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1. MARKET HIGHLIGHTS

This report covers market performance and highlights during the spring quarter of 2018 (March through May). The annual figures shown on the charts in this report represent only this three-month period for each year, unless labelled otherwise. Higher loads, which were a result of abnormal temperatures, affected market outcomes during this period. Highlights of this spring period are as follows:

- The hourly average load for spring 2018 was up around eight percent from spring 2017. While March and April load in 2018 increased slightly compared to 2017, May 2018 average load was 14 percent higher than May 2017. These changes were primarily driven by lower than normal temperatures during March and April 2018, and much higher than normal temperatures during May 2018.

- Average monthly real-time generation increased by six percent from spring 2017 to spring 2018. Generation by coal-powered resources continued falling, accounting for only 37 percent of energy produced in the spring 2018 period. During this same period, wind resources accounted for almost 29 percent of total generation.

- During spring 2018, the day-ahead wind capacity factor was 38 percent. The capacity factor increased to 46 percent in the real-time market. The disparity between day-ahead and real-time capacity factors can contribute to negative price intervals.

- Use of the “market” commitment status in the day-ahead market continued to rise, while the use of the “self” commitment status declined.

- During spring 2018, the average day-ahead price was $23/MWh, an increase of 13 percent over spring 2017, and the average real-time price $22/MWh, a ten percent increase over spring 2017.

- Average monthly gas price at the Panhandle Eastern hub averaged $2.14/MMBtu for spring 2018, down from $2.70/MMBtu in spring 2017, a 20 percent decrease. For comparison, spring 2016 saw an extremely low natural gas cost of $1.68/MMBtu.
• After a long trend of increases, occurrences of negative price intervals decreased from the winter period, as well as spring 2017. Prices were negative in just over five percent of real-time intervals and just under two percent of day-ahead hours in spring 2018.

• The area with the highest congestion in the spring 2018 period was in southeast Oklahoma, while the area with the highest congestion for the past 12 months was in west-central Oklahoma. In addition, the high levels of congestion have abated on the Neosho – Riverton constraint in southwest Missouri/southwest Kansas.

• Overall congestion the SPP market footprint declined. Intervals with breaches in the real-time market declined from 40 percent in spring 2017 to 20 percent in spring 2018. Also, intervals with no congested constraints increased from 10 percent in spring 2017 to just over 21 percent in spring 2018. (Figure 5–4)

• The special issues section for the spring includes discussion of congestion and auction revenue rights in the SPP market. A study by the MMU has led to three main conclusions:
  
  o Successful ARR nominations have decreased.
  o The market’s overall need for hedges has increased.
  o Nomination behavior has remained relatively consistent.

More detailed discussion on auction revenue rights can be found in Section 6.

• Although outside of the date range covered by this report, the merger between Westar Energy and Great Plains Energy, parent company of Kansas City Power and Light, and the KCPL GMOC subsidiary, was completed effective June 5, 2018. The combined company would have accounted for 19.2 of total system load, using 2017 figures, making it the largest user of energy in the SPP market footprint.
2. LOAD AND RESOURCES

2.1 LOAD

The average hourly load for each month is shown in Figure 2–1 below.

Overall, the hourly average load for spring 2018 was just over 28,000 megawatts, which was up nearly eight percent from spring 2017. While March and April 2018 were slightly higher than the prior year, May 2018 average loads were 14 percent higher than 2017. This increase was primarily weather-driven as shown below. Load continued to follow the typical pattern with a trough in March and April, then began to climb in May to the summer peak.

Heating and cooling degree days are used to estimate the impact of actual weather conditions on energy consumption as shown in Figure 2–2 and Figure 2–3.
During the first four months of 2018, heating degree days were well above normal as compared to prior years. During May 2018, heating degree days dropped below the prior years and the 30 year average. Conversely, cooling degree days in the first four months of 2018 mirrored levels of prior years. However, May 2018 saw a significant increase compared to both prior years and the 30 year average. The high level of heating degree days in March and April is indicative of lower temperatures compared to prior years, and was mostly
concentrated in the northern portion of the SPP footprint. The high level of cooling degree days in May indicates higher average temperatures, and was fairly evenly distributed across the SPP footprint. SPP issued a hot weather alert for May 31 and June 1 due to unusually high temperatures for that time of year. These weather patterns were a key driver to the increased load during the spring season as shown in Figure 2–1.

2.2 RESOURCES

Total monthly generation, broken down by technology type of resources, is shown below in Figure 2–4. The “renewable” category includes biomass and other renewable resources (not including wind, solar, and hydro resources), while the “other” category includes fuel oil and miscellaneous resources.

Overall generation levels continue to increase slightly from year-to-year during the spring period, with spring 2018 average generation about six percent higher than spring 2017. This is consistent with the overall increase in loads in spring 2018. Figure 2–5 below shows the percentage of total generation attributed to each technology type.¹

¹ Only the most prevalent technology types are shown in this figure. Solar, renewable, hydro, and other resources are not shown.
The percentage of total generation provided by coal resources went from 41 percent in spring 2016, to 40 percent in spring 2017, and then dropped to 37 percent in spring 2018. Wind generation is up from 22 percent in spring 2016, to 28 percent in spring 2017, and to 29 percent in spring 2018. The percentage of total generation provided by simple-cycle natural gas resources has doubled from four percent in spring 2017 to eight percent in spring 2018. Nuclear generation in spring 2018 was about half the level of total generation in spring 2016, decreasing from 10 percent to five percent. This is primarily due to the retirement of the Fort Calhoun nuclear plant in October 2016, as well as outages of other nuclear resources due to maintenance.

Figure 2–6 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.\(^2\)

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\(^2\) 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 to the market.
Wind capacity in the footprint continues to grow steadily, with nameplate wind capacity increasing from 12,800 MW at the end of May 2016, to 17,700 MW at the end of May 2018.

The wind capacity factor in the real-time market increased by just 0.5 percent from spring 2017 to spring 2018, while the day-ahead wind capacity factor increased by nearly two percent during the same period. The real-time wind capacity factor for April 2018 was 48.8 percent, which is the highest real-time wind capacity factor since April 2014. Interestingly, the total nameplate wind capacity in April 2018 is 10,000 MW higher than the wind capacity in April 2014.

Figure 2–7 and Figure 2–8 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 day-ahead market, coal resources remain steady in being the marginal technology type, ranging from 25 to 28 percent in the spring season over the past three years. Gas resources also remain steady, setting prices in 30 to 33 percent of intervals in the spring. The biggest changes have been in the area of virtual transactions and wind resources on the margin. In spring 2016, virtual transaction set prices in 32 percent of day-ahead intervals. This dropped to 27 percent of intervals in spring 2017 and 17 percent of intervals in spring 2018. In the meantime, wind resources set prices in 22 percent of day-ahead intervals in spring 2018, up from 10 percent in spring 2016 and 17 percent in spring 2017. These trends have been consistent over the past several seasonal periods. Other resources, primarily representing oil-fired resources, increased from setting prices in a negligible number of intervals in prior years to three percent of all intervals in spring 2018. This can primarily be attributed to an increase in commitment of oil-fired generation to meet higher peak loads compared to previous years.
In the real-time market, coal resources were marginal in about 28 percent of all intervals in spring 2017 and 2018, compared to being marginal in over 44 percent of all intervals in spring 2016. This decline mirrors the decline in coal generation as a percent of all generation during this same period, which is shown in Figure 2–5 above. The decline was primarily offset with increases in gas simple cycle generation (20 percent in spring 2016, to 23 percent in spring 2017, and to 29 percent in spring 2018), and wind resources (9 percent in spring 2016, 15 percent in 2017, and 18 percent in 2018) on the margin.

2.3 EXTERNAL TRANSACTIONS

The SPP Integrated Marketplace has greater than 6,000 megawatts of AC interties with MISO to the east, 810 megawatts of DC ties to ERCOT to the south, and over 1,000 megawatts of DC ties to WECC to the west. Additionally, SPP has over 1,500 megawatts of interties with the Southwestern Power Administration (SPA) in Arkansas, Missouri, and Oklahoma, and over 5,000 megawatts of AC interties the Associated Electric Cooperative (AECl) in Oklahoma and Missouri.

As shown in Figure 2–9, SPP is typically a net exporter in real time, with the exception of the peak summer months where it is just slightly a net importer. In spring 2018, net exporters were lower than the previous years at 225 MW in spring 2018, compared to 420 MW in
spring 2016 and 550 MW in spring 2017. This change was likely a result of higher loads and higher corresponding prices in spring 2018 compared to prior years.

**Figure 2–9  Exports and imports, SPP system**

Generally, SPP exports follow the wind production curve for the day. Typically, as wind generation increases, exports increase. The same pattern of exports following wind is also evident on a month-to-month basis, as the highest wind generation months in the spring and the fall see the highest exports.

SPP began the market-to-market (M2M) process with MISO in March 2015. The market-to-market process under the joint operating agreement allows the monitoring and non-monitoring RTOs\(^3\) 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 to address flows.

Each RTO is allocated property rights on market-to-market constraints. These are known as firm flow entitlements (FFE), and each RTO calculates its real-time usage, known as market flow. RTOs exchange money (market-to-market settlements) for redispatch based on the non-monitoring RTO’s market flow in relation to its firm flow entitlement. The non-monitoring

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\(^3\) 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.
RTO receives money from the monitoring RTO if its market flow is below its firm flow entitlement. The non-monitoring RTO pays the monitoring RTO if its market flow is above its firm flow entitlement.

The total monthly market-to-market payments are shown in Figure 2–10, while the market-to-market payments by flowgate for the spring period are shown in Figure 2–11.
Market-to-market payments have returned to levels that are more typical after peaking during the period from October 2017 through February 2018. During that period high levels of congestion on the Neosho-Riverton for the loss of Neosho-Blackberry flowgate was the main driver for the high market-to-market payments. Two flowgates saw over $1 million in market-to-market payments to SPP during the spring period - NASXFRNASW (Nashua transformer for the loss of Nashua-Hawthorn) and NEORIVNEOBLC (Neosho-Riverton for the loss of Neosho-Blackberry) flowgate.
3. UNIT COMMITMENT AND DISPATCH PROCESSES

3.1 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 3–1. Capacity above the line indicates that there is generally sufficient available capacity to meet peak load obligations.

Figure 3–1   Peak hour offered capacity, real-time

![Figure 3–1](image)

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 wind capacity during the spring season typically ranged from 15 to 20 percent in spring 2017 and 2018, up from around 10 percent in the previous spring seasons. As can be seen from Figure 3–2, the load could be met on average during spring 2018 even without any wind generation.

Figure 3–2 shows the real-time average peak hour capacity overage. SPP calculates the amount of capacity overage required for the operating day to ensure that unit commitment is

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4 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.
sufficient to reliably serve load in real time while maintaining the operating reserve requirements.

Figure 3–2  Peak hour capacity overage, real-time average

The average peak hour overage for spring 2018 was around 3,700 MW, nearly identical to the level from spring 2016. Spring 2017 has a lower average of 3,200 MW.

3.2 GENERATION SCHEDULING

The day-ahead market provides market participants with the ability to submit offers to sell energy, regulation-up service, regulation-down service, spinning reserves, and supplemental reserves, and/or to submit bids to purchase energy. The day-ahead market co-optimizes the clearing of energy and operating reserve products out of the available capacity. All day-ahead market products are traded and settled on an hourly basis.

In 2017, participation in the day-ahead market was robust for both generation and load. Load-serving entities consistently offered generation into the day-ahead market at levels in excess of the requirements of the limited day-ahead must-offer obligation. Participation by merchant generation—for which no such obligation exists—was comparable to that of the load-serving entities.
Figure 3–3 shows generation participation offers in the day-ahead market by commitment status.

**Figure 3–3  **Day-ahead market offers by commitment status

The “market” commitment status averaged 55 percent and “self” commitment status averaged 25 percent of the total offered capacity in the day-ahead market for spring 2018. Resources with commitment statuses of “reliability,” “not participating,” and “outage” all have remained steady from spring 2016 to spring 2018.

Figure 3–4 shows just “market” and “self” commitment status in line form, giving a better view of the overall trend in these statuses.

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5 Of the self-committed resources, qualifying facilities (QF) account for three to four percent. Qualifying facilities often use self-commit status to exercise their rights under the Public Utilities Regulatory Policies Act of 1978 (PURPA).
“Market” commitment status is on a steady upward trend with 47 percent of all day-ahead commitments in spring 2016, 51 percent in spring 2017, and then 55 percent in spring 2018. Offered capacity in “self” commitment status is moving in the opposite direction with 34 percent in spring 2016, 30 percent in spring 2017, and 25 percent is spring 2018. Self-commitment status represented 23.5 percent of offered capacity in April. This was the lowest value since April 2014, just after the launch of the Integrated Market.

While we view the reduction of self-committed offers as a positive trend, which may have also helped contribute to a reduction in the frequency of negative prices, we continue to encourage market participants and the RTO to find ways to enhance market efficiencies and reduce self-commitment.

Figure 3–5 shows online capacity commitment as a percent of load.
The capacity commitment as a percent of load has decreased significantly over the past few years. Some factors that contribute to lower levels of online capacity are fewer self-committed coal plants and the continued growth of wind capacity and generation. Lower online capacity levels may be a result of market participants and market operators adjusting to these changes in market conditions.

### 3.3 VIRTUAL TRADING

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 3–6) and supply offers (Figure 3–7).
As these figures show, virtual demand bids have steadily increased from year-to-year, while virtual supplier offers were at similar levels from spring 2017 to 2018.

Cleared virtual transactions as a percent of load are shown in Figure 3–8.
For the spring period, virtual transactions as a percent of load have increased steadily from ten percent in 2016, to 17 percent in 2018.

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.

Figure 3–9 and Figure 3–10 show virtual transactions by participant type, either financial-only entities, or entities with resources and/or load. These figures show that financial-only market participants place the vast majority of virtual transactions.
While the number of virtual demand bids and supply offers by resource/load owners has remained negligible over time, both demand bids and supply offers by financial-only participants have nearly doubled from spring 2016 to 2018.

Virtual transactions can be made at hubs, interfaces, loads and resources, as shown in Figure 3–11.
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 external interfaces and hubs. Virtual transactions at load locations have been increasing on a year-to-year basis, but not as much as the increase in transactions at resource locations.

As with the volume of virtual transactions, the majority of the profits, shown in Figure 3–12, from virtual transactions are derived from resource locations.
Compared to spring 2017, the profits of virtual transactions from resource locations in spring 2018 was about half that of the prior year.

Overall profit and loss from virtual transactions is shown in Figure 3–13.

**Figure 3–13  Virtual transactions, profit/loss**

Gross virtual profits for spring 2018 averaged just over $22 million, while gross virtual losses averaged nearly $20 million, for an average net profit of $2.2 million. In comparison, spring 2017 had average gross profits of nearly $24 million and average gross losses of nearly $19 million, for an average net profit of almost $5 million. Given the profile of many virtual transactions, much of the decline in profitability this spring was likely a result of the change in market dynamics because of the different load patterns this spring.
4. PRICES

4.1 MARKET PRICES

Historically, gas and electricity prices have been highly correlated in the SPP market. Workably competitive electricity markets are expected to see highly correlated gas costs and electricity prices in general. Although this correlation is generally observed over time, some periods exhibit divergence.

**Figure 4–1  Electricity and gas prices**

Since spiking to $3.23/MMBtu in January 2018, the average gas prices at the Panhandle Eastern hub have ranged between $2.08/MMBtu and $2.23/MMBtu on a monthly basis. For the spring period, gas prices dropped by just over 20 percent from $2.70/MMBtu in spring 2017 to $2.14/MMBtu in 2018. The average gas price for spring 2016 was even lower, at $1.68/MMBtu.

During spring 2018 the average day-ahead price was $23.08/MWh, and the average real-time price was $22.03/MWh, as shown in Figure 4–1. This represents an increase in average day-ahead price of 13 percent over spring 2017, and a 10 percent increase in real-time price for the same period. As stated earlier, there are periods where gas costs decrease, while energy prices increase, as was the case in spring 2018. This can be partially attributed to
higher loads during the spring period compared to previous years, as well as fewer negative price intervals, and generation outages.

Figure 4–2 shows the day-ahead to real-time price divergence at the SPP system level. Price divergence\(^6\) 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.

**Figure 4–2   Price divergence, day-ahead and real-time**

![Graph showing price divergence between day-ahead and real-time markets.](image)

Divergence percent increased from slightly negative in spring 2017, to seven percent in spring 2018. After a steep increase from spring 2016 to 2017, absolute divergence percent dropped slightly from 10 percent in spring 2017 to 9.5 percent in 2018.

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

\(^6\) Price divergence percent is calculated as the day-ahead price minus the real-time price, divided by the day-ahead price.
Lower prices are typically 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. Lately, the areas with highest congestion have been in southeast Oklahoma,\(^7\) northwest Kansas around Hays,\(^8\) and the southwest Missouri/southeast Kansas region.\(^9\)

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.

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\(^7\) TMP109_22593, Tupelo Tap-Tupelo 138kV for the loss of Seminole-Pittsburg 345kV; and TMP322_23590, Tupelo Tap-Tupelo 138kV for the loss of Terry Road-Sunnyside 345kV

\(^8\) VINHAYPOS(KNO, Vine Tap-North Hays 115kV for the loss of Post Rock-Knoll 230kV; and TMP309_23629, Vine Tap-North Hays 115kV for the loss of Post Rock-Axtell 345kV

\(^9\) NEORIVNEOBLC, Neosho-Riverton 161kV for the loss of Neosho-Blackberry 345kV
Figure 4–4 and Figure 4–5 display average prices paid by load-serving entity for the spring period and the last twelve months. For the spring period, the footprint average, along with nearly all load-serving entities, have returned to having higher day-ahead prices than real-time prices.

**Figure 4–4  Price by load-serving entity, spring**

Spring period average real-time prices are the highest in northeast Texas (East Texas Electric Cooperative and Tenaska/Gateway), while the highest day-ahead average price was at the Kansas City (KS) Board of Public Utilities. Average prices continued to be lowest for entities located in western Kansas, along with a few entities in the northern portion of the SPP footprint. Congestion on TMP289_23515 (Craig – Lenexa 161kV ftlo Craig – Pflumm 161kV ) in February and March 2018 was due to transmission outages that impacted prices around the Kansas City area.
Figure 4–5  Price by load-serving entity, rolling 12 month

Figure 4–6 shows monthly average day-ahead and real-time prices for the SPP North and SPP South trading hubs. A trading hub is a settlement location consisting of an aggregation of price nodes for financial and trading purposes.

Figure 4–6  Trading hub prices

Because of an abundance of lower-cost generation in the northern part of the SPP footprint, prices at the North hub are typically lower than the South hub. As shown above, North hub day-ahead and real-time average prices were higher than South hub prices during each of
the three months in the spring period. This can be attributed to many factors, including
colder temperatures in the northern portion the SPP footprint in March and April, the
upgrade to the Woodward transformer shifting some congestion out of the South hub, and a
decrease in market-to-market transactions impacting the South hub.

4.2 NEGATIVE PRICES

After steady growth of intervals with negative prices, spring 2018 saw a decrease in negative
price intervals as shown in Figure 4–7.

Figure 4–7   Negative price intervals, day-ahead

![Negative price intervals chart]

In spring 2018, one percent of all asset owner intervals\(^{10}\) in the day-ahead market had prices
below zero. This is down from three percent of asset owner intervals in spring 2016, and four
percent of asset owner intervals in spring 2017.

\(^{10}\) Asset owner intervals are calculated as the number of asset owners serving load that are active in an
interval. For example, if there 60 asset owners active in one five minute interval throughout an entire
30 day month, the total asset owner intervals would be 518,400 for the month (60 asset owners * 288
intervals per day * 30 days).
While the same pattern holds in the real-time market (see Figure 4–8), the frequency of negative price intervals in the real-time market is about three times that of the day-ahead market.

**Figure 4–8  Negative price intervals, real-time**

Spring 2018 had about four percent of all asset owner intervals with negative prices, compared to just over five percent spring 2016 and 10 percent in spring 2017. The reduction can be attributed to higher load in the SPP system due to the weather, along with the energizing of Woodward – Tatonga – Matthewson 345kV project, which was completed in February 2018. Note that negative prices in the day-ahead market are almost exclusively between $−0.01/MWh and $−25/MWh, where in the real-time market a sizable number of intervals have prices lower than $−25/MWh.

4.3 OPERATING RESERVE MARKET

The following figures (Figure 4–9 through Figure 4–12) show marginal clearing prices for the four operating reserve products: (1) regulation-up, (2) regulation-down, (3) spinning reserve, and (4) supplemental reserve. The regulation products are used to ensure the amount of generation matches load on a subinterval basis. Generators respond to regulation instructions in seconds. Spinning and supplemental products are reserved for contingency situations and respond to instructions within ten minutes.
While energy prices increased from spring 2017 to 2018, operating reserve market clearing prices for regulation products dropped in the same period, mirroring the decrease in the gas price.
Spinning reserves followed the same pattern as regulation products, decreasing from $1.69/MW in spring 2017 to $0.64 in spring 2018. Day-ahead supplemental reserves increased slightly from $0.76/MW in spring 2017 to $0.93 in spring 2018, but fell from $1.69/MW to $0.64 for real-time supplemental reserves for the same period.
4.4 MITIGATION

SPP uses an automated conduct and impact mitigation approach to address potential market power abuse. 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 4–13 shows the frequency of mitigation of incremental energy, operating reserves, and no-load costs in the day-ahead market.

Spring 2018 had an average of 0.13 percent of total resource hours mitigated for all products in the day-ahead market, down from 0.24 percent of resource hours in spring 2017.

For the real-time market, the mitigation of incremental energy is shown in Figure 4–14.
Mitigation frequency in the real-time market remains at very low levels. Mitigation frequency for the past three spring seasons has averaged less than 0.01 percent.

Figure 4–15 shows the mitigation of start-up offers for different commitment types.
The overall level for mitigation of start-up offers is typically low during the spring months, peaking in the summer and fall. Over the past three spring seasons, mitigation of start-up offers has been around two percent.

4.5 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 4–16) applies to commitments from the day-ahead market. Day-ahead make-whole payments are typically less frequent and smaller in magnitude than those in the real-time market.

Figure 4–16  Make whole payments, day-ahead

Typically most day-ahead make-whole payments are attributed to coal and gas resources. Compared to the previous year, spring 2018 day-ahead make-whole payments were up about eight percent, an increase of roughly $500,000. Make-whole payments to coal resources were up around $1 million from spring 2017 to 2018, while payments to gas resources were down around $500,000.

The reliability unit commitment (RUC) make-whole payment (Figure 4–17) applies to commitments made in the day-ahead RUC and intra-day RUC processes. The majority of the
reliability unit commitment make-whole payments are paid to gas resources, and more specifically gas simple-cycle resources.

**Figure 4–17  Make whole payments, reliability unit commitment**

Spring 2018 monthly real-time make-whole payments totaled just over $7 million, about $3 million lower than spring 2017. This was driven primarily by a decline in uplift payments to combined cycle resources in spring 2018. May 2018 saw more reliability unit commitment make-whole payments than the other spring months, and was roughly equal to May 2017. However, the amount of make-whole payments paid to resources with a technology type of “other,” which are typically oil-fired resources, was over $640,000. This is the highest amount of make-whole payments to “other” resources since the start of the Integrated Marketplace. This can mostly be attributed to oil-fired commitments during peak load periods after other fuel types with fast start ability had been committed.

The make-whole payment distribution charge, as shown in Figure 4–18, 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.

**Figure 4–18  Make whole payment distribution rate**

The day-ahead distribution rate remains steady in all months, averaging around $0.10/MWh. The real-time distribution rate for spring 2018 was right at $0.70/MWh, down from $0.95/MWh in spring 2017.

Regulation compensation includes payment to market participants, which are shown in Figure 4–19 and Figure 4–20, based on changes in energy output for regulation deployment.
Regulation-up mileage make-whole payments remained steady in both the day-ahead and real-time markets. The regulation-up mileage factor decreased from 0.19 in spring 2017 to 0.14 in 2018.

Day-ahead regulation-down mileage make-whole payments, as well as the regulation-down mileage factor have steadily increased over the past three spring seasons. Real-time regulation-down mileage make-whole payments decreased slightly from spring 2017 to
spring 2018. Generally, as the wind output increases, regulation-down deployment increases, which increases the mileage factor. Additionally, many thermal units cannot regulate on their economic minimum so the market pays the opportunity cost to move them to the regulation minimum increasing the regulation down prices.

Revenue neutrality uplift (RNU), shown in Figure 4–21, 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.

**Figure 4–21  Revenue neutrality uplift**

Total revenue neutrality uplift for spring 2018 was $13.5 million, just under the spring 2017 total of $14.1 million. On a monthly basis, revenue neutrality uplift typically averages around $4 million per month, with variations primarily driven by seasonality and congestion levels.

The all-in cost, shown in Figure 4–22 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.

**Figure 4–22 All-in cost**

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 spring 2018 was $23.78/MWh, just three percent higher than the spring 2017 level of $23.13/MWh.

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11 Reserve sharing group costs and demand response costs are included in the all-in price, however costs for both of those items are zero.
5. CONGESTION AND TRANSMISSION CONGESTION RIGHTS MARKET

5.1 CONGESTION

The impact of a constraint on the market is represented 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 increment of relief on a congested constraint in reducing the total production costs. This is the marginal congestion component of the energy price. Congestion by shadow price for the spring period is shown in Figure 5–1, while congestion by shadow price for the rolling 12-month period ending May 2018 is shown in Figure 5–2. 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.

Figure 5–1 Congestion by shadow price, spring
During the spring season, the TMP109_22593 (Tupelo Tap-Tupelo 138kV for the loss of Seminole-Pittsburg 345kV) has been the most congested flowgate. This flowgate is located in southeast Oklahoma and has experienced an increase in congestion over the past year since installation of an extra-high voltage phase-shifting transformer at Woodward in May 2017. As a point of comparison, the WDFWPLTATNOW (Woodward-FPL switch 138kV for the loss of Tatonga-Northwest 345kV) constraint had a shadow price of nearly $120/MWh in real-time and nearly $150/MWh in the day-ahead market for the spring 2017 period. The Neosho – Riverton 161kV constraint is a market-to-market flowgate that has been highly congested over the past several months. SPP and MISO wind impacts this flowgate, as well as flows from neighboring non-market areas.\textsuperscript{12} Congestion in this area has abated somewhat recently.

\textbf{Figure 5–2} Congestion by shadow price, rolling 12 month

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{congestion_diagram.png}
\caption{Congestion by shadow price, rolling 12 month}
\end{figure}

\textsuperscript{12} Neighboring non-markets include; Tennessee Valley Authority, Associated Electric Cooperative Inc., and Southwestern Power Administration.
With the prevalence of wind generation in the western portion of the SPP footprint, the Woodward flowgate (WDWFPLTATNOW), had been the most congested flowgate for a period extending over one year. This flowgate now does not appear in the top ten congested flowgates for the past 12 months. This can primarily be attributed to the installation of an extra-high voltage phase-shifting transformer at Woodward in late May 2017, which increased the amount of transfer capability in the area. However, the most congested flowgate over the past 12 months has been TMP118_22847 (Southard-Roman Nose 138kV ftlo Tatonga-Matthewson 345kV), which is located to the east of the Woodward flowgate. The installation of the extra-high voltage transformer at Woodward has not eliminated congestion, but rather redistributed congestion across a wider area, thus making the TMP118_22847 the most congested flowgate for the past 12 months.

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 5–3) and real-time (Figure 5–4) markets.

**Figure 5–3  Congestion by interval, day-ahead**
In the day-ahead market over 99 percent of all intervals have only binding constraints, with uncongested intervals and intervals with a breach making up just a fraction of all intervals.

**Figure 5–4  Congestion by interval, real-time**

Overall, real-time market congestion decreased markedly from the last spring period, with 20 percent of intervals with a breach in spring 2018, down from 40 percent of all intervals in spring 2017. The Woodward – Tatonga – Matthewson 345kV project was completed in February 2018 which has helped reduce congestion in the western portion of the footprint. Another reason for a reduction in breaches could be the change to violation relaxation limits in March 2017 which allowed the market to solve at a higher shadow price before relaxing a constraint limit. Intervals without congestion increased in spring 2018, with just over 20 percent of all intervals having no congestion.

### 5.2 TRANSMISSION CONGESTION RIGHTS MARKET

In the Integrated Marketplace, the day-ahead market generally charges load a higher price than it pays generation. The difference in price is generally due to congestion. 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.

The transmission congestion right and auction revenue right net payments paid to entities in the SPP are shown in Figure 5–5.

**Figure 5–5  Total congestion payments, TCR year**

<table>
<thead>
<tr>
<th>(in $ millions)</th>
<th>Load-serving entities</th>
<th>Non-load-serving and financial only entities</th>
</tr>
</thead>
<tbody>
<tr>
<td>DA congestion</td>
<td>136.1</td>
<td>341.3</td>
</tr>
<tr>
<td>RT congestion</td>
<td>4.7</td>
<td>36.2</td>
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<tr>
<td>Net congestion</td>
<td>140.8</td>
<td>377.5</td>
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<td>TCR charges</td>
<td>60.4</td>
<td>46.3</td>
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<td>TCR payments</td>
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<td>(272.0)</td>
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<tr>
<td>TCR uplift</td>
<td>14.5</td>
<td>21.4</td>
</tr>
<tr>
<td>TCR surplus *</td>
<td>(2.3)</td>
<td>(5.6)</td>
</tr>
<tr>
<td>ARR payments</td>
<td>(88.5)</td>
<td>(67.8)</td>
</tr>
<tr>
<td>ARR surplus</td>
<td>(25.1)</td>
<td>(59.7)</td>
</tr>
<tr>
<td>Net TCR/ARR</td>
<td>(159.2)</td>
<td>(337.4)</td>
</tr>
</tbody>
</table>

*remaining at year end

Payments to load-serving entities of $459 million exceeded their day-ahead congestion costs of $395 million for the 2017. Additionally, the sum of the day-ahead and real-time congestion costs was also less than the payments to load-serving entities, totaling $407 million. This shows that overall, load-serving entities did a good job at hedging congestion through the transmission congestion right market. Day-ahead congestion costs, for load-serving entities, have had major increases with a 151 percent increase in 2016, and another 16 percent increase in 2017.

Additionally, non-load-serving and financial only entities collected transmission congestion right and auction revenue right net revenues of $127 million, which exceeded their day-ahead and real-time market congestion costs of $59 million. This shows that overall, non-load-serving, and financial only entities were effective at hedging congestion through the transmission congestion right market. Figure 5–5 also shows significant increases in day-

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13 The TCR year spans from June through the following May.
ahead congestion costs for non-load-serving and financial only entities. Day-ahead congestion for these market participants increased 284 percent in 2016, and increased 24 percent again in 2017.

Figure 5–6 shows, by market participant, the day-ahead congestion exposure along with the value of the auction revenue right and transmission congestion hedges, as well as the net overall position.

**Figure 5–6   Net congestion revenue by market participant,\(^{14}\) 2017 TCR year**

Figure 5–6 highlights that the majority of participants received positive net revenues, while a handful of participants had hedges that significantly did not cover their day-ahead congestion costs. For instance, the bottom five participants collectively paid nearly $50 million more in congestion costs than was hedged by their auction revenue right and transmission congestion right positions.

Figure 5–7 below shows transmission congestion right funding, day-ahead revenue, net surplus/shortfall, and transmission congestion right funding percent.

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\(^{14}\) Figure 5–6 displays participants who received auction revenue right closeout settlements.
Transmission congestion right funding levels fell within the target range\textsuperscript{15} during both the 2016 and 2017 TCR years near 94 percent. Furthermore, transmission congestion right funding for the 2017 and 2018 spring quarters also fell within the target range at 97 percent and 95 percent respectively. This is an increase from spring 2016 where funding reached 88 percent.

\textsuperscript{15} Target range is implied in the Protocols section 5.3.3. “In the event the cumulative funding is at or below 90% or above 100%, MWG may approve an additional adjustment…“
Figure 5–8  Transmission congestion right funding, monthly, 2017 TCR year

Figure 5–8 shows transmission congestion right funding percentages appear relatively consistent over the 2017 TCR year. The funding peaks in July around 110 percent and troughs in February near 81 percent. Only one-third of the funding percentages fell within the target range.

Daily observations of transmission congestion right funding for the 2017 TCR year are shown in Figure 5–9.

Figure 5–9  Transmission congestion right funding, daily, TCR year
Most daily observations of transmission congestion right funding fall between 80 percent and 105 percent. While variation in funding can be expected as a result of factors including transmission outages and derates, the fact that the majority of funding falls in this range indicates that the overall process is generally effective.

Figure 5–10 shows transmission congestion right revenue, auction revenue right funding, net surplus, and auction revenue right funding percent.

Figure 5–10  Auction revenue right funding, TCR year and spring quarter

In reference to TCR years, auction revenue right funding percentages decreased from 182 percent in 2016 to 158 percent in 2017. While the surplus dollars doubled during this period, the decrease in funding percentage is due to an even greater percentage increase in auction revenue right funding.

Spring quarter figures followed roughly the same pattern as the figures associated with TCR year. Although, during the spring quarters of 2017 and 2018 funding percentages were much higher than those associated with the TCR year. Funding in the spring of 2017 was over 240 percent and subsequently decreased in 2018 to 184 percent.

Figure 5–11 shows the auction revenue right funding percentages by month for the 2017 TCR year.
Figure 5–11 shows auction revenue right funding percentages remained mostly consistent near 145 percent prior to increasing in January 2018. In addition to the spike in January, spring 2018 saw much higher funding percentages, which peaked in April near 200 percent.

The auction revenue rights funding surplus (and funding percent) remain elevated. These funding levels may be a reflection of the market’s historical congestion expectation, or possibly an indication of the market’s appetite for risk.
6. SPECIAL ISSUES

Congestion and auction revenue rights

As the Integrated Marketplace has matured, market participants have expressed difficulty in obtaining hedges through the auction revenue rights (ARR) allocation process. To investigate this issue the MMU has evaluated day-ahead market congestion and auction revenue right ARR bidding behavior. The study has led to three main conclusions: successful ARR nominations have decreased, the market’s overall need for hedges has increased, and nomination behavior has remained relatively consistent.

Successful ARR nominations have decreased

To study the claim that some participants are unable to obtain hedges, the MMU developed a metric that identifies how successful a participant is at receiving ARRs that they nominate, as seen in Figure 6–1. This ratio divides the awarded ARR megawatts by the nominated ARR megawatts.

Figure 6–1  Percentage of ARRs awarded to ARRs nominated

16 This metric is an ARR nomination success ratio. The long-term congestion right (LTCR) success ratios were also calculated and amounted to 100 percent for both prevailing flow and counter flow during the 2017 TCR year.
As the figure shows, market participants have been awarded much less than they have attempted to nominate, ranging from around 68 percent in the 2015 TCR year to 57 percent in the 2017 TCR year.\textsuperscript{17} As this figure shows, the success of nominated ARRs decreased by more than 16 percent over the past three years.

This trend is nearly identical between on-peak and off-peak products. While the trend is directionally similar in both prevailing flow\textsuperscript{18} and counter flow\textsuperscript{19} paths, it is more significant in those paths classified as counter flow, as seen in Figure 6–2 below.

**Figure 6–2** Percentage of ARRs awarded to ARRs nominated by flow type

Because counter flow generally relieves constraints, it may seem peculiar that the auction did not award these paths at all. However, it is possible that day-ahead counter flow paths could have been modeled, accurately, as prevailing flow in the congestion hedging models and, as such, more likely to be curtailed.

\textsuperscript{17} The TCR year runs from June to the following May. When referring to the 2017 TCR year, this covers the period beginning June 2017 through May 2018.

\textsuperscript{18} Prevailing flow, as classified by the day-ahead market, is where day-ahead congestion is larger at the sink and smaller at the source.

\textsuperscript{19} Counter flow, as classified by the day-ahead market, is where day-ahead congestion is smaller at the sink and larger at the source.
Additionally, as shown in Figure 6–3 below, market participants achieve varying levels of success in the allocation.

**Figure 6–3  Percentage of ARRs awarded to ARRs nominated by market participant, 2017 TCR year**

This disparity in successfully receiving nominated ARR positions likely correlates with the topology of the transmission system and is also likely related to differences between the day-ahead and allocation models.

**The market’s need for hedges has increased**

To achieve success in the congestion hedging process, a market participant must receive hedges for their congested paths, or obtain paths\(^ {20} \) that provide revenues, which offset their congestion cost. We quantify hedging need by measuring the magnitude of day-ahead congestion rent\(^ {21} \) by market participant. We do this because auction clearing prices tend not to reflect participant hedging needs as well as congestion rent.\(^ {22} \) Figure 6–4 below shows that the market participants’ collective hedging needs are increasing.

\(^ {20} \) SPP Integrated Marketplace Protocols – Section 5.3.1 ARR Nominations  
\(^ {21} \) Measured as the difference in the marginal congestion components at the source and sink.  
\(^ {22} \) There are multiple reasons for the differences including bidding approaches and outages.
However, each market participant’s hedging needs may differ significantly. Market participants who have negative congestion rent have no net hedging need. Conversely, market participants who have positive congestion rent have net hedging needs. As hedging needs differ among participants, some are advantaged from the start, whereas others are disadvantaged, as seen in Figure 6–5.

**Figure 6–5**  Day-ahead congestion rent by market participant, 2017 TCR year
For instance, the largest value shown above amounts to over $75 million, which means this market participant must obtain hedges equal to this value to breakeven with respect to their day-ahead congestion position. On the other hand, the smallest value amounts to roughly negative $7 million. This market participant can do nothing and their day-ahead congestion position will profit by this amount. Similar to the starting position in an automotive race, some participants start at the front whereas others start from the back.

**Market participant behavior has remained relatively consistent**

To measure behavioral trends in the allocation, the MMU has developed another metric. This metric divides ARR megawatt nominations by the total amount of candidate ARR megawatts available to be nominated by market participants. This metric is one way of measuring participant intent as seen in Figure 6–6.

**Figure 6–6  Percentage of ARR nominations to candidate ARRs**

The market’s behavior has been relatively consistent even though individual market participants have varying levels of hedging needs. Prevailing flow has been constant over the past three TCR years at 70 percent. Counter flow has varied somewhat between, 15 and 25 percent.

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23 This metric is an ARR attempt ratio where candidate ARRs are the megawatts available to be nominated, which are derived from transmission service reservations, are divided by market participant ARR nominations.
While the overall trends have been similar, the nomination behavior among participants materially differs. Figure 6–7 below shows that some participants attempt to nominate the majority of their portfolio, while other participants attempt to nominate specific paths within their portfolio.

One potential cause for the inconsistency in nomination behavior could be a result of the settlement incentives surrounding counter flow. Because counter flow products can obligate payments on paths, their nomination is generally disincentivized. However, given the differences in congestion results between the ARR process and day-ahead market, we find several paths that are represented as counter flow in the ARR process that end up as prevailing flow in the day-ahead market. As such, some participants may nominate counter flow with the calculated anticipation that the flow could change to prevailing flow in the day-ahead market.

**Congestion and auction revenue rights summary**

In summary, successful nominations have decreased, the market’s overall need for hedges has increased, and nomination behavior has remained relatively consistent.
The growth in day-ahead congestion generally correlates with the overall increase in wind production in the footprint. With over 28 gigawatts\textsuperscript{24} of additional wind capacity planned in the generation interconnection queue, the need for hedging will likely continue to increase.

There are many possible causes for the decrease in awarded ARRs relative to nominated ARRs. Given that participant behavior has not materially changed, the root cause tends to point toward something other than market participant behavior. One potential root cause could be differences in the models between the day-ahead market and the allocation. These differences likely relate to outages, timing of the allocation, length of the products, and other system conditions. However, even with the challenges discussed in this section, as shown in Figure 5–6, most participants with significant day-ahead congestion exposure were able successfully hedge their positions for the 2017 TCR year.

Going forward, the MMU recommends further review and consideration of the auction revenue right process by the RTO and stakeholders given the trends identified in this report.

\textsuperscript{24} Southwest Power Pool, Market Monitoring Unit 2017 Annual State of the Market Report, Figure 2-18.
# COMMON ACRONYMNS

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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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