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1 MARKET HIGHLIGHTS

This report covers market performance and highlights during the winter quarter of 2020 (December 2019 through February 2020). Annual figures shown on the charts in this report represent only this three-month period for each year, unless labelled otherwise. Highlights of this winter period are as follows:

- Average hourly load in winter 2020 was down three percent from 2019. Warmer temperatures than prior years during this period contributed to the lower load.

- Generation by coal resources as a percent of total generation continued to decline, down from 44 percent in winter 2019 to 30 percent in winter 2020. This decrease has primarily been offset by increases in gas-fired and wind generation.

- Net market-to-market payments for winter 2020 were just over $5 million paid by MISO to SPP. Total payments from MISO to SPP were just over $5.5 million, while payments from SPP to MISO were nearly $600,000. This is down from winter 2019 when net payments from MISO to SPP were nearly $6.3 million.

- Resources were in “market” commitment status in nearly 62 percent of all intervals, up from 51 percent in winter 2019.

- Offered capacity in “self” commitment status fell, with approximately 21 percent of commitments with this status in winter 2020, down from nearly 32 percent in winter 2019.

- After a sustained trend of increasing outages, winter 2020 saw 30,000 GWh of total generation outages, compared to 35,500 GWh in winter 2019.

- The winter 2020 average gas price at the Panhandle Eastern pipeline was $1.68/MMBtu, a drop of 46 percent from the winter 2019 price of $2.99/MMBtu.

- During winter 2020, the average day-ahead energy price was $18.18/MWh, and the average real-time price was $16.93/MWh. These prices are both down about 27 percent from winter 2019 energy prices.
- The areas with highest prices in the footprint for the winter are concentrated in the far southeast portion of the SPP footprint, while low prices were abundant in the western portion of the footprint.

- Overall, real-time market congestion was higher in winter 2020. In winter 2020, 34 percent of all real-time intervals had a breach, up from around 30 percent in both winter 2018 and 2019.

- The surplus between the congestion payments and the day-ahead congestion cost for load-serving entities shows that overall all load-serving entities fully covered their congestion cost through the congestion hedging market.

- The special issues section provides a summary of the 2019 Frequently Constrained Area study, which was published in March 2020. Based on the analysis, the MMU proposed the removal of the Southwest Missouri and Central Kansas Frequently Constrained Areas (FCA), with no additions at this time.
2 LOAD AND RESOURCES

This chapter reviews load and resources in the SPP market for the winter 2020 period. Key points from this chapter include:

- Average hourly load in winter 2020 was down three percent from 2019. Warmer temperatures than prior years during this period contributed to the lower load.

- Generation by coal resources as a percent of total generation continued to decline, down from 44 percent in winter 2019 to 30 percent in winter 2020. This decrease has primarily been offset by increases in gas-fired and wind generation.

- Wind generation capacity at the end of February 2020 was nearly 22,500 MW. This amount increased by 600 MW since August 2019. Wind generation increased by nearly 18 percent when compared with winter 2019, which was a lower wind period.

- In the real-time market, gas resources set prices most frequently at half of all intervals. Coal resources were next at 34 percent and wind resources were price setting during 16 percent of all intervals.

- Net market-to-market payments for winter 2020 were just over $5 million paid by MISO to SPP. Total payments from MISO to SPP were just over $5.5 million, while payments from SPP to MISO were nearly $600,000. This is down from winter 2019 when net payments from MISO to SPP were nearly $6.3 million.

2.1 LOAD

The average hourly load for each month is shown in Figure 2–1 below.
Average hourly load for the 2020 winter season was just under three percent below winter 2019. December load was nearly identical to the prior year, while January and February load was well below 2019.

Heating degree days are used to estimate the impact of actual weather conditions on energy consumption as shown in Figure 2–2.

Heating degree days for all months of the 2020 winter season were below the prior years. In addition, December 2019 and January 2020 were below the 30-year average. Overall, heating
degree days were down about 10 percent from winter 2019 to winter 2020. This is primary driver for lower load in 2020, as shown in Figure 2–1.

### 2.2 RESOURCES

Total monthly generation, broken down by technology type of resource, is shown below in Figure 2–3. 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.

**Figure 2–3  Generation by technology type, real-time**

Overall generation levels were down three percent from winter 2019 to winter 2020, matching the decrease in load in the same period. Wind generation increased 18 percent from winter 2019 to winter 2020, while gas, simple-cycle and gas, combined-cycle generation increased by 59 and 24 percent, respectively in the same period. Coal generation, meanwhile, decreased by 33 percent from winter 2019 to winter 2020.

Figure 2–4 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. This chart does not include solar, renewable, hydro, and other resources.
Overall, wind generation surpassed all other fuel types during the quarter. Generation by coal resources as a percentage of total generation continues to decline, dropping from 44 percent in winter 2019, to 30 percent in winter 2020. While wind generation as a percentage of total generation was flat at 26 percent from winter 2018 to winter 2019, it grew to just over 31 percent on total generation in winter 2020, slightly exceeding coal generation for the quarter. Generation by both gas, simple-cycle and gas, combined cycle resources also increased from winter 2019 to winter 2020. This can be primarily attributed to continued low gas costs in the period.

Figure 2–5 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 but the resource may not be providing any generation to the market.
Wind capacity in the footprint continues to grow steadily year-over-year, with nameplate wind capacity increasing from a monthly average of 17,700 MW in winter 2018, to 20,900 MW in winter 2019, and to 22,500 in winter 2020.

The wind capacity factor in the real-time market climbed from 39 percent in winter 2019 to 42 percent in winter 2020, while the day-ahead wind capacity factor climbed from 31 percent to 33 percent during the same period. The winter 2020 capacity factors for both day-ahead and real-time were below the levels from winter 2018. This can primarily be attributed to increased capacity added to the market over the years.

Figure 2–6 and Figure 2–7 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 the real-time 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 were the marginal technology type in about 35 percent of intervals in winter 2018 and 2019. In winter 2020, coal resources dropped to being the marginal technology type in 28 percent of intervals. Virtual transactions set prices in 30 percent of intervals in winter 2020, up from 22 and 24 percent of intervals in winter 2018 and 2019, respectively. Gas combined-cycle and simple-cycle resources acting as the marginal technology type has remained consistent over the past three winter seasons. Wind resources set prices in the day-ahead market in 10 percent of intervals in winter 2020, up from nine percent in 2019, but down from 12 percent in 2018.
In the real-time market, each of the major technology types set prices around a quarter of all intervals. Coal resources were the highest technology type to set prices at 34 percent of all real-time intervals in winter 2020, down from 40 percent in both winter 2018 and 2019. Gas combined-cycle and simple-cycle resources set prices the next highest, and remained consistent over the last three winter seasons at 31 percent and 19 percent, respectively. Wind resources were the marginal technology type in 16 percent of intervals in winter 2020, up from 12 percent in 2019, and 10 percent in 2018.

2.3 EXTERNAL TRANSACTIONS

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

Figure 2–8 shows average hourly imports and exports across the SPP system.

SPP had typically been a net exporter in real time, with the exception of May 2019; however, starting in December 2019, SPP was a net importer for the three winter 2020 months. While exports for winter 2020 were down slightly from 2018 and 2019, the level of imports have
climbed steadily from winter 2018 to winter 2020, which reduced net exports from an average of 345 MW per hour to a net import of nearly 100 MW per hour. The increase in imports can primarily be attributed to an increase in imports from Southwestern Power Administration and Associated Electric Cooperatives. Lower loads (similar to those experienced by SPP in this period) in these areas may have played a role in the increased imports from these regions.

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 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 2–9, while the market-to-market payments by flowgate for the summer period are shown in Figure 2–10.

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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.
Payments are predominantly from MISO to SPP for most of the year, with the exception of the summer. For the winter period, market-to-market payments paid to SPP by MISO were just over $5.5 million, while total payments from SPP to MISO were nearly $600,000, for a net paid from MISO to SPP of just over $5 million. During winter 2018, the Neosho to Riverton flowgate was highly congested, resulting in high payments from MISO to SPP.

While the vast majority of market-to-market constraints has net market-to-market payments in winter 2020 of less than $250,000, two market-to-market flowgates had payments over $1
million – the Neosho to Riverton flowgate at $1.3 million, and TMP405_25342 [Oahe to Sully Buttes 230kV (WAUE)].
3 UNIT COMMITMENT AND DISPATCH

This chapter reviews unit commitment and dispatch processes in the SPP market for the winter 2020 period. Key points from this chapter include:

- Peak hour capacity overage increased from nearly 3,500 MW in winter 2019 to just over 4,200 MW in winter 2020.
- Resources were in “market” commitment status in nearly 62 percent of all intervals, up from 51 percent in winter 2019.
- Offered capacity in “self” commitment status fell, with approximately 21 percent of commitments with this status in winter 2020, down from nearly 32 percent in winter 2019.
- After a sustained trend of increasing outages, winter 2020 saw 30,000 GWh of total generation outages, compared to 35,500 GWh in winter 2019.
- Cleared virtual supply offers as a percent of load in winter 2020 continued to climb – from 9.4 percent in winter 2019 to 10.5 percent in 2020. Cleared demand bids were virtually unchanged in winter 2020 from the previous year at 7.3 percent.
- Net virtual profits for winter 2020 totaled nearly $8 million before fees, decreasing to nearly $1 million after fees. This is a decrease from about $22 million before fees in winter 2019 and nearly $8 million after fees.

3.1 UNIT COMMITMENT

Figure 3–1 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 sufficient to reliably serve load in real time while maintaining the operating reserve requirements.
The average peak hour overage\(^4\) for winter 2020 was 4,200 MW, up from about 3,500 MW in winter 2019 and just over 4,000 MW in winter 2018. This increase may partially be attributed to higher capacity commitments because of more wind in the footprint.

### 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.

Participation in the day-ahead market tends to be robust for both generation and load in the market. Load procures over 98 percent of its requirements in the day ahead market. 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

\(^4\) The calculation for real-time average peak hour capacity overage is: economic maximum – load – net scheduled interchange – (regulation up + spinning reserves + supplemental reserves). All capacity from wind generation is not included in the economic maximum. Only capacity from traditional fuel resources is included in this calculation.
generation—for which no such obligation exists—was comparable to that of the load-serving entities.

Figure 3–2 shows the percentage of capacity\(^5\) in the day-ahead market for the “market,” “self,” and “outage” commitment statuses. “Reliability” and “not participating” are other statuses that are available, but the total of those statuses typically average around five to six percent on a monthly basis.

**Figure 3–2 Day-ahead commitment status**

\(^\text{5}^\) All resources, including wind, are included at nameplate capacity.
The capacity commitment as a percent of demand for the past three winter seasons has ranged from around 117 percent to 122 percent. The increase in capacity as a percent of demand in the June to October period may reflect operator actions to commit additional capacity to meet uncertainty. As was stated in last year’s annual state of the market report and updated in the 2019 Annual State of the Market report⁶, the MMU is continuing to promote the creation of an uncertainty product to help remediate this issue.

Generation outages by fuel type of resource are shown in Figure 3–4. This metric shows the total gigawatt-hours of resources on outage for each fuel type.

---

After a sustained trend of increasing outages, winter 2020 saw just over 30,000 GWh of total generation outages, down from just over 32,000 GWh in winter 2019, but up from 29,000 GWh in winter 2018. The decrease is most pronounced among coal resources, where total outages has dropped from 11,500 GWh in winter 2019 to just under 8,300 GWh in winter 2020.

### 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 both cleared and uncleared virtual demand bids (Figure 3–5) and supply offers (Figure 3–6).
As these figures show, both cleared and uncleared virtual supply offers have steadily increased from winter 2018 to 2020. Additionally, uncleared virtual demand bids have also steadily increased, as well, with the exception of a slight decrease in cleared demand bids from winter 2019 to winter 2020.

Cleared virtual transactions as a percent of load are shown in Figure 3–7.
Figure 3–7  Cleared virtual transactions as a percent of load

For the winter period, total cleared virtual transactions as a percent of load were just under 18 percent in winter 2020, up from around 17 percent in winter 2019 and 15 percent in winter 2018. The majority of the virtual offers are at wind resources and offer volumes at these locations tend to increase on windier days.

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 3–8 and Figure 3–9 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.
Virtual demand bids by financial-only participants dropped from about 1,500 GWh to 1,400 GWh from winter 2019 to 2020, while virtual supply offers by financial-only participants increased during this period from nearly 1,900 GWh in winter 2019 to just over 2,000 GWh in winter 2020. While the number of virtual demand bids and supply offers by resource/load owners has remained low compared to financial-only participants over time, both demand bids and supply offers by resource/load owners are slowly, but steadily growing over time.
Virtual transactions can be made at hubs, interfaces, loads, and resources, as shown in Figure 3–10.

**Figure 3–10 Virtual transactions by location type, megawatts**

The great majority of virtual transactions are made at resources (primarily wind resources), with nearly 2,300 GW in winter 2020, compared to 2,000 GW in winter 2018 and 2019. Historically, participants have placed the fewest virtual transactions at external interfaces and hubs. While virtual transactions at load locations overall represent about 20 percent of all virtuals, they have been slowly increasing over the past few years.

As with the volume of virtual transactions, the majority of the profits (before fees), shown in Figure 3–11, from virtual transactions are derived from resource locations.
Average monthly profit from virtual transactions at the resource level increased was just over $2 million in winter 2020, down from nearly $4 million in winter 2019. Profits from virtual transactions at hubs, loads, and interfaces also dropped from winter 2019 to winter 2020.

Overall profit and loss from virtual transactions, both before and after fees, is shown in Figure 3–12.
Net virtual profits before fees for winter 2020 totaled nearly $8 million, down from $21.5 million in winter 2019. Net virtual profits after fees in winter 2020 were $800,000, compared to nearly $8 million in winter 2019.
4 MARKET PRICES AND COSTS

This chapter reviews prices in the SPP market for the winter 2020 period. Key points from this chapter include:

- The winter 2020 average gas price at the Panhandle Eastern pipeline was $1.68/MMBtu, a drop of 46 percent from the winter 2019 price of $2.99/MMBtu.
- During winter 2020, the average day-ahead energy price was $18.18/MWh, and the average real-time price was $16.93/MWh. These prices are both down about 27 percent from winter 2019 energy prices.
- The areas with highest prices in the footprint for the winter are concentrated in the far southeast portion of the SPP footprint, while low prices were abundant in the western portion of the footprint.
- Both day-ahead and real-time prices at the North and South hubs were very close in winter 2020, with day-ahead prices around $18/MWh and real-time prices around $17/MWh. After seeing North hub prices below the South hub prices in the previous two winter seasons, the North and South hub prices have converged.
- Winter 2020 saw nearly 4.4 percent of real-time intervals having negative prices. This is down from 4.7 percent in winter 2019, and down from 5.5 percent in winter 2018.
- Revenue neutrality uplift for winter 2020 was nearly $17 million, down nearly half from $32 million in winter 2019.

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.
Gas prices at the Panhandle Eastern hub have remained under $2.00/MMBtu since April 2019, reaching a low of $1.37/MMBtu in June 2019. This is the lowest average monthly gas price since the start of the SPP Integrated Marketplace. For winter 2020, the average gas price was $1.62/MMBtu; this is down by nearly half from $2.99/MMBtu in winter 2019. Gas prices in the Permian Basin have been even lower, reaching below $0.50/MMBtu on some days.

During winter 2020, the average day-ahead energy price was $18.18/MWh, and the average real-time price was $16.93/MWh, as shown in Figure 4–1, both down about 27 percent from winter 2019. These low prices are, in part, a result of the low gas prices and high wind generation.

Implied heat rate shows the relative efficiency of generation required to cover the variable costs of production, given system prices. Figure 4–2 shows the implied heat rate for the winter period for the past three years.
As the figure above shows, the implied heat rate has climbed from winter 2019 to winter 2020. As a result of the low gas prices, the average implied heat rate for winter 2020 increased to 10,400 Btu/KWh, up from 7,800 Btu/KWh in winter 2019. This growth in the implied heat rate matches the growth in generation by gas resources, as shown in Figure 2–4.

Figure 4–3 shows the day-ahead to real-time price divergence at the SPP system level. Price divergence 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. Price divergence percent is calculated as the day-ahead price minus the real-time price, divided by the day-ahead price. The absolute divergence is calculated by taking the absolute value of the divergence for each interval.
Absolute divergence, divergence, and the divergence percent all decreased from winter 2019 to 2020. This is an encouraging sign, as price convergence is an indicator of an effectively and efficiently operating market. Although price divergence has improved, a ramping capability product would likely address some of the ramping limitations that can cause price volatility.7

Overall price patterns between the day-ahead and real-time markets are similar, as shown on the price contour map below in Figure 4–4. 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.

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Lower prices are typically more prevalent in the west-central part of the footprint due to abundant low-cost wind generation in that area. However, this can change because of localized congestion and outages. The areas with highest prices in the footprint for the winter are concentrated in the southeast portion of the SPP footprint. Congestion in these areas that contributed to the high and low prices is discussed in Chapter 5 of this report. The lowest prices in the footprint for the winter were found in the western portion of the footprint.

Figure 4–5 and Figure 4–6 display average prices paid by load-serving entity for the winter period and the last 12 months.
Winter period average prices were the highest in the People’s Electric Cooperative and City Utilities of Springfield, and lowest in entities in western Kansas.

Over the past 12 months, People’s Electric Cooperative and entities around southwest Missouri saw the highest prices overall, while entities in the northern portion of the footprint and in western Kansas saw the lowest prices overall. Western Kansas has abundant low-cost generation, primarily wind, while the northwest portion of the footprint has primarily low-cost
coal and hydro generation. Typically, entities in those portions of the SPP footprint see some of the lowest prices overall.

Figure 4–7 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 4–7  Trading hub prices**

Because of an abundance of lower-cost generation in the northern part of the SPP footprint, historically prices at the North hub have typically been lower than the South hub. Both day-ahead and real-time prices at the North and South hubs were very close in winter 2020, with day-ahead prices around $18/MWh and real-time prices around $17/MWh. After seeing North hub prices below the South hub prices in the previous two winter seasons, the North and South hub prices have converged.

In addition, hub prices can be broken down into on-peak and off-peak prices, as shown in Figure 4–8 and Figure 4–9.
Historically, there has been a price spread between on- and off-peak prices at both hubs around $10/MWh. However, in winter 2020, the spread between day-ahead and real-time prices has converged to about $6/MWh. While there are monthly variations, the average spread has remained fairly consistent over the past several years.

While negative prices are a legitimate market outcome, they can make it difficult for generators to earn revenue. Negative price intervals can be caused by many different factors including high amounts of wind generation, self-commitment of resources in the day-ahead market, negative
natural gas prices, and external impacts. Negative price intervals for the day-ahead market are shown in Figure 4–10.

**Figure 4–10**  Negative price intervals, day-ahead

In winter 2020, less than one percent of asset owner intervals⁸ in the day-ahead market had prices below zero. This is down from nearly two percent in winter 2018.

Typically, the frequency of negative price intervals in the real-time market is about three times that of the day-ahead market as shown in Figure 4–11.

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⁸ 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).
Winter 2020 had 4.4 percent of all asset owner intervals in the real-time market with negative prices, compared to 5.5 percent in winter 2018 and 4.7 percent in winter 2019.

The MMU discussed during SPP’s Holistic Integrated Tariff Team process potential concerns with unduly low offers on price. The Holistic Integrated Tariff Team ultimately adopted a recommendation to review the effects of these offers and potentially develop automatic mitigation to ensure that prices are only negative when market fundamentals dictate it.9

4.2 OPERATING RESERVE MARKET

The following figures (Figure 4–12 through Figure 4–15) 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.

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Both regulation-up and regulation-down prices in winter 2020 fell from levels in winter 2018 and 2019. Regulation-up and regulation-down mileage dropped during that same period, as well.
Marginal clearing prices for both spinning and supplemental reserves dropped in both the day-ahead and real-time markets from winter 2018 and 2019 to winter 2020. While these reserve prices continue to be low, SPP operators remain concerned about wind forecast errors. These concerns do not appear to be addressed with the supplemental reserve product, because of its short time frame. The uncertainty product under development by SPP, which is also a Holistic
Integrated Tariff Team recommendation, should help compensate generators that are specifically needed to mitigate the risk associated with forecast error.\textsuperscript{10}

### 4.3 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 4–16 shows the frequency of mitigation of incremental energy, operating reserves, and no-load costs in the day-ahead market.

#### Figure 4–16 Mitigation frequency, day-ahead market

![Mitigation frequency graph]

Mitigation frequency in energy, operating reserves, and no-load in the day-ahead market remains low, averaging just under 0.1 percent of resource hours mitigated in winter 2020, along with a continued downward trend from year to year.

For the real-time market, the mitigation of incremental energy is shown in Figure 4–17.

Mitigation frequency in the real-time market remains at very low levels as well, with less than 0.01 percent of resource intervals mitigated in real-time in each month in winter 2020. Average mitigation levels for winter 2020 were roughly one-third of the level in winter 2019.

Figure 4–18 shows the mitigation of start-up offers for different commitment types.

The overall level for mitigation of start-up offers climbed from winter 2019 at 1.3 percent, to 1.8 percent in winter 2020.
4.4 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 4–19) 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 4–19 Make-whole payments, day-ahead**

Typically, most day-ahead make-whole payments are attributed to coal and gas resources. Winter 2020 day-ahead make-whole payments were just over $8.2 million, up from $5.7 million in winter 2019, but down from nearly $10 million in winter 2018. Most notably, coal make-whole payments increased from about $1.5 million in winter 2019 to nearly $3.8 million in winter 2020. This increase is likely attributable to lower day-ahead prices.

The reliability unit commitment (RUC) make-whole payment (Figure 4–20) applies to commitments made in the day-ahead RUC, intra-day RUC processes, short-term RUC, and manual commitments. The majority of the reliability unit commitment make-whole payments are paid to gas resources, and more specifically gas simple-cycle resources.
Winter 2020 monthly real-time make-whole payments totaled just over $9 million, down from $14 million in winter 2019. This decrease can mostly be attributed to a decrease in manual commitments when compared to the previous winter season.

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.
Total revenue neutrality uplift for winter 2020 was just over $16 million, nearly half the level of $32 million in winter 2019. This decrease mostly can be attributed to lower levels of congestion and load.
This chapter reviews congestion and transmission congestion rights in the SPP market for the winter 2020 period. Key points from this chapter include:

- During the winter 2020 season, the most congested flowgate was in south central Oklahoma – TMP461_25432 (Russet Switch-Brown 138kV (WFEC) ftlo Johnson County-Caney Creek 138kV (OKGE)). However, the most congested flowgate over the past 12 months remains TMP175_24736 (Braman-Newkirk Tap 69kV for the loss of Hunter-Woodring 345kV).
- Overall, real-time market congestion was higher in winter 2020. In winter 2020, 34 percent of all real-time intervals had a breach, up from around 30 percent in both winter 2018 and 2019.
- The surplus between the congestion payments and the day-ahead congestion cost for load-serving entities shows that overall all load-serving entities fully covered their congestion cost through the congestion hedging market.
- For the quarter, 54 percent of participants received positive net revenues, while 46 percent of participants held hedges that did not cover their day-ahead congestion costs.
- The transmission congestion right (TCR) funding has remained nearly flat for the past three winter seasons at 92 percent.
- Auction revenue rights (ARR) remain overfunded for winter 2020. However, the magnitude of the overfunding decreased when compared to winter 2019.

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 winter period is shown in Figure 5–1, while congestion by shadow price for the rolling 12-month period ending February 2020 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, winter**

During the winter season, the most congested flowgate was in south central Oklahoma – TMP461_25432 (Russett Switch-Brown 138kV (WFEC) ftlo Johnson County-Caney Creek 138kV (OKGE)). In fact, the top five most congested flowgates were located in various areas of Oklahoma. Most of this congestion can be attributed to transmission outages in the area.
The most congested flowgate over the past 12 months remains TMP175_24736; with the other constraint in the area (TMP379_24692), the fourth most congested flowgate over 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.
Typically, 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. Uncongested intervals did increase in February 2020, with 16 intervals having no congestion.

Overall, real-time market congestion for winter 2020 in terms of intervals with breached flowgates was about four percentage points higher than both winter 2018 and 2019. Transmission outages, along with high levels of wind output, are the most likely causes of this
increased congestion. Interestingly, at over 20 percent, there were two times more real time intervals without congestion in winter 2020 when compared to winters 2019 and 2018.

5.2 TRANSMISSION CONGESTION RIGHTS MARKET

The transmission congestion right and auction revenue right net payments are classified and presented in Figure 5–5.

**Figure 5–5 Total congestion payments, winter**

<table>
<thead>
<tr>
<th></th>
<th>Load-serving entities</th>
<th>Non-load-serving and financial only entities</th>
</tr>
</thead>
<tbody>
<tr>
<td>DA congestion</td>
<td>117.8</td>
<td>114.8</td>
</tr>
<tr>
<td>RT congestion</td>
<td>(0.9)</td>
<td>(1.5)</td>
</tr>
<tr>
<td>Net congestion</td>
<td>116.9</td>
<td>113.4</td>
</tr>
<tr>
<td>TCR charges</td>
<td>49.1</td>
<td>74.3</td>
</tr>
<tr>
<td>TCR payments</td>
<td>(109.4)</td>
<td>(114.1)</td>
</tr>
<tr>
<td>TCR uplift</td>
<td>10.4</td>
<td>9.1</td>
</tr>
<tr>
<td>TCR surplus *</td>
<td>(2.5)</td>
<td>(2.1)</td>
</tr>
<tr>
<td>ARR payments</td>
<td>(58.3)</td>
<td>(90.3)</td>
</tr>
<tr>
<td>ARR closeout #</td>
<td>(32.9)</td>
<td>(30.2)</td>
</tr>
<tr>
<td>Net TCR/ARR</td>
<td>(143.6)</td>
<td>(153.3)</td>
</tr>
</tbody>
</table>

* remaining at period end
# accrued throughout the quarter

During winter, load-serving entities earned $118 million in congestion payments. These payments exceeded their day-ahead congestion cost of $101 million. Real-time congestion costs aided load-serving entities, reducing the total congestion cost to $75 million.

The difference between the congestion payments and the total congestion cost shows that for the quarter, all load-serving entities fully covered their day-ahead congestion cost through the congestion hedging market. Moreover, day-ahead congestion costs for load-serving entities decreased 12 percent when compared to winter 2019.

Additionally, non-load-serving and financial-only entities collected congestion payments of $5 million. These payments did not exceed their $23 million in day-ahead congestion costs. Real-time congestion costs did not aid non-load-serving and financial-only entities, increasing their
total congestion cost to $27 million. Therefore, non-load-serving, and financial-only entities did not fully cover their congestion cost through the transmission congestion right market.

Figure 5–6 shows, by market participant,\textsuperscript{11} the day-ahead congestion exposure along with the value of all congestion hedges, as well as the net overall position.

\textbf{Figure 5–6} \hspace{1cm} Net day-ahead congestion revenue by market participant, winter

Figure 5–6 also highlights that 54 percent of participants received positive net revenues, while 46 percent of participants held positions that did not cover their day-ahead congestion costs. The bottom ten participants each paid over $1 million more in congestion costs than was offset by their auction revenue right and transmission congestion right positions.

Figure 5–7 shows, by market participant, the day-ahead and real-time congestion exposure along with the value of all congestion hedges, as well as the net overall position.

\textsuperscript{11} Figure 5–6 and 5–7 reference market participants who hold ARR entitlements.
Figure 5–7 highlights that 59 percent of participants received positive net revenues, while 41 percent of participants held positions that did not cover their total congestion costs. The bottom eight participants also each paid over $1 million more in congestion costs than was offset by their auction revenue right and transmission congestion right positions.

Figure 5–8 below shows transmission congestion right funding, day-ahead revenue, net surplus/shortfall, and transmission congestion right funding percent.
Transmission congestion right funding levels fell within the target range\textsuperscript{12} during all three months of the winter 2020 season. The last three winter seasons have all had funding of around 93 percent. The shortage decreased from $15 million in winter 2019 to $9 million in winter 2020.

Daily observations of transmission congestion right funding for the last three winter periods are shown in Figure 5–9.

\textbf{Figure 5–9}  \hspace{1cm} \textit{Transmission congestion right funding, winter}

Most daily observations of transmission congestion right funding fell between 80 percent and 120 percent for the winter 2020 quarter.\textsuperscript{13} In winter 2020, only four funding events for the quarter fell below 80 percent funded.

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

\textsuperscript{12} 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…”

\textsuperscript{13} Ninety-six percent of the winter 2020 funding observations fell within this range.
Figure 5–10  Auction revenue right funding

Auction revenue right funding percentages remained relatively stable over the winter 2020 quarter, but decreased when compared to the related period in 2019. The surplus also decreased by almost $8 million from winter 2019 to winter 2020.
On March 17, 2020, the SPP MMU issued its 2019 Frequently Constrained Area study. In this study, the MMU analyzed real-time market data from September 1, 2018 through August 31, 2019. In addition, data through February 29, 2020 was used to gauge recent trends versus the study period. Based on the analysis, the MMU proposed the removal of the Southwest Missouri and Central Kansas Frequently Constrained Areas (FCA), with no additions at this time.

Frequently Constrained Areas are areas of the Integrated Marketplace footprint that experience high levels of congestion and are associated with one or more pivotal suppliers. The SPP Open Access Transmission Tariff defines Frequently Constrained Areas as:

“an electrical area identified by the Market Monitor that is defined by one or more binding transmission constraints or binding Reserve Zone constraints that are expected to be binding for at least five-hundred (500) hours during a given twelve (12)-month period and within which one (1) or more suppliers are pivotal.”

The SPP MMU reevaluates the Frequently Constrained Area designations at least annually. With the proposals in this year’s report, there have been seven different Frequently Constrained Areas since the start of the Integrated Marketplace.

For the 2019 report, the MMU identified eight areas as candidates for Frequently Constrained Area designation with five of these being candidate areas studied in the previous Frequently Constrained Area study.

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15 SPP Open Access Transmission Tariff, Att. AF, Section 3.1.1 (Frequently Constrained Areas)
16 SPP Open Access Transmission Tariff, Att. AF, Section 3.1.1.3 (Changes to Frequently Constrained Area Designation)
Figure 6–1  Frequently constrained area candidate locations

<table>
<thead>
<tr>
<th>Geographical area</th>
<th>FCA candidate name</th>
</tr>
</thead>
<tbody>
<tr>
<td>Southwest Missouri</td>
<td>SW Missouri *</td>
</tr>
<tr>
<td>Central Kansas (Hays, KS)</td>
<td>Central Kansas *</td>
</tr>
<tr>
<td>Lubbock, TX</td>
<td>Lubbock</td>
</tr>
<tr>
<td>North Oklahoma (Braman, OK)</td>
<td>North Oklahoma</td>
</tr>
<tr>
<td>Southeast Oklahoma (Stonewall, OK)</td>
<td>SE Oklahoma</td>
</tr>
<tr>
<td>Oklahoma City, OK</td>
<td>Oklahoma City #</td>
</tr>
<tr>
<td>Tulsa, OK</td>
<td>Tulsa #</td>
</tr>
<tr>
<td>East Kansas (Waverly to LaCygne)</td>
<td>East Kansas #</td>
</tr>
</tbody>
</table>

* existing Frequently Constrained Area from 2018 report
# new areas to 2019 study

Study process

The impact analysis counts the number of hours for which the price impact in the Frequently Constrained Area candidate exceeds a $25/MWh threshold. The table below provides the impact analysis results for these eight candidate areas along with the binding and pivotal supplier hours.

Figure 6–2  Frequently constrained area study results

<table>
<thead>
<tr>
<th>FCA Candidate</th>
<th>Binding (Hours)</th>
<th>FCA Total</th>
<th>Percent Hours with Pivotal Supplier</th>
<th>Binding Hours over $25/MWh Impact Threshold</th>
</tr>
</thead>
<tbody>
<tr>
<td>SW Missouri *</td>
<td>663</td>
<td>502</td>
<td>76%</td>
<td>154</td>
</tr>
<tr>
<td>Central Kansas *</td>
<td>348</td>
<td>151</td>
<td>43%</td>
<td>193</td>
</tr>
<tr>
<td>Lubbock</td>
<td>905</td>
<td>757</td>
<td>84%</td>
<td>212</td>
</tr>
<tr>
<td>Northern OK</td>
<td>1,069</td>
<td>154</td>
<td>14%</td>
<td>610</td>
</tr>
<tr>
<td>Southeast OK</td>
<td>650</td>
<td>291</td>
<td>45%</td>
<td>315</td>
</tr>
<tr>
<td>Oklahoma City #</td>
<td>1,120</td>
<td>571</td>
<td>51%</td>
<td>135</td>
</tr>
<tr>
<td>Tulsa #</td>
<td>1,018</td>
<td>731</td>
<td>72%</td>
<td>418</td>
</tr>
<tr>
<td>East Kansas</td>
<td>729</td>
<td>338</td>
<td>46%</td>
<td>107</td>
</tr>
</tbody>
</table>

* existing Frequently Constrained Area from 2018 report
# new areas to 2019 study
Four candidate areas had over 500 hours where there was at least one pivotal supplier. Only the North Oklahoma candidate area had over 500 binding hours with an impact of $25/MWh but this area only experienced pivotal supplier hours only 14 percent of its binding hours. The existing Southwest Missouri Frequently Constrained Area did exceed 500 pivotal hours but the $25/MWh threshold was only met during 154 of its binding hours. Central Kansas, the other existing Frequently Constrained Area, fell below 500 pivotal supplier hours with 151.

For comparison, the previous year analysis showed 1,685 pivotal supplier hours for the Southwest Missouri Frequently Constrained Area and decreased to 502 for the current analysis period. The hours where the $25/MWh threshold was met during binding hours fell from 631 hours to 154. The Central Kansas Frequently Constrained Area fell from 687 pivotal supplier hours to 151.

The Lubbock candidate area still maintains a high percentage of binding hours that are pivotal with over 80 percent but the number of hours has declined over the past few years. Over 2,400 hours were pivotal in the previous year and fell to about 750 in this year’s analysis.

The North Oklahoma area appeared in the previous year analysis but the constraints and candidate resources differed from this year’s analysis. Over 1,000 binding hours occurred in this area but only 14 percent of the hours contained a pivotal supplier. Over 600 of the binding hours were calculated to have over a $25/MWh price impact. This indicates the resource candidates in this area have a significant price impact but are usually not pivotal in relieving the constraint.

The Southeast Oklahoma area appeared in the previous year analysis with over 2,000 binding hours and over 1,500 being pivotal. Even with the high number of pivotal supplier hours, only 327 of the binding hours met a $25/MWh impact. This year’s analysis binding hours dropped to 650 with less than 300 being pivotal which is below the 500-hour pivotal supplier criteria.

The Oklahoma City area experienced the most binding hours of all eight candidate areas with over 1,100 binding hours and over 570 being pivotal. Only 135 of the binding hours met the
$25/MWh threshold indicating the candidate resource group’s limited price impact on the constraints in this area.

The Tulsa, Oklahoma area also experienced one of the higher number of binding hours for this year’s analysis with over 1,000 binding hours and about 730 being pivotal. Over 400 of the binding hours exceeded the $25/MWh impact threshold indicating a significant level of price impact of the candidate resources.

The East Kansas area represents congestion south of Kansas City with over 700 binding hours and less than 340 being pivotal. Just over 100 of the binding hours exceeded the $25/MWh impact threshold in this analysis.

The highest binding hours in this analysis was over 1,100 hours in the Oklahoma City area while the highest area with pivotal supplier hours was Lubbock with over 750 hours. For comparison, previous years have had areas such as Woodward, the Texas Panhandle, and Lubbock which have all exceeded 3,500 binding hours in a past study. Historical pivotal supplier hours for these areas have ranged from 1,500 to almost 3,500 hours.

Analysis

The results of the study indicate two possible areas for consideration of Frequently Constrained Area designation and removal of the two existing Frequently Constrained Areas. The Tulsa area exceeded the 500 hours with at least one pivotal supplier but fell slightly below 500 hours where the candidate resources had a $25/MWh impact. The North Oklahoma candidate area resources exceeded the $25/MWh impact with over 600 of the binding hours. However, the area experienced about 150 pivotal supplier hours which is only 14 percent of the total binding hours and well below the 500-hour pivotal supplier hour criteria.

The Southwest Missouri and Central Kansas areas have decreased in congestion compared to the previous year’s studies and now both fall below 500 binding hours with a $25/MWh impact. The Southwest Missouri area had just over 500 pivotal supplier hours but only about 150 exceeded a $25/MWh threshold. This area had over 1,600 pivotal hours in the previous year analysis. The monitored element (Neosho – Riverton 161kV) for the primary constraint in this
area had an upgrade in December 2018 increasing the capability on this facility by 20 megawatts.

The Central Kansas area congestion decreased in this year’s analysis with less than 350 binding hours compared to over 1,600 in the previous year. A second Post Rock – Knoll 230kV circuit was energized in December 2018 which appeared to provide relief to this area.

The North Oklahoma area is a concentrated area of congestion on a 69kV facility. The number of pivotal suppliers is small at about 150 hours which is only about 14 percent of binding hours. There is also a transmission reconfiguration in this area to reduce congestion that went into place in January 2020. Congestion has decreased and the reconfiguration (manually operated switch outage) is scheduled to be in place through the end of the year. Should this change, the Market Monitor has to ability to reanalyze this area.

The Tulsa area warrants consideration but falls just short of 500 binding hours with a $25/MWh impact. Although, the $25/MWh threshold is not a requirement to be met, it does give an indicator of the candidate resources’ impact to price in the area.

The binding hours, pivotal supplier, and impact analysis results for the existing Southwest Missouri and Central Kansas Frequently Constrained Areas show that congestion and market power concerns diminished. The expectation of the Market Monitor is that the Central Kansas area will not be vulnerable to the exercise of market power during the next twelve-month period. The Southwest Missouri area has also lessened in frequency of market power concern such that the Market Monitor proposes the removal of this area.

Most candidate areas included in this study are areas from south of Kansas City, through southwest Missouri and Tulsa, and down to Oklahoma City. These areas form a line of separation of higher prices in the southeast corner of the SPP from the rest of the footprint. Congestion is not as concentrated to a particular area as past studies, but appears more dispersed along this southeast region.
Conclusion

As a result of this analysis, the MMU does not propose to add any Frequently Constrained Areas at this time and have removed the SW Missouri and Central Kansas Frequently Constrained Areas. The Tulsa area merits continued observation given the reduction in the nearby Southwest Missouri area. The MMU has the ability to reanalyze the impacts of these recommendations or any changes to congestion patterns at any time.

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