Memorandum

To: ISO Board of Governors

From: Eric Hildebrandt, Director, Market Monitoring

Date: May 7**,** 2015

Re: **Market Monitoring report**

This memorandum does not require Board action.

EXECUTIVE SUMMARY

This memo provides key findings from the Department of Market Monitoring's 2014 annual report, which DMM plans to publish later this month. This year's report provides analysis showing that the ISO market continued to perform efficiently and competitively in 2014. After accounting for significantly higher natural gas costs and changes in greenhouse gas prices, the total wholesale price of load served by the ISO system increased by about 3 percent. Additional factors contributing this slight increase in electric price included record low hydro-electric generation and a slight decline in imports. Moderate loads and the addition of new solar generation with about 1,900 MW of peak summer capacity helped to keep market prices low and highly competitive. Wholesale energy prices over the course of 2014 were about equal to what DMM estimates would result under highly competitive conditions, taking into account these actual system conditions.

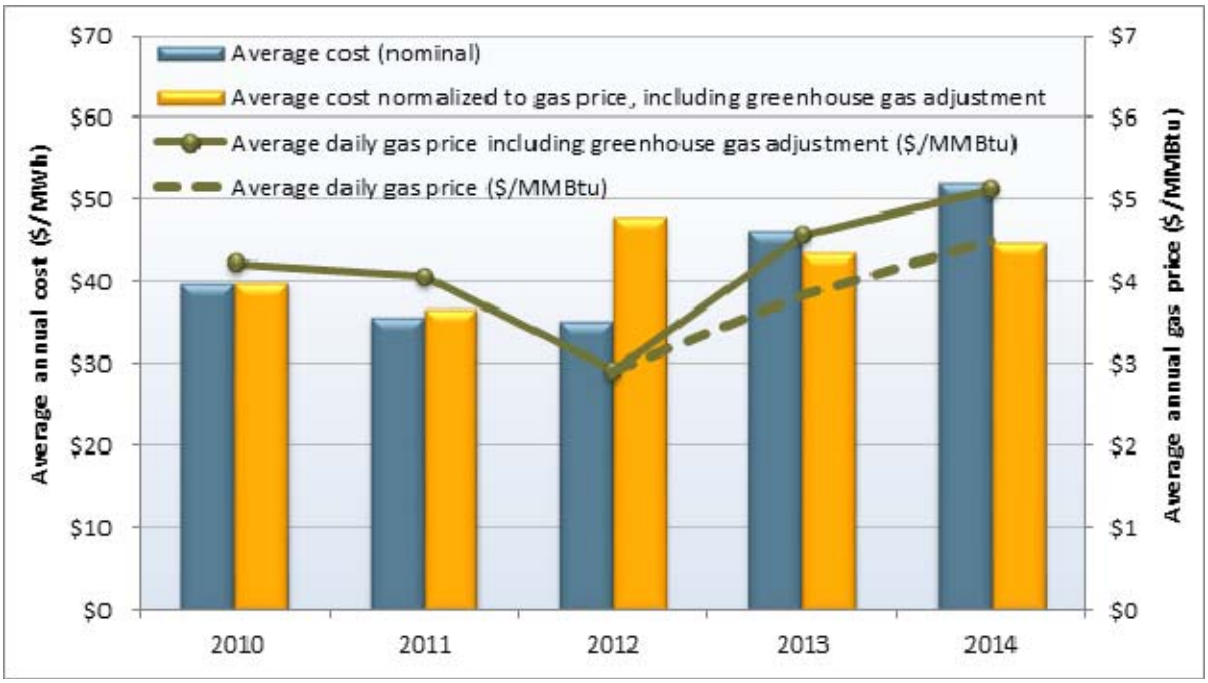
The report also summarizes DMM's recommendations on market design initiatives that are underway or being implemented in 2015.

MARKET PERFORMANCE

DMM finds that the ISO market continued to perform efficiently and competitively overall in 2014. Other highlights of market performance noted in DMM's 2014 annual report include the following:

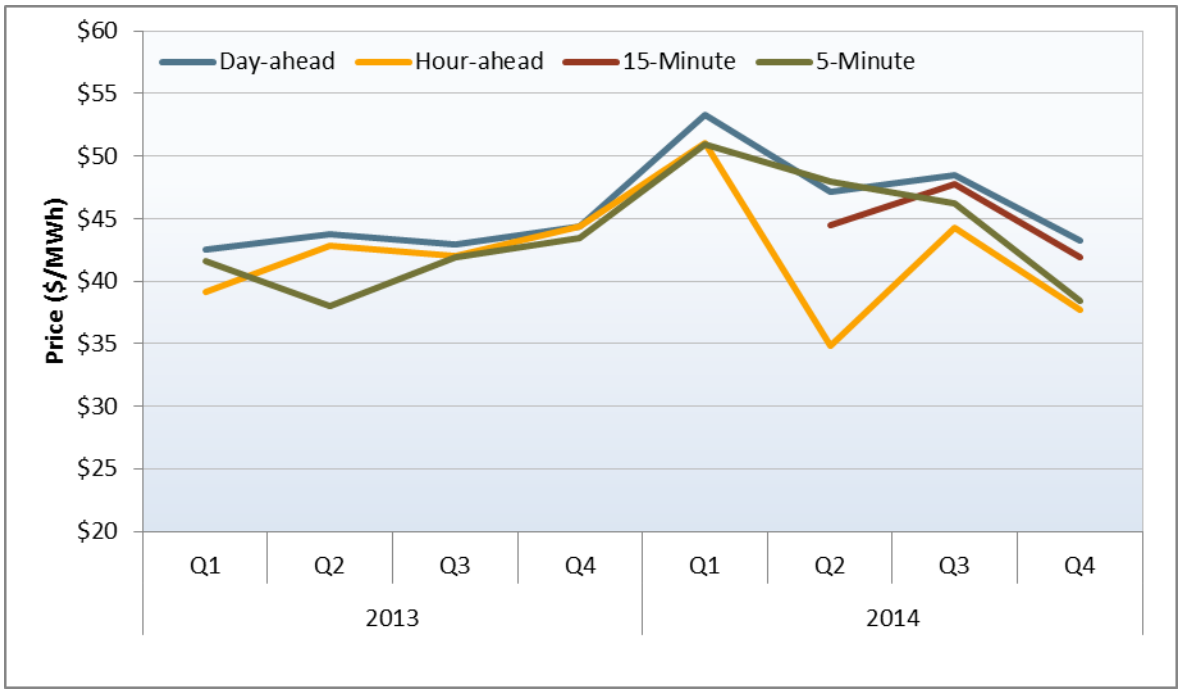
- Total estimated wholesale electric costs per megawatt of load served by the ISO system increased by 13 percent (see blue bars in Figure 1). This estimate of total costs includes costs of energy in each of the ISO's energy markets, as well as other administrative and uplift costs assessed to for load served by the ISO system.

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



- The increase in electric costs was driven primarily by an 17 percent increase in natural gas prices in 2014 compared to 2013 (see dotted green line in Figure 1). After accounting for the natural gas and greenhouse gas price changes, wholesale electric costs increased by only 3 percent (see yellow bar in Figure 1).
- Overall prices in the ISO energy market over the course of 2014 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.
- Average real-time prices tended to be lower than average day-ahead prices in both 2013 and 2014, as shown in Figure 2. The trend of lower real-time prices is partly attributable to a low frequency of high real-time price spikes caused by limitations in ramping energy compared to prior years. This trend is also partly attributable to additional unscheduled generation in real time, particularly from wind and solar units.
- Under the real-time market design implemented in 2014, most real-time energy and all virtual bids are settled based on 15-minute prices. Prices in the new 15-minute real-time market implemented in May 2014 tracked relatively closely with day-ahead prices, particularly after initial implementation in the second quarter. Average 15-minute prices averaged only about $1/MWh less than day-ahead prices in all hours in the second half of the year, as shown in Figure 2.

Figure 2 Average system energy prices (all hours)



- Average prices in the 5-minute real-time market tended to be lower than average day-ahead prices by a wider margin. As shown in Figure 2, 2014 average prices in the 5-minute market were about $1/MWh lower than day-ahead prices in the first half of the year, but averaged about $3.50/MWh less than day-ahead prices in the second half of the year.

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

- Ancillary service costs totaled $69 million, or about 21 percent more than in 2013. This increase was driven by higher ancillary service prices in 2014, driving the increase in overall cost. The increase is related to a decrease in ancillary services from hydro-electric generators compared to 2013 and an increase in natural gas prices.

- Bid cost recovery payments totaled $95 million, or less than 1 percent of total energy costs in 2014, compared to about $108 million of total energy costs in 2013.

- Payments for units scheduled by the residual unit commitment process accounted for $5 million of bid cost recovery payments, compared to $23 million in 2013. This decrease was driven in large part by changes implemented in early 2014 to better account for renewables forecasted to be available in real time during the residual

unit commitment process, rather than primarily accounting for only the renewables that were scheduled in the day-ahead market.

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

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

- Real-time market revenue imbalance charges allocated to load-serving entities increased slightly from $183 million in 2013 to $188 million in 2014. While revenue imbalance charges associated with congestion fell from $126 million in 2013 to $106 million in 2014, charges related to real-time energy imbalance costs increased from $57 million in 2013 to $81 million in 2014. However, these charges includes several components which caused energy offset charge to increase in 2014, but which are offset by decreases in other settlement charges allocated to load-serving entities.[1]

- Net revenues paid to convergence bidders totaled about $26 million in 2013, up from $17 million in 2013. The majority of these profits were associated with virtual supply bids, which tended to be profitable due to the trend of lower real-time prices relative to day-ahead prices that began in 2013. These net virtual supply positions helped offset part – but not all – of the volume of renewable generation that is not scheduled in the day-ahead market.

- Congestion revenue rights had a net revenue shortfall of about $95 million in 2014. This was a substantial reduction from the $23 million and $3 million surpluses in 2012 and 2013, and represents the first annual shortfall since the nodal market began in 2009. This revenue shortfall was attributable to multiple issues, including outages and differences in how the transmission system is modeled in the congestion revenue rights auction compared to the day-ahead market. The ISO has taken steps to address this issue by incorporating more constraints in the model used in the congestion revenue rights auction.

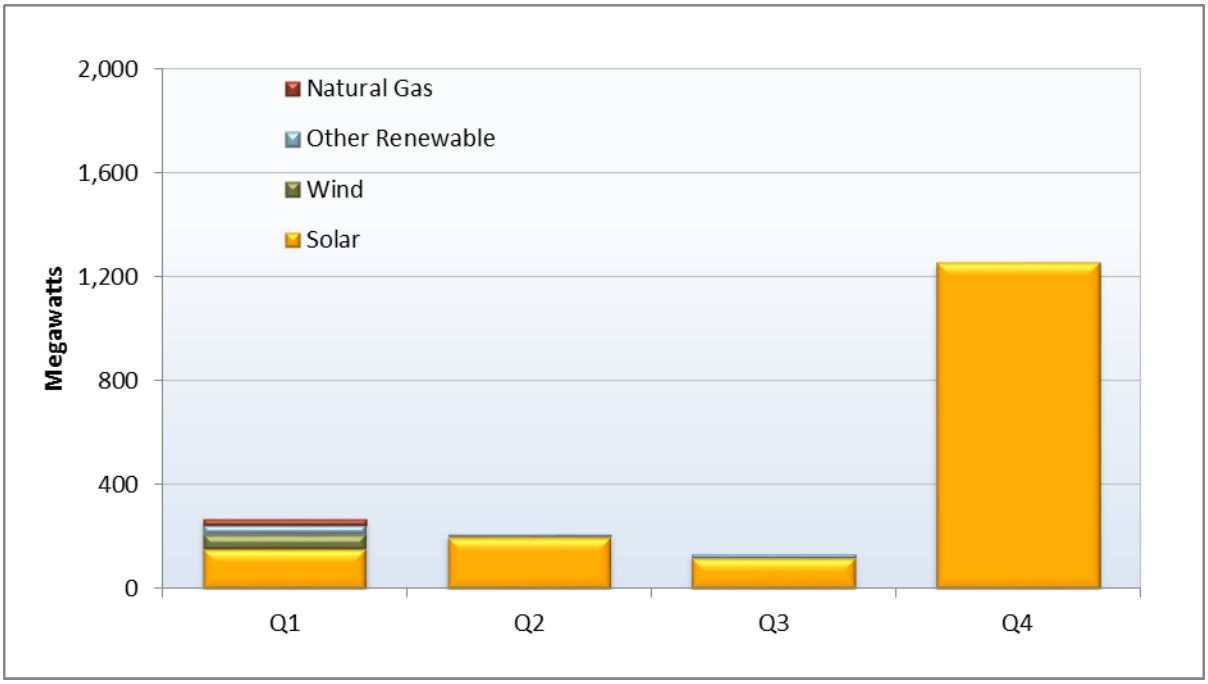
[1] For further detail, see the *Review of Real-Time Imbalance Energy Offset,* Department of Market Monitoring, revised: November 26, 2014: http://www.caiso.com/Documents/Review-Real-TimeImbalanceEnergyOffset-DMMWhitePaper_Revised.pdf.

LONGER TERM RESOURCE ISSUES

DMM's report will also highlight key aspects of market performance and issues relating to longer-term resource investment, planning and market design. For instance, as shown Figure 3:

- About 1,900 MW of summer peak generating capacity was added in 2014, with about 93 percent of the new capacity coming from new solar generation.
- Energy from wind and solar provided more than 10 percent of system energy, compared to about 8 percent in 2013. While wind still produced slightly more energy than solar in 2014, the amount of energy generated by solar more than doubled compared to 2013.

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 CPUC, ISO and stakeholders are working toward development of a multi-year capacity procurement that includes flexible capacity requirements. DMM continues to be supportive of this effort as a long term market design goal. Although a variety of new market enhancements are being developed to provide greater economic incentives for resources to provide additional flexibility in the market, DMM believes it is prudent to continue development of a market design that includes provisions to ensure sufficient flexible capacity is built or maintained on the timeline needed to meet growing needs for resource flexibility.

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 2015.

Full network model

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

DMM has provided specific recommendations relating to more detailed metrics and analysis that we recommend be used by the ISO to assess the impacts of the expanded modeling functionality.[2] DMM recommends that more detailed, automated metrics focus on the following:

- The impact that the full network model is having on specific constraints which are at or near their limits in the day-ahead and real time markets based on estimated or actual flows.

- Constraints on which congestion costs are highest and differ between the day-ahead and 15-minute markets, as measured by total modeled flows and congestion prices.

- All internal constraints, as well on the inter-ties included in the ISO's metrics.

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

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

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

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

Congestion revenue rights

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

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

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

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

In 2014 DMM proposed a general methodology that could be used to allocate congestion revenue rights revenue inadequacy costs back to holders of congestion revenue rights on an interval and constraint specific basis. This alternative allocation approach would limit the total amount of revenues that can be transferred from load-serving entities to congestion revenue rights holders through uplift. Moreover, this allocation method would reduce the incentive for entities purchasing congestion revenue rights to target the modeling differences that create revenue inadequacy costs.[3]

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

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

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

Bidding rules

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

DMM has expressed concern that in 2014 this important market enhancement has been deferred again, and that given the current status and resources being applied to this project, it may be very difficult for the ISO to complete the development, testing and stakeholder review of an opportunity cost model and rules in time for consideration of this issue by the Board in September 2015 as planned.[4]

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

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

[4] For more information, see DMM's Memorandum to the ISO Board, March 19, 2015: http://www.caiso.com/Documents/Department_MarketMonitoringReport-Mar2015.pdf.