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1 EXECUTIVE SUMMARY

Many of the themes that have been identified in previous years, such as increasing wind generation, make-whole payments, and resource adequacy challenges, continue and deepen in 2022. Wind generation continues to play an increasing role in SPP’s markets. This has produced many challenges including increasing variability and uncertainty of supply, out-of-market actions to ensure system reliability, higher make-whole payments, and increased negative prices. These, however, are not necessarily new developments in the SPP market for 2022.

With effects of the February 2021 winter weather event skewing many of the metrics during that year, some comparisons in this report are made by comparing 2022 results to 2021 results excluding February. Any metrics having this exclusion will be noted.

The following list identifies key observations in the SPP marketplace during 2022.

- **Day-ahead market and real-time market prices increased.** The average day-ahead price was $48/MWh and the average real-time price was $43/MWh for 2022. When compared to 2021 with February prices excluded (this removes the effects of the winter weather event on prices), the day-ahead prices represent an 80 percent increase, and real-time prices represent a 75 percent increase over 2021. Higher gas prices in 2022 are the largest contributor for the increase.

- **Gas prices increased.** The average gas price for 2022 at the Panhandle Eastern hub was $5.83/MMBtu, an increase of 69 percent over 2021 (with February prices excluded).

- **Revenue neutrality uplift increased.** Revenue neutrality uplift was up markedly over 2021. Revenue neutrality uplift for 2022 was $548 million, up 92 percent from $285 million in 2021. Most of the increase can be attributed to an increase in the real-time congestion component, which was up 189 percent, from $226 million in 2021 to $653 million in 2022.

- **Make-whole payments increased.** When removing February from 2021 day-ahead make-whole payments, payments in 2022 of $173 million were up 130 percent from 2021 at $75 million. Likewise, reliability unit commitment make-whole payments were up 152 percent, from $116 million in 2021 (excluding February) to $292 million in 2022. Much of these increases can be attributed to the increase in natural gas prices.

- **Addition of wind resources has slowed.** In 2022, just over 1,500 MW nameplate capacity of new wind resources was added to the market. In comparison, 2021 added
nearly 3,200 MW of wind capacity and 2020 added just over 4,800 MW of new wind capacity. However, the generation interconnection queue still contains a large amount of new wind resources potentially to be added to the market, along with a growing amount of solar and battery/storage resources.

- **Wind penetration increased.** Installed nameplate wind capacity stood at 32,032 MW at the end of 2022. Wind generation capacity now accounts for 32 percent of installed nameplate capacity in the SPP market.

- **Generation mix changed.** In 2020, for the first time, wind resources produced the highest percentage of total generation in the market, displacing coal resources as the leading producer. That trend reverted back to coal being the largest producer of total generation in 2021, buoyed by high gas prices causing gas resources to be less economic. Wind resources recaptured the highest percentage in 2022 at nearly 38 percent of total generation, with coal resources producing just over 33 percent of total generation.

- **Negative priced intervals decreased in the day-ahead market, but increased in the real-time market.** The frequency of negative priced intervals decreased by one percentage point in the day-ahead market and increased by one percentage point in the real-time market over 2021. Just over seven percent of all asset owner intervals in the day-ahead market had negative prices, down from just under eight percent in 2021. Just over 15 percent of the real-time asset owner intervals had negative prices, up from just under 15 percent in 2021. Although, the growth in negative prices intervals has slowed, most likely attributable to the slowing addition of new wind generation, the MMU remains concerned about continued increasing frequency of negative price intervals. Negative prices may not be a problem in and of themselves; however, they do indicate an increase in surplus energy on the system and/or an increase in available low-cost generation.

- **Congestion costs increased.** Total congestion payments for 2022 were nearly $2.0 billion; up from $1.2 billion in 2021. This marked increase can primarily be attributed to the proximity of existing generation to load, the proximity of newly constructed generation to load, the outage of key transmission facilities, and the volatility in fuel prices.

- **Transmission congestion rights funding fell outside of the targeted range.** While the annual funding percentage increased to 88 percent in 2022 from 84 percent in 2021, the
annual shortfall increased by more than $85 million year over year. Much of this shortfall was the result of unaccounted for outages in the congestion hedging model.

- **Demand response capacity increased.** During 2022, 28 dispatchable demand response resources representing 186 MW of nameplate capacity were added to the SPP market. These resources ranged in size from 0.1 MW to 100 MW. At the end of 2022, there was 362 MW of dispatchable demand response resources installed nameplate capacity.

- **Market-to-market payments from MISO were up.** Net market-to-market payments from MISO to SPP for 2022 were $160 million, up 84 percent from $87 million in 2021.

- **Virtual profits decreased.** Average profit per cleared virtual megawatt after fees was $1.47/MW in 2022, down 20 percent from $1.84/MW (excluding February) in 2021.

- **Outaged capacity decreased.** Total outages for capacity taken out-of-service for maintenance decreased by nine percent from 2021 to 2022. Forced outages had a slight increase of two percent from 2021 to 2022.

- **Energy consumption increased.** Monthly average system energy consumption was up five percent compared to 2021. Most of this increase can be attributed to weather impacts and increased load.

- **Self-committed capacity increased slightly.** The average percent of total offered capacity by commitment status shows a less than one percentage point increase in self-commit status and a six percentage point decrease in market status. The capacity offered by the intra-day reliability unit commitment and short-term reliability unit commitment were up three percentage points and two percentage points, respectively.

- **Regional congestion patterns.** The areas that experienced the highest congestion costs in 2022 were the southeastern corner of the SPP footprint, as well as a concentrated area in southeast North Dakota. Much of Kansas, Nebraska, South Dakota, and a concentrated area in northwest Oklahoma experienced the lowest congestion costs for the year.

- **Overall, hedging covered congestion costs.** In aggregate, load-serving entities covered 137 percent of their congestion cost and non-load-serving entities covered 108 percent of their total congestion cost.

- **Individual congesting hedging ranged in performance.** Individual market participants hedged congestion with varying degrees of effectiveness. Overall 72 percent of load-serving entities recovered at least all of their congestion cost.
Auction revenue right funding decreased. Auction revenue right funding decreased from 128 percent to 122 percent. The ARR surplus increased by more than $140 million year over year.

SPP markets remain competitive. Structural and behavioral metrics indicate that the SPP markets have been competitive over the last several years. The market share, Herfindahl-Hirschman Index (HHI), and pivotal supplier analyses all indicate minimal to moderate potential structural market power in SPP markets outside of frequently constrained areas.

Offer mitigation increased slightly but remains rare. Incremental energy offer mitigation in 2022 slightly increased in frequency in both the day-ahead and real-time markets. Despite the minor increase in mitigated resource hours, energy offer mitigation remains very rare, at 0.22 and 0.08 percent of resource hours in the day-ahead and real-time markets respectively. The total frequency of mitigation across all other products was similarly low and in line with prior years, with a slight uptick in spinning reserve mitigation concentrated in August and September.

Exercising market power remains rare. Behavioral measures suggest that attempts to actually exercise market power by manipulating the price (economic withholding) or quantity (physical withholding) of generation are rare. The output gap, an inference of economically withheld generation, rose slightly compared to 2021. This was primarily driven by coal resources facing supply shortage issues. The level of physically unoffered generation remained level in 2021 and 2022 after disruptions to maintenance and outages in 2020 attributable to the COVID-19.

Resource adequacy issues persist. The February 2021 winter weather event and December 2022 winter storm both highlighted that significant issues with SPP’s resource adequacy approach persist and pose a significant risk to reliability. Key issues include a lack of a seasonal resource adequacy requirement, fuel availability risk, correlated output and outages among similar resources, and an accreditation process that does not reflect actual resource performance.
1.1 OVERVIEW

As with previous years, the largest component of total wholesale costs remains energy costs, which represented 96 percent of total costs in 2022. Historically, the percentage has remained around 96 percent since the start of the Integrated Marketplace in 2014. 2021 was an outlier; however, with make-whole payments of over $1 billion as a result of the 2021 winter weather event, that percentage decreased to 85 percent. Removing February from the calculation in 2021 results in energy costs being 95 percent of total wholesale market costs, which is much closer to the historical average.

The annual five-minute peak demand of 52,870 MW was 2.5 percent higher this year compared to last year, while total electricity consumption was up five percent. Of the 1,750 MW increase in nameplate generation capacity from 2021, 1,579 MW was from wind resources, 161 MW was from dispatchable demand response, and 10 MW was from solar resources.

Wind generation as a percent of total generation continued its steady climb as it represented nearly 38 percent of system generation in 2022, up from nearly 35 percent in 2021. After a rise from 2020 to 2021, coal generation decreased, representing just over 33 percent of total generation in 2022, down from nearly 36 percent in 2021. The increase in coal generation from 2020 to 2021 is primarily the result of higher gas prices in 2021 making coal generation more economic than some gas resources.

1.2 DAY-AHEAD AND REAL-TIME MARKET PERFORMANCE

Overall, both day-ahead and real-time energy prices were higher in 2022 compared to 2021 (when excluding February, which eliminates the effects of the February 2021 winter weather event). The average hourly day-ahead price of $48/MWh in 2022 was 80 percent higher than the 2021 price (with February excluded) of $27/MWh. Likewise, the average hourly real-time price of $43/MWh in 2022 was 75 percent higher than the 2021 price (with February excluded) of $25/MWh. Interestingly, even without excluding February 2021 from the real-time average price for 2021 (making the average $37/MWh), the 2022 real-time average was still 17 percent higher than 2021. Much of this increase can be attributed to higher loads and increased real-time congestion.

Gas prices were also up in 2022, with a monthly average of $5.83/MMBtu, an increase of 18 percent over 2021 (with February included) and an increase of 69 percent (with February excluded). The monthly average gas price ranged from $4.46/MMBtu in January to $8.03/MMBtu in August.
Load participation in the day-ahead market dropped in 2022. The average monthly level of participation for the load assets was between 97 percent and 99 percent of the actual real-time load, with the annual average at 98 percent. Prior to 2022, the monthly level averaged between 98 and 101 percent, with annual averages of 100 percent in 2020 and 99 percent in 2021.

Additionally, on average for the year, wind generation was 2,800 MW higher in the real-time market compared to the amount scheduled in the day-ahead market on an hourly basis. This represents a continued and increasing challenge to the market as wind generation continues to increase substantially.

Virtual bids and offers may theoretically offset the under-scheduling of renewable supply in the day-ahead market, however, in net they did not as they averaged 1,450 MW of net virtual supply. Furthermore, it is important to recognize that even if virtual transactions were to match the quantity of under-scheduled renewables, the prices associated with the virtual offers are not likely to fully represent the offer prices of the renewable resources in order to preserve a profit margin.

In general, virtual transactions were profitable in the SPP market. Net profit before fees was $369 million in 2022, down from $680 million in 2021, but up from $72 million in 2020. Profits from virtual transactions were extraordinarily high in 2021 due to the effects of the winter weather event. When charges and transaction fees are included, net profit for virtual transactions was $116 million in 2022, down from $535 million in 2021, but up from $36 million in 2020. If February was removed from the 2021 calculations, net profit before fees would have been $213 million and after fees would have been $112 million.

Generation offers in the day-ahead market averaged just over 63 percent as market commitment status followed by self-commitment status at 14 percent of the total capacity commitments for 2021. This continues the trend of increasing market commitments and decreasing self-commitment since 2016.

SPP has designed a ramp capability product, which was implemented on March 1, 2022. While the MMU generally supported the proposed design, the MMU did have some concerns with the design prior to implementation. In addition to these concerns, the MMU identified an issue after implementation with the deliverability of ramp cleared by the ramp-up capability product.

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1 Tariff Revisions to Add Ramp Capability, FERC Docket No. ER20-1617.
2 See MMU comments in Docket No. ER20-1617.
1.3 TRANSMISSION CONGESTION AND HEDGING

Locational marginal prices reflect the sum of the marginal cost of energy, the marginal cost of congestion, and the marginal cost of losses for each pricing interval at any given pricing location in the market. Certain locations of the footprint experience significant price movements resulting from congestion caused by high wind generation and transmission limitations.

The areas that experienced the highest congestion costs in 2022 were the southeastern corner of the SPP footprint as well as a concentrated area in southeast North Dakota. Much of Kansas, Nebraska, South Dakota, and a concentrated area in northwest Oklahoma experienced the lowest congestion costs for the year. The frequently constrained area study for 2021 identified southwest Missouri and southeast Oklahoma as frequently constrained areas and these areas continued to see elevated congestion prices in 2022.

Total congestion payments for 2022 were nearly $2 billion; up from $1.2 billion in 2021. This marked increase can primarily be attributed to the proximity of existing generation to load, the proximity of newly constructed generation to load, the outage of key transmission facilities, and the volatility in fuel prices. While most load-serving entities were able to successfully hedge their congestion exposure with auction revenue rights and transmission congestion rights, a handful of participants were under-hedged. The largest amount over-hedged was $162 million, while the largest amount under-hedged was $168 million.

1.4 UPLIFT COSTS

Generators receive make-whole payments to ensure that they receive sufficient revenue to cover energy, start-up, no-load, and operating reserve costs for both market and local reliability commitments. Make-whole payments are additional market payments in cases where prices result in revenue that is below a resource’s cleared offers. These payments are intended to make resources whole to energy, commitment, and operating reserve costs.

For 2022, combined day-ahead and reliability unit commitment make-whole payments totaled just over $465 million. Reliability unit commitment make-whole payments represented $292 million, or 63 percent, of the total. Because of the February 2021 winter weather event, make-whole payments climbed to levels well beyond those ever experienced in the Integrated Marketplace. Even removing February from 2021 totals, make-whole payments were up from 2021 to 2022.

Day-ahead make-whole payments for 2021 (without February) totaled $75 million, compared $173 million in 2022, an increase of 130 percent. Reliability unit commitment make-whole
payments for 2021 (without February) totaled $116 million, compared to $292 million in 2022, an increase of 152 percent. Much of the increase in make-whole payments can be attributed to higher gas prices overall for 2022. An additional driver for the increase in reliability unit commitment make-whole payments was for manual capacity commitments in the real-time market to meet ramping needs. The increase in capacity commitments was primarily caused by two factors. First, the increase in generation outages reduced the availability of capacity to meet uncertainty of both supply and demand. Second, the higher level of wind penetration on the system has increased the overall level of uncertainty in the market.

The MMU is very concerned about increasing make-whole payments. With the expectation that wind generation will continue to have an increasing role in the SPP market, uncertainty and ramping needs will continue to increase. Although the implementation of the ramping product has not yet produced anticipated results, the hope is that the uncertainty product will provide market signals for flexible ramping capability. Furthermore, additional rules are required to address MMU concerns with outages and their impacts to both market prices and make-whole payments.

Revenue neutrality uplift (RNU) ensures settlement payments/receipts for each real-time hourly settlement interval equals 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 2022 was $548 million, up 92 percent from 2021, and up ten-fold from $54.7 million in 2020. The two main components of revenue neutrality uplift are real-time congestion and real-time joint operating agreement (also known as market-to-market). The joint operating agreement component generally acts to decrease revenue neutrality uplift, while the congestion component generally acts to increase revenue neutrality uplift. The real-time joint operating agreement portion of revenue neutrality uplift was $162 million in 2022, an increase of 86 percent from $87 million in 2021. The real-time congestion component of revenue neutrality uplift was $653 million in 2022, an increase of 189 percent from $226 million in 2021. The increase in the real-time congestion component of revenue neutrality uplift has been the topic of much discussion over the past year. At the February 2023 Market Working Group meeting, SPP staff reported on the increased congestion component. The SPP staff findings are discussed in section 4.2.5 of this report. The Market Monitoring Unit will continue

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to monitor the increased revenue neutrality uplift and will report additional findings in future reports.

1.5 COMPETITIVENESS ASSESSMENT

Overall, structural and behavioral metrics indicate that the SPP markets have been competitive over the last several years. The market share, HHI, and pivotal supplier analyses all indicate minimal to moderate potential structural market power in SPP markets outside of a few frequently congested areas.

The market share indicator in 2022 continued a trend of decreasing concentration after an acute rise following an intra-market merger that formed Evergy, Inc. in June 2018. In 2022, Evergy possessed the largest market share in over 99 percent of intervals above and below the 20 percent threshold. Market shares by the largest supplier exceeded the 20 percent threshold in 45 percent of hours during the year.

Meanwhile, another general measure of structural market power—the Herfindahl-Hirschman Index (HHI) calculation for supplier concentration—pointed to incrementally elevated concentration year-over-year and higher concentration generally following the aforementioned merger. The HHI market concentration analysis shows that nine percent of hours were considered moderately concentrated in 2022, a decrease of six percentage points from 2021. The decrease in both the market share indicator and HHI indicate decreasing structural market power in the SPP market.

Structural market power in the SPP footprint only creates the potential for market manipulation. The MMU continues to believe that the existing local market power mitigation measures are sufficiently robust to moderate the impact of an actual exercise of that potential, should it occur. The MMU will continue to evaluate structural market power concerns going forward.

Any exercise of market power is most likely to be profitable in transmission-constrained areas where concerns regarding potential local market power are highest. MMU analysis and continued close scrutiny of potential areas under frequent constraints confirm that existing mitigation measures are effective to mitigate the exercise of local market power.

Behavioral indicators were also assessed by analyzing the conduct of market participants, and the impact of that conduct on market prices, in order to detect the exercise of market power. The MMU examined offer price markups, offer quantities, mitigation frequency, and measures of implied economic and physical withholding in reviewing market behavior. The MMU noted overall improvements in the convergence of market price and imputed costs, but still observes
negative prices at a level and frequency that warrants continued concern. Wind units in particular had exceptionally low markups, a concern that the MMU has raised in prior Annual State of the Market Reports.

Mitigation for economic withholding remains relatively infrequent overall despite small increases in day-ahead and real-time energy offer mitigation. Mitigation of no-load offers remains low as well, and while operating reserve mitigation increased over 2021, this was largely concentrated in spinning reserve resource intervals during the months of August and September.

The remaining metrics suggest that actual withholding behavior is infrequent. The measured economic output gap increased slightly in 2022 and the amount of physically unoffered generation remained at normal levels following transitory disruptions in outage patterns associated with COVID-19 in 2020.

Markups on marginal coal and gas resources increased significantly in 2022, while wind markups decreased to even more deeply negative levels than seen in 2021. The increase in thermal resource markups brought SPP’s average offer price markup to slightly positive levels for the first time in several years. As with the increase in unoffered economic capacity, though, these metrics largely reflect behavioral changes and supply curve shifts stemming from acute supply chain problems in coal surface transportation networks. In mid-2022, the MMU introduced Revision Request number 502 (RR502) as a response to these issues. RR502 expanded the scope of allowed opportunity costs in offers for coal resources, with the intent of making these input shortages more transparent in wholesale electric costs while simultaneously giving coal plant operators an additional, economic tool to maintain safe and reliable coal stockpile levels. The MMU observed several market participants taking partial or full advantage of this increase in allowed opportunity costs and is largely satisfied with its performance to date.

Overall, the SPP Integrated Marketplace provides effective market incentives and mitigation measures to produce competitive market outcomes, particularly during market intervals where the exercise of local market power is a concern. While some behavioral indicators increased relative to low prior-year levels, these largely reflected conditions external to the market, and structural indicators showed continued levels of diverse and healthy competition. Market behaviors and results remained workably competitive overall, only infrequently requiring mitigation of local market power to achieve those outcomes. Nonetheless, mitigation of economic withholding remains an essential tool in ensuring that market results are competitive during periods when such market conditions offer suppliers the potential to abuse local market power.
1.6 RESOURCE ADEQUACY ISSUES

The February 2021 winter weather event highlighted significant issues with SPP’s resource adequacy approach. The MMU and SPP outlined several of these issues in our winter weather reports. The December 2022 winter storm, while less severe, demonstrated the same resource adequacy issues persist and pose a significant risk to reliability. Key issues include a lack of a seasonal resource adequacy requirement, fuel availability risk, correlated output and outages among similar resources, and an accreditation process that does not reflect actual resource performance.

SPP does not have a seasonal resource adequacy requirement. While stakeholders are currently reviewing a revision that would add a winter resource adequacy requirement, currently, SPP only counts on resources to be available for summer loads. However, February 2021 and December 2022 exposed that capacity tightness can happen in the winter. Furthermore, capacity can also be tight in the shoulder periods as resources take maintenance outages, something the MMU observed in both 2021 and 2022. Resource adequacy is something that needs to be considered year round, not just in the summer.

Resources experienced significant fuel supply issues that limited their availability. While almost all fuel-types experienced some issue during the winter weather event, by far, both natural gas and coal resources in the SPP region experienced a high level of outages related to fuel supply limitations. Though SPP may not experience adverse weather events every year, correlations in forced outages due to fuel supply shocks need to be incorporated into any resource adequacy approach in order to ensure a more accurate accounting of the expected availability of resources.

SPP does not have an effective mechanism to measure and incorporate performance in resource availability accreditation. While SPP and stakeholders worked on a mechanism to factor in performance in 2022, this mechanism falls short in accurately assessing resource performance. Resources that have a track record of low availability should not be expected to perform in the future absent some substantial change to improve availability. Proper measurement will allow for proper incentives to address any shortfalls. Those that perform better should be treated

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5 This is known as performance-based accreditation. SPP and stakeholders are currently working on tariff language, which will likely be filed with FERC later this year.
differently from those that perform poorly. This differentiation is necessary to promote proper incentives to improve grid reliability.

Addressing resource adequacy is perhaps the most important lesson from February 2021 and December 2022. The SPP system was lucky to have significant imports from MISO, PJM, and others. SPP cannot plan to count on these systems to help SPP in a future event as a wider regional cold snap could limit imports. In December 2022, SPP avoided severe outcomes largely because of the availability of wind – another condition SPP cannot always count on. Effectively improving resource adequacy will require seasonal variation, differentiation of resource performance through effective measurement of performance, a requirement that counts for different contingencies, and incentives. The MMU has and will continue to engage in the SPP stakeholder processes to help promote improved resource adequacy.

1.7 RECOMMENDATIONS

One of the primary responsibilities of a market monitoring unit is to evaluate market rules and market design features for market efficiency and effectiveness. When we identify issues with the market, one of the ways to correct them is to make recommendations on market enhancements. These recommendations are highlighted in detail in Chapter 7. The MMU is making four new recommendations for 2022, as well as highlighting some existing recommendations in an effort to promote the need for these issues to be addressed.

1.7.1 NEW RECOMMENDATIONS

2022.1 Consider limitations on virtual trading during emergency conditions

In 2022, the MMU published a paper examining the impacts of virtual trading during the February 2021 winter weather event. The MMU noted that the merits of virtual transactions, such as aiding price convergence, decrease or are even erased under conditions of scarcity, particularly when day-ahead prices exceed the $1,000 offer cap. The combination of large price spreads and an inability to displace more expensive generation during scarcity events lends to extremely high profit per megawatt values with little to no impact on price or market convergence. Where virtual transactions did create positive impacts, their high cost and profits largely outweighed their benefits.

In light of these findings, the MMU made multiple recommendations regarding the impact of virtual transactions during extreme weather events and options for alleviating those impacts.

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6 Virtual activity during the 2021 winter weather event: An analysis
2022.2 Address limitations with the ramp capability product

SPP implemented its ramp capability product in March 2022. In fall 2022, the MMU performed a review of the product’s effectiveness. The results of the analysis were documented in the fall 2022 quarterly state of the market report. The review identified that the majority of resources procured for ramp-up are stranded behind congested constraints and unable to deliver the ramp cleared. In addition, the MMU noted concerns that low prices on the ramp capability up demand curve may result in prices that undervalue ramp-up.

The MMU recommends SPP and stakeholders evaluate options to address the stranded ramping issue as it relates to the product’s deliverability as well as evaluating the effectiveness of the ramping capability product demand curve.

2022.3 Improve situational awareness of transmission upgrades and improve process to reassign projects

Recent analysis by SPP staff has shown that several transmission projects are behind expected relevant deadlines. Some of these projects are potentially several years beyond their expected in service dates. This analysis has highlighted a lack of transparency on the status of many transmission projects and upgrades.

Delays in transmission upgrades can significantly affect congestion. As shown in this report, congestion in 2022 was at the highest levels experienced since implementation of the Integrated Marketplace. Many of the top 10 constraints have projects that have been identified to remediate congestion. However, many of these projects are delayed. This can have significant ramifications on market outcomes, and costs paid by ratepayers. As such, the MMU recommends that SPP and stakeholders develop a process to improve the transparency of the status of transmission projects and upgrades. In addition, the MMU recommends additional detail be provided such as information regarding project assignments and regular updates from transmission developers regarding project statuses.

2022.4 Improve congestion hedging mechanisms to enhance equity

In July 2019, the Holistic Integrated Tariff Team (HITT) published its recommendation report, including 21 board-approved recommendations. Marketplace enhancement recommendation one (HITT M1), “Implement congestion hedging improvements” remains outstanding. In January 2023, SPP staff presented an updated HITT M1 recommendation to the Markets and

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7 Fall 2022 quarterly state of the market report. Section 6 - Special Issues.
8 March 1, 2023 Project Service Working Group presentation, 7. In-Service Date Report
Operations Policy Committee that targets nine components of the congestion hedging process including enhancements to both the long-term congestion rights and auction revenue rights processes. The MMU supports the current proposal and recommends SPP and stakeholders approve and implement the proposed design in its entirety.

1.7.2 EMPHASIS ON PREVIOUS RECOMMENDATION

The following recommendation was made by the MMU in a previous report but would like to highlight as a higher priority issue needing to be addressed.

2017.5 Address inefficiency when forecasted resources are under-scheduled day-ahead

The MMU noted in its 2017 report that the systematic under-scheduling of wind resources in the day-ahead market can contribute to distorted price signals, suppressing real-time prices and affecting revenue adequacy for all resources. This also poses a problem for resource adequacy as the current, low average prices in the SPP market do not support the new entry of any resource type except wind (see Chapter 4, Section 4). Noting that variable energy resources are generally able to produce close to a forecasted amount, the MMU recommended that this issue be addressed through market incentives and rule changes that focus on market inefficiencies associated with under-scheduling of variable energy resources in the day-ahead market based on forecasted supply. The MMU has included this recommendation in each annual state of the market report since 2017.

While the MMU continues to view this as a high priority issue, in 2021, stakeholders voted to move this issue to the list of parking lot initiatives. Despite efforts to revive this initiative during the 2022 roadmap prioritization meetings, stakeholders chose not to elevate this initiative from the parking lot. The MMU will continue to study the effects of under participation of wind in the day-ahead market and recommends the RTO and its stakeholders explore both policy and incentive options to increase day-ahead participation.

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10 2020 SPP Annual State of the Market Report, Chapter 8, 2017.5 Address inefficiency when forecasted resources under-schedule day-ahead
1.7.3 WINTER WEATHER EVENT – CRITICAL RECOMMENDATIONS

The recommendations below represent three critical areas the MMU emphasized in its written report on the February 2021 winter weather event.\(^\text{11}\)

**WWE1 Ensure availability of resources**

In its report, the MMU noted that, if SPP is to rely on any resource to be available to provide energy, then that resource should be available. This requires accounting for more granular approaches to measuring capacity including seasonality and forced outage rates. In addition, availability may require resources to have secondary or backup fuel sources, or alternatively storage capabilities.

While SPP and stakeholders did approve an enhancement to accreditation as compared to the status quo, this approach falls short in addressing SPP’s resource adequacy concerns. In order to improve resource adequacy, and to ensure non-discriminatory treatment of resources, the MMU recommends that SPP and its stakeholders adopt an adequate approach to valuing resource accreditation that accurately measures total resource availability. This would include maintenance outages, outages beyond management control, and other correlated outages; would not allow for observations to be removed; and would implement this approach in a consistent timeline across all resource types.

**WWE2 Establish incentive mechanism for accredited capacity**

The MMU included recommendations in the report to allow for meaningful incentives for availability noting that, to the extent that a resource is more available there should be incentives, and to the extent that a resource is less available, there should be disincentives.

This recommendation continues to be discussed in the stakeholder forums as part of overall discussions regarding the winter weather event. An initiative\(^\text{12}\) was added to the SPP Roadmap to address this recommendation. The MMU has argued in stakeholder forums that the accreditation approach both affects and is affected by an incentive mechanism. The MMU has discussed the incentive mechanism as part of the Improved Reliability Task Force and Supply Adequacy Working Group discussions to improve resource accreditation.

\(^{11}\) SPP MMU Winter Weather Report 2021

\(^{12}\) SIR310 WWE MMU R2
WWE3 Establish more frequent resource adequacy requirement

In its report, the MMU recognized that different times of the year present different system challenges. The MMU noted that SPP resource adequacy requirements focus on meeting peak summer load and that a more frequent resource adequacy requirement, such as seasonal (or perhaps monthly), would be preferred.

The MMU recommends that SPP resource adequacy requirements address resource needs to meet the demand in each season independently. In the past two calendar years, SPP has experienced a winter weather event that has tested the region and exposed reliability concerns related to the availability of adequate capacity to meet demand during system shocks.

SPP is currently working with stakeholders to change the winter season resource obligation into a requirement, complete with penalty charges for deficiency. The MMU is engaged in the stakeholder process in support of this effort, but additionally recommends the same effort be undertaken for the spring and fall seasons. The MMU sees the seasonal resource adequacy requirement as the final leg of a balanced approach that uses accurate measurements, meaningful incentives, and adequate requirements, to ensure reliability.

1.7.4 PREVIOUS RECOMMENDATIONS

2021.1 Expand multi-configuration combined cycle resource model to include additional resource types

In the 2021 report\(^\text{13}\), the MMU recommended SPP expand the multi-configuration combined cycle resource model or create a new multi-configuration model to include additional resource types that have multiple operating modes, or configurations. This recommendation comes in response to observed inefficiencies from participants attempting to optimize their plant’s schedule without the benefit of such logic. The MMU noted in its report SPP’s multi-configuration combined cycle resource model provides the market several efficiency gains by optimizing the schedule of configurations, improving participant abilities to offer different parameters for each configuration, and providing real-time operational awareness.

\(^{13}\) 2021 Annual State of the Market report, Chapter 7 Recommendations, 2021.1 Expand Multi-Configuration Combined Cycle Resource Model to Include Additional Resource Types
2020.1 Update market and outage requirements to improve funding for transmission congestion rights

The MMU made recommendations in the 2020 report to update outage requirements and develop market rules and market incentives associated with outages to better align the network models used by the transmission congestion rights auctions and the day-ahead market. This recommendation was a result of the MMU observation of a continued downward trend in the overall funding of transmission congestion rights from day-ahead market congestion rents.

The MMU continues to recommend that SPP and stakeholders address TCR underfunding. As part of that recommendation, the MMU strongly recommends improving outage consistency between the congestion hedging market, the day-ahead market, and the real-time market to alleviate funding issues due to misaligned outages.

2020.2 Enhance market-to-market efficiencies through collaboration with MISO

In 2019 and 2020, the MMU worked with the MISO market monitor on a series of recommendations for the Joint Regional State Committee / Organization of MISO States Seams Liaison Committee. Based on the results of the joint study, the MMU recommended in the 2020 annual report to evaluate the processes and mechanisms used to effectuate the market-to-market agreement between SPP and MISO.\textsuperscript{14} One of the items identified by the market monitors in this process was that SPP had real-time market-to-market congestion that was not materializing in the day-ahead market. Upon further evaluation, it was determined that this was because MISO market-to-market constraints were not being activated in the SPP day-ahead market. SPP began a new process in October 2022 that activates MISO market-to-market constraints in the day-ahead market based on recent congestion trends in the real-time market.\textsuperscript{15} The MMU supports SPP’s recent efforts in aligning day-ahead and real-time congestion along the SPP-MISO seam and recommends SPP make any necessary modifications to the TCR model to address concerns with TCR underfunding.

The MMU continues to recommend that SPP and stakeholders address inefficiencies in the market-to-market agreement between SPP and MISO.

\textsuperscript{14} 2020 SPP Annual State of the Market Report, Chapter 8, 2020.2 Enhance market-to-market efficiencies through collaboration with MISO

\textsuperscript{15} https://spp.org/Documents/68224/MWG%20Agenda%208%20Background%20Materials%2020221115-16.zip, item 9.
2020.3 Raise offer floor to minus $100/MW

The MMU recommended in the 2020 report to raise the energy offer floor to -$100/MWh. This recommendation was the result of analysis performed by the MMU which observed resources offering at the offer floor, -$500/MWh, and setting price. As noted in the 2020 report, the MMU believes that raising the offer floor is a simple and cost effective solution that avoids any limitation of what costs can be included in a market offer, however, as part of the SPP Roadmap process, this initiative was added to the list of parking lot initiatives. The MMU recommends SPP remove this initiative from the parking lot and include it in the list of initiatives to be acted on.

2019.1 Improve price formation

In the MMU report on the February 2021 winter weather event, the MMU made recommendations related to improving price formation during emergency and scarcity conditions. In that report, the MMU highlighted situations where price signals did not accurately reflect underlying conditions. The recommendations in the February 2021 winter weather report, which are aimed at improving pricing outcomes, closely align with the 2019 recommendation to improve price formation. The MMU believes this recommendation is being addressed through the stakeholder processes focusing on enhancements needed as a result of the February 2021 winter weather event.

2019.2 Incentivize capacity performance

As part of its February 2021 winter weather event report, the MMU made multiple recommendations regarding capacity adequacy and performance, many of which align with this recommendation. As such, the MMU believes this recommendation will be addressed through those stakeholder processes focused on enhancements needed as a result of the February 2021 winter weather event.

2019.3 Update and improve outage coordination methodology

In the 2019 report, the MMU recommended that the outage coordination methodology be updated to cover reserve shutdown outages and to consider a lower threshold for outages to be submitted. These recommendations are included with other recommendations documented in the report published by the Generator Outage Task Force.
2018.1 Limit the exercise of market power by creating a backstop for parameter changes

In the 2018 report, the MMU recommended that SPP strengthen the language regarding non-dollar-based parameters so that the expectation for the basis of these values is clear and well-defined. The MMU noted that changes to these parameters should be limited to actual capability and should be verified, at a minimum, in the presence of market power.

2018.2 Enhance credit rules to account for known information in assessments

The Credit Practices Working Group has developed and implemented the first phase of credit policy enhancements in response to needed improvements following a credit default in the PJM market that resulted in significant financial impacts to its market participants. The second phase focused on incorporating forward-looking known information into the financial security calculations. SPP staff reviewed options for a forward-looking approach in 2021, including a mark-to-auction process, however, SPP and stakeholders elected to not implement those phase two changes.

In July 2022, FERC issued an order to show cause to four ISO/RTO’s as to why their tariffs were just and reasonable in absence of either of (1) mark-to-auction mechanisms for the calculation of financial transmission right (FTR) market participants’ collateral requirements and/or (2) volumetric minimum collateral requirements for FTR market participants. FERC directed SPP, to show cause, as to why its tariff is just and reasonable without mark-to-auction mechanisms. SPP filed comments in support of its current tariff whereas the MMU filed comments in support of mark-to-auction. FERC has yet to provide a final rule.

2018.3 Develop compensation mechanism to pay for capacity to cover uncertainties

SPP market participants approved a revision request\(^\text{16}\) to implement an uncertainty product in April 2021 and was approved by the SPP Board of Directors July 2021. The Tariff changes for the uncertainty product design were filed with FERC in January 2022. Implementation is currently targeted for July 6, 2023.\(^\text{17}\) Once implemented, the MMU will consider this recommendation closed.

\(^{16}\) Revision request 449 – Uncertainty Product

2018.5 Improve regulation mileage price formation

In the 2018 report, the MMU recommended SPP staff review the performance of regulation mileage, and develop potential approaches to improve regulation mileage price formation. In addition, the MMU recommended that SPP staff consider adjusting the mileage factor. SPP drafted revision request 504 – improved economic incentive of regulation mileage in August 2022 to address both MMU recommendations. It passed the SPP stakeholder process in December 2022, and is expected to be filed with FERC by mid-2023.

The MMU expects these changes to adequately address the recommendations regarding regulation mileage.

2017.2 Enhance commitment of resources to increase ramping flexibility

In 2017, the MMU recommended that SPP and its stakeholders address the issue of inadequate ramping flexibility by modifying its market rules to enhance the commitment of resources and increase ramping flexibility. The MMU noted potential options to address the commitment concerns and recommended SPP and its stakeholders explore options, such as those noted, to enhance commitment of resources and increase flexibility. This initiative is on the SPP Roadmap and is currently ranked as a high priority.

2017.3 Enhance market rules for energy storage resources

SPP implemented its design for energy storage for compliance with FERC Order No. 841 in 2021. While the MMU filed supportive comments for the implementation of energy storage in the SPP market, the MMU noted further areas of enhancements to be considered with electric storage integration. Enhancements include the MMU recommendation for inclusion of mitigation measures for excessively low offers.

2017.4 Address inefficiency caused by self-committed resources

The MMU continues to recommend that SPP and its stakeholders explore and develop ways to reduce the incidence of self-commitment of resources outside of the market solution, including considering adding an additional day to the optimization process. An initiative was added to the SPP Roadmap to implement these enhancements. This initiative is currently on hold while SPP evaluates the accuracy of its multi-day forecasts.

18 https://www.spp.org/search?q=rr504
19 SIR 9 - Enhanced Commitment
20 SIR 18 - HITT R3c: Implement Marketplace Enhancements: Multi-Day Market
2014.3 Address gaming opportunity for multi-day minimum run time resources

The MMU recommended changes to address a gaming opportunity in the market for resources with minimum run times greater than two days in its 2014 report. While Tariff changes to address this concern were approved by the SPP board in 2018, subsequent changes were needed to address inconsistent tariff language that the revisions revealed but did not address. An associated revision request\(^ {21}\) and additional tariff modification was approved through the stakeholder process. SPP filed these changes with FERC on May 7, 2020\(^ {22}\) and the MMU filed comments in support of the Tariff changes on June 12, 2020.\(^ {23}\) The current implementation date for this enhancement is October 1, 2023.

2014.4 Address issues with the day-ahead must offer requirement

The MMU continues to recommend that SPP and stakeholders either eliminate the limited day-ahead must-offer provision and revise the physical withholding rules to include a penalty for non-compliance, or address the design weaknesses. The MMU submitted this recommendation as an initiative\(^ {24}\) on the SPP Roadmap. This initiative is currently ranked on the roadmap as a high priority.

1.7.5 IMPLEMENTED RECOMMENDATIONS

2014.1 Improve quick-start logic

SPP implemented its fast-start resource design in May 2022. The MMU completed an analysis on fast-start pricing and documented the results of that analysis in a special issue in the fall 2022 quarterly state of the market report.\(^ {25}\) The MMU will continue monitor the impacts fast-start resources in the market and identify and report on those impacts where appropriate. The MMU considers this recommendation addressed with the implementation of the fast-start logic.

\(^{21}\) Revision request 382 – Multi-Day Minimum Run Time and Clarifications
\(^{24}\) SIR6 – DA Must Offer and Physical Withholding
\(^{25}\) SPP MMU quarterly state of the market report fall 2022
2017.1 Develop a ramping product

In the 2017 report, the MMU recommended SPP develop a ramping product to incent actual, deliverable flexibility which to send appropriate price signals to the market that value resource flexibility.

SPP, stakeholders, and the MMU worked together to complete a ramping product design in April 2019 which was approved by the Market Operations and Policy Committee in October 2019. This design was approved by FERC in July 2020 and implemented on March 1, 2022.

There are, however, some issues with the performance of the ramping product, as stated in this year’s new recommendation, 2022.2 Address limitations with the ramp capability product.

2018.4 Enhance ability to assess a range of potential outcomes in transmission planning

The MMU has continued to recommend in its annual state of the market reports that SPP and stakeholders identify ways to study and plan for the more aggressive carbon emissions reduction targets in the 10- and 20-year studies. SPP has continued to make enhancements to its planning processes that include lowering carbon emissions targets and increasing renewable capacity. With the recent enhancements to the 2024 ITP studies, the MMU believes this recommendation has been addressed. The MMU will continue to engage with SPP and stakeholders to ensure future studies include reasonable assumptions with regard to renewable integration on the SPP system.
2 LOAD AND RESOURCES

This chapter reviews load and resources in the SPP market for 2022. Key points from this chapter include:

- Monthly average system energy consumption was up five percent compared to 2021 levels. Most of this increase can be attributed to weather impacts and increased load.

- Nearly 1,500 MW of wind generation capacity was added to the market in 2022. Wind generation capacity now accounts for 32 percent of installed nameplate capacity in the SPP market.

- During 2022, 28 dispatchable demand response resources representing 186 MW of nameplate capacity were added to the SPP market. These resources ranged in size from 0.1 MW to 100 MW. At the end of 2022, there was 362 MW of dispatchable demand response resource installed nameplate capacity.

- The generation interconnection queue has nearly 104,000 MW of projects in the queue at the end of 2022. Of the queue, about 34,000 MW are wind resources, 42,000 MW are solar resources, 14,000 MW are battery/storage resources, with the remainder hybrid or gas simple-cycle resources.

- Wind generation represented the largest portion of total energy produced at 37.5 percent of the total. Coal generation was slightly behind at 33.4 percent of the total.

- SPP remained a net exporter for 2022 with an hourly average of 601 MW, up from 240 MW in 2021. April 2022 saw an hourly average of 1,235 MWh of net exports, which was the second highest since the start of the Integrated Marketplace. April 2022 also saw the highest hourly average wind production since the start of the Integrated Marketplace.

- Net market-to-market payments from MISO to SPP was $160 million, 84 percent higher than 2021 payments of nearly $87 million. February, April, and December each exceeded $20 million in net market-to-market payments from MISO to SPP while no months in 2022 netted market-to-market payments from SPP to MISO. July had the lowest net market-to-market payment from MISO to SPP of almost $3 million.

- Cleared virtual energy bids and offers as a percentage of load for 2022 was 29 percent, up from 25 percent in 2021.

- Average profit per cleared virtual megawatt after fees was $1.47/MW, down 20 percent from 2021 (excluding February) which was at $1.84/MW.
2.1 THE INTEGRATED MARKETPLACE

SPP is a Regional Transmission Organization (RTO) authorized by the Federal Energy Regulatory Commission (FERC) to ensure reliable power supplies, adequate transmission infrastructure, and competitive wholesale electricity prices. FERC granted RTO status to SPP in 2004. SPP provides many services to its members, including reliability coordination, tariff administration, regional scheduling, reserve sharing, transmission expansion planning, wholesale electricity market operations, and training. This report focuses on the 2022 calendar year of the SPP wholesale electricity market referred to as the Integrated Marketplace, which started on March 1, 2014.

The Integrated Marketplace has a full day-ahead market with transmission congestion rights, virtual trading, a reliability unit commitment process, a real-time balancing market, and a price-based operating reserves market. SPP simultaneously put into operation a single balancing authority as part of the implementation of the Integrated Marketplace. The primary benefit of a day-ahead market is improved efficiency of daily resource commitments. Another benefit of this market includes the joint optimization of the available capacity for energy and operating reserves.

2.1.1 SPP MARKET FOOTPRINT

The SPP market footprint is located in the westernmost portion of the Eastern Interconnection, with Midcontinent ISO (MISO) to the east, Electric Reliability Council of Texas (ERCOT) to the south, and the Western Interconnection to the west. Figure 2–1 shows the current operating regions of the nine RTO/ISO markets in the United States and Canada, as well as a more detailed view of the SPP footprint. The SPP market also has connections with other non-RTO/ISO areas such as Saskatchewan Power Corporation, Associated Electric Cooperative, and Southwestern Power Administration.²⁶

²⁶ Southwestern Power Administration belongs to the SPP RTO, Reliability Coordinator (RC), and Reserve Sharing Group (RSG) footprints. Associated Electric Cooperative belongs to the SPP RSG.
2.1.2 SPP MARKET PARTICIPANTS
At the end of 2022, 285 entities were participating in the SPP Integrated Marketplace. SPP market participants can be divided into several categories: regulated investor-owned utilities, electric cooperatives, municipal utilities, federal and state agencies, independent power producers, and financial only market participants that do not own physical assets. Figure 2–2 shows the distribution of the 155 asset owners registered to participate in the Integrated Marketplace.
The independent power producers account for 58 percent of all asset owners because most variable energy producers are included in this category. There may be a number of asset owners in a given category with the same corporate parent. For example, an independent power producer owns five wind farms and each are registered as a different asset owner; these would count as five different asset owners.

Figure 2–3 shows generation nameplate capacity owned by the type of asset owner.

Although investor-owned utilities represent only a small portion of the total number of asset owners at nine percent, they own the highest portion of the SPP generation capacity at 48 percent. This is in contrast to the “independent power producer” category, which has a large
number of asset owners (58 percent) representing a smaller portion (20 percent) of total nameplate capacity.

2.2 ELECTRICITY DEMAND

2.2.1 SYSTEM PEAK DEMAND

One way to evaluate load is to review peak system demand statistics over an extended period. The market footprint has changed over time as participants have been added to or withdrawn from the market. The peak demand values reviewed in this section are coincident peaks, calculated out of total generation dispatch across the entire market footprint that occurred during a specific real-time market five-minute interval. The peak experienced during a particular year or season is affected by events such as unusually hot or cold weather, daily and seasonal load patterns, and economic growth and change.

Figure 2–4 shows a month-by-month comparison of five-minute demand for the last three years.

![Figure 2–4 Monthly peak system demand](image)

Every month of 2022 had a five-minute system peak demand higher than 2021, with the exception of February, due to the winter weather event in 2021, and October, due to lower overall weather impacts in 2022. As shown on the chart, December 2022 set a new all-time high winter five-minute peak of 47,891 MW; this is over 4,100 MW higher than the previous winter peak set in February 2021. The SPP system five-minute interval peak demand in 2022 was 53,381 MW, which occurred on July 19 at the five-minute interval beginning at 4:35 PM. This is 4.5 percent higher than the 2021 system five-minute interval peak of 51,041 MW.
2.2.2 MARKET PARTICIPANT LOAD

The amount of load participating in the day-ahead market has been declining over the past three years as shown in Figure 2–5.

Figure 2–5 Cleared demand bids in day-ahead market

The average monthly participation rates in the day-ahead market for load assets on an aggregate level were between 97 and 99 percent of the actual real-time load in 2022. Accurate reflection of demand in the day-ahead market economically incents generation to participate in the day-ahead market. Additionally, accurate reflection of the load helps to converge prices. Load participation in the day-ahead market has dropped steadily over the past three years, with averages in both on-peak and off-peak periods around 98 percent in 2022.

Figure 2–6 depicts 2022 total energy consumption and the percentage of energy consumption attributable to each entity in the market.
### Figure 2–6  System energy usage

<table>
<thead>
<tr>
<th>Company</th>
<th>2020 Energy consumed (GWh)</th>
<th>Percent of system</th>
<th>2021 Energy consumed (GWh)</th>
<th>Percent of system</th>
<th>2022 Energy consumed (GWh)</th>
<th>Percent of system</th>
</tr>
</thead>
<tbody>
<tr>
<td>* Evergy, Inc.</td>
<td>47,651</td>
<td>19.0%</td>
<td>48,862</td>
<td>19.0%</td>
<td>49,953</td>
<td>18.5%</td>
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<td>American Electric Power</td>
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<td>40,988</td>
<td>16.0%</td>
<td>43,231</td>
<td>16.0%</td>
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<td>Oklahoma Gas and Electric</td>
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<td>29,077</td>
<td>11.3%</td>
<td>31,286</td>
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<td>25,660</td>
<td>10.0%</td>
<td>25,255</td>
<td>9.3%</td>
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<td>Basin Electric Power Cooperative</td>
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<td>22,027</td>
<td>8.6%</td>
<td>23,391</td>
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<tr>
<td>^ The Energy Authority</td>
<td>16,736</td>
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<td>17,473</td>
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<td>18,482</td>
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<td>Golden Spread Electric Cooperative Inc.</td>
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<td>Kansas Municipal Energy Agency</td>
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<td>City of Independence (Missouri)</td>
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<td>0.4%</td>
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<td>0.3%</td>
<td>845</td>
<td>0.3%</td>
<td>828</td>
<td>0.3%</td>
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<tr>
<td>Missouri Electric Commission (f/k/a Missouri Joint Municipal EUC)</td>
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<td>732</td>
<td>0.2%</td>
<td>756</td>
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<tr>
<td>People’s Electric Cooperative</td>
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<td>—</td>
<td>—</td>
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<tr>
<td>City of Fremont (Nebraska)</td>
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<td>500</td>
<td>0.2%</td>
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<td>MidAmerican Energy Company</td>
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<td>0.1%</td>
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<td>0.1%</td>
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<tr>
<td>Kansas Electric Power Cooperative</td>
<td>—</td>
<td>—</td>
<td>78</td>
<td>&lt;0.1%</td>
<td>225</td>
<td>0.1%</td>
</tr>
<tr>
<td>South Sioux City</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>99</td>
<td>&lt;0.1%</td>
</tr>
<tr>
<td>City of Grand Island (Nebraska)</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>67</td>
<td>&lt;0.1%</td>
</tr>
<tr>
<td>Tyre Energy</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>58</td>
<td>&lt;0.1%</td>
</tr>
<tr>
<td>Harlan (Iowa) Municipal Utilities</td>
<td>16</td>
<td>&lt;0.1%</td>
<td>16</td>
<td>&lt;0.1%</td>
<td>18</td>
<td>&lt;0.1%</td>
</tr>
<tr>
<td>Rainbow Energy Marketing</td>
<td>69</td>
<td>&lt;0.1%</td>
<td>71</td>
<td>&lt;0.1%</td>
<td>16</td>
<td>&lt;0.1%</td>
</tr>
<tr>
<td>Otter Tail Power Company</td>
<td>4</td>
<td>&lt;0.1%</td>
<td>1</td>
<td>&lt;0.1%</td>
<td>6</td>
<td>&lt;0.1%</td>
</tr>
<tr>
<td>NSP Energy</td>
<td>5</td>
<td>&lt;0.1%</td>
<td>4</td>
<td>&lt;0.1%</td>
<td>5</td>
<td>&lt;0.1%</td>
</tr>
<tr>
<td>City of Neligh (Nebraska)</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>—</td>
<td>3</td>
<td>&lt;0.1%</td>
</tr>
<tr>
<td><strong>System Total</strong></td>
<td>251,399</td>
<td></td>
<td>256,514</td>
<td></td>
<td>270,182</td>
<td></td>
</tr>
</tbody>
</table>

* Evergy was formed in June 2018 and is the corporate parent of Evergy, Kansas Central (f/k/a Westar Energy), Evergy, Missouri Metro (f/k/a Kansas City Power and Light), and Evergy, Missouri West (f/k/a Kansas City Power and Light GMOC).

^ The Energy Authority acts as an agent for Nebraska Public Power District, City Utilities of Springfield (Missouri), the Municipal Energy Agency of Nebraska, and some small municipalities in Nebraska.
The four largest entities comprise 55 percent of energy consumed in the market. This concentration is understandable as SPP’s market is primarily composed of vertically integrated investor-owned utilities, which tend to be large. Overall, the total system energy usage in 2022 was five percent above the 2021 level. Much of this increase can be attributed to more weather impacts and higher load in 2022.

### 2.2.3 SYSTEM ENERGY CONSUMPTION

Figure 2–7 shows the monthly system energy consumption in thousands of gigawatt-hours.

#### Figure 2–7 System energy consumption

For the year, monthly average energy consumption was up five percent compared to 2021. The monthly average was higher in all months of 2022 compared to 2021, except for February, when the 2021 winter weather event caused much higher consumption. May and December 2022
were each 12 percent above 2021, driven mostly by a warmer than usual May and a colder than usual December.

Figure 2–8 depicts load duration curves from 2020 to 2022. These load duration curves display hourly loads from the highest to the lowest for each year.

**Figure 2–8  Load duration curve**

![Load duration curve graph](image)

In 2022, the maximum hourly average load was 50,903 MW, which was up four percent from 2021. The minimum hourly load for 2022 was 20,867 MW, which was also four percent above 2021. Comparing annual load duration curves shows differentiation between cases of extreme loading events and more general increases in system demand. If only the extremes are higher or lower than the previous year, then short-term loading events are likely the reason. If the entire curve is higher across the entire range, this is more indicative of increased system demand. For 2022, the gap remains at a fairly consistent distance along the length of the curve, indicating a general increase in system demand.

### 2.2.4 HEATING AND COOLING DEGREE DAYS

Changes in weather patterns from year-to-year have a significant impact on electricity demand. One way to evaluate this impact is to calculate heating degree days (HDD) and cooling degree days (CDD). These values can then be used to estimate the impact of actual weather conditions
on energy consumption, compared to normal weather patterns. 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.

Figure 2–9 shows monthly heating and cooling degree days’ impact over the last three years compared to the average hourly load.

**Figure 2–9  Heating and cooling degree days**

As shown in the chart, cooling degree days are more prevalent in the higher load months of May through September, whereas heating degree days are more prevalent in the other months. Total degree day impact was nearly the same for 2020 and 2021, however, the trend is toward warmer temperatures during the cooling seasons and colder temperatures during the heating seasons, thus increasing total degree day impact. Average hourly load had a slight increase from 2020 to 2021, but had a 5.5 percent increase from 2021 to 2022. Some of the decrease in

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27 To determine heating degree days and cooling degree days for the SPP footprint, several representative locations are used in the calculation. These locations include Shreveport LA, Lubbock TX, Oklahoma City OK, Amarillo TX, Kansas City, MO, Hays, KS, Omaha NE, North Platte NE, Sioux Falls SD, Rapid City SD, Grand Forks ND, and Williston/Stanley ND. The base temperature separating heating and cooling periods is 65 degrees Fahrenheit. If the average temperature of a day at a location is 75 degrees Fahrenheit, there would be 10 (=75–65) cooling degree days at that location. If a day’s average temperature is 50 degrees Fahrenheit, there would be 15 (=65–50) heating degree days at that location. Using statistical tools, the daily estimated load impact of a single cooling degree day is just over four times higher than the impact of a single heating degree day. This is in part because more electric is used for cooling than electric heating. So, in order to show the actual impact of degree days, cooling degree days are multiplied by 4.2 in Figure 2–9.
2020 can be attributed to lower loads as a result of the beginning of the COVID-19 pandemic starting in March of that year.

Figure 2–10, Figure 2–11, and Figure 2–12 show load levels, cooling degree days, and heating degree days for the past three years compared to a normal year. Normal load was derived from a regression analysis of actual footprint heating degree days, cooling degree days, weekends, and holidays, substituting footprint normal temperatures.

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28 The 30 year normal temperatures are from the 1991-2020 U.S. Climate Normals product from the National Oceanic and Atmospheric Association (NOAA).
Figure 2–12  Heating degree days compared with a normal year

The figures indicate loads are influenced by cooling demand in the late spring and summer months, whereas late fall and winter loads are, to a lesser degree, influenced by heating demand. Moreover, the figures show that cooling degree days in 2021 were well above the 30-year average in all “cooling months” (April through October). Heating degree days in “heating months” (January through March, November, and December) were above the 30-year average in all months. The higher heating degree days for February 2021 is a direct result of the winter weather event during the month.
2.3 INSTALLED GENERATION CAPACITY

Figure 2–13 depicts the Integrated Marketplace installed generation capacity for the SPP market footprint.

**Figure 2–13  Generation nameplate capacity by technology type**

<table>
<thead>
<tr>
<th>Fuel type</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>Percent as of year-end 2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>27,326</td>
<td>30,493</td>
<td>32,032</td>
<td>32%</td>
</tr>
<tr>
<td>Gas, simple-cycle</td>
<td>22,762</td>
<td>22,829</td>
<td>22,727</td>
<td>23%</td>
</tr>
<tr>
<td>Coal</td>
<td>22,899</td>
<td>22,825</td>
<td>22,503</td>
<td>23%</td>
</tr>
<tr>
<td>Gas, combined-cycle</td>
<td>13,548</td>
<td>13,619</td>
<td>13,619</td>
<td>14%</td>
</tr>
<tr>
<td>Hydro</td>
<td>3,431</td>
<td>3,431</td>
<td>3,431</td>
<td>3%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>2,061</td>
<td>2,061</td>
<td>2,061</td>
<td>2%</td>
</tr>
<tr>
<td>Oil</td>
<td>1,566</td>
<td>1,569</td>
<td>1,569</td>
<td>2%</td>
</tr>
<tr>
<td>Solar</td>
<td>235</td>
<td>235</td>
<td>245</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Dispatchable demand response</td>
<td>34</td>
<td>176</td>
<td>362</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Other</td>
<td>84</td>
<td>78</td>
<td>86</td>
<td>&lt;1%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>93,946</td>
<td>97,314</td>
<td>98,635</td>
<td></td>
</tr>
</tbody>
</table>

*Note: Capacity is nameplate rating at year-end.*

Total installed nameplate generation capacity in the SPP Integrated Marketplace was 98,635 MW at the end of 2022, representing an increase of 1.4 percent (or 1,321 MW) from 2021.29 This increase was driven by a five percent increase (1,539 MW) in nameplate wind capacity in 2022. Total 2022 market share of wind capacity represented 32 percent of total nameplate generation.

When both types of natural gas resources are combined, natural gas-fired installed generation capacity still represents the largest share of generation capacity in the SPP market at 37 percent (gas simple-cycle 23 percent and gas combined-cycle 14 percent) of nameplate capacity, with coal being the third largest type at 23 percent. Also of note, an additional 186 MW of nameplate capacity of dispatchable demand response resources was added to the market in 2022, bringing the total nameplate capacity of these resources to 362 MW.

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29 The change in total generation capacity from year to year includes additions, retirements, fuel type changes, and nameplate rating changes that occur during the year.
2.3.1 AGGREGATE SUPPLY

Figure 2–14 shows the total SPP aggregate real-time generation supply curves by offer price, peak demand, and average demand for the summers of 2020 to 2022, while Figure 2–15 shows the same data for the winter months. Resources in outage status were excluded from the supply curve. To calculate the supply curves, the peak day for each season was used for each analysis year. The aggregate generation supply curves were calculated by using the real-time offers of non-wind resources and wind forecast data for wind resources.

Figure 2–14  Aggregate supply curve, peak summer day

Total aggregate real-time generation supply for summer 2022 was 76,905 MW, compared to 68,435 MW for summer 2021, an increase of 12 percent. The system peak demand in 2022 of 53,381 MW was about 4.5 percent higher than 2021. Average demand had an even larger increase, up 6.5 percent from 2021 to 2022. Based on the heating and cooling degree days analysis in Section 2.2.4, the SPP market footprint had much higher cooling degree days in July 2022 compared to 2021, which resulted in higher demand in the summer months as compared to the previous year.

Also evident is the approximately 22 GW gap between this maximum supply and the total installed nameplate generation capacity on the peak summer day. This is primarily a result of the difference between the wind forecast and installed capacity of wind resources (approximately 15 GW), resources reporting on outage (approximately 6.5 GW), and reduced summer capacity due to high ambient temperatures (less than 1 GW).
The total aggregate real-time generation supply for winter 2022 was 64,305 MW, compared to 44,285 MW for winter 2021, a 31 percent increase. However, the impact of the February 2021 winter weather event skews this analysis. Comparing winter 2022 supply to winter 2022 supply results in a 1.5 percent increase from winter 2020 to 2022. The system winter peak demand of 47,891 MW for 2022 was 9.5 percent higher than 2021. This large increase can be attributed to the December 2022 winter weather event. More detailed discussion of the December 2022 winter weather event can be found in Section 2.9.2. Although the winter peak demand increased by nearly 10 percent, the winter average demand only increased by five percent from 2021 to 2022.

The section of the offer curve below $0/MWh is mostly due to wind and solar energy and can vary between 1,000 MW and 20,000 MW, based on wind and solar availability. Negative offers typically reflect opportunity costs associated with state and federal tax incentives. The sharp uptick in price at the top of the supply curves of 2020 and 2022 represents the transition from natural gas units to oil units. Due to the significantly high gas price during the winter event in February 2021, the supply curve of 2021 does not reach to the sharp uptick stage under the $1,600/MWh price as several offers were at or above the $2,000/MWh offer cap.

### 2.3.2 GENERATION INTERCONNECTION

SPP is responsible for performing engineering studies to determine if the interconnection of new generation within the SPP footprint is feasible, and to identify any transmission development that would be necessary to facilitate the proposed generation. The generation...
interconnection process involves a cluster study methodology allowing participants several windows to submit requests for evaluation.  

Figure 2–16 shows the megawatts of capacity by generation technology type in all stages of development. Included in this figure are interconnection agreements in the process of being created; those under construction; those already completed, but not yet in commercial operation; and those in which work has been suspended as of year-end 2022.

**Figure 2–16  Active generation interconnection requests, megawatts**

As shown above, generation capacity from renewable, storage, and hybrid resources accounts for the vast majority of proposed generation interconnection, at 100 GW of the nearly 104 GW in the generation interconnection queue. Wind generation in the queue at the end of 2020 was 47.0 GW. This has dropped to 34.4 GW in 2022. Interconnection requests for solar generation continued to increase, rising from 35.4 GW at the end of 2020 to 41.5 GW at the end of 2022. Storage interconnection requests have also increased with 14 GW in the queue at the end of 2022.

Development of renewable generation in the SPP region is expected to continue and the proper integration of wind and solar generation is fundamental to maintaining market stability and the reliability of the SPP system.

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30 See [Guidelines for Generator Interconnection Requests to SPP’s Transmission System](#)
31 Hybrid resources typically consist of a renewable generation source, paired with a battery/storage resource at the same location.
Figure 2–17  Executed generation interconnection requests, on-schedule

As the chart above shows, at the end of 2022, generation totaling 14.7 GW has an executed generation request that is on-schedule to be added to the market in 2023 and beyond, with wind representing 11.6 GW of this generation. It is important to note that of the on-schedule projects, 79 percent are for wind resources, 19 percent are for solar resources, and two percent are for battery/storage resources. However, when looking at the entire generation interconnection queue, 33 percent of the projects are for wind resources, 40 percent are for solar resources, 13 percent are for battery/storage resources, and 10 percent are for hybrid resources. Although, solar resources make up a larger portion of the entire queue, the fact that wind resources represents a larger portion of the on-schedule projects in the queue indicates that wind resources will still be the predominant type of resource added to the market in the near future. Also key, is that generation can still be added or removed from the on-schedule project list, even in the current year. However, there is more surety to the levels of generation scheduled to go into production closer to the current year, and additions and deletions to on-schedule projects are more typical in future years.

2.4 GENERATION

2.4.1 GENERATION BY TECHNOLOGY

An analysis of generation by technology type used in the SPP Integrated Marketplace is useful in understanding pricing and reliability, as well as the potential impact of environmental and additional regulatory requirements on resources in the SPP system. Information on fuel types
and fleet characteristics is also useful in understanding market dynamics regarding congestion management, price volatility, and overall market efficiency.

Figure 2–18 depicts annual generation percentages in the SPP real-time market by technology type for the years 2014 through 2022.

**Figure 2–18  Generation by technology type, real-time, annual**

The long-term trend for coal-fired generation had been relatively flat prior to 2014 (not shown on chart above), but has been in a steady decline ever since. However, in 2021, because of higher gas prices, coal generation became more economic than many gas resources, resulting in an increase in the percentage of total generation by coal to 36 percent. That dropped to 33 percent of total generation in 2022, which is still up from the all-time low of 31 percent in 2020.

The wind generation share continues to steadily increase, from 12 percent in 2014 to nearly 38 percent in 2022. With higher gas prices in 2021 and 2022, generation from simple-cycle gas units such as gas turbines and gas steam turbines dropped from nine percent of total generation in 2020 to seven percent in 2021 and back up to eight percent in 2022. Gas combined-cycle generation had a much larger decrease, dropping from 18 percent of total generation in 2020 to 13 percent in 2021 and 2022.

Some of the annual fluctuations in generation by technology type shares are driven by the relative difference in primary fuel prices, namely natural gas versus coal. Gas prices from 2015 to 2020 were low, resulting in some displacement of coal by efficient gas generation, as can be seen in the higher generation from combined-cycle gas plants. However, with the higher gas prices in 2021 and 2022, this trend reversed.
Retirement of older coal generation, environmental limits, and competition from wind and natural gas technologies are some of the factors that will continue to put pressure on coal generation levels. Wind generation is expected to continue to increase in the years ahead.

Figure 2–19 depicts the 2022 monthly fluctuation in generation by technology type.

**Figure 2–19  Generation by technology type, real-time, monthly**

Wind generation as a percentage of total generation is generally lowest in the summer months at levels around 20 to 25 percent. In the highest wind generation months in the spring and fall, monthly levels can approach 50 percent of total generation, and even reached 54 percent in April 2022. In 2022, wind generation outpaced coal in every month, except for June through September.

One method commonly used to assess price trends and relative efficiency in electricity markets originating from non-fuel costs is the implied heat rate. The implied heat rate is calculated by dividing the electricity price, net of a representative value for variable operations and maintenance (VOM) costs, by the fuel (gas) price. For a gas generator, the implied heat rate serves as a “break-even” point for profitability such that a unit producing output with an operating (actual) heat rate below the implied heat rate would be earning profits, given market prices for electricity and gas. If the price of natural gas was $3/MMBtu, and the electricity price was $24/MWh, the implied heat rate would be (24/3) = 8 MMBtu/MWh (8,000 Btu/kWh). This

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32 For the implied heat rate calculation, natural gas units are assumed to be on the margin and accordingly, gas prices are taken as the relevant fuel cost. Emission costs are ignored in fuel cost as they rarely apply in the SPP market.
implied heat rate shows the relative efficiency required of a generator to convert gas to electricity and cover the variable costs of production, given market prices.

Figure 2–20 shows the monthly implied heat rate using real-time electricity prices for 2020 to 2022, along with an annual average for those years.

As shown above, the implied heat rates for 2021 and 2022 were significantly below 2020, with the 2021 and 2022 average of about 7,500 Btu/KWh, both down 23 percent from about 9,700 Btu/KWh in 2020. In fact, for 2022, the peak implied heat rate was in July at 10,400 Btu/KWh, down from a peak in 2020 (also in July) of 14,700 Btu/KWh, but up from the peak in 2021 at 9,400 Btu/KWh. With actual heat rates for most gas resources above the levels of implied heat rates in 2022, most gas resources would be unprofitable given electricity and gas prices during the year.

2.4.2 GENERATION ON THE MARGIN

The system marginal price represents the price of the next increment of generation available to meet the next increment of total system demand. The locational marginal price at a particular pricing node is the system marginal energy price plus any marginal congestion charges and marginal loss charges associated with that pricing node.

Day-ahead generation on the margin, shown in Figure 2–21, is different from real-time in that the day-ahead market includes virtual transactions. The real-time market does not include virtual transactions and is required to adjust to unforeseeable market conditions such as unexpected plant and transmission outages.
In 2022, coal resources, wind resources, and virtual transactions were on the margin almost an identical amount of time – coal at 22.6 percent of intervals, virtuals at 22.5 percent of intervals, and wind at 22.0 percent of intervals. Gas, simple-cycle accounted for 17.6 percent of intervals, while gas, combined-cycle accounted for 14.7 percent of intervals. While marginal virtual offers occur at all types of settlement locations, 70 percent of marginal virtual offers are at resource settlement locations, with a significant amount of that activity at wind generation resource locations.

Figure 2–22 illustrates the frequency with which different technology types were marginal and price setting in the real-time market. For a generator to set the marginal price, the resource must be: (a) dispatchable by the market; (b) not at the resource economic minimum or maximum; and (c) not ramp limited. In other words, it must be able to move to provide the next increment of generation.
It is worth noting the increase in wind generation being on the margin in the real-time market—from five percent of all intervals in 2014 and 2015 (not shown on the chart above) to nearly 39 percent in 2022. With the growing amount of dispatchable wind generation and an overall share of 32 percent of total nameplate capacity, wind generation is increasingly becoming the marginal technology a higher percentage of the time. At the end of 2022, 96 percent of nameplate wind capacity was dispatchable, compared to 93 percent at the end of 2021, and 89 percent at the end of 2020. At the beginning of the Integrated Marketplace in March 2014, just 27 percent of nameplate wind capacity was dispatchable.

The most significant difference between day-ahead and real-time fuel on the margin is the absence of virtual offers in the real-time market. From the day-ahead to the real-time market, wind resources on the margin increased from 22 percent to 39 percent of all intervals (17 percentage points), while gas, simple-cycle and combined-cycle increased by four and five percentage points, respectively. Coal resources on the margin dropped by five percentage points from the day-ahead to the real-time.

On a monthly basis, intervals with coal generation on the margin are typically lower in the spring and fall months, offset by wind resources acting as base load units. This results in coal- and gas-fired units cycling more often. Increased wind generation is also affecting prices to some extent in every month of the year. The higher wind generation on the margin values in the spring and fall are as expected given that these periods are the windiest times of the year, as well as the lowest demand periods in the SPP footprint.
2.5 DEMAND RESPONSE

At the implementation of the Integrated Marketplace in March 2014, six demand response resources were registered in the market representing 48 MW of capacity. Those resources withdrew from the market in January 2015. There were no registered demand response resources in the SPP market until December 1, 2019. Figure 2–23 shows the number of dispatchable demand response resources and the nameplate capacity of those resources by year.

Figure 2–23  Demand response resources, count and capacity

In 2019, three demand response resources became active in the market representing 0.3 MW of capacity. As of December 31, 2022, there were 140 demand response resources in the SPP market, representing 361.8 MW of nameplate capacity.

Figure 2–24 shows average hourly generation by dispatchable demand response for 2022 and for the past three years.
Figure 2–24  Demand response resources, average hourly generation

As shown above, generation levels for dispatchable demand response resources remain low, with a high of 1.7 MWh of average hourly generation in January 2022. Average hourly generation by dispatchable demand response resources for 2022 was 0.45 MWh, down from 1.46 MWh in 2021.

2.6 GROWING IMPACT OF WIND GENERATION CAPACITY

2.6.1  WIND CAPACITY AND GENERATION

The SPP region has a high potential for wind generation given wind patterns in many areas of the footprint. Federal incentives and state renewable portfolio standards and incentives are additional factors that have resulted in significant investment of wind generation capacity in the SPP footprint during the last several years.

Figure 2–25 depicts nameplate capacity and average monthly generation of SPP wind facilities by year since 2014.
Total registered wind nameplate capacity at the end of 2022 was 32,032 MW, an increase of about 1,500 MW from 2021. At the end of 2022, 96 percent of all nameplate wind capacity was dispatchable, while just four percent was non-dispatchable. Average monthly wind generation output increased by 15 percent in 2022 to just over 107,000 GWh.

Consistent with previous years, wind generation fluctuated seasonally with summer being the low wind season, as usual, while spring and fall were the high wind seasons. Also typical of wind patterns is lower production during on-peak hours than off-peak. Furthermore, higher levels of wind generation tend to coincide with the morning ramp periods.

Figure 2–26 shows the wind capacity factor. Note that the wind capacity factor is reported for the entire month.\(^\text{33}\)

\(^{33}\) 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.
The wind capacity factor in the real-time market dropped from 38 percent in 2020 to 37 percent in 2021, then climbed to 39 percent in 2022. The day-ahead wind capacity factor followed the same trend, dropping from 30 percent in 2020 to 27 percent from 2021, then climbing to 29 percent in 2022. The slowing of the addition of new wind capacity over the past year, coupled with an increase in wind generation drove the increase in the capacity factors from 2021 to 2022. The spread between the real-time and the day-ahead wind capacity, which historically has remained around a 10 percentage point difference, indicates a disconnect in the amount of wind in the real-time market, compared to the cleared wind in the day-ahead market.

Figure 2–27 shows the monthly real-time wind capacity factor for the past three years.
As shown above, the real-time capacity factor in 2022 has generally followed the same trend as prior years, with lower capacity factors in the summer months, and higher capacity factors in the other months of the year. Obviously outliers include an unusually windy month in June 2020 and an unusually low wind month in February 2021, especially during the winter weather event in that month.

2.6.2 WIND IMPACT ON THE SYSTEM

Average annual wind generation as a percent of load continues to increase as shown in Figure 2–28. The chart shows the trend for average and maximum wind generation as a percent of load since 2014, illustrating the continued increase since the start of the Integrated Marketplace.

Figure 2–28 Wind generation as a percent of load

Average wind generation as a percent of load in the real-time market increased nearly six percentage points to 39.8 percent in 2022. After leveling off from 2017 to 2018, the growth of average wind generation as a percent of load has climbed steadily from 2018 to 2022. Wind generation peaked at 22,897 MW in 2022 on a five-minute interval basis, an increase of over eight percent from 21,118 MW in 2021. Wind generation as a percent of load for any five-minute interval reached a maximum value of just over 88 percent in 2022, which was up from 77 percent in 2021.

Figure 2–29 shows wind production duration curves that represent wind generation as a percent of load by real-time (five-minute) interval for 2019 through 2021.
The shift upward for the curve from year-to-year reflects an increase in total wind generation on an annual basis. The wind production curves show a consistent increase at all levels from 2020 to 2022, although the values tend to converge near the lower end of the curve. Wind generation served at least 31 percent of the total load during half of the year in 2020, with that figure increasing to 34 percent in 2021 and 40 percent in 2022.

Figure 2–30 below shows average demand by hour of day, along with wind generation, and net demand (demand minus wind generation) for 2022.
Wind generation typically produces more energy when demand is lowest and less when demand is highest. Wind generation is at the highest levels in the overnight hours while demand is low. In the morning hours, wind generation decreases while load increases. To navigate these transitional hours, available rampable capacity is necessary. During these transitional hours, ramp scarcity is more likely. While wind generation is very inexpensive, it must be paired with available rampable capacity.

While Figure 2–29 shows the yearly average load, wind, and net demand, there are seasonal differences. For instance, in the summer, wind generation is lower than during other times of the year, and loads are higher. Thus, the effect on net demand is smaller. However, in spring and fall, loads are lower and wind can have a significant effect on net demand.

### 2.6.3 WIND INTEGRATION

Wind integration brings low cost generation to the SPP region but does not count for much accredited capacity. There are a number of operational challenges in dealing with substantial wind capacity. For instance, wind energy output varies by season and time of day. This variability is estimated to be about four times more than load when measured on an hour-to-hour basis. Moreover, wind is counter-cyclical to load. As load increases (both seasonally and daily), wind production typically declines. The increasing magnitude of wind capacity additions, along with the locational concentration, volatility, and timeliness of wind, can create challenges for grid operators with regard to managing transmission congestion and resolution of ramping constraints (which began being reflected in scarcity pricing in May 2017) as well as challenges for short- and long-run reliability. Several price spikes occurred because of wind forecast errors. Under-clearing of wind is also the leading cause of day-ahead and real-time price divergence.

In the SPP market, wind and other qualifying resources were allowed to register as non-dispatchable variable energy resources, provided the resource had an interconnection agreement executed by May 21, 2011 and was commercially operated prior to October 15, 2012. As discussed in Section 2.4.2, in April 2019 FERC approved a change of the tariff in 2019 that required all non-dispatchable variable energy resources to become dispatchable by January 1, 2021, or 10 years after beginning commercial operations, unless the resource was a run-of-the-river hydro-electric facility or exercising its rights under the Public Utility Regulatory Policies Act (PURPA).

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34 This is discussed in Section 3.2.1.
Figure 2–31 illustrates dispatchable variable energy resources (DVERs) and non-dispatchable variable energy resources (NDVERs) wind output since 2019.

**Figure 2–31 Dispatchable and non-dispatchable wind generation**

April 2022 saw an hourly average of nearly 15,500 MWh of wind production, which was the highest since the start of the Integrated Marketplace. Also of note is the non-dispatchable generation continues to trend downward from year to year as more and more non-dispatchable resources are converted to dispatchable. In 2020, 18 percent of wind generation was produced by non-dispatchable variable energy resources, this declined to six percent in 2022.

Figure 2–32 illustrates average hourly curtailments for wind resources over the past three years. In real-time, there are two sources of wind curtailments: automated market software and manual. Automated market software curtailments occur when wind resources are dispatched down by the market system primarily to mitigate transmission constraints, while manual curtailments occur when the SPP reliability coordinator issues an out-of-merit-energy (OOME) instruction to manage reliability issues that cannot be handled through re-dispatch instructions.
From 2020 to 2022, average hourly curtailments increased substantially from 244 MW to 1,260 MW. In addition, over this duration manual curtailments increased slightly as a share of total curtailments from five percent to seven percent, likely due to less transmission outages in 2020. Three factors associated with this curtailment increase are the large amount of wind generation in the market relative to the regional transmission buildout, the counter-cyclical nature of wind curtailments compared to load, and the conversion of previously non-dispatchable wind resources to dispatchable wind resources. As previously illustrated, wind capacity in the SPP footprint increased from approximately 27,300 MW in 2020 to over 32,000 MW in 2022, while MISO’s installed wind capacity increased by 3,000 MW in 2021 and was expected to increase by approximately 4,000 MW in 2022. Additional MISO capacity can create loop flow, potentially adding more congestion on SPP lines. This large increase in installed wind capacity has increased competition for access to transmission lines which in turn has led to a sharp increase in congestion and curtailments.

Manual dispatches are typically fewer during the lower wind output and higher demand months of summer, and more numerous during the higher wind output spring and fall months. Line loading in excess of 104 percent, operating guides, and outages caused 75 percent of manual

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dispatches for dispatchable variable energy wind resources. These same factors, plus transmission switching, caused 80 percent of manual dispatches for non-dispatchable variable energy wind resources.

Next, wind curtailments are inversely related to load at both an hourly and seasonal level. Figure 2–33 depicts this relationship by showing that curtailments are relatively high during the morning, night, and shoulder months when load is relatively low.

**Figure 2–33  Average hourly automated market software wind curtailments**

In the 2022 Spring Quarterly State of the Market Report, MMU staff performed a regression analysis on wind curtailments in the market. This analysis found that wind production and real-time congestion dollars were able to explain 71.5 percent of wind curtailment levels. In addition, this relationship was stronger during periods of high-wind production and low load levels. This relationship exists because wind production is relatively high during off-peak times when congestion is already relatively high, making it more likely for curtailment to occur.

Lastly, the conversion of previously non-dispatchable wind resources into dispatchable wind resources helped increase wind curtailment levels. Because of this rule change, non-dispatchable wind generation fell dramatically as a percentage of total generation over the past

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36 Transmission switching out-of-merit instructions are issued to accommodate switching of 345kV transmission lines, because of stability concerns during the switching process. Typically, these instructions last from two hours prior to switching to two hours after switching is completed, whereas the 345kV line may be out of service for a longer timeframe.

three years. This affected automated market software curtailments because non-dispatchable resources are subject only to manual curtailments in the real-time market.

2.7 SEAMS

2.7.1 EXPORTS AND IMPORTS

The SPP Integrated Marketplace has greater than 6,000 MW of AC interties with MISO to the east, 720 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 2–34 shows the imports and exports for SPP over the last three years and monthly imports and exports for 2022, both in real-time.

![Figure 2–34 Exports and imports, SPP system](image)

SPP has been a net exporter in real-time since 2017, prior to that it was a net importer. Typically, as wind generation increases, exports increase. In 2022, net exports were highest in April with an average of over 1,200 MWh. Nine of the 12 months averaged over 500 MWh of net exports while October was the only month with an average net import. Net exports for 2022 were 600 MWh, up from 240 MWh in 2021 and 122 MWh in 2020.

Figure 2–35 through Figure 2–39 show the data for the four most heavily used interfaces in real-time, namely ERCOT (includes North and East interfaces), SPA, MISO, and AECI. Also shown is PJM, which had an increase in imports from SPP in April during SPP’s highest wind generation in
2022. Tight supply conditions and high prices normally drive exports to ERCOT. Exports to ERCOT increased in 2022 compared to 2021 and 2020 and were particularly elevated from May to August compared to other months in 2022. Southwestern Power Administration hydropower is imported to serve municipals tied to SPP transmission and is highest during on-peak hours, but is typically scheduled day-ahead. MISO interchange generally follows wind production, while AECI interchange is coordinated on an ad hoc basis. DC tie imports and exports are scheduled hourly, and the DC ties are not responsive to real-time prices. Nonetheless, many exports and imports with ERCOT and MISO are adjusted based on day-ahead price differences in the organized markets and expectations of renewable generation. Interchange with SPA and AECI is less responsive to prices. Transactions between SPP and PJM are minimal except during some of the highest wind generation months in SPP that drives exports.

**Figure 2–35 Exports and imports, ERCOT interface**

[Graph showing exports, imports, and net for ERCOT interface]

**Figure 2–36 Exports and imports, Southwestern Power Administration interface**

[Graph showing exports, imports, and net for SPP interface]
**Figure 2–37 Exports and imports, MISO interface**

![Diagram showing exports and imports for MISO interface with data for 2020, '21, and '22.]

**Figure 2–38 Exports and imports, Associated Electric Cooperative interface**

![Diagram showing exports and imports for Associated Electric Cooperative interface with data for 2020, '21, and '22.]

**Figure 2–39 Exports and imports, PJM interface**

![Diagram showing exports and imports for PJM interface with data for 2020, '21, and '22.]

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2.7.2 MARKET-TO-MARKET

SPP began the market-to-market (M2M) process with MISO in March 2015 as part of a FERC requirement that also included regulation compensation and long-term congestion rights. 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. It pays if above its firm flow entitlement. Figure 2–39 shows payments by month between SPP and MISO (positive is payment from MISO to SPP and negative is payment from SPP to MISO.)

Figure 2–40 Market-to-market settlements

All months in 2022 were a net payment from MISO to SPP. Payments from MISO to SPP totaled over $183 million in 2022 while payments from SPP to MISO totaled almost $23 million. This resulted in a net payment from MISO to SPP of $160 million compared to $87 million in 2021. The dotted line represents the total net payment trend removing the winter weather event in

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38 The market-to-market process, regulation compensation, and long-term congestion rights were required to be implemented one year after go-live of the SPP Integrated Marketplace. The market-to-market process under the joint operating agreement allows the monitoring RTO and non-monitoring RTO 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 relieve congestion.

39 Essentially, the RTO which manages the limiting element of the constraint is the monitoring RTO. In most cases, the monitoring RTO has most of the impact and resources that provide the most effective relief of a congested constraint.
February from the 2021 results. This results in a net payment from MISO to SPP of $139 million in 2021, still 15 percent less than the $160 million in 2022.

Figure 2–41 shows market-to-market payments (over $2 million from MISO to SPP and over $1 million from SPP to MISO) by flowgate for 2022.

Figure 2–41  Market-to-market settlements by flowgate

MISO wind impacts many SPP market-to-market flowgates and can increase the amount of market-to-market payments from MISO to SPP. Potomac Economics (external Independent Market Monitor for MISO) notes in their annual report that MISO’s average wind output was 14 percent higher in 2021 than in 2020 and 61 percent higher over the past three years. In 2022, April was the month with the highest net payments from MISO to SPP totaling over $26 million. Wind generation as a percentage of total generation was at its highest in SPP in the month of April in 2022 as well. The continued increase in wind and market-to-market payments signify low cost wind generation in both SPP and MISO both vying for transmission capacity to serve load economically.

Thirty flowgates had payments from MISO to SPP over $1 million for 2022, with eight of those flowgates having payments over $5 million and four of those over $10 million. Only four flowgates had payments from SPP to MISO of over $1 million. For 2022, the constraint with the highest payments from MISO to SPP was the Neosho-Riverton 161kV flowgate with over $25 million in payments. This constraint has resulted in payments from MISO to SPP totaling over $73 million since the start of the market-to-market process, which is the highest total for all

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constraints. The constraint with the third highest amount of payments from MISO to SPP was TMP499_26328\textsuperscript{41} resulting in payments over $18 million in 2022. This and other MISO constraints were consistently not binding in the SPP day-ahead market until October 2022. The constraint with the highest amount of payments from SPP to MISO was TMP278_25759\textsuperscript{42} totaling almost $4 million in 2022.

2.8 VIRTUAL TRADING

Market participants in SPP’s Integrated Marketplace may submit virtual energy offers and bids at any settlement location in the day-ahead market. Virtual offers represent energy sales to the day-ahead market that the participant needs to buy back in the real-time market. These are referred to as “increment offers,” which are like generation. Virtual bids represent energy purchases in the day-ahead market that the participant needs to sell back in the real-time market. These are referred to as “decrement bids,” which are like load. The value of virtual trading lies in its potential to converge day-ahead and real-time market prices, and improve day-ahead unit commitment decisions.

In order for virtual transactions to converge prices, there must be sufficient competition in virtual trading; transparency in day-ahead market, reliability unit commitment, and real-time market operating practices; and predictability of market events. Since the market began in 2014, there has been increasing levels of virtual participation. Figure 2–42 displays the total volume of virtual transactions as a percentage of real-time market load along with wind output levels.

\begin{itemize}
\item\textsuperscript{41} MISO flowgate TMP499_26328: (Forman Xfmr 230/1 kV for the loss of Hankinson-Wahpeton 230 kV (OTP)).
\item\textsuperscript{42} MISO flowgate TMP278_25759: (Overton Xfmr 345/161 kV (AMRN) for the loss of Overton-McCredie 345 kV (AECI-AMRN)).
\end{itemize}
As shown in the figure, virtual transactions averaged 29.5 percent of real-time market load, compared to 25 percent in 2021 and 19 percent in 2020. Historically, the greatest increases in virtual transactions as a percentage of load have been with cleared virtual offers, however, this trend did not continue in 2022. Cleared virtual offers as a percentage of load amounted to over 11.5 percent, up from nine percent in 2021 and seven and one-half percent in 2019. Virtual cleared offers increased from slightly over 15.5 percent in 2021 to nearly 18 percent in 2022 while only averaging just under 12 percent in 2020. Virtual bids typically increase during high load hours. Virtual bids typically increase during high load hours.

At 29.5 percent of load, the average hourly total volume of cleared virtuals ranged from 3,631 MW of withdrawal to 5,569 MW of injection. The net cleared virtual positions in the market averaged about 1,938 MW of injection, or supply, each hour – a one percent increase year-over-year.

The majority of virtual transactions occurred at wind resources in 2022 – a trend that has been increasing since mid-2015. Figure 2–43 illustrates the settlement location types where virtual offers clear.
In total, the monthly average of cleared virtual offers for 2022 was over 4,000 GW, up from nearly 3,400 GW in 2021. This figure shows that an average of almost 1,900 GW of virtual offers cleared at variable energy resources per month during 2021. This is up from an average of nearly 1,500 GW per month in 2021. Virtual offers at wind locations remain the largest volume of any single location type. These large volumes highlight the possibility that market participants with registered wind resources may be missing financial opportunities by under-cleared in the day-ahead market.

Figure 2–44, below, shows the cleared virtual bids by settlement location types.

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43 This includes both dispatchable and non-dispatch variable energy locations.
44 Section 4.1.3 on price divergence discusses the effects of under-cleared wind in the SPP market.
The locations where virtual bids occur are in contrast with the locational volumes of virtual offers. Cleared virtual bids were primarily at resources other than variable energy resources, followed by load locations. Variable energy resources had the lowest volume of virtual bids by location.

Average monthly cleared virtual bids increased from just under 2,000 GW in 2021 to over 2,500 GW in 2022. Cleared virtual bids at non-variable energy resources had a monthly average of nearly 703 GW cleared at non-variable energy resource locations in 2022, up from 589 GW in 2020. Virtual bids at load locations have been steadily increasing, up to a monthly average of 807 GW in 2022, up four percent from nearly 601 GW in 2021.

Figure 2–45 shows how virtual bids and offers are offered and cleared at the day-ahead market.

The cleared demand bids that offered more than $30/MWh over the cleared day-ahead price, and the supply offers offered at less than $30/MWh under the cleared day-ahead price, are considered "price-insensitive." Compared to 2021, price-insensitive bids increased 110 percent and price-insensitive offers increased 76 percent. Cleared bids increased 33 percent, and cleared offers increased 20 percent. Price-insensitive bids and offers are willing to buy/sell at a much higher/lower price that could lead to price divergence rather than competitive, or price-sensitive, bids and offers leading to price convergence between the day-ahead and real-time markets. Price-insensitive bids and offers usually occur at locations with congestion and arbitrage against the day-ahead and real-time price differences. Given that price-insensitive bids and offers are likely to clear, these can be unprofitable if congestion around these locations does not materialize, leading to divergence between the markets.
Financial information for virtual trades is shown monthly and on an annual basis for 2022 in Figure 2–46.

### Figure 2–46 Virtual profits with distribution charges

<table>
<thead>
<tr>
<th>Month</th>
<th>Gross profit</th>
<th>Gross loss</th>
<th>Gross net profit (prior to fees)</th>
<th>RNU charges/credits</th>
<th>Day-ahead make-whole payment charges</th>
<th>Real-time make-whole payment charges</th>
<th>Virtual fee</th>
<th>Total net profit</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>77.0</td>
<td>-38.3</td>
<td>38.7</td>
<td>-8.1</td>
<td>-1.2</td>
<td>-8.0</td>
<td>-0.2</td>
<td>21.1</td>
</tr>
<tr>
<td>February</td>
<td>88.6</td>
<td>-43.6</td>
<td>45.0</td>
<td>-7.1</td>
<td>-1.6</td>
<td>-8.6</td>
<td>-0.2</td>
<td>27.5</td>
</tr>
<tr>
<td>March</td>
<td>78.6</td>
<td>-45.7</td>
<td>32.9</td>
<td>-9.4</td>
<td>-2.1</td>
<td>-9.3</td>
<td>-0.3</td>
<td>11.8</td>
</tr>
<tr>
<td>April</td>
<td>78.2</td>
<td>-41.8</td>
<td>36.3</td>
<td>-9.8</td>
<td>-3.5</td>
<td>-10.2</td>
<td>-0.3</td>
<td>12.6</td>
</tr>
<tr>
<td>May</td>
<td>67.1</td>
<td>-36.1</td>
<td>31.1</td>
<td>-8.2</td>
<td>-2.2</td>
<td>-14.2</td>
<td>-0.2</td>
<td>6.4</td>
</tr>
<tr>
<td>June</td>
<td>47.8</td>
<td>-26.5</td>
<td>21.4</td>
<td>-5.0</td>
<td>-1.4</td>
<td>-17.8</td>
<td>-0.2</td>
<td>-3.0</td>
</tr>
<tr>
<td>July</td>
<td>56.0</td>
<td>-38.1</td>
<td>17.9</td>
<td>-2.0</td>
<td>-0.6</td>
<td>-23.1</td>
<td>-0.1</td>
<td>-8.0</td>
</tr>
<tr>
<td>August</td>
<td>51.9</td>
<td>-27.8</td>
<td>24.1</td>
<td>-2.5</td>
<td>-0.7</td>
<td>-17.7</td>
<td>-0.1</td>
<td>3.1</td>
</tr>
<tr>
<td>September</td>
<td>40.8</td>
<td>-11.8</td>
<td>29.0</td>
<td>-5.2</td>
<td>-1.2</td>
<td>-14.8</td>
<td>-0.2</td>
<td>7.7</td>
</tr>
<tr>
<td>October</td>
<td>49.3</td>
<td>-20.4</td>
<td>28.8</td>
<td>-5.3</td>
<td>-1.1</td>
<td>-8.2</td>
<td>-0.2</td>
<td>14.1</td>
</tr>
<tr>
<td>November</td>
<td>66.0</td>
<td>-37.5</td>
<td>28.5</td>
<td>-8.0</td>
<td>-1.2</td>
<td>-9.1</td>
<td>-0.2</td>
<td>10.1</td>
</tr>
<tr>
<td>December</td>
<td>78.9</td>
<td>-43.5</td>
<td>35.4</td>
<td>-5.4</td>
<td>-2.4</td>
<td>-14.3</td>
<td>-0.2</td>
<td>13.1</td>
</tr>
<tr>
<td>Total</td>
<td>780.1</td>
<td>-411.1</td>
<td>369.0</td>
<td>-76.0</td>
<td>-19.1</td>
<td>-155.2</td>
<td>-2.3</td>
<td>116.4</td>
</tr>
</tbody>
</table>

*All figures in $ millions.*

Ten months in 2023 were profitable in aggregate for virtual transactions with June and July being the exceptions. In the 106 months since the market began, only 15 months have had a net loss when factoring in fees. Three factors that led to virtual trading losses in June and July were low wind generation, low load, and relatively higher day-ahead and real-time make-whole payments. Usually, virtual trading profits are higher during periods of high wind and low load which creates large price differences between the day-ahead and real-time markets. These price differences stem, in part, from under-cleared wind in the day-ahead market. This contributes to a higher portion of negative prices in real-time as compared to the day-ahead.45

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45 Section 4.1.3, price divergence, discusses the effects of unscheduled wind in the SPP market.
Financial information for virtual trades on an annual basis for the past three years is shown in Figure 2–47.

**Figure 2–47  Virtual profits with distribution charges, annual**

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>Raw profit</td>
<td>$252.4</td>
<td>$1,070.1</td>
<td>$780.1</td>
</tr>
<tr>
<td>Raw loss</td>
<td>-180.5</td>
<td>-390.0</td>
<td>-411.1</td>
</tr>
<tr>
<td>Raw net profit, before charges and fees</td>
<td>71.8</td>
<td>680.2</td>
<td>369.0</td>
</tr>
<tr>
<td>Revenue neutrality uplift charges/credits</td>
<td>-5.4</td>
<td>-29.1</td>
<td>-76.0</td>
</tr>
<tr>
<td>Day-ahead make-whole payment charges</td>
<td>-3.8</td>
<td>-9.8</td>
<td>-19.1</td>
</tr>
<tr>
<td>Real-time make-whole payment charges</td>
<td>-26.2</td>
<td>-104.8</td>
<td>-155.2</td>
</tr>
<tr>
<td>Virtual fees</td>
<td>-0.8</td>
<td>-1.7</td>
<td>-2.3</td>
</tr>
<tr>
<td>Net profit</td>
<td>$35.6</td>
<td>$534.7</td>
<td>$116.4</td>
</tr>
</tbody>
</table>

All figures in $ millions

Virtual trades profited $369 million before charges and fees in 2022, nearly a 46 percent increase from 2020. The large decrease from 2021 to 2022 in aggregate profit stems largely from the 2021 winter weather event. Virtual bids can be charged distribution fees for day-ahead make-whole payments and virtual offers are susceptible to real-time make-whole payment distribution fees. In addition, both types of transactions can receive revenue neutrality uplift charge/credits and are assessed a per megawatt virtual fee. The average 2022 rates per megawatt for day-ahead make-whole payments, real-time make-whole payments, and real-time revenue neutrality uplift distributions are $0.23/MWh, $2.17/MWh, and $0.91/MWh, respectively. When factoring in these charges and credits, the net virtual trading profits for 2022 were $116.4 million, which is about 15 percent of the profit level before fees. Net profits in 2022 decreased 78 percent from $534.7 million in 2021.

Net profits are typically small when assessed on a per megawatt basis. However, the 2021 average was much larger than in 2020 and 2022. Figure 2–48 illustrates the monthly average profit per megawatt for a cleared virtual in 2022.
The chart shows that, when factoring in all fees, the average profit per megawatt in 2022 was $1.47 per cleared megawatt, a decrease from $8.26 per cleared megawatt in 2021. However, if February 2021 were excluded due to the impacts of the winter weather event, the 2021 average profit per megawatt would have been $1.84/MW. This would mean that average profit per megawatt was down 20 percent for from 2021 (excluding February) to 2022.

One hundred and thirteen participants transacted virtuals in 2022, an increase of ten from 2021. Figure 2–49 illustrates each virtual participant’s virtual portfolio for the year by both net megawatts cleared and profits before and after adjusting for fees.
Six participants accounted for about 64 percent of the virtual profits after fees, which can also be referred to as net profits. These participants account for roughly 21 percent of the transactional volume in the market. Virtual trading generated profits before fees for 96 participants, and profits after fees for 73 participants. The total losses after fees amounted to roughly $21.6 million, and three entities accounted for nearly 55 percent of that loss.

Additionally, Figure 2-49 highlights the disparity in the trading fees paid by each market participant. These fees totaled over $145 million in 2022; they include: virtual fees (one percent), real-time revenue neutrality uplift fees (20 percent), day-ahead make-whole payment fees (seven percent), and real-time make-whole payment fees (72 percent). Virtual bids are subject to virtual fees, real-time revenue neutrality fees, and day-ahead make-whole payment fees. Virtual offers are subject to virtual fees, real-time revenue neutrality fees, and real-time make-whole payment fees. Nearly three-quarters of the total fees assessed to virtual transactions are assessed only to virtual offers.

The discrepancy in virtual fees relates to the quantity calculation associated with payers of real-time make-whole payments – specifically, the real-time net settlement location deviation hourly amount. This determinant accounted for over 85 percent of the real-time make-whole payments in 2021, or roughly $133 million. As the name implies, the quantity applied to applicable non-virtual transactions includes only the incremental deviations from day-ahead, however the quantities assessed to virtual offers include the full virtual offer quantity.

This calculation methodology, when combined with the larger make-whole payments normally associated with real-time, generally leads to higher fees associated with virtual offers when compared to virtual bids. In 2022, the fees associated with virtual offers amounted to $4.79 per megawatt compared to $3.06 per megawatt for virtual bids. This calculation methodology and associated incentives could be part of the reason why virtual trading offsets only part of the under-clearing of wind resources in the day-ahead market and should be considered as part of any analysis or evaluated as part of any potential solution to address price divergence. The market monitor will continue to evaluate these trends going forward.

Cross-product market manipulation has been a concern in other RTO/ISO markets, and extensive monitoring is in place to detect potential cases in the SPP market. For example, a market participant may submit a virtual transaction intended to create congestion that benefits a transmission congestion right position. Generally, this behavior shows up as a loss in one market, such as a virtual position, and a substantial associated benefit in another market, such as a transmission congestion right position. In the SPP market, only seven market participants lost more than $100,000 in virtual transactions before fees, and 17 lost more than $100,000 in virtual
transactions after fees in 2022. The market monitor reviews these outcomes and takes actions as needed.

2.9 RESOURCE ADEQUACY

In February 2021, resource adequacy challenges were brought to the forefront as SPP’s resource adequacy construct was tested during a severe cold snap. This event highlighted several issues including the lack of seasonal resource adequacy requirements and the need to improve accreditation to better factor in availability. The MMU made several recommendations after the February winter weather event to address resource adequacy. SPP is currently addressing these as well as other recommendations and issues in the stakeholder process, with varying degrees of success.\textsuperscript{46,47}

This section highlights the state of SPP capacity within the SPP footprint.

2.9.1 CAPACITY AGE, ADDITIONS, AND RETIREMENTS

Figure 2–50 illustrates that certain segments of the SPP generation fleet are aging.

\textbf{Figure 2–50  Capacity by age of resource}

As of the end of 2022, nearly 43 percent of SPP’s generation fleet is more than 30 years old. In particular, 87 percent of coal capacity and 42 percent of gas capacity is older than 30 years. According to the U.S. Energy Information Administration (EIA), the national average retirement

\textsuperscript{46} SPP MMU Report on February 2021 Winter Weather Event
\textsuperscript{47} IRATF process
age of coal-fired generation in 2021 was 52 years.\textsuperscript{48} Aside from the resources that joined SPP from Nebraska in 2009 and the Integrated System\textsuperscript{49} in 2015, the largest source of new capacity in the SPP footprint over the last 10 years has been wind capacity.

Figure 2–50 shows the annual trend of capacity additions and retirements over the past three years.

**Figure 2–51  Capacity additions and retirements by year**

Almost all of the coal and gas capacity retired since 2016 has been 1950s era plants. Most of the wind units that retired were first-generation wind resources. One of the wind units retired in 2022 was partially built, abandoned, and never entered commercial operation. Of the 766 MW of retired capacity in 2022, 340 MW were wind units, 322 MW were on a coal unit, 100 MW were gas units, and the remaining four MW were on dispatchable demand response units.

Total nameplate capacity additions were 1,750 MW in 2022. For capacity additions, wind generation has accounted for 92 percent of the additions over the last three years. Of note, only 1,579 MW of wind generation was added in 2022, this is down markedly from 4,800 MW in 2020 and 3,800 MW in 2021. Even with the increased amount of solar generation in the generation interconnection queue, only one 10 MW solar resource was added in 2022. Several dispatchable demand response resources were added to the market in 2022, ranging in size from 0.1 MW to 100 MW. Considering the 1,750 MW in capacity additions along with 766 MW of retirements, 984 MW of net generating capacity was added to the SPP market in 2022.

\textsuperscript{48} Through December 2021. See \url{https://www.eia.gov/electricity/data/eia860M/}.

\textsuperscript{49} Market participants added as part of the Integrated System are Western Area Power Administration – Upper Great Plains (Western), Basin Electric Power Cooperative, and Heartland Consumers Power District.
2.9.2 GENERATION AVAILABILITY

Generation availability represents the generating capacity available to the market to serve load and ancillary service requirements. In 2022, SPP had over 98 GW of generation capacity of which 64.5 GW were accredited. Average hourly available capacity averaged 63,655 MW.\(^{50}\)

The MMU recommends the accreditation process render an accredited capacity that reflects the true generation availability at any given time as closely as possible. For resources that are not covered under SPP’s proposed effective load carrying capability (ELCC) process,\(^{51}\) the current capacity accreditation process for ensuring available capacity to serve demand is completed annually and is singularly focused on adequate resource availability during the summer peak. Accreditation numbers are based on a performance test of a resource’s installed capacity and do not reflect historic performance or planned maintenance.

The Improved Resource Availability Task Force (IRATF) and the Supply Adequacy Working Group (SAWG) led the review of the resource accreditation process in 2021 due to concerns that the current process was not accurately reflecting the expected availability of generation. After reviewing several approaches, their ultimate recommendation was to adopt a single summer season performance-based accreditation (PBA) process using equivalent forced outage rate demand (EFORd’), a methodology that isolates the effects of planned maintenance and outages, and to bring the equations more in line with how other regions measure outage rates for accreditation purposes.\(^{52}\) Under current timelines, performance based accreditation will be implemented partially in 2025 and phased in over the next several seasons.\(^{53}\) However, availability data suggest that this updated accreditation process will likely not provide an accurate reflection of resource availability and will likely be insufficient to ensure reliability absent other changes.

\(^{50}\) The maximum capacity available in any given hour was 80,446 MW on February 11 and the minimum capacity available occurred on November 6 when 43,325 MW were available.

\(^{51}\) While FERC initially approved ELCC in August 2022, it since reversed its decision in March 2023. See ER22-379-003.

\(^{52}\) See “GTTF Performance Based Accreditation Recommendations for Conventional Resources” published by the Generator Testing Task Force.

\(^{53}\) Performance based accreditation and the current timeline are currently on hold as stakeholder groups address concerns brought up in FERC’s reversal of their approval of ELCC accreditation in March 2023.
Figure 2–52 shows the expected availability percentage using performance based accreditation.\textsuperscript{54} It also shows the actual availability of non-ELCC accredited capacity that is registered internally to SPP (and hence, whose performance is directly measurable) throughout 2022. Any difference between these two numbers represents the gap between what we would expect to be available under performance-based accreditation versus what was actually available during a given period.

**Figure 2–52  Percent of accredited capacity available**

In 2022, the internal accredited capacity was approximately 63,122 MW, or roughly 98 percent of total accredited capacity in SPP. Resources not using ELCC accreditation (steam turbines, large hydro, etc.) accounted for just under 58,000 MW or 90 percent of accredited capacity. Figure 2–51 shows that, for the non-ELCC accredited megawatts, roughly 76 percent were available on average in 2022. That figure went as high as 89 percent (56,000 MW) in a total of 3 hours, and as low as 58 percent (37,000 MW) for an hour. Availability was significantly below average during the winter storm in December, hitting a minimum availability of 64 percent for multiple hours on December 24.

These figures are significantly lower than the expected availability of 93 percent in summer using the performance based accreditation methodology. Figure 2–52 also highlights the SPP recommendation that a winter season be included in the adequacy process in addition to summer. Here too, available capacity was significantly lower than the expected availability of 90

\textsuperscript{54} This calculation excludes resources that are proposed to be accredited under the ELCC approach, including wind, solar, and storage resources. Excluding these resources provides a direct comparison between the proposed accreditation approaches and the performance of the resources that would be accredited under those approaches.
percent for winter. The MMU recommends that a resource adequacy requirement be applied to all four seasons, and preferably monthly. The significant troughs in actual availability in the spring and autumn seasons reflects a lower forecasted demand and lower probability of a significant event. This should be reflected in a lower supply adequacy requirement that would provide SPP a reasonable estimate of actual expected available generation while giving resources an opportunity to take planned maintenance outages when the risks and needs to the system change.

Looking at generation availability relative to demand shows the reliability margin available to the region. Figure 2–53 shows, for each day, the minimum hourly capacity available from all internal resources registered in the market as a percentage of demand for that same hour for 2022 and 2021. The SPP planning criteria requires a resource planning margin of 12 percent above each load responsible entity’s summer season net peak load, an amount that increased to 15 percent in 2023.

**Figure 2–53  Minimum capacity available as a percent of load**

The maximum amount of capacity offered during any hour in the day-ahead market was just under 77,000 MW while the maximum demand was 53,332 MW. While these numbers indicate SPP has sufficient capacity to cover internal demand in theory, in reality, the margin between available capacity and demand varies significantly. During 2022, minimum availability as a percent of load during a given day averaged 140 percent, but went as low as 93 percent. The

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55 All resources includes both accredited and non-accredited generation resources for all generation resource types. Behind the meter resources that are not registered in the market are assumed to be included in the load performance.
margin between available capacity and load dipped significantly during both the summer peak and a major winter event in December.

As the proportion of variable energy resources (VERs) in SPP’s supply mix continues to grow, the system’s need to count on the availability of conventional resources increases. In 2022, conventional resources accounted for 97 percent of the available generation on average, ranging from 60 percent to nearly 100 percent. Variable energy resources, primarily wind, accounted for 2 percent on average, ranging from less than one percent to nearly 40 percent.

Figure 2–54 compares internal conventional capacity to its actual availability and load plus contingency reserves by hour for 2022. The hours when total conventional capacity is nearly equal to load plus contingency reserves are often those where system reliability depended on variable energy resources. Because the output of these resources are variable and forecast based, frequent reliance on variable energy resources to prevent operating reserve or energy shortages without adequate improvements to transmission and investment in energy storage or complementary conventional generation represents a real risk to system reliability.

**Figure 2–54  Conventional capacity available versus load**

Aside from the winter storm in December, this chart shows that the reliability margin without variable energy resources was very tight frequently throughout the summer season, currently the only season with a resource adequacy requirement. Because the percentage of variable energy generation in the SPP region is increasing due to more wind and solar coming online and more conventional resources retiring, the number of periods SPP will rely on variable energy resources to prevent shortages will likely continue to increase, requiring a strategic approach to managing the grid. This could include targeted investments in transmission to improve variable
energy resource deliverability and policies or incentives to increase investment in energy storage resources.

Metrics that reflect daily, monthly, or seasonal average neglect to reflect the extremes of the period. Reliability requires planning for and mitigating those extremes. Figure 2–55 shows average load as a percent of available capacity along with the maximum percent of capacity load reached by month. This shows that while average load hovered around 60 to 70 percent of available capacity for much of the year, during the tightest hours, it often exceeded 90 percent of available capacity and reached as high as 107 percent in September. Load exceeded 90 percent of available generation in 465 day-ahead hours, or roughly 5 percent of day-ahead intervals. These maximum values and hours where load is at least 90 percent of available generation demonstrate periods where excess capacity was limited and system reliability was at greater risk.

**Figure 2–55  Average and maximum load as a percentage of available capacity**

Figure 2–55 provides a similar comparison but for average and minimum percent capacity available out of total monthly accredited capacity. This demonstrates the lowest period of availability where system reliability was at greatest risk. The monthly average capacity available ranged from 42 percent to 57 percent, whereas the monthly minimum capacity available ranged from 37 percent to 54 percent.
The analysis in this section demonstrates how managing capacity to a single summer peak or even a winter and summer peak as an accreditation process is not sufficient to ensure resource adequacy and reliability, or to incentivize resources to plan maintenance during periods of low forecasted demand. Although work has been done to try to address this known gap, it does not go far enough to address the reliability risks related to supply adequacy and resource availability. As such, the MMU has the same four critical recommendations related to supply adequacy, with slight modifications based on lessons learned over the past two years:

1) If SPP is to rely on any resource to provide energy, then that resource should be available. The resource adequacy process should take into account all outages to more accurately represent expected availability and include an analysis of outage correlation between resources in similar areas and using the same fuels. Deliverability should also be considered, similar to the effective load carrying capability methodology.

2) There should be meaningful incentives related to reliability. There should be market, out-of-market, and/or regulatory policy mechanisms to incentivize reliability attributes. These attributes include but are not limited to flexibility on outage timing and duration, dual-fuel capability, and winterization.

3) A more frequent resource adequacy requirement, such as a seasonal (or perhaps monthly) requirement, should be developed. The February 2021 winter weather event and December 2022 winter storm both demonstrated the importance of having an accurate expectation of resource availability during cold weather, not just summer peak. Our data also demonstrate low availability levels during the shoulder season when most
planned outages are taken. The MMU supports the Winter Season Resource Adequacy Requirement currently going through the stakeholder process and further, recommends exploring the feasibility of a spring and fall resource adequacy requirement as well.

4) SPP should plan for shocks to generator availability including adverse weather events, pipeline outages, wind turbine icing, and solar eclipses. Express attention should be paid to the pattern and correlation of outages between resource types and locations. SPP should implement mitigation measures to ensure the reliable operation of the grid under all circumstances. This may include strategic investments in transmission to enhance deliverability of capacity, development of energy storage resources, and price sensitive demand.
UNIT COMMITMENT AND DISPATCH PROCESSES

This chapter covers unit commitment and dispatch, scarcity pricing, and ramp. Key points from this chapter include:

- In 2022, capacity started by the day-ahead market decreased by six percentage points and capacity started by self-commitments increased by one percentage point.

- Total outages for capacity dropped seven percent from 2021. Overall, long-term outaged capacity decreased by about four percent from 2021 to 2022.

- The ramp capability product implemented in March 2022 and fast-start pricing implemented in May 2022 brought changes to scarcity pricing. Ramp-up scarcity averaged around 185 intervals per month, with an average scarcity price of roughly $20/MWh. There was no ramp-down scarcity during any interval during 2022. Regulation up and regulation down both had decreases in the number of real-time scarcity intervals in comparison to 2021. Regulation up was down 26 percent and regulation down 60 percent. Operating reserve shortage intervals, conversely, increased eight percent from 2021. The impact of fast-start pricing on scarcity events appears to be minimal.

- About 19 percent of regulation-up scarcities and about 37 percent of regulation-down scarcities occurred in the first interval of the hour. This is compared to an average of seven percent for the other intervals of each hour. This trend has held since the inception of the SPP marketplace and continues to increase.

- SPP designed a ramp capability product, which was implemented on March 1, 2022.56 There were issues identified with the deliverability of ramp in the market shortly after its implementation. SPP is working to address these issues.

- Fast-start resources were implemented on May 18, 2022 to meet compliance with FERC’s order. There was little discernable impacts to fast-start revenues from the new process.

- Fast-start resources are still predominately cleared in the day-ahead market, although their key benefit is to provide quick offline to online generation for real-time uncertainty events.

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56 Tariff Revisions to Add Ramp Capability, FERC Docket No. ER20-1617.
Thirty percent of the energy produced in 2022 came from self-committed resources. This is down from the 31 percent seen in 2021 and 36 percent seen in 2020.

3.1 COMMITMENT PROCESS

The Integrated Marketplace uses centralized unit commitment to determine an efficient scheduling and dispatch of generation resources to meet energy demand and operating reserve requirements. Most commitments begin in the day-ahead market. The day-ahead market attempts to commit sufficient capacity to meet the loads that were bid into the day-ahead market. Because of differences between day-ahead and real-time and locational issues, it is often necessary to commit additional capacity outside the day-ahead market. This is done through the reliability unit commitment (RUC) processes and manual commitments. SPP employs five reliability commitment processes:

- multi-day reliability assessment (MDRA);
- day-ahead reliability unit commitment (DA RUC) process;
- intra-day reliability unit commitment (ID RUC) process;
- short-term intra-day reliability unit commitment (ST RUC) process; and
- manual commitment instructions issued by the RTO.

Figure 3–1 shows a timeline describing when the various commitment processes are executed.

Figure 3–1 Commitment process timeline

Multi-day reliability assessments are made for at least three days prior to an operating day. This assessment determines if any long lead-time generators are needed for capacity or are needed to address an emergency for the operating day. Any generator committed from this process is treated as a “must commit” in the day-ahead market. The day-ahead closes at 0930 Central time and is executed on the day before the operating day, with the results posted no later than 1300. The day-ahead reliability unit commitment process is executed approximately 45 minutes after the posting of the day-ahead market results. This allows market participants time to re-offer their uncommitted resources, often with better information on forecasts and gas markets.
The intra-day reliability unit commitment process is run throughout the operating day, with at least one execution occurring every four hours. The short-term intra-day reliability unit commitment may be executed as needed to assess resource adequacy over the next two hour period as part of the intra-day process. SPP operators may also issue manual commitment instructions for capacity, transmission, or local reliability issues during the operating day to address reliability needs not fully reflected in the security constrained unit commitment algorithm used in the day-ahead and reliability unit commitment processes. Transmission operators occasionally also initiate local reliability commitments.

### 3.1.1 RESOURCE STARTS

The SPP resource fleet, excluding variable energy resources, started just over 4.3 million MW of capacity in 2022. That represents a 16 percent increase from 2021. The major contributors of the increase of started capacity came from resources started by the day-ahead market and simple-cycle combustion turbine resources started by intra-day reliability unit commitment. Figure 3–2 shows the percentage of capacity from starts by commitment process. For all generation participation offers in the day-ahead market by commitment status, see Figure 3–10.

**Figure 3–2 Started capacity by commitment type**

<table>
<thead>
<tr>
<th>Commitment Type</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day-ahead market</td>
<td>75%</td>
<td>69%</td>
<td>63%</td>
</tr>
<tr>
<td>Self-commitment</td>
<td>14%</td>
<td>19%</td>
<td>20%</td>
</tr>
<tr>
<td>Intra-day RUC</td>
<td>4%</td>
<td>5%</td>
<td>8%</td>
</tr>
<tr>
<td>Short-term RUC</td>
<td>1%</td>
<td>2%</td>
<td>4%</td>
</tr>
<tr>
<td>Manual, regional reliability</td>
<td>4%</td>
<td>4%</td>
<td>3%</td>
</tr>
<tr>
<td>Day-ahead RUC</td>
<td>&lt;1%</td>
<td>1%</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Manual, local reliability</td>
<td>1%</td>
<td>1%</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Multi-day reliability assessment</td>
<td>&lt;1%</td>
<td>&lt;1%</td>
<td>&lt;1%</td>
</tr>
</tbody>
</table>

As shown above, 63 percent of started capacity in 2022 was a result of the day-ahead market, which continues to be the primary commitment process. The day-ahead market is the preferred

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57 This table represents started capacity, meaning the capacity is counted each time the resource is started. To see day-ahead cleared capacity for each hour, see Figure 3-11.
58 For this table, the day-ahead market category excludes resources started due to self-commitment in the day-ahead market.
59 Self-commitment includes resources started in the day-ahead market due to a self-commitment.
60 Manual commitments for regional reliability include commitments for additional capacity and manually staggering start-up or shutdown times.
method of start-up for resources with longer lead times. However, a limiting factor on the number of day-ahead commitments is that the optimization algorithm is restricted to a 48-hour window, hence, large base-load resources with long lead-times and long run times may not appear economic to the day-ahead market commitment algorithm. Some market participants choose to self-commit these resources, which contributes to the amount of self-commitments.

Within the operating day, commitment flexibility is limited by resource start-up times. As the operating hour approaches, fewer resources are eligible to be started. The reliability unit commitment processes—day-ahead, intra-day, short-term, and manual—represent about 16 percent of the started capacity. Many of these commitments are due to uncertainty of the forecasted resources or needing additional ramp-able capacity. The ramp product, implemented in March of this year, and the uncertainty product, to be implemented in 2023, are expected to help reduce these amounts. Figure 3–3 shows that a large majority of start-up instructions issued to combined-cycle generators are the result of the day-ahead market. This result is expected given the lower variable costs and different operating parameters for these resources relative to other gas units.

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61 Commitments are evaluated over 48-hour window, which covers the operating day and the next day. Although two days are evaluated, start-up and shutdown instructions are issued for the operating day only. The day after the operating day is evaluated to decrease inefficiencies across day-boundaries (e.g., shutting down a resource at the end of one day only to start it an hour later on the next day).
62 This is day-ahead reliability unit commitment process, not the day-ahead market.
63 The ramp product is discussed in further detail in Section 3.2.3.2, and the uncertainty product is discussed in Section 3.2.3.2.3.
Figure 3–3  Origin of start-up instructions for gas resources

<table>
<thead>
<tr>
<th>Commitment process</th>
<th>Combined-cycle</th>
<th>Simple-cycle, combustion turbine</th>
<th>Simple-cycle, steam turbine</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day-ahead market</td>
<td>88%</td>
<td>88%</td>
<td>89%</td>
</tr>
<tr>
<td>Day-ahead RUC</td>
<td>0%</td>
<td>&lt;1%</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Intra-day RUC</td>
<td>2%</td>
<td>2%</td>
<td>3%</td>
</tr>
<tr>
<td>Short term RUC</td>
<td>0%</td>
<td>&lt;1%</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Manual, local reliability</td>
<td>0%</td>
<td>1%</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Manual, regional</td>
<td>1%</td>
<td>1%</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Self-commitment</td>
<td>9%</td>
<td>7%</td>
<td>7%</td>
</tr>
<tr>
<td>Multi-day reliability</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
</tbody>
</table>

For gas-fired generators with simple-cycle combustion turbine technology, the day-ahead market accounted for 72 percent of their total starts. This is consistent with 2021. Steam turbine starts increased in the day-ahead market with 59 percent in 2022, compared to 58 percent the year before and 56 percent in 2020.

The intra-day RUC had a larger percentage of starts than 2021. Gas-fired generators with simple-cycle combustion turbine technology increased to 13 percent of starts in 2022 from seven percent in 2021. Simple-cycle steam turbine increased from 10 percent from 2021 to 12 percent of total starts for 2022. Combined cycle resources’ intra-day RUC starts also increased from two percent in 2021 to three percent in 2022.

Some reliability unit commitments are made to meet instantaneous load capacity requirements. However, this is not a product that generators are directly compensated for by the market. These commitments are often not supported by real-time prices and can lead to make-whole payments. The next section discusses the drivers behind reliability commitments.

3.1.2 DEMAND FOR RELIABILITY

Figure 3–2 noted that about 14 percent of SPP start-up instructions by capacity originated from SPP reliability unit commitment processes. To understand the need for the reliability
commitments, it is useful to discuss the different assumptions, requirements, and rules that are used in the reliability unit commitment processes after the day-ahead market.

One difference between day-ahead and real-time is wind generation. Eighty-eight percent of the real-time wind production cleared in the day-ahead market in 2022. Market participants determine the participation levels for their wind resources in the day-ahead market through supply offers. In contrast, SPP’s wind forecast is used by the reliability unit commitment processes.

Another important difference between the two studies is virtual transactions. Market participants submit virtual bids to buy and virtual offers to sell energy in the day-ahead market. A virtual transaction is not tied to an obligation to generate or consume energy; rather, it is a financial instrument that is cleared by taking the opposite position in the real-time market. Because the reliability unit commitment processes must ensure sufficient generation is on-line to meet energy demand, virtual transactions are not included in the reliability unit commitment processes used in day-ahead, intra-day, or short-term.

Other differences also affect net energy demand. Net energy demand is demand net of both variable energy generation, the combination of imports, exports, and parallel flows from other markets. Import and export transaction data are updated to include the latest information available for the reliability unit commitment processes. A fundamental difference between the two studies is the definition of demand. In the day-ahead market, demand is determined by bids submitted by the market participants whereas, in the real-time market, demand is physical. Demand bids in the day-ahead market average around 98 percent of the real-time values, as shown in Figure 2–5. Other smaller differences between the two markets include losses and operating reserves.

These types of differences are referred to as resource gaps (i.e., a gap in meeting demand) between the day-ahead and real-time markets. The resource gap is the excess price-following, physical generation cleared in the day-ahead market that was not needed in real-time. A negative resource gap would indicate that the total generation cleared in the day-ahead market is insufficient to serve real-time demand. The resource gap is typically positive, indicating more dispatchable generation is cleared in the day-ahead market than was necessary to serve real-time load.
The primary drivers for the resource gaps are:

1) differences in virtual supply net of virtual demand,

2) differences in real-time wind generation compared to wind cleared in the day-ahead market, and

3) real-time net exports exceeding day-ahead net exports.

It is generally true that the day-ahead market clears less wind generation than is produced in real-time. The mismatch is partly because some market participants with wind generation assets, recognizing the uncertainty of the wind forecast in day-ahead, offered such that the full amount of forecasted capacity did not clear in the day-ahead market. This may cause other generation to clear in the day-ahead market that will not be needed in real-time when the wind replaces it.

The resource gaps can help explain why some generators produce much less in real-time or why additional commitments occur after the day-ahead market has cleared. Figure 3–4 compares on-line capacity between the day-ahead and real-time markets alongside marginal energy price.

**Figure 3–4   Average hourly capacity increase from day-ahead to real-time**

The chart indicates that in 2022 there was, on average, around 4,200 MWh of additional dispatchable generation cleared incremental to the day-ahead market, a decrease of 6 percent compared to 2021. The spike in day-ahead 2021 prices can be attributed to the February 2021 winter weather event. The high prices in the summer 2022 are related to high peak loads and low capacity margins, which are typically seen each year. As previously mentioned, two of the main drivers of the excess capacity in day-ahead are shown in Figure 3–5.
Figure 3–5 shows that the gaps due to wind and virtuals are still the main drivers for the resource gap. These two elements make up 82 percent of the total resource gap in 2022. However, these wind and virtuals gaps decreased 14 percent from 2021. These decreases helped contribute to the 7 percent drop in the total resource gap from 2021 to 2022.

As shown by the graphed gaps in Figure 3–5, the shapes of the wind gap and virtuals gap very nearly match the shape of the overall resource gap. This further indicates that the wind and virtuals gap are driving the variations of the overall resource gap. As discussed in section 2.8, virtuals occur mostly at wind generator locations. The effect of this is seen in Figure 3–5 as the shape of the virtual gap largely follows the shape of the wind gap. This indicates that, on average, the virtuals are reacting to the changes in wind generation. Therefore, the resource gap is ultimately caused by the wind gap.

The wind gap can be caused by insufficient clearing of wind generation in the day-ahead market. To balance this insufficiency, the day-ahead market may then clear other generation that represents physically dispatchable generation in real-time. Then, in real-time, the actual wind generation replaces the additional dispatchable generation that was cleared in day-ahead. The result can be that the day-ahead market clears excessive generation. In real-time, this excess generation will likely run at minimum output. The excess generation’s minimum output can cause other generators to run lower on their offer curve, which can lower the real-time energy price, making real-time prices diverge from day-ahead prices.
On average, the market-wide resource gap is positive, and no additional capacity is needed in real-time. However, in some cases, the day-ahead market can clear insufficient generation. This can be a case that is not represented by the average, a locational insufficiency due to congestion, or a parameter that is not directly or sufficiently cleared in the day-ahead market such as ramp. When the day-ahead market clears insufficient generation, additional capacity may be committed for reliability after day-ahead.

One of the reasons for reliability commitments is the need for ramp capability. The instantaneous load capacity constraint may commit additional resources to ensure there is adequate ramping capacity to meet the instantaneous peak demand for any given hour. The instantaneous load capacity constraint is defined as the greater of the forecasted instantaneous peak load, or an SPP defined default value. Figure 3–6 shows the percentage of hours for which the default value is used for the upper bound and lower bound of instantaneous load capacity.

**Figure 3–6  Frequency of minimum requirement for instantaneous load capacity**

A value is calculated for upper bound (upward ramp) and a lower bound (downward ramp) based on forecasted load. However, the default, or minimum requirement, is not based on market information. Because the default value is used in over half of all intervals, the instantaneous load capacity constraint can contribute to reliability commitments that are not based on current market information. The default requirements are hourly values as low as 200 MW. SPP evaluates the default values quarterly.

The percent of hours at various upper bound requirements is shown in Figure 3–7.
The most frequent observations were from 400 MW to 499 MW at around 29 percent of the observations. There were about the same number of observations in lower requirements as last year and the year before. While a market-based product is more appropriate for a market efficiency improvement, keeping this requirement low may help reduce unnecessary make-whole payments.

Resources committed to provide ramp capability can affect real-time prices, whether as a result of applying the instantaneous load capacity constraint in a reliability unit commitment process or a manual process. Without the appropriate scarcity pricing rules that reflect the market value of capacity shortages due to ramp capability, the cost of bringing the resource on-line may not be fully reflected in the real-time prices. The resource keeping the market from being scarce may not be paid to provide the needed capability. Additionally, manual commitments made during conservative operations, while possibly needed for capacity, similarly suppress the price signals when they are needed most.

Reliability commitments, along with wind exceeding the day-ahead forecast, can dampen real-time price signals, as is evidenced by 51 percent of real-time make-whole payments made for reliability unit commitments, as shown in Figure 4–29.64

### 3.1.3 FAST-START RESOURCES COMMITMENT

As of May 18, 2022 a fast-start resource is defined as any dispatchable resource that can start, synchronize, begin injecting energy within 10 minutes of SPP notification, and have a minimum-

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64 This is the sum of the intra-day RUC, short-term RUC, and day-ahead RUC in Figure 4-29.
run time of one hour or less. Market Storage Resources meeting these criteria while having a discharge time of 60 minutes or less also meet the fast-start criteria. Prior to this date, dispatchable resources with a start-time of less than 10 minutes and choosing to classify as quick-starts were considered quick-start resources, regardless of run time requirements.

In 2016, FERC issued a Notice of Proposed Rulemaking (NOPR) on fast-start pricing processes as a part of a broad initiative aimed at improving price formation in regulated wholesale power markets in the United States.\(^{65}\) This was followed by an order published in December 2017 which specifically targeted SPP’s fast-start pricing, finding it unjust and unreasonable.\(^{66}\) FERC’s stance remained largely unchanged in response to numerous briefs and replies from a broad array of stakeholders, including those provided by the SPP Market Monitoring Unit.\(^{67}\) As a result, SPP filed proposed changes to its pricing practices, which were accepted by FERC in June 2019\(^{68}\) and went live in May 2022.

Below are the SPP changes made to comply with the order:

- The addition of a separate “pricing run” in market execution;
- The ability to relax minimum capacity levels for pricing purposes in the new pricing run, potentially as low as zero megawatts;
- The inclusion of amortized start-up and no-load costs as function of resource capacity and run time when calculated permissible energy offers;
- The elimination of SPP’s prior “screening run” used to manually eliminate uneconomic fast-start commitments; and
- Changes to eligibility for dispatch and cost reimbursement under fast-start procurement, including a one-hour ceiling on minimum run times and automatic consideration of resource eligibility based on physical parameters.

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\(^{67}\) Comments and Recommendations of the Southwest Power Pool Market Monitoring Unit. 12 February 2018. SPP MMU. Docket EL18-35-000.

The changes to permissible costs in energy offers for fast-start resources resulted in the formulation of two new adders that reflect amortized start-up and no-load costs, respectively. These adders are described by the formula below:

**Figure 3–8  Fast-start resource composite offer adders**

**Start-up adder**

\[
\text{StartupAdder} = \frac{\text{StartupCost}}{\text{EcoMax} \times \frac{\text{MinRunDuration}}{1 \text{ Hour}}}
\]

**No-load adder**

\[
\text{NoLoadAdder} = \frac{\text{NoLoadCost}}{\text{EcoMax} \times \frac{\text{MinRunDuration}}{1 \text{ Hour}}}
\]

Functionally, the two adders translate dollar-denominated startup and no-load costs into dollar per megawatt-hour costs that the market-clearing engine can integrate into and interpret as incremental production costs. Combined with the existing incremental energy offer, the three components sum to a “composite offer” specifically employed for fast-start qualified resources.

There were 86 resources offered in with parameters meeting the fast-start criteria after implementation in 2022. Figure 3-9 below illustrates the total nameplate capacity by fuel type for resources meeting the fast start criteria.

**Figure 3–9  Nameplate capacity of fast-start resources**

<table>
<thead>
<tr>
<th>Fuel type</th>
<th>Nameplate capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural gas</td>
<td>2,126</td>
</tr>
<tr>
<td>Hydro</td>
<td>596</td>
</tr>
<tr>
<td>Fuel oil</td>
<td>282</td>
</tr>
<tr>
<td>Market storage resource</td>
<td>11</td>
</tr>
</tbody>
</table>

Historically, SPP has seen a large percentage of the fast-start resources clearing in the day-ahead market. Figure-3-10 shows the megawatts cleared by fast start resources in the day-ahead market compared to megawatts dispatched incremental to day-ahead in real-time.
The chart shows that resources meeting the fast-start criteria post-implementation appear to have cleared a higher percentage in the day-ahead market than in real-time after the new fast-start logic implementation. This is a concerning trend, as one of the key attributes of fast-start resources is to sit off-line near real-time and respond to ramp and uncertainty needs. Nearly 80 percent of the fast-start megawatts cleared in the day-ahead market were natural gas resources with the remaining 20 percent being hydroelectric plants.

One of the key objectives of the fast-start logic was to reduce uplift in the market, particularly for fast-start resources. The expectation was that higher energy prices set by the fast-start resources’ composite offers would reduce the need for uplift. Figure 3-11 and 3-12 show the 2022 day-ahead and real-time make-whole payments, by month, for the 86 resources qualifying as fast-starts post implementation.
Total make-whole payments to fast-start resources were roughly $38 million dollars, with $12.6 million of that coming from the day-ahead market. Figure 3–11 shows a reduction in day-ahead make-whole payments to fast-start resources starting around the time of the fast-start resource logic implementation in May. However, when we compare the day-ahead make-whole payments for these resources from June through December 2021 to the same period in 2022 we see there was a 300 percent increase in make-whole payments. Much of the increase in make-whole payments to natural gas resources is directly attributable to increased fuel costs. Contrarily, real-time make-whole payments to fast-start resources appear to be relatively the same as prior to fast-start periods. The upticks in December for both markets stem from the winter weather event during the end of the month.
Day-ahead make-whole payments per megawatt eligible for day-ahead cost reimbursement was $2.11/MWh for natural gas, and $0.25/MWh for hydro. These metrics for real-time were $551/MWh for fuel oil, $75/MWh for natural gas, and $1.70/MWh for hydro.

There are many elements that can affect make-whole payments to include the frequency of the resources’ deployments, the associated market prices, and the resources’ fuel costs. The newly implemented fast-start logic did not have a direct effect on the total operating cost of fast-start resources, but it does have an effect on the revenues those resources can receive.

As described above, offline fast-start resources are cleared and dispatched based of their energy offers and submitted resource parameters. However, they can set higher prices in the pricing run based off their composite offers, described above. Make-whole payments are composed of resource’s costs compared to revenues during a commitment period. Because the fast-start logic did not affect the costs that resources are made-whole to, changes in revenues will be the only driver for the changes in make-whole payments.

Prior to the fast-start logic, resources’ energy day-ahead revenues were calculated by multiplying the day-ahead locational marginal price in the day-ahead dispatch-run by the megawatts generated in the day-ahead dispatch run. After the fast-start logic, resources are compensated by multiplying the day-ahead dispatch megawatt from the day-ahead dispatch-run times to the pricing-run’s applicable day-ahead location-marginal price. These methods apply to both day-ahead and real-time markets, except in real-time day-ahead megawatts-cleared are subtracted from the real-time and multiply the product by the real-time locational marginal prices. Figure 3-13 below shows the difference in the revenues to fast-start resources with the new fast-start pricing method verses the pre-fast-start method.
The above chart shows that there was very little change in the revenues to fast-start units due to the new fast-start pricing. The fast start pricing appeared to have created 1.5 percent increase in day-ahead revenues to fast start resources and a half a percent increase in real-time revenues. All else equal, the increase in revenue would cause a negligible reduction in make-whole payments.

3.1.4 GENERATION SCHEDULING

The day-ahead market provides market participants with the ability to submit offers to sell energy, regulation-up service, regulation-down service, spinning reserve, and supplemental reserve, 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 offered capacity. All day-ahead market products are traded and settled on an hourly basis.

In 2022, participation in the day-ahead market continued to be robust for both generation and load. Load-serving entities that also own generation assets 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. However, as shown in Figure 3–14, merchant generators self-commit at a much lower rate than load-serving entities. This is likely because merchant generators have incentive structures in place based primarily on market outcomes.

Figure 3–14 shows day-ahead market offers by commitment status and participant type.
Overall, the offers in “market” status have increased while offers in a self-commitment status decreased. However, the merchant variable energy resource owners decreased their offered capacity in “market” status while increasing their “not participating” and “outage” status. Merchant variable energy resource owners also reduced self-commitment.

Figure 3–15 shows generation capacity in the day-ahead market by commitment status.

The average percent of total offered capacity by commitment status shows a decrease in the “self-commit” status and a slight decrease in the “outage” status. The “market” commitment status averaged 63 percent while resources with the commitment status of “reliability” averaged around two percent and the commitment status “not participating” increased to about seven percent. The “outage” commit status averaged 14 percent. The “self-commit” status averaged around 14 percent of total offered capacity which was about the same as 2021. Self-commitments have declined for the last three years as shown above.
Compared with Figure 3–3 in Section 3.1.1, which shows origins of only initial started capacity, these values represent commitment status of all generation capacity offered including those on-line. Self-commit started capacity increased for the second straight year from 19 percent in 2021 to 20 percent in 2022, however, the self-commit percent of all capacity offered decreased from 15 percent to 14 percent.

Figure 3–16 shows on-line capacity commitment as a percent of load.

**Figure 3–16  On-line capacity as a percent of load**

Capacity commitment as a percent of load increased slightly from 2021. Beginning in 2016, capacity as a percent of load decreased yearly through 2018. However, from 2018 through 2020, there were small increases from 120 percent in 2018, to 121 percent in 2019 and 123 percent in 2020. The 2021 results marked a decline in online capacity as a percent of load to 2018 levels. Having too much capacity on-line with non-zero minimums causes other resources to operate lower on their offer curves, which can contribute to under-recovery of costs and, therefore, increased make-whole payments.

Additional capacity may be beneficial for necessary rampable capacity. Prior to the ramp product, which was implemented in March 2022, there was no rampable capacity requirement other than instantaneously load capacity, which has a reserved use. The ramp product is covered in section 3.2.3, below. SPP plans to implement an uncertainty product, covered in section 3.2.4, in late 2023. The uncertainty product along with the ramp product are anticipated to help supply rampable capacity to the market. Prior to these products, the market clearing software had no method for optimizing or pricing the clearing of rampable capacity for a given
interval. There are issues, outlined in sections 3.2.3 and 3.2.4, for both products that will need to be addressed for the effective delivery of procured ramp.

### 3.1.5 MUST-OFFER PROVISION

The Integrated Marketplace has a limited day-ahead must-offer provision that was intended to incentivize load-serving entities with generation assets to participate in the day-ahead market. Market participants that are non-compliant are assessed a penalty based on the amount of capacity available in the day-ahead market relative to the market participant’s peak hourly real-time load. The requirement is limited in the sense that not all resources or capacity must be offered. Only market participants with generation assets that serve load are subject to the must-offer requirement, and they are required to offer only enough generation to cover most of their load plus reserve obligations, per asset owner, which may not be all of their resources or available capacity. An alternative way to satisfy the provision is to offer all generation that is not on outage. In 2022, no day-ahead must-offer penalties were assessed. In 2021, one day-ahead must-offer penalty of $7,413 was assessed. Six penalties were assessed in 2020 totaling $42,679. While this provision does highly encourage available generation to be offered, it does not impose a penalty for excessive outages, which has been cited as a reason for conservative operations in the past. The day-ahead must-offer provision also does not tie into Attachment AA, which defines the resource adequacy requirement in the SPP tariff.

The MMU continues to recommend updating the day-ahead must offer requirement and addressing FERC’s concerns. In light of the increased volume of outages that contributed to conservative operations in 2019, the MMU has assigned a higher priority to addressing the issue. See further discussion in Section 7.4.

### 3.2 DISPATCH

The real-time market co-optimizes the clearing of energy and operating reserve products out of the available offered capacity based on the offer price for each product while respecting physical parameters. The real-time market clears every five minutes for all products. The settlement of the real-time market also occurs at the five-minute level and is based on market participants' deviations from their day-ahead positions.

### 3.2.1 SCARCITY PRICING

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 additional supply, 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.

When an insufficient amount of ramp capability-up service, ramp capability-down service, 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. As of May 2022, scarcity prices are set by the pricing run according to the dispatch in the pricing run.\(^69\) Scarcity or a lack of scarcity, in the dispatch run has no bearing on scarcity prices in the marketplace.

Regulation, ramp capability, and contingency reserve scarcities are priced by demand curves. The regulation demand curves, for both up and down, consist of six steps with a maximum price of $600/MW. The demand curve for ramp capability, for both up and down, also consist of six steps, but the maximum scarcity price is based on the average cost to run a dispatchable fast-start resource at its maximum output for its minimum run time. SPP updates this maximum demand curve price monthly based on three months of historical offers. The highest maximum demand curve price was $53/MW in February. The contingency reserve demand curve consists of three steps with a maximum price 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 3–17 and Figure 3-18 displays the number of scarcity intervals in the day-ahead market and average prices by month, along with an annual average of values.

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\(^{69}\) Pricing runs and dispatch runs are products of the newly implemented fast-start logic, discussed in section 3.1.3
Six hours of regulation-up scarcity occurred during 2022, with two intervals in May, three in June, and one in July. Outside of the winter weather event in February, 2021 had only one hour of regulation-up scarcity (in October), and 2020 had three hours of regulation-up scarcity.

Ramp capability-up scarcity occurs much more frequently in the day-ahead market compared to regulation and contingency reserve scarcity. During these shortages, the median ramp-up cleared was about 90 percent of the requirement while the fifth percentile was about 63 percent. Ramp capability-up was rarely short at significant levels in the day-ahead market. The median shadow price during a shortage was around $20/MW. Ramp capability-up scarcities peaked in August, with scarcity price levels peaking in December.
Figure 3–19 and 3–20 display the number of scarcity intervals in the real-time market and average prices for each product by month, along with an annual average of monthly values.

**Figure 3–19  Scarcity intervals and prices, regulation and operating reserves, real-time**

Regulation-up scarcity occurred in just under 1,000 intervals. During these shortages, a median of about 91 percent of the requirement was cleared with a fifth percentile of about 18 percent of the requirement. There were about 165 operating reserve scarcity intervals. The median operating reserve cleared during these shortages was about 92 percent of the requirement while the fifth percentile was about 70 percent. Regulation-down was scarce in about 100 intervals. The median regulation-down cleared during shortage was about 94 percent of the requirement with a fifth percentile of about 75 percent. There were no ramp capability-down shortages. Regulation-down and operating reserve were rarely scarce and cleared nearly all their requirement during shortages. Both regulation-up and ramp capability-up cleared nearly their entire requirement almost all of the time but had occasional significant shortages.

Excluding February 2021, regulation-up scarcities decreased by about 26 percent from 2021 while regulation-down scarcity decreased by about 59 percent. Contingency reserve decreased by about 22 percent from 2021.

Regulation-up scarcity peaked in April, followed by May and March. Regulation-down scarcity peaked in May, although there were few. Operating reserve was evenly distributed throughout the year.

The average scarcity prices were about $280/MW for the regulation-up, $220/MW for regulation-down, and $450/MW contingency reserve. The highest monthly average regulation-up and, regulation-down scarcity prices occurred in October and did not correspond to the peak
scarcity intervals. The highest monthly average scarcity price for operating reserve occurred in December, mostly during the winter weather event. The average scarcity prices for each scarcity type have been increasing in recent years.

**Figure 3–20  Scarcity intervals and prices, ramp-up and ramp-down, real-time**

The most frequent scarcity in real-time was ramp capability-up, implemented March 1, with about 8,500 scarce intervals. There was no ramp capability-down scarcity during 2022. The median ramp-up cleared during shortages was about 85 percent of the requirement while the fifth percentile was about 26 percent. Like the day-ahead market, ramp capability-up in the real-time market peaked in August, about 50 percent higher than the next highest months: July and September.

The average scarcity price for 2022 was $22/MW for ramp capability-up. The monthly average ramp capability-up scarcity prices peaked in November.

Scarcity related price spikes for regulation-up, regulation-down, and contingency reserve happened more frequently at the beginning of each hour while ramp capability-up scarcity peaked toward the end of the hour. **Figure 3–21 and Figure 3–22** below illustrate a count of the scarcity events in the real-time market by the 12 intervals of each hour.
About 19 percent of regulation-up scarcities and about 37 percent of regulation-down scarcities occurred in the first interval of the hour. Regulation scarcity events typically happen at the beginning of the hour and have since the inception of the marketplace. Contingency reserve scarcities were more equally distributed across the hour, though they also peaked at 13 percent in the first interval of the hour. Ramp capability-up scarcities were more evenly distributed throughout the hour than regulation scarcities. However, they peaked toward the end of the hour in interval beginning :50, followed by the two preceding intervals.

One potential reason for regulation scarcities peaking at the beginning of the hour is that SPP does not pre-position regulating resources to be within their regulating maximum and minimum...
limits prior to the period that the resource is cleared for regulation. Consider a resource that is currently dispatched to its minimum of 100 MW. If this resource clears 20 MW of regulation-down reserves in the next hour, it will need to move up to 120 MW. If the resource’s ramp rate does not allow it to ramp up 20 MW in one interval, the resource cannot provide regulation-down in the first interval. If this causes a scarcity, the resource may have to buy back a day-ahead position at scarcity prices. However, if the resource moves there prior to the hour, it will deviate from its current dispatch instruction, which has financial penalties. Consequently, resources often follow dispatch until the first interval of the regulation commitment, contributing to shortages in the first interval of the regulating commitment.

There are reasons for SPP to pre-position resources to their regulating ranges prior to the regulation period. However, should opportunity costs occur for these resources during the pre-position period, this may need to be addressed.

3.2.2 RAMPING

The increase or decrease of the resource’s output to achieve the next dispatch instruction is called “ramp.” The number of megawatts a resource can ramp in one minute is the resource’s “ramp rate.”

In real-time, resources are increasing and decreasing output to meet changes in both load and non-dispatchable generation. These changes can be measured as changes in net load. Net load is net of both non-dispatchable generation, the combination of imports, exports, and parallel flows from other markets.

Figure 3–23 shows the frequency and extent of net load changes from one real-time interval to the next.

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70 Resources that deviate from their dispatch signals can receive Uninstructed Deviated Charges for the deviated megawatts. The median price per megawatt for deviation in 2022 was about $3.60. However, the maximum price charged for deviation was about $44.20. In addition to this charge, resources do not receive cost reimbursement for any deviated megawatts in the event energy prices are lower than energy cost.
Figure 3–23  Frequency of net load change, real-time

![Figure 3–23](image)

Figure 3–23 represents decreases in net load and increases in net load for the year. Of the net load changes between real-time intervals, 95 percent were between a decrease of about 381 MW and an increase of about 359 MW. This is up from 2021 when the decrease was about 345 MW and the increase was about 330 MW. The 95th percentile net load changes, both positive and negative, increased by about nine percent in 2022, up one percent from 2021 changes, and a five percent increase from previous year’s trends. This means that the market is seeing a slow increase in net load swings. These changes in net load must be balanced by resources with a flexible dispatch range, or ramp capability.

Figure 3–24 below shows the volatility in net load change since 2014.

Figure 3–24  Volatility of interval-to-interval net load change

![Figure 3–24](image)
Net load volatility increased about eight percent from 2020 to 2021 and about ten percent from 2021 to 2022. For the most part, net load volatility has slowly increased since 2014.

As variable energy resources serve more load, volatility is expected to increase. Forecasted variable energy resources, wind and solar, produced about 38 percent of total generation. Of all intervals where these resources were on-line and available for economic dispatch, forecasted variable energy resources were expected to follow dispatch in about eight percent of resource-intervals, compared to about 80 percent for non-forecasted energy resources. When these forecasted resources are not following dispatch, it is possible for them to reduce the ramp need when they move in the same direction as demand, as long as they don’t overshoot demand by too much. However, they can also increase the amount of ramp need when they move in the opposite direction as demand or overshoot demand by a large quantity. When they increase the system ramp need, flexible, dependable resources are needed to account for the additional ramp they cause.

Figure 3–25 below shows the how much additional ramp was needed in real-time intervals due to undispatched, forecasted variable energy resources with the ramp that would have been needed for demand alone.

**Figure 3–25  Additional ramp need due to undispatched forecasted resources, 95th percentile, real-time**

When forecasted resources were not following dispatch, they increased the real-time system net ramp need in about 74 percent of intervals. The 95th percentile increase in net ramp need was nearly 800 MW in several months. This is almost four times the ramp needed to meet the 95th
percentile demand alone in these months. In contrast, undispatched forecasted resources decreased net ramp need by only about 180 MW at the upper end. Because the precise timing of the fluctuations of forecasted resources is unknown, rampable capacity must be committed and available throughout the day. This is even more challenging when the resources’ real-time output does not follow the forecast. While forecasted variable energy resources provide inexpensive energy, it comes at the cost of a greater need for more system ramp.

In any interval, resources typically have a range either above or below their current operating point that they can move to in the next interval. The rate at which they can move is their ramp rate. The total amount they can ramp is their rampable capacity. SPP operators count on this rampable capacity to meet future energy needs and to protect against uncertainty.

Figure 3–26 shows the average up-rampable and down-rampable capacity by month after energy and operating reserve obligations are accounted for.

Figure 3–26  Average rampable capacity

Although many factors affect available ramp, rampable capacity in the up direction, when averaged by month, was lowest in March, and highest in November. The amount of rampable

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Rampable capacity may be limited by a resource’s ramp rate parameter and/or maximum or minimum operating limit. When a resource is near its maximum operating limit, even though its ramp rate allows it to ramp quickly, the amount it can ramp up is limited.

The figures showing average rampable capacity are approximations. The market clearing engine allows for ramp sharing and also allows for some products to go short so that higher priority products can clear. There can be different amounts of rampable capacity available depending on the product. These graphs average the amount of load increase or decrease that would cause a shortage on the product that is nearest to a shortage.
capacity in the down direction is much larger than in the up direction when averaged by month, as shown above.

While the monthly averages do not change significantly throughout the year, the up-rampable capacity is on average about 28 percent higher and the down-rampable capacity is on average about 12 percent higher in 2022 than in 2021. The March implementation of the ramp capability product, covered in Section 3.2.3, had some effect on the increased volumes seen in the last 3 quarters of 2022.

Figure 3–27 shows the average rampable capacity in both the upward and downward directions by hour of the day.

Figure 3–27  Average rampable capacity, by hour

Rampable capacity in the up direction is lowest following the morning ramp in hours beginning 08, 09, 10, and 11. From hour beginning 12 until hour beginning 19, the rampable capacity increases slightly but remains lower. This is when load is relatively high for the day and resources operate closer to their maximums. As resources move closer to their minimum limits during the night, this rampable capacity increases. The ramp capability product is a step in the right direction to incentivize rampable capacity, but a design flaw, discussed in section 3.2.3, makes it unclear yet if prices based on lost opportunity will incentivize sufficient rampable capacity long term.

As previously mentioned, there is much more rampable capacity in the down direction than in the up direction. Although this rampable capacity is less in the early morning and late evening hours, this amount does not vary significantly throughout the day.
Ramp capability is needed to meet all of these changes in generation and load from interval to interval. A resource’s ramp rate is used to calculate its dispatch instruction. A resource will generally not be dispatched beyond the capability of the resource’s ramp rate. The ramp capability product, implemented in March 2022, procures ramp for expected uncertainty events in the subsequent 10-minute horizon.

3.2.3 RAMP CAPABILITY PRODUCT

The volume of scarcity events highlighted in Figure 3–13, illustrates the need for ramp capability. A resource’s ability to ramp should be part of the clearing and dispatch decision and should be valued at a price to the extent the ramp is beneficial to the market. The MMU believes that a properly designed ramp capability product will be beneficial to the market, as it will properly price the need for rampable capacity.

SPP has designed a ramp capability product, which was implemented on March 1, 2022.73 While the MMU generally supported the proposed design, the MMU did have some concerns with the design prior to implementation.74 In addition to these concerns, the MMU identified an issue after implementation with the deliverability of ramp cleared by the ramp-up capability product. The MMU pre-implementation concerns and the deliverability concerns are both discussed later in this section.

3.2.3.1 Ramping limitations affect market outcomes

The real-time dispatch does not consider future intervals. It simply calculates one value: a dispatch instruction for the next interval. While the real-time balancing market considers a resource’s ramp capability for the purpose of calculating the dispatch instruction for the next interval, ramp is not considered for any interval after that. Prior to the ramp product’s implementation, ramp needs were not accounted for in terms of the subsequent dispatch instructions even though ramp is the very capability that allows a resource to get to future dispatch instructions.

Not having ramp capability considered for future intervals, can cause the market clearing engine to not be able to procure enough energy to serve the load or provide sufficient operating reserves in those future intervals. Even when enough capacity is available, a lack of ramp renders that capacity unreachable. Moreover, sufficient ramp has typically been offered, by the market participants, but the clearing process has not left enough available for future use. When

73 See RR361, RR441, RR470, RR488, and Docket No. ER20-1617.
74 See MMU comments in Docket No. ER20-1617.
this occurs in the pricing run, it often leads to short-term transitory price spikes.\textsuperscript{75} Scarcity events in the dispatch run are shown in Figure 3–27.

### Figure 3–28 Interval length of scarcity events in the dispatch run

This figure shows that a scarcity pricing event in real-time was most likely to occur for only one five-minute interval. Comparably few scarcity pricing events last more than two intervals. This pattern has been consistent in recent years.

Figure 3–29 shows the interval length for the different types of scarcity events.

### Figure 3–29 Interval length of short-term price spikes, percentage

\textsuperscript{75} This is essentially temporal, or time-based, congestion.
Of all the regulation-up scarcity events, about 65 percent lasted for only one interval, and about 13 percent lasted for two intervals. For regulation-down scarcity events, about 70 percent lasted for only one interval, and about 16 percent lasted for two intervals. Operating reserve scarcity event lengths were more diverse with about 49 percent lasting for one interval, about 15 percent lasting two intervals, and about 7 percent lasting three intervals. These are roughly in line with 2021 results. For ramp-up scarcity events, 28 percent lasted one interval, and 14 percent lasted for two intervals. While ramp-up scarcity events decrease quickly as event length increases, like other products, there were many more ramp-up scarcity events, and they lasted longer. About a third of ramp-up scarcity events lasted longer than five intervals. Though relatively few, some ramp-up scarcity events lasted over 60 consecutive intervals. There were no ramp-down scarcity events.

Where sufficient capacity cannot be dispatched, scarcity prices are invoked. Scarcity prices are economic signals alerting market participants to the insufficient supply of a product. Almost all of these intervals with scarcity pricing were due to a lack of cleared ramp and not a lack of capacity. If sufficient ramp were reserved in advance for these scarcity intervals, then these scarcities likely could have been avoided. Ramp availability increased in previous years, but scarcity events have also increased, highlighting the continued need for systematic ramp procurement. The ramp capability product was expected to help reduce these transient scarcity events.

In addition, marginal energy prices can be elevated even when energy is not scarce. When ramp in the up direction is short, energy will always be given the highest priority. If there is not sufficient ramp to meet both energy and regulation-up, for instance, then the regulation-up scarcity price will be reflected in the marginal energy price. This causes a high marginal energy price even though there is no energy scarcity because the two products are competing for ramp. This makes energy prices more volatile. If sufficient ramp had been available, then regulation-up scarcity prices would not have raised the marginal energy price. A well-designed ramp capability product can ensure that more rampable capacity is available to meet energy so that regulation-up scarcity prices can be avoided. This helps to better reflect system conditions and reduces dispatch volatility.

3.2.3.2 Design of the ramp capability product

In the 2017 annual report, the market monitor recommended that SPP create a ramp capability product. SPP implemented the ramp capability product on March 1, 2022.76

76 See RR361, RR441, RR470, and RR488 and Docket No. ER20-1617.
The ramp capability product design optimizes the resources’ dispatch instructions over a ten-minute period to allocate any economically available ramp for the interval starting ten minutes in the future. Future ramp needs get met by pre-positioning online resources with available ramp if the cost of this action is less than the applicable ramp-scarcity demand curve price. The ramp requirement is set to procure enough ramp to meet forecasted net load changes plus an amount to cover unexpected net load changes based on historical needs. The ramp product optimizes only online ramp. Off-line ramp is not eligible to clear the ramp capability product, due to the short 10-minute clearing horizon. A market-clearing price will be set by the opportunity cost of providing other products. Figure 4-25 displays the average day-ahead and real-time ramp capability-up market clearing prices.

As shown in Figure 4–25, the average real-time market clearing prices for ramp-up averaged $5.69/MWh for the ten months it was in effect for 2022, while the average day-ahead prices only averaged $2.29/MWh. The disparity between the two markets prices stems from an issue discovered with resources clearing ramp capability-up behind binding constraints. This issue is described, in detail, below in section 3.2.3.2.1. The price for ramp-down was zero for every interval during the year for both real-time and day-ahead markets illustrating that the marketplace has a lesser need for rampable capacity in the down direction.

Figure 3–30 and Figure 3–31 below show the day-ahead and real-time cleared ramp-up megawatt hours for each product by fuel type.

**Figure 3–30** Day-ahead cleared ramp-up by resource type
As can be seen in the two above charts the vast majority of ramp capability-up is cleared by wind and natural gas resources. These figures also show that wind resources clear a greater percentage in the day-ahead market than the real-time market. Sixty-three percent of the ramp capability-up cleared in the day-market was cleared by wind, as compared to only 50 percent in cleared by wind resources real-time.

In winter 2022, the market monitor evaluated the effectiveness of the newly implemented ramp product, and discovered a design issue. This issue along with the market monitor’s other preimplantation concerns are addressed below.77

3.2.3.2.1 Ramp capability-up procured behind binding constraints

The MMU was concerned with the trend of day-ahead ramp capability up scarcity events being roughly two and a half times the frequency of real-time ramp capability up scarcity events.78 This is not a logical trend as there is far less uncertainty in the day-ahead market than the real-time market. In the day-ahead market, resources are considered to always stay on dispatch, forecasted outputs are assumed to be in line with forecasted quantities, and resources are not considered to trip. These assumptions do not hold true in the real-time market, so typically there are far more regulation and operating reserve shortages due to ramp limitations in real-time than day-ahead.79

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77 See MMU comments in Docket No. ER20-1617.
78 See Figures 3-13 and 3-14.
79 See Figures 3-13 and 3-14.
The reason for the disparity between day-ahead and real-time ramp shortages has to do with how ramp capability-up is accessed for clearing. The resource owners do not offer a cost for either ramp capability-up or -down. Instead, the products clear solely based off their opportunity costs for not clearing other products, such as energy. For instance, if a resource had an energy locational marginal price of $35/MWh and marginal energy cost of $30/MWh, the opportunity cost for ramp capability-up would be $5/MWh. This means that the price for ramp capability-up will need to be at least $5/MWh for this resource to clear the product. However, all dispatchable resource types with available ramp may participate in clearing this product, and congestion is not considered in the clearing. This means that a resource behind a constraint may have a negative $65/MWh energy locational marginal price and marginal energy cost of $10/MWh. In this case, this resource’s opportunity cost would be negative $55/MWh. The market-clearing engine considers all negative opportunity cost to have $0/MWh opportunity costs.

There is a disconnect with the assumptions used in the clearing of the ramp capability product and the actual deployment of the ramp. When the market clearing engine goes to deploy the ramp cleared behind the constraint, it is often too expensive to meet the ramp needs in the market. This can make the market go short products, when the cost of congestion relief costs are higher than the scarcity demand curves. In the example above, the negative $55/MWh opportunity cost will likely get more negative as the resource gets dispatched up for ramp. When the costs to ramp-up the resource get higher than the scarcity or violation relaxation limits the market will go scarce the product and price it with the associated scarcity price. Ramp capability scarcity demand curves are discussed in section 3.2.3.2.2.

Figure 3–32 below shows the megawatts of ramp capability-up cleared on resources with shift factors on a binding or breached constraint in the real-time market.
The above graph illustrates that there is a large percentage of ramp capability-up being cleared behind a binding or breached constraint in the real-time market. The negative values represent resources with shift factors that increase congestion on a constraint, thus decreasing the ability to deliver ramp-up to the market. This is a leading contributor to the market not being able to use the ramp procured. SPP is working on solutions to reduce the effects of stranding ramp behind constraints.

3.2.3.2.2 Ramp product demand curve prices are likely too low

The ramp product prices scarcity with a demand curve. The MMU had concerns that the demand curve prices for ramp are likely too low. Prior to implementation, there was a concern that low prices may not allow the market to provision rampable capacity even though it is available. Consequently, physical ramp may be insufficient, and the price may not reflect the actual value of ramp, which undermines the purpose of a ramp product.

The MMU recommended that the maximum demand curve price be set slightly below the minimum regulation demand curve price. Avoiding regulation scarcity events in the future is the primary goal of a ramp product. A higher scarcity price may be needed to clear physical ramp and to incentivize ramp capability. The MMU reviewed the ramp-up and ramp-down scarcity demand curve’s effectiveness. Ramp-down has had a $0/MW market clearing price since implementation in March. This is due to the abundance of rampable down capacity available in the market, as shown in Figure 3–26, above.

As stated before, ramp capability-up did have scarcity in both day-ahead and real-time markets. However, the MMU was unable to analyze the effects of the ramp-up demand curves, due to the
issues discussed in the previous section concerning the deliverability of the procured ramp capability-up. In order to assess the effectiveness of the demand curves, we recommend that SPP staff evaluate the effectiveness of the demand curves when assessing solutions to the stranded ramping issue. There were no concerns with ramp capability-down scarcity demand curves as the product never went scarce in either day-ahead or real-time.80

3.2.3.2.3 Reduced need for instantaneous load capacity

The process known as instantaneous load capacity is ramp procurement without ramp payment. The instantaneous load capacity ensures that sufficient rampable capacity is committed to ramp from one average hourly load to the next. Resources committed to provide this rampable capacity add value to the market but are not paid for that value. These resources often run at a financial loss for most of the hour and are merely made-whole to their costs. The instantaneous load capacity requirement is not removed or reduced by the proposed ramp product. If more than one ramping timeframe is needed for more than one ramping purpose,81 then the market monitor could support multiple ramp products.

SPP is working to implement an uncertainty product that will work similarly to the ramp product, with a one-hour time horizon, and off-line resources will be able to participate.82 The MMU believes that this product, in conjunction with the ramp capability product, should significantly reduce the need for the use of committing the uncompensated capacity, currently defined as instantaneous load capacity. The MMU will evaluate the effects of both products in the day-ahead and real-time market after implementation of the uncertainty product and also after deliverability issues are addressed for the ramp capability-up product.

3.2.4 UNCERTAINTY RESERVE PRODUCT

SPP has proposed an uncertainty reserve product that has been approved by FERC and is slated to go into production on July 6, 2023.83 The uncertainty reserve product is designed to provide one-hour rampable capacity. Both on-line and off-line resources will be able to clear, though off-line resources are not eligible to be made whole for fixed costs. This product will clear in both day-ahead and real-time markets.

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80 See Figures 3-13 and 3-14.
81 For instance, it may be appropriate to have a ramp product similar to instantaneous load capacity to address inter-hour ramping needs in addition to an intra-hour ramp product to address short-term load variability.
82 See RR449, FERC Docket No. ER22-914.
83 See RR449, FERC Docket No. ER22-914.
The MMU has noted some concerns with the uncertainty product design, and will monitor the implementation and make recommendations if necessary. Issues discussed in section 3.2.3.1 with the ramp capability product clearing undeliverable rampable capacity will also be present for the uncertainty product, once implemented. SPP stated they plan to apply similar corrections to the uncertainty product as those used to correct deliverability of the ramp capability product. Those corrective actions are not identified at this time.

The MMU also has concerns that the proposed uncertainty product may clear in amounts less than an off-line resource’s minimum limit. Because the proposed design does not make off-line resources eligible to be made whole to their fixed costs, clearing below their minimum limit could make it difficult to represent those costs in their offers. Also, a resource’s minimum will actually be produced if it comes on line, so the MMU believes that a resource’s minimum limit should be the minimum a resource can clear for uncertainty reserve. Market participants may respond to this by increasing their offer enough to recover these costs with a small clearing amount. This, however, can over represent costs, which can cause the demand curve to clear before physical generation. However, if market participants do not increase their offer while clearing below their minimum limit, they could under-recover their costs. Addressing this concern would require significantly more complicated software, which would increase solution times.

The MMU is also concerned that the maximum price on the demand curve is at 20 percent scarcity. Having the maximum price so low on the stepped demand curve could cause the demand curve to clear uncertainty reserves rather than physical resources. The MMU will monitor these issues after implementation and will make recommendations as necessary.

### 3.3 SELF-COMMITMENTS

The purpose of the centralized unit commitment processes is to commit sufficient resources to serve load, subject to transmission and resource constraints, while minimizing cost. The centralized unit commitment process is able to minimize commitment costs because it has information, such as the amount of capacity required, the current transmission topology, the parameters of each resource, and the current state of each transmission and resource constraint.

The idea behind centralized unit commitment is essentially this: In the same way a team will likely realize better outcomes when the coach selects both the players and plays, the Integrated

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84 See Motion to Intervene and Comments of the Market Monitoring Unit of Southwest Power Pool, FERC Docket No. ER22-914.
Marketplace will also probably realize better outcomes, for the collective, when it commits units in addition to dispatching them. While the team’s record might be the same regardless of who is on the field, it is unlikely that the plays called, points scored, or yards gained would be the same.

Much like players choosing when to play, the SPP market allows participants to self-commit resources rather than have the market choose which units to run. While there may be good reasons for this, the practice can distort prices, offer and bid behavior, market outcomes, and investment signals.

Figure 3–33 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.

Figure 3–33  Percentage of megawatts dispatched by commitment status

The volume of dispatched megawatts from self-committed resources remains nearly one-third of the total dispatch megawatt volumes. In other words, nearly one-third of the energy produced in 2022 was from a resource that was not economically selected by the day-ahead market’s centralized unit commitment process.

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85 For more detail on this and other metrics, see the MMU’s whitepaper on self-commitment, **Self-committing in SPP markets: Overview, impacts, and recommendations**.

86 Reliability unit commitments that continued to run in the day-ahead market were considered a market commitment.
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 3–34 shows dispatch megawatts by fuel type by commitment type for each year of the study period.

**Figure 3–34  Dispatch megawatt hours by fuel type by commitment type**

While resources of various fuel types self-commit, coal resources have produced and continue to account for the largest portion of self-committed megawatts. After declining by 19 percent from 2020 to 2021, Coal self-commitments increased by seven percent from 2021 and 2022. Additionally, after decreasing by three percent from 2020 to 2021, wind self-commitments increased by 23 percent from 2021 to 2022.

Resource lead-times, also called start-up times, are time-based operational parameters that vary widely by fuel type. In the Integrated Marketplace, resources can submit three different lead times: cold, intermediate, and hot. Thermal resources generally have longer lead times when they are cold as opposed to when they are hot. In the following section, lead times by commitment status and fuel type are examined.

Figure 3–35 shows the relationship between commitment status and start-up time.
Self-committed resources tend to have longer lead times than market-committed resources. Because the centralized unit commitment must observe constraints other than cost, such as lead time, it may continue to run a unit even when the marginal price falls below that unit’s offer.

Nuclear units have the longest cold start-up time, followed by coal and natural gas.

Start-up offers are generally representative of the cost that a market participant incurs when starting a generating unit from an off-line state to its economic minimum and the cost to eventually shut the unit down. These offers are submitted in terms of dollars per start.

Figure 3–36 shows the relationship between commitment status and start-up cost.
Many of the units with high start-up costs have minimum run times that extend past the day-ahead market window. If the optimization evaluated start-up costs over each resource’s full minimum run time, their start-up offers would be more competitive with shorter lead-time resources. This issue compounds for those resources with long lead times and high start-up costs. Because these units cannot come online until much later than the first hour of the day-ahead market day, their start-up cost is optimized over even fewer hours. Somewhat similar to lead-time, coal units have the highest cold start-up cost, followed by nuclear and natural gas.

Self-commitment represents a significant portion of the transaction volume in the Integrated Marketplace, and while it cannot be eliminated completely, the practice can likely be reduced substantially. By reducing self-commitment, prices and investment signals will likely be less distorted. A smaller distortion will likely help market participants make better short-run and long run decisions, which tends to coincide with improved market efficiency and profit maximization.

While the MMU has seen gradual reductions in self-commitments over the last few years, generation from self-committed generators still represents about one-third of the generation in the SPP market. Given its significance, the MMU recommends that the SPP and its stakeholders continue to find ways to further reduce self-commitments including developing a multi-day economic assessment.87

3.4 GENERATION OUTAGES

Generators cannot run constantly at full capacity and occasionally need to be out of service or derated. When a generation resource is out of service, its entire capacity is unavailable for dispatch. When a generation resource is derated, a portion of the capacity of the generation resource is unavailable for dispatch. Unless otherwise specified, outaged capacity refers to both out-of-service and derated unavailable generation.

Two major reasons for generation outages are generator maintenance and a forced event, such as an equipment failure. Generally, maintenance outages are planned or scheduled in advance in order to perform routine work, whereas forced outages are generally not scheduled and are difficult to predict in advance.

SPP assesses outages to determine real-time and future reliability of the bulk electric system. As the reliability coordinator and balancing authority, SPP approves, denies, or reschedules outages

87 Chapter 7, recommendation 2017.4 “Address inefficiency caused by self-committed resources” for more information.
to ensure system reliability. The outage coordination methodology  
SPP Reliability Coordinator Outage Coordination Methodology. 
SPP’s mission statement says that it will “economically keep the lights on.”  
Practically speaking, the more efficient and effective the market, the more economic incentives drive behavior that increase reliability. However, circumstances exist that are not promoting reliability through economic incentives. Some of the circumstances exacerbating the separation of economics from reliability in the market are outage driven.

3.4.1 OVERVIEW
Outaged capacity has historically trended upward. However, in 2020 outaged capacity decreased, an anomaly due in large part to effects of the COVID-19 pandemic. In 2021, outaged capacity resumed the normal upward trend, increasing overall from the previous year by 11 percent. In 2022, the outaged capacity dropped seven percent from 2021. The higher levels of outaged capacity in 2021 may be explained by maintenance that was deferred from 2020 that was performed in 2021.

Overall in 2022, there was a slight decrease of outaged capacity likely due to normalizing of outaged capacity after the catch-up period in 2021. More specifically, maintenance outages decreased by nine percent while forced outages had a slight increase of two percent. Resulting in an overall decrease of outaged capacity between 2021 and 2022 of four percent. This can be seen in Figure 3–36, which shows capacity derated and taken out-of-service by reason—forced or maintenance.  
Each reason is further categorized by fuel type.

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88 SPP Reliability Coordinator Outage Coordination Methodology.
89 https://www.spp.org/about-us/, emphasis added.
90 For purposes of this study, forced outages include forced, emergency, and urgent outage priorities. All other outage priorities, planned, opportunity, and operational, are classified as maintenance. Excess capacity/economic and upcoming model change outages are excluded from the results. Derated resources are still available to the market at a reduced capacity. Out-of-service resources are entirely unavailable.
As in previous years, capacity taken out-of-service for maintenance accounts for the largest portion of outaged capacity. This is followed by capacity forced out-of-service; then by forced derates; and finally by maintenance derates. Coal provided about 33 percent of total generation\(^\text{91}\) and accounted for about 33 percent of outaged capacity in 2022. Combined cycle gas provided about 13 percent of total generation and about 15 percent of outaged capacity, a similar ratio to coal. However, simple-cycle gas provided about eight percent of total generation, but about 34 percent of outaged capacity, a much higher ratio than coal or combined-cycle gas. The amount of capacity on outage is largely influenced by the amount of generation, but simple cycle gas has the highest rate of outaged capacity per generation. Currently, simple-cycle gas capacity is accredited the same in the resource adequacy process as coal and combined-cycle gas.

\(^{91}\) See Figure 2–20.
Figure 3–37 shows outaged capacity for long-term outages and derates greater than seven days.

**Figure 3–38  Long-term outages, greater than seven days**

Outages and derates lasting longer than seven days are considered long-term. The majority of long-term outaged capacity is for maintenance. Overall, long-term outaged capacity decreased by about four percent from 2021 to 2022. However, misuse of long-term outages remains a concern.

Specific areas of concern are:

- placement of units on long-term outages during known or anticipated retirement;
- entry into the market, new construction projects;
- repowering projects;
- standing derates increasing in magnitude as wind farms age; and
- scheduling long duration outages during summer and/or winter peaks.
Figure 3–38 shows outaged capacity for short-term outages and derates of seven days or less.

**Figure 3–39  Short-term outages, seven days or less**

Outages lasting seven days or less are considered short-term. The majority of short-term outages are forced outages. Overall, short-term outages decreased about six percent from 2021 to 2022. Although there are multiple factors that contribute to the occurrence and completion of outages, the MMU remains concerned about the use of short-term forced outages, especially of accredited capacity.

When it comes to outages, 2020 can be viewed as an outlier due to the unusual conditions produced by the COVID-19 pandemic. Overall, the MMU is concerned about outages as outages affect both reliability and market efficiency. The MMU maintains that while some progress has been made there remains a lack of appropriate incentives to promote resource availability.

### 3.4.2 INSUFFICIENT INCENTIVES TO BE AVAILABLE

Even though there are legitimate reasons for resources to be on outage, proper incentives can promote reliability. A robust market design can help prepare for the best possible response to unforeseen difficulties by appropriately incentivizing availability through appropriate price formation, generation availability compensation, or true up, such as a claw back or receiving appropriate credit for resource adequacy.

In 2022, the Improved Resource Availability Task Force (IRATF) and Supply Adequacy Working Group (SAWG) reviewed recommendations from the Generator Testing Task Force (GTTF) to improve the accuracy of accreditation through a performance-based methodology. Stakeholders ultimately approved the option to use equivalent forced outage rate (EFORd’) to
adjust installed capacity for forced outages within management control. While this is a step in the right direction, the MMU ultimately believes this proposed accreditation process will fall short of providing any true incentive for availability.

### 3.4.2.1 Real-time and day-ahead market incentives

Historically, the SPP market tends to have relatively low prices as evidenced in Figure 4–1. As shown in Figure 2–5, on aggregate, load cleared nearly 100 percent of its real-time consumption in the day-ahead market. Typically, real-time generation procurement is not due to a load gap between day-ahead and real-time.

Low prices in the real-time and day-ahead markets are less likely to provide financial incentive for generators to complete maintenance and/or repairs as soon as possible. MISO provides a price floor during a maximum generation event based on the highest non-emergency offer.\(^\text{92}\) ERCOT removes some reliability units from pricing and applies a risk adder to the price in certain situations.\(^\text{93}\) In SPP, during conservative operations, resources have historically been paid large amounts in make-whole payments, while the prices were relatively low.

Price spikes in the SPP market are generally transient in nature. However, prices remained relatively high for a relatively long duration during the 2021 winter weather event. Otherwise, the generally low market prices during emergencies do not adequately reflect the value of reliability while large out-of-market payments are not transparent and do not properly inform investment decisions such as generator improvements, new generation, demand response resources, or imported energy. In order for maintenance and repair costs to be recovered, the value a resource provides must be reflected in some type of market price. A market price could also inform generators about the most reliable time to take outages. The current pricing mechanisms are not sending proper price signals to incentivize generation availability.

As noted in response to the February 2021 winter weather event, the MMU recommended that SPP and its stakeholders review price formation rules to consider if prices appropriately incentivize generation availability during emergencies and outages and would likely reduce outage volume and duration and increase the value of fuel certainty.

### 3.4.2.2 Resource adequacy incentives

The purpose of accrediting capacity to fulfill a Resource Adequacy Requirement (detailed in Attachment AA of the SPP OATT) is to ensure Load Responsible Entities (LREs) will be able to cover their net peak demand and that, on aggregate, SPP will have enough generation to cover

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\(^{92}\) *MISO Tariff*, Schedule 29A. II. D.

\(^{93}\) *ERCOT Protocols*, Section 6.5.7.3.1
system wide net peak demand with a probability of shedding load of one day in every ten years. Currently, SPP has a resource adequacy requirement for the summer season, and evaluates anticipated availability of summer capacity on February 15. While the RTO’s process may assess capacity, it does not assess availability of that capacity.

Currently, the tariff lacks appropriate incentives for resources to remain available as there is no mechanism that addresses units that were claimed as capacity but become unavailable after February 15. LREs who have capacity that is accredited but is unavailable for the entire summer will not be subject to the capacity deficiency payment, the main tariff mechanism incentivizing LREs to carry an appropriate level of capacity. Without a mechanism to incentivize or ensure availability, there is a disconnect between the capacity SPP accredits for resource adequacy and the actual capacity available to operate the system reliably.

Additionally, the resource adequacy requirement omits capacity shortages in non-summer months as there is currently no resource adequacy requirement for winter, spring, or fall. Capacity shortages have been seen across every season, potentially compromising system reliability. For instance, capacity shortages can occur during extreme winter weather, such as the February 2021 winter weather event or the December 2022 winter storm. In both cases, a large portion of capacity accredited for the Summer Season was not available due to system shocks such as fuel deliverability and quality issues, equipment failures, and when wind resources experience icing and/or conditions outside of their operating threshold/tolerance. Planning for peak summer days as the only shock to capacity availability lacks the necessary complexity to ensure reliability year-round.

In numerous forums, SPP operations has described the importance of the availability of schedulable resources with a dependable fuel source due to the volatility of variable energy resources and system shocks such as adverse weather or pipeline outages. As outlined in section 2.9.2, the Improved Resource Availability Task Force (IRATF) and the Supply Adequacy Working Group (SAWG) reviewed the resource accreditation process in 2021, ultimately recommending to adopt a single summer season performance based accreditation (PBA) process using equivalent forced outage rate demand (EFORd) for conventional resources. This process would adjust the installed capacity of resource accounting for forced outages, which would bring accreditation closer in line with expected availability, but would still fall short of

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94 SPP Open Access Transmission Tariff, Sixth Revised, Volume No. 1, Attachment AA, Section 9
95 SPP Stakeholders are currently reviewing a Revision Request that would convert the Winter Season Obligation to a full Resource Adequacy Requirement
96 See “GTTF Performance Based Accreditation Recommendations for Conventional Resources” published by the Generator Testing Task Force.
being accurate. For variable energy resources, SPP adopted effective load carrying capability (ELCC) methodology. This methodology is more detailed, taking into account how much of installed capacity can be delivered given all other variable energy resources on the system.

The tariff design of performance-based accreditation is currently going through the stakeholder process but will likely be submitted to FERC later this year. ELCC was approved by FERC in August but later reversed in March 2023. In their reversal, FERC determined that SPP’s accreditation approach of assessing capacity differently for different resources was unduly discriminatory. In addition, in a concurring opinion, Commissioner Clements expressed that the current accreditation process and any proposed accreditation process for just conventional resources is likely to not meet FERC’s standard of just and reasonable and would be likely be deemed unduly discriminatory.

Even with the work SPP and its stakeholders have done toward creating a more accurate accounting of capacity, there is still nothing in the resource adequacy requirement that would mandate a minimum level of realized availability. The MMU believes it is essential for the RTO to have accurate accounting of the registered capacity that is realistically deliverable, the portion available for dispatch, and incentives or disincentives to ensure that SPP’s expectation of availability mirrors actual availability.

To ensure not only adequate capacity but that that capacity is deliverable when needed, the MMU recommends SPP and its stakeholders pursue mechanisms that would improve the availability of accredited capacity to ensure market participants have sufficient resources available to reliably serve load and planning reserve obligations year round. There are numerous ways to potentially achieve this. However, the MMU strongly recommends an approach where LREs need to either offer enough to cover their load at all times or compensate another entity whose unused and unobligated capacity was used to cure any deficiency (see recommendations in Section 2.9 for more details).

While there is no way to be absolutely certain that capacity will be available in real-time, incentives can provide much more certainty than that exists with today’s steel-in-the-ground capacity requirement. A sufficient requirement and accurate measurements of available capacity balance the plan to serve load reliably. SPP and its stakeholders should continue to work on

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97 *SPP Open Access Transmission Tariff*, Sixth Revised, Volume No. 1, Attachment AA, Section 9

98 The Market Monitor is advisory in nature and presents possible solutions from an economic perspective. Other solutions of a regulatory nature are also under consideration by SPP.
mechanisms that reward resources that perform more reliably and are available when needed by SPP operations.

3.4.2.3 Outage coordination methodology

The outage coordination methodology is SPP’s process document for scheduling outages. The Generator Outage Task Force recommended changes to the outage coordination methodology for better alignment with North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS) and for increased accuracy and flexibility of generator outage reporting. This includes alignment of the outage coordination methodology reporting threshold with SPP’s registration threshold by decreasing it from 25 MW to 10 MW for accredited resources. Decreasing the outage or derate reporting threshold is intended to increase transparency and more accurately predict unavailable capacity which is especially important during reliability events such as conservative operations and energy emergency alerts (EEAs).

Other improvements being implemented to the outage coordination methodology include decreasing the priority types from six down to three; updates, additions, and deletion of cause codes to improve accuracy and transparency of outage scheduling; and increasing the forced generation outages maximum lead-time to seven days maximum.

Resources in reserve shutdown that can be recalled, started, and synchronized within seven days are not required to report the outage to SPP. This rule allows resources to take an outage without the knowledge or approval of SPP. Furthermore, there is no guarantee, or even attempt to consider, if an emergency condition may occur during this time. The Generator Outage Task Force endorsed changes to the outage coordination methodology to require review of all reserve shutdown outages and to provide approval through the existing outage scheduling approval process.

The outage coordination methodology requires a reason and planned end date for the outage at both the time of the outage submittal and at the submittal of each change. An exception is that a forced outage can be submitted with an unknown cause, but the cause and planned end date are required to be updated promptly as soon as more information is known. The MMU has observed insufficient, omitted, delayed, and incorrect outage information. The MMU maintains material misstatements of outage information could be considered providing false information to the RTO and may result in referral to FERC. SPP’s roadmap initiative intended to resolve this market deficiency was recently given the lowest priority, effectively marking this item not to be evaluated again until SPP’s roadmap is reassessed. Because outage submissions are intended to

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99 18 CFR § 35.41
be used for assessing real-time and future reliability of the bulk electric system, the MMU continues to recommend that SPP enhance the outage coordination methodology.

Additionally, an outage's original scope of work cannot always be completed in the original scheduled timeframe. Therefore, the current outage coordination methodology allows an outage to be extended. However, outage extensions can reduce efficiency of the outage coordination process. Regardless of the outage extension priority, outage extensions are approved similar to the way new forced outages are approved as the highest priority. Therefore, outage extensions have the potential to be inappropriately prioritized higher than new outages, resulting in denial of the new outages. The MMU has observed outages extended for reasons different than the original outage reason, resulting in misclassified and nontransparent outage extensions. The trend of outage denials is increasing as the maintenance margin becomes tighter over time making accuracy and transparency in the outage scheduling process of increasing importance. The GOTF did not determine an endorsed path forward to close the gap of potential gaming opportunities of the current outage extension process. For some performance-based resource adequacy calculations, misclassified outages could affect the amount of capacity accredited under SPP’s approved performance-based accreditation approach. Misclassified outages can also affect out-of-market budgetary items, such as state recovery rates and taxes.

Similar to forced outages, outage extensions decrease the amount of available maintenance margin. The unexpected nature of outage extensions can adversely affect other processes such as the congestion hedging market. Figure 3–40 shows generator outage extensions that are greater than one week by duration.

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100 *SPP Reliability Coordinator Outage Coordination Methodology*, Section 1
101 SPP allows a limited amount of planned megawatts on outage at any given time, referred to as the maintenance margin.
The amount of outage extensions continue to increase. Outage extensions can make outage coordination less efficient and can affect other downstream processes. The MMU remains concerned about the improper use of outage extensions, especially outage extensions of long duration. In 2022, there were 830 outages extended longer than one week, an eight percent uptick from 2021. The MMU encourages SPP to implement processes and mechanisms to properly schedule, classify, report, and prioritize outage extensions.

### 3.4.2.4 Generation assessment process

SPP implemented the generation assessment process in 2020 for outage scheduling to help ensure capacity adequacy. The generation assessment process analysis determines maintenance margin, which is the amount of capacity allocated for generator maintenance outages. Original implementation was at the daily level for both the short-term, seven-day maintenance margin forecast, and the long-term, greater than seven days maintenance margin forecast. In 2021, SPP implemented the Generator Outage Task Force (GOTF) recommendation to further refine the short-term maintenance margin to hourly to make the maintenance margin more accurate. The adjustment to a more granular short-term maintenance margin forecast allows for additional maintenance margin during off-peak hours, to accommodate weather-related outages for renewables, and to increase short-term transparency for the most concerning intervals, such as high demand low wind forecast intervals.

Additionally, the Generator Outage Task Force recommended a predictive generation assessment process impact study to evaluate impacts on outage scheduling due to increased
variable energy entry and thermal resource retirements. This study is intended to predict whether future maintenance margins will be sufficient for generator maintenance and to determine if there is a need for the resource adequacy process to align with the generation assessment process. The MMU encourages SPP to complete this study and continue improving outage scheduling.

3.4.2.5 Communication and transparency
SPP recognizes relationships as a key element of successful operation of the bulk electric grid. Email distribution lists are a way SPP disseminates information quickly to appropriate stakeholders. SPP has implemented the Generator Outage Task Force recommendation of distribution lists for generator operators and owners to improve communication and transparency for items such as generation assessment process and the outage coordination methodology.

3.4.2.6 Pipeline availability
Gas generator outages may be the result of natural gas pipeline maintenance. Generally, the natural gas industry takes pipeline outages during its low demand period, which is typically the summer. These pipeline outages often coincide with peak annual electric demand. Specifically, resources with interruptible service often experience interruptions. Additionally, the natural gas industry can experience low supply and high demand scenarios during winter weather events. Pipelines can charge shortage prices, or stop filling nominations made after the timely cycle. Even firm gas can be interrupted during shortages or limited deliverability. A secondary fuel source and/or a stored fuel source tends to be more dependable than firm gas. Incentives are insufficient to change behavior for these predictable generation shortages. Rules should measure dependability and availability of the generation fleet and incentivize sufficient procurement of firm natural gas service as well as investment in secondary and/or stored fuel sources for capacity resources.

Toward this end, SPP and its stakeholders are making progress. The Improved Resource Availability Task Force (IRATF) was created to address fuel assurance and resource availability policies recommended from the Comprehensive Review of SPP’s Response to the February 2021 Winter Storm report.103 Final revision requests addressing fuel supply and dual-fuel capability are currently scheduled to be completed in September 2023. The MMU supports revisions that properly incent investment in these reliability attributes.

103 https://spp.org/documents/65037/comprehensive%20review%20of%20spp's%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf
3.4.2.7 Fuel procurement

Although SPP and market participants made adjustments to the day-ahead market commitment schedule through the stakeholder process, natural gas timely nominations are still due prior to market participants receiving their commitment schedule.\(^{104}\) Depending on the pipeline’s capacity and the type of service the gas generator has, this could have multiple undesired consequences.

First, a market participant could opt not to procure fuel without a day-ahead commitment. If the generator receives a day-ahead commitment or a reliability unit commitment, the market participant will likely pay a premium to procure fuel in a non-timely cycle. Additionally, at times of low pipeline capacity, non-timely cycle purchases are more likely to be curtailed. In this case, without a secondary fuel source or backup fuel, the market participant may have to buy back its day-ahead position at real-time prices and/or pay make-whole distribution charges. The MMU does not accept mitigated offers that include the generator owner’s risk of premiums for non-timely procurement of fuel.

Second, a market participant could opt to procure fuel without a day-ahead commitment. If the generator does not receive a day-ahead commitment or a reliability unit commitment, the market participant could be charged natural gas fees, typically referred to as parking fees in dollars per MMBtu. The parking fees are generally assessed per day until the fuel is moved from the pipeline.

Rules should incentivize procurement of the most reliable lowest cost natural gas service, firm timely natural gas service, when appropriate, as well as investment in secondary and/or stored fuel sources for capacity resources. The Improved Resource Availability Task Force addressed several initiatives put forth by SPP and the MMU in this area in 2022. This included looking into the value of requiring firm fuel contracts to ensure reliability and into possible gas-electric coordination. However, their efforts to date have not translated into any proposed policy or operational changes.

\(^{104}\) Docket No. ER19-2681.
4 MARKET PRICES AND COSTS

This chapter covers market prices and costs in the SPP market, along with related metrics on negative prices, make-whole payments, and long-run price signals for investment. Highlights of this chapter include:

- Average gas price for 2022 at the Panhandle Eastern hub was $5.83/MMBtu, up 70 percent from 2021 at $3.44/MMBtu with February excluded. Comparing to the full 2021 year, the average gas price was up 18 percent from 2021.

- The day-ahead market price for 2022 averaged $48/MWh, an increase of 80 percent from $27/MWh in 2021 with February excluded. Had February been included, the full year price for 2021 was $63/MWh.

- The real-time market price was $43/MWh for 2022, up 75 percent from $25/MWh in 2021 with February excluded. Had February been included, the full year price for 2021 was $37/MWh.

- The frequency of negative priced intervals decreased by eight percent in the day-ahead market and increased by three percent in the real-time market over 2021. Over 15 percent of all asset owner intervals in the real-time market had negative prices, slightly up from just under 15 percent in 2021. Just above seven percent of the day-ahead asset owner intervals had negative prices, down from almost eight percent in 2021. The MMU remains concerned about the frequency of negative price intervals. Negative prices may not be a problem in and of themselves, however, they do indicate an increase in surplus energy on the system and/or an increase in available low-cost generation.

- Day-ahead make-whole payments for 2022 totaled $173 million compared to $75 million in 2021 with February excluded, a 130 percent increase. Much of the increase can be attributed to higher gas prices in 2022. The 2021 day-ahead make-whole payments for the full 2021 year totaled $980 million.

- Reliability unit commitment make-whole payments totaled $292 million for 2022, up 152 percent from $116 million 2021 with February excluded. Like day-ahead make-whole
payments, much of the increase can be attributed to higher gas prices in 2022. The 2021 reliability unit commitment make-whole payments for the full 2021 year totaled $354 million.

- For 2022, one resource received $19 million dollars in make-whole payments, and in total only four resources received over $10 million in make-whole payments for the year. On a market participant level, 12 participants received over $10 million in make-whole payments, accounting for 89 percent of total make-whole payments.

- Total revenue neutrality uplift for 2022 was $548 million, up 92 percent from 2021, and up ten-fold from $54.7 million in 2020. The majority of the increase can be attributed to the real-time congestion component of revenue neutrality uplift, which was $653 million in 2022, an increase of 189 percent from $226 million in 2021. The SPP RTO is continuing to study this increase in revenue neutrality uplift.

- Historically, revenues have been insufficient to support the cost of new entry of scrubbed coal, advanced combined-cycle, advanced combustion turbine generation, wind, and solar photovoltaic since the inception of the Integrated Marketplace. (An exception was 2021 due to increased revenue because of the February winter storm.) This analysis shows that, in 2022, only wind resources would be able to recover their cost of entry.

### 4.1 MARKET PRICES AND COSTS

This section reviews market prices and costs by focusing on the energy market and fuel prices, price volatility, negative prices, operating reserve prices, and market settlement results. Overall, annual energy prices were up from previous years in both the day-ahead and real-time markets. This increase can be mostly attributed to two main contributors, the February winter weather event and the increase in fuel prices—primarily gas but also coal—even with an increased share of wind in total generation in 2021. Furthermore, the 2021 percentage of negative price intervals saw a substantial increase in the both markets, when compared to previous years.
**4.1.1 ENERGY MARKET PRICES AND FUEL PRICES**

Figure 4–1 below compares day-ahead and real-time prices\(^{105}\) in SPP between 2014 and 2022\(^{106}\) with natural gas prices. The markers in the chart below indicate 2021 averages with February excluded, thus removing the impact from the February 2021 winter weather event.

**Figure 4–1**  **Energy price versus natural gas price, annual**

Historically, electric market prices have followed the cost of natural gas. The winter weather event in February 2021 had a big impact on the energy market prices for that year driven by extremely high natural gas prices. When excluding February (values shown for 2021 on the chart above indicated with markers), the average gas cost at the Panhandle hub increased by 69 percent from $3.44/MMBtu for 2021 to $5.83/MMBtu for 2022. The average hourly day-ahead price increased by 80 percent from $26.62/MWh in 2021 (excluding February) to $47.86/MWh in 2022 and the real-time price increased by 75 percent from $24.64/MWh in 2021 (excluding February) to $43.24/MWh in 2022.

Interestingly, the 2022 real-time average price was still above the 2021 average price, even without excluding February 2021. In addition to increasing gas prices affecting the increase in prices from 2021 to 2022, both load and congestion increased in 2022, which also contributed to the price increase.

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\(^{105}\) Day-ahead and real-time prices shown are calculated using the average of the SPP North and SPP South hub prices for each period.

\(^{106}\) The 2014 real-time average includes two months of prices from the Energy Imbalance Service market and 10 months of prices from the Integrated Marketplace.
Figure 4–2 illustrates day-ahead and real-time energy prices, as well as gas costs, on a monthly basis for 2022.

**Figure 4–2   Energy price versus natural gas cost, monthly**

On a monthly basis in 2022, natural gas prices were lowest in January at $4.05/MMBtu and highest in August at $8.03/MMBtu. Electricity prices were lowest in March due in part to low gas prices ($4.31/MMBtu, the second lowest monthly average for the year) and abundant wind generation, and highest in August due to high gas prices and high load.

Additionally, energy prices can be broken down into on-peak and off-peak prices as shown in Figure 4–3. As can be expected, on-peak prices are consistently higher than off-peak prices.
Historically, on-peak prices tend to average about $15/MWh higher than off-peak prices, in both day-ahead and real-time. However, in 2022, the average spread between on-peak and off-peak prices grew to a difference of $25/MWh. Summer months saw the largest spread in both the day-ahead and real-time, approaching $50/MWh. The differences between on-peak and off-peak prices can be mostly attributed to lower loads and a higher percentage of lower cost wind generation in off-peak hours.

Changes in gas prices have historically had the highest impact on electricity prices compared to other fuels. This is because the short-run marginal costs of coal-fired generation historically have been cheaper than natural gas-fired generation. The energy pricing continued to trend with the gas prices throughout the year. Figure 4–4 compares various fuel price indices with real-time prices.
This figure shows that regional natural gas prices increased significantly from 2020 to 2021 and stayed high in 2022, on an annual basis. The Southern Star gas price averaged $6.00/MMBtu for 2022, while the Panhandle Eastern Pipeline averaged $5.79/MMBtu, and the Henry Hub was $6.37/MMBtu for 2022.\(^{107}\) Henry Hub and Southern Star average prices were slightly higher than Panhandle Eastern average prices in 2022. Price differences between Henry Hub and Panhandle Eastern continued to trend close, averaging $0.28/MMBtu in 2020, -$1.24/MMBtu in 2021\(^{108}\) and $0.37/MMBtu in 2022. This difference is likely driven by pipeline constraints in the Texas and Oklahoma area. Often, natural gas is a byproduct of oil drilling. Natural gas production has continued to outpace takeaway capacity in this area, with incremental production volumes quickly inundating any available space in the pipelines and keeping supply-area prices at discounts compared to other hubs.

Coal prices have remained relatively stable since 2016, but saw an increase in 2021, and the trend continued during the first six months of 2022.\(^{109}\) The price for 8,400 Btu/lb. at the Powder River Basin increased from $0.72/MMBtu in 2021 to $0.86/MMBtu (up 20 percent) in 2022, and the 2021 price for 8,800 Btu/lb. was $1.09/MMBtu up twenty cents from the 2021 average. The increase in coal prices in 2022 can likely be attributed to a shortage of supply. After several years of declining coal demand, the demand for coal, coinciding with the increase in natural gas

\(^{107}\) The relevant natural gas prices for the SPP market are those of the Henry Hub, the Panhandle Eastern Pipeline (PEPL), and Southern Star. These prices do not include transport costs.

\(^{108}\) This is due to the high gas price at Panhandle Eastern in February 2021.

\(^{109}\) Platt’s coal prices are exclusive of transport costs. Transportation costs can have a significant impact on a coal resource’s short-run marginal costs, and may often exceed commodity costs.
prices, increased. Many coal suppliers were unable to quickly respond to the increase in demand, contributing to the increase in prices and reduced available supply. In addition, unit sets of coal trains had decreased availability, thus decreasing the ability to transport coal even when available from suppliers.

Adjusting for changes in fuel prices helps to identify the underlying changes in electricity prices from other factors.\(^\text{110}\) Figure 4–5 below adjusts the marginal energy cost for changes in fuel costs.\(^\text{111}\)

**Figure 4–5 Fuel-adjusted marginal energy cost**

As the figure shows, fuel-adjusted marginal energy costs were significantly lower in 2022 compared to nominal marginal energy costs\(^\text{112}\) every month of the year, especially during the summer months, which was due to the significantly high natural gas and coal prices in 2022. On average, the natural gas prices increased 29 percent and coal prices increased 16 percent in 2022 from 2021. There were some increases in both fuel-adjusted marginal energy cost and

\(^\text{110}\) In addition to fuel, other variables also affect real-time prices. These variables include seasonal load levels, transmission congestion, outages, scarcity pricing, and wind-powered generation.

\(^\text{111}\) The marginal energy component (MEC) indicates the system-wide marginal cost of energy (excluding congestion and losses). Fluctuations in marginal fuel prices can obscure the underlying trends and performance of the electricity markets. Fuel price-adjusted marginal energy costs is a metric to estimate the price effects of factors other than the change in fuel prices, such as changes in load or changes in supply, or heat rate (efficiency) improvements. It is based on the marginal fuel in each real-time five-minute interval, when indexed to the three-year average of the price of the marginal fuel during the interval. If multiple fuels were marginal in an interval, weighted average marginal energy costs are based on the dispatched energy of different fuel types.

\(^\text{112}\) Nominal marginal energy costs represent the non–fuel adjusted marginal energy costs.
nominal marginal energy cost when compared to 2021 outcomes, with the respective annual increase being 21 percent and six percent. The largest differences between nominal and fuel-adjusted prices occurred in August, where the fuel-adjusted energy cost was roughly $35/MWh lower than the real-time energy cost, which was due to high natural gas prices and opportunity cost adders (beginning in August) added to coal resources due to coal transportation limitations. Fuel-adjusted marginal energy costs were higher in 2022 compared to 2021 when including the February winter weather event. The higher energy prices seen in 2022 were mainly contributed by the high fuel prices and transportation limitations, and also result from the high demand in 2022.

SPP has two pricing hubs: the SPP North hub and the SPP South hub. The SPP North hub represents a portion of pricing nodes in the northern part of the SPP footprint, generally in Nebraska. The SPP South hub represents a portion of pricing nodes in the south-central portion of the footprint, generally in central Oklahoma. Figure 4–6 shows the average day-ahead prices and real-time prices at the two SPP market hubs.

![Figure 4–6 Hub prices, day-ahead and real-time](image)

Typically, the SPP South hub prices exceed the SPP North hub prices. This pattern had narrowed in 2020, with just $0.23/MWh of average price separation between day-ahead average prices and $0.93/MWh separation between the real-time average prices. This spread has increased to $14.18/MWh in the day-ahead and $16.98/MWh in the real-time in 2022. The increased separation in 2022 coincides with the increase in natural gas costs and the increase in congestion. The general pattern of higher prices in the south and lower in the north is primarily due to fuel mix and congestion. Coal, nuclear, and wind are the dominant fuels in the north and
west. Gas generation represents a much larger share of the fuel mix in the south and east, which was much more impacted by the much higher than normal gas prices.

On a monthly basis, South hub prices almost always exceed North hub prices. Starting in July 2017, months started to appear where the North hub real-time average price exceeded the South hub real-time average price. In 2021, the North hub only exceeded the South hub in the month of December in the day-ahead market, and only by a few cents.

It is important to understand how SPP’s day-ahead prices compare to prices in other regions. Average on-peak, day-ahead prices for the SPP hubs, as well as other RTO hubs in the region are shown in Figure 4–7.

### Figure 4–7 Comparison of RTO/ISO average on-peak, day-ahead prices

<table>
<thead>
<tr>
<th>Hub Type</th>
<th>2020</th>
<th>2021</th>
<th>2021 (no Feb)</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>SPP North hub</td>
<td>$21</td>
<td>$79</td>
<td>$31</td>
<td>$53</td>
</tr>
<tr>
<td>SPP South hub</td>
<td>$22</td>
<td>$90</td>
<td>$38</td>
<td>$69</td>
</tr>
<tr>
<td>ERCOT West hub</td>
<td>$24</td>
<td>$150</td>
<td>$37</td>
<td>$37</td>
</tr>
<tr>
<td>ERCOT North hub</td>
<td>$26</td>
<td>$155</td>
<td>$42</td>
<td>$76</td>
</tr>
<tr>
<td>MISO Arkansas hub</td>
<td>$22</td>
<td>$42</td>
<td>$38</td>
<td>$69</td>
</tr>
<tr>
<td>MISO Louisiana hub</td>
<td>$24</td>
<td>$42</td>
<td>$40</td>
<td>$71</td>
</tr>
<tr>
<td>MISO Minnesota hub</td>
<td>$20</td>
<td>$44</td>
<td>$40</td>
<td>$55</td>
</tr>
<tr>
<td>MISO Texas hub</td>
<td>$27</td>
<td>$48</td>
<td>$40</td>
<td>$70</td>
</tr>
<tr>
<td>PJM Western hub</td>
<td>$23</td>
<td>$43</td>
<td>$43</td>
<td>$81</td>
</tr>
</tbody>
</table>

Average on-peak day-ahead prices climbed at both the North and South hubs of SPP, mostly due to higher natural gas prices throughout the year. If February 2021 prices are excluded, all of the other RTO/ISOs’ day-ahead average hub prices at the SPP seams increased in 2022, with the exception of the ERCOT West hub. The MISO Minnesota hub price increased by 38 percent, while all of the other hubs increased anywhere from 71 percent to 88 percent. The price increases in each region can primarily be attributed to higher natural gas prices relative to prior years.

### 4.1.2 ENERGY PRICE VOLATILITY

Price volatility in the SPP market is shown in Figure 4–8 below. As expected, day-ahead prices are much less volatile than those in real-time. The day-ahead market does not experience the

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\[113\] Volatility is calculated as the standard deviation for prices received by load-serving entities in the SPP market. The standard deviation is calculated using hourly price in the day-ahead market and interval (five minute) price in the real-time market.
actual (unexpected) congestion and changes in load or generation found in the real-time market. Real-time volatility tends to peak in the spring and fall, roughly corresponding with times of higher wind and lower load, but can also peak during the summer months because of peak load conditions.

**Figure 4–8  System price volatility**

In 2022, volatility in both the day-ahead market and real-time market increased. Day-ahead volatility (standard deviation) for 2022 was 37; this is up from 12 in 2020. 2021 had extraordinarily high volatility due to the winter weather event. Real-time volatility was up as well, from 42 in 2020 to 76 in 2022. Much of the increased volatility can be attributed to increased congestion.

Price volatility varies across the SPP market footprint for asset owners primarily because of varying levels of congestion on the system, which is based on the layout of the transmission system and the distribution of the types of generation in the fleet. The volatility for the majority of asset owners is consistent with the SPP average in both the day-ahead and real-time markets as shown in Figure 4–10.
Increased volatility was observed in certain geographic areas in 2022. Areas in Texas and southwest Missouri/SE Kansas had the highest price volatility in 2022, while the lowest volatility was found in Nebraska and the Integrated System.

4.1.3 DAY-AHEAD AND REAL-TIME PRICE CONVERGENCE

Price convergence between day-ahead and real-time prices is important, because the more day-ahead prices reflect real-time prices, the better unit commitment and positioning of resources occurs for real-time operations.

While average prices in the day-ahead and real-time markets have been close over the past several years, average prices can mask real-time volatility and underlying price differences. The averaging of price spikes, and in particular, high prices during periods of scarcity, drove real-time average prices up, closer to day-ahead prices. These short-term, transient price spikes can be attributed to limitations in ramping capability.114

In this section, underlying differences in prices after controlling for scarcity events are highlighted. This analysis shows that a significant volume of generation, particularly from wind resources, not cleared in the day-ahead market, drives down real-time prices.

114 For further information on ramping issues, see Section 3.2.1.
Many factors cause prices to diverge between the day-ahead and real-time markets. Some of these factors may include, but are not limited to:

- Day-ahead offers may include premiums to account for uncertainty in real-time fuel prices.\(^{115}\)
- Load and wind forecast errors can cause differences in the real-time market results.
- Participants may not bid in all load or offer all generation in the day-ahead market.
- Modeling differences including transmission outages between the two markets.
- Generation outages or derates that were different in real-time than was anticipated in the day-ahead.
- Impacts from other RTOs, that were not anticipated, may affect the SPP real-time market.
- Changes in imports and exports from other systems in the real-time markets.
- Unanticipated weather changes affect the real-time markets.

Price divergence\(^{116}\) between the day-ahead and real-time markets at the system level is shown in Figure 4–10 below. Market participants may be willing to pay a premium for more price certainty in in day-ahead market. This can result in higher prices in the day-ahead market. A large divergence between day-ahead and real-time prices may also indicate that actual conditions in the market do not match expected conditions. An extended period of a large variance between day-ahead and real-time prices may indicate a structural or design deficiency in the market.

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\(^{115}\) Additionally, Revision Request 239 allowed historic fuel cost uncertainty to be considered in the development of mitigated energy offers.

\(^{116}\) 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. The absolute divergence is calculated by taking the absolute value of the divergence for each interval.
Average absolute divergence for 2022 was $19.89/MWh, this is down from $45.26/MWh in 2021. However, 2021 figures are skewed heavily by the winter weather event. The average absolute divergence during 2021 when excluding February was $20.12/MWh, which then shows absolute divergence has dropped by a slight amount ($0.23/MWh) from 2021 (excluding February) to 2022. Historically, absolute divergence has averaged around $10 per month up through 2020. Much of increased deviation over the last two years can be attributed to unplanned and extended transmission outages, along with other factors. The under-clearing of renewable resources and short-term ramping limitations also contribute to increased price divergence. It was hoped that implementation of the ramping product on March 1, 2022 would also have a positive effect on this divergence; however, this has not been the case to date. Moreover, the MMU has recommended many improvements resulting from the February winter weather event, and recommends that additional work be done to improve price divergence related to under-clearing of renewable generation in the day-ahead market.

Figure 4–11, below, shows the marginal energy costs for both the day-ahead and real-time markets during on-peak hours after controlling for scarcity events. Figure 4–12 shows the same information, but for off-peak hours.
The marginal energy cost is one of three components that factor into locational marginal prices and represents the marginal cost to provide the next increment of dispatch absent losses and congestion. Day-ahead prices are generally at a premium when compared to real-time prices (excluding scarcity pricing), particularly in the off-peak hours. Also of note is that the marginal energy prices follow the same monthly trend as gas prices.

Figure 4–13 shows average hourly incremental differences in megawatts produced between the real-time and day-ahead market in 2021.
Wind generation made up 71 percent of the 4,038 MW of incremental real-time generation in 2022 (up from 70 percent in 2021 and 63 percent in 2020), with an hourly average of 2,849 MW of additional generation in real-time. Self-committed generation accounted for an additional 326 MW and reliability unit committed or manually committed generation averaged 821 MW. While SPP is a net exporter in both the day-ahead and real-time markets on average, it sees an average hourly increase of 42 MW in real-time market net imports compared to the day-ahead. This results in additional capacity committed in day-ahead not necessarily needed in real-time. Averaging 1,445 MW an hour, net virtual positions helped to offset the additional generation, but only accounted for about 36 percent of the difference for the year. This is down significantly from the 1,936 MW (51 percent) in 2021 and 1,214 MW (44 percent) in 2020. Netting out the changes in virtual transactions, there was 2,593 MW of additional net supply in real-time in 2022.

Figure 4–14 shows the difference between the day-ahead offered wind generation and the day-ahead cleared wind generation. The wind forecast figure is derived from the mid-term wind forecast, which is created one day prior to the operating day.
In 2022, 88 percent of the wind offered in the day-ahead cleared. This is down from the 91 percent in 2021 and the 92 percent in 2020. In 2022, 102 percent of forecasted wind was offered into the day-ahead, this is consistent with 101 percent in 2021 and 102 percent in 2020. However, even though wind resources are generally offering in close to full forecasted capacity to the day-ahead, a portion of this is at offer levels that exceed prevailing prices and thus does not clear the market. Typically, wind will clear all of the megawatts that are physically offered into the day-ahead market if the economic offers are consistent with real-time offers. The MMU observed that almost all wind megawatts offered into the day-ahead market and not cleared had higher economic offers in the day-ahead market than real-time.

Systematic under-clearing of wind resources in the day-ahead market can contribute to distorted price signals, suppressing real-time prices, and affecting revenue adequacy. Variable energy resources are generally able to produce close to a forecasted amount. Therefore, the MMU continues to recommend that SPP and its stakeholders address this issue through market incentives and rule changes that focus on market inefficiencies associated with under-clearing of variable energy resources in the day-ahead market based on forecasted supply. These rule changes could focus on changing incentives for wind resources, or alternatively encouraging virtual transactions.

4.1.4 NEGATIVE PRICES

With the prolific growth of wind generation in the SPP market, the incidence of intervals with negative prices continues to be a growing concern. The frequency of negative price intervals,
however, decreased slightly in the day-ahead market from 2021 to 2022, as shown in Figure 4–15.

**Figure 4–15  Negative price intervals, day-ahead, monthly**

In 2022, 7.1 percent of all asset owner intervals\textsuperscript{118} in the day-ahead market had prices below zero, as shown in Figure 4–15. This is down from 7.7 percent of all intervals in 2021 and up from 4.6 percent in 2020. March had the highest percentage of negative intervals in the day-ahead market, at nearly 17 percent.

Historically, negative price intervals in the real-time market occur around two times more frequently than in the day-ahead market. While negative price intervals increased slightly in the day-ahead market, negative price intervals increased slightly in the real-time market, as shown in Figure 4–16.

\textsuperscript{118} Asset owner intervals are calculated as the number of asset owners serving load that are active in an interval. For example, if there are 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).

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The frequency of negative price intervals in the real-time market was 15.2 percent of 2022 intervals, up slightly from 14.8 percent in 2021. The slowing increase in negative price intervals can partially be attributed to a slowing of the addition of new wind resources in the SPP market.

Negative prices in the day-ahead market were almost exclusively between $0.01/MWh and $25/MWh, with only four percent of intervals with negative prices having prices lower than $25/MW. However, in the real-time market 25 percent of intervals with negative prices had prices lower than $25/MWh.

Additionally, occurrences of negative prices in the day-ahead market are most prevalent in the overnight, low-load hours as shown in Figure 4–17.
This figure shows that the day-ahead negative price intervals in 2022 during overnight hours are higher than the 2020, but lower than 2021. Higher loads in 2022 are one of the main drivers for the lower day-ahead price intervals during the year.

Negative price intervals in the real-time market (see Figure 4–18) follow the same pattern as the day-ahead market with most negative price intervals occurring in the overnight, low-load hours.

**Figure 4–18  Negative price intervals, real time, by hour**

As shown above negative price intervals in the real-time market occur much more frequently than in the day-ahead market, with a 2022 peak of over 26 percent of intervals in real-time in the third hour of the day, compared to a peak of just under 20 percent in day-ahead. During 2022, the first five hours and last hour of the day experienced negative prices over 20 percent of the time, which was the same as 2021.

At the asset owner level (for those serving load), the distribution of negative price intervals during 2021 clustered around the footprint average, as shown in Figure 4–19.

**Figure 4–19  Negative price intervals, real-time, by asset owner**
In 2022, 33 of 61 asset owners with load experienced negative prices in more than 15 percent of intervals. This is a substantial increase from 2020, where only nine asset owners experienced negative prices in excess of 15 percent of intervals. The asset owner with the highest percentage of intervals with negative prices had 32 percent of intervals with negative prices; this is up from 2021 when the highest percentage was 28 percent of all intervals.

The MMU remains concerned about the frequency of negative price intervals. Negative prices may not be a problem in and of themselves, however, they do indicate an increase in surplus energy on the system. This is exacerbated by the practice of self-committing of resources and manual commitments for capacity. In the SPP market where there is an abundance of capacity and significant levels of renewable resources, negative prices can occur when renewable resources need to be backed down in order for traditional resources to meet their committed generation. Moreover, unit commitment differences, due to under-clearing of wind resources in the day-ahead market and then producing more in the real-time market, can create differences in the frequency of negative price intervals between the day-ahead and real-time markets. This disparity between the markets negatively impacts the efficient commitment of resources.

As more wind generation is anticipated to be added over the coming years, the frequency of negative prices has the potential to increase. Negative price intervals in the day-ahead highlight the need for changes in market rules to address self-committing of resources in the day-ahead market and addressing differences in supply between day-ahead and real time. These issues are discussed further in Chapter 7.

### 4.1.5 OPERATING RESERVE MARKET PRICES

Operating reserve is made up of four 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.

In addition, regulating units are compensated for mileage costs incurred when moving from one set point instruction to another. The market calculates a mileage factor for both products each month that represents the percentage a unit is expected to be deployed compared to what it cleared. If a unit is deployed more than the expected percentage, then the unit is entitled to reimbursement for the excess at the regulation mileage marginal price. If the unit is deployed less, it must buy back its position at the real-time mileage clearing price.
Generally speaking, regulation-up and regulation-down usually have the highest market clearing prices. Supplemental reserves always have the lowest average prices of the operating reserve products, with prices typically averaging less than two dollars on an annual basis. There has been a general upward trend in operating reserve product prices over the past three years.

Day-ahead and real-time price patterns vary for regulation-up and regulation-down, see Figure 4–20 and Figure 4–21. The dots shown on the charts represent prices for 2021 without February, thus showing the trend compared to a more normal year.

**Figure 4–20  Regulation-up service prices**

The regulation-up day-ahead market clearing price averaged nearly $18/MW, while the real-time price for 2022 averaged just over $21/MW. Excluding February 2021, the average day-ahead regulation-up market clearing price was up nine percent from 2021 to 2022, while real-time market clearing price was up 14 percent. The higher periods of regulation-up pricing from April through September coincide with the period of highest gas prices during the year. The regulation-up mileage price for 2022 was $16/MW, this is up 15 percent from $13.71/MW in 2021, excluding February.
Regulation-down market clearing price in the day-ahead market averaged $6/MW in 2022, which is flat compared to the 2021 price without February of $6/MW. Real-time regulation-down market clearing prices averaged nearly $11/MW for 2021, up a dollar (or eight percent) from 2021 without February. The regulation-down mileage price continues to grow sharply over the past three years – from $8.16/MW in 2020 to $21.50/MW in 2022.

The MMU analyzed regulation mileage prices in 2017 and found a design inefficiency. This design inefficiency was still present in 2022. The issues occur because mileage prices are not set by the marginal resource’s cost like other products. Instead, resources are cleared for regulation based on their service offers. These service offers are derived by taking the competitive offer for regulation and adding the mileage offer to it after discounting the mileage offer by the applicable mileage factor. For instance, the service offer of a resource with a competitive regulation-down offer of $1 and a regulation-down mileage offer of $36 would be $10 if the mileage factor is 25 percent.¹¹⁹ If the $10 service offer is economic, then the resource will clear for regulation-down and the regulation-down mileage price will be set at $36, assuming this is the highest mileage price for regulation-down mileage that cleared in the market.

The MMU has observed instances where resources cleared with regulation-down competitive offers of $0 and mileage offers just under $50. These units consistently cleared with this offer strategy because the service offer was near $10.50 (e.g. 21 percent * $50) which was lower than the services offers of other resources offering in higher competitive offers. For instance, another resource may offer in a $12 competitive offer and $0 mileage offer. This would make that

¹¹⁹ $1 + $36 * 0.25 percent = $10
resource’s service offer $12 (($12 + $0) * 21 percent). In this circumstance, the resource with the highest service offer will set the regulation-down price at $12, but the mileage offer will be $50, set by the highest cleared mileage offer.

In addition, the MMU observed systematic overpayment of regulation mileage in the day-ahead market, which appears to be the result of the mileage factor being set consistently too high relative to actual mileage deployed. This occurred because the mileage factor is being set on historical instructed regulation megawatts rather than deployed regulation. When resources have to buy back their position, they typically have to buy back at the inflated mileage offer. Using the example above, if a resource clears for 10 megawatts it will receive the $12 clearing price for a total payment of $120, which was set using a $0 mileage offer. However, if it does not get deployed for regulation it will have to buy back 2.1 megawatts at the $50 mileage offer, because they performed less than expected. The unit was paid 2.1 megawatts at a $0 price for expected mileage at the clearing, but the buyback is now $105. This makes the total payment to the resource for clearing regulation $15 or $1.50 per cleared megawatt.

The instructed values for regulation are on average two and a half times what resources perform. If the mileage factor was forecasted in the exact amount of what was performed, then the excess mileage payments should closely offset the unused mileage charges. However, this is not the case. The reason for the difference is that regulation is deployed on a four second basis, but it is settled on a five-minute basis. Resources could be directed to move up 10 megawatts at the beginning of the interval. However, 20 seconds later they may be directed to hold off on providing that regulation. If their ramp rate is only 10 megawatts per minute, they will only have provided 3.3 megawatts of regulation. This is generally what causes the instructed values to vary from the actual values.

Figure 4–22 below illustrates the differences between the unused mileage charges and the excess payments.
Negative values represent the payments made to resources that deployed for more regulation megawatts than were expected and positive values represent charges made to resources that deployed for less than what was expected. In 2022, just over $3.5 million more was charged for mileage buyback compared to payouts for excess mileage deployment, with $15.1 million being paid for excess mileage and $18.6 million being charged for unused mileage. This is up from $2.1 million in 2021, but down from $3.9 million in 2020. These net charges reduce the profitability of resources clearing regulation.

The MMU observed that participants with resources frequently deployed for regulation have an incentive to inflate the mileage prices by offering in $0 regulation capability offers and high mileage offers. The MMU also has concerns that the inflated mileage factors are causing units to buy back megawatts at the inflated amounts that may be eligible to be made whole and can ultimately lead to higher uplift costs in the market. As such, the MMU has recommended that SPP review and revise the regulation mileage pricing approach to send more appropriate price signals.

SPP responded to the recommendation with revision request 504, which will effectively reduce the buyback costs for mileage to participants, while lowering the unduly high mileage clearing prices. It will do this by applying two changes. The first change will set the expected mileage deployment used by settlements to be the historical ratio of actual mileage provided to mileage cleared. The current method uses the historical ratio of instructed mileage to cleared mileage. As described in detail above, the four-second mileage instructions are not feasible for participants to completely follow, so the instructed mileage ends up being about double the actual mileage delivered. Setting the expected mileage factor to the historically delivered ratio
of mileage for all resources will reduce roughly half the buyback cost. Secondly, the current mileage method set the mileage offer to the highest mileage offer cleared. As described above, since the mileage offers get discounted by the mileage factor, and added to the competitive offer to make a clearing offer, it allowed high mileage offers to clear and set the mileage-clearing price. The revision request will help remediate this issue by ranking all mileage megawatts by cleared cost and setting the price at the cost of the highest expected deployed megawatt. This revision request has passed all phases of the SPP stakeholder process and is awaiting FERC approval.

Spinning and supplemental reserve prices are shown below in Figure 4–23 and Figure 4–24. The dots shown on the charts represent prices for 2021 without February, thus showing the trend compared to a more normal year.

**Figure 4–23  Spinning reserve prices**

The market clearing price for day-ahead spinning reserves averaged $12/MW in 2022, an increase of 24 percent from $9/MW in 2021, excluding February. Real-time spinning reserves price for 2022 averaged $7.50/MW, up from $6.75/MW in 2021, excluding February, an increase of nine percent.
When excluding February 2021, day-ahead supplemental reserve prices climbed from $0.82/MW in 2021 to $1.81/MW in 2022 and real-time prices increased from $1.00/MW in 2021 to $1.79/MW in 2022. At these levels, the supplemental reserve price does not indicate a large need for stand by generation.

Historically, 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 should help compensate generators that are specifically needed to mitigate the risk associated with wind forecast error.\textsuperscript{120} The uncertainty product received FERC approval in mid-August 2022 and is awaiting implementation by SPP on July 6, 2023.

The SPP ramping capability product was implemented on March 1, 2022. This product is used to provision rampable up and down capacity for uncertainty events in net load forecasts across a 10-minute future time horizon. Historically, SPP operators procured ramp through out-of-market mechanisms, often resulting in uplift payments.

The ramp capability product was designed to allow for more economical and transparent management of the intermittent aspects of the system. Its function was to procure ramp-up and ramp-down to meet historical net load forecast needs up to the historical 95\textsuperscript{th} percentile of error. This new product allows a systematic way to hold back resources that have ramp

\textsuperscript{120} SPP Holistic Integrated Tariff Team report, page 18.
capability for future intervals in which ramp may be needed. Ramp product prices are shown in Figure 4–25.

**Figure 4–25  Ramp product prices**

There have been no ramp down product prices since implementation on March 1. The maximum ramp-up price per interval was $44/MW, which occurred in October. Average ramp-up capability product prices for 2022 since implementation were $5.69/MW in day-ahead and $2.39/MW in real-time.

The MMU’s preliminary findings raise the following concerns with performance of the ramp capability product:

1. Variable energy resources cannot produce regulation-up in the SPP market. However, 58 percent of the day-ahead ramp-up and just over half of the 2022 real-time ramp-up product was cleared on variable energy resources.

2. Thirty-one percent of the real-time ramp-up was procured from resources having shift factors lower than five percent on binding or breached constraints. These resources increment congestion on these constraints, thus are typically unable to dispatch upward to meet ramping needs.

3. The scarcity demand curve prices for the ramp capability up product may be set too low. There is a high frequency of ramp-up scarcity events, especially when taking in the fact that non-deployable ramp-up is being cleared to meet the requirement.

SPP is currently testing a design fix that will allow a market pre-run to identify resources with non-deliverable ramp-up and exclude those from the clearing of the ramp capability-up product.
4.2 UPLIFT

The Integrated Marketplace provides make-whole payments to generators to ensure that the market provides sufficient revenue to cover the cleared offers providing energy and operating reserves for a period in which the resource was committed. To preserve the incentive for a resource to meet its market commitment and dispatch instruction, market payments should cover the sum of the incremental energy cost, start-up cost, no-load cost, transition cost, and cost of operating reserve products. The make-whole payment provides additional market payments in cases where revenue is below a resource’s offer to make the resource whole to its offers of operating reserve products, incremental energy, start-up, transition, and no-load.

For the resources that are not combined-cycle, settlements separately evaluate: (1) day-ahead market commitments based on day-ahead market prices and cleared offers; and (2) reliability unit commitments based on real-time market prices and cleared operating reserve offers. Combined-cycle resources that registered as multi-configuration resources are unique in that they can be cleared in both the day-ahead and real-time markets at the same time. As a result, settlements must evaluate the revenues and cost of both real-time and day-ahead commitments when calculating real-time make-whole payments for combined-cycles.

4.2.1 MAKE-WHOLE PAYMENTS

Figure 4–26 shows monthly and annual day-ahead make-whole payment totals by technology type. Figure 4–27 shows the same make-whole payment information for reliability unit commitment.

Figure 4–26 Make-whole payments by fuel type, day-ahead
Because of the 2021 February winter weather event, make-whole payments climbed to levels well beyond those ever experienced in the Integrated Marketplace. For 2022, day-ahead market and reliability unit commitment make-whole payments combined totaled just over $465 million. Reliability unit commitment make-whole payments constituted 63 percent of the total make-whole payments in 2022.

Day-ahead make-whole payments were nearly $292 million in 2022, down from $979 million in 2021, as decrease of 82 percent from 2021. Reliability unit commitment make-whole payments in 2022 totaled $292 million, down from $354 million in 2021, representing a 21 percent decrease from 2021. Also of note is the fact that real-time make-whole payments were highest in July, which coincided with the summer peak and day-ahead make-whole payments were highest in December, which coincided with the winter peak.

Make-whole payments occur for several reasons, which include some of the following: local reliability commitments, uncaptured congestion in the day-ahead market, under-cleared generation (primarily wind) in the day-ahead market, inflexibility of resources to move in economic ranges or go offline between on-peak and off-peak hours, and excessive transmission congestion not being solved by the market.

Total make-whole payments per megawatt generated averaged $0.08/MWh for 2022, down from $5.83/MWh in 2021. However, roughly 31 percent of SPP’s generation in 2021 was provided by self-committed resources.\footnote{See Section 3.3, Figure 3–24.} In addition 2021 make-whole payments were much...
higher due to the effects of the winter weather event. These resources are not eligible for make-whole payment reimbursements. Primarily, resources committed under reliability or market status are eligible for cost reimbursement.

Figure 4–28 illustrates the 2020 to 2022 average make-whole payments per each megawatt eligible for cost reimbursement, or in other words those megawatts generated under market or reliability status. These include manual commitments made by operators.

**Figure 4–28  Make-whole payments for eligible megawatts**

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day-ahead market</td>
<td>$0.32</td>
<td>$6.42</td>
<td>$0.94</td>
</tr>
<tr>
<td>make-whole payments</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>/ eligible MWh</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Real-time market</td>
<td>$15.77</td>
<td>$94.58</td>
<td>$43.13</td>
</tr>
<tr>
<td>make-whole payments</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>/ eligible MWh</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Because of the February winter weather event, both day-ahead and real-time make-whole payments per eligible megawatt rose steeply. In addition, rising prices of natural gas late in the year played a role in the increasing make-whole payments.

Operators often commit resources when the available ramp capacity needs in future intervals is perceived to be short. These actions often reduce the occurrence of scarcity events. However, this has the effect of potentially suppressing the price signal that would indicate a problem as capacity is brought on to meet the perceived ramp shortage. Additionally, the resources that were manually committed are typically expensive in comparison to the energy prices for which they run, requiring them to receive cost reimbursement through make-whole payments.

Another way to view the real-time make-whole payments is that on the average $43.13/MWh was paid to avoid reliability problems that were not able to be addressed directly by the real-time market.

In addition, most scarcity events last less than two intervals and most resources have start times that are longer than this period and minimum-run times that are much longer than this period. This means that even if these resources are able to capture one to two intervals of the high

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122 These numbers were not presented under this method in prior years. Prior years reported total make-whole payments divided by total generation. This method shows total make-whole payments divided only by megawatts eligible for cost reimbursement.
prices, they may have to run an hour or two longer with less economic price levels, leading to the need for cost reimbursement.

The MMU believes that a revamped ramp capability product (see section 3.2.3), which went into production on March 1, 2022, and the upcoming uncertainty product, slated to be implemented in the second quarter of 2023, and fast-start resource pricing logic, will help provide the appropriate pricing and compensation mechanisms for meeting ramp capacity needs in the market. However, the ramp capability product needs to be enhanced and improved to provide maximum benefit to the market. This includes reducing make-whole-payments and bringing transparency to the market. They will also improve price formation and better compensate resources that provide the much-needed ramping flexibility, as well as reduce the need for manual commitments for capacity.

Figure 4–29 shows the share of each cause of make-whole payments in the real-time and day-ahead markets.

**Figure 4–29  Make-whole payments, commitment reasons**

<table>
<thead>
<tr>
<th>Real-time commitment reason</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>Manual, SPP transmission</td>
<td>34.6%</td>
<td>9.5%</td>
<td>29.0%</td>
</tr>
<tr>
<td>Manual, SPP capacity</td>
<td>22.8%</td>
<td>38.5%</td>
<td>14.4%</td>
</tr>
<tr>
<td>Intra-day RUC</td>
<td>16.0%</td>
<td>25.0%</td>
<td>30.1%</td>
</tr>
<tr>
<td>Manual, voltage</td>
<td>11.7%</td>
<td>3.5%</td>
<td>3.4%</td>
</tr>
<tr>
<td>Short-term RUC</td>
<td>8.0%</td>
<td>4.7%</td>
<td>15.8%</td>
</tr>
<tr>
<td>Day-ahead RUC</td>
<td>3.9%</td>
<td>17.9%</td>
<td>5.1%</td>
</tr>
<tr>
<td>Manual, stagger</td>
<td>2.7%</td>
<td>0.8%</td>
<td>2.2%</td>
</tr>
<tr>
<td>Other</td>
<td>0.2%</td>
<td>0.2%</td>
<td>0.1%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Day-ahead commitment reason</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day-ahead market</td>
<td>97.1%</td>
<td>99.8%</td>
<td>99.0%</td>
</tr>
<tr>
<td>Voltage support, manual</td>
<td>2.9%</td>
<td>0.2%</td>
<td>1.0%</td>
</tr>
</tbody>
</table>

In recent years, there has been a large increase in make-whole payments occurring during periods that resources are manually committed for capacity. In fact, just under 15 percent of the real-time make-whole payments were paid to resources committed manually for capacity needs. This is lower than the 39 percent in 2021, however, capacity commitments were much higher in 2021 during the winter weather event, leading to this increase. There was a large increase in resources committed for transmission, which was lower in 2021 due to the winter weather.
These commitments had 29 percent of the real-time make whole payments in 2022, up from 10 percent in 2021, but down from 35 percent in 2020.

Make-whole payments associated with voltage support commitments do not follow the same uplift process outlined in Section 4.3.1. Instead, the cost of these make-whole payments is distributed to the settlement areas that benefited from the commitment by way of a load ratio share. Figure 4–30 illustrates the level of make-whole payments associated with voltage support commitments.

**Figure 4–30  Make-whole payments for voltage support**

The make-whole payments stemming from voltage support commitments almost doubled in 2022, with day-ahead voltage supports commitments showing the largest increase. The increase in gas prices in 2022 is the main driver for the increase in make-whole payments for voltage support.

Many SPP resources received high levels of make-whole payments in 2022, as highlighted in Figure 4–31.
Because of the higher total levels of make-whole payments, 160 resources received over $1 million in total make-whole payments in 2022, compared to 130 in 2021, with the highest payment to a single resource of $19 million. The resource receiving the highest amount of make-whole payments in 2022 is in an area with frequent congestion and most of these make-whole payments stem from manual commitments needed to control regional transmission and voltage concerns.

Figure 4–32 reveals there is concentration in the market participants that receive make-whole payments.

**Figure 4–32  Number of market participants receiving make-whole payments**

<table>
<thead>
<tr>
<th>Dollar ranges in millions</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>$1-5</td>
<td>5</td>
<td>7</td>
<td>8</td>
</tr>
<tr>
<td>$5-10</td>
<td>3</td>
<td>3</td>
<td>4</td>
</tr>
<tr>
<td>&gt;$10</td>
<td>5</td>
<td>15</td>
<td>12</td>
</tr>
</tbody>
</table>

In 2022, there were 12 market participants that each received annual make-whole payments in excess of $10 million. These 12 market participants accounted for 89 percent of the total make-whole payments paid out in 2022, which is eight percentage points lower than what the 15 market participants received in 2020.
4.2.2 MAKE-WHOLE PAYMENT ALLOCATION

The allocation of both day-ahead and real-time make-whole payments has important consequences to the market. In principle, for market efficiency purposes uplift cost allocation should be directed to those members that contributed to the need for the make-whole payments (i.e., cost causation).

For the day-ahead market, make-whole payment costs are distributed to both physical and virtual withdrawals on a per-MWh rate. The per-MWh rate is derived by dividing the sum of all day-ahead make-whole payments for an operating day by the sum of all cleared day-ahead market load megawatts, export megawatts, and virtual bids for the operating day. The average per-MWh rate for withdrawing locations in the day-ahead market was $0.55/MWh for 2022; the per-MWh rate for 2021 was $0.29/MWh, compared to $0.19/MWh in 2020.

For the real-time market, make-whole payment costs are distributed through a per-MWh rate that is assigned to all megawatt-hours of deviation in the real-time market. The rate was the per-MWh rate for 2022 was $3.67/MWh, nearly double the 2021 rate of $1.81/MWh. There are eight categories of deviation and each category receives an equal amount per megawatt, which can vary by operating day, when the cost of make-whole payments is applied.

Figure 4–33 shows the total megawatts of deviation by each category, as well as the total real-time make-whole payment uplift charges for each deviation category.

**Figure 4–33 Make-whole payments by market uplift allocation, real-time**

<table>
<thead>
<tr>
<th>Uplift Type</th>
<th>Deviation MWs (Thousands)</th>
<th>Uplift charge (thousands)</th>
<th>Share of MWP charges</th>
<th>Cost per MW of deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Settlement location deviation</td>
<td>74,081</td>
<td>$ 250,995</td>
<td>85.9%</td>
<td>$ 3.39</td>
</tr>
<tr>
<td>Outage deviation</td>
<td>3,438</td>
<td>$ 14,233</td>
<td>4.9%</td>
<td>$ 4.14</td>
</tr>
<tr>
<td>Maximum limit deviation</td>
<td>1,410</td>
<td>$ 7,810</td>
<td>2.7%</td>
<td>$ 5.54</td>
</tr>
<tr>
<td>Status deviation</td>
<td>1,940</td>
<td>$ 7,853</td>
<td>2.7%</td>
<td>$ 4.05</td>
</tr>
<tr>
<td>Uninstructed resource deviation</td>
<td>1,285</td>
<td>$ 4,426</td>
<td>1.5%</td>
<td>$ 3.45</td>
</tr>
<tr>
<td>Reliability unit commitment, self-commit deviation</td>
<td>1,168</td>
<td>$ 4,217</td>
<td>1.4%</td>
<td>$ 3.61</td>
</tr>
<tr>
<td>Reliability unit commitment deviation</td>
<td>275</td>
<td>$ 1,950</td>
<td>0.7%</td>
<td>$ 7.08</td>
</tr>
<tr>
<td>Minimum limit deviation</td>
<td>221</td>
<td>$ 840</td>
<td>0.3%</td>
<td>$ 3.79</td>
</tr>
</tbody>
</table>
Even though each category of deviation is applied the same rate for deviation, approximately 86 percent (settlement location deviation in the table above) of the real-time make-whole payment costs were paid by entities withdrawing (physical or virtual) more megawatts in the real-time market than the day-ahead market.

Transactions susceptible to this charge are virtual offer megawatts; real-time load megawatts different from the day-ahead megawatts cleared; import, export, and through megawatts in real-time different from the megawatts cleared in the day-ahead market; and units pulling substation power different from any megawatts produced by the unit. However, virtual offers are the most susceptible as 100 percent of their megawatts are considered incremental. Because of this, virtual offers alone paid 53 percent of all real-time make-whole payments in 2022, up from 30 percent in 2021. Historically, virtuals have paid around 50 percent of real-time make-whole payments annually. However, with the higher amount of make-whole payments due to the winter weather event, the annual percentage was much lower in 2021.

Cost causation has been an area of concern in the SPP working groups in the past few years. In particular, participants raised concerns that the market is not properly allocating the market cost back to those responsible for causing those costs. With virtual offers bearing such a heavy burden of these costs, it reduces the incentives for behavior changes among those that are causing the cost and it adds a premium to virtual transactions. This should be considered as part of the evaluation of under-clearing of wind in the day-ahead as these incentives likely contribute to the lack of price convergence between day-ahead and real-time.

### 4.2.3 REGULATION MILEAGE MAKE-WHOLE PAYMENTS

In March 2015, SPP introduced regulation compensation changes for units deployed for regulation-up and regulation-down. One component of the regulation compensation charges is regulation-up and regulation-down mileage make-whole payments for units that are charged for unused regulation-up or regulation-down mileage at a rate that is in excess of the regulation-up or regulation-down mileage offer.

SPP calculates mileage factors monthly for both regulation-up and regulation-down. These mileage factors are ratios of historical averages of the percentage of each regulation product deployed to the regulation product cleared in the prior month. The regulation-up mileage factor averaged 32 percent in 2022, up significantly from 16 percent in 2021, while the regulation-down mileage factor averaged 37 percent in 2022, up from 21 percent in 2021.

The mileage factor is a key component in the computation of mileage make-whole payments. When the mileage factor is greater than the percentage of deployed regulating megawatts to
cleared regulating megawatts for each product, the resource must buy back the non-deployed megawatts at the mileage marginal clearing price for the respective product. If the mileage marginal clearing price used for the buyback is greater than the unit’s cost for the product a make-whole payment may be granted.

Figure 4–34, below, illustrates the mileage make-whole payments for 2022 and the prior two years.

**Figure 4–34  Regulation mileage make-whole payments**

Regulation-up mileage make-whole payments were around $560,000 in 2022, up 32 percent from 2021. Regulation-down mileage make-whole payments were over $2 million in 2022, up 37 percent from 2021, and up 71 percent from 2020. The design deficiency described in section 4.1.6 can be directly attributed to the disparity between the regulation-down and regulation-up mileage make-whole payments seen in Figure 4–38. This design inefficiency is one of the main contributors to the disparity between the mileage make-whole payments paid out to regulation-up and regulation-down.

### 4.2.4 DISTRIBUTION OF MARGINAL LOSSES (OVER-COLLECTED LOSS REVENUE)

Both the congestion and loss components of prices create excess revenues for SPP that must be distributed to market participants in an economically efficient manner. In the case of marginal loss revenues, this requires that the distribution does not alter market incentives.
The current design consolidates the distributions of day-ahead and real-time over-collected loss rebates into one distribution.\textsuperscript{123} Both day-ahead and real-time over-collected loss rebates are distributed on just real-time withdrawing megawatts. This includes loads, substation power, exports, wheel-throughs, pseudo-ties, and bilateral settlement schedules (BSS). The only exception is that both day-ahead and real-time bilateral settlement schedules are entitled to the rebate, as long as the underlying megawatts associated to the bilateral settlement schedules are not less than the megawatts of the bilateral settlement schedule.

Over-collected losses for the past three years are shown in Figure 4–35.

**Figure 4–35 Over-collected losses, real-time**

A total of $252 million was paid out in over-collected losses rebates during 2022, with $231 million (92 percent) going to load. This is up from the $130 million in over-collected losses rebates paid out in 2021 (excluding February), and the $86 million paid in 2020. The increase in over-collected losses can primarily be attributed to higher energy prices and higher levels of demand.

**4.2.5 REVENUE NEUTRALITY UPLIFT**

Revenue neutrality uplift (RNU), shown in Figure 4–36, 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

\textsuperscript{123} Prior years over-collected loss designs are described in the 2018 Annual State of the Market report under Section 4.2.3.
uplift indicates where SPP receives excess revenue, which must be credited back to market participants.

**Figure 4–36  Revenue neutrality uplift**

Total revenue neutrality uplift for 2022 was $548 million, up 92 percent from 2021, and up tenfold from $54.7 million in 2020. The two main components of revenue neutrality uplift are real-time congestion and real-time joint operating agreement (also known as market-to-market). The joint operating agreement component generally acts to lessen revenue neutrality uplift, while the congestion component generally acts to increase revenue neutrality uplift. Real-time joint operating agreement portion of revenue neutrality uplift was $162 million in 2022, an increase of 86 percent from $87 million in 2021. The real-time congestion component of revenue neutrality uplift was $653 million in 2022, an increase of 189 percent from $226 million in 2021. The high level of day-ahead and real-time revenue inadequacy portion in 2021 was a result of the February winter weather event.
The increase in the real-time congestion component of revenue neutrality uplift has been the topic of much discussion over the past year. At the February 2023 Market Working Group meeting, SPP staff reported on the increased congestion component. SPP staff stated that they attributed the increase in real-time congestion to:

- Increased virtual net injection
- Wind
  - Underperforming in the day-ahead market
  - Increase in wind capacity
- Increased real-time marginal congestion component of locational marginal price
  - Increased number of constraints
  - Higher gas prices
- Differences between day-ahead and real-time.

SPP staff stated that overall, as real-time congestion increases, the congestion imbalance between day-ahead and real-time drive up revenue neutrality uplift. In October 2022, the RTO began a day-ahead market process to activate market-to-market flowgates, although this did provide some relief in the congestion imbalance, it was not a significant impact. SPP staff will continue to study the increase in revenue neutrality uplift, specifically, the increase in real-time congestion, and will provide updates as more information is learned. The MMU will continue to monitor this trend, and report any additional findings in future reports.

**4.3 TOTAL WHOLESALE MARKET COSTS AND PRODUCTION COSTS**

Figure 4–37 plots the average all-in price of energy and the cost of natural gas, measured at the Panhandle Eastern (PEPL) hub. The average all-in price includes the costs of energy, day-ahead and real-time reliability unit commitment make-whole payments, operating reserves, reserve sharing group costs, and payments to demand response resources.

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125 Operating reserves are resource capacity held in reserve for resource contingencies and NERC control performance compliance, which includes the following products: regulation-up service, regulation-down service, spinning reserve and supplemental reserve.
The figure shows that the vast majority of costs are from the day-ahead and real-time energy.\footnote{Scarcity pricing is included in the energy component and not easily separated out in the SPP settlement data. See Section 3.2.1 for a discussion of scarcity pricing impacts.}

It also shows that the market cost of operating reserves and make-whole payments constituted approximately four percent of the $50.83/MWh all-in price for full year 2022, while energy accounted for 96 percent. Since the start of the Integrated Marketplace, historically energy makes up around 97 percent of the all-in price. The 2022 all-in price was 17 percent higher than the 2021 average, which can be attributed to increase in natural gas prices in 2022.

Production cost “is defined as the settlement cost for the market … for all resources.”\footnote{Integrated Marketplace Protocols, Section 7.2.1}

Production cost, in this case, is the sum of four components:

- energy: cleared megawatts multiplied by locational marginal prices;
- ancillary service: cleared operating reserves multiplied by market clearing prices;
- start-up: “… the out of pocket cost that a Market Participant incurs in starting up a generating unit from an off-line state …;”\footnote{Integrated Marketplace Protocols, Start-Up Offer} and
- no-load: “… the hourly fee for operating a synchronized Resource at zero … output.”\footnote{Integrated Marketplace Protocols, No-Load Offer}

Figure 4–38 shows the average daily production cost for the day-ahead market, while Figure 4–39 shows the average for the real-time market.
The day-ahead daily average production cost decreased 31 percent from 2021 to 2022. However, due to the effects of the February 2021 winter weather event, 2021 production costs were inflated due to the higher gas prices experienced during the event. Removing February from the daily production cost for 2021, the increase from 2021 to 2022 is 81 percent. The increase in production cost was almost fully attributed to the energy component, which increased with gas prices. The energy component is sensitive to numerous inputs, which include fuel cost, amount of subsidized renewable energy, operating reserve scarcity, and load levels. In 2022 daily day-ahead production costs ranged between ~$5 million and $159 million. Additionally, 66 percent of the daily production costs ranged between $0 and $45 million.

Figure 4–39  Production cost, daily average, real-time
Real-time production cost decreased by nine percent from 2021 to 2022 to a daily average of nearly $34 million. However, due to the effects of the February 2021 winter weather event, 2021 production costs were inflated due to the higher gas prices experienced during the event. Removing February from the daily production cost for 2021, the increase from 2021 to 2022 is 41 percent. The increase in production cost, similar to day-ahead, was also almost fully attributed to the energy component. The range of the daily real-time production costs in 2022 ranged from −$7 million to $207 million. Much like day-ahead market production costs, 67 percent of the daily production costs in real-time ranged between $0 million and $45 million.

4.4 LONG-RUN PRICE SIGNALS FOR INVESTMENT

In the long term, market prices provide signals for investment in new transmission and generation, as well as ongoing maintenance of existing generation and transmission assets to meet load. Given the relatively low average SPP market prices since the beginning of the market, the MMU does not expect SPP market prices by themselves to support new entry of generation investments. While the SPP market on its own has historically offered low incentives for new generation, some reasons for new generation investments include expansion of corporate renewable goals, bilateral contracts, purchase power agreements, SPP market protocol requirements, federal and/or state incentives, state-regulated investments, emerging technologies, and emission reduction plans. However, stakeholder reactions and feedback to SPP’s Board of Directors approval of a 3 percentage point increase in the Planning Reserve Margin (PRM) suggests that these out-of-market factors are not significant enough to drive enough investment in new generation to keep up with SPP’s reliability needs.

To determine the extent market prices could support new investments, the MMU analyzed the fixed costs, and annual fixed operating and maintenance costs of five generation technologies relative to their potential net revenues\textsuperscript{130} at SPP market prices. The generator types include scrubbed coal, natural gas combined-cycle (combined-cycle), industrial frame natural gas combustion turbine (combustion turbine), wind, and solar photovoltaic with storage. This analysis uses daily averages and assumptions to estimate profitability of constructing new generation and supporting the on-going cost of a new generator. It does not reflect profitability of any specific existing generator. Many costs, such as supply adequacy penalties and individual contracts, are not included in this analysis.

\textsuperscript{130} Net revenue is equal to revenues minus estimated marginal cost.
This is a very high-level analysis that uses several assumptions and averages. Daily averages at a hub were used for gas prices. A single gas hub was assumed for each region. These gas prices did not account for bilateral trades or any additional charges not represented by the hub price. Energy prices used were daily unweighted averages across the footprint.

Figure 4–40 provides the cost assumptions for a new generator. A capital recovery factor of 12.6 percent was used in the annual fixed operating and maintenance cost component.

**Figure 4–40  Net revenue analysis assumptions**

<table>
<thead>
<tr>
<th></th>
<th>Scrubbed coal</th>
<th>Combined-cycle</th>
<th>Combustion turbine</th>
<th>Wind</th>
<th>Solar</th>
</tr>
</thead>
<tbody>
<tr>
<td>Size (MW)</td>
<td>650</td>
<td>418</td>
<td>237</td>
<td>200</td>
<td>150</td>
</tr>
<tr>
<td>Total overnight cost ($/kW-yr)</td>
<td>$5,096</td>
<td>$1,201</td>
<td>$785</td>
<td>$1,718</td>
<td>$1,748</td>
</tr>
<tr>
<td>Variable overhead and maintenance ($/MWh)</td>
<td>$7.41</td>
<td>$2.67</td>
<td>$5.96</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Fixed overhead and maintenance ($/kW-yr)</td>
<td>$56.84</td>
<td>$14.76</td>
<td>$7.33</td>
<td>$27.57</td>
<td>$33.67</td>
</tr>
<tr>
<td>Heat rate (Btu/kWh)</td>
<td>9,751</td>
<td>6,431</td>
<td>9,905</td>
<td>n/a</td>
<td>n/a</td>
</tr>
</tbody>
</table>

Source: EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022

Figure 4–41 shows the results of the market-wide net revenue analysis. The analysis assumes the market dispatches the hypothetical resource when the day-ahead\(^{131}\) price exceeds the short-run marginal cost of production.\(^{132}\) Natural gas prices were based on the Panhandle Eastern Pipeline Company (PEPL) pipeline. To determine the variable cost of a new gas resource, these gas prices were multiplied by a heat rate and added to a variable operation and maintenance cost. The energy prices and variable costs determined a resource's margin, which determined the annual net revenue from SPP. Wind was attributed a capacity factor of 37 percent across all hours while solar was attributed a capacity factor of just under 40 percent during peak hours. Additionally, the average marginal cost of wind has been credited to account for production tax

\(^{131}\) Real-time prices produce similar results.

\(^{132}\) Parameters such as start-up time, minimum down time, max daily energy, and ramp rate are not modeled. This analysis assumes the resources is always available at maximum capacity.
incentives. The annual revenue requirement represents the cost to construct the generator and its fixed operating and maintenance cost.

**Figure 4–41  Net revenue analysis results**

<table>
<thead>
<tr>
<th>Technology</th>
<th>Average marginal cost ($/MWh)</th>
<th>Net revenue from SPP market ($/MW yr.)</th>
<th>Annual revenue requirement ($/MW yr.)</th>
<th>Able to recover new entry cost</th>
<th>Annual fixed O&amp;M cost ($/MW yr.)</th>
<th>Able to recover fixed O &amp; M cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scrubbed coal</td>
<td>$26.62</td>
<td>$197,629</td>
<td>$696,773</td>
<td>No</td>
<td>$54,570</td>
<td>Yes</td>
</tr>
<tr>
<td>Combined-cycle (single-shaft)</td>
<td>$49.44</td>
<td>$117,767</td>
<td>$165,576</td>
<td>No$\textsuperscript{133}</td>
<td>$14,760</td>
<td>Yes$\textsuperscript{133}</td>
</tr>
<tr>
<td>Combustion turbine (industrial frame)</td>
<td>$78.00</td>
<td>$41,598</td>
<td>$105,907</td>
<td>No$\textsuperscript{133}</td>
<td>$7,330</td>
<td>Yes$\textsuperscript{133}</td>
</tr>
<tr>
<td>Wind</td>
<td>-$30.00</td>
<td>$245,237</td>
<td>$243,309</td>
<td>Yes$\textsuperscript{134}</td>
<td>$27,570</td>
<td>Yes</td>
</tr>
<tr>
<td>Solar PV (storage)</td>
<td>$0.00</td>
<td>$126,083</td>
<td>$253,176</td>
<td>No</td>
<td>$33,670</td>
<td>Yes</td>
</tr>
</tbody>
</table>

With the exception of potentially 2021, SPP market revenues have been insufficient to support the cost of new entry of thermal generation since the inception of the Integrated Marketplace in 2014. Since 2015, regional average prices have supported the ongoing maintenance cost of combined-cycle and combustion turbine units but have not supported the ongoing maintenance cost of coal units. Thus, for a hypothetical gas-powered generator, the net revenues are not sufficient to cover new investment. However, whether revenues would support new investment more broadly may not be as clear given specific differences in revenues and costs. The analysis supporting Figure 4-41 is a market-wide analysis and does not account for regional and resource-specific factors influencing margin such as fuel storage, fuel contracts, etc. Currently, at the market level, revenues are only sufficient to ensure the cost of new entry is recovered for wind turbines.

$\textsuperscript{133}$ For gas resources, a simple yes or no is not sufficient to explain whether or not resource can recover costs. This analysis uses market-wide energy prices and average prices at gas hubs to determine profit margins. If a gas resource used an alternate fuel or had fuel storage, then that resource’s margin would be large, and it could have recovered all of its costs. However, if a resource bought gas at the extreme prices, then it would not have sufficient margin to recover costs. Because this analysis is performed on a market-wide basis, and not per resource, the wide range of profit margins cannot be generalized to a yes-or-no determination.

$\textsuperscript{134}$ Wind generation was likely to be able to recover its cost of new entry if it was able to generate at the annual average capacity factor.
Net revenues were calculated using average daily gas prices and average daily energy prices. The volatility of both gas and energy prices cause the average to be less representative of more granular market conditions and, therefore, less reliable for long-term investment decisions. As stated above, if gas resources were available with a secondary fuel source, their profit margins could have been very high, similar to coal and wind.

To determine how long run price signals for investment may vary across the footprint, a regional analysis is needed. Figure 4–42 provides results by SPP resource zone, as indicated by the dominant utility in the area.

### Figure 4–42 Net revenue analysis by zone

<table>
<thead>
<tr>
<th>Resource zone</th>
<th>Net revenue from SPP market ($/MW yr)</th>
<th>Able to recover net entry cost</th>
<th>Able to recover fixed O&amp;M cost</th>
<th>Net revenue from SPP market ($/MW yr)</th>
<th>Able to recover net entry cost</th>
<th>Able to recover fixed O&amp;M cost</th>
<th>Net revenue from SPP market ($/MW yr)</th>
<th>Able to recover net entry cost</th>
<th>Able to recover fixed O&amp;M cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEP</td>
<td>$261,207</td>
<td>No</td>
<td>Yes</td>
<td>$159,083</td>
<td>No</td>
<td>Yes</td>
<td>$55,343</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>KCPL</td>
<td>$173,765</td>
<td>No</td>
<td>Yes</td>
<td>$96,451</td>
<td>No</td>
<td>Yes</td>
<td>$32,174</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>NPPD</td>
<td>$151,449</td>
<td>No</td>
<td>Yes</td>
<td>$80,648</td>
<td>No</td>
<td>Yes</td>
<td>$27,216</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>OGE</td>
<td>$250,940</td>
<td>No</td>
<td>Yes</td>
<td>$163,302</td>
<td>No</td>
<td>Yes</td>
<td>$73,104</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>SPS</td>
<td>$200,198</td>
<td>No</td>
<td>Yes</td>
<td>$137,999</td>
<td>No</td>
<td>Yes</td>
<td>$54,039</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>WAUE</td>
<td>$177,698</td>
<td>No</td>
<td>Yes</td>
<td>$93,162</td>
<td>No</td>
<td>Yes</td>
<td>$28,777</td>
<td>No</td>
<td>Yes</td>
</tr>
</tbody>
</table>

Overwhelmingly, the conclusions do not vary geographically, despite differing energy prices and fuel costs. Historically, the SPS region has had higher net revenues than other regions for gas resources. This is likely because combined-cycle plants and combustion turbines in the Permian
Basin (West Texas) region consistently experience below average natural gas prices. However, this year the analysis showed that a gas resource in the AEP and OGE regions could have had higher revenues, though this was primarily driven by higher energy prices in these regions as both regions still experienced higher gas prices on average than SPS.

Based on these results, the MMU expects the market to continue to signal the retirement of some coal generation while also not signaling the long-term investment of other types of new generation. A decrease in overall available capacity—along with observed higher outages—and changes in the generation fleet profile could present challenges for reliability (see section 2.9 and section 3.4 for a more detailed analysis).

External economic decisions can provide additional impetus needed for new generation investments, such as the expansion of corporate renewable goals, SPP out-of-market payments, bilateral contracts, purchase power agreements, SPP market protocol requirements, federal and/or state incentives, state-regulated investments, emerging technologies, and/or emission reduction plans. However, market prices, by themselves, have not historically signaled new generation entry since the inception of the Integrated Marketplace. Other revenue streams for value added could change this conclusion. For instance, resources could be paid to ensure their generation is highly dependable, or resources could be paid to remain available for specific performance requirements in the short to medium timeframe. As the market is currently designed, it does not incentivize new entry for energy capacity.

Out-of-market actions by SPP operators, and the resultant uplift payments, for reliability (manual) commitments reflect some of the symptomatic issues. However, these do not necessarily signal the overall need for more steel-in-the-ground generation. Make-whole payments fund cost recovery and do not necessarily increase net revenue. If these make-whole payments were represented in a market price for a product, then this would likely reduce make-whole payments for manual commitments, but it would not necessarily increase net revenue. Because make-whole payments do not increase net revenue, they do not necessarily indicate the need for additional energy capacity. However, as previously mentioned, products could be implemented to pay for specific performance requirements, such as highly dependable available generation, schedulable generation, or rampable capacity. If such products were implemented, these product prices may indicate the need for these specific, non-energy capacity products.

Continuing to value flexibility will be important going forward. Compensation for reliable accreditation and performance could be an additional revenue stream to high-performing generation. This is discussed in more detail in chapter 7 of this report. The effectiveness of the pricing of such products and capacity ratings to align reliability and economics will shape future price signals for investment in the SPP market.
5 CONGESTION AND TRANSMISSION CONGESTION RIGHTS MARKET

This chapter reviews transmission congestion in the SPP market footprint, as well as the transmission congestion rights market in the Integrated Marketplace. Key points from this chapter include:

- The areas that experienced the highest congestion costs in 2022 were the southeastern corner of the SPP footprint, as well as a concentrated area in southeast North Dakota near the MISO seam. Much of Kansas, Nebraska, South Dakota, and a concentrated area in northwest Oklahoma experienced the lowest congestion costs for the year.

- Overall, congestion patterns were similar as the previous year in the SPP footprint but price splits were greater with lower congestion costs in high wind areas and higher congestion costs in the southeastern corner of SPP that is predominately natural gas resources. Intervals having no congestion are again rare in day-ahead in 2022 but decreased by more than half in real-time. Intervals having a breached constraint increased again in 2022 with over three-quarters of the intervals breached in the real-time market.

- The 2021 frequently constrained area study identified the southwest Missouri and southeast Oklahoma areas and these areas continued to see elevated congestion prices in 2022.

- In aggregate, load-serving entities covered 137 percent of their congestion cost and non-load-serving entities covered 108 percent of their total congestion cost.

- Individual market participants hedged congestion with varying degrees of effectiveness. Overall 72 percent of load-serving entities recovered at least all of their congestion cost.

- Total congestion payments for 2022 were nearly $2.0 billion; up from $1.2 billion in 2021. This marked increase can primarily be attributed to the proximity of existing generation to load, the proximity of newly constructed generation to load, the outage of key transmission facilities, and the volatility in fuel prices.
• Transmission congestion rights funding fell outside the target range. While the annual funding percentage increased to 88 percent from 84 percent, the annual shortfall worsened by more than $85 million year over year.

• Auction revenue right funding decreased from 128 percent to 122 percent. Relatedly, the ARR surplus increased by more than $140 million year over year.

• Participants can transfer congestion rights through use of a bulletin board or sell back positions in the auction. However, most congestion rights are not transferred or sold. Intra-auction sales\textsuperscript{135} increased slightly in volume, and averaged about six percent of the total auction volume. Bulletin board trades amounted to less than one percent of the total auction volume cleared during 2022.

5.1 TRANSMISSION CONGESTION

The locational marginal price (LMP) for over 1,300 settlement locations in the SPP market reflects the sum of three components:

1) marginal energy component (MEC) - system-wide marginal cost of the energy required to serve the market,

2) marginal congestion component (MCC) - the marginal cost of any increase or decrease in energy at a location with respect to transmission constraints, and

3) marginal loss component (MLC) - the marginal cost of any increase or decrease in energy to minimize system transmission losses.

\[ LMP = MEC + MCC + MLC \]

LMPs are a key feature of electricity markets that ensure the efficient scheduling, commitment, and dispatch of generation given the system load and reliability constraints. LMPs also provide price signals for efficient incentives for future generation and transmission investment and help guide retirement decisions.

This section focuses on the congestion and loss components of price and related items including:

• geographic pattern of congestion and losses,

\textsuperscript{135} The sale of a previously acquired position in a subsequent auction.
changes in the transmission system that alter congestion patterns,
congestion impacts on local market power,
load-serving entities hedging congestion costs in the transmission congestion rights market, and
distribution of marginal congestion and loss amounts.

5.1.1 PRICING PATTERNS AND CONGESTION
Figure 5–1 shows price contour maps representing the day-ahead and real-time average prices in 2022.

Figure 5–1  Price map, day-ahead and real-time market

Annual average day-ahead market prices ranged from around $16/MWh on the western edge of SPP to around $92/MWh in the south section of Oklahoma. Congestion accounted for about 85 percent of the price variation and marginal losses accounted for 15 percent in 2022. This is the highest percentage in price variation due to congestion since the beginning of the Integrated
Marketplace in 2014. Because congestion is more volatile in the real-time market, the average geographic price range is slightly larger, from $10/MWh to $100/MWh.

Transmission buildout has allowed higher levels of low-cost wind generation in the western parts of the SPP footprint to serve load centers located in the eastern portions of SPP. In addition, congestion remains mainly on the southeastern edge of SPP extending from northern Missouri to south Oklahoma.

The southwest Missouri\textsuperscript{136} area along the SPP eastern border continued to see congestion with average real-time prices increasing from around $39/MWh in 2021 to around $66/MWh in 2022. Another area along the SPP border that continues to see consistent congestion is southeast Oklahoma.\textsuperscript{137} Prices in this area were some of the highest in SPP with an average real-time price of $98/MWh in 2022. Congestion has also been prevalent around Oklahoma City\textsuperscript{138} for the past four years with average prices of $37/MWh in 2021 and $70/MWh in 2022. Lastly, real-time prices in a concentrated area in southeast North Dakota around a MISO market-to-market constraint\textsuperscript{139} averaged over $95/MWh in 2022.

5.1.2 CONGESTION BY GEOGRAPHIC LOCATION

The major drivers of the congestion pattern in SPP are the physical characteristics of the transmission grid and associated transfer capability, the geographic distribution of load, the geographic differences in fuel costs, and external flows from neighboring areas. The eastern side of the SPP footprint, with a higher concentration of load, also has a higher concentration of high-voltage (345 kV) transmission lines. Historically, high-voltage connections between the west and east have been limited but transmission buildout has resulted in most congestion occurring on the southeastern edge of the SPP footprint.

The costs of coal-fired generation increases as transportation costs rise. For example, transportation cost increases with distance from the Wyoming Powder River Basin near the northwest corner of SPP’s footprint. This is important because even though it is declining, coal still accounts for 23 percent of SPP’s installed capacity and 33 percent energy generation in 2022.

\textsuperscript{136} NEORIVNEOBLC (Neosho – Riverton 161kV for the loss of Neosho – Blackberry 345kV)
\textsuperscript{137} TMP109_22593 (Stonewall Switch – Tupelo Tap 138kV for the loss of Seminole – Pittsburg 345kV), TEMP29_23044 (Stonewall Switch - Tupelo Tap 138kV for the loss of Pittsburg-Valliant 345kV), TMP322_23590 (Stonewall Switch - Tupelo Tap 138kV for the loss of Sunnyside-Terry Road 345kV) and TMP493_24541 (Stonewall Switch - Tupelo Tap 138kV for the loss of Sunnyside-Hugo 345kV)
\textsuperscript{138} FRAMIDCANCED (Franklin – Midwest 138kV for the loss of Cedar Lane – Canadian 138kV)
\textsuperscript{139} TMP499_26328 (Forman Xfmr 230/1 kV ftlo Hankinson-Wahpeton 230kV)
Natural gas-fired generation, SPP’s largest fuel type by installed capacity (37 percent in 2022), resides predominantly in the southern portions of SPP. Wind-powered generation generally lies in the western half of the footprint, and nuclear generation resides near the center, while the majority of hydro is located in the north.

These factors combine to create a general northwest to southeast split in prices. One exception is slightly higher prices in the northern area of North Dakota along the border of Montana resulting from the growth of, and associated demand from, oil and gas exploration and production facilities. Other exceptions are along the MISO seam in North Dakota near a MISO constraint\(^\textsuperscript{140}\) and the lower southwest section of the SPP region around Lubbock, Texas and New Mexico.

Figure 5–2 depicts the average marginal congestion component for the day-ahead market across the SPP footprint in 2022.

\textbf{Figure 5–2} Marginal congestion cost map, day-ahead market

\footnotesize{\textsuperscript{140} TMP499\_26328 (Forman Xfmr 230/1 kV ftlo Hankinson-Wahpeton 230kV)}
The lowest average day-ahead marginal congestion costs occurred in the concentrated areas around west Kansas and west Nebraska, at -$20/MWh to -$16/MWh. The highest marginal congestion costs lie around the congestion in southeast Oklahoma and along the MISO seam in North Dakota, at almost $39/MWh.

The congestion in the southwest Missouri area increased from 2020 to 2021 and again in 2022. Congestion remained consistent in this area and in neighboring areas to the south, such as northwest Arkansas, Tulsa, and eastern Oklahoma. Transmission buildout over the years has widened congestion along the southeastern edge of the SPP footprint.

5.1.3 TRANSMISSION EXPANSION

Transmission projects totaling almost $40 million were completed or expected completion during 2022 (shown on Figure 5–3 below) will support the efficient transmission of energy across the SPP footprint and promote reliability. A list of these projects are included in the SPP Transmission Expansion Plan report.141 SPP’s Transmission Planning processes such as the Integrated Transmission Planning assessment, Generation Interconnection studies, and Transmission Service studies identify needs for transmission projects. The Integrated Transmission Planning assessment identified the projects in Figure 5–3 and the projects depicted on the map in Figure 5–4 are projects that will further enhance the SPP transmission grid in future years.

![Figure 5–3 SPP transmission expansion with 2022 in-service date](image)

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141 [2023 SPP Transmission Expansion Plan Report in Board of Directors/Members Committee January 31, 2023 meeting materials](#).
The SPP board of directors approved these projects and received a written notice from SPP to construct, or notification to construct (NTC) in 2022. The Integrated Transmission Plan (ITP) projects shown were identified in the ITP process looking ahead 10 years and seek to target a reasonable balance between long-term transmission investments and congestion costs to customers. The Generation Interconnection and Transmission Services projects were identified through aggregate studies of customers requesting generator interconnection projects or long-term requests for network and point-to-point transmission service. Projects identified to accommodate changes in delivery point facilities were through the AQ Studies process identified in Attachment AQ in the SPP tariff.

Figure 5–9 lists planned projects that may provide relief for the most congested areas in SPP. The planned projects in Figure 5–4 and Figure 5–9 will support the efficient transmission of energy across the SPP footprint and promote reliability. However, recent analysis by SPP staff has shown significant delays of several transmission projects, which will slow the benefits of these upgrades and can result in increased congestion costs. The transparency on these delays is currently limited. Therefore, the MMU recommends improving situational awareness of transmission upgrades and improving the process to reassign projects should transmission owners be unable to perform the upgrades in a reasonable timeframe.¹⁴²

¹⁴² See new recommendation 2022.3, Improve situational awareness of transmission upgrades and improve process to reassign projects in section 7.1.
5.1.4 TRANSMISSION CONSTRAINTS

Market congestion reflects the economic dispatch cost of honoring transmission constraints. SPP uses these constraints to manage the flow of energy across the physical bottlenecks of the grid in the least costly manner while ensuring reliability. In doing so, SPP calculates a shadow price for each constraint, which indicates the potential reduction in the total market production costs if the constraint limit were increased by one megawatt for one hour. Figure 5–5 provides the top 10 flowgate constraints by shadow price for 2022.

### Figure 5–5 Congestion by shadow price, top 10 flowgates

<table>
<thead>
<tr>
<th>Flowgate name</th>
<th>Region</th>
<th>Flowgate location</th>
</tr>
</thead>
<tbody>
<tr>
<td>TMP499_26328</td>
<td>North Dakota</td>
<td>Forman Xfmr 230/1 kV ftlo Hankinson-Wahpeton 230kV (OTP)</td>
</tr>
<tr>
<td>TMP270_23432</td>
<td>Oklahoma</td>
<td>Cleveland-Cleveland AECI 138 kV (AECI-GRDA) ftlo Cleveland-Tulsa North 345 kV (CSWS-GRDA)</td>
</tr>
<tr>
<td>CIMXF3CIMXF2</td>
<td>Oklahoma City</td>
<td>Cimarron Xfmr 345/1 kV ftlo 3 contingent elements of Cimarron Xfmr (OKGE)</td>
</tr>
<tr>
<td>OSAWEBCLES0O</td>
<td>Oklahoma</td>
<td>Osage-Webb Tap 138 kV (CSWS-OKGE) ftlo Sooner-Cleveland 345 kV (GRDA-OKGE)</td>
</tr>
<tr>
<td>TMP159_24149</td>
<td>South Oklahoma</td>
<td>Russett-South Brown 138kV (WFEC) ftlo Little City-Brown Tap 138kV (OKGE)</td>
</tr>
<tr>
<td>NEORIVNENOBLC*</td>
<td>SW Missouri/SE Kansas</td>
<td>Neosho-Riverton 161kV (EDE-WR) ftlo Neosho-Blackberry 345kV (AECI-WR)</td>
</tr>
<tr>
<td>TMP551_26749</td>
<td>Texas Panhandle</td>
<td>Conway-Kirby Sw. Station 115kV (SPS) ftlo Nichols-Grapevine 230kV (SPS)</td>
</tr>
<tr>
<td>TMP278_25759^</td>
<td>Missouri</td>
<td>Overton Xfmr 345/161 kV (AMRN) ftlo Overton-McCredie 345 kV (AECI-AMRN)</td>
</tr>
<tr>
<td>CHAWATCHAPAT*</td>
<td>North Dakota</td>
<td>Charlie Creek-Waterford City 230kV (WAUE) ftlo Charlie Creek-Patentgate 345kV (WAUE)</td>
</tr>
<tr>
<td>TEMP90_26027</td>
<td>SW Missouri</td>
<td>Monett-Aurora 161kV (EDE) ftlo Blackberry-Jasper 345kV (AECI)</td>
</tr>
</tbody>
</table>

* SPP market-to-market flowgate during all or part of 2022
^ MISO market-to-market flowgate during all or part of 2022
The southeastern edge of the SPP footprint from northern Missouri to southern Oklahoma continues to see higher prices. This results from congestion impacted by inexpensive wind generation in the west and external flows from the east. Areas around Tulsa, Oklahoma City, and southeast Oklahoma continue to see consistent congestion in 2022. The Cleveland-Cleveland AECI flowgate west of Tulsa was the second most congested flowgate in 2022 with an average shadow price over $90/MWh in the real-time. The Cimarron transformer flowgate near Oklahoma City averaged a real-time shadow price of $87/MWh. The Russett-South Brown flowgate in southeast Oklahoma averaged a real-time shadow price over $56/MWh. The Neosho-Riverton flowgate was the only SPP market-to-market constraint to appear as one of the top 10 most congested flowgates in 2022 averaging a real-time shadow price of $42/MWh.

Two MISO market-to-market flowgates appeared as two of the top 10 most congested constraints in real-time in 2022. One of these is the Forman transformer that had the highest average real-time shadow price of $101/MWh in 2022 but only averaged $35/MWh in the day-ahead in 2022. This constraint was not congested in the SPP day-ahead market until October 1, 2022. The joint Market-to-Market Coordination study for the SPP Regional State Committee and Organization of MISO States highlights this inefficiency. The MMU recommended in 2020 that SPP collaborate with MISO to study and address this and other inefficiencies in its 2020 annual state of the market report. This flowgate was congested in 27 percent of intervals in real-time compared to 17 percent of the intervals in the day-ahead. All day-ahead congested intervals occurred after October 1, 2022 when SPP began including MISO constraints consistently in the day-ahead market.

5.1.4.1 Southwest Missouri

SPP and MISO wind, as well as flows from neighboring non-market areas impact the southwest Missouri area. The primary constraint in this area is the Neosho – Riverton market-to-market flowgate and dates back prior to the start of the Integrated Marketplace. 

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143 TMP270_23432: Cleveland-Cleveland AECI 138 kV ftlo Cleveland-Tulsa North 345 kV
144 CIMXF3CIMXF2: Cimarron Xfmr 345/1 kV ftlo 3 contingent elements of Cimarron Xfmr
145 TMP159_24149: Russett-South Brown 138kV ftlo Little City-Brown Tap 138kV
146 NEORIVNEOBLC: Neosho-Riverton 161kV ftlo Neosho-Blackberry 345kV
147 TMP499_26328: Forman transformer 230//1kV ftlo Hankinson-Wahpeton 345kV
148 OMS-RSC Seams Study: Market-to-Market Coordination prepared by Potomac Economics
149 SPP MMU 2020 Annual State of the Market report
150 Neighboring non-markets include Tennessee Valley Authority, Associated Electric Cooperative Inc., and Southwestern Power Administration.
151 NEORIVNEOBLC: Neosho-Riverton 161kV ftlo Neosho-Blackberry 345kV
constraint was one of the top 10 congested flowgates in 2022. Section 5.1.5 notes the Neosho-Riverton 161kV project that may provide relief to this area. This upgrade was energized in January 2023. Figure 5–6 compares congestion on the Neosho – Riverton 161kV constraint since 2020.

**Figure 5–6** Southwest Missouri congestion

Congestion increased significantly from 2021 to 2022 for the Neosho-Riverton 161kV flowgate. The average real-time shadow price increased from $15/MWh in 2021 to $42/MWh in 2022. The day-ahead average shadow price increased from $21/MWh to almost $52/MWh over the same period. The percent of intervals binding in the real-time increased from almost seven percent in 2021 to 11 percent in 2022. Over $73 million in payments from MISO to SPP has settled since the start of the market-to-market process\(^\text{152}\) for the Neosho-Riverton constraint. This is the highest amount settled between SPP and MISO for any constraint since the start of the process.

### 5.1.4.2 Southeast Oklahoma

Another area of consistent congestion over the last few years is the southeast Oklahoma area. There are four constraints with Stonewall Switch – Tupelo Tap 138kV\(^\text{153}\) and although none were the top 10 congested flowgates in 2022, at least one of these four constraints appeared in 2019 through 2021. TMP322_23590 was the seventh most constrained flowgate by average real-time shadow price in 2021. TEMP29_23044 was the second most constrained flowgate in 2020 and

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\(^{152}\) The market-to-market process between SPP and MISO began March 2015.

\(^{153}\) TMP322_23590 (Stonewall Switch-Tupelo Tap 138kV for the loss of Sunnyside-Terry Road345kV), TEMP29_23044 (Stonewall Switch -Tupelo Tap 138kV for the loss of Pittsburg-Valliant 345kV), TMP109_22593 (Stonewall Switch – Tupelo Tap 138kV for the loss of Seminole – Pittsburg 345kV) and TMP493_24541 (Stonewall Switch -Tupelo Tap 138kV for the loss of Sunnyside-Hugo 345kV)
TMP109_22593 was the second most constrained in 2019. These constraints have the same limiting facility with differing contingent facilities. Figure 5–7 compares congestion for all four of the flowgates with the limiting facility of Stonewall Switch-Tupelo Tap since 2020.

**Figure 5–7 Southeast Oklahoma congestion**

The Stonewall Switch – Tupelo Tap market-to-market flowgates have seen consistent congestion since 2018 (not shown) but decreased in 2022. These constraints experienced congestion in almost 20 percent of all intervals in the day-ahead market in 2022 that is unchanged from 2021. These constraints experienced almost three percent of congestion during all intervals in the real-time market in 2022 compared to five percent in 2021. The average shadow prices in 2022 were almost $19/MWh in real-time and almost $21/MWh in day-ahead.

Another area that has seen consistent congestion in real-time is in the Oklahoma City area. The Midwest - Franklin\(^{154}\) constraint was the fifth most congested constraint in both 2019 and 2020 but has not appeared as one of the top 10 constraints in 2021 or 2022. However, congestion still increased in 2022 with respect to shadow price. Figure 5–8 compares congestion for this constraint since 2020.

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\(^{154}\) FRAMIDCANCELED: Midwest-Franklin 138kV for the loss of Cedar Lane-Canadian 138kV.
The Midwest – Franklin constraint is located east of Oklahoma City and increased in real-time shadow price from 2021 to 2022. This constraint experiences less congestion in day-ahead when compared to real-time. Almost seven percent of all real-time intervals experienced congestion in 2022 compared to less than three percent of all day-ahead intervals in the same year. This difference between real-time and day-ahead is also apparent in the average shadow prices for both markets where the real-time averages more than $25/MWh and day-ahead only averages $3/MWh.
5.1.5 PLANNED TRANSMISSION PROJECTS

Figure 5–9 provides a list of projects that may alleviate congestion on the 10 most congested flowgates in the SPP system.

**Figure 5–9  Top 10 congested flowgates with projects**

<table>
<thead>
<tr>
<th>Flowgate name</th>
<th>Region</th>
<th>Flowgate location</th>
<th>Projects that may provide relief</th>
</tr>
</thead>
<tbody>
<tr>
<td>TMP499_26328^</td>
<td>North Dakota</td>
<td>Forman Xfmr 230/1 kV ftlo Hankinson-Wahpeton 230kV (OTP)</td>
<td>2023 ITP need</td>
</tr>
<tr>
<td>TMP270_23432</td>
<td>Oklahoma</td>
<td>Cleveland-Cleveland AECI 138 kV (AECI-GRDA) ftlo Cleveland-Tulsa North 345 kV (CSWS-GRDA)</td>
<td>New Sooner-Wekiwa 345kV line <a href="155">2019 ITP Assessment</a></td>
</tr>
<tr>
<td>CIMXF3CIMXF2</td>
<td>Oklahoma City</td>
<td>Cimarron Xfmr 345/1 kV ftlo 3 contingent elements of Cimarron Xfmr (OKGE)</td>
<td>Minco – Pleasant Valley – Draper 345kV <a href="156">2020 ITP</a></td>
</tr>
<tr>
<td>OSAWEBCLESOO</td>
<td>Oklahoma</td>
<td>Osage-Webb Tap 138 kV (CSWS-OKGE) ftlo Sooner-Cleveland 345 kV (GRDA-OKGE)</td>
<td>New Sooner-Wekiwa 345kV line <a href="155">2019 ITP Assessment</a></td>
</tr>
<tr>
<td>TMP159_24149</td>
<td>South Oklahoma</td>
<td>Russett-South Brown 138kV (WFEC) ftlo Little City-Brown Tap 138kV (OKGE)</td>
<td>NTC 210586 Russett – S Brown Rebuild [2020 ITP]</td>
</tr>
<tr>
<td>TMP551_26749</td>
<td>Texas Panhandle</td>
<td>Conway-Kirby Sw. Station 115kV (SPS) ftlo Nichols-Grapevine 230kV (SPS)</td>
<td>Border – Woodward 345kV (156) and Minco – Pleasant Valley – Draper 345kV [2020 ITP]</td>
</tr>
<tr>
<td>TMP278_25759^</td>
<td>Missouri</td>
<td>Overton Xfmr 345/161 kV (AMRN) ftlo Overton-McCrede 345 kV (AECI-AMRN)</td>
<td>MISO LRTP Tranche 1 (Northern Missouri Corridor)</td>
</tr>
<tr>
<td>CHAWATCHAPAT*</td>
<td>North Dakota</td>
<td>Charlie Creek-Waterford City 230kV (WAUE) ftlo Charlie Creek-Patentate 345kV (WAUE)</td>
<td>NTC 210675 Kummer Ridge – Roundup 345 kV</td>
</tr>
<tr>
<td>TEMP90_26027</td>
<td>SW Missouri</td>
<td>Monett-Aurora 161kV (EDE) ftlo Blackberry-Jasper 345kV (AECI)</td>
<td>None at this time. Will evaluate in 2023 ITP</td>
</tr>
</tbody>
</table>

* SPP Market-to-Market flowgate during all or part of 2022
^ MISO Market-to-Market flowgate during all or part of 2022

5.1.6 GEOGRAPHY AND MARGINAL LOSSES

Variable transmission line losses decrease with increased line voltage or decreased line length for the same amount of power moved. In the SPP footprint, much of the low-cost generation resides at a distance from the load and with limited high-voltage interconnection. The average variable losses on the SPP system for 2022 were 3.2 percent in the day-ahead market. This is up slightly from 3 percent in 2021 and 2.7 percent in 2020. The marginal loss component of the

155 NTC 210540, 210544, and 210593: Multi – Sooner – Wekiwa 345 kV and Sand Springs – Sheffield 138 kV
156 NTC 210616, 210656, and 210670: Multi – Minco – Pleasant Valley – Draper 345 kV
157 NTC 210569 and 210570: Line – Neosho – Riverton 161 kV
158 NTC 210627 and 210628: Multi – Border – Woodward 345 kV Tap
price captures the change in the total system cost of losses with an additional increment of load at a particular location relative to the reference bus.

Figure 5–10 maps the annual average day-ahead market marginal loss components for 2022.

Figure 5–10  Marginal loss component map, day-ahead

The average day-ahead marginal loss component ranges from less than −$7/MWh in western Nebraska to over $6/MWh in southern Oklahoma to eastern Texas. Negative values reduce prices through the marginal loss component relative to the marginal energy cost. Positive values increase prices as generation from these locations are more beneficial from a marginal loss perspective. The $13/MWh spread between geographic prices in 2022 is higher than the $8/MWh spread between geographic prices in 2021 is higher than the $5/MWh spread in 2020.
5.1.7 FREQUENTLY CONSTRAINED AREAS AND LOCAL MARKET POWER

Congestion in the market creates local areas where only a limited number of suppliers can provide the energy to serve local load without overloading a constrained transmission element. Under these circumstances, the pivotal suppliers have local market power and the ability to raise prices above competitive levels thereby extracting higher than normal profits from the market. SPP’s tariff provides provisions for mitigating the impact of local market power on prices, and the effectiveness of market power mitigation is described in section 6.2.2. Local market power can be either transitory, as is frequently the case with an outage, or persistent, when a particular load pocket is frequently import-constrained.

Since the SPP tariff calls for more stringent market power mitigation for frequently constrained areas, the MMU analyzes market data at least annually to assess the appropriateness of the frequently constrained area designations. The 2021 study\(^{159}\) identified two areas to be added with one being the previous frequently constrained area of southwest Missouri and the other in southeast Oklahoma. These areas experienced increases in pivotal supplier hours in the 2021 study after slightly falling under thresholds in the 2020 analysis. These frequently constrained areas became effective on December 27, 2021. The southwest Missouri frequently constrained area consists of nine constraints and eleven resources while the southeast Oklahoma area consists of seven constraints and five resources. These areas continued to see high levels of congestion in both frequency and price through 2022.

5.1.8 MARKET CONGESTION MANAGEMENT

In optimizing the flow of energy to serve the load at the least cost, the SPP market makes extensive use of the available transmission up to constraint limits. When constraints reach their limits, they are considered binding. The market occasionally allows transmission lines to exceed their rating if the price to correct the overload becomes too high.\(^{160}\) This is considered a breached constraint. Figure 5–11 highlights day-ahead market binding, breached, and uncongested intervals.

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\(^{159}\) [Frequently Constrained Area Report 2021](#)

\(^{160}\) SPP uses hourly intervals in the day-ahead market and five-minute intervals in the real-time market for scheduling, dispatch, and settlement purposes.
The figure shows that breached intervals increased in day-ahead market year over year. Historically in the Integrated Marketplace, less than one percent of day-ahead market intervals incur a breached condition but over four percent of intervals incurred a breach in 2021 and increased to over eight percent in 2022. Uncongested intervals in the day-ahead are rare. Less than one percent of intervals were uncongested in the day-ahead in 2021 and 2022 compared to 1.5 percent in 2020.

In the more dynamic environment of the real-time market, uncongested intervals and breached intervals occur more frequently than in the day-ahead market. Real-time congestion is shown in Figure 5–12.
As shown above, uncongested intervals reduced since 2020. Only three percent of intervals in real-time in 2022 were uncongested compared to eight percent in 2021 and 18 percent in 2020. Real-time intervals with a breached constraint continued to increase since 2018. Intervals with a breach in 2022 were 76 percent compared to 68 percent in 2021 and 46 percent in 2020.

Market-to-market coordination with MISO, as discussed in 2.7.2, was implemented in March 2015. A market-to-market breach of a MISO constraint could be an indicator that MISO has more efficient generation than SPP to alleviate congestion on that constraint. Of the 76 percent of the real-time intervals with a breached constraint in 2022, almost 80 percent of these had a breached market-to-market constraint compared to 85 percent in 2021, 86 percent in 2020, and 74 percent in 2019. This is noticeable in Figure 5–1 and Figure 5–2 showing the congestion on the eastern edge of SPP where neighboring flows are more prevalent.

Real-time congestion by flowgate type is shown in Figure 5–13.

**Figure 5–13  Breached and binding intervals real-time, by flowgate type**

<table>
<thead>
<tr>
<th></th>
<th>Binding</th>
<th>Breached</th>
<th>Uncongested</th>
</tr>
</thead>
<tbody>
<tr>
<td>Excluding market-to-market flowgates</td>
<td>56%</td>
<td>55%</td>
<td>49%</td>
</tr>
<tr>
<td>Market-to-market flowgates only</td>
<td>10%</td>
<td>7%</td>
<td>8%</td>
</tr>
<tr>
<td>All flowgates</td>
<td>36%</td>
<td>25%</td>
<td>21%</td>
</tr>
</tbody>
</table>

Internal constraints increased in the percentage of breached intervals in real-time from 2020 to 2021 and again in 2022. The percentage of intervals with a breached market-to-market constraint was 60 percent in 2022, up slightly from 58 percent in 2021. The percentage of intervals with only binding internal constraints fell slightly from 55 percent in 2021 to 49 percent in 2022. The market’s ability to maintain flow on constraints at or below their limits are binding, or manageable. Breached constraints indicate the instances where the market allows flow to exceed a constraint’s limit at a certain cost. These are also known as unmanageable intervals. As the percentage of uncongested intervals and manageable intervals continue to decrease, unmanageable intervals increase.

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161 Excluding market-to-market constraints
5.1.9 CONGESTION PAYMENTS AND UPLIFTS

Market participants in the energy market incur congestion costs and receive congestion payments based on their marginal impact on total market congestion cost through the marginal congestion component of price. Most SPP market participants owning physical assets are vertically integrated, so their net congestion cost depends on two things. The first is whether they are a net buyer or seller of energy. The second is the relative marginal cost component at their generation and load. For financial market participants, congestion costs reflect the impact of virtual positions on a binding or breached constraint in the day-ahead and real-time markets.

Figure 5–14 shows the annual day-ahead and real-time market congestion payments for load-serving market participants during 2021.

Figure 5–14  Annual congestion payment by load-serving entity

Most load-serving entities face congestion costs, depicted as negative payments (charges) in the graph. Congestion stems from various injection and withdrawal market activities and can manifest as either a charge or credit. Day-ahead congestion payments ranked by load-serving entities ranged from more than $360 million in charges to almost $35 million in payments.162

Market participants also receive payments and incur costs for real-time market congestion, which are charged and paid based on deviations between day-ahead and real-time market positions. At an aggregate level, absent the additional revenue neutrality uplift costs, 92 percent of the SPP load-serving entities’ net congestion costs stemmed from the day-ahead market.

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162 Day-ahead congestion collections funds transmission congestion rights. These rights are described in greater detail in Section 5.2.
Figure 5–15 provides the aggregate congestion costs and hedging totals for load-serving entities, non-load-serving entities and financial only entities, and the total for all entities.

**Figure 5–15 Total congestion payments**

<table>
<thead>
<tr>
<th>(in $ millions)</th>
<th>Load-serving entities</th>
<th>Non-load-serving and financial-only entities</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day-ahead congestion</td>
<td>$ 352</td>
<td>$ 849</td>
<td>$ 1,706</td>
</tr>
<tr>
<td>Real-time congestion</td>
<td>-9</td>
<td>-10</td>
<td>-158</td>
</tr>
<tr>
<td>Net congestion</td>
<td>344</td>
<td>838</td>
<td>1,548</td>
</tr>
</tbody>
</table>

Net congestion payments for 2022 exceeded $2.0 billion, up from nearly $1.2 billion in 2021. This marked increase can primarily be attributed to the proximity of existing generation to load, the proximity of newly constructed generation to load, the outage of key transmission facilities, and the volatility in fuel price.

The real-time market congestion payments result in a net benefit of $158 million for load-serving entities. Total real-time market congestion payments for non-load-serving and financial only entities also resulted in a net benefit and amounted to $527 million. On an individual basis, real-time market congestion ranged from $18 million in payments to nearly $39 million in costs for load-serving entities. Real-time market congestion ranged from $116 million in payments to $67 million in costs for non-load-serving entities. Many of the non-load-serving entities incurring costs represent wind farms, which may sell at negative prices or buy back day-ahead market positions.

Unlike day-ahead congestion, which funds transmission congestion rights, real-time market congestion costs are allocated to market participants through revenue neutrality uplift (RNU) charges. In 2022, SPP allocated about 90 percent of revenue neutrality uplift charges to load-serving entities, resulting in an additional $591 million in congestion-related charges for load-serving entities.\(^\text{163}\)

\(^\text{163}\) Real-time congestion uplift is not allocated in the same proportion in which it is collected.
5.2 CONGESTION HEDGING MARKET

In the Integrated Marketplace, the locational marginal prices assessed to load are generally higher than the locational marginal prices assessed to generators. The largest portion of this price difference is almost always attributed to congestion. This is an expected outcome and central to the design of nodal electricity markets. The difference between what generators are paid and what loads pay is often referred to as congestion rent. SPP remains revenue neutral in all Integrated Marketplace transactions and therefore must allocate the congestion rent back to the market participants. The congestion hedging market is the mechanism used to allocate congestion over-collections.\(^{164}\)

5.2.1 MARKET DESIGN

Market participants participate in the congestion hedging market by obtaining auction revenue rights and/or transmission congestion rights. Auction revenue rights begin as entitlements associated with long-term, firm transmission service reservations. These transmission service reservations are a revenue source for transmission owners and an expense for transmission customers. More specifically, transmission owners receive revenues from transmission customers for building and maintaining the transmission lines, and transmission customers pay the transmission owners for the use of the lines by way of the charges associated with transmission service reservations.\(^{165}\)

Auction revenue rights link the transmission service, which provides physical rights, to the Integrated Marketplace by converting these to financial rights. SPP verifies transmission service entitlements, which become candidate auction revenue rights. To obtain auction revenue rights, market participants nominate candidate auction revenue rights in the annual auction which awards revenue rights from June to May. If the nominations pass the allocation’s simultaneous feasibility test, the candidate auction revenue rights become auction revenue rights. The simultaneous feasibility test ensures that the market’s aggregate nomination of auction revenue rights does not violate thermal constraint limits under a single contingency.\(^{166}\) The test incorporates information from the network model, which aids SPP in aligning the supply of auction revenue rights with the capacity of the underlying transmission system. The simultaneous feasibility test aims to ensure the revenues generated from the congestion right auction will sufficiently fund the quantity of auction revenue rights nominated. If a candidate

\(^{164}\) With respect to day-ahead congestion rent only.

\(^{165}\) These charges are assessed through transmission settlements and include various tariff schedules.

\(^{166}\) *SPP Open Access Transmission Tariff*, Section 5.3.3, Simultaneous Feasibility
auction revenue right nomination fails the simultaneous feasibility test, this reduces the quantity of auction revenue rights successfully converted from candidate rights.\(^{167}\)

Once market participants have successfully nominated their candidates into auction revenue rights, they must choose to either hold their auction revenue right or convert it into a transmission congestion right through a process known as self-conversion.\(^{168}\) If a market participant holds their auction revenue right, they will receive, or pay, a stream of unchanged cash flows over the life of the product. The size and direction of the cash flow depends on the market’s collective assessment of the congestion rent along the auction revenue right path as assessed by prices during the transmission congestion right auction. If a market participant believes that the auction prices will undervalue the congestion rent associated with their auction revenue right, the market participant will likely self-convert. When a market participant self-converts, their auction revenue right becomes a transmission congestion right, which means their cash flow is subject to the fluctuations in day-ahead market congestion rent.

Financial-only\(^ {169}\) market participants participate alongside traditional utilities in the transmission congestion right auctions to provide additional liquidity and price discovery. All participants compete for the residual network capacity, on price. The auction software attempts to maximize auction revenue without violating the simultaneous feasibility test. This test helps align the supply of transmission congestion rights with the residual capacity of the underlying transmission system. If a transmission congestion right bid fails the simultaneous feasibility test, the quantity of transmission congestion rights successfully obtained will be reduced to the point where the bid no longer violates the test. Once a market participant obtains a transmission congestion right, they can hold it through to settlement, offer it for sale in a subsequent auction, or transact on the bulletin board outside of the auction cycle. The overwhelming majority of positions are held through to settlement.

### 5.2.2 Market Transparency

#### 5.2.2.1 Hedging effectiveness by classification

The transmission congestion right and auction revenue right net payments paid to entities in the SPP market are shown in Figure 5–16.


\(^{168}\) SPP Open Access Transmission Tariff, Section 5.4.1 (2)

\(^{169}\) Financial-only market participants do not generate or serve load in the SPP footprint.
### Figure 5–16  Total congestion and hedges

<table>
<thead>
<tr>
<th></th>
<th>Load-serving entities</th>
<th>Non-load-serving and financial only entities</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>DA congestion</td>
<td>352</td>
<td>849</td>
<td>1,760</td>
</tr>
<tr>
<td>RT congestion</td>
<td>(9)</td>
<td>(10)</td>
<td>(158)</td>
</tr>
<tr>
<td>Net congestion</td>
<td>344</td>
<td>838</td>
<td>1,548</td>
</tr>
<tr>
<td>TCR charges</td>
<td>243</td>
<td>295</td>
<td>815</td>
</tr>
<tr>
<td>TCR payments</td>
<td>(409)</td>
<td>(859)</td>
<td>(1,737)</td>
</tr>
<tr>
<td>TCR uplift</td>
<td>55</td>
<td>124</td>
<td>164</td>
</tr>
<tr>
<td>TCR surplus *</td>
<td>(2)</td>
<td>(8)</td>
<td>(11)</td>
</tr>
<tr>
<td>ARR payments</td>
<td>(325)</td>
<td>(442)</td>
<td>(1,170)</td>
</tr>
<tr>
<td>ARR surplus</td>
<td>(72)</td>
<td>(80)</td>
<td>(182)</td>
</tr>
<tr>
<td>Net TCR/ARR</td>
<td>(509)</td>
<td>(970)</td>
<td>(2,122)</td>
</tr>
</tbody>
</table>

* remaining at year-end

Payments to load-serving entities of $2.1 billion exceeded their day-ahead congestion costs of $1.7 billion in 2022. Additionally, real-time congestion costs aided load-serving entities by $158 million, thereby reducing total congestion cost to $1.5 billion. This shows that overall, load-serving entities hedged their day-ahead congestion effectively, in aggregate. In 2022, non-load-serving and financial only entities collected transmission congestion right and auction revenue right net revenues of $533 million, which exceeded their day-ahead and real-time market congestions costs of $493 million. Overall, day-ahead congestion cost increased ninety-five percent from $1.4 billion in 2021 to $2.7 billion in 2022.

#### 5.2.2.2 Bidding behaviors

The SPP working groups continued dialogue over the past year with respect to obtaining auction revenue rights, and by extension self-converted transmission congestion rights. These discussions and the related policy development are expected to continue. The MMU will continue to take part in its advisory capacity.

As noted above, in aggregate, load-serving entities received more revenue from their congestion hedges than they paid in day-ahead and real-time congestion cost. However, on the individual participant level, some load-serving entities under-hedged while others over-hedged.
Figure 5–17 shows, by load-serving market participant, the day-ahead congestion exposure along with the value of auction revenue rights and transmission congestion rights as well as the net overall position.

**Figure 5–17  Net congestion revenue by market participant**

The figure highlights that the majority of load-serving participants received positive net revenues, while a handful of participants held portfolios that did not cover their day-ahead congestion costs. For instance, the bottom five participants paid $261 million more in congestion costs than was offset by their auction revenue right and transmission congestion right positions. This is more than double the $125 million paid by the bottom five participants in the 2021 calendar year.

The range of participant outcomes is influenced by three main factors: hedging need, individual participant bidding behavior, and the market’s collective bidding behavior.

With respect to hedging need, each participant experiences varying levels of congestion exposure mostly related to geographic location and type of physical interconnection. The various levels of congestion exposure lead to different hedging needs among market participants.

The bidding behavior of the individual participant affects the auction revenue rights they receive through the allocation. Participants can, and do, employ numerous strategies with varying degrees of success.

The bidding behavior of the other market participants, as a whole, affects the ability of each and every other market participant to obtain hedges through the auction revenue right allocation. More specifically, if a transaction is physically feasible with respect to transmission service, and
by extension the day-ahead market, it does not necessarily mean the transaction will also be feasible in the auction revenue right allocation. The issue arises because the transmission system’s capacity, represented by transmission service requests,\textsuperscript{170} includes both prevailing flow and counter-flow transactions. However, participants often choose not to nominate their counter-flow candidate auction revenue rights in the allocation process, in part, because these positions tend to carry negative cash flows. These incentives motivate individual participants to abstain from counter-flow positions.\textsuperscript{171} By not nominating all candidate auction revenue rights, the capacity in the allocation will not match the capacity of the physical system. Because the basis of the auction revenue right is transmission service, if the two capacities do not align, a participant’s auction revenue right may not perfectly hedge their transmission service and their related day-ahead market activity.

Differences between outages modeled in the auction processes and day-ahead market can also affect market participants’ ability to obtain hedges. Details on outage modeling are discussed below.

5.2.2.3 Transmission outage modeling

When there are outages in the day-ahead market that were not in the transmission congestion rights auction, there is a reduction in system capacity, which can cause underfunding. Figure 5–18 shows transmission outages by reported lead time.

\textbf{Figure 5–18 Transmission outages by reporting lead time}

\textsuperscript{170} Long-term, firm, transmission service requests

\textsuperscript{171} SPP MWG Meeting Materials, 1/22/2019, Item 11a, SPP MMU_ARR Observation.pdf
SPP models only transmission outages that were reported at least 45 days prior to the first of the month in the transmission congestion rights auction. However, SPP only requires transmission owners to submit planned outages 14 days in advance. The above figure shows that the majority of outages are not considered in the transmission congestion rights markets solely due to the submission lead time. Roughly, 77 percent of outages are ruled out of the transmission congestion rights model by this phase alone. This is a similar level as prior years.

Figure 5–19 shows the duration in days for the different types of outages.

**Figure 5–19  Transmission outages by duration**

Outages shorter than five days are excluded from auction revenue right/transmission congestion right processes. This means the vast majority of outages (80 percent) are excluded from the transmission congestion rights models because they are less than five days or were not reported in the time allowed to be included in the transmission congestion rights models.

Figure 5–20 shows outages by real-time, day-ahead, and transmission congestion right markets.

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172 Integrated Marketplace Protocols, Section 6.6
173 SPP Operating Criteria, Appendix OP-2
While the number of outages in the day-ahead and real-time are similar, the outages represented in the transmission congestion rights market are only a fraction of the total number of outages. The transmission congestion market only includes outages that are longer than five days, and are submitted at least 45 days in advance of the first of the month. This represented only about six percent of the total outages in the day-ahead market. These differences in outages can create underfunding of transmission congestion rights.

Ideally, outages in the transmission congestion rights markets would be perfectly aligned with the day-ahead market. However, the MMU understands the challenges associated with accounting for outages in the transmission congestion rights market and recognizes that there can never be an exact match among the markets. Even so, improving how outages are handled and accounted for in the auction processes could help to improve underfunding. We encourage stakeholders to improve how outages are accounted for in the transmission congestion right auction process to improve the congestion hedging market results.

**5.2.3 FUNDING**

Funding for transmission congestion rights\(^\text{174}\) increased in 2022, however, it remains below the 90 percent target. Conversely, the funding percentage for auction revenue rights and auction

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\(^{174}\) This report shows metrics for transmission congestion rights on a calendar year. However, this differs from the TCR year, which is reported by the SPP RTO, and covers a period starting June 1 and ending on May 31 of the following year. Therefore, the 2022 TCR year starts on June 1, 2022 and ends on May 31, 2023. The Spring 2022 Quarterly State of the Market report shows totals for the 2022 TCR year, which ended on May 31, 2022. The 2022 TCR year will be reviewed in the MMU's Spring 2023 Quarterly State of the Market report.
revenue right closeout decreased in 2022. As mentioned in previous reports, the overfunding of auction revenue rights could be cause for concern. The market monitor continues to encourage SPP to review and address the reasons for this overfunding.

Figure 5–21  Transmission congestion right funding levels, annual, calendar year

The 2020 calendar year produced 82 percent transmission congestion right funding while the following calendar years increased to 84 percent in 2021 and 88 percent in 2022. The 2022 underfunding is primarily the result of outages in the day-ahead market that were not included in the transmission congestion hedging models. The funding percentage increased modestly year-over-year, however the shortfall increased by roughly $85 million during 2022.

The transmission congestion right funding, represented in Figure 5-21, incorporates both underfunded and overfunded constraints. The sum of the overfunded and underfunded constraints resulted in net underfunding of $355 million in 2022.

Monthly transmission congestion right funding levels and revenue are shown in Figure 5–22.

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175 SPP MMU 2017 Annual State of the Market report
The monthly funding percentage fluctuated throughout the year ranging from 82 percent to 98 percent. Six monthly funding percentages fell within the 90 to 100 percent target range.\(^{176}\) This is a material improvement from 2021, where only one month’s funding percentage fell within the target range.

When outages, especially those on large elements, are not included in the congestion hedging models, their funding and congestion impact can be significant. This is exacerbated when those same outages are extended. The MMU sees the outage process as a primary concern that significantly affects TCR underfunding. The MMU has recommended that SPP and stakeholders address TCR underfunding. As part of that recommendation, the MMU strongly recommends improving outage consistency between the congestion hedging market, the day-ahead market, and the real-time market to improve TCR funding. Moreover, incentives can be used to ensure that those that take the outage work to minimize the impact on market outcomes.

Figure 5–23 shows the auction revenue right funding percentage since 2020.

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\(^{176}\) *Integrated Marketplace Protocols*, Section 5.3.3 specifies a target range. "In the event the cumulative funding is at or below 90 percent or above 100 percent, MWG may approve an additional adjustment..."
Auction revenue right funding has fluctuated over the last three calendar years. In 2020, auction revenue rights were 123 percent funded, followed by 128 percent funded in 2021, and 122 percent in 2022. Auction revenue right surpluses also fluctuated over the last three years. In 2020, the auction revenue right surplus was $78 million, followed by $131 million in 2021, and $272 million in 2022. Additionally, the surplus increased materially year over year and presents a potential concern, as it could be an indicator of inefficiency. The market monitor urges SPP, along with the stakeholders, to determine the root cause of the overfunding, and analyze the surplus distribution methodology to ensure it is equitably allocated.

Figure 5–24 shows the 2022 monthly funding levels and revenues for auction revenue rights.
The shift in auction revenue rights funding beginning in June reflects the change in the TCR year, which runs from June to May. The figure also shows the auction revenue right funding fluctuated throughout the 2022 calendar year.

## 5.2.4 INTRA-AUCTION SALES AND BULLETIN BOARD TRANSACTIONS

Intra-auction sales refer to the sale of a previously acquired transmission congestion right position in a subsequent auction. Bulletin board transactions refer to trades where a market participant buys or sells a position outside of the auction cycle through the SPP bulletin board. Overall, both inter-auction sales and bulletin board transactions remain low.

Figure 5–25 shows the transaction volume by type as a percentage of all transmission congestion right purchase volume.

### Figure 5–25 Intra-auction sales and bulletin board transactions

![Chart showing transaction volume by type as a percentage of all transmission congestion right transactions for 2020, 2021, and 2022.]

No bulletin board transactions cleared in 2020 or 2021, however in 2022 a small number of bulletin board transactions cleared. Additionally, intra-auction sale volume decreased slightly, but remains low, around six percent of the total transmission congestion right volume.

Outside their relationship to the auction cycle, these transactions also differ from each other in another material way. Bulletin board transactions are similar to the secondary equity market, where a share of stock is offered for sale and that same share is later purchased by another market participant. As such, the bulletin board transactions do not affect total supply; they only affect ownership of the existing supply.
However, intra-auction sales can affect supply in addition to ownership. When market participants offer their prevailing flow positions for sale intra-auction, the capacity of those positions once used is available to the market again. But, the newly available system capacity can be taken up by any path, not just the path sold intra-auction. Furthermore, to sell counter-flow positions intra-auction, unclaimed prevailing flow capacity must exist for the transaction to clear. This is because counter-flow intra-auction sales reduce the total capacity available. The counter-flow now offered for sale, previously facilitated other prevailing flow positions. If the counter-flow sale were to clear without considering supply, the prevailing flow once facilitated by this counter-flow would no longer be feasible. So in order for these existing prevailing flow transactions to remain feasible, additional prevailing flow capacity must exist. Practically, the additional prevailing flow capacity required plays the same role once played by the counter-flow being offered for sale. These circumstances likely also incentivize market participant abstentions from counter-flow. Generally, if a market participant holds a counter-flow position, it could be very difficult to sell the position intra-auction, which is the main source of intra-marketplace liquidity.178

### 5.2.5 ISSUES, PROGRESS, AND NEXT STEPS

The following four areas highlight where continued progress could bring about improved market outcomes, risk reduction, and efficiency gains.

1. **Obtaining long-term congestion rights and auction revenue rights**

   Market participants experience varying levels of success in obtaining long-term congestion rights, as well as auction revenue rights and by extension self-converted transmission congestion rights. Improving the process to better align transmission service with long-term congestion right and auction revenue right entitlements would likely improve the outcomes materially.

   In January 2023, SPP staff presented an updated HITT M1 recommendation to the Markets and Operations Policy Committee. Staff’s proposed solution incorporates a much broader suite of recommendations than the original HITT M1 recommendation. The MMU supports the staff proposal.

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177 The additional capacity could also be provided by another counter-flow intra-auction bid.

178 Intra-market refers to inside the SPP Integrated Marketplace.
2. Credit policy
The Credit Practices Working Group has developed and implemented the first phase of credit policy enhancements. These enhancements are a material improvement. The second phase focused on incorporating forward-looking known information into the financial security calculations. SPP staff reviewed options for a forward-looking approach in 2021, including a mark-to-auction process. However, no changes were implemented.

In July 2022, FERC issued an order to show cause to four ISO/RTO’s as to why their tariffs were just and reasonable in absence of either of (1) mark-to-auction mechanisms for the calculation of financial transmission right (FTR) market participants’ collateral requirements and/or (2) volumetric minimum collateral requirements for FTR market participants. SPP’s phase one efforts included the development and implementation of a volumetric minimum collateral requirement. However, SPP did not elect to develop and implement mark-to-auction mechanisms. SPP therefore was directed, to show cause, as to why its tariff is just and reasonable without mark-to-auction mechanisms. SPP filed comments in support of its current tariff whereas the MMU filed comments in support of mark-to-auction. FERC has yet to provide a final rule.

3. Secondary intra-market liquidity
Breaking the trend over the last four years, market participants transacted some TCRs over the SPP bulletin board in 2022. However, the transactions were of a very limited magnitude. Intra-auction sales continue to represent modest transaction volume. The limited liquidity associated with these products is not unique to the SPP markets; however, improved liquidity would likely prove beneficial for all market participants and enhance efficient auction price formation. The market monitor encourages SPP to adopt policies and procedures that deepen liquidity by incentivizing market participants to transact in SPP’s secondary market.

4. Modeling inconsistencies
Modeling inconsistencies and outage discrepancies between the congestion hedging and day-ahead models continued in 2022. As stated in previous reports, the process and rules surrounding the modeling of congestion hedging outages should be prioritized and addressed. Therefore, the MMU recognizes and supports the efforts of the MWG/ORWG Strike Team, which is working to improve TCR underfunding.
5.3 INTEGRATED TRANSMISSION PLANNING PROCESS

The SPP tariff\textsuperscript{179} requires SPP to conduct an annual Integrated Transmission Planning (ITP) Assessment to evaluate the transmission system upgrades for a ten-year planning horizon. The planning assessment serves as a regional planning process. This process involves many aspects of transmission planning including the considerations for reliability, public policy, operational, and economic needs, and generator interconnection to develop a cost-effective transmission portfolio for a ten-year planning horizon.\textsuperscript{180} In addition, a 20-year assessment is required.

In 2022, the MMU continued to engage in planning discussions.

Meanwhile, due to SPP staff resource constraints, the Economic Studies Working Group (ESWG) reduced the scope of the 2022 ITP 10-year study to address only reliability requirements eliminating the economic analysis from the 2022 ITP.\textsuperscript{181}

\textsuperscript{179} SPP Open Access Transmission Tariff, Attachment O Transmission Planning Process, Section III.

\textsuperscript{180} The latest version of the ITP manual published can be found at https://www.spp.org/engineering/transmission-planning/.

\textsuperscript{181} The ESWG made this decision in its January 2022 meeting, and it was subsequently approved by the SPP stakeholder process. Full assessment, however, is planned for the 2023 and 2024 ITPs.
Chapter 6 of this report provides a competitive assessment of the SPP market. Key points from this chapter include:

- Structural and behavioral metrics indicate that the SPP markets have been competitive over the last several years. The market share, Herfindahl-Hirschman Index (HHI), and pivotal supplier analyses all indicate minimal to moderate potential structural market power in SPP markets outside of frequently constrained areas.

- In 45 percent of the hours in 2022, the market share of the largest on-line supplier in terms of real time energy output exceeded 20 percent, a declining trend observed since the June, 2018 formation of Evergy, Inc. as SPP’s largest market participant.

- The HHI market concentration analysis shows that 9 percent of hours were considered moderately concentrated in 2022. The SPP market remained mostly unconcentrated—with 88 percent of all intervals since 2019 considered unconcentrated. No intervals were considered highly concentrated in 2022, and the percentage of intervals considered unconcentrated (91 percent) was at its highest level since 2017.

- The results of the pivotal supplier analyses indicate that the percent of hours with a pivotal supplier is the highest in two zones—New Mexico/West Texas and Iowa/Dakotas/Montana—with nearly all intervals possessing pivotal suppliers regardless of demand.

- Off-peak and on-peak annual average markups increased from all-time lows in 2020 and 2021, suggesting a convergence between market prices and short run marginal costs. This increase was driven primarily by high average markups for coal and gas resources. Wind resources, however, continue to offer at exceptionally low markup levels.

- Incremental energy offer mitigation in 2022 slightly increased in frequency in both the day-ahead and real-time markets. Despite the minor increase in mitigated resource hours, energy offer mitigation remains very rare, at 0.22 and 0.08 percent of resource hours in the day-ahead and real-time markets respectively. The total frequency of mitigation across all other products was similarly low and in line with prior years, with
operating reserve mitigation increasing largely due to an increase in spin product mitigation in August and September 2022.

- Behavioral measures suggest that attempts to actually exercise market power by manipulating the price (economic withholding) or quantity (physical withholding) of generation are rare. The output gap, an inference of economically withheld generation, rose slightly over the levels seen in 2021. This was primarily driven by coal resources facing supply shortage issues. The level of physically unoffered generation remained level in 2022 and 2021 after disruptions to maintenance and outage scheduled in 2020 attributable to COVID-19.

- Markups on marginal coal and gas resources increased significantly in 2022, while wind markups decreased to even more deeply negative levels than seen in 2021. The increase in thermal resource markups brought SPP’s average offer price markup to slightly positive levels for the first time in several years. In mid-2022, the MMU introduced revision request number 502 (RR 502) as a response to the coal supply issues behind these markups, expanding the scope of allowable opportunity cost in order to curb coal dispatch. The MMU observed several market participants taking partial or full advantage of this increase in allowed opportunity costs and is largely satisfied with its performance to date.

The SPP Integrated Marketplace provides sufficient market incentives to produce competitive market outcomes in regions and periods lacking local market power. The MMU’s competitive assessment provides evidence that in 2022, market outcomes were workably competitive, requiring only infrequent mitigation of local market power.

The market power analysis in this report considers both structural and behavioral aspects of market power concerns. Structural aspects are examined with techniques such as market share analysis, market-wide concentration indices, and pivotal supplier analysis. These structural indicators illuminate the potential for market power without regard to the actual exercise of market power. Behavioral analyses, on the other hand, look for the exercise of market power by assessing the actual offer or bid conduct of market participants, and the impact of that conduct on market prices. These analyses examined offer price markup, economic withholding, the frequency of automated mitigation, uneconomic production, and physical withholding.

This chapter evaluates the SPP market’s competitive environment by establishing the level of structural market power and then examining market prices for indications of the exercise of that
power. Structural market power is assessed both at the SPP footprint level through supplier concentration indices and at the local (transmission-constrained) level through pivotal supplier analysis. In the SPP markets, mitigation of economic withholding is accomplished *ex-ante* through automatic market power mitigation processes that limit the ability of generators with local market power to raise prices above competitive levels. The mitigation program is monitored and evaluated to ensure it is efficient and effective. Accordingly, the following subsections examine the significance of market power and the effectiveness of local market power mitigation in the SPP markets.

### 6.1 STRUCTURAL ASPECTS OF THE MARKET

Three core metrics of structural market power are the market share analysis, the Herfindahl-Hirschman Index (HHI), and pivotal supplier analysis. The first two of these indicators measure market-wide concentration, ignoring local constraints. Pivotal supplier analysis, on the other hand, accounts for the dynamics of power markets and considers changing demand conditions and locational transmission constraints in assessing potential market power.

Figure 6–1 displays the market share of the largest on-line supplier in terms of energy dispatch in the real-time market by hour for 2022.

*Figure 6–1  Market share of largest supplier*
The market share ranged from 10 percent to 31 percent, exceeding the 20 percent threshold\textsuperscript{182} in 3,961 hours (45 percent) for the year. In 2021, market shares ranged from 11 percent to 32 percent, with market shares exceeding the 20 percent threshold in 61 percent of intervals. This continues a trend of decreasing concentration after an acute rise in most concentration metrics following the formation of Evergy, Inc. in 2018. Evergy remains the largest on-line supplier in over 99 percent of intervals. Note that although a mere increase in market share does not itself pose a threat to the structural competitiveness of the SPP market, other relevant market data including pivotal supplier hours and local market power mitigation must also be closely evaluated for competitive assessment (see below).

The Herfindahl–Hirschman Index (HHI) is another general measure of structural market power, analyzing overall supplier concentration in the market. It is calculated by using the sum of the squares of the market shares of all suppliers in a market as follows:

\begin{equation}
HHI = \sum_i \left( \frac{MW_i}{\sum_i MW_i} \times 100 \right)^2
\end{equation}

According to FERC’s “Merger Policy Statement,”\textsuperscript{183} which is similar to the Department of Justice’s merger guidelines, an HHI below 1,000 is an indication of an unconcentrated market, an HHI of 1,000 to 1,800 indicates a moderately concentrated market, and an HHI above 1,800 indicates a highly concentrated market.

Figure 6–2 provides the number of hours for each concentration category in terms of actual generation over the last three years.\textsuperscript{184}

\textsuperscript{182} The 20 percent threshold is a historically accepted standard for identifying structural market power. Note, however, that neither market share nor the HHI metric alone would be sufficient for the assessment of market power particularly in today’s spot electricity markets where load pockets formed by transmission congestion may lead to market power with much smaller market shares and/or HHI values.

\textsuperscript{183} Inquiry Concerning the Commission’s Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, Issued December 18, 1996 (Docket No. RM96-6-000).

\textsuperscript{184} The SPP MMU calculates HHI by actual generation as determined by real-time market (five-minute) dispatch solutions aggregated to the hourly level. The FERC merger guidelines uses capacity owned. Some years may reflect hour counts that, when totaled, do not constitute a full 8,760 hours. Generally, this is due to sustained real-time market system outages lasting longer than one hour. In accordance with the SPP Integrated Marketplace Protocols for pricing during system outages, if the market has not solved for a full hourly interval, it is excluded from the HHI analysis.
The SPP market was unconcentrated in 88 percent of hours from 2020 to 2022. However, 12 percent of hours were considered moderately concentrated during the same period. 2022 saw a decrease in both the number of intervals considered “moderately concentrated” as well as a decrease in the number of intervals with a maximum market share of over 20 percent. The SPP market has never risen above the highly concentrated threshold of 1,800 since the start of the Integrated Marketplace in 2014. Figure 6–3 depicts the hourly real-time market HHI in terms of generation for 2022.

Hourly HHI values ranged from 413 to 1,318 during 2022, a slightly narrower range than observed in 2021. This narrower range corresponded to a less volatile year generally in HHI values, with a lower standard deviation and coefficient of variation compared to the HHI values observed in 2021.

Figure 6–4 shows a graphical breakdown of the HHI for all hours since the start of the Integrated Marketplace in March 2014. For the years with significant events impacting the make-up of the
As shown above, the market remained mostly unconcentrated from the addition of the Integrated System to the date of the Great Plains/Westar merger that created Evergy. Even though moderately concentrated hours increased following the creation of Evergy, only 12, 15, and 9 percent of hours fell into this category in 2020, 2021, and 2022, respectively. In contrast, in 2014, just over 50 percent of hours were considered moderately concentrated, and in 2015, prior to the addition of the Integrated System, nearly 40 percent of hours were moderately concentrated.

While moderately concentrated hours increased following the creation of Evergy, it is not necessarily a cause for alarm, as they still remain below 2015 levels, prior to the Integrated System joining the market. Later metrics in this report will more closely examine specific market behavior by market participants in terms of the exercise of local market power.

The MMU’s market share analysis and HHI metrics both indicate a moderate potential for general structural market power in SPP markets outside of frequently constrained areas. Structural market power is also assessed at a more localized level and in the context of

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185 Note that the HHI analysis is performed at the market participant level. There may be asset owners under market participants on a contractual basis, where bidding control is not under the purview of the market participant.

186 Section 6.2 analyzes behavioral aspect of market power.
locaional transmission constraints by reevaluating frequently constrained areas periodically and (re)defining them accordingly, as discussed in section 5.1.7.

Pivotal supplier analysis takes into account the dynamic nature of the power market, particularly variable demand conditions, and evaluates the potential for market power in the presence of pivotal suppliers. A supplier is pivotal when market demand cannot be met without some or all of its generation. There may be one or more pivotal suppliers in a particular market defined by transmission constraints and load conditions, and a supplier’s pivotal status may vary between time periods irrespective of its size. Economic withholding by pivotal suppliers is automatically mitigated in real time by SPP’s market clearing process, while physical withholding is monitored for and reported on by the MMU.

The following metric identifies the frequency with which at least one supplier was pivotal in the five different reserve zones\(^{187}\) (regions) of the SPP footprint in 2022.\(^{188}\) The frequency with which a supplier is pivotal is an indication of their potential to raise prices above competitive levels. While the mere size of a supplier does not itself render the supplier pivotal, suppliers which are frequently pivotal in high-demand intervals have a greater ability to exercise market power. For this reason, the pivotal supply frequency is analyzed at various levels of demand across these five regions, as shown in Figure 6–5.

\(^{187}\) SPP divides market resources (generation) into five reserve zones. For the purpose of this report, these reserve zones are named as “Nebraska”, “Western Kansas and Panhandles”, “New Mexico and West Texas”, “Kan., Mo., Okla., Ark., East Texas, La.,” and “Iowa, Dakotas, Montana.” Thus, each generation resource is mapped to one of these reserve zones. To define a load zone to match with a resource zone, each load settlement location was mapped to a reserve zone to approximate demand within a particular zone. Additionally, import limits are approximated by the average of the reserve zone limits for the times they were activated in 2022.

\(^{188}\) It is important to note that reserve zones have rarely been activated in the SPP market.
The results indicate that the percent of hours with a pivotal supplier is the highest (100 percent) in the New Mexico and West Texas region, regardless of demand level. This has been the case for the last several years. This is followed by the Iowa, Dakotas, Montana region where a nearly 100 percent pivotal supplier frequency was observed for all demand levels in 2022.

Compared to 2021, the percent of hours with a pivotal supplier at peak demand level decreased in the Kansas, Missouri, Oklahoma, Arkansas, East Texas, Louisiana region from nearly 13 percent to six percent.\(^{189}\) The pivotal supplier frequency at the Nebraska region was almost the same as 2021.

### 6.2 BEHAVIORAL ASPECTS OF THE MARKET

#### 6.2.1 OFFER PRICE MARKUP

In a competitive market, prices should reflect the short-run marginal cost of producing the marginal unit. In SPP’s Integrated Marketplace, market participants submit hourly mitigated energy offer curves that represent their short-run marginal cost of energy. Market participants also submit their market-based offers, which may differ from their mitigated offers. To assess market performance, a comparison is made between the market offer and the mitigated offer for the marginal resources for each real-time market interval.

\(^{189}\) Note that this analysis differs from the MMU’s Frequently Congested Areas (FCA) study where \textit{impact} of congestion, as well as specific pivotal hours and transmission constraints, are taken into account when FCA designation is determined. Here, the suppliers’ pivotal hours’ frequency is analyzed only by considering demand levels and reserve zone/demand area assumptions.
Figure 6–6 provides the average marginal resource offer price markups\textsuperscript{190} by month for on-peak and off-peak periods. While the MMU observed increasingly negative markups in the period from 2018 through 2020—implying significant price pressure in the SPP market—this trend abated in 2021, which saw several months with positive average markups for the first time since early 2018. 2022 saw a further continuation of this trend, particularly in summer peaking months, with offer price markups higher than $40/MWh during on-peak hours.

\textbf{Figure 6–6} \hspace{1em} \textit{Average offer price markup of marginal resource, monthly}

Despite high average monthly markups in on-peak hours during the summer months especially, the average offer price markup remained low on an annual basis, a trend that has persisted since 2017. The lowest markups occurred in April, at negative levels not observed since 2020. From May through September, on-peak average markups were all higher than $10/MWh, a level attained in no other months. By August, the average offer price markup rose to nearly $50/MWh. However, this summer trend disappeared almost immediately with the arrival of autumn shoulder months.

Figure 6–7 below points to an uptick in off-peak and on-peak average marginal resource offer markups in 2022 relative to the deeply negative levels seen in 2020 and 2021.

\textsuperscript{190} Offer price markup is calculated as the difference between market-based offer and the mitigated offer where the market-based offer may or may not be equal to the mitigated offer. The markups are weighted based on megawatt to reflect each marginal resource’s proportional impact on price.
In competitive markets, markups should approach $0/MWh and the MMU monitors for markup levels that are both abnormally high and abnormally low. Average offer markups in 2022 continued a pattern of year-over-year increases beginning in 2020, with one of the largest yearly increases ever observed in average offer price markups from 2021 to 2022. This increase brought yearly average markups above $0/MWh for the first time in several years, reversing a trend that raised concerns about the continued commercial viability of some sectors of generation in SPP. The increase was attributable to markups in coal and gas offers. Of note, several coal resources experienced coal deliverability issues as a result of rail limitations, which resulted in many resources offering higher than typical mark-ups. The rail deliverability issue is discussed in further detail below.

Figure 6–8 shows the average on-peak marginal resource offer price markup by fuel type.
Positive markups were observed both coal and gas at much more elevated levels than those seen in 2021, excluding the winter weather event period in February of that year. Elevated on-peak markups were also observed in many months for gas, with a clear correlation to trends in the prevailing price of gas and overall load patterns within the SPP footprint. Many months, particularly in the summer, saw markups, which exceeded SPP’s automated “impact test” threshold of $25/MWh. In 2021, by comparison, this level was only exceeded by one fuel type (natural gas) in one month (February). These positive markups are best understood as a shift in the market supply curve stemming from scarcity in coal supplies, due to rail limitations and high natural gas costs, across the market footprint. After the implementation of revision request 502, a decrease in thermal markups is observed. Because markups represent that distance between price and cost, however, this could just as well be attributable to an increase in allowed costs as to a decrease in market prices.

Nonetheless, all months saw negative markups for wind resources, with markup levels continuing to decrease throughout the year to levels generally lower than those seen in 2021. This deepening of negative markup levels, in combination with the steep increase in markups for thermal resources helps explain why the annualized markups depicted in Figure 6–7 showed an increase in both their average level but also the spread from minimum to maximum markup.

Negative markups indicate that many market participants’ real-time market offers were below their mitigated offers.\(^{191}\) This could occur where generators decide to offer below their marginal cost to:

- meet their day-ahead positions in order to avoid financial risk associated with buying back energy in real time market,
- maintain commitments or reflect temporary negative fuel prices, as in the case of natural gas units,\(^ {192}\) or
- ensure eligibility for production tax credits (PTC), as in the case of wind resources that constitute a sizeable share in total resource portfolio.

\(^{191}\) Wind units may have negative mitigated offers primarily as a result of the federal production tax credit (PTC) for renewable energy.

\(^{192}\) Tariff rules only allow for submitting monotonically non-decreasing offer curves by market participants, and this may result in market offers by natural gas units below their mitigated offers during periods with negative prevailing gas prices. Additionally, real-time market offers may be below mitigated offers when natural gas units’ mitigated offers are indexed to hub prices when in fact the cost of gas received could be below that hub price. Some SPP market participants have experienced negative natural gas prices in the past, but it remains a rare occurrence.
For instance, wind resources on the margin in the real-time market increased from 22 percent of all resource intervals in 2020 to 39 percent in 2022 (Figure 2–22).

### 6.2.2 Mitigation Performance and Frequency

SPP resources’ incremental energy, start-up, no-load, and operating reserve offers are subject to mitigation for economic withholding when the following three circumstances occur simultaneously in a market solution:

1) The resource has local market power;

2) The offer has failed the conduct test. Resources submit two offers for each product: a mitigated offer representing the competitive baseline costs that must adhere to the mitigated offer development guidelines\(^{193}\) and a second offer generally referred to as a market offer, which often includes risk-based and strategy-based adjustments. An offer is considered for mitigation when the market offer exceeds the mitigated offer by more than the allowed threshold; and

3) The resource either:
   a) Is manually committed by SPP for capacity, transmission constraint, or voltage support; or by a local transmission operator for local transmission problems or voltage support; or
   b) The application of mitigation impacts market prices or make-whole payments by more than the allowed $25/MWh threshold.

Despite slight increases in day-ahead mitigation frequency, the overall mitigation frequency remains very low at less than one half of one percent across energy and no load resource intervals, and less than one percent for operating reserve intervals. Figure 6–9 shows the mitigation frequency of incremental energy, operating reserve, and no-load offers in the day-ahead market in 2022. Figure 6–10 below reflects an increase in real-time mitigation frequency that is commensurate with the year over year trends in slightly increased energy mitigation frequency in the day-ahead market in 2022.

\(^{193}\) As indicated in Appendix G of SPP’s Integrated Market Protocols.
Mitigation frequency for operating reserves was concentrated in August and September, and was largely driven by increases in the mitigation frequency of spinning reserve offers. Excluding spin, operating reserve mitigation is comparable to levels observed in 2021. Annual mitigation frequency for no-load increased by a small extent compared to 2021, but this increase was minor and not concentrated in any specific month or season. The application of mitigation in the day-ahead market occurred at levels of 0.99 percent for operating reserves, 0.38 percent for no-load, and 0.22 percent for incremental energy. The low level of mitigated resource hours relative to market activity is a hallmark of the day-ahead market, and while operating reserves saw a larger increase in mitigation frequency than seen in previous years, it remains below one percent, while energy and no-load mitigation has continued to be below one-half of one percent in every year since 2014.

Mitigation of incremental energy in the real-time market is shown in Figure 6–11 below.

For the real-time market, the annual mitigation frequency increased slight compared to 2021. Although October 2021 had a higher percentage of resource hours mitigated than any month of 2022, in 2021 only four months had percentages over 0.05 percent, whereas 2022 had nine months with percentages over 0.05 percent.

Figure 6–11 depicts the mitigation frequency for start-up offers for the various commitment types.
The annual mitigation frequency of start-up offers in 2022 was nearly equivalent to 2021 at slightly over four percent. While the frequency of reliability unit commitment mitigation has been nonexistent since 2017, manual mitigation remained similar in 2022 to 2021 levels at approximately 0.7 percent. Day-ahead mitigation accounted for 86 percent of the total start-up offer mitigation. The highest levels of start-up offer mitigation occurred in June, October, and November, with the lowest start-up mitigation levels occurring in December.

6.2.3 OUTPUT GAP (MEASURE FOR POTENTIAL ECONOMIC WITHHOLDING)

Economic withholding is defined as submitting a resource offer that is artificially high, such that either the resource will not be scheduled or dispatched, or—if scheduled or dispatched—the offer will set a higher than competitive market clearing price. Accordingly, the output gap metric aims to measure the economic (or competitive) amount of output withheld from the market through the submission of offers in excess of competitive levels. The output gap is the amount of generation not produced as a result of offers exceeding the mitigated offer above an appropriate conduct threshold. The conduct threshold is employed to compensate for any inaccuracies or uncertainties in estimating the cost, similar to the one used in economic withholding mitigation. In this report, the output gap is calculated as the difference between a resource’s economic level of output at the prevailing market clearing price and the greater of
actual offered MWs and actual amount of production. The economic level of output is produced by a generator between its minimum and maximum economic capacity.  

The MMU employs a 17.5 percent conduct threshold for the frequently constrained areas and a 25 percent conduct threshold for the rest of the footprint to reflect the actual thresholds used in the clearing process’s automatic economic withholding mitigation. In order to account for the discrepancy between a resource’s offered capacity and the dispatched amount (due to possible limitations in real-time market conditions such as transmission constraints, operator actions or ramp limitations, virtual participants), an upward adjustment is made by taking the greater of the day-ahead scheduled or the real-time dispatched amount to reflect the actual amount of production.

Note that certain market conditions such as congestion (supplier location), supplier size, or high demand can create market power and facilitate economic withholding behavior. For this reason, the output gap is calculated as percentages of total economic output withheld compared to total reference capacity for the SPP footprint. In addition, the output gap is calculated for the largest three suppliers (market participant portfolios) in each frequently constrained area, if so designated, comparing the levels to those of the remaining suppliers. Similar to the last year’s report, the annual calculations were run for all days and evaluated at varying levels of demand as a potential market condition that can affect the withholding outcome.

Figure 6–12 below shows the monthly level of the output gap across the SPP footprint from 2020 to 2022.

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194 The MMU calculates this metric by including all resources’ total (reference level) capacity when calculating output gap percentages.

195 The two frequently constrained areas identified in the 2021 study became effective on December 27, 2021. Therefore, two frequently constrained areas were added to this 2022 report.
Compared with the previous years, the output gap was slightly higher in 2022. It was about 0.04 percent higher in 2022 compared to 2021. Overall it still remains at very low levels, averaging less than 0.3 percent in all months, reflecting a high level of participation in the market overall.

The significant increase in output gap in June and July might be due to the coal shortage and the opportunity cost that was added to mitigated offers. The coal resources only raised the market offers to reflect this shortage. Following the implementation of revision request 502 in August 2022, coal resources were allowed to include opportunity cost adders in their mitigated offers due to a transportation issue. Figure 6-12 shows the decline in output gap, as more and more coal resources included opportunity cost adders in their mitigated offers in August, September and October.

While Figure 6–13 displays the output gap calculated by demand level and participant size for the entire SPP market footprint, Figure 6-14 shows the output gap for the Southwest Missouri frequently constrained area for 2022. There was no output gap in the Southeast Oklahoma frequently constrained area for any demand and supply levels in 2022.

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196 RR502 “Opportunity Cost Revisions Addressing Coal Transportation Issues.”
197 The Southeast Oklahoma and Southwest Missouri frequently constrained areas were activated on December 27, 2021 therefore, data shown cover the whole year of 2022.
Although still at low levels, the highest level of output gap (no more than 0.2 percent) was observed belonging to the top three largest suppliers and during high demand periods in 2022. The results indicate a very low level of economic output withheld in the SPP footprint and Southwest Missouri frequently constrained area. These outcomes are generally consistent with expectations of competitive market conduct. In general, more output is expected to be withheld at higher demand levels or by larger suppliers. However, at times output may also be withheld in low load periods, as prices are often negative during the lowest 20 percent of load hours.
6.2.4 UNOFFERED GENERATION CAPACITY (MEASURE FOR POTENTIAL PHYSICAL WITHHOLDING)

As part of the competitive assessment, the MMU reviewed potential physical withholding behavior by generators throughout the 2020 to 2022 period. Physical withholding refers to a conduct where a supplier derates a resource or otherwise does not offer it into the market. Physical withholding may include: intentionally not following dispatch instructions, declaring false derates or outages, refusing to provide offers, or providing inaccurate resource parameters such as capability limitations. Any economic generation capacity that is not made available to the market through a derate, outage, or otherwise not offered to the market is considered for this analysis.\(^{198,199}\)

Total economic capacity that was derated from respective reference levels was classified by reason and duration. Derates can be reflected as planned or forced outages submitted through SPP’s outage scheduling system or any undesignated unoffered capacity.\(^{200}\) Any derates from reference levels are considered in this analysis.

Derates were classified as either short-term or long-term. Those of less than seven days’ duration were classified as short-term and the rest as long-term. This is because the economic capacity that was not offered short-term has more potential for physical withholding relative to long-term derates as it would be less costly—because of loss of sales—for a supplier to withhold capacity for a short duration of time.

As in the case for economic withholding, the potential for physical withholding is also affected by various market conditions at the time offers are made including location (congestion), supplier size, or demand levels. Larger suppliers would be in a more advantageous position to exercise market power. During tight market conditions, suppliers have more incentive and opportunity to physically withhold capacity for strategic reasons. In addition, scheduling maintenance outages in high demand periods may indicate a strategic behavior to create artificial shortages.

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\(^{199}\) Economic capacity is determined in a similar way as in the output gap analysis in Section 6.2.3 by comparing resource’s (cost-based) mitigated offer to the prevailing locational price.

\(^{200}\) The planned maintenance outages by nuclear generation and unoffered capacity by hydro, wind, and solar is excluded in this analysis.
The MMU assessed derated and unoffered economic capacity both in the day-ahead and real-time markets. Similar to the output gap analysis, the MMU modelled commitments based on day-ahead market outcomes for all units.\(^{201}\) The unoffered capacity is calculated as the difference between the unit’s economic capacity\(^{202}\) and its offered maximum economic capacity operating limit during intervals when the unit was deemed economic (i.e., covering its costs given the clearing price).

The following figures shows unoffered economic capacity as percent of total resource reference levels by month for the SPP footprint, frequently constrained areas\(^ {203}\) and by supplier (participant) size against varying load levels.\(^{204}\)

**Figure 6–14  Unoffered economic capacity**

Figure 6-14 shows that on an annual average basis the total unoffered capacity equaled 1.5 percent in 2020, 2.3 percent in 2021, and 2.6 percent in 2022.

The figure shows that the majority of the outages were long-term and concentrated in spring and fall shoulder months. The chart reflects a normal level of maintenance outages in 2022. Comparing with the previous year, there is a significant increase of long-term outages in November and December which may likely be due to the coal rail limitations, which occurred in fall 2022. Some coal resources used the outages to preserve coal for the winter months. When

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\(^{201}\) Due to the new fast-start logic implemented in 2022.

\(^{202}\) Bounded by a resource’s reference level.

\(^{203}\) The two frequently constrained areas identified in the 2021 study became effective on December 27, 2021.

\(^{204}\) Unoffered capacity percentages are calculated out of the total reference levels of the corresponding market area.
short and long-term outages were excluded from the averages, the remaining unoffered capacity amounts to 0.21 percent, 0.35 percent and 0.47 percent for 2020 through 2022, respectively. From an overall market perspective, the results generally indicate reasonable levels of total unoffered economic capacity.\textsuperscript{205}

Figure 6–16 shows that short-term outages by large suppliers stay at one percent at all load levels, while short-term outages by others slightly rise with increasing load (which correlate to increasing prices) across the SPP footprint.

**Figure 6–15  Unoffered economic capacity at various load levels, SPP footprint**

At the same time, unoffered economic capacity of gas (peaker) units—both by large and other suppliers—also slightly rises with increased load albeit at very low levels. Larger suppliers also show higher unoffered economic capacity than other suppliers at the same load levels. Unoffered economic capacity as a percentage of load is more apparent for the remaining resource types, but does not exceed three percent for either of the supplier groups at any demand level.

Figure 6–17 and Figure 6–18 show the unoffered capacity at the two frequently constrained areas.\textsuperscript{206} The Southwest Missouri frequently constrained area has a similar unoffered capacity level as the entire SPP footprint, while the Southeast Oklahoma frequently constrained area has a significantly higher level, which is due to the size of these areas. The Southeast Oklahoma

\textsuperscript{205} On an individual resource level, not offering economic capacity may be physical withholding depending on the facts and circumstances of the situation.

\textsuperscript{206} All the resources in these areas are from the top three suppliers, hence no data were displayed for other suppliers.
frequently constrained area is quite small. As such, any resource on outage or derate will lead to a high unoffered capacity percentage in that area.

**Figure 6–16** Unoffered economic capacity at various load levels, Southwest Missouri area

The SPP-wide generation outage data\(^{207}\) (see Section 3.4) shows that most long-term outages were maintenance outages (59 percent). Out of the short-term outages, approximately 63 percent were forced outages.

\(^{207}\) Covering all resources in the SPP market including nuclear, hydro, wind and solar generation.
6.3 START-UP AND NO-LOAD BEHAVIOR

Market participants also submit their market-based no-load and start-up offers, which may differ from their mitigated offers. To assess market performance, a comparison is made between the market no-load and start-up offers and the mitigated no-load and start-up offers for all resources for each real-time market interval. Figure 6–19 shows the mitigation start-up offer mark-up by fuel category in 2022.

![Mitigation start-up offer mark-up by fuel category](image)

Analysis of start-up offers showed that many market participants submitted start-up offers considerably above their mitigated offer levels. Nonetheless, start-up mitigation occurred in less than five percent of intervals in 2022 and day-ahead mitigation accounted for 86 percent of the total start-up cost mitigation. These figures were very similar to results in 2021, except for seeing less blank space at the end of the gas, turbine/engine category, which represents less resources offering $0 start-up offers.

Figure 6–20 shows the mitigation no-load offer mark-up by fuel category in 2022.
Figure 6–19  Mitigation no-load offer mark-up by fuel category

Most market participants submitted no-load offers within the threshold range of their mitigated offer levels. There are a small number of gas, turbine/engine resource type that marked up their no-load offers above the 25 percent mitigation threshold.
7 RECOMMENDATIONS

One of the core functions of a market monitor is “to advise the Commission, the RTO or ISO, and other interested entities of its views regarding any needed rule and tariff changes.”\(^{208}\) The MMU accomplishes this responsibility through many forums, including but not limited to active participation in the SPP stakeholder meetings process, commenting on FERC notices of proposed rulemakings, submitting comments at FERC on SPP filings, and making recommendations in the Annual State of the Market report. This section outlines the MMU recommendations to SPP and stakeholders to address our concerns with the current design, rules, and processes.

This section highlights new recommendations and updates recommendations made in prior reports based on 2022 market outcomes. The MMU has identified four new recommendations for 2022. Along with the new recommendations, the MMU has highlighted and updated existing recommendations in an effort to promote the need for these issues to be addressed. These include continued emphasis on recommendations documented in the Winter Weather Report\(^ {209}\) that address MMU concerns arising from the February 2021 winter weather events.

7.1 NEW RECOMMENDATIONS

2022.1 CONSIDER LIMITATIONS ON VIRTUAL TRADING DURING EMERGENCY CONDITIONS

In 2022, the MMU published a paper examining the impact of virtual trading during the February 2021 winter weather event.\(^ {210}\) In the paper, the MMU demonstrated how the merits of virtual transactions, such as aiding price convergence, decrease or are even erased under conditions of scarcity, particularly when day-ahead prices exceed the $1,000/MWh offer cap. The combination of large price spreads and an inability to displace more expensive generation during scarcity events lends to extremely high profit per megawatt values with little to no impact on price or market convergence. Where virtual transactions did create positive impacts, their high cost and profits largely outweighed their benefits.

In light of these findings, the MMU made the primary recommendation to suspend virtual trading during scarcity events, particularly when day-ahead prices exceed the $1,000/MWh offer

\(^{208}\) As defined by FERC in Order No. 719.

\(^{209}\) SPP MMU Report on February 2021 Winter Weather Event

\(^{210}\) Virtual activity during the 2021 winter weather event: An analysis
The MMU further recommended that analysis should be done to determine what price levels, price spreads, and virtual volume to load ratios at which virtual transactions are no longer a cost-effective tool for aiding price and market convergence. This will allow SPP to know under which specific conditions virtual trading should be temporarily suspended in order to avoid unduly high costs related to virtual transactions. The MMU also recommended studying how violation relaxation limits (VRLs) interact with the profitability and cost-effectiveness of virtual transactions since they fundamentally alter price formation and can lead to artificially large price spreads. This likely also decreases the effectiveness of virtual transactions in aiding price and market convergence.

The MMU submitted an initiative on the SPP Roadmap\textsuperscript{211} for SPP to study the effectiveness of virtual transactions during the winter weather event and identify any potential lessons learned or recommendations going forward. This initiative is currently on the parking lot of initiatives to be addressed. The MMU recommends SPP and stakeholders consider the recommendations made in the MMU report on virtual bidding behavior.

\textbf{2022.2 ADDRESS LIMITATIONS WITH THE RAMP CAPABILITY PRODUCT}

In fall 2022, the MMU performed a review of the ramp capability product’s effectiveness and documented the results in its quarterly report.\textsuperscript{212} The review identified that the majority of resources procured for ramp-up are stranded behind congested constraints and unable to deliver the ramp. This is occurring across multiple resource types, including variable energy resources and conventional resources.

Congestion patterns have increased dramatically since SPP staff first evaluated the potential benefits of adding a ramping product. MMU analysis and subsequent SPP staff analysis have confirmed that the benefits of the ramping capability product have been limited due to this issue since its implementation in March 2022. The MMU recommends that SPP and stakeholders evaluate options to address the stranded ramping issue as it relates to the product’s deliverability. SPP staff have noted they are considering and testing multiple options for remediation with the preference being for an option that would pre-qualify resources based on their ability to ramp quickly and efficiently.

\textsuperscript{211} The SPP Roadmap is a process where SPP staff and stakeholders identify, educate, rank, and approve new and existing Integrated Marketplace initiatives for development over the next two to five years. More information on this process can be found at https://www.spp.org/stakeholder-center/spp-roadmap/.

\textsuperscript{212} Fall 2022 quarterly state of the market report, Section 6 - Special Issues.
on expected congestion. The MMU is open to this non-discriminatory approach and looks forward to working with the SPP and stakeholders on addressing this concern.

In addition to the stranded ramping issue, the MMU is also concerned that low prices on the ramp capability up demand curve may result in prices that undervalue ramp-up. While it is difficult to assess the full extent of this issue given the stranded ramping issue, the MMU recommends that SPP staff evaluate the effectiveness of the ramping capability product demand curve when assessing solutions to the stranded ramping issue. This evaluation could identify the need for additional enhancements or increased demand curve prices.

2022.3 IMPROVE SITUATIONAL AWARENESS OF TRANSMISSION UPGRADES AND IMPROVE PROCESS TO REASSIGN PROJECTS

Recent analysis by SPP staff has shown that several transmission projects and upgrades are behind expected relevant deadlines. Some of these projects are potentially several years beyond their expected in service dates. This analysis has highlighted a lack of transparency on the status of many transmission projects and upgrades. This issue encompasses both reliability and economic projects.

Delays in transmission upgrades can significantly contribute to congestion. As shown in this report, congestion in 2022 was at the highest levels experienced since implementation of the Integrated Marketplace. Many of the top 10 constraints have projects that have been identified to remediate congestion. However, many of these projects are delayed. This can have significant ramifications on market outcomes, and costs paid by ratepayers. Moreover, resource decisions, including generator interconnection, are made based on expectations and information on the status of transmission upgrades. Thus, in order to better inform the market, the MMU recommends that SPP and stakeholders develop a process to improve the transparency of the status of transmission projects and upgrades.

Current public reporting of these projects’ statuses provides three separate dates:

- RTO determined need date
- The latest project owner indicated in-service date
- Letter of notification to construct issue date

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213 March 1, 2023 Project Service Working Group presentation, 7. In-Service Date Report
The RTO needed date can be before the issuance of the Notification to Construct,\textsuperscript{214} thus it is not a plausible tracking mechanism for evaluating the timeliness of the transmission upgrades. In addition, the Project Owner Indicated In-Service Date is the most recent in service date supplied by the designated transmission owner and does not fully show the delays in the project. The MMU recommends that an “Original Project Owner Indicated In-Service Date” be added to the public reports. This will allow full transparency into the delay in the projects. It is the understanding of the MMU that not all designated transmission owners respond with an Indicated In-Service Date. The MMU recommends that this date be required and that the supplied date be benchmarked.

Furthermore, there should be regular updates from the transmission developer indicating the status of the project, along with detailed descriptions of the delaying issues. This detail should be at a granular enough level to be able to discern the entity and upgrades delaying the project. This additional information can improve situational awareness, and aid resource developers and decision makers.

In addition to the enhanced information, the MMU recommends that SPP improve tariff clarity to assist in determining if transmission projects should be reassigned. Currently, the SPP tariff affords the RTO to ensure that “due diligence” has been taken to develop a project in a timely manner.\textsuperscript{215} We recommend that the SPP and stakeholders develop a clear set of guidelines as to what constitutes due diligence. Ultimately, if a transmission developer is unwilling or incapable of developing a project within an acceptable timeline, the SPP Board should have clear guidelines, including a potential timeline, when deciding on when to move a project to another developer.

\textbf{2022.4 APPROVE CONGESTION HEDGING MECHANISMS TO ENHANCE EQUITY}

In July 2019, the Holistic Integrated Tariff Team (HITT) published its recommendation report, including 21 board-approved recommendations.\textsuperscript{216} Marketplace enhancement recommendation one (HITT M1), “Implement congestion hedging improvements” remains outstanding. After years of discussion in the Market Working Group and a failure to come to consensus, the Board of Directors intervened, directing SPP, with input from stakeholders, to

\textsuperscript{214} The SPP Tariff defines the Notification to Construct as a written notice from the Transmission Provider directing an entity that has been selected to construct one or more transmission project(s) to begin or continue implementation of the transmission project(s).
\textsuperscript{215} SPP OATT, Attachment Y, Section V
\textsuperscript{216} https://www.spp.org/documents/60372/hitt%20report%2020190730.pdf
develop a proposal. In January 2023, SPP staff presented an updated HITT M1 recommendation to the Markets and Operations Policy Committee. While the new proposal does not address the inherent mismatch between contract paths and the economic delivery of energy, it incorporates a much broader suite of recommendations than the original.

The recommendation package comprises nine components, which target the upstream, mid-stream, and down-stream aspects of the congestion hedging process. The upstream components focus on model alignment between transmission service studies and the congestion hedging process. The mid-stream components center around the mechanics within the long-term congestion right and auction revenue right allocations. The downstream recommendations focus on the distribution of excess auction revenues and stakeholder education. The package also incorporates a feedback loop from the congestion hedging process to the planning process.

Stakeholders have been reluctant to adopt the proposal as a whole, with some preferring certain components to others, and opposing certain components. However, an à la carte approach is not ideal. While it is true each of the components provides a standalone incremental improvement, the combination of all the components work together to deliver an improvement that is greater than the sum of the parts. For this reason, the MMU stands in support of this proposal, and recommends SPP and stakeholders approve and implement the recommended package in its entirety.

7.2 EMPHASIS ON PREVIOUS RECOMMENDATION

The following recommendation regarding market inefficiencies due to forecasted resources consistently under-scheduled in the day-ahead market has been documented in each annual state of the market report since the 2017 report. The MMU considers this a significant issue with widespread market implications and continues to encourage SPP and stakeholders to address the inefficiencies caused by the under-scheduling of forecasted resources in the market.

2017.5 ADDRESS INEFOFFICIENCY WHEN FORECASTED RESOURCES ARE UNDER-SCHEDULED DAY-AHEAD

The MMU noted in its 2017 report that the systematic under-scheduling of wind resources in the day-ahead market can contribute to distorted price signals, suppressing real-time prices and affecting revenue adequacy for all resources.\(^{217}\) This also poses a problem for resource

\(^{217}\) \textit{2020 SPP Annual State of the Market Report}, Chapter 8, 2017.5 Address inefficiency when forecasted resources under-schedule day-ahead
adequacy as the current, low average prices in the SPP market do not support new entry of any resource type except wind (see Chapter 4, Section 4). Noting that variable energy resources are generally able to produce close to a forecasted amount, the MMU recommended that this issue be addressed through market incentives and rule changes that focus on market inefficiencies associated with under-scheduling of variable energy resources in the day-ahead market based on forecasted supply. The MMU has included this recommendation in each annual state of the market report since 2017.

In 2021, the MMU noted that the percent of wind offered and cleared in the day-ahead market continues to decrease. At that time, although total wind offered was generally close to forecast, a portion of this is at offer levels that exceed prevailing prices and therefore is not cleared in the day-ahead market. In 2022, most day-ahead wind offers had a single segment that was generally offered at prices below prevailing prices, but at a quantity below forecast. Their real-time offers, in contrast, were generally set at a higher megawatt quantity and a lower offer price. This inter-market practice does not accurately reflect the risk, across the operating range of the resource, incurred by the market participant relative to the accuracy of the forecast.

As part of the 2021 report, the MMU noted the concerning increase in the frequency of negative prices in the market. The frequency of negative price intervals in the real-time market increased by 11 percent in 2020 and occurred two times more frequently in the real-time market than in the day-ahead market. In 2022, the frequency of negative pricing intervals decreased slightly from eight percent to seven percent in day-ahead, but increased another one percent in real-time.

One cause of these negative pricing interval differentials between the day-ahead and real-time markets is net differences in unit commitments due to under-clearing of wind resources in the day-ahead market relative to their real-time production. These negative prices can occur when renewable resources are backed down in order for traditional resources committed in the day-ahead market to operate at minimum output. This disparity between the markets negatively impacts the efficient commitment of resources. The MMU recognizes that, as more wind generation is anticipated to be added over the coming years, the frequency of negative prices has the potential to increase.

In 2021, the MMU submitted an initiative\(^{218}\) to be added to the SPP Roadmap to address the negative impacts of variable energy resources being under-scheduled in the day-ahead market. As part of the initiative, the MMU noted that the issue could be addressed through multiple

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\(^{218}\) [SIR 74 - DAMKT VER Participation]
avenues included 1) incentivizing more variable energy resource participation in the day-ahead market 2) incentivizing more virtual energy participation in the day-ahead market and 3) allocating measurable costs to causers. While the MMU continues to view this as a high priority issue, in 2021, stakeholders voted to move this issue to the list of parking lot initiatives. Despite efforts to revive this initiative during the 2022 roadmap prioritization meetings, stakeholders chose not to elevate this initiative from the parking lot. Initiatives that are perpetually in the parking lot are at risk of being removed from the roadmap process entirely. The MMU will continue to study the effects of under participation of wind in the day-ahead market and recommend the RTO and its stakeholders explore both policy and incentive options to increase day-ahead participation.

7.3 WINTER WEATHER REPORT – CRITICAL RECOMMENDATIONS

As part of its review and analysis of the February 2021 winter weather events, the MMU published a report outlining multiple recommendations for consideration by SPP and stakeholders in the areas of resources, price formation, scheduling and dispatch, and gas-electric coordination. The MMU has presented its report and findings to SPP, stakeholders, and FERC in multiple forums. The recommendations below represent three critical areas the MMU continues to emphasize in those discussions.

WWE1 ENSURE AVAILABILITY OF RESOURCES

An accurate measure of resource-level availability on a seasonal basis to meet seasonal demands remains on the MMU’s list of critical recommendations for reliability. An inadequate measure of the likelihood for capacity to be available during peak demand or a system shock such as a weather event leads to the reliance on neighboring regions, and unaccredited capacity to keep the lights on. If the scope of the system shock is large enough, as it was in February 2021, it leads to load shed.

In July 2022, the SPP Board of Directors approved the policy paper, recommended by SPP and approved by the Market and Operations Policy Committee (MOPC) and the Supply Adequacy Working Group (SAWG), for performance based accreditation using a variant of a demand-weighted probabilistic equivalent forced outage rate demand (EFORD). While this approach is an improvement over the status quo, this method of measuring resource availability does not address the main resource availability issues experienced during the February 2021 or December

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219 SPP Board of Directors action: https://www.spp.org/documents/67635/bod_mc%20minutes%202022%2007%2026.pdf
2022 winter weather events. Specifically, this approach does not account for maintenance outages or outages due to conditions beyond management control, and correlated outages by resource type. Furthermore, the approach only considers the best four out of five years, and implementation is anticipated in 2028.

All the while, the availability of accredited capacity to the market continues to fall significantly short of accreditation, with 2022 down 14 percent from 2021. PJM and MISO currently use EFORd in their capacity evaluation, and are actively looking for more accurate alternatives.

EFORd is proposed for use on all resources not included in SPP’s filing to use effective load carrying capability (ELCC). In August 2022, FERC approved the use of ELCC for wind, solar, and run-of-the-river hydroelectric resource as a measure of availability for capacity accreditation purposes, subject to the condition that SPP submit a compliance filing to include additional detail; which SPP did in September 2022. In March 2023, FERC reversed that ruling on the grounds of ineffective definitions and a lack of clearly specified rates in the tariff. In FERC’s reversal, Commissioner Clements commented in her concurrence that ELCC may be unduly discriminatory and recommended SPP adopt a consistent framework for all resource types.

In order to improve resource adequacy, and to ensure non-discriminatory treatment of resources, the MMU recommends that SPP and its stakeholders adopt an adequate approach to valuing resource accreditation that accurately measures total resource availability. This would include maintenance outages, outages beyond management control, and other correlated outages; would not allow for observations to be removed; and would implement this approach in a consistent timeline across all resource types.

**WWE2 ESTABLISH INCENTIVE MECHANISM FOR CREDITED CAPACITY**

The MMU continues to see the need for implementing both market and non-market mechanisms to incentivize resource attributes that enhance reliability through resiliency and availability. The MMU proposed a set of market mechanisms to incentivize existing resources to

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220 [https://www.spp.org/documents/66044/20211110_revisions%20to%20implement%20effective%20load%20carrying%20capability%20methodology_er22-379-000.pdf](https://www.spp.org/documents/66044/20211110_revisions%20to%20implement%20effective%20load%20carrying%20capability%20methodology_er22-379-000.pdf)


increase their availability to the market, and efficiently schedule maintenance outages, through valuing the availability of capacity when it is needed in the region. By placing a value of availability, participants can make economic choices on which resource attributes can be improved to most economically increase availability based on resource type, geographic location, and environmental and government policies.

The MMU initiative is currently ranked as “high” in the 2023 SPP Roadmap prioritization. While the initiative is not actively being worked on, the topic continues to surface in stakeholder meetings as “resource reliability attributes”, and “a market for maintenance”. Stakeholders have also expressed support for the Performance Credit Mechanism pursued in the ERCOT market. The MMU recommends the development of market and non-market incentives for “reliability attributes” in conjunction with the development of an accurate measurement for resource availability as two legs of a three-legged stool that ensures reliability through measurements, incentives, and requirements.

The MMU included recommendations in its winter weather report to allow for meaningful incentives for availability noting that, to the extent that a resource is more available there should be incentives, and to the extent that a resource is less available, there should be disincentives. The MMU recommended the establishment of an incentive mechanism for actual resource performance for accredited capacity.

This recommendation continues to be discussed in the stakeholder forums as part of overall discussions regarding the winter weather event. An initiative was added to the SPP Roadmap to address this recommendation. The MMU has argued in stakeholder forums that the accreditation approach both affects and is affected by an incentive mechanism. The MMU has discussed the incentive mechanism as part of the Improved Reliability Task Force and Supply Adequacy Working Group discussions to improve resource accreditation.

**WWE3 ESTABLISH MORE FREQUENT RESOURCE ADEQUACY REQUIREMENT**

The MMU continues to emphasize the uniqueness of seasonal demands and the resource attributes needed to meet those demands. The MMU recommends that SPP resource adequacy requirements address resource needs to meet the demand in each season independently. In the past two calendar years, SPP has experienced a winter weather event that has tested the region.

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223 The [Performance Credit Mechanism](#) has elements similar to the MMU’s proposed availability incentive approach.

224 [SIR310 WWE MMU R2](#)
and exposed reliability concerns related to the availability of adequate capacity to meet demand during system shocks. A look at the availability of accredited capacity shows the largest differences in the spring and fall seasons, which have no obligation nor requirement.

SPP is currently working with stakeholders to change the winter season resource obligation into a requirement, complete with penalty charges for deficiency. The MMU is engaged in the stakeholder process in support of this effort, but additionally recommends the same effort be undertaken for the spring and fall seasons. The MMU sees the seasonal resource adequacy requirement as the final leg of a balanced approach which uses accurate measurements, meaningful incentives, and adequate requirements, to ensure reliability.

7.4 PREVIOUS RECOMMENDATIONS

The MMU has provided recommendations to improve market design in each of our previous annual state of the market reports since the launch of the Integrated Marketplace in 2014. While SPP and its stakeholders have found ways to effectively address some of the MMU concerns, there remain many outstanding recommendations. A high level summary of each of these recommendations, including recent updates and current status are outlined below. Additional information for these recommendations can be found in the corresponding annual state of the market report.

2021.1 EXPAND MULTI-CONFIGURATION COMBINED CYCLE RESOURCE MODEL TO INCLUDE ADDITIONAL RESOURCE TYPES

In the 2021 report, the MMU recommended SPP expand the multi-configuration combined cycle resource model or create a new multi-configuration model to include additional resource types that have multiple operating modes, or configurations. This recommendation comes in response to observed inefficiencies from participants attempting to optimize their plant’s schedule without the benefit of such logic. The MMU noted that SPP’s multi-configuration combined cycle resource model provides the market several efficiency gains by optimizing the schedule of configurations, improving participant abilities to offer different parameters for each configuration, and providing real-time operational awareness.

Additional information, including further potential applications of the multi-configuration combined cycle resource model, is documented in the 2021 report.

**2020.1 UPDATE MARKET AND OUTAGE REQUIREMENTS TO IMPROVE FUNDING FOR TRANSMISSION CONGESTION RIGHTS**

The MMU made recommendations in the 2020 annual report to update outage requirements and develop market rules and market incentives associated with outages to better align the network models used by the transmission congestion rights auctions and the day-ahead market. This recommendation was a result of the MMU observation of a continued downward trend in the overall funding of transmission congestion rights from day-ahead market congestion rents. The MMU noted, at the time of the initial recommendation, that overall funding for transmission congestion rights had decreased materially from 2018 through 2020. The funding remained materially below the 90 percent target for the 2021 calendar year, and while funding for 2022 increased, it remained below the 90 percent target.

The MMU continues to recommend that SPP and stakeholders address transmission congestion right underfunding. As part of that recommendation, the MMU strongly recommends improving outage consistency between the congestion hedging market, the day-ahead market, and the real-time market to alleviate funding issues due to misaligned outages.

This recommendation is currently an initiative on the SPP Roadmap ranked as a high priority and is currently being discussed in the stakeholder process.

**2020.2 ENHANCE MARKET-TO-MARKET EFFICIENCIES THROUGH COLLABORATION WITH MISO**

In 2019 and 2020, the MMU worked with the MISO market monitor on a series of recommendations for the Joint Regional State Committee / Organization of MISO States Seams Liaison Committee. Based on the results of the joint study, the MMU recommended in the 2020 annual report to evaluate the processes and mechanisms used to effectuate the market-to-market agreement between SPP and MISO. One of the items identified by the market monitors in this process was that SPP had real-time market-to-market congestion that was not

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226  *2020 SPP Annual State of the Market Report*, Chapter 8, 2020.1 Update market outage requirements to improve funding for transmission congestion rights

227  *SIR77 - TCR Funding*

228  *2020 SPP Annual State of the Market Report*, Chapter 8, 2020.2 Enhance market-to-market efficiencies through collaboration with MISO
materializing in the day-ahead market. Upon further evaluation, it was determined that this was because MISO market-to-market constraints were not being activated in the SPP day-ahead market. SPP began a new process in October 2022 that activates MISO market-to-market constraints in the day-ahead market based on recent congestion trends in the real-time market. SPP staff indicated one of the chief concerns with activation of day-ahead MISO market-to-market constraints was the potential to increase TCR underfunding. The MMU supports SPP’s recent efforts in aligning day-ahead and real-time congestion along the SPP-MISO seam and recommends SPP make any necessary modifications to the TCR model to address concerns with TCR underfunding.

To the extent that costs are incurred by either market as a result of implementing changes per the joint agreement, the MMU recommends SPP and MISO work to address this through their Joint Operating Agreement. Currently, the Joint Operating Agreement indicates that SPP and MISO would address how to assign costs with day-ahead at a future date. The MMU believes that now is an appropriate future period to resolve these outstanding items with the agreement.

The MMU continues to recommend that SPP and stakeholders address inefficiencies in the market-to-market agreement between SPP and MISO. This initiative is currently on the SPP Roadmap as a high priority.

2020.3 RAISE OFFER FLOOR TO -$100/MWH

The MMU recommended in the 2020 report to raise the energy offer floor to -$100/MWh. This recommendation was the result of analysis performed by the MMU which observed resources offering at the offer floor, -$500/MWh, and setting price. These offers did not represent cost, were often costly to the offering resource, and harmful to nearby resources. The MMU worked with the Market Working Group to add this as an initiative on the SPP Roadmap. As noted in the 2020 report, the MMU believes that raising the offer floor is a simple and cost effective solution that avoids any limitation of what costs can be included in a market offer, however, as part of the SPP Roadmap process, this initiative was added to the list of parking lot initiatives. Initiatives that are perpetually in the parking lot are at risk of being removed from the roadmap process entirely. The MMU recommends SPP remove this initiative from the parking lot and include it in the list of initiatives to be acted on.

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229 [MWG presentation]
230 SIR75 - Market-to-Market Improvements
231 SIR76 - Mitigation of Unduly Low Offers
2019.1 IMPROVE PRICE FORMATION

In the 2019 report, the MMU identified circumstances where market prices provide neither a short-term nor a long-term economic incentive to ensure reliability and recommended SPP and stakeholders review price formation during scarcity events and establish graduated demand curves that incentivize proper price formation.

In the MMU report on the February 2021 winter weather event, the MMU made recommendations related to improving price formation during emergency and scarcity conditions. In that report, the MMU highlighted situations where price signals did not accurately reflect underlying conditions. The recommendations in the February 2021 winter weather report, which are aimed at improving pricing outcomes, closely align with the 2019 recommendation to improve price formation. The MMU believes this recommendation is being addressed through the stakeholder processes focusing on enhancements needed as a result of the February 2021 winter weather event.

2019.2 INCENTIVIZE CAPACITY PERFORMANCE

In the 2019 report, the MMU recommended the SPP and stakeholders work to incentivize capacity performance and suggested potential options. In 2021, as part of its February 2021 winter weather event report, the MMU also made recommendations regarding capacity adequacy and performance, many of which align with this recommendation. As such, the MMU believes this recommendation will be addressed through those stakeholder processes focused on enhancements needed as a result of the February 2021 winter weather event.

2019.3 UPDATE AND IMPROVE OUTAGE COORDINATION METHODOLOGY

In the 2019 report, the MMU recommended that the outage coordination methodology be updated to cover reserve shutdown outages, lower the threshold for outages to be submitted, and properly categorize and prioritize outages as well as outage extensions. The Generator Outage Task Force, a temporary group that reported directly to the Markets and Operations Policy Committee, was tasked with reviewing and making recommendations to improve the outage coordination processes.

The Generator Outage Task Force finalized its recommendation report in fall 2021. Of the four major recommendations from that report, the hourly generation assessment process has been implemented, the outage coordination methodology changes are scheduled to be completed
April 2023, the generation assessment process impact study is being evaluated by the Supply Adequacy Working Group, and the email distribution lists are in effect.

The MMU continues to evaluate whether additional enhancements to the outage coordination methodology and processes are necessary to minimize the negative impacts of inefficient outages on the market. There are four areas of concern remaining: misalignment of outage reporting timelines and the TCR processes; outage extensions; material misstatements; and missing, inaccurate, and incomplete outage information.

2018.1 LIMIT THE EXERCISE OF MARKET POWER BY CREATING A BACKSTOP FOR PARAMETER CHANGES

In the 2018 report, the MMU recommended that SPP strengthen the language regarding non-dollar-based parameters so that the expectation for the basis of these values is clear and well-defined. The MMU noted that changes to these parameters should be limited to actual capability and should be verified, at a minimum, in the presence of market power. This recommendation is currently an initiative 232 on the SPP Roadmap ranked as a high priority.

2018.2 ENHANCE CREDIT RULES TO ACCOUNT FOR KNOWN INFORMATION IN ASSESSMENTS

In the 2018 report, the MMU made recommendations to improve SPP’s credit policy in light of a credit default in the PJM market that resulted in significant financial impacts to its market participants. The MMU engaged with SPP’s Credit Practice Working Group regarding this issue and the potential impact to SPP and its market participants. SPP stakeholders proposed a two-phase approach to mitigate SPP’s exposure.

The Credit Practices Working Group has developed and implemented the first phase of credit policy enhancements. These enhancements are a material improvement. The second phase focused on incorporating forward-looking known information into the financial security calculations. SPP staff reviewed options for a forward-looking approach in 2021, including a mark-to-auction process. While, no phase two changes were implemented, the MMU continues to recommend the SPP and stakeholders evaluate ways to incorporate forward-looking information in the credit evaluation process.

In July 2022, FERC issued an order to show cause to four ISO/RTO’s as to why their tariffs were just and reasonable in absence of either of (1) mark-to-auction mechanisms for the calculation

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232 SIR 22 - Limit Market Power Through Physical Parameters
of financial transmission right (FTR) market participants’ collateral requirements and/or (2) volumetric minimum collateral requirements for FTR market participants. SPP’s phase one efforts included the development and implementation of a volumetric minimum collateral requirement. However, SPP did not elect to develop and implement mark-to-auction mechanisms. SPP therefore was directed, to show cause, as to why its tariff is just and reasonable without mark-to-auction mechanisms. SPP filed comments in support of its current tariff whereas the MMU filed comments in support of mark-to-auction. FERC has yet to provide a final rule.

2018.3 DEVELOP COMPENSATION MECHANISM TO PAY FOR CAPACITY TO COVER UNCERTAINTIES

In the 2018 report, the MMU recommended SPP develop a compensation mechanism to pay for capacity needed to address uncertainties in the market.

SPP market participants approved a revision request233 to implement an uncertainty product in April 2021 and was approved by the SPP Board of Directors July 2021. The Tariff changes for the uncertainty product design were filed with FERC in January 2022. Implementation is currently targeted for July 6, 2023.234 Once implemented, the MMU will consider this recommendation closed.

2018.5 IMPROVE REGULATION MILEAGE PRICE FORMATION

In the 2018 annual state of the market report, the MMU recommended SPP staff review the performance of regulation mileage, and develop potential approaches to improve regulation mileage price formation. In addition, based on independent analysis, the MMU recommended SPP staff address two inefficiencies; one in the calculation of the factor used to determine average expected mileage, and one in the calculation of the clearing price for mileage.

SPP drafted revision request 504 – improved economic incentive of regulation mileage in August 2022 to address both MMU recommendations.235 It passed the SPP stakeholder process in December 2022, and is expected to be filed with FERC by mid-2023.

The revision is expected to reduce excess regulation mileage buy-back by resources cleared for regulation, and improve price formation for the clearing price of regulation mileage. The

233 [Revision request 449 – Uncertainty Product](https://www.spp.org/search?q=rr449)
235 [https://www.spp.org/search?q=rr504](https://www.spp.org/search?q=rr504)
revision will lower the expected megawatts for cleared mileage by using the historical ratio of actual response from instructed mileage to cleared regulation, instead of instructed mileage to cleared regulation ratios, in setting the mileage factor. The actual response to mileage deployment has historically been roughly half of the instructed mileage, due to unattainable instructions coming from the four-second setpoint instructions. Making this change will reduce the mileage factor and by extension excess unused mileage buyback. The second change will set the mileage-clearing price based on the mileage offer of the marginal resource, instead of the highest mileage offer cleared. Making this change will reduce the clearing price for regulation mileage, and payments for excess mileage.

The MMU expects these changes to adequately address the recommendations regarding regulation mileage.

2017.2 ENHANCE COMMITMENT OF RESOURCES TO INCREASE RAMPING FLEXIBILITY

In 2017, the MMU recommended that SPP and its stakeholders address the issue of inadequate ramping flexibility by modifying its market rules to enhance the commitment of resources and increase ramping flexibility. The MMU noted potential options to address the commitment concerns and recommended SPP and its stakeholders explore options, such as those noted, to enhance commitment of resources and increase flexibility. This initiative236 is on the SPP Roadmap and is currently ranked as a high priority.

2017.3 ENHANCE MARKET RULES FOR ENERGY STORAGE RESOURCES

SPP implemented its design for energy storage for compliance with FERC Order No. 841 in 2021. While the MMU filed supportive comments for the implementation of energy storage in the SPP Market, the MMU noted further areas of enhancements to be considered with electric storage integration.

Multiple initiatives were added to the SPP Roadmap to address the additional enhancements needed to fully integrate electric storage resources in the SPP markets. The MMU had previously made comments to an SPP initiative to make enhancements to the energy storage design. However, the MMU recommendation for inclusion of mitigation measures for excessively low offers was not reflected in the initiatives that were added to the SPP Roadmap.

236 SIR 9 - Enhanced Commitment
The MMU continues to recommend SPP and stakeholders consider the implementation of mitigation measures for excessively low offers in the market.

2017.4 ADDRESS INEFFICIENCY CAUSED BY SELF-COMMITTED RESOURCES

The MMU recommended in the 2017 report that SPP and its stakeholders address the inefficiencies caused when market participants self-commit their resources in the market. The MMU then conducted an in-depth study of self-commitment practices and associated inefficiencies in 2019.237

The MMU continues to recommend that SPP and its stakeholders explore and develop ways to reduce the incidence of self-commitment of resources outside of the market solution, including considering adding an additional day to the optimization process. An initiative238 was added to the SPP Roadmap to implement these enhancements. This initiative is currently on hold while SPP evaluates the accuracy of its multi-day forecasts.

2014.3 ADDRESS GAMING OPPORTUNITY FOR MULTI-DAY MINIMUM RUN TIME RESOURCES

The MMU recommended changes to address a gaming opportunity in the market for resources with minimum run times greater than two days in its 2014 report. While Tariff changes to address this concern were approved by the SPP board in 2018, subsequent changes were needed to address inconsistent tariff language that the revisions revealed but did not address. An associated revision request239 and additional tariff modification was approved through the stakeholder process. SPP filed these changes with FERC on May 7, 2020240 and the MMU filed comments in support of the tariff changes on June 12, 2020.241 The current implementation date for this enhancement is October 1, 2023.

238 SIR 18 - HIT R3c: Implement Marketplace Enhancements: Multi-Day Market
239 Revision request 382 – Multi-Day Minimum Run Time and Clarifications
2014.4 ADDRESS ISSUES WITH THE DAY-AHEAD MUST OFFER REQUIREMENT

The MMU continues to recommend that SPP and stakeholders eliminate the limited day-ahead must-offer provision and revise the physical withholding rules to include a penalty for non-compliance, or address the design weaknesses. This initiative is on the SPP Roadmap and is currently ranked as a high priority.

7.5 IMPLEMENTED RECOMMENDATIONS

The following recommendations from previous reports have been implemented in 2022.

2014.1 Improve quick-start logic

SPP implemented its fast-start resource design in May 2022. The MMU completed an analysis on fast-start pricing and documented the results of that analysis in a special issue in the fall 2022 quarterly state of the market report. The MMU will continue monitor the impacts fast-start resources in the market and identify and report on those impacts where appropriate. The MMU considers this recommendation addressed with the implementation of the fast-start logic.

2017.1 Develop a ramping product

In the 2017 report, the MMU recommended SPP develop a ramping product to incent actual, deliverable flexibility which to send appropriate price signals to the market that value resource flexibility.

SPP, stakeholders, and the MMU worked together to complete a ramping product design in April 2019 which was approved by the Market Operations and Policy Committee in October 2019. This design was approved by FERC in July 2020 and implemented on March 1, 2022.

There are, however, some issues with the performance of the ramping product, as stated in this year’s new recommendation, 2022.2 Address limitations with the ramp capability product.

2018.4 Enhance ability to assess a range of potential outcomes in transmission planning

The MMU has continued to recommend in its annual state of the market reports that SPP and stakeholders identify ways to study and plan for the more aggressive carbon emissions reduction targets in the 10- and 20-year studies. SPP has continued to make enhancements to its planning processes that include lowering carbon emissions targets and increasing renewable

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242 SIR6 – DA Must Offer and Physical Withholding
243 SPP MMU quarterly state of the market report fall 2022
capacity. With the recent enhancements to the 2024 ITP studies, the MMU believes this recommendation has been addressed. The MMU will continue to engage with SPP and stakeholders to ensure future studies include reasonable assumptions with regards to renewable integration on the SPP system.

7.6 RECOMMENDATIONS UPDATE

The table below lists the status of Annual State of the Market recommendations included in previous reports and those that are new to this report. Recommendations closed prior to the completion of the previous year’s report do not appear in this table. To review closed recommendations that are not covered in this report, please review earlier reports.

**Figure 7–1 Annual State of the Market recommendations**

<table>
<thead>
<tr>
<th>Recommendation</th>
<th>Report year</th>
<th>Current status</th>
</tr>
</thead>
<tbody>
<tr>
<td>2022.1 Consider limitations on virtual trading during emergency conditions</td>
<td>2022</td>
<td>New recommendation in 2022</td>
</tr>
<tr>
<td>2022.2 Address limitations with the ramp capability product</td>
<td>2022</td>
<td>Discussions beginning at Market Working Group</td>
</tr>
<tr>
<td>2022.3 Improve situational awareness of transmission upgrades and improve process to reassign projects</td>
<td>2022</td>
<td>Discussions beginning at Project Cost Working Group</td>
</tr>
<tr>
<td>2022.4 Approve congestion hedging mechanism to enhance equity</td>
<td>2022</td>
<td>SPP recommendation expected at Board meeting in 2023</td>
</tr>
<tr>
<td>2021.1 Expand multi-configuration combined cycle resource model</td>
<td>2021</td>
<td>No action at this time</td>
</tr>
<tr>
<td>2020.1 Update market and outage requirements to improve funding for transmission congestion rights</td>
<td>2020</td>
<td>Stakeholder discussions in progress</td>
</tr>
<tr>
<td>2020.2 Enhance market-to-market efficiencies through collaboration with MISO</td>
<td>2020</td>
<td>SPP Roadmap initiative</td>
</tr>
<tr>
<td>Recommendation</td>
<td>Report year</td>
<td>Current status</td>
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<tr>
<td>----------------</td>
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<td>----------------</td>
</tr>
<tr>
<td>Raise offer floor to -$100/MWh</td>
<td>2020</td>
<td>SPP Roadmap initiative</td>
</tr>
<tr>
<td>Improve price formation (two issues)</td>
<td>2019</td>
<td>Issue A: SPP Roadmap initiative Issue B: Engaging stakeholders</td>
</tr>
<tr>
<td>Incentivize capacity performance</td>
<td>2019</td>
<td>Stakeholder discussions in progress</td>
</tr>
<tr>
<td>Update and improve outage coordination methodology</td>
<td>2019</td>
<td>Stakeholder discussion in process; some improvements have been implemented</td>
</tr>
<tr>
<td>Limit market power by backstopping parameter changes</td>
<td>2018</td>
<td>SPP Roadmap initiative</td>
</tr>
<tr>
<td>Enhance credit process to account for known information</td>
<td>2018</td>
<td>Awaiting FERC response to Show Cause Order</td>
</tr>
<tr>
<td>Develop compensation or product for capacity used for uncertainties</td>
<td>2018</td>
<td>Awaiting implementation in 2023</td>
</tr>
<tr>
<td>Enhance ability for transmission planning to cover range of outcomes</td>
<td>2018</td>
<td>Recommendation complete</td>
</tr>
<tr>
<td>Improve regulation mileage price formation</td>
<td>2018</td>
<td>Awaiting FERC filing</td>
</tr>
<tr>
<td>Develop ramping product</td>
<td>2017</td>
<td>Implemented 2022 – recommendation complete</td>
</tr>
<tr>
<td>Enhance unit commitment logic</td>
<td>2017</td>
<td>SPP Roadmap initiative</td>
</tr>
<tr>
<td>Enhance energy storage design</td>
<td>2017</td>
<td>SPP Roadmap initiative</td>
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<tr>
<td>Reduce self-scheduling in market</td>
<td>2017</td>
<td>SPP Roadmap initiative</td>
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<tr>
<td>Address under-scheduling of wind</td>
<td>2017</td>
<td>SPP Roadmap initiative – parking lot</td>
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<tr>
<td>Improved quick-start logic</td>
<td>2014</td>
<td>Implemented 2022 – recommendation complete</td>
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<td>Recommendation</td>
<td>Report year</td>
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<tr>
<td>2014.3</td>
<td>Manipulation of make-whole payment provisions</td>
<td>2014</td>
</tr>
<tr>
<td>2014.4</td>
<td>Address issues with the day-ahead must-offer requirement</td>
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</table>