SPP Southwest Power Pool
Market Monitoring Unit

STATE OF THE MARKET
2017

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Southwest Power Pool, Inc.
Market Monitoring Unit

State of the Market 2017

TABLE OF CONTENTS

Southwest Power Pool, Inc.
Market Monitoring Unit

LIST OF FIGURES

1 EXECUTIVE SUMMARY

The Southwest Power Pool (SPP) Market Monitoring Unit's (MMU) Annual State of the Market report for 2017 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 workably competitive, 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 2017, which was about seven percent higher than in 2016. This was primarily caused by increases in energy costs.
- As natural gas-fired resources set prices in the SPP market a majority of the time, changes in natural gas prices influences electricity prices. Natural gas prices increased about 14 percent in 2017 compared to 2016.
- When system prices are controlled for changes in fuel prices, they averaged about eight percent lower in 2017 compared to 2016.
- While day-ahead and real-time prices both averaged around $23/MWh for the year, real-time price volatility nearly doubled in 2017 compared to 2016. Much of this volatility was the result of short-term transient ramping related price spikes.
- The incidence of negative prices doubled in 2017 to around seven percent of all real-time intervals, up from about 3.5 percent of intervals in 2016.
- Day-ahead and real-time congestion costs totaled over $500 million in 2017, a 70 percent increase from almost $300 million in 2016. The increase in congestion is related to continued development of wind resources and transmission limitations in the SPP system.

- Wind generation peaked at 15.7 GW and peak wind penetration was almost 57 percent of load in December. Wind capacity increased to almost 17.6 GW in 2017, up about nine percent from 2016.
- Wind generation totaled 23 percent of all generation in 2017, up from 18 percent in 2016. Coal generation fell from 48 percent in 2016 to 46 percent in 2017.
- New capacity additions were almost 2,200 MW at nameplate capacity, with wind representing 70 percent of the new capacity. Retirements were low, at around 130 MW.
- The interconnection process includes almost 48 GW of additional resources, of which 93 percent are renewable.
- SPP continues to have significant excess capacity at peak loads. The MMU estimates that capacity at peak is 30 percent higher than the peak demand level in 2017.
- 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.
- Market uplifts were low at about $68 million in 2017, which was down slightly from 2016 levels.
- Combined operating reserve costs totaled $80 million last year, an increase of 28 percent over 2016. This was driven by a combination of factors including higher spinning reserve requirements and prices.
- Auction revenue rights were funded at almost 165 percent in 2017, up from just over 140 percent in 2016.
- Transmission congestion rights funding increased to 94 percent in 2017 from 92 percent in 2016.
- While many participants sufficiently hedged their congestion costs with auction revenue rights and transmission congestion rights in 2017, some participants did not.

1.2 OVERVIEW

Overall, SPP markets produced highly competitive market results 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 2017. While total costs increased by seven percent in 2017 compared to 2016, a main driver for the increase in energy costs was a 14 percent increase in natural gas prices. For instance, the annual average gas price at the Panhandle hub increased from $2.32/MMBtu in 2016 to $2.65/MMBtu in 2017. When adjusted for fuel prices, average SPP marginal energy prices declined.

While the annual peak load of 51,181 MW was one percent higher this year compared to last year, total electricity consumption was down about one percent. Much of the 2,200 MW increase in nameplate generation capacity last year was from wind resources. This continues a pattern that has occurred over the past several years. However, the rate of new additions has declined significantly from around 11,350 MW in 2015 and 3,900 in 2016. Even so, wind generation continued to increase as it represented almost 23 percent of system generation, up from 18 percent in 2016 and 14 percent in 2015. Conversely, coal generation continued to decline, representing around 46 percent of total generation last year, down from 48 percent in 2016. Prior to last year, coal represented 55 percent or more generation in SPP.

There were several market based developments in 2017. Foremost of these occurred in September 2017 when the Mountain West Transmission Group announced that they would pursue membership with SPP. The Mountain West Transmission Group consists of entities located in Colorado, Wyoming, New Mexico, Arizona, Nebraska, and South Dakota, and is located in the Western Interconnection.[1,2] A graphical representation of the SPP and the Mountain West Transmission Group footprints is shown in Figure 1–1.

Though the SPP board has approved system integration, further approvals still need to be obtained. Even so, review of market design changes has begun in the SPP stakeholder process. The requisite filings are anticipated to be made with the FERC and other governing bodies in 2018. SPP anticipates integration of the Mountain West Transmission Group into the SPP market by spring 2020. While the MMU has not been involved in the negotiation process, the MMU supports the concept of expanding the market footprint to enhance market efficiencies, and we are reviewing the proposed integration changes along with other SPP stakeholders.

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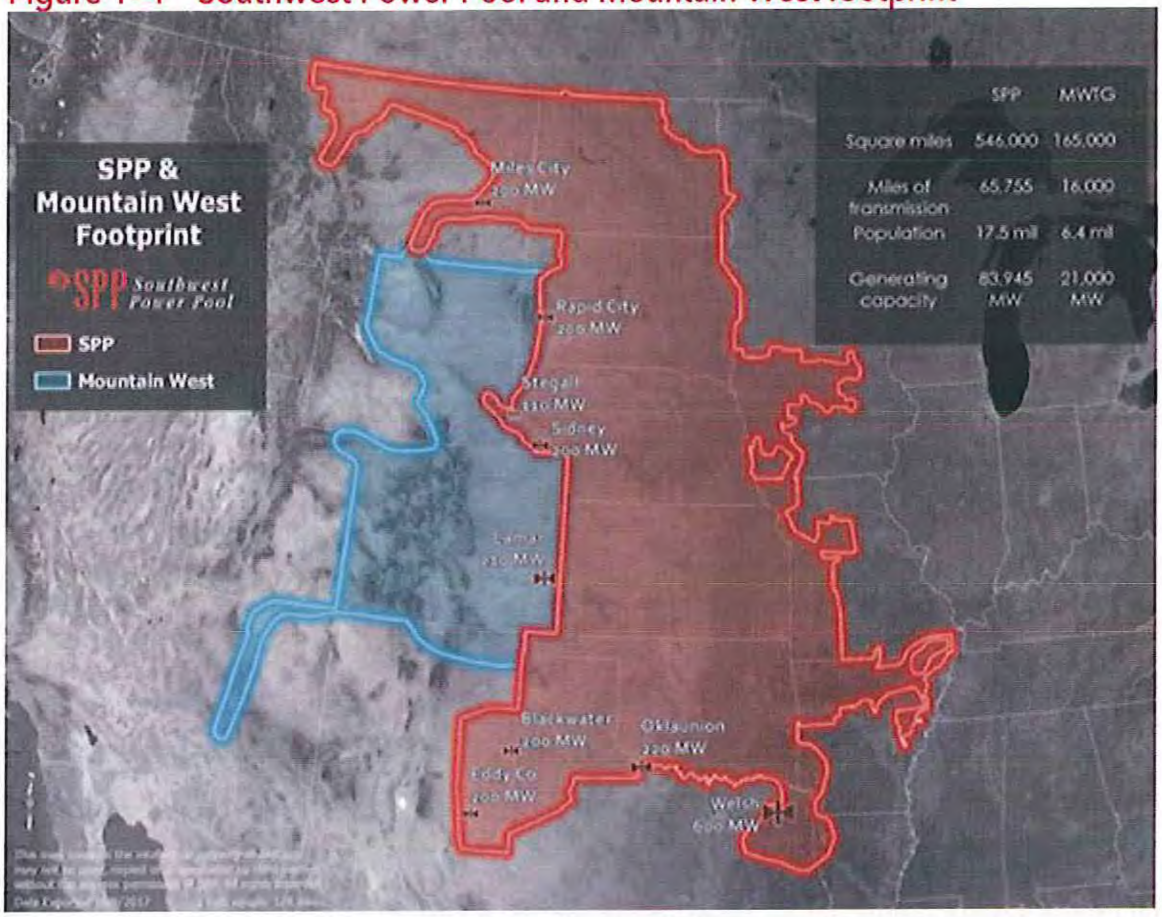
[1] More detail on the Mountain West Transmission Group can be found at https://www.spp.org/mountain-west/.

[2] On April 20, 2018, SPP received notice from Xcel Energy-Colorado, indicating that they are ending their participation in the Mountain West Transmission Group and their effort to pursue membership in SPP. At this time, Mountain West and SPP staff, stakeholders, and board of directors are currently evaluating the implications of this announcement, and determining next steps.

Figure 1–1 Southwest Power Pool and Mountain West footprint



Other significant market events in 2017 included:

- The addition of the phase-shifting transformer to address congestion at the Woodward, Oklahoma substation.[3] Our analysis shows that this transformer has substantially changed the congestion pattern in SPP after deployment, shifting congestion further east.
- Implementation of new tariff language with regard to jointly-owned resources.[4] While this modification was intended to relieve a gaming opportunity, it has had several unintended consequences on settlements and has opened up the opportunity for a new gaming issue. SPP, stakeholders, and the MMU are currently working on a solution.
- Implementation of new scarcity pricing rules.[5] Two sets of changes occurred. The first was in May and was consistent with FERC Order No. 825. This change removed the

[3] See Section 5.1 for further discussion.
[4] See Section 4.3.4 for further discussion.
[5] Scarcity pricing is covered in Section 4.2.

violation relaxation limits for resource capacity constraints, resource ramp constraints, and global power constraints. Additional changes were implemented in August. These changes replaced fixed price demand curves with variable price demand curves.

- Market participant concerns with the effectiveness of the auction revenue rights process to allow participants to receive sufficient hedges for congestion.[6] We observe that while many participants were able to manage congestion, a handful of participants did not have sufficient hedges. There were multiple reasons for this including the nature of congestion patterns, outages, and market participant strategies.

1.3 DAY-AHEAD AND REAL-TIME MARKET PERFORMANCE

While load participation in the day-ahead market continued to be strong in 2017, generation participation, particularly from wind resources contributed to substantial increases in supply in the real-time market and increasing incidence of negative real-time prices. For instance, the average level of participation for the load assets was between 98 percent and 101 percent of the actual real-time load. However, we found that on average for the year, wind generation was over 1,200 MW higher in the real-time market compared to the amount scheduled in the day-ahead market. This represents an increasing challenge to the market as wind generation has increased substantially over the past few years.

While virtual bids and offers may theoretically offset the under-scheduling of renewable supply in the day-ahead market, in net they did not as they averaged around 650 MW of net virtual supply. While about half of all virtual offer activity occurs at renewable locations, the other half does not. 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 increasingly profitable in the SPP market. Total profits increased in 2017 to about $54 million from about $33 million in 2016. When transaction fees are included, net profit for virtual transactions was $35 million in 2017, more than double

[6] Auction revenue rights and transmission congestion rights are covered in Section 5.2.

the amount received in 2016. Net virtual profits were highest in April ($5.9 million) and October ($7.9 million) when winds are typically highest and loads are lower.

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. Some of the reasons for self-committing may include 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, and a risk-averse business practice approach. Generation offers in the day-ahead market averaged almost 55 percent as "market" commitment status followed by "self-commit" status at 31 percent of the total capacity commitments for 2017.[7] In 2016, the "market" and "self-commit" shares were at 48 percent and 36 percent, respectively. While the increase in market commitments and decrease in self-commitments highlights an improvement, self-commitments still represent over 30 percent of generation, a trend that has existed since the Integrated Marketplace began in 2014. In order to improve market commitment in the SPP market, we recommend that SPP and stakeholders look to find ways to address this issue. This is discussed further below.

Day-ahead prices have historically been higher than real-time prices. However, real-time prices were higher than day-ahead prices in nine months last year primarily because of higher real-time price volatility, which almost doubled in 2017 when compared to 2015 and 2016. This increased volatility mostly was caused by scarcity pricing events, which caused short-term real-time prices spikes that typically only occurred for one interval. These scarcity pricing events highlighted ramping limitations, which can be thought of as temporal congestion. Unlike some other RTO/ISO markets, the current SPP model does not account for forecasted ramping needs. Our analysis (see Section 3.3.1) shows that accounting for ramping needs would greatly assist in preparing and compensating generation for both anticipated and unanticipated ramping needs. As such, we recommend, as discussed below, that SPP and stakeholders develop a ramping product.

[7] Other resource commitment statuses are "reliability", "not participating", and "outage" at two percent, three percent, and 10 percent, respectively. These all represent similar numbers when compared over the past several years.

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.

In total, congestion costs were over $500 million in 2017. This was a significant increase from almost $300 million in 2016. 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 significantly under-hedged. In 2017, the total of all transmission congestion right and auction revenue right net payments to load-serving entities of $408 million was less than the total day-ahead and real-time markets congestion costs of $413 million. However, on an individual basis, some participants were over-hedged, whereas others were under-hedged. Three participants were each under-hedged by over $30 million.

As a result, there were discussions in the stakeholder process about the effectiveness of the auction revenue right process in allocating desired rights. The MMU believes that the lack of allocated auction revenue rights appears to be, in part, related to bidding strategy. The MMU identified instances where both prevailing flow and counter-flow positions that could have been nominated by participants were not nominated. Moreover, transmission service reservations are studied and granted with assumptions that include counter-flow megawatts. This means that without the use of counter-flow, many of the prevailing flow paths are not feasible. Nominating the appropriate counter-flow paths in the allocation will help to increase the amount of prevailing flow paths allocated. This ultimately means the less counter-flow nominated will result in less prevailing flow allocated. MMU and SPP analysis identified that these positions could have improved hedges in some cases.

Finally, modeling of outages in the transmission congestion rights market are not well aligned with actual outages that occur in the day-ahead market. Only around five percent of the number of day-ahead outages were included in the transmission congestion rights market. While each outage can have its own unique impacts on the market, this is a substantial difference and is likely to be a factor influencing the effectiveness of the hedges.

Considering positions including prevailing flow and counter-flow as well as outages will be important as stakeholders continue to consider how to improve hedging mechanisms.

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 2017, total make-whole payments were approximately $68 million, down slightly from $71 million in 2016. Make-whole payments averaged about $0.26/MWh in 2017, which was about the same as in 2016. In comparison to other RTO/ISO markets, SPP's make-whole payments were on the low end of uplift costs, which varied from $0.22/MWh to $0.57/MWh in 2016.[8]

Day-ahead make-whole payments constituted about 42 percent of the total make-whole payments in 2017. SPP pays about 85 percent of all make-whole payments to gas-fired resources with 65 percent of reliability unit commitment make-whole payments to simple-cycle gas resources.

Last December, FERC found SPP's quick-start pricing practice may be unjust and unreasonable, and argued that pricing enhancements would improve uplifts.[9] Our analysis shows that uplift payments remain fairly low. Furthermore, our assessment of FERC's proposal suggests that, if anything, FERC's proposal would transfer, if not increase, uplifts.[10]

[8] ISO NE State of Market Report https://www.potomaceconomics.com/wp-content/uploads/2017/07/ISO-NE-2016-SOM-Report_Full-Report_Final.pdf , MISO Annual state of Market report http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-sec4.pdf , PJM website www.pjm.com

[9] *Order Instituting Section 206 Proceeding and Commencing Hearing Procedures and Establishing Refund Effective Date,* 161 FERC ¶ 61,296 (2017).

[10] Southwest Power Pool Market Monitoring Unit Reply Brief, Docket No. EL18-35-000, March 13, 2018.

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 2017 were workably competitive and that the market required mitigation of local market power infrequently to achieve competitive outcomes. Even with these low levels of mitigation, stakeholders proposed market design changes, and significant discussion occurred around changing behavioral mitigation parameters during the stakeholder process in 2017.[11]

As with previous years, structural competitiveness metrics–which review the structural potential for the exercise of market power–indicate minimal potential structural market power in SPP markets outside of areas that are frequently congested. For the two frequently constrained areas, where potential for concerns of local market power is the highest, existing mitigation measures serve 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 in 2017 relative to 2016 levels to just over three percent.

The decline in mitigation may be the result of 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 -$3.50/MWh and -$1.70/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. Even so, only about 130 MW of generation retired in 2017.

[11] It is likely that much of this discussion had little to do with the frequency of mitigation, but more to do with the exclusion of major maintenance from mitigated start-up and no-load offers. In January 2018, the SPP board approved a proposal to allow major maintenance costs to be included in commitment costs. This proposal was supported by the MMU.

The monthly average output gap–which measures economic withholding–shows very low levels of economic withholding in all months in 2017. Specifically, there was no measurable output withheld in the two frequently constrained areas. These low levels of economic output withholding reflect highly competitive participation in the market.

This year we introduced a new metric for competitive assessment. This metric measures 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 1.8 percent in 2015, 2.0 percent in 2016, and 1.9 percent in 2017. When short and long-term outages are removed, the remaining unoffered capacity was 0.03 percent, 0.22 percent, and 0.23 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 using a new methodology that capacity was 30 percent higher than the peak load in 2017. SPP's current annual planning capacity requirement is 12 percent.

Wind capacity has more than doubled from 8.6 GW in 2014 to 17.6 GW in 2017. 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 23 percent in 2017; the all-time high rate of wind generation penetration was set in March 2018 at 60.6 percent of load. Furthermore, the interconnection process includes almost 48 GW of additional resources, of which 93 percent are renewable resources.

The shift in generation mix towards renewable resources is a significant and positive development; however, it carries both market and operational challenges. This includes an increase in the incidence of negative prices as they increased from 3.5 percent of real-time intervals in 2016 to seven percent of intervals in 2017, and growing congestion charges which were over $500 million in 2017, up from almost $300 million in 2016. Furthermore, these challenges are further exacerbated by the fact that currently 36 percent of the total wind capacity is non-dispatchable.

It is in the best interest of SPP market stakeholders to prepare for the challenges these changes to the market present. Expanding the SPP footprint, is one way to help manage the growing levels of renewable generation. 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 7. Below is a summary of our 2017 recommendations.

1.8.1 INCREASE MARKET FLEXIBILITY

The SPP market needs more flexible generation to meet increasing ramping requirements as renewable generation levels continue to increase and as renewable generation dominates the interconnection queue over the next several years. Because of the variable output nature of these renewable energy resources, the market needs increasing capability to respond to the inevitable fluctuations in order to promote efficient market outcomes and ensure reliability. It is imperative for SPP and its members to improve its market mechanisms to address this growing concern. We recommend that SPP:

- **Develop a ramping product** - A ramping product that incents actual, deliverable flexibility can send appropriate price signals to value resource flexibility. This resource flexibility can help prepare the system for fluctuations in both demand and supply that result in transient short-term positive and negative price spikes.

- **Improve rules related to decommitting resources** - Over-commitment of resources in real time suppresses prices and leads 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 on-line. The MMU recommends that SPP and its stakeholders address this issue by enhancing its market rules to economically decommit a resource that is planned to start.

- **Enhance market rules for energy storage resources** - FERC Order No. 841 requires SPP to develop rules to create a participation model for energy storage resources. We fully concur with FERC's objectives as energy storage resources can add significant market flexibility to address changing demand and supply conditions. We look forward to working with SPP and stakeholders on this enhancement.

1.8.2 IMPROVE MARKET EFFICIENCY

One of the key benefits of the day-ahead market is the unit commitment process. Market participants offer resources into the day-ahead market and the market optimization process minimizes production costs. Inefficient market outcomes can occur when participants self-commit resources and when forecasted generation–such as wind–are withheld from the day-ahead market run, even though their expected generation levels are much higher.

- **Address market efficiency caused by self-committing resources** - While market participants have identified several reasons why they self-commit resources in the market, it is imperative to minimize the need to self-commit resources to realize the full benefits of SPP's market. We recommend that the SPP and stakeholders explore ways to minimize self-committing. One potential approach is through the development of a multi-day unit commitment process.

- **Address market efficiency when forecasted resources are under-scheduled day-ahead** - Our analysis shows that, on average, 82 percent of forecasted wind generation was scheduled in the day-ahead market in 2017, and that under-scheduling of wind is a growing problem. While some of this difference may be related to forecasting challenges, market participants also significantly under-schedule wind relative to their day-ahead forecasted levels. On average for the year, over 1,200 MWh of real-time wind generation was not included in the day-ahead market. This can contribute to distorting market price signals, suppressing real-time prices, and affecting revenue adequacy for all resources.

1.8.3 CONTINUE ALIGNMENT OF PLANNING PROCESSES WITH OPERATIONAL CONDITIONS

Enhancing the accuracy of planning processes with operational realities enables SPP and its members to more effectively plan for future system needs and conditions. Many of the challenges outlined in this report–including increased congestion, negative prices, and low generator net revenues–and some of the improvements–including the Woodward phase-shifting transformer–are, in part, a reflection of planning decisions. The more the planning process can learn from and incorporate operational information, the more planning can identify and address concerns in advance of market operations. While SPP has done much in this area, there are a few additional areas that could benefit by aligning and reflecting operational information. Specifically, the economic studies and the resource adequacy processes are two planning processes that could benefit further from alignment.

1.8.4 ADDRESS OUTSTANDING RECOMMENDATIONS

The MMU has provided recommendations to improve market design in our previous annual reports. Overall, SPP and its stakeholders have found ways to effectively address many of our concerns. However, there are a number of recommendations that remain outstanding. A description of each of these outstanding recommendations are outlined below.

- **Convert non-dispatchable variable energy resources to dispatchable** - In the 2015 Annual State of the Market report, the MMU identified non-dispatchable variable energy resources as a concern because of their adverse impact on market price and system operations. These resources exacerbate congestion, reduce prices for other resources, increase the magnitude of negative prices, cause the need for market-to-market payments, and force manual commitments of resources that can increase uplift. SPP and its stakeholders at the Market Working Group discussed this issue in 2017 and passed an SPP proposal in early 2018 to require conversion of non-dispatchable resources. The MMU fully supports this change, which is currently awaiting further stakeholder review.
- **Address gaming opportunity for multi-day minimum run time resources** - 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 Market Working Group has identified a potential solution which would limit the make-whole payments for any resource with multi-day minimum run times to the lower of the market offer or the mitigated offer after the first day for resources that bid at or above their mitigated offer on the first day. While a solution has been developed, the proposal remains in the stakeholder process. We recommend that this solution continue to move forward.

- **Convert the local reliability mitigation threshold to a cap** – In the 2016 Annual State of the Market report, the MMU recommended converting the 10 percent mitigation threshold for local reliability commitments to a 10 percent cap. This recommendation addresses an unbalanced risk associated with mitigation of resource commitments for local reliability. This change was approved by the board in October and is pending a FERC filing. The MMU strongly supports this change and will support this when filed at FERC.

- **Replace the day-ahead must offer requirement and add a physical withholding provision** – FERC rejected in fall 2017, 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. While the MMU remains concerned with the current day-ahead must offer requirement, we recommend that further consideration of this issue be a low priority at this time given competing priorities.

2 LOAD AND RESOURCES

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 2017 calendar year of the SPP wholesale electricity market referred to as the Integrated Marketplace, which started on March 1, 2014.

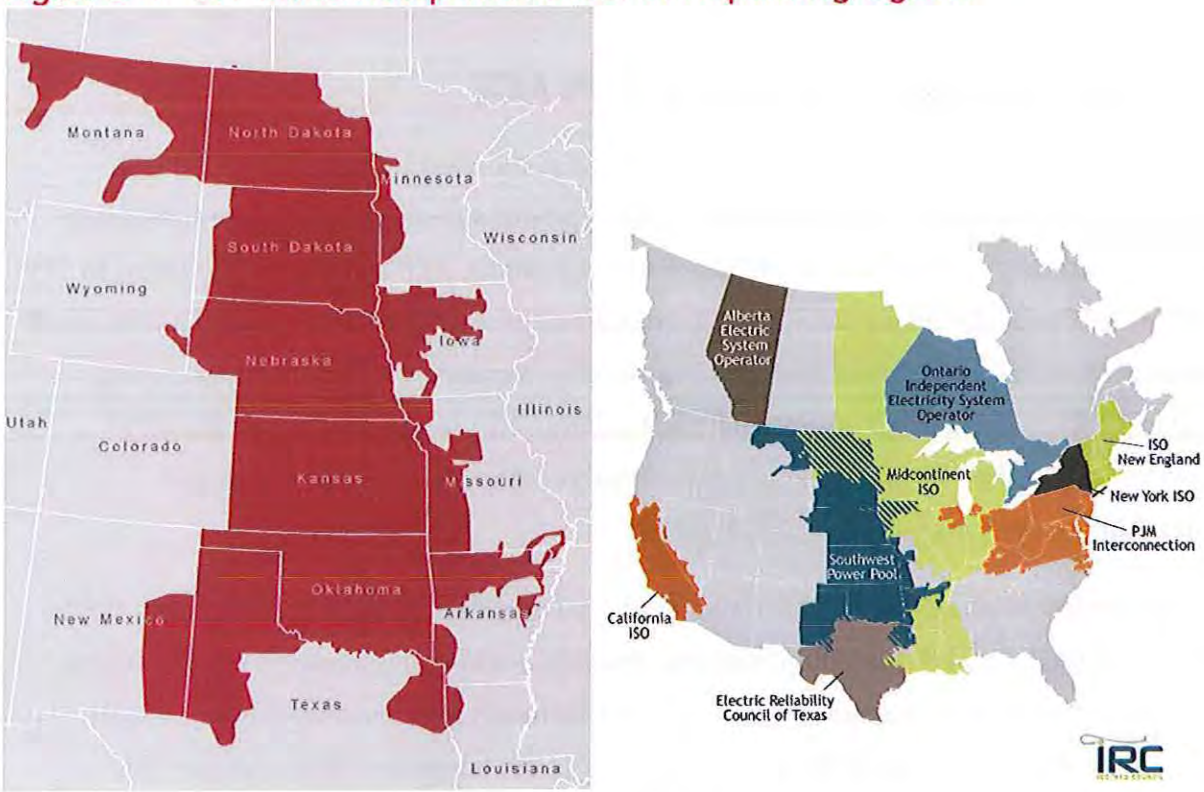
The Integrated Marketplace is a full day-ahead market with transmission congestion rights, virtual trading, a reliability unit commitment process, a real-time balancing market, and a price-based operating reserves market. SPP simultaneously put into operation a single balancing authority as part of the 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 the new 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 Western Electricity Coordinating Council (WECC) to the west. Figure 2–1 shows the current operating regions of the nine ISO/RTO 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-ISO/RTO areas such as Saskatchewan Power Corporation, Associated Electric Cooperative, and Southwestern Power Administration.[12]

[12] Southwestern Power Administration belongs to the SPP RTO, Reliability Coordinator (RC), Reserve Sharing Group (RSG), and Regional Entity (RE) footprints. Associated Electric Cooperative belongs to the SPP RSG.

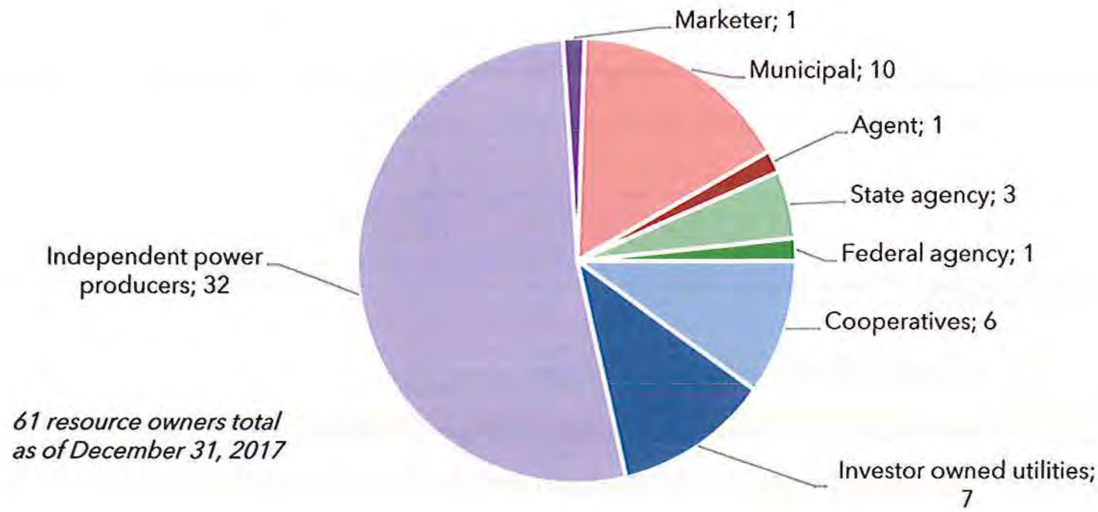
Figure 2–1 SPP market footprint and ISO/RTO operating regions



2.1.2 SPP MARKET PARTICIPANTS

At the end of 2017, 211 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 61 resource owners registered to participate in the Integrated Marketplace.

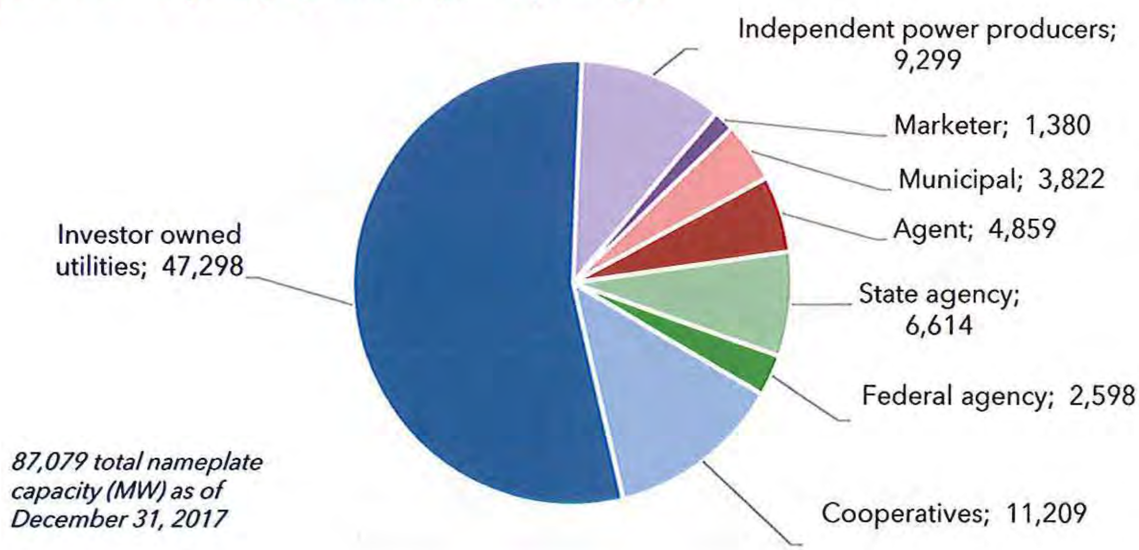
Figure 2–2 Market participants by type



The number of independent power producers is high since 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.

Figure 2–3 Capacity by market participant type



Although investor-owned utilities represent only a small percent of the number of participants in the market at 11 percent, they own the majority of the SPP generation capacity at 54 percent. This is in contrast to the "independent power producer" category, which has a large number of participants (52 percent) representing only a small portion (11 percent) of total nameplate capacity.

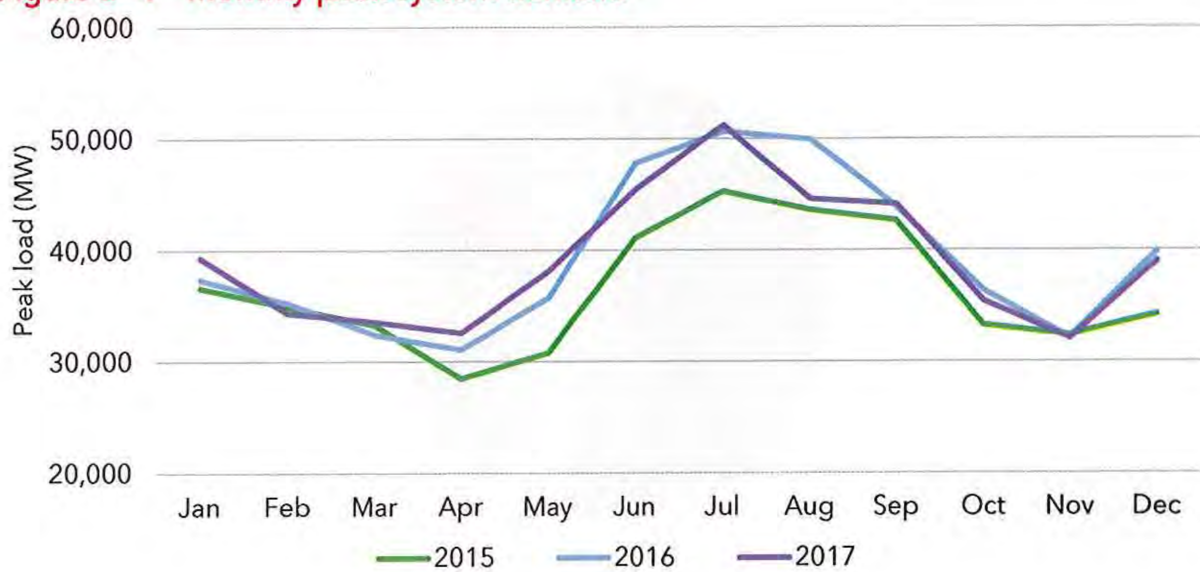
2.2 ELECTRICITY DEMAND

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 were added or removed. 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 market interval. The peak experienced during a particular year or season is affected by events such as unusually hot or cold weather, and daily and seasonal load patterns.

Figure 2–4 shows a month-by-month comparison of peak-day demand for the last three years. The SPP system coincident instantaneous peak demand[13] in 2017 was 51,181 MW, which occurred on July 20 at 4:30 PM. This is one percent higher than the 2016 system peak of 50,622 MW.

Figure 2–4 Monthly peak system demand

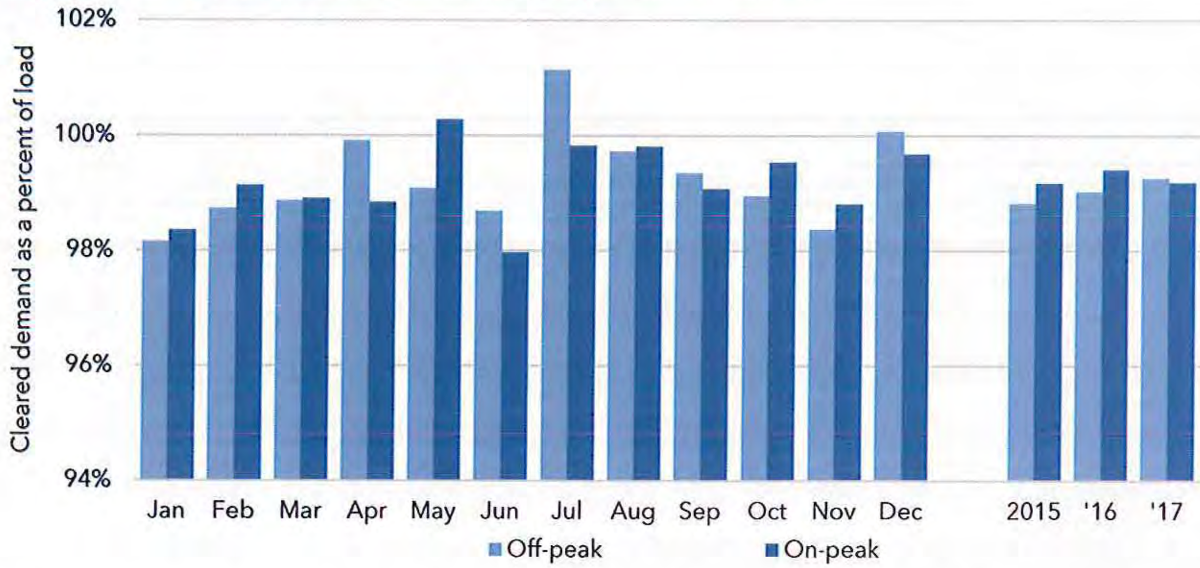


[13] Includes firm sales minus firm purchases, and includes losses.

2.2.2 MARKET PARTICIPANT LOAD

In 2017, load continued to participate in the day-ahead market at high levels as shown in Figure 2–5.

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



The average monthly participation rates for the load assets on an aggregate level were between 98 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 clearing prices. This remains consistent with prior years.

Figure 2–6 depicts 2017 total energy consumption and the percentage of energy consumption attributable to each entity in the market.

Figure 2–6 System energy usage

Name	2015		2016		2017	
	Energy consumed (GWh)	Percent of system	Energy consumed (GWh)	Percent of system	Energy consumed (GWh)	Percent of system
American Electric Power	43,078	18.9%	42,746	17.2%	41,887	17.0%
Oklahoma Gas and Electric	28,433	12.5%	28,078	11.3%	27,747	11.3%
Southwestern Public Service Company	25,590	11.2%	25,658	10.3%	25,826	10.5%
Westar Energy	23,544	10.3%	23,885	9.6%	23,845	9.7%
Kansas City Power and Light, Co	23,642	10.4%	23,951	9.6%	23,470	9.5%
Basin Electric Power Cooperative *	5,147	2.3%	17,859	7.2%	18,665	7.6%
The Energy Authority, NPPD	12,943	5.7%	13,248	5.3%	13,206	5.4%
Omaha Public Power District	10,854	4.8%	11,168	4.5%	11,066	4.5%
Western Farmers Electric Cooperative	9,041	4.0%	8,448	3.4%	8,046	3.3%
Grand River Dam Authority	5,616	2.5%	5,957	2.4%	5,581	2.3%
Empire District Electric Co.	5,156	2.3%	5,144	2.1%	4,984	2.0%
Golden Spread Electric Cooperative Inc.	4,840	2.1%	5,132	2.1%	4,817	2.0%
Sunflower Electric Power Corporation	4,646	2.0%	4,732	1.9%	4,693	1.9%
Western Area Power Administration, Upper Great Plains #	1,128	0.5%	4,477	1.8%	4,534	1.8%
Arkansas Electric Cooperative Corporation	3,172	1.4%	3,708	1.5%	3,675	1.5%
Lincoln Electric System Marketing	3,434	1.5%	3,515	1.4%	3,441	1.4%
The Energy Authority, CU	3,270	1.4%	3,332	1.3%	3,227	1.3%
Oklahoma Municipal Power Authority	2,797	1.2%	2,857	1.1%	2,766	1.1%
Kansas City Board of Public Utilities	2,392	1.0%	2,427	1.0%	2,347	1.0%
Midwest Energy Inc.	1,719	0.8%	1,710	0.7%	1,715	0.7%
Northwestern Energy #	394	0.2%	1,651	0.7%	1,632	0.7%
Kansas Municipal Energy Agency	1,437	0.6%	1,480	0.6%	1,473	0.6%
Tenaska Power Service Company	1,212	0.5%	1,363	0.5%	1,365	0.6%
Missouri River Energy Services #	304	0.1%	1,260	0.5%	1,226	0.5%
City of Independence	1,017	0.4%	1,065	0.4%	1,030	0.4%
Municipal Energy Agency of Nebraska	999	0.4%	1,015	0.4%	1,022	0.4%
Kansas Power Pool	857	0.4%	860	0.3%	843	0.3%
City of Chanute	489	0.2%	482	0.2%	487	0.2%
City of Fremont	435	0.2%	441	0.2%	433	0.2%
Missouri Joint Municipal Electrical Utility Commission	448	0.2%	450	0.2%	430	0.2%
MidAmerican Energy Company #	74	0.0%	284	0.1%	280	0.1%
South Sioux City, Nebraska +					225	0.1%
Harlan Municipal Utilities #	4	0.0%	19	0.0%	17	0.0%
NSP Energy #	1	0.0%	4	0.0%	5	0.0%
Otter Tail Power Company ^			41	0.0%	3	0.0%
System Total	**228,113**		**248,446**		**246,009**	

* Expanded footprint in SPP on October 1, 2015
# Joined SPP on October 1, 2015
^ Load added to the footprint on January 1, 2016
+ Joined SPP on January 1, 2017

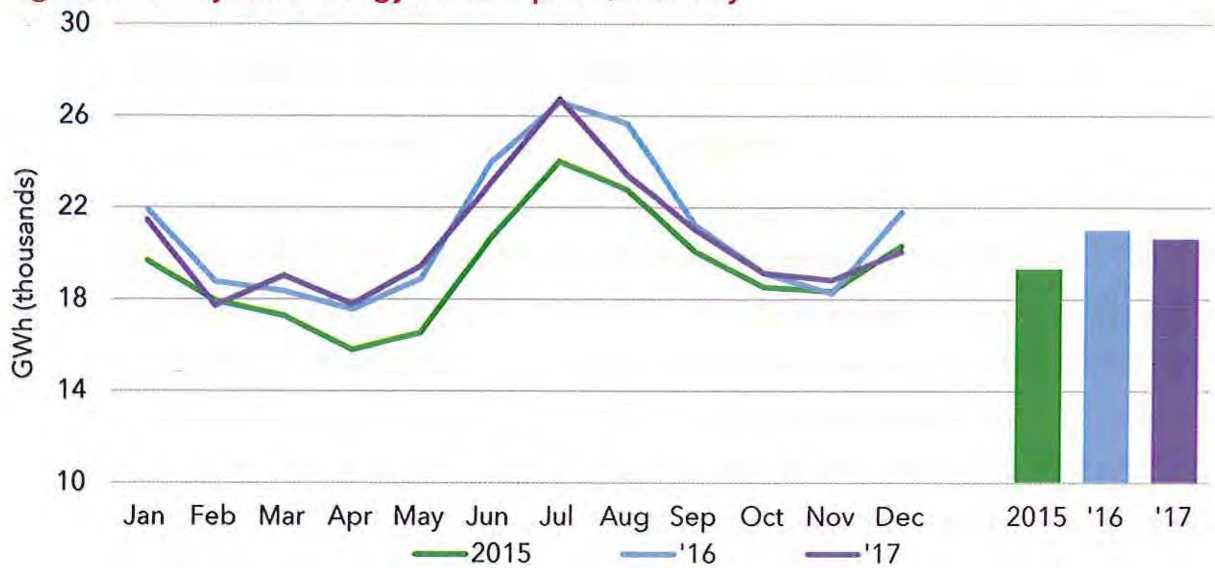
The largest five entities account for 58 percent of the total system energy usage, which is understandable because SPP's market is primarily composed of vertically integrated investor-owned utilities, which tend to be large. Overall, the total system energy usage in 2017 was one percent below the 2016 level, primarily due to cooler weather experienced in August 2017.

Also of note is the pending merger between Westar Energy and Great Plains Energy, parent company of Kansas City Power and Light, and the KCPL GMOC subsidiary.[14] Using 2017 figures, when this merger is completed, the combined company would account for 19.2 percent of total system load. This would make the combined company the largest user of system energy in the SPP market footprint.

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

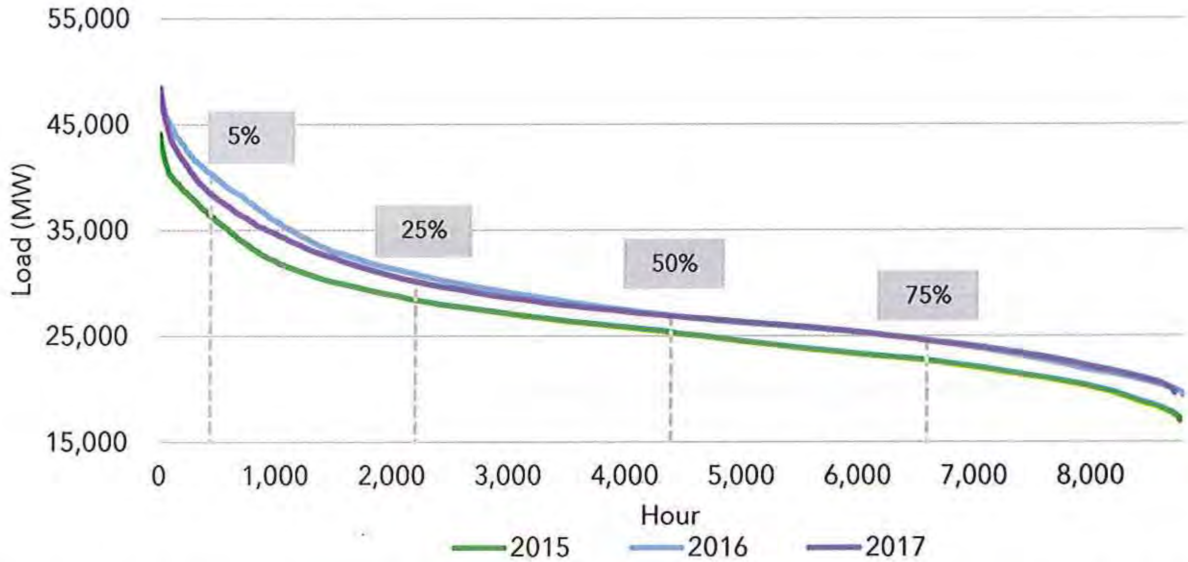


Monthly levels for 2016 and 2017 tracked closely together for most months, with the exception being August, when 2016 load was significantly higher, which was mostly attributed to high temperatures in that month.

Figure 2–8 depicts load duration curves from 2015 to 2017. These load duration curves display hourly loads from the highest to the lowest for each year.

[14] http://www.greatplainsenergy.com/about-gpe/westar-energy-acquisition

Figure 2–8 Load duration curve



In 2017, the maximum hourly average load was 48,375 MW, down just slightly from the high of 48,547 MW in 2016. The minimum hourly load for 2017 was 19,601 MW, which was slightly above the 2016 minimum of 19,377 MW. Comparing annual load duration curves shows differentiation between cases of extreme loading events and more general increases in system demand. If the extremes only are higher or lower than the previous year, then short-term loading events are likely the reason. However, if the entire load curve is higher than the previous year, it indicates that total system demand has increased.

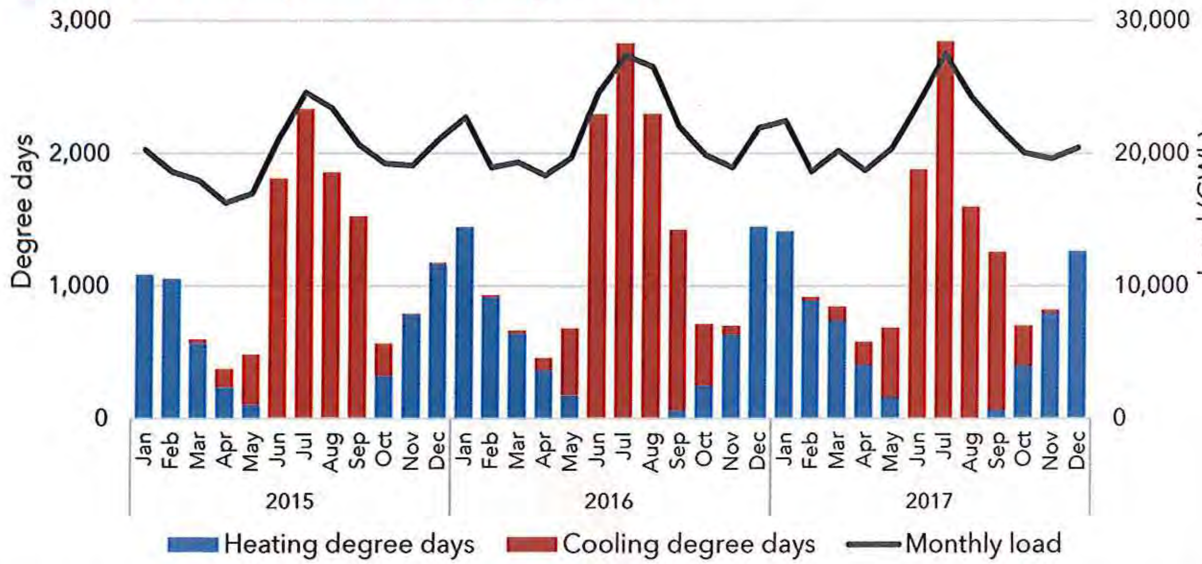
Reference percentage lines indicate a similar load pattern over the last three years at load levels above the 25 percent reference level. The largest notable difference between loads during these three years occurred at the higher load levels around the five percent reference value. Significantly higher temperatures across the footprint occurred in the summer of 2016 compared to the summer of 2017. The consistent difference between 2016 and 2017 compared to 2015 can largely be attributed to the addition of the Integrated System in October 2015.

2.2.4 HEATING AND COOLING DEGREE DAYS

Based on analysis of temperature impact on demand in the SPP footprint from 2011 through 2017, the MMU estimates that normal seasonal temperature variation tends to impact monthly total load by 29 percent (spring vs. summer). 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[15] were used to calculate system daily average temperatures.[16] 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 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 much higher than the impact of a single heating degree day. The impact of a single cooling degree day on load is significantly higher than that of a heating degree day in part because of more electric cooling than electric heating.

Figure 2–9 Heating and cooling degree days



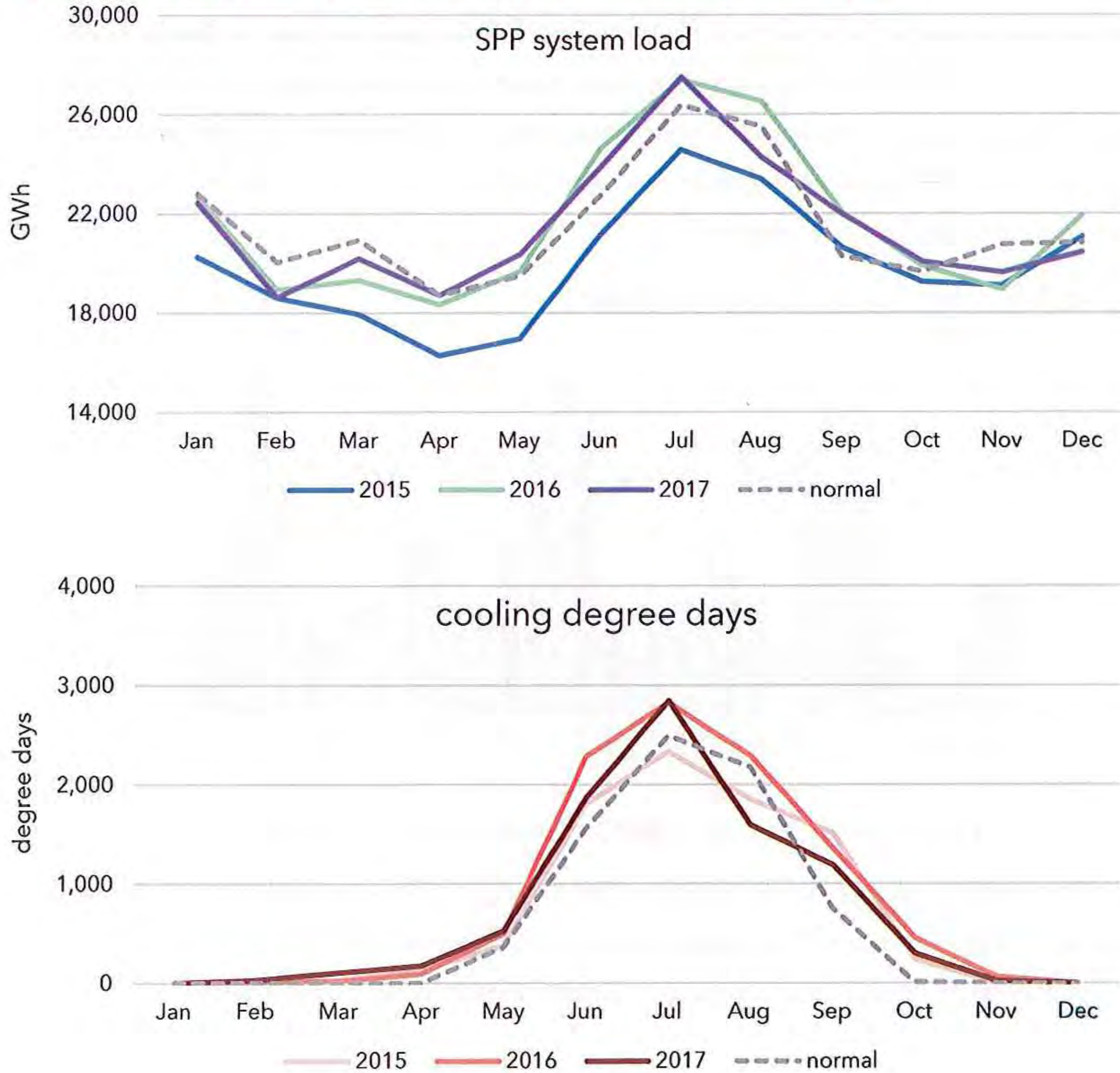
The SPP market footprint experienced cooler temperatures in June and August 2017 which resulted in a steeper monthly demand curve during that time period as compared to the two previous years. August temperatures were milder than normal, explaining the sharp drop in

[15] Amarillo TX, Topeka KS, Oklahoma City OK, Tulsa OK, and Lincoln NE. After October 1, 2015, Bismarck ND was added to represent SPP's expanded market footprint.
[16] Daily average temperature is calculated as the average of the daily lowest and highest temperatures. The source of temperature data is the National Oceanic and Atmospheric Administration (NOAA).

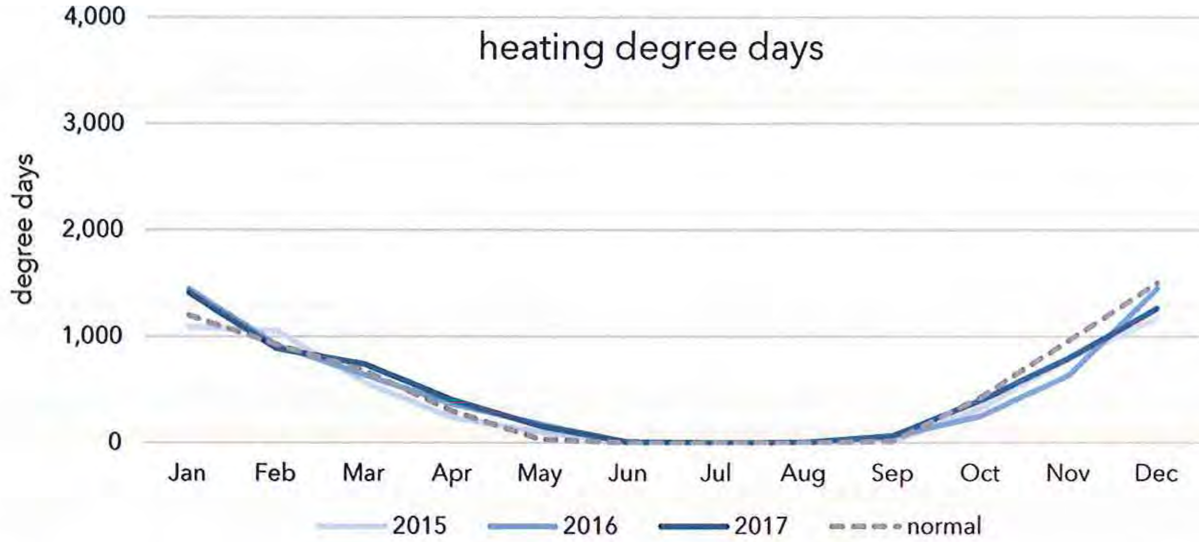
market load from July to August. Otherwise, 2017 SPP footprint load and temperatures (as measured by degree days) were similar to 2016.

Figure 2–10 shows heating degree days, cooling degree days, and load levels from 2015 through 2017 compared to a normal year.[17] Normal 2017 load was derived from a regression analysis of actual footprint heating degree days, cooling degree days, weekends, and holidays, substituting footprint normal temperatures.

Figure 2–10 Degree days and loads compared with a normal year



[17] 30 year normal temperatures are from the 1981-2010 U.S. Climate normals product from NOAA.



The charts 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.

2.3 INSTALLED GENERATION CAPACITY

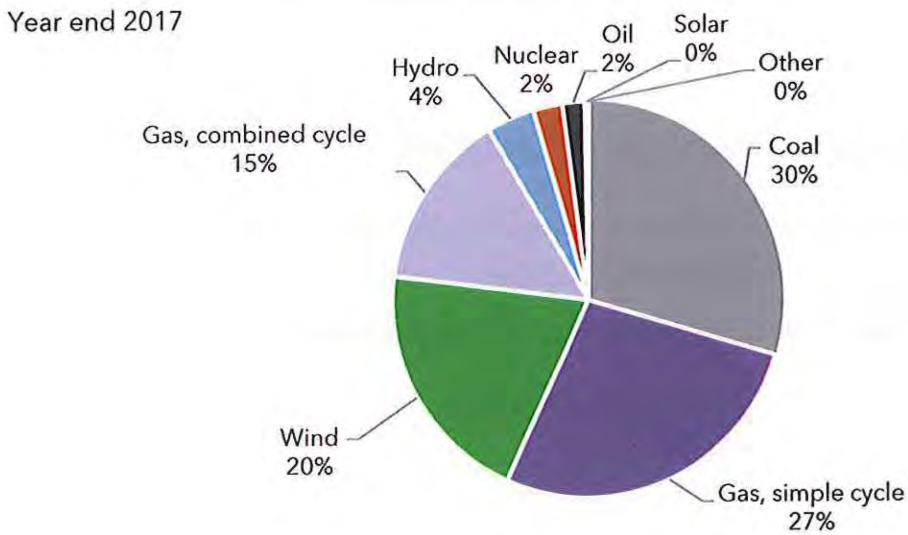
Figure 2–11 depicts the Integrated Marketplace installed generation for the SPP market footprint at the end of the year. Total installed generation in the SPP Integrated Marketplace was 87,079 MW by the end of 2017, representing a very slight decrease of less than one percent from 2016.[18]

[18] The change in total generation capacity from year to year includes additions, retirements, and nameplate rating changes that occur during the year.

Figure 2–11 Generation nameplate capacity by technology type

Fuel type	2015	2016	2017	Percent as of year-end 2017
Coal	28,821	26,939	25,717	30%
Gas, simple-cycle	23,910	24,024	23,737	27%
Wind	12,397	16,114	17,596	20%
Gas, combined-cycle	12,025	12,870	12,618	15%
Hydro	3,430	3,428	3,422	4%
Nuclear	2,629	2,107	2,061	2%
Oil	1,608	1,684	1,639	2%
Solar	50	215	215	0%
Other	74	74	74	0%
Total	84,943	87,453	87,079	

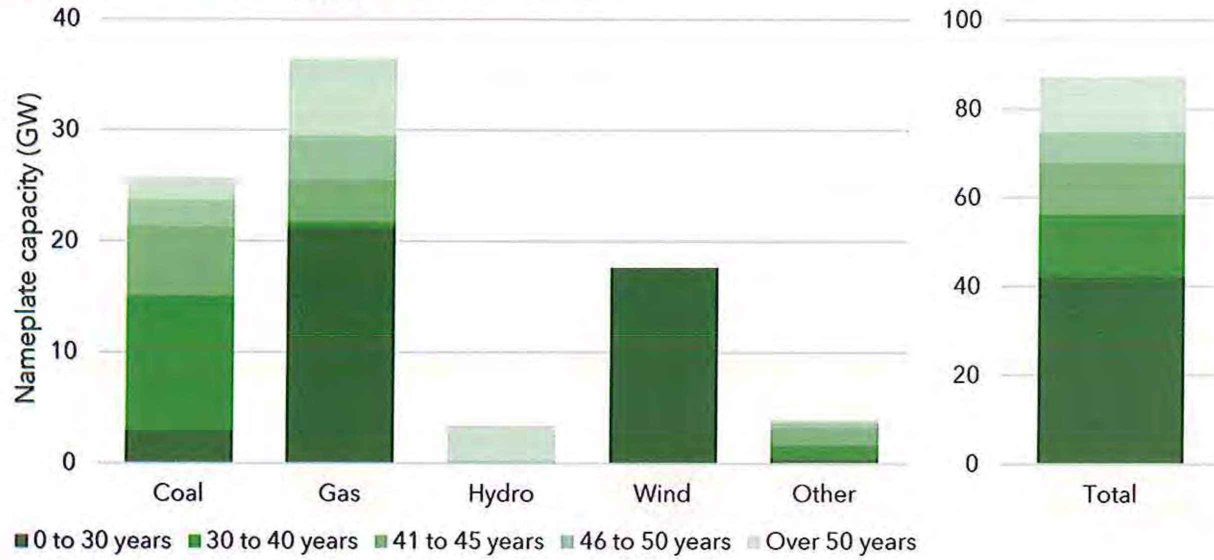
Note: Capacity is nameplate rating at year-end.



Natural gas-fired installed generation capacity still represents the largest share of generation capacity in the SPP market at 42 percent (gas simple-cycle 27 percent, gas combined-cycle 15 percent), with coal being the second largest type at 30 percent. Wind continues to increase due largely to new additions, with a 2017 market share of 20 percent of total capacity in the SPP market.

Figure 2–12 illustrates that certain segments of the SPP generation fleet are aging.

Figure 2–12 Capacity by age of resource



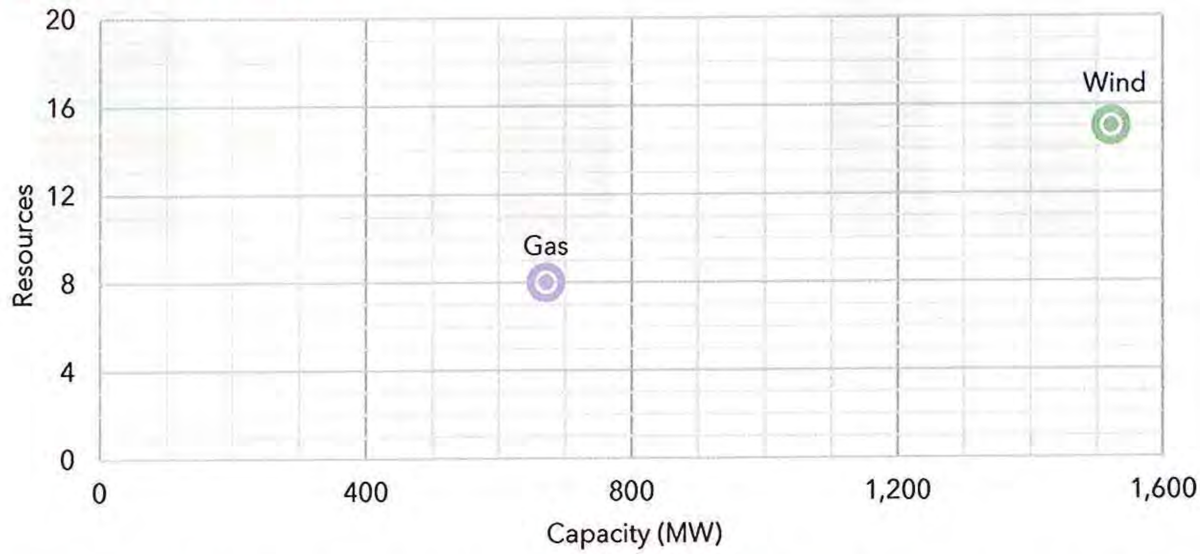
Nearly 52 percent of SPP's fleet is more than 30 years old. In particular, nearly 90 percent of coal capacity and just over 40 percent of gas capacity is older than 30 years. According to the U.S. Energy Information Administration (EIA), the national average retirement age of coal-fired generation that retired in 2015 was 54 years.[19] Aside from the resources that joined SPP from Nebraska in 2009 and the Integrated System in 2015, the great majority of significant new capacity in the SPP footprint over the last 10 years has been wind capacity.

[19] https://www.eia.gov/todayinenergy/detail.php?id=25272

2.3.1 CAPACITY ADDITIONS AND RETIREMENTS

Figure 2–13 shows the capacity by the technology and the number of resources added in 2017.

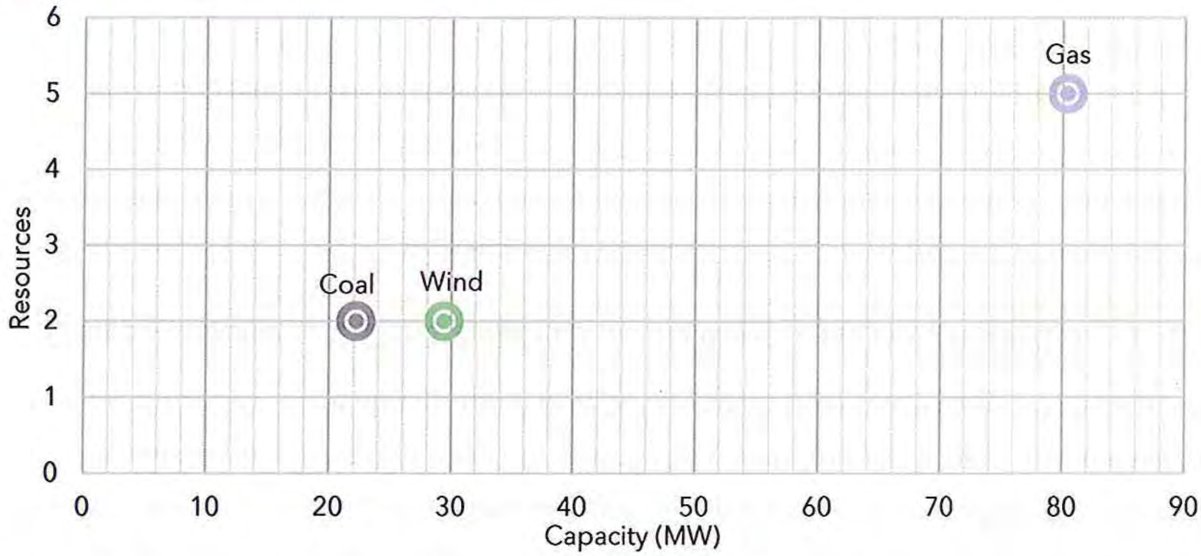
Figure 2–13 Capacity additions



Nearly 2,200 MW of new generation capacity was added to the SPP market during 2017. Two-thirds of the new capacity was wind, with natural gas representing the remaining portion. All of this new market capacity was new construction.

In 2017, the SPP market had a low number of generation retirements amounting to just 132 MW of installed capacity, shown in Figure 2–14.

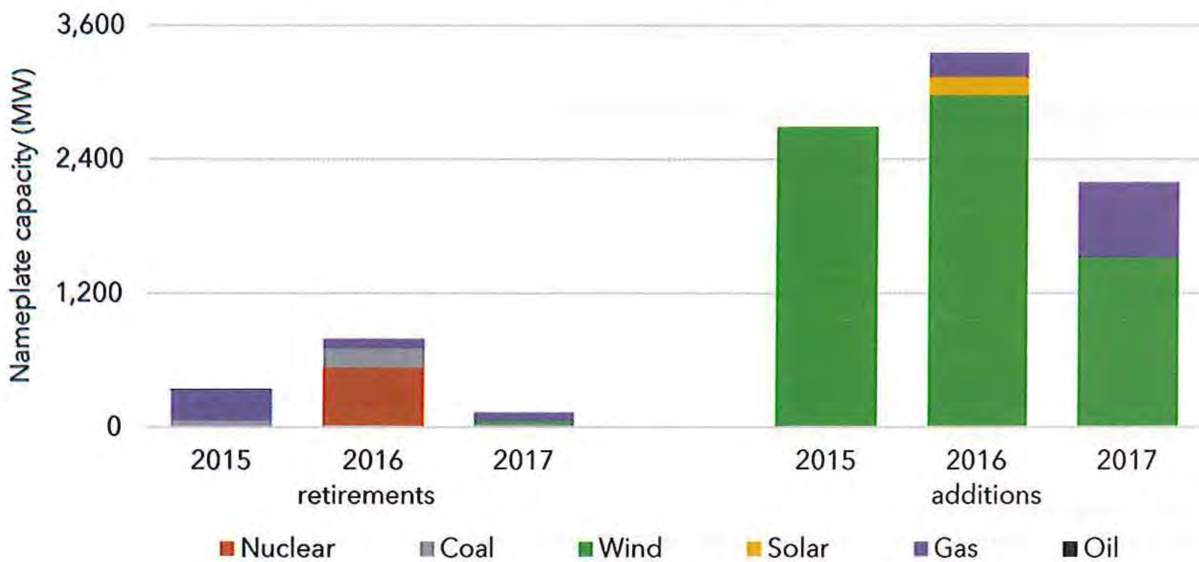
Figure 2–14 Capacity retirements



Two relatively small coal resources representing 22 MW of capacity, two wind resources representing 29 MW of capacity, and five gas resources representing 80 MW of capacity were retired in 2017.

Figure 2–15 shows the annual trend of capacity additions and retirements over the past three years.

Figure 2–15 Capacity additions and retirements by year



Almost all of the coal and gas capacity retired since 2015 has been 1950s era plants. The nuclear unit retired in 2016 was commissioned in the early 1970s. The wind units that retired were first-generation wind resources with very low capacity.

For capacity additions, wind generation additions slowed in 2017 compared to prior years with just over 1,500 MW of capacity added in 2017, compared to over 2,600 MW in each of the two prior years. Almost 100 MW of solar generation was added in 2016. Looking forward, the amount of solar resources in the generation interconnection queue has grown over four-fold in the past year. This is discussed more below in Section 2.3.3 of this report.

2.3.2 GENERATION CAPACITY COMPARED TO PEAK LOAD

The MMU has created a new peak available capacity metric to replace our previous reserve margin metric[20] 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 (as shown in Figure 2–11). Solar resources are derated to 50 percent of capacity. Wind resources are derated to a capacity based on actual production in July and August in the SPP market. From 2014 to 2016, 12 percent of wind generation capacity is included in the calculation. That figure increases to 14 percent for 2017. These percentages are consistent with figures used by other RTOs.[21]

The peak available capacity percent is the amount of extra system capacity available after serving system peak load, and is shown in Figure 2–16.

[20] The reserve margin metric used unit registration ratings (i.e. nameplate capacity) to determine system capacity, with wind counted at only five percent of registered capacity.
[21] https://old.misoenergy.org/Library/Repository/Study/LOLE/2018%20Wind%20Capacity%20Report.pdf

Figure 2–16 Peak available capacity percent

Year	Peak available capacity (MW)	Peak load (MWh)	Peak available capacity percent
2014	61,302	45,301	35%
2015	61,499	45,279	36%
2016	67,319	50,622	33%
2017	66,509	51,181	30%

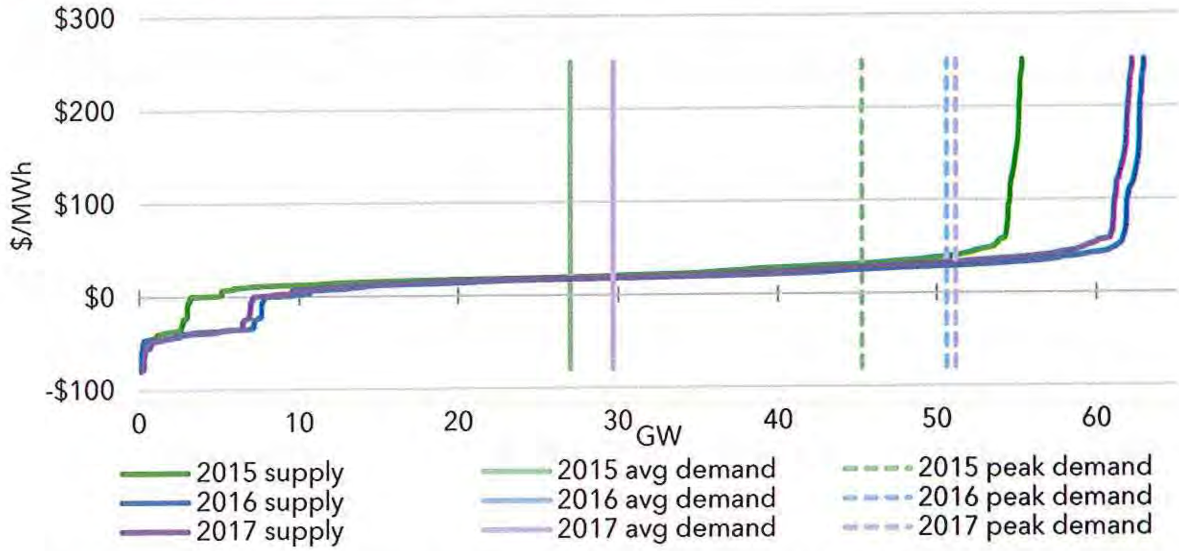
For 2017, the peak available capacity percent was 30 percent, down from 33 percent in 2016, and 36 percent in 2015.[22] The 30 percent peak available capacity percentage is still nearly three times higher than SPP's minimum required planning reserve margin of 12 percent.[23] Also note that the peak availability 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 our metric includes all system resources interconnected with the SPP grid using derate factors that are consistent with other regions.

A relatively high peak available capacity percentage such as this has positive implications for both reliability and for 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.[24]

Figure 2–17 shows the total SPP aggregate real-time generation supply curves by offer price, peak demand, and average demand for the summers of 2015 to 2017. Resources in "outage" status were excluded from the supply curve. To calculate the summer supply curves, a typical summer day was used for each analysis year. Using the real-time offers of non-wind resources and wind forecast data for wind resources, the aggregate generation supply curves were developed.

[22] 2015 uses the total capacity on September 30, prior to the addition of the Integrated System.
[23] SPP Planning Criteria 4.1.9.
[24] We recognize that grid resiliency is a topic of concern and discussion. However, we feel that resiliency must be properly measured and evaluated in the SPP market to ensure that ratepayers are not burdened by unnecessary costs of excess capacity.

Figure 2–17 Aggregate supply curve, typical summer day



Total aggregate real-time generation supply for summer 2017 was 62,252 MW, compared to 62,988 MW for summer 2016, just a one percent difference. This difference can mostly attributed to varying of the wind forecast, as well as differing outages, on those days. Total aggregate real-time generation supply in summer 2015 was significantly lower, at 55,260 MW. As discussed earlier in this report, the SPP Integrated Marketplace footprint expanded on October 1, 2015 to include the Integrated System (IS), which added more than 7,600 MW of generating capacity to SPP market.

Also evident is the approximately 20 GW gap between this maximum supply and the total installed nameplate generation capacity. This is primarily a result of excluding the resources in "outage" status from the available supply (approximately 4 GW), reduced summer capacity due to high ambient temperatures (approximately 6 GW), as well as the difference between the wind forecast and installed capacity of wind resources (approximately 8 GW).

The section of the offer curve below $0/MWh is mostly due to subsidized wind and solar energy and can vary between 1,000 and 13,000 megawatts, based on wind and solar availability. The sharp uptick in price around 62 GW in 2017 represents the transition from natural gas units to oil units.

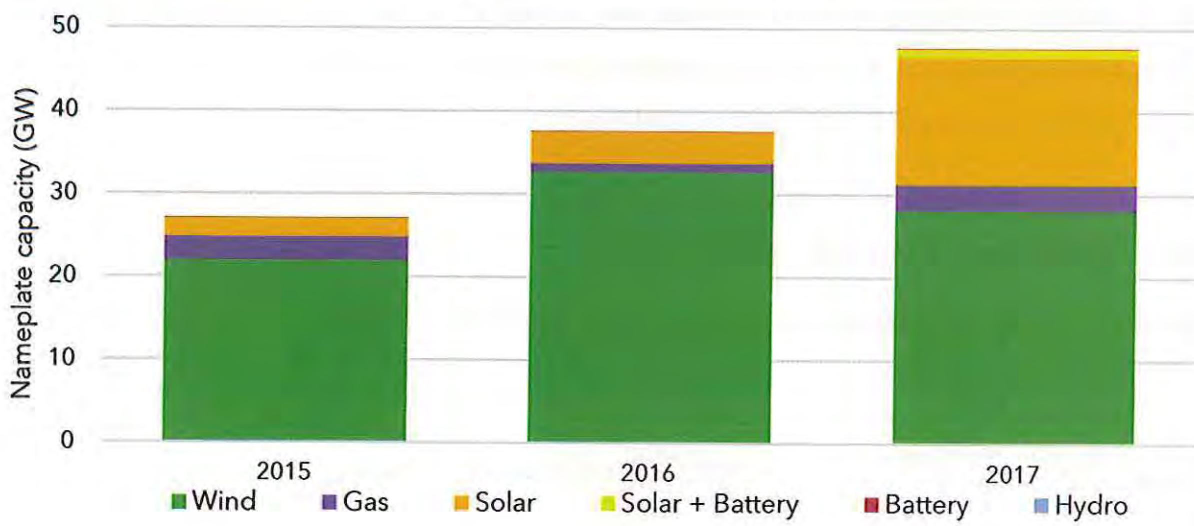
2.3.3 GENERATION INTERCONNECTION

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.[25]

Figure 2–18 shows the megawatts of capacity by generation technology type in all stages of development. Included in this figure are interconnection agreements in the process of being created; those under construction; those already completed, but not yet in commercial operation; and those in which work has been suspended as of year-end 2017.

Figure 2–18 Active generation interconnection requests, megawatts

Prime mover	2015	2016	2017
Wind	21,930	32,690	28,147
Gas	2,900	1,080	3,122
Solar	2,200	3,770	15,306
Battery	60	40	52
Solar + battery[26]	0	0	1,083
Hydro	10	0	0
Total	27,100	37,580	47,710



As can be seen in the table, generation capacity from renewable resources accounts for the vast majority of proposed generation interconnection, representing 93 percent of the total. Interestingly, the amount of wind generation in the interconnection queue decreased from

[25] See Guidelines for Generator Interconnection Requests to SPP's Transmission System http://sppoasis.spp.org/documents/swpp/transmission/studies/GuidelinesAndBusinessPracticesForGIP.pdf.

[26] The solar + battery category represents a generation interconnection request where the site is both a solar farm and a battery storage site.

the previous year for the first time in the SPP market, but was still greater than the 2015 amount. Interconnection requests for solar generation, on the other hand, increased over four-fold from 2016 to 2017. Although the level of battery only interconnection requests remains minimal, over 1,000 MW of interconnection requests for combined solar farm/battery storage sites were received in 2017.

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 the reliability of the SPP system. Additional wind impact analysis follows in the Section 2.5.

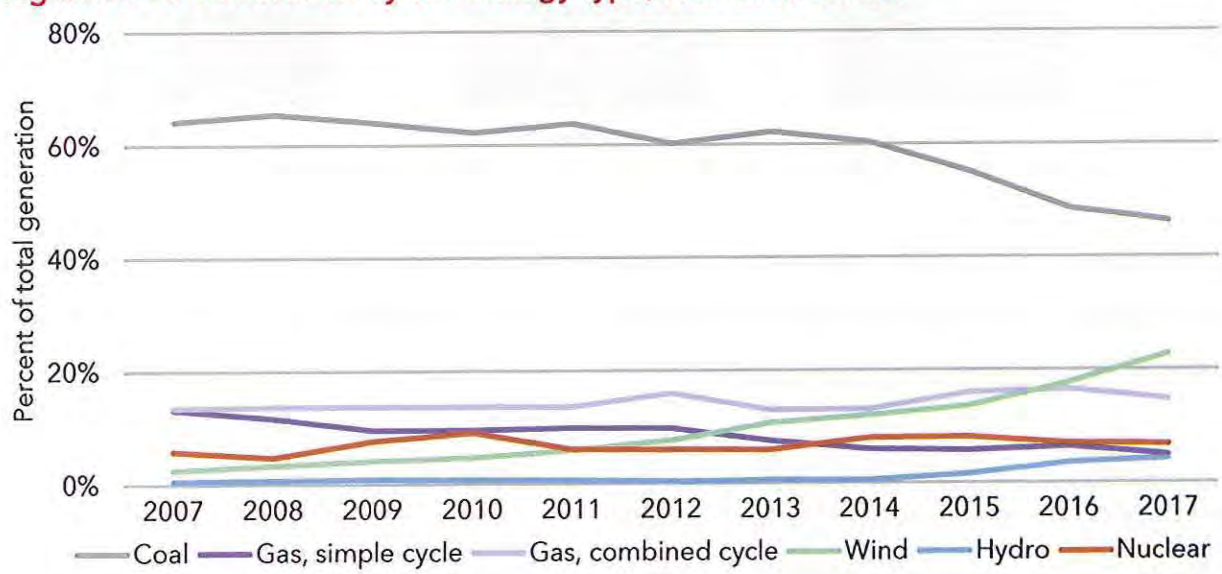
2.4 GENERATION

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 2007 through 2017.

Figure 2–19 Generation by technology type, real time, annual



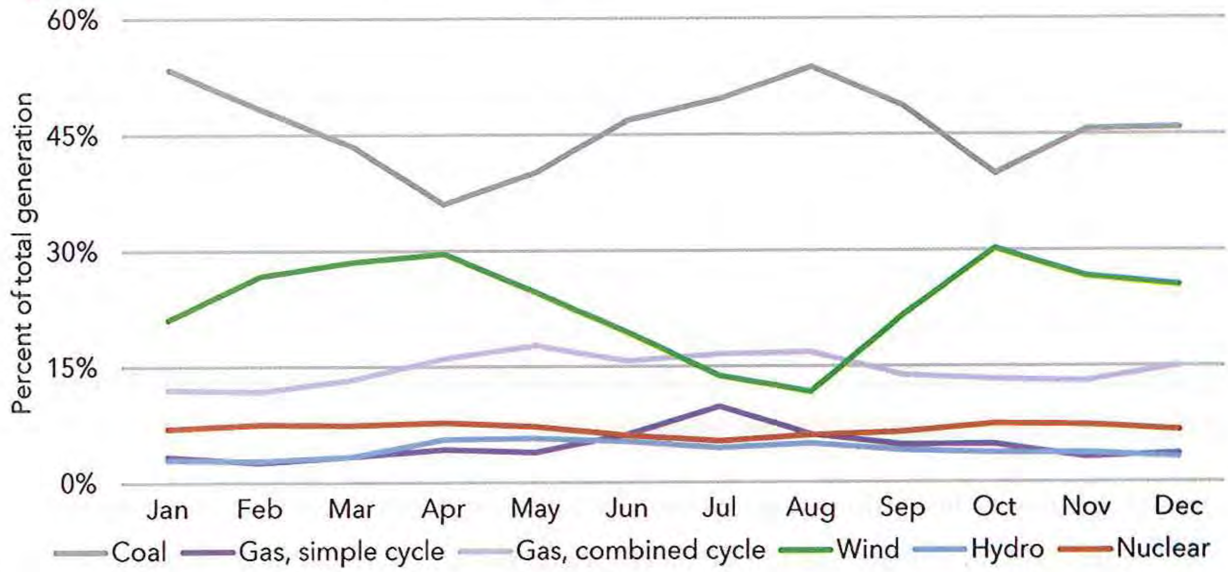
Generation from simple-cycle gas units such as gas turbines and gas steam turbines has seen a significant decline over the past few years, decreasing share from 13 percent in 2007 to just under five percent in 2017. Gas combined-cycle generation has remained relatively stable at about fifteen percent for the past three years, which can mostly be attributed to low gas prices. Wind generation share continues to increase from nearly three percent in 2007 to nearly 23 percent in 2017. Coal generation share decreased to 46 percent of total generation in 2017, down from 48 percent in 2016. The long-term trend for coal-fired generation had been relatively flat through 2014 at around 60 to 65 percent of total generation, but has declined to under 50 percent in 2016 and 2017. This can primarily be attributed to increasing wind generation and 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 in 2012, and 2015 to 2017 were extremely 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, making it less competitive.

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 2017 monthly fluctuation in generation by technology type.

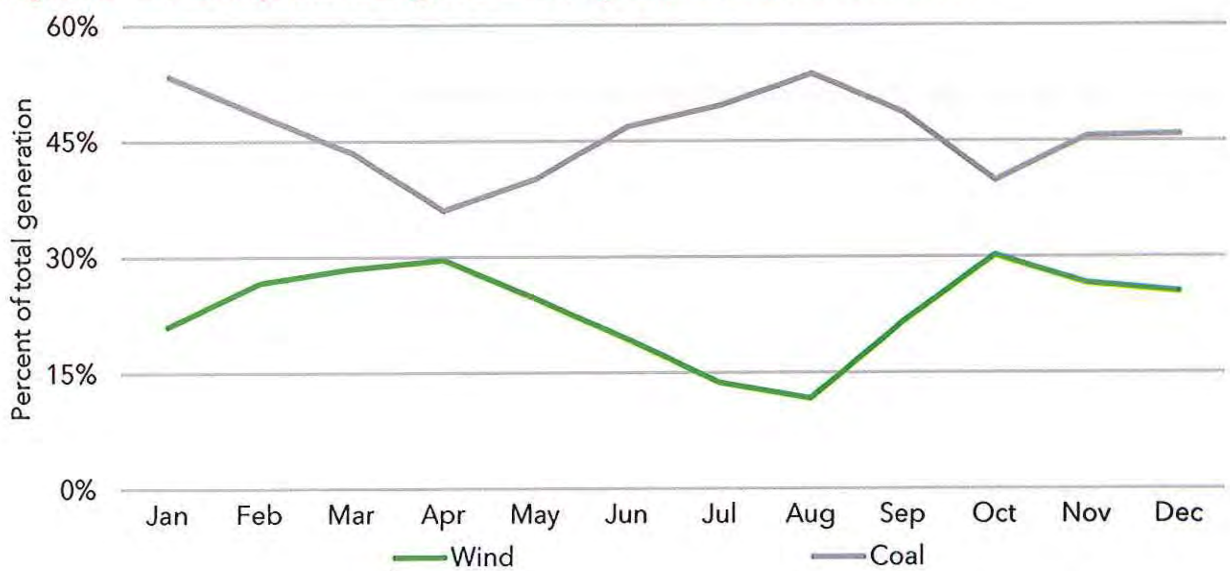
Figure 2–20 Generation by technology type, real time, monthly



Wind generation fluctuates from around 12 percent in the summer months to peaks around 30 percent in the highest wind generation months of April and October. The increase in wind generation accompanied with low natural gas prices resulted in coal-fired generation market share falling to below 40 percent in both April and October 2017.

Figure 2–21 below uses the data from Figure 2–20 above, but only shows monthly coal and wind generation.

Figure 2–21 Comparison of generation by coal and wind resources

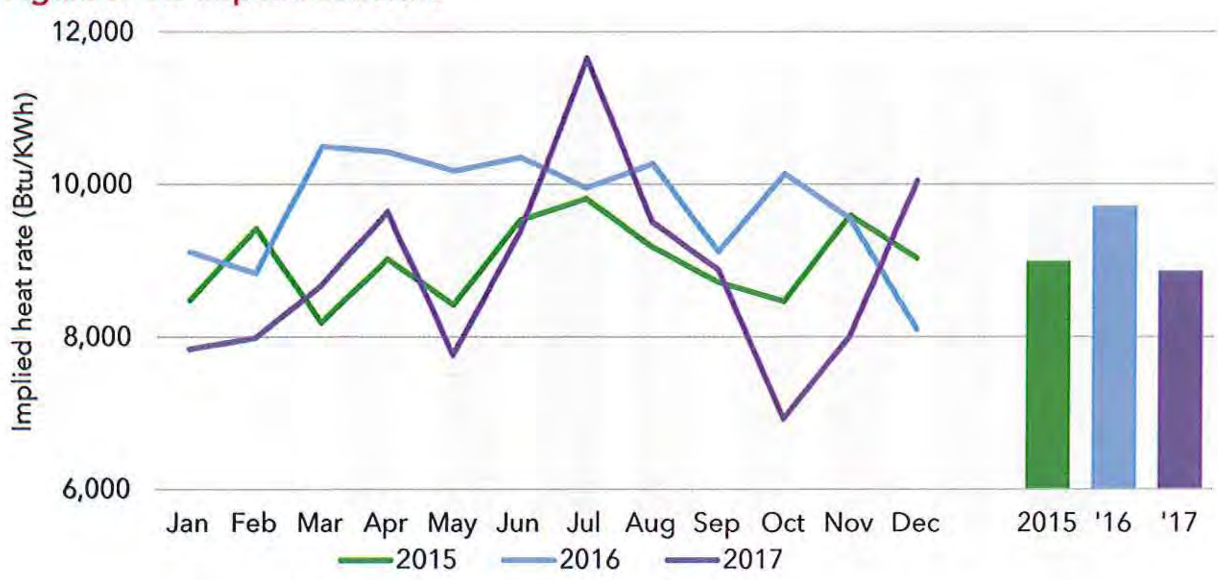


The monthly generation percentages show an inverse relationship between monthly levels of wind and coal generation in 2017, as wind generation increases, coal generation decreases and vice versa.

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.[27] 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 system prices.

Figure 2–22 shows the monthly implied heat rate using real-time electricity prices for 2015 to 2017, along with an annual average for those years.

Figure 2–22 Implied heat rate



[27] 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. We ignore emission costs in fuel cost as they rarely apply in the SPP market.

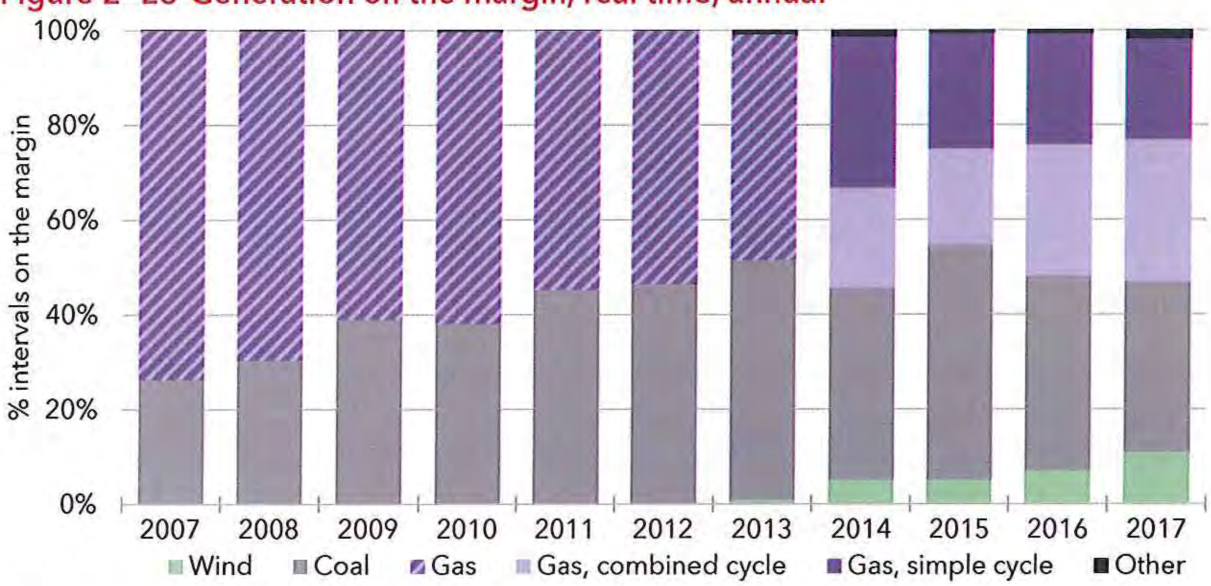
The chart shows an overall decline in implied heat rates in 2017 compared to 2016 and 2015. In particular, the 2017 implied heat rate was more variable monthly, even though natural gas prices were fairly constant for most of the year. Of note, wind generation and load affected electricity prices in 2017. For instance, wind affected electricity prices in May and October, lowering average heat rates, whereas high temperatures in July increased load and electricity prices.

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 2–23 illustrates the frequency with which different technology types were marginal and price setting. 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 2–23 Generation on the margin, real time, annual



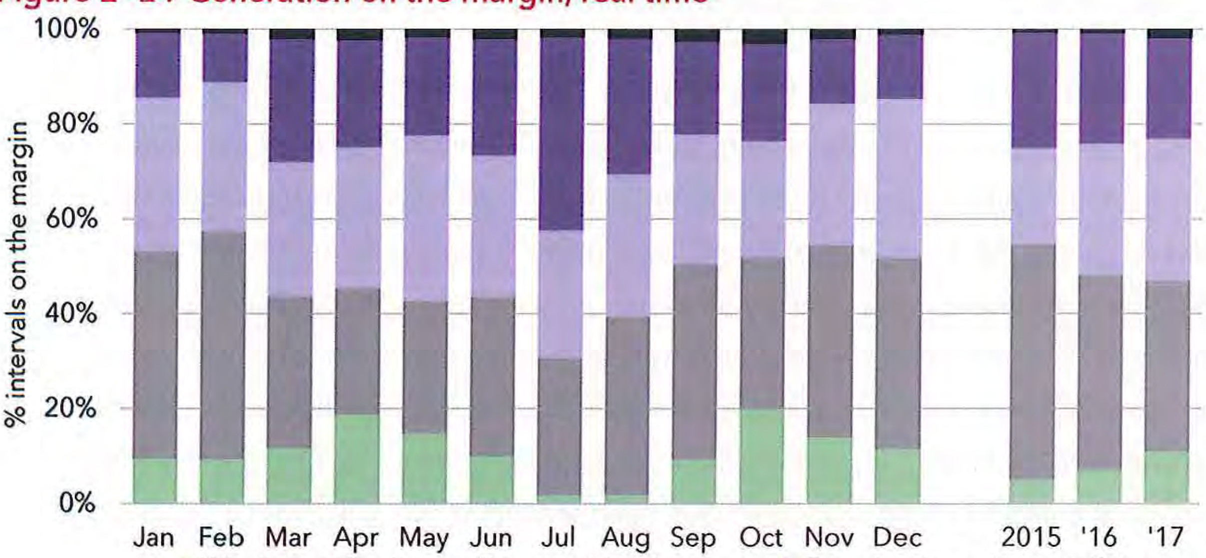
This chart illustrates the dramatic shift in technology on the margin with natural gas representing about 75 percent in the first year of an SPP market in 2007 to only about 50 percent in 2017. There is a corresponding shift in coal generation on the margin from about

25 percent in 2007, peaking at around 50 percent in 2015, then declining to 36 percent by 2017. This change is driven by market efficiency improvements as reflected in the decline in simple-cycle natural gas generation as shown in Figure 2–19. As a result of these market efficiency improvements, along with low natural gas prices, coal-fired plant owners are experiencing more daily swings in dispatch level, which are reflected in this generation on the margin analysis.

It is worth noting the increase in wind generation being on the margin–from five percent in 2014 and 2015 to nearly 11 percent in 2017. With the growing amount of dispatchable wind generation and an overall quantity of 20 percent of total nameplate capacity, wind generation is increasingly becoming the marginal technology a higher percentage of the time. At the end of 2017, 64 percent of wind capacity was dispatchable, compared to 60 percent at the end of 2016, 46 percent at the end of 2015, and 27 percent at the beginning of the Integrated Marketplace in March 2014. The recommendation to convert non-dispatchable variable energy resources to dispatchable variable energy resources is discussed in Section 7.4.1 below.

Figure 2–24 shows monthly values for real-time generation on the margin for 2017.

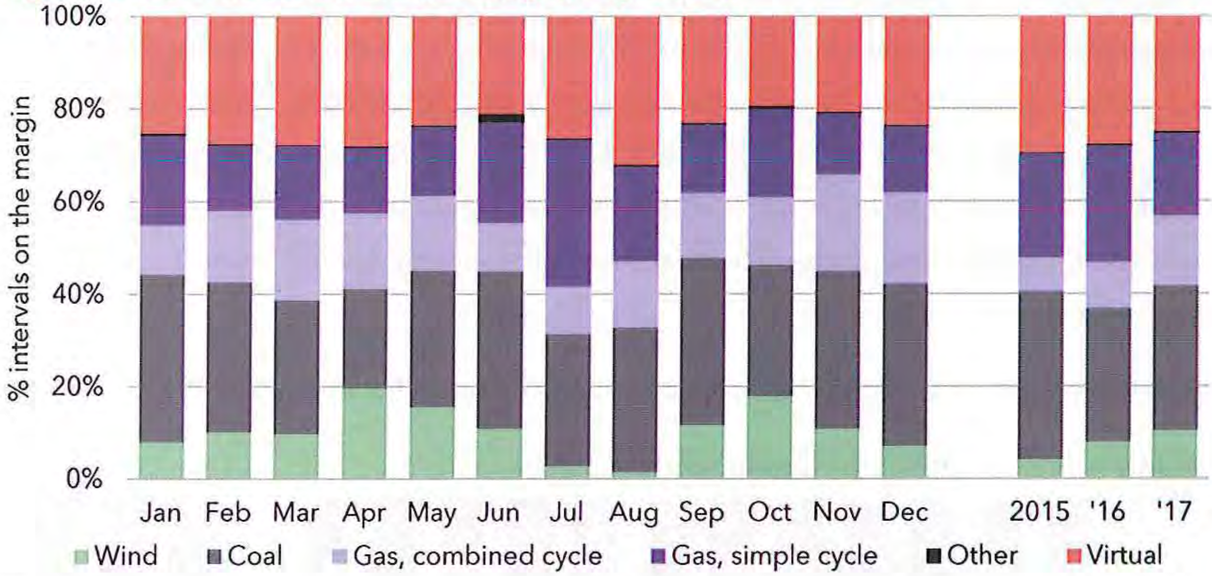
Figure 2–24 Generation on the margin, real time



Intervals with coal generation on the margin are typically lower in the spring and fall months, resulting in more coal-fired units running as base load units with less cycling. The 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 time of the year, as well as the lowest demand periods in the SPP footprint.

Day-ahead generation on the margin, shown in Figure 2–25, 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.

Figure 2–25 Generation on the margin, day-ahead



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 declining over the past three years, with 25 percent of the marginal offers in the day-ahead market in 2017, compared to 28 percent in 2016 and 30 percent in 2015. While marginal virtual offers occur at all types of settlement locations, 57 percent of marginal virtual offers are at resource settlement locations, with a significant amount of activity at non-dispatchable wind generation resource locations. Note that high virtual activity frequently occurs at wind locations because wind generation resources are typically under-scheduled in the day-ahead market.

2.5 GROWING IMPACT OF WIND GENERATION CAPACITY

2.5.1 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 are additional factors that have resulted in significant wind investment in the SPP footprint during the last five years.

Figure 2–26 below shows a high potential for wind development in the SPP footprint, which is outlined in black.

Figure 2–26 Wind speed map

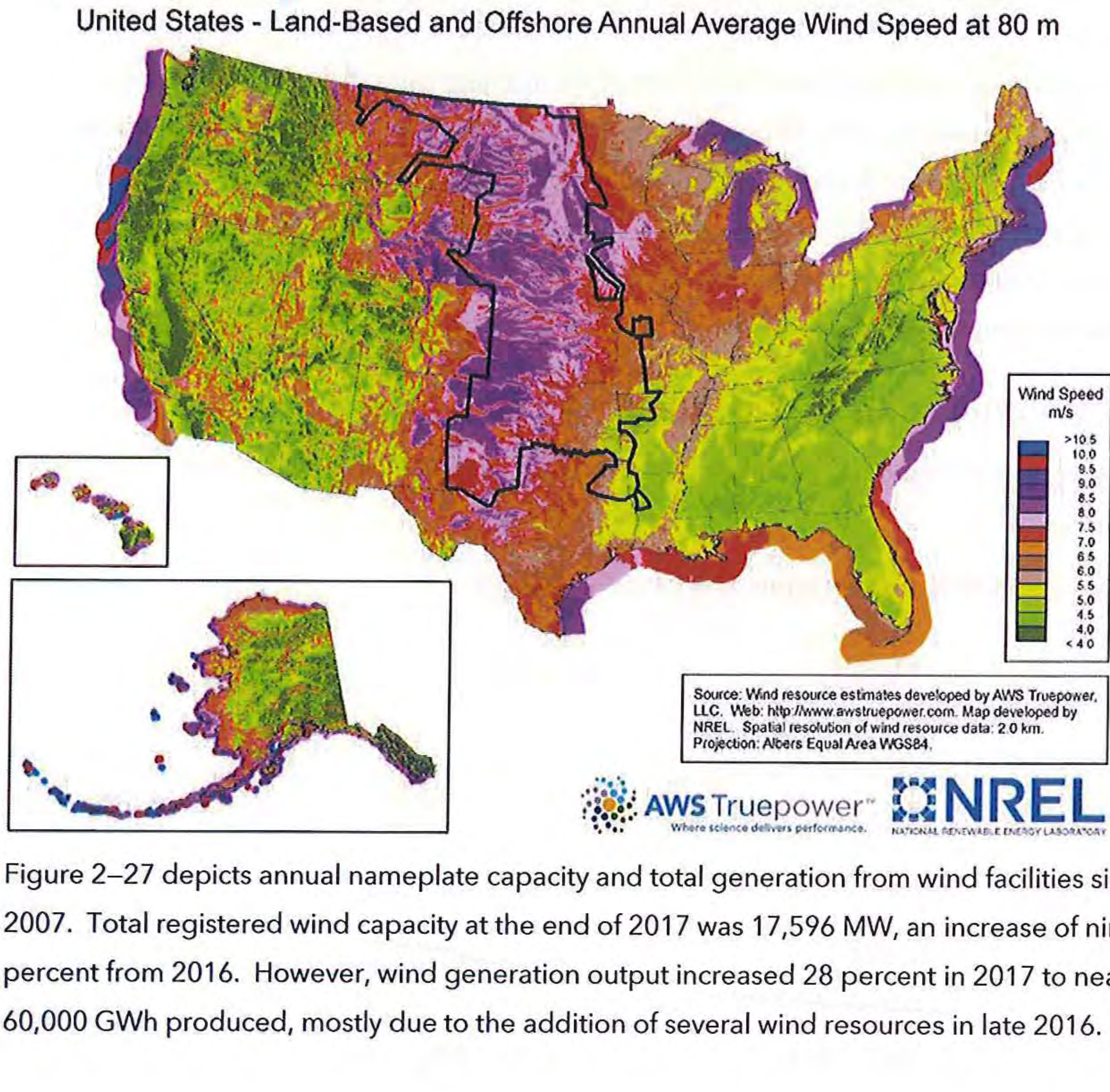
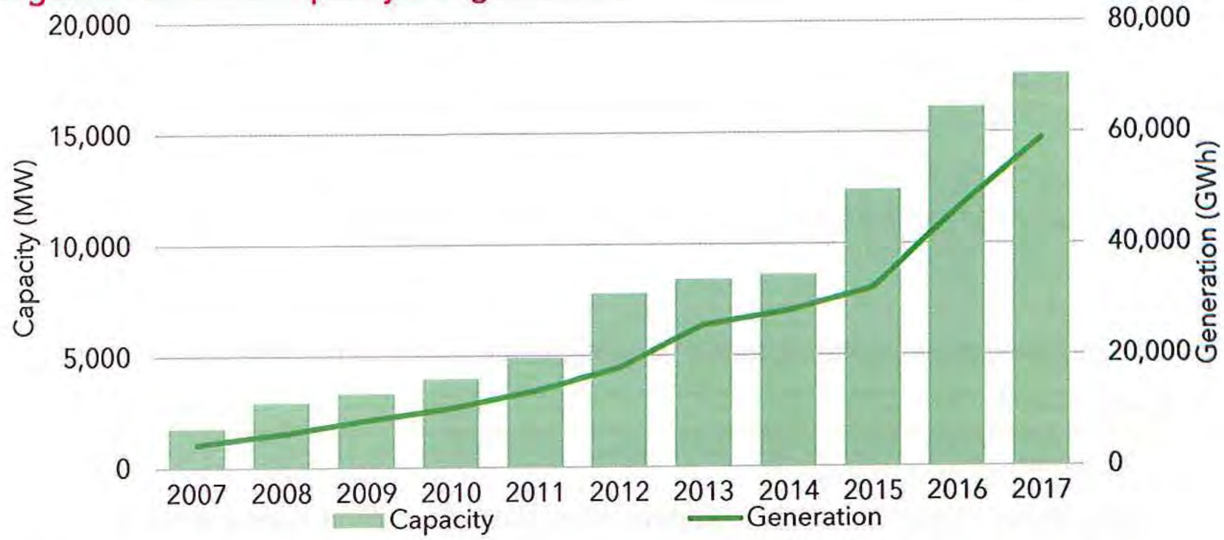


Figure 2–27 depicts annual nameplate capacity and total generation from wind facilities since 2007. Total registered wind capacity at the end of 2017 was 17,596 MW, an increase of nine percent from 2016. However, wind generation output increased 28 percent in 2017 to nearly 60,000 GWh produced, mostly due to the addition of several wind resources in late 2016.

Figure 2–27 Wind capacity and generation

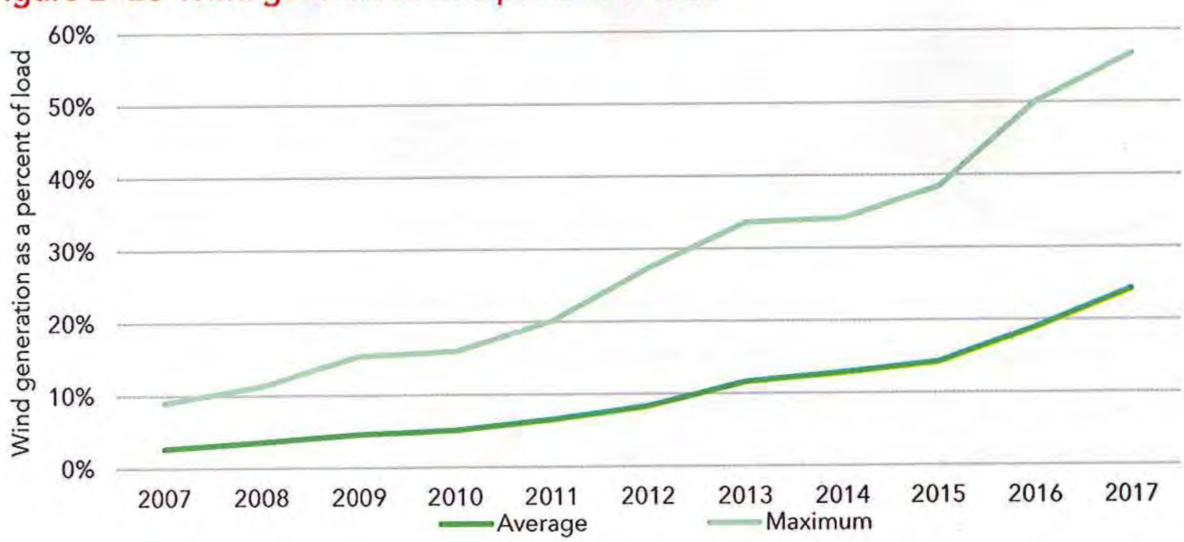


Wind resources comprise about 20 percent of the installed capacity in the SPP market, behind only natural gas with 42 percent and coal with 30 percent. Consistent with previous years, wind generation fluctuated seasonally, where summer was usually the low wind season, and spring and fall were the high wind seasons. Also typical of wind patterns is lower production during on-peak hours than off-peak. Furthermore, wind generation tends to fall across the morning ramp periods.

2.5.2 WIND IMPACT ON THE SYSTEM

Average annual wind generation as a percent of load continues to increase as shown in Figure 2–28.

Figure 2–28 Wind generation as a percent of load

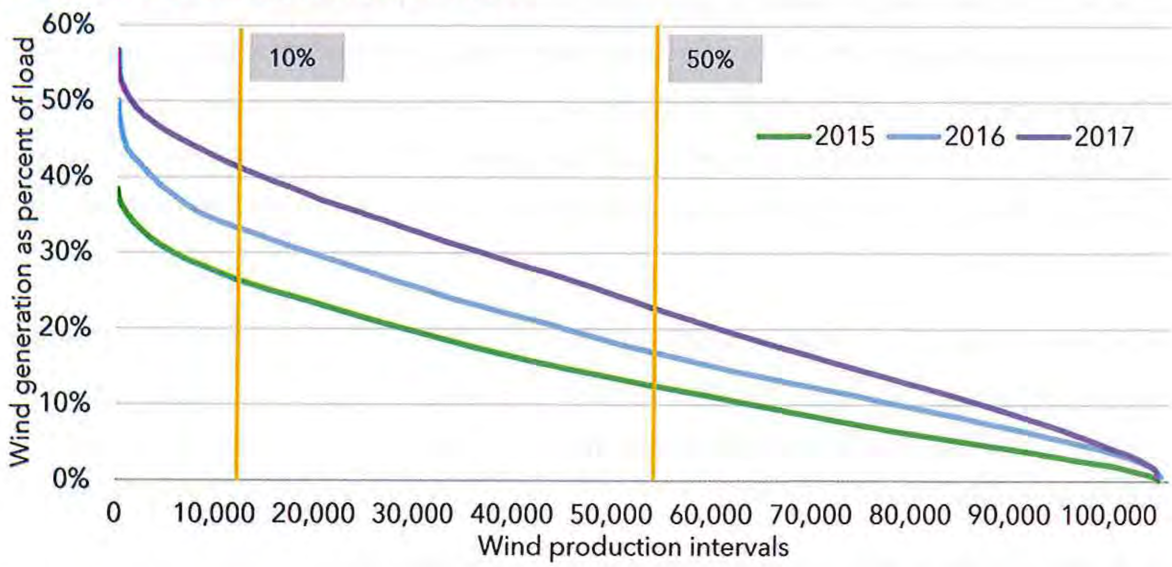


Wind generation as a percent of load increased in the real-time market to just over 24 percent in 2017, up from 19 percent in 2016, and 14 percent in 2015. Wind generation peaked at just over 15,675 MW in 2017 on a five-minute interval basis. Wind generation as a percent of load for any five-minute interval reached a maximum value of nearly 57 percent, which was higher than just under 50 percent in 2016 and 38 percent in 2015.

The chart also shows the trend for average and maximum wind generation as a percent of load since 2007, illustrating the dramatic increase since the start of the SPP markets.

Figure 2–29 shows wind production duration curves that represent wind generation as a percent of load by real-time (five-minute) interval for 2015 through 2017.

Figure 2–29 Wind production curve



The shift upward for the curve from year to year reflects an increase in total wind generation on an annual basis. Wind generation in 2017 served at least 24 percent of the total load during half of the year, compared to 17 percent in 2016 and 13 percent in 2015. It is also important to note that the low end to curve continues to gradually approach zero while the high end of the curve increases very steeply.

2.5.3 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 three 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 since 2007, 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. Wind forecast errors are 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 36 percent (6,364 MW) of the existing installed wind capacity is composed of non-dispatchable variable energy resources, and these generally produce without regard to price, grid operators must still issue manual dispatch instructions to reduce or limit their output at certain times.

Figure 2–30 illustrates dispatchable variable energy resources (DVERs) and non-dispatchable variable energy resources (NDVERs) wind output since the beginning of the Integrated Marketplace, with dispatchable variable energy resource output mirroring the increasing percentage of installed wind capacity.

Figure 2–30 Dispatchable and non-dispatchable wind generation

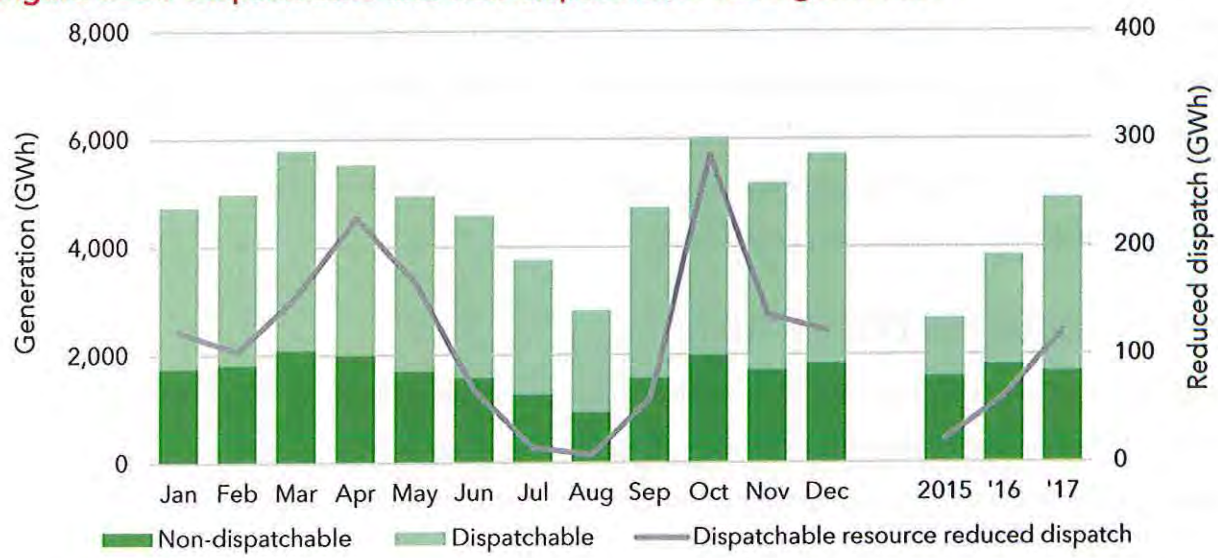
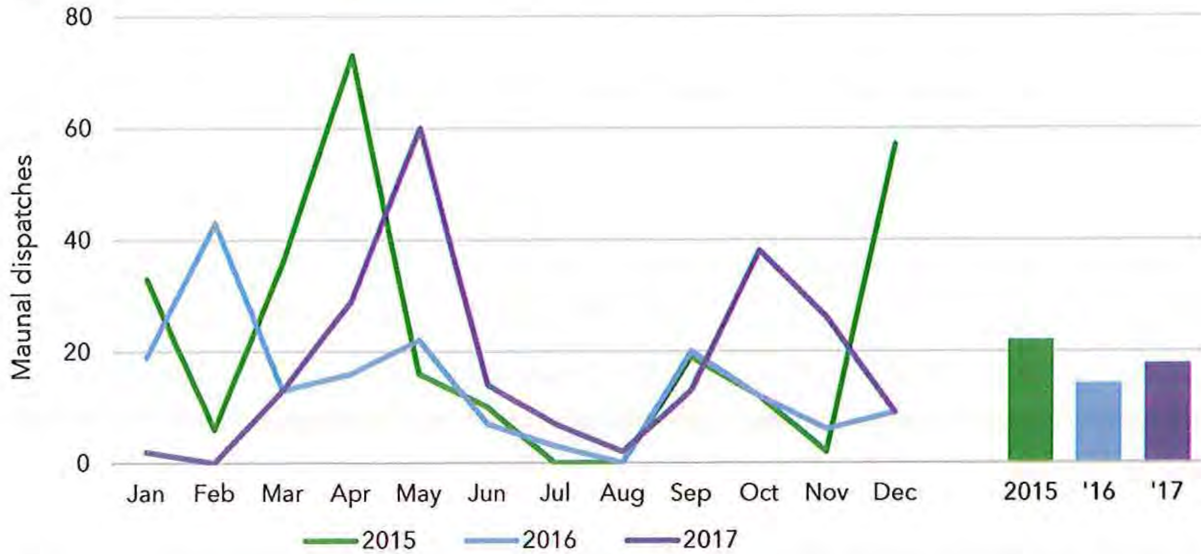


Figure 2–30 also shows the amount of reduced output of dispatchable variable energy resources below their forecast. This depicts the increase in reductions of dispatchable variable energy resource dispatch output, which is expected due to the increase in wind capacity and transmission limitations. This also follows 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. October 2017 saw over 6,000 GWh of monthly wind production, which was the highest since the start of the Integrated Marketplace and over a third of this output originated from non-dispatchable variable energy resource capacity.

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. It is worth noting that 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 only entice further development of wind capacity.

Figure 2–31 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.

Figure 2–31 Manual dispatches for wind resources



As expected, manual dispatches are fewer during the lower wind output and higher demand months of summer. In 2017, 33 percent of the 470 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 dispatchable manual dispatches. These same factors plus transmission switching[28] caused 80 percent of non-dispatchable manual dispatches.

SPP is at the forefront among RTOs in managing wind energy integration. The Integrated Marketplace has reliably managed wind generation when it represented more than 50 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. Ramp shortages began being reflected in prices in May 2017.

2.5.4 CHALLENGES WITH NON-DISPATCHABLE VARIABLE ENERGY RESOURCES

A non-dispatchable variable energy resource is defined as "a variable energy resource not capable of being incrementally dispatched down by the transmission provider."[29] This

[28] Transmission switching out-of-merit instructions are issued to accommodate switching of 345kV transmission lines, due to 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.
[29] SPP Tariff, Attachment AE, Section 1.1.

definition does not delve into the requirements of a non-dispatchable variable energy resource. However, the market design requires that these resources, barring absence of fuel or mechanical limitations, follow close to their current output or forecast. This concept also applies to dispatchable variable energy resources not receiving a signal to follow dispatch and all resources in manual control status that are not in start-up or shutdown. Significant deviation from the most recent actual or forecasted output causes market inefficiencies that will be evaluated by the MMU.

Large swings in generation from non-dispatchable variable energy resources responding to the ex-ante real-time price is known as "price chasing". This behavior introduces oscillations on constraints, adversely impacting prices and dispatch instructions for other resources as well as an impact on regulation products. Price chasing occurs when non-dispatchable variable energy resources or resources on manual control respond to prices by curtailing output in response to lower prices and increasing production when prices rise. Such behavior can cause operational problems. For instance, it can create breaches on flowgates when these resources raise output in response to a price increase. This in turn causes more relief than necessary and security constrained economic dispatch effectiveness declines. Other impacts include additional volatility in the real-time market, more regulation needs, and more output loss due to increased regulation. Operators have at times resorted to reducing line ratings to ensure system reliability. As a result, out-of-merit energy directives are issued to other resources, which means extra cost (uplift) to the system, which translates into lower market efficiency.

In addition to the inefficiencies introduced to the market because of price chasing behavior, there are also inefficiencies introduced by non-dispatchable variable energy resources when they are physically incapable of responding to dispatch signals or when they are acting as "price takers". These inefficiencies exist at times when a non-dispatchable variable energy resource is operating uneconomically even when considering any (state or federal) subsidies or contract terms outside the market. This results in transmission congestion not being relieved by the most efficient unit possible, greater price differences, and volatility.

Consistent with its 2015 recommendation, the MMU reiterates the need for non-dispatchable variable energy resources to transition to dispatchable variable energy resource status in order to lessen the negative impact of such resources on the market. Other markets have taken measures to move their resources from non-dispatchable variable energy resources to dispatchable variable energy resources status as much as possible. For instance, FERC approved ISO-NE market rule changes in December 2016 that required nearly 1,200 MW of non-dispatchable generation assets to become dispatchable by early 2018,[30] and denied a request by the California ISO to delay transitioning resources from becoming dispatchable.[31]

2.6 EXTERNAL TRANSACTIONS

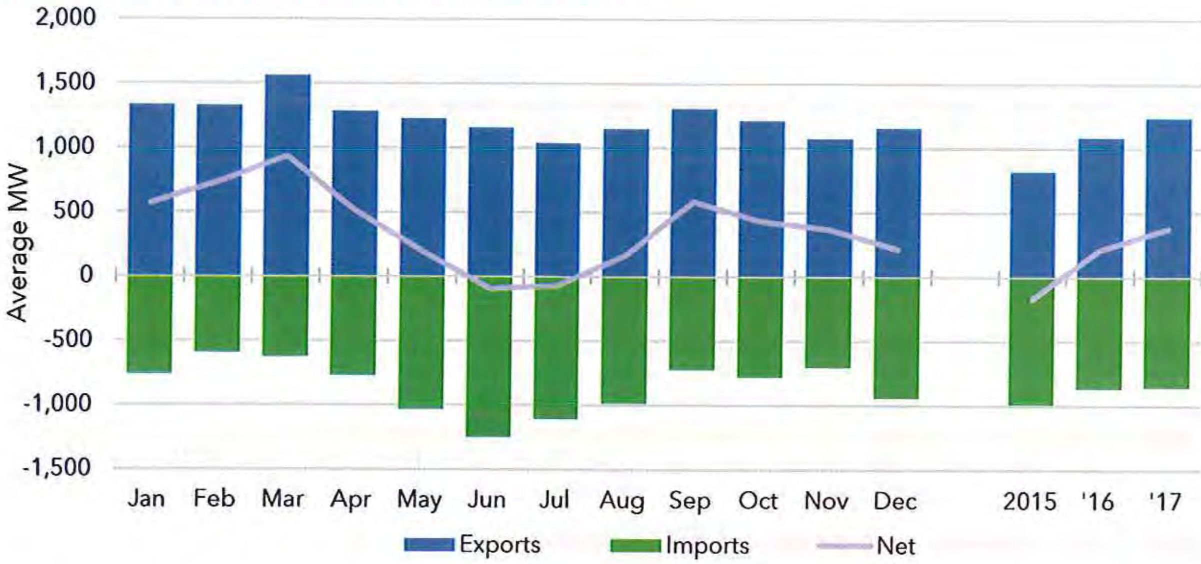
2.6.1 EXPORTS AND IMPORTS

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 WECC 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 the Associated Electric Cooperative (AECI) in Oklahoma and Missouri.

As shown in Figure 2–32, SPP is a net exporter in real time in 2017, as it was in 2016, while it was a net importer in 2015. The two primary drivers for this shift from net importing to net exporting are the increase in wind generation, and the Integrated System addition in October 2015. Prior to the addition of the Integrated System to SPP, Western Area Power Administration (WAPA) generally exported to SPP. Since the integration, those transactions became internal transactions within the SPP footprint.

[30] See the FERC ruling at https://www.ferc.gov/CalendarFiles/20161209170835-ER17-68%20-000.pdf.
[31] See FERC Docket No. ER17-1337-000.

Figure 2–32 Exports and imports, SPP system



Generally SPP exports follow the wind production curve for the day. As wind generation increases, exports increase. The same pattern of exports following wind is also evident on a month-to-month basis, as the highest wind generation months in the spring and the fall see the highest exports.

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 2–33 through Figure 2–35 show the data for the three most heavily used interfaces in real time, namely SPA, MISO, and AECI.

Figure 2–33 Exports and imports, Southwestern Power Administration interface

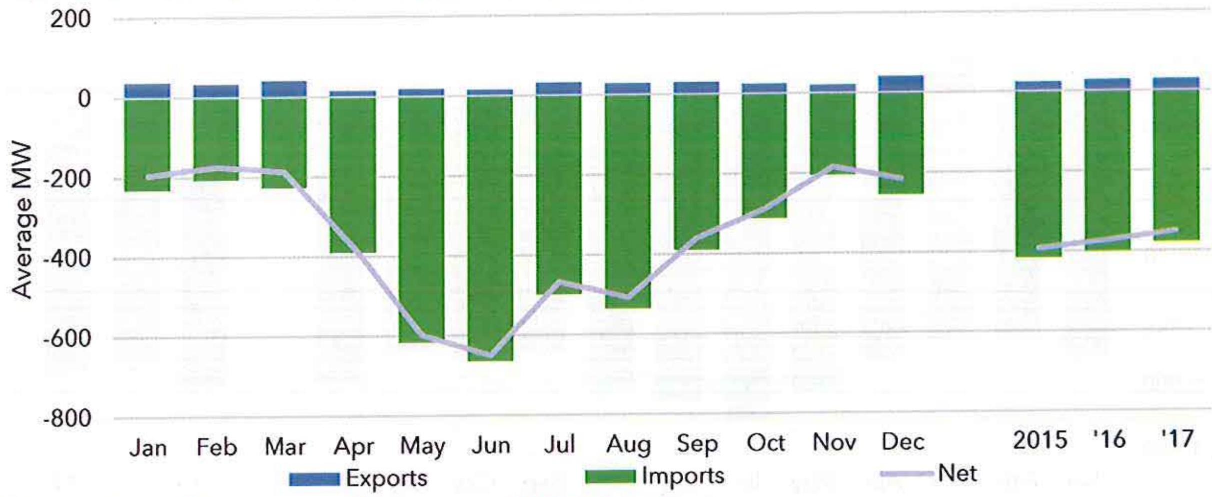


Figure 2–34 Exports and imports, MISO interface

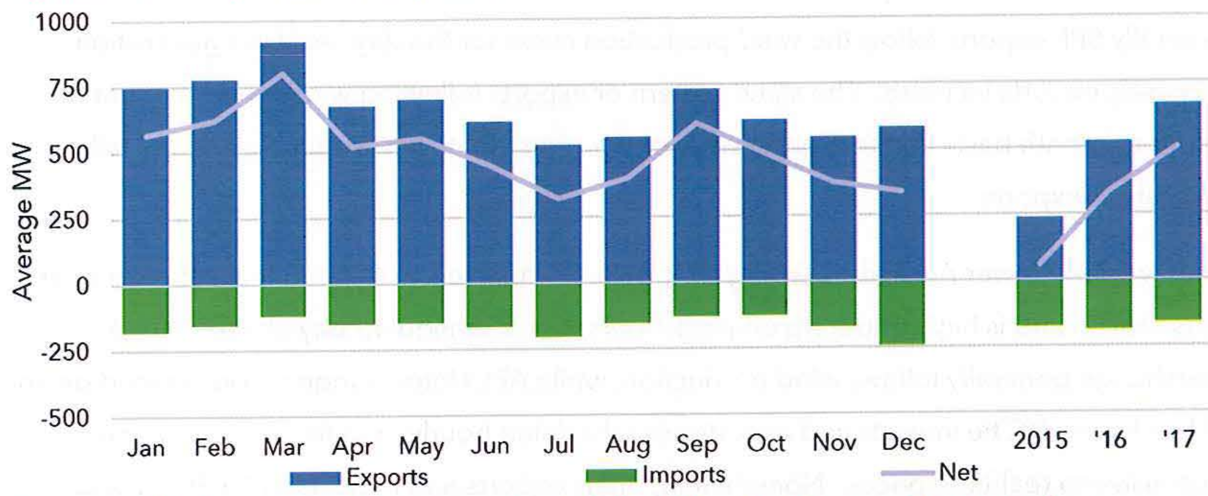
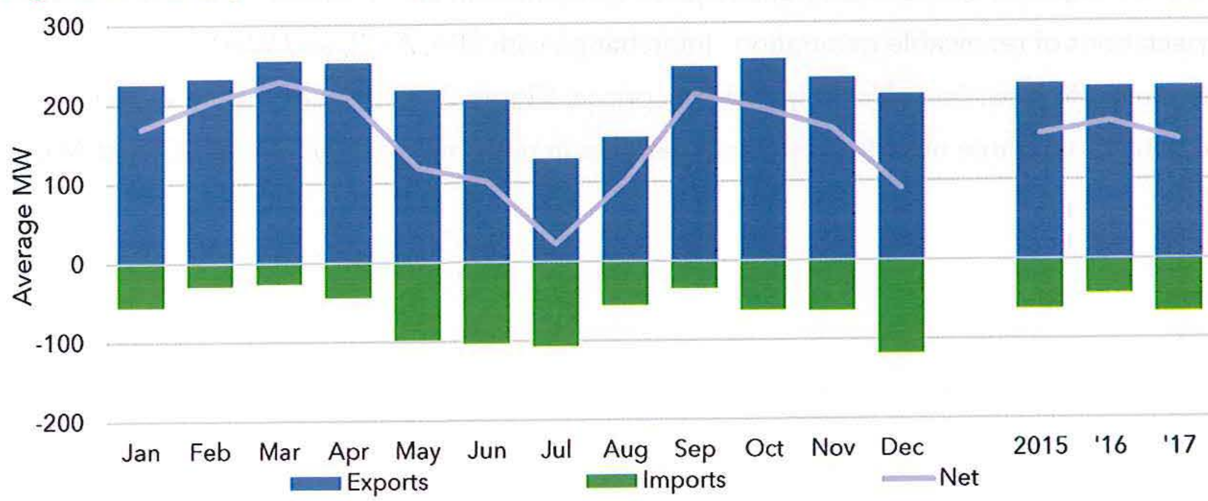


Figure 2–35 Exports and imports, Associated Electric Cooperative interface



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:

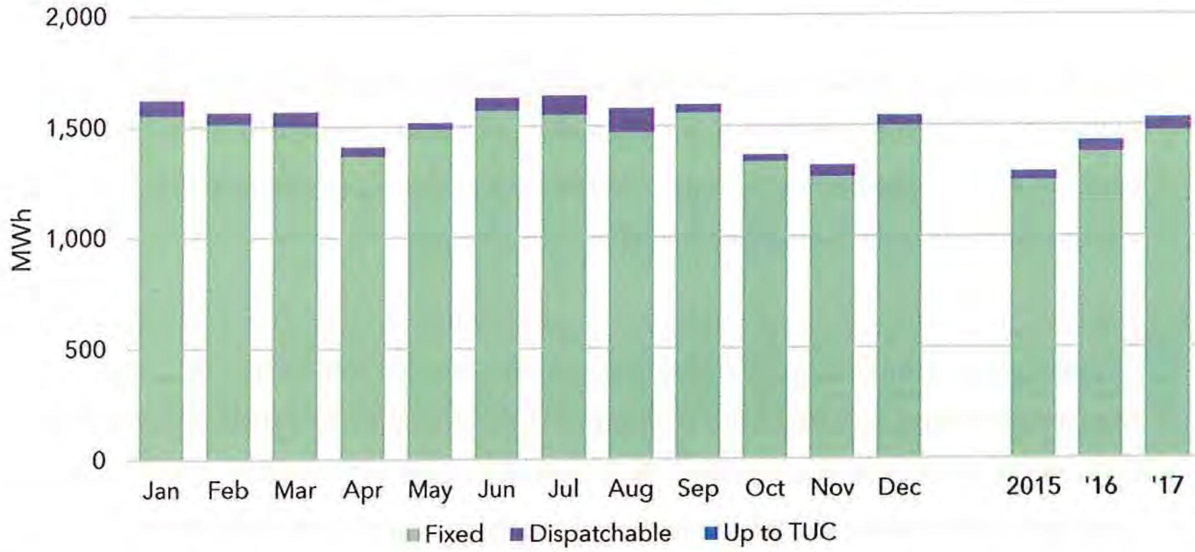
- Fixed interchange transactions are physical transactions that bring energy into or out of the SPP balancing authority. Energy prices are settled at the price at the applicable external interface settlement location. Submitters of this type of transaction in the Integrated Marketplace are price takers 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.[32]

As shown in Figure 2–36, 96 percent of all interchange transactions cleared in the day-ahead market are fixed, four percent are dispatchable, and none are up-to-TUC.

[32] Per Market Protocols section 4.2.2.7 Import Interchange Transaction Offers.

Figure 2–36 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, SPA hydro contracts, and 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.

2.6.2 MARKET-TO-MARKET COORDINATION

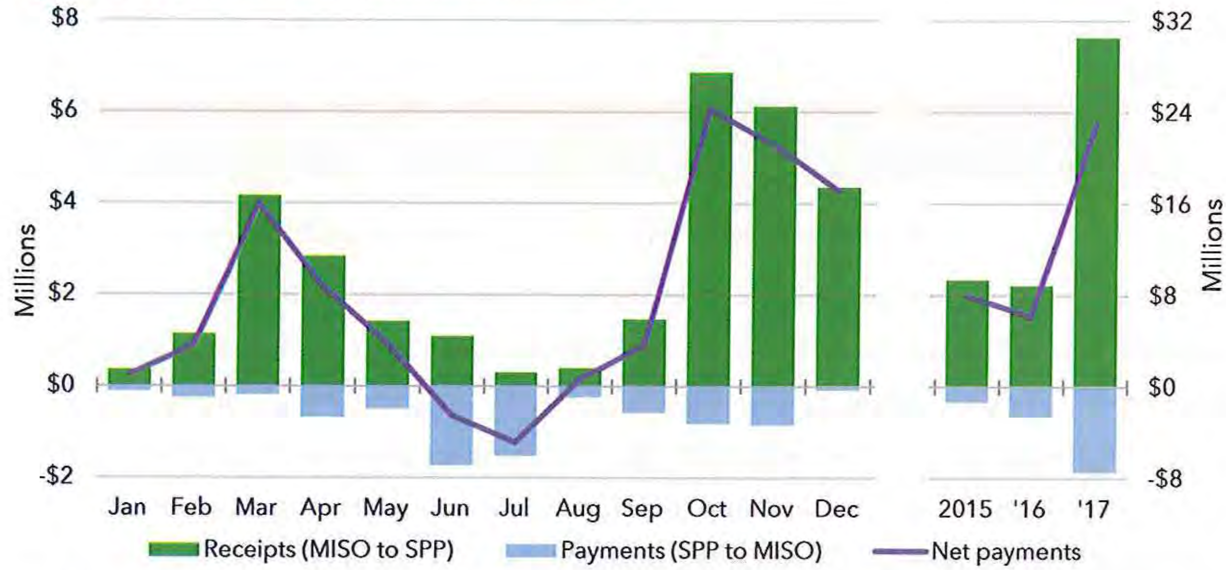
SPP began the market-to-market (M2M) process with MISO in March 2015 as part of a FERC requirement that also included regulation compensation and long-term congestion rights. These were required to be implemented one year after go-live of the SPP Integrated Marketplace. The market-to-market process under 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.[33]

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

[33] 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.

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 2–37 shows payments by month between SPP and MISO (positive is payment from MISO to SPP and negative is payment from SPP to MISO.)

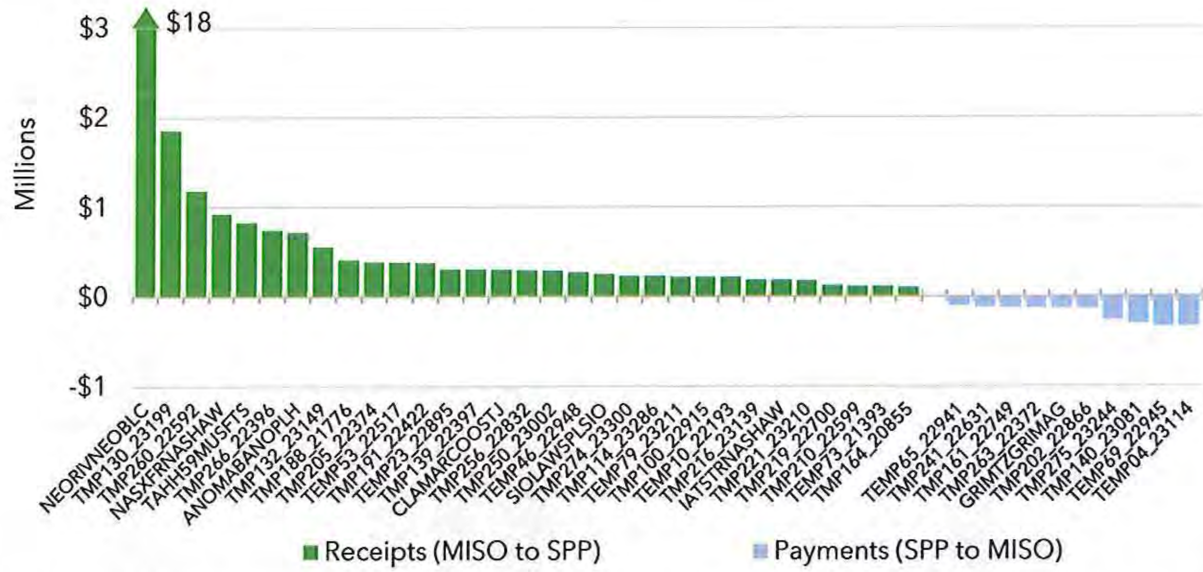
Figure 2–37 Market-to-market settlements



For 2017, total market-to-market payments from MISO to SPP totaled just over $30 million, while market-to-market payments from SPP to MISO totaled nearly $8 million, resulting in a net payment of approximately $23 million from MISO to SPP for the year. This increase from previous years can be attributed to the Neosho - Riverton 161kV constraint discussed more below.

Figure 2–38 shows market-to-market payments (over $100,000 either from SPP to MISO, or MISO to SPP) by flowgate for 2017.

Figure 2–38 Market-to-market settlements by flowgate



Only eight flowgates had payments from MISO to SPP over $500,000. The highest payment from SPP to MISO was just over $340,000. The Neosho-Riverton 161kV flowgate was highly congested in the latter half of 2017 and was impacted by wind and external flows. This is discussed in more detail in Section 5.1.4.3. Market-to-market payments from MISO to SPP in 2017 on this flowgate alone totaled over $18 million. This was a ten-fold increase above the next highest flowgate, which had total payments in 2017 of $1.8 million.

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. The following are points of discussion between MISO and SPP mentioned in the previous annual report and the MMU feels improvements in these areas could lead to improved benefits for both markets. Two areas which were addressed in a memorandum of understanding executed between SPP and MISO in June 2017 were; 1) monitoring/non-monitoring designation and 2) market-to-market flowgate coordination. These are discussed below. Other points discussed below are use of transmission loading relief and market flow methodology. These topics were not discussed in 2017 but are operational practices or design concepts that can impact market-to-market settlements.

2.6.2.1 Monitoring/non-monitoring designation

SPP and MISO implemented the ability to transfer monitoring and non-monitoring RTO roles in December 2017. MISO and PJM have been utilizing this function to address constraint volatility or power swings when the non-monitoring RTO may have more "effective control" on certain constraints. The MMU feels this added ability of transferring roles will help alleviate power swings on certain constraints bringing about better price convergence.

2.6.2.2 Market-to-market flowgate coordination

In August 2017, SPP and MISO implemented additional criteria and processes to the market-to-market flowgate coordination tests. A series of coordination tests are performed to determine if flowgates should become a market-to-market flowgate. These tests are run when a flowgate is created and reanalyzed periodically. In some cases a flowgate may pass for scenarios that no longer exist such as outages. This may cause the non-monitoring RTO to be asked to provide relief during a configuration that has changed. The additional criteria added in June 2017 per the memorandum of understanding allowed for the removal of several flowgates from market-to-market. These more frequent tests better represent current conditions. The market monitor feels the added criteria and frequent tests better reflect current conditions alleviating unattainable relief by a non-monitoring RTO.

2.6.2.3 Use of transmission loading relief

SPP, per its market protocols, uses the transmission loading relief (TLR) process when tagged impacts or other external impacts are present on an SPP constraint. The market monitor believes that the transmission loading relief process is not needed when the SPP and MISO markets have the majority of impacts, but is still needed when external impacts from non-market (third party) entities are significant. Assuming interface price definitions correctly reflect congestion, tagged transactions should respond to the market conditions and either withdraw or delay submitting tags during congestion. Thus, this should alleviate the need for transmission loading relief when impacts on the constraint are mostly between SPP and MISO.

When third-party impacts exist, the MMU believes transmission loading relief is warranted to subject the third party to redispatch.[34] A scenario observed between SPP and MISO entailed

[34] Third parties include Tennessee Valley Authority, Associated Electric Cooperative Incorporated, and Southwestern Power Administration.

third-party firm network and native load impacts that are not subjected to redispatch by either market. The third party does not have a market signal in the form of a price and by the absence of a transmission loading relief will not have an incentive to provide relief on the constraint. Transmission loading relief is not as efficient as a market using price and dispatch to manage congestion on a constraint. Market-to-market is the preferred method in addressing congestion along the seams, but until further development is made in areas outside RTO markets, transmission loading relief is the current mechanism to manage impacts between markets and non-markets.

2.6.2.4 Market flow methodology

SPP, MISO, and PJM calculate market flows differently. MISO and PJM use a marginal zone methodology (although the margins are derived in different manners), and SPP uses a tagging impact approach. This topic was not discussed in 2017, but because market flow is a component used in market-to-market settlements, the MMU suggests this topic should be revisited to ensure consistency and equitable measurements across RTOs.

3 UNIT COMMITMENT AND DISPATCH PROCESSES

3.1 COMMITMENT PROCESS

The Integrated Marketplace uses a centralized unit commitment program to determine an efficient scheduling and dispatch of generation resources to meet energy demand and operating reserve requirements. The principal component of the commitment program 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. 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 adequacy 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 hours. 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.

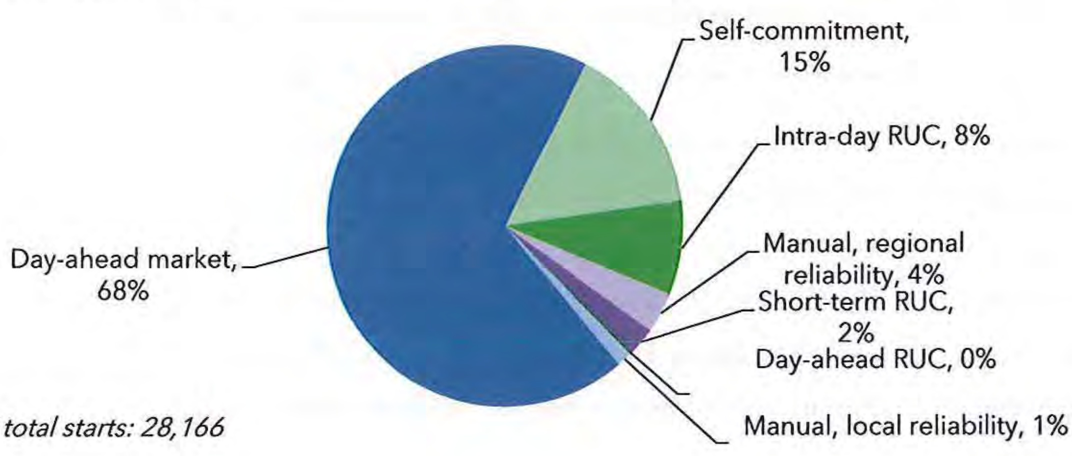
The intra-day reliability unit commitment process is run throughout the operating day, with at least one execution occurring every four hours. The short-term intra-day reliability unit commitment may be executed as needed to assess resource adequacy over the next two hour period as part of the intra-day process. SPP operators may also issue manual commitment instructions for capacity, transmission, or local reliability 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 28,166 starts during 2017. This is up 13 percent from 24,881 starts last year. The following two tables and graphs provide a breakdown of the origins of the commitment decisions for resources. For all generation participation offers in the day-ahead market by commitment status see Figure 3–10.

Figure 3–2 Start-up instructions by resource count

	2015	2016	2017
Day-ahead market	49%	59%	68%
Self-commitment	21%	19%	15%
Intra-day RUC	12%	10%	8%
Manual, regional reliability	7%	5%	4%
Short-term RUC		3%	2%
Day-ahead RUC	9%	2%	<1%
Manual, local reliability	1%	2%	1%

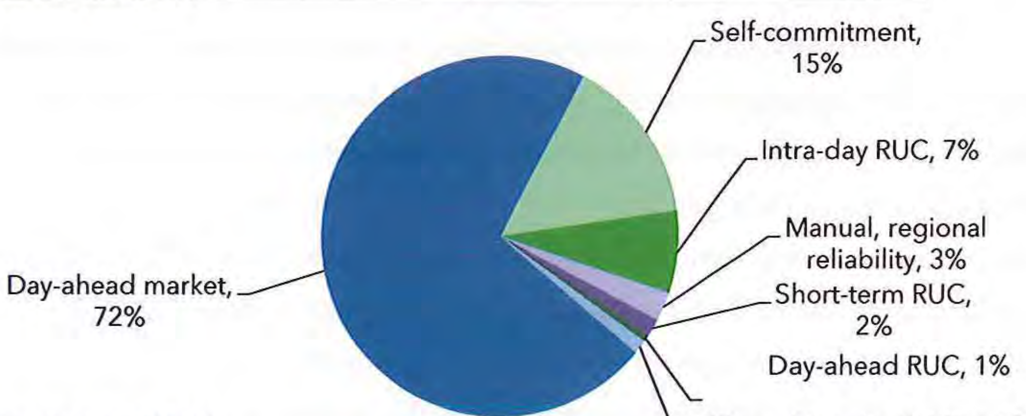


Sixty-eight percent of start-up instructions in 2017 were a result of the day-ahead market. As shown in Figure 3–2, each year there has been an increase in day-ahead market starts and a decrease in self-commitment starts. This is an encouraging trend as it leads to greater market efficiency and suggests that resource owners may be gaining confidence in allowing the market to commit 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 time 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 large number 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 day-ahead, intra-day, short-term, and manual reliability unit commitments represent 15 percent of the resource start-ups.

Figure 3–3 is based on capacity committed and provides a slightly different look at the data with the percentages based on capacity committed to startup.

Figure 3–3 Start-up instructions by resource capacity

	2015	2016	2017
Day-ahead market	50%	59%	72%
Self-commitment	21%	21%	15%
Intra-day RUC	10%	9%	7%
Manual, regional reliability	6%	4%	3%
Short-term RUC		3%	2%
Day-ahead RUC	11%	3%	1%
Manual, local reliability	2%	2%	1%



2017 total starts: 28,166

One important observation is the percentage differences between Figure 3–2 and Figure 3–3. This is 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.

Once within the operating day, commitment flexibility is limited by resource start-up times. As we get closer to the operating hour, fewer resources are eligible to be started. Quick-start units can be directly dispatched by the real-time balancing market and the reliability unit commitment processes will not start other units if the quick-start units are able to resolve the problem. SPP issued more than 73 percent of all start-up instructions to gas-fired generators in 2017, up from 69 percent of all start-ups in 2016.

Figure 3–4 Origin of start-up instructions for gas resources

Commitment Process	Combined-cycle			Simple-cycle - combustion turbine			Simple-cycle - steam turbine		
	2015	2016	2017	2015	2016	2017	2015	2016	2017
Day-ahead market	89%	92%	94%	45%	59%	69%	34%	46%	64%
Day-ahead RUC	0%	1%	0%	14%	2%	0%	34%	16%	3%
Intra-day RUC	1%	1%	1%	20%	15%	12%	20%	18%	15%
Short-term RUC	---	0%	0%	---	6%	4%	---	4%	4%
Manual instruction	0%	0%	0%	15%	11%	7%	5%	9%	2%
Self	9%	6%	5%	7%	7%	7%	5%	8%	11%

Figure 3–4 shows that almost all 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. SPP issued day-ahead starts for gas-fired generators with simple-cycle combustion turbine technology accounted for 69 percent of their total starts. This is an increase from 59 percent last year. Steam turbine starts saw an increase in the day-ahead market starts as well, with 64 percent compared to 46 percent the year before. While self-commitments have dropped for combined-cycle units, the MMU is concerned about the increase in self-commitments in gas steam units.

Some reliability unit commitments are made to meet instantaneous load capacity requirements; however, this is not a product generators are directly compensated for by the market. Therefore, reliability commitment processes, more often than the day-ahead market, make commitments that may not be supported by real-time price levels. These situations often lead to make-whole payments. The next section discusses the drivers behind the reliability commitments and thus high on-line resource commitments.

3.1.2 DEMAND FOR RELIABILITY

The previous section noted that 15 percent of SPP start-up instructions 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 versus 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, and averages between 98 to 101 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 day-ahead, intra-day, or short-term reliability unit commitment algorithms.

The assumptions regarding wind generation differ as well. Only 82 percent of the real-time wind production cleared in the day-ahead market on an average hourly basis in 2017. While the market participants determine the participation levels for their wind generators in the day-ahead market through the use of supply offers, a 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.

The primary drivers for the negative resource gaps are differences in virtual supply net of virtual demand, differences in real-time wind generation compared to wind cleared in the day-ahead market, and real-time net exports exceeding day-ahead net exports. 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 because some market participants with wind generation assets do not participate or offer the full amount of forecasted capacity in the day-ahead market. Instead, they take real-time positions given the uncertainty of the wind generation.

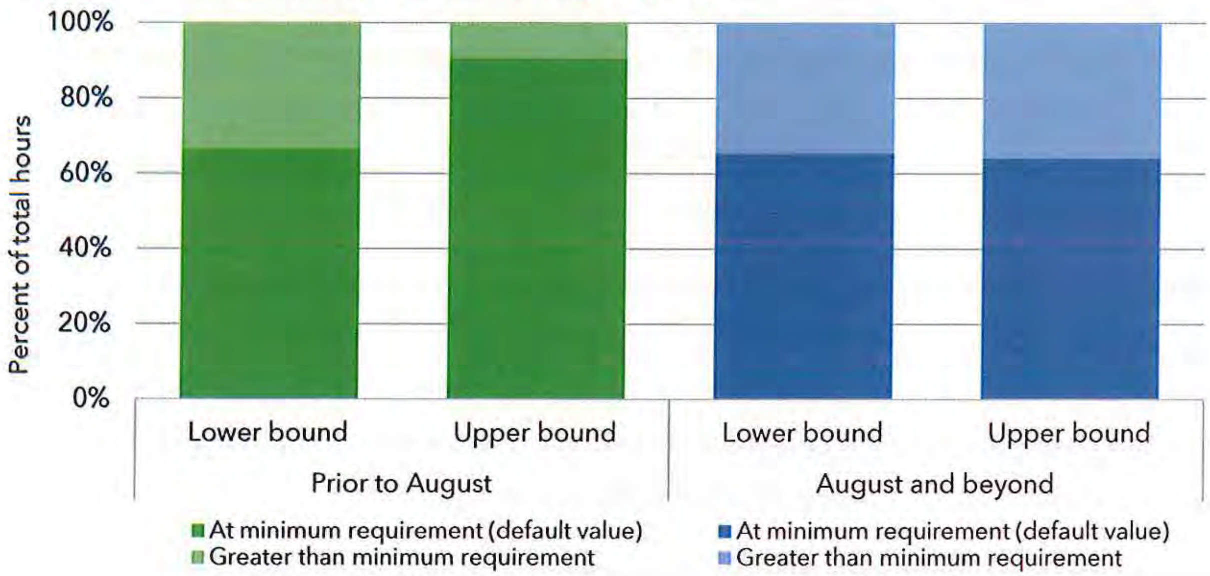
The resource gaps can help explain why additional commitments occur after the day-ahead market has cleared. Figure 3–5 compares on-line capacity between the day-ahead and real-time markets.

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

The chart indicates that in 2017 there was, on average, around 1,900 MW of additional capacity on-line during the real-time market relative to the capacity cleared in the day-ahead market, a reduction of 27 percent compared to 2016.

One well-known and much discussed issue with respect to 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 the majority of the time, 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.

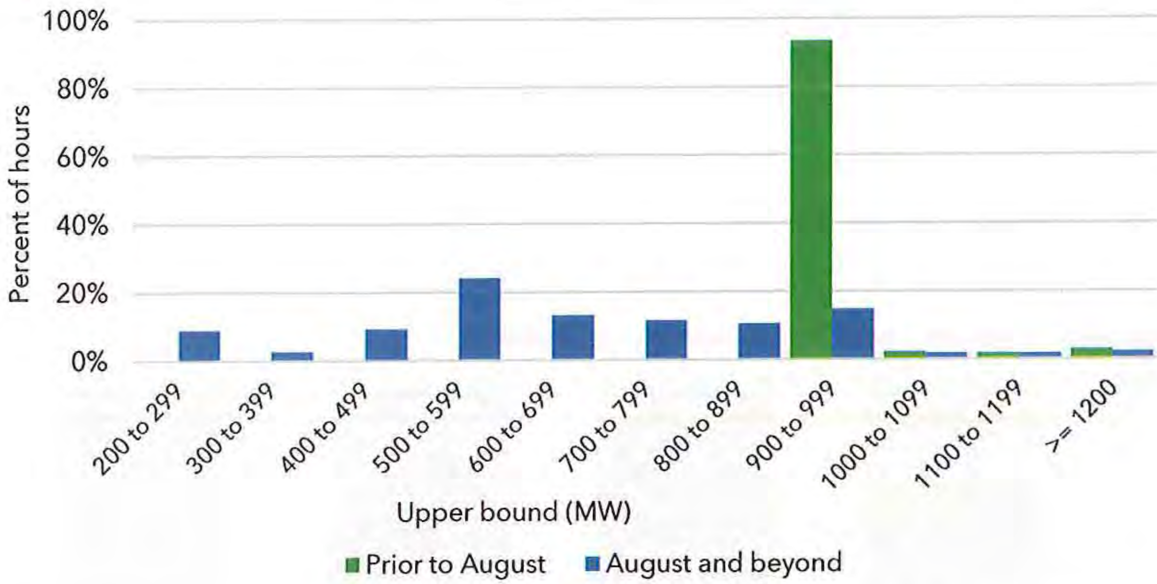
Figure 3–6 Instantaneous load capacity required



Before August 1, only one value was used for the upper bound for the entire day. The same is true for the lower bound. During this time the upper bound default was 900 MW and the lower bound was 500 MW. The upper bound default value was used for 91 percent of total hours during this first part of the year. After August 1, a software update allowed for an hourly value. After this change, default values were used less, approximately 65 percent of all hours.

During the second part of the year, the default values for the upper bound ranged from 200 to 900, and were less than 900 MW for most hours, as seen in Figure 3–7. The lower bound default values remained at 500 for all hours of the day.

Figure 3–7 Instantaneous load capacity upper bound default levels



Resources committed to provide ramp capability, whether as a result of applying the instantaneous load capacity constraint in a reliability commitment algorithm or a manual process, can affect real-time prices. 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.

Reliability commitments, along with wind exceeding the day-ahead forecast, can dampen real-time price signals, as is evidenced by 58 percent of make-whole payments made for reliability unit commitments.

3.1.3 QUICK-START RESOURCES COMMITMENT

A quick-start resource can be started, synchronized, and begin injecting energy within 10 minutes of SPP notification. Proposed changes to the definition of quick-start resources also include a minimum run time of an hour or less.[35] There are 87 resources in the SPP footprint that have both a 10-minute start time with a minimum run time of an hour or less. Nameplate

[35] RR116 defines a Quick-Start Resource as, "A Resource that can (i) be started, synchronized and inject Energy within ten minutes of Transmission Provider notification, (ii) operate with a Minimum Run Time of one hour or less…" See RR116 Recommendation Report, available at (https://www.spp.org/Documents/30429/mrr116.zip). FERC required SPP to "Include in the definition of quick-start resources a requirement that those resources have a minimum run time of one hour or less". See *Order Instituting Section 206 Proceeding and Commencing Hearing Procedures and Establishing Refund Effective Date*, 161 FERC ¶ 61,296 (2017) at 25.

capacity for the quick-start capable resources totals 4,566 MW and consists of a mix of gas-fired, hydro, and oil-fired generators. During 2017, the reliability unit commitment processes committed 67 of the 87 quick-start capable resources.

Figure 3–8 summarizes the start-up instructions issued to resources with real-time offers indicating a 10-minute start-up capability and a minimum run time less than one hour. In 2017, 817 start instructions originated in a reliability commitment process, 5,044 start instructions originated from the day-ahead market, and 508 were manually committed. Of particular interest is the average lead time for reliability commitment start-up orders. The lead time is calculated as the number of hours between the commitment notification time and the first hour of the 10-minute resource's commitment period.

Figure 3–8 Commitment of quick-start resources

Commitment process	Number of starts	Committed capacity (MW)	Lead time (hours)	Hours in original commitment	Actual hours on-line
Day-ahead RUC	0	N/A	N/A	N/A	N/A
Intra-day RUC	517	28,129	1.7	3.9	5.9
Short-term RUC	300	13,451	0.3	2.5	4.9
Manual	508	26,642	0.6	4.0	6.4

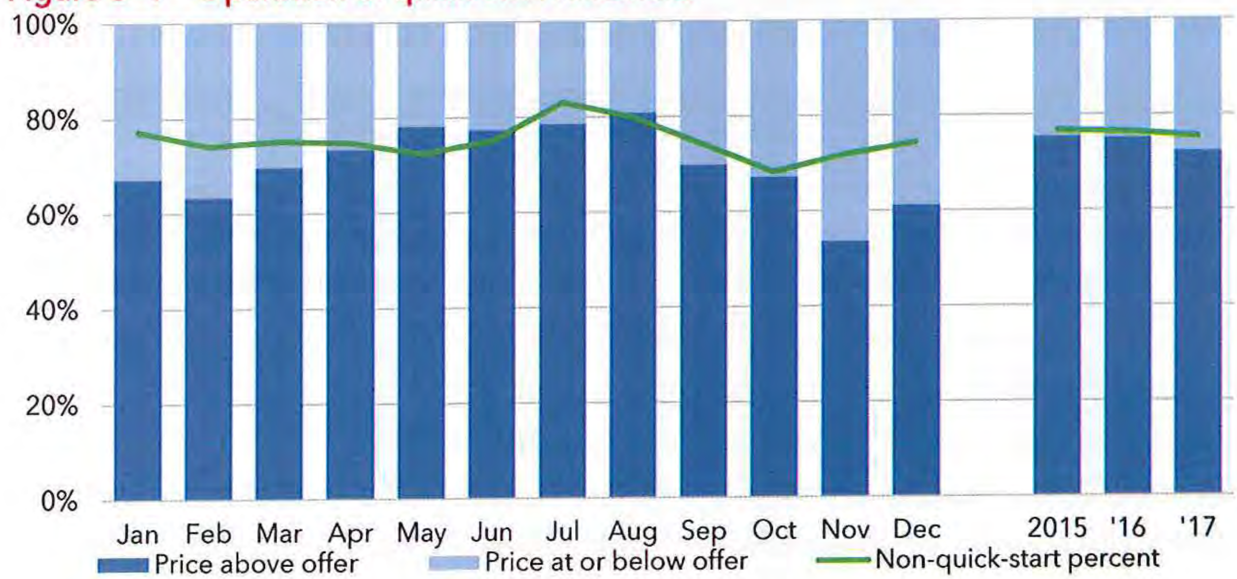
The level of make-whole payments associated with the commitment of quick-start resources in the reliability processes is still noteworthy. In 2017, 78 percent of the reliability processes commitments for quick-start units resulted in real-time make-whole payments. This is similar to 2015 and 2016 which were 75 and 79 percent, respectively. In 2017, quick-start resources received $9.5 million in real-time make-whole payments and $485,000 in day-ahead make-whole payments. This is a slight increase from their respective 2016 make-whole payments of $9.3 million and $439,000 respectively. The MMU believes that the commitment costs of quick-start resources needs to be included in the commitment decisions of these resources, which is consistent with changes developed through the stakeholder process.

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 short-term unit commitment process was brought into the market in February 2016, and can evaluate intervals 15 minutes ahead. This leaves time to commit these quick-start resources when needed, but 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.

The Integrated Marketplace protocols[36] describe the real-time market dispatch and registration options of resources with quick-start capability. Resources use these quick-start capabilities in their real-time offer, and registered as quick-start capable, can choose not to receive start-up and/or shutdown orders out of the short-term, intra-day RUC.

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

Figure 3–9 Operation of quick-start resources



Over the last three years, 25 percent of the megawatt-hours produced by quick-start resources had energy prices below real-time energy offers. This is consistent with relative relationship 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 nor is the

[36] Integrated Marketplace protocols, Section 4.4.2.3.1 and Section 6.1.1.

minimum run time respected.[37] This is a concern that revision request 116 is designed to address.

In order to deal with the issue of uneconomic production, SPP staff presented a new quick-start design proposal that was well-received by stakeholders in May 2015. Subsequently, this proposal was submitted to the Market Working Group (MWG) by Golden Spread Electric Cooperative[38] and was approved in September 2015. The MMU agrees with the proposal and believes that incorporating commitment costs in the evaluation of the commitment will help reduce the incidence where these resources are committed and prices are insufficient to cover costs.

While this change was pending FERC filing, FERC began a Section 206 proceeding[39] in late-December 2017 finding SPP's current practices regarding pricing of quick-start resources may be unjust and unreasonable. In response, the MMU filed an initial brief and reply comments highlighting the following positions:

- Commitment costs should be evaluated as part of market optimization to ensure production costs are minimized.
- Quick-start resources should have a minimum run time of less than or equal to one hour.
- Economic minimum operating levels should not be reduced (relaxed) to zero because the approach would set prices based on resource flexibility and availability that is false (does not exist) and would likely require another optimization run that could put pressure on performance time and affect the real-time mitigation process.
- SPP's screening run and subsequent pricing and scheduling runs are reflective of actual available resources and that the optimization logic uses appropriate operational and reliability constraints (i.e., relies on a resources' physical offer parameters that determine how and when a resource should operate).
- The Commission's proposal departs from the marginal pricing methodology upon which the SPP market is based and would likely result in average cost pricing.
- Uplift would likely be transferred under the Commission's proposal and not necessarily reduced.

[37] Protocols 4.4.2.3.1 states that only the offer curves are used to dispatch.
[38] Revision Request 116 (Quick-Start Real-Time Commitment) by the SPP board, but was placed on hold in lieu of FERC's Order issued December 21, 2017.
[39] https://www.ferc.gov/whats-new/comm-meet/2017/122117/E-5.pdf

- Tariff language regarding the basis of parameters needs to be revised to ensure that information is accurate and based on physical and environmental factors.

FERC is expected to respond to comments and propose further direction on modeling of quick-start resources by fall 2018.

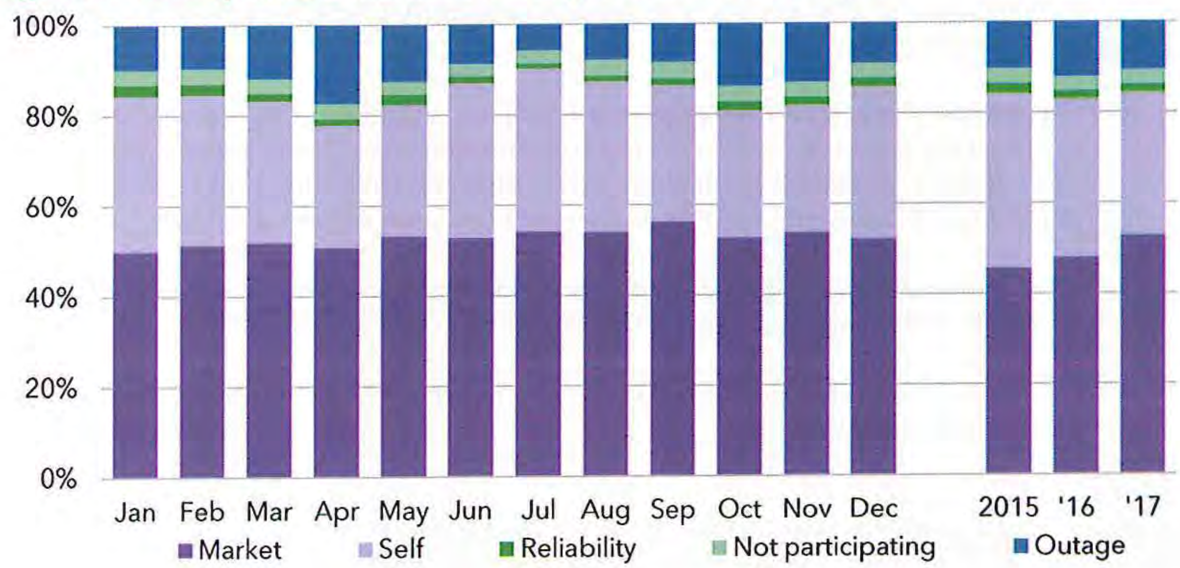
3.2 GENERATION SCHEDULING

The day-ahead market provides market participants with the ability to submit offers to sell energy, regulation-up service, regulation-down service, spinning reserves, and supplemental reserves, and/or to submit bids to purchase energy. The day-ahead market co-optimizes the clearing of energy and operating reserve products out of the available capacity. All day-ahead market products are traded and settled on an hourly basis.

In 2017, 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.

Figure 3–10 shows generation participation offers in the day-ahead market by commitment status.

Figure 3–10 Day-ahead market offers by commitment status

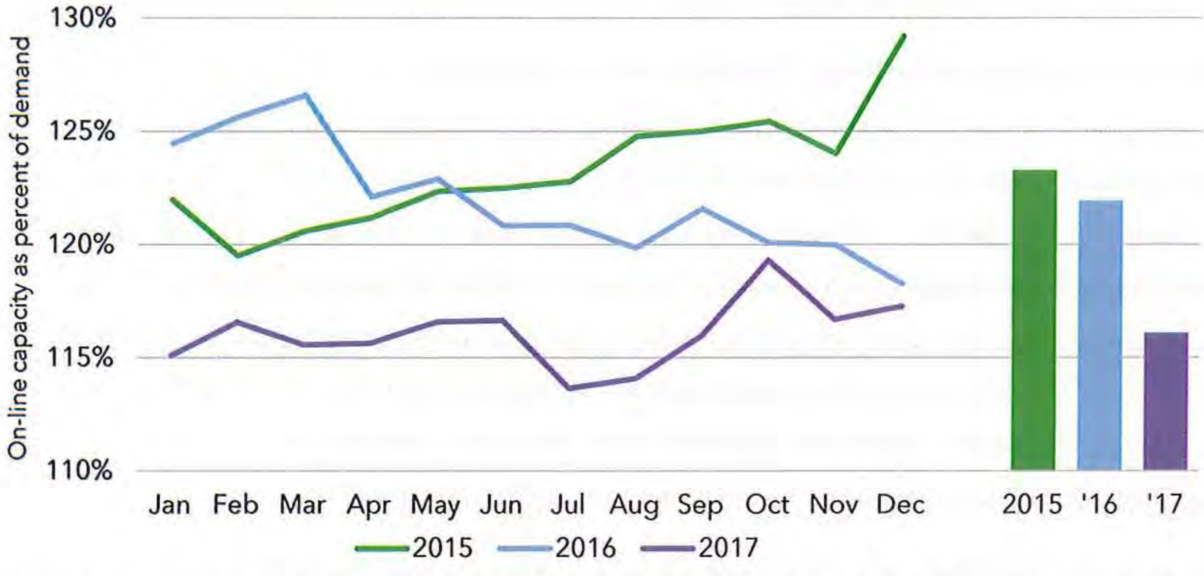


The "market" commitment status averaged 53 percent and "self-commit" status averaged 31 percent of the total offered capacity for 2017, which is a slight change from 2016.[40] Resources with commitment statuses of "reliability" and "not participating" averaged one percent and three percent, respectively, which is close to what was experienced in 2016. "Outage" status accounted for the final 10 percent, a decrease from 12 percent in 2016. While self-commits decreased from 2016, 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. Initial starts show 15 percent being self-committed in 2017 where all capacity offered averaged 31 percent. This can be attributed to desire to keep resources on-line after its initial start even during low prices.

Figure 3–11 shows on-line capacity commitment as a percent of load.

Figure 3–11 On-line capacity as a percent of load



The capacity commitment as a percent of load has decreased significantly over the past few years. Some factors in 2017 that contribute to lower levels of on-line capacity are fewer self-committed coal plants and the continued growth of wind capacity and generation. As more renewables are added to the system, there have been an increasing incidence of negative

[40] 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).

prices (see Section 4.1.6) and higher real-time price volatility (see Section 4.1.4). Lower on-line capacity levels may be a consequence as market participants and market operators adjust to these changes in market conditions.

3.3 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.

3.3.1 RAMP CAPABILITY PRODUCT

Evidence suggests that a ramp capability product would be beneficial to the market. A resource's ability to ramp should be planned for and should be valued by a price to the extent the ramp is beneficial to the market.

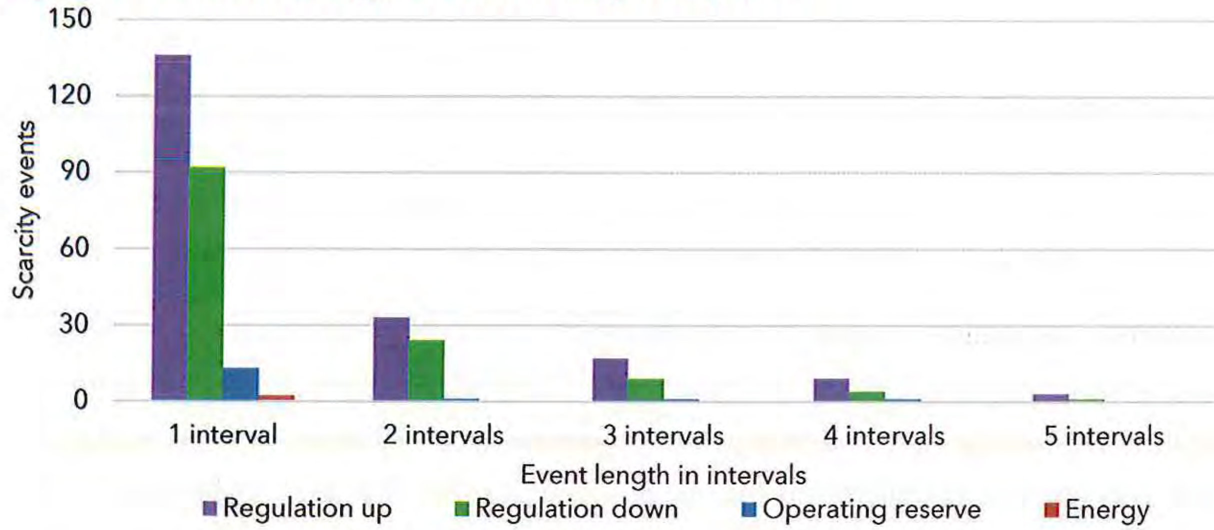
3.3.1.1 Ramping limitations affecting market outcomes

The real-time dispatch does not consider future intervals. It simply calculates one value: a dispatch instruction for the next interval. 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". 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 next dispatch instructions even though ramp is the very capability that allows a resource to get to the next dispatch instruction.

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 the next interval. Even when enough capacity is available, a lack of ramp renders that capacity unreachable. This often leads to short-term transitory price spikes,[41] as seen in Figure 3–12.

[41] This is essentially temporal, or time-based, congestion.

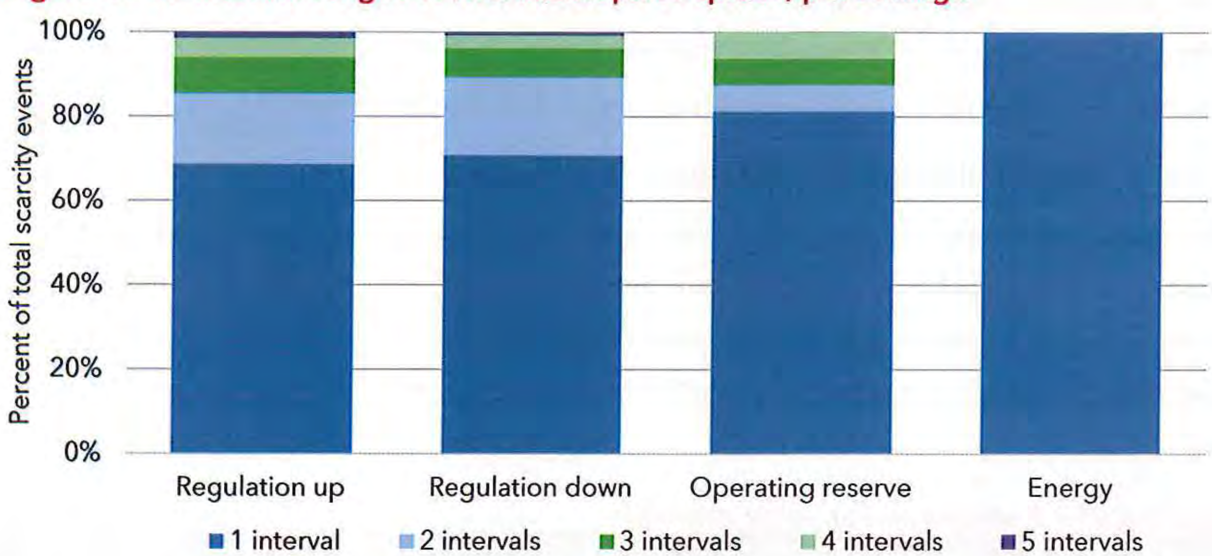
Figure 3–12 Interval length of short-term price spikes



This figure shows that most scarcity pricing events in real time only occur for only one 5-minute interval. Very few scarcity pricing events last more than three intervals.

Figure 3–13 shows the interval length for the different types of scarcity events.

Figure 3–13 Interval length of short-term price spikes, percentage



About 70 percent of regulation-up and regulation-down scarcity events lasted for one interval. About 80 percent of the operating reserve scarcity events lasted only one interval, and no energy scarcity lasted longer than one interval. This indicates that the cause of the scarcity was ramp shortage and not actual capacity shortage. If sufficient ramp were available for these single-interval events, then these scarcities would have been avoided.

Furthermore, instances 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. The incidence of real-time scarcity events are increasing. Some of the increase is due to FERC Order No. 825 which required SPP to price scarcity events that were not priced in previous years. Almost all of these events were the result of the lack of ramping capability, rather than a reflection of true scarcity of capacity.

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. This makes prices more volatile, and the lack of ramp can raise both the regulation-up price and the energy price because the ramp shortage affects both products. This scenario represents about 20 percent of all regulation-up shortages in 2017. If sufficient ramp had been available, then regulation-up scarcity prices would not have raised the marginal energy price. When regulation-up is short, the scarcity price affects 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.

3.3.1.2 Design limitations accounting for expected ramp

The current market design does not effectively consider ramp in real-time dispatch. As an example, parameters for two resources are shown in Figure 3–14. Assume no congestion, losses, or any constraints other than the ones mentioned; and assume load occurs exactly as forecasted and generation performs exactly as instructed. In this case, all changes are expected.

Figure 3–14 Parameters for ramp example

Offers and parameters	Minimum	Maximum	Offer	Ramp rate
Resource A	20 MW	50 MW	$10/MWh	2 MW/min
Resource B	20 MW	50 MW	$15/MWh	1 MW/min

Figure 3–15 Ramp example, market results not considering ramp

Market results not considering ramp	Initial interval	Interval 1	Interval 2
Resource A	40 MW	50 MW	50 MW
Resource B	20 MW	20 MW	25 MW
Total generation	**60 MW**	**70 MW**	**75 MW**
Total load	60 MW	70 MW	76 MW
Price	$10/MWh	$15/MWh	$5,000/MWh

The cheaper resource has a faster ramp rate, and faster load increases in future intervals. Resource A can ramp 10 MW in a five-minute interval while resource B can ramp only 5 MW in that time. Figure 3–15 shows that in Interval 1, the cheaper resource is dispatched to its maximum limit, and resource B's output remains the same because it is out of the money. In Interval 2, resource B does not have sufficient ramp to serve load. The energy scarcity price of $5,000/MWh[42] is invoked, signaling a shortage of energy. Although the scarcity price is more alarming, a higher-priced resource could cause an unnecessarily high price in this situation as well.

In the above example, the market had enough energy capacity to serve the load. Furthermore, sufficient ramp was also provided. If the dispatch instruction for Interval 1 is constrained by the ramp needed to for Interval 2, then a solution without scarcity is feasible. This is shown in the alternative solution in Figure 3–16.

Figure 3–16 Ramp example, market results considering ramp

Market results considering ramp	Initial interval	Interval 1	Interval 2
Resource A	40 MW	45 MW	50 MW
Resource B	20 MW	25 MW	26 MW
Total generation	**60 MW**	**70 MW**	**76 MW**
Total load	60 MW	70 MW	76 MW
Price	$10/MWh	$15/MWh	$15/MWh

Resource A is not dispatched to its maximum limit in Interval 1. Its dispatch instruction is calculated so that some ramp is held back for Interval 2. No scarcity is invoked because the market was not short. The production cost is significantly lower in the example in which the resources were prepositioned for future ramping needs. Scarcities can be avoided by leveraging load forecast and planning for ramp needs.

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[42] $5,000/MWh was the price used for the price spike on June 7, 2017.

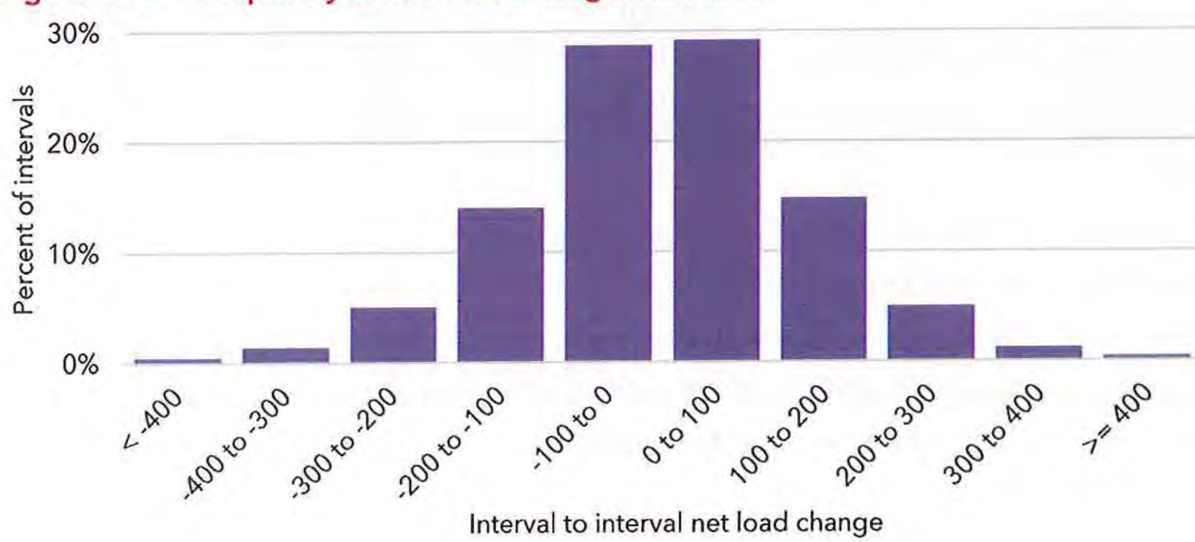
3.3.1.3 Design limitations accounting for unexpected ramp

The above example demonstrated the shortcoming of the current pricing mechanism with the assumption that load occurs exactly as forecasted and generation performs exactly as instructed. These are expected changes. However, the issue is further complicated when the load and generation do not move as anticipated. Unexpected changes in net load also can contribute to shortages as well.

Net load is load net of both variable energy generation and the combination of imports and exports. Each term of this equation is forecasted, and there will always be some error between a forecasted value and the actual value. Load is constantly varying and is not controlled by SPP. Generation is forecasted in that the market clearing software assumes that the dispatch instruction will be followed. Some resources submit a dispatch status reflecting its inability to follow dispatch for various reasons. Even under the best circumstances, dispatchable resources are not able to follow dispatch precisely. Actual imports and exports vary from expected values for similar reasons, particularly during start-up and shutdown periods. For these reasons, the expected net load will always have a margin of error. This margin of error can increase the amount of ramp needed to achieve the next dispatch instruction.

Figure 3–17 shows the frequency of how often the net load changes from one real-time interval to the next.

Figure 3–17 Frequency of net load change, real time



About 13 percent of intervals have a net load change of over 200 megawatts when both positive and negative changes are considered. Some of these net load changes peaked over 1,000 megawatts. While the percentage of total intervals is low, these greater deviations cause greater price volatility. This difference must be provided by resources with a flexible dispatch range.

Figure 3–18 below shows that the volatility in net load change increased significantly each year from 2015.

Figure 3–18 Volatility of interval-to-interval net load change

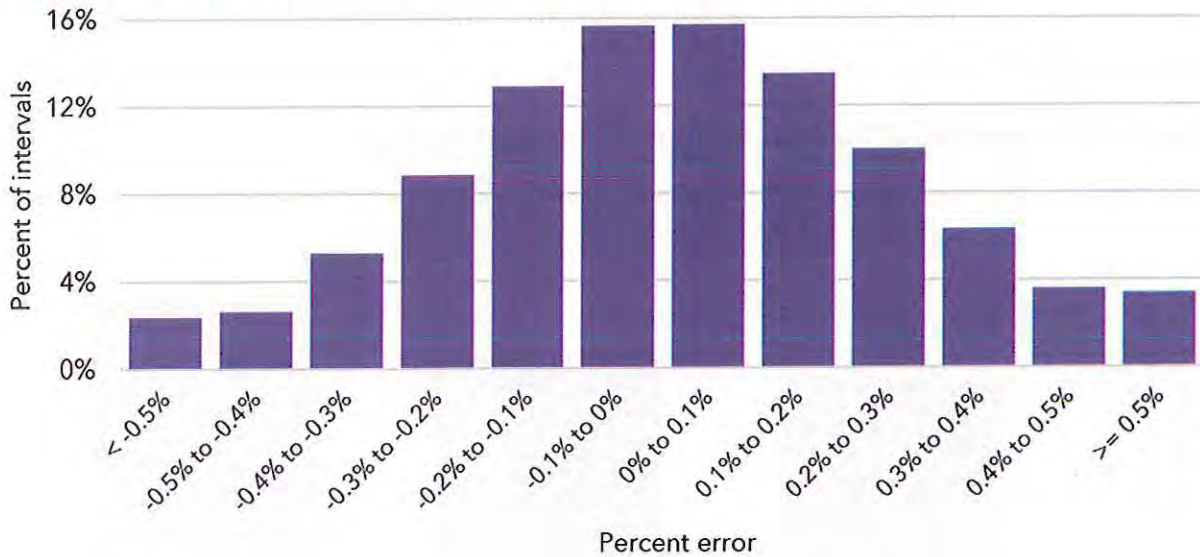
This volatility increased about 10 percent from 2015 to 2016 and about 19 percent from 2016 to 2017.

Variable energy resources typically are assumed to remain at the same output level at which they were last observed. Practically, this will not be the case. This discrepancy can require more ramp in the next interval. In 2017 about 23 percent of total generation was from wind resources. This was a significant source of deviation from anticipated output in 2017. With over 28 gigawatts of wind-powered generation and over 15 gigawatts of solar generation with an active generation interconnection request,[43] this problem will be exacerbated in the future as volatility from variable energy resources increases.

[43] See Figure 2–18.

Although wind and load are forecasted so that their impact can be expected, forecasts are always accompanied by forecast error. While the short-term load forecast, as shown in Figure 3–19, is very accurate overall, the deviations can leave regulation to make up for the error instead of adjusting to the change in load during the five-minute interval.

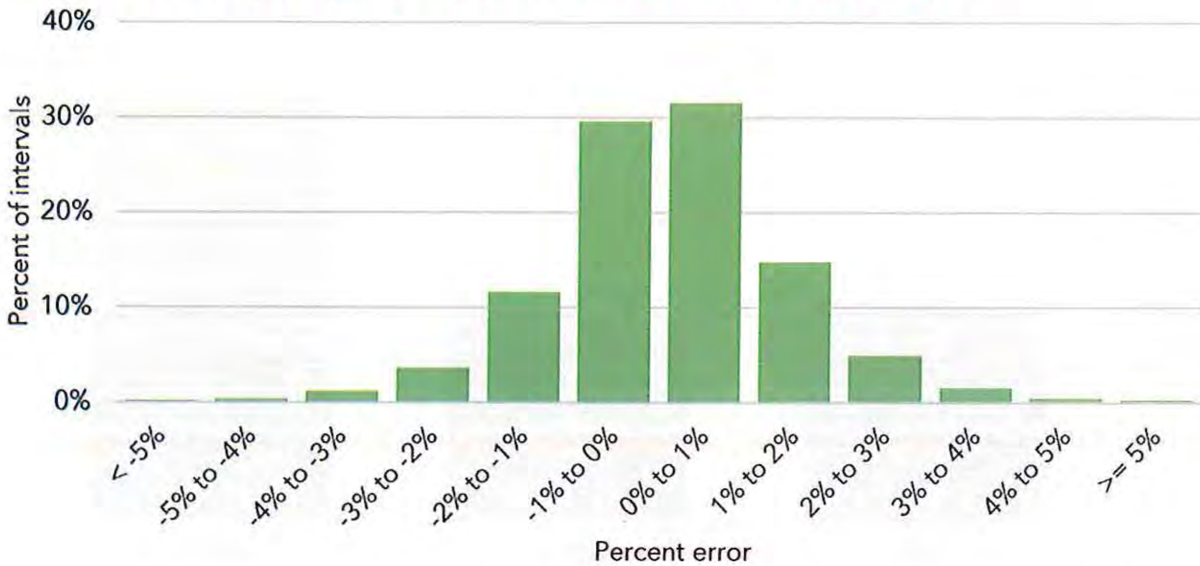
Figure 3–19 Frequency of short-term load forecast error, real time



The largest magnitude of error shown in Figure 3–19 is 0.5 percent for both positive and negative errors. While these categories look small, they make up about six percent of all intervals. This represents about 6,000 intervals during the year, or about 500 hours. During some of these intervals, the load forecast error was around one percent, which represents an error of about 300 megawatts. This is only one source of unexpected net load change.

Another source of unexpected net load change is short-term wind forecast error. This can also occur in both positive and negative directions and is shown in Figure 3–20.

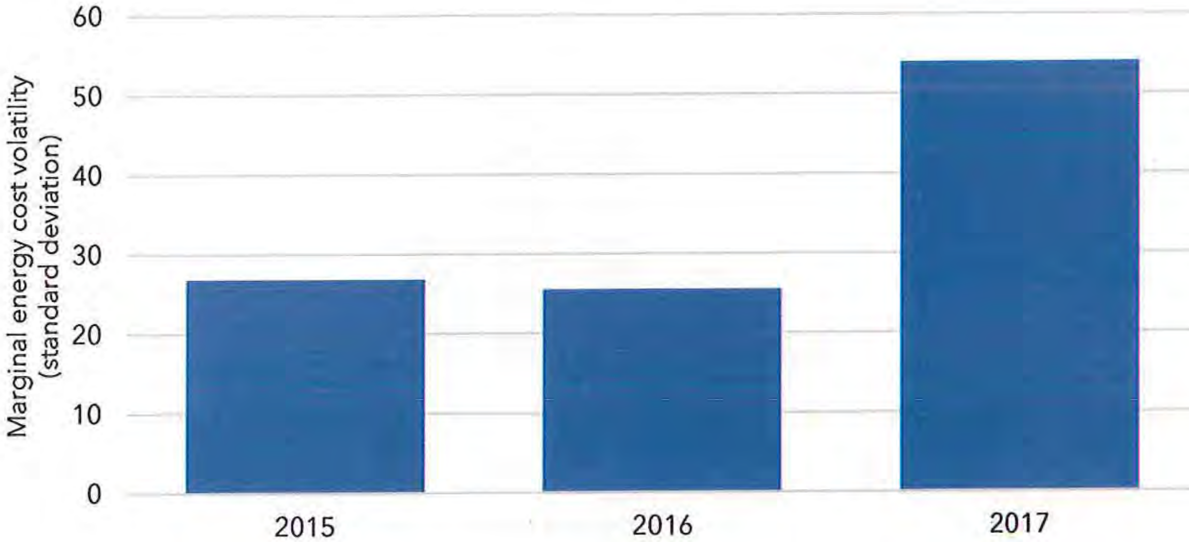
Figure 3–20 Frequency of short-term wind forecast error, real time



While the frequency of wind forecast error in excess of three percent in magnitude for both positive and negative changes is rare, this represents over 4,000 intervals, or about 330 hours. The average wind forecast error for these intervals where the error is greater than +/-3 percent is about 625 megawatts. This too is a significant source of unexpected net load change.

Net load change, with all of its causes, will change the marginal energy price from interval-to-interval because of the constant need to balance generation and load. The volatility of the interval-to-interval difference in the real-time marginal energy price was very high in 2017, as shown in Figure 3–21.

Figure 3–21 Volatility of marginal energy cost interval-to-interval, real time



The amount of interval-to-interval change in the marginal energy component has doubled since 2016, even though it remained steady from 2015 to 2016. A ramp capability product could reduce that volatility by prepositioning resources so that higher prices, because of inflexible dispatch range, are avoided. This should provide steadier prices in real time.

Procuring ramping capability to address both anticipated and unexpected uncertainty has value in smoothing out real-time price volatility and reducing the incidence of scarcity events. Currently, SPP does not value and incentivize this flexibility. A resource's dispatch instruction is currently based solely on the cost of generation at the dispatch instruction. However, because ramp capability adds value to the market, ramping capability should be valued and incentivized by the market.

3.3.1.4 Recommendation

Given the limitations with the current market design in preparing for both expected and unexpected ramping needs, and the growing evidence that market outcomes are increasingly affected by ramping constraints, the MMU recommends that SPP and its members develop a ramping capability product. The benefits of a ramp capability product include increasing reliability through an economic signal and improving market signals.

A ramp capability product can provide ramp more reliably than the current design because it is systematically procured and readily available. The MMU prefers a market-based solution over manual commitments and commitment of capacity to gain ramp. Scarcities, which are not a true reflection of system conditions, can be avoided and the resources that are used to avoid the scarcity should be paid for that benefit that they are providing. This will also incentivize future resources to be flexible.

Other RTO/ISO markets have implemented and designed ramp products that SPP and stakeholders can consider in its design and development. For instance, Midcontinent ISO and California ISO have implemented ramp products, and ISO New England is in the development process. However, at a minimum, we recommend that the design should include the following features:

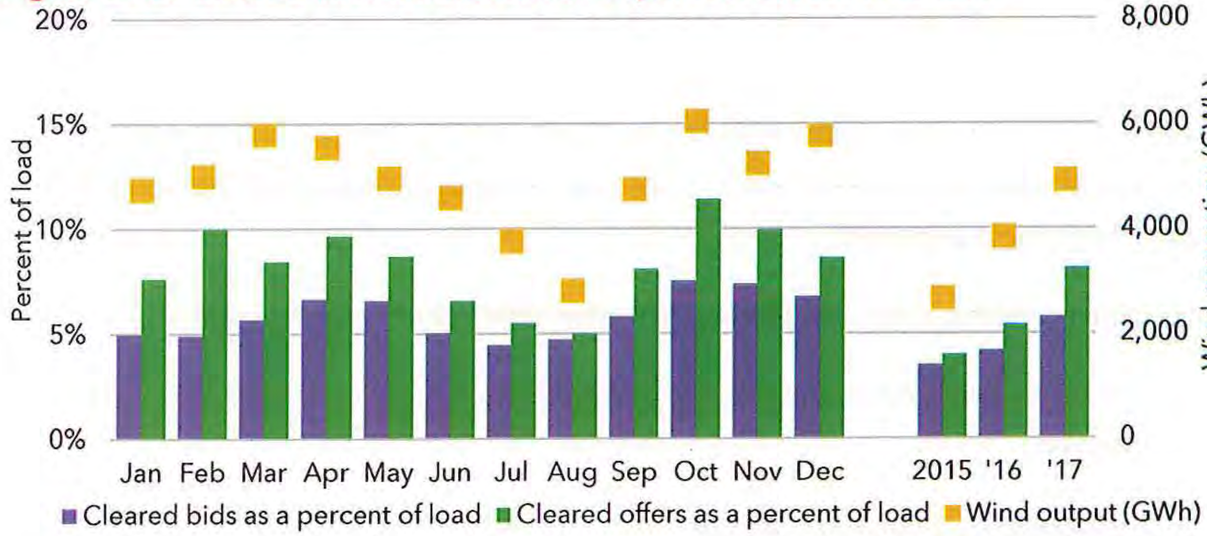
- Two products: ramp capability up and ramp capability down;
- Co-optimization with energy and other products to ensure the most economical solution;
- Opportunity cost basis for pricing;
- No limitations on resource type as long as the resource can reliably provide ramp in the direction for which it is cleared; and
- Consideration of both expected and unexpected ramping needs.

3.4 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 moderate, and increasing levels of virtual participation. Figure 3–22 displays the total volume of virtual transactions as a percentage of real-time market load along with wind output levels.

Figure 3–22 Cleared virtual transactions as percent of real-time load

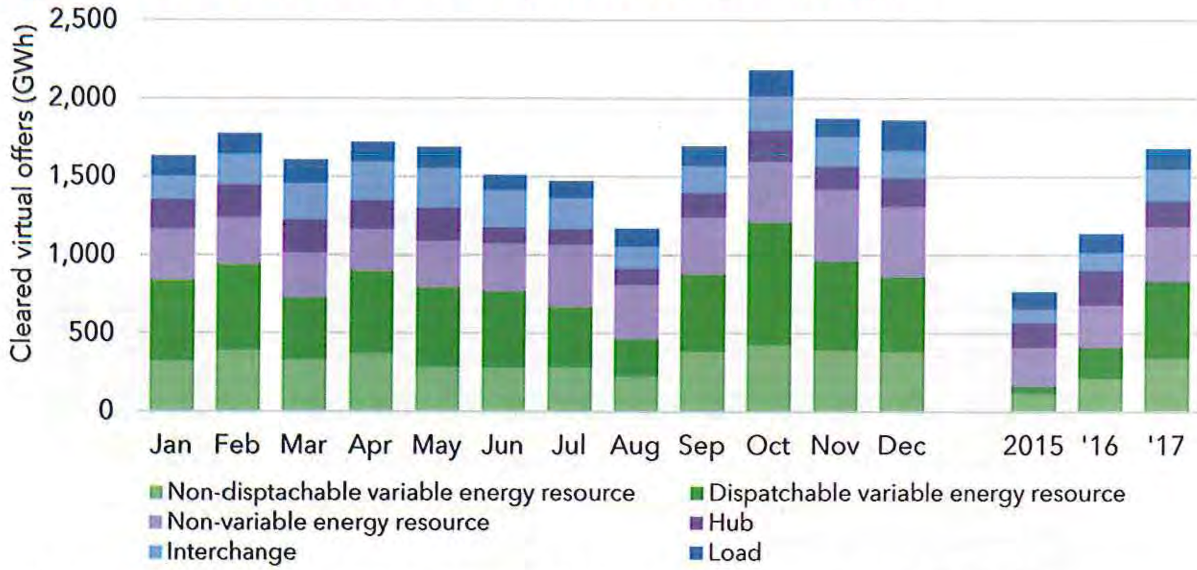


As shown in the figure, virtual transactions averaged 13.9 percent of real-time market load, compared to 9.4 percent in 2016. The greatest increases in virtual transactions as a percentage of load has been with cleared virtual offers, which increased to 8.1 percent in 2017 from 5.4 percent in 2016 and 4.0 percent in 2015. Virtual cleared bids also increased from 3.5 percent in 2015 to 4.2 percent in 2016 and further upward to 5.8 percent in 2017. In particular, there was a large increase in cleared virtual offers in October 2017. Days with high wind output see an increase in virtual offer activity. Virtual bids increase during high load hours.

At about 14 percent of load, the average hourly total volume of cleared virtuals ranged from 3,300 MW of withdrawal, to 5,700 MW of injection. The net cleared virtual positions in the market averaged about 660 MW each hour.

The majority of virtual transactions occurred at wind resources in 2017. This is a trend that has been increasing since mid-2015. Figure 3–23 illustrates the settlement location types where virtual offers clear.

Figure 3–23 Cleared virtual offers by settlement location type

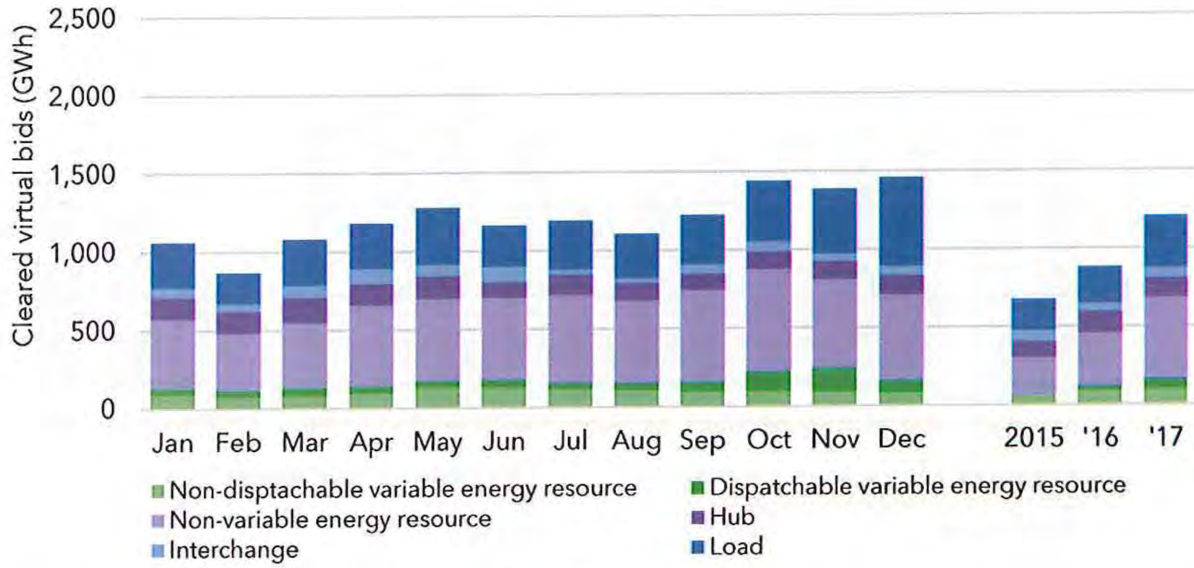


This figure shows that just over 49 percent of the virtual offers cleared at variable energy resources during 2017.[44] This is a significant increase from 35 percent in 2016 and 21 percent in 2015. The large volumes of virtual offers at variable energy resources highlight the fact that those resource types may be missing financial opportunities by under-scheduling in the day-ahead market.[45]

This is in contrast with the locational volumes of virtual bids. Cleared virtual bids were primarily at resources other than variable energy resources, followed by load locations. Figure 3–24, below, shows the cleared virtual bids by settlement location types.

[44] This includes both dispatchable and non-dispatch variable energy locations.
[45] Section 4.1.5 on price divergence discusses the effects of unscheduled wind in the SPP market.

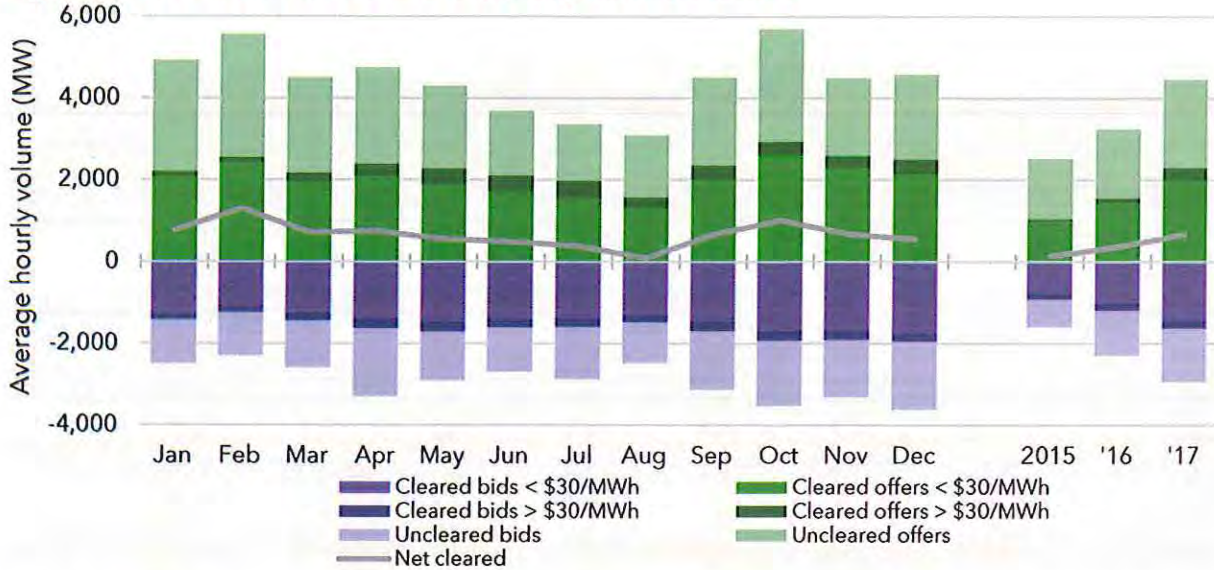
Figure 3–24 Cleared virtual bids by settlement location type



Forty-three percent of cleared virtual bids in 2017 were at non-variable energy resource locations, which is up from the 39 percent in 2016 and the 35 percent in 2015. Another 28 percent of the cleared virtuals bids were at load locations in 2017, which is comparable to the values in 2016 (26 percent) and 2015 (30 percent) when compared on a percentage basis. However, the volume increase in cleared bids at load locations between 2016 and 2017 was over 44 percent.

Figure 3–25 shows 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.

Figure 3–25 Virtual offers and bids, day-ahead market



These types of bids and offers are called "price-insensitive" and occurred more often with bids up until 2017. Price-insensitive bids have remained steady with about 12 to 14 percent of cleared bids since 2015, but that number has increased for offers from four percent in 2015 to 13 percent in 2017. 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 2017 in Figure 3–26.

Figure 3–26 Virtual profits with distribution charges

Month	Raw profit	Raw loss	Raw net profit (prior to fees)	RNU charges/ credits	Day-ahead make-whole payment charges	Real-time make-whole payment charges	Virtual transaction fee	Total net profit
January	$13.6	-$8.2	$5.3	$0.1	$0.1	$1.6	$0.0	$3.6
February	10.4	-10.3	0.1	0.1	0.1	0.7	$0.0	-0.8
March	15.7	-11.4	4.3	0.0	0.1	1.2	$0.0	2.9
April	21.4	-13.4	8.0	0.1	0.2	1.7	$0.0	5.9
May	16.0	-12.7	3.3	0.1	0.1	1.7	$0.0	1.4
June	15.5	-11.1	4.4	0.1	0.1	1.5	$0.0	2.8
July	13.3	-8.6	4.6	0.1	0.1	2.3	$0.0	2.2
August	6.0	-6.0	0.1	0.0	0.1	1.1	$0.0	-1.1
September	14.2	-10.6	3.6	0.1	0.2	1.0	$0.0	2.4
October	23.8	-14.3	9.5	0.1	0.2	1.2	$0.0	7.9
November	19.6	-12.2	7.4	0.1	0.2	1.5	$0.0	5.6
December	18.2	-14.7	3.6	0.0	0.2	1.5	$0.0	1.9
Total	**$187.8**	**-$133.5**	**$54.3**	**$0.9**	**$1.6**	**$16.9**	**$0.4**	**$34.6**

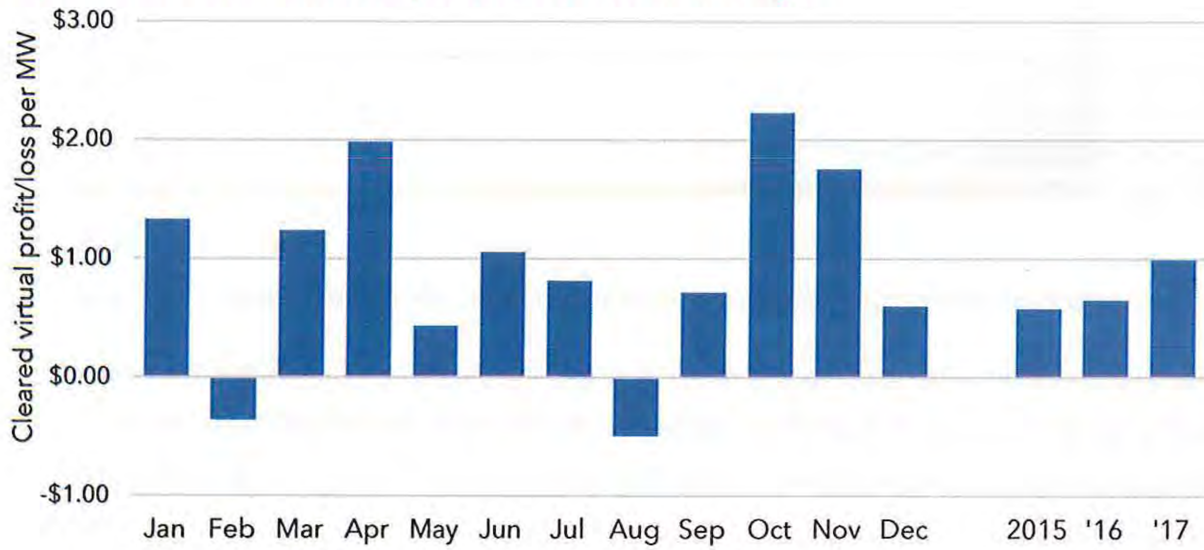
All figures in $ millions

Virtual trades profited in aggregate for the year by about $54 million, which is a 63 percent increase from the $33 million in 2016 and $21 million in 2015, larger than the 39 percent increase in hourly volume. 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 a $0.05 per virtual bid or offer transaction fee for processing virtual transactions. The average 2017 rates per megawatt for day-ahead make-whole payments, real-time make-whole payments, and real-time revenue neutrality uplift distributions are $0.11/MWh, $0.90/MWh, and $0.12/MWh, respectively. When factoring in these charges and credits, the total virtual bidding profits for 2017 are reduced by 36 percent to $34.6 million.

Every month in 2017 was profitable in aggregate for virtual transactions before factoring in transaction fees. However, once the fees were accounted for February and August become unprofitable in aggregate. In the 46 months since the market began, only seven months have had a net loss when factoring in fees. The highest payout months in 2017 happened in April and October with net payouts just over $5.9 million and $7.9 million, respectively. These months coincide with high wind periods and low load months 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.[46]

Net profits are typically small when assessed on a per megawatt basis. Figure 3–27 illustrates the monthly average profit per megawatt for a cleared virtual in 2017.

Figure 3–27 Profit and loss per cleared virtual, average

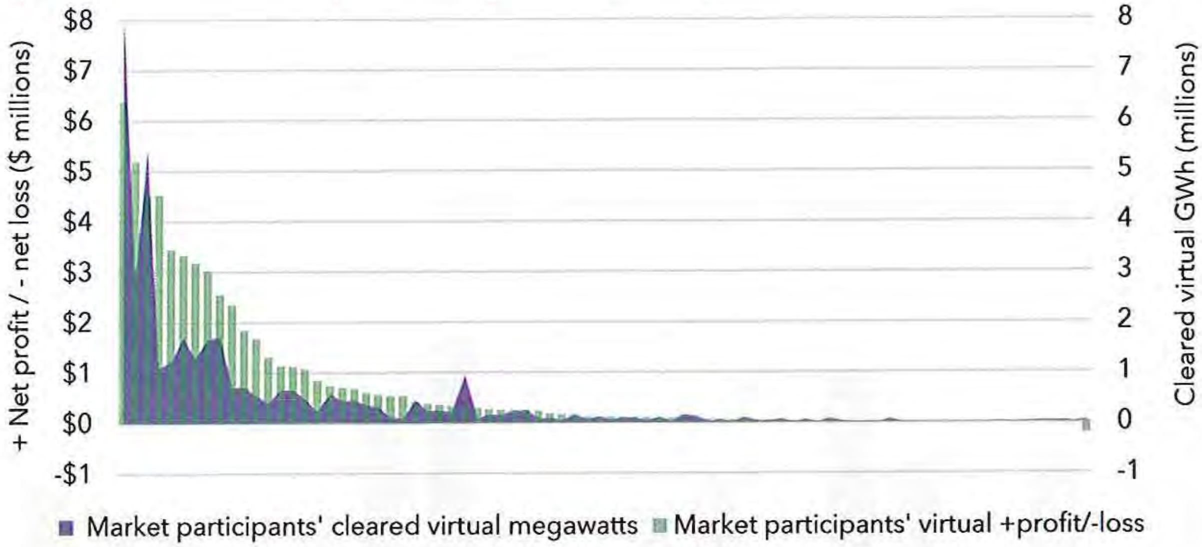


The chart shows that when factoring in all fees the average profit per megawatt for 2017 was $1.00 per cleared megawatt, a more than 50 percent increase from $0.65 in 2016.

There were eighty SPP participants that had virtual transactions in 2017. Figure 3–28 illustrates each virtual participant's net virtual portfolio for the year by both megawatts cleared and net profits. The chart is sorted to show the participants in order from those with the highest net virtual profit to those with the greatest net virtual loss.

[46] Section 4.1.5, Price divergence, discusses the effects of unscheduled wind in the SPP market.

Figure 3–28 Net virtual portfolio by virtual participant



As seen in the chart, the overall profitability in virtual transactions was concentrated with a few market participants. Five participants accounted for over 42 percent of the total aggregate virtual profits and 50 percent of the transactional volume. In aggregate, virtuals were profitable for most participants. However, fourteen participants did have unprofitable virtual portfolios in 2017. The total net losses for these entities was just over $350,000, with one entity accounting for over $200,000 of that loss. Thus, the overall profitability results show that gains far exceeded losses.

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, eight market participants lost more than $10,000 in 2017, which is only slightly more than in 2016. In addition to the low net losses, few SPP market participants are active in both virtual bidding and with transmission congestion rights, which reduces the potential for cross-product manipulation.

4 PRICES

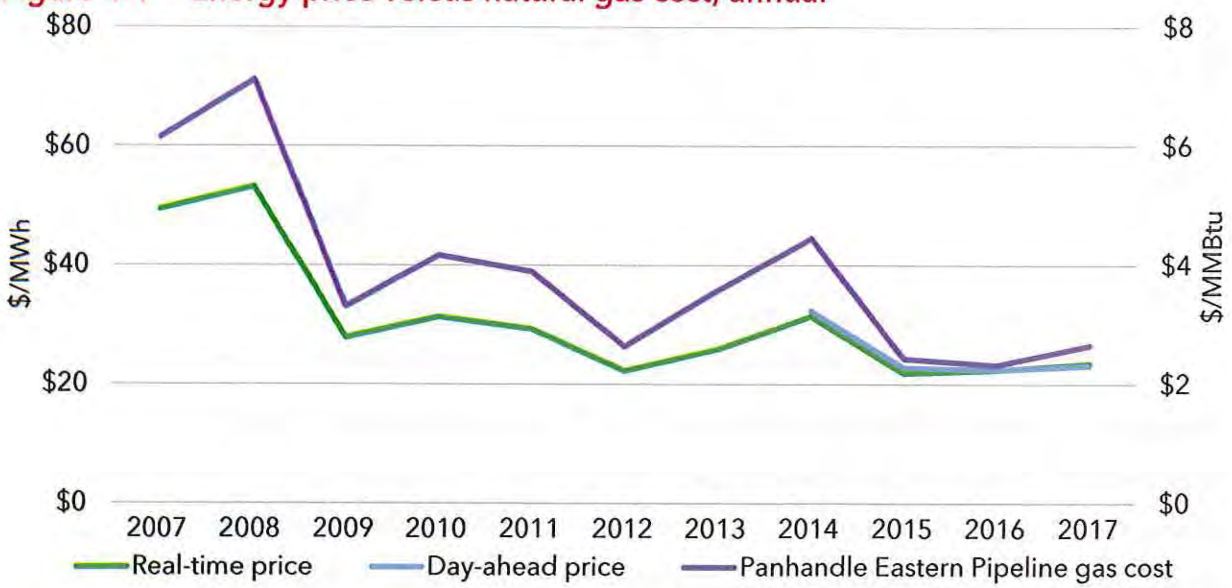
4.1 MARKET PRICES AND COSTS

This section reviews market prices and costs by focusing on the fuel prices, price volatility, negative prices, operating reserve prices, and market settlement results including make-whole payments. Overall, annual prices remained fairly stable compared to previous years with just a slight increase in both the day-ahead and real-time prices in 2017. However, annual numbers mask underlying issues related to market flexibility and efficiency. For instance, we discuss increasing periods of price volatility and instances of negative prices. Chapter 7 discusses recommendations for addressing these issues.

4.1.1 ENERGY MARKET PRICES AND FUEL PRICES

Figure 4-1 below compares day-ahead and real-time prices in SPP between 2007 and 2017[47] with natural gas prices.

Figure 4-1 Energy price versus natural gas cost, annual



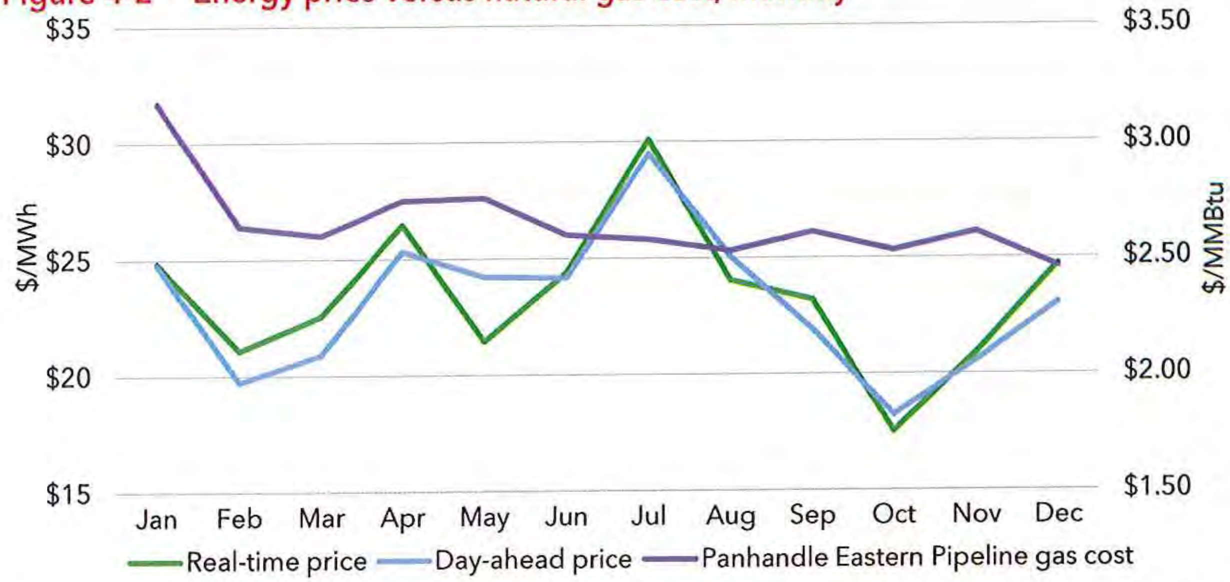
Historically, electric market prices have followed the cost of natural gas. As natural gas prices have remained low overall, so have SPP market prices. Electricity prices remained low in 2017, as day-ahead market prices averaged about $23/MWh in 2017, up about three percent

[47] From 2007 to 2013, the average price from the Energy Imbalance Service market is shown. 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.

from 2016. The average real-time price for 2017 was $23.43/MWh, an increase of seven percent over 2016. The average gas cost, using the price at the Panhandle Eastern Pipeline (PEPL) increased by 14 percent from 2016 to 2017. This is in sharp contrast to the change from 2014 to 2015, when energy prices dropped by 30 percent, while gas costs dropped by 45 percent.

On a monthly basis, day-ahead and real-time prices were highest in July at about $30/MWh as temperatures increased and loads peaked (as seen in Figure 4-2). Prices were lowest in October at around $18/MWh as periods of high wind generation coincided with low loads. Natural gas prices were highest in January at over $3/MMBtu and lowest in December at around $2.50/MMBtu.

Figure 4-2 Energy price versus natural gas cost, monthly



Changes in gas costs have historically had the highest impact on electricity prices compared to other fuels. This is because natural gas-fired generation frequently is the marginal price setting fuel as coal fired generation is cheaper on a $/MMBtu basis. However, natural gas generators are more flexible than coal generators in scheduling or dispatch by SPP, as they have shorter start-up times and minimum run times. Figure 4-3 compares various fuel price indices with real-time prices.

Figure 4-3 Fuel price indices and wholesale power prices

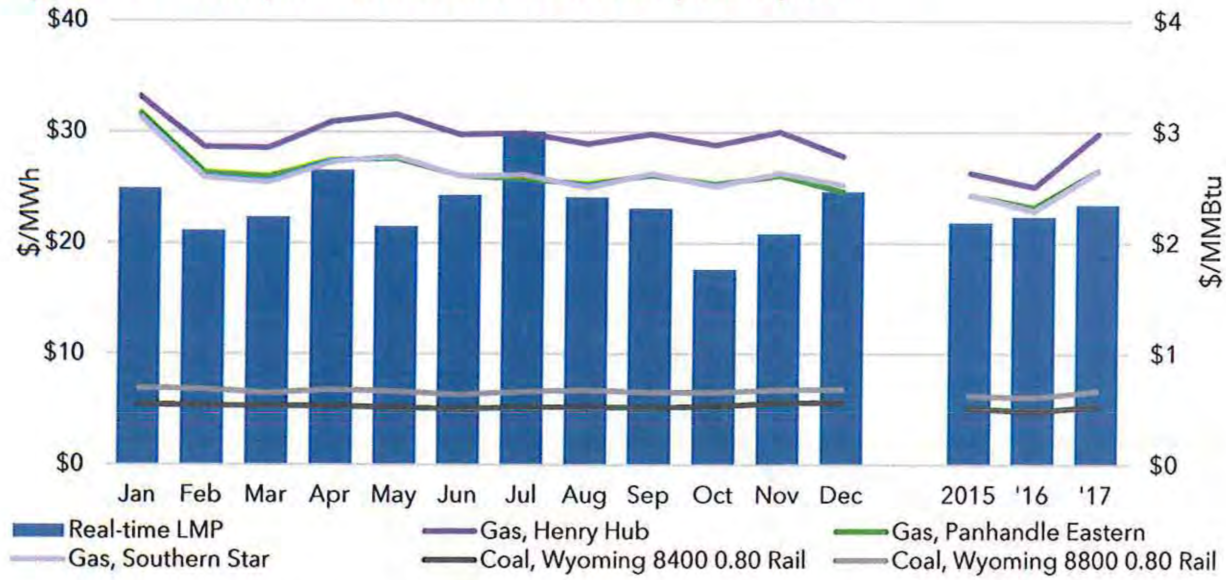


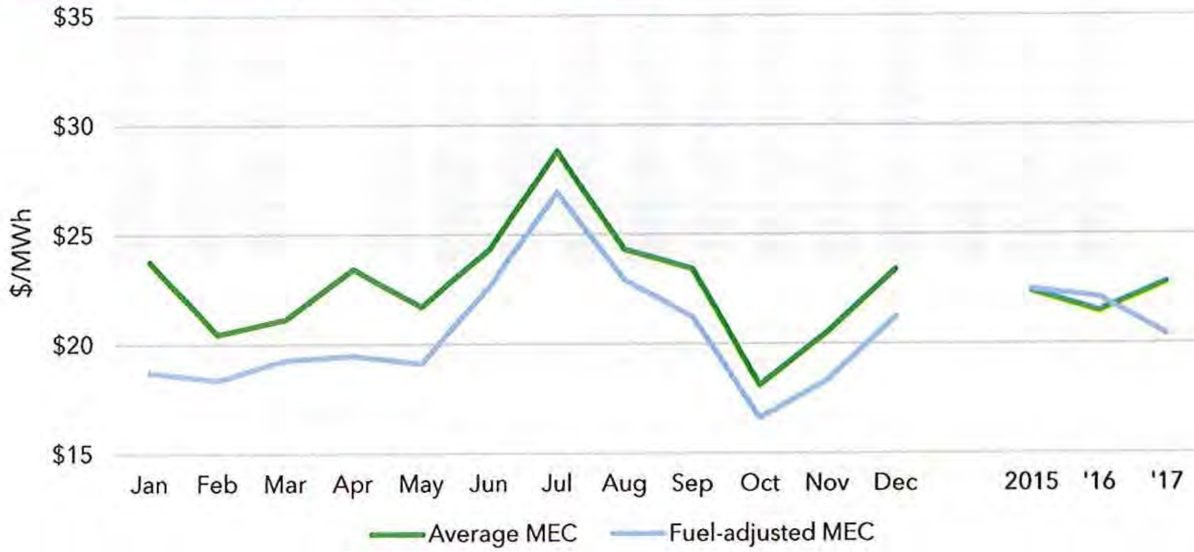
Figure 4-3 shows that regional natural gas prices trended up from 2016 to 2017, following the national trend as represented by the Henry Hub. However, the price for all three indices was still below $3/MMBtu for 2017.[48] The annual average gas price at the Panhandle Eastern hub increased by 14 percent, from $2.32/MMBtu in 2016 to $2.65/MMBtu in 2017.

Coal prices have remained relatively stable since 2015 with a slight increase overall from 2016 to 2017.[49] Annual average coal prices at Powder River Basin for both types, 8,400 Btu/lb., and 8,800 Btu/lb., increased by nearly 10 percent. The price for 8,400 Btu/lb. increased from $0.48/MMBtu in 2016 to $0.53/MMBtu in 2017, and the price for 8,800 Btu/lb. increased from $0.60/MMBtu in 2016 to $0.67/MMBtu in 2017.

[48] 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.
[49] Coal prices are inclusive of transport costs.

Controlling for changes in fuel prices helps to identify the underlying changes in electricity prices from other factors.[50] Figure 4-4 below adjusts the marginal energy cost for changes in fuel costs.[51]

Figure 4-4 Fuel-adjusted marginal energy cost



As the figure shows, fuel adjusted marginal energy costs were lower in 2017 compared to nominal marginal energy costs both annually and in each month. While the average nominal marginal energy cost in 2017 increased six percent from 2016, the fuel-adjusted marginal energy cost decreased by eight percent because of the higher fuel prices and higher wind generation in 2017. Looking by month, the highest fuel-adjusted marginal energy cost occurred in July 2017 during which SPP experienced high-temperature periods and 2017's peak demand. The largest downward movement occurred in January and April which might be due to the high marginal fuel price appeared in these months. The SPP market normally experiences more fuel shortages in these winter months, due to pipeline outages and gas limitations.

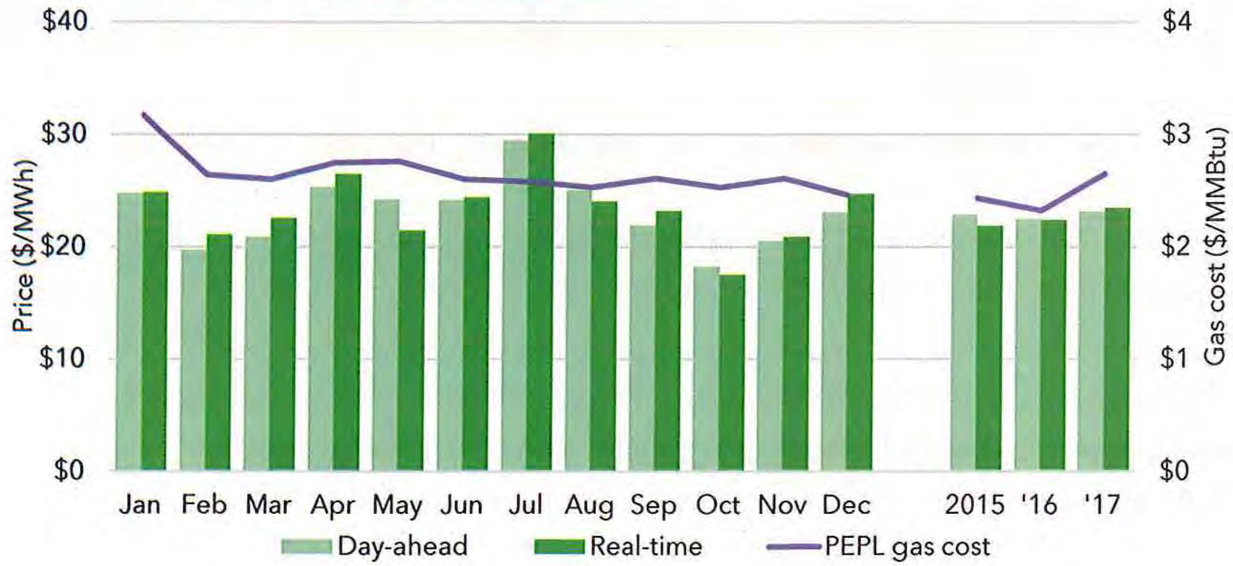
[50] In addition to fuel, other variables also affect real-time prices. These variables include seasonal load levels, transmission congestion, scarcity pricing, and wind-powered generation.

[51] 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 which indexed to the three-year average of the price of the marginal fuel during the interval. If multiple fuels were marginal in an interval, we calculate weighted average marginal energy costs based on the dispatched MW on different fuel types.

4.1.2 REAL-TIME AND DAY-AHEAD PRICE COMPARISONS

Day-ahead prices have historically been higher than real-time prices. However, average real-time prices exceeded day-ahead prices in 2017. This is primarily a result of increased price volatility in real time because of higher actual (unexpected) congestion, along with load and generation changes. Unexpected congestion is typically more pronounced during the high wind seasons of spring and fall. Figure 4-5 shows day-ahead and real-time market monthly and annual prices compared with the cost of natural gas.

Figure 4-5 Price, day-ahead and real time



In the first 22 months of the Integrated Marketplace, the average real-time price exceeded the day-ahead price only once. In 2016, the real-time price exceeded the day-ahead price during five months. And in 2017, the real-time price exceeded the day-ahead price in all but three months. Figure 4-6 below shows the monthly day-ahead / real-time price premium for 2017, as well as annually for the past three years.

Figure 4-6 Difference between day-ahead and real-time prices

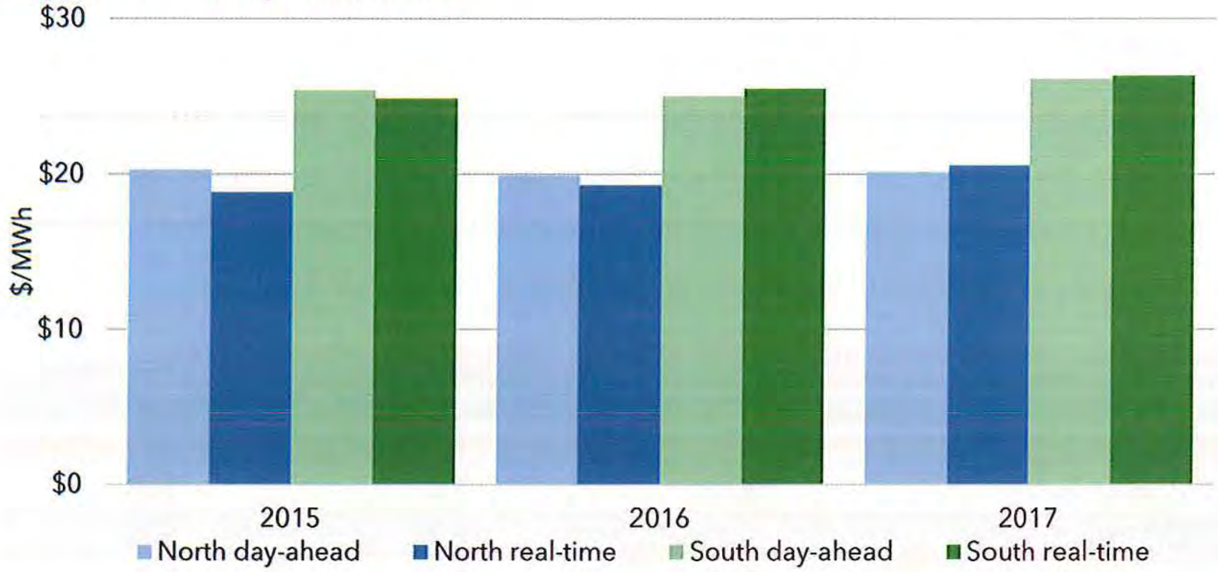
Day-ahead prices exceeded real-time prices in May, August, and October. May had the largest difference with a day-ahead average price $2.77/MWh higher than real time. In both March and December, the real-time average price was $1.67/MWh higher than day-ahead. On an annual basis, the day-ahead premium has gradually gone away with a day-ahead premium of around $1/MWh for 2014 (not shown) and 2015, to a day-ahead premium of $0.07/MWh in 2016, and then moving to a real-time premium of $0.32/MWh for 2017.

4.1.3 HUB PRICES

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 2017. 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.

Figure 4-7 and Figure 4-8 show the day-ahead and real-time energy prices at the two SPP market hubs.

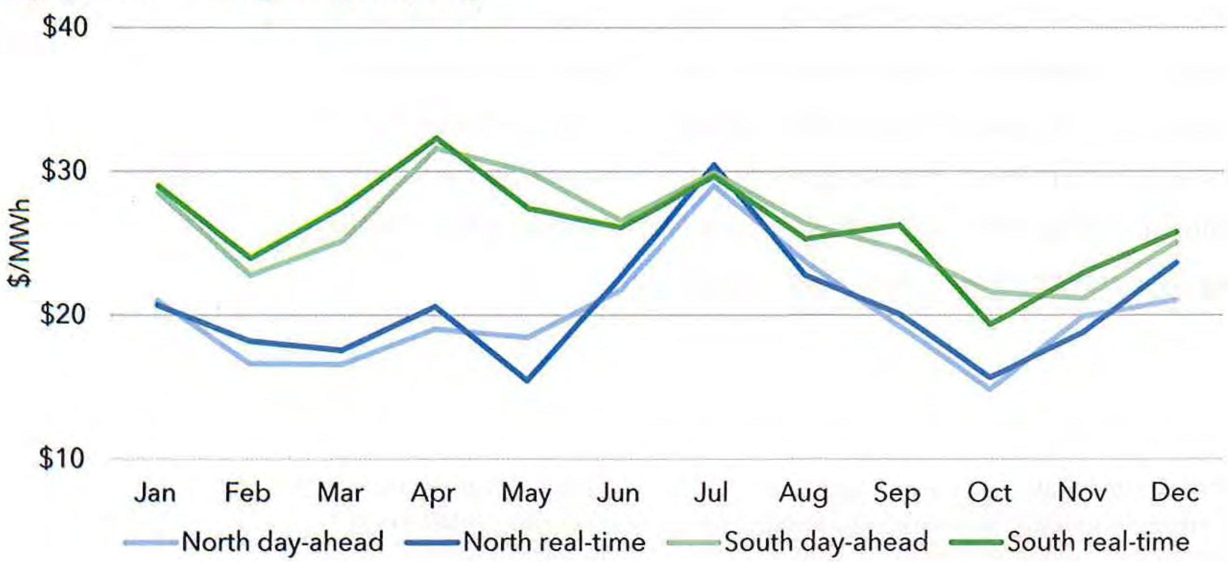
Figure 4-7 Hub prices, annual



On an annual basis hubs prices have remained fairly stable with North hub prices averaging around $20/MWh, and South hub prices averaging around $25/MWh. These prices were slightly higher than 2016 prices.

On a monthly basis, South hub prices were higher than North hub prices in all but one month, as seen in Figure 4-8.

Figure 4-8 Hub prices, monthly



In July, for the first time in the Integrated Marketplace, the North hub real-time price exceeded the South hub real-time price. Temperatures in July were warmer than normal in the northern area, which increased demand and price. For further discussion on temperatures, see Section 2.2.4.

The price separation between the North and South hub averaged $6/MWh in 2017, slightly higher than the $5/MWh spread in 2015 and 2016. The overall level and trend in energy prices were consistent with other RTO/ISO markets, as shown in Figure 4-9. When compared to other regions, the North hub was among the lowest priced hubs in the region.

Figure 4-9 Comparison of ISO/RTO average on-peak, day-ahead prices

	2015	2016	2017
SPP North hub	$ 24	$ 24	$ 25
SPP South hub	$ 29	$ 29	$ 31
ERCOT North hub	$ 31	$ 26	$ 26
ERCOT West hub	$ 31	$ 26	$ 26
MISO Arkansas hub	$ 29	$ 27	$ 31
MISO Louisiana hub	$ 33	$ 34	$ 34
MISO Minnesota hub	$ 27	$ 25	$ 28
MISO Texas hub	$ 32	$ 31	$ 38
PJM West hub	$ 43	$ 35	$ 34

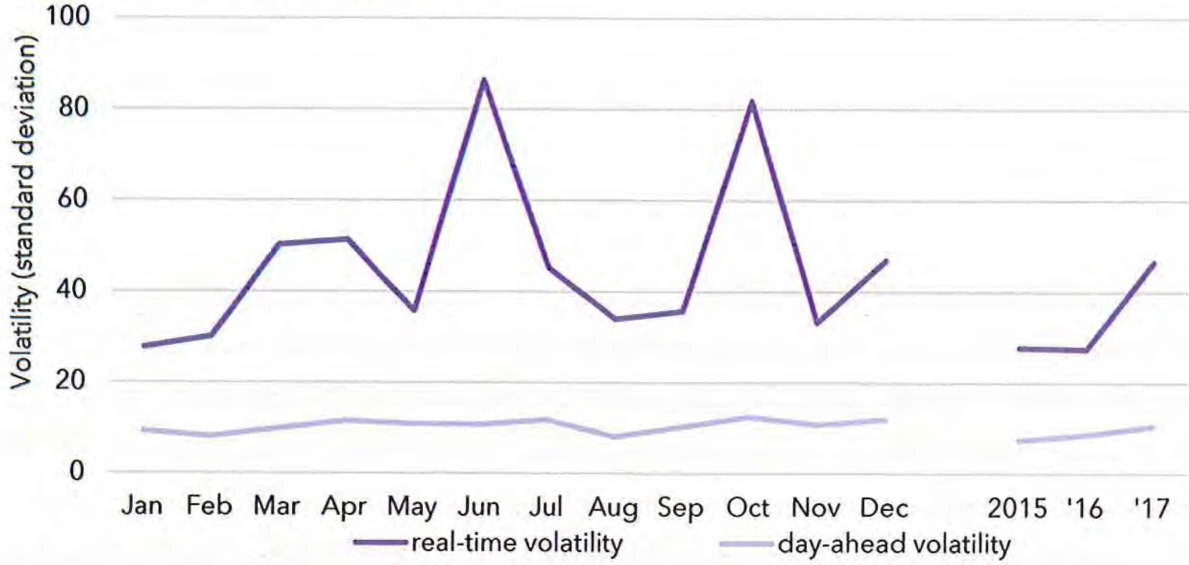
4.1.4 ENERGY PRICE VOLATILITY

Price volatility[52,53] in the SPP market is shown in Figure 4-10 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 due to peak load conditions.

[52] 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. In prior reports volatility was measured using the coefficient of variation (standard deviation divided by mean), however, this method gave artificially high volatility to asset owners with a low average price.

[53] A measure of volatility is also shown earlier in this report at Figure 3-19. That volatility calculation is based on the interval-to-interval change in marginal energy cost. The volatility calculation in Figure 4-10 is based on the interval locational marginal prices for load-serving entities in the SPP market. Although the results are different, the magnitude of the annual change is very similar.

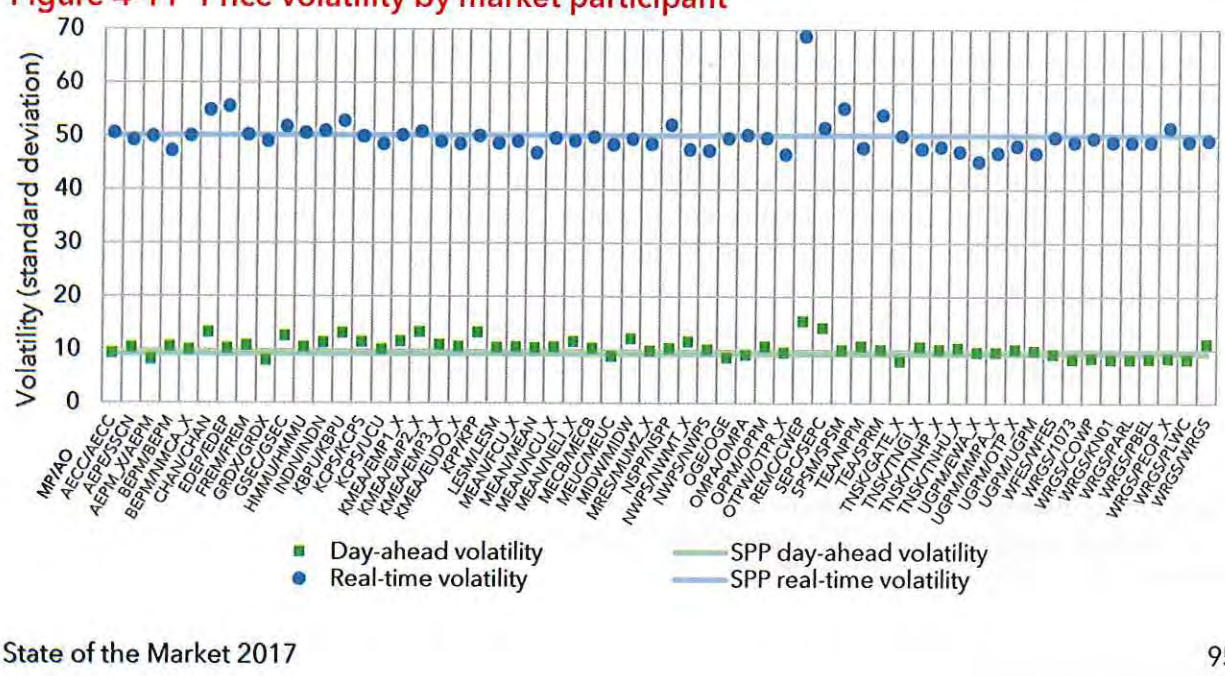
Figure 4-10 System price volatility



Volatility in 2017 was slightly higher than 2016 in the day-ahead market, and has taken a steady upward trend on an annual basis. However, volatility in the real-time market nearly doubled from 2016 to 2017. This can partially be attributed to high levels of wind generation in the spring and fall. High volatility during June can mostly be attributed to several short-lived energy shortages.

Price volatility varies across the SPP market footprint for asset owners primarily due to 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.

Figure 4-11 Price volatility by market participant



The volatility for the majority of asset owners is grouped very close to the SPP average in both the day-ahead and real-time markets as shown in Figure 4-11. The area of the footprint that experienced the most volatility in 2017 was in southwest Missouri and southeast Kansas. This area experienced a great deal of congestion during the year, mostly on the Neosho-Riverton flowgate, which is discussed in more detail in Section 5.1.4.3.

4.1.5 PRICE DIVERGENCE

As mentioned above, real-time prices were slightly higher than day-ahead prices in 2017. Moreover, system volatility nearly doubled in 2017 compared to 2016 and 2015. These metrics indicate that while average prices are similar, the underlying prices in the day-ahead and real-time markets were different. The averaging of price spikes, and in particular, high prices during periods of scarcity, drove real-time average prices just above day-ahead prices. We attribute these short-term, transient price spikes with limitations in ramping capability.[54] In this section, we highlight underlying differences in prices after controlling for scarcity events. This analysis shows that significant generation, particularly from wind resources not accounted for in the day-ahead market, drives down real-time prices.

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. However, there are many factors than 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.[55]
- 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.
- Unanticipated weather changes affect the real-time markets.

[54] For further information on ramping issues, see Section 3.3.1.
[55] Additionally, revision request 239 allowed historic fuel cost uncertainty to be considered in the development of mitigated energy offers.

Figure 4-12, below, shows the marginal energy costs for both the day-ahead and real-time markets during off-peak hours after controlling for scarcity events.[56] Figure 4-13 shows the same information, but for on-peak hours.

Figure 4-12 Off-peak marginal energy prices, excluding scarcity hours

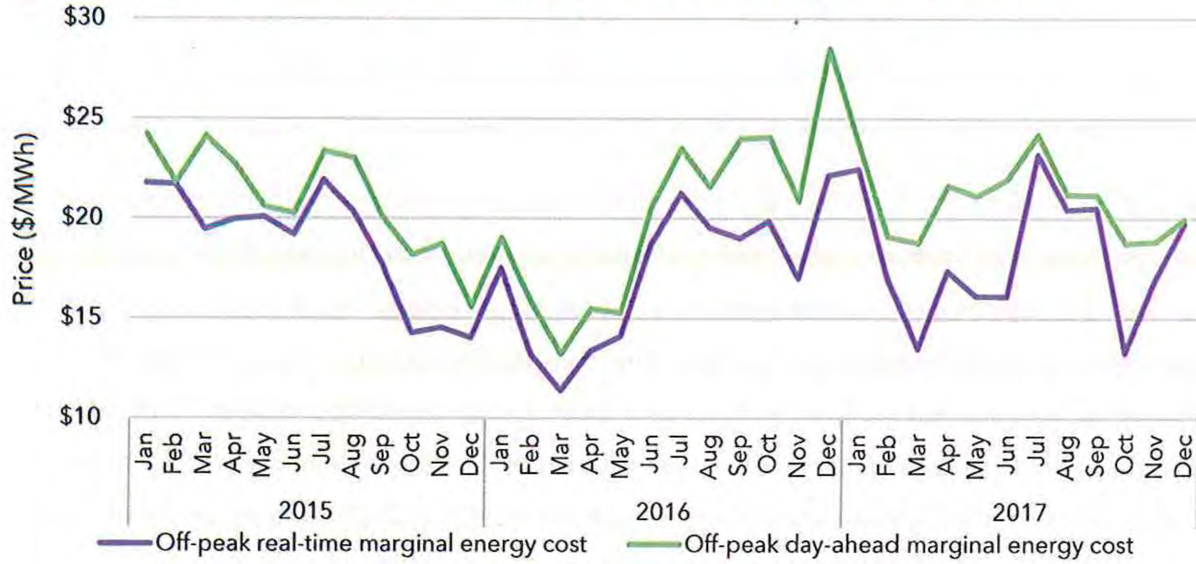
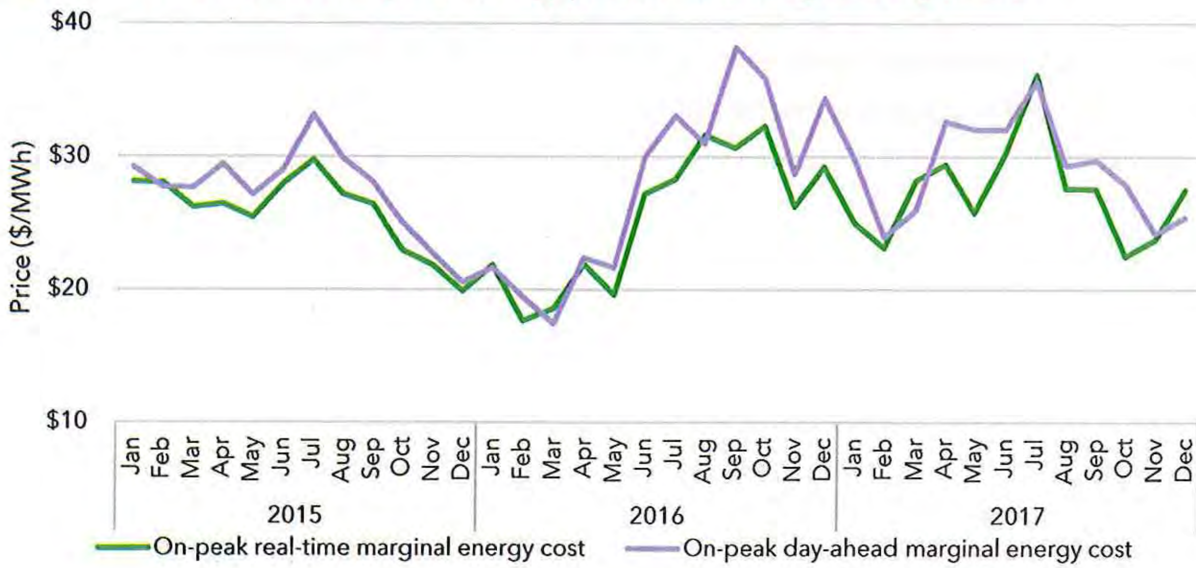


Figure 4-13 On-peak marginal energy prices, excluding scarcity hours



[56] These numbers reflect only hours where scarcity demand curves where not applied. SPP uses scarcity demand curves for intervals when ramp or capacity requirements cannot be met through dispatch. During these intervals the scarcity demand curves can drive marginal energy cost as high as $5,000. Scarcity demand curves are discussed in detail in Section 4.2, below.

The marginal energy cost is one of three components that factor into location marginal prices and represents the marginal cost to provide the next megawatt 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 when controlling for scarcity, particularly in the off-peak hours. In 2017, day-ahead marginal energy costs, for all hours, were 10 percent higher than real-time prices.[57] This is slightly higher than the nine percent price divergence in 2016 and slightly lower than the 11 percent in 2015.

The main contributors influencing the price differences are under-scheduling of wind resources in the day-ahead market, self-committing of units after the day-ahead market, and economic reliability unit commitments. In fact, only 82 percent of the wind generation was scheduled in the 2017 day-ahead market. This changes the supply curve by shifting it outward and causes real-time prices to drop relative to the day-ahead market. Furthermore, the real-time market appropriately honors the minimum limits of all committed resources. With the unanticipated generation, many non-wind units fall to their 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.[58]

Figure 4-14 shows average hourly incremental differences in megawatts produced between the real-time and day-ahead market in 2017.

[57] The MMU observed that 77 percent of the hours in 2017 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.
[58] Negative prices are discussed in detail in Section 4.1.6.