2015 State of the Market

15 August 2016

SPP Market Monitoring Unit

SPP Southwest Power Pool

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Table of Contents

List of Figures

1. Executive Summary

The Southwest Power Pool (SPP) Market Monitoring Unit's Annual State of the Market report for the second 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 report fulfills the MMU's requirement under Attachment AG of the SPP Open Access Transmission Tariff to review and report on market performance with particular regard to market efficiency, competitiveness of market outcomes, and prevention of the exercise of market power and market manipulation. 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.

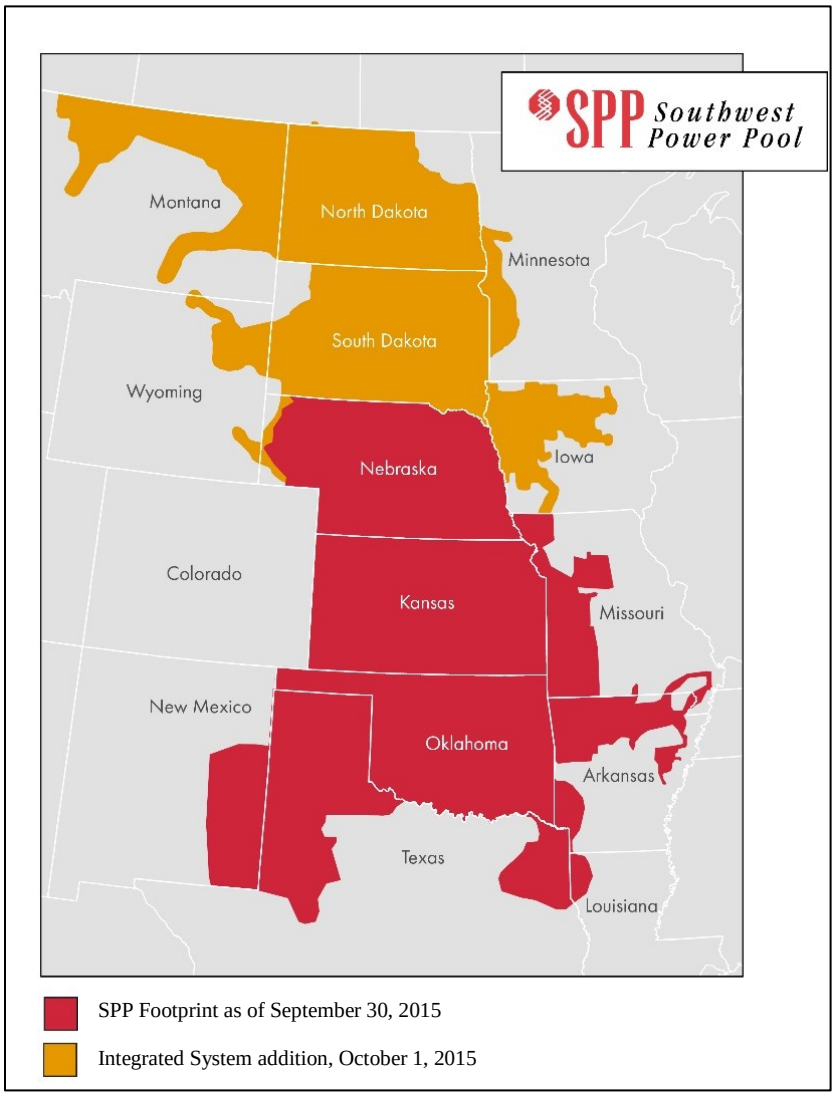
1.1. Overview

The second year of the Integrated Marketplace shows significant maturing of the market, which is reflected in high levels of participation, lower levels of make-whole payments and mitigation compared to other markets, and a modest level of scarcity pricing. Major factors impacting the market include low and declining natural gas prices, increasing wind generation capacity and output, declining levels of overall congestion with increased congestion in the wind-sourced generation areas, and an expanding market footprint.

The SPP Market footprint experienced an increase of about 10% in both generation and load in 2015 with the addition of the Integrated System (IS). The SPP Market now covers most of North and South Dakota and parts of several adjacent states. This expansion occurred on October 1, 2015.

Average monthly natural gas prices were generally flat at about $2.50/MMBtu through September and then declining to below $2.00/MMBtu in December. Monthly average electricity prices (LMP) in the Integrated Marketplace for 2015 were generally flat with some variation in the $20 to $25/MWh range with the annual average all-in price of $23.48/MWh. The cost of operating reserves represented about 1% of the total all-in price, with Make-Whole Payments representing only about 1.3% of the total price of electricity. 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.



In 2015 installed generation capacity increased slightly to 67,251 MW from 67,095 MW in 2014. This increase in installed capacity, along with a slightly lower system peak load compared to 2014, resulted in a slight increase in the market resource margin to 49% in 2015 from 48% in 2014. The market expansion resulting from the addition of the Integrated System did not impact the resource margin figure because the expansion occurred after the system peak.

Generation in the market by fuel type is changing as a result of two primary factors: 1) increased installed wind generation capacity and output; and 2) declining natural gas prices. Wind-sourced

generation continues to increase and represented almost 20% of total SPP generation in November and December. On the other hand, coal generation has declined from a historical average of 60–65% to an annual average of 55% in 2015, with November coal generation representing only 45% of SPP total generation for the month.

In 2015 year-end installed wind generation capacity in the SPP Market increased by 44%, from 8,606 MW of registered capacity in 2014 to 12,398 MW in 2015. 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 4,000 MW of new wind capacity in 2015 will not be felt until 2016. Initial results from 2016 indicate that at times generation is approaching 50% of total load. This is a substantial increase from 34% in 2015 and 33% in 2014.

Given the large resource margin and the frequency with which the LMP represents inexpensive generation, prices generally did not rise to levels high enough to support investment in new generating capacity.

1.2. Energy and Operating Reserve Markets

The Integrated Marketplace introduced a centralized unit commitment and dispatch process, a Day-Ahead Market, and a Real-Time Balancing Market with both energy and Operating Reserve products. The centralized unit commitment and dispatch constituted the largest and most immediate financial benefit to the SPP Market, as it allowed SPP to reduce online generating capacity by 10% in 2014 and a somewhat lower amount in 2015. Changing generation patterns in 2015 driven by extremely low natural gas prices, high wind generation, and decreased use of coal generation all have increased uncertainty and appear to be affecting the capacity commitment process. This is reflected in high online capacity as a percent of demand in December comparable to what was generally experienced during the last year of the EIS Market. The MMU considers this a temporary state as the market adjusts to new conditions and gas prices increase to more normal historical levels.

In addition to committing capacity to meet the load and operating reserve obligations, SPP also committed resources for reliability needs through its Reliability Unit Commitment (RUC) processes. The demand for reliability met through the Day-Ahead and Real-Time RUC processes

supplemented the load and operating reserve obligations with market ramping and local reliability constraints, services for which the market provided no additional payment. The commitment of additional capacity to meet these constraints dampened real-time prices, increased RUC Make-Whole Payments, and implied that faster-starting resources may not have received market revenues sufficient to cover annual avoidable costs. Through the stakeholder process and in particular the Price Formation Task Force, SPP is assessing this issue and looking into alternatives. The MMU continues to support these activities and will provide suggestions and recommendations as appropriate.

In 2015 scarcity pricing levels for aggregate Operating Reserves at about $1,100/MWh, for Regulating Reserves at about $700/MWh, and for Spinning Reserves at about $300/MWh are comparable to 2014 levels and consistent with what other markets experience. These high prices allowed the market to reflect the demand for reliability.

However, average prices below $100/MWh in 2015 for ramp-constrained shortages are similar to what was experienced in 2014. The MMU continues to have a concern for these low prices such that they do not reflect the value of demand for ramp capability provided by fast-responding resources, creating a market separation between economics and reliability.

The Integrated Marketplace provides relatively simple provisions for market uplift, or Make-Whole Payments, when compared to other RTO markets. Coupled with five-minute RTBM settlements, these provide incentives for resources to meet their commitment and dispatch instructions by ensuring that the market covers the short run marginal costs of production. The level of make-whole payments in 2015 continued to constitute about 1% of the all-in price of electricity, with 70% of make-whole payments related to RUC commitments, slightly less than what was experienced in 2014. The level of make-whole payments in the SPP Market continue to be about half of what is experienced in other markets.

1.3. Day-Ahead Market

The Day-Ahead Market produced economically sound LMPs and resource commitments consistently and transparently. Load participation in the Day-Ahead Market by participants declined from a high of 109% in some 2014 months to less than 101% in all month for 2015. The

market design flaw in the allocation of Over-Collected Losses (OCL), which SPP corrected, appears to have addressed the incentives that drove the OCC-related improper behavior in 2014.

Virtual transactions as a percentage of load increased slightly in 2015 to about 7.5% of load, although the participation rate is lower than the level experienced in other RTO markets, which approaches 10%. Virtual trading profits declined in 2015 to about $21 million from about $24 million in 2014. This lower level of profits is consistent with lower energy prices and a maturing of the market resulting from more competition. Generators also participated fully in the Day-Ahead Market, whether or not they held a day-ahead must-offer obligation, with the exception of the wind farms. Overall, the first two years of the market experienced moderate levels of virtual participation, consistent profitability of virtual trading, and increasing convergence of DA Market and RTBM LMPs. All these factors indicate a reasonably efficient virtual market.

1.4. Congestion and Losses

Locational Marginal Prices reflect the marginal cost of energy, marginal cost of congestion, and marginal cost of losses at any given pricing location in the market. With its historic transmission bottlenecks and ever-expanding network, the SPP Market's geographic pricing pattern continued to evolve in 2015. The challenge of moving inexpensive power generated by coal and wind resources from the northern and western parts of the footprint to the eastern load centers resulted in an average $22/MWh spread between the lowest and highest LMP points. This is slightly higher than what was experienced in 2014 and likely the result of an increase in wind generation penetration.

The market charged Load-Serving Entities a total of $150 million in congestion costs for 2015. This total is consistent with but lower than the 2014 total of $290 million given the lower overall average system price in 2015, 25% lower than what was experienced in 2014. This also reflects the full impact of the significant expansion in transmission capacity activated in 2014. Load-Serving Entities may hedge the congestion cost with Transmission Congestion Rights (TCRs) and Auction Revenue Rights (ARRs). This market provided them with $170 million in payments in 2015. Therefore, in aggregate the load was hedged. However, the TCR and ARR payments for a few Load-Serving Entities fell well short of their congestion costs. In total, non-load

participants profited by $15 million from SPP congestion and by $26 million from TCRs. Despite the overall gains from TCRs and ARRs, the TCR market performance could be enhanced by improvements to market efficiency and transparency. The 86% funding of TCRs from Day-Ahead Market congestion was low, and the 118% funding of ARR positions by TCR auction revenues was high. Reductions in transmission capacity made available in the TCR and ARR process to more realistic levels, earlier reporting of planned transmission outages, and improvements to modeling of the conversion of ARRs to TCRs would enhance price formation and thus the ability to effectively and economically hedge load for congestion costs.

1.5. Competitive Assessment

The SPP Integrated Marketplace provides sufficient market incentives and mitigation measures 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 market results in 2015 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 market results are competitive during periods of high demand and supply shortages when such market conditions offer suppliers the potential to abuse significant local market power.

Three metrics—Market Share Analysis, Herfindahl-Hirschman Index (HHI), and Pivotal Supplier Analysis (PSA)—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 ranked maximum market share duration curve. The market share rank ranged from 10% to 21%, exceeding the 20% benchmark in only six hours for the year.

The overall 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 unconcentrated more than 70% of the hours in 2015 and moderately concentrated only about 29% of the time. HHI never rose above the 1,800 threshold determined for a high level of concentration.

The third structural metric, the PSA, was used to evaluate the potential of market power in the presence of "pivotal" suppliers. In this report the PSA identified 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 2015. The results indicate that the percent of hours with pivotal supplier is the highest (around 100%) in the New Mexico and Texas region irrespective of demand level. This region is followed by Iowa and the Dakotas where—depending on the level of load—13% to 36% of the hours exhibit at least one pivotal supplier. The remaining regions of Nebraska, Oklahoma and Kansas City, and Western Kansas and Panhandles indicate that suppliers became pivotal for only negligible periods.

In sum, the MMU's Market Share, HHI, and Pivotal Supplier Analyses all indicate minimal potential structural market power in SPP Markets outside of areas that are frequently congested. For the FCAs—only one such area was so designated in 2015—where potential for concerns of local market power is the highest, existing mitigation measures with relatively tight thresholds provided effective levels of local market power mitigation in terms of preventing pivotal suppliers unilaterally raising prices.

The structural indicators discussed above were used to 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 and the impact of such behavior on market prices to look for the exercise of market power.

In that context, the frequency of mitigation in 2015 was dramatically lower than that experienced in 2014. The mitigation for incremental energy, regulation, and no-load in 2015 was generally below the 0.1% level in many months, while the mitigation level for these market components was virtually zero in some months. This is in stark contrast to the mitigation levels in 2014 when some of these market components experienced mitigation levels approaching 1%. The decline in the frequency of start-up offer mitigation in the Day-Ahead market in 2015 is similar to that experienced for the other market components, declining from 15–20% levels in 2014 to about the 1% level in 2015. This overall decline of more than 90% in the level of mitigation is attributed to normal market maturing and the addressing of some specific market implementation problems.

The overall mitigation frequency levels experienced in 2015 are consistent with the levels experienced in other markets.

Finally, output gap as a measure for Economic Withholding was also calculated and the results show that the overall (average) level of output gap varies between 0.48% and 1.26%, the latter showing the amount of (economic) capacity withheld at the highest load percentile level. This low level of withholding is consistent with competitive market conduct.

1.6. 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. The MMU does this through multiple forums. One such forum is the 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 RRs submitted by the 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 NOPRs.

In the 2014 Annual State of the Market report, the MMU made a number of recommendations that are currently in various stages of being addressed. The MMU considers several of these recommendations as being resolved by SPP, including Quick-Start logic, jointly owned units Combined Resource Option, over-allocation of annual TCR and ARR system availability, and systematic blocking of bids at electrically equivalent settlement locations. The MMU has withdrawn the recommendation to change mitigation conduct thresholds. The recommendations that remain open at the time this report is published include ramp-constrained shortage pricing, several concerns regarding the potential manipulation of Make-Whole Payment provisions, Day-Ahead Must-Offer requirements and physical withholding penalty rules, TCR and ARR system availability in the monthly allocation process, and allocation of over-collected losses. The MMU is currently recommending transition of Non-Dispatchable Variable Energy Resources NDVERs) to Dispatchable Variable Energy Resources (DVER) status, thereby lessening the negative impact of such resources on the market as discussed in this report.

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

2. Overview of the SPP Market

2.1. Market Description

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 (ISOs)/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 2015 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 converting to 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 Midcontinent ISO (MISO) to the north and east, Electric Reliability Council of Texas (ERCOT) to the south, and the Western Electricity Coordinating Council to the west[1]. Figure 2–1 shows the operating regions of the nine ISOs and RTOs 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]

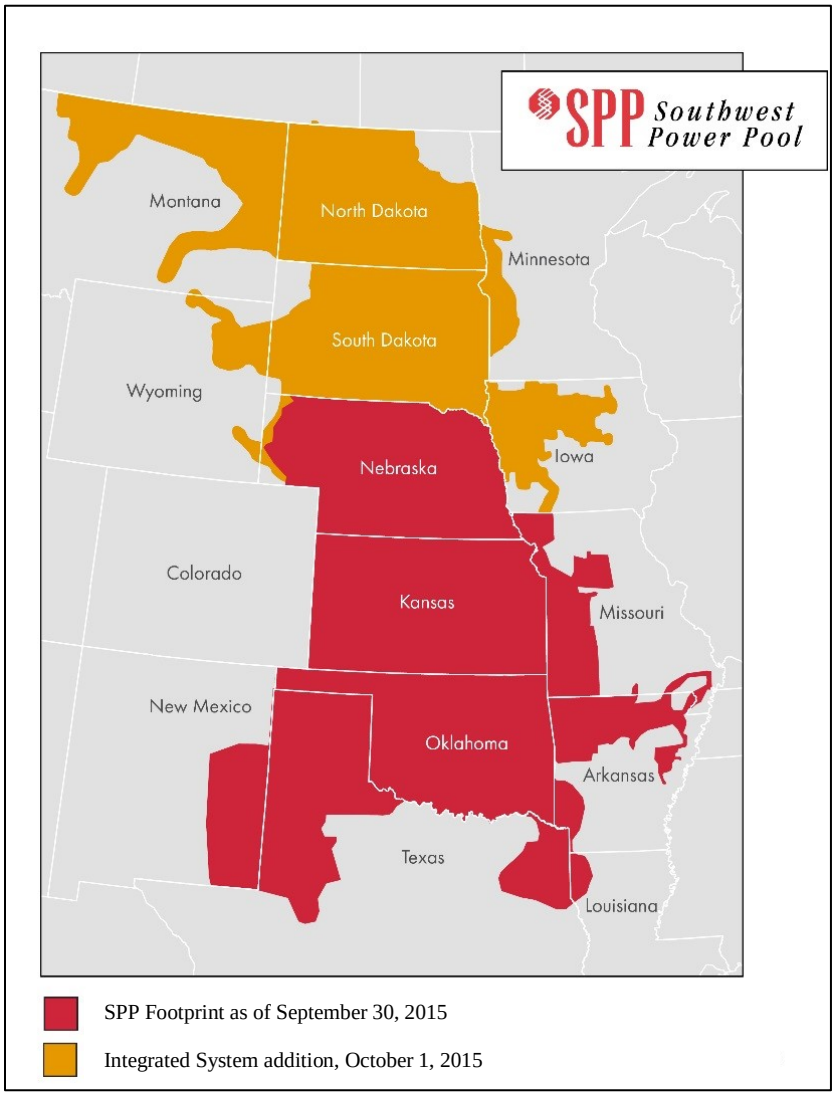
[1] SPP has limited HVDC asynchronous interconnection capacity with ERCOT and WECC.
[2] Southwestern Power Administration belongs to the SPP RTO, Reliability Coordinator (RC), Reserve Sharing Group (RSG), and Regional Entity (RE) footprints. Associated Electric Cooperative belongs to the SPP RSG.

Figure 2–1 ISO RTO Operating Regions

Source: ISO/RTO Council

The SPP Integrated Marketplace footprint expanded on October 1, 2015 to include the Integrated System (IS), which is composed of the Western Area Power Administration – Upper Great Plains, Basin Electric Power Cooperative, and Heartland Consumers Power District. The IS covers much of the Dakotas and small adjacent parts of Iowa, Minnesota, Montana, Nebraska, and Wyoming; see Figure 2–2. The IS added more than 7,600 MW of generating capacity, 5,000 MW of load, and nearly 10,000 miles of high-voltage transmission lines, increasing the length of SPP-managed transmission lines by 18% to more than 58,000 miles.

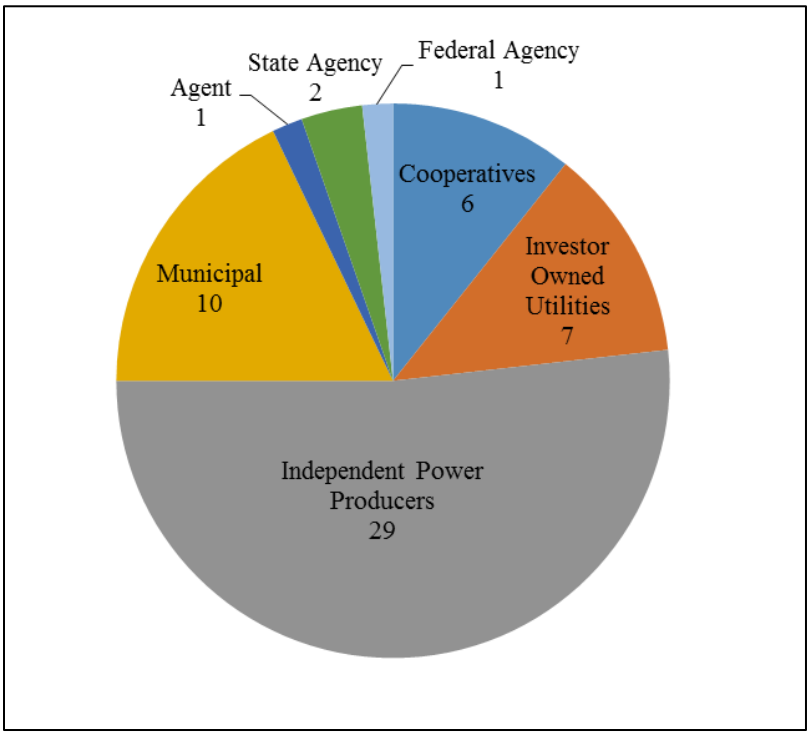
Figure 2–2 Integrated System Addition to the SPP Market



2.1.2. SPP Market Participants

At the end of 2015, 162 entities were participating in the SPP Integrated Marketplace, which includes six new Market Participants with the addition of the IS. SPP Market Participants can be divided into several categories: investor owned utilities (IOUs), electric cooperatives, municipal utilities, federal or state agencies, independent power producers (IPPs), 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 IPPs is high because most wind producers are categorized as IPPs. Several 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 2–3 Distribution of Number of Market Participants with Resources by Type

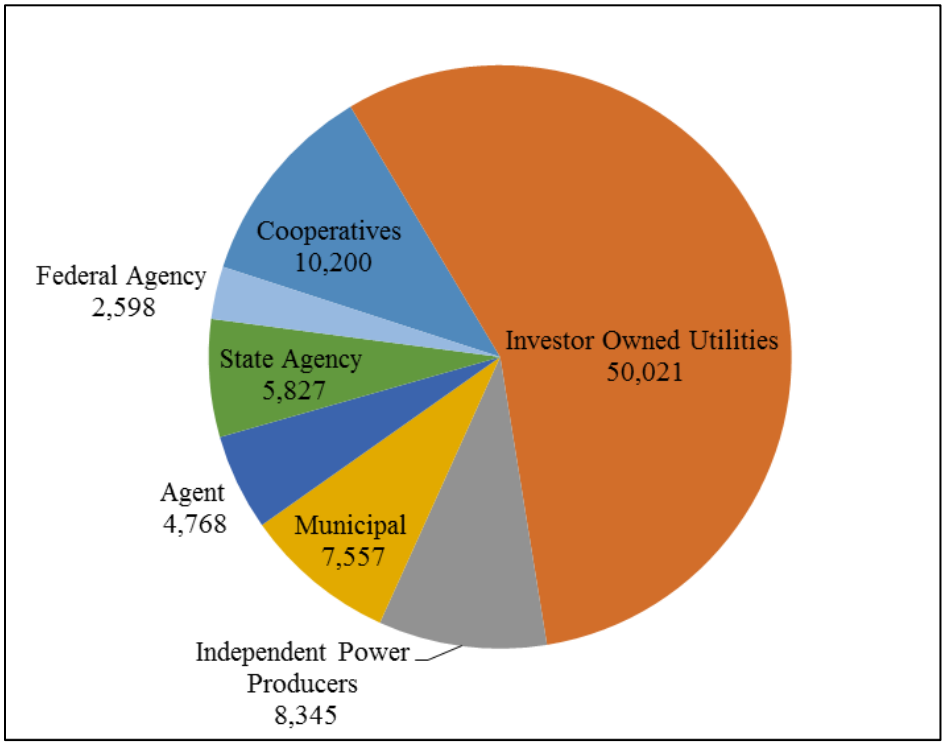


As of December 31, 2015

Figure 2–4 shows generation capacity owned by market participant type. As can be seen from this chart, even though IOUs represent only a small percent of the number of participants in the market at 11%, they hold the majority of the SPP generation capacity at 58%. This is in contrast

to the IPP category with a large number of participants but representing only a small portion of total capacity. With the addition of the Integrated System, IPPs' total capacity increased from 5,900 MW to 8,345 MW, an increase of 41%.

Figure 2–4 Capacity (MW) by Market Participant Type

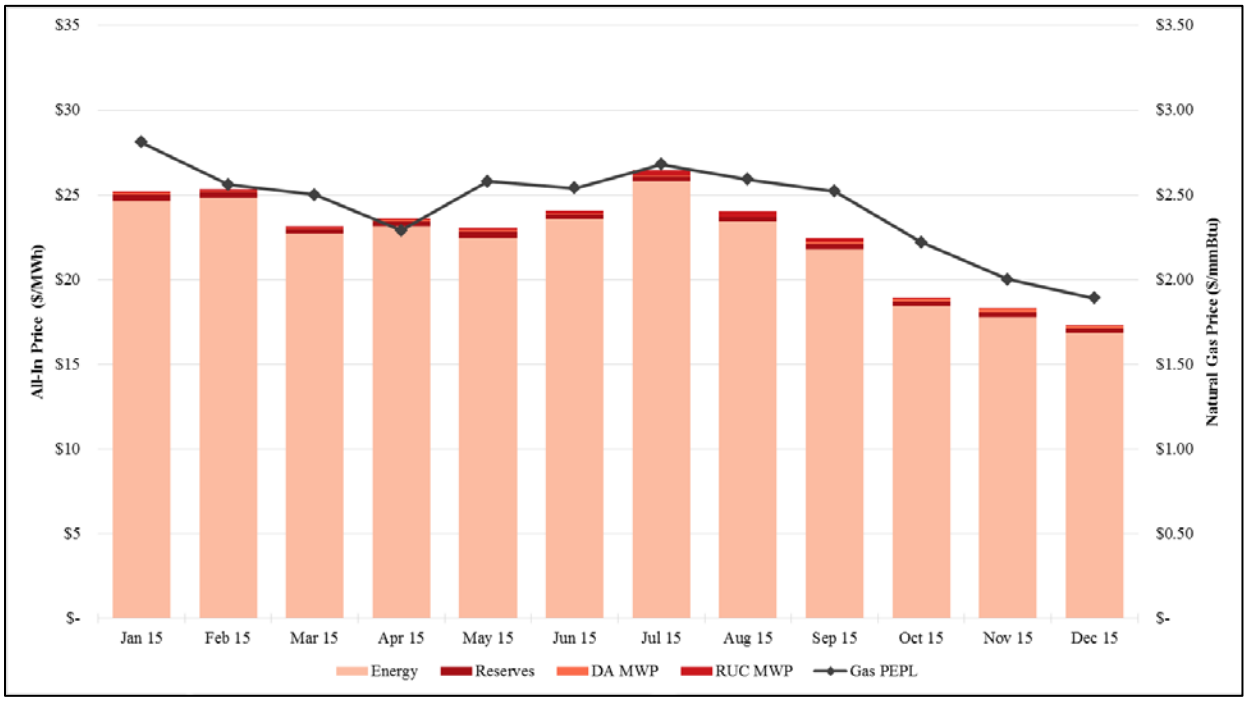


As of December 31, 2015

2.2. Market Prices

The average price of energy in SPP's real-time market for 2015 was $22.94/MWh[3]. The 12-month average all-in price, which includes the costs of energy, Day-Ahead and Real-Time RUC Make-Whole Payments, Operating Reserves[4] and Reserve Sharing Group costs, and payments to Demand Response Resources, was $23.48/MWh.[5] The cost of energy includes all the shortage pricing components. Figure 2–5 plots the monthly average all-in price of energy and the price of natural gas, measured at the Panhandle Eastern Hub.

Figure 2–5 SPP All-In Price of Electricity



The preceding figure shows the significant correlation between the price of natural gas and the price of energy. This is an indication that the market generally functioned well, in that coal prices

[3] The average price is calculated as the simple (arithmetic) average of North Hub and South Hub settlement location prices.
[4] 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.
[5] The Reserve Sharing Group costs and payments to Demand Response Resources were negligible for the year.

are relatively stable where gas prices are much more volatile, resulting in the high correlation of gas and electric prices given that gas or coal are the fuel on the margin 95% of the time. Much of the deviation from the energy-gas price trend, also known as the implied heat rate, resulted from monthly fluctuation in load, marginal fuel, and the coal/natural gas price spread. The graph also shows that the market cost of operating reserves constituted approximately 2.3% of the all-in price, with Make-Whole Payments and reserves amounting to $0.24/MWh and $0.30/MWh, respectively. Shortage pricing is included in the energy component and not easily separated out in the SPP settlement data; see Section 3.5 for a discussion of shortage pricing impacts. Figure 3–13 in Section 3 shows annual real-time prices starting with the beginning of the Energy Imbalance Market in 2007.

The overall level and trend in Integrated Marketplace prices were consistent with other RTOs. Figure 2–6 shows that the on-peak Day-Ahead LMP for SPP's South Hub averaged near the price of the MISO Indiana Hub and the ERCOT North Hub in 2014 and slightly lower in 2015.

Figure 2–6 ISO/RTO Comparison of Average Hub On-Peak Day-Ahead LMP

	2014 (Mar–Dec)	2015 (Jan–Dec)
SPP North Hub	$35	$24
SPP South Hub	$43	$28
MISO Indiana Hub	$41	$33
PJM West Hub	$48	$44
ERCOT North Hub	$44	$31

2.2.1. Long Run Price Signals

In the long term, efficient market prices provide signals for any needed investment in new generation and ongoing maintenance of existing generation to meet load. Given the very high resource margin[6] of nearly 50% in the SPP Market footprint for 2015, the MMU does not expect market prices to support new entry of investments.

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

[6] Resource margin is the system capacity at time of peak load, less peak load, divided by peak load. (See section 2.3.2 Resource Margin.)

three new generation technologies relative to their potential net revenues[7] at SPP Market prices. The plants considered include a scrubbed coal plant, a natural gas combined cycle, and a combustion turbine. Figure 2–7 provides the cost assumptions and Figure 2–8 shows the results of the net revenue analysis. The analysis assumes the market dispatches the hypothetical resource when LMP exceeds the short run marginal cost of production. In addition to these assumptions a capital recovery factor of 13.38% was used in the annual fixed operating and maintenance cost component.

In 2014, revenues were insufficient to support the cost of new entry generation for all three technologies and this did not change in 2015. In 2014, coal, combined cycle, and combustion turbine technologies were able to support their ongoing maintenance costs with that year's prices. However, Figure 2–8 illustrates that while 2015 prices did support the ongoing maintenance cost of combined cycle and combustion turbine units, they did not support the cost of scrubbed coal units. This is the result of the declining LMPs illustrated in Figure 2–6 for 2015.

Figure 2–7 Assumptions for Net Revenue Analysis

Descriptor	Scrubbed Coal	Advanced Gas/Oil Combined Cycle	Advanced Combustion Turbine
Size (MWh)	1,300	400	210
Total Overnight Cost ($/kW-yr)	2,917	1,017	2,072
Variable O & M ($/MWh)	4.47	3.27	10.37
Fixed O & M ($/kW-yr)	31.16	15.37	7.04
Heat rate (Btu/kWh)	8,800	6,430	9,750

Source: Cost assumptions for each technology are from the EIA Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, April 2013.

Figure 2–8 Net Revenue Results

Technology	AVG 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	23.74	20,626	421,684	NO	31,160	NO
Gas Combined Cycle	19.22	36,122	151,525	NO	15,370	YES
Combustion Turbine	34.55	9,533	284,437	NO	7,040	YES

[7] Net revenue is equal to revenues minus marginal cost.

Figure 2–9 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 LMPs and fuel prices. Other ISOs/RTOs 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 higher net revenue price signals 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 2–9 Net Revenue Analysis by Zone and by Technology

Resource Zone	Scrubbed Coal			Gas/Oil Combined Cycle			Combustion Turbine		
	Net Revenue from SPP Market ($/MW Yr)	Able to Recover All Cost	Able to Recover Avoidable Cost	Net Revenue from SPP Market ($/MW Yr)	Able to Recover All Cost	Able to Recover Avoidable Cost	Net Revenue from SPP Market ($/MW Yr)	Able to Recover All Cost	Able to Recover Avoidable Cost
AEP	22,265	NO	NO	46,601	NO	YES	12,221	NO	YES
KCPL	15,974	NO	NO	32,374	NO	YES	10,845	NO	YES
NPPD	12,054	NO	NO	18,312	NO	YES	8,206	NO	YES
OGE	20,306	NO	NO	41,680	NO	YES	11,171	NO	YES
SPS	20,257	NO	NO	38,890	NO	YES	11,230	NO	YES
WR	15,057	NO	NO	31,389	NO	YES	9,604	NO	YES

2.3. Capacity in SPP

2.3.1. Installed Capacity

Figure 2–10 depicts the Integrated Marketplace installed generating capacity for the SPP Consolidated Balancing Authority at the end of the first year of the market (December 31, 2014) and at the end of 2015. Total generating capacity in the SPP Integrated Marketplace was 84,943 MW in 2015, representing an increase of 13% over the first year of the Integrated Marketplace. The addition of the Integrated System (IS) added more than 7,600 MW to the Integrated Marketplace with hydro capacity being the largest category at almost 2,600 MW. Natural gas-fired generation still represents the largest share of the SPP Market at 42%, with coal being the second largest type at 34%. Wind continues to see an increase as the result of new construction.

Excluding approximately 1,000 MW of wind capacity added with the IS, wind still saw a 33% increase in 2015.

Figure 2–10 SPP Market Generation Capacity by Technology

Fuel Type	December 31, 2014	December 31, 2015	Percent as of 12/31/15
Natural Gas	35,016	35,935	42%
Coal	26,486	28,821	34%
Wind	8,582	12,397	15%
Hydro	832	3,430	4%
Nuclear	2,569	2,629	3%
Oil	1,527	1,608	2%
Other	155	123	<1%
Total	75,167	84,943	

Note: Capacity is nameplate rating.

2.3.2. 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 taken to be unit registration ratings. In 2015, SPP reserve margin was up 1% from 48% in 2014, as shown in Figure 2–11, which amounts to four times the SPP's Annual Planning Capacity Requirement of 12%. This relatively high reserve margin has positive implications for both reliability and for mitigation of the potential exercise of market power within the market.[8]

Figure 2–11 Reserve Margin by Year for 2008–2015

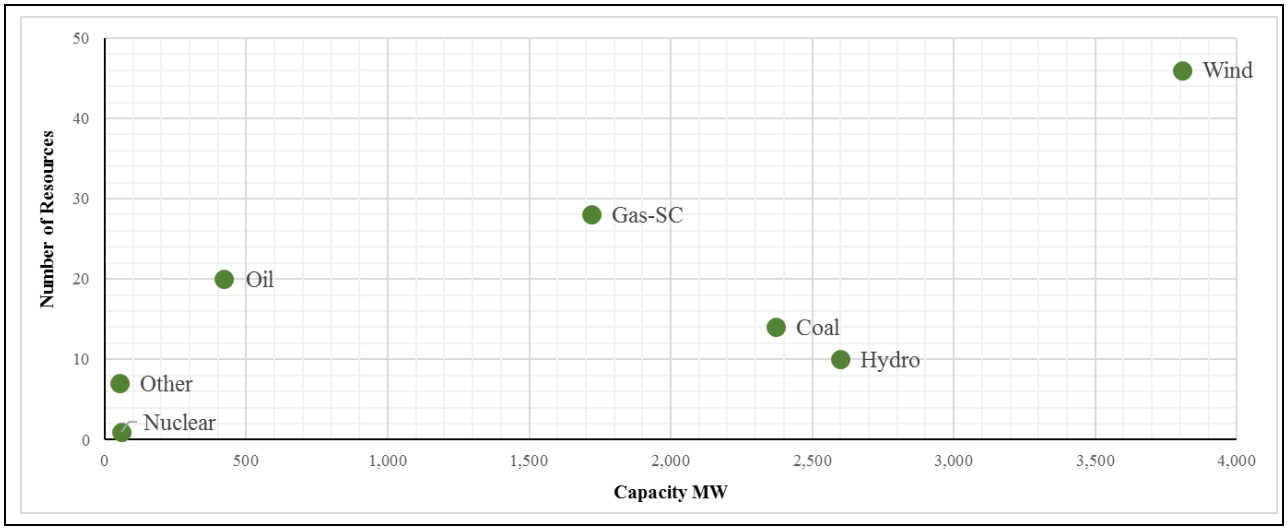
Year	Capacity (MW)	Peak Load (MW)	Reserve Margin
2008	49,561	36,538	36%
2009	58,223	39,622	47%
2010	61,570	45,373	36%
2011	63,367	47,989	32%
2012	64,053	47,142	36%
2013	66,668	45,256	47%
2014	67,095	45,301	48%
2015	67,251	45,279	49%

[8] Figure 2–11 differs from Figure 2–10 by counting only 5% of wind capacity. The 5% 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.

2.3.3. Capacity Additions and Retirements

In 2015 about 11,345 MW of new generation capacity was added to the SPP Market, which includes the capacity associated with the IS. Most of this capacity was wind at 34%, followed by hydro at 24%, coal at 21%, natural gas at 17%, and oil at 4%. Figure 2–12 shows the capacity by the technology and the number of resources added. Of this capacity, only 2,689 MW were new construction, all belonging to the wind category.

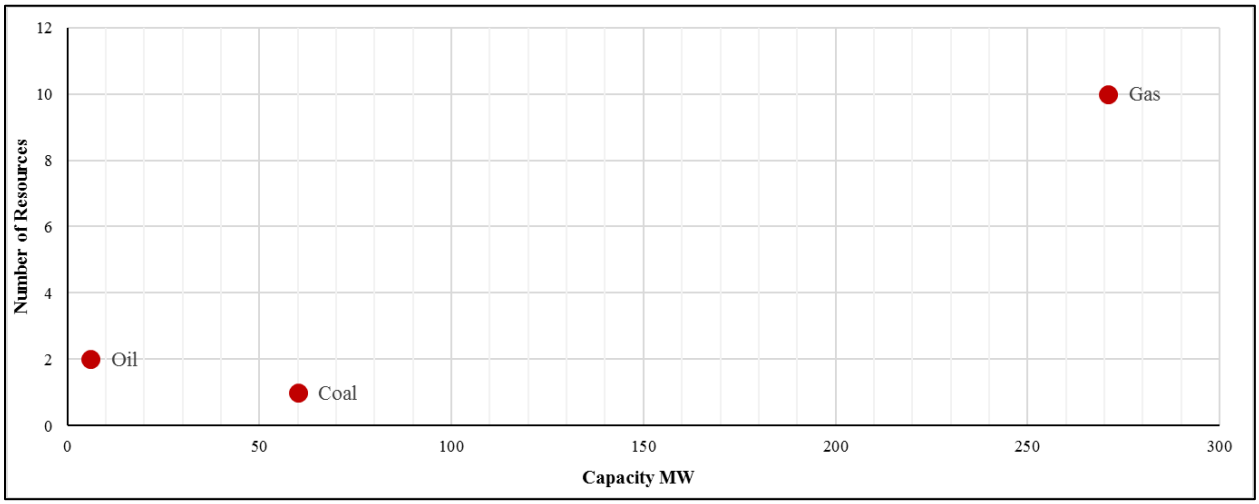
Figure 2–12 New Capacity in 2015



In 2015, the SPP Market also experienced generation retirements amounting to 337 MW in installed capacity, of which 271 MW (80.4%) was gas-fired[9], 60 MW (17.8 %) was coal-fired, and 6 MW (1.8 %) was oil-fired. The bulk of the retired capacity was 1950s, 1970s, and 1980s vintage coal-fired units followed by 1950s, 1960s, and 1970s vintage gas-fired units. Figure 2–13 shows capacity retirements in 2015 by the fuel and technology type.

[9] Out of 271 MW gas-fired generation retired, 12 MW belongs to CT units, with the remainder being ST units.

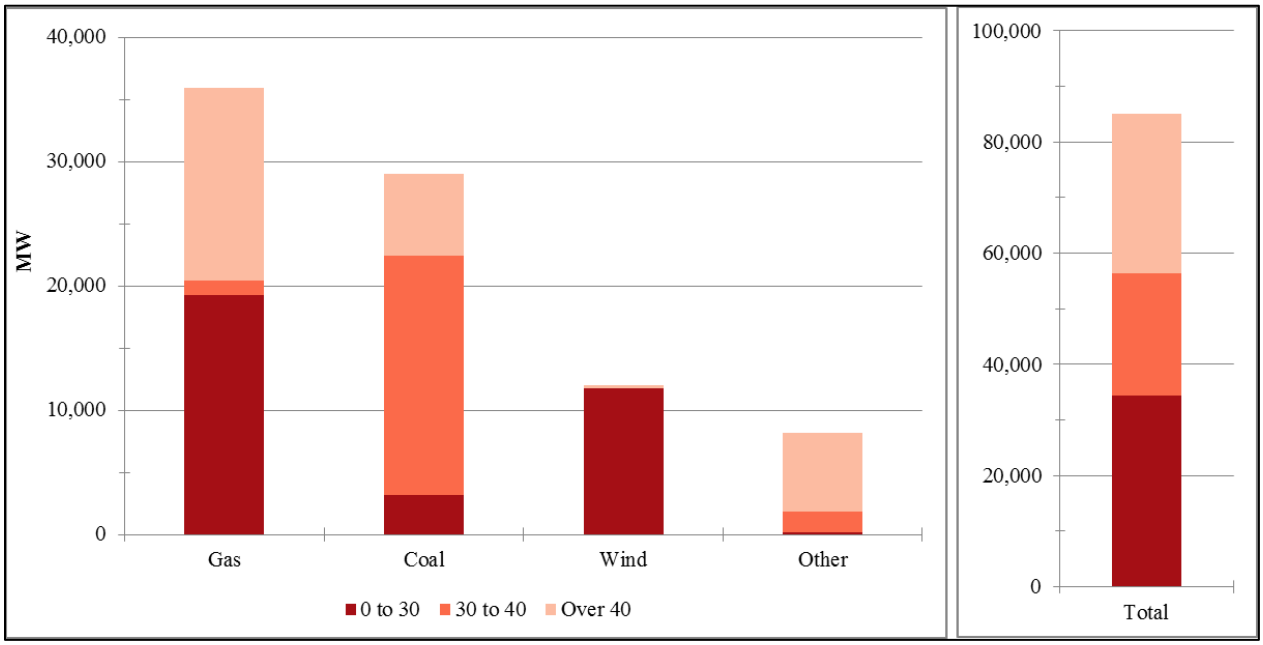
Figure 2–13 Capacity Retirements in 2015



2.3.4. Capacity by Age

Figure 2–14 illustrates that the SPP generation fleet is aging. Nearly 60% of SPP's fleet is more than 30 years old. In particular, nearly 90% of coal capacity and just over 40% of gas capacity are older than 30 years. The national average retirement age of coal-fired generation is 48 years. Outside of the resources that joined SPP in the IS integration, the only significant new capacity in the SPP footprint over the last 10 years was wind generation.

Figure 2–14 Capacity by Age of Resource



2.4. Electricity Demand in the SPP Market

The SPP Integrated Marketplace is composed of Market Participants that are responsible for serving load and/or generating energy, but are scheduled and dispatched by the market system. One way to evaluate load is to review peak system demand statistics over an extended period of time. The market footprint can and has changed over time as participants were added or removed. Last year, one notable change occurred in SPP's market footprint, the addition of the Integrated System in October of 2015.

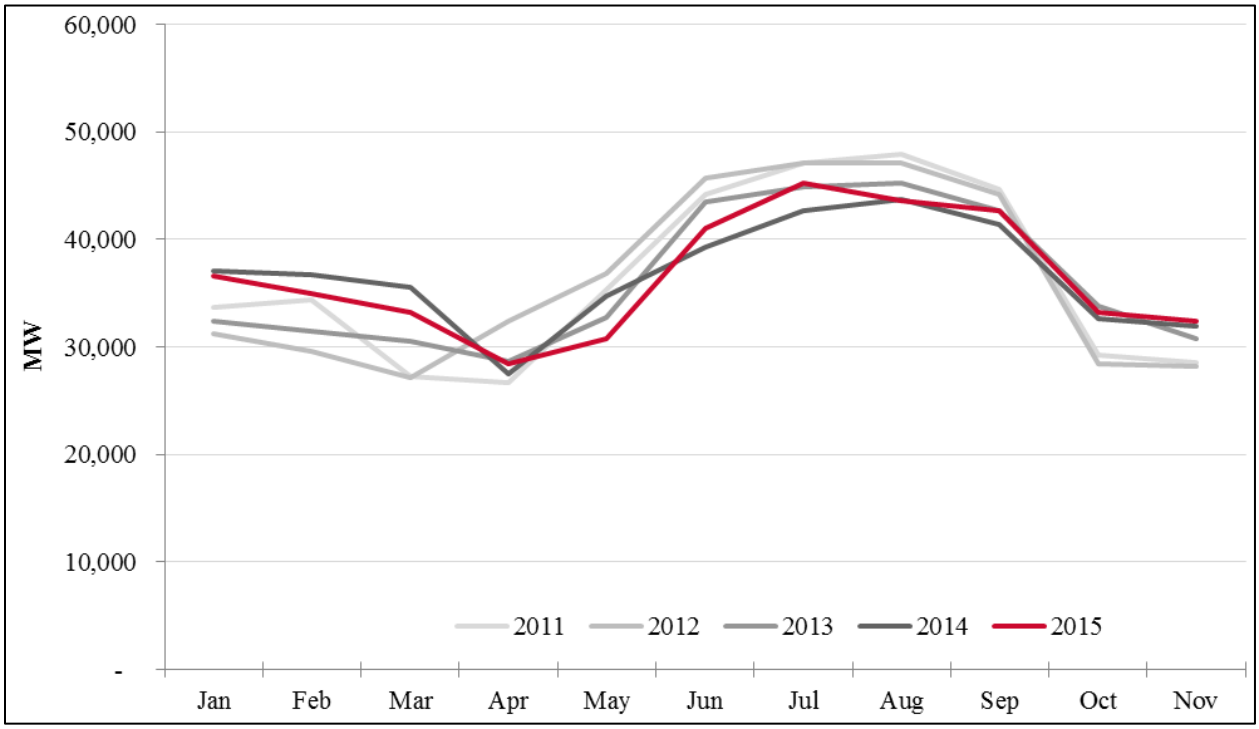
The peak demand values reviewed in this section are coincident peaks, representing total dispatch across all load areas that occurred during a particular market interval. The peak experienced during a particular year or season is affected by events such as unusually hot or cold weather in addition to daily and seasonal load patterns.

2.4.1. System Peak Demand

The SPP system coincident peak demand in 2015 was 45,279 MW, which occurred on July 28 at 5:00 PM. This is higher than the 2014 system peak of 44,148 MW and about 6% lower than the all-time system peak of 47,989 MW in 2011. Figure 2–15 shows a month-by-month comparison

of peak-day demand for the last five years. Summer monthly peaks for 2013–2015 have been lower than 2011 and 2012 because of normal summer weather patterns versus the unusually warm summers experienced in 2011 and 2012. Weather patterns and the resulting impact on energy demand are discussed later in this section.

Figure 2–15 Monthly Peak Electric Energy Demand, 2011–2015



2.4.2. Market Participant Load

Figure 2–16 depicts 2015 total energy consumption, Market Participants' annual loads, and the percent of energy consumption attributable to each Market Participant. The largest four participants account for more than half of the total system load, which is expected since SPP is primarily composed of legacy vertically integrated IOUs, which tend to be quite large. The addition of the IS entities added approximately 6,800 GWh of new load to the SPP footprint during the last three months of the year.

Figure 2–16 Market Participant Energy Usage, 2014–2015

Market Participant Name	2015		2014	
	Energy Consumed (GWh)	Percent of System	Energy Consumed (GWh)	Percent of System
American Electric Power	43,078	18.9%	43,046	19.0%
Oklahoma Gas and Electric	28,433	12.5%	29,387	13.0%
Southwestern Public Service Company	25,590	11.2%	25,898	11.4%
Westar Energy	23,544	10.3%	24,238	10.7%
Kansas City Power and Light, Co	15,303	6.7%	15,630	6.9%
The Energy Authority, NPPD	12,943	5.7%	13,339	5.9%
Omaha Public Power District	10,854	4.8%	11,208	5.0%
Western Farmers Electric Coooperative	9,041	4.0%	9,106	4.0%
Kansas City Power and Light, GMOC	8,339	3.7%	8,607	3.8%
Grand River Dam Authority	5,616	2.5%	5,413	2.4%
Empire District Electric Co.	5,156	2.3%	5,274	2.3%
Basin Electric Power Cooperative *	5,147	2.3%	751	0.3%
Golden Spread Electric Cooperative Inc.	4,840	2.1%	5,562	2.5%
Sunflower Electric Power Corporation	4,646	2.0%	4,916	2.2%
Lincoln Electric System Marketing	3,434	1.5%	3,450	1.5%
The Energy Authority, CU	3,270	1.4%	3,278	1.4%
Arkansas Electric Cooperative Corporation	3,172	1.4%	3,005	1.3%
Oklahoma Municipal Power Authority	2,797	1.2%	2,818	1.2%
Kansas City Board of Public Utilities	2,392	1.0%	2,368	1.0%
Midwest Energy Inc.	1,719	0.8%	1,748	0.8%
Kansas Municipal Energy Agency	1,437	0.6%	1,373	0.6%
Tenaska Power Service Company	1,212	0.5%	1,216	0.5%
Western Area Power Administration, Upper Great Plains #	1,128	0.5%		
City of Independence	1,017	0.4%	1,026	0.5%
Municipal Energy Agency of Nebraska	999	0.4%	981	0.4%
Kansas Power Pool	857	0.4%	953	0.4%
City of Chanute	489	0.2%	493	0.2%
Missouri Joint Municipal Electrical Utility Commission	448	0.2%	825	0.4%
City of Fremont	435	0.2%	360	0.2%
Northwestern Energy #	394	0.2%		
Missouri River Energy Services #	304	0.1%		
MidAmerican Energy Company #	74	0.0%		
Harlan Municipal Utilities #	4	0.0%		
NSP Energy #	1	0.0%		
System Total	228,113		226,271	

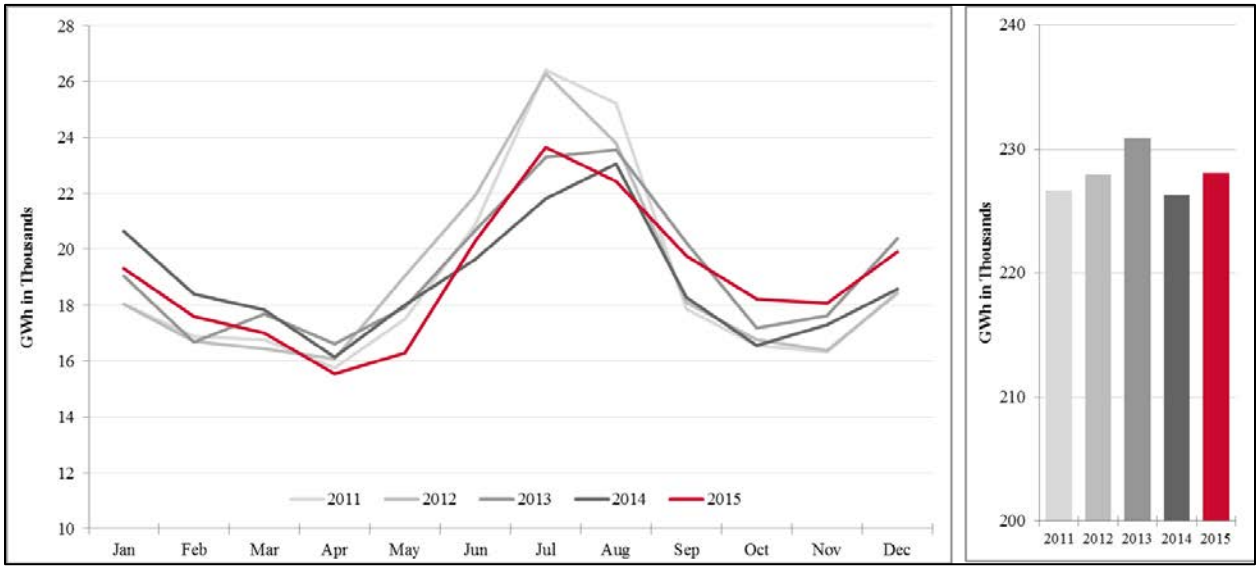
Joined SPP on October 1, 2015

* Expanded footprint in SPP on October 1, 2015

2.4.3. SPP System Energy Consumption

Figure 2–17 shows the monthly system energy consumption in thousands of GWh. Total SPP system annual energy consumption in 2014 and 2015 were similar with 228,000 GWh in 2015, compared to 226,000 GWh in 2014. Load was slightly lower during the first five months of 2015 compared to 2014 but was higher in most other months. The last three months includes the energy consumption from the addition of the Integrated System. Without this additional energy consumption in October through December, the year 2015 would have experienced slightly lower consumption than the previous year.

Figure 2–17 Monthly and Annual System Energy Consumption, 2011–2015



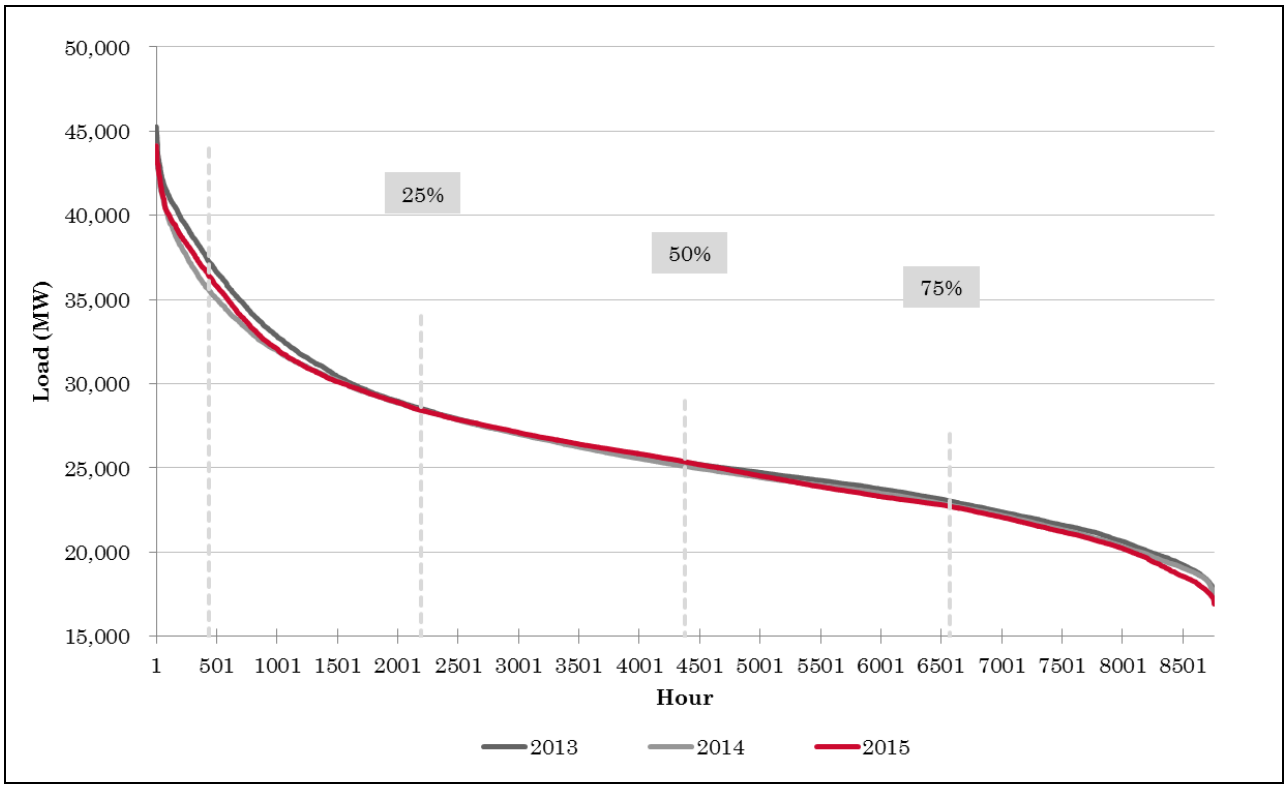
2.4.4. Load Duration Curve

Figure 2–18 depicts load duration curves from 2013 to 2015. These load duration curves display hourly loads from the highest to the lowest for each year. The shape of the curves is typical for a summer-peaking system such as the SPP Market.

In 2015, the total system peak hourly load was 45,279 MW and the minimum was 16,922 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 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 below the 25% reference level. The largest difference to note is loads between these three years above the 25% reference level. This implies a different weather pattern during the summer peak period, which is explained in the next section.

Figure 2–18 Electrical Energy Load Duration Curve, 2013–2015



2.4.5. Heating and Cooling Degree Days

Heating and cooling end use demand accounts for 40% of all electrical energy used in the United States. 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 energy consumption, assuming weather patterns were normal.

To determine HDD and CDD for the SPP footprint, several representative locations[10] were used to calculate system daily average temperatures[11]. In this 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 CDD was determined to be 3,340 MWh compared to 816 MWh per HDD. As expected, the impact of a single CDD on load is significantly higher than that of an HDD in part because of the higher saturation of electric cooling than electric heating. HDD values were adjusted accordingly in the graph below to reflect load impact differences.

Figure 2–19 illustrates that 2015 experienced a very similar level of cooling degree days to the prior two years, all substantially lower than 2011 and 2012. Lower temperatures in the last three summers are the major cause of lower peak loads shown in Figure 2–10 and lower total energy consumption shown in Figure 2–15.

[10] 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.
[11] 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).

Figure 2–19 Monthly Heating Degree Days and Cooling Degree Days, 2012–2015

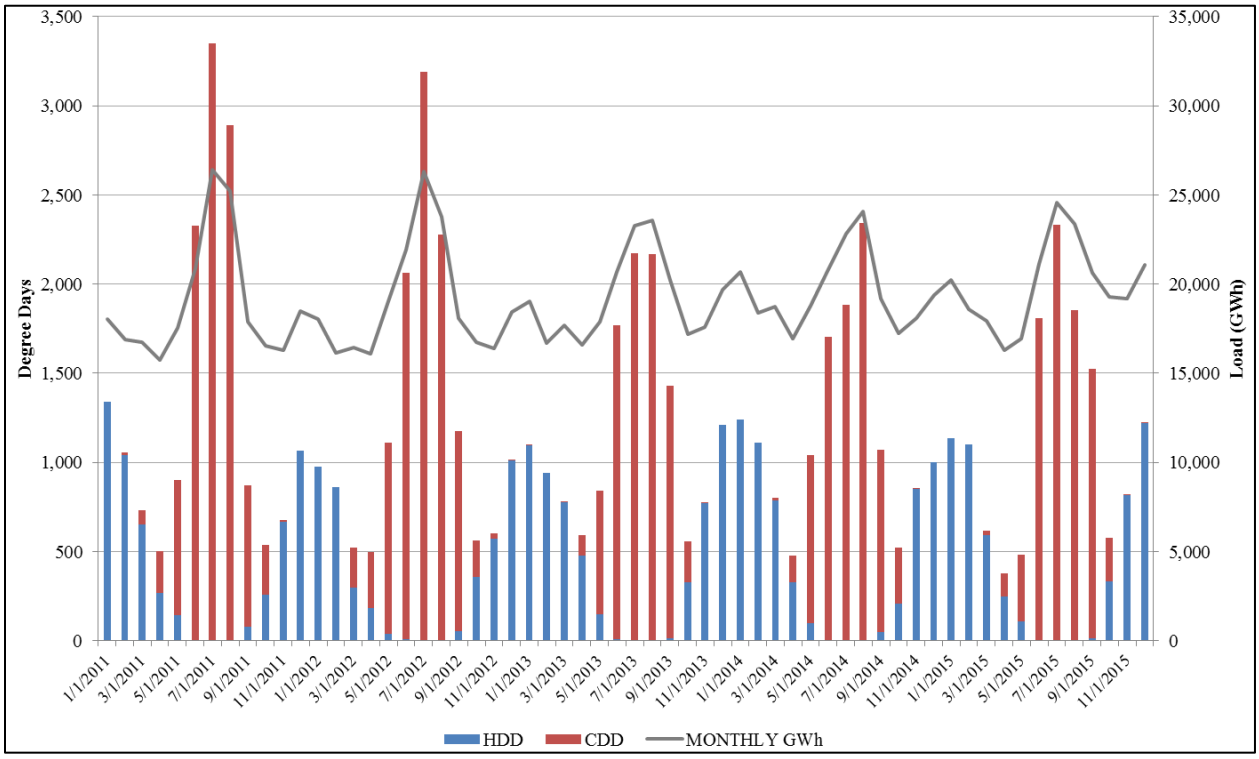
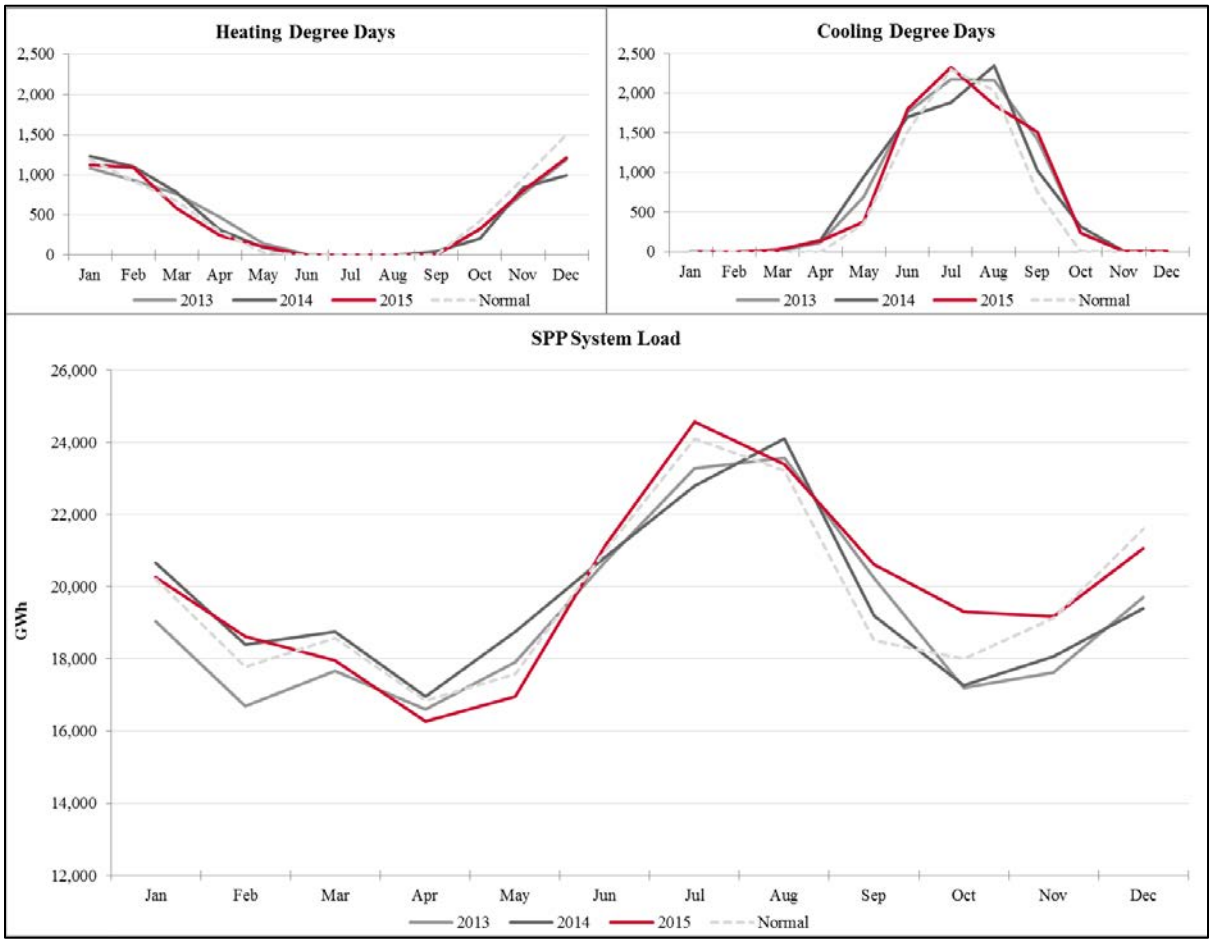


Figure 2–20 shows the numbers for HDD, CDD, and load levels from 2013 through 2015 compared to a normal year. The definition of normal temperatures is the average temperature for the last 30 years. Normal 2015 load was derived from a regression analysis of footprint actual HDD, CDD, weekends, and holidays, substituting footprint normal temperatures.

The year 2015 was a little warmer than normal for the cooling load season except for August, with the resulting load being a little higher than what would be expected for a normal season (see Figure 2–20, SPP System Load). Summer temperatures in 2013 and 2014 were also slightly above a normal year, resulting in a very similar relative load to that experienced in 2015. The early 2015 heating season appears near normal, while the late 2015 heating season was delayed, similar to the previous two years.

Figure 2–20 Yearly Degree Days and Loads Compared with a Normal Year, 2013–2015



2.5. Electricity Supply in the SPP Market

2.5.1. Generation by Technology Type

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 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 2–21 depicts annual generation percentages in the SPP real-time markets by generation type for years from 2007 through 2015. 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% in 2007 to only 6% in 2015. Gas combine cycle generation has remained relatively stable with about 13–14% of total generation with a slight increase to 16% in 2015. Wind generation share continues to increase from almost 3% in 2007 to about 14% in 2015. Coal generation share decreased about 5% in 2015 to 55% of total generation. The long-term trend for coal-fired generation had been relatively flat over the previous eight years at about 60–62% of total generation, but increasing wind generation and low gas prices prompted a decline in 2015.

Some of the annual fluctuations in generation by technology type shares are driven by the relative difference in primary fuel prices, namely natural gas versus coal. Gas prices in 2012 and 2015 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 economical.

Figure 2–21 Percent Generation by Technology Type – Real-Time Market, 2007–2015

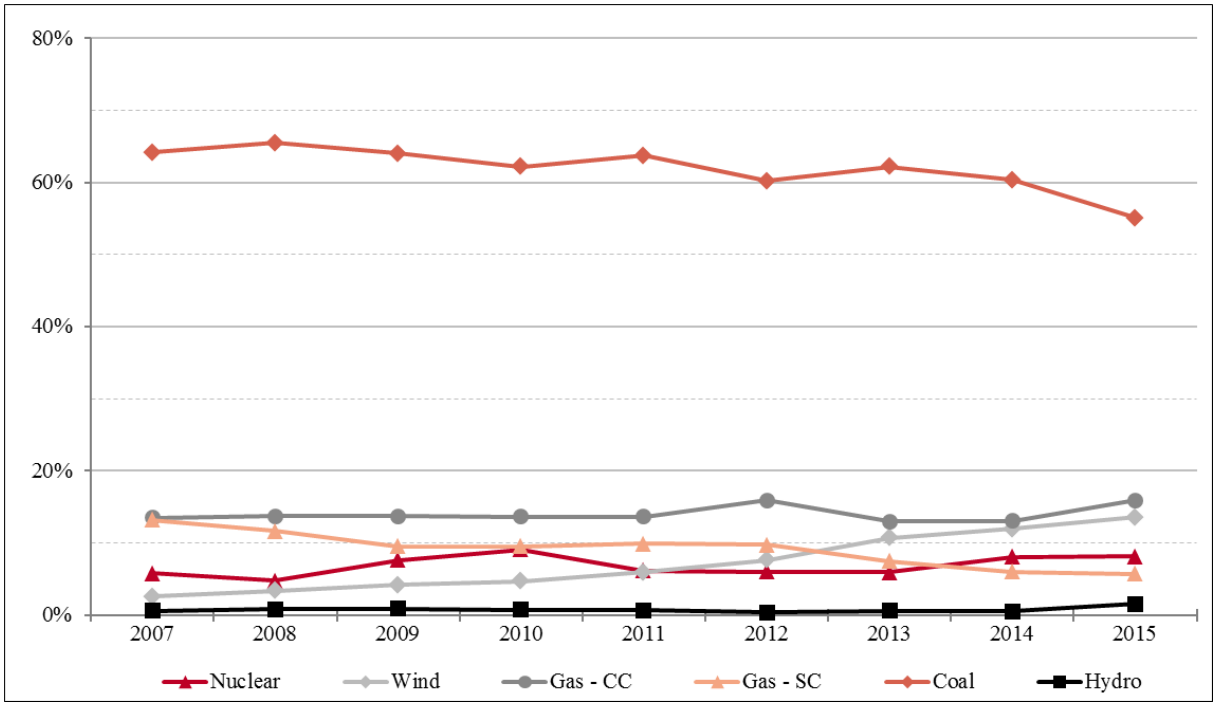
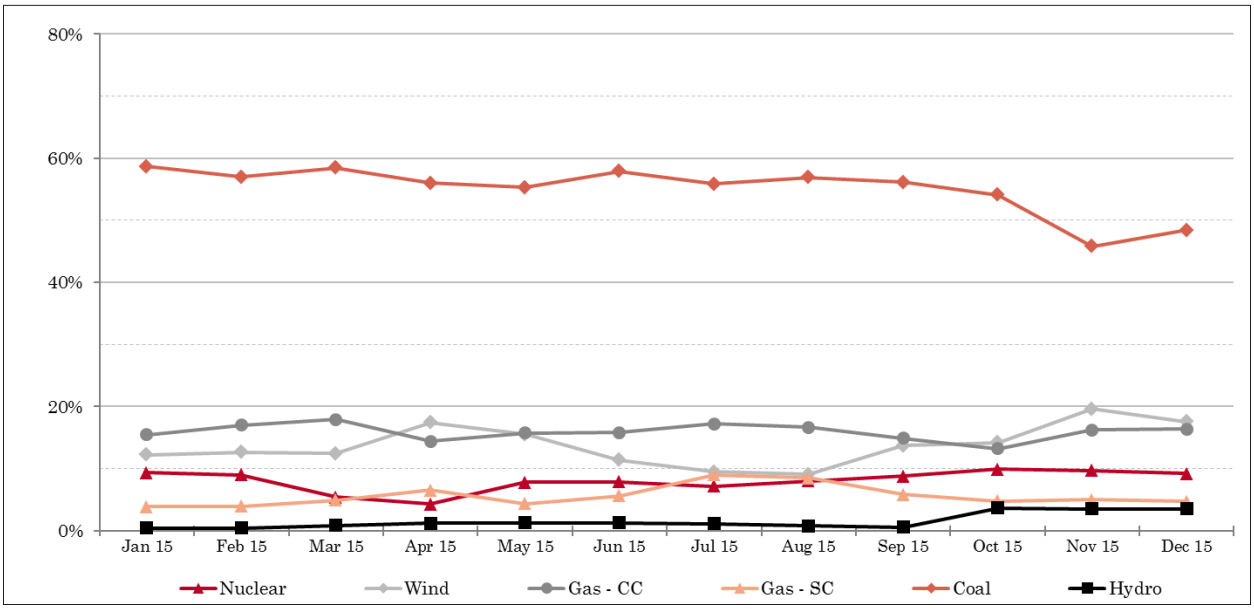


Figure 2–22 depicts the 2015 monthly fluctuation in generation by technology type. Wind generation fluctuates dramatically from 10% in the summer months to 20% in the fall and winter.

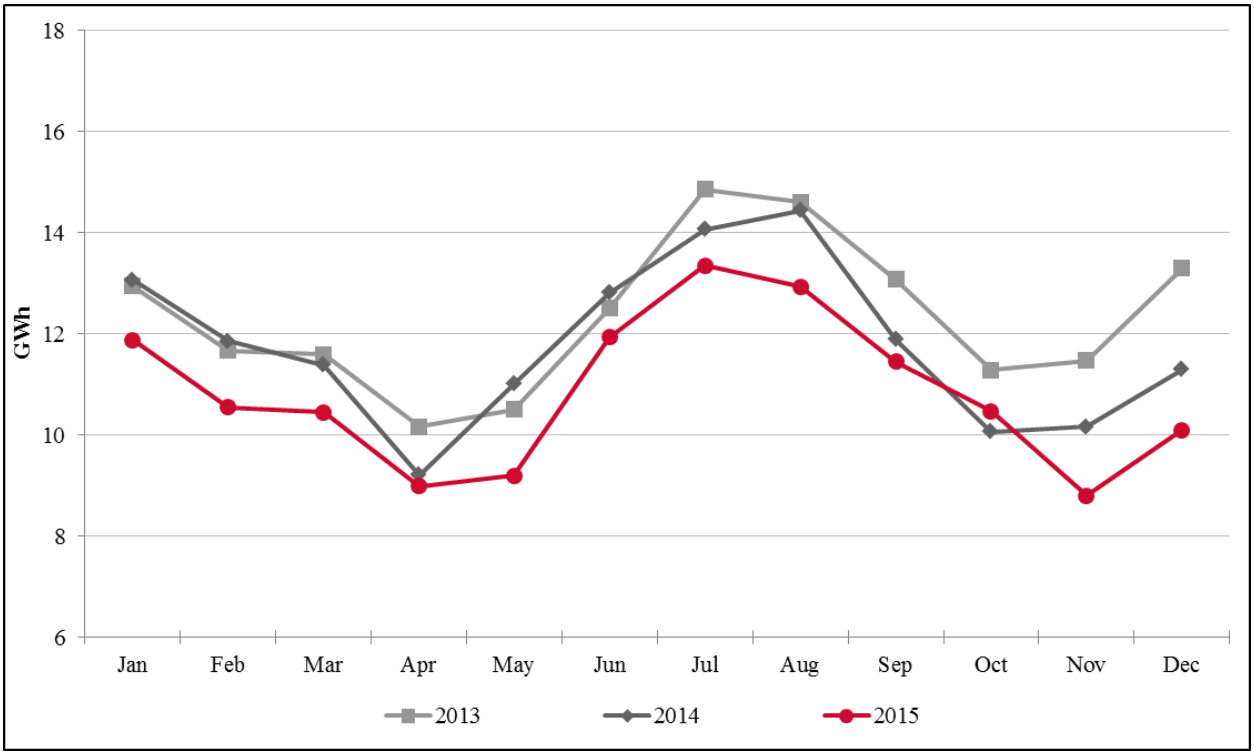
The increase in wind accompanied with low natural gas prices at year's end resulted in coal-fired generation market share falling to 45% compared to a historical average of over 60%.

Figure 2–22 Generation by Technology Type – Real-Time Market by Month, 2015



The SPP Market experienced lower total coal generation every month in 2015 than what has been experienced in the last two years except one; see Figure 2–23. The primary reason was the low natural gas prices. A secondary driver is the ever increasing level of wind generation. This situation is expected to be a major factor in the SPP Market as long as the natural gas price is near or below $2.00/MMBtu.

Figure 2–23 Coal-Fired Generation, 2013–2015

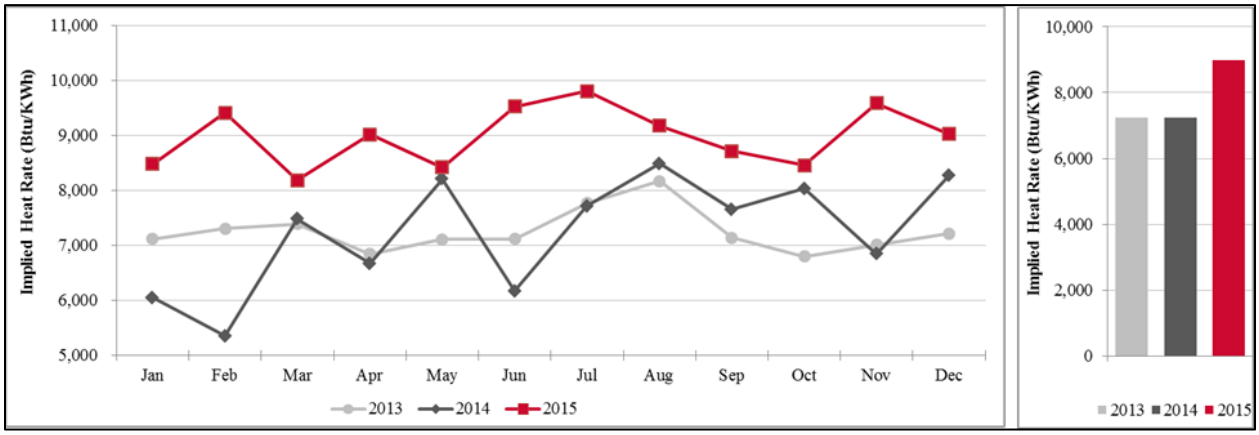


One method commonly used to assess trends and the efficiency of electricity market prices over time is the implied heat rate. The implied heat rate is a standard measure of the maximum heat rate where it would be profitable to operate a resource given electricity prices and the price of natural gas as a fuel for generation, ignoring all non-fuel costs. The implied heat rate is calculated by dividing the electricity price by the fuel price. If the price of natural gas was $3.00/MMBtu, and the LMP was $24.00/MWh, the implied heat rate would be (24.00/3.00) = 8.0 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 2–25 shows the monthly implied heat rate for 2013–2015, along with an annual average for those years. The chart shows a general increase from 2013 and 2014 to 2015. 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. However, with the low gas prices reaching parity with the price of coal in 2015, a much higher implied heat rate is observed for 2015. For systems like SPP where coal

generation sets electric price 49% of the time, as it did in 2015, this cross-fuel impact on implied heat rate can be significant.

Figure 2–24 Implied Heat Rate



The U.S. Energy Information Administration forecasts natural gas-fired generation in 2016 to overtake coal as the primary source of fuel in the United States. Even though coal generation in the SPP footprint is declining, it will continue to be the dominant source of generation. In 2015, coal generation represented about 55% of generation, whereas total (simple cycle and combined cycle) gas-fired generation represented only about 22% 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, whereas natural gas prices are likely to recover in 2016 or 2017. The short-term outlook is for reduced pressure on coal generation as gas prices recover, but the long-term outlook is for increased pressure due to environmental factors and increased wind generation capacity.

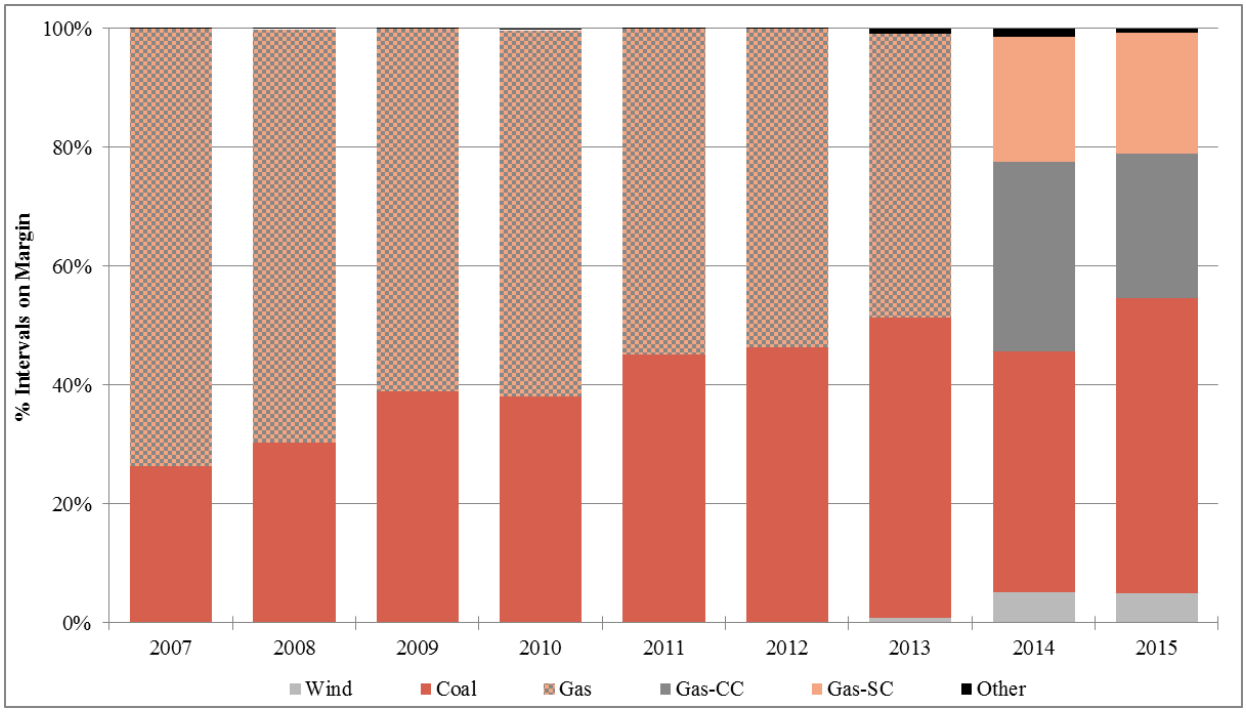
2.5.2. Generation on the Margin

The system marginal price represents the price of the next MW available to meet total system demand. The locational marginal price is the system marginal energy price plus any marginal congestion charges and marginal loss charges associated with the pricing node. Figure 2–25 illustrates which technology type was on the margin, thus setting market prices. 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.

Figure 2–25 clearly illustrates the dramatic shift in technology on the margin with natural gas representing about 75% in the first year of an SPP Market in 2007 to only about 45% in 2015. There is a corresponding shift in coal generation on the margin from about 25% in 2007 and increasing to about 50% in 2015. This dramatic change is driven by market efficiency improvements as reflected in the dramatic decline in simple cycle natural gas generation as shown in Figure 2–21. As a result of these market efficiency improvements, coal-fired plant owners are experiencing more daily swings in dispatch level, which are reflected in the technology on the margin metric.

Figure 2–25 Real-Time Generation on the Margin by Technology Type, 2007–2015

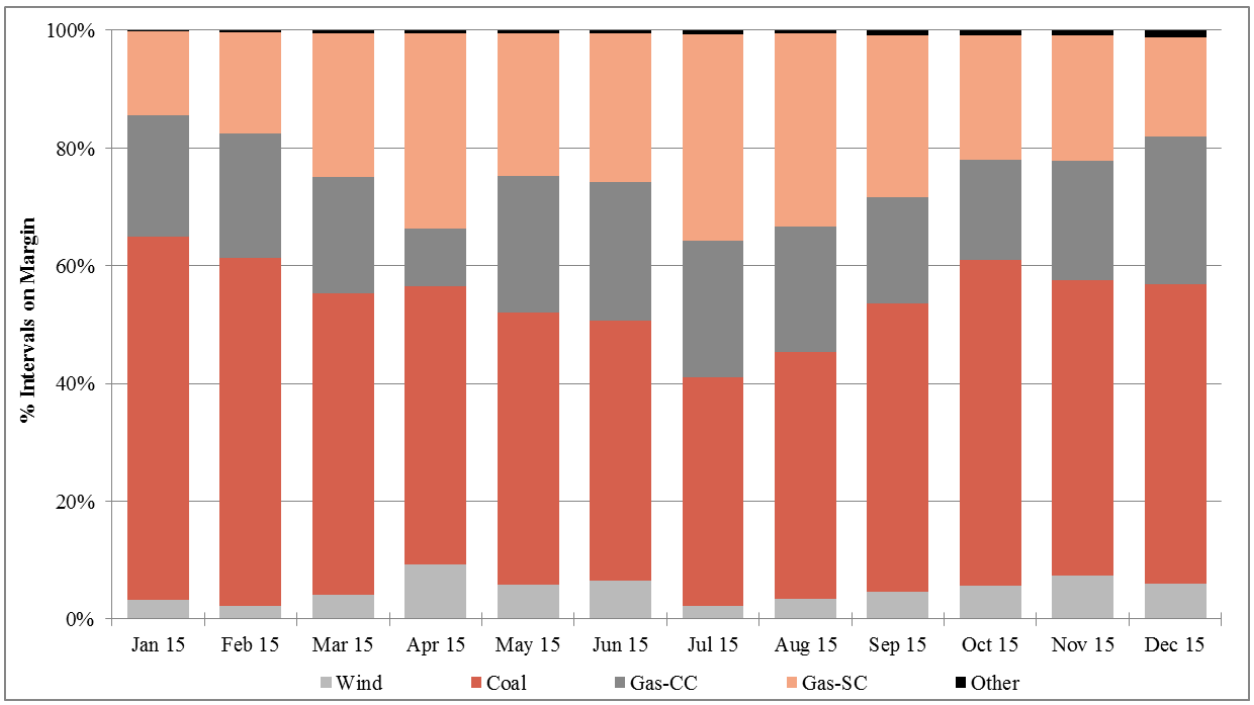


Worth noting is the significant increase in the portion of wind technology being on the margin, from 4.5% in 2014 to just over 5% in 2015. Wind generation as the marginal technology for a significant amount of time is as expected because the quantity of wind generation is now almost 14% of total generation, and because of the establishment of wind generation as a dispatchable

resource in the new market. At the end of 2015 just over 46% of wind capacity was dispatchable, compared to 27% at the beginning of the Integrated Marketplace in March 2014. All but 5% of wind capacity in the EIS Market was a price taker in 2013.

Figure 2–26 shows monthly average values for generation on the margin for 2015. Coal generation values are lower in the summer months when demand is high, resulting in more coal-fired units running as true 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 those periods are the windiest time in the SPP footprint.

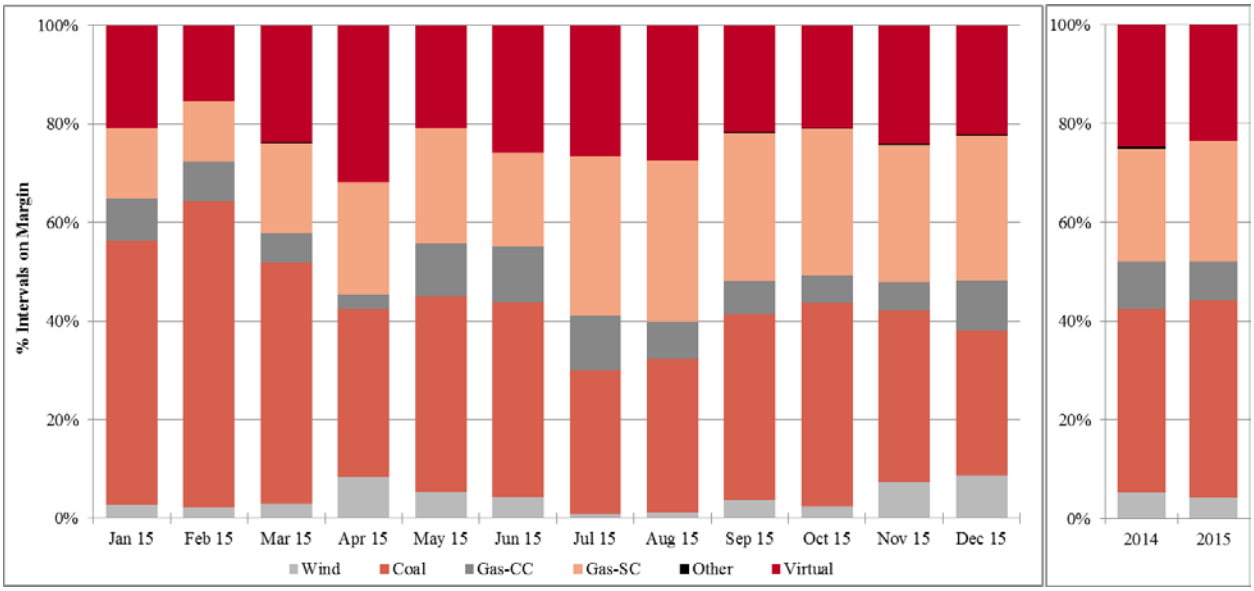
Figure 2–26 Real-Time Market Generation on the Margin, 2015 – Monthly



Day-ahead generation on the margin (see Figure 2–27) is different from real-time, as would be expected in that the Day-Ahead Market is based on model results including virtual transactions, whereas the Real-Time Market is required to adjust to unforeseeable market conditions such as unexpected plant outages. Wind generation on the margin is comparable in the Day-Ahead Market to Real-Time Market with a similar annual cyclical pattern. Coal generation on the margin in the Day-Ahead Market is noticeably lower at about 37% in both 2014 and 2015,

compared to 42% in 2014 and just under 50% in the Real-Time Market. This is most likely the result of some displacement by virtual offers. The most significant difference shows up in the displacement of gas-fired generation by virtual offers in the Day-Ahead Market. Virtual energy offers accounted for approximately 24% of the marginal offers in the Day-Ahead Market in both 2014 and 2015. The marginal virtual offers occur at all types of settlement locations, but 80% of marginal virtual offers are at resource settlement locations, with a significant amount of activity at the non-dispatchable wind generation resources.

Figure 2–27 Day-Ahead Market Generation on the Margin, Monthly (2015) and Annual (2014–2015)



Typically, coal-fired generation is on the margin more often in low load months, while gas-fired generation is on the margin more often in high load months. Natural gas units in the SPP region are normally used for load following, and have historically been on the margin more than coal.

2.5.3. Generation Interconnection

SPP is responsible for performing engineering studies to determine if the interconnection of new generation within the SPP footprint is feasible, and to identify any transmission development that would be necessary to facilitate the proposed generation. Types of engineering studies include:

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

Figure 2–28 shows the MW 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, and those in which work has been suspended as of 2015. As can be seen in the table, wind generation capacity accounts for the vast majority of proposed generation interconnection, nearly 22,000 MW or 80% 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 next section. Of note is that this is the first instance of a proposed battery resource in the SPP footprint.

Figure 2–28 Active Generation Interconnection Requests by Fuel Type

Prime Mover	MW Capacity
Wind	21,930
Gas	2,900
Solar	2,200
Battery	60
Hydro	10
Total	**27,100**

2.6. Growing Impact of Wind Generation Capacity on the SPP System

2.6.1. Wind Capacity and Generation

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

Figure 2–29 below shows an abundance of locations with a high potential for wind development in the SPP footprint. The SPP footprint is outlined in black and includes the addition of the Integrated System in October 2015. Wind generation capacity expansion resumed in 2015 after slowed growth in 2013 and 2014 due to the expected expiration of federal tax credits at the end of 2012.

Figure 2–29 United States Wind Speed Map

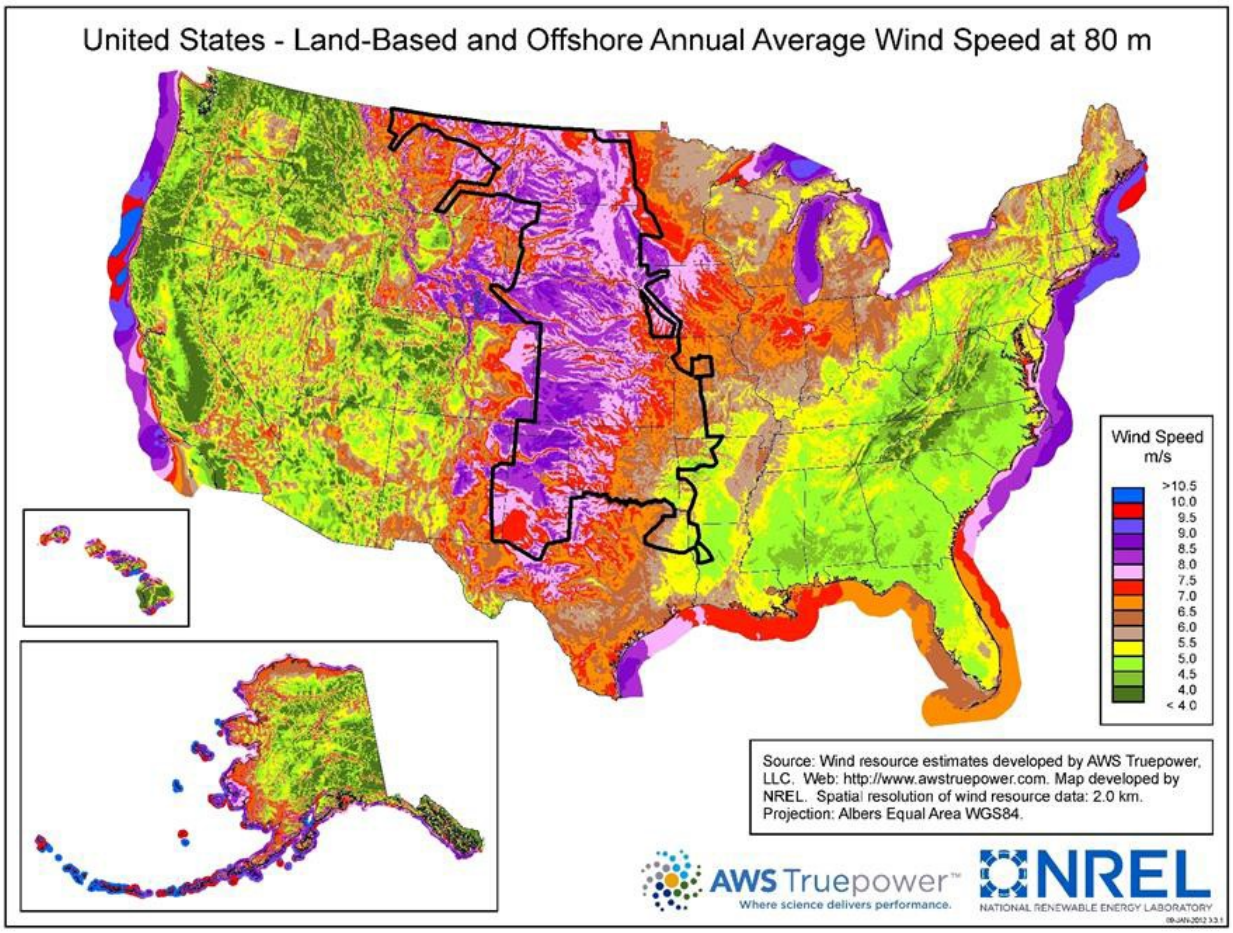
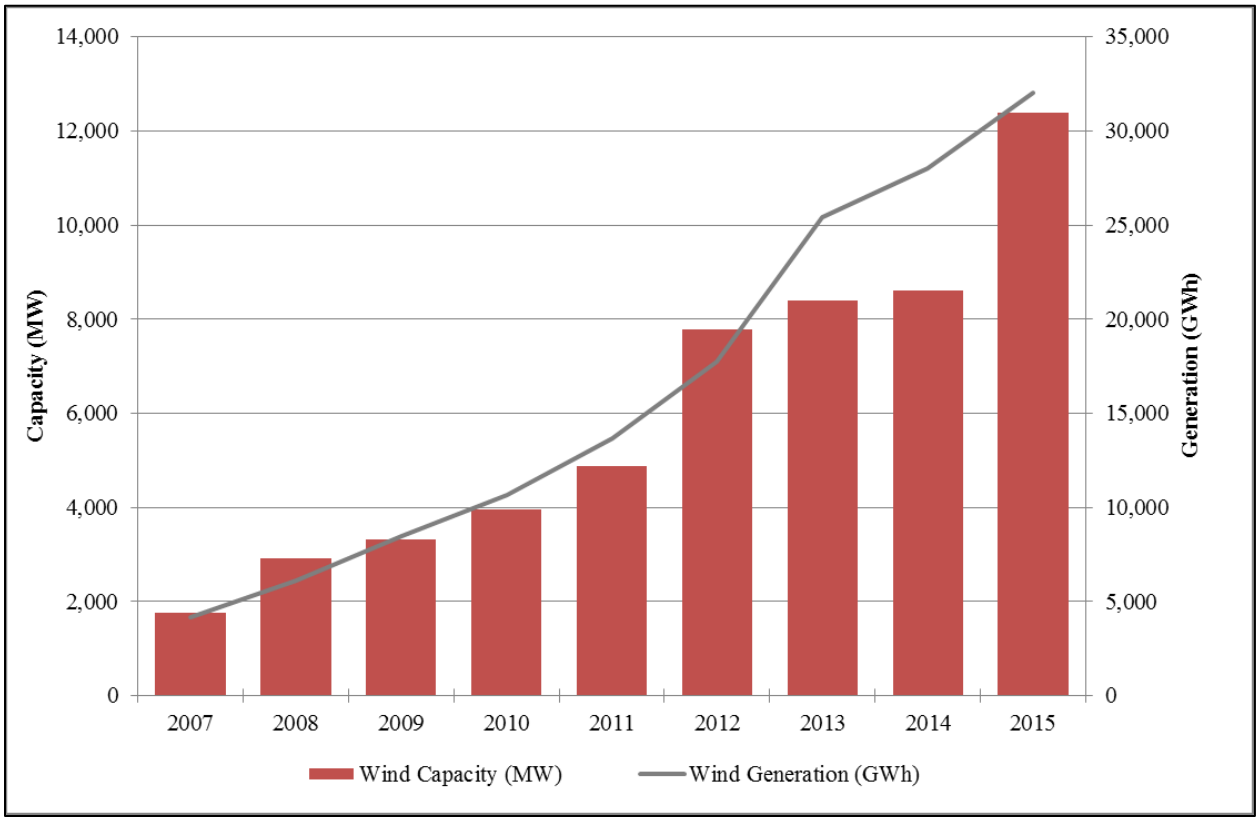


Figure 2–30 depicts annual capacity and total generation from wind facilities since 2007. Total registered wind capacity at the end of 2015 was 12,398 MW, an increase of 44% from 2014. Wind generation increased only 14% in 2015. The generation increase is significantly lower because units that enter service in a year are not operational for the entire year; there is always a testing and trial period before the units become operational. Wind technology comprises about 15% of the installed capacity in the SPP Market, behind only natural gas with 43% and coal with 35%. 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.

Figure 2–30 Wind Capacity and Generation, 2007–2015



2.6.2. Wind Impact on the System

Average annual wind generation as a percent of average load increased to 14% in 2015 from 12% in 2014. The highest level of wind generation for 2015 was 10,022 MW, which occurred on December 20. Wind generation as a percent of load for any hour reached a maximum value of 34% on December 20, which was comparable to the high of 33% in 2014 and 34% in 2013.

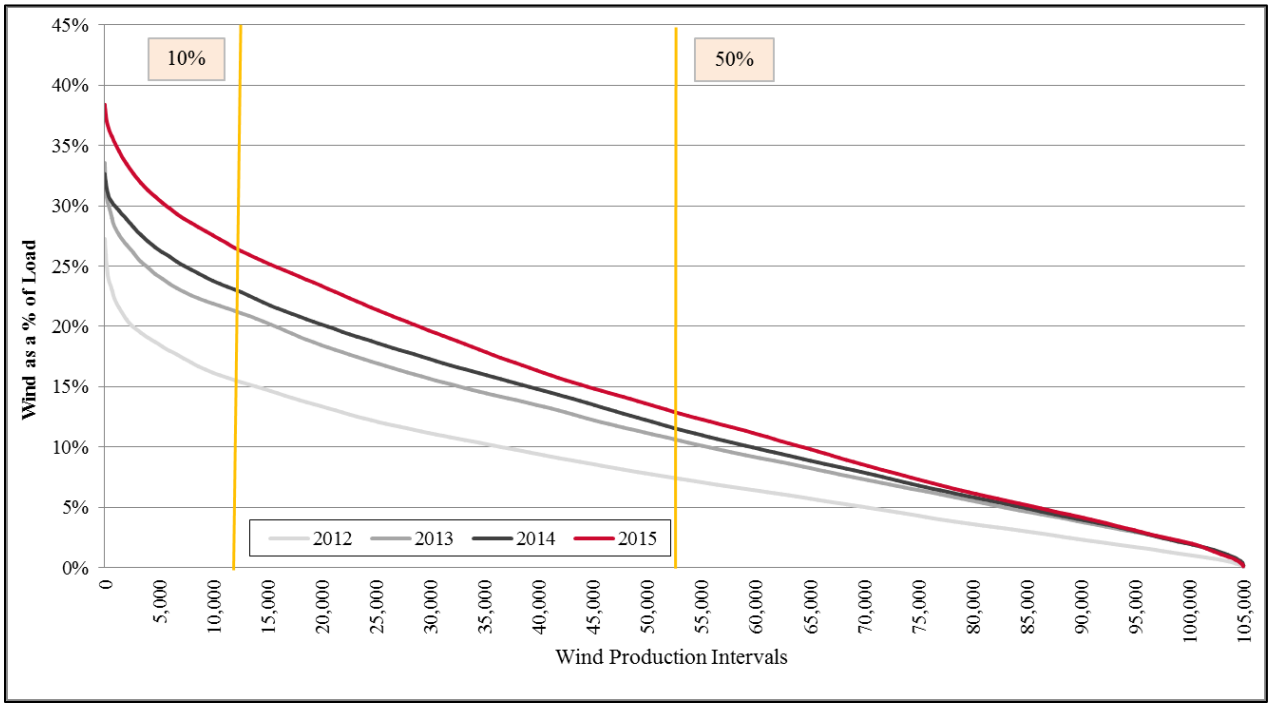
Figure 2–31 shows the annual average and the hourly maximum wind generation as a percent of load for the last eight years, illustrating a dramatic increase since the start of the SPP Markets in 2007.

Figure 2–31 Wind Generation as a Percent of Load, 2007–2015

Year	Avg. Wind Generation as a Percent of Load	Max. Wind Generation as a Percent of Load
2007	3%	9%
2008	4%	11%
2009	5%	15%
2010	5%	16%
2011	7%	20%
2012	8%	27%
2013	12%	34%
2014	12%	33%
2015	14%	34%

Figure 2–32 shows wind production duration curves that represent wind generation as a percent of load for 2012 through 2015. The significant shift up in the curve for 2013 represents the influx of wind capacity in 2012 resulting from the expected expiration of federal tax credits at the end of 2012. The curve for 2015 is only slightly higher than 2014, reflecting an increase in total wind generation capacity year over year. It is important to note that in 2015 wind generation served about 12% of the total load during half of the year, compared to 8% in 2012.

Figure 2–32 Wind Production Duration Curve by Interval – Wind as a Percent of Load, 2012–2015



2.6.3. Wind Integration

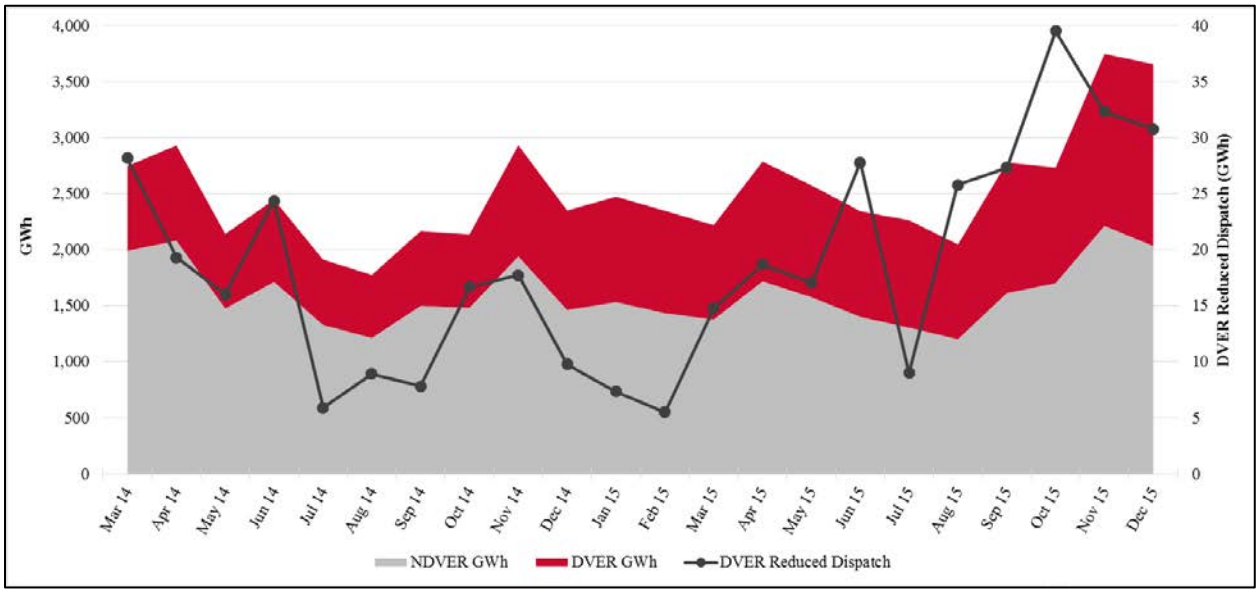
Wind integration brings low cost generation to the SPP region but supports very little future capacity needs. There are a number of operational issues in dealing with substantial wind capacity. Wind energy output varies by season and time of day. This variability is estimated to be about three times 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 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.

Prior to SPP's Integrated Marketplace, Dispatchable Variable Energy Resources (DVERs) were only subject to curtailment in the Energy Imbalance Service Market (EIS) based on impacts to a constraint and transmission service priority. Implementation of the SPP Integrated Marketplace starting in March 2014 introduced rules where DVERs would receive dispatch instructions based on offers and LMP, in a manner similar to other dispatchable resources. At the start of the

Integrated Marketplace, installed DVER capacity was 28% of all wind capacity, increasing to 46% by the end of 2015. Figure 2–33 illustrates DVER and Non-Dispatchable Variable Energy Resources (NDVERs) wind output since the beginning of the Integrated Marketplace, with DVER output mirroring the increasing percentage of installed wind capacity. DVER output increased from about 28% of total wind generation at the beginning of the Marketplace to about 44% at the end of 2015. 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 Market.

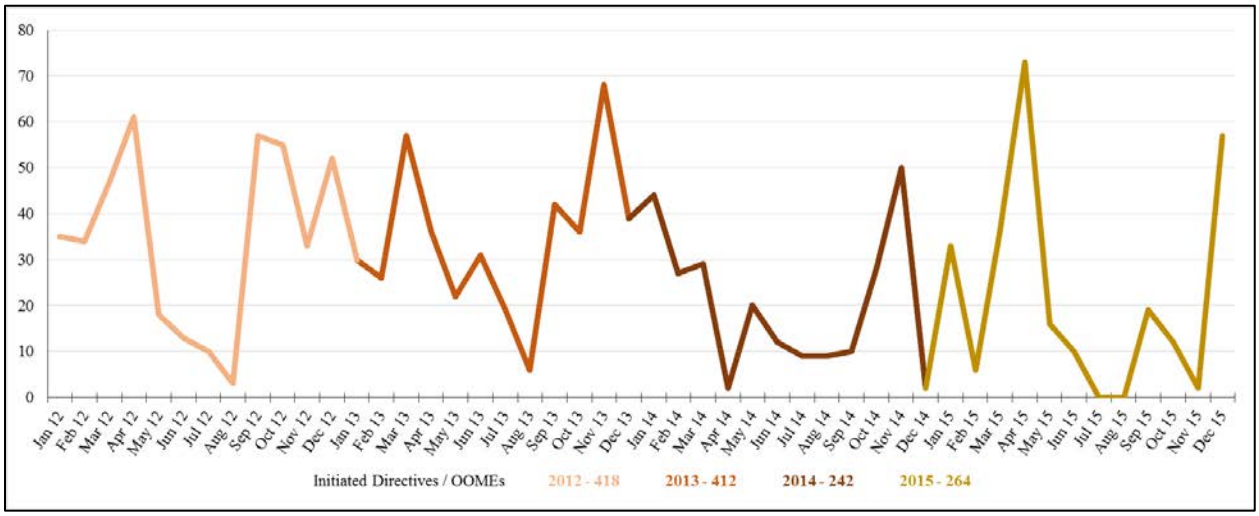
Substantial transmission upgrades in the SPP footprint over the past few years provided an increase in transmission capability for wind-producing regions, helping to address concerns related to high wind production and resulting congestion. It is worth noting that the increased transmission capability directly reduces localized congestion, creating a more integrated system with higher diversity and greater flexibility in managing high levels of wind production. November 2015 saw over 3,700 GWh of wind production, which was the highest since the start of the Integrated Marketplace. Over 2,200 GWh of this output originated from NDVER capacity, which was also the highest since the start of the Integrated Marketplace. One attributing factor is the 1,000 MW of NDVER wind capacity added with the SPP Market expansion with addition of the Integrated System in October of 2015.

Figure 2–33 Wind Generation by Month, 2014–2015



In the SPP Market, wind and other qualifying resources were allowed to register as NDVER, provided the resource had an interconnection agreement executed by May 21, 2011 and was commercially operated prior to October 15, 2012. Because more than half of the existing installed wind capacity is composed of NDVERs, grid operators must still issue manual dispatch instructions to reduce or limit their output at certain times. Figure 2–34 shows the number of directives initiated during the last two years of the EIS Market and Out-of-Merit Energy (OOME) instructions for wind resources during the first two years of the Integrated Marketplace. These numbers include manual dispatch for both DVER and NDVERs, although most are for NDVERs since March 2014. As expected, OOMEs are fewer during the lower wind output months of summer. One area to note is that of the 264 instances in 2015, 178 (67%) of the OOMEs are for a group of five NDVERs where transmission is limited, particularly during periods when there are transmission outages in the area.

Figure 2–34 Number of Manual Dispatches, 2012–2015



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, serving at times when wind generation represents more than 34% of load. Even though the use of OOMEs are limited and SPP continues to see an expanding dispatchable wind generation fleet, ramping capability is needed because of the variability of wind.

MMU Concerns

An NDVER is defined as "a Variable Energy Resource that is not capable of being incrementally dispatched by the Transmission Provider." This definition does not delve into the requirements of an NDVER 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. This concept also applies to DVERs not receiving a follow dispatch signal and all resources in manual control status that are not in start-up or shutdown. Some deviation from the actual or initial output is expected but large swings such as NDVERs in the SPP footprint cause market inefficiencies, in part, by responding to the ex-ante RTBM LMP, known as "price chasing". This introduces oscillations on constraints and other dispatchable resources as well as an impact on regulation products. Price chasing occurs when NDVERs follow LMPs and curtail output in response to a lower LMP or come back when an LMP is rising. Such behavior causes operational problems such that when NDVERs return unexpectedly in response to an LMP rise, they create violation on flowgates. This

in turn causes more relief than necessary and SCED effectiveness declines. Other impacts include additional volatility in RTBM, more regulation is needed, and more output is lost due to increased regulation. As a result, OOMEs are issued to NDVERs, 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 NDVERs' price chasing behavior, there are also inefficiencies introduced by NDVERs due to their being physically incapable of responding to a dispatch or acting as "price takers". These inefficiencies exist at times when an NDVER 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 differences in price splits and price volatility.

MMU Recommendation - NDVER Transition to DVER Status

At the end of 2015, just over half of all registered wind capacity was NDVERs, which reduces flexibility and/or results in resources "chasing" price. Although MMU does not deem NDVER price chasing to be a direct Tariff violation behavior per se since there are no restrictive rules on this behavior, the MMU does have a role to play in terms of addressing market inefficiencies caused by suboptimal design features. For this reason, the MMU recommends SPP continue discussions to transition NDVERs to DVER status and thereby lessen the negative impact of such resources on the market, as discussed above.

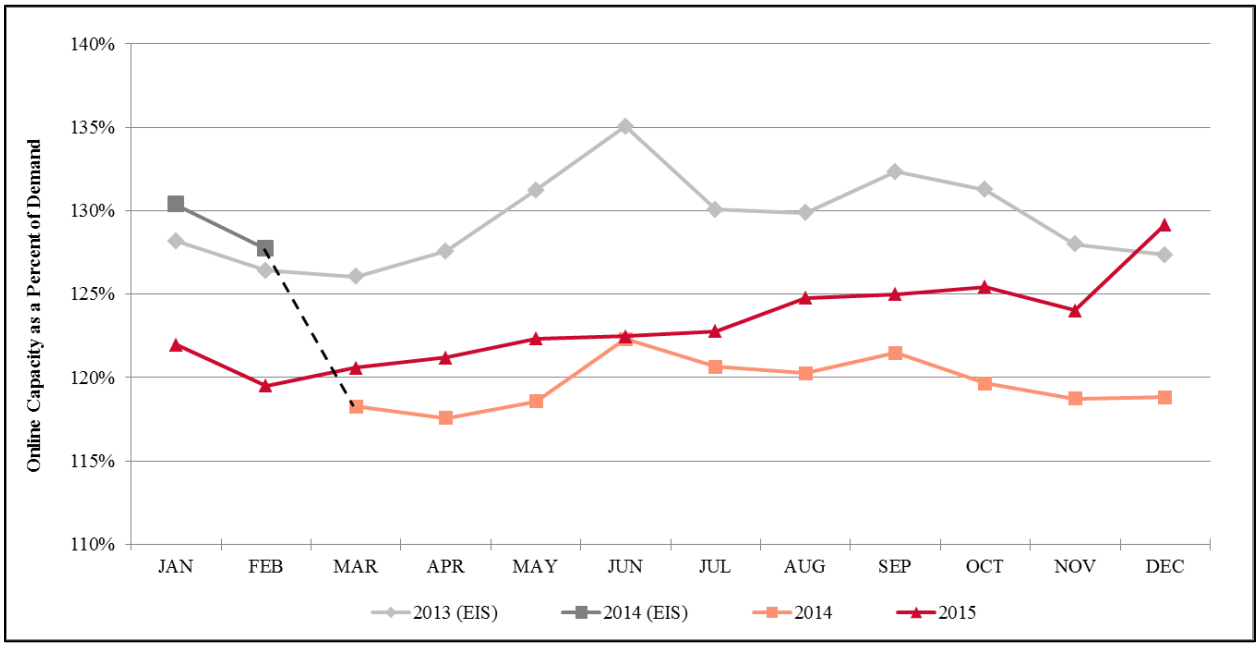
3. Real-Time Balancing Market

The Real-Time Balancing Market (RTBM) is the real-time market for Energy, Regulation-Up Service, Regulation-Down Service, Spinning Reserves, and Supplemental Reserves. The RTBM algorithm co-optimizes the clearing of energy and operating reserve products out of the available capacity. The RTBM clears every five minutes for all products. The settlement of the RTBM also occurs at the five-minute level, and the settlement is based on Market Participants' deviations from their day-ahead positions.

Prior to the start of the Integrated Marketplace and the SPP Centralized Balancing Authority (CBA), SPP was composed of 16 distinct balancing authorities, and the participants in the SPP real-time market, the Energy Imbalance Service (EIS) Market, made their own commitment decisions. The CBA and the Integrated Marketplace, as implemented on March 1, 2014, provide cost savings through the efficiency gains of an auction-based market mechanism combined with a centralized unit commitment process.

Figure 3–1 shows that in the first year of the market SPP reduced the online capacity about 10% below what was committed in the EIS Market. It appears that capacity commitment as a percent of load has been increasing during 2015, thereby reducing the savings achieved in 2014. Changes in the SPP Market in 2015 that may be driving a higher level of online capacity are low gas prices, coal plants self-committing, and higher levels of wind generation. All of these factors are driving down system average prices but also driving up volatility and risk. Higher 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. The MMU has indications that online capacity levels in 2016 are returning to 2014 levels.

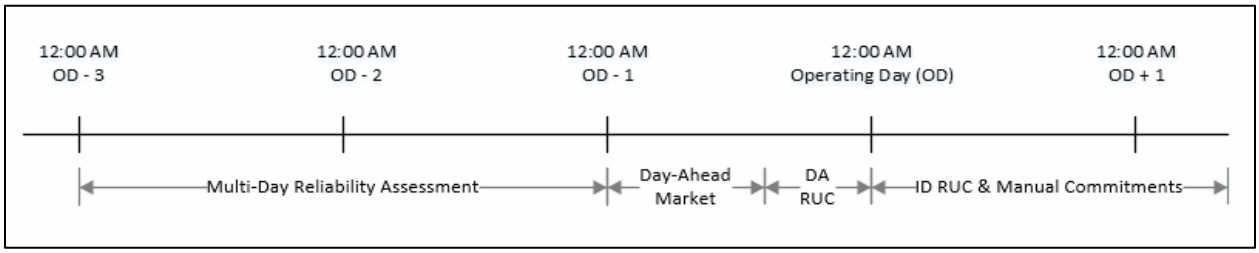
Figure 3–1 Online Capacity as Percent of Demand



3.1. Unit Commitment: Day-Ahead and Real-Time 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 (DA) Market, which uses a rigorous algorithm to determine a least cost commitment that meets day-ahead energy demand, ancillary services, and operating reserve requirements. Most of the time it becomes necessary to commit additional capacity outside the DA Market to ensure all reliability needs are addressed and to adjust the DA commitment for real-time conditions. This is done through SPP's Reliability Unit Commitment (RUC) processes. SPP employs four 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; and (4) manual commitment instructions issued by the RTO. Figure 3–2 shows a timeline describing when the various commitment processes are executed.

Figure 3–2 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 the operating day. The Day-Ahead Market is executed on the day before the operating day, and the results are posted by 16:00 hours. The Day-Ahead Market treats any generators identified in the Multi-Day Reliability Assessment as "must-commit" resources. The DA RUC process is executed approximately one hour after the posting of the Day-Ahead Market results. This allows Market Participants time to re-bid their resources. The ID RUC process is run throughout the operating day, with at least one execution of the ID RUC occurring every four hours. SPP operators also issue manual commitment and de-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 DA and ID RUC processes.

3.1.1. Overview

The SPP resource fleet, excluding variable energy resources, experienced 19,700 starts during 2015. This is down from the 22,000 starts during the first 12 months of the market. Figure 3–3 and Figure 3–4 provide a breakdown of the origins of the commitment decisions. Figure 3–3 is based on the number of resources committed. Forty-nine percent (49%) of start-up instructions were a result of the Day-Ahead Market, which includes the Multi-Day RUC commitments. 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 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 DA RUC, ID RUC, and manual commitments represent 29% of the resource start-ups.

Figure 3–3 SPP Start-Up Instructions by Resource Count, 2015

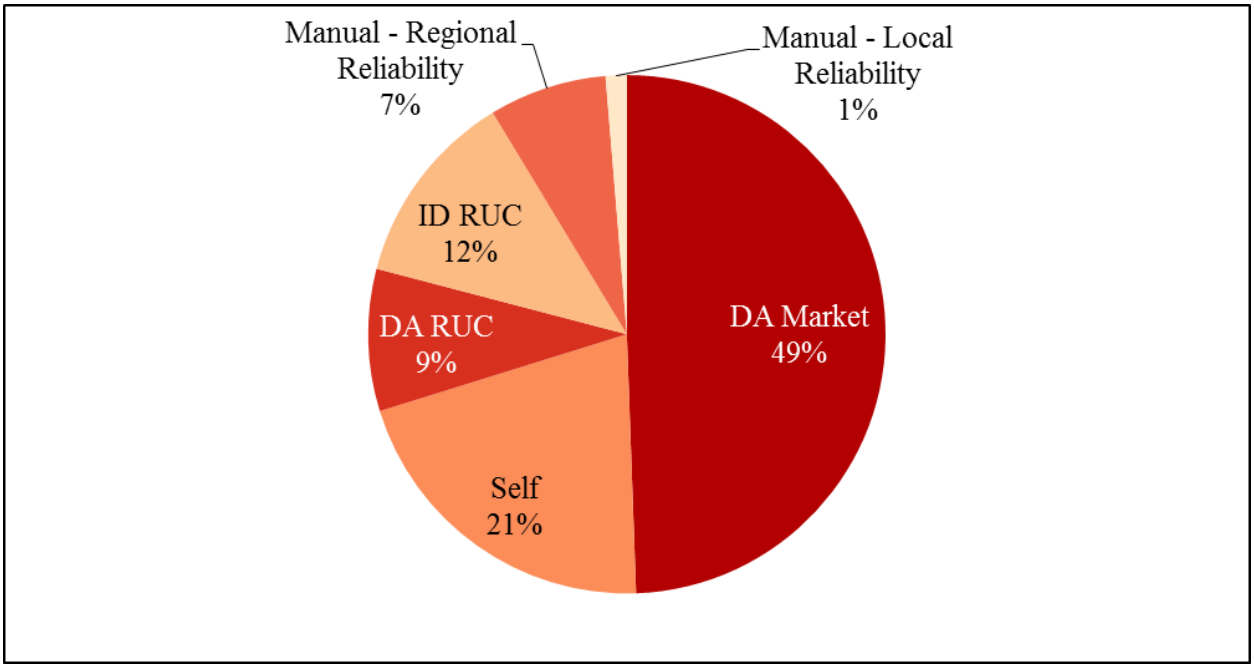
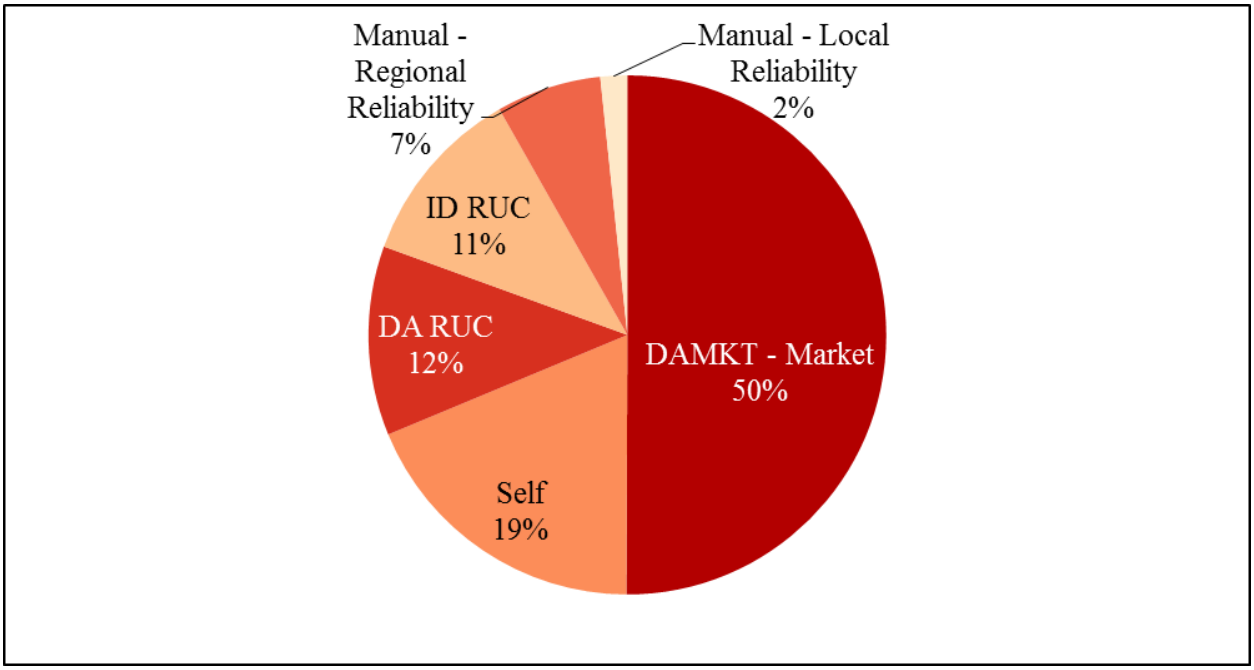


Figure 3–4 is based on capacity committed and provides a slightly different look at the data with the percentages based on capacity committed to startup. One important observation is the percentage differences between the two charts. This is the result of larger resources either self-committed or committed by the Day-Ahead Market, and smaller resources with shorter lead times committed in the DA RUC, ID RUC, and manual commitment process.

Figure 3–4 SPP Start-Up Instructions by Resource Capacity



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 resource fleet. SPP issued more than 12,400 start-up instructions to gas-fired generators in 2015, 400 more than the 12,000 started in the first 12 months of the market. Figure 3–5 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 48% of their starts. This is a six percent reduction from the 54% incurred in the first 12 months of the market. Combustion Turbines saw a large reduction as well with only 36% of the units' starts being committed in the Day-Ahead Market in 2015, down 14% from the 50% committed in the first 12 months of the market. These low Combustion Turbine and Simple Cycle Day-Ahead Market commitment rates are indicative of the fact the Day-Ahead Market prices are rarely high enough to support these more expensive resources. This effect grew with the decreasing energy prices in 2015 and the addition of more wind capacity in the market.

Figure 3–5 Origin of Start-Up Instruction for Gas-Fired Resources

2015				2014			
Commitment Process	Combined Cycle	Simple Cycle – CT	Simple Cycle – ST	Commitment Process	Combined Cycle	Simple Cycle – CT	Simple Cycle – ST
DAMKT - Market	99%	48%	36%	DAMKT - Market	97%	54%	50%
DA RUC	0%	15%	36%	DA RUC	1%	4%	20%
ID RUC	1%	21%	21%	ID RUC	1%	29%	27%
Manual Instruction	0%	16%	6%	Manual Instruction	0%	13%	3%

Alternatively, the reliability 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 price levels. These situations often lead to Make-Whole Payments and put the generators at risk for not earning sufficient revenues to cover their costs going forward. The next section discusses the drivers behind the reliability commitments.

3.1.2. Demand for Reliability

The previous section noted that 29% of SPP start-up instructions originated from the SPP reliability commitment processes: DA RUC (9%), ID RUC (12%), manual-regional reliability (7%), and manual-local reliability (1%). 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 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 will not necessarily be a good indicator of the actual energy demand and hence the DA RUC and ID RUC processes use a load forecast to measure the energy demand.

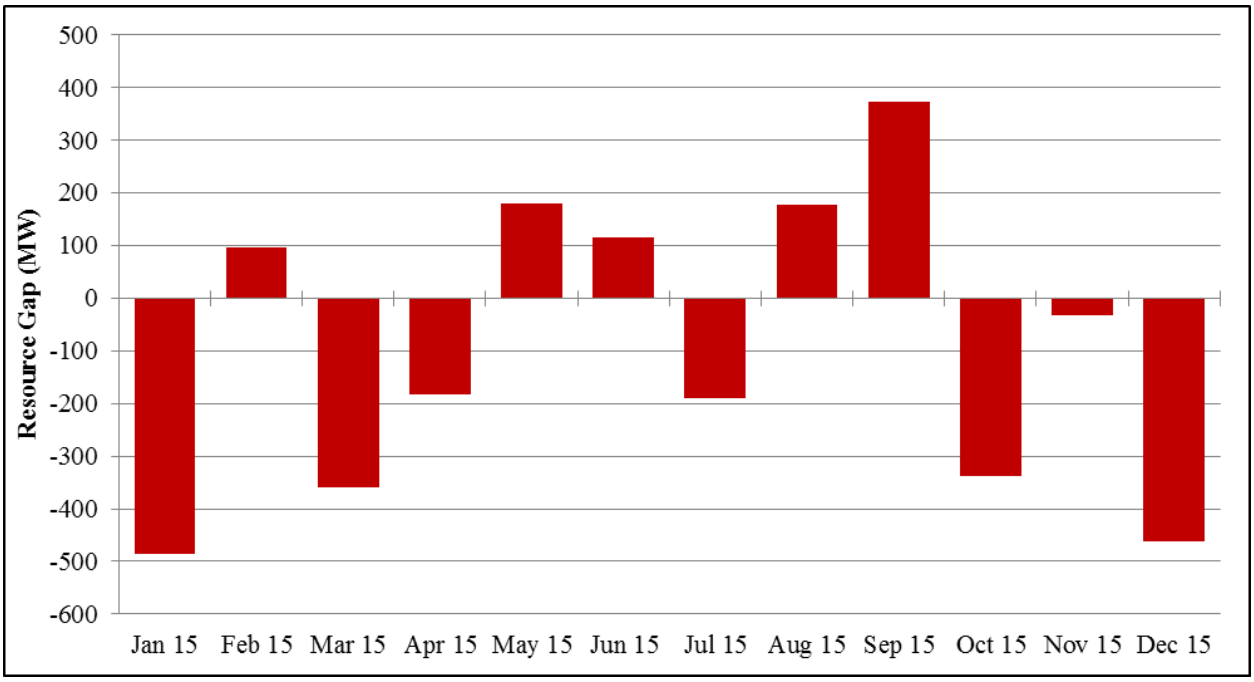
Another important difference between the two studies is the virtual transactions. Market Participants submit virtual bids to buy and virtual offers to sell energy in the Day-Ahead Market. A virtual transaction is not tied to an obligation to generate or consume energy; rather, it is a financial instrument that is cleared by taking the opposite position in the Real-Time Balancing

Market. Since the reliability commitment processes must ensure sufficient generation is online to meet the energy demand, virtual transactions are not used in the DA RUC and ID RUC algorithms.

The assumptions regarding wind generation differ as well. A wind forecast is used by the reliability commitment processes, while the Market Participants determine the participation levels for their wind generators in the Day-Ahead Market. Import and export transaction data are updated to include the latest information available for the reliability processes.

These types of differences are referred to as resource gaps between the Day-Ahead and Real-Time Markets. Figure 3–6 displays the average aggregated resource gaps for all months of 2015. The resource gaps are the sum of: (1) real-time wind generation in excess of the cleared supply bids on wind generators in the Day-Ahead Market; (2) real-time load in excess of load cleared in the Day-Ahead Market; (3) virtual supply net of virtual demand; (4) real-time net exports in excess of day-ahead net exports; and (5) real-time losses in excess of day-ahead losses.

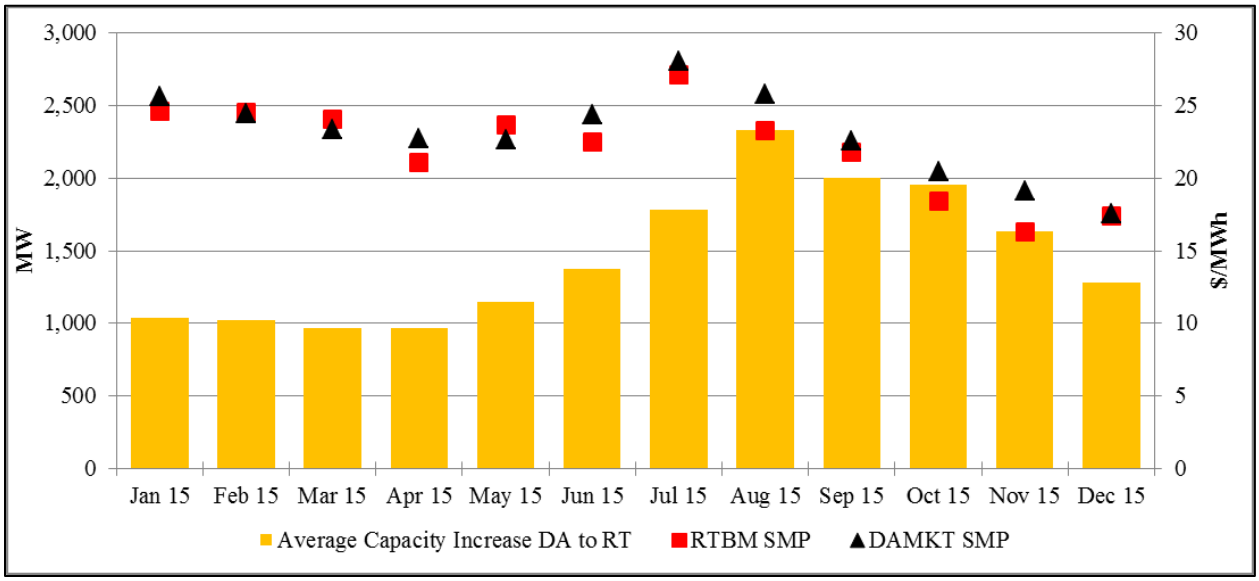
Figure 3–6 Average Hourly Day-Ahead Market/RUC Resource Gaps



For January 2015, Figure 3–6 indicates the average hourly resource gap was approximately negative 500 MW. For most months the resource gaps are a few hundred megawatts, indicating that some additional generation may need to be committed after the Day-Ahead Market committed. The primary driver for the negative resource gaps is the virtual supply net of virtual demand, in conjunction with excess actual wind as compared to wind cleared in the Day-Ahead Market, and real-time net exporting exceeding day-ahead net exporting. It is generally true that real-time wind generation exceeds the clearing of wind in the Day-Ahead Market. In four of the 11 months with excess real-time wind generation, virtual transactions filled the gap between day-ahead and real-time wind generation. The mismatch between real-time and day-ahead wind is expected because Market Participants with wind generation assets often choose to avoid a day-ahead position given the uncertainty of the wind.

In the last three months of the year, real-time wind generation exceeded forecasted day-ahead wind generation by approximately 500 MW on average. However, the virtual supply net of virtual demand in October and November was 200 MW, and in December was only 25 MW. The reason for the low resource gap in November can be attributed to an increase in exports that month as well as an under commitment of load in the Day-Ahead Market. The year 2015 showed distinct differences in virtual play between the on-peak and off-peak hours. Off-peak hours had excess virtual bids in all months, while on-peak had excess bids on average for all but one month. There appears to be a strong correlation between the virtual offering/bidding behavior and average daily wind generation patterns.

Figure 3–7 Average Hourly Capacity Increases



The resource gaps are clearly not insignificant, but they are not high enough to explain the level of commitments in the reliability commitment processes. Figure 3–7 compares online capacity between the Day-Ahead Market and the RTBM. The chart indicates that in January 2015 an additional 1,000 MW of capacity was online during the RTBM relative to the capacity cleared in the Day-Ahead Market. The bars are consistently above or near 1,000 megawatts and are seemingly uncorrelated with the resource gaps in Figure 3–6. The conclusion from Figure 3–6 and Figure 3–7 is that the resource gaps are not a major driver for commitments originating from the reliability commitment processes.

3.1.3. 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 need to ramp up and ramp down in short intervals of time. This is present in all electricity markets and to some extent is caused by increasing and decreasing load, planned and unplanned outages, along with the volatility of wind generation, which exacerbates the need for ramp capability in the SPP Market. The SPP Market design recognizes this need and includes a headroom constraint in the DA RUC and ID RUC algorithms. It is difficult to know the impacts of the headroom constraint, but the MMU does believe the ramp demand is a major driver of the reliability commitments in excess of the

resource gaps. What is not clear is if these commitments are resulting from the headroom constraint in the DA RUC and ID RUC algorithms or rather from the manual commitment process whereby they show up in the data as manual commitments for regional reliability.

The issue with ramp procurement is a problem in all of the ISOs/RTOs in the United States and was a topic in the price formation workshops held by the FERC in 2014. 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, depress the real-time price signals. The cost of bringing the resource online is not reflected in the real-time prices, and often the real-time prices will not be high enough for the resource to recover its operating costs.

Figure 3–7 above shows the average system marginal price (SMP) for both the Day-Ahead and Real-Time Markets. For 2015, the day-ahead SMP exceeds the real-time SMP by $1/MWh, and is higher by almost $3/MWh in some months. Many factors contribute to the price differences between day-ahead and real-time prices, and it is difficult to quantify the impacts of the reliability commitments on the real-time prices. Nevertheless, the direction of the impact is clear: reliability commitments dampen the real-time price signals. Several ISOs/RTOs, 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.

3.1.4. Quick-Start Resources Commitment

A Quick-Start Resource is defined by SPP as a resource that can be started, synchronized, and start injecting energy within 10 minutes of SPP notification. The Market Monitoring database indicates that in 2015 the SPP generation fleet included 74 resources that met the 10-minute start-up time requirement for quick-start capability. The total capacity for the quick-start capable resources totals 3,100 MW and consists of a mix of gas-fired, hydro, and oil-fired generators. During 2015 the reliability commitment processes committed 61 of the 74 quick-start capable resources. Ten additional resources submitted real-time bids with cold start-up times less than or equal to 10 minutes and were also committed by the DA RUC or ID RUC processes. Figure 3–8 summarizes the start-up instructions issued to resources with real-time bids indicating a 10-minute start-up capability. In 2015, 541 start instructions originated in a reliability commitment process, 2,660 start instructions originated from the Day-Ahead Market, and 747 were manually

committed. 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. The average lead time for 10-minute resources started by the DA RUC study is 20 hours, while ID RUC's average lead time was only two hours.

Figure 3–8 Commitments of Quick-Start Resources

Commitment Process	Number of Starts	Committed Capacity (MW)	Lead Time (hours)	Hours in Original Commitment	Actual Hours Online
DA RUC	37	2,072	5.0	3.5	4.0
ID RUC	504	27,999	2.0	3.0	4.0
Manual	747	41,826	0.1	2.0	4.0

The average number of hours in the initial commitment instructions varied between 2.0 to 3.5 hours for the starts initiated by a reliability process in contrast to one hour for starts originating from the Day-Ahead Market. Once online, the 10-minute resources are often picked up by subsequent reliability processes and kept online. The actual hours online were four hours on average for the DA RUC starts and were in line with the four-hour averages for the ID RUC and five-hour averages for the Day-Ahead Market. The average minimum run time for this group of resources is approximately one hour.

The level of Make-Whole Payments associated with the commitment of 10-minute resources in the reliability processes is noteworthy. Slightly more than half of the 1,288 starts originating in the reliability commitment processes resulted in real-time Make-Whole Payments. Additionally, starts that originated in the Day-Ahead Market and were extended in real-time led to real-time Make-Whole Payments. In total, Quick-Start Resources received $7.9 million in real-time Make-Whole Payments and $0.09 million in day-ahead Make-Whole Payments. Resources with operational flexibility should not rely on Make-Whole Payments as a significant source of revenue. 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 RTBM should make the need for Make-Whole Payments a rare occurrence. The MMU's concerns about this issue in 2014 have been mostly addressed in 2015.

There appears to be significant opportunity to improve the commitment efficiency of Quick-Start Resources. Committing these resources hours ahead of the actual start time, sometimes more than a day, ignores the value of their flexible capability. The value of flexibility, the optionality value of waiting, is prevalent throughout markets, and the long lead-time commitment far exceeding the 10-minute requirement of these resources by the system operator ignores this value.

The Integrated Marketplace Protocols Section 4.4.2.3.1 describes the RTBM dispatch of resources with quick-start capability. However, the ability for the system operator to optimally deploy the Quick-Start Resources 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 DA RUC and ID RUC, are unable to account for resources participating in the RTBM as quick-start ready resources, and therefore 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 RTBM.

In May 2015, RTO staff presented a new design proposal that was well received by stakeholders. Subsequently, this proposal was submitted to the Market Working Group (MWG) by a Market Participant[12] and was approved in September 2015. In January 2016, the MWG also formed a Price Formation Task Force (PFTF) "to evaluate the efficiency and transparency of Energy and Operating Reserve pricing" and is expected to complete its tasks by the end of 2016.[13]

[12] Revision Request 116 "Quick-Start Real-Time Commitment" received all the necessary approvals from the various SPP committees and, as of May 2016, is awaiting FERC filing and implementation.
[13] PFTF Charter, January 19, 2016 available at http://www.spp.org/organizational-groups/board-of-directorsmembers-committee/markets-and-operations-policy-committee/market-working-group/price-formation-task-force/.

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

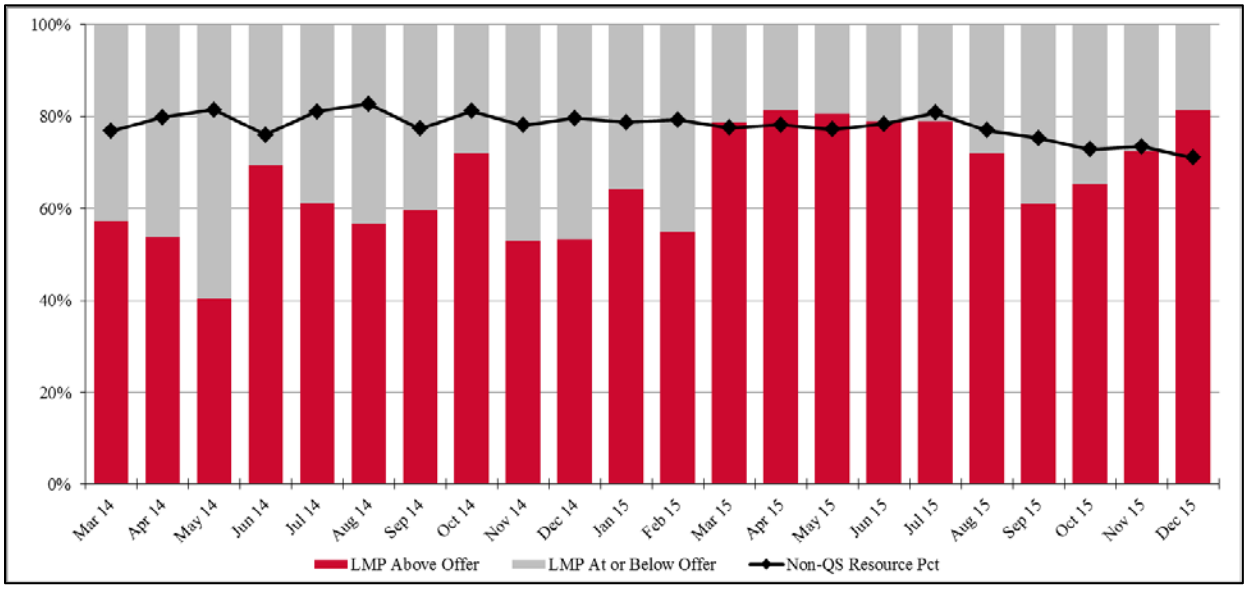
- Quick-Start Resources (QSRs) should not be physically committed prior to RTBM, even for a day-ahead position, and therefore QSRs should be allowed to be dispatched from an offline state in real-time.
- QSRs' parameters should be respected (Econ Min, Min Run Time, Min Down Time, etc.).
- QSRs should have a clear shutdown process.
- RTBM should automatically roll up a QSR offer.
- QSRs should be Make-Whole Payments eligible for their Minimum Run Time.

A registered QSR will not receive a physical commitment before real-time unless it is for a reliability reason. If a QSR is committed, it must start at its communicated start time. If a QSR is offered in the Day-Ahead Market, then it will receive a physical commitment if cleared in real-time. Market Participants may use virtual offers in the Day-Ahead Market to take a day-ahead position. For real-time operations, ID RUC or Short-Term RUC (introduced in April 2016) will determine if the QSR is needed for reliability, needed for economic reasons, or not needed at all. If the QSR is needed for reliability, it will receive a physical commitment. If it is needed for economic reasons, then it may receive economic dispatch instructions in real-time and will receive a real-time physical commitment following an online dispatch by RTBM. If it is not needed at all, the unit will not be dispatched in real-time.

Figure 3–13 shows the percent of time Quick-Start Resources generated power when the LMP was higher than their offer. For the first 12 months of the Integrated Marketplace, Quick-Start Resources were dispatched during intervals where the LMP was above the marginal production cost for just over half of the power produced. In May of 2014, 60% of the time Quick-Start Resources on average were generating power when the price was below their offer. During 2015, over two-thirds of MWh produced by Quick-Start Resources were with LMP above real-time energy offers. This is consistent with relative relationship of offers to LMP for the balance of the SPP fleet that is represented by the line in the figure below. The Market Monitors recognize this

as progress towards more efficient use of these resources. Considering economic dispatch of Quick-Start Resources, a trend of more economic dispatch is observed in 2015, and early indications are that the trend continues in 2016.

Figure 3–9 Efficient Operation of Quick-Start Resources



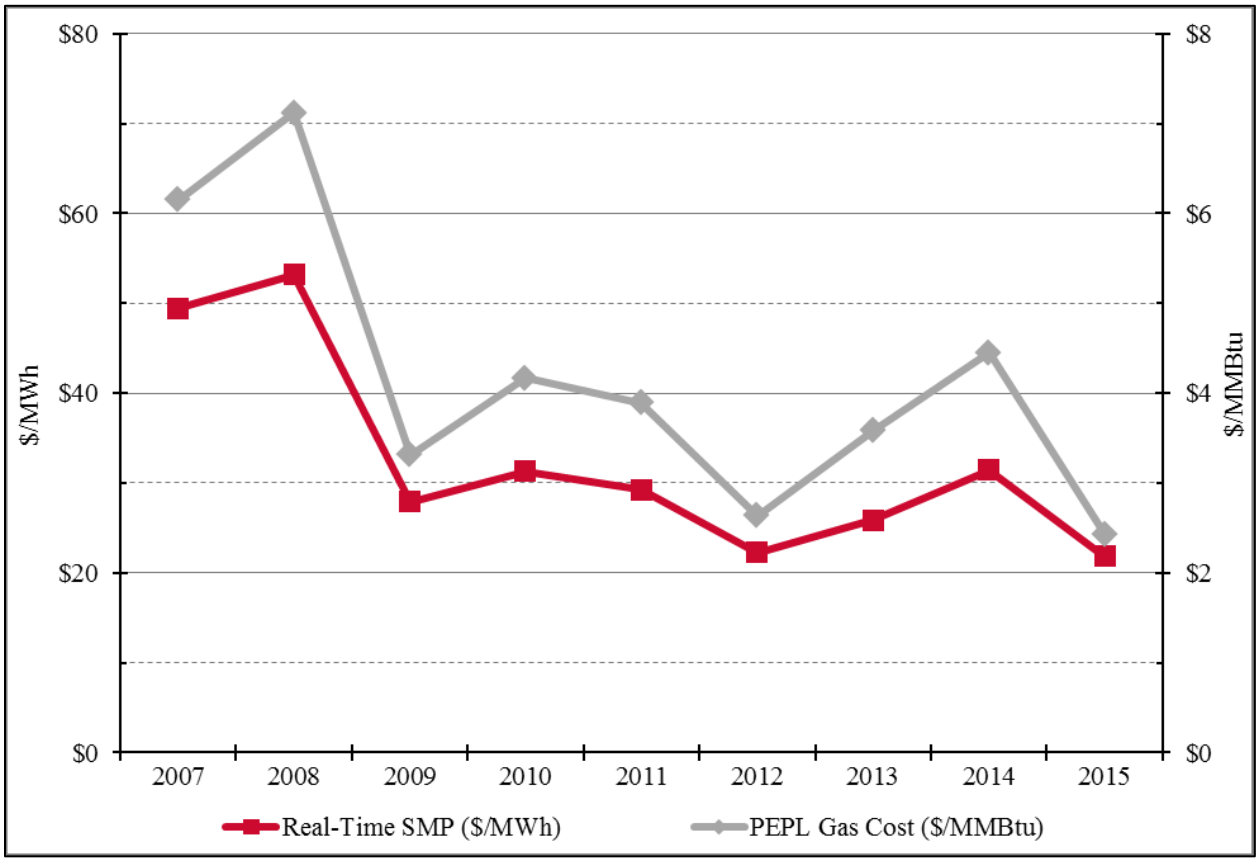
MMU Recommendation – Quick-Start Logic

In 2014 the MMU recommended that SPP development new rules governing the commitment and dispatch of Quick-Start Resources. Two key components of the new design are as follows: (1) Resources with a 10-minute start capability should not be subject to an ID RUC or DA RUC commitment; and (2) resources that are participating in the RTBM as Quick-Start Resources should not be eligible for a Make-Whole Payment. The second key component is likely to cause concern, but a properly designed quick-start deployment coupled with five-minute settlement alleviates the need for a Make-Whole Payment, and eliminating a Make-Whole Payment incents the offering of ramp to the market. Market analysis of Quick-Start Resources indicates significant progress during 2015 in addressing these concerns. The MMU considers this recommendation closed.

3.2. Energy

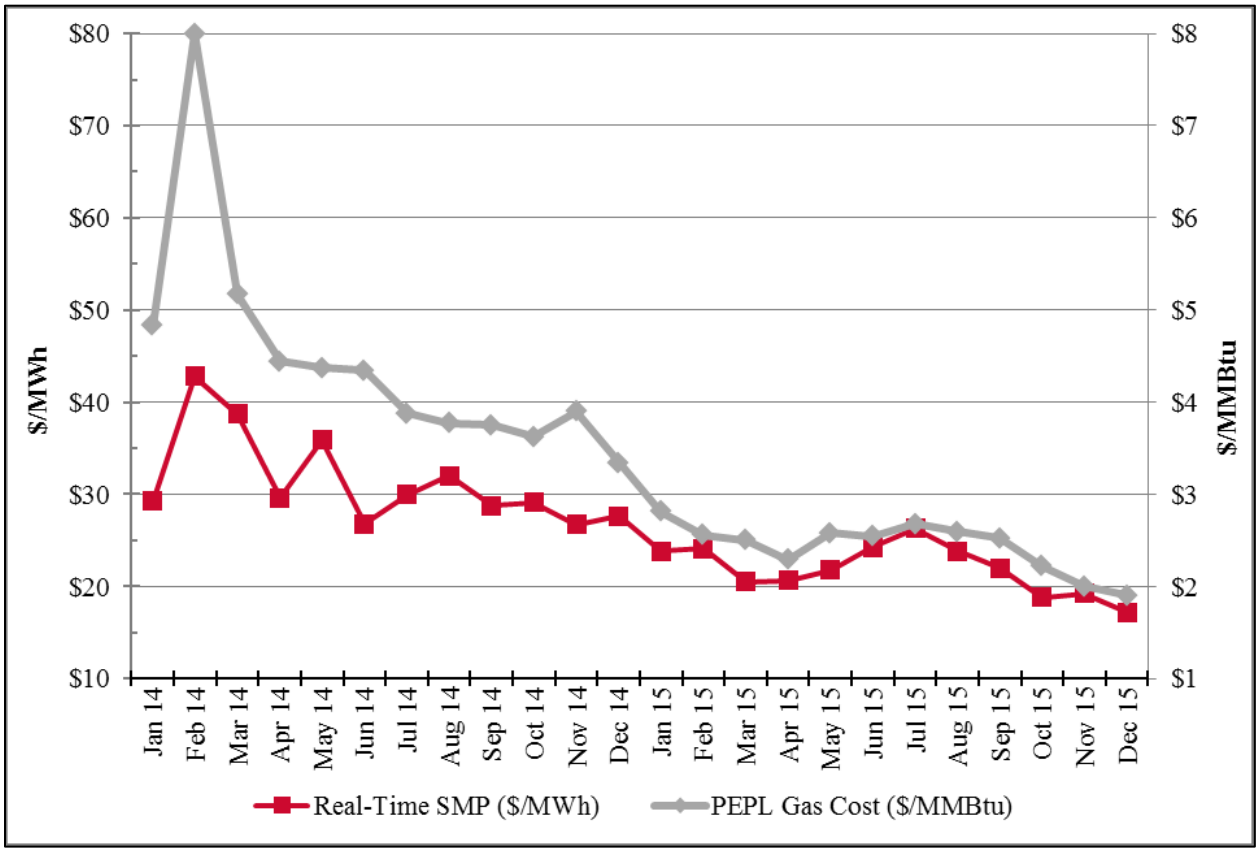
Energy prices in the SPP Integrated Marketplace track very closely with the price of natural gas as was true in the Energy Imbalance Service (EIS) Market. Figure 3–13 shows the average real-time energy price for the past nine years. The 2014 average includes two months of Locational Imbalance Prices (LIPs) from the EIS Market and 10 months of Locational Marginal Prices (LMPs) from the Integrated Marketplace. The 2014 average RT energy price of $31.42/MWh is a 21% increase over the comparable 2013 average price. The 2015 average RT energy price, on the other hand, was $21.85/MWh, which represents a 31% decrease relative to 2014. The 2015 average price of natural gas at the Panhandle Eastern Pipeline hubs was $2.43, a 45% decrease from 2014. In 2015 the annual average energy prices decreased noticeably, primarily due to the historically low gas prices. All ISO/RTO markets in the U.S. experienced this overall, downward trend in energy prices in 2015.

Figure 3–10 Real-Time Energy Price vs. Natural Gas Price, 2007–2015



Unlike the previous year, 2015 was characterized by mild weather and historically low gas prices. This led to less extreme system conditions as shown in Figure 3–11. 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 the intervals in 2015, and gas is the one primary fuel with 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. Average gas prices at the Panhandle Eastern Pipeline hub remained low throughout the year and ranged from a low of $1.90/MMBtu in December to a high of $2.81 in January. Similarly, average monthly Real-Time SMPs were markedly lower in 2015 than the previous year.

Figure 3–11 Real-Time Energy Price by Month vs. Natural Gas Price, 2014–2015



3.3. Real-Time and Day-Ahead Price Comparisons

Figure 3–12 is a comparison of the 2015 Day-Ahead Market system marginal price (SMP) with the RTBM counterpart. The average price differences range from $0.10 per MWh in February to $1.91 per MWh in July. The average monthly day-ahead SMP exceeded the real-time in all months throughout the year.

Figure 3–12 System Marginal Price Day-Ahead and Real-Time

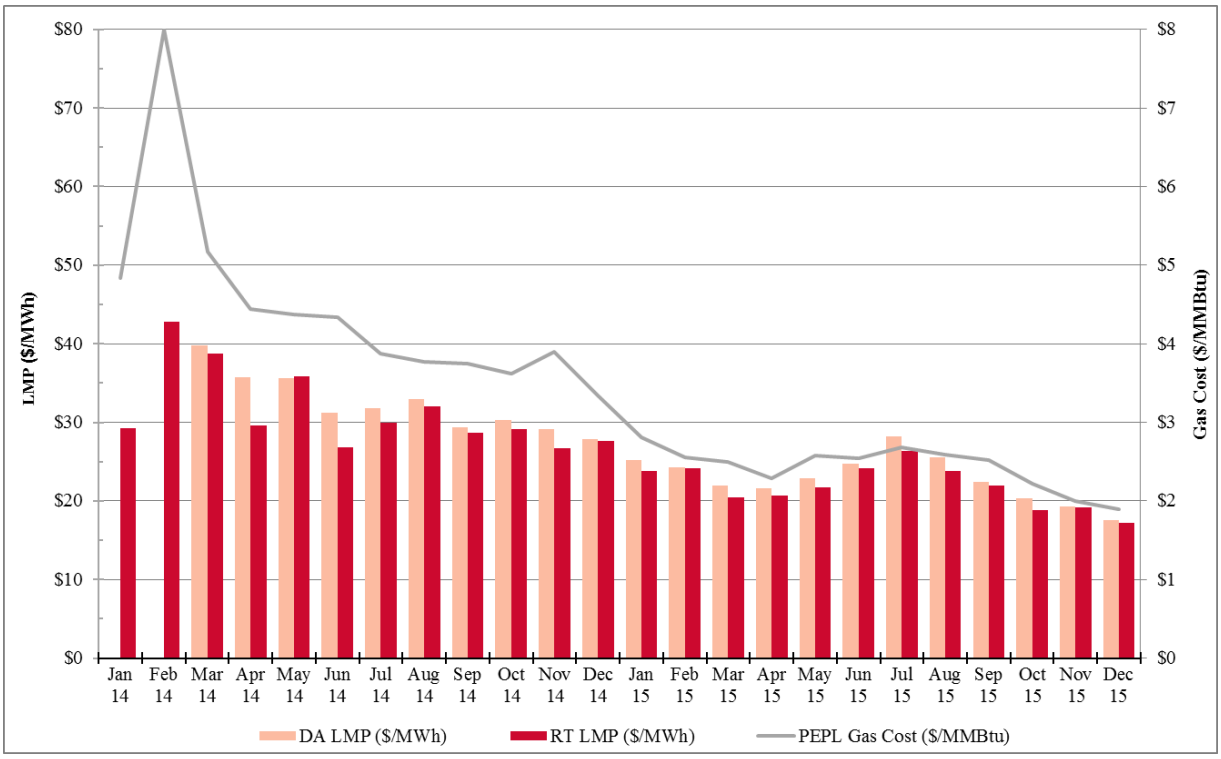


Figure 3–13 shows the day-ahead and real-time energy prices at the two SPP market hubs. The SPP North Hub is composed of pricing nodes in the northern part of the SPP footprint and the SPP South Hub is composed of pricing nodes in the south-central portion of the footprint. The general pattern of higher 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. The day-ahead premium, the amount by which the day-ahead energy price exceeds the real-time energy price, is larger at the North Hub. The annual average day-ahead premium is $2.83/MMBtu at the North Hub

versus only $1.62/MMBtu at the South Hub. Downward price spikes in the RTBM drive the high premiums at the North Hub.

Figure 3–13 SPP Market Hub Prices, 2015

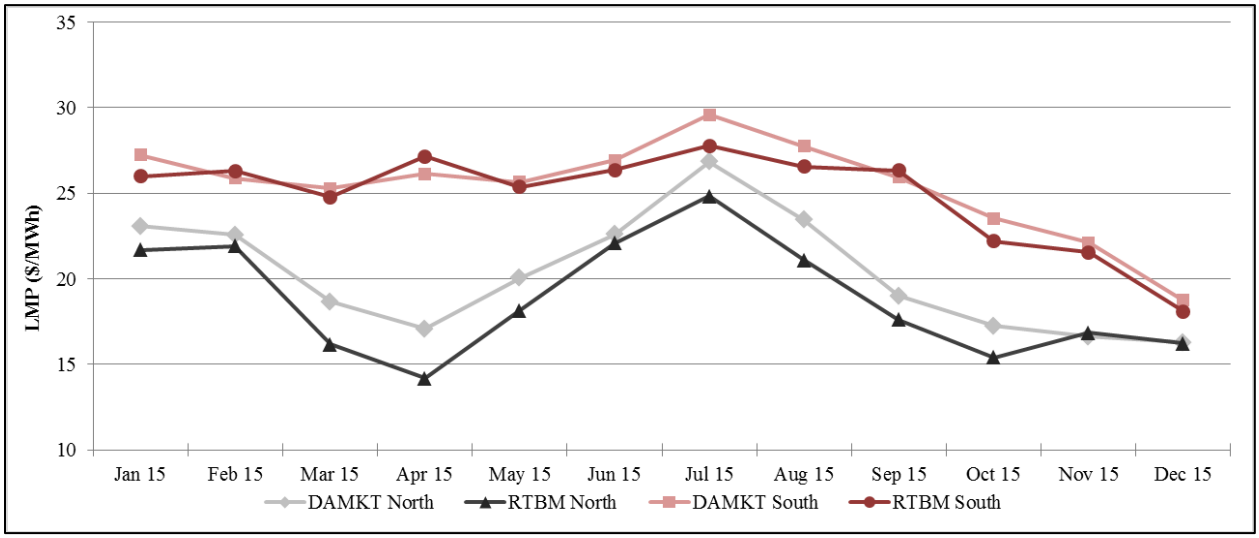
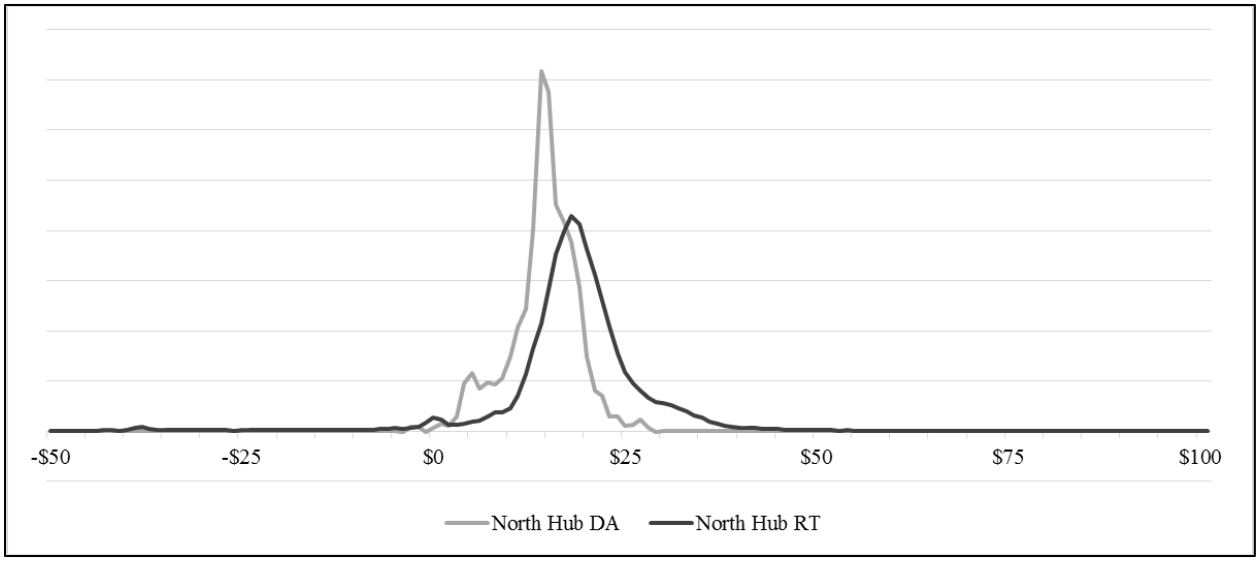


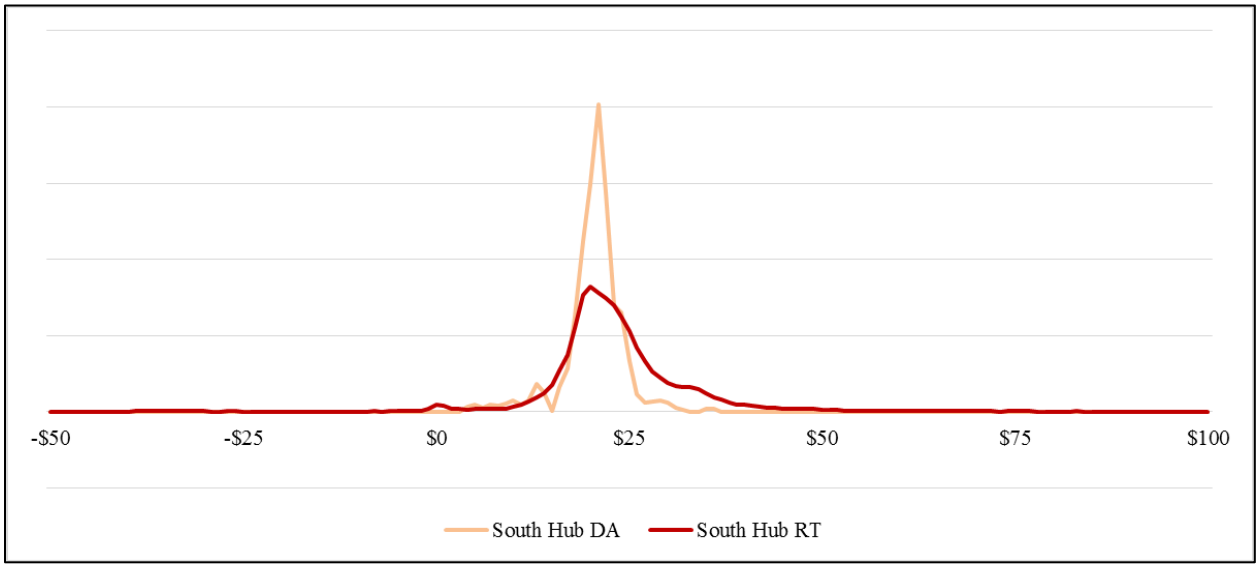
Figure 3–14 presents the probability density curves associated with the energy prices at the SPP North Hub. The real-time curve is noticeably shifted to the left of the day-ahead curve, and there is significant area under the RTBM curve just above the zero-dollar tick on the horizontal axis.

Figure 3–14 North Hub Price Density Curves



This is indicative of low price spikes at the North Hub in the RTBM. 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 has a similar but much less pronounced leftward shift as shown in Figure 3–15.

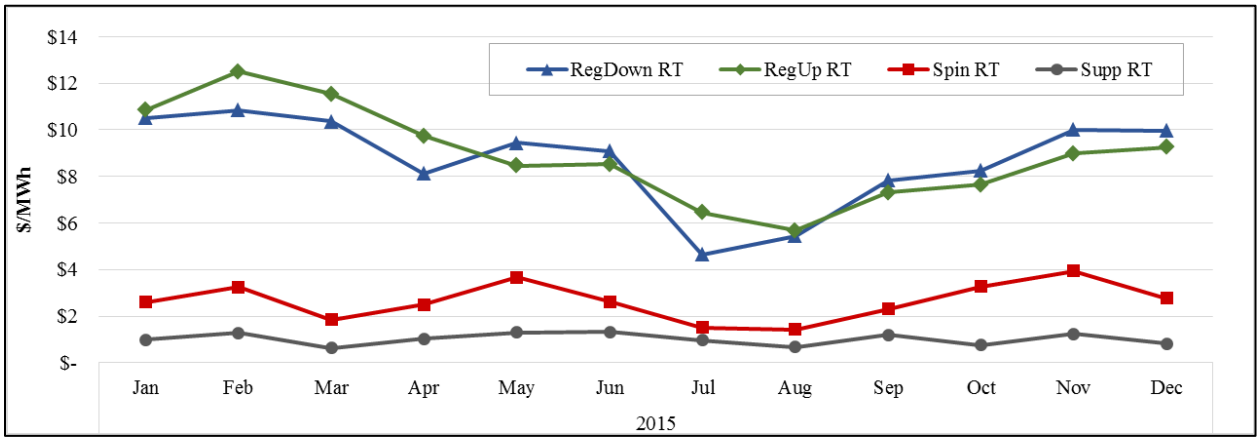
Figure 3–15 South Hub Price Density Curves



3.4. Ancillary Services

Average real-time prices for the operating reserve products are presented in Figure 3–16. The 2015 average marginal clearing price for Regulation-Up, Regulation-Down, and Spinning Reserve services are down 30–40% from 2014 to $8.87/MWh, $8.73/MWh, and $2.66 /MWh respectively for 2015. The marginal clearing prices for Supplemental Reserves are down more than 50% from 2014 to $1.01/MWh for 2015.

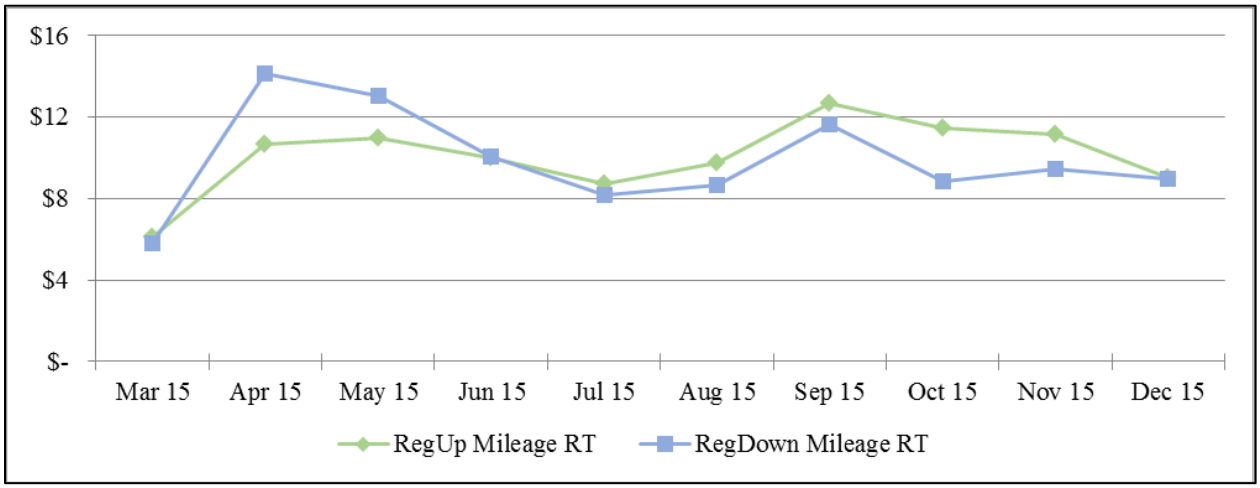
Figure 3–16 Real-Time Operating Reserve Product Prices, 2015



There are a couple of contributors to the reduction in prices from last year. In late September 2014 the RTO stopped enforcing the reserve zone constraints. The energizing of new transmission lines in the western part of the SPP footprint alleviated the need for zonal procurement of the reserve products. This helped foster increased competition in the market for operating reserves and is consistent with the downward trend in prices we observed after that period in 2014.

In March 2015 the RTO introduced new products paying regulating units for mileage cost incurred when moving from one set point instruction to another. These mileage costs are paid directly through the Operating Reserve prices shown for Regulation-Up and Regulation-Down in Figure 3–16. 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 they are entitled to reimbursement at the Regulation Mileage Marginal Clearing Price. Figure 3–17 illustrates the Marginal Clearing Prices for 2015.

Figure 3–17 Real-Time Regulation Mileage Prices, 2015



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 MCP 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 Payment, which will be discussed in section 3.6.2 below.

The day-ahead and real-time price patterns vary across the ancillary service products. Figure 3–18 through Figure 3–21 provide comparisons between day-ahead and real-time for 2015 as well as their 2014 averages. All four products' prices have declined since the inception of the market. Declining gas prices is the primary cause of this ancillary services price decline. Some portion of the price decline is the result of the normal maturing of the market improving the overall efficiency of the market.

Figure 3–18 Regulation-Up Service Prices

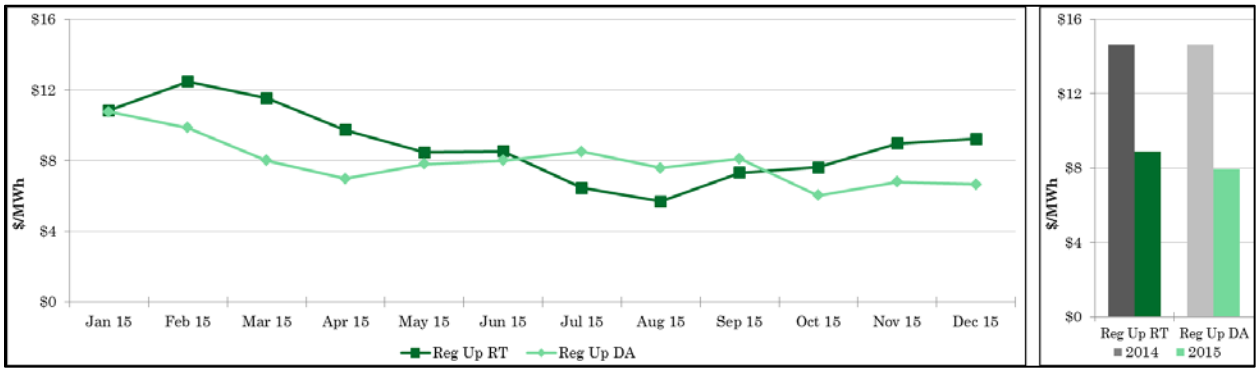


Figure 3–19 Regulation-Down Service Prices

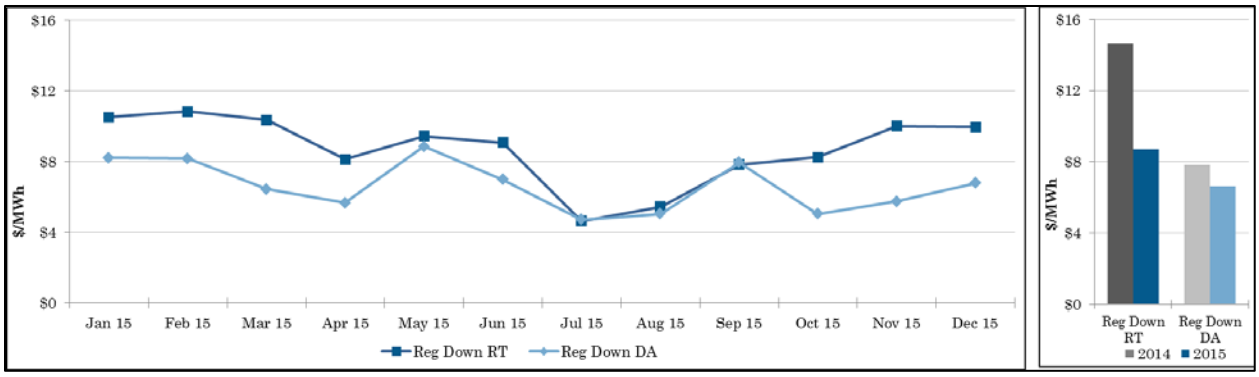


Figure 3–20 Spinning Reserve Prices

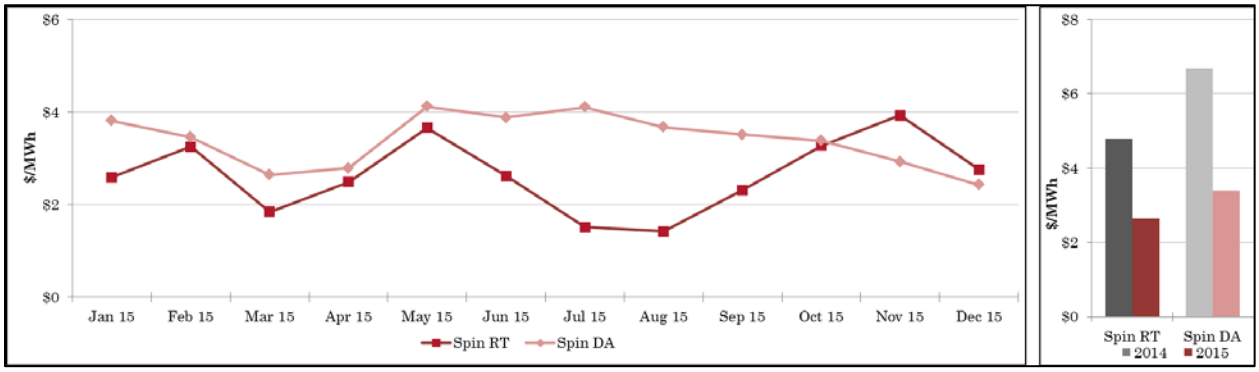
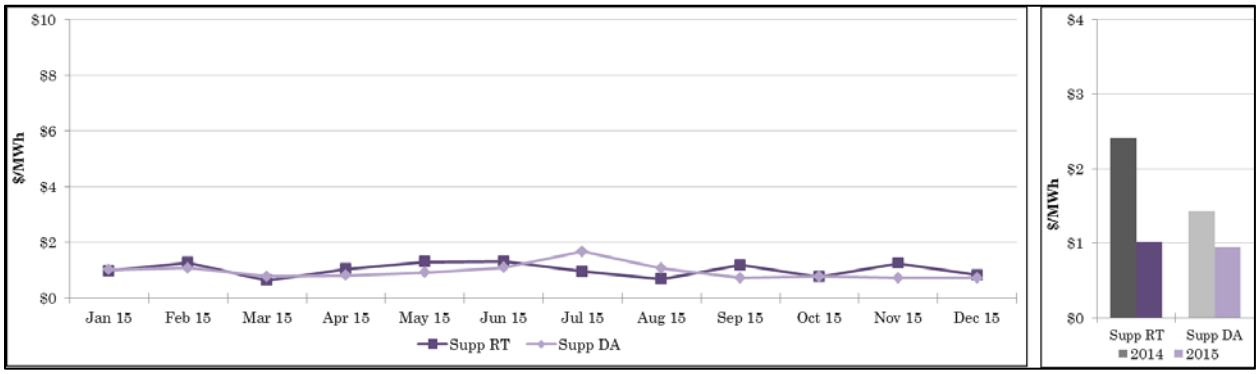


Figure 3–21 Supplemental Reserve Prices



3.4.1. Market Settlement Results

Ninety-eight percent (98%) of the energy consumed in the Integrated Marketplace settled in the Day-Ahead Market. This is consistent with the first 12 months of the Integrated Marketplace, which settled 97% in the Day-Ahead Market. Figure 3–22 shows that approximately 230 terawatt-hours of energy were purchased in the Day-Ahead Market at load settlement locations of which only four terawatt hours were in excess of the real-time consumption, resulting in real-time sales at the load settlement locations. An additional six terawatt hours of energy were purchased in the RTBM because the real-time consumption was higher than that of the day-ahead.

Figure 3–22 Energy Settlements – Load

	Day-Ahead Market Purchases	RTBM Purchases	RTBM Sales
Load – Energy (GWh)	229,736	6,721	4,329
Cash Flow (Millions)	$5,530	$159	$ 95

Ninety-two percent (92%) of generation was settled in the Day-Ahead Market, a 2% increase from the first 12 months of the Integrated Marketplace. Figure 3–23 presents the settlement numbers for the generation assets. Ten percent (10%) of the energy cleared in the Day-Ahead Market was settled by purchasing energy in the RTBM rather than generating the energy, compared to 8% in 2014.

Figure 3–23 Energy Settlements – Generation

	Day-Ahead Market Sales	RTBM Sales	RTBM Purchases
Energy (GWh)	234,280	20,809	23,021
Cash Flow (Millions)	$5,273	$450	$456

The RTO plays the role of the customer in the ancillary services market. At 0700 hours 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 RTBM, there is considerable activity with respect to the operating reserve products in the RTBM. Figure 3–24 presents the settlements data.

Figure 3–24 Operating Reserve Products Settlements

	Day-Ahead Market Sales	RTBM Sales	RTBM Purchases
Regulation-Up Service (GWh)	2,982	841	1,101
Regulation-Down Service (GWh)	2,983	954	1,154
Spinning Reserves (GWh)	5,852	1,286	1,949
Supplemental Reserves (GWh)	5,802	994	1,486

A large percentage of day-ahead sales are settled in the RTBM by purchasing the operating reserve product rather than supplying the service in the RTBM. Thirty-seven percent (37%) of the day-ahead sales of regulation-up service were settled through purchasing the product in the RTBM in 2015. This is in contrast to 98% of energy generation settling at the day-ahead prices. This trend is down 3% from the 40% that was displayed in the first 12 months of the market.

Forty-nine percent (49%) of the 2015 real-time Regulation-Up Service was settled at the day-ahead prices, down from 61% in the first 12 months of the Market. The corresponding percentages for Regulation-Down Service, Spinning Reserves, and Supplemental Reserves are 46%, 55%, and 64% respectively, down from their respective numbers in the first 12 months of the market of 62%, 63%, and 77%. This essentially means that the operating reserve products are being moved around to different resources, but in less volumes than 2014. This is likely due to

the additional capacity online as part of the reliability commitment processes. Resources that were not committed in the Day-Ahead Market, and subsequently committed by a reliability commitment process, are generally more expensive and once online it is economical to carry reserves on these resources.

One issue that is not clear is the high level of Regulation-Down Service that is being purchased by generation owners to cover their day-ahead positions. Figure 3–19 shows that real-time prices consistently exceed the day-ahead prices for Regulation-Down Service. This means that 32% of the regulation-down megawatts that clear in the Day-Ahead Market are oftentimes being bought back at a higher price. In most cases, this should not be an issue due to the co-optimization of offered capacity for energy and operating reserves. Presumably, the resource's capacity is being more efficiently used for energy generation. However, there are cases where the resources are taken out of the real-time market for regulation due to transmission constraint issues. In these cases, the set point required for the provision of regulation services causes a transmission constraint to overload.

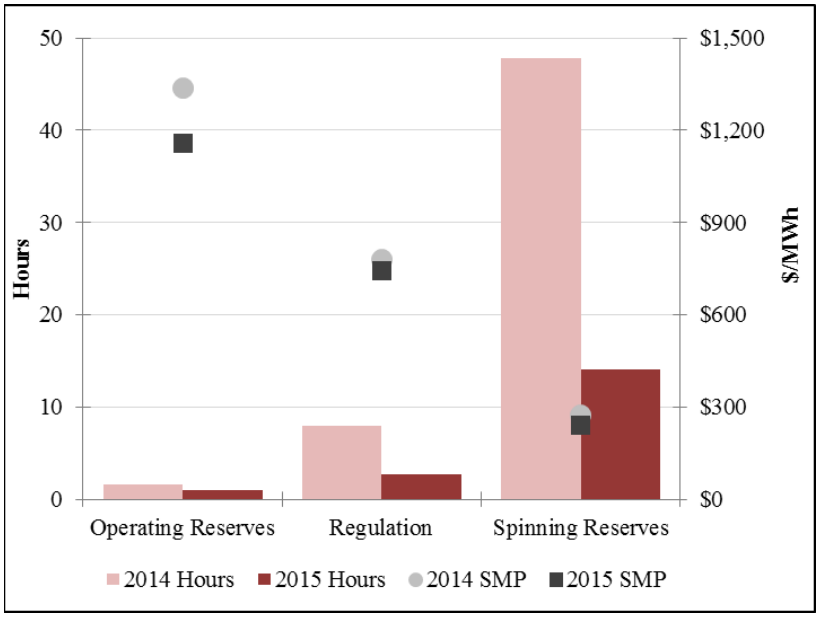
3.5. Shortage Pricing

The Integrated Marketplace employs scarcity pricing demand curves that administratively set price during 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 RTBM experienced 24 hours of capacity shortages in 2015. Most shortages, 90%, were for Spinning Reserve. There was one hour of regulation shortage and only five-minute interval of aggregate operating reserve shortage. A capacity shortage occurs when there is not enough online generation to meet both the energy demand and the operating reserve requirements. No capacity shortages occurred in the Day-Ahead Market.

Figure 3–25 displays the number of shortage hours and the corresponding average of the system marginal price (SMP). The high SMP during the operating reserve shortage reflects the

$1,100/MW scarcity demand curve. Similarly, the average SMPs when short of regulation and Spinning Reserves reflect the $600/MW and $200/MW scarcity demand curves, respectively. Note that in each instance the corresponding SMP is higher than the demand curve because the SMP includes the marginal cost of energy as well as the administratively determined marginal cost of not clearing sufficient reserves.

Figure 3–25 Capacity Shortages



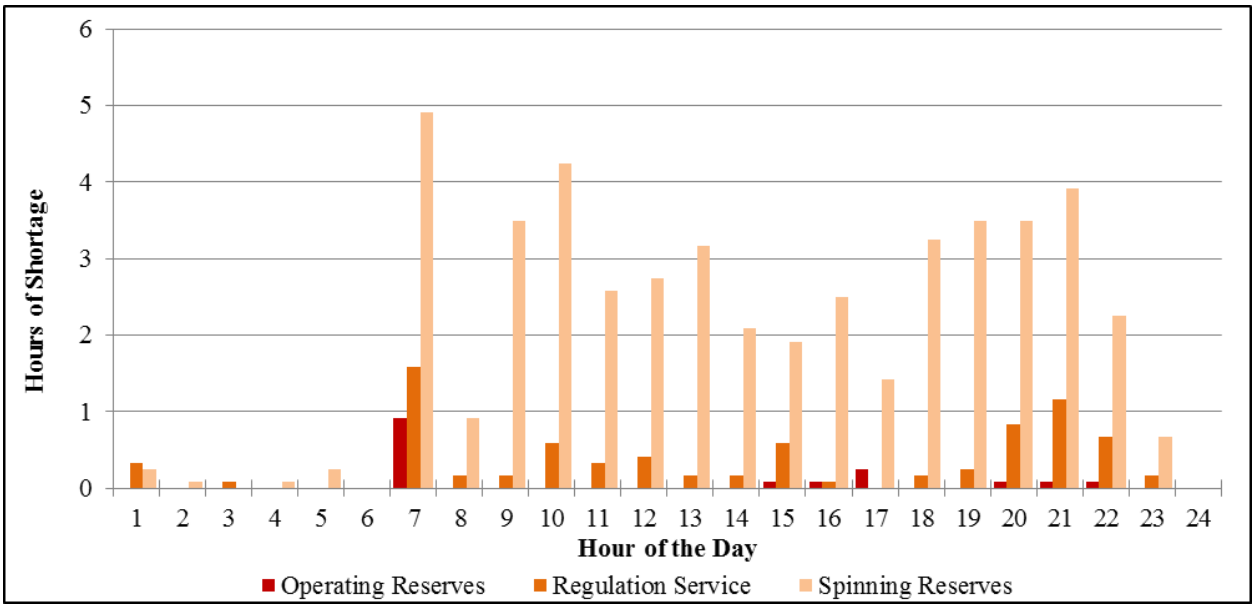
There was one operating reserve shortage event in 2015 compared to eight in 2014. The event happened on November 27 and lasted five minutes. Figure 3–26 provides details around the number of shortage events, the MW values of the events, and the duration of the events for all components for the first two years of the market. The number of events and the magnitude of the events are down substantially in 2015. Most of the decline is attributable to maturing of the market over the first couple of years, though some is the result of weather patterns and the degree to which planned and unplanned outages affect the market.

Figure 3–26 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	2015	1	5	5	231	231
	2014	8	12	45	307	586
Regulation Up	2015	10	6	10	98	323
	2014	70	7	25	92	430
Spinning Reserves	2015	97	14	40	125	543
	2014	294	10	55	115	602

Figure 3–27 provides details on the capacity shortages that occurred during 2015 by time of day. The hour of the day experiencing the most shortage events is, not surprisingly, the hour ending 7:00 AM. Regulation shortages tend to occur in the morning ramp as well as between 10:00 PM and 11:00 PM because 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 3–27 Capacity Shortages – Hour of Day for 2015



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

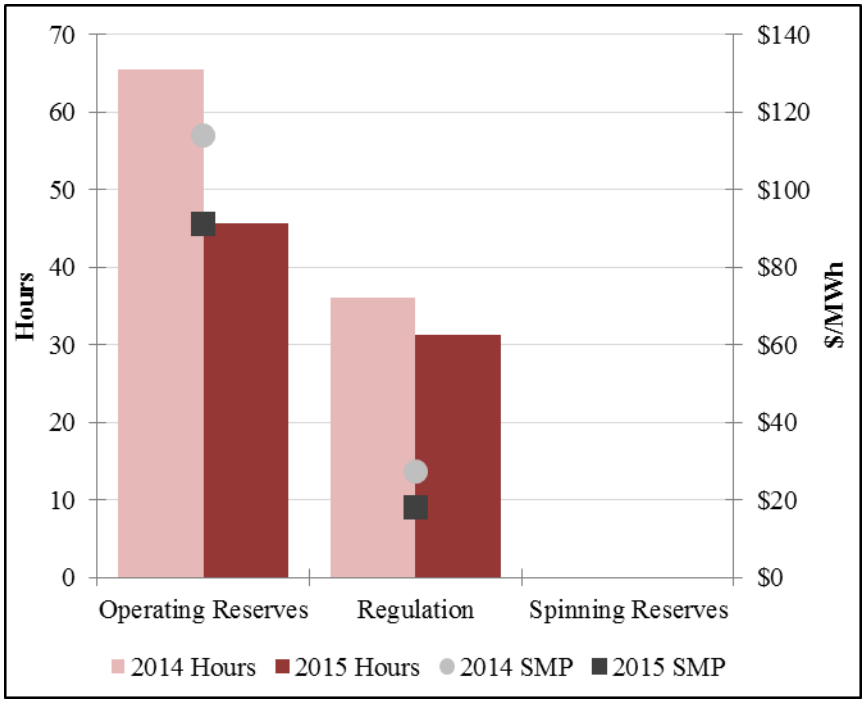
annual revenue. These resources generally have higher costs and low capacity factors, and therefore must generate income at a much higher rate than base or intermediate load resources. Scarcity pricing is an effective means for sending a correct price signal to these resources.

Prices generally exceed $1,000/MWh during operating reserve shortages. This provides an incentive for resources to ramp up quickly and for Quick-Start Resources to come online. One area where MMU contends that the correct price signal is not being sent is with respect to ramp-constrained capacity shortages. A ramp-constrained operating reserve shortage occurs when there is enough capacity online, but due to ramp constraints the market is unable to meet both the energy demand and the operating reserve requirements.

3.5.1. Ramp-Constrained Shortages

In 2015 there were 46 hours of ramp-constrained operating reserve shortages, and 31 hours of ramp-constrained regulation shortages; see Figure 3–28. The price signals during these events are dramatically different than the signals during a capacity shortage. The average SMP during the ramp-constrained operating reserve shortages was $91/MWh (similar to the $114/MWh in 2014). 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. This price signal does not provide the correct incentives for fast-ramping resources. This issue has not changed from what was shown in the assessment of the market results for 2014.

Figure 3–28 Ramp-Constrained Shortages



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. Figure 3–29 illustrates that the number of events and the magnitude of these events have not changed significantly from 2014 to 2015. This is in contrast to the dramatic change in the capacity shortage statistics shown in Figure 3–26.

Figure 3–29 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	2015	425	8	30	45	451
	2014	547	7	55	47	454
Regulation Up	2015	271	11	55	23	337
	2014	321	7	35	24	304
Spinning Reserves	2015	0	0	0	0	0
	2014	0	0	0	0	0

MMU Recommendation – Ramp-Constrained Shortage Pricing

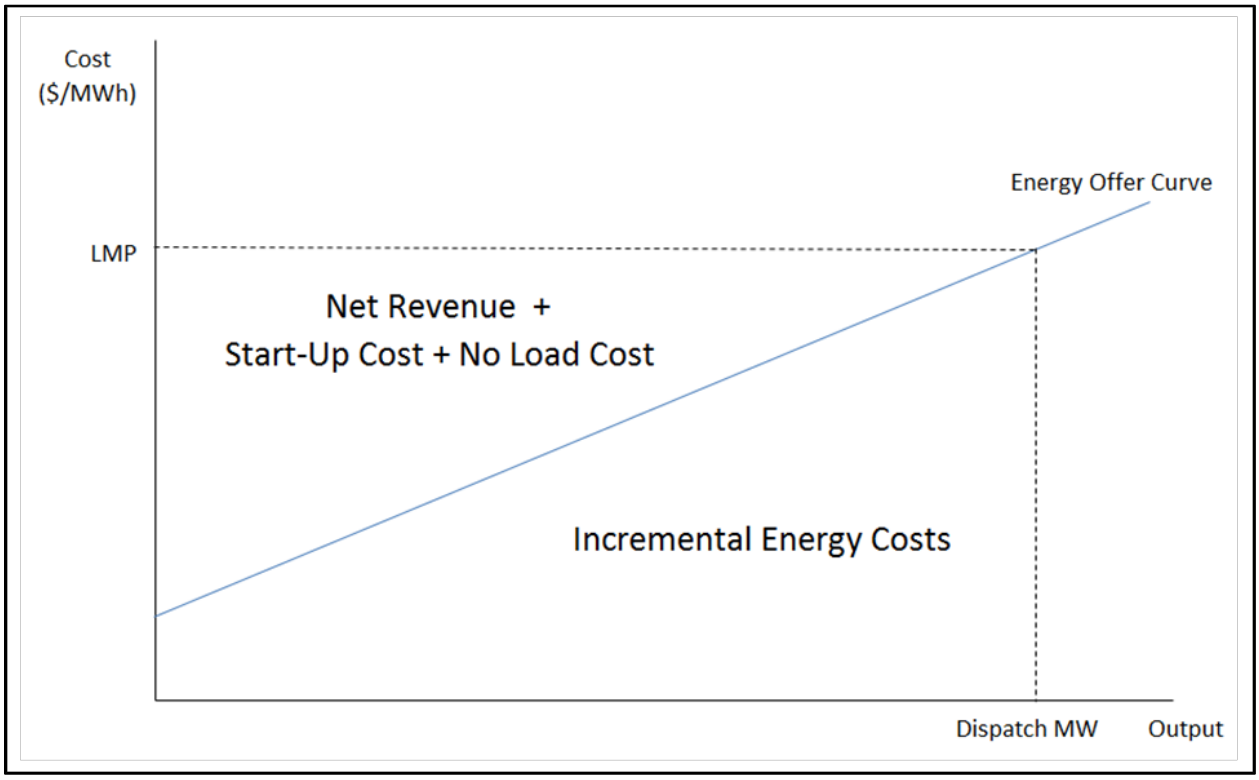
As was the case in 2014, the MMU recommends pricing the ramp-constrained operating reserve shortages in a manner similar to the operating reserve capacity shortages. As noted above, efficient prices reflect the cost of the marginal action. The marginal action during ramp-constrained shortage pricing events is no different than the marginal action during a capacity shortage event. In each case, the operating reserve obligation is reduced, enabling the system to meet the market demand. The RTO should consider upward sloping scarcity pricing demand curves, similar to those in place in the Midcontinent ISO that apply to both capacity and ramp-constrained shortages. The megawatt shortages associated with ramp-constrained shortages are generally lower and an upward sloping scarcity demand curve will capture the increasing cost associated with the larger shortages.[14]

3.6. Make-Whole Payments

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 energy and operating reserves for a market commitment period. 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, and no load cost. Any net revenue beyond those costs supports annual avoidable costs and capital costs. Figure 3–31 conceptually depicts costs and revenues for a simple case of a resource cleared for one market interval for energy only. The Make-Whole Payment provides additional market payment in cases where net revenue is negative, to make the resource whole to its ancillary service product's cost, incremental energy, start-up, and no load costs.

[14] No action was taken with regard to this issue by the SPP during 2015. The MMU did not initiate any action either because in September 2015 FERC issued a NOPR on a closely related subject "Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators" (RM 15-24-000), and the MMU preferred to wait for the FERC decision per this NOPR. The MMU then filed comments with FERC regarding the NOPR and now is in the process of reviewing the resulting order, Order No. 825 issued on June 16, 2016.

Figure 3–30 Revenue and Cost Conceptual Graph

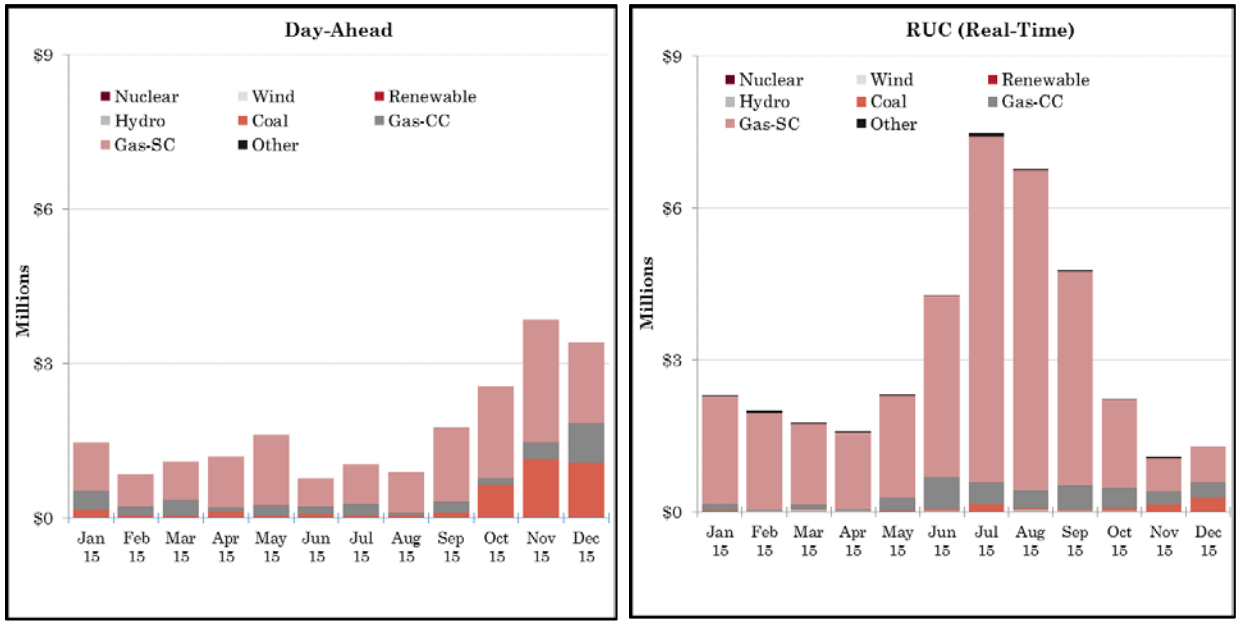


The calculations separately evaluate: (1) Day-Ahead Market commitments based on Day-Ahead Market prices, dispatch, and cleared offers; and (2) RUC commitments based on RTBM prices, dispatch, and cleared offers. The calculations sum revenues and costs across contiguous market intervals for the shorter of the commitment period or the operating day.

For 2015, DA Market and RUC Make-Whole Payments totaled approximately $58 million, down from $77 million in the first year of the market. Much of the decrease can be attributed to declining gas prices and their effect on locational marginal prices in both the Day-Ahead and Real-Time Markets. Make-Whole Payments averaged about $0.25/MWh for 2015. In comparison to other ISOs/RTOs, SPP's Make-Whole Payments fall below the low end of the range reported by the Federal Energy Regulatory Commission of $0.30 to $1.40/MWh. This is not surprising, given that SPP has fewer types of Make-Whole Payments than other RTOs. Figure 3–31 shows monthly DA Market and RUC Make-Whole Payment totals by technology type. Day-Ahead Make-Whole Payments constituted about 35% of the total Make-Whole Payments in 2015. SPP pays about 90% of all Make-Whole Payments to gas-fired resources, and

78% of all Make-Whole Payments to simple cycle gas resources through RUC Make-Whole Payments.

Figure 3–31 Make-Whole Payment Totals by Fuel Type, 2015



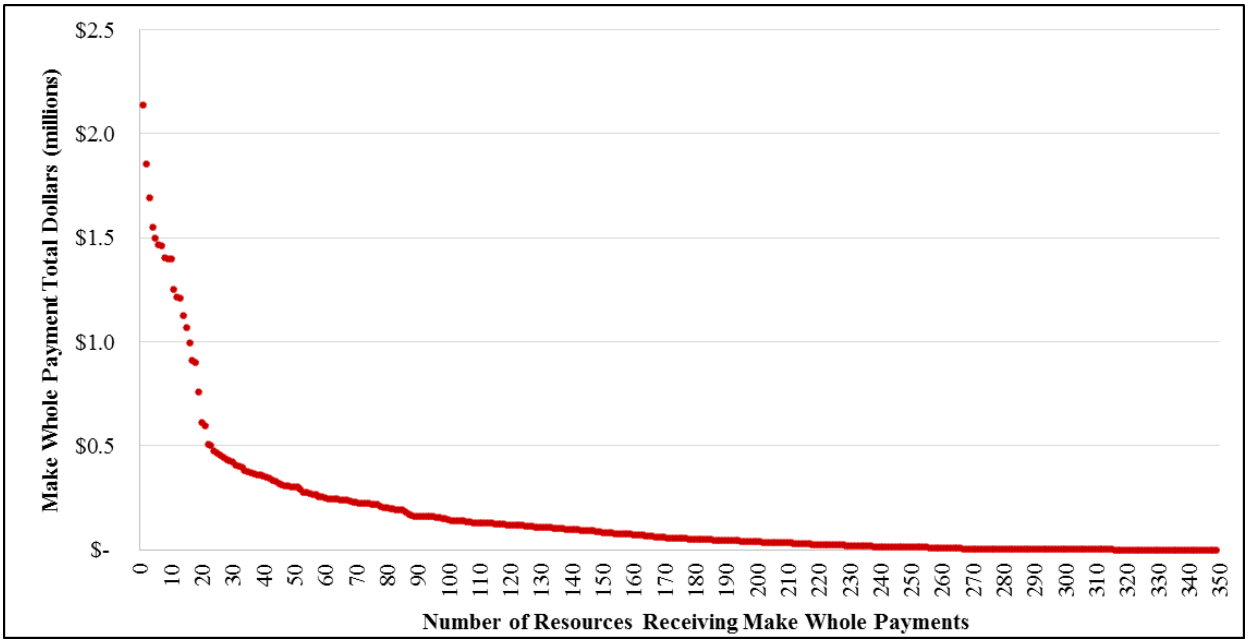
As discussed in section "3.5.1 Ramp-Constrained Shortages," RTBM prices frequently do not support the cost of RUC commitments, resulting in Make-Whole Payments. Many of the commitments result from local reliability issues, uncaptured congestion in the Day-Ahead Market, and SPP's rampable headroom requirement. The causes of uplift in the SPP Market are similar to those discussed in other ISOs/RTOs in the September 8, 2014 FERC Price Formation Workshop, for which the Commission prepared the previously mentioned study.[15]

There was an influx in Day-Ahead Make-Whole Payments in the last three months of 2015. Major contributors for this increase were the implementation of the Integrated System and more units being online, as well as voltage support issues created by outages starting during that timeframe. Make-Whole Payments paid to units being manually committed for voltage support were approximately $13.5 million dollars in 2015. These voltage support commitments represent 67% of the Day-Ahead Make-Whole Payments during the last four months of 2015 and almost all of the Day-Ahead Make-Whole Payments to coal units in those months.

[15] See FERC Docket AD 14-14.

While Figure 3–32 shows most SPP resources received modest total annual Make-Whole Payments, only one resource received over $2 million and four resources received over $1.5 million. This is a significant decline in the concentration level from 2014 when six resources received over $2 million.

Figure 3–32 Concentration of Make-Whole Payments by Resource



SPP frequently used two of these five resources to support a local reliability issue. Unlike other ISOs/RTOs, no single resource received over $2.5 million.[16] Figure 3–33 reveals some concentration in the Market Participants that received the highest levels of Make-Whole Payments. These statistics place SPP in the lower end of the pack relative to the other ISOs/RTOs.[17] The concentration coincides with the 68% share of generation by six participants.

[16] See Figure 2, Concentration of Uplift Payments by Plant During each RTO's or ISO's Most Concentrated Year, of FERC Staff Analysis of Uplift in RTO and ISO Markets, August 2014, Docket AD14-14.
[17] See Figure 3, Percent of Annual Uplift Credits Paid to 'Large Recipients' Plants, of FERC Staff Analysis of Uplift in RTO and ISO Markets, August 2014, Docket AD14-14.

Figure 3–33 SPP Market Participants Receiving Make-Whole Payments

Year	Participant Total MWP Category	Count of Participants	Share of Total MWPs
2015	Greater than $1 million	12	93%
First 10 Months of Market	Greater than $1 million	12	92%
2015	Greater than $5 million	5	65%
First 10 Months of Market	Greater than $5 million	6	71%
2015	Greater than $10 million	0	0%
First 10 Months of Market	Greater than $10 million	1	19%

3.6.1. Make-Whole Payment Allocation

The allocation of both Day-Ahead and Real-Time Make-Whole Payments has important consequences to the market. Uplift cost should be directed to those members that attributed to the need for the Make-Whole Payments.

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 withdrawals for the Operating Day. The average per-MWh rate for withdrawing locations in Day-Ahead Market was just under $.09.

For the Real-Time Market, Make-Whole Payment costs are distributed through a per-MWh rate that is assigned to all MWh(s) of deviation in the Real-Time Balancing Market, and had an average real-time distribution rate of $1.12 per MWh in 2015. There are eight categories of deviation and each category receives an equal amount per MW when the cost of Make-Whole Payments is applied. Even though each category of deviation is applied the same rate for deviation, approximately 76% of the Real-Time Make-Whole Payment costs were paid by entities withdrawing (physical or virtual) more MWs in the Real-Time Market than the Day-Ahead Market.

Figure 3–34 illustrates what deviation types are providing payment for Real-Time Make-Whole Payments.

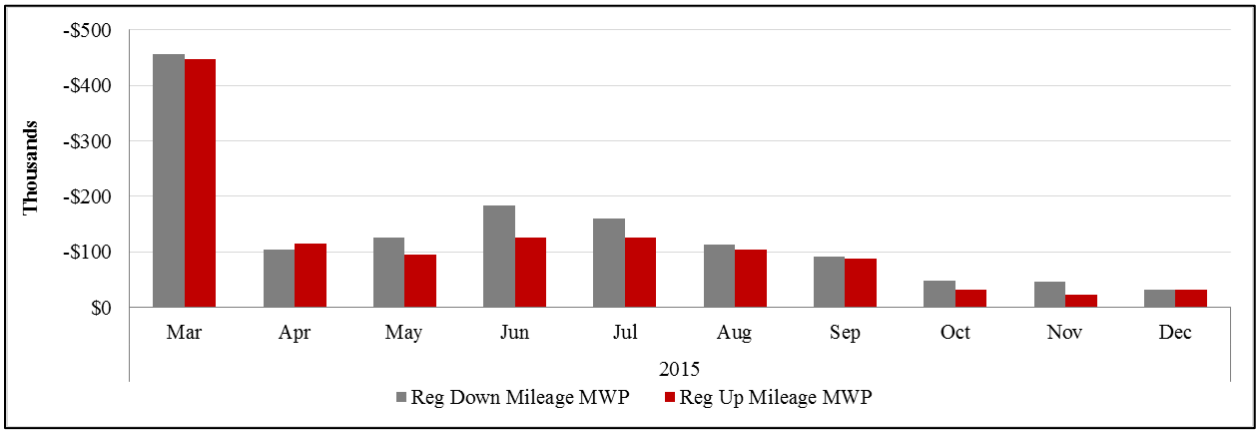
Figure 3–34 SPP Real-Time Make-Whole Payments by Market Uplift Allocations

Uplift Type	Uplift Charges (Thousands)	Share of Uplift Payments
Settlement Location Deviation	$28,822	75.68%
Outage Deviation	$4,318	11.34%
Status Deviation	$1,426	3.75%
Maximum Limit Deviation	$1,337	3.51%
Reliability Unit Commitment Self-Commit Deviation	$771	2.02%
Uninstructed Resource Deviation	$699	1.84%
Minimum Limit Deviation	$397	1.04%
Reliability Unit Commitment Deviation	$311	0.82%

3.6.2. Regulation Mileage Make-Whole Payments

In March of 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 Down Mileage at a rate that is in excess of the Regulation Up or Down Mileage Offer. Figure 3–35 illustrates both regulating products. The exorbitant amounts in March are due to the fact that the mileage factor in March was set to “1”. This means that the amount expected to be deployed for Regulation Compensation was 100% of what cleared, but actual deployment was approximately 20% of the cleared products. This caused units to buy back mileage at a rate higher than their cost of mileage, thus being entitled a Mileage Make-Whole Payment. The decrease in the Mileage Make-Whole Payments after October can be attributed to the correction of a settlement issue with how Mileage Make-Whole Payments’ Marginal Revenue was derived. The correction was retroactive, so there will be decreases to months prior to August once the resettlements occur.

Figure 3–35 SPP Real-Time Mileage Make-Whole Payments



3.6.3. 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.[18] 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
3) Make-Whole Payments for out of merit energy.

[18] See 144 FERC 61,068.

In 2014, MMU's recommendation 3 covered the following with regard to the manipulations of Make-Whole Payment Provisions:

- 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.
- Disqualify resources with fixed Regulation bids from receiving the Regulation Deployment Adjustment Charge.
- Utilize automatic mitigation provisions for local reliability commitments for local reliability OOME events.

In each case, a Market Participant has the ability to situate its resource to receive a Make-Whole Payment without economic evaluation of its offers by the market clearing engine. At the time of the preparation of this report, SPP has not closed the vulnerability gaps for any of the three issues, with the exception of rule changes that a self-committed resource is not recognized as eligible for a Make-Whole Payment if it changes to Market commitment status prior to the completion of its minimum run time.[19] SPP's Market Design Unit is currently working with the MMU to gather details behind each vulnerability and draft design changes for each provision.

The MMU continues to monitor the market for all three gaps. Exposures to all three vulnerabilities are still present; however, the MMU has not identified an OOME in the upward direction for a local event at this time. This is a necessary event for the exploitation of vulnerability gap number 3 concerning OOME Make-Whole Payments, stated above. Due to infrequency of these events, the MMU will continue to monitor the gap, but feels that there may not be a cost-benefit present to justify SPP addressing the issue via a design change at this time. However, the MMU fully feels that the issues concerning commitments across the midnight hour and the regulation deployment adjustment should be addressed as to remove the exposure of exploitation.

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

[19] See MRR 25/MPRR 211, Self-Commit Run Time Make-Whole Payment Exemption

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 the 2014 report was released, SPP was considering design alternatives through stakeholder process as follows:

- Remove the ability to manipulate Make-Whole Payments under the JOU Combined Resource Option and improve market efficiency in the JOU design.

At the time this report was released, SPP had approved but not implemented MRR127, a change in the market design to address this issue. The MMU review of this design indicates the change will address this vulnerability.

4. Day-Ahead Market

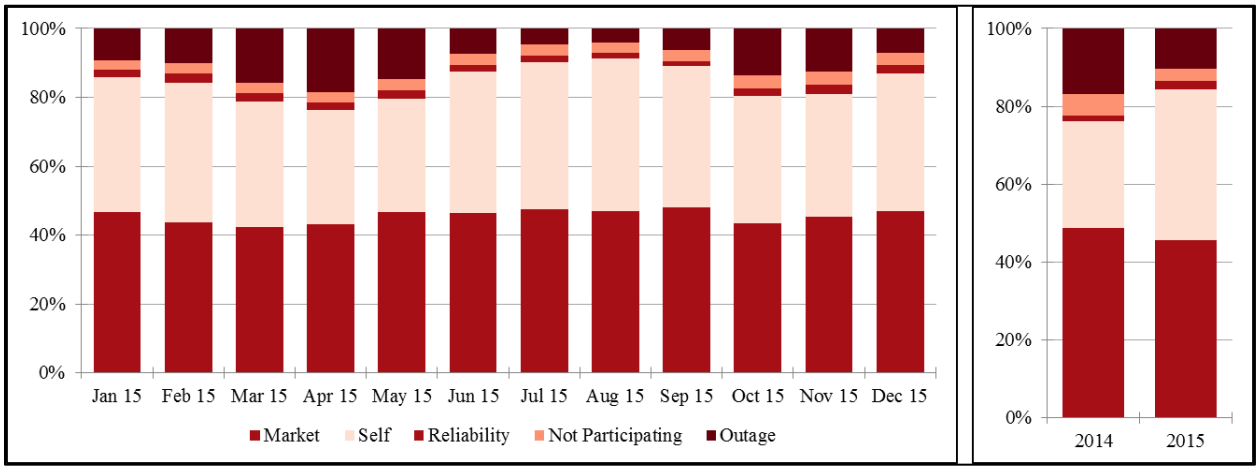
The Day-Ahead Market provides Market Participants with the ability to submit offers to sell Energy, Regulation-Up Service, Regulation-Down Service, Spinning Reserve, and Supplemental Reserve and/or to submit bids to purchase Energy.

4.1. Generation

In 2015 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 rivaled that of the Load-Serving Entities.

Figure 4–1 shows generation participation in the Day-Ahead Market by commitment status. The Market and Self-commit statuses averaged 83% of the total capacity for 2015, which is a significant increase from the 2014 average of 77%. Resources with commitment statuses of Reliability and Not Participating averaged 2% and 4%, respectively, which is close to what was experienced in 2014. Outage status accounted for the final 11%, a decrease from 16% in 2014. There was a substantial uptick in self-commitments from 2014. Much of the increase can be attributed to coal plants needing to burn coal stocks 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.

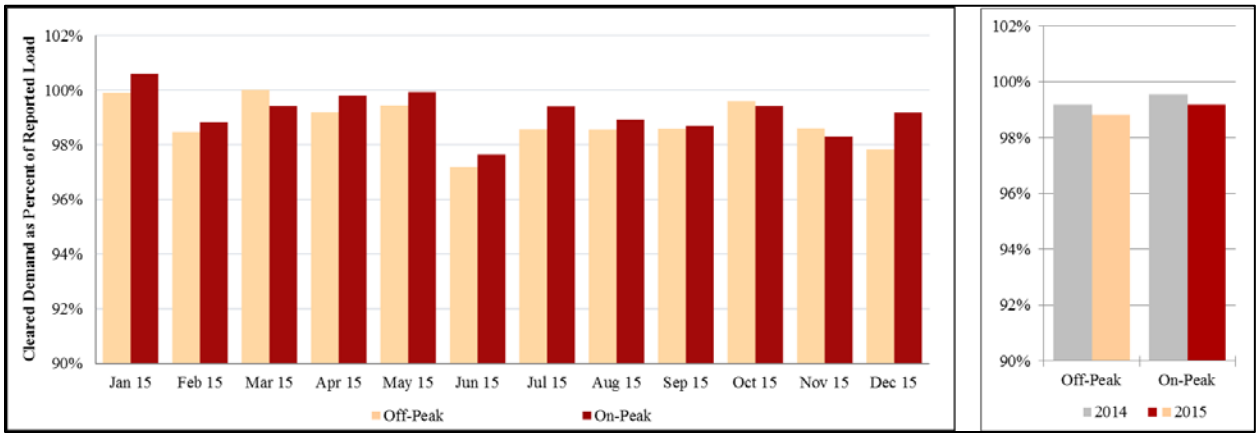
Figure 4–1 Day-Ahead Market Commitment by Status, 2015



4.2. Load

In 2015 load continued to participate in the Day-Ahead Market at high levels. Figure 4–2 shows the average monthly participation rates for the load assets on an aggregate level to be between 97% and 100% of the actual real-time load. On a disaggregated basis, we found a surprising result that several Market Participants cleared day-ahead load in excess of their real-time load. In some cases, day-ahead purchases have exceeded actual consumption by 10% for a month. This behavior is not consistent with a competitive energy market such that these large variations in cleared amounts of load between the DA Market and RTBM could be a contributing factor of not achieving the desired degree of convergence between DA and real-time LMPs. The MMU continues to evaluate this issue to determine the cause and whether there are any significant adverse impacts on the market.

Figure 4–2 Cleared Demand Bids in Day-Ahead Market



In 2014 the MMU recommended that the Over-Collected Loss Settlement Calculation be corrected to address design flaws that incented Load-Serving Entities to over-bid in Load in the Day-Ahead Market. In April 2015 MRR212 was implemented to correct the design flaw. Although there was some lag in the effects on the over-bidding, the design change appears to have driven the over-bidding down, as can be seen in Figure 4–2.

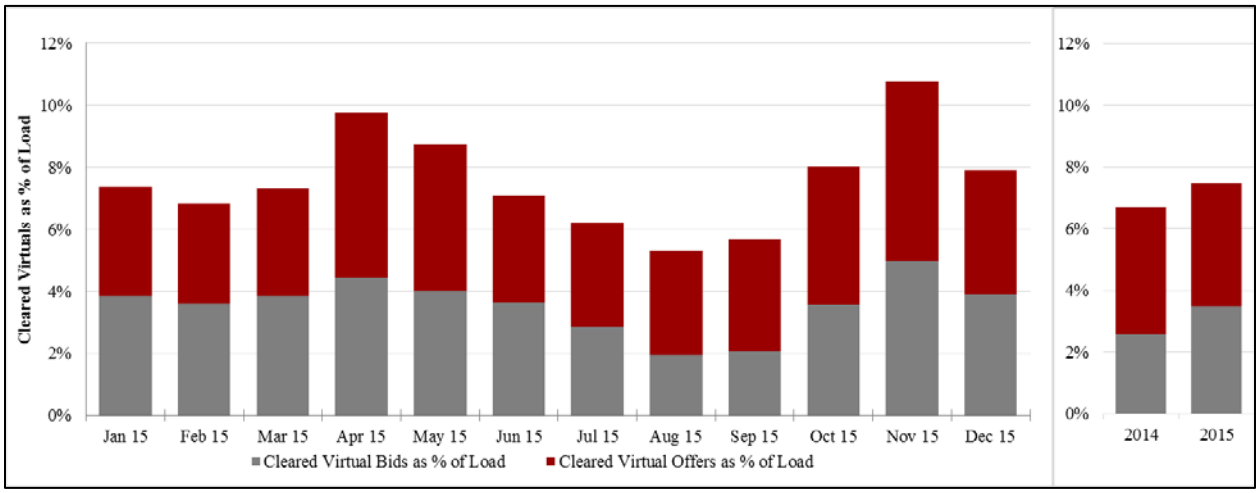
4.3. Virtual Trading

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 Balancing Market. These are referred to as "INCs," or increment offers that emulate generation. Virtual bids represent energy purchases in the Day-Ahead Market that the participant needs to sell back in the Real-Time Balancing Market. These are referred to as "DECs," or decrement bids that emulate load. The value of virtual trading lies in its potential to converge Day-Ahead and RTBM LMPs.

Convergence due to virtuals requires sufficient competition in virtual trading; transparency in Day-Ahead Market, RUC, and RTBM 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 of DA Market and RTBM LMPs. All these factors indicate a reasonably efficient virtual market.

Figure 4–3 displays the total volume of virtual transactions as a percentage of SPP market load. It averaged 7.5% for 2015, compared to 6.8% for the period of March through December of 2014. The increase was in cleared virtual bids, 2.6% compared to 3.5%, where virtual offers remained constant at 4%. In 2015 the monthly pattern of cleared virtuals realized the lowest percentages during the summer and the highest during the spring and fall. This pattern is consistent with what was seen in the first 10 months of the Integrated Marketplace in 2014.

Figure 4–3 Virtual Transactions as Percentage of SPP Market Load, 2014–2015

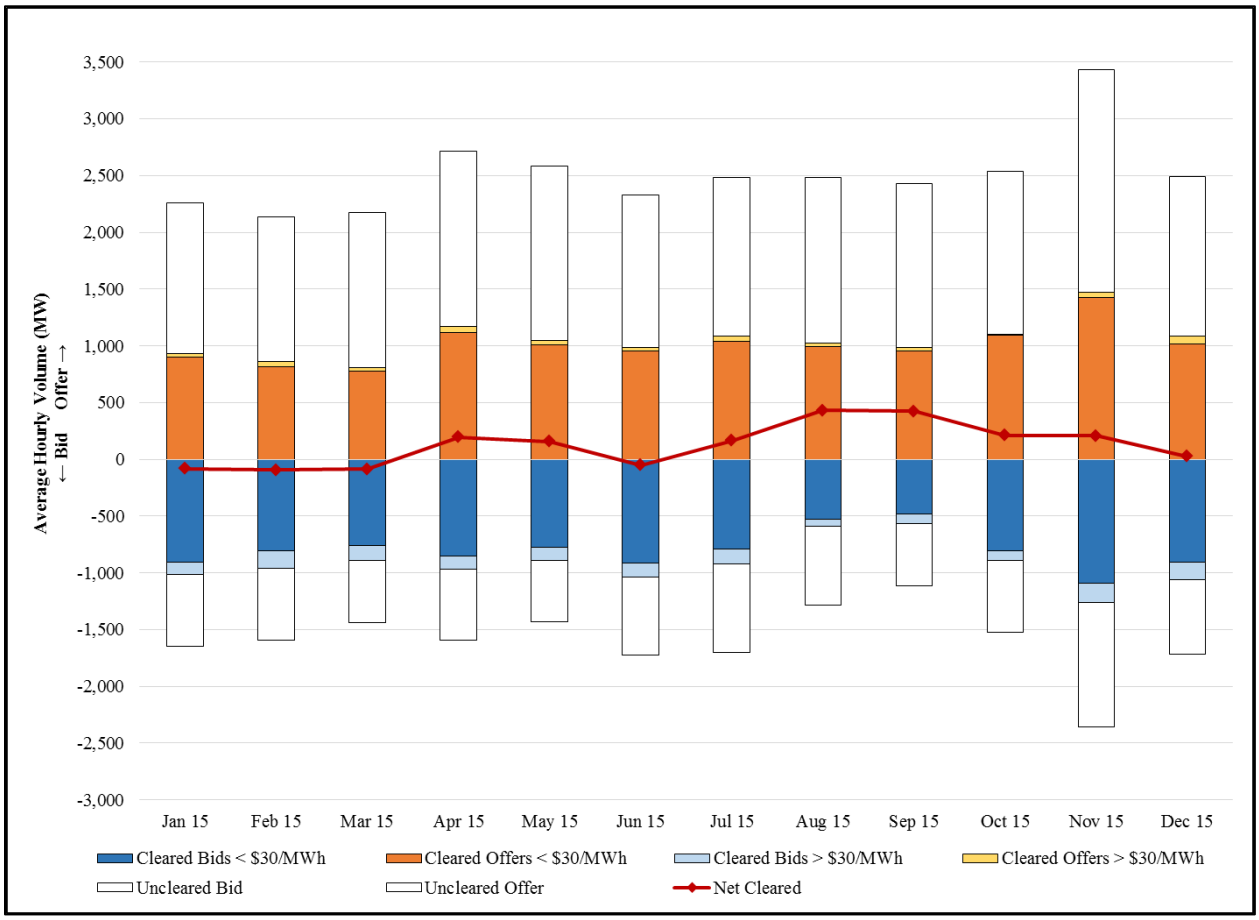


At about 7.5% of load, the average hourly total volume of cleared virtuals ranged from 1,550 to 2,735 MW. The average hourly volume that did not clear ranged from 1,911 to 3,059 MW. The net cleared virtual positions in the market averaged about 127 MW, indicating that virtual trading did not generally distort the relative DA Market to RTBM market load balance. As shown in Figure 4–3 above, the percentage of cleared virtuals was lowest during summer months. Figure 4–4 below indicates that bids (cleared and uncleared) realize more fluctuation during these summer months. November experienced the highest levels of virtual activity. This was the result of increased activity at Settlement Locations in the Integrated System, particularly in the congested North Dakota area.

Figure 4–4 also shows cleared demand bids that offered more than $30/MWh over the realized real-time LMP, and the supply offers offered at less than $30/MWh under the realized real-time LMP. These types of bids and offers are called “price-insensitive” and occur more often with

bids (13% of cleared) as opposed to offers (3.5% on average). 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 realizing 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.

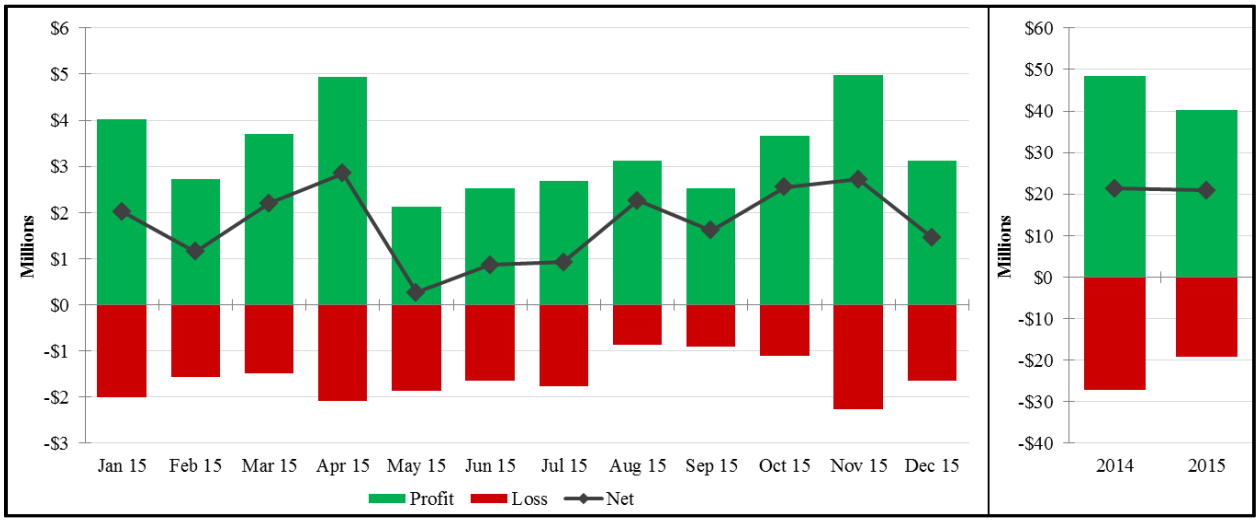
Figure 4–4 Virtual Offers and Bids in Day-Ahead Market, 2015



Virtual trades profited in aggregate for the year by about $20.8 million, which is down from the $21.2 million from the first 10 months of the Integrated Marketplace in 2014. Except for May 2014, net profitability has been positive each month since the start of the Integrated Marketplace,

with March and April 2014 being the highest with more than $4 million. Since March 2014, net monthly profitability averaged over $1.8 million ($1.7 million for 2015). Profitability trending lower reflects increased competition among traders and fewer systematic differences between the Day-Ahead Market and RTBM. The overall profitability in virtuals was concentrated with a few Market Participants, with the top 20% accounting for 83% of the total aggregate virtual profits.

Figure 4–5 Virtual Profit/Loss, 2015



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 TCR 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 TCR position. In the SPP Market, only three Market Participants lost more than $10,000 in 2015, with the most at just more than $30,000. This is substantially less than what was experienced in 2014 where three Market Participants lost more than $100,000. Additionally, few SPP Market Participants actively trade in both virtuals and TCRs, reducing the potential for cross-product manipulation.

4.4. Must-Offer Provision

4.4.1. Day-Ahead Must-Offer Overview

The Integrated Marketplace has a limited day-ahead must-offer provision that incentivizes load-serving entities to participate in the Day-Ahead Market. Market Participants that are non-compliant are assessed a penalty based on the amount of capacity offered into the Day-Ahead Market relative to the Market Participant's real-time consumption. 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, or provide scheduling information indicating a firm power purchase, to cover 90% of their real-time load, will not be subject to a penalty. An alternative way to satisfy the provision and avoid a penalty is to offer all generation that is not on an outage to the market.

4.4.2. Penalties for Day-Ahead Must-Offer Non-Compliance

During 2015 six penalties were assessed to three asset owners due to non-compliance with day-ahead must-offer rules. Human error and uncertainty of resource availability during transition from outage status were cited as reasons for non-compliance. Figure 4–6 shows the penalty assessments by month. Instances of non-compliance only occurred in April, May, and August.

Figure 4–6 Penalties for Non-Compliance with Day-Ahead Must-Offer Provisions, 2015

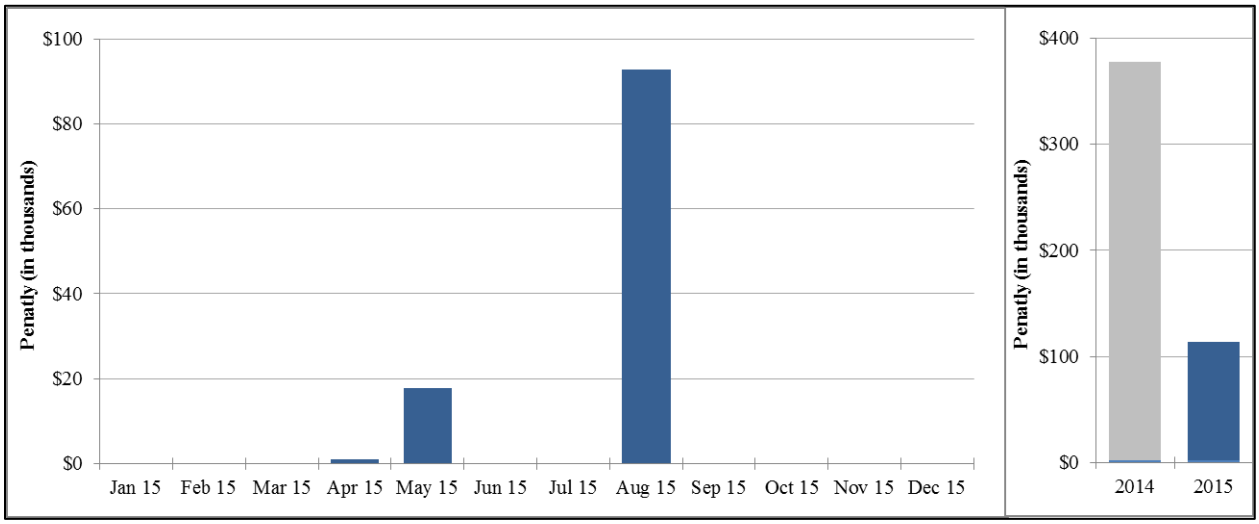
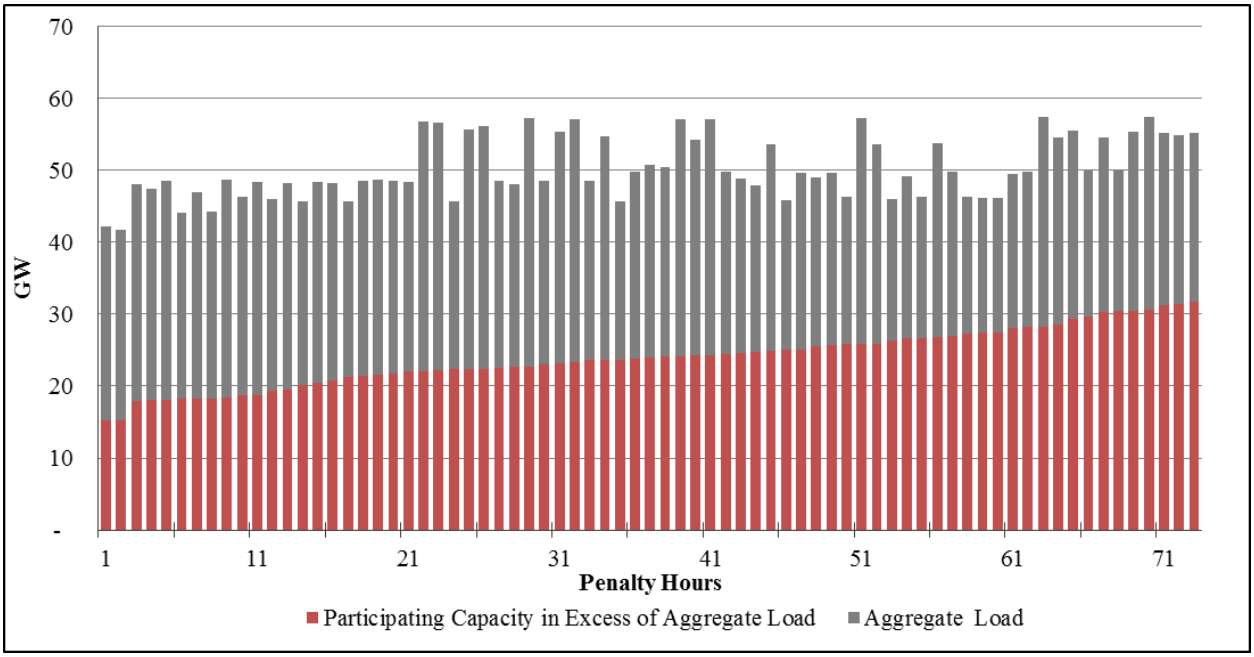


Figure 4–7 compares capacity offered into the Day-Ahead Market with the reported load during the 73 hours when at least one Market Participant was non-compliant. The days are sorted from lowest to highest excess capacity for each day. As can be seen, the lowest level of excess capacity was about 15,000 MW or about 36% of total offered capacity. The reserve obligation, which is not reflected in the chart, represents an additional 5% to 10% of reported load.

Figure 4–7 Offered Capacity and Reported Load during Non-Compliant Hours



4.4.3. Assessment

It is clear that participation in the Day-Ahead Market is robust, but it is not evident that this is due to the limited day-ahead must-offer provisions and the associated penalty for non-compliance. The Day-Ahead Market provides incentives for participation, especially for the Load-Serving Entities that hold transmission congestion rights as a hedge against congestion costs. Day-ahead positions for both generation and load assets reduce their exposure to volatile real-time prices. Since the beginning of the Integrated Marketplace, 99% of SPP's reported load clears in the Day-Ahead Market, incenting generation assets to offer into the Day-Ahead Market. Load participation did not drop off much due to the redesigned allocation of over-collected losses. Instead, it stayed at relatively similar levels as the participation prior to the change.

One other challenge to the necessity of the limited day-ahead must-offer provision is that the merchant generation participation levels are consistent with those of generation that has load obligations with one exception—that being the offer behavior for variable energy resources as expected.

Figure 4–8 shows the percentage participation by resource type, owner type, and commitment status. For the fossil fuel generation assets, there is very little difference in the participation measures for Load-Serving Entities and merchant owners when you aggregate the Market and Self Commitment statuses. Large coal and nuclear generation make up a large portion of the fossil fuel capacity for Load-Serving Entities and are more likely to use the Self Commitment status. The merchant generation owners do not have a day-ahead must-offer obligation and hence the 94% participation by merchant owners' fossil fuel generation is due to market incentives.

There does appear to be a significant difference in the participation of the merchant owners and Load-Serving Entities with respect to the variable energy resources. The merchant owners are 10 times more likely to put their variable energy resources in Not Participating status than the Load-Serving Entities. By not participating in the Day-Ahead Market, the merchants avoid the risk of having a day-ahead position on a resource with an uncertain level of generation. The MMU is concerned that the limited must-offer provision is affecting the behavior of the Load-Serving Entities by incentivizing them to take day-ahead positions on variable energy resources that would not otherwise occur in a competitive market.

Figure 4–8 Day-Ahead Participation

		Commitment Status				
Resource Type	Owner Type	Market	Self	Reliability	Not Participating	Outage
Fossil Fuel	Load-Serving Entity	44%	42%	3%	0%	11%
	Merchant	78%	16%	0%	0%	6%
Variable Energy Resource	Load-Serving Entity	53%	40%	0%	3%	4%
	Merchant	39%	8%	0%	32%	20%

The market forces appear to be incenting participation in the Day-Ahead Market. Load-Serving Entities are participating at levels well above that required by the limited day-ahead must-offer

provisions. The merchant generation is choosing to participate in the Day-Ahead Market at levels comparable to the Load-Serving Entities, and a very high level of load is clearing in the Day-Ahead Market without any rules governing the participation of load. The SPP Market Working Group has a pending revision request to remove the Day-Ahead Must-Offer provision.

4.4.4. Update on the 2014 Recommendation by the MMU on the Day-Ahead Must-Offer Requirement Provision

In 2014 the MMU recommended that SPP 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 the meantime, the MMU submitted a proposal that introduced conduct thresholds and impact test requirement for physical withholding penalties in conjunction with establishing a formula-based penalty structure.[20] The MMU engaged in discussions with the Market Participants through May 2016, at which time the MMU decided to withdraw its proposal and perform studies including simulations regarding implementation and impact of the new proposal on the marketplace.[21] The MMU plans to bring back its proposal to Market Participants as early as the intended work is completed.

Similarly, in 2014 the MMU made the assessment that in the event the limited must-offer provision is continued, five weaknesses in the current provisions should be addressed, which still remain valid:

1) A Market Participant with load assets can avoid a day-ahead must-offer obligation entirely by registering its load assets and generation assets under different asset owners.
2) There is no requirement or incentive for an SPP Market Participant with a day-ahead must-offer obligation to report a firm power sale. For example, in the case that the

[20] The MMU submitted RR135-Revision of Physical Withholding Rules to the MWG in December 2015.
[21] The Market Working Group (MWG) approved Revision Request (RR)-125 Removal of Day-Ahead Limited Must-Offer in November 2015 and Markets and Operations Policy Committee (MOPC) tabled it in July 2016 until July 2017 or the MMU's resubmission of RR135.

purchaser is an SPP Market Participant that chooses not to report the purchase, the seller is not required to inform SPP or the MMU of this transaction and it may not be properly accounted for with respect to the seller's day-ahead must-offer obligation.

3) The current design forces Market Participants to take a day-ahead position on Variable Energy Resources. These resources should be exempted from the must-offer requirement.

4) There is no automated link between the must-offer penalty calculation and the generation outages system. The current system is reliant on the Market Participant correctly report the outage in the day-ahead market offer submissions.

5) The non-controlling asset owner of a jointly owned resource is at risk of being non-compliant if the controlling asset owner chooses to put the resource in Not Participating status.

5. Congestion and Losses

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)

Thus,

$$LMP = MEC + MCC + MLC$$

Locational prices are a key feature of electricity markets, providing price signals that ensure the efficient scheduling, commitment, and dispatch of generation in the presence of reliability constraints and efficient incentives for future investment. This section describes the many aspects of LMP as:

- 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
- Distribution of marginal congestion and loss revenues

5.1. Geographic Pricing Patterns

Figure 5–1 and Figure 5–2 are price contour maps showing the Day-Ahead Market and Real-Time Balancing Market average LMPs in 2015. The annual average Day-Ahead Market LMP ranges from $17/MWh–19/MWh in most of the Dakotas and Western Nebraska, to $40/MWh in the Woodward area of Northwest Oklahoma. With the exception of the Northern area of North

Dakota, the newly added Integrated System observed LMPs toward the lower range. The year 2015 continued to see a higher LMP ($28/MWh) in the New Mexico and lower Texas Panhandle area. About 76% of this price variation is due to congestion and 24% is due to marginal losses. There are more hours with congestion in the Day-Ahead Market than in the RTBM because the DA Market uses the transmission system more extensively than the RTBM. Congestion events are more volatile in the RTBM so the average geographic price range is slightly higher, $16/MWh–$41/MWh for RTBM LMPs versus $18/MWh–$35/MWh for DA LMPs.

Figure 5–1 Average LMP for Day-Ahead Market, 2015

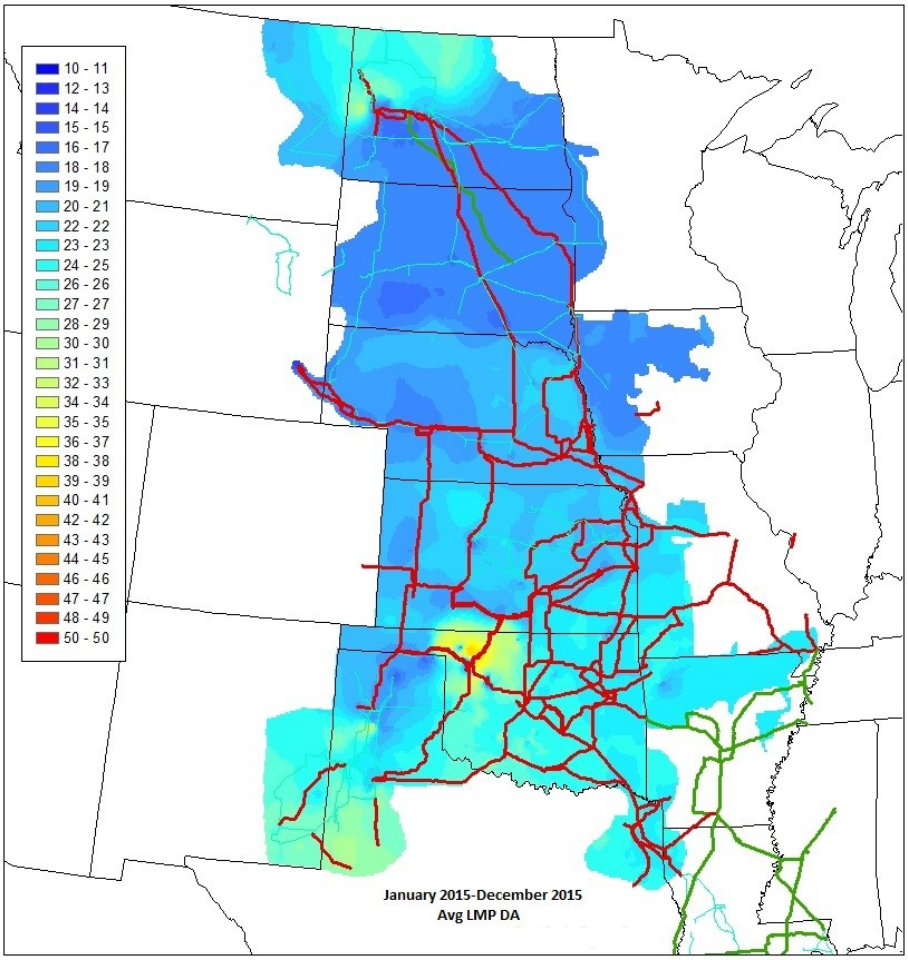
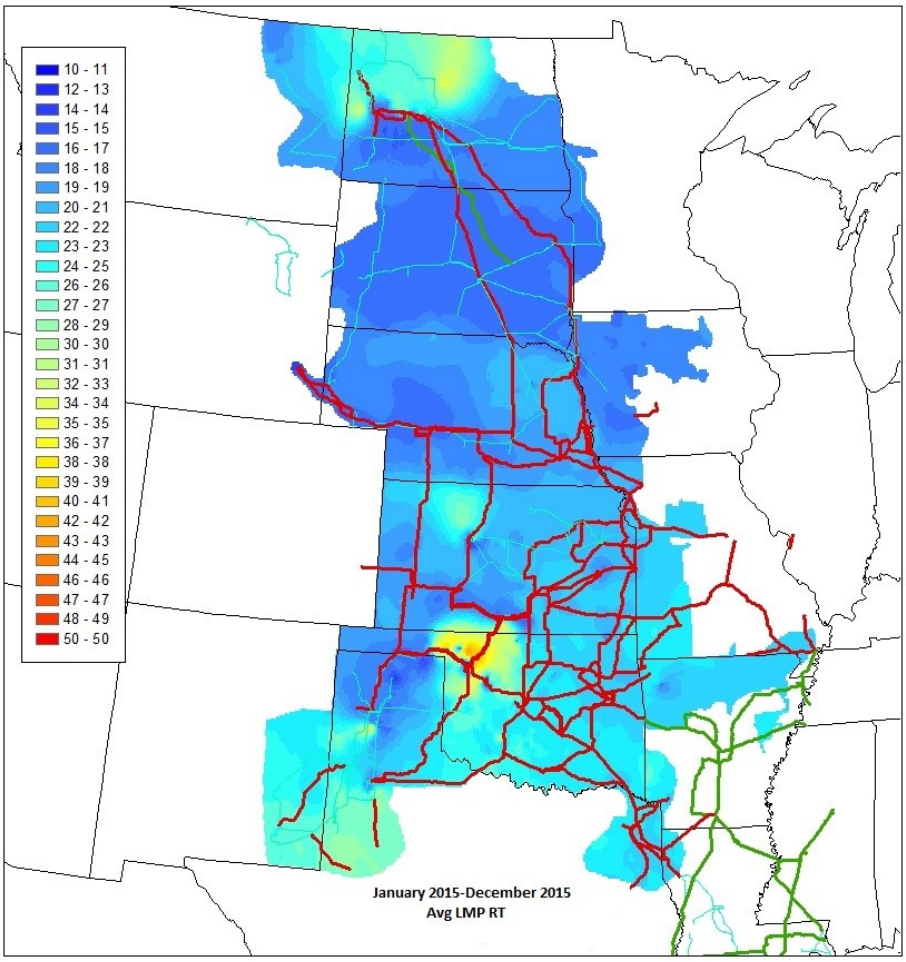


Figure 5–2 Average LMP for Real-Time Balancing Market, 2015



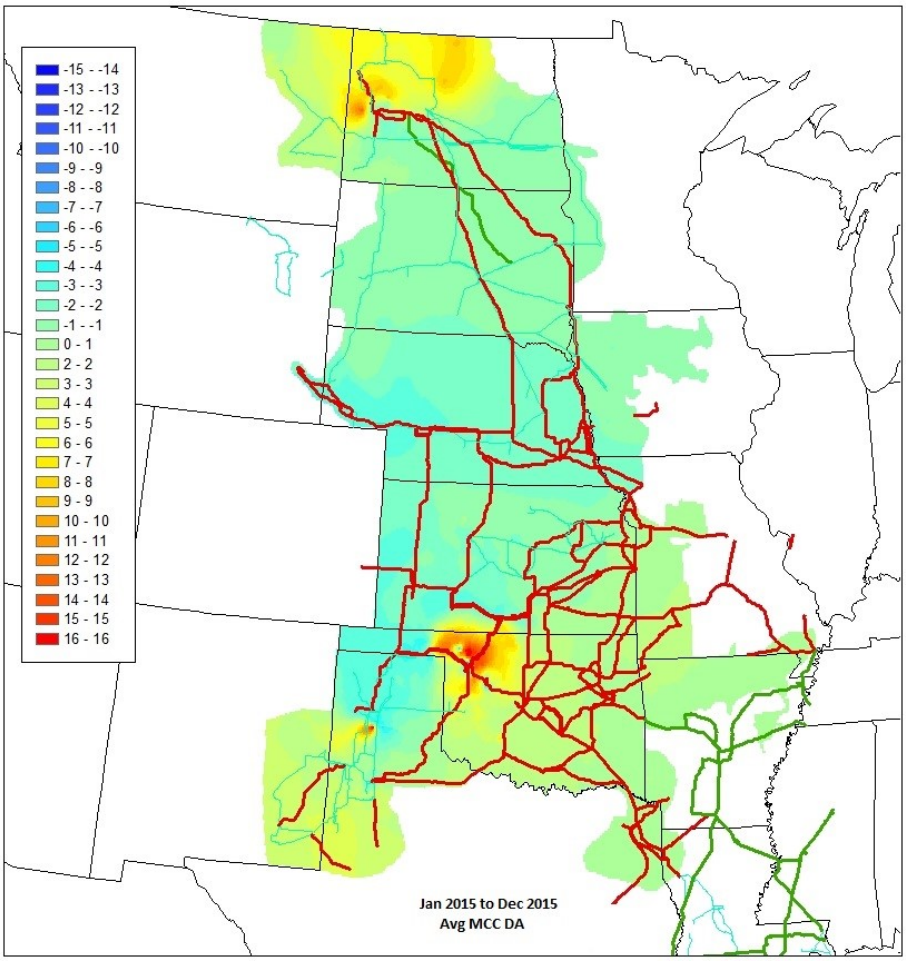
5.2. Congestion by Geographic Location

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, 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 (55% in 2015), rises with distance from the Wyoming Powder River Basin, which is near the northwest corner of SPP's footprint. The cost of natural gas, SPP's largest fuel type by installed capacity measures (42% in 2015) rises in the opposite direction, from the southeast to

the northwest. Wind-powered generation lies in the western half of the footprint, and nuclear generation resides in the northeast. These factors combine to create a general northwest-southeast split in LMPs. The exception is higher prices in the north 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 LMPs compared to the rest of the footprint.

Figure 5–3 depicts the average Marginal Congestion Component (MCC) of LMPs by settlement location for the Day-Ahead Market. The lowest MCCs occur in the Oklahoma and Texas Panhandles, at -$6/MWh, and the highest MCCs lie in the Woodward, Oklahoma area at $16/MWh, the northern area of North Dakota at $8/MWh, and the New Mexico and western Texas areas at $5/MWh. This congestion cost pattern is similar to what was experienced in the first year of the Integrated Marketplace in 2014, though the Woodward area was significantly higher in 2015. The Woodward area congestion cost was higher in 2015 even though overall market prices were lower than the previous year.

Figure 5–3 Average MCC for Day-Ahead Market, 2015



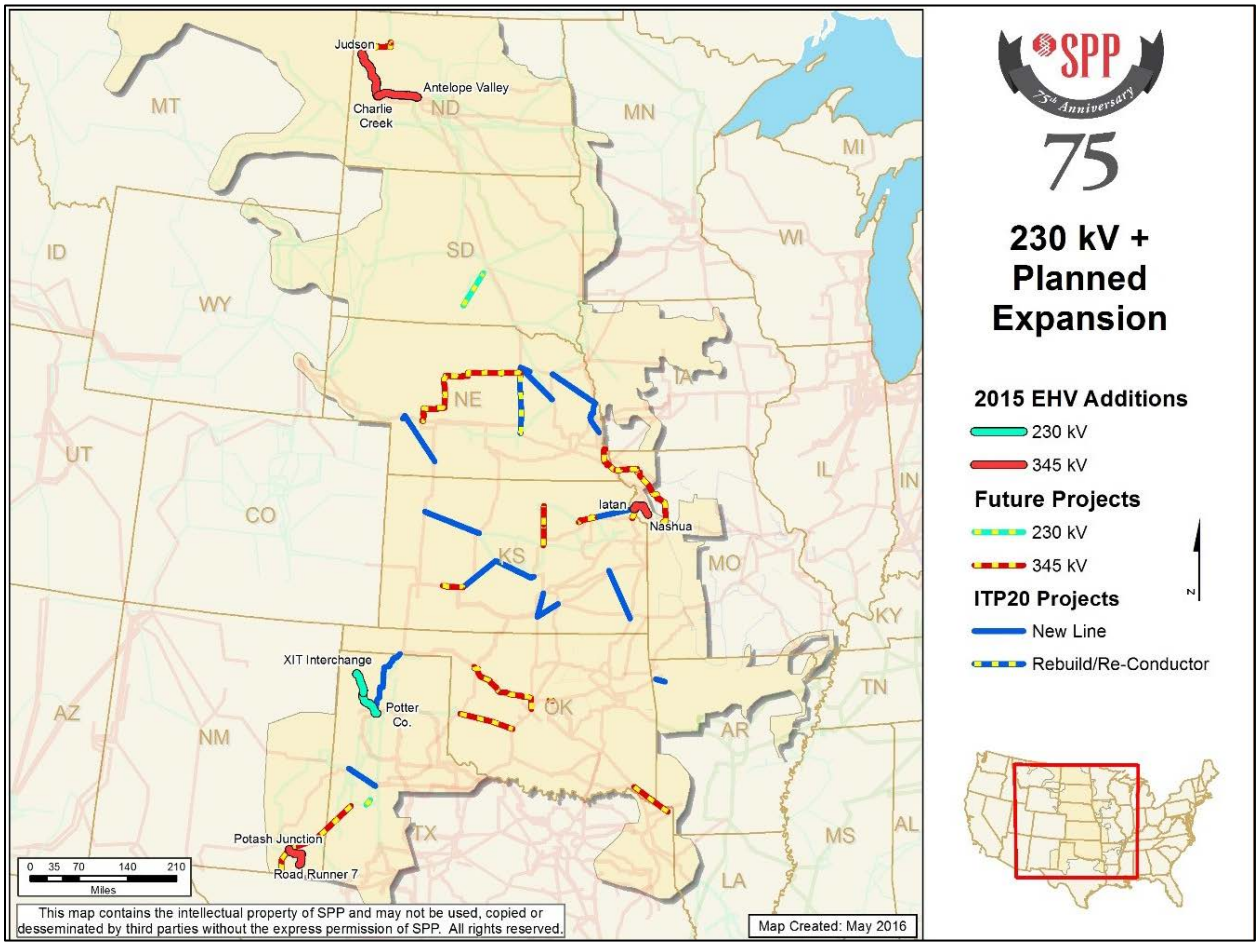
SPP energized major transmission projects in 2014 that allowed for increased transfer of inexpensive wind generation from the west. These impacts were observed when analyzing congestion, losses, and Frequently Constrained Areas for 2015. The projects energized in 2015 are shown in Figure 5–4. New 345 kV lines brought into service are depicted in solid red and 230kV in solid green.

- Nashua 345kV Project
  - Energized: April 2015
  - Nashua 345/161kV transformer and tap between St. Joseph and Hawthorn 345kV
- Iatan – Nashua 345kVPotash Junction – Road Runner 345kV
  - Energized: October 2015

- Judson – Charlie Creek – Antelope Valley 345kV
  - Energized: December 2015
- XIT Interchange – Potter Co. 230kV
  - Energized: December 2015

The other lines depicted on the map are planned projects that will further support the efficient transmission of energy across the SPP footprint.

Figure 5–4 SPP Transmission Expansion Plan, May 2016 Map

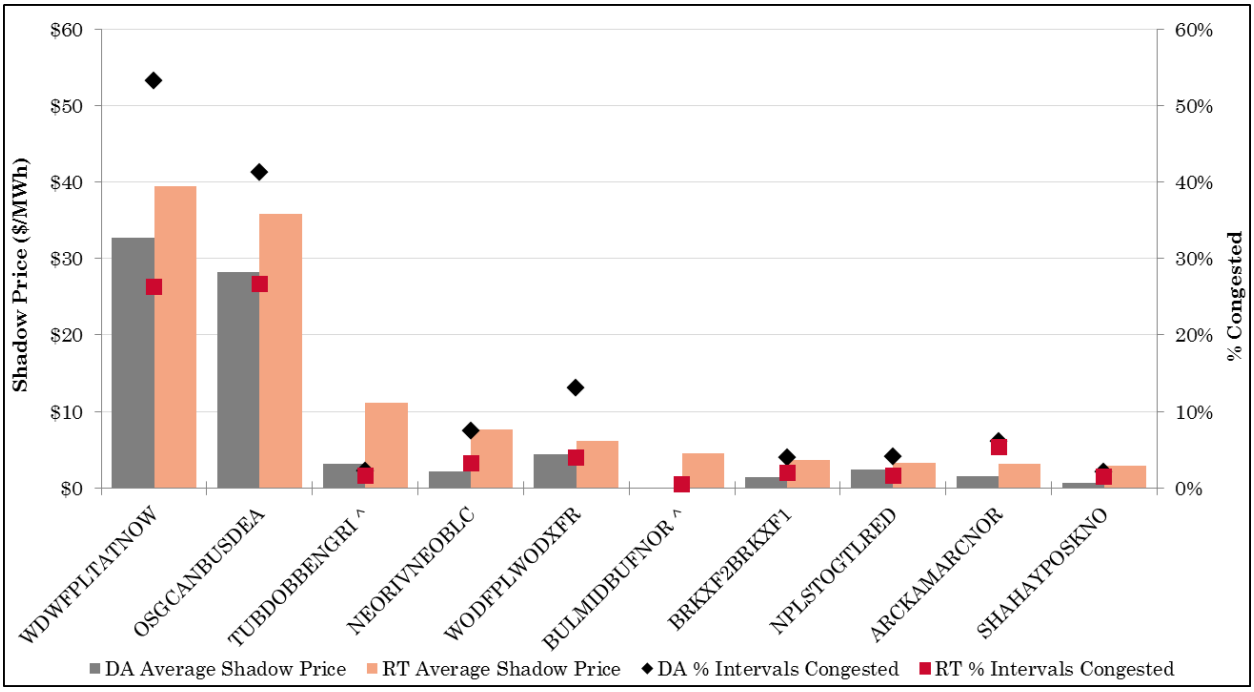


5.3. Transmission Constraints

Market congestion reflects the economic dispatch cost of honoring transmission constraints. SPP utilizes 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 MW for one hour. Figure 5–5 provides the top 10 flowgate constraints by shadow price for 2015.

Figure 5–5 SPP Congestion by Shadow Price, 2015



% Intervals Congested includes both breached and binding intervals

Flowgate Name	Region	Flowgate Location
WDWFPLTATNOW	Western Oklahoma	Woodward-FPL Switch (138) ftlo Tatonga-Northwest (345)
OSGCANBUSDEA	Texas Panhandle	Osage Switch-Canyon East (115) ftlo Bushland-Deaf Smith (230)
TUBDOBBENGRI ^	East Texas	Tubular-Dobbins (138) ftlo Dobbin-Grimes (138)
NEORIVNEOBLC	SE Kansas	Neosho-Riverton (161) ftlo Neosho-Blackberry (345)
WODFPLWODXFR	Western Oklahoma	Woodward-FPL Switch (138) ftlo Woodward Xfmr (138/69)
BULMIDBUFNOR ^	Arkansas-Missouri border	Bull Shoals-Midway (161) ftlo Buford-Norfork (161)
BRKXF2BRKXF1	SW Missouri	Brookline Xfmr 2 (345/161) ftl Brookline Xfmr 1 (345/161)
NPLSTOGTLRED	Western Nebraska	North Platte-Stockville (115) ftlo Gentleman-Red Willow (345)
ARCKAMARCNOR	Oklahoma	Arcadia-Jones KAMO (138) ftlo Arcadia-Northwest Station (345)
SHAHAYPOSKNO	Central Kansas	South Hays-Hays (115) ftlo Knoll Xfmr (230/115)

^ 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, OK area and the north-to-south flows through the Texas Panhandle. Both areas are significantly impacted by inexpensive wind generation in that region

of the market. The Woodward, OK and surrounding areas had extensive 345kV buildouts energized in 2014, allowing higher transfers of wind generation to the more populated and high-cost eastern portion of SPP. The Texas Panhandle corridor relies mainly on 230 kV transmission lines between Amarillo and Lubbock, TX. The transmission corridor is impacted by the predominantly gas-fired generation in the south that is more expensive than wind generation to the north. It is important to note that the Woodward and Texas Panhandle constraints occur in over 25% of RTBM intervals and over 40% in the Day-Ahead Market. The next highest constraints occur in only 5% of RTBM and 7% of Day-Ahead Market. The Woodward, OK and surrounding areas had extensive 345kV buildouts energized in 2014, allowing higher transfers of wind generation to the more populated eastern portion of SPP where more expensive gas and coal-fired generation reside.

A notable constraint missing from the 2015 list is the Kansas City area constraint Iatan – Stranger Creek 345kV for the loss of St. Joe – Hawthorn 345kV. The Nashua 345kV tap between St. Joe – Hawthorn energized in April 2015 and the Iatan – Nashua 345kV line energized in May 2015 appear to have alleviated much of the loading in this area.

5.3.1. Texas Panhandle

The Texas Panhandle area from Lubbock southwest into southwest New Mexico has historically been the most congested transmission corridor in the SPP Market. In 2015 it was the second most congested area, which is represented by the high shadow price on the Osage Switch-Canyon East Flowgate. The 2015 RTBM shadow price for this flowgate was about $36/MWh compared to about $80/MWh in 2014 and about $44/MWh in 2013. The Day-Ahead Market also realized a decrease from about $73/MWh for the first 12 months of the Market to $28/MWh in 2015. 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.

Upgrades to the transmission system in the last three years that have helped address the congestion in the Texas Panhandle area are:

- 230 kV line from the Randall County Interchange to the Amarillo South Interchange, energized in April 2013, has eliminated the SPS North-South constraint from the top ten flowgate list
- 345 kV line from the Tuco Interchange to Woodward, OK, energized in September 2014

5.3.2. Western Oklahoma

The most significant change to the SPP transmission system in 2014 and 2015 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 average Woodward-FPL Switch Flowgate shadow price for 2014 was about $19/MWh and increased to about $39/MWh in 2015 even though overall electric price declined about 30%.

The west-east price differentials in this area create a transmission bottleneck at Woodward, as indicated by two of the top 10 flowgates. The Woodward to FPL Switch 138kV for the loss of Tatonga to Northwest 345kV had the highest shadow price, at $39/MWh in the RTBM and $33/MWh in the Day-Ahead Market. This compares to $21/MWh and $14/MWh in 2014 for RTBM and Day-Ahead, respectively. The Woodward to FPL Switch for the loss of Woodward 138/69kV transformer also appears in the top 10 congested constraints for 2015 with a shadow price of $6/MWh in the RTBM and $4/MWh in the Day-Ahead Market. There is further expansion planned in the Western Oklahoma area that provides for more transfer of wind generation from west to east and is listed in Figure 5–6.

5.3.3. Southeast Kansas – Southwest Missouri

The Neosho – Riverton 161kV for the loss of Neosho – Blackberry 345kV in SE Kansas and the Brookline 345/161kV #2 transformer for the loss of Brookline 345/161 #1 transformer in SW

Missouri have several factors that can lead to loading in these areas. Loading in NW Arkansas and SW Missouri, high exports, and limited hydro and Springfield generation can lead to these constraints becoming congested. In 2015 the NEORIVNEOBLC flowgate saw about $8/MWh average shadow price in the RTBM and $2/MWh in the Day-Ahead Market. This compares to $6/MWh and $2/MWh in 2014.

5.3.4. Planned Transmission Projects

Figure 5–6 provides a detailed list of projects expected to alleviate congestion on the SPP system.

Figure 5–6 Congestion by Shadow Price with Projects

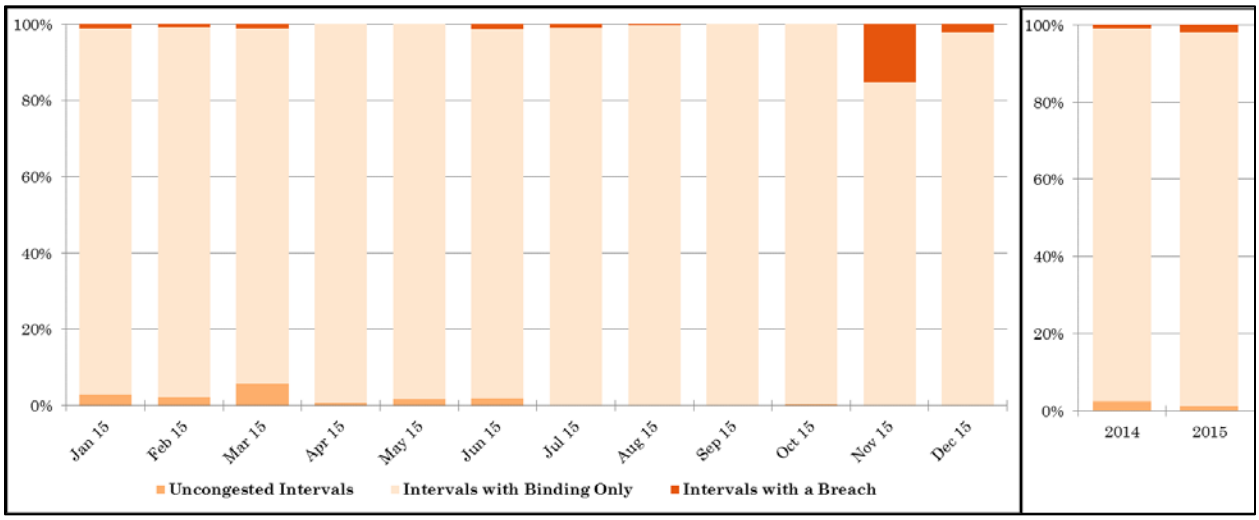
Flowgate Name	Region	Location	Projects that may provide mitigation
WDWFPLTATNOW	Western Oklahoma	Woodward – FPL Switch (138) ftlo Tatonga – Northwest (345)	Matthewson – Tatonga 345 kV Ckt 2 (June 2017 – ITP10)
OSGCANBUSDEA	Texas Panhandle	Osage Switch – Canyon East (115) ftlo Bushland – Deaf Smith (230)	Canyon East Sub – Randall County Interchange 115 kV line (March 2018 – Aggregate Studies)
TUBDOBBENGRI ^	Entergy – East Texas	Tubular-Dobbins (138) ftlo Dobbin-Grimes (138)	No projects identified at time of report publication.
NEORIVNEOBLC	SE Kansas	Neosho – Riverton (161) ftlo Neosho – Blackberry (345)	No projects identified at time of report publication.
WODFPLWODXFR	Western Oklahoma	Woodward-FPL Switch (138) ftlo Woodward Xfmr (138/69)	1. Matthewson – Tatonga 345 kV Ckt 2 (June 2017 – ITP10) 2. Woodward – Tatonga 345 kV Ckt 2 (March 2021 – ITP10)
BULMIDBUFNOR^	Arkansas-Missouri border	Bull Shoals-Midway (161) ftlo Buford-Norfork (161)	No projects identified at time of report publication.
BRKXF2BRKXF1	SW Missouri	Brookline Xfmr 2 (345/161) ftlo Brookline Xfmr 1 (345/161)	No projects identified at time of report publication.
NPLSTOGTLRED	Western Nebraska	North Platte-Stockville (115) ftlo Gentleman-Red Willow (345)	1. Gentleman – Cherry Co. – Holt 345 kV (June 2018 – ITP10) 2. Thedford 345/115 kV transformer (June 2018 – HPILS)
ARCKAMARCNOR	Oklahoma	Arcadia-Jones KAMO (138) ftlo Arcadia-Northwest Station (345)	No projects identified at time of report publication.
SHAHAYKNOXFR	Central Kansas	South Hays – Hays (115) ftlo Knoll Xfmr (230/115)	Hays Plant – South Hays 115 kV Ckt 1 (June 2016 – ITPNT)

^ *MISO Market-to-Market flowgate*

5.4. 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 was best seen in the Day-Ahead Market (see Figure 5–7), where uncongested market time intervals and breached intervals are rare. Only 2% of Day-Ahead Market intervals incur a breached condition compared to 16% for RTBM since the start of the Integrated Marketplace.[22] The high price resulting from breached conditions is consistent with the objective of promoting reliability. A notable exception to very low breaches in the Day-Ahead Market was November 2015, which experienced 15% of Day-Ahead Market intervals with breaches mainly due to a MISO constraint in the central Louisiana area. Discussions of Market-to-Market coordination with MISO and its impacts are in Section 5.10.

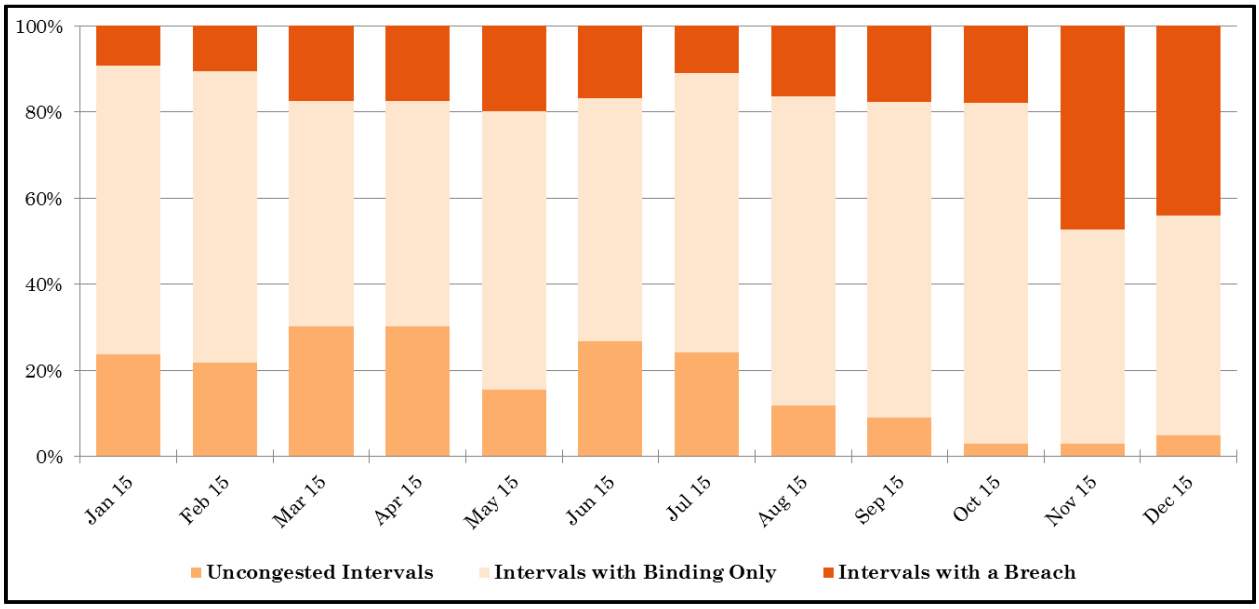
Figure 5–7 Congestion – Breached and Binding Intervals for Day-Ahead Market, 2014–2015



In the less controlled environment of the Real-Time Balancing Market, uncongested intervals were about 17% of all time intervals, and intervals with a constraint breach were at 20% for 2015, as shown in Figure 5–8.

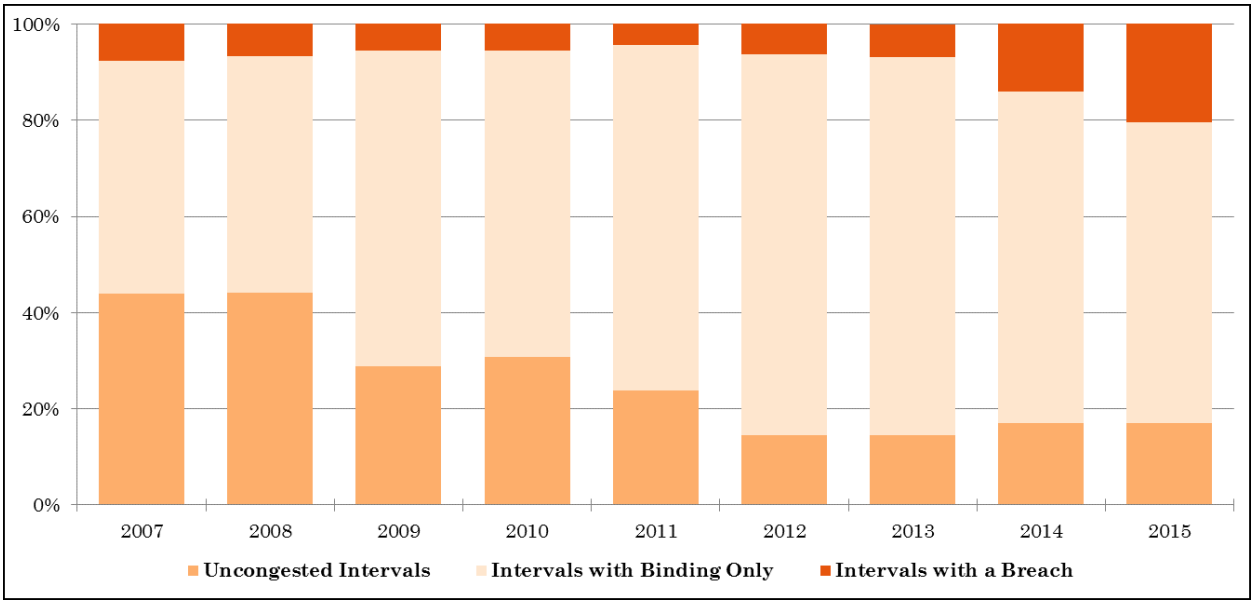
[22] SPP uses hourly intervals in the Day-Ahead Market and 5-minute intervals in the RTBM for scheduling, dispatch, and settlement purposes.

Figure 5–8 Breached and Binding Intervals for Real-Time Balancing Market, 2015



Since the start of the EIS market in 2007, SPP has made increasingly efficient use of the transmission grid. Figure 5–9 shows this trend over time for RTBM in the EIS and Integrated Marketplace. In 2007 the market experienced no congestion in more than 40% of all market intervals. Uncongested intervals have been below 20% since 2012 with the integration of Nebraska in 2009. 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 was implemented in March 2015 and the integration of the IS occurred in October, 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. In 2014 the instances of breaches were largely driven by one flowgate, OSGCANBUSDEA; see Section "5.3.1 Texas Panhandle". This flowgate still appears in 2015 but WDWFPLTATNOW (see Section "5.3.2 Western Oklahoma") now accounts for most breaches in the RTBM. This frequent occurrence is reflected with it being the primary constraint for the newly created Frequently Constrained Area, Woodward, (Section 5.5) starting in 2016.

Figure 5–9 Breached and Binding Intervals for RTBM Annual Comparison, 2007–2015



5.5. 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. Competitive Assessment". 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.

The SPP Tariff calls for more stringent market power mitigation for Frequently Constrained Areas (FCAs), and the MMU analyzes market data at least annually to assess the appropriateness of the FCA designations. In 2014 the MMU found that two of the three previously identified FCAs no longer required the designation.[23] In 2015, the MMU conducted the annual frequently constrained area (FCA) study and recommended the Texas Panhandle area maintain the designation as an FCA and that the Woodward area be designated as a new FCA. SPP filed a

[23] See Southwest Power Pool Frequently Constrained Areas – 2014 Study, January 2015, FERC Docket ER15-1049.

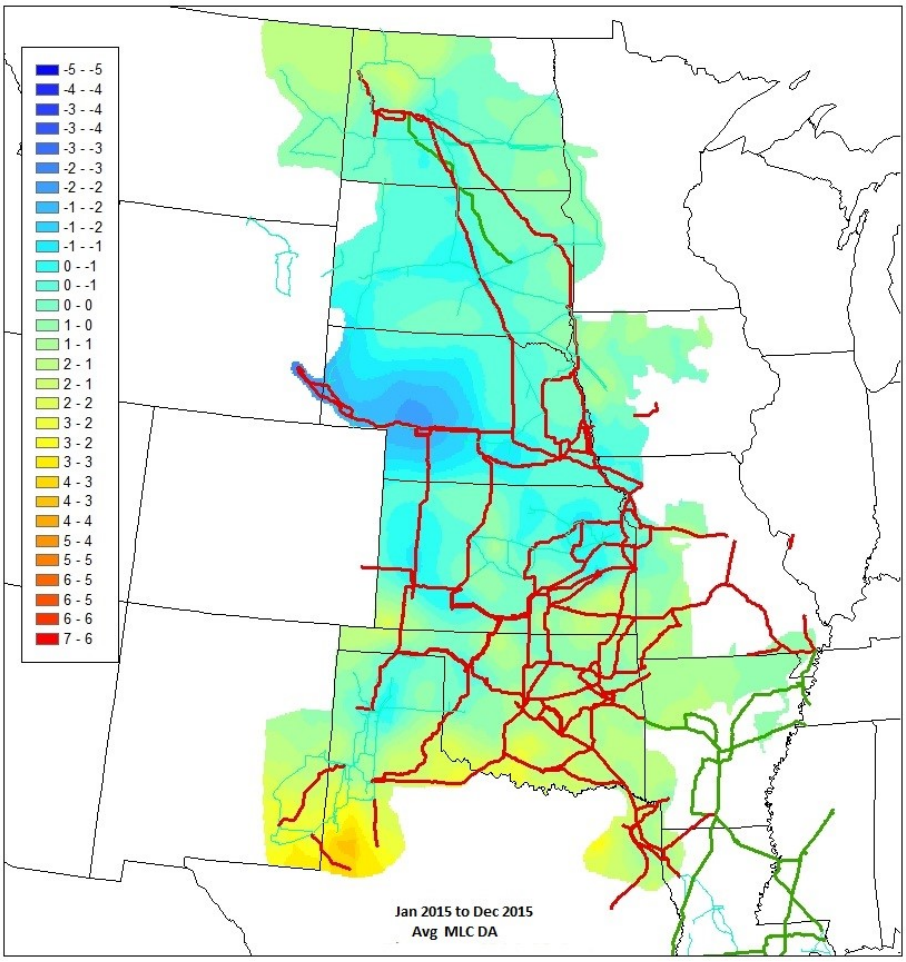
report with FERC on February 5, 2016 and the new FCA designations were effective April 5, 2016. The complete report is available on the SPP web page.

5.6. Geography and Marginal Losses

Variable transmission line losses decrease with increased line voltage or decreased line length for the same amount of power moved. In the SPP footprint, much of the low cost generation resides at a distance from the load and with limited high voltage interconnection. The average variable losses on the SPP system for 2015 were 2.4%. The Marginal Loss Component (MLC) of the LMP captures the change in the total system cost of losses with an additional MW of load at a particular location, relative to the load-weighted (reference) center of the market.

Figure 5–10 maps the annual average Day-Ahead Market MLCs. The average day-ahead MLC ranges from about -$3/MWh near North Platte, Nebraska, to -$2.6/MWh at the Laramie River Station in Eastern Wyoming, to zero in the Kansas City areas, to $1/MWh in the Hobbs, New Mexico area, and up to $2.40/MWh in the southeast corner of New Mexico.

Figure 5–10 Annual MLC Map – Day-Ahead Market, 2015



The loss component of LMP is a significant contributor to SPP prices. As stated in last year's report, the building of new transmission in 2014 appears to have reduced the marginal cost of providing energy from Western Nebraska and Kansas. The 345 kV lines from Spearville to Thistle in Western Kansas, and from Thistle to Woodward, OK, provided west-east connections in December 2014. The year 2015 did not have the level of transmission expansion seen in 2014, with 345Kv lines added in Western North Dakota, Eastern Kansas, and North Texas and Southeast New Mexico, causing some reduction in losses in those areas starting mid-2015. MLCs were down across the footprint. This reduction is attributed to the lower cost of those lost MW stemming from lower gas prices in the market.

5.7. Congestion Hedging and Revenue Distribution

Prior to the introduction of the Integrated Marketplace, SPP Load-Serving Entities scheduled energy delivery from generation to load with no additional market charges above the cost of transmission service. In the Integrated Marketplace, the market generally charges load a higher LMP than it pays generation, as illustrated in the geographic congestion patterns described above. Transmission service, no longer used for internal scheduling, now serves as the underpinning of the Transmission Congestion Rights (TCR) Market, which provides Day-Ahead Market payments to hedge the cost of congestion. Annual and monthly TCR auctions award the "rights" to shares of Day-Ahead Market congestion revenue. SPP allocates Auction Revenue Rights (ARRs) in annual and monthly processes based on transmission ownership, and ARR holders receive payments from the auction revenue that offset the cost of TCR purchases and conversions of ARRs into TCRs.

The purpose of the TCR 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 TCR market is expressed by the degree to which TCRs and ARRs provided a congestion hedge to load customers as well as the efficiency of the market. As in any market, efficiency means that the market maximizes the total benefits to all Market Participants. In an efficient market, prices signal the marginal value of the product, which requires competition and transparency of information. The degree to which Day-Ahead Market congestion revenues sufficiently fund the TCRs awarded in the TCR auctions serves as a measure of load hedging, market efficiency, and transparency.

At an aggregate level, the SPP load was hedged for the explicit congestion costs paid in the Day-Ahead Market and Real-Time Balancing Market in the first year of the market. Figure 5–11 provides the aggregate congestion costs and hedging totals for Load-Serving Entities (LSEs) and non-LSEs. It shows that the total of all TCR and ARR net payments to LSEs of $168 million exceeded the total Day-Ahead Market and RTBM congestion costs of $152 million. In aggregate, non-LSEs pay Day-Ahead Market congestion and receive RTBM congestion rents.

The net payments of $8.6 million are in addition to the total TCR market net payments of $12 million. The aggregate numbers do not reveal the underlying variation among Market

Participants. There are both winners and losers in SPP Market congestion costs among both groups of Market Participants.

Figure 5–11 Total Congestion Payments for Load-Serving Entities and Non-Load Entities

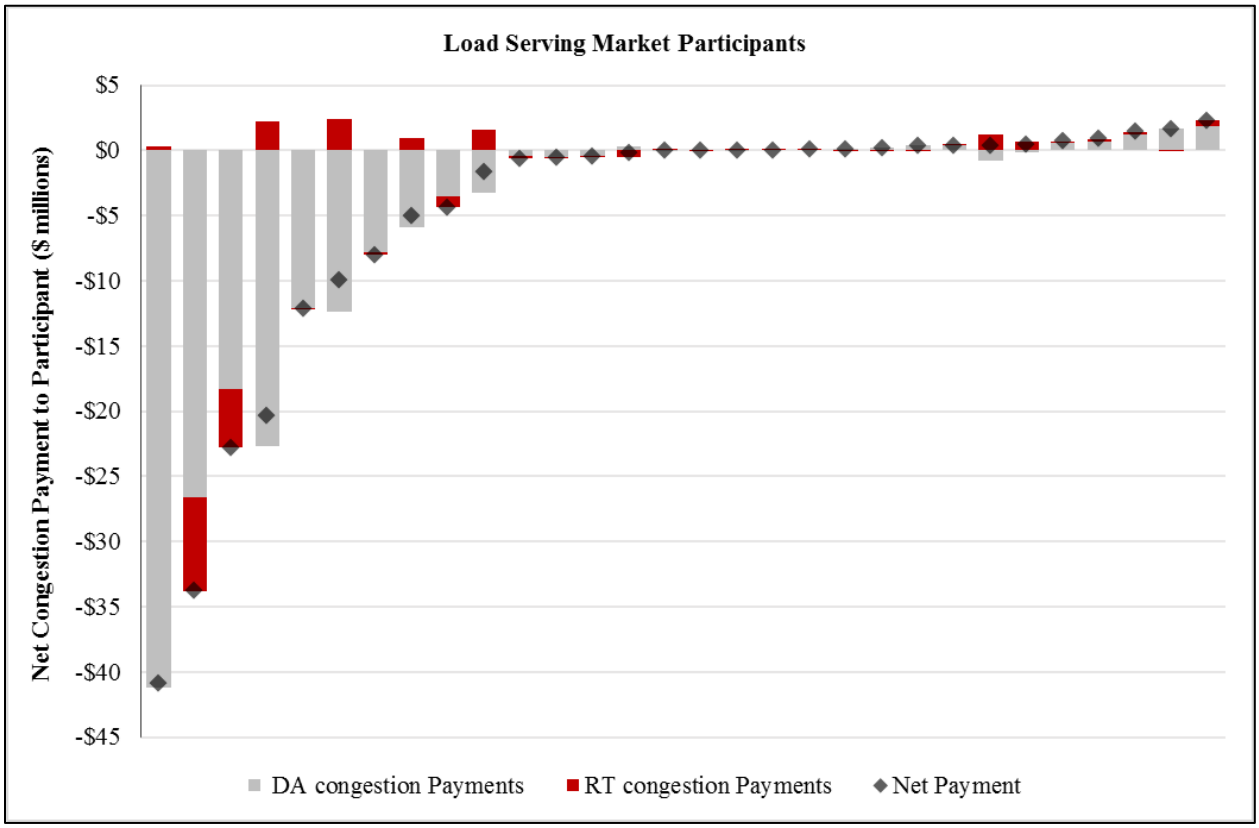
($ millions)	LSE	Non-LSEs
DA Congestion	$ (148.60)	$ (31.46)
RTBM Congestion	$(3.39)	$40.05
NET Congestion	$ (151.99)	$8.59
TCR Charges	$(148.23)	$ (76.35)
TCR Payments	$126.65	$83.27
TCR Uplift	$ (18.30)	$ (15.17)
TCR Surplus (remaining at year end)	$2.18	$1.43
ARR Payment	175.60	$15.80
ARR Surplus	$30.57	$3.40
NET TCR/ARR	$168.46	$12.39

5.8. Market Congestion Costs

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 (MCC) of the LMP. 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 MCCs at their generation and load. For financial Market Participants, congestion costs reflect the value of virtual positions in the Day-Ahead Market and RTBM.

Figure 5–12 shows the annual Day-Ahead Market and RTBM congestion payments for load-serving Market Participants during 2015.

Figure 5–12 DA Market and RTBM Net Annual Congestion Payment by LSE



Most LSEs face congestion costs, depicted as negative payments in the graph, because they are part of vertically-integrated entities with higher MCCs at load than at resources. Day-ahead congestion payments by ranked LSE ranged from about $1.8 million in payments to about $41 million in costs. For non-LSEs, they range from about $5.7 million in payments to $41 million in costs. Market Participants also receive payments and incur costs for Real-Time Balancing Market congestion, which are charged and paid to deviations between Day-Ahead Market and RTBM positions. RTBM congestion ranges from $7.2 million in costs to $2.4 million in payments for LSEs. It ranges from $3.5 million in costs to $18 million in payments for non-LSEs. Many of the non-LSEs incurring costs represent wind farms, which may often sell at negative prices or buy back Day-Ahead Market positions. The largest RTBM congestion payments represent virtual transaction settlements, which result in the net positive $40 million in RTBM congestion payment to non-LSEs, shown in Figure 5–11.

5.9. Hedging Congestion with TCRs and ARRs

5.9.1. TCR Payment Structure

The congestion rents collected in the Day-Ahead Market for any given hour (*h*) are disbursed to TCR holders based on the auction awards (*t*) and the difference in prices between the source and sink settlement locations for the award, as follows:

$$TCR\ Payment_{h,t} = \left(DA\ MCC_{Sink\ t,h} - \ DA\ MCC_{Source\ t,h}\right) * MW\ award_t$$

To the extent that the Day-Ahead Market does not provide sufficient congestion revenues to support the full value of all payments to TCR holders (*a*) for a given day (*d*), SPP charges each TCR holder a share of the underfunding proportional to the absolute value of its TCR portfolio for that day, as follows:

$$TCR\ Uplift\ Ratio\ Weight_{a,d} = \left|\sum_h \sum_t \left(DA\ MCC_{Sink\ t,h} - DA\ MCC_{Source\ t,h}\right) * MW\ award_{a,t}\right|$$

SPP charges each TCR holder a portion of the day-ahead revenue shortfall proportional to this weight. The absolute value formulation creates a balanced treatment for the payment of both prevailing flow and counter-flow TCR positions.

5.9.2. ARR Payment Structure

TCRs are awarded in annual and monthly auctions. SPP disperses the auction revenue to the holders of ARRs. ARRs are allocated for all times of year based on transmission service sufficient to meet up to 103% of each network transmission owner's annual peak load and all point-to-point service, known as the ARR nomination cap. ARR holders may self-convert an ARR to a TCR, in which case the TCR charge equals the ARR payment, or hold the ARR for payment based on the auction clearing prices for the ARR path. To the extent that SPP collects surplus auction revenue, it disperses this to ARR holders proportional to the ARR MW nomination cap.

5.9.3. ARR and TCR Positions

As shown in Figure 5–11 above, the aggregate TCR payments and uplift for LSEs fell $33 million short of TCR charges. ARR payments offset this net cost, but it indicates that the value of an ARR was generally higher when held, as opposed to self-converted to a TCR. In fact, LSEs holding more ARRs tended to hedge congestion more successfully than those that self-converted all ARRs to TCRs. In aggregate for non-LSEs, TCR payments net uplift charges exceeded TCR auction charges by 9%. This profitability is severely curtailed to only 1.8% when TCR Uplift is considered. This is lower than expected, as Market Participants without load to hedge only have an incentive to participate in a market with expected positive returns. Of the 108 Market Participants with TCR and/or ARR positions, only about 25% showed a positive net TCR position.

5.9.4. Adequacy of ARRs and TCRs in Hedging Load

While the ARR and TCR positions provided an adequate hedge for load in the aggregate, several SPP LSEs fell far short of receiving ARR and TCR payments sufficient to cover congestion costs. In fact, six LSEs fell short in excess of $1 million dollars each; the largest of these shortfalls being about $10.3 million. These six lie in different parts of the footprint and have varying sized loads, and other similarly located Market Participants had fully hedged load. The aggregate numbers do not indicate a failure to hedge load in the market design. However, there is room for improvement in transparency of TCR market processes and market efficiency. SPP continues to work on improvements in this area in the stakeholder process.

5.9.5. TCR Market Transparency and Efficiency

The degree of disparity between TCR payments, net of TCR uplift, and TCR auction charges, as shown in Figure 5–11, indicates that TCR auction prices do not accurately reflect the value of TCRs, nor does the current TCR market design accurately reflect how much system capacity will actually be available in the Day-Ahead Market. The MMU recognizes three contributing factors: 1) the over-allocation of ARRs and resulting overselling of TCRs 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 TCR bids. Each of these factors create difficulty for Market Participants in estimating the value of SPP TCRs, hindering the full information

necessary for efficient market outcomes. The funding percentage levels for TCRs and ARRs are good metrics for evaluating market performance in this area.

The TCR funding level from day-ahead congestion revenues is calculated as follows:

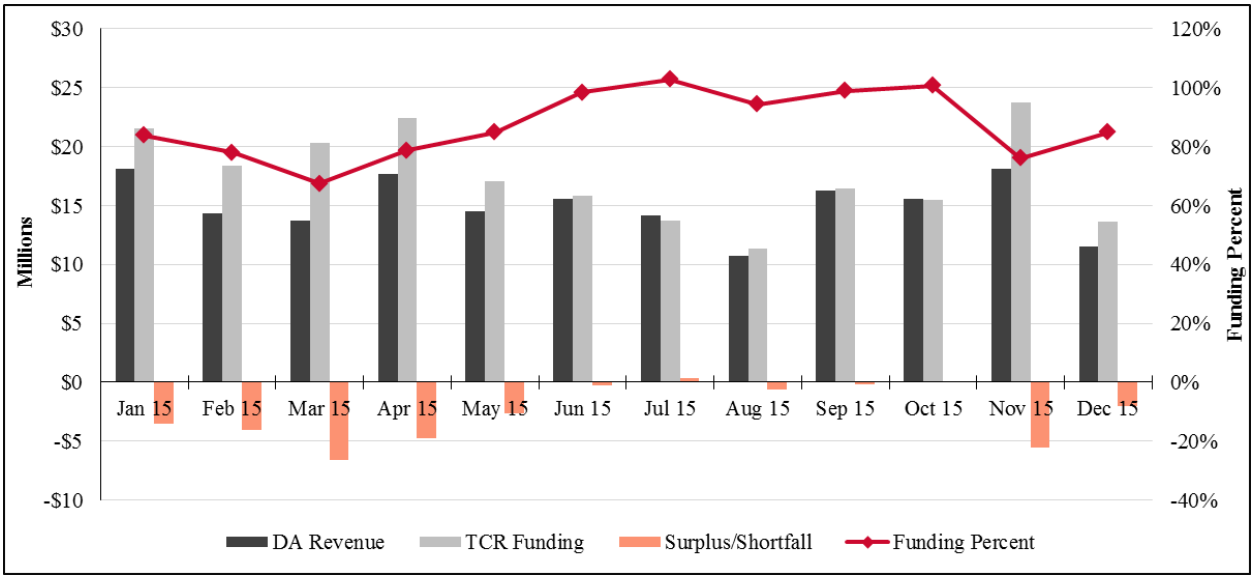
$$TCR\ Funding\ \% = \frac{DA\ Congestion\ Revenue}{TCR\ Payments}$$

The TCR funding was 86% cumulative during 2015, with total payments exceeding funding by $33 million. This contrasts with the ARR funding level of 118%, with total revenue exceeding total payments by $34 million. The ARR funding from auctions is calculated as follows:

$$ARR\ Funding\ \% = \frac{Auction\ Revenue}{ARR\ Payments}$$

Figure 5–13 and Figure 5–14 show the monthly TCR and ARR funding levels for 2015. In all but two months, day-ahead congestion revenues fell short of TCR payments, while in every month auction revenues exceeded ARR payments. Monthly TCR funding levels ranged from 68% to 103% with a median of 85%, while ARR funding levels ranged from 112% to 132% with a median of 120%. The most notable observations to be made when studying Figure 5–13 concern two trends that were observed in both 2014 and 2015: 1) TCR funding levels are notably lowest during spring and fall “outage season”; and 2) TCR funding is at its lowest in the spring when ARRs and TCRs from the annual process were allotted about a year in advance.

Figure 5–13 Monthly TCR Funding Levels, 2015

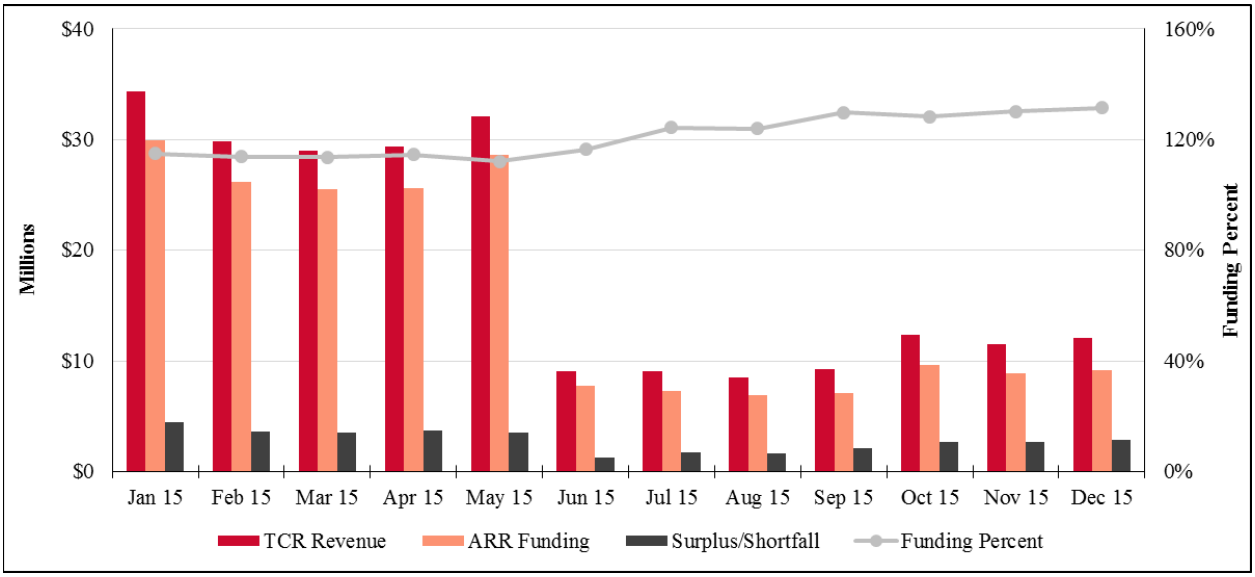


The following two notable observations can also be made about Figure 5–14:

1) The drastic reduction of market volume that coincided with the implementation of the LTCR process. This process provides an alternative path for MPs with long-term, firm transmission service to convert that service into TCRs, and necessarily reduces the volume of ARRs that can be allocated and the TCRs that remain to be sold.

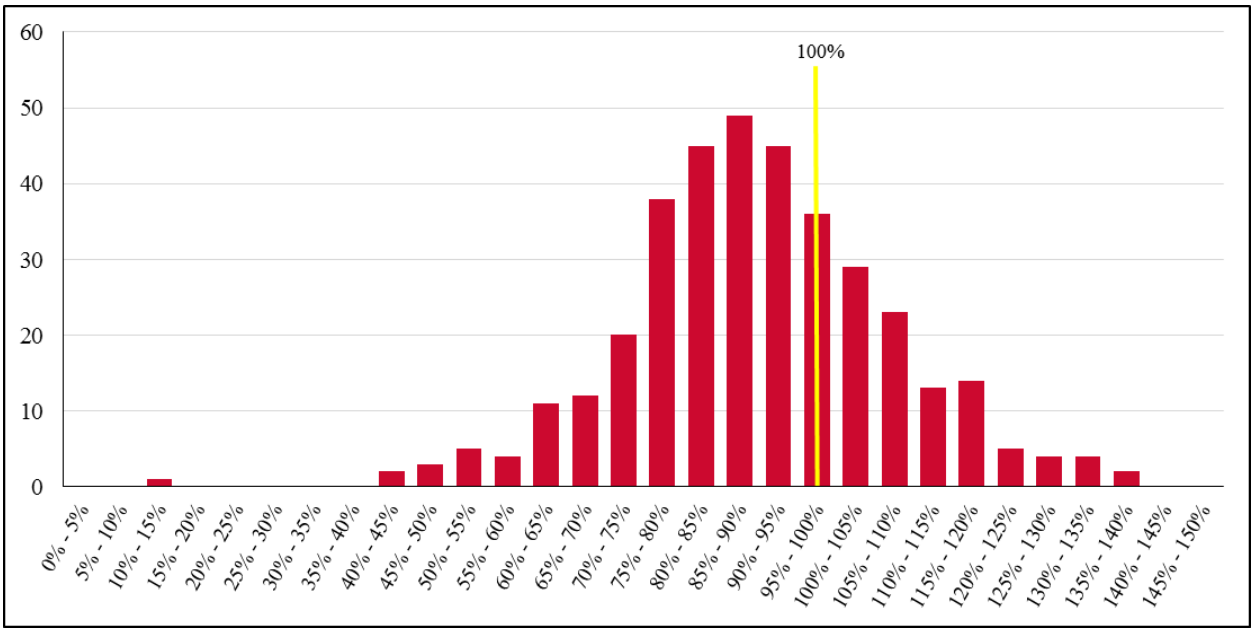
2) A slight increase can be observed in October through December, which coincides with the addition of the Integrated System to the SPP footprint.

Figure 5–14 Monthly ARR Funding Levels, 2015



By plotting a histogram of daily funding percentages (see Figure 5–15), it can be observed that the most common funding percentages are 85% to 90% with nearly equal amounts above and below this region.

Figure 5–15 Daily Funding Percent, 2015



5.9.6. Awarding ARRs and TCRs Beyond the Transmission System Capability

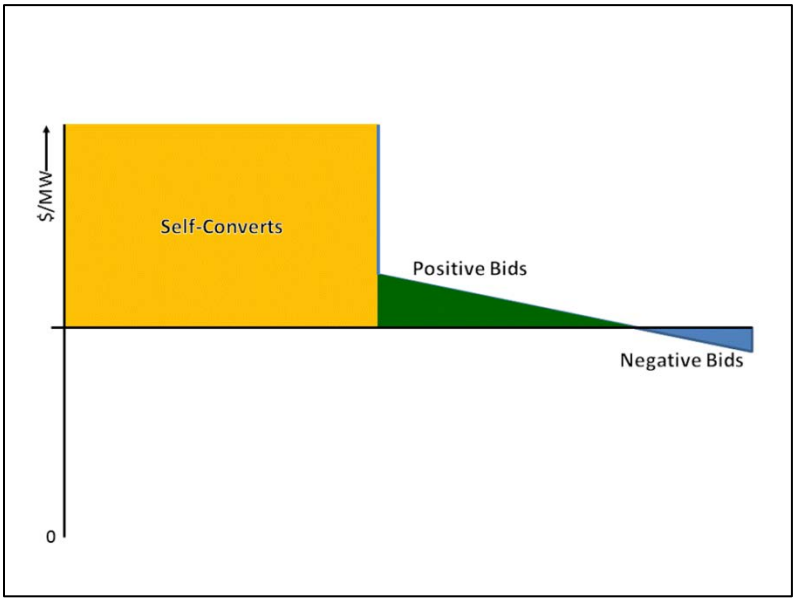
The key factor in the funding disparity is the allocation of ARRs and subsequent awarding of TCRs beyond the physical limits of the SPP system. Much of the excessive allocation of TCRs stems from the design of SPP's TCR market and the quantity of system capacity that it makes available in the ARR allocations and TCR auctions.

As previously mentioned, SPP's ARR funding was 118% cumulative for 2015. Another way of stating this would be that SPP's TCR Market could have sold 85% (1/1.18) of system capacity and still fully funded ARR holders (with provisions discussed later). Also mentioned previously, SPP's TCR Market was funded at 86% cumulative for 2015. Another way of stating this is that the TCR Market sold 116% (1/0.86) of what the Day-Ahead Market could support, or that if SPP had sold 86% of the system, the TCR Market would be fully funded. Therefore, generally the TCR Market uses the BES about 15% more efficiently than what can be achieved by the ARR Allocation alone. Also, the amount of transmission capacity awarded by the TCR Market is about 15% more than what will actually be available in Day-Ahead.

As mentioned in the 2014 ASOM, in the Interim Allocation as well as 2014 and 2015 Annual Allocations, the full (100%) transmission capability of the SPP system was awarded to candidate ARR holders for point-to-point service plus sufficient network transmission service to serve up to 103% of an LSE's annual peak load for all 12 months of the year. These ARRs could then be self-converted into TCRs in the auction process. For the 2016 Annual Process and going forward, SPP will scale the capability of the transmission system to 100% for June, 90% for the summer months, and 60% for the remaining fall, winter, and spring months. For the annual TCR auction, SPP scales the capability of the transmission system to 100% for June, 90% for the summer months, and 60% for the remaining fall, winter, and spring months. In the case where an ARR holder self-converts an allocated ARR to a TCR, the desired transaction enters the TCR auction as a TCR bid at a price 1,000 times greater than the difference between the highest and lowest submitted bids in the market as can be seen in Figure 5–19. The artificially high demand can lead to the uneconomic clearing of TCRs that provide counter-flow to the self-convert bids. The high volume of ARR allocations and self-conversion modeling results in an abundance of TCRs awarded in the annual process. Left unchecked, this would cause extreme price divergence

when the equilibrium point of the market solution included one of these artificially high self-convert bid prices. Figure 5–16 gives a conceptual illustration of this situation.

Figure 5–16 TCR Bids by Value



To mitigate this situation, SPP instead expands the limits in the monthly ARR allocation to accommodate ARRs allocated in the annual process. This limit expansion is then carried forward to ensure that sufficient capacity is available to award all self-convert bids.

In the monthly ARR allocation and TCR auction, SPP may award up to 100% of the expected transmission system capability. All TCRs awarded and ARRs allocated during the annual process are preserved by the expansion of constraint limits in the model. For example, if SPP has learned that outages or parallel flow expectations have changed such that a 1,000 MW constraint limit has fallen to 500 MW, SPP raises the limit as high as necessary to preserve all TCRs and ARRs awarded based on the 1,000 MW limit. This is necessary to preserve the integrity of the annual process. Due to the large quantity of annual awards, it creates a known, frequent situation where the TCR market flow exceeds the Day-Ahead Market flow for particular paths, which necessarily results in selling TCRs for transmission that will not be in service during Day-Ahead Market, and thereby causing TCR uplift.

An additional cause of overselling TCRs is the amount of system capacity made available in the annual and monthly TCR auctions. Besides the 100% offered in the month of June, SPP's market design requires that 90% of system capacity be offered for the July, August, and September months, and 60% of the system be offered for fall, winter, and spring seasons. Outages, parallel flows, and other factors can contribute to system topology changes that make TCRs sold far in advance infeasible. The MMU has noted cases in which flowgate ratings have been decreased to a low of 50% of nominal value due to maintenance outages. Even if SPP knows the decreased ratings in advance of the monthly TCR auction, it cannot expect to know many of the reductions in ratings as far in advance as the annual auction. The MMU would like to withdraw its recommendation for SPP to lower these limits at this time until the effect of reducing the ARR capacity offered in the Annual Allocation can be analyzed. Since this change is taken into effect during the 2015 Annual Allocation, the MMU will have ample data to analyze and determine if lowering this limit is still necessary.

In July 2015 SPP stakeholders approved a change in market design expected to reduce the required limit expansion in the monthly ARR allocations and TCR auctions. The MMU expects improvement in the number of required limit expansions in many of the monthly TCR auctions with this change. SPP should achieve further improvement in funding disparity by reducing full system availability in the annual ARR allocation to match the system availability levels in the annual TCR auction. The issue could still remain that SPP will not need to perform as much limit expansion in Monthly Allocations/Auctions, but could still oversell the system by selling a flat 100% rather than using lower system scaling factors for June in the Annual TCR Auction, Monthly ARR Allocations, and Monthly TCR Auctions.

The MMU expects some reduction in limit expansion due to implementation described above, and a corresponding reduction in underfunding due to over-allocation in the annual process. However, this does not address the issue of over-allocation of ARRs and TCRs in the monthly process. The MMU expects TCR funding from day-ahead to be similar through the summer months (i.e., 80%–100%) and an improvement in the remaining seasons (formerly 60%–80%) up to a level nearer that of previous summers. Should this occur the MMU recommends that SPP reduce the system capacity available in the monthly ARR/TCR processes so as not to oversell TCRs in relation to day-ahead.

MMU Recommendation – TCR and ARR System Availability in Annual Process

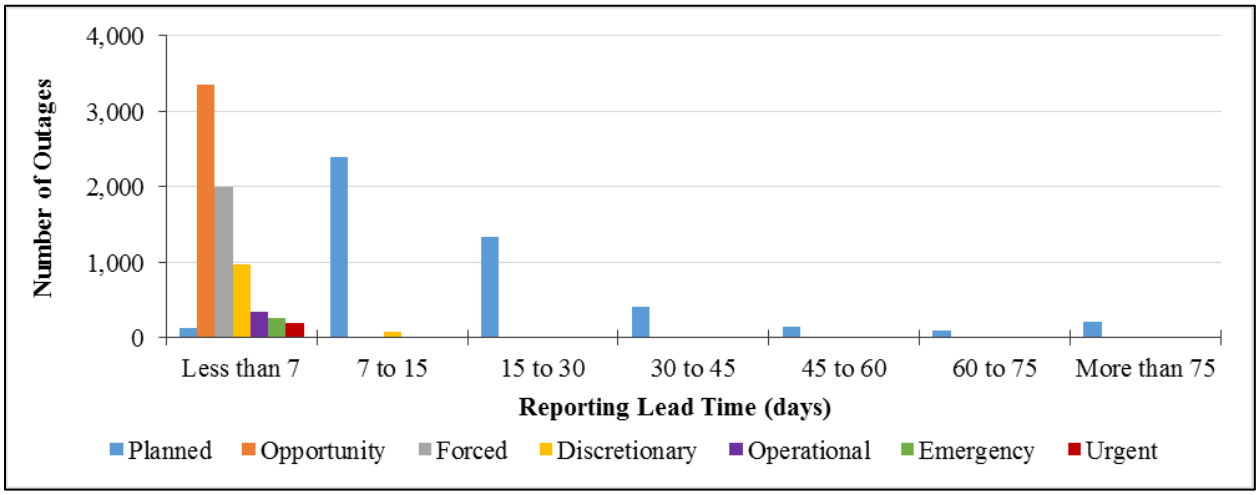
- In the 2014 ASOM the MMU recommended that SPP match the ARR and TCR system availability in the annual process to eliminate required limit expansion for infeasible ARRs. This recommendation has been addressed with the passage and implementation of RR91 – Annual Allocation Percent Change.

5.9.7. Transmission Outage Reporting and Modeling

As noted in the 2014 ASOM, SPP's accommodating reporting requirements for transmission outages and the exclusion of shorter duration outages from the TCR models exacerbated the overall TCR and ARR funding discrepancies described above. Uncaptured outages in the first year of the market created particularly low daily funding percentages, as low as 40%, when an outage contributed significantly to local congestion. This local congestion curtailed the net transfer capacity of the physical system in the Day-Ahead Market relative to the TCR auction models, increasing the TCR payment for the path while also reducing the congestion rents collected in the Day-Ahead Market. In several cases SPP could have adjusted the TCR models to reflect the outages had they been reported sooner.

The monthly ARR allocations and TCR auctions only captured outages reported at least 45 days prior to the first of the month. Transmission operators would have needed to report outages near the end of the month as far as 75 days in advance for SPP to capture them in the TCR auction models. Since the 2014 ASOM, SPP has increased the requirement from only seven days advance reporting of planned outages out to 14 days advance reporting. However, this is still far short of the needed 45- to 75-day advance notice. Figure 5–17 shows the lead time of planned transmission outage reporting.

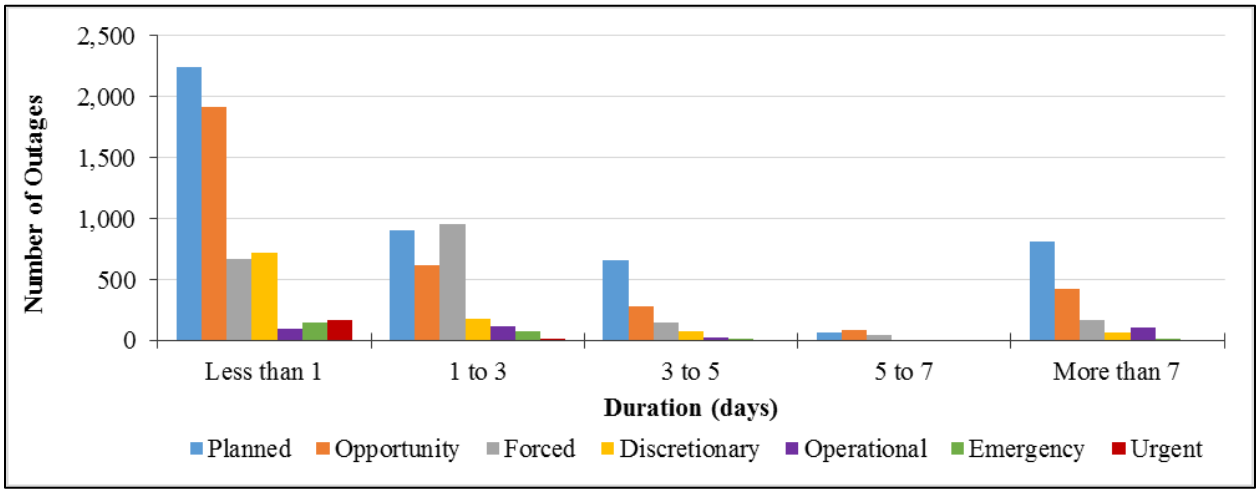
Figure 5–17 Transmission Outages by Reporting Lead Time



SPP transmission operators reported the vast majority of outages in the 7- to 30-day timeframe. They reported less than 10% of planned outages in the 45-day plus timeframe required for reflection in the monthly ARR and TCR models. As noted in the 2014 ASOM, SPP staff noted room for improvement and proposed modifications to historical outage reporting practices to require earlier reporting of planned outages. The MMU supported this effort and its recommendations above. During the stakeholder process, however, the proposed 45 days prior to the first of the month deadline for outage submission was changed to a 14-day lead time. It is again worth noting that lowering the capacity made available in the allocations and auctions would also mitigate the overselling of TCRs due to unknown outages.

SPP's outage duration criteria for inclusion in the ARR and TCR models changed during the first year of the market. Until late 2014, SPP included almost all known outages. With stakeholder feedback, a criterion of a 120-hour minimum duration was created. Figure 5–18 shows that most outages lasted less than three days, and several fell into the three- to five-day category.

Figure 5–18 Transmission Outages by Duration



Outage duration does not imply market impact, and SPP at times excluded impactful outages based on their short duration. Moreover, even if an individual element is taken out of service multiple times in a given month (e.g., eight-hour outages five days a week for three weeks), these outages would be excluded under the current criteria even though the total time in outage may exceed 120 hours. SPP could add flexibility to its processes by allowing more operational/engineering judgement in the criteria for outage inclusion in ARR and TCR models. As noted previously, this issue could also be addressed by lowering the system capacity offered in the TCR Market.

MMU Recommendation – TCR and ARR System Availability in Monthly Process

- In the 2014 ASOM the MMU recommended that SPP increase lead time for planned outages to 45 days prior to the first of the month in which the outage is to begin. The principal issue is the mismatch between the TCR and ARR allocation process based on the monthly modeling and the actual availability of transmission capacity in real time. The MMU continues to recommend changes to improve the accuracy of the outage reporting, but there are other ways to address this issue as discussed in this section.

5.9.8. Self-Convert Modeling

Many Load-Serving Entities self-convert most or all ARRs to TCRs in the annual and monthly TCR auctions. The auction assigns the requested self-convert ARRs 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 TCR bid. These high bids far exceed the economic value of the resulting TCRs, yet they influence the economic clearing of the market with the potential to distort market outcomes from efficient levels. Figure 5–16 conceptually depicts the ranked bids for TCR MWs in a typical auction. It shows that approximately half of all auction bid MWs represent self-converted ARRs with effectively infinite prices. Figure 5–19 gives re-calculated $/MW bids that were used for self-converts for TCR markets in 2015.

Figure 5–19 Self-Convert Modeled Prices, 2015

Market Name	Minimum TCR Bid ($/MW)	Maximum TCR Bid ($/MW)	Difference ($/MW)	Self-Convert Bid ($/MW)
January Monthly Auction	(40,800)	12,444	53,244	53,244,000
February Monthly Auction	(28,160)	8,800	36,960	36,960,000
March Monthly Auction	(31,280)	9,735	41,015	41,015,900
April Monthly Auction	(10,000)	13,408	23,408	23,408,920
May Monthly Auction	(18,656)	21,174	39,830	39,830,600
2015 Annual Auction	(54,285)	41,815	96,100	96,100,300
July Monthly Auction	(13,246)	26,019	39,265	39,265,700
August Monthly Auction	(33,779)	16,320	50,099	50,099,340
September Monthly Auction	(17,018)	11,904	28,922	28,922,420
October Monthly Auction	(13,810)	14,700	28,510	28,510,200
November Monthly Auction	(15,000)	20,050	35,050	35,050,000
December Monthly Auction	(19,600)	15,628	35,228	35,228,800

In contrast, non-self-convert bids (bids) are limited to $100k/MW in most cases (exceptions are $200k/MW in fall and spring periods, and $400/MW in winter periods of the Annual TCR Auction). SPP and the MMU are evaluating the impact of the self-convert modeling on TCR auction prices and awards, as well as exploring alternative processes used by other RTOs. Notably this is the biggest issue that necessitates the current linkage of system capacity percentages used in ARR and TCR processes. If this issue were corrected, SPP could offer a higher system capacity percent (as mentioned earlier) for the ARR Allocation than for the TCR

Auction, and still fully fund ARRs. Additionally, if this issue were corrected SPP could offer a lower capacity in the auction, and thereby alleviate overselling TCRs and reduce TCR uplift payments.

5.9.9. Bidding at Electrically Equivalent Settlement Locations

As noted in the 2014 ASOM, SPP's OATT prohibits bidding between pairs of electrically equivalent settlement location (EESL) pairs, which allow infinite or near-infinite quantities of TCRs to be awarded at zero cost. SPP publishes a list of prohibited pairs of settlement locations on SPP's Marketplace Portal and removes the bids from the auction. Such bidding constitutes a violation of SPP's Tariff. Up to this point the Tariff provision has not ceased the bidding activity between electrically equivalent settlement locations. In the 2014 ASOM the MMU recommended that the RTO implement appropriate safeties in the Market User Interface to prevent this behavior in the future.

Subsequent to the publication of the 2014 ASOM, SPP has taken the following actions to address the MMU's concerns: 1) approved software changes to the TCR MUI validation rules to ensure that no bids between EESL pairs are permitted; and 2) began drafting a Revision Request (RR) to modify the SPP Market Protocols and SPP OATT to state that SPP will remove any submitted EESL bids.

MMU Recommendation – TCR Bidding at Electrically Equivalent Settlement Locations

- The MMU believes the actions taken by SPP regarding software changes, when fully implemented, will prevent the TCR system from accepting bids from EESL pairs. This addresses the MMU's concerns.

5.9.10. Hedging Real-Time Congestion

It has been noted above that net ARR and TCR payments provided sufficient revenue to cover the Day-Ahead Market and Real-Time Balancing Market congestion costs for Load-Serving Entities. It should also be noted that SPP allocates RTBM congestion costs to Market Participants through Revenue Neutrality Uplift (RNU) charges. SPP allocates about 90% of

RNU to LSEs, resulting in an additional $18 million in congestion-related charges for LSEs for a net total of $2 million in congestion-related charges.

Figure 5–20 Total Congestion Payments for Load-Serving Entities and Non-Load Entities

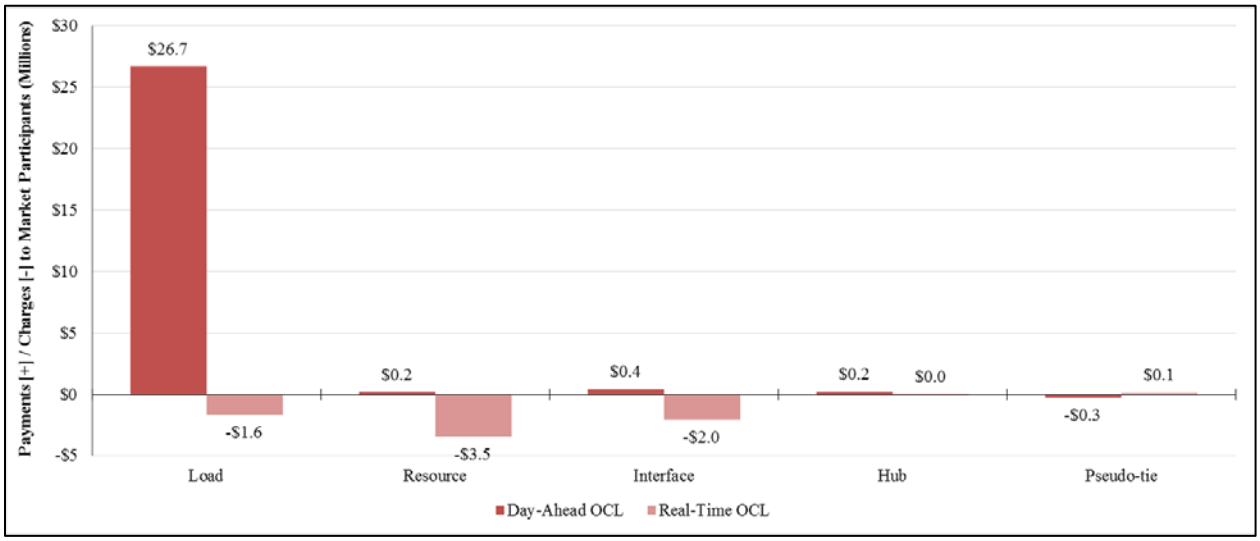
($ millions)	LSE	Non-LSEs
DA Congestion	$ (148.60)	$ (31.46)
RTBM Congestion	$ (3.39)	$ 40.05
NET CONGESTION	$ (151.99)	$ 8.59
TCR Charges	$ (148.23)	$ (76.35)
TCR Payments	$ 126.65	$ 83.27
TCR Uplift	$ (18.30)	$ (15.17)
TCR Surplus (remaining at year end)	$ 2.18	$ 1.43
ARR Payment	$ 175.60	$ 15.80
ARR Surplus	$ 30.57	$ 3.40
NET TCR/ARR	$ 168.46	$ 12.39
RTBM Congestion Uplift	$ 20.77	$ 5.38

5.9.11. Distribution of Marginal Loss Revenues (Over-Collected Losses)

Both the congestion and loss components of LMP create additional 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 ER15-763. The Commission accepted these changes, which went into effect in April 2015.

Prior to April 1, 2015, the marginal loss revenues, referred to as "over-collected losses," were separately disbursed in the Day-Ahead Market based on market withdrawals and in the Real-Time Balancing Market based on net market withdrawals relative to day-ahead transactions. Figure 5–21 provides the total over-collected loss distributions and charges by settlement location type for the first three months of 2015, prior to the OCL changes. Notice that the old OCL calculation on average caused a net charge to units withdrawing in the Real-Time Market.

Figure 5–21 Over-Collected Losses Totals for January–March 2015

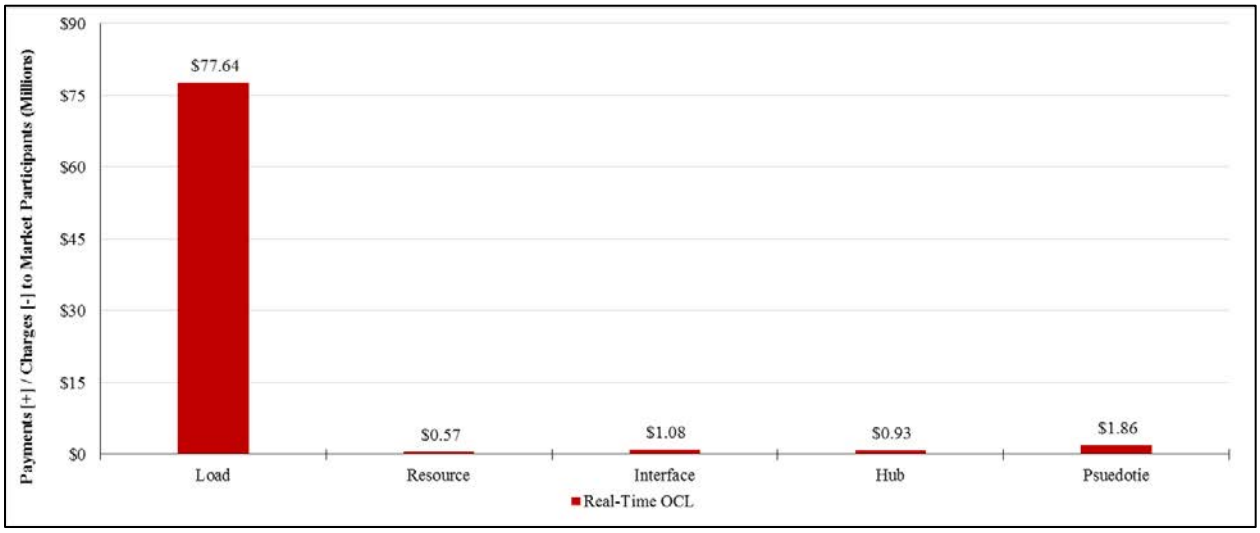


Due to high Day-Ahead Market load bids, the load received $27 million in January through March, or 124% of all over-collected losses, while RTBM deviations from day-ahead positions paid $7 million. As stated in last year's ASOM, this real-time charge had significant impacts on export and through transactions, causing an average charge of about $2.27/MWh with charges sometimes exceeding $1,000/MWh.

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-collected loss rebates are distributed on just real-time withdrawing MWs. This includes loads, substation power, exports, throughs, Pseudo-Ties, and Bilateral Settlement Schedules (BSS). The only exception is that both day-ahead and real-time BSS are entitled to the rebate. In addition to consolidating the distributions to only real-time withdrawing MWs, changes were made to loss pool allocations. Under the old method, virtual play drove up the SPP Loss Pools allocation of OCL rebates, even though virtual activity was not eligible for rebates. This caused real-time exporters to get a large percentage of the OCL rebates, which during that time were typically a charge. Virtuals no longer play a role in the loss pool distributions. The MMU feels 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 5–22 below, $82 million was paid out in OCL rebates during the periods of April through December 2015, with $77.6 million or 94.6% going to the loads. This brings the total OCL rebates for 2015 up to $108 million. This is slightly higher than the $105.6 million paid in the first 12 months of the market. This increase can be partly attributed to the increased load brought on by the Integrated System in the last three months of the year.

Figure 5–22 Over-Collected Losses Totals April – December, 2015



The use of BSS changes the distribution of over-collected losses. The BSS 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 BSS does not change the net withdrawal at the location, the charges and credits for losses simply change hands between the entities owning the BSS exchange. Where the BSS creates a net withdrawal that would not otherwise exist, it creates credits and charges that would not otherwise exist. For example, if a BSS 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 MWs of the BSS. The same occurs with the BSS at hubs, where no energy is withdrawn, other than a BSS. The $570 thousand in distributions at resource settlement locations during April through December occurred for this reason, as well as the $930 thousand at hubs. These distributions cause concern for the MMU, because they create an incentive to game the market rules by

transacting using the BSS. Exploitation of this aspect of the loss distribution calculation is market manipulation.

Over-collected losses no longer create charges in the Real-Time Balancing Market. Total loss revenues are calculated from both the Day-Ahead Market and the RTBM. SPP distributes them based on RTBM withdrawals only. Virtual transactions no longer factor into the loss pool calculation, ameliorating 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, BSS do not contribute to the over-collection of losses, but they are entitled to rebates. As stated earlier, any scenario where a BSS creates a net withdrawal that would not have existed had the BSS not been placed creates an opportunity for an OCL rebate. When this happens, the OCL rebate is diluting other rebates that contributed to the over-collection of losses.

MMU Recommendation – Allocation of Over-Collected Losses

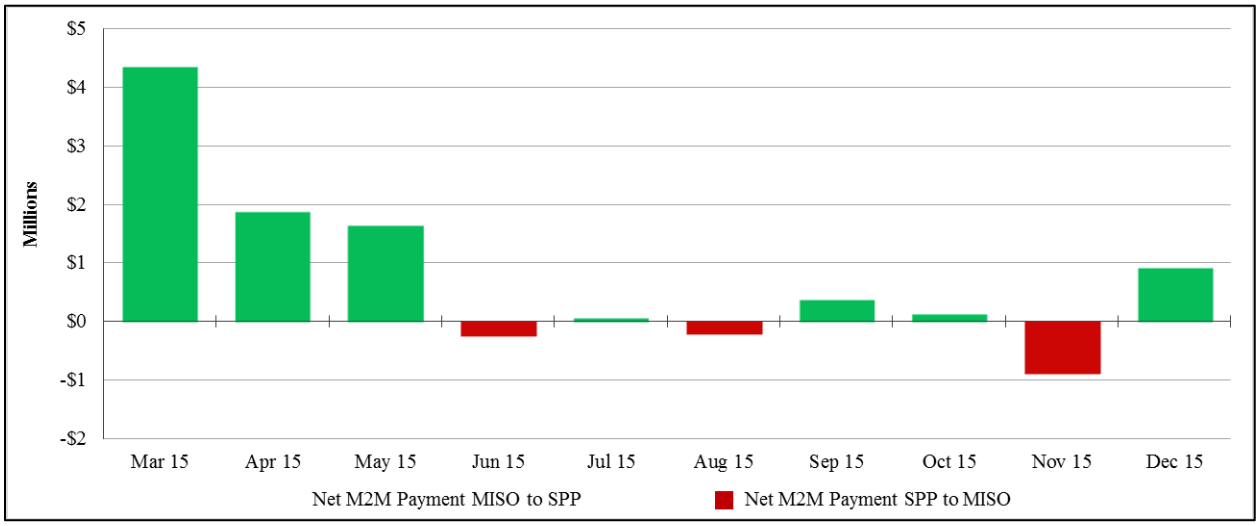
- Remove Bilateral Settlement Schedule transactions from the over-collected losses distribution calculation. This was a recommendation in the 2014 ASOM report. The MMU has made presentations to the SPP Market Working Group outlining the reasons for the recommendation. SPP Market Design is currently working on a method that reduces the vulnerabilities associated with OCL payments made to Bilateral Settlement Schedules.

5.10. 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 M2M process under the Joint Operating Agreement (JOA) allows the Monitoring (MRTO) and Non-Monitoring RTO (NMRTO) to efficiently manage M2M constraints by exchanging information (shadow prices, relief request, control indicators, etc.) and utilizing the RTO with the more economic redispatch. Each RTO is allocated property rights on M2M constraints known as Firm Flow Entitlements (FFE), and each RTO calculates its real-time

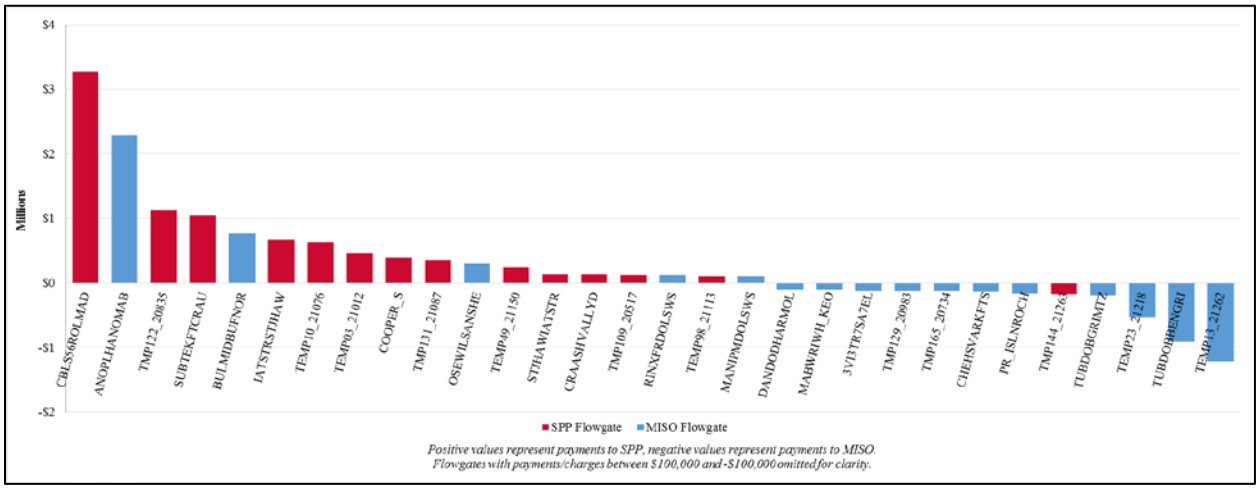
usage known as market flow. Exchange of money (M2M settlements) for redispatch is based on the NMRTO's market flow in relation to its FFE. The NMRTO will receive money from the MRTO if its market flow is below its FFE and will pay if above its FFE. Figure 5–23 shows net payments by month between SPP and MISO (positive is payment from MISO to SPP and negative is payment from SPP to MISO.)

Figure 5–23 Market-to-Market Settlements, 2015



For the 10 months of M2M coordination in 2015, total M2M payments from MISO to SPP totaled almost $8 million of which over half occurred in the first month, which is still in discussions of being resettled. These discussions revolve around the MRTO and NMRTO designations and are discussed later along with other areas of focus. Figure 5–24 represents M2M settlements by flowgate for the 10-month period in 2015. The Council Bluffs – Sub 3456 345kV ftlo Rolling Hills – Madison 345kV [CBLS56ROLMAD] flowgate attributed to much of the M2M settlements during March 2015.

Figure 5–24 Net Settlements by Flowgate



M2M allows for a coordinated approach between markets to provide a more economic dispatch of generation to solve congestion. The following areas of focus were observed during the first 10 months of the M2M, while others were existing issues. Focus on these areas could lead to improved benefits for both markets.

5.10.1. MRTO/NMRTO Designation

Essentially, the RTO, which manages the limiting element of the constraint, is the MRTO. In most cases, the MRTO has most of the impact and resources that provide the most effective relief. MISO and PJM currently implement a procedure on constraints where the MRTO transfers control to the NMRTO when the NMRTO has 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 MRTO/NMRTO designation has been discussed with SPP stakeholders but concerns over legal obligations (Transmission Operators contract with SPP to manage their facilities) have delayed this between SPP and MISO. The Market Monitor urges both SPP and MISO to continue discussions on a procedure to explore this option and for it to be flexible enough to address temporary conditions.

5.10.2. Shadow Price Override

SPP and MISO have also adopted a mechanism used between MISO and PJM called shadow price overrides. This mechanism requires the NMRTO to enter an agreed upon shadow price

limit rather than the shadow price from the MRTO. This is utilized between SPP and MISO due to oscillation of flows on a constraint. Although this alleviated the reliability issue of flow oscillation, the observed shadow price from SPP was $0 and a non-zero shadow price from MISO. In this scenario MISO provided all the relief at a level that kept SPP's market from binding (hence the $0 shadow price). This addresses the reliability issue of oscillation on the facility but does not provide the correct price signals to both markets. This situation may be an issue that can be addressed with the MRTO and NMRTO designations.

5.10.3. Use of TLR

SPP, per its Market Protocols, utilizes the TLR process when tagged impacts or other external impacts are present on an SPP facility while MISO seldom utilizes this mechanism. The Market Monitor believes that the TLR 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 TLR when impacts on the constraint are mostly between SPP and MISO. When third-party impacts exist, the Market Monitor feels a TLR 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 is not subjected to redispatch by either market. The third party does not have a disincentive in the form of a price and by the absence of a TLR will not have an obligation to provide relief on the constraint. Although TLR is not as efficient as a market using price and impacts to redispatch congestion on a constraint, issuing a TLR (level 5 is required in this case) will subject the third party to a level of redispatch based on an NNL relief obligation that both markets would no longer bear, which would be reflected in lower shadow prices. M2M is the preferred method in addressing congestion along the seams, but until further development is made in the NERC arena TLR is the only mechanism to manage impacts between markets and non-markets.

5.10.4. M2M Flowgate Coordination

Flowgates are subjected to a series of coordination tests to determine if they should become an M2M 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 (resource(s) out-of-service, N-1 condition in test not present in real-time, etc.). This may cause the NMRTO to be asked to provide relief during a configuration when it physically cannot provide relief (i.e., NMRTO asked to provide negative market flow and resource(s) 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 M2M coordination.

5.10.5. 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 M2M 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 marginal 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 M2M settlements (market flow is used to measure what portion of the NMRTO's FFE is being utilized), this topic should be revived to ensure consistency and equitable measurements across RTOs.

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 2015 market outcomes were workably competitive and that the market required mitigation of local market power infrequently to achieve those outcomes.

This market power analysis looks at both the structural and behavioral aspects of market power concerns. The structural aspects can be detected by various techniques such as concentration indices, Market Share Analysis, 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 6.2.1; and through the output gap analysis, see Section 6.2.3), and Physical Withholding Analysis (addressed through FERC referrals).

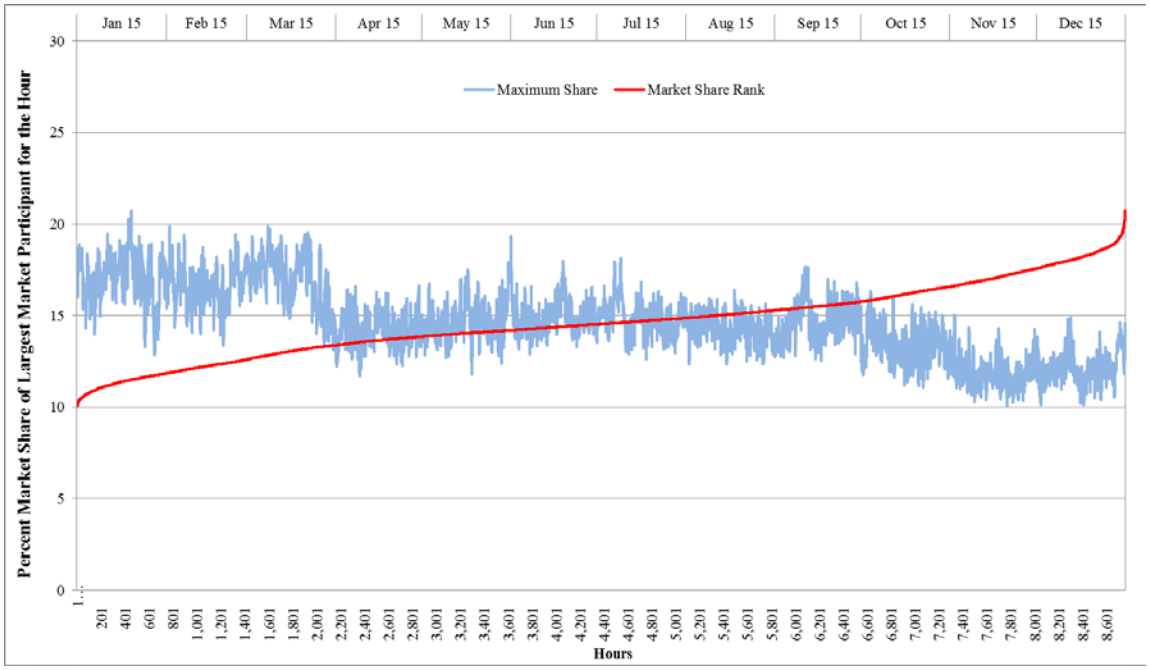
The assessment of the competitive environment during 2015 establishes the level of structural market power and then examines market prices for indications of market power impact. Automatic market power mitigation processes limit the ability of generators with local market power to raise prices above competitive levels. This section assesses the potential existence of global market power and analyzes prices without regard to whether market power mitigation measures were in place. Section 6.2 analyzes the behavioral aspects of market power. The following subsections examine the effectiveness of local market power mitigation and the significance of market power in the SPP Markets.

6.1. Structural Aspects of the SPP Market

Three core metrics of structural market power are the Market Share Analysis, the Herfindahl-Hirschman Index (HHI), and Pivotal Supplier Analysis (PSA). The first two of these indicators measure concentration in the market and are of static nature. PSA, 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 RTBM by hour for the period of January 1, 2015 to December 31, 2015, along with a ranked maximum market share duration curve.

Figure 6–1 Market Share of Largest Supplier by Hour



The market share rank ranged from 10% to 21%, exceeding the 20% benchmark[24] in only six hours for the year. The highest market share hours mostly occurred during the off-peak months

[24] The 20% 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.

of the year, and before the IS joined the market in October. The values appear to drop about 2–3% in the October to December period as would be expected because of the increased diversity in the market resulting from a significant expansion.

The HHI is another general measure of structural market power, analyzing overall concentration in the market. It is calculated by using the sum of the squares of the market shares of all suppliers (*i*) 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,"[25] similar to DOJ 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. It shows that in terms of installed capacity, the SPP Market was unconcentrated more than 70% of the hours in 2015 and moderately concentrated only about 29% of the time. HHI never rose above the 1,800 threshold determined for high level of concentration.

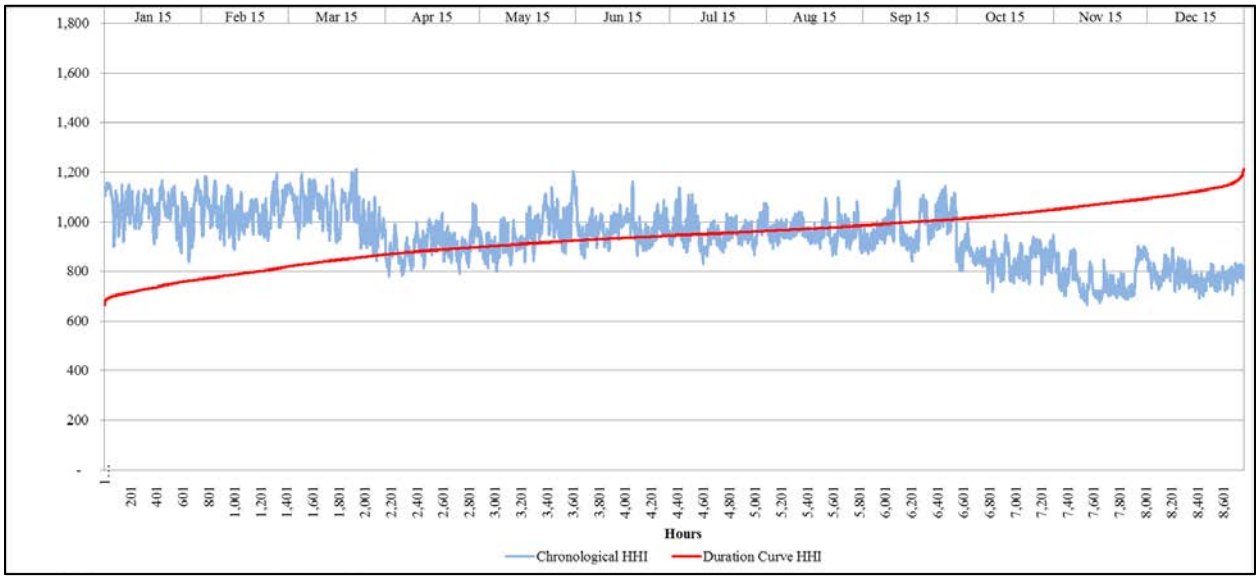
Figure 6–2 Count of RTBM Hours by Market Concentration Level, 2015

	HHI Level	Hours	% of Hours
Unconcentrated	Below 1,000	6,234	71%
Moderately Concentrated	1,000 to 1,800	2,525	29%
Highly Concentrated	Above 1,800	0	0%

Figure 6–3 depicts the hourly RTBM HHI for the second year of the Integrated Marketplace along with a ranked HHI duration curve. The hourly HHI ranges from 700 to about 1,215 during the course of the year, with higher concentration levels in the early months.

[25] 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 Hourly HHI, 2015



On the other hand, market structure conditions in the SPP footprint change with the technology mix of online resources. Base load (coal, nuclear, and wind) generation produced about 77% of SPP's energy for 2015, down slightly from 80% in 2014, and these resources do at times set the marginal price, especially during off-peak hours. Prices rise and the market structure becomes more favorable for the potential exercise of market power with natural gas-fired generation on the margin, especially when the marginal cost spread between natural gas and coal is large. In most of 2015, gas prices were depressed, reducing the possibility of this potential condition.

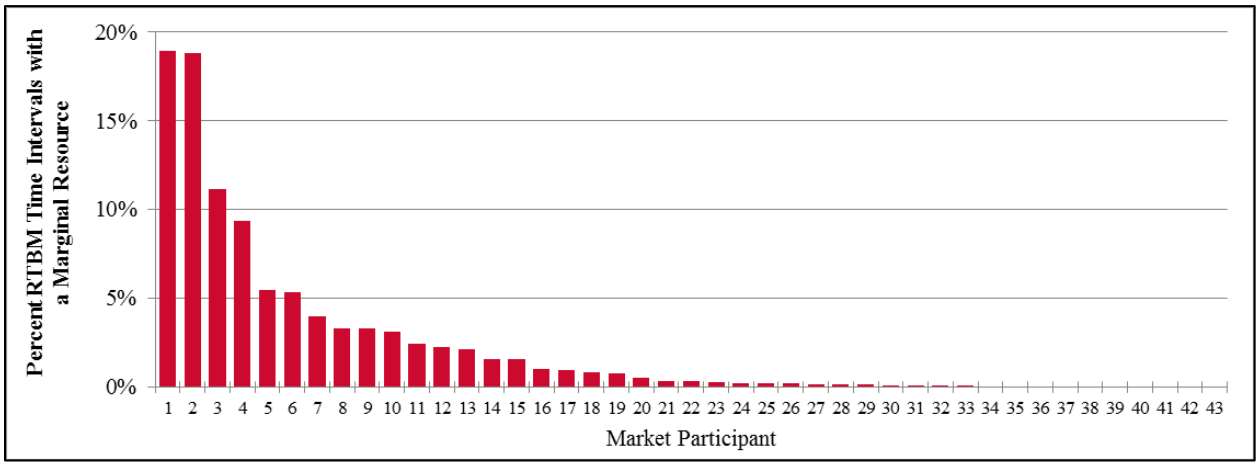
Even though the potential impact to the market is reduced because of reduced cost difference between peaking and base load units, the level of market concentration continues to exist under certain conditions; see Figure 6–4. The figure indicates that there are periods when intermediate and peaking segments of the market were highly concentrated, as represented by HHI values in excess of 1,800.

Figure 6–4 Hourly HHI Statistics by Supply Curve Segment, 2015

Supply Segment	% of Hours Online	Min. HHI	Avg. HHI	Max HHI
Base load	50 to 100	675	962	1,219
Intermediate	10 to 50	805	1,699	7,001
Peaking	0 to 10	865	6,516	10,000

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 6–5 provides the percent of RTBM market intervals that each ranked Market Participant had a resource on the margin. It shows that three Market Participants each set price in more than 10% of all RTBM time intervals. These percentages are not additive because multiple Market Participants may have a resource on the margin at the same time.

Figure 6–5 Market Participants on the RTBM Margin, 2015



In conclusion, the MMU's HHI and Market Share Analysis both indicate minimal potential structural market power in SPP Markets outside of areas that are frequently congested.

PSA takes into account the dynamic nature of the power market—particularly of demand conditions—and evaluates the potential of 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 five different reserve zones (regions) of the SPP footprint in 2015.[26] While one amplifying market condition for a pivotal supplier to have an ability to raise prices above competitive levels is the frequency with which it becomes pivotal, another market condition is the times of shortage or high demand. The mere size of a supplier has no link to being pivotal; however, suppliers with high frequency of being pivotal in tight supply periods have a greater ability to have market power. For this reason, the frequency of being a pivotal supplier is also analyzed vis-à-vis to the level of demand across these five regions.

Figure 6–6 Percent of Hours at Least One Supplier Being Pivotal by Demand Level

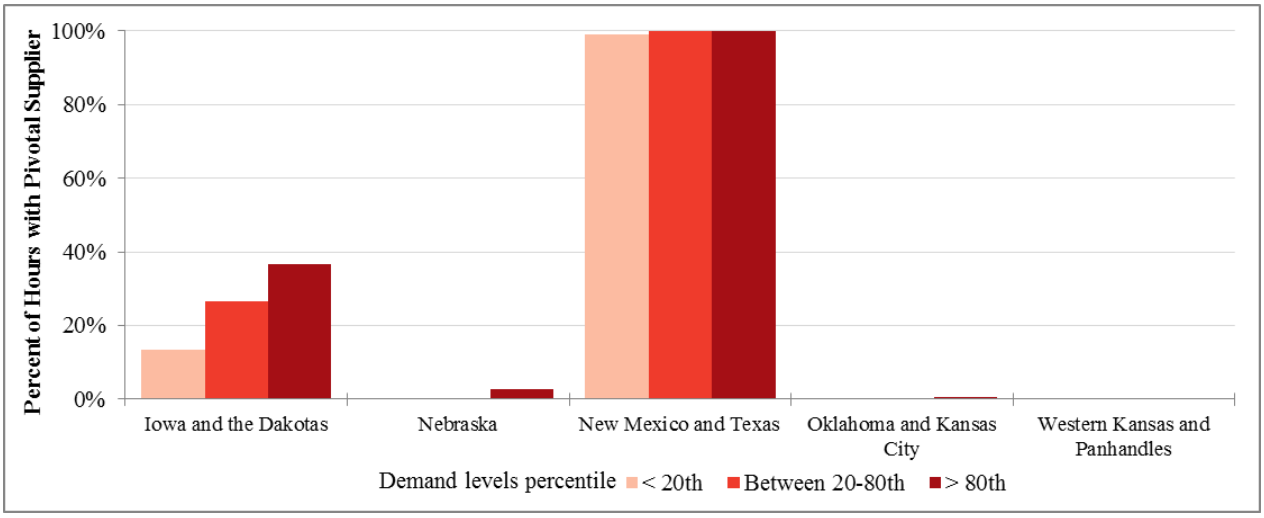


Figure 6–6 shows the frequency when a supplier is pivotal at varying load levels. The results indicate that the percent of hours with pivotal supplier is the highest (around 100%) in the New Mexico and Texas region—irrespective of demand level—where the SPP's only Frequently Constrained Area (FCA) in 2015 was located. [27] This region is followed by Iowa and the Dakotas where, depending on the level of load, 13% to 36% of the hours exhibit at least one pivotal

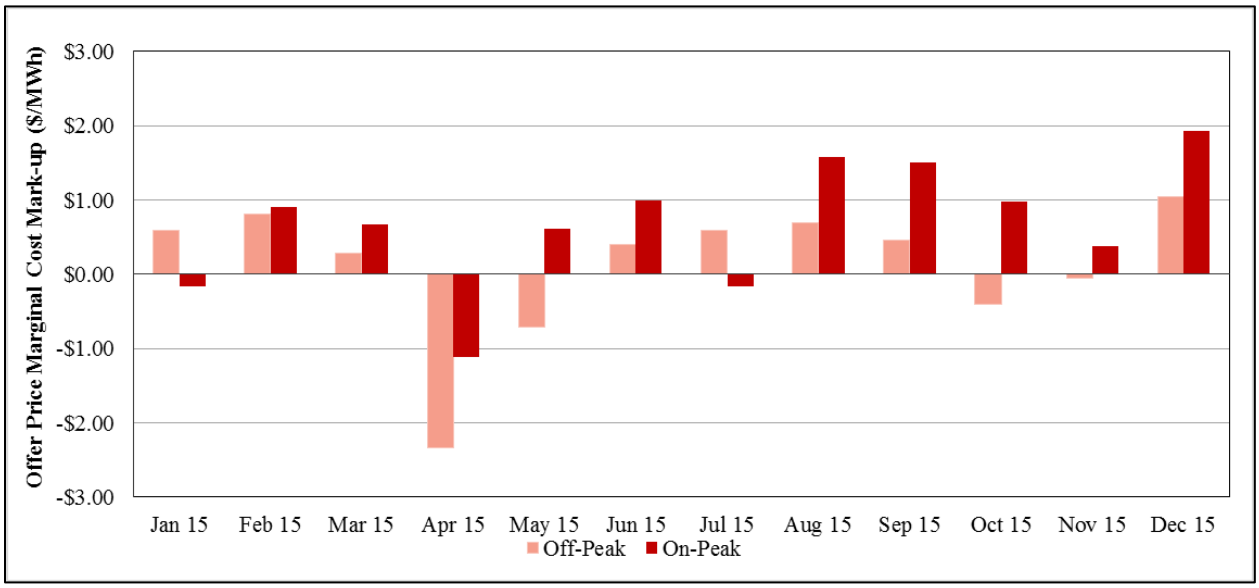
[26] SPP divides market resources (generation) into roughly five reserve zones. For the purpose of this report these reserve zones are named as Nebraska, Western Kansas and Panhandles, New Mexico and Texas, Oklahoma and Kansas City, and Iowa and Dakotas. Thus, each generation resource is mapped to one of these reserve zones. To define a load zone to match with a resource zone, each load settlement location was mapped, as closely as possible, 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 2015.
[27] Except those months of June and October.

supplier. The remaining regions of Nebraska, Oklahoma and Kansas City, and Western Kansas and Panhandles indicate that suppliers became pivotal for only negligible periods.

6.2. Behavioral Aspects of the SPP Market

In a competitive market, prices should reflect the short run marginal cost of production. 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 RTBM interval. Figure 6–7 provides the average marginal resource markups[28] by month for on-peak and off-peak periods.

Figure 6–7 Monthly Average Offer Price Markups, 2015



In 2015 the markups ranged from -$2.34 to $1.04/MWh for off-peak periods and from -$1.12 to $1.92/MWh for on-peak periods. The lowest markups occurred in spring 2015 for off-peak hours. These months had the most wind generation on the margin and were some of the windiest

[28] 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 system marginal price.

months overall. In three months, the average on-peak markup was also negative. This reflects RTBM offers below mitigated offers. This could occur where generators may have offered below their marginal cost to maintain commitments or updated real-time offers from day-ahead levels as gas prices fell throughout the week. Note that on-peak markups rose to almost $2/MWh during the month of December.[29]

6.2.1. Mitigation Performance Assessment

SPP employs a conduct and impact automated mitigation scheme to address potential market power abuse through economic withholding. The mitigation applies to resources that can potentially exercise local market power due to transmission congestion, and in instances where there is the potential for cost recovery manipulation due to a manual commitment that guarantees recovery of all costs reflected in the resource's submitted offers.

6.2.2. Mitigation Frequency

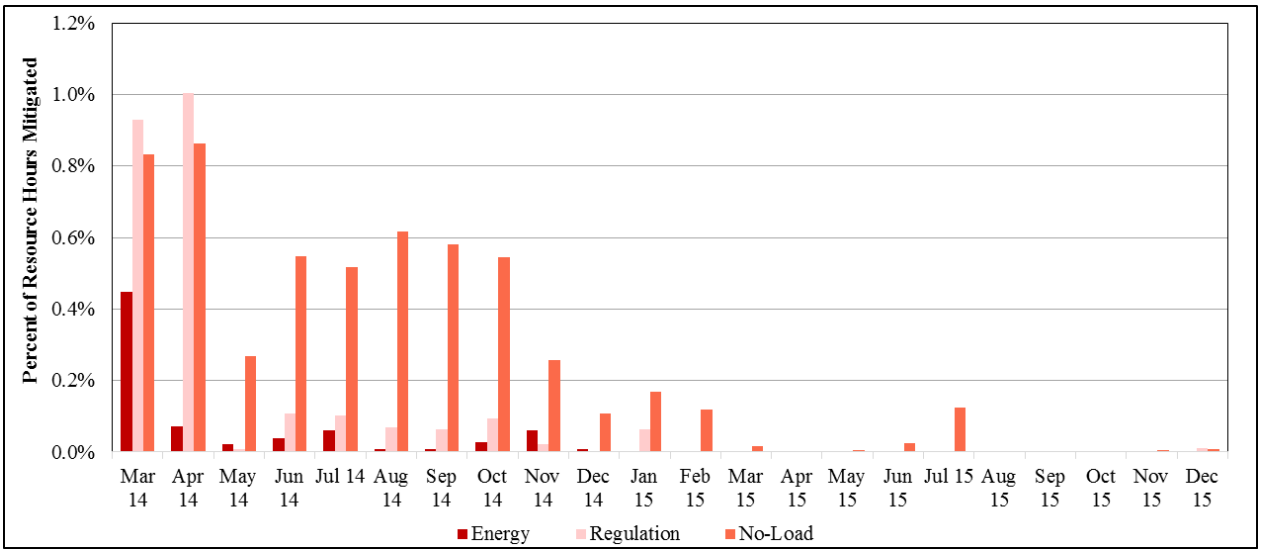
SPP resources' incremental energy, start-up, no-load, and operating reserve offers are subject to mitigation when the following three circumstances occur simultaneously in a market solution:

1) 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[30]; and a second offer, generally referred to as a market-base or strategic offer. An offer fails the Conduct Test when the market-based offer exceeds the Mitigated Offer by more than the allowed threshold.
2) The resource has local market power due to transmission congestion or the potential for cost recovery manipulation is present due to a local reliability issue.
3) The application of mitigation impacts market prices or Make-Whole Payments by more than the allowed threshold, or when the resource is manually committed by the SPP or by a local transmission operator.

[29] It should be noted that some outlier markup observations were removed from the data. These reflected high offers at coal plants with limited fuel supply, where the Market Participants chose not to reflect the opportunity cost of the fuel supply limitation in the mitigated offer. These verifiable circumstances distort the averages, and they do not reflect economic withholding.
[30] As indicated in Appendix G of the SPP's Market Protocols.

The mitigation frequency varies across products and markets. Figure 6–8 shows that the mitigation of incremental energy, no-load, and operating reserve products was infrequent in the Day-Ahead Market in 2015. The application of mitigation to incremental energy, no-load, and operating reserve offers has declined dramatically in the second year of the market starting with March of 2015. The application of mitigation in the RTBM is on average less than 0.1% for 2015 with levels almost nonexistent in all but one of the last 10 months of 2015 for all three components.

Figure 6–8 Mitigation Frequency, Day-Ahead Market



The mitigation of start-up offers has also been dramatically lower in the second year of the market, starting with March 2015. Figure 6–9 shows the mitigation frequency for start-up offers for the various means of commitment. An important takeaway is the downward trend of the chart. The mitigation of start-up offers fell to less than 10% in February 2015 and has since fallen to less than 2%. There are two reasons for the reductions:

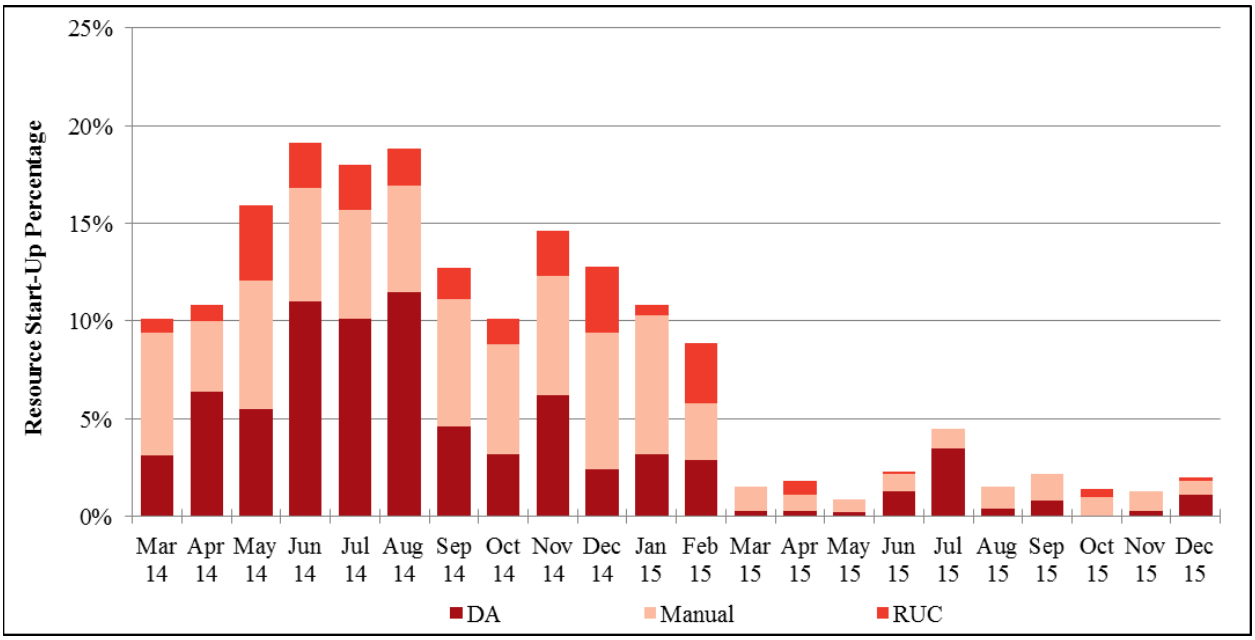
1) New rules on the application of mitigation to manually committed resources went into effect in mid-February.[31] The new rules make it clear that the more stringent mitigation process, originally applicable to all manual commitments, only applies to manual commitments that are a local reliability issue. Other manual commitments are

[31] See FERC Docket ER15-673.

subject to mitigation procedures comparable to those applied in the Day-Ahead Market and DA RUC, and ID RUC;

2) The other reason for the drop is the increase in the impact test threshold to $25/MWh.

Figure 6–9 Mitigation Frequency, Day-Ahead Market Start-Up Offers



6.2.3. Output Gap as a Measure for Economic Withholding

Economic withholding by a resource is defined as submitting offers that are unjustifiably high such that either the resource is not or will not be scheduled/dispatched, or if dispatched such offers 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. Competitive offers (i.e., mitigated offers) in the SPP Market are determined at the level of short-run marginal cost of production and the output gap corresponds to that withheld—not produced—output as a result of offers exceeding the mitigated offer by a 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—corresponding to a level between minimum and maximum economic capacity—and the actual amount of production.[32]

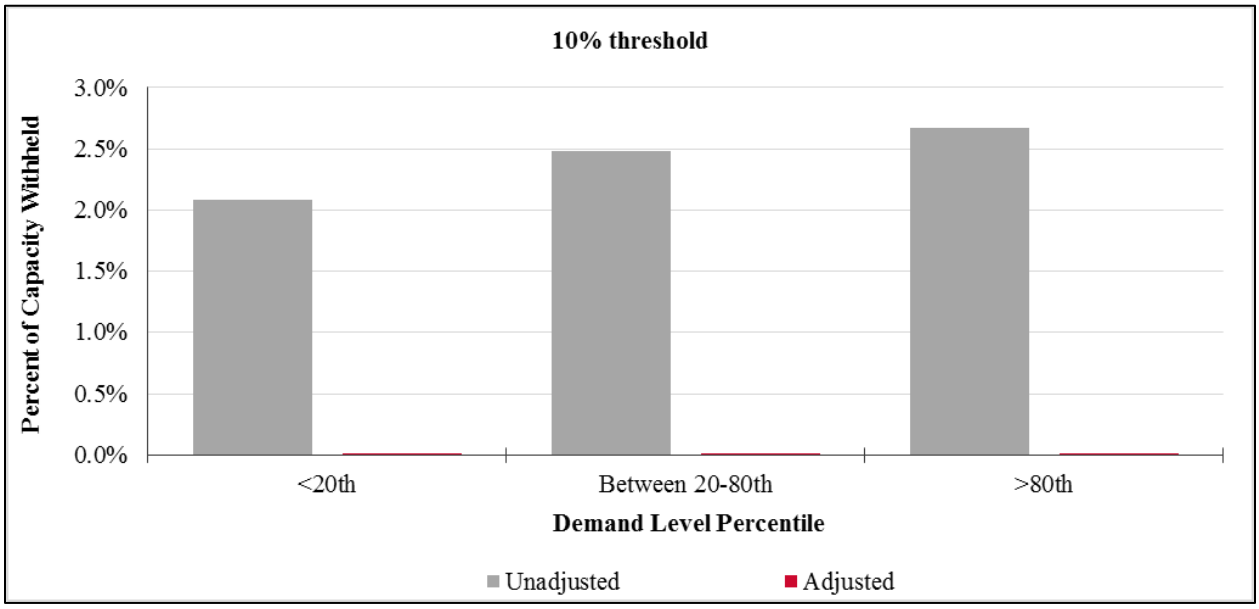
Unlike the case for the PSA, one SPP-wide overall—rather than regional—output gap figure is estimated. However, similar to the PSA, the calculations were run against the level of demand as a potential market condition that can affect the outcome.[33]

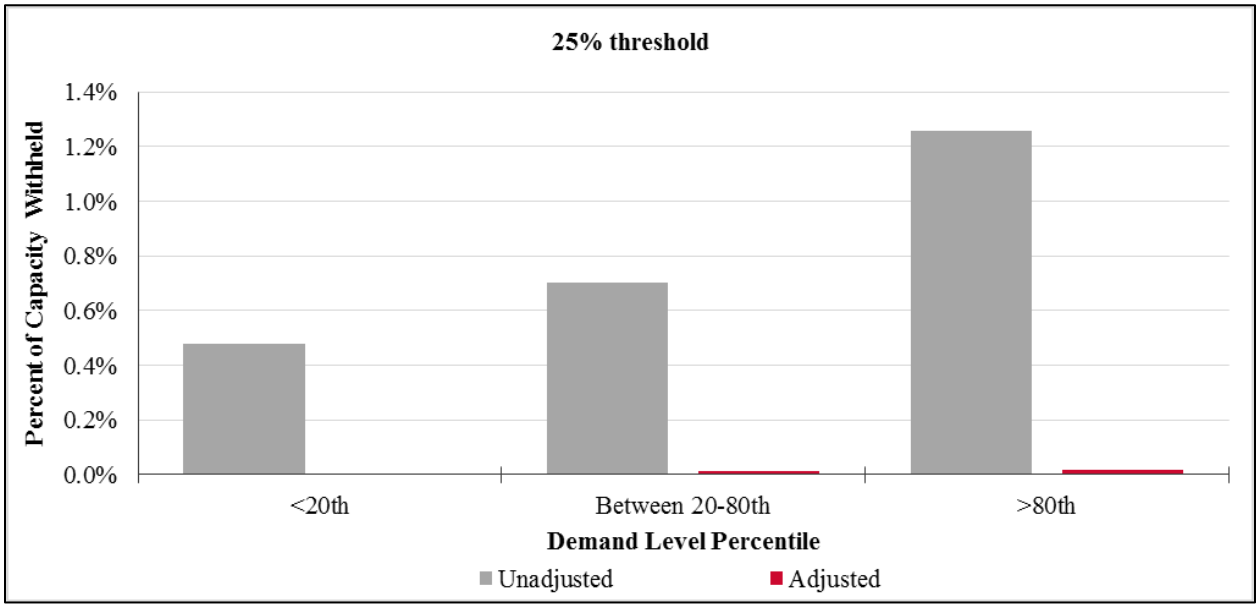
Most of the energy for non-Quick-Start Resources was awarded in the Day-Ahead Market, whereas QSRs are generally exposed to real-time prices. Therefore, day-ahead prices are used for non-QSRs and real-time prices are used for QSRs for assessing the output gap. Also, the MMU considered 10% and 25% conduct threshold levels for economic withholding at varying demand levels. Finally, 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 adjustment is made by taking the maximum of the offer and the dispatched amount to reflect the actual amount of production.

The results in Figure 6–10 show that the overall (average) level of output gap varies between 0.48% and 1.26%, the latter showing the amount of (economic) capacity withheld at the highest load percentile level. This low level of withholding is consistent with competitive market conduct.

[32] The MMU introduces the output gap metric in its 2015 report for the first time and the calculations are of preliminary nature. Going forward the MMU will continue to use this metric consistently at a more elaborate level.
[33] It is expected that the output gap would increase at higher levels of demand, as the higher demand would provide more opportunity for economic withholding.

Figure 6–10 Output Gap by Load Level and Conduct Threshold





6.3. Summary Assessment

The structural and behavioral metrics indicate that the market was generally competitive in its first two years. The MMU's Market Share, HHI, and Pivotal Supplier Analyses all indicate minimal potential structural market power in SPP Markets outside of areas that are frequently congested. For the FCAs—only one such area was so designated in 2015—where the potential

for concerns of local market power is the highest, existing mitigation measures with relatively tight thresholds provided an effective level of local market power mitigation in terms of preventing pivotal suppliers 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. In that context, the frequency of mitigation in 2015 was dramatically lower than that experienced in 2014. The mitigation for energy, regulation, and no-load in 2015 was generally below the 0.1% level in many months, while the mitigation level for these market components was virtually zero for all but one of the last eight months of the year. This is in stark contrast to the mitigation levels in 2014 when some of these components experienced mitigation levels approaching 1%. The decline in the frequency of start-up offer mitigation in the Day-Ahead Market in 2015 is similar to that experienced for the other market components, declining from 15–20% levels in 2014 to about the 1% level in 2015. This overall decline in the level of mitigation of more than 90% is attributed to normal market maturing and the addressing of some specific market implementation problems. The overall mitigation frequency levels experienced in 2015 is consistent with those levels experienced in other markets.

Finally, output gap as a measure for economic withholding was also calculated and the results show that the overall (average) level of the output gap varies between 0.48% and 1.26%, the latter showing the amount of (economic) capacity withheld at the highest load percentile level. This low level of withholding is consistent with competitive market conduct.

Overall, 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 market results in 2015 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 market results are competitive during periods of high demand and supply shortages 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 the 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 NOPERs, submitting comment at FERC on SPP filings, and making recommendations in the Annual State of the Market report, to name some of the better known forums. 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 and that the MMU will monitor conditions as needed. Those topics, as well as others, will continue to be monitored. Should those topics need to be addressed in future, then the MMU will present new recommendations in a forum that is most appropriate for that issue.

The 2014 report contained a number of 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 by the MMU. The SPP Board of Directors' serious consideration of those recommendations is greatly appreciated by the MMU. It is the opinion of the MMU that significant progress has been made on many of the 2014 recommendations as described in this section. Some of the recommendations have been revised given the changes in the market and are the result of additional analysis by the MMU.

7.1. Quick-Start Logic

In the 2014 ASOM the MMU identified Quick-Start Resources as an area of concern and made several recommendations. Analysis presented in the body of this report demonstrates that significant progress has been made in addressing those concerns.

In 2015 SPP pursued two market design changes that should have a positive impact on the commitment of and Make-Whole Payments to QSRs: 1) RR99 Short-Term RUC (ST RUC) with Quick-Start Carve-Out, which is fully implemented as of April 2016; and 2) MPRR116 Quick-Start Resource Enhancements, which is expected to be implemented by mid-2017. While these design changes reduce QSRs' inclusion for consideration in RUC processes, these resources will still be subject to RTMB commitment and thus be eligible for Make-Whole Payments. Late in 2015, the MWG proposed to wait and see the results of RR99 and RR116 changes before taking any further action related to QSRs.

Generally, the MMU supports the efforts of the RTO to shorten the time between QSR commitment and dispatch to enable more economic commitments as forecast data improves. In that context a trend of more economic dispatch is observed in 2015, and early indications are that the trend continues in 2016. For the first 12 months of the Integrated Marketplace (March 2014 to March 2015), the share of QSR dispatches during intervals where the LMP was above the market offers covers just over half of the power produced. During 2015 over two-thirds of the power produced by QSRs corresponded to intervals where LMP was above the market offer compared to the three quarters share of other types of resources. The MMU recognizes this as progress towards more efficient use of these units, and encourages the RTO to implement the planned changes quickly. The MMU also recognizes that there may be individual QSRs that fall outside the general trend and need to be assessed individually.

An analysis of RUC Make-Whole Payments to QSRs shows the trend is down at the end of 2015, and early indications in 2016 suggest the trend continues. As the Short-Term RUC process is implemented in 2016, fewer Make-Whole Payments to QSRs may be observed. However, the MMU will continue to follow the implementation of this process and evaluate the impact of the changes.

Given the significant progress in addressing the identified concerns, and the pending implementation of additional changes that should further advance the resolution of the issues regarding QSRs, the MMU considers the recommendations regarding QSRs to be addressed. The MMU will continue to monitor the participation of these resources in the market and make new recommendations as needed.

7.2. Ramp-Constrained Shortage Pricing

The Market Monitor previously recommended pricing the ramp-constrained operating reserve shortages in a manner similar to the operating reserve capacity shortages. Efficient prices reflect the cost of the marginal action. Analysis presented in the body of this report indicates that ramp-constrained shortage pricing continues to be low. The MMU is not aware of any direct action with regard to this issue by the SPP during 2015.

The MMU is aware of the FERC issued Notice of Proposed Rulemaking (NOPR) and the subsequently issued order on a closely related subject, "Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators" (RM 15-24-000).[34] The MMU is also aware of SPP's preference to wait for the FERC decision per this NOPR and the order before initiating discussions on this subject.

In the meantime, the MWG formed a Price Formation Task Force (PFTF) "to evaluate the efficiency and transparency of Energy and Operating Reserve pricing," which is expected to complete its tasks by the end of 2016. The PFTF is expected to discuss and address various pricing issues including the scarcity/shortage pricing, refinement of existing product pricing, and the introduction of new products to the SPP Market.

The MMU will continue to track this issue, assess the results of the activities describe above, and then determine if and which concerns outlined in the 2014 report are sufficiently addressed.

7.3. Manipulation of Make-Whole Payment Provisions

The MMU initiated discussion with the Market Working Group in late 2013 with regard to potential market manipulation issues experienced in other markets with a Day-Ahead Market. The MMU also identified a concern with potential manipulation of Make-Whole Payments for the JOU Combined Resource Option.

The Market Working Group has approved a design change that addresses the manipulation issue associated with the JOU Combined Resource, and most of the market efficiency concerns also associated with this JOU issue. The change is scheduled to be implemented in the first quarter of

[34] NOPR, RM 15-24-000 issued September 17, 2015 and Order No. 825 issued June 16, 2016.

2017, and the MMU continues to actively monitor this issue. The MMU considers this issue to be resolved.

As of June 25, 2015 no solutions have been implemented to correct the other potential market manipulation issues previously described. The RTO is currently in discussions with the MMU to find the best measures for abating the risks associated with the local OOME events, resources committed across the midnight hour, and the regulation deployment adjustment. The MMU continues to actively monitor these issues pending the development of permanent rules to directly address the concern.

7.4. Day-Ahead Must-Offer Requirement

The MMU recommended previously that SPP eliminate the limited day-ahead must-offer provision and establish physical withholding rules to include a penalty for non-compliance. These changes would ensure an efficient level of participation in the Day-Ahead Market and enhance the protection against the potential exercise of market power abuse through physical withholding. An incentive to withhold generation may exist if participation in the Day-Ahead Market is voluntary. Thus, enhancing the physical withholding rules to include a penalty provision will provide additional protection. The physical withholding rules are targeted to identify withholding that directly impacts the competitive outcomes in the market. Assessing penalties as a result of violating the physical withholding rules is a more efficient methodology for ensuring efficient participation levels in the Day-Ahead Market.

In the event that the limited must-offer provision is continued, five weaknesses in the current provisions should be addressed. See the 2014 report for details.

In 2015 Market Participants approved a proposal to eliminate the current limited Day-Ahead Must-Offer provision of the SPP Tariff. In the meantime, the MMU submitted a proposal for physical withholding penalties that included conduct thresholds and impact test requirements in conjunction with establishing a formula-based penalty structure. The MMU engaged in discussions with the Market Participants through May 2016, at which time the MMU withdrew the proposal pending MMU's development of impact simulations. The MMU plans to reintroduce the proposal to Market Participants as early as appropriate studies are completed.

Meanwhile, the Day-Ahead Must-Offer elimination proposal was tabled by MOPC until July 2017 or the MMU's resubmission of the physical withholding proposal. The five weaknesses in the current day-ahead must-offer provision still remain valid.

7.5. TCR and ARR System Availability in Annual Process

The MMU, in concert with the SPP Congestion Hedging team, identified concerns regarding over-collecting revenue in the ARR market while also under-collecting revenue in the TCR market. Potential solutions included matching the ARR and TCR system availability in the annual process to eliminate required limit expansion for infeasible ARRs, lowering the transmission system capacity available for award in the annual ARR Allocation, and lowering the transmission system capacity available for award in the monthly ARR allocations and TCR auctions.

SPP filed and FERC approved a Tariff change that requires ARR system capacity to match the TCR system capacity in the annual process. The MMU expects improvement in the number of required limit expansions in many of the monthly TCR auctions with this change. SPP should achieve further improvement in funding disparity by reducing full system availability in the annual ARR allocation to match the system availability levels in the annual TCR auction.

The MMU will continue to monitor TCR market results in relation to day-ahead and ARR settlements. The need for additional changes will depend on the effectiveness of the changes already approved.

7.6. TCR and ARR System Availability in Monthly Process

The MMU continues to support SPP's efforts to improve market efficiency and transparency in the Monthly ARR/TCR Process. The MMU believes improved outage inclusion could help in achieving this goal. Additionally, SPP could spread the reduced system capacity across individual transmission elements and the system as a whole.

SPP submitted Revision Request (RR) 96 – Proposed Transmission Outage Scheduling to the Operating Reliability Working Group (ORWG). This revision request included language that

would have extended the deadline for submitting planned outages from a seven-day lead time to 45 days prior to the first of the month in which the outage starts. This RR was modified and approved by the ORWG to a 14-day lead time, which does nothing to address the MMU's concerns. The MMU maintains its recommendation to extend this deadline.

The MMU maintains its recommendation made in 2014 not to ignore outages based solely on duration. Additionally, the MMU recommends that SPP give its operators the authority to appropriately rate system elements and the system as a whole to prevent the overselling of TCRs. Other changes worth considering include derating system components of the system as a whole if overselling of ARRs/TCRs continues in the monthly ARR/TCR Process, and implementing a different Self-Convert methodology than the "near-infinite price" method now used.

7.7. TCR Bidding at Electrically Equivalent Settlement Locations

In several forums the MMU recommended a system change to block all TCR bidding at electrically equivalent settlement locations, thereby preventing ongoing tariff violations, eliminating potential human errors, and improving operational efficiency. SPP's MWG has approved funding for development of a system change that will block these bids from being submitted into the TCR Market User Interface. Detailed Tariff language and system requirements are yet to be developed. This change fully addresses the MMU's concerns. The MMU will continue to monitor this issue until the system change is fully implemented and tested.

7.8. Allocation of Over-Collected Losses

The use of Bilateral Settlement Schedule (BSS) transactions has been identified as a potential way of distorting the distribution of over-collected losses. This market behavior issue would adversely impact the equitable distribution of over-collected losses and potentially distort market incentives.

There appears to be consensus in the stakeholder process that there is a flaw in the over-collected losses distribution methodology, resulting in a gaming opportunity. SPP staff is in the process of preparing a proposed solution that will remove the gaming opportunities of over-collected loss

payments to BSS transactions. The MMU's initial assessment of the proposed changes indicates the new measure will address this issue. The MMU will continue to monitor activities in this area and assess the effectiveness of the final proposal as part of the stakeholder process. The MMU will also monitor the efficiency of the actual implementation.

7.9. Market Power Mitigation Conduct Thresholds

The MMU previously recommended an increase in offer conduct thresholds for start-up offers, regulation offers, and energy offers for Frequently Constrained Areas. The MMU is withdrawing this recommendation. Having observed lower than expected mitigation levels during 2015, the MMU decided to maintain a cautious approach to considering these items as potential issues.

7.10. NDVER Transition to DVER Status

The MMU has identified Non-Dispatchable Variable Energy Resources as a concern because of their adverse impact on market price. When prices are depressed in high wind production regions (LMP occurs below the short run marginal cost of wind resources), non-dispatchable resources will have an adverse impact on prices in two ways. Some resources chase price, ignoring the system pseudo dispatch (market system assumes the resources continue generating at the previously known level), and self-dispatching to a lower level in an attempt to avoid the cost associated with producing when prices are very low. This behavior at times causes unexpected volatility on the system and distorts prices. The alternative behavior is for these units to continue to produce as expected even when prices are below their true marginal cost. This uneconomic level of production drives prices below what would be an appropriate market clearing price. Both cases result in sub-optimal market results.

The MMU recommends SPP continue discussions to transition NDVER Resources to DVER status and thereby lessen the negative impact of such resources on the market.

Appendix A. Common Acronyms

AEP	American Electric Power
ARR	Auction Revenue Rights
BSS	Bilateral Settlement Schedules
BTU	British Thermal Unit
CC	Combined Cycle
CDD	Cooling Degree Days
CT	Combustion Turbine
DA	Day-Ahead
DAMKT	Day-Ahead Market
DA RUC	Day-Ahead Reliability Unit Commitment
DASMP	Day-Ahead System Marginal Price
DISIS	Definitive Interconnection System Impact Study
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	Greater Missouri Operations Company
GW	Gigawatt
GWh	Gigawatt Hour
HDD	Heating Degree Days
HHI	Herfindahl-Hirschman Index
HVDC	High-Voltage Direct Current
IA	Interconnection Agreement
ID RUC	Intra-Day Reliability Unit Commitment
IDC	Interchange Distribution Calculator
IS	Integrated System

ISO	Independent System Operator
ITP	Integrated Transmission Plan
JOU	Jointly Owned Unit
KCPL	Kansas City Power & Light
kV	Kilovolt (1,000 volts)
LIP	Locational Imbalance Price
LMP	Locational Marginal Price
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
NDVER	Non-Dispatchable Variable Energy Resource
NERC	North American Electric Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration
NPPD	Nebraska Public Power District
O&M	Operation and Maintenance
OGE	Oklahoma Gas & Electric
OOME	Out-of-Merit Energy
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PEPL	Panhandle Eastern Pipe Line Company
PISIS	Preliminary Interconnection System Impact Study
RNU	Revenue Neutrality Uplift
RT	Real-Time
RTBM	Real-Time Balancing Market
RTO	Regional Transmission Organization
RTSMP	Real-Time System Marginal Price
RUC	Reliability Unit Commitment
SC	Simple Cycle

SMP	System Marginal Price
SPP	Southwest Power Pool, Inc.
SPS	Southwestern Public Service Company
SECI	Sunflower Electric Power Corporation
TCR	Transmission Congestion Right
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WR	Westar Energy, Incorporated