					-$0.03	-0.08%
SLIC 2023351 TL50002_PV			-$0.01	-0.02%	$0.02	0.04%
SOUTHEAST_IMPORTS					$0.02	0.06%
SLIC 2020108 IV500 NBUS_NG					$0.02	0.06%
SLIC 1832324_SOL7_REV1	-$0.01	-0.03%	$0.01	0.02%	$0.01	0.02%
24114_PARDEE _230_24147_SYLMAR S_230_BR_2 _1		-0.01%		0.01%	-$0.01	-0.04%
SLIC 2040200 Goodrich PVD out					-$0.02	-0.04%
22844_TALEGA _230_22840_TALEGA _138_XF_1					$0.02	0.05%
Other	$0.21	0.71%			$0.10	0.29%
Total	-$1.84	-6.2%	$1.55	4.8%	$3.73	10.7%

7.4 Consistency of day-ahead and real-time congestion

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

The frequency of real-time congestion is typically lower than in the day-ahead market for several reasons. First, congestion is often managed in the day-ahead market so that the chance of congestion occurring in real-time is lower. In 2012, the potential for congestion in the day-ahead market was also increased by virtual bidding, which often resulted in net virtual demand being added to the day-ahead market. These virtual bids liquidated in real-time.

Real-time congestion can occur as system conditions change and as constraints are sometimes adjusted to account for unscheduled flows being observed in real-time and the need to maintain a reliability margin to protect against unpredictable changes in actual flows. When congestion does occur in real-time, prices are often much higher since there are fewer resources that can be quickly re-dispatched to manage the congestion. For example, hourly imports scheduled in the hour-ahead market cannot be re-dispatched in the 5-minute real-time market to reduce congestion.

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

Nevertheless, the consistency of day-ahead congestion with congestion in the hour-ahead and real-time energy markets provides a potential indicator of the degree to which the market and network model efficiently incorporate and manage similar conditions and congestion. For example, if a constraint is frequently not binding in the day-ahead market but is in the real-time market, this may warrant further review of how the constraint is modeled in the day-ahead and real-time markets.

This was a particular challenge for the ISO in 2012, as systematic differences in congestion on select constraints contributed to large real-time congestion imbalance offset costs (see Section 3.4.2 for further detail). After significant congestion differences in the third quarter, the ISO developed procedures to help operators better manage constraint modeling in the day-ahead to better reflect anticipated real-time conditions.

Figure 7.3 compares the frequency and consistency of congestion on binding constraints influencing prices at load aggregation points in 2012. Table 7.7 provides a more detailed comparison of these data.

As shown in Figure 7.3, congestion was extremely low in both the day-ahead and real-time markets on most internal constraints. On many constraints, the overall frequency of congestion in the day-ahead market tended to be slightly higher than in the real-time. This may reflect the fact that in real-time, operators can adjust constraint limits upwards to avoid congestion if actual real-time flows are observed to be lower than flows calculated by the market software. This is discussed in more detail in Section 7.5.

While the consistency of internal constraints was relatively inaccurate between the day-ahead and real-time markets, the consistency of external constraints was more accurate between the day-ahead and hour-ahead markets. Table 7.8 provides a more detailed comparison of the frequency and consistency of congestion on inter-ties with neighboring control areas in the day-ahead and hour-ahead markets, including the following:

- The Pacific AC inter-tie was congested about 42 percent in the day-ahead market but increased to nearly 49 percent in the hour-ahead market. This was primarily due to seasonal flows of hydro generation, planned and forced outages, and line maintenance coupled with unscheduled flows.
- The Nevada / Oregon Border (NOB) inter-tie was congested about 40 percent of the time in both the day-ahead and hour-ahead markets. As with the Pacific AC inter-tie, NOB was congested primarily due to seasonal flows of hydro generation, planned/forced outages and line maintenance coupled with unscheduled flows.

Figure 7.3 Consistency of internal congestion in day-ahead and real-time markets

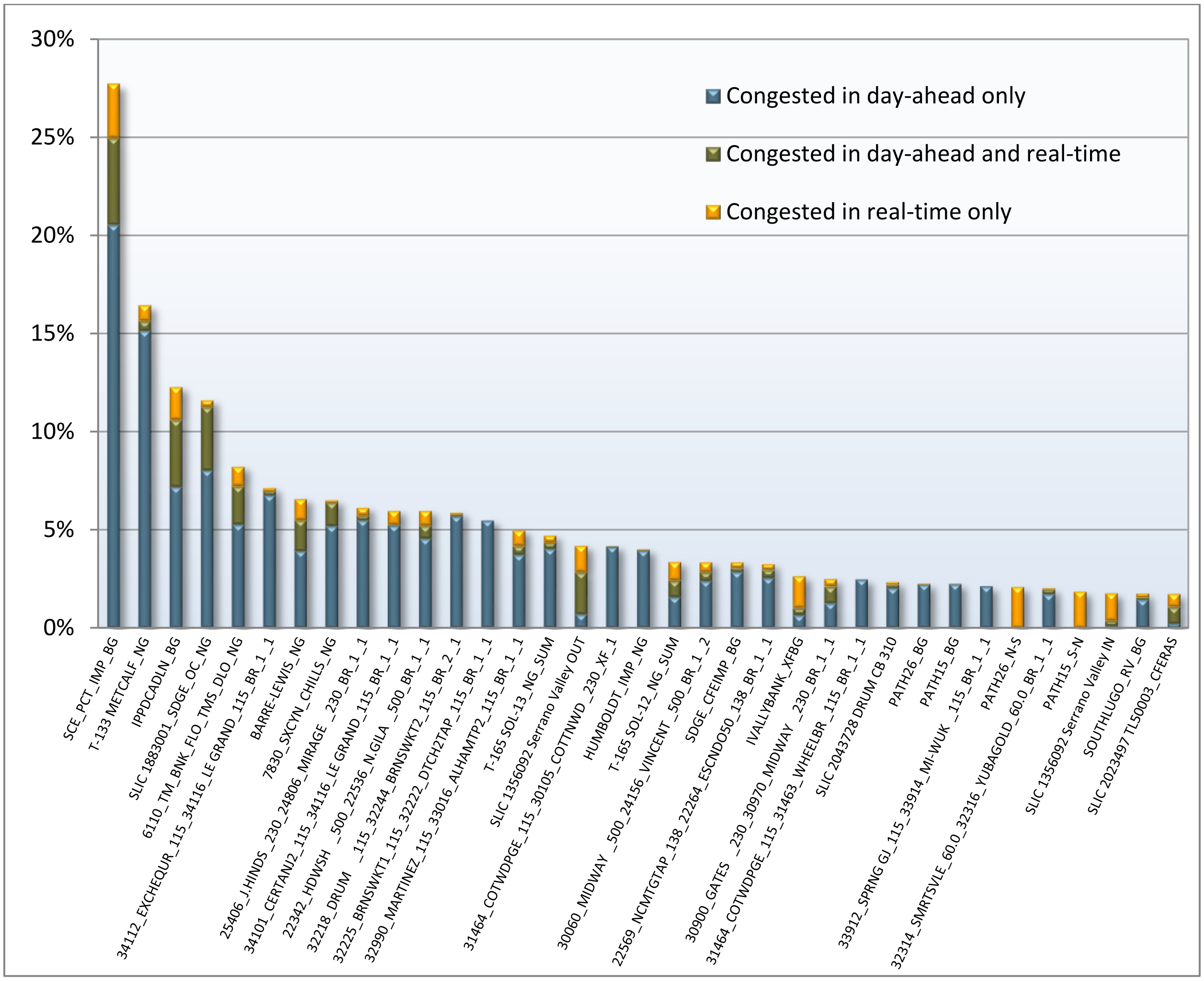


Table 7.7 Summary of day-ahead and real-time congestion on internal constraints

Constraint Name	Average Binding Limit (MW)	Total Binding Frequency in IFM	Total Binding Frequency in RTD	Binding in IFM Only		Binding in RTD Only		Binding in Both IFM and RTD		
				Frequency of Congestion	Average Shadow Price	Frequency of Congestion	Average Shadow Price	Freq. of Cong.	Avg. SP IFM	Avg. SP RTD
SCE_PCT_IMP_BG	7,086	24.9%	7.2%	20.5%	$6	2.8%	$109	4.4%	$7	$87
T-133 METCALF_NG	145	15.7%	1.3%	15.2%	$11	0.8%	$791	0.5%	$19	$714
IPPDCADLN_BG	425	10.7%	5.1%	7.2%	$3	1.7%	$71	3.4%	$3	$72
SLIC 1883001_SDGE_OC_NG	2,419	11.3%	3.6%	8.1%	$7	0.3%	$42	3.2%	$8	$42
6110_TM_BNK_FLO_TMS_DLO_NG	1,040	7.3%	3.0%	5.3%	$46	1.0%	$346	2.0%	$83	$1,019
34112_EXCHEQUR_115_34116_LE GRAND_115_BR_1 _1	56	7.0%	0.4%	6.8%	$30	0.2%	$235	0.2%	$116	$718
BARRE-LEWIS_NG	1,470	5.5%	2.7%	4.0%	$24	1.1%	$326	1.6%	$38	$191
7830_SXCYN_CHILLS_NG	249	6.5%	1.3%	5.2%	$205	0.1%	$649	1.2%	$374	$865
25406_J.HINDS _230_24806_MIRAGE _230_BR_1 _1	350	5.8%	0.7%	5.5%	$108	0.4%	$387	0.2%	$22	$349
34101_CERTANJ2_115_34116_LE GRAND_115_BR_1 _1	69	5.3%	0.8%	5.3%	$13	0.7%	$138	0.1%	$21	$145
22342_HDWSH _500_22536_N.GILA _500_BR_1 _1	1,425	5.3%	1.4%	4.6%	$40	0.8%	$1,006	0.7%	$46	$1,069
32218_DRUM _115_32244_BRNSWKT2_115_BR_2 _1	74	5.8%	0.2%	5.7%	$33	0.1%	$621	0.1%	$39	$670
32225_BRNSWKT1_115_32222_DTCH2TAP_115_BR_1 _1	74	5.5%		5.5%	$33					
32990_MARTINEZ_115_33016_ALHAMTP2_115_BR_1 _1	87	4.2%	1.3%	3.8%	$33	0.8%	$479	0.5%	$32	$475
T-165 SOL-13_NG_SUM	80	4.4%	0.7%	4.1%	$38	0.4%	$598	0.3%	$45	$765
SLIC 1356092 Serrano Valley OUT	50	2.9%	3.5%	0.7%	$16	1.4%	$18	2.2%	$11	$40
31464_COTWDPGE_115_30105_COTTNWD _230_XF_1	114	4.2%	0.0%	4.2%	$14	0.0%	$39	0.0%	$4	$48
HUMBOLDT_IMP_NG	80	4.0%	0.1%	4.0%	$8	0.0%	$705	0.0%	$9	$2
T-165 SOL-12_NG_SUM	80	2.4%	1.8%	1.6%	$182	1.0%	$855	0.9%	$235	$597
30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2	1,487	2.9%	1.0%	2.4%	$19	0.5%	$178	0.5%	$14	$248
SDGE_CFEIMP_BG	1,867	3.1%	0.5%	2.9%	$5	0.3%	$219	0.2%	$5	$42
22569_NCMTGTAP_138_22264_ESCNDO50_138_BR_1 _1	77	3.0%	0.7%	2.6%	$51	0.3%	$393	0.4%	$27	$113
IVALLYBANK_XFBG	980	1.0%	2.0%	0.7%	$9	1.7%	$32	0.4%	$12	$29
30900_GATES _230_30970_MIDWAY _230_BR_1 _1	294	2.1%	1.3%	1.3%	$29	0.4%	$175	0.9%	$44	$85
31464_COTWDPGE_115_31463_WHEELBR _115_BR_1 _1	84	2.5%	0.0%	2.5%	$24	0.0%		0.0%		
SLIC 2043728 DRUM CB 310	41	2.2%	0.3%	2.1%	$30	0.1%	$703	0.2%	$35	$804
PATH26_BG	755	2.2%	0.1%	2.2%	$3	0.1%	$77			
PATH15_BG	2,756	2.3%		2.3%	$4					
33912_SPRNG GJ_115_33914_MI-WUK _115_BR_1 _1	96	2.2%		2.2%	$5					
32314_SMRTSVLE_60.0_32316_YUBAGOLD_60.0_BR_1 _1	24	2.0%	0.3%	1.8%	$102	0.1%	$143	0.3%	$174	$238
SLIC 1356092 Serrano Valley IN	50	0.4%	1.7%	0.1%	$2	1.4%	$16	0.3%	$23	$7
SOUTHLUGO_RV_BG	4,458	1.6%	0.3%	1.5%	$25	0.2%	$654	0.1%	$28	$497
SLIC 2023497 TL50003_CFERAS	358	1.1%	1.5%	0.2%	$171	0.7%	$453	0.9%	$198	$731
22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80	846	1.4%	0.3%	1.3%	$11	0.2%	$278	0.1%	$14	$32
T-135 VICTVLUGO_EDLG_NG	2,700	0.4%	1.2%	0.4%	$13	1.2%	$354			
SLIC1852244PATH26LIOSN2S	880	1.2%	1.1%	0.4%	$3	0.3%	$14	0.8%	$4	$13
T-167 SOL 1_NG_SUM	172	1.0%	0.5%	1.0%	$24	0.4%	$968	0.0%	$522	$1,000
24601_VICTOR _230_24085_LUGO _230_BR_2 _1	490	1.0%	0.9%	0.5%	$7	0.4%	$147	0.5%	$7	$12
T-165 SOL-4_NG_SUM	199	1.2%	0.2%	1.1%	$41	0.1%	$25	0.1%	$44	$53
T-167 SOL 2_NG_SUM	172	0.6%	0.7%	0.5%	$24	0.7%	$965	0.05%	$286	$1,000
SDGEIMP_BG	2,004	1.2%	0.1%	1.2%	$8	0.1%	$431			
SLIC 1956086_ELD-MCCUL HDW	2,700	1.1%	0.3%	1.0%	$12	0.2%	$387	0.1%	$18	$428
33200_LARKIN _115_33204_POTRERO _115_BR_2 _1	151	1.1%	0.1%	1.1%	$9	0.1%	$1,000			
14013_HDWSH _500_22536_N.GILA _500_BR_1 _1	1,571	0.3%	0.9%	0.3%	$40	0.8%	$1,006	0.0%	$46	$1,069
31336_HPLND JT_60.0_31206_HPLND JT_115_XF_2	41	0.7%	0.6%	0.5%	$24	0.4%	$642	0.2%	$22	$885
SLIC 1883001 Miguel_BKS_NG_2	1,600	0.8%	0.4%	0.7%	$17	0.2%	$46	0.2%	$13	$94
31256_FLTN JT1_115_31974_MADISON _115_BR_1 _1	59	1.0%		1.0%	$12					
SLIC 2037503 Geysers SOL2	120	0.9%	0.1%	0.9%	$19	0.1%	$84	0.05%	$38	$86
31474_FRBSTNTP_115_31476_KANAKAJT_115_BR_1 _1	124	1.0%		1.0%	$19					
33020_MORAGA _115_32780_CLARMNT _115_BR_2 _1	83	0.6%	0.3%	0.6%	$69	0.3%	$950			
30550_MORAGA _230_33020_MORAGA _115_XF_3 _P	386	0.6%	0.3%	0.6%	$42	0.3%	$1,005	0.01%	$4	$950
34794_TEMBLOR _115_35061_PSEMCKIT_115_BR_1 _1	89	0.9%	0.0%	0.9%	$215	0.0%	$1,000			
SLIC 1903365_PAL_NIC_SOL2_NG	380	0.8%	0.5%	0.4%	$36	0.1%	$145	0.4%	$38	$116
SLIC 1953921 TESLA_MANTECA	173	0.7%	0.3%	0.6%	$19	0.2%	$991	0.1%	$14	$1,012
24017_BLYTHESC_161_24035_EAGLEMTN_161_BR_1 _1	181	0.8%	0.1%	0.8%	$16	0.1%	$359			
24086_LUGO _500_24085_LUGO _230_XF_1 _P	1,077	0.6%	0.3%	0.5%	$7	0.2%	$79	0.1%	$12	$105
SDGE_PCT_UF_IMP_BG	1,408	0.7%	0.1%	0.7%	$5	0.1%	$373	0.02%	$8	$2
33542_LEPRINO _115_33546_TRACY JC_115_BR_1 _1	124	0.7%	0.02%	0.7%	$351	0.02%	$1,000			

Table 7.8 Summary of day-ahead and hour-ahead congestion on inter-ties

Inter-Tie name	Full (Import) Rating (MW)	Total Binding Frequency in IFM	Total Binding Frequency in HASP	Binding in IFM Only		Binding in HASP Only		Binding in IFM and HASP		
				Binding Frequency	Avg. Shadow Price	Binding Frequency	Avg. Shadow Price	Binding Frequency	Avg. SP IFM	Avg. SP HASP
PACI_ITC	3200	41.9%	48.7%	8.7%	$10	15.5%	$11	33.2%	$11	$19
NOB_ITC	1564	39.4%	40.1%	7.7%	$9	8.4%	$18	31.7%	$13	$24
CASCADE_ITC	80	20.4%	5.4%	18.3%	$16	3.3%	$29	2.1%	$10	$30
MEAD_ITC	1460	18.0%	22.0%	7.1%	$9	11.0%	$9	10.9%	$9	$12
PALOVRDE_ITC	3328	11.5%	6.6%	6.8%	$13	1.9%	$33	4.6%	$17	$20
COTPISO_ITC	33	8.2%	2.6%	7.6%	$18	2.0%	$68	0.6%	$9	$36
ELDORADO_ITC	1655	6.3%	5.0%	3.6%	$9	2.3%	$22	2.7%	$12	$16
SUMMIT_ITC	90	2.7%	2.2%	2.2%	$27	1.8%	$82	0.5%	$24	$152
PARKER_ITC	220	0.9%	0.5%	0.8%	$47	0.4%	$82	0.1%	$33	$31
BLYTHE_ITC	218	0.7%	0.4%	0.6%	$79	0.4%	$243	0.03%	$3	$114
SILVERPK_ITC	17	0.1%	0.3%	0.1%	$14	0.2%	$151	0.02%	$49	$155

Day-ahead and real-time price differences by local capacity area

This section provides a more detailed analysis of locational price differences in the day-ahead and real-time markets as a result of congestion. Locations examined in this analysis represent the aggregation of all generation nodes within the local capacity areas used for determining local resource adequacy requirements (see Section 1.1.2). These areas have been identified as the major transmission constrained load pockets in the system.

As noted above, day-ahead and real-time prices in local capacity areas can diverge as a result of differences in congestion between these two markets. Table 7.9 and Table 7.10 show quarterly average price differences during peak off-peaks hours by local capacity area. Various shades of red in the tables indicate areas where average monthly real-time prices were higher than day-ahead prices, while various shades of blue indicate areas where average monthly real-time prices were lower.

As shown in Table 7.9 and Table 7.10, differences in day-ahead and real-time prices between local capacity areas and sub-areas within each load aggregation point varied more in 2012 than in 2011. This reflects that divergences in day-ahead and real-time prices have been primarily driven by congestion rather than specific grid and market conditions. In 2012, there were numerous specific examples of how congestion differences in prices were related to congestion, including the following:

- In SP26, the LA Basin and the San Diego-IV sub-areas primarily experienced positive price divergence in the second quarter of 2012. This was primarily due to outages of the SONGS units.
- The Sierra area within NP26 experienced price divergence in the last three quarters of 2012. This was primarily due to outages on the Drum-Rio Oso #1 115 kV line and the Drum-Grass Valley-Weimar 70 kV line.
- The Stockton sub-area was likely influenced by outages on Path 15 (Tracy-Los Banos 500 kV, Morro Bay-Midway #1 230 kV, Diablo Unit #1 and Gates-Panoche #2 line).
- The Big Creek-Ventura sub-area experienced higher real-time prices in the off-peak hours in the second quarter. This was primarily due to the planned outage on the Gould-Sylmar 220 kV line.

- In SP26, the San Diego sub-area experienced its largest price divergence in the second quarter.[106] This was primarily due to the SONGS outage and associated constraints (1883001_SDGE_OC_NG nomogram).

- The limit on the Humboldt branch group was conformed for grid reliability. This issue was outlined in an ISO technical bulletin.[107]

Table 7.9 Average difference between real-time and day-ahead price by local capacity area – peak hours

		2011				2012			
Region	**LCA (Sub-Area)**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
NP26	Humboldt	17%	-11%	-14%	-9%	2%	9%	-25%	-6%
	Sierra	13%	-11%	-7%	0%	-1%	53%	31%	-6%
	North Coast North Bay	13%	-11%	-12%	-7%	-1%	24%	-13%	-5%
	Bay Area	12%	-11%	-14%	-7%	-1%	32%	-10%	-4%
	Stockton	13%	-9%	-9%	-4%	-1%	45%	-3%	-5%
	Fresno	13%	-12%	-12%	-6%	0%	11%	-10%	-4%
SP26	Kern	12%	-11%	-13%	-8%	-2%	8%	-11%	-8%
	Big Creek-Ventura	15%	1%	-10%	-4%	1%	6%	-15%	-14%
	LA Basin	14%	-4%	-10%	-4%	3%	14%	4%	-2%
	San Diego-IV	21%	-5%	-6%	-4%	7%	13%	20%	0%
	No LCA	13%	-10%	-14%	-8%	-1%	18%	-9%	-5%

Table 7.10 Average difference between real-time and day-ahead price by local capacity area – off-peak hours

		2011				2012			
Region	**LCA (Sub-Area)**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
NP26	Humboldt	25%	27%	-5%	-6%	-8%	-16%	-7%	2%
	Sierra	21%	34%	6%	-3%	-6%	14%	5%	4%
	North Coast North Bay	20%	33%	1%	-4%	-6%	-10%	-8%	3%
	Bay Area	21%	33%	1%	-4%	-6%	-8%	-9%	3%
	Stockton	21%	30%	6%	-4%	-6%	12%	-1%	3%
	Fresno	21%	34%	2%	-4%	-6%	-4%	-6%	4%
SP26	Kern	-21%	-34%	-1%	-6%	-6%	-5%	-7%	0%
	Big Creek-Ventura	24%	28%	-1%	-5%	0%	45%	7%	8%
	LA Basin	25%	29%	-2%	-5%	-4%	23%	12%	12%
	San Diego-IV	12%	12%	12%	12%	-7%	-3%	16%	-1%
	No LCA	22%	22%	22%	22%	-6%	1%	-1%	5%

[106] In September 2010, the ISO automated the enforcement of an under-frequency import limit in the market model to meet the 25 percent minimum generation requirement for the local San Diego area *Technical Bulletin 2010-09-03 Local San Diego Area 25% Minimum, Generation Requirement,* September 21, 2010: http://www.caiso.com/Documents/TechnicalBulletin-LocalSanDiegoArea25PercMinimumGenerationRequirement.pdf.

[107] In December 2010, the ISO automated the enforcement of an under-frequency import limit in the market model to meet the minimum generation requirement for the local Humboldt area *Technical Bulletin 2010-11-01 Minimum Generation Online Commitment in Humboldt Area*, November 24, 2010: http://www.caiso.com/2858/2858789a3c1c0.pdf.

7.5 Conforming constraint limits

Constraint limits in the market software are sometimes adjusted or *conformed* to account for differences in flows calculated by the market model and actual flows observed in real-time. The two most common reasons to adjust transmission limits are the following:

- Achieve greater alignment between the energy flows calculated by the market software and those observed or predicted in real-time operation across various paths. For example, operators sometimes adjust operating limits upward to avoid *phantom congestion* in the day-ahead or real-time market. Phantom congestion refers to cases when congestion occurs in the market model when the actual physical flows are below the limit in the market model. In other cases, operators adjust constraints in the day-ahead market to mitigate the potential for congestion occurring in the real-time market.

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

Table 7.11 lists constraints conformed in the real-time market by percent conformed and averages for megawatt bias, limit and conformed limit, and shadow prices. This table only presents the statistics calculated for intervals in which the conforming action moved the effective limit from the actual limit as shown in Table 7.11 below:

- Out of the 67 constraints presented, only 17 (25 percent of the constraints) were conformed greater than 9 percent of the time in 2012, of which 3 were conformed greater than 49 percent of the time. Nine of the conformed constraints in 2012 were adjusted in real-time more than 20 percent of the time.

- Out of the 67 constraints about 9 percent – or 6 constraints – were conformed in the upward direction to avoid congestion that was not actually occurring based on observed flows.

- Only 24 percent or 16 constraints were conformed only in the downward direction, mainly for transmission management. Operators tend to conform down the operating limit of these major transmission lines to maintain an adequate reliability margin. The margin ensures the flows stay within the lines' operating limits, even when sudden unpredictable flow changes occur in real-time.

There was strong consistency in conforming between the hour-ahead and real-time markets in both frequency and level of adjustment. Table 7.12 compares the consistency of conforming limits in the real-time market to the hour-ahead market for every interval. This analysis indicates conforming performed in these markets was consistently applied across most constraints. Only 3 constraints had differences in market conformance limits of greater than 1 percent.

Table 7.11 Real-time congestion and conforming of limits by constraint

Flowgate name	Conformed downward							Conformed upward							
	Conformed interval	Average percent of conformed limit	Average conformed limit	Average MW Limit	Average MW bias	Congested intervals	Average shadow price	Conformed interval	Average percent of conformed limit	Average conformed limit	Average MW Limit	Average MW bias	Congested intervals	Average shadow price	Conformed intervals
LBS_WITH_PUMPS_NG	50%	80%		4,000				10%	105%		4,000				61%
T-165 SOL-4_NG_SUM	56%	97%	180	205	-25	0.3%	$261	0%	107%		205				56%
LBN_S-N	35%	90%	1,230	3,800	-2,570	0.1%	$875	13%	142%		3,800				49%
T-133 SOL-2_NG_SUM	43%	80%		449											43%
7820_TL 230S_OVERLOAD_NG	36%	65%	257	400	-143	0.5%	$591	0%	102%		400				36%
T-133 SOL-2_NG_WIN	25%	95%		518				0%	101%		518				25%
SLIC 1883001_SDGE_OC_NG	23%	97%	2,290	2,450	-160	2.2%	$35	1%	106%	2,580	2,450	130	0.03%	$3	24%
34101_CERTANJ2_115_34116_LE GRAND_115_BR_1_1	0%	80%	68	87	-20	0.1%	$175	23%	160%	75	50	9	0.04%	$176	23%
30500_BELLOTA _230_38206_COTTLE A_230_BR_1_1	0%	50%	296	591	-296	0.002%	$1,097	22%	267%	295	122	58	0.02%	$683	22%
PATH15_S-N	19%	47%	2,328	5,400	-3,072	0.9%	$56								19%
SCE_PCT_IMP_BG	9%	95%	7,044	7,834	-547	2.2%	$90	10%	105%	7,040	6,938	204	0.23%	$157	19%
PATH15_BG								19%	200%		1,376				19%
7830_SXCYN_CHILLS_NG	17%	97%	234	251	-17	0.5%	$980	1%	111%	256	251	5	0.01%	$120	18%
T-165 SOL-3_NG_NORAD	18%	94%		100											18%
T-165 SOL-8_NG_SUM	17%	81%		475											17%
T-165 SOL-6_NG_WIN	0%	88%		36				14%	106%		36				14%
PATH26_N-S	11%	49%	716	4,000	-3,284	1.3%	$66	0%	200%		4,000				11%
32990_MARTINEZ_115_33016_ALHAMTP2_115_BR_1_1	1%	90%	88	98	-10	0.5%	$732	9%	122%	93	77	11	0.40%	$529	9%
PATH26_BG	0%	82%	3,000	3,670	-940	0.03%	$113	8%	207%		1,036				8%
BARRE-LEWIS_NG	4%	96%	1,406	1,470	-64	1.1%	$196	3%	113%	1,576	1,470	106	0.05%	$1,906	8%
22076_BORDER _69.0_22080_BORDERTP_69.0_BR_1_1	7%	37%	137	369	-233	0.004%	$1,000								7%
6110_TM_BNK_FLO_TMS_DLO_NG	6%	88%	870	1,066	-196	1.5%	$1,126	1%	106%	1,092	1,066	26	0.03%	$163	7%
IVALLYBANK_XFBG	4%	83%				1.3%	$34	3%	195%				0.001%	$12	7%
T-135 VICTVLUGO_EDLG_NG	3%	92%	2,433	2,714	-267	0.4%	$438	2%	179%		2,828				5%
SLIC 1356092 Serrano Valley OUT	5%	42%	17	50	-33	2.6%	$34	0%	230%	73	50	23	0.09%	$21	5%
22708_SANLUSRY_69.0_22712_SANLUSRY_138_XF_3	0.1%	76%	149	200	-17	0.1%	$51	4%	149%	156	103	36	0.03%	$87	4%
22342_HDWSH _500_22536_N.GILA _500_BR_1_1	4%	86%	1,594	1,886	-400	0.6%	$1,080	0%	923%	1,647	177	1,475	0.001%	$405	4%
22569_NCMTGTAP_138_22264_ESCNDO50_138_BR_1_	3%	94%	80	83	-4	1.1%	$311	2%	124%	81	67	4	0.01%	$19	4%
NEWMELONP_BG								4%	188%	384	215	135	0.04%	$1,007	4%
SLIC 1902749 ELDORADO_LUGO-1	4%	94%	2,515	2,700	-185	0.7%	$165								4%
T-133 METCALF_NG	3%	86%	124	145	-21	0.3%	$458	0%	118%		145				4%
TMS_DLO_NG	4%	49%	154	472	-318	0.1%	$1,076								4%
PATH26_S-N	4%	30%	300	3,000	-2,700	0.1%	$62	0%	171%		3,000				4%
30750_MOSSLD _230_30790_PANOCHE _230_BR_1_1	0.1%	76%	318	433	-78	0.1%	$84	3%	149%		207				3%
T-165 SOL-12_NG_SUM	3%	88%	70	80	-10	1.3%	$753	0%	115%		80				3%
SLIC 1883001 Miguel_BKS_NG	3%	89%	1,163	1,400	-237	0.3%	$70								3%
30055_GATES1 _500_30900_GATES _230_XF_11_P	2%	94%	1,072	1,141	-70	0.3%	$39	1%	104%	1,068	1,030	36	0.02%	$14	3%
SLIC 2042305 ELD-LUGO PVDV	3%	93%	2,451	2,700	-249	0.4%	$486	0%	102%		2,700				3%
SLIC1852244PATH26LIOSN2S	3%	65%	520	880	-360	0.7%	$13	0%	105%		880				3%
SLIC 2043728 DRUM CB 310	3%	54%	26	57	-31	0.2%	$820								3%
SLIC 2023497 TL50003_CFERAS	2%	76%	286	382	-96	1.1%	$660	0%	194%		382				3%
30900_GATES _230_30970_MIDWAY _230_BR_1_1	2%	91%	296	326	-34	0.8%	$128	0%	105%		281				2%
SLIC1852244PATH26LIOSS2N	2%	63%	687	925	-238	0.01%	$2								2%
14013_HDWSH _500_22536_N.GILA _500_BR_1_1	2%	76%	1,558	2,072	-648	0.3%	$1,021								2%
34157_PANOCHET_115_34156_MENDOTA _115_BR_1_	0.2%	68%	212	289	-422	0.002%	$641	2%	120%	117	108	11	0.004%	$1,000	2%
22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80	2%	73%	754	983	-339	0.2%	$209	0%	111%	869	786	57	0.001%	$23	2%
IID-SCE_BG								2%	200%	392	291	56	0.01%	$434	2%
SLIC 1903365_PAL_NIC_SOL2_NG	2%	93%	345	380	-35	0.4%	$117								2%
33020_MORAGA _115_32780_CLARMNT _115_BR_2_1								2%	119%	93	76	6	0.13%	$980	2%
T-165 SOL-13_NG_SUM	1%	89%	66	80	-14	0.3%	$691	0%	109%		80				2%
32780_CLARMNT _115_32782_STATIN D_115_BR_2_1								2%	120%	195	164	32	0.00%	$462	2%
30060_MIDWAY _500_24156_VINCENT _500_BR_1_2	1%	94%	1,490	1,591	-138	0.2%	$99	1%	109%	1,483	1,371	84	0.05%	$307	2%
30550_MORAGA _230_33020_MORAGA _115_XF_3_P	0%	93%	396	426	-22	0.1%	$1,140	1%	106%	397	374	12	0.01%	$1,000	1%
30875_MC CALL _230_30880_HENTAP2 _230_BR_1_1	0.3%	86%	328	381	-58	0.01%	$33	1%	121%	327	300	65	0.001%	$76	1%
SLIC 1956086_ELD-MCCUL EL-LU	1%	90%	2,313	2,700	-387	0.02%	$265								1%
PATH15_N-S	1%	73%	847	1,275	-428	0.4%	$73	0%	142%		1,275				1%
34112_EXCHEQUR_115_34116_LE GRAND_115_BR_1_1	0.2%	95%	62	61	-3	0.0%	$43	1%	120%	56	48	8	0.003%	$865	1%
PGE_IMPORT	1%	51%	3,378	8,000	-4,622	0.1%	$141								1%
24601_VICTOR _230_24085_LUGO _230_BR_2_1	1%	90%	485	543	-58	0.5%	$27	0%	116%	491	433	15	0.04%	$11	1%
24086_LUGO _500_24085_LUGO _230_XF_1_P								1%	104%	1,100	1,053	42	0.09%	$70	1%
SLIC 1902748 ELDORADO_LUGO-1	1%	97%	2,579	2,700	-121	0.2%	$42	0%	106%		2,700				1%
HASYAMPA-NGILA-NG1	1%	64%	801	1,550	-749	0.1%	$821								1%
25406_J.HINDS _230_24806_MIRAGE _230_BR_1_1	1%	90%	349	392	-68	0.2%	$282	0%	142%	356	262	71	0.001%	$1,000	1%
SLIC 1883001 Miguel_BKS_NG_2	1%	90%	1,403	1,600	-197	0.3%	$69								1%
32314_SMRTSVLE_60.0_32316_YUBAGOLD_60.0_BR_1_	0.2%	94%	24	26	-2	0.02%	$841	1%	134%	23	18	6	0.01%	$798	1%
SLIC 2040200 Goodrich PVD out	1%	96%	2,533	2,700	-167	0.02%	$599	0%	103%		2,700				1%
SLIC 1956086_ELD-MCCUL HDW	1%	90%	2,361	2,700	-339	0.1%	$540	0%	101%		2,700				1%

Table 7.12 Conforming of constraint limits in hour-ahead and real-time markets

Flowgate name	Conforming in RTD	Conforming Level Match in RTD and HASP	Conforming Level Does not Match in RTD and HASP	Avg. Conforming Level Match in RTD and HASP (%)	Avg. Conforming Level Does not Match in RTD and HASP (%)
SCE_PCT_IMP_BG	17.9%	14.8%	3.1%	101	96
34101_CERTANJ2_115_34116_LE GRAND_115_BR_1 _1	8.3%	8.2%	0.1%	147	109
IVALLYBANK_XFBG	6.0%	4.7%	1.3%	144	90
30500_BELLOTA _230_38206_COTTLE A_230_BR_1 _1	4.9%	4.8%	0.1%	193	151
22342_HDWSH _500_22536_N.GILA _500_BR_1 _1	4.4%	2.6%	1.8%	88	84
32990_MARTINEZ_115_33016_ALHAMTP2_115_BR_1 _1	3.5%	3.4%	0.1%	117	112
22256_ESCNDIDO_69.0_22264_ESCNDO50_138_XF_50	3.1%	3.1%	0.0%	150	150
SCIT_BG	3.1%	2.8%	0.3%	85	79
NEWMELONP_BG	2.7%	2.6%	0.1%	182	176
30750_MOSSLD _230_30790_PANOCHE _230_BR_1 _1	2.5%	2.3%	0.1%	147	91
30900_GATES _230_30970_MIDWAY _230_BR_1 _1	2.5%	1.6%	0.9%	91	91
22708_SANLUSRY_69.0_22712_SANLUSRY_138_XF_3	2.4%	2.1%	0.3%	142	130
30055_GATES1 _500_30900_GATES _230_XF_11_P	2.3%	1.6%	0.7%	97	94
14013_HDWSH _500_22536_N.GILA _500_BR_1 _1	2.0%	1.3%	0.7%	78	73
22569_NCMTGTAP_138_22264_ESCNDO50_138_BR_1 _1	2.0%	1.4%	0.6%	113	105
22356_IMPRLVLY_230_22360_IMPRLVLY_500_XF_80	1.8%	1.3%	0.5%	70	83
30060_MIDWAY _500_24156_VINCENT _500_BR_1 _2	1.5%	1.4%	0.1%	102	102
30550_MORAGA _230_33020_MORAGA _115_XF_3 _P	1.4%	1.4%	0.0%	106	100
SDGE_CFEIMP_BG	1.4%	1.1%	0.3%	116	77
34157_PANOCHET_115_34156_MENDOTA _115_BR_1 _1	1.3%	1.3%	0.03%	113	81
30500_BELLOTA _230_30505_WEBER _230_BR_1 _1	1.3%	1.3%	0.01%	193	146
30875_MC CALL _230_30880_HENTAP2 _230_BR_1 _1	1.3%	1.1%	0.2%	119	90
24601_VICTOR _230_24085_LUGO _230_BR_2 _1	1.2%	1.0%	0.2%	95	95
33020_MORAGA _115_32780_CLARMNT _115_BR_2 _1	1.2%	1.2%	0.03%	116	114
34112_EXCHEQUR_115_34116_LE GRAND_115_BR_1 _1	1.2%	1.2%	0.03%	116	111
24017_BLYTHESC_161_24035_EAGLEMTN_161_BR_1 _1	1.1%	1.1%	0.02%	117	108
25406_J.HINDS _230_24806_MIRAGE _230_BR_1 _1	1.1%	0.9%	0.2%	111	95
PATH15_BG	1.0%	1.0%	0.003%	200	200
33378_WTRSHTPA_60.0_33380_JEFFERSN_60.0_BR_1 _1	1.0%	1.0%	0.01%	190	173

Congestion in the day-ahead market is reviewed by ISO operators on a regular basis to determine the need for conforming the constraints' operating limits. Compared to previous years, the day-ahead market constraint limits were conformed at a greater frequency resulting in a greater percent of congested intervals in 2012. This is likely due to procedural changes as a result of systematic modeling differences between the day-ahead and real-time markets contributing to high real-time uplifts (see Section 3.4).

Table 7.13 lists all internal constraints conformed in the day-ahead market. In previous years, the majority of the conformed hours were conformed upward to account for transmission outages and inconsistencies between the market software and actual values. In 2012, the majority of the conformed hours were conformed downward to better align the day-ahead modeling with anticipated real-time modeling.

Table 7.13 Conforming of internal constraints in day-ahead market

Flowgate name	Conformed downward							Conformed upward							Conformed intervals
	Conformed interval	Average percent of conformed limit	Average conformed limit	Average MW Limit	Average MW bias	Congested intervals	Average shadow price	Conformed interval	Average percent of conforme	Average conformed limit	Average MW Limit	Average MW bias	Congested intervals	Average shadow price	
T-165 SOL-4_NG_SUM	57%	97%	199	205	-6	0.02%	$37								57%
T-133 SOL-2_NG_SUM	44%	80%		449											44%
22342_HDWSH _500_22536_N.GILA _500_BR_1 _1	36%	89%	1,610	1,820	-222	0.02%	$43								36%
T-133 SOL-2_NG_WIN	25%	95%		518											25%
SLIC 1883001_SDGE_OC_NG	23%	98%	2,408	2,450	-42	0.01%	$7	1%	106%	2,608	2,450	158	0.03%	$3	24%
SCE_PCT_IMP_BG	19%	94%	6,917	7,370	-420	0.01%	$7								19%
T-165 SOL-8_NG_SUM	18%	81%		475											18%
T-165 SOL-3_NG_NORAD	18%	94%		100											18%
7830_SXCYN_CHILLS_NG	16%	98%	245	251	-6	0.02%	$277								16%
T-165 SOL-6_NG_WIN								14%	106%		36				14%
22569_NCMTGTAP_138_22264_ESCNDO50_138_BR_1	11%	95%	75	78	-4	0.01%	$39								11%
SLIC 1979766 VACA BNK2/2A	7%	100%		462											7%
SLIC 2043728 DRUM CB 310	2%	70%	40	57	-17	0.01%	$31								2%
PATH15_BG	2%	98%	2,993	3,033	-64	0.01%	$2								2%
SLIC-1939924-ENCINA-GEN	1%	53%	200	360	-160	0.02%	$4								1%
IPPUTAH_MSL	0.3%	95%	191	202	-11	0.01%	$55	0.3%	103%	191	185	6	0.02%	$12	1%
SLIC 2023497 TL50003_CFERAS_DAM	0.3%	48%	382	800	-418	0.01%	$68	0.2%	1250%		800				1%
SLIC 2034795 BC1 - Rector								0.5%	101%		395				0.5%
SDGE_PCT_UF_IMP_BG	0.3%	95%		1,653											0.3%
SLIC1832262PATH26LIOSS2N								0.3%	514%		180				0.3%
SLIC1832262PATH26LIOSN2S								0.3%	733%	880	120	760	0.01%	$4	0.3%
SCIT_BG	0.3%	95%													0.3%
6110_TM_BNK_FLO_TMS_DLO_NG	0.3%	90%	959	1,066	-107	0.02%	$65								0.3%
SLIC 2050390_BARRE-LEWIS_NG								0.1%	212%	1470	694	776	0.001%	$11	0.1%

7.6 Constraints with large impacts on day-ahead and real-time prices

This section provides a brief description of selected constraints with large impacts on congestion in 2012. Many of these constraints were active primarily in the third quarter.

- ***San Diego import nomograms.*** The SONGS outages of over 2,000 MW of baseload capacity had a significant impact on congestion in the San Diego and Southern California Edison areas. In spring 2012, the ISO initiated a number of steps to contend with this situation, including creation of, and adjustment to existing, constraints.[108] The 1883001_SDGE_OC_NG nomogram was created to deal with the SONGS outages. It was removed as a monitored constraint with the addition of the Sunrise Powerlink in mid-June.[109] This addition increased SDG&E import capabilities, negating the need for the nomogram.

- ***Hoodoo Wash – North Gila 500 kV nomograms.*** These nomograms are for Hoodoo Wash to North Gila 500 kV lines, which are a segment of the Southwest Powerlink (SWPL), a major transmission corridor (500 kV) that runs from the Palo Verde/Hassayampa Substation in Arizona to the Miguel Substation in San Diego County, California. It is jointly owned by San Diego Gas & Electric Company (SDG&E), Arizona Public Service Company (APS) and Imperial Irrigation District (IID). Improved analysis and detailed modeling was performed in 2012 around this constraint. This analysis resulted in the development of new nomograms to better represent actual system flow and protect for the low voltage loss of Hassayampa to North Gila. The ISO included these new constraints in the model in the middle of the year. Shortly after deploying the new constraints, the ISO revised the constraints to better model real-time conditions.

[108] For example, Huntington Beach 3 and 4 returned to service, the Barre-Ellis transmission upgrade was accelerated and the completion of the Sunrise Powerlink was also accelerated. Additional detail can be found in the following ISO summer preparedness document: http://www.caiso.com/Documents/BriefingSummer2012OperationsPreparedness-Presentation-Mar2012.pdf.

[109] The Sunrise Powerlink transmission project constructed a 117-mile long 500 kV power line to bring 1,000 MW of renewable energy from the Imperial Valley to the San Diego area. It was one of the most important transmission additions in 2012.

- ***Sycamore Canyon – Carlton Hills nomogram.*** This nomogram was affected when the new Sunrise Powerlink 500 kV line came into service, which increased transfer capability and voltage stability, and improved San Diego import capability. This nomogram is for the Sycamore Canyon to Carlton Hills 138 kV line in San Diego, California. With the addition of the new Sunrise line, there is a possible potential for overload on the Sycamore Canyon to Carlton Hills 138 kV line due to the loss of the Imperial Valley to Miguel 500 kV line. This nomogram protects the Sycamore Canyon to Carlton Hills 138 kV line by limiting the flows on other transmission lines.

- ***Table Mountain Bank nomogram.*** This nomogram is to protect the transformer bank connecting Table Mountain with Tesla, Vaca and Rio Oso. Specifically, the 6110_TM_BNK_FLO_TMS_DLO_NG nomogram is for the Table Mountain 500/230 kV transformer for the double loss of the 500 kV lines Table Mountain to Tesla and Table Mountain to Vaca. One of the key reasons for congestion was related to Northern California dispatch (which includes Northern California Hydro, Hatchet Ridge wind farm North of Round Mountain and redispatched generation in the Feather River area) and the Caribou (Chips) fire. Other reasons for congestion on this nomogram include unscheduled north-to-south flows from the Pacific Northwest on the California-Oregon Inter-tie (COI), which, combined with the Caribou fire, created the need for adjustments to line limits and generation re-dispatch.

Frequently, the actual real-time transmission conditions would differ from modeled day-ahead conditions on many of these transmission elements, particularly with respect to unscheduled flows.[110] When this occurred, ISO operators often conformed the modeled transmission limits to better align market flows with actual flows. When these limits were changed, this often resulted in high shadow prices and market prices in real-time. These high prices were mostly the result of a limited set of resources available to resolve the transmission situation in the real-time dispatch.[111]

To better anticipate expected real-time conditions and to better align resources to resolve the transmission constraints, the ISO made adjustments to its process in mid-August to allow for the adjustment of day-ahead and hour-ahead limits to better reflect anticipated conditions in real-time. DMM was supportive of this change as it would allow the day-ahead to better reflect expected conditions in real-time. This, in turn, would allow for better unit commitment and inter-tie scheduling to resolve the real-time conditions.

7.7 Congestion revenue rights

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

- The number and volume of congestion revenue rights awarded in 2012 remained relatively consistent when compared to 2011.

[110] In particular, unscheduled flows greatly affected the Hoodoo Wash to North Gila and the Table Mountain to Tesla bank nomograms.

[111] The ability to resolve constraints in the real-time market is more limited than in the day-ahead and hour-ahead markets. For instance, unit commitment and inter-tie schedule adjustments are not available in the 5-minute real-time market to relieve congestion, only re-dispatch.

- A $24 million revenue surplus existed at the end of 2012, which will be allocated to measured demand. While revenue deficiencies occurred in the fourth quarter, these were offset by additional revenues collected during the first three quarters.
- Average profitability of all congestion revenue rights was about $0.40/MW in 2012, compared to about $0.07/MW in 2011. This increase was driven largely by higher levels of congestion related to the SONGS outage.
- The most consistently profitable congestion revenue rights were those in the same direction of prevailing congestion patterns. Between 2009 and 2011, congestion revenue rights in the counter direction of prevailing congestion were more profitable.[112]

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 the peak or off-peak hours as defined by Western Electricity Coordinating Council guidelines.[113]
- ***Megawatt quantity —*** This is the volume of congestion revenue rights allocated or purchased. For instance, one megawatt of congestion revenue rights with a January 2012 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.

[112] Participants pay for prevailing congestion revenue rights in the auction and receive payment when congestion occurs. Participants are paid to receive counter-flow congestion revenue rights in the auction and pay when congestion occurs in the day-ahead market.

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

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

- 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.

A more detailed explanation of the congestion revenue right processes is provided in the ISO's *2012 Annual Market Performance CRR Report.*[114]

Market resultsFigure 7.4 and Figure 7.5 show the monthly average amount of the various types of congestion revenue rights awarded within a quarter since 2010 for peak and off-peak hours, respectively. The following is shown in these figures:

- The total volume of congestion revenue rights remained relatively consistent in 2012 compared to 2011. The short-term auction for 2012 was conducted in November 2011.
- During 2012, rights purchased through the monthly auction remained relatively consistent through the first three quarters with a slight uptick in the last quarter. All other processes for acquiring congestion revenue rights for 2012 were completed in 2011. Therefore, market participants wanting to increase participation in the congestion revenue rights market for 2012 had to do so through the monthly processes.
- The overall amount of rights purchased through the monthly auction in 2012 also remained stable compared to 2011 levels. This reflects the fact that participants wanting to procure rights for 2012 relied more heavily on the short-term auction for seasonal congestion revenue rights conducted in November 2011.
- 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. In 2012, the monthly allocation processes changed, which resulted in more monthly allocations in 2012 compared to 2011.[115]

[114] For further details, please see the following: http://www.caiso.com/Documents/Annual2012CRRMarketReport.pdf.

[115] There are now two mechanisms used to adjust the CRR system capacity made available in the monthly allocation and auction. The first mechanism is the global derate factor (GDF), often referred to as global scaling factor, which is only applied to line and transformer limits. The second and new mechanism is the local derate factor (LDRF), which is applied to individual interface/nomogram constraints. The local derate factor allows for more focused de-rates on specific interfaces compared to the global derate factor which, prior to 2012, was applied across all interfaces in addition to line and transformer limits. Additional information can be found in the *2011 CRR Enhancements Revised Draft Final Proposal*, May 20, 2011: http://www.caiso.com/Documents/RevisedDraftFinalProposal-CongestionRevenueRights2011Enhancements.pdf and in the Business Practice Manual for Congestion Revenue Rights, version 14, last revised on December 3, 2012: http://bpmcm.caiso.com/BPM%20Document%20Library/Congestion%20Revenue%20Rights/BPM_for_CRR_2012_12_03_V14_clean.doc.

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

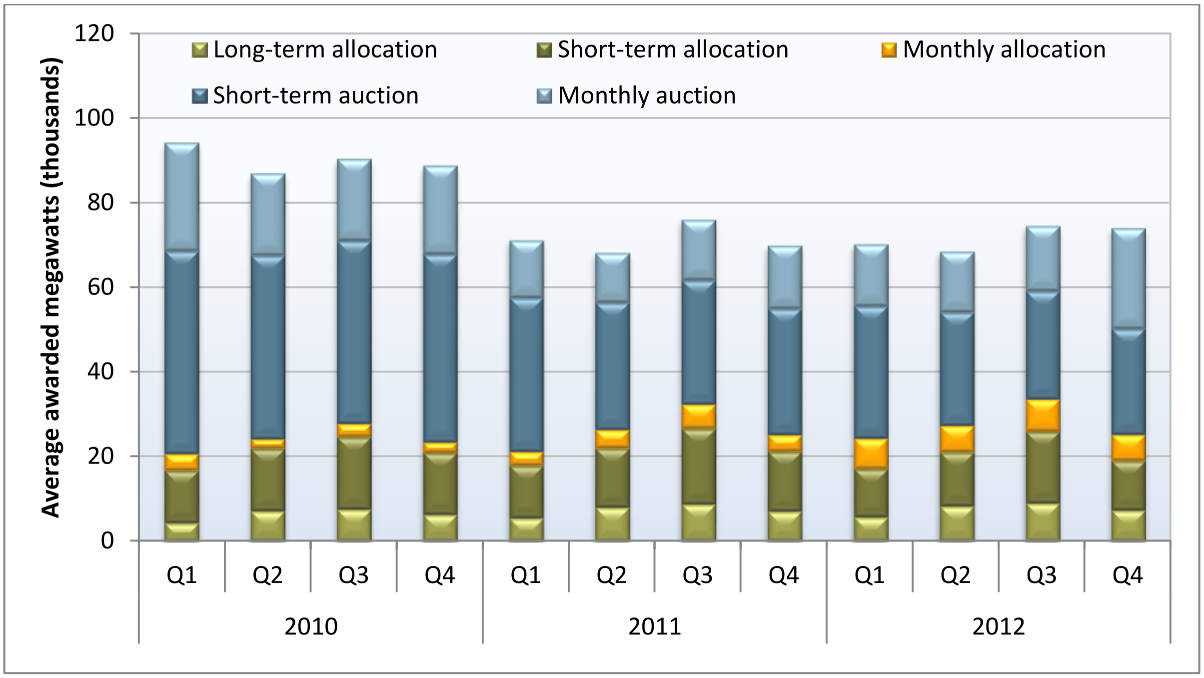


Figure 7.5 Allocated and awarded congestion revenue rights (off-peak hours)

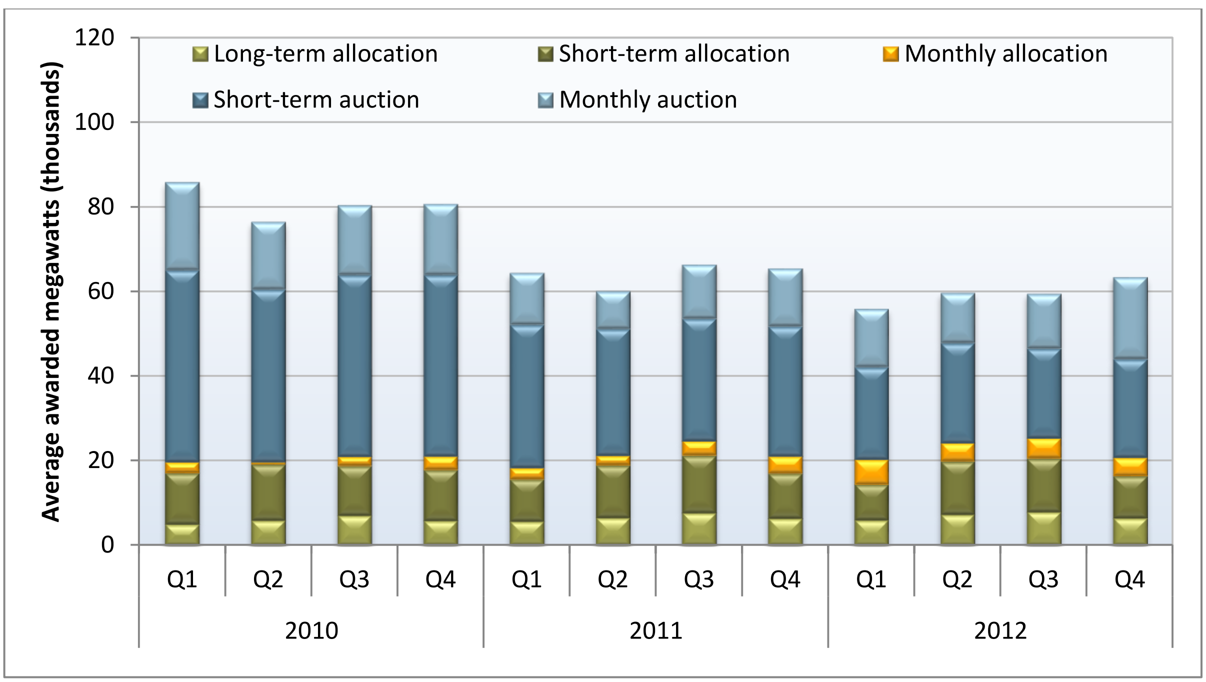


Figure 7.6 and Figure 7.7 provide a high level summary of the market clearing quantities and prices in the auctions for seasonal and monthly congestion revenue rights for each quarter over the last three years. Prices in these figures represent the price per megawatt-hour for each congestion revenue right. This is equal to the market clearing price divided by the total hours for which the right is valid. This allows the seasonal rights to be grouped and compared with monthly rights.

The same general trends occur for both peak and off-peak hours. On average, roughly 35 percent of 2012 awarded megawatts had a clearing price of between $0/MWh and $0.10/MWh. Figure 7.6 and Figure 7.7 show consistency in the average number of awarded congestion revenue rights and average awarded megawatts from 2011 to 2012.

The average monthly megawatts awarded between $0 and $0.10/MWh decreased by more than 35 percent from 2011 to 2012 for both peak and off-peak congestion revenue rights. There were two main reasons for this decrease:

- A decrease in bids submitted for the short-term auction process resulted in less awarded congestion revenue rights and cleared megawatts, most notably priced between $0/MWh and $0.10/MWh.
- Less congestion revenue rights in the counter-flow direction cleared. Thus, this did not allow more congestion revenue rights in the positive prevailing direction to also clear.

Although the price of different congestion revenue rights varies widely, the price of most rights was within ±$0.10 MWh. In addition, there appears to be an on-peak trend towards greater awarded megawatts in clearing prices greater than $0.25/MWh. This trend was most pronounced in the fourth quarter of 2012.

Figure 7.6 Auctioned congestion revenue rights by price (peak hours)

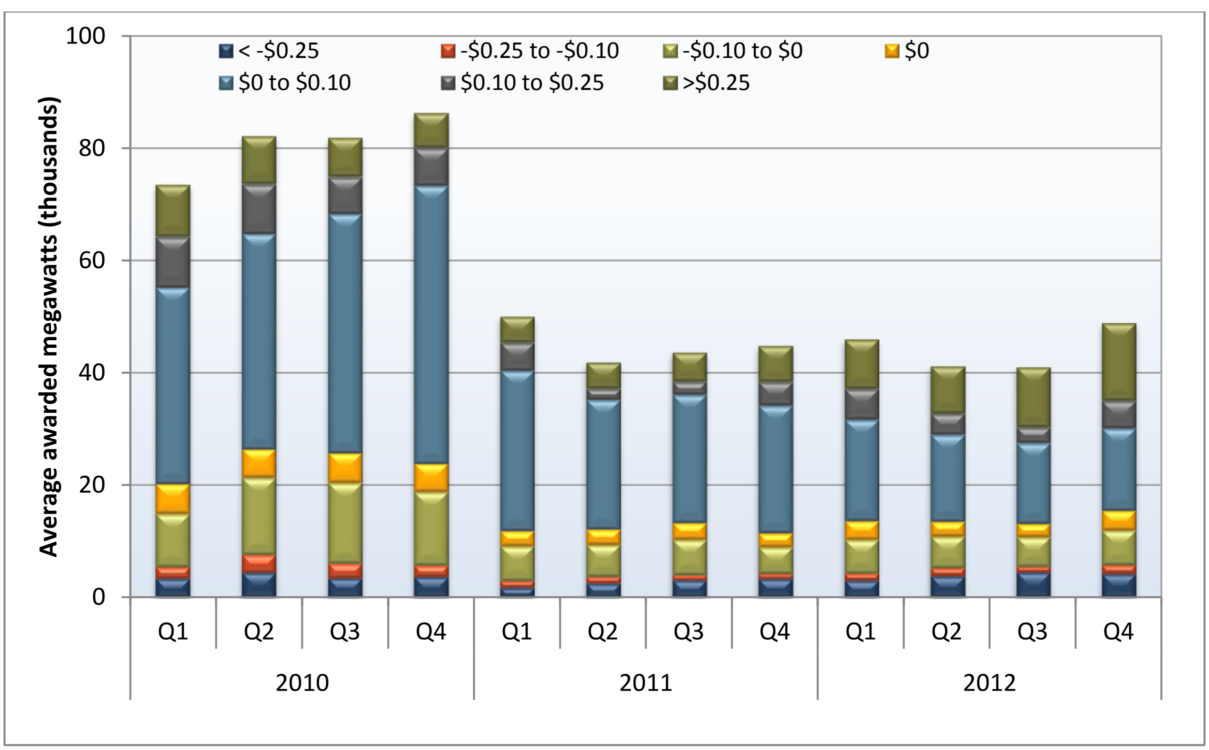
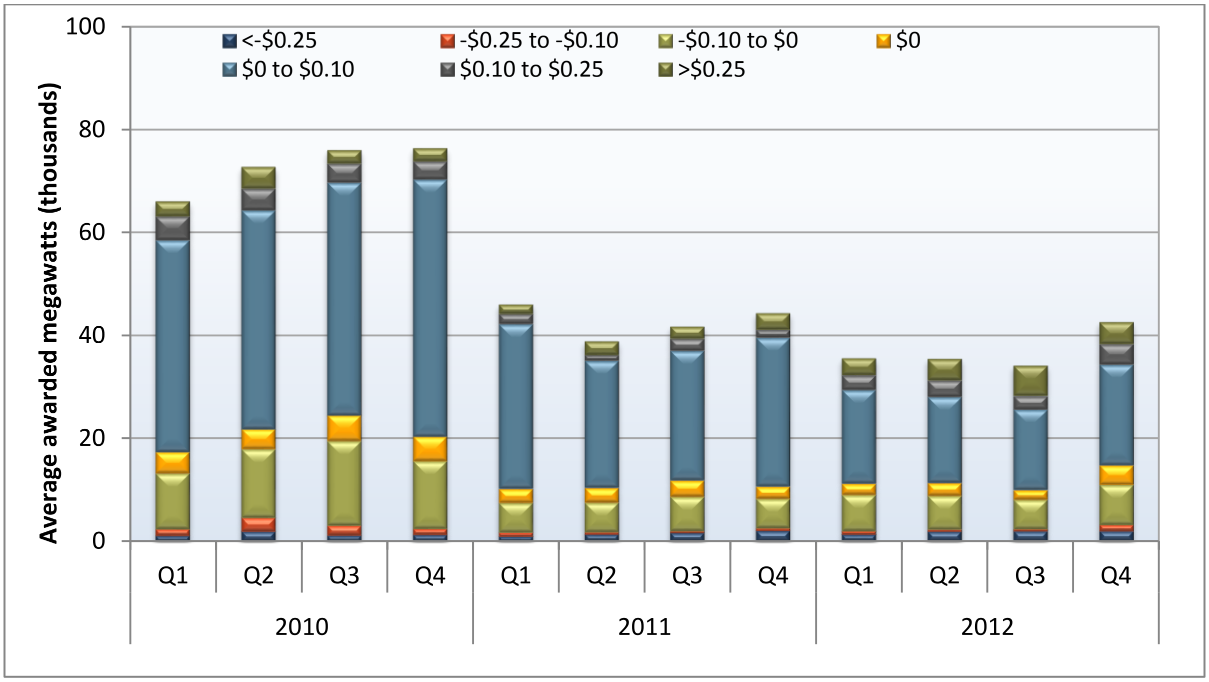


Figure 7.7 Auctioned congestion revenue rights by price (off-peak hours)



Congestion revenue right revenue adequacy

The market for congestion revenue rights is designed such that the amount of congestion rents collected from the day-ahead energy market is sufficient to cover all the payments to rights holders. This is referred to as revenue adequacy. The ISO limits the number of congestion revenue rights available in the allocation and auction processes between various sources and sinks to help maintain overall revenue adequacy by enforcing constraint limits similar to those enforced in the day-ahead market.[116]

However, under actual market conditions, events such as transmission outages and derates can create revenue deficiencies and surpluses even when the congestion expectations in the auction and in the day-ahead market are identical. Therefore, all revenues from the annual and monthly auction processes are included in the congestion revenue right balancing account to help ensure revenue adequacy, if needed. Any shortfall or surplus in the balancing account is tracked hourly with a clearing performed twice a month. Any shortfall or surplus is allocated to measured demand.

Figure 7.8 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.

[116] For a more detailed explanation of congestion revenue rights revenue adequacy and the simultaneous feasibility test, please see the ISO's 2012 reports on congestion revenue rights at: http://www.caiso.com/market/Pages/ProductsServices/CongestionRevenueRights/Default.aspx.

- 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.

As seen in Figure 7.8, revenue surplus was high in the second quarter and deficiency occurred for the third and fourth quarters of 2012 before taking into account auction revenues. The second quarter revenues were the highest since the market began in April 2009 and the fourth quarter revenues were the lowest. A few notable revenue adequacy observations for the last three quarters are below:[117]

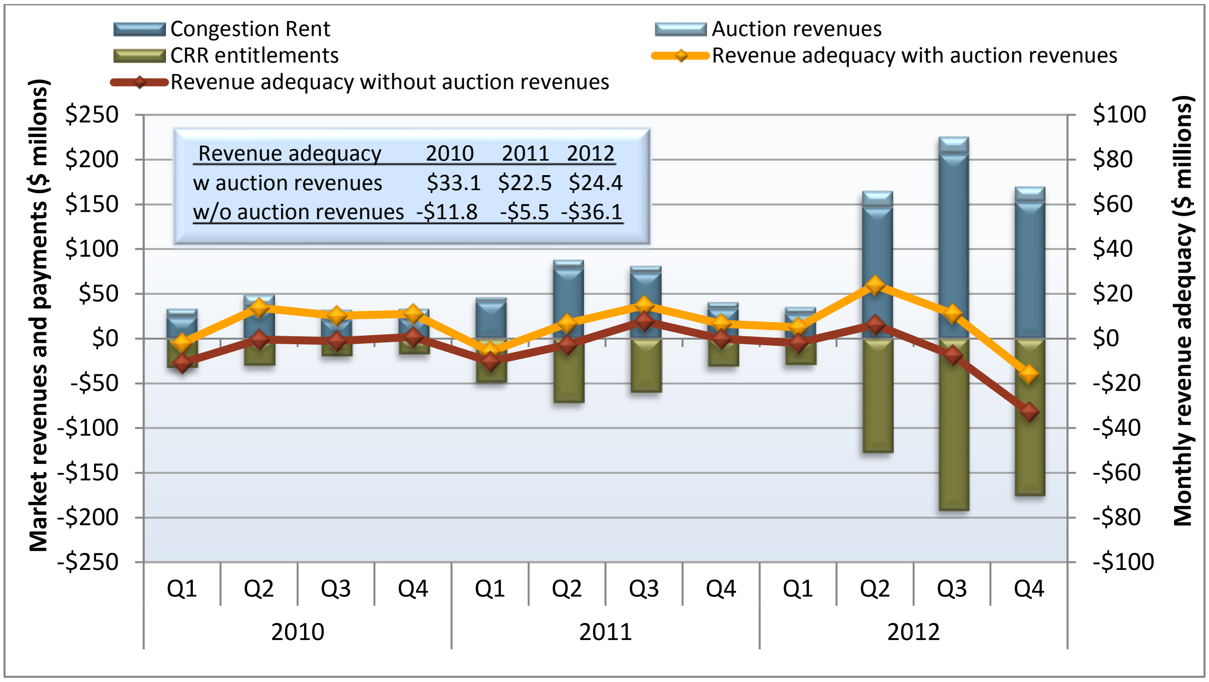
- In the second quarter, the SCE_PCT_IMP_BG was congested in April and May due primarily to the SONGS outage in the Southern California region, causing revenue surplus of about $3 million and $3.5 million, respectively. These revenue surpluses were mainly due to the fact that fewer congestion revenue rights were released for these paths than the actual transmission capacity available in the day-ahead market.
- In the third quarter, a revenue shortfall of about $20 million occurred on the nomogram 6110_TM_BNK_FLO_TMS_DLO_NG due to an inherent timing difference when incorporating the nomogram into the congestion revenue rights process compared to the day-ahead market. Also, the 22342_HDWSH _500_22536_N.GILA 500 kV line was binding in September, resulting in revenue shortfall of over $1.7 million. On the other hand, the SCE_PCT_IMP_BG caused revenue surplus of about $4 million.
- In October and November of the fourth quarter, the nomogram SLIC 2023497 TL50003_CFERAS was binding and resulted in revenue shortfall of about $2.5 million and $6.5 million, respectively. This nomogram was enforced when the Imperial Valley to Suncrest 500 kV line was cleared for transmission and substation upgrades. Also the BARRE-LEWIS_NG nomogram had a shortfall in December of approximately $1.8 million.

In total for the first three quarters of 2012, revenues for congestion revenue rights were approximately neutral before taking into account auction revenues. With auction revenues included, revenues were positive each of the first three quarters of 2012.

The total cumulative revenue adequacy of the congestion revenue rights balancing account for 2012 was about $24.4 million, approximately a $2 million increase from 2011. This represents only 40 percent of total net revenues from the annual and monthly auctions for 2012.

[117] For further detail see the *Quarterly Market Performance CRR Report (2012)*: http://www.caiso.com/market/Pages/MarketMonitoring/MarketIssuesPerfomanceReports/Default.aspx.

Figure 7.8 Quarterly revenue adequacy



Profitability of congestion revenue rights

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

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

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

Figure 7.9 through Figure 7.12 show the profitability distribution of congestion revenue rights for peak and off-peak hours in 2012.[118] The figures only include congestion revenue rights acquired through the auction process since these rights were valued through a market process. Each chart distinguishes between prevailing flow and counter-flow congestion revenue rights.

Results of these figures show the following:

- About 50 percent of the seasonal prevailing flow rights were profitable, while 44 percent of monthly rights were profitable. Overall, profits for seasonal prevailing flow rights averaged about \$0.47/MWh, whereas profits averaged about \$0.61/MWh for monthly rights.
- About 57 percent of all seasonal counter-flow rights had positive profits, while about 68 percent of monthly rights had positive profits. Profits for seasonal counter-flow rights averaged -\$0.33/MWh, while profits averaged about -\$0.05/MWh for monthly rights.

In the monthly auction, the most profitable and unprofitable congestion revenue rights were those impacted by unforeseen outages, de-rates and modeling discrepancies. Congestion on major transmission constraints, beginning in the second quarter and continuing through the year, caused congestion in the day-ahead markets. This made some counter-flow rights highly unprofitable and some prevailing flow rights highly profitable.

[118] The congestion revenue rights profit is defined as the total congestion revenue rights revenues minus auction cost, divided by the quantity megawatts and number of hours for which that right is valid. The same profit is represented for each awarded megawatt on the same path. For example, assume a 10 MW monthly on-peak congestion revenue right cost \$100 in the auction (10 MW x \$10/MW). If this right received \$900 in day-ahead congestion revenues this would represent a net profit of \$800 over the life of the right. Since the congestion revenue right is valid for 400 hours and was for 10 MW, the profit per megawatt hour would be \$0.20/MWh (\$800/400hrs/10MW = \$0.20/MWh). This profit would be shown with a frequency of 10, representing each awarded megawatt.

Figure 7.9 Profitability of congestion revenue rights - seasonal CRRs, peak hours

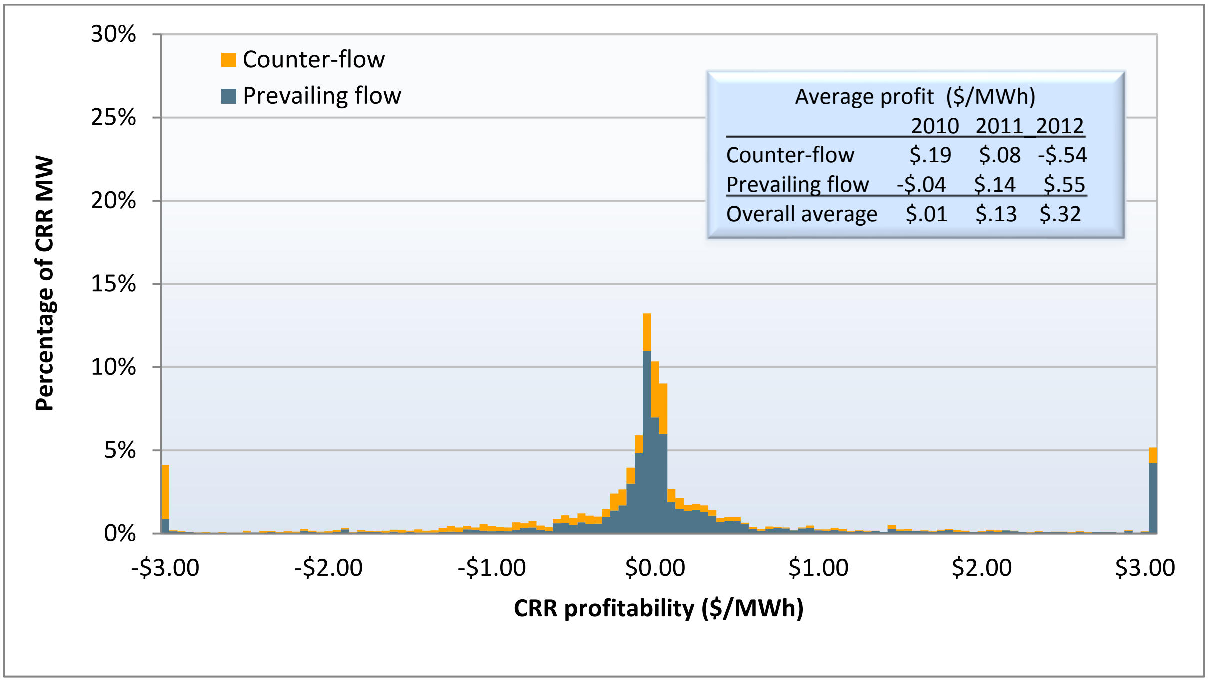


Figure 7.10 Profitability of congestion revenue rights - seasonal CRRs, off-peak hours

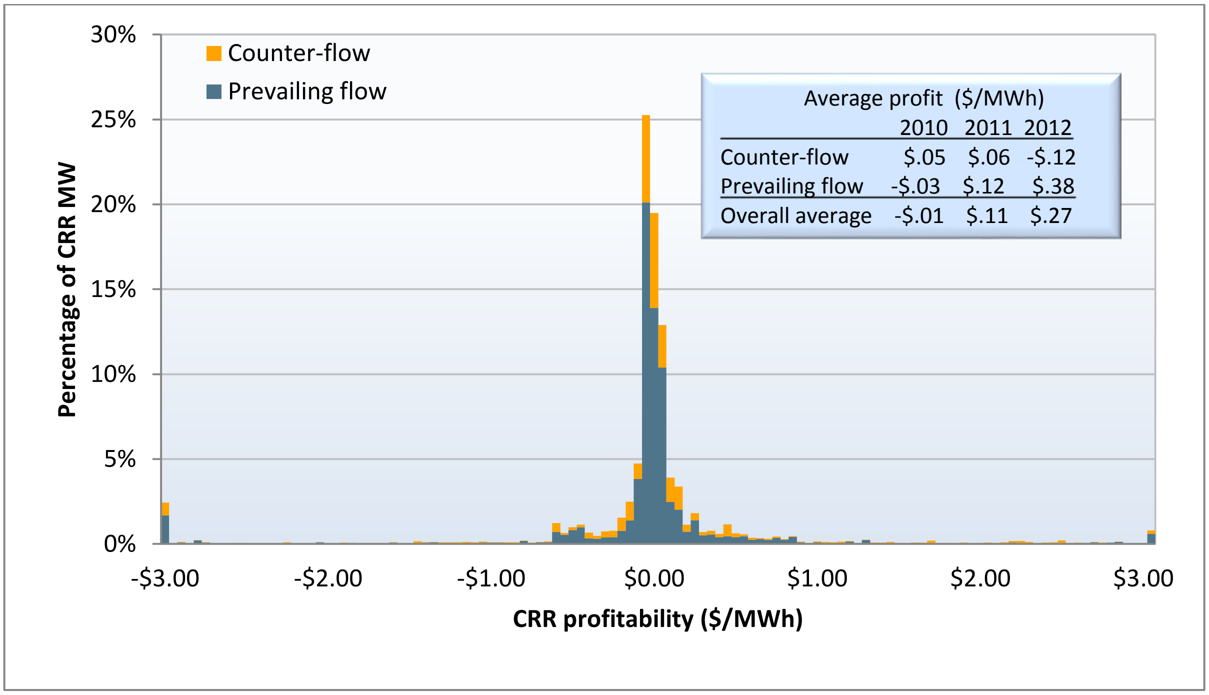


Figure 7.11 Profitability of congestion revenue rights - monthly CRRs, peak hours

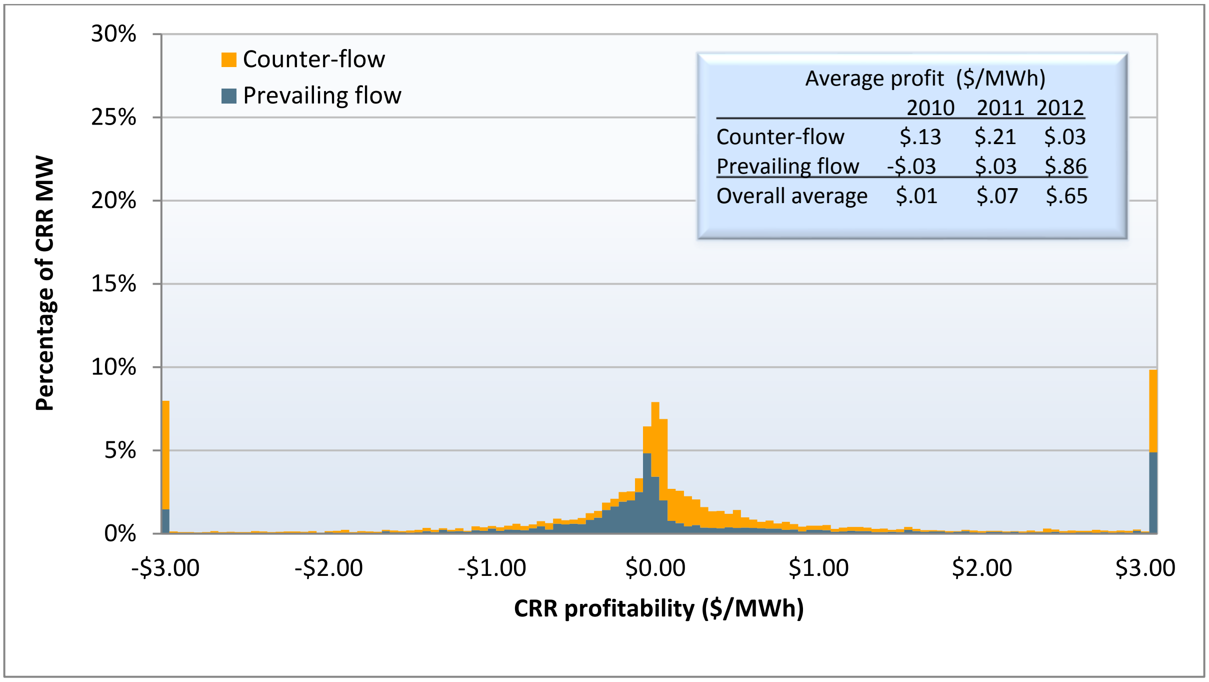
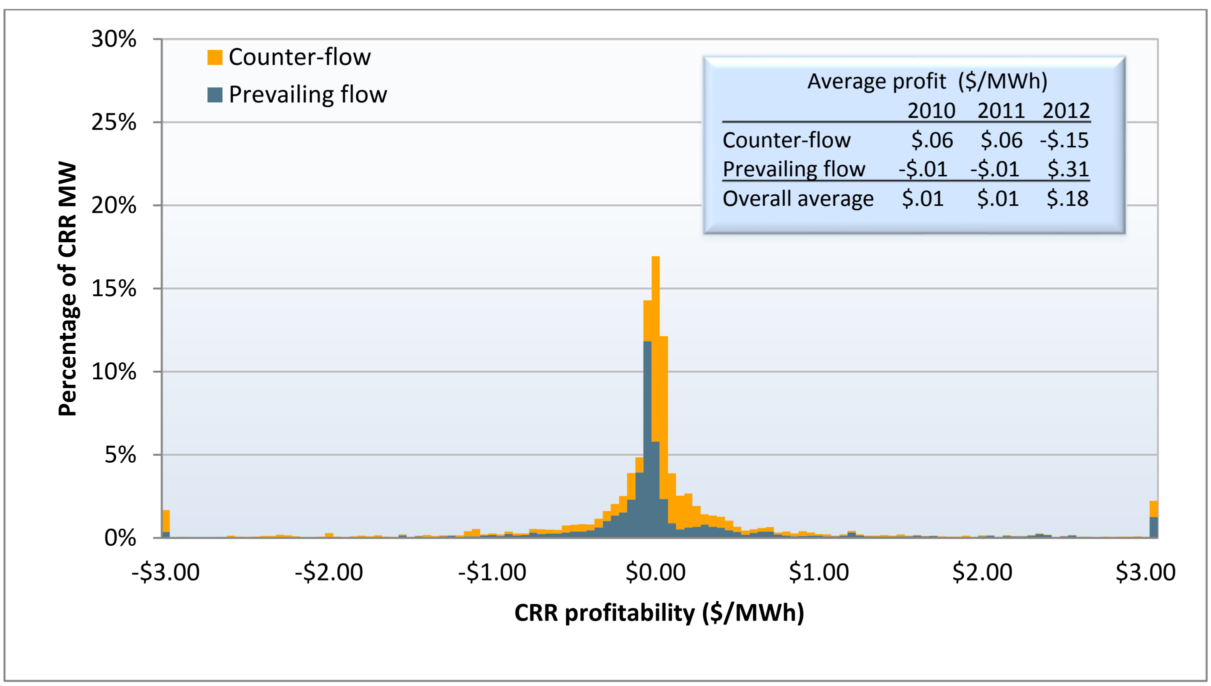


Figure 7.12 Profitability of congestion revenue rights - monthly CRRs, off-peak hours



Congestion revenue right settlement rule

The congestion revenue right settlement rule is an automated rule that limits the gaming opportunity where the value of a participant's congestion revenue rights holdings becomes 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 the ISO settlement compares the constraint's impact on the value of the market participant's congestion revenue rights.[119] If the constraint increased 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 around $600,000 in 2011 and $1.4 million in 2012. Total congestion revenue rights payments were $213 million in 2011 and $525 million in 2012. Thus, the settlement rule affected just under 0.3 percent of the congestion revenue rights payments in both years. This indicates that most participant convergence bidding positions did not affect congestion revenue rights positions above the threshold level.

[119] 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.[120] 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. The ISO may need to modify market prices after the fact to correct for data and metering discrepancies or information system failures.[121]

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;
- compensating injections made at inter-ties to account for loop flows;
- blocked dispatch instructions;
- aborted and blocked pricing runs in the real-time market; and
- price corrections.

In 2012, the ISO established goals to reduce multiple categories of market adjustments – which are also sometimes referred to as *market interventions*. The ISO was able to meet some of its target goals with regards to some adjustments, but did not meet its goals with respect to others. In 2013, the ISO is continuing to place a priority on reducing various market adjustments.

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 create opportunities for the exercise of temporal market power by suppliers.

[120] 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.

[121] Price correction is a tariff-defined process that is not an operator adjustment, but rather is an after the fact process separate from operational conditions.

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 their 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 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.

Increased total energy from exceptional dispatch

Total energy resulting from all the types of exceptional dispatches described above increased by over 35 percent in 2012 from 2011, as shown in Figure 8.1.[122] Total energy from exceptional dispatches, including minimum load energy from unit commitments, equaled 0.53 percent of system loads in 2012, compared to 0.40 percent in 2011. Thus, total energy from exceptional dispatches remains a relatively low portion of total system loads.

Minimum load energy from units committed through exceptional dispatch remained roughly unchanged from 2011, and accounted for about 55 percent of all energy from exceptional dispatches in 2012. About 35 percent of energy from exceptional dispatches in 2012 was from out-of-sequence energy, with the remaining 10 percent from in-sequence energy.

The increase in total energy from exceptional dispatches was driven mainly by an increase in energy above minimum load. As discussed later in this chapter, non-modeled constraints relating to the need for ramping capacity and the SONGS outages were two primary drivers of exceptional dispatch in 2012. These factors were exacerbated by the exercise of temporal market power and economic withholding in the real-time market, as discussed in Section 6.4.

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.

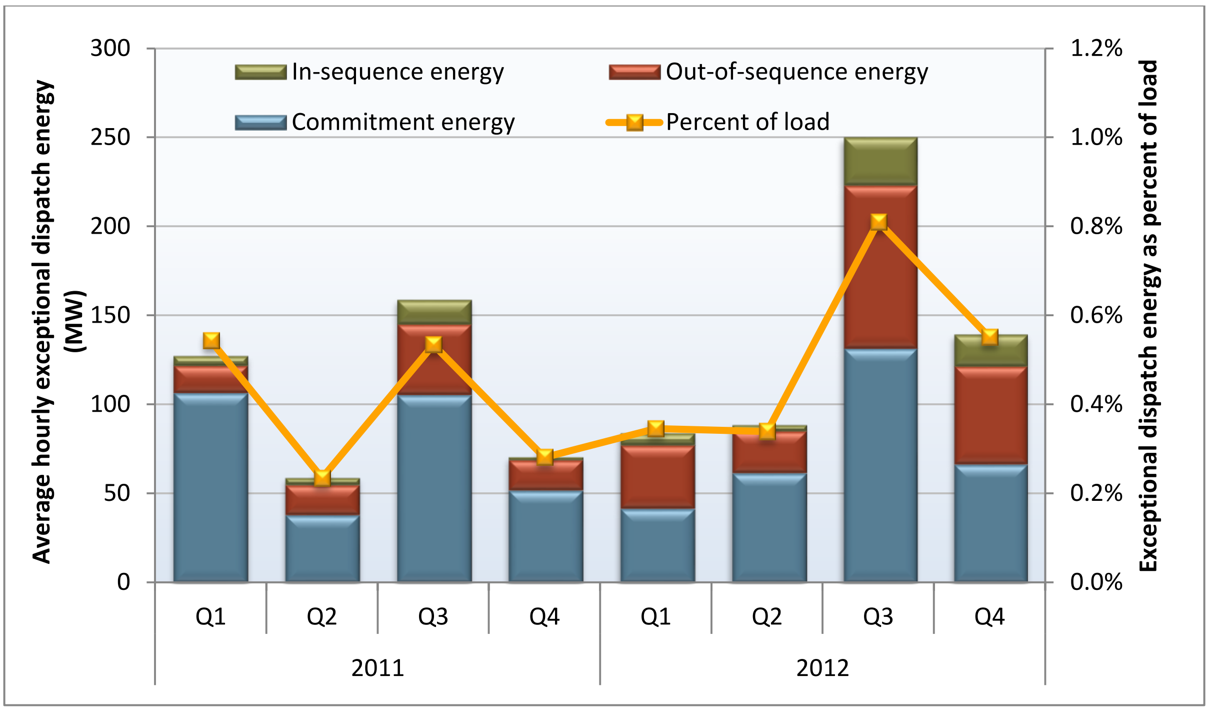
[122] All exceptional dispatch data are estimates derived from SLIC logs, market prices, dispatch data, bid submissions, and default energy bid data. DMM's methodology for calculating exceptional dispatch energy and costs has been revised and refined since previous reports. Exceptional dispatch data reflected in this report may differ from previous annual and quarterly reports as a result of these enhancements.

For instance, as discussed later in this chapter, the bulk of energy from exceptional dispatches results is minimum load energy from unit commitments or energy from positioning units at a higher level where they could ramp up more quickly in case of a contingency. Neither of these types of energy would 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.

As discussed in Chapter 10, the ISO has initiated a stakeholder process to directly incorporate constraints and reliability issues leading to many exceptional dispatches into the day-ahead and real-time market model. As part of this initiative, the ISO is considering the extent to which resources helping to meet these constraints should receive compensation and, if so, how such compensation should be provided. DMM is very supportive of this initiative.

Figure 8.1 Average hourly energy from exceptional dispatch



Exceptional dispatches for unit commitment

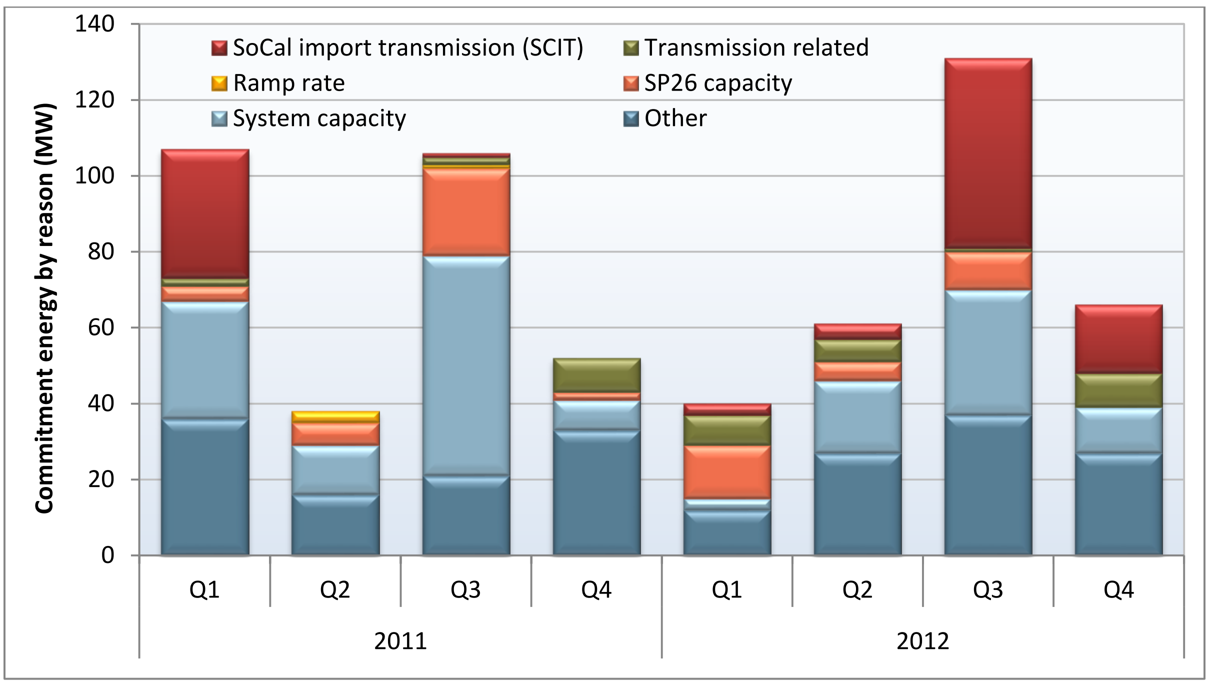
The ISO sometimes finds instances where the day-ahead market process did not commit sufficient capacity to meet certain reliability requirements not directly incorporated in the day-ahead market model. The ISO may then commit additional capacity by issuing an exceptional dispatch for resources to come on line and operate at minimum load.

The frequency of exceptional dispatch for unit commitment was reduced significantly in 2010 largely as the result of the addition of new day-ahead market constraints, known as *minimum online* *constraints*.[123] These constraints require that a certain amount of capacity be committed in key areas to meet voltage requirements and other reliability criteria that cannot be directly incorporated in the power flow model used in the day-ahead market.

Minimum load energy from unit commitments made though exceptional dispatch were about the same in 2012 compared to 2011. As shown in Figure 8.2, much of the minimum load energy from unit commitments was in the third and fourth quarters to manage potential contingencies associated with the Southern California import transmission limit (SCIT). A significant amount of this minimum energy also continued to result from unit commitments made for more general system contingencies and load uncertainty.

Lower loads and off-peak season prices may have contributed to the need to commit units as these factors can reduce the amount of capacity committed in the day-ahead market. In addition, some additional unit commitments were made as the result of increased economic withholding from the day-ahead market, as discussed in Chapter 6.

Figure 8.2 Average minimum load energy from exceptional dispatch unit commitments



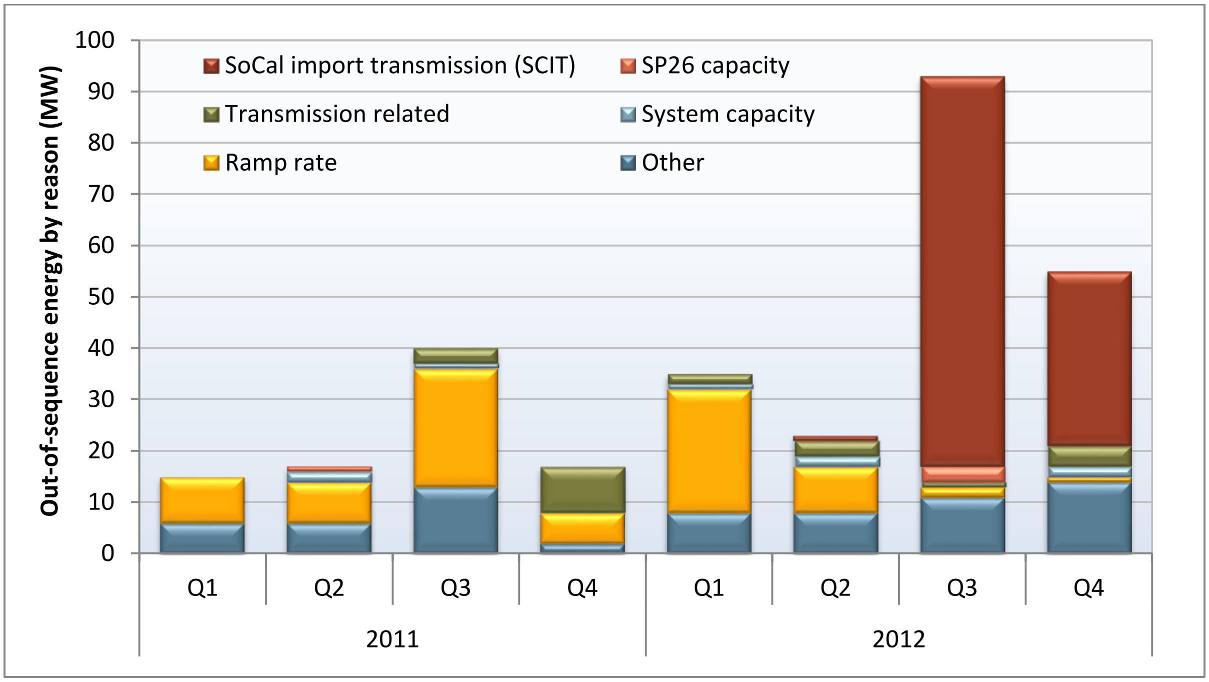
Exceptional dispatches for energy

Energy from real-time exceptional dispatches to ramp units up above minimum load or their regular market dispatch increased considerably in 2012, rising about 130 percent. Most of this exceptional dispatch energy (about 85 percent) was out-of-sequence, meaning the bid price was greater than the locational market clearing price, as previously illustrated in Figure 8.1.

[123] For further discussion see, *2010 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2011, p. 75-77.

Figure 8.3 shows that this increase in out-of-sequence energy was driven primarily by an increase in exceptional dispatches to protect against contingencies relating to the Southern California import transmission limit. Most of these exceptional dispatches were to move resources above minimum operating levels to their minimum dispatchable level, at which they could be more quickly ramped up in the event of a contingency. The higher ramp capability at minimum dispatchable levels allows the ISO to manage reliability issues not adequately modeled in the ISO market software. These include 30-minute contingencies and other potential system conditions within the 30 to 60 minute time frame.[124]

Figure 8.3 Out-of-sequence exceptional dispatch energy by reason



Exceptional dispatch costs

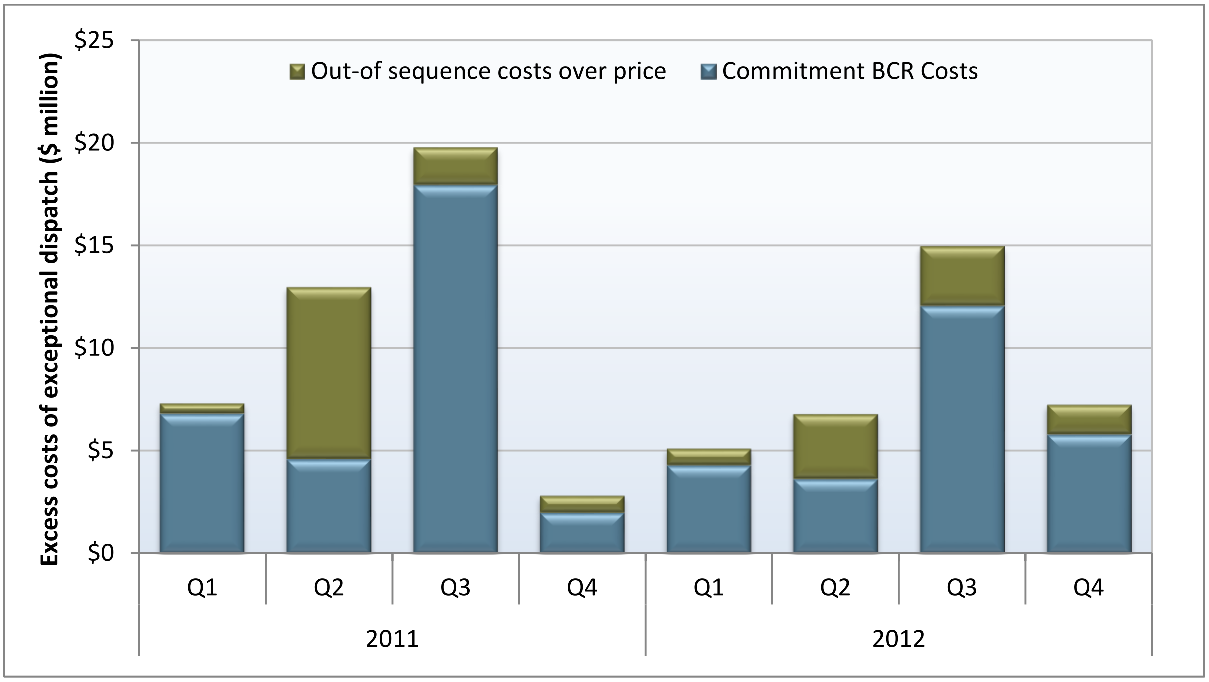
Exceptional dispatches can create two types of additional costs not recovered through the market clearing price of energy.

- 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.

[124] Additional discussion of resource dispatchable minimum load is found in "Exceptional Dispatch and Residual Imbalance Energy Mitigation Tariff Amendment" in FERC Docket No. ER12-2539-000, August 28, 2012, at: http://www.caiso.com/Documents/August282012ExceptionalDispatch-ResidualImbalanceEnergyMitigationTariffAmendment-DocketNoER12-2539-000.pdf.

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 paid through bid cost recovery decreased from about $31 million to almost $26 million, while out-of-sequence energy costs decreased from just under $12 million to around $8 million.[125] Overall, these above-market costs decreased about 20 percent from $43 million in 2011 to $34 million in 2012.

Figure 8.4 Excess exceptional dispatch cost by type



Thus, while the amount of energy resulting from exceptional dispatches increased substantially in 2012, the above-market cost of this energy rose only slightly. This reflects the fact that a much greater portion of exceptional dispatches for energy were subject to local market power mitigation provisions of the ISO tariff in 2012 than in 2011. Under these provisions, exceptional dispatches for energy made to manage reliability issues associated with constraints that have not been deemed to be competitive are mitigated based on a default energy bid, which is designed to be reflective of their marginal operating costs. Amendments to the ISO tariff, effective August 29, 2012, also allowed the ISO to mitigate payments for all exceptional dispatches made to a resource's minimum dispatchable level in real-time.[126] More discussion of local market power mitigation for exceptional dispatch is included in Section 6.3.2.

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125 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.

126 See "Exceptional Dispatch and Residual Imbalance Energy Mitigation Tariff Amendment" in FERC Docket No. ER12-2539-000, August 28, 2012, at: http://www.caiso.com/Documents/August282012ExceptionalDispatch-ResidualImbalanceEnergyMitigationTariffAmendment-DocketNoER12-2539-000.pdf.

8.2 Load adjustments

In the hour-ahead and real-time markets, the ISO frequently adjusts real-time loads 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. Other inconsistencies result from the fact that the hour-ahead market is based on a model that solves for 15-minute time intervals, while the real-time market actually dispatches units for 5-minute intervals.

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, load adjustments made by operators are less likely to have an extreme effect on market prices without increasing the actual supply of system energy. A more detailed explanation and discussion of the power balance constraint is provided in Section 3.2.

Figure 8.5 shows the average hourly load adjustment profile for the hour-ahead, 15-minute pre-dispatch and 5-minute real-time markets during the first half of 2012 (January through June). Figure 8.6 shows the average load adjustments for each operating hour in these markets during the second half of the year (July through December). The following is shown in these figures:

- During the first half of the year, adjustments were made most consistently to the 5-minute real-time market, whereas the hour-ahead market was adjusted only slightly in the early morning hours and during the peak hour (hour ending 18).
- During the second half of the year, load adjustments increased in all three markets. In particular, adjustments in the hour-ahead market exceeded both the 15-minute and 5-minute real-time market adjustments for most of the day by 100 MW or more. The adjustments to the 15-minute market increased in the second half of the year and were more consistent with the load adjustments to the 5-minute market. This increase in adjustments occurred as the ISO operators increased ramping capacity to better meet system ramping needs during the steep evening load ramp.

Figure 8.7 highlights how load adjustments changed during peak hour ending 18 from month-to-month over the course of 2012.

- The use of load adjustments in all markets increased beginning in July and continued for much of the rest of the year.
- The load adjustments were highest in November for all markets. This is not uncommon as the ISO used load adjustments together with adjustments to the flexible ramp constraint to account for ramping needs in the steeper evening ramping period during the fall and winter months.
- Real-time load adjustments were negative in the months of June and July and well below the hour-ahead levels in the months of August through December.

Figure 8.5 Average hourly load adjustments (January through June)

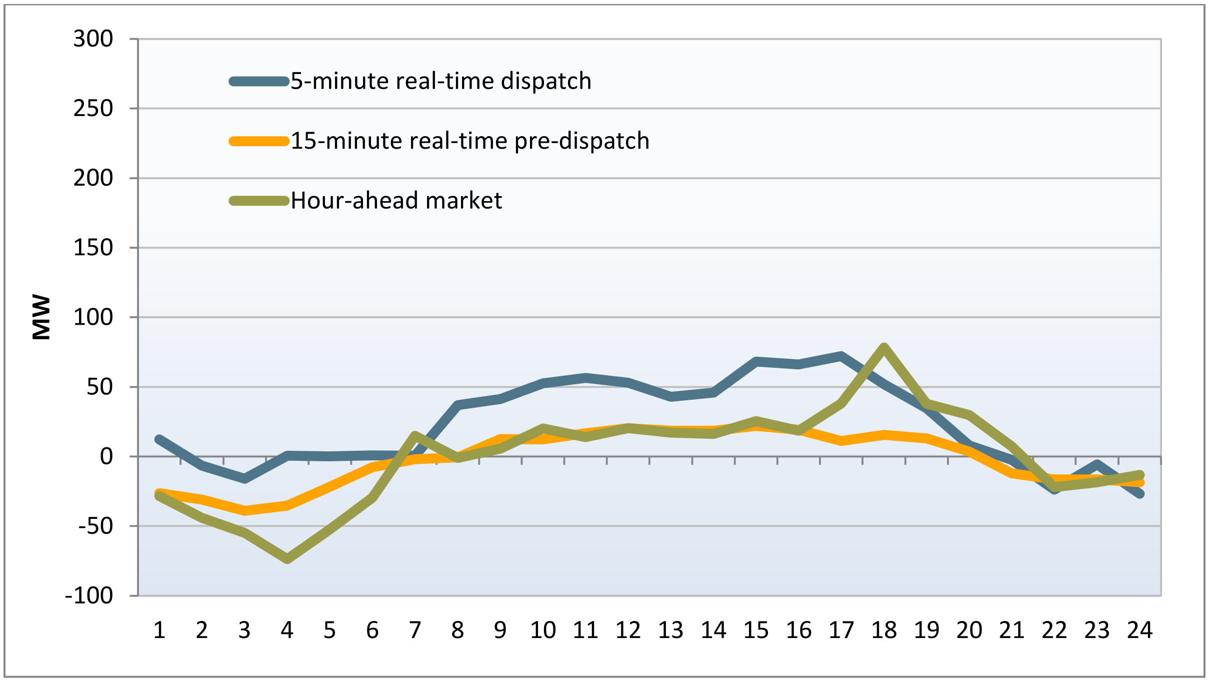


Figure 8.6 Average hourly load adjustments (July through December)

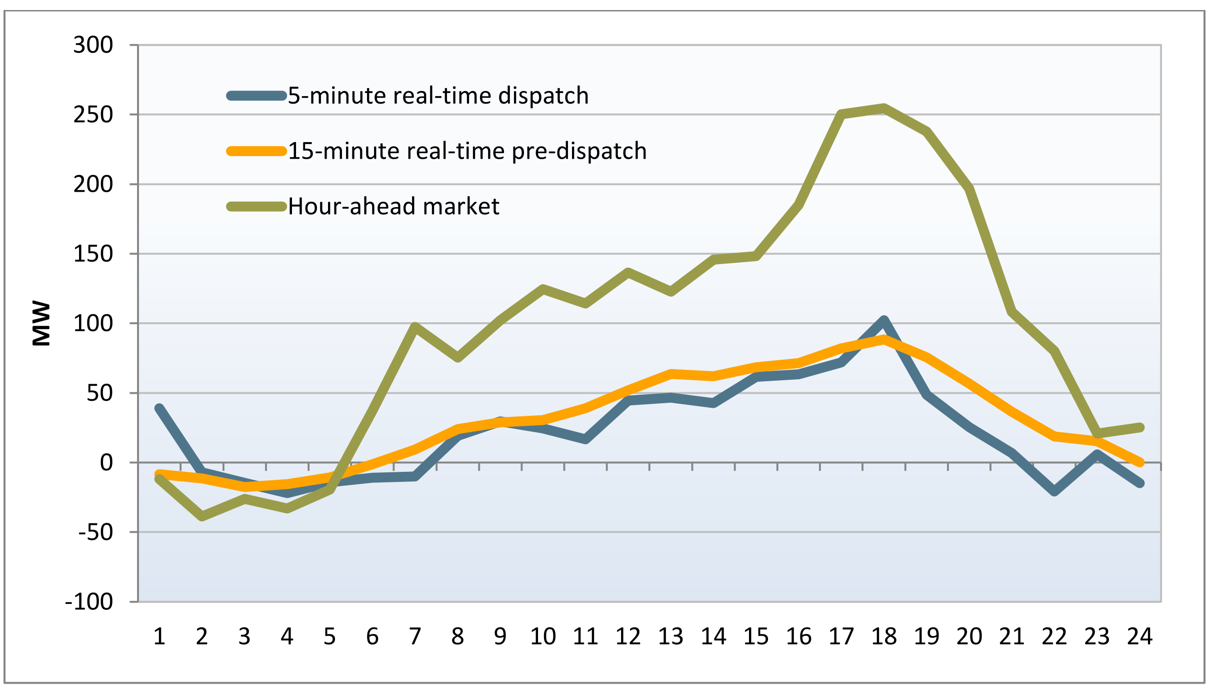
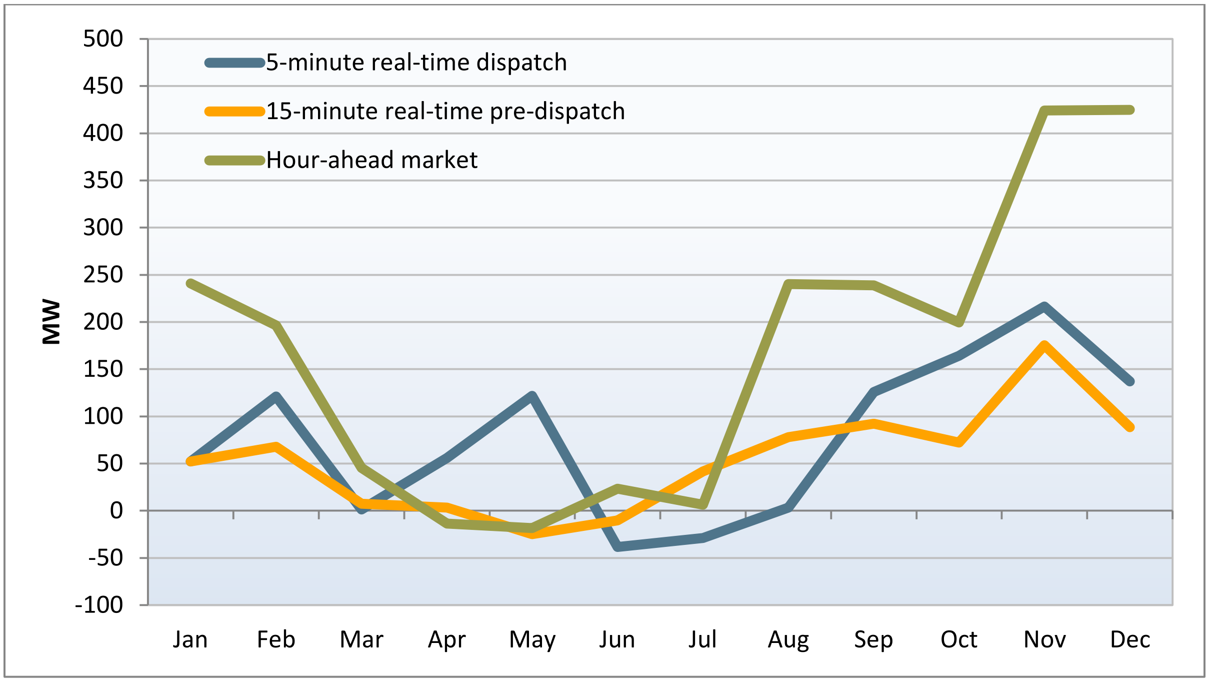


Figure 8.7 Average monthly load adjustments (hour ending 18)



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.[127] 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.[128]

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.

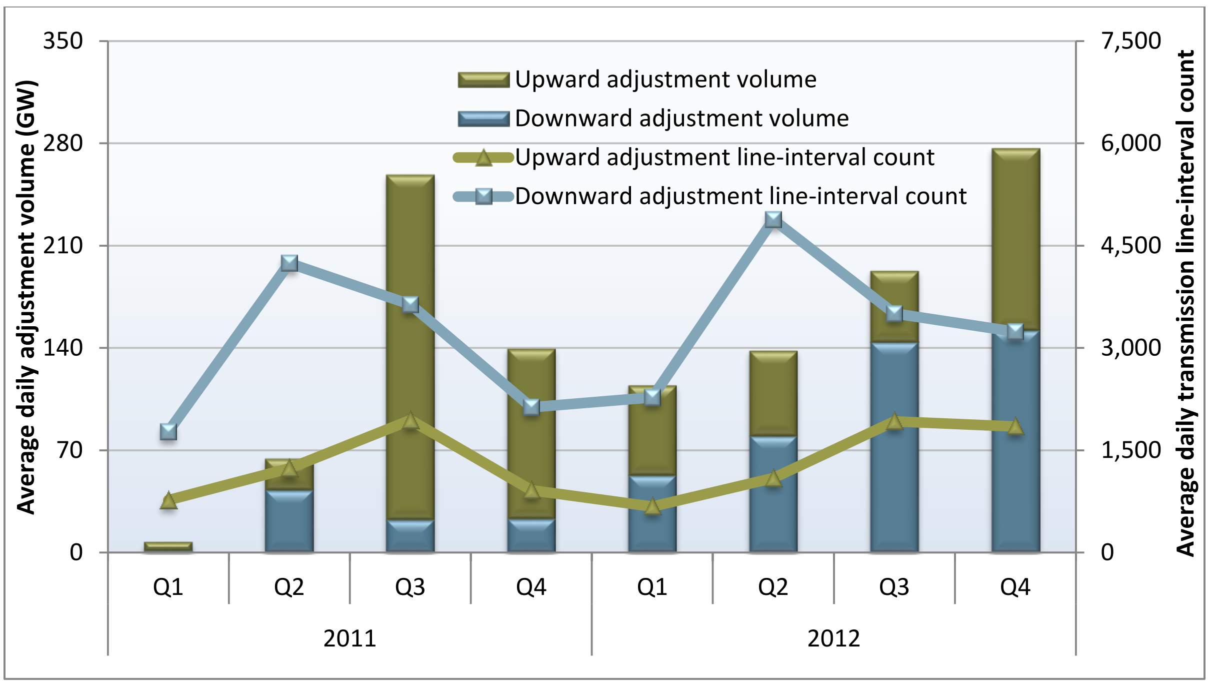
[127] The ISO attempts to model these flows at the inter-ties through a feature known as *compensating injections* (see Section 8.4).

[128] 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 or downward direction, along with the average volume of these transmission adjustments.[129]

Figure 8.8 Average daily frequency and volume of internal transmission adjustments by quarter



The frequency of transmission adjustments increased by around 14 percent in 2012 compared to 2011. In 2012, the ISO enhanced the ability to adjust transmission for nomograms. This was the main factor causing the increase in the frequency of transmission adjustments.

The volume of transmission adjustments increased by 50 percent in 2012 compared to 2011. This increase was primarily driven by the increase in the volume of downward adjustments.[130] When a line

[129] 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 2012 can be found in the later sections of the monthly performance metric catalogue reports: http://www.caiso.com/Documents/Market%20performance%20metric%20catalog%202012.

[130] When adjusting transmission in the upward direction, the goal is to alleviate false congestion. Therefore, the size of the upward adjustment is less important than a downward adjustment, as it is designed to eliminate congestion; the higher the number for an upward adjustment the more likely congestion will be eliminated. The size of a downward adjustment is important because the larger the adjustment, the bigger the potential market effect.

shows signs of overloading but is not yet binding, the ISO operators can exceptionally dispatch a generator to prevent the line from overloading. In 2012, as part of efforts to reduce exceptional dispatches, the ISO operators conformed the line limits down to signal the market to adjust the flows to prevent an overload on the conformed line.

8.4 Compensating injections

In late September 2012, the ISO made enhancements to the operational characteristics of compensating injections. As a result of the updates, the total effect of compensating injections became more consistent throughout the day and significantly less variable. That is, in about 97 percent of intervals, compensating injections were in a single status for three hours or more.

Background

In July 2010, the ISO re-implemented an automated feature in the hour-ahead and real-time software to account for unscheduled flows along the inter-ties. This feature accounts for observed unscheduled flows by incorporating *compensating injections* into the market model. These are additional injections and withdrawals that are added to the market model at various locations external to the ISO system.[131] Before implementing this feature, the ISO identified that if the net quantity of compensating injections – the difference between the injections and withdrawals added to the market model – is significantly positive or negative, this can create operational challenges due to the impact this has on the area control error (ACE).[132]

To avoid creating problems managing the area control error, a constraint was added to the software that limits the net impact of compensating injections to an absolute difference of no more than 100 MW. This limitation was imposed by applying a discount factor to the compensating injections calculated by the software as this absolute difference increases beyond this 100 MW threshold. This reduces the compensating injections at each location if the overall net system-level compensating injections exceed this 100 MW threshold.

As a result of this constraint, there were often three distinct modes or statuses of compensating injections.

- **Full compensating injections.** This is when compensating injections are fully enabled and are not limited by the discount factor.
- **Partial compensating injections.** This is when the compensating injections are limited by the discount factor.
- **Compensating injections turned off.** This is when the compensating injections are turned off because the net compensating injections value would have been too high relative to the area control error to resolve the solution.

[131] The quantity and location of these compensating injections are calculated to minimize the difference between actual observed flows on inter-ties and the scheduled flows calculated by the market software. The software re-calculates the level and location of these injections in the real-time pre-dispatch run performed every 15 minutes. The injections are then included in both the 15-minute and 5-minute market runs.

[132] The ACE is a measure of the instantaneous difference in matching supply and demand on a system-wide basis. It is a critical tool for managing system reliability.

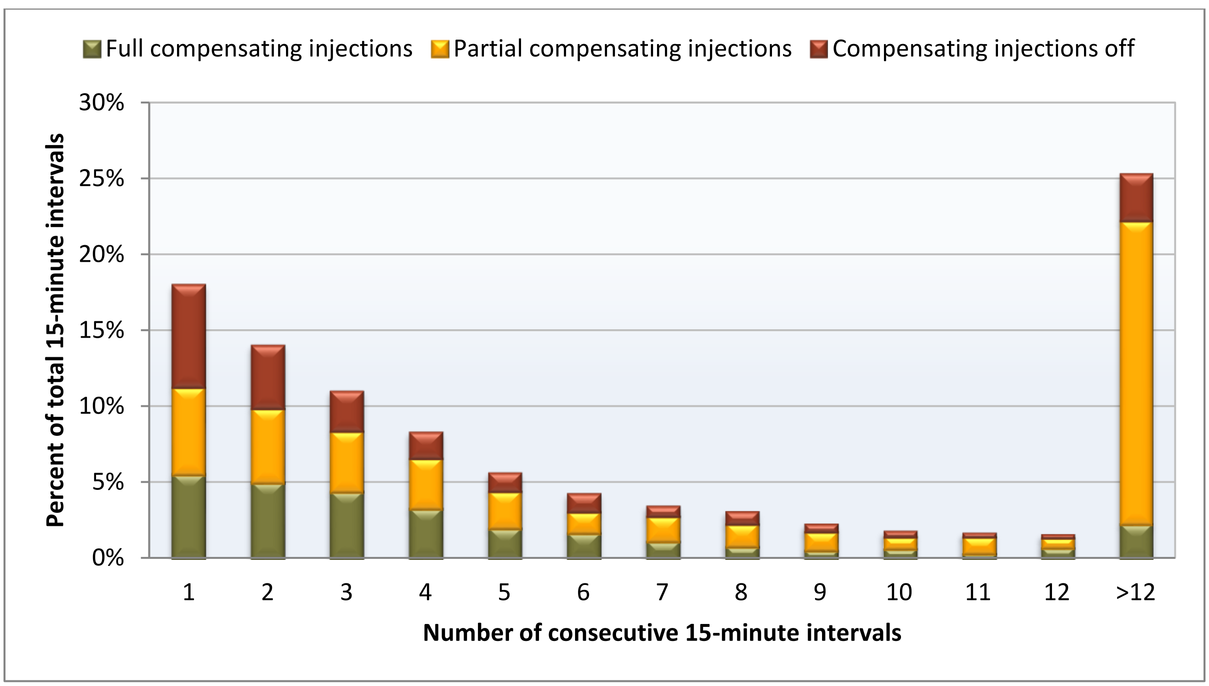
In summer 2012, ISO operators identified challenges managing transmission flows caused by the changes in modeled flows by compensating injections. In late September, the ISO implemented various enhancements to the operational characteristics of compensating injections. The following sections provide an analysis of the performance of compensating injections before and after the enhancements took effect.

Analysis of performance before the enhancements

Compensating injections varied frequently between the full, partial and off statuses before September. Figure 8.9 shows how often the compensating injection status varied over consecutive 15-minute intervals during the first eight months of 2012.

- About 43 percent of the time, compensating injections remained in a single status for less than an hour. This frequent status-switching added an additional level of variability to the real-time model as modeled flows varied on impacted lines.
- In about 57 percent of 15-minute intervals, compensating injections were in a single status for an hour or more. The compensating injection feature remained completely on for an hour or more for only about 13 percent of the time.

Figure 8.9 Frequency of compensating injection status change prior to the enhancements in September 2012



Analysis of performance after the enhancements

In late September, the ISO made enhancements to the operational characteristics of compensating injections to make them more consistent over the day and less variable. The enhancements were focused on the following aspects of compensating injections:

- As the net compensating injections approach a new threshold level (40 MW), they are gradually reduced to zero using a reduction factor.[133] Previously, when the compensating injections approached the threshold (100 MW), the software would immediately take the net compensating injections down to zero in the next interval.
- As the net compensating injections increase above a threshold level (40 MW) and remain below a higher threshold (2,000 MW), their system effect is gradually reduced using a reduction factor that reduces imports and increases exports or vice versa, in order to have a more gradual impact to the market flows.[134] Previously, both exports and imports were reduced by a single fixed parameter value in the next interval.

As a result of the updates, the total effect of compensating injections has become more consistent over the day and less variable. That is, in about 97 percent of intervals, compensating injections were in a single status for three hours or more.

Figure 8.10 shows the daily profile of the compensating injections prior to the recent enhancements performed by the ISO. The chart shows that the compensating injection status varied over the day. Figure 8.11 shows the daily profile of compensating injections after the ISO performed the enhancements. As the figure shows, the status remained more consistent and less variable than before the enhancements. There have only been a handful of intervals when the compensating injection status was limited or off after the enhancements.

[133] In the previous mechanism, the compensating injection algorithm shut down the entire algorithm when the net compensating injection hit a pre-defined value (100 MW in most cases). The enhancement to the algorithm reduces the net compensating injection gradually by utilizing a pre-defined reduction factor (less than 1). The value tends to approach zero over multiple market intervals. Imports are increased and exports are decreased proportionately over these intervals to reflect the decreasing value of net compensating injection.

[134] In the previous mechanism, imports and exports were both decreased simultaneously to bring the net compensating injection within the defined range. The resultant power balance is applied to all the subsequent market intervals. The enhancement to the algorithm reduces the power balance gradually by utilizing a pre-defined reduction factor (less than 1). The value tends to approach zero over multiple market intervals. Imports are increased and exports are decreased proportionately over these intervals to reflect the decreasing value of power balance. This provides a more even compensating injection value over multiple market intervals.

Figure 8.10 Compensating injection levels prior to enhancements (July 24, 2012)

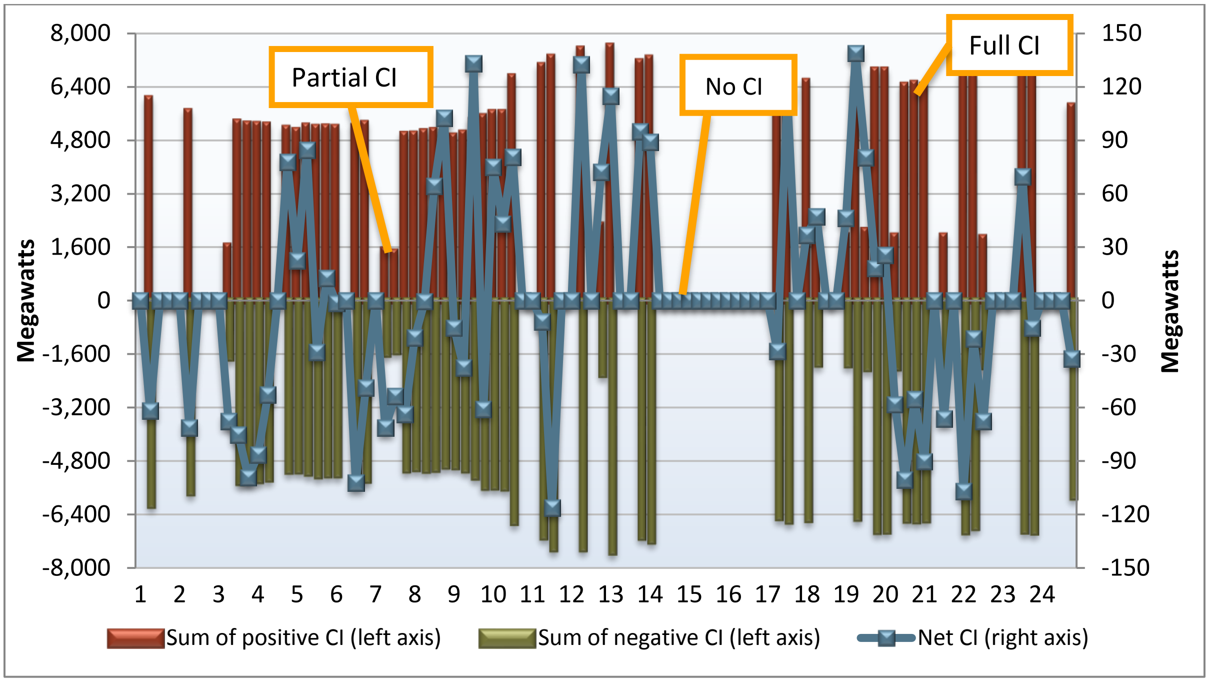
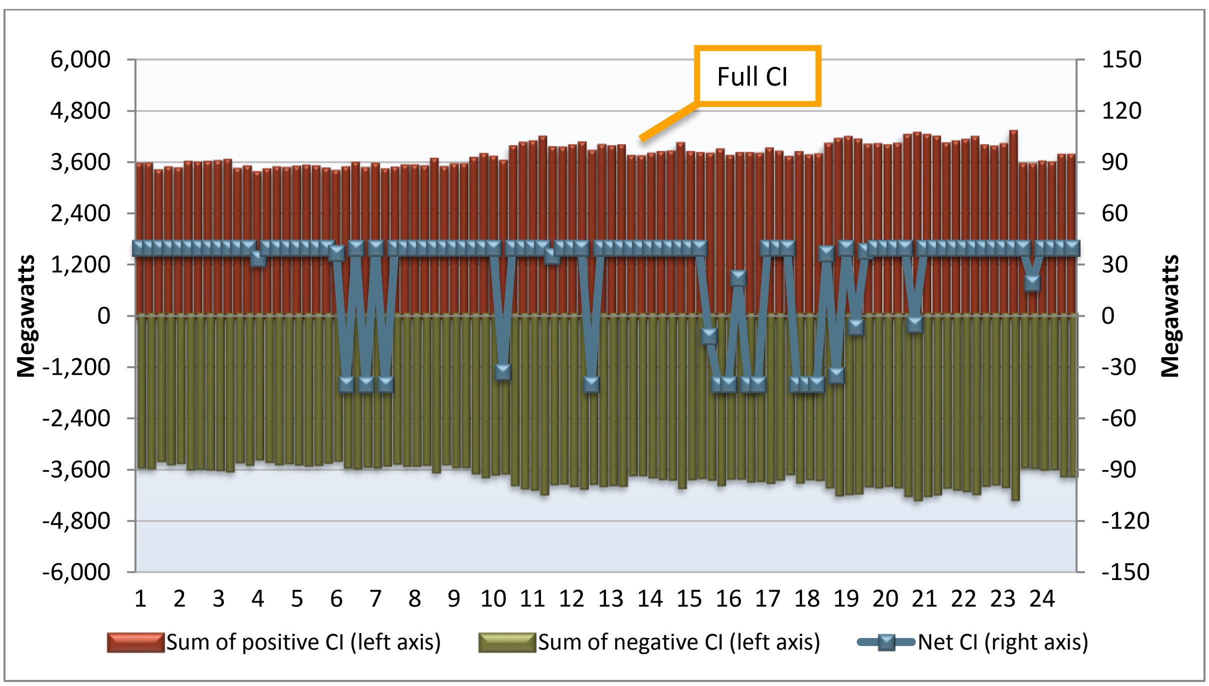


Figure 8.11 Compensating injection levels after enhancements (November 5, 2012)



Overall, as a result of these enhancements, the aggregate variability in compensating injections has been reduced considerably. However, variability on certain paths has remained significant. DMM recommends that the ISO continue to assess and improve its methodology to resolve the variability of compensating injections on individual paths.

8.5 Blocked instructions

The ISO's real-time market functions using a series of processes. Imports and exports are dispatched through the hour-ahead scheduling process. The 15-minute pre-dispatch process is used to commit or de-commit short-start peaking units within the ISO and to transition multi-stage generating units from one configuration to another. Finally, the 5-minute dispatch process is used to increase or decrease the dispatch level of online resources within the ISO.

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. 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 will 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 perform the various processes required 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 was lower in 2012 compared to 2011, the change in blocked instructions was mixed as blocked instructions decreased on the inter-ties and increased for internal units. Figure 8.12 shows the frequency and volume of blocked dispatches on inter-ties. Figure 8.13 shows the frequency of blocked real-time commitment start-up and shut-down and multi-stage generator transition instructions for internal generators.[135]

[135] 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/Documents/Market%20performance%20metric%20catalog%202012.

Figure 8.12 Frequency and volume of blocked real-time inter-tie instructions

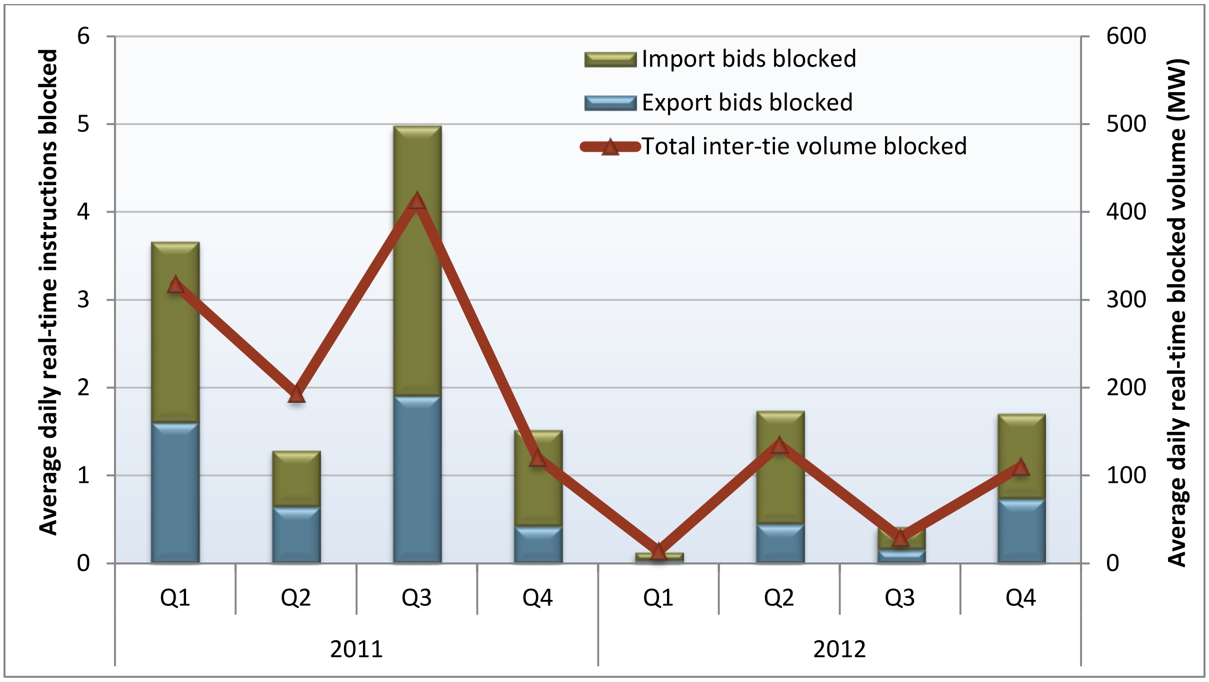
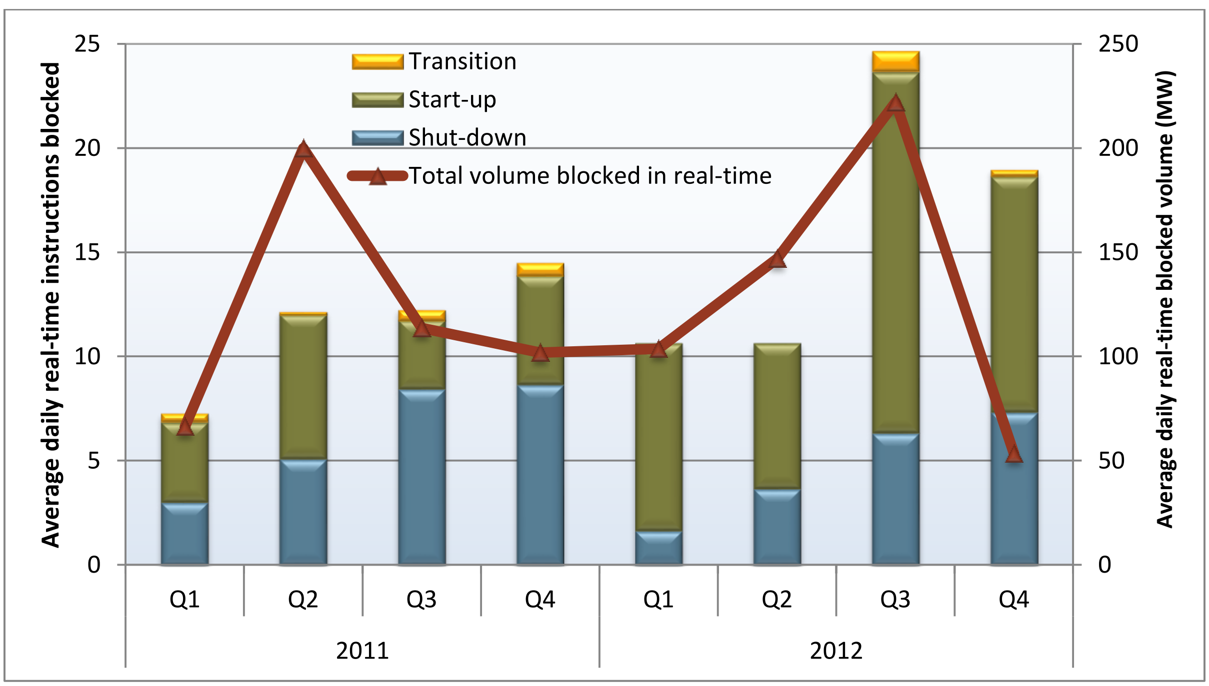


Figure 8.13 Frequency and volume of blocked real-time internal instructions



The average number of daily blocked inter-tie instructions in 2012 is almost a third of the blocked instructions in 2011. This decrease occurred mainly as a result of improvements to the operational procedures related to load adjustments in the hour-ahead market and the implementation of the flexible ramping constraint.

Blocked instructions for internal resources increased by over 40 percent in 2012 compared to 2011.[136] The increase in blocked instructions for resources within the ISO is mainly driven by about a 100 percent increase in blocked start-up instructions in 2012 compared to 2011. Moreover, blocked start-up instructions were the most common reason for blocked instructions at 69 percent. Blocked shut-down instructions accounted for 29 percent of blocked instructions within the ISO in 2012, with blocked transition instructions to multi-stage generating units accounting for only 2 percent.

Increases in transmission adjustments primarily caused the increase in blocked instructions for internal resources in 2012. This occurred because transmission adjustments sometimes caused the software to dispatch additional units not needed to address actual system conditions. In these cases, the ISO operators blocked the start-up of these extra units. 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. In 2012, the ISO operating engineers enhanced the ability to conform nomograms. Prior to this enhancement, there were potential limits that would be monitored in real-time that were not included in the nomogram. By enhancing the nomogram, this change allowed the market software to consider the adjusted transmission limits in the model and make commitment and dispatch decisions accordingly. This is intended to result in fewer exceptional dispatches and fewer blocked dispatches in real-time.

8.6 Aborted and blocked dispatches

Operators review dispatches issued in the 5-minute 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 more frequently 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

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[136] The maximum number of start-up instructions blocked in a single day was 52 on November 28, 2012. The start-up instructions were blocked by the software to prevent exceeding the decremental threshold. There were 172 shut-down instructions blocked on July 7, 2012 and 101 on September 8, 2012. The shut-down instructions were blocked as a result of reliability concerns caused by wildfires threatening the Pacific DC Intertie and as a result of incorrect estimated time of return data for a line outage, respectively. The maximum transition blocks were 16 on November 22, 2012. In the late hours of the day, unit schedules were bridged to the schedules for the next day through exceptional dispatch instructions.

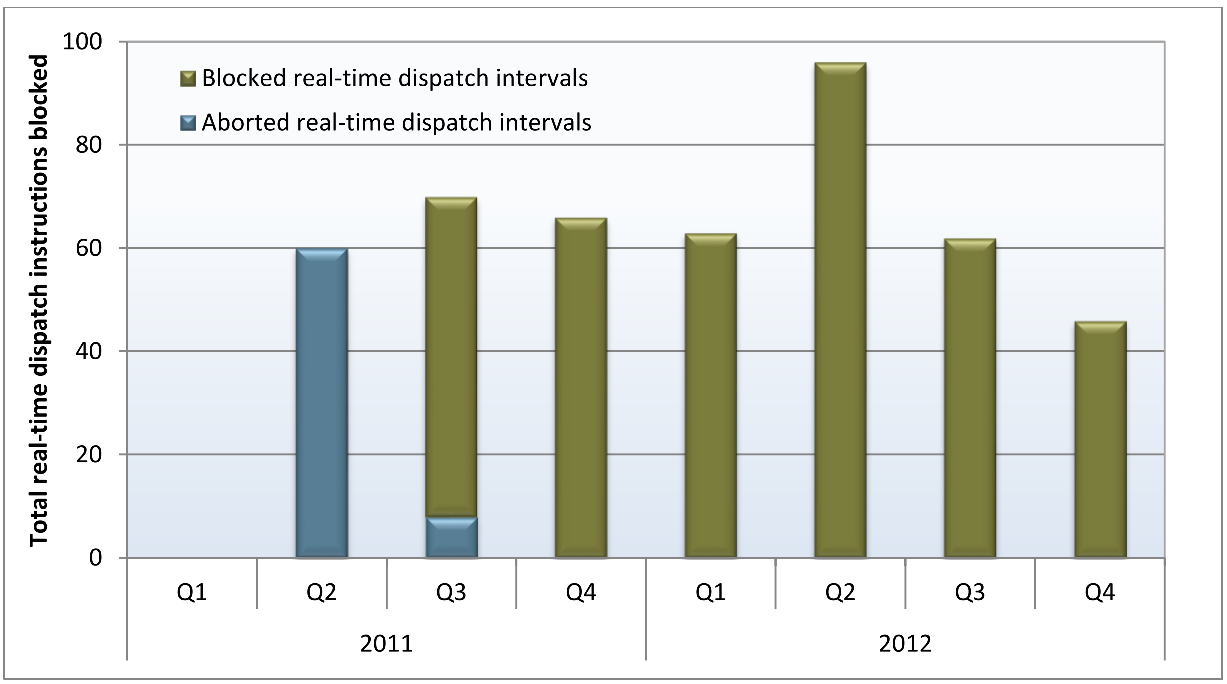
data. Furthermore, the market software is also capable of automatically blocking the solution when the market results exceed threshold values.[137]

In 2011, the ISO did not have a tool that allowed operators to block these dispatch and price signals, even if they knew that these were inaccurate. Instead, operators could only abort or cancel the entire 5-minute real-time dispatch signal. This eliminated all data associated with the interval, so that the market results could not be reviewed after the fact. Alternatively, operators could block the dispatch, but the associated prices for the blocked dispatch would be published, sending inaccurate price signals. The benefit of blocking compared to aborting was that blocking preserves the data.[138]

As a result, the ISO developed software functionality to block the dispatch and price signal and replace these with the previous 5-minute market solution. This new tool for blocking 5-minute interval results was implemented in late July 2011.

Figure 8.14 shows the frequency that operators aborted and blocked price results from the real-time dispatch process in 2011 and 2012. In August 2011, the ISO discontinued the option of aborting unreliable market results. This approach has been replaced with a blocking procedure which preserves the original market solution.

Figure 8.14 Frequency of aborted and blocked real-time dispatch intervals



Since implementation of the blocking procedure, real-time market results were blocked at the rate of about 60 intervals per quarter, with the exception of the second and fourth quarters of 2012. In the

[137] For example, if the load were to drop by 50 percent in one interval, the software can automatically block the results.

[138] DMM raised concerns with the ISO that the aborted results could not be reviewed for accuracy or were not sufficiently logged or tracked, and that the procedures around the abort process were not well defined. The block interval feature that was deployed in late July 2011, as well as an enhanced procedure, addressed DMM's concerns.

second quarter, a higher frequency of the blocked intervals was attributed to software issues that occurred for a couple of days in May. The software triggered automatic blocking instructions until the issues were resolved. In the fourth quarter, a lower frequency of the blocked intervals occurred in October, when market software performed well within tolerance thresholds.

8.7 Price corrections

While the total frequency of price correction intervals increased in 2012 compared to 2011, the volume of price corrections in terms of total number of nodes corrected was smaller. Corrections occurred more frequently primarily because some locations were improperly modeled, and also because of inappropriate network congestion. This section summarizes the frequency and category of price corrections over the last two years.

The tariff allows the ISO to perform price corrections for three distinct reasons:[139]

- invalid data input errors;
- software/hardware errors; and
- tariff inconsistencies.

Figure 8.15 and Figure 8.16 categorize price corrections, by interval and by node, respectively, using the following categorizations:

- **Data input errors** — This includes any price corrections due to incorrect data input that is not influenced by an ISO internal process, such as receiving bad telemetry or receiving inaccurate default energy bids. These are represented by the blue bars.
- **Software and hardware errors** — These are attributed to the market software functionality and are not related to the ISO internal process, and are represented by the red bars.
- **Results inconsistent with tariff** — This includes market results that are inconsistent with the ISO tariff and are represented by the yellow bars.
- **Process errors** — These are errors originating in an error or flaw in an internal ISO process. Such errors resulted in invalid market input data or in results inconsistent with the tariff, which are reasons for price corrections. These errors include among others market application errors, incorrect actions of the dispatchers and incorrect model outages. These are represented by the green bars.

While the total frequency of price corrected intervals increased from 2011 to 2012, the percentage of corrected nodes decreased during the same period by 10 percent. This occurred because systemwide price corrections were more common in 2011. In 2012, corrections related to congestion were more common. One system-wide interval price correction can often fix more nodes than multiple intervals of localized price corrections.

[139] The ISO corrects prices pursuant to tariff Section 35.

The most frequent price correction category by both interval and node was process errors. This type of error occurred in 0.78 percent of intervals in 2012, up from 0.59 percent in 2011. However, process errors occurred in 0.14 percent of nodes in 2012, down from 0.17 percent in 2011. The most significant process errors include the following categories: market application errors, model promotions errors, invalid outages and incorrect load adjustments.

The second most frequent price correction category was hardware and software issues, representing 0.18 percent of the corrected intervals in both 2011 and 2012. On the nodal level, these corrections represented 0.05 percent of nodal corrections in 2012, down from 0.09 percent in the previous year. In 2011, interval software errors were more evenly distributed across each quarter, while in 2012 most of the intervals were corrected in the fourth quarter. In 2012, more intervals and fewer nodes were impacted by software defects.

Numerous participants have expressed concern with the ISO price correction process. DMM recognizes that price corrections are inevitable, given the growing complexity of the market software and the need for prices to reflect just and reasonable rates. In late 2011, the ISO centralized the function of validating prices and the quality of the market solution into a new group. The main objective of this group is to continue to perform timely price validation using consistent and enhanced procedures, and to provide feedback to other groups to help reduce the incidence of recurring price corrections.

The ISO has also established a root-cause process to engage various business units within the ISO that may impact data inputs being used in the market software. One of the process improvements that has been put in place as a result of this effort is proactive validation of the day-ahead market inputs and results. This process includes running the day-ahead market software two days in advance in order to identify and address issues prior to the actual day-ahead market process.

DMM also recognizes the importance of price accuracy. While the ISO is improving the quality and accuracy of the prices, there appears to still be room for improvement in the ISO processes that drive the need for price correction and process for reporting feedback that identifies areas for improvement.

Figure 8.15 Frequency of price corrections by category and interval in 2012

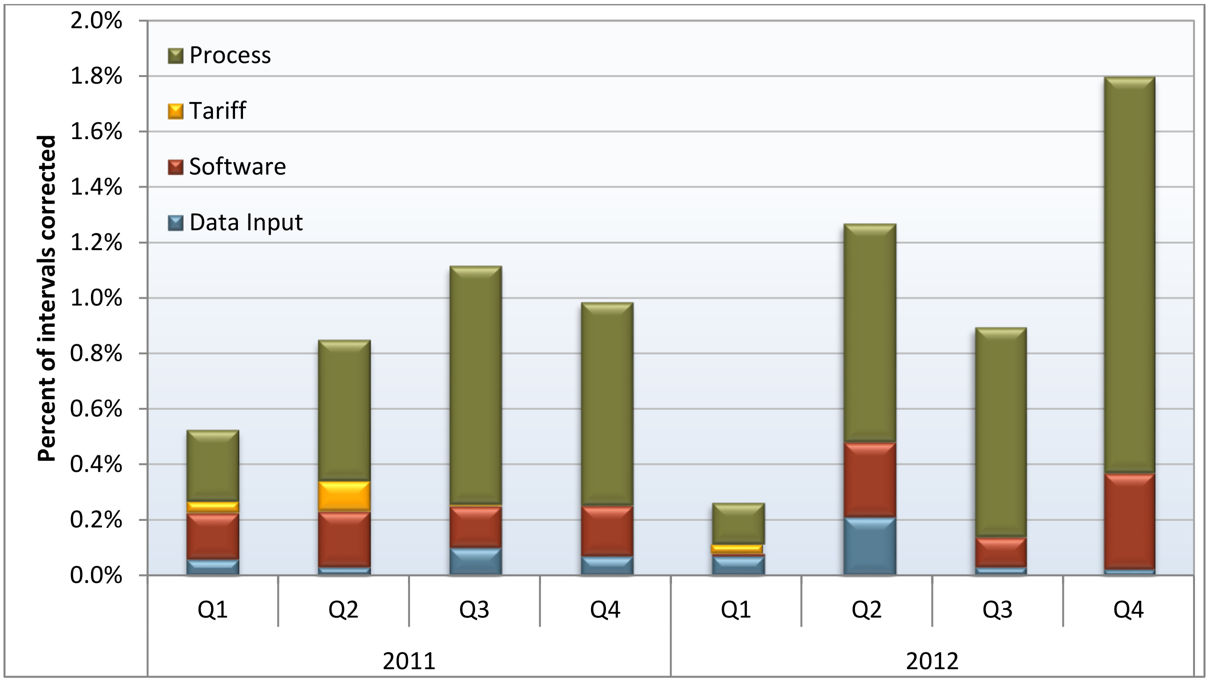
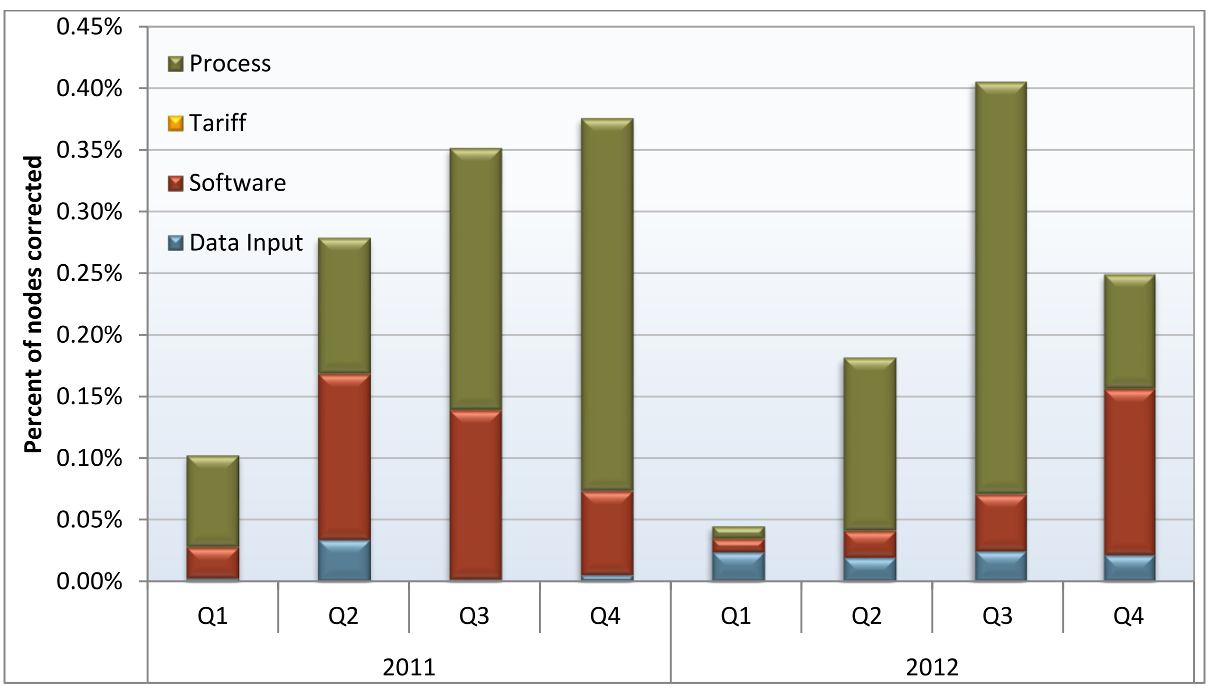


Figure 8.16 Frequency of price corrections by category and by nodal prices corrected in 2012



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 2012. 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. In 2012, this includes all hours with peak load over 38,925 MW. Key findings of this analysis include the following:

- During the 210 hours with the highest loads, about 91 percent of resource adequacy capacity was available to the day-ahead energy market and the residual unit commitment process. This is approximately equal to the target level of availability incorporated in the resource adequacy program design and similar to the availability in 2011.

- Capacity made available under the resource adequacy program in 2012 was mostly sufficient to meet system-wide and local area reliability requirements. However, due to the outage of the two SONGS units and potential local contingencies in certain areas, the ISO frequently relied on the capacity procurement mechanism provisions of the ISO tariff.

- Output of wind and solar resources during these peak hours appeared to be generally lower than their resource adequacy capacities, most of which are based on resource performance over the prior three years. These intermittent resources are currently used to meet a small portion of overall resource adequacy capacity requirements, but may be used to meet a growing portion of these requirements in future years. The CPUC is reportedly considering modifications to the current methodology for determining the resource adequacy rating of intermittent resources.

The resource adequacy program was not designed to serve as a mechanism for longer-term investments and contracting needed to ensure future supplies. The potential retirement of the Sutter Energy Center in late 2011 highlighted several key limitations of the current resource adequacy program and the backup capacity procurement mechanism in the ISO tariff.[140] Both of these mechanisms are based on procurement of capacity only one year in advance. In addition, neither of these mechanisms incorporates any specific capacity or operational requirements for the type of flexible capacity characteristics that will be needed to integrate the large volume of intermittent renewable resources coming online in the next few years.

In 2012, the ISO began a collaborative initiative with investor-owned utilities and other stakeholders to propose that the CPUC establish a multi-year resource adequacy requirement, including flexibility requirements, in the CPUC proceeding that would establish resource adequacy requirements starting in 2014. This could be followed by development and implementation of a more comprehensive solution for subsequent years. In addition, the ISO began the process of working with stakeholders – including

[140] For more detail on this issue, see *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, p. 193. http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

the CPUC and other local regulatory authorities that also set resource adequacy requirements – to integrate these potential new flexible capacity requirements into its tariff. In February 2013, the ISO and CPUC also took steps toward further discussion and potential development of a forward capacity market.[141]

9.1 Background

The resource adequacy provisions of the ISO tariff require load-serving entities to procure generation capacity to meet 115 percent of their forecast peak demand in each month.[142] The 115 percent requirement is designed to include the additional operating reserve needed above peak load (about 7 percent), plus an allowance for outages and other resource limitations (about 8 percent). This capacity must then be bid into the market through a must-offer requirement. Load-serving entities provide these resource adequacy showings to the ISO on a year-ahead basis 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, with a total capacity of around 25,000 MW. If the market participant does not submit bids or report capacity as being on outage, the ISO automatically creates bids for these resources.

Imports represent around 10 percent of resource adequacy capacity. Beginning on January 1, 2012, the ISO began to automatically create default 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 hour-ahead market. If an import clears the day-ahead market and is not self-scheduled or re-bid, 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:

- 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.[143]
- Non-dispatchable generators, which include nuclear, qualifying facilities, wind, solar and other miscellaneous resources. These resources account for about 17 percent of capacity.

[141] The ISO and CPUC co-hosted a summit to educate key decision makers and stakeholders about the current status of California's energy market construct for long-term resource adequacy and to identify alternatives to the existing framework based on experience from energy markets in other regions. Information from the summit can be found at: http://www.caiso.com/informed/Pages/MeetingsEvents/PublicForums/Long-TermRASummit.aspx.

[142] 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.

[143] Use-limited thermal resources generally have environmental or regulatory restrictions on the hours they can operate, such as a maximum number of operating hours in a month or year. 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. These plans describe their restrictions and outline their planned operation.

All available resource adequacy capacity must be offered in the ISO market through economic bids or self-schedules.

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 2012, 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 2012. The red line shows the total amount of this capacity used to meet resource adequacy requirements.[144] 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.[145]

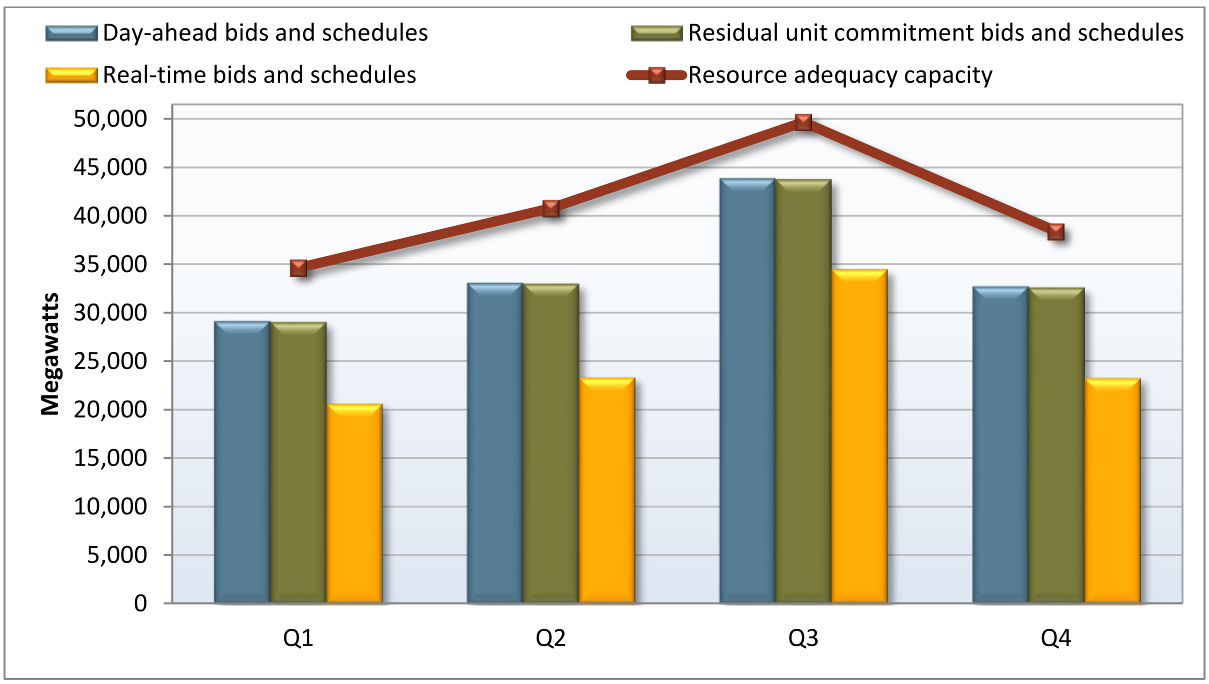
[144] The resource adequacy capacity included in this analysis excludes as much as 5,000 MW of resource adequacy capacity for which this analysis cannot be performed or is not highly meaningful. This includes resource adequacy resources representing some imports and firm import liquidated damages contracts, resource adequacy capacity from reliability must-run resources, resource adequacy requirements met by demand response programs, and load-following metered subsystem resources.

[145] 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.

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 the 49,700 MW of resource adequacy capacity included in this analysis, an average of around 43,900 MW (or about 88 percent) was available in the day-ahead market.
- The lowest level of availability was during the second quarter, during which about 81 percent of resource adequacy capacity was available to the day-ahead market.
- Over all months, virtually 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 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 (2012)



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.[146] The rules do not specify that these hours must include the hours of the highest load or most critical system conditions. Since participants do not have perfect foresight when the highest loads will actually occur, the program assumes that they will manage these use-limited generators so that they are available during the peak load hours.

Each of the last four years, DMM has evaluated the availability of resource adequacy during the 210 hours with the highest system loads to provide an indication of how well program requirements are meeting actual peak loads. In 2012, this includes all hours with peak load over 38,925 MW.

Figure 9.2 provides an overview of monthly resource adequacy capacity, monthly peak load, and the number of hours with loads over 38,925 MW during that period. Most of the highest load hours occurred during persistent heat waves in August. 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.

Figure 9.3 shows the amount of capacity scheduled or bid in the day-ahead and real-time market during these 210 peak hours. These results are ranked in descending order of total resource adequacy megawatts bid or scheduled in each of the three markets listed below.[147] Figure 9.3 indicates the following:

- ***Day-ahead market*** — Bids and self-schedules for resource adequacy capacity in this market averaged about 87 percent of overall resource adequacy capacity, varying in individual hours from about 79 to 94 percent of resource adequacy capacity.
- ***Residual unit commitment*** — Resource adequacy capacity available to this process was 87 percent of overall resource adequacy capacity, just slightly less than the amount available to the day-ahead market.
- ***Real-time market*** — Bids and self-schedules for resource adequacy capacity in the real-time market averaged about 75 percent of overall resource adequacy capacity, varying in individual hours from about 62 to 85 percent. This primarily reflects the fact that many gas-fired units not committed in the day-ahead market are unavailable to start-up in real-time. A limited amount of imports and use-limited gas units are also not required to be offered in the real-time market when not scheduled in the day-ahead market.

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

[147] Real-time bid amounts shown include energy bids and self-schedules for energy from resource adequacy capacity submitted to the real-time market and included in a day-ahead energy schedule.

Figure 9.2 Summer monthly resource adequacy capacity, peak load, and peak load hours (May through September 2012)

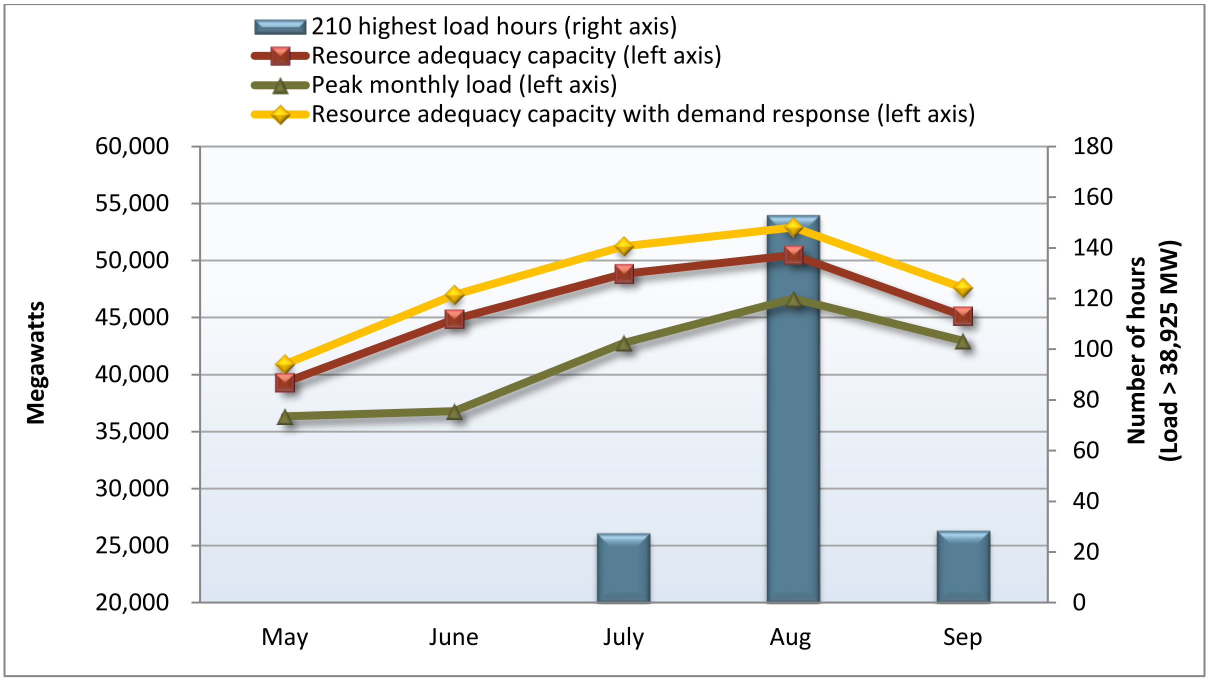


Figure 9.3 Resource adequacy bids and self-schedules during 210 highest peak load hours

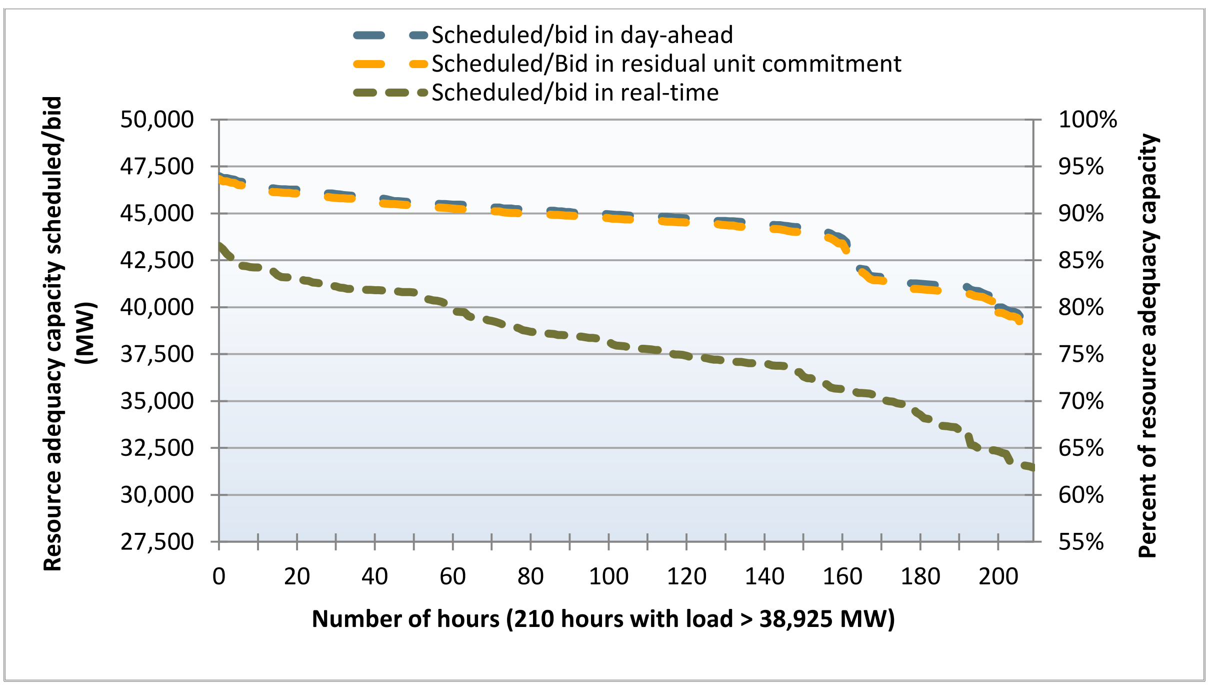


Table 9.9.1 provides a detailed summary of the availability of resource adequacy capacity over the 210 summer peak load hours for each type of generation. Separate sub-totals are provided for resources for which the ISO creates bids if market participants do not submit a bid or self-schedule, and resources for which the ISO does not create bids. As shown in Table 9.9.1:

- ***Resource adequacy capacity after reported outages and derates*** — Average resource adequacy capacity was around 50,699 MW during the 210 highest load hours in 2012. After adjusting for outages and derates, the remaining capacity equals about 91 percent of the overall resource adequacy capacity. This represents an outage rate of about 9 percent during these hours.
- ***Day-ahead market availability*** — For the 24,581 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 83 percent of the available capacity of these resources after accounting for reported derates and outages. This compares to the 91 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 9.9.1 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. An average of about 87 percent of the resource adequacy capacity that was potentially available to the real-time market was scheduled or bid in the real-time market.
- ***Use limited gas units*** — Almost 4,000 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 88 percent of this capacity was available in the day-ahead market during the highest 210 load hours. In real-time, about 2,330 MW of this 4,000 MW of capacity was scheduled or bid into the real-time market. Due to the outage of SONGS units and the reduction in hydro capacity, load-serving entities used more capacity from use-limited gas units.
- ***Nuclear units*** — Around 5,000 MW of nuclear capacity were used to meet resource adequacy requirements in 2011. This capacity was reduced to around 3,600 MW prior to the summer of 2012 to reflect about 1,400 MW of capacity from the two SONGS units that were expected to be unavailable by that time. However, the outage of the two units made them completely unavailable in the summer months. This was reflected in Table 9.9.1 where 21 percent of the nuclear capacity used to meet resource adequacy requirements (or about 700 MW) were not available in the peak hours of the summer. SCE compensated for some of this unavailable nuclear capacity with new resource adequacy contracts from other resources, which were mainly gas units.
- ***Imports*** — Around 5,300 MW of imports were used to meet resource adequacy requirements. About 99 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. As a result, about 94 percent of this capacity was also scheduled or bid into the real-time market. The availability of imports is discussed in more detail in Section 9.4.

The availability of wind, solar, qualifying facilities, and other non-dispatchable resources is discussed in more detail in Section 9.5.

Table 9.9.1 Average resource adequacy capacity and availability during 210 highest load hours

Resource type	Total resource adequacy capacity (MW)	Net outage adjusted resource adequacy capacity		Day-ahead bids and self-schedules		Residual unit commitment bids		Total real-time market resource adequacy capacity (MW)	Real-time market bids and self-schedules	
		MW	% of total RA Cap.	MW	% of total RA Cap.	MW	% of Total RA Cap.		MW	% of real-time RA Cap.
ISO Creates Bids:										
Gas-Fired Generators	25,243	23,078	91%	23,071	91%	23,068	91%	20,777	19,064	92%
Other Generators	875	765	87%	761	87%	761	87%	873	744	85%
Subtotal	**26,118**	**23,843**	**91%**	**23,832**	**91%**	**23,830**	**91%**	**21,650**	**19,808**	**91%**
ISO Does Not Create Bids:										
Use-Limited Gas Units	3,983	3,493	88%	3,334	84%	3,334	84%	2,582	2,328	90%
Hydro Generators	6,502	5,651	87%	4,847	75%	4,781	74%	6,502	4,746	73%
Nuclear Generators	3,602	2,841	79%	2,840	79%	2,840	79%	2,841	2,839	100%
Wind/Solar Generators	910	897	99%	525	58%	525	58%	910	910*	100%
Qualifying Facilities	3,438	3,278	95%	3,056	89%	3,056	89%	3,341	2,857	86%
Other Non-Dispachable	835	830	99%	609	73%	608	73%	834	660	79%
Imports	5,311	5,311	100%	5,241	99%	5,241	99%	4,950	4,646	94%
Subtotal	**24,581**	**22,301**	**91%**	**20,452**	**83%**	**20,384**	**83%**	**21,960**	**18,076**	**82%**
Total	**50,699**	**46,144**	**91%**	**44,284**	**87%**	**44,214**	**87%**	**43,610**	**37,884**	**87%**

* 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 much of their resource adequacy requirement. There are roughly 11,000 MW of total import capability into the ISO system and net imports averaged about 9,300 MW during the peak summer months. Utilities used imports to meet over 5,000 MW, about 9 percent, of the resource adequacy requirements. This reflects a 25 percent increase in the resource adequacy capacity from imports in 2012, compared to 2011.

Imports used to meet resource adequacy requirements are not required to originate from generating units or be backed by specific portfolios of generating resources. In addition, resource adequacy imports are only required to 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 hour-ahead market.

In prior years, market participants have self-scheduled a very large portion of resource adequacy imports in the day-ahead market, noted in previous DMM annual reports. Most of the remainder of these imports was bid at relatively low prices. However, this changed in 2012 when the quantity and prices of economic bids for some resource adequacy imports started to increase.

Figure 9.4 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 or economically bid in the day-ahead market. The gold line (plotted against the right axis) shows the average maximum bid prices for resource adequacy import resources for which market participants submitted economic bids to the day-ahead market.

Compared to 2011, the quantity of imports with economic bids in 2012 increased by around 16 percent, while the quantity of self-scheduled bids decreased by 18 percent. Most of the increase in economic bids occurred in the second half of the year (see Figure 9.4). In the fourth quarter of 2012, the quantity of economic bids surpassed the quantity of self-scheduled bids. Even though more economic bidding was used, DMM's analysis shows that day-ahead schedules from resource adequacy imports in 2012 were only slightly lower, by less than 1 percent, than in 2011.

Figure 9.4 Resource adequacy import self-schedules and bids (peak hours)

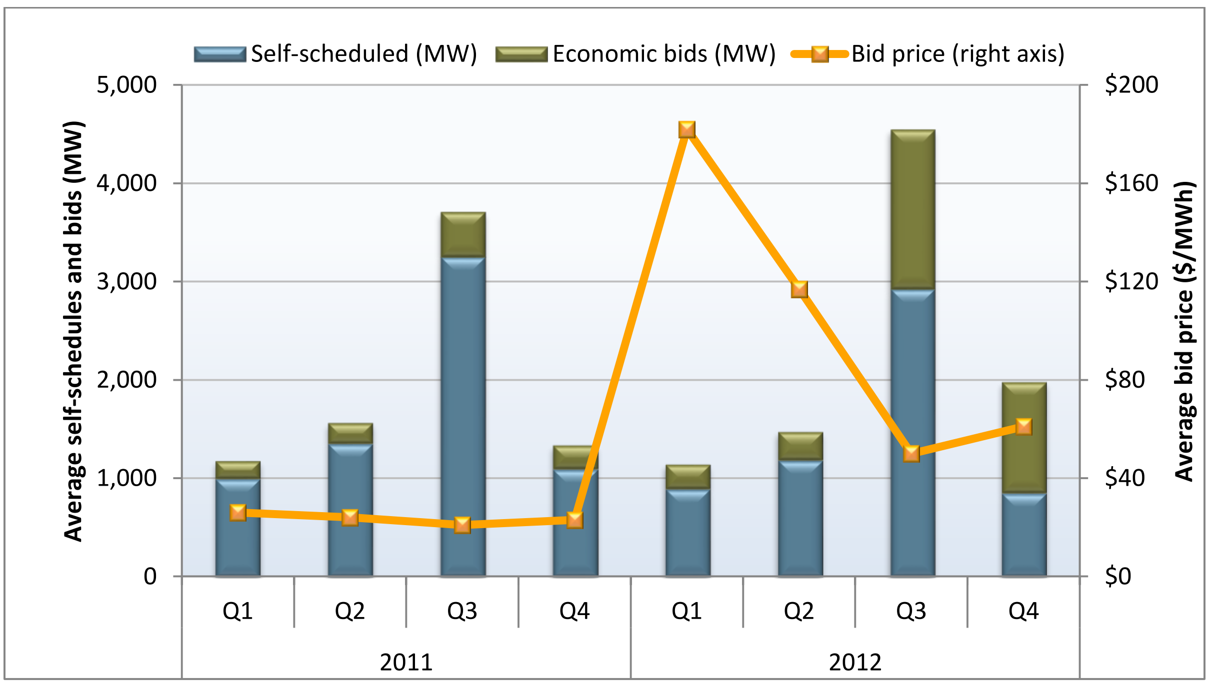


Figure 9.4 also shows that market participants submitted notably higher-priced economic bids in 2012. The weighted average of bid prices increased from $23/MWh in 2011 to $70/MWh in 2012. In the first half of the year, a handful of imports bid especially high prices ($500/MWh or higher). Since the quantity of economic bids was relatively small in the first half of the year, this caused much higher

average bid prices. Later in the year, weighted average bid prices decreased, as there were higher volumes of economic bids with lower bid prices.

This change may be partly attributable to the change in rules requiring resource adequacy imports to bid into the day-ahead market. In the event that no bid is submitted for import capacity that is not reported to be unavailable due to an outage, the ISO now submits a default bid for the capacity. This new rule may cause importers of resource adequacy capacity to submit relatively high economic bids in the day-ahead market rather than not offer this capacity into the market.

9.5 Intermittent resources

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

The net qualifying capacity of wind and solar resources is based on the output that they exceed in 70 percent of peak hours (1:00 p.m. to 6:00 p.m.) during each month over the previous three years.[148] These amounts are adjusted upward by a factor that reflects the system-wide benefit that is assumed to result from a low covariance between the outputs of many individual intermittent generators. The CPUC is reportedly considering modifications to the current methodology for determining the resource adequacy rating of intermittent resources.

This analysis compares the following three measures of different types of intermittent resource capacity:

- The estimated amount of capacity from these resources used to meet 2012 resource adequacy requirements or the net qualifying capacity.
- The estimated values of the 70th percentile of the output of these resources during hours used to calculate the net qualifying capacity (weekdays from 1:00 p.m. to 6:00 p.m.).
- The estimated values of the 70th percentile of the output of these resources during the 210 highest load hours in 2012.

Figure 9.5 and Figure 9.6 show this comparison for wind and solar resources.[149] As shown in Figure 9.5, in July and August, DMM's estimates of wind resources' output (at the 70th percentile) in both the hours used to calculate net qualifying capacity and the 210 highest load hours were less than their resource adequacy capacity.[150] In July and August of 2012, capacity factors from wind units appeared to be generally lower than 2011 both for the resource adequacy units and for all wind resources. Moreover, there were a handful of new wind units that came online in 2012 and their generation performances

[148] This methodology sorts the generation from a specified period in a descending order and calculates the 70th percentile of the observations of each month. The calculated value at the 70th percentile means that the generation is expected to be above the calculated value 70 percent of the time.

[149] DMM excluded one wind outlier in the resource adequacy capacity data that did not appear consistent with the general resource adequacy capacity values. This outlier was likely to skew the results.

[150] Note that the calculated 70th percentile refers to a minimum generation value. That is, generation is expected to be above this calculated value 70 percent of the time.

appeared to be lower than their estimated resource adequacy capacities. In contrast, output from wind resources in September exceeded their resource adequacy capacity. Also, in September, wind output was higher in the highest peak load hours than in the hours used to determine the net qualifying capacity. Resource adequacy capacity and wind generation were significantly less in September than the previous two months.

Figure 9.6 shows a comparison of the same data for solar resources in July through September. Solar output in hours used to calculate net qualifying capacity was greater than the output in the 210 highest summer peak load hours in July and August. In all three months, the solar resources' output in both the hours used to calculate net qualifying capacity and the 210 highest load hours were less than their resource adequacy capacity. Actual solar output in the 210 highest summer peak load hours equaled about 90 percent of solar resource adequacy capacity during these months.

Figure 9.7 provides a similar analysis for qualifying facilities and other miscellaneous non-dispatchable resources. The net qualifying capacity of qualifying facilities and other non-dispatchable resources is based on their average output during peak hours over the previous three years and is calculated for each month. An annual net qualifying capacity value is calculated based on their output during the summer months. This analysis shows the average actual output of these resources during these hours.

As shown in Figure 9.7, the output of these resources in July through September 2012 during hours used to calculate net qualifying capacity was less than their output in the 210 highest load hours. In July and August, resource adequacy capacity was higher than both net qualifying capacity output and actual output in the 210 highest load hours.

Figure 9.5 Resource adequacy capacity available from wind resources

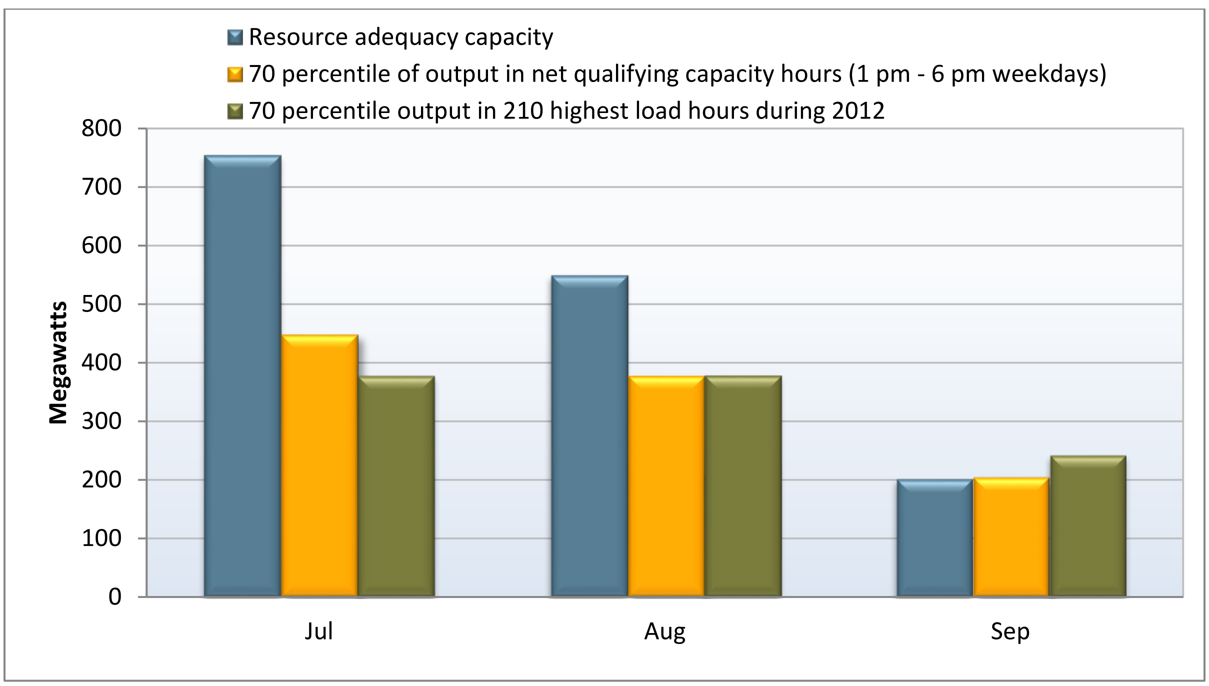


Figure 9.6 Resource adequacy capacity available from solar resources

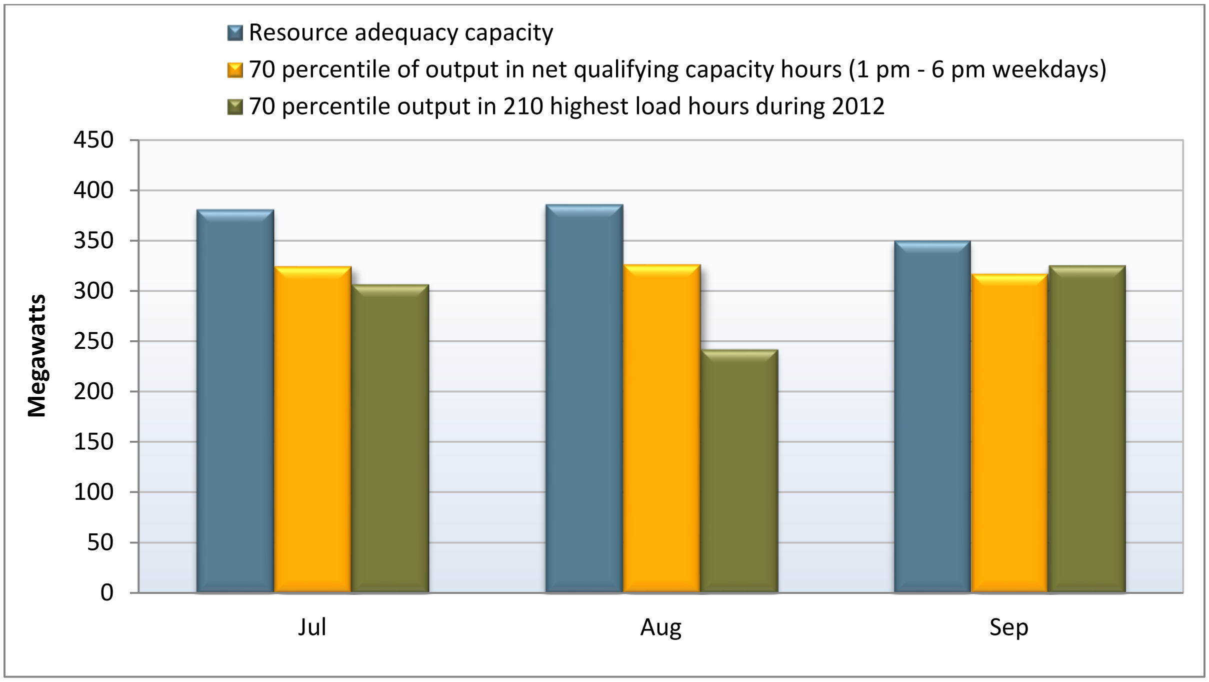
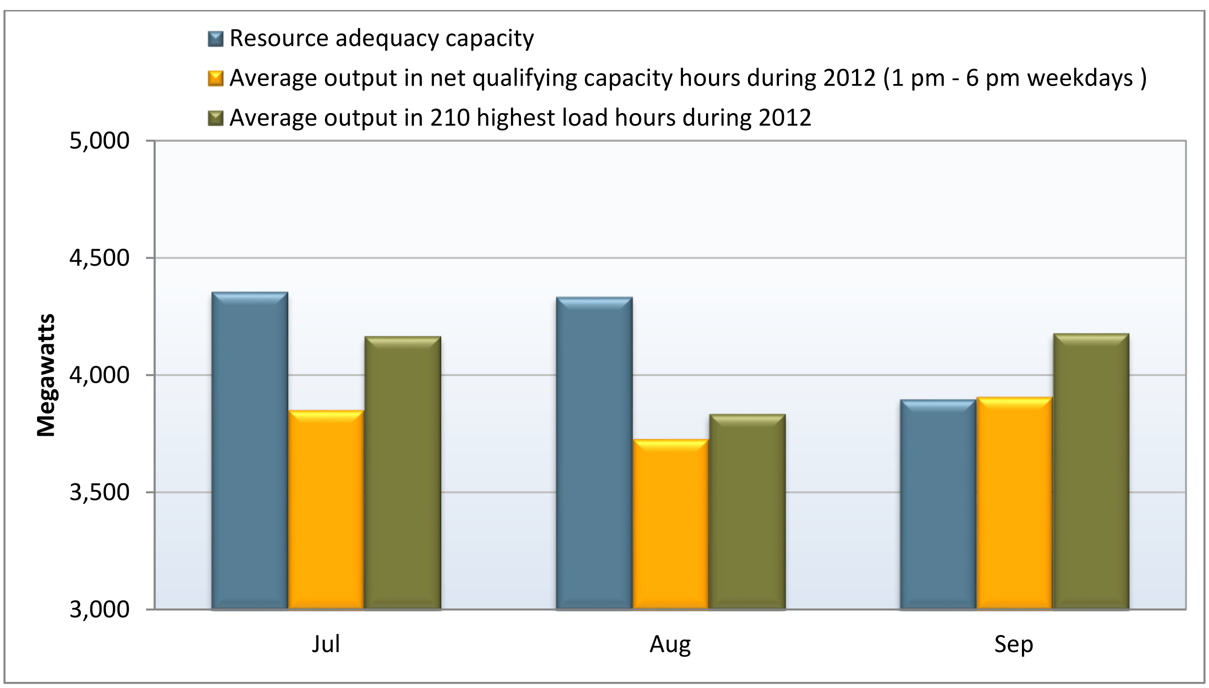


Figure 9.7 Resource adequacy capacity available from qualifying facility resources



9.6 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.

Since 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 has been relatively low. These costs totaled around $7 million and $6 million in 2011 and 2012, respectively.

However, while reliability must-run payments remained low, capacity payments related to the capacity procurement mechanism increased. The increase in the capacity procurement mechanism payments in 2012 were directly related to the outages of SONGS units 2 and 3, which were offline for almost all of 2012 due to a combination of both planned and forced outages as well as for testing of critical systems.

These combined outages created local reliability concerns. In response to the outages of the SONGS units, the ISO used the capacity procurement mechanism to procure a total capacity of 966 MW (as shown in Table 9.2). The procurement periods varied from one month to six months and procurement cost totaled about $26 million in 2012. In 2011, capacity procurement mechanism payments totaled around $1.5 million.

Table 9.9.2 Capacity procurement mechanism costs (2012)

Resource	Local capacity area	CPM designation (MW)	Estimated cost	CPM designation dates
Huntington Beach Unit 1	LA Basin	20	$121,810	2/8 - 3/8
Huntington Beach Unit 1	LA Basin	98	$1,255,748	3/1 - 4/29
Encina Unit 4	San Diego	300	$3,844,125	3/1 - 4/29
Huntington Beach Unit 1	LA Basin	226	$2,892,704	5/1 - 6/29
Huntington Beach Unit 3	LA Basin	225	$8,360,972	5/11 - 10/31
Huntington Beach Unit 4	LA Basin	215	$7,989,373	5/11 - 10/31
Huntington Beach Unit 1	LA Basin	226	$1,446,352	9/5 - 10/4
		966*	**$25,911,084**	

* All the units are dispatched due to the outages of San Onofre Generating Stations Units 2 and 3.

9.7 Resource adequacy developments

The resource adequacy program was not designed to serve as a mechanism for longer-term investments and contracting needed to ensure future supplies. The potential retirement of the Sutter Energy Center in late 2011 highlighted several key limitations of the current resource adequacy program and the backup capacity procurement mechanism in the ISO tariff.[151]

[151] For more detail on this issue, see *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, p. 193: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

In late 2011, Calpine Corporation informed the ISO that it intended to retire a 550 MW combined cycle unit (Sutter Energy Center) in 2012 unless it either received a resource adequacy contract or was contracted by the ISO through the capacity procurement mechanism. While the ISO determined that this capacity was not needed in 2012, the ISO indicated the unit is likely to be needed in 2017 due to the potential retirement of other existing gas-fired capacity as a result of the state's once-through-cooling regulations. The Sutter unit was specifically needed since it can provide flexible ramping capabilities that will be needed to integrate the large volume of intermittent renewable resources coming online in the next few years.[152]

In March 2012, the CPUC approved a resolution that directed three of the state's investor-owned utilities to start resource adequacy contract negotiations with Calpine to allow the Sutter unit to remain operational in 2012. By June, Calpine officially withdrew its request for capacity procurement mechanism designation as it had obtained approval for their resource adequacy contracts for the Sutter unit and these contracts were approved by the CPUC. Soon after, the ISO determined that ISO action with FERC to support the procurement of the Sutter capacity through a resource adequacy contract was not necessary and the waiver petition was withdrawn.

This case has highlighted several key limitations of the state's current long-term procurement planning and resource adequacy programs.

- Neither of these processes incorporates 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 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 these procurement mechanisms and the multi-year timeframe over which some units at risk of retirement may need to be kept online to meet projected future needs for system flexibility or local reliability requirements.

The ISO and other entities have taken several steps to address these issues:

- In 2012, the ISO completed a stakeholder process to develop an interim mechanism in the ISO tariff to ensure the ISO has sufficient backstop procurement authority to procure any capacity at risk of retirement not contracted under the resource adequacy program that the ISO identifies as needed up to five years in the future to maintain system flexibility or local reliability. However, in early 2013, FERC rejected the ISO's tariff filing to establish this backstop procurement authority.[153]

- A collaborative initiative by the ISO and investor-owned utilities in 2012 proposed that the CPUC incorporate flexibility requirements into its resource adequacy process. This resulted in the CPUC considering a flexible capacity requirement in its current resource adequacy proceeding and will potentially result in a flexible capacity requirement for capacity procured for 2014.

- In 2012, the ISO also started a new stakeholder process, flexible resource adequacy criteria and must-offer obligations. As described above, the ISO is working with the CPUC, other regulatory

[152] For a detailed discussion see California Independent System Operator Corporation Petition for Waiver of Tariff Revisions and Request for Confidential Treatment, January 25, 2012: http://www.caiso.com/Documents/2012-01-26_ER12-897_Sutter_Pet_TariffWaiver.pdf.

[153] For further details see *Flexible Capacity Procurement Market and Infrastructure Policy Straw Proposal*, March 7, 2012: http://www.caiso.com/Documents/StrawProposal-FlexibleCapacityProcurement.pdf.

authorities and stakeholders to integrate requirements for new categories of flexible resource characteristics into the resource adequacy program.[154] The ISO envisions that this stakeholder process will result in flexible capacity requirements, backstop procurement provisions and availability metrics.

[154] For further details on this market initiative see the stakeholder process site: http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx.

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's recommendations on five major current market design issues:

- Re-design of the hour-ahead and 5-minute real-time markets.
- Flexible ramping product.
- Modeling enhancements to protect against contingencies.
- Procurement of flexible capacity multiple years in advance.
- Centralized capacity market.

DMM has also provided a variety of specific recommendations for short-term market improvements in our prior annual and quarterly reports. This chapter summarizes DMM recommendations on several of these issues, along with steps that have been taken or are underway to address these issues.

10.1 Current market design issues

Re-design of the real-time market

In June 2012, FERC approved Order No. 764, which is designed to remove barriers to the integration of variable energy resources by requiring every transmission provider to allow adjustment of energy schedules between balancing areas every 15 minutes, rather than allowing only hourly scheduling on inter-ties. The ISO viewed Order No. 764 as an opportunity to implement real-time market changes that were not possible before the order. In addition to providing an improved scheduling framework for variable energy resources, the ISO also sought to address some of the fundamental market inefficiencies that lead to high real-time energy imbalance offset costs and the suspension of virtual bidding on inter-ties.

By early 2013, the ISO was completing development of a proposal to re-design its real-time dispatch and scheduling process.[155] The ISO's proposed changes better integrate the process for dispatching and settling inter-tie transactions between the ISO and other balancing areas with the 5-minute process used to dispatch and settle resources within the ISO. Currently, almost all inter-tie transactions consist of fixed hourly imports and exports established in the hour-ahead market. The ISO's current real-time market also includes a 15-minute process for real-time unit commitment and procurement of incremental ancillary services. Under the proposed changes, dispatches and prices produced by this 15-minute dispatch market will be financially binding for all internal generation and inter-tie transactions.

DMM worked closely with the ISO and stakeholders in developing these market design changes, which include several key modifications made to address concerns identified by DMM. We are very supportive

[155] For further information, please see the ISO's Draft Final Proposal posted on March 26, 2013: http://www.caiso.com/Documents/DraftFinalProposal-FERC-Order764MarketChanges.pdf.

of the final proposal and believe it represents a major improvement over the current market structure. Compared to the current hour-ahead market, dispatches and prices produced in the 15-minute process should be much more consistent with 5-minute market results. DMM's more specific comments on these proposed design changes include the following:

- **Real-time imbalance offset costs.** The proposed changes should significantly reduce revenue imbalances allocated to load through real-time imbalance offset charges by decreasing the difference in prices used to settle inter-tie transactions and 5-minute prices currently used to settle energy from resources within the ISO. However, as discussed in Chapter 3, DMM cautions that despite the proposed market improvements large real-time revenue imbalances could still occur if transmission limits are adjusted downward after the day-ahead market to account for unscheduled flows when congestion occurs. This creates offset costs by reducing the volume of energy flows in the real-time market over congested constraints. Thus, it will remain important for the ISO to continue efforts to improve modeling of flows in these two markets, so that the need to reduce flows in real-time by adjusting constraint limits downward is reduced.
- **Fixed hourly inter-tie transactions.** Under the ISO proposal, a portion of imports and exports will continue to be bid and scheduled on an hourly basis as part of an hour-ahead scheduling process. However, fixed hourly schedules resulting from this process will be settled based on prices that are determined through the dispatch process that is performed each 15-minutes throughout the operating hour. Bid cost recovery will not be paid if these 15-minute prices fail to cover the bid price of fixed hourly transactions. DMM recommends this approach since it creates appropriate price signals that more closely reflect the value of fixed hourly-block resources and provides an incentive to transition to providing 15-minute scheduling flexibility.
- **Virtual bidding.** The ISO is proposing to re-implement virtual bidding on inter-ties in conjunction with these market design changes. Virtual bids on inter-ties and internal locations within the ISO will all be settled at the 15-minute prices. This eliminates the problem that led to high revenue imbalance costs and the suspension of virtual bidding on inter-ties in late 2011.[156] However, DMM cautions that virtual bidding on inter-ties could inflate real-time revenue imbalances in the event that constraint limits need to be adjusted downward in the 15-minute process to account for unscheduled flows not incorporated in the day-ahead market model, as noted above. Thus, DMM recommends the ISO carefully consider this issue and that if virtual bidding on inter-ties is re-implemented this be done in a very limited and gradual manner that is contingent on the observed performance of this new market design.
- **Scheduling of variable energy resources.** The proposed changes allow variable energy resources to reserve hourly inter-tie transmission capacity to accommodate fluctuations in these resources' 15-minute schedules. Hourly transmission capacity reserved for variable energy resources will either become financially binding or released for other resources in the 15-minute market. However, this has the potential to displace inter-tie resources with fixed hourly schedules. Consequently, DMM has recommended that the ISO retain the authority to utilize 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.

[156] 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.

The ISO currently plans on filing this proposal with FERC in late 2013 for implementation in spring 2014.

Flexible ramping product

The ISO is proposing to replace the flexible ramping constraint currently incorporated in the real-time market software with a flexible ramping product to be implemented in late 2014. This product would be procured in both the day-ahead and real-time markets. DMM is supportive of this product as a more effective way of ensuring operational ramping flexibility than the current flexible ramp constraint.

The ISO's flexible ramping product proposal contains several provisions relating to market power mitigation. The proposal includes a bid price cap of $250/MW which is consistent with the existing caps on ancillary services. The ISO will also seek to procure substantial portions of capacity in the day-ahead market. This will help address potential temporal market power that may arise subsequently in the real-time market by securing a majority of the requirement under conditions where the market has more choices.

The flexible ramping product proposal also includes a provision that ensures all energy bid into the day-ahead and real-time markets is available to meet market requirements for this product. This will help ensure sufficient supply exists to meet the requirements by preventing physical withholding. However, these provisions do not prevent the exercise of market power by bidding up to the $250/MW bid cap.

Since this product will be procured to a system-wide requirement, DMM does not view additional mitigation measures as necessary. However, the ISO has left open the potential to procure flexible ramping product regionally, which would require further assessment of competitiveness and potentially additional mitigation measures.

Contingency modeling enhancements

After a real-time transmission or major generation outage, flows on other transmission paths may begin to exceed their *system operating limit*. According to 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 its system operating limit (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.

Some stakeholders have objected to the use of exceptional dispatches and minimum online capacity constraints to help meet these reliability requirements since this approach does not incorporate resources' commitment costs into locational marginal prices. The ISO has identified these reliability requirements as one of the primary drivers of exceptional dispatches, and has placed a high priority on reducing the need for exceptional dispatches to meet these requirements. Meeting these requirements by constraints directly incorporated in the market model is also likely to allow these constraints to be met more efficiently by the overall market optimization.

As part of an initiative to reduce the need for exceptional dispatches, 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.[157] 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.

DMM is highly supportive of this initiative. The initiative directly addresses one of the recommendations in our 2011 annual report, in which we recommended that ISO monitor and seek to limit exceptional dispatches related to needs for online capacity and ramping capability to meet overall system and south of Path 26 needs.[158] From DMM's perspective, one of the main additional benefits of this approach is that it will allow these reliability requirements to be met more efficiently, since 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.

Incorporating these reliability requirements into the market model should also allow the ISO to develop and implement automated rules within the market software for mitigating any market power that may exist by resources capable of meeting these requirements. In some cases, requirements that can only be met by resources controlled by a limited number of suppliers would give rise to local market power. In the real-time market, temporal market power may also exist in cases when only a limited number of resources that are capable of meeting a requirement are committed to operate. Once additional information is available on these requirements and how they will be modeled, DMM will work with the ISO to determine if additional market power mitigation provisions are needed and, if so, how these might be incorporated into the market process in the most automated manner possible.

Forward procurement of flexible capacity

Background

Under current market conditions, additional new generic gas-fired capacity does not appear to be needed at this time. 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 capacity is also needed to provide the operational flexibility needed to integrate and back up the large volume of intermittent renewable resources coming online. This capacity is increasingly uneconomic to keep available without some form of capacity payment and will need to be retrofitted or replaced to eliminate use of once-through-cooling technology over the next decade. Under current market conditions, even relatively new gas-fired capacity without once-through-cooling may be uneconomic to continue operating without significant revenues from capacity payments.

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. However, in 2011, it also became apparent that a gap exists between the state's current

[157] *Contingency Modeling Enhancements Issue Paper*, March 11, 2013, http://www.caiso.com/Documents/IssuePaper-ContingecyModelingEnhancements.pdf.

[158] *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, p. 200: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

long-term procurement planning and the one year-ahead timeframe of the state's resource adequacy program.[159] Specifically:

- Neither of these processes incorporates 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 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 these procurement mechanisms 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 is working 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, as previously summarized in Section 9.7 of this report.

Recommendations

DMM is very supportive of a multi-year capacity procurement that includes multi-dimensional flexible requirements. 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.** The ISO is developing a 5-minute flexible ramping product to be implemented in 2014. 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 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.

In the 2011 resource adequacy proceeding, the ISO proposed three different types of flexible capacity requirements (regulation, load following and maximum continuous ramping), and continues to indicate that this type of multi-dimensional flexibility requirement will be needed. The CPUC and some stakeholders expressed concern that this approach was overly complex to incorporate into the resource adequacy requirements at this time. The current interim proposal being considered in the first phase of

[159] This gap was highlighted when the ISO was notified that a large combined cycle generating unit, not under a resource adequacy contract, was scheduled for retirement. The ISO determined that the unit was not needed in 2012, but that the unit is likely to be needed in the 2017-2018 timeframe. The ISO determined that the unit would be needed to provide flexible ramping capabilities to integrate the large volume of intermittent renewable resources coming online in the next few years, given the likely retirement of other existing gas-fired capacity subject to the state's once-through-cooling regulations. See California Independent System Operator Corporation Petition for Waiver of Tariff Revisions and Request for Confidential Treatment, January 25, 2012: http://www.caiso.com/Documents/2012-01-26_ER12-897_Sutter_Pet_TariffWaiver.pdf.

a CPUC resource adequacy process to address this issue includes the same one-year time period as the current resource adequacy program, and would establish a single 3-hour continuous ramping requirement for the 2014 compliance year.

DMM believes this interim proposal is a step in the right direction, but recommends that the ISO and CPUC should continue to work toward multi-year ahead flexibility requirements which ensure that all operational and market flexibility requirements can be met by capacity procured to meet these requirements. The first phase of this process has highlighted the challenges in quantifying flexible resource capacity, specifying requirements and defining appropriate must-offer obligations linking flexible capacity procured with the ISO's operational and market needs.

For example, DMM is concerned that a single 3-hour continuous ramping requirement may not ensure that shorter-term ramping requirements are met. These shorter-term requirements include those associated with the 5-minute flexible ramping product to be implemented in 2014, as well as new model constraints being developed to ensure sufficient additional capacity is available to respond to contingencies within 30 minutes.

These issues will need to be addressed in more detail in future phases of this initiative, and as part of any proposed centralized capacity market design, as discussed below.

Forward capacity market

The ISO has suggested that a new capacity paradigm is needed in California due to the dramatic change in net load predicted to begin in 2015.[160]

DMM is supportive of efforts to begin a detailed design of a multi-year capacity market, such as a five year-ahead market. However, in prior annual reports and other comments, we have noted the difficulties of incorporating local requirements in a capacity market, defining and quantifying flexibility characteristics of different resource types, and linking forward procurement of flexible capacity to ISO operational and market needs through must-offer and price mitigation provisions.[161] These complexities must be specifically addressed well in advance of the start of a multi-year capacity market.[162] As noted above, the ISO and CPUC are engaged in a variety of initiatives in conjunction with the stakeholders in which these issues are being addressed.

Given California's current ownership of resources, environmental regulations and ISO operational requirements, a centralized capacity market may offer several significant benefits relative to the option of further modifying the state's current resource adequacy program:

[160] See the *Comprehensive Forward Capacity Procurement Framework*, CAISO, February 26, 2013: http://www.caiso.com/Documents/CaliforniaISO-BriefingPaper-LongTermResourceAdequacySummit.pdf.

[161] *2010 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2011, pp. 14-15: http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.pdf.

[162] For instance, if a resource counted toward meeting a specific flexible requirement – such as load following – then rules must be established in advance to ensure that this ramping flexibility is made available in the real-time market. Current market rules allow resources to self-schedule or bid in lower ramp rates so any fast ramping capacity procured may not actually be available to the real-time market.

- Local area reliability requirements and mitigation of local market power could be incorporated into the capacity market design itself. This would preempt the need for an outside mechanism, which does not exist under the state's current resource adequacy program.[163]
- Procurement of multiple flexible capacity requirements may be more reliably and efficiently met through a centralized market than through bilateral procurement of each flexible attribute separately.
- Experience in other ISOs suggests that a capacity market may result in increased development of energy efficiency and demand response, which are preferred resources under California's state regulatory policy guidelines. In PJM and other ISOs with capacity markets, older resources have been replaced with retrofits and demand response resources.
- A capacity market may help enable a more cost-effective response to environmental regulations – such as continuing to have enough capacity to meet local capacity requirements while meeting the state's once-through-cooling restrictions.

Other potential benefits of a capacity market are that a centralized capacity market may:

- Reduce costs by enabling competition.
- Provide greater transparency in prices and local and flexibility requirements, and more appropriate pricing of different supply options.
- Make it easier for smaller load-serving entities to buy needed amounts of each capacity requirement (e.g., system, local or type of flexibility).
- Provide a market for larger load-serving entities to sell any excess of any type of capacity that may be procured through longer-term procurement decisions as a result of changes in load growth or the mix of available resources.

10.2 Follow-up on other recommendations

Cost allocation

Recommendation: As noted in prior annual reports, DMM continues to recommend the costs of any additional products needed to integrate different resources should be allocated in a way that reflects the reliability and operational characteristics of different resources. This will help ensure proper price signals for investment in different types of new resources.

Follow-up: In 2012, the ISO completed a process to define principles that will be applied in determining cost allocation for specific market and non-market items going forward. The proposed principles include cost causation, along with providing proper incentives, participants receiving benefits, rationality (e.g., the cost of implementation relative to the cost to be allocated), and alignment with public policy. DMM has recommended that cost causation should be the driving principle of cost allocations.[164] When cost

[163] See Section 1.1.2 for a discussion of the concentration of ownership of supply within major transmission constrained areas of the ISO system.

[164] See DMM comments at http://www.caiso.com/Documents/DMM_Comments-CostAllocationGuidingPrinciplesStrawProposal.pdf.

causation is unclear or very difficult to assess, DMM believes that allocating costs based on benefits received by various participants may be appropriate and equitable.

The ISO has begun to apply these principles to the allocation of costs associated with the flexible ramping constraint implemented in December 2011 and the flexible ramping product scheduled for implementation in 2014. The current proposal of the flexible ramping product would allocate these costs in a manner that reflects the contribution of each individual resource to the real-time variability that ultimately influences the quantity and cost of procurement. This revised approach should provide an incentive for resources to reduce variability which will, over time, reduce the procurement requirement and cost associated with this product.

Improve price convergence

Recommendation: In prior reports, DMM has highlighted the lack of price convergence in the ISO markets. In particular, DMM stressed the difference between the hour-ahead and real-time markets as problematic.

Follow-up: In 2012, the ISO continued to implement additional measures as part of an effort to improve system reliability and price convergence:

- ***Derating transmission limits in the day-ahead and hour-ahead markets to better align resources to deal with anticipated transmission conditions in real-time.*** DMM was supportive of this change as it allows the day-ahead and hour-ahead markets to better reflect expected conditions in real-time, which allows for better unit commitment and inter-tie scheduling to resolve the real-time situation.

- ***Adjusting load levels in the hour-ahead and real-time markets.*** As shown in Section 8.2, the ISO adjusted load levels in the hour-ahead and 15-minute real-time pre-dispatch markets to better align resources to meet 5-minute ramping needs.

- ***Implementing the transmission reliability margin (TRM).***[165] This allows the ISO to create a transmission margin on inter-ties in the hour-ahead market to better allow for management of unscheduled flows before real-time. The ISO implemented this in the third quarter on selected paths.

- ***Enhancing compensating injections to reduce variability.***[166] As noted in prior reports, DMM found that the compensating injections used to model unscheduled flows on inter-ties were highly variable from one 15-minute interval to another. This variability appeared to reduce the effectiveness of compensating injections and even create additional difficulties in managing flows in real-time. The ISO has implemented enhancements to this software feature that have removed the variability at the aggregate level and should improve the ability to manage flows on individual constraints.

- ***Taking steps to modify transmission constraint relaxation parameters.*** In early 2013, the ISO filed with FERC tariff revisions to reduce the real-time transmission constraint relaxation parameter from

[165] For further detail on transmission reliability margin, see the following: http://www.caiso.com/informed/Pages/StakeholderProcesses/TransmissionReliabilityMargin.aspx.

[166] See Section 8.4 for further detail.

$5,000/MWh to $1,500/MWh. This will help to address the uneconomic effect of diminishing returns when high shadow prices are produced with insignificant amount of flow reductions.[167]

While the ISO has taken numerous actions that have ultimately improved price convergence, DMM recommends that the ISO remain committed to addressing the modeling and operational issues that can contribute to price divergence between the day-ahead, hour-ahead and 5-minute real-time markets.

Re-implementing convergence bidding on inter-ties

Recommendation: Following the suspension of virtual bidding on inter-ties in late 2011, DMM recommended that virtual bidding on inter-ties only be re-implemented in conjunction with market design changes that will ensure that virtual bidding on inter-ties will be beneficial to overall market efficiency and will not impose significant costs on other participants.

Follow-up: The ISO initiated a major stakeholder process in 2011 to assess modifications that might address the problems that led to the suspension of convergence bidding on inter-ties in late 2011. However, after more than a year of careful consideration, none of the options for reintroducing convergence bidding at the inter-ties appeared to improve overall market efficiency. While one of these options would have mitigated the high real-time energy imbalance offset costs, this option would have created additional complexities for the market and operations and introduced new market and operational risks.[168]

The ISO has proposed to re-implement virtual bidding on inter-ties in 2014 in conjunction with the real-time market re-design stemming from FERC Order No. 764. The re-design greatly reduces potential for the high revenue imbalance costs that led to suspension of virtual bidding on inter-ties in 2011.[169] However, DMM cautions that virtual bidding on inter-ties could inflate real-time revenue imbalances in the event that constraint limits need to be adjusted downward in the 15-minute process to account for unscheduled flows not incorporated in the day-ahead market model, as noted previously. Thus, DMM recommends the ISO carefully consider this issue and that if virtual bidding on inter-ties is re-implemented this be done in a limited and gradual manner contingent on the observed performance of this new market re-design.

Impact of exceptional dispatches on bid cost recovery payments

Recommendation: In DMM's 2012 annual report, we recommended that ISO monitor and carefully manage exceptional dispatches and costs related to needs for online capacity and ramping capability to meet overall system and south of Path 26 needs.[170] DMM also suggested incorporating additional

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[167] For more information, see the following: http://www.caiso.com/informed/Pages/StakeholderProcesses/TransmissionConstraintRelaxationParameterChange.aspx.

[168] The ISO's final straw proposal can be found here: http://www.caiso.com/Documents/ThirdRevisedStrawProposal-IntertiePricingSettlement.pdf. DMM's comments on the final straw proposal can be found here: http://www.caiso.com/Documents/DMM-Comments-IntertiePricingSettlementThirdRevisedStrawProposal.pdf.

[169] 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.

[170] *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, pp. 200: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

modeling enhancements in the day-ahead market to the extent possible to avoid these exceptional dispatches.

Follow-up: In 2012, the ISO reviewed factors that were causing exceptional dispatches and took a number of steps to reduce exceptional dispatches. The ISO created an inter-departmental team that focused on identifying the drivers for the most frequently occurring exceptional dispatch and attempted to address those through improved modeling. Despite these efforts, the overall volume of exceptional dispatches increased because of several factors. The outage of over 2,000 MW of nuclear generation and an increase in uncompetitive bidding by some suppliers in Southern California increased the need for exceptional dispatches. The ISO's effort to address exceptional dispatch continues into 2013 with a market initiative to introduce a corrective capacity constraint or product into the market. This would ensure market schedules would be sufficient to provide 30-minute response for major transmission paths and should reduce need for the ISO to exceptionally dispatch resources to meet these reliability requirements.

Review effectiveness of the 200 percent cap for registered costs

Recommendation: In 2011, DMM observed that the majority of bids for both start-up and minimum load costs for units under the registered cost option have approached the current cap of 200 percent of fuel costs.[171] DMM recommended that the ISO re-evaluate the appropriateness and effectiveness of the current cap. If this cap was lowered, DMM supported inclusion of a fixed component for non-fuel costs associated with any verifiable start-up and minimum load costs.

Follow-up: In 2012, the ISO included this item as part of its commitment cost refinement stakeholder process.[172] The ISO lowered the cap for start-up and minimum load costs to 150 percent of start-up and minimum load costs, and included a non-fuel component for verifiable major maintenance costs.

DMM continues to recommend that the ISO revise the caps for transition cost bids for multi-stage generating units. DMM believes this may become increasingly important if the ISO requires additional resources to be modeled as multi-stage generating units.

Analyze compensating injections

Recommendation: In our 2011 annual report, DMM recommended that the ISO capture additional data elements needed to more effectively determine the impacts of compensating injections.[173] DMM believes analysis of the difference between modeled versus actual flows over longer time periods could provide insights into systematic patterns in unscheduled flows that might be incorporated into the day-ahead modeling process, rather than only the 15-minute and 5-minute real-time markets. As described in Chapter 3, discrepancies between unscheduled and actual flows can have a major financial impact on real-time imbalance congestion offset charges.

Follow-up: As discussed in Section 8.4, the performance of the compensating injection feature of the ISO software became much more consistent in 2012 after a series of enhancements were made. However, DMM reiterates the recommendation that more data and analysis is required to allow for

[171] *Quarterly Report on Market Issues and Performance*, November 8, 2011, pp. 41-44: http://www.caiso.com/Documents/QuarterlyReport-MarketIssues_Performance-November2011.pdf.

[172] See http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCostsRefinement2012.aspx.

[173] *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, pp. 200-201: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

better understanding of the actual effectiveness of compensating injections and how unscheduled flows may be incorporated into the day-ahead modeling process.