Memorandum

To: ISO Board of Governors

From: Eric Hildebrandt, Director, Market Monitoring

Date: May 21, 2014

Re: **Market Monitoring report**

This memorandum does not require Board action.

EXECUTIVE SUMMARY

Each year the Department of Market Monitoring (DMM) publishes an annual report on the performance of the markets administered by the ISO. A copy of the report is attached. This year's report provides analysis showing that the ISO market continued to perform efficiently and competitively in 2013. Total costs per MWh of load served by the ISO increased by about 31 percent, primarily as the result of a 30 percent increase in gas prices. After accounting for gas price increases, electric prices increased by 5 percent. Additional factors causing the electric price increase included implementation of the state's greenhouse gas program, as well as decreased hydro-electric generation in the second half of the year. Wholesale energy prices over the course of 2013 were about equal to what DMM estimates would result under highly competitive conditions, taking into account these actual system conditions.

The report also summarizes DMM's recommendations on a variety of market design initiatives that are underway or being implemented in 2014.

MARKET PERFORMANCE

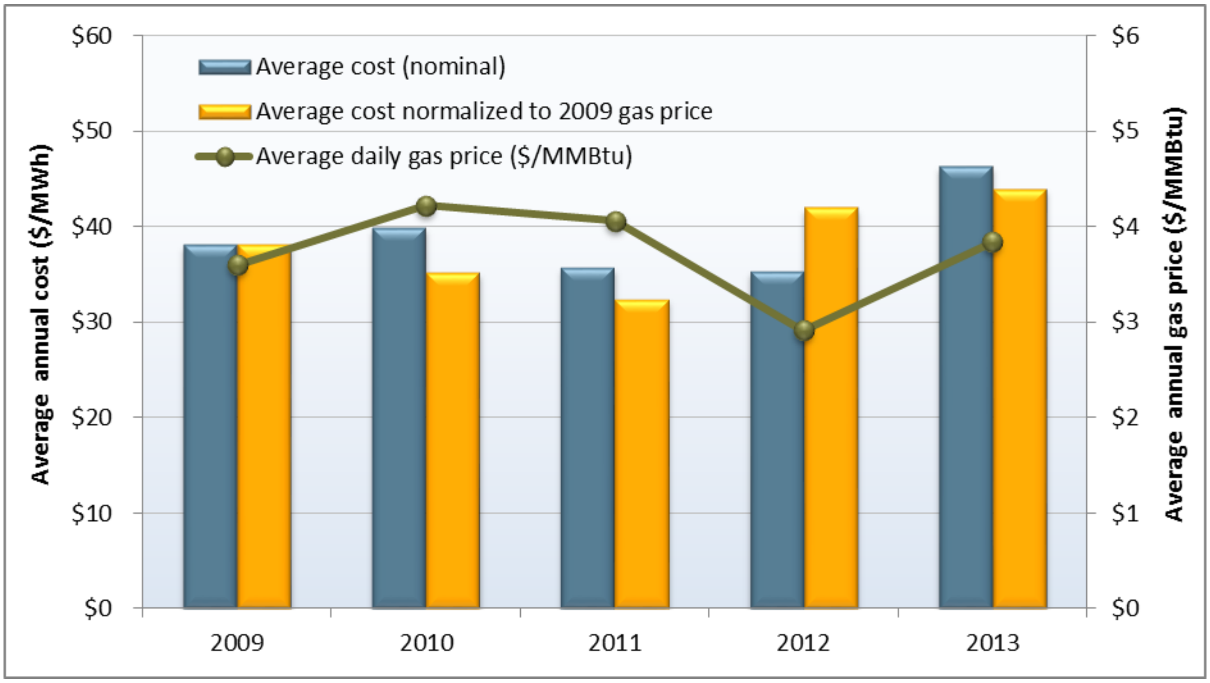
DMM finds that the ISO market continued to perform efficiently and competitively overall in 2013. Other highlights of market performance noted in DMM's 2013 annual report include the following:

- Total wholesale electric costs increased by 31 percent. This increase was primarily driven by a 30 percent increase in natural gas prices in 2013 compared to 2012 (Figure 1).

- After accounting for the gas price increase, wholesale electric costs increased by 5 percent, primarily as a result of implementation of the state's greenhouse gas cap-and-trade program.

- Overall prices in the ISO energy market over the course of 2013 were highly competitive, averaging very close to what DMM estimates would result under highly competitive and efficient conditions, with most supply being offered at or near marginal operating costs.

Figure 1 Total annual wholesale costs per MWh of load (2009-2013)

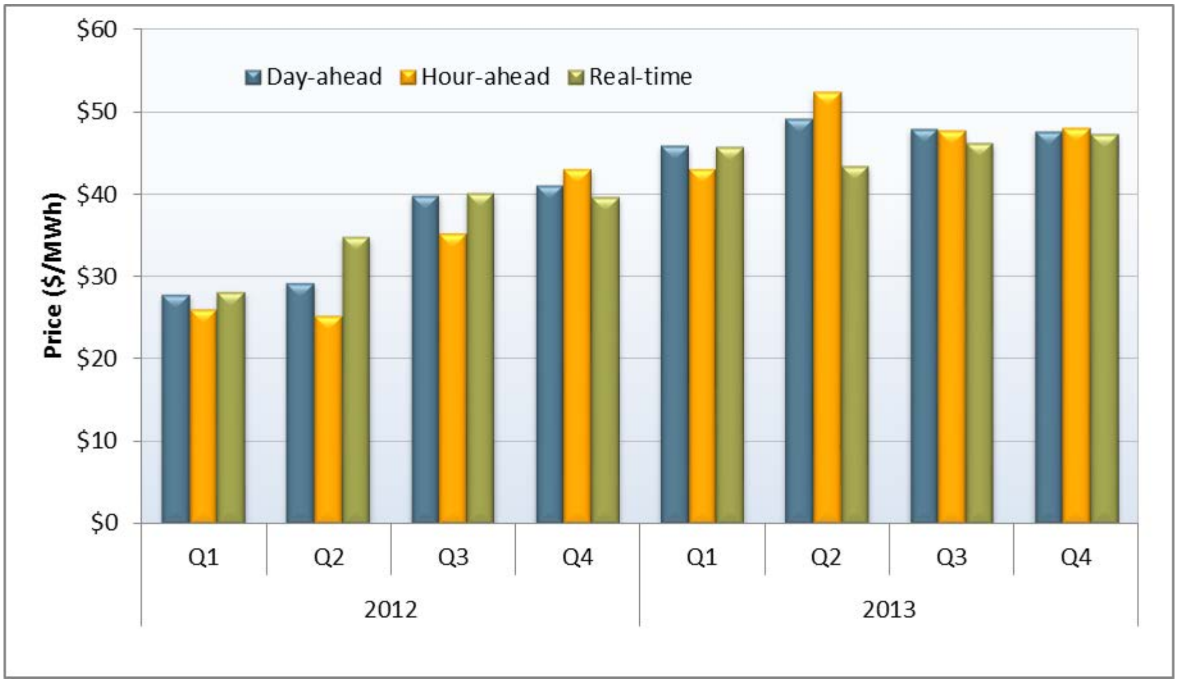


- About 97 percent of physical system load was scheduled in the day-ahead energy market, which continued to be highly efficient and competitive.

- Average real-time prices were systematically lower than day-ahead market prices throughout the year. Day-ahead prices averaged just over $2/MWh higher than real-time prices for the year, peaking in the second quarter at almost $6/MWh higher (see Figure 2).

- This price trend marks a reversal from prior years when average real-time prices tended to be higher than average day-ahead prices. This new trend of lower real-time prices is largely attributable to a decrease in brief but high real-time price spikes caused by limitations in ramping energy. This trend is also partly attributable to additional unscheduled generation in real time, particularly from wind and solar units and from other sources.

Figure 2 Comparison of system energy prices (peak hours)



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

- The ISO implemented new automated local market power mitigation procedures in the real-time software which mitigated local market power more effectively and accurately than the previous approach.
- Ancillary service costs totaled $57 million, or about 31 percent less than in 2012. This decrease was driven by a decrease in the quantity of ancillary services procured by the ISO due to lower loads and lower ancillary services prices.
- Bid cost recovery payments totaled $108 million, or about 1 percent of total energy costs in 2013, compared to about $104 million or 1.3 percent of total energy costs in 2012. Payments for units committed by the residual unit commitment process accounted for $23 million of these costs, compared to $8 million in 2012. This increase was driven in large part by the need to schedule physical capacity to meet the portion of the day-ahead load forecast met by net virtual supply in the day-ahead energy market. In 2013, about $9 million or 8 percent of bid cost recovery payments were allocated to virtual bidders with net virtual supply positions.
- Exceptional dispatches, out-of-market unit commitments and energy dispatches issued by ISO grid operators to meet constraints not incorporated in the market

software, decreased from 2012 and remained relatively low. Energy from all exceptional dispatches totaled about 0.26 percent of total system energy in 2013 compared to 0.53 percent in 2012. The above-market costs resulting from these exceptional dispatches decreased almost 50 percent from $34 million in 2012 to $18 million in 2013.

- Congestion within the ISO system decreased in 2013, particularly in the second half of the year. The reduction in real-time congestion can be attributed partly to improved ISO procedures that better align day-ahead constraint limits with real-time limits. This allows for better commitment and scheduling of resources to resolve anticipated congestion in real time.
- Lower real-time congestion drove real-time market revenue imbalance charges allocated to load-serving entities lower. These charges decreased from $187 million in 2012 to $120 million in 2013, or just over 1 percent of total wholesale costs.
- Net revenues paid to convergence bidders (after allocation of bid cost recovery payments) totaled about $17 million in 2013, down from $52 million in 2012. The majority of these profits were associated with virtual supply. Net revenue paid for virtual bids totaled about $26 million, but about $9 million in bid cost recovery payments were allocated to virtual bidders with net virtual supply positions, so that net profits from virtual bidding totaled about $17 million.

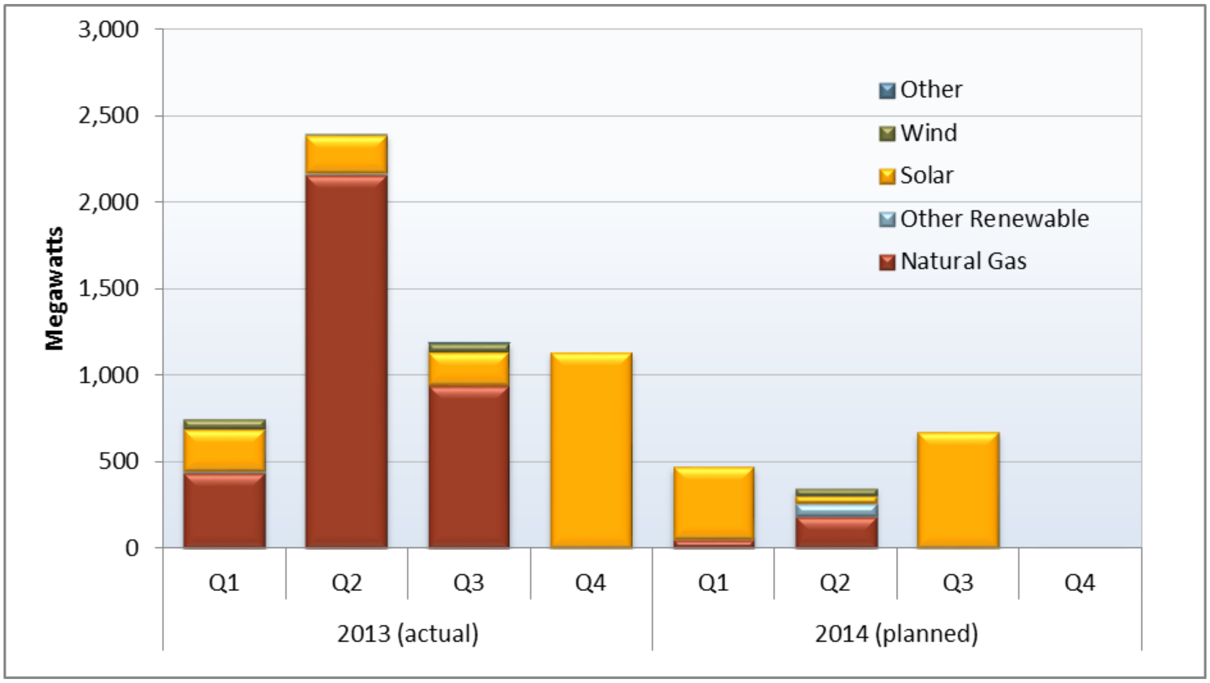
This report also highlights key aspects of market performance and issues relating to longer-term resource investment, planning and market design.

- About 2,000 MW of summer peak hour generating capacity from renewable generation was added in 2013, with most of this coming from increased solar generation. Energy from wind and solar resources directly connected to the ISO grid provided about 8 percent of system energy, compared to about 5 percent in 2012.[1]
- Energy from new wind and solar resources is expected to increase at a much higher rate in the next few years as a result of projects under construction to meet the state's renewable portfolio standards. This will increase the need for flexible and fast ramping capacity that can be dispatched by the ISO to integrate increased amounts of variable energy efficiently and reliably.
- Over 3,500 MW of new gas-fired generation was added in 2013. Most of this capacity was added as part of the California Public Utilities Commission's long term procurement process. However, this increase in capacity was mostly offset by over 2,900 MW of thermal generation retirements in 2013, including both units at the San Onofre Nuclear Generating Station (SONGS).

---

[1] In calculating the portion of state's energy for purposes of renewable portfolio standards, the CPUC includes renewables from imports and other sources not included in the wind and solar energy directly connected to the ISO grid.

Figure 3 Generation additions by resource type (summer peak capacity)



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

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

The ISO and the CPUC continued to address these resource adequacy issues through several initiatives in 2013. One initiative involved the development of specific requirements for flexible generating capacity needed to integrate increasing amounts of intermittent renewable generation into the ISO system. In June 2013, the CPUC established interim resource adequacy flexibility capacity procurement obligations for load serving entities. In In early 2014, the ISO Board of Governors approved a proposal for a complementary set of provisions for implementing flexibility requirements into the resource adequacy process administered by the ISO.[2] The ISO and CPUC are continuing to collaborate on a process to incorporate these flexibility requirements into a multi-year ahead resource adequacy process supplemented with a market-based backstop procurement mechanism administered by the ISO.

RECOMMENDATIONS

DMM works closely with the ISO to provide recommendations on current market issues and market design initiatives on an ongoing basis. DMM's annual report also summarizes DMM's recommendations on a variety of market design initiatives that are underway or being implemented in 2014.

Energy imbalance offset costs

The new 15-minute market implemented in May 2014 should significantly reduce revenue imbalances allocated to load through real-time imbalance offset charges by decreasing the difference in prices used to settle inter-tie transactions and 5-minute prices currently used to settle energy from resources within the ISO system. However, DMM cautions that, despite the proposed market improvements, large real-time revenue imbalances could still occur if transmission limits are adjusted downward after the day-ahead market to account for unscheduled flows when congestion occurs. The full network model scheduled for implementation in the fall of 2014 is intended to avoid the need to manually adjust transmission constraints to account for unscheduled flows. Until this modeling enhancement is implemented, DMM recommends the ISO seek to continue to manually manage transmission limits in the day-ahead market to account for potential unscheduled flows. After modeling enhancement is implemented, DMM recommends that the ISO carefully monitor the effectiveness of this enhancement and remain ready to manage this new modeling feature manually if necessary, as discussed below.

Full network model

DMM strongly supports the ISO's final proposal to expand its network model. By expanding the full network model to include other balancing areas, the ISO will also be able to reflect their outages and other reliability parameters and analyze how they may affect the ISO market. However, creating and testing an expanded network model is likely to be a difficult and complex task. Consequently, both DMM and the Market Surveillance Committee have recommended that the ISO analyze, validate, and benchmark the full network model before and after implementation to ensure this feature provides the intended benefits.

---

[2] For more information on the ISO Board decision, see http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=585EB499-6AEF-4FAA-8656-D9F5C253A63E.

The ISO has committed to performing a variety of studies as part of pre-implementation testing and to report on these results to stakeholders and the Board. DMM supports this approach and has provided specific recommendations relating to the metrics and analysis for the ISO to use in assessing the expanded modeling functionality impacts. DMM also emphasizes that this pre-implementation testing be viewed as the first step in an ongoing process of monitoring, analysis, refinement and improvement of the full network model.

Flexible ramping product

The ISO is proposing to replace the flexible ramping constraint currently incorporated in the real-time market software with a flexible ramping product to be implemented in 2015. DMM is supportive of this product as a more effective way of ensuring operational ramping flexibility than the current flexible ramp constraint. The ISO's last proposal includes a bid price cap of $250/MW, which is consistent with the existing caps on ancillary services. DMM recommends that the ISO's proposal be modified to eliminate the ability for participants to bid up to $250/MW of this capacity, since no specific short-term marginal costs have been demonstrated or described that these bids would be used to cover. Without capacity bids, resources providing this product would still earn revenues since prices would be set by the highest opportunity cost of all resources chosen to provide this service. The ISO is in the process of developing a revised flexible ramping proposal to be issued in early June and is currently evaluating whether to remove the capacity bidding element from the design.

Flexible capacity procurement requirements

DMM is highly supportive of these initiatives as ways of increasing the efficiency of the state's capacity procurement process and addressing key gaps in the state's current market design. DMM believes the ISO's recent flexible capacity proposal is a step in the right direction, but recommends that the ISO and CPUC continue working toward developing multi-year ahead flexibility requirements. DMM continues to strongly recommend that these requirements include counting criteria, must-offer requirements and performance penalties that ensure capacity procured to meet these requirements actually meet operational and market flexibility requirements. The ISO and CPUC are planning to revisit these issues as part of a separate initiative that could include performance criteria for the 2016 compliance year.

Energy imbalance market

In 2013, the ISO completed its proposed design for the new energy imbalance market (EIM) that is scheduled for implementation in the fall of 2014. DMM worked closely with the ISO to ensure that this new market will offer benefits for both current participants within the ISO system as well as entities outside the ISO that will be participating in this new market as sellers or relying on it to meet their imbalance energy needs. DMM supports the general design outline in the ISO final proposal, and will collaborate with the ISO to develop the appropriate monitoring capabilities and identify actions that may be taken to mitigate any issues that arise following implementation in October 2014.

DMM has noted that the energy imbalance market's local market power mitigation provisions do not protect against market power in cases where there may be one or two major suppliers in an EIM balancing authority area. Consequently, DMM recommended the rules may need to be modified so that bid mitigation tests and procedures be triggered when congestion occurred into an EIM balancing authority area on an EIM scheduling constraint from the ISO or another EIM balancing area. The ISO's EIM proposal approved by the Board calls for a further analysis of this issue along with a Management recommendation to be presented to the Board at its July 2014 meeting. Under the EIM tariff filed at FERC, the Board will have the authority to approve the application of market power mitigation tests on an EIM-wide level.