STATE OF THE MARKET

SPRING 2020

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1 MARKET HIGHLIGHTS

This report covers market performance and highlights during the spring quarter of 2020 (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 in spring 2020 was down six percent from 2019. Milder weather, as indicated by lower heating and cooling degree days, along with decreased demand due to the COVID-19 pandemic contributed to the lower load.

- Generation by coal resources as a percent of total generation continued to decline, down from 32 percent in spring 2019 to 24 percent in spring 2020. This decrease has primarily been offset by increases in gas-fired and wind generation.

- Net market-to-market payments for spring 2020 were nearly $14 million paid by MISO to SPP. Total payments from MISO to SPP were just over $16 million, while payments from SPP to MISO were just over $2 million. This is nearly double from spring 2019 when net payments from MISO to SPP were $7.5 million.

- Resources were in market commitment status in 60 percent of all intervals, up from 49 percent in spring 2019. Offered capacity in both self-commitment and outage status fell to 17 percent of commitments in spring 2020, both down from 23 percent in spring 2019.

- After a sustained trend of increasing outages, spring 2020 saw just over 37,000 GWh of total generation outages, down from nearly 52,000 GWh in spring 2019. The decrease was most pronounced among coal resources and gas, simple-cycle resources.

- The spring 2020 average gas price at the Panhandle Eastern pipeline was $1.39/MMBtu, a drop of 35 percent from the spring 2019 price of $2.14/MMBtu.
• During spring 2020, the average day-ahead energy price was $14.03/MWh, and the average real-time price was $12.58/MWh. These prices are down about 41 and 44 percent, respectively, from spring 2019 energy prices.

• The April 2020 day-ahead price of $14.03/MWh and real-time price of $10.43/MWh are the lowest monthly average prices since the start of the Integrated Marketplace in March 2014.

• Spring 2020 saw 15 percent of real-time intervals having negative prices. This is double the level experienced in spring 2019. In the day-ahead market, six percent of intervals had negative prices in spring 2020, up from two percent in spring 2019.

• Overall, real-time market congestion was higher in spring 2020. In spring 2020, 44 percent of all real-time intervals had a breach, up from around 40 percent in spring 2019 and 20 percent in spring 2020.

• The transmission congestion right (TCR) funding for the 2019 TCR year declined relative to 2018, down from 93 to 86 percent.

• Auction revenue rights (ARR) remain overfunded for the 2019 TCR year. However, the overfunding has continued on a downward trend, from 158 percent in the 2017 TCR year, to 133 percent in the 2018 TCR year, and to 123 percent in the 2019 TCR year.

• The special issues section includes a discussion of FERC Order No. ER18-1632, which implemented a major maintenance cost component for mitigated offers. The filing was made to address market participants’ concerns about recovering costs associated with resource operation during times of mitigation.
2 LOAD AND RESOURCES

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

- Average hourly load in spring 2020 was down six percent from 2019. Milder weather, as indicated by lower heating and cooling degree days, along with decreased demand due to the COVID-19 pandemic contributed to the lower load.

- Generation by coal resources as a percent of total generation continued to decline, down from 32 percent in spring 2019 to 24 percent in spring 2020. This decrease has primarily been offset by increases in gas-fired and wind generation.

- Wind generation capacity at the end of May 2020 was just under 23,000 MW. This amount is an increase of 1,500 MW since August 2019.

- In the real-time market, gas resources set prices most frequently at nearly half of all intervals. Wind resources were next at 26 percent, while coal resources set the price during 25 percent of all intervals.

- Net market-to-market payments for spring 2020 were nearly $14 million paid by MISO to SPP. Total payments from MISO to SPP were just over $16 million, while payments from SPP to MISO were just over $2 million. This is nearly double from spring 2019 when net payments from MISO to SPP were $7.5 million.

- Cleared virtual supply offers as a percent of load in spring 2020 continued to climb – from 10.3 percent in spring 2018 to 12.2 percent in 2020. Cleared demand bids were nearly unchanged in spring 2020 from the previous two years at 7.7 percent.

- Net virtual profits for spring 2020 totaled $16 million before fees, decreasing to $10 million after fees. This is a decrease from about $23 million before fees in spring 2019 and nearly $11 million after fees.
2.1 LOAD

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

Average hourly load for the 2020 spring season was just under six percent below spring 2019. This decrease was consistent for all three months of the spring season.

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 2020 spring season were about 4.5 percent below spring 2019. March degree days were down 19 percent from 2019 to 2020; April was up 13 percent from 2019 to 2020; and May was virtually unchanged. Milder weather, as evidenced by decreased degree days, along with decreased demand due to the COVID-19 pandemic, are the primary drivers for the load reduction 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.
Overall generation levels were down five percent from spring 2019 to 2020. Gas combined-cycle generation was up 17 percent from spring 2019 to 2020, wind generation increased nearly seven percent from spring 2019 to 2020, while gas simple-cycle decreased by 21 percent, and coal generation decreased by just over 27 percent from spring 2019 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 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 37 percent in spring 2018, to 24 percent in spring 2020. Wind generation as a percentage of total generation was up from 29 percent of total generation from spring 2018 to just over 35 percent for spring 2020.

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

**Figure 2-5  Wind capacity and capacity factor**

Wind capacity in the footprint continues to grow steadily year-over-year, with nameplate wind capacity increasing from a monthly average of 17,725 MW in spring 2018 to 22,695 MW in spring 2020.

The wind capacity factor in both the day-ahead and real-time markets were essentially flat from spring 2019 to spring 2020, with real-time capacity factor at 40 percent and day-ahead capacity factor at 32 percent. Both day-ahead and real-time capacity factors were down from spring

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.
2018. This can primarily be attributed to increased capacity added to the market over the years, as well as the timing of wind resources beginning commercial operations.

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, coal resources were the marginal technology type in about 25 percent of intervals in spring 2020, up from 19 percent of intervals in spring 2019. Virtual transactions set prices in 35 percent of intervals in spring 2020, nearly the same level as spring 2019. Wind resources set prices in the day-ahead market in 15 percent of intervals in spring 2020, down from 17 percent in spring 2019.
In the real-time market, each of the major technology types set prices around a quarter of all intervals. Coal resources set prices in 25 percent of all real-time intervals in spring 2020, which was the same level as spring 2019. Gas combined-cycle and simple-cycle resources set prices 26 percent and 21 percent, respectively. Wind resources were the marginal technology type in 26 percent of intervals in spring 2020, up from 21 percent in 2019, and 18 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 (AECI) in Oklahoma and Missouri.

Figure 2–8 shows average hourly imports and exports across the SPP system.
SPP has typically been a net exporter in real time, with the exception of May 2019 and 2020, and the winter of 2019-20. While exports for spring 2020 were up slight from 2019, the level of imports has remained steady. The increase in exports can primarily be attributed to an increase in exports to ERCOT. Higher prices in ERCOT may have played a role in the increased exports from this region.

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 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.

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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.
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.

**Figure 2-9  Market-to-market, monthly**

Payments are predominantly from MISO to SPP for most of the year, with the exception of the summer. For the spring period, market-to-market payments paid to SPP by MISO were just over $16 million, while total payments from SPP to MISO were just over $2 million, for a net paid from MISO to SPP of nearly $14 million.
During spring 2020, six market-to-market flowgates had payments over $1 million from MISO to SPP, with two of those flowgates having over $2 million in payments – TMP441_25211 [Maryville-Midway 161kV (MPS) for the loss of Cooper-St. Joe 345kV (NPPD-MPS)] and TMP170_20876 [Kelly-Tecumseh Hill 161kV (WR) for the loss of Cooper-St. Joe 345kV (NPPD-MPS)].

### 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 virtual supply offers have steadily increased from spring 2018 to 2020. Uncleared virtual demand bids have remained steady during this same period.

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 at 20 percent in 2020, up from around 19 percent in spring 2019 and 17 percent in spring 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 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 were flat from spring 2019 to 2020 at 1,300 GWh, while virtual supply offers by financial-only participants increased during this period from just over 2,000 GWh in spring 2019 to just over 2,100 GWh in spring 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 remained flat from spring 2019 to 2020.
Virtual transactions can be made at hubs, interfaces, loads, and resources, as shown in Figure 2–16.

The great majority of virtual transactions are made at resources (primarily wind resources), with nearly 2,200 GW in spring 2020, compared to just over 2,200 GW in spring 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 2–17, from virtual transactions are derived from resource locations.
Average monthly profit from virtual transactions at the resource level was just over $3.6 million in spring 2020, down from nearly $5.9 million in spring 2019, due mostly to May. Profits from virtual transactions at hubs and loads also dropped from spring 2019 to 2020, while profits increased slightly at interfaces during the same period.

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 2020 totaled just over $16 million, down from $23 million in spring 2019. Net virtual profits after fees in spring 2020 were $10 million, compared to just under $11 million in spring 2019.

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

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

Profit after fees from virtual transactions dropped slightly from $0.94/MW in spring 2019 to $0.86/MW in spring 2020.
This chapter reviews unit commitment and dispatch processes in the SPP market for the spring 2020 period. Key points from this chapter include:

- Peak hour capacity overage increased from 3,000 MW in spring 2019 to just 4,000 MW in spring 2020.
- Resources were in market commitment status in 60 percent of all intervals, up from 49 percent in spring 2019.
- Offered capacity in both self-commitment and outage status fell to 17 percent of commitments in spring 2020, both down from 23 percent in spring 2019.
- Dispatched megawatts of generation in market commitment status represented 61 percent of all generation in spring 2020, up from 48 percent in both spring 2018 and 2019.
- Overall, the average number of monthly scarcity events in spring 2020 at 94 events, was just slightly higher than the monthly average of 92 events in spring 2019.
- After a sustained trend of increasing outages, spring 2020 saw just over 37,000 GWh of total generation outages, down from nearly 52,000 GWh in spring 2019. The decrease was most pronounced among coal resources and gas, simple-cycle resources.

### 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.

The average peak hour overage\(^4\) for spring 2020 was 4,000 MW, up from about 3,000 MW in spring 2019 and nearly 3,700 MW in spring 2018.

\[^4\text{The calculation for real-time average peak hour capacity overage is: economic maximum – load – net scheduled interchange – (regulation up + spinning reserves + supplemental reserves). All capacity from wind generation is not included in the economic maximum. Only capacity from traditional fuel resources is included in this calculation.}\]
Figure 3–2 shows the percentage of capacity⁵ offered 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 four to six percent on a monthly basis.

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

Market commitment status in spring 2020 was 60 percent of all intervals up from 49 percent in spring 2019. Outage status for the spring was around 17 percent, down from 23 percent in spring 2019. Offered capacity in self-commitment status continues on a downward trend with approximately 19 percent of commitments with this status in spring 2020, down from 25 percent in spring 2018 and 24 percent in spring 2019.

While we view the reduction of self-committed 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.⁶ All output from a self-committed unit is counted as self.

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⁵ All resources, including wind, are included at nameplate capacity.

The volume of market-committed\(^7\) megawatts has been on an increasing trend recently. Spring 2020 saw 61 percent of megawatts dispatched were from resources in market status, this is up from 52 percent in spring 2018 and 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 demand for the past three spring seasons has ranged from around 118 percent to 123 percent, with spring 2020 at 123 percent. The periods with an increase in capacity as a percent of demand may reflect operator actions to commit additional capacity to meet uncertainty. As was stated in the 2018 annual state of the market report and updated in the 2019 Annual State of the Market report, the MMU is continuing to promote the development of an uncertainty product to help remediate this issue.

### 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

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that product, and should provide some 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 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 by month, along with an annual comparison of monthly averages. Typically, more regulation-down is available than regulation-up. This contributes to typically having more regulation-up scarcity events than regulation-down scarcity events. 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.
Spring 2020 saw an average of 110 scarcity events per month, down from an average of 139 in spring 2019, but up from 59 in spring 2018. Operating reserve scarcity events dropped markedly from a monthly average of 33 in spring 2019 to seven in spring 2020, and regulation-up scarcity events also dropped from a monthly average of 70 in spring 2019 to 56 in spring 2020. Conversely, regulation-down scarcity intervals were up compared to 2019, from 36 in spring 2019 to 47 in spring 2020. The increase in regulation-down scarcity intervals can mostly be attributed to increased levels of wind generation in the spring 2020 season.

More scarcity intervals generally occur during the shoulder spring and fall seasons, as these months typically have high wind production, low load, and more generator outages. Because wind provides a relatively high amount of capacity, fewer flexible resources are available to provide reserves. When wind production is volatile, the dispatchable resources’ highest priority is to provide energy, with reserves as a lower priority.

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 for each fuel type.

**Figure 3-6** Generation outages by fuel type

After a sustained trend of increasing outages, spring 2020 saw just over 37,000 GWh of total generation outages, down from nearly 52,000 GWh in spring 2019 and 43,000 GWh in spring 2018. The decrease is most pronounced among coal resources, where total outages have dropped from 20,000 GWh in spring 2019 to 16,000 GWh in spring 2020, and gas, simple-cycle resources which decreased from 18,000 GWh in spring 2019 to 12,000 GWh is spring 2020. These drops in spring 2020 are likely a result of responses to the COVID-19 pandemic.
4 MARKET PRICES AND COSTS

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

- The spring 2020 average gas price at the Panhandle Eastern pipeline was $1.39/MMBtu, a drop of 35 percent from the spring 2019 price of $2.14/MMBtu.
- During spring 2020, the average day-ahead energy price was $14.03/MWh, and the average real-time price was $12.58/MWh. These prices are down about 41 and 44 percent, respectively, from spring 2019 energy prices.
- The April 2020 day-ahead price of $14.03/MWh and real-time price of $10.43/MWh are the lowest monthly average prices since the start of the Integrated Marketplace in March 2014.
- The areas with highest prices in the footprint for the spring are concentrated in the far southeast and southwest portion of the SPP footprint, while low prices were abundant in the northern portion of the footprint.
- Both day-ahead and real-time prices at the North and South hubs were very close in spring 2020, with prices in the $12/MWh to $14/MWh range.
- Spring 2020 saw 15 percent of real-time intervals having negative prices. This is double the level experienced in spring 2019. In the day-ahead market, six percent of intervals had negative prices in spring 2020, up from two percent in spring 2019.
- Revenue neutrality uplift for spring 2020 was nearly $8 million, down markedly from $36 million in spring 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.

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

Gas prices at the Panhandle Eastern hub have remained under $2.00/MMBtu since April 2019, reaching a low of $1.28/MMBtu in March 2020. This is the lowest average monthly gas price since the start of the SPP Integrated Marketplace. For spring 2020, the average gas price was $1.39/MMBtu; this is down from $2.14/MMBtu in both spring 2018 and 2019.

During spring 2020, the average day-ahead energy price was $14.03/MWh, and the average real-time price was $12.58/MWh, as shown in Figure 4–1, both down over 40 percent from spring 2019. April 2019 saw the lowest monthly average energy prices since the start of the Integrated Marketplace, at $13.21/MWh in the day-ahead market and $10.43/MWh in the real-time market. These low prices are, in part, a result of the low gas prices, high wind generation, less heating and cooling demand, and lower demand due to the COVID-19 pandemic.

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 spring period for the past three years.
As the figure above shows, the implied heat rate dropped from spring 2019 to 2020. Typically, the implied heat rate is lowest in the spring period, primarily due to lower loads as well as increased 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.
While the divergence percent was up from spring 2019 to spring 2020, divergence was flat, and absolute divergence decreased. The MMU feels that absolute divergence is the best measurement of divergence, as this method eliminates the “softening” of averages when positive and negative values are encountered. 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.

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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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.

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 spring are concentrated in the southern portion of the SPP footprint, specifically in west Texas and a small area of southeast Oklahoma. 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 spring were found in the western and northern portions of the footprint.

Figure 4–5 and Figure 4–6 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 in west Texas and northeast Arkansas/southeast Missouri, and lowest in western Kansas and the northern portion of the SPP footprint.

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.

![Trading Hub Prices Graph](graph.png)

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 spring 2020, with day-ahead prices around $14/MWh and real-time prices around $12/MWh.

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. In spring 2020, the spread between day-ahead and real-time prices has converged to about $8/MWh. However, in April 2020, the spread between on-peak and off-peak real-time prices at the North hub expanded to nearly $13/MWh. This can primarily be attributed to higher renewable generation in the north portion of the SPP footprint during the overnight hours. 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 4–10.

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

In spring 2020, just over six percent of asset owner intervals\(^{11}\) in the day-ahead market had prices below zero. This is up from two percent in spring 2019. At just under 10 percent of hours, April 2020 had the highest percentage of hours with negative prices in the day-ahead market 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 4–11.

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\(^{11}\) 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).
Spring 2020 had just nearly 16 percent of all asset owner intervals in the real-time market with negative prices, compared to just under eight percent in spring 2019. Like the day-ahead market in April, the real-time market had the highest monthly percentage of negative price intervals since the start of the Integrated Marketplace at just over 20 percent. Furthermore, the magnitude of negative prices was largest in April 2020 with about five percent of intervals less than −$25/MWh for the month.

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.12

### 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,

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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 4-12 Regulation-up prices**

![Regulation-up prices chart](image)

**Figure 4-13 Regulation-down prices**

![Regulation-down prices chart](image)

Regulation-up prices fell by 40 percent in the both the day-ahead and real-time markets from spring 2019 to 2020. Conversely, regulation-down prices climbed in both markets from spring
2019 to 2020; the day-ahead market price was up by 35 percent, while the real-time price was up by 10 percent.

**Figure 4-14  Spinning reserve prices**

![Spinning reserve prices graph](image)

**Figure 4-15  Supplemental reserve prices**

![Supplemental reserve prices graph](image)

Marginal clearing prices for both spinning and supplemental reserves dropped in both the day-ahead and real-time markets from spring 2019 to 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.¹³

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 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 spring 2020, along with a downward trend from the prior year.

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

**Figure 4-17  Mitigation frequency, real-time market**

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 spring 2020. Average mitigation levels for spring 2020 were roughly one-half of the level in spring 2019.

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

**Figure 4-18  Mitigation frequency, start-up offers**
The overall level for mitigation of start-up offers climbed slightly from 2.1 percent in spring 2019 to 2.4 percent in spring 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.

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

Typically, most day-ahead make-whole payments are attributed to coal and gas resources. Spring 2020 day-ahead make-whole payments were just over $11 million, up from nearly $6 million in spring 2019. Most notably, coal make-whole payments increased from about $2.8 million in spring 2019 to nearly $5.6 million in spring 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.

**Figure 4-20  Make-whole payments, reliability unit commitment**

Spring 2020 monthly real-time make-whole payments totaled around $8.5 million, down from $18.6 million in spring 2019. Spring 2019 saw a high number of manual capacity commitments; this factor was mostly responsible for the high level of reliability unit commitment make-whole payments during this period.

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 spring 2020 was just under $8 million, just a fraction of the level of $36 million in spring 2019. The high level of revenue neutrality uplift in spring 2019 can primarily be attributed to high levels of real-time congestion payments in April and May 2019.
5 CONGESTION AND TRANSMISSION RIGHTS MARKET

This chapter reviews congestion and transmission congestion rights in the SPP market for the spring 2020 period. Key points from this chapter include:

- During the spring season, the most congested flowgate was in west Texas – TEMP42_25314 Sundown2-Sundown 115kV for the loss of Sundown2-Amoco Switch 230kV (SPS). After having the top five most congested flowgates in the winter season clustered in Oklahoma, the most congested flowgates are more spread out in the spring season.

- Overall, real-time market congestion was higher in spring 2020. In spring 2020, 44 percent of all real-time intervals had a breach, up from around 40 percent in spring 2019 and 20 percent in spring 2020.

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

- For the 2019 TCR year, ended in May 2020, 67 percent of participants received positive net revenues, while 33 percent of participants held hedges that did not cover their day-ahead congestion costs.

- The transmission congestion right (TCR) funding for the 2019 TCR year declined relative to 2018, down from 93 to 86 percent.

- Auction revenue rights (ARR) remain overfunded for the 2019 TCR year. However, the overfunding has continued on a downward trend, from 158 percent in the 2017 TCR year, to 133 percent in the 2018 TCR year, and to 123 percent in the 2019 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 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, spring**

![Congestion by shadow price, spring](image)

<table>
<thead>
<tr>
<th>Flowgate Description</th>
<th>Shadow Price ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>TEMP42_25314</td>
<td></td>
</tr>
<tr>
<td>TEMP441_25211</td>
<td></td>
</tr>
<tr>
<td>TEMP548_25525</td>
<td></td>
</tr>
<tr>
<td>TEMP170_20876</td>
<td></td>
</tr>
<tr>
<td>BULMEDBUFNOR</td>
<td></td>
</tr>
<tr>
<td>TMP208_24721</td>
<td></td>
</tr>
<tr>
<td>TMP142_25323</td>
<td></td>
</tr>
<tr>
<td>BULMEDBUFNOR#</td>
<td></td>
</tr>
<tr>
<td>TMP518_25556*</td>
<td></td>
</tr>
</tbody>
</table>

* SPP market-to-market flowgate

# MISO market-to-market flowgate
During the spring season, the most congested flowgate was in west Texas – TEMP42_25314 Sundown2-Sundown 115kV ftlo Sundown2-Amoco Switch 230kV (SPS). After having the top five most congested flowgates in the winter season clustered in Oklahoma, the most congested flowgates are more spread out in the spring season. Most of this congestion can be attributed to transmission outages in the area.

**Figure 5-2  Congestion by shadow price, rolling 12 month**

The most congested flowgate over the past 12 months remains TMP175_24736; with the other constraint in the area (TMP379_24692), the third 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.

**Figure 5-3  Congestion by interval, day-ahead**

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 May 2020, with 28 intervals having no congestion.
Overall, real-time market congestion for spring 2020 in terms of intervals with breached flowgates was about five percentage points higher than spring 2019 and over double the level of spring 2018. Transmission outages, along with high levels of wind output, 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.
During spring 2020, load-serving entities earned $120 million in congestion payments. These payments exceeded their day-ahead congestion cost of $70 million. Real-time congestion costs did not aid load-serving entities, and increased the total congestion cost to $75 million. When compared to spring 2019, the 2020 surplus between congestion payments and total congestion costs increased from $43 million to $45 million.

The surplus between the congestion payments and the day-ahead congestion cost shows that overall, for the quarter, load-serving entities fully covered their congestion cost through the congestion hedging market. Moreover, day-ahead congestion costs for load-serving entities decreased 28 percent when compared to spring 2019.

Additionally, non-load-serving and financial-only entities collected congestion payments of $2 million. These payments did not exceed their $47 million in day-ahead congestion costs. Real-time congestion costs aided non-load-serving and financial-only entities, decreasing their total congestion cost to $22 million. This shows that overall, non-load-serving, and financial-only entities did not cover their congestion cost through the transmission congestion rights market.
During the 2019 TCR Year, load-serving entities earned $443 million in congestion payments. These payments exceeded their day-ahead congestion cost of $312 million. Real-time congestion costs aided load-serving entities, reducing the total congestion cost to $314 million. When compared to TCR year 2018, the 2019 surplus between congestion payments and total congestion costs decreased two percent, from $132 million to $129 million.

The surplus between the congestion payments and the day-ahead congestion cost shows that overall, for the TCR Year, load-serving entities fully covered their congestion cost through the congestion hedging market. Moreover, day-ahead congestion costs for load-serving entities decreased 27 percent when compared to TCR Year 2018.

Additionally, non-load-serving and financial-only entities collected congestion payments of $65 million. These payments did not exceed their $197 million in day-ahead congestion costs. Real-time congestion costs aided non-load-serving and financial-only entities, decreasing their total congestion cost to $101 million. This shows that overall, non-load-serving, and financial-only entities did not cover their congestion cost through the transmission congestion right market.
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.

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 $10 million more in congestion costs than was offset by their auction revenue rights and transmission congestion right positions.

* does not include Auction Revenue Rights closeout

14 Figure 5-7 through Figure 5-10 reference market participants who hold ARR entitlements.
Figure 5–8 highlights that 67 percent of participants received positive net revenues, while 33 percent of participants held hedges that did not cover their day-ahead congestion costs. The bottom five participants collectively paid $36 million more in congestion costs than was offset by their auction revenue right and transmission congestion right positions.

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.

* includes Auction Revenue Rights closeout
Figure 5–9 highlights that 61 percent of participants received positive net revenues, while 39 percent of participants held hedges that did not cover their total congestion costs. The bottom five participants collectively paid $13 million more in congestion costs than was offset by their auction revenue right and transmission congestion right positions.

Figure 5–10 highlights that seventy-one percent of participants received positive net revenues, while twenty-nine percent of participants held hedges that did not cover their total congestion costs.
costs. The bottom five participants collectively paid $31 million more in congestion costs than was offset by their auction revenue right and transmission congestion right positions.

**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. Based on results from MMU analysis, there are two main reasons causing the shortfalls of the 2020 spring months. The first being increasing short-term outages (less than 120 hours) in the spring months of 2020, that occurred in the day-ahead market, but were not included in monthly TCR model. Another reason is the high external flow on some market-to-market flowgates. It is hard to predict the parallel flow amount in adjacent market months ahead. When the TCR model under-predicted the parallel flow amount, it would contribute to the underfunding on the flowgate.
Figure 5–12 above shows transmission congestion right funding, day-ahead revenue, net surplus/shortfall, and transmission congestion right funding percent.

The spring 2020 funding of 79 percent declined from 89 percent in spring 2019. Furthermore, the spring 2020 funding deficit increased nearly 60 percent from spring 2019 levels and stands near negative $31 million for the quarter.

The 2019 TCR year cumulative funding of 86 percent declined from 93 percent in the 2018 TCR year. Furthermore, the 2019 TCR year funding deficit increased nearly $40 million against the 2018 TCR year and stands in excess of negative $85 million. The TCR underfunding is driven by differences in line ratings, outages, and market-to-market constraints. The MMU continues to evaluate TCR underfunding and will make recommendations as necessary.

Daily observations of transmission congestion right funding for the 2017, 2018, and 2019 spring periods are shown in Figure 5–13.
Most daily observations of transmission congestion right funding fell between 80 percent and 120 percent over the 2020 spring quarter.\(^\text{15}\) However, the funding distributions have shifted noticeably toward lower percentages when compared to the previous two spring quarters. In spring 2020, 38 percent of the funding events for the quarter fell between 45 percent and 79 percent funded.

\(^{15}\) Sixty percent of the spring 2020 funding observations fell within this range.
Most daily observations of transmission congestion right funding fell between 80 percent and 120 percent over the 2018 TCR year.\textsuperscript{16} However, the funding distributions have shifted noticeably toward lower percentages when compared to the previous two TCR years. In TCR year 2019, 23 percent of the funding events fell between 45 percent and 79 percent funded. MMU analysis showed the short term outages (less than 120 hours) increased in the spring months of 2020, comparing with those in the spring month of 2019. This might be a factor contributing to the trend shifting.

Figure 5–15 shows transmission congestion right revenue, auction revenue right funding, net surplus, and auction revenue right funding percent.

\textbf{Figure 5-15  
Auction revenue right funding, monthly}

Auction revenue right funding percentages remained stable over the spring 2020 quarter, but decreased when compared to the related period in 2019.

\textsuperscript{16} Seventy-four percent of the 2018 TCR year funding observations fell within this range.
The spring 2020 quarterly funding percentage decreased from 135 percent to 121 percent. The related quarterly surplus dollars also decreased from $34 million to $21 million. Additionally, the 2019 TCR year funding percentage decreased from 133 percent to 123 percent. The related surplus dollars also decreased from $109 million to $77 million.
FERC Order No. ER18-1632 implemented a major maintenance cost component for mitigated offers. The filing was made to address market participants’ concerns about recovering costs associated with resource operation during times of mitigation.

The order, implemented on April 18, 2019, allowed market participants to submit documentation of major maintenance costs that could be tied to run time or starts to be included in a no-load or start-up major maintenance adder.

There are 491 thermal units eligible for major maintenance adders. As of the publishing of this report:

- 113 units have been approved for major maintenance;
- 56 resources have approved start-up adders with an average cost of $3,472;
- 94 resources have approved no-load adders with an average cost of $197/hour; and
- 26 resources have both start-up and no-load adders with an average start-up cost of $2,868 and average no-load cost of $211/hour.

One of the questions the market monitor has been investigating is the potential impact that these adders might have had on make-whole payments.

A challenge to evaluating the impact of major maintenance on make-whole payments is that major maintenance adders were not available until mid-April 2019, and that 2019 was an exceptional year for make-whole payments due to higher than usual outages and ten conservative operations events. Conversely, 2020 has had lower make-whole payments than the previous years through the spring.
In order to measure the effects of major maintenance adders, make-whole payments have been analyzed by grouping the data into before, January 1, 2017 through April 17, 2019, and after implementation on April 18, 2019 through May 31, 2020, (as seen in Figure 6-1), and split by day-ahead market and real-time market (as seen in Figure 6-2). The total megawatts cleared have been included to calculate make-whole payments on a per megawatt hour basis for comparison.

**Figure 6-1  Make-whole payments per MW before and after implementation**

<table>
<thead>
<tr>
<th></th>
<th>Before major maintenance</th>
<th>After major maintenance</th>
<th>Grand total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Make-whole payments</td>
<td>$99,498,096</td>
<td>$101,544,759</td>
<td>$201,042,856</td>
</tr>
<tr>
<td>MW cleared</td>
<td>13,548,964</td>
<td>15,594,594</td>
<td>29,143,557</td>
</tr>
<tr>
<td>Make-whole payments per MW</td>
<td>$7.34</td>
<td>$6.51</td>
<td>$6.90</td>
</tr>
</tbody>
</table>

**Figure 6-2 Make-whole payments per MW before and after implementation, day-ahead and real-time**

<table>
<thead>
<tr>
<th></th>
<th>Day-ahead</th>
<th>Real-time</th>
<th>Grand Total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Before major maintenance</td>
<td>After major maintenance</td>
<td>Before major maintenance</td>
</tr>
<tr>
<td>Make-whole payments</td>
<td>$33,814,939</td>
<td>$41,959,685</td>
<td>$65,683,158</td>
</tr>
<tr>
<td>MW cleared</td>
<td>10,928,997</td>
<td>12,791,710</td>
<td>2,619,967</td>
</tr>
<tr>
<td>Make-whole payments per MW</td>
<td>$3.09</td>
<td>$3.28</td>
<td>$25.07</td>
</tr>
</tbody>
</table>

The total make-whole payment per megawatt cleared was $7.34 and $6.51 from before and after implementation respectively. When divided into day-ahead and real-time payments, the make-whole payment per megawatt increases slightly, from $3.09 to $3.28, for the day-ahead and declines significantly, from $25.07 to $21.26, for the real-time.

A further breakdown of make-whole payments before and after implementation (Figure 6-3) shows that resources that have major maintenance adders decreased more significantly than the resources that did not.
### Figure 6-3  Make-whole payments before and after implementation, by resources with and without major maintenance adders

<table>
<thead>
<tr>
<th></th>
<th>Before major maintenance</th>
<th>After major maintenance</th>
<th>Grand total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Non-major maintenance resources</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Make-whole payments</td>
<td>$66,590,322</td>
<td>$75,926,319</td>
<td>$142,516,641</td>
</tr>
<tr>
<td>MW cleared</td>
<td>9,580,425</td>
<td>11,678,278</td>
<td>21,258,703</td>
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<tr>
<td>Make-whole payments per MW</td>
<td>$6.95</td>
<td>$6.50</td>
<td>$6.70</td>
</tr>
<tr>
<td><strong>Major maintenance resources</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Make-whole payments</td>
<td>$32,907,774</td>
<td>$25,618,440</td>
<td>$58,526,214</td>
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<tr>
<td>MW cleared</td>
<td>3,968,539</td>
<td>3,916,316</td>
<td>7,884,854</td>
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<tr>
<td>Make-whole payments per MW</td>
<td>$8.29</td>
<td>$6.54</td>
<td>$7.42</td>
</tr>
</tbody>
</table>

When examining the same data split into day-ahead and real-time make-whole payments (Figure 6-4) the day-ahead payments increased for both groups of resources while the real-time payments decreased.

### Figure 6-4  Make-whole payments before and after implementation, by resources with and without major maintenance adders for day-ahead and real-time

<table>
<thead>
<tr>
<th></th>
<th>Day-ahead</th>
<th>Real-time</th>
<th>Grand total</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Before major maintenance</td>
<td>After major maintenance</td>
<td>Before major maintenance</td>
</tr>
<tr>
<td><strong>Non-major maintenance resources</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Make-whole payments</td>
<td>$26,309,773</td>
<td>$33,271,875</td>
<td>$40,280,549</td>
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<tr>
<td>MW cleared</td>
<td>8,185,233</td>
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<tr>
<td>Make-whole payments per MW</td>
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<td><strong>Major maintenance resources</strong></td>
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<td></td>
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<tr>
<td>Make-whole payments</td>
<td>$7,505,165</td>
<td>$8,687,810</td>
<td>$25,402,609</td>
</tr>
<tr>
<td>MW cleared</td>
<td>2,743,764</td>
<td>2,863,623</td>
<td>1,224,774</td>
</tr>
<tr>
<td>Make-whole payments per MW</td>
<td>$2.74</td>
<td>$3.03</td>
<td>$20.74</td>
</tr>
</tbody>
</table>
Of note, major-maintenance resources accounted for 22 percent of the day-ahead and 39 percent of the real-time make-whole payments before adders were implemented. After implementation, these resources accounted for 21 percent of the day-ahead and 28 percent of the real-time make-whole payments.

Conclusion

Despite 2019 having higher make-whole payments than usual because of higher than normal days of conservative operations, it appears as though the major maintenance adder did not increase make-whole payments on a per megawatt hour basis. There was a slight increase in the day-ahead market make-whole payments, but the increase occurred across all resources. Real-time make-whole payments decreased per megawatt hour across all resources, especially for resources that submitted major maintenance adders.

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