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1 EXECUTIVE SUMMARY

The Southwest Power Pool (SPP) Market Monitoring Unit’s (MMU) Annual State of the Market report for 2019 presents an overview of market design and market outcomes, assesses market performance, and provides recommendations for improvement. The purpose of this report is to provide SPP market stakeholders with reliable and useful analysis and information to use in making market-related decisions. The MMU emphasizes that economics and reliability are inseparable and that an efficient wholesale electricity market provides the greatest benefit to the end user both presently and in the years to come.

1.1 MARKET HIGHLIGHTS

The following list identifies key observations in the SPP marketplace over the past year.

- SPP market results were competitive overall, with infrequent mitigation of offers and high resource participation levels.
- Total wholesale market costs—including energy, operating reserve, and uplift payments—averaged around $24/MWh in 2019, which was about 12 percent lower than in 2018.
- Day-ahead prices averaged around $22/MWh and real-time prices averaged around $21/MWh for the year, both down from $25/MWh in 2018.
- The annual peak load of 51,230 MW was three percent higher this year compared to last year, while total electricity consumption was down about one-half percent.
- The incidence of negative prices in the real-time market in 2019 was about seven percent of intervals, about double the level in 2018.
- Make-whole payments in the reliability unit commitment process were up markedly, rising from $45 million in 2018 to nearly $70 million in 2019, a 55 percent increase. The increase in real-time make-whole payments can primarily be attributed to more
resources being brought on from the reliability unit-commitment processes, including manual commitment for capacity needs.

- Natural gas-fired resources frequently set prices in the SPP market, with natural gas prices decreasing about 25 percent in 2019 compared to 2018.

- When system prices control for changes in fuel prices, they averaged about eight percent higher in 2019 compared to 2018.

- Scarcity events increased in 2019 when compared to 2018 levels. 2019 experienced 1,220 five-minute intervals of scarcity, up 72 percent from 709 intervals in 2018.

- Out-of-service, maintenance outages for gas, simple-cycle resources increased by over 30 percent from 2018 to 2019.

- SPP operations issued ten Conservative Operations Alerts in 2019, covering 35 days, and had one Energy Emergency Alert 1 (EEA 1) in August. These are the first Conservative Operations Alerts and EEA 1 since the inception of the Integrated Marketplace in March 2014.

- The average percent of total offered capacity by commitment status remained consistent in 2019 with prior year levels with a slight decrease in the self-commit status and increases in both the market and outage statuses.

- Cleared virtual energy offers as a percentage of load increased nearly 19 percent, while cleared virtual energy bids as a percentage of load increased nearly 14 percent year-over-year.

- Average profit per cleared virtual megawatt after fees increased from $0.46/MW to $0.63/MW.

- Day-ahead and real-time congestion costs totaled over $457 million in 2019, a one percent increase from 2018.
• Wind generation peaked at nearly 17.9 GW and peak wind penetration was nearly 69 percent of load, both during October. Wind capacity increased to almost 22.5 GW in 2019, up about nine percent from 2018.

• Wind generation totaled just over 27 percent of all generation in 2019, up slightly from 23.5 percent in 2018. Coal generation fell from 42 percent in 2018 to 35 percent in 2019.

• On a monthly basis, wind generation as a percent of total generation outpaced coal generation in both April and October 2019. These are the first two months in the Integrated Marketplace where this has occurred.

• New capacity additions were just over 1,800 MW at nameplate capacity, with wind representing all of the new capacity. Capacity retirements were just under 1,500 MW in 2019, with coal resources accounting for nearly 1,000 MW and gas resources accounting for nearly 500 MW.

• The generator interconnection process includes nearly 82 GW of additional resources, of which all but 270 MW are renewable or storage.

• SPP continues to have significant excess capacity at peak loads. The MMU estimates that capacity at peak is 31 percent higher than the peak demand level in 2019. This is down from 35 percent in 2018, but can mostly be attributed to an increase in the peak load in 2019. Available capacity only dropped less than one percent from 2018 to 2019.

• Market prices themselves do not signal new investment in generation. Furthermore, MMU analysis shows that market revenues do not support going forward costs for coal resources.

• In total, market participants were effective in hedging congestion in the SPP market using SPP’s congestion hedging products. Load-serving entities covered more than 135 percent and non-load-serving entities covered more than 105 percent of their total congestion cost. Auction revenue rights were funded at 129 percent in 2019, down from just over 145 percent in 2018.
• Transmission congestion rights funding fell outside the target range, with funding down from 94 percent in 2018, to 89 percent 2019.

• 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.

1.2 OVERVIEW

The SPP market produced competitive market results overall with total market costs around $24/MWh. As with previous years, the largest component of total wholesale costs remains energy costs, which represented almost 98 percent of total costs in 2019. As total costs decreased by 12 percent in 2019 compared to 2018, the main driver for the decrease in energy costs was a decrease in gas cost of 25 percent. When adjusted for fuel prices, average SPP marginal energy prices increased by eight percent.

While the annual peak load of 51,230 MW was three percent higher this year compared to last year, total electricity consumption was down about one-half percent. All of the 1,800 MW increase in nameplate generation capacity last year was from wind resources. Wind generation as a percent of total generation continued to increase as it represented 27 percent of system generation, up from 24 percent in 2018. Conversely, coal generation continued to decline, representing around 35 percent of total generation last year, down from 42 percent in 2018. In fact, wind generation as a percent of total generation outpaced coal generation in both April and October 2019.

There have been increasing challenges to the market in 2019. SPP operators increasingly called on resources to meeting ramping needs to address uncertainty in the market. This contributed to a 40 percent increase in make-whole payments. Furthermore, the market saw a jump in negative prices to seven percent of all intervals. The MMU identified that self-committed generation reduces the system wide price by about $2/MWh and shifts congestion throughout the system. Distorting prices can affect net revenues and potentially signal retirement for resources that may be needed but for the self-commitment. Finally, outage levels, particularly
for maintenance, increased in 2019. This resulted in system tightness and the need for SPP operators to call upon conservative operations. Unfortunately, the price signals during emergency conditions did not reflect the overall tightness of market conditions. The MMU provides several recommendations to address these concerns. SPP and stakeholders have an opportunity to take actions before these concerns lead to further issues.

Significant market events in 2019 included:

- SPP operations issued ten Conservative Operations Alerts in 2019, covering 35 days, and had one Energy Emergency Alert 1 (EEA 1) in August. These are the first Conservative Operations Alerts and EEA 1 since the inception of the Integrated Marketplace in March 2014.

- Even with the conservative operations events and EEA 1 event, the MMU, along with some stakeholders, are concerned that prices during the EEA 1 event did not reflect emergency conditions. During this period, the additional generation SPP depended on to address emergency conditions lowered prices. The MMU recommends that SPP and stakeholders consider creating reliability pricing rules for EEAs and maximum generation events to economically incentivize reliable generator behavior.

- Capacity taken out-of-service for maintenance outages by gas, simple-cycle resources increased by over 30 percent from 2018 to 2019. This directly resulted in many conservative operations called on by SPP operators. Some of the outages resulted in resources unavailable for most of the year, and some forced outages were misclassified when they were really maintenance outages.

- SPP wrapped up the Holistic Integrated Tariff Team effort. This group comprised members, Board of Directors, Regional State Committee members, and supported by SPP staff, focused on developing problem statements, reviewing analysis, and proposing solutions to related areas of concern including transmission cost allocation, auction revenue right allocation, market enhancements, and load integration. The findings of the group were approved at the July 2019 board meeting.
• SPP began to offer contract-based products to utilities in the Western Interconnection in 2019, with additional services to be offered in coming years.
  
  o In December 2019, SPP began to operate in the Western Interconnection as a North American Electric Reliability Corporation (NERC) certified reliability coordinator.
  
  o In February 2021, SPP plans to launch the Western Energy Imbalance Services Market (WEIS), a real-time wholesale electricity market that balances generation and load regionally. This market is modelled on SPP’s Energy Imbalance Service (EIS) market that ran from 2007 to 2014. As of March 1, 2020, eight entities have entered into agreements to participate in the Western Energy Imbalance Service market.

1.3 DAY-AHEAD AND REAL-TIME MARKET PERFORMANCE

Overall, real-time energy prices were about $4/MWh lower in 2019 compared to 2018, while day-ahead energy prices were down $3/MWh in the same period. This decrease can primarily be attributed to lower gas costs across the SPP market footprint, with those costs down 25 percent from 2018 to 2019.

Load participation in the day-ahead market continued to be strong in 2019. For instance, the average level of participation for the load assets was between 99 percent and 101 percent of the actual real-time load. However, on average for the year, wind generation was over 1,300 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 has continued to increase substantially over the past several years.

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 around 660 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 increased in 2019 to nearly $75 million, up from $44 million in 2018. When charges and transaction fees are included, net profit for virtual transactions was nearly $31 million in 2019, up from just under $18 million in 2018. Net virtual profits were highest in January ($5.6 million), when loads were high, and October ($8.9 million) when wind generation was high and loads were low.

Self-commitment of generation continues to be a concern because it does not allow the market software to determine the most economic market solution. Furthermore, it can contribute to market uplifts and low prices. Specifically, MMU analysis shows that the marginal costs of energy drops by $2/MWh due to self-commitment. Moreover, the MMU identified that congestion patterns also changed with self-commitment, with some areas increasing on average by about $1/MWh and others decreasing by about $1/MWh.

Generation offers in the day-ahead market averaged just over 55 percent as “market” commitment status followed by “self-commit” status at nearly 25 percent of the total capacity commitments for 2019. This continues the trend of increasing market commitments and decreasing self-commitment since 2016. While the overall increase in market commitments and decrease in self-commitments highlights an improvement, self-commitments still represent nearly about half of the capacity in the market. In order to improve market commitment in the SPP market, the MMU recommends that SPP and stakeholders look to find ways to reduce the incidence of self-commitment and to consider adding an additional day the day-ahead unit commitment process. For more details on the MMU’s study of self-commitments in the SPP market, refer to the whitepaper on self-commitment published in December 2019.¹

Scarcity events increased in 2019 when compared to 2018 levels. 2019 experienced 1,220 five-minute intervals of scarcity, up 72 percent from 709 intervals in 2018. Nearly half of the scarcity intervals happened during four months of 2019 – April, May, October, and November – months that typically have high wind production, low load, and more generation outages. Additionally, looking at the intervals where scarcity occurs each hour shows that nearly 30 percent of all

scarcity events, and nearly 42 percent of regulation-down scarcity events, in 2019 occurred in the first interval of the hour. One potential reason for this trend is that SPP does not preposition regulating resources to be at their regulating effective maximum and minimum limits prior to the period that the resource is cleared for regulation. Unlike some other RTO/ISO markets, the current SPP model does not account for forecasted ramping needs. In 2018 and into 2019, SPP, stakeholders, and the MMU have discussed design elements of a ramping product. A ramping design was finalized in April 2019, and approved by the Market Operations and Policy Committee on October 2019. Tariff revisions were filed with FERC in April 2020[^2], and the MMU will file comments in May 2020[^3].

### 1.4 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. Although the SPP market currently maintains a high reserve margin, certain locations of the footprint experience significant price movements resulting from congestion caused by high wind generation and transmission limitations.

The area that experienced the highest congestion costs in 2019 was the southeastern corner of SPP including eastern Kansas, southwest Missouri, and southeastern Oklahoma. A concentrated area on the Kansas and Oklahoma border and western Nebraska experienced the lowest congestion costs for the year. The frequently constrained area study for 2019 saw the removal of the central Kansas and southwest Missouri frequently constrained areas and no additions, so there are no frequently constrained areas at this time.

In total, net congestion costs were just over $457 million in 2019. This was up slightly from $453 million in 2018. 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 by just over $34 million, while the largest amount under-hedged was nearly $15 million.

[^3]: MMU comments have yet to be filed at the time of this report publication, Docket No. ER20-1617.
1.5 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.

In 2018, total make-whole payments were approximately $101 million, up from nearly $72 million in 2018. Make-whole payments averaged about $0.37/MWh in 2019, up just over 40 percent from $0.26/MWh in both 2017 and 2018. In comparison to other RTO/ISO markets, SPP’s make-whole payments were at the high-end of uplift costs, which varied from $0.11/MWh to $0.23/MWh in 2018 and 2019.

Reliability unit commitment make-whole payments constituted almost 70 percent of the total make-whole payments and increased 55 percent in 2019. A primary driver of these make-whole payments was for manual capacity commitments in the real-time market to meet ramping needs. The increase in capacity commitments was caused by a few 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. Third, very low gas prices – which were negative at times in some regions – resulted in flexible resources being committed for energy in the day-ahead and unavailable to provide additional ramping flexibility in real-time.

The MMU is very concerned about the significant increase in 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. This increase provides further evidence that both a ramping product and an uncertainty product are needed to 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.
1.6 COMPETITIVENESS ASSESSMENT

The SPP market provides effective incentives and mitigation measures to produce competitive market outcomes, even during periods when the potential for the exercise of local market power could be a concern. The MMU’s competitive assessment using structural and behavioral metrics indicate that market results in 2019 were competitive overall and that the market required mitigation of local market power infrequently to achieve competitive outcomes.

Structural competitiveness metrics—which review the structural potential for the exercise of market power—indicate minimal to moderate potential structural market power in SPP markets outside of areas that are frequently congested. The market share of the largest on-line supplier in terms of real-time energy output exceeded 20 percent in 55 percent of all hours in 2019, which represents a significant increase from 2018. This trend has been observed since June 2018, which coincides with the merger between Great Plains Energy and Westar Energy to form Evergy, Inc., and is attributable to real-time dispatch of resources owned and controlled by the merged entity. This is up from 2017, when no hours were above the 20 percent threshold, and the highest value was 17 percent.

An additional measure of structural market power is the Herfindahl-Hirschman Index (HHI). This analysis, based on actual generation, indicates that 11 percent of hours in 2019 had values between 1,000 and 1,800, which indicates a moderate level of concentration. The market had been considered unconcentrated since the addition of the Integrated System in October 2015, up until the creation of Evergy in June 2018. Prior to the addition of the Integrated System, nearly 40 percent of all hours were considered moderately concentrated.

While moderately concentrated hours increased following the creation of Evergy, an increase in market share and HHI in themselves does not 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 evaluated for competitive assessment.

For the two frequently constrained areas that were in effect for most of 2019, where potential for concern of local market power is the highest, existing mitigation measures served well to prevent pivotal suppliers from unilaterally raising prices.
Behavioral indicators—which assess the actual exercise of market power—show low levels of mitigation frequency. Mitigation of day-ahead energy, operating reserve, and no-load offers each occurred less than 0.2 percent of the time and real-time mitigation occurred about 0.01 percent of the time. The overall mitigation frequency of start-up offers was the lowest since the market began in 2014, as it decreased slightly from the previous low in 2018, at just under three percent.

The decline in mitigation may be related to declining offer price mark-ups. Both off-peak and on-peak average offer markups were at the lowest levels since implementation of the Integrated Marketplace at around −$8.78/MWh and −$8.49/MWh, respectively. Although a lower offer price markup level in itself would indicate a competitive pressure on suppliers in the SPP market, the observed continuous downward trend may raise questions about the commercial viability of generating units and the possibility of generation retirements.

The monthly average output gap—which measures economic withholding—shows very low levels of economic withholding in all months in 2019, at less than 0.2 percent each month. Specifically, there were miniscule amounts of measurable output withheld in the frequently constrained areas. These low levels of economic output withholding reflect highly competitive participation in the market.

Another method of competitive assessment is unoffered generation capacity for potential physical withholding. Specifically, any economic generation capacity that is not made available to the market through derates, outages, or otherwise not offered to the market is considered for this analysis. Annually for the SPP footprint, the total unoffered capacity (as a percent of total resource reference levels) equaled 2.0 percent in 2017, 3.2 percent in 2018, and 2.9 percent in 2019. When short and long-term outages are removed, the remaining unoffered capacity was 0.23 percent, 0.39 percent, and 0.43 percent, respectively. The majority of the outages were long-term outages due to maintenance during the shoulder fall and spring months. From a competitive market perspective, the results indicate reasonable levels of total unoffered economic capacity and are consistent with the results in other RTO/ISO markets.
1.7 STRUCTURAL ISSUES

Installed generation capacity in the SPP market has grown rapidly over the past several years. This has contributed to high levels of capacity at peak loads. Specifically, the MMU estimates that capacity was 31 percent higher than the peak load in 2019. SPP’s current annual planning capacity requirement is 12 percent.

Wind capacity has nearly tripled from 8.6 GW in 2014 to 22.5 GW in 2019. At the same time, wind generation has constituted a growing and significant part of the total annual generation, from around 12 percent in 2014 to 27 percent in 2019. Furthermore, the interconnection process includes nearly 82 GW of additional resources, of which all but 270 MW are renewable resources.

The shift in generation mix towards renewable resources is a significant development and carries both market and operational challenges. Furthermore, these challenges are further exacerbated by the fact that at the end of 2019, 24 percent of the total wind capacity is non-dispatchable. However, the conversion of non-dispatchable resources to dispatchable resources continues, and should be full converted by the later of January 1, 2021 or the 10-year anniversary of the original commercial operations date.

A recent wave of generator retirements, particularly of coal-fired generation, has been widely observed throughout the country. The SPP market is expected to follow this trend because of excess capacity, aging fleet, and cost disadvantages of certain types of generation technologies vis-à-vis the prevailing market prices.

The MMU believes that SPP and stakeholders should prepare for the challenges these changes, and potential changes, to the market present. However, additional changes from planning to operations needs to be developed to improve market outcomes. As such, we make several recommendations to address these growing market concerns.
1.8 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 8. Below is a summary of our 2019 recommendations.

1.8.1 NEW RECOMMENDATIONS FOR 2019

2019.1 Improve price formation

Price formation is the economic basis of incentivizing both short-term operational and long-term investment decisions. The MMU has identified circumstances where market prices provide neither a short-term nor a long-term economic incentive to ensure reliability. The following recommendations are two areas to improve price formation.

A. Improve price formation during emergencies

The MMU reviewed the prices during each conservative operations event as well as the Energy Emergency Alert event in 2019. Prices were very low for a significant amount of time during the event, although they were very high at the beginning of the event. These very low prices do not signal that generation and imports need to be available during these events. The MMU highly recommends reviewing price formation during emergencies.

The MMU recommends that SPP and stakeholders address this as a high priority. Setting proper prices during emergency events can signal market participants to take actions to address the underlying emergency condition, such as increasing imports. Proper prices also provide proper investment signals to deal with and avoid future emergencies.
B. Improve price formation during scarcity

The MMU reviewed the prices during scarcity events and noted a dramatic increase of intervals where scarcity pricing was invoked. While regulation and contingency reserves use graduated demand curves for price formation during scarcity events, energy and spinning reserve price formation relies on violation relaxation limits (VRL). The instance of shadow prices capped at the VRL during spinning reserve scarcity events decreases as the scarcity increases. The market clearing price for spinning reserve in the most scarce intervals was often $8/MW or less. Relaxing the spinning reserve requirement instead of clearing the requirement from a graduated demand curve undervalues spinning reserves when there is competition between products and does not provide a price signal that ensures generator availability.

The MMU highly recommends SPP and stakeholders review price formation during scarcity events and establish graduated demand curves that incentivize proper price formation. In the short-term, scarcity prices can ensure resources are performing at their maximum limits and that energy imports are incentivized. Even when no more capacity is physically available and imports are exhausted, improved price formation may not result in more product availability during a scarcity event, but will produce a price signal that will incentivize future availability.

2019.2 Incentivize capacity performance

The MMU observed that capacity adequacy requirements did not have any actual performance requirements. Other RTOs use methods to compensate resources that are available more often than the average or by adjusting the next year’s capacity accreditation based on availability during a certain timeframe. Another option is to develop time estimates of forced outages and maintenance outages during high-demand periods and prorate the available megawatt-hours for capacity accreditation. A true-up of available capacity at the end of the year would be required to determine whether a market participant met their capacity requirement. This helps to ensure that capacity is actually available during the most important days of the year, and helps to reduce the number of conservative operations events. The Supply Adequacy Working Group, an SPP Stakeholder Group, has formed a Generator Testing Task Force to address capacity performance among other matters.
2019.3 Update and improve outage coordination methodology

MMU observations of outages led to two recommendations. First, all market participants should review their outage procedures to ensure they are compliant with SPP’s Outage Coordination Methodology, in particular, with requirements to accurately report outage reasons and times. The MMU also recommends updating the outage coordination methodology in order to have SPP approve all Reserve Shutdown outages. The stakeholders should also consider if the outage reporting threshold of 25 MW should be lowered to the registration threshold of 10 MW.

1.8.2 PREVIOUS RECOMMENDATIONS

The MMU has provided recommendations to improve market design in our previous annual reports, these recommendations are summarized here.

2018.1 Limit the exercise of market power by creating a backstop for parameter changes

The MMU recommends that SPP strengthen the language regarding non-dollar-based parameters so that the expectation for the basis of these values is clear and the potential exercise of market power is much more limited. The expectations for the basis of the parameters should be clear and well-defined. Changes to these parameters should be limited to actual capability and should be verified, at a minimum, in the presence of market power. One option would be to require parameters to always reflect actual limitations. Actual limitations could include physical and environmental limitations and potentially other true and verifiable limitations. Another option could be to automatically apply parameter mitigation in the presence of market power, and congesting a transmission line, similar to the automatic mitigation of dollar-based offer components.

2018.2 Enhance credit rules to account for known information in assessments

The MMU has engaged SPP’s Credit Practice Working Group and has contributed to the dialogue about next steps. SPP and its stakeholders generally agree that updating the SPP credit policy to protect from exposure such as that experienced in PJM is a priority. SPP stakeholders have proposed a two-phase approach to mitigate SPP’s exposure. The first phase includes both quantitative and qualitative enhancements, such as position collateral minimums,
know-your-customer best practices, and stronger capitalization requirements. The second phase will incorporate forward-looking information into financial security requirements. The phase one package is working through the SPP stakeholder process. The phase two package is in the research phase. The MMU recommends that SPP continue to move forward with both phases of credit policy development.

2018.3 Develop compensation mechanism to pay for capacity to cover uncertainties

The MMU has engaged SPP’s Market Working Group and has participated in a high level discussion on the need for an uncertainty or standby reserve product. SPP staff has conducted considerable analysis and developed a white paper and initial design. The Market Working Group is expected to discuss the uncertainty product in depth and complete the design in 2020. The MMU fully supports these efforts to compensate capacity used to cover uncertainty of generation and load.

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

The MMU recommends that SPP enhance their study process to allow the ability to study a range of potential outcomes. If such range of potential outcomes are not captured in a third case study, the MMU recommends to factor them into either an existing case study or potentially as part of the 20-year assessment. The wider the range of possibilities studied, the more robust the results will be.

2018.5 Improve regulation mileage price formation

The MMU discussed our concerns with the Market Working Group at its August 2018 meeting. While an action item was developed requesting SPP staff and the MMU to review the effectiveness of the regulation mileage pricing process and present further options, no additional work has been done since that time. We recommend that SPP staff review the performance of regulation mileage, and develop potential approaches to improve regulation mileage price formation. Furthermore, we recommend that SPP staff consider adjusting the mileage factor. We believe that SPP staff and stakeholders should include these items as part of its analysis and change development processes for moving forward.
2017.1 Develop a ramping product

The MMU supports the proposed design as a significant improvement and expects that this will reduce transitory price spikes caused by ramp shortages that are solely due to the market clearing and dispatch process. Price increases due to capacity shortages and true ramp shortages will continue to occur under these design changes. The MMU will continue to monitor this through and after implementation. It should be noted that SPP is also proposing an uncertainty product that will work similarly to the ramp product, but will allow both online and eligible offline resources to clear for the product. The product will pay resources for providing available ramp capacity over a two hour period for possible unforecasted rampable capacity needs over that period. This issue has been reviewed by SPP’s Holistic Integrated Tariff Team and was also included in their report as a recommendation.

2017.2 Enhance commitment of resources to increase ramping flexibility

The MMU recommends that SPP and its stakeholders address this issue by enhancing its markets rules to enhance the commitment of resources to increase ramping flexibility. The MMU previously described this as enhancing decommitment of resources. However, having explored this issue further, the issue is not just about decommitment of resources, but is also about improving how resources are committed. The MMU recommends that SPP and stakeholders explore options to enhance commitment of resources to increase flexibility. This is viewed as a high priority item by the MMU.

2017.3 Enhance market rules for energy storage resources

FERC issued Order No. 841 in February 2018 to reduce barriers to participation and to develop a participation model for electric storage resources. Over the course of 2018, SPP, stakeholders, and the MMU worked on changes that would comply with FERC Order No. 841. These changes passed the October 2018 SPP Board meeting and SPP filed the changes with FERC in December 2018. These changes were approved by FERC in October 2019 and will be implemented in the Integrated Market in August 2021. The MMU filed supportive comments with FERC. In the MMU comments, multiple areas of further work were identified. These areas include further enhancements to electric storage integration, including addressing the potential for storage
resources to exercise downward market power, the potential for market storage resources (MSR) to manipulate the transmission market, possible market design gaps regarding major maintenance and quick-start resource requirements, and the inefficient commitment of non-continuously dispatchable resource requirements in relation to market storage resources. The Market Working Group is in the process of prioritizing initiatives including follow-up development on storage resources.

The MMU views integration of storage resources in the SPP markets as an ongoing high priority as several outstanding items beyond compliance with FERC Order No. 841 need to be addressed in order to fully integrate electric storage resources in the SPP markets.

2017.4 Address inefficiency caused by self-committed resources

Broadly, the MMU recommends that SPP and its stakeholders continue to explore and develop ways to reduce the incidence of self-commitment of resources outside of the market solution. With regards to the development of multi-day forecasting of prices or schedules or a multi-day unit commitment process, the MMU supports these as attempts to reduce self-commitment of generation. Based on MMU analysis of lead times and start-up costs, the MMU recommends that SPP and stakeholders add an additional day to the day-ahead commitment process. The MMU views reducing self-commitment of generation as a high priority for SPP and its stakeholders as this will enhance market efficiency and improve price signals.

2017.5 Address inefficiency when forecasted resources under-schedule day-ahead

The MMU continues to recommend that SPP and its stakeholders address this issue through market rules changes that address the consequences of the under-scheduling of forecasted supply resources in the day-ahead market. This is a high priority as it helps to enhance market efficiency and improve price signals. This issue has been reviewed by SPP’s Holistic Integrated Tariff Team and was also included in their report as a recommendation. Some possible avenues to explore are removing the physical withholding exemption in the day ahead market, considering whether to require a certain level of offer for all or a subset of variable resources, or have significantly underoffered wind contribute to paying make-whole payments. Other solutions that address this problem may arise from the SPP stakeholder process.
2014.1 Improve quick-start logic

The MMU recommended that quick-start logic be improved after implementation of the Integrated Marketplace. SPP and stakeholders developed a proposal to enhance the quick-start logic several years ago. However, before the proposal was filed, FERC began a 206 process that preliminarily found that the treatment of fast-start generators was unjust and unreasonable. In June 2019, FERC issued an order directing SPP to make a compliance filing addressing pricing practices related to fast-start generators. SPP submitted a compliance filing addressing the six issues outlined in the FERC order. The MMU filed comments offering a limited protest to SPP’s proposed tariff revisions to comply with the FERC order. The MMU recommended that FERC direct SPP to modify their proposed tariff revisions related to fast-start resources in two areas. SPP and the MMU are currently waiting for FERC to rule on the SPP compliance filing.

SPP and stakeholders are currently working on a revision to the intra-day reliability unit commitment (IDRUC) process in order to commit fast-start resources in a more timely and economic manner. The MMU supports improvements to the real-time commitment process to increase market flexibility and improve market efficiency.

2014.3 Address gaming opportunity for multi-day minimum run time resources

The SPP board passed a proposal at the July 2018 meeting that would limit make-whole payments for any resource with multi-day minimum run times to the lower of the market offer or the mitigated offer. This limitation only applies for offers falling in hours not accessed by one of the security constrained unit commitment (SCUC) processes and the resource bid at or above their mitigated offer on the first day. The MMU supported the proposal. Subsequent to board

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approval of the proposal, SPP legal staff identified internally inconsistent tariff language that the revisions revealed, but did not address. An associated additional tariff modification was approved by the stakeholder process. A FERC filing will occur in 2020. The MMU strongly supports these changes.

2014.4 Address problems with day-ahead must offer requirement

In 2017, FERC rejected SPP’s proposal to remove the day-ahead must offer requirement and indicated that it would consider removal of the requirement if it were paired with additional physical withholding provisions.

The MMU remains concerned with the design weaknesses of the current limited day-ahead must offer requirement. We 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. The MMU has continued to monitor and track market performance concerns and has identified a marked increase in generator outages, as discussed in Chapter 3, that are not prevented by the current limited must offer requirement, and have contributed to the 35 days of conservative operations in the SPP region during 2019. In light of the increased reliability concerns exacerbated by conservative operations events, the MMU recommends the priority of this issue be elevated to high. The MMU has submitted this recommendation as an initiative in the newly formed SPP roadmap process, and is waiting for the Market Working Group to prioritize the issue.
This chapter reviews load and resources in the SPP market for 2019. Key points from this chapter include:

- Total system energy consumption was down less than one percent from 2018 to 2019.

- Variations in demand continue to trend with seasonal temperature changes and departures from normal temperatures.

- Just over 1,800 MW of wind generation was added to the market in 2019. Wind generation now accounts for 25 percent of installed nameplate capacity in the SPP market.

- The generation interconnection queue has nearly 82,000 MW of projects in the queue at the end of 2019. Only 270 MW is from fossil fuel generation, with the remainder from renewable or storage resources.

- Of total energy produced in 2019, 35 percent was from coal resources, while wind resources produced just over 27 percent of energy produced. For comparison, just five years ago coal generation represented 60 percent of the total, and wind generation accounted for 12 percent of the total.

- SPP remained a net exporter for 2019 with an hourly average of just over 270 MW.

- Market-to-market payments totaled $17.5 million from MISO to SPP for 2019.

- Cleared virtual energy offers as a percentage of load increased nearly 19 percent, while cleared virtual energy bids as a percentage of load increased nearly 14 percent year-over-year.

- Average profit per cleared virtual megawatt after fees increased from $0.46/MW to $0.63/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 2019 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 the introduction of a day-ahead market was to improve the 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.10

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10 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 2019, 249 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 number of the 72 resource owners registered to participate in the Integrated Marketplace.
The number of independent power producers is high because most wind producers are included in this category. Market participants referred to as an “agent” represent several individual resource owners that would individually be classified as different types, such as municipal utilities, electric cooperatives, and state agencies.

Figure 2–3 shows generation nameplate capacity owned by the type of market participant. Investor-owned utilities and cooperatives own two-thirds of the nameplate generation capacity in the SPP market.
Although investor-owned utilities represent only a small portion of the total market participants at 10 percent, they own the majority of the SPP generation capacity at 51 percent. This is in contrast to the “independent power producer” category, which has a large number of participants (57 percent) representing only a small portion (13 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 of time. 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 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 peak-day demand for the last three years. The monthly peak demand in five months in 2019 was higher than the monthly peak demand in both 2017 and 2018. Heating and cooling demand increases contributed to this change (see Section 2.2.4).
Figure 2–4 Monthly peak system demand

The SPP system coincident instantaneous peak demand in 2019 was 51,230 MW, which occurred on August 19 at 4:50 PM. This is 2.6 percent higher than the 2018 system peak of 49,926 MW.

2.2.2 MARKET PARTICIPANT LOAD

Load continued to participate in the day-ahead market at high levels in 2019 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 99 and 101 percent of the actual real-time load. 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. After a one percent increase from 2017 to 2018, load participation in the day-ahead market was at similar levels in 2018 and 2019.

Figure 2–6 depicts 2019 total energy consumption and the percentage of energy consumption attributable to each entity in the market.

Evergy was formed in June 2018 and is the corporate parent of Evergy, Kansas Central (formerly known as Westar Energy), Evergy, Missouri Metro (formerly known as Kansas City Power and Light), and Evergy, Missouri West (formerly known as Kansas City Power and Light GMOC). When Evergy is considered one entity in the market, it represents the largest user of energy in the SPP market footprint at 19 percent of the total, and the four largest entities then comprise 58 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 2019 was just less than one-half of one percent below the 2018 level.
## Figure 2–6  System energy usage

<table>
<thead>
<tr>
<th>* Evergy, Inc.</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy consumed (GWh)</td>
<td>Percent of system</td>
<td>Energy consumed (GWh)</td>
<td>Percent of system</td>
</tr>
<tr>
<td>* Evergy, Inc.</td>
<td>-</td>
<td>-</td>
<td>49,965</td>
</tr>
<tr>
<td>American Electric Power</td>
<td>41,887</td>
<td>17.0%</td>
<td>43,109</td>
</tr>
<tr>
<td>Oklahoma Gas and Electric</td>
<td>27,747</td>
<td>11.3%</td>
<td>29,411</td>
</tr>
<tr>
<td>Southwestern Public Service Company</td>
<td>25,826</td>
<td>10.5%</td>
<td>27,359</td>
</tr>
<tr>
<td>* Westar Energy</td>
<td>23,845</td>
<td>9.7%</td>
<td>-</td>
</tr>
<tr>
<td>Basin Electric Power Cooperative</td>
<td>18,665</td>
<td>7.6%</td>
<td>20,165</td>
</tr>
<tr>
<td>^ The Energy Authority</td>
<td>16,433</td>
<td>6.7%</td>
<td>16,356</td>
</tr>
<tr>
<td>* Kansas City Power and Light, Co.</td>
<td>15,194</td>
<td>6.2%</td>
<td>-</td>
</tr>
<tr>
<td>Omaha Public Power District</td>
<td>11,066</td>
<td>4.5%</td>
<td>11,431</td>
</tr>
<tr>
<td>* Kansas City Power and Light, Greater</td>
<td>8,275</td>
<td>3.4%</td>
<td>-</td>
</tr>
<tr>
<td>Western Farmers Electric Cooperative</td>
<td>8,046</td>
<td>3.3%</td>
<td>8,312</td>
</tr>
<tr>
<td>Grand River Dam Authority</td>
<td>5,581</td>
<td>2.3%</td>
<td>5,805</td>
</tr>
<tr>
<td>Golden Spread Electric Cooperative Inc.</td>
<td>4,817</td>
<td>2.0%</td>
<td>5,684</td>
</tr>
<tr>
<td>Liberty Utilities (f/k/a Empire District Electric)</td>
<td>4,984</td>
<td>2.0%</td>
<td>5,413</td>
</tr>
<tr>
<td>Sunflower Electric Power Corporation</td>
<td>4,693</td>
<td>1.9%</td>
<td>4,906</td>
</tr>
<tr>
<td>Western Area Power Administration, Upper Great Plains</td>
<td>4,534</td>
<td>1.8%</td>
<td>4,471</td>
</tr>
<tr>
<td>Arkansas Electric Cooperative Corporation</td>
<td>3,675</td>
<td>1.5%</td>
<td>4,258</td>
</tr>
<tr>
<td>Lincoln Electric System Marketing</td>
<td>3,441</td>
<td>1.4%</td>
<td>3,570</td>
</tr>
<tr>
<td>Oklahoma Municipal Power Authority</td>
<td>2,766</td>
<td>1.1%</td>
<td>2,846</td>
</tr>
<tr>
<td>Kansas City (Kansas) Board of Public Utilities</td>
<td>2,347</td>
<td>1.0%</td>
<td>2,530</td>
</tr>
<tr>
<td>Northwestern Energy</td>
<td>1,632</td>
<td>0.7%</td>
<td>1,748</td>
</tr>
<tr>
<td>Midwest Energy Inc.</td>
<td>1,715</td>
<td>0.7%</td>
<td>1,762</td>
</tr>
<tr>
<td>Kansas Municipal Energy Agency</td>
<td>1,473</td>
<td>0.6%</td>
<td>1,557</td>
</tr>
<tr>
<td>Tenaska Power Service Company</td>
<td>1,365</td>
<td>0.6%</td>
<td>1,418</td>
</tr>
<tr>
<td>Missouri River Energy Services</td>
<td>1,226</td>
<td>0.5%</td>
<td>1,309</td>
</tr>
<tr>
<td>East Texas Electric Cooperative</td>
<td>-</td>
<td>-</td>
<td>983</td>
</tr>
<tr>
<td>City of Independence (Missouri)</td>
<td>1,030</td>
<td>0.4%</td>
<td>1,094</td>
</tr>
<tr>
<td>Kansas Power Pool</td>
<td>843</td>
<td>0.3%</td>
<td>866</td>
</tr>
<tr>
<td>AEP Energy Partners</td>
<td>225</td>
<td>0.1%</td>
<td>261</td>
</tr>
<tr>
<td>Big Rivers Electric Corporation</td>
<td>310</td>
<td>0.1%</td>
<td>491</td>
</tr>
<tr>
<td>City of Fremont (Nebraska)</td>
<td>433</td>
<td>0.2%</td>
<td>450</td>
</tr>
<tr>
<td>Missouri Joint Municipal Electrical Utility Commission</td>
<td>430</td>
<td>0.2%</td>
<td>445</td>
</tr>
<tr>
<td>^ Municipal Energy Agency of Nebraska</td>
<td>1,022</td>
<td>0.4%</td>
<td>1,057</td>
</tr>
<tr>
<td>MidAmerican Energy Company</td>
<td>280</td>
<td>0.1%</td>
<td>285</td>
</tr>
<tr>
<td>Rainbow Energy Marketing Corporation</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Harlan (Iowa) Municipal Utilities</td>
<td>17</td>
<td>0.0%</td>
<td>18</td>
</tr>
<tr>
<td>NSP Energy</td>
<td>5</td>
<td>0.0%</td>
<td>5</td>
</tr>
<tr>
<td>Otter Tail Power Company</td>
<td>3</td>
<td>0.0%</td>
<td>1</td>
</tr>
<tr>
<td>@ City of Chanute (Kansas)</td>
<td>487</td>
<td>0.2%</td>
<td>497</td>
</tr>
<tr>
<td>System Total</td>
<td>246,009</td>
<td>6%</td>
<td>259,653</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 and City Utilities of Springfield (Missouri).

# Beginning in May 2019, The Energy Authority began to act as an agent for the Municipal Energy Agency of Nebraska and several small municipalities in Nebraska.

@ Beginning in January 2019, Evergy, Kansas Central began to act as an agent for City of Chanute (Kansas).
2.2.3 SPP SYSTEM ENERGY CONSUMPTION

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

**Figure 2–7  System energy consumption, monthly**

For the year, total system energy consumption was down less than one half of one percent in 2019 compared to 2018. While consumption was higher in August and September in 2019 compared to 2018, May and June were lower in 2019. On the whole, these balanced out, creating an almost identical monthly average energy consumption for 2018 and 2019.

Figure 2–8 depicts load duration curves from 2017 to 2019. These load duration curves display hourly loads from the highest to the lowest for each year.
In 2019, the maximum hourly average load was 48,567 MW, up from both prior years. The minimum hourly load for 2019 was 20,288 MW, which was slightly above both previous years. 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. However, if the load curve is similar to the previous year, as it was in 2019, it indicates that total system demand has remained relatively stable.

### 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.

To determine heating degree days and cooling degree days for the SPP footprint, several representative locations are used in the calculation. In this report, 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

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11 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.
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 approximately three and a half times higher than the impact of a single heating degree day. This is in part because of more electric cooling than electric heating.

Figure 2–9 shows monthly heating and cooling degree days’ impact over the last three years compared to the total monthly load. In order to show the impact of degree days, cooling degree days are multiplied by 3.5 in the chart below.

**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.

Figure 2–10, Figure 2–11, and Figure 2–12 show load levels, cooling degree days, and heating degree days from 2017 through 2019 compared to a normal year.¹² 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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¹² The 30 year normal temperatures are from the 1981-2010 U.S. Climate normals product from NOAA.
Figure 2–10 Loads compared with a normal year

Figure 2–11 Cooling 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 2019 were above the 30-year average in all “cooling months” (April through October), while heating degree days in “heating months” (January through March, November, and December) were below the 30-year average in January and December, but above in the other months. Most notable is the much higher cooling degree days for September 2019, which was well above prior years and the average. The higher temperatures in that month are reflected in the higher load that occurred in September.

2.3 INSTALLED GENERATION CAPACITY

Figure 2–13 depicts the Integrated Marketplace installed generation for the SPP market footprint at the end of the year. Total installed nameplate generation in the SPP Integrated Marketplace was 89,526 MW by the end of 2019, representing an increase of just under 0.5 percent from 2018.\(^{13}\) This slight increase was driven by a nine percent increase in nameplate

\(^{13}\) 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.
wind capacity in 2019 and a decrease of 8.5 percent in nameplate coal capacity, some of which was converted to gas.

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

<table>
<thead>
<tr>
<th>Fuel type</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>Percent as of year-end 2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas, simple-cycle</td>
<td>23,847</td>
<td>22,596</td>
<td>23,297</td>
<td>26%</td>
</tr>
<tr>
<td>Coal</td>
<td>25,717</td>
<td>25,064</td>
<td>22,920</td>
<td>26%</td>
</tr>
<tr>
<td>Wind</td>
<td>17,596</td>
<td>20,589</td>
<td>22,482</td>
<td>25%</td>
</tr>
<tr>
<td>Gas, combined-cycle</td>
<td>12,868</td>
<td>13,498</td>
<td>13,473</td>
<td>15%</td>
</tr>
<tr>
<td>Hydro</td>
<td>3,422</td>
<td>3,431</td>
<td>3,431</td>
<td>4%</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>1,639</td>
<td>1,639</td>
<td>1,563</td>
<td>2%</td>
</tr>
<tr>
<td>Solar</td>
<td>215</td>
<td>215</td>
<td>215</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Other</td>
<td>74</td>
<td>74</td>
<td>84</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Total</td>
<td>87,079</td>
<td>89,167</td>
<td>89,526</td>
<td></td>
</tr>
</tbody>
</table>

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

Natural gas-fired installed generation capacity still represents the largest share of generation capacity in the SPP market at 41 percent (gas simple-cycle 26 percent, gas combined-cycle 15 percent), with coal being the second largest type at 26 percent. Wind continues to increase, due largely to new additions, with a 2019 market share of 25 percent of total nameplate capacity in the SPP market. Coal resources decreased from 28 percent of total nameplate capacity in 2018 to 26 percent in 2019.

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 2017 to 2019. Resources in "outage" status were excluded from the supply curve. To calculate the summer supply curves, the peak summer day 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.
Total aggregate real-time generation supply for summer 2019 was 65,645 MW, compared to 65,296 MW for summer 2018, an increase of 0.5 percent. Just over 1,810 MW of capacity was added to the SPP market in 2019, and most of the 1,457 MW of retirements occurred before the summer season. The system peak-demand of 2019 was almost three percent higher than 2018, and less than one percent higher than 2017. On the other hand, there was a 1.5 percent decrease of average demand in 2019 compared to 2018. Based on the heating and cooling degree days analysis in Section 2.2.4, the SPP market footprint experienced much warmer temperatures in September 2019, which resulted in higher demand during that month as compared to the previous year.

Also evident is the approximately 24 GW gap between this maximum supply and the total installed nameplate generation capacity on the peak summer day. This is primarily a result of resources reporting on outage (approximately six gigawatts), reduced summer capacity due to high ambient temperatures (approximately five gigawatts), as well as the difference between the wind forecast and installed capacity of wind resources (approximately 13 gigawatts).

The section of the offer curve below $0/MWh is mostly due to wind and solar energy and can vary between 1,000 and 16,000 megawatts, based on wind and solar availability. Negative offers typically reflect opportunity costs associated with state and federal tax incentives.
uptick in price at the top of the supply curves represents the transition from natural gas units to oil units.

2.3.1 CAPACITY ADDITIONS AND RETIREMENTS

Figure 2–15 shows the capacity by the technology and the number of resources added in 2018.

Figure 2-15 Capacity additions

Just over 1,800 MW of generation capacity was added to the SPP market during 2019. Of the new capacity added in 2019, all nine resources added were wind resources. All of the added wind capacity was new construction.

In 2019, the SPP market had generation retirements amounting to just over 1,457 MW of installed capacity, shown in Figure 2–16.
Six medium-sized coal resources representing 973 MW of capacity; six simple-cycle gas resources representing 462 MW of capacity; and one oil resource representing 22 MW of capacity were retired in 2019.\textsuperscript{14}

A look at annual trends in additions and retirements can be found in Section 6.1.1.

### 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.\textsuperscript{15}

Figure 2–17 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

\textsuperscript{14} The totals shown in Figure 2-14 differ from the change from 2018 to 2019 shown in Figure 2-11. This can be due to resources being rerated or changing fuel source. Two resources, totaling 1,060 MW of generation, converted from coal-fired to gas-fired units in 2019, thus were counted as coal capacity in 2018, and gas, simple-cycle capacity in 2019.

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 2019.

**Figure 2-17 Active generation interconnection requests, megawatts**

As shown above, generation capacity from renewable resources accounts for the vast majority of proposed generation interconnection, with only 271 MW of non-renewable generation interconnection requests out of a total of 81,751 MW in 2019. After an increase of wind generation in the queue from 2017 to 2018, the amount of wind generation of the queue decreased 16 percent in 2019. Interconnection requests for solar generation increased from 2018 to 2019, but not nearly as much as from 2017 to 2018. Storage interconnection requests also increased from 2018 to 2019 with nearly seven gigawatts in the queue at the end of 2019.

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.
As the chart above shows, at the end of 2019, just over six gigawatts of generation have an executed generation request that is on-schedule to be added to the market in 2020. In the next two years, nearly 190 MW of solar generation is currently on-schedule to be added to the market. It is important to note that generation can still be added or removed from the list, even in the current year. However, there is more surety to the levels of generation to go into production closer to the current year, and additions and deletions to on-schedule projects are more typical in future years. Additionally, FERC has approved revisions to the SPP Generator Interconnection Procedures, which are intended to address the backlog which exists in the generator interconnection queue today.¹⁶

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. The ramping products and uncertainty products recommended in previous years will help with transparency regarding the value of these services, see Section 8.2 for further detail. Additional wind impact analysis follows in the Section 2.5.

¹⁶ [https://www.ferc.gov/CalendarFiles/20190628123105-ER19-1579-000.pdf](https://www.ferc.gov/CalendarFiles/20190628123105-ER19-1579-000.pdf)
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, 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 2–19 depicts annual generation percentages in the SPP real-time market by technology type for the years 2014 through 2019.

The long-term trend for coal-fired generation had been relatively flat prior to 2014 (not shown on chart above) making up around 60 to 65 percent of total generation, but declined to 55 in 2015, then to under 50 percent beginning in 2016. In 2019, coal generation accounted for 35 percent of total generation, down from 42 percent in 2018. This decrease can primarily be attributed to increasing wind generation and low natural gas prices.

The wind generation share continues to increase, from 12 percent in 2014 to just over 27 percent in 2019. With low gas prices during much of 2018 and 2019, generation from simple-cycle gas units such as gas turbines and gas steam turbines increased to nearly 10 percent in
2019. Gas combined-cycle generation has remained relatively stable at about 16 percent for the past five years, which can mostly be attributed to low gas prices.

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 2019 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. Another trend appears to be the increase in wind generation pushing simple-cycle gas generation up the supply curve, though this generation has become more competitive as gas prices have fallen.

Retirement of older coal generation, environmental limits, along with 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 2–20 depicts the 2019 monthly fluctuation in generation by technology type.

**Figure 2–20 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 percent. In the highest wind generation months of April and October, monthly levels approached 40 percent in 2019. For the first time, in April and October, wind generation as a percentage of total generation outpaced coal generation. After January and February, coal generation as a percentage of total dropped below 40 percent each month.
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.\textsuperscript{17} 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 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 2–21 shows the monthly implied heat rate using real-time electricity prices for 2017 to 2019, along with an annual average for those years.

**Figure 2–21  Implied heat rate**

![Implied heat rate chart](image)

The chart shows a marked increase in implied heat rates in 2019 compared to 2017 and 2018. The extremely low gas prices (reaching a trough of $1.37/MMBtu in June) experienced in 2019 had a large impact of the implied heat rate. At these low levels, gas resources become more economic, resulting in higher implied heat rates. April through August saw average monthly

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\textsuperscript{17} 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 rates above 12,000 Btu/KWh in conjunction with gas prices averaging $1.65/MMBtu in the same period.

### 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.

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.

![Figure 2-22 Generation on the margin, real-time](image)

It is worth noting the increase in wind generation being on the margin in the real-time market—from five percent in 2014 and 2015 (not shown on the table above) to just over 17 percent in 2019. With the growing amount of dispatchable wind generation and an overall quantity of 25 percent of total nameplate capacity, wind generation is increasingly becoming the marginal technology a higher percentage of the time. At the end of 2019, 76 percent of nameplate wind capacity was dispatchable, compared to 71 percent at the end of 2018, and 64 percent at the...
end of 2017. At the beginning of the Integrated Marketplace in March 2014, just 27 percent of nameplate wind capacity was dispatchable.

April 2019, FERC approved a proposed revision to the SPP tariff that would require nondispatchable variable energy resources to become dispatchable by January 1, 2021, or 10 years after starting operations. The conversion is not required for Public Utility Regulatory Policies Act (PURPA) qualifying facilities or run-of-the-river hydro resources that are incapable of following dispatch instructions. Under the timeline, all wind nondispatchable variable energy resources will be converted by October 2022, all non-wind nondispatchable variable energy resources (accounting for approximately 30 MW of capacity) will be converted by January 2027.

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 more 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.

Day-ahead generation on the margin, shown in Figure 2–23, 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.
Wind generation on the margin is comparable in the day-ahead and real-time markets with a similar annual cyclical pattern. Both coal and gas generation on the margin in the day-ahead market is noticeably lower than in the real-time market. The most significant difference is the displacement of natural gas-fired generation by virtual offers in the day-ahead market. Virtual energy offers on the margin have been increasing over the past three years, with virtual energy offers representing 31 percent of the marginal offers in the day-ahead market in 2019, compared to 28 percent in 2018 and 25 percent in 2017. While marginal virtual offers occur at all types of settlement locations, 65 percent of marginal virtual offers are at resource settlement locations, with a significant amount of that activity at non-dispatchable wind generation resource locations.

### 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. Since that time, there have been no registered demand response resources in the SPP market until December 1, 2019. At that time, three demand response resources became active in the market representing 0.3 MW of capacity.
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 wind investment in the SPP footprint during the last several years.

Figure 2–24 is a wind speed map of the United States of America with the SPP footprint outlined in black.

**Figure 2-24 Wind speed map**

United States - Land-Based and Offshore Annual Average Wind Speed at 80 m

Outside of coastal areas, much of the SPP footprint highlighted on the map is covered with some of the highest wind speeds in the country. As has been discussed, there continues to be a high potential for additional wind resource development in the SPP footprint going forward.
Figure 2–25 depicts nameplate capacity and total generation of SPP wind facilities since 2014.

**Figure 2-25 Wind capacity and generation**

Total registered wind nameplate capacity at the end of 2019 was 22,482 MW, an increase of nine percent from 2018. At the end of 2019, 76 percent of all nameplate wind capacity was dispatchable, while 24 percent was non-dispatchable. Wind generation output increased by 15 percent in 2019 to just over 74,000 GWh produced.

Wind resources comprise about 25 percent of the installed capacity in the SPP market, behind only natural gas with 41 percent and coal with 26 percent. 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. \(^{18}\)

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\(^{18}\) 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 40.3 percent in 2017 to 39.4 percent in 2019, while the day-ahead wind capacity factor, after rising from 2017 to 2018, dropped from 32.4 percent to 31.5 percent from 2018 to 2019. A 15 percent increase in wind generation from 2018 to 2019, coupled with a 16 percent increase in average monthly capacity, drove this slight drop in real-time capacity factor. The spread between the real-time and the day-ahead wind capacity 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 wind capacity factor for the first six months of 2019 was well below the levels of the prior two years. This lower level is likely due to new wind resources that have been added to the capacity figure, but not in commercial operation, as well as weather patterns.

### 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 about four percentage points to nearly 29 percent in 2019. After levelling off from 2017 to 2018, the growth of average wind generation as a percent of load has climbed more sharply from 2018 to 2019. Wind generation peaked at 17,852 MW in 2019 on a five-minute interval basis, an increase of over nine percent from 16,329 MW in 2018. Wind generation as a percent of load for any five-minute interval reached a maximum value of nearly 69 percent, which was up from 64 percent in 2018 and 57 percent in 2017.

Figure 2–29 shows wind production duration curves that represent wind generation as a percent of load by real-time (five-minute) interval for 2017 through 2019.
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 for 2017 and 2018 are nearly identical for the lower two-thirds of the curve, while in the upper third of the curve, 2018 values climb above 2017. Wind generation in both 2017 and 2018 served at least 23 percent of the total load during half of the year, which climbed to 27 percent in 2019.

Figure 2–30 below shows average demand by hour of day, along with wind generation, and net demand (demand minus wind generation) for 2019.
With wind generation at the highest levels in the overnight hours, net demand climbs more steeply than total demand, as wind generation begins to taper off when approaching the peak hours of the day. This can have an impact on the market as generation needed from traditional resources climbs more quickly than demand. When this occurs, ramp scarcity is more likely. This is discussed in Section 3.2.1

While Figure 2–30 shows the yearly average load, wind, and net demand, there are seasonal differences. For instance, in the summer, wind is less than during other times of year, and loads are higher. Thus, the effect on net demand is smaller. However, in the shoulder periods, like the spring and fall, loads are lower and wind can have a significant effect on net demand. For instance, in October, net demand during off-peak hours is as high as average wind generation, meaning that wind represents about half of all generation in off-peak hours during the month.

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 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-scheduling 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. Because 24 percent (5,473 MW) of the existing installed wind capacity is composed of non-

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19 Additional discussion on accreditation of capacity for wind and solar resources can be found in Section 6.2.
dispatchable variable energy resources, and these generally produce without regard to price, SPP operators must still issue manual dispatch instructions to reduce or limit their output at certain times. As discussed in Section 2.4.2, in April 2019, FERC approved a revision to the SPP tariff that would require nondispatchable variable energy resources to become dispatchable by January 1, 2021, or 10 years after starting operations.

Figure 2–31 illustrates dispatchable variable energy resources (DVERs) and non-dispatchable variable energy resources (NDVERs) wind output since 2017.

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

October 2019 saw over 7,600 GWh of monthly wind production, which was the highest since the start of the Integrated Marketplace and 22 percent of this output originated from non-dispatchable variable energy resource capacity.

Figure 2–31 also shows the amount of reduced real time output of dispatchable variable energy resources below their forecast (grey line). This depicts the increase in reductions of dispatchable variable energy resource dispatch output from 2018 to 2019. This change was likely the result of increased wind output and stable loads. Reductions in dispatchable resource generation also follow the seasonal pattern of lower wind output during the summer months, resulting in the decrease in need to reduce dispatchable variable energy resource output during these times. This increase in dispatchable wind capacity has helped in the management of congestion caused by high levels of wind generation in some of the western parts of the SPP footprint.
Substantial transmission upgrades in the SPP footprint over the past few years have provided an increase in transmission capability for wind-producing regions, helping to address concerns related to high wind production, and resulting congestion. The increased transmission capability directly reduces localized congestion, creating a more integrated system with higher diversity and greater flexibility in managing high levels of wind production. However, given the historical growth of wind capacity and indicators of future additions in the generation interconnection queue, additional transmission upgrades may entice further development of wind capacity.

Figure 2-32 shows the number of out-of-merit energy directives (manual dispatches) initiated for dispatchable and non-dispatchable variable energy wind resources for the past three years.

Manual dispatches are typically fewer during the lower wind output and higher demand months of summer, and more numerous during higher wind output spring and fall months. While manual dispatches were below or near previous year totals in most of the first six months of 2019, manual dispatches increased markedly in the second half of the year. In 2019, 73 percent of the 302 manual dispatches were for dispatchable variable energy wind resources, whereas 27 percent were for non-dispatchable variable energy wind resources. Line loading in excess of 104 percent, operating guides, and outages caused 75 percent of manual 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.

SPP is at the forefront among RTOs in managing wind energy integration. The Integrated Marketplace has reliably managed wind generation as it has approached 70 percent of load. Even though the use of manual dispatch is limited and SPP continues to see an expanding dispatchable wind generation fleet, ramping capability is needed because of the variability of wind. Since May 2017, ramp shortages are reflected in prices. Section 3.2.1 discusses the pricing of ramp shortages.

2.7 SEAMS

2.7.1 EXPORTS AND IMPORTS

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

As shown in Figure 2–33, SPP has been a net exporter in real-time since 2017, prior to that it was a net importer.

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20 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 time frame.
Typically, as wind generation increases, exports increase. However, in 2019, exports were highest in February, August, and September. February saw increased exports to the Western Interconnection, while August and September saw increased exports to ERCOT due to high real-time prices in ERCOT.

Exports to ERCOT were driven by tight supply conditions and high prices during the summer months. Southwestern Power Administration hydro power is imported to serve municipals tied to SPP transmission and is highest during on-peak hours, but is 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, AECI, and Western Interconnection parties is less responsive to prices. Figure 2–34 through Figure 2–37 show the data for the four most heavily used interfaces in real-time, namely ERCOT, SPA, MISO, and AECI.
**Figure 2-34** Exports and imports, ERCOT interface

![Graph showing exports and imports, ERCOT interface.]

**Figure 2-35** Exports and imports, Southwestern Power Administration interface

![Graph showing exports and imports, Southwestern Power Administration interface.]

State of the Market 2019
Interchange transactions in the SPP market can be scheduled in the real-time market, as well as in the day-ahead market. The day-ahead market has three types of interchange transactions:

- Fixed interchange transactions are physical transactions that bring energy into or out of the SPP balancing authority. Energy prices are settled at the price at the applicable external interface settlement location. Submitters of this type of transaction in the Integrated Marketplace are price takers for that energy.
• Dispatchable interchange schedules are physical transactions that bring energy into or out of the SPP balancing authority and specify a bid or offer for an amount of megawatts. These schedules are supported in the day-ahead market only and also must meet all market requirements. Prices are determined in the day-ahead market at the appropriate external interface settlement location representing the interface between the SPP balancing authority and the applicable external balancing authority.

• An up-to-transmission usage charge (or up-to-TUC) offer on an interchange transaction specifies both a megawatt amount and the maximum amount of congestion cost and marginal loss cost the customer is willing to pay if the transaction is cleared in the day-ahead market.

All interchange transactions cleared in the day-ahead market, regardless of type, become fixed interchange transactions in the reliability unit commitment and real-time market.21

As shown in Figure 2–38, of the 1,654 MW of day-ahead import and export transactions in 2019, 96 percent were fixed in the day-ahead market, four percent were dispatchable, and none were up-to-TUC. Dispatchable transactions decreased from an average of 173 MW in 2018 to an average of 66 MW in 2019. Dispatchable transactions were highest in the summer months peaking at almost 160 MW in August.

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21 Integrated Marketplace Protocols, Section 4.2.2.7, Import Interchange Transaction Offers.
Figure 2-38 Imports and export transactions by type, day-ahead

Some reasons for the fixed transactions that make up the vast majority of interchange transactions include bilateral contracts with external entities, Southwestern Power Administration hydro contracts, and generally lower prices of the SPP market compared to other RTOs. To enhance market efficiency, market participants should consider further use of the dispatchable and up-to-TUC imports and exports, which allow for a specific strike price to be set, allowing for more economic imports and exports.

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. These 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.22

22 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.
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 2–39 Market-to-market settlements**

For 2019, total market-to-market payments from MISO to SPP totaled almost $29 million, while market-to-market payments from SPP to MISO totaled nearly $12 million, resulting in a net payment of approximately $17.5 million from MISO to SPP for the year. The two months with the largest payments from MISO to SPP were May and October 2019, and the month with the highest payments from SPP to MISO was June 2019.

Figure 2–40 shows market-to-market payments (over $200,000 either from SPP to MISO, or MISO to SPP) by flowgate for 2019.
Seven flowgates had payments from MISO to SPP over $1 million, while three flowgates had payments from SPP to MISO over $1 million. As with previous years, the Neosho-Riverton 161kV flowgate was the constraint that SPP received the highest payments ($3.5 million) from MISO. This constraint is impacted by wind and external flows and is discussed in more detail in Section 5.1.4.2.

Market-to-market allows for a coordinated approach between markets to provide a more economical dispatch of generation to solve congestion. In most cases, MISO is paying SPP to help resolve congestion at a lower cost than what was available to MISO and in a few cases, SPP pays MISO to help resolve congestion. Potomac Economics (external Independent Market Monitor for MISO) is leading an effort to study the benefit of improving specific mechanics of the market-to-market process. Some of these include more timely or automation of identifying coordinated flowgates, transferring monitoring authority for a constraint, and relief request improvements. This study has not been released at the time of this report.
2.7.3 ANALYSIS

This study is part of a joint effort\(^23\) of the MMU and Potomac Economics to study seams issues for the SPP Regional State Committee (RSC) and Organization of MISO States (OMS) Liaison Committee. Other efforts involved are analysis of:

- Rate pancaking and unreserved use
- Joint dispatch
- Interchange optimization
- Interface pricing
- Coordinated transaction scheduling
- Regional directional transfer limit
- Targeted market efficiency projects
- Outage and day-ahead coordination

The rate pancaking and unreserved use study\(^24\) was led by the SPP MMU and focused on the economic efficiency effects on the SPP-MISO seam. Rate pancaking occurs when electricity is scheduled across more than one transmission providers' borders and each provider assesses full or partial transmission charges for the use of the transmission facilities they manage through an open access transmission tariff. This can lead to duplicate transmission fees among the multiple transmission providers. Full or partial duplication of transmission charges may provide significant disincentives for transactions between transmission providers. The MMU evaluated these effects on economic efficiency on the seam by conducting a review of the current charges.

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\(^23\) MMU and Potomac Economics joint efforts can be found on the RSC/OMS Liaison Committee Reference Documents page, [https://www.spp.org/spp-documents-filings/?id=173559](https://www.spp.org/spp-documents-filings/?id=173559).

on transmission service and the historical trends of imports and exports between the two regions.

Our analysis shows that rate pancaking has a very limited effect on import and export volumes with the removal of duplicate transmission charges. Furthermore, our analysis shows that many transactions are inelastic to the market clearing price. The majority of the elastic transactions are already taking advantage of Market Import Service in the SPP footprint and a comparable service in MISO, which waive the majority of the transmission fees imposed under the SPP and MISO tariffs.  

Unreserved use charges may be assessed when a transmission customer in the Regional Transmission Organization (RTO) does not reserve adequate transmission service to cover its load obligation. These charges are higher than the cost of reserving transmission and have a ratcheting effect that is punitive in nature. These charges can affect load on the seam when a transmission outage causes it to be served by the adjacent region’s transmission facilities. The market monitors have not discerned whether transmission service is being obtained to serve load in each region or to avoid unreserved use charges during specific outages but are aware that entities may engage in this practice to some degree to mitigate risk. Analysis revealed that SPP and MISO have charged minimal amounts for unreserved use arising from topology changes on the SPP-MISO seam.

The joint dispatch study was led by Potomac Economics and published in November 2019. This analysis estimated potential savings from joint dispatch between SPP and MISO using a MISO 2018 base case model. The results estimated annual benefits of $17 million for joint dispatch between SPP and MISO and an annual benefit of $29 million for joint dispatch with joint commitment. These savings represent about 0.1 percent and 0.2 percent of the combined region’s total production costs. In both the joint dispatch and joint dispatch with commitment analysis, SPP’s production costs increased while MISO’s decreased due to the increase in net exports from SPP to MISO.

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25 When Market Import Service is used in SPP Schedules 7, 8, 9 and 11 under the SPP tariff are waived. The comparable service in MISO, the Spot-In service, waives all transmission charges.

Transmission planning

The MMU and MISO IMM ranked each of the joint effort issues in order of importance and the MMU identified targeted market efficiency projects as the top issue. Transmission development has the potential to yield the greatest benefits over time by alleviating congestion and improving inter-regional and intra-region transfers. SPP and MISO continue to discuss options to overcome hurdles in coordinated projects along the seam. The latest 2019 MISO-SPP Coordinated System Plan study\(^\text{27}\) included enhancements to the process that removed the need of developing a joint model, enhanced benefit metrics, and removed the $5 million threshold to qualify as an interregional project. However, the coordinated study targeted 13 transmission needs but none of the over 40 proposed solutions analyzed met the criteria in the MISO-SPP Joint Operating Agreement for interregional cost allocation. The previous process in the Coordinated System Plan required a substantial joint model building effort and analysis that identified areas of need along the seams. Solutions that met criteria in the Joint Operating Agreement were then recommended to be analyzed by each region's respective regional planning processes.\(^\text{28}\)

The enhancements used for the 2019 study allowed the SPP and MISO regional planning processes and stakeholders recommend areas of transmission needs along the seams during an annual review process for analysis rather than being identified by the Coordinated System Plan process. Solution proposals to identified transmission needs are then coordinated between SPP and MISO and analyzed by each area for economic benefit and reliability and policy needs that are then used by the coordinated study. The coordinated study along with input from the Interregional Planning Stakeholder Advisory Committee\(^\text{29}\) help guide the Joint Planning Committee to recommend projects that meet criteria in the Joint Operating Agreement for SPP and MISO's regional approvals. These enhancements allow each region and stakeholders to highlight needs along the seams and calculate their respective benefit identified from their


\(^{28}\) SPP’s planning process is the Integrated Transmission Plan (ITP) and MISO’s planning process is the MISO Transmission Expansion Plan (MTEP).

\(^{29}\) Interregional Planning Stakeholder Advisory Committee participation is open to all SPP and MISO stakeholders.
regional processes rather than another complex joint modeling effort with additional criteria. However, different methodologies, assumptions, and criteria still exist in each region’s processes for determining benefit and need of the solutions and do not target ongoing market-to-market congestion.

**Price/power swings**

As noted above, the MISO market monitor is currently analyzing potential issues with the market-to-market process, with one focus on achieving the optimal amount of relief between markets to solve congestion. Suboptimal relief requests between markets can lead to oscillations on the seams that lead to price volatility and reliability concerns with power swings. One contributing factor to these oscillations are fast moving resources. SPP applies logic (known as reload) in its real-time market that lessens oscillations across its region and has suggested this feature to MISO. However, only SPP uses this logic to prevent oscillations today.

SPP and MISO have taken approaches targeted at market-to-market mechanisms to minimize these oscillations on the seams. Some enhancements include allowing the RTOs the ability to reverse roles of the monitoring and non-monitoring RTO or the ability to apply shadow price overrides. These targeted enhancements work in some instances, however, oscillations still occur on the seams and in other areas of both markets. With the added focus on market-to-market issues, further effort on potential solutions to prevent the longstanding issue of oscillations should be collaboratively developed by both RTOs with input from market monitors.

### 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 2–41 displays the total volume of virtual transactions as a percentage of real-time market load along with wind output levels.

**Figure 2–41  Cleared virtual transactions as percent of real-time load**

As shown in the figure, virtual transactions averaged 17 percent of real-time market load, compared to nearly 15 percent in 2018 and 14 percent in 2017. Historically, the greatest increases in virtual transactions as a percentage of load have been with cleared virtual offers. This trend continued in 2019, as the percent of virtual offers to load was nearly 10 percent, up from just over eight percent in 2017 and 2018. Virtual cleared bids increased from nearly six percent in 2017 to almost seven percent in 2018 and further upward over seven percent in 2019. Days with high wind output typically see an increase in virtual offer activity. Virtual bids typically increase during high load hours.

At 17 percent of load, the average hourly total volume of cleared virtuals ranged from 2,213 MW of withdrawal to 2,879 MW of injection. The net cleared virtual positions in the market averaged about 665 MW of injection, or supply, each hour.
The majority of virtual transactions occurred at wind resources in 2019, and this is a trend that has been increasing since mid-2015. Figure 2-42 illustrates the settlement location types where virtual offers clear.

**Figure 2-42 Cleared virtual offers by settlement location type**

In total, the hourly average of cleared virtual offers for 2019 was just over 2,100 GWh for 2019, up from just over 1,800 GWh in 2018. This figure shows that an hourly average of just over 905 GWh of virtuals offers cleared at variable energy resources per month during 2019.\(^{30}\) This is up from an hourly average of nearly 780 GWh per month in 2018. 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-scheduling in the day-ahead market.\(^{31}\)

Figure 2-43, below, shows the cleared virtual bids by settlement location types.

---

\(^{30}\) This includes both dispatchable and non-dispatch variable energy locations.

\(^{31}\) Section 4.1.3 on price divergence discusses the effects of unscheduled wind in the SPP market.
This is 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.

As a total average hourly cleared virtual bids climbed from just 1,400 GWh in 2018 to just over 1,600 GWh in 2019. Cleared virtual bids at non-variable energy resources had an hourly average of just over 580 GWh cleared at non-variable energy resource locations in 2019, up slightly from 575 GWh in 2018. Virtual bids at load locations have been steadily increasing, up to an hourly average of nearly 510 GWh, up 14 percent from nearly 450 GWh in 2018.

Figure 2–44 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 2018, both price-insensitive bids and offers, and cleared bids and offers, increased two percent and three percent respectively. 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 2019 in Figure 2–45.
### Figure 2–45 Virtual profits with distribution charges, monthly

<table>
<thead>
<tr>
<th>Month</th>
<th>Raw profit</th>
<th>Raw loss</th>
<th>Raw 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 transaction fee</th>
<th>Total net profit</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>$ 20.6</td>
<td>−$ 12.2</td>
<td>$ 8.4</td>
<td>−$ 0.8</td>
<td>−$ 0.1</td>
<td>−$ 1.8</td>
<td>−$ 0.0</td>
<td>$ 5.6</td>
</tr>
<tr>
<td>February</td>
<td>24.0</td>
<td>−17.4</td>
<td>6.6</td>
<td>−0.8</td>
<td>−0.2</td>
<td>−2.7</td>
<td>0.0</td>
<td>2.8</td>
</tr>
<tr>
<td>March</td>
<td>20.8</td>
<td>−14.2</td>
<td>6.5</td>
<td>−0.4</td>
<td>−0.1</td>
<td>−3.7</td>
<td>0.0</td>
<td>2.3</td>
</tr>
<tr>
<td>April</td>
<td>25.7</td>
<td>−18.7</td>
<td>7.0</td>
<td>−1.4</td>
<td>−0.2</td>
<td>−2.3</td>
<td>0.1</td>
<td>3.0</td>
</tr>
<tr>
<td>May</td>
<td>30.0</td>
<td>−20.2</td>
<td>9.9</td>
<td>−1.8</td>
<td>−0.2</td>
<td>−2.4</td>
<td>0.1</td>
<td>5.4</td>
</tr>
<tr>
<td>June</td>
<td>20.2</td>
<td>−15.9</td>
<td>4.3</td>
<td>−0.8</td>
<td>−0.2</td>
<td>−1.6</td>
<td>−0.1</td>
<td>−1.6</td>
</tr>
<tr>
<td>July</td>
<td>15.8</td>
<td>−15.1</td>
<td>0.7</td>
<td>−0.2</td>
<td>−0.2</td>
<td>−2.4</td>
<td>−0.1</td>
<td>−2.1</td>
</tr>
<tr>
<td>August</td>
<td>13.6</td>
<td>−10.9</td>
<td>2.7</td>
<td>−0.2</td>
<td>−0.1</td>
<td>−2.1</td>
<td>0.0</td>
<td>0.2</td>
</tr>
<tr>
<td>September</td>
<td>18.2</td>
<td>−13.7</td>
<td>4.5</td>
<td>−0.9</td>
<td>−0.4</td>
<td>−4.4</td>
<td>−0.1</td>
<td>−1.2</td>
</tr>
<tr>
<td>October</td>
<td>30.9</td>
<td>−18.4</td>
<td>12.5</td>
<td>−0.4</td>
<td>−0.3</td>
<td>−2.8</td>
<td>−0.1</td>
<td>8.9</td>
</tr>
<tr>
<td>November</td>
<td>24.3</td>
<td>−17.0</td>
<td>7.3</td>
<td>−1.8</td>
<td>−0.2</td>
<td>−2.5</td>
<td>−0.1</td>
<td>2.8</td>
</tr>
<tr>
<td>December</td>
<td>16.1</td>
<td>−11.9</td>
<td>4.2</td>
<td>−0.6</td>
<td>−0.2</td>
<td>−2.1</td>
<td>−0.1</td>
<td>1.2</td>
</tr>
<tr>
<td>Total</td>
<td>$ 260.2</td>
<td>−$ 185.6</td>
<td>$ 74.6</td>
<td>−$ 10.2</td>
<td>−$ 2.2</td>
<td>−$ 31.0</td>
<td>−$ 0.7</td>
<td>$ 30.5</td>
</tr>
</tbody>
</table>

*All figures in $ millions.*

Every month in 2019 was profitable in aggregate for virtual transactions before factoring in transaction fees. However, after accounting for these fees, July and September were unprofitable in aggregate. In the 70 months since the market began, only 11 months have had a net loss when factoring in fees. The highest payout months in 2019 happened in October and January with net payouts over $8.9 million and $5.6 million, respectively. As shown in Section 2.5.3, there was over 7,600 GWh of wind production in October 2019, which was the highest since the start of the Integrated Marketplace. October coincided with high wind and low load when high price differences can occur between day-ahead and real-time markets as a result of under-scheduled wind in the day-ahead market.\(^{32}\)

Financial information for virtual trades on an annual basis for the past three years is shown in Figure 2–46.

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\(^{32}\) Section 4.1.3, price divergence, discusses the effects of unscheduled wind in the SPP market.
Virtual trades profited in aggregate for 2019 in the amount of $75 million, a 69 percent increase from last year. 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 $0.05 per virtual bid or offer transaction fee for processing virtual transactions. The average 2019 rates per megawatt for day-ahead make-whole payments, real-time make-whole payments, and real-time revenue neutrality uplift distributions are $0.05/MWh, $0.70/MWh, and $0.22/MWh, respectively. When factoring in these charges and credits, the net virtual bidding profits for 2019 were $30.5 million, which is about 40 percent of the profit level before fees. Net profits in 2019 increased 71 percent from $17.8 million in 2018.

Net profits are typically small when assessed on a per megawatt basis. Figure 2–47 illustrates the monthly average profit per megawatt for a cleared virtual in 2019.
Figure 2-47 Profit and loss per cleared virtual, after fees

The chart shows that when factoring in all fees the average profit per megawatt for 2019 was $0.63 per cleared megawatt, a 37 percent increase from $0.46 in 2018, but a 32 percent decrease from $0.92 per cleared megawatt in 2017.

Eighty-eight participants transacted virtuals in 2019. Figure 2-48 illustrates each virtual participant’s virtual portfolio for the year by both net megawatts cleared and net profits before adjusting for fees.

Figure 2-48 Virtual portfolios by market participant
Six participants accounted for about 48 percent of the virtual profits after fees, which can also be referred to as net profits. These participants account for roughly 20 percent of the transactional volume in the market. In aggregate, virtual trading generated net profits for most participants. However, 25 virtual participants lost money on a net profit basis. The total losses after fees amounted to roughly $2.3 million, and five entities accounted for over $1.5 million of that loss.

Additionally, Figure 2–48 highlights the disparity in the trading fees paid by each market participant. These fees totaled just over $44 million in 2019; they include: virtual transaction fees (two percent), real-time revenue neutrality uplift fees (23 percent), day-ahead make-whole payment fees (five percent), and real-time make-whole payment fees (70 percent). Virtual bids are subject to virtual transaction fees, real-time revenue neutrality fees, and day-ahead make-whole payment fees. Virtual offers are subject to virtual transaction 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 nearly 80 percent of the real-time make-whole payments in 2019, or roughly $55 million. Virtual offers paid 56 percent of this amount, about $31 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 offers when compared to virtual bids. In 2019, the fees associated with virtual offers amounted to $1.47 per megawatt compared to $0.36 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-scheduling 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, three market participants lost more than $100,000 in virtual transactions before fees, and seven lost more than $100,000 in virtual transactions after fees in 2019. The market monitor reviews these outcomes and takes actions as needed.
UNIT COMMITMENT AND DISPATCH PROCESSES

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

- In 2019, day-ahead commitments increased by one percent and self-commitments decreased by three percent. This is a positive trend.

- Capacity of gas, simple-cycle resources taken out of service for maintenance increased by over 30 percent from 2018 to 2019. Total outages for capacity taken out-of-service for maintenance increased by one percent from 2018 to 2019.

- In 2019, there were 260 intervals with operating reserve scarcity. The average scarcity price for these events was $439/MWh. This was a 56 percent increase in operating reserve scarcity intervals from 2018 to 2019, and a 21 percent increase in scarcity price for the same period.

- Over 40 percent of the regulation-down scarcity and nearly 30 percent of regulation-up scarcity events happened in the first interval of the hour. This trend has held since the inception of the SPP marketplace and continues to increase.

- SPP has designed a ramp capability product.³³

- The average percent of total offered capacity by commitment status remained consistent in 2019 with prior year levels with a slight decrease in the “self-commit” status and increases in both the “market” and the “outage” statuses.

- SPP operations issued ten Conservative Operations Alerts in 2019, covering 35 days, and had one Energy Emergency Alert 1 (EEA 1) in August. These are the first Conservative Operations Alerts since the inception of the Integrated Marketplace in March 2014.

³³ Tariff Revisions to Add Ramp Capability, Docket No. ER20-1617, at https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=15514435, see also SPP MMU comments, which will be filed in May 2020, after the publication of this report.


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. The principal component of the commitment process is the day-ahead market, which determines a least cost commitment schedule that meets day-ahead energy demand and operating reserve requirements simultaneously. Most of the time it becomes necessary to commit additional capacity outside the day-ahead market to ensure all reliability needs are addressed and to adjust the day-ahead commitment for real-time conditions. This is done through the reliability unit commitment (RUC) processes and manual commitments. SPP employs five reliability commitment processes:

- multi-day reliability assessment;
- 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 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 at 1400. 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. In 2019, unlike in 2017 and 2018, SPP committed units out of this process.

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 issue local reliability commitments.

3.1.1 RESOURCE STARTS

The SPP resource fleet, excluding variable energy resources, had 33,642 starts during 2019. This is down almost six percent from 35,568 starts last year. The following two tables and graphs provide a breakdown of the origins of the commitment decisions for resources. Figure 3-2 shows the percentage of resource starts by commitment process. For all generation participation offers in the day-ahead market by commitment status see Figure 3–11.

**Figure 3-2  Start-up instructions by resource count**

<table>
<thead>
<tr>
<th></th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day-ahead market</td>
<td>68%</td>
<td>74%</td>
<td>75%</td>
</tr>
<tr>
<td>Self-commitment</td>
<td>15%</td>
<td>11%</td>
<td>8%</td>
</tr>
<tr>
<td>Intra-day RUC</td>
<td>8%</td>
<td>7%</td>
<td>7%</td>
</tr>
<tr>
<td>Manual, regional reliability</td>
<td>4%</td>
<td>5%</td>
<td>7%</td>
</tr>
<tr>
<td>Short-term RUC</td>
<td>2%</td>
<td>3%</td>
<td>2%</td>
</tr>
<tr>
<td>Day-ahead RUC</td>
<td>&lt;1%</td>
<td>&lt;1%</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Manual, local reliability</td>
<td>1%</td>
<td>1%</td>
<td>1%</td>
</tr>
<tr>
<td>Starts</td>
<td>28,160</td>
<td>35,328</td>
<td>33,643</td>
</tr>
</tbody>
</table>

34 Day-ahead market excludes resources started due to self-commitment in the day-ahead market.

35 Self-commitment includes resources started in the day-ahead market due to a self-commitment.

36 Manual commitments for regional reliability include commitments for additional capacity and manually staggering start-up or shutdown times.
As shown in Figure 3–2 above, 75 percent of start-up instructions in 2019 were a result of the day-ahead market. Each year there has been an increase in day-ahead market starts and a decrease in self-commitment starts. This is an encouraging trend as it leads to greater market efficiency and suggests that resource owners may be gaining confidence in the market to start resources. 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. Nonetheless, many market participants have improved their operating practices to decrease the start-up times on the units to take advantage of the market commitment process. The reliability unit commitment processes—day-ahead, intra-day, short-term, and manual—represent 14 percent of the resource start-ups. The MMU notes that the manual, reliability commitments have increased in 2019. Many of these commitments are due to uncertainty of the forecasted resources or needing additional ramp-able capacity. The ramp product and uncertainty products should help reduce these amounts after implementation.

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37 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).

38 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 provides a slightly different look at starts by showing percentage of total capacity committed by each process.

**Figure 3–3  Start-up instructions by resource capacity**

<table>
<thead>
<tr>
<th></th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day-ahead market</td>
<td>72%</td>
<td>75%</td>
<td>76%</td>
</tr>
<tr>
<td>Self-commitment</td>
<td>15%</td>
<td>13%</td>
<td>9%</td>
</tr>
<tr>
<td>Intra-day RUC</td>
<td>7%</td>
<td>5%</td>
<td>7%</td>
</tr>
<tr>
<td>Manual, regional reliability</td>
<td>3%</td>
<td>4%</td>
<td>5%</td>
</tr>
<tr>
<td>Short-term RUC</td>
<td>2%</td>
<td>2%</td>
<td>1%</td>
</tr>
<tr>
<td>Day-ahead RUC</td>
<td>1%</td>
<td>&lt;1%</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Manual, local reliability</td>
<td>1%</td>
<td>1%</td>
<td>1%</td>
</tr>
<tr>
<td>Capacity started (MW)</td>
<td>2,459,589</td>
<td>2,882,506</td>
<td>2,678,789</td>
</tr>
</tbody>
</table>

The percentage differences between Figure 3–2 and Figure 3–3 are the result of larger resources either self-committed or committed by the day-ahead market, and smaller resources with shorter lead times committed in the day-ahead reliability unit commitment, intra-day reliability unit commitment, and manual commitment processes.

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. Seventy-six percent of all capacity was started in the day-ahead market in 2019, up slightly from 75 percent of all start-ups in 2018, and 72 percent in 2017. Gas-fired generators are 41 percent of all capacity in SPP.

Figure 3–4 shows that 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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39 Day-ahead market excludes resources started due to self-commitment in the day-ahead market.
40 Self-commitment includes resources started in the day-ahead market due to a self-commitment.
41 Manual commitments for regional reliability include commitments for additional capacity and manually staggering start-up or shutdown times.
SPP issued day-ahead starts for gas-fired generators with simple-cycle combustion turbine technology accounted for 75 percent of their total starts, about the same as 2018. This is an increase from 69 percent in 2017. Steam turbine starts decreased in the day-ahead market and increased in intra-day reliability unit commitment and self-commitment with 63 percent in 2019, compared to 73 percent the year before. Overall, self-commitments for all gas resources decreased by one percent from 2018 to 2019.

The MMU is encouraged by an overall increase in all unit types being started by the day-ahead market, and the accompanying decrease in manual commitments, as well as self-commitments. Starts in the day-ahead market are preferred since the market clearing engine will optimize starts and dispatch to the most benefit to the market.

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 price levels and lead to make-whole payments. The next section discusses the drivers behind reliability commitments.
3.1.2 DEMAND FOR RELIABILITY

Figure 3–3 noted that eight 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. A fundamental difference is the definition of energy demand between the two studies. The energy demand in the day-ahead market is determined by bids submitted by the market participants, which average around 100 percent of the real-time values, as shown in Figure 2–5.

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.

The assumptions regarding wind generation differ as well. Eighty-four percent of the real-time wind production cleared in the day-ahead market on an average hourly basis in 2019. While the market participants determine the participation levels for their wind resources in the day-ahead market through the use of supply offers, SPP’s wind forecast is used by the reliability unit commitment processes. Import and export transaction data are updated to include the latest information available for the reliability unit commitment processes.

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 difference between the (1) excess supply between day-ahead and real-time markets, and the (2) excess demand between the day-ahead and real-time markets.

A negative resource gap indicates that the total generation cleared in the day-ahead market is insufficient to serve real-time demand. The primary drivers for the negative resource gaps are (i) differences in virtual supply net of virtual demand, (ii) differences in real-time wind generation compared to wind cleared in the day-ahead market, (iii) real-time net exports exceeding day-
ahead net exports, and (iv) manual commitments. It is generally true that real-time wind generation exceeds the clearing of wind in the day-ahead market. The mismatch between real-time and day-ahead wind is partly because some market participants with wind generation assets offered such that the full amount of forecasted capacity did not clear in the day-ahead market. Then, market participants take real-time positions with the uncleared portion of their capacity given the uncertainty of the wind generation.

The resource gaps can help explain why additional commitments occur after the day-ahead market has cleared. Figure 3–5 compares on-line capacity between the day-ahead and real-time markets.

**Figure 3-5  Average hourly capacity increase from day-ahead to real-time**

The chart indicates that in 2019 there was, on average, around 2,300 MW of additional capacity on-line during the real-time market relative to the capacity cleared in the day-ahead market, an increase of 29 percent compared to 2018.

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. A value is calculated for upper bound (upward ramp) and a lower bound (downward ramp). Because the default value is used about half of all
intervals, the MMU believes that instantaneous load capacity constraint can contribute to reliability commitments in excess of the resource gaps. 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  Instantaneous load capacity required**

The percent of hours at various upper bound default levels is shown in Figure 3–7. The most frequent observations were from 400 MW to 499 MW at around 22 percent. Overall, the 2019 levels were less than 2018. While a product is more appropriate, this reduction may help lower unnecessary make-whole payments. SPP evaluates the default values quarterly. The default requirements are hourly values as low as 200 MW. This is an improvement from 2018 when 500 MW was the minimum.
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 prices signals.

Reliability commitments, along with wind exceeding the day-ahead forecast, can dampen real-time price signals, as is evidenced by 29 percent of make-whole payments made for reliability unit commitments, as shown in Figure 4-36.
3.1.3 QUICK-START RESOURCES COMMITMENT

A quick-start resource\(^{42}\) can start, synchronize, and begin injecting energy within 10 minutes of SPP notification. This section will detail the ways quick-start resources are used, which includes quick-start resources dispatched by the real-time market without a commitment.\(^{43}\)

Beginning in 2018, this report considers the definition of a quick-start resource to be a resource that was dispatched from an off-line state by the real-time market without a commitment. This differs from the 2017 definition which included some committed quick-start resources. In 2019, 96 resources counted as quick-start resources, all of which have been offered and used by the real-time market at least once during 2019 in this capacity.

Figure 3–8 summarizes the deployment\(^{44}\) methods available for quick-start resources with the number of times each method was selected, lead time, original commitment hours, and actual hours on-line.

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\(^{42}\) SPP is in the process changing the quick-start market design to have separate dispatch and pricing runs. The dispatch run will not change, but the pricing run will relax the minimum of fast-start resources to zero MW and will be based on an offer that includes start-up and no-load costs. See RR375 (FERC Order on Fast-Start Pricing), a revision for compliance with FERC’s fast-start order (Docket No. EL18-35), which is currently an open docket (Docket No. ER20-644).

\(^{43}\) Integrated Marketplace Protocols, Section 4.4.2.3.1.

\(^{44}\) The more encompassing term “deployment” is used to account for both commitment and dispatch of resources.
Figure 3–8 Deployment of quick-start resources

<table>
<thead>
<tr>
<th>Commitment process</th>
<th>Number of starts</th>
<th>Committed available capacity (MW)</th>
<th>Lead time (hours)</th>
<th>Hours in original commitment</th>
<th>Actual hours on-line</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day-ahead RUC</td>
<td>0</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Intra-day RUC</td>
<td>468</td>
<td>18,251</td>
<td>2.2</td>
<td>3.1</td>
<td>5.2</td>
</tr>
<tr>
<td>Short-term RUC</td>
<td>253</td>
<td>9,804</td>
<td>0.4</td>
<td>2.8</td>
<td>4.4</td>
</tr>
<tr>
<td>Manual</td>
<td>691</td>
<td>26,182</td>
<td>0.1</td>
<td>4.7</td>
<td>4.8</td>
</tr>
<tr>
<td>Day-ahead market</td>
<td>16,960</td>
<td>603,337</td>
<td>20.8</td>
<td>7.2</td>
<td>18.8</td>
</tr>
<tr>
<td>Real-time market</td>
<td>2,806</td>
<td>82,089</td>
<td>0.1</td>
<td>0.1</td>
<td>0.6 (^{45})</td>
</tr>
</tbody>
</table>

The level of make-whole payments associated with the commitment of quick-start resources in the reliability processes is noteworthy.\(^{46}\) In 2019, 76 percent of the reliability commitments for quick-start units resulted in real-time make-whole payments, which is similar to 2018. In 2019, quick-start resources received $6.8 million in real-time make-whole payments and $159,000 in day-ahead make-whole payments. This is a decrease from their respective 2018 make-whole payments of $7 million and $350,000.

With the inception of the short-term reliability unit commitment process in February 2016, there has been a significant reduction in the number of day-ahead reliability unit commitments for these units. The short-term reliability unit commitment can commit units in as little as 15 minutes ahead, increasing certainty of the need for the unit. Before the short-term reliability unit commitment process was implemented, units had often been committed hours ahead of the actual start time—sometimes more than a day—ignoring the value of their flexible capability. The 15-minute lead-time leaves time to commit these quick-start resources when needed, which allows the commitment to be held off longer, providing more certainty of the need of the resource. This also minimizes the time these units are at minimum load levels with market prices below their marginal costs, while still allowing for a make-whole payment.

Figure 3–9 shows the percent of time quick-start resources generated power and the relationship of prices to their offer.

\(^{45}\) The real-time market actual on-line hours represent the total amount of time quick-start resources were dispatched by the market and does not include any on-line commitment time that may have directly proceeded or followed the quick-start dispatch period.

\(^{46}\) Quick-start resources started by the real-time market are not eligible for any make-whole payments.
Over the last three years, about 25 percent of the megawatt-hours produced by quick-start resources\(^{47}\) had energy prices below real-time energy offers. In 2019, this is about the same as the percentage of offers to energy price for other resources in the SPP footprint, which is represented by the green line in Figure 3–9. Quick-start resources directly dispatched in real-time using the quick-start logic are not eligible for a make-whole payment.\(^ {48}\) Revision Request 375 proposes to make SPP-committed fast-start resources whole and to eliminate the dispatch of uncommitted fast-start resources.\(^ {49}\)

### 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 reserves, and supplemental reserves, and/or to submit bids to purchase energy. The day-ahead market co-optimizes the clearing of energy and operating reserve products out of the available capacity. All day-ahead market products are traded and settled on an hourly basis.

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\(^{47}\) Quick-start resources are defined as those resources with a 10 minute start-up time and a minimum run time of one hour or less. Variable energy resources for which SPP forecasts the output are not considered quick-start resources.

\(^ {48}\) *Integrated Market Protocols*, Section 4.4.2.3.1 states that only the offer curves are used to dispatch.

\(^ {49}\) RR375 is currently under FERC review, Docket No. ER20-644.
In 2019, participation in the day-ahead market was robust for both generation and load. Load-serving entities consistently offered generation into the day-ahead market at levels in excess of the requirements of the limited day-ahead must-offer obligation. Participation by merchant generation—for which no such obligation exists—was comparable to that of the load-serving entities. However, as seen in Figure 3–10, 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 3–11 shows day-ahead market offers by commitment status and participant type.

**Figure 3–10  Day-ahead market offers by commitment status and participant type**

<table>
<thead>
<tr>
<th>Resource type</th>
<th>Owner type</th>
<th>Market</th>
<th>Self</th>
<th>Reliability</th>
<th>Not participating</th>
<th>Outage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fossil fuel resources</td>
<td>Load-serving entity</td>
<td>54%</td>
<td>30%</td>
<td>2%</td>
<td>1%</td>
<td>14%</td>
</tr>
<tr>
<td></td>
<td>Merchant</td>
<td>70%</td>
<td>12%</td>
<td>0%</td>
<td>0%</td>
<td>18%</td>
</tr>
<tr>
<td>Variable energy resources</td>
<td>Load-serving entity</td>
<td>53%</td>
<td>42%</td>
<td>0%</td>
<td>0%</td>
<td>5%</td>
</tr>
<tr>
<td></td>
<td>Merchant</td>
<td>51%</td>
<td>13%</td>
<td>0%</td>
<td>19%</td>
<td>16%</td>
</tr>
</tbody>
</table>

Figure 3–11 shows generation capacity in the day-ahead market by commitment status.

**Figure 3–11  Day-ahead market capacity by commitment status**
The average percent of total offered capacity by commitment status remained consistent with 2018 levels with a slight decrease in the “self-commit” status and increase in the “outage” status. The “market” commitment status averaged 55 percent while resources with commitment statuses of “reliability” and “not participating” averaged two percent and three percent, respectively. The “outage” commit status averaged 16 percent up from 12 percent in 2018. The “self-commit” status averaged 25 percent of total offered capacity which was a slight decrease compared to 30 percent in 2018. While self-commitments decreased from 2018, they still constitute a large amount of the capacity offered into the market.

Compared with Figure 3–2 and Figure 3–3 in Section 3.1.1, which shows origins of only initial starts, these values represent commitment status of all generation capacity offered including those on-line. Self-committed resources accounted for only eight percent of initial starts but 25 percent of all capacity offered on average. This can be attributed to the desire to keep a resource on-line after its initial start even during low prices.

Figure 3–12 shows on-line capacity commitment as a percent of load.

Figure 3–12  On-line capacity as a percent of load

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50 Of the self-committed resources, qualifying facilities (QF) account for three to four percent. Qualifying facilities often use self-commit status to exercise their rights under the Public Utilities Regulatory Policies Act of 1978 (PURPA).
The capacity commitment as a percent of load has decreased significantly over the past few years, however, in 2019, has a small increase from 120 percent in 2018 to just over 121 percent in 2019.

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 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, 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 2019, two day-ahead must-offer penalties, totaling $37,000, were assessed. One penalty was assessed in 2018. While this provision does highly encourage available generation to be offered, it does not impose a penalty for excessive outages (which were cited as a reason for conservative operations) or otherwise tie into Attachment AA, which defines the resource adequacy requirement in the SPP tariff.

In 2014, the MMU recommended that SPP simultaneously eliminate the limited day-ahead must-offer provision and revise the physical withholding rules to include a penalty for non-compliance based on the premise that the recommended penalty provision would be sufficient to ensure an efficient level of participation in the day-ahead market. SPP stakeholders then approved the removal of the day-ahead must-offer with no additional physical withholding provisions, and SPP filed the tariff revision with FERC in 2017. FERC denied the removal of the limited must-offer requirement, as it did not include physical withholding non-compliance penalties.51

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

51 FERC ruling at https://www.ferc.gov/CalendarFiles/20171013130834-ER17-2312-000.pdf.
conservative operations in 2019, the MMU has assigned a higher priority to addressing the issue. See further discussion in Section 8.2

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 the settlement 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 an additional supplier, so price cannot be determined by the next increment. In this case, a scarcity price is used to set marginal price. The Integrated Marketplace uses demand curves to set graduated scarcity prices so that small scarcities are priced lower than large scarcities. Scarcity prices inform market participants that the product was short and incentivize future provision of that product.

When an insufficient amount of regulation-up service, regulation-down service, or contingency reserve is cleared, a scarcity price is set by a demand curve. The scarcity of these products can be caused by a lack of capacity or a lack of ramp. Scarcities are due to capacity when there are insufficient resources at maximum output available to meet demand. Scarcities are due to ramp when sufficient capacity is available, but ramp rate limitations do not allow access to the full capacity. When multiple products compete for the same, limited capability of resources, the scarcity of one product can also raise the price of other products.

Total scarcity events in 2019 were about 70 percent higher than 2018. Regulation-up and operating reserve scarcities each increased about 60 percent, and regulation-down scarcity increased by about 140 percent.
While operating scarcity events happened relatively evenly across the hour, regulation scarcity events did not. About 40 percent of the regulation-down reserve scarcity intervals in 2019 occurred in the first interval of the hour. The same pattern occurred with regulation-up reserve scarcity events, but to a lesser degree, with 30 percent in the first interval of the hour.

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

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

Figure 3–13 displays the number of scarcity intervals and prices for by month, along with an annual comparison of monthly averages.

**Figure 3-13  Scarcity intervals and marginal energy cost**

In 2019, there were 680 intervals with regulation-up reserve scarcity, 280 intervals with regulation-down scarcity, and 260 intervals with operating-reserve scarcity. There are far more regulation-up scarcities than regulation-down scarcities. This is likely because more regulation-down is typically available. First, variable energy resources are able to provide regulation-down and not regulation-up. Second, the market dispatches energy from a resource’s minimum until it is no longer profitable or until the resource is limited by a parameter, such as ramp rate up or
a maximum operating limit. Consequently, many resources are operating closer to their maximum than their minimum which provides more downward capability than upward capability. Regulation-up scarcities and operating reserve scarcities both increased by about 60 percent compared to 2018 while regulation-down scarcities more than doubled. While many factors affect scarcities, about 64 percent of regulation-up scarcities and about 58 percent of operating reserve scarcities happened in intervals when variable energy production increased the amount of ramp up needed. About 44 percent of regulation-down scarcities happened in intervals when variable energy production increased the amount of ramp down needed.

About half of all scarcity intervals occurred in only a third of the year, i.e., April, May, October, and November. These months typically have high wind production, low load, and more generator outages. Because wind provides a relatively high amount of capacity, fewer flexible resources are available to provide reserves. When wind production is volatile, the dispatchable resources’ highest priority is to provide energy, with reserves as a lower priority.

The average scarcity prices for the regulation-up, regulation-down and operating reserve events were $195/MW, $153/MW, and $439/MW respectively. The highest regulation scarcity prices occurred in May, and the highest operating reserve scarcity prices occurred in November. The average scarcity prices for regulation-up are about the same as 2018, but prices are higher for regulation-down and operating reserve in 2019.

Regulation-up and down price spikes happened more frequently at the beginning of each hour. Figure 3–14 below illustrates a count of the 2019 scarcity events in the real-time market by the 12 intervals of each hour.
Figure 3–14  Scarcity events by interval of the hour

About 40 percent of regulation-down reserve scarcity intervals occurred in the first interval of the hour. The same pattern occurred with regulation-up reserve scarcity events, but to a lesser degree. Almost 30 percent of regulation-up scarcity intervals occurred in the first interval. Operating reserves are more equally dispersed across the hour. The pattern of regulation scarcity events at the beginning of the hour has occurred since the inception of the marketplace.

One potential reason for this pattern 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

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52 Resources that deviate from their dispatch signals can receive Uninstructed Deviated Charges for the deviated megawatts. The median price per megawatt for deviation in 2018 was about $0.80. However, the maximum price charged for deviation was about $12.90. 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.
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.

Though scarcity prices apply to regulation-up, regulation-down, and operating reserves, spinning reserve scarcity is currently not priced through scarcity demand curves. Instead, SPP uses a violation relaxation limit (VRL) during periods of spin scarcity. The VRL for spinning reserve scarcity is set at $200/MW. This means that SPP will keep dispatching resources to meet the spinning reserve requirement up to the point the redispatch cost reaches $200/MW. At this point, the market will relax the spinning reserve requirement to the quantity of spinning reserve megawatts that can be obtained at a redispatch cost under the $200/MW shadow price. The spinning reserve price will be the price of the marginal resource cleared at the relaxed limit for that product, plus any scarcity pricing from an operating reserve scarcity event. Because spinning reserve is a higher-priority product than supplemental reserve, the market will never set the spinning reserve price lower than the supplemental reserve price.

In most instances, when the VRL shadow price is reached, the marginal clearing price is set near $200/MW. However, in circumstances where the spinning reserve is scarce because of competition with other products, the spinning reserve shadow prices can be set at or near $0/MW. Even though the shadow prices are $0/MW, the actual spinning reserve clearing prices are typically set by an operating reserve scarcity event price. Figure 3–15 shows a scatter plot of 2019 spinning reserve shortages with distribution curves for each axis showing where shadow prices and shortage percentages are clustered.

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53 The operating reserve scarcity price is based on a requirement that is the sum of requirements for (i) regulation-up, (ii) spinning reserve, and (iii) supplemental reserve. This requirement is separate from the requirement and scarcity price for regulation-up. If cleared spinning reserve is short of the spinning reserve requirement, then additional regulation-up or supplemental reserves can count towards the operating reserve requirement. Even though the spinning reserve requirement is not met, scarcity pricing may not be invoked.
This figure plots spinning reserve shadow prices, during periods of shortage, against the percentage of spinning reserves short. The chart shows that prices were frequently near the $200/MW shadow price limit, mostly when spinning reserve was slightly short. However, as the distribution curve on the right shows, shadow prices were frequently near or at $0/MW. As the shortage percent increases, the high shadow prices become less frequent. In fact, when spinning reserve was more than 45 percent short, almost all prices were $8/MW or less. In 2019, there were five intervals where shadow prices were set at $0/MW during a spinning reserve shortage. This means that the cost to meet the requirement was more than $200/MW, but the market valued it at $0/MW. This is significantly below the value of the reliability that this spinning reserve provides. Rather than pay the marginal price, the market procured insufficient spinning reserve. As stated above, in these cases, the supplemental reserve price set the spinning reserve price, most of which were around $2/MW.

Energy shortages are currently priced using the VRL process. There are three VRL constraints associated with energy shortages. The current energy shortage VRL shadow prices are $5,000/MW for ramp shortages, $50,000/MW for balancing resources’ dispatch to load consumption, and $100,000/MW for resource capacity shortages. If these requirements are not met, the requirement will be relaxed and prices may feasibly be no higher than without a shortage.
When product prices and shadow prices do not reflect shortages, beneficial behavior is not incentivized and investment signals for the addition of new generation or demand response resources are distorted. In some cases, this pricing may cause harmful behavior, such as when prices remain low during a shortage causing exports to increase while SPP remains short.\textsuperscript{54} Demand curves relax the physical requirement while pricing the value of scarce product. Therefore, The MMU highly recommends SPP and stakeholders review price formation during scarcity events and establish graduated demand curves that incentivize proper price formation.\textsuperscript{55}

### 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 generation. These changes can be measured as changes in net load. Net load is load net of both variable energy generation, the combination of imports, exports, and parallel flows from other markets.

Figure 3–16 shows the frequency and extent of net load changes from one real-time interval to the next.

\textsuperscript{54} This could be a particular concern with the development of the coordinated transaction scheduling under review as part of the SPP Regional State Committee/Organization of MISO States project.

\textsuperscript{55} See recommendation in Chapter 8.
Figure 3–16 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 310 MW and an increase of about 300 MW. This is up from 2018 when the decrease was about 290 MW and the increase was about 285 MW. These changes in net load must be balanced by resources with a flexible dispatch range, or ramp capability.

Figure 3–17 below shows the volatility in net load change.

Figure 3–17 Volatility of interval-to-interval net load change
Net load volatility increased about four percent from 2018 to 2019. Net load volatility has increased from 2016 and previous years but has leveled off in the last three years.

As variable energy resources serve more load, volatility is expected to increase. About one-quarter of total generation was produced by wind and solar resources in 2019. When variable energy resource production changes by the same amount or in the same direction as the load change, it can reduce the magnitude of the net load change, which decreases the ramp required from more dispatchable resources. However, when variable energy production does not change in the same direction, it can increase the magnitude of the net load change, which increases the ramp required from more dispatchable resources. Wind resources increased the net load change, both up and down, in about 73 percent of intervals. Of these intervals, the need for ramp down increased an average of about 70 MW while 95 percent of intervals required less than about 190 MW. The need for ramp up increased an average of about 70 MW, while 95 percent required less than about 190 MW. With over 46 GW of wind-powered generation and over 28 GW of solar generation with an active generation interconnection request, this problem will likely increase in the future as volatility from variable energy resources increases. The soon to be implemented ramp product should help compensate resources for this ramping reliability need.

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.

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56 Interconnection requests may be viewed at http://opsportal.spp.org/Studies/GIActive.
57 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.
Rampable capacity in the up direction, when averaged by month, is lowest in April, when wind production is typically high. Figure 3–18 shows the average up-rampable capacity by month after energy and operating reserve obligations are accounted for.58

**Figure 3-18 Average up-rampable capacity**

The amount of rampable capacity in the down direction is much larger than in the up direction when averaged by month, as shown in Figure 3–19. While the monthly averages do not change significantly throughout the year, the up-rampable capacity is on average seven percent higher and the down-rampable capacity is on average 17 percent higher in 2019 than in 2018. The downward ramp increase is likely the result of an overall increase in wind production and the continuing conversion of wind resources from non-dispatchable to dispatchable.

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58 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.
Figure 3–19 Average down-rampable capacity

![Graph of average down-rampable capacity over months from 2017 to 2019 with data points indicating significant capacity variations.]

Figure 3–20 shows the average rampable capacity in the up direction by hour of the day. Rampable capacity in the up direction is lowest following the morning ramp in hours beginning 08, 09, and 10. From hour beginning 11 until hour beginning 21, 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 17 percent increase in average up-rampable capacity in 2019 indicates an increasing need for ramp commitments, but since this capacity is not being compensated, there is no guarantee for it to be available in the future.
Figure 3–20 Average up-rampable capacity by hour

Figure 3–21 shows the average rampable capacity in the down direction by hour. 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 late evening hours, this amount does not vary significantly throughout the day.

Figure 3–21 Average down-rampable capacity by hour

Ramp capability is needed to meet all of these changes in generation and load from interval to interval. However, unlike capacity, ramp is not procured ahead of time. 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. Unlike capacity, the market clearing engine does not specifically procure ramp ahead of time to meet these intra-hour net load changes, although committed capacity usually comes with incidental ramp capability.

### 3.2.3 RAMP CAPABILITY PRODUCT

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. 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.

SPP has designed a ramp capability product, which is awaiting FERC response. The MMU is in general support of the proposed design, however, there are some concerns with the current design, which are 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. Ramp is not currently 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.

When ramp capability is not considered for future intervals, then the market clearing engine may 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. This often leads to short-term transitory price spikes, as seen in Figure 3–22.

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60 *MMU comments* have yet to be filed at the time of this report publication, Docket No. ER20-1617.

61 This is essentially temporal, or time-based, congestion.
This figure shows that a scarcity pricing event in real-time was most likely to occur for only one five-minute interval. Very few scarcity pricing events last more than two intervals. This pattern has been consistent in recent years, but the total number of scarcity events increased by 57 percent from 2018 to 2019.

Figure 3–23 shows the interval length for the different types of scarcity events.

Figure 3-22 Interval length of short-term price spikes

Figure 3-23 Interval length of short-term price spikes, percentage
Of all the regulation-up scarcity events, about 67 percent lasted for only one interval and about 18 percent lasted for two intervals. For regulation-down scarcity events, about 77 percent lasted for only one interval. Operating reserve scarcity event lengths were more diverse with about 56 percent lasting for one interval, about 12 percent lasting two intervals, and about 11 percent lasting three intervals. Operating reserve scarcity events lasted up to 13 intervals, though there were very few events that lasted longer than three intervals. Scarcity events in the SPP market continue to be short in duration.

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 2019, but scarcity events have also increased, highlighting the continued need for systematic ramp procurement.

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 ramp capability product can ensure that more ramping 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 Proposed design of the ramp capability product

In the 2017 annual report, the market monitor recommended that SPP create a ramp capability product. SPP has designed a ramp capability product that has passed all the stakeholder processes and is awaiting FERC response.\(^{62}\)

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The proposed ramp capability product will optimize the resources’ dispatch instructions over a ten-minute period to allocate any economically available ramp for the interval starting ten minutes in the future. It will meet this future ramp need 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 proposed ramp requirement will be enough ramp to meet forecasted net load changes plus an amount to cover unexpected net load changes based on historical needs. The current design will optimize only online ramp. Off-line ramp will not be eligible to clear the ramp capability product. A market clearing price will be set by the opportunity cost of providing other products. While the market monitor is in general support of the proposed ramp capability design there are some concerns:

3.2.3.2.1 Proposed ramp product has incentives to ignore dispatch

The proposed ramp product has no process for clawing back ramp payments from resources that do not respond to dispatch. In fact, with this design there are scenarios where resources’ price incentives could lead them to ignore dispatch instructions. The ramp product pays resources to hold back rampable capacity for a future interval. A resource that does not follow dispatch, in an interval for which it cleared the ramp product, is withholding the capability for which it was paid. This is payment without delivery, and the resource should not be paid. The MMU prefers to see a claw back process for not following dispatch instructions associated with ramp. However, the MMU has agreed to monitor for this behavior and report any potential manipulation to FERC.

3.2.3.2.2 Proposed ramp product demand curve prices are too low

The proposed ramp product prices scarcity with a demand curve. The MMU is concerned that the demand curve prices are too low. Using 2019 prices, the MMU estimates that the demand curve will begin relaxing the ramp requirement when the cost is around $8.50/MW and will completely relax the ramp requirement around $50/MW. These prices may not clear physical ramp 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.

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63 MMU comments have yet to be filed at the time of this report publication, Docket No. ER20-1617
64 As specified under the SPP Open Access Transmission Tariff, Sixth Revised, Volume No. 1, Attachment AG, 4.4, “Monitoring for Potential Integrated Marketplace Manipulation”
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. After implementation, the MMU will analyze the cost effectiveness of the demand curve prices.

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, then the market monitor could support multiple ramp products.

SPP is currently proposing 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. This product is in the early stages of the stakeholder process. The MMU believes that this product, in conjunction with the proposed ramp capability product, should severely limit the need for the use of committing the uncompensated capacity, currently defined as instantaneous load capacity.

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.

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65 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.
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 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 and investment signals.

Figure 3–24 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 3–24 Percentage of megawatts dispatched by commitment status

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The volume of self-committed megawatts has declined over the last several years, but remains nearly half of the total dispatch megawatt volumes. In other words, nearly half of the energy produced in 2019 was from a resource that was not economically selected by the day-ahead market’s centralized unit commitment process.\(^67\)

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 3–25 shows dispatch megawatts by fuel type by commitment type for each year of the study period.

![Figure 3-25 Dispatch megawatt hours by fuel type by commitment type](image)

While resources of various fuel types self-commit, coal resources have produced and continue to produce the largest portion of self-committed megawatts. The trend is positive however, as the overall level of self-commitment is declining, and with coal resources declining by 27 percent between 2018 and 2019.

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

\(^{67}\) Reliability unit commitments that continued to run in the day-ahead market were considered a market commitment.
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 3–26 shows the relationship between commitment status and start-up time.

**Figure 3–26  Lead time hours by commitment status**

Self-committed resources tend to have longer lead times than market-committed resources. Because centralized unit commitment must observe constraints other than cost, such as minimum run 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, as well as the cost to eventually shut the unit down. These offers are submitted in terms of dollars per start.

Figure 3–27 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. 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 profit maximization. Enhanced profit maximization combined with effective regulation and monitoring will likely lead to ratepayer benefits in the form of cost reduction.

While the MMU has seen gradual reductions in self-commitments over the last few years, generation from self-committed generators still represents about half 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.68

3.4 GENERATION OUTAGES

A central tenet of SPP is that “reliability and economics are inseparable.” 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. The MMU has observed an upward trend in outages from 2017 to 2019.

3.4.1 OVERVIEW

Other than growth in wind capacity and decline in coal capacity, the capacity of other fuel types remains relatively constant. Yet, there has been an upward trend in capacity on outage. Total capacity on outage increased six percent from 2018 to 2019, and 40 percent when compared to 2017.

Figure 3–28 shows capacity derated and taken out-of-service by reason—forced or maintenance.69 Each reason is further categorized by fuel type.

68 Chapter 8, recommendation 2017.4 “Address inefficiency caused by self-committed resources” for more information.

69 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 were excluded from the results. Derated resources are still available to the market at a reduced capacity. Out-of-service resources are entirely unavailable.
Over the past three years, capacity taken out-of-service for maintenance have accounted for the largest share of capacity on outage. This is followed by capacity forced out-of-service; then forced derates; and finally by maintenance derates. In 2019, simple-cycle gas was the largest contributor of capacity on outage in all categories except derated forced outages where coal was the largest contributor of capacity on outage. Similarly, from 2018 to 2019, simple-cycle gas accounted for the largest increases in capacity on outage in all categories except derated forced outages where wind had the largest increase. From 2018 to 2019, the capacity that was taken out-of-service for maintenance by simple-cycle gas resources increased by just over 30 percent, from 25,000 GWh to 33,000 GWh.

Figure 3–29 shows capacity on outage for long-term outages (greater than seven days).
The amount of capacity for both derated and out-of-service for maintenance long-term outages, lasting longer than seven days, is increasing, which could indicate there is less incentive to complete outages quickly. The duration of long-term outage has increased each year since 2017.

Figure 3–30 shows capacity on outage for short-term outages (seven days or less).
Despite the overall increase in capacity on outage in 2019, there was a decrease in capacity on outage for short-term, out-of-service maintenance, lasting seven days or less. This may further indicate lessened incentive to complete outages quickly. Compared to the increase of long-term capacity on outage, this may indicate that out-of-service maintenance is taking longer each year. If long-term maintenance outages continue to increase while short-term maintenance outages decrease, it may threaten reliability as the capacity available to serve load is lower.

Generation outages were specifically cited as a reason for several of the conservative operations events in 2019.

In the figures above, it is notable that the largest and most significant portion of capacity on outage is simple-cycle gas resources. Figure 3–31 shows capacity on outage of simple-cycle gas resources as a percentage of total registered simple-cycle gas capacity\textsuperscript{70} by outage reason.

![Figure 3-31 Outage percentage, gas, simple-cycle](image)

The simple-cycle gas capacity taken out-of-service increased in almost all categories. In particular, the capacity taken out-of-service for maintenance climbed dramatically, from about 12 percent in 2017 to about 21 percent in 2019.

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\textsuperscript{70} Total registered simple-cycle gas capacity is the product of (i) the sum of highest economic maximums of simple-cycle gas resources and (ii) the number of hours in the year, 8,760 hours. Using the highest economic maximum may overstate the number of available hours, which would understate the percent of capacity on outage.
Figure 3-32 depicts maintenance outages for simple-cycle units as a percentage of total registered simple-cycle gas capacity at the asset-owner level. This figure uses the same methodology to determine unavailability as the previous figure.

**Figure 3-32 Maintenance outage percentage by asset owner, gas, simple-cycle**

For simple-cycle gas units, the capacity on outage for maintenance for each asset owner averaged about 15 percent. In 2019, 11 out of 35 asset owners have above average levels of unavailability due to maintenance outages. For many asset owners, the results are similar in 2017 and 2018. This could indicate there are differences in business practices and incentives among asset owners, such as the number of maintenance outages taken and the length of those maintenance outages.

Overall, the MMU is concerned about the increasing trend in outages as this affects both reliability and market efficiency. While the MMU maintains that there is a lack of appropriate incentives to promote resource availability, the increase in capacity on outage could also be due in part to circumstances unique to 2019.

Unique to 2019 was the May flooding of the Arkansas River. The flooding resulted not only in outages during the flood, but additional maintenance after the flood, affecting several gas units and hydro plants through June. Due to this flooding, two non-hydro units were not certified as deliverable capacity in time for summer.
Also, some variable energy resources, while converting from non-dispatchable to dispatchable, were out-of-service for large periods of the summer.

Low gas prices, including some negative prices, caused natural gas resources to be economic more often. As a result, these resources had less economic downtime than in previous years. Consequently, outages had to be taken during some economic periods. Moreover, previously infrequent outages (e.g., every 300 starts) became more prevalent with increased resource use. Higher use also revealed water supply issues—pressure and quality—that were not previously limiting for some natural gas steam units, leading to additional derates. Because of operating conditions this year, SPP exercised its tariff authority under Attachment U (rate schedule for compensation for rescheduled maintenance costs) to reschedule certain outages.

While these circumstances are unique, a robust market design can help prepare for the best possible response to unforeseen difficulties by appropriately incentivizing availability through appropriate price formation or generation availability compensation or true-up.

### 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. However, there are several outage-related areas where economic and reliability incentives may diverge.

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

The SPP market tends to have relatively low prices as evidenced in Figure 4–1. The load in SPP tends to procure 98 percent or more of its requirements in the day-ahead market. Typically, real-time generation procurement is mostly from virtual offers, load forecast errors, and generators with day-ahead positions.

During conservative operations and an energy emergency alert (EEA 1), when generation should be highly valued to avoid load shed, prices remained relatively low. Low prices in the real-time and day-ahead markets are less likely to provide financial incentive for generators to complete maintenance and repairs as soon as possible.

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71 See Section 3.5, Conservative Operations.
MISO provides a price floor during a maximum generation event based on the highest non-emergency offer. \(^{72}\) ERCOT removes some reliability units from pricing and applies a risk adder to the price in certain situations. \(^{73}\) In SPP, during conservative operations on August 6, ten resources were paid more than $100/MWh in make-whole payments, while the prices were about $25/MWh.

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 for new generation or demand response resources. In order for maintenance and repair costs to be recovered, the value a resource provides must be reflected in the market price. The current pricing mechanisms are not sending proper price signals to incentivize generation availability.

The MMU recommends that SPP and its stakeholders review price formation rules to consider if prices (i) appropriately incentivize generation availability during emergencies and outages and (ii) would likely reduce outage volume and duration and increase the value of fuel certainty.

### 3.4.2.2 Resource adequacy incentives

The resource adequacy requirement, Attachment AA to the tariff, lacks appropriate incentives for resources to remain available. In particular, anticipated availability of summer capacity is evaluated on February 15. Currently, no tariff mechanism addresses units that were claimed as capacity, but become unavailable after February 15. Instead, full summer capacity can be claimed, and the capacity deficiency payment can be avoided, even if that capacity is unavailable for the entire summer.

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.

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\(^{72}\) *MISO Tariff*, Schedule 29A. II. D.

\(^{73}\) *ERCOT Protocols*, Section 6.5.7.3.1
resources, particularly in the event that wind resources experience a decline in output. Yet nothing in the resource adequacy requirement mandates a minimum level of realized availability. The MMU believes that improved financial mechanisms could incentivize market participants to keep adequate resources available to serve peak load and planning reserve obligations. Alternatively, these resources claimed for capacity adequacy could be considered in a must offer requirement.

Some resources claimed for resource adequacy credit experienced natural gas outages as a result of interruptible service. Others experienced fuel curtailments despite possessing firm service. This is often due to pipeline maintenance which occurs predominantly in the summer months. Because of very low natural gas prices, gas-powered generation was at an all-time high for the 2019 summer. As gas-powered resources are serving an increasing portion of load, the importance of proper incentives is essential to reliability. As gas-powered generation increases, efforts should increase to align incentives with desired behavior.

Incentivizing availability in the resource adequacy requirement does not necessarily depend on the day-ahead and real-time market rules. The day-ahead and real-time markets require only available resources to participate in the market and do not have requirements for resources to be available for a minimum number of intervals. Nevertheless, the absence of availability requirements in the resource adequacy requirement undermines its purpose of ensuring adequate resources will be able to serve load reliably. Addressing availability in the resource adequacy requirement could be pursued independently of improvements to the day-ahead and real-time markets.

SPP and its stakeholders could consider a mechanism to reward resources that perform more reliably and are available when needed by SPP operations. One option is for resources with higher than required realized availability be paid by resources with lower than required realized availability. Compensating units with excess realized availability may encourage asset owners to

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74 SPP Open Access Transmission Tariff, Sixth Revised, Volume No. 1, Attachment AA, Section 9
75 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.
76 Generally, outages must be approved by SPP’s outage approval process. Non-forced outages are not approved if they pose a significant reliability risk. Additionally, the day-ahead and real-time markets have physical and economic withholding rules that guard against unreasonable outages.
minimize downtime by minimizing part repair or replacement delays, storing adequate spare parts on-site, scheduling repair and maintenance work during off-peak times and minimizing unnecessary work stoppages. Without realized capacity incentives, asset owners are incentivized to minimize repair costs at the expense of availability, which is detrimental to system reliability.

Alternatively, the amount of capacity a resource can count toward the resource adequacy requirement could be its tested capacity discounted by its availability rate from the previous year or season. The previous availability rate could be derived from the days most important to reliability such as a certain season, yearly average, or conservative operations days.

Another option is to require a percentage of capacity used to satisfy the resource adequacy requirement to be offered in the day-ahead and real-time markets and considered by the must offer provisions.

SPP should consider these options and others to ensure that the resource adequacy is effective to serve load reliably.

3.4.2.3 Outage coordination methodology

Resources are not required to enter an outage request for outages less than 25 MW, yet the tariff requires registration at 10 MW. SPP should consider aligning the minimum gross reduction in capacity threshold for outage reporting with the threshold for registration requirement. Market participants and generator operators generally adhered to the Conservative Operations Alert notice to report all outages during the conservative operations event.

Resources that are in reserve shutdown, but 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

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77 SPP Reliability Coordination Outage Coordination Methodology, Section 3 Generation Outages and Derate Submission Requirements; and SPP Open Access Transmission Tariff, Sixth Revised, Volume No. 1, Attachment AE, Section 2.2(6).
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 MMU highly recommends that SPP update the Outage Coordination Methodology to require review of all reserve shutdown outages and provide approval through the existing 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. Moreover, a forced outage (due to a failed pump, for example) with a planned or opportunity maintenance outage for a pipeline requires the participant to submit two different outage requests to SPP for approval. The MMU has observed insufficient, omitted, delayed, and incorrect outage information that does not meet the requirements of the outage coordination methodology.

Because outage submissions are intended to be used for assessing real-time and future reliability of the bulk electric system, the MMU recommends SPP enhance and that market participants adhere to the outage coordination methodology. Material misstatements of outage information could be considered providing false information to the RTO and may result in referral to FERC.

3.4.2.4 Pipeline maintenance

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: summer. These pipeline outages coincide with peak annual electric demand. Specifically, resources with interruptible service were often interrupted and several pipelines were not filling nominations.

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78 Reliability Coordinator Outage Coordination Methodology, https://www.spp.org/documents/56881/spp%20rc%20outage%20coordination%20methodology%201.0.pdf
79 Ibid., Section 1
80 18 CFR § 35.41
made after the timely cycle. Incentives are insufficient to change behavior for this predictable generation shortage. Rules should incentivize procurement of firm natural gas service as well as investment in secondary and/or stored fuel sources for capacity resources.81

3.4.2.5 Fuel procurement

Although SPP and market participants made adjustments to the market commitment schedule through the stakeholder process, natural gas timely nominations are still due prior to day-ahead commitments.82 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 must 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.

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.

3.4.2.6 Summary

Outages appear to be causing circumstances that are detrimental to reliability. Therefore, the upward trend of outages from 2017 to 2019 can be cause for reliability and market concerns.

The MMU recommends the use of economic incentives to drive behavior that increase reliability. Specifically, the MMU recommends review of price formation to consider if prices appropriately

81 While expectations are laid out in the planning criteria (four hours), the Commission required this to be added to SPP’s tariff for this to be enforceable (ER19-460, EL19-101) p. 59-65.
82 Docket No. ER19-2681.
incentivize generation availability, which would reduce outage capacity and increase the value of fuel certainty.

SPP could:

1) Consider a mechanism to reward resources that perform more reliably and are available when needed by SPP operations, and

2) Consider aligning the minimum gross reduction in capacity threshold for outage reporting with the threshold for registration requirement.

SPP should:

1) Update the Outage Coordination Methodology to require review of all reserve shutdown outages and provide approval through the existing process,

2) Enhance and adhere to the outage coordination methodology,

3) Review rules to consider if they appropriately incentivize procurement of firm natural gas service, as well as investment in secondary and/or stored fuel sources, and

4) Review rules to consider if they appropriately incentivize procurement of the most reliable lowest cost natural gas service, firm timely natural gas service, as well as investment in secondary and/or stored fuel sources.

See Chapter 8 of this document for a full list of recommendations.

3.5 CONSERVATIVE OPERATIONS

In 2019, the SPP Balancing Authority Area (BAA) called for conservative operations on ten different occasions, covering 35 days. Before 2019, SPP never called for conservative operations.

Conservative operations indicates the need to operate the SPP BAA more conservatively in order to avoid an emergency. During conservative operations, the SPP Balancing Authority (BA), in

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83 SPP BA Emergency Operating Plan, Section 9, https://www.spp.org/documents/58740/spp%20ba%20emergency%20operating%20plan_v%207.0.pdf.
coordination with the SPP Reliability Coordinator (RC) may take actions including, but not limited to:

- Operating with greater unit commitment timeframes, including selecting resources out of the multiday reliability assessment (MDRA) which occurs before the day-ahead commitments;
- Operating with increased operating reserve requirements; and
- Operating with an increased reliability margin.

During this time, stakeholders are encouraged to ensure resource plans are current, particularly startup and run times; report any weather-limited resources; and report fuel shortages and concerns.

In addition, the SPP BAA issued an Energy Emergency Alert 1 (EEA 1) on August 6. This was the first EEA 1 issued since the start of the Integrated Marketplace in March 2014 and resulted in every available unit being committed. The SPP Balancing Authority requests that the SPP Reliability Coordinator issue an EEA 1 if it is concerned about sustaining contingency reserves while all available resources are committed to meet (i) forecasted or actual firm load, (ii) firm transactions, and (iii) operating reserve commitments.

During an EEA 1, the SPP BA will take the following actions:

- Issue a maximum emergency generation notification;
- Identify and curtail non-firm external energy sales;
- Commit all available resources that are needed, including resources in reliability only status or are currently offline;
- Recall grid switching capable resources;

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84 SPP BA Emergency Operating Plan, Section 6.3, [https://www.spp.org/documents/58740/spp%20ba%20emergency%20operating%20plan_v%207.0.pdf](https://www.spp.org/documents/58740/spp%20ba%20emergency%20operating%20plan_v%207.0.pdf)
• Identify generation outages that can be postponed;

• Identify the pertinent transmission outages that can be recalled; and

• Utilize maximum emergency operating limits of resources currently online.

On August 6, SPP issued a Conservative Operations Alert starting at 09:00. Loads were high across the footprint, while wind generation was at unusually low levels, and all able resources were brought on-line. Real-time situations resulted in SPP operations declaring an EEA 1 at 14:45. Though required by the SPP BA Emergency Operating Plan, a maximum emergency generation notification was not issued. A timeline of events for the day85 follows:

09:00  SPP declared conservative operations

13:00  Reliability status generation committed

13:30  290 MW resource tripped off-line

14:45  SPP declared EEA 1

14:47  SPP issued operating instruction for 478 MW of capacity of grid-switchable resources to be brought back into SPP from ERCOT

15:14  SPP curtailed non-firm export schedules

19:00  SPP declared the EEA 1 was over

Figure 3–33 below illustrates the marginal energy price, not including costs of congestion and losses, during conservative operations and the EEA 1.

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In the hours before 14:00, real-time energy prices, excluding costs of congestion and losses, were generally in the $20/MWh to $30/MWh range. Starting at 14:05, before the EEA 1, the real-time energy prices jumped from around $28/MWh to about $1,300/MWh until 14:45 when SPP issued the EEA 1. The energy price remained around $1,300/MWh for only two more intervals and then, at 14:55, dropped to the $300/MWh to $600/MWh range for four intervals. At 15:15, the energy price returned to around $25/MWh and remained there until SPP ended the EEA 1.

High prices lasted for only six intervals of the energy emergency. The energy price increased before the EEA 1, as expected. However, when SPP issued the energy emergency, the energy price quickly returned to a typical price.

The MMU, along with some stakeholders, are concerned that prices during the EEA 1 event did not reflect emergency conditions. During this period, the additional generation SPP depended

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86 SPP experienced operating reserve scarcity pricing with regulation-up, spinning reserve, and supplemental reserve prices similar to the high energy prices.
on to address emergency conditions lowered prices. Demand response resources could be an effective option in these emergency conditions, however, the low prices experienced do not incentivize investment in demand response resources. The MMU recommends that SPP and stakeholders consider creating reliability pricing rules for EEAs and maximum generation events to economically incentivize reliable generator behavior.\textsuperscript{87}

\textsuperscript{87} See recommendations in Chapter 8.
Unit commitment and dispatch processes
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:

- Day-ahead market prices averaged $22.04/MWh in 2019, down roughly twelve percent from 2018. The average real-time price for 2019 was $20.85/MWh, a decrease of fifteen percent from 2018. Lower gas prices, as well as higher wind penetration levels appear to be a large contributor for the decrease.

- The price differences in the SPP North and South hub remained relatively the same, with only a $2/MWh average price difference between the two in 2019. The price convergence between the regions can be primarily attributed to reductions in congestion due to transmission expansion, as well as a milder summer in the southern region.

- Price divergence between the day-ahead and real-time markets continued to increase in 2019, climbing 140 percent to $1.20/MWh from $0.50/MWh in 2018. Analysis has found that wind forecast errors, under-clearing of renewable resources, and capacity committed after the day-ahead market are drivers for the divergence.

- The frequency of negative price intervals doubled from 2018. Just under seven percent of all intervals in the real-time market had negative prices, up from the three and a half percent in 2018. The MMU remains concerned about the 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.

- The average make-whole payment per megawatt-hour for resources committed in real-time was $19.64/MWh in 2019, up from the $18.94/MWh in 2017 and $14.73/MWh in 2018.

- One resource received $6.5 million dollars in make-whole payments, with 99 percent of those payments coming from the real-time market. This resource is in an area with
frequent congestion and most of its make-whole payments stem from manual commitments needed to control regional transmission issues.

- Roughly 80 percent of real-time make-whole payments’ costs were allocated to loads, virtual offers, exports, and sub-station power that withdrew more in real-time than their day-ahead market cleared megawatts. Virtual offers were the largest source of payments, paying for just under 50 percent of the 2019 total real-time make-whole payments.

- Revenues have been insufficient to support the cost of new entry of scrubbed coal, advanced combined-cycle, and advanced combustion turbine generation since the inception of the Integrated Marketplace, and 2019 was no exception.

### 4.1 MARKET PRICES AND COSTS

This section reviews market prices and costs by focusing on the fuel prices, price volatility, negative prices, operating reserve prices, and market settlement results. Overall, annual energy prices remained stable compared to previous years, with just a slight decrease in both the day-ahead and real-time prices in 2019. However, annual numbers may mask underlying issues related to market flexibility and efficiency. For instance, increasing periods of price volatility and instances of negative prices are discussed later in this chapter.

#### 4.1.1 ENERGY MARKET PRICES AND FUEL PRICES

Figure 4–1 below compares day-ahead and real-time prices in SPP between 2014 and 2019 with natural gas prices.

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88 Day-ahead and real-time prices shown are calculated using the average of the SPP North and SPP South hub prices for each period.

89 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.
Historically, electric market prices have followed the cost of natural gas. As natural gas prices have remained low overall, so have SPP market prices. The average gas cost in 2019, using the price at the Panhandle Eastern Pipeline (PEPL), was $1.93/MMBtu down $0.66/MMBtu from 2018. Day-ahead market prices averaged $22.04/MWh in 2019, down about twelve percent from 2018. The average real-time price for 2019 was $20.84/MWh, a decrease of fifteen percent from 2018.

In addition to gas prices declining from 2018 to 2019, wind generation as a percent of load increased steadily year over year, driving up the percentage of intervals with negative prices as seen in Figure 4–18 for day-ahead intervals and Figure 4–19 for real-time intervals.\(^90\)

Figure 4–2 illustrates day-ahead and real-time energy prices, as well as gas costs, on a monthly basis for 2019, along with an annual comparison for the past three years.

\(^{90}\) Wind generation as a percentage of consumed load averaged 29 percent in 2019. However, October 2019 averaged 39 percent.
On a monthly basis, natural gas prices averaged around $1.93/MMBtu for 2019 at the Panhandle Eastern hub. As seen in Figure 4–2, gas prices at the Panhandle Eastern hub dropped in the spring of 2019 and stayed below $2/MMBtu for the remainder of the year. Day-ahead prices were highest in March at around $27/MWh, and real-time prices were highest in May at around $24/MWh. Prices were lowest in October, with day-ahead prices just under $17/MWh and real-time prices below $14/MWh, as periods of high-wind generation coincided with low loads and low natural gas prices.

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.
As shown above, on-peak prices tend to average about $10/MWh higher than off-peak prices, in both day-ahead and real-time. In the real-time market, the largest on-peak/off-peak price spread was just over $17/MWh in July, and the smallest was just under $6/MWh in December. In the day-ahead market, the largest on-peak/off-peak price spread was just under $14/MWh in September and the smallest was just over $6/MWh in January.

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. However, as natural gas prices have fallen, the short-run marginal costs of natural gas fired generation have been more competitive with coal fired generation, and in some instances displacing coal generation. Figure 4–4 compares various fuel price indices with real-time prices.
This figure shows that regional natural gas prices trended down from 2017 to 2019, especially during the spring of 2019. The Henry Hub gas price averaged $2.60/MMBtu for 2019, while the Southern Star was $2.09/MMBtu and Panhandle Eastern averaged $1.93/MMBtu in 2019. The difference between Henry Hub prices and Panhandle Eastern and Southern Star prices has grown over the last few years, with differences averaging $0.33/MMBtu in 2017, $0.57/MMBtu in 2018, and $0.66/MMBtu in 2019. 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 trade hubs. Much like last year, natural gas prices in West Texas (Waha and El Paso) have been less than $1/MMBtu on a number of days, and in fact, had some periods of negative natural gas prices, which have helped high heat rate units in this area be profitable.

91 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.
Coal prices have remained relatively stable since 2016. The price for 8,400 Btu/lb. at Powder River Basin increased from $0.55/MMBtu in 2018 to $0.58/MMBtu (up over 5 percent) in 2019, and the 2019 price for 8,800 Btu/lb. was the same as 2018 at $0.71/MMBtu.

Controlling for changes in fuel prices helps to identify the underlying changes in electricity prices from other factors. Figure 4–5 below adjusts the marginal energy cost for changes in fuel costs.

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

As the figure shows, fuel-adjusted marginal energy costs were higher in 2019 compared to nominal marginal energy costs both annually and all months after March. While the average nominal marginal energy cost in 2019 decreased 14 percent from 2018, the fuel-adjusted

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92 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.

93 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.

94 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. 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.

95 Nominal marginal energy costs represent the non-fuel adjusted marginal energy costs.
marginal energy cost increased by eight percent. The natural gas spot prices in the previous years which were used to establish the adjusted fuel prices were greater than those seen in 2019, thus inflating the fuel-adjusted energy cost. The largest differences between nominal and fuel-adjusted prices occurred in August, where the fuel-adjusted energy cost was roughly $6/MWh higher than the real-time energy cost.

SPP has two hubs: the SPP North hub and the SPP South hub. The SPP North hub represents pricing nodes in the northern part of the SPP footprint, generally in Nebraska. The SPP South hub represents pricing nodes in the south-central portion of the footprint, generally in central Oklahoma. Typically, the SPP South hub prices exceed the SPP North hub prices. This was again true in 2019, but the separation has decreased when compared to years prior to 2018. 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. In May 2018, a major upgrade was completed in the upper-central region of Oklahoma which relieved a large component of the north to south congestion flows.

Figure 4–6 shows the average day-ahead prices and Figure 4–7 shows the average real-time prices at the two SPP market hubs.

**Figure 4–6 Hub prices, day-ahead**

![Graph showing average day-ahead prices for the two SPP market hubs from 2017 to 2019. The graph displays the price trends over time, with two lines representing the SPP North and South hubs.]
On an annual basis, the North and South hub prices have converged when compared to 2017. The North hub prices averaged around $20/MWh, and South hub prices averaged around $21/MWh for 2019. Historically, the South hub price had been on average about $5/MWh higher than the North hub price. As stated earlier, this reduction in price spread can be attributed to reductions in congestion, which was primarily a result of the addition of the second circuit of the Woodward to Mathewson 345kV line in mid-2018.

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 2019, the North hub exceeded the South hub in the months of February, March, April, May, and December in both the day-ahead and real-time markets. This is one month more than 2018.

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 4–8.
Average on-peak day-ahead prices dropped at both the North and South hubs of SPP. In fact, all of the other RTO’s day-ahead average hub prices at the SPP seams decreased with the exception of ERCOT. The average on-peak day-ahead SPP South and North hub prices were just a dollar different on average. The transmission expansion completed in mid-2018 appears to be still relieving the congestion previously seen between the North and South regions. The ERCOT hub price increases were rather significant, increasing by over 14 percent from 2018 to 2019, however, this is less than the 50 percent increases seen from 2017 to 2018. These price increases were likely driven by tight capacity conditions, particularly during the summer months.

### 4.1.2 ENERGY PRICE VOLATILITY

Price volatility\(^96\) in the SPP market is shown in Figure 4–9 below. As expected, day-ahead prices are much less volatile than those in real-time. The day-ahead market does not experience the 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.

\(^{96}\) Volatility is calculated as the standard deviation for 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.
Volatility in the 2019 day-ahead market has climbed three percent from 2018, while the 2019 real-time volatility increased 17 percent from 2018. The increase in volatility appears to stem from inter-day changes in forecasted generation.

Price volatility varies across the SPP market footprint for asset owners primarily because 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.
Similar to 2017 and 2018, southwest Missouri/southeast Kansas area had a high volume of volatility in 2019. This area was impacted by external flows and congestion during the year, mostly on the Neosho-Riverton constraint, a market-to-market flowgate, which is discussed in more detail in Section 5.1.4.1. Areas in the Texas panhandle, west Texas and eastern New Mexico all experienced higher levels of volatility in 2019, as well.

**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. Figure 4–11 shows day-ahead and real-time prices monthly for 2019 and annually for the past three years.
Figure 4-11  Day-ahead and real-time prices

Figure 4-12 below shows the monthly difference between day-ahead and real-time prices for 2019, as well as annually for the past three years.

Figure 4-12  Difference between day-ahead and real-time prices

Day-ahead prices exceeded real-time prices every month except April and May. April had the highest spread of real-time prices above day-ahead at $1.70/MWh, while March had the highest spread of day-ahead prices over real-time at $5.70/MWh. The day-ahead average energy price was $1.20/MWh higher than real-time in 2019, this is up from fifty cents in 2018. In 2017, the average real-time prices were 32 cents higher than the average day-ahead prices. Going back to
the beginning of the Integrated Marketplace in 2014, 2017 was the only year that had an annual premium for real-time prices. Real-time price volatility in conjunction with scarcity pricing drove the annual real-time price premium in 2017.

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.97

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 accounted for in the day-ahead market, drives down real-time prices.

Many factors cause prices to diverge between the day-ahead and real-time markets. Some of those factors may include, but are not limited to:

- Day-ahead offers may include premiums to account for uncertainty in real-time fuel prices.98
- Load and wind forecast errors can cause differences in the real-time market results.
- Participants may not offer in all of their load or 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, affect the SPP real-time market.
- Changes in imports and exports from other systems in the real-time markets.

97 For further information on ramping issues, see Section 3.2.1.
98 Additionally, Revision Request 239 allowed historic fuel cost uncertainty to be considered in the development of mitigated energy offers.
• Unanticipated weather changes affect the real-time markets.

Price divergence\(^99\) between the day-ahead and real-time markets at the system level is shown in Figure 4–13 below. Market participants may be willing to pay a premium for more certainty in prices. 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.

**Figure 4-13 Price divergence**

The absolute price divergence has increased by nearly 26 percent from 2017 to 2019, climbing from $8.43/MWh to $10.59/MWh. Analysis by the MMU has found that under-clearing of renewable resources and short-term ramping limitations are primary drivers of this divergence. The MMU made recommendations in the 2017 Annual State of the Market report to address the under scheduling of renewable resources and to implement a ramping product. The MMU

\(^{99}\) 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.
anticipates that addressing these two recommendations would improve absolute price divergence and are currently being addressed though the RTO Holistic Integrated Tariff Team initiatives.\textsuperscript{100}

Figure 4–14, below, shows the marginal energy costs for both the day-ahead and real-time markets during on-peak hours after controlling for scarcity events.\textsuperscript{101} Figure 4–15 shows the same information, but for off-peak hours.

\textbf{Figure 4-14 On-peak marginal energy prices, excluding scarcity hours}

\textsuperscript{100} The Holistic Integrated Tariff Team was initiated in March 2018 to take a holistic look at the many issues challenging the SPP region. For more information, see: https://spp.org/organizational-groups/board-of-directors-members-committee/holistic-integrated-tariff-team/.

\textsuperscript{101} These numbers reflect only hours where scarcity demand curves where not applied for any interval during the hour. SPP uses scarcity demand curves for intervals when ramp or capacity requirements cannot be met through dispatch. Scarcity demand curves are discussed in detail in Section 3.2.1.
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. Both charts clearly show that day-ahead prices are usually at a premium when compared to real-time prices (excluding scarcity pricing), particularly in the off-peak hours. In 2019, day-ahead marginal energy costs for all hours, were just over 26 percent higher than real-time prices. This is higher than the 19 percent price divergence in 2018 and the 26 percent in 2017. The majority of the price decrease in 2019 can be attributed to lower gas prices and to the high volume of price spikes seen in the final quarter of 2018 compared to 2019.

The main contributors influencing the price differences between markets are offered megawatts versus cleared megawatts of wind resources in the day-ahead market, reliability unit commitments needed in real-time not seen in the day-ahead market, and increased importing after the day-ahead market. In fact, only 84 percent of the wind generation was cleared in the 2019 day-ahead market, down one percent from 2018. This changes the supply curve in real-time.

102 The MMU observed that 78 percent of the hours in 2019 had higher marginal energy cost in the day-ahead market than the real-time market. This is after removing any hours associated with scarcity pricing.
time by shifting it outward and causes real-time prices to drop relative to the day-ahead market. Furthermore, the market appropriately honors the minimum submitted limits of all committed resources. With the unanticipated generation, many non-wind units are dispatched down by the market to their minimum capacity limits, allowing wind to set prices. When this happens, prices often go negative as the energy offers for wind units are typically negative to account for production tax credits.\(^\text{103}\)

Figure 4–16 shows average hourly incremental differences in megawatts produced between the real-time and day-ahead market in 2019.

**Figure 4-16 Average hourly real-time generation incremental to day-ahead market**

Wind generation had 58 percent of the 2,300 MW of incremental real-time generation in 2019, with an hourly average of 1,366 MW of additional generation in real-time. Self-committed generation accounted for an additional 237 MW and reliability unit committed or manually committed generation averaged about 445 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 296 MW in real-time market net imports compared to the day-ahead. This results in additional capacity committed in day-ahead not needed in real-time. Averaging 660 MW an hour, net virtual positions helped to offset the additional generation, but only accounted for about 28 percent of

\(^{103}\) Negative prices are discussed in detail in Section 4.1.4.
the difference for the year. This is up from the 490 MW (27 percent) in 2018 and 650 MW (34 percent) in 2017.

Figure 4–17 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.

**Figure 4-17  Day-ahead wind offered versus cleared**

In 2017 and 2019, 93 percent of the generation offered cleared in the day ahead, while in 2018, this was 96 percent. While the wind offered in the day ahead was closer to forecast in 2019 compared to 2018, the percent of generation that cleared decreased. 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. 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-scheduling 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 for 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 increased from 2018 to 2019, as shown in Figure 4–18. This increase was primarily due to an increase of negatively priced wind-generation supplying a relatively stable demand for energy.

**Figure 4-18 Negative price intervals, day-ahead, monthly**

In 2019, slightly less than two percent of all asset owner intervals in the day-ahead market had prices below zero, as shown in Figure 4–18. This is up from the one percent of all intervals in 2018 and down from the three percent in 2017.

While the same pattern holds in the real-time market (see Figure 4–19), negative price intervals in the real-time market occurred over three times as frequently than in the day-ahead market. October had the highest percentage of negative intervals in the day-ahead market, at just under six percent. This month also had the highest wind as a percentage of load, at 39 percent.

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104 Asset owner intervals are calculated as the number of asset owners serving load that are active in an interval. For example, if there 60 asset owners active in one five-minute interval throughout an entire 30 day month, the total asset owner intervals would be 518,400 for the month (60 asset owners * 288 intervals per day * 30 days).
The frequency of negative price intervals in the real-time market was just under seven percent of 2019 intervals, up from just over three percent in 2018. Negative prices in the day-ahead market were almost exclusively between −$0.01/MWh and −$25/MWh, with only 0.01 percent of intervals with negative prices having prices lower than −$25/MW. However, in the real-time market just over one percent of intervals with negative prices had prices lower than −$25/MW.

Additionally, occurrences of negative prices in the day-ahead market are most prevalent in the overnight, low-load hours as shown in Figure 4–20.

**Figure 4–20 Negative price intervals, day-ahead, by hour**
This figure shows that the day-ahead negative price intervals in 2019 during overnight hours are below the 2017 numbers, but higher than 2018 levels. Also of note, during the on-peak hours, less than 0.6 percent of intervals in the day-ahead market were negative in 2019. This is slightly higher than 2018 where only 0.2 percent of the on-peak, day-ahead hours were negative.

Negative price intervals in the real-time market (see Figure 4–21) follow the same pattern as the day-ahead market with most negative price intervals occurring in the overnight, low-load hours.

**Figure 4-21 Negative price intervals, real time, by hour**

These negative price intervals in the real-time market occur much more frequently than the day-ahead market, with a 2019 peak of 16 percent of intervals in real-time in the third hour of the day, compared to a peak of just over seven percent in day-ahead. During 2019, the first five hours and last hour of the day experienced negative prices over 10 percent of the time. However, in 2018 no intervals had negative prices over 10 percent of the time. In 2019, the real-time market had an average of about four percent of intervals with negative prices during the on-peak hours. This is up from the 3.5 percent seen in 2018. Overall, the frequency of hourly negative real-time prices was very similar to 2017.

At the asset owner level (for those serving load), the distribution of negative price intervals during 2019 clustered around the footprint average, as shown in Figure 4–22.
In 2019, seven asset owners experienced negative prices in more than 10 percent of intervals. This is in contrast to 2018, where only one asset owner experienced negative prices in excess of 10 percent of intervals. Seventy-five percent of the market participants received negative prices for five percent or more of the intervals in 2019. This is in stark contrast to 2018 where only ten-percent experienced negative prices more than five 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 may be 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 wind resources not forecasting the full amount 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 next several 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 the systematic absence of some variable energy resources’ forecasted outputs in the day-ahead market to improve market efficiency. These issues are discussed further in Chapter 8.

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.

Average monthly real-time prices for operating reserve products are presented in Figure 4–23.

**Figure 4–23 Operating reserve product prices, real-time**

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 averaging less than two dollars on an annual basis.

Day-ahead and real-time price patterns vary across the operating reserve products, see Figure 4–24 through Figure 4–27.
Figure 4-24 Regulation-up service prices

From 2018 to 2019, the average real-time market clearing price for regulation-up increased from $9/MW to $11/MW. Average day-ahead regulation-up market clearing price increased almost a dollar from 2018 to 2019, with the average day-ahead regulation-up 2019 price at $9.45/MW. Monthly prices for regulation-up were highest in the peak wind months during the spring and especially in the fall. The high prices during these periods can mostly be attributed to higher wind penetration levels during these periods.

Figure 4-25 Regulation-down service prices
Regulation-down market clearing price in the real-time market averaged about $7.60/MW in 2019, up from the 2018 average price of $6.40 but down from the average in 2017 at nearly $10/MW. The higher 2017 prices can generally be attributed to the high levels of wind production in that year, particularly in high wind and low load months. During these months, many thermal units were operating at their economic minimums, which are lower than regulation minimums. Costs are higher to move these units up to the regulation range. Day-ahead regulation-down market clearing prices averaged $4.60/MW for the year. This is in line with the 2018 average of $4.68/MW.

Figure 4–26  Spinning reserve prices

The market clearing price for real-time spinning reserves increased $0.13 from 2018 to 2019 at $5.17/MW. April experienced the highest monthly market clearing price in 2019 for real-time spinning reserves, at just over $8.80/MW. This can mostly be attributed to the higher volume of operating reserve scarcity events in that month. Day-ahead spinning reserves had a slightly higher annual average than real-time at almost $5.90/MW.
Supplemental reserve market clearing prices remained low in both markets, with prices averaging about $1.75/MW, up from the $1.04/MW average in 2018. This price does not indicate a large need for generators to be standing by. On the other hand, there have been several concerns raised by SPP operations staff regarding wind uncertainty and outages. Wind uncertainty is better addressed through the proposed ramp product and the uncertainty product. Increased outages and outage duration may point to issues with price formation as discussed in Section 8.1. On a monthly basis, the August average real-time market clearing price for supplemental reserves was just under $4/MW. This is the highest price since May 2014, with generator outages contributing to tighter conditions for supplemental reserves.

Regulating units are compensated for mileage costs incurred when moving from one set point instruction to another. These mileage payments are paid directly through the operating reserve prices shown for regulation-up and regulation-down, as shown in Figure 4–28. 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.
On an annual basis, average monthly regulation-up mileage prices for 2019 remained at roughly $10/MW. Average monthly regulation-down mileage prices in 2019 averaged $7.70/MW, down from the $8.14/MW average in 2018, this matches the pattern in regulation-down mileage prices prior the anomaly year of 2017. The high prices in 2017 can be attributed to one participant’s high bidding patterns during that year.

The MMU analyzed regulation mileage prices in 2017 and found a design inefficiency. This design inefficiency was still present throughout 2019. 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.\(^{105}\) 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 if this is the highest mileage price 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

\(^{105}\) $1 + $36 \times 0.25 \text{ percent} = $10
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 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 a $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 4–29 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 2019, roughly twice as much was charged for mileage buyback as was paid out for excess mileage deployment, with $4.4 million being paid for excess mileage and $8 million being charged for unused mileage. This ratio of charges to payments is consistent with all prior years. These net charges reduce the profitability of resources clearing regulation.

The MMU is concerned that participants with resources frequently deployed for regulation will have an incentive to inflate the mileage prices by offering in $0 regulation 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 which 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.

4.1.6 MARKET SETTLEMENT RESULTS

The day-ahead market accounted for 99 percent of the energy consumed in the Integrated Marketplace. This is one percent higher than 2018. Figure 4-30 shows that approximately 262 terawatt-hours of energy were purchased in the day-ahead market at load settlement locations, of which just less than six terawatt hours were in excess of the real-time consumption, requiring a sale back to the market.
Negative gigawatt hours denote withdrawals from the grid. Negative cash flows denote charges to load-serving entities. Positive gigawatt hours represent sales of day-ahead gigawatt hours back to the real-time market and negative cash flows represent payments to load owners for those sales. As stated above, during several hours of 2019 load over purchased in the day-ahead market causing a sale back in real-time. However, there were also several hours where the load consumed in real-time was greater than the day-ahead cleared quantities.

In aggregate, just under six terawatt hours of energy was purchased in the real-time market because the real-time demand was higher than that of the day-ahead market. The close relationship of day-ahead load consumption to real-time load consumption is a sign of an efficient day-ahead market. The below charts illustrate that while generation output stayed relatively the same as 2018, the payments for those generated megawatts where down from their 2018 levels. This can be attributed to the lower day-ahead and real-time energy prices seen in Figure 4-1.

Day-ahead generation accounted for 90 percent of generation settled in the market, which is the same percentage as 2018 and a one percent increase from 2017. Figure 4-31 presents the settlement of SPP generators.
Figure 4–31  Energy settlements, generation

Positive gigawatt hours denote injections into the grid. Positive cash flows denote payments to generators. Negative gigawatt hours represent repurchases in the real-time market and negative cash flows represent charges to generators for those repurchases. Ten percent of the energy cleared in the day-ahead market was settled by purchasing energy in the real-time market rather than generating the energy, which is up one percent from the trailing three year average.

SPP plays the role of the customer in the operating reserve market. At hour ending 6:00 AM on the day before the operating day, SPP posts the forecasted amount of each operating reserve product that is to be procured during each hour. This data sets the demand for the products for the day-ahead market. SPP can change the demand levels after the clearing of the day-ahead market, but this a rare occurrence. Even though the demand is essentially the same between the day-ahead market and the real-time market, there is considerable activity with respect to shifts in the clearing of the operating reserve products in the real-time market. Figure 4–32 presents the settlements data for operating reserves.
Sales represent the cleared gigawatt hours for ancillary services in each market. Purchases represent the repurchase of day-ahead cleared ancillary service in the real-time market.

A large percentage of day-ahead sales (35 percent) are settled in the real-time market by repurchasing the operating reserve product rather than supplying the service in the real-time market. This is in contrast to 10 percent of the real-time energy generation in excess of day-ahead cleared generation, which is settled at real-time prices.

Sixty-four percent of the 2019 real-time regulation-up service was settled at day-ahead prices, one percent less than previous year. The corresponding percentages for regulation-down service, spinning reserves, and supplemental reserves are 63 percent, 68 percent, and 68 percent respectively. These results were similar with the respective numbers in 2018 of 63 percent, 69 percent, and 61 percent. This essentially means that operating reserve products are being moved around to different resources, due to their day-ahead and real-time clearing, in about the same volumes as last year. This causes some resources to buy back their day-ahead cleared megawatts at real-time prices, while other resources clear those same quantities of megawatts and get paid real-time prices for their clearing.\(^{106}\)

\(^{106}\) When ancillary service products become scarce, they borrow from their respective scarcity demand curves. This can make the aggregate cleared megawatts for each product different between the day-ahead and real-time markets even though the requirement did not change.
The above numbers represent the aggregate repurchases of ancillary service. However, it is important to analyze the repurchase rates at the resource level. The aggregate revenue from all 344 resources that cleared operating reserves was $81.7 million in 2019. Eight resources had net negative cash-flows on operating reserves for a total amount of $741,000. These negative cash flows are not inclusive of any margins gained on energy cleared in real-time that caused the purchase of the day-ahead positions for ancillary service. Even without evaluating those cash flows, there were only seven resources that lost money in 2019 on ancillary service products. In fact, 99 percent of those resources’ negative cash-flows from ancillary service products occurred at four wind resources that cleared regulation-down in the day-ahead market.

Resources that clear for contingency reserve in the day-ahead market and get deployed for a contingency reserve event could have to buy back the contingency reserve in intervals subsequent to the event at higher prices than they were paid in the day-ahead market. This is because resources deployed for the contingency reserve often get deployed to their maximum limits, which means those resources cannot clear contingency reserves in subsequent intervals as they have not had time to be dispatched down to clear the product. However, those intervals often have scarcity pricing, due to the product’s shortage, making the buyback expensive in relation to the amounts paid in the day-ahead market for the product.

Most resources had positive cash-flows from each ancillary service product, even without taking the money made on energy margins into account. Seventeen resources had negative cash-flows from regulation-down, four from regulation-up, four from spin, and 12 from supplemental. The total negative cash-flows for these resources’ products were $0.8 million, $0.7 million, $0.6 million, and $0.2 million, respectively. This numbers appear small considering the overall total of money transacting for energy and ancillary service in Integrated Market Place.

4.2 MAKE-WHOLE PAYMENTS

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, cleared offers and dispatch; and (2) reliability unit commitments based on real-time market prices, cleared offers, and dispatch. Combined-cycle resources can be cleared in both the day-ahead and real-time markets at the same time, which is unique to combined-cycles. 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.

For 2019, day-ahead market and reliability unit commitment make-whole payments totaled approximately $101 million, up forty percent from $72 million last year. Total make-whole payments averaged about $0.38/MWh for 2019, which is a substantial increase from the $0.26/MWh seen in 2017 and 2018. In comparison to other RTO/ISO markets, SPP’s make-whole payments per megawatt-hour of generation were in the middle, which varied from $0.17/MWh to $0.57/MWh in 2018.\footnote{2018 ISO NE State of Market Report, \url{https://www.potomaceconomics.com/wp-content/uploads/2019/06/ISO-NE-2018-SOM-Report_Final-1.pdf}} This $0.38/MWh represents the total cost of uplift in 2019 to all megawatts generated. However, roughly half of SPP’s generation in 2019 was provided by self-committed resources.\footnote{See Section 3.3, Figure 3–24.} These resources are not eligible for make-whole payment reimbursements. Only resources committed under reliability or market status are eligible for cost reimbursement.

Figure 4–33 illustrates the 2017 to 2019 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.
This shows that day-ahead make-whole payments per eligible megawatt have been going down over the last three years. This is likely due to decreasing gas prices and increasing wind generation as percentage of all generation. However, the real-time make-whole payments per eligible megawatt have been increasing. This can be partially attributed to the increased real-time market volatility and the need for rampable capacity. 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 $19.64/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 minimum-run times much longer than this period. This means that even if these resources are able to capture one to two intervals of the high 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 the proposed ramp capability and uncertainty products, if designed properly, will help provide the appropriate pricing and compensation mechanisms for meeting ramp capacity needs in the market. This includes reducing make-whole-payments and bringing transparency to the market. They will also help to better compensate resources that are

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109 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.
providing the much needed ramping flexibility, as well as reduce the need for manual commitments for capacity.

Figure 4–34 shows monthly and annual day-ahead make-whole payment totals by technology type. Figure 4–35 shows the same make-whole payment information for reliability unit commitment.

**Figure 4-34** Make-whole payments by fuel type, day-ahead

**Figure 4-35** Make-whole payments by fuel type, reliability unit commitment
Day-ahead make-whole payments constituted 32 percent of the total make-whole payments in 2019. Gas-fired resources represent about 83 percent of all make-whole payments, with 63 percent of all make-whole payments to simple-cycle gas resources through reliability unit commitment make-whole payments. While day-ahead make-whole payments increased 16 percent from 2018 to 2019, there were substantial increases in real-time make-whole payments. Real-time make-whole payments where nearly $70 in 2019, up nearly 53 percent from 2018.

Make-whole payments occur for several reasons, which include some of the following: local reliability commitments, uncaptured congestion 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. Make-whole payments to resources in the "other" category primarily represent payments to oil-fired resources. The increase in real-time make-whole payments in 2019 can primarily be attributed to more resources being brought on from the reliability unit-commitment processes, including manual commitment, for capacity needs. This increasing trend concerns the MMU, as it shows the rapidly increasing need for rampable capacity.

Figure 4–36 shows the share of each cause of make-whole payments in the real-time and day-ahead markets.

**Figure 4-36 Make-whole payments, commitment reasons**

<table>
<thead>
<tr>
<th>Real-time commitment reason</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Manual, SPP capacity</td>
<td>4.5%</td>
<td>24.9%</td>
<td>33.8%</td>
</tr>
<tr>
<td>Manual, SPP transmission</td>
<td>31.6%</td>
<td>27.5%</td>
<td>27.7%</td>
</tr>
<tr>
<td>Intra-day RUC</td>
<td>35.7%</td>
<td>26.1%</td>
<td>22.2%</td>
</tr>
<tr>
<td>Manual, voltage</td>
<td>6.4%</td>
<td>4.4%</td>
<td>6.6%</td>
</tr>
<tr>
<td>Manual, stagger</td>
<td>0.0%</td>
<td>0.9%</td>
<td>2.6%</td>
</tr>
<tr>
<td>Day-ahead RUC</td>
<td>7.5%</td>
<td>1.8%</td>
<td>2.4%</td>
</tr>
<tr>
<td>Short-term RUC</td>
<td>6.1%</td>
<td>13.7%</td>
<td>4.7%</td>
</tr>
<tr>
<td>Manual, intra-day RUC</td>
<td>6.1%</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Other</td>
<td>0.8%</td>
<td>0.3%</td>
<td>0.0%</td>
</tr>
<tr>
<td>Manual, day-ahead RUC</td>
<td>1.2%</td>
<td>0.0%</td>
<td>0.0%</td>
</tr>
</tbody>
</table>
Day-ahead commitment reason | 2017 | 2018 | 2019  
--- | --- | --- | ---
Day-ahead market | 73.2% | 93.7% | 99.7%  
Manual, voltage support | 26.8% | 6.3% | 0.3%

Over the last three 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 34 percent of the real-make-whole payments were paid to resources committed manually for capacity needs. Manual intra-day and day-ahead RUC commitments were removed as an option in 2018, thus make-whole payments that were attributed to those categories in prior years are now captured under other manual commitment codes.

There was an initiative in late 2017 to clean up the categorizing of manual commitments.\(^{110}\) Prior to the initiative operators often categorized capacity commitments under the intra-day RUC and day-ahead RUC manual codes. However, after the manual RUC codes were removed, manual commitments for capacity should all be coded under the SPP capacity code.

There a couple of things that appear to be driving the rise in manual commitments. Gas prices were down in 2019 causing many faster starting and faster ramping gas resources to get cleared in the day-ahead market and be dispatched up towards their effective maximum limits. When this happens, there is less rampable capacity available to the market to adjust for rapidly changing needs, causing the operators to manually commit resources to acquire rampable capacity. Many of these commitments were made to expensive fuel type resources.

Also, as shown in Section 2.4.1 wind generation as a percentage of total generation has been steadily increasing.\(^{111}\) Wind can be difficult to forecast, causing the market to be scarce rampable capacity, leading to the need for operator intervention. In fact, because of the emergency conditions seen on May 31, 2018 an Uncertainty Response Team was established by SPP. The Uncertainty Response Team consists of SPP Operations staff that provides daily assessments to ensure the SPP region has the required rampable capacity to serve demand after accounting for

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\(^{111}\) Section 2.4.1, Figure 2–19.
load, resource, and wind uncertainties. For instance, the Uncertainty Response Team looks back at a historical average of differences between forecasted generation needs and actual generation needs and takes the 95th percentile of deviation seen during the time assessed. If there is not enough rampable capacity available to meet the forecasted need plus the deviation assessed at the 95th percentile of historical averages, more capacity will be committed. This can lead to more make-whole payments as more resources are online, lowering prices as a result of increased supply.

As noted earlier in this section, SPP is working on both an uncertainty product and a ramping capability product. The MMU expects these products, if properly designed, to better preposition rampable resources. This should reduce the need for some of the excess capacity currently carried for uncertain events.

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 4–37 illustrates the level of make-whole payments associated with voltage support commitments.

**Figure 4–37  Make-whole payments for voltage support**

The make-whole payments stemming from voltage support commitments are up 82 percent from 2018.
The majority of SPP resources received modest total annual make-whole payments in 2019, as highlighted in Figure 4–38.

**Figure 4–38 Concentration of make-whole payments by resource**

Seventy-three percent of resources in SPP received less than $250,000 in make-whole payments in 2019. However, 17 resources received over $1 million, compared to just seven resources with $1 million make-whole payments in 2018. In fact, one resource received $6.5 million dollars in make-whole payments, with 99 percent coming from the real-time market. This resource is in an area with frequent congestion and most of these make-whole payments stem from manual commitments needed to control regional transmission concerns.

Figure 4–39 reveals there is concentration in the market participants that receive make-whole payments.
In 2019, there were 16 market participants that each received annual make-whole payments in amounts greater than $1 million. These 16 market participants accounted for 94 percent of the total make-whole payments paid out in 2019, which is exactly the same as 2018. Fifteen of the participants with $1 million in make-whole payments from 2019 also received over $1 million each in 2018 and 12 participants received over a $1 million in make-whole payments for each of the last three years.

In 2019, there were eight participants that received over $5 million each in make-whole payments and out of that three received over $10 million. The participant with the highest cost reimbursement received just under $18 million in make-whole payments in 2019, accounting for 18 percent of the make-whole payments.

### 4.2.1 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

<table>
<thead>
<tr>
<th></th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market participants</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>receiving make-whole</td>
<td>12</td>
<td>16</td>
<td>16</td>
</tr>
<tr>
<td>payments</td>
<td>5</td>
<td>5</td>
<td>8</td>
</tr>
<tr>
<td>% of make-whole payments</td>
<td>90%</td>
<td>94%</td>
<td>94%</td>
</tr>
<tr>
<td>by category</td>
<td>61%</td>
<td>57%</td>
<td>78%</td>
</tr>
<tr>
<td></td>
<td>18%</td>
<td>14%</td>
<td>43%</td>
</tr>
</tbody>
</table>
per-MWh rate for withdrawing locations in the day-ahead market was just under $0.11/MWh in 2019. This is approximately one and a half cents greater than the 2018 average, but the same as the 2017 average.

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 average real-time distribution has steadily been increasing, as has the total volume of real-time make-whole payments. The rate was $1.35/MWh for 2019, this is up from the $0.98/MWh in 2018 and the $0.91/MWh in 2017. There are eight categories of deviation and each category receives an equal amount per megawatt when the cost of make-whole payments is applied.

Figure 4–40 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 4–40 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>43,155</td>
<td>$55,372</td>
<td>79.67%</td>
<td>$1.28</td>
</tr>
<tr>
<td>Outage deviation</td>
<td>4,590</td>
<td>$7,126</td>
<td>10.3%</td>
<td>$1.55</td>
</tr>
<tr>
<td>Maximum limit deviation</td>
<td>1,553</td>
<td>$2,215</td>
<td>3.2%</td>
<td>$1.43</td>
</tr>
<tr>
<td>Status deviation</td>
<td>1,724</td>
<td>$2,437</td>
<td>3.5%</td>
<td>$1.41</td>
</tr>
<tr>
<td>Uninstructed resource deviation</td>
<td>611</td>
<td>$725</td>
<td>1.0%</td>
<td>$1.19</td>
</tr>
<tr>
<td>Reliability Unit Commitment self-commit deviation</td>
<td>640</td>
<td>$821</td>
<td>1.2%</td>
<td>$1.28</td>
</tr>
<tr>
<td>Reliability Unit Commitment deviation</td>
<td>226</td>
<td>$326</td>
<td>0.5%</td>
<td>$1.44</td>
</tr>
<tr>
<td>Minimum limit deviation</td>
<td>230</td>
<td>$481</td>
<td>0.7%</td>
<td>$2.09</td>
</tr>
</tbody>
</table>

Even though each category of deviation is applied the same rate for deviation, approximately 80 percent 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 in excess of the day-cleared megawatts cleared, exporting megawatts in real-time in excess of the...
export megawatts cleared in the day-ahead market, and units pulling substation power in excess of 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 for half of all real-time make-whole payments in 2019.

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-scheduling of wind in the day-ahead as these incentives likely contribute to the lack of price convergence between day-ahead and real-time.

4.2.2 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 and regulation-down mileage factors averaged 16 percent and 24 percent, respectively, for 2019. The regulation-up mileage factor is up one percent from last year and the regulation-down mileage factor is down one percent.

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 4-41, below, illustrates the mileage make-whole payments for 2019 and the prior two years.

**Figure 4-41 Regulation mileage make-whole payments**

Regulation-up mileage make-whole payments were around $300,000 in 2019, up 12 percent from 2018. Regulation-down mileage make-whole payments were around $750,000 in 2019, down two percent from 2018. 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 4-41. 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.

**4.2.3 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 over-collected loss rebates into one distribution.\textsuperscript{112} 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 4–42.

\textbf{Figure 4–42 Over-collected losses, real-time}

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{over_collected_losses.png}
\caption{Over-collected losses payments for 2017, 2018, and 2019.}
\end{figure}

A total of $126 million was paid out in over-collected losses rebates during 2019, with $118 million (94 percent) going to load. This is down from the $144 million in over-collected losses rebates paid out in 2018, but slightly more than the $120 million paid in 2017. The decrease in losses between 2018 and 2019 can be attributed to lower energy prices.

\textsuperscript{112} Prior years over-collected loss designs are described in the 2018 Annual State of the Market report under Section 4.2.3.
4.2.4 POTENTIAL FOR MANIPULATION OF MAKE-WHOLE PAYMENTS

In the 2014 Annual State of the Market report (and highlighted in every annual report since), the MMU pointed out specific vulnerabilities that market participants could potentially manipulate in SPP’s make-whole payment provisions. The vulnerabilities were directly associated with the FERC order regarding the make-whole payments and related bidding strategies of JP Morgan Ventures Energy Corp. At this time only one issue has still not been fully addressed, which is make-whole payments for generators committed across the midnight hour. Under this scenario, a market participant has the ability to position its multi-day committed resource to receive a make-whole payment without economic evaluation of its offers by the market.

A revision request was passed by the SPP Markets and Operations Policy Committee (MOPC) during the January 2020 meeting to address this design gap. The revision request corrects the issue by limiting make-whole payments for any resource with multi-day minimum-run times to the lower of the market offer or the mitigated offer. This limitation only applies to offers falling in hours in which the resource’s offers were not assessed by one of the security constrained unit commitment (SCUC) processes and the resource bid at or above their mitigated offer on the first day. Subsequent to board approval of the original proposal, in June of 2018, SPP legal staff identified tariff language that requires modification as it conflicts with the language passed in the proposal. This required that additional tariff modifications go through the stakeholder process. For this reason, the original revision request was withdrawn and replaced with the newer version. The new version’s FERC filing is currently targeted for the third quarter of 2020.

The MMU strongly recommends that this filing be submitted to FERC in a timely manner, so that changes can be implemented to address these gaming concerns.

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113 144 FERC ¶ 61,068.
114 Revision Request 382, 2014 ASOM MWP MMU Recommendation (3-Day Minimum Run Time).
115 Revision Request 306 2014 ASOM MWP MMU Recommendation (3-Day Minimum Run Time). This proposal was withdrawn and replaced with 382, which removes conflicting language present in the tariff.
4.2.5 JOINTLY-OWNED UNIT MAKE-WHOLE PAYMENTS

Another make-whole payment concern existed related to jointly-owned resources and the combined resource option. At the time the MMU made their original recommendations, the market committed jointly-owned units as one unit, dispatched each separate owner on a percentage of ownership, and paid make-whole payments for energy based on the individual owners’ energy offers. This allowed a shareowner to benefit from a higher energy offer than its co-owners through high minimum energy costs in the make-whole payment.

In late 2017, corrections were made to address the issue of co-owners benefiting from higher energy offers. However, with these corrections new issues arose.116 A new design has been passed through all stages of the stakeholder process and is expected to be implemented in late 2020.

The new design requires that jointly-owned units offer in as one unit. The market system will dispatch the resource as one unit, and then the settlements process will allocate the cost and revenues out by percentage of ownership of the resource. The new design will correct the concerns outlined above.

4.3 TOTAL WHOLESALE MARKET COSTS AND PRODUCTION COSTS

The average annual all-in price, which includes the costs of energy, day-ahead and real-time reliability unit commitment make-whole payments, operating reserves,117 reserve sharing group costs, and payments to demand response resources, was $24.28/MWh in 2019. This is comparable to the average price of energy at load pricing nodes in SPP’s real-time market for

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116 Descriptions of these issues can be viewed in the 2018 Annual State of the Market report under Section 4.2.5
117 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.
2019 of $23.56/MWh.\textsuperscript{118} The all-in price was just over 12 percent lower than the 2018 average all-in price, which is partially attributed to the decrease in load and the decline in natural gas prices in 2019.\textsuperscript{119} Figure 4–43 plots the average all-in price of energy and the cost of natural gas, measured at the Panhandle Eastern (PEPL) hub.

**Figure 4–43 All-in price of electricity and natural gas cost**

The figure shows that the vast majority of costs are from the day-ahead and real-time energy payments.\textsuperscript{120} It also shows that the market cost of operating reserves and make-whole payments constituted approximately three percent of the all-in price, with make-whole payments and operating reserves amounting to $0.27/MWh and $0.31 in 2018 $0.38/MWh and $0.34/MWh, respectively.

\textsuperscript{118} The cost of energy includes all of the shortage pricing components.

\textsuperscript{119} The Reserve Sharing Group costs and payments to demand response resources were negligible for both years.

\textsuperscript{120} 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.
Production cost “is defined as the settlement cost for the market … for all resources.”\(^{121}\)

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 …,”\(^ {122}\) and
- no-load: “…the hourly fee for operating a synchronized Resource at zero … output.”\(^ {123}\)

Figure 4–44 shows the average daily production cost for the day-ahead market.

**Figure 4–44 Production cost, daily average, day-ahead**

![Chart showing production cost by month from January 2017 to December 2019, with a breakdown of energy, ancillary service, no-load, and start-up components.]($0\rightarrow$30)

The daily average production cost decreased 14 percent from 2018 to 2019. The decrease in production cost was almost fully attributed to the energy component, which decreased with gas prices. The energy component is sensitive to numerous inputs, which include fuel cost, amount of subsidized renewable energy, ancillary service scarcity, and load levels. The range of the 2019 daily day-ahead production costs exceeded $62 million ranging from $3 million to $65 million.

\(^{121}\) [Integrated Marketplace Protocols, Section 7.2.1]
\(^{122}\) [Integrated Marketplace Protocols, Start-Up Offer]
\(^{123}\) [Integrated Marketplace Protocols, No-Load Offer]
Additionally, nearly 94 percent of the daily production costs ranged between $5 million and $30 million.

**Figure 4-45  Production cost, daily average, real-time**

Real-time production cost decreased more than 16 percent from 2018 to 2019, putting it more in line with 2017’s cost. The decrease in production cost, similar to day-ahead, was also almost fully attributed to the energy component. The range of the 2019 daily real-time production costs ranged from −$1.4 million to almost $90 million. However, 89 percent of the daily production costs in real-time ranged between $5 million and $30 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, the MMU does not expect SPP market prices to support new entry of generation investments. While the SPP market on its own offers low incentives for new generation, some reasons for new generation investments include 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 emission reduction plans.
The MMU conducted analysis to determine if the SPP market would support investments in new generation by analyzing the fixed costs, and annual fixed operating and maintenance costs of five generation technologies relative to their potential net revenues\(^{124}\) at SPP market prices. The plants considered include scrubbed coal, natural gas combined-cycle (combined-cycle), natural gas combustion turbine (combustion turbine), wind, and solar photovoltaic – tracking (solar).

Figure 4–46 provides the cost assumptions. Solar capital costs have been credited to account for investment tax incentives. In addition to these assumptions, a capital recovery factor of 12.6 percent was used in the annual fixed operating and maintenance cost component.

**Figure 4–46 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>550</td>
<td>237</td>
<td>100</td>
<td>150</td>
</tr>
<tr>
<td>Total overnight cost ($/kW-yr)</td>
<td>$5,716</td>
<td>$794</td>
<td>$691</td>
<td>$1,624</td>
<td>$1,378</td>
</tr>
<tr>
<td>Variable O &amp; M ($/MWh)</td>
<td>$9.89</td>
<td>$2.06</td>
<td>$11.02</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Fixed O &amp; M ($/kW-yr)</td>
<td>$83.75</td>
<td>$10.30</td>
<td>$7.01</td>
<td>$48.42</td>
<td>$22.46</td>
</tr>
<tr>
<td>Heat rate (Btu/kWh)</td>
<td>9,257</td>
<td>6,200</td>
<td>8,500</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 2020*

Figure 4–47 shows the results of the net revenue analysis. The analysis assumes the market dispatches the hypothetical resource when day-ahead\(^{125}\) price exceeds the short-run marginal cost of production. Natural gas prices were based on the Panhandle Eastern Pipeline Company (PEPL) pipeline. Wind was attributed a capacity factor of 39 percent across all hours while solar was attributed a capacity factor of 49 percent during peak hours. Additionally, the average marginal cost of wind has been credited to account for production tax incentives.

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124 Net revenue is equal to revenues minus estimated marginal cost.
125 Real-time prices form the same results.
### Figure 4–47  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 avoidable cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scrubbed coal</td>
<td>$28.89</td>
<td>$18,170</td>
<td>$801,540</td>
<td>NO</td>
<td>$83,750</td>
<td>NO</td>
</tr>
<tr>
<td>Advanced gas/oil combined-cycle</td>
<td>$24.43</td>
<td>$76,898</td>
<td>$110,007</td>
<td>NO</td>
<td>$10,300</td>
<td>YES</td>
</tr>
<tr>
<td>Advanced combustion turbine</td>
<td>$41.69</td>
<td>$20,157</td>
<td>$93,783</td>
<td>NO</td>
<td>$7,010</td>
<td>YES</td>
</tr>
<tr>
<td>Wind</td>
<td>-$30.00</td>
<td>$178,165</td>
<td>$252,355</td>
<td>NO</td>
<td>$48,420</td>
<td>YES</td>
</tr>
<tr>
<td>Solar</td>
<td>$0.00</td>
<td>$69,196</td>
<td>$195,541</td>
<td>NO</td>
<td>$22,460</td>
<td>YES</td>
</tr>
</tbody>
</table>

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, and 2019 was no exception. Since 2015, prices have supported the ongoing maintenance cost of combined-cycle and combustion turbine units, though they have not supported the ongoing maintenance cost of coal units. This is consistent with the 2019 results shown above. In 2019, SPP market revenues were also insufficient to support the cost of new entry of renewable generation, wind and solar. However, similar to natural gas generation, 2019 prices supported the ongoing maintenance cost of renewables. A large contributor to the low revenues relative to total costs for all resource types is the generally low day-ahead market prices. On average, day-ahead market prices are in the $20/MWh range, as shown in Figure 4–1.

Figure 4–48 provides results by SPP resource zone, as indicated by the dominant utility in the area.
Overwhelmingly, the conclusions do not vary geographically, despite differing energy prices and fuel costs. The one exception is the SPS region where combined-cycle plants in the Permian Basin (West Texas) region consistently experience below average natural gas prices.

Based on these results, the MMU expects the market to signal the retirement of some coal generation while also not signaling the investment of other types of new generation. A decrease in overall available capacity—along with the recently observed higher outages since 2017—and changes in the generation fleet profile could present challenges for reliability.
Economic decisions 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 can provide additional impetus needed for new generation investments.

However, market prices, by themselves, have not been signaling new generation entry for some time. Moreover, out-of-market actions by SPP operators and resulting uplift payments for reliability (manual) commitments reflect some of the symptomatic issues, but do not signal the overall need for more generation flexibility. In 2019, day-ahead market and reliability unit commitment make-whole payments totaled approximately $101 million, up forty percent from $72 million last year (see Section 4.2). Even so, make-whole payments still do not provide sufficient revenue to change results of the net revenue analysis as the analysis typically addresses recovery of short-run marginal costs, and not necessarily fixed costs.

As the MMU has indicated throughout this report as well as in other forums, the MMU advises SPP and members to implement products such as ramp and uncertainty\(^\text{126}\) to value flexibility and to produce accurate price signals. The MMU also recommends developing accreditation factors and performance-based metrics to obtain accurate capacity ratings based on actual performance that will more appropriately incentivize reliable operation and price formation in the SPP Integrated Marketplace.

Continuing to value flexibility will be important going forward. Compensation for reliable summer performance could be an additional revenue stream to high performing generation. This is discussed in more detail in Section 8.1 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 area that experienced the highest congestion costs in 2019 was the southeastern corner of SPP including eastern Kansas, southwest Missouri, and southeastern Oklahoma. A concentrated area on the Kansas and Oklahoma border and western Nebraska experienced the lowest congestion costs for the year.

- Overall, congestion is up across the SPP footprint, with intervals having no congestion decreasing in 2019 and intervals having a breached constraint increasing in 2019.

- The frequently constrained area study for 2019 saw the removal of the central Kansas and southwest Missouri frequently constrained areas and no additions, so there are no frequently constrained areas at this time.

- In aggregate, market participants were effective in hedging congestion in the SPP market using SPP’s congestion hedging products. Load-serving entities covered more than 135 percent and non-load-serving entities covered more than 105 percent of their total congestion cost.

- Individual market participants hedged congestion with varying degrees of effectiveness — overall 84 percent of load-serving-entities recovered more than 90 percent of their congestion cost.

- Transmission congestion rights funding fell outside the target range. The annual funding percentage fell to 89 percent, and the annual shortfall decreased by more than $40 million. Auction revenue right funding decreased from 145 percent to 129 percent; relatedly, the ARR surplus decreased by more than $26 million.

- 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.
No bulletin board trades cleared during 2019. Intra-auction sales\textsuperscript{127} increased slightly in volume, and continue to average only about five percent of the total auction volume.

5.1 TRANSMISSION CONGESTION

The locational marginal price (LMP) for the over 950 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,
- 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.

\textsuperscript{127} The sale of a previously acquired position in a subsequent auction.
5.1.1 PRICING PATTERNS AND CONGESTION

Figure 5–1 shows price contour maps representing the day-ahead and real-time average prices in 2019.

![Price map, day-ahead and real-time market](image)

Annual average day-ahead market prices ranged from around $8/MWh in a concentrated area on the Kansas/Oklahoma border to around $35/MWh in the southeast section of Oklahoma. About 75 percent of this price variation can be attributed to congestion and 25 percent to marginal losses, which is consistent with prior years. Because congestion is more volatile in the real-time market, the average geographic price range is slightly larger, from $5/MWh to $36/MWh.

Continued 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 has shifted eastward. The congestion pocket normally seen in the ...
western and central areas of the footprint has shifted towards the southeastern edge of SPP extending from Kansas City to Oklahoma City.

The Hays, Kansas area was frequently congested in prior years with prices averaging around $31/MWh in 2018. This area saw reduced congestion in 2019 due to transmission upgrades in the area resulting in prices falling to around $22/MWh. The southwest Missouri area along the SPP eastern border continued to see congestion but prices decreased from around $31/MWh in 2018 to around $27/MWh in 2019. The MMU recommended removing these as frequently constrained areas as part of the 2019 Frequently Constrained Area study and report.\textsuperscript{128} Lastly, day-ahead prices in the southeast Oklahoma area around a market-to-market constraint\textsuperscript{129} have averaged over $35/MWh over the past two years.

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, and the geographic differences in fuel costs. 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 is still SPP’s predominant fuel for energy generation at 35 percent in 2019.

Natural gas-fired generation, SPP’s largest fuel type by installed capacity (41 percent in 2019), resides predominantly in the southern portions of SPP. Wind-powered generation generally lies

\textsuperscript{129} TMP109_22593 (Stonewall Tap – Tupelo Tap 138kV for the loss of Seminole – Pittsburg 345kV)
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. The other exception is the lower southwest area of the SPP region around Lubbock, Texas. This congestion historically extended further north into the Texas panhandle but transmission buildout and additional generation has moved congestion further south.

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

**Figure 5-2** Marginal congestion cost map, day-ahead market

The lowest average marginal congestion costs occurred in a concentrated area in the north central Oklahoma area, at −$12/MWh, and the highest marginal congestion costs lie around the congestion in southeast Oklahoma at around $11/MWh.
The congestion in the central Kansas and southwest Missouri areas was persistent in 2017 and 2018 but reduced in 2019. Even with the reduction, congestion remained in the southwest Missouri area and in neighboring areas to the south, such as northwest Arkansas, Tulsa, and eastern Oklahoma. With the addition of the phase-shifting transformer at Woodward, Oklahoma in 2017 and upgrades in central Kansas in December 2018, congestion in SPP is prevalent mainly on the southeastern edge of the SPP footprint.

5.1.3 TRANSMISSION EXPANSION

A handful of major transmission projects (230kV or above) were completed during 2019 (shown on Figure 5–3 below) that will support the efficient transmission of energy across the SPP footprint.130

- Yoakum – Hobbs 345kV
  - location: west Texas
  - energized: May 2019

- Arcadia – Redbud 345kV (circuit 3)
  - location: central Oklahoma
  - energized: June 2019

Figure 5–3 SPP transmission expansion in service, 2019

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The lines depicted on the map in Figure 5–4 below are projects that will further enhance the SPP transmission grid in future years.

**Figure 5–4  SPP transmission expansion plan**

The Integrated Transmission Plan (ITP) projects shown are recommended upgrades to the extra-high-voltage backbone (345kV and above) for a 20-year horizon. The ITP process seeks to target a reasonable balance between long-term transmission investments and congestion costs to customers. The notification to construct (NTC) and ITP projects shown have received a written notice from SPP to construct a transmission project that was approved by the SPP board of directors. Planned projects that may provide relief for the most congested areas in SPP are listed in Figure 5–10.

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 could be increased by one megawatt for one hour. Figure 5–5 provides the top ten flowgate constraints by shadow price for 2019.
Although the level of congestion in the southwest Missouri and central Kansas areas declined from 2018 to 2019, the eastern Oklahoma area continues to see consistent congestion. The most congested flowgates in this area (Stonewall Tap-Tupelo Tap for the loss of Seminole-Pittsburg and Tahlequah-Highway 59 for the loss of Muskogee-Fort Smith) had real-time shadow prices of around $22/MWh and $19/MWh, and were congested in almost five and three
percent of real-time intervals. The flowgate with the highest congestion in 2019 (Braman-Newkirk Tap for the loss of Hunter-Woodring) had an annual real-time shadow price of around $50/MWh, and was congested 11 percent of all real-time intervals. This flowgate is in north-central Oklahoma which includes another highly congested flowgate (Braman-Newkirk Tap for the loss of Kildeer Tap-Chikaskia) for 2019 which had an annual real-time shadow price of around $15/MWh, and was congested just over five percent of all-real time intervals. These two flowgates in the north-central Oklahoma are 69kV elements which typically result in higher shadow prices because of the limited generation around the localized congestion.

Most of the congested areas in the SPP footprint are significantly impacted by inexpensive wind generation but the areas on the eastern edge of SPP are also impacted by external flows given their market-to-market designations. Projects are planned throughout the SPP footprint that may address these areas and are listed in Figure 5–10.

5.1.4.1 Central Kansas constraints

The central Kansas area is impacted by wind generation and several constraints have appeared consistently since prior to the start of the SPP Integrated Marketplace. Figure 5–6 compares congestion over the years for day-ahead and real-time in the central Kansas area since 2017.

**Figure 5–6 Central Kansas congestion**

![Central Kansas congestion chart](image)

131 Values combined for the following constraints: SHAHAYPOSKNO (South Hays – Hays 115kV); VINHAYPOSKNO (Vine – Hays 115kV); VINHAYKNOXFR (Vine – Hays 115kV); TEMP94_21410 (South Hays – Mullergren 230kV)
The central Kansas area congestion declined in 2019. These constraints experienced congestion in twelve percent of all intervals in the day-ahead market and less than two percent of all intervals in the real-time market. The yearly average shadow price for the real-time market was less than $6/MWh for 2019 compared to $27/MWh in 2018. A second Post Rock – Knoll 230kV circuit was energized in December 2018 which appeared to provide relief to this area.

5.1.4.2 Southwest Missouri

The Neosho – Riverton 161kV constraint is a market-to-market flowgate that is impacted by SPP and MISO wind, as well as flows from neighboring non-market areas. Congestion in this area dates back to prior to the start of the Integrated Marketplace. Wind in SPP and neighboring areas contributes to the congestion in this area, but has decreased in 2018 and 2019. Figure 5–7 compares congestion on the Neosho – Riverton 161kV constraint since 2017.

Figure 5–7 Southwest Missouri congestion

Congestion increased substantially on this constraint in 2017 when compared to previous years, however, reductions in 2018 continued into 2019. Congestion still remains on this and other constraints in the area but an upgrade to the limiting element of Neosho – Riverton 161kV in December 2018 has appeared to provide some relief to this area. This constraint has been a focus of seams discussions on the amount of market-to-market payments and transmission

132 Neighboring non-markets include: Tennessee Valley Authority, Associated Electric Cooperative Inc., and Southwestern Power Administration.
upgrades that may benefit SPP, MISO, and other neighboring non-market entities. The market-to-market process has settled over $30 million in payments for the Neosho-Riverton constraint from MISO to SPP, and is discussed in Section 2.7.2.

5.1.4.3 Eastern Oklahoma

As the southwest Missouri congestion has decreased over the past two years, several areas in Oklahoma have increased. The eastern Oklahoma area consists of two of the top congested flowgates in 2019. Figure 5–8 compares congestion for the TMP109_22593 flowgate since 2017.

Figure 5–8 Eastern Oklahoma congestion - TMP109_22593

The Stonewall Tap – Tupelo 138kV constraint is a market-to-market flowgate and has seen an increase in congestion in both 2018 and 2019. This constraint experienced congestion in 27 percent of all intervals in the day-ahead market in 2019 compared to eleven percent in 2018. Five percent of all intervals in the real-time market experienced congestion in both 2018 and 2019. Although the percent of congested intervals in the real-time market remained consistent,

133 TMP109_22593: Stonewall Tap-Tupelo Tap 138kV (WFEC) fto Seminole-Pittsburg 345kV. Other constraints appear in this area as well but TMP109_22593 is the top congested in this particular area.
the yearly average shadow price increased from about $16/MWh in 2018 to over $22/MWh in 2019.

Another highly congested constraint in eastern Oklahoma is the TAHH59MUSFTS\textsuperscript{134} flowgate. Figure 5–9 compares congestion for this flowgate since 2017.

**Figure 5–9  Eastern Oklahoma congestion - TAHH59MUSFTS**

The Tahlequah – Highway 59 161kV constraint along the Oklahoma – Arkansas border is also a market-to-market flowgate and has seen an increase in congestion in both 2018 and 2019. This constraint experienced congestion in eleven percent of all intervals in the day-ahead market in 2019 compared to eight percent in 2018. Intervals in the real-time market with congestion experienced a slight increase from almost two percent in 2018 to over three percent in 2019. However, the yearly average shadow price increased from about $10/MWh in 2018 to over $19/MWh in 2019.

5.1.5  PLANNED TRANSMISSION PROJECTS

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

\textsuperscript{134} TAHH59MUSFTS: Tahlequah-Highway 59 161kV for the loss of Muskogee-Fort Smith 345kV. Other constraints appear in this area as well but TMP109_22593 is the top congested in this particular area.
**Figure 5-10 Top ten 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>TMP175_24736</td>
<td>North-central Oklahoma</td>
<td>Braman-Newkirk Tap 69kV for the loss of Hunter-Woodring 345kV (OKGE)</td>
<td>TOP and SPP RC implemented re-configuration option. No Projects identified at this time.</td>
</tr>
<tr>
<td>TAHHS59MUSFTS*</td>
<td>West Arkansas/East</td>
<td>Tahlequah-Highway 59 161kV ftlo Muskogee-Fort Smith 345kV (GRDA-OKGE)</td>
<td>SPP RC and TOP have an Operating Guide in place that considers multiple reconfiguration options if normal congestion management is not effective. No Projects identified at this time.</td>
</tr>
<tr>
<td>TMP379_24692</td>
<td>North-central Oklahoma</td>
<td>Braman-Newkirk Tap 69kV ftlo Kildeer Tap-Chikaskia 138kV (OKGE)</td>
<td>TOP and SPP RC implemented re-configuration option. No Projects identified at this time.</td>
</tr>
<tr>
<td>FRAMIDCANCED</td>
<td>Central Oklahoma</td>
<td>Franklin-Midwest 138kV (OKGE-WFEC) ftlo Cedar Lane-Canadian 138kV (OKGE)</td>
<td>None identified at this time</td>
</tr>
<tr>
<td>TMP127_23359*</td>
<td>Western Nebraska</td>
<td>Scotsbluff-Victory Hill 115kV (NPPD) ftlo Stegall Xfmr 345kV/1 (WAUE)</td>
<td>None identified at this time</td>
</tr>
<tr>
<td>TMP421_24095</td>
<td>Central Oklahoma</td>
<td>Cimarron Xfmr 345/138kV (OKGE) ftlo Cimarron Xfmr 345/138kV (OKGE)</td>
<td>None identified at this time</td>
</tr>
<tr>
<td>SUNAMOTOLYOA^</td>
<td>West Texas (Lubbock)</td>
<td>Sundown-Amoco Sw. 230kV ftlo Needmore-Yaokum 230kV (SPS)</td>
<td>NTC 200395, Sundown-Amoco terminal upgrades (2016 ITPNT), in service December 2019</td>
</tr>
<tr>
<td>NEORIVNEOBLC*</td>
<td>SW Missouri/SE Kansas</td>
<td>Neosho-Riverton 161kV (EDER-WR) ftlo Neosho-Blackberry 345kV (WR-AECI)</td>
<td>Neosho-Riverton 161kV Rebuild (October 2023, ATSS SPP-2019-AG1-AFS-2)</td>
</tr>
<tr>
<td>TMP285_23829*</td>
<td>Northeast Kansas</td>
<td>Kelly-Goff 115kV (WR) ftlo Cooper-St. Joe (NPPD-MPS)</td>
<td>None identified at this time</td>
</tr>
</tbody>
</table>

* SPP Market-to-Market flowgate during all or part of 2019

^ also includes congestion from TEMP411_24410

### 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 2019 were 2.8 percent in the day-ahead market. This is consistent with 2.8 percent in 2018 and 2017. The marginal loss component of the 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 5–11 maps the annual average day-ahead market marginal loss components.
The average day-ahead marginal loss component ranges from about \(-$3.15/MWh\) at the Laramie River Station in eastern Wyoming, to \(-$2.70/MWh\) near North Platte, Nebraska, to \(-$1.50/MWh\) in the Texas panhandle area, to \(-$0.10/MWh\) in the Kansas City area, and over \+$2.50/MWh\) in northeast 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 \+$5.65/MWh\ spread between geographic prices in 2019 is less than the \+$7.12/MWh\ spread in 2018.

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 7.2.2. 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.

Because 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 2018 results removed the Texas Panhandle (Lubbock) area and added two new areas; southwest Missouri and central Kansas. These changes were implemented February 22, 2019. The 2019 study results identified a reduction in congestion in the southwest Missouri and central Kansas areas and recommended removal of these two frequently constrained areas. No new areas were identified to be added at the time of the study, but several areas such as Tulsa, Oklahoma City, and southeast Oklahoma experienced increases in pivotal supplier hours. The removals of the southwest Missouri and central Kansas areas were implemented March 31, 2020.

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. This is considered a breached constraint. Figure 5-12 highlights day-ahead market binding, breached, and uncongested intervals.
The figure shows that uncongested intervals and breached intervals are rare in day-ahead. Historically in the Integrated Marketplace, less than one percent of day-ahead market intervals incur a breached condition compared to over 25 percent for the real-time market.\textsuperscript{135}

In the more dynamic environment of the real-time market, uncongested intervals and breached intervals occur much more frequently than in the day-ahead market. Real-time congestion is shown in Figure 5–13.

\textsuperscript{135} SPP uses hourly intervals in the day-ahead market and five-minute intervals in the real-time market for scheduling, dispatch, and settlement purposes.
As shown above, uncongested intervals decreased slightly from 18 percent of intervals with no congestion in 2018 to 16 percent in 2019. Real-time intervals with a breached constraint increased, with 39 percent of intervals with a breach in 2019, compared to 27 percent in 2018.

Market-to-market coordination with MISO, as discussed in Section 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 39 percent of the real-time intervals with a breached constraint, nearly three-fourths of these had a breached market-to-market constraint. 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.

### 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 2019.

**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 about $65 million in charges to more than $6 million in payments.136

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, 97 percent of the SPP load-serving entities’ net congestion costs stemmed from the day-ahead market.

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.

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136 Day-ahead congestion collections funds transmission congestion rights. These rights are described in greater detail in Section 5.2.
The real-time market congestion payments result in a net benefit of $10 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 $126 million. On an individual basis, real-time market congestion ranged from almost $9 million in payments to over $8 million in costs for load-serving entities. Real-time market congestion ranged from $26 million in payments to $8 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 2019, SPP allocated about 83 percent of revenue neutrality uplift charges to load-serving entities, resulting in an additional $105 million in congestion-related charges for load-serving entities.\(^{137}\)

### 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

\(^{137}\) Real-time congestion uplift is not allocated in the same proportion in which it is collected.
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 overcollections.\footnote{With respect to day-ahead congestion rent only.}

\subsection*{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.\footnote{These charges are assessed through transmission settlements and include various tariff schedules.}

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.\footnote{\textit{SPP Open Access Transmission Tariff}, Section 5.3.3, Simultaneous Feasibility} 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 auction revenue right nomination fails the simultaneous feasibility test, this reduces the quantity of auction revenue rights successfully converted from candidate rights.141

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.142 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-only143 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,

142 SPP Open Access Transmission Tariff, Section 5.4.1 (2)
143 Financial-only market participants do not generate or serve load in the SPP footprint.
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.

**Figure 5–16 Total congestion and hedges**

<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>DA congestion</td>
<td>$365</td>
<td>$391</td>
<td>$362</td>
</tr>
<tr>
<td>RT congestion</td>
<td>41</td>
<td>−10</td>
<td>−10</td>
</tr>
<tr>
<td>Net congestion</td>
<td>$405</td>
<td>$381</td>
<td>$352</td>
</tr>
<tr>
<td>TCR charges</td>
<td>$122</td>
<td>$215</td>
<td>$250</td>
</tr>
<tr>
<td>TCR payments</td>
<td>−309</td>
<td>−331</td>
<td>−358</td>
</tr>
<tr>
<td>TCR uplift</td>
<td>24</td>
<td>26</td>
<td>34</td>
</tr>
<tr>
<td>TCR surplus *</td>
<td>−4</td>
<td>−5</td>
<td>−5</td>
</tr>
<tr>
<td>ARR payments</td>
<td>−147</td>
<td>−249</td>
<td>−315</td>
</tr>
<tr>
<td>ARR surplus</td>
<td>−94</td>
<td>−113</td>
<td>−89</td>
</tr>
<tr>
<td>Net TCR/ARR</td>
<td>−$408</td>
<td>−$458</td>
<td>−$482</td>
</tr>
</tbody>
</table>

*remaining at year-end

Payments to load-serving entities of $482 million exceeded their day-ahead congestion costs of $362 million in 2019. Additionally, real-time congestion costs aided load-serving entities by $10 million, thereby reducing total congestion cost to $352 million. This shows that overall, load-serving entities hedged their day-ahead congestion effectively, in aggregate. In 2019, non-load-serving and financial only entities collected transmission congestion right and auction revenue right net revenues of $111 million, which exceeded their day-ahead and real-time market congestions costs of $106 million. Overall, day-ahead congestion cost increased six percent year-to-year, from $561 million in 2018 to $593 million in 2019.
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. The market monitor reported on this topic in the quarterly state of the market report for spring 2018,144 and is actively engaged in efforts to improve this issue. The Holistic Integrated Tariff Team has adopted a recommendation to provide a limited amount of counterflow in order to increase the amount of prevailing flow.145 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 participants received positive net revenues, while a handful of participants held portfolios that did not cover their day-ahead congestion costs. For

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instance, the bottom five participants paid almost $36 million more in congestion costs than was
offset by their auction revenue right and transmission congestion right positions. This is more
than the $26 million for the bottom five participants in the 2018 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{146} 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{147} 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.

\textsuperscript{146} Long-term, firm, transmission service requests
\textsuperscript{147} SPP MWG Meeting Materials, 1/22/2019, https://www.spp.org/spp-documents-filings/?id=18437, Item
11a, SPP MMU_ARR Observation.pdf
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.

**Figure 5-18 Transmission outages by reporting lead time**

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.\(^{148}\) However, SPP only requires transmission owners to submit planned outages 14 days in advance.\(^{149}\) 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 85 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.

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\(^{148}\) *Integrated Marketplace Protocols*, Section 6.6

\(^{149}\) *SPP Operating Criteria*, Appendix OP-2
Outages shorter than five days are excluded from auction revenue right/transmission congestion right processes. This means the vast majority of outages (81 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.

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 five 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 consider improving 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 decreased slightly in 2019. Additionally, funding percentage for auction revenue rights and auction revenue right closeout decreased in 2019. As mentioned in previous reports,\textsuperscript{150} 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.

The 2017 and 2018 calendar years, produced 94 percent transmission congestion right funding while the 2019 calendar year decreased to 89 percent, which is slightly below the 90 percent target. The funding percentage declined significantly year-over-year, and the shortfall declined by more than $40 million during 2019. The cumulative funding by constraint tends to fall between −$1 and $1 million. However, there are a handful of constraints with more than −$1 million underfunding. For example, almost $30 million of the decrease in funding relates to the overselling of flowgate TMP175_24736 (Braman – Newkirk 69kV.) Typically, 69kV lines are not considered in the annual auctions unless they are known to be impactful. SPP staff included this constraint in monthly auctions which helped to reduce overselling in later monthly auctions. Without this specific modeling parameter in the annual auction, the funding percentage would have been 93 percent, which is within the target range.

Monthly transmission congestion right funding levels and revenue are shown in Figure 5–22.
The monthly averages appear fairly consistent until May, with the majority of the months hovering near the 90 to 100 percent target range. The lowest funding percentage was 75 percent in June and the highest was at 96 percent in April.\textsuperscript{151}

Daily observations of transmission congestion right funding for the past three years are shown in Figure 5–23.

\textbf{Figure 5–23 Transmission congestion right funding, daily}

\textsuperscript{151} \textit{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…”
Most daily observations of transmission congestion right funding percent fall between 80 percent and 120 percent, as seen in Figure 5–23. While variation in funding can be expected as a result of factors including transmission outages and derates, the fact that the majority of funding falls in this range indicates that the overall process is generally effective. It is important to note that there was a decrease in funding events in excess of 155 percent, but there was an increase in funding events below 50 percent from three in 2018 to eight in 2019. This data suggests that while the annual funding percentage is relatively stable year-over-year, the downside volatility in the daily observations increased in 2019.

The magnitude of downside volatility also increased in 2019. Most daily funding observations fell between plus and minus $250,000 in 2019. However, the frequency of downside events outside this range continues to increase. For example, in 2017, there were 15 days where daily underfunding exceeded $1 million. In 2018, there were 20 of these events and in 2019 there were 29 events. Conversely, the frequency in overfunding events in excess of $1 million declined from two events in 2018 to zero in 2019.

Figure 5–24 shows the auction revenue right funding percentage since 2017.

Figure 5–24  Auction revenue right funding levels, annual

In 2017, auction revenue rights were 164 percent funded which was an increase from 138 percent in 2016 (not shown.) In 2018, auction revenue rights decreased to 146 percent funded and again in 2019 to 129 percent funded. Auction revenue right surpluses increased from $101
million in 2017 to $122 million in 2018 and declined in 2019 to $96 million. While the decrease in funding percentage is encouraging, the surplus is still quite substantial 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 5–25 shows the 2019 monthly funding levels and revenues for auction revenue rights.

Figure 5–25  Auction revenue right funding levels, monthly

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 was elevated during the last five months of the 2018 TCR year when compared to the first four months of the 2019 TCR 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 5–26 shows the transaction volume by type as a percentage of all transmission congestion right purchase volume.

**Figure 5-26 Intra-auction sales and bulletin board transactions**

No bulletin board transactions cleared in 2018 and 2019. Additionally, intra-auction sale volume remained relatively stable around five 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.\(^{152}\) 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.

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\(^{152}\) The additional capacity could also be provided by another counter-flow intra-auction bid.
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.\textsuperscript{153}

5.2.5 ISSUES, PROGRESS, AND NEXT STEPS

While the congestion hedging market is workably effective overall, the market monitor highlights the following four areas where continued progress could bring about improved market outcomes, risk reduction, and efficiency gains.

1. **Obtaining auction revenue rights**

Market participants experience varying levels of success in obtaining auction revenue rights and by extension self-converted transmission congestion rights. This issue prompted the Holistic Integrated Tariff Team to issue the recommendation: implement congestion hedging improvements in April 2019.\textsuperscript{154} However, after nearly a year of deliberation, the Market Working Group overwhelmingly prefers the status quo. Given the HITT’s recommendation, we encourage the Market Working Group to continue to develop policy in this area.

2. **Credit policy**

The Credit Practices Working Group has reviewed SPP’s credit policy and is working toward a solution, which more fully addresses the various risks associated with congestion hedges. The solution will incorporate both qualitative and quantitative aspects and is expected to be developed and implemented in two phases. Given the

\textsuperscript{153} Intra-market refers to inside the SPP Integrated Marketplace.

\textsuperscript{154} Holistic Integrated Tariff Team Report, Marketplace Enhancement Recommendations, Implement congestion hedging improvements: SPP should continue with a market mechanism to hedge load against congestion charges. The existing market design should include modifications to implement counter-flow optimization that is limited to excess auction revenues.
significance of the GreenHat Energy default in PJM, the market monitor encourages the Credit Practices Working Group to continue make these enhancements its highest priority going forward.

3. **Secondary intra-market liquidity**

Zero megawatts were transacted on SPP’s bulletin board in 2019, a continuation of the observations from 2018. 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 worsened in 2019. As stated in previous reports, the process and rules surrounding the modeling of congestion hedging outages should be reviewed, and during the review SPP and its stakeholders should determine if the current practice is appropriate. The market monitor recognizes the significant challenges associated with model convergence and encourages SPP’s continued focus in this area.
6 PLANNING PROCESS

The scope of market monitoring work covers all aspects of the SPP market including activities that could impact the short-term and long-term operation of the market. The planning process and its outcomes, in particular, affect congestion patterns, operational effectiveness, and costs, as well as reliability.

The MMU’s capability to possess and analyze comprehensive market information positions it to be able to provide valuable input in the planning process. For this reason, starting in 2018 the MMU, in its advisory capacity, has been involved in SPP’s planning process, primarily with meetings and the discussions of the Economic Studies Working Group (ESWG), but also with the Transmission Working Group (TWG) and Supply Adequacy Working Group (SAWG). The MMU feedback in the planning process on relevant topics has already proved beneficial by improving planning outcomes, and benefitting the market as a whole.

Key highlights from this chapter include:

- The 2021 Integrated Transmission Planning (ITP) will maintain 2020 ITP’s two-scenario approach, the Reference case (Future 1) and the Emerging Technologies case (Future 2). However, Future 2 will have sensitivities for some elements including a carbon adder, increased renewables and storage, and retirement sensitivities to proxy a third (bookend) scenario supported by the MMU.

- While the 2021 ITP Future 1 maintained the generator retirement age assumptions from the 2020 ITP, Future 2 assumed coal generators, and gas-fired and oil generators to retire over the age of 52 and 48, respectively.

155 The ESWG advises and assists SPP staff, various working groups, and task forces in the development and evaluation principles for economic studies. The group provides technical support for the development and application of economic studies. The group also reviews the economic planning processes for adherence to sound economic metrics methods and provides recommendations for improvement of the economic evaluations (see https://www.spp.org/organizational-groups/board-of-directormembers-committee/markets-and-operations-policy-committee/economic-studies-working-group/).
The 2021 ITP adopted Effective Load Carrying Capability (ELCC) as the method of accreditation for *total projected* utility scale solar, wind, and storage.

The ITP Manual language was modified in several aspects including the use of new federal corporate tax rate change from 35 percent to 21 percent in calculating renewable curtailment price.

The 2021 ITP Assessment will start using two percent instead of 2.5 percent as the inflation factor, based on an MMU recommendation.

SPP’s ITP 20-year assessment will be completed in October 2022.

The MMU’s peak available capacity metric was 31 percent in 2019, down from 35 percent in 2018.

Addressing congestion related issues requires consideration of both transmission and generation investment options from an overall market view. For instance, the current excess generation capacity in the SPP market—even in the presence of increased outages since 2017—and its implication on market outcomes is a topic that needs to be evaluated in the planning process. For the last several years, the persistently high amount of available generation capacity has been a contributing factor to the relatively low market prices in the SPP market. This affects the financial viability of generators as low prices that are not supportive of the existing generation capacity makes future retirements more likely.

The MMU outlined its recommendations to improve planning processes in it 2017 and 2018 annual reports. In 2019, the MMU maintained its involvement in helping stakeholders develop key inputs to the ITP scope and futures case studies, this time for the 2021 ITP. In particular, MMU provided feedback on the following items for the 2021 ITP:

- The MMU recommended that the ESWG evaluate a third scenario by considering recent market changes such as higher than initially projected renewable capacity build, more

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generator retirements, and associated carbon reduction levels. While the stakeholders decided to follow 2020 ITP’s two-scenario approach—the Reference case and the Emerging Technologies case—the Emerging Technologies case will have sensitivities to reflect elements originally proposed by the MMU including a carbon adder, increased renewables and storage, and retirement sensitivities to proxy a third (bookend) scenario.

- The 2021 ITP Reference Case scenario kept the generator retirement age assumptions from 2020 ITP. However, based on current information and trends, the Emerging Technologies scenario assumed coal generators, and gas-fired and oil generators to retire over the age of 52 and 48, respectively. This more closely aligns with the MMU recommendation.

Section 6.1 of this chapter covers the resource adequacy process. The remainder of this chapter covers in more detail the transmission planning process and the input provided by the MMU.

### 6.1 RESOURCE ADEQUACY

#### 6.1.1 CAPACITY ADDITIONS AND RETIREMENTS

At the end of 2019, nearly 46 percent of SPP’s fleet is more than 30 years old. In particular, nearly 85 percent of coal capacity and 40 percent of gas capacity is older than 30 years. According to the U.S. Energy Information Administration (EIA), the national average retirement age of coal-fired generation was 52 years.157 Aside from the resources that joined SPP from Nebraska in 2009 and the Integrated System in 2015, the largest source of new capacity in the SPP footprint over the last 10 years has been wind capacity.

Figure 6–1 illustrates that certain segments of the SPP generation fleet are aging. The chart highlights that about 30 GW of generation is over 40 years old. Almost half of which is gas, and about a third is coal.

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Almost all of the coal and gas capacity retired since 2016 have been 1950s era plants. The nuclear unit that retired in 2016 was commissioned in the early 1970s. The wind units that retired in 2017 were first-generation wind resources with very low capacity. Of the 1,457 MW of retired capacity in 2019, 973 MW belong to coal units, with the remaining 462 MW and 22 MW gas and fuel oil units, respectively.
For capacity additions, wind generation has accounted for 88 percent of the additions over the last three years and all of the additions in 2019. Total nameplate capacity additions were 1,810 MW in 2019. Even with the increased amount of solar generation in the generation interconnection queue, the last solar generation added to the SPP market was in 2016 at 165 MW. Considering the 1,810 MW in capacity additions along with 1,457 MW of retirements, 353 MW of net generating capacity was added to the SPP market in 2019.

### 6.1.2 GENERATOR RETIREMENTS

The SPP market currently has a significant amount of excess generation capacity, even in the presence of increased outages since 2017. Furthermore, the substantial incoming—and projected—new capacity, primarily wind, and the projected low rates of load growth are likely to exacerbate this situation absent significant amount of generator retirements. While the SPP Planning Criteria provides for a 12 percent capacity (reserve) margin for the footprint, the MMU’s calculated peak available capacity metric discussed in Section 6.1.3 points to levels well above the required level, at 31 percent. Reserve margin requirements are based on long-established standards and are intended to provide for sufficient support for reliability, however, significant excess capacity imposes inefficiencies on the market. When such excess capacity exists, functioning competitive markets send signals mainly through (low) energy prices incentivizing the exit of that capacity.

A wave of generator retirements, particularly of coal-fired generation, is occurring throughout the country. The SPP market is likely to follow this trend given its excess capacity and aging fleet, and the cost disadvantages of certain generation technologies in regard to prevailing market prices.

Considering these developments, and starting in 2017, the MMU has been involved with the SPP’s initiative to develop a new process for evaluating generator retirement applications. The

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158 While the 12 percent is calculated based on the non-coincident peak of the load serving entities, the MMU’s 31 percent is based on the SPP coincident peak.
159 As highlighted in Section 7.2.1, market offers are less than mitigated offers, which contributes to price formation.
160 Coal unit retirements have been steady across the U.S. with 2,809 MW in 2014, 12,439 MW in 2015, 6,568 MW in 2016, 4,925 MW in 2017, 9,699 MW in 2018 and 7,505 MW in 2019 (See EIA 860 electric utility data as of December 2019, available at [https://www.eia.gov/electricity/data/eia860M/](https://www.eia.gov/electricity/data/eia860M/))
MMU has approached this primarily from market economics and market power perspectives, as a strategically-motivated generator retirement particularly in a congested area could constitute physical withholding by creating a shortage that leads to sustained price spikes. The MMU is already evaluating generator retirements for reasonable technical and economic justifications, market impacts, and concerns regarding physical withholding.

The MMU has communicated with SPP staff and the market participants in regard to its proposed review process through internal meetings and presentations at the Market Working Group, and will continue to provide feedback as necessary. In December 2019, the MMU posted a data template and related instructions on SPP.org for calculating going forward costs should the MMU request a market participant to provide such data to be evaluated for physical withholding.\(^\text{161}\) This new approach will aid the MMU in better assessing the economic justifications for retirement. Given the amount of excess capacity in the SPP market and market economics associated with it, the MMU expects these requests to apply only to only a small portion of retirements.

6.1.3 GENERATION CAPACITY COMPARED TO PEAK LOAD

In the 2017 annual report, the MMU introduced a new peak available capacity metric to replace the previous reserve margin metric\(^\text{162}\) used in prior reports. The new metric uses a percentage of the average maximum capacity for each resource during July and August, and divides that figure by the nameplate capacity for the resource. This method essentially creates a derated capacity value due to ambient temperatures for each resource and is a more conservative measure of capacity when compared to nameplate, or even summer rated capacity. A percentage is then calculated for each fuel type of resource and that percentage is applied to the total nameplate capacity. Wind and solar resources are derated based on capacity factors during the afternoon hours in July and August. Solar resources are derated to 50 percent of nameplate capacity. For wind resources, 24 percent of nameplate capacity is included in the calculation.

\(^{161}\) The documents are available at [https://www.spp.org/spp-documents-filings/?id=18510](https://www.spp.org/spp-documents-filings/?id=18510).

\(^{162}\) The previous reserve margin metric used unit registration ratings (i.e. nameplate capacity) to determine system capacity, while wind counted at only five percent of registered capacity.
The peak available capacity percent is the amount of extra system capacity available after serving system peak load, and is shown in Figure 6–3.

**Figure 6–3  Peak available capacity percent**

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak available capacity (MW)</th>
<th>Peak load (MWh)</th>
<th>Peak available capacity percent</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>62,332</td>
<td>45,301</td>
<td>38%</td>
</tr>
<tr>
<td>2015</td>
<td>62,958</td>
<td>45,279</td>
<td>39%</td>
</tr>
<tr>
<td>2016</td>
<td>68,839</td>
<td>50,622</td>
<td>36%</td>
</tr>
<tr>
<td>2017</td>
<td>67,950</td>
<td>51,181</td>
<td>33%</td>
</tr>
<tr>
<td>2018</td>
<td>67,475</td>
<td>49,926</td>
<td>35%</td>
</tr>
<tr>
<td>2019</td>
<td>66,953</td>
<td>51,230</td>
<td>31%</td>
</tr>
</tbody>
</table>

For 2019, the peak available capacity percent was 31 percent, down from 35 percent in 2018. Although peak available capacity decreased by around 500 MW from 2018 to 2019, the increase in peak load of 1,300 MW was the primary driver for the decrease in peak available capacity percent. At 31 percent, peak available capacity is still over two and a half times higher than SPP’s minimum required planning reserve margin of 12 percent. Also, note that the peak availability capacity metric will differ from the reserve margin calculated by SPP because of differences in methodology. Most notably, the SPP methodology only includes capacity with firm transmission, whereas the MMU’s metric includes all system resources interconnected with the SPP grid using derate factors.

A relatively high peak available capacity percentage such as this has positive implications for both reliability and mitigation of the potential exercise of market power within the market. However, it also contributes to downward pressure on market prices, negatively affects revenue adequacy, and can burden ratepayers with additional and potentially unnecessary costs.

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163 2015 uses the total capacity on September 30, prior to the addition of the Integrated System.
164 *SPP Planning Criteria*, Section 4.1.9.
The SPP tariff requires SPP to conduct an annual Integrated Transmission Planning 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. The assessment employs a set of modeling assumptions that are used as the starting point for planning studies and identifies system needs from interconnection and transmission service requests within the limits of the process timelines established. The process coordinates the evaluation of transmission service needs and associated projects with those identified in the ITP assessment. This approach facilitates continuity in SPP’s overall transmission expansion plan.

Each integrated transmission plan has a study scope that receives input from stakeholders in conjunction with the assumptions and parameters that are not standardized in the integrated transmission process manual. The SPP transmission planning studies coordinate the evaluation of transmission service needs—resulting from generator interconnection and transmission service requests—and associated projects with those identified in the ITP assessment to conduct an overall transmission expansion plan.

SPP, along with the ESWG and the Transmission Working Group (TWG), develops an assessment scope for each ITP assessment for items that require SPP stakeholder review and approval with each new study. The study scope document describes the assumptions and methodologies that need to be updated at each study cycle so that the future performance of the existing transmission system and any needed improvements can be assessed.

165 *SPP Open Access Transmission Tariff*, Sixth Revised Vol. No. 1, Attachment O Transmission Planning Process, Section III.
166 The latest version of the ITP manual published can be found at [https://www.spp.org/engineering/transmission-planning/](https://www.spp.org/engineering/transmission-planning/).
167 SPP also performs a 20-year assessment. The first ITP 20-year assessment will be completed in October 2022.
170 The most recent scope document is the “2021 Integrated Transmission Planning Assessment Scope,” published on January 23, 2020. The document was approved by the SPP stakeholder process.
In 2019, the MMU participated in the development discussions of the 2021 ITP scope. The MMU’s input included assumptions for futures to incorporate various market developments.

### 6.1.4 2021 ITP ASSESSMENT SCOPE FUTURES

The initial 2021 ITP scope proposal developed by the ESWG maintained the 2020 ITP’s two-scenario approach—the Reference case (Future 1) and the Emerging Technologies case (Future 2). The MMU recommended adding a third case to the scope to take into account recent market developments such as higher levels of renewable build and generator retirements, a possible shift in environmental regulations, accelerated deployment of storage devices or electric vehicles, and announced changes in corporate policies in the footprint toward more reduced carbon emissions. The MMU further argued that if the cost concerns of running a third future from 2020 ITP still remain, then the study process should be enhanced by allowing to study a range of potential outcomes through factoring them into either an existing case study or potentially as part of the 20-year assessment. The MMU also pointed out other RTO practices and proposals, particularly MISO’s initiative to update its planning scenario assumptions related to some of the above-mentioned market developments.

Subsequently, and based on the early ESWG discussions whether to follow a two or three future approach, the MMU made the following recommendations:

- If a two-scenario approach is to be adopted, the second future should be a Carbon Reduction future as a bookend to reflect a higher renewable build and more generator retirements.
- Should a third future to be considered (i.e., the Emerging Technologies case), it should be the middle future.

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171 During the 2020 ITP discussions, inclusion of a third scenario recommended by stakeholders and the MMU was rejected due to additional cost concerns for running a third scenario.


173 MMU presented these recommendations at the October 15-16, 2019 MOPC meeting as well.
- The Carbon Reduction future be included in the consolidation calculations for final portfolio decisions.

- Generator retirement age assumptions should be updated based on current information and trends.

- Higher historical growth rates of renewable build and penetration should be represented.

The SPP’s stakeholder process approved the two-scenario approach, the Reference case and the Emerging Technologies case for the 2021 ITP scope study.\(^{174}\) Subsequently, the ESWG approved that sensitivities be performed for the 2021 ITP to proxy the previously recommended third future assumptions individually and comprehensively.\(^{175}\) In addition to natural gas prices and demand, these sensitivities will reflect elements originally proposed by the MMU including a carbon adder, increased renewables and storage, and fossil fuel retirements.

Meanwhile, the Reference Case scenario maintained the generator retirement age assumptions from the 2020 ITP. However, based on current information and trends the Emerging

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\(^{174}\) In its August 2019 meeting, the ESWG failed to approve a motion to include the third future in final portfolio consolidation calculations. However, in its October 2019 meeting, the ESWG approved a motion to fully develop a portfolio for the third future as a bookend—Mandated Carbon Reduction—and use it to inform consolidation decisions between futures 1 and 2. This decision was carried over to the October 2019 Markets and Operations Policy Committee (MOPC) meeting as well where it was rejected by the stakeholders in favor of a two-future decision. The decision-making for the consolidation portion of the 2021 ITP scope was discussed at the April 2020 MOPC meeting where ESWG and SPP staff provided additional information, and input from the SPP’s Strategic Planning Committee was received in its April 2020 meeting.

\(^{175}\) “Sensitivity analyses will be defined in the scope and conducted to measure the flexibility of the final portfolio in each ITP assessment. Generally, these sensitivities will not be used to select the proposed transmission projects, nor to filter out projects. Sensitivities may consider variations in demand, fuel prices, renewable energy, or other relevant considerations as determined during futures development.” See the ITP manual section 7.2.
Technologies scenario assumes coal generators, and gas-fired and oil generators to retire over the age of 52 and 48, respectively. This more closely aligns with the MMU recommendation.

Finally, the stakeholder process also approved the following:\(^{176}\)

- Total projected utility scale solar, wind, and storage will be accredited based on the approximate average ELCC value for the respective resource.\(^{177,178}\)

- Projected wind and energy storage resources accredited capacity used to meet load and reserve requirements will be capped at 12 percent of a load serving entity’s total load. This reflects the assumption that these resources will not have transmission service and thus can only be used to meet the 12 percent reserve margin.

### 6.1.5 2021 ITP GENERATOR RETIREMENT ASSUMPTIONS

The initial 2020 ITP scope proposal carried forward the 2019 ITP assumptions which assumed 60 years as the retirement age of for coal and natural gas-fired generators. Last year, the MMU recommended updating the 2020 ITP retirement assumptions to no more than the Energy Information Administration (EIA) average for the last five years (2013 through 2017) as the existing assumptions appeared to underestimate the actual retirement trend in the SPP market.

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\(^{177}\) Accreditation of existing renewable units is determined by market participant data. If no data are submitted then it will default first to previous ITP study data and secondly to the average of the submitted data for existing resources in the 2021 ITP, capped at the accreditation values for projected values. A projected resource that is assigned ownership to a load serving entity is eligible for capacity credit. Projected wind, utility scale solar, and energy storage resources will have a stand-alone capacity accredited at 20, 70, and 100 percent, respectively. *Ibid.*

\(^{178}\) In 2019, first the Supply Adequacy Working Group (SAWG) and later the ESWG approved the ELCC method as the guiding principle for the accreditation of solar and wind resources. As of March 2020, the SAWG is also in the process of adapting ELCC as the method for the accreditation of energy storage resources as well. (See Section 6.2 for more on the MMU’s involvement in other working groups).
The averages were 56 years for coal and 50 years for natural gas-fired generators. The MMU based its analysis on the historic retirement data compiled by the EIA. The stakeholder process approved the MMU recommendation.

In 2019, the MMU recommended updating the generator retirement age assumptions for the Emerging Technologies future to consider the latest EIA data. As a result, while the 2021 ITP Reference Case scenario kept the generator retirement age assumptions from 2020 ITP, the Emerging Technologies scenario assumed coal generators, and gas-fired and oil generators to retire over the age of 52 and 48, respectively, which more closely aligns with the MMU recommendation.

The MMU continues to argue that its net revenue analysis indicates a new coal resource cannot recover fixed operating and maintenance (O&M) costs at current market prices (see Section 4.4 for 2019 results). In addition, the trend for coal and natural gas resources’ average retirement ages in 2019 remained below the five-year EIA averages. As such, even lower retirement ages for the next 10 years could be expected. The MMU’s argument is also supported by the announcements of several market participants over the last couple years redirecting their investment policies towards more renewable resources and less carbon intensity.

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179 The last five year averages through November 2018 (2014-2018) were even lower, 55 years for coal and 49 years for gas-fired resources.

180 The MMU used the EIA’s monthly generator retirement data for the entire U.S. to calculate historic averages for each year. The average retirement years were calculated for the three five-year sub periods to see historical trends for coal and gas-fired generators, and the most recent sub period was used for the recommendation. Only the electric utility generators were included in this calculation (See EIA-860M Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860 available at https://www.eia.gov/electricity/data/eia860M/).

181 For instance, Omaha Public Power District (OPPD) set a long-term goal of providing at least 50 percent of its retail sales from renewable sources and reducing its carbon intensity by 20 percent from 2010 to 2030 (S&P Global Market Intelligence published on Nov., 5, 2018). Xcel Energy Inc. announced that it plans to completely decarbonize its power supply portfolio serving eight states by midcentury, first cutting carbon emission by 80 percent by 2030, from 2005 levels in its utility service territories in Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin (S&P Global Market Intelligence published on Dec., 4, 2018). AEP first announced in February 6, 2018 that it will pursue a goal to reduce its CO2 emissions of its generating units 60 percent by 2030 and 80 percent by 2050 from 2000 levels. (https://www.aep.com/news/releases/read/1503/AEPs-Clean-Energy-Strategy-Will-Achieve-Significant-Future-Carbon-Dioxide-Reductions-). In September 10, 2019, the company stated that it’s cutting CO2 emissions faster than anticipated and revised its 2030 reduction target to 70 percent from 2000 levels. (https://www.aep.com/news/releases/read/1615/AEP-Accelerates-Carbon-Dioxide-Emissions-Reduction-Target).
Figure 6–4 shows the data for average age of retirements for coal and natural gas-fired resources for the U.S.

**Figure 6–4  Average age of retirements for coal and gas resources**

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>48</td>
<td>54</td>
<td>64</td>
<td>54</td>
<td>54</td>
<td>56</td>
<td>58</td>
<td>56</td>
<td>56</td>
<td>49</td>
<td>50</td>
</tr>
<tr>
<td>Gas</td>
<td>52</td>
<td>43</td>
<td>49</td>
<td>48</td>
<td>51</td>
<td>52</td>
<td>48</td>
<td>46</td>
<td>52</td>
<td>46</td>
<td>51</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>2002-19</th>
<th>2010-19</th>
<th>2015-19</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>54</td>
<td>55</td>
</tr>
<tr>
<td>Gas</td>
<td>49</td>
<td>49</td>
</tr>
</tbody>
</table>

Source: EIA-860 Electric Utility Retirements (data through December 2019).

Figure 6–5 below presents the age of all existing resources along with the original proposed retirements and with the change associated with using EIA averages.

**Figure 6–5  Average age of generators in the SPP market**

![Diagram showing average age of generators in the SPP market]

6.1.6 **OTHER TOPICS**

Additionally, the ESWG made several decisions including the following:

**ITP 20-year assessment**
In addition to annual ITP assessments, SPP is also required to perform 20-year assessments at least once every five years, or more frequently if approved by the SPP Board of Directors.\(^{182}\) These assessments review the system for a twenty-year planning horizon and address, at a minimum, facilities 300 kV and above needed in year 20. SPP’s ITP 20-year assessment will be completed in October 2022.\(^{183}\)

**Inflation rate assumption**

As the result of a market participant request at the ESWG, SPP staff was tasked to investigate if the—then existing—2.5 percent inflation rate assumption used in ITP assessments was appropriate. SPP staff requested the MMU’s help, and the MMU recommended that two percent would be a more appropriate figure, based on the publically available data and expectations. The ESWG approved the MMU recommendation. The 2021 ITP Assessment will use two percent instead of 2.5 percent as the inflation factor.

**The new federal corporate tax rate, PTC “phase out” and renewable curtailment pricing**

The ESWG approved Revision Request (RR) 362 which proposed “...[to align] the Market Economic Model curtailment price of wind resources more closely with the marginal cost of wind observed in real-time operation of the SPP Integrated Marketplace, with existing PTC [production tax credit] rules and federal corporate tax rate."\(^{184}\) Among other things, the revision request provided that:

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\(^{182}\) SPP Open Access Transmission Tariff, Sixth Revised Vol. No. 1, Attachment O, Section IV.2.

\(^{183}\) Per MOPC Action Item 300 (issued in the October 15–16, 2019 MOPC meeting), SPP staff investigated the feasibility and budget impacts of expediting the ITP 20-year assessment to assess if it can be used to inform the 2021 ITP in a manner similar to the ESWG’s proposal to add a third future in the 2021 ITP. Only one of the three options evaluated by the staff had a possibility that could be used to inform the 2021 ITP project consolidation with a completion time of October 2020. Staff recommended—and the Transmission Working Group and the ESWG endorsed—the option that did not include the above-mentioned capability.

\(^{184}\) Revision Request 362, ITP Manual Renewable Curtailment Pricing. MMU filed comments in support of the recommendations made through Revision Request 362.
• The approximate “grossed-up” PTC value used in determining the curtailment price that qualifying wind facilities receive will be calculated by using the new federal corporate tax rate of 21 percent, which changed from 35 percent in 2019.185

• The ITP manual language to include a process and formula for calculating an inflation adjusted “grossed-up” PTC value per study rather than a predetermined PTC value for qualifying wind facilities.

• The renewable curtailment pricing methodology in the ITP manual to reflect PTC “phase out” for existing qualifying wind facilities in accordance with applicable laws and regulations.186

• The renewable curtailment pricing methodology in the ITP manual is updated to apply a $0/MWh curtailment price to utility-scale solar, and allows SPP and the ESWG to determine an appropriate negative curtailment price for distributed solar to limit distributed solar curtailments.187

6.2 MMU INVOLVEMENT IN OTHER WORKING GROUPS

In addition to the ESWG, the MMU followed other working group activities in 2019 including the Supply Adequacy Working Group (SAWG), the Regional Tariff Working Group (RTWG), the Business Practices Working Group (BPWG), the Operating Reliability Working Group (ORWG),

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185 SPP employs a negative $35/MWh curtailment price as an approximation of the “grossed up” $23/MWh PTC value in 2016 dollars and 35 percent federal tax rate. The new figure changes approximately to $30/MWh in 2016 dollars based on the new 21 percent federal tax rate.
186 The PTC “phase out” is the reduction in PTC for wind facilities commencing construction in 2017, 2018, and 2019 by 20 percent, 40 percent, and 60 percent, respectively and the requirement to be in service within four calendar years after the calendar year during which construction commenced (see RR 362). The—then—current manual language did not have this provision.
187 The current manual language does not differentiate between distributed solar and utility-scale solar. The distributed solar is generally nonresponsive to locational marginal prices, and the proposal introduces a more realistic approach.
and the Transmission Working Group (TWG). The MMU’s involvement was primarily in the context of generator retirements and the adoption of Effective Load Carrying Capability (ELCC) as the method for accrediting renewable resource capacity.

For generator retirements, the MMU participated in stakeholder discussions primarily for the following two reasons: 1) explain and educate market participants about the MMU’s new approach for enhancing data gathering process for generator retirement evaluations, including the use of going forward cost data templates; and 2) attend stakeholder discussions regarding the SPP’s new generator retirement process introduced in Revision Request 373. For the former, the MMU conducted presentations to explain the process and answer stakeholder questions during the working group discussions. For the latter, the MMU provided feedback either in the form of participating in discussions or filed comments for Revision Request 373 in order to ensure that the SPP’s new process will not have adverse market impacts or impede with the MMU’s market power monitoring functions.

For the ELCC topic, the MMU closely followed discussions on the adoption of ELCC as the method for accrediting renewable resources first in SAWG and later in ESWG. In 2019, the SAWG initiated and stakeholders approved to adopt the ELCC method as the guiding principle for accrediting solar, wind, and storage resources to replace the current accreditation methodology found in section 7.1.6.1 (7) of the SPP Planning Criteria. Subsequently, the ESWG also approved to use the ELCC method for wind and solar accreditation in 2019.

As of March 2020, the SAWG is also in the process of adopting ELCC as the method for the accreditation of energy storage resources. The MMU provided input into the methodology.
discussion\(^{189}\) that the ELCC is a better approach for accreditation of storage resources compared to the alternative Capacity Value method,\(^{190}\) primarily because:

- It is a more sound method for accrediting storage resources when compared to the Capacity Value as it more accurately accounts the effective capacity that a system can use;
- It represents a consistent approach since the ELCC is the recently adopted method for determining renewable—wind and solar—resources' capacity accreditation in the SPP market; and
- Its use would be consistent with other RTOs/ISOs applications as it gains more acceptance among them.

The Economic Arbitrage—rather than the Preserve Reliability—approach should be considered as the underlying principle for allowing and operating storage resources. The Economic Arbitrage schedules storage resources in order to optimize economic arbitrage.\(^{191}\) The model will still schedule these resources to be dispatched during high net load hours however, since the model does not have perfect foresight of generator performance, the schedule may be suboptimal from a reliability perspective. For instance, when a storage resource is scheduled for dispatch at the highest net load hours of the day, and a generator fails toward the end of the high net load period, a reliability issue can be created. Because the storage resource was dispatched during the high load hours, they will no longer be available to prevent firm load shed.

\(^{189}\) Through written comments provided on the energy storage accreditation methodology white paper, prepared by an outside consultant.

\(^{190}\) The capacity value methodology calculates the capacity credit as follows: First, a “base” case of the system is established by using reliability standard of 0.1 (or one day in ten years) Loss of Load Expectation (LOLE). Next, the storage resources are added to the system, improving reliability. Then, conventional capacity with an equivalent forced outage rate (EFOR) of 5 percent or below is removed until the LOLE returns to the 0.1 reliability level. The capacity credit of the storage resource is taken to be the ratio of the capacity of storage added to the capacity of conventional resources removed. (See “Energy Storage Accreditation Methodology” (ELCC Storage White Paper), SPP, January 2020 at p. 3, in Supply Adequacy Working Group March 11, 2020 meeting materials).

\(^{191}\) Ibid. at 5-6.
The Preserve Reliability method, on the other hand, would not have dispatched such resources during the high net load hours if they were not needed to prevent firm load shed. Under this approach, storage resources is not scheduled in advance, and only dispatched when needed to prevent load shed. Accordingly, the economic arbitrage method provides less capacity credit than the Preserve Reliability method depending on the extent of generator performance uncertainty. Additional uncertainty elements such as uncertainties on load forecast or renewable output could introduce more divergence between the two methods.

The MMU supports the Economic Arbitrage approach in the SPP market because:

- SPP operates on a principle that reliability and economics are inseparable,

- SPP’s—FERC approved—mitigation methodology for storage resources

  - Presumes economic optimization and arbitrage as the underlying market offer behavior by such resources, and establishes that storage resources will make offer, charging and discharging decisions based on forecasted prices, and

  - Similar to other resources, commercially owned storage facilities are expected to operate on a profit maximization—or economic arbitrage—principle.

While describing storage resources expected economic behavior, the MMU underlined that the asset’s physical parameters (e.g., maximum/economic operating limits) should be observed so as to avoid physical withholding behavior. In that context, and under the Preserving Reliability approach, the MMU stated that not scheduling a resource in advance and preserving it for peak periods to prevent firm load shed may lead to physical withholding behavior where the market participant may be subject to mitigation. The MMU noted that current SPP market rules do not provide an option for “preserving reliability” should a resource derate or declare outages for the above-mentioned purpose and recommended SAWG to consider these points when evaluating available options.

Finally, for hybrid resources the MMU recommended SAWG to consider and evaluate the following options separately for storage resources for both reliability and efficiency:
• When a resource operates as a standby asset charging and discharging from/into the system

• When a resource is co-located with renewable resource(s), and

• When a resource is co-located with renewable resource(s) behind the meter

The MMU will continue to follow working group discussions particularly with respect to specific topics that may have market efficiency implications for the SPP market.

6.3 ASSESSMENT

The MMU has a unique position to evaluate SPP data and market outcomes and provide feedback in the planning process to improve efficiencies and outcomes. This involvement has already proven beneficial as stakeholders have approved previous MMU recommendations for the 2020 ITP. Similarly, the MMU also provided input into the development of 2021 ITP scope assumptions based on recent market developments such as recommending to add a third future to reflect higher renewable capacity build, increased retirements, and associated carbon reductions. Although the MMU’s recommendation was not accepted by the stakeholders, the Emerging Technologies case (Future 2) will have sensitivities to incorporate such market changes including a carbon adder, increased renewables and storage, and retirement sensitivities to proxy a third (bookend) scenario originally proposed by the MMU.

In other instances such as updating the inflation rate assumption and renewable curtailment pricing of the ITP manual, the MMU was able to provide valuable feedback to the SPP staff and the ESWG due to its expertise on market issues as well as having the most up-to-date data. As in the case of such topics, the MMU is also prepared to provide directional guidance to the planning process to enhance market efficiency and planning outcomes when financial assumptions are made.

6.4 RECOMMENDATIONS GOING FORWARD

Based on its experience with the planning process starting in 2018, the MMU recommends the planning process continue to use data gathering and analysis methods to determine economic
modeling inputs so that a more accurate assessment can be made for the SPP’s system needs and conditions. One way to accomplish this is to keep abreast of ongoing market and regulatory developments, assess likely changes, and review best practices across other organized markets.

Another important issue is the generator retirement age assumptions used in economic modeling. In addition to market participant input, substantial consideration needs to be given to the operational realities and historical trends when the assumptions for retirement ages are made. The MMU will continue to provide feedback to the ESWG on this issue as more data become available. The futures used in the planning process allow for the assessment of likely deviations from the (base) reference case where the impact could be significant. When including scenarios, the ITP scope should consider developments occurring in the power sector in general with due considerations given for probable shifts in environmental regulations, market trends, or technological advancements. In addition, the planning processes should factor in announcements with regard to major shifts in corporate policies given the evolving market trends and technologies towards more renewable generation and reduced emissions.

The planning process should have the ability to assess a range of potential outcomes in transmission planning. Following market trends helped shape the MMU’s thinking in terms of how to consider the future generation mix and the potential need for an additional scenario. As in the case of 2020 ITP, the MMU believed that a third (standalone) scenario would provide a bookend scenario for the 2021 analysis but was rejected again by stakeholders as it was considered too costly to study.

While the transmission planning process theoretically can include a third scenario, in practice it does not have the flexibility to include one as the cost of including a third scenario was not unique to the 2021 planning process. This appears to be a significant shortcoming in the planning process as the study process is limited to only two potential scenarios in its 5- and 10-year look ahead. This limits the range of potential outcomes that SPP could study\(^{192}\) or alternatively requires the cases to be very broad and different from each other.

\(^{192}\) The MISO transmission planning process studies four cases, see https://cdn.misoenergy.org/MTEP19%20Futures%20Summary291183.pdf.
Notwithstanding, although the stakeholders decided to follow 2020 ITP’s two-scenario approach for 2021 ITP—the Reference case and the Emerging Technologies case—the Emerging Technologies case will have sensitivities to reflect elements originally proposed by the MMU including a carbon adder, increased renewables and storage, and retirement sensitivities to proxy a third (bookend) scenario. The MMU is aware that these sensitivities will only be used to consider variations of above-mentioned market changes, and not to select or filter out transmission projects however, they represent an improvement in the absence of including a third standalone scenario in futures development.

The MMU continues to recommend that SPP enhance their study process to allow the ability to study a range of potential outcomes. If such a range of potential outcomes are not captured in a third case study, the MMU recommends to factor them into either an existing case study by way of running sensitivities or potentially as part of the 20 year assessment. The wider the range of possibilities studied, the more robust the results will be.
7 COMPETITIVE ASSESSMENT

Chapter 7 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 55 percent of the hours in 2019, the market share of the largest on-line supplier in terms of real time energy output exceeded 20 percent, which represents a significant increase from 2018. This trend, which coincides with the merger between Great Plains Energy and Westar Energy to form Evergy, Inc., has been observed since June 2018 and is attributable to real-time dispatch of resources owned and controlled by the merged entity.

- The HHI market concentration analysis shows that 11 percent of hours were considered moderately concentrated in 2019. As with the market share analysis, the HHI analysis shows a sustained increase in market concentration beginning with the aforementioned 2018 merger.

- The results of the pivotal supplier analyses indicate that the percent of hours with a pivotal supplier is the highest in the New Mexico and West Texas region, regardless of demand level. Meanwhile, the Iowa, Dakotas, Montana region experienced a continued decrease in pivotal supplier frequency from 2018 when demand was below the 80th percentile; however, the highest demand block still exhibited 100 percent pivotal supplier frequency.

- Both off-peak and on-peak annual average markups were at their lowest levels since the implementation of the Integrated Marketplace at around $8.78/MWh and $8.48/MWh, respectively.

- Incremental energy offer mitigation in 2019 was extremely low, with less than 0.01 percent of hours mitigated in both the day-ahead real-time markets. The overall mitigation frequency of start-up offers was the lowest since the market started in 2014.
The combined mitigation frequency of start-up offers for day-ahead, reliability unit commitment, and manual commitments was 2.8 percent in 2019.

- The output gap in 2019 increased relative to prior years, but still remains infrequent. The results of the output gap analysis continue to show very low levels of economic output withheld in the SPP footprint—less than 0.2 percent on annual average level. These outcomes are consistent with competitive market conduct.

- The unoffered economic capacity analysis results show that, on an annual average basis, total unoffered capacity equaled 1.9 percent in 2017, 3.2 percent in 2018, and 2.9 percent in 2019. The majority of the unoffered capacity was due to long-term outages for maintenance in the spring and fall shoulder months.

- Participants began including major maintenance costs in mitigated start-up and no-load offers in April 2019. Following this policy change, the day-ahead mitigation frequency for start-up and no-load offers continued a downward trend when measured against the same period in previous years.

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 2019, 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. Behavioral indicators include offer price markup,\textsuperscript{193} economic withholding analysis, addressed through automated mitigation and indicated by output gap analysis; uneconomic production; and physical withholding.\textsuperscript{194}

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 \textit{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.

7.1 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 7–1 displays the market share of the largest on-line supplier in terms of energy dispatch in the real-time market by hour for 2019.

\textsuperscript{193} While the SPP MMU uses offer price markup, other market monitors may use price cost markup as a behavioral indicator.

\textsuperscript{194} The uneconomic production and physical withholding analysis are addressed through FERC referrals instead of automatic mitigation.
The market share ranged from 11.3 percent to 28 percent, exceeding the 20 percent threshold\(^{195}\) in 4,837 hours (55 percent) for the year. In 2018, market shares ranged from 9.1 percent to 28.4 percent, with market shares exceeding the 20 percent threshold in 35 percent of intervals. The increase in intervals with a market share over 20 percent continues a pattern that began in June 2018 with the merger between Great Plains Energy (parent company of Kansas City Power & Light) and Westar Energy to form Evergy, Inc. In fact, during almost all of hours with a largest share above 20 percent, the largest on-line supplier was Evergy. Furthermore, these 4,837 hours are distributed throughout the year, without any noticeable concentration during any period or season. 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:

\(^{195}\) 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.
According to FERC’s “Merger Policy Statement,”\textsuperscript{196} 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 7–2 provides the number of hours for each concentration category in terms of actual generation over the last three years.\textsuperscript{197}

\begin{figure}[h]
\centering
\begin{tabular}{|c|c|c|c|c|c|}
\hline
\textbf{Concentration} & \textbf{HHI Level} & \textbf{2017} & \textbf{2018} & \textbf{2019} \\
\hline
Unconcentrated & Below 1,000 & 8,760 & 7,692 & 7,768 \\
\hline
Moderately concentrated & 1,000 to & 0 & 1,067 & 984 \\
\hline
Highly concentrated & Above 1,800 & 0 & 0 & 0 \\
\hline
\end{tabular}
\caption{Market concentration level, real-time}
\end{figure}

The SPP market was unconcentrated in all hours of 2016 and 2017. However, 12 and 11 percent of hours were considered moderately concentrated in 2018 and 2019, respectively. The SPP market has never risen above the highly concentrated threshold of 1,800 since the start of the Integrated Marketplace in 2014. Figure 7–3 depicts the hourly real-time market HHI in terms of generation for 2019.

\textsuperscript{196} 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{197} 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. Nonetheless, there were only eight such missing hours in 2019, amounting to less than 0.1% of all observed intervals.
Hourly HHI values ranged from 601 to 1,192 during 2019, consistent with post-merger values observed in 2018.

Figure 7–4 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 market—2015, for the addition of the Integrated System; and 2018, with the creation of Evergy—the years are divided on the chart showing the HHI before and after the event.
As shown above, the market remained mostly unconcentrated from the addition of the Integrated System to the date of the Great Plains/Westar merger. Even though moderately concentrated hours increased following the creation of Evergy, only 11 percent of hours fell into this category in 2019. 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. Given the HHI results in conjunction with the elevated market shares, this report takes a closer look at market behavior by market participants in terms of the exercise of local market power.

SPP market participants with large, diversified generation portfolios have the greatest ability to benefit from structural market power. These market participants may frequently set prices regardless of the technology type on the margin. Figure 7–5 depicts the percentage of real-time market intervals in which each market participant had a resource on the margin.

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198 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.

199 Section 7.2 analyzes behavioral aspect of market power.

200 The Kansas City Power & Light and Westar Energy market participants were combined for the purpose of this analysis.
The top three market participants each set price in approximately 10 to 15 percent of all real-time market time intervals. Conversely, the majority of participants set price in less than one percent of all intervals.²⁰¹

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 locational 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

²⁰¹ The percentages on this chart are not additive because multiple market participants may have a resource on the margin during any given interval.
time periods irrespective of its size. SPP’s market clearing process automatically evaluates and—if necessary—mitigates local market power throughout the network.

The following metric identifies the frequency with which at least one supplier was pivotal in the five different reserve zones\(^2\) (regions) of the SPP footprint in 2019.\(^3\) 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 7–6.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure7-6.png}
\caption{Hours with at least one pivotal supplier}
\end{figure}

\(^2\) 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 2019.

\(^3\) 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 continuing downward trend has occurred since 2017 for all demand levels with the exception of the highest demand block exhibiting 100 percent pivotal supplier frequency.\textsuperscript{204,205}

Compared to 2018, while the Kansas, Missouri, Oklahoma, Arkansas, East Texas, Louisiana region increased from nearly 3 percent to 32 percent the Nebraska region decreased from 34 percent to 11 percent during the highest demand hours with a pivotal supplier.\textsuperscript{206}

### 7.2 BEHAVIORAL ASPECTS OF THE MARKET

#### 7.2.1 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

\textsuperscript{204} Pivotal supplier frequency from 2018 to 2019 decreased from 66 to 61 percent for blocks less than the 20\textsuperscript{th} percentile and from 86 to 77 percent for demand blocks between the 20-80\textsuperscript{th} percentiles.
\textsuperscript{205} This downward trend originates, in part, from the improvement of the methodology by recalculating pivotal supplier frequency compared to previous years. The previous approach removed megawatts in market status only—assuming as available capacity—without removing megawatts in self-commit or reliability status which may potentially distort the market pivotal status. The new method removes all non-outaged resources by a market participant for the test. As a result, this decreases total available supply by all resources from which the largest supplier will be chosen as pivotal. The numbers recalculated based on this new methodology show changes to some extent in the Kansas, Missouri, Oklahoma, Arkansas, East Texas, Louisiana region, and the Nebraska region. The Western Kansas and Panhandles region, when recalculated, did not have significant changes.
\textsuperscript{206} Note that this analysis differs from the MMU’s Frequently Congested Areas (FCA) study where 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.
market performance, a comparison is made between the market offer and the mitigated offer for the marginal resources for each real-time market interval.

Figure 7–7 provides the average marginal resource offer price markups\textsuperscript{207} by month for on-peak and off-peak periods. The MMU observed a growing trend of negative markups in both on-peak and off-peak periods in 2018,\textsuperscript{208} which continued across all months in 2019 (see Figure 7–8 for annual ranges). This implies significant and increased price pressure in the SPP market.

Figure 7–7  
\textbf{Average offer price markup of marginal resource, monthly}

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure7-7}
\end{figure}

In 2019 average monthly markups ranged from $-11.41$ to $-3.84$/MWh for off-peak periods and from $-18.50$ to $-3.04$/MWh for on-peak periods. The lowest markups occurred in spring and winter in off-peak and on-peak hours, when wind generation was generally the highest.

Figure 7–8 below points to a continued annual decline in off-peak and on-peak average marginal resource offer markups.

\textsuperscript{207} 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.

\textsuperscript{208} With the exception of January, November, and December 2018.
Both off-peak and on-peak average annual markups were at the lowest levels since implementation of the Integrated Marketplace at around −$8.78/MWh and −$8.48/MWh, respectively, showing significantly lower levels compared to 2018 figures. Although a lower offer price markup level in itself would indicate competitive pressure on suppliers in the SPP market, the observed continuous and deepening downward trend may raise questions about the continued commercial viability of generating units and the possibility of generation retirements, as well as inappropriate behavior.209 Despite this trend, SPP continues to add new generation (mostly wind), and generation capacity relative to peak loads remains high (see Section 6.1.3). More renewable generation is anticipated to be added over the next few years, which is expected to outweigh planned retirements. As such the trend in negative offer-price mark ups will likely continue, further pressuring the economic viability of many generating resources. This concern is also a reason why the MMU recommended, and the Holistic Integrated Tariff Team adopted, a recommendation to study if automatic mitigation of unduly low offers should be developed.

Figure 7–9 shows the average on-peak marginal resource offer price markup by fuel type for 2019.

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209 Uneconomic Production is reviewed per the Market Monitoring Plan, SPP Open Access Transmission Tariff, Attachment AG, Section 4.6.1.
The observed levels of negative markups indicate that many market participants’ real-time market offers were below their mitigated offers. 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, or

- ensure they run to be able to receive production tax credits (PTC), as in the case of wind resources that constitute a sizeable share in total resource portfolio.

For instance, wind resources at the margin in the real time market increased from 11 percent of all resource intervals in 2017 to just over 17 percent in 2019 (see Figure 2–22).

Wind units may have negative mitigated offers primarily as a result of the federal production tax credit (PTC) for renewable energy.

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 negative 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 experienced negative natural gas prices in 2019.
7.2.2 MITIGATION PERFORMANCE AND FREQUENCY

SPP employs an automated conduct and impact mitigation process to prevent the exercise of local market power through economic withholding. The mitigation applies to resources that exercise local market power in transmission-constrained areas, resources in reserve zones experiencing shortages, and resources manually committed by SPP.

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 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.

Mitigation frequency remains very low, with some variation across products and markets. Figure 7–10 shows that the mitigation of incremental energy, operating reserve, and no-load offers was generally infrequent in the day-ahead market in 2019.

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212 No reserve zone shortages occurred in 2019.
213 As indicated in Appendix G of SPP’s Integrated Market Protocols.
Overall patterns for mitigation frequency for the three products in the day-ahead market were similar to those in 2018, with relatively small increases in mitigation frequency for operating reserves concentrated primarily in the first half of 2019. Mitigation frequency increased slightly in April, May, and October, particularly for no-load offers, but remained lower on an annual basis than in 2018. The application of mitigation in the day-ahead market occurred at levels of 0.08 percent for operating reserves, 0.15 percent for no-load, and less than 0.01 percent for incremental energy.

Mitigation of incremental energy in the real-time market is shown in Figure 7–11 below.
For the real-time market, the mitigation of incremental energy has remained low since the start of the market, with an annual average less than 0.01 percent in 2019, lower than the averages observed in 2017 and 2018.

Figure 7–12 depicts the mitigation frequency for start-up offers for the various commitment types.

The annual mitigation frequency of start-up offers in 2019 was at its lowest level since the market began in 2014 at just under three percent. While the frequency of reliability unit
commitment mitigation has been nonexistent since 2017, day-ahead and manual mitigation remained nearly identical to 2018 levels with 2.3 and 0.4 percent, respectively. Day-ahead mitigation accounted for 84 percent of the total start-up cost mitigation. The highest level of start-up offer mitigation occurred in October, at 6.5 percent, with the lowest occurring in August, at less than one percent.

7.2.3 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 actual amount of production. The economic level of output is produced by a generator between its minimum and maximum economic capacity.\(^\text{214}\)

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.\(^\text{215}\) 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

\(^{214}\) The MMU calculates this metric by including all resources’ total (reference level) capacity when calculating output gap percentages.

\(^{215}\) The frequently constrained area Lubbock stayed as such until February 22, 2019 after which Central Kansas and Southwest Missouri were designated as the two new frequently constrained areas in the SPP footprint. The following charts reflect this situation.
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 and for the two frequently constrained areas. In addition, the output gap is calculated for the largest three suppliers (market participant portfolios) in each area 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 7–13 below shows the monthly level of the output gap across the SPP footprint from 2017 to 2019.

Figure 7–13 Output gap, monthly

![Output gap, monthly chart]

Compared with the previous years, the output gap was significantly higher in 2019. Even so, it still remained at very low levels, averaging less than 0.2 percent in all months, reflecting a high level of participation in the market overall. The increase in April was due to the extreme

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flooding across the Midwest adversely impacting railroad service and coal deliveries to coal-fired plants. Because of the flooding, two coal resources increased their market offers to keep the inventory at higher levels without changing their mitigated offers. As for the elevated output gap in the following months, this was mainly due to a few resources consistently having significantly higher market offers relative to their mitigated offers, which accounted about 50 percent of the total output gaps in 2019.

Figure 7–14 displays the output gap calculated by demand level and participant size for the entire SPP market footprint, while Figure 7–15 and Figure 7–16 show the output gap for the two frequently constrained areas.217 The Lubbock frequently constrained area is excluded from the charts below as it was only active for the first two months of 2019 with insignificant impacts to the analysis. 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.

217 The Central Kansas and Southwest Missouri frequently constrained areas were activated on February 22, 2019, therefore data shown only cover March through December 2019.
The highest level of output gap (less than two percent) was observed in the newly designated Central Kansas frequently constrained area and only by the top three largest suppliers and during high demand periods. In general, the results indicate a very low level of economic output withheld in the SPP footprint, less than 0.1 percent on an annual average level. These outcomes are generally consistent with expectations of competitive market conduct.
7.2.4 UNOFFERED GENERATION CAPACITY (MEASURE FOR POTENTIAL PHYSICAL WITHHOLDING)

As part of the competitive assessment, the MMU also looked into the potential physical withholding behavior by generators throughout the 2017 to 2019 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.218,219

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.220 Any derates from reference levels are considered in this analysis.

Derates were divided into short-term and long-term. Those with 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

219 Economic capacity is determined in a similar way as in the output gap analysis in Section 7.2.3 by comparing resource’s (cost-based) mitigated offer to the prevailing locational price.
220 The planned maintenance outages by nuclear generation and unoffered capacity by hydro, wind, and solar is excluded in this analysis.
maintenance outages in high demand periods may indicate a strategic behavior to create artificial shortages.

In the assessment, the MMU considered derated and unoffered economic capacity both in day-ahead and real-time. Similar to the output gap analysis, the commitment decisions were made based on day-ahead market outcomes for non-quick-start units and real-time market outcomes for quick-start units. The unoffered capacity is calculated as the difference between the unit’s economic capacity 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 show unoffered economic capacity as percent of total resource reference levels by month for the SPP footprint, for the two frequently constrained areas, and by supplier (participant) size against varying load levels.

**Figure 7–17 Unoffered economic capacity**

Figure 7–17 shows that on an annual average basis the total unoffered capacity equaled 1.9 percent in 2017, 3.2 percent in 2018, and 2.9 percent in 2019.

The figure also shows that the majority of the outages were long-term and concentrated during the spring and fall shoulder months, and have increased since 2017. When short and long-term

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221 Bounded by a resource’s reference level.

222 Unoffered capacity percentages are calculated out of the total reference levels of the corresponding area (i.e., SPP footprint or each of the frequently constrained areas).
outages were excluded from the averages, the remaining unoffered capacity amounts to 0.23 percent, 0.39 percent, and 0.43 percent for 2017 through 2019, respectively. From an overall market perspective, the results generally indicate reasonable levels of total unoffered economic capacity.\(^{223}\) The latter results (net of outages), which are very low, could also be interpreted to indicate pressure on market participants, particularly on coal-fired resources, to offer—and maintain commitments—given their long-term coal contracts.\(^{224}\) The general high levels of self-scheduling of supply offers in the SPP market could be another contributing factor to this outcome.

Additionally, while the summer months had a large number of outages that caused conservative operations events, some of these resources would not have been profitable. This has raised concerns about price formation during emergency conditions, as well as incentives for availability. These concerns are raised in more detail in Section 3.4.

Figure 7–18 shows that short-term outages by either large suppliers or others do not rise with increasing load across the SPP footprint.

**Figure 7–18 Unoffered economic capacity at various load levels, SPP footprint**

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\(^{223}\) On an individual resource level, not offering economic capacity may be physical withholding depending on the facts and circumstances of the situation.

\(^{224}\) Resources may prefer to offer at times even below their mitigated offers to guarantee to be scheduled or dispatched. See also the offer price markup analysis earlier in Section 7.2.1 and the negative markup results reported therein.
On the other hand, unoffered economic capacity of gas (peaker) units—both by large and other suppliers—rises with increased load albeit at very low levels. Unoffered economic capacity with respect to load levels is more apparent for the remaining resource types, however, it does not exceed 0.24 percent for either of the supplier groups at any demand level.

Another take away from the results is that while long-term outages constitute the majority of total outages in the SPP footprint at higher load levels, short-term outages play a larger role in the two frequently constrained areas, as shown in Figure 7–19 and Figure 7–20. As with the output gap metrics, the Lubbock frequently constrained area was only active for the first two months of 2019, with results of this frequently constrained area being insignificant, they are not included as a chart in this section.

Figure 7–19 Unoffered economic capacity at various load levels, Central Kansas area

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225 The two new frequently constrained areas were activated on February 22, 2019, therefore data shown only covers March through December 2019.
The two frequently constrained area results, in general, show the dominance of larger participants in declaring short-term outages. Comparing with the SPP-wide data, the higher percentage of unoffered economic capacity in frequently constrained areas is mainly due to the size of the area. The total capacity of Central Kansas is 341 MW and Southwest Missouri is 1,355 MW. Consequently, even a single unit outage will represent a high percentage of unoffered capacity.226

The SPP-wide generation outage data227 (see Section 3.1.4) shows that most long-term outages were for out-of-service, maintenance outages (65 percent). Out of the short-term outages, approximately 42 percent were forced outages.

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226 On an individual resource level, outages are assessed for potential physical withholding depending on the facts and circumstances of the situation.

227 Covering all resources in the SPP market including nuclear, hydro, wind and solar generation.
7.3 ENERGY OFFER BEHAVIOR DUE TO MITIGATION THRESHOLD

As discussed in the 2016 State of the Market report, the MMU observed inefficient market behavior with regard to the mitigated threshold. The MMU recommended that mitigation measures for resources committed for a local reliability issue be treated separately from the mitigation measures for economic withholding.\textsuperscript{228} Resources that fall into this category are not subject to the three tests associated with economic withholding, which is appropriate.

The MMU submitted Revision Request 231\textsuperscript{229} to the Market Working Group in May 2017 to address this issue. In that revision request, the MMU proposed converting the 10 percent threshold for local reliability mitigation to a 10 percent cap. The change was implemented in December 2018 and caps offers at the mitigated offer plus ten percent for local commitments.

This should allow for more rational competitive energy offers from market participants without the concern for being mitigated to their mitigated offer curve to address a local reliability issue. Analysis was done to compare the offer behavior of the same month before and after the change. The results showed natural gas resources offering in the nine to ten percent range decreased from an average of 17 resources in November 2018 to eight resources in November 2019, indicating less self-mitigation.

7.4 START-UP AND NO-LOAD BEHAVIOR

Analysis of no-load and start-up offers showed that many market participants made start-up and no-load offers considerably above their mitigated offer levels (see Figure 7–21). Nonetheless, start-up mitigation only occurred in less than three percent of intervals in 2019 and day-ahead mitigation accounted for 84 percent of the total start-up cost mitigation. These figures were similar to results in 2018.

\textsuperscript{228} In its 2016 \textit{Annual State of the Market} report, \url{https://www.spp.org/documents/53549/spp_mmu_asom_2016.pdf}, the MMU recommended converting the 10 percent mitigation threshold for local reliability commitments to a 10 percent cap.

\textsuperscript{229} Revision Request 231, Mitigation of locally committed resources.
The MMU’s further analysis and discussion indicated that start-up mitigation was most frequently the result of major maintenance costs due to the repeated thermal stresses of starting-up and shutting down units that were included in market based offers but not mitigated offers. As the purpose of the mitigated offer is to prevent undue costs not directly tied to a commitment or dispatch decision from being imposed on the market, Revision Request 245 was developed and submitted in late 2017.\textsuperscript{230} This revision request allows for the inclusion of major maintenance costs that can be directly tied to the number of run hours or starts to be included in the mitigated offers for start-up and no-load and properly evaluated by the market clearing engine in determining commitments. Revision Request 245 was approved by the FERC in October 2018.\textsuperscript{231} Major maintenance costs have been included in mitigated start-up and no-load offers since April 2019. Following this change, day-ahead mitigation frequency continued to trend down when compared with the same period in previous years. The average start-up mitigation was 2.65 percent in May through December in 2019, 3.35 percent in 2018, and 4.13 percent in 2017 for the same period. The MMU will continue to assess the effectiveness of this revision request.

\textsuperscript{230} Revision Request 245, Mitigated start-up and no-load offer maintenance cost.

\textsuperscript{231} FERC Order Accepting Tariff Revisions Docket No. ER18-1632-001, October 18, 2018.
7.5 COMPETITIVE ASSESSMENT SUMMARY

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 limited number of frequently congested areas.

The market share indicators demonstrate a moderately increased level of concentration following the merger of Great Plains and Westar to form Evergy, Inc. in June 2018. In 2019, the market share of the largest on-line supplier in real-time market hours exceeding the 20 percent threshold is up to 55 percent from 35 percent in 2018. The data show that during almost all of this 55 percent of hours the largest on-line supplier was an Evergy-controlled resource.

Meanwhile, another general measure of structural market power—the HHI calculation for supplier concentration—reveals that the percent of the hours where the SPP market was unconcentrated declined from 100 percent in 2017 to 88 percent in 2018 and to 89 percent in 2019. 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. These analyses both indicate a moderate potential for general structural market power in SPP markets outside of areas that are frequently congested. The MMU will continue to evaluate structural market power concerns going forward.

Despite slightly elevated HHI and market share metrics, there were only two frequently constrained areas in 2019, where concerns regarding potential local market power are highest. MMU analysis and continued close scrutiny of these areas 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. One such indicator—the negative offer price mark-ups—continues to show increasingly negative offer levels relative to those observed in 2018 and 2017, in both on-peak and off-peak

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232 Lubbock maintained its frequently constrained area status until February 22, 2019 after which Central Kansas and Southwest Missouri were designated as two areas such in the SPP footprint.
periods. Strikingly, in 2019 this negative markup pattern was observed in all 12 months, including winter and summer peak periods. This could occur when 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 or to maintain commitments or reflect temporary negative fuel prices, as in the case of natural gas units. In addition, wind units—that constitute a sizeable share in total resource portfolio—may decide to ensure their run to be able to receive production tax credits. While a low offer price markup level in itself could indicate competitive pressures on suppliers in the SPP market, the observed continuous and deepening downward trend raises questions about the commercial viability of generating units and the possibility of generation retirements; automatic mitigation of unduly low offers is being studied.

Similar to 2018, mitigation for economic withholding remained infrequent. In particular, incremental energy mitigation in 2019 was extremely low in both markets, at less than 0.01 percent in both the day-ahead real-time markets. The overall mitigation frequency of start-up offers in 2019 were at the lowest levels since the market started in 2014 as the combined frequency of mitigation of start-up offers for day-ahead, reliability unit commitment, and manual commitments was 2.8 percent. Meanwhile, the combined frequency of no-load and operating reserve mitigation in the day-ahead market decreased from 2018 levels and remained at negligible levels.

While the system-wide monthly output gap results show significant increases in 2019, they are still low—averaging less than 0.2 percent in all months. These low overall levels of withheld economic output are consistent with competitive market conduct, and reflect a high level of participation in the market.

Average unoffered economic capacity was 1.9, 3.2, and 2.9 percent in 2017, 2018 and 2019, respectively. The majority of the outages responsible for unoffered capacity were long-term, and primarily the result of maintenance in the spring and fall shoulder months. Furthermore, short-term outages by either large suppliers or others were uncorrelated with increasing load across the SPP footprint. The increase in long-term outages from 2017 to 2019 indicates that there may not be incentives for repairing generators as quickly as possible.\(^{233}\)

\(^{233}\) See Section 3.4 for further detail.
The very low level (0.43 percent) of unoffered capacity net of outages could indicate requirements for market participants to offer and maintain commitments given long-term obligations external to the market. The high level of self-committed supply in the market could be another factor in the low levels of unoffered capacity.

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. Addressing the MMU concerns discussed earlier in this report such as the role of—lack of—incentives in price formation during emergency conditions and high share of self-commitments will greatly enhance the effectiveness of the market. The competitive assessment in this report provides evidence that market results in 2019 were, to a great extent, workably competitive overall and that the market required mitigation of local market power infrequently to achieve those outcomes. Nonetheless, mitigation 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.
8 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.” 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. The current status of previous recommendations are also identified. Overall, SPP and its stakeholders have made significant progress on many outstanding MMU recommendations. Section 8.3 lists the status of open past and current annual report recommendations.

8.1 NEW RECOMMENDATIONS

The following recommendations are new for 2019. Improving incentives for generation availability through better pricing rules and revisions to the capacity adequacy requirements to consider performance will lead to improved reliability through generator availability. Revisions to the outage criteria will also improve reliability.

An increased amount of generation outages occurred in the summer of 2019. As cited by SPP Operations, generation outages were a listed reason for 25 of 35 Conservative Operation days, one of which included an Energy Emergency Alert. Strangely, this occurred despite having generation that is over 30 percent more than peak load, which is significantly more than the 12 percent reserve margin. As discussed in Section 3.4, during the MMU’s review of potential physical withholding incidents, which includes reviewing some generator outages, the MMU determined that four areas should be addressed: (1) increase incentives for generator

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234 As defined by FERC in Order No. 719.
availability, (2) improve price formation, (3) incentivize capacity performance, and (4) update and improve outage coordination methodology.

Poor resource availability can often be tied to economic incentives. While generators in market status are guaranteed compensation up to their offers if cleared, they do not earn revenue if they do not clear in the day-ahead market and are not committed later. Sometimes this means that they are not earning revenue, even if available.

The first area to be addressed – increase incentives for generator availability – is tied to two recommendations from prior year Annual State of the Market reports and the Holistic Integrated Tariff Team (HITT). The first is creation of a ramp product, and the second is the creation of an uncertainty product. These two new products under development will compensate generators for their availability when they clear these products. Additionally, market procurement of these products should replace a number of manual capacity commitments which generally lower the prices paid to resources in real time. Details around these products are found in Section 8.2. The remaining three areas to be addressed are detailed below.

2019.1 IMPROVE PRICE FORMATION

Price formation is the economic basis of incentivizing both short-term operational and long-term investment decisions. The MMU has identified circumstances where market prices provide neither a short-term nor a long-term economic incentive to ensure reliability. The following recommendations are two areas to improve price formation.

A. Improve price formation during emergencies

The MMU reviewed the prices during each conservative operations event as well as the Energy Emergency Alert event in 2019 (Section 3.5). Prices were very low for a significant amount of time during the Energy Emergency Alert, although they were very high at the beginning of the event (as shown in Figure 3-33). These very low prices do not signal that generation and imports need to be available during these events. The MMU highly recommends reviewing price formation during emergencies.
Other markets ensure the marginal energy price is not lower than the highest economic offer, typically an oil-fired unit. Alternatively, a reliability risk adder could be determined and then added to the operating reserve cost. For example, if reserves reduce the risk of a loss of load event by one percent, then these reserves have a value of $150/MWh, based on a lost load value of $15,000/MWh. Developing a way to value reliability helps to ensure resources are available when needed. Further, this allows the market to resolve the situation with a minimum of manual commitments.

The MMU recommends that SPP and stakeholders address this as a high priority. Setting proper prices during emergency events can signal market participants to take actions to address the underlying emergency condition, such as increasing imports. Proper prices also provide proper signals for investment in new generation or demand response resources to deal with and avoid future emergencies.

B. Improve price formation during scarcity

The MMU reviewed the prices during scarcity events (Section 3.2.1) and noted that there was a significant increase in intervals where scarcity pricing was invoked (Figure 3-13). While regulation and operating reserves use graduated demand curves during scarcity events, energy and spinning reserve use violation relaxation limits (VRL) which may have no effect on price.235 As shown in Figure 3-15, the instance of shadow prices capped at the VRL during spinning reserve scarcity events decreases as the scarcity increases. The market clearing price for spinning reserve in the most scarce intervals was often $8/MW or less. Relaxing the spinning reserve requirement instead of clearing the requirement from a graduated demand curve undervalues spinning reserves when there is competition between products and does not provide a price signal that ensures generator availability.

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235 The operating reserve scarcity price is based on a requirement that is the sum of requirements for (i) regulation-up, (ii) spinning reserve, and (iii) supplemental reserve. This requirement is separate from the requirement and scarcity price for regulation-up. If cleared spinning reserve is short of the spinning reserve requirement, then additional regulation-up or supplemental reserves can count towards the operating reserve requirement. Even though the spinning reserve requirement is not met, scarcity pricing may not be invoked.
The MMU highly recommends SPP and stakeholders review price formation during scarcity events and establish graduated demand curves that incentivize proper price formation. In the short-term, scarcity prices can ensure resources are performing at their maximum limits and that energy imports are incentivized. Even when no more capacity is physically available and imports are exhausted, improved price formation may not result in more product availability during a scarcity event, but will produce a price signal that will incentivize future availability.

2019.2 INCENTIVIZE CAPACITY PERFORMANCE

The MMU observed that the capacity adequacy requirements did not have any actual performance requirements. Other RTOs use methods to compensate resources that are available more often than the average or by adjusting the next year’s capacity accreditation based on availability during a certain timeframe. Another option is to develop time estimates of forced outages and maintenance outages during high-demand periods and prorate the available MWh for capacity accreditation. A true-up of available capacity at the end of the year would be required to determine whether a market participant met their capacity requirement. This helps to ensure that capacity is actually available during the most important days of the year, and helps to reduce the number of conservative operations events. The Supply Adequacy Working Group, an SPP stakeholder group, has formed a Generator Testing Task Force to address capacity performance among other matters. We highly recommend that this task force work to incentivize capacity performance.

2019.3 UPDATE AND IMPROVE OUTAGE COORDINATION METHODOLOGY

During a review of outages in 2019, MMU observations identified the need to update and improve the outage coordination methodology. The MMU also recommends updating the outage coordination methodology in order to have SPP approve all reserve shutdown outages. Additionally, SPP and stakeholders should also consider if the outage threshold of 25 MW should be lowered to the registration threshold of 10 MW.

The MMU highly recommends that outage coordination methodology be updated to cover reserve shutdown outages and to consider a lower threshold. At a minimum, all market participants should review their outage procedures to ensure they are compliant with SPP’s
Outage Coordination Methodology, in particular, with requirements to accurately report outage reasons and times.

8.2 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. Overall, SPP and its stakeholders have found ways to effectively address many of our concerns. However, there remain outstanding recommendations. A description of each of these recommendations and their current status is outlined below.

2018.1 LIMIT THE EXERCISE OF MARKET POWER OF PARAMETER CHANGES

The market is currently vulnerable to the exercise of market power by the manipulation of a resources’ non-dollar based parameters. Where there is no market power, a seller cannot control price because other sellers are competing for revenue. Market power is a market participant’s ability to manipulate price by manipulating either supply, demand, or both through either dollar or non-dollar based offers. Where a seller has market power, the seller can control price.

When market power is present, market participants can exercise market power by manipulating a resource’s non-dollar-based parameters. For instance, a resource can manipulate energy price by reducing its maximum operating limit from its actual limitation so that it reduces the supply of energy, shifts the supply curve to the left, and raises the price. Non-dollar-based parameters should not be manipulated for the purpose of affecting market clearing. Although SPP’s tariff and market protocols have well-defined expectations and precise limitations for the basis of dollar-based offer components in the presence of local market power, the expectations for the basis of non-dollar-based offer components are much less clearly defined and the limitations are much less precise. Additionally, resources who have adjusted their parameters to increase congestion on the loading side of a constraint are not subject to mitigation, which is a problem in light of increasing negative prices.
The MMU recommends that SPP strengthen the language regarding non-dollar-based parameters so that the expectation for the basis of these values is clear and the potential exercise of market power is much more limited. The expectations for the basis of the parameters should be clear and well-defined. Changes to these parameters should be limited to actual capability and should be verified, at a minimum, in the presence of market power. One option would be to require parameters to always reflect actual limitations. Actual limitations could include physical and environmental limitations and potentially other true and verifiable limitations. Another option could be to automatically apply parameter mitigation in the presence of market power, and congesting a transmission line, similar to the automatic mitigation of dollar-based offer components. SPP and stakeholders are considering this recommendation as part of its 2020 Strategic Roadmap process.236

2018.2 ENHANCE CREDIT RULES TO ACCOUNT FOR KNOWN INFORMATION IN ASSESSMENTS

In 2018, GreenHat Energy, a financial-only market participant in PJM, defaulted on its portfolio of congestion hedging products in the PJM markets. The current estimate of the default exposure exceeds $160 million.237 GreenHat Energy acquired its portfolio in compliance with the PJM credit policy, which due to its design, required GreenHat Energy to post less than $1 million in financial security. The disconnect between the projected loss and the required financial security stems largely from PJM’s credit policy’s assessment of the historic congestion patterns associated with GreenHat Energy’s positions. Planned transmission expansion changed the historic congestion patterns in the PJM markets, which caused GreenHat Energy’s congestion

236 The SPP Strategic Market 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/.

hedging portfolio to become unprofitable. Ultimately, GreenHat Energy defaulted and has forced the rest of the PJM market to absorb the costs.

While the SPP market is different from the PJM market, SPP’s credit policy is similar to PJM’s in some respects. For instance, SPP’s financial security requirements for transmission congestion rights are based only on historic congestion patterns, even when significant transmission upgrades are planned or have occurred. As noted in the 2017 Annual State of the Market report, congestion patterns in SPP shifted significantly after installation of the phase shifting transformer at the Woodward substation, which changed congestion patterns throughout the footprint.²³⁸ This known event was not factored into SPP’s financial security requirements for transmission congestion rights even though it was expected to have a significant effect on outcomes. Furthermore, the congestion pattern was so noticeably shifted that after only a few months the MMU recommended eliminating a frequently constrained area as a result of the expansion.²³⁹ However, SPP’s financial security requirements only factored in the historic data.²⁴⁰

The MMU has engaged SPP’s Credit Practice Working Group and has contributed to the dialogue about next steps. SPP and its stakeholders generally agree that updating the SPP credit policy to protect from exposure such as that experienced in PJM is a priority. SPP stakeholders have proposed a two-phase approach to mitigate SPP’s exposure. The first phase includes both quantitative and qualitative enhancements, such as position collateral minimums, know-your-customer best practices, and stronger capitalization requirements. The second phase will incorporate forward-looking information into financial security requirements. The phase one package is working through the SPP stakeholder process. The phase two package is in the research phase. The MMU recommends that SPP continue to move forward with both phases of credit policy development, as the second phase directly addresses one of the major sources of risk that GreenHat had in PJM.

²⁴⁰ Per SPP Open Access Transmission Tariff, Attachment X, Section 5A.2.
2018.3 DEVELOP COMPENSATION MECHANISM TO PAY FOR CAPACITY TO COVER UNCERTAINTIES

Because of unexpected variations in wind output, SPP operators often manually commit resources (often in excess of 50 units) in order to meet instantaneous load capacity requirements. Often, however, these resources do not earn enough revenue to cover their offered costs\(^{241}\) which contributed to an increase in real-time make-whole payments.\(^{242}\) Moreover, resources providing this reliability service are not compensated specifically for the need. Even when resources are needed so much that they are committed for capacity, the supplemental reserve price is still very low. While the MMU recognizes that SPP operators may need to commit units to account for unforeseen circumstances, manual capacity commitments occur often enough that systematic solutions should be developed. The design of the ramping product should allow for many of the capacity and stagger needs to be met with the compensated ramping product instead of the uncompensated headroom. However, the large number of manual capacity commitments may indicate that there is a need for a new uncertainty product beyond just a short-term ramping product that might better address problems in the one-hour to three-hour time frame.\(^{243}\) Developing products to reduce the need for the large number of manual capacity commitments would help ensure appropriate compensation is being provided for the reliability services provided.

Addressing uncertainty in the market is a HITI initiative and has been submitted by SPP as an initiative in the newly formed SPP roadmap process. The MMU has engaged SPP’s Market Working Group and has participated in a high level discussion on the need for an uncertainty or standby reserve product. SPP staff has conducted considerable analysis and developed a white paper and initial design. The Market Working Group is scheduled to prioritize the uncertainty product as part of the SPP roadmap. As an ongoing concern, they are expected to discuss the product in depth and complete the design in 2020. The MMU fully supports these efforts to compensate capacity used to cover uncertainty of generation and load.

\(^{241}\) Offered costs included their incremental energy, no load, start-up and reserve offers. When mitigated, the resource offers are replaced with the mitigated offers.

\(^{242}\) See Section 4.2.

\(^{243}\) The exact time periods of potential uncertainty products should be determined through the technical expertise of the stakeholder process.
2018.4 ENHANCE ABILITY TO ASSESS A RANGE OF OUTCOMES IN TRANSMISSION PLANNING

SPP’s transmission planning process develops an annual look-ahead plan. This plan evaluates transmission needs over a 5-year and 10-year time horizon. The plan typically evaluates two scenarios.\textsuperscript{244} The first case is a base case, and the second case is an emerging technology case. The process could consider a third scenario. In 2019, the MMU and stakeholders requested that SPP staff consider an additional case. The third case would have considered a shift in environmental regulations—such as a carbon tax or adder—and a change in technologies/market trends including accelerated deployment of storage devices or electric vehicles, higher levels of generation retirement, and higher penetration of renewables.\textsuperscript{245}

MMU staff follows market trends to keep abreast of developments, including corporate announcements on carbon reduction and renewable energy targets. Following these trends helped shape the MMU’s thinking in terms of how to consider the future generation mix and the potential need for an additional scenario. The MMU believed that a third scenario would provide a bookend scenario for the 2021 analysis and supported inclusion of the scenario as part of the 2021 Integrated Transmission Plan. Ultimately, stakeholders passed the third scenario at the Economic Studies Working Group, but rejected it at the Market Operations and Policy Committee and at the Strategic Planning Committee.

While the transmission planning process theoretically can include a third scenario, in practice it does not have the flexibility to include one given that cost of including a third scenario was not unique to the 2021 planning process. This appears to be a significant shortcoming in the planning process as the study process is limited to only two potential scenarios in its 10-year look ahead. This limits the range of potential outcomes that SPP could study.\textsuperscript{246} The MMU recommends that SPP enhance their study process to allow the ability to study a range of potential outcomes. If such range of potential outcomes are not captured in a third case study, the MMU recommends to factor them into either an existing case study or potentially as part of

\textsuperscript{244} These scenarios are also known as futures cases.
\textsuperscript{245} This scenario was similar to a scenario used in the MISO transmission plan. https://cdn.misoenergy.org/MTEP19%20Futures%20Summary291183.pdf
\textsuperscript{246} The MISO transmission planning process studies four cases.
the 20-year assessment. The wider the range of possibilities studied, the more robust the results will be.

2018.5 IMPROVE REGULATION MILEAGE PRICE FORMATION

In addition to regulation capacity payments, resources that are deployed for regulation also receive payments for costs incurred when moving from one set point instruction to another. These mileage payments are paid directly through regulation-up and regulation-down payments in the day-ahead market. 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 clearing price. If the unit is deployed less, the position must be bought back.

The MMU has identified a mileage price inefficiency. Mileage prices are not set by the marginal cost of mileage like other products. Instead, units are cleared for regulation based on what are known as regulation service offers. These service offers are calculated by taking the competitive offer for regulation and adding the mileage offer to it after discounting the mileage offer by the mileage factor.

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 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, which would set the mileage clearing price.

The MMU is also concerned that the mileage clearing price does not correctly reflect price formation of mileage given that this price does not represent the expected or realized mileage deployment. Furthermore, the MMU is concerned that participants with resources frequently deployed for regulation will have an incentive to inflate the mileage prices by offering in $0 regulation offers and high mileage offers. The MMU also identified 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.

The MMU discussed our concerns with the Market Working Group at its August 2018 meeting. While an action item was developed requesting SPP staff and the MMU to review the effectiveness of the regulation mileage pricing process and present further options, no additional work has been done since that time. We recommend that SPP staff review the performance of regulation mileage, and develop potential approaches to improve regulation mileage price formation. Furthermore, we recommend that SPP staff consider adjusting the mileage factor. We believe that SPP staff and stakeholders should include these items as part of its analysis and change development processes for moving forward. SPP and stakeholders are considering this initiative as part of the SPP roadmap process. The MMU ranked this issue as a mid-level recommendation as part of the roadmap process that could be included as part of a package of initiatives to improve regulation.

2017.1 DEVELOP A RAMPING PRODUCT

A ramping product that incents actual, deliverable flexibility can send appropriate price signals that value resource flexibility. This resource flexibility can help protect the market from fluctuations in both demand and supply that result in transient short-term positive and negative price spikes.

Today, the SPP real-time dispatch engine solves for only the current interval and has no look-ahead logic to ensure that there is enough rampable capability to meet the needs of future intervals. Without properly valuing ramp, this leads to quick-ramping resources being economically dispatched to their maximum limits for energy, leaving the market vulnerable to a ramp shortage resulting in scarcity pricing. This is not a reflection of a lack of rampable generation being on-line, but rather a lack of rampable capacity available for a given dispatch interval. A ramping product will compensate resources for holding back rampable capability in one interval for use as energy in a future interval. This will reduce the frequency of scarcity events and provide an economic incentive to resources providing rampable capability.

Both the California ISO and Midcontinent ISO have designed and successfully implemented ramping products. 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 filed with FERC in April 2020.\textsuperscript{247}

While the MMU supports the proposed design as a significant improvement and expects that it will reduce transitory price spikes caused by ramp shortages due to improperly valuing ramp, we have noted some potential deficiencies.\textsuperscript{248}

- A lack of performance incentives in way of a claw back process;
- A demand curve insufficient to procure adequate ramp to prevent transient price spikes; and
- A demand curve set to cap procurement of ramp at 40 percent of the ramp requirement.

The MMU will continue to monitor price increases due to capacity shortages and true ramp shortages through and after implementation.

\textbf{2017.2 ENHANCE COMMITMENT OF RESOURCES TO INCREASE RAMPING FLEXIBILITY}

Increasing ramping flexibility is becoming increasingly important to integrate higher levels of renewable generation.\textsuperscript{249} For instance, one way to address ramping flexibility is to ensure sufficient ramping resources are on-line to meet changing conditions. Over-commitment of resources in real-time can reduce market flexibility, suppress prices, and lead to increased make-whole payments. This can be caused by changing conditions between the time a resource is locked into a commitment by the market software and the time the resource actually comes online. In 2017, the MMU recommended that SPP and its stakeholders address this issue by modifying its market rules to enhance the commitment of resources and increase ramping flexibility. At that time, the MMU described the issue as enhancing the decommitment of

\textsuperscript{248} MMU comments have yet to be filed at the time of this report publication, Docket No. ER20-1617.
resources. However in 2018, having explored the issue further, it was updated to not just be about decommitment of resources, but also included improving how resources are committed.

For instance, the market software frequently commits resources well in advance of when they are actually required to start. This commitment is based on the known assumptions and information available at the time the market engine clears the market. However, conditions change over time. For example, load forecasts, wind forecasts, and outages change, and resources trip off-line. Resources are committed because the market software evaluates it to be profitable over that study period. When conditions change, the resource may no longer be profitable, however, resources continue to start-up and to run as the commitment. This is due, in part, to the current tariff language that only allows the decommitment of day-ahead market committed resources to prevent anticipated excess supply conditions or other emergency conditions.

The MMU evaluated a day in June 2018 where wind output increased by several thousand megawatts. Several quick-start and other short lead time resources were identified that had day-ahead schedules that ran in real-time. Real-time system marginal energy costs were about $35/MWh less than day-ahead costs during the peak hours. Other markets have different commitment rules that would help increase market flexibility. For instance, PJM and California ISO delay the commitment of short start resources and quick-start resources until the real-time market, making the day-ahead commitment instruction advisory. Furthermore, the California ISO can also decommit resources after a resource’s minimum run time has been met, ignoring the day-ahead commitment period. These commitment rules can help increase the flexibility of resources in the SPP markets and help improve pricing outcomes.

The MMU recommends that SPP and stakeholders explore options, such as those noted above, to enhance commitment of resources and increase flexibility. The MMU views this as a high priority item, which is currently being evaluated as part of the SPP roadmap process.

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250 The MMU evaluated June 12, 2018. Wind was approximately 4,000 MW higher in real-time than expected in the day-ahead market.

251 The day-ahead market committed 25 quick start resources that could be started within 10 minutes or less and an additional 18 resources with start-up times less than four hours.
2017.3 ENHANCE MARKET RULES FOR ENERGY STORAGE RESOURCES

With the increase in wind penetration in the SPP market, there is not only a need for resource flexibility, but also for storage due to the increased frequency of negative prices, as discussed in Section 4.1.4. Stored energy resources have the potential to address both the need for flexibility and reduce the incidence of negative prices. However, SPP’s current tariff does not easily allow these resources to integrate in our market. In order to capture the benefits of these new technologies, a new market design was developed.

FERC issued Order No. 841 in February 2018 to reduce barriers to participation and to develop a participation model for electric storage resources.\footnote{252 https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-1.pdf} Over the course of 2018, SPP, stakeholders, and the MMU worked on changes that would comply with FERC Order No. 841. These changes passed the October 2018 SPP Board meeting and SPP filed the changes with FERC in December 2018. The MMU filed supportive comments shortly after. These changes were approved by FERC on October 17, 2019. In the MMU comments, multiple areas of further work were identified. These areas include further enhancements to electric storage integration include addressing the potential for storage resources to exercise downward market power, the potential for market storage resources (MSR) to manipulate the transmission market, possible market design gaps regarding major maintenance and quick-start resource requirements, and the inefficient commitment of non-continuously dispatchable resource requirements in relation to market storage resources.\footnote{253 Some market storage resources have a non-dispatchable range between their charging range and discharging range. The dispatch calculation for this type of non-continuous dispatch range is much more complicated than the typical linear dispatch calculation. SPP’s current proposal is to commit this type of market storage resource for either charging or discharging. This type of commitment is inefficient because it does not make the whole dispatch range available. For more detail, see Motion to Intervene and Comments of the Southwest Power Pool Market Monitoring Unit, Section I.B.5, Docket No. ER19-460, December 7, 2018.} In December 2019, SPP made a subsequent filing with FERC requesting to defer the effective date for the implementation of the revisions to comply with Order No. 841 to August 2021, which was accepted\footnote{254 https://www.spp.org/documents/61704/20200227_order%20on%20effective%20date%20order%20no.%20841%20compliance%20filing_er19-460-004.pdf} by FERC on February 27, 2020.
The MMU views integration of storage resources in the SPP markets as an ongoing high priority as several outstanding items beyond compliance with FERC Order No. 841 need to be addressed in order to fully integrate electric storage resources in the SPP markets. An initiative to enhance storage rules is currently being evaluated in the SPP roadmap process.

2017.4 ADDRESS INEFFICIENCY CAUSED BY SELF-COMMITTED RESOURCES

Market participants have noted several reasons for self-commitment including contract terms for coal plants, low gas prices that reduce the opportunity for coal units to be economically cleared in the day-ahead market, long startup times, overtime costs, increased major maintenance costs, environmental testing, cold weather operations, and a risk-averse business practice approach. However, it is imperative to minimize the need to self-commit resources to realize the full benefits of SPP’s market. While there may not be a single reason causing market participants to self-commit resources, there can be ways that SPP and its stakeholders can work to minimize the incentives to self-commit. The previously cited major maintenance costs should no longer be a concern as those costs could start being included based after April 2019.

The MMU conducted an in depth study of self-commitment practices and associated inefficiencies in 2019.\(^\text{255}\) As confirmed in the simulation study, long lead-time and long run-time resources are often self-committed and contribute to depressing prices in the SPP market. The current market structure is limited in its ability to commit these resources, and thus market participants often commit them during uneconomic periods. The current clearing engine logic does not provide commitments beyond the 24-hour period of the next operating day. The creation of a market process that economically evaluates resources over a longer period will allow for more efficient market solutions, as well as decreased production costs.\(^\text{256}\) A multi-day market was also adopted as a Holistic Integrated Tariff Team recommendation.\(^\text{257}\)

In the current design, a resource that is required to run for multiple days is not evaluated by the day-ahead market to see if the resource is economic over its minimum run-time. The clearing


\(^{256}\) This would be different from the current multi-day reliability unit commitment process.

engine may see that it is economic on the first day and issue the commitment, and then in future days the resource will stay on until its minimum run-time is met even if it is uneconomic. As such, many resources that have multi-day minimum run times avoid the market clearing process and instead self-commit in the market based not on an evaluation by the market, but on their own evaluation of market conditions. This is not the optimal solution for the SPP market as it removes the ability for the SPP market software to evaluate and commit the resources economically relative to all other resources in the market.

Adding multi-day unit commitment logic is at the top of the current stakeholder market design initiative list and has been discussed in 2018 and 2019 in the stakeholder process. The Holistic Integrated Tariff Team adopted a recommendation to move towards a multi-day market.258

The MMU recommends that SPP and its stakeholders continue to explore and develop ways to reduce the incidence of self-commitment of resources outside of the market solution. Further, we recommend, based on its analysis, that SPP and stakeholders consider adding an additional day to the optimization process, as this will best balance forecast accuracy with the ability to commit long lead time and high start-up cost resources. The MMU continues to view reducing self-commitment of generation as a high priority for SPP and its stakeholders as this will enhance market efficiency and improve price signals.

2017.5 ADDRESS INEFFECTIVENESS WHEN FORECASTED RESOURCES UNDER-SCHEDULED DAY-AHEAD

Analysis shows that, on average, 84 percent of real-time wind generation was cleared in the day-ahead market in 2019, compared to 85 percent in 2018, and 82 percent in 2017. On average for the year, nearly 1,400 MW of real-time wind generation was not included in the day-ahead

market solution for each hour. When this happens, day-ahead prices are frequently observed to exceed real-time prices. While virtual transactions at wind locations during these times were observed, analysis found that price convergence, in absolute terms, is not improving. As a result, under-scheduling of wind reduces the efficiency of the day-ahead unit commitment process. This leads to the over commitment of non-variable energy resources in the day-ahead market, which results in real-time prices that are significantly lower than day-ahead prices when the nearly 1,400 MW of wind generation shows up in the real-time market. In 2018, the MMU noted the under-scheduling of wind in the day ahead due to market participants offering below the forecasted values for wind resources. In 2019, while the wind generation offered into the day ahead was closer to the forecasted values, the percent cleared was less than in 2018.

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. 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-scheduling of variable energy resources in the day-ahead market based on forecasted supply.

This is a high priority for the MMU as it helps to enhance market efficiency and improve price signals. This issue has been reviewed by SPP’s Holistic Integrated Tariff Team and is in their report as a recommendation. It was also submitted as an initiative by SPP in the newly formed SPP roadmap process. Some possible avenues to explore are removing the physical withholding exemption in the day ahead market, requiring all or a subset of variable energy

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259 From a reliability standpoint, the reliability unit commitment assesses wind resources at forecasted levels. However, the reliability unit commitment process cannot economically decommit resources scheduled by the day-ahead market.

260 In many cases, virtual transactions are setting prices at wind locations with positive offer prices. In most cases, market participants do not offer wind resources at positive values. As a result, while the virtual transactions may be reflecting missing quantity values at a resource location, they are not reflecting the offer a wind resource would likely have. Moreover, virtual participants may pair virtual offers at resource locations with offsetting virtual bids at other locations. This effectively works to capture congestion differences between the day-ahead and real-time markets, but does not work to converge the energy price component.

resources to offer a certain percentage of their day-ahead forecast into the day-ahead market, or including deviations from day-ahead clearing in make-whole payment distributions for resources in manual control mode. Other solutions could focus on addressing make-whole payments allocated to virtual transactions. Today, virtual transactions pay about half of all real-time make-whole payments. As such, this significantly increases the premium necessary for virtual transactions to converge prices and can potentially act as a barrier to market efficiency. These as well as other solutions should be reviewed by SPP and stakeholders to improve price convergence.

2014.1 IMPROVE QUICK-START LOGIC

The MMU recommended that quick-start logic be improved after implementation of the Integrated Marketplace.262 SPP and stakeholders developed a proposal to enhance the quick-start logic several years ago.263 However, before the proposal was filed, FERC began a 206 process that identified that the treatment of fast-start generators was unjust and unreasonable.264 In June 2019, FERC issued an order265 directing SPP to make a compliance filing addressing pricing practices related to fast-start generators. SPP submitted a compliance filing266 on December 19, 2019 addressing the six issues outlined in the FERC order. The MMU filed comments267 offering a limited protest to SPP’s proposed tariff revisions to comply with the FERC order. The MMU recommended that FERC direct SPP to modify their proposed tariff revisions related to fast-start resources in two areas.

In the order, FERC directed SPP to separate the security constrained economic dispatch of generation from the price formation of energy. The SPP proposed revisions apply the mitigation process to prevent the exercise of local market power only in the price formation run. The MMU

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recognizes that local market power can be exercised through economic dispatch and through price formation of energy. The MMU recommends the mitigation process be applied to both pieces of market clearing.

In the order, FERC directed SPP to include start-up and no-load costs for fast-start resources in the price formation of energy. The SPP proposed revisions use the current start-up and no-load offers available at the time of price formation, even when that offer was submitted after unit commitment evaluation. This allows prices to be formed with start-up and no-load offers that were never evaluated by any unit commitment process. The MMU recognizes the opportunity for start-up and no-load offers to be modified after the economic evaluation and unit commitment process, allowing fast-start resources to manipulate the difference between their offers in the economic dispatch and the price formation. The MMU recommends price formation be performed using the start-up and no-load offers economically evaluated during the unit commitment process.

SPP and the MMU are currently waiting for FERC to rule on the SPP compliance filing.

SPP and stakeholders are currently working on a revision to the intra-day reliability unit commitment (IDRUC) process in order to commit fast-start resources in a more timely and economic manner. The MMU supports improvements to the real-time commitment process to increase market flexibility and improve market efficiency.

2014.3 ADDRESS GAMING OPPORTUNITY FOR MULTI-DAY MINIMUM RUN TIME RESOURCES

Resources with minimum run times greater than two days have the opportunity to game the market. The current implementation of the market rules limit make-whole payments to the as-committed market offers for the first two days of a resource’s minimum run time. However, after the second day, no rule exists to limit make-whole payments for a resource that increases its offers from the third day onward until the resource’s minimum run time is satisfied. For resources with minimum run times greater than two days, the market participant knows that the resource is required to run and can increase their market offers after the second day to increase make-whole payments.
The SPP board passed a proposal\textsuperscript{268} at the July 2018 meeting that would limit make-whole payments for any resource with multi-day minimum run times to the lower of the market offer or the mitigated offer. This limitation only applies for offers falling in hours not accessed by one of the security constrained unit commitment (SCUC) processes and the resource bid at or above their mitigated offer on the first day. The MMU supported the proposal. Subsequent to board approval of the proposal, SPP legal staff identified internally inconsistent tariff language that the revisions revealed but did not address. An associated additional tariff modification was approved by the stakeholder process. A FERC filing will occur in 2020. The MMU strongly supports these changes.

\textbf{2014.4 ADDRESS ISSUES WITH DAY-AHEAD MUST OFFER}

In 2017, FERC rejected SPP’s proposal to remove the day-ahead must offer requirement and indicated that it would consider removal of the requirement if it were paired with additional physical withholding provisions.

The MMU remains concerned with the design weaknesses of the current limited day-ahead must offer requirement. We 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. The MMU has continued to monitor and track market performance concerns and has identified a marked increase in generator outages, as discussed in Chapter 3, that are not prevented by the current limited must offer requirement and have contributed to the 35 days of conservative operations in the SPP region during 2019. In light of the increased reliability concerns exacerbated by conservative operations events, the MMU recommends the priority of this issue be elevated to high. The MMU has submitted this recommendation as an initiative in the newly formed SPP roadmap process, and is waiting for the Market Working Group to prioritize the issue.

\textsuperscript{268} Revision Request 306, 2014 ASOM MWP MMU Recommendation (3-Day Minimum Run Time)
### 8.3 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. All previous annual reports can be found at [https://www.spp.org/spp-documents-filings/?id=18512](https://www.spp.org/spp-documents-filings/?id=18512).

**Figure 8-1  Annual State of the Market recommendations update**

<table>
<thead>
<tr>
<th>Recommendation</th>
<th>Report year</th>
<th>Current status</th>
</tr>
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<tbody>
<tr>
<td>Improve price formation during emergencies</td>
<td>2019</td>
<td>Awaiting stakeholder engagement</td>
</tr>
<tr>
<td>Incentivize capacity performance</td>
<td>2019</td>
<td>Awaiting stakeholder engagement</td>
</tr>
<tr>
<td>Update and improve outage coordination methodology</td>
<td>2019</td>
<td>Awaiting stakeholder engagement</td>
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<tr>
<td>Limit market power by backstopping parameter changes</td>
<td>2018</td>
<td>Awaiting stakeholder prioritization</td>
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<tr>
<td>Enhance credit process to account for known information</td>
<td>2018</td>
<td>To be addressed as part of phase 2 of stakeholder process</td>
</tr>
<tr>
<td>Develop compensation or product for capacity used for uncertainties</td>
<td>2018</td>
<td>Design under development</td>
</tr>
<tr>
<td>Enhance ability for transmission planning to cover range of outcomes</td>
<td>2018</td>
<td>Included sensitivities as part of 2021 ITP process</td>
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<tr>
<td>Improve regulation mileage price formation</td>
<td>2018</td>
<td>Awaiting stakeholder prioritization</td>
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<tr>
<td>Develop ramping product</td>
<td>2017</td>
<td>Awaiting FERC filing</td>
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<tr>
<td>Enhance unit commitment logic</td>
<td>2017</td>
<td>Awaiting stakeholder prioritization</td>
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<tr>
<td>Enhance energy storage design</td>
<td>2017</td>
<td>Awaiting stakeholder prioritization</td>
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<tr>
<td>Recommendation</td>
<td>Report year</td>
<td>Current status</td>
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<tr>
<td>Reduce self-scheduling in market</td>
<td>2017</td>
<td>Multi-day commitment process – under stakeholder consideration</td>
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<tr>
<td>Address under-scheduling of wind</td>
<td>2017</td>
<td>HITT recommendation – SPP performing analysis</td>
</tr>
<tr>
<td>Non-dispatchable variable energy resource transition to dispatchable variable energy resource status</td>
<td>2015</td>
<td>FERC accepted filing in April 2019, transition underway</td>
</tr>
<tr>
<td>Improved quick-start logic</td>
<td>2014</td>
<td>Awaiting FERC order</td>
</tr>
<tr>
<td>Manipulation of make-whole payment provisions (multiple items)</td>
<td>2014</td>
<td>Across midnight hour – awaiting FERC filing</td>
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<td></td>
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<td>Out-of-merit payments – withdrawn by MMU</td>
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<tr>
<td></td>
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<td>Jointly-owned units – awaiting implementation</td>
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<tr>
<td></td>
<td></td>
<td>Regulation – implemented in 2018</td>
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<tr>
<td>Day-ahead must offer requirement and physical withholding</td>
<td>2014</td>
<td>Awaiting stakeholder prioritization</td>
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</tbody>
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