Memorandum

To: ISO Board of Governors

From: Eric Hildebrandt, Executive Director, Market Monitoring

Date: November 7, 2018

Re: **Department of Market Monitoring update**

This memorandum does not require Board action.

EXECUTIVE SUMMARY

This memo provides highlights of market performance from the Department of Market Monitoring's recent quarterly *Report on Market Issues and Performance*.[1]

- Energy prices in the third quarter increased compared to the same months in 2017, driven primarily by high gas prices, along with lower hydro generation. Prices were particularly high in the day-ahead market, which reached record highs in July and peaked at almost $980/MWh. Average prices in the ISO's day-ahead market for peak hours (7-22) tracked closely with prices in the daily bilateral markets on high priced days.

- The energy imbalance market continued to perform well, with prices reflecting summer supply and demand conditions and transmission constraints in the different regions. Prices in Northwest areas (PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex) continued to be lower than in other areas because of limited transfer capability from this lower cost region.

- Bid cost recovery payments in Q3 totaled about $88 million, the highest amount in any quarter since 2011. High bid cost recovery payments were driven by high gas prices, along with actions taken by grid operators due to system conditions. Bid cost recovery payments to units committed through exceptional dispatches issued by grid operators to meet special reliability issues totaled $27 million.

- Congestion revenue rights auction revenues were $41.5 million less than payments made in the third quarter to non-load-serving entities purchasing these rights. This brings total losses to transmission ratepayers from congestion revenue rights sold in the ISO's auction to about $102 million in just the first three quarters of 2018 – which already exceeds the $101 million in losses incurred in all of 2017.

[1] http://www.caiso.com/Documents/2018ThirdQuarterReportonMarketIssuesandPerformance.pdf

ENERGY MARKET PERFORMANCE

As shown in Figure 1, energy prices on Q3 (July – September) increased significantly compared to the same quarter in 2017, particularly in the day-ahead market. The increase in prices was driven by a combination of factors, including high gas prices and reduced hydro generation.

Gas prices

Figure 2 shows monthly average natural gas prices at key delivery points in Northern California (PG&E Citygate) and in Southern California (SoCal Citygate) as well as for the Henry Hub trading point, which acts as a point of reference for the national market for natural gas. Prices at SoCal Citygate were extremely high on some days in July and August of 2018 due to increased natural gas demand amid high temperatures, combined with unplanned pipeline maintenance, restricted storage activity at Aliso Canyon and anticipation of potential low operational flow order (OFO) non-compliance penalty charges.

SoCal Citygate gas prices often impact overall system energy prices for two reasons: there are large numbers of natural gas resources in the south, and there is often greater congestion in the south that creates load pockets. The ISO did not activate any of the special Aliso Canyon gas constraints or gas price scalars during the third quarter. Market and system performance was sustained during periods of tight gas and electric supply without these measures in place.

Renewable generation

Total generation from hydroelectric resources in the third quarter was about 33 percent lower than in Q3 2017, as show in Figure 3. Wind production rose about 10 percent from the third quarter of 2017, while solar production rose about 20 percent compared to last year.

Regional bilateral prices

Figure 4 compares system marginal energy costs for energy in the ISO's day-ahead market during peak hours (7 to 22) to average bilateral prices for these same hours at the Palo Verde and Mid-Columbia hubs. Extremely high prices at Palo Verde on some days in July and August drove average monthly prices at Palo Verde higher than average peak hour prices in the ISO's day-ahead market in these months.

Bilateral prices at Mid-Columbia and Palo Verde were lower than prices in the ISO during about 85 percent and 65 percent of days, respectively. The relatively higher prices in California on most days without unusually high prices reflect the greenhouse gas compliance cost associated with delivering energy into the state and the cost of congestion across limited intertie capacity. Low prices at Mid-Columbia reflect the availability of low-cost hydroelectric resources and limited transfer capacity from the northwest to the ISO.

Figure 1. Average monthly system marginal energy price (all hours)

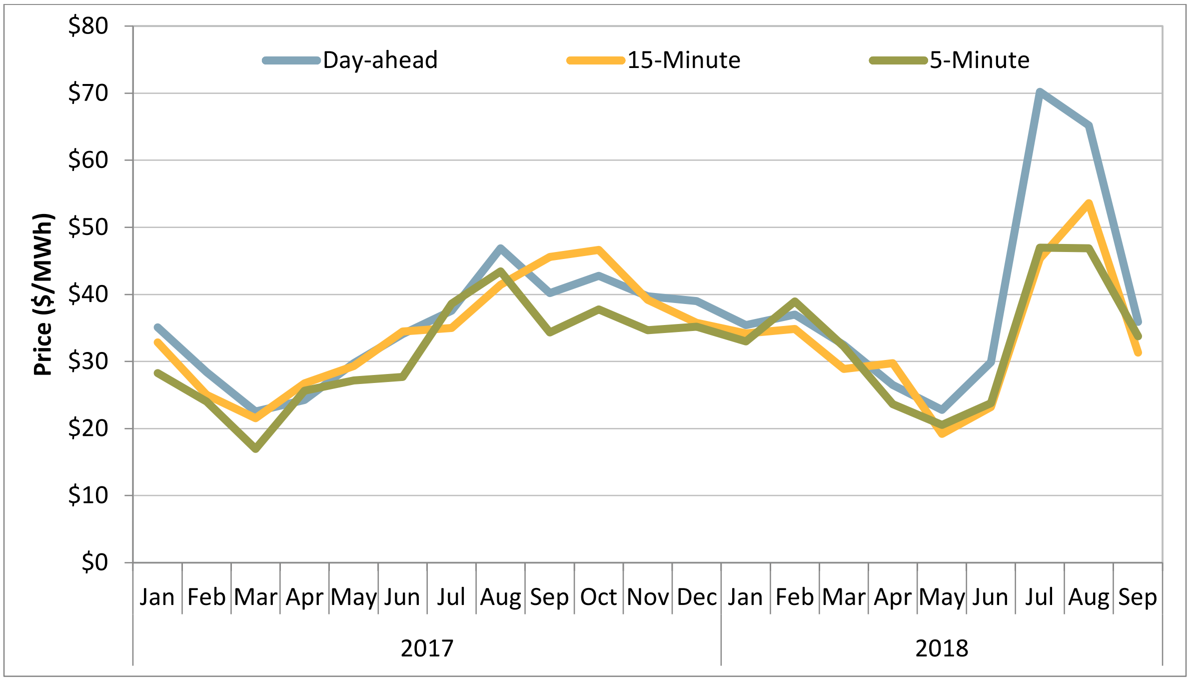


Figure 2. Monthly average natural gas prices

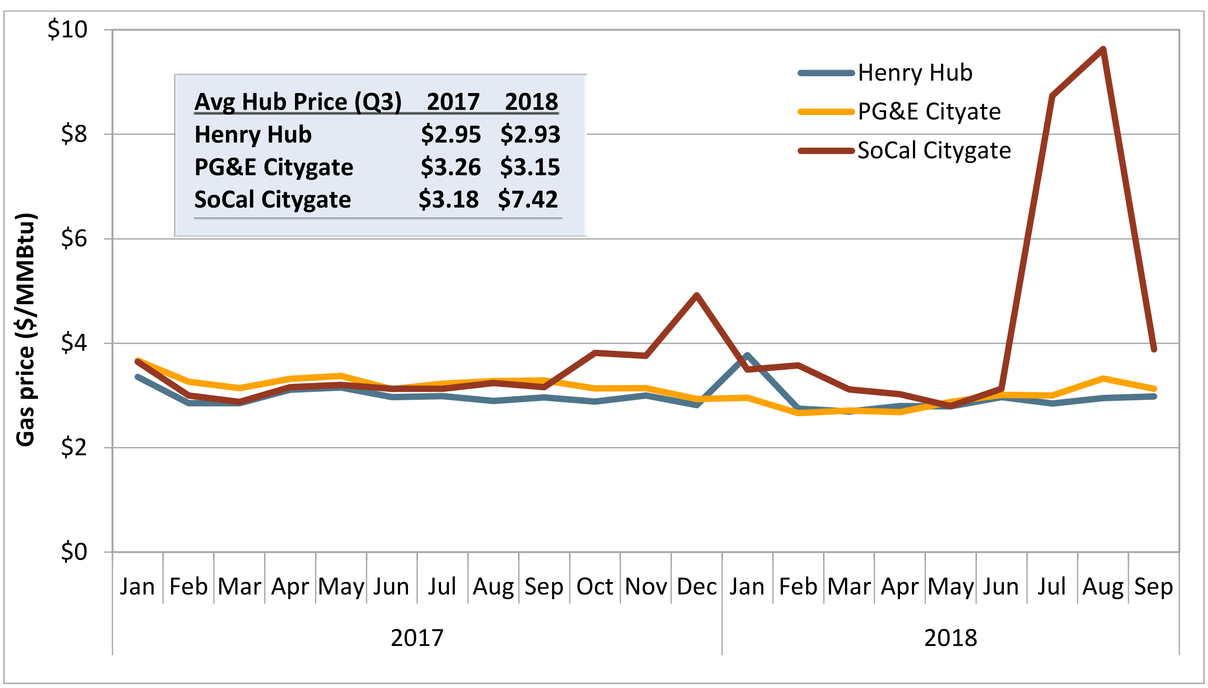


Figure 3. Average hourly hydroelectric, wind and solar energy by month

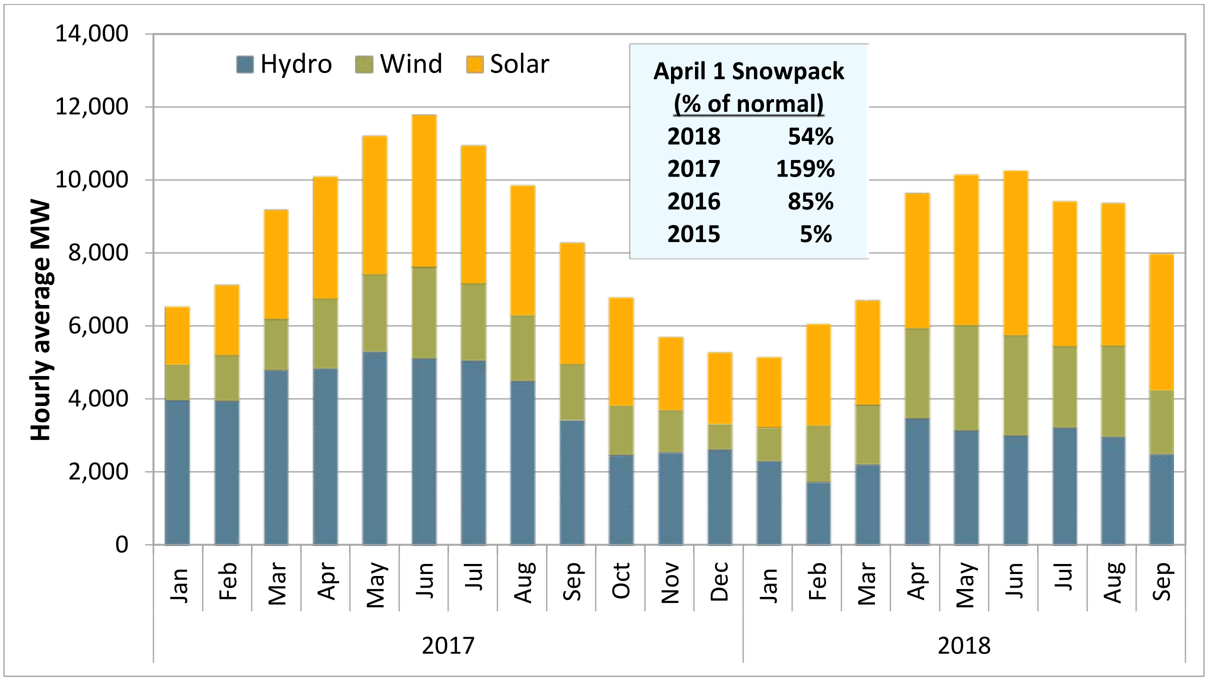
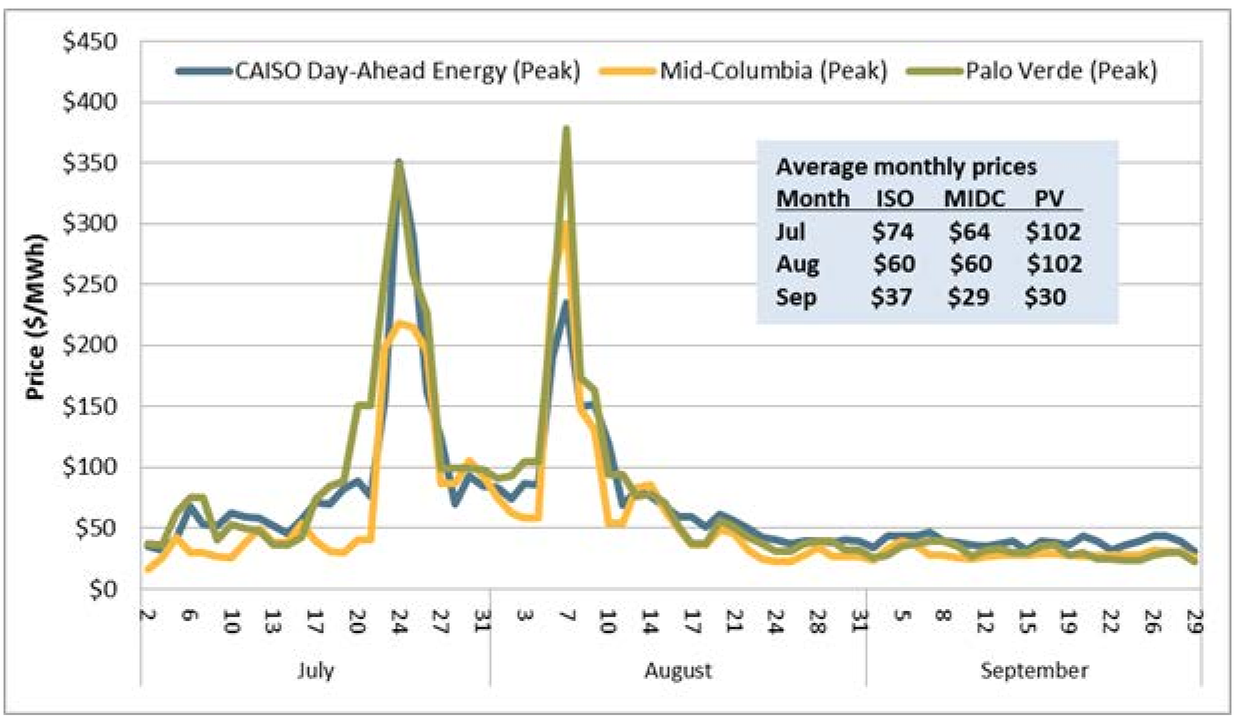


Figure 4. Day-ahead ISO and bilateral market prices for peak hours (7-22)



Energy imbalance market

The energy imbalance market continued to perform well, with prices reflecting summer supply/demand conditions and transmission constraints in the different regions.

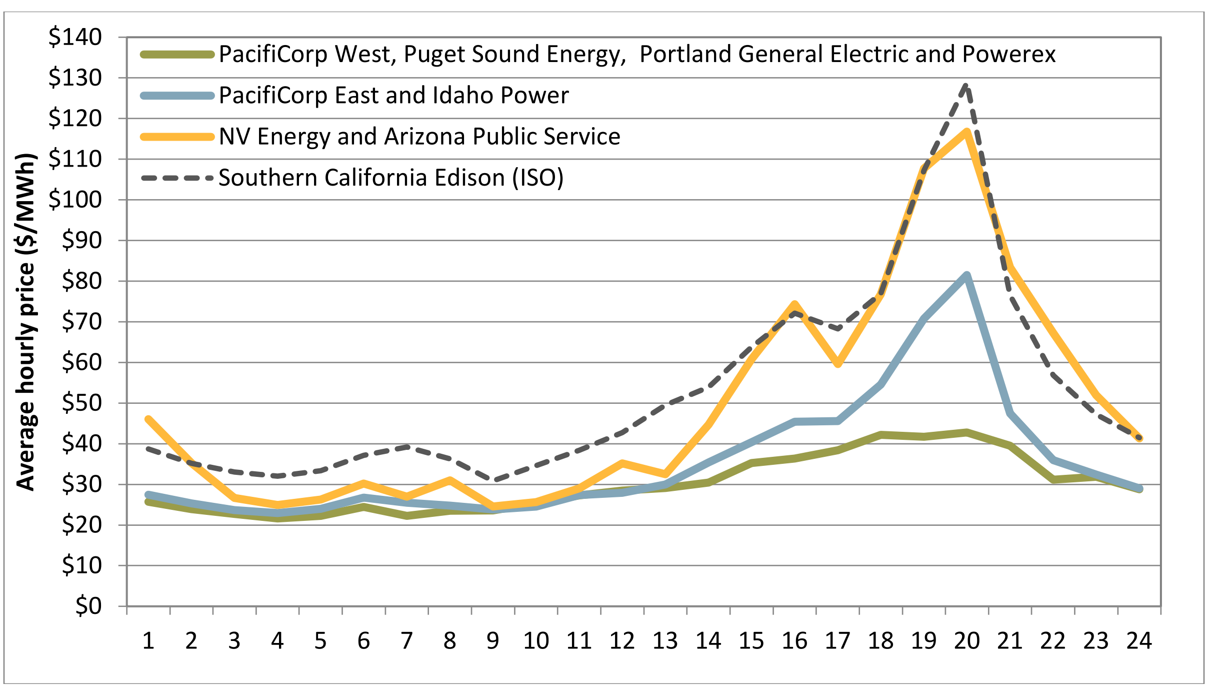
As shown in Figure 5, prices in the northwest region (including PacifiCorp West, Puget Sound Energy, Portland General Electric and Powerex) continued to be significantly lower than in the ISO and other energy imbalance market balancing areas. Transfers from these lower cost areas to the ISO and other higher priced areas were limited by transmission from this region available in the energy imbalance market almost one-third of 15-minute intervals.

Prices in the southwest areas (APS and NV Energy) tracked closely with real-time prices in the ISO, with very low congestion occurring between these areas due to the high levels of transfer capacity between these areas in the energy imbalance market.

Prices in the PacifiCorp East and Idaho Power tracked closely together, with average prices falling in between the lower priced areas in the northwest and higher priced areas in the ISO and southwest. Prices in PacifiCorp East and Idaho Power are driven lower by limited transmission less frequently than in the northwest balancing areas.

Congestion on constraints within energy imbalance areas continues to be minimal, except on one constraint in PacifiCorp East (WYOMING_EXPORT), which limited flows from low cost supply in Wyoming about 9 percent of intervals in the 15-minute and 5-minute markets.

Figure 5. Energy imbalance market prices
(Hourly average 15-minute prices, July – September 2018)



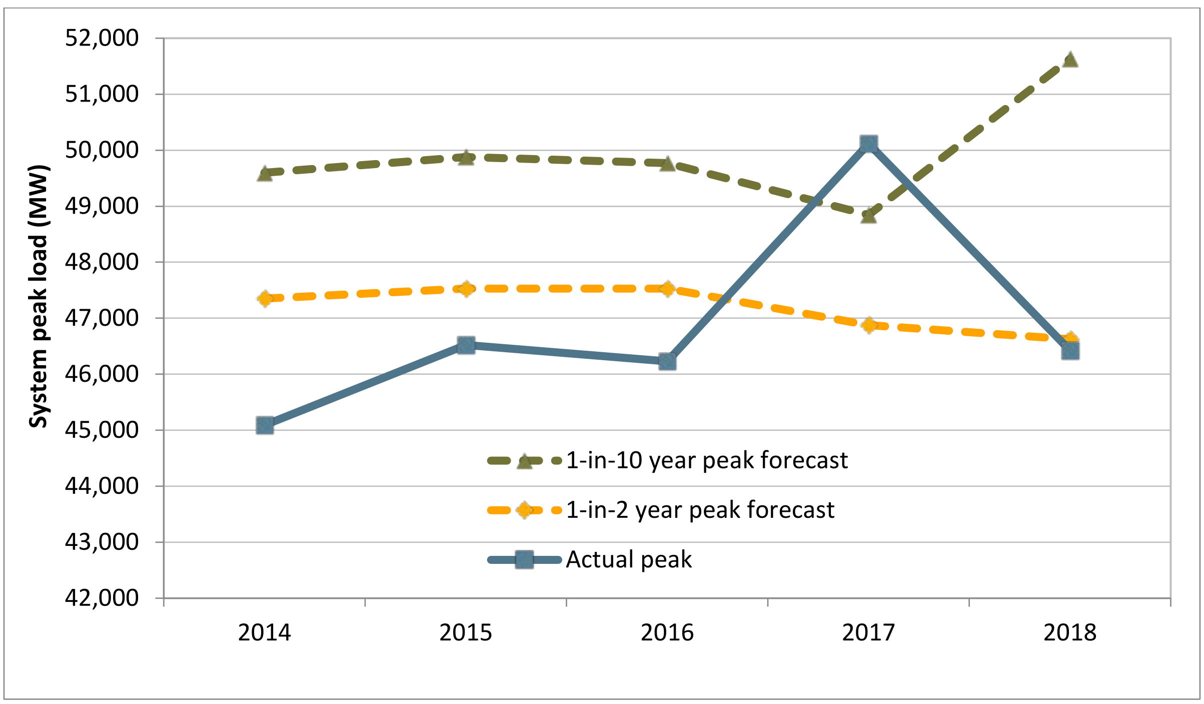
Summer loads and forecast uncertainty

Peak summer loads in 2018 were not exceptionally high, but the ISO's day-ahead load forecasts exceeded actual loads by a significant margin on numerous days. This forecast uncertainty appears to have also been reflected in expectations of higher demand by market participants bidding in the day-ahead market, which contributed to very high day-ahead prices on numerous days.

One reason for a trend of over-forecasting of load in the day-ahead market relative to real-time load was error in weather forecasts used as input to day-ahead load forecasts, particularly on high demand days. The ISO reported that "the National Weather Service (NWS) submitted excessive heat warnings starting July 24, but actual temperatures came in 10 degrees cooler than forecasted in some regions."[2]

The instantaneous peak load this summer occurred on July 25 at 17:33, and was 46,625 MW – or about 7 percent lower than the peak in 2017. As shown in Figure 6, the peak load this summer was very close to the ISO's 1-in-2 year load forecast (46,625 MW) and about 10 percent lower than the 1-in-10 year forecast (51,632 MW).

Figure 6. Actual peak load compared to planning forecasts



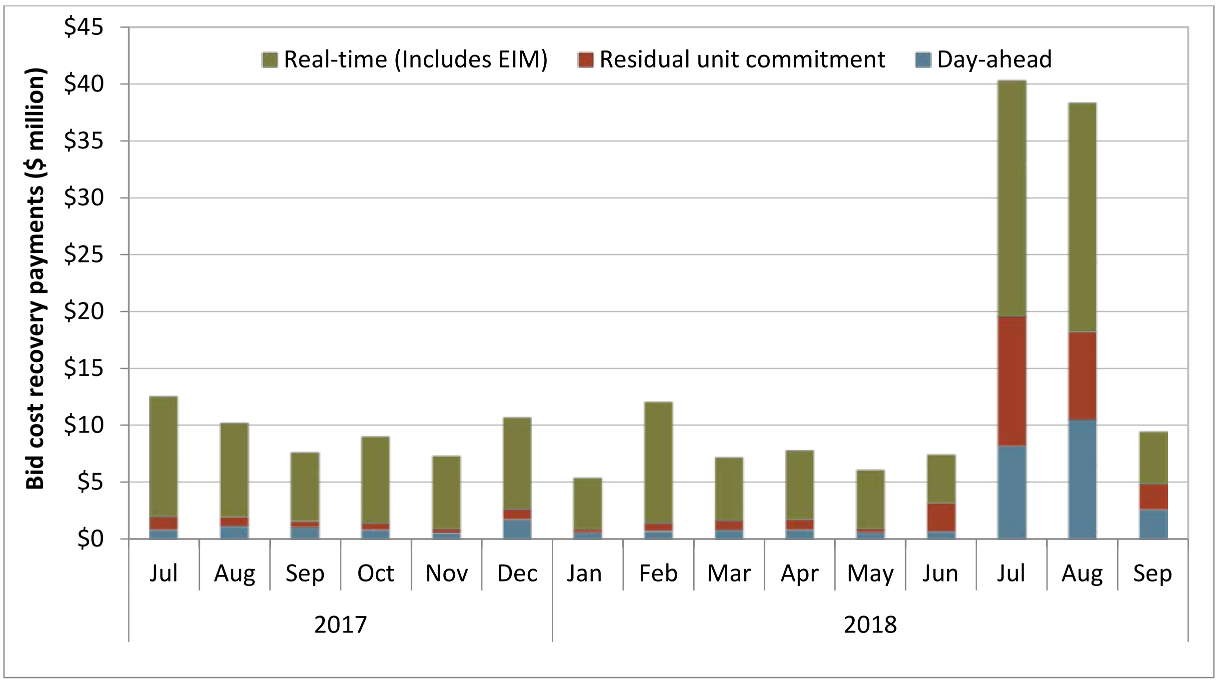
[2] See Market Performance and Planning Forum presentation, slide 47 at http://www.caiso.com/Documents/Presentation-MarketandPerformancePlanningForum-Aug292018.pdf.

Bid cost recovery payments

Bid cost recovery payments for the third quarter of 2018 totaled about $88 million, the highest cost of any quarter since 2011. As shown in Figure 7, this amount was substantially higher than the total amount of bid cost recovery in the previous quarter and in the third quarter of 2017, which were about $21 million and $30 million, respectively. Only $2.5 million of the bid cost recovery payments were attributable to the energy imbalance market.

Bid cost recovery payments for residual unit commitment during the quarter totaled about $21 million, compared to $3.7 million in the prior quarter. Long-start gas resources committed in the residual unit commitment process received about $10 million of these bid cost recovery payments, while short-start resources received about $11 million in residual unit commitment bid cost recovery payments.

Figure 7. Monthly bid cost recovery payments



The significant increase in residual unit commitment bid cost recovery payments in the quarter can be attributed to high volumes of net virtual supply combined with periods of high loads in July and August along with operator adjustments causing the residual unit commitment process to procure more capacity.

Bid cost recovery attributed to the real-time market totaled about $45 million, compared to $25 million in the third quarter of 2017. Of the $45 million, about $33 million was awarded to gas resources in the SoCal Gas service area. More than $25 million of the real-time bid cost recovery payments was awarded to gas resources bidding their start-up and minimum load costs at the 125 percent proxy cost cap.

Bid cost recovery payments for units committed through exceptional dispatches also played an important role in real-time bid cost recovery payments. Bid cost recovery payments to units committed through exceptional dispatches issued by grid operators totaled $27 million. In the third quarter, the majority of these exceptional dispatches were due to load forecast uncertainty in July and August.

Congestion revenue rights

Congestion revenue rights auction revenues were $41.5 million less than payments made in the third quarter to non-load-serving entities purchasing these rights. Auction revenues in Q3 totaled only about 43 percent of payments made to non-load-serving entities purchasing congestion revenue rights in the auction, down from 71 percent during the same quarter in 2017.

This brings total losses to transmission ratepayers from congestion revenue rights sold in the ISO's auction to about $102 million in just the first three quarters of 2018. These losses already exceed the $101 million in losses from congestion revenue rights incurred in 2017. About 42 percent of losses in 2018 (or $42 million) are from congestion revenue rights between "delivery pairs" that the ISO will continue to auction off in 2019 under the ISO's Track 1A and 1B initiatives.

Figure 8. Auction revenues compared to payments for auctioned CRRs (through Q3 2018)