SPP Southwest Power Pool
Market Monitoring Unit

State of the Market
Fall 2017

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1. MARKET PERFORMANCE HIGHLIGHTS

This report covers market performance during the fall quarter of 2017 (September - November). The annual figures shown on the charts in this report represent only this three-month period for each year. Highlights of this fall period are as follows:

- During fall 2017, the average day-ahead and real-time prices were $20.22/MWh and $20.53/MWh, respectively. October 2017 prices averaged around $18/MWh which were the lowest monthly average prices in the Southwest Power Pool (SPP) market since spring 2016.

- Average monthly gas cost at the Panhandle Eastern hub continues to average around $2.60/MMBtu, as it has for the past ten months.

- The all-in cost in fall 2017 was $22.40/MWh, a 12 percent decrease compared to the fall 2016 level of $25.53/MWh. Gas price at the Panhandle Eastern hub decreased by one percent for the same period.

- In terms of monthly real-time generation by technology, coal-powered resources continued their downward trend with only 45 percent of energy produced in the fall 2017 period compared to 50 percent in fall 2016 and 52 percent in fall 2015. Wind generation on the other hand, continued its upward trend with 26 percent of energy produced in fall 2017 compared to 20 percent in fall 2016 and 15 percent in fall 2015.

- As in the summer of 2017, the Woodward flowgate (WDWFPLTATNOW) did not appear in the top ten congested flowgates for the fall period even though it is still ranked as the flowgate with the highest shadow price for the past 12 months. This decrease in congestion can primarily be attributed to the installation of an extra high voltage phase-shifting transformer at Woodward in late May, which increased the amount of transfer capability in the area.

- In the real-time market, just over 11 percent of all intervals in fall 2017 had no congestion, compared to two percent in fall 2016 and nearly four percent in fall 2015.

- With the prolific growth of wind generation in the SPP market, the frequency of intervals experiencing negative prices continues to increase. On an annual basis, the total percentage of negative price intervals the real-time market has increased from 2.6 percent in 2015, to 3.5 percent in 2016, and to 7.0 percent in 2017 (through November).

- The growing frequency of negative prices indicates the potential need for changes in market rules to address self-committing of resources in the day-ahead market and the systematic absence of some forecasted variable energy resources in the real-time market to improve market efficiency. More detailed discussion regarding negative prices can be found in the special issues chapter of this report.

2. PRICES AND MARKET COSTS

Prices

Workably competitive electricity markets are expected to see highly correlated gas costs and electricity prices in general. Historically, gas and electricity prices have been highly correlated in the SPP market. Although this correlation is generally observed over time, some periods exhibit divergence. Average gas prices have been relatively stable with average monthly prices at the Panhandle Eastern hub ranging between \$2.50 and \$2.80/MMBtu since July 2016. The exceptions are December 2016 and January 2017 when prices went above \$3/MMBtu, and November 2016 when gas prices dropped to around \$2.25/MMBtu. Gas prices decreased by one percent from fall 2016 to 2017, from \$2.61/MMBtu to \$2.58/MMBtu.

During fall 2017 the average day-ahead price was \$20.22/MWh and the average real-time price was \$20.53/MWh, as shown in Figure 2–1. In comparison, day-ahead and real-time prices for fall 2016 were \$24.43/MWh and \$25.10/MWh, respectively. This decrease in prices from 2016 to 2017 can be attributed to several factors, including lower gas prices in 2017, as well as less congestion in 2017. July 2017 energy prices averaged around \$30/MWh, which was the highest monthly average price in the SPP market since August 2014.

Figure 2–1 Electricity and gas prices

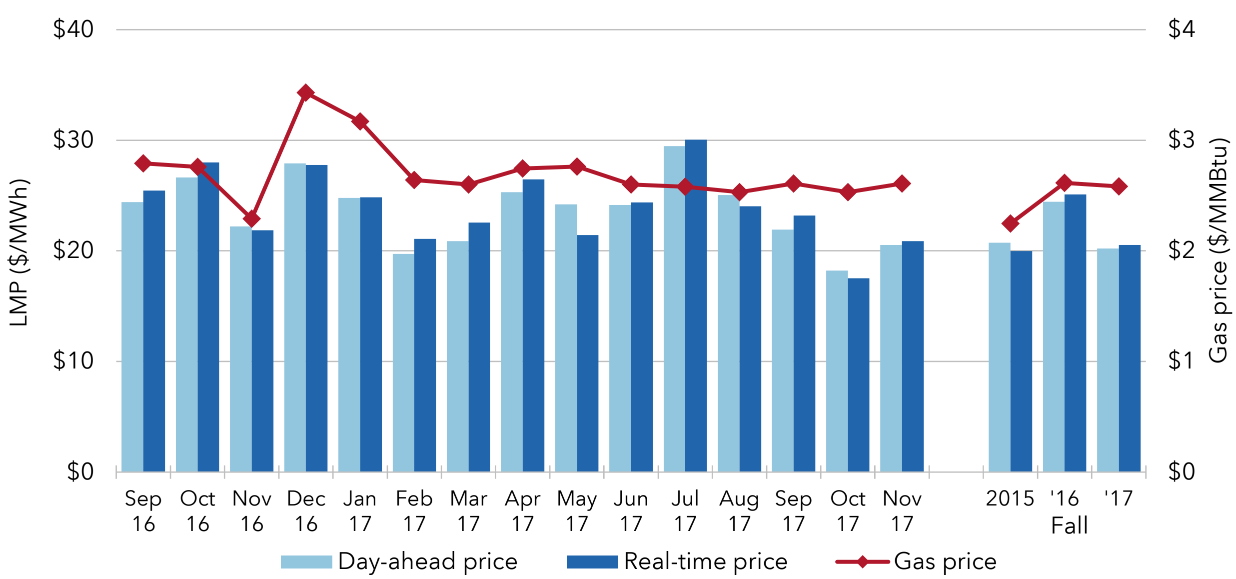
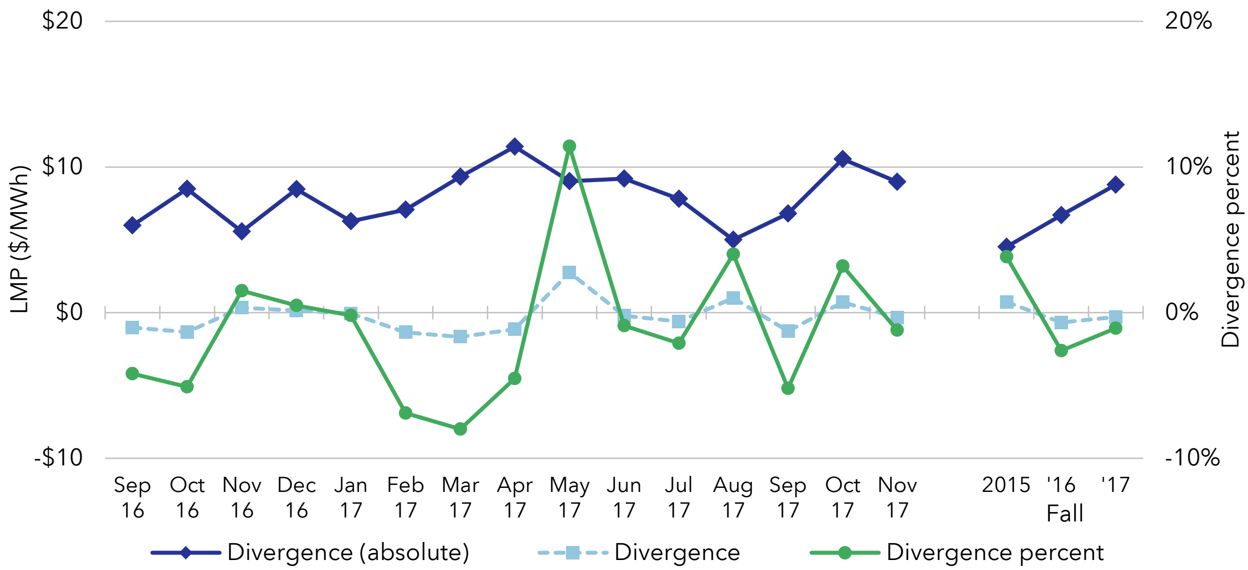


Figure 2–2 shows the day-ahead to real-time price divergence at the SPP system level. Price divergence[1] is calculated as the difference between day-ahead and real-time prices, using system prices for each five-minute (real-time) or hour (day-ahead) interval. The absolute divergence is calculated by taking the absolute value of the divergence for each interval.

While divergence and divergence percent fluctuate between fall 2015 and fall 2017, the absolute divergence has been climbing, indicating a higher level of volatility.

Figure 2–2 Price divergence, day-ahead and real-time



Overall, price patterns between the day-ahead and real-time markets are similar, as shown on the price contour maps below in Figure 2–3 and Figure 2–4. Blue represents lower prices and red represents higher prices. Significant color changes across the map signify constraints that limit the transmission of electricity from one area to another.

Lower prices are more prevalent in the north due to less expensive generation in the area, and in the west-central part of the footprint due to abundant low-cost wind generation in that area. Generally, the areas seeing the highest congestion and thus the highest average prices, include the area south of the Texas panhandle, northwest Oklahoma near Woodward,

[1] Price divergence percent is calculated as real-time price minus the day-ahead price, divided by the day-ahead price.

northwest Kansas near Hays, and in the tristate area of Missouri, Kansas, and Oklahoma. Factors that can influence congestion and resulting prices are transmission bottlenecks, generator and transmission outages, weather events, differences in fuel prices and cost of generation, and differences in temperatures across the footprint.

Figure 2–3 Price map, fall (all hours)

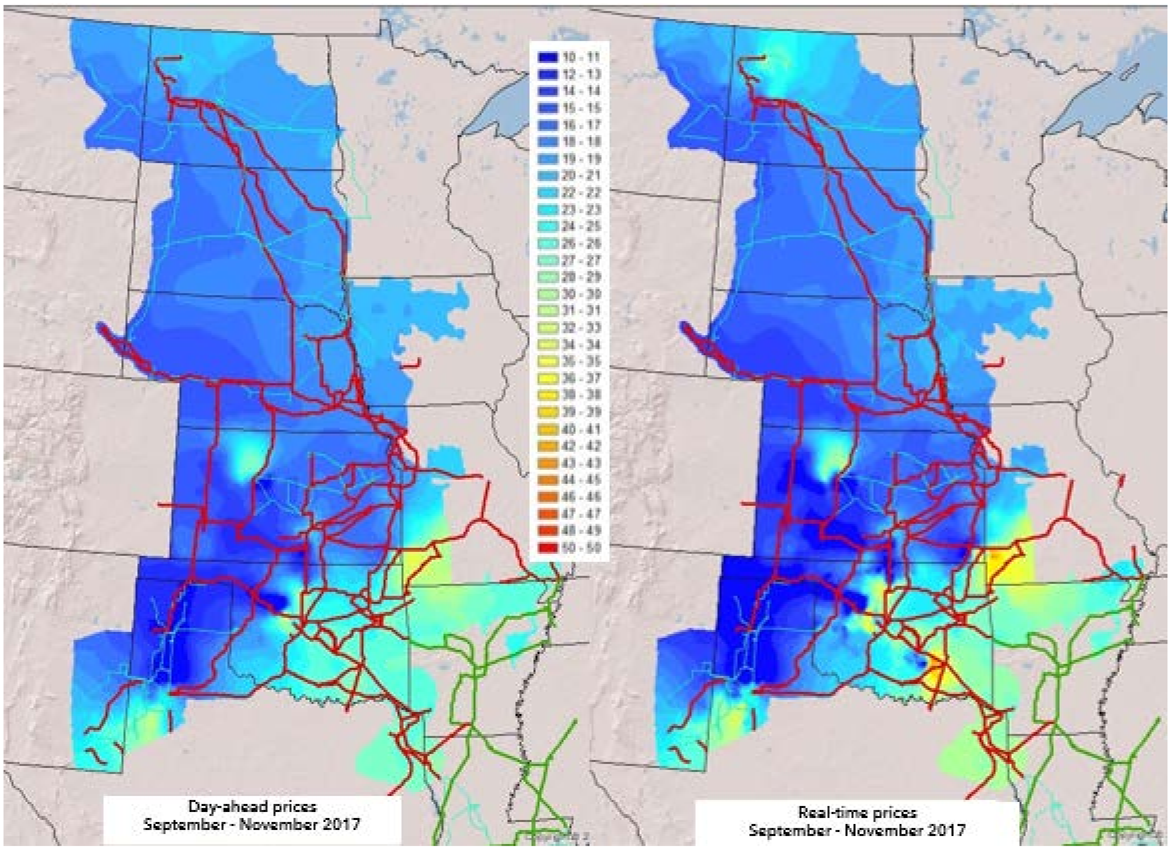


Figure 2–4 Price map, rolling 12 month (all hours)

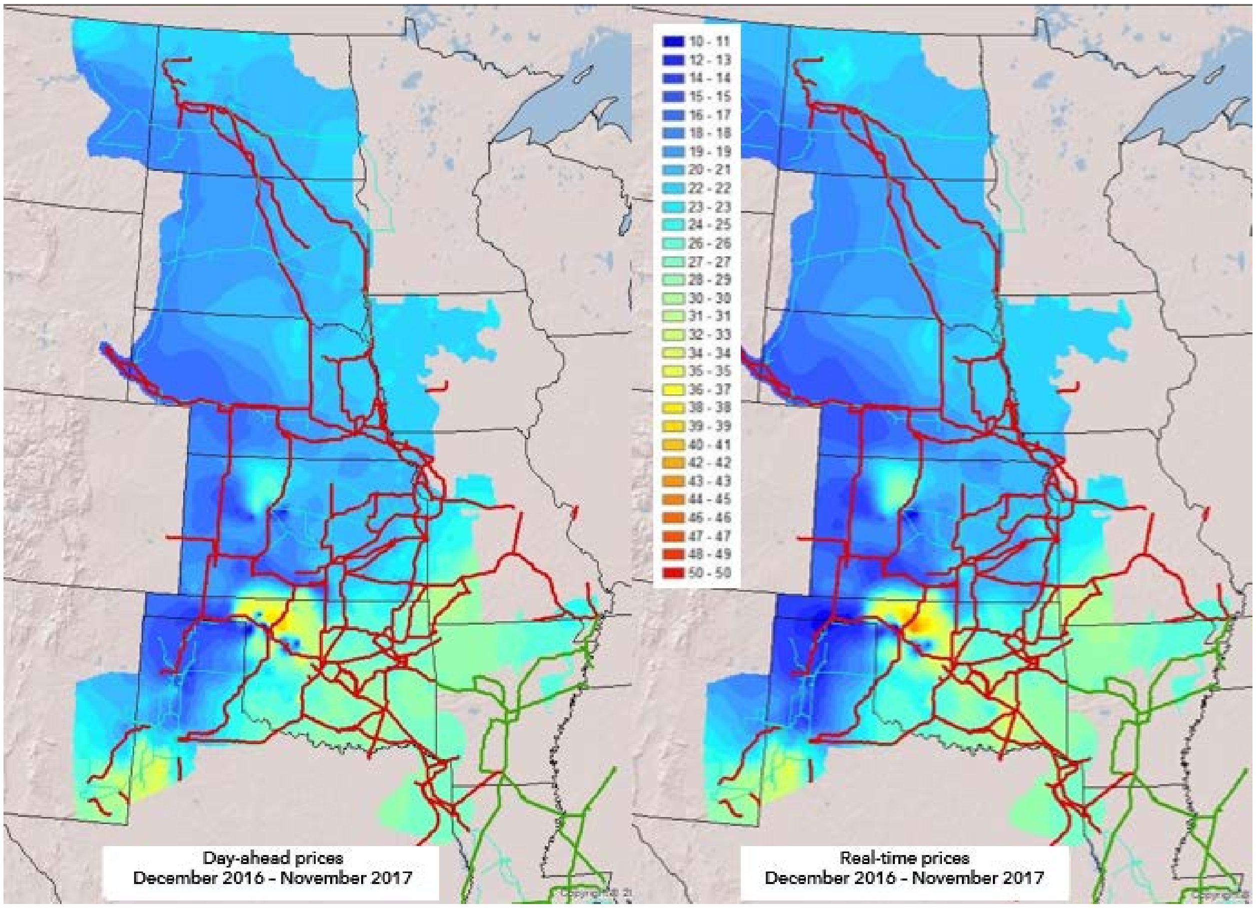


Figure 2–5 and Figure 2–6 display average prices paid by load serving entity, for the fall and last twelve month periods. Fall period average prices are the highest for City of Carthage, City of Springfield, and Empire District, all located in the tristate area discussed above; and are lowest for Sunflower Electric, Kansas Power Pool, and Midwest Energy, all in western Kansas.

High prices in the Missouri/Kansas/Oklahoma area can primarily be attributed to congestion on the NEORIVNEOBLC (Neosho-Riverton for the loss of Neosho-Blackberry) flowgate. Some reasons for congestion in this area are high levels of internal and external wind generation, and external north to south flow. There were also generation and transmission outages during this period such as the Delaware to Northeast 345kV line, which was out for most of October and November.

Figure 2–5 Price by load-serving entity, fall

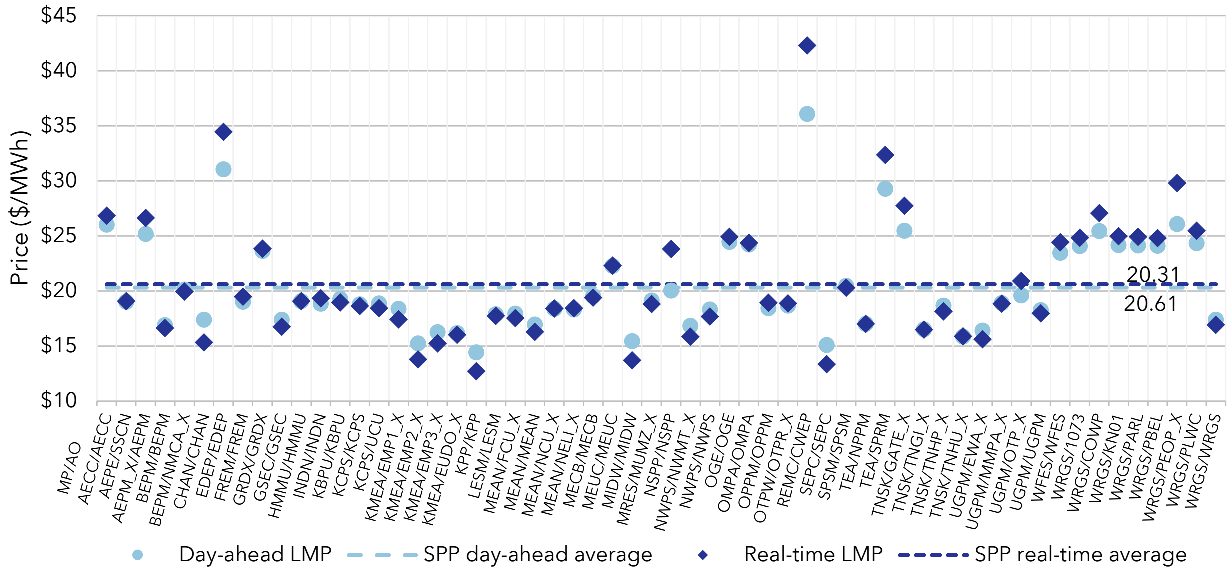


Figure 2–6 Price by load-serving entity, rolling 12 month

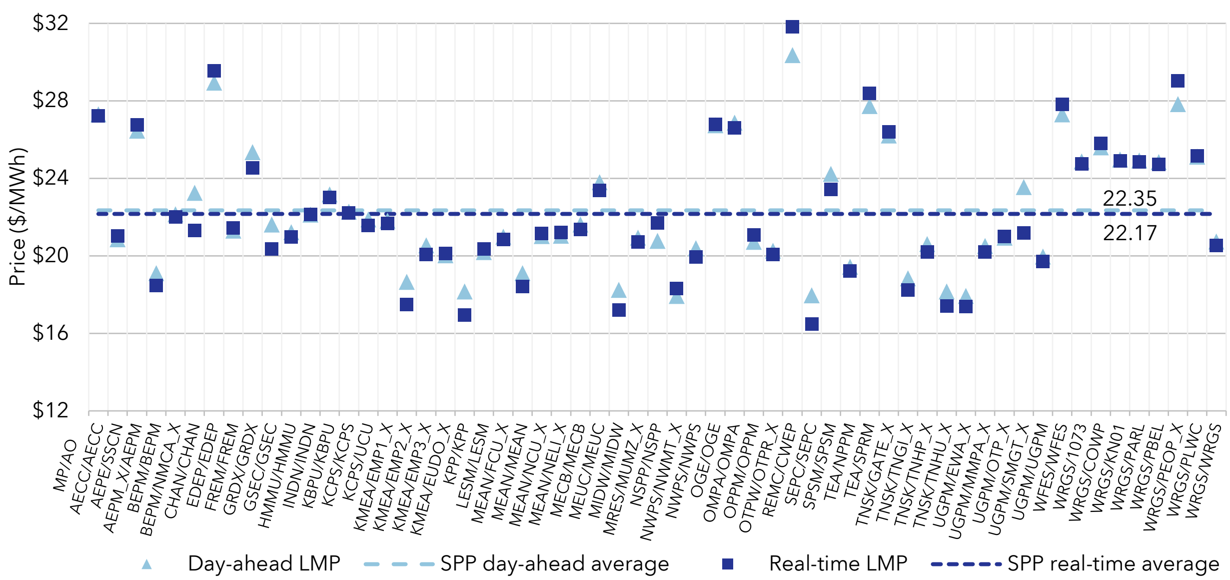
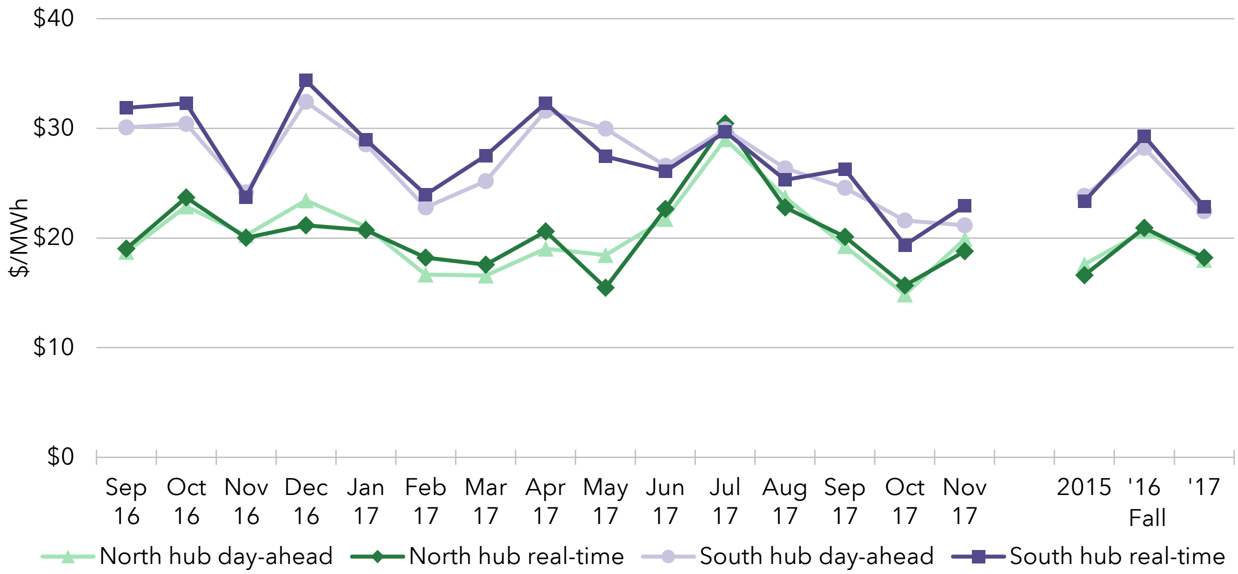


Figure 2–7 shows monthly average day-ahead and real-time prices for the two trading hubs. A trading hub is a settlement location consisting of an aggregation of price nodes developed for financial and trading purposes. Due to an abundance of lower-cost generation in the northern part of the SPP footprint, prices at the North hub have been consistently lower than the South hub. The average spread in absolute value terms for real-time prices between the two hubs for fall 2017 was $4.66/MWh, compared to $8.38/MWh for fall 2016. Much of the

reason for the smaller spread in fall 2017 compared to fall 2016 is the addition of the phase-shifting transformer at Woodward in May 2017. The addition of this transformer has significantly decreased congestion, thus decreasing the marginal congestion component of prices, particularly in the southern portion of the SPP footprint.

Figure 2–7 Trading hub prices



Ancillary services

The following figures (Figure 2–8 through Figure 2–11) show marginal clearing prices for ancillary services. All operating reserve products are priced as market-based. Following FERC Order No. 825, SPP proposed, and the market participants approved, a new design feature of a variable demand curve for the four operating reserve products. The new design introduces an upward sloping demand curve for contingency (spin and supplemental) reserves products, and regulation-up and regulation-down products. The new functionality became effective as of operating day August 11, 2017. Since this functionality is new, the MMU does not have sufficient data to report on its impacts at this time. The MMU will monitor and report on impacts of this change in a later report.

Regulation-down prices for October 2017 were at very high levels, with a day-ahead marginal clearing price of $9.99/MW, which is the highest price experience in the Integrated

Marketplace; and a real-time marginal clearing price of $16.70/MW, which is the highest since the first month of the market (March 2014 when the price was $18.14/MW). In addition, the regulation-down mileage price of $23.85/MW was the highest since this product was added to the market in March 2015. The high prices for regulation-down in October can be partly attributed to record high wind for that month. The Market Monitoring Unit is reviewing the causes of these higher regulation-down mileage prices and will report on them in a future report.

Figure 2–8 Regulation-up prices

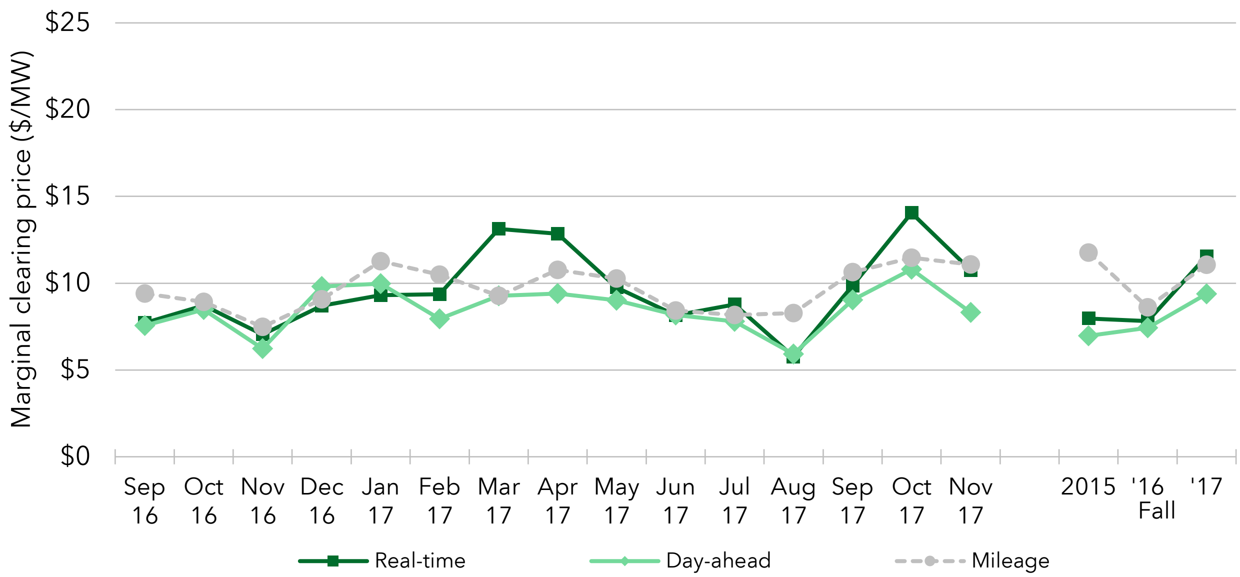


Figure 2–9 Regulation-down prices

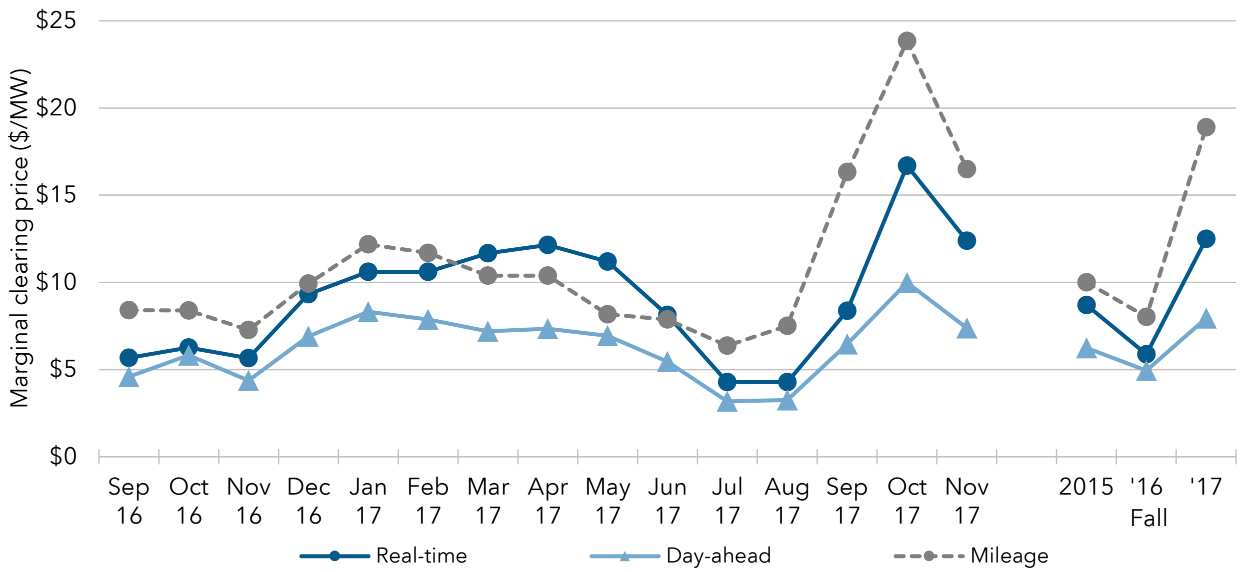


Figure 2–10 Spinning reserve prices

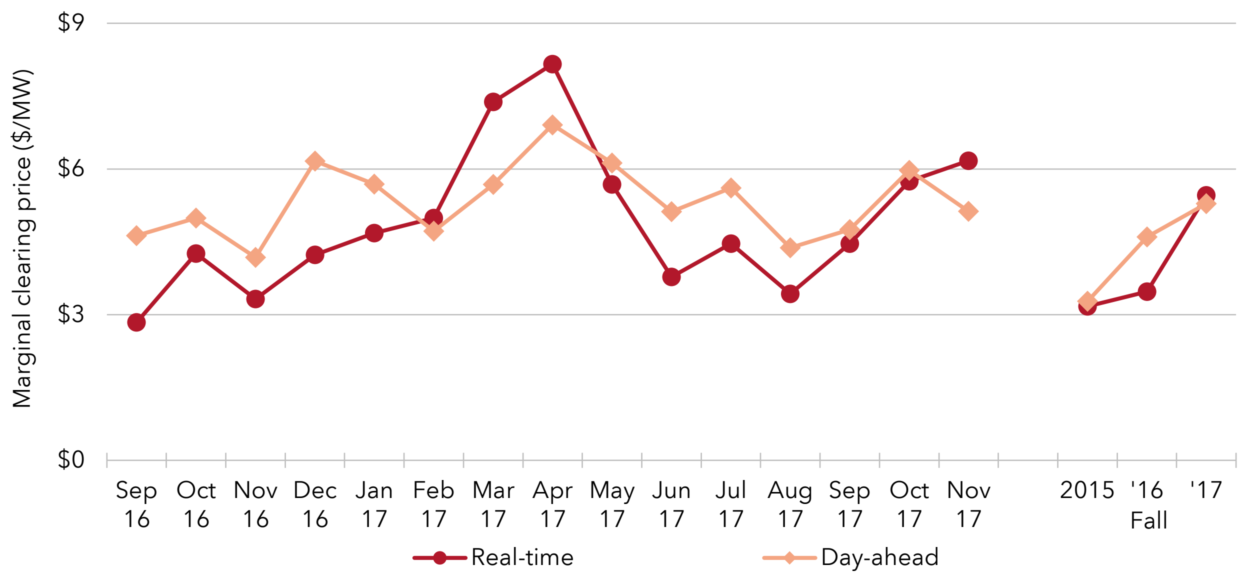
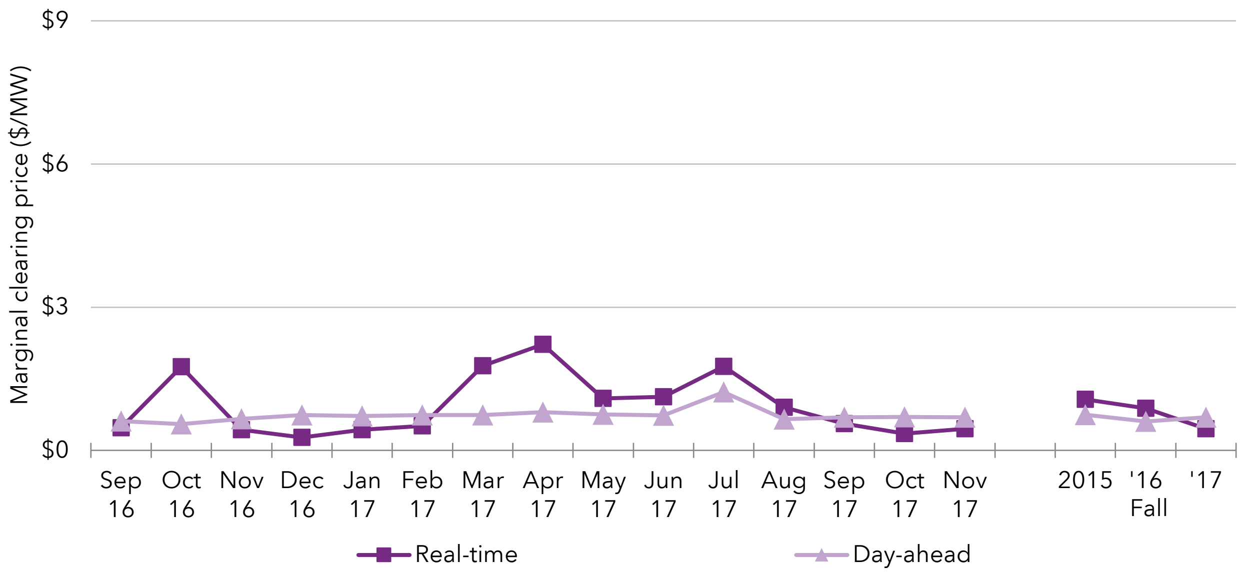


Figure 2–11 Supplemental reserve prices

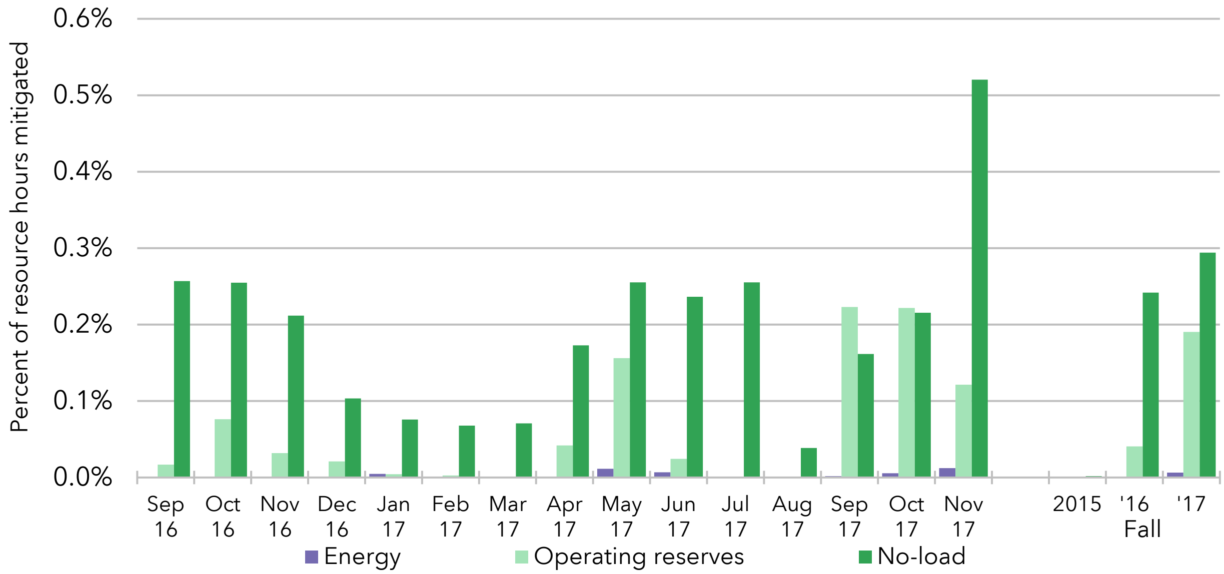


Mitigation

SPP employs an automated conduct and impact mitigation approach to address potential market power abuse through economic withholding. SPP resources' incremental energy, start-up, no-load, and operating reserve offers are subject to mitigation for economic withholding.

Mitigation frequency varies across products in the SPP market. Figure 2–12 shows that the mitigation of incremental energy, operating reserves, and no-load costs remains infrequent in the day-ahead market. Typically, most mitigation occurs in the summer peak and fall seasons, with the winter off-peak season seeing the least mitigation. Fall 2017 had an average of just less than 0.5 percent of total resource hours mitigated for all products, and has increased slightly from just under 0.3 percent of resource hours in fall 2017.

Figure 2–12 Mitigation frequency, day-ahead market



In the real-time market, the mitigation of incremental energy remains at very low levels. During fall 2017, real-time mitigation averaged just over 0.02 percent of intervals. This is down from 0.08 percent in fall 2016.

Figure 2–13 Mitigation frequency, real-time market

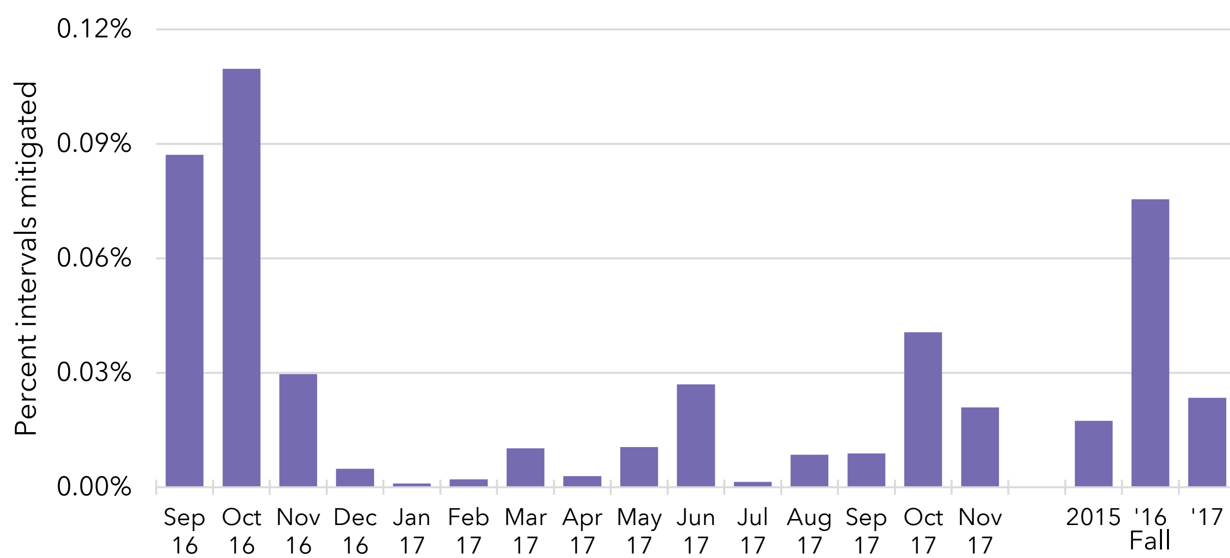
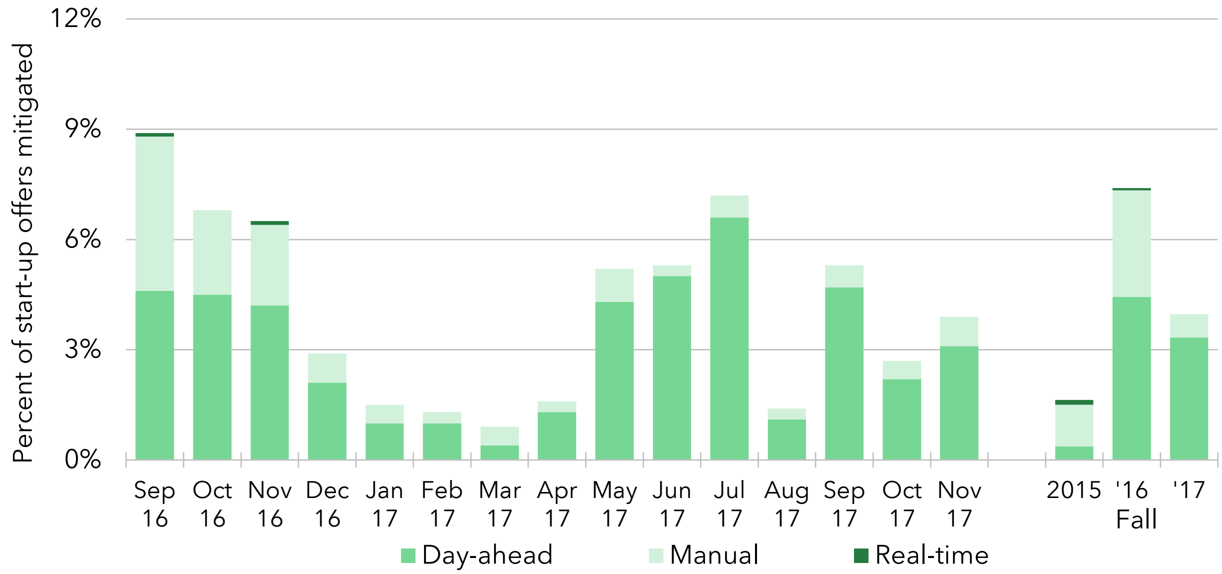


Figure 2–14 shows the mitigation of start-up offers for various means of commitment. The overall level for mitigation of start-up offers has decreased from around 7.5 percent in fall 2016 to 4 percent in fall 2017. The highest level of mitigation for start-up offers in the fall

2017 period was right at 5 percent in September, when in fall 2016 all three months were over 6 percent, with September 2016 reaching almost 9 percent.

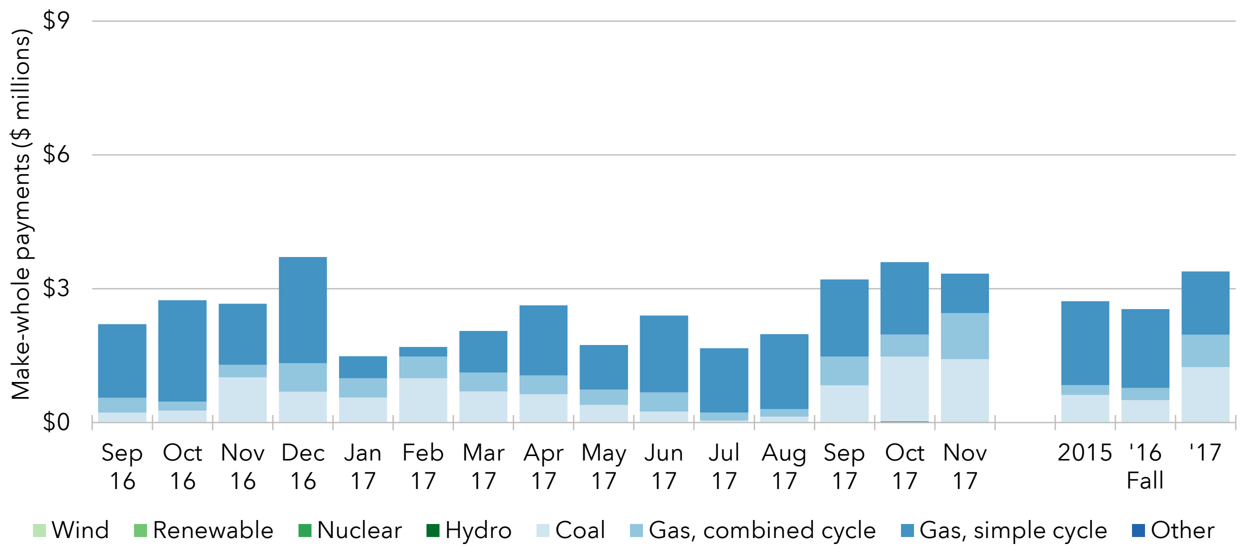
Figure 2–14 Mitigation frequency, start-up offers



Uplift

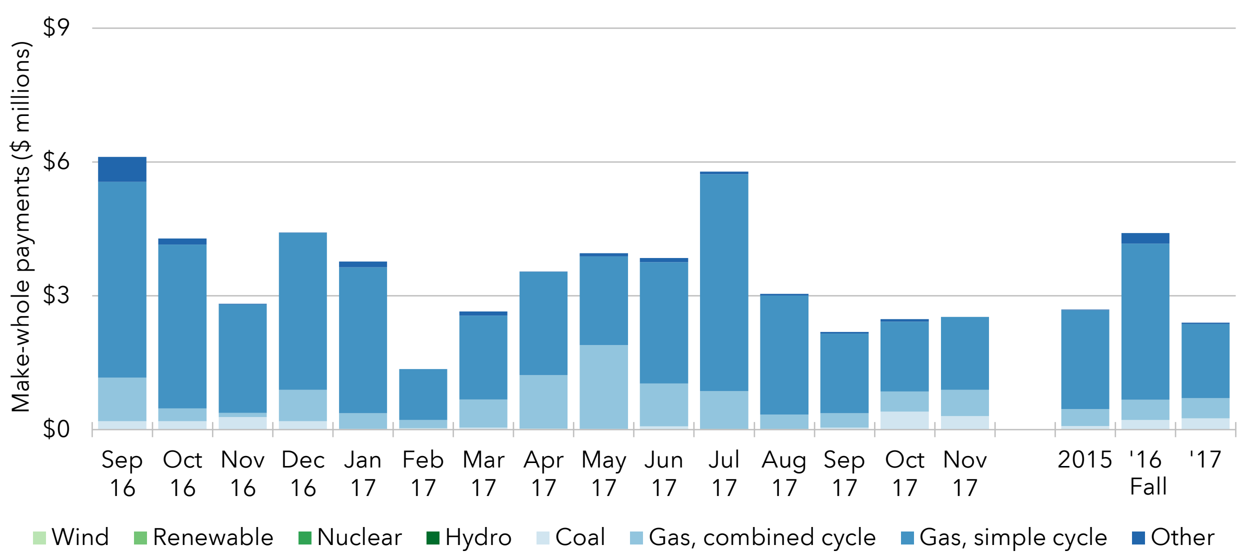
A make-whole payment (uplift) is paid to a generator when the market commits a generator with offered costs exceeding the realized market revenue from providing energy and ancillary services for the commitment period. The day-ahead make-whole payment (Figure 2–15) applies to commitments from the day-ahead market. The reliability unit commitment (RUC) make-whole payment (Figure 2–16) applies to commitments made in the day-ahead RUC and intra-day RUC processes. Day-ahead make-whole payments are typically less frequent and smaller in magnitude than those in the real-time market. The majority of the RUC make-whole payments are paid to gas resources, and more specifically gas simple-cycle resources. Compared to previous fall periods, fall 2017 day-ahead make-whole payments were up slightly.

Figure 2–15 Make whole payments, day-ahead



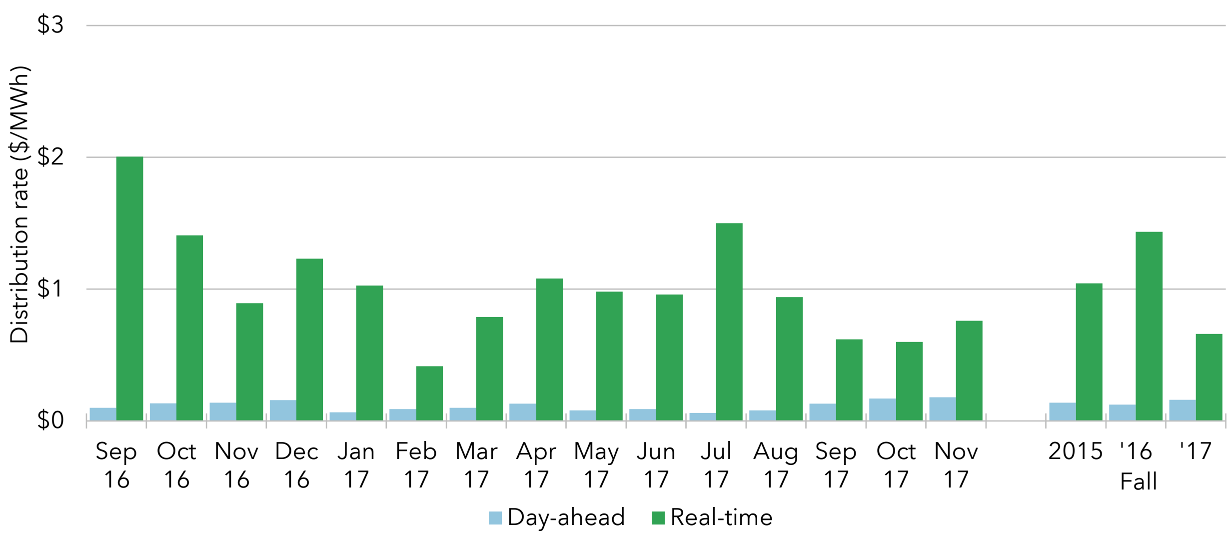
Fall 2017 monthly average real-time make-whole payments were about $2.4 million, about 33 percent lower than fall 2016, and slightly lower than fall 2015.

Figure 2–16 Make whole payments, real-time



The make-whole payment distribution charge, as shown in Figure 2–17, is applied to asset owners that receive benefits from units committed in the day-ahead and real-time markets. The day-ahead make-whole payment distribution amount is an hourly charge or credit based on a daily allocation. The total of all make-whole payments paid to generation resources is spread among all load according to the ratio of the withdrawals relative to a specific market. For the day-ahead market, the distribution rate is the sum of all day-ahead market make-whole payments for the day, divided by the total day-ahead market withdrawals. For the real-time market, the distribution rate is the sum of real-time make-whole payments for the day divided by the total real-time market deviation from day-ahead schedules. The day-ahead distribution rate remains fairly steady in all months, averaging around $0.15/MWh. The real-time distribution rate was about $0.66/MWh in fall 2017, which was about half of the value of the previous two years.

Figure 2–17 Make whole payment distribution rate



On March 1, 2015, SPP implemented its new regulation compensation design feature in compliance with FERC Order 755. It includes payment to market participants based on changes in energy output for regulation deployment, which are shown in Figure 2–18 and Figure 2–19. During March 2015, SPP cleared more regulation mileage than necessary with a regulation mileage factor of 1.0 for both regulation up and down. The factor has been adjusted monthly based on historical usage, averaging near 0.2, since then. The lower factor results in fewer unused mileage make-whole payments for both regulation-up and regulation-down.

Regulation-up mileage make-whole payments remained steady in both day-ahead and real-time from fall 2016 to fall 2017. However, regulation-down make-whole payments for the day-ahead market increased significantly from averaging just under $30,000 for fall 2015 and 2016 to averaging nearly $100,000 in fall 2017. The Market Monitoring Unit is reviewing this in conjunction with the higher regulation-down mileage prices and will report on them in a future report.

Figure 2–18 Regulation-up mileage make whole payments

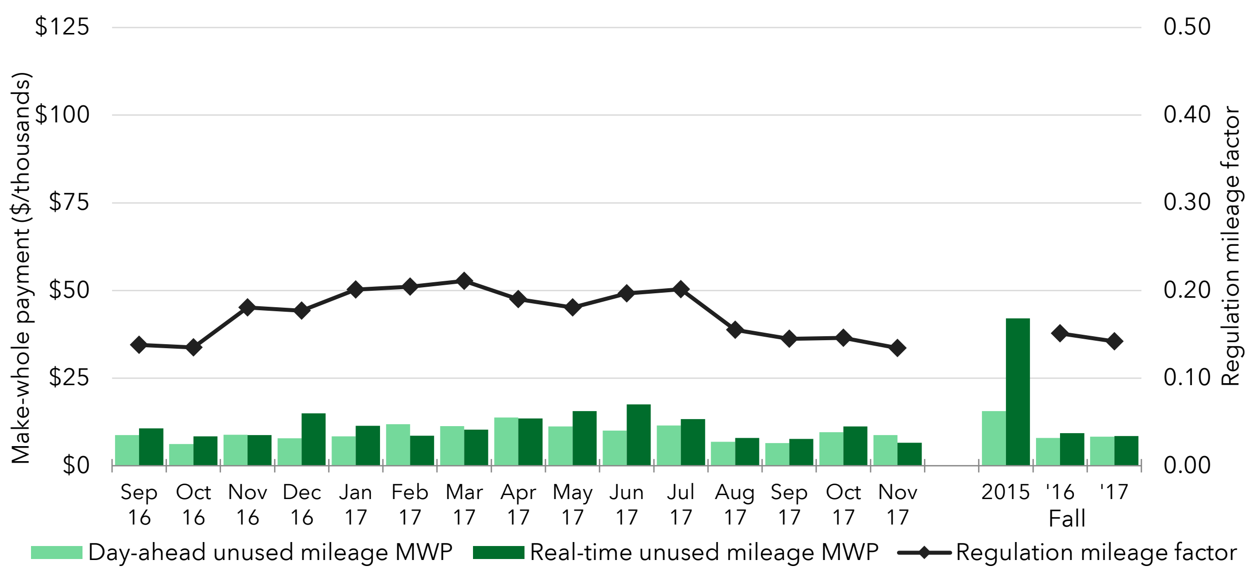
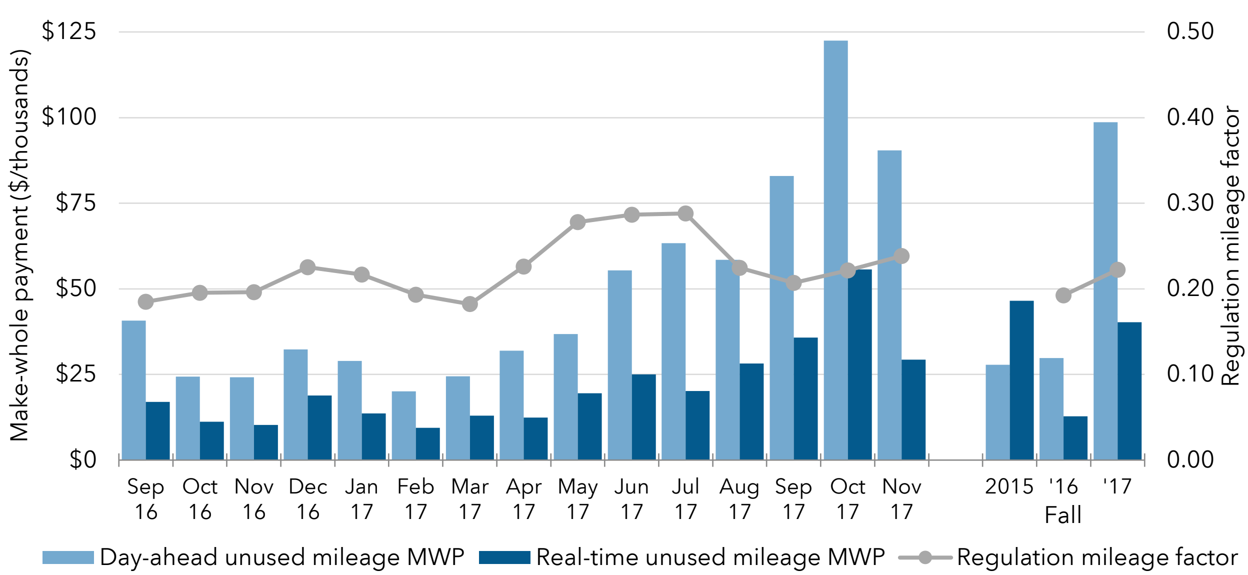


Figure 2–19 Regulation-down mileage make whole payments

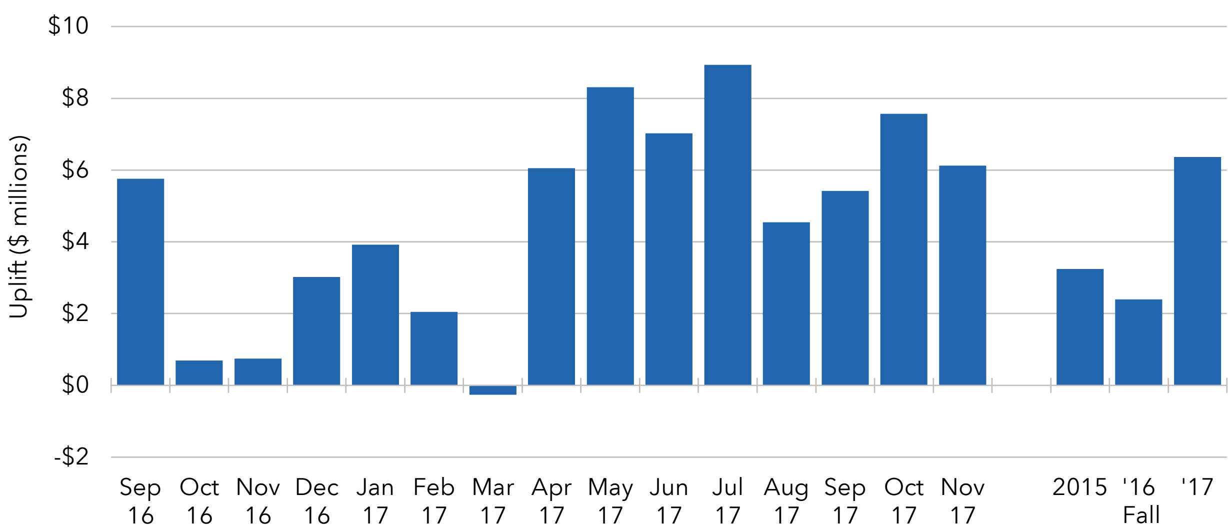


Revenue neutrality uplift (RNU), shown in Figure 2–20, ensures settlement payments/receipts for each hourly settlement interval equal zero. Positive revenue neutrality uplift indicates that SPP receives insufficient revenue and collects from market participants. Negative revenue-neutrality uplift indicates where SPP receives excess revenue, which must be credited back to market participants.

Revenue neutrality uplift is comprised by the following components:

- day-ahead revenue inadequacy
- real-time revenue inadequacy
- real-time out-of-merit energy (OOME) make-whole payment
- real-time regulation deployment adjustment
- real-time joint owned asset adjustment
- real-time inadvertent interchange adjustment
- real-time congestion adjustment

Figure 2–20 Revenue neutrality uplift



amounts shown are from the latest available settlement data and are subject to change due to resettlements

Market costs

SPP began the market-to-market (M2M) process with MISO in March 2015 as part of a FERC mandate to be implemented one year after go-live of the SPP Integrated Marketplace. The market-to-market process under the joint operating agreement allows the monitoring and non-monitoring RTOs[2] to efficiently manage market-to-market constraints by exchanging information (shadow prices, relief request, control indicators, etc.) and using the RTO with the more economic redispatch.

Review of the market-to-market process in the first year of operation resulted in discussions between SPP and MISO to address issues mainly involving constraint volatility or power swings. This resulted in a memorandum of understanding being developed to enhance market-to-market coordination. The memorandum was executed in June 2017 and included criteria to exclude some market-to-market flowgates that pass coordination tests, but are not significantly impacted by the non-monitoring RTO's market flows in real-time. This criteria initially resulted in the removal of over 50 of the approximately 230 market-to-market flowgates on August 1, 2017. These tests are now routinely performed, which can result in flowgates being added or removed from the market-to-market designation.

Other aspects of the memorandum of understanding were implemented late December 2017 pending FERC filings and software changes. One aspect to address volatility was the ability for the RTOs to switch monitoring and non-monitoring roles in the market-to-market process. This feature has not been utilized at this time but should allow for price convergence on constraints that see power swings resulting in price differences between the RTOs. This feature is typically utilized when the non-monitoring RTO has more effective dispatch relief capability on a constraint.

Each RTO is allocated property rights on market-to-market constraints known as firm flow entitlements (FFE), and each RTO calculates its real-time usage, known as market flow. Exchange of money (market-to-market settlements) for redispatch is based on the non-monitoring RTO's market flow in relation to its firm flow entitlement. The non-monitoring RTO will receive money from the monitoring RTO if its market flow is below its firm flow entitlement and will pay if above its firm flow entitlement. The total monthly market-to-market payments are shown in Figure 2—21, while the market-to-market payments by flowgate for the fall period are shown in Figure 2—22.

[2] The RTO which manages the most limiting element of the constraint is the monitoring RTO. In most cases, the monitoring RTO has most of the impact and resources that provided the most effective relief of a congested constraint.

The sharp increase in total market-to-market payments in October and November 2017 is almost exclusively due to the NEORIVNEOBLC (Neosho-Riverton for the loss of Neosho-Blackberry) flowgate. The flowgate was highly congested during these months, resulting in increased payments from MISO to SPP during this time.

Figure 2–21 Market-to-market, monthly

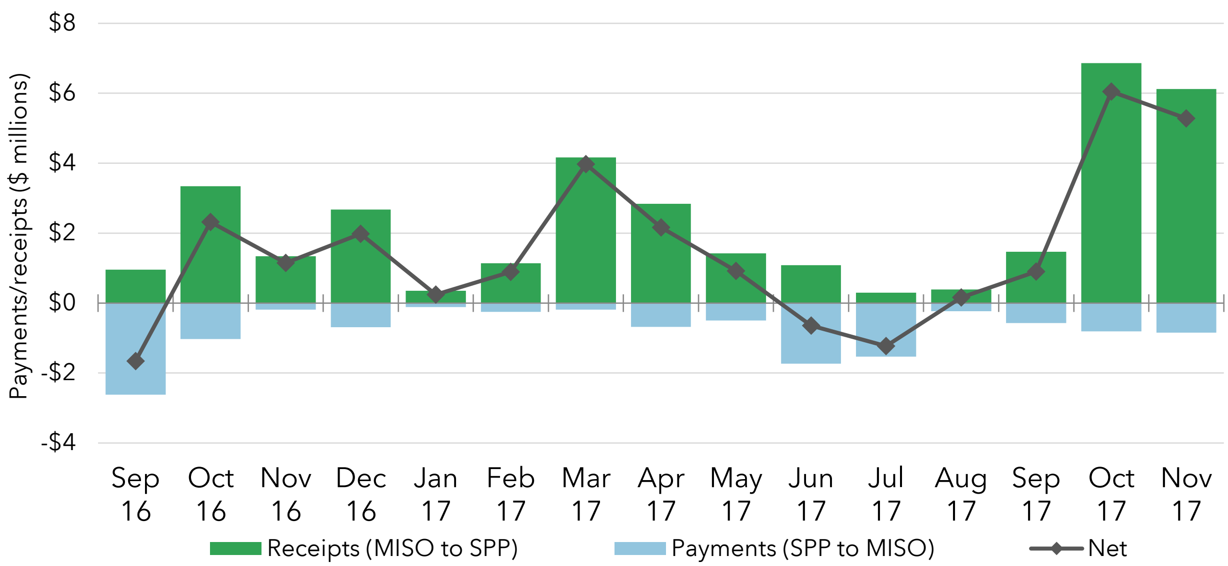
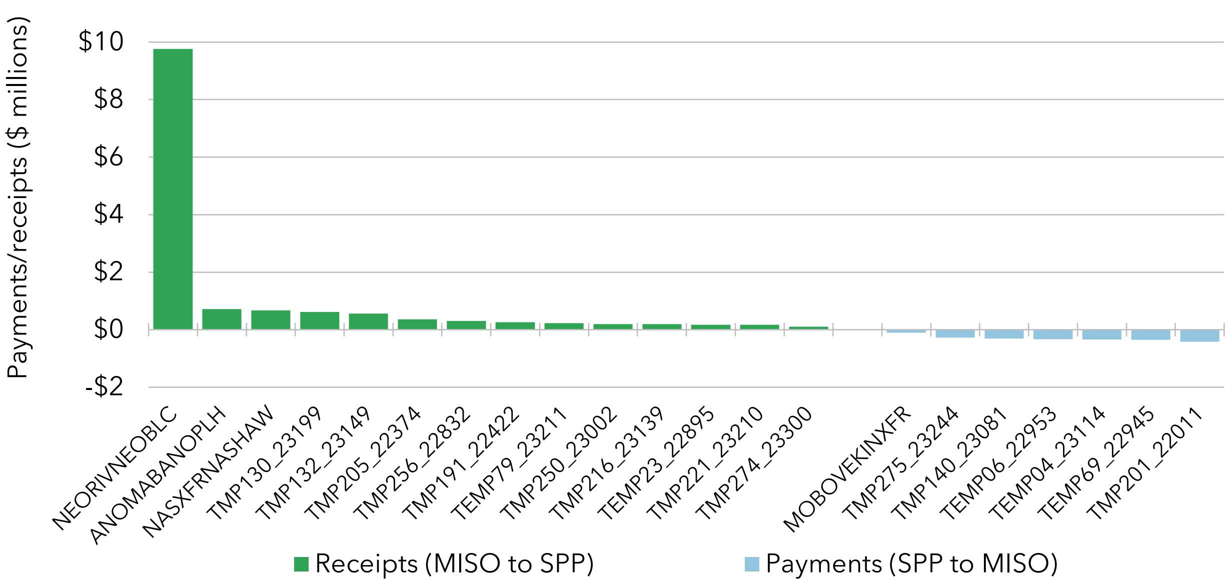


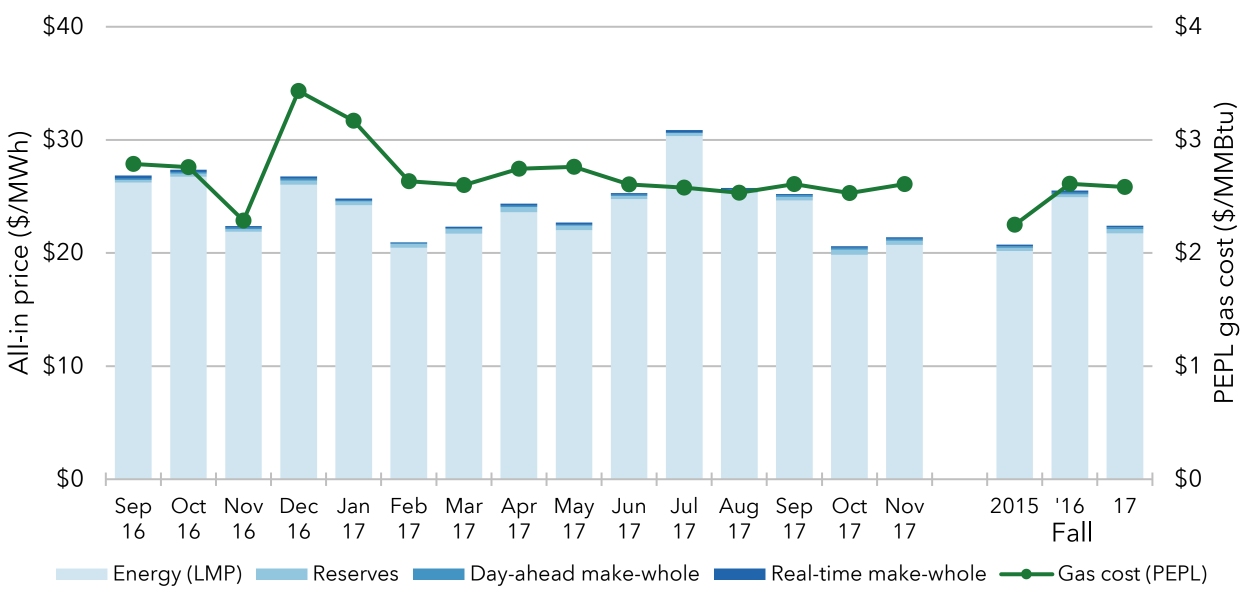
Figure 2–22 Market to market, by flowgate



The all-in cost, shown in Figure 2–23 includes the cost of energy, day-ahead and real-time reliability make-whole payments (uplift), operating reserves costs, reserve sharing group costs, and payment to demand response resources. The cost of energy includes all of the shortage pricing components.

Generally, the energy cost in the SPP market constitutes around 97.5 percent of the all-in price, showing that uplift makes up a very small portion of the total price incurred by market participants. All-in cost in fall 2017 was $22.40/MWh indicating a 12 percent decrease compared to the fall 2016 level of $25.53/MWh. As stated earlier in this report, gas cost decreased from an average of $2.61/MMBtu for fall 2016, to $2.58/MMBtu for fall 2017, a decrease of one percent. The operating reserve and day-ahead uplift components of all-in cost increased from fall 2016 to fall 2017, while the real-time uplift decreased from fall 2016 to fall 2017.

Figure 2–23 All-in cost



2017 ($/MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Price (LMP)	$ 24.21	$ 20.45	$ 21.71	$ 23.61	$ 22.02	$ 24.76	$ 30.33	$ 25.32	$24.65	$19.84	$20.72	
Operating reserves	0.36	0.34	0.38	0.43	0.38	0.29	0.26	0.21	0.32	0.44	0.35	
Uplift, day-ahead	0.07	0.09	0.1	0.14	0.09	0.10	0.06	0.08	0.15	0.18	0.18	
Uplift, real-time	0.17	0.07	0.14	0.19	0.20	0.16	0.21	0.13	0.10	0.13	0.15	
All-in price	**$ 24.81**	**$ 20.95**	**$ 22.33**	**$ 24.37**	**$ 22.69**	**$ 25.31**	**$ 30.86**	**$ 25.74**	**$25.22**	**$21.40**	**$21.40**	

2016 ($/MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Price (LMP)	$ 19.68	$ 15.79	$ 15.37	$ 17.98	$ 17.15	$ 24.04	$ 25.33	$ 27.07	$ 26.23	$ 26.73	$ 21.86	$ 26.03
Operating reserves	0.23	0.25	0.29	0.29	0.22	0.25	0.24	0.23	0.24	0.28	0.23	0.36
Uplift, day-ahead	0.13	0.10	0.15	0.09	0.10	0.05	0.07	0.06	0.10	0.14	0.14	0.17
Uplift, real-time	0.04	0.03	0.02	0.08	0.12	0.28	0.28	0.23	0.28	0.22	0.15	0.20
All-in price	**$ 20.08**	**$ 16.17**	**$ 15.83**	**$ 18.44**	**$ 17.59**	**$ 24.62**	**$ 25.92**	**$ 27.59**	**$ 26.85**	**$ 27.37**	**$ 22.38**	**$ 26.76**

Reserve sharing group costs and demand response costs would be included in the all-in price, however costs for both of those items are zero.

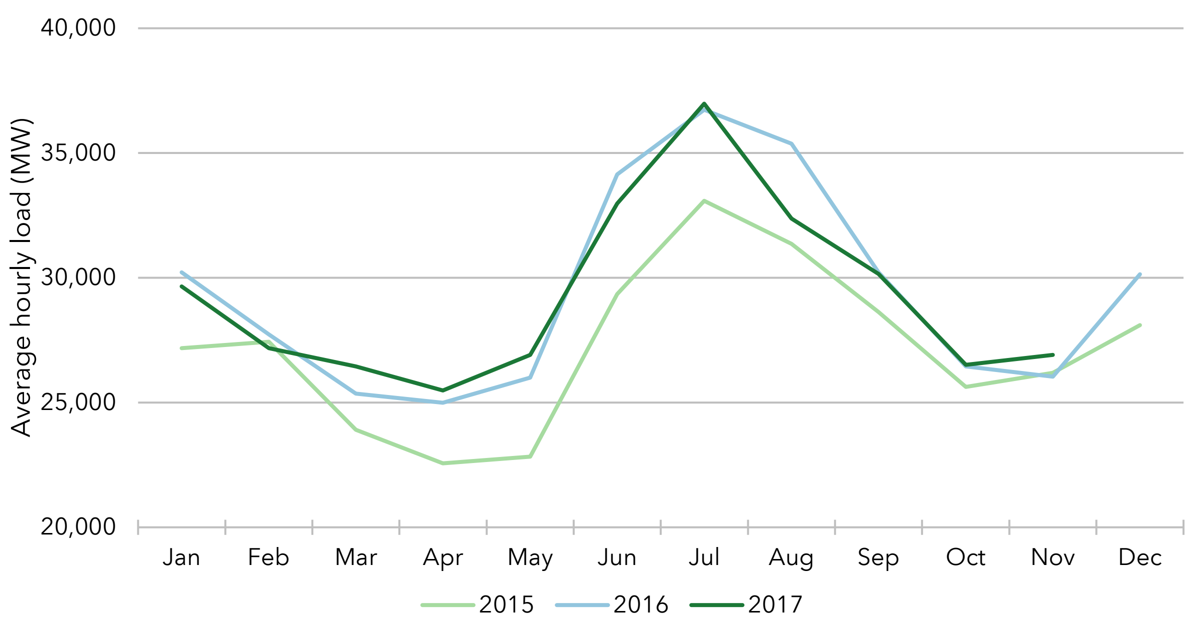
3. DEMAND, GENERATION AND UNIT COMMITMENT

Demand

The SPP market experiences peak loads in the summer, typically during the month of July or August. The average hourly load for each month is shown in Figure 3–1 below. The Integrated System became part of the SPP market in October 2015, which accounts for the upward shift of the load levels at that time.

Overall the hourly average load for fall 2017 was just under 28,000 megawatts, which was nearly identical to fall 2016. In all years load significantly drops from September to October and November.

Figure 3–1 Average hourly load



Cooling and heating degree days are used to estimate the impact of actual weather conditions on energy consumption. Although July 2017 saw a significant spike in cooling degree days above prior years, other months have been more consistent from year-to-year in both heating and cooling degree days, as shown in Figure 3–2 and Figure 3–3. The fall period indicates the shift from cooling season to heating season, as heating degree days are nearly zero during the summer months, and cooling degree days are nearly zero in the winter months.

Figure 3–2 Cooling degree days, SPP footprint

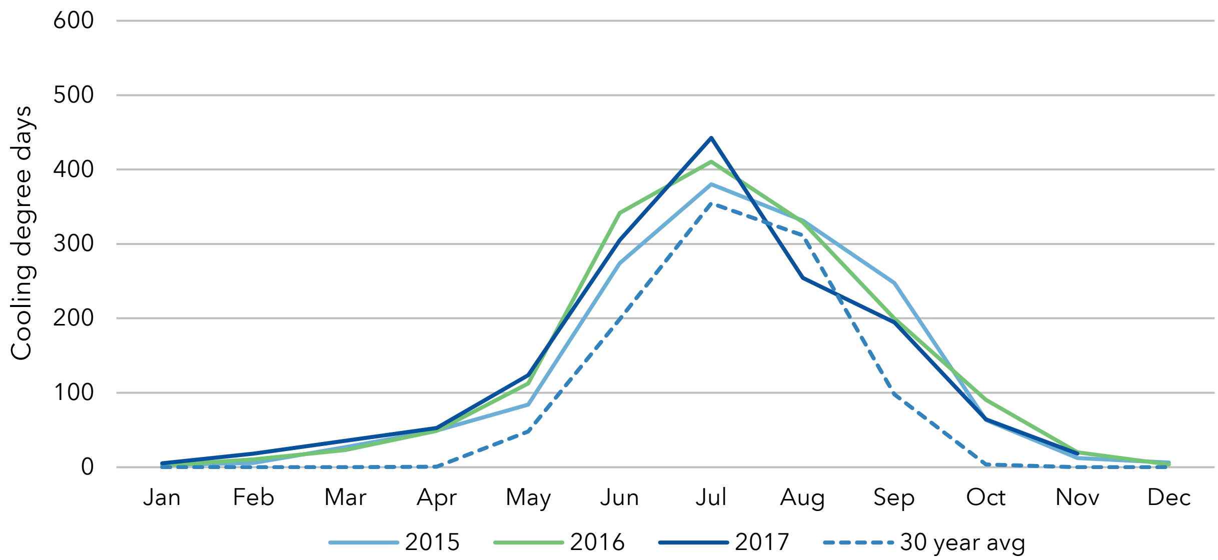


Figure 3–3 Heating degree days, SPP footprint

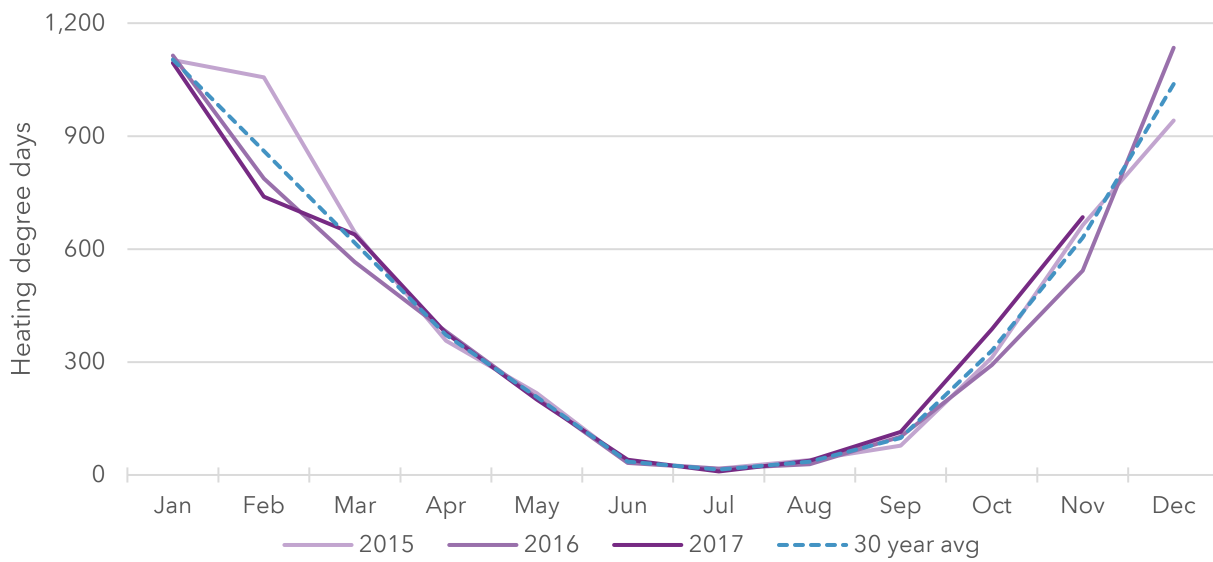
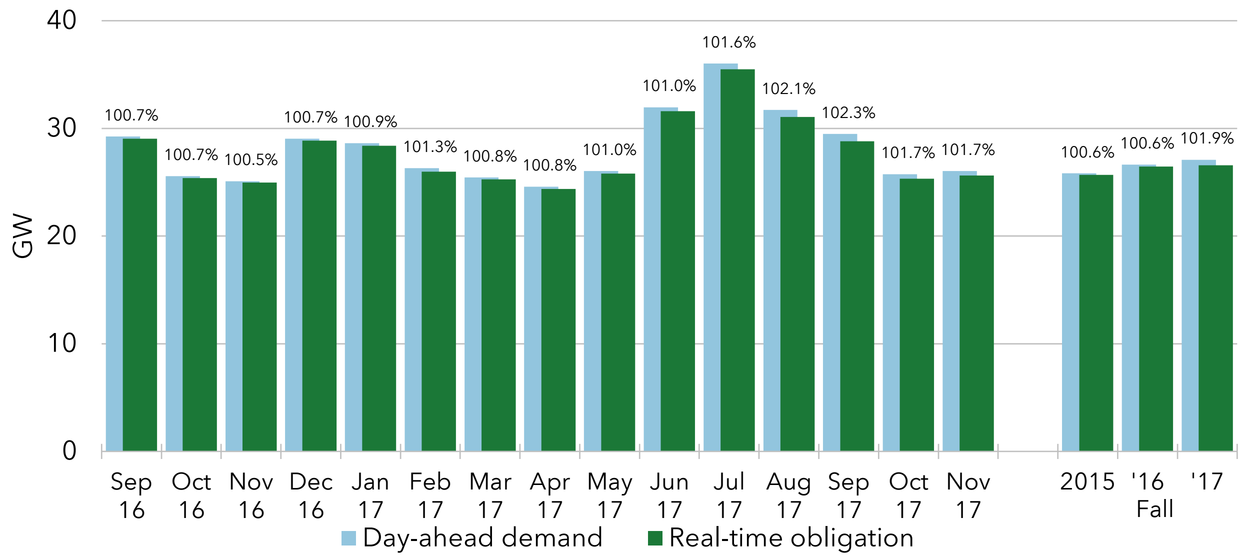


Figure 3–4 shows load scheduling for the peak hour. Under-scheduling load can cause SPP to commit more expensive peaking resources in real-time in order to satisfy load. Some real-time commitments may be made regardless of load scheduling due to the need to address reliability concerns, relieve local congestion, or meet ramp demands. Over-scheduling load can suppress real-time price signals by overstating load.

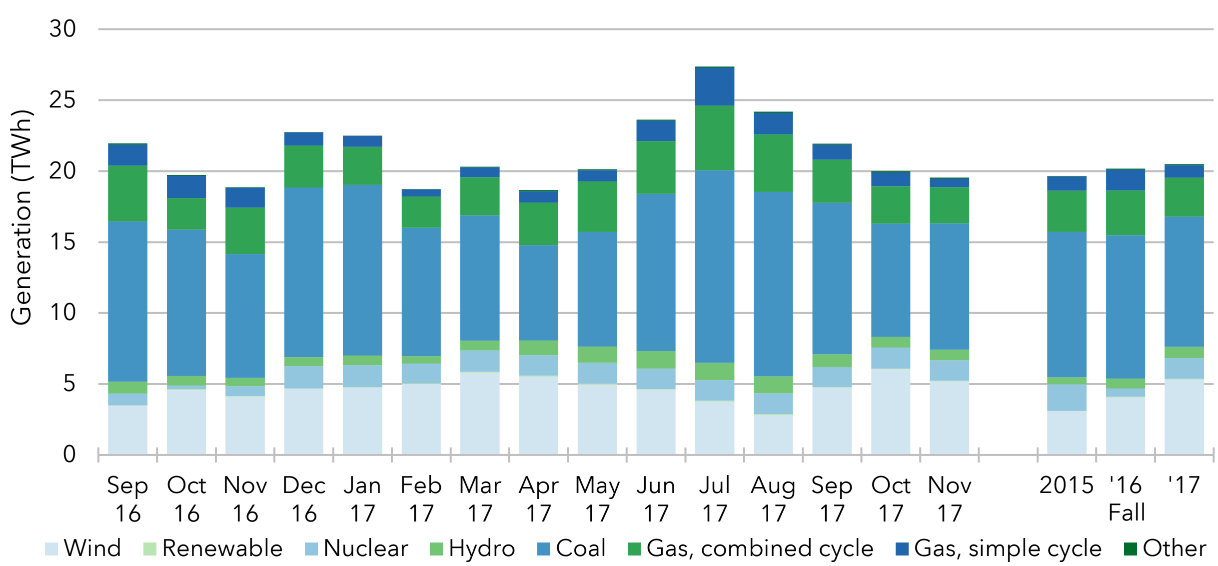
Figure 3–4 Day-ahead load scheduling



Generation

Total monthly generation, broken down by technology type of resources, is shown below in Figure 3–5. The 'renewable' category includes solar, biomass and other renewable resources (not including wind and hydro resources), while the 'other' category includes fuel oil and miscellaneous resources. Overall, average monthly generation during the fall period has increased very slightly each year from 2015 to 2017.

Figure 3–5 Generation by technology type, real-time



Although overall generation levels have increased just slightly from year-to-year in the fall period, as stated above, Figure 3–6 below shows that the type of resources generating in the market makes a significant shift during this period. The percentage of total generation by provided by coal resources has decreased from 52 percent in fall 2015, to 50 percent in fall 2016, and to 45 percent in fall 2017. This decline has been primarily offset by increases in wind generation, which is up from 16 percent in fall 2015, to 20 percent in fall 2017, and to 26 percent in fall 2017.

Figure 3–6 Generation by technology type, real-time by percent

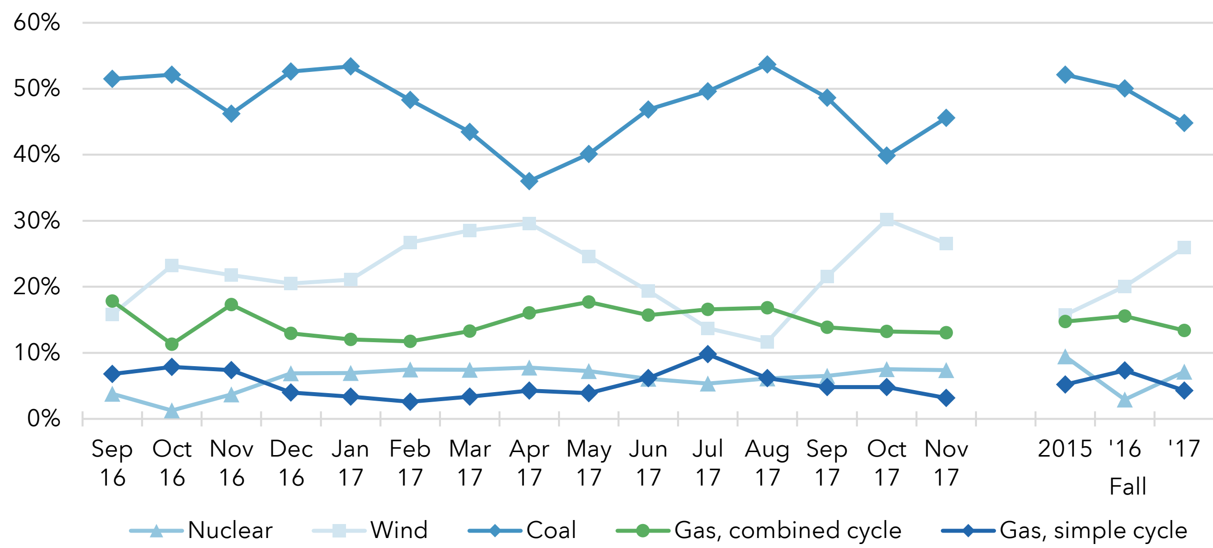


Figure 3–7 shows wind capacity (nameplate in megawatts) along with the wind capacity factor. Note that the wind capacity figure is reported as of month-end, while the capacity factor is reported for the entire month. Wind resources may be considered in-service, but not yet in commercial operation. In this situation, the capacity will be counted while the resource may not be providing any generation. Wind capacity in the footprint continues to steadily grow, with wind capacity increasing from 12,200 MW at the end of November 2015, to 15,700 MW in November 2016, and to 17,400 MW in November 2017.

The wind capacity factor in both the day-ahead and real-time markets remained consistent from fall 2015 to fall 2016, with around 30 percent in day-ahead and 36 percent in real-time. However, fall 2017 increased markedly in both markets, up from 30 percent to 33 percent in the day-ahead market, and up from 36 percent to 42 percent in the real-time market. The wind capacity for October 2017 in real-time was 46.7 percent, just below the highest wind capacity factors in the spring months.

Figure 3–7 Wind capacity and capacity factor

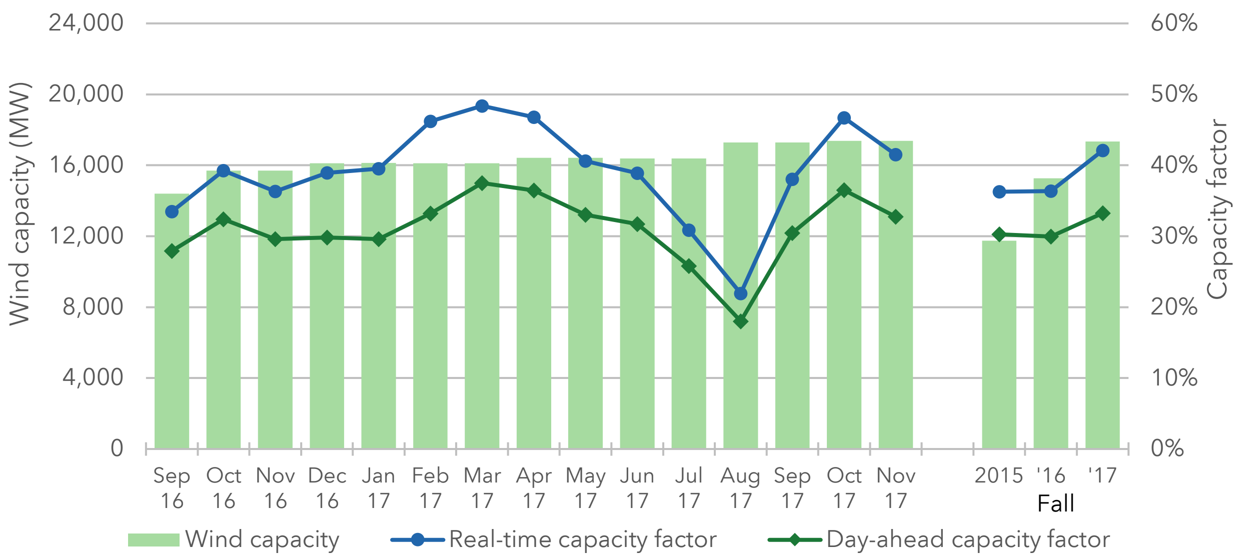


Figure 3–8 and Figure 3–9 show the technology types of marginal units in both the real-time and day-ahead markets. Marginal units set the locational marginal price in each hour in the day-ahead market and each five minute interval in the real-time market. One important distinction is that virtual transactions can be marginal in the day-ahead market, but are not included in the real-time market and, thus, cannot set price. During congested periods, the market is effectively segmented into several sub-areas, each with its own marginal resource(s). During non-congested periods, one resource sets the price for the entire market, thus that resource is marginal for the interval. When there is congestion, there can be more than one marginal unit during an interval within a particular sub-area.

In the real-time market coal resources were marginal in about 37 percent of all intervals in fall 2016 and fall 2017, compared to being marginal in nearly 52 percent of all intervals in fall 2015. This decline mirrors the decline in coal generation as a percent of all generation during this same period, which is shown in Figure 3–6 above. The decline was primarily offset with increases in gas combined-cycle (19 percent in fall 2015, 27 percent in fall 2016 and 2017) and wind resources (6 percent in fall 2015, 9 percent in 2016, 14 percent in 2017) on the margin.

Figure 3–8 Technology on the margin, day-ahead

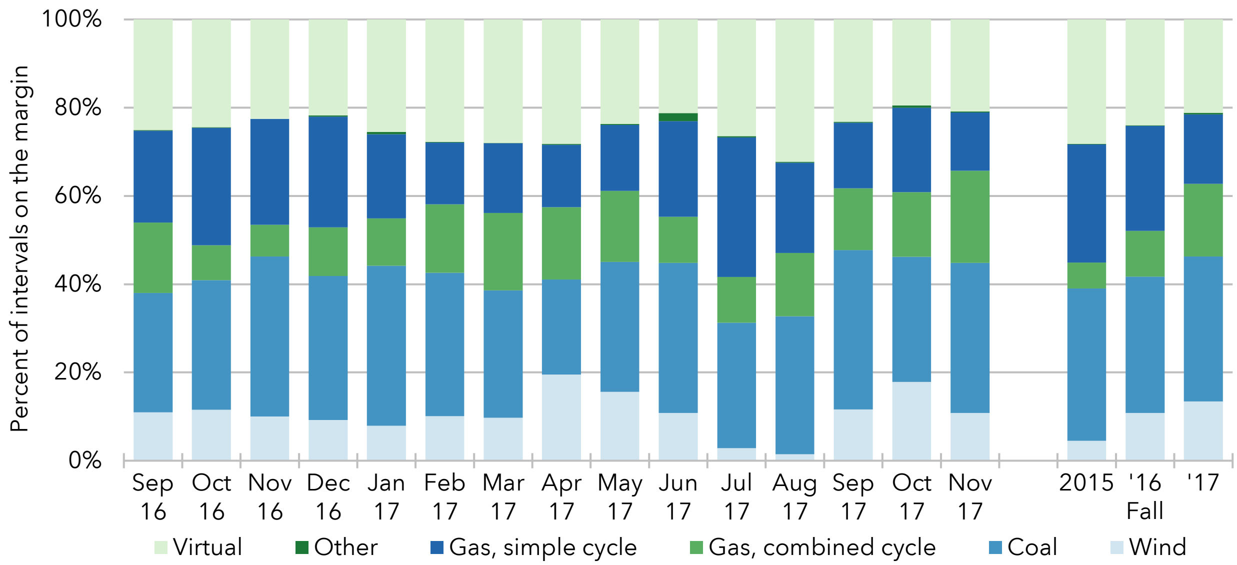
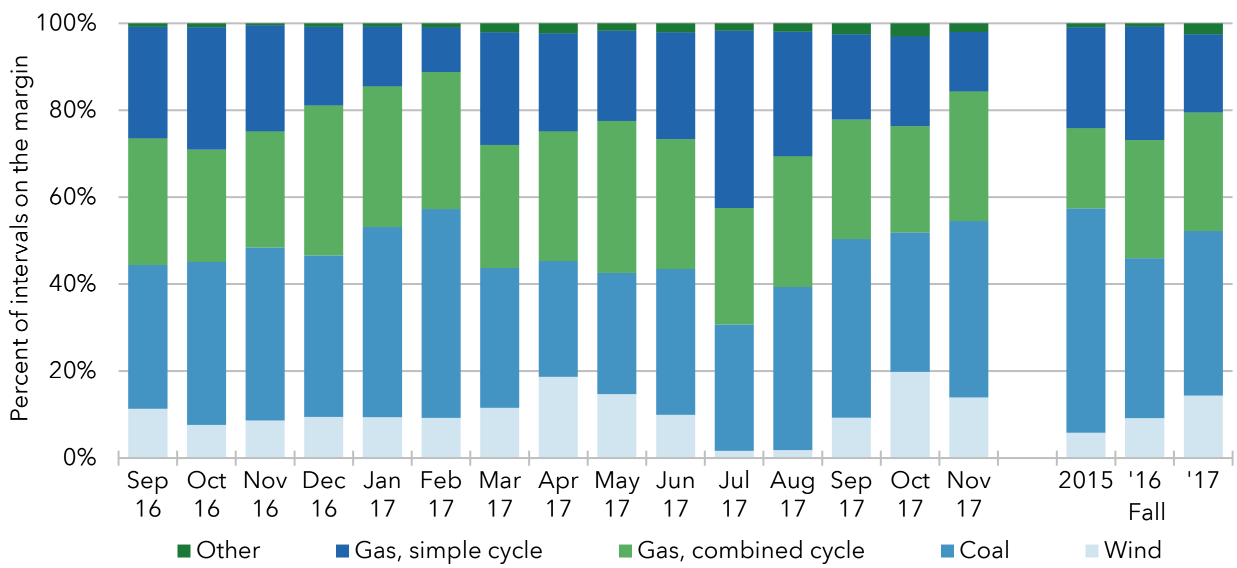


Figure 3–9 Technology on the margin, real-time



Ramp available to the system as standardized by available capacity, compared to the average on-line capacity is shown in Figure 3–10. Ramp rates play a key role in market operations because they place limits on how quickly a unit can respond to changes in load conditions and the need for redispatch to manage congestion.

Figure 3–10 Ramp rate offered

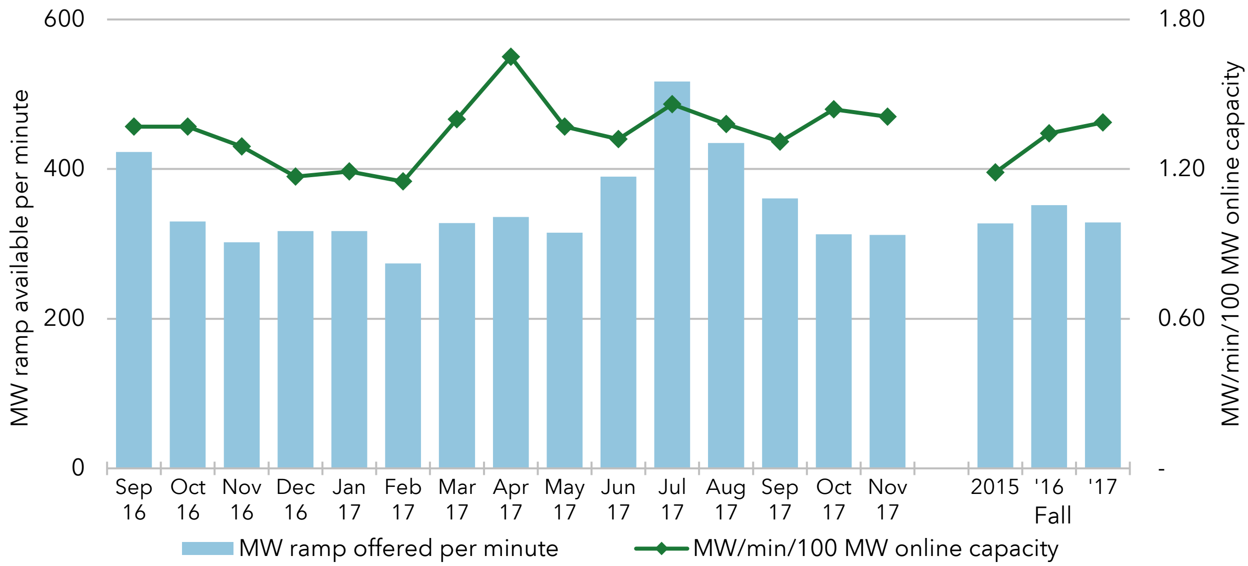
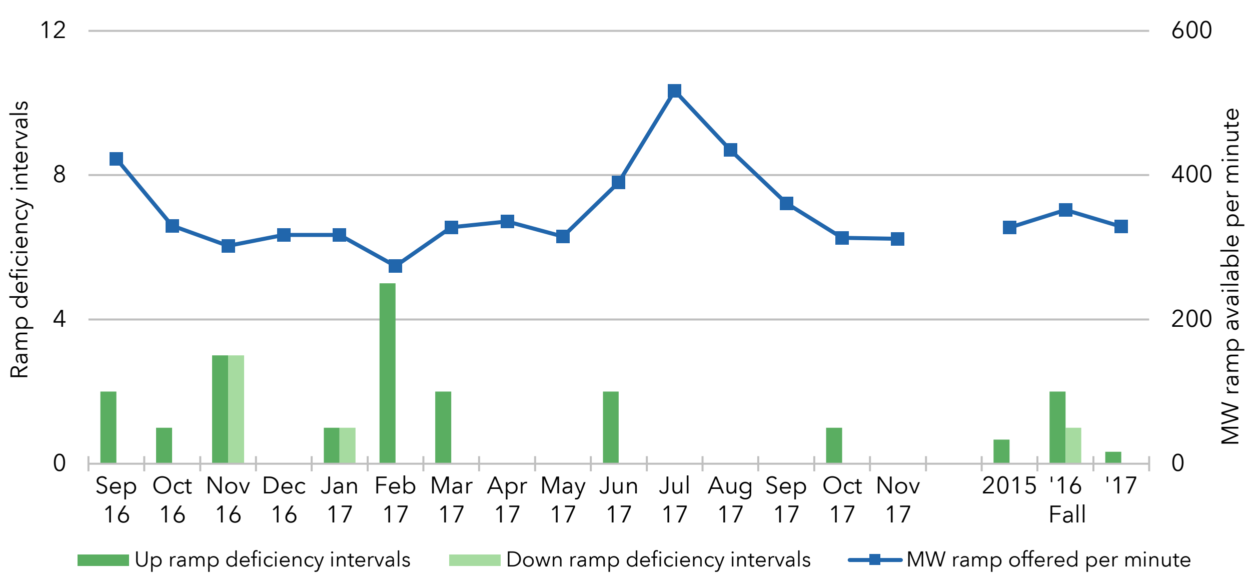


Figure 3–11 shows the monthly average available ramp per interval along with the number of intervals with a ramp deficiency each month. If ramp rates are too low, the market cannot respond quickly enough to manage system changes and ramp deficiencies will occur. Deficiencies result in price spikes, indicating a need for additional ramp. Offered ramp remains strong, with only one interval of up ramp deficiency in fall 2017, compared to six intervals of up ramp deficiency and one interval of down deficiency in fall 2016.

Figure 3–11 Ramp offered and deficiency intervals



Unit commitment

The real-time average hourly offered capacity for the peak hour, along with the real-time peak load obligation for that hour is shown in Figure 3–12. Capacity above the line indicates that there is generally sufficient available capacity to meet peak load obligations. Although levels fluctuate from month to month, coal and gas resources typically account for 75 to 85 percent of offered capacity during peak hours. With the continued growth in wind capacity, the percent of offered capacity during peak hours by wind resources has increased accordingly, from nine percent in fall 2015, to 12 percent in fall 2016, and 16 percent in fall 2017.

Figure 3–12 Hourly offered capacity, real-time average

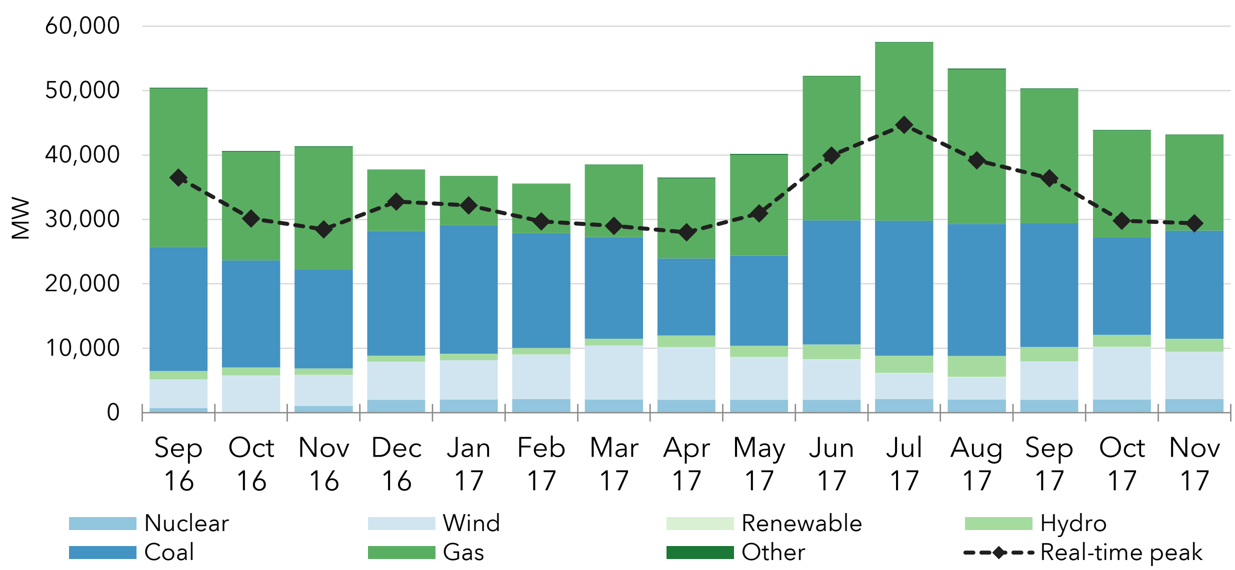
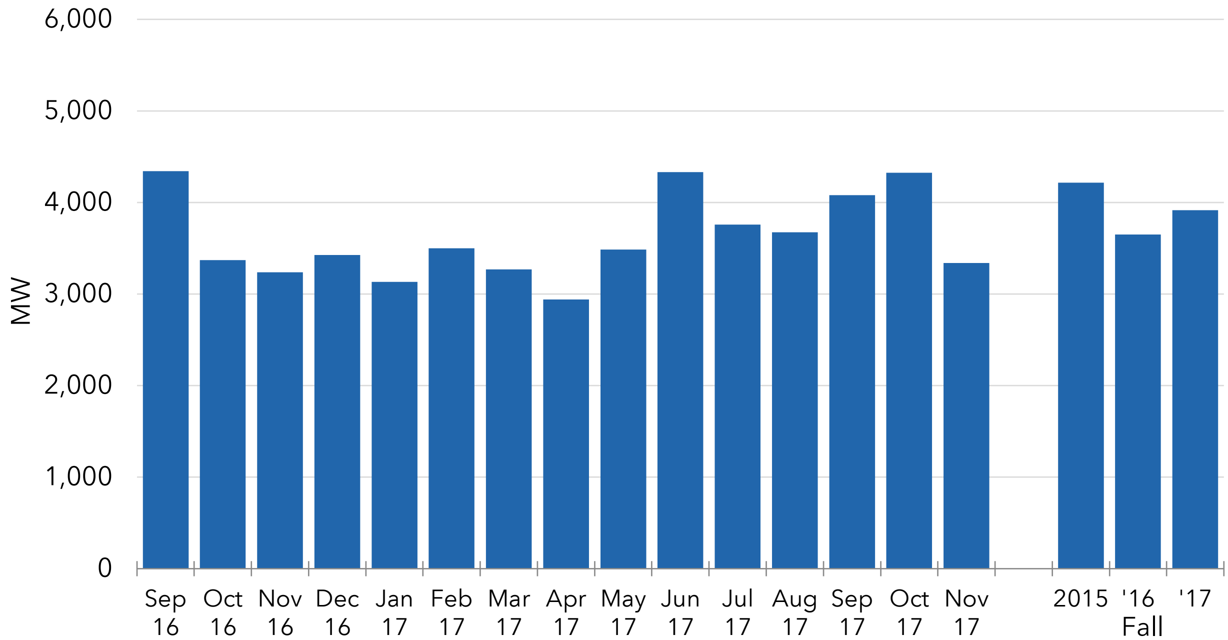


Figure 3–13 shows the real-time average peak hour capacity overage. SPP calculates the amount of capacity overage[3] required for the operating day to ensure that unit commitment is sufficient to reliably serve load in real-time while maintaining the operating reserve requirements. The average peak hour overage for fall 2017 was around 3,900 MW, compared to 4,200 MW in fall 2015, and 3,700 MW in fall 2016.

[3] The calculation for real-time average peak hour capacity overage is: economic maximum – load – net scheduled interchange – (regulation up + spinning reserves + supplemental reserves). Capacity from wind generation is not included in the economic maximum. Only capacity from traditional fuel resources is included in this calculation.

Figure 3–13 Peak hour capacity overage, real-time average



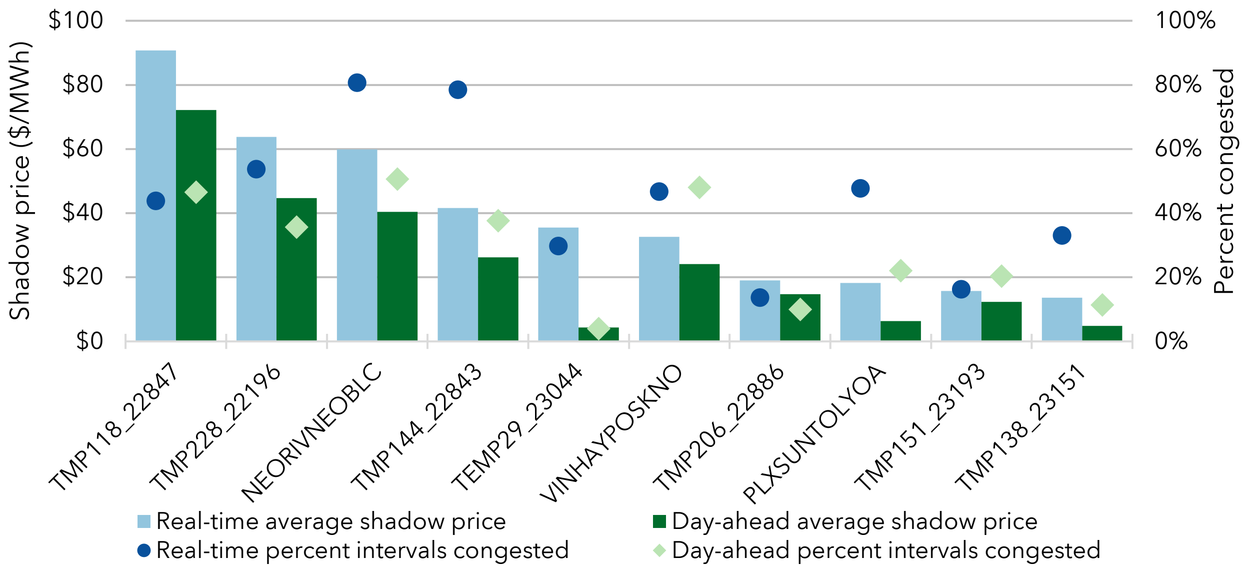
4. CONGESTION AND TRANSMISSION CONGESTION RIGHTS MARKET

Congestion

The impact of a constraint on the market can be illustrated by its shadow price, which reflects the magnitude of congestion on the path represented by the flowgate. The shadow price indicates the marginal value of an additional megawatt of relief on a congested constraint in reducing the total production costs. The shadow price is also a key determinant of the marginal congestion component (MCC) of the locational marginal price for each pricing point. Congestion by shadow price for the fall period is shown in Figure 4–1, while congestion by shadow price for the rolling 12-month period ending November 2017 is shown in Figure 4–2.

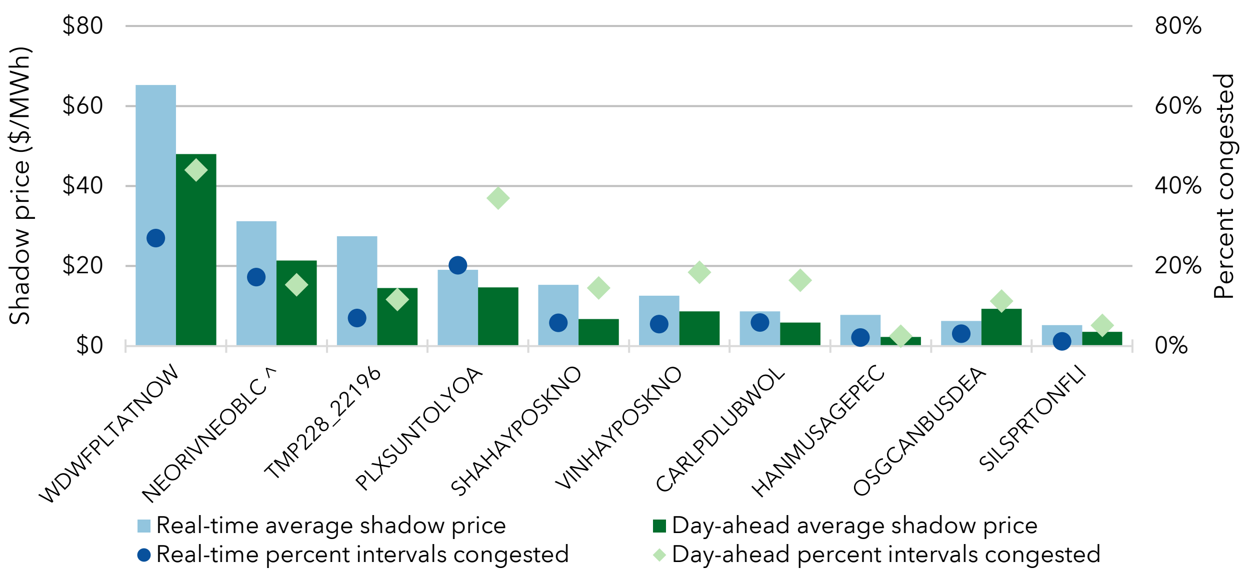
Areas of the footprint experience varying congestion, which is caused by many factors, including transmission bottlenecks, transmission and generation outages (planned or unplanned), weather events, and external impacts. The Woodward flowgate (WDWFPLTATNOW) does not appear in the top ten congested flowgates for the fall even though it still has the highest shadow price for the past 12 months. This decrease in congestion can primarily be attributed to the installation of an extra high voltage phase-shifting transformer at Woodward in late May, which increased the amount of transfer capability in the area.

Figure 4–1 Congestion by shadow price, fall



TMP118_22847 Southard-Roman Nose 138kV ftlo Tatonga-Matthewson 345kV (OGE)
TMP228_22196 Hale County-Tuco 115kV ftlo Swisher County-Tuco 230kV (SPS)
NEORIVNEOBLC ^ Neosho-Riverton 161kV (WR-EDE) ftlo Neosho-Blackberry 345kV (WR-AECI)
TMP144_22843 Woodring Xfmr 345/138kV ftlo Woodring-Sooner 345kV (OGE)
TEMP29_23044 Tupelo Tap-Tupelo 138kV ftlo Pittsburg-Valliantt 345kV (CSWS)
VINHAYPOSKNO Vine Tap-North Hays 115kV ftlo Post Rock-Knoll 230kV (MIDW)
TMP206_22886 Kress-Hale County 115kV ftlo Swisher County-Tuco 230kV (SPS)
PLXSUNTOLYOA Plant X Sub-Sundown 230kV ftlo Tolk Sub-Yoakum 230kV (SPS)
TMP151_23193 Oakland East Switch-Atlas Junction 161kV ftlo Asbury Plant-Purcell Southwest 161kV (EDE)
TMP138_23151 Wichita Xfmr 345/138kV ftlo Wichita-Benton 345kV (WR)
^ SPP market-to-market flowgate

Figure 4–2 Congestion by shadow price, rolling 12 month

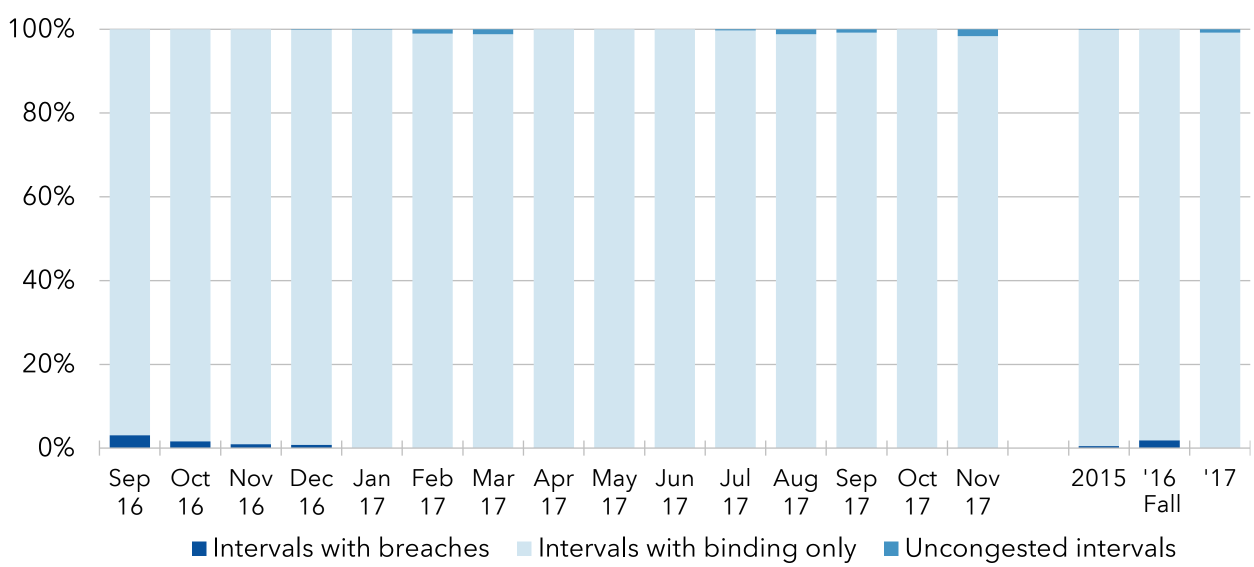


WDWFPLTATNOW Woodward-FPL Switch 138kV ftlo Woodward EHV-Northwest 345kV (OGE)
NEORIVNEOBLC ^ Neosho-Riverton 161kV (WR-EDE) ftlo Neosho-Blackberry 345kV (WR-AECI)
TMP228_22196 Hale County-Tuco 115kV ftlo Swisher County-Tuco 230kV (SPS)
PLXSUNTOLYOA Plant X Sub-Sundown 230kV ftlo Tolk Sub-Yoakum 230kV (SPS)
SHAHAYPOSKNO South Hays-Hays 115kV ftlo Post Rock-Knoll 230kV (MIDW)
VINHAYPOSKNO Vine Tap-North Hays 115kV ftlo Post Rock-Knoll 230kV (MIDW)
CARLPDLUBWOL Carlisle-LP Doud 115kV ftlo Lubbock South-Wolfforth 230kV (SPS)
HANMUSAGEPEC Hanncock-Muskogee 161kV ftlo Agency-Pecan Creek 161kV (OGE)
OSGCANBUSDEA Osage Switch-Canyon East 115kV ftlo Bushland-Deaf Smith 230kV (SPS)
SILSPRTONFLI Siloam-Siloam Springs 161kV ftlo Tonnece-Flint Creek 345kV (CSWS-GRDA)
^ SPP market-to-market flowgate

One way to analyze transmission congestion is to study the total incidence of intervals in which a flowgate was either breached or binding. A breached condition is one in which the load on the flowgate exceeds the effective limit. A binding flowgate is one in which flow over the element has reached but not exceeded its effective limit.

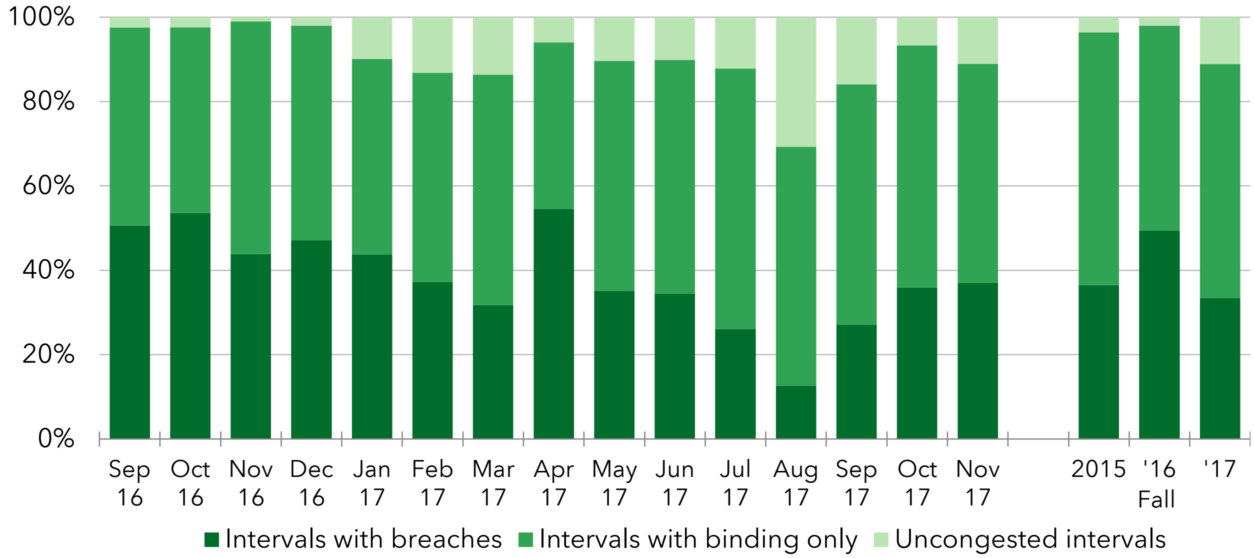
The figures below show the percent of intervals by month that had at least one breach, had only binding flowgates (but no breaches), or had no flowgates that were breached or binding (uncongested) in both the day-ahead (Figure 4–3) and real-time (Figure 4–4) markets. The frequency of breached intervals in the day-ahead market remains low.

Figure 4–3 Congestion by interval, day-ahead



In the real-time market, just under 31 percent of all intervals in August 2017 had no congestion. This is the highest percentage of uncongested intervals in any month since the start of the Integrated Marketplace in 2014. Overall, real-time market congestion decreased during fall 2017 with 11 percent of intervals having no congestion, compared to two percent in fall 2016 and four percent in fall 2015.

Figure 4–4 Congestion by interval, real-time



Transmission congestion rights market

In the Integrated Marketplace, the market generally charges load a higher price than it pays generation. Transmission services serve as the underpinning of the transmission congestion rights market, which provides day-ahead market payments to hedge the cost of congestion. Annual and monthly transmission congestion right auctions award the "rights" to shares of day-ahead market congestion revenue. SPP allocates auction revenue rights in annual and monthly processes based on transmission ownership, and auction revenue right holders receive payments from the transmission congestion rights auction and conversions of auction revenue rights into transmission congestion rights.

Funding is derived as follows:

1. Day-ahead revenue is collected daily
2. Transmission congestion right holders are paid daily based on awarded transmission congestion right megawatts and day-ahead congestion rents (i.e., the difference between the marginal congestion components of the sink and source settlement locations of the LMP)

    a. Uplift is charged daily
    b. Surpluses are redistributed monthly and annually
3. Transmission congestion right revenue is collected daily based on transmission congestion right megawatts and transmission congestion right auction clearing prices (consistent through month/season)
4. Auction revenue right holders are paid daily based on auction revenue right megawatts and transmission congestion right auction clearing prices (consistent through month/season)
    a. Uplift is charged daily
    b. Surpluses are redistributed monthly and annually

Revision Request 91, which changed the annual allocation percentage for auction revenue rights, was implemented in July 2016. The purpose of this was to reduce the over-allocation of auction revenue rights in outlying seasons of the annual auction revenue right allocation, and to align the percentages of transmission capacity with that of the annual transmission congestion right auction.

Figure 4–5 below shows 90 percent average net transmission congestion right funding during fall 2017 compared to 95 percent in fall 2016 and 92 percent in fall 2015. This increase can primarily be attributed to an increase in the purchase of transmission congestion rights.

Figure 4–5 Transmission congestion right funding

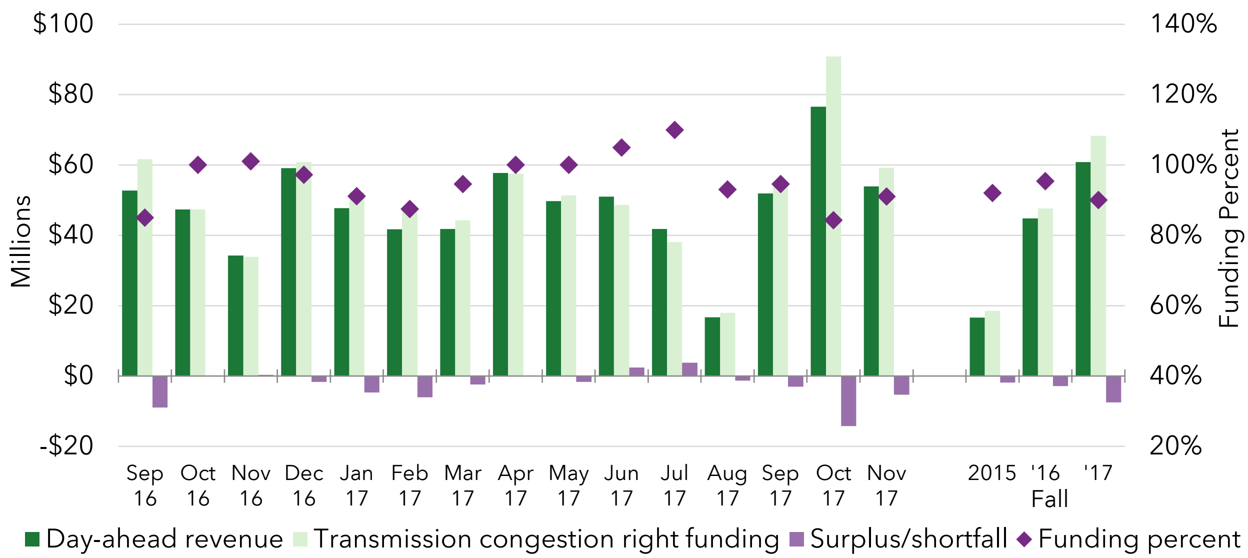
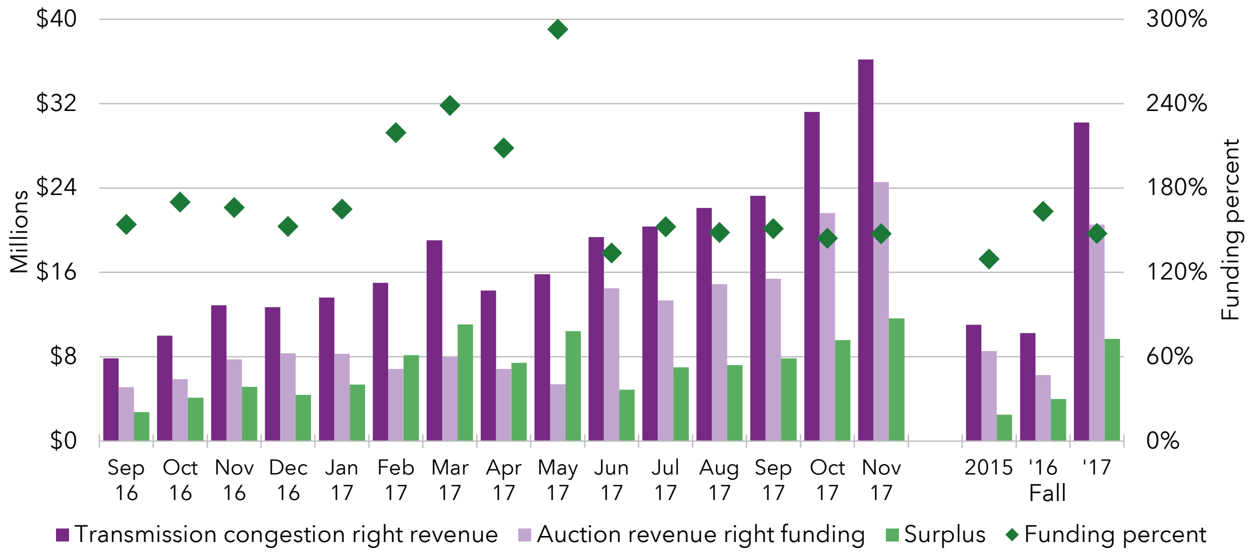


Figure 4–6 indicates that during fall 2017 auction revenue right funding was at 148 percent compared to the fall 2016 level of 163 percent. Meanwhile the fall 2017 auction revenue right funding surplus and transmission congestion right revenue were both over triple the fall 2016 figure. Auction revenue rights funding surplus (and funding percent) have remained at high levels primarily because market participants have been consistently valuing transmission congestion rights at high levels in anticipation of higher congestion. Higher transmission congestion auction revenues in excess of the payment level are required to fund auction revenue rights payments which yield a funding surplus.

Figure 4–6 Auction revenue right funding



5. VIRTUAL TRANSACTIONS

Virtual trading in the day-ahead market aims to facilitate convergence between the day-ahead and real-time prices, while helping to improve the efficiency of the day-ahead market and moderate market power. Virtual transactions scheduled in the day-ahead market are settled in the real-time market.

Virtual demand bids are profitable when the real-time energy price is higher than the day-ahead price. Virtual supply offers are profitable when the day-ahead energy price is higher than the real-time price.

The following figures show cleared and uncleared virtual demand bids (Figure 5–1) and supply offers (Figure 5–2). As these figures, and other figures in this section show, virtual transactions have steadily increased from year to year, with the vast majority of the increase attributed to financial only market participants.

Figure 5–1 Virtual demand bids

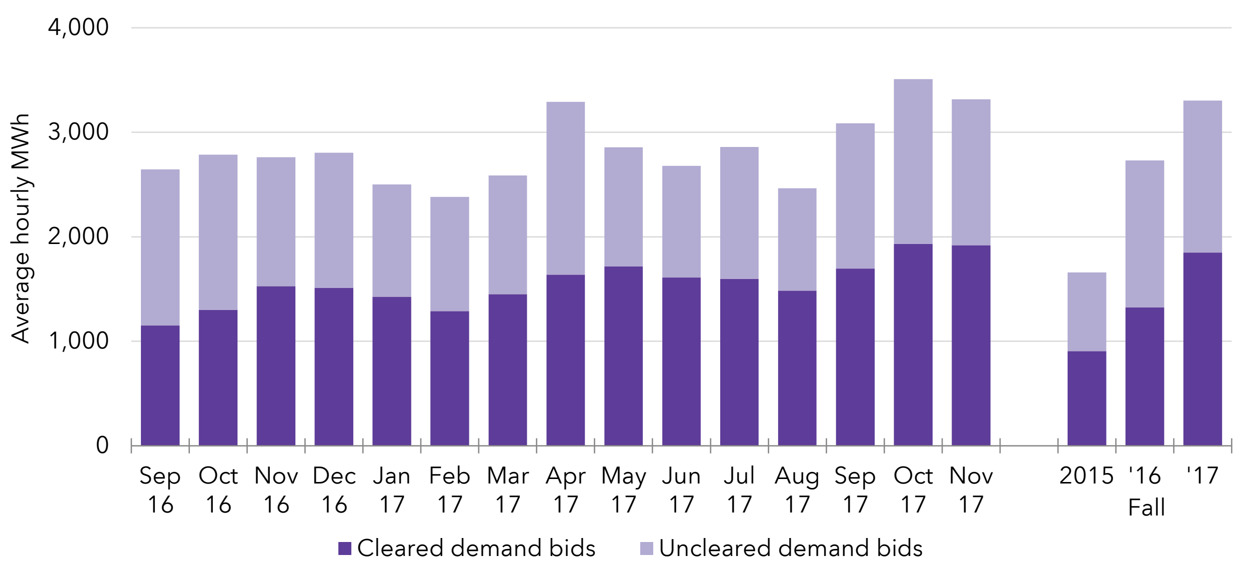
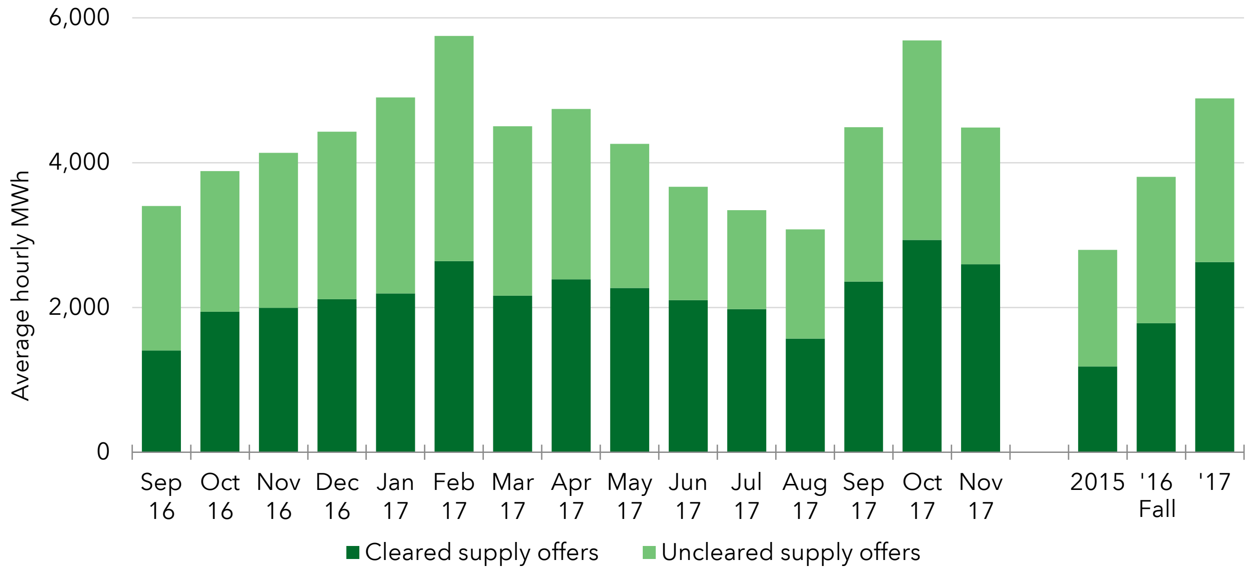
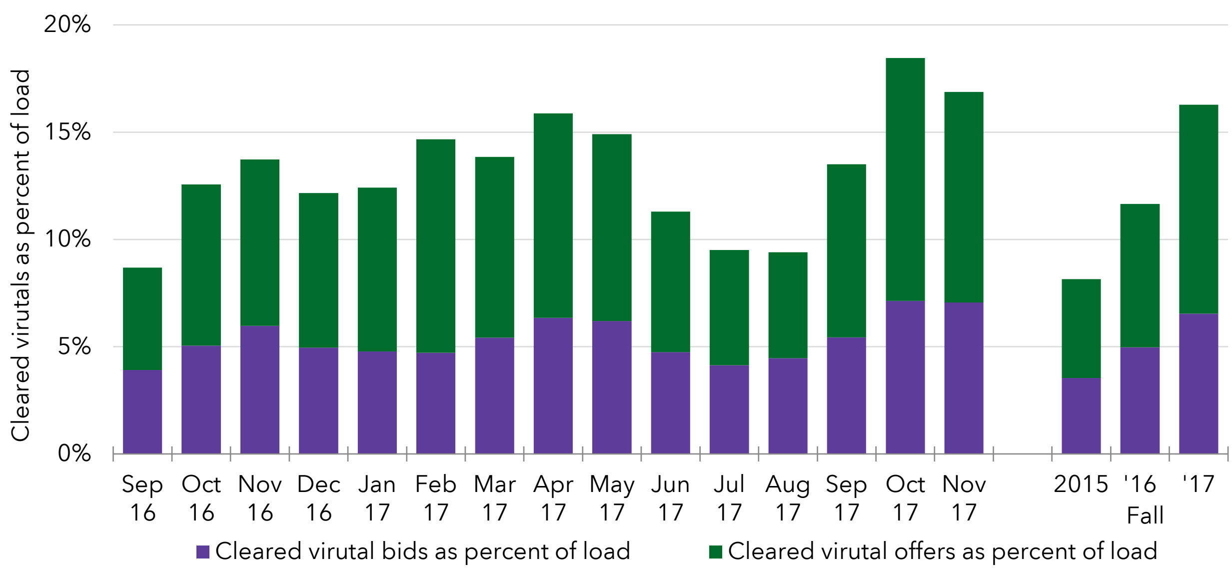


Figure 5–2 Virtual supply offers



For the fall period, virtual transactions as a percent of load has increased from eight percent in 2015, to 12 percent in 2016, and to 16 percent in 2017, as shown in Figure 5–3.

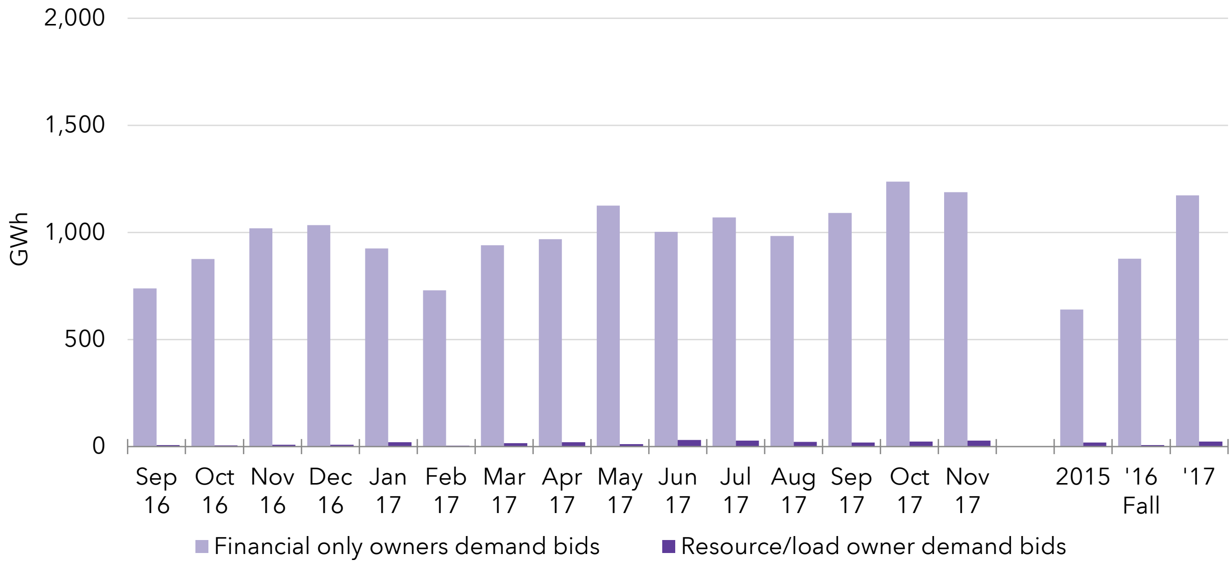
Figure 5–3 Cleared virtual transactions as a percent of load



Generally, market participants with physical assets (resources and/or load) place virtual transactions in order to hedge physical obligations. In contrast, financial-only market participants generally place virtual transactions to arbitrage prices.

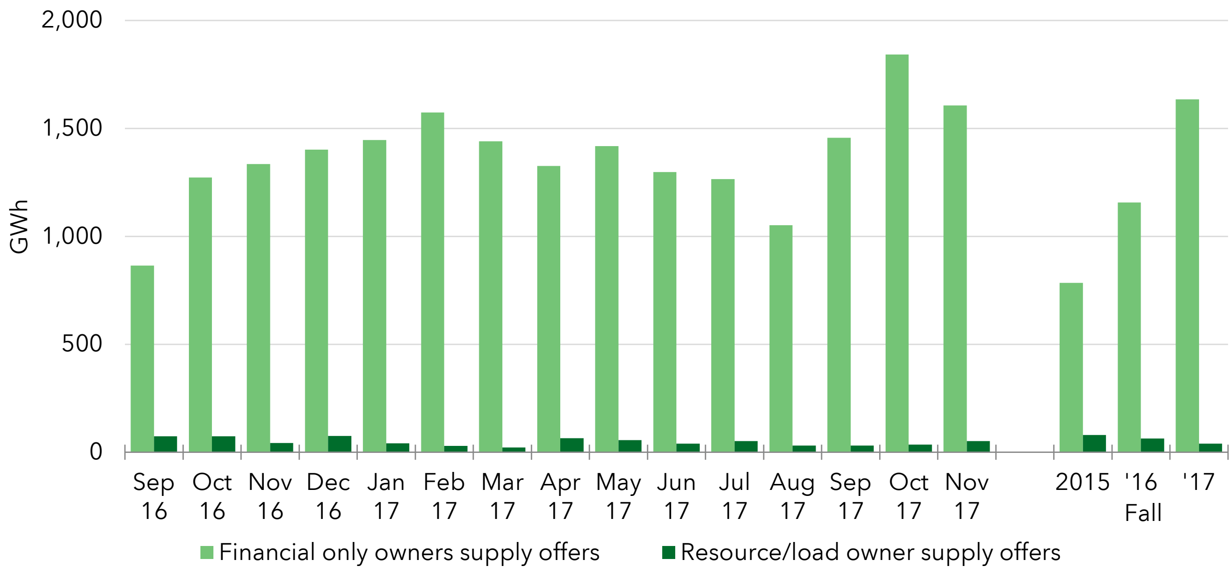
While the number of virtual demand bids by resource/load owners has remained negligible, demand bids by financial-only participants have nearly doubled from fall 2015 to 2017. As shown in Figure 5–4 and Figure 5–5, the vast majority of virtual transactions are placed by financial-only market participants.

Figure 5–4 Virtual demand bids by participant type



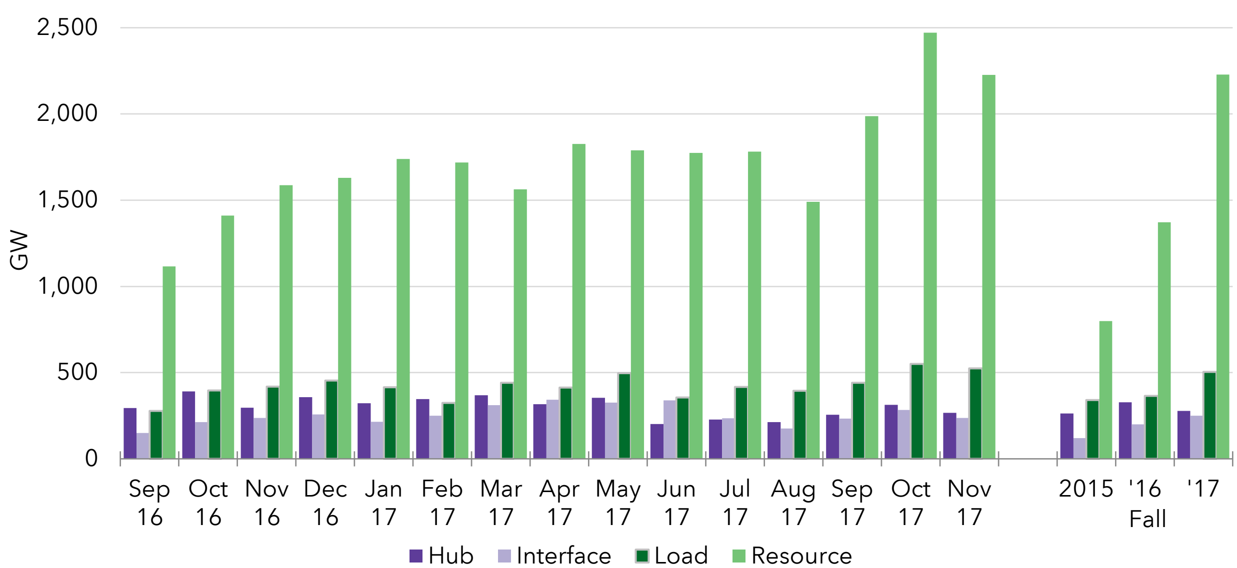
Virtual supply offers by resource/load owners have been on a general downward trend from fall 2015 to fall 2017. However, those amounts have remained negligible while financial-only participants have doubled their virtual supply offers during that same period.

Figure 5‒5 Virtual supply offers by participant type



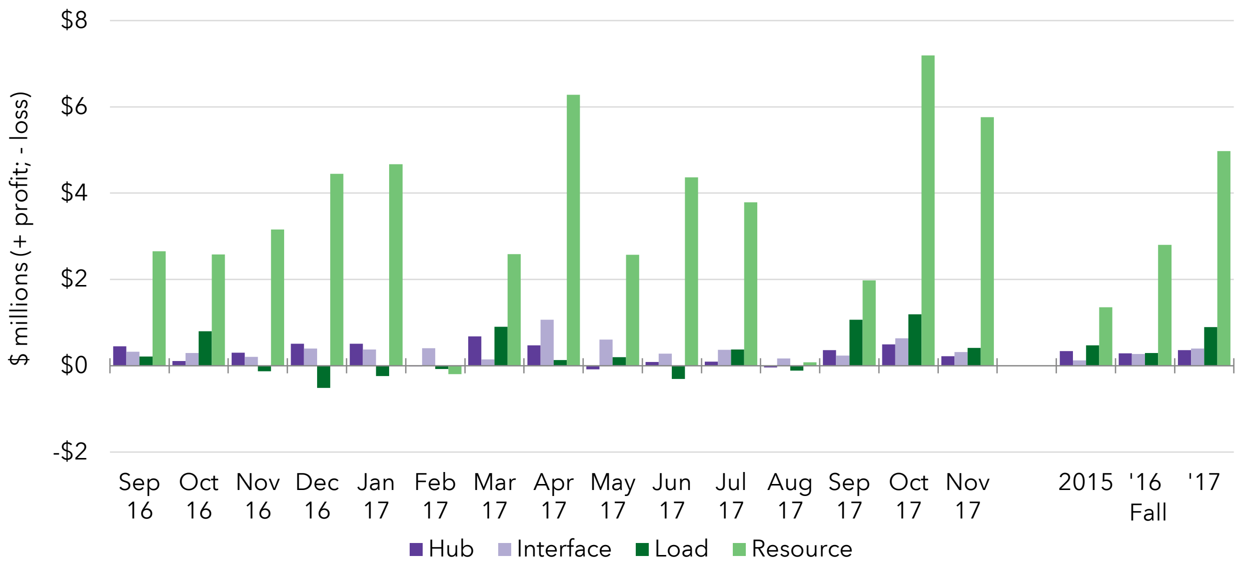
Shown in Figure 5‒6, the great majority of virtual transactions are made at resources (primarily wind resources), and are steadily increasing from year-to-year, with the fewest transactions at hubs and external interfaces.

Figure 5‒6 Virtual transactions by location type, megawatts



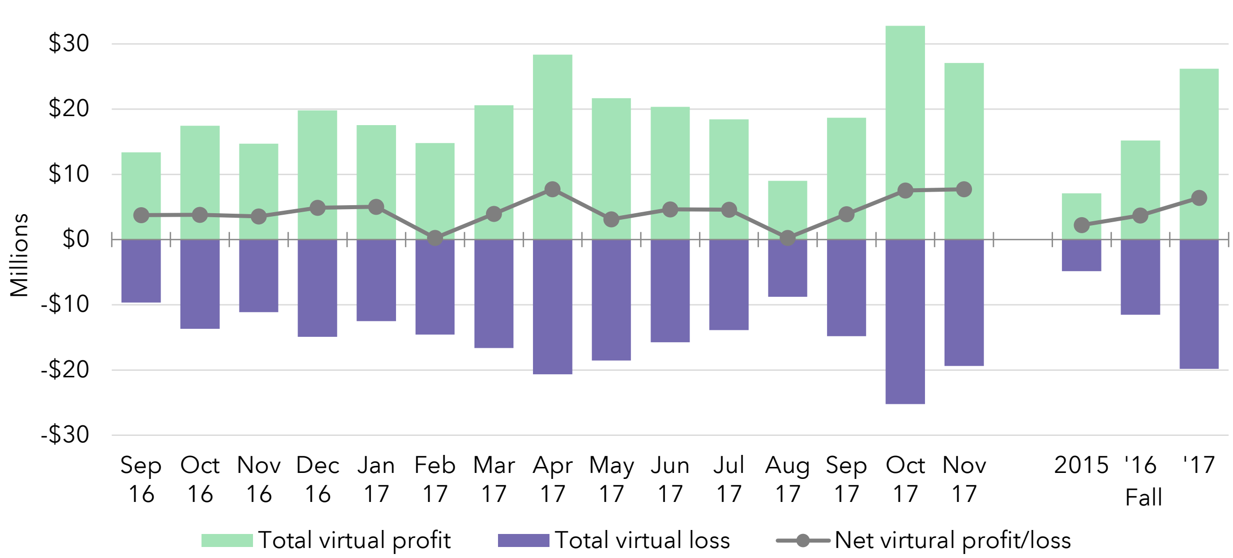
As with the volume of virtual transactions, the majority of the profits (shown in Figure 5‒7) from virtual transactions are derived from resource locations, and are steadily increasing.

Figure 5–7 Virtual transactions by location type, profit/loss



Gross virtual profits for fall 2017, as shown in Figure 5–8, totaled just over $26 million, while gross virtual losses totaled nearly $20 million, for a net profit of $6 million. In comparison, fall 2016 had gross profits of just over $15 million and gross losses of just over $11 million, for a net profit close to $4 million.

Figure 5–8 Virtual transactions, profit/loss

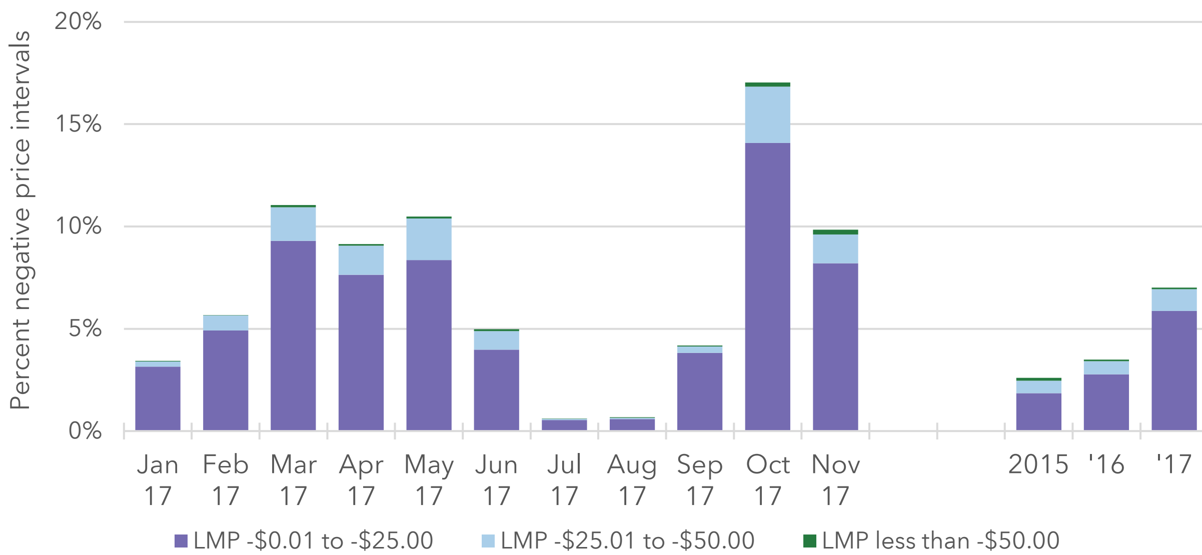


6. SPECIAL ISSUES

Negative prices

With the prolific growth of wind generation in the SPP market, the number of intervals with negative prices continues to increase. In October 2017, 17 percent of all market participant intervals[4] in the real-time market had prices below zero, as shown in Figure 6–1 below. On a year-to-year basis, the total percentage of negative price intervals in the real-time market has increased from 2.6 percent in 2015, to 3.5 percent in 2016, and to 7.0 percent in 2017 (through November).

Figure 6–1 Negative price intervals, real-time, monthly

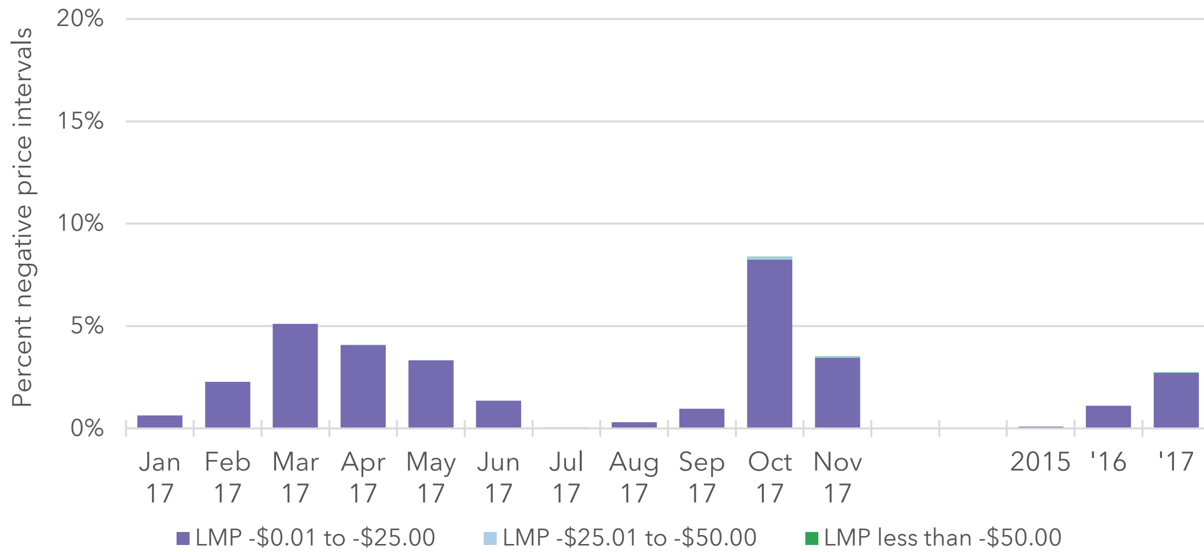


While the same pattern holds in the day-ahead market (see Figure 6–2), the magnitude of negative price intervals in the day-ahead market is around half of the real-time market. Note that negative prices in the day-ahead market are almost exclusively between -$0.01/MWh

[4] Market participant intervals are calculated as the number of market participants serving load that are active in an interval. For example, if there 60 market participants active in one five minute interval throughout an entire 30 day month, the total market participant intervals would be 518,400 for the month (60 market participants * 288 intervals per day * 30 days).

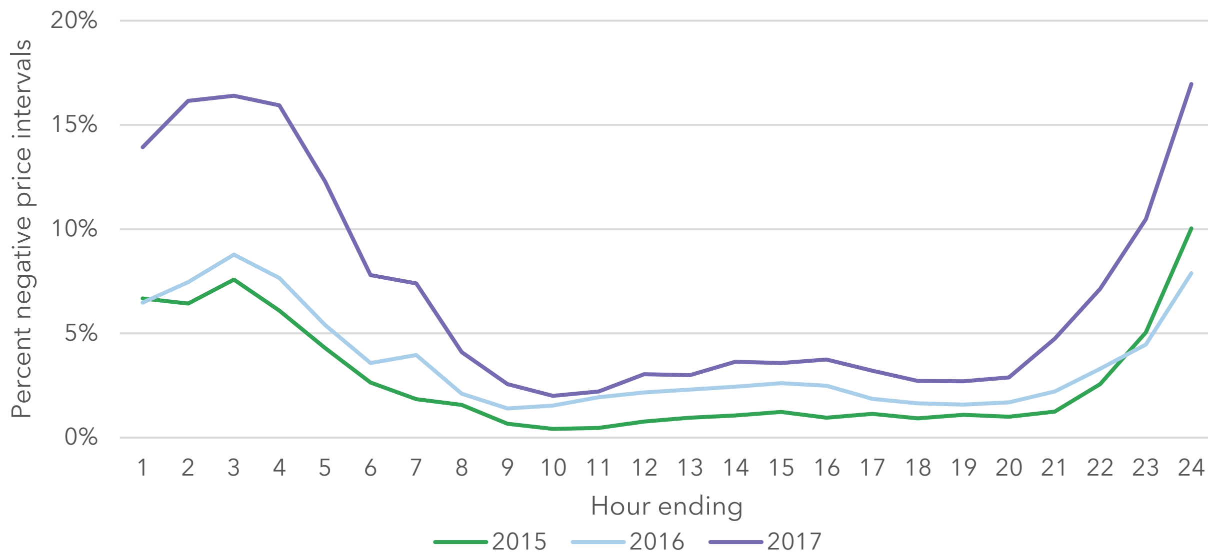
and -$25/MWh, where in the real-time market a sizable number of intervals have prices lower than -$25/MWh.

Figure 6–2 Negative price intervals, day-ahead, monthly



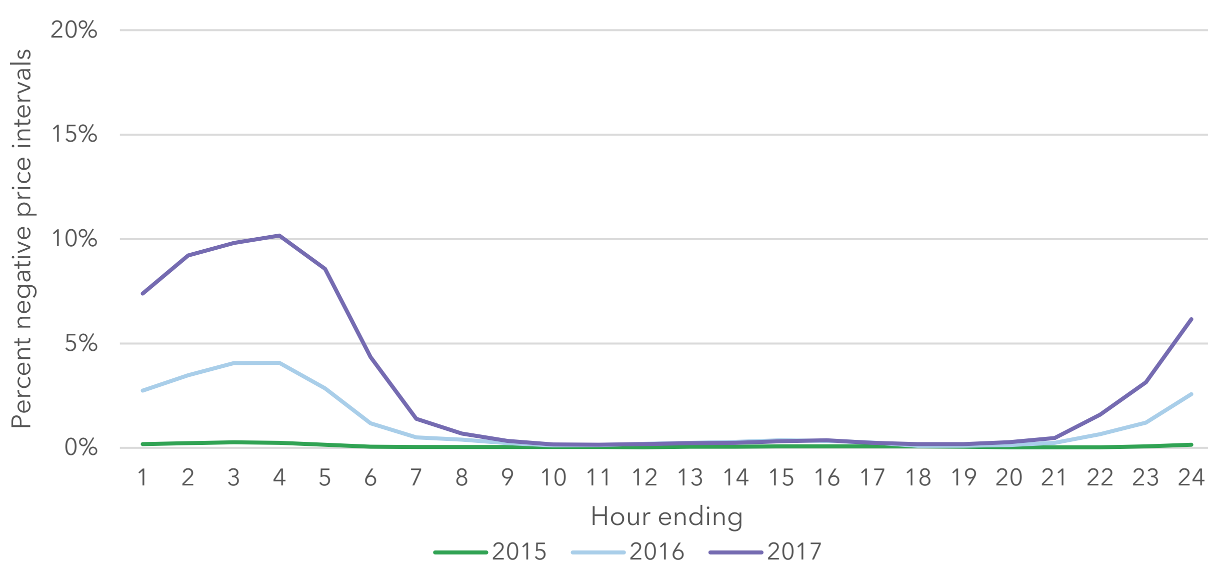
Additionally, occurrences of negative prices in the real-time market are most prevalent in the overnight, low-load hours as shown in Figure 6–3. On this chart we can see that the negative price intervals in 2017 during those overnight hours are at one and a half to two times the frequency of 2015 and 2016. During 2017 the first five hours and last two hours of the day experienced negative prices in over 10 percent of all intervals. The highest level in any hour during prior years was just 10 percent.

Figure 6–3 Negative price intervals, real-time, by hour



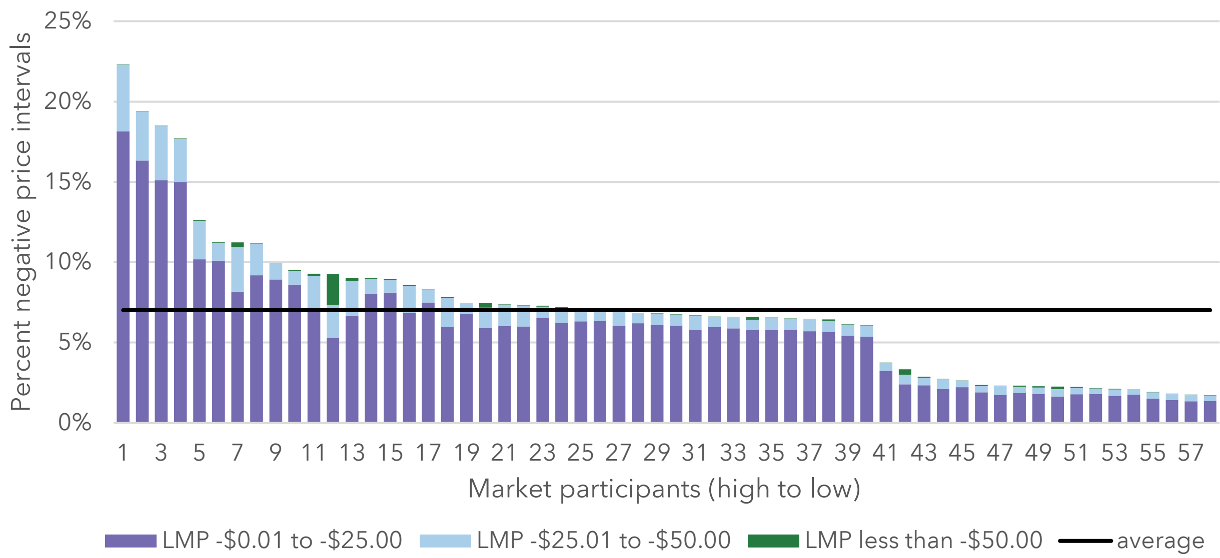
Again, negative price intervals in the day-ahead market (see Figure 6–4) follow the same pattern as the real-time market with most negative price intervals occurring in the overnight, low-load hours. But again, this happens at a much lower frequency than in real-time. Also of note, during the on-peak hours, less than 0.5 percent of intervals in the day-ahead market were negative. In 2017 the real-time market on average had nearly four percent of intervals with negative prices during the on-peak hours.

Figure 6–4 Negative price intervals, day-ahead, by hour



At the market participant level (for those participants serving load), the distribution of negative price intervals during 2017 is clustered around the footprint average, as shown in Figure 6–5. However, four market participants experienced negative prices in over 15 percent of all intervals. On the low end, 18 market participants experienced negative prices in fewer than five percent of intervals.

Figure 6–5 Negative price intervals, real-time, by market participant



The Market Monitoring Unit is concerned with the marked increase in the frequency of negative price intervals. Negative prices may not be a problem in and of themselves, they do indicate an increase in surplus energy on the system. This may be exacerbated by the practice of self-committing resources in the day-ahead market. In the SPP market where there is an abundance of capacity and significant levels of renewable resources, negative prices can occur when renewable resources need to be backed down in order for traditional resources to meet their scheduled generation. Moreover, unit commitment differences, due to wind resources not being in the day-ahead market and then coming on-line for the real-time market, can create differences in the frequency of negative price intervals between the day-ahead and real-time markets. This disparity between the markets negatively impacts the efficient commitment of resources.

Thus, the growing frequency of negative prices indicates the potential need for changes in market rules to address self-committing of resources in the day-ahead market and the systematic absence of some forecasted variable energy resources in the day-ahead market to improve market efficiency.

COMMON ACRONYMNS

AECC	Arkansas Electric Cooperative Corporation
AECI	Associated Electric Cooperative, Inc.
AEP/AEPM	American Electric Power
BEPM	Basin Electric Power Cooperative
CHAN	City of Chanute (Kan.)
EDE/EDEP	Empire District Electric Co.
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GMOC/UCU	Greater Missouri Operations Company (KCPL)
GRDA/GRDX	Grand River Dam Authority
GSEC	Golden Spread Electric Cooperative, Inc.
HMMU	Harlan (Iowa) Municipal Utilities
INDN	City of Independence (Mo.)
IS	Integrated System
KBPU	Kansas City (Kan.) Board of Public Utilities
KCPL/KCPS	Kansas City Power & Light
KMEA	Kansas Municipal Energy Agency
KPP	Kansas Power Pool
LES/LESM	Lincoln (Nebr.) Electric System
MEAN	Municipal Energy Agency of Nebraska
MEC/MECB	MidAmerican Energy Company
MEUC	Missouri Joint Municipal Electric Utility Commission
MIDW	Midwest Energy Inc.
MISO	Midcontinent Independent Transmission System Operator
MRES	Missouri River Energy Services
NDVER	non-dispatchable variable energy resource
NERC	North American Electric Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration
NPPD/NPPM	Nebraska Public Power District
NSP/NSPP	NSP Energy

NWPS	Northwestern Energy
OGE	Oklahoma Gas & Electric
OMPA	Oklahoma Municipal Power Authority
OPPD/OPPM	Omaha Public Power District
OTPW/OTPR	Otter Tail Power Company
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PEPL	Panhandle Eastern Pipe Line
SECI/SEPC	Sunflower Electric Power Corporation
SPA	Southwestern Power Administration
SPP	Southwest Power Pool, Inc.
SPRM	City Utilities of Springfield (Mo.)
SPS	Southwestern Public Service Company
TEA	The Energy Authority
TNSK	Tenaska Power Service Company
UGPM	Western Area Power Administration, Upper Great Plains
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WFEC/WFES	Western Farmers Electric Cooperative
WR/WRGS	Westar Energy, Incorporated

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