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MARKET HIGHLIGHTS

This report covers market performance and highlights during the spring quarter of 2021 (March through May). Annual figures shown on the charts in this report represent only this three-month period for each year, unless labelled otherwise. Highlights of this spring period are as follows:

- Average hourly load for the 2021 spring season was four percent above spring 2020. Some of the reason for lower load in spring 2020 includes effects from the COVID-19 pandemic.

- Wind generation was the primary fuel type in terms of generation during the spring 2021 quarter accounting for 45 percent of total generation, an increase from 35 percent in spring 2020. Coal generation as a percentage of total generation increased from 24 percent of total generation in spring 2020 to 28 percent of the total in spring 2021. Both gas, combined-cycle and gas, simple-cycle resources declined from 2020 to 2021, from 18 percent to 12 percent, and nine percent to five percent, respectively.

- For market-to-market payments during the spring period, $39 million was paid from MISO to SPP, and $2 million from SPP to MISO, for a net of $37 million paid from MISO to SPP.

- Net virtual profits before fees for spring 2021 totaled $44 million, while net virtual profits after fees for spring 2021 totaled $28 million. These are both up from spring 2020, which was $16 million before fees and $10 million after fees.

- Use of market commitment status had been on a steady rise for the past two years, with 80 percent of capacity offered in market status in spring 2021, up from 74 percent in 2021 and 65 percent in 2019. Overall self-commitment status decreased for the spring period, from 32 percent in spring 2019 to 23 percent in spring 2020, then to 17 percent in spring 2021.
• After experiencing a decrease in outages during spring 2020 due to the effects of the COVID-19 pandemic, generation outages in spring 2021 returned to a slightly lower, but comparable level to spring 2019.

• The average gas price at the Panhandle Eastern hub continued its steady rise, increasing to $2.66/MMBtu in May; this is the highest price since March 2019, with the exception of February 2021. Overall, the average gas price increased by 76 percent from $1.39/MMBtu in spring 2020 to $2.45/MMBtu in spring 2021.

• Electricity prices also increased from spring 2020 to spring 2021, albeit at a lower rate. Day-ahead prices increased from an average of $14.03/MWh in spring 2020 to $15.97/MWh in 2021, an increase of 14 percent. Real-time prices increased from an average of $12.58/MWh in spring 2020 to $13.87/MWh in 2021, an increase of 10 percent.

• During the spring season, the most five most congested flowgates were located in Oklahoma and western Missouri. For the last 12 months, nine of the top ten most congested flowgates are located in Oklahoma (5) and western Missouri (4), with the final flowgate located in western Kansas.

• Overall, real-time market congestion for spring 2021 in terms of intervals with breached flowgates increased to nearly 70 percent of all intervals. April 2021 saw a record high 82 percent of intervals breached.

• Total transmission congestion right funding for spring 2021 was 80 percent, up slightly from 79 percent in spring 2020. This low funding remains a concern.
2 LOAD AND RESOURCES

This chapter reviews load and resources in the SPP market for the spring 2021 period. Key points from this chapter include:

- Average hourly load for the 2021 spring season was four percent above spring 2020. Some of the reason for lower load in spring 2020 includes effects from the COVID-19 pandemic.

- Wind generation was the primary fuel type in terms of generation during the spring 2021 quarter accounting for 45 percent of total generation, an increase from 35 percent in spring 2020. Coal generation as a percentage of total generation increased from 24 percent of total generation in spring 2020 to 28 percent of the total in spring 2021. Both gas, combined-cycle and gas, simple-cycle resources declined from 2020 to 2021, from 18 percent to 12 percent, and nine percent to five percent, respectively.

- Wind generation nameplate capacity at the end of May 2021 was 27,618 MW. This is an increase of nearly 4,800 MW from the prior year.

- The level of exports peaked during March, which was the peak month for wind, for the spring season. Imports increased during April, much of this increase can be attributed to generation outages near the seams.

- For market-to-market payments during the spring period, $39 million was paid from MISO to SPP, and $2 million from SPP to MISO, for a net of $37 million paid from MISO to SPP.

- For the spring period, total cleared virtual transactions as a percent of load were 27 percent in 2021, up from around 19 percent in spring 2019 and 2020.

- Net virtual profits before fees for spring 2021 totaled $44 million, while net virtual profits after fees for spring 2021 totaled $28 million. These are both up from spring 2020, which was $16 million before fees and $10 million after fees.
2.1 LOAD

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

Figure 2-1  Average hourly load

Average hourly load for the 2021 spring season was nearly four percent above spring 2020. March 2021 loads were at nearly the same level as the previous year, however, April and May 2021 saw average hourly load higher than 2021. The lower load in April and May 2020 can be partially attributed to effects of the COVID-19 pandemic.

Heating and cooling degree days are used to estimate the impact of actual weather conditions on energy consumption as shown in Figure 2–2. Regression analysis has shown that a cooling degree has about 4.2 times the impact of a heating degree on load, so cooling degree days are multiplied by 4.2 in the chart below.
Degree days for the 2021 spring season were about seven percent below spring 2020, with each of the spring months in 2021 at levels below 2020.

### 2.2 RESOURCES

Average hourly 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.
Overall generation levels were up four percent from spring 2020 to 2021. Coal generation increased by 19 percent for the same period, while wind generation increased by 32 percent. Gas, simple-cycle generation declined 35 percent and gas, combined-cycle generation declined 28 percent from 2020 to 2021. The increase in coal generation and decrease in gas generation can mostly be attributed to higher gas costs in spring 2021 compared to 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 miscellaneous resources.
Wind generation was the primary fuel type in terms of generation during the spring 2021 quarter accounting for 45 percent of total generation, an increase from 35 percent in spring 2020. Coal generation as a percentage of total generation increased from 24 percent of total generation in spring 2020 to 28 percent of the total in spring 2021. Both gas, combined-cycle and gas, simple-cycle resources declined from 2020 to 2021, from 18 percent to 12 percent, and nine percent to five percent, respectively.

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

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 at the end of May 2021 at 27,618 MW of nameplate capacity. On a monthly basis, the addition of new wind generation has leveled out, after a large increase from July to August 2020. The wind capacity factor in both the day-ahead market has remained the nearly the same for the past three spring seasons, around 32 percent. The real-time wind capacity factor, after being flat at 40 percent for spring 2019 and 2020, rose to 44 percent in spring 2021.

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.
Figure 2-6  Technology on the margin, day-ahead

In the day-ahead market, virtual transactions set prices in 32 percent of intervals in spring 2021, down from 35 percent in 2020. Coal resources were the marginal technology type in about 24 percent of intervals in spring 2021, down slightly from 25 percent in 2020. Wind resources set prices in the day-ahead market in 21 percent of intervals in spring, up from 15 percent in 2020. Gas, combined-cycle resources were down slightly from 2020 to 2021, while gas, simple-cycle resources were virtually unchanged.

Figure 2-7  Technology on the margin, real-time
In the real-time market, wind resources set prices in 39 percent of all real-time intervals in spring 2021, up sharply from 26 percent in 2020. Coal resources set prices 20 percent of all intervals, down from 25 percent in 2020, while gas, simple-cycle resources also dropped from 21 percent in spring 2020 to 16 percent in 2021. Gas, combined-cycle resources were virtually unchanged, setting prices in 10 percent of all intervals in both spring 2020 and 2021.

### 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 (AECI) in Oklahoma and Missouri.

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

![Figure 2-8] Exports and imports, SPP system

The level of exports peaked during March, which was the peak month for wind, for the spring season. Imports increased during April, much of this increase can be attributed to generation outages near the seams. Overall, SPP is on a very slight upward trend, moving from basically neutral on imports and exports in 2019, to being a slight net importer in spring 2021.
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 (with payments more than $700,000) for the spring period are shown in Figure 2–10.

\(^3\) 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.
Historically, on a monthly basis, payments are predominantly from MISO to SPP for most of the year, with the exceptions typically being during the summer months and February 2021 winter weather event. For the spring period, $39 million was paid from MISO to SPP, and $2 million from SPP to MISO, for a net of $37 million paid from MISO to SPP.

Figure 2-10  Market to market, by flowgate

TMP423_25727*  Maryville-Midway 161kV (MPS) ftlo Maryville-Nodaway 161kV (MPS)
WBWAFAMOOVE*  Warrensburg-Whiteman AFB 161kV (MPS) ftlo Sibley-Overton 345kV (KCPL-AMRN)
RAUTEKRAUTFC*  Raun-Tekamah 161kV ftlo Raun-Fort Calhoun 345kV (OPPD-MEC)
NEORIVNEOBLC*  Neosho-Riverton 161kV (EDE-WR) ftlo Neosho-Blackberry 345kV (AECI-WR)
TMP499_26328^  Forman Xfmr 230/1kV ftlo Hankinson-Wahpeton 230kV (OTP)
TMP431_25866*  Wardlaw-Bismarck 230kV (WAUE) ftlo Buffalo-Jamestown Tap 345kV (OTP)
During spring 2021, the flowgate with the highest payments from MISO to SPP of nearly $8.5 million was TMP423_25727 (Maryville-Midway 161kV [MPS] for the loss of Maryville-Nodaway 161kV [MPS]). For payments from SPP to MISO, the top flowgate in spring 2021 was TMP465_26500 (Chub Lake transformer 345kV/1 [NSP] for the loss of Chub Lake-Hampton Corner 345kV [NSP]) with just over $700,000 in payments.

### 2.4 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 2–11) and supply offers (Figure 2–12).
As these figures show, both cleared and uncleared demand bids have grown from spring 2020 to 2021. Cleared and uncleared supply offers also grew from spring 2020 to 2021, with cleared supply offers increasing by 50 percent.

Cleared virtual transactions as a percent of load are shown in Figure 2–13.
For the spring period, total cleared virtual transactions as a percent of load were 27 percent in 2021, up from around 19 percent in spring 2019 and 2020. April 2021 saw the highest amount of cleared virtual transactions as a percent of load, at 30 percent.

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 2–14 and Figure 2–15 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 for the spring season rose, from 1,300 GWh in 2020 to 1,800 GWh in 2021, while virtual demand bids from physical asset owners continues to decline, albeit the values are a very low levels. Virtual supply offers by financial-only participants increased sharply, from 2,100 GWh in spring 2020 to 3,300 GWh in 2021, while virtual supply offers from physical asset owners remains at low levels with no growth over the past three spring seasons.
Virtual transactions can be made at hubs, interfaces, loads, and resources, as shown in Figure 2–16.

**Figure 2-16  Virtual transactions by location type**

The great majority of virtual transactions are made at resources (primarily wind resources), with an average of just over 3,300 GW in spring 2021, compared to nearly 2,200 GW in 2020. Virtual transactions at hubs, interfaces, and loads all grew from spring 2020 to 2021. 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 2–17, from virtual transactions are derived from resource locations.
Virtual transactions at resource locations saw an average monthly profit for spring 2021 of just over $10 million, while interfaces were second highest with just over $2.3 million.

Overall profit and loss from virtual transactions, both before and after fees, is shown in Figure 2–18.
Net virtual profits before fees for spring 2021 totaled $44 million, while net virtual profits after fees for spring 2021 totaled $28 million. These are both up from spring 2020, which was $16 million before fees and $10 million after fees.

Applying the profit and loss from virtual transactions on a per megawatt basis is shown in Figure 2-19.

**Figure 2-19** Virtual transactions, profit/loss per MW (before and after fees)

On a per megawatt basis, profit before fees from virtual transactions for spring 2021 was $2.69/MW, compared to $1.39/MW in 2020. Profit after fees for virtual transactions for spring 2021 was $1.69/MW, compared to $0.86/MW in 2020.
3 UNIT COMMITMENT AND DISPATCH

This chapter reviews unit commitment and dispatch processes in the SPP market for the spring 2021 period. Key points from this chapter include:

- Use of market commitment status had been on a steady rise for the past two years, with 80 percent of capacity offered in market status in spring 2021, up from 74 percent in 2021 and 65 percent in 2019. Overall self-commitment status decreased for the spring period, from 32 percent in spring 2019 to 23 percent in spring 2020, then to 17 percent in spring 2021.

- Spring 2021 saw 70 percent of megawatts dispatched from resources in market status, up from 61 percent in 2020 and 52 percent in 2019.

- Spring 2021 saw a monthly average of 108 regulation-up scarcity intervals, up from 56 in 2020. Both regulation-down (monthly average of 28 in spring 2021, down from 47 in 2020) and contingency reserve scarcity (monthly average of six in spring 2021, down from seven in 2020) were down from spring 2021 to 2020. The average scarcity price for all products was up from spring 2020 to 2021.

- After experiencing a decrease in outages during spring 2020 due to the effects of the COVID-19 pandemic, generation outages in spring 2021 returned to a slightly lower, but comparable level to spring 2019.

3.1 UNIT COMMITMENT

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 generation—for which no such obligation exists—was comparable to that of the load-serving entities.

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.

![Peak hour capacity overage, real-time average](image)

The average peak hour overage\(^4\) for spring 2021 was just over 4,000 MW, up slightly from 2020.

Figure 3–2 shows the status, by percent, of the physical resources offered in the day-ahead market.\(^5\) This metric replaces a previous metric that used nameplate capacity and included

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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). All capacity from wind generation is not included in the economic maximum. Only capacity from traditional fuel resources is included in this calculation.

\(^5\) All resources offered use their economic maximum for this capacity calculation.
capacity on outage and not-participating status. The new metric gives a better view of resources available in market status, and those offered by self-commitment as well as reliability status, as it includes only resources that could be committed by the RTO.

**Figure 3-2  Day-ahead physical resources offered by status**

Use of market commitment status had been on a steady rise for the past two years, with 80 percent of capacity offered in market status in spring 2021, up from 74 percent in 2021 and 65 percent in 2019. Overall self-commitment status decreased for the spring period, from 32 percent in spring 2019 to 23 percent in spring 2020, then to 17 percent in spring 2021.

While we view the reduction of self-commitment offers as a positive trend, we continue to encourage market participants and the RTO to find ways to enhance market efficiencies and reduce self-commitment.  

Figure 3–3 shows the percentage of dispatch megawatts by commitment status in the day-ahead market. All output from a self-committed unit is counted as self.

6 See the MMU’s whitepaper on self-commitment, *Self-committing in SPP markets: Overview, impacts, and recommendations.*
The volume of market-committed\(^7\) megawatts has continued its increasing trend. Spring 2021 saw 70 percent of megawatts dispatched from resources in market status, up from 61 percent in 2020 and 52 percent in 2019. Generation dispatched in self-commitment status indicates that the energy produced was from a resource that was not economically selected by the day-ahead market’s centralized unit commitment process.

Self-commitment shifts the merit order of the supply curve by treating the self-committed generators as price insensitive at their minimum, which shifts the supply curve to the right. The expected result of a rightward shift in supply is a decline in the marginal price of energy.

Figure 3–4 shows on-line capacity commitment as a percent of demand.

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\(^7\) Reliability unit commitments that continued to run in the day-ahead market were considered a market commitment.
The capacity commitment as a percent of average monthly demand for the past three spring seasons has ranged from around 118 percent to 123 percent. An uncertainty product, which was recommended in the 2018 Annual State of the Market report and updated in the 2019 Annual State of the Market report, was approved at the July 2021 MOPC.

### 3.2 SCARCITY

A scarcity price is a price that reflects the value of a product when there is not enough of the product to meet the demand. SPP’s market uses marginal cost pricing, which prices a product by the cost to produce the next increment. When a product is scarce, there may not be an additional supplier, so price cannot be determined by the next increment. In this case, a scarcity price is used to set marginal price. The Integrated Marketplace uses demand curves to set graduated scarcity prices so that small scarcities are priced lower than large scarcities. Scarcity prices inform market participants that the product was short and incentivize future provision of that product, and should provide representation of the reliability risk of not having a product.

When an insufficient amount of regulation-up service, regulation-down service, or contingency reserve is cleared, a scarcity price is set by a demand curve. The scarcity of these products can

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8 SPP MMU 2019 Annual State of the Market report.
be caused by a lack of capacity or a lack of ramp. Scarcities are due to capacity when there are insufficient resources at maximum output available to meet demand. Scarcities are due to ramp when sufficient capacity is available, but ramp rate limitations do not allow access to the full capacity. When multiple products compete for the same, limited capability of resources, the scarcity of one product can also raise the price of other products.

Regulation and operating reserve scarcities are priced by demand curves. The regulation demand curves, for both up and down, consist of six steps with a maximum of $600/MW. The operating reserve demand curve consists of three steps with a maximum of $1,100/MW.

The clearing engine does not record the reason for the scarcity, (i.e., capacity or ramp.) The MMU suggests that SPP capture the appropriate information so that the reason for the scarcity will be transparent.

Figure 3–5 displays the number of scarcity intervals and prices for scarcity by month, along with an annual comparison of monthly averages. Typically, more regulation-down is available than regulation-up. First, variable energy resources are able to provide regulation-down and not regulation-up. Second, the market dispatches energy from a resource’s minimum until it is no longer profitable or until the resource is limited by a parameter, such as ramp rate up or a maximum operating limit. Consequently, many resources are operating closer to their maximum than their minimum which provides more downward capability than upward capability.
More scarcity intervals typically occur during the shoulder spring and fall seasons, as these months typically have high wind production, low load, and more generator outages. Spring 2021 saw a monthly average of 108 regulation-up scarcity intervals, up from 56 in 2020. Both regulation-down (monthly average of 28 in spring 2021, down from 47 in 2020) and contingency reserve scarcity (monthly average of six in spring 2021, down from seven in 2020) were down from spring 2021 to 2020.

The average scarcity price for all products was up from spring 2020 to 2021, with the average contingency reserve price increasing from $281/MW in spring 2020 to $364/MW in 2021, average regulation-down price increasing from $153/MW in spring 2020 to $212/MW in 2021, and average regulation-up price increasing from $182/MW to $247/MW.

February 2021 saw the first widespread scarcity in the day-ahead market. Prior to February, only three other hours (in December 2020) had day-ahead scarcity since the start of the Integrated Marketplace. There was no day-ahead scarcity during the spring 2021 period.

### 3.3 GENERATION OUTAGES

Generation outages by fuel type of resource are shown in Figure 3-6. This metric shows the total gigawatt-hours of resources on outage and derated for each fuel type.
Spring 2021 saw an increase in generation outages from nearly 30,000 GWh in 2020 nearly 48,000 GWh in 2021. However, in comparison to spring 2019, the level of outages for spring 2021 is lower. The increase in outages is evenly distributed across all fuel types. Spring 2020 saw many outages and much maintenance deferred due to effects of the COVID-19 pandemic. Spring 2021 reflects a more typical level of outages for the spring season.
MARKET PRICES AND COSTS

This chapter reviews prices in the SPP market for the spring 2021 period. Key points from this chapter include:

- The average gas price at the Panhandle Eastern hub continued its steady rise, increasing to $2.66/MMBtu in May; this is the highest price since March 2019, with the exception of February 2021. Overall, the average gas price increased by 76 percent from $1.39/MMBtu in spring 2020 to $2.45/MMBtu in spring 2021.

- Electricity prices also increased from spring 2020 to spring 2021, albeit at a lower rate. Day-ahead prices increased from an average of $14.03/MWh in spring 2020 to $15.97/MWh in 2021, an increase of 14 percent. Real-time prices increased from an average of $12.58/MWh in spring 2020 to $13.87/MWh in 2021, an increase of 10 percent.

- The areas with highest prices in the footprint for the spring were found in the southern portion of the SPP footprint, concentrated around southwest Missouri and southeast Oklahoma.

- Spring 2021 had nearly 20 percent of all asset owner intervals in the real-time market with negative prices, compared to 15 percent in 2020. In the day-ahead market, 13 percent of asset owner intervals had negative prices in spring 2021, compared to six percent in 2020.

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.
Notwithstanding February, the average gas price at the Panhandle Eastern hub continued its steady rise, increasing to $2.66/MMBtu in May; this is the highest price since March 2019.

Overall, the average gas price increased by 76 percent from $1.39/MMBtu in spring 2020 to $2.45/MMBtu in spring 2021. Electricity prices also increased from spring 2020 to spring 2021, albeit at a lower rate. Day-ahead prices increased from an average of $14.03/MWh in spring 2020 to $15.97 in 2021, an increase of 14 percent. Real-time prices increased from an average of $12.58/MWh in spring 2020 to $13.87/MWh in 2021, an increase of 10 percent.

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 past three years.
As the figure above shows, the implied heat rate dropped sharply from spring 2020 to spring 2021. This drop can partially be attributed to the increase in gas prices, coupled with higher levels of wind generation and lower loads. Typically, the implied heat rate is lowest in the shoulder months (spring and fall), primarily due to lower loads as well as increased wind generation, and highest in the summer period due to higher loads coupled with generally lower levels of wind generation.

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 is the best measurement of divergence, as this method eliminates the “softening” of averages when positive and negative values are encountered. Continued price convergence is generally one indicator of an effectively and efficiently operating market.⁹ Absolute divergence for spring 2021 was $11.94/MWh, up from $6.78/MWh in 2020, but below the $13.16/MWh in 2019. The percent of divergence has steadily climbed over the last three spring seasons, from 3.5 percent in spring 2019, to 13.4 percent in 2021. The implementation of a ramping capability product in early 2022 should address some of the ramping limitations that can cause price volatility.¹⁰

Overall price patterns between the day-ahead and real-time markets are similar, as shown on the price contour maps below in Figure 4–4 and Figure 4-5. 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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⁹ For example, if one hour had a price divergence of +$10/MWh and the next hour had a price divergence of −$10/MWh, the average divergence for those two hours would be zero. By using the absolute divergence, the absolute average divergence would be $10/MWh.

¹⁰ The design for a ramping product was approved by FERC on July 16, 2020. Tariff Revisions to Add Ramp Capability, Docket No. ER20-1617.
Typically, lower prices are 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 highest off-peak prices were found in the southeast portion of the SPP footprint – western Missouri, northwest Arkansas, and eastern Oklahoma; the southwest portion of the footprint – eastern New Mexico and west Texas; and a small area of southeast North Dakota.
As discussed below, on-peak prices historically average around $10/MWh higher than off-peak prices. The same areas seeing the highest prices in the off-peak hours remain for the on-peak hours – the southeastern and southwestern portions of the SPP footprint, and the small area in southeast North Dakota.

Figure 4-6 and Figure 4-7 display average prices paid by load-serving entity for the spring period and the last 12 months.
Average prices for the spring period were the highest in entities around northeast Texas, southwest Missouri, and portions of Oklahoma, and lowest in western Kansas and Nebraska.

Over the past 12 months, entities around southwest Missouri and eastern Oklahoma 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 4-8 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 4-8 Trading hub prices](image)

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. For spring 2021, average real-time prices were $15.95/MWh at the South hub and $11.79/MWh at the North hub. However, in the day-ahead market, the average price for spring 2021 was $16.97/MWh at the South hub and $14.97/MWh at the North hub.

In addition, hub prices can be broken down into on-peak and off-peak prices, as shown in Figure 4-9 and Figure 4-10.
Historically, there has been a price spread between on- and off-peak prices at both hubs around $10/MWh. For the spring season, that spread has increased to about $12/MWh. On average, while there are monthly variations, the spread between on-peak and off-peak prices 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 4-11.

![Figure 4-11 Negative price intervals, day-ahead](image)

In spring 2021, nearly 13 percent of settlement location intervals\(^\text{11}\) in the day-ahead market had prices below zero. This is up nearly double from just over six percent in 2020. The increase can be attributed, in part, to the increase in wind capacity and generation over the prior year for the spring period. The 16 percent of settlement location intervals with negative prices in March is the highest level since the start of the Integrated Marketplace.

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 4-12.

\(^{11}\) Settlement location intervals are calculated as the number of settlement locations serving load that are active in an interval. For example, if there 100 settlement locations active in one five minute interval throughout an entire 30 day month, the total asset owner intervals would be 864,000 for the month (100 settlement locations * 288 intervals per day * 30 days).
Spring 2021 had nearly 20 percent of all settlement location intervals in the real-time market with negative prices, compared to just over 15 percent in spring 2020. Like the day-ahead market, all months in spring 2021 saw an increase from 2020. March 2021 had nearly 26 percent of all intervals with negative prices, nearly double the previous year. As noted with the increase in the frequency of day-ahead negative prices, the increase in real-time negative prices can be attributed, in part, to the increase in wind capacity and generation for the spring period as compared to last year. This increase in negative prices highlights a growing concern.

During SPP’s Holistic Integrated Tariff Team process, the MMU discussed 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. After study and completion of a white paper, the MMU identified specific problems with the recommendation: load prices are on average $5/MWh lower, generator prices are less negative, and breached transmission lines are reduced by 25 percent when offers of -$500/MWh are replaced by -$100/MWh offers. As such, an adjustment to the market floor is recommended for

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12 SPP Holistic Integrated Tariff Team report, page 25.
13 SPP MMU Study of Unduly Low Offers white paper.
addition to the Market Roadmap. The MMU will continue to evaluate the market to identify if further changes are warranted.

4.2 OPERATING RESERVE MARKET

The following figures (Figure 4-13 through Figure 4-16) 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.

**Figure 4-13  Regulation-up prices**

For spring 2021, real-time regulation-up was $15.14/MW, up from $8.72/MW in spring 2020; and day-ahead regulation-up was $16.79/MW in spring 2021, up from $10.87/MW in 2020. Higher demand for increased generation generally results in the higher regulation-up prices. Units incur higher opportunity costs to provide ancillary services.
Regulation-down prices were down from spring 2020 to spring 2021, with day-ahead regulation-down at $5.53/MW in spring 2021, compared to $6.66/MW in spring 2020; and real-time regulation-down at $9.75/MW in spring 2021, compared to $10.78 in spring 2020. These decreases can primarily be attributed to reduced need to decrease generation. Regulation-down mileage, however, was up markedly from spring 2020 to spring 2021.

**Figure 4-14  Regulation-down prices**

![Graph showing regulation-down prices from March 2020 to March 2021, with a significant drop from spring 2020 to spring 2021. The graph compares real-time, day-ahead, and mileage regulation-down prices. The mileage price is consistently lower than the real-time and day-ahead prices.](image)

**Figure 4-15  Spinning reserve prices**

![Graph showing spinning reserve prices from March 2019 to March 2021, with a significant spike in February 2021. The graph compares real-time and day-ahead prices.](image)
Spinning reserve prices increased in both the day-ahead and real-time markets, while supplemental reserves remained flat from spring 2020 to 2021.

Reserve prices have generally been low. Correspondingly, SPP operators remain concerned about wind forecast errors and often manually commit resources for capacity. These concerns do not appear to be addressed with the supplemental reserve product, because of its short time frame. However, 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 wind forecast error.\(^{14}\)

### 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.

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\(^{14}\) SPP [Holistic Integrated Tariff Team report](https://example.com), page 18.
Mitigation frequency varies across products in the SPP market. Figure 4-17 shows the frequency of mitigation of incremental energy, operating reserves, and no-load costs in the day-ahead market.

**Figure 4-17  Mitigation frequency, day-ahead market**

Mitigation frequency in energy, operating reserves, and no-load in the day-ahead market remains low, however, beginning November 2020, operating reserve mitigation began to climb, but has abated somewhat in the spring of 2021. However, compared to previous springs, mitigation is up. Generally speaking, as wind increases, congestion increases which increases instances of local market power, which increases potential candidates for mitigation. The MMU is studying this increased mitigation, and will report on the findings in an upcoming report.

For the real-time market, the mitigation of incremental energy is shown in Figure 4-18.
Mitigation frequency in the real-time market has remained at very low levels, with less than 0.03 percent of resource intervals mitigated in real-time in each month in through November 2020. However, an increase in real-time mitigation began in December 2020, peaking in January 2021 and then lessening in spring 2021. Even at these higher levels, overall real-time mitigation average of 0.2 percent of intervals in spring 2021 remains a low level overall. The MMU is studying this increased mitigation, and will report on the findings in an upcoming report.

Figure 4-19 shows the mitigation of start-up offers for different commitment types.
The overall level for mitigation of day-ahead start-up offers tripled from spring 2020 to 2021. The MMU is studying this increased mitigation, and will report on the findings in an upcoming report.

### 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 4-20) 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, though this was not the case in February.

**Figure 4-20**  Make-whole payments, day-ahead

![Make-whole payments, day-ahead](image)

Typically, most day-ahead make-whole payments are attributed to coal and gas resources. Total day-ahead make-whole payments for spring 2021 were nearly double the level of spring 2020. The majority of the increase can be attributed to a high level of make-whole payments to coal resources in March.

The reliability unit commitment (RUC) make-whole payment (Figure 4-21) 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.

Figure 4-21  Make-whole payments, reliability unit commitment

Total reliability unit commitment make-whole payments for spring 2021 were nearly double the level of spring 2020, but below spring 2019 levels. However, in comparison to recent months (outside of February), the levels for the spring months are at consistent levels.

The make-whole payments during the February weather event are subject to revision on subsequent settlements statements as the MMU verifies actual costs of resources with offers over $1,000/MWh.

Revenue neutrality uplift (RNU), shown in Figure 4-22, 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 4-22  Revenue neutrality uplift

Total revenue neutrality uplift for spring 2021 was nearly $33 million, this is an increase from spring 2020, but slightly below spring 2019.
5 CONGESTION AND TRANSMISSION RIGHTS MARKET

This chapter reviews congestion and transmission congestion rights in the SPP market for the spring 2021 period. Key points from this chapter include:

- During the spring season, the most five most congested flowgates were located in Oklahoma and western Missouri. For the last 12 months, nine of the top ten most congested flowgates are located in Oklahoma (5) and western Missouri (4), with the final flowgate located in western Kansas.
- Overall, real-time market congestion for spring 2021 in terms of intervals with breached flowgates increased to nearly 70 percent of all intervals. April 2021 saw a record high 82 percent of intervals breached.
- The surplus between the congestion payments and the total congestion cost shows that overall, for the quarter, load-serving entities fully covered their congestion cost through the congestion hedging market.
- Total TCR funding for spring 2021 was 80 percent, up slightly from 79 percent in spring 2020. This remains a concern.
- Auction revenue right funding percentages increased quarter over quarter, but remain flat relative to spring 2019. Additionally, auction revenue right funding is flat TCR year over TCR year, but down relative to the 2018 TCR year.

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 2021 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 three of the five most congested flowgates were in Oklahoma (TMP322_23590, TMP202_26363, and TMP270_23432), while the other two were in western Missouri (TMP423_25727 and WBUWAFAAMOOVE). Most of the congestion can be attributed to high west-to-east flows, along with outside impacts in northwest Missouri.
Nine of the top ten most congested flowgates for the last 12 months are located in Oklahoma (5) and western Missouri (4), with the final flowgate located in western Kansas. The most congested flowgate over the past 12 months remains TMP208_24721 (Okeene-Dover Sw. 138kV [WFEC] for the loss of Waukomis-Waukomis Tap 138kV [OKGE]). Most of the congestion can be attributed to high west-to-east flows, along with outside impacts on the eastern edge of the SPP footprint.

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**

![Figure 5-3](image)

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. This trend has stayed the same for the spring 2021 season.

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

![Figure 5-4](image)
Overall, real-time market congestion for spring 2021 in terms of intervals with breached flowgates increased to nearly 70 percent of all intervals. April 2021 saw a record high 82 percent of intervals breached. Transmission and generation outages, along with higher levels of imports, are the most likely causes of this increased congestion.

### 5.2 TRANSMISSION CONGESTION RIGHTS MARKET

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, spring**

<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>97.0</td>
<td>70.1</td>
</tr>
<tr>
<td>RT congestion</td>
<td>(6.0)</td>
<td>4.9</td>
</tr>
<tr>
<td>Net congestion</td>
<td>91.0</td>
<td>75.0</td>
</tr>
<tr>
<td>TCR charges</td>
<td>71.3</td>
<td>68.1</td>
</tr>
<tr>
<td>TCR payments</td>
<td>(90.3)</td>
<td>(88.5)</td>
</tr>
<tr>
<td>TCR uplift</td>
<td>8.0</td>
<td>13.0</td>
</tr>
<tr>
<td>TCR surplus *</td>
<td>(1.3)</td>
<td>(0.2)</td>
</tr>
<tr>
<td>ARR payments</td>
<td>(90.6)</td>
<td>(92.9)</td>
</tr>
<tr>
<td>ARR surplus</td>
<td>(31.2)</td>
<td>(19.2)</td>
</tr>
<tr>
<td>Net TCR/ARR</td>
<td>(134.1)</td>
<td>(119.7)</td>
</tr>
</tbody>
</table>

*remaining at year end*

During spring 2021, load-serving entities earned $197 million in congestion payments. These payments exceeded their day-ahead congestion cost of $124 million. Real-time congestion costs aided load-serving entities, and decreased the total congestion cost to $123 million. When compared to spring 2020, the 2021 difference between congestion payments and total congestion costs increased from a surplus of $45 million to a surplus of $73 million.

The surplus between the congestion payments and the total congestion cost shows that overall, for the quarter, load-serving entities fully covered their congestion cost through the congestion hedging market.
Additionally, non-load-serving and financial-only entities received congestion payments of $49 million. These payments did not exceed their $121 million in day-ahead congestion costs. Real-time congestion costs aided non-load-serving and financial-only entities and decreased their total congestion cost by $67 million to $54 million. This shows the $49 million in payments to non-load-serving, and financial-only entities did not fully cover their total congestion cost through the transmission congestion rights market.

Moreover, day-ahead congestion costs increased 76 percent for load-serving entities and 156 percent for non-load-serving and financial-only entities when compared to spring 2020.

**Figure 5-6 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></td>
<td>2018 TCR Year</td>
<td>2019 TCR Year</td>
</tr>
<tr>
<td>DA congestion</td>
<td>388.0</td>
<td>311.6</td>
</tr>
<tr>
<td>RT congestion</td>
<td>(11.8)</td>
<td>2.5</td>
</tr>
<tr>
<td>Net congestion</td>
<td>376.2</td>
<td>314.1</td>
</tr>
<tr>
<td>TCR charges</td>
<td>256.9</td>
<td>243.8</td>
</tr>
<tr>
<td>TCR payments</td>
<td>(354.2)</td>
<td>(336.3)</td>
</tr>
<tr>
<td>TCR uplift</td>
<td>27.9</td>
<td>37.2</td>
</tr>
<tr>
<td>TCR surplus *</td>
<td>(5.1)</td>
<td>(1.9)</td>
</tr>
<tr>
<td>ARR payments</td>
<td>(312.9)</td>
<td>(315.2)</td>
</tr>
<tr>
<td>ARR surplus</td>
<td>(100.3)</td>
<td>(71.1)</td>
</tr>
<tr>
<td>Net TCR/ARR</td>
<td>(487.8)</td>
<td>(443.4)</td>
</tr>
</tbody>
</table>

* remaining at year end

During the 2021 TCR year\(^{15}\), load-serving entities earned $668 million in congestion payments. These payments exceeded their day-ahead congestion cost of $523 million. Real-time congestion costs did not aid load-serving entities, and increased the total congestion cost to $528 million. When compared to the 2020 TCR year, the 2021 difference between congestion payments and total congestion costs increased from a surplus of $129 million to a surplus of $139 million.

\(^{15}\) The TCR year runs from June to the following May.
The surplus between the congestion payments and the total congestion cost shows that overall, for the quarter, load-serving entities fully covered their congestion cost through the congestion hedging market.

Additionally, non-load-serving and financial-only entities received congestion payments of $185 million. These payments did not exceed their $352 million in day-ahead congestion costs. Real-time congestion costs aided non-load-serving and financial-only entities and decreased their total congestion cost by $100 million to $252 million. This shows the $185 million in payments to non-load-serving, and financial-only entities did not fully cover their total congestion cost through the transmission congestion rights market.

Moreover, day-ahead congestion costs increased 68 percent for load-serving entities and 78 percent for non-load-serving and financial-only entities when compared to the 2020 TCR year.

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

* does not include Auction Revenue Rights closeout

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16 Figure 5-6 and Figure 5-7 reference market participants who hold ARR entitlements.
Figure 5-7 highlights that 63 percent of participants received positive net revenues, while 37 percent of participants held hedges that did not cover their day-ahead congestion costs. The bottom five participants collectively paid $38 million more in congestion costs than was offset by their auction revenue right and transmission congestion right positions. This is a drastic increase in the related figure in spring 2020 where the bottom five participants collectively lost $10 million.

Figure 5-8 highlights that 64 percent of participants received positive net revenues, while 36 percent of participants held hedges that did not cover their day-ahead congestion costs. The bottom five participants collectively paid $82 million more in congestion costs than was offset by their auction revenue right and transmission congestion right positions. This is a significant increase in the related 2020 figure where the bottom five participants collectively lost $36 million.

Figure 5-9 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.
Figure 5-9 highlights that 71 percent of participants received positive net revenues, while 29 percent of participants held hedges that did not cover their total congestion costs. The bottom five participants collectively paid $46 million more in congestion costs than was offset by their auction revenue right and transmission congestion right positions. This is also a significant increase over and above spring 2020 figure of $13 million.

Figure 5-10 highlights that 66 percent of participants received positive net revenues, while 34 percent of participants held hedges that did not cover their total congestion costs. The bottom
five participants collectively paid $96 million more in congestion costs than was offset by their auction revenue right and transmission congestion right positions. This is a significant increase over and above TCR year 2020 where the same figure amounted to $31 million.

Figure 5-11  Transmission congestion right funding, monthly

Figure 5-11 above shows transmission congestion right funding, day-ahead revenue, net surplus/shortfall, and transmission congestion right funding percent by month. Outside of February, monthly TCR funding was relatively stable over the 2020 TCR year, ranging between 78 and 88 percent. February 2021 is the outlier, with both elevated congestion and funding. The higher than normal values observed in February stem from the winter weather event.
Figure 5-12   Transmission congestion right funding, TCR year and spring quarter

Figure 5-12 above shows transmission congestion right funding, day-ahead revenue, net surplus/shortfall, and transmission congestion right funding percent by quarter and TCR year. The trend over both periods is similar in that funding is flat relative to the previous period, and down relative to two periods ago.

Daily observations of transmission congestion right funding for the 2019, 2020, and 2021 spring periods are shown in Figure 5-13.

Figure 5-13   Transmission congestion right funding, spring
Slightly less than two-thirds of the daily observations of transmission congestion right funding fell between 80 percent and 120 percent over the 2020 spring quarter.\textsuperscript{17} The funding distributions have shifted noticeably toward lower percentages over the last two quarters when compared to the 2019 spring quarter. In spring 2021, 33 percent of the funding events for the quarter fell between 45 percent and 79 percent funded.

Daily observations of transmission congestion right funding for the 2018, 2019, and 2020 TCR years are shown in Figure 5-14.

\textbf{Figure 5-14}  Transmission congestion right funding, TCR year

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure514.png}
\caption{Transmission congestion right funding, TCR year}
\end{figure}

Slightly more than one-half of the daily observations of transmission congestion right funding fell between 80 percent and 120 percent over the 2020 TCR year.\textsuperscript{18} Over the last two periods, the funding distributions have shifted noticeably toward lower percentages when compared to the 2019 TCR year. In spring 2021, 35 percent of the funding events for the quarter fell between 45 percent and 79 percent funded.

\textsuperscript{17} Sixty-five percent of the spring 2021 funding observations fell within this range.

\textsuperscript{18} Fifty-seven percent of the spring 2021 funding observations fell within this range.
Figure 5-15 shows transmission congestion right revenue, auction revenue right funding, net surplus, and auction revenue right funding percent, by month.

**Figure 5-15  Auction revenue right funding, monthly**

Funding percent

0% 30% 60% 90% 120% 150%

$0 $10 $20 $30 $40 $50

Millions


Transmission congestion right revenue  Auction revenue right funding  Surplus  Funding percent

Auction revenue right funding percentages increased steadily over the 2020 TCR year and the 2021 spring quarter.

Figure 5-16 shows transmission congestion right revenue, auction revenue right funding, net surplus, and auction revenue right funding percent, by quarter and TCR year.

**Figure 5-16  Auction revenue right funding, TCR year and spring quarter**

Funding percent

0% 40% 80% 120% 160% 200%

$0 $100 $200 $300 $400 $500

Millions

Transmission congestion right revenue  Auction revenue right funding  Surplus  Funding percent

Spring total TCR Year
Auction revenue right funding percentages increased quarter over quarter, but remain flat relative to spring 2019. Additionally, auction revenue right funding is flat TCR year over TCR year, but down relative to the 2018 TCR year.