California Independent System Operator

California ISO

Q3 Report on Market Issues and Performance

November 8, 2011

Prepared by: Department of Market Monitoring

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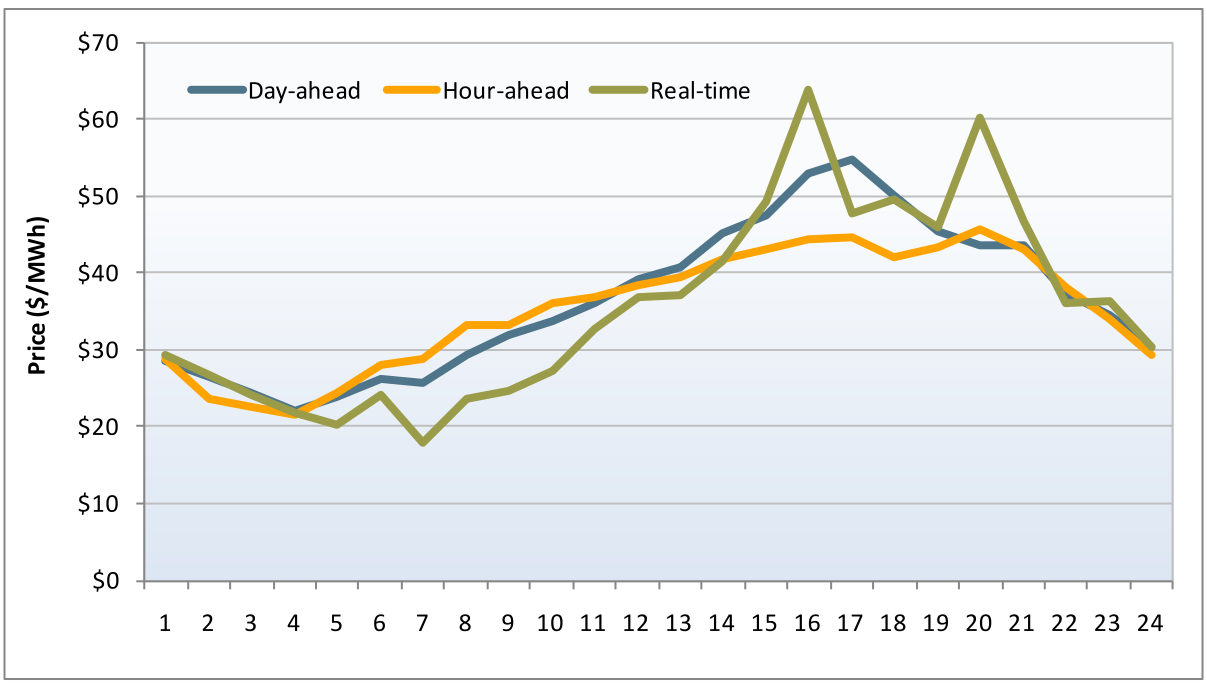
Executive summary

This report provides an overview of general market performance during the third quarter of 2011 (July – September) by the Department of Market Monitoring (DMM).

Energy market performance

- The day-ahead integrated forward market was stable and competitive. The level of load and supply scheduled in the day-ahead market was within a few percentages of actual loads in most hours. Average day-ahead and real-time energy prices continued to be approximately equal to benchmark prices that DMM estimates would occur under highly competitive conditions.
- Average peak and off-peak real-time prices were much closer to day-ahead and hour-ahead prices in August and September, but were much lower than both day-ahead and hour-ahead peak prices in July. While price convergence appears to have improved in August and September, price divergence in ramping hours, where hour-ahead prices were higher than real-time prices, offset price divergence in other hours, where hour-ahead prices were lower than real-time prices (see Figure E.1). Real-time prices were higher than day-ahead and hour-ahead prices in many peak hours (15 through 21). In hours 5 through 14 and in hour 22, real-time prices were often much lower than both day-ahead and hour-ahead prices.

Figure E.1 Hourly comparison of PG&E load aggregation point prices – August and September



- Congestion within the ISO system had minimal impact on overall prices. However, day-ahead congestion continued to occur more frequently than congestion in the real-time market, particularly on constraints related to hydro-electric generation. DMM has reviewed the differences in the day-ahead and real-time congestion patterns on these constraints and has not identified any behavioral or market design related problems at this time. DMM will continue to evaluate congestion pattern differences.

- Total bid cost recovery payments declined about 50 percent in the third quarter relative to the second quarter. Day-ahead market bid cost recovery payments decreased by 90 percent in the three months since bid cost recovery rules were modified to address flaws in the bid cost recovery calculation. These payments were exploited by certain manipulative bidding behaviors. While overall bid cost recovery payments declined in the third quarter, bid cost recovery payments associated with real-time market commitments and dispatches have increased by almost 50 percent. This increase occurred mainly as a result of exceptional dispatch commitment to meet seasonal system and south of Path 26 capacity needs.

- In early August, the ISO began to procure day-ahead ancillary services using dynamic ramp rates. Prior to August, the ISO procured ancillary services using a fixed ramp rate. Because the fixed ramp rates did not account for the ramp rate associated with energy schedules, some units with day-ahead ancillary service awards were not capable of providing their scheduled day-ahead reserves in real-time. This caused real-time exceptional dispatch or re-procurement of ancillary services to offset this limitation. Dynamic ramping of ancillary services takes into account both energy schedules and operational ramp rates, leading to more effective ancillary service procurement. Both the quantity of ancillary services procured and the prices of ancillary services in real-time dropped significantly in August from previous months after deployment of the new dynamic ramp rate feature.

Convergence bidding

The ISO implemented functionality for convergence (or virtual) bidding in the day-ahead market for February 1, 2011. Convergence bidding is designed to allow any creditworthy entity, regardless of whether or not they own physical load or generation, to place bids to buy power and offers to sell power into the day-ahead market. As these bids are only virtual and not physical, they will liquidate in real-time and cause the physical system to re-dispatch accordingly.

Convergence bidders profit by arbitraging the difference between day-ahead and real-time prices. In theory, as participants take advantage of opportunities to profit through convergence bids, this activity should drive real-time and day-ahead prices closer. While average price convergence appears to have improved since February 2011, this improvement is a result of averaging hourly prices over the day. In some hours, real-time prices still tend to be higher than day-ahead and hour-ahead prices, and in other hours, real-time prices are lower. These systematic price differences continue to make convergence bidding profitable.

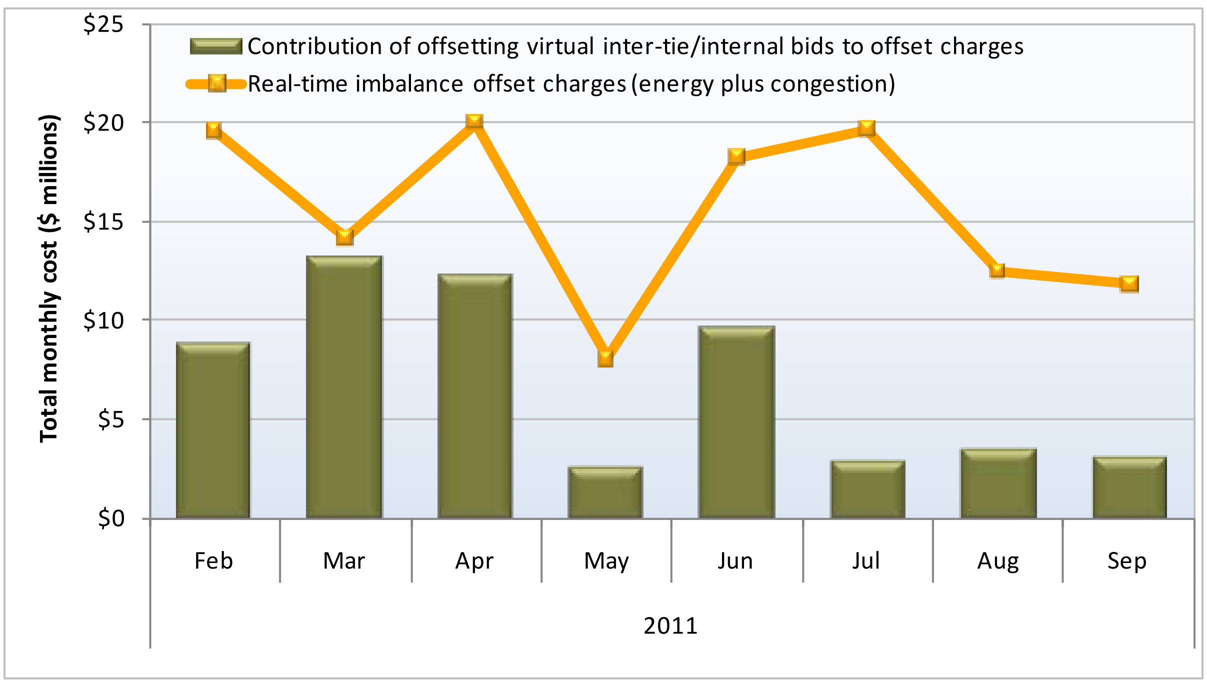
Convergence bidding activity has been marked by a few key trends:

- The vast majority of convergence bidding activity on the inter-ties has been virtual supply. This pattern has remained constant since the start of convergence bidding in February;

- In the first and second quarters, the vast majority of convergence bidding activity on internal nodes was virtual demand. While the majority of convergence bids at internal nodes have remained virtual demand, virtual supply activity at internal nodes increased in the third quarter;
- The volume of virtual bids clearing the market increased steadily over the first few months until the second half of April. Afterwards, volumes dropped precipitously and then began to increase steadily through July. Cleared convergence bidding volumes again began to decline in August and September.

Individual participants continue to bid in positions at inter-ties that offset their positions at internal nodes. However, the use of this strategy receded in the third quarter, reaching the lowest volumes in August and September since convergence bidding began in February. Even so, small volumes of offsetting positions continued to pose imbalance costs of around $3 million per month in the third quarter (see Figure E.2).

Figure E.2 Contribution of offsetting virtual supply and demand to real-time imbalance charges



In the third quarter, net revenues paid out to convergence bidding entities totaled almost $23 million – or just over the $19 million paid to convergence bidding entities in the second quarter. DMM's overall assessment of convergence bidding since its implementation in February is that because of the impact of virtual bids on the inter-ties in terms of off-setting virtual bids at points within the ISO, convergence bidding has had little or no benefit in terms of helping to improve price convergence or the efficiency of day-ahead unit commitment decisions. Because inter-tie and internal convergence bids are interrelated, DMM has not be able to effectively assess the benefits of convergence bidding in the absence of inter-tie bids.

As noted in DMM's memos for the August and October Board of Governors meetings, fundamental structural aspects of the current market design tend to create systematic differences in hour-ahead and real-time prices. Under this current market design, convergence bidding on inter-ties has allowed some participants to profit from persistent and predictable differences in hour-ahead and real-time price differences. These profits contribute to revenue imbalances that are allocated to load-serving entities without providing any significant market efficiency benefits.[1]

Numerous modeling and operational changes have been made by the ISO over the past few months to address price convergence. While it appears these changes – along with favorable seasonal conditions – have resulted in some improvements in price convergence, significant and systematic hourly differences in hour-ahead and real-time prices persist. These trends illustrate that despite recent improvement in price convergence, eliminating convergence bidding at the inter-ties remains important. Historically, the divergence of hour-ahead and real-time prices has also tended to increase in winter and spring months because of market conditions during these periods. Whenever such divergences occur, convergence bidding at the inter-ties can exacerbate real-time imbalance offset charges without providing any market efficiency benefits.

Therefore, DMM believes that the suspension of convergence bidding at the inter-ties is important until the ISO addresses structural differences between the hour-ahead and real-time markets. Furthermore, suspension of convergence bidding at the inter-ties should allow for more effective internal convergence bidding to converge day-ahead and real-time prices. DMM will evaluate and monitor the effectiveness of internal convergence bids on price convergence should virtual bidding at the inter-ties be suspended.

Special Issues

- **Hour-ahead manual load adjustments.** Operators manually adjusted the load forecast in the hour-ahead market to over 3,000 MW in several peak hours from July 5 through July 7. This adjustment along with tight system conditions caused hour-ahead energy prices to approach $3,500/MWh for one interval and nearly $1,000/MWh in other intervals. While DMM has not been able to determine the basis for this specific level of manual forecast adjustment, this level of adjustment has been limited to these three days and has not been a reoccurring issue. Historically, hour-ahead market prices have been much lower than real-time prices. DMM and ISO operations have discussed lessons learned (Section 3.1) to help avoid further occurrences of these results.

- **September power outage.** On Thursday September 8, 2011, a power outage affecting multiple balancing authorities resulted in the loss of approximately 7,890 MW of firm load in the Pacific Southwest region. At 3:27 p.m., a fault at the North Gila 500 kV substation started the sequence of events including generation and transmission outages and voltage disturbances. Finally, a power outage occurred at 3:38 p.m. The ISO temporarily suspended the market at 6:00 p.m. and an administrative price of $250/MWh was set for all prices for the hour-ahead and real-time energy markets. Later, the administrative energy price was revised to $100/MWh at 10:00 p.m. The market for the PG&E and SCE service areas was resumed at 1:00 a.m. on September 9. Beginning at 4:00 a.m., all markets were restored back to normal operations.

[1] See Memorandum to the ISO Board of Governors, RE: Market Monitoring Report, October 20, 2011, available at http://www.caiso.com/Documents/111027Department_MarketMonitoringReport-Memo.pdf.

- **Load forecast performance issues.** The ISO implemented a new load forecasting system known as ALFS3 in May 2011. ALFS3 has generally produced accurate day-ahead load forecasts. However, during a few of days in July, most notably on July 4 and July 17, ALFS3 created load forecasting errors, which ultimately resulted in erroneous real-time price spikes. Problems that affect the forecast mainly relate to inaccurate input data. After the incidents in July, the ISO further developed mechanisms to prevent bad forecasts from reaching the market model. The overall performance of the tool has improved in the second half of the third quarter.

- **Changes in start-up and minimum load bids.** Starting in April 2011, generators were able to independently elect either the proxy or registered cost option for start-up and minimum load costs. With this change, a noticeable increase occurred in the amount of capacity choosing the registered cost option for both start-up (21%) and minimum load (13%) costs. Moreover, market participants have heavily skewed their election of both costs toward the 200 percent cap, especially for steam turbine capacity.

Recommendations

- **Identify structural changes to address systematic price divergence.** One long-term solution for minimizing real-time imbalance offset charges is to redesign the real-time market so that all external and internal resources are scheduled and settled in the same market. However, the implementation of such a redesign is likely several years away. DMM believes that even with the removal of virtual bidding at the inter-ties, these offset charges may be significant enough to warrant further action prior to the implementation of the real-time market redesign as part of the renewable integration initiative. Thus, DMM recommends that the ISO continue to consider a phased approach that would start with the elimination of virtual bidding at the inter-ties, as well as a second phase to address remaining issues with physical inter-tie schedules. In particular, DMM believes the ISO should continue to consider the merits of the NYISO's real-time method for settling inter-tie schedules.

- **Monitor and limit impact of exceptional dispatches on bid cost recovery payments.** While total bid cost recovery payments declined in the third quarter, real-time bid cost recovery payments increased to the highest levels since the start of the nodal market in 2009. DMM recommends that the ISO continue to monitor and limit the economic impact of exceptional dispatches needed to meet capacity needs. DMM suggests incorporating additional system or local capacity requirements in the day-ahead market to the extent possible to avoid these exceptional dispatches. DMM would support tariff changes to facilitate these results if necessary.

- **Refine tariff provisions related to administrative pricing.** During the September power outage, the ISO suspended real-time markets and initially set administrative prices to $250/MWh and later dropped them to $100/MWh. DMM recommended to the ISO that the process for setting administrative prices should be further reviewed and potentially refined in the tariff to better prescribe in advance how prices should be settled during a market suspension.[2] The September events highlight that the current tariff provisions for administrative prices were not effective in achieving the desired operational outcomes.

- **Review the effectiveness of the 200 percent cap on registered costs.** As the majority of registered costs for both start-up and minimum load approach the 200 percent cap, DMM recommends that

[2] The ISO petition for waiver of tariff provisions (FERC Docket No. ER12-205-000) filing on October 26, 2011 contains proposed future actions consistent with this DMM recommendation. For further information, see the following document: http://www.caiso.com/Documents/pet_waiver_tariffprov_adminpricing.pdf.

the ISO reevaluate the composition of registered costs to determine the validity and effectiveness of the current cap. Furthermore, DMM continues to support consideration of the inclusion of a fixed component for non-fuel costs associated with start-up and minimum load costs, given that they can be reasonably quantified and verified.[3]

[3] This fixed component would then be added to fuel costs associated with start-up and minimum load costs, which would be calculated based on daily spot market gas prices. Since there was little participation in previous requests for data on specific examples of these costs it was not possible to assess the nature and magnitude of these potential costs.

1 Energy market performance

Day-ahead market

In the third quarter, the day-ahead integrated forward market continued to be stable and competitive. The level of load and supply scheduled in the day-ahead market continued to be within a few percentages of actual loads most hours. Average day-ahead energy prices continued to be approximately equal to benchmark prices that DMM estimates would occur under highly competitive conditions.

Real-time market

Average peak and off-peak real-time prices were much closer to day-ahead and hour-ahead prices in August and September, but were much lower than both day-ahead and hour-ahead peak prices in July. While price convergence appears to have improved in August and September, price divergence in ramping hours, where hour-ahead prices were higher than real-time prices, offset price divergence in other hours, where hour-ahead prices were lower than real-time prices. Real-time prices were higher than day-ahead and hour-ahead prices in many peak hours (15 through 21). In hours 5 through 14 and in hour 22, real-time prices were often much lower than both day-ahead and hour-ahead prices.

Congestion

Congestion within the ISO system had minimal impact on overall prices. However, day-ahead congestion continued to occur more frequently than congestion in the real-time market, particularly on constraints related to hydro-electric generation. DMM has reviewed the differences in the day-ahead and real-time congestion patterns on these constraints and has not identified any behavioral or market design related problems at this time. DMM will continue to evaluate congestion pattern differences.

Ancillary services

In early August, the ISO began to procure day-ahead ancillary services using dynamic ramp rates. Prior to August, the ISO procured ancillary services using a fixed ramp rate. Because the fixed ramp rates did not account for the ramp rate associated with energy schedules, some units with day-ahead ancillary service awards were not capable of providing their scheduled day-ahead reserves in real-time. This caused real-time re-procurement of ancillary services to offset this limitation. Dynamic ramping of ancillary services takes into account both energy schedules and operational ramp rates, leading to more effective ancillary service procurement. Indeed, both the quantity of ancillary services procured and the prices of ancillary services in real-time dropped significantly in August from previous months after deployment of the new dynamic ramp rate feature.

1.1 Energy market performance

Figure 1.1 and Figure 1.2, below, show monthly average prices for peak and off-peak periods for the PG&E load aggregation point, respectively.

Figure 1.1 Average monthly on-peak prices - PG&E load aggregation point

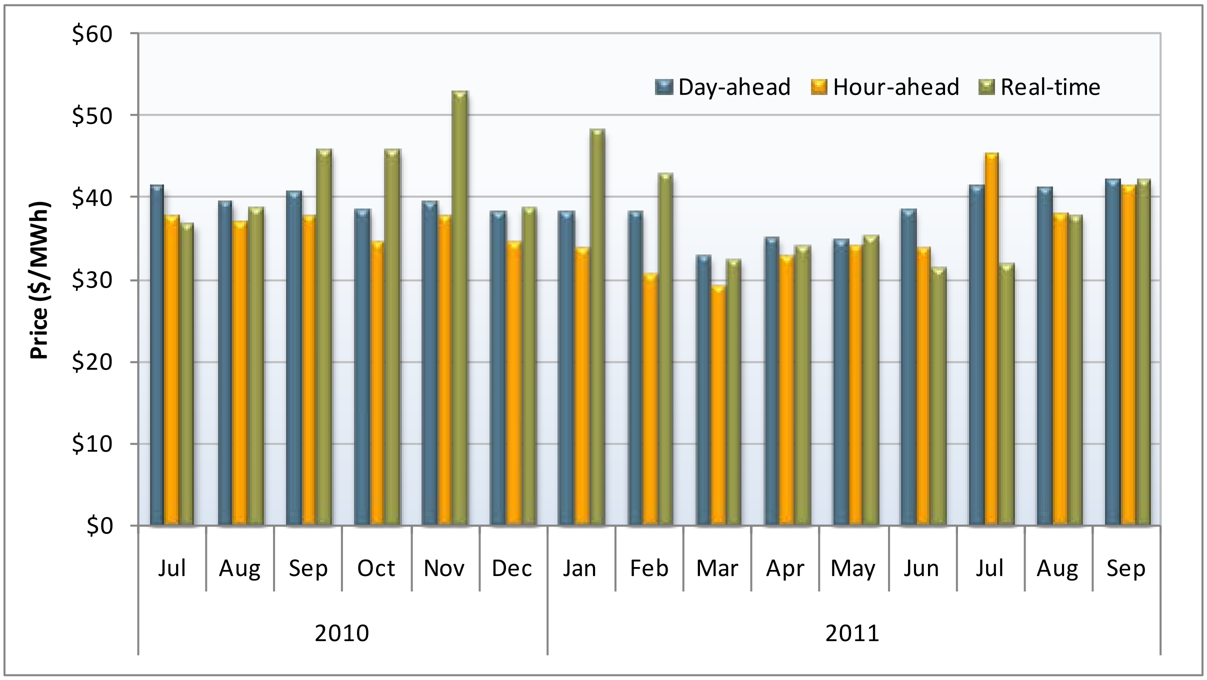
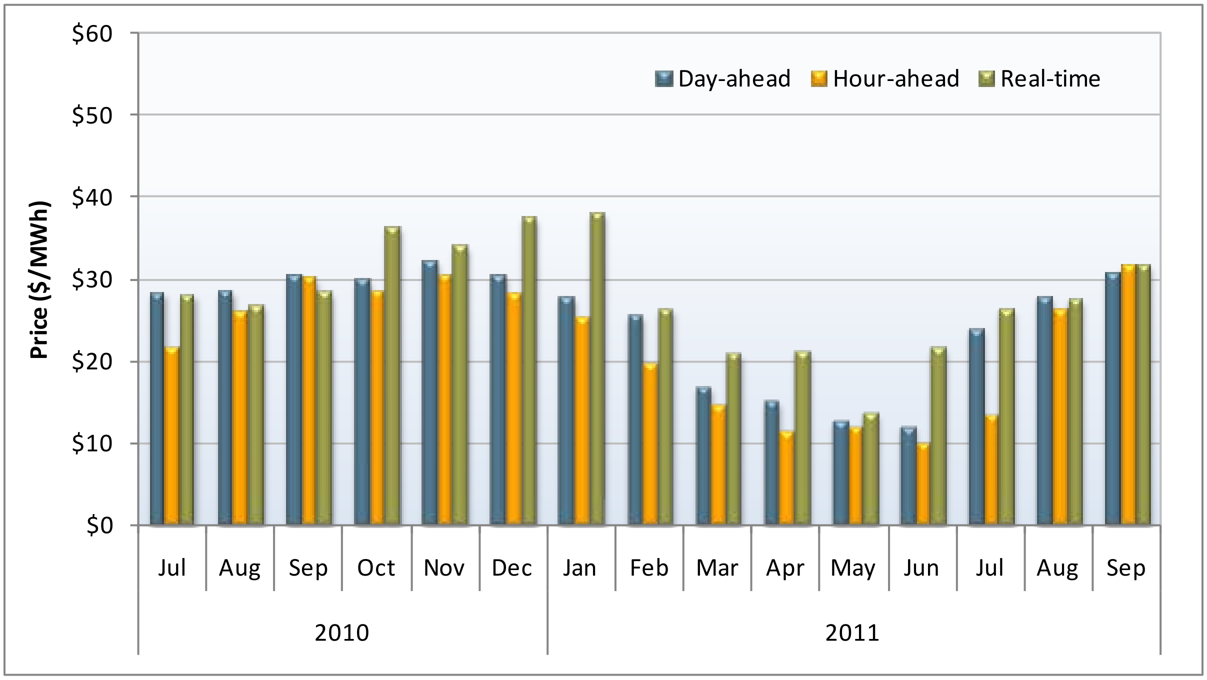


Figure 1.2 Average monthly off-peak prices - PG&E load aggregation point



- In the month of July, average hour-ahead market prices were significantly different from the 5-minute real-time market prices in both peak and off-peak periods.[4] In the months of August and September, average hour-ahead and 5-minute real-time prices converged well in both the peak and off-peak periods.
- During peak hours, average prices in the 5-minute real-time market were well below day-ahead and hour-ahead prices in July and very close to day-ahead prices in September.
- During off-peak hours, prices in all markets increased as hydro-electric generation decreased and as loads increased.

Figure 1.1 and Figure 1.2 suggest that hour-ahead and real-time market price convergence improved in August and September. However, this improvement is a result of averaging price differences over the day. In some hours, real-time prices were lower than hour-ahead prices and in other hours real-time prices were higher than hour-ahead prices. When averaged together, prices appear to converge, but in reality, price divergence in some hours offset price divergence in other hours.

Figure 1.3 and Figure 1.4 indicate hourly variations in price divergence:

- Figure 1.3 shows average hourly prices for August and September.[5] Real-time prices were higher than day-ahead and hour-ahead prices in many peak hours (15 through 21). In hours 5 through 14 and in hour 22, real-time prices were often much lower than both day-ahead and hour-ahead prices.
- Figure 1.4 highlights the magnitude of these differences by taking the average of the absolute difference in prices in the hour-ahead and real-time markets.[6] When taking the straight average of prices (green line), price convergence appears to have improved significantly since January. However, when the average absolute differences are taken into account, the magnitude of price differences began to diverge in March, indicating that price divergence has grown. This trend continued into the third quarter, with July having the largest absolute price divergence since June 2010. In the months of August and September, the average absolute price divergence fell to around $10/MWh, the lowest levels since August and September 2010. Even so, the difference between the simple average and the average absolute difference remained around $10/MWh, larger than the months preceding convergence bidding implementation in February 2011. Thus, even though recent results have improved, this difference highlights that persistent divergence continued among hourly averages.

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[4] These results were largely the result of outliers in the hour-ahead market. These outliers occurred on July 5 hours ending 16 through 19, July 6 hours ending 14 through 17, July 7 hour ending 14, and July 19 hours ending 4 and 10. The reasons for the July 5, 6 and 7 outliers are discussed in further detail in Section 3.1.

[5] The monthly trends for July were skewed as a result of large outliers. As a result, only the August and September results are shown. See Footnote 4 for further detail.

[6] By taking the absolute value, the direction of the difference is eliminated and only the magnitude of the difference remains. If the magnitude decreases, price convergence would be improving. If the magnitude increases, price convergence would be getting worse.

Figure 1.3 Hourly comparison of PG&E load aggregation point prices – August and September2011

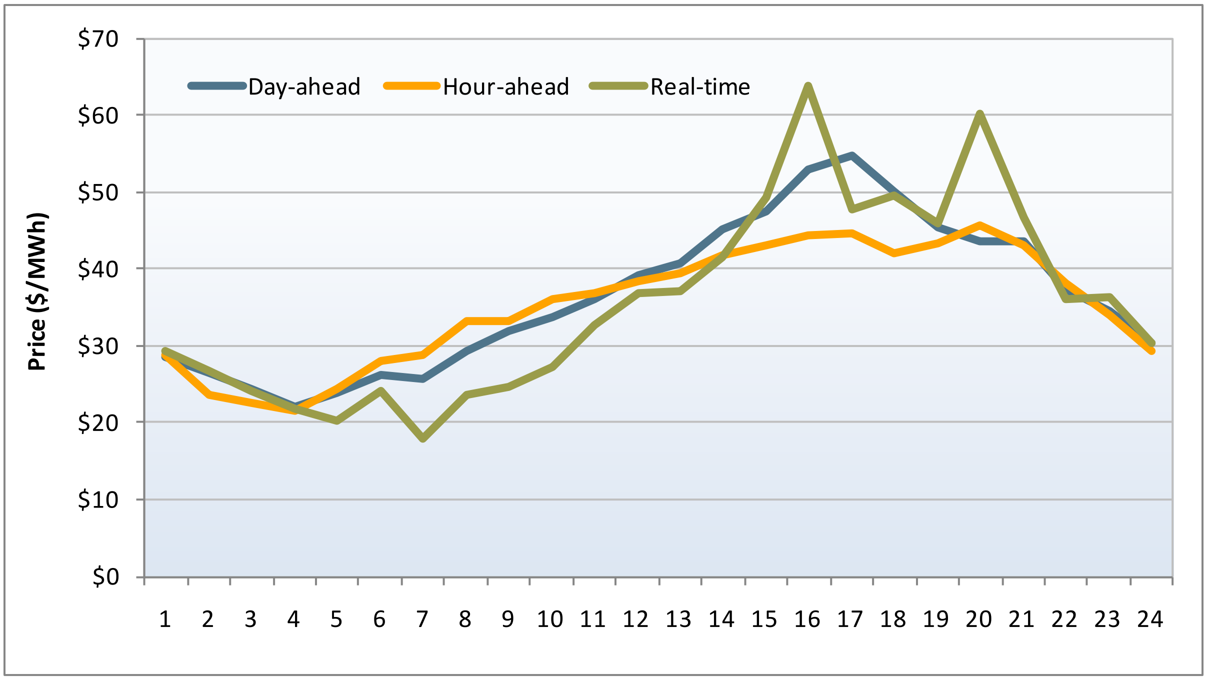
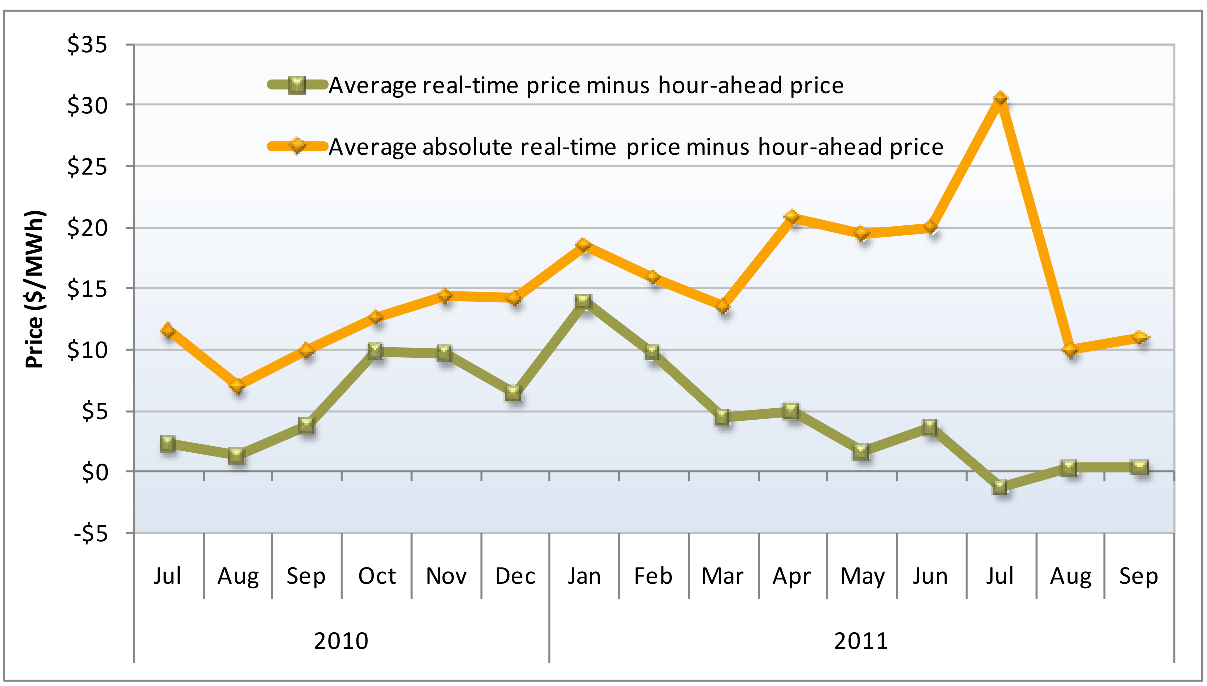


Figure 1.4 Difference in monthly hour-ahead and real-time prices when taking a simple average and absolute average of price differences (PG&E LAP, all hours)



1.2 Power balance constraint

The system-wide power balance constraint continues to contribute to both large positive and negative real-time prices. Figure 1.5 and Figure 1.6 show the frequency the power balance constraint was relaxed in the 5-minute real-time market software since the third quarter of 2010.

- Figure 1.5 shows that insufficiencies of dispatchable incremental energy caused the power balance constraint to be relaxed in around 0.5 percent of all 5-minute intervals in the third quarter of 2011. The number of relaxations in the third quarter continues a downward trend that began in the second quarter, falling to the lowest level since the second quarter of 2009. In the third quarter, power balance constraint relaxations from shortages of upward ramping capacity generally were dispersed over different hours of the day, continuing a trend from the previous quarter. The main factors for these improvements include changes in operational procedures and software enhancements, particularly those related to load adjustments, load forecasting and ramping constraints, reduction in hydro-eletric output that freed downward ramping capability, and increased load, which added additional ramping capability through unit commitment.
- Figure 1.6 shows that the decreasing trend in the number of real-time power balance constraint relaxations from insufficiencies of dispatchable decremental energy continued through August. DMM also attributes this improvement to changes in operational procedures and software enhancements, including enhancements to the software to account for generation shut-down profiles, and reduction in hydro-electric output.
- Figure 1.7 shows that while the frequency of price spikes remained less than 1 percent of intervals during the third quarter, the proportion of prices over $750/MWh remained a large portion of these intervals. In September, the frequency of intervals with prices between $250 and $500/MWh increased from 0.1 percent to 0.5 percent. This increase was the result of the ISO setting administrative prices to $250/MWh on September 8 for multiple hours of the power outage in the San Diego region.[7]

[7] For further detail on the September blackout, please refer to section 3.2.

Figure 1.5 **Relaxation of power balance constraint because of insufficient upward ramping capacity**

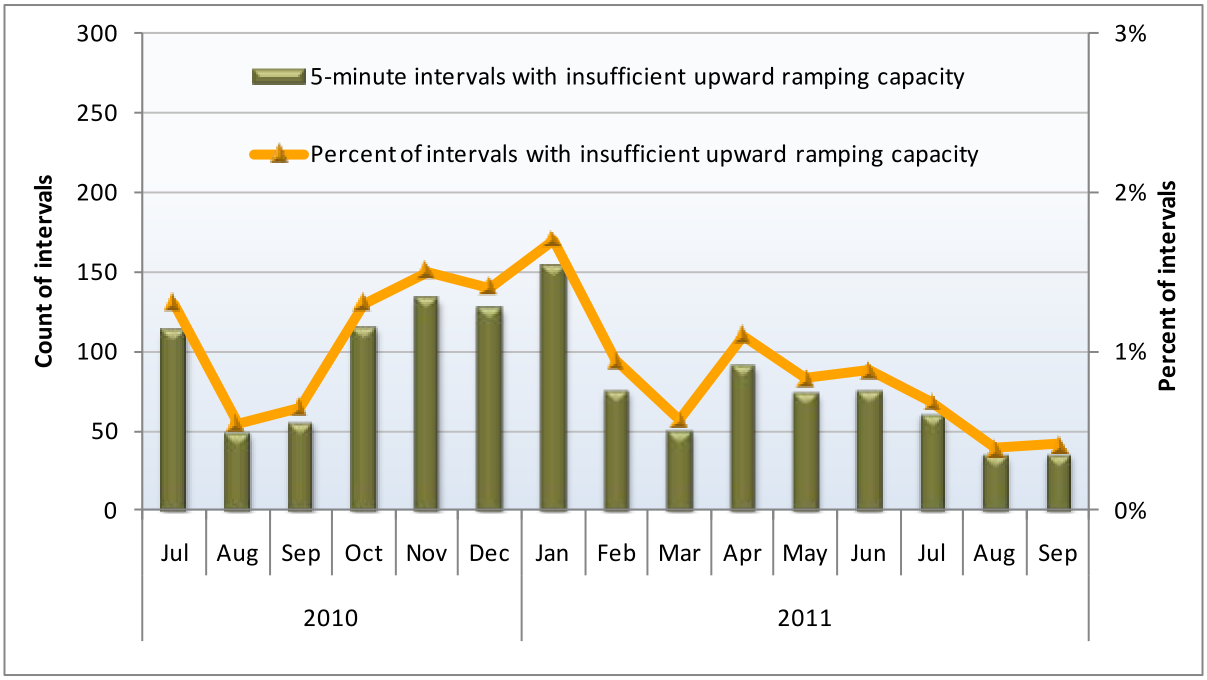


Figure 1.6 **Relaxation of power balance constraint because of insufficient downward ramping capacity**

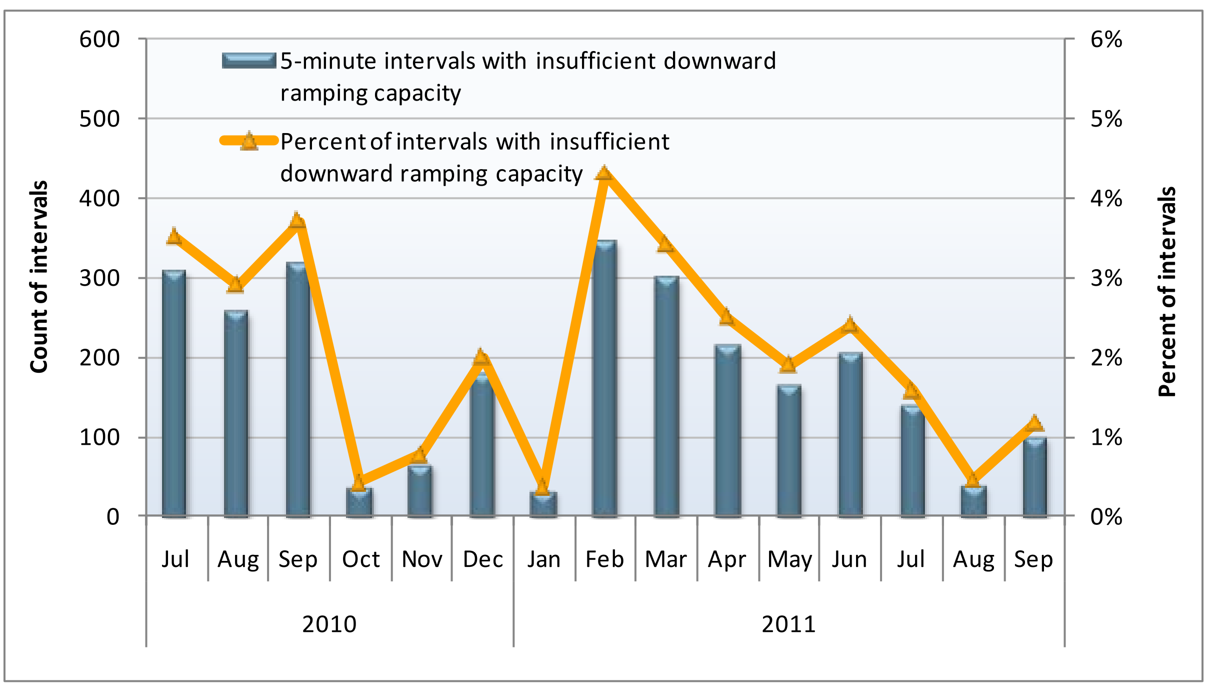
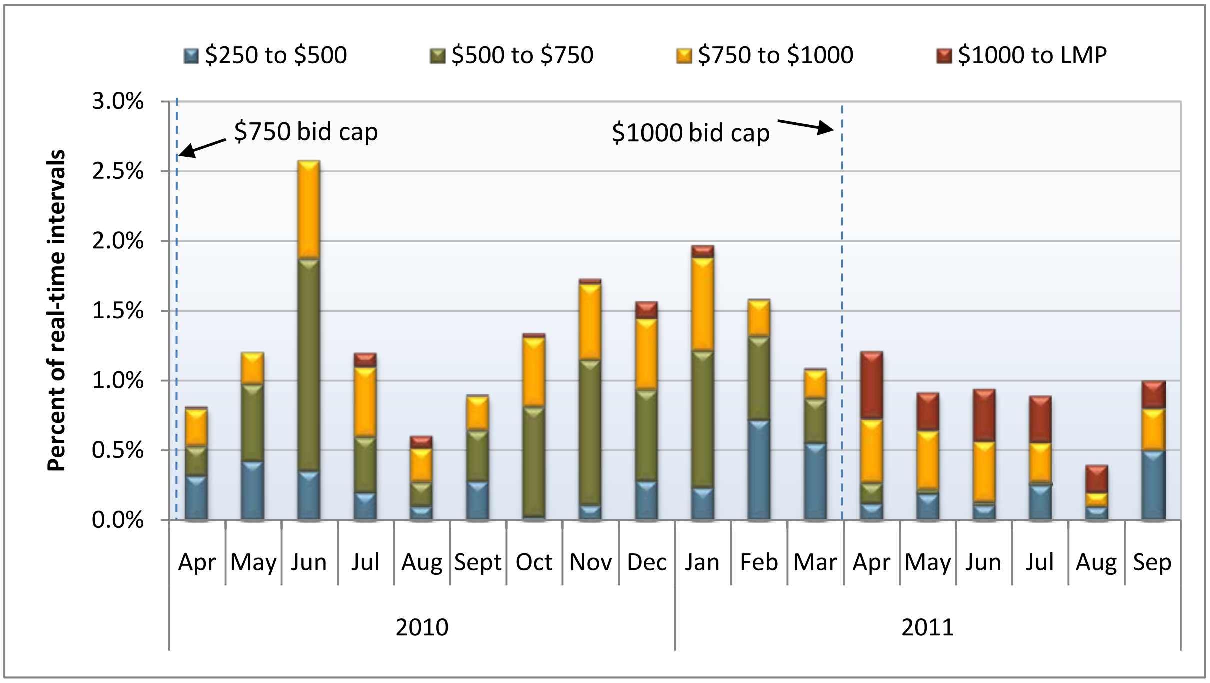


Figure 1.7 Frequency of price spikes (all LAP areas)



The power balance constraint was relaxed because of insufficient incremental energy less than 1 percent of intervals in the third quarter. Price spikes during these intervals continued to have a significant impact on overall average real-time prices because of the bid cap and penalty prices used in the pricing run when this relaxation occurs.

Excluding the hours with power balance constraint relaxations, day-ahead prices remained slightly higher, on average, than the prices in the hour-ahead and 5-minute real-time markets in the third quarter. Moreover, power balance constraint relaxations had the smallest impact on real-time prices in the third quarter of this year since the third quarter of last year. When the price spikes are excluded, real-time prices are lower, on average, than the hour-ahead prices in the third quarter.

Starting in the second quarter, the ISO systematically began to adjust the load in the hour-ahead market upward, most notably in ramping periods to account for observed differences in load and imbalance conditions between hour-ahead and real-time. The ISO did this to resolve modeling differences between the hour-ahead and 5-minute models, which may cause price spikes in the 5-minute real-time market. These systematic adjustments appear to cause higher hour-ahead prices when power balance constraint relaxations are excluded. These adjustments also appear to reduce the frequency of price spikes associated with ramping limitations.

1.3 Market competitiveness

DMM calculates competitive baseline prices by re-simulating the market using the day-ahead market software with bids reflecting the marginal cost of gas-fired units. Overall, average day-ahead and real-time prices were approximately equal to competitive baseline prices that DMM estimates would result under perfectly competitive conditions.

DMM finds the following:

- The day-ahead market has continued to be very stable and competitive;
- Prices in the day-ahead market during each month of the third quarter continued to be approximately equal to prices DMM estimates would result under perfectly competitive conditions. These conditions are based on competitive baseline prices DMM develops by re-running the day-ahead market with default energy bids reflecting each unit's actual marginal cost simulated under actual system load; and
- Given the time lag of rerunning the market software and modeling discrepancies, DMM was not able to successfully rerun and benchmark the model results for February, March and April.

Methodology

To assess the competitiveness of the day-ahead market, DMM runs two simulations using its stand-alone copy of the day-ahead software.

- The first is a re-run of the day-ahead software using data for the applicable save case (the ISO's archive of market and system inputs and settings saved after completion of the final day-ahead market run). Results of this initial re-run are benchmarked against actual day-ahead results to validate that the DMM stand-alone system is accurately reproducing results of the actual market software.[8] Days for which the stand-alone system does not produce results comparable to the actual market run are excluded from the analysis.[9]
- The second run of the stand-alone software is designed to represent a perfectly competitive scenario which provides a *competitive baseline* against which the re-run of actual day-ahead prices can be compared. In this second run, bids for gas-fired generating resources are replaced with their respective default energy bids (DEBs), which are designed to represent each unit's actual variable or opportunity costs.[10] The system demand is exogenously set to the actual system load. This run reflects the assumption that under perfectly competitive conditions, each resource would bid at their marginal operating or opportunity costs under the actual system load.[11] The percentage difference between actual market prices and prices resulting under this competitive baseline scenario represents the *price-cost mark-up index* for the day-ahead market. Generally, DMM

[8] Results of the market software and DMM's stand-alone version can vary for several reasons. First, DMM had difficulties loading and rerunning save cases for several months, thus the DMM system was rerun with subsequent versions of the network models and system updates. When model settings are changed, such as binding constraint corrections or multi-stage generation patches, a re-run may not duplicate the original day-ahead results.

[9] DMM expects the portion of re-runs that do not accurately replicate market outcomes (and are therefore excluded from such analyses) to decrease as updates to the IFM software decline, and as DMM is able to successfully perform a greater portion of re-runs with a smaller lag time from the date of actual market operation.

[10] Under the market power mitigation provisions of the ISO tariff, cost-based default energy bids are increased by 10 percent to reflect potential costs that may not be entirely captured in the standard fuel and variable cost calculations upon which cost-based DEBs are based (Tariff Section 39.7.1.1). Units such as use-limited resources may also have a default energy bid that reflects their opportunity costs under the negotiated cost option of the ISO tariff (Tariff Section 39.7.1.3, and *Business Practice Manual for Market Instruments*, Version 16, Revised: Sep 19, 2011, D-3 to D-4).

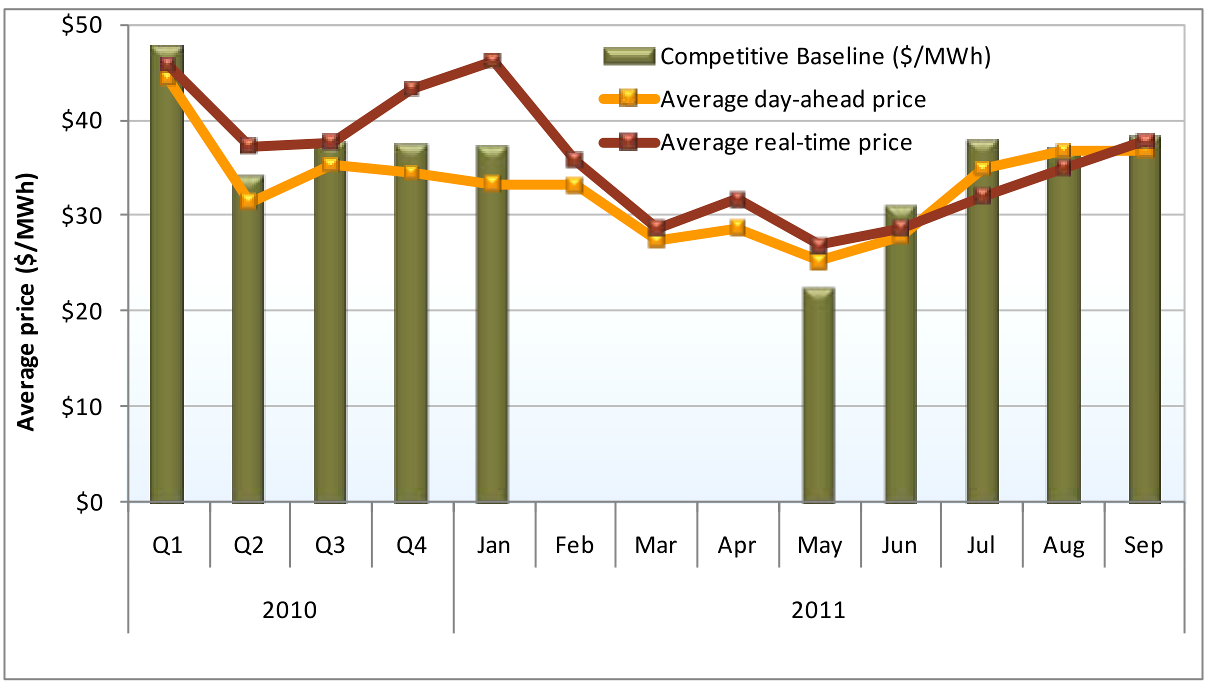
[11] A further refinement of the competitive baseline methodology would be to also remove convergence bids. DMM hopes to make this modification for a subsequent report.

considers a market to be competitive if the index indicates no more than a 10 percent mark-up over the competitive baseline.

Figure 1.8 compares this competitive baseline price to average system-wide prices in the day-ahead and 5-minute real-time markets. As seen in Figure 1.8, prices in the day-ahead market have consistently been about equal to the competitive baseline prices. Since June, the competitive baseline prices exceeded the state-wide average prices by about 8 percent. Since May, average real-time prices have been closer to both average day-ahead prices and the competitive baseline than in 2010 and in January 2011. This improvement has mainly been a result of the decreased frequency of penalty prices influencing real-time prices because of ramping limitations in the real-time market (see Section 1.2).

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

Figure 1.8 Comparison of competitive baseline with day-ahead and real-time prices



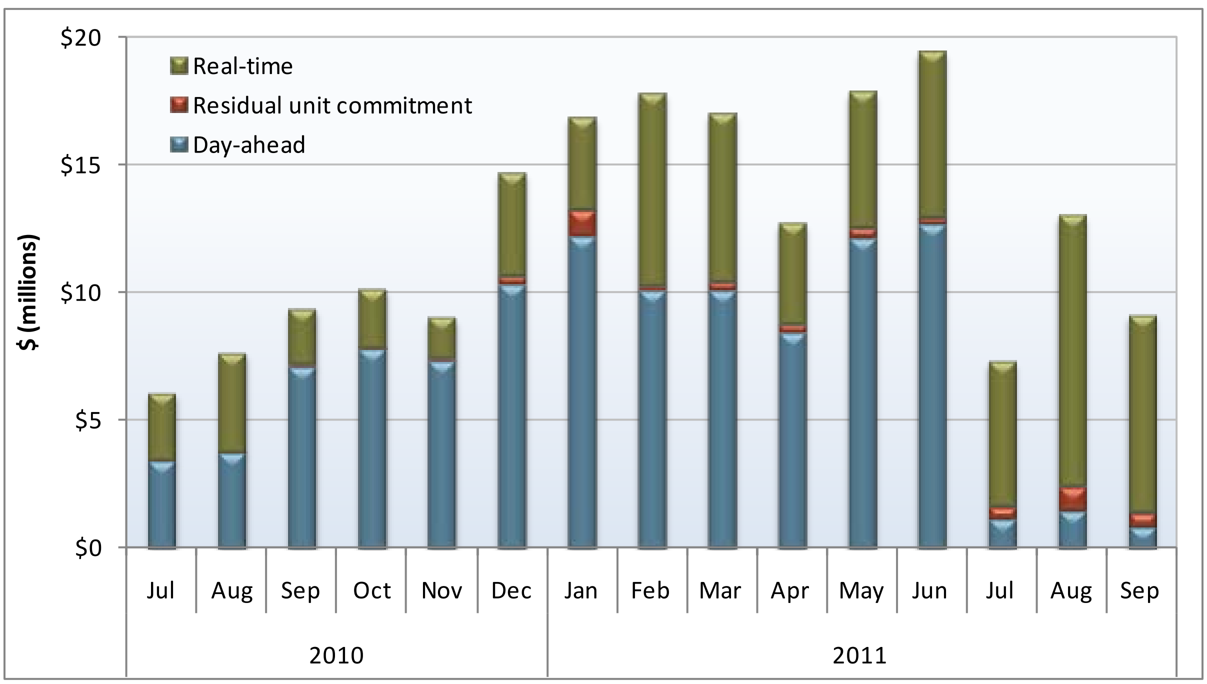
1.4 Bid cost recovery payments

Bid cost recovery payments are designed to ensure that generators receive enough market revenues to cover the cost of all their bids when dispatched by the ISO.[12] Early this year, the ISO had identified flaws in the calculation of these payments which – when exploited by certain manipulative bidding behaviors – led to excessively high bid cost recovery payments associated with the day-ahead market. In April and June, the ISO made two emergency filings with the Federal Energy Regulatory Commission (FERC) to modify bid cost recovery rules to mitigate this behavior.

Since these rule changes, bid cost recovery payments have dropped significantly, particularly for the day-ahead market. As shown in Figure 1.9:

- Overall bid cost recovery payments are down about 50 percent in the third quarter relative to the second quarter. Bid cost recovery payments associated with the day-ahead market (represented by the blue bar) have decreased by 90 percent in the three months since bid cost recovery rules were last modified;
- However, bid cost recovery payments associated with real-time market dispatches have increased by almost 50 percent in the third quarter compared to the second quarter.

Figure 1.9 Bid cost recovery payments



Operation logs indicate that the increases in real-time payments were primarily related to exceptional dispatches made by the ISO to commit additional capacity after the day-ahead market for two reasons.

[12] Bid cost recovery covers the bids for start-up, minimum load, ancillary services, residual unit commitment availability, and day-ahead and real-time energy.

First, exceptional dispatches for system capacity help to meet generation capacity requirements for the entire ISO region. As noted in DMM's 2010 annual report, this type of unit commitment typically occurs when system loads approach their annual peaks in the late summer months.[13] These additional unit commitments are made after the day-ahead market to protect the system from voltage collapse and potential thermal overloads on critical inter-ties should worst-case contingencies occur. Second, additional on-line capacity located south of Path 26 that can be ramped up in 30 minutes to meet a contingency such as an outage on the Nevada-Oregon Border (NOB) transmission path, also known as the Pacific DC Inter-tie (PDCI).

In July and August, most unit commitments for these two reasons coincided with peak load days. In September, many of these commitments were associated with the outage of the 500 kV line connecting Arizona with the ISO and peak load days.[14]

DMM recognizes that exceptional dispatches will continue to be necessary to resolve circumstances not addressed by the market model. Even so, DMM recommends that the ISO monitor its use of exceptional dispatches and seek to limit its impact on bid cost recovery payments. DMM will continue to monitor and analyze bid cost recovery payments for anomalies and will make further recommendations and referrals as necessary.

1.5 Congestion

Congestion within the ISO system had minimal impact on overall prices. However, the frequency of day-ahead congestion increased, particularly on constraints in generation pockets and those relating to imports into the Southern California Edison and San Diego Gas and Electric areas. Moreover, congestion in the day-ahead market did not usually materialize in the real-time market.

Historically, the Spring Gap to Mi-Wuk 115 kV line[15] has been the most congested constraint in the spring and summer months. However, congestion primarily occurs on this line in the day-ahead market and not in the real-time market. DMM reviewed this situation and identified the lack of congestion in the real-time market as a result of:

- the functioning of the ISO markets;
- operating procedures; and
- a two-settlement system.

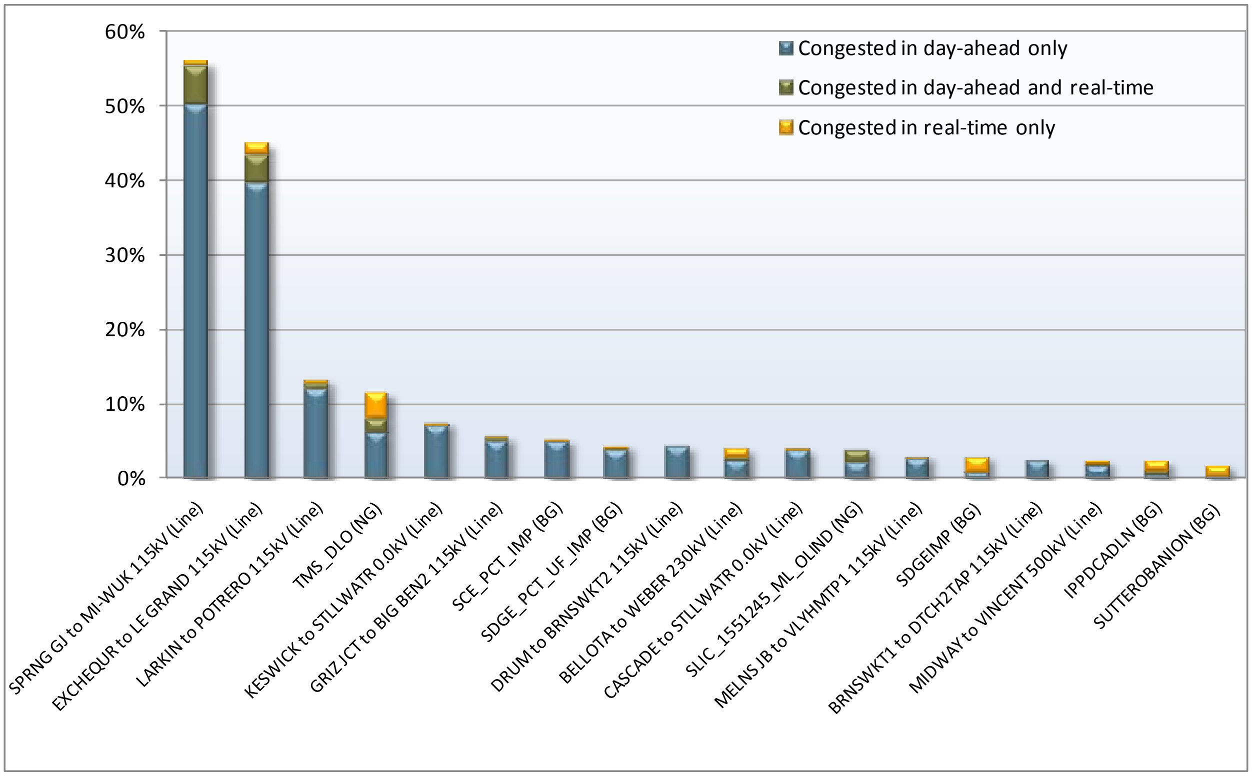
No misleading, deceptive or manipulative market actions appear to have caused the differences in congestion. Nevertheless, DMM continues to monitor and evaluate differences in congestion between the day-ahead and real-time markets.

[13] See discussion of exceptional dispatches in DMM's *2010 Annual Report on Issues and Performance*, pp. 70-74. http://www.caiso.com/Documents/2010AnnualReportonMarketIssuesandPerformance.

[14] As loads have abated in October, DMM has observed a reduction in capacity related exceptional dispatches and a corresponding reduction in real-time bid cost recovery payments.

[15] Similar generation pocket constraints include Exchequr to Le Grand 115 kV (line), Drum to Brnswkt2 115 kV (line), Brnswkt1 to Dtch2tap 230 kV (line), Electra to Bellota 230 kV (line), Smrtsvle to Yubagold 69 kV (line), Grizjct to bigben2 115 kV (line) and Swtwtrtp to Sweetwtr 69 kV (line).

Figure 1.10 Consistency of congestion in day-ahead and real-time markets (July - Sep 2011)



In the third quarter, planned outages on Round Mountain - Table Mountain 500 kV line and Table Mountain - Vaca 500 kV line contributed to congestion on the TMS_DLO nomogram.[16] Congestion on the Larkin to Potrero 115 kV constraint was related to a number of outages in connection with the A-Y #1 115kV Cable (Potrero-Larkin).

Outages on the Southwest Powerlink (SWPL) (North Gila-Hassayampa and Imperial Valley-Miguel) contributed to congestion into the SCE and SDG&E areas. When outages occur on SWPL, the internal San Diego percent of generation requirement increases to 30 percent from 25 percent. Limits are also placed on the South of SONGS transmission lines. Congestion in the SDG&E area was also increased by manual reductions (or conforming) of transmission limits for reliability reasons, and by local outages (e.g., Mission-San Luis Rey 230 kV).

[16] This is a nomogram in the COI Master Operating Procedure (#6110). This procedure specifies system operating limits (SOL) and provides both normal and contingency operations, and background and guidance for all COI related paths. Specifically, this nomogram is for the double loss of 500 kV lines Table Mountain-Tesla and Table Mountain-Vaca to protect 230 kV line Table Mountain-Rio Oso. ISO operations planning indicates that recent congestion was related to Northern California dispatch (that includes Northern California Hydro plus Colusa and the Hatchet Ridge wind farm North of Round Mountain) as one of the key reasons for congestion. Other reasons for recent congestion include COI north to south flows and local area load.

1.6 Ancillary service markets

In August, the ISO implemented new software designed to more accurately procure ancillary services in the day-ahead market. The new software uses dynamic ramp rates to procure day-ahead ancillary services.[17] Prior to the August deployment of dynamic ramp rates, a fixed ramp rate was used to procure day-ahead ancillary services.

Scheduling coordinators submit a fixed maximum ramp rate for ancillary services in the day-ahead market. However, the resource can have a lower operational ramp rate depending on its day-ahead energy schedule. As a result, the procurement of ancillary services was based on a fixed maximum ramp rate, not necessarily the operational ramp rate. At times, this would mean that awarded ancillary services would not be completely deliverable in real-time depending on where the unit was dispatched on its energy curve.

If ancillary services are unable to perform in real-time because of ramp rate limitations, the ISO is forced to either re-procure more ancillary services – often at higher prices – or to exceptionally dispatch the unit to an energy level capable of supporting the faster ramp rate. To address these concerns, the ISO now evaluates the energy operational ramp rate, in conjunction with the fixed ancillary service ramp rate for day-ahead ancillary service procurement. Specifically, the ancillary service ramp rate is either the operational ramp rate or the fixed ramp rate, whichever is lower. The ramp rate is dynamic, based on the resource's day-ahead schedule.[18]

Since its implementation, DMM has observed decreased need for re-procurement of ancillary services in real-time as well as lower real-time ancillary service prices. Furthermore, scarcity pricing of ancillary services only occurred once after the new dynamic ramp rate feature was deployed. This instance was corrected because of errors.

Figure 1.11 shows a significant drop in the average amount of additional megawatts procured in real-time during an hour of incremental ancillary service procurement beginning in August and continuing into September. Figure 1.12 shows a decrease in monthly average ancillary service prices for the same period. DMM attributes the higher incremental megawatts, along with higher average ancillary service prices during the second quarter of the year, to a market participant behavior issue identified in the ISO's June 22, 2011 FERC filing.[19]

[17] For further discussion, see the following technical bulletin: http://www.caiso.com/Documents/TechnicalBulletin-DynamicRampRate_AncillaryServiceProcurement.pdf.

[18] For example, consider a hypothetical unit with the following operational characteristics. The operational ramp rate for spin is 2 MW/minute at an energy output between 100 to 200 MW and 4 MW/minute at an energy output between 200 to 300 MW. The fixed ramp rate for spin is 3 MW/minute. In this scenario, if the resource has a day-ahead schedule of 150 MW for the operating hour (i.e., between 100 and 200 MW) its maximum spin award is 20 MW (based on a 10 minute profile of 2 MW/minute of the operational ramp rate). However, if the unit's day-ahead schedule is 250 MW for the operating hour, then the resource's maximum spin award is 30 MW (based on the 10 minute profile of the 3 MW/minute of the fixed ramp rate).

[19] For more information, see FERC Docket No. ER11-3856-000: https://www.ferc.gov/EventCalendar/Files/20110819155553-ER11-3856-000.pdf.

Figure 1.11 Additional ancillary service megawatts procured in real-time

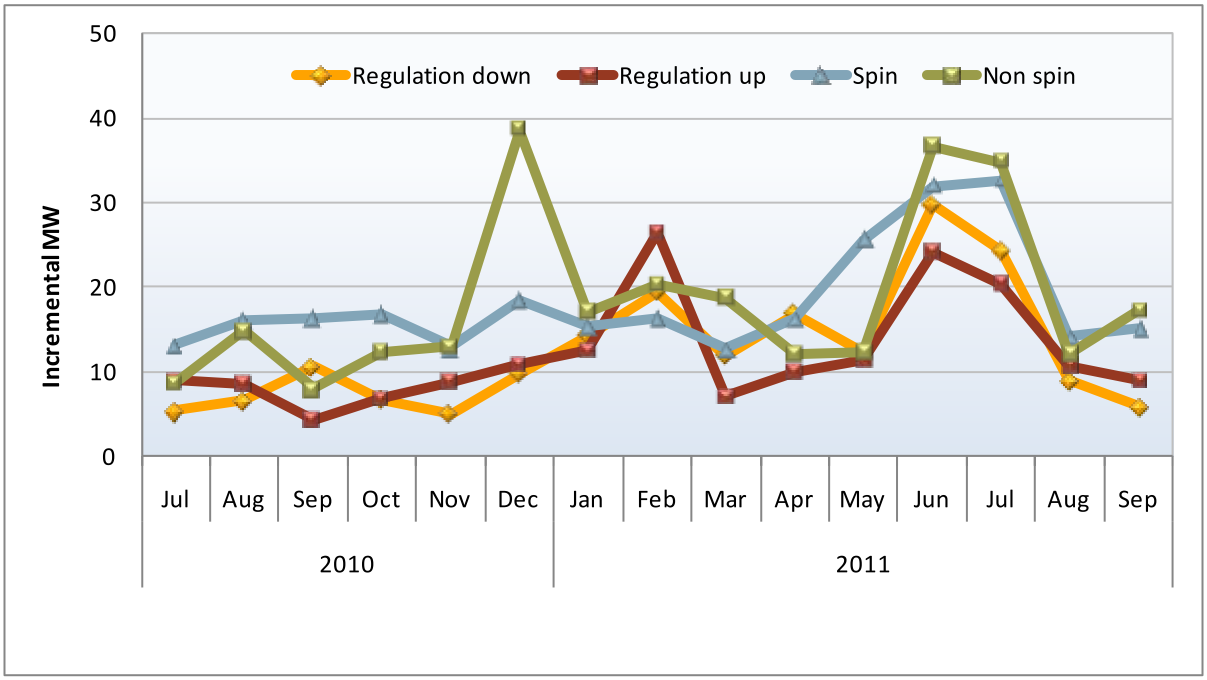
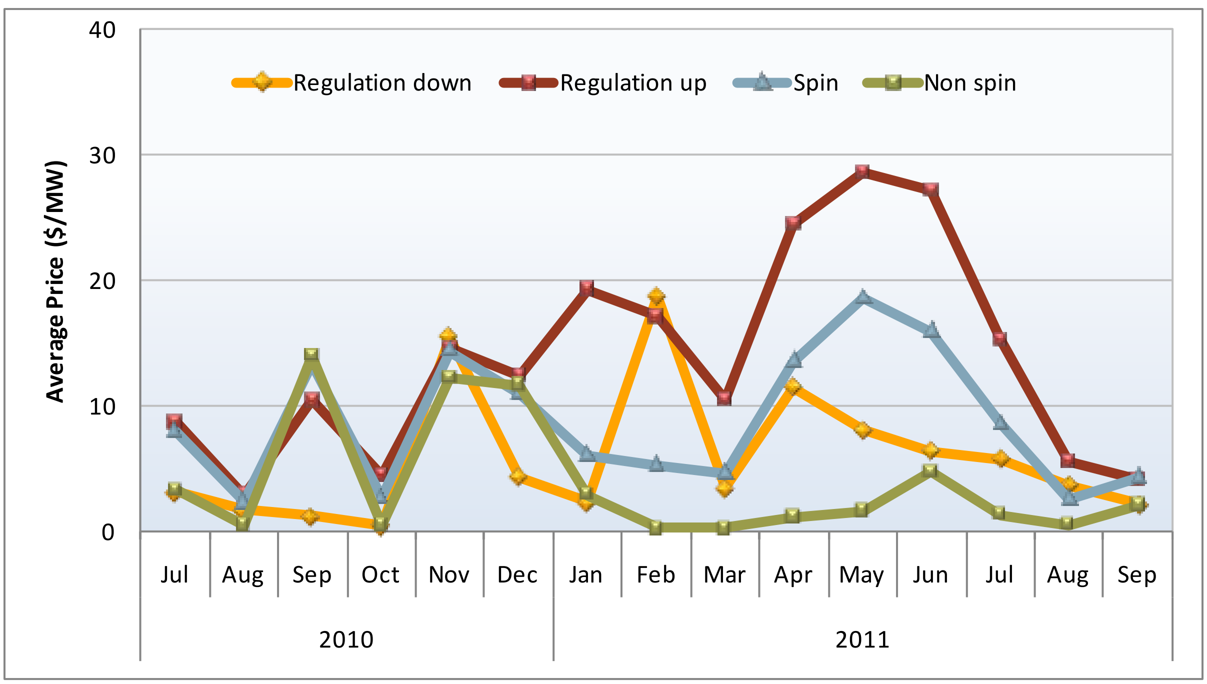


Figure 1.12 Average price for real-time ancillary service incremental megawatts



2 Convergence bidding

Convergence bidding was implemented in the day-ahead market for February 1, 2011. Net revenues for convergence bidding entities have been just over $58 million for the first eight months of this new market feature (February through September). DMM's overall assessment of convergence bidding since its implementation in February is that because of the impact of virtual bids on the inter-ties, in terms of off-setting virtual bids at points within the ISO, convergence bidding has had little or no benefit in terms of helping to improve price convergence or the efficiency of day-ahead unit commitment decisions.

As shown in Section 1.1, average price convergence did appear to improve, particularly in the months of August and September. However, on an hourly basis, prices in real-time tended to exceed day-ahead and hour-ahead prices in some hours and consistently fell behind hour-ahead prices in others. This indicates that convergence was largely achieved through averaging over relatively broad ranges of peak and off-peak hours.

Background

Convergence bidding is designed to allow any creditworthy entity, regardless of whether or not they own physical load or generation, to place bids to buy power and offers to sell power into the day-ahead market. As these bids are only virtual and not physical, they will liquidate in real-time and cause the physical system to re-dispatch accordingly.

In theory, these participants profit by arbitraging the difference between day-ahead and real-time prices. As participants take advantage of opportunities to profit through convergence bids, this activity should drive real-time and day-ahead prices closer. The following illustrates how virtual demand and supply are designed to work.

- If prices are higher in the real-time market relative to the day-ahead market, convergence bidders should place virtual demand bids. Virtual demand will raise load in the day-ahead, which could lead to additional unit commitment. This additional unit commitment would occur because of higher prices in the day-ahead market. This additional unit commitment would be available in real-time and would have a dampening effect on real-time prices. The virtual demand would then be paid the difference between the real-time price and the day-ahead price for each virtual megawatt.

- If prices are lower in the real-time market relative to the day-ahead market, convergence bidders should place virtual supply bids. Virtual supply will displace the supply of physical generation in the day-ahead and could lead to units being committed lower on their bid curves. Also, it could potentially even displace additional unit commitments.[20] This reduction in physical commitment would occur because of lower prices in the day-ahead market. In real-time, these virtual supply resources would not materialize and should therefore have an elevating effect on real-time prices. The virtual supply would then be paid the difference between the real-time price and the day-ahead price for each virtual megawatt.

[20] 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.

The California market has a unique feature that makes it different from most other ISOs and RTOs. California's market design re-optimizes imports and exports in an hour-ahead market. Unlike other ISOs, the ISO settles these inter-tie resources based on hour-ahead prices rather than 5-minute real-time prices. The same is true for convergence bids on the inter-ties. These bids also settle against hour-ahead prices rather than the 5-minute real-time prices.

As shown in Section 2.1.3, this feature of the ISO market design has led to a particular convergence bidding strategy that has been exploited when prices diverge between the hour-ahead and real-time markets. While this virtual bidding strategy has been highly profitable and has increased revenue imbalances allocated to load-serving entities, it does not appear to have provided any significant benefits in terms of helping to converge prices in the hour-ahead and 5-minute real-time markets.

2.1 Convergence bidding activity

2.1.1 Change in convergence bidding rules

Since convergence bidding was implemented in February, several changes have been made or proposed to different aspects of the ISO's convergence bidding market design:

- For the day-ahead market for July 20, the ISO made available for convergence bidding nine inter-tie locations.[21] Convergence bidding at these locations was suspended earlier this year because of modeling and software limitations.
- Since August 29, 2011, the ISO disqualified virtual bidding on six fully encumbered inter-ties. These inter-ties are fully encumbered by existing rights that effectively set the available transfer capability at 0 MW.[22] Physical bids are not allowed to be placed on the fully encumbered inter-ties beyond the existing rights. The change on August 29 applied the bidding limitation to convergence bids. The ISO implemented this change through a modification to the market operations business practice manual.
- In August, the ISO Board approved a proposal to suspend convergence bidding activity on the inter-ties. In September, the ISO filed with the FERC to do so.[23] The matter is currently pending a FERC decision.
- On October 1, 2011, position limits on the inter-ties were set to increase from the current limit of 5 percent to 25 percent of the applicable operating transfer capability.[24] However, the ISO filed and FERC accepted a hold on this increase. FERC is evaluating the ISO's proposal to suspend virtual

[21] Further detail on these inter-ties can be found in the CAISO Market Notice: http://www.caiso.com/Documents/ConvergenceBiddingIntertieLocationsRe-enabled_TradingDateJuly20.htm.

[22] Further detail on fully encumbered inter-ties can be found in the CAISO Market Notice: http://www.caiso.com/Documents/VirtualBiddingNotAllowed-FullyEncumberedIntertiesAug_22_2011.htm.

[23] See FERC filing of Tariff Amendment Eliminating Convergence Bidding at the Interties, docket no. ER11-4580-000, submitted on September 21, 2011.

[24] According to FERC order 113 FERC ¶61,039 the following future position limits on the inter-ties were originally set to apply:

- 50 percent of the transfer capability beginning from February to May 2012;
- No position limits starting June 1, 2012.

bidding on the inter-ties before any limit changes come into effect.[25] On internal nodes, the limits increased from 10 percent to 50 percent of physical supply resources and forecasts.[26] The ISO enforces no position limits on trading hub nodes or load aggregation points.

2.1.2 Change in convergence bidding volumes

While the pattern of overall convergence bidding volumes has changed over time, the vast majority of net positions remain virtual supply on inter-ties. Initially, volumes increased steadily over the first few months until the second half of April. Afterwards, volumes dropped precipitously in April. The volumes increased through June until turning again in July and decreasing through September. Second, the vast majority of virtual supply positions are found on inter-ties, whereas both virtual demand and supply are allocated internally.

Convergence bidding volumes increased steadily from the start of convergence bidding on February 1 until mid-April. In the second and the third quarter, convergence bidding volumes stabilized at a lower level than in the first two months, though trading activity fluctuated slightly in mid-July and August. Figure 2.1 and Figure 2.2 show the quantities of both virtual demand and supply offered and cleared in the market.

As shown in Figure 2.1:

- On average, 60 percent of virtual supply and demand bids cleared in the first three quarters of convergence bidding.
- With the exception of the very first weeks of convergence bidding, cleared virtual supply has outweighed cleared virtual demand on average by around 600 MW. In the third quarter this value increased to over 675 MW.

As shown in Figure 2.2:

- On average, virtual supply exceeds virtual demand in every hour of the day, especially during off-peak hours.
- The total volume of offered and cleared virtual bids is consistent for much of the day.

[25] FERC order 136 FERC ¶ 61,214 granting temporary waiver request of tariff provisions (September 2011).

[26] No position limits on internal nodes will apply starting February 1, 2012.

Figure 2.1 Monthly average offered and cleared virtual activity

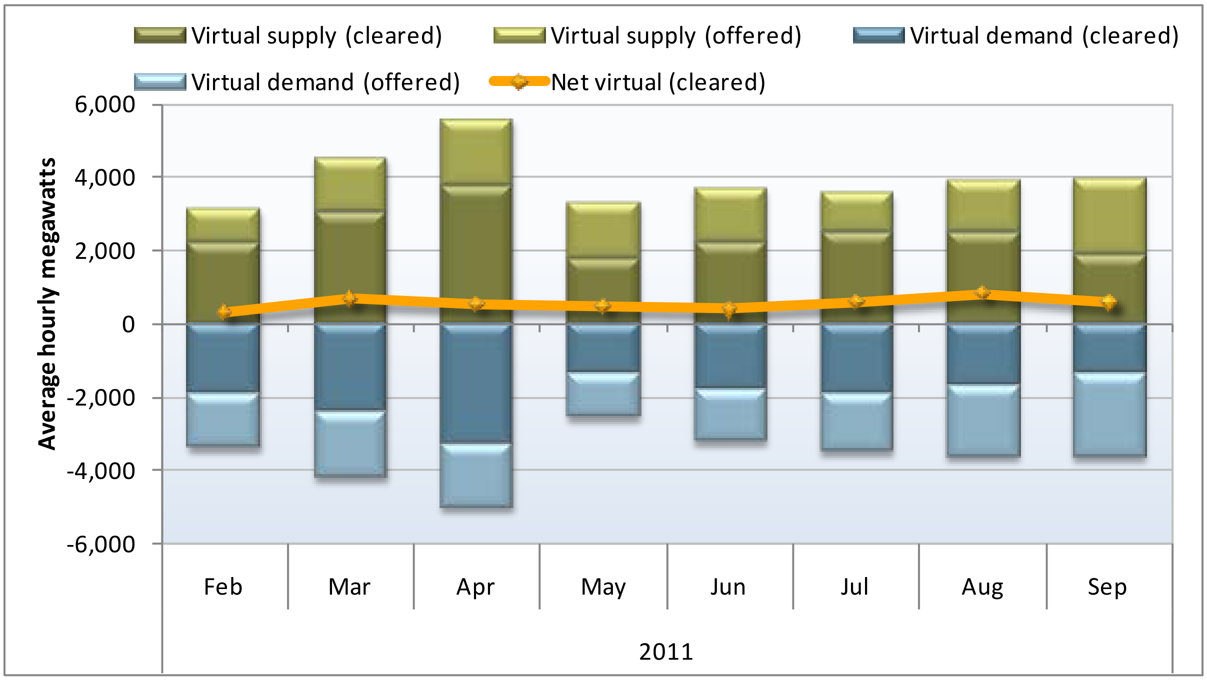
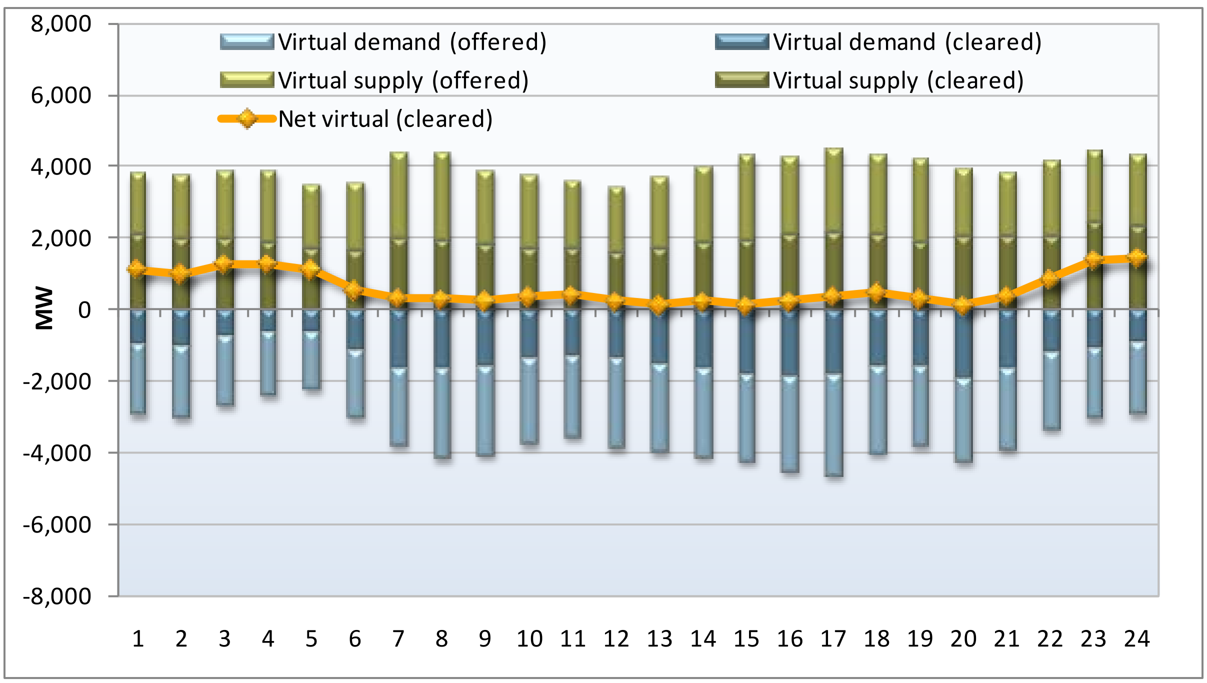


Figure 2.2 Hourly offered and cleared virtual activity (July-September 2011)



2.1.3 Virtual supply at the inter-ties and virtual demand at internal nodes

Convergence bidding positions at inter-ties and at internal nodes show a distinctive pattern in the first two quarters. Virtual supply on inter-ties and virtual demand on internal nodes comprised 86 percent of the total trading volumes. In the third quarter, virtual supply volumes at internal nodes increased and offset internal virtual demand more than in previous quarters. As shown in Figure 2.3, convergence bidding on inter-ties (shown in green) is weighted towards virtual supply. Convergence bidding on internal locations (shown in blue) is weighted towards virtual demand.

During the first several months, numerous market participants have employed a strategy where they place virtual supply positions at the inter-ties and then place an equal and opposite virtual demand position at internal locations. Figure 2.4 shows the volume of these overlapping positions. The blue bars represent the weekly average megawatts associated with this strategy, whereas the green bars represent offsetting positions attributable to different convergence bidding entities placing offsetting positions. There was a sharp drop off in this strategy in mid-April. After an uptick in the strategy in June and early July, the use of the strategy decreased even further. By late August and September, the megawatts associated with the strategy were the lowest since convergence bidding began in February.

Figure 2.3 Average monthly cleared convergence bids at inter-ties and internal locations

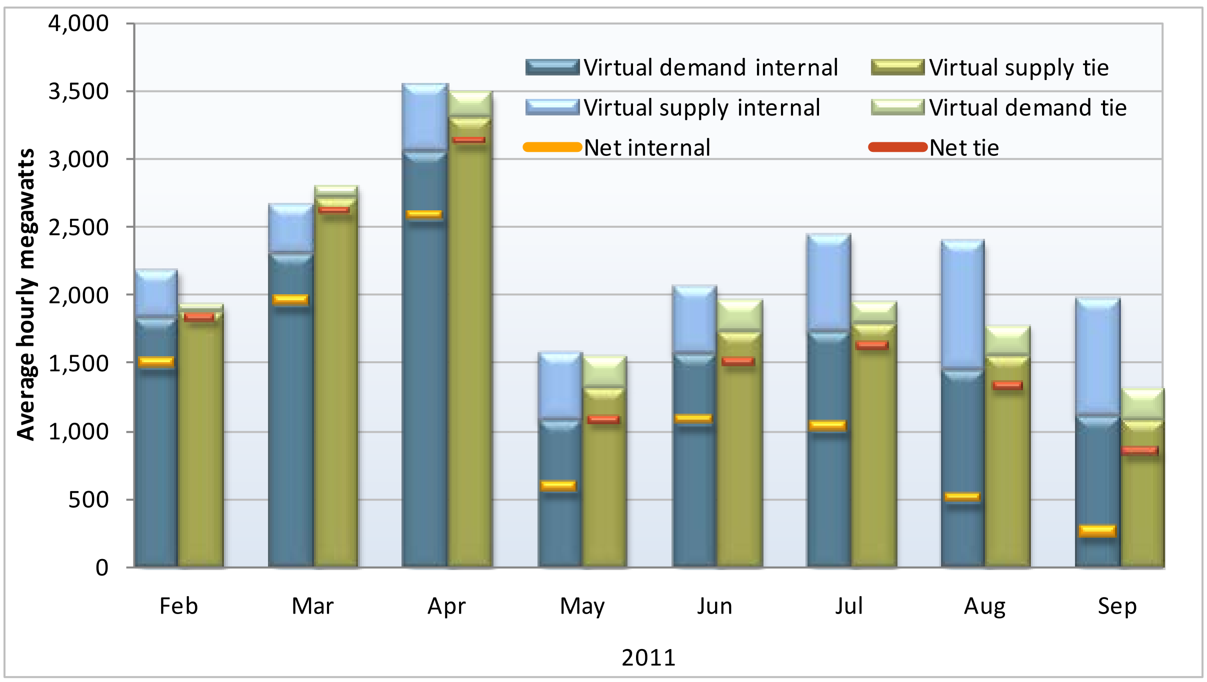
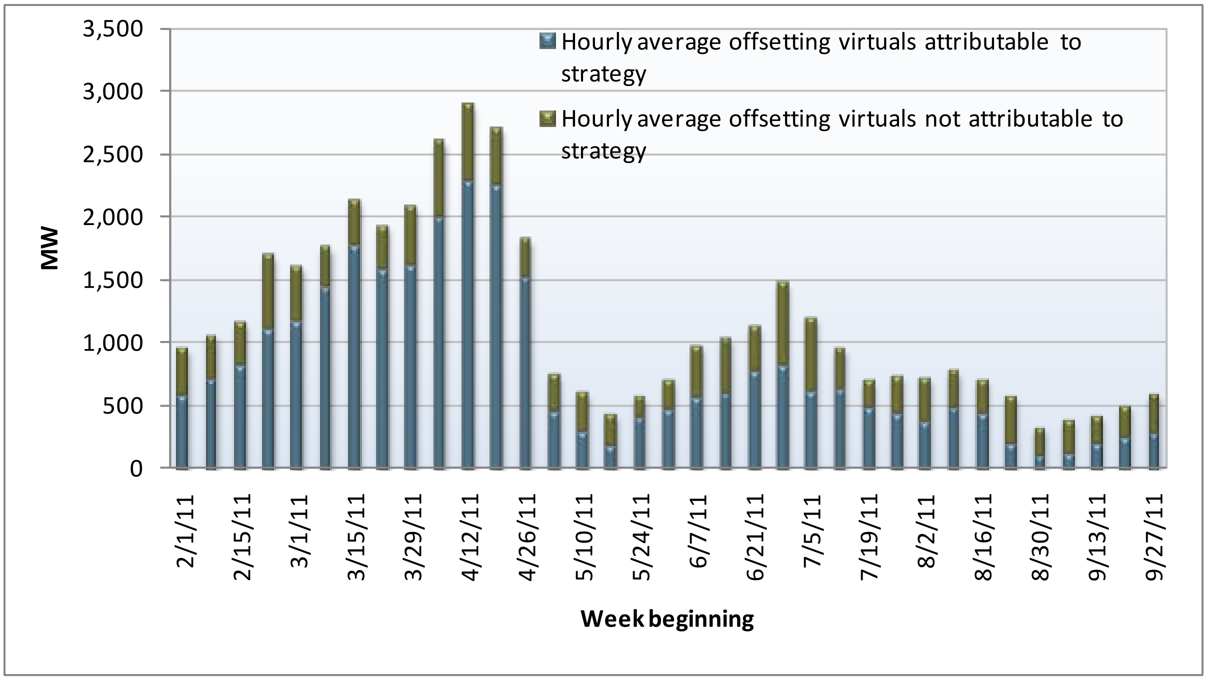


Figure 2.4 Portion of cleared virtual bids attributable to offsetting virtual bids submitted by same participant (virtual imports plus virtual internal demand)



As noted above, convergence bidding at the inter-ties settles against the hour-ahead market prices, whereas convergence bidding at internal nodes settles against the 5-minute real-time market prices. If prices in the hour-ahead market were consistent with 5-minute real-time market prices these positions would not create cause for concern. Yet, as shown in the next section, prices between these markets have been markedly different at times, even in the third quarter. This has led to continued uplifts that are outlined further in Section 2.2.3.

2.2 Convergence bidding effects on the market

If convergence bidding is working as intended, day-ahead, hour-ahead and 5-minute real-time market prices should converge. The following aspects about price convergence are described in detail in Section 1.1.

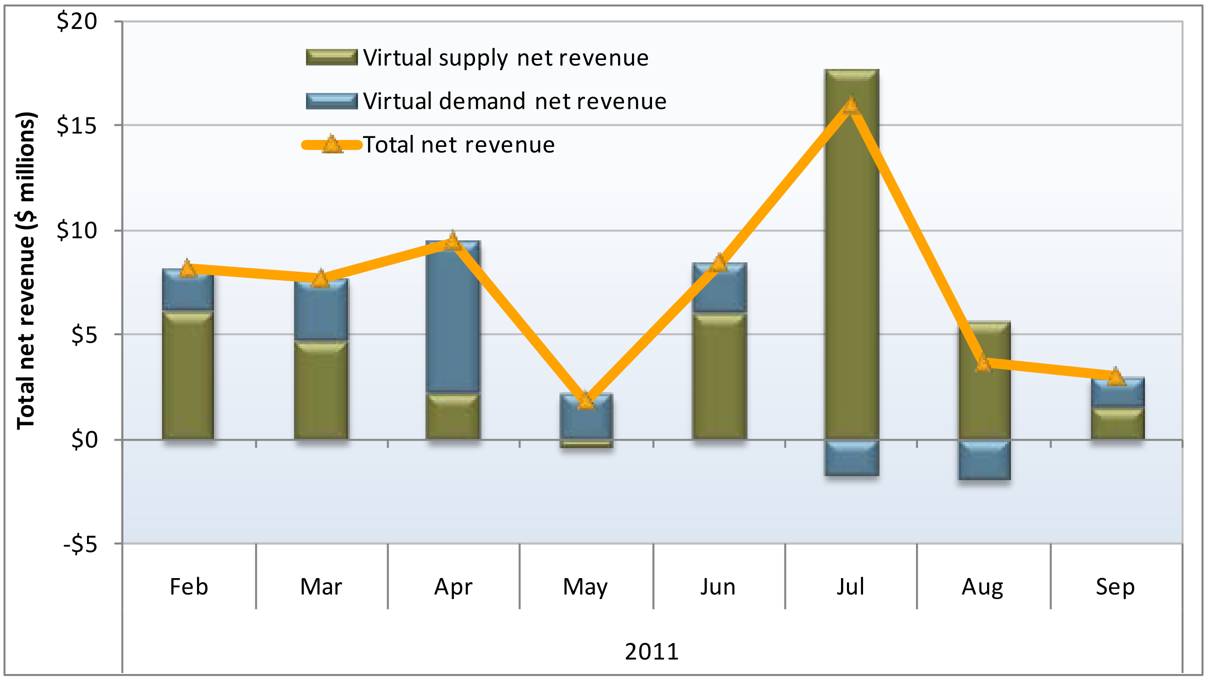
- Since the start of convergence bidding, price divergence was largest in the months of June and July. The July results were skewed by a small set of outliers in the hour-ahead market.[27]
- Overall average price convergence appeared to improve in the months of August and September. Even though monthly convergence improved, price divergence persisted at an hourly level.
- Much of the improvement in price convergence can be attributable to changes in ISO operational procedures and software changes to address ramping limitations in real-time.

[27] See Footnote 4.

2.2.1 Net profits from convergence bidding

With the exception of July and August, the total net revenues on virtual demand paid to convergence bidding entities have been positive (see Figure 2.5). Virtual supply transactions were profitable in all months except May. Over the course of the third quarter, net revenues paid out to convergence bidding entities totaled $23 million, up from $19 million paid to convergence bidding entities in the second quarter. Net revenues were highest in July as a result of virtual supply revenues on inter-ties.

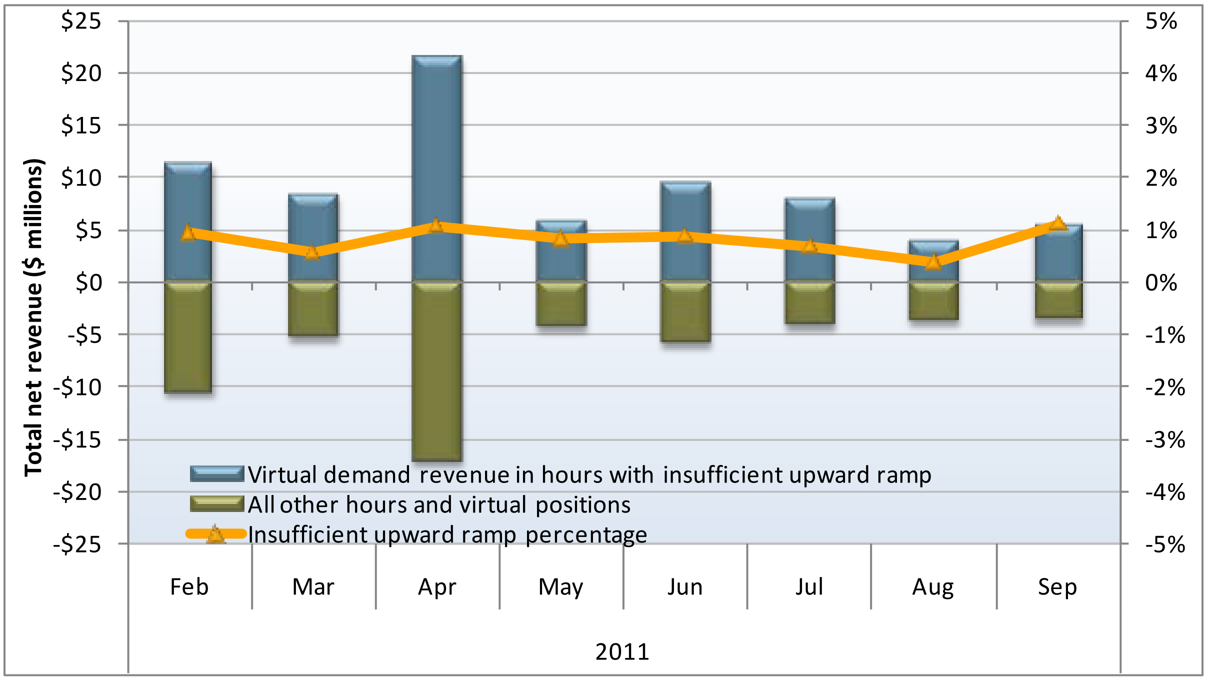
Figure 2.5 Total monthly convergence bidding net revenues



Net revenues on internal nodes

Approximately 90 percent of virtual demand bids clear at internal locations. Virtual demand bids at internal nodes are profitable when real-time prices spike in the 5-minute real-time market. Intervals when the system power balance constraint relaxes account for almost all of the positive revenues for internal virtual demand positions, as shown in Figure 2.6. As noted in Section 1.2, when the power balance constraint is relaxed, the system marginal energy component of the price is set to the bid cap, which was $750/MWh in the first two months of convergence bidding and increased to $1,000/MWh on April 1. Net revenues received from these brief but extreme price spikes are typically 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 losses in the remaining intervals of the hour.

Figure 2.6 Convergence bidding revenues at internal nodes



These price spikes are typically associated with brief shortages of ramping capacity. Convergence bidding can potentially add additional capacity, but that capacity may not be enough to address the ramping limitations. Moreover, in the event of over-generation, real-time prices can be negative, but they never go 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.

2.2.2 Changes in unit commitment

In the day-ahead market, if scheduled demand is less than the ISO forecasted demand, the residual unit commitment process procures additional capacity to meet the forecasted demand, as well as any forecasted shortfalls of minimum generation requirements.

Cleared virtual supply outweighs cleared virtual demand at the system level in approximately 79 percent of all hours since the beginning of the virtual markets. As a result, more residual unit commitment capacity is needed to replace the net virtual supply with physical supply. This is likely to increase both the direct capacity procurement costs and bid cost recovery payments associated with residual unit commitment.

In the third quarter of 2011, total direct residual unit commitment costs reached $306,000. Since convergence bidding started in February, direct residual unit commitment costs have totaled around $691,000, compared to the 2010 total of $83,000. Bid cost recovery payments for the residual unit commitment capacity amounted to over $1.9 million in the third quarter. Since the beginning of convergence bidding, bid cost recovery payments for the residual unit commitment capacity reached $3.4 million, compared to $1.4 million in all of 2010.

2.2.3 Costs associated with continued price divergence and convergence bidding

Divergence in prices can pose unnecessary additional inefficiencies and costs on the system. When net imports decrease in the hour-ahead market, but real-time imbalance energy increases, the decrease in net imports may be inefficient.[28] Moreover, if net virtual supply on the inter-ties outweighs net virtual demand on internal nodes, and real-time imbalance energy increases, this may also be inefficient.

Such reductions are inefficient if hour-ahead prices are systematically lower than real-time prices, so that the ISO is selling both physical and virtual supply in the hour-ahead at a low price and then dispatching additional energy in real-time at a higher price. Conversely, if both physical supply and virtual demand are purchased in the hour-ahead market at high prices and then additional energy is dispatched in real-time at lower prices, this can also create imbalances. These situations can create substantial uplifts that must be recovered from load-serving entities through the real-time imbalance energy and congestion offset charges.[29]

Physical net imports in the hour-ahead market relative to day-ahead market

Historically, hour-ahead market prices have been lower than both day-ahead and real-time market prices. However, over the course of the last few months, hour-ahead prices have become more in line with real-time prices and closer to day-ahead prices (as shown in Section 1). This has coincided with the change in operational load adjustment patterns whereby loads are adjusted upward systematically in the hour-ahead market to compensate for modeling discrepancies.[30] Correspondingly, there has been a shift in the hour-ahead market from reducing net imports, to increasing net imports on average.[31]

Figure 2.7 shows hourly average differences of scheduled physical hour-ahead market imports and exports from the scheduled physical day-ahead imports and exports. Continuing the trend started in March, the average change in physical imports has outweighed the average change in physical exports in the hour-ahead market. Although the total volume of physical imports and exports in the hour-ahead market declined slightly in August and September, the net megawatts of imports has continued to increase during the third quarter, reaching 335 MW in September and averaging approximately 300 MW over the quarter. For the third quarter, net virtual supply has outweighed net virtual demand by around 675 MW.

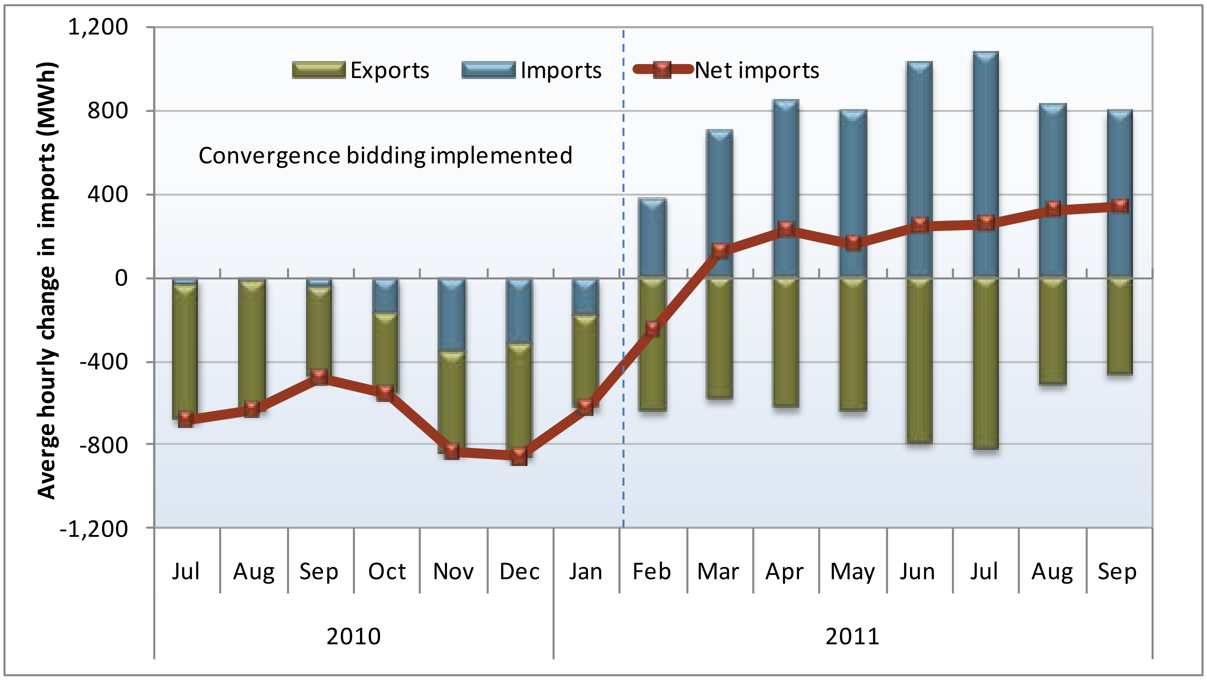
[28] The inter-tie prices are relative to prices in neighboring systems. If prices outside of the ISO system are higher, it makes economic sense for net imports to decrease in the hour-ahead scheduling process. This can be accomplished by either reducing imports or increasing exports.

[29] More information about the Real-Time Imbalance Energy Offset charge can be found on the ISO website at http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/Real-TimeImbalanceEnergyOffset2009.aspx.

[30] *Quarterly Report on Market Issues and Performance*, Department of Market Monitoring, Revised August 24, 2011, p. 11, http://www.caiso.com/Documents/RevisedQuarterlyReportonMarketIssuesandPerformance-August2011.pdf.

[31] At this time, DMM has not been able to determine the extent that the load adjustments have led to increased net imports relative to the actions of convergence bidding.

Figure 2.7 Change in net imports in hour-ahead relative to final day-ahead



Costs of differences in physical net imports in the hour-ahead relative to real-time market

Real-time energy imbalances can occur when physical net imports decrease at hour-ahead prices that are lower than real-time prices when the real-time dispatch energy increases. Imbalances can also increase when physical net imports increase at hour-ahead prices that are higher than real-time prices when the real-time dispatch energy decreases. In both cases the ISO procures energy in the higher cost market and sells off energy in the lower cost market.[32] The effects of these movements are outlined below.

A. Costs of decreases in physical net imports in the hour-ahead relative to real-time market

When physical net imports decrease in the hour-ahead and real-time imbalance energy increases, the decreased imports in the hour-ahead are likely to have increased the need to dispatch imbalance energy in real-time.[33] This scenario occurred in almost 42 percent of the hours in the third quarter.

The blue bars in Figure 2.8 show DMM's estimate of the average hourly decrease in hour-ahead net imports that were subsequently re-procured by the real-time dispatch by month. The lines in Figure 2.8 compare the corresponding weighted average prices at which this decrease in net imports was settled in the hour-ahead market and the weighted average prices for additional energy procured in the real-time

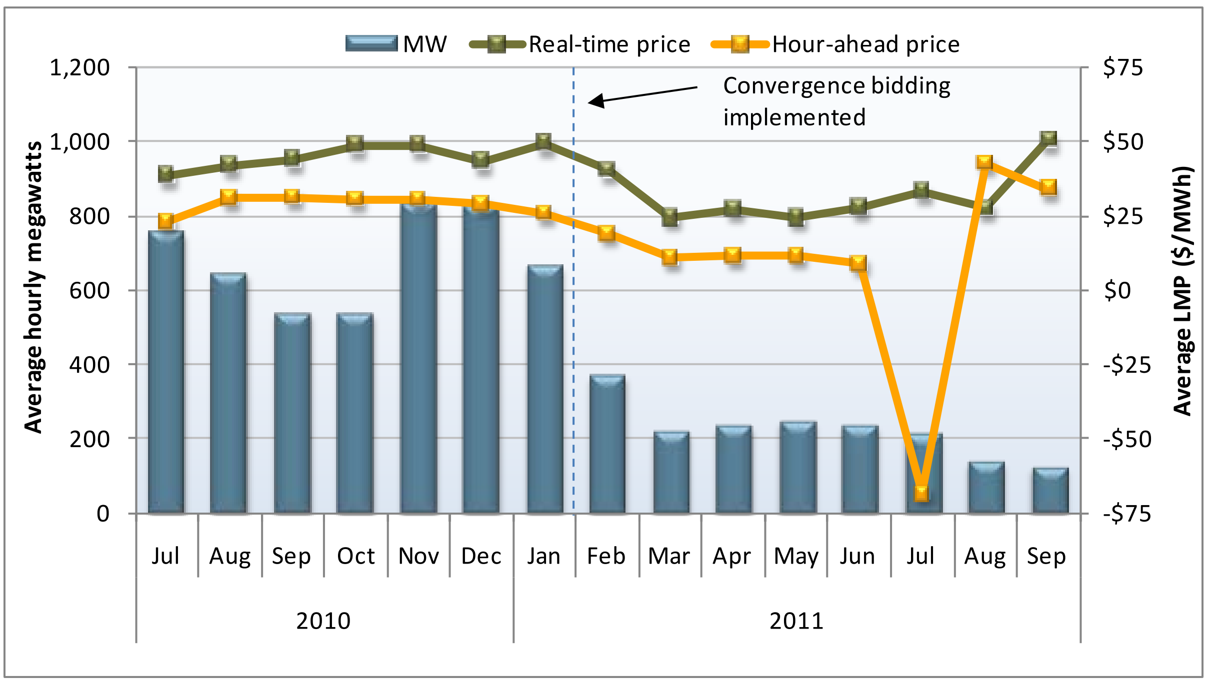
[32] When physical net imports in the hour-ahead market and real-time dispatch energy move in the same direction, no real-time imbalance is attributable to changes in physical net imports.

[33] In some cases, reductions in net imports may be necessary in the hour-ahead market to manage congestion or reduce supply because of energy not scheduled in the day-ahead market, such as renewable generation or unscheduled start-up or minimum load energy from thermal units. The hour-ahead software should take this energy into account and seek to optimize prices between imports and exports adjusted in the hour-ahead and subsequent dispatches and prices in the 5-minute real-time market.

market during each month.[34] Together, the hourly decrease in hour-ahead net imports and the difference in hour-ahead and real-time prices produce the estimated imbalance energy costs. The total costs are determined by the quantity that is reduced in the hour-ahead market and then re-procured in the 5-minute real-time market, combined with the difference in prices in these two markets.

As shown in Figure 2.8, the volatility in hour-ahead prices has increased during these hours in the third quarter with July having an average hour-ahead price of about -$68/MWh.[35] In August, hour-ahead prices were higher than real-time prices for the first time by $15/MWh. As a consequence, the price divergence between hour-ahead and 5-minute real-time market prices in the third quarter of 2011 has increased in comparison to the third quarter of 2010. The average price difference in the third quarter of 2011 was around $34/MWh with a diminished average quantity of about 157 MW compared to about $13/MWh in average price difference with 645 MW quantity in the third quarter of 2010.

Figure 2.8 Monthly average quantity and prices of net import reductions in the hour-ahead market and resulting increase in real-time energy dispatched



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

[35] This was the result of large negative prices on July 19 hour ending 4 and 10.

B. Cost of increases in physical net imports in the hour-ahead relative to real-time market

When physical net imports increase in the hour-ahead and real-time imbalance energy decreases, the increased imports in the hour-ahead may have increased the need to dispatch decremental imbalance energy in real-time. This scenario occurred in over 25 percent of the hours in the third quarter.

The blue bars in Figure 2.9 show DMM's estimate of the average hourly increase in hour-ahead net imports that were subsequently re-sold by the real-time dispatch by month. The lines in Figure 2.9 compare the corresponding weighted average prices at which this increase in net imports was settled in the hour-ahead market and the weighted average prices for additional energy sold in the real-time market during each month.[36] Together, the hourly increase in hour-ahead net imports and the difference in hour-ahead and real-time prices produce the estimated imbalance energy costs. The total costs are ultimately determined by the quantity that is increased in the hour-ahead market and then sold in the 5-minute real-time market, combined with the difference in prices in these two markets.

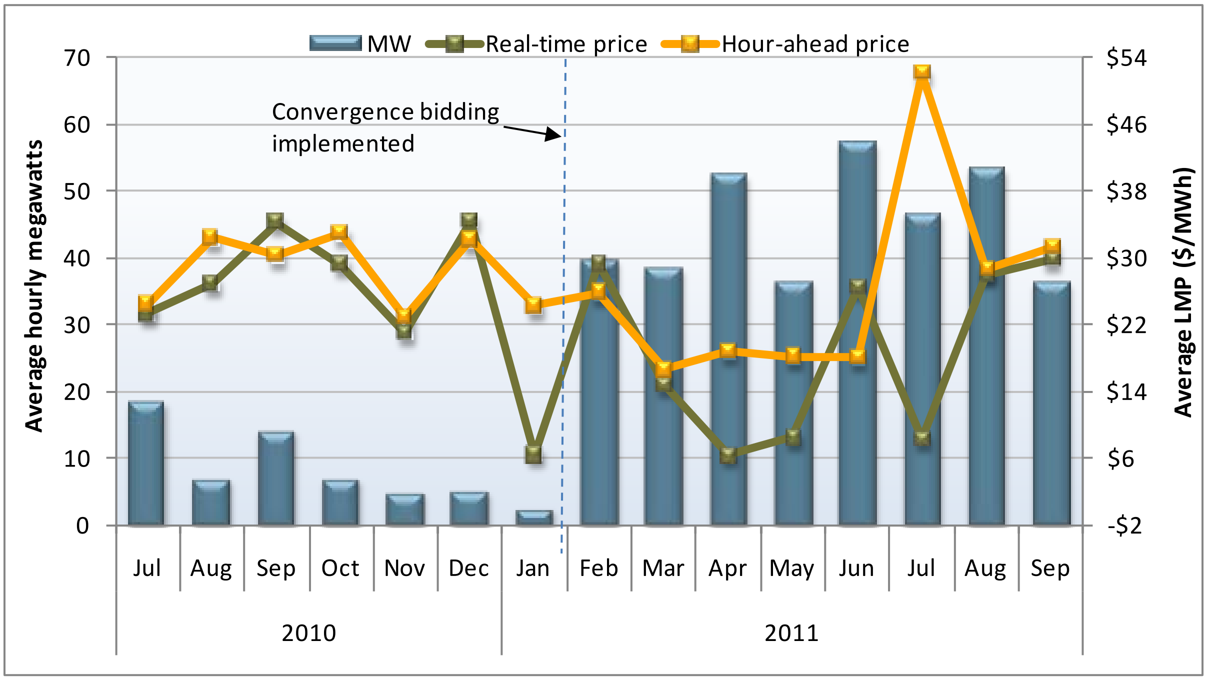
The average hourly volume of dispatch energy sold has more than quadrupled since the launch of convergence bidding in February this year, from an average of roughly 11 MW for the year prior to convergence bidding to 45 MW after. This also contributes to the imbalance cost as energy that is purchased in the hour-ahead market at higher prices is sold off in the real-time market at lower prices. Historically, these volumes have been low and the relative price differences fairly tight, and the effect on overall imbalance charges have been low. However, as shown in Figure 2.9, the average hour-ahead and real-time prices have diverged in July 2011, with the hour-ahead price exceeding the real-time price by about $45/MWh during these hours,[37] and at volumes consistent since the inception of convergence bidding.

Overall, this has been and remains a relatively small contributor to the real-time energy imbalance costs. However, as the hour-ahead market takes in more net imports and as the hour-ahead price exceeds the real-time price, this situation can also increase real-time imbalance costs.

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

[37] The July result was driven by large positive prices in the hour-ahead market on July 5, 6, 7 and 12.

Figure 2.9 Monthly average quantity and prices of net import increases in the hour-ahead market and resulting decrease in real-time energy dispatched



Real-time imbalance costs

Figure 2.10 shows the estimated costs of additional imbalance energy and congestion because of changes in net imports in the hour-ahead that is offset by imbalance energy in real-time at a different price.[38] With the introduction of convergence bidding in February 2011, these costs changed substantially and have been replaced by a virtual bidding imbalance cost. This virtual bidding imbalance cost is related to liquidating virtual positions on the inter-ties at different prices from internal virtual positions in the 5-minute real-time market.

The total convergence bidding imbalance cost during the first eight months (February – September) was around $61 million. Convergence bidding impacts on imbalance costs were the highest of any month in July since the February start-up and were the lowest in September. July results were driven mainly by congestion. The August and September results were driven by improved overall price convergence.

In each month there are differences between the estimated value (bars) and the settlement system value (line). In July, the difference is partly because of price estimation assumptions in DMM's methodology. In August and September, the differences are mainly attributable to unaccounted for

[38] DMM estimates these costs based on the following: 1) the decrease in hour-ahead net imports that were subsequently re-procured in real-time; 2) the increase in hour-ahead imports that were subsequently sold in real-time; and 3) the difference in hour-ahead versus real-time prices during the corresponding hour. This cost estimate is only one element of the real-time imbalance energy offset charge and, therefore, will differ from the total value of the charge for various reasons. Further detail on the different elements contained within the charge can be found in the following report: http://www.caiso.com/2416/2416e7a84a9b0.pdf.

energy (UFE).[39] Typically, the UFE number is revised to a more accurate number when the load serving entities submit metered data to the ISO.

Figure 2.10 Estimated imbalance costs because of changes in physical and virtual hour-ahead net imports at different prices than physical and virtual dispatch in the 5-minute market

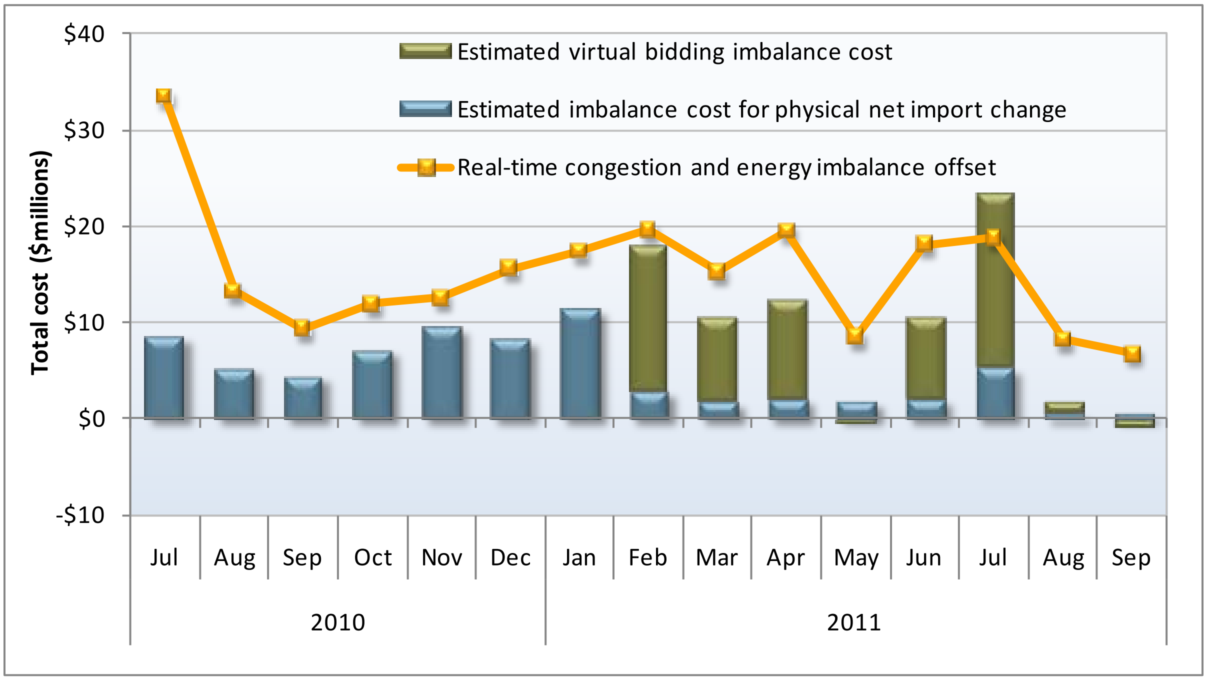
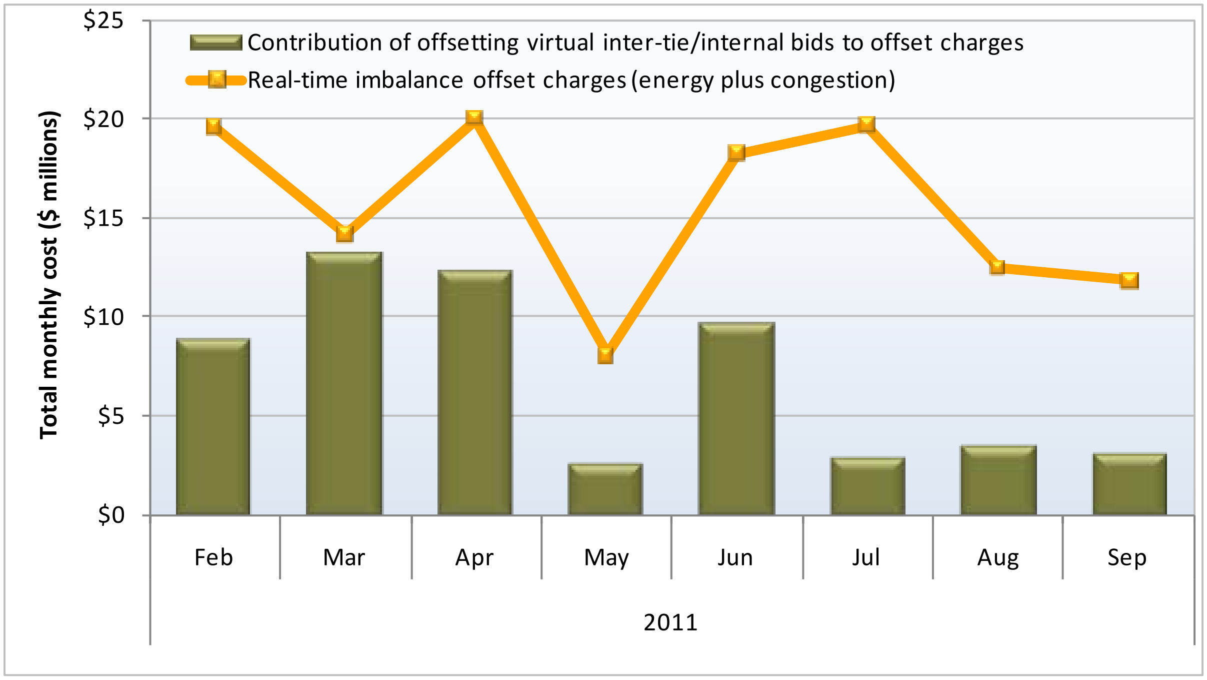


Figure 2.11 shows the breakdown of the estimated real-time imbalance cost associated with offsetting virtual supply on inter-ties and virtual demand at internal locations. Interestingly, imbalance costs associated with offsetting virtual positions are near $3 million in the months of August and September. This highlights that even though the total virtual positions create a small imbalance (as seen in Figure 2.10), or a net credit in the month of September, the offsetting positions can still contribute to imbalance costs. Since the market began in February, DMM estimates that charges associated with offsetting virtual positions have totaled $56 million, about 45 percent of the total imbalance costs. In the third quarter, DMM estimates that these charges totaled about $10 million, representing about 22 percent of the total imbalance charges.

[39] Unaccounted for energy is attributable to meter measurement errors, power flow modeling errors, energy theft, statistical load profile errors, and distribution loss deviations.

Figure 2.11 Contribution of offsetting virtual supply and demand to real-time imbalance charges



2.3 Recommendations

DMM remains supportive of the ISO's proposal to eliminate virtual bidding at the inter-ties as a short-term option for reducing real-time imbalance costs. Convergence bidding has not resolved the issue of real-time price convergence and has contributed to high real-time imbalance costs. Until price convergence can be reached through more effective modeling or structural changes between these two markets, convergence bidders can continue to take advantage of these differences between the hour-ahead and real-time markets. As long as these systematic price differences continue, participants can bid in offsetting virtual supply bids on the inter-ties and virtual demand bids on internal nodes. This strategy will continue to impose unnecessary costs to the market while providing little or no market or reliability benefits.

3 Special Issues

In the third quarter, there were several notable system and market events. These include:

- A three-day period of relatively extreme hour-ahead market load adjustments in July.
- The September power outage in the San Diego area.
- Performance issues related to the deployment of the new real-time load forecasting system known as ALFS3.

This section provides a review of each of these issues, along with analysis of rules changes related to the registered cost option implemented in April 2011 for minimum load and start-up costs.

3.1 Hour-ahead market manual load adjustments

From July 5 through 7, day-ahead forecast load was significantly below actual real-time load.[40] During numerous hours on these days grid operators manually adjusted the load forecast in the hour-ahead market by over 3,000 MW (see Figure 3.1 below). This adjustment was on top of the hour-ahead load forecasts, which were close to the actual loads on these days.

The high level of manual load forecast adjustment on these days resulted in high prices in the hour-ahead market. The hour-ahead market software hit system penalty prices, causing hour-ahead energy prices to approach $3,500/MWh for one interval and nearly $1,000/MWh for several other intervals. The events on each day are detailed below.

- **July 5, 2011.** Real-time load was coming in more than 1,100 MW over the day-ahead forecast for much of the day as the weather was hotter than anticipated throughout much of the west. This caused tighter supply conditions than normal both inside and outside the ISO balancing authority area. The loss of 530 MW of imported generation in the real-time hour 12 because of a forced generator outage further tightened system conditions. In the early afternoon, ISO operators manually increased the hour-ahead load forecast by 3,000 MW, causing hour-ahead prices to exceed $1,000/MWh.[41] DMM has not been able to determine the basis for this specific level of manual forecast adjustment.

- **July 6, 2011.** The real-time load was more than 1,900 MW higher than the day-ahead forecast for many of the peak hours, reaching as much as 2,400 MW above the day-ahead forecast in one hour. In addition, 600 MW of imports were not delivered in real-time hour 13 and approximately 750 MW of net exports were declined in hour 15. The exports were cut by the market software as a result of a 3,500 MW manual load forecast adjustment input into the model by ISO operators. The manual load adjustment caused the software to hit a penalty price, and caused some self-scheduled exports to be cut. ISO operators indicated to market participants that the export reductions were not a

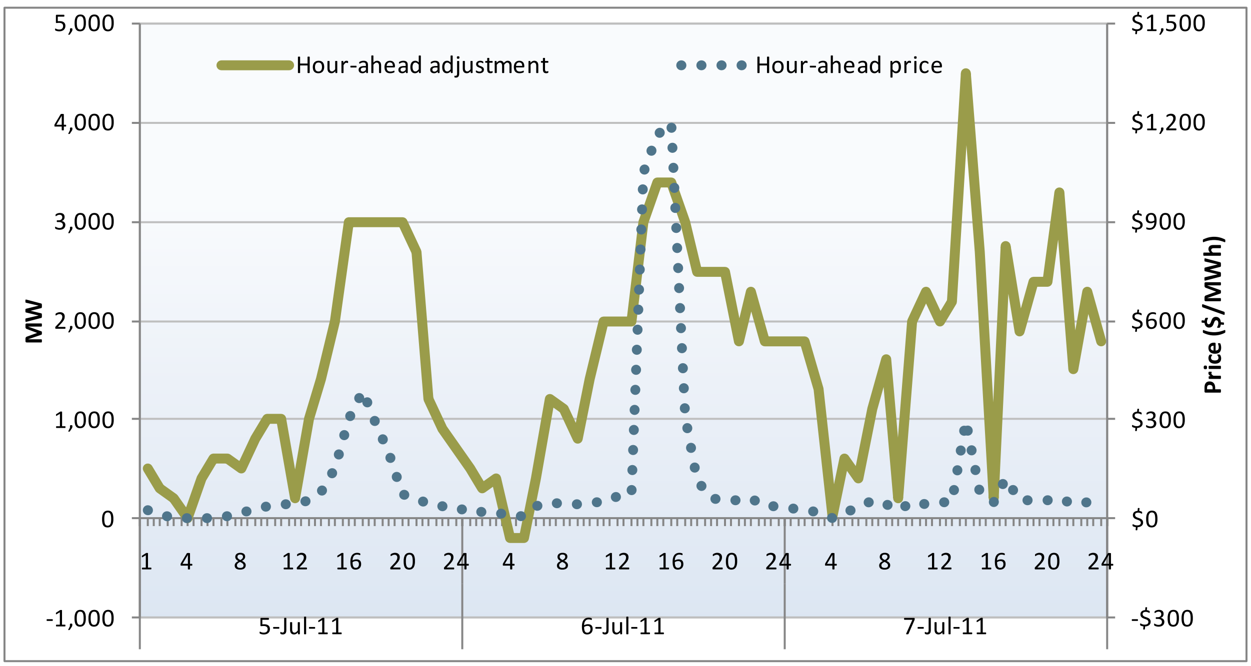
[40] Real-time actual loads came in over a couple thousand megawatts higher than day-ahead forecasts in some hours. The cause for the difference appears to have been driven by poor weather forecasting input into the model and not the load forecasting mechanism itself.

[41] Between April and June 2011, the average maximum daily hour-ahead adjustment for peak hours was just over 650 MW. During this period, load was adjusted over 1,000 MW for 19 intervals and only reached 1,800 MW twice.

result of a reliability issue. Consequently, the export schedule cuts were declined by the market participants and the exports were delivered. The magnitude of the upward load adjustments in the hour-ahead market on this day appear to have been driven by the operator's decision to replicate hour-ahead manual load adjustment levels made the previous day.

- **July 7, 2011.** Load was around 800 MW higher in real-time than in the day-ahead forecast during the afternoon hours. In hour 14, the hour ahead manual load adjustment was increased to 4,500 MW. Based on DMM's review of operational data and information, it appears that operators did not intend to adjust load by 4,500 MW.[42]

Figure 3.1 Hour ahead manual load forecast adjustment and average LMP (PG&E LAP)



Based on DMM's review of events on these three days, we have suggested the following potential lessons learned to ISO operations staff:

- The criteria and guidelines for making manual adjustments to the hour-ahead market load forecast should continue to be refined to reduce the need for operator judgment and to more quickly and directly reflect observed market performance during prior hours. For example, based on DMM's review of this period, the 3,000 MW increase in the hour-ahead forecast on July 5 appears to exceed the ISO's normal guidelines and specific basis for this level of adjustment could not be determined. On July 6, our review suggests that the forecast was adjusted by a similar amount primarily because that adjustment had been made the day before. However, a review of market performance on July 5 may have indicated that this level of hour-ahead load adjustment was too high.

[42] Specifically, it appears that the hour-ahead load forecast was adjusted upwards once, and was unintentionally adjusted upwards a second time. The ISO indicated that a software glitch may have caused the error to occur.

- Extremely high level of hour-ahead load adjustments may not result in additional imports, and may actually result in greater discrepancies between hour-ahead dispatches and real-time conditions. For example, the extremely high load adjustments in hour-ahead on July 6 caused the hour-ahead software to curtail exports on the inter-ties when all economic resources were exhausted. Since ISO operators indicated these curtailments were not necessary for reliability, these curtailments were declined. This created a greater discrepancy between hour-ahead dispatches and real-time conditions.
- Logging of data input errors remains important. For example, on July 7, our review suggests that extreme prices resulted from high hour-ahead load forecast adjustments that resulted from a data input error. However, this was not logged by operators or communicated to the price correction team. Had this potential error been logged or communicated, it may have resulted in price correction under the ISO's criteria for price corrections.

Finally, DMM notes that the extremely high levels of manual load adjustment described above appear to be limited to this three-day period and have not been a reoccurring issue. Although the hour-ahead manual load adjustment resulted in a few high hour-ahead energy price spikes, it is important to note that hour-ahead market prices historically have been much lower than real-time prices.

3.2 September power outage

On Thursday September 8, 2011, a power outage resulted in the loss of approximately 7,890 MW of firm load in the Pacific Southwest region, leaving about 2.8 million people without power. The event affected multiple balancing authorities, including Arizona Public Service, California ISO, Comision Federal de Electricidad, Imperial Irrigation District, and Western Area Power Administration, Lower Colorado Region.

The sequence of events started at 3:27 p.m. when a fault occurred at the North Gila 500 kV substation. This was followed quickly by other events, including generation and transmission outages, transformer overloads and voltage disturbances. Finally, the San Onofre Nuclear Generating Station separated from San Diego as a part of the San Onofre 230 kV system separation scheme,[43] and tripped several seconds later. A power outage occurred at 3:38 p.m., or only eleven minutes from the first event.

Initially, the ISO market continued to operate after the power outage. However, because of data issues related to the power outage, the market results were not indicative of system conditions. Prices prior to the market suspension were either administratively set based on the market price during the last good interval before the disturbance (hour ending 16 interval 10) for any failed or blocked interval or corrected using the same price (hour ending 16 interval 10) until markets were suspended. The ISO temporarily suspended the market at 6:00 p.m. (hour ending 19) and a special administrative price of $250/MWh was set for all prices for the hour-ahead and real-time energy markets. Later, the special administrative energy price was revised to $100/MWh at 10:00 p.m.

[43] The San Onofre 230 kV system separation scheme operated correctly, separating the Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) ties at San Onofre resulting in an island consisting of SDGE, Comision Federal de Electricidad (CFE) and Yuma, Arizona, load. This scheme operated as designed to reconfigure the San Onofre 230 kV switchyard by transferring both San Onofre nuclear units to the SCE system and isolating the five 230 kV lines south of San Onofre to SDGE. Following the separation, the imbalance between generation and load resulted in a rapid decline in frequency. The remaining load and generation in SDGE, CFE and Yuma tripped on underfrequency.

From hour ending 19 on September 8 through hour ending 1 on September 9, the ISO initially informed generators to follow their day-ahead schedules in energy and ancillary services markets unless the ISO issued a specific verbal exceptional dispatch to a different operating level. This instruction was later revised and the ISO instructed generators to follow their current output levels unless instructed otherwise. The market was resumed for the PG&E and SCE service areas at 1:00 a.m. (hour ending 2) on September 9. Units within the SDG&E service area still followed verbal exceptional dispatch until 4:00 a.m. on September 9. Beginning at 4:00 a.m. (hour ending 5), all markets were restored and all dispatches for energy and ancillary services were issued through the automated dispatch system.

DMM monitored the events both during and after the disturbance. However, since the events were mainly operational and resulted in market suspension, there was little market activity to review. Upon review of the events, DMM recommends that the ISO further review and potentially refine tariff provisions and procedures related to administrative pricing.

3.3 Real-time load forecast implementation issues

The ISO implemented a new load forecasting system known as ALFS3 in May 2011. Since implementation, the ISO estimates an 8.5 percent improvement in accuracy, compared to the previous model (ALFS2).[44] ALFS3 has generally produced accurate day-ahead load forecasts. However, during a couple of days in July, most notably on July 4 and July 17, ALFS3 created load forecasting errors, which ultimately resulted in real-time price spikes. The ISO determined that the resulting prices were caused by load forecast data errors and corrected the prices. Problems that affect the forecast mainly relate to updating of input data, auto-publishing of input data, and communication problems with other systems.

The ISO has worked to resolve these forecast errors and has improved mechanisms to limit the problems. For example, ALFS3 has features that detect and prevent bad forecasts from reaching the market model. After the incidents in July, the ISO further developed mechanisms to identify and prevent issues. A patch was also applied to ALFS3 on September 26 to address some outstanding input data problems in the PG&E area.

The performance of ALFS3 is dependent on the accuracy of outside factors, including weather forecasts and the forecast of intermittent generation from renewables. The ISO is in the process of improving these forecasts. The ISO now has the renewable desk focused on ALFS3 forecast accuracy. The ISO also trains the operators on forecasting issues, as the operators are responsible for the final forecast and do have tools to manually improve or override the forecast.

[44] ALFS3 automatically produces 5-minute load forecasts. It is an improvement to ALFS2 which produced 30-minute average load forecasts that required interpolation to create 5-minute forecasts.

3.4 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.[45] Prior to April 1, 2011, owners electing the registered cost option were required to submit costs for both minimum load and start-up. Starting on April 1, 2011, the options changed. Owners can now elect whichever combination of proxy or registered minimum load and start-up costs they prefer.[46]

3.4.1 Capacity under registered cost option

At the start of the nodal market in April 2009, about 25 percent of gas-fired capacity was on the registered cost option for start-up and minimum load bids. This increased to approximately 48 percent by December 2010. As shown in Figure 3.2 and Figure 3.3, 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. As shown in these figures:

- Compared to April 2011, the portion of natural gas fueled capacity for start-up costs under the registered cost option increased approximately 29 percent in September, while minimum load capacity increased over 13 percent.
- About 61 percent of all natural gas fueled capacity, or approximately 21,000 MW, was on the registered cost start-up option. About 53 percent, approximately 18,000 MW, was on the registered cost option for minimum load bids.
- Over 9 percent was on the registered cost option for start-up costs only. Only approximately 1 percent of all natural gas fueled capacity under the registered cost option chose solely the minimum load option.
- The portion of capacity at or near the bid cap for start-up costs has remained large and stable, as shown in Figure 3.2.[47] In September, over 80 percent of the registered 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 3.3. In September, about 24 percent of minimum load bids were less than 120 percent of the bid cap, while 55 percent submitted greater than 180 percent of the cap.

[45] 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.

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

[47] An apparent shift in bid composition occurred in July 2011. This can be partially attributed to the specific day of the month the data is analyzed. In this case, the analysis is performed on the 15th of every month. There can be overlap of valid gas prices for a period since owners can elect to change their costs every 30 days and the future gas prices are effective starting the first of every month. A data lag can form. As a result, a valid monthly gas price may no longer be applicable to a given unit because of the timing of its unique 30 day validity period.

Figure 3.2 Gas fired capacity and start-up bids by month

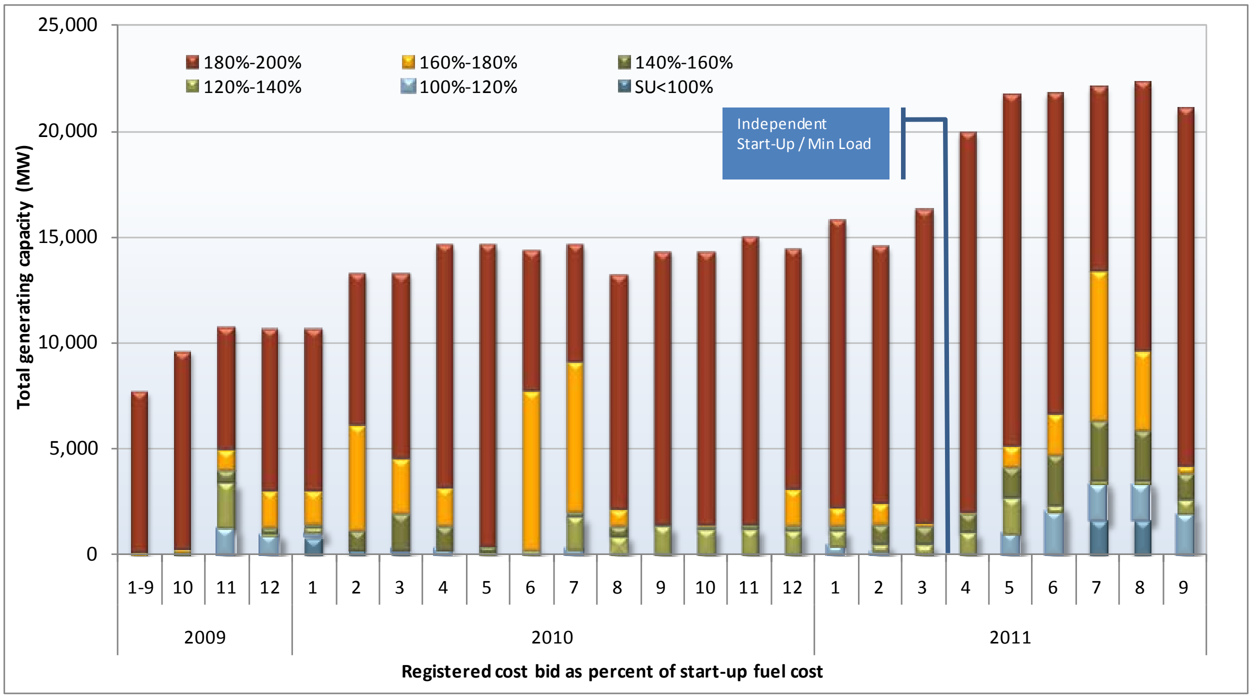
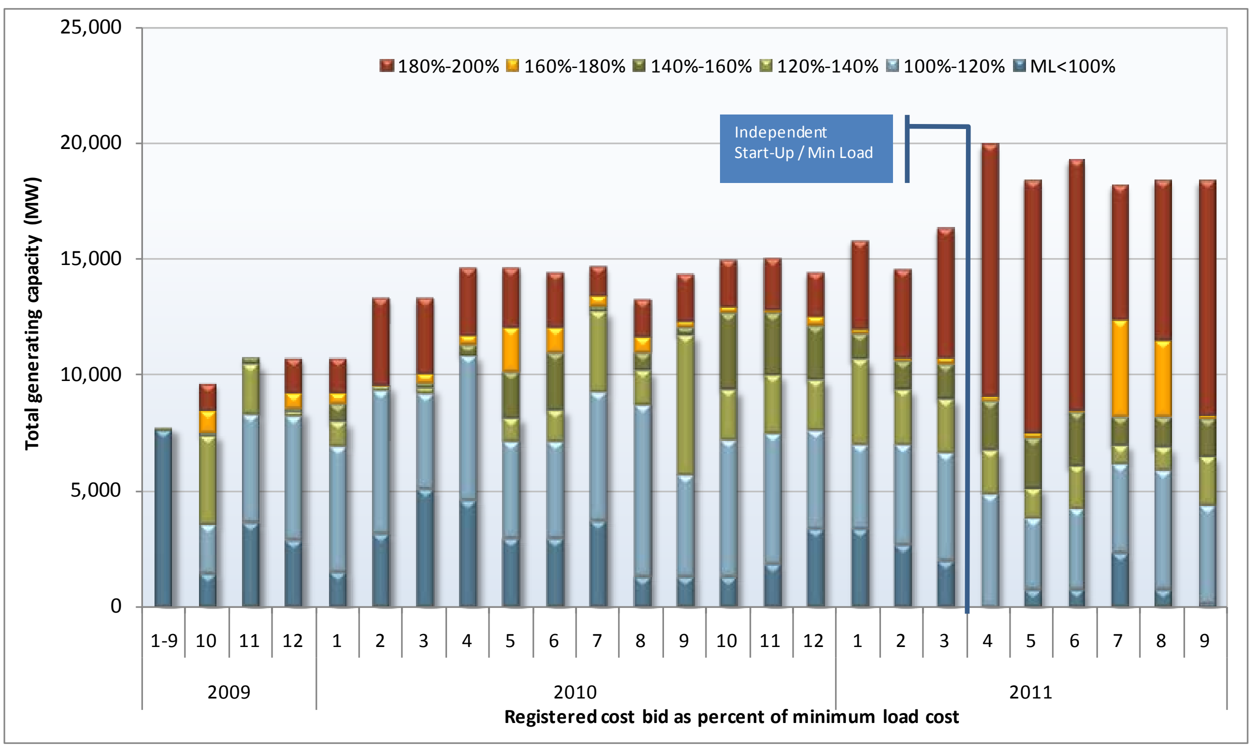


Figure 3.3 Gas fired capacity and minimum load bids by month



3.4.2 Registered cost option by technology

DMM also examined the amount of capacity under the registered cost option by technology.[48] As shown in Figure 3.4 and Figure 3.5:

- Of total natural gas capacity, the registered start-up option is chosen by over 69 percent of combined cycles and 66 percent of steam turbines. Only 36 percent of gas turbines elect this option.
- Of total natural gas capacity, the registered minimum load option is chosen by over 52 percent of combined cycles and 66 percent of steam turbines. Only 31 percent of gas turbines elect this option.
- Most capacity under the start-up registered cost bid option is submitting bids at or near the bid cap. This trend began in December 2010. As shown in Figure 3.4, 80 percent of capacity under the registered cost option submit 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. Over 50 percent of the bids are less than 140 percent of the actual minimum load fuel 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 range throughout the spectrum.

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.

Given these results, DMM recommends that the ISO reevaluate the composition of registered costs to determine the validity and effectiveness of the 200 percent cap. Furthermore, DMM continues to support consideration of the inclusion of a fixed component for non-fuel costs associated with start-up and minimum load costs, given that they can be reasonably quantified and verified.[49] This has been noted at the March 19, 2010, Market Surveillan ce Committee meeting[50] and in DMM's 2009 annual report.[51]

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

[49] This fixed component would then be added to fuel costs associated with start-up and minimum load costs, which would be calculated based on daily spot market gas prices. Since there was little participation in previous requests for data on specific examples of these costs it was not possible to assess the nature and magnitude of these potential costs.

[50] Meeting information can be found here: http://www.caiso.com/Documents/Market%20Surveillance%20Committee%20meeting%2019-Mar-2010.

[51] Department of Market Monitoring, *2009 Market Issues and Performance Annual Report*, April 2010, pp. 4.25-4.28: http://www.caiso.com/2777/27778a322d0f0.pdf.

Figure 3.4 Registered cost start-up bids by generation type – September 2011

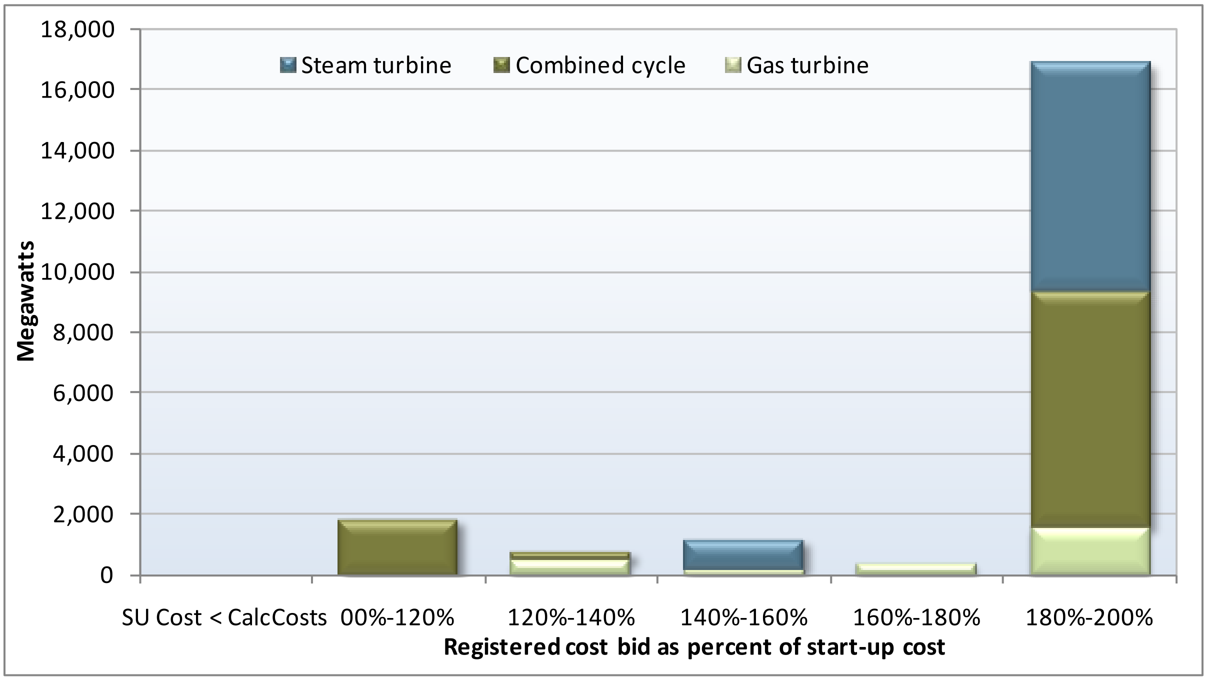

Figure 3.5 Registered cost minimum load bids generation type – September 2011