Southwest Power Pool
Market Monitoring Unit

State of the Market
Summer 2017

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1. MARKET PERFORMANCE HIGHLIGHTS

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

- During summer 2017, the average day-ahead and real-time prices were $26.22/MWh and $26.16/MWh, respectively. July 2017 prices averaged around $30/MWh which is the highest monthly average price in the Southwest Power Pool (SPP) market since August 2014. High July prices were primarily due to high demand experienced in the SPP footprint as a whole and in the northern part in particular.

- All-in cost in summer 2017 was $27.30/MWh indicating a five percent increase compared to the summer 2016 level of $26.04/MWh, mostly due to higher energy costs in July.

- Average monthly gas cost at the Panhandle Eastern hub ranged between $2.50 and $2.60/MMBtu during the summer and has remained below $3/MMBtu since December 2014, with the exception of two months.

- Overall, the hourly average load for summer 2017 was just over 34,000 megawatts, peaking at just over 51,000 MW. The average hourly load was approximately four percent lower than summer 2016, while the peak load was just slightly higher than summer 2016. However, in the northern portion of the SPP footprint during July, load was eight percent higher in 2017 compared to 2016. During August, load across the entire SPP footprint was down nearly nine percent in 2017 compared to 2016.

- In terms of monthly real-time generation by technology, coal-powered resources continued their downward trend with only 50 percent of energy produced in the summer 2017 period compared to 51 percent in summer 2016 and 57 percent in summer 2015. Wind generation on the other hand, continued its upward trend with 15 percent of energy produced in summer 2017 compared to 12 percent in summer 2016 and 10 percent in summer 2015.

- The summer 2017 monthly average real-time make whole payments were $4.2 million, 38 percent lower than the summer 2016 period.

- The Woodward flowgate (WDWFPLTATNOW) did not appear in the top ten congested flowgates for the summer period even though it is still ranked as the flowgate with the highest shadow price for the past 12 months. This decrease in congestion during the summer months 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 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.

- In June 2017, SPP and the Midcontinent Independent System Operator (MISO) executed a memorandum of understanding to enhance market-to-market coordination. This included criteria to exclude some market-to-market flowgates that pass coordination tests but are not significantly impacted by the non-monitoring regional transmission organization's (RTO) market flows in real-time. This criteria initially resulted in the removal of over 50 of approximately 230 market-to-market flowgates on August 1, 2017.

- SPP filed with FERC to modify the methodology by which scarcity pricing for contingency reserves and regulation products is determined. The new methodology instituted a variable demand curve through which the value of the contingency reserves and regulation products is more appropriately reflected during intervals of scarcity pricing. The new design feature became functional as of operating day August 11, 2017.

- A change was made to the market design for jointly owned units, which was implemented in August 2017. With the new design, each share is required to submit a minimum capacity of zero megawatts. When this type of unit is uneconomical and dispatched down to its physical minimum capacity, the cheapest share may be the only share dispatched up to meet the physical minimum capacity—all the other shares could be at zero megawatts. In this case, the revenues are less than the costs of that share, and this share is taking the brunt of all the losses and effects on make whole payments. Under the original design, each share would be dispatched down to their share ratio of the physical minimum capacity. Through other discussions with RTO staff and stakeholders, there have been many other issues pointed out. There is on-going discussion at the Market Working Group on this topic.

2. PRICES, MITIGATION, 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 over the past 12 months with average monthly prices mostly ranging between $2.50 and $2.80/MMBtu at the Panhandle Eastern hub. The exception is December and January when prices went above $3/MMBtu, and November when gas prices dropped to around $2.25/MMBtu.

During summer 2017 the average day-ahead price was $26.22/MWh and the average real-time price was $26.16/MWh. In comparison, day-ahead and real-time prices for summer 2016 were $26.43/MWh and $25.60/MWh, respectively. Figure 2–1 below shows that July 2017 prices averaged around $30/MWh, the highest monthly average price in the SPP market since August 2014. High July prices were primarily due to high demand in the SPP footprint as a whole and in the northern part in particular.

Figure 2–1 Electricity and gas prices

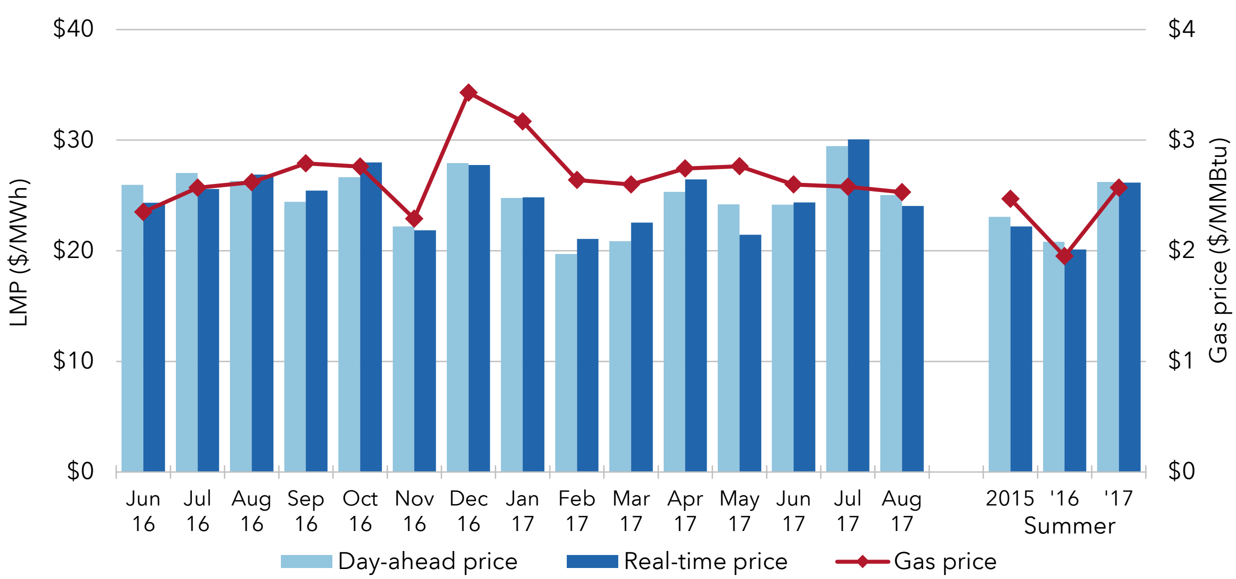
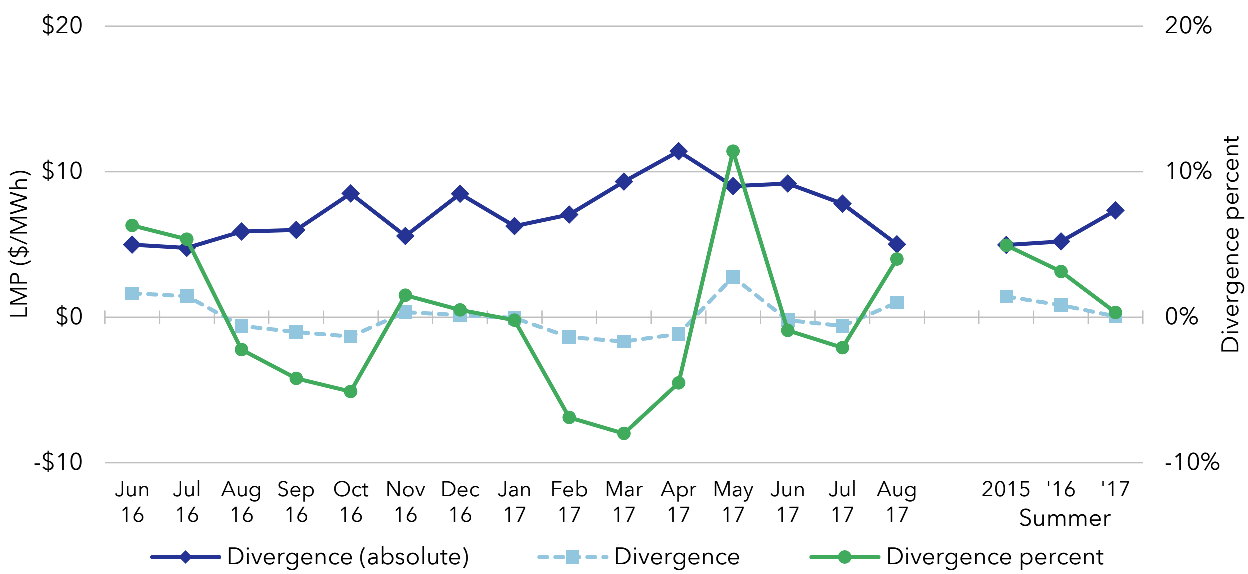


Figure 2–2 shows the day-ahead to real-time price divergence at the SPP system level. Price divergence[1] is calculated as the difference between day-ahead and real-time prices, using system prices for each five-minute (real-time) or hour (day-ahead) interval. The absolute divergence is calculated by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

Although the divergence and divergence percent calculations are declining from summer 2015 to summer 2017, the absolute divergence has been climbing during this same period, 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

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

prices, include the area south of the Texas panhandle and in northwest 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, summer (all hours)

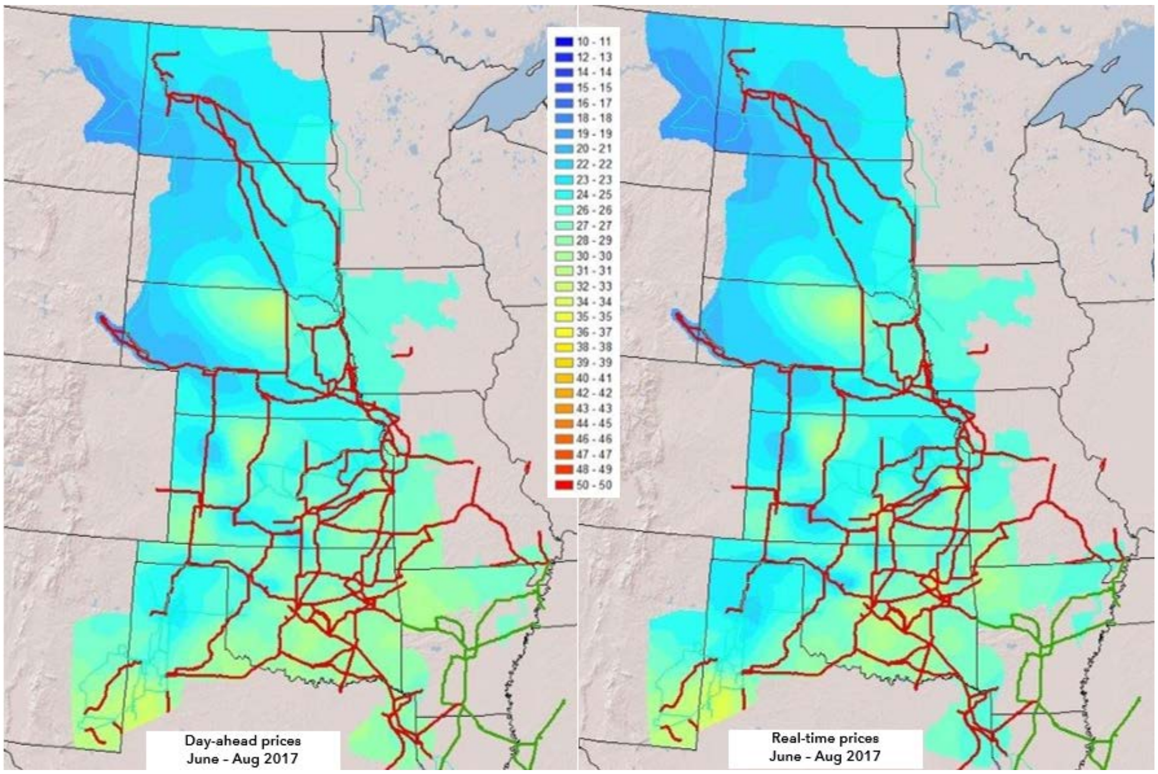


Figure 2–4 Price map, rolling 12 month (all hours)

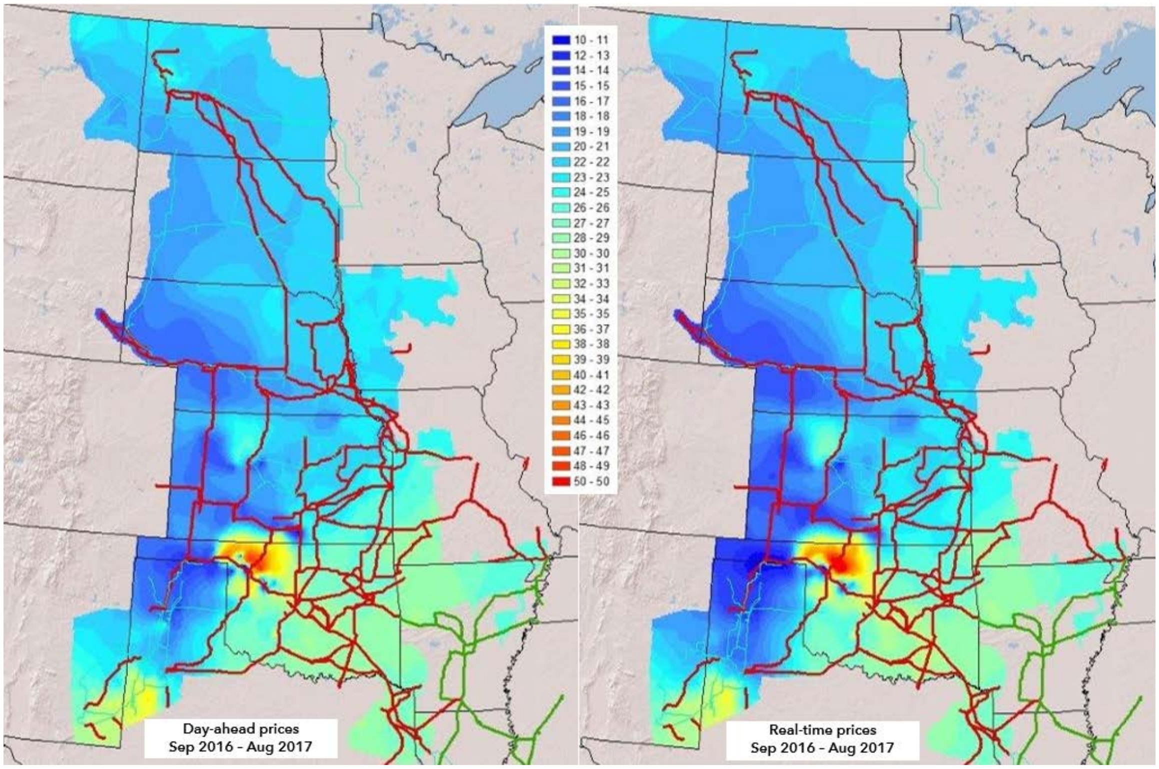


Figure 2–5 and Figure 2–6 display average prices paid by load serving entity, for the summer and last twelve month periods, respectively. Summer period prices are more clustered around the SPP average price compared to those of the annual period because seasonal price data points observed by each individual load serving entity contain a subset of the annual data which yields less variation.

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

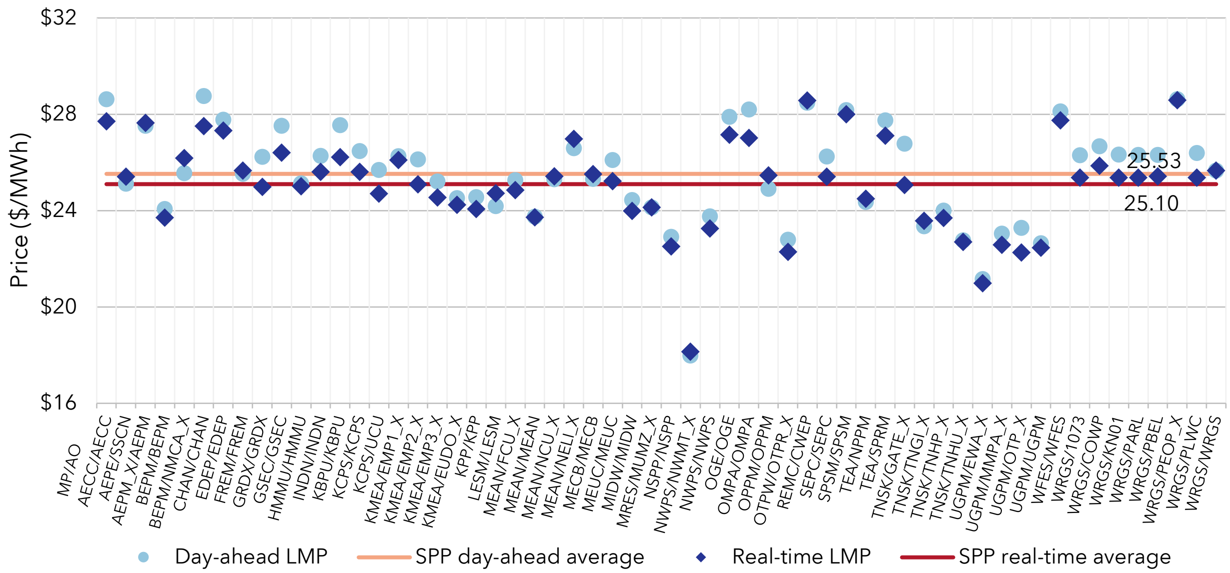


Figure 2–6 Price by load-serving entity, rolling 12 month

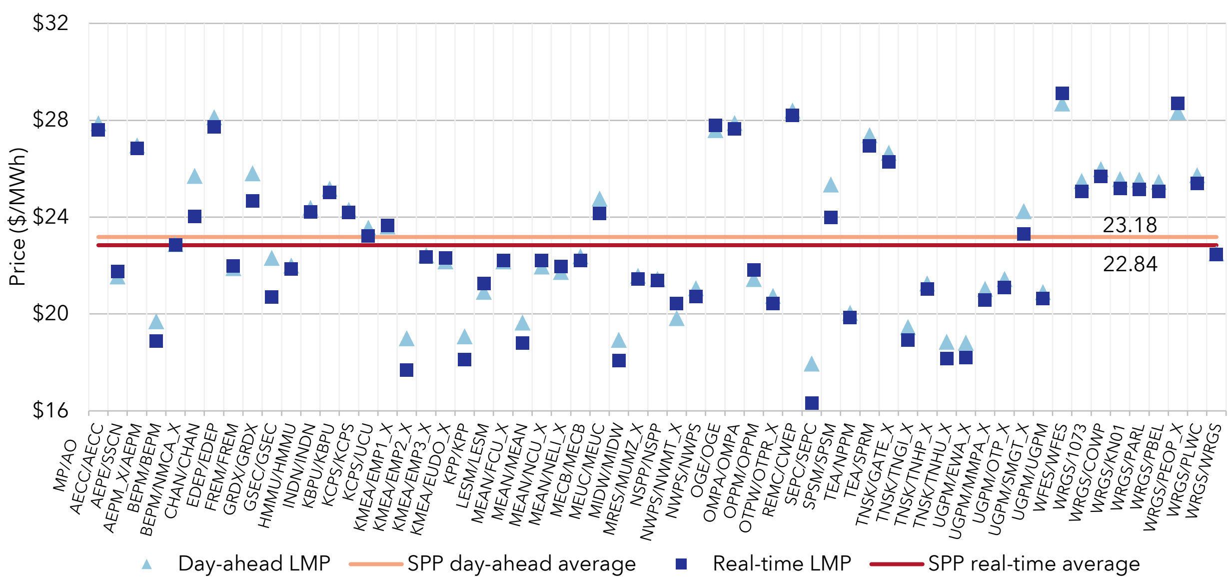
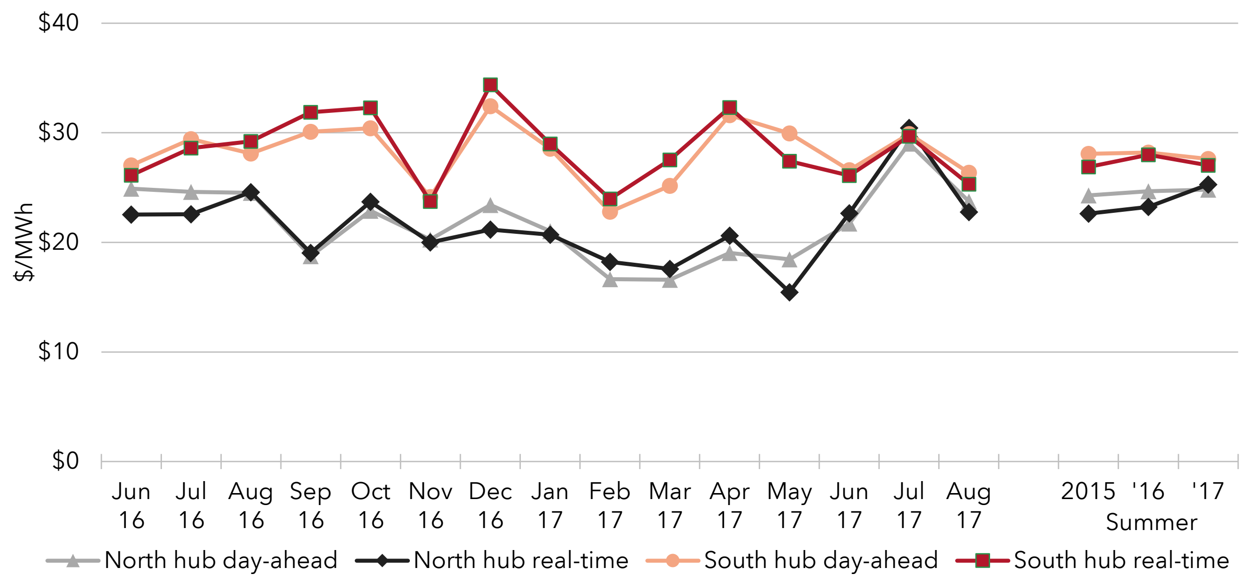


Figure 2–7 shows monthly average day-ahead and real-time prices for the two trading hubs. A trading hub is a settlement location consisting of an aggregation of price nodes developed for financial and trading purposes. Due to an abundance of lower-cost generation in the northern part of the SPP footprint, 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 summer 2017 was $2.27/MWh, compared to $4.75/MWh for summer 2016.

However, in July the real-time price at the North hub was higher than the price at the South hub. Market-to-market events on both SPP and MISO constraints in the Nebraska and Iowa areas drove North hub prices higher for July. Additionally, temperatures in the northern portion of the SPP footprint were much higher in July (see Figure 3–3), increasing demand in the area.

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 has become effective as of operating day August 11, 2017. Since this functionality is so 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.

Figure 2–8 Regulation-up prices

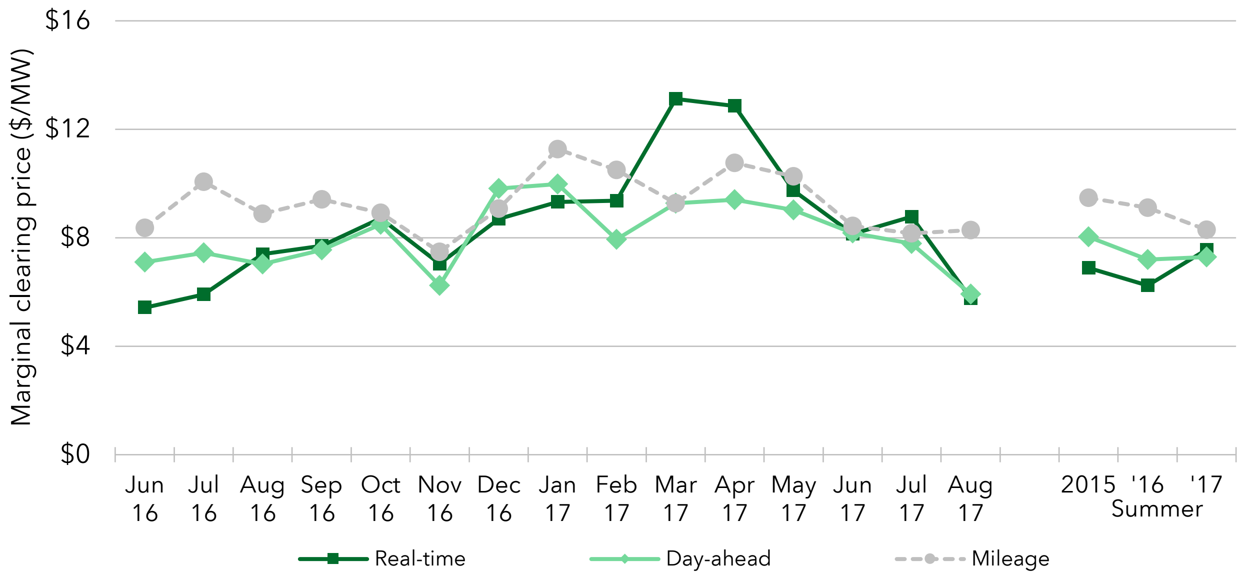


Figure 2–9 Regulation-down prices

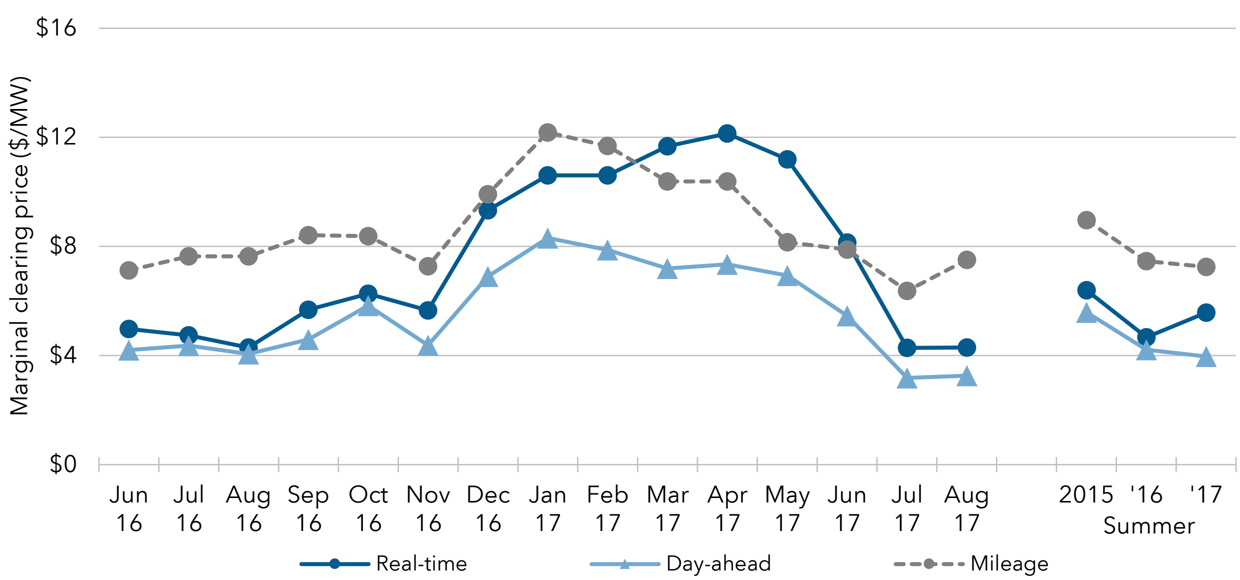


Figure 2–10 Spinning reserve prices

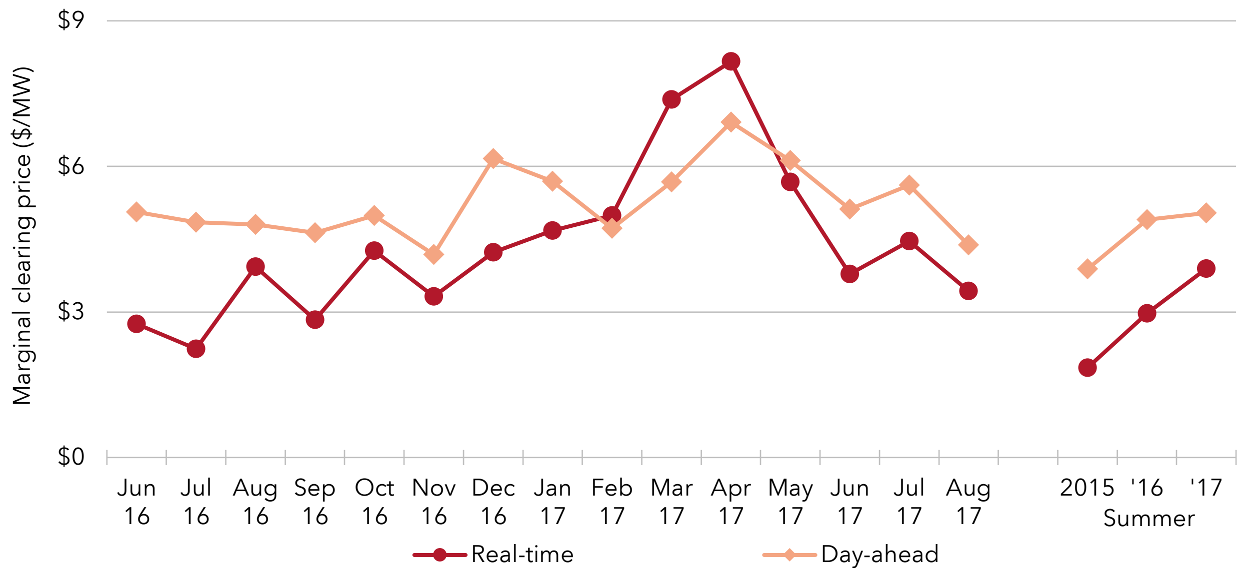
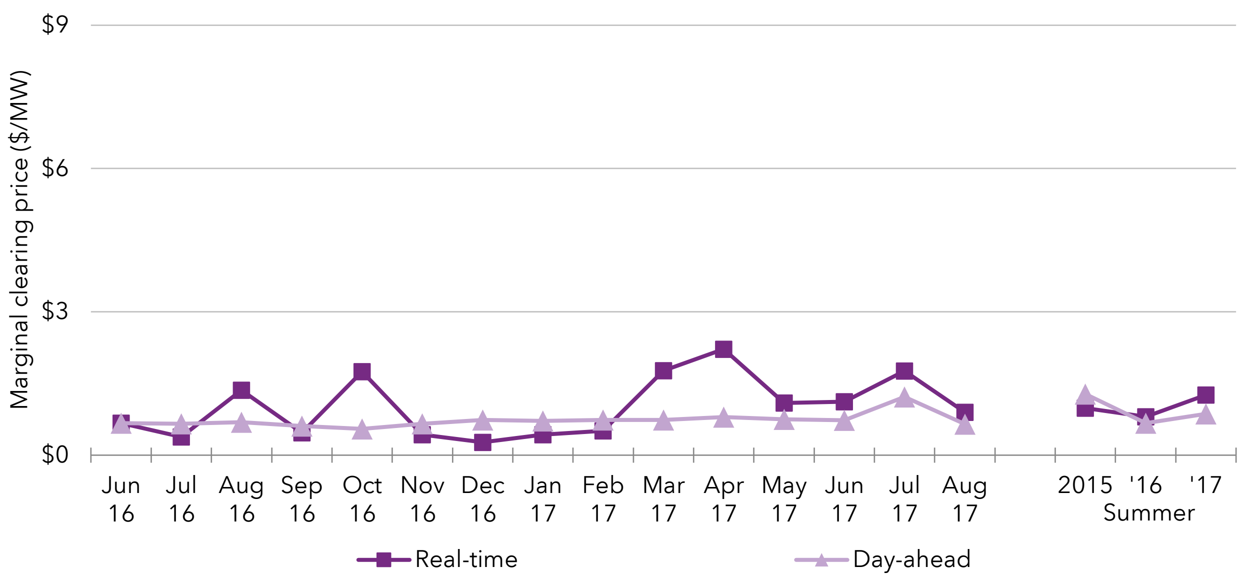


Figure 2–11 Supplemental reserve prices

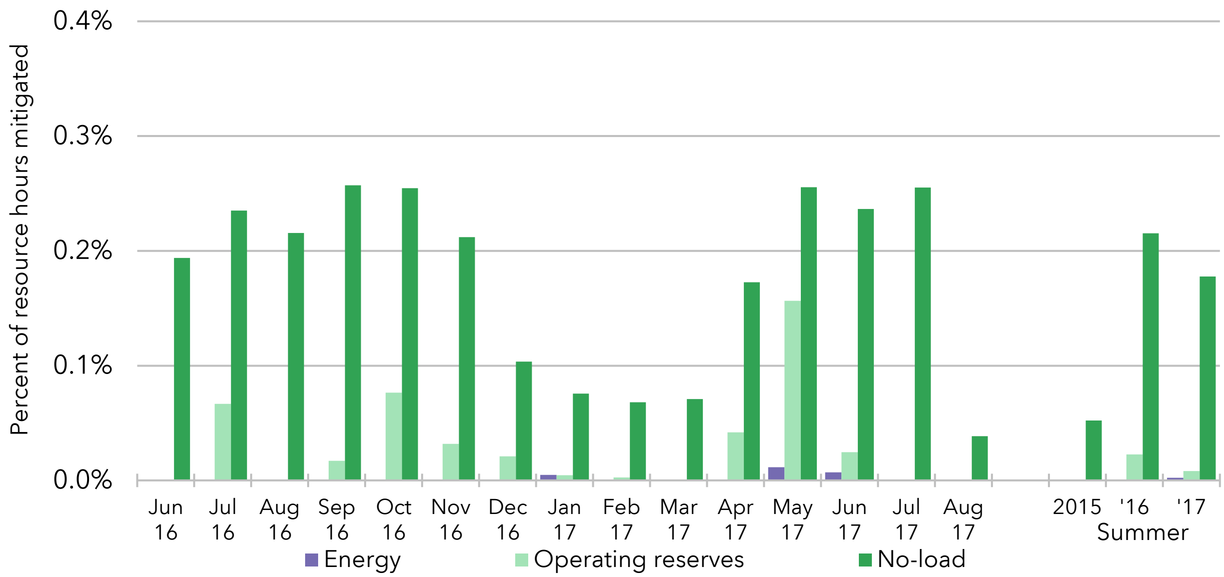


Mitigation

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. Summer 2017 had an average of less than 0.2 percent of total resource hours mitigated for all products, and has declined from just under 0.25 percent of resource hours in summer 2016.

Figure 2–12 Mitigation frequency, day-ahead market



In the real-time market, the mitigation of incremental energy remains at very low levels. During summer 2017, real-time mitigation averaged of just over 0.01 percent of intervals. This is down from 0.02 percent in summer 2015, and just under 0.05 percent in summer 2016.

Figure 2–13 Mitigation frequency, real-time market

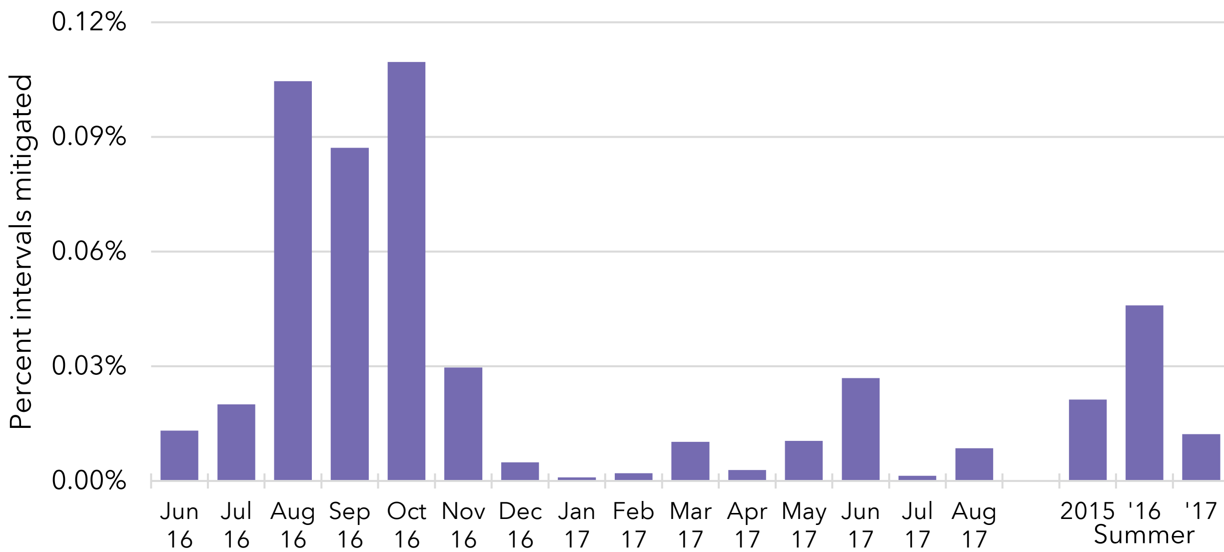
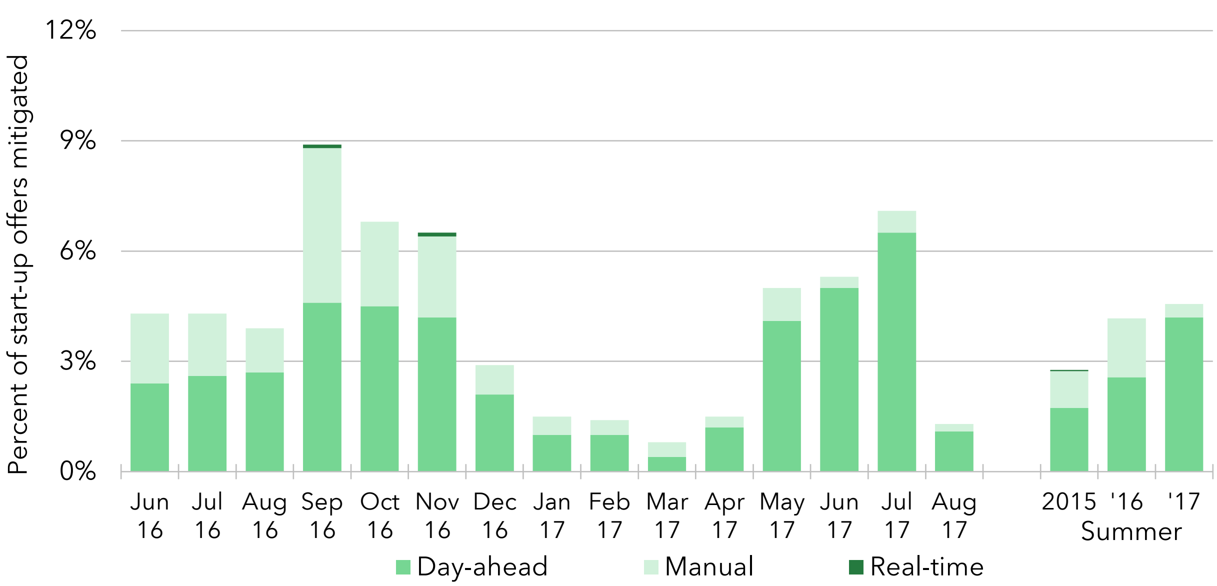


Figure 2–14 shows the mitigation of start-up offers for various means of commitment. The overall level for mitigation of start-up offers has increased from 2.8 percent in summer 2015, to 4.2 percent in summer 2016, and then to 4.6 percent in summer 2017. August 2017 experienced very low mitigation of start-up offers at just over one percent, compared to five percent in June and seven percent in July.

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 summers, summer 2017 day-ahead payments were up slightly.

In line with higher load and prices in July, the real-time make whole payments increased as well. This is because SPP committed and dispatched more generators to meet the increased load which created a higher potential for make whole payments. July total make-whole payments were nearly 50 percent higher than those of June and August and were paid largely to simple-cycle gas resources. However, the summer 2017 monthly average real-time make-whole payments were $4.2 million, 38 percent lower compared to the summer 2016 period level.

Figure 2–15 Make whole payments, day-ahead

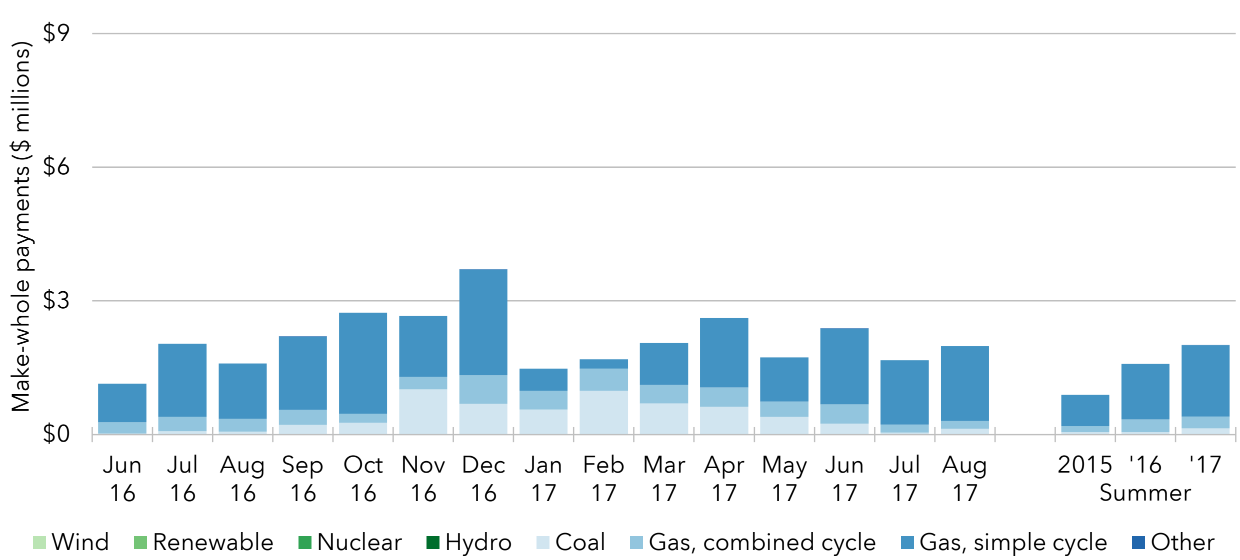
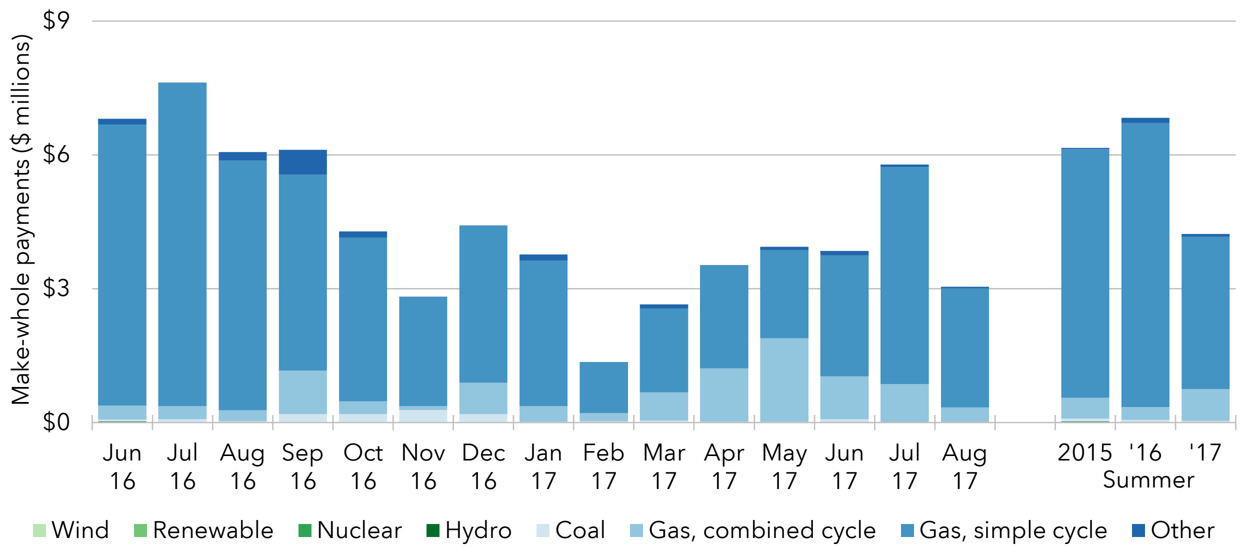
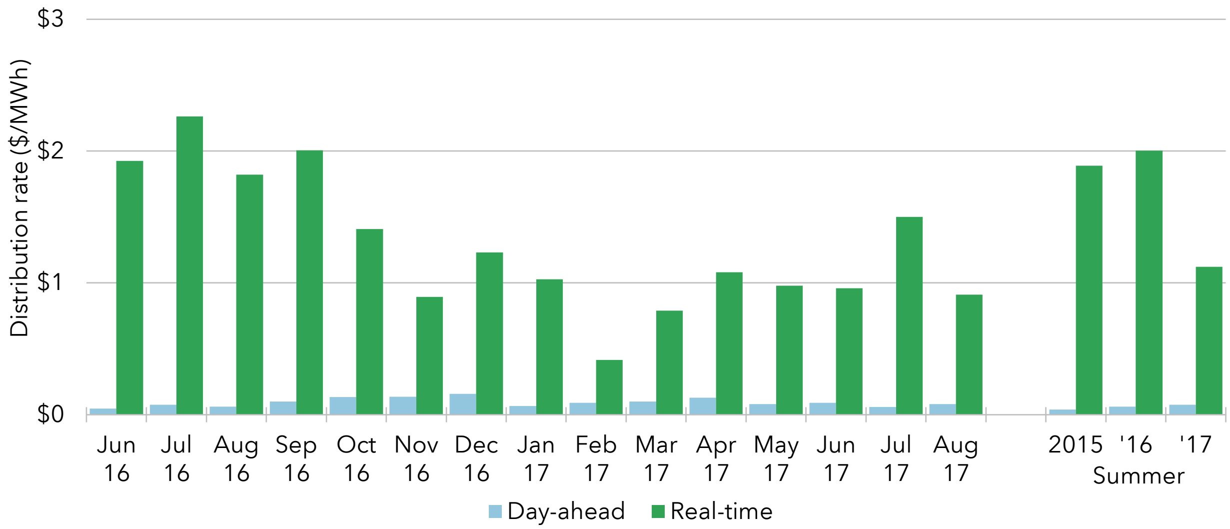


Figure 2–16 Make whole payments, real-time



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 real-time distribution rate was about $1/MWh in summer 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.

Figure 2–18 Regulation-up mileage make whole payments

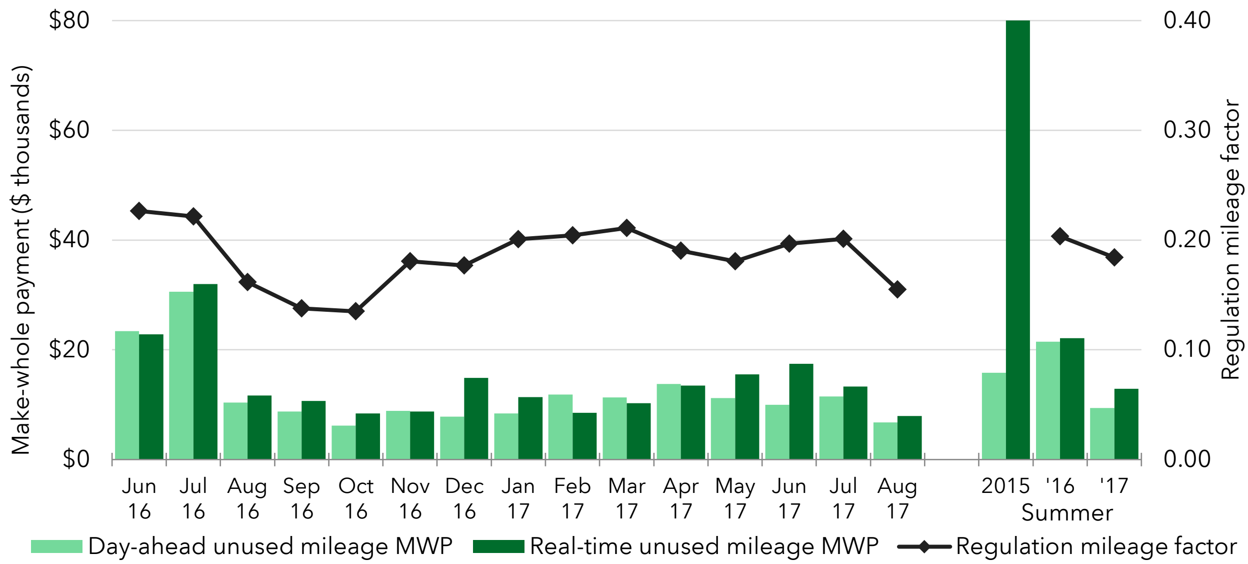
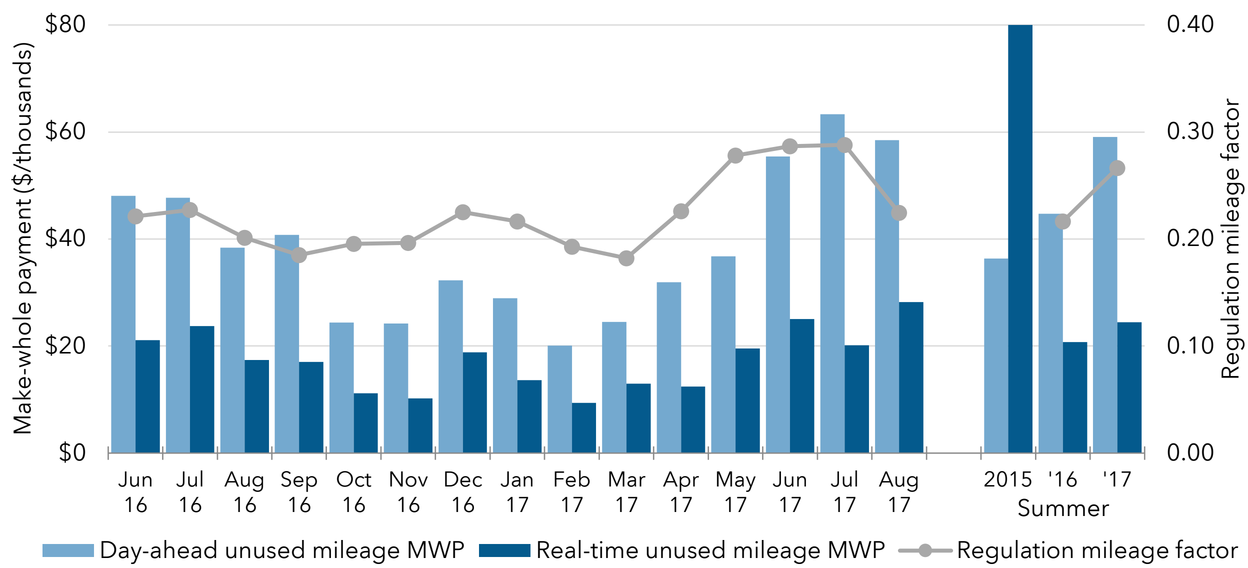


Figure 2–19 Regulation-down mileage make whole payments

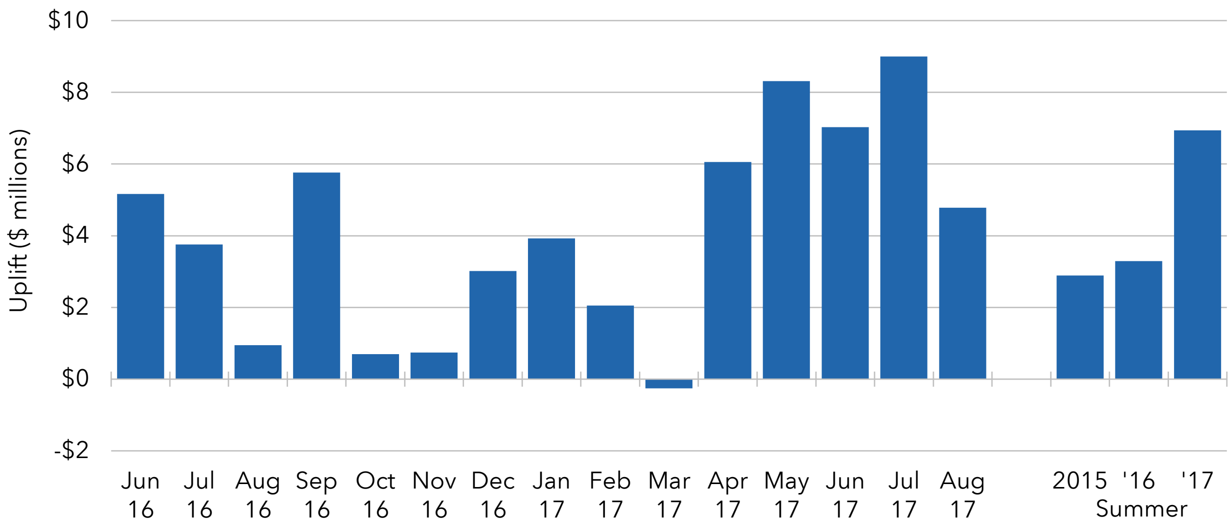


Revenue neutrality uplift (RNU), shown in Figure 2–20, ensures settlement payments/receipts for each hourly settlement interval equal zero. Positive revenue neutrality uplift indicates that SPP receives insufficient revenue and collects from market participants. Negative revenue-neutrality uplift indicates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

[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 contested constraint.

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 to be developed that enhances 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 performed daily, which can result in the inclusion of previous or additional removals. Other aspects of the memorandum of understanding are slated for implementation later in 2017 or pending FERC filings.

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 summer period are shown in Figure 2—22.

Figure 2–21 Market-to-market, monthly

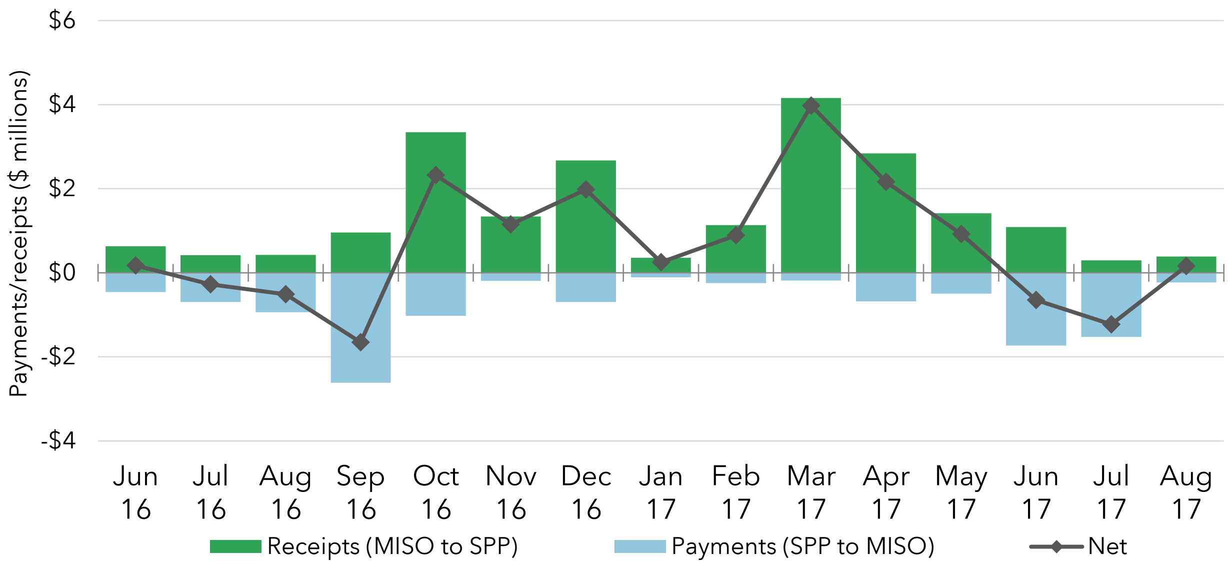
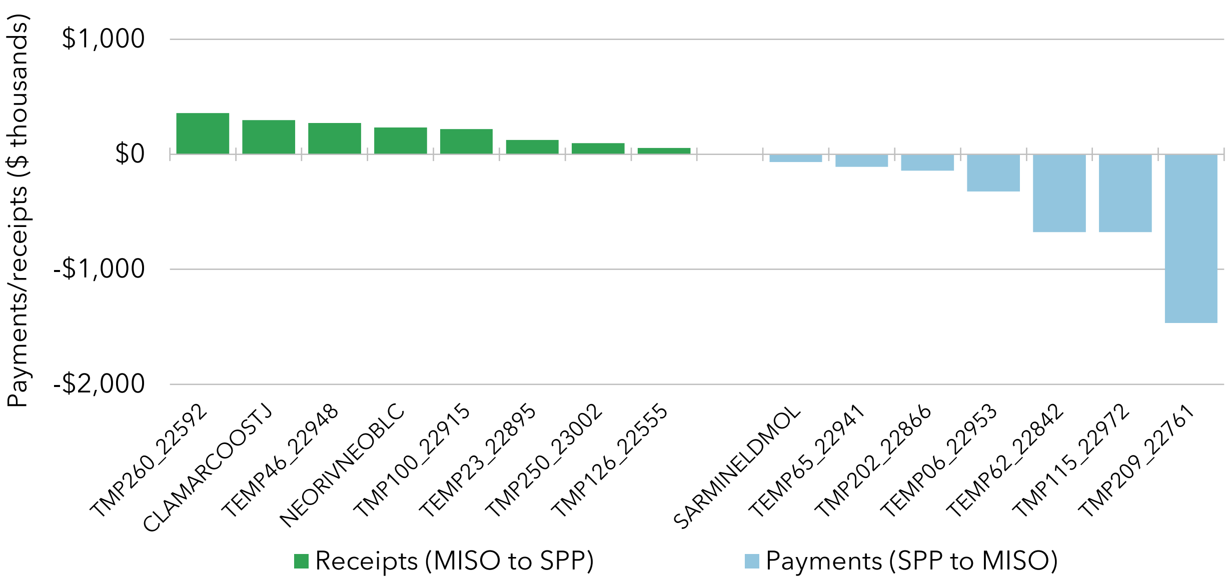


Figure 2–22 Market to market, by flowgate

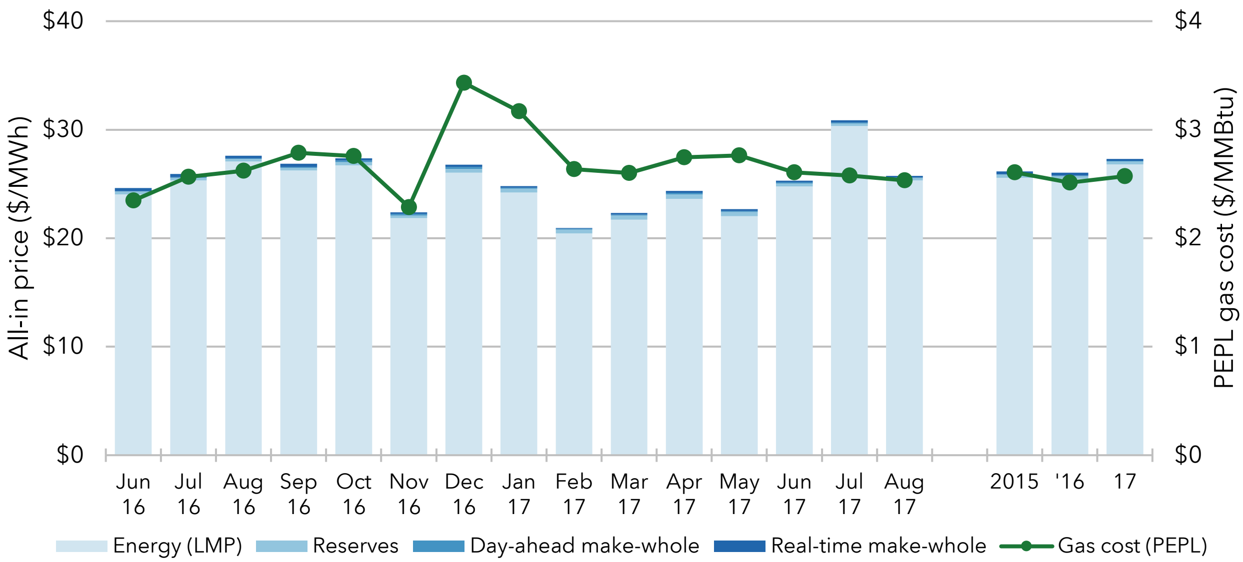


The all-in cost, shown in Figure 2–23 includes the cost of energy, day-ahead and real-time reliability make-whole payments (uplift), operating reserves costs, reserve sharing group costs, and payment to demand response resources. The cost of energy includes all of the shortage pricing components.

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 summer 2017 was $27.30/MWh indicating a five percent increase compared to the summer 2016 level of $26.04/MWh. This was primarily from higher energy costs in July.

Other components of all-in cost in summer 2017 remained virtually unchanged compared to summer 2016 except that the share of make-whole payments decreased from 1.2 percent to 0.9 percent in summer 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				
Operating reserves	0.36	0.34	0.38	0.43	0.38	0.29	0.26	0.21				
Uplift, day-ahead	0.07	0.09	0.1	0.14	0.09	0.10	0.06	0.08				
Uplift, real-time	0.17	0.07	0.14	0.19	0.20	0.16	0.21	0.13				
All-in price	**$ 24.81**	**$ 20.95**	**$ 22.33**	**$ 24.37**	**$ 22.69**	**$ 25.31**	**$ 30.86**	**$ 25.74**				

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.

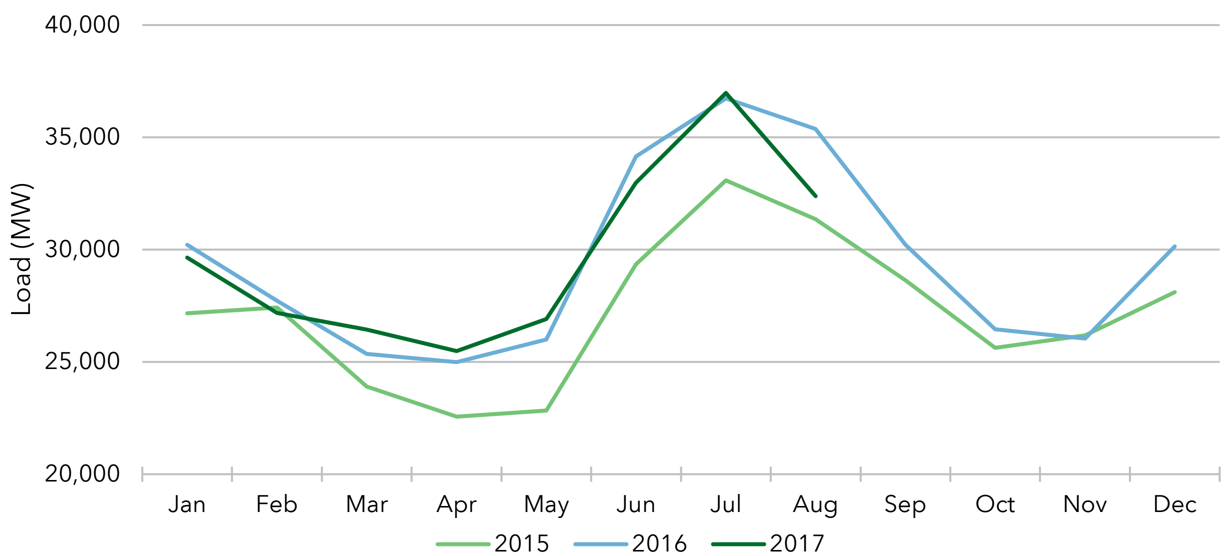
3. DEMAND, GENERATION AND UNIT COMMITMENT

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. It is important to note that the Integrated System became part of the SPP market in October 2015. This would account for the shift of the load levels upward at that time.

Overall the hourly average load for summer 2017 was just over 34,000 megawatts, which was approximately 1,000 megawatts lower than summer 2016. For the summer period, the average hourly load was slightly higher in July 2017 compared to 2016. However for both June and August the average hourly load was significantly lower in 2017 compared to 2016.

Figure 3–1 Average hourly load



Cooling degree days are used to estimate the impact of actual weather conditions on energy consumption. Much of the higher load in July can be attributed to higher temperatures in the SPP footprint as shown in Figure 3–2. Conversely, the much lower load in August can be primarily attributed to cooler temperatures during that month. Additionally, cooling degrees have been calculated for the geographic northern and southern regions of the footprint. 'Northern SPP' represents the portion of the footprint from Nebraska and Iowa, and the area to the north. 'Southern SPP' represents Kansas and Missouri and areas to the south. As shown in Figure 3–3, temperatures in the northern part of the SPP footprint were significantly higher in July 2017 than previous years and the 30-year average. These higher temperatures in July also had an impact on prices at the SPP North hub, which is discussed at Figure 2–7.

Figure 3–2 Cooling degree days, SPP footprint

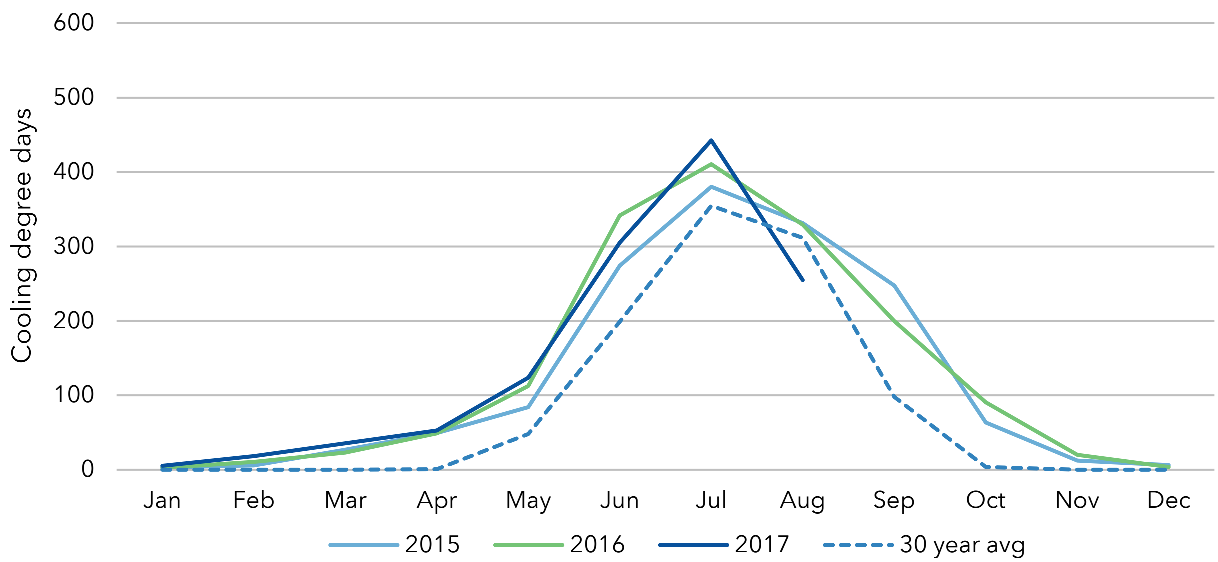


Figure 3–3 Cooling degree days, regional

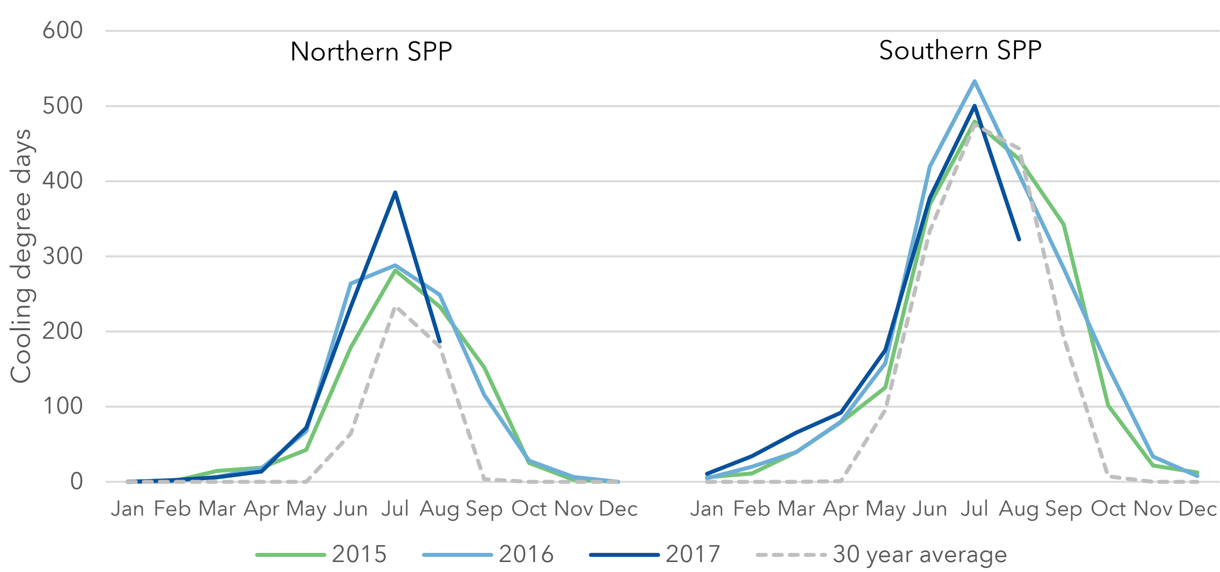
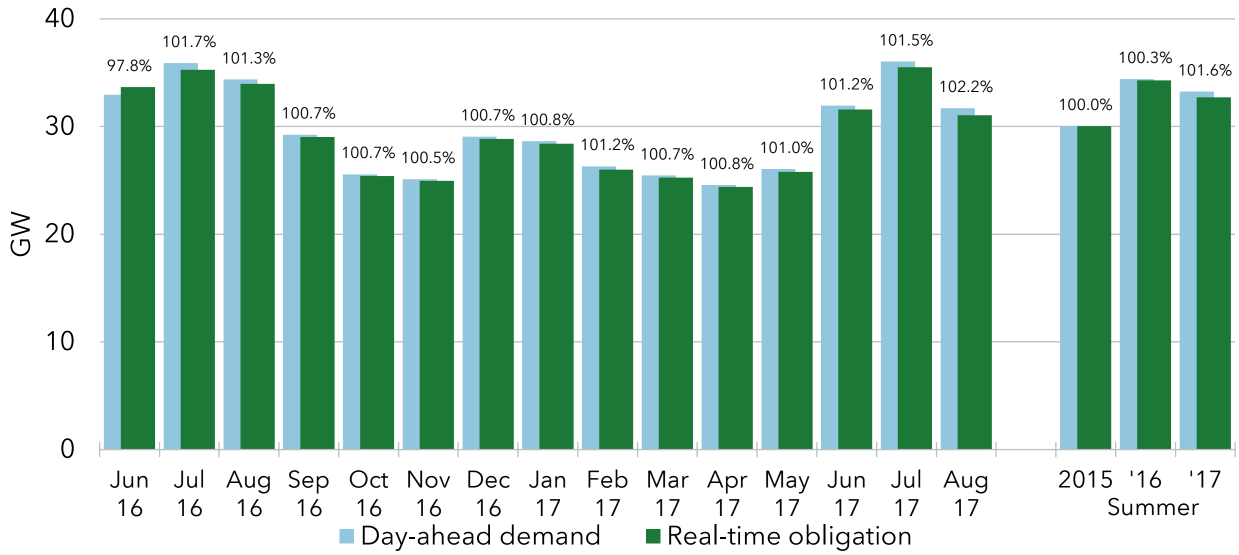


Figure 3–4 shows load scheduling for the peak hour. Under-scheduling load can cause SPP to commit more expensive peaking resources in real-time in order to satisfy load. Some real-time commitments may be made regardless of load scheduling due to the need to address

reliability concerns, relieve local congestion, or meet ramp demands. Over-scheduling load can suppress real-time price signals by overstating load.

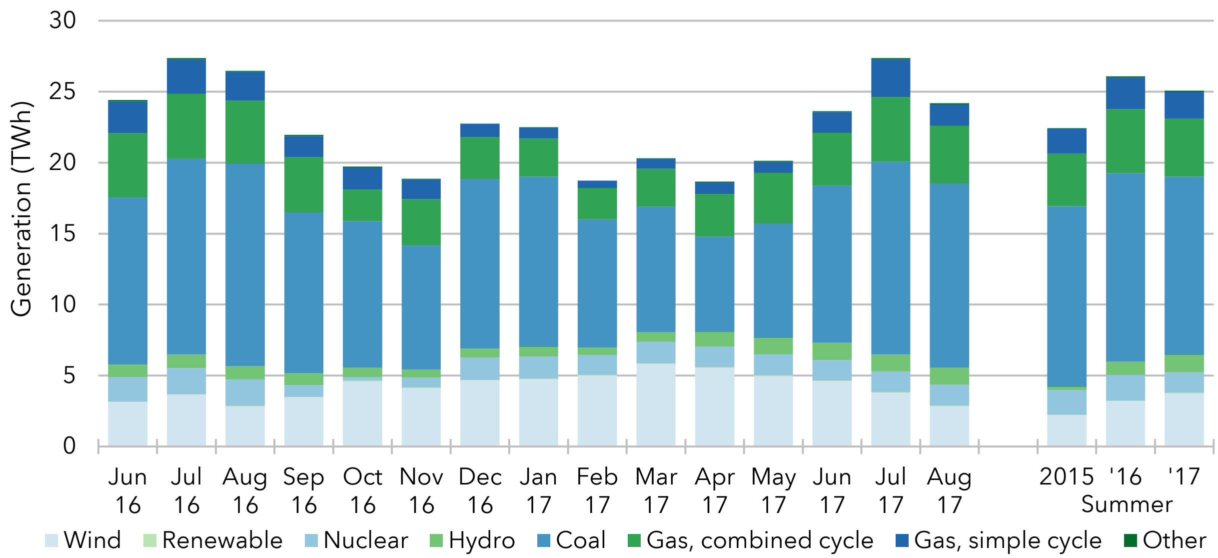
Figure 3–4 Day-ahead load scheduling



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), while the 'other' category includes fuel oil and miscellaneous.

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



As shown in Figure 3–6 below real-time market generation by coal-powered resources continues a downward trend representing only 50 percent of total energy produced in the summer 2017 period, compared to 57 percent in 2015. This decline has been primarily offset by increases in wind generation, which is up from 10 percent in summer 2015 to 15 percent in 2017.

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

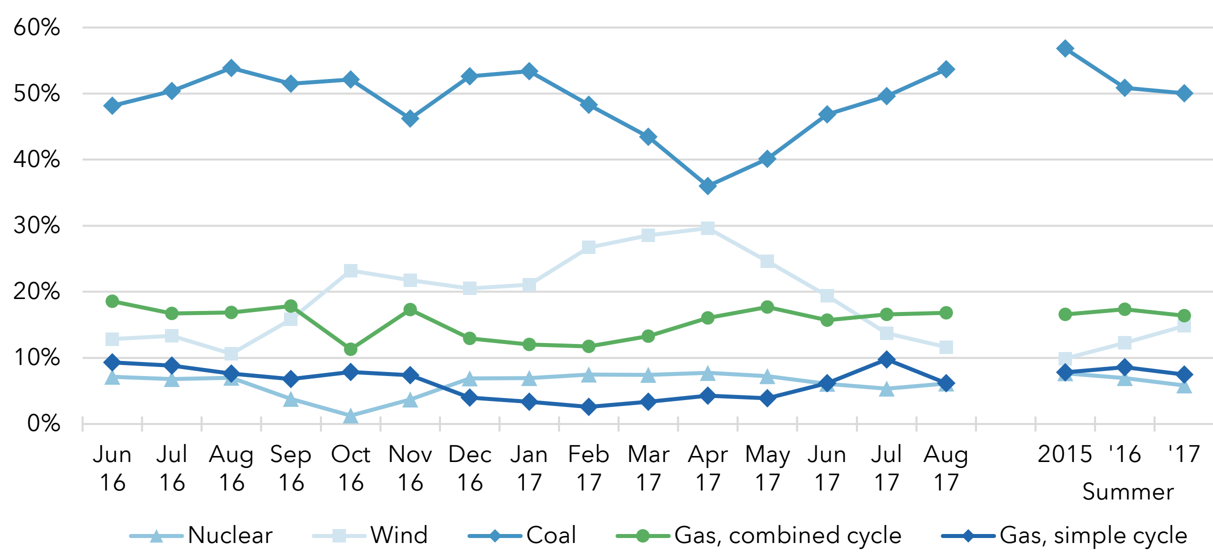


Figure 3–7 shows wind capacity (nameplate in megawatts) along with the wind capacity factor. Note that the wind capacity figure is reported as of month-end, while the capacity factor is reported for the entire month. Wind resources may be considered in-service, but not yet in commercial operation. In 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 14,400 MW in August 2016 to 17,300 in August 2017.

Figure 3–7 Wind capacity and capacity factor

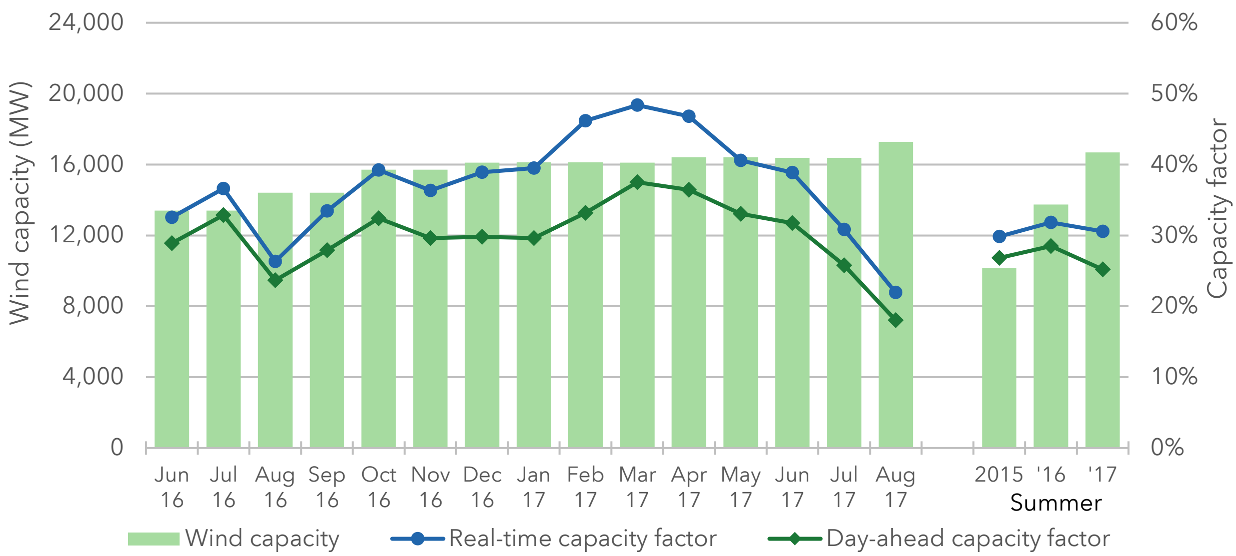


Figure 3–8 and Figure 3–9 show the technology types of marginal units in both the real-time and day-ahead markets. Marginal units set the locational marginal price in each hour in the day-ahead market and each five minute interval in the real-time market. One important distinction is that virtual transactions can be marginal in the day-ahead market while not appearing in the real-time market. 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 34 percent of all intervals in summer 2016 and summer 2017, compared to being marginal in about 42 percent of all intervals in summer 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. This decline was primarily offset with increases in gas combined-cycle and wind resources on the margin.

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

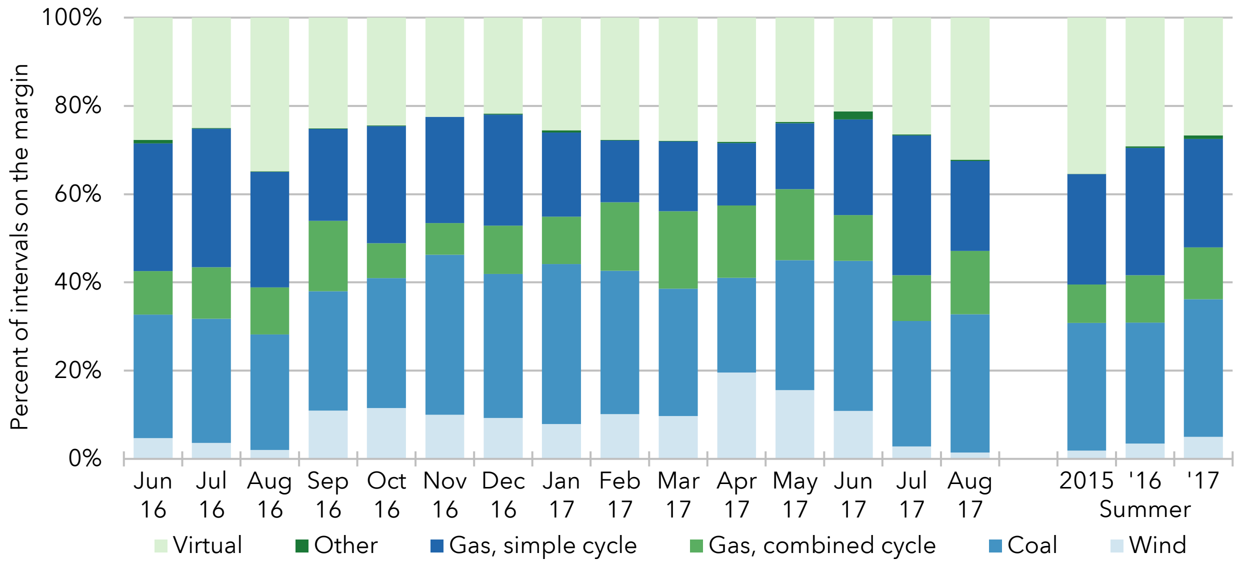
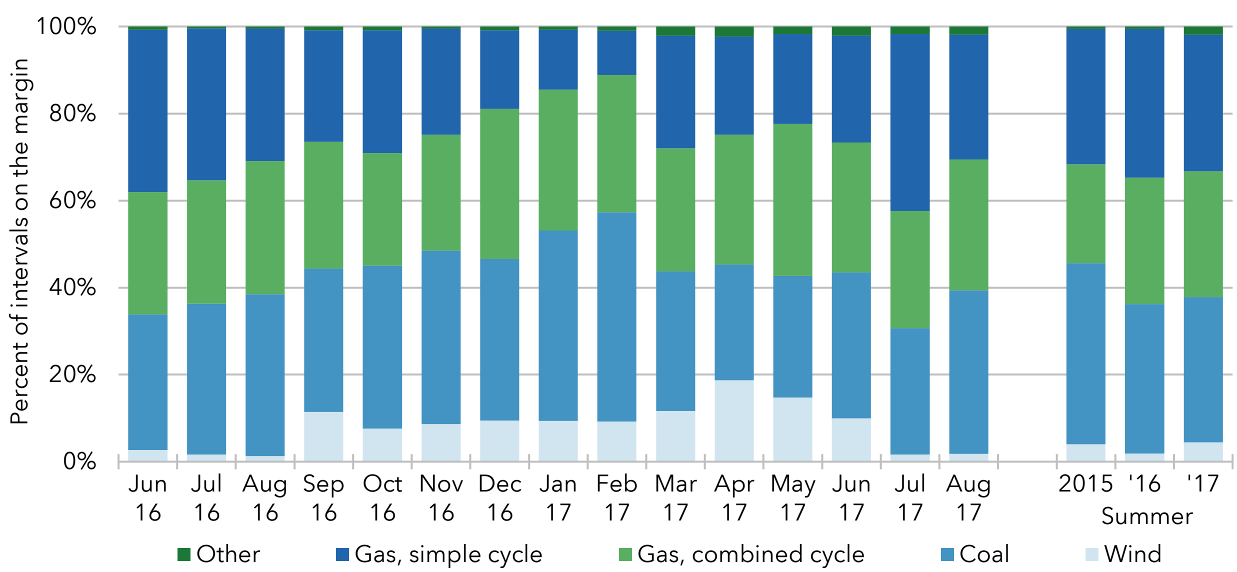


Figure 3–9 Technology on the margin, real-time



Ramp available to the system as standardized by available capacity, compared to the average online 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

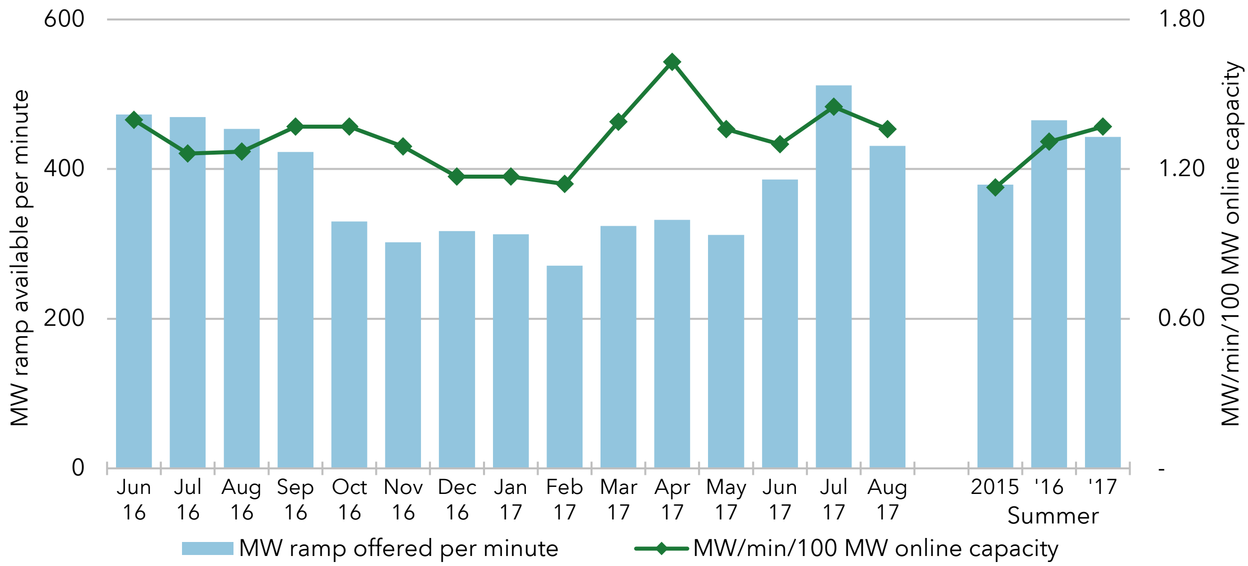
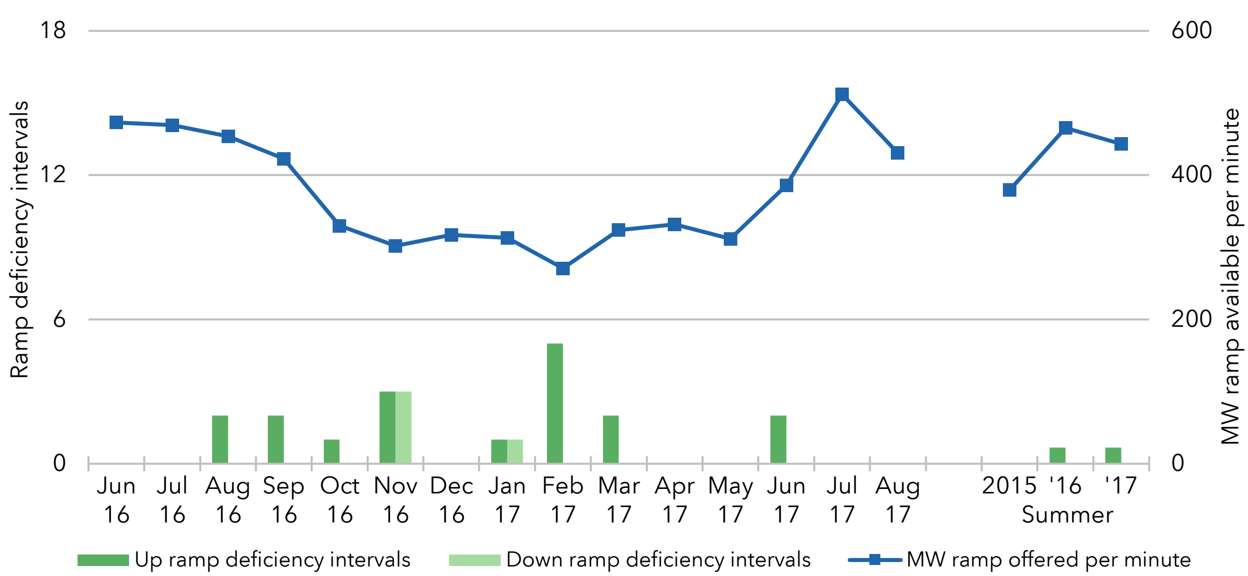


Figure 3–11 shows the monthly average available ramp per interval along with the number of intervals with a ramp deficiency each month. If ramp rates are too low, the market cannot respond quickly enough to manage system changes and ramp deficiencies will occur. Deficiencies result in price spikes, indicating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

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 80 to 90 percent of offered capacity during peak hours.

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

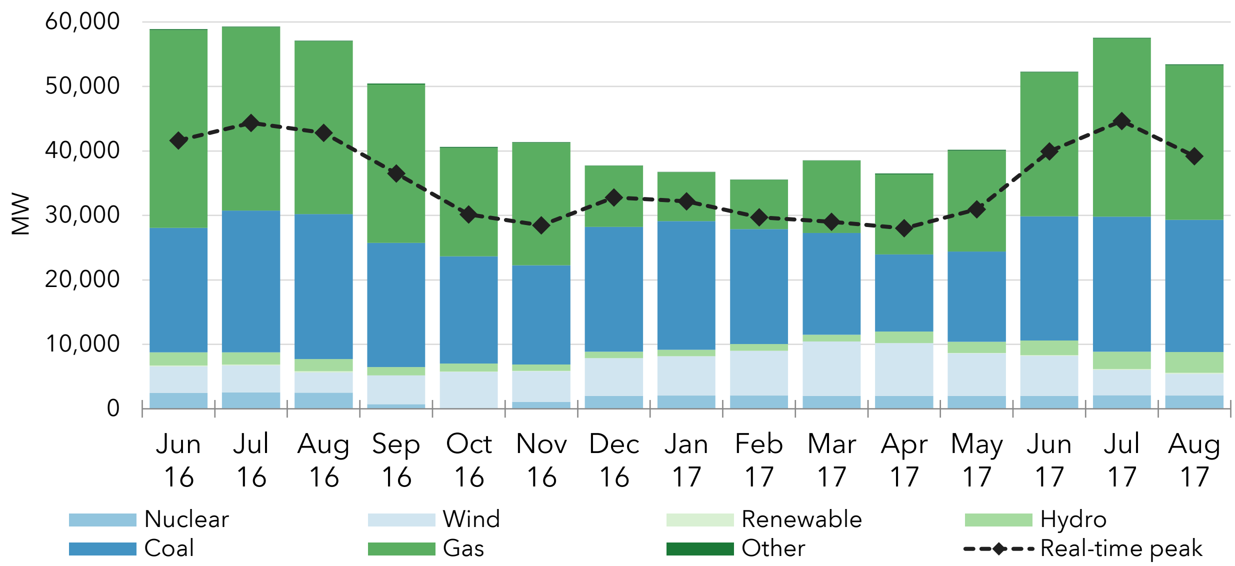


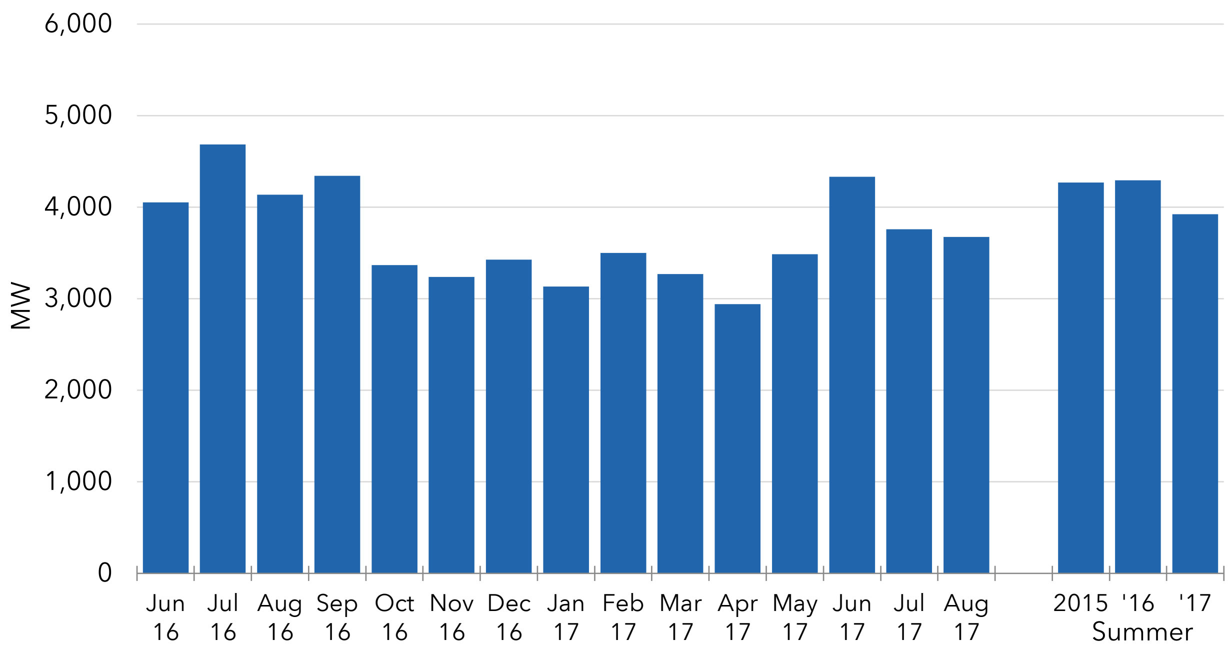
Figure 3–13 shows the real-time average peak hour capacity overage. SPP calculates the amount of capacity overage[3] required for the operating day to ensure that unit commitment is sufficient to reliably serve load in real-time while maintaining the operating reserve requirements.

The average peak hour overage for summer 2017 was around 3,900 megawatts, compared to nearly 4,300 megawatts in both summer 2015 and summer 2016. This decrease can be

[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.

attributed to increasing wind generation available, thus allowing fewer traditional fuel resources to be committed to meet load.

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



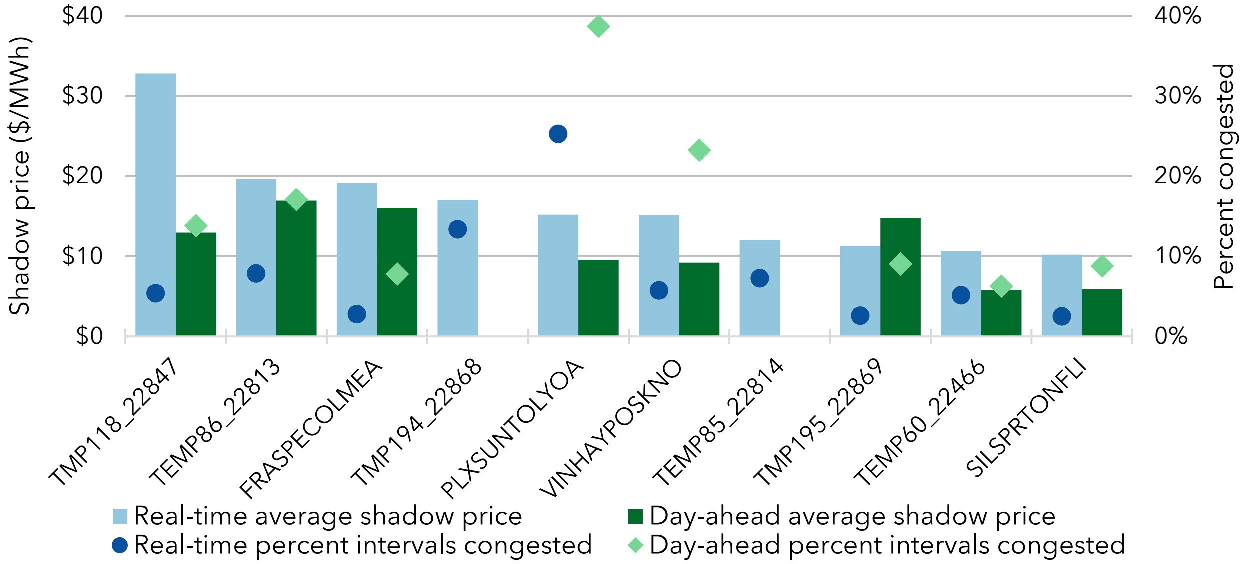
4. CONGESTION AND TRANSMISSION CONGESTION RIGHTS MARKET

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 summer period is shown in Figure 4–1, while congestion by shadow price for the rolling 12 months ending August 2017 is shown in Figure 4–2.

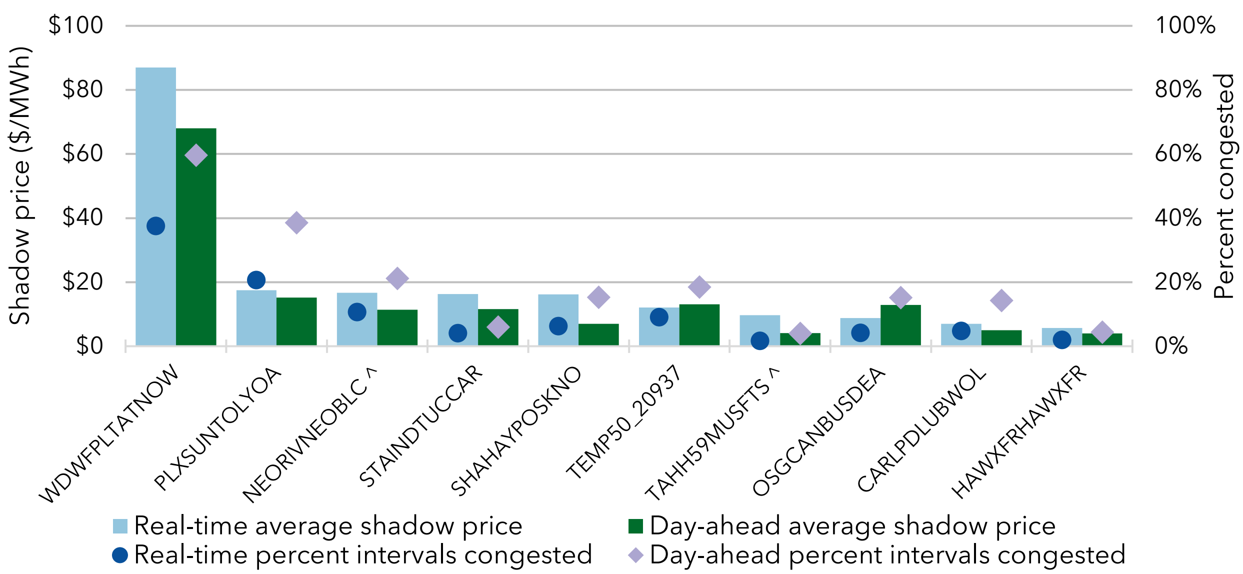
Areas of the footprint experience varying congestion, which is caused by many factors, including transmission bottlenecks, transmission and generation outages (planned or unplanned), weather events, and external impacts. The Woodward flowgate (WDWFPLTATNOW) does not appear in the top ten congested flowgates even though it still has the highest shadow price for the past 12 months. This decrease in congestion during the summer months 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, summer



TMP118_22847 Southard-Roman Nose 138kV ftlo Tatonga-Matthewson 345kV (OGE)
TEMP86_22813 Arnold-Ransom 115kV (SECI) ftlo Mingo-Setab 345kV (NPPD-SECI)
FRASPECOLMEA Fort Randall-Spence 115kV (NPPD-WAUE) ftlo Meadow Grove-Kelly 230kV (NPPD)
TMP194_22868 Oneta Transformer 345/138kV ftlo Oneta Transformer 345/138kV (CSWS)
PLXSUNTOLYOA Plant X Sub-Sundown 230kV ftlo Tolk Sub-Yoakum 230kV (SPS)
VINHAYPOSKNO Vine Tap-North Hays 115kV ftlo Post Rock-Knoll 230kV (MIDW)
TEMP85_22814 Wichita Transformer 345/138kV ftlo Wichita Transformer 345/138kV (WR)
TMP195_22869 Platte City-KCI 161kV ftlo Nashua-Roanridge 161kV (GMOC)
TEMP60_22466 Tuco-Stanton 115kV ftlo Tuco-Carlisle 230kV (SPS)
SILSPRTONFLI Siloam-Siloam Springs 161kV ftlo Tonnece-Flint Creek 345kV (CSWS-GRDA)

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

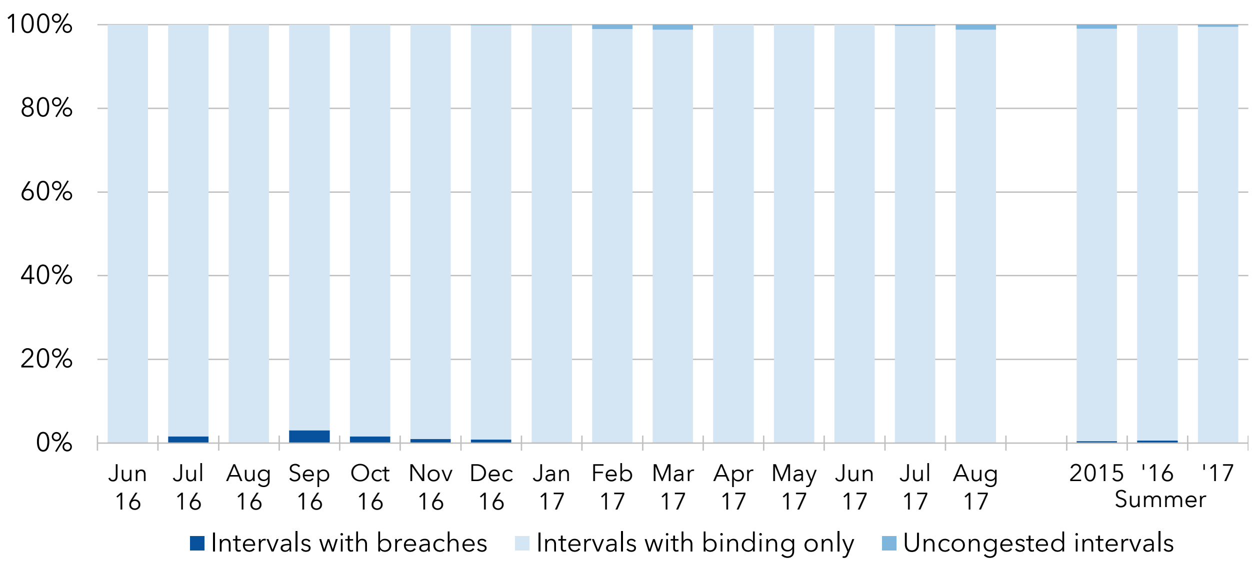


WDWFPLTATNOW Woodward-FPL Switch 138kV ftlo Woodward EHV-Northwest 345kV (OGE)
PLXSUNTOLYOA Plant X Sub-Sundown 230kV ftlo Tolk Sub-Yoakum 230kV (SPS)
NEORIVNEOBLC Neosho-Riverton 161kV (WR-EDE) ftlo Neosho-Blackberry 345kV (WR-AECI)
STAINDTUCCAR Stanton-Indiana 115kV ftlo Tuco-Carlisle 230kV (SPS)
SHAHAYPOSKNO South Hays-Hays 115kV ftlo Post Rock-Knoll 230kV (MIDW)
TEMP50_20937 Wolfforth-Terry County 115kV ftlo Sundown-Amoco Switching 230kV (SPS)
TAHH59MUSFTS Tahlequah-Highway 59 161kV ftlo Muskogee-Fort Smith 345kV (GRDA-OKGE)
OSGCANBUSDEA Osage Switch-Canyon East 115kV ftlo Bushland-Deaf Smith 230kV (SPS)
CARLPDLUBWOL Carlisle-LP Doud 115kV ftlo Lubbock South-Wolfforth 230kV (SPS)
HAWXFRHAWXFR Hawthorn Xfmr 345/161kV ftlo Hawthorn Xfmr 345/161kV (KCPL)

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.

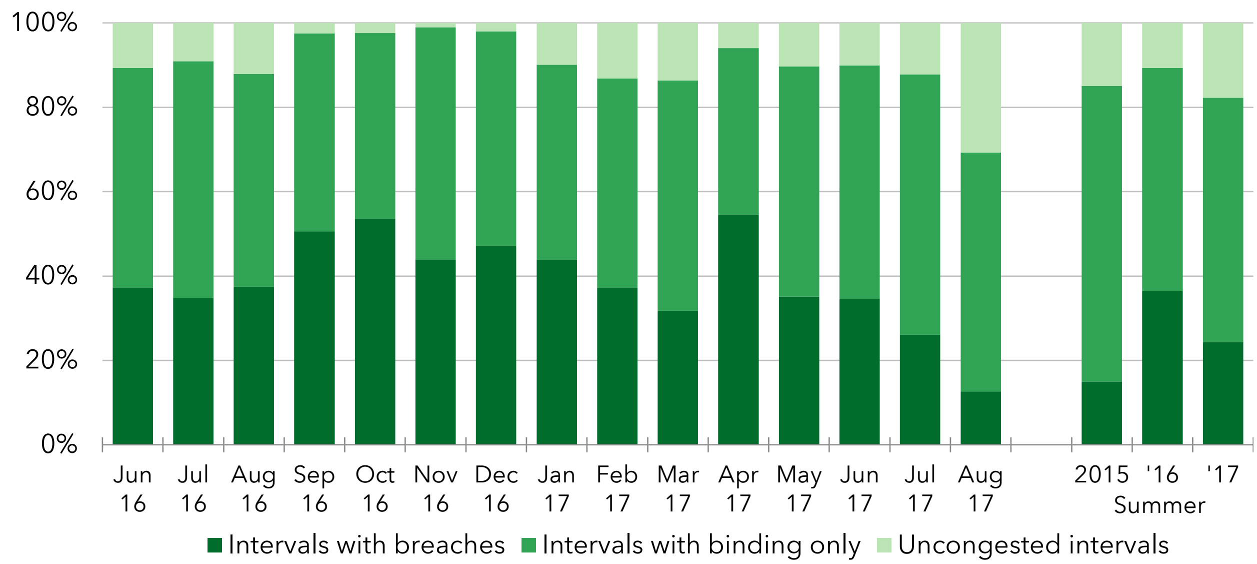
The figures below show the percent of intervals by month that had at least one breach, had only binding flowgates (but no breaches), or had no flowgates that were breached or binding (uncongested) in both the day-ahead (Figure 4–3) and real-time (Figure 4–4) markets. The frequency of congestion in the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

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 summer 2017 with 18 percent of intervals having no congestion, compared to 11 percent in summer 2016 and 15 percent in summer 2015. This can be primarily attributed to lower overall demand for the summer, especially in August when demand was significantly lower than the prior year, which is shown in Figure 3–1.

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 103 percent average net transmission congestion right funding during summer 2017 compared to 91 percent in summer 2016. August funding was at 93 percent indicating underfunding of transmission congestion rights due to low wind generation output and lower congestion resulting in lower day-ahead market congestion revenues. Year-to-date, 2017 day-ahead market congestion revenues and transmission congestion right payments are higher compared to 2016 levels primarily due to increased wind generation and resulting higher congestion.

Figure 4–5 Transmission congestion right funding

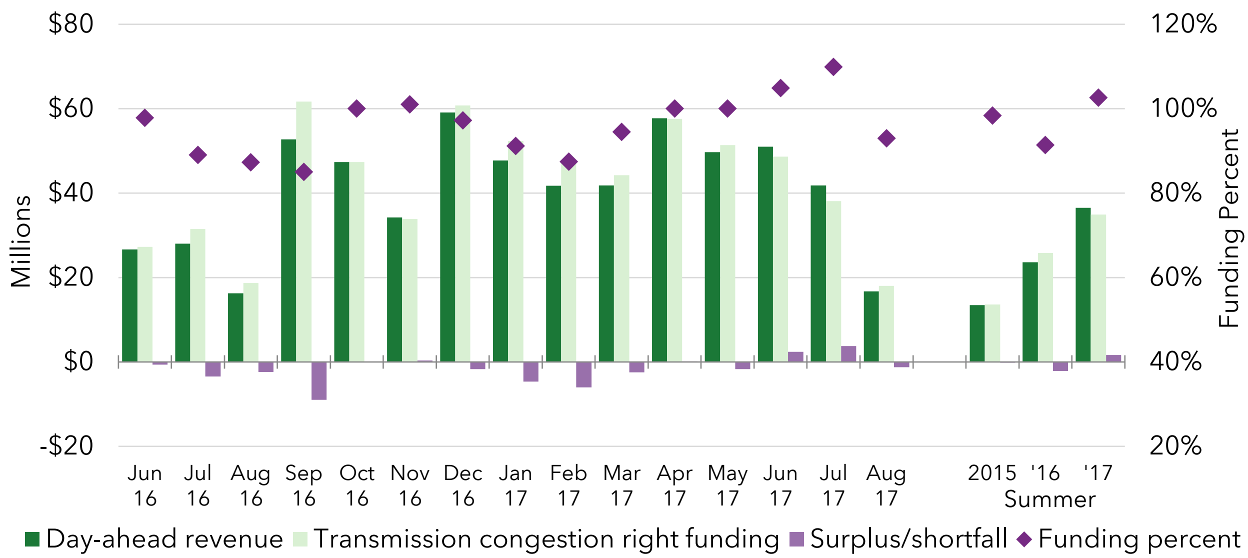
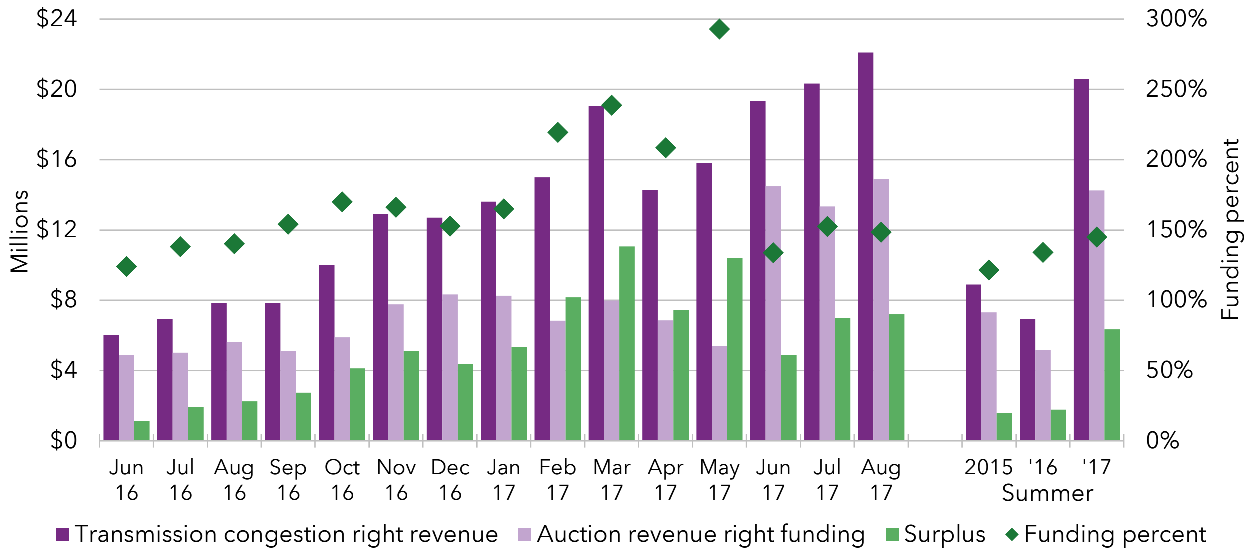


Figure 4–6 indicates that during summer 2017 auction revenue right funding was at 145 percent compared to summer 2016 level of 134 percent. Meanwhile the summer 2017 auction revenue right funding surplus was over triple the summer 2016 figure. Auction revenue rights funding surplus (and funding percent) 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 required to fund auction revenue rights payments 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

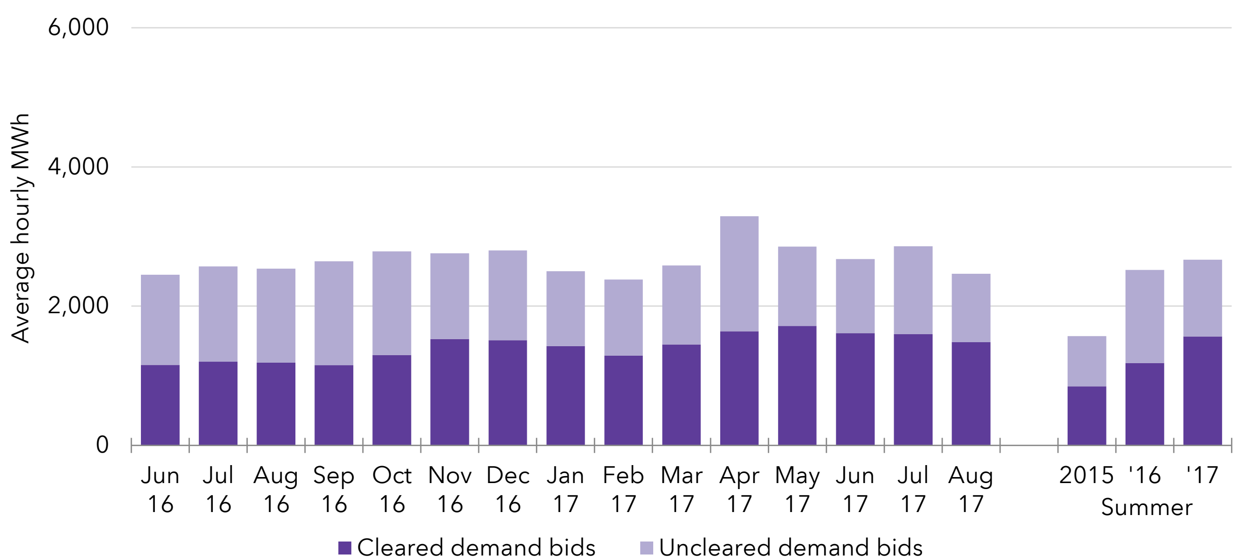
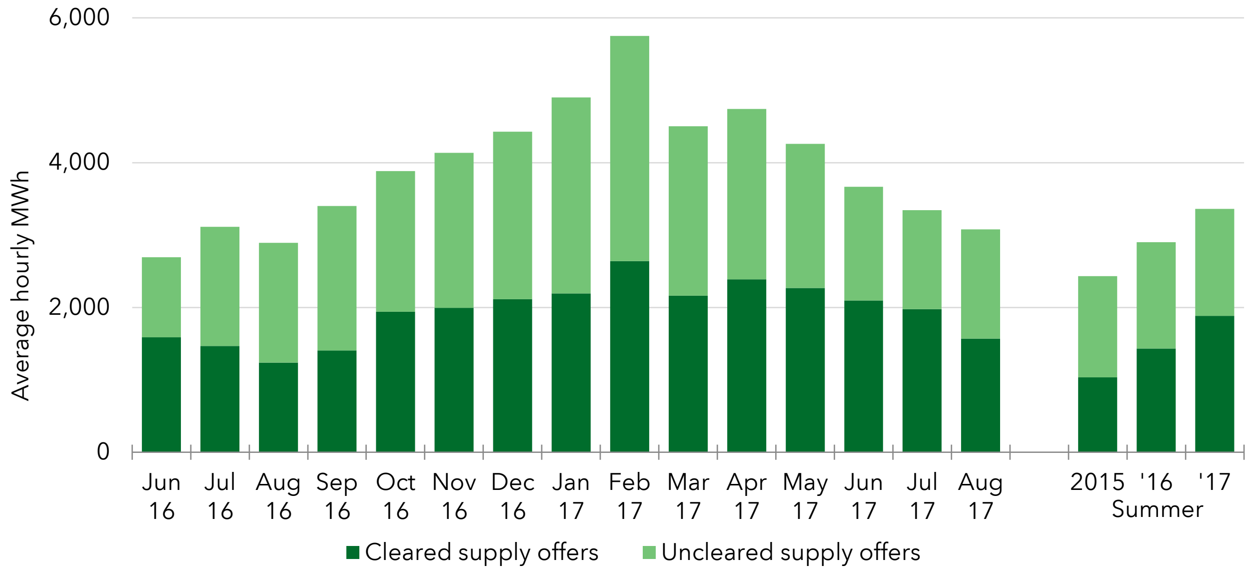
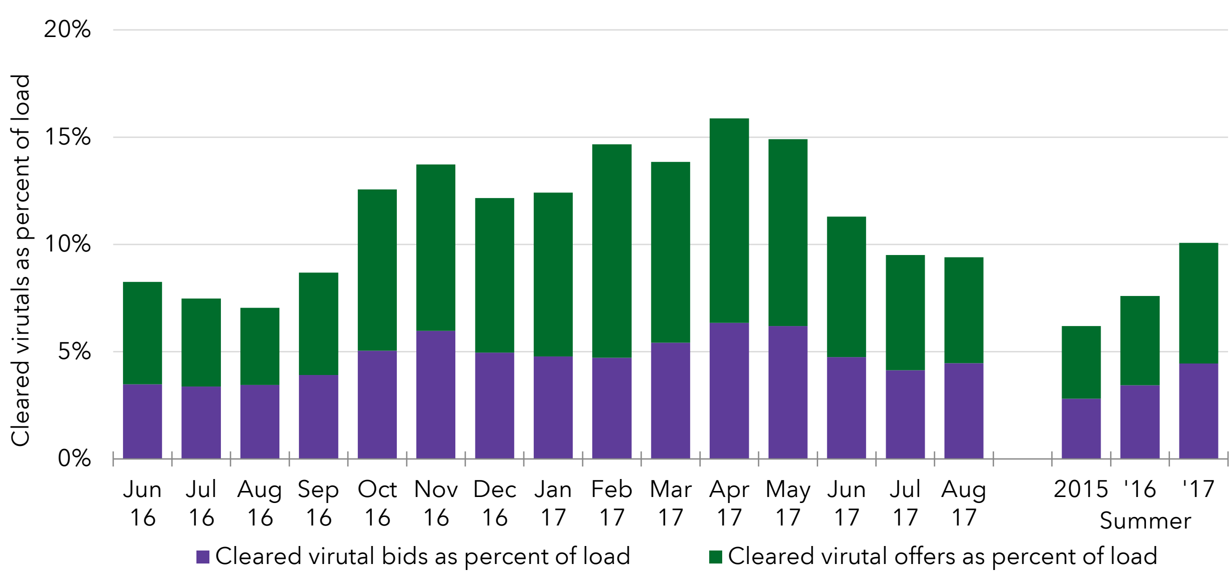


Figure 5–2 Virtual supply offers



For the summer period, virtual transactions as a percent of load has increased from six percent in 2015, to eight percent in 2016, and to 10 percent in 2017, as shown in Figure 5–3.

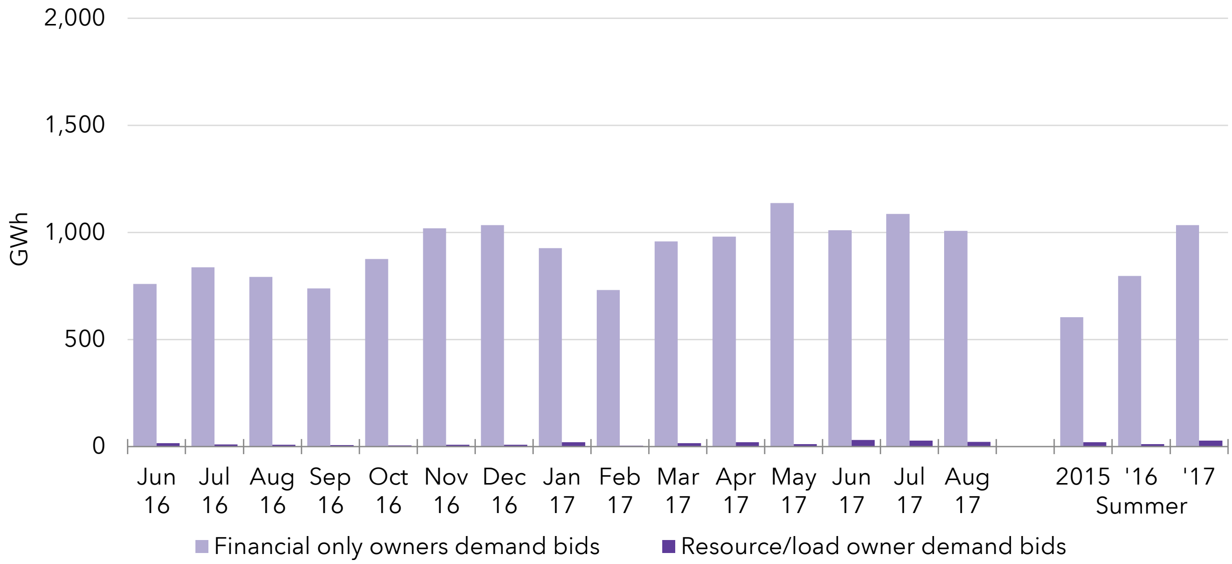
Figure 5–3 Cleared virtual transactions as a percent of load



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.

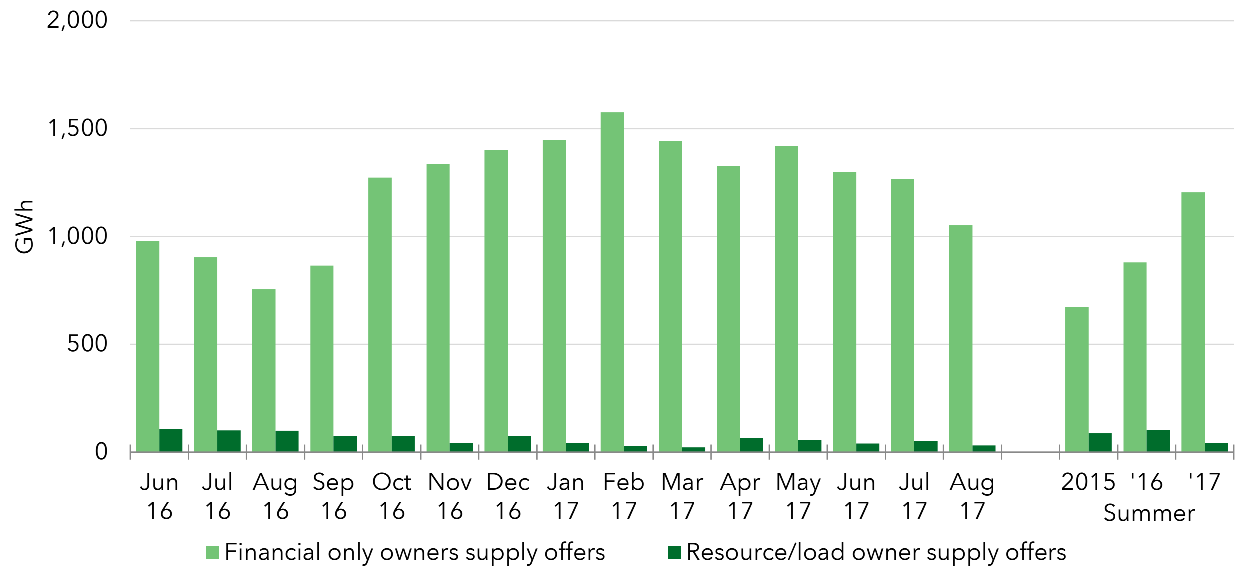
While the number of virtual demand bids by resource/load owners has remained negligible, demand bids by financial-only participants has increased by nearly 40 percent from 2015 to 2017. As shown in Figure 5–4 and Figure 5–5, the vast majority of virtual transactions are placed by financial-only market participants.

Figure 5–4 Virtual demand bids by participant type



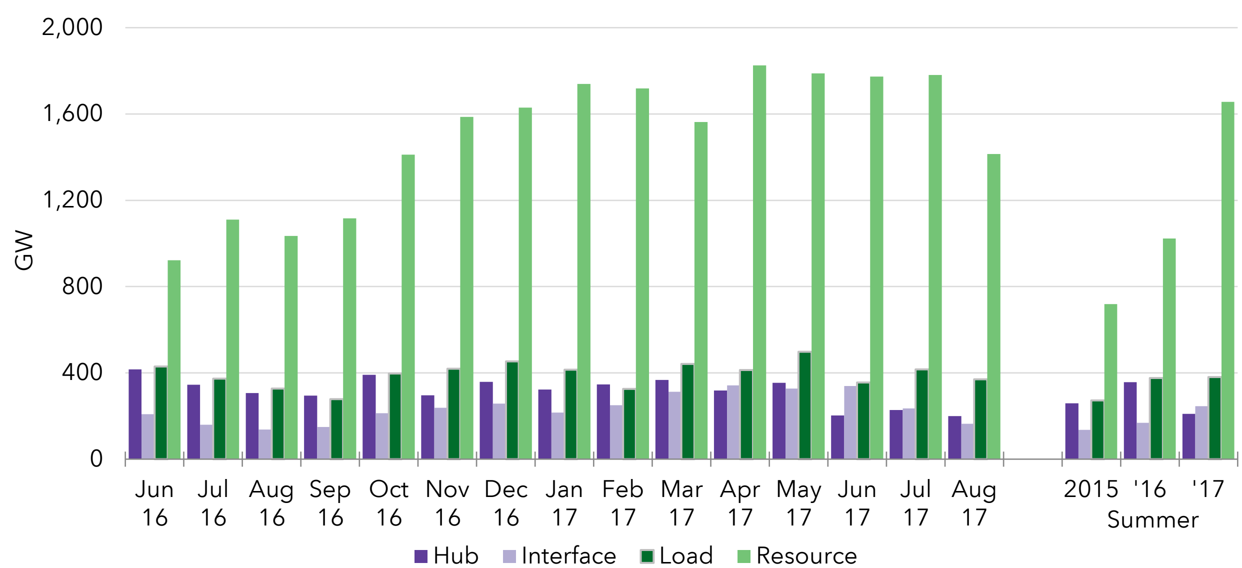
Virtual supply offers by resource/load owners have remained negligible as well, while financial-only participants have nearly doubled their virtual supply offers in that same period.

Figure 5–5 Virtual supply offers by participant type



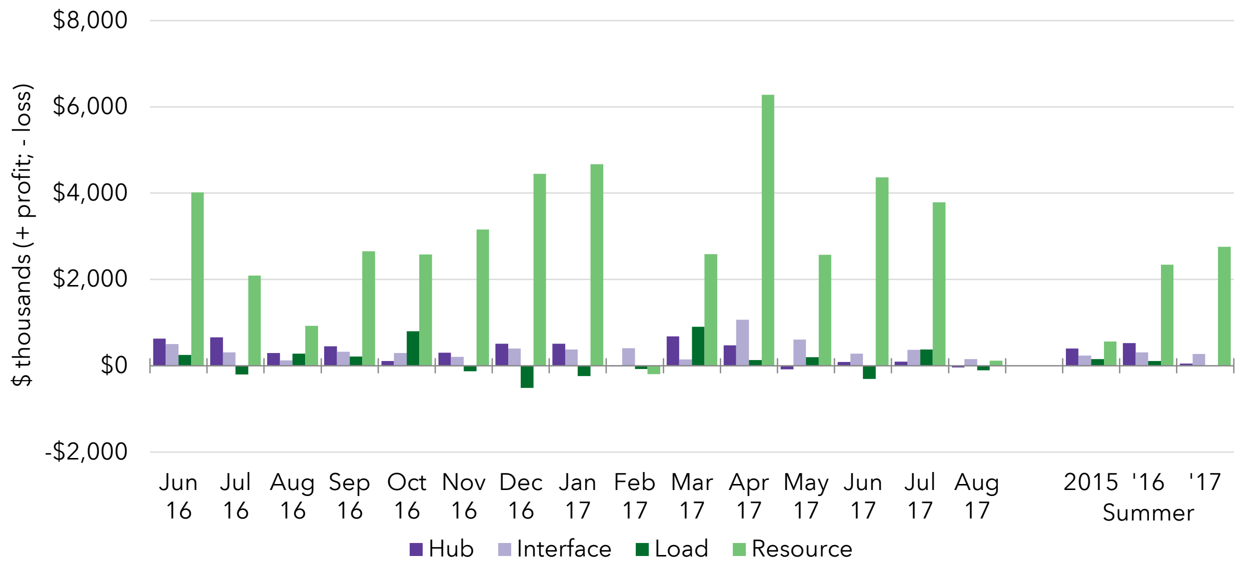
Shown in Figure 5–6, the great majority of virtual transactions are made at resources (primarily wind resources), with the fewest transactions at hubs and external interfaces.

Figure 5–6 Virtual transactions by location type, megawatts



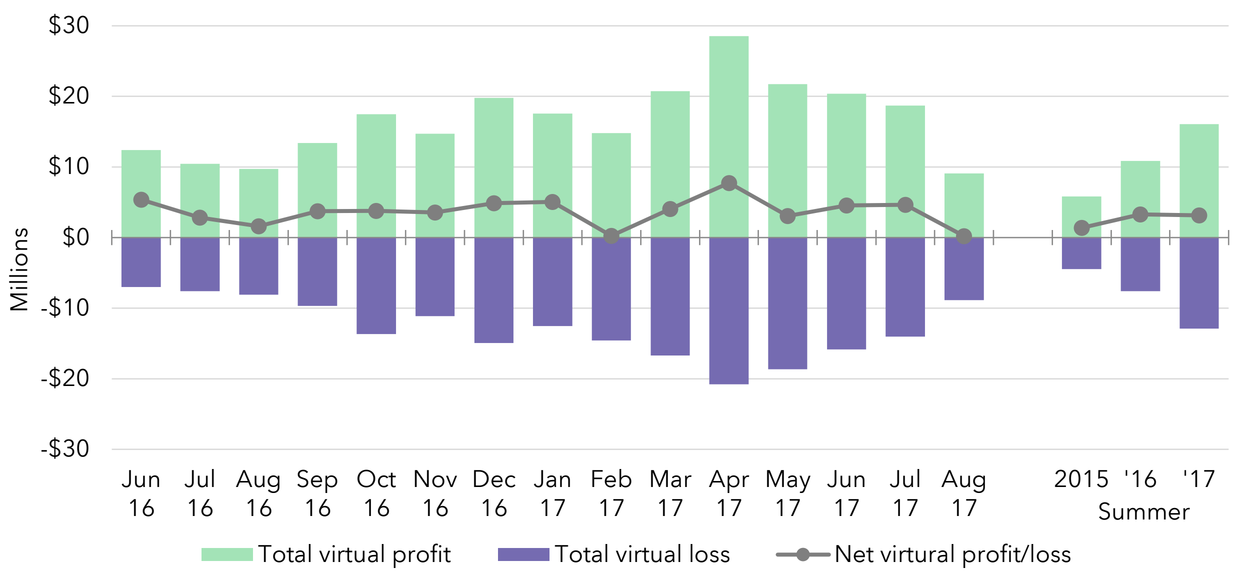
As with the volume of virtual transactions, the majority of the profits (shown in Figure 5–7) from virtual transactions are derived from resource locations.

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



Gross virtual profits for summer 2017, as shown in Figure 5–8, totaled just over $16 million, while gross virtual losses totaled nearly $13 million, for a net profit of $3.1 million. In comparison, summer 2016 had gross profits of nearly $11 million and gross losses of nearly $8 million, for a net profit of $3.1 million.

Figure 5–8 Virtual transactions, profit/loss



6. SPECIAL ISSUES

Scarcity pricing

In March 2017, SPP filed with FERC to modify the methodology by which scarcity pricing for contingency reserves (i.e., spinning and supplemental reserves) and regulation products is determined. The new methodology institutes a variable demand curve through which the value of the contingency reserves and regulation products is more appropriately reflected during intervals of scarcity pricing. On May 10, 2017, FERC issued a deficiency letter to SPP's filing asking for additional information including an explanation of rationale and methodology of the determinants used in the new variable demand curve. Subsequently, on June 9, 2017, SPP filed a response to the deficiency letter, and on August 4, 2017, FERC accepted the tariff revisions for filing, to become effective May 11, 2017, subject to refund and further FERC order without issuing a final order because of an "Absence of Quorum." The new design functionality was in SPP production as of May 11, 2017, however, it remained inactivated until SPP received a FERC order. Subsequently, it has been activated as of operating day August 11, 2017. Most recently, on September 20, 2017, FERC issued an order directing SPP to revise certain provisions of its earlier filing and make a compliance filing.

The previous scarcity mechanism for contingency reserves and regulation services had a single price for each product without regard to the level of scarcity or ramping limitation. In contrast, the new design establishes three blocks for contingency reserves products with increasing degrees of scarcity on a contingency reserve demand curve. The new design for regulation-up and regulation-down demand curves includes similar constructs as well as proposes six segments for each of the two products. In addition, the regulation-up and -down curves have a regulation base demand price to be used in determining scarcity prices. The regulation base demand price aims to incorporate the cost to commit a fast start resource to provide ramp or capacity to the market and is used in determining the magnitude of the blocks on the curve. The cost to commit a resource per megawatt is equal to the sum of the cold start-up cost and the product of the minimum run time, the sum of the average no-load cost and the average energy at minimum cost divided by the average resource minimum normal capacity operating limit.

Note that the previous SPP rules for capacity shortages did not include operating reserve shortages due to ramping limitations. In this filing, SPP took into account ramp-constrained operating reserve shortages when calculating scarcity prices and incorporated such shortages in establishing regulation-up and regulation-down demand curves. The respective demand curves are instituted within the market clearing engine and are used in calculating locational marginal prices.

Jointly owned units

Since the beginning of the Integrated Marketplace, SPP has given market participants several options for modeling of their jointly owned units. A market participant can register their jointly owned unit as:

1. a single resource in the market, in which the market participant would handle any division of revenues/charges to the individual shares outside of the market, or
2. as a "JOU" in the market, in which case they must choose to register as:
    a. an "individual JOU", where each individual share participates like an individual resource in the market and is committed and dispatched independently, or
    b. a "combined JOU", where each share owner submits offer cost data independently, but one designated share owner submits the physical parameters. With this option, the market system aggregates the offers into a single offer for commitment purposes, but then uses each individual shares' offers for dispatch purposes.

A market manipulation loophole was discovered with the combined option, which led to a market monitor recommendation in its 2014 annual report. A change was made to the design, which was implemented in August 2017. Almost immediately after implementation, market participants voiced concerns about the new design. With the new design, each share is required to submit a minimum capacity of zero megawatts. When this type of unit is uneconomical and dispatched down to its physical minimum capacity, the cheapest share may be the only share dispatched up to meet the physical minimum capacity—all the other shares could be at zero megawatts. In this case, the revenues are less than the costs of that share, and this share is taking the brunt of all the losses and effects on make whole payments.

Under the original design, each share would be dispatched down to their share ratio of the physical minimum capacity. Through other discussions with RTO staff and stakeholders, there have been many other issues pointed out, in both the combined option and the individual option. There is on-going discussion at the Market Working Group on this topic.

Price corrections

In early 2017, SPP proposed a new tariff revision modifying the criteria by which repricing is conducted and the proposed new rules were approved by FERC with an effective date of June 3, 2017. The new rules give SPP more discretion in determining price corrections in the day-ahead and real-time markets.

COMMON ACRONYMS

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