California ISO

California Independent System Operator Corporation

Memorandum

To: ISO Board of Governors

From: Eric Hildebrandt, Director, Market Monitoring

Date: December 10, 2015

Re: Department of Market Monitoring update

This memorandum does not require Board action.

EXECUTIVE SUMMARY

This memo provides an update on recent performance of the ISO and the energy imbalance market by the Department of Market Monitoring (DMM):

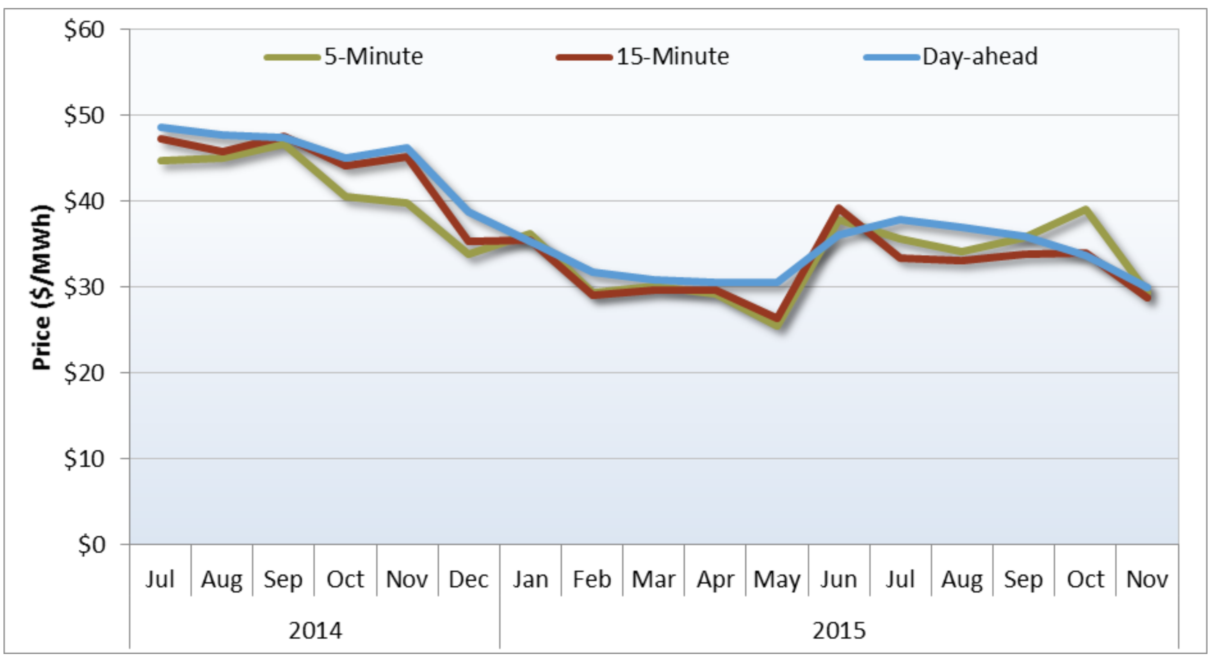
- **ISO market performance.** The ISO market has continued to perform efficiently and competitively through November 2015. Average monthly system energy prices have been lower over the past few months compared to the previous year as gas prices have been about 38 percent lower for the same period. While day-ahead prices exceeded real-time market prices during the summer, day-ahead and 15-minute prices have tracked fairly closely in October and November. The lower summer real-time prices were as a result of a combination of multiple factors including lower loads relative to day-ahead forecasts, additional generation from renewable sources beyond levels included in day-ahead forecasts and schedules, and additional generation from thermal units committed after the day-ahead market for reliability reasons.
- **Bid cost recovery.** Bid cost recovery payments increased during the summer months, particularly in July. These increased costs were driven by payments for units committed for reliability purposes during periods of warmer temperatures and higher loads, and due to the need to ensure enough physical supply to offset net virtual supply clearing in the day-ahead market. Payments totaled over $12 million between June and October, compared to only $1.4 million in the first five months of the year.
- **Energy imbalance market**. While overall performance of the energy imbalance market improved over the course of 2015, EIM prices have begun to diverge over the last few months. Beginning in August, the frequency of flexible ramping constraint relaxations increased significantly, particularly in PacifiCorp East. These shortages of ramping capacity compared to flexible ramping capacity requirements in the 15-minute market caused significant increases in 15-minute

prices. When the flexible capacity constraint is relaxed, but the power balance constraint is feasible, special price discovery provisions are not triggered. These shortages drove 15-minute prices in PacifiCorp East more than 20 percent above bilateral market prices in September and October. This increase has been driven by a combination of factors including increases in the flexible ramping constraint requirement, generation outages, and, to a lesser extent, a software defect that was corrected in late November. The ISO anticipates that the addition of NV Energy to the EIM should help to alleviate some of shortfalls and is working with PacifiCorp to minimize ramping issues.

ISO MARKET PERFORMANCE

The ISO market has continued to perform efficiently and competitively through November 2015. As shown in Figure 1, average monthly system energy prices in the day-ahead and real-time markets are down in 2015 compared to 2014 and have tracked fairly closely in most months. Summer day-ahead prices were down 23 percent in 2015 compared to 2014 as gas prices have fallen by 31 percent.

Figure 1 Average monthly system energy prices (July 2014 – November 2015)



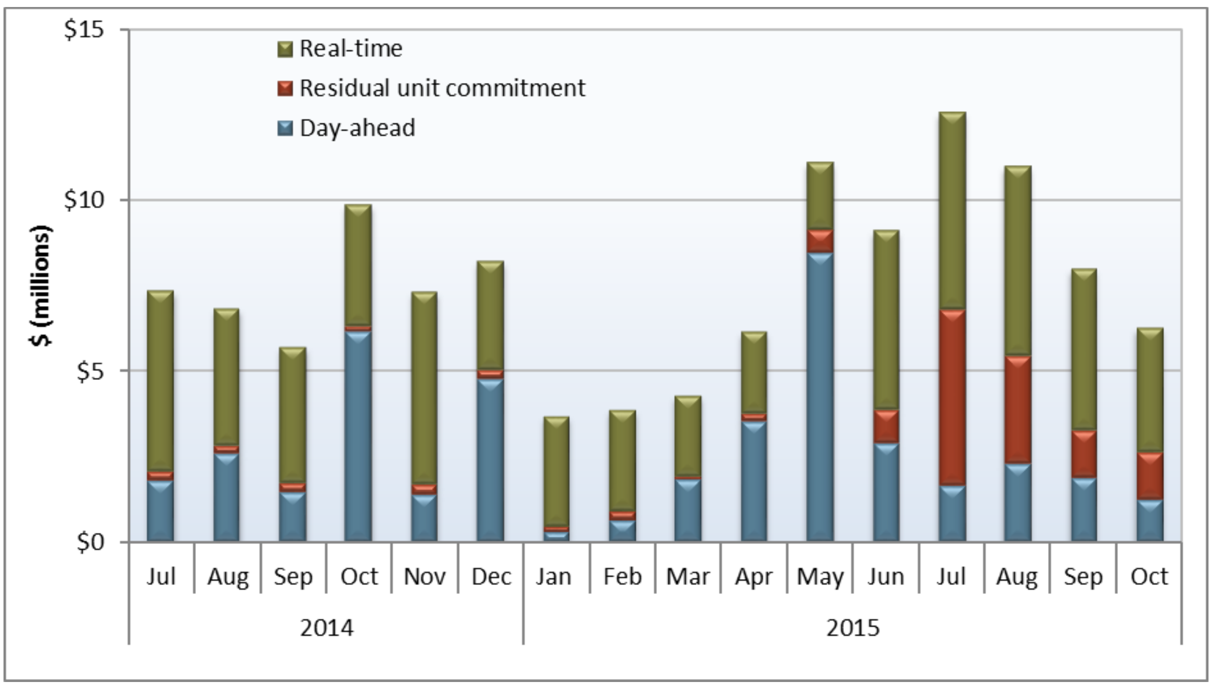
Real-time prices tended to be slightly lower than day-ahead prices in the summer months as a result of lower loads than were forecasted and cleared in the day-ahead market. Additional generation during some hours from renewable sources beyond levels included in day-ahead forecasts and schedules, and additional generation from thermal units committed after the day-ahead market for reliability reasons.[1] In the fall, 15-minute prices have tracked day-ahead prices more closely. In October, 5-minute market prices increased because of high prices on a few days caused by differences in forecasted and actual loads and generation.

Bid cost recovery payments

Generating units are eligible to receive bid cost recovery payments if total market revenues earned over the course of a day do not cover the sum of all the unit's accepted bids. The calculation includes bids for start-up, minimum load, ancillary services, residual unit commitment, and day-ahead and real-time energy. Excessively high bid cost recovery payments can indicate inefficient unit commitment or dispatch.

Figure 2 shows that bid cost recovery payments made to units for residual unit commitment increased significantly since May, particularly in the summer months. Payments totaled over $12 million between June and October, compared to only $1.4 million in the first five months of the year and $5 million in all of 2014.

Figure 2 Bid cost recovery payments (July 2014 – October 2015)



The purpose of the residual unit commitment market is to ensure that there is sufficient capacity online or reserved to meet actual load in real time. The residual unit commitment market is run right after the day-ahead market and procures capacity sufficient to bridge the

[1] System energy prices exclude the differences in locational marginal prices (LMPs) at different points within the ISO system due to congestion.

gap between the day-ahead load forecast load and the amount of physical supply scheduled in the day-ahead market. Capacity procured in the residual unit commitment must be bid into the real-time market.

Two factors contributed to this trend. First, beginning in May there was an increase in net virtual supply clearing in the day-ahead market. When net virtual supply clears the day-ahead market, physical capacity must be available to meet forecasted demand. Because virtual supply can contribute to residual unit commitment costs, a portion of these costs are allocated to participants with net virtual supply clearing the day-ahead market.

Second, during the summer, higher loads often require that residual unit commitment needs be met by units that are less efficient and have longer start times and minimum operating periods. These resources are required to start up based on their residual unit commitment schedules and receive payments for this energy at the real-time price. However, real-time prices were lower than day-ahead prices for much of the summer. As noted above, much of this was driven by lower loads in real time, which were caused by changes in weather and forecasted temperatures. As a result, the revenues earned by these units were frequently insufficient to cover their costs.

As loads and virtual supply levels have decreased at the conclusion of the summer months, there was a noticeable decline in the level of bid cost recovery for units committed by the residual unit commitment process.

Energy imbalance market

During most intervals, EIM prices continue to be set by bids closely reflective of the marginal operating cost of the highest cost resource dispatched to balance loads and generation. Bids for most capacity continue to be slightly below or slightly above default energy bids used for market power mitigation. When bids are mitigated due to market power mitigation provisions, these procedures generally result in modest reductions in bid prices.

The percentage of intervals when the flexible ramping constraint was relaxed in the 15-minute market increased significantly from July to October. For instance, the frequency of these ramping relaxations increased from under 2 percent in July to almost 14 percent in October, in PacifiCorp East. During these intervals, the energy price in the 15-minute market includes a $60/MWh penalty price for the flexible ramping constraint.[2]

The increased frequency of flexible ramping constraint shortages has driven up prices in the 15-minute market significantly in both PacifiCorp areas since August. During September, flexible ramping constraint shortages increased 15-minute prices by about $5/MWh in PacifiCorp East and over $3/MWh in PacifiCorp West. This drove average 15-minute prices above average bilateral prices by about 20 percent and 10 percent in these EIM areas, respectively.

[2] When price discovery provisions are triggered by relaxation of the power balance constraint, the penalty price for the flexible ramping constraint is changed from $60/MWh to $0/MWh in the pricing run, so that the shadow price of this constraint is $0.

Similarly, flexible ramping constraint shortages in October increased prices by about $8/MWh in PacifiCorp East. As a result, EIM prices in PacifiCorp East were 34 percent higher than bilateral market prices in October. Price impacts from flexible ramping constraint shortages in PacifiCorp West during October were only a $1.65/MWh, coinciding with the reduced frequency of flexible ramping shortage occurrences in that region.

The increased impact of the flexible ramping constraint on prices appears to be attributable to a number of factors. Analysis by DMM indicates that this trend has been driven in large part by an increase in the level of flexible ramping requirements and a reduction of available ramping capacity due to generation outages. According to the ISO, other factors contributing to this trend include a software defect impacting the multi-stage generation unit logic, as well as data alignment issues that can contribute to flexible ramping constraint infeasibilities in a similar way that such issues contribute to power balance infeasibilities. DMM is working with the ISO and PacifiCorp to further assess and mitigate these flexible ramping constraint issues.

Figure 3 and Figure 5 show the frequency that constraints have been relaxed in the 15-minute market by month in the PacifiCorp East and West areas, respectively. Figure 4 and Figure 6 show the monthly average 15-minute prices in these areas *with* and *without* the special price discovery mechanism being applied to mitigate prices during intervals when the energy imbalance constraint needed to be relaxed. These figures also include monthly average bilateral market prices that are estimated by DMM.

Figure 7 and Figure 8 show average monthly prices in the 5-minute market *with* and *without* the special price discovery mechanism in PacifiCorp East and PacifiCorp West, respectively. The frequency of power balance constraint relaxation in the 5-minute market tends to be higher due to the more constrained supply conditions that exist on a 5-minute basis. However, beginning in June, monthly average prices in the 5-minute market were about equal to or below bilateral prices with price discovery provisions in both PacifiCorp areas. In PacifiCorp West there were modest premiums in the price without price discovery compared to the bilateral market price in September and October, which was likely driven by a transmission outage during this period that limited transfers from PacifiCorp East to PacifiCorp West.

Figure 3 Frequency of constraint relaxation (PacifiCorp East – 15-minute market)

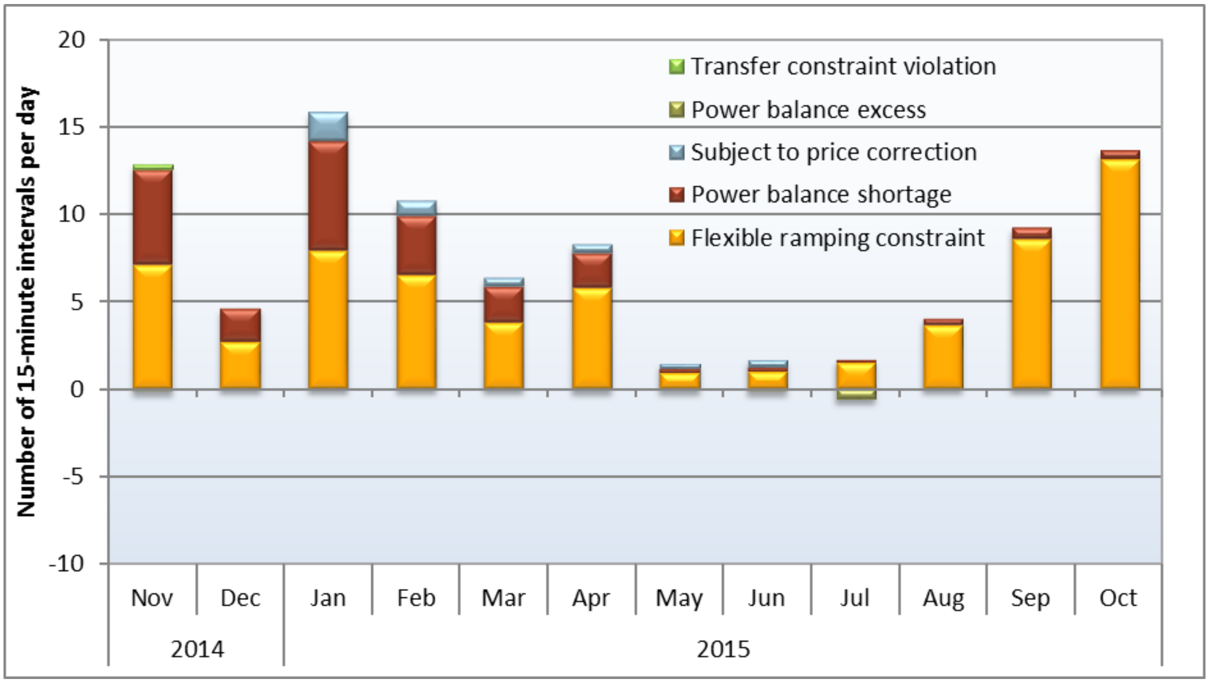


Figure 4 Average monthly prices (PacifiCorp East - 15-minute market)

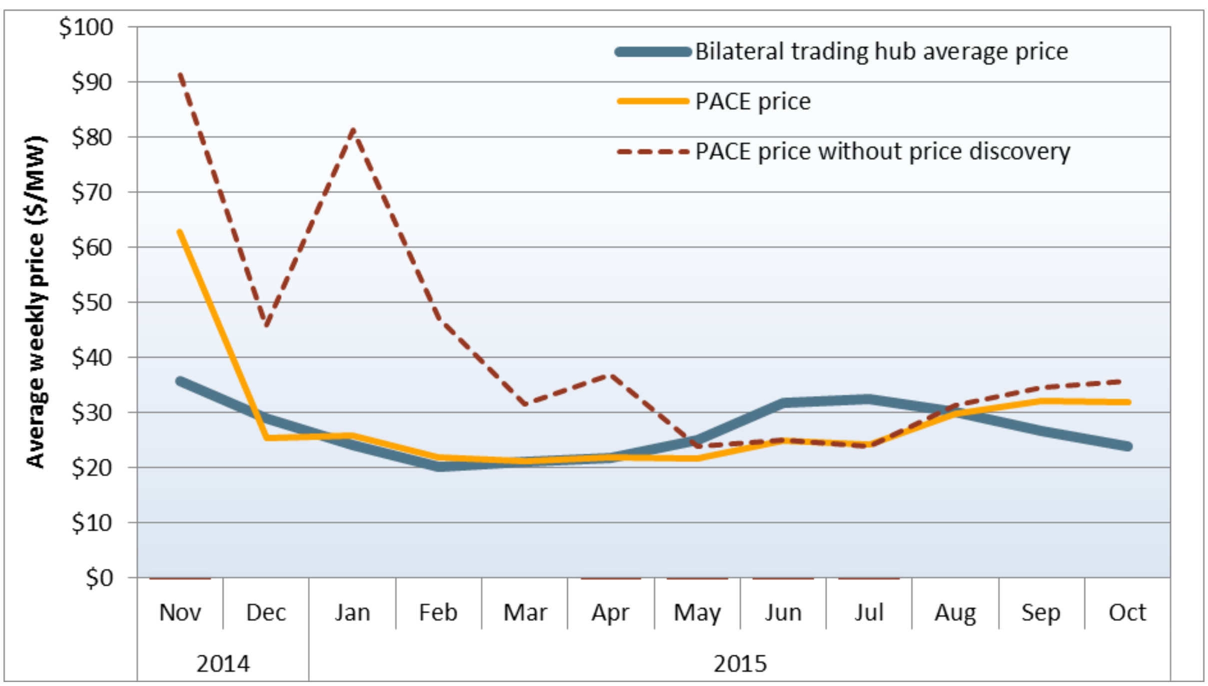


Figure 5 Frequency of constraint relaxation (PacifiCorp West – 15-minute market)

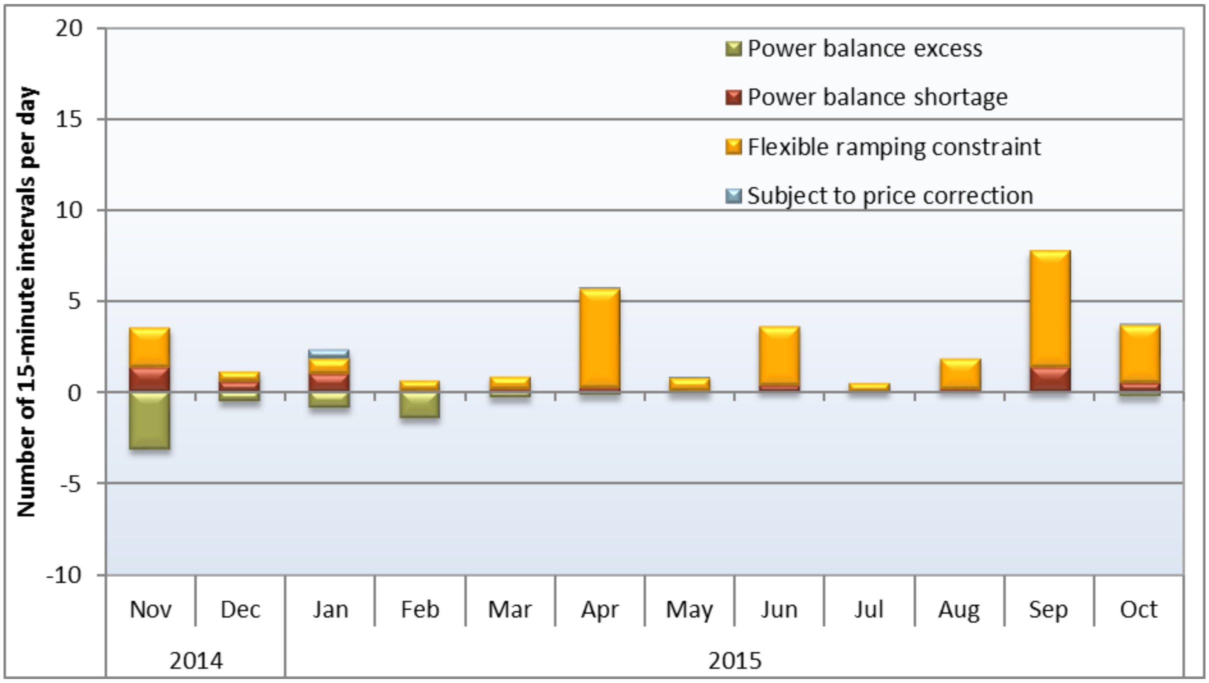


Figure 6 Average monthly prices (PacifiCorp West – 15-minute market)

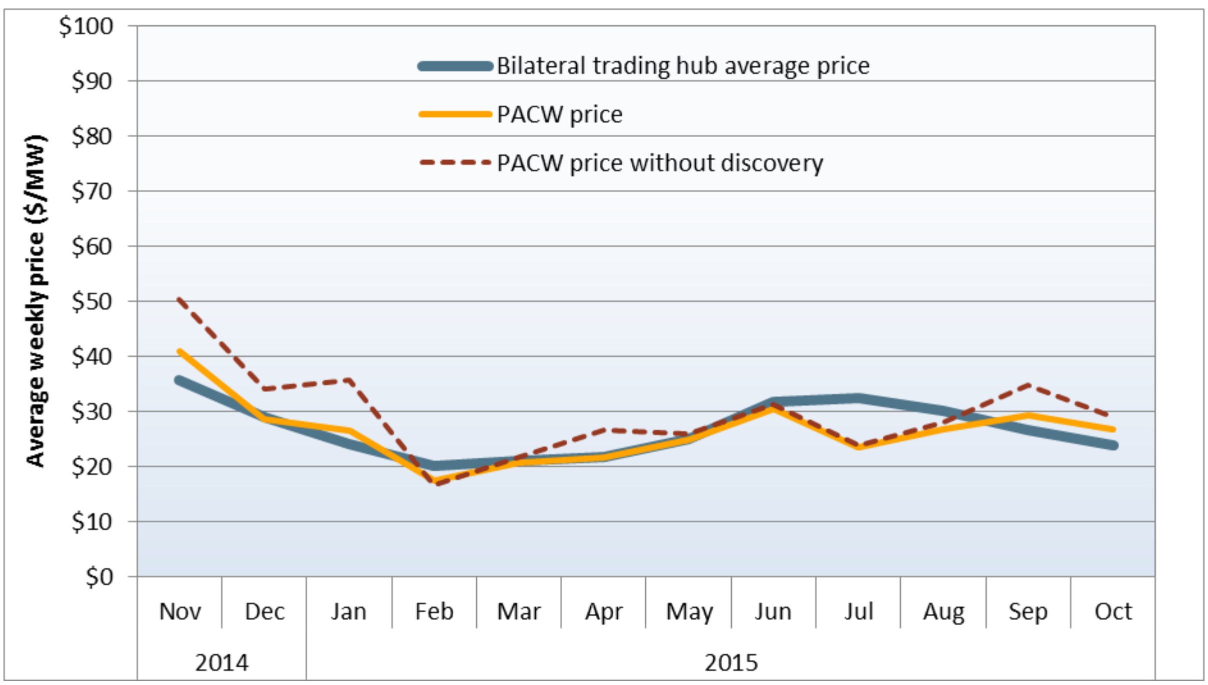


Figure 7 Average monthly prices (PacifiCorp East – 5-minute market)

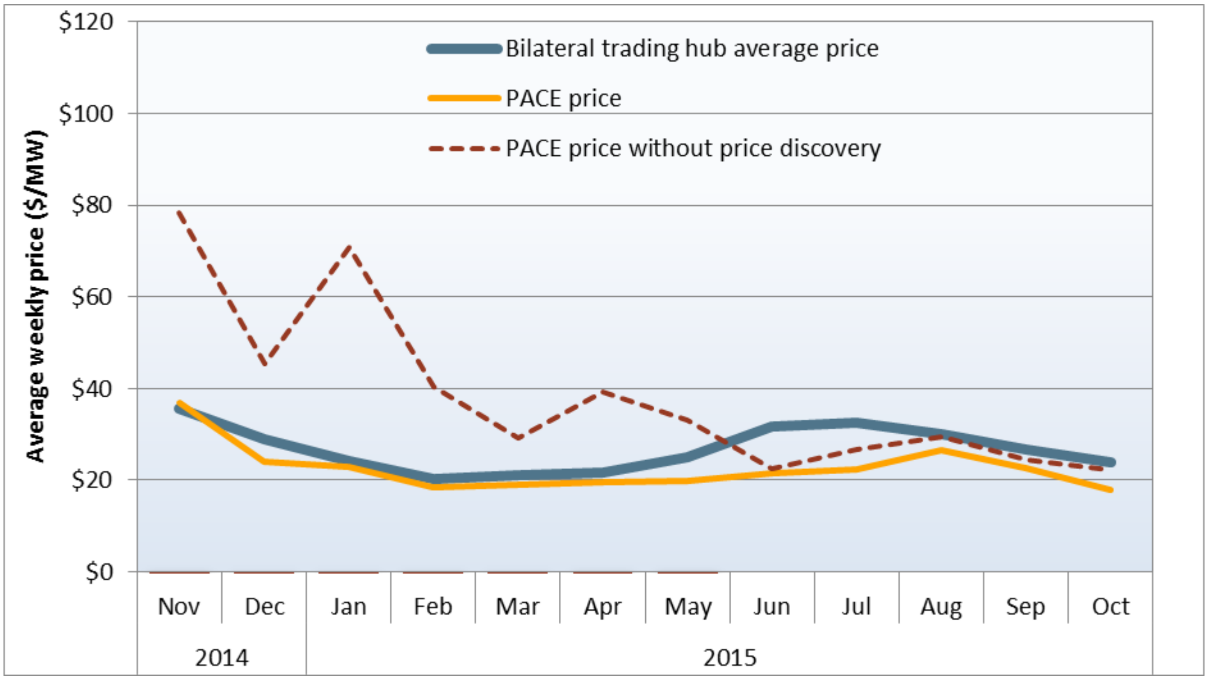
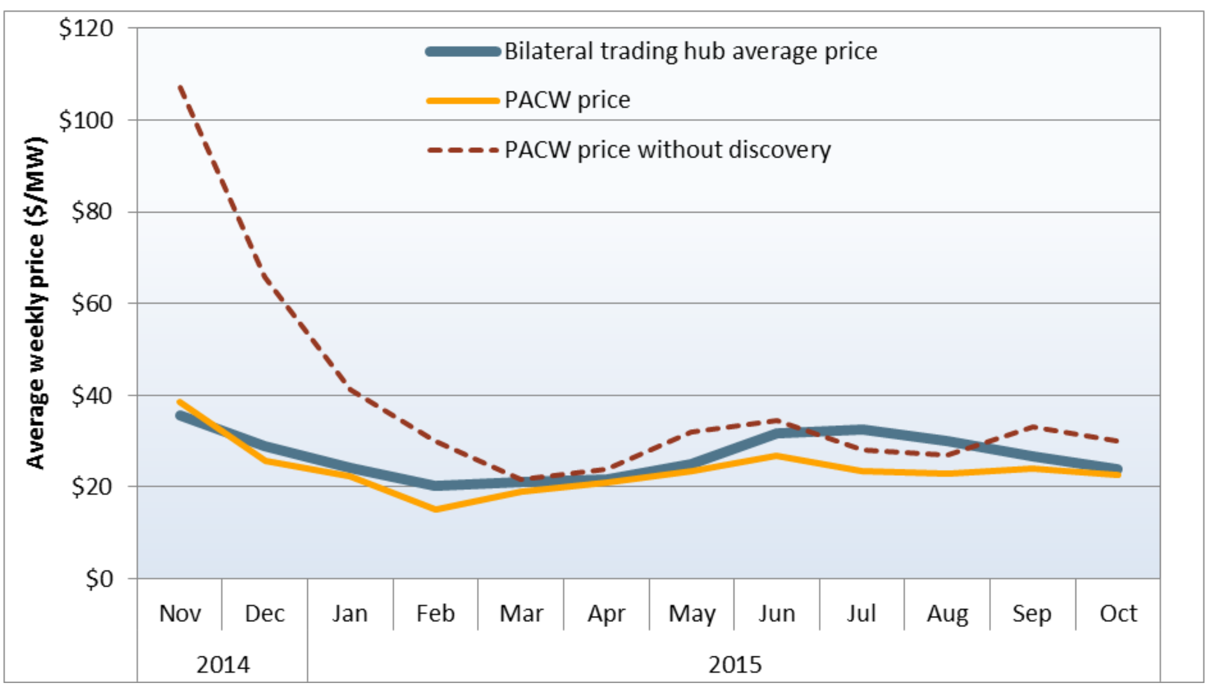


Figure 8 Average monthly prices (PacifiCorp West – 5-minute market)



This trend continued in November, with prices in the 15-minute market continuing to exceed bilateral prices due to the impact of the flexible ramping constraint. This trend may be mitigated with the addition of NV Energy to the EIM, since this may significantly increase the amount of additional energy that can be scheduled in the 15-minute market into the PacifiCorp areas. Although flexible ramping capacity cannot be directly imported from other EIM areas, additional energy imports can allow more ramping capacity from resources within an EIM area to remain unloaded and available to meet flexible ramping constraint requirements.