Southwest Power Pool
Market Monitoring Unit

STATE OF THE MARKET
2016

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1 EXECUTIVE SUMMARY

The Southwest Power Pool (SPP) Market Monitoring Unit's Annual State of the Market report for the third year of the SPP Integrated Marketplace presents an overview of the 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. Along with this goal, 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 OVERVIEW

The Integrated Marketplace introduced centralized unit commitment and dispatch processes, day-ahead and real-time balancing markets and a transmission congestion rights market. The trading of energy and operating reserve and virtual products was also introduced in this design. The centralized unit commitment and dispatch processes resulted in the largest and most immediate financial benefit to the SPP market, as it allowed SPP to reduce online generating capacity—as a percent of demand—by nine percent in 2014, six percent in 2015 and seven percent in 2016 compared to what was generally experienced during the last year of the Energy Imbalance Service market. Changing generation patterns, which began in 2015, driven by extremely low natural gas prices, high wind generation, and decreased use of coal generation all have increased uncertainty and appeared to have affected the capacity commitment process particularly from December 2015 through March 2016. Beginning in May 2016, the online generating capacity figures have exhibited a general downward trend indicating efficiency improvements with the current market design.

The third year of the Integrated Marketplace shows a mature and very competitive market. Indicators of this market state include:

- High levels of participation in the day-ahead market transactions in terms of the total megawatt-hour volume transacted across the SPP market;
- High levels of participation in the day-ahead market for load (98 to 101 percent) and 80 percent for generation;

- Lower levels of make-whole (uplift) payments (seven percent reduction);
- Low levels of mitigation; and
- A modest level of scarcity pricing events.

Major drivers of the 2016 market outcomes include the continuing decline of natural gas prices, and increasing wind generation capacity and output. The increase in wind generation appears to be the cause of increasing levels of overall congestion in the market.

Average monthly natural gas prices in 2016 at the Panhandle Eastern Pipeline hub fluctuated from $1.53/MMBtu to $2.79/MMBtu through November and then climbed to $3.43/MMBtu in December 2016. For the entire year of 2016, the average monthly natural gas price was $2.32/MMBtu representing a 4.5 percent decline from the 2015 average. 2016 experienced some of the lowest monthly gas prices and the lowest annual average gas price since the start of SPP's first market in 2007.

The monthly average real-time electricity price in the Integrated Marketplace for 2016 varied between $16/MWh to $27/MWh with the annual average price of $22.36/MWh. These are some of the lowest monthly and annual average electricity prices since the start of SPP's first market.

The average annual all-in price of electricity was $22.47/MWh. The cost of operating reserves and make-whole payments for 2016 represented about two percent of the total all-in price of electricity, mirroring 2015 shares for both. The total price is comparable to prices in other markets in the region and the non-energy components compare favorably with other wholesale electricity markets.

Installed generation capacity increased in 2016 to 87,453 MW from 84,943 MW in 2015 indicating a three percent growth rate. The installed capacity at time of system peak that qualifies for determining the reserve margin increased from 67,251 MW in 2015 to 72,145 MW in 2016. Peak load increased from 45,279 MW in 2015 to 50,622 in 2016. The increase in capacity and load was primarily the result of SPP market expansion into the Dakotas and adjacent states. System peak load increased more than capacity because of higher than normal summer temperatures in 2016. This weather pattern resulted in a sizable decrease in the reserve margin to 43 percent in 2016 from 49 percent in 2015. The drop in reserve margin was not the result of a high level of plant retirements or increased overall native load.

Generation in the SPP market by technology is changing primarily because of two factors: 1) relative difference in fuel prices, namely declining natural gas prices compared to coal prices; and 2) increased installed wind generation capacity and output. Consequently, extremely low natural gas prices have resulted in displacement of coal generation by gas generation. Another trend is increasing wind generation making simple cycle gas generation less economical.

Wind generation in 2016 continued to increase and represented almost 23 percent of total SPP generation in the months of March, April, and October, with an annual average share of 18 percent. Conversely, the share of coal generation has declined from a historical average of 60 to 65 percent to an annual average of 48 percent in 2016, which is down from 55 percent in 2015. April 2016 coal generation represented just under forty percent of total generation for the month. This is the lowest monthly share of coal since the start of organized markets in SPP in 2007.

Year-end installed wind generation capacity in the SPP market increased 30 percent from 2015, reaching 16,114 MW at the end of 2016. This continued a trend that has occurred over the past several years. Because actual generation resulting from new capacity does not show up in the market for several months after registration, the full impact of this nearly 3,700 MW of new wind capacity in 2016 will not occur until 2017. Wind generation as a percent of load for any hour reached a maximum value of 48 percent in 2016, which was higher than maximums of 38 percent in 2015 and 33 percent in 2014. On an interval basis, initial results from 2017 indicate that at times, wind-sourced generation has exceeded 50 percent (54.5 percent in April 2017) of total load.

Given the large resource margin and the frequency with which prices reflect inexpensive generation, prices in 2016 generally did not rise to levels high enough to support investment in new *non-wind* generating capacity. Even though federal and/or state subsidies are declining, wind generation is likely to continue to increase substantially in the next three to four years.

In addition to committing capacity to meet the load and operating reserves obligations in the day-ahead market, SPP also committed resources for reliability needs through its reliability unit commitment processes and manual commitment processes. This provided SPP operations with the capability to address issues regarding ramping, headroom, and local reliability constraints—services that aren't directly reflected in the market prices. The commitment of additional capacity to address these issues dampened prices and increased reliability unit commitment make-whole payments.

There are a number of resource categories that may not be receiving market revenues sufficient to cover their annual avoidable costs. This includes resources committed for voltage support, quick-start resources, and large base load resources with a significant level of fixed operations and maintenance costs such as coal units. Factors influencing this issue include low market prices driven by low gas prices and high wind generation, large reserve margin, and high level of self-committed capacity. The MMU, through its advisory role to SPP and participation in the stakeholder process, is assessing these issues.

Scarcity pricing levels in 2016 were about $1,300/MWh for aggregate operating reserves, about $900/MWh for regulating reserves, and about $200/MWh for spinning reserves. This is comparable to 2015 levels and consistent with other markets.

Marginal energy component prices for ramp-constrained shortages, however, averaged just over $51/MWh in 2016, $10/MWh less than what was experienced in 2015. The MMU has voiced concern that these low prices do not reflect the value of demand for ramp capability provided by fast-responding resources, creating a market separation between economics and reliability. The RTO addressed this concern in May 2017 by implementing ramp scarcity with the use of demand curves during times of ramp shortages.

The Integrated Marketplace provides fewer categories of market uplift, or make-whole payments, when compared to other RTO markets, reflecting an efficient market design. Coupled with five-minute real-time market settlements, these provisions generally provide incentives for resources to meet their commitment and dispatch instructions by ensuring that the market covers cleared costs. The level of make-whole payments in 2016 constituted about 1.2 percent of the all-in price of electricity, which was seven percent less than 2015 levels (1.3 percent of all-in price) and 24 percent less than 2014 levels (1.5 percent of all-in).

1.2 DAY-AHEAD AND REAL-TIME MARKET PERFORMANCE

Load and generation participation in the day-ahead market continued to be strong in 2016. The average monthly day-ahead market participation rate for generation assets was about 80 percent of installed capacity (115 percent of load) and the average level of participation for the load assets was between 98 percent and 101 percent of the actual real-time load.

Generation offers in the day-ahead market averaged 48 percent as 'market' commitment status followed by 'self-commit' status at 35 percent of the total capacity commitments for 2016. In 2015, the 'market' and 'self-commit' shares were at 46 percent and 39 percent, respectively. Other resource commitment statuses for 2016 were 'reliability' at two percent and 'not participating' at three percent, which are very close to 2015 figures. The 'outage' status accounted for the remaining 12 percent, an increase from 10 percent in 2015. The MMU monitors generation in 'outage', 'reliability', and 'not participating' status for possible physical withholding concerns. The MMU is also assessing the high use of self-commitment status because of the limitations this commitment type places on the market. Some of the reasons for this 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.

The total volume of virtual transactions as a percentage of real-time market load averaged 9.4 percent for 2016 from 7.5 percent in 2015. In general, virtual transactions have been profitable in the SPP marketplace increasing in 2016 to about $33 million from about $21 million in 2015. When transaction fees are included net profit for virtuals is only $16 million for 2016. Every month in 2016 was profitable in aggregate for virtual transactions, before factoring in the transaction fees. Out of 82 market participants with virtual transactions in 2016, only five took in over 50 percent of the net profits from virtual transactions.

The real-time market is settled according to market participants' deviations from their day-ahead positions. Day-ahead prices are generally higher than real time prices, which indicates a higher value (or premium) attached to the relative certainty of day-ahead prices for load and generation, compared to the potential volatility in the real-time market. Real-time prices will be higher at times due to this volatility, which can be caused by changing generation or load levels, outages, and congestion. The average monthly real-time price exceeded the day-ahead price only once during the first 22 months of the Integrated Marketplace. However, in 2016 real-time average prices were higher than day-ahead prices during five months.

The day-ahead and real-time energy prices at the two SPP market hubs, the North and South hubs, differ due to congestion and differing fuel mixes in the two regions. The North hub generally experiences lower prices because coal, nuclear, and wind are the dominant technologies in that area. The South hub, on the other hand, has a larger share of gas-fired plants.

1.3 TRANSMISSION CONGESTION AND HEDGING

Locational marginal prices reflect the sum of the marginal cost of energy, the marginal cost of congestion, and the marginal cost of losses for each pricing interval at any given pricing location in the market. 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.

Load-serving entities may hedge the congestion cost with transmission congestion rights and auction revenue rights. At an aggregate level, the SPP load was 88 percent hedged for the explicit congestion costs paid in the day-ahead and real-time markets. In 2016, the total of all transmission congestion right and auction revenue right net payments to load-serving entities of $243 million was less than the total day-ahead and real-time markets congestion costs of $280 million.

This is in contrast to 2015 when transmission congestion right and auction revenue right net payments to load-serving entities exceeded their congestion costs. This change could be due to a variety of factors, including the market design change with Revision Request 91[1], market participant behavior, or overall increased congestion patterns in the market. Meanwhile, in 2016 non-load-serving entities collected transmission congestion right and

[1] Revision Request 91 (Annual Allocation Percent Change) changes the annual auction revenue right allocation system capacity to match annual that of the annual transmission congestion right auction. This should result in higher funding percentages, allowing market participants to more accurately value their transmission congestion rights.

auction revenue right net revenues of nearly $91 million, which exceeded their day-ahead and real-time market congestions costs of $18 million.

1.4 OUT-OF-MARKET ACTIONS AND UPLIFT COSTS

The Integrated Marketplace provides make-whole payments (MWPs) to generators to ensure that the market provides sufficient revenue to cover the short-run marginal cost of resources that provide energy, start-up, no-load, and operating reserve products for a market commitment period and for local reliability commitments. Make-whole payments are additional market payments in cases where prices result in revenue that is below a resource's cleared offer. These payments are intended to make resources whole to the costs of providing the above-mentioned products.

In 2016, total make-whole payments were approximately $71 million, up from $58 million in 2015. Much of the increase can be attributed to two factors: 1) the expansion of the market footprint in late 2015, and 2) more negative price periods primarily driven by wind generation. There were approximately 500 negative real-time price intervals in 2016, which is about six percent more intervals with negative prices than 2015.

Make-whole payments averaged about $0.27/MWh for 2016. In comparison to other ISO/RTO markets, SPP's make-whole payments are comparable to other ISO/RTOs which vary from $0.22/MWh to $0.57/MWh in 2016. Day-ahead make-whole payments constituted about 38 percent of the total make-whole payments in 2016. SPP pays about 87 percent of all make-whole payments to gas-fired resources with 72 percent of reliability unit commitment make-whole payments to simple cycle gas resources.

1.5 COMPETITIVENESS ASSESSMENT

The SPP Integrated Marketplace provides effective market 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 2016 were workably competitive and that the market required mitigation of local market power infrequently to achieve competitive outcomes. Nonetheless, mitigation remains an essential tool in ensuring that market results are competitive during periods of high demand and supply shortages and when such market conditions offer suppliers the potential to abuse local market power.

Three metrics—market share analysis, Herfindahl-Hirschman Index (HHI), and pivotal supplier analysis—were used to evaluate structural market power in the SPP footprint. The market share analysis assessed the market share of the largest supplier in terms of energy output in the real-time market by hour for the entire year, along with a duration curve showing ranked market share. The market share rank ranged from 9.6 percent to 19.7 percent, which did not exceed the 20 percent benchmark in any hours in 2016.

The overall supplier concentration in the SPP market was evaluated by employing the HHI in terms of installed capacity, and the results show that the SPP market was not concentrated in any hours in 2016, which is an improvement from 29 percent concentrated in 2015.

The third structural metric, the pivotal supplier analysis, was used to evaluate the potential of market power in the presence of "pivotal" suppliers. In this report, the metric identifies the frequency with which at least one supplier was pivotal at varying load levels in five different reserve zones (regions) of the SPP footprint in 2016. The results showed the percent of hours with pivotal supplier is the highest (around 100 percent) in the New Mexico and Texas region—irrespective of demand level—where one of the SPP's frequently constrained areas in 2016 was located. This region is followed by Iowa and the Dakotas where, depending on the level of load, 17 percent to 36 percent of the hours exhibit at least one pivotal supplier. The remaining regions experience pivotal supplier conditions for only negligible periods.

In sum, all the three metrics discussed above 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.

The structural indicators discussed above look for the potential for market power without regard to the actual exercise of market power. Behavioral indicators, on the other hand, were assessed through the analysis of actual offer or bid behavior (i.e., conduct) of the market participants to look for the actual exercise of market power.

The frequency of mitigation (i.e., the percent of resource hours mitigated) varied across products and markets. The level of mitigation for incremental energy, regulation, and no-load in the day-ahead market were infrequent and up slightly in 2016 from 2015 levels. Nonetheless, the level of mitigation was still very low throughout the year. The day-ahead mitigation was on average is 0.05 percent for 2016. The mitigation of start-up offers increased to nine percent in September 2016 and has since fallen to less than three percent in December 2016. While this is similar to the trend that was experienced for the other market components, it was observed at higher levels. The combined frequency of mitigation of start-up offers for day-ahead, reliability unit commitment and manual commitments increased to 3.8 percent in 2016 from 2.8 percent in 2015.

The mitigation of energy in the real-time market, on average, was at very low levels with annual average around 0.03 percent for 2016 resource hours. The results represent dramatic improvement relative to the first year of the market in 2014 where some of these market components experienced mitigation levels approaching one percent.

Finally, the output gap as a measure for economic withholding was calculated first for the SPP footprint, with values ranging from 0.69 to 2.06 percent, with the largest gap appearing in December. The output gap was also calculated for two areas in the footprint – the Texas Panhandle and Woodward frequently constrained areas. The calculated output gap values at all three locations are consistent with competitive market conduct.

1.6 STRUCTURAL ISSUES

Installed generation capacity in the SPP market has grown rapidly since the beginning of the Integrated Marketplace in early 2014 and has maintained a high level of reserve margin approaching 50 percent in 2014 and 2015, and 43 percent in 2016. SPP's current annual planning capacity requirement is 12 percent.

The influx of wind capacity accounted for most of the observed growth of installed capacity in the SPP market with growth rates of 44 percent in 2015 and 30 percent in 2016 relative to prior year. At the same time, wind generation constituted a significant part of the total annual generation, around 18 percent in 2016, with an all-time high rate of wind generation penetration of 54.5 percent of load in April 2017.

The shift in generation mix towards renewable resources is a significant and positive development, however it carries market and operational challenges and risks, both in the short- and long-run. Market inefficiencies and operational impacts of wind generation makes the current mix even more of a concern since 40 percent of the total wind capacity is non-dispatchable.

Low cost wind generation is becoming a contributing factor to the low levels of SPP's energy prices. The limited controllability of wind and the significant level of state and federal subsidies distort market prices and stresses other aspects of a properly functioning market. It is in the best interest of SPP market stakeholders to begin preparing for potential changes to the market.

Market participants have recently complained of inadequate cost recovery and have initiated discussions at various levels on existing mitigation rules as a way of addressing such issues. The MMU views this market outcome as a byproduct of increasing wind capacity and generation, high reserve margins, low gas prices, and certain offer behavior in the SPP market. Hence, the MMU has explained to market participants on several occasions that the root cause of the issue was a combination of structural issues and certain offer behaviors (e.g., self-commitments by suppliers, which is nearly 35 percent in the day-ahead market in 2016) not "over-mitigation". In fact, the mitigation data for energy, regulation, start-up, and no-load components of offers in 2015 and 2016 reveal that the SPP market experienced very low levels of mitigation frequency.

1.7 RECOMMENDATIONS

One of the primary responsibilities of a market monitoring unit is to evaluate market rules and market design features for market efficiency and effectiveness, as well as the prevention of market power abuse. The MMU does this through multiple forums. One such forum is this Annual State of the Market report. Other forums the MMU uses to fulfill this responsibility include preparation and submittal of revision request (RR) forms used in the RTO stakeholder process, commenting on revision requests submitted by SPP and stakeholders, presenting comments and recommendations directly to the SPP Board of Directors and FERC regarding proposed tariff changes, and filing comments on FERC Notice of Proposed Rulemakings (NOPRs.)

In the 2014 and 2015 Annual State of the Market reports, the MMU made several recommendations, most of which have been addressed through the SPP stakeholder process. Two recommendations remain open at the time this report is published. This includes the revision of rules to eliminate potential make-whole payment manipulation related to commitments across the midnight hour and fixed regulation bids. The recommendation to transition non-dispatchable variable energy resources (NDVERs) to dispatchable variable energy resources (DVER) status, which will lessen the negative impact of such resources on the market is currently being assessed by the SPP Market Working Group. A recommendation to change mitigation conduct thresholds and physical withholding penalty rules have been withdrawn by the MMU, pending further monitoring and analysis.

In this 2016 Annual State of the Market Report, the MMU recommends SPP address the biased mitigation rule for resources committed to resolve local reliability problems. The MMU specifically recommends converting the 10 percent threshold rule for local reliability commitments to a 10 percent cap. This will remove the risk to these resources of having their market offer reduced to the mitigated offer level for economic withholding mitigation when their offer is between 10 percent and 25 percent (17.5 percent for resources in designated frequently constrained areas) as is the case for all other resources that are not subject to local reliability commitments.

The MMU appreciates the constructive effort of the Market Working Group, SPP staff, and other groups involved in the SPP stakeholder process to identify and implement solutions that address these recommendations. Detailed discussion of each open recommendation is contained in the body of this report.

2 THE SPP MARKET IN 2016

2.1 THE INTEGRATED MARKETPLACE

Southwest Power Pool (SPP) is a Regional Transmission Organization (RTO) authorized by the Federal Energy Regulatory Commission (FERC) with a mandate to ensure reliable power supplies, adequate transmission infrastructure, and competitive wholesale electricity prices. FERC granted RTO status to SPP in 2004. SPP is one of nine Independent System Operators/Regional Transmission Organizations (ISO/RTOs) and one of eight NERC Regional Entities in North America. 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 2016 calendar year of the SPP wholesale electricity market referred to as the Integrated Marketplace, which started on March 1, 2014.

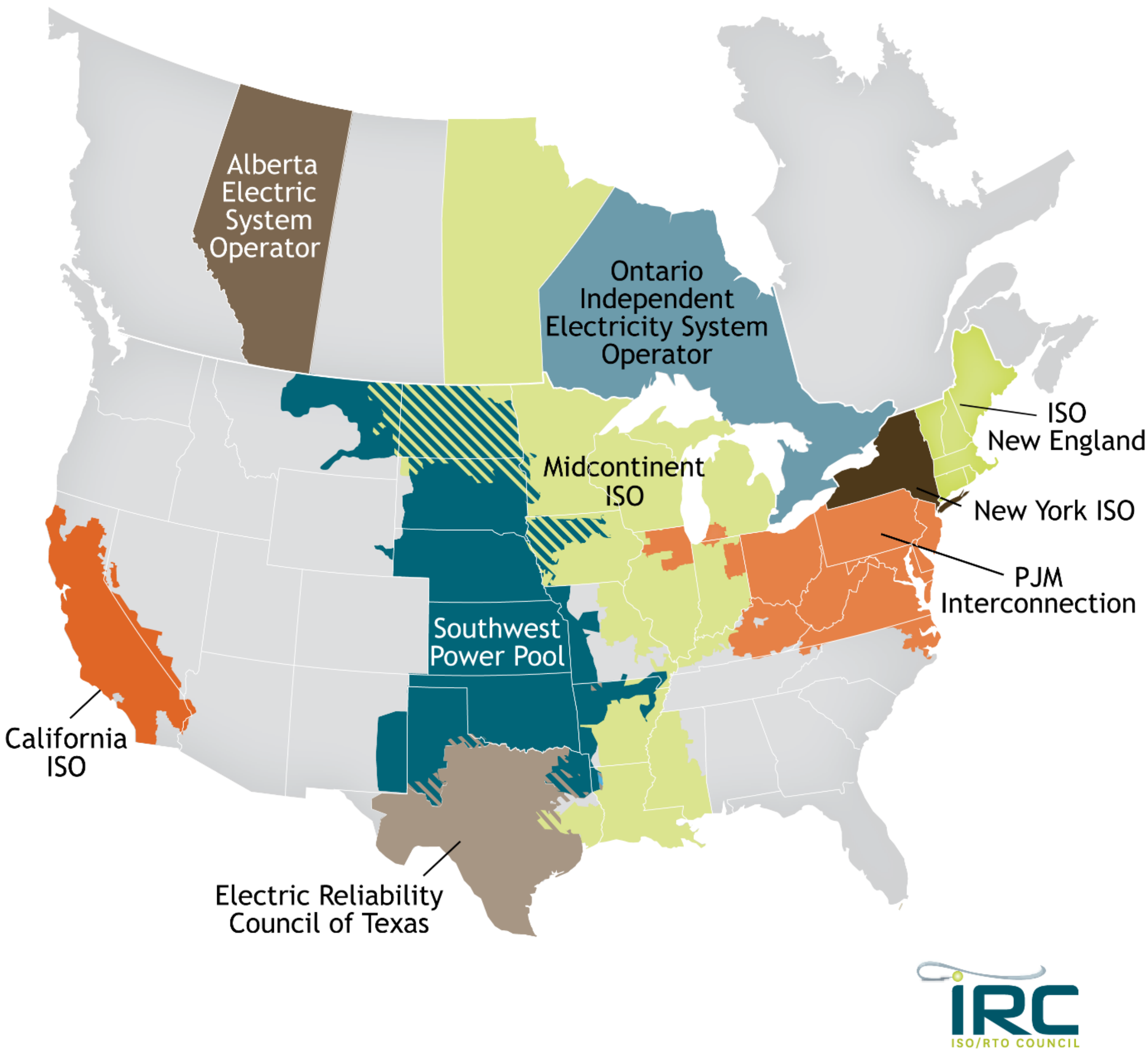
The Integrated Marketplace is a full day-ahead market with transmission congestion rights, virtual trading, a reliability unit commitment (RUC) process, a real-time balancing market (RTBM), and a price-based operating reserves market. SPP simultaneously put into operation a single balancing authority as part of the implementation of the Integrated Marketplace. The primary benefit of introducing a day-ahead market is 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 the Midcontinent ISO (MISO) to the east, the Electric Reliability Council of Texas (ERCOT) to the south, and the Western Electricity Coordinating Council (WECC) to the west. Figure 2–1 shows the operating regions of the nine ISO/RTO markets in the United States and Canada. The SPP market also has connections with other non-ISO/RTO areas such as Saskatchewan Power Corporation, Associated Electric Cooperative, and Southwestern

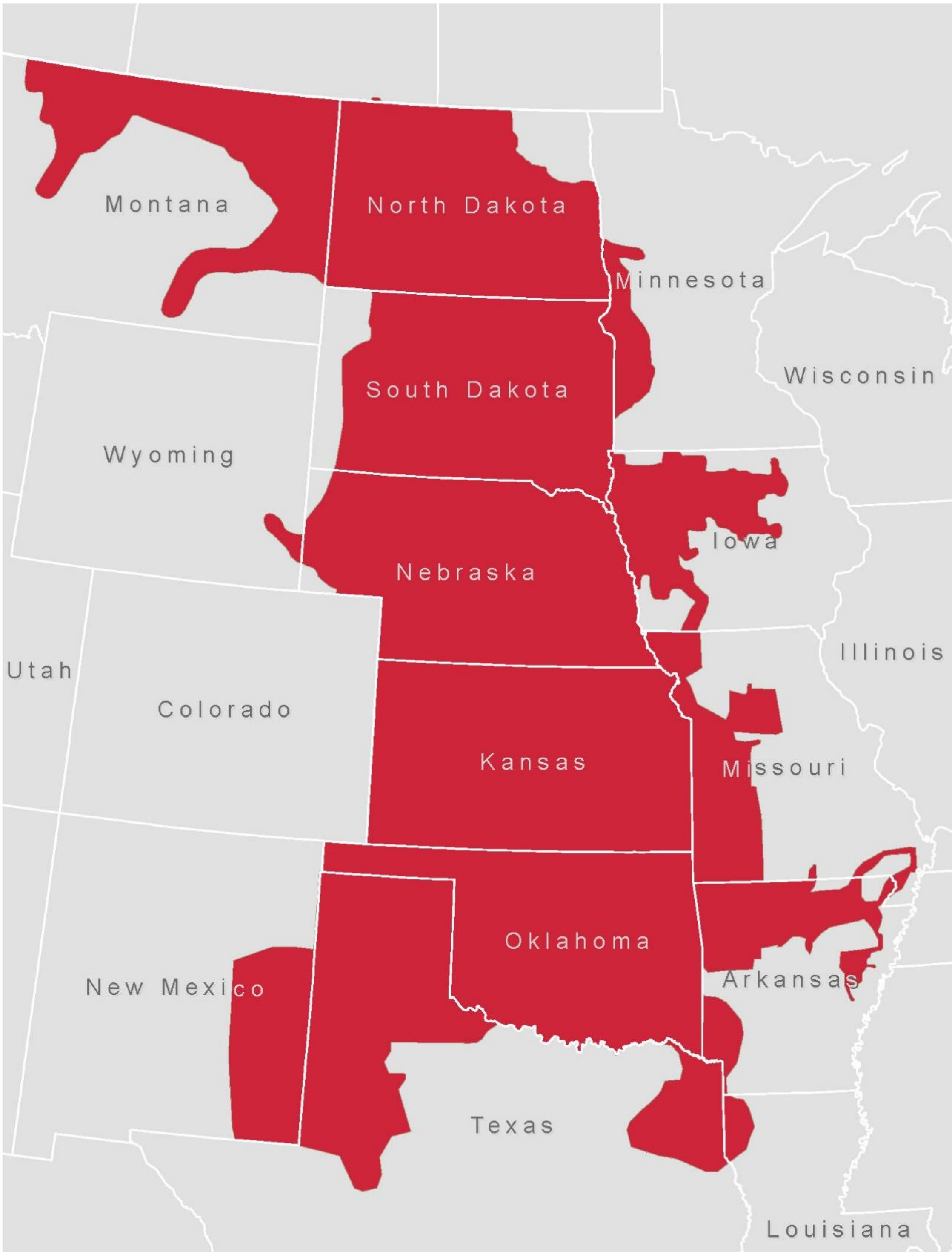
Power Administration.[2] Figure 2–2 shows a more detailed view of the Southwest Power Pool footprint.

Figure 2–1 ISO/RTO operating regions



[2] 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 2–2 SPP market footprint



2.1.2 SPP MARKET PARTICIPANTS

At the end of 2016, 182 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—3 shows the distribution of the number of resource owners registered to participate in the Integrated Marketplace. The number of independent power producers is high since most wind producers are included in this category. Market participants referred to as agents represent several individual resource owners that would individually be classified in different types, such as municipal utilities, electric cooperatives, and state agencies.

Figure 2—4 shows generation capacity owned by market participant type. As can be seen from this chart, even though investor-owned utilities represent only a small percent of the number of participants in the market at 12 percent, they hold the majority of the SPP generation capacity at 56 percent. This is in contrast to the independent power producer's category, which has a large number of participants representing only a small portion (11 percent) of total capacity. Independent power producers' total capacity increased from 8,345 MW in 2015 to 9,268 MW in 2016, an increase of 11 percent, mostly wind.

Figure 2–3 Market participants by type

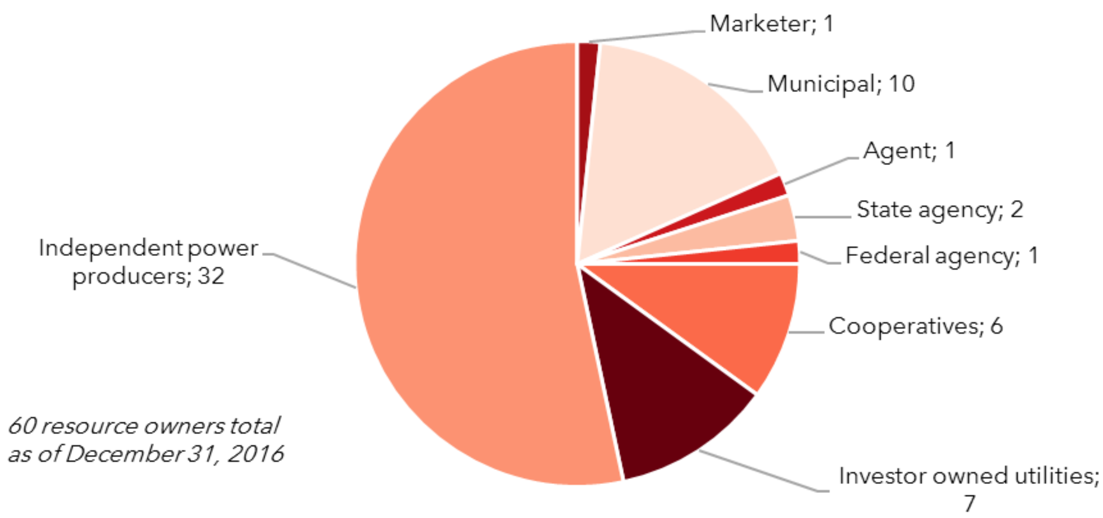
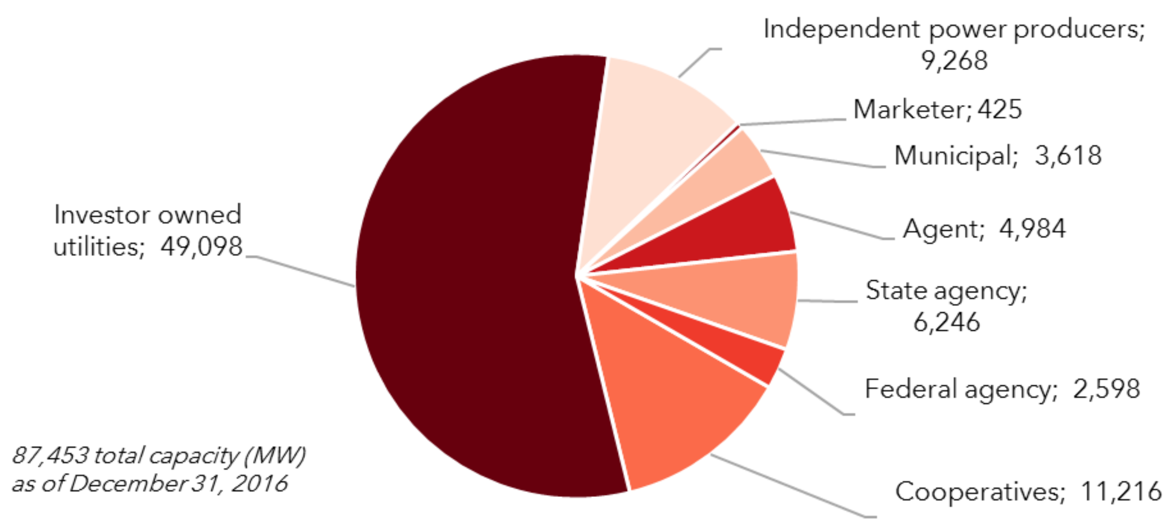


Figure 2–4 Capacity by market participant type



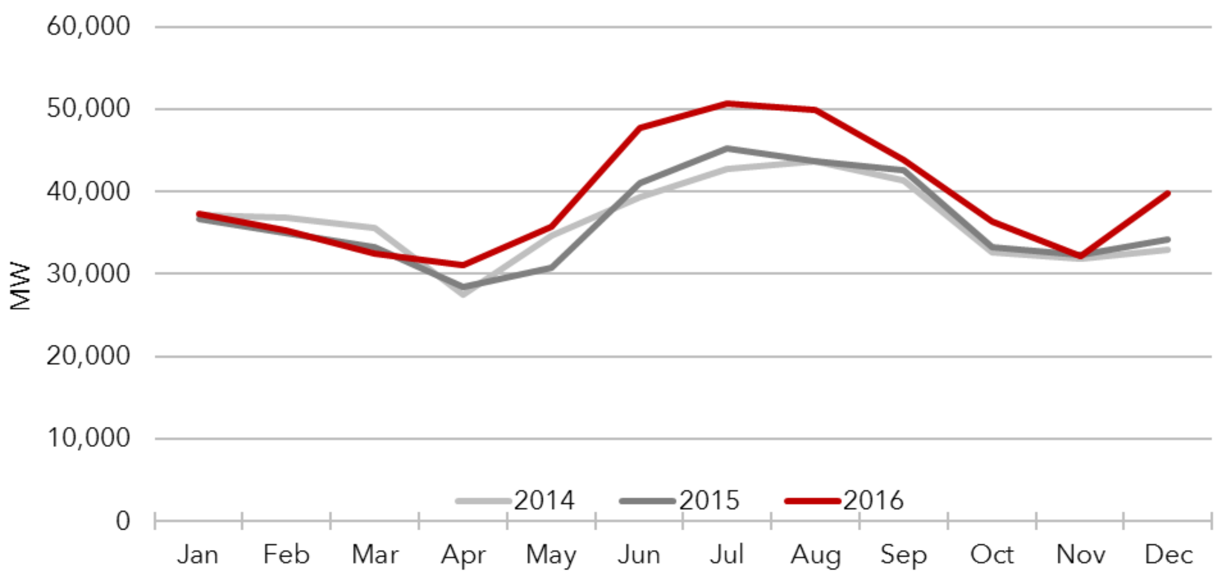
2.2 ELECTRICITY DEMAND

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 dispatch across all load areas that occurred during a particular market interval. The peak experienced during a particular year or season is affected by events such as unusually hot or cold weather, in addition to daily and seasonal load patterns.

The SPP system coincident peak demand in 2016 was 50,622[3] MW, which occurred on July 21 at 5:00 PM. This is higher than the 2015 system peak of 45,279 MW and about five percent higher than the all-time system peak of 47,989 MW in 2011. Figure 2–5 shows a month-by-month comparison of peak-day demand for the last three years. Summer monthly peaks for 2016 were higher than any of the previous years due to a warmer than normal summer, as well as an approximate 10 percent increase in load as a result of the SPP market expansion in October 2015 into the Dakotas and adjacent states.

Figure 2–5 Monthly peak energy demand



[3] SPP 2016 Annual Report

2.2.2 MARKET PARTICIPANT LOAD

In 2016, load continued to participate in the day-ahead market at high levels. Figure 2–6 shows the average monthly participation rates for the load assets on an aggregate level to be between 98 and 101 percent of the actual real-time load.

Figure 2–6 Cleared demand bids in day-ahead market

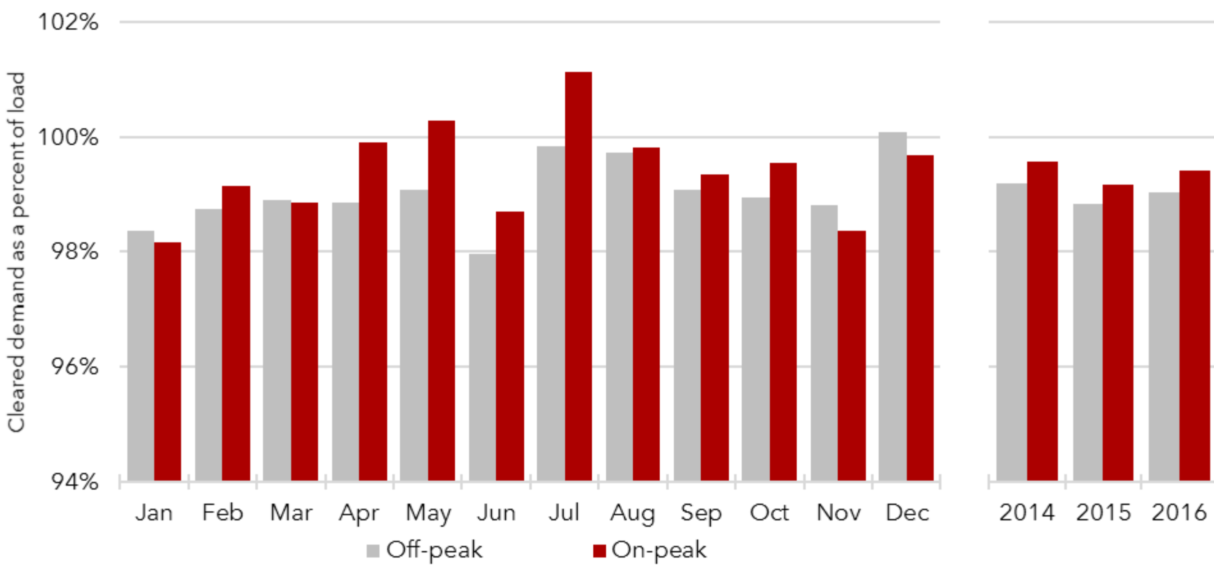


Figure 2–7 depicts 2016 total energy consumption, market participants' annual loads, and the percent of energy consumption attributable to each market participant. The largest four participants account for just under 50 percent of the total system load, which is understandable since SPP's market is primarily composed of vertically integrated investor-owned utilities, which tend to be quite large.

Figure 2–7 Market participant energy usage

Market Participant	2014		2015		2016	
	Energy consumed (GWh)	Percent of system	Energy consumed (GWh)	Percent of system	Energy consumed (GWh)	Percent of system
American Electric Power	43,046	19.0%	43,078	18.9%	42,746	17.2%
Oklahoma Gas and Electric	29,387	13.0%	28,433	12.5%	28,078	11.3%
Southwestern Public Service Company	25,898	11.4%	25,590	11.2%	25,658	10.3%
Westar Energy	24,238	10.7%	23,544	10.3%	23,885	9.6%
Basin Electric Power Cooperative *	751	0.3%	5,147	2.3%	17,859	7.2%
Kansas City Power and Light, Co	15,630	6.9%	15,303	6.7%	15,528	6.3%
The Energy Authority, NPPD	13,339	5.9%	12,943	5.7%	13,248	5.3%
Omaha Public Power District	11,208	5.0%	10,854	4.8%	11,168	4.5%
Western Farmers Electric Cooperative	9,106	4.0%	9,041	4.0%	8,448	3.4%
Kansas City Power and Light, GMOC	8,607	3.8%	8,339	3.7%	8,423	3.4%
Grand River Dam Authority	5,413	2.4%	5,616	2.5%	5,957	2.4%
Empire District Electric Co.	5,274	2.3%	5,156	2.3%	5,144	2.1%
Golden Spread Electric Cooperative Inc.	5,562	2.5%	4,840	2.1%	5,132	2.1%
Sunflower Electric Power Corporation	4,916	2.2%	4,646	2.0%	4,732	1.9%
Western Area Power Administration, Upper Great Plains #			1,128	0.5%	4,477	1.8%
Arkansas Electric Cooperative Corporation	3,005	1.3%	3,172	1.4%	3,708	1.5%
Lincoln Electric System Marketing	3,450	1.5%	3,434	1.5%	3,515	1.4%
The Energy Authority, CU	3,278	1.4%	3,270	1.4%	3,332	1.3%
Oklahoma Municipal Power Authority	2,818	1.2%	2,797	1.2%	2,857	1.1%
Kansas City Board of Public Utilities	2,368	1.0%	2,392	1.0%	2,427	1.0%
Midwest Energy Inc.	1,748	0.8%	1,719	0.8%	1,710	0.7%
Northwestern Energy #			394	0.2%	1,651	0.7%
Kansas Municipal Energy Agency	1,373	0.6%	1,437	0.6%	1,480	0.6%
Tenaska Power Service Company	1,216	0.5%	1,212	0.5%	1,363	0.5%
Missouri River Energy Services #			304	0.1%	1,260	0.5%
City of Independence	1,026	0.5%	1,017	0.4%	1,065	0.4%
Municipal Energy Agency of Nebraska	981	0.4%	999	0.4%	1,015	0.4%
Kansas Power Pool	953	0.4%	857	0.4%	860	0.3%
City of Chanute	493	0.2%	489	0.2%	482	0.2%
Missouri Joint Municipal Electrical Utility Commission	825	0.4%	448	0.2%	450	0.2%
City of Fremont	360	0.2%	435	0.2%	441	0.2%
MidAmerican Energy Company #			74	0.0%	284	0.1%
Otter Tail Power Company ^					41	0.0%
Harlan Municipal Utilities #			4	0.0%	19	0.0%
NSP Energy #			1	0.0%	4	0.0%
System total	**226,271**		**228,112**		**248,884**	

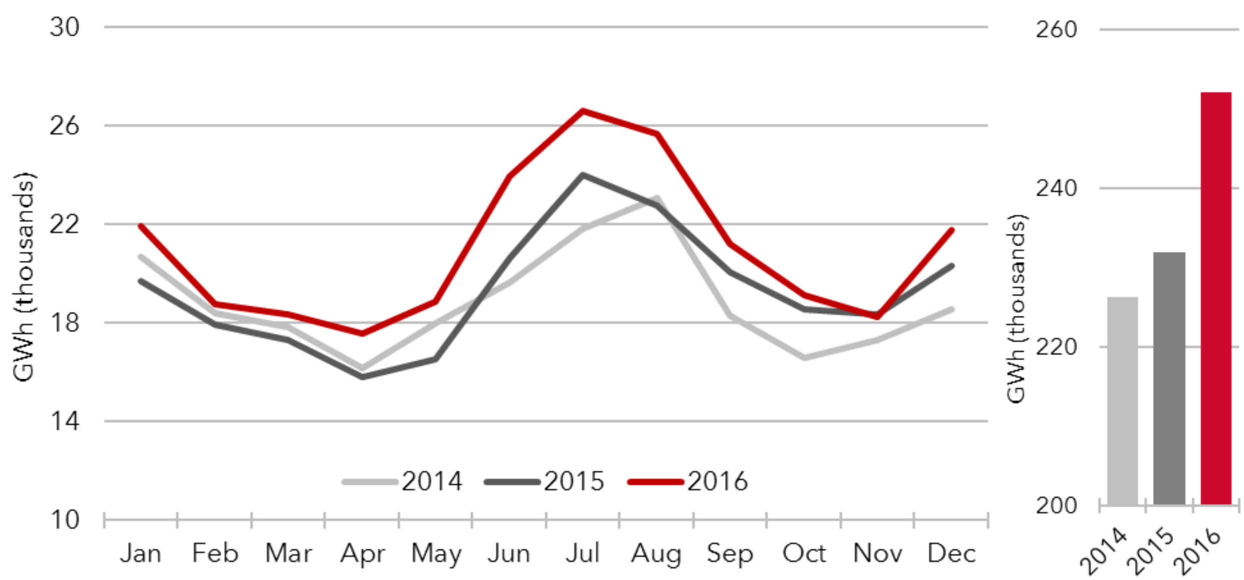
Joined SPP on October 1, 2015
* Expanded footprint in SPP on October 1, 2015
^ Load added to the footprint on January 1, 2016

2.2.3 SPP SYSTEM ENERGY CONSUMPTION

Figure 2–8 shows the monthly system energy consumption in thousands of gigawatt-hours. Total SPP system annual energy consumption in 2016 was 8.7 percent higher than 2015 with 248,000 GWh in 2016, compared to 228,000 GWh in 2015. However, if the Integrated

System load is removed from both year's numbers, the increase is only about 2.3 percent. This increase appears to be driven by higher than normal summer temperatures.

Figure 2–8 System energy consumption

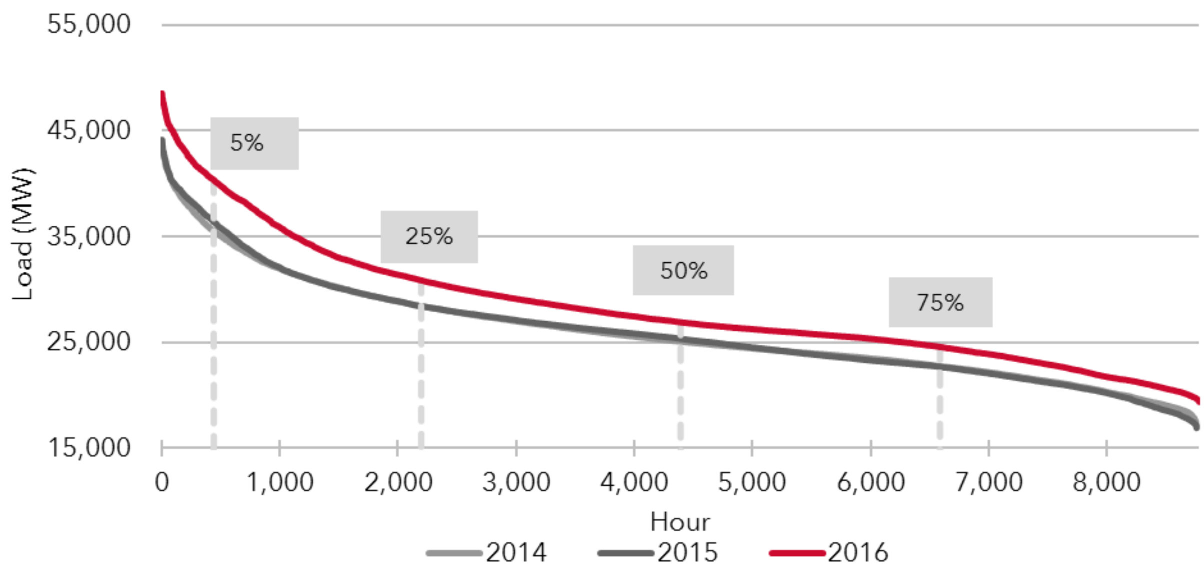


2.2.4 LOAD DURATION CURVE

Figure 2–9 depicts load duration curves from 2014 to 2016. These load duration curves display hourly loads from the highest to the lowest for each year.

In 2016, the maximum hourly average load was 48,547 MW and the minimum was 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 near identical load pattern over the last three years at load levels below the 25 percent reference level. The largest notable difference between loads during these three years occurred at load levels above the 25 percent reference level. This is due to a different weather pattern during the summer peak periods discussed in the next section, as reflected in the relative upward tilt of the load duration curve. Overall, load in 2016 was about eight percent higher than the previous three years reflecting upward shift in the curve. Most of this overall increase can be attributed to the addition of the Integrated System in October 2015, as stated in previous sections.

Figure 2–9 Load duration curve



2.2.5 HEATING AND COOLING DEGREE DAYS

Based on analysis of temperature impact on demand in the SPP footprint from 2011 through 2016, the MMU estimates that 21 percent of daily demand in the footprint is explained by variations in temperature. This explains why 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[4] were used to calculate system daily average temperatures[5]. In this

[4] 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.
[5] Daily average temperature is calculated as the average of the daily lowest and highest temperatures. The source of the temperature is the National Oceanic and Atmospheric Administration (NOAA).

report, the base temperature separating heating and cooling periods is 65 degrees Fahrenheit. If the average temperature of a day is 75 degrees Fahrenheit, there would be 10 (=75-65) cooling degree days. If a day's average temperature is 50 degrees Fahrenheit, there would be 15 (=65-50) heating degree days. Using statistical tools, the estimated load impact of a single cooling degree days was determined to be 825 MWh compared to 513 MWh per heating degree days. As expected, 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.

There was a slightly higher level of cooling degree days in 2016 compared to the prior years as illustrated in Figure 2–10 and can be seen by the higher values in the 2016 months. The impact of this weather pattern is reflected in total annual load as discussed above and system reserve margin that is discussed in the next section.

Figure 2–10 Heating and cooling degree days

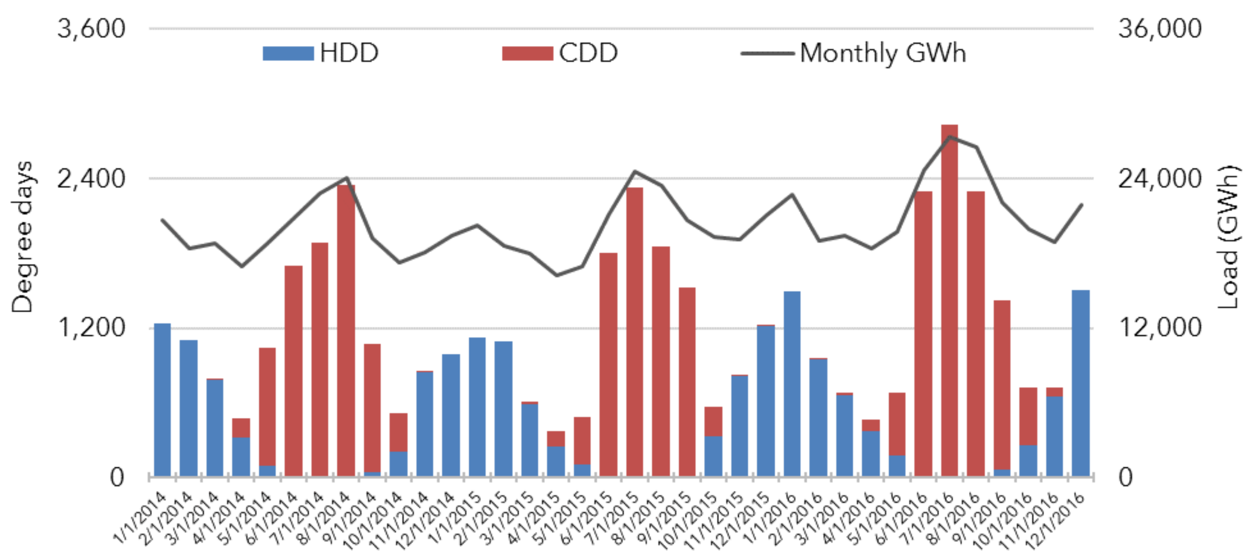
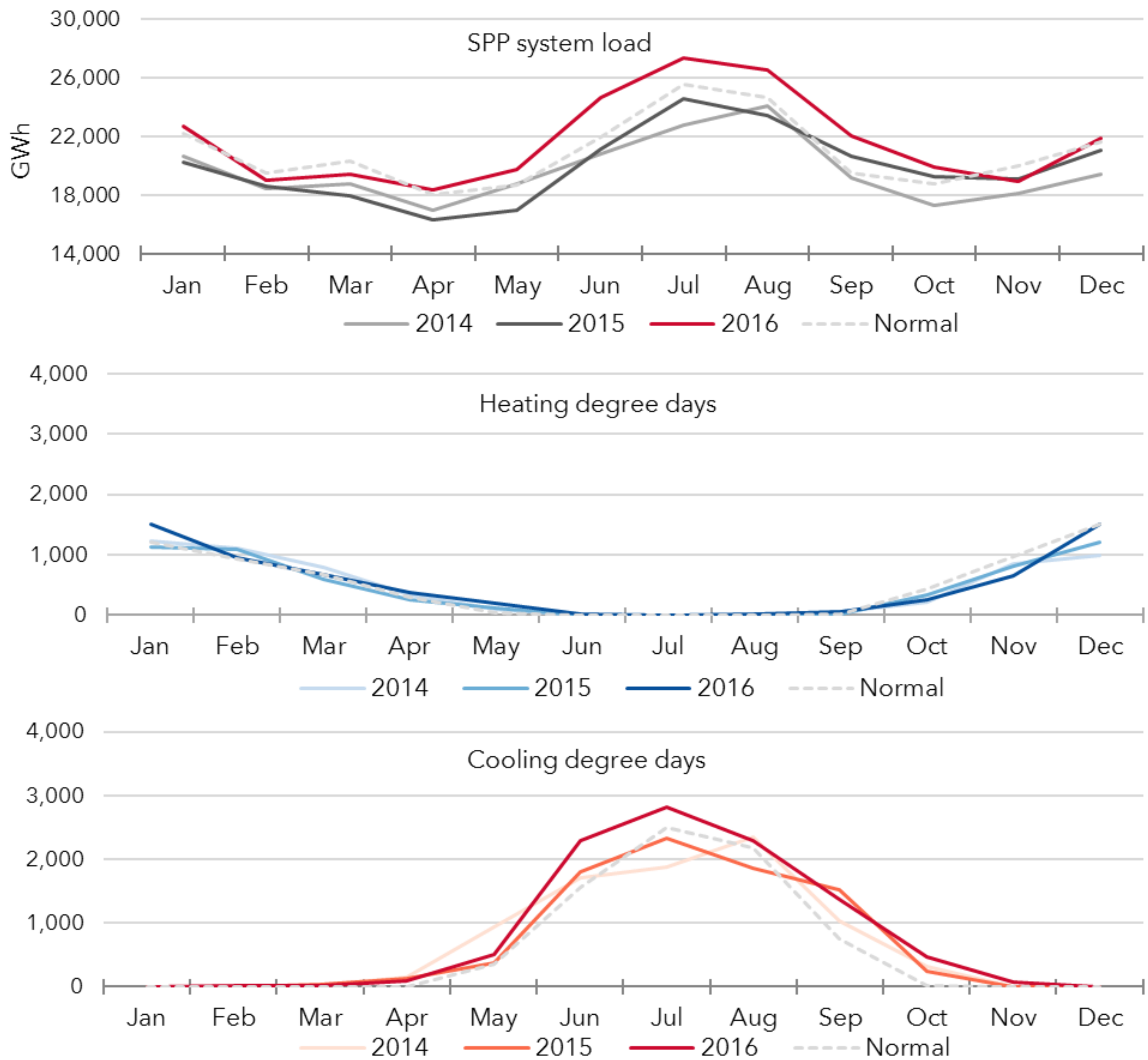


Figure 2–11 shows the numbers for heating degree days, cooling degree days, and load levels from 2014 through 2016 compared to a normal year. The definition of normal temperature is the average temperature for the last 30 years. Normal 2016 load was derived from a regression analysis of actual footprint heating degree days, cooling degree days, weekends, and holidays, substituting footprint normal temperatures.

Figure 2–11 Degree days and loads compared with a normal year



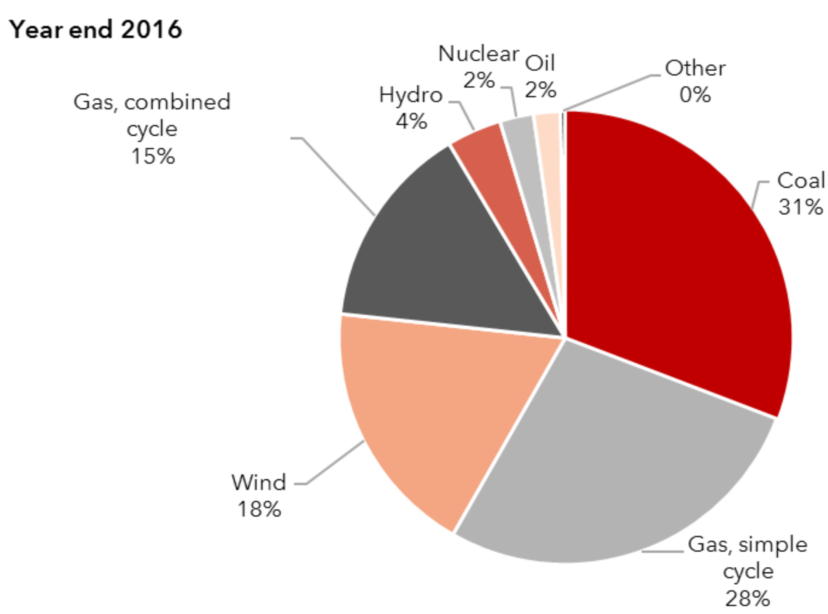
2.3 INSTALLED CAPACITY AND GENERATION

Figure 2–12 depicts the Integrated Marketplace installed generating capacity for the SPP consolidated balancing authority at the end of the year. Total generating capacity in the SPP Integrated Marketplace was 87,453 MW by the end of 2016, representing an increase of three percent over 2015.[6] Natural gas-fired installed generation capacity still represents the largest share of the SPP market at 43 percent (gas simple cycle 28 percent, gas combined cycle 15 percent), with coal being the second largest type at 31 percent. Wind continues to see an increase as the result of new construction, with a 2016 market share of 18 percent.

Figure 2–12 Generation capacity by technology type

Fuel type	2014	2015	2016	Percent as of year-end 2016
Coal	26,486	28,821	26,939	31%
Gas, simple cycle	22,694	23,910	24,024	28%
Wind	8,583	12,397	16,114	18%
Gas, combined cycle	12,322	12,025	12,870	15%
Hydro	832	3,430	3,428	4%
Nuclear	2,569	2,629	2,107	2%
Oil	1,527	1,608	1,684	2%
Other	155	124	289	0%
Total	75,167	84,943	87,453	

Note: Capacity is nameplate rating at year-end.

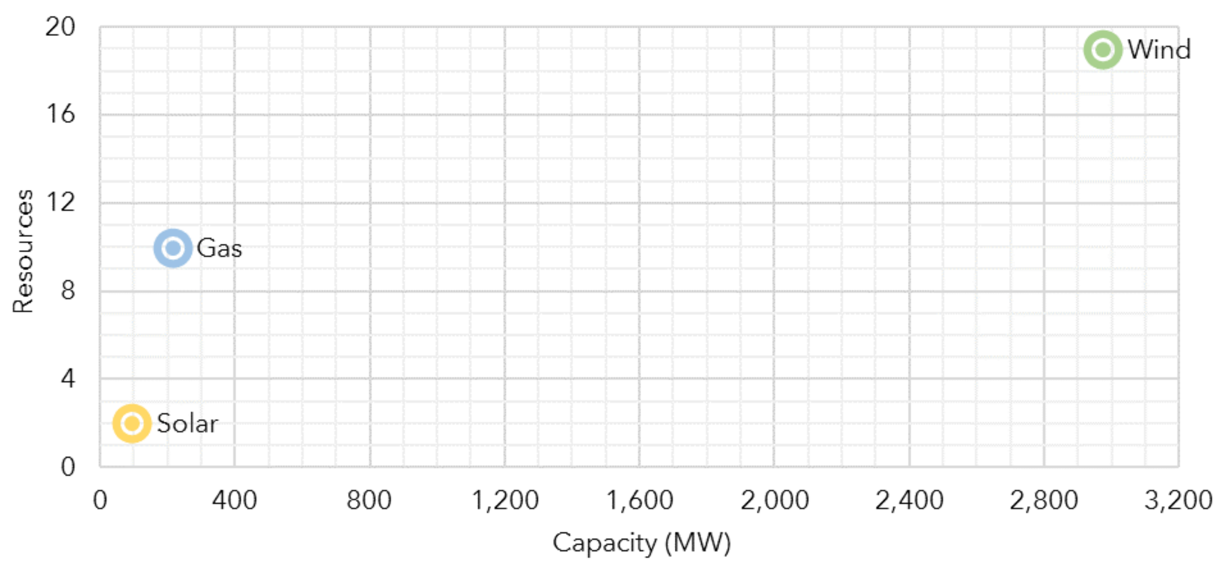


[6] The change in total generation capacity from year to year includes additions, retirements, and nameplate rating changes that occur during the year.

2.3.1 CAPACITY ADDITIONS AND RETIREMENTS

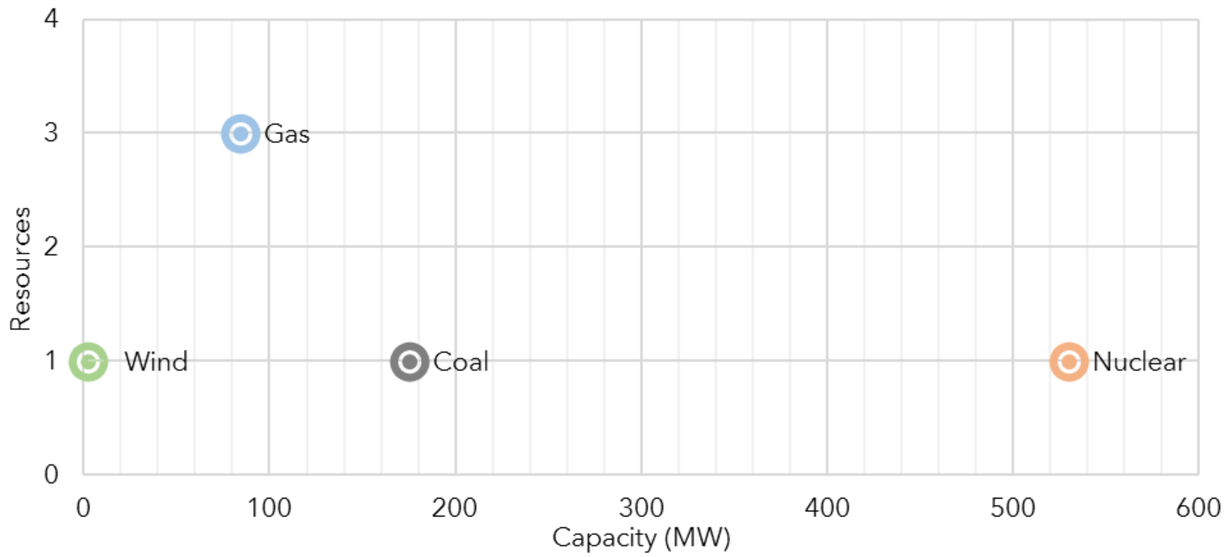
In 2016, about 3,890 MW of new generation capacity was added to the SPP market. This is much lower than the 11,345 MW of new capacity added in 2015, which was mostly from the entrance of the Integrated System. Most of the new capacity in 2016 was wind at 78 percent, followed by natural gas at 20 percent and solar at two percent. Figure 2–13 shows the capacity by the technology and the number of resources added. All of this new market capacity was new construction.

Figure 2–13 Capacity additions



In 2016, the SPP market also experienced generation retirements amounting to 791 MW in installed capacity, of which 67 percent was nuclear, 22 percent coal, 11 percent gas simple cycle and less than one percent wind. The nuclear, coal, and wind retirements were all one resource each and the gas retirements represented three resources. Figure 2–14 shows capacity retirements in 2016 by the fuel type. The nuclear facility that was retired was commissioned in the early 1970s and the coal plant in the late 1950s.

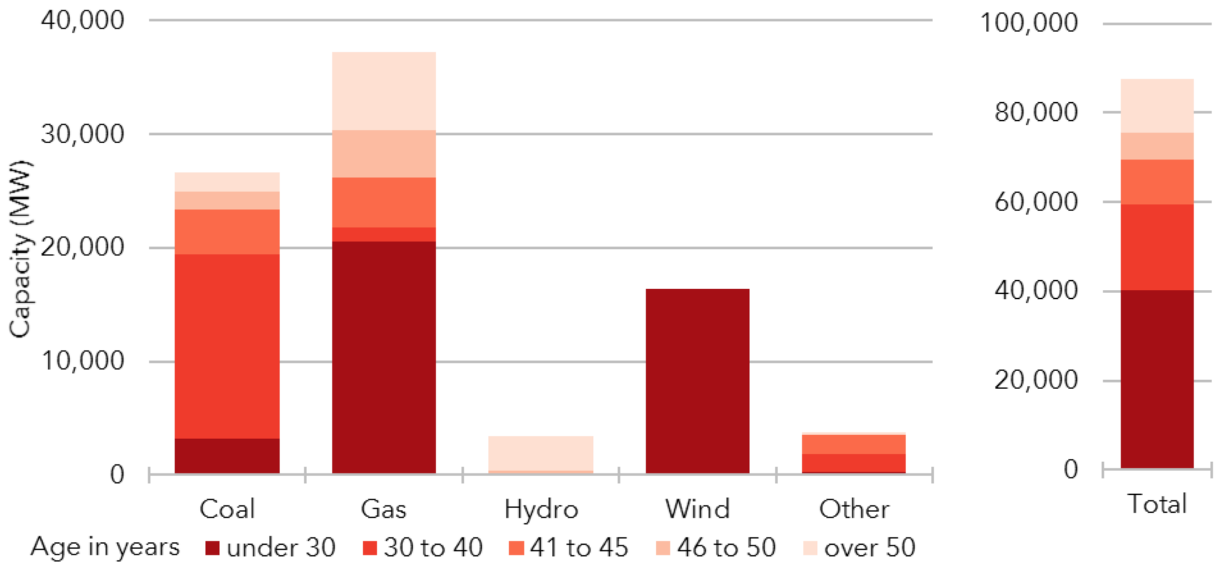
Figure 2–14 Capacity retirements



2.3.2 CAPACITY BY AGE

Figure 2–15 illustrates that certain segments of the SPP generation fleet are aging. Nearly 55 percent of SPP's fleet is more than 30 years old. In particular, nearly 90 percent of coal capacity and just over 50 percent of gas capacity are older than 30 years. The national average retirement age of coal-fired generation is 54 years. Outside of 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 generation.

Figure 2–15 Capacity by age of resource



2.3.3 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 2–16 depicts annual generation percentages in the SPP real-time market by technology type for the years 2007 through 2016. 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 only six percent in 2016. Gas combined cycle generation has remained relatively stable at around 13 percent of total generation with a slight increase to 16 percent in 2015 and 2016 because of low gas prices. Wind generation share continues to increase from nearly three percent in 2007 to about 18 percent in 2016. Coal generation share decreased to 48 percent of total generation 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 increasing wind generation and low gas prices has prompted a decline to 55 percent in 2015 and under 50 percent in 2016.

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, 2015, and 2016 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. The other general trend appears to be the increase in wind generation pushing simple cycle gas generation up the supply curve, making it less competitive.

Figure 2–16 Generation by technology type, real-time, annual

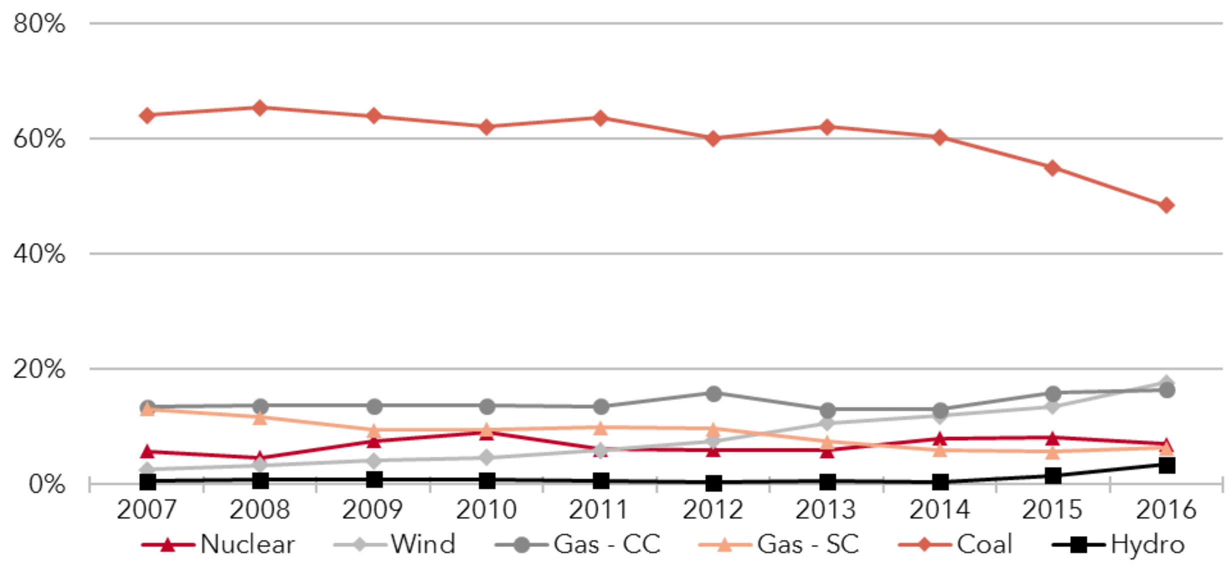
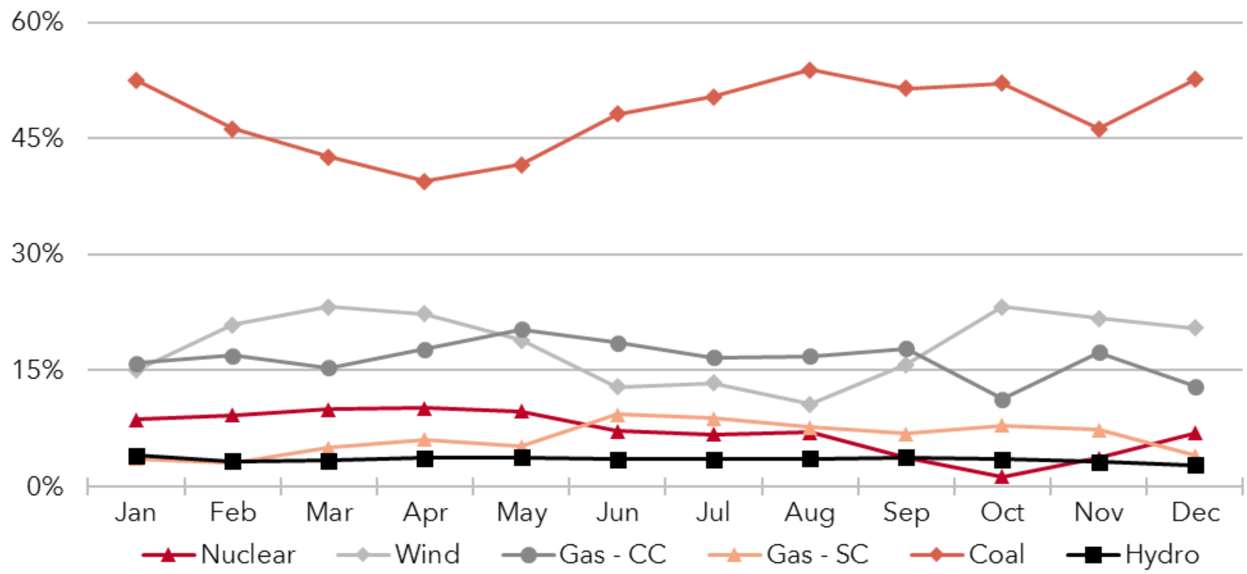


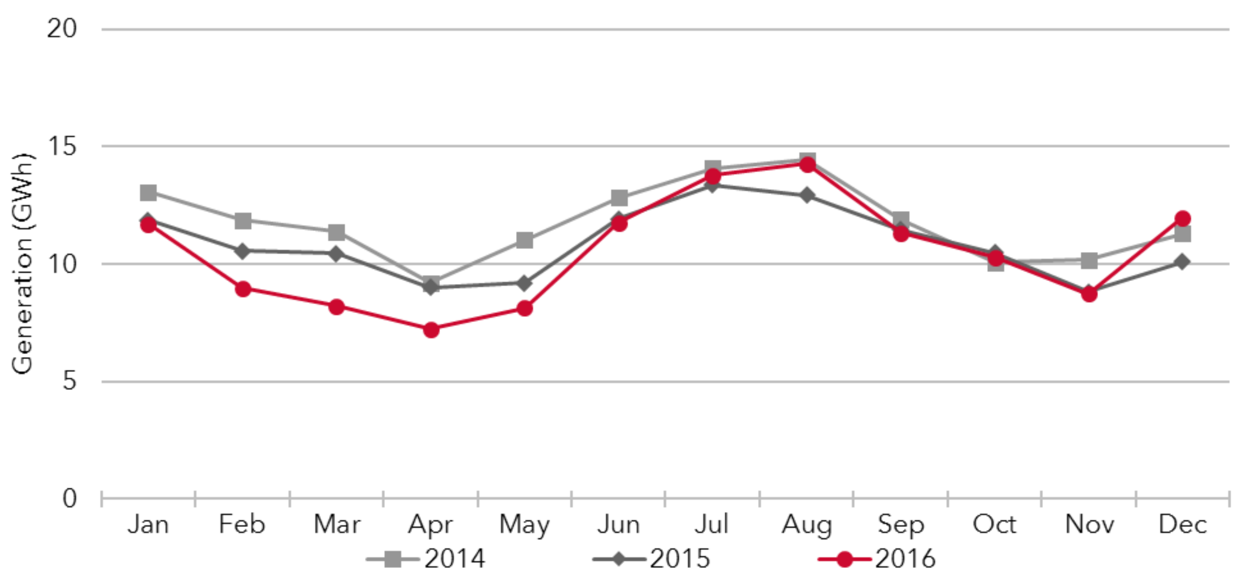
Figure 2–17 depicts the 2016 monthly fluctuation in generation by technology type. Wind generation fluctuates dramatically from 10 percent in the summer months to 20 percent in the fall and winter. The increase in wind generation accompanied with low natural gas prices resulted in coal-fired generation market share falling to below 40 percent in April 2016.

Figure 2–17 Generation by technology type, real-time, monthly



Only in December did coal generation in 2016 exceed the levels in 2014 and 2015, as shown in Figure 2–18. The gas cost increased in December to $3.43/MMBtu, while January through November averaged around $2.22/MMBtu, a roughly 50 percent increase for December. A secondary driver is the ever increasing level of wind generation. Downward pressure on coal generation should lessen with an increase in gas prices offsetting the expected increase in wind generation.

Figure 2–18 Generation by coal resources

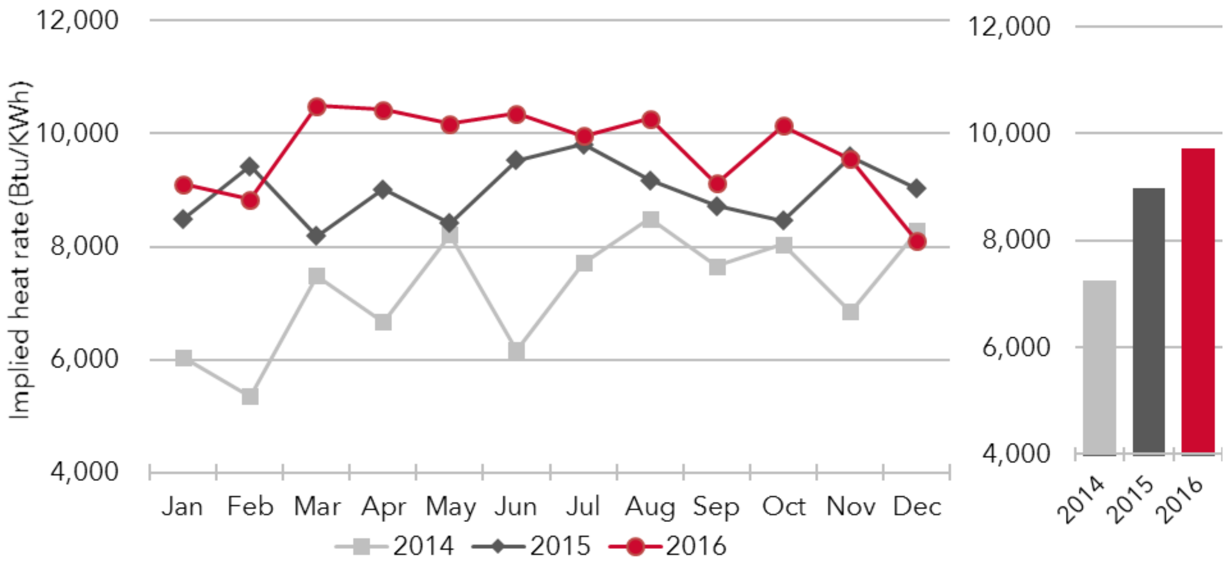


One method commonly used to assess price trends and relative efficiency in electricity markets originating from non-fuel costs is the implied heat rate. The implied heat rate is calculated by dividing the electricity price, net of a representative value for variable operations and maintenance (VOM) costs, by the fuel (gas) price.[7] 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 LMP 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—19 shows the monthly implied heat rate for 2014 to 2016, along with an annual average for those years. The chart shows a steady increase from 2014 to 2016. Typically, the more electric prices are set by coal generation, the lower the implied heat rate will be. This effect is very strong when gas and coal price differences are large, and diminishes as the two prices approach parity. With the low gas prices reaching parity with the price of coal during most of 2016, a much higher implied heat rate is observed. For systems like SPP where coal generation sets electric price 41 percent of the time, as it did in 2016, this cross-fuel impact on implied heat rate can be significant.

[7] 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 to the SPP market.

Figure 2–19 Implied heat rate



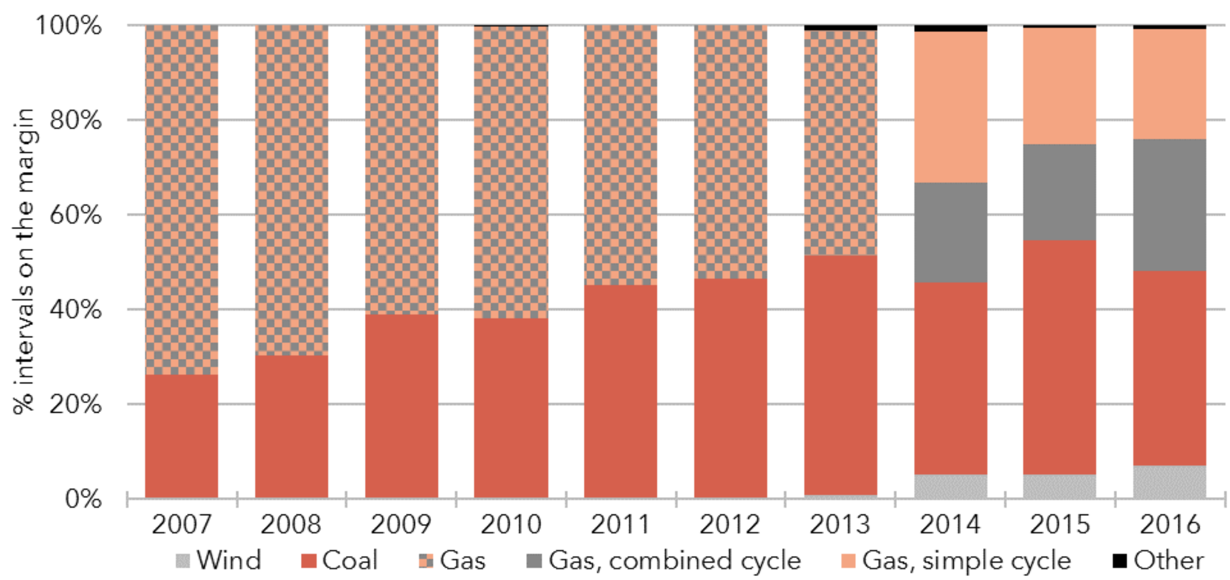
In 2016, coal generation represented about 48 percent of generation, whereas total (simple cycle and combined cycle) gas-fired generation represented only about 23 percent of total generation in the SPP market. Retirement of older coal generation, environmental limits, along with competition from wind and natural gas technologies are some of the factors that will continue to put pressure on coal generation. Wind generation capacity is expected to continue to increase in the years ahead.

2.3.4 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 2–20 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 2–20 clearly 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 51 percent in 2016. There is a corresponding shift in coal generation on the margin from about 25 percent in 2007 and increasing to about 41 percent in 2016. This change is driven by market efficiency improvements as reflected in the decline in simple cycle natural gas generation as shown in Figure 2–16. 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 the generation on the margin metric.

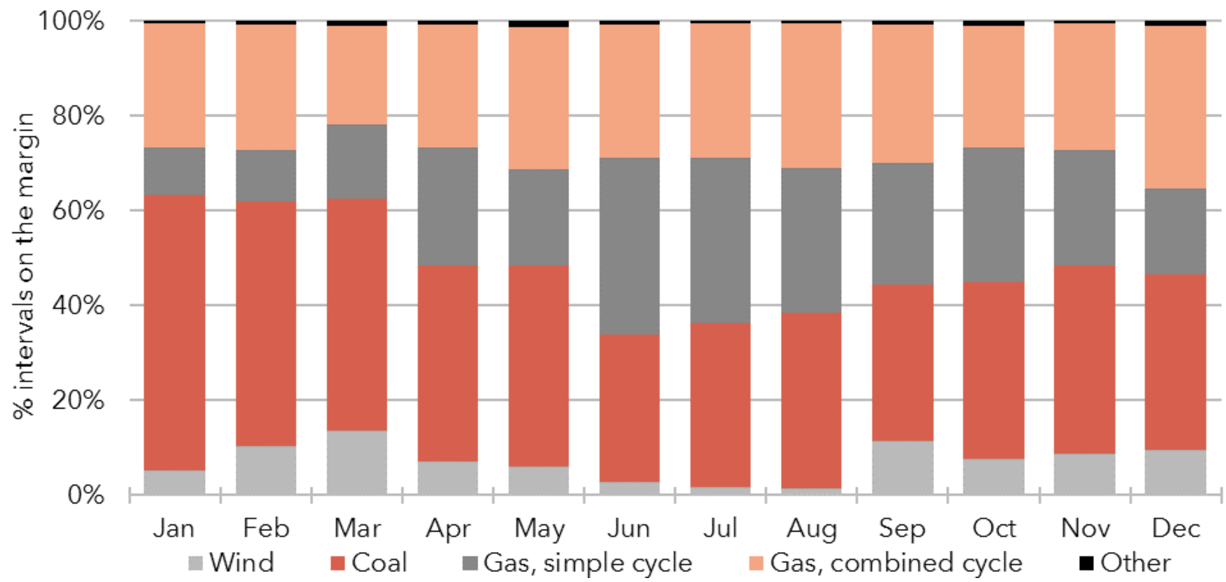
Figure 2–20 Generation on the margin, real-time, annual



It is worth noting the increase in wind technology being on the margin—from five percent in 2015 to just over seven percent in 2016. With the growing amount of dispatchable wind generation and an overall quantity of 18 percent of total capacity, wind generation is the marginal technology for a significant amount of time. At the end of 2016, just over 60 percent of wind capacity was dispatchable, compared to 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 2.5.4 below.

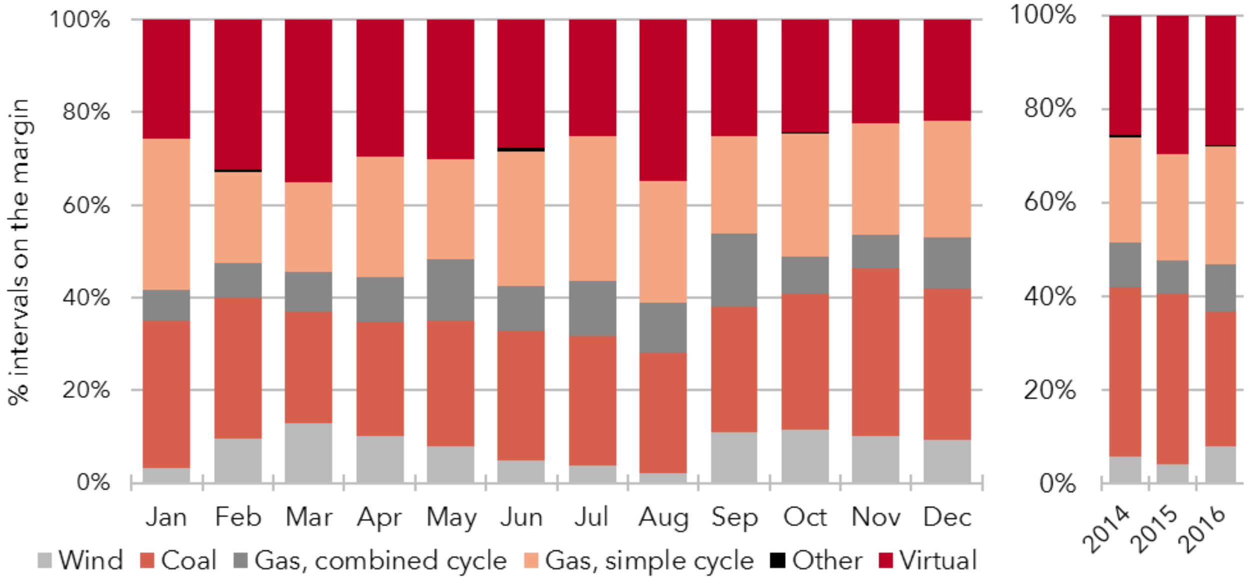
Figure 2–21 shows monthly values for real-time generation on the margin for 2016. Intervals with coal generation on the margin are lower in the summer months when demand is high, resulting in more coal-fired units running as base load units with less cycling. The increased wind generation is also directly affecting prices to some extent in every month of the year. The higher values in the spring and fall are as expected given that these periods are the windiest time of the year, along with the lowest demand periods in the SPP footprint.

Figure 2–21 Generation on the margin, real-time, monthly



Day-ahead generation on the margin, shown in Figure 2–22, is different from real-time in that the day-ahead market includes virtual transactions, whereas the real-time market is required to adjust to unforeseeable market conditions such as unexpected plant and transmission outages. Wind generation on the margin is comparable in the day-ahead and real-time markets with a similar annual cyclical pattern. Both coal and gas generation on the margin in the day-ahead market is noticeably lower than in the real-time market. The most significant difference is the displacement of natural gas-fired generation by virtual offers in the day-ahead market. Virtual energy offers accounted for approximately 28 percent of the marginal offers in the day-ahead market in 2016, compared to 26 percent in 2014 and 30 percent in 2015. While marginal virtual offers occur at all types of settlement locations, 80 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 occurs at wind locations because wind generation resources are frequently under scheduled in the day-ahead due to the fact that they are not required to offer in the day-ahead market.

Figure 2–22 Generation on the margin, day-ahead



2.3.5 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. Types of engineering studies include:

- Feasibility
- Preliminary Interconnection System Impact Study (PISIS)
- Definitive Interconnection System Impact Study (DSIS)
- Facility (descriptions provided below)

Figure 2–23 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 2016. As can be seen in the table, wind generation capacity accounts for the vast majority of proposed generation interconnection, nearly 33,000 MW, or 87 percent, of the total. Development of wind generation in the SPP region is expected to continue and the proper integration of wind generation is fundamental to maintaining the reliability of the SPP system. Additional wind impact analysis follows in the Section 2.5. At year-end 2015, 60 MW of battery resources was in the generation interconnection queue; this has been reduced to 40 MW at year-end 2016. Subsequently, by the end of the first quarter of 2017 there are no battery resources in the generation interconnection queue.

Figure 2–23 Active generation interconnection requests

Prime mover	2014	2015	2016
Wind	18,000	21,930	32,690
Gas	2,100	2,900	1,080
Solar	600	2,200	3,770
Battery	0	60	40
Hydro	0	10	0
Total	20,700	27,100	37,580

2.3.6 RESERVE MARGIN

The SPP market-wide reserve margin is the amount of extra system capacity available after serving system peak load as a percentage of peak load. For this analysis, system capacity is the unit registration ratings. It is important to note that only five percent of the registered capacity of wind is considered as reserve capacity.[8] In 2016, SPP actual reserve margin was 43 percent, down six percent from 2015 and five percent from 2014, as shown in Figure 2–24. This decline is likely the result of above normal temperatures during the peak summer period as described above in Section 2.2.5.

The 43 percent reserve capacity still amounts to nearly four times SPP's minimum required capacity margin of 12 percent[9]. A relatively high reserve margin such as this has positive implications for both reliability and for mitigation of the potential exercise of market power within the market. However, it may also contribute to the currently observed downward pressure on market prices. A larger amount of excess capacity also has an impact of revenue adequacy, which has been a concern of many market participants.

[8] Figure 2–24 assumes only five percent of wind capacity. The five percent wind capacity factor was used in this analysis to be consistent with Integrated Transmission Planning (ITP) Year 20 Assessment methodology as approved by SPP Economic Studies Working Group on 19 January 2010.
[9] SPP Planning Criteria.

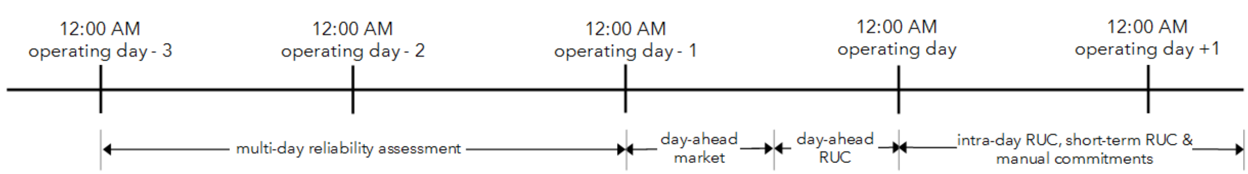
Figure 2–24 Reserve margin

Year	Capacity (MW)	Peak load (MWh)	Reserve margin
2008	49,561	36,538	36%
2009	58,223	39,622	47%
2010	61,570	45,373	36%
2011	63,367	47,989	32%
2012	64,053	47,142	36%
2013	66,668	45,256	47%
2014	67,095	45,302	48%
2015	67,251	45,279	49%
2016	72,145	50,622	43%

2.4 UNIT COMMITMENT AND DISPATCH PROCESSES

The Integrated Marketplace employs a centralized unit commitment program to determine an efficient scheduling and dispatch of generation resources to meet energy demand and the operating reserve requirements. The principal component of the commitment program is the day-ahead market, which uses a rigorous algorithm to determine 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: (1) the multi-day reliability assessment; (2) the day-ahead reliability unit commitment (DA RUC) process; (3) the intra-day reliability unit commitment (ID RUC) process; (4) the short-term intra-day reliability unit commitment (ST RUC) process, and (5) manual commitment instructions issued by the RTO. Figure 2–25 shows a timeline describing when the various commitment processes are executed.

Figure 2–25 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. The day-ahead market is executed on the day before the operating day, and the results are posted at 1400 hours. Prior to October 2016, when a scheduling change was made to better align with the gas day, these results were posted at 1600 hours. The day-ahead market treats any generators committed in the multi-day reliability assessment as "must-commit" resources. 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 resources.

The intra-day reliability unit commitment process is run throughout the operating day, with at least one execution of the intra-day reliability unit commitment occurring every four hours. A new 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 reliability unit commitment process. SPP operators also issue manual commitment instructions during the operating day to address reliability needs that are not fully reflected in the security constrained unit commitment algorithm that is used for commitment decisions in the day-ahead and reliability unit commitment processes.

2.4.1 RESOURCE STARTS

The SPP resource fleet, excluding variable energy resources, experienced 23,990 starts during 2016. This is up from the 19,798 last year. Figure 2–26 and Figure 2–27 provide a breakdown of the origins of the commitment decisions. Figure 2–26 is based on the number of resources committed. Sixty-three percent of start-up instructions were a result of the day-ahead market. As shown in the chart, each year we have observed an increase in day-ahead market starts and a decrease in self-commitment starts. It appears that resource owners are becoming more confident in the market and allowing the market to commit the resource instead of self-committing their resource. 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 substantial start-up costs may not appear economic to the day-ahead market commitment algorithm. The expectation is that the market participants will choose to self-commit the long-lead time resources, which contributes to the large number of self-commitments. The day-ahead reliability unit commitment, intra-day reliability unit commitment, short-term intra-day reliability unit commitment, and manual commitments represent 25 percent of the resource start-ups.

Figure 2–26 Start-up instructions by resource count

	2014	2015	2016
Day-ahead market	21%	49%	63%
Self-commitment	58%	21%	12%
Intra-day RUC	2%	12%	10%
Manual, regional reliability	3%	7%	7%
Short-term RUC			4%
Day-ahead RUC	15%	9%	2%
Manual, local reliability	1%	1%	2%

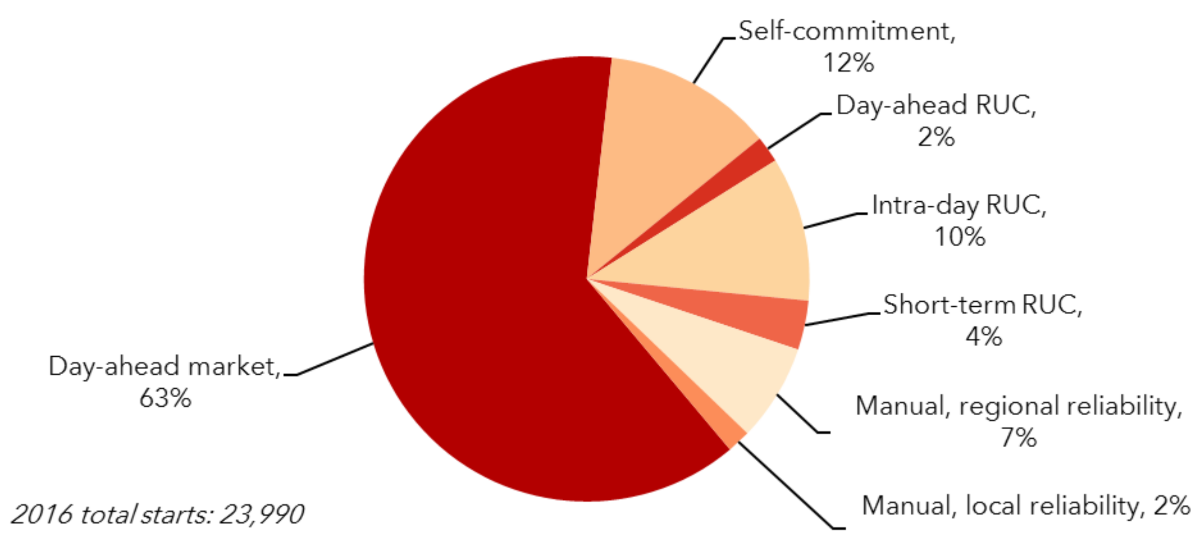
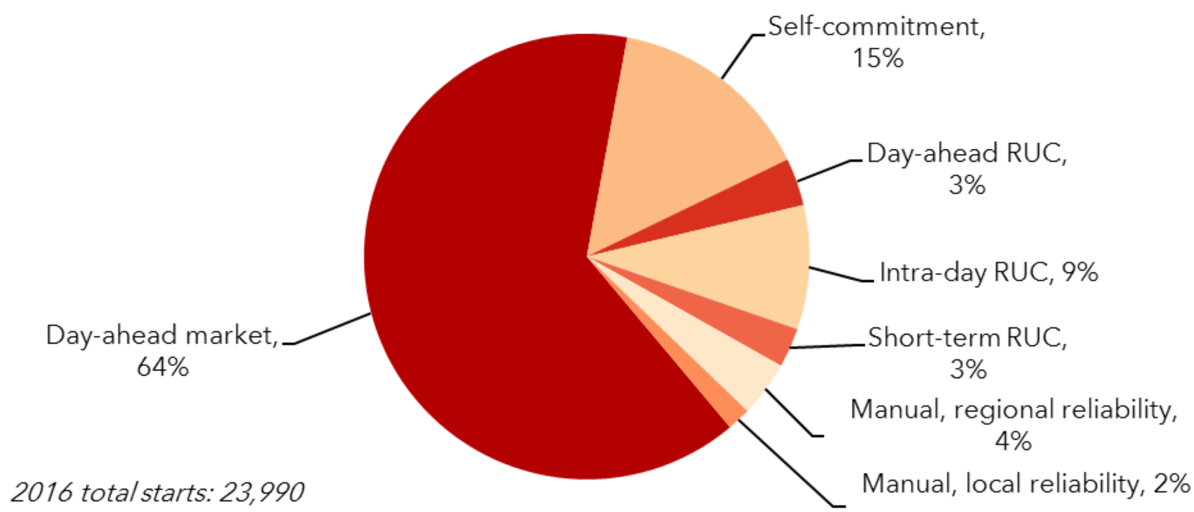


Figure 2–27 is based on capacity committed and provides a slightly different look at the data with the percentages based on capacity committed to startup. One important observation is the percentage differences between Figure 2–26 and Figure 2–27. This is the result of larger resources either self-committed 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.

Figure 2–27 Start-up instructions by resource capacity

	2014	2015	2016
Day-ahead market	7%	50%	64%
Self-commitment	74%	19%	15%
Intra-day RUC	2%	11%	9%
Manual, regional reliability	2%	7%	4%
Short-term RUC			3%
Day-ahead RUC	13%	12%	3%
Manual, local reliability	1%	2%	2%



Once within the operating day, commitment flexibility is severely constricted by resource start-up times. This is particularly noticeable with respect to the gas-fired resources. SPP issued more than 16,603 start-up instructions to gas-fired generators in 2016, up from 12,400 starts in 2015. Figure 2–28 shows that almost all start-up instructions issued to combined cycle generators are the result of the day-ahead market. Day-ahead starts for gas-fired generators with simple cycle technology account for 55 percent of their starts. This is a seven percent increase from the 48 percent incurred last year. Combustion turbines saw an increase as well, with 65 percent of the units' starts being committed in the day-ahead market in 2016, up 17 percent from the 48 percent committed the year before. This increase in starts can be attributed to an increase in energy prices, an increase in on-peak load, as well as a decrease in units running in self-commit status in the day-ahead market.

Figure 2–28 Origin of start-up instructions for gas resources

Commitment Process	Combined cycle			Simple cycle - combustion turbine			Simple cycle - steam turbine		
	2014	2015	2016	2014	2015	2016	2014	2015	2016
Day-ahead market	97%	99%	98%	54%	48%	65%	50%	36%	55%
Day-ahead RUC	1%	0%	1%	4%	15%	2%	20%	36%	18%
Intra-day RUC	1%	1%	1%	29%	21%	16%	27%	21%	21%
Short-term RUC	---	---	0%	---	---	6%	---	---	4%
Manual Instruction	0%	0%	0%	13%	16%	11%	3%	6%	3%

Alternatively, the reliability unit commitment processes make commitments to maintain reliability standards and oftentimes the reliability needs are not reflected in the real-time prices. Therefore, reliability commitment processes, more often than the day-ahead market, make commitments that are not supported by the real-time price levels. In particular, some reliability unit commitments are made to meet headroom requirements; however, headroom is not a product generators are compensated for by the market. These situations often lead to make-whole payments and put some generators at risk for not earning sufficient revenues to cover their costs going forward. The next section discusses the drivers behind the reliability commitments and thus high online resource commitments.

2.4.2 DEMAND FOR RELIABILITY

The previous section noted that 25 percent of SPP start-up instructions originated from the SPP reliability unit commitment processes: day-ahead reliability unit commitment (three percent), intra-day reliability unit commitment (nine percent), short-term reliability unit commitment (four percent), manual-regional reliability (seven percent), and manual-local reliability (two percent). 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 the bids submitted by the market participants. The bid-in load may not necessarily be a good indicator of the actual energy demand, hence the reliability unit commitment processes use a load forecast to measure the energy demand.

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. Since the reliability unit commitment processes must ensure sufficient generation is online to meet the energy demand, virtual transactions are not used in the day-ahead, intra-day, or short-term reliability unit commitment algorithms.

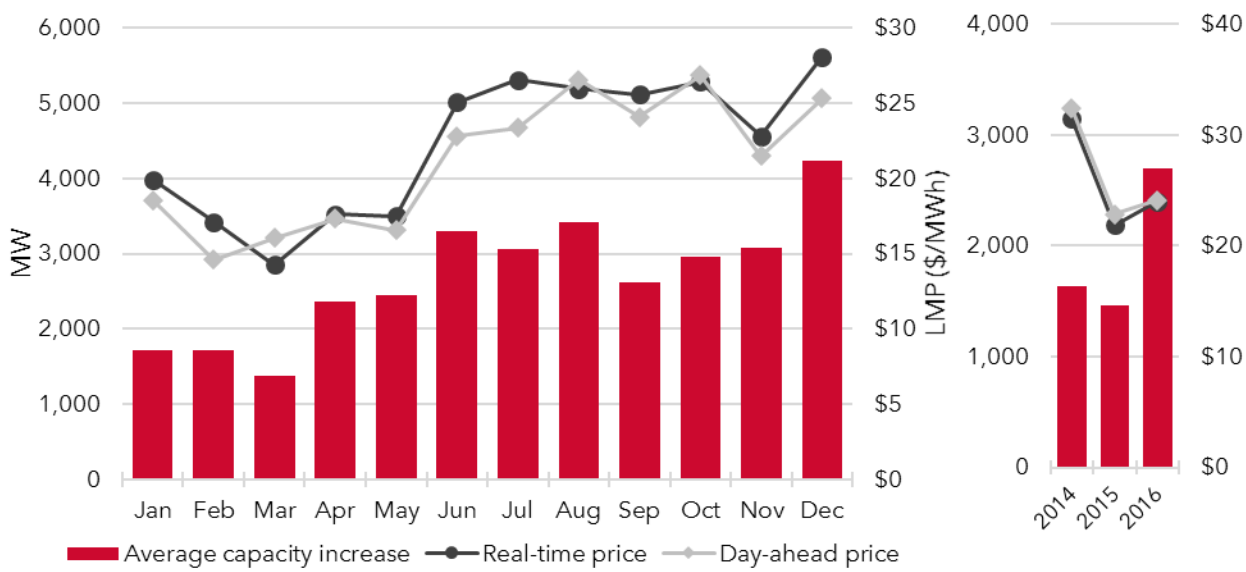
The assumptions regarding wind generation differ as well. While the market participants determine the participation levels for their wind generators in the day-ahead market through the use of supply offers, a wind forecast is used by the reliability unit commitment processes. Import and export transaction 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 market participants with wind generation assets often choose to avoid taking a day-ahead position given the uncertainty of the wind generation, and instead take real-time positions.

The resource gaps can help to explain why additional commitments occur after the day-ahead market has cleared. Figure 2—29 compares online capacity between the day-ahead market and the real-time market. The chart indicates that in 2016 there was on average more than 2,500 MW of additional capacity online during the real-time market relative to the capacity cleared in the day-ahead market.

Figure 2–29 Average hourly capacity increase from day-ahead to real-time



2.4.3 RAMP CONSTRAINTS

One well-known and much discussed issue with respect to reliability commitments is the need for ramp capability. Real-time electricity markets continuously ramp up and ramp down resources in short intervals of time. This is present in all electricity markets and is caused by increasing and decreasing load, planned and unplanned outages, changes in imports and exports, and changes in variable energy resources including wind. All of these factors exacerbate the need for ramp capability in the SPP market. The SPP market design has several products and constraints that allow for additional ramp to be available above and beyond what is normally needed to meet energy demand. These include the operating reserve products and the headroom constraint. The headroom constraint may commit additional resources to ensure there is adequate capacity to meet the instantaneous peak demand for any given hour. The headroom constraint is defined as the greater of the forecasted instantaneous peak load, or an SPP defined default value. Because the default value is used the majority of the time, the MMU does believe that headroom constraint is a major driver of the reliability commitments in excess of the resource gaps.

The issue with ramp procurement is a problem in many of the ISO/RTO markets. SPP implemented system changes in compliance with FERC requirements regarding ramp in early 2017. The MMU will be monitoring these changes and any findings will be included in future reports.

Resources committed to provide additional capacity for ramp capability, whether as a result of applying the headroom 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 online may not be fully reflected in the real-time prices, as will be discussed in Section 2.9.

Figure 2—29 above shows the average energy price for both the day-ahead and real-time markets. For 2016, the annual average day-ahead price converges closely with the real-time price, with day-ahead prices higher in some months and real-time prices higher in other months. Many factors contribute to the price differences between day-ahead and real-time prices, and it is difficult to quantify the impacts of reliability commitments on real-time prices. Nevertheless, the direction of the impact is clear: reliability commitments, along with wind exceeding the day-ahead forecast, can dampen real-time price signals, as is evidenced by 62 percent of make-whole payments made for reliability unit commitments. Several ISO/RTO markets, including SPP, are currently studying the possibility of adding a ramping product to their array of ancillary service products and the MMU supports this effort.

2.4.4 QUICK-START RESOURCES COMMITMENT

A quick-start resource is defined by SPP as a resource that can be started, synchronized, and begin injecting energy within 10 minutes of SPP notification. The market monitoring database indicates that in 2016 the SPP generation fleet included 81 resources that met the 10-minute start-up time requirement for quick-start capability. The total capacity for the quick-start capable resources totals 3,807 MW and consists of a mix of gas-fired, hydro, and oil-fired generators. During 2016, the reliability unit commitment processes committed 62 of the 81 quick-start capable resources.

Figure 2—30 summarizes the start-up instructions issued to resources with real-time offers indicating a 10-minute start-up capability. In 2016, 1,276 start instructions originated in a reliability commitment process, 2,967 start instructions originated from the day-ahead market, and 675 were manually committed. The average minimum run time for this group of resources is just over one hour. One statistic of particular interest is the average lead time for the 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. With the inception of the short-term reliability unit commitment process in February 2016, there has been large 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. The MMU is monitoring the effects of the new commitment process and will report the results when more data is available.

Figure 2–30 Commitment of quick-start resources

Commitment process	Number of starts	Committed capacity (MW)	Lead time (hours)	Hours in original commitment	Actual hours online
Day-ahead RUC	1	98	10.0	9.0	17.0
Intra-day RUC	908	51,612	2.0	4.4	6.0
Short-term RUC	367	20,405	0.3	1.0	8.9
Manual	675	25,709	0.6	2.5	4.9

The level of make-whole payments associated with the commitment of 10-minute resources in the reliability processes is still noteworthy. In 2016, 75 percent of the reliability processes commitments for quick-start units resulted in real-time make-whole payments. This is down only slightly from 79 percent in 2015. In total, quick-start resources received $9.3 million in real-time make-whole payments and $439,000 in day-ahead make-whole payments. This is an increase from their respective 2015 make-whole payments of $8.9 million and $92,000 respectively. In addition to the efficient 10-minute startup, these resources typically have low minimum run times and higher than average ramp rates. This operational flexibility coupled with five-minute settlement in the real-time market should reduce the need for make-whole payments. Some of the MMU's concerns expressed in 2014 report have been addressed with the inception of the short-term reliability unit commitment process, price scarcity revisions for ramp shortages, and through other quick start logic expected to be implemented during late 2017.

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 leaving time to commit these quick-start resources when needed, but allowing 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 minimums with market prices below their marginal costs.

The Integrated Marketplace protocols[10] describes the real-time market dispatch of resources with quick-start capability. However, the ability for the system operator to optimally commit and dispatch the quick-start resources by waiting until the real-time market appears to be hampered by concerns that the quick-start resources will not perform when needed. Uncertainty as to the resources' true capabilities contributes to these concerns. There is also a system issue contributing to the inefficient commitment of 10-minute resources. The issue is that the automated reliability commitment processes, the day-ahead reliability unit commitment and intra-day reliability unit commitment, are unable to account for resources participating in the real-time market as quick-start ready resources, and therefore are unable to adjust the online capacity calculations to reflect the additional capacity available for dispatch. Without changes to the system, a manual workaround must be used to track the quick-start capacity available in the real-time market.

In May 2015, SPP staff presented a new quick-start design proposal that was well-received by stakeholders. Subsequently, this proposal was submitted to the Market Working Group (MWG) by a market participant[11] and was approved in September 2015. In January 2016, the Market Working Group also formed a Price Formation Task Force (PFTF) to evaluate the efficiency and transparency of energy and operating reserve pricing. This task force was disbanded in February 2017 with the idea that any remaining tasks will be handled through the Market Working Group.

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[10] Section 4.4.2.3.1.

[11] Revision Request 116 (Quick-Start Real-Time Commitment) received all the necessary approvals from FERC and is expected to be implemented in November 2017.

The new quick-start design is expected to be implemented by the latter half of 2017, and was developed to address the following concerns:

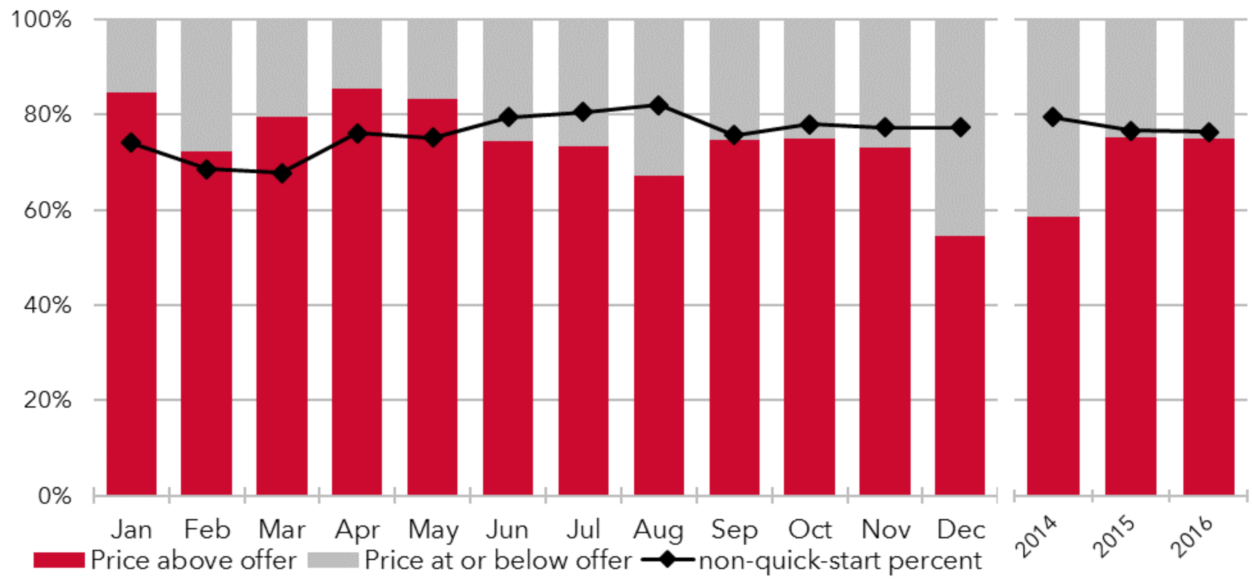
- Quick-start resources should not be physically committed prior to the real-time market for economics, unless the resource receives a day-ahead position, and therefore quick-start resources should be allowed to be dispatched from an offline state in real-time.
- Quick-start resources' parameters should be respected (economic minimum, minimum run time, minimum down time, etc.)
- Quick-start resources should have a clear shutdown process.
- The real-time market should automatically roll up the start-up and no-load offers into the quick-start resource energy offer.
- Quick-start resources should be make-whole payment eligible for their minimum run time.

A quick-start resource that clears in the day-ahead market will be granted a day-ahead commitment, and quick-start resources needed for reliability reasons will receive a physical commitment in real-time. However, quick-start resources needed for economic reasons by any reliability unit commitment will not receive a commitment.

If any reliability unit commitment determines an economic need for at least the resource's minimum runtime, the unit will be earmarked as quick-start eligible. Once the unit has been designated as quick-start eligible it will be dispatched at any point that the energy price goes above the unit's cost. After the quick-start resource has been dispatched, it will be provided a commitment for the residual portion of its minimum run time by the unit commitment process. The MMU feels that holding off the commitment until the time of dispatch will greatly increase the certainty in the need for these quick-start resources, and should lead to a reduction in needed make-whole payments.

Figure 2–31 shows the percent of time quick-start resources generated power when the energy price was higher than their offer. For the first 12 months of the Integrated Marketplace, quick-start resources were dispatched during intervals where the price was above the marginal production cost for just over half the time. In 2014, 42 percent of the time quick-start resources on average were generating power when the price was below their offer. During 2015 and 2016, just over 25 percent of the megawatt-hours produced by quick-start resources were with energy prices above real-time energy offers. This is consistent with relative relationship of offers to energy price for the balance of the SPP fleet that is represented by the line in the Figure 2–31 below. The MMU recognizes this as progress toward more efficient use of these resources.

Figure 2–31 Efficient operation of quick-start resources



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 2–32 below shows a high potential for wind development in the SPP footprint, which is outlined in black.

Figure 2–32 Wind speed map

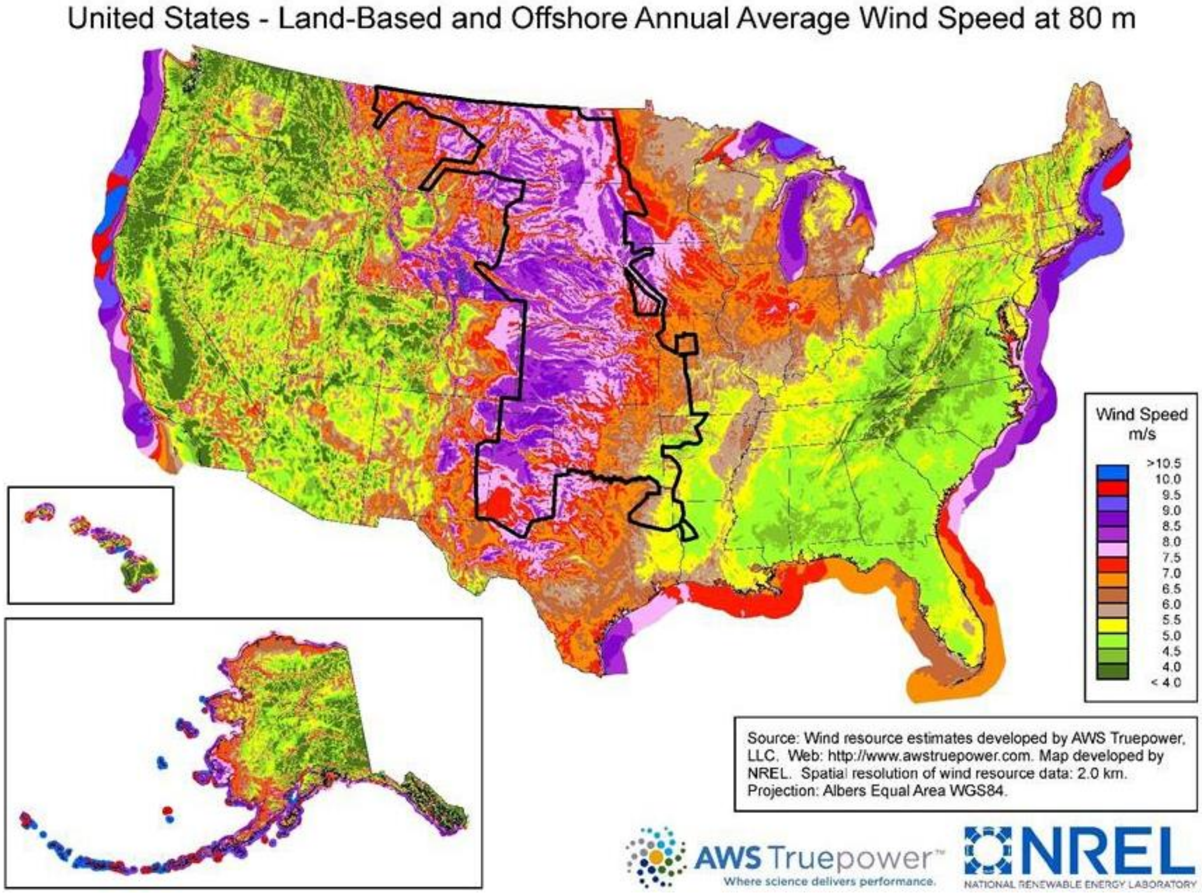
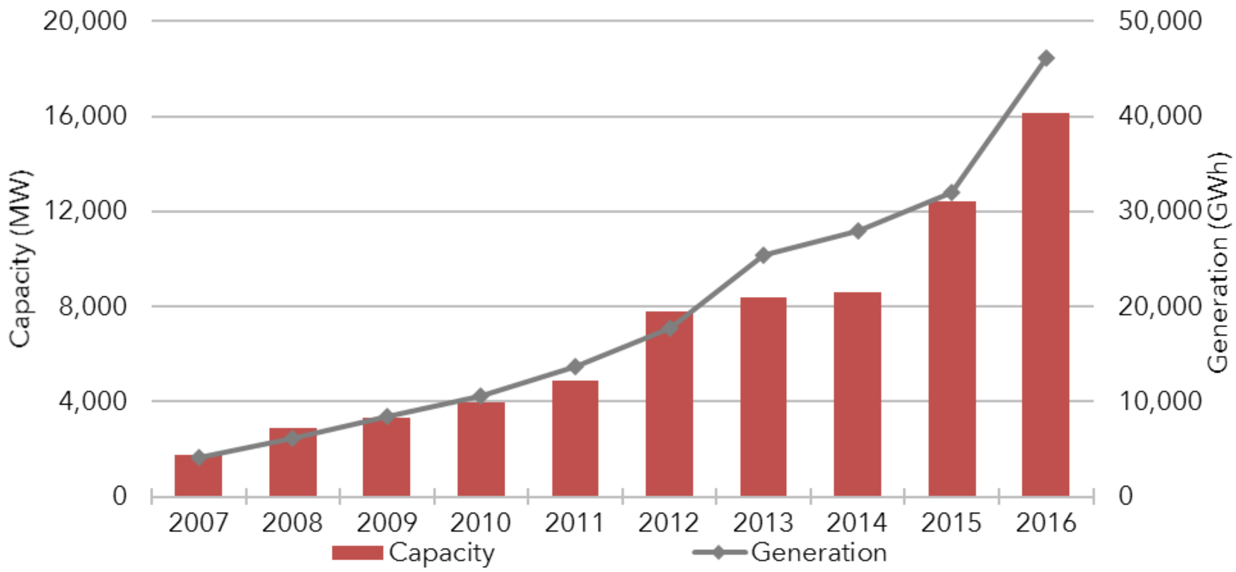


Figure 2–33 depicts annual capacity and total generation from wind facilities since 2007. Total registered wind capacity at the end of 2016 was 16,114 MW, an increase of 30 percent from 2015. Wind generation increased 44 percent in 2016 to over 46,000 GWh produced. Wind technology comprises about 18 percent of the installed capacity in the SPP market, behind only natural gas with 43 percent and coal with 31 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 as well as wind drops across the morning ramp periods.

Figure 2–33 Wind capacity and generation



2.5.2 WIND IMPACT ON THE SYSTEM

Average annual wind generation as a percent of average load increased to nearly 21 percent in 2016 from 14 percent in 2015. The peak wind generation for 2016 was just over 12,000 MW. Wind generation as a percent of load for any hour reached a maximum value of 48 percent, which was higher than 38 percent in 2015 and 33 percent in 2014. These records have since been eclipsed in 2017.[12]

Figure 2–34 shows the annual average and the hourly maximum wind generation as a percent of load since 2007, illustrating the dramatic increase since the start of the SPP markets.

[12] For the first six months of 2017, wind generation as a percent of load averaged just over 28 percent, with a maximum of just over 53 percent.

Figure 2–34 Wind generation as a percent of load

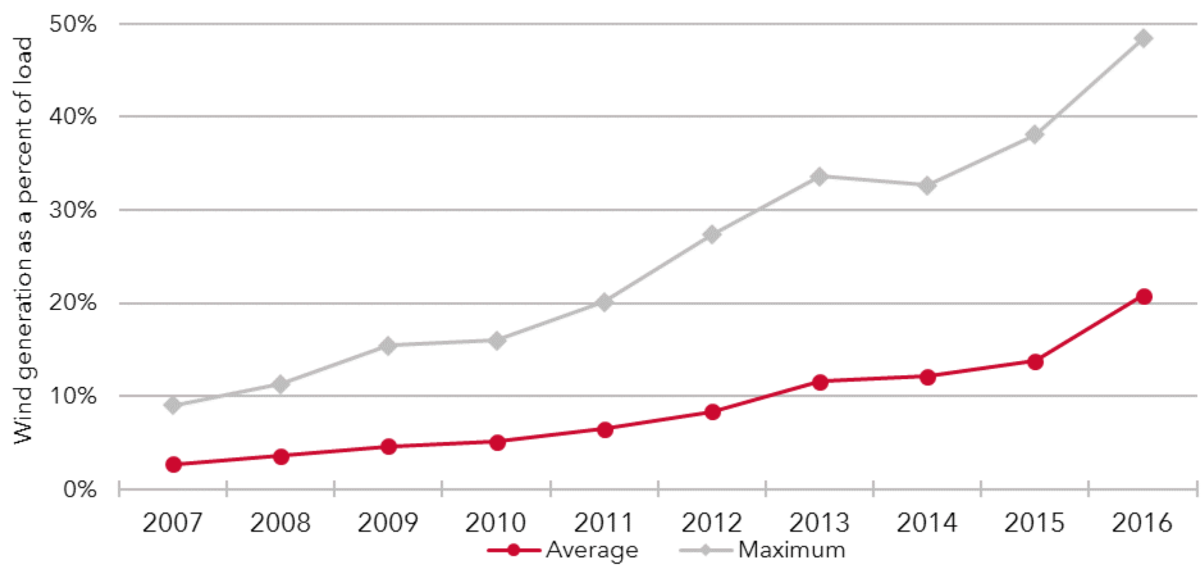
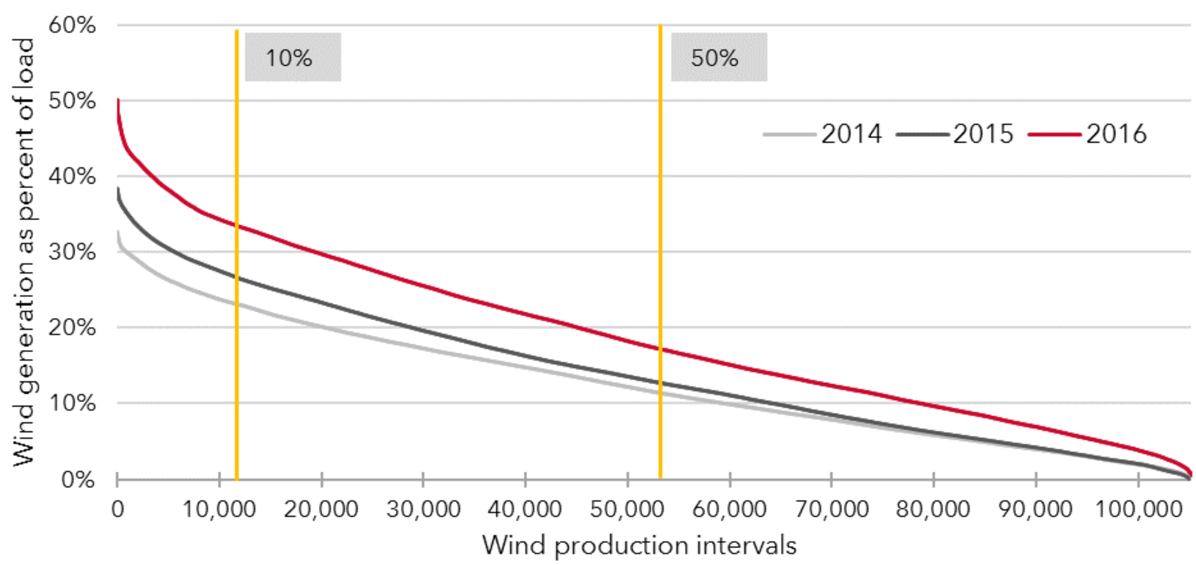


Figure 2–35 shows wind production duration curves that represent wind generation as a percent of load by real-time interval for 2014 through 2016. The curve for 2016 is higher than 2015, reflecting an increase in total wind generation year-over-year. Wind generation in 2016 served at least 17 percent of the total load during half of the year, compared to 13 percent in 2015 and 12 percent in 2014. 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 dramatically.

Figure 2–35 Wind production curve



2.5.3 WIND INTEGRATION

Wind integration brings low cost generation to the SPP region but supports very little in future capacity needs. There are a number of operational issues in dealing with substantial wind capacity. 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 ramp constraints as well as challenges for short- and long-run reliability.

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 40 percent (or 6,446 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.

At the start of the Integrated Marketplace, installed dispatchable variable energy resource capacity was 27 percent of all wind capacity, increasing to 46 percent by the end of 2015 and just over 60 percent at the end of 2016. Figure 2—36 illustrates dispatchable variable energy resources 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 2–36 Wind generation by month

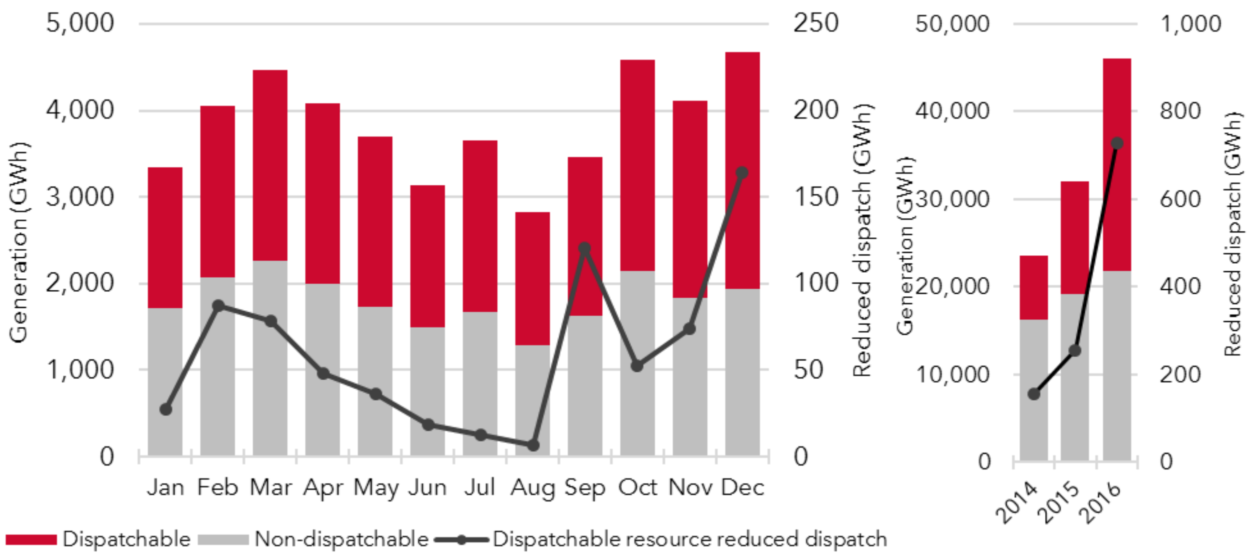
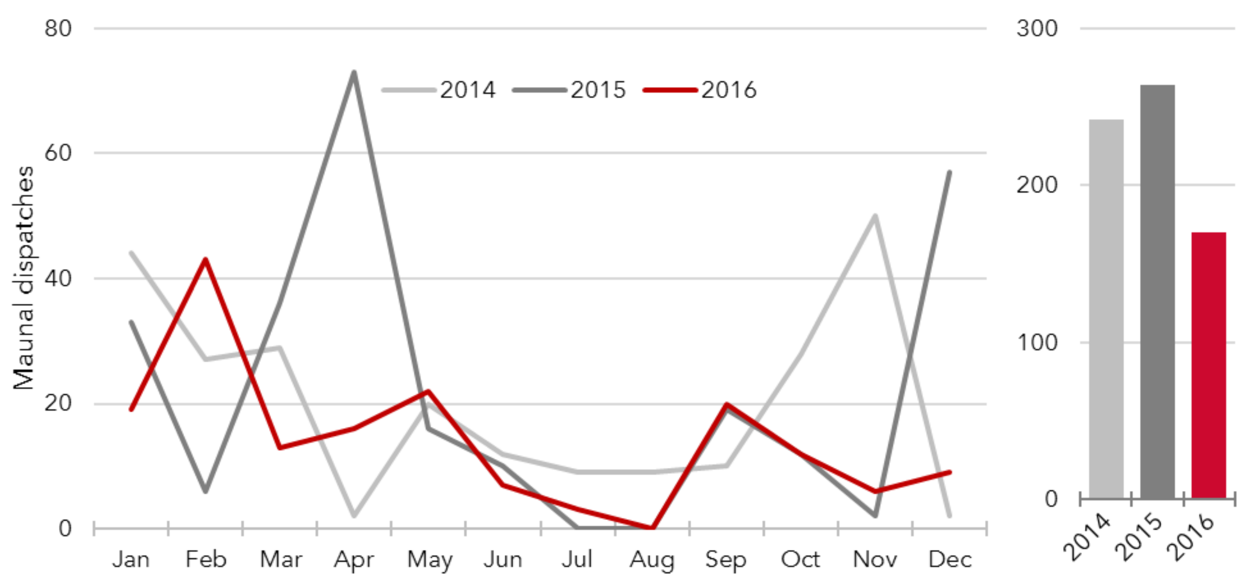


Figure 2–36 also shows the amount of reduced output of dispatchable variable energy resources below their forecast. This depicts the increase of reduced dispatchable variable energy resource dispatch output since 2014, which is expected due to the increase in wind capacity. This also follows the seasonal 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. December 2016 saw over 4,600 GWh of monthly wind production, which was the highest since the start of the Integrated Marketplace and over 1,900 GWh 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 without regard to the broader fuel mix needed.

Figure 2–37 shows the number of out-of-merit energy directives initiated for wind resources for the past three years. These figures include manual dispatch for both dispatchable variable energy resources and non-dispatchable variable energy resources, with non-dispatchable variable energy resources representing the great majority of manual dispatches. As expected, out-of-merit energy directives (manual dispatches) are fewer during the lower wind output and higher demand months of summer. In 2015, over half of the out-of-merit energy directives were for a group of five non-dispatchable variable energy resources where transmission is limited, particularly during periods when there are transmission outages in the area. These same five resources once again appeared in 2016 accounting for over half of the 170 manual dispatch instances.

Figure 2–37 Manual dispatches for wind resources



SPP is at the forefront among RTOs in managing wind energy integration with a traditional fossil fuel run fleet. The Integrated Marketplace has reliably dispatched wind generation, at times when wind generation represents more than 50 percent of load. Even though the use of out-of-merit energy directives are limited and SPP continues to see an expanding dispatchable wind generation fleet, ramping capability is needed because of the variability of wind.

2.5.4 MMU CONCERNS

A non-dispatchable variable energy resource is defined as "a variable energy resource not capable of being incrementally dispatched down by the transmission provider." This definition does not delve into the requirements of a non-dispatchable variable energy resource but it is discernable through design that these resources, barring absence of fuel or mechanical limitations, are expected to 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.

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 uneconomic production, which leads to exacerbating transmission congestion and 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 require nearly 1,200 MW of non-dispatchable generation assets to become dispatchable by early 2018.[13]

2.6 EXTERNAL TRANSACTIONS

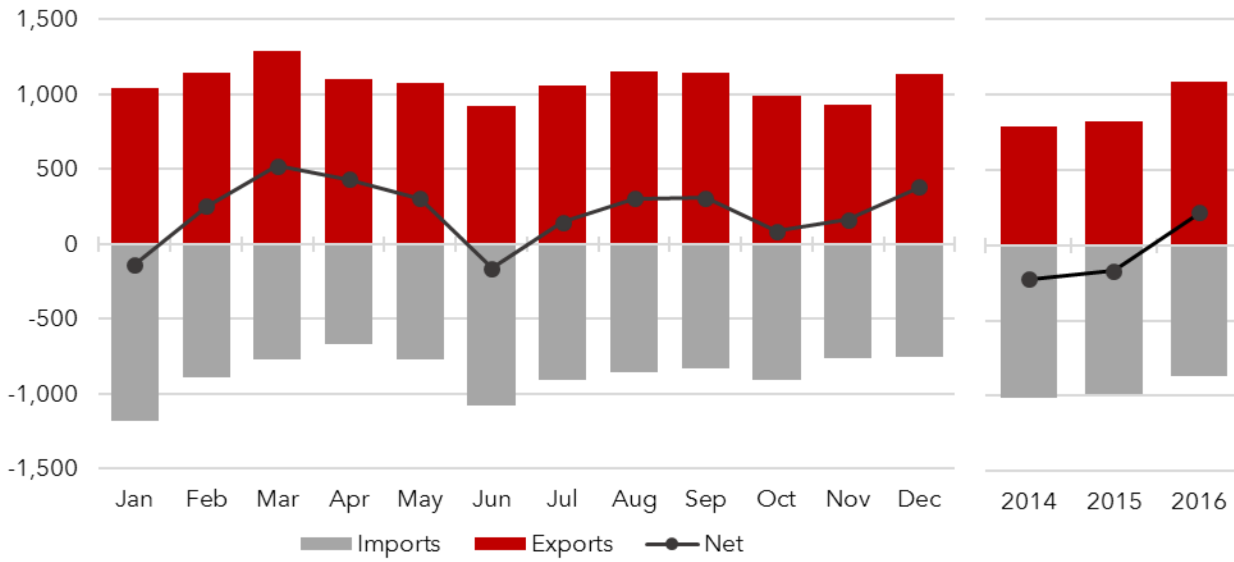
2.6.1 IMPORTS AND EXPORTS

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—38, SPP is a net exporter in real-time in 2016, while it was a net importer in 2014 and 2015. The two primary drivers for this change 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 footprint.

[13] See the FERC ruling at https://www.ferc.gov/CalendarFiles/20161209170835-ER17-68%20-000.pdf.

Figure 2–38 Imports and exports, SPP system



Generally SPP exports follow the wind production curve for the day. As wind generation increases, exports increase. SPA 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 other parties is less responsive to prices. Figure 2–39 through Figure 2–41 show the data for the three most heavily used interfaces, namely SPA, MISO and AECI.

Figure 2–39 Imports and exports, SPA interface

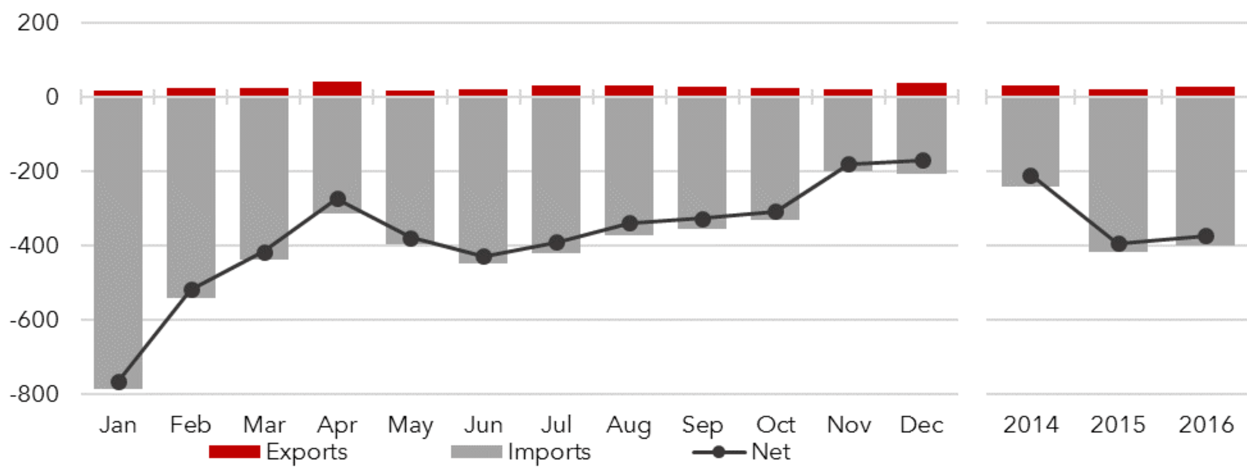


Figure 2–40 Imports and exports, MISO interface

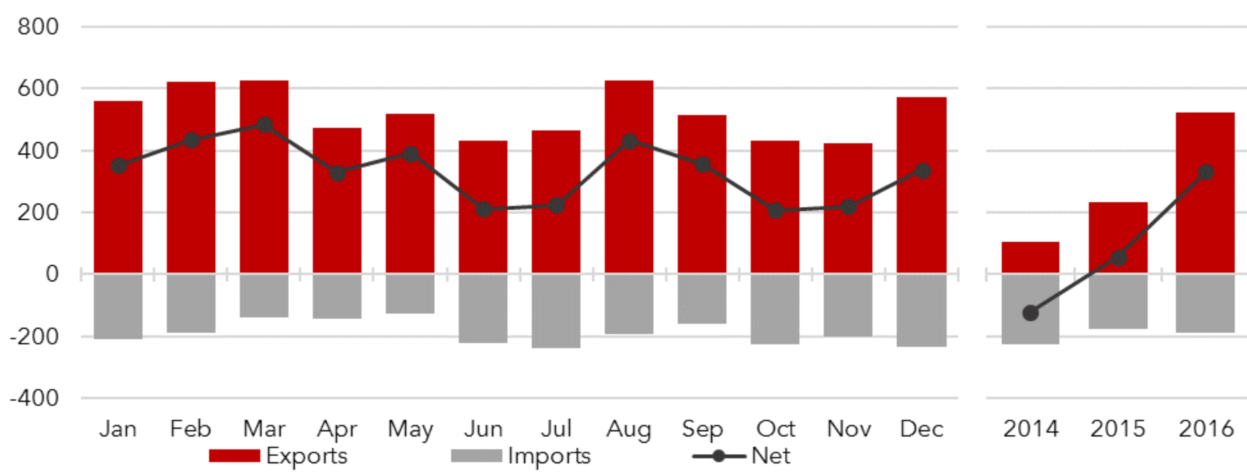
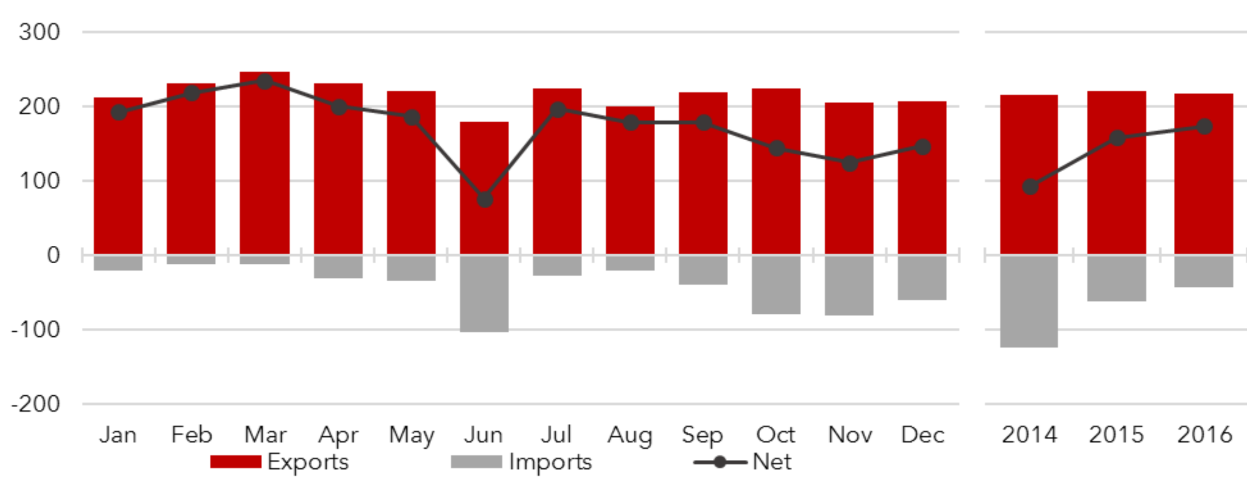


Figure 2–41 Imports and exports, AECI interface



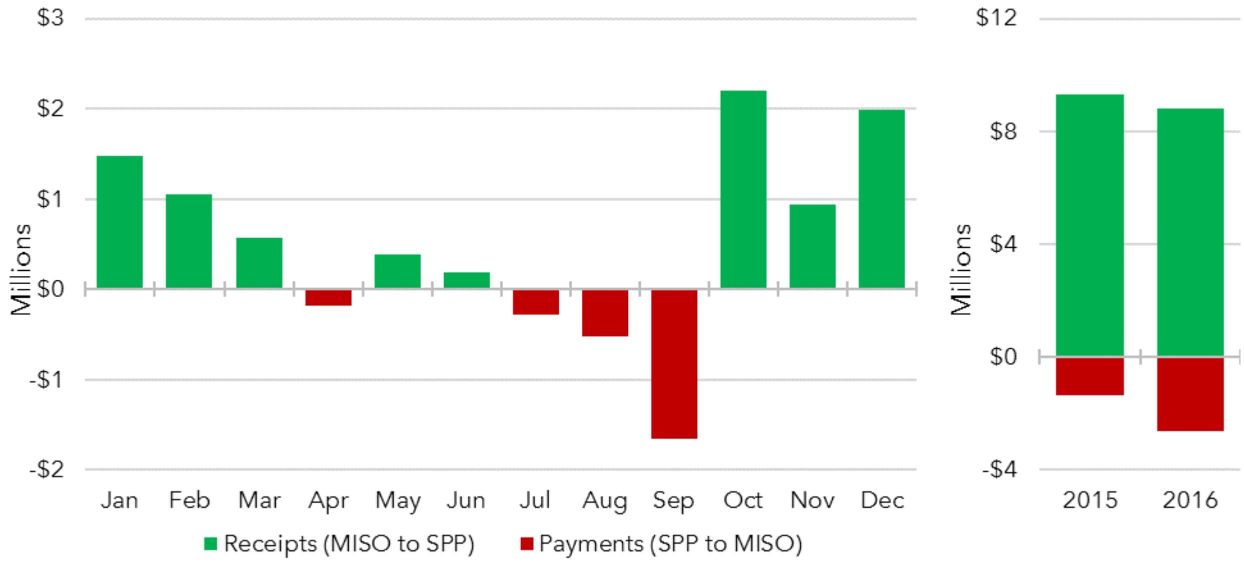
2.6.2 MARKET-TO-MARKET COORDINATION

SPP began the market-to-market (M2M) process with MISO on March 1, 2015 as part of a FERC mandate that also included regulation compensation and long-term congestion rights, which 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.[14]

Each RTO is allocated property rights on market-to-market constraints known as firm flow entitlements (FFE), and each RTO calculates its real-time usage, known as market flow. Exchange of money (market-to-market settlements) for redispatch is based on the non-monitoring RTO's market flow in relation to its firm flow entitlement. The non-monitoring RTO will receive money from the monitoring RTO if its market flow is below its firm flow entitlement and will pay if above its firm flow entitlement. Figure 2—42 shows net payments by month between SPP and MISO (positive is payment from MISO to SPP and negative is payment from SPP to MISO.)

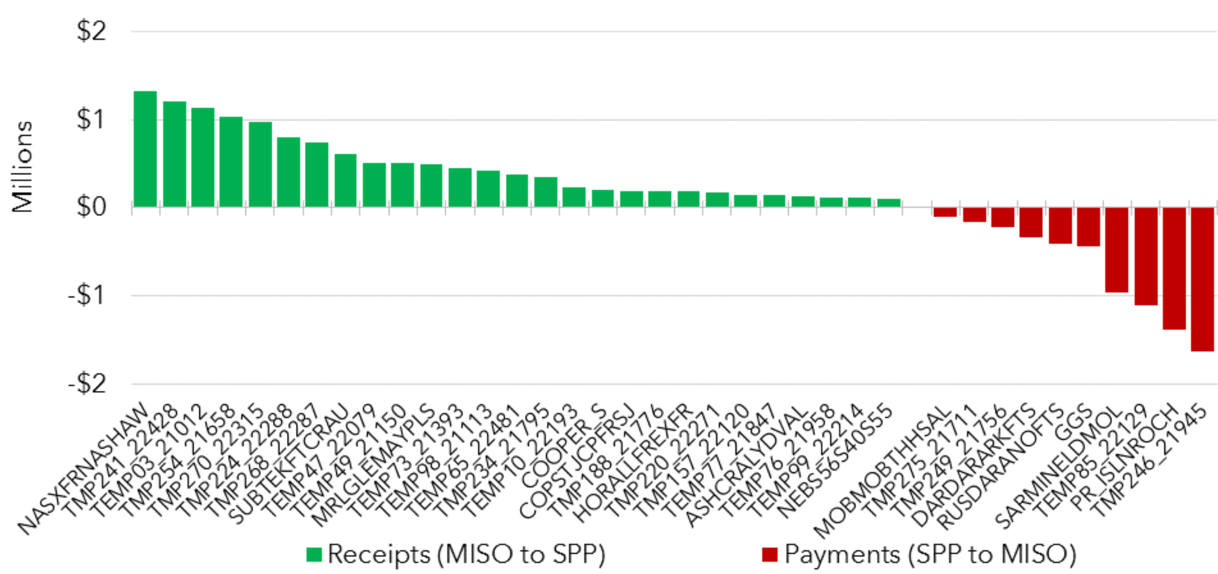
[14] Essentially, the RTO which manages the limiting element of the constraint is the monitoring RTO. In most cases, the monitoring RTO has most of the impact and resources that provide the most effective relief of a congested constraint.

Figure 2–42 Market-to-market settlements



For 2016, total market-to-market payments from MISO to SPP totaled nearly $9 million, while market-to-market payments from SPP to MISO totaled just over $2.5 million, resulting in a net payment of approximately $6 million from MISO to SPP for the year. Figure 2–43 show market-to-market payments (over $100,000 in either direction) by flowgate for 2016.

Figure 2–43 Market-to-market settlements by flowgate



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 that could lead to improved benefits for both markets along with MMU assessment and comments.

2.6.2.1 Monitoring/non-monitoring designation

Currently, MISO and PJM implement a procedure on constraints where the monitoring RTO transfers control to the non-monitoring RTO when there is what is referred to as "effective control." Effective control can be a number of things such as faster ramping resources or resources with lower costs and/or higher impacts on the constraint. Changing the monitoring RTO/non-monitoring RTO designation has been discussed with SPP stakeholders but concerns over legal obligations (transmission operators contract with SPP to manage their facilities) have delayed this being implemented between SPP and MISO. The market monitor urges both SPP and MISO to develop a more effective procedure for transferring effective control of constraints to the mutual benefits of both markets.

2.6.2.2 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 facility. 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 would respond to the market conditions and either withdraw or delay submitting tags during congestion, therefore alleviating 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. The scenario observed between SPP and MISO entailed third-party firm network and native load (NNL) impacts that are not subjected to redispatch by either market. The third party does not have an incentive in the form of a price and by the absence of a transmission loading relief will not have an obligation 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 only mechanism to manage impacts between markets and non-markets.

2.6.2.3 Market-to-market flowgate coordination

Flowgates are subjected to a series of coordination tests to determine if they should become a market-to-market flowgate. These tests are run ahead of time when a flowgate is created (reanalyzed periodically), and in some cases a flowgate may pass for scenarios that are no longer present in real-time (resources out-of-service, condition in test not present in real-time, etc.). This may cause the non-monitoring RTO to be asked to provide relief during a configuration when it physically cannot provide relief (i.e., non-monitoring RTO asked to provide negative market flow and resource is off-line in real-time). The market monitor feels automated tests reflecting more recent topology (possibly day-ahead or two-day-ahead) could be used to determine when a flowgate should be subject to market-to-market coordination.

2.6.2.4 Market flow methodology

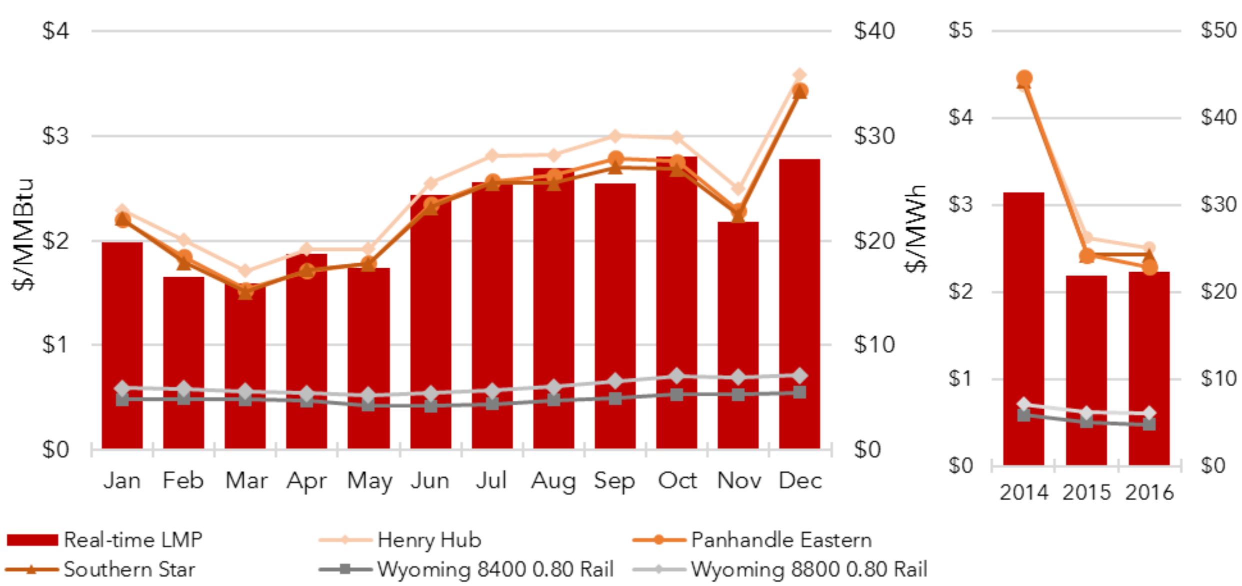
Different methodologies used by each RTO can, and often do, have a significant impact on how each RTO serves its load and can have a significant adverse impact on the efficiency of market-to-market coordination. This condition has existed for years between SPP, MISO, and PJM. Discussions on this issue ceased with all parties agreeing to accept the differences in each of their approaches. MISO and PJM utilize a marginal zone methodology (although the margins are derived in different manners), and SPP uses a tagging impact approach. The market monitor does not feel any method has proved to be consistently more accurate. Given the importance of the market flow in market-to-market settlements (market flow is used to measure what portion of the non-monitoring RTO's firm flow entitlement is being utilized), the MMU suggests this topic should be revived to ensure consistency and equitable measurements across RTOs.

2.7 FUEL PRICES

Since many generators use coal and natural gas as their primary fuel, this section analyzes the levels and the trends of coal and natural gas prices over the last three years. Figure 2–44 shows that the trend of declining natural gas prices since 2015 has changed course in the upward direction starting in March 2016, however on an annual average basis the prices were still lower in 2016 compared to the 2015 levels, for all three indices.[15]

During 2016, monthly average natural gas prices at the Panhandle hub varied from the low of \$1.53/MMBtu in March to a high of \$3.43/MMBtu in December resulting in a 4.5 percent decline on an annual average basis from 2015. Even though natural gas-fired units are the marginal units that set the prices in the SPP market about 50 percent of the time, changes in gas costs have the highest impact on electricity prices compared to price changes of other fuels because the price of other fuels is generally very stable. The inherent advantage of natural gas units is that they are more flexible, putting them in an advantageous position over the coal units in scheduling or dispatch by SPP despite the fact that the relative prices of natural gas and coal usually favors coal. Meanwhile, the chart below illustrates the expected close link between the cost of natural gas and the real-time prices and the volatility of gas prices.

Figure 2–44 Fuel price indices and wholesale power prices



[15] The relevant natural gas prices for the SPP market are those of the Henry Hub, the Panhandle Eastern Pipeline (PEPL) and Southern Star, and do not include transport costs.

Coal prices have been relatively stable since 2015 with a slight uptick observed beginning in the second half of 2016.[16] Annual average prices for Powder River Basin 8,400 (Btu/lb.) and the 8,800 (Btu/lb.) type coals declined by nearly six percent (to $0.48/MMBtu) and by two percent (to $0.60/MMBtu), respectively compared to the 2015 levels. However, the end of year monthly average prices for these two types of coal were $0.54/MMBtu and $0.71/MMBtu, respectively indicating a slightly upward trend.

On annual average terms, shown in Figure 2–45, natural gas prices were down approximately five percent. However, prices for both electric trading hubs in the SPP market in 2016 were up by two percent. This is not in conflict with the short-term link established above between natural gas and wholesale power prices as the generators' offers are mostly fuel-related. The annual average change figures for real-time prices have the potential to reflect other market conditions such as higher summer load levels, transmission congestion, temporary scarcities, and the impact of wind generation on the overall system.

Figure 2–45 Fuel prices, annual

Fuel Price	2014	2015	2016	2015-16 % Change
Henry Hub	$ 4.37	$ 2.63	$ 2.51	-4.8%
Panhandle Pipeline Hub	$ 4.42	$ 2.43	$2.32	-4.5%
Southern Star Hub	$ 4.47	$ 2.43	$2.29	-5.9%
Powder River Basin 8,400, 0.8 Rail	$ 0.59	$ 0.51	$ 0.48	-5.9%
Powder River Basin 8,800, 0.8 Rail	$ 0.71	$ 0.62	$ 0.60	-1.6%

Energy Price	2014	2015	2016	2015-16 % Change
SPP North hub, real-time	$ 26.77	$ 18.85	$ 19.27	+2.2%
SPP South hub, real-time	$ 36.26	$ 24.86	$ 25.45	+2.4%

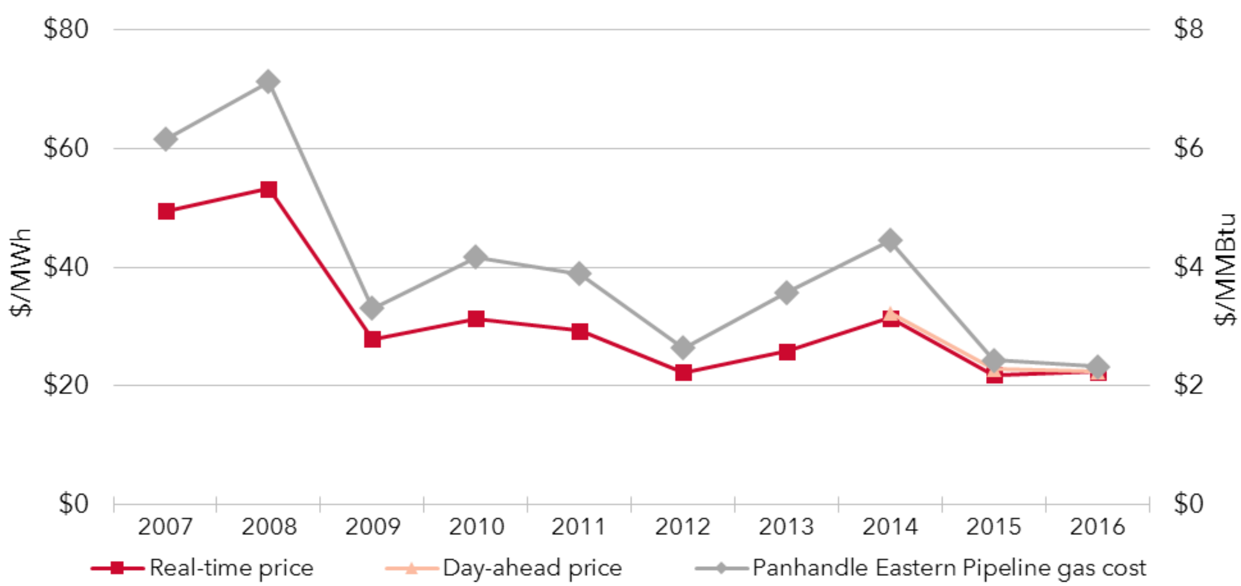
[16] The coal prices are inclusive of transport costs.

2.8 MARKET PRICES AND COSTS

2.8.1 ENERGY MARKET PRICES

Locational marginal prices for energy in the SPP Integrated Marketplace track very closely with the price of natural gas, as was true in the Energy Imbalance Service market prior to the implementation of the Integrated Marketplace. Figure 2–46 shows the average energy price for the past ten years.[17] Both energy prices and gas costs remained virtually unchanged from 2015 to 2016. The average real-time price for 2016 was $22.36/MWh, an increase of two percent over 2015, while the average day-ahead price for 2016 was $22.43/MWh, a decrease of two percent from 2015. The average gas cost, using the price at the Panhandle Eastern Pipeline decreased by 4.5 percent from 2015 to 2016. 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.

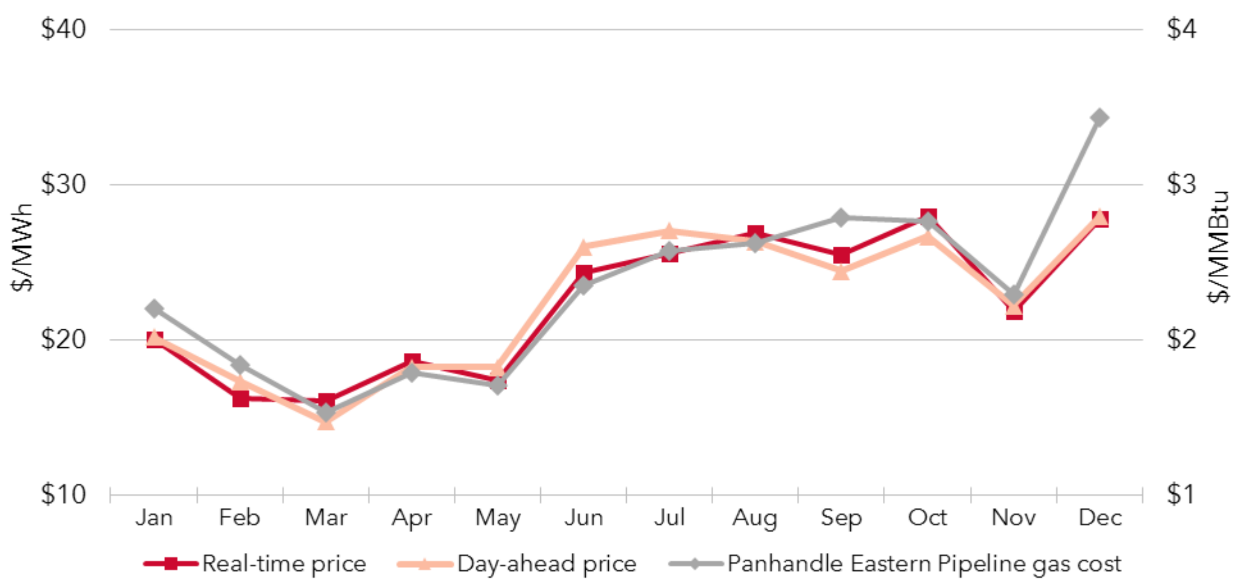
Figure 2–46 Energy price versus natural gas cost, annual



[17] The 2014 average includes two months of prices from the Energy Imbalance Service market and 10 months of prices from the Integrated Marketplace.

Figure 2–47 shows a consistent relationship between energy prices and natural gas costs on a monthly basis for 2016. The strong relationship between energy prices and natural gas costs is expected in a well-functioning centralized competitive market. Natural gas-fired resources in the SPP footprint represent the marginal source of supply in about half of all intervals in 2016, and gas is the one primary fuel having significant price volatility. As a result, energy price movement is about half that experienced by gas because gas resources are marginal about half the time.

Figure 2–47 Energy price versus natural gas cost, monthly



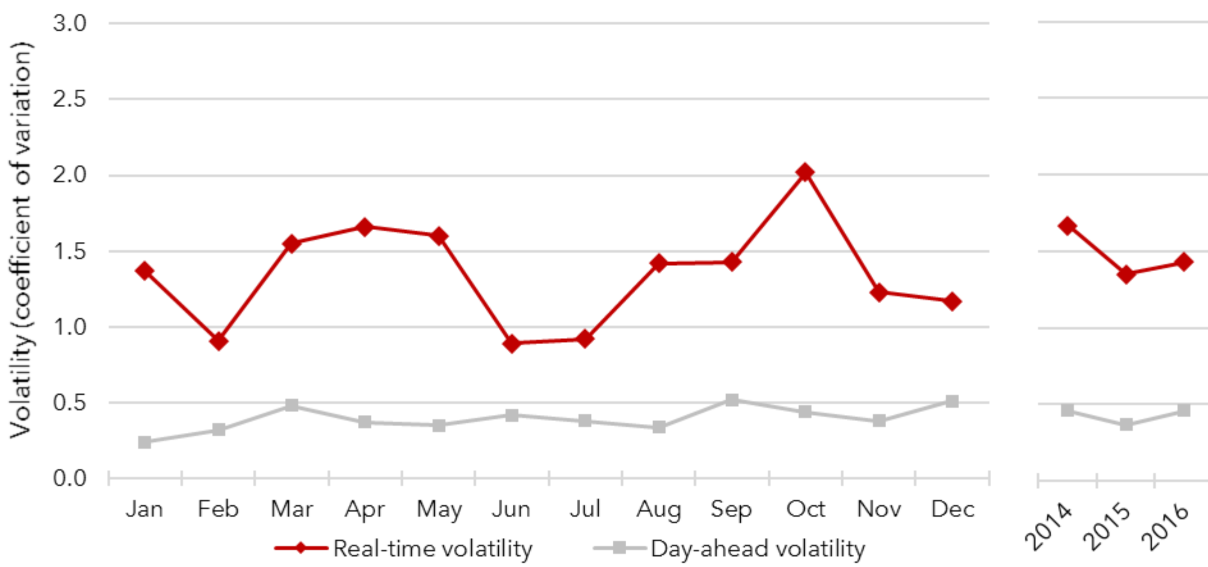
2.8.2 ENERGY PRICE VOLATILITY

Price volatility[18] in the SPP market is shown in Figure 2–48 below. As expected, day-ahead prices are much less volatile than those in real-time because 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. Volatility in 2016 was slightly higher than 2015, and gas prices tended to vary more during 2016 than 2015. Volatility was higher in 2014

[18] Volatility is calculated as the coefficient of variation (standard deviation divided by mean) using data for each settlement period using hourly price in the day-ahead market and interval (five minute) price in the real-time market for load-serving entities in the SPP market.

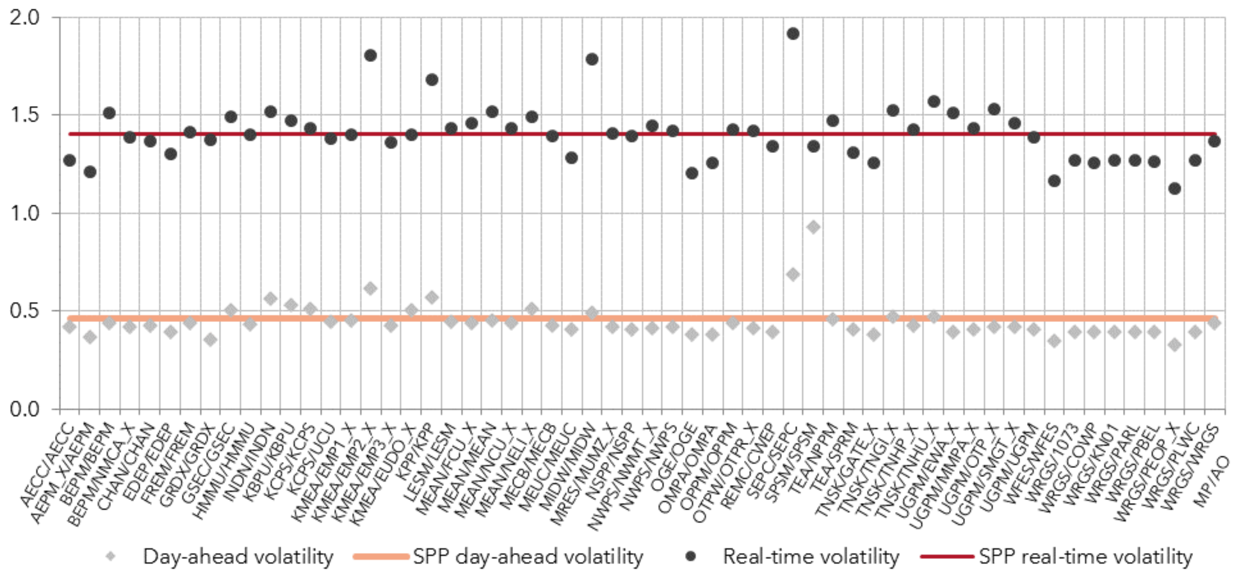
driven by significantly higher volatility in gas price and some learning experience in the first year of the Integrated Marketplace.

Figure 2–48 System price volatility



Price volatility varies across the SPP market footprint primarily because of congestion on the system, which is based on the layout of the transmission system and because of the distribution of the types of generation in the fleet. Typically, prices in western Kansas tend to be the most volatile as shown in Figure 2–49 below, while prices in Oklahoma tend to be the least volatile. This pattern tends to hold across both the real-time and day-ahead markets. However, there is an outlier in the day-ahead market, where Southwestern Public Service (SPSM) experienced the highest volatility. This is because of extreme December weather conditions during a four hour period when several units tripped due to icing which caused very high prices for a short period. Without this four hour event, Southwestern Public Service price volatility would have been very near their historic average volatility levels, and the system average for the year.

Figure 2–49 Price volatility by market participant

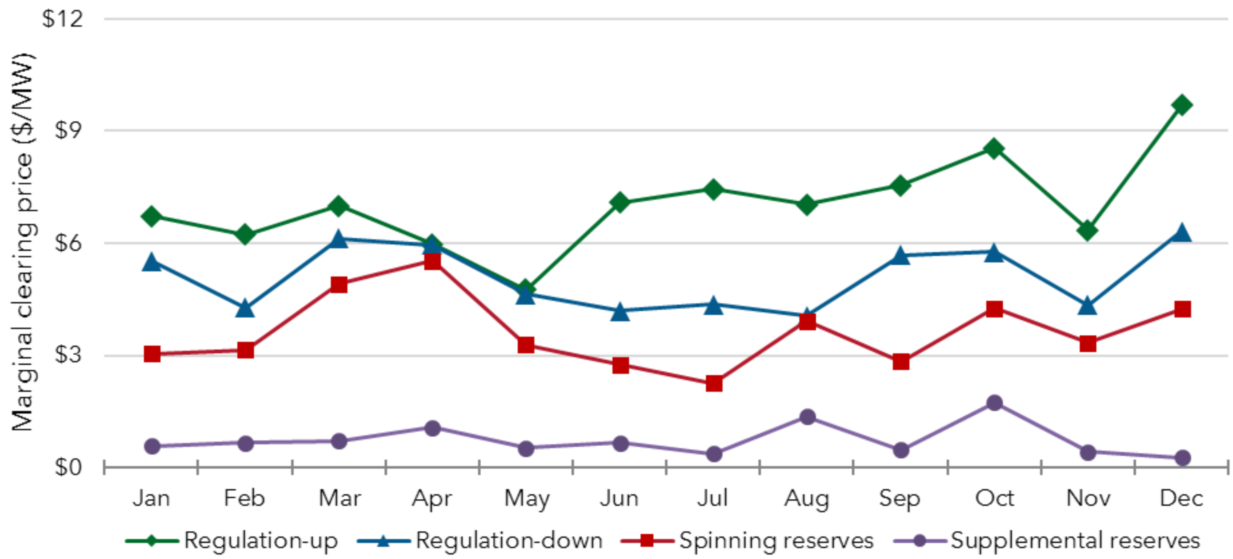


2.8.3 ANCILLARY SERVICES MARKET PRICES

Average monthly real-time prices for operating reserve products are presented in Figure 2–50. From 2015 to 2016, the average real-time marginal clearing price for regulation-up decreased by 20 percent, from $8.91/MW to $7.03/MW; regulation down decreased by 40 percent, from $8.71/MW to $5.11/MW; and supplemental reserves decreased by nearly 30 percent, from $1.02/MW to $0.74/MW.

During this same period the average real-time marginal clearing price for spinning reserves increased by nearly 40 percent, from $2.64/MW to $3.62/MW. This is still below the 2014 average of $4.79/MW. Analysis shows that the marginal clearing price for spinning reserves in 2015 was unusually low due to coal resources offering high levels of spinning reserves to the market due to low gas prices.

Figure 2–50 Operating reserve product prices, real-time



Day-ahead and real-time price patterns vary across the ancillary service products, see Figure 2–51 through Figure 2–54. All four products' prices have declined since the inception of the market. Declining gas prices and the overall price of energy is the primary cause of this price decline. Some portion of the price decline is the result of the normal maturing of the market reflecting an overall improvement in the efficiency of the market.

Figure 2–51 Regulation-up service prices

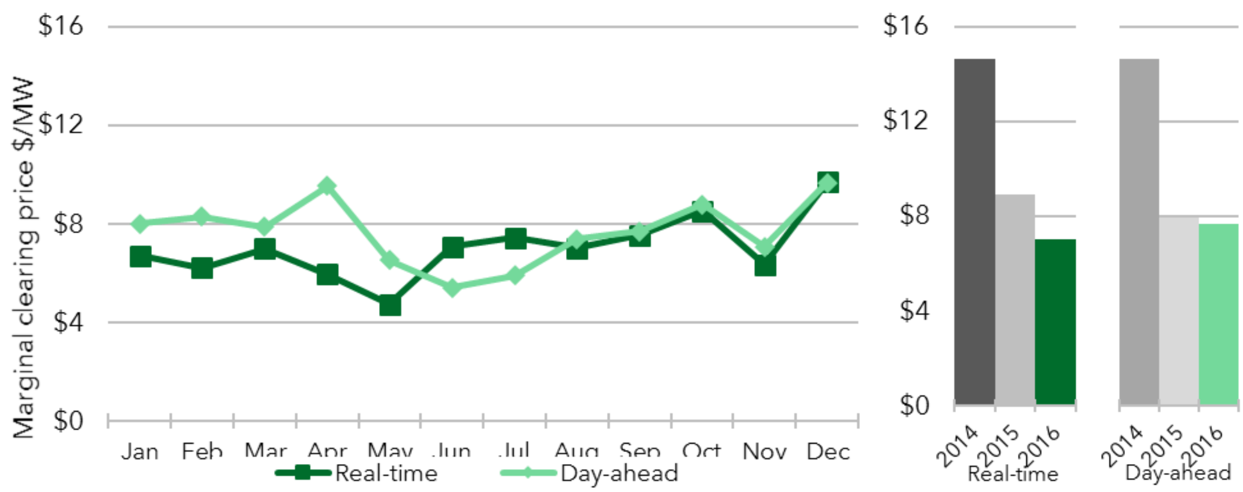


Figure 2–52 Regulation-down service prices

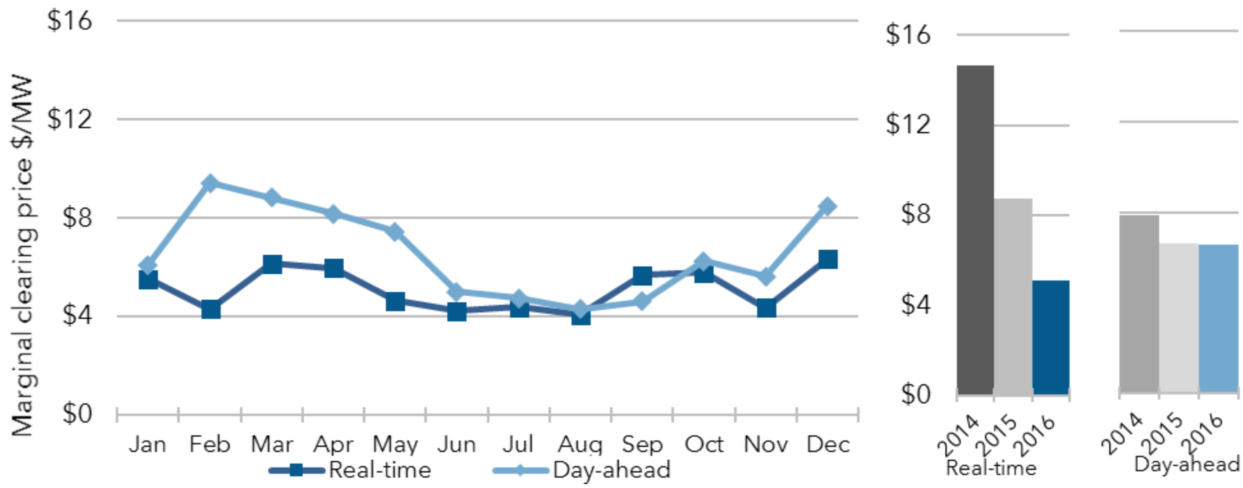


Figure 2–53 Spinning reserve prices

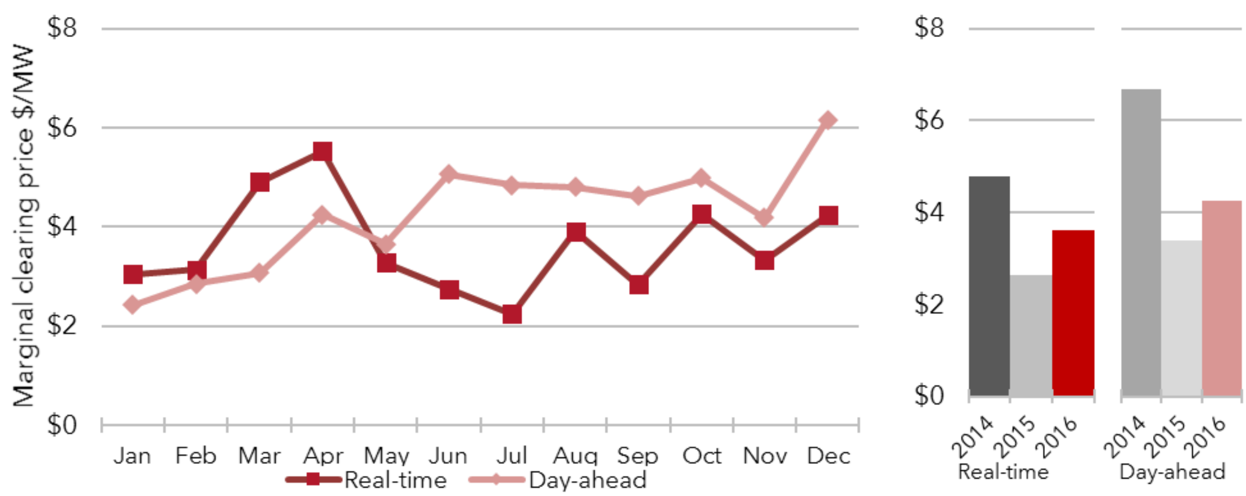
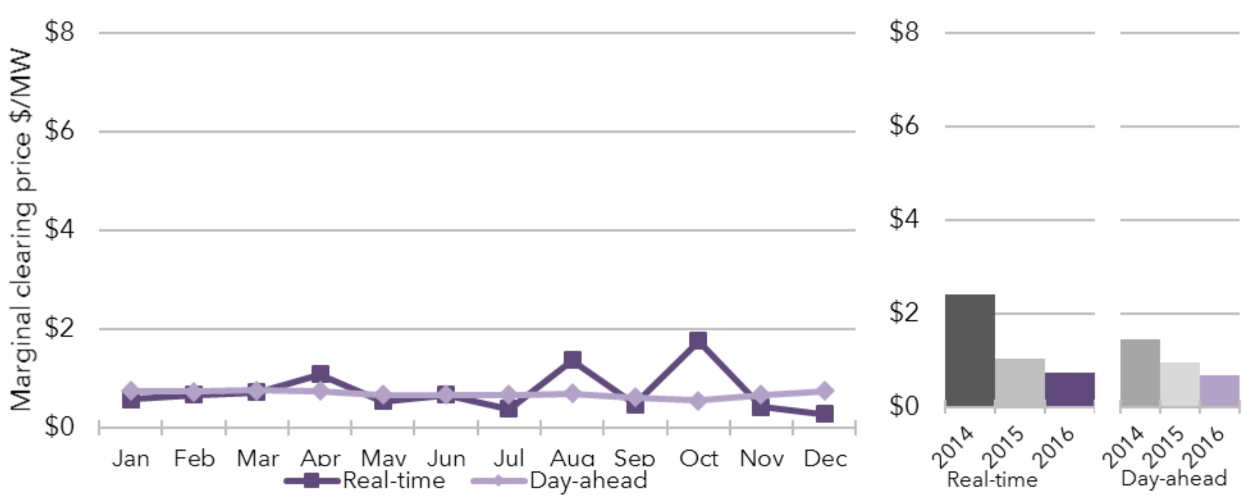
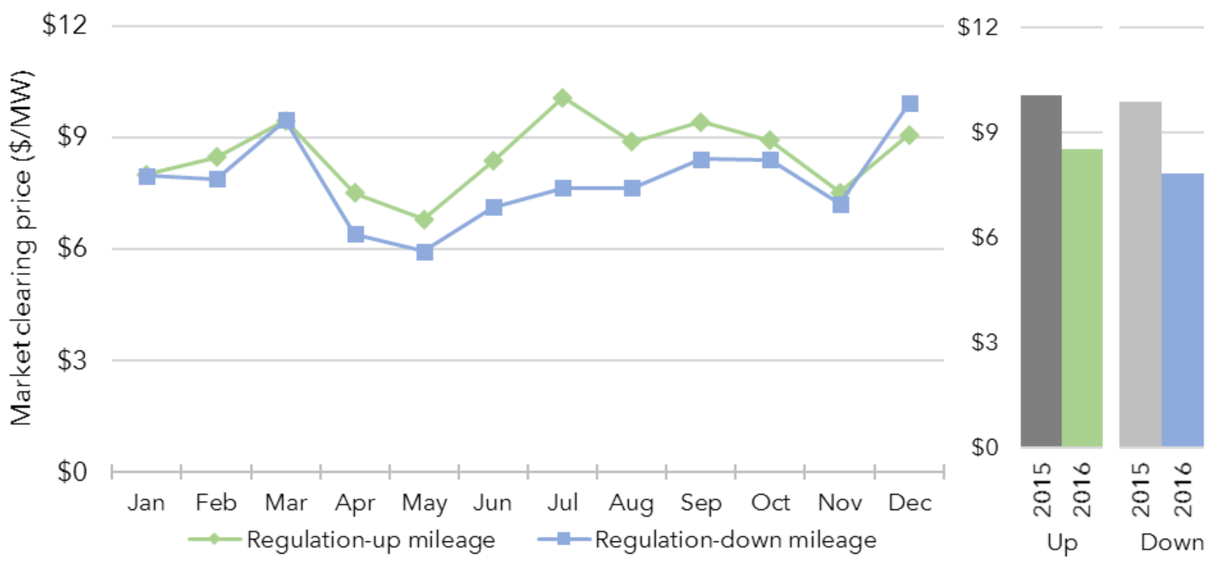


Figure 2–54 Supplemental reserve prices



In March 2015, SPP introduced a new product paying regulating units for mileage costs incurred when moving from one set point instruction to another. These mileage payments are paid directly through the operating reserve prices shown for regulation-up and regulation-down, as shown in Figure 2–55. The market calculates a mileage factor for both products each month that represents the percentage a unit is expected to be deployed compared to what it cleared. If a unit is deployed more than the expected percentage, then the unit is entitled to reimbursement for the excess at the regulation mileage marginal clearing price.

Figure 2–55 Regulation mileage prices, real-time



Units deployed less in real-time than the forecasted percentage of their cleared quantities set in the day-ahead market are then required to pay back the market the unused quantities at the respective mileage price. Resources that are charged an unused amount at a mileage marginal clearing price that is greater than their mileage cost for the product are eligible to have the excess reimbursed through both regulation-up and regulation-down unused mileage make whole payments, which will be discussed in Section 2.10.2 below.

2.8.4 MARKET SETTLEMENT RESULTS

Ninety-eight percent of the energy consumed in the Integrated Marketplace is settled in the day-ahead market. This is consistent with last year and in line with improving market efficiency. Figure 2–56 shows that approximately 250 terawatt-hours of energy were purchased in the day-ahead market at load settlement locations of which only four and a half terawatt hours were in excess of the real-time consumption. An additional six terawatt hours of energy were purchased in the real-time market because the real-time consumption was higher than that of the day-ahead.

Figure 2–56 Energy settlements, load

	Day-ahead purchases	Real-time purchases	Real-time sales
Load (GWh)	250,318	6,208	-4,521
Cash flow (millions)	$ 5,913	$ 149	-$ 101

Ninety-two percent of generation was settled in the day-ahead market, a two percent increase from last year. Figure 2–57 presents the settlement numbers for the generation assets. Ten percent of the energy cleared in the day-ahead market was settled by purchasing energy in the real-time market rather than generating the energy, which was the same as experienced in 2015.

Figure 2–57 Energy settlements, generation

	Day-ahead sales	Real-time sales	Real-time purchases
Generation (GWh)	- 256,908	- 16,582	20,513
Cash flow (millions)	-$ 5,558	-$ 280	$ 400

The RTO plays the role of the customer in the ancillary services market. At hour ending 8:00 AM on the day before the operating day, the RTO posts the forecasted amount of each operating reserve product that is to be procured, and this data sets the demand for the products for the day-ahead market. The RTO can change the demand levels after the clearing of the day-ahead market. Even though the demand is essentially the same between the day-ahead market and the real-time market, there is considerable activity with respect to the operating reserve products in the real-time market. Figure 2–58 presents the settlements data.

Figure 2–58 Operating reserve product settlements

Settlements (GWh)	Day-ahead sales	Real-time sales	Real-time purchases
Regulation up	2,851	1,009	1,009
Regulation down	2,854	1,204	1,206
Spinning reserves	6,413	1,926	1,932
Supplemental reserves	6,414	2,517	2,512

A large percentage of day-ahead sales are settled in the real-time market by purchasing the operating reserve product rather than supplying the service in the real-time market. Thirty-five percent of the day-ahead sales of regulation-up service were settled through purchasing the product in the real-time market in 2016. This is in contrast to 92 percent of energy generation settling at the day-ahead prices. This trend is down two percent from last year and five percent from the 40 percent that occurred in the first 12 months of the market.

Sixty-five percent of the 2016 real-time regulation-up service was settled at day-ahead prices, up from 49 percent in the previous year. The corresponding percentages for regulation-down service, spinning reserves, and supplemental reserves are 58 percent, 70 percent, and 61 percent respectively, in line with their respective numbers from 2015 of 49 percent, 55 percent, and 64 percent. This essentially means that the operating reserve products are being moved around to different resources in about the same volumes as last year, with the exception of supplemental reserves, which increased in volume. This is likely because of the additional capacity online as part of the reliability unit commitment processes.

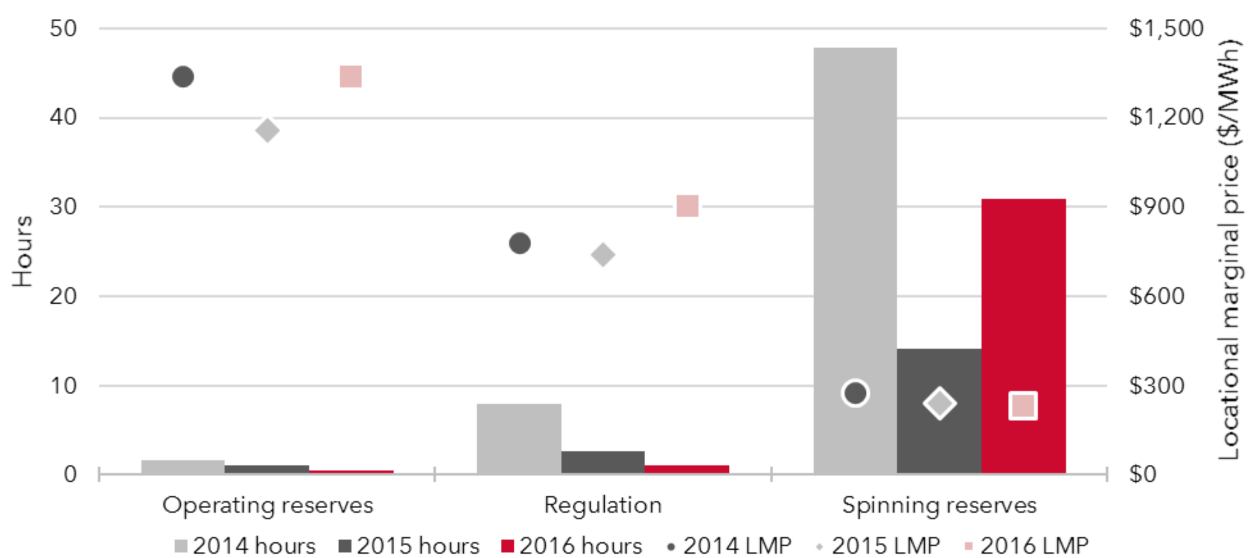
2.9 SHORTAGE PRICING

2.9.1 CAPACITY SHORTAGES

The Integrated Marketplace employs scarcity pricing demand curves that administratively set prices during periods of capacity shortages. An efficient electricity price reflects the cost of the marginal action required to meet the market demand. Generally, the marginal action to meet demand is the clearing of energy from a generator. However, during shortage pricing events, the marginal megawatt comes from reducing the amount of operating reserves. The scarcity pricing demand curves reflect the administratively determined cost of the marginal action during operating reserve shortages. The real-time market experienced 57 hours of capacity shortages in 2016, compared to 18 hours in 2015 and 33 hours in 2014. Most shortages, approximately 83 percent, were for spinning reserve. There was one hour of regulation shortage and only one five-minute interval of aggregate operating reserve shortage. A capacity shortage occurs when there is not enough on-line generation to meet both the energy demand and the operating reserve requirements. No capacity shortages occurred in the day-ahead market.

Figure 2–59 displays the number of shortage hours and the corresponding average price. The high price during the operating reserve shortage reflects the $1,100/MW scarcity demand curve cap. Similarly, the average prices when short of regulation and spinning reserves reflect the $600/MW and $200/MW scarcity demand curve caps, respectively. Note that in each instance the corresponding price is higher than the demand curve because the price includes the marginal cost of energy as well as the administratively determined marginal cost of not clearing sufficient reserves.

Figure 2–59 Capacity shortages



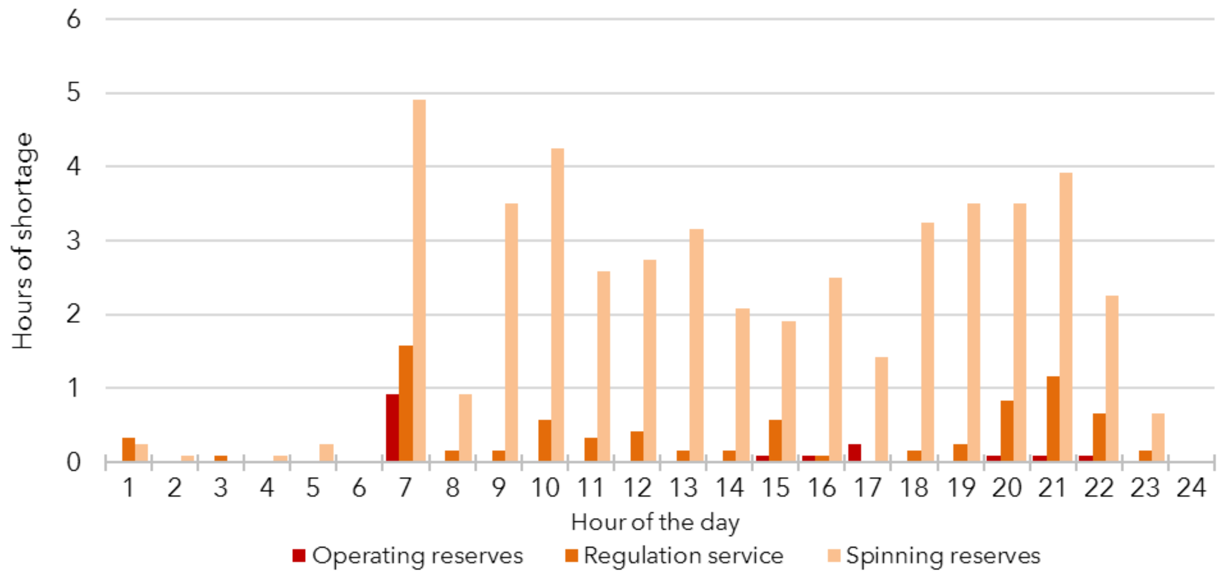
There were six operating reserve capacity shortage events (see Figure 2–60) in 2016, compared to one in 2015, and eight in 2014. This chart provides details around the number of shortage events, the megawatt values of the events, and the duration of the events for all components for the first three years of the market. The number of events and the magnitude of the events are up slightly from what was experienced in 2015. Overall, the numbers are small, and consistent with an effective market when considering weather patterns and the degree to which planned and unplanned outages affect the market.

Figure 2–60 Operating reserve capacity shortage statistics

Shortage type	Year	Number of events	Average duration (minutes)	Maximum duration (minutes)	Average shortage amount (MW)	Maximum shortage amount (MW)
Aggregate operating reserves	2016	6	15	15	336	412
	2015	1	5	5	231	231
	2014	8	12	45	307	586
Regulation-up	2016	13	7	10	122	505
	2015	10	6	10	98	323
	2014	70	7	25	92	430
Spinning reserves	2016	371	17	55	115	696
	2015	97	14	40	125	543
	2014	294	10	55	115	602

Figure 2–61 provides details on the capacity shortages that occurred during 2016 by time of day. The period of the day experiencing the most shortage events is the hour ending 7:00 AM, right at the morning ramp time. Regulation shortages tend to occur in the morning ramp, as well as between 10:00 PM and 11:00 PM since the online capacity is reduced for the off-peak hours of the day. Spinning reserve shortages are more evenly spread throughout the peak hours of the day.

Figure 2–61 Operating reserve capacity shortages, hour of day



Scarcity pricing is an important component of the Integrated Marketplace. It is during the shortage events that quick-start and fast-ramping resources earn a significant portion of their annual revenue. These resources generally have higher costs and low capacity factors than base load or intermediate load resources, and therefore must generate income at a much higher rate when they are running. Scarcity pricing is an effective means for sending a correct price signal to these resources.

Energy prices generally exceed $1,000/MWh during operating reserve capacity shortages. This provides an incentive for resources to ramp up quickly and for quick-start resources to come on-line. In its 2014 and 2015 State of the Market reports, the MMU recommended that SPP price ramp-constrained operating reserve shortages in a manner similar to the operating reserve capacity shortages emphasizing that the marginal action during ramp-constrained shortage pricing events is no different than the marginal action during a capacity shortage event.

Following FERC Order 825[19], SPP proposed and the market participants approved, a new design feature of variable demand curve for operating reserve products, which is an improvement over the previous design.[20] The new design introduces an upward sloping demand curve for operating reserves—contingency reserves and regulation services—and energy products during shortages. The scarcity price along the demand curve for contingency reserves (i.e., spinning and supplemental reserves) is determined as the product of scarcity factors and sum of energy offer and contingency reserve offer caps. Scarcity factors are set depending of the level of megawatt shortage. The scarcity prices along the regulation demand curves are determined by considering ramp as well as capacity shortages. The scarcity price for energy is set at a flat level of $5,000/MWh.

2.9.2 RAMP-CONSTRAINED SHORTAGES

Ramp-constrained operating reserve periods of shortage and shortage prices continued to decline in 2016; see Figure 2–62. The price signals during these events are dramatically different from the signals during a capacity shortage. During ramp-constrained operating reserve shortages, the market-clearing engine relaxes the reserve requirement to the level that the market can provide given the ramp constraints, and then the market resolves and posts the prices. The resulting prices reflect the marginal cost of energy and cost of meeting the reduced reserve requirements. There is no indication in the prices that the full amount of reserves has not cleared and that the marginal action to meet demand was a reduction in cleared operating reserves. In the first three years of the market, this price signal has not provided the correct incentives for fast-ramping resources.

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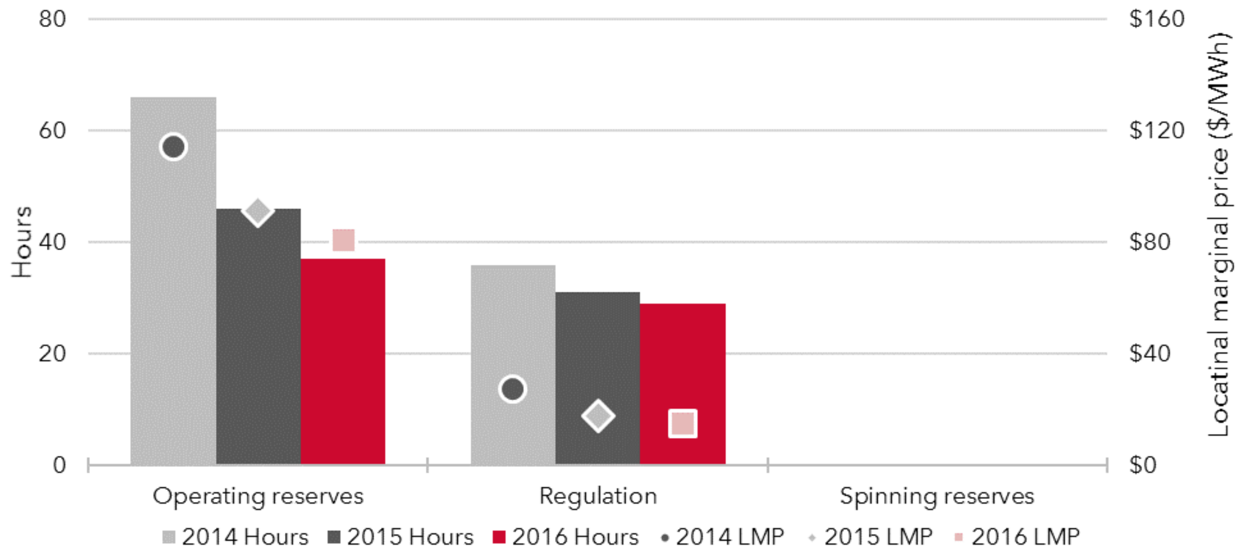
[19] FERC Order No. 825 Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, Docket No. RM15-24-000 (issued on June 16, 2016). Among other provisions in it, Order 825 directed RTOs/ISOs "…to trigger shortage pricing for any interval in which a shortage of energy or operating reserves is indicated during the pricing of resources for that interval." p. 90. The FERC order further stipulated that the pricing should reflect the value such resources provides and apply to any shortage regardless of the duration or cause of the shortage. *Ibid.*

[20] In the current rules, capacity shortages do not include operating reserve shortages due to ramping limitations. If scarcity pricing is triggered the situation is mitigated via ramp sharing and ultimately through constraint relaxation (i.e., scarcity pricing without demand curves).

Figure 2–62 Ramp-constrained shortages



Ideally, the prices during ramp-constrained operating reserve shortages should reflect the cost of a reduction in system reliability, and the cost of any operator actions that are employed to counteract the ramp shortage such as resource commitment. Prices that reflect these costs incentivize fast ramping and quick-start capable resources to participate in the markets. Ramp shortage subject to scarcity pricing was implemented in May 2017 (see Section 2.9 above for discussion). Figure 2–63 illustrates that the number of events and the magnitude of these events have not changed significantly over the first three years of the market.

Figure 2–63 Ramp-constrained shortage statistics

Shortage type	Year	Number of events	Average duration (minutes)	Maximum duration (minutes)	Average shortage amount (MW)	Maximum shortage amount (MW)
Aggregate operating reserves	2016	453	11	55	47	750
	2015	425	8	30	45	451
	2014	547	7	55	47	454
Regulation-up	2016	363	10	55	16	504
	2015	271	11	55	23	337
	2014	321	7	35	24	304
Spinning reserves	2016	0	0	0	0	0
	2015	0	0	0	0	0
	2014	0	0	0	0	0

2.10 MAKE-WHOLE PAYMENTS

The Integrated Marketplace provides make-whole payments (MWPs) to generators to ensure that the market provides sufficient revenue to cover the cleared offers providing energy and operating reserves for a period in which the resource was committed. To preserve the incentive for a resource to meet its market commitment and dispatch instruction, market payments should cover the sum of the incremental energy cost, start-up cost, no-load cost, transition cost, and cost of operating reserve products. Any revenue beyond those costs supports annual avoidable costs and provide a profit margin. The make-whole payment provides additional market payment in cases where revenue is below a resource's market offers (occasionally mitigated offers) to make the resource whole to its offers of ancillary service products, incremental energy, start-up, transition, and no-load.

The calculations separately evaluate: (1) day-ahead market commitments based on day-ahead market prices, cleared offers and dispatch; and (2) reliability unit commitments based on real-time market prices, cleared offers, and dispatch.

For 2016, day-ahead market and reliability unit commitment make-whole payments totaled approximately $71 million, up from $58 million last year. Much of the increase is the result of two factors: 1) the expansion of the market by about 10 percent more load and generation in late 2015; and 2) more wind generation contributing to a higher frequency of negative prices. For instance, there were six percent more real-time market intervals (approximately 500) with negative prices in 2016 compared to 2015.

Make-whole payments averaged about $0.27/MWh for 2016. In comparison to other ISO/RTO markets, SPP's make-whole payments are comparable to other ISO/RTOs which vary from $0.22/MWh to $0.57/MWh in 2016.[21] Figure 2–64 shows monthly day-ahead market and Figure 2–65 shows monthly reliability unit commitment make-whole payment totals by technology type. Day-ahead make-whole payments constituted about 38 percent of the total make-whole payments in 2016. SPP pays about 87 percent of all make-whole payments to

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[21] 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

gas-fired resources, with 72 percent of all make-whole payments to simple cycle gas resources through reliability unit commitment make-whole payments.

Figure 2–64 Make-whole payments by fuel type, day-ahead

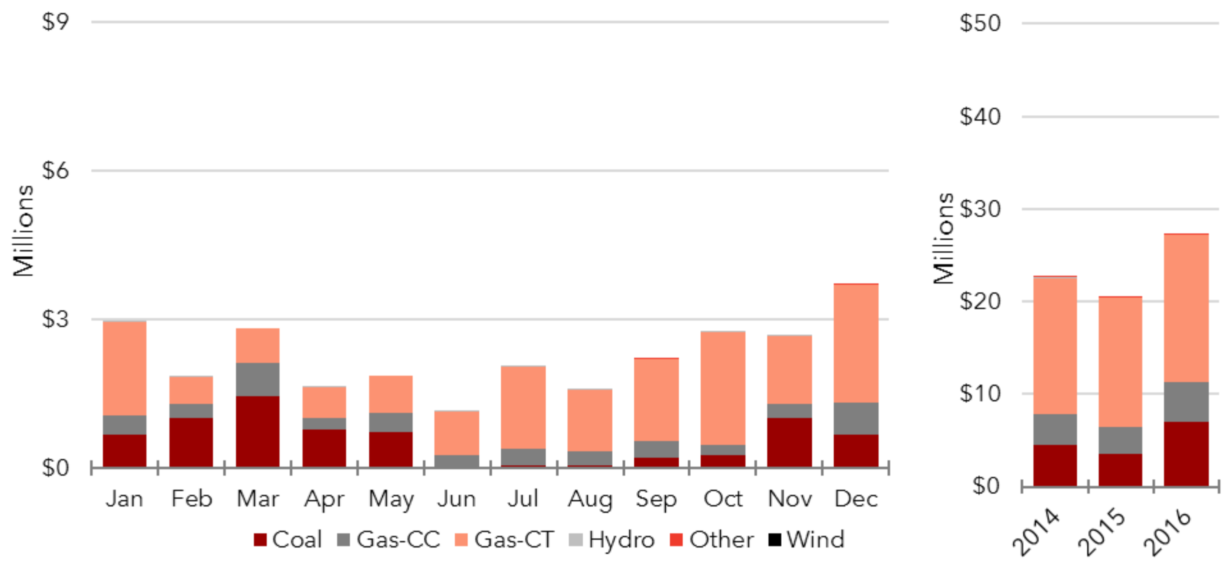
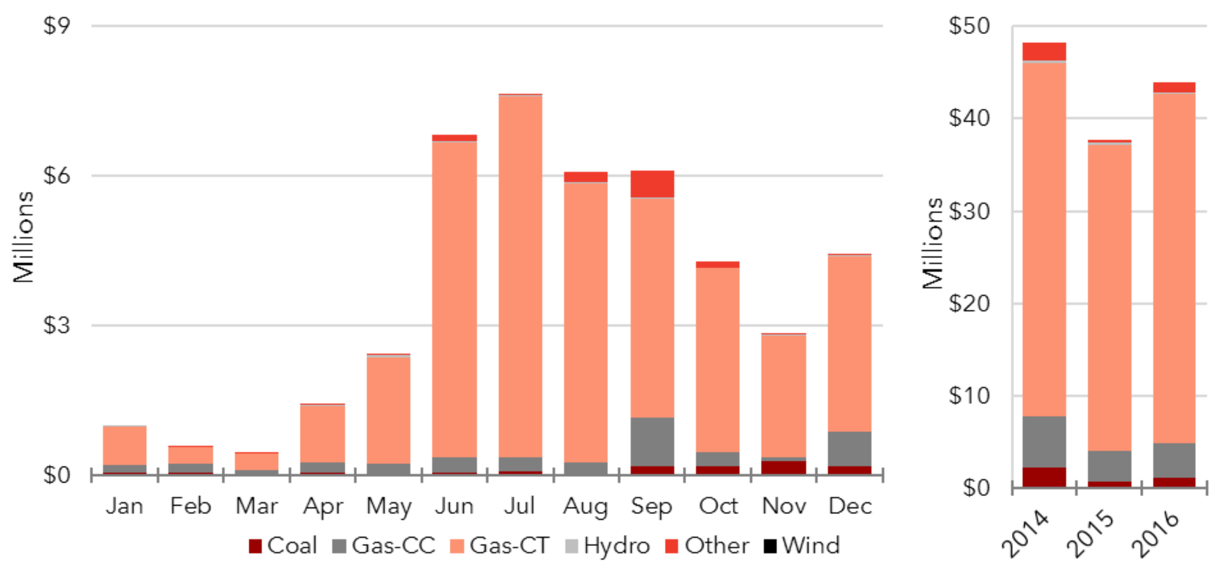


Figure 2–65 Make-whole payments by fuel type, real-time



Some commitments result from local reliability issues, uncaptured congestion in the day-ahead market, and SPP's rampable instantaneous load capacity (or head-room/floor-room) requirement.

Figure 2–66 shows the share of each cause of uplift payments in total. In 2016, SPP introduced the short-term reliability unit commitment process which allowed the day-ahead and intra-day reliability unit commitments to defer some starts. Additionally, SPP changed their processes to categorize more starts as transmission instead of reliability unit commitment manual starts to more clearly track for which flowgate they were needed.

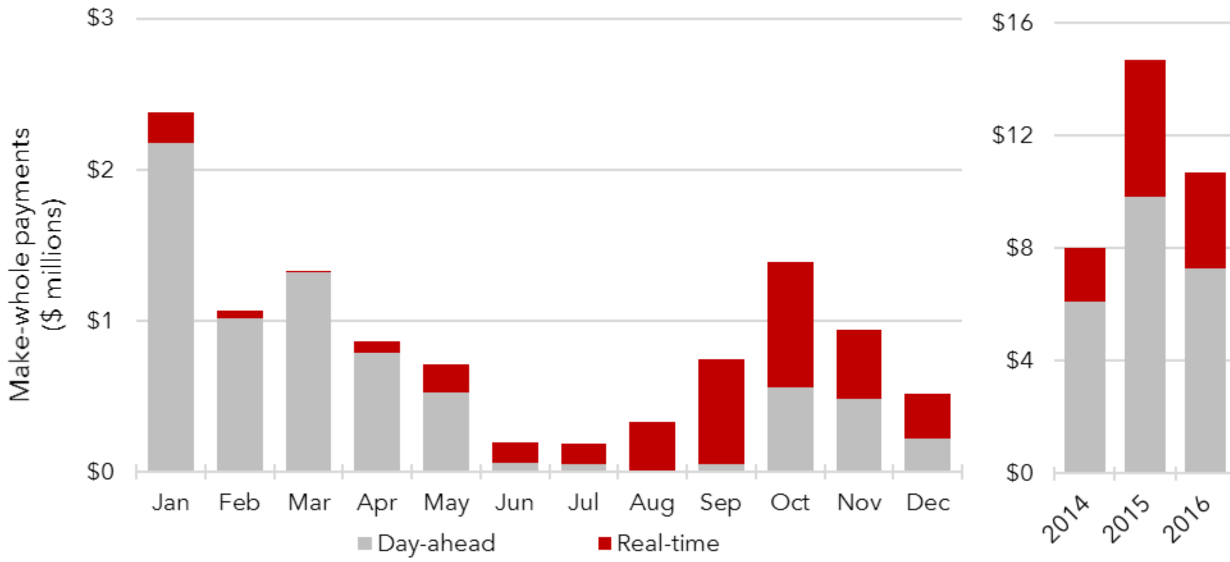
Figure 2–66 Make-whole payments, commitment reasons

Real-time commitment reason	2014	2015	2016
Intra-day RUC	39.9%	21.6%	24.4%
Manual, SPP transmission	2.2%	8.9%	23.2%
Day-ahead RUC	34.5%	33.8%	20.1%
Short-term RUC	0.0%	0.0%	12.9%
Manual, intra-day RUC	15.4%	17.2%	8.4%
Manual, voltage	5.1%	13.5%	8.0%
Manual, SPP capacity	2.4%	4.3%	2.6%
Manual, day-ahead RUC	0.3%	0.1%	0.3%
Manual, off supplemental	0.0%	0.0%	0.1%
Other	0.1%	0.6%	0.0%

Day-ahead commitment reason	2016	2015	2016
Day-ahead market	72.8%	53.4%	73.2%
Manual, voltage support	27.2%	46.6%	26.8%

Starting in October 2015 there was a large increase in day-ahead make-whole payments associated with manual commitments for voltage support. This trend carried into the first three months of 2016, however at much lower amounts than 2015. Make-whole payments associated with voltage support commitments bypass the conventional uplift process outlined in the next section. Instead, the cost of these make-whole payments are distributed out to the settlement areas that benefited from the commitment via a load ratio share. The below chart (Figure 2–67) illustrates the level of make-whole payments associated with voltage support commitments by month.

Figure 2–67 Make-whole payments for voltage support



As Figure 2–68 shows, most SPP resources received modest total annual make-whole payments. Eight resources received over $1.5 million, with two of those resources receiving over $2 million. Both of these numbers are twice the level as last year. When looking at the top eight resources we find that five of those resources were run extensively for voltage support, with over 90 percent of the top units' make-whole payments attributed to voltage support commitments.

Figure 2–68 Concentration of make-whole payments

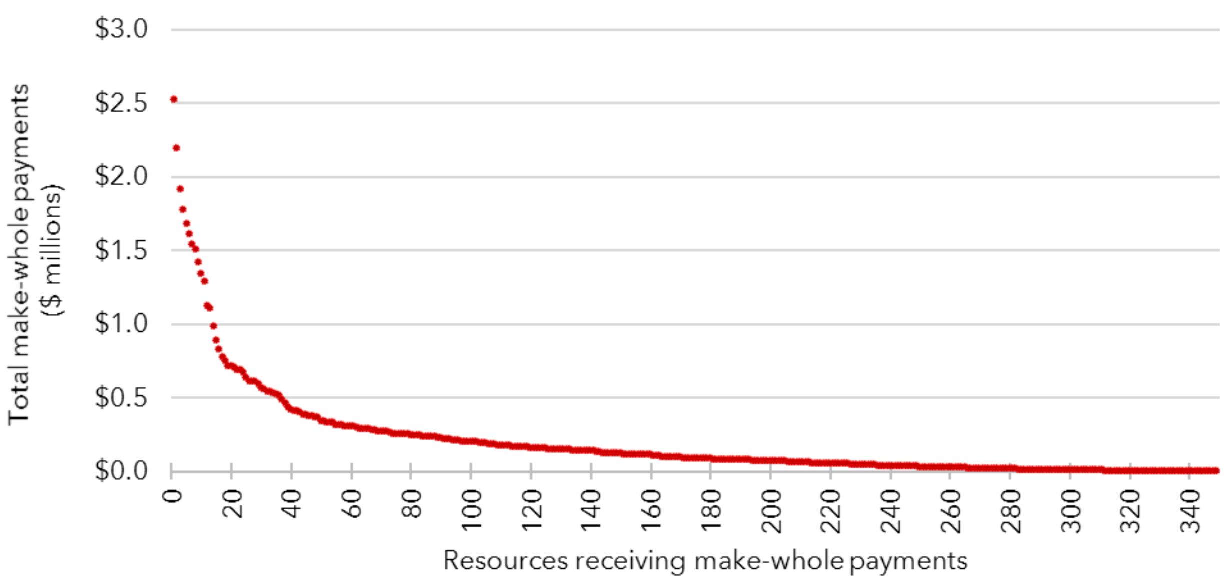


Figure 2–69 reveals some concentration in the market participants that received the highest levels of make-whole payments.

Figure 2–69 Market participants receiving make-whole payments

	2014			2015			2016		
	> $1 million	> $5 million	> $10 million	> $1 million	> $5 million	> $10 million	> $1 million	> $5 million	> $10 million
Market participants receiving make-whole payments	12	6	1	12	5	0	12	4	2
Sum of make-whole payments	92%	71%	19%	93%	65%	0%	92%	61%	38%

2.10.1 MAKE-WHOLE PAYMENT ALLOCATION

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

For the day-ahead market, make-whole payment costs are distributed to both physical and virtual withdrawals on a per-MWh rate. The per-MWh rate is derived by dividing the sum of all day-ahead make-whole payments for an operating day by the sum of all cleared day-ahead market load megawatts, export megawatts, and virtual bids for the operating day. The average per-MWh rate for withdrawing locations in the day-ahead market was just over $0.10 in 2016, which is slightly higher than the $0.09 average in 2015.

For the real-time market, make-whole payment costs are distributed through a per-MWh rate that is assigned to all megawatt-hours of deviation in the real-time market, and had an average real-time distribution rate of $1.14/MWh for 2016, slightly higher than the $1.12/MWh in 2015. There are eight categories of deviation and each category receives an equal amount per megawatt when the cost of make-whole payments is applied.

Even though each category of deviation is applied the same rate for deviation, approximately 76 percent of the real-time make-whole payment costs were paid by entities withdrawing (physical or virtual) more megawatts in the real-time market than the day-ahead market, through the settlement deviation charge, as show in Figure 2–70 below. Transactions susceptible to this charge are virtual offer megawatts, real-time load megawatts in excess of the day-cleared megawatts for a unit, exporting megawatts in real-time in excess of the export megawatts cleared in the day-ahead market, and units pulling substation power in excess of any megawatts produced by the unit.

Figure 2–70 Make-whole payments by market uplift allocation, real-time

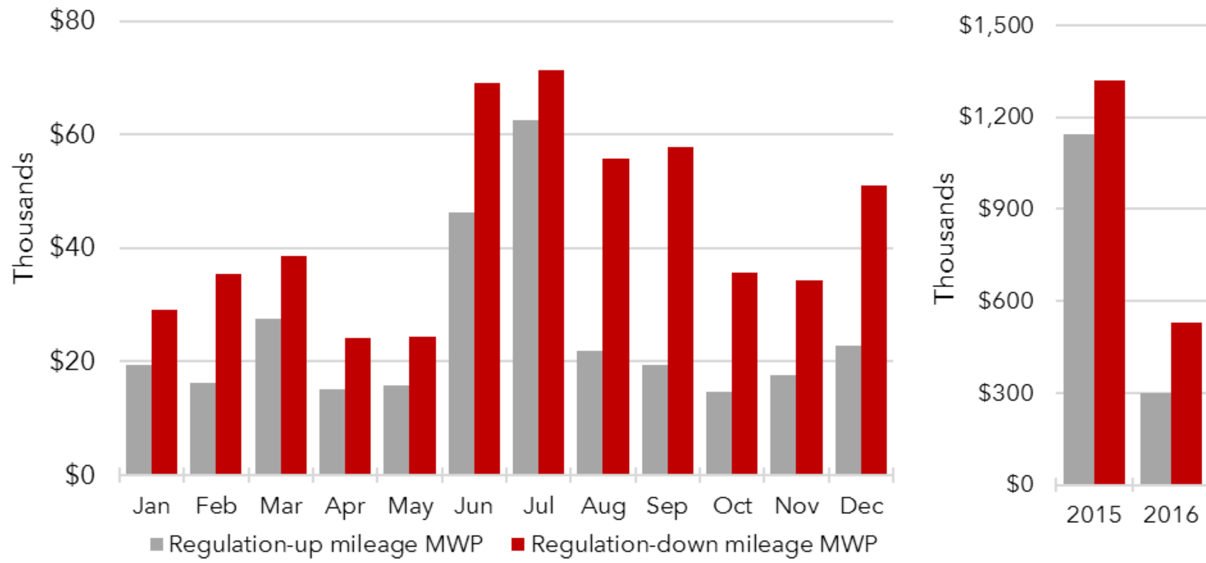
Uplift type	Deviation MWs (thousands)	Uplift charge (thousands)	Share of MWP charges	Cost per MW of deviation
Settlement location deviation	28,483	$ 33,607	76.40%	$ 1.18
Outage deviation	3,902	$ 4,964	11.28%	$ 1.27
Status deviation	1,411	$ 1,765	4.01%	$ 1.25
Maximum limit deviation	1,220	$ 1,596	3.63%	$ 1.31
Reliability unit commitment self-commit deviation	636	$ 672	1.53%	$ 1.06
Uninstructed resource deviation	530	$ 604	1.37%	$ 1.14
Minimum limit deviation	384	$ 405	0.92%	$ 1.06
Reliability unit commitment deviation	299	$ 374	0.85%	$ 1.25

2.10.2 REGULATION MILEAGE MAKE-WHOLE PAYMENTS

In March 2015, SPP introduced regulation compensation charge types for units deployed for regulation-up and regulation-down. One component of the regulation compensation charge types is regulation-up and regulation-down mileage make-whole payments for units that are charged for unused regulation-up or regulation-down mileage at a rate that is in excess of the regulation-up or -down mileage offer. Figure 2–71 illustrates both regulating products.

The large change from 2015 to 2016 can be attributed to a higher mileage factor being used early in market. In fact, the mileage factor was set to 100 percent in March 2015 until forecastable numbers became available April 2015. This resulted in much higher mileage make-whole payments in March 2015; mileage make-whole payments after May 2015 have remained consistent. Since that time the mileage factor has averaged around 20 percent. When the mileage factor is greater than the percentage of deployed megawatts to cleared megawatts for each product, the resource must buy back the undeployed megawatts at the mileage marginal clearing price for the respective product. If the mileage marginal clearing price used for the buyback is greater than the unit's cost for the product a make-whole payment may be granted.

Figure 2–71 Regulation mileage make-whole payments



2.10.3 POTENTIAL FOR MANIPULATION OF MAKE-WHOLE PAYMENT PROVISIONS

In the 2014 Annual State of the Market Report, the MMU highlighted four specific vulnerabilities that market participants could potentially manipulate in SPP's make-whole payment provisions. Three of the four vulnerabilities were directly associated with the FERC order regarding the make-whole payments and related bidding strategies of JP Morgan Ventures Energy Corp.[22] Shortly before the launch of the Integrated Marketplace, SPP and the MMU noted the following exposures in SPP's market design:

1) make-whole payments for generators committed across the midnight hour;

2) make-whole payments for regulation deployment; and

[22] See 144 FERC 61,068.

3) make-whole payments for out-of-merit energy.

In 2014, one of the MMU's recommendations covered the following with regard to the manipulations of make-whole payment provisions:

1) Evaluate solutions adopted by other RTOs to reduce exposure to market manipulation opportunities in make-whole payment provisions for resources committed across the midnight hour.
2) Disqualify resources with fixed regulation offers from receiving the regulation deployment adjustment charge.
3) Utilize automatic mitigation provisions for local reliability commitments for local reliability out-of-merit energy events.

In each case, a market participant has the ability to position its resource to receive a make-whole payment without economic evaluation of its offers by the market. At the time of the preparation of this report, all three of these issues are still susceptible to manipulation. However, RR 221[23] was brought forward by the RTO to ensure that units with long minimum run times could not manipulate their make-whole payments by inflating their offers on days subsequent to the initial commitment. Though the Market Working Group rejected the revision request in early 2017, the MMU appealed the rejection to the Market Operations and Policy Committee and the revision request was remanded back to the Market Working Group for further review. The MMU will continue to work with the Market Working Group to address this issue.

The MMU also worked with SPP's market design department to draft language concerning the vulnerability around the regulation deployment adjustment charge type. However, upon review the MMU discovered that the design gap was more pervasive than just fixed regulation. The MMU closed this recommendation and is working on a new recommendation to address the full issue.

Because exposures to all three vulnerabilities are still present, the MMU continues to monitor the market for all three of these gaps. This is necessary for exploitation of the third gap

[23] RR 221 (2014 ASOM MWP MMU Recommendation [3-Day Minimum Run Time])

concerning out-of-merit energy make-whole payments. Because of the infrequency of these events, the MMU will continue to monitor the gap, as we feel that there may not be a cost-benefit present to justify SPP addressing the issue through a market design change at this time.

In addition to these recommendations, the following recommendation was made concerning a potential gap allowing the manipulation of make-whole payments by jointly-owned units though the combined resource option. The market commits these units as one, and it provides separate dispatch instructions and make-whole payments by ownership share. This allows a shareowner to benefit from a higher energy offer than its co-owners through high minimum energy costs in the make-whole payment. At the time this report was released, SPP has approved but not implemented MRR 127,[24] a change in the market design to address this issue. The MMU review of this design indicates the change will address this vulnerability.

2.11 TOTAL WHOLESALE MARKET COSTS

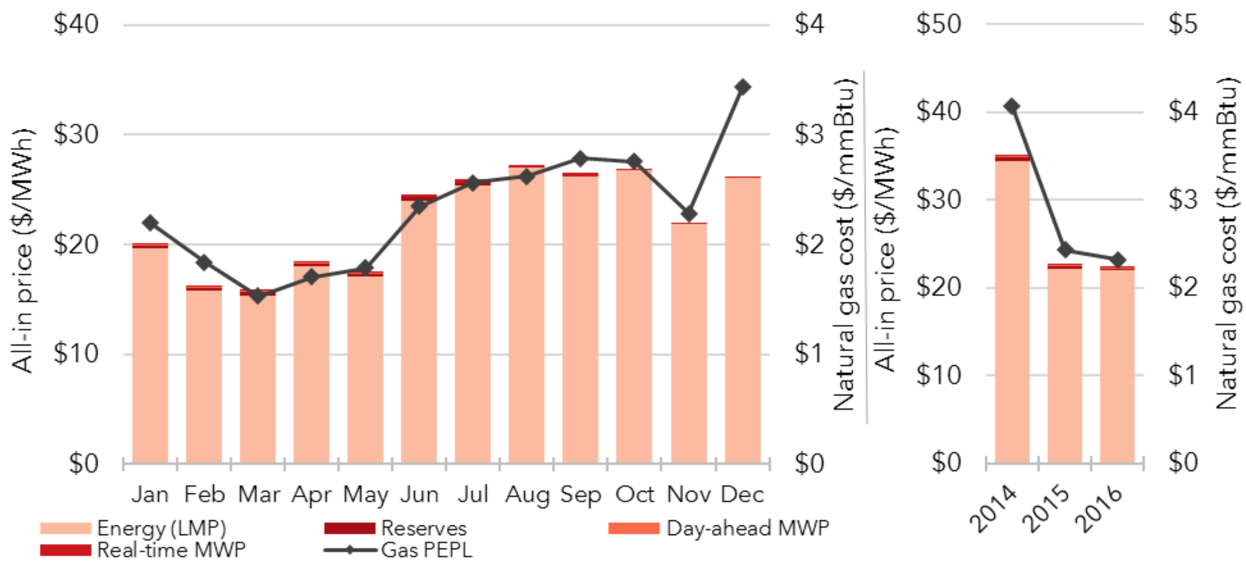
The average price of energy at load pricing nodes in SPP's real-time market for 2016 was $21.94/MWh. The average annual all-in price, which includes the costs of energy, day-ahead and real-time reliability unit commitment make-whole payments, operating reserves,[25] reserve sharing group costs, and payments to demand response resources, was $22.47/MWh, slightly down from the 2015 average.[26] The cost of energy includes all of the shortage pricing components. Figure 2—72 plots the average all-in price of energy and the cost of natural gas, measured at the Panhandle Eastern Hub.

[24] MRR 127 (JOU combined option – aggregate energy offer curve)

[25] Operating reserves are resource capacity held in reserve for resource contingencies and NERC control performance compliance, which includes the following products: regulation-up service, regulation-down service, spinning reserve and supplemental reserve.

[26] The Reserve Sharing Group costs and payments to demand response resources were negligible for both years.

Figure 2–72 All-in price of electricity and natural gas cost



The preceding figure shows the significant correlation between the price of natural gas and the price of energy, as expected since gas or coal are the fuel on the margin 92 percent of the time. Much of the deviation from the energy price/gas cost trend, also known as the implied heat rate, resulted from monthly fluctuation in load, marginal fuel, and the coal/natural gas price spread.[27] The graph also shows that the market cost of operating reserves and make-whole payments constituted approximately two percent of the all-in price, with make-whole payments and operating reserves amounting to $0.27/MWh and $0.26/MWh, respectively. Shortage pricing is included in the energy component and not easily separated out in the SPP settlement data; see Section 2.9 for a discussion of shortage pricing impacts.

The overall level and trend in energy prices were consistent with other ISO/RTO markets. Figure 2–73 shows that the on-peak day-ahead prices for SPP's hubs compared to prices in other ISO/RTO markets. The price separation between the North and South hub averaged $5/MWh in 2016, slightly higher than the $4/MWh in 2015.

[27] See Figure 2-24 for implied heat rate.

Figure 2–73 Comparison of ISO/RTO, on-peak day-ahead prices

	2014*	2015	2016
SPP North hub	$ 35	$ 24	$ 24
SPP South hub	$ 43	$ 28	$ 29
ERCOT North hub	$ 44	$ 31	$ 26
ERCOT West hub	$ 44	$ 31	$ 26
MISO Arkansas hub	$ 40	$ 29	$ 27
MISO Louisiana hub	$ 43	$ 33	$ 34
MISO Minnesota hub	$ 37	$ 27	$ 25
MISO Texas hub	$ 50	$ 32	$ 31
PJM West hub	$ 48	$ 44	$ 35

* 2014 values include prices starting March 1, which was the start of the SPP Integrated Marketplace.

2.12 LONG-RUN PRICE SIGNALS FOR INVESTMENT

In the long term, efficient market prices provide signals for any needed investment in new transmission, generation, and ongoing maintenance of existing generation to meet load. Given the very high resource margin[28] of about 43 percent in the SPP market footprint for 2016, the MMU does not expect market prices to support new entry of non-wind generation investments. In this context, the only explanation for wind generation investments can be the federal and/or state subsidies for those resources.

An analysis was conducted to determine if the SPP market would support investments in new generation by analyzing the fixed costs and annual fixed operating and maintenance costs of three generation technologies relative to their potential net revenues[29] at SPP market prices. The plants considered include a scrubbed coal plant, a natural gas combined cycle, and a combustion turbine. Figure 2–74 provides the cost assumptions and Figure 2–75 shows the results of the net revenue analysis. The analysis assumes the market dispatches the hypothetical resource when price exceeds the short-run marginal cost of production. In

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[28] Reserve margin is the system capacity at time of peak load, less peak load, divided by peak load (see Section 2.3.6).
[29] Net revenue is equal to revenues minus estimated marginal cost.

addition to these assumptions a capital recovery factor of 13.4 percent was used in the annual fixed operating and maintenance cost component.

Revenues have been insufficient to support the cost of new entry generation for all three technologies since the inception of the Integrated Marketplace, and 2016 was no exception. In 2015, prices did support the ongoing maintenance cost of combined cycle and combustion turbine units, though it did not support the cost of scrubbed coal units. This is consistent with the 2016 results shown below. Declining gas prices are the leading contributor to the decline in the profitability of coal plants.

Figure 2–74 Net revenue analysis assumptions

	Scrubbed coal	Advanced gas/oil combined cycle	Advanced combustion Turbine
Size (MW)	650	429	237
Total overnight cost ($/kW-yr.)	$ 5,098	$ 1,080	$ 644
Variable overhead and maintenance ($/MWh)	$ 6.95	$ 1.96	$ 10.47
Fixed overhead and maintenance ($/kW-yr.)	$ 68.49	$ 9.78	$ 6.65
Heat rate (Btu/kWh)	9,750	6,300	9,800

Source: EIA Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, January 2017

Figure 2–75 Net revenue analysis results

Technology	Average marginal cost ($/MWh)	Net revenue from SPP market ($/MW yr.)	Annual revenue requirement ($/MW yr.)	Able to recover new entry cost	Annual fixed O&M cost ($/MW yr.)	Able to recover avoidable cost
Scrubbed coal	$ 24.71	$ 22,532	$ 751,004	NO	$ 68,490	NO
Advanced gas/oil combined cycle	$ 17.58	$ 50,373	$ 154,369	NO	$ 9,780	YES
Advanced combustion turbine	$ 34.77	$ 12,652	$ 92,868	NO	$ 6,650	YES

Figure 2–76 provides results by SPP resource zone, as indicated by the dominant utility in the area. It shows that the conclusions do not vary geographically, albeit with differing energy prices and fuel costs. Other ISO/RTO markets have experienced a “missing money problem” in their markets, where net revenues do not support needed new investments. The MMU expects the market to signal the retirement of inefficient generation. Aging of the fleet and

increased environmental restrictions will eventually change the resource margin such that price signals for higher net revenue become increasingly important. The ability of market forces to provide these incentives and long run price signals is a strong benefit of the Integrated Marketplace.

Figure 2–76 Net revenue analysis by zone

	Scrubbed coal			Gas/oil combined cycle			Combustion turbine		
Resource Zone	Net revenue from SPP market ($/MW yr.)	Able to recover net entry costs	Able to recover avoidable cost	Net revenue from SPP market ($/MW yr.)	Able to recover net entry costs	Able to recover avoidable cost	Net revenue from SPP market ($/MW yr.)	Able to recover net entry costs	Able to recover avoidable cost
AEP	$ 23,298	NO	NO	$ 68,478	NO	YES	$ 15,723	NO	YES
KCPL	$ 21,218	NO	NO	$ 49,536	NO	YES	$ 15,451	NO	YES
NPPD	$ 11,823	NO	NO	$ 33,557	NO	YES	$ 10,258	NO	YES
OGE	$ 20,654	NO	NO	$ 59,036	NO	YES	$ 16,424	NO	YES
SPS	$ 47,933	NO	NO	$ 79,285	NO	YES	$ 12,139	NO	YES
WAUE	$ 10,985	NO	NO	$ 22,137	NO	YES	$ 10,636	NO	YES
WR	$ 16,679	NO	NO	$ 43,651	NO	YES	$ 17,660	NO	YES

2.13 TRANSMISSION CONGESTION

The locational marginal price (LMP) for the almost 19,000 pricing nodes in the SPP market reflects the sum of three components:

1) system-wide marginal cost of the energy required to serve the market (marginal energy component, or MEC);
2) the marginal cost of any increase or decrease in energy at a location with respect to transmission constraints (marginal congestion component, or MCC);
3) the marginal cost of any increase or decrease in energy to minimize system transmission losses (marginal loss component, or MLC).

$$LMP = MEC + MCC + MLC$$

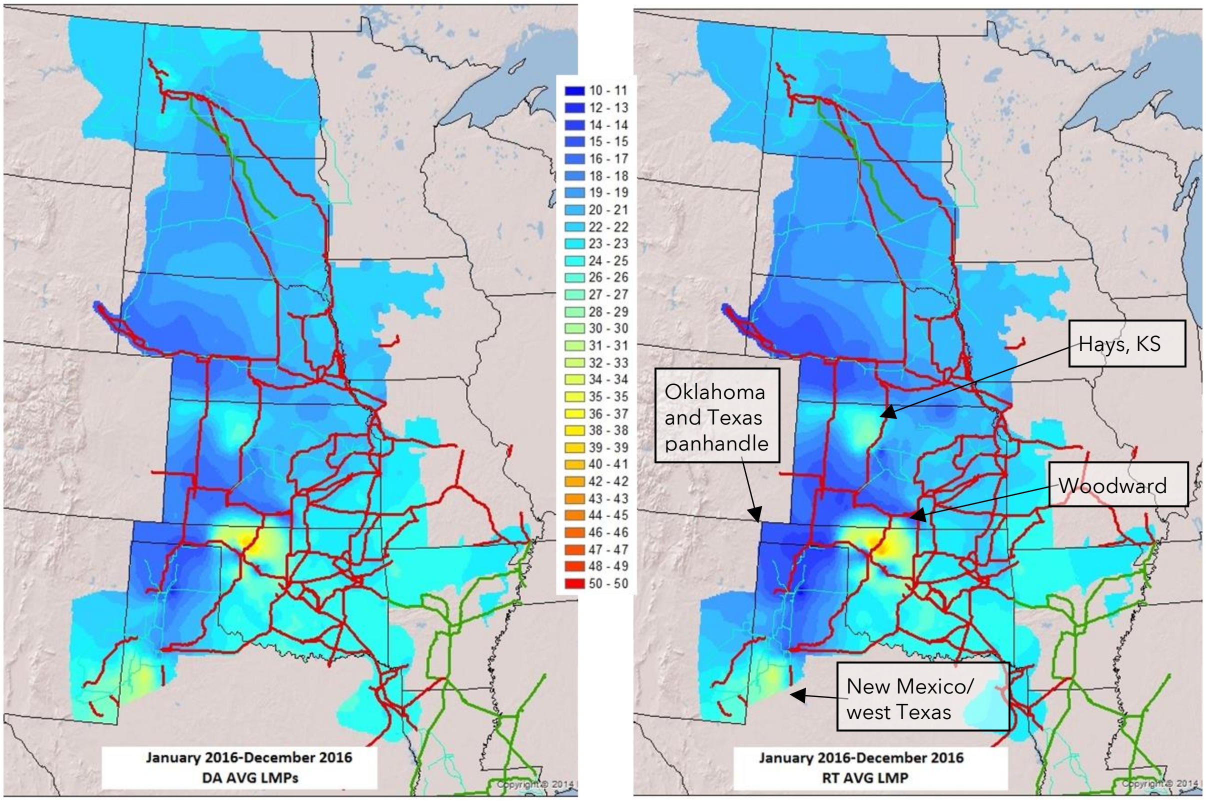
LMPs are a key feature of electricity markets that ensure the efficient scheduling, commitment, and dispatch of generation given the system load and reliability constraints. LMPs also provide price signals for efficient incentives for future generation and transmission investment. This section discusses factors that impact locational marginal prices:

- Geographic pattern of congestion and losses;
- Changes in the transmission system that alter congestion patterns;
- Congestion impacts on local market power;
- Load-serving entities hedging congestion costs in the transmission congestion rights market; and
- Distribution of marginal congestion and loss amounts.

2.13.1 PRICING PATTERNS AND CONGESTION

Figure 2—77 shows price contour maps representing the day-ahead and real-time average prices in 2016. Annual average day-ahead market prices range from around $18/MWh in western Nebraska, southeast Kansas and the Oklahoma and Texas panhandles, to around $41/MWh in the Woodward area of northwest Oklahoma. 2016 continued to see higher prices ($34/MWh) in the New Mexico and west Texas area, as well as around Hays, Kansas ($28/MWh). About 72 percent of this price variation can be attributed to congestion and 28 percent to marginal losses. Congestion events are more volatile in the real-time market so the average geographic price range is slightly higher, from $15/MWh to $44/MWh for real-time market prices versus $18/MWh to $41/MWh for day-ahead prices.

Figure 2–77 Prices, day-ahead and real-time market



2.13.2 CONGESTION BY GEOGRAPHIC LOCATION

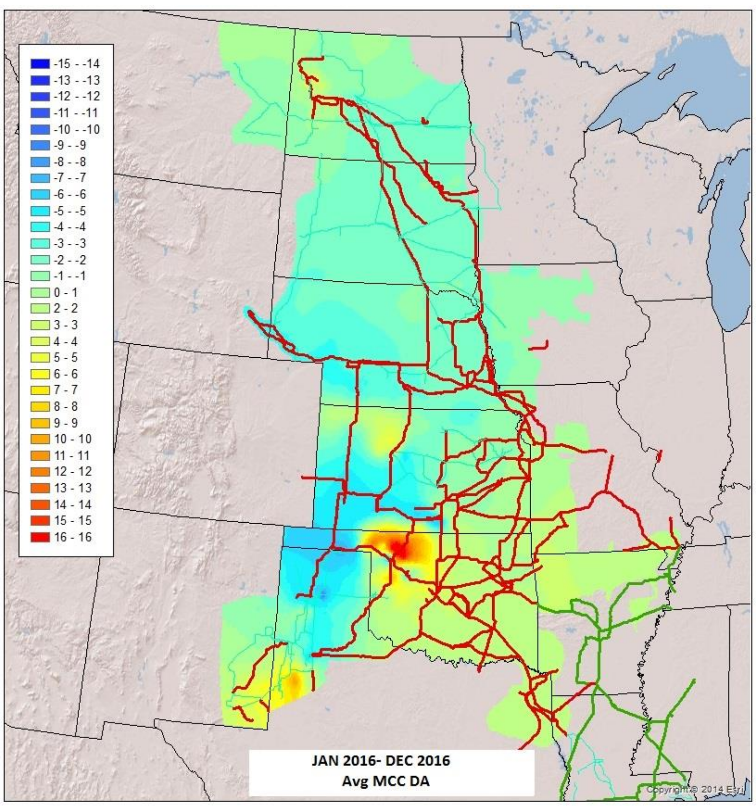
The physical characteristics of the transmission grid and associated transfer capability, the geographic distribution of load, and geographic differences in fuel costs drive the pattern of congestion in the SPP market. The eastern side of the SPP footprint, with a higher concentration of load, also has a higher concentration of high voltage (345 kV) transmission lines. Historically, high voltage connections between the west and east have been limited, as have high voltage connections into the Texas Panhandle area.

The cost of coal, SPP's predominant fuel for energy generation (48 percent in 2016), rises with distance from the Wyoming Powder River Basin, which is near the northwest corner of SPP's footprint, because of increased transportation costs. The cost of natural gas, SPP's largest fuel type by installed capacity (43 percent in 2016) rises in the opposite direction, from the southeast to the northwest. Wind-powered generation generally lies in the western half of the footprint, and nuclear generation resides near the center, while the majority of hydro is located in the north.

These factors combine to create a general northwest-southeast split in prices. The exception is slightly higher prices in the northern area of North Dakota resulting from the growth of, and associated demand from, oil and gas exploration and production facilities. Outside of the extreme northern part of North Dakota, the Integrated System typically saw lower prices compared to the rest of the footprint.

Figure 2–78 depicts the average marginal congestion component by settlement location for the day-ahead market. The lowest marginal cost components occur in the Oklahoma and Texas Panhandles, at -$7/MWh, and the highest marginal cost components lie in the Woodward, Oklahoma area at $16/MWh, and the New Mexico and west Texas areas at $9/MWh. This congestion cost pattern has remained basically the same since the beginning of the Integrated Marketplace.

Figure 2–78 Marginal congestion cost map, day-ahead market

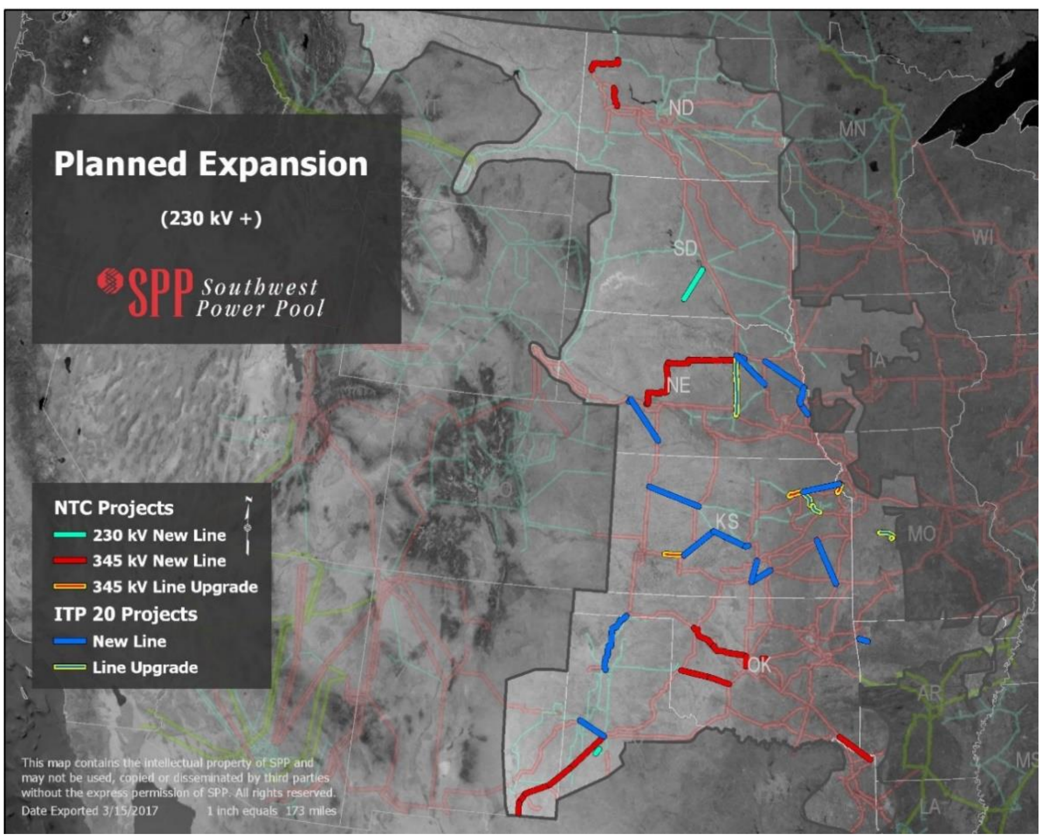


Several major 345 kV transmission projects were completed during 2016 that will support the efficient transmission of energy across the SPP footprint.

- Hoskins – Neligh 345kV (circuit 1)
    - Location: Nebraska
    - Energized: June 2016
- Cimarron-Matthewson 345kV (circuit 2)
    - Location: Central Oklahoma
    - Energized: July 2016
- Sibley-Mullin Creek-Nebraska City 345kV
    - Location: Northwest Missouri to southeast Nebraska
    - Energized: December 2016
- Elm Creek – Summit 345kV (circuit 1)
    - Location: Central Kansas
    - Energized: December 2016

The lines depicted on the map in Figure 2–79 below are projects that will further enhance the SPP transmission grid. Planned projects that may provide relief for the most congested areas in SPP are listed below in Figure 2–81.

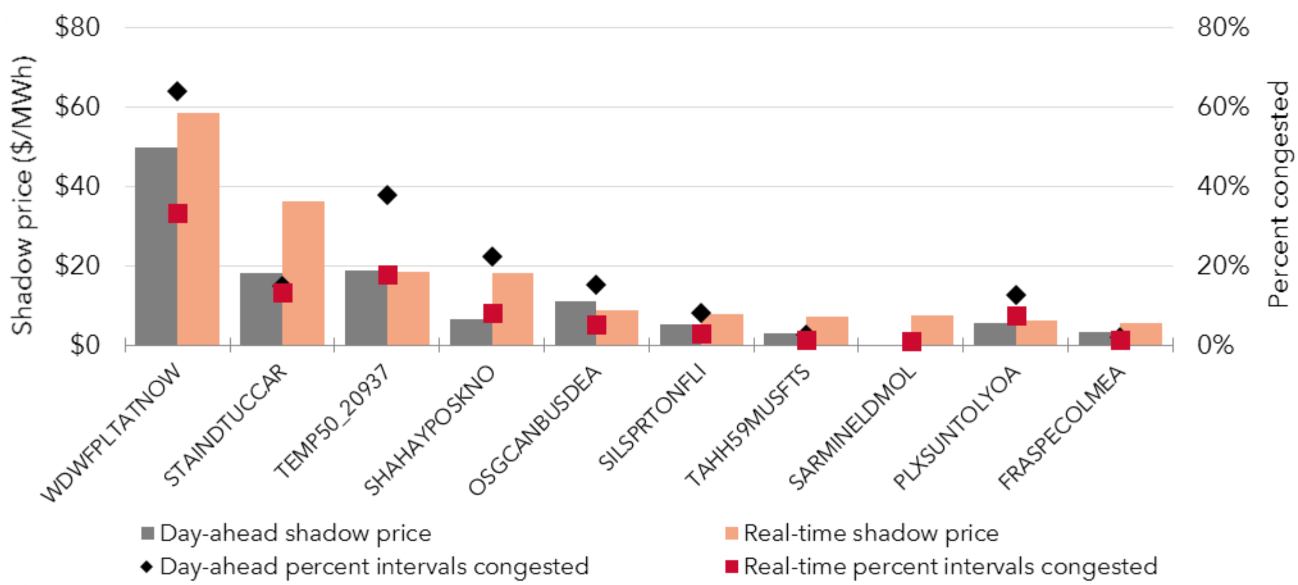
Figure 2–79 SPP transmission expansion plan



2.13.3 TRANSMISSION CONSTRAINTS

Market congestion reflects the economic dispatch cost of honoring transmission constraints. SPP uses these constraints to manage the flow of energy across the physical bottlenecks of the grid in the least costly manner while ensuring reliability. In doing so, SPP calculates a shadow price for each constraint, which indicates the potential reduction in the total market production costs if the constraint limit could be increased by one megawatt for one hour. Figure 2–80 provides the top 10 flowgate constraints by shadow price for 2016.

Figure 2–80 Congestion by shadow price, top ten flowgates



Flowgate name	Region	Flowgate location
WDWFPLTATNOW	Western Oklahoma	Woodward-FPL Switch (138) ftlo Tatonga-Northwest (345)
STAINDTUCCAR #	West Texas (Lubbock)	Stanton-Indiana (115) ftlo Tuco-Carlisle (230)
TEMP50_20937	West Texas (Lubbock)	Wolfforth-Terry County (115) ftlo Sundown-Amoco Switching (230)
SHAHAYPOSKNO	Western Kansas	South Hays-Hays (115) ftlo Post Rock-Knoll (230)
OSGCANBUSDEA	Texas Panhandle (Amarillo)	Osage Switch-Canyon East (115) ftlo Bushland-Deaf Smith (230)
SILSPRTONFLI	NW Arkansas	Siloam-Siloam Springs (161) ftlo Tonnence-Flint Creek (345)
TAHH59MUSFTS ^	Arkansas/Oklahoma	Tahlequah-Highway 59 (161) ftlo Muskogee-Fort Smith (345)
SARMINELDMOL *	Arkansas/Louisiana	Sarepta-Minden (115) ftlo El Dorado EHV-Mount Olive (500)
PLXSUNTOLYOA	West Texas (Lubbock)	Plant X Sub-Sundown (230) ftlo Tolk Sub-Yoakum (230)
FRASPECOLMEA	Nebraska-South Dakota	Fort Randall-Spencer (115) ftlo Meadow Grove-Kelly (230)

STAINDTUCCAR also includes congestion from TMP145_21718, which became STAINDTUCCAR

^ SPP market-to-market flowgate

* MISO market-to-market flowgate

The chart indicates that the two most congested corridors on the system were the west-to-east flows through the Woodward, Oklahoma area, and the north-to-south flows through west Texas and the Texas Panhandle. Both areas are significantly impacted by inexpensive wind generation in those regions of the market.

The Woodward, Oklahoma, and surrounding areas, had extensive 345kV buildouts energized in 2014, allowing higher transfers of wind generation to the more populated and higher-cost eastern portion of SPP. However, new wind generation keeps pace with transmission improvements. It is important to note that the Woodward constraint was congested in around two-thirds of all intervals in the day-ahead market and around one-third of all intervals in the real-time market.

The Texas Panhandle corridor relies mainly on 230kV transmission lines between Amarillo and Lubbock, Texas. The transmission corridor is impacted by the predominantly natural gas-fired generation in the south that is more expensive than the wind generation to the north. Texas Panhandle and west Texas constraints are congested in close to 40 percent of all intervals in the day-ahead market and 20 percent in the real-time market.

The area around Hays, Kansas is congested in 20 percent of all intervals in the day-ahead market and just under 10 percent of all intervals in the day-ahead market. Constraints in all other areas of the footprint are congested less than 10 percent of all intervals in both the day-ahead and real-time markets.

2.13.3.1 Western Oklahoma constraints

One of the most significant changes to the SPP transmission system in the past three years was the addition of the 345kV double circuit from Hitchland to Woodward, which went into service in May 2014. The line enables SPP to move more energy from the wind generation corridor in the west to the load centers in the east. This buildout appears to have resulted in complications on the lower voltage system in the Woodward area, as reflected in the significant increase in congestion. The west-east price differentials in this area create a transmission bottleneck at Woodward, as evidenced by the most congested flowgate in 2016. The average Woodward-FPL Switch flowgate shadow price for 2014 was about $19/MWh, increased to about $39/MWh in 2015, and then to nearly $59/MWh in 2016.

Projects are planned in the Western Oklahoma area that provide for more transfer of wind generation from west to east as listed in Figure 2‒81.

2.13.3.2 West Texas and Texas Panhandle constraints

The west Texas and Texas Panhandle area from Lubbock down into southeast New Mexico has historically been the most congested transmission corridor in the SPP market. In 2016 it was the second most congested area, with four of the top ten flowgates in this area. The Stanton-Indiana 115kV flowgate had the highest real-time market shadow price at $36/MWh. Of particular note is the Osage Switch-Canyon East 115kV flowgate, which was the fifth most congested in 2016 with a $9/MWh shadow price in the real-time market. The 2015 real-time market shadow price for this flowgate was about $36/MWh compared to nearly $80/MWh in 2014 and around $44/MWh in 2013. The day-ahead market also realized a similar magnitude decrease from about $73/MWh for the first 12 months of the market to $28/MWh in 2015 and then $11/MWh in 2016. This significant decline in the cost of congestion for this is as would be expected given the additional 345kV transmission facilities in the area and the overall lower electricity prices.

2.13.4 PLANNED TRANSMISSION PROJECTS

Figure 2‒81 provides a list of projects that may alleviate congestion on the 10 most congested flowgates in SPP system.

Figure 2–81 Top ten congested flowgates with projects

Flowgate name	Region	Flowgate location	Projects that may provide mitigation
WDWFPLTATNOW	Western Oklahoma	Woodward-FPL Switch (138) ftlo Tatonga-Northwest (345)	1. Matthewson–Tatonga 345 kV Ckt 2 (July 2018, ITP10) 2. Woodward EHV phase shifting transformer (June 2017, Generation Interconnection)
STAINDTUCCAR #	West Texas (Lubbock)	Stanton-Indiana (115) ftlo Tuco-Carlisle (230)	1. Tuco–Yoakum 345 kV Ckt 1 (June 2020, ITPNT) 2. Tuco–Stanton – Indiana – Erskine 115 kV terminal upgrades (June 2018, 2017 ITP10)
TEMP50_20937	West Texas (Lubbock)	Wolfforth-Terry County (115) ftlo Sundown-Amoco Switching (230)	1. Wolfforth–Terry County 115 kV terminal upgrades (June 2018, ITPNT)
SHAHAYPOSKNO	Western Kansas	South Hays-Hays (115) ftlo Post Rock-Knoll (230)	1. Hays–South Hays 115 kV rebuild (Oct 2016 – ITPNT) 2. Post Rock–Knoll 230kV Ckt 2 (Jan 2019, 2017 ITP10)
OSGCANBUSDEA	Texas Panhandle (Amarillo)	Osage Switch-Canyon East (115) ftlo Bushland-Deaf Smith (230)	1. Canyon East Sub–Randall County Interchange 115 kV line (March 2018 – Aggregate Studies) 2. Potter–Tolk 345 kV (Jan 2023, 2017 ITP10 – not yet approved)
SILSPRTONFLI	Northwest Arkansas	Siloam-Siloam Springs (161) ftlo Tonnence-Flint Creek (345)	1. Siloam–Siloam Springs 161kV rebuild (Jan 2019, 2017 ITP10)
TAHH59MUSFTS ^	Arkansas/ Oklahoma	Tahlequah-Highway 59 (161) ftlo Muskogee-Fort Smith (345)	No projects identified at the time of report publication.
SARMINELDMOL *	Arkansas/ Louisiana	Sarepta-Minden (115) ftlo El Dorado EHV-Mount Olive (500)	No projects identified at the time of report publication.
PLXSUNTOLYOA	West Texas (Lubbock)	Plant X Sub-Sundown (230) ftlo Tolk Sub-Yoakum (230)	1. Plant X–Sundown 230 kV terminal upgrades (Dec 2018, 2017 ITPNT – not yet approved)
FRASPECOLMEA	Nebraska/ South Dakota	Fort Randall-Spencer (115) ftlo Meadow Grove-Kelly (230)	No projects identified at the time of report publication.

STAINDTUCCAR also includes congestion from TMP145_21718, which became STAINDTUCCAR
^ SPP market-to-market flowgate
* MISO market-to-market flowgate

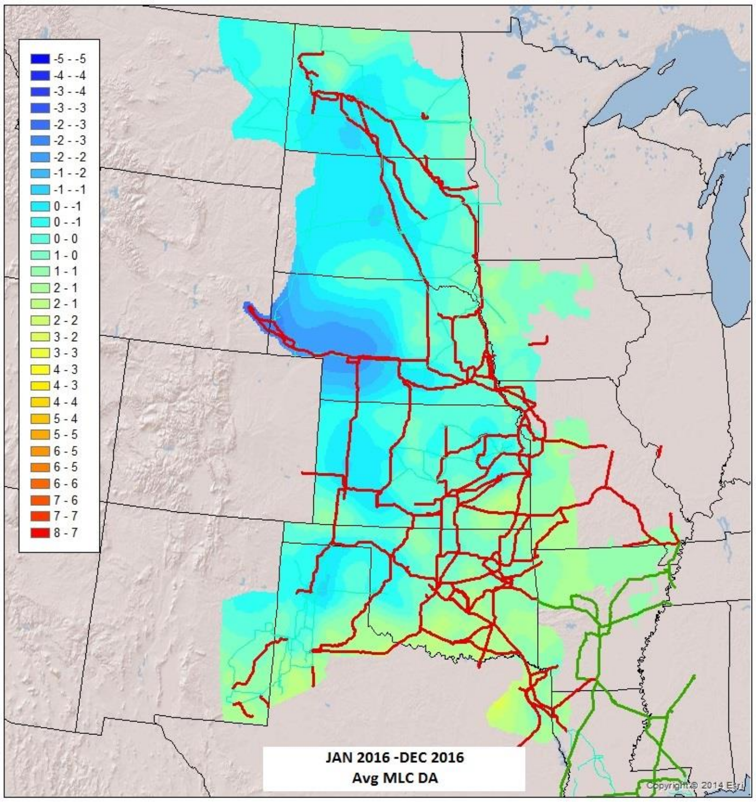
2.13.5 GEOGRAPHY AND MARGINAL LOSSES

Variable transmission line losses decrease with increased line voltage or decreased line length for the same amount of power moved. In the SPP footprint, much of the low-cost generation resides at a distance from the load and with limited high voltage interconnection. The average variable losses on the SPP system for 2016 were 2.4 percent. The marginal loss component of the price captures the change in the total system cost of losses with an additional megawatt of load at a particular location, relative to the reference bus.

Figure 2–82 maps the annual average day-ahead market marginal loss components. The average day-ahead marginal loss component ranges from about -$3/MWh near North Platte, Nebraska, to -$3/MWh at the Laramie River Station in eastern Wyoming, to zero in the Kansas

City area, to $1/MWh in the Hobbs, New Mexico area, and up to $2/MWh in the southeast corner of New Mexico.

Figure 2–82 Marginal loss component map, day-ahead



2.13.6 FREQUENTLY CONSTRAINED AREAS AND LOCAL MARKET POWER

Congestion in the market creates local areas where only a limited number of suppliers can provide the energy to serve local load without overloading a constrained transmission element. Under these circumstances, the pivotal suppliers have local market power and the ability to raise prices above competitive levels there by extracting higher than normal profits from the market. SPP's tariff provides provisions for mitigating the impact of local market power on prices, and the effectiveness of market power mitigation is described in Section 6. Local market power can be either transitory, as is frequently the case with an outage, or persistent, when a particular load pocket is frequently import-constrained.

Since SPP tariff calls for more stringent market power mitigation for frequently constrained areas, the MMU analyzes market data at least annually to assess the appropriateness of the frequently constrained area designations. In December 2015, the MMU conducted the annual frequently constrained area study for year 2016 based on expectations and recommended the Texas Panhandle area maintain the designation as a frequently constrained area and that the Woodward area be designated as a new frequently constrained area. SPP filed a report with FERC on February 5, 2016 and the new frequently constrained area designations were effective April 5, 2016. The 2017 analysis completed in late 2016 for use in 2017 recommended retaining the two existing frequently constrained areas. The final reports are available on the SPP web page.[30]

2.13.7 MARKET CONGESTION MANAGEMENT

In optimizing the flow of energy to serve the load at the least cost, the SPP market makes extensive use of the available transmission up to the flowgate constraint limits. This is best seen in the day-ahead market (see Figure 2—83), where uncongested intervals and breached intervals are rare. Less than one percent of day-ahead market intervals incur a breached condition compared to nearly 25 percent for the real-time market since the start of the Integrated Marketplace.[31] The high price resulting from breached conditions is consistent with the objective of promoting reliability.

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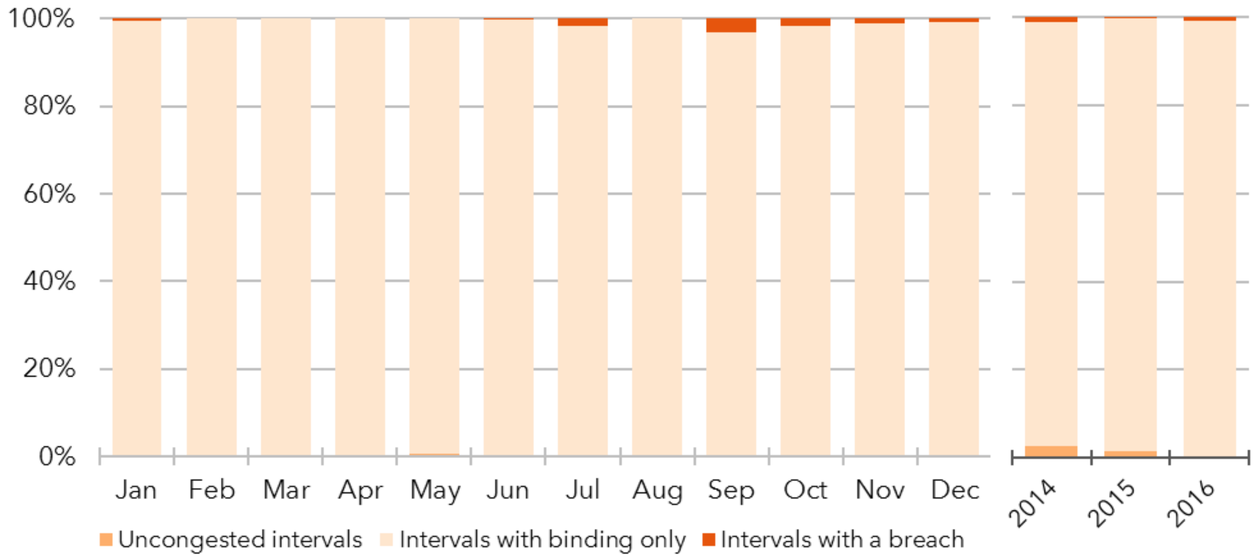
[30] https://www.spp.org/documents/46323/fca%202016%20report%20-%20final.pdf
[31] SPP uses hourly intervals in the day-ahead Market and five minute intervals in the real-time market for scheduling, dispatch, and settlement purposes.

Figure 2–83 Breached and binding intervals, day-ahead market



In the more dynamic environment of the real-time market, uncongested intervals were about 14 percent of intervals for 2016, whereas intervals with a constraint breach were at 37 percent, as shown in Figure 2–84.

Figure 2–84 Breached and binding intervals, real-time, monthly

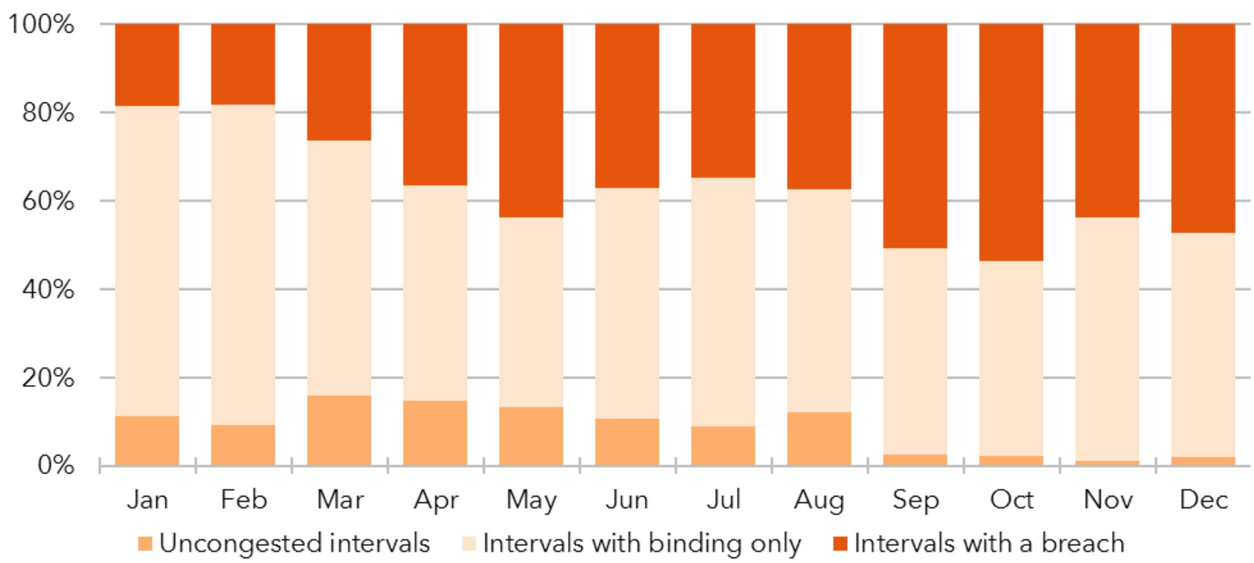
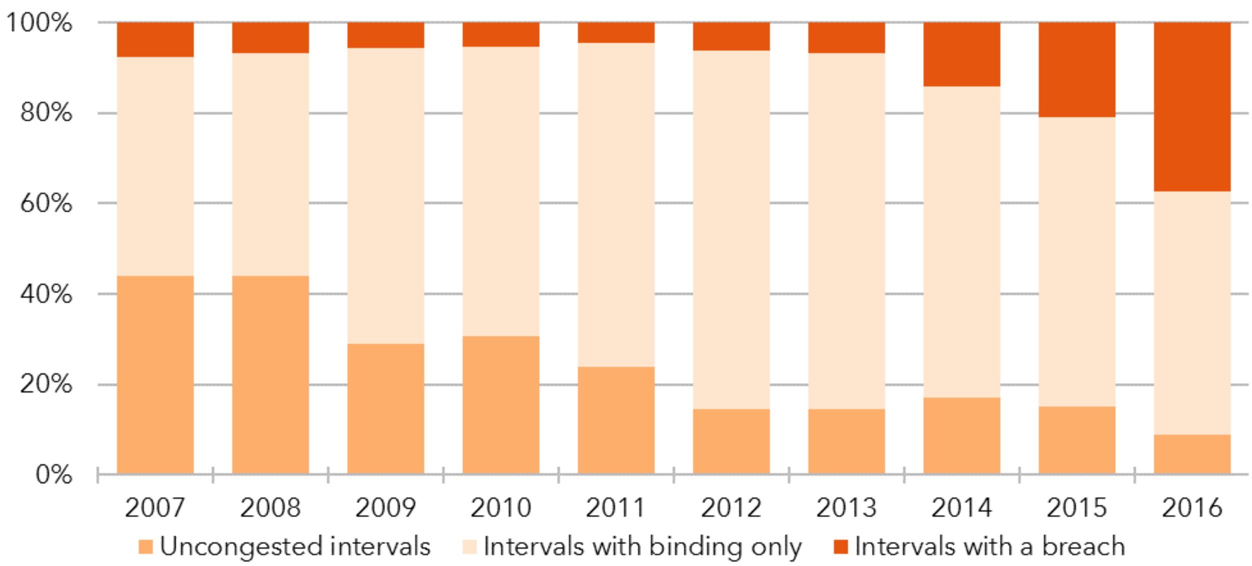


Figure 2–85 shows this trend over time for real-time market in the Energy Imbalance Service market and the Integrated Marketplace. In 2007 the market experienced no congestion in more than 40 percent of all market intervals. Uncongested intervals have been below 20 percent since 2012. The introduction of the Integrated Marketplace in 2014 did not

substantially alter the level of congestion in the market, though the frequency of constraint breaches has risen.

Market-to-market coordination with MISO, as discussed in Section 2.6, was implemented in March 2015 and the integration of the Integrated System occurred in October of that year, both of which increased the number of constraint breaches. A market-to-market breach of a MISO constraint could be an indicator that MISO has more efficient generation than SPP to alleviate congestion on that constraint.

Figure 2–85 Breached and binding intervals, real-time, annual



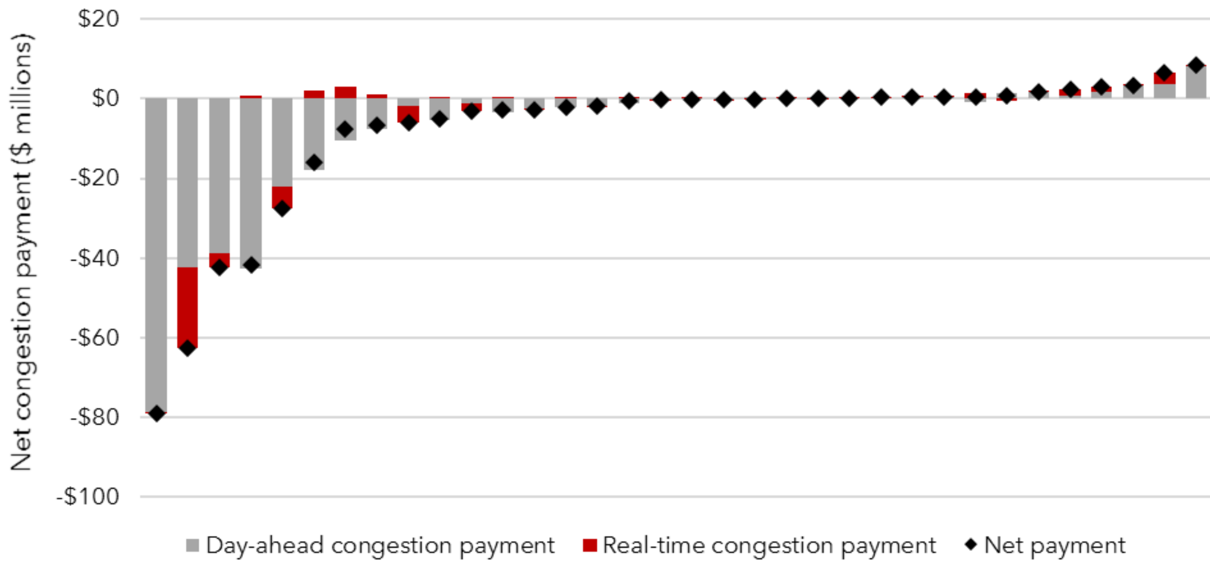
2.13.8 MARKET CONGESTION COSTS, DAY-AHEAD AND REAL-TIME IMPACTS

2.13.8.1 Congestion payments

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

Figure 2–86 shows the annual day-ahead and real-time market congestion payments for load-serving market participants during 2016.

Figure 2–86 Annual congestion payment by load-serving entity



Most load-serving entities face congestion costs, depicted as negative payments in the graph, because they are part of vertically-integrated entities with higher marginal congestion components at load than at resources. Day-ahead congestion payments by ranked load-serving entities ranged from about $8 million in payments to about $78 million in costs.

Market participants also receive payments and incur costs for real-time market congestion, which are charged and paid based on deviations between day-ahead and real-time market positions. Real-time market congestion ranged from $20 million in costs to $3 million in payments for load-serving entities. These ranges were from $13 million in costs to $25 million in payments for non-load-serving entities. Many of the non-load-serving entities incurring costs represent wind farms, which may sell at negative prices or buy back day-ahead market positions. The real-time market congestion payments result in a net positive $64 million for non-load-serving entities, as shown in Figure 2–87. Virtual transactions make up the largest payments associated with the real-time congestion to non-load-serving entities.

2.13.8.2 Hedging real-time congestion

SPP allocates real-time market congestion costs to market participants through revenue neutrality uplift (RNU) charges. In 2016, SPP allocated about 91 percent of revenue neutrality uplift to load-serving entities, resulting in an additional $39 million in congestion-related charges for load-serving entities.

At an aggregate level, the SPP load was not fully hedged for the explicit congestion costs paid in the day-ahead and real-time markets. Figure 2–87 provides the aggregate congestion costs and hedging totals for load-serving entities (LSEs) and non-load-serving entities. It shows that the total of all transmission congestion right and auction revenue right net payments to load-serving entities of $243 million was less than the total day-ahead and real-time market congestion costs of $280 million. This is in contrast to 2015 when transmission congestion right and auction revenue right net payments to load-serving entities exceeded their congestion costs. This change could be due to a variety of factors, including the design change with RR 91,[32] market participant behavior, or overall increased congestion patterns in the market. In aggregate for 2016, non-load-serving entities collected transmission congestion right and auction revenue right net revenues of nearly $91 million, which exceeded their day-ahead and real-time market congestions costs of $18 million.

[32] RR 91 (Annual allocation percent change)

Figure 2–87 Total congestion payments [33]

(in $ millions)	Load-serving entities			Non-load-serving entities		
	2014	2015	2016	2014	2015	2016
DA congestion	(268.8)	(148.6)	(259.6)	(54.0)	(31.5)	(81.2)
RT congestion	(11.1)	(3.4)	(20.4)	42.3	40.1	63.7
Net congestion	(279.9)	(152.0)	(280.0)	(11.6)	8.6	(17.5)
TCR charges	(360.5)	(148.2)	(51.0)	(65.3)	(76.4)	(63.5)
TCR payments	268.9	126.7	212.4	105.3	83.3	158.7
TCR uplift	(33.5)	(18.3)	(21.0)	(21.5)	(15.2)	(18.0)
TCR surplus ^		2.2	4.2		1.4	4.1
ARR payments	375.5	175.6	74.8	3.1	(15.8)	6.5
ARR surplus	45.2	30.6	24.0	1.2	3.4	3.1
Net TCR/ARR	295.6	168.5	243.3	22.9	19.2	90.8
RT congestion uplift	(17.9)	(20.8)	(39.4)	(1.4)	(5.4)	(4.0)

^ remaining at year end

2.13.8.3 Distribution of marginal loss revenues (over-collected losses)

Both the congestion and loss components of prices create excess revenues for SPP that must be distributed to market participants in an economically efficient manner. In the case of marginal loss revenues, this requires that the distribution does not alter market incentives. This was not the case during the first year of SPP's market, and SPP took steps that largely corrected the incentive issues. SPP proposed changes to the method for distributing over-collected losses in FERC Docket No. ER15-763.[34] The Commission accepted these changes, which went into effect in April 2015.

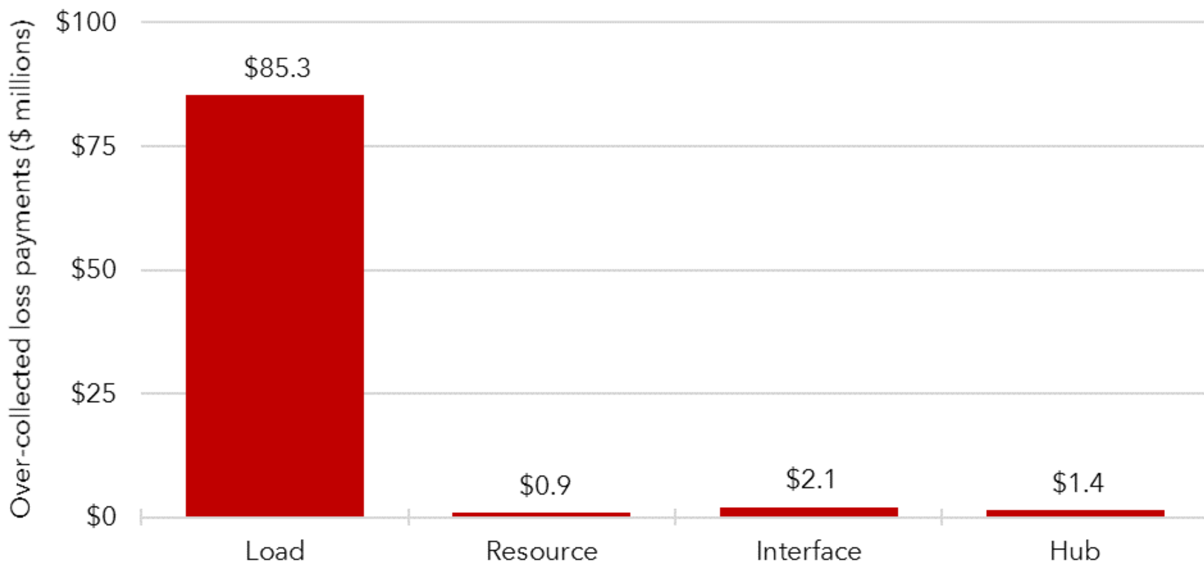
In April 2015, SPP enhanced the over-collected losses distribution calculations. The enhanced design consolidates the distributions of day-ahead and over-collected loss rebates into only one distribution. Under this new design, both day-ahead and real-time over-

[33] Transmission congestion right charges and auction revenue right payments are less in 2016 because of the long-term transmission congestion right design. Long-term transmission congestion rights get converted directly to transmission congestion rights, and therefore, aren't accessed auction revenue right payments or transmission congestion right charges.
[34] https://www.ferc.gov/CalendarFiles/20150331172533-ER15-763-000.pdf

collected loss rebates are distributed on just real-time withdrawing megawatts. This includes loads, substation power, exports, wheel-throughs, pseudo-ties, and bilateral settlement schedules (BSS). The only exception is that both day-ahead and real-time bilateral settlement schedules are entitled to the rebate. In addition to consolidating the distributions to only real-time withdrawing megawatts, changes were made to loss pool allocations. Under the old method, virtual transactions drove up the SPP loss pools allocation of over-collected losses rebates, even though virtual activity was not eligible for rebates. This caused real-time exporters to get a large percentage of the over-collected losses rebates, which during that time were typically a charge. Virtual transactions are no longer considered in the loss pool distributions. These design enhancements better allocate the over-collected losses to the transactions that contributed to the over-collection while removing some of the adverse incentives present under the former design.

As can been seen in Figure 2—88 below, a total of $89 million was paid out in over-collected losses rebates during 2016, with $85 million or 95 percent going to load. This is down from the $108 million in over-collected losses rebates paid out in 2015 and the $106 million paid in the first 12 months of the market. Since the over-collected losses changes were made in April 2015, it is not possible to compare annual over-collected losses payments. Instead, we can compare the April to December 2015 rebates to the April to December rebates of 2016. This comparison shows that the rebates dropped by seven percent from $78 million between April and December 2015 to $73 million in that same period of 2016.

Figure 2–88 Over-collected losses, real-time



The use of bilateral settlement schedules changes the distribution of over-collected losses. The bilateral settlement schedules enables market participants to transfer energy from one entity to another at a particular settlement location. It creates a financial withdrawal at the settlement location for the seller and a financial injection at the settlement location for the buyer. As long as the bilateral settlement schedules do not change the net withdrawal at the location, the charges and credits for losses simply change hands between the entities owning the bilateral settlement schedules. Where the bilateral settlement schedules create a net withdrawal that would not otherwise exist, it creates credits and charges that would not otherwise exist. For example, if a bilateral settlement schedule amount at a resource settlement location exceeds the cleared output of the resource, it creates a net withdrawal, and the generation owner receives a loss distribution credit for the excess megawatts of the bilateral settlement schedule. The same occurs with a bilateral settlement schedule at hubs, where no energy is withdrawn, other than a bilateral settlement schedule. The majority of the $930,000 in distributions at resource settlement locations during 2016 occurred for this reason, as well as $1.4 million at hubs. These distributions cause concern for the MMU, because they create an incentive to game the market rules by transacting using the bilateral settlement schedules. Exploitation of this aspect of the loss distribution calculation can potentially be market manipulation.

Over-collected losses no longer create charges in the real-time market. Total loss revenues are calculated from both the day-ahead market and the real-time market. SPP distributes them based on real-time market withdrawals only. Virtual transactions no longer factor into the loss pool calculation, reducing the exaggeration of distributions at interfaces and hubs. However, incentives for transacting bilateral settlement schedules in hours with high percentages paid to the SPP loss pool still exist. Additionally, as stated above, bilateral settlement schedules do not contribute to the over-collection of losses, but they are entitled to rebates. As stated earlier, any scenario where a bilateral settlement schedule creates a net withdrawal that would not have existed had the bilateral settlement schedule not been placed creates an opportunity for an over-collected losses rebate. When this happens, the over-collected losses rebate is diluting other rebates that contributed to the over-collection of losses.

A recommendation in the 2014 Annual State of the Market report was to remove bilateral settlement schedule transactions from the over-collected losses distribution calculation. The SPP Market Working Group approved Revision Request 200[35] in January 2017 that should alleviate the adverse incentives given to bilateral settlement schedules to transact in amounts that vary from the underlying flows of the transaction. The implementation of these changes are still pending, but are expected to be in effect before the end of 2017.

[35] RR 200 (Design change for bilateral settlement schedule and over-collected losses distribution)

3 DAY-AHEAD MARKET

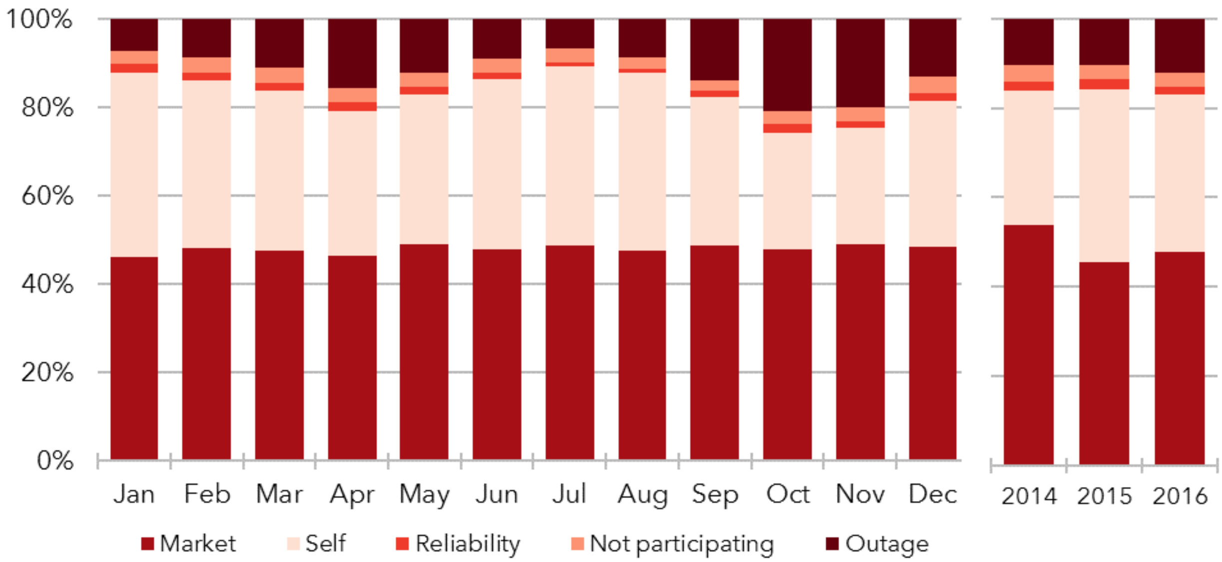
3.1 LOAD AND GENERATION SCHEDULING

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 algorithm 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 2016, 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—rivaled that of the load-serving entities.

Figure 3–1 shows generation participation offers in the day-ahead market by commitment status. The 'market' commitment status averaged 48 percent and 'self-commit' status averaged 35 percent of the total offered capacity for 2016, which is a slight change from 2015 when 'market' commitment status averaged 46 percent and 'self-commit' status averaged 39 percent. Resources with commitment statuses of 'reliability' and 'not participating' averaged two percent and three percent, respectively, which is very close to what was experienced in 2015. 'Outage' status accounted for the final 12 percent, an increase from 10 percent in 2015. While self-commits are down from 2015, they still constitute a large amount of the capacity offered into the market. Much of the increase can be attributed to coal plants needing to burn coal stock while the low gas prices reduced the opportunity for coal units to be economically cleared in the day-ahead market. The lower outage level could indicate an improvement in the efficiency of the market if the trend is sustained over time.

Figure 3–1 Day-ahead market offers by commitment status



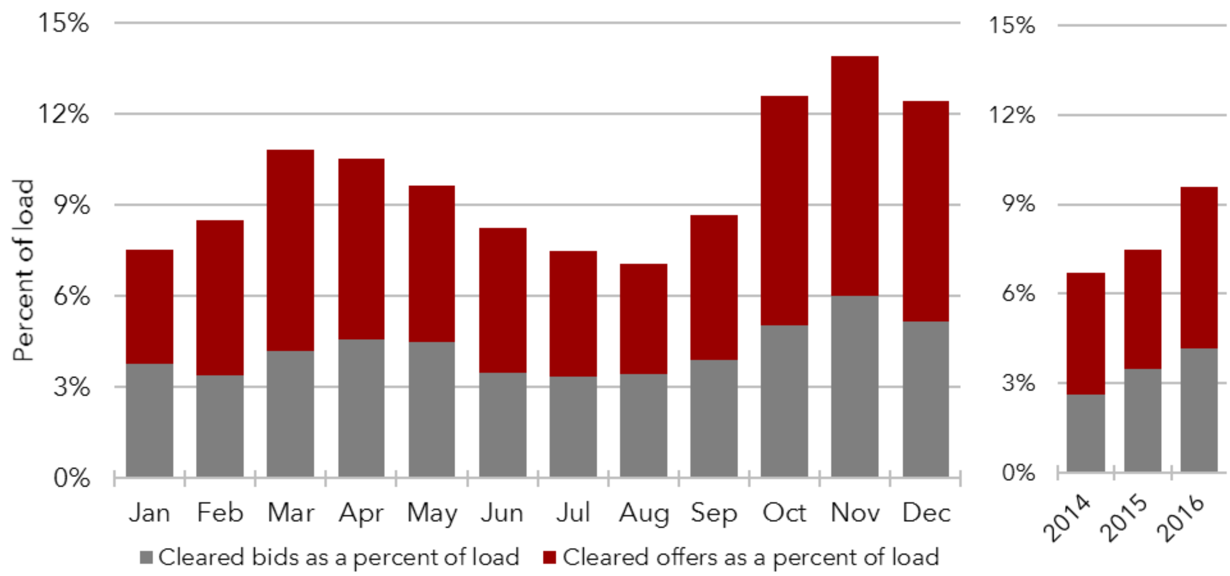
3.2 VIRTUAL TRADING

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 emulate 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 emulate load. The value of virtual trading lies in its potential to converge day-ahead and real-time market prices.

Price convergence because of virtual transactions requires sufficient competition in virtual trading; transparency in day-ahead market, reliability unit commitment, and real-time market operating practices; and predictability of market events. The first two years of the market experienced moderate levels of virtual participation, consistent profitability of virtual trading, and increasing convergence between day-ahead and real-time market prices. All of these factors indicate a reasonably efficient virtual trading market.

Figure 3–2 displays the total volume of virtual transactions as a percentage of real-time market load. As seen in the figure, virtual transactions averaged 9.4 percent of real-time market load, compared to 7.5 percent in 2015. The increase was mostly in cleared virtual offers, 5.4 percent in 2016 compared to 4.0 percent in 2015, but also in virtual cleared bids which increased from 3.5 percent in 2015 to 4.2 percent in 2016. In particular, there was a large increase in cleared virtual offers in October 2016. This is a typical trend as outages occur following the peak summer season.

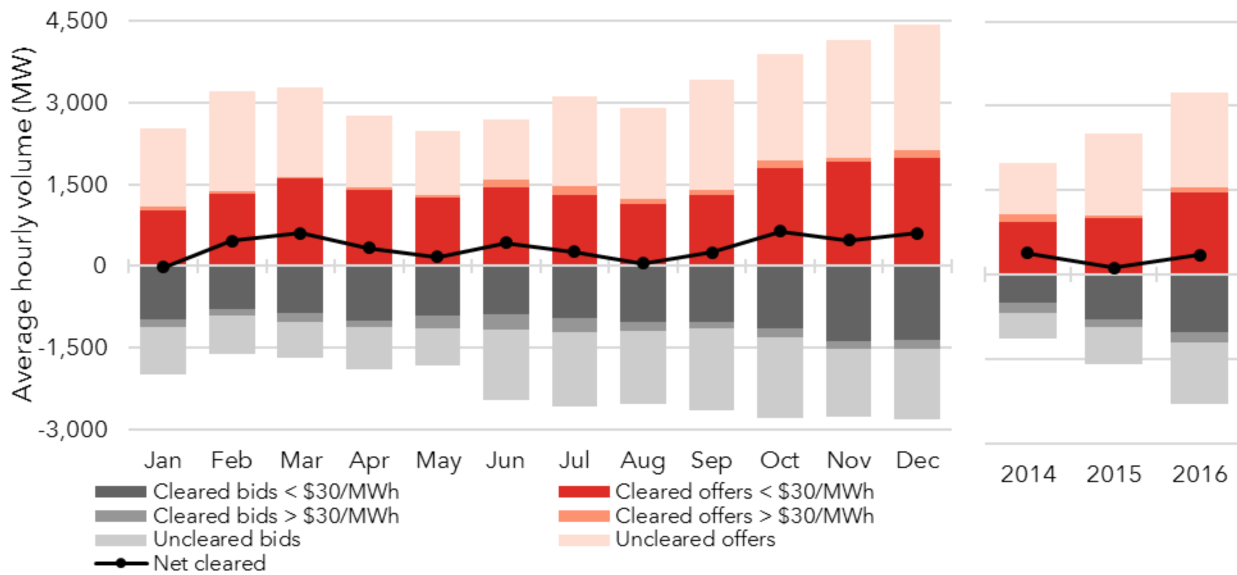
Figure 3–2 Virtual transactions as percent of real-time load



At about nine percent of load, the average hourly total volume of cleared virtuals ranged from 2,200 MW to 3,600 MW. The average hourly volume that did not clear ranged from 2,300 MW to 3,600 MW. The net cleared virtual positions in the market averaged about 355 MW. As shown in Figure 3–2 above, the percentage of cleared virtual transactions was lowest during summer months. Figure 3–3 below indicates that bids (cleared and uncleared) realize more fluctuation during these summer months. November experienced the highest levels of virtual activity as a percentage of real-time load.

Figure 3–3 shows cleared demand bids that offered more than $30/MWh over the realized real-time price, and the supply offers offered at less than $30/MWh under the realized real-time price. These types of bids and offers are called "price-insensitive" and occur more often with bids (18 percent of cleared bids) as opposed to offers (10 percent). Price-insensitive bids and offers are willing to buy/sell at a much higher/lower price that could lead to price divergence rather than competitive, or price-sensitive, bids and offers leading to price convergence in 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.

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



Virtual trades profited in aggregate for the year by about $33 million, which is up from $21 million in 2015. 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 2016 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, $1.14/MWh, and $0.05/MWh, respectively. When factoring in these charges and credits, the total profits realized for 2016 are reduced by 52 percent to $16 million. A monthly break down of these profits and fees can be seen in Figure 3–4. Every month in 2016 was profitable in aggregate for virtual transactions, before factoring in the transaction fees. However, once the fees were accounted for March and April become unprofitable in aggregate.

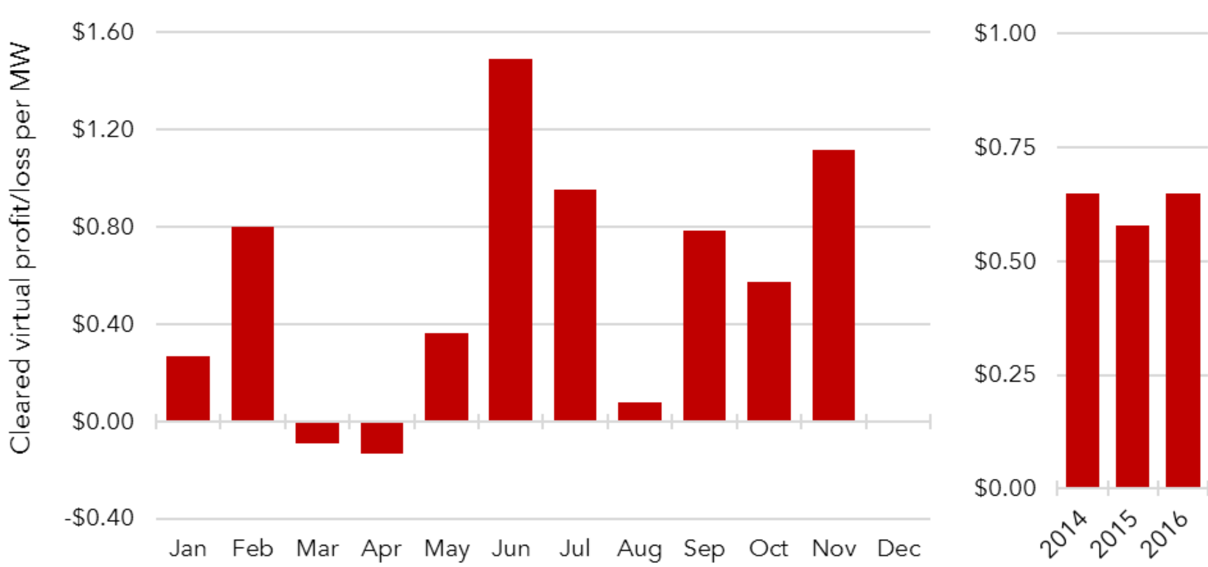
Figure 3–4 Virtual profits with distribution charges

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	$2.5	-$1.8	$0.8	$0.0	$0.1	$0.2	$0.0	$0.4
February	$2.8	-$1.3	$1.5	$0.0	$0.1	$0.2	$0.0	$1.3
March	$3.5	-$1.5	$2.0	$0.0	$0.1	$2.0	$0.0	-$1.8
April	$3.6	-$2.0	$1.6	$0.0	$0.1	$1.8	$0.0	-$0.3
May	$3.0	-$2.0	$1.0	$0.0	$0.1	$0.2	$0.0	$0.7
June	$7.6	-$2.2	$5.4	$0.0	$0.1	$2.4	$0.0	$2.9
July	$5.1	-$2.3	$2.9	$0.0	$0.1	$0.8	$0.0	$1.9
August	$4.2	-$2.6	$1.6	$0.0	$0.1	$1.3	$0.0	$0.1
September	$6.8	-$3.2	$3.7	$0.0	$0.1	$2.1	$0.0	$1.4
October	$7.5	-$3.7	$3.8	$0.0	$0.1	$2.3	$0.0	$1.4
November	$6.7	-$3.1	$3.5	$0.1	$0.1	$0.6	$0.0	$2.8
December	$9.6	-$4.8	$4.9	$0.1	$0.2	$1.6	$0.0	$3.0
Total	**$63.0**	**-$30.4**	**$32.6**	**$0.2**	**$1.1**	**$15.4**	**$0.2**	**$15.6**

All figures in $ millions

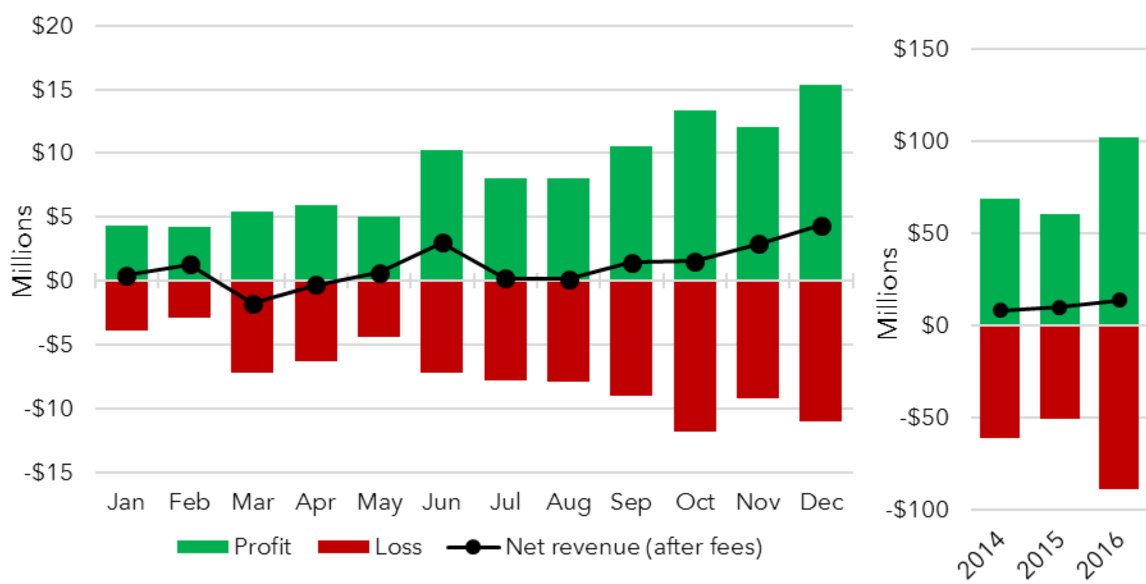
Net profits are typically small when assessed on a per megawatt basis. Figure 3–5 below illustrates the monthly average profit per megawatt for a cleared virtual in 2016. When factoring in all fees the average profit per megawatt for 2016 was $0.65 per cleared megawatt.

Figure 3–5 Profit and loss per cleared virtual, average



In general, virtual transactions have been profitable in the SPP marketplace as shown in Figure 3–6. In the 34 months of the marketplace only five months have had a net loss when factoring in fees. The highest payout month in 2016 happened in December with net payouts just over $4 million. The increase in the net revenue can be attributed to the addition of the Integrated System, which opened new areas for virtual transactions. The overall profitability in virtual transactions was concentrated with a few market participants, with five participants accounting for over 50 percent of the total aggregate virtual profits.

Figure 3–6 Virtual net revenues



Cross-product market manipulation has been a concern in other 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, six market participants lost more than $10,000 in 2016, with the most at just more than $49,000. This is substantially less than what was experienced in 2014 where three market participants lost more than $100,000, but higher than 2015 when only three market participants lost more $10,000. In addition to the low net losses, few SPP market participants actively trade in both virtuals and transmission congestion rights, reducing the potential for cross-product manipulation.

3.3 MUST-OFFER PROVISION

The Integrated Marketplace has a limited day-ahead must-offer provision that was intended to incentivize load-serving entities to participate in the day-ahead market. Market participants that are non-compliant are assessed a penalty based on the amount of available capacity available in the day-ahead market relative to the market participant's real-time load. The requirement is limited in the sense that only market participants with generation assets that serve load are subject to the rules. Load-serving market participants that offer enough generation, and/or provide scheduling information indicating a firm power purchase to cover at least 90 percent of their real-time load are not subject to a penalty. An alternative way to satisfy the provision is to offer all generation that is not on outage. Three penalties were assessed in 2016, with the total dollar amount being just under $10,000.

In 2014, the MMU recommended that SPP simultaneously eliminate the limited day-ahead must-offer provision and revise the physical withholding rules to include a penalty for non-compliance based on the premise that the recommended penalty provision would be sufficient to ensure an efficient level of participation in the day-ahead market.

Market participants approved a proposal to eliminate the current limited day-ahead must-offer provision of the SPP tariff in late 2015.[36] The removal of the day-ahead must-offer was then tabled by the SPP stakeholders until the Market Working Group completed its review of the physical withholding revisions proposed by the MMU. The market monitor engaged the Market Working Group in a discussion on conduct thresholds and impact test requirements for physical withholding penalties, in conjunction with establishing a formula-based penalty structure.[37] As a result of those discussions, the market monitor developed several modifications to the proposal.[38] The final proposal adjusted the physical thresholds and changed the measurement of financial impact so that it did not require off-line market case

[36] RR 125 (Removal of day-ahead limited must-offer) was approved by the Market Working Group in October 2015.
[37] The market monitor submitted RR 135 (Revision of physical withholding rules) to the Market Working Group in December 2015.
[38] The market monitor submitted RR 204 (Physical withholding) to the Market Working Group in December 2016.

re-runs. This final proposal was rejected by the SPP stakeholders.[39] SPP stakeholders then approved the removal of the day-ahead must-offer, and SPP plans to file the tariff revision with FERC in the summer of 2017 with implementation estimated later in 2017 pending FERC approval.

The market monitor decided to not appeal the Market Working Group decision regarding the physical withholding penalty and withdrew its proposal, pending additional analysis and studies including simulations regarding implementation and impact of the new proposal on the marketplace. The market monitor still maintains that the market is best served by removing the day-ahead must-offer in parallel with the establishment of a physical withholding penalty.

[39] RR 204 rejected by Market Working Group in February 2017.

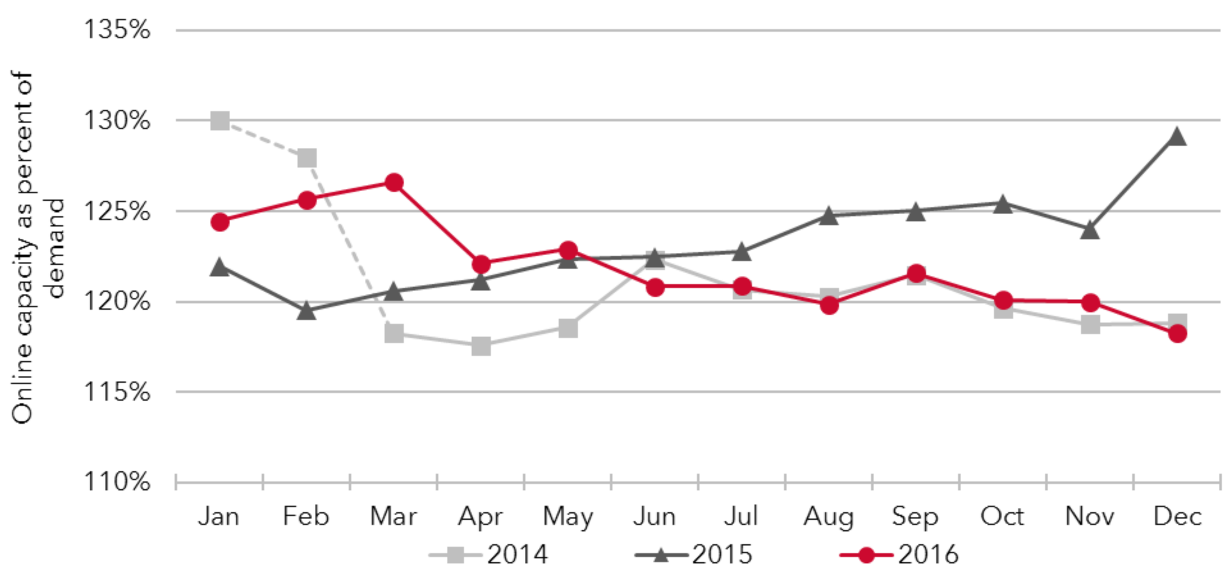
4 REAL-TIME BALANCING MARKET

4.1 REAL-TIME MARKET OPERATIONS

The real-time market is similar to the day-ahead market, however, the energy, regulation-up service, regulation-down service, spinning reserves, and supplemental reserves products are transacted in real-time. Similar to the day-ahead market, the real-time market co-optimizes the clearing of energy and operating reserve products out of the available offered capacity. 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.

Figure 4–1 shows that capacity commitment as a percent of load has been decreasing during 2016, thereby returning to the same levels as 2014. Some factors in 2016 that contribute to lower levels of online capacity are fewer coal plants starting via self-commitment and completion of integration of new market participants. Some of these factors are driving down system average prices but also driving up volatility and risk. Lower online capacity levels may be an unintended consequence as individual plant owners and SPP operations adjust to these changes in market conditions that are resulting in a higher level of volatility and risk.

Figure 4–1 On-line capacity as a percent of demand



4.2 REAL-TIME AND DAY-AHEAD PRICE COMPARISONS

Day-ahead prices are generally higher than real time prices, which indicate a higher value (or premium) attached to the relative certainty of day-ahead prices for load and generation compared to the potential volatility in the real-time market. As discussed earlier in Section 2.8.2 of this report, the market generally experiences higher volatility in real-time relative to the day-ahead because of higher actual (unexpected) congestion, along with load and generation changes. Unexpected congestion is more pronounced during high wind seasons of spring and fall. Figure 4–2 shows 2016 day-ahead and real-time market prices compared with the cost of natural gas. 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.

In June, the day-ahead price was $1.65/MWh higher than real-time price, while in March the real-time price exceeded day-ahead price by $1.31/MWh. Coincidentally, March is when the market experienced record low gas prices, averaging $1.53/MMBtu, as well as the lowest monthly average prices in both the day-ahead ($14.75/MWh) and real-time markets ($16.06/MWh).

Figure 4–2 Price, day-ahead and real-time

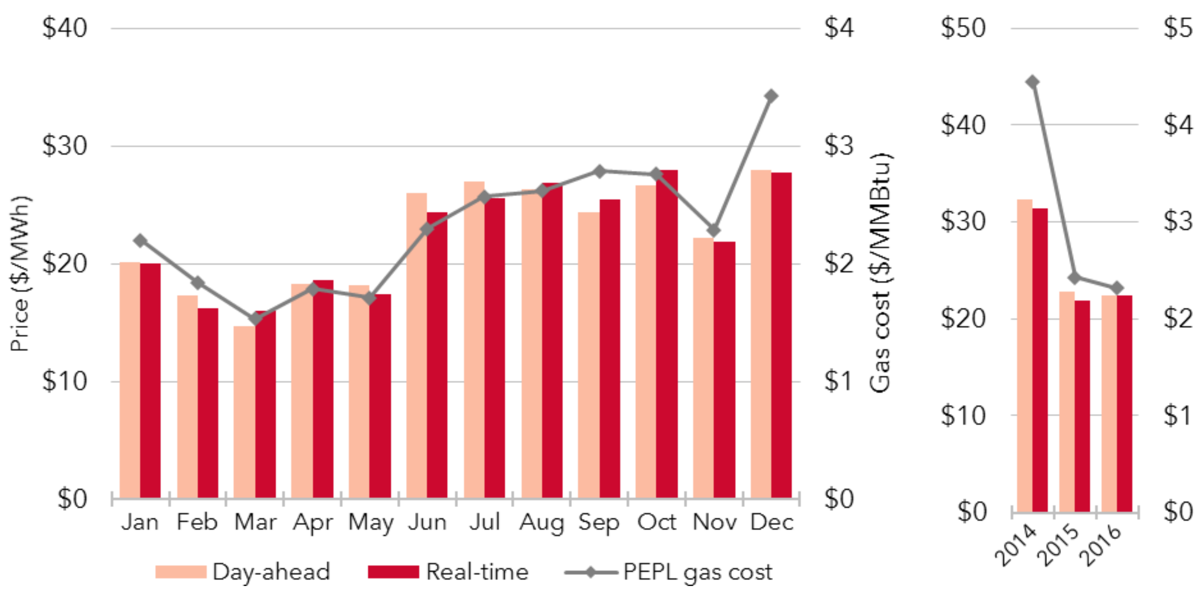


Figure 4–3 and Figure 4–4 show the day-ahead and real-time energy prices at the two SPP market hubs. The SPP North hub is composed of pricing nodes in the northern part of the

SPP footprint, generally in Nebraska, and the SPP South hub is composed of pricing nodes in the south-central portion of the footprint, generally in central Oklahoma. 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.

The day-ahead premium, the amount by which the day-ahead energy price exceeds the real-time energy price, is larger at the SPP North hub. In 2016 the annual average day-ahead premium is $0.61/MWh at the north hub, in contrast to the South hub, which had an average real-time premium of $0.47/MWh. High congestion in the real-time market, particularly around Woodward in western Oklahoma, drove the real-time premium at the South hub.

Figure 4–3 Hub prices, monthly

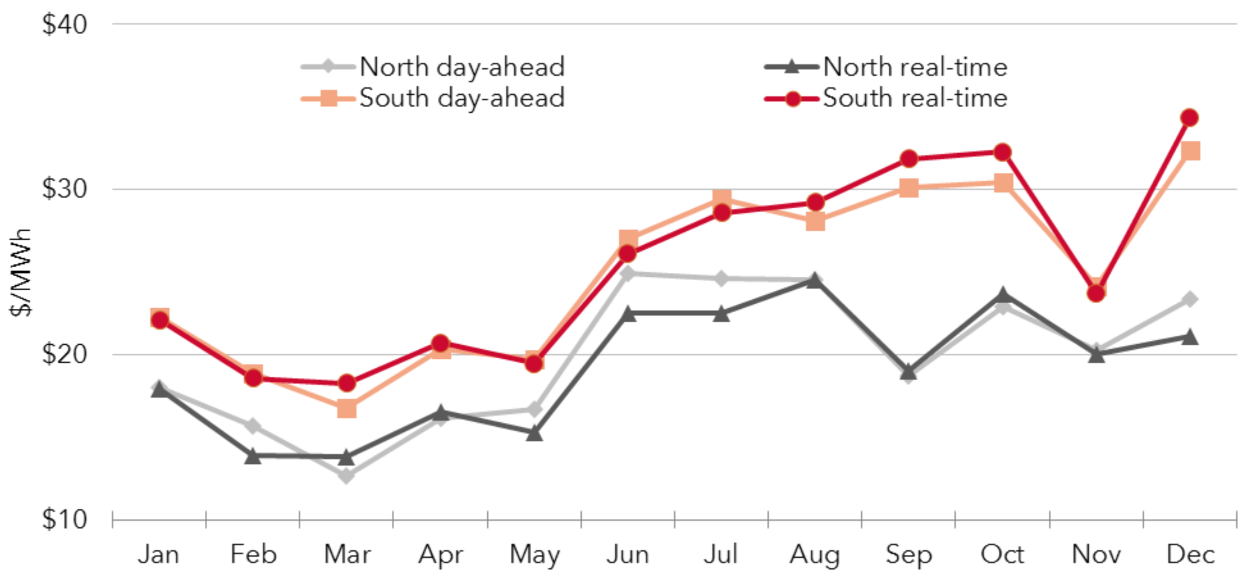


Figure 4–4 Hub prices, annual

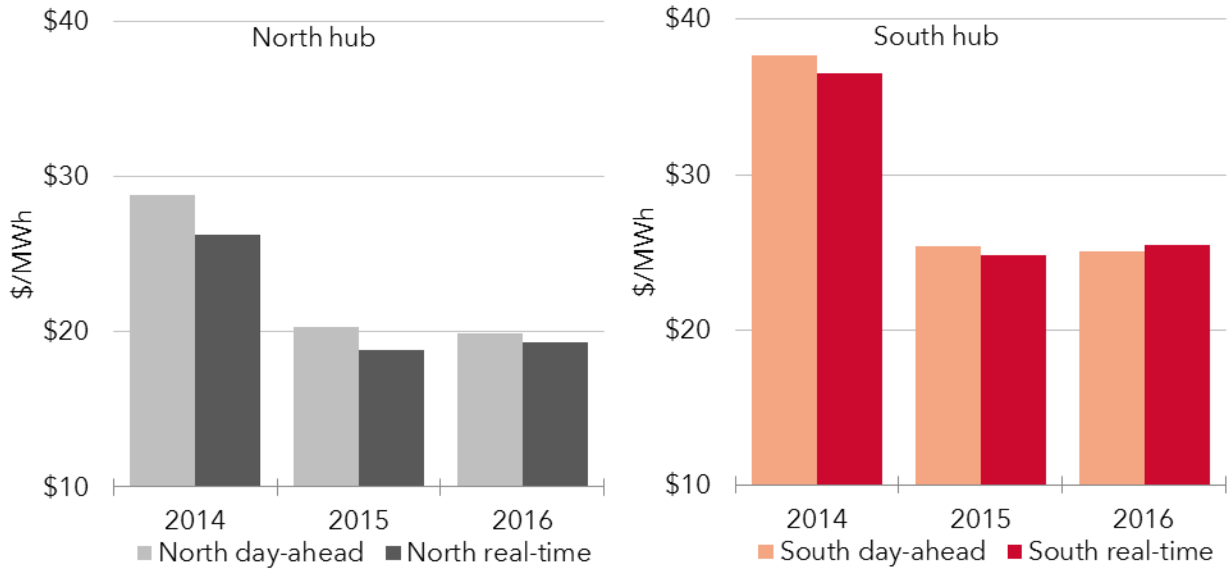
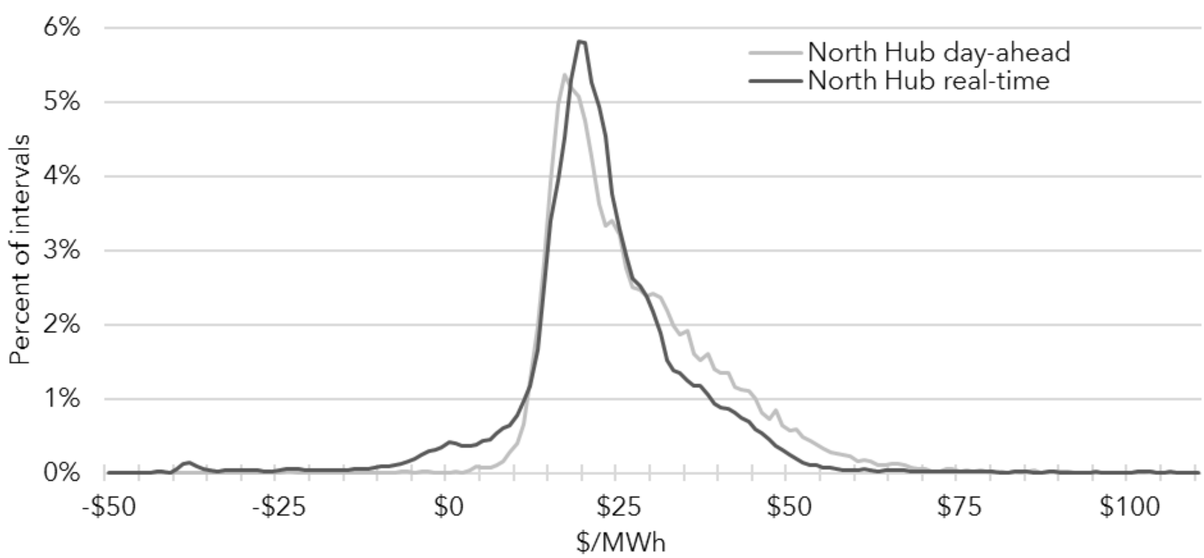


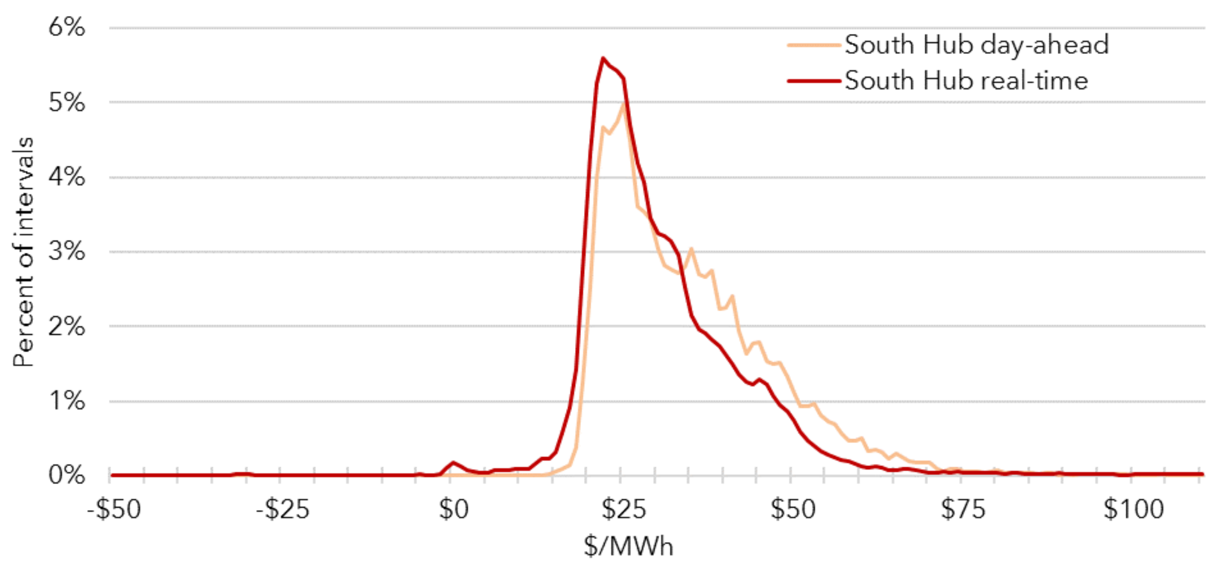
Figure 4–5 presents the price density curves (i.e., the frequency of prices at a particular price level) associated with the energy prices at the SPP North hub. The real-time curve is similar to the day-ahead curve, though there is an area under the real-time market curve just above the zero-dollar tick on the horizontal axis and below for the curves in the $35/MWh to $55/MWh range.

Figure 4–5 North hub price density curve



This is indicative of a low frequency of price spikes at the North hub in the real-time market. The increase in online capacity contributes to the leftward shift. Real-time congestion related to wind generation is also a contributing factor. The SPP South hub day-ahead curve is shifted slightly to the right of the real-time curve indicating a more general price premium for the South hub, as shown in Figure 4–6.

Figure 4–6 South hub price density curve



5 TRANSMISSION CONGESTION RIGHTS MARKET

In the Integrated Marketplace, the market generally charges load a higher price than it pays generation. Transmission services serve as the underpinning of the transmission congestion rights market, which provides day-ahead market payments to hedge the cost of congestion. Annual and monthly transmission congestion right auctions award the "rights" to shares of day-ahead market congestion revenue. SPP allocates auction revenue rights in annual and monthly processes based on transmission ownership, and auction revenue right holders receive payments from the auction revenue that offset the cost of transmission congestion right purchases and conversions of auction revenue rights into transmission congestion rights.

The purpose of the transmission congestion right market is to provide a market mechanism for SPP load-serving entities to hedge the cost of congestion in the market. The performance of the transmission congestion right market is expressed by the degree to which transmission congestion rights and auction revenue rights provide a congestion hedge to load customers. The degree to which day-ahead market congestion revenues sufficiently fund the transmission congestion rights awarded in the transmission congestion right auctions serves as a measure of load hedging, market efficiency, and transparency.

5.1 PAYMENT STRUCTURE

The congestion costs collected in the day-ahead market for any given hour are disbursed to transmission congestion right holders based on the auction awards (t) and the difference in prices between the source and sink settlement locations for the award, as follows:

$$\text{DA Congestion Charge} = \sum_{t} (\text{DA Quantity}_{SL} * \text{DA MCC}_{SL})$$

$$\text{TCR Payment} = \sum_{t} \left[\text{TCR Quantity}_{source,sink} * (\text{DA MCC}_{source} - \text{DA MCC}_{sink})\right]$$

To the extent that the day-ahead market does not provide sufficient congestion revenues to support the full value of all payments to transmission congestion right holders for a given day, SPP charges each transmission congestion right holder a share of the underfunding proportional to the absolute value of its transmission congestion right portfolio for that day. The absolute value formulation creates a balanced treatment for the payment of both prevailing flow and counter-flow transmission congestion right positions.

Since Integrated Marketplace implementation in March 2014, SPP's transmission congestion right market process has consistently sold transmission congestion rights in excess of what system capacity was available in the day-ahead market. This over-selling of transmission congestion rights requires uplift to be charged to market participants resulting in transmission congestion right underfunding:

$$\text{TCR Funding \%} = \frac{\text{DA Congestion Charge}}{\text{TCR Payment}}$$

Transmission congestion rights are awarded in annual and monthly auctions. SPP disperses the auction revenue to the holders of auction revenue rights.

$$\text{TCR Charge} = \sum_{t} \left[\text{TCR Quantity}_{source,sink} * (\text{TCR ACP}_{source} - \text{TCR ACP}_{sink})\right]$$

$$\text{ARR Payment} = (-1) * \sum_{t} \left[\text{ARR Quantity}_{source,sink} * (\text{TCR ACP}_{source} - \text{TCR ACP}_{sink})\right]$$

Auction revenue rights are allocated for all times of year based on transmission service sufficient to meet up to 103 percent of each network transmission owner's annual peak load and all point-to-point service, known as the auction revenue right nomination cap. Auction revenue right holders may self-convert an auction revenue right to a transmission congestion right, in which case the transmission congestion right charge equals the auction revenue right payment, or hold the auction revenue right for payment based on the auction clearing prices for the auction revenue right path. Surplus auction revenue collected by SPP is dispersed to auction revenue right holders proportionally to the auction revenue right megawatt nomination cap. SPP's transmission congestion right market has consistently sold transmission congestion rights in excess of what was required to fund auction revenue right payments resulting in a surplus of funds:

$$\text{ARR Funding \%} = \frac{\text{Total TCR Charges}}{\text{Total ARR Payments}}$$

5.2 MARKET TRANSPARENCY AND EFFICIENCY

As pointed out in the 2015 Annual State of the Market report, the MMU noted the degree of disparity between transmission congestion right payments, net of transmission congestion right uplift, and transmission congestion right auction charges. This disparity indicated that transmission congestion right auction prices do not accurately reflect the value of transmission congestion rights, nor did the transmission congestion right market design accurately reflect how much system capacity would actually be available in the day-ahead market.

In the 2015 Annual State of the Market report, the MMU recognized three contributing factors to this outcome: 1) the over-allocation of auction revenue rights and resulting over-selling of transmission congestion rights above and beyond the physical limits of the transmission system; 2) the delayed reporting of planned transmission outages; and 3) the excessive valuing of self-convert transmission congestion right bids. Each of these factors created difficulty for market participants in estimating the value of transmission congestion rights. In the latter half of 2016, the MMU has observed that by addressing auction revenue right over-allocation through Revision Request 91, SPP has improved transmission congestion right funding.

5.3 REVISION REQUEST 91

In the 2014 Annual State of the Market report, the MMU recommended that SPP limit the over-allocation of auction revenue rights during the annual auction revenue right allocation by matching the percentage of available system capacity to that of the annual transmission congestion right auction. At that time the percent of system capacity used throughout the year was 100 percent for all months and seasons in the annual allocation, but was 100 percent for June, 90 percent for July-September, and 60 percent for fall, winter, and spring in the annual auction. The goal of this recommendation was to prevent or reduce over-allocation of auction revenue rights and the resultant over-selling of transmission congestion rights through self-converts beyond the physical limits of the transmission system.

SPP first presented RR 91 in July 2015. SPP stakeholders approved this change in market design, and in October 2015 SPP filed an amended version of RR 91 wherein the outlying seasons allocated 80 percent of system capacity rather than matching the annual transmission congestion rights auction's 60 percent. FERC conditionally approved this filing in February 2016 given that SPP instead use 60 percent for the outlying seasons as initially presented to stakeholders. SPP made an amended filing including this change, which FERC approved in July 2016. These system changes were implemented prior to running the 2016 annual auction revenue right/transmission congestion right process, and its effects were positive as expected.

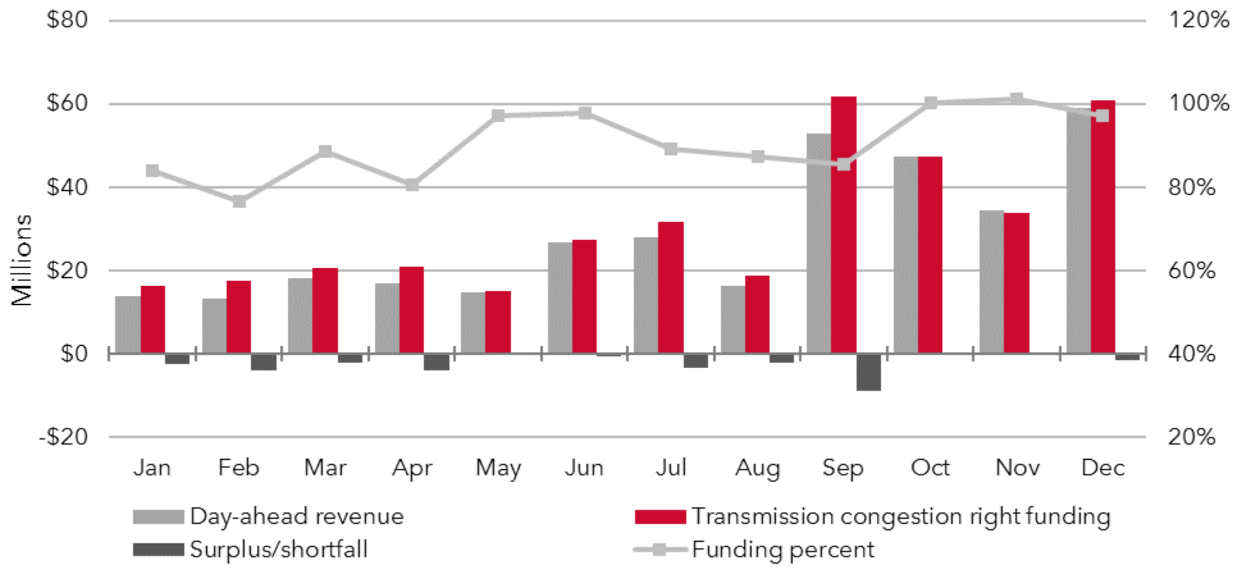
Not only had SPP implemented other recommendations from the MMU, such as educating members about the importance of reporting outages well in advance, and better parallel flow modeling (which reduced transmission congestion right over-selling from 18 percent in 2014 to 12 percent in the twelve months prior to RR 91 implementation[40]), but RR 91 further reduced transmission congestion right over-selling to seven percent.[41] While this shows excellent progress on the part of SPP, two other factors must still be addressed if a cumulative 100 percent of transmission congestion right net funding is to be achieved: 1) improved self-convert modeling; and 2) improved transmission outage modeling in the monthly auction revenue right/transmission congestion right process. Each is discussed at length later in this sub-section.

[40] Transmission congestion rights were 85 percent funded in 2014; commonly called underfunding. The MMU views this as transmission congestion rights being sold above and beyond that system capacity available in the day-ahead market. By taking the inverse of 85 percent it can be seen that 118 percent of system capacity was subscribed; 18 percent over-sold. June 2015 through May 2016 saw TCRs 89 percent funded or 112 percent capacity subscribed; 12 percent over-sold.

[41] Transmission congestion rights were 94 percent funded from July to December 2016 or 107 percent of capacity subscribed; 7 percent over-sold.

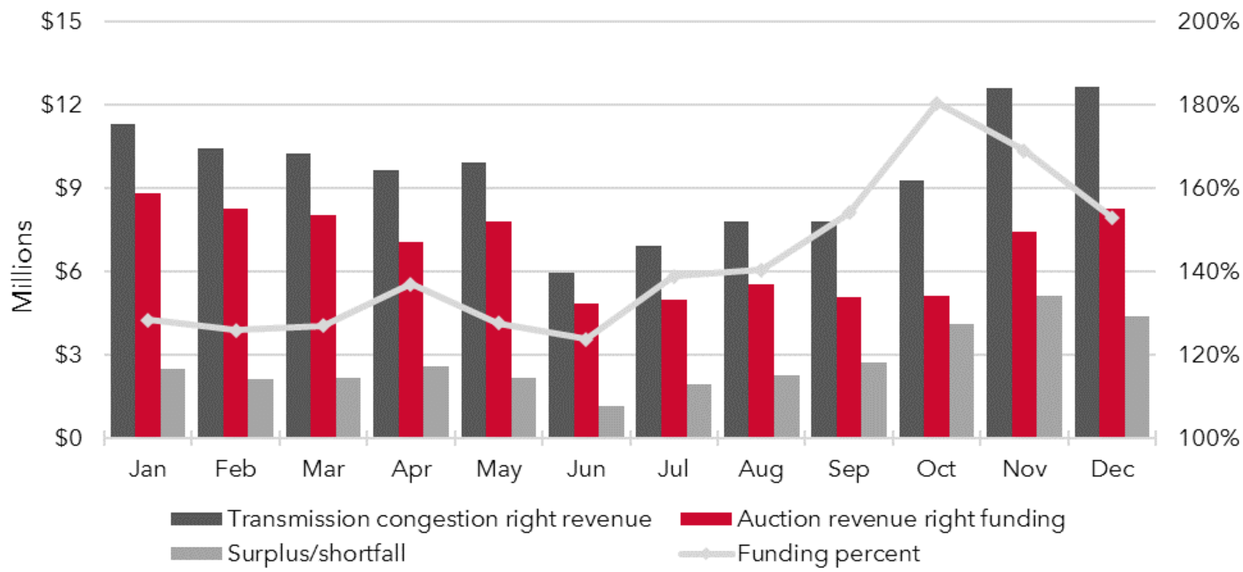
5.4 FUNDING

Figure 5–1 Transmission congestion right funding levels, monthly



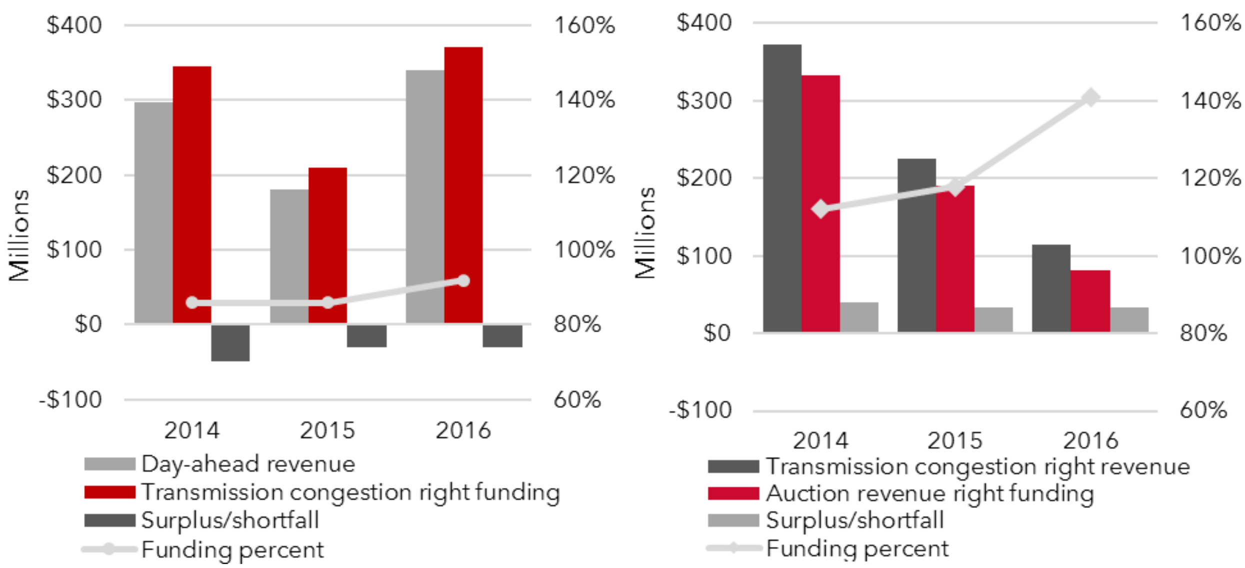
Comparing the five months prior to RR 91 implementation to six months post (June omitted for lack of monthly process), pre-RR 91 showed 85 percent net transmission congestion right funding, whereas post-RR 91 showed 94 percent net transmission congestion right funding. Outages in the last four months of the year (notably one for reconductoring of the Hays to South Hays line) coupled with increasing wind production caused much more congestion. While the percent of funding was improved by the implementation, higher congestion costs meant underfunding was around $3 million per month both before and after RR 91 was implemented. The trend of over-selling transmission congestion rights continues, but was reduced by RR 91. As long as the tariff and market protocols prescribe selling 100 percent of expected transmission capacity, this is likely to remain the case.

Figure 5–2 Auction revenue right funding levels, monthly



Similarly comparing auction revenue right funding for the five months prior to RR 91 and the six months after (omitting June), it can be seen that auction revenue right funding percentage and dollars increased dramatically after the implementation of RR 91. This is due to the decreased amount of auction revenue right megawatts by having a reduced transmission capability in the annual allocation. This reduction of auction revenue rights was the known and expected outcome of RR 91, but the design allows for 'less infeasible' auction revenue rights. The drastic increase in auction revenue right funding was not expected, and presents a concern.

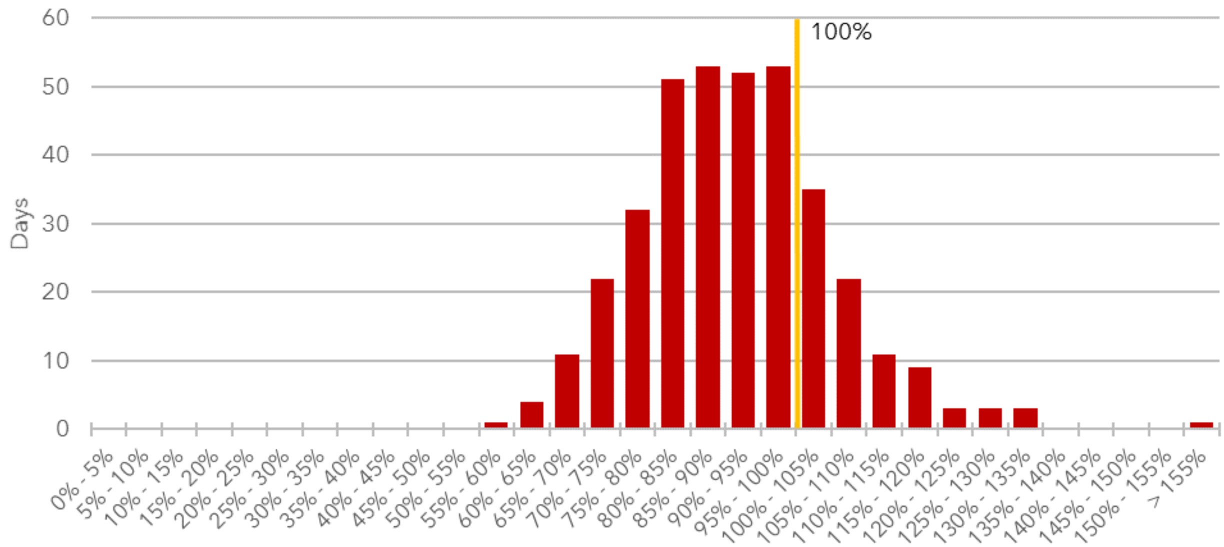
Figure 5–3 Funding levels, annual



In both 2014 and 2015, transmission congestion rights were approximately 86 percent funded by the day-ahead market while auction revenue rights were 112 percent funded in 2014 and 118 percent funded in 2015. Reduction in natural gas prices meant the order of magnitude of funding in 2015 was just over half the funding of 2014. From 2015 to 2016, day-ahead market revenues and transmission congestion right payments rose again due to congestion caused by increased wind generation. Meanwhile funding percent rose in the latter half of the year due to RR 91.

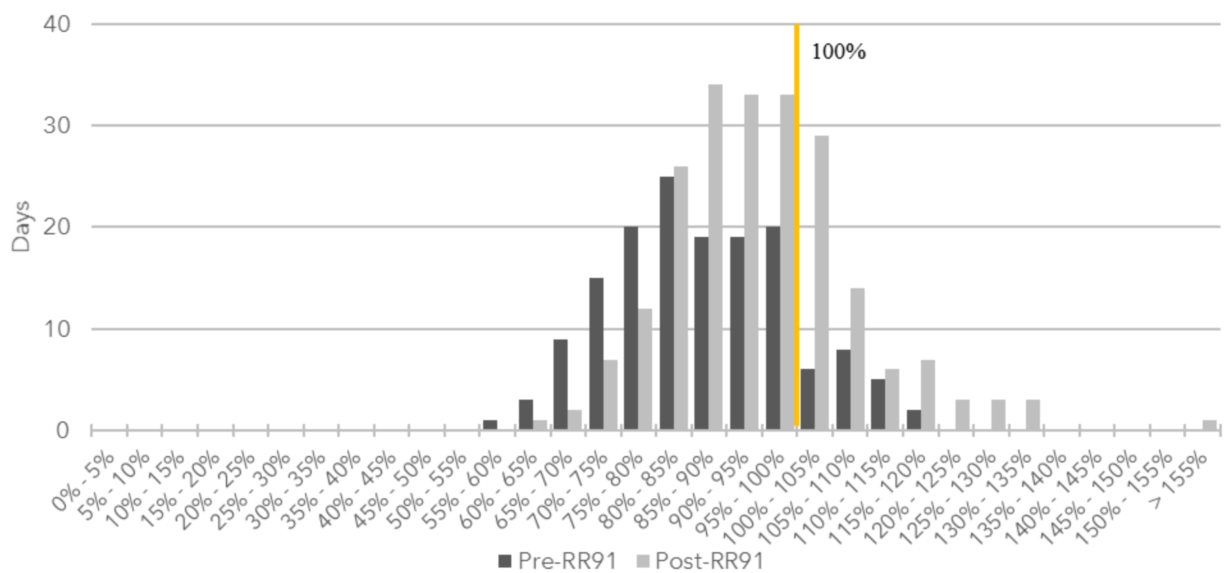
Also in 2016, transmission congestion right revenues and auction revenue right payments were halved again because of the implementation of the long-term transmission congestion right process—allowing market participants to bypass the auction revenue right process when acquiring transmission congestion rights—and by the implementation of RR 91. Interestingly, transmission congestion right shortfalls ($49 million, $30 million, and $30 million for the years of 2014 to 2016, respectively) and auction revenue right surpluses ($40 million, $34 million, and $33 million for the same years) have correlated well despite many changing factors and changing market design. This once again leads the MMU to believe that these are related, and further that the root cause is over-selling of transmission congestion rights.

Figure 5–4 Transmission congestion right funding, daily



By plotting the daily funding percentage of transmission congestion from day-ahead market congestion, a rather flat distribution from 80 percent to 100 percent can be observed.

Figure 5–5 Transmission congestion right funding, pre-/post-RR 91, daily



This was likely caused by various factors throughout 2016. A primary factor was the long lead time of auction revenue rights allocated for the spring outage season, which when combined with the pre-RR 91 rules, caused a great deal of underfunding. Compared with the shorter lead-time and post-RR 91 rules, the summer season with forced outages and the fall season with planned outages, saw much better funding overall. This can be seen by splitting the values into pre- and post-RR91 implementation (as shown in Figure 5–5).

5.5 MODELING CONCERNS

The MMU has reported on several transmission congestion right modeling issues in its previous annual reports that still present a cause for concern. These concerns are related to the auction revenue right funding levels, self-convert logic, and the inclusion of outages.

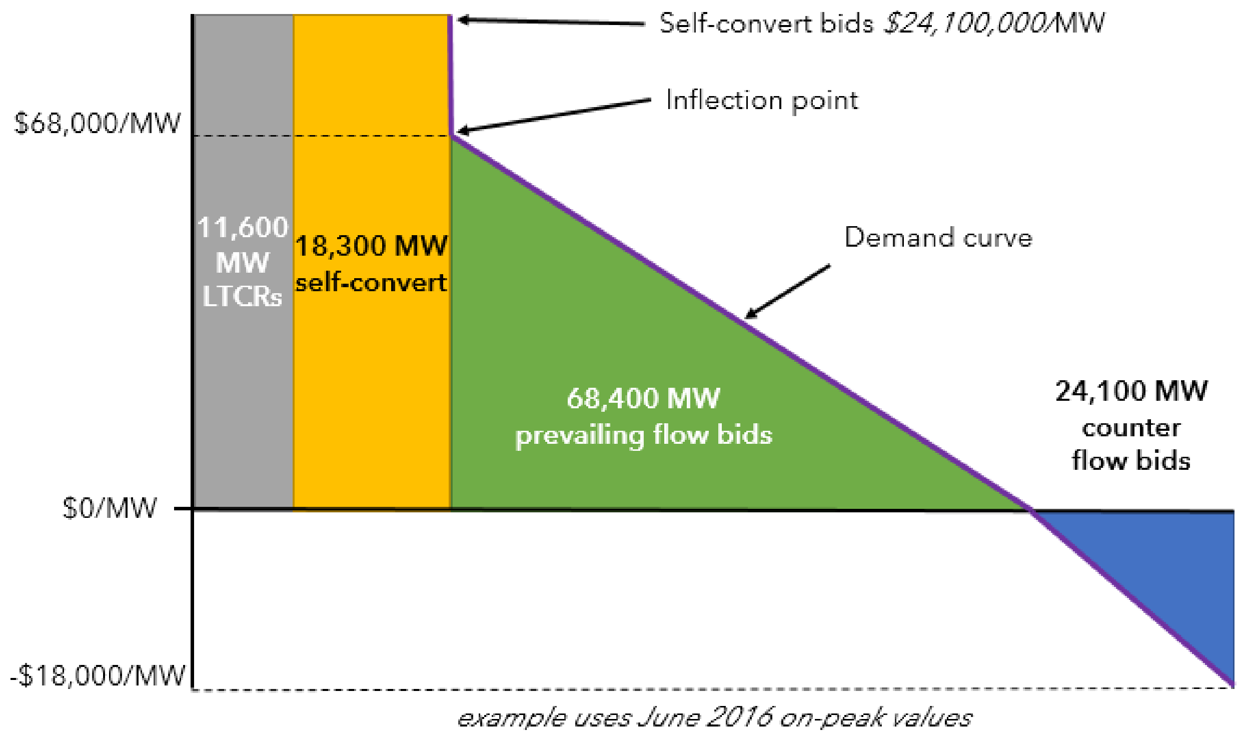
5.5.1 AUCTION REVENUE RIGHT FUNDING

As previously noted, the auction revenue right funding levels have drastically increased after the implementation of RR 91. Auction revenue right surplus in conjunction with transmission congestion right underfunding tend to point to an overselling of transmission congestion rights. More revenues are collected from the purchases of transmission congestion rights than are needed to fund the auction revenue rights. Transmission congestion right owners may have paid too much for their transmission congestion rights, but instead of receiving a refund, the over-payment was allocated to the auction revenue right holders. This extreme amount of surplus causes a concern for a few reasons. First, the entities that make up the pool of transmission congestion right holders are not the same entities that make up the pool of auction revenue right holders. Auction revenue right holders are only those entities with long-term firm transmission service. Another reason for concern is how the surplus is allocated. The over-payment of transmission congestion rights could primarily come from a small constrained area, but the allocation goes back to auction revenue right holders in a method similar to the load ratio share and has nothing to do with where the excess funds came from. The MMU urges SPP, along with the stakeholders, to develop a plan to get the auction revenue right funding to a more reasonable level, along with re-analyzing the distribution of surplus to ensure it is performed in an equitable manner.

5.5.2 SELF-CONVERT MODELING

Many load-serving entities self-convert most or all auction revenue rights to transmission congestion rights in the annual and monthly transmission congestion right auctions. The auction assigns the requested self-convert auction revenue rights a bid value equal to 1,000 times the difference between the highest and lowest submitted bids in the auction. The clearing of self-converts then functions the same as any other transmission congestion right bid. These high bids far exceed the economic value of the resulting transmission congestion rights, yet they influence the economic clearing of the market with the potential to distort market outcomes from efficient levels. Figure 5–6 conceptually depicts the ranked bids for transmission congestion right megawatts in a typical auction, as noticed from the June 2016 on-peak transmission congestion right auction. It shows that approximately one-third of all auction bid megawatts represent self-converted auction revenue rights with effectively infinite prices.

Figure 5–6 Self-convert modeled prices



This creates a situation where a lack of counter flow (either by bids of other self-converts) could cause price spikes. One extreme example would be where a particular one megawatt of self-convert from settlement location A to settlement location B required 100 MW of counter flow to be purchased from settlement location C to settlement location D (because of different shift factors on a constraint). In this example, all counter flow megawatts would be bought for asking price (using a monthly minimum bid of -$100,000) and the self-convert would clear for $10M/MW ($10/watt). The 2016 self-convert modeled prices are shown in Figure 5–7 below.

Figure 5–7 Self-convert modeled Prices

Market name	Product period	On-peak self-convert bid value ($/MW)	Off-peak self-convert bid value ($/MW)
2016 January monthly auction	January 16	$28.7	$32.1
2016 February monthly auction	February 16	$22.6	$25.7
2016 March monthly auction	March 16	$27.1	$26.2
2016 April monthly auction	April 16	$17.1	$21.0
2016 May monthly auction	May 16	$19.2	$27.2
2016 Annual auction	June 16	$24.1	$28.5
	July 15	$21.0	$31.4
	August 16	$25.2	$28.7
	September 16	$24.6	$30.3
	Fall 16	$52.2	$63.6
	Winter 16	$100.3	$117.2
	Spring 17	$49.5	$62.3
2016 July monthly auction	July 16	$13.0	$19.4
2016 August monthly auction	August 16	$24.1	$39.2
2016 September monthly auction	September 16	$24.4	$44.1
2016 October monthly auction	October 16	$46.3	$49.1
2016 November monthly auction	November 16	$41.9	$51.4
2016 December monthly auction	December 16	$55.4	$61.2

($ millions)

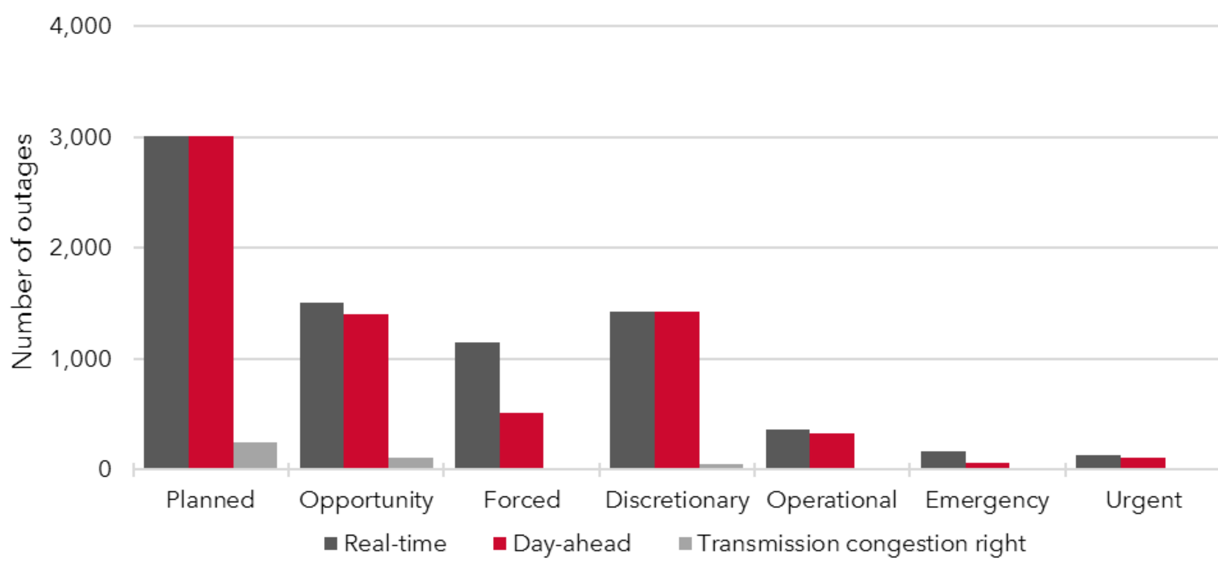
In contrast, non-self-convert bids are limited to $100,000/MW per month.[42] Additionally, this price modeling values off-peak transmission products as more valuable than on-peak transmission products, which is not normally the case. While it is hoped that no market participant will, by intent, action, or omission, cause one of these price spikes, they do give cause for concern.

[42] Exceptions are $200,000/MW in the fall and spring periods, and $400,000/MW in winter periods of the annual transmission congestion right auction.

5.5.3 TRANSMISSION OUTAGE MODELING

SPP only models transmission outages that were reported 45 days prior to the month of the transmission congestion rights auction.[43] However, SPP only requires transmission owners to submit planned outages 14 days in advance.[44] This, when coupled with the Market Working Group's request that outages shorter than five days be excluded from auction revenue right/transmission congestion right processes, means the vast majority of outages do not appear in system models used to sell transmission congestion rights, as shown in Figure 5–8. When these outages appear in the day-ahead market, they then reduce system capacity and cause underfunding.

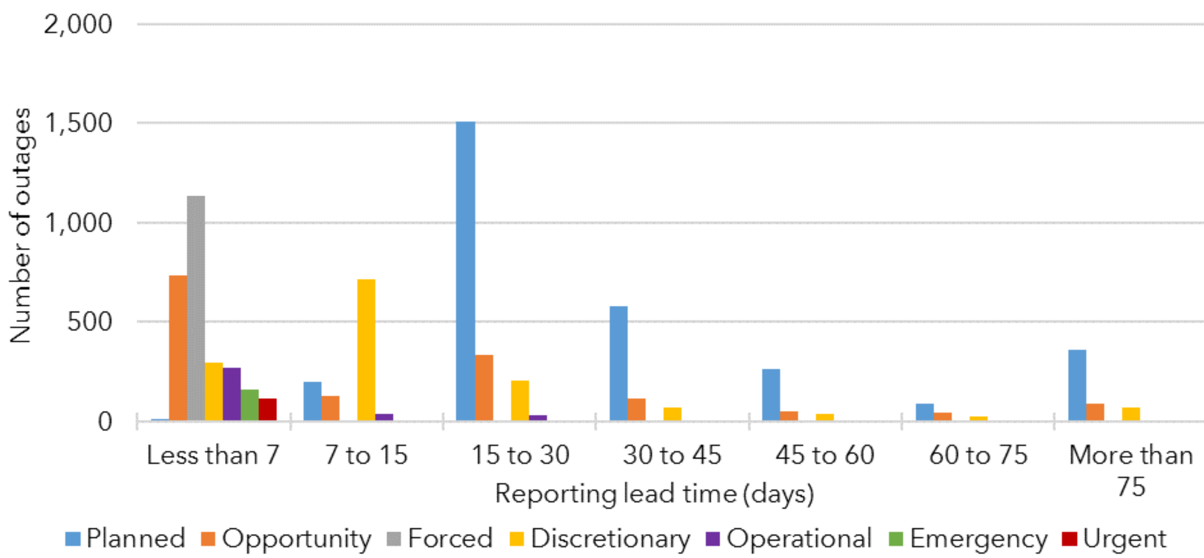
Figure 5–8 Transmission outages by market



These transmission outages were calculated using data from SPP's outage scheduling system used by resource owners and SPP operations to report outages. The transmission congestion rights market includes far fewer outages than reported in the day-ahead and real-time markets.

[43] SPP Integrated Marketplace Protocols, Section 6.6
[44] SPP Operating Criteria Appendix OP-2

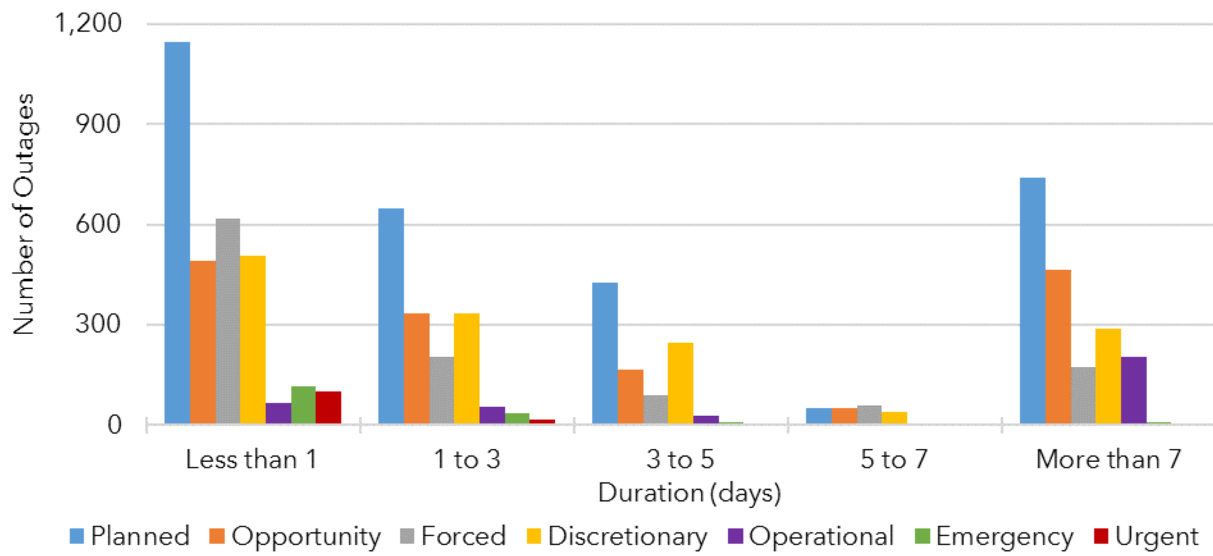
Figure 5–9 Transmission outages by reporting lead time



At the recommendation of the MMU, SPP staff submitted RR 96[45] through the stakeholder process to align the submission requirements of planned transmission outages with the requirements to be included in the auction revenue right/transmission congestion right process. The revision request was modified as it went through the process. In its final form, slight improvements were made, but still did not lead to a much greater accuracy in outage modeling in transmission congestion right models.

[45] RR 96 (Transmission outage timing requirements modification)

Figure 5–10 Transmission outages by duration



At the request of the Market Working Group, SPP formed the Outage Task Force, which was charged with finding and addressing the contribution of transmission outages to transmission congestion right underfunding. In part by submission of RR 96, but also by educating transmission owners about auction revenue right and transmission congestion right business practices, several other improvements were made. SPP staff now monitors for dual circuit outages[46], and outages spanning less than 120 consecutive hours are now omitted. In the 2015 Annual State of the Market report, the MMU noted that these changes provide more accuracy with respect to individual line availability in the transmission congestion right market.

The MMU still has concerns with the disparity between outages in the transmission congestion right market compared to outages in the day-ahead market. The MMU understands the challenges associated with this topic, and knows there can never be an exact match between the two markets. However, the MMU believes the effects of transmission congestion rights over-selling can be greatly reduced by allowing SPP staff to make transmission system predictions based on historical outages and congestion patterns to

[46] Instances where two outages with non-overlapping durations occur on similar elements, e.g. circuit 1 and circuit 2 of point A to point B lines.

more accurately rate the system. The MMU would like to see continued improvement in outage modeling in the auction revenue right/transmission congestion right processes.

5.6 BIDDING AT ELECTRICALLY EQUIVALENT SETTLEMENT LOCATIONS

As noted in the 2014 and 2015 Annual State of the Market reports, SPP's tariff prohibits bidding between pairs of electrically equivalent settlement locations, which allow infinite or near-infinite quantities of transmission congestion rights to be awarded at zero cost. Until January 2017, SPP staff removed such bids from the auction. Such bidding constituted a violation of the SPP tariff. Since tariff language had not prevented bidding activity between electrically equivalent settlement location pairs, the MMU recommended in the 2014 Annual State of the Market report that the RTO implement appropriate safeties in the market user interface (MUI) to prevent this behavior in the future. In the 2015 Annual State of the Market report, the MMU gave an update stating that the market-user interface fix was due to be completed, and the MMU would continue to monitor for electrically equivalent settlement location bidding until the fix was implemented in January 2017. At this time the software fix has been fully tested and implemented, and the MMU considers this recommendation successfully completed and closed. MMU staff will continue dialogue with SPP and FERC staff if any related issues should arise.

6 COMPETITIVE ASSESSMENT

The SPP Integrated Marketplace provides sufficient market incentives to produce competitive market outcomes in regions and periods when there are no concerns with regard to local market power. The MMU's competitive assessment provides evidence that in 2016 market outcomes were workably competitive and that the market required mitigation of local market power infrequently to achieve those outcomes.

The market power analysis in this report considers both the structural and behavioral aspects of market power concerns. The structural aspects can be detected by various techniques such as market share analysis, (market-wide) concentration indices, and pivotal supplier analysis (PSA). The structural indicators are used to look for the potential for market power without regard to the actual exercise of market power. Behavioral aspects, on the other hand, assess the actual offer or bid behavior (i.e., conduct) of the market participants and the impact of such behavior on market prices by looking for the exercise of market power. These behavioral indicators include price-cost margin (or markup), economic withholding analysis (addressed through automated mitigation, see Section 6.2.2, and through the output gap analysis, see Section 6.2.3), as well as physical withholding and uneconomic production analyses (addressed through FERC referrals).

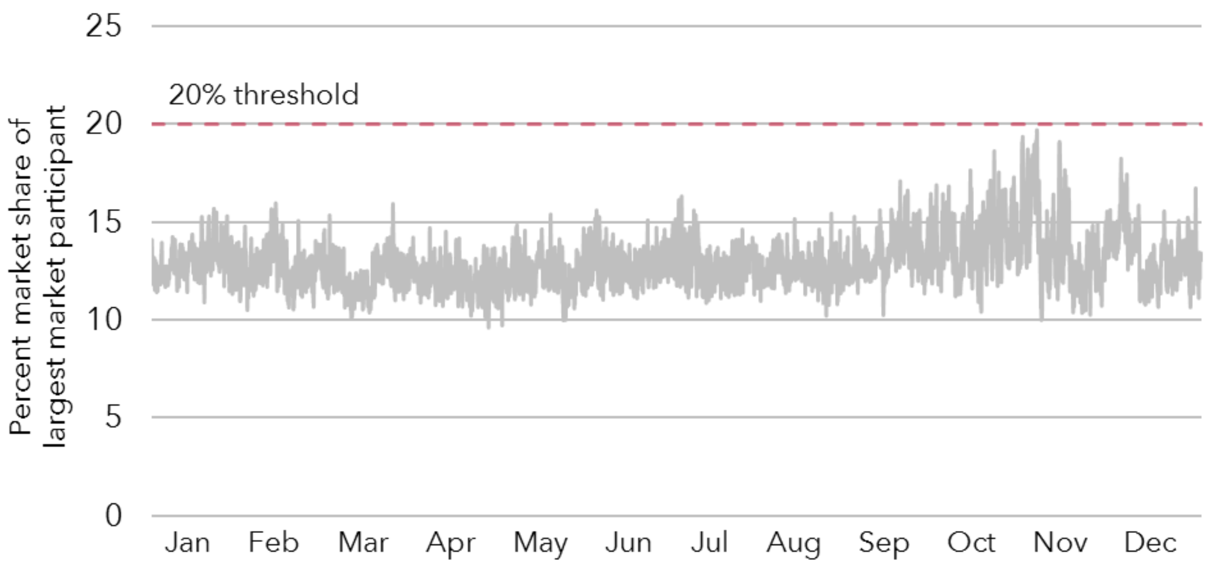
This chapter evaluates the SPP market's competitive environment first by establishing the level of structural market power and then examining market prices for indications of market power impact. This is done by analyzing the potential existence of global market power and prices without regard to whether market power mitigation measures were in place. Mitigation of economic withholding is accomplished *ex-ante* through automatic market power mitigation processes that limit the ability of generators with local market power to raise prices above competitive levels. The mitigation program is monitored and evaluated to ensure it is efficient and effective. Accordingly, the following subsections examine the significance of market power and the effectiveness of local market power mitigation in the SPP markets.

6.1 STRUCTURAL ASPECTS OF THE MARKET

Three core metrics of structural market power are the market share analysis, the Herfindahl-Hirschman Index (HHI), and pivotal supplier analysis. The first two of these indicators measure concentration in the market and are of a static nature. Pivotal supplier analysis, on the other hand, takes into account the dynamic nature of power markets and considers changing demand conditions and locational transmission constraints in assessing potential market power.

Figure 6–1 displays the market share of the largest online supplier in terms of energy output in the real-time market by hour for 2016. The market share ranged from 9.6 percent to 19.7 percent, never exceeding the 20 percent benchmark[47] in any of the hours for the year. The majority of the highest market share hours occurred during the off-peak months of the year.

Figure 6–1 Market share of largest supplier



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[47] The 20 percent threshold is one of the generally accepted metrics that would indicate structural market power. Note, however, that neither market share nor the HHI metric alone would be sufficient for the assessment of market power particularly in today's spot electricity markets where load pockets formed by transmission congestion may lead to market power with much smaller market shares and/or HHI values.

The HHI is another general measure of structural market power, analyzing overall supplier concentration in the market. It is calculated by using the sum of the squares of the market shares of all suppliers in a market as follows:

$$HHI = \sum_i \left(\frac{MW_i}{\sum_i MW_i} * 100 \right)^2$$

According to FERC's "Merger Policy Statement,"[48] similar to Department of Justice merger guidelines, an HHI less than 1,000 is an indication of an unconcentrated market, an HHI of 1,000 to 1,800 indicates a moderately concentrated market, and an HHI over 1,800 indicates a highly concentrated market. Figure 6–2 provides the number of hours for each concentration category over the last three years. In terms of installed capacity, the SPP market was unconcentrated 100 percent of the hours in 2016. In fact, the HHI for the market has remained under 1,000 since the Integrated System joined SPP in October 2015. The HHI has never risen above the 1,800 threshold determined for high level of concentration.

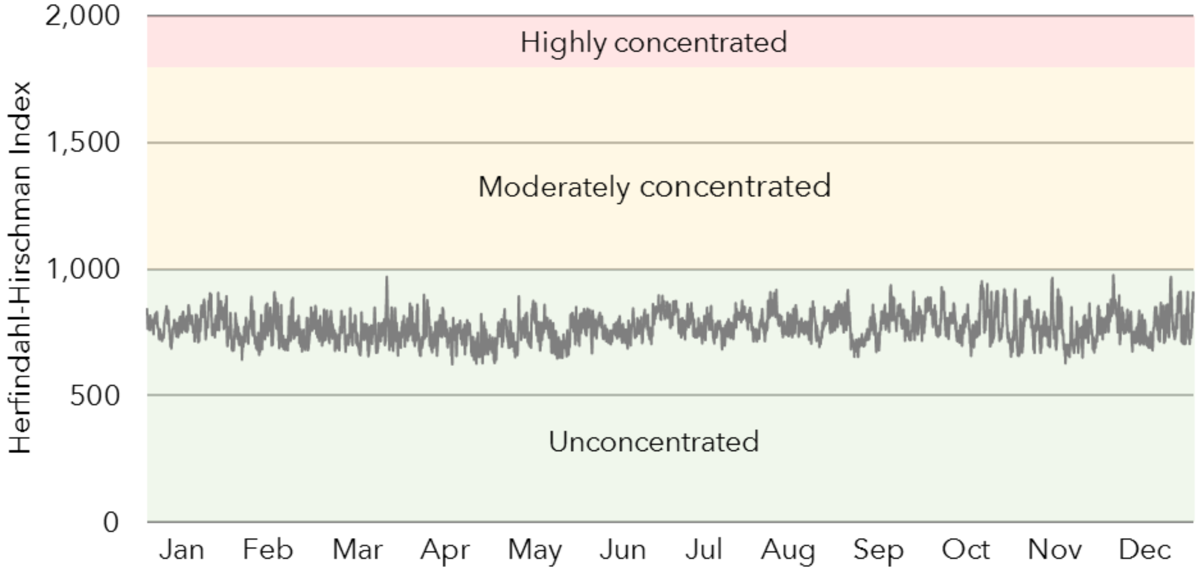
Figure 6–2 Market concentration level, real-time

Concentration	HHI Level	2014		2015		2016	
		Hours	% of Hours	Hours	% of Hours	Hours	% of Hours
Unconcentrated	Below 1,000	4,102	47%	6,234	71%	8,784	100%
Moderately Concentrated	1,000 to 1,800	4,658	53%	2,526	29%	0	0%
Highly Concentrated	Above 1,800	0	0%	0	0%	0	0%

Figure 6–3 depicts the hourly real-time market HHI for the third year of the Integrated Marketplace, with hourly HHI values ranging from 624 to 977 during the year.

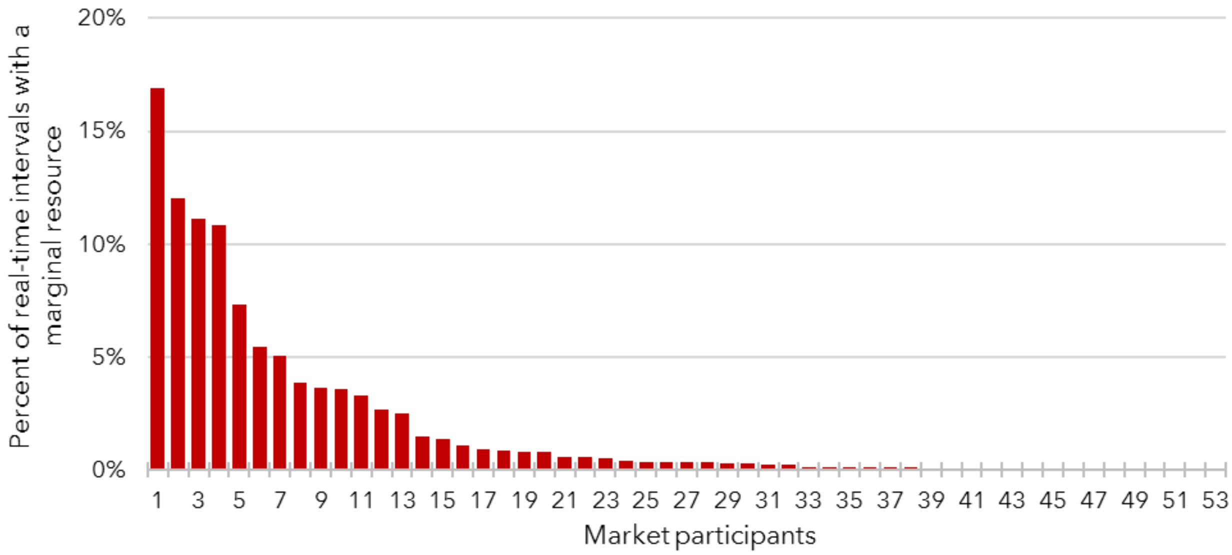
[48] Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, Issued December 18, 1996 (Docket No. RM96-6-000).

Figure 6–3 Herfindahl-Hirschman Index



SPP market participants with generation spanning all supply segments have the greatest ability to benefit from structural market power. These market participants may frequently set prices regardless of the technology type on the margin. Figure 6–4 provides the percent of real-time market intervals that each ranked market participant had a resource on the margin. It shows that four market participants each set price in more than 10 percent of all real-time market time intervals. These percentages are not additive because multiple market participants may have a resource on the margin at the same time.

Figure 6–4 Market participants with a marginal resource, real-time



In conclusion, the MMU's market share analysis and calculated HHI both indicate minimal potential structural market power in SPP markets outside of areas that are frequently congested.

Pivotal supplier analysis takes into account the dynamic nature of the power market, particularly demand conditions, and evaluates the potential for market power in the presence of "pivotal" suppliers. A supplier is pivotal when its resources are needed to meet demand. There may be one or more pivotal suppliers in a particular market defined by transmission constraints and load conditions, and a supplier's status of being pivotal may vary between time periods irrespective of its size.

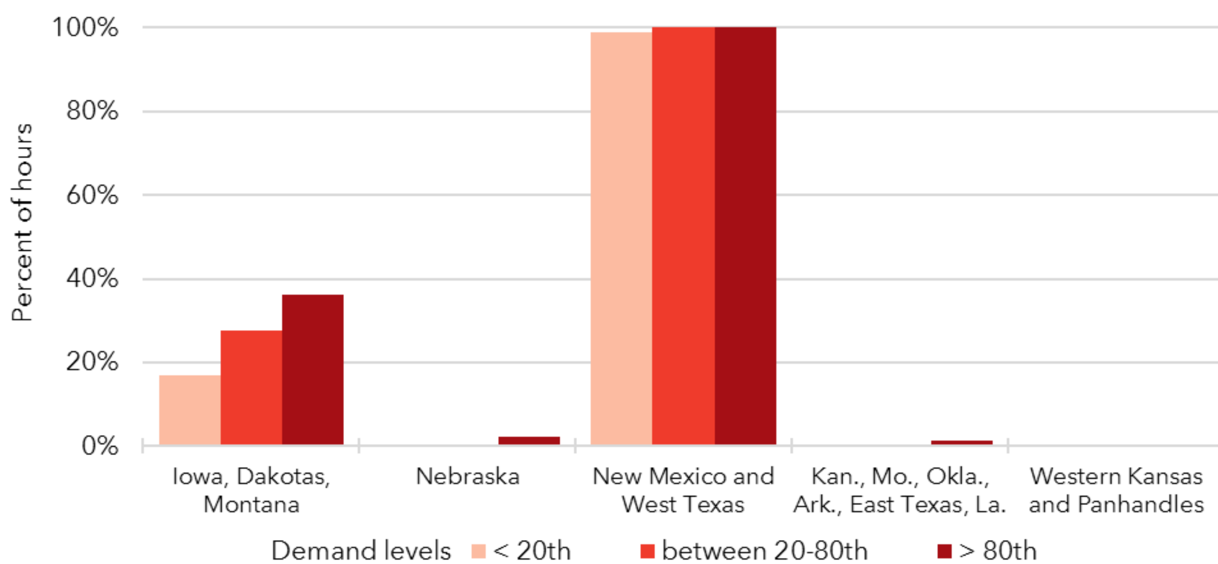
The following analysis identifies the frequency with which at least one supplier was pivotal in the five different reserve zones (regions) of the SPP footprint in 2016.[49] One condition for a supplier to have an ability to raise prices above competitive levels, is the frequency it

[49] SPP divides market resources (generation) into five reserve zones. For the purpose of this report, these reserve zones are named as 'Nebraska', 'Western Kansas and Panhandles', 'New Mexico and West Texas', 'Kan., Mo., Okla., Ark., East Texas, La.', and 'Iowa, Dakotas, Montana'. Thus, each generation resource is mapped to one of these reserve zones. To define a load zone to match with a resource zone, each load settlement location was mapped to a reserve zone to approximate demand within a particular zone. Additionally, import limits are approximated by the average of the reserve zone limits for the times they were activated in 2016.

becomes pivotal. Another market condition is during times of shortage or high demand. The mere size of a supplier has no link to being pivotal; however, suppliers with a high frequency of being pivotal in tight supply periods have an even greater ability to exercise market power. For this reason, the frequency of being a pivotal supplier is also analyzed vis-à-vis the level of demand across these five regions.

Figure 6–5 shows how frequently a supplier is pivotal at varying load levels. The results indicate that the percent of hours with pivotal supplier is the highest (around 100 percent) in the New Mexico and West Texas region, irrespective of demand level, which is where one of the SPP's frequently constrained areas in 2016 was located. This region is followed by the Iowa, Dakotas, Montana region where, depending on the level of load, 17 to 36 percent of the hours exhibit at least one pivotal supplier. The remaining regions experience pivotal supplier conditions for only negligible periods, and only at the higher load levels.

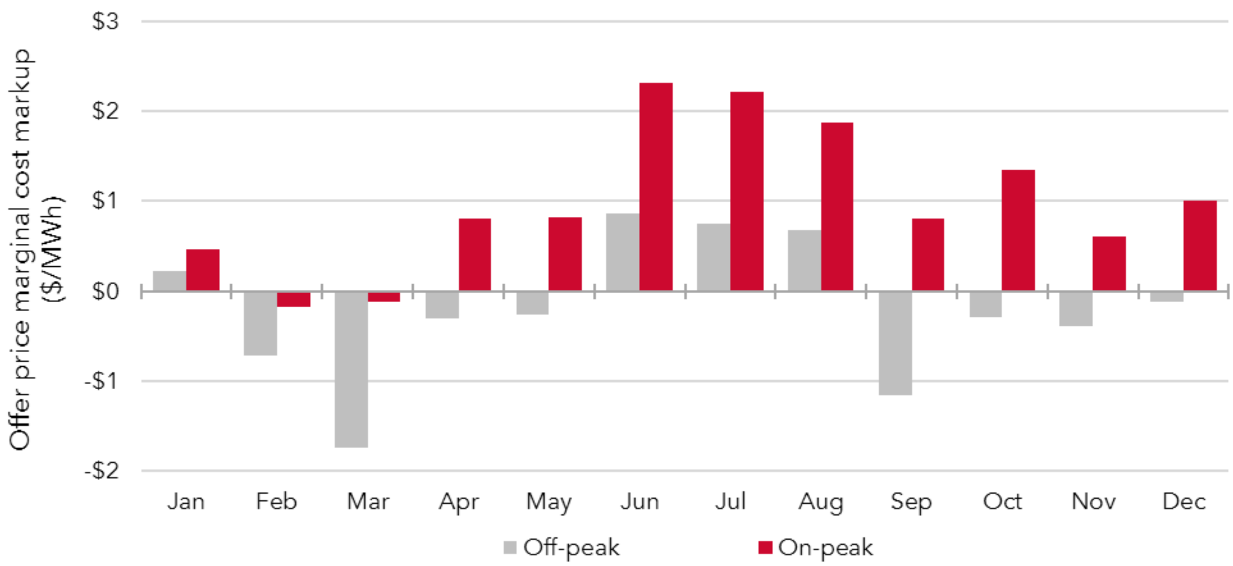
Figure 6–5 Hours with at least one pivotal supplier



6.2 BEHAVIORAL ASPECTS OF THE MARKET

In a competitive market, prices should reflect the short-run marginal cost of production of the marginal unit. In SPP's Integrated Marketplace, market participants submit hourly mitigated energy offer curves that represent their short-run marginal cost of energy. Market participants also submit their market-based offers, which may differ from their mitigated offers. To assess market performance, a comparison is made between the market offer and the mitigated offer for the marginal resources for each real-time market interval. Figure 6–6 provides the average marginal resource offer price markups[50] by month for on-peak and off-peak periods.

Figure 6–6 Average offer price markup, monthly

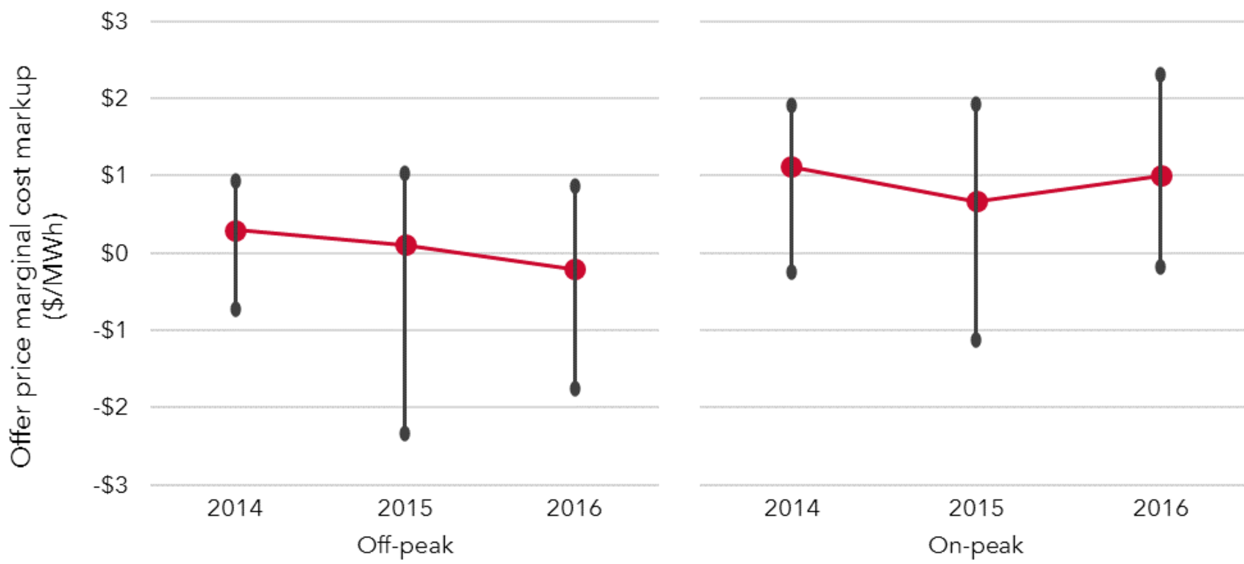


In 2016 the average monthly markups ranged from -$1.75 to $0.86/MWh for off-peak periods and from -$0.17 to $2.31/MWh for on-peak periods. The lowest markups occurred in spring and fall in off-peak hours, when wind generation is generally the highest. During two months, the average on-peak markup was also negative. The observed levels of negative markups indicate that some market participants' real-time market offers are below their mitigated offers. This could occur where generators decide to offer below their marginal cost to maintain commitments. Coal plant operators may have a negative opportunity cost resulting from an oversupply of coal or possible exposure to a take-or-pay contract. Negative markups could also occur when wind units become marginal and their (negative) offers clear the market.[51] Note that on-peak markups exceeded $2/MWh during the months of June and July. Figure 6–7 below points to a declining trend of an off-peak average markup where the

[50] Offer price markup is calculated as the difference between market-based offer and the mitigated offer where the market-based offer may or may not be equal to the mitigated offer. The MMU calculates a simple average over all marginal resources for an interval. The markups are not weighted to reflect each marginal resource's proportional impact on the price.
[51] Wind units may have negative mitigated offers due to subsidies they receive.

on-peak average markup is returning to the level experienced in the first year of the Integrated Marketplace, at around $1/MWh. Lower offer price markup levels indicate a competitive pressure on the suppliers in the SPP market.

Figure 6–7 Average offer price markup, annual



6.2.1 MITIGATION PERFORMANCE ASSESSMENT

SPP employs an automated conduct and impact mitigation scheme to address potential market power abuse through economic withholding. The mitigation applies to resources that exercise local market power in areas of transmission congestion, reserve zone shortages, and manual commitments in instances where there is the potential for manipulation due to a manual commitment that guarantees recovery of a resource's submitted offers.

6.2.2 MITIGATION FREQUENCY

SPP resources' incremental energy, start-up, no-load, and operating reserve offers are subject to mitigation for economic withholding when the following three circumstances occur simultaneously in a market solution:

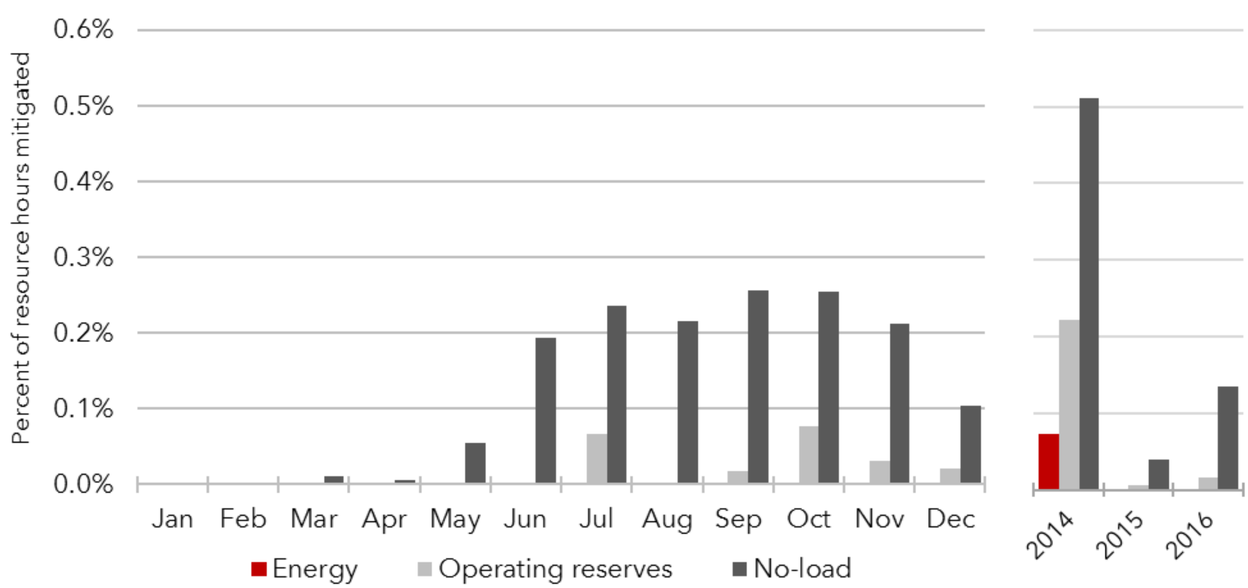
1) The resource has local market power;

2) The offer has failed the conduct test. Resources submit two offers for each product: a mitigated offer representing the competitive baseline costs that must adhere to the mitigated offer development guidelines[52] and a second offer generally referred to as a market offer. An offer fails the conduct test when the market offer exceeds the mitigated offer by more than the allowed threshold;

3) The resource is manually committed by SPP for capacity, transmission constraint, or voltage support; or by a local transmission operator for local transmission problems or voltage support; and the application of mitigation impacts market prices or make-whole payments by more than the allowed $25/MWh threshold.

Mitigation frequency varies across products and markets. Figure 6–8 shows that the mitigation of incremental energy, operating reserves and no-load was infrequent in the day-ahead market in 2016, but has slightly increased starting in March. The application of mitigation in the day-ahead market totals 0.15 percent of all resource hours for 2016, with levels of 0.02 percent for operating reserves and 0.13 percent for no-load and null for incremental energy.

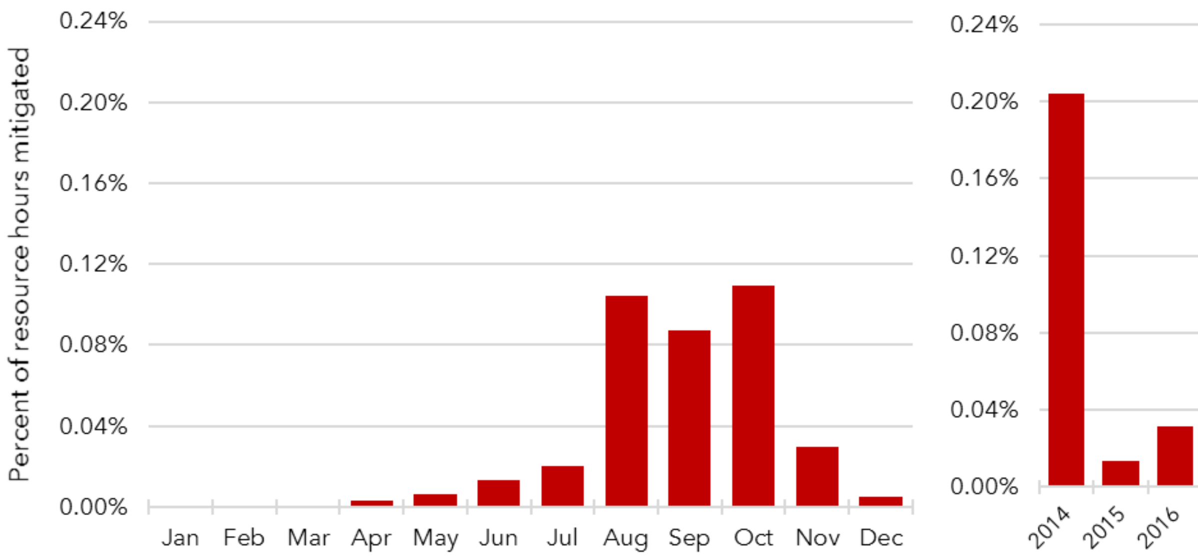
Figure 6–8 Mitigation frequency, day-ahead market



[52] As indicated in Appendix G of the SPP's Market Protocols.

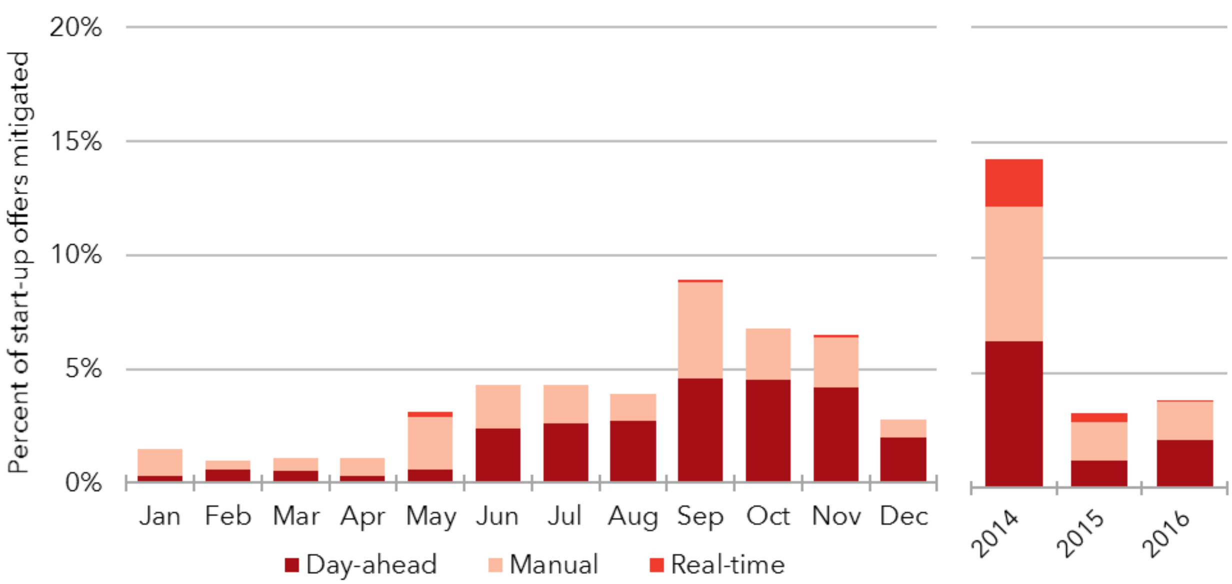
For the real-time market, the mitigation of incremental energy has been at very low levels with annual average around at 0.03 percent in 2016, as shown in Figure 6–9 below.

Figure 6–9 Mitigation frequency, real-time market



The mitigation of start-up offers had a slight increase in 2016, with the level of mitigation increasing starting in May. Figure 6–10 shows the mitigation frequency for start-up offers for the various means of commitment. The mitigation of start-up offers increased to nine percent in September 2016 and has since fallen to less than three percent in December.

Figure 6–10 Mitigation frequency, start-up offers



6.2.3 OUTPUT GAP AS A MEASURE FOR ECONOMIC WITHHOLDING

Economic withholding by a resource is defined as submitting an offer that is unjustifiably high such that either the resource will not be dispatched, or if dispatched such that the offer will set a higher than competitive market clearing price. Accordingly, the output gap metric aims to measure the amount of output that was withheld from the market by submitting offers in excess of competitive levels. Mitigated offers in the SPP market are defined to be the short-run marginal cost of production. The output gap is the amount not produced as a result of offers exceeding the mitigated offer above the conduct threshold. In this report, the output gap is calculated as the difference between the resource's economic level of output at the market clearing price, which corresponds to the level between the minimum and maximum economic capacity, and the actual amount of production.[53]

In 2015, the annual report only showed the SPP-wide overall output gap figures on an annual average basis. This year the data are shown by month and the output gap percentages are also shown for the two frequently constrained areas (FCAs) as well. Furthermore, the output gap is calculated for the largest three suppliers in each area comparing the levels to those of the remaining suppliers. Similar to the last year's report, the annual calculations were run varying levels of demand as a potential market condition that can affect the outcome.

Most of the energy for non-quick-start resources was awarded in the day-ahead market, whereas quick-start resources are generally committed on short notice and fully exposed to real-time prices. Therefore, day-ahead prices are used for non-quick-start resources and real-time prices are used for quick-start resources for assessing the output gap. Also, this year the MMU considered only the 25 percent conduct threshold level for economic withholding at varying demand levels because the mitigation for economic withholding primarily occurs at that threshold level. Additionally, in order to account for the discrepancy between a resource's offered capacity and the dispatched amount (due to possible changes in real-time market conditions such as transmission constraints), an adjusted value is calculated by taking

[53] The MMU calculates this metric by including only those resources that can potentially (economically) withhold (i.e., those with local market power) and use these resources' total capacity when calculating output gap percentages.

the maximum of the day-ahead offer or the real-time dispatched amount to reflect the actual amount of production.

The results in Figure 6–11 below show that the SPP footprint-wide monthly levels of the output gap varies between 0.69 percent and 2.06 percent with the highest gap occurring in December.

Figure 6–11 Output gap, monthly

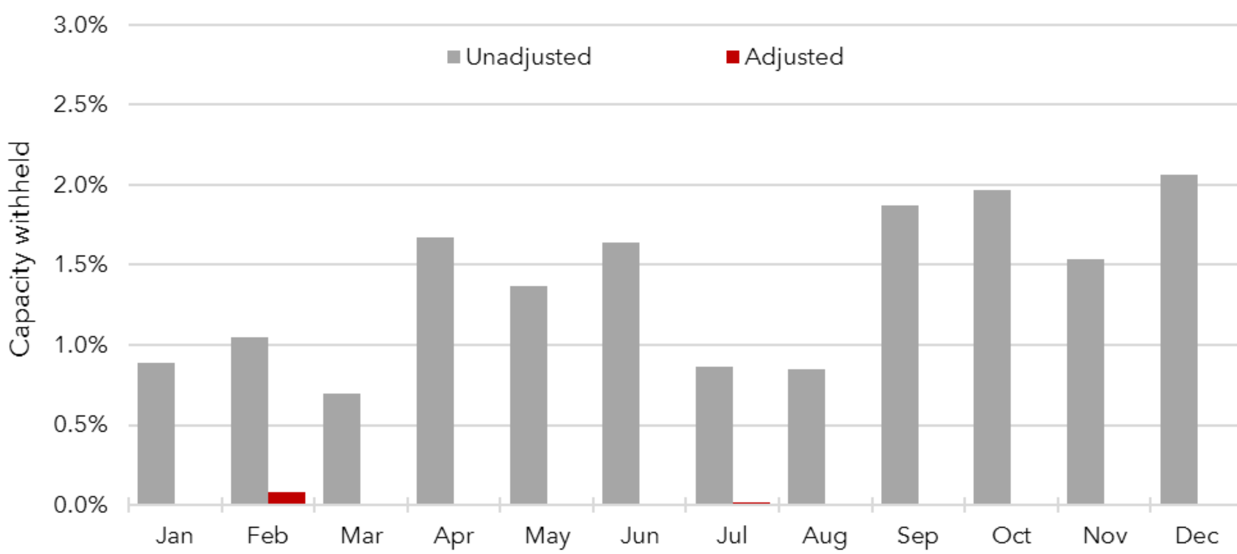


Figure 6–12 through Figure 6–14 display the output gap calculations by demand level for three areas, namely the entire SPP market footprint and the two frequently constrained areas. In general more output is expected to be withheld at higher demand levels. However, at times, output may also be withheld in low load periods, as prices are often negative during the lowest 20 percent of load hours. All results indicate low levels of (economic) capacity withheld in 2016, which is consistent with competitive market conduct.

Figure 6–12 Output gap, SPP footprint

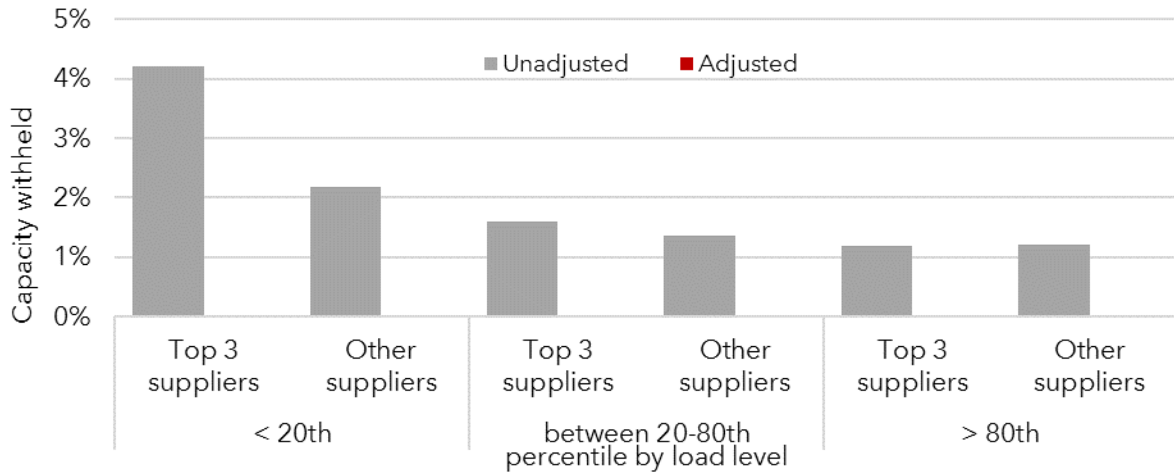


Figure 6–13 Output gap, Texas Panhandle frequently constrained area

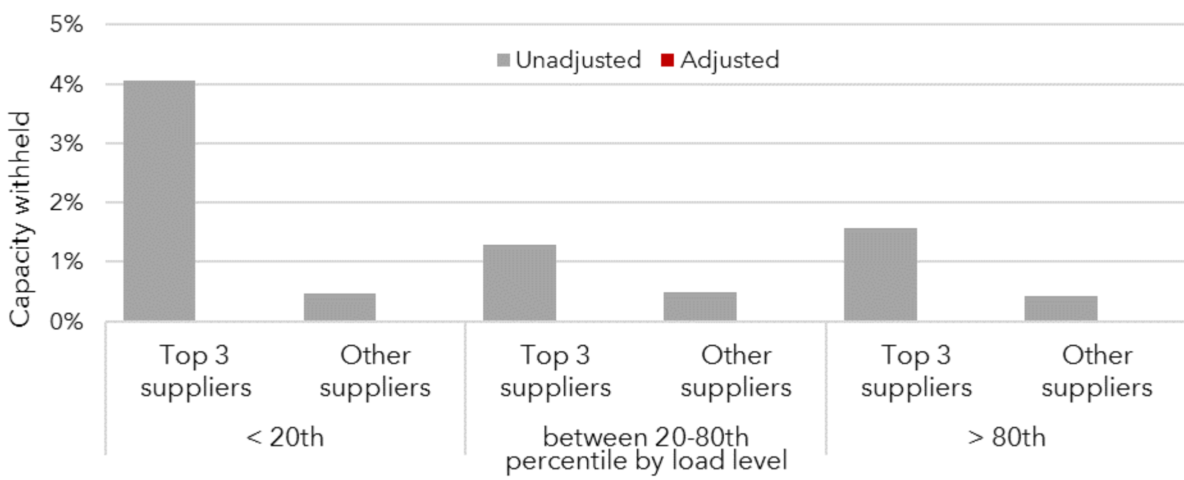
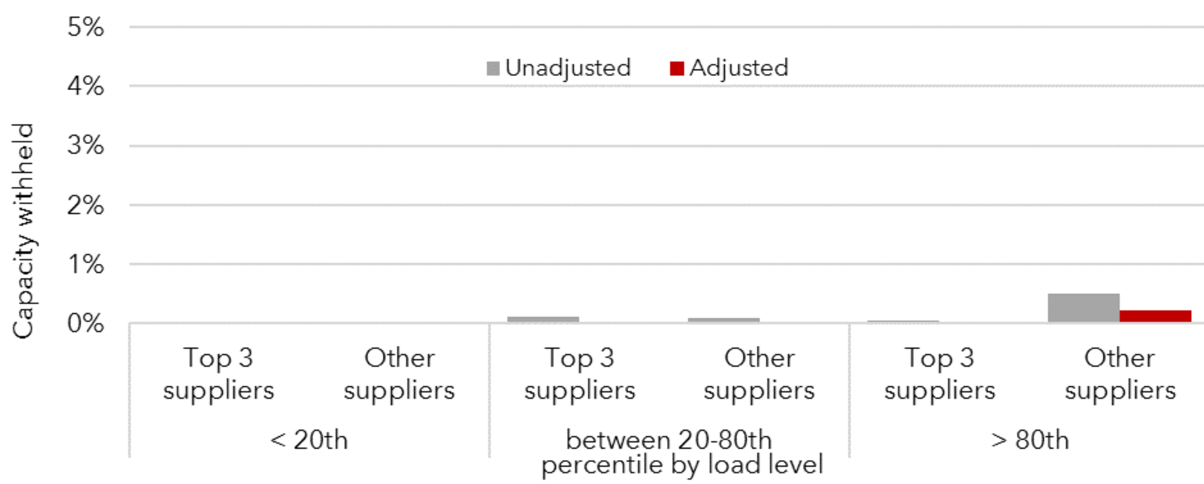


Figure 6–14 Output gap, Woodward frequently constrained area



6.3 OFFER BEHAVIOR DUE TO MITIGATION THRESHOLD

SPP market rules require market participants submit both a 'market-based' energy offer curve and a 'cost-based' mitigated energy offer curve. The FERC imposed offer cap of $1,000/MWh and the floor of -$500/MWh are the only limits to the energy offer curve. Market participants can submit any energy offer curve within these bounds. The market clearing engine will use the energy offer curve, unless the resource is mitigated. When mitigated, the mitigated offer curve will replace the energy offer curve.

In order for offers to be mitigated, the resource must fail all three of the following tests: local market power test, conduct test, and impact test. These three criteria for activating mitigation are described in Section 6.2.2.

Market participants directly affect the conduct test, sometimes referred to as the behavior test. When a market participant submits an energy offer that exceeds the mitigated offer by more than the thresholds described below, then the offer fails the conduct test.

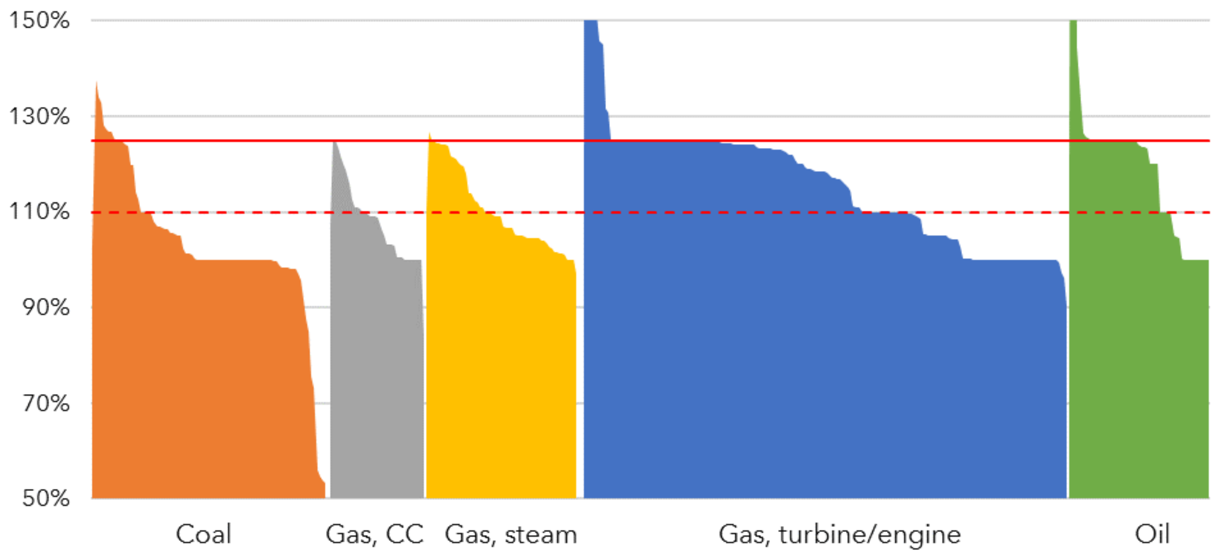
The thresholds are defined as:

- 10 percent above the mitigated energy offer for resources committed to address a local reliability issue;
- 17.5 percent above the mitigated energy offer for resources in a frequently constrained area; and
- 25 percent above the mitigated energy offer for all other resources.

As shown in Figure 6–15, there is a noticeable plateau at the 110 percent and 125 percent marks, particularly for natural gas and oil-fired resources. In the figure, the dashed red line represents the 110 percent threshold, and the solid red line represents the 125 percent threshold. The plateaus appear to be due to participants offering their resources just under the conduct test thresholds in order to guarantee that they are not mitigated. This self-mitigating behavior is problematic.

The purpose of mitigation for economic withholding is to protect the market from resources that have the unilateral ability to increase market prices. Resources flagged for economic withholding mitigation have local market power, and allowing inflated market offers only gives them more opportunity to exercise market power. Resources that are committed for a local reliability issue, often for voltage support, should not fall into this category. Even though these resources are needed and must be committed, they are committed outside of the market clearing engine logic, and do not have the ability to increase prices.

Figure 6–15 Mitigation offer mark-up by fuel category



Resources receiving a commitment for local reliability (about two percent of all commitments) are subject to a 10 percent mitigation threshold for the duration of that commitment cycle. The market system replaces market offers that are more than 10 percent above the mitigated offer with the mitigated offer for that commitment. Resources that do not receive commitments for local reliability are not at risk of being mitigated down to the mitigated offer level for offers between 10 percent and 25 percent above the mitigated offer (17.5 percent for resources in designated frequently constrained areas, which accounts for nine percent of all resources).

When resource owners decide on a market offer for a resource that has the possibility of receiving a reliability commitment, the owner may factor in the risk of being mitigated to the mitigated offer level for offers above 10 percent. All other resource owners do not face this risk and will not have their market offer reduced to the mitigated offer level, if the market offer does not exceed 25 percent above the mitigated offer. By converting the 10 percent threshold for reliability commitments to a 10 percent cap, the risk of making an offer between 10 percent and 25 percent above the mitigated offer would be the same as for all other resource owners. This is a subtle but important risk for the small number of market participants exposed to reliability commitments. These resource owners are subject to a higher level of risk through no fault of their own and it is therefore inappropriate.

The MMU recommends that mitigation measures for resources committed for a local reliability issue be treated separately from the mitigation measures for economic withholding. Resources that fall into this category are not be subject to the three tests associated with economic withholding, which is appropriate. This viewpoint was submitted by the MMU to the Market Working Group through Revision Request 231[54] in May 2017, and is still being discussed at the stakeholder level.

6.4 SUMMARY ASSESSMENT

The structural and behavioral metrics indicate that the markets were very competitive in its first three years. The market share, HHI, and pivotal supplier analyses all indicate minimal potential structural market power in SPP markets outside of areas that are frequently congested. There were two frequently constrained areas so designated in 2016 where the potential for concerns of local market power is the highest. Ongoing analysis shows existing mitigation measures to be an effective deterrent in preventing pivotal suppliers from unilaterally raising prices.

Behavioral indicators were also assessed through the analysis of actual offer or bid behavior (i.e., conduct) of the market participants and the impact of such behavior on market prices to look for the exercise of market power. Economic withholding mitigation is still at a low level in absolute terms, even though the frequency of mitigation for incremental energy, no-load, and operating reserve offers in the day-ahead market was slightly up in 2016. The annual average real-time market mitigation was extremely low, at around 0.03 percent for 2016. The slight increase in the frequency of start-up offer mitigation in the day-ahead market in 2016 is similar to the trend that was experienced for the other market components however, it is observed at higher absolute levels. The combined frequency of mitigation of start-up offers for day-ahead, reliability unit commitment, and manual commitments increased to 3.8

[54] Revision Request 231 (Mitigation of locally committed resources).

percent in 2016 from 2.8 percent in 2015. The overall mitigation frequency levels experienced in 2016 are consistent with the levels experienced in other markets.

The system wide output gap results show a very low-level varying from 0.69 percent to 2.06 percent with the highest gap occurring in December. Out of the two frequently constrained areas, Texas Panhandle experienced the highest monthly output gap at 1.93 percent, again occurring in December. The Woodward FCA exhibited very low levels of output gap within the year with monthly levels ranging from 0.01 percent to 0.39 percent. These low levels of (economic) capacity withheld in 2016 is consistent with competitive market conduct.

Overall, the SPP Integrated Marketplace provides sufficient and effective market incentives and mitigation measures to produce competitive market outcomes particularly during market intervals where exercise of local market power is a concern. The competitive assessment in this report provides evidence that market results in 2016 were workably competitive and that the market required mitigation of local market power infrequently to achieve those outcomes. Nonetheless, mitigation remains an essential tool in ensuring that market results are competitive during periods when such market conditions offer suppliers the potential to abuse local market power.

7 RECOMMENDATIONS

One of the core functions of a market monitor as defined by FERC in Order No. 719 is "to advise the Commission, the RTO or ISO, and other interested entities of its views regarding any needed rule and tariff changes." The MMU accomplishes this responsibility through many forums, including but not limited to active participation in the SPP stakeholder meetings process, commenting on FERC notices of proposed rulemakings, submitting comments at FERC on SPP filings, and making recommendations in the Annual State of the Market report. In order to be effective and efficient, the MMU identifies and uses the most appropriate forum or combination of forums given the issue under consideration.

This section summarizes the status of previous recommendations, discusses revisions to previous recommendations, identifies open issues, and presents new recommendations. The MMU has determined several previous recommendations have been addressed to a satisfactory level as noted below. Those topics will continue to be monitored to ensure the changes are effective. Should additional concerns arise; the MMU will present new recommendations in a forum that is most appropriate for that issue.

Previous annual reports contain recommendations identified during or before the startup of the Integrated Marketplace. As with the startup of any program the size of the Integrated Marketplace, it was not surprising that there were a number of concerns identified. The serious consideration of those recommendations by the SPP board of directors and other stakeholders is greatly appreciated. Significant progress has been made on most of the recommendations presented in previous reports and some of the recommendations have been revised given changes in the market, and as a result of additional analysis. Section 7.3 below lists the status of past and current annual report recommendations.

7.1 LOCAL RELIABILITY COMMITMENT MITIGATION

The MMU recommends converting the 10 percent mitigation threshold for local reliability commitments to a 10 percent cap. This recommendation addresses an unbalance risk associated with mitigation of resource commitments for local reliability.

When resource owners decide on a market offer for a resource that has the possibility of receiving a reliability commitment, the owner must factor in the risk of being mitigated to the mitigated offer level for offers above 10 percent. All other resources owners do not face this risk and will not have their market offer reduced to the mitigated offer level if the market offer does not exceed 25 percent above the mitigated offer. By converting the 10 percent threshold for reliability commitments to a 10 percent cap, the risk of making an offer between 10 percent and 25 percent above the mitigated offer would be the same as for all other resources owners. This is a subtle but important risk for the small number of market participants exposed to reliability commitments. These resource owners are subject to a higher level of risk through no fault of their own and it is therefore inappropriate.

7.2 PREVIOUS RECOMMENDATIONS REMAINING OPEN

7.2.1 NON-DISPATCHABLE VARIABLE ENERGY RESOURCE CONVERSION TO DISPATCHABLE

The 2015 Annual State of the Market report identified non-dispatchable variable energy resources as a concern because of their adverse impact on market price and system operations. The adverse impact these resources have on the market continues to increase as the total volume of wind generation increases in the SPP market. FERC demonstrated strong support for the elimination of most instances of non-dispatchable resources with the approval of a rule change for the New England market in December 2016. Markets function best when all market participants make a positive contribution to the market in the form of dispatchability. The MMU continues to encourage the SPP stakeholders to move forward with rule changes to transition non-dispatchable variable energy resources to dispatchable variable energy resource status, thereby reducing the adverse impact of this category of resources on all other market participants.

7.2.2 MAKE-WHOLE PAYMENT MANIPULATION

At the time of publishing of the 2015 Annual State of the Market report, there were three outstanding recommendations to address potential threats of make-whole payment manipulation that where either recently closed or still open. The recommendation associated with the local out-of-merit energy events has been closed. The recommendation associated with the regulation deployment adjustment charge has been closed, although the issue still exists. The remaining area of concern is regarding resources committed with long minimum run time.

The potential for exploiting make whole payments related to local out-of-merit energy events is remote and easily identified. The expense and effort to eliminate the risk appears to exceed the potential benefits. The Market Working Group officially closed the action item related to the out-of-merit energy recommendation in October 2016 and the MMU considers this recommendation officially closed as well. If conditions change, resulting an increased exposure regarding this design flaw, the MMU will address the concern through a new recommendation. The MMU will continue to monitor and refer all incidences to FERC.

The recommendation for resources committed with a long minimum run time was refined to capture resources with a minimum runtime that took it into the third operating day. As previously noted, the Market and Operations Policy Committee (MOPC) recently remanded this topic back to the Market Working Group for further review. The recommendation to disqualify resources with fixed regulation bids from receiving a regulation deployment adjustment charge has been withdrawn by the MMU. After extensive discussions with the RTO staff, it was determined that the issue was not confined to only resources with fixed regulation bids. The MMU is working with the RTO to understand the core problem. A new recommendation regarding this issue is pending the result of additional analysis.

7.3 RECOMMENDATIONS UPDATE

The table below lists all of the Annual State of the Market recommendations that were closed in 2016 through the date of this report, those that remain open, and those that are new. Recommendations closed prior to the completion of the previous year's report do not appear in this table. To review closed recommendations that are not covered in this report, please consult earlier reports. All previous annual reports can be found at https://www.spp.org/spp-documents-filings/?id=18512.

Figure 7–1 Annual State of the Market recommendations update

Recommendation	Report year	Current status
1. Local reliability commitment mitigation threshold conversion to a cap	2016	open
2. Non-dispatchable variable energy resource transition to dispatchable variable energy resource status	2015	open
3. Quick-start logic	2014	closed
4. Ramp-constrained shortage pricing	2014	closed
5. Manipulation of make-whole payment provisions	2014	open
6. Day-ahead must offer requirement and physical withholding	2014	closed
7. Transmission congestion right and auction revenue right system availability	2014	closed
8. Transmission outage reporting and modeling	2014	closed
9. Transmission congestion right bidding at electrically equivalent settlement locations	2014	closed
10. Allocation of over-collected losses	2014	closed
11. Increase conduct test thresholds in frequently constrained areas	2014	closed

COMMON ACRONYMS

AECC	Arkansas Electric Cooperative Corporation
AECI	Associated Electric Cooperative, Inc.
AEP/AEPM	American Electric Power
ARR	auction revenue rights
BEPM	Basin Electric Power Cooperative
BSS	bilateral settlement schedules
BTU	British thermal unit
CC	combined cycle
CDD	cooling degree days
CHAN	City of Chanute (Kan.)
CT	combustion turbine
DA	day-ahead
DAMKT	day-ahead market
DA RUC	day-ahead reliability unit commitment
DISIS	definitive interconnection system impact study
EDE/EDEP	Empire District Electric Co.
EHV	extra high voltage
EIA	Energy Information Administration
EIS	energy imbalance service
ERCOT	Electric Reliability Council of Texas
FCA	frequently constrained area
FERC	Federal Energy Regulatory Commission
GI	generation interconnection
GLDF	generator to load distribution factor
GMOC/UCU	Greater Missouri Operations Company (KCPL)
GRDA/GRDX	Grand River Dam Authority
GSEC	Golden Spread Electric Cooperative, Inc.
GW	gigawatt
GWh	gigawatt hour
HDD	heating degree days
HHI	Herfindahl-Hirschman Index

HMMU	Harlan (Iowa) Municipal Utilities
HVDC	high-voltage direct current
IA	interconnection agreement
ID RUC	intra-day reliability unit commitment
IDC	interchange distribution calculator
INDN	City of Independence (Mo.)
IOU	investor owned utility
IPP	independent power producer
IS	Integrated System
ISO	independent system operator
ITP	Integrated Transmission Plan
JOU	jointly owned unit
KBPU	Kansas City (Kan.) Board of Public Utilities
KCPL/KCPS	Kansas City Power & Light
KMEA	Kansas Municipal Energy Agency
KPP	Kansas Power Pool
kV	kilovolt (1,000 volts)
LES/LESM	Lincoln (Nebr.) Electric System
LIP	locational imbalance price
LMP	locational marginal price
MCC	marginal congestion component
MEAN	Municipal Energy Agency of Nebraska
MEC/MECB	MidAmerican Energy Company
MEUC	Missouri Joint Municipal Electric Utility Commission
MIDW	Midwest Energy Inc.
MISO	Midcontinent Independent Transmission System Operator
MLC	marginal loss component
MM	million
MMBtu	million British thermal units (1,000,000 Btu)
MMU	Market Monitoring Unit
MW	megawatt (1,000,000 watts)
MWh	megawatt hour
MWP	make-whole payment

MRES	Missouri River Energy Services
NDVER	non-dispatchable variable energy resource
NERC	North American Electric Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration
NPPD/NPPM	Nebraska Public Power District
NSP/NSPP	NSP Energy
NWPS	Northwestern Energy
O&M	operation and maintenance
OGE	Oklahoma Gas & Electric
OMPA	Oklahoma Municipal Power Authority
OOME	out-of-merit energy
OPPD/OPPM	Omaha Public Power District
OTPW/OTPR	Otter Tail Power Company
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PEPL	Panhandle Eastern Pipe Line
PISIS	preliminary interconnection system impact study
RC	reliability coordinator
RNU	revenue neutrality uplift
RR	revision request
RSG	reserve sharing group
RT	real-time
RTBM	real-time balancing market
RTO	regional transmission organization
RUC	reliability unit commitment
SC	simple cycle
SECI/SEPC	Sunflower Electric Power Corporation
SPA	Southwestern Power Administration
SPP	Southwest Power Pool, Inc.
SPRM	City Utilities of Springfield (Mo.)
SPS	Southwestern Public Service Company
ST	steam turbine
ST RUC	short-term reliability unit commitment
TCR	transmission congestion right

TEA	The Energy Authority
TNSK	Tenaska Power Service Company
UGPM	Western Area Power Administration, Upper Great Plains
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WFEC/WFES	Western Farmers Electric Cooperative
WR/WRGS	Westar Energy, Incorporated