2014 State of the Market

24 August 2015

SPP Market Monitoring Unit

Southwest Power Pool

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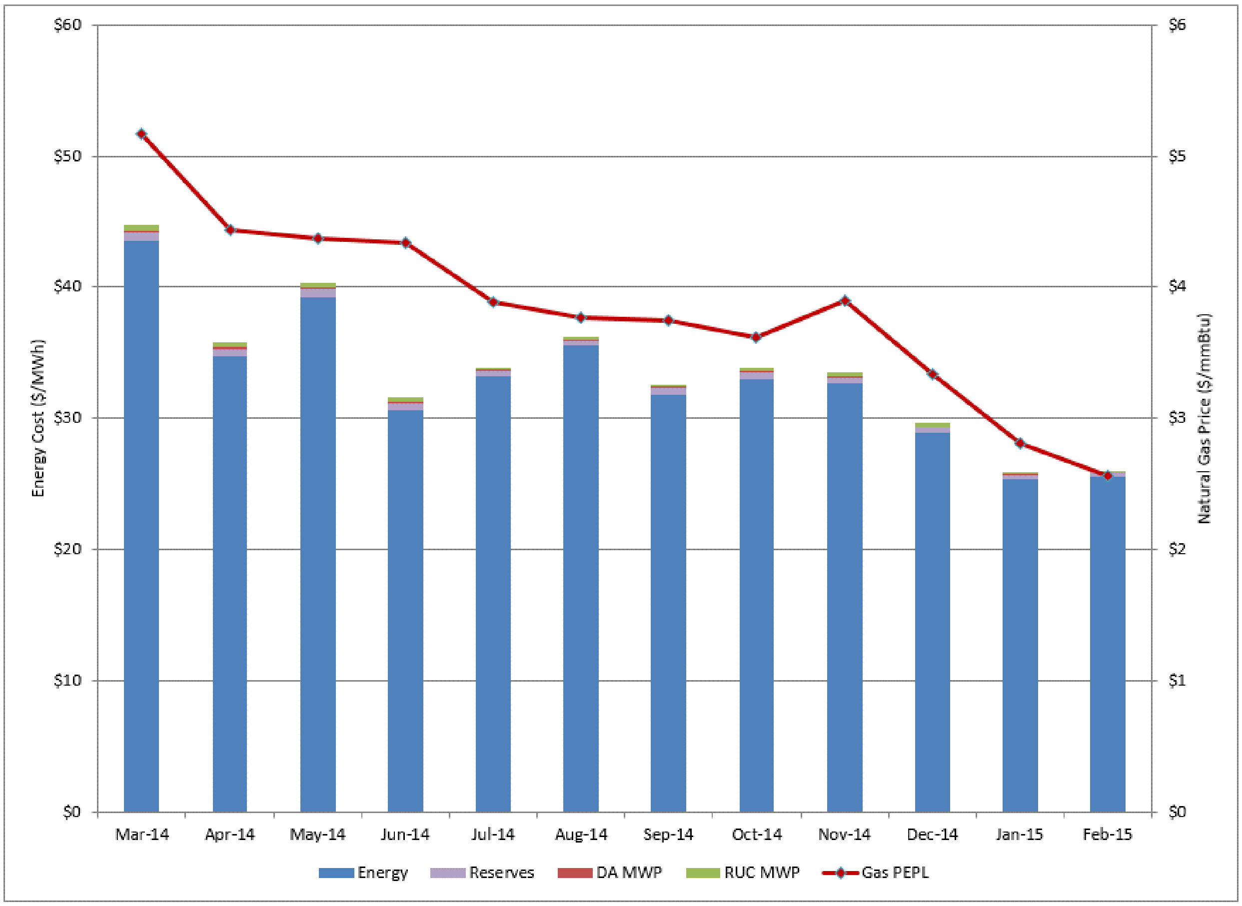
1. Executive Summary

The SPP Market Monitoring Unit's Annual State of the Market report for the first 12 months of the SPP's 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 the efficiency and competitiveness of market outcomes as well as the prevention of the exercise of market power and market manipulation from a perspective that is independent of both the RTO and its members. 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. This executive summary presents a summary of the assessment and lists the MMU's recommendations for improved market performance.

1.1. Overview

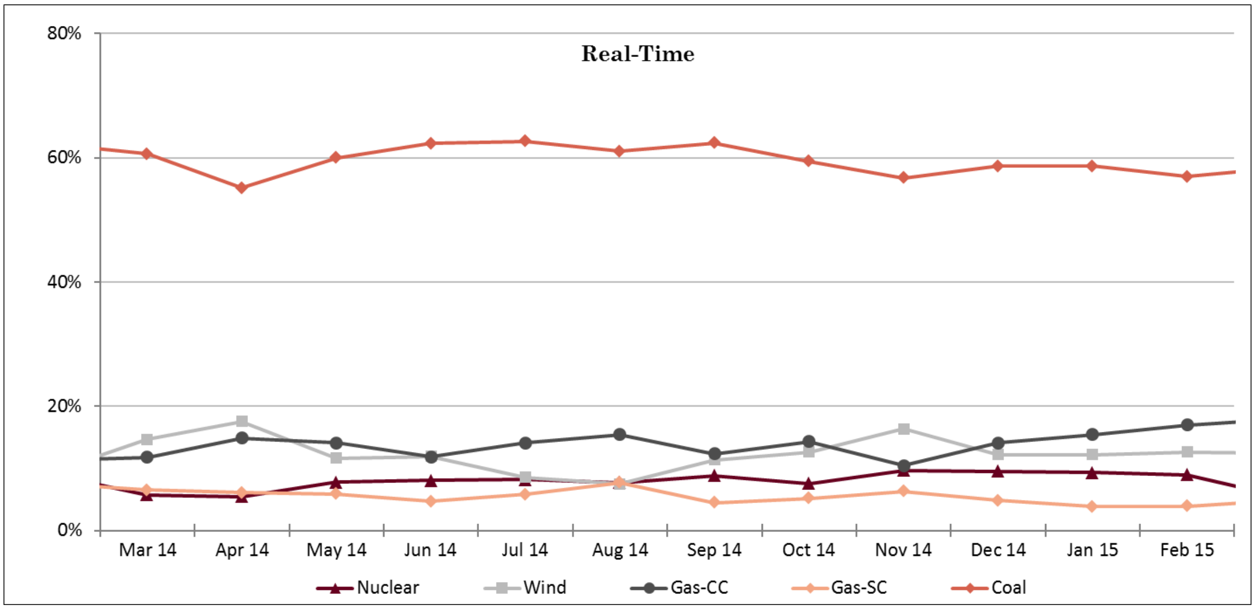
In the year since its March 1, 2014 start, the Integrated Marketplace has provided wholesale electricity at modest prices that compare favorably to those in regions with well-established markets. Average Locational Marginal Prices (LMPs) generally tracked the price of natural gas, and market uplift payments represented a small share of the average all-inclusive price.

Figure 1–1 SPP All-In Price of Electricity



SPP met the majority of its energy needs, peaking at 45 GW of load, from about 25 GW of coal-fired capacity, with an ample 35 GW of natural gas-fired capacity to meet the margin. Furthermore, SPP successfully integrated 9 GW of wind turbines in 2014, with up to 33% of energy needs met by wind in certain hours. In 2014 the market also navigated a winter weather event with a natural gas supply shortage in March and coal delivery delays through the summer and fall.

Figure 1–2 Generation by Fuel Type Real-Time Graph

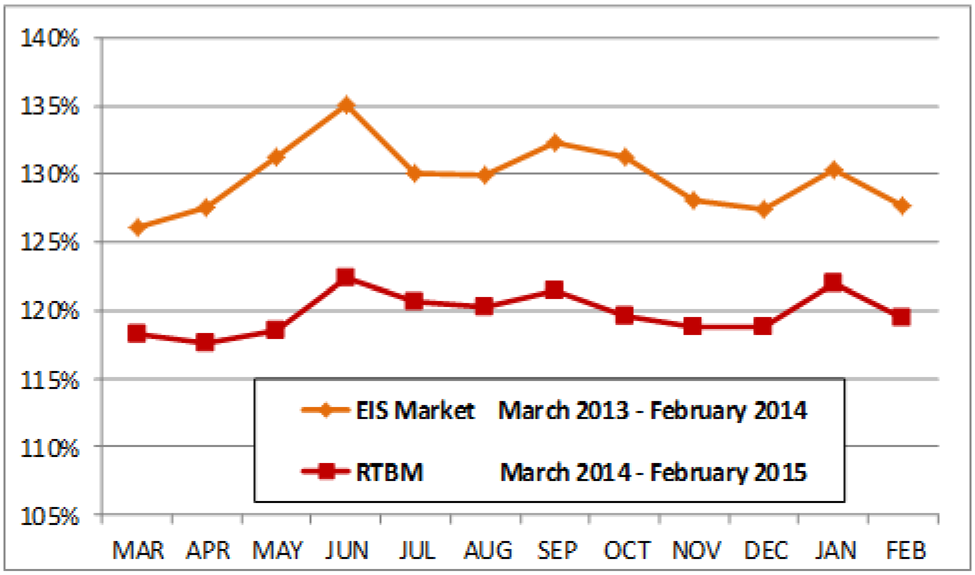


Given the large reserve margin and the frequency with which the LMP represents inexpensive generation, prices did not rise to levels high enough to support investment in new generating capacity. They did rise to a level that supports the annual avoidable costs of new, efficient generation. To the extent that existing capacity did not receive market revenues sufficient to cover annual avoidable costs, the market either did not dispatch them efficiently or was signaling the inefficiency of the resource. The former presents a market performance concern, while the latter is an efficient market outcome.

1.1.1. Energy and Operating Reserve Markets

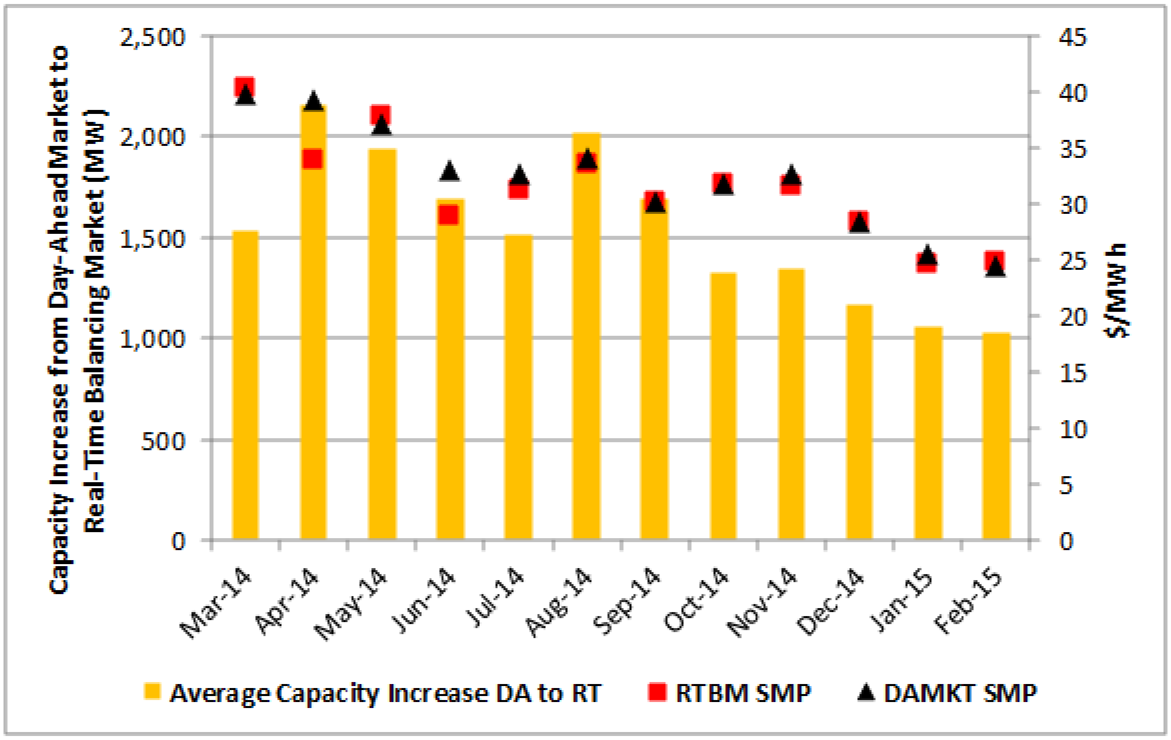
The Integrated Marketplace introduced a centralized unit commitment process, a Day-Ahead Market, and a Real-Time Balancing Market with both energy and Operating Reserve products. The centralized unit commitment constituted the largest and most immediate financial benefit of the market to SPP, as it allowed SPP to reduce online generating capacity by 10%.

Figure 1–3 Online Capacity as Percent of Demand



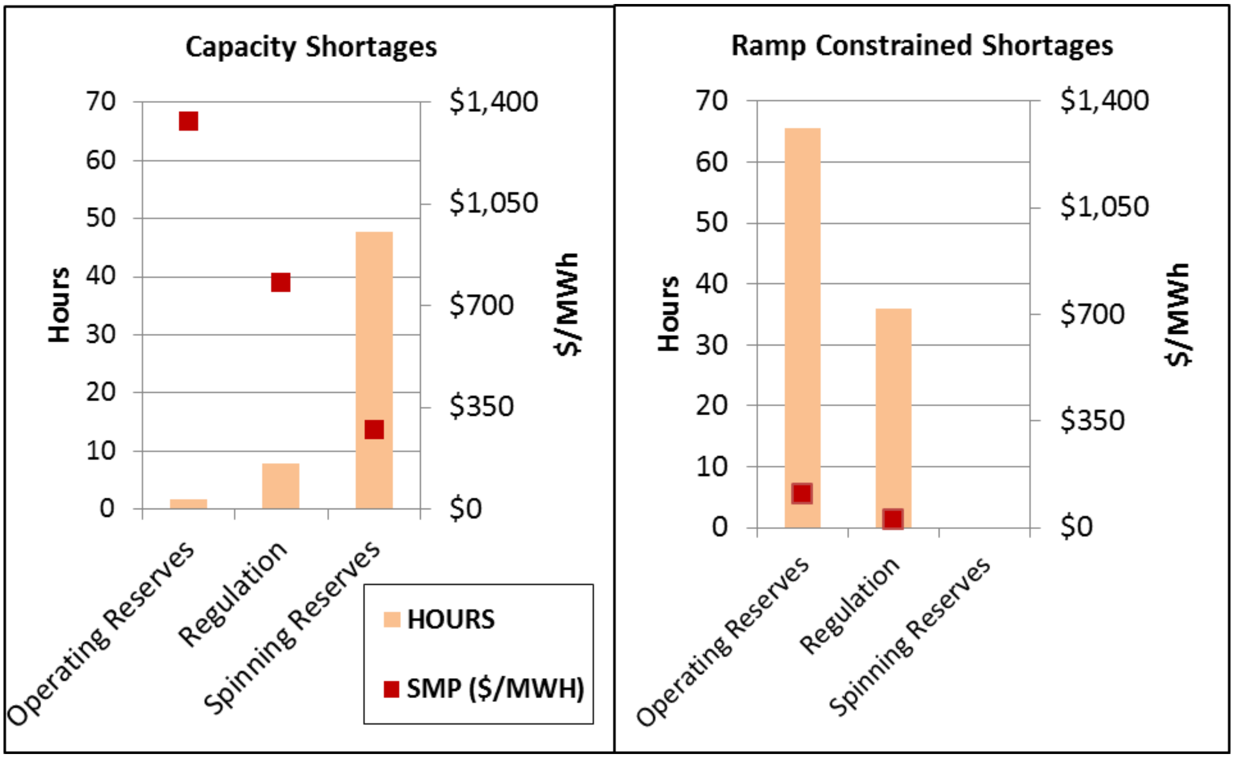
In addition to committing capacity to meet the load and operating reserve obligations, SPP also committed resources for reliability needs through its Reliability Unit Commitment (RUC) processes. The demand for reliability met through the RUC processes supplemented the load and operating reserve obligations 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 their annual avoidable costs. A particular concern to the MMU has been the RUC commitment of "quick start" resources. These resources can start in less than ten minutes and generally require only an hour of minimum run time, but the RUC process committed them to run several hours in advance and kept them online for an average of more than four hours.

Figure 1–4 Average Hourly Capacity Increases by RUC Processes



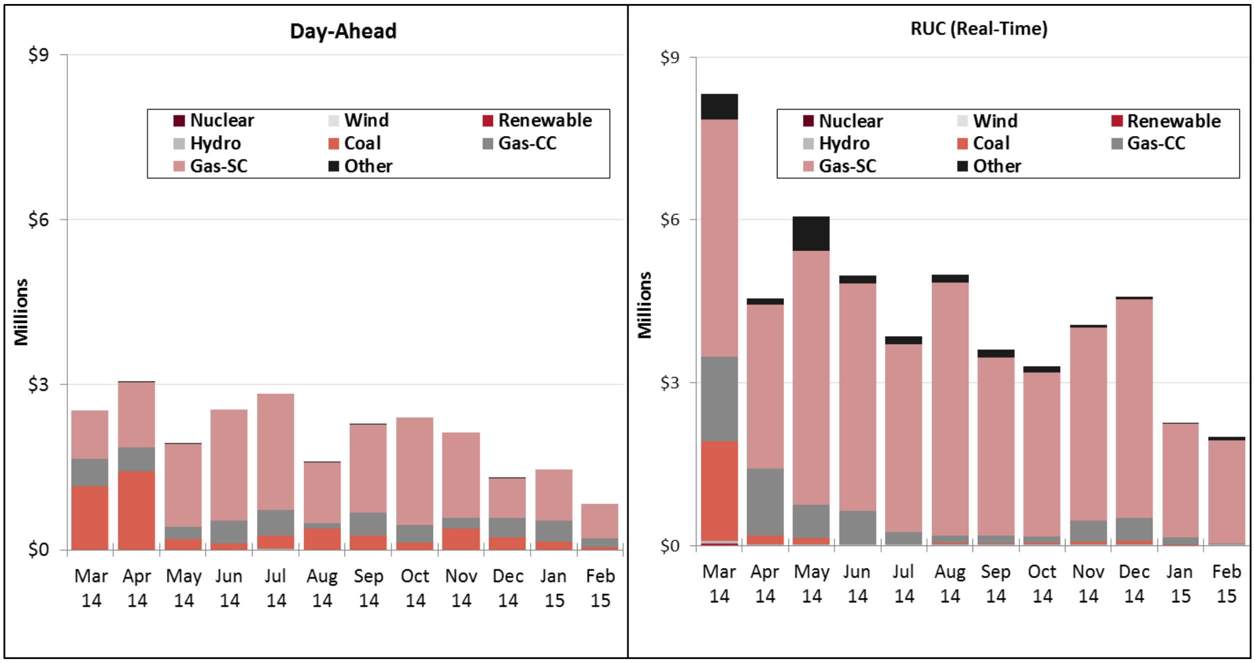
The SPP market reflected shortages of operating reserves during 58 hours with scarcity pricing levels at an average over $1,000/MWh for aggregate operating reserves, over $700/MWh for regulating reserves, and about $300/MWh for Spinning Reserves. These high prices allowed the market to reflect the demand for reliability. Average prices below $100/MWh for ramp constrained shortages did not reflect the demand for reliability, creating a market separation between economics and reliability. In its recommendations, the MMU encourages SPP to create tighter links between economics and reliability by enhancing RUC processes and scarcity pricing to allow the market to fully reflect the demand for reliability.

Figure 1–5 Capacity Shortages and Ramp Constrained Shortages



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 the first year constituted less than 1% of the all-inclusive price of electricity, with 70% of make whole payments related to RUC commitments. Their total magnitude was intermediate relative to generator uplift costs in other RTOs. The MMU recommendations around the RUC processes and scarcity pricing could reduce the need for make whole payments. This report also summarizes some known opportunities for market manipulation of the make whole payment provisions and provides corresponding recommendations.

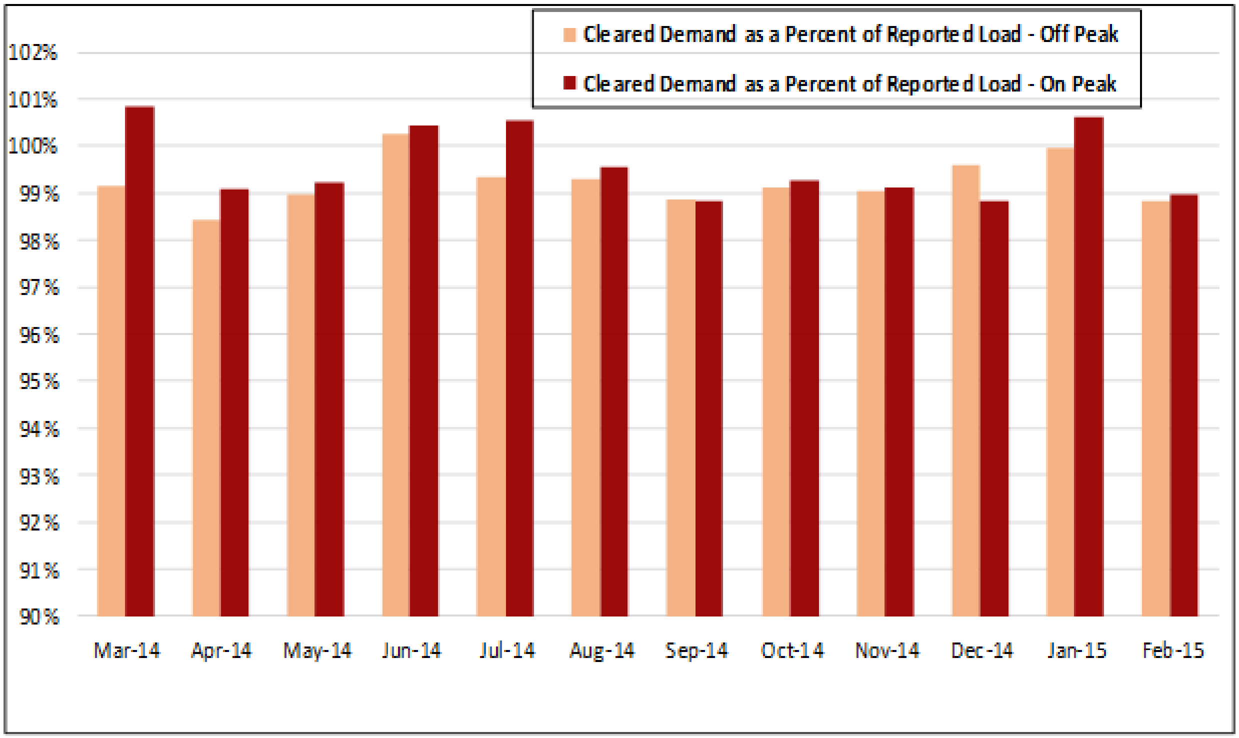
Figure 1–6 Make Whole Payments by Fuel Type



1.1.2. Day-Ahead Market

The Day-Ahead Market produced economically sound LMPs and resource commitments consistently and transparently. Ninety-seven percent (97%) of load and all of the operating reserve obligations settled in the Day-Ahead Market. In fact, load participation in the Day-Ahead Market by some participants rose to 109% in some months. A market design flaw in the allocation of Over-Collected Losses, which SPP has since corrected, incentivized this behavior. Moderate participation in virtual trading profited by about $24 million for the year. 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. A number of weaknesses in the current limited must-offer provisions should be addressed by SPP. Alternatively, the MMU recommends removal of the day-ahead must-offer requirement and replacement with a physical withholding penalty that targets resources that have a financial incentive to withhold.

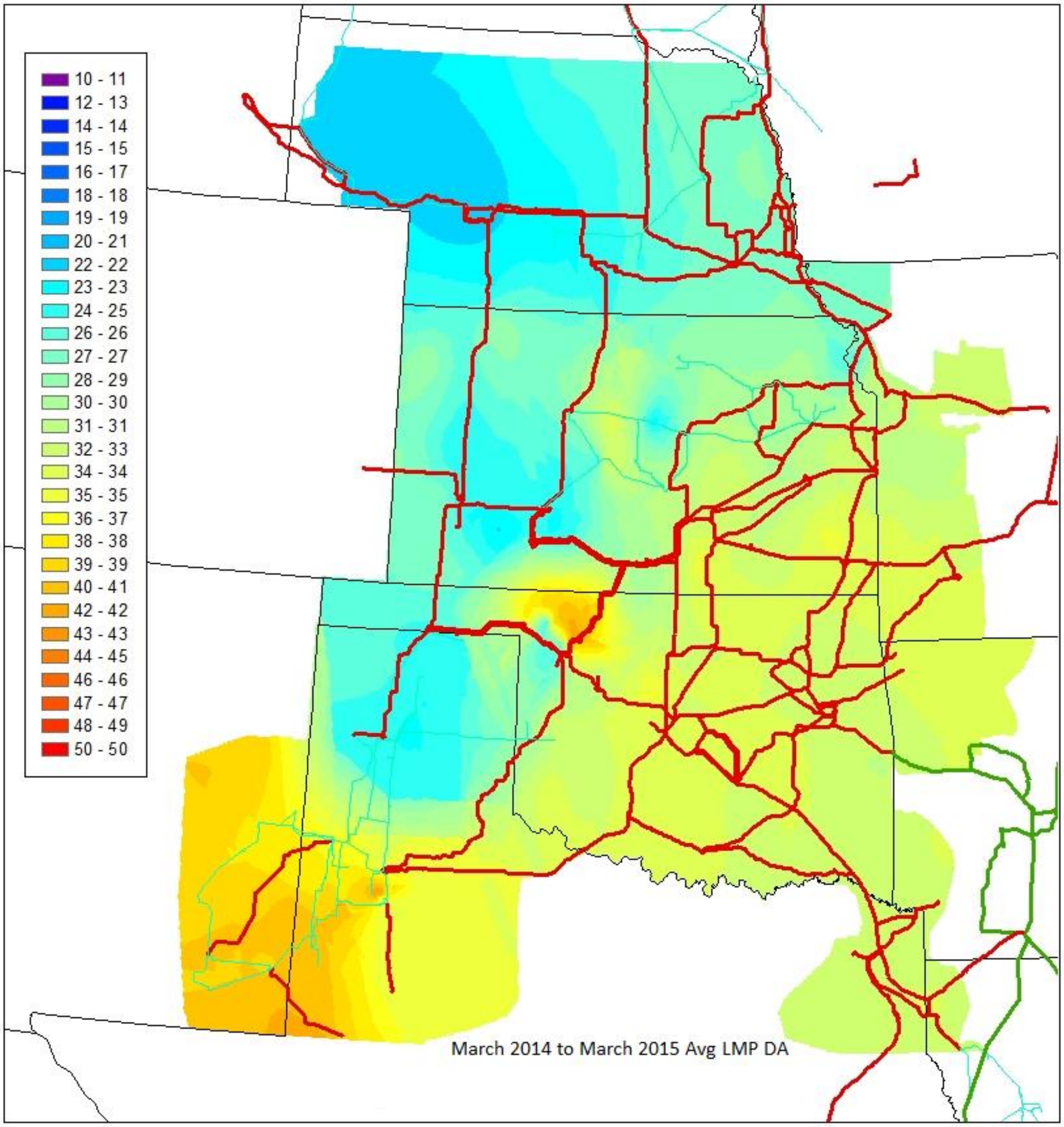
Figure 1–7 Cleared Demand Bids in Day-Ahead Market



1.1.3. Congestion and Losses

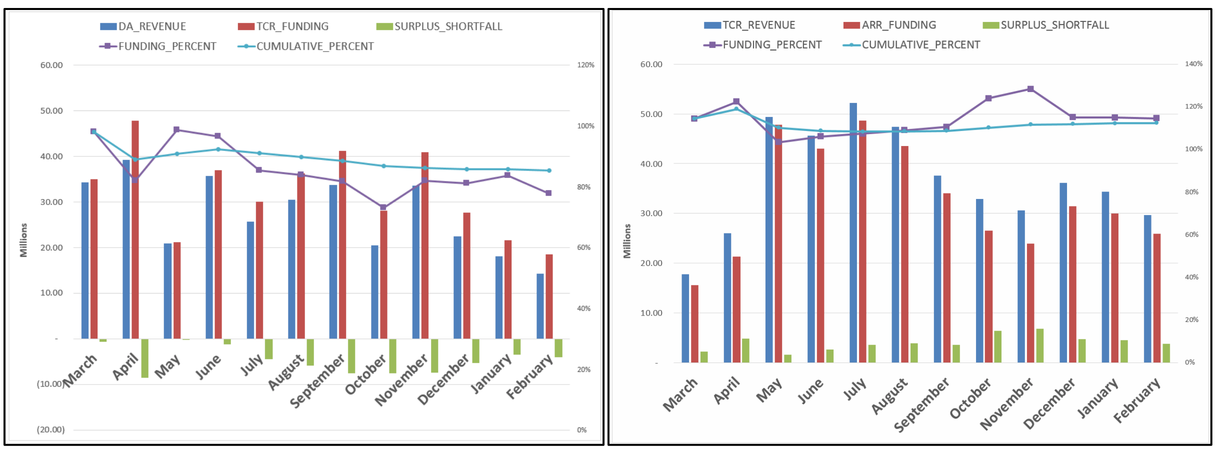
Locational Marginal Prices reflect the marginal costs of energy, congestion, and losses at any given pricing location in the market. With its historic transmission bottlenecks and ever-expanding network, the SPP market's geographic pricing pattern continued to evolve in 2014. The challenge of moving inexpensive power from coal and wind resources out of the north and west of the SPP market footprint to the eastern load centers resulted in an average \$20/MWh spread between the lowest and highest LMP points. The addition of new transmission capacity reduced the cost of congestion and losses over the course of the year. It also reduced the prevalence of local market power.

Figure 1–8 March to March Average LMP for the Day-Ahead Market



The market charged load serving entities a total of $290 million in congestion costs for the year. Load serving entities may hedge the congestion cost with Transmission Congestion Rights (TCRs) and Auction Revenue Rights (ARRs). This market provided them with $300 million in payments. 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 85% funding of TCRs from Day-Ahead Market congestion was low, and the 112% funding of ARR positions by TCR auction revenues was high. Reductions in the amount of transmission capacity made available in the TCR and ARR process to more realistic levels, earlier reporting of planned transmission outages, and improvements to modelling of the conversion of ARRs to TCRs would enhance price formation and thus the ability to effectively and economically hedge load from congestion costs.

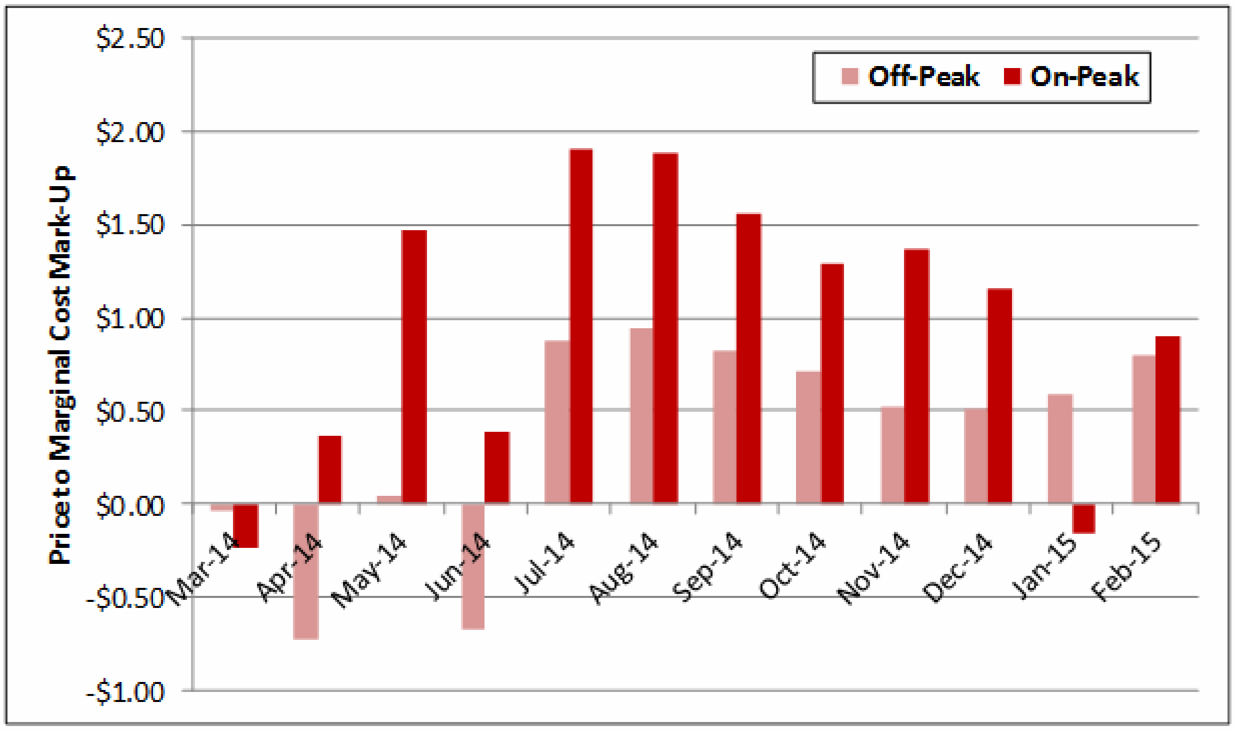
Figure 1–9 Monthly TCR Funding Levels and Monthly ARR Funding Levels



1.1.4. Market Power and Mitigation

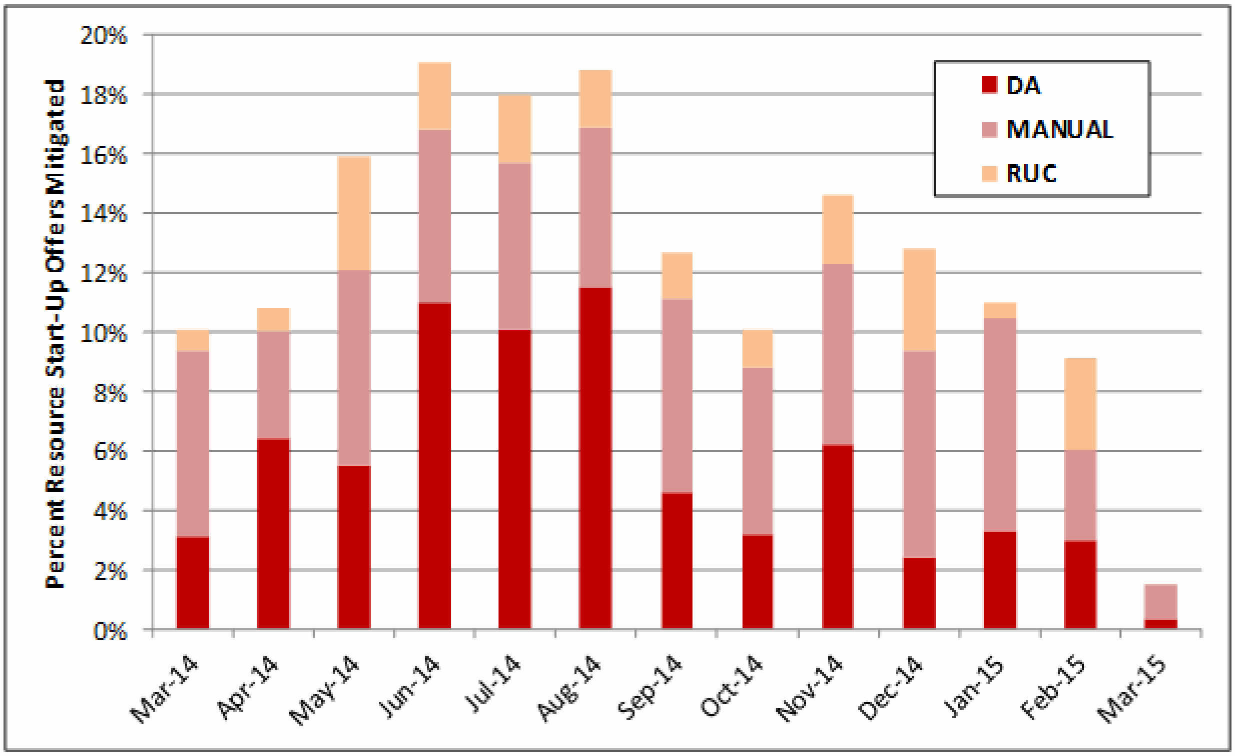
The competitive assessment of structural market power and prices shows that the SPP market produced prices near competitive levels, requiring local market power mitigation to achieve such outcomes. The hourly largest supplier market share averaged around 15%, and the market was moderately concentrated about half the time. The market generally reached highly concentrated levels in the intermediate and peaking segments of the supply curve. Despite some structural market power, average monthly price-cost mark-ups did not exceed $2/MWh and fell with increased competition between coal and gas-fired generation when gas prices fell in the winter.

Figure 1–10 Monthly Average Mark-Ups



Automatic offer mitigation limited the impact of local market power on prices. The market rarely applied mitigation to energy, no load, and operating reserve offers, at less than 1% of market resource hours. A mistake in system implementation of the mitigation caused over-mitigation of start-up offers for the majority of the year. With that correction and an increase in the threshold for market power impacts, start-up offer mitigation fell from a high of 18% to as low as 1%.

Figure 1–11 Mitigation Frequency Start-Up Offers



Despite infrequent mitigation, the MMU recommends some increases in the offer conduct thresholds for mitigation to account for cost uncertainty. It maintains its contention that market power mitigation to competitive offer levels, short run marginal costs, is necessary to support competitive market outcomes, which maximize the benefits of the SPP market.

1.2. Summary of Recommendations

The SPP MMU has the responsibility to make market design recommendations independent of any and all market stakeholders including the RTO. This is part of the checks and balances to ensure the benefits of the market are equitably distributed to all Market Participants regardless of size or influence of individual or groups of Market Participants. The MMU does this through active participation in SPP staff reviews, in SPP stakeholder meetings, before the Federal Energy Regulatory Commission, and in public reports. Some of the recommendations presented in this report have been made through these various channels and have received varying levels of consideration.

The following recommendations, supporting analysis, and educational background may be found throughout this report:

MMU Recommendation 1. Quick Start Logic

The MMU supports the development of new rules governing the dispatch of quick-start resources that: (1) do not subject quick-starts to RUC commitment; and (2) do not provide make whole payment eligibility for RTBM dispatch.

MMU Recommendation 2. Ramp-Constrained Shortage Pricing

Ramp-constrained operating reserve shortages should be priced in a manner similar to the operating reserve capacity shortages.

MMU Recommendation 3. Manipulation of Make Whole Payment Provisions

Potential for make whole payment manipulation for resources committed across the midnight hour, fixed regulation bids, Out-of-Merit energy payments, and jointly-owned units should be eliminated.

MMU Recommendation 4. Day-Ahead Must-Offer Requirement

The MMU recommends that SPP eliminate the limited day-ahead must-offer provision and revise the physical withholding rules to include a penalty for non-compliance. In the event that the limited must-offer provision is continued, SPP should address design weaknesses.

MMU Recommendation 5. TCR and ARR System Availability

TCR and ARR system availability should be reduced to minimize the over-allocation of TCRs and ARRs that Day-Ahead Market congestion revenues do not support.

MMU Recommendation 6. Transmission Outage Reporting and Modelling

The MMU supports SPP's current efforts to improve planned outage reporting and suggests adding flexibility to outage inclusion criteria for ARR and TCR modelling.

MMU Recommendation 7. TCR Bidding at Electrically Equivalent Settlement Locations

A systematic block of TCR bidding at electrically equivalent settlement locations should be implemented to prevent ongoing tariff violations by Market Participants.

MMU Recommendation 8. Allocation of Over-Collected Losses

SPP should remove the Bilateral Settlement Schedule transactions from the over-collected losses distribution calculation and consider over-collected losses distributions to exports relative to interface transaction profit margins to assess potential distortion of market incentives.

MMU Recommendation 9. Market Power Mitigation Conduct Thresholds

The MMU supports a modest increase in offer conduct thresholds for start-up offers, regulation offers, and energy offers for Frequently Constrained Areas.

2. Overview of SPP Market Footprint

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. SPP was granted RTO status by FERC 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, training, and wholesale electricity market operations. This report focuses on the first full year (12 months) of the SPP wholesale electricity market referred to as the Integrated Marketplace, which started on March 1, 2014. This affords us the opportunity to effectively analyze and compare the Marketplace results to other annual reports. When relevant, this report will discuss certain aspects of the Energy Imbalance Services Market that was operational for the first two months of 2014. Subsequent annual reports will return to a normal 12 month calendar year reporting period.

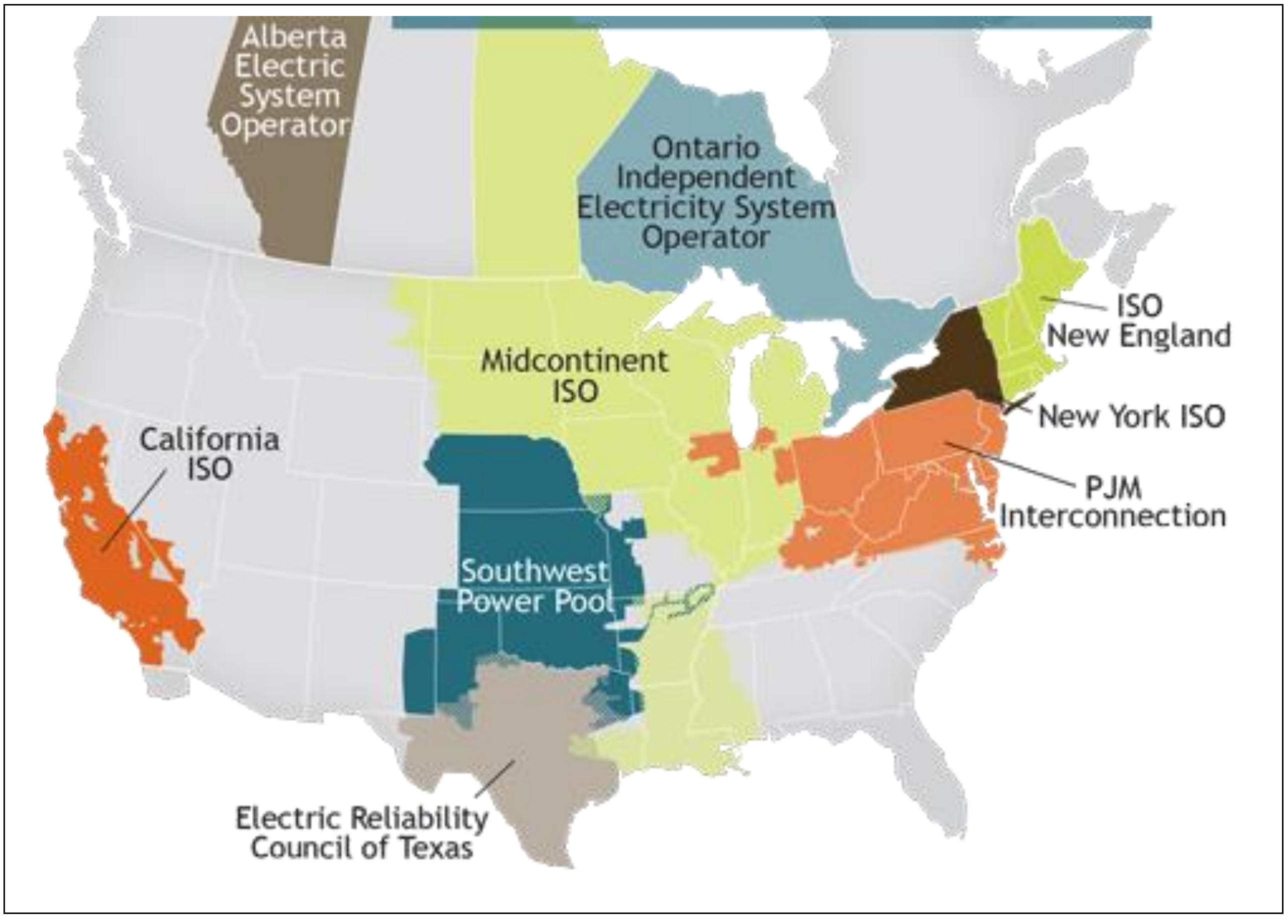
The Integrated Marketplace is a full Day-Ahead Market with Transmission Congestion Rights, virtual trading, a Reliability Unit Commitment process, a Real-Time Balancing Market, and a price-based Operating Reserves market. SPP simultaneously put into operation a single Balancing Authority as part of the implementation of the Integrated Marketplace. The real time market that was in place prior to the Integrated Marketplace was supported by 16 balancing authorities consisting of large vertically integrated utilities in the RTO footprint. 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 capacity for energy and operating reserves.

2.1.1. SPP Location

SPP is located in the west-central portion of the Eastern Interconnection. It is bordered by the Midcontinent ISO (MISO) to the north and east and the Electric Reliability Council of Texas (ERCOT) to the south. SPP also shares borders with the Western Electricity Coordinating

Council (WECC) to the west with limited HVDC interconnection capacity. Figure 2–1 shows the operating regions of the nine ISOs and RTOs in the United States and Canada.

Figure 2–1 ISO RTO Operating Regions



Source: ISO/RTO Council

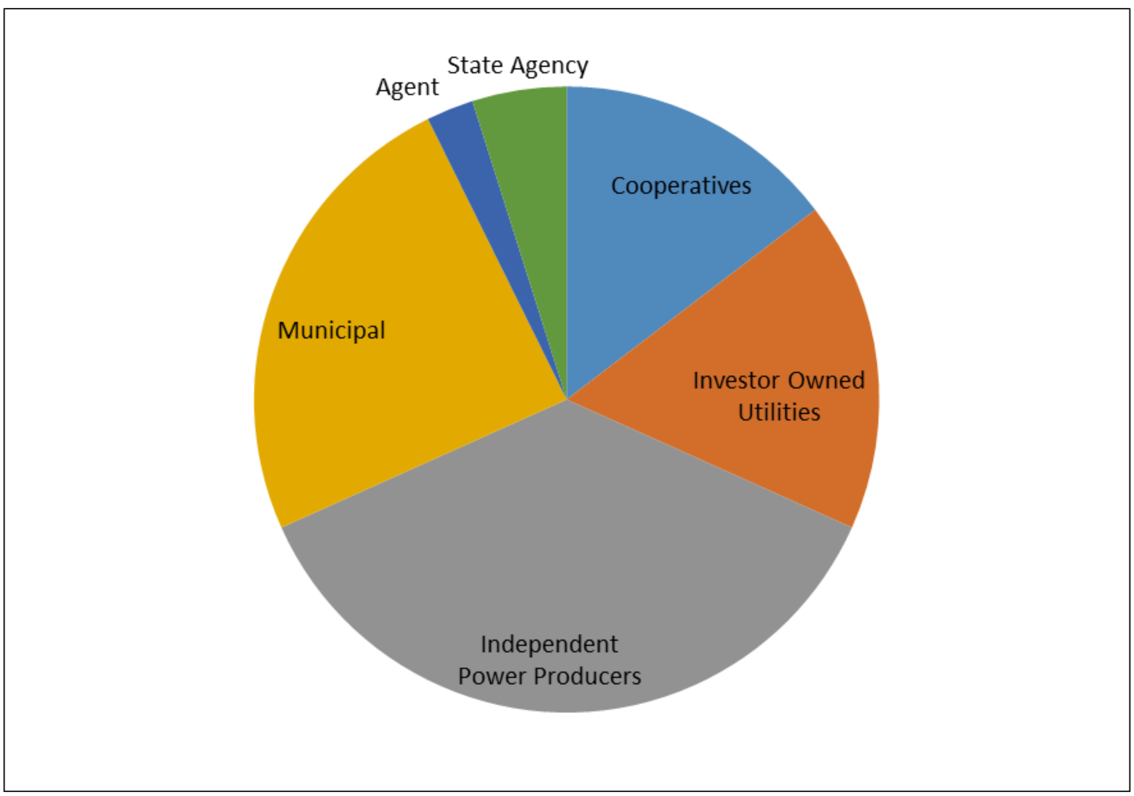
The SPP Integrated Marketplace footprint will be expanding in the fall of 2015 to include the Integrated System (IS), composed of the Western Area Power Administration (WAPA) – Upper Great Plains, Basin Electric Power Cooperative, and Heartland Consumers Power District. The IS covers much of the Dakotas and small adjacent parts of Iowa, Minnesota, Montana, Nebraska, and Wyoming. The IS will add 5,000 MW of load, and almost 10,000 miles of high-voltage transmission lines increasing the length of SPP-managed transmission lines by 18% to more than 58,000 miles.

2.1.2. SPP Market Participants

At the end of 2014, 134 entities were participating in the SPP Integrated Marketplace. This is a substantial increase from the 102 participating in the predecessor EIS Market in 2013. The Marketplace is open to financial and physical asset owners, whereas the EIS Market required all participants to own assets such as generation or load.

Market participants can be divided into several categories: investor owned utilities, cooperatives, municipals, state agencies, independent power producers, and financial only. Figure 2–2 shows the distribution of resource owners registered to participate in the Integrated Marketplace. The number of Independent Power Producers is high because most of the wind producers are included in this category. Several Market Participants, referred to as agents, represent several individual resource owners that would individually be classified in different types such as municipal, cooperatives, and state agency.

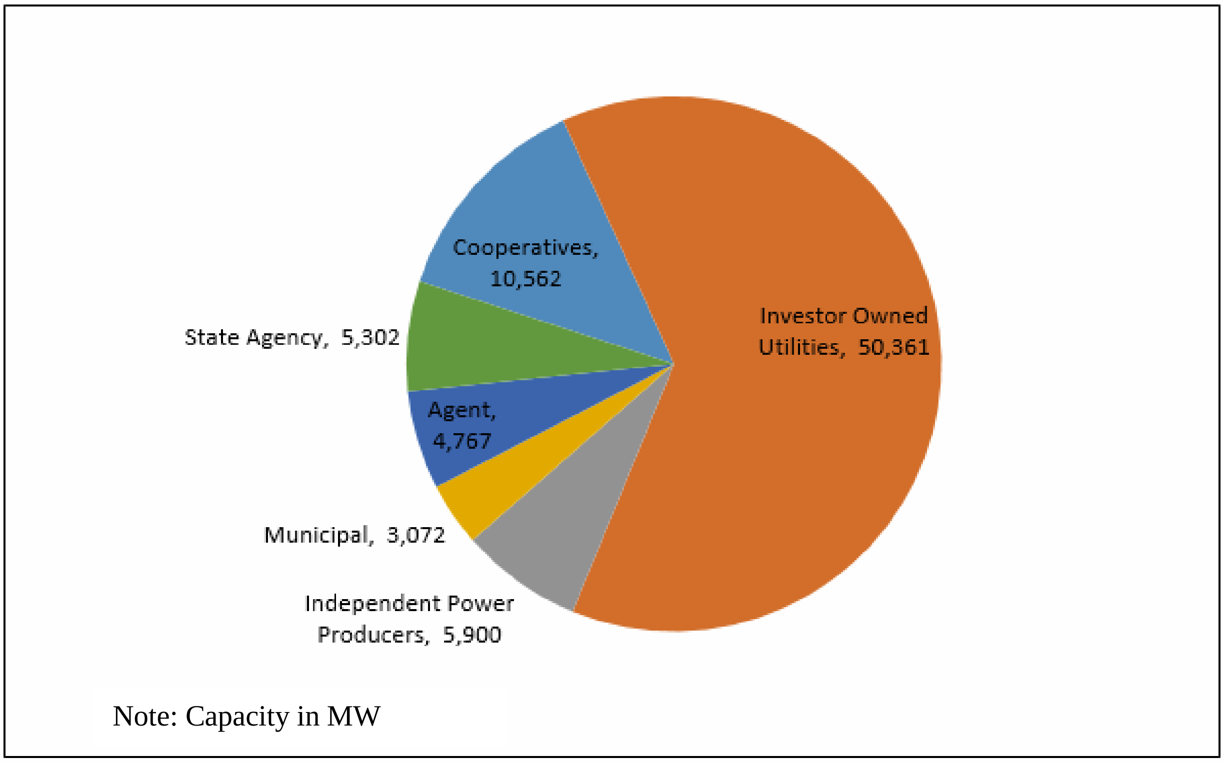
Figure 2–2 Distribution of Market Participants with Resources by Type



As of December 31, 2014

Figure 2–3 shows market capacity owned by Market Participant Type. This chart indicates investor owned utilities have the majority of capacity, 63%, even though they represent only a small percent of participants, 17%, in the market. This is in contrast to the Independent Power Producer category with a large number of participants, 37%, but representing only a small portion of total capacity, 7%.

Figure 2–3 Capacity by Market Participants Type

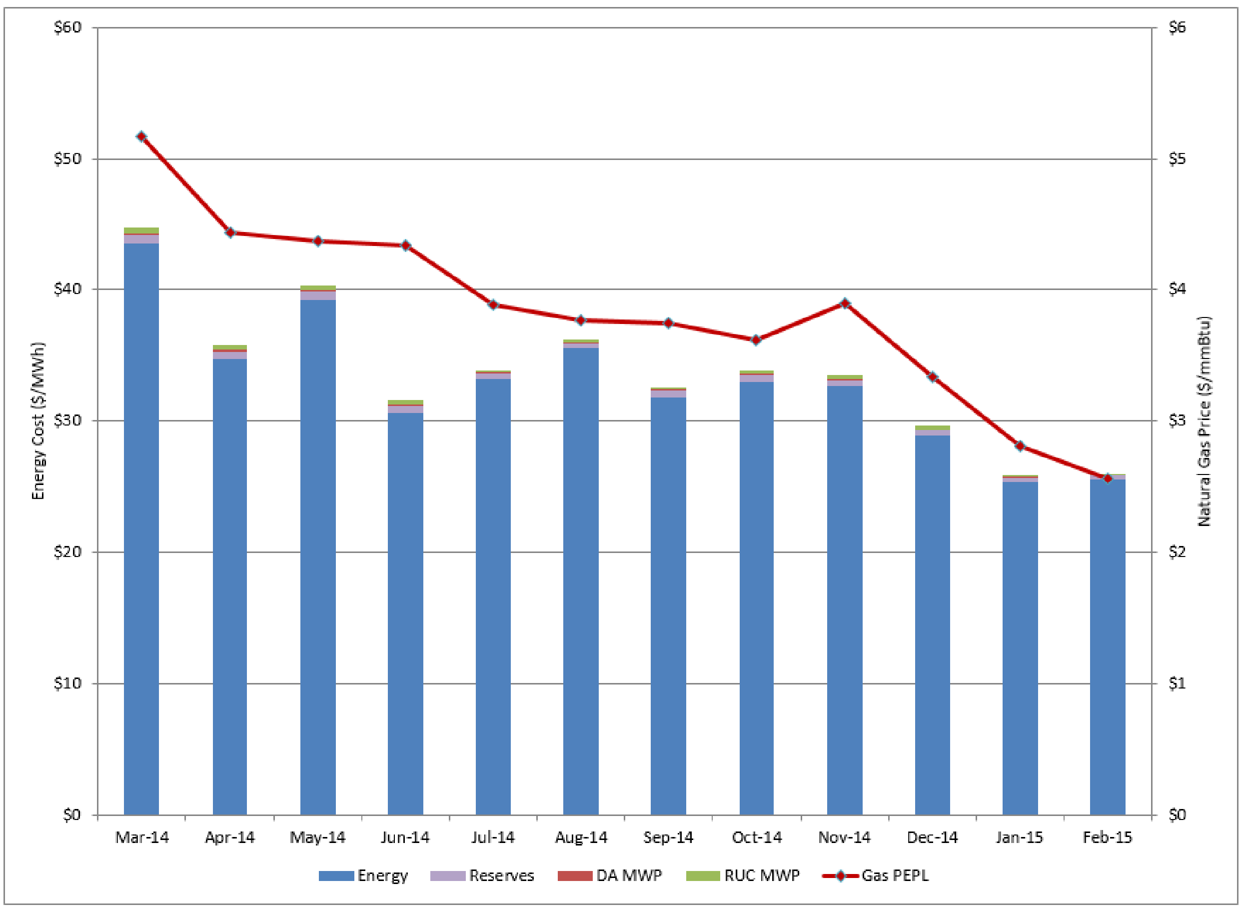


As of December 31, 2014

2.2. Market Prices

The average price of energy in SPP's real-time market for the year March 2014 through February 2015 was $32.82/MWh. The 12 month average all-in price, which includes the costs of energy market make whole payments and reserves, was $33.65/MWh.[1] Figure 2–4 plots the monthly average all-in price of energy and the price of natural gas, measured at the Panhandle Eastern hub.

Figure 2–4 SPP All-In Price of Electricity



This figure shows the strong correlation between the price of natural gas and the price of energy. This is a sign that the market generally functioned well during its first year, as gas fired generation often sets the clearing price in the SPP energy market and fuel cost constitutes the

[1] The all-in price also includes Reserve Sharing Group costs and payments to Demand Response Resources. Both were negligible for the year.

vast majority of the marginal cost of energy. 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 sum of uplift payments to generators and the market cost of reserves constituted less than 2.5% of the all-in price, with make whole payments at $0.33/MWh and reserves at $0.47/MWh.

The overall level and trend in Integrated Marketplace prices were modest and reasonable when compared to other RTOs. Figure 2–5 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.

Figure 2–5 RTO Comparison of Average On-Peak Day-Ahead LMP

	Ten Month Average	Twelve Month Average
Market Hub	Mar. 2014 – Dec. 2014	Mar. 2014 – Feb. 2015
SPP North	$35	$33
SPP South	$43	$41
Indiana	$41	$41
PJM West	$48	$51
ERCOT North	$44	$41

In January and February of 2014, the average EIS market Locational Imbalance Prices were $29.22/MWh and $42.78/MWh, with natural gas prices of $4.83/mmBtu and $8.00/mmBtu, respectively. The high average gas prices reflect a few days in early February, especially February 6, 2014, when the price spiked to over $30/mmBtu for most of the SPP footprint.

Sections "3. Energy and Operating Reserve Markets" (page 47) and "4. Day-Ahead Market" (page 80) of this report provide deeper analysis of prices as locational and time specific market signals, and section "3.2.6 Make Whole Payments" (page 73) discusses uplift.

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 sufficient existing generation to meet load. Given the resource margin near 50% for 2014, the MMU does not expect market prices to support investment in new entry. The MMU does expect prices to support ongoing maintenance of efficient generation technologies. Analysis of market net revenues relative to the cost of new generating technologies shows that price levels for 2014 met both of these expectations.[2]

The MMU analyzes the fixed costs of three new generation technologies relative to their potential net revenues at SPP market prices: a scrubbed coal plant, a natural gas combined cycle, and a combustion turbine.[3] Figure 2–6 provides the cost assumptions and results of the analysis, which assumes that the market dispatches the hypothetical resource when LMP exceeds the short run marginal cost of production.

Figure 2–6 Assumptions and Results for Net Revenue Analysis

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	19.84	97,836	556,386	No	37,800	Yes
Gas Combined Cycle	27.75	58,636	178,806	No	15,370	Yes
Combustion Turbine	40.81	31,516	115,039	No	7,040	Yes

The marginal cost for the combined cycle and the combustion turbine vary throughout the year with the price of natural gas, so the reported cost is an annual average. The net revenues for these three technologies in the first year of SPP's market fell short of the full annual revenue requirement for new capital investment, while exceeding annual avoidable costs. Figure 2–7 provides results by SPP resource zone, as indicated by the dominant utility in the area. It shows that the conclusions do not vary geographically, with differing LMPs and fuel prices.

Other RTOs have experienced a "missing money problem" in energy markets, where net revenues do not support needed new investments. SPP had a high, 48%, resource margin for 2014, so the MMU does not expect net revenue to cover the cost of new investment.[4] SPP prices for the first year of the Integrated Marketplace were high enough to support ongoing operation and maintenance costs of new efficient generators dispatched economically. The MMU expects

[2] Net Revenue is equal to revenues minus marginal cost.
[3] Cost assumptions for each technology were derived from the EIA Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, April 2013 and estimates of variable O&M provided by Pasteris Energy, Inc. for the PJM Annual State of the Market Report 2014, Section 7.
[4] See section "2.3.2 Resource Margin" (page 23)

the market to signal the retirement of inefficient generation. Aging of the fleet and increased environmental restrictions may 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 2–7 Net Revenue Analysis by Zone

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	116,418	No	Yes	76,128	No	Yes	38,951	No	Yes
KCPL	90,587	No	Yes	54,951	No	Yes	31,295	No	Yes
NPPD	61,254	No	Yes	27,561	No	Yes	22,410	No	Yes
OGE	113,870	No	Yes	74,573	No	Yes	39,912	No	Yes
SPS	117,831	No	Yes	72,394	No	Yes	40,661	No	Yes
WR	99,046	No	Yes	61,909	No	Yes	34,252	No	Yes

2.3. Capacity in SPP

2.3.1. Installed Capacity

Figure 2–8 depicts the Integrated Marketplace installed generating capacity for the SPP Consolidated Balancing Authority at the launch of the Integrated Marketplace (March 1, 2014) and at the end of the first year of the market (March 1, 2015). Total generating capacity in the SPP Integrated Marketplace was 75,458 MW, an increase of about 1.5% over the first year of the Integrated Marketplace. Natural gas represents the largest share of the market at 47%, with coal the second largest type at 35%.

Some of the changes in the capacity numbers are attributed to existing capacity registering to participate in the SPP market. This capacity, which is often owned by municipal utilities, has moved from behind the meter to directly participating in the market. Most of this capacity is older and small units. Additional changes are attributed to retirements, mostly very small older coal units. Wind continues to increase as the result of actual new construction.

Figure 2–8 Generation Capacity by Fuel Type for the SPP Market

Fuel Type	March 2014	March 2015	Percent as of 3/2015
Natural Gas	35,360	35,109	47%
Coal	25,822	26,435	35%
Wind	7,637	8,884	12%
Nuclear	2,569	2,569	3%
Oil	1,419	1,523	2%
Hydro	832	832	1%
Other	551	57	0%
Total	74,189	75,458	

Note: Capacity is based on name plate rating

2.3.2. Resource Margin

The region's resource margin is the amount of extra system capacity available after peak load has been served. It is calculated by comparing total annual generating capacity to peak demand (system capacity less peak load, divided by peak load). For this analysis, system capacity is based on unit registration rating. In 2014, the SPP resource margin was 48%, as shown in Figure 2–9, which was four times the Annual Planning Capacity Requirement of 12%. Wind nameplate capacity value is discounted by 95% when used in calculating the resource margin. This is the reason the capacity values shown in Figure 2–9 are lower than the value shown in Figure 2–8.[5] Higher capacity combined with lower peak load contributed to a resource margin increase from 36% in 2012. This resource margin has positive implications for both reliability and for mitigation of the potential exercise of market power within the market.

Figure 2–9 Resource Margin by Year for 2008–2014

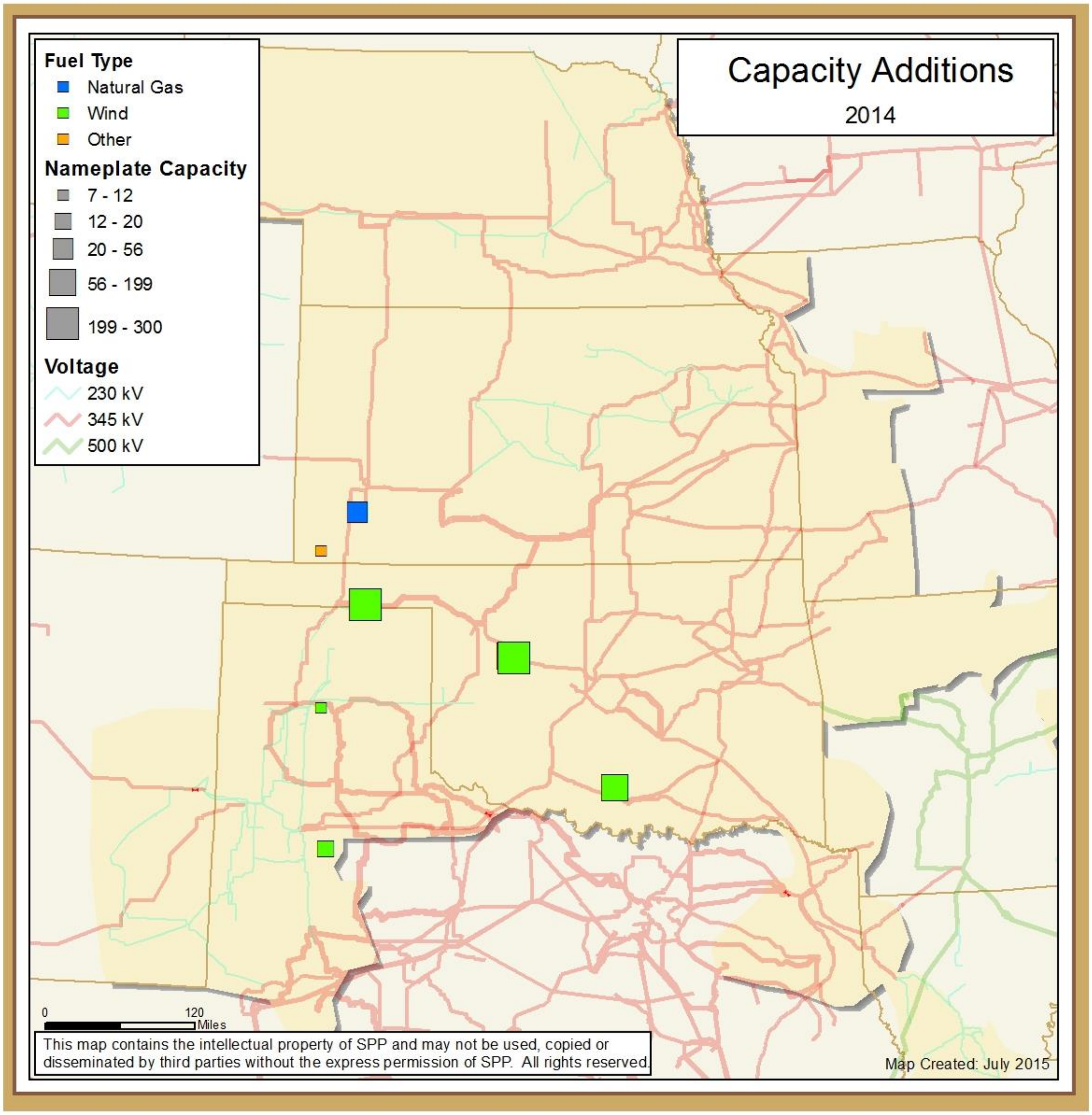
Year	Capacity (MW)	Peak Load (MW)	Resource Margin
2008	49,561	36,538	36%
2009	58,223	39,622	47%
2010	61,570	45,373	36%
2011	63,367	47,989	32%
2012	64,053	47,142	36%
2013	66,668	45,256	47%
2014	67,095	45,301	48%

[5] Figure 2–9 differs from Figure 2–8 by counting only 5% of wind capacity. The 5% wind capacity factor was used in this analysis to be consistent with ITP Year 20 Assessment methodology as approved by SPP Economic Studies Working Group on 19 January, 2010.

2.3.3. New Capacity Construction

In 2014 about 1,000 MW of new generation capacity was completed and entered service in the SPP market. Most of this capacity was wind, 94%, 5% was natural gas, and 1% was agricultural byproducts. Figure 2–10 shows the location, fuel type, and relative size of this new capacity.

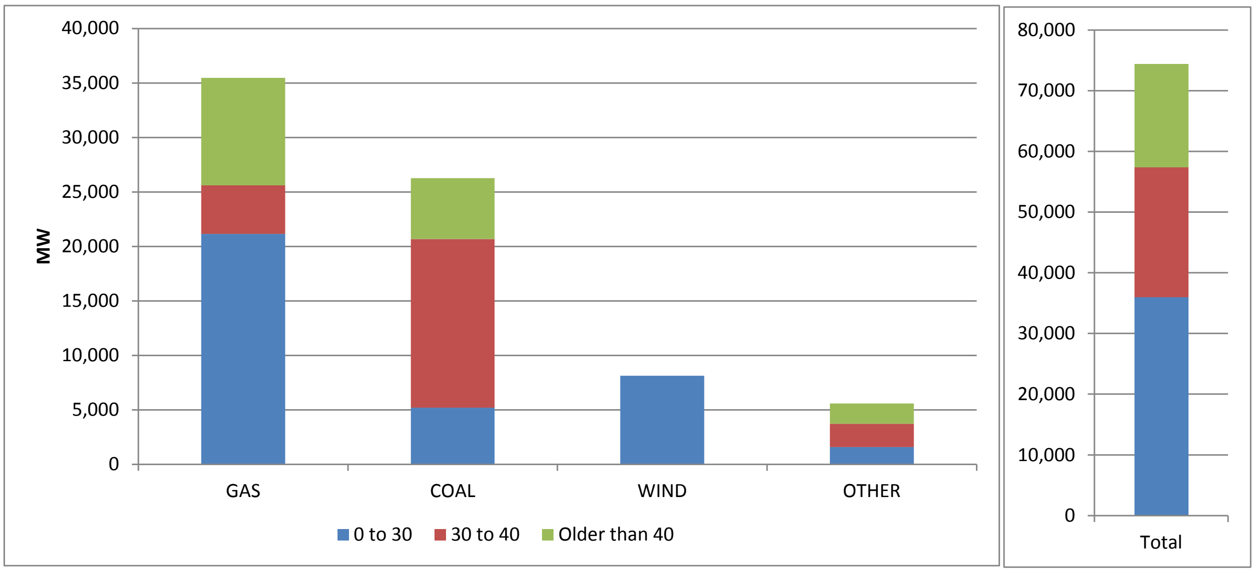
Figure 2–10 New Capacity in 2014



2.3.4. Capacity by Age

Figure 2–11 illustrates that, overall, SPP has an aging generation fleet. About 50% of SPP's fleet is more than 30 years old. In particular, about 80% of coal capacity and 40% of gas capacity are older than 30 years. The national average retirement age of coal-fired generation is 48 years. The only significant new capacity over the last year in the SPP footprint was wind generation.

Figure 2–11 Capacity by Age of Resource



2.4. Electricity Demand and Energy in SPP

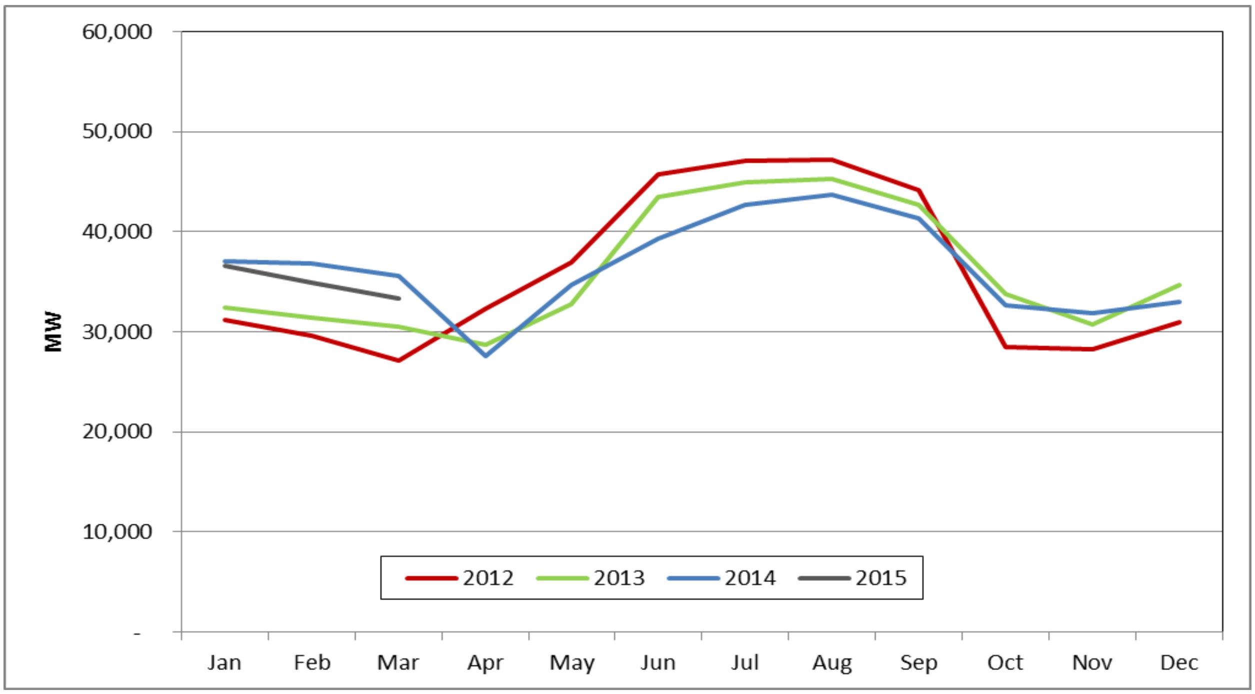
The SPP Integrated Marketplace is composed of Market Participants that are responsible for load and/or resources but are all served by SPP. One way to evaluate load is to review peak system demand statistics over an extended period of time. The market footprint can change—and has changed—over time as participants are added or removed. In the last three years, one notable change occurred in SPP's market footprint, the addition of City Utilities of Springfield in 2011.

The peak demand value reviewed in this section is described as coincident peak, representing total dispatch across all load areas that occurred during a particular market interval. The peak experienced during a particular year or season may be 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 2014 was 44,148 MW, which occurred on August 21 at 5:00 PM. This is lower than the 2013 system peak of 45,256 MW, and about 9% lower than the all-time system peak of 47,989 MW in 2011. Figure 2–12 shows a month-by-month comparison of monthly peak day demand for the last three years. Summer monthly peaks in 2013 and 2014 were lower than in 2012 because the last two years experienced summer weather patterns close to normal versus the unusually warm summers experienced in 2011 and 2012. Weather patterns and resulting impact on energy demand are discussed later in this section.

Figure 2–12 Monthly Peak Electric Energy Demand for 2012–2014



2.4.2. Market Participant Energy for Load

Figure 2–13 depicts 2014 total energy consumption, Market Participants' annual loads, and the percent of energy consumption attributable to each Market Participant. The largest four participants account for over half of the total system load, which is expected since SPP is primarily comprised of legacy vertically-integrated utilities, which tend to be quite large. One new load entity exists in 2014 and that is City of Fremont, which was previously embedded within a larger legacy Balancing Authority.

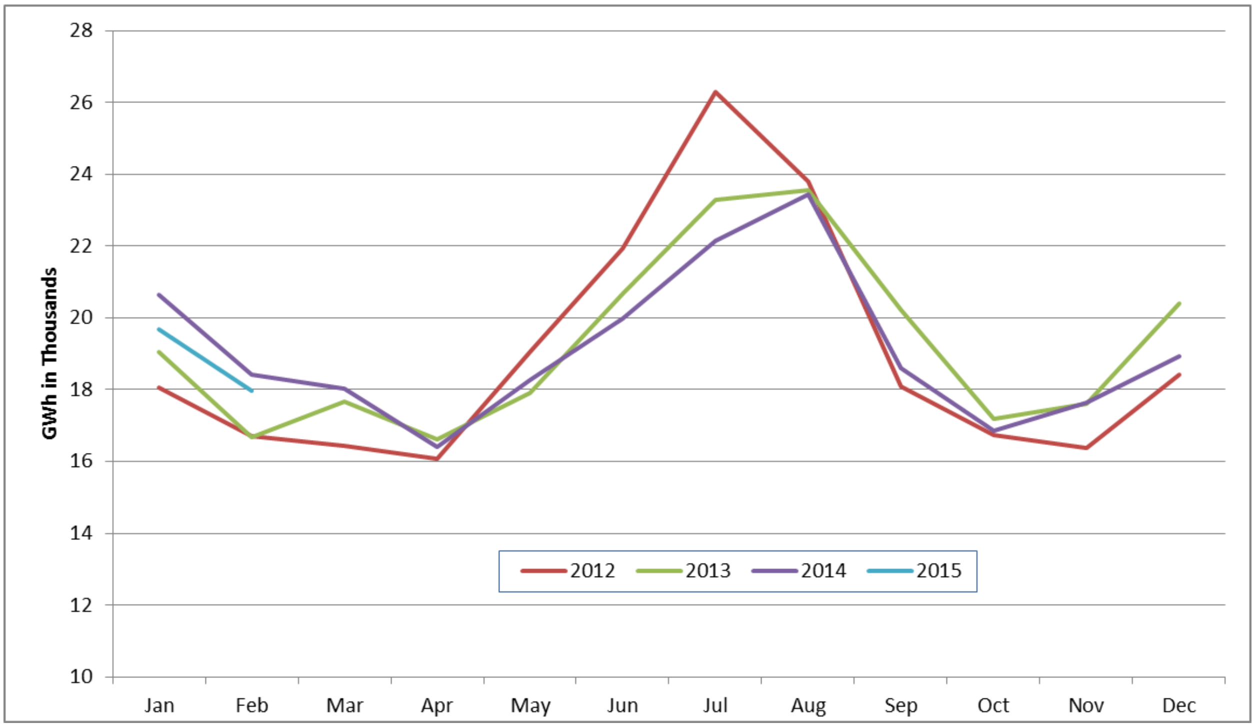
Figure 2–13 Market Participant Energy Usage

	2014		2013	
Market Participant Name	Energy Consumed (GWh)	Percent of System Total	Energy Consumed (GWh)	Percent of System Total
American Electric Power	43,046	19.0%	43,828	19.0%
Oklahoma Gas and Electric	29,387	13.0%	29,965	13.0%
Southwestern Public Service Company	25,898	11.4%	27,202	11.8%
Westar Energy	24,238	10.7%	24,187	10.5%
Kansas City Power and Light, Co	15,630	6.9%	16,048	7.0%
The Energy Authority, NPPD	13,339	5.9%	13,923	6.0%
Omaha Public Power District	11,208	5.0%	12,249	5.3%
Western Farmers Electric Coooperative	9,106	4.0%	8,632	3.7%
Kansas City Power and Light, GMOC	8,607	3.8%	8,841	3.8%
Golden Spread Electric Cooperative Inc.	5,562	2.5%	5,944	2.6%
Grand River Dam Authority	5,413	2.4%	4,925	2.1%
Empire District Electric Co.	5,274	2.3%	5,306	2.3%
Sunflower Electric Power Corporation	4,916	2.2%	5,631	2.4%
Lincoln Electric System Marketing	3,450	1.5%	3,532	1.5%
The Energy Authority, CU	3,278	1.4%	3,314	1.4%
Arkansas Electric Cooperative Corporation	3,005	1.3%	3,571	1.5%
Oklahoma Municipal Power Authority	2,818	1.2%	2,529	1.1%
Kansas City Board of Public Utilities	2,368	1.0%	2,426	1.1%
Midwest Energy Inc.	1,748	0.8%	1,547	0.7%
Kansas Municipal Energy Agency	1,373	0.6%	373	0.2%
Tenaska Power Service Company	1,216	0.5%	1,125	0.5%
City of Independence	1,026	0.5%	1,066	0.5%
Municipal Energy Agency of Nebraska	981	0.4%	807	0.3%
Kansas Power Pool	953	0.4%	2,011	0.9%
Missouri Joint Municipal Electrical Utility Commission	825	0.4%	1,067	0.5%
Basin Electric Power Cooperative	751	0.3%	797	0.3%
City of Chanute	493	0.2%	32	0.0%
City of Fremont	360	0.2%		
System Total	226,271		230,879	

2.4.3. SPP System Energy

Figure 2–14 shows the monthly system energy consumption in thousands of GWh. Total SPP system annual energy consumption in 2013 and 2014 were essentially the same at about 230,000 GWh. Load was higher in the winter months of 2014 as the result of winter storms, but slightly lower than 2013 the rest of the year, resulting in similar total consumption for both years.

Figure 2–14 Monthly System Energy Consumption for 2012–2014

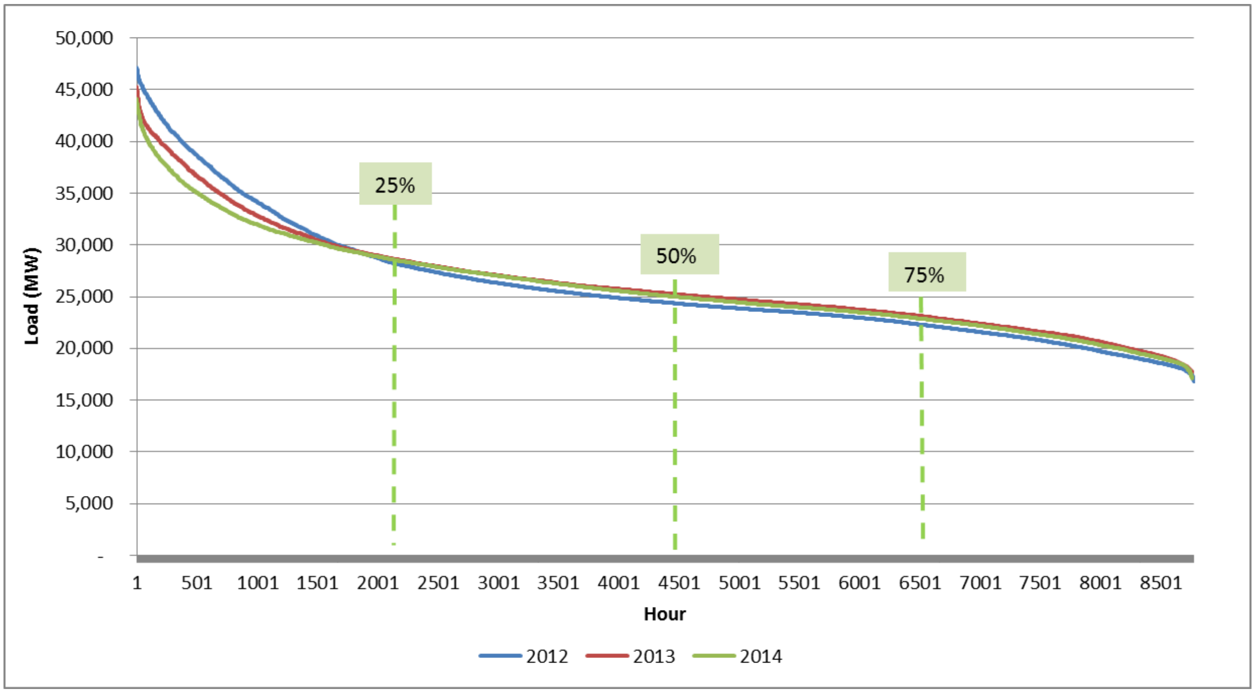


2.4.4. Load Duration Curve

Figure 2–15 depicts load duration curves for 2012 to 2014. 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 SPP.

In 2014 the total system peak hourly load was 44,148 MW and the minimum was 17,135 MW. Comparing annual load duration curves shows differentiation between cases of extreme loading events and more general increases in system demand. If only the extremes are higher than the previous year, 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 over the last two years above the 25% reference level. This implies a different weather pattern during the summer peak period, which is covered in the next section.

Figure 2–15 Electric Load Duration Curve for 2012–2014



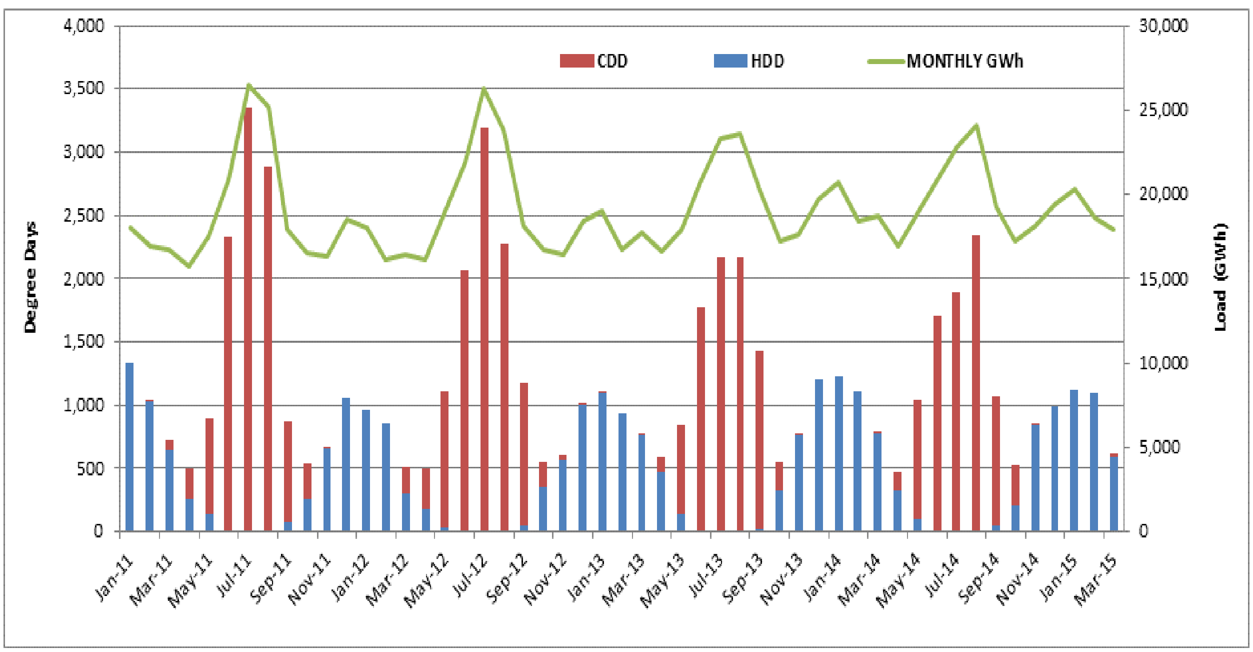
2.4.5. Heating and Cooling Degree Days

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 SPP, five representative locations[6] in the SPP market were chosen to calculate system daily average temperatures.[7] 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 cooling degree days (75-65). If a day's average temperature is 50 degrees Fahrenheit, there would be 15 heating degree days (65-50). Using statistical tools, the estimated load impact of a single CDD was determined to be 3,081 MW compared to 446 MW for HDD. The impact of a single CDD on load is significantly higher than HDD as expected in part because of the higher saturation of electric cooling than electric heating. HDD values were adjusted to reflect load impact differences.

Figure 2–16 illustrates that 2014 experienced a very similar level of cooling degree days to 2013, with both years substantially lower than 2011 and 2012. Lower temperatures in the last two summers are the major cause of lower peak loads shown in Figure 2–9 and lower total energy consumption shown in Figure 2–14.

Figure 2–16 Monthly Heating Degree Days and Cooling Degree Days



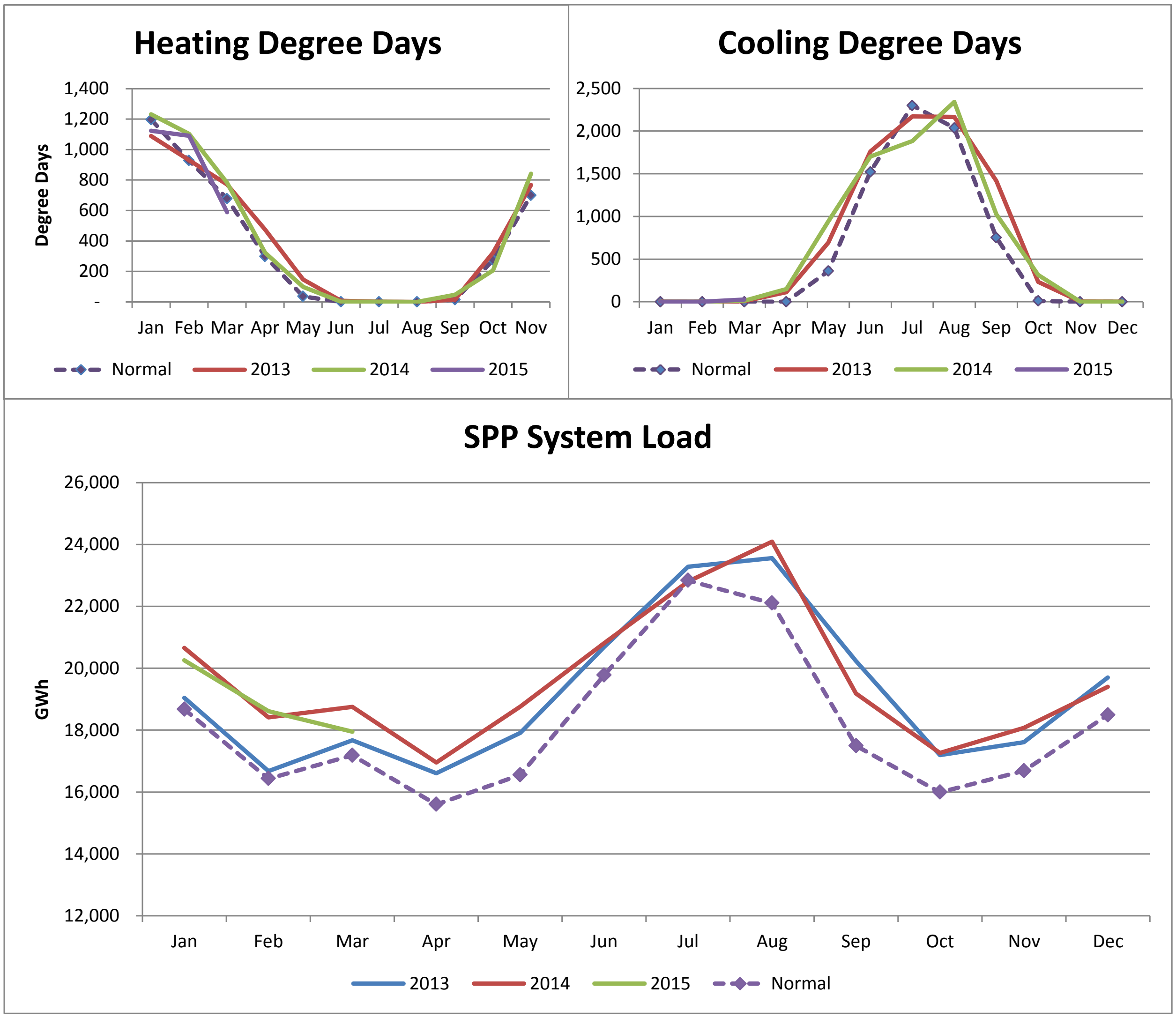
[6] Amarillo TX, Topeka KS, Oklahoma City OK, Tulsa OK, and Lincoln NE.

[7] Daily average temperature is calculated as the average of the daily lowest and highest temperatures. The source of the temperature is NOAA.

Figure 2–17 shows the numbers of HDD, CDD, and load levels in 2013, 2014, and the first three months of 2015 compared to a normal year. Normal temperatures are defined as a 30-year average by National Oceanic and Atmospheric Administration (NOAA). Normal load was derived from a regression analysis and normal temperatures.

The year 2014 was a little warmer than normal for the cooling load season except for July, resulting load being a little higher than what would be expected for a normal season (see Figure 2–17, SPP System Load). Summer temperatures in 2013 were also slightly above a normal year, resulting in a very similar relative load to that experienced in 2014. The last two heating seasons appear to be slightly above normal as well, which is reflected in an SPP System Load during the winter season above what would be expected for a normal year.

Figure 2–17 Yearly Degree Days and Loads Compared with a Normal Year



2.5. Electricity Supply in SPP

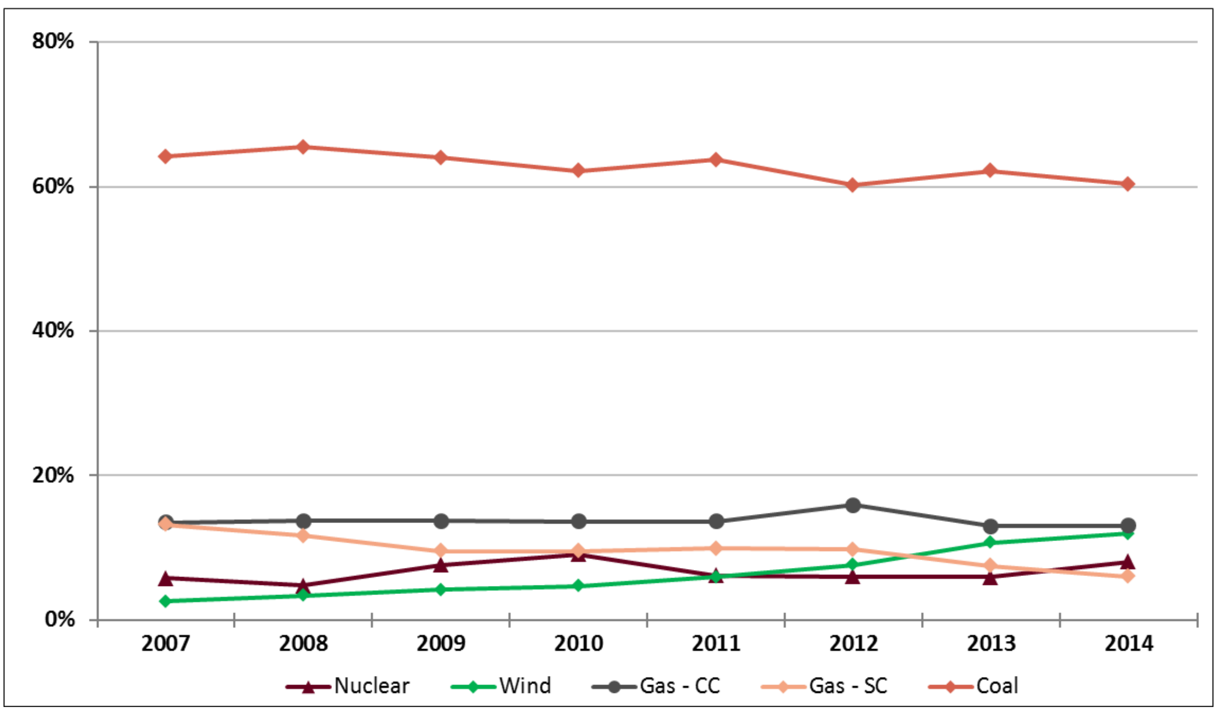
2.5.1. Generation by Fuel Type and Technology

An analysis of fuel types used in the SPP 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 2–18 depicts annual generation percentages in the SPP Real-Time markets by fuel type for years 2007 through 2014. Generation from simple cycle gas units such as gas turbines and gas steam turbines continues to decline, decreasing from 13% in 2007 to only 6% in 2014. Gas combine cycle generation has remained relatively stable over the same period at about 13–14% of total generation. Wind generation continues to increase from less than 3% in 2007 to about 12% in 2014. This includes an increase of about 1.5% from 2013 to 2014. Coal market share decreased about 2% in 2014 to 60% of all generation. The long term trend for coal has been relatively flat over the last five years at about 60–62% of total generation.

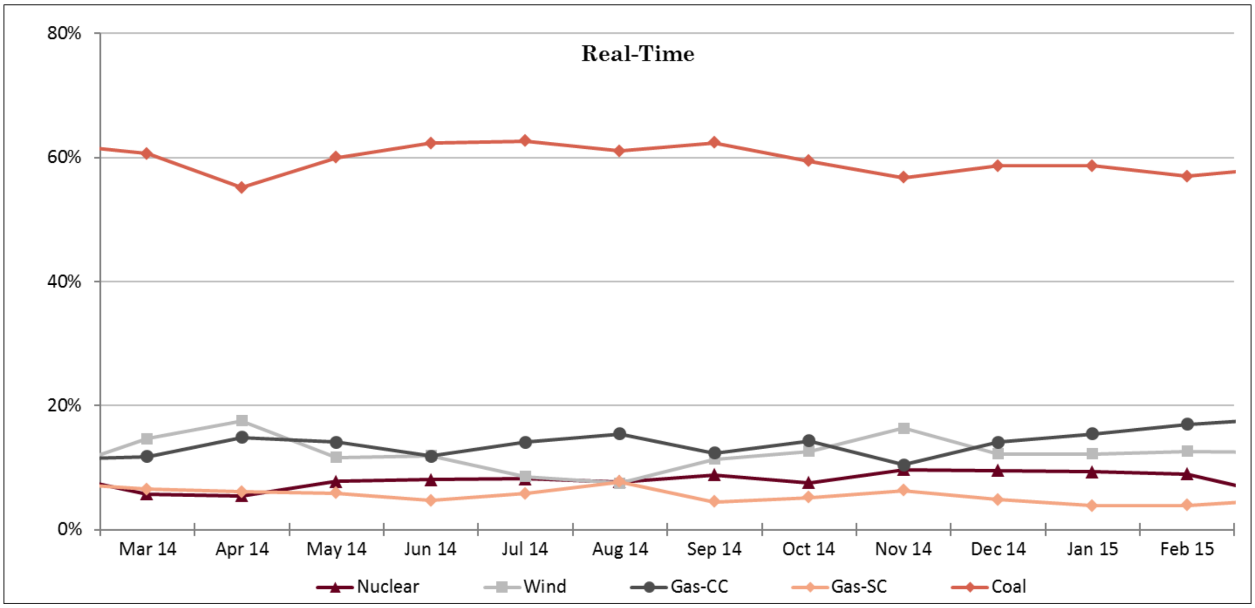
Some of the annual fluctuations in fuel market share are driven by the relative difference in primary fuel prices, gas versus coal. Gas prices in 2012 were extremely low, resulting in some displacement of coal by efficient gas generation as can be seen in the higher generation from combined cycle gas 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 2–18 Percent Generation by Fuel Type – Real-Time Market



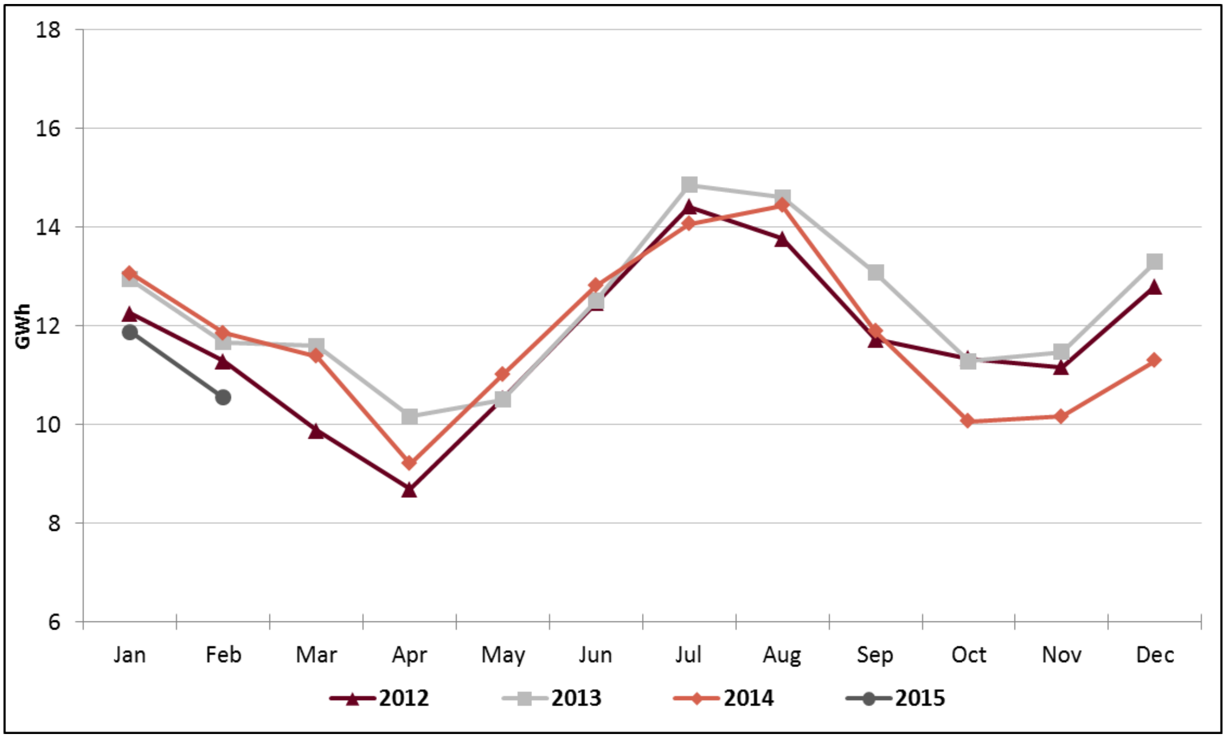
The year also saw a fair amount of monthly fluctuation in generation by fuel type, as shown in Figure 2–19. Wind output in the fall and spring reached 17–18%, displacing coal and natural gas. Combined cycle gas output rises through the winter with lower natural gas prices, displacing coal.

Figure 2–19 Generation by Fuel Type – RTBM by Month



The SPP footprint experienced delayed rail deliveries of coal in the summer and fall of 2014. Market participants raised the offer price on coal units to reflect the opportunity cost of scarce fuel, reduced output limits, and initiated outages to preserve coal. A mild summer lessened the impact of the fuel supply limitation. An annual comparison of monthly coal output trends, shown in Figure 2–20, reveals a drop in 2014 of coal output relative to previous years in October through December. When natural gas and oil prices fell in December, coal deliveries resumed to their historic pace and competition from combined cycle gas explains the continued displacement of energy from coal through the winter.

Figure 2–20 Coal-Fired Generation

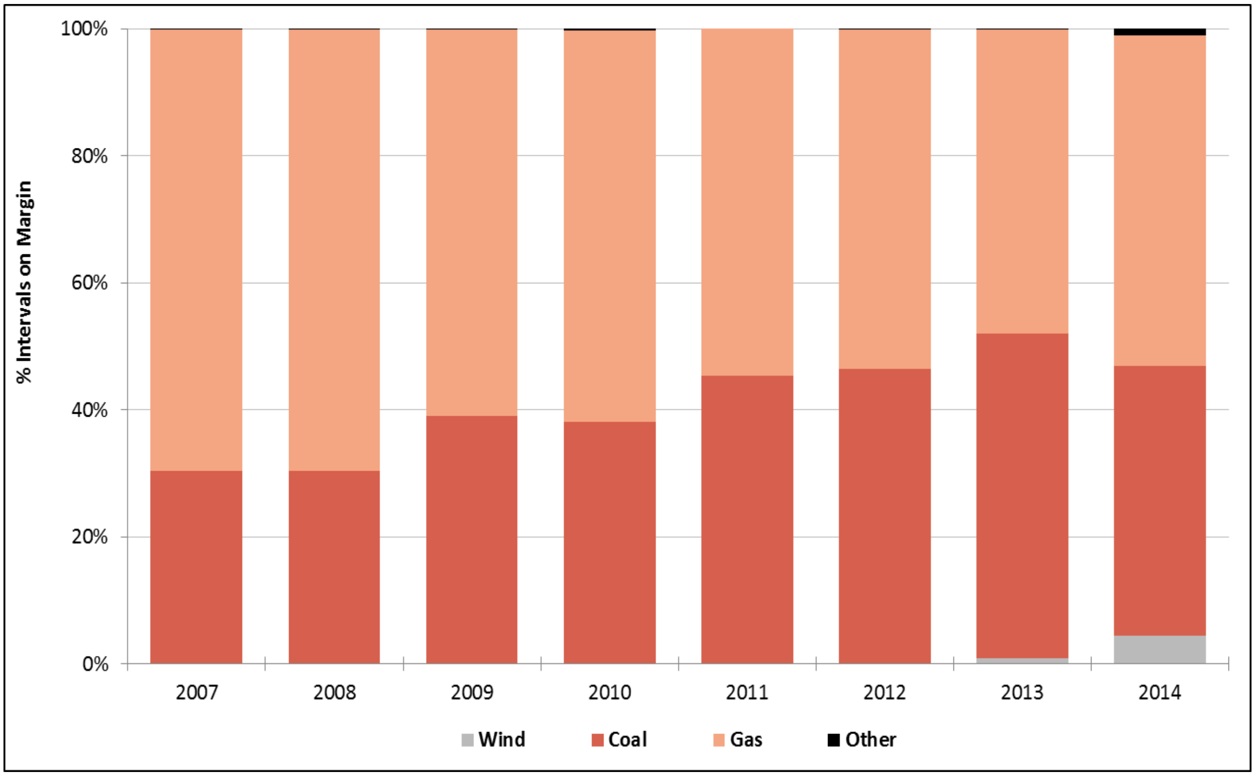


2.5.2. Generation on the Margin

The system marginal price represents the price of the next MW available to meet total system demand. The LMP is the system marginal energy price plus any marginal congestion charges and marginal loss charges associated with the pricing node. Figure 2–21 illustrates which fuel 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 schedule economic minimum or maximum; and (c) not ramp limited.

As highlighted in Figure 2–18, generation from coal-fired resources was responsible for about 60% of all generation in SPP. Because coal resources in the SPP region are predominantly base load units, they set price less than their overall percent of generation. Also, coal plants have some mechanical limitations that reduce operational flexibility as compared to other fuel types such as certain gas units.

Figure 2–21 Real Time Generation on the Margin by Fuel Type

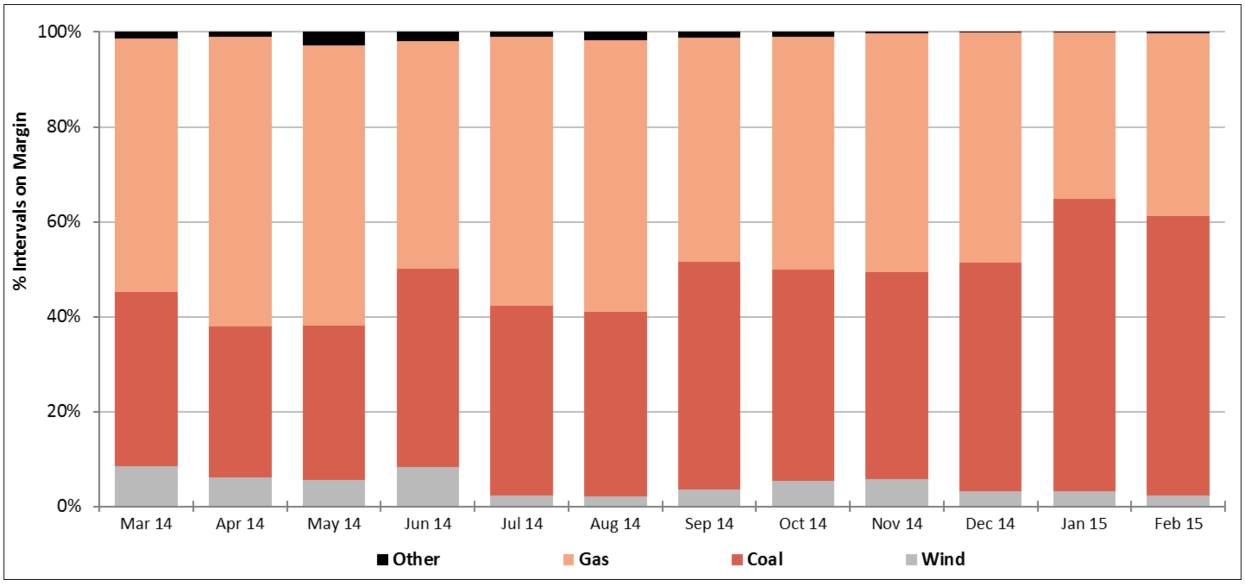


Coal on the margin has increased dramatically since the start of the SPP EIS Market, increasing from about 30% in the first year of the EIS Market, 2007, to about 52% in the last full year of that market, 2013. Coal on the margin for the first year of the Marketplace was lower at about 47%. This may be the result of fewer large, inefficient gas units committed for capacity and running at minimums, allowing coal units to operate at a maximum output thereby not setting price as often.

Two other aspects of the 2014 results worth noting are the significant increase in wind on the margin, 4.5%, and the level of Other at about 1%. Wind as the marginal fuel in a significant amount of time is as expected because of the quantity of wind generation, almost 12% of total generation, and the establishment of wind as a dispatchable resource in the new market. About 30% of wind capacity in the Marketplace is dispatchable and therefore capable of setting price, whereas all but 5% of wind capacity in the EIS Market was a price taker. Other is mostly oil and that fuel on the margin is most likely a result of the uncertainty associated with a new capacity commitment system implemented with Marketplace and not likely to be as significant as market operations become more experienced and efficient. Figure 2–22 shows a significant reduction in the time oil is the marginal fuel over the last four months of the Marketplace first year.

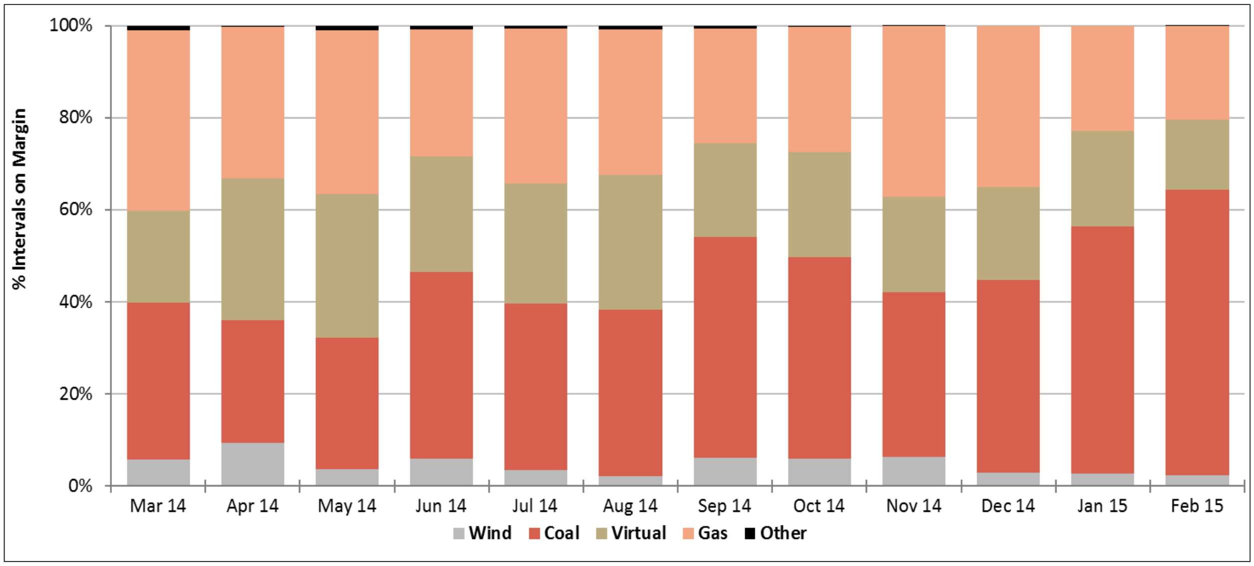
The significant drop off in marginal wind starting in July 2014 is the result of transmission investments that are now relieving some of the congestion and resulting in wind having less price impact in the wind production regions of the SPP Marketplace. This topic is discussed in section "5.5 Frequently Constrained Areas and Local Market Power" (page 102) of this document.

Figure 2–22 Real Time Generation on the Margin – Monthly



Day-ahead generation on the margin (see Figure 2–23) is different from real time, as would be expected in that the Day-Ahead Market is based on model results including virtuals, whereas the Real-Time Market is required to adjust to unforeseeable market conditions. The Day-Ahead Market oil generation on the margin is trending lower as the market matures, consistent with results in the Real-Time Market. Wind on the margin is comparable in the Day-Ahead Market with no distinct trends. Coal on the margin in the Day-Ahead Market is noticeably lower, about 3% lower than in the Real-Time Market during the first 12 months of the Marketplace. This may be the result of some displacement by virtual offers. The most significant difference shows up in the displacement of gas by virtual offers in the Day-Ahead Market. Virtual energy offers account for approximately 24% of the marginal offers in the Day-Ahead Market. The marginal virtual offers occur at all types of settlement location, but 80% are virtual offers at resource settlement locations, with a significant amount of activity at the non-dispatchable wind generation resources.

Figure 2–23 Day-Ahead Market Marginal Supply – Monthly



Typically coal is on the margin more often in low load months, while gas 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. This typical seasonal pattern is less obvious in the first year of the Marketplace.

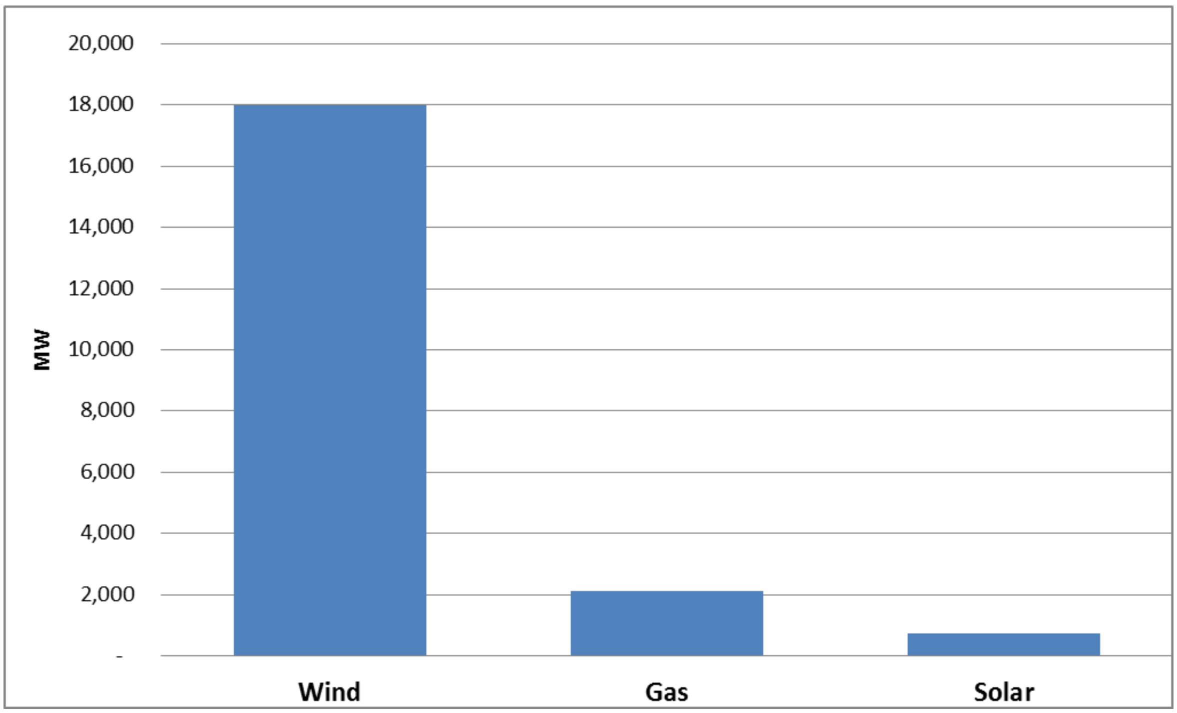
2.5.3. Generation Interconnection

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)

The MWs of capacity by fuel type in any stage of development is displayed in Figure 2–24. 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 can be seen in the figure, wind accounts for the vast majority of proposed generation interconnection, about 18,000 MW. Development of wind generation in the SPP region is going 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.

Figure 2–24 Active Generation Interconnection Requests by Fuel Type



This chart includes only active GI requests and not IAs that are fully operational. Last year was the first year to produce this chart and it included IAs that were fully operational, which accounts for the change in capacity.

2.6. Growing Impact of Wind 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 2–25 below shows an abundance of locations with a high potential for wind development in the SPP footprint. The footprint is outlined in black, including the 2015 expansion. Even though wind generation continued to expand during 2014, it was substantially less than what was experienced in 2012 when the federal tax credits were expected to expire at the end of that year.

Figure 2–25 US Wind Speed Map

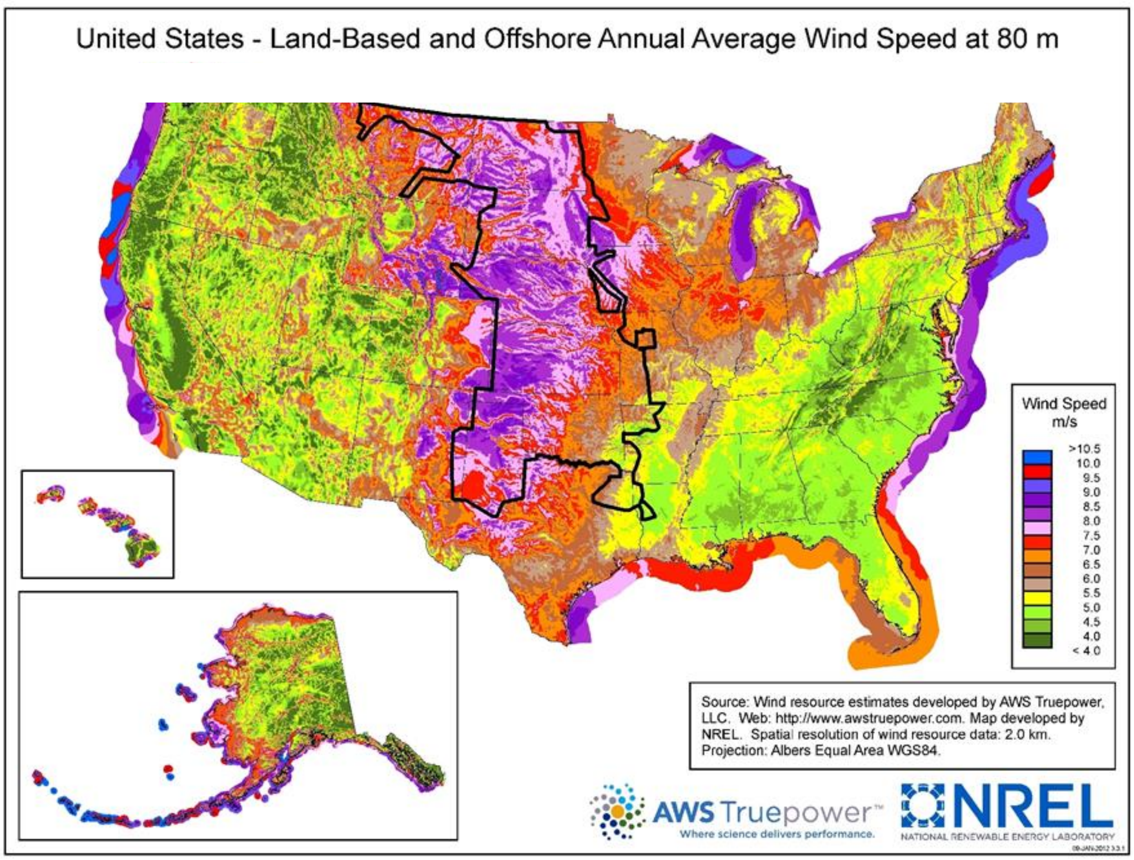
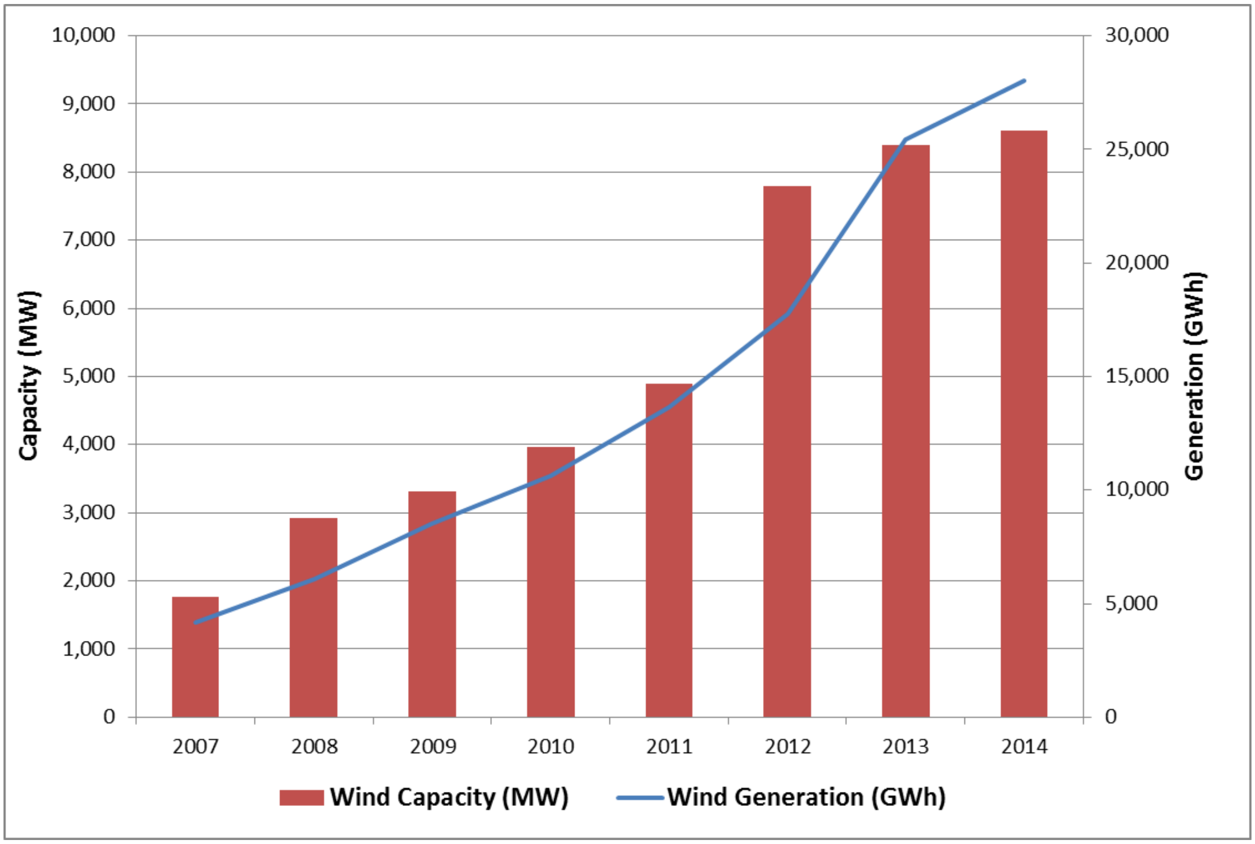


Figure 2–26 depicts annual capacity and total generation from wind facilities since 2007. Total registered wind capacity at the end of 2014 was 8,606 MW, a slight increase of 2.4% from 2013. Despite the only 2.4% capacity increase, wind generation still increased 10% in 2014 from the previous year. Wind comprises about 12% of the installed capacity in the SPP Marketplace behind only natural gas (47%) and coal (35%). Consistent with previous years, wind generation fluctuates seasonally, where summer is usually the low wind season and spring and fall are the high wind seasons.

Figure 2–26 Wind Capacity and Generation



2.6.2. Wind Impact on the System

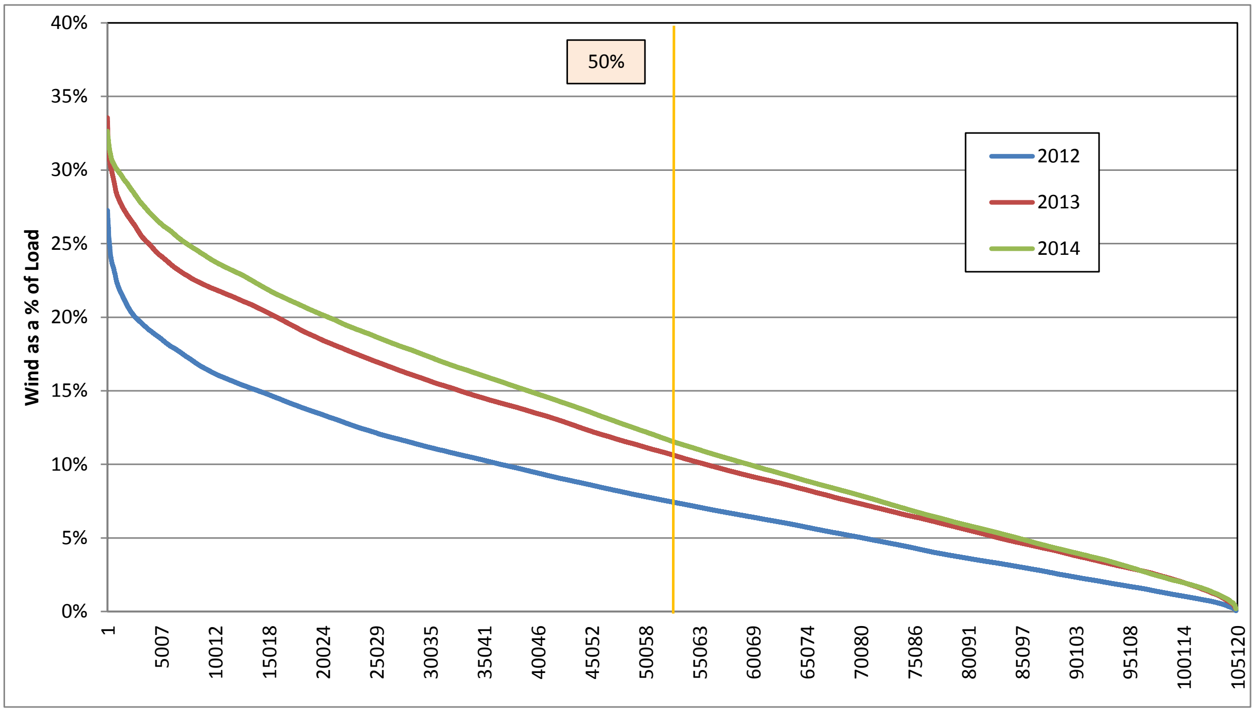
Wind generation remained consistent from 2013 to 2014 with an average percent of load of 12% compared to 11.6% in 2013. The highest level of wind generation for 2014 was 7,725 MW, which occurred on December 23. Wind as a percent of load reached a maximum value of 32.7% on November 2, which was comparable to the high of 33.6% in 2013. Figure 2–27 shows the annual average and the hourly maximum wind generation as a percent of load for the last eight years, illustrating a steady increase since the start of the SPP Markets in 2007.

Figure 2–27 Wind Generation as a Percent of Load

Year	Avg Wind Generation as a Percent of Load	Max Wind Generation as a Percent of Load
2007	2.7%	9.0%
2008	3.6%	11.3%
2009	4.6%	15.4%
2010	5.1%	16.0%
2011	6.5%	20.1%
2012	8.3%	27.3%
2013	11.6%	33.6%
2014	12.0%	32.6%

Figure 2–28 shows wind production duration curves that represent wind generation as a percent of load for 2012, 2013, and 2014. The significant shift up in the curve for 2013 shows wind's increasing contribution to serving load all year long. The curve for 2014 is only slightly higher than 2013, reflecting a small increase in total wind generation capacity year over year. It is important to note that wind generation is now serving more than 12% of load half of the year compared to 7% in 2012. There are now times when wind is the source of generation for more than 30% of load.

Figure 2–28 Duration Curve by Interval – Wind as a Percent of Load



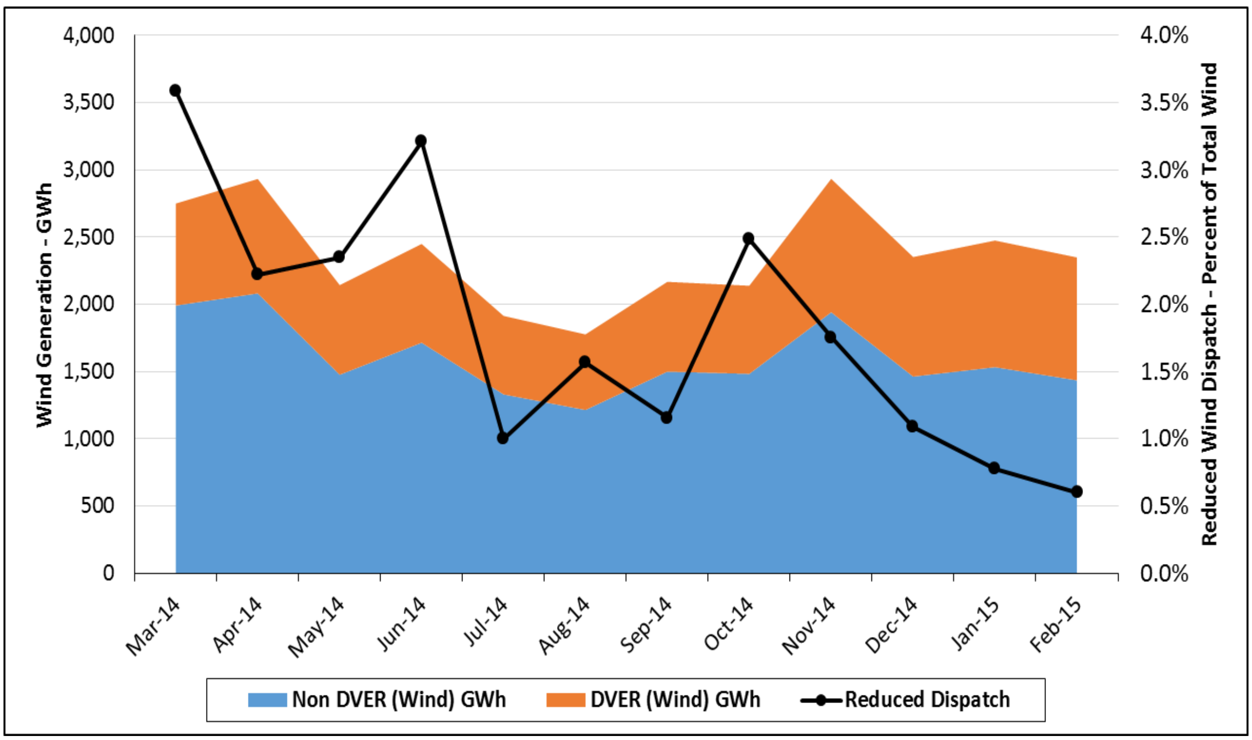
2.6.3. Wind Integration

Wind integration brings low cost generation to the SPP region and supports future capacity needs given the aging of the fossil fuel fleet and anticipated environmental regulations. However, a number of operational issues exist 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 Marketplace, Dispatchable Variable Energy Resources (DVER) were subject to curtailment in the Energy Imbalance Service Market (EIS) based on impacts to a constraint and transmission service priority. Implementation of the SPP Marketplace in March 2014 introduced rules so that DVERs could be dispatched down based on offers and LMP in a similar manner to other dispatchable resources. In March 2014, installed DVER capacity was 28% of all wind with this increasing to 37% in February 2015. Figure 2–29 illustrates DVER and NDVER wind output for the first 12 months of the Marketplace with DVER output mirroring the increasing percentage of installed capacity. DVER output increased from about 28% of total wind generation at the beginning of the Marketplace to about 38% of wind generation after 12 months. This increase in dispatchable wind has helped in the management of congestion caused by high levels of wind generation in some western parts of the market.

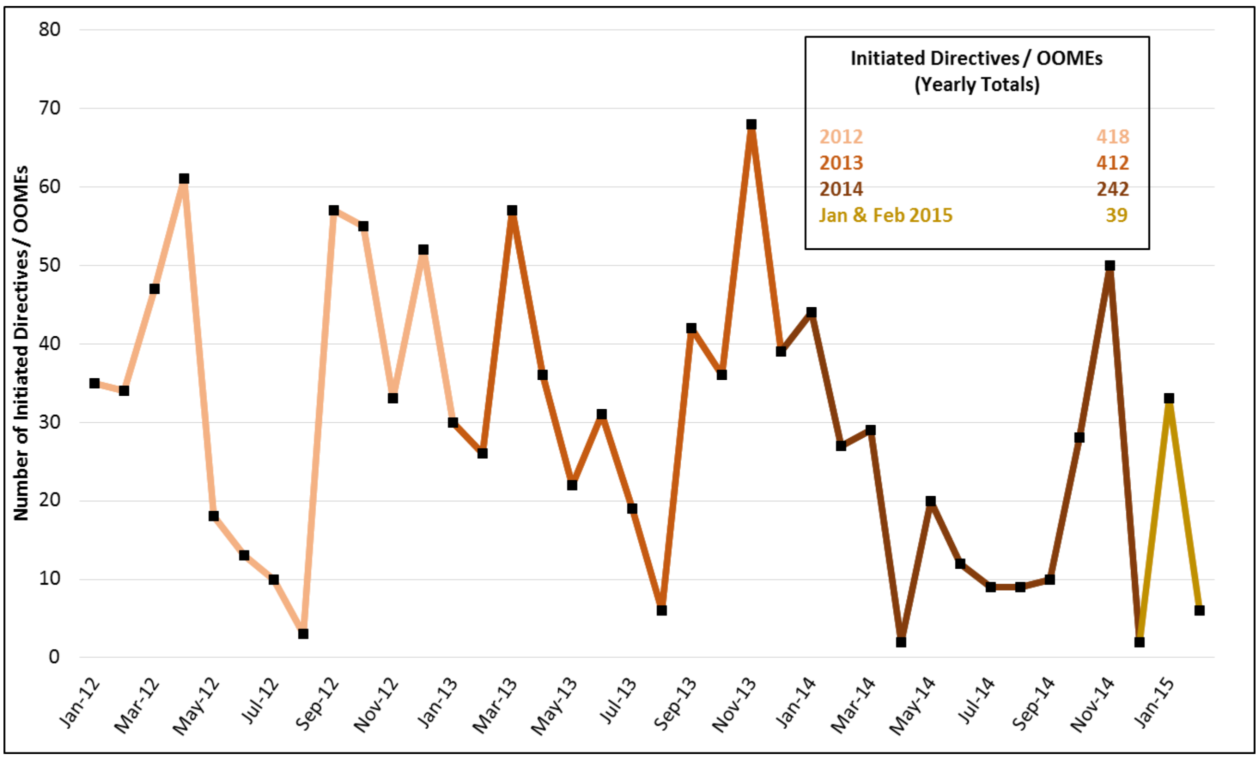
Substantial transmission upgrades that provided an increase in transmission capability for wind producing regions starting in 2014 also helped address concerns related to high wind production. This increased capability directly reduces localized congestion, creating a more integrated system with higher diversity and greater flexibility in managing high levels of wind production. Dispatching DVER wind resources down is usually congestion related and the upgrades energized in 2014 have reduced this somewhat. Figure 2–29 reflects this trend downward for the first 12 months of the SPP Marketplace, showing dispatchable wind being dispatched below a maximum level estimated from wind forecasts.

Figure 2–29 Dispatchable Wind Generation



Non-dispatchable resources were allowed to register as Non-Dispatchable Variable Energy Resources (NDVER), provided the resource had an interconnection agreement executed by May 21, 2011 and was commercially operated prior to October 15, 2012. Because installed wind capacity is composed of 65% NDVERs, grid operators must still issue manual dispatch instructions to reduce or limit their output at certain times. Figure 2–30 shows the number of initiated directives during the EIS and Out-of-Merit Energy (OOME) Marketplace for wind resources. These numbers include manual dispatch for both DVER and NDVERs, although most are for NDVERs since March 2014. The spike in November 2014 is attributed mostly to the 18 day outage of the Smokey Hills – Summit 230kV line limiting several NDVERs in the area.

Figure 2–30 Manual Dispatch

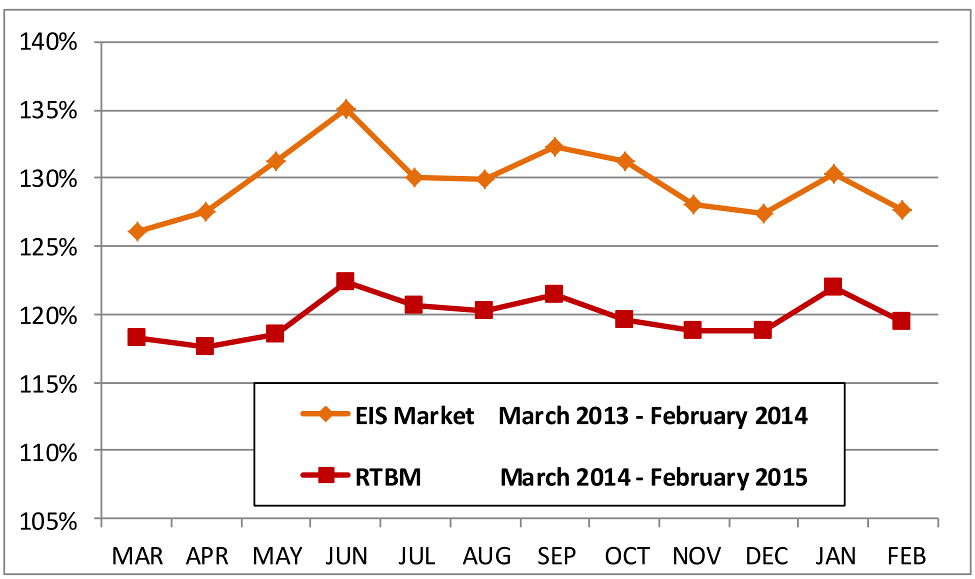


SPP is at the forefront among RTOs in managing wind energy integration with a traditional fossil fuel fleet. The Integrated Marketplace has reliably dispatched generation with wind serving up to 33% of load. Section “3. Energy and Operating Reserve Markets” (page 47) addresses some of the market efficiency issues encountered in providing the market ramping capability needed to manage wind integration, and the MMU has recommendations to support this aspect of the market. SPP and its stakeholders continue to discuss future improvements in this area.

3. Energy and Operating Reserve Markets

Prior to the start of the Integrated Marketplace and the SPP Centralized Balancing Authority, 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. A key driver for the development of the Integrated Marketplace was the promise of efficiency gains and cost savings through a centralized unit commitment process. Figure 3–1 shows that SPP has indeed made significant strides in this respect. The amount of online capacity relative to energy demand is on average 10% less in the RTBM as compared to levels in the EIS Market. A breakdown between on- and off-peak hours shows a decrease of 8% in on-peak hours and 12% in off-peak hours.

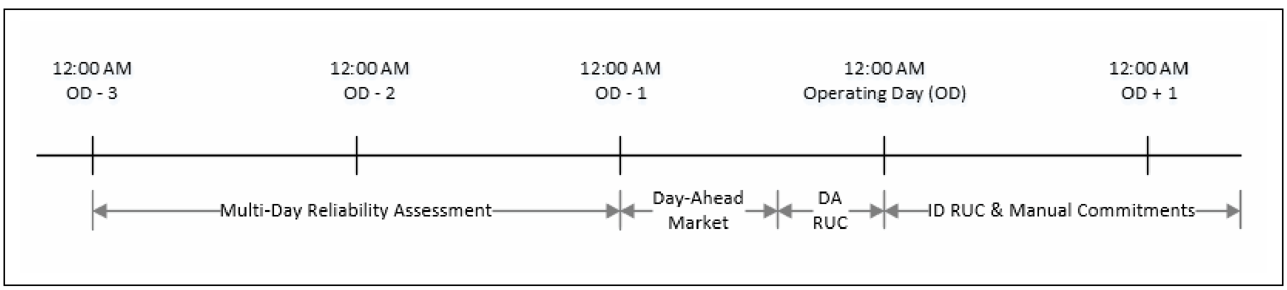
Figure 3–1 Online Capacity as Percent of Demand



3.1. Unit Commitment Processes

The Integrated Marketplace employs a centralized unit commitment program to determine an efficient commitment of generation resources to meet energy demand and the operating reserve requirements. The principal component of the commitment program is the Day-Ahead Market, which uses a rigorous algorithm to determine a least cost commitment that meets day-ahead energy demand and operating reserve requirements. It is necessary to commit additional capacity outside the Day-Ahead Market to ensure all reliability needs are addressed and to adjust the day-ahead commitment for real-time conditions. This is done through SPP's Reliability Unit Commitment processes. SPP employs four reliability commitment processes: (i) the Multi-Day Reliability Assessment; (ii) the Day-Ahead Reliability Unit Commitment (DA RUC) process; (iii) the Intra-Day Reliability Unit Commitment (ID RUC) process; and (iv) 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

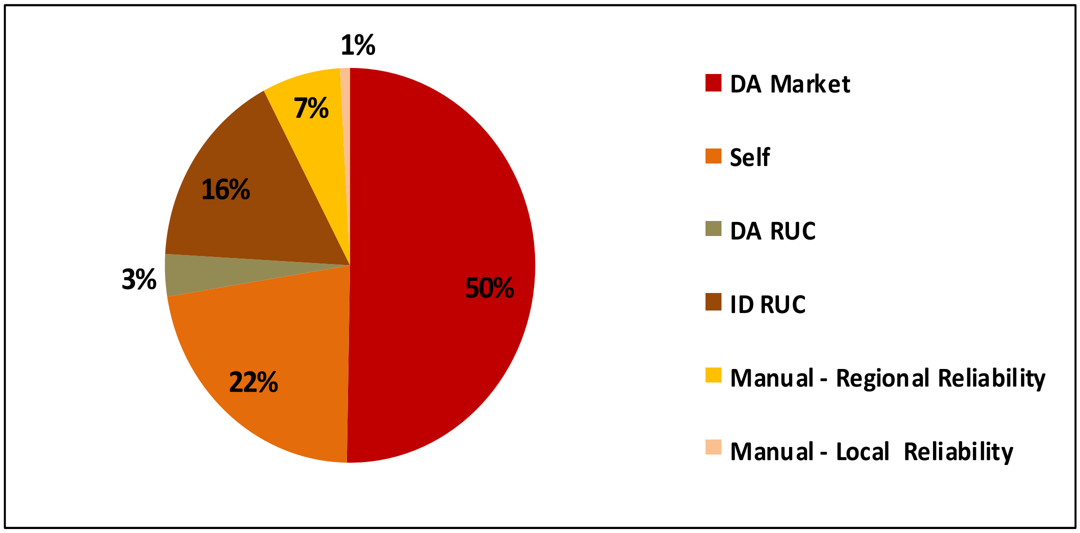


Multi-Day Reliability Assessments are made for at least three days prior to an operating day. This assessment determines if any long-lead time generators are needed for the operating day. The Day-Ahead Market is executed on the day before the operating day, and the results are posted by 1600 hours. The 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

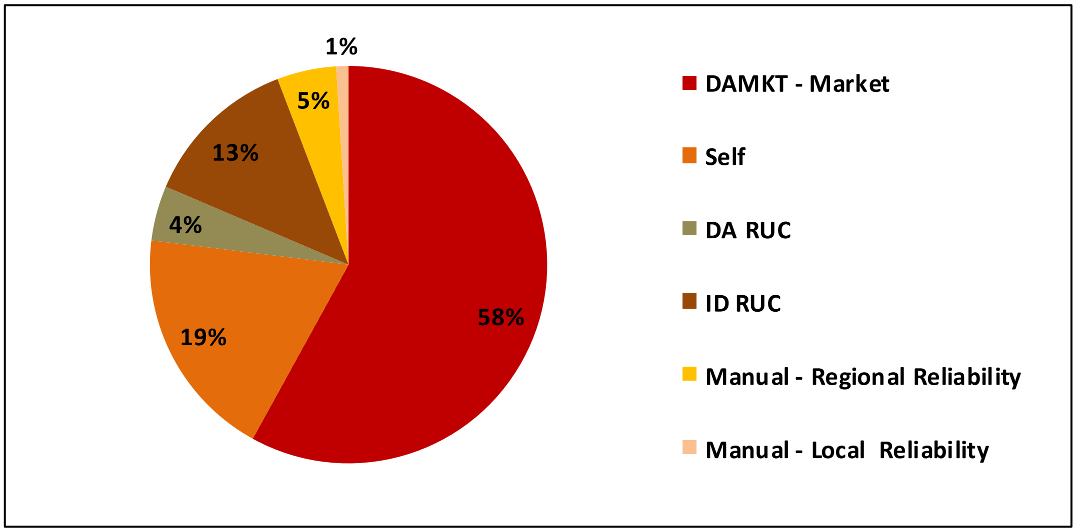
The SPP resource fleet, excluding variable energy resources, experienced 22,000 starts during the first 12 months of the Integrated Marketplace. Figure 3–3 and Figure 3–4 provide a breakdown of where the commitment decision originated. Figure 3–3 is based on the number of resources committed and Figure 3–4 is based on capacity committed.

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



Fifty percent (50%) 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 27% of the resource start-ups. Figure 3–4 provides a slightly different look at the data with the percentages based on capacity committed to start-up. The primary reason for the percentage differences between the two charts is that the larger base-load resources are either self-committed or committed by the Day-Ahead Market, and smaller resources with shorter lead times are more frequently 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 over 12,000 start-up instructions to gas-fired generators. 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 50% of their starts, reflecting the fact that Day-Ahead Market prices are rarely high enough to support these more expensive resources. 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 going-forward costs. The next section discusses the drivers behind the reliability commitments.

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

Commitment Process	Combined Cycle	Simple Cycle – CT	Simple Cycle – ST
Day-Ahead Market	97%	54%	50%
DA RUC	1%	4%	20%
ID RUC	1%	29%	27%
Manual Instruction	0%	14%	3%

3.1.2. Demand for Reliability

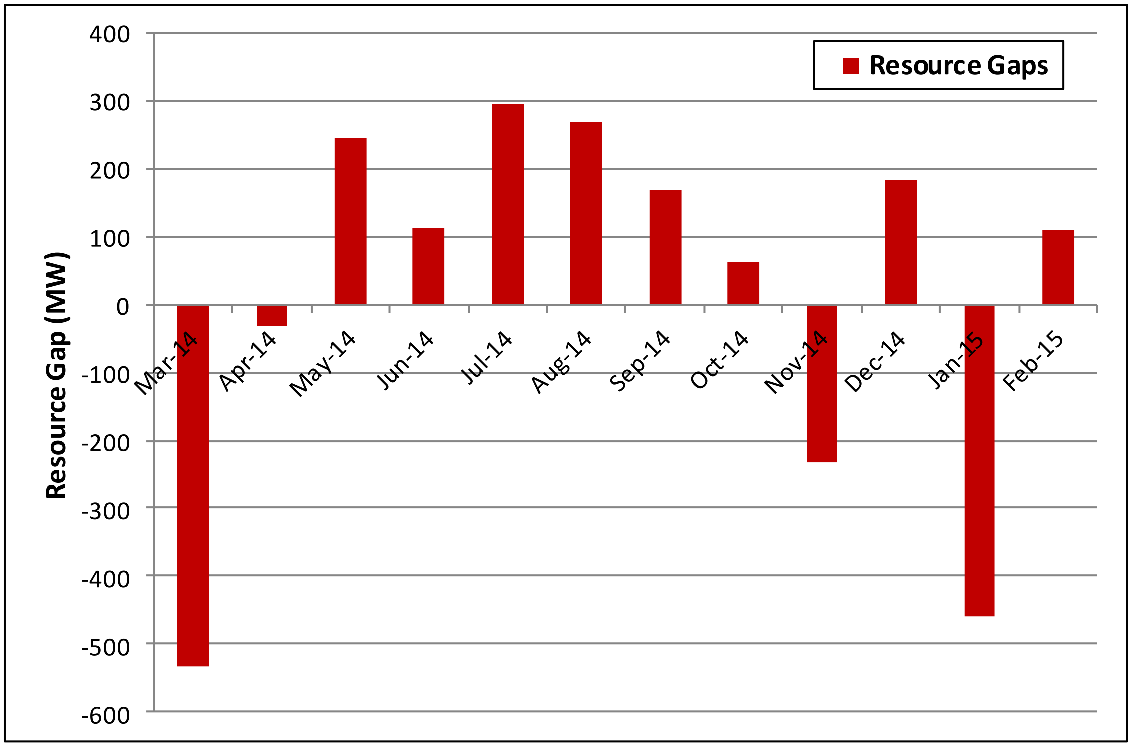
In the previous section we noted that 27% of SPP start-up instructions originated from the SPP reliability commitment processes: DA RUC (3%), ID RUC (16%), manual-regional reliability (7%), and manual-local reliability (1%). To understand the need for the reliability commitments it is useful to discuss 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 sell energy in the Day-Ahead Market. A virtual bid 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 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 also updated to include the latest information available for the reliability processes.

These types of differences lead to resource gaps between the day-ahead and real-time. Figure 3–6 displays the average aggregated resource gaps for the first 12 months of the Integrated Marketplace. The resource gaps are the sum of: (i) the real-time wind in excess of the cleared supply bids on wind generators in the Day-Ahead Market; (ii) real-time load in excess of load cleared in the Day-Ahead Market; (iii) virtual supply net of virtual demand; (iv) real-time net exports in excess of day-ahead net exports; and (v) real-time losses in excess of day-ahead losses.

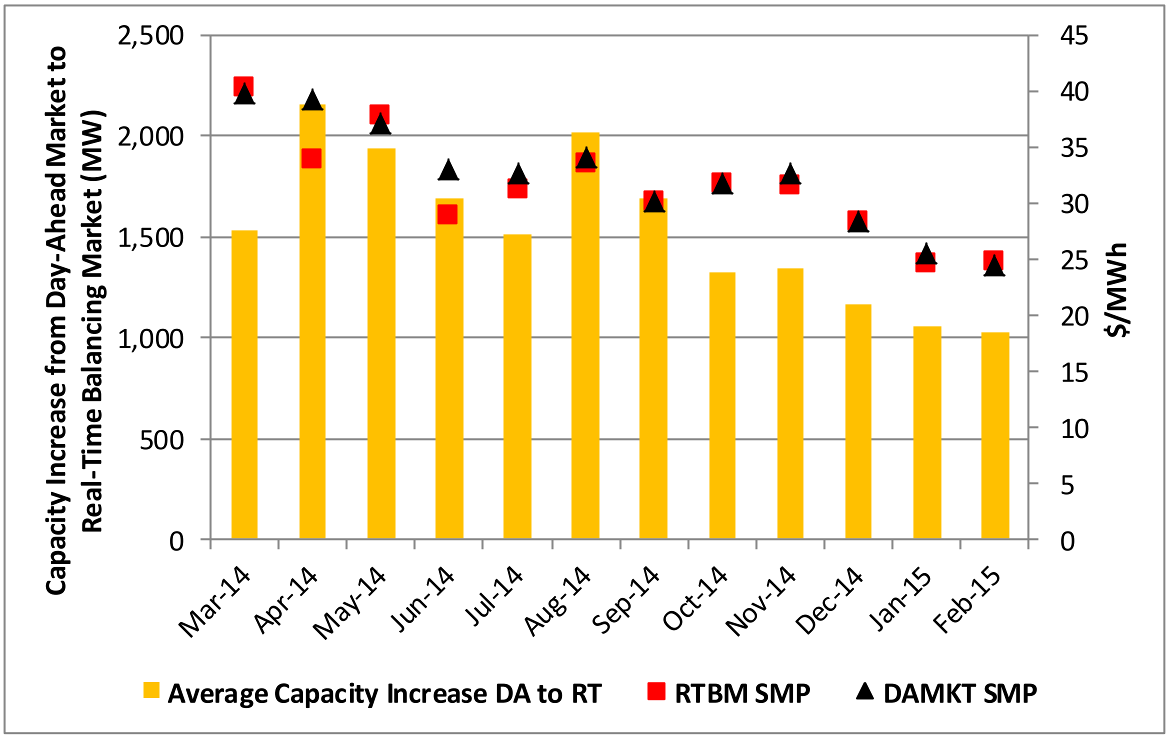
Figure 3–6 Average Day-Ahead Market/RUC Resource Gaps



In March 2014, Figure 3–6 indicates the average hourly resource gap for the month was approximately negative 500 megawatts. 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. The principal driver for the large negative resource gaps in March 2014, November 2014, and January 2015 is a low level of virtual supply net of virtual demand. It is generally true that real-time wind generation exceeds the clearing of wind in the Day-Ahead Market. However, in most months virtual transactions fill the gap between day-ahead and real-time wind. 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 fuel supply.

In both March and April, real-time wind exceeded day-ahead wind by approximately 1,000 megawatts on average. However, the virtual supply net of virtual demand in April was 800 megawatts and only 300 megawatts in March 2014. Virtual supply dropped off in the last few months of the 12 month period, with virtual demand exceeding virtual supply on average. The reduced virtual activity coupled with the wind differences also led to a negative resource gap in January 2015.

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 in March 2014 an additional 1,500 megawatts of capacity was online during the RTBM relative to the capacity cleared in the Day-Ahead Market. The bars are consistently above 1,500 megawatts through September 2014 and are seemingly uncorrelated with the resource gaps in Figure 3–6. We do see a distinct shift downward in the chart beginning in October 2014 and continuing through February 2015. At this time it is not clear if this represents a seasonal shift or perhaps a change in the reliability commitment process. We conclude from Figure 3–6 and Figure 3–7 that the so-called 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. 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, but in SPP the volatility of wind generation acerbates the need for ramp capability. 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 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 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 includes the average system marginal price for both day-ahead and real-time. For the first 12 months, the day-ahead system marginal price exceeds the real-time by $1/MWh, up to $5/MWh in some months. Many factors contribute to the price differences between day-ahead and real-time, and we are unable to quantify the impacts of the reliability commitments on the real-time prices. But the direction of the impact is clear—reliability commitments dampen the real-time price signals. Several 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 resources that can be started, synchronized, and inject energy within ten minutes of SPP notification. The Market Monitoring database indicates that the SPP generation fleet includes 74 resources that meet the ten-minute start-up time requirement for quick-start capability. The total capacity for the quick-start capable resources totals 3,000 megawatts and consists of a mix of gas-fired, hydro, and oil-fire generators. Sixty-one of the 74 quick-start capable resources were committed by the reliability commitment processes during the first year of operation. Six additional resources submitted real-time bids with cold start-up times less than or equal to ten 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 ten-minute start-up capability. In total, 2,506 start instructions originated in a reliability commitment process and 4,210 start instructions originated from the Day-Ahead Market during the first 12 months of the Integrated Marketplace. 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 ten-minute resource's commitment period. The average lead-time for ten-minute resources started by the DA RUC study is 16 hours; for the ID RUC, the average lead time is three 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	153	6,500	16	3.0	8
ID RUC	1,192	59,400	3	2.5	4
Manual	1,161	64,700	0.25	2.0	4
DA Market	4,210	171,900	21	1.0	5

The average number of hours in the initial commitment instructions varied between two and three 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 ten-minute resources are often picked up by subsequent reliability processes and kept online. The actual hours online was eight hours on average for the DA RUC starts and exceeded four hours on average for the starts initiated by the ID RUC, Day-Ahead Market, and manual instructions. 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 ten-minute resources in the reliability processes is noteworthy. Well over half of the 2,506 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 $11.5 million in real-time make-whole payments and $0.3 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 ten-minute start-up, 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.

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 value of waiting, is prevalent throughout markets, and the current treatment of ten-minute resources by the system operator ignores this value.

Section 4.4.2.3.1 in the Integrated Marketplace Protocols 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 work-around must be used to track the quick-start capacity available in the RTBM.

RTO staff began working with stakeholders in June 2014 to address the quick-start design issues. The initial effort to find a workable solution did not produce results; however, in May 2015 RTO staff presented a new design proposal that was well received by stakeholders and it appears that the stakeholder process will lead to new rules governing the commitment and dispatch of quick-start resources in the latter half of 2015.

MMU Recommendation 1. Quick Start Logic

RTO staff should continue working with stakeholders and the MMU in the development of new rules governing the dispatch of quick-start resources. Two key components of the new design are as follows: (1) Resources with a ten-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.

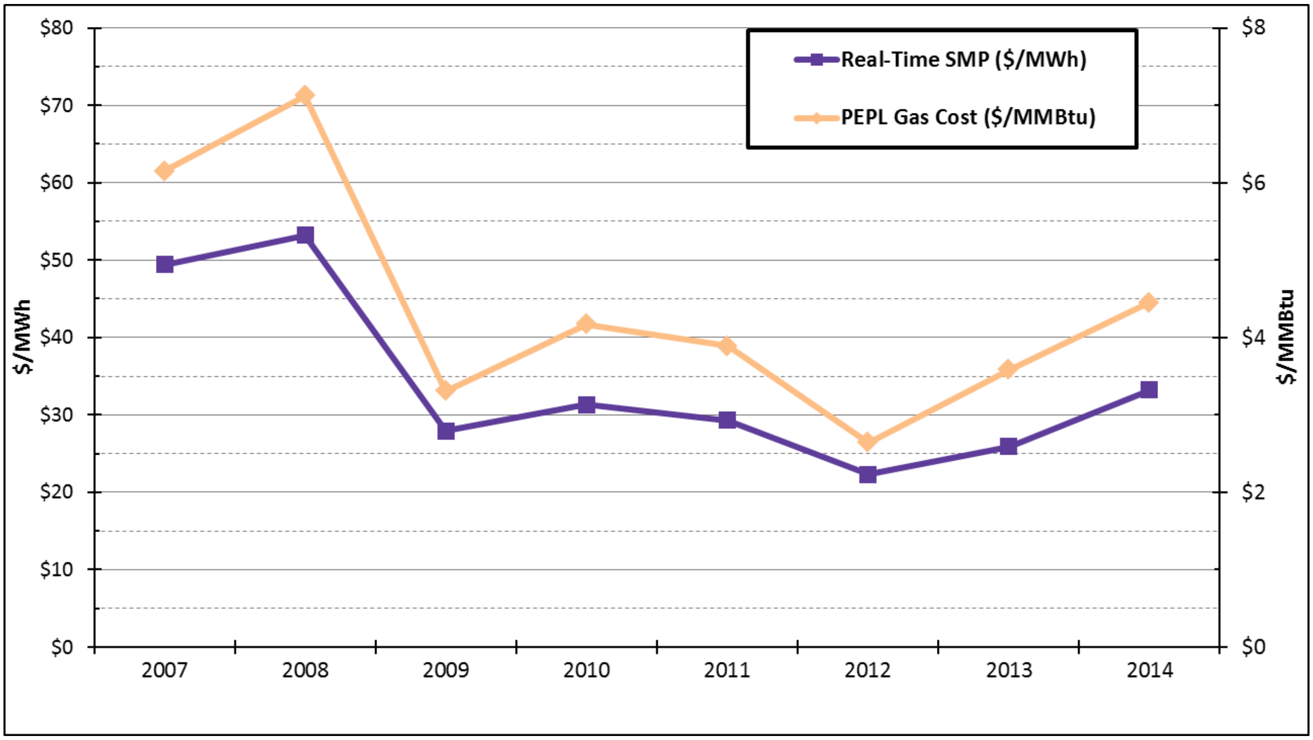
3.2. Real-Time Balancing Market

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.

3.2.1. Energy and Ancillary Service Prices

Energy prices in SPP track very closely with the price of natural gas. This was true in the Energy Imbalance Service (EIS) Market and continues to be the case in the Integrated Marketplace. Figure 3–9 shows the average real-time energy price for the past eight years. The 2014 average includes two months of Locational Imbalance Prices (LIPs) from the EIS Market and ten months of Locational Marginal Prices (LMPs) from the Integrated Marketplace. The 2014 average energy price of $31.42 is a 21% increase over the comparable 2013 average price. The 2014 average price of natural gas at the Panhandle Eastern Pipeline hubs is $4.45, a 24% increase over 2013 levels. In 2014 the annual average gas price and the annual average energy price are noticeably skewed by the high gas prices that occurred in February 2014 due to the number and intensity of winter storms.

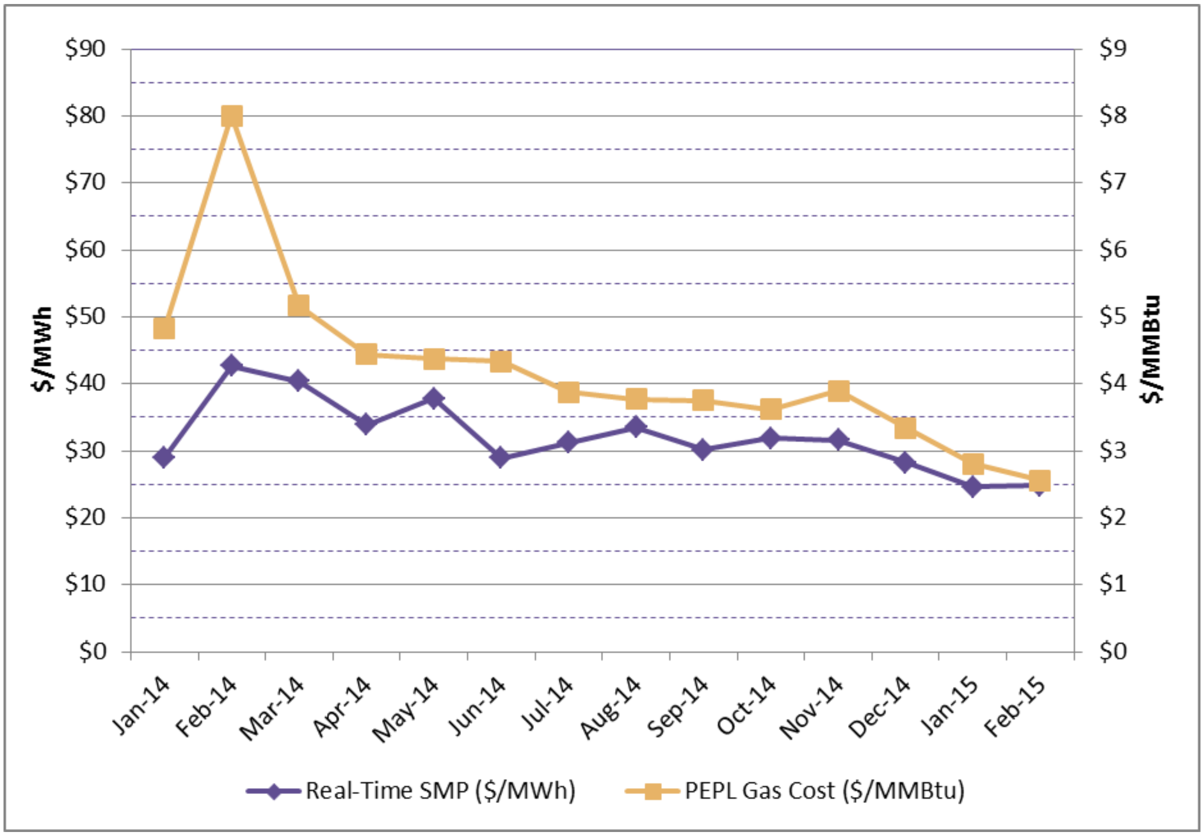
Figure 3–9 Real-Time Energy Price



The impact of the winter storms is clear in the monthly average energy price chart in Figure 3–10. The average gas price at the Panhandle Eastern Pipeline hub was $8/MMBtu for the month of February, resulting in a real-time SMP of $43/MWh. The gas price dropped sharply in March 2014 to $5/MMBtu on average, and has since gradually dropped to just below $3/MMBtu in February 2015. Similarly, the average SMP dropped from the high of $44/MWh in February 2014 to $25/MWh in February 2015. The most notable exception to gas-electricity price correlation occurs in May 2014. Except for March 2014 when there were gas supply interruptions, May 2014 was impacted by scarcity pricing more so than any other month. In May 2014 the RTBM experienced 10 minutes of operating reserve shortage, 1 hour and 20 minutes of regulation shortage, and 7 hours and 35 minutes of Spinning Reserve shortages. The average SMP during the nine hours of shortage pricing during May was $400/MWh, a shortage pricing impact of approximately $300/MWh.

Electricity price and gas price are also negatively correlated in July and August. This is a typical pattern that SPP experiences in most years because higher summer loads result in less efficient gas unit commitments. As a result, prices are higher even though the gas price is flat through the hottest part of the summer.

Figure 3–10 Real-Time Energy Price by Month

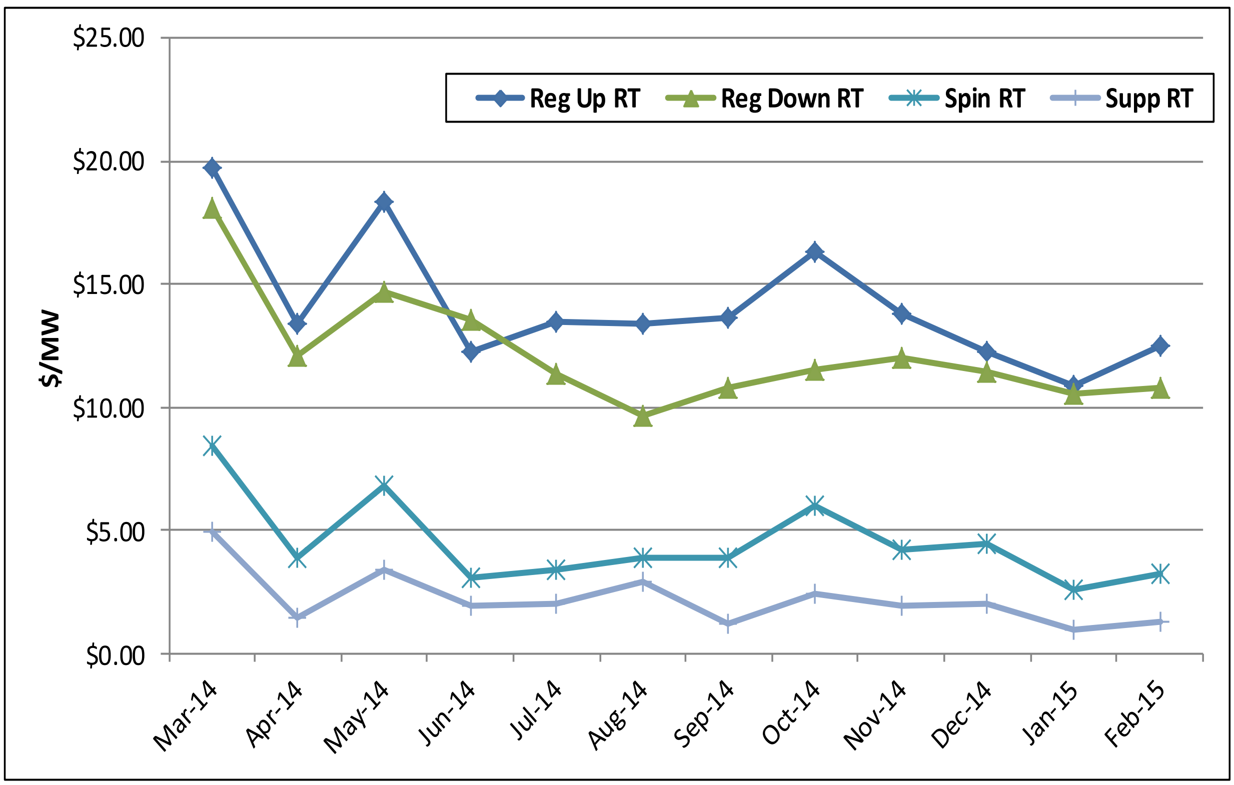


Average real-time prices for the operating reserve products are presented in Figure 3–11. All four products hit their high marks for the 12 month period in March 2014. The 12 month average marginal clearing price for Regulation-Up service is $14.14/MW. The 12 month averages for Regulation Down Service, Spinning Reserves, and Supplemental Reserves are $12.21/MW,

$4.48/MW, and $2.20/MW respectively. The general pattern is similar to the energy price chart in Figure 3–10 with scarcity pricing impacts in March and May.

In late September 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 should foster increased competition in the market for operating reserves and is consistent with the downward trend in prices we observe in Figure 3–11 over the last few months of the period.

Figure 3–11 Real-Time Operating Reserve Product Prices



3.2.2. Real-Time and Day-Ahead Price Comparisons

Figure 3–12 is a comparison of the Day-Ahead Market system marginal price with the RTBM counterpart. The average price differences are right around $1/MWh or less for all but three months. The day-ahead SMP exceeded the real-time SMP by $5.35/MWh and $4.23/MWh in April and June, respectively, and by $1.49/MWh in July.

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

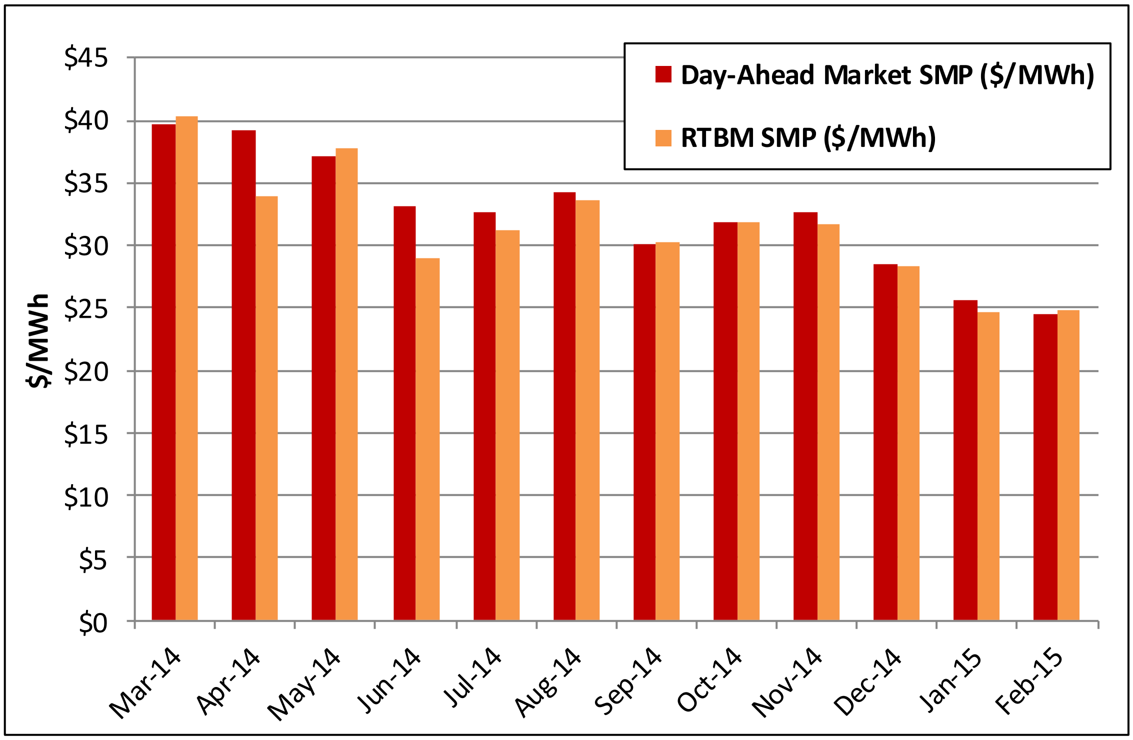


Figure 3–13 shows the day-ahead and real-time energy prices at the two SPP market hubs. The SPP North Hub is composed of pricing nodes in the northern part of the SPP footprint and the SPP South Hub is composed of pricing nodes in the south-central portion of the footprint. The general pattern of higher 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 is the predominate fuel in the south. The day-ahead premium, the amount by which the day-ahead energy price exceeds the real-time energy price, is much larger at the North Hub. The annual average day-ahead premium is $2.83 at the North Hub versus only $0.50 at the South Hub. The high premiums at the North Hub are driven by downward price spikes in the RTBM.

Figure 3–13 Market Hub Prices

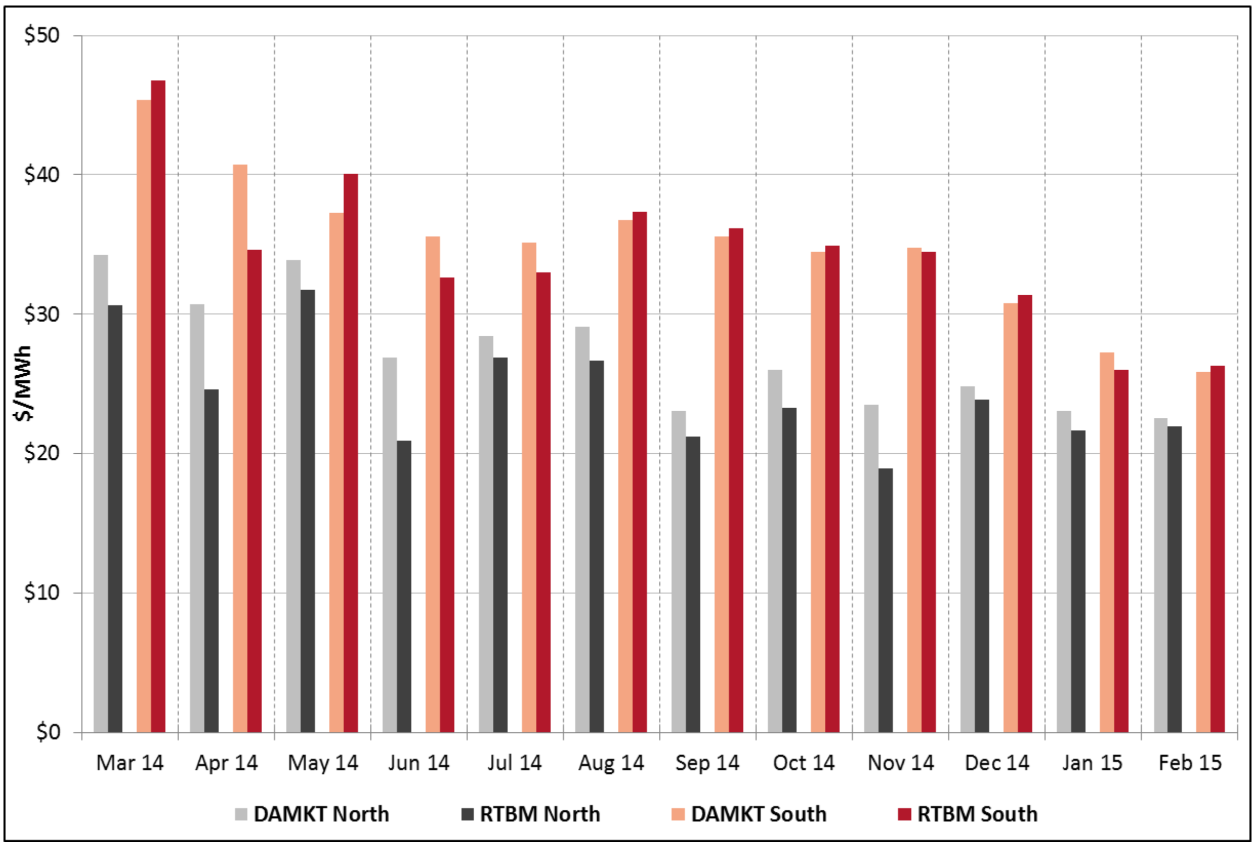


Figure 3–14 presents the probability density curves associated with the energy prices at the SPP North Hub. The real-time curve is noticeably shifted to the left of the day-ahead curve, and there is significant area under the RTBM curve just above the zero dollar tick on the horizontal axis.

This is indicative of negative pricing 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. A similar leftward shift is evident in Figure 3–15, which shows the comparable graph for the SPP South Hub.

Figure 3–14 North Hub Price Density Curves

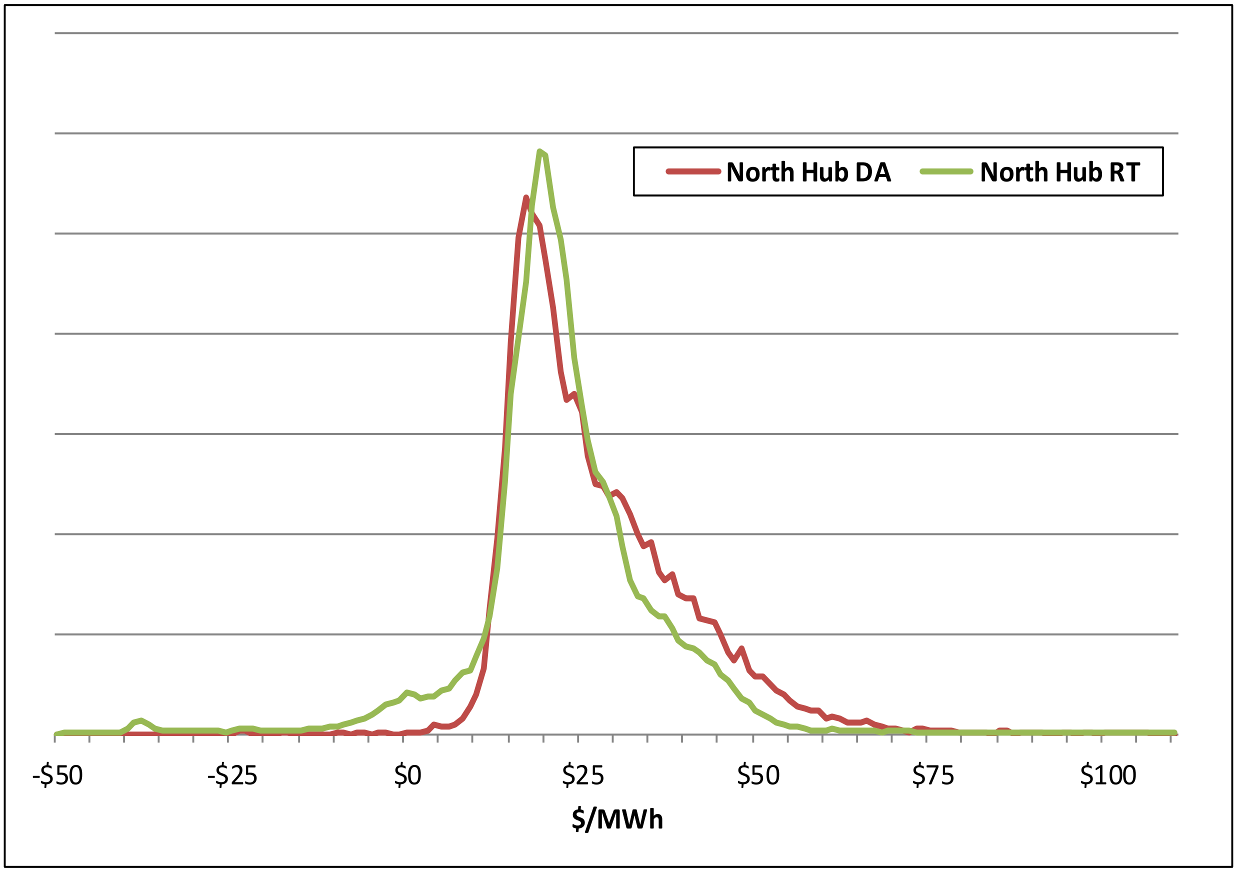
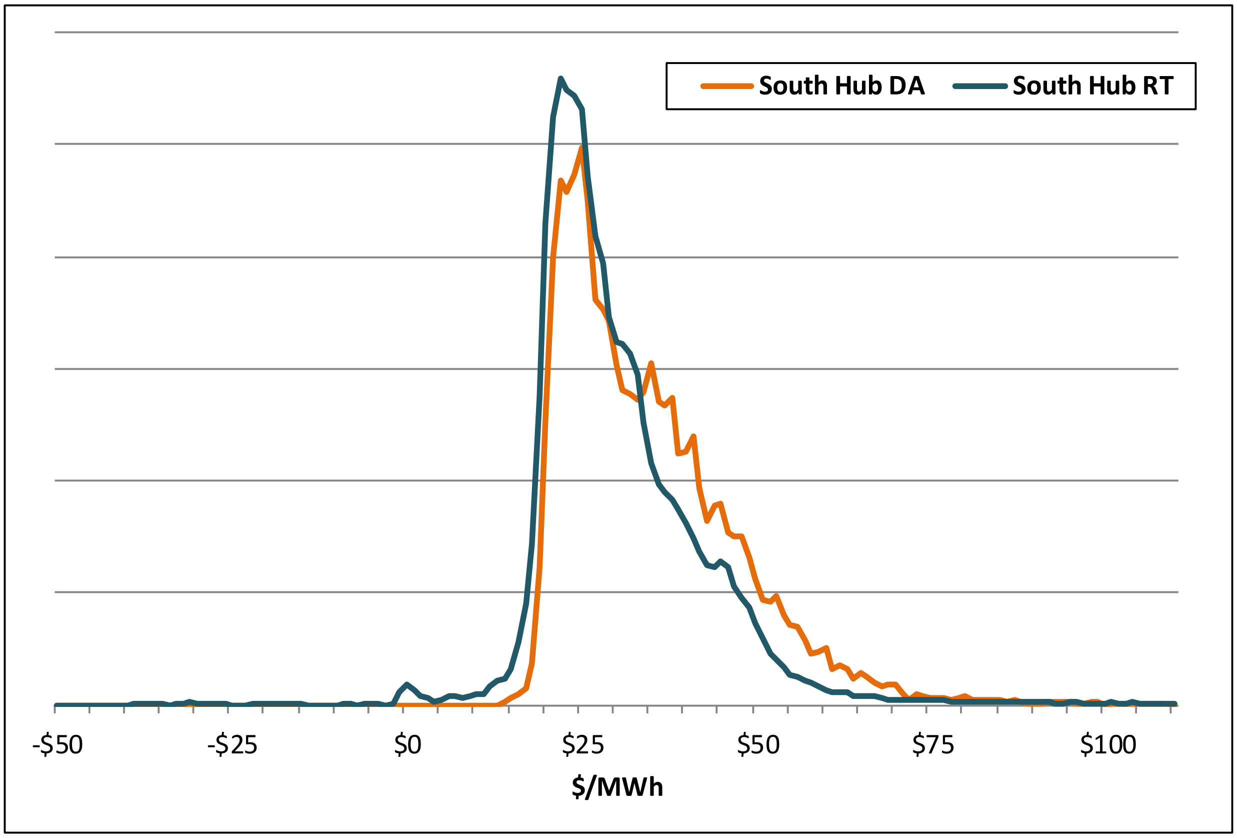


Figure 3–15 South Hub Price Density Curves



3.2.3. Ancillary Services Prices

The day-ahead and real-time price patterns vary across the ancillary service products. Figure 3–16 through Figure 3–19 provide comparisons between day-ahead and real-time for the first 12 months of the market. The Regulation-Up Service average price varied from $10/MW to $20/MW during the first 12 months with no clear pattern evident between day-ahead and real-time. On the other hand, the real-time price for Regulation-Down Service consistently exceeds the day-ahead price. The annual average real-time price is $4/MW higher than the day-ahead price. This price difference correlated highly with congestion on the transmission constraint OSGCANBUSDEA, indicating its relationship with a market clearing engine limitation. The RTBM did not recognize the reliability impact of the deployment of Operative Reserves, especially Regulation Down, on the constraint. SPP disqualified resources that relieved the constraint from Regulation Down during the operating day, which required clearing more expensive resources to meet the Regulation-Down requirement.8 Spinning Reserve prices are generally lower in real-time and supplement reserve prices are generally higher in real-time.

[8] At the time of this report, SPP staff had just introduced a proposed solution, Reserve Post-Deployment Constraints.

Figure 3–16 Regulation-Up Service Prices

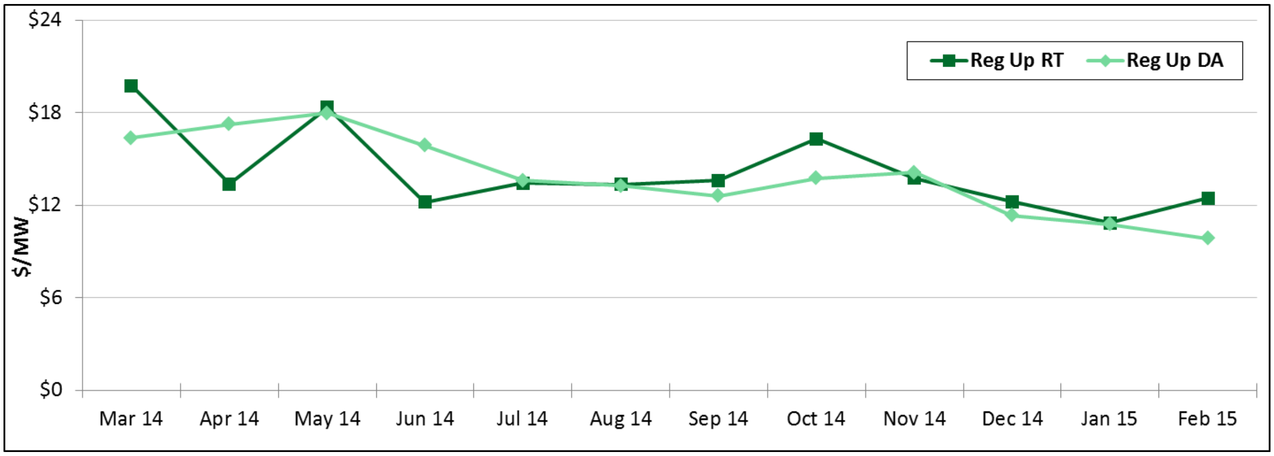


Figure 3–17 Regulation-Down Service Prices

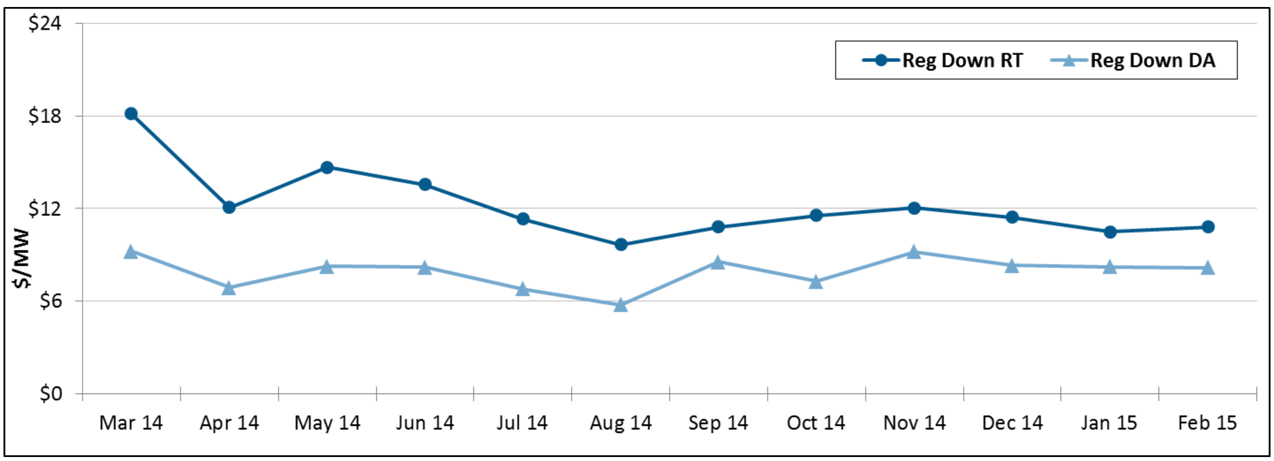


Figure 3–18 Spinning Reserve Prices

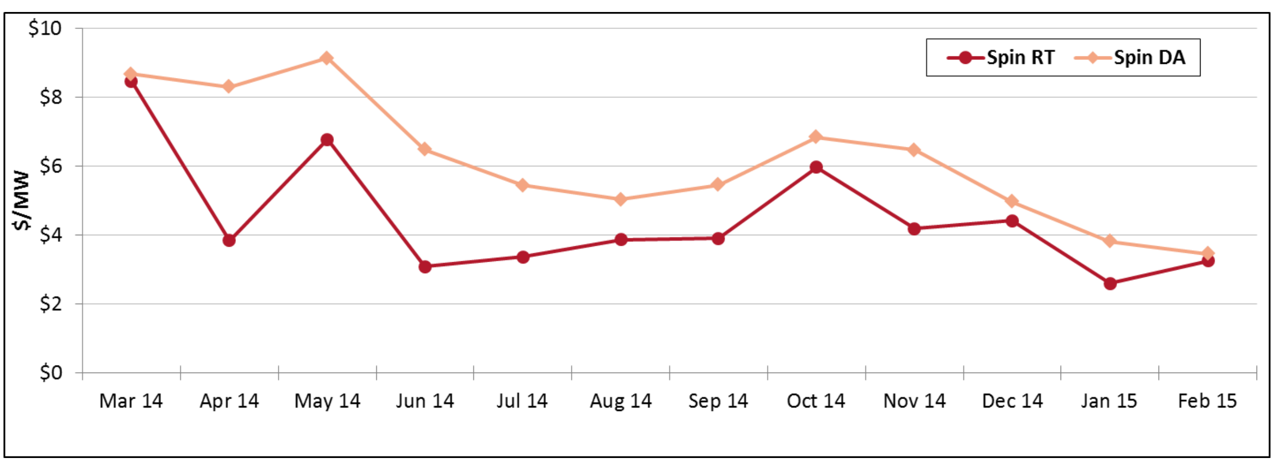
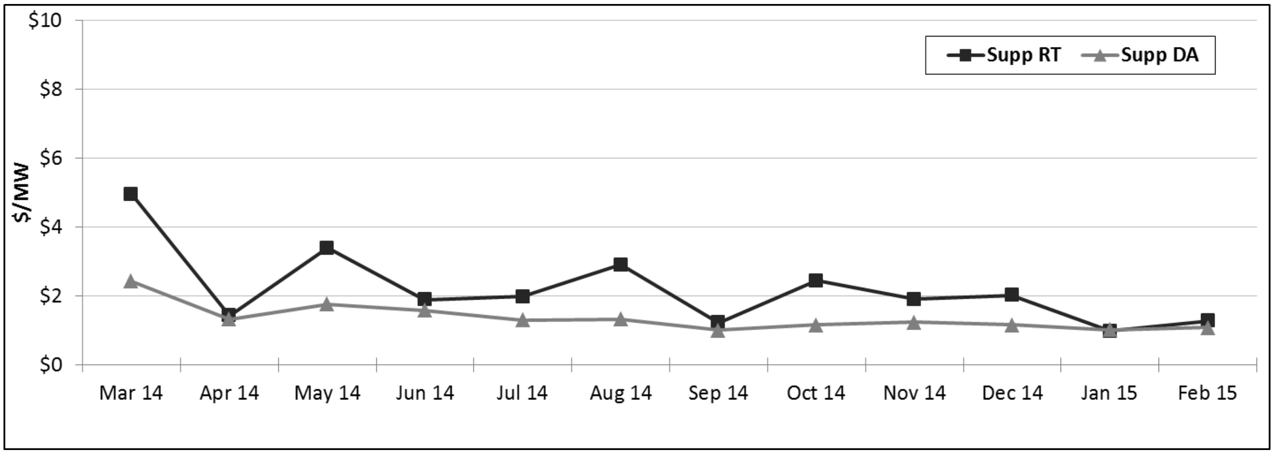


Figure 3–19 Supplemental Reserve Prices



3.2.4. Market Settlement Results

Ninety-seven percent (97%) of energy consumed in the Integrated Marketplace was settled in the Day-Ahead Market. Figure 3–20 shows that 228 terawatt-hours of energy were purchased in the Day-Ahead Market at load settlement locations. Approximately six of the 228 terawatt hours were in excess of the real-time consumption, resulting in real-time sales at the load settlement location. An additional seven terawatt-hours of energy were purchased in the RTBM.

Figure 3–20 Energy Settlements – Load

	Day-Ahead Market Purchases	RTBM Purchases	RTBM Sales
Load – Energy (GWh)	227, 764	7,124	5,757
Cash Flow (Millions)	$7,815	$236	$181

Ninety percent (90%) of generation was settled in the Day-Ahead Market. Figure 3–21 presents the settlement numbers for the generation assets. Eight percent (8%) of the energy cleared in the Day-Ahead Market was settled by purchasing energy in the RTBM rather than generating the energy. The displacement of day-ahead energy is partially due to the participation of the wind generators. Thirty-one percent (31%) of the 29,000 gigawatt-hours of wind generation cleared in the RTBM. The additional 1,000 to 1,500 megawatts committed by the reliability commitment processes also impacts the real-time purchases by generators.

Figure 3–21 Energy Settlements – Generation

	Day-Ahead Market Sales	RTBM Sales	RTBM Purchases
Energy (GWh)	229,460	23,238	19,081
Cash Flow (Millions)	$7,287	$649	$574

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 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. Contingency reserves were increased by 54 megawatts for part of one day in August but generally there are no significant changes. 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 3–22 presents the settlements data.

Figure 3–22 Operating Reserve Settlements

	Day-Ahead Market Sales	RTBM Sales	RTBM Purchases
Regulation Up Service (GW-Hours)	2,904	1,122	1,126
Regulation Down Service (GW-Hours)	2,904	1,096	1,097
Spinning Reserves (GW-Hours)	5,759	2,116	2,119
Supplemental Reserves (GW-Hours)	5,698	1,338	1,334

A large percentage of day-ahead sales are settled in the RTBM by purchasing the reserve product rather than supplying the service in the RTBM. Forty percent (40%) of the day-ahead sales of regulation up service are settled through purchasing the product in the RTBM. This is in contrast to 90% of energy generation settling at the day-ahead prices. Only 61% of the real-time Regulation-Up Service is settled at the day-ahead prices. The corresponding percentages for Regulation-Down Service, Spinning Reserves, and Supplemental Reserves are 62%, 63%, and 77% respectively. This essentially means that the operating reserve products are being moved around to different resources. 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. As noted previously, the RTO commits between 1,000 and 1,500 MW through the reliability commitment processes, which increases the supply from which the reserve product demand can be served.

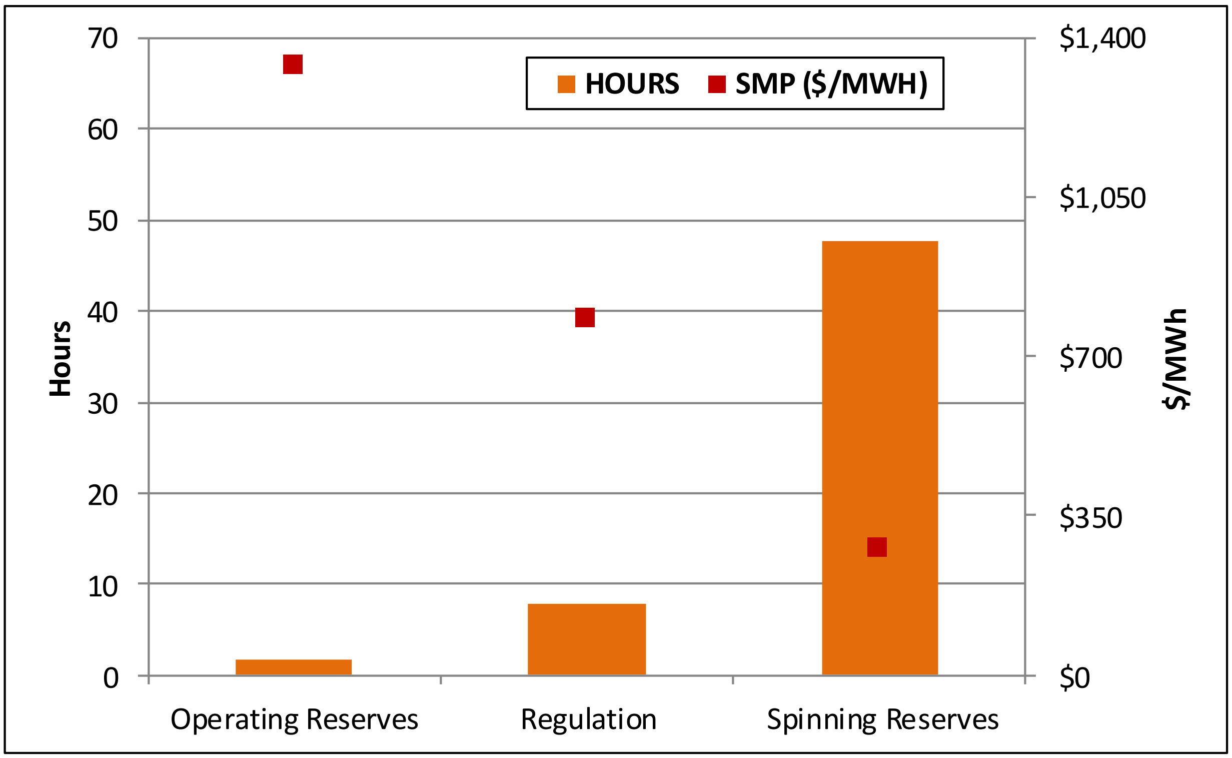
One issue that is not clear is the high level of Regulation-Down Service that is being purchased by generation owners to cover their day-ahead positions. Figure 3–17 shows that real-time prices consistently exceed the day-ahead prices for Regulation-Down Service. This means that 38% of the regulation-down 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 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. SPP staff has developed a proposed solution to the system limitation, and the market monitor is making a mitigation design change related to this issue; see the mitigation design recommendations in section "6.2.2 Analysis of Conduct and Impact Thresholds“ (page136).

3.2.5. Shortage Pricing

The Integrated Marketplace employs scarcity pricing demand curves to 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 58 hours of capacity shortages in the first 12 months of market operation. Most shortages (83%) were for Spinning Reserve. There were eight hours of regulation shortages and two hours of aggregate operating reserve shortages. 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 3–23 displays the number of shortage hours and the corresponding average of the 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 3–23 Capacity Shortages



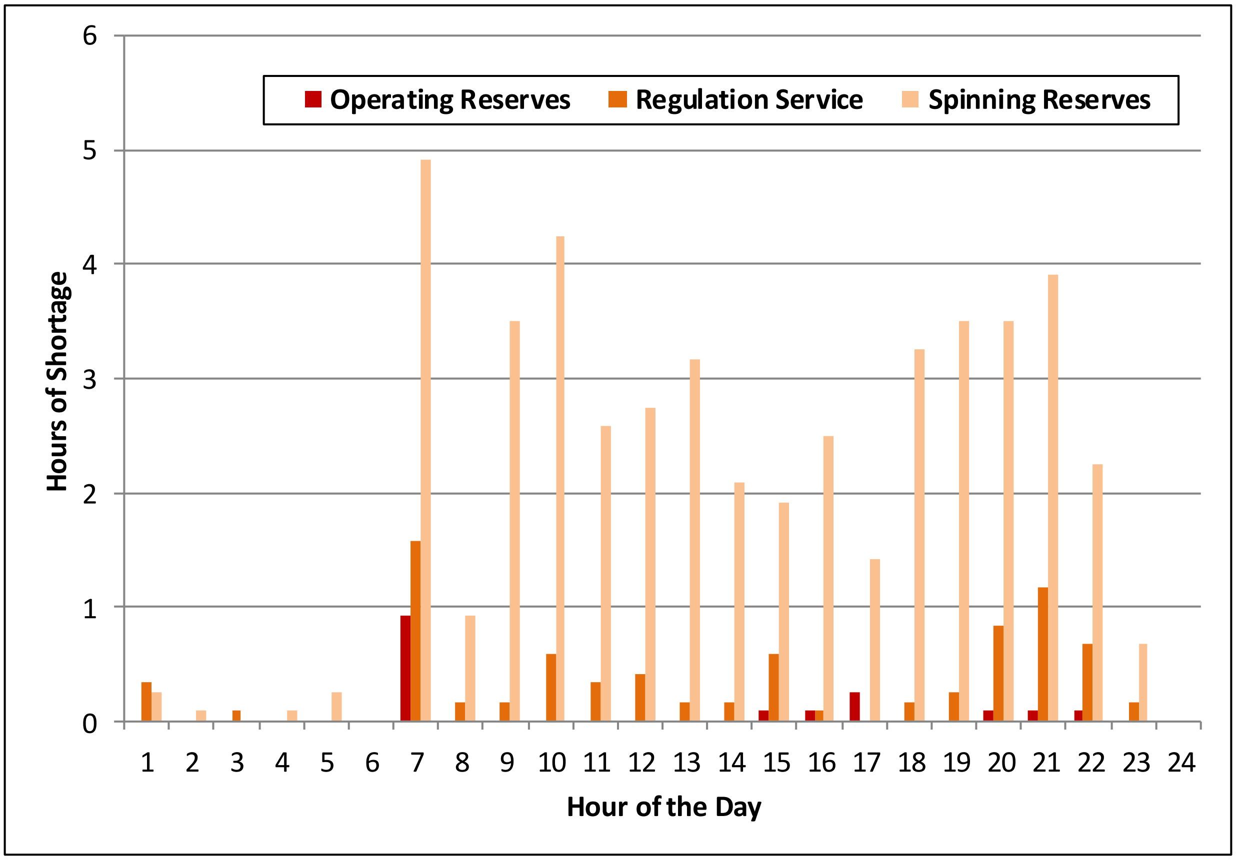
There were eight separate operating reserve shortage events in the first year of the market spread across six days. A single shortage event is composed of consecutive RTBM solutions with a shortage. The average duration of the eight events was 12 minutes. The longest event lasted 45 minutes on March 3, 2014, which was caused by gas supply limitations. A 15 minute operating reserve shortage occurred on August 21, 2014, which was triggered by a forced outage of a

Figure 3–24 Capacity Shortage Statistics

Shortage Type	Number of Events	Average Duration (minutes)	Maximum Duration (minutes)	Average Shortage Amount (MW)	Maximum Shortage Amount (MW)
Aggregate Operating Reserves	8	12	45	307	586
Regulation-Up	70	7	25	92	430
Spinning Reserves	294	10	55	115	602

generator. Figure 3–24 provides details on the capacity shortages that occurred during the first 12 months of the Integrated Marketplace. The hour of the day experiencing the most shortage events is not surprisingly the hour between 6:00 AM and 7:00 AM. Regulation shortages tend to occur in the morning ramp as well as between 8:00 PM and 11:00 PM as 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 3–25 Capacity Shortages – Hour of Day

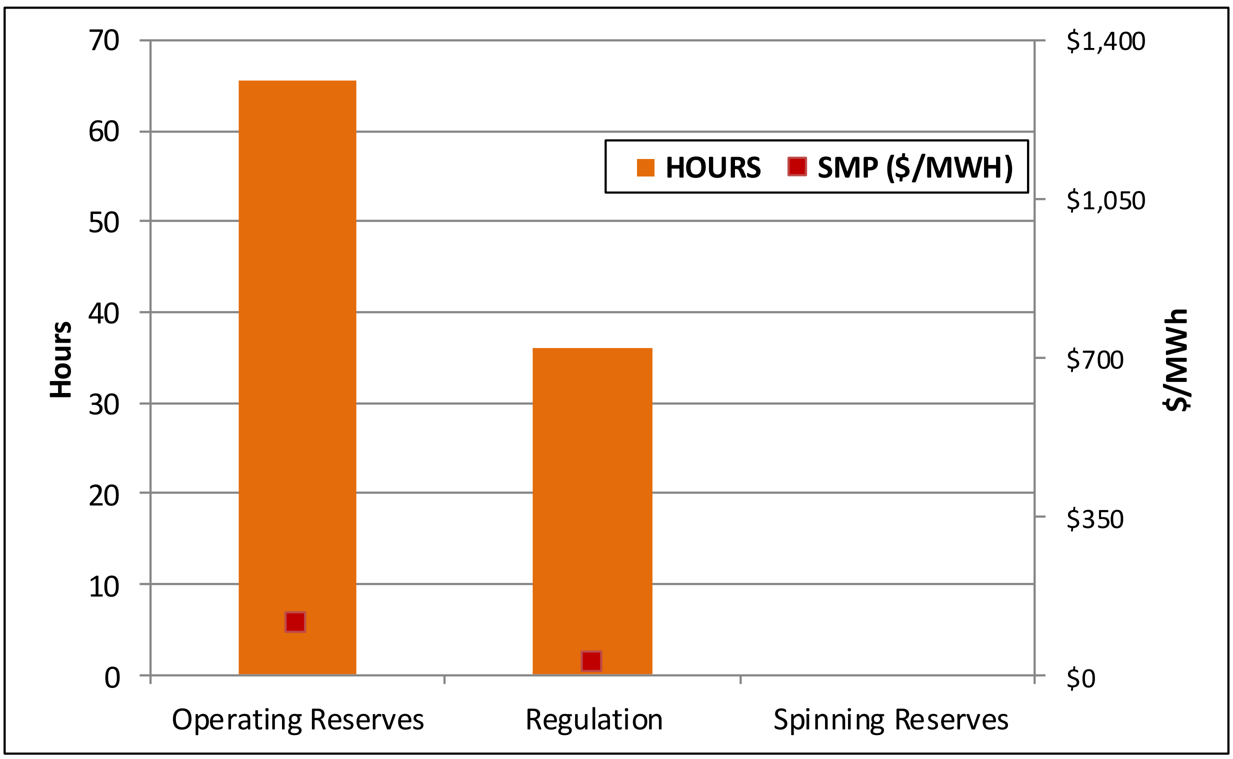


Scarcity pricing is an important component of the Integrated Marketplace. It is during the shortage events that quick-start and fast ramping resources earn a significant portion of their annual revenue. These resources generally have higher costs and low capacity factors, and therefore must generate 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 resource to come online. One area where the Market Monitor 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.

There were 66 hours of ramp-constrained operating reserve shortages, and 36 hours of ramp-constrained regulation shortages. 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 $114/MWh. 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.

Figure 3–26 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 3–27 Ramp-Constrained Shortage Statistics

Shortage Type	Number of Events	Average Duration (minutes)	Maximum Duration (minutes)	Average Shortage Amount (MW)	Maximum Shortage Amount (MW)
Aggregate Operating Reserves	547	7	55	47	454
Regulation	321	7	35	24	304
Spinning Reserves	0	0	0	0	0

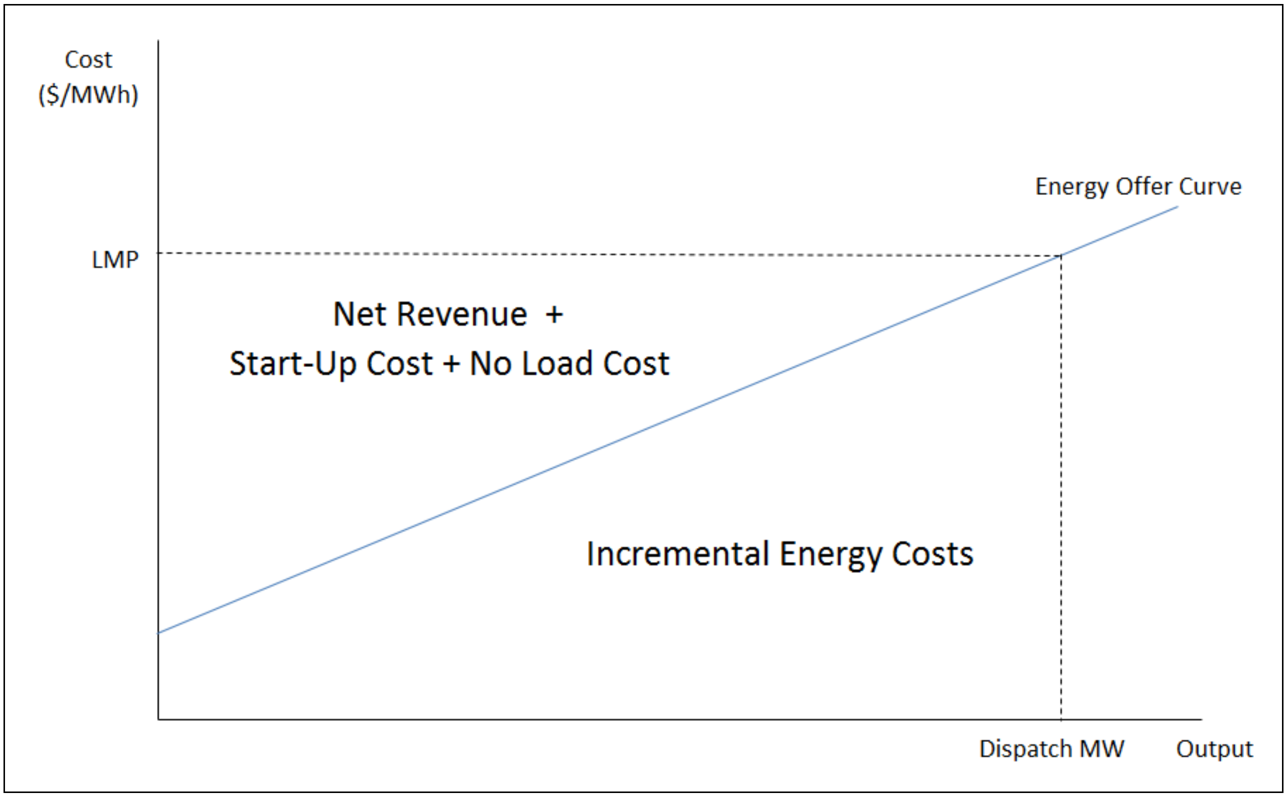
MMU Recommendation 2. Ramp-Constrained Shortage Pricing

The Market Monitor 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 Mid-Continent 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.

3.2.6. Make Whole Payments

The Integrated Marketplace provides uplift payments to generators to ensure that the market provides payment sufficient 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 3–28 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 short run energy, start-up, and no load costs.

Figure 3–28. Revenue and Cost Conceptual Graph



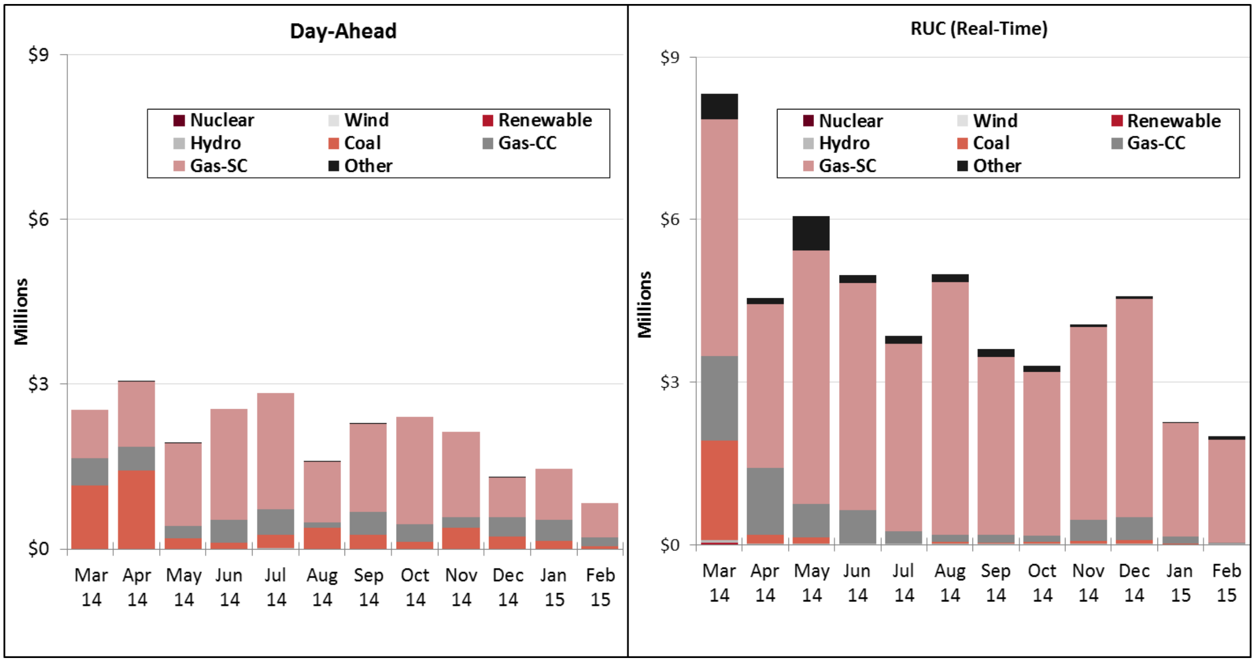
The calculations separately evaluate Day-Ahead Market commitments based on Day-Ahead Market prices, dispatch, and cleared offers and RUC commitments based on RTBM prices, dispatch, and cleared offers, summing revenues and costs across contiguous market intervals for the shorter of the commitment period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

For the first year of the market, DA Market and RUC make whole payments totaled approximately $77 million. As shown in Figure 2–4, make whole payments averaged about $0.33/MWh for the year. In comparison to other RTOs, this falls on the low end of the range reported by the Federal Energy Regulatory Commission of $0.30 to $1.40/MWh.[9] This is not

[9] See FERC Staff Analysis of Uplift in RTO and ISO Markets, August 2014, Docket AD14-14.

surprising, given that SPP has fewer types of make whole payments than other RTOs. Figure 3–29 shows monthly DA Market and RUC make whole payment totals by fuel type. Day-ahead make whole payments constitute about one third of the total. SPP pays about 90% of all make whole payments to gas-fired resources, and 76% of all make whole payments to simple cycle gas resources through RUC make whole payments.

Figure 3–29 Make Whole Payment Totals by Fuel Type



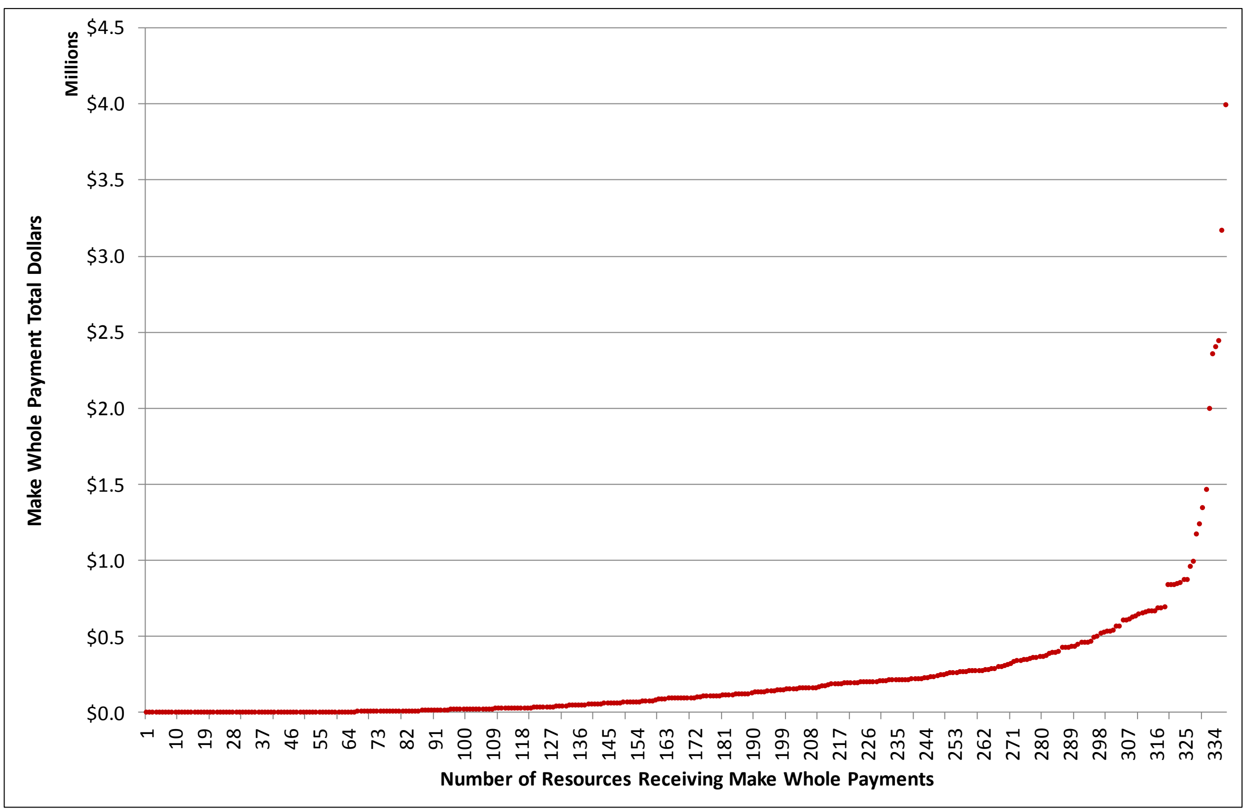
As discussed in section “3.1.3 Ramp Constraints” (page 54), RTBM prices frequently do not support the cost of RUC commitments resulting in make whole payments. RUC make whole payments to combustion turbines remained steady at about $400,000 each month until natural gas prices fell. Many of the commitments result from local reliability issues, uncaptured congestion in the Day-Ahead Market, and SPP’s rampable headroom requirement. These causes of uplift in SPP’s market are similar to those discussed in other RTOs in the September 8, 2014 FERC Price Formation Workshop, for which the Commission prepared the previously mentioned study.[10]

[10] See FERC Docket AD 14-14.

Make whole payments trended downward over the course of the year. Mostly, this occurred with the fall in natural gas prices in winter. Some anomalies in the first months of the market resulted in higher coal make whole payments. For example, an approximate $800,000 make whole payment to a coal plant occurred in late March 2014 with a discrepancy between the DA Market and the DA RUC forecasts. DA Market make whole payments for coal in spring 2014 primarily resulted from high levels of congestion and a technical issue at a large resource. About $265,000 in RUC make whole payments to oil-fired resources in March 2014 resulted from natural gas scarcity during the first week of that month. With the exception of May 2014, RUC make whole payments to oil fell significantly in subsequent months.

Other RTOs and the FERC have noted high levels of concentration in make whole payments in the other markets. Figure 3–30 shows that most SPP resources received modest total annual make whole payments, while one resource received over $4 million and six resources received over $2 million.

Figure 3–30 Concentration of Make Whole Payments by Plant



SPP frequently used one of these six resources to support a local reliability issue and four to frequently relieve congestion. The sixth is the coal resource receiving the March RUC make whole payment described above. Unlike other RTOs, no resource received over $5 million.[11] Figure 3–31 reveals some concentration in the Market Participants that received the highest levels of make whole payments. These statistics place SPP in the middle of the pack relative to the other RTOs.[12] The concentration coincides with the 63% share of generation by five participants.

Figure 3–31 Market Participants Receiving Make Whole Payments

Participant Total MWP Category	Count of Participants	Share of Total MWPs
Greater than $5 million	6	71%
Greater than $10 million	2	33%

3.2.6.1. Potential for Manipulation of Make Whole Payment Provisions

The MMU has noted vulnerability that Market Participants could potentially manipulate in SPP's make whole payment provisions. In the first year of the market, the MMU worked closely with the SPP Market Design, Operations, and Settlements departments to minimize exposure, make adjustments to market design, and monitor for inappropriate make whole payments. No exploitation of the magnitude seen in some other markets occurred during the first year of the Integrated Marketplace. The MMU credits this to the limited, and relatively simple, make whole payment provisions in the Integrated Marketplace design. SPP continues to make adjustments through the stakeholder process. In this section, we note the potential issues and pending changes to make whole payment provisions.

[11] 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.
[12] 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.

With the release of the FERC Order regarding the Make Whole Payments and Related Bidding Strategies of JP Morgan Ventures Energy Corp.[13] 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

In each case, a Market Participant has ability to situate its resource to receive a make whole payment without economic evaluation of its offers by the market clearing engine. In 2014, SPP clarified that it does not recognize a self-committed resource as eligible for a make whole payment if it changes to Market commitment status prior to the completion of its minimum run time.[14] Further changes may be required to address market commitments across the midnight hour, regulation deployment adjustment charges, and out of merit energy payments.

MMU Recommendation 3. Manipulation 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 March 2014, SPP became aware that market systems flagged resources that were offline or declared an outage during a particular window of time before the commencement of a Day-Ahead Market commitment as eligible for start-up costs in the make whole payment. In some cases, a coal plant, which has very high start costs, met these circumstances and initially received a very high make whole payment that the market clearing engine had never evaluated. To correct the payments and prevent potential exploitation of the system flaw, SPP clarified and corrected

[13] See 144 FERC ¶ 61,068.
[14] See MRR 25/MPRR 211, Self-Commit Run Time Make Whole Payment Exemption.

the make whole payment eligibility. SPP and the MMU continue to monitor for these circumstances. At the time of this report, SPP planned system changes to automate this process.[15]

In early 2015, SPP and the MMU noted an inefficiency and potential to manipulate make whole payments for jointly-owned units using 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 of this report, SPP was considering design alternatives through the stakeholder process.

- Remove the ability to manipulate make whole payments under the JOU Combined Resource Option and improve market efficiency in the JOU design.

[15] See SPP MPRR 190, FERC Docket ER15-45, clarifying the eligibility rules.

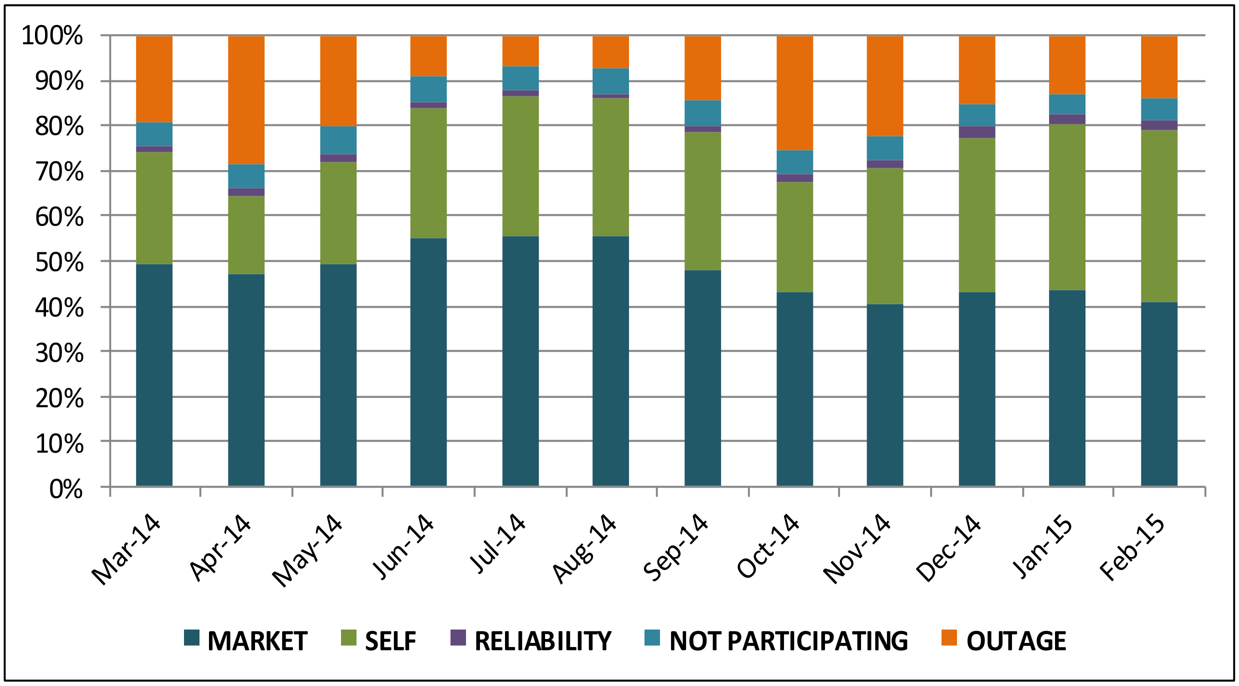
4. Day-Ahead Market

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

Participation in the Day-Ahead Market during the first 12 months has been robust for both generation and load. Load serving entities consistently offer 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 rivals that of the load serving entities. Figure 4–1 shows the percentage breakdown of commitment status for the Day-Ahead Market. The Market and Self statuses average 77% of the total capacity for the first 12 months of the Integrated Marketplace. Resources with commitment statuses of Reliability and Not Participating averaged 2% and 5%, respectively, and Outage status accounted for the final 16%. Eighty-eight percent (88%) of the Not Participating capacity is registered to merchant generation owners.

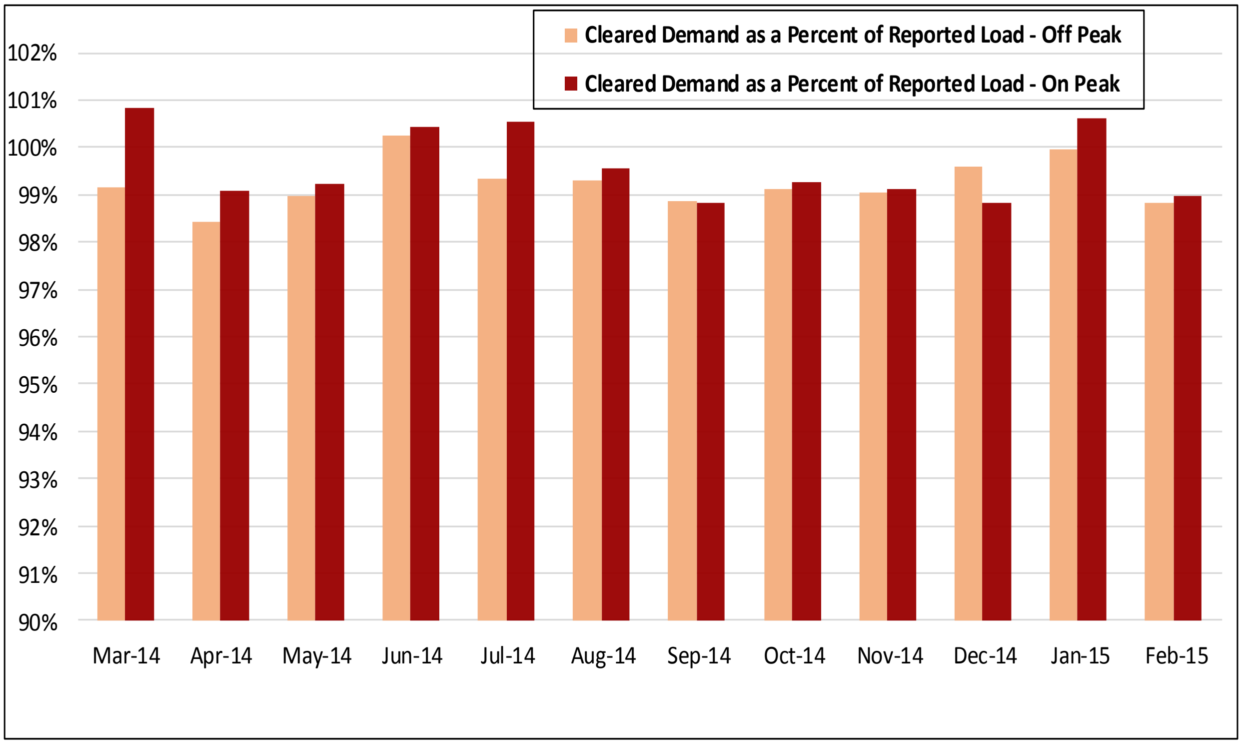
Figure 4–1 Day-Ahead Market Commitment Status Breakdown



4.2. Load

Load is choosing to participate in the Day-Ahead Market at high levels as well. Figure 4–2 shows the average monthly participation rates for the load assets on an aggregate level to be between 99% and 100% of the actual real-time load. On a disaggregated basis, we find 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 9% for a month. This behavior is not consistent with a competitive and efficient energy market and appears to be incented by a market design flaw related to the allocation of over-collected losses. The flaw is fully reviewed in section “5.9.11 Distribution of Marginal Loss Revenues (Over-Collected Losses)” (page 123). A new rule addressing the market design flaw was implemented in May 2015.

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

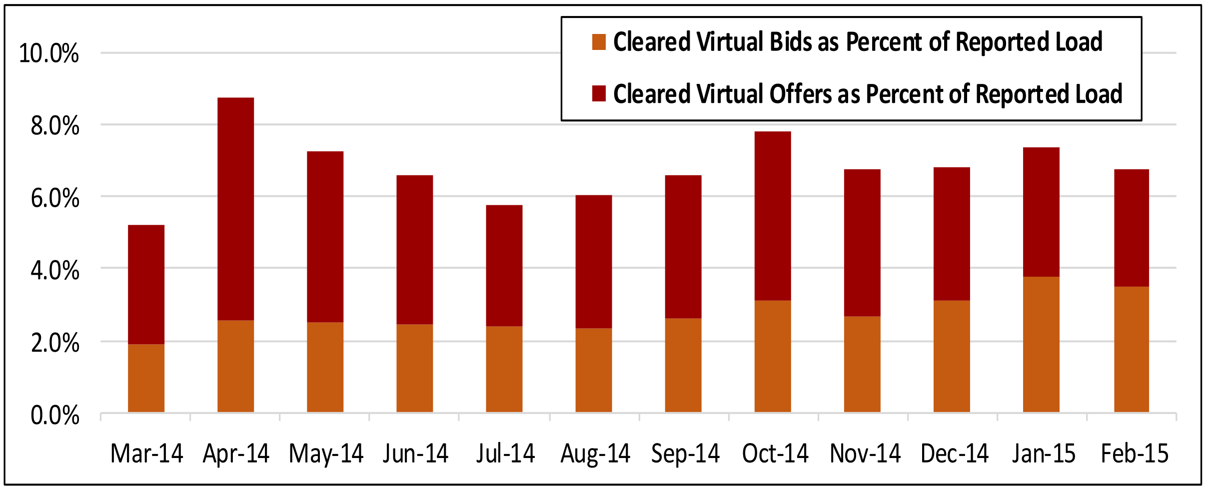


4.3. Virtual Trading

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 buys back in the Real-Time Balancing Market, sometimes referred to as "incs." Virtual bids represent energy purchases in the Day-Ahead Market that the participant sells back in the Real-Time Balancing Market, also known as "decs." 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 12 months of the market saw moderate levels of virtual participation, consistent profitability of virtual trading, and increasing convergence of DA Market and RTBM LMPs.

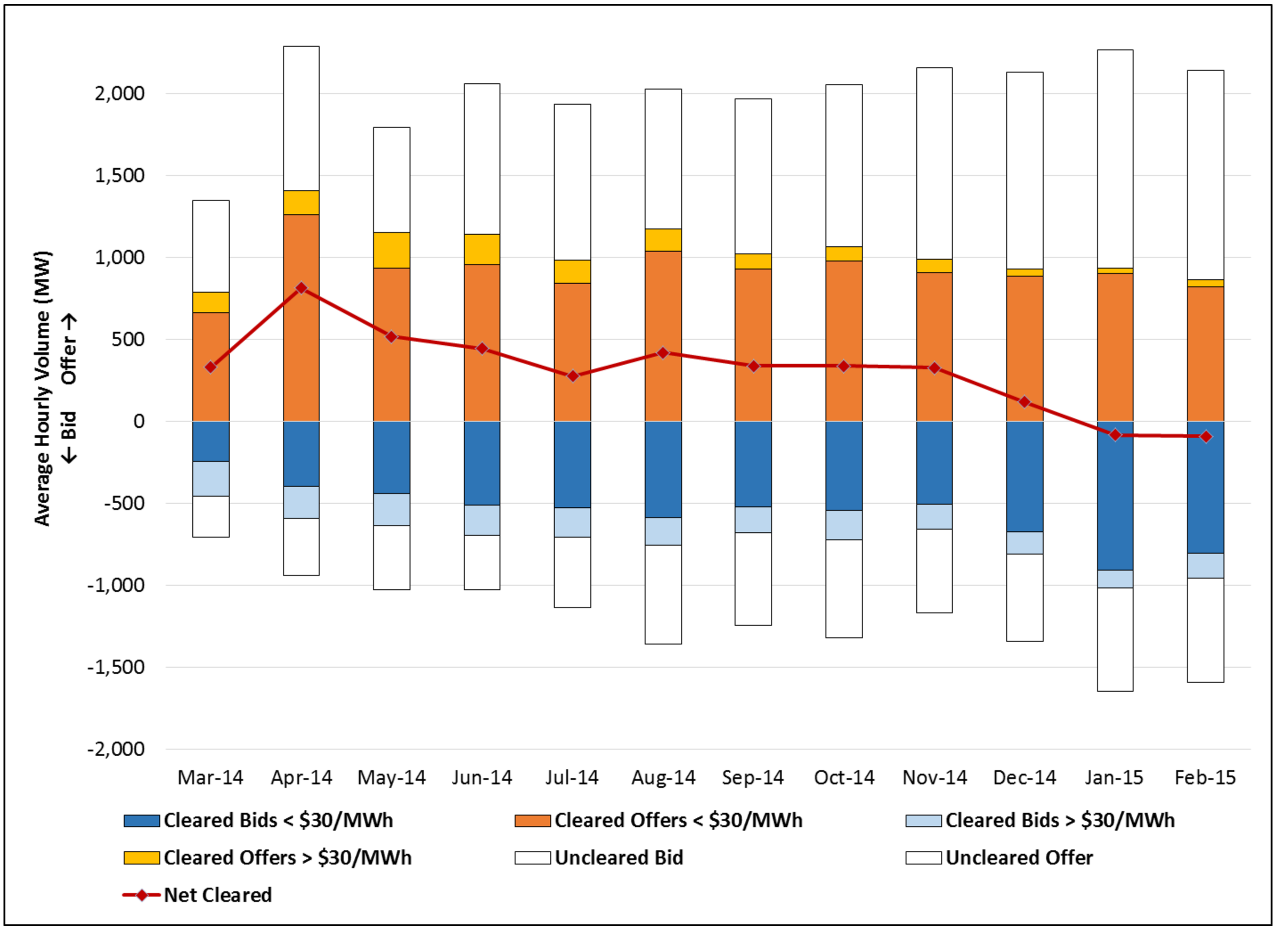
Figure 4–3 displays the total volume of virtual transactions as a percentage of SPP market load. It averaged about 6.8% for the year. Several Market Participants did not register for participation in SPP's Integrated Marketplace in time to actively trade virtuals in March 2014, hence the uptick in April 2014. Participation in virtual trading declined from there, but recovered to a steady 7% for the second six months.

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



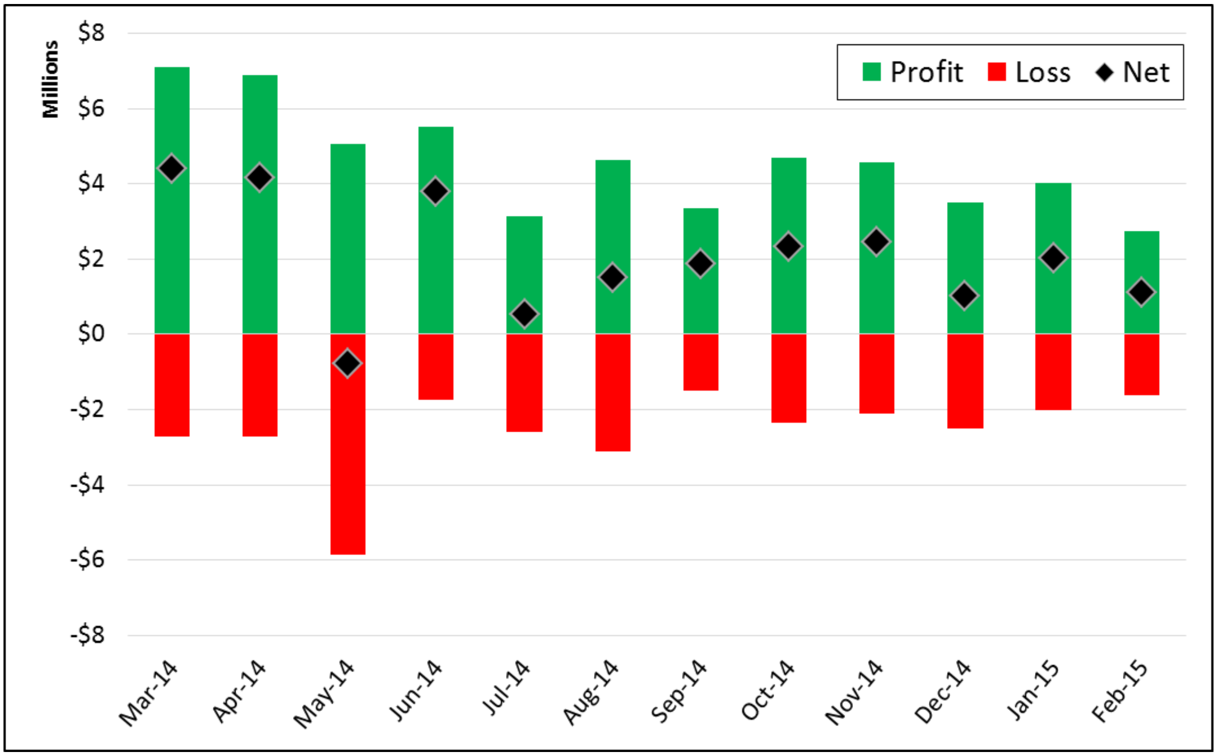
At about 7% of load, the average hourly total volume of cleared virtuals ranged from 1,240 to 2,000 MW. The average hourly uncleared volume ranged from 810 to 1960 MW. The data shows little overall fluctuation in the level of virtual trading after the first two months. The net cleared virtual positions in the market averaged about -50 MW, indicating that virtual trading did not generally distort the relative DA Market to RTBM market load balance.

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



Virtual trades profited in aggregate for the year by about $24.4 million. Profitability trended down, reflecting increased competition among traders and fewer systematic differences between the Day-Ahead Market and RTBM. One large mistaken transaction distorted the trend in May 2014. The overall profitability in virtuals was concentrated with two Market Participants, who profited by $12.5 million between them. The five Market Participants earning more than $1 million for the year held a 68% combined share of the total aggregate virtual profits.

Figure 4–5 Virtual Profit/Loss



The MMU also monitors losing virtual transactions, because they indicate potential cross-product market manipulation. For example, a Market Participant may submit a virtual transaction intended to create congestion that benefits a TCR position. Three Market Participants lost over $100,000 for the year in virtual trading, and no Market Participant lost as much as $500,000. Two of those three held highly profitable TCR positions for the year. In general, few Market Participants actively trade both virtuals and TCRs.

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 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 Must-Offer Non-Compliance

In the first year of the market, 14 penalties were assessed to nine asset owners due to non-compliance with day-ahead must-offer rules. Resource submission errors and unfamiliarity with the rules were cited as reasons for non-compliance. Figure 4–6 shows the penalty assessments by month. Most instances of noncompliance occurred in the first three months of the market; one case of non-compliance each in August and September of 2014, and no cases of non-compliance from October 2014 through February 2015.

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

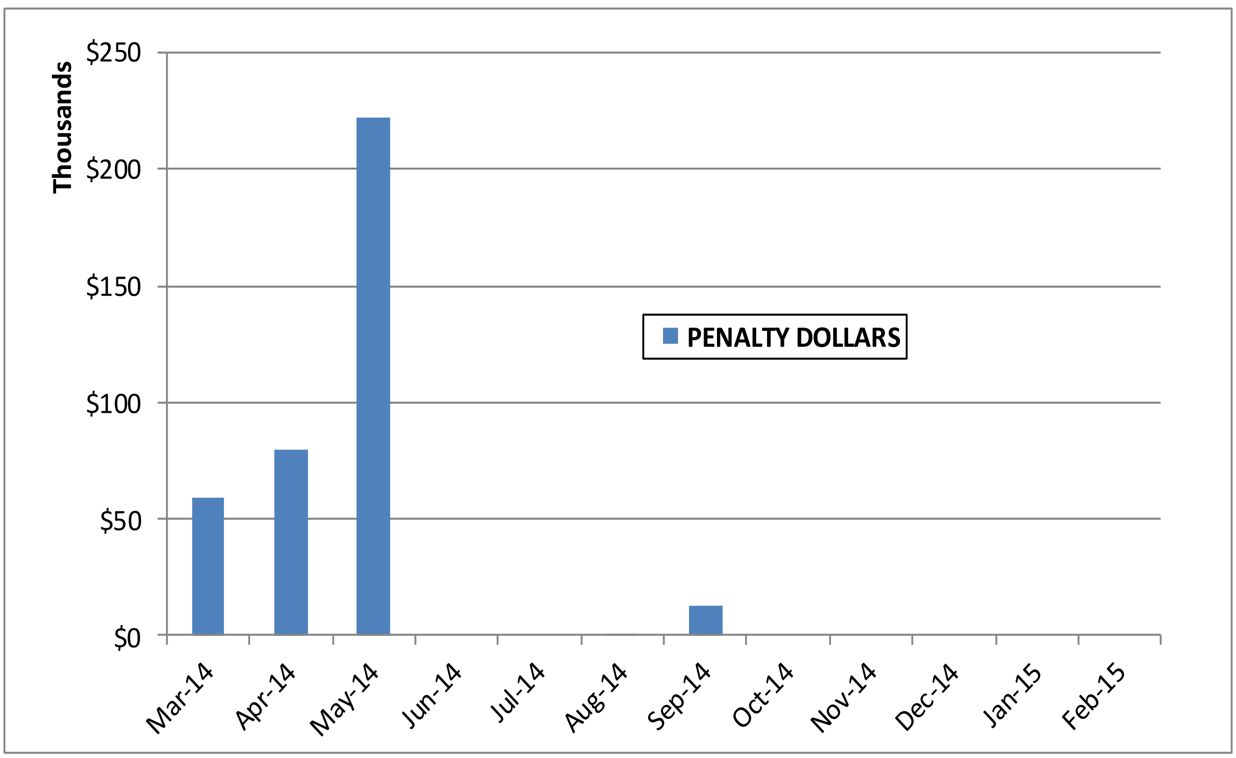
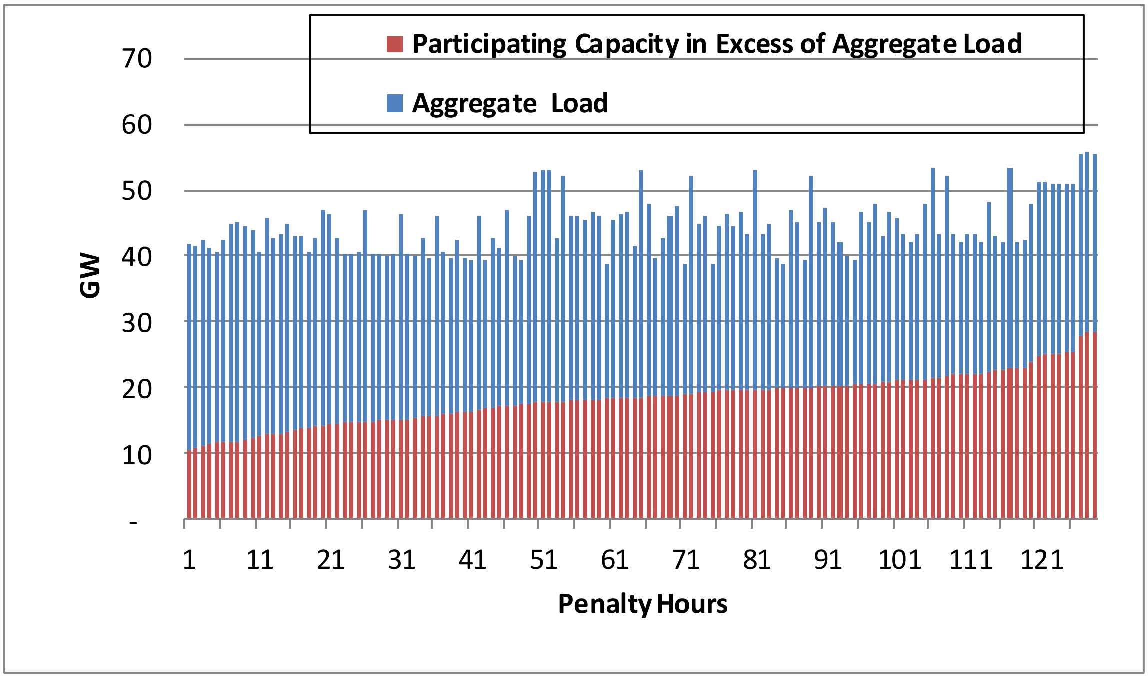


Figure 4–7 compares the capacity offered into the Day-Ahead Market with the reported load during the 129 hours when at least one Market Participant was non-compliant. The days are sorted from lowest to highest excess capacity for each day. As can be seen, the lowest level of excess capacity was about 10,000 MW or about 25% of total offered capacity. The reserve obligation, which is not reflected in the chart, is between 5% and 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 threat of 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. Ninety-nine percent (99%) of the reported load clears in the Day-Ahead Market, incenting generation assets to offer into the Day-Ahead Market. Load participation will likely drop off as a result of the redesigned allocation of over-collected losses, but it is expected that the participation will remain at robust levels. One other challenge to the necessity of the limited day-ahead must-offer provisions is that the merchant generation participation levels are consistent with load-serving entities with one exception; the exception being the offer behavior for variable energy resources.

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 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 status. The merchant generation owners do not have a day-ahead must-offer obligation and hence the 82% 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 three 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 fuel supply. The Market Monitor 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	48%	32%	2%	0%	18%
	Merchant	77%	5%	0%	6%	12%
Variable Energy Resource	Load Serving Entity	52%	27%	0%	10%	11%
	Merchant	48%	12%	0%	32%	8%

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. During the upcoming months, SPP and its stakeholders plan to study the strengths and weaknesses of the limited day-ahead must-offer requirement, and will consider rule changes as well as the necessity of the limited must-offer provisions given that the market forces may be enough to incentivize participation.

MMU Recommendation 4. Day-Ahead Must-Offer Requirement

The MMU recommends that SPP eliminate the limited day-ahead must-offer provision and revise the physical withholding rules to include a penalty for non-compliance. These provisions are sufficient to ensure an efficient level of participation in the Day-Ahead Market. The SPP Tariff must provide adequate protection against the potential exercise of market power. 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, and assessing penalties as a result of the 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:

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 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 direct, automated link between the must-offer penalty calculation and the system that tracks generation outages. The current system is reliant on the Market Participant to correctly identify the resource as being on an outage in its day-ahead market offer submission.

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 any of the almost 17,000 pricing nodes in SPP reflects the sum of the system-wide marginal cost of the energy required to serve the market (MEC), the marginal cost of any increase or decrease in energy at that location to respect the transmission constraints on the SPP grid (MCC), and the marginal cost of any increase or decrease in energy to minimize system transmission losses (MLC).

$$LMP = MEC + MCC + MLC$$

Locational prices are a key feature of electricity markets, providing price signals that ensure the efficient dispatch of generation in the presence of reliability constraints and efficient incentives for future investment. This section describes the geographic pattern of congestion and losses, anticipates changes in the transmission system that will alter that pattern, analyzes how congestion impacts local market power, explains how load-serving entities hedge congestion costs in the Transmission Congestion Rights market, describes the distribution of marginal congestion and loss revenues, and assesses the performance of the market in these areas.

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. Annual average Day-Ahead Market LMPs range from $21/MWh in Western Nebraska to $40/MWh in New Mexico. About 75% of this price variation is due to congestion and 25% 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 increases to $19/MWh–$41/MWh for RTBM LMPs.

Figure 5–1 March 2014 to March 2015 Average LMP for Day-Ahead Market

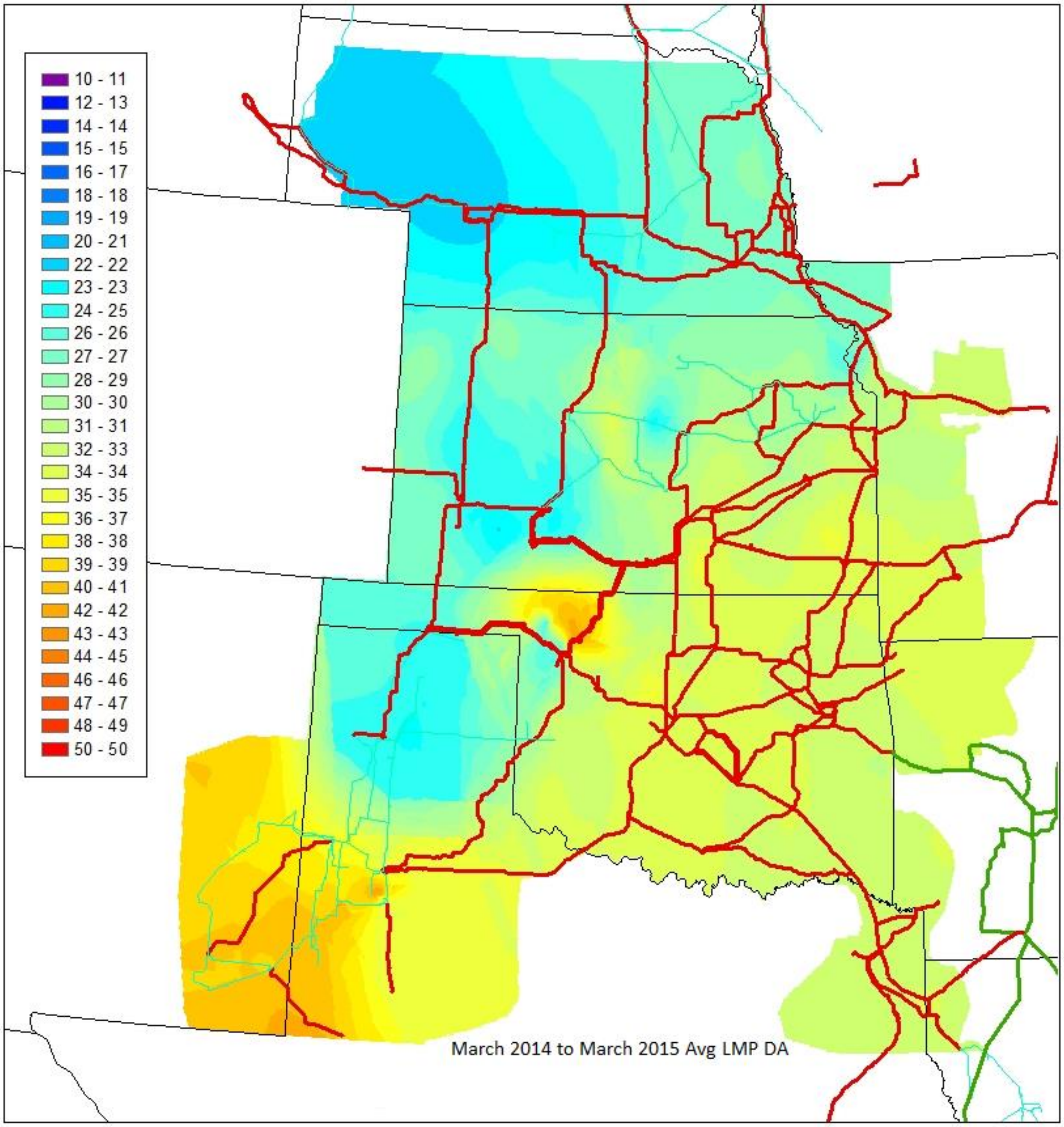
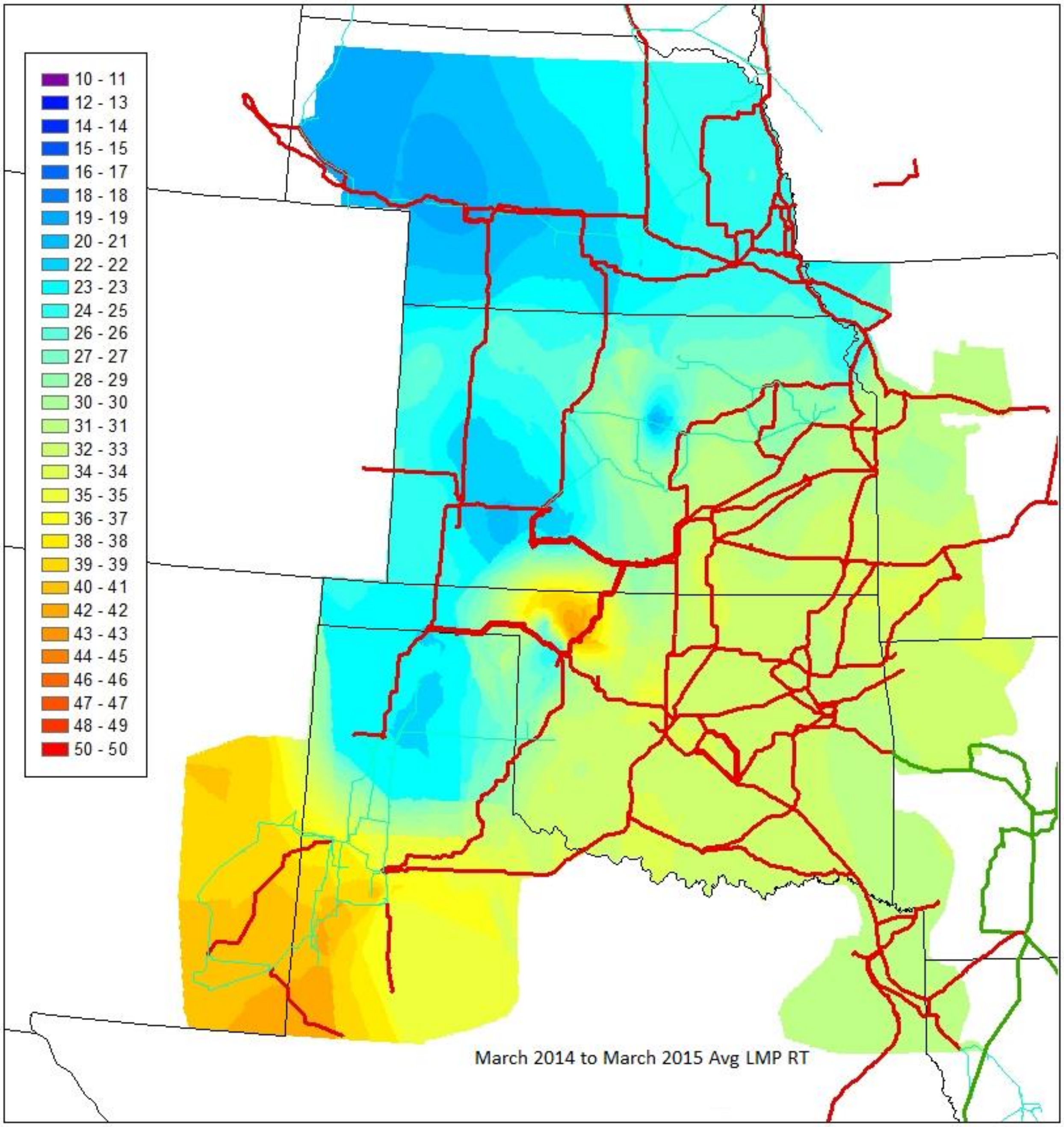


Figure 5–2 March 2014 to March 2015 Average LMP for Real-Time Balancing Market

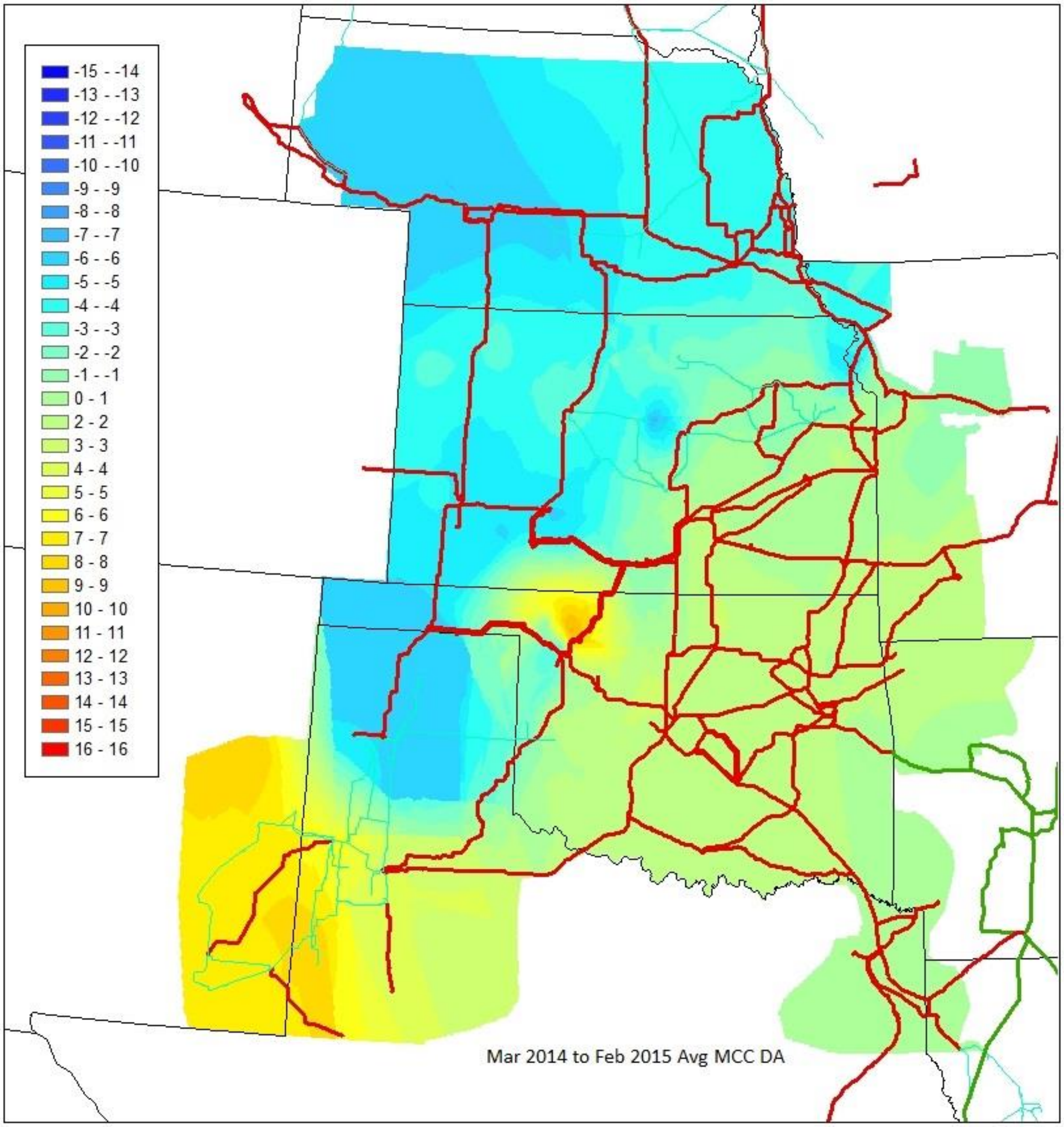


5.2. Geographic Congestion

The physical characteristics of the transmission grid, the geographic distribution of load, and geographic differences in fuel costs drive the pattern of congestion in the SPP energy markets. 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. The cost of coal, SPP's predominant fuel for energy generation, 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 capacity measures, rises in the opposite direction, from the southeast to the northwest. Wind-powered generation lies on 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.

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 northwest Nebraska at Gerald Gentleman Station and at Smoky Hills wind farm in Central Kansas, at -$7/MWh, and the highest MCCs lie in the Woodward, Oklahoma area at $11/MWh and the Hobbs, New Mexico area at $7/MWh.

Figure 5–3 March 2014 to February 2015 Average MCC for Day-Ahead Market

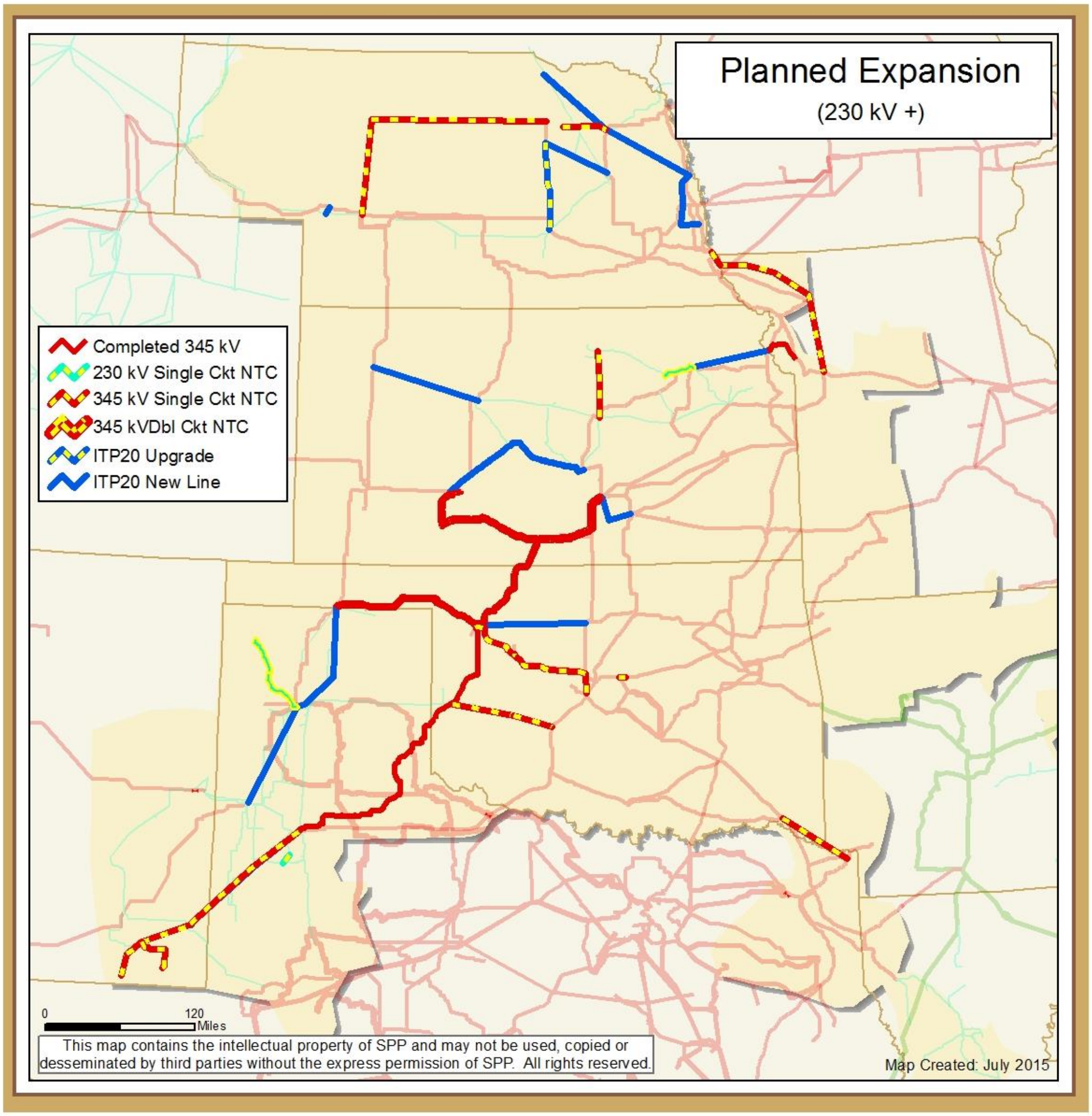


SPP recently brought into service some major new transmission projects and continues to plan and build, as shown in Figure 5–4.[16] New 345 kV lines brought into service in 2014 are depicted in solid red. These new lines changed LMP patterns in 2014, reducing congestion and losses,

[16] The light green lines not identified in the legend represent the reconductoring or conversion of an existing line to 230kV.

while also creating new bottlenecks on the system. The other lines depicted on the map are planned projects that will further support the efficient transmission of energy across the SPP footprint.

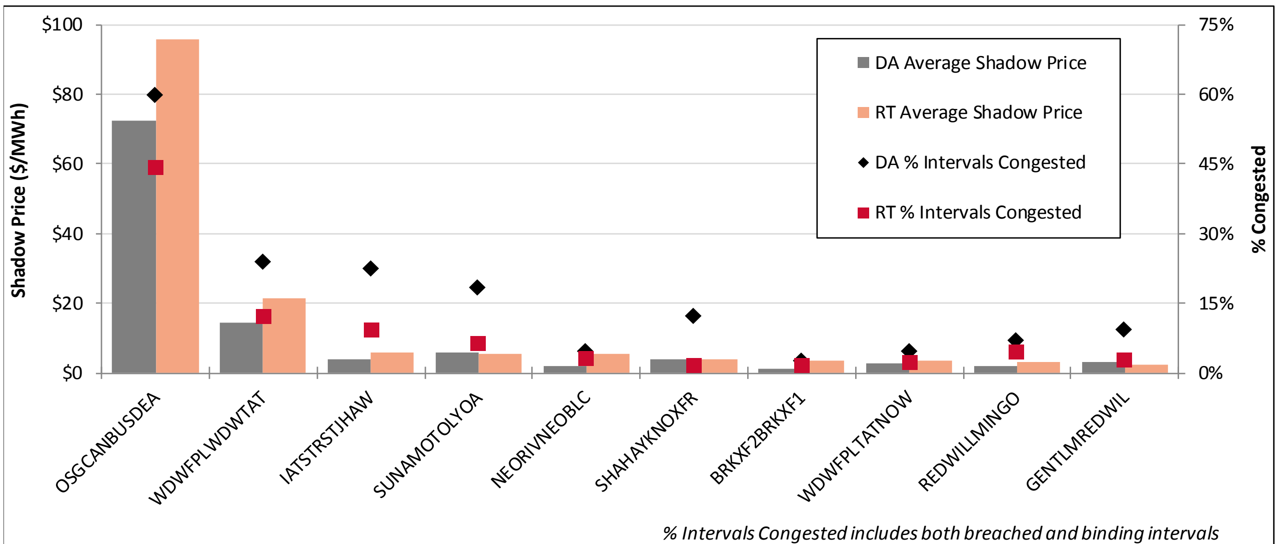
Figure 5–4 Planned Transmission Expansion July 2015 Map



5.3. Transmission Constraints

Market congestion reflects the economic dispatch cost of honoring transmission constraints. SPP utilizes these constraints to reliably manage the flow of energy across the physical bottlenecks of the grid in the least costly manner. 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 ten flowgate constraints by shadow price for the first 12 months of the market.

Figure 5–5 Congestion by Shadow Price



Flowgate Name	Region	Flowgate Location
OSGCANBUSDEA	Texas Panhandle	Osage Switch-Canyon East (115) ftlo Bushland-Deaf Smith (230) [SPS]
WDWFPLWDWTAT	Western Oklahoma	Woodward-FPL Switch (138) ftlo Woodward EHV-Tatonga (345) [OGE]
IATSTRSTJHAW*	KC-Omaha Corridor	Iatan-Stranger Creek (345) ftlo St. Joe-Hawthorn (345) [KCPL-WR-GMOC]
SUNAMOTOLYOA	Texas Panhandle	Sundown-Amoco (230) ftlo Tolk-Yoakum (230) [SPS]
NEORIVNEOBLC	SE Kansas	Neosho-Riverton (161) [WR-EDE] ftlo Neosho-Blackberry (345) [WR-AECI]
SHAHAYKNOXFR	Central Kansas	South Hays - Hays (115) ftlo Knoll Xfmr (230/115) [MIDW]
BRKXF2BRKXF1	SW Missouri	Brookline Xfmr 1 (345/161) [AECI] ftlo Brookline Xfmr 2 (345/161) [SPRM]
WDWFPLTATNOW	Western Oklahoma	Woodward-FPL Switch (138) ftlo Woodward EHV-Northwest (345) [OGE]
REDWILLMINGO*	West SPP N-S Corridor	Red Willow [NPPD] - Mingo [SECI] (345)
GENTLMREDWIL*	West SPP N-S Corridor	Gentleman-Red Willow (345) [NPPD]

** Reciprocally Coordinated Flowgate with MISO*

The list indicates that the most congested corridor on the system was the north to south flow through the Texas Panhandle, which relies on 230 kV transmission lines between Amarillo and Lubbock, TX, and where predominantly gas-fired generation in the south was more expensive than the wind and coal power to the north. Other notable bottlenecks were the west to east flows through the Woodward, OK area, and the flows from the Omaha, NE area into Kansas City.

5.3.1. Texas Panhandle

The most limiting element in the Texas Panhandle area and the most frequently congested point in the market was represented by the flowgate Osage-Switch to Canyon East for the loss of Bushland to Deaf Smith. It saw a higher average shadow price and more frequent congestion during the first year of the Integrated Marketplace at $95.86/MWh and 44.4%, respectively, compared to $44.13/MWh and 36.7% for 2013. Transmission system changes in the area and new wind generation on the loading side of the flowgate contributed to higher shadow prices.

Upgrades to the transmission system in 2013 and 2014 alleviated some bottlenecks in the Texas Panhandle. For example, a new 230 kV line from the Randall County Interchange to the Amarillo South Interchange has eliminated the SPS North-South constraint from the top ten flowgate list. The most limiting transmission element in the southern part of the Texas Panhandle became Sundown to Amoco for the loss of Tolk to Yoakum. The addition of a 345 kV line from the Tuco Interchange to Woodward, OK in September 2014 lowered the average shadow price on OSGCANBUSDEF to about $50/MWh in the RTBM and under $40/MWh in the Day-Ahead Market for December 2014 through February 2015, an almost 50% drop from the 12 month average.

5.3.2. Western Oklahoma

The most significant change to the SPP transmission system in 2014 was the addition of the 345 kV double circuit from Hitchland to Woodward, which went into service in May 2014. It complemented the new Tuco to Woodward line described above. Hitchland to Woodward enables SPP to move more energy from the wind corridor in the west to the load centers in the east. The west-east price differentials in this area created a new bottleneck at Woodward, as indicated by two new top ten flowgates. Woodward to FPL Switch for the loss of Woodward EHV to Tatonga had the second highest shadow price, at $21.33/MWh in the RTBM and $14.45/MWh in the Day-Ahead Market. Further expansion to the 345 kV system in Western Oklahoma may mitigate this congestion.

5.3.3. Kansas City – Omaha

The Kansas City area has been another long-standing bottleneck in the SPP 345 kV system. The north-south flow from Nebraska and Iowa meets just north of Kansas City in the market's effort to meet Kansas City and Topeka load with lower cost energy. This area was particularly sensitive to loop flows from MISO. The second and third most congested flowgates for 2013 were in this area. Upgrades, especially to the Eastowne transformer, reduced congestion in this area from historic levels. Iatan to Stranger Creek for the loss of St. Joe to Hawthorne remained in the top ten flowgate list. It had an average RTBM shadow price of $5.86/MWh. A 345 kV line from Iatan to Nashua, which went into service in April 2015, is expected to reduce congestion in this area. 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

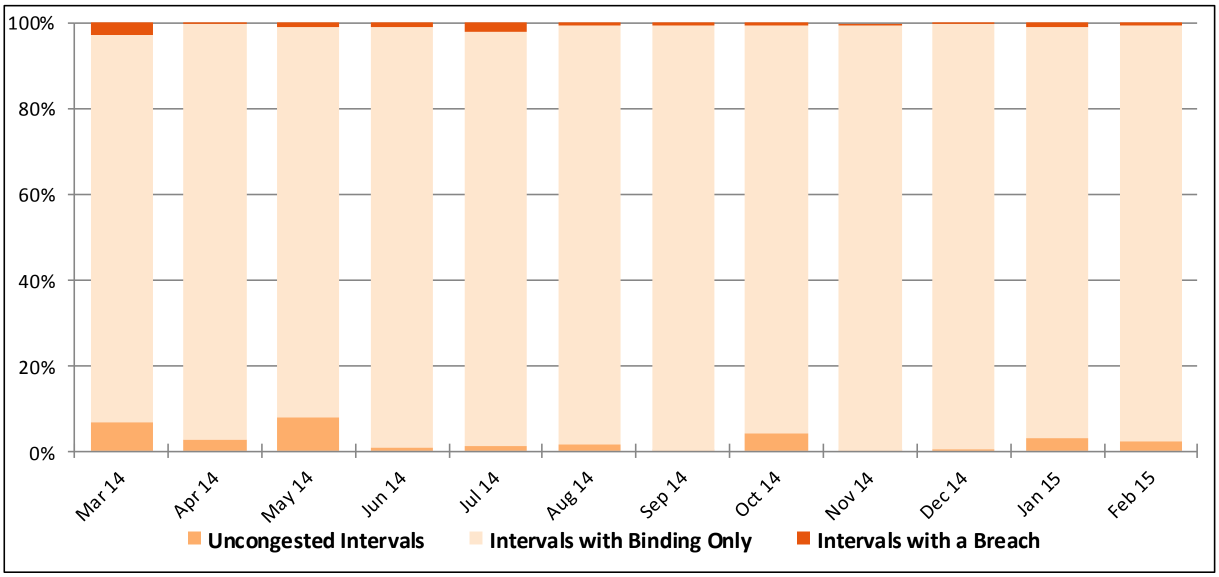
Flowgate Name	Region	Location	Projects that may provide mitigation
OSGCANBUSDEA	Texas Panhandle	Osage Switch - Canyon East (115) ftlo Bushland - Deaf Smith (230) [SPS]	Canyon East Sub –Randall County Interchange 115 kV line (March 2018 – Aggregate Studies)
SUNAMOTOLYOA	Texas Panhandle	Sundown - Amoco (230) ftlo Tolk - Yoakum (230) [SPS]	1. Tuco Interchange – Yoakum 345 kV Ckt 1 (June 2020 – HPILS) 2. Amoco - Sundown 230 kV Terminal Upgrades (April 2019 - 2015 ITP10)
WDWFPLWDWTAT	Western Oklahoma	Woodward - FPL Switch (138) ftlo Woodward EHV - Tatonga (345) [OGE]	Woodward – Tatonga ck2 345 kV (March 2021 - ITP10)
WDWFPLTATNOW	Western Oklahoma	Woodward - FPL Switch (138) ftlo Tatonga - Northwest (345) [OGE]	1. Matthewson - Tatonga 345 kV Ckt 2 (March 2021 – ITP10) 2. Elk City - Red Hills 138 kV Ckt 1 Reconductor (June 2015, ITPNT)
IATSTRSTJHAW*	KC-Omaha Corridor	Iatan - Stranger Creek (345) ftlo St. Joe - Hawthorn (345) [KCPL-WR-GMOC]	Sibley – Mullin Creek 345 kV (December 2016 – High Priority)
NEORIVNEOBLC	SE Kansas	Neosho - Riverton (161) ftlo Neosho - Blackberry (345) [WR-EDE-AECI]	No projects identified at time of report publication.
BRKXF2BRKXF1	SW Missouri	Brookline Xfmr 1 (345/161) [AECI] ftlo Brookline Xfmr 2 (345/161) [SPRM]	No projects identified at time of report publication.
REDWILLMINGO*	Western SPP N-S Corridor	Red Willow [NPPD] - Mingo [SECI] (345)	Gentleman - Cherry Co. - Holt 345 kV Ckt 1 (January 2018 – ITP10)
GENTLMREDWIL*	Western SPP N-S Corridor	Gentleman - Red Willow (345) [NPPD]	Gentleman - Cherry Co. - Holt 345 kV Ckt 1 (January 2018 – ITP10)

** Reciprocally Coordinated Flowgate with MISO*

5.4. Market Congestion Management

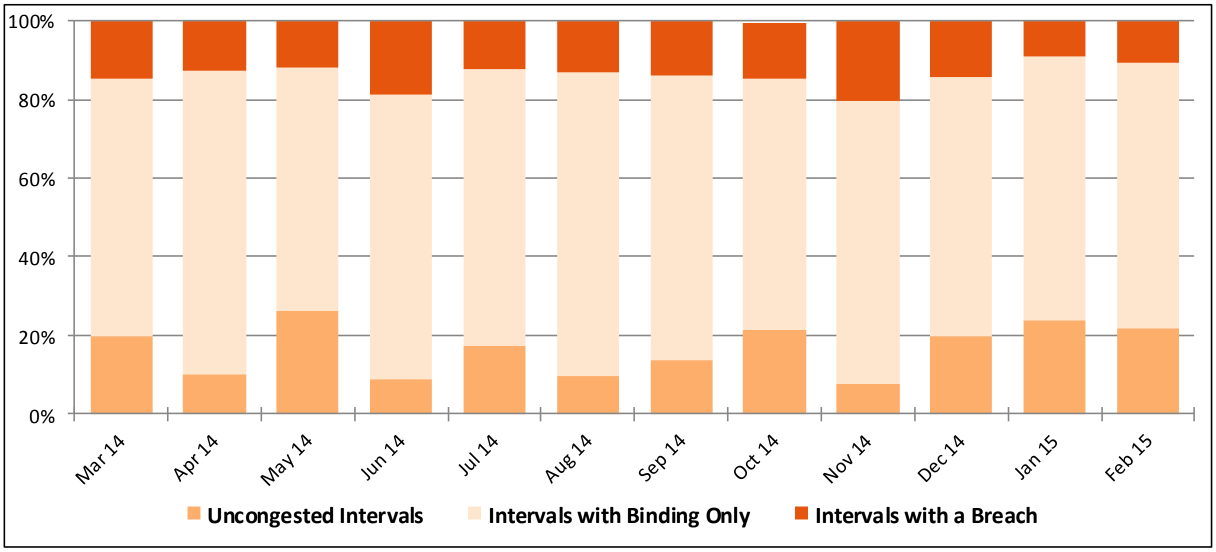
In optimizing the flow of energy to serve the load at the least cost, the SPP market makes extensive use of the available transmission up to the flowgate constraint limits. This was best seen in the Day-Ahead Market (see Figure 5–7), where uncongested market time intervals were rare. To preserve reliability, the market penalizes breaches of the constraints, which were also rare in the Day-Ahead Market.

Figure 5–7 Congestion – Breached and Binding for Day-Ahead Market



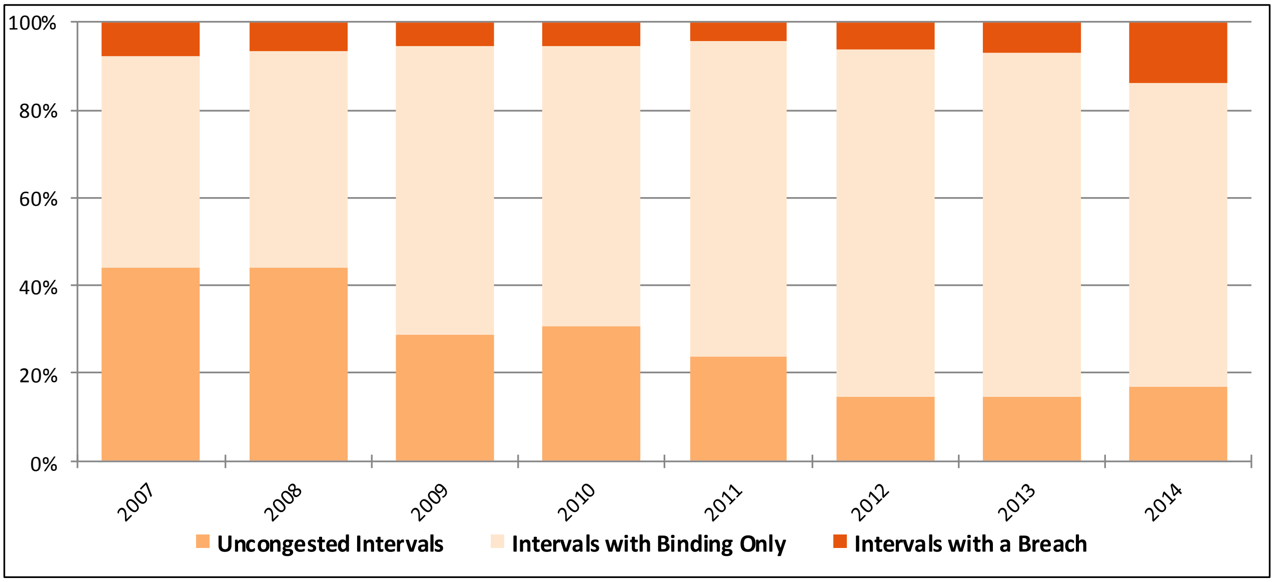
In the less controlled environment of the Real-Time Balancing Market, uncongested intervals rose to about 20% of all time intervals, and intervals with a constraint breach had a similar frequency, as shown in Figure 5–8.

Figure 5–8 Congestion – Breached and Binding for Real-Time Balancing Market



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. In 2007, the market experienced no congestion in more than 40% of all market intervals. That figure fell markedly in 2009 with the integration of Nebraska and now sits below 20%. 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. This increase in breaches is largely driven by one flowgate, OSGCANBUSDEF; see section “5.3.1 Texas Panhandle” (page 98). It may also result from lower excess on line capacity as shown in Figure 3–1. Higher levels of online capacity in the EIS Market could instantly address congestion through higher ramp capability and higher base generation near load centers.

Figure 5–9 Congestion – Breached and Binding for RTBM Annual Comparison



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 profitably raise prices above competitive levels. 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. Market Power and Mitigation" (page 126). 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, and the MMU analyzes market data at least annually to assess the appropriateness of the Frequently Constrained Area (FCA) designations. In 2014, the MMU found that two of the three previously identified FCAs no longer required the designation.[17] Due to upgrades in the transmission system, the Kansas City area and the Northwest Kansas areas no longer require designation as FCAs. The Texas Panhandle remains an FCA. Figure 5–10, reproduced from the January 2014 Frequently Constrained Areas Study, shows the frequency of binding constraint and pivotal supplier hours for primary constraints defining the FCAs.

Figure 5–10 Binding and Pivotal Supplier Hours

Candidate Area	Constraint Name	Monitored Element	Binding Hours	Pivotal Supplier Hours
Kansas City Area	IATSTRSTJHAW	Iatan to Stranger Creek - 345 kV	999	348
Kansas City Area	IATSTRIATEAT	Iatan to Stranger Creek - 345 kV	516	363
Kansas City Area	PENMUN87TCRA	Pentagon to Mund – 115 kV	498	405
NW Kansas	REDWILLMINGO	Redwillow to Mingo – 345 kV	359	300
NW Kansas	GENTLREDWIL	Gentleman to Redwillow – 345 kV	302	283
Texas Panhandle	OSGCANBUSDEA	Osage Switch to Canyon - 115 kV	4,808	4,726
Texas Panhandle	HARRANNNICAMA	Harrington to Randall Co., 230 kV	794	765

5.5.1. Kansas City FCA

Several constraints in the Kansas City area had a high frequency of congestion with a pivotal supplier in the year ending August 2014. There are three constraints with the Iatan to Stranger Creek 345 kV line as the monitored element; the Eastowne transformer is located north of Kansas City. The Pentagon to Mund line is southwest of Kansas City. In the initial FCA study completed in 2013, two primary constraints were identified for the Kansas City FCA, Iatan to Stranger Creek and Lake Road to Alabama. The Lake Road to Alabama constraint does not appear in Figure 5–10, indicating that there was no significant congestion on this constraint during the study period. This is due to the installation of the Eastowne Transformer, which

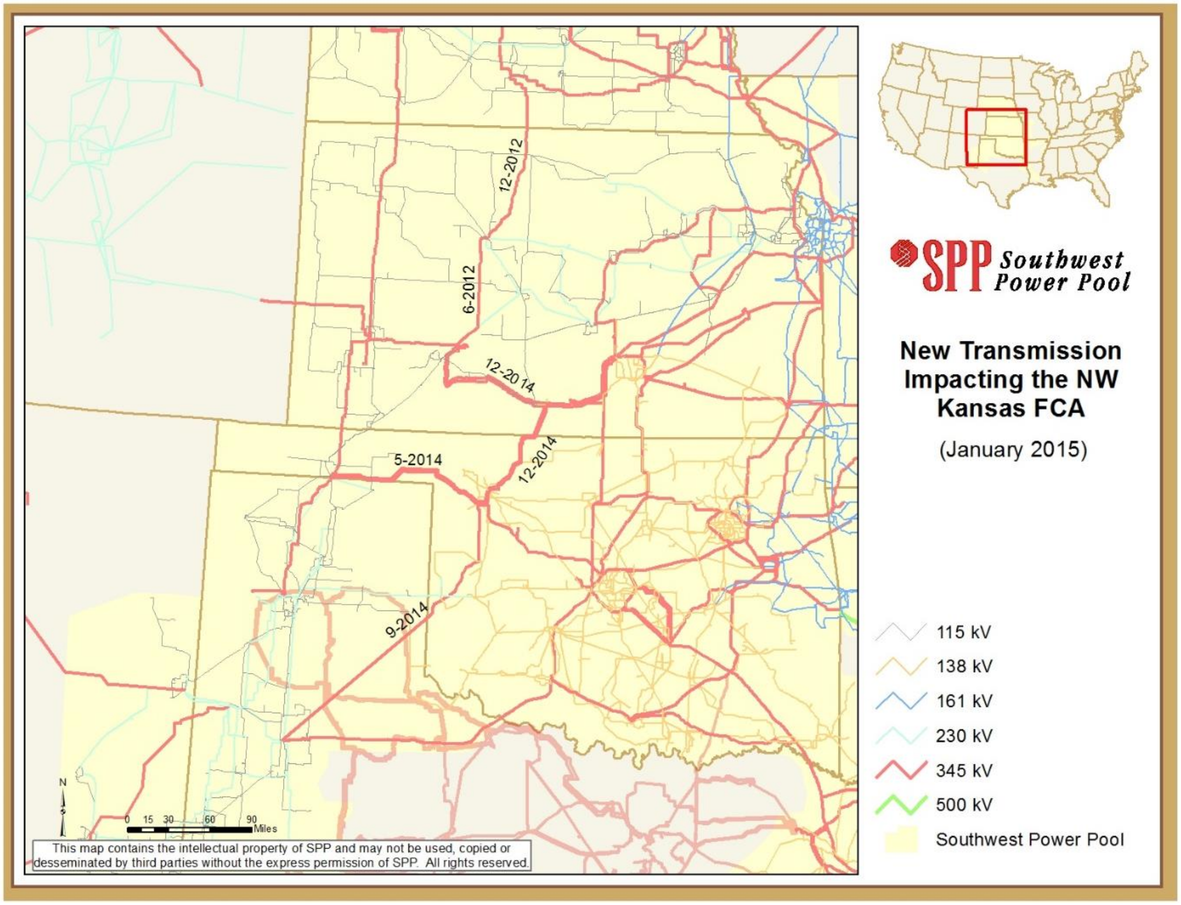
[17] See Southwest Power Pool Frequently Constrained Areas – 2014 Study, January 2015, FERC Docket ER15-1049.

connects a 161 kV electrical system north of Kansas City to the 345 kV line from St. Joseph to Iatan. This upgrade to the transmission system, completed in the summer of 2013, resolved the congestion on the 161 kV transmission system and the Lake Road to Alabama constraint, and there is no expectation that significant congestion will occur in this area going forward. Furthermore, the study found that no pivotal supplier in the Kansas City area had the ability to impact prices by more than $5/MWh for more than the FCA cutoff of 500 hours per year.

5.5.2. Northwest Kansas FCA

Historically, the SPP market experienced frequent north-south congestion across the Nebraska-Kansas border on the west side of the footprint along the Gentlemen to Red Willow to Mingo 345 kV lines. Binding hours and pivotal supplier impacts were down in the Northwest Kansas area for the year ending August 2014 due to the transmission expansion in the western part of the footprint. Figure 5–11 shows the transmission expansion in the western part of the SPP footprint since 2012. The map shows six lines that have gone into service since 2012. The Post Rock to Spearville 345 kV line in central Kansas went into service in June 2012, followed in December 2012 by the Axtel to Post Rock 345 kV from Nebraska into central Kansas. The impacts of the these lines were fully captured in the 2014 FCA study; however, given the 2011–2012 study period, only partial impacts of these lines would have been captured in the 2013 FCA study. The 345kV double circuit from Hitchland to Woodward went into service in May 2014 and likely contributed to the reduction in pivotal supplier impacts in the Northwest Kansas area. The 2014 FCA study also noted a systematic drop in Northwest Kansas pivotal supplier impacts correlating with the service start date for the Hitchland to Woodward line.

Figure 5–11 FCA Study New Transmission Map



5.5.3. Texas Panhandle FCA

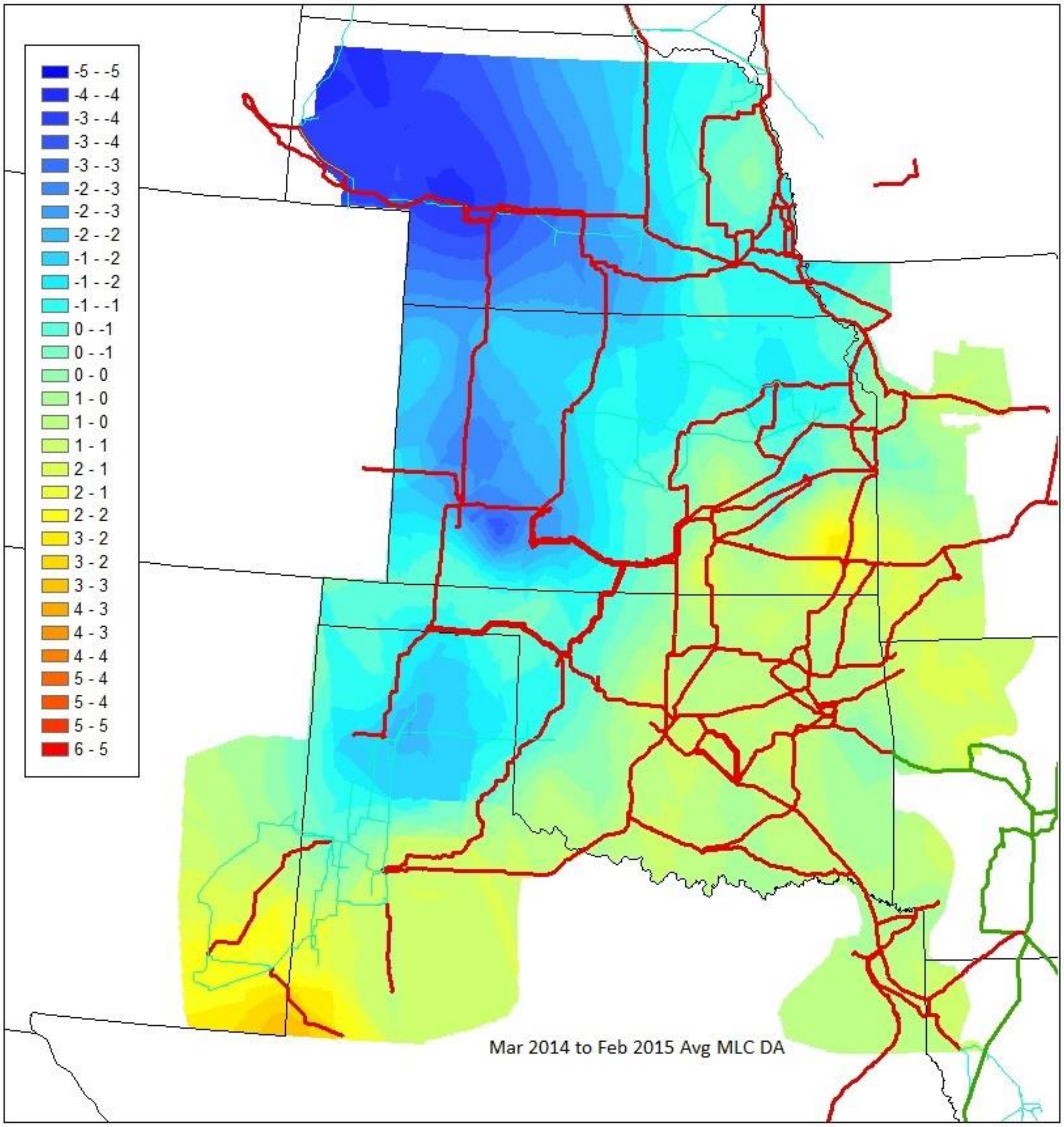
The binding hours and pivotal supplier hours for OSGCANBUSDEA remained significant in the year ending August 2014, as did the ability of a pivotal supplier to impact LMPs. The MMU noted that the SPP footprint is still undergoing transmission expansion with several lines going into service since September 2014. Three of these lines are shown Figure 5–11. The Tuco to Woodward 345 kV line went into service in late September. The Woodward to Thistle 345 kV double circuit and the Clark County to Thistle 345 kV double circuit were energized in the latter part of 2014. The FCA study noted that in the last four months of 2014 the pivotal supplier impacts do not vary significantly on an annualized basis from the results for the study period, and the MMU concluded that the expansion had not resolved the congestion and pivotal supplier issues in the Texas Panhandle area. The SPP Market Monitor will continue to monitor the impacts of transmission expansion on the FCA designation and will initiate a new study if the forward looking impact analysis indicates a need.

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 SPP 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 the first year of the Integrated Marketplace were 2.6%. 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 center of the market.

Figure 5–12 maps the annual average MLCs. The average MLC ranges from about -$6/MWh near Dodge City, Kansas to -$4/MWh at the Gerald Gentleman Station in Western Nebraska to zero in the Tulsa, OK and Kansas City areas to $1/MWh in the Hobbs, New Mexico area, and up to $3/MWh in the Southeast corner of New Mexico.

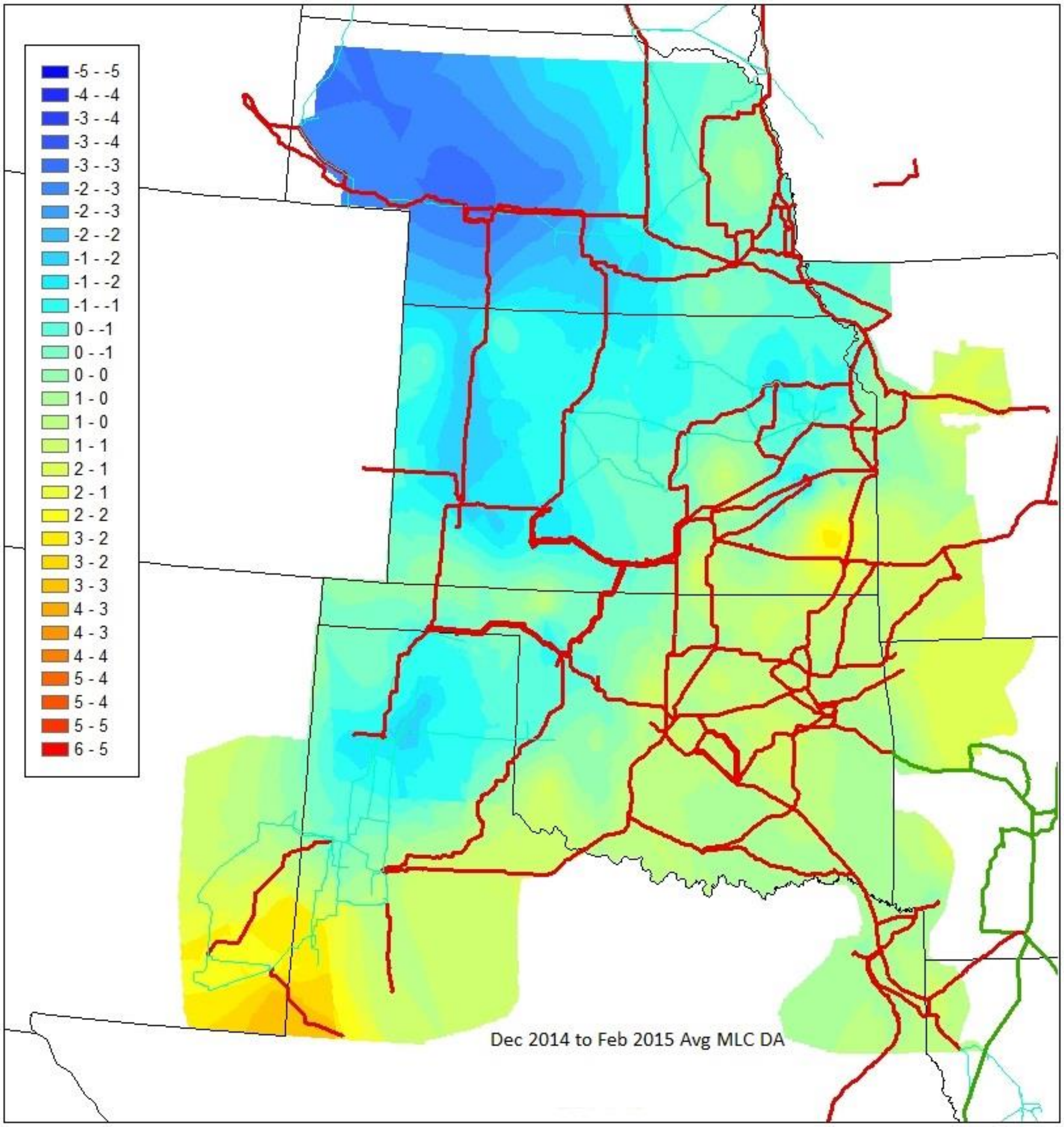
Figure 5–12 Annual MLC Map – Day-Ahead Market



The $5/MWh difference in the MLC down the western side of the footprint, say between Gerald Gentleman Station and the Hobbs area, accounts for 25% of the price separation. The loss component of LMP cannot be discounted as a significant contributor to SPP prices.

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. In Figure 5–13, depicting average MLCs for winter 2014-2015, the dark blue areas around Dodge City and Gerald Gentleman Station are lighter. The average MLCs in these areas rose by $3.70/MWh and $1.00/MWh, respectively, and the blue area in the upper Texas Panhandle lightened a bit. Some of this change may reflect seasonal fluctuation, but given the consistency of the rest of the map with the annual, the new transmission appears impactful in reducing losses. Future planned transmission projects may further reduce the cost of losses to SPP load.

Figure 5–13 Winter MLC Map – Day-Ahead 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. In assessing the performance of the TCR market the MMU evaluates 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. It is not viewed by the MMU to be an end in itself.

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 5–14 provides the aggregate congestion costs and hedging totals for load serving entities and non-load serving entities. It shows that the total of all TCR and ARR net payments to LSEs of $296 million exceed the total Day-Ahead Market and RTBM congestion costs of $280 million. In aggregate, non-LSEs pay Day-Ahead Market congestion and receive RTBM congestion rents. The net costs of $11.6 million fall under the total TCR market net payments of $23 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 5–14 Total Congestion Payments for Load Serving Entities and Non-Load Entities

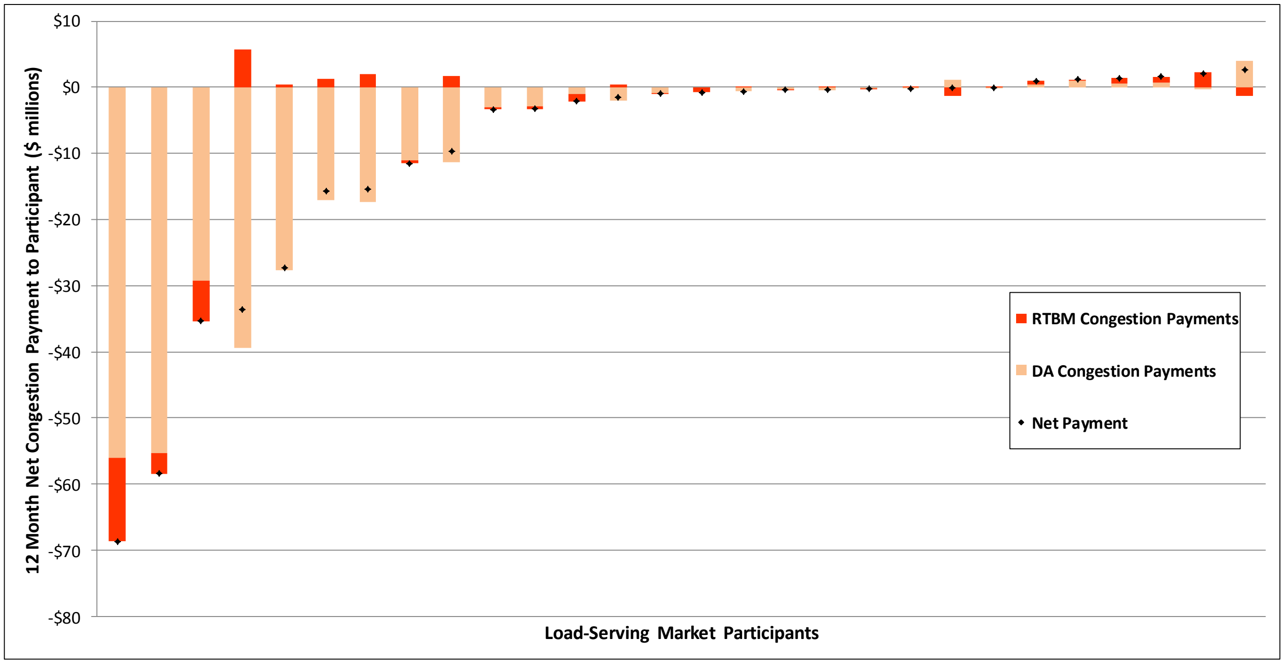
($ millions)	LSEs	Non-LSEs
DA Congestion	(268.8)	(54.0)
RTBM Congestion	(11.1)	42.3
NET CONGESTION	(279.9)	(11.6)
TCR Charges	(360.5)	(65.3)
TCR Payments	268.9	105.3
TCR Uplift	(33.5)	(21.5)
ARR Payment	375.5	3.1
ARR Surplus	45.2	1.2
NET TCR/ARR	295.6	22.9

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 5–15 shows the annual Day-Ahead Market and RTBM congestion payments for load serving Market Participants during the first year of the market.

Figure 5–15 DA Market and RTBM Net Annual Congestion Payment by LSE



Most face congestion costs, depicted as negative payments in the graph, because they are vertically integrated load serving entities (LSEs) with higher MCCs at load than at resources. Day-ahead congestion payments by ranked LSE ranged from about $4 million in payments to about $56 million in costs. For non-LSEs, they range from about $2 million in payments to $21 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 $12.5 million in costs to $6 million in payments for LSEs. It ranges from $8 million in costs to $24 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 $42.3 million in RTBM congestion payment to non-LSEs, shown in Figure 5–14.

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:

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

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 5–14 above, the aggregate TCR payments and uplift for LSEs fell $123 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 25%. This profitability is expected, as Market Participants without load to hedge only have an incentive to participate in a market with expected positive returns. In general, most all Market Participants gained on their net TCR position, though there were a few notable losers among non-LSEs.

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, four LSEs fell short by $5 to $10 million dollars each. These four 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 is currently working 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 5–14, indicates that TCR auction prices do not accurately reflect the value of TCRs. The MMU recognizes three contributing factors: 1) the awarding of ARRs and TCRs 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 85% over the first 12 months of the Integrated Marketplace, with total payments exceeding funding by $56 million. This contrasts with the ARR funding level of 112%, with total revenue exceeding total payments by $48 million. The ARR funding from auctions is calculated as follows:

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

Figure 5–16 and Figure 5–17 shows the monthly TCR and ARR funding levels for the first year of the market. In every month, day-ahead congestion revenues fell short of TCR payments, while auction revenues exceeded ARR payments.

Figure 5–16 Monthly TCR Funding Levels

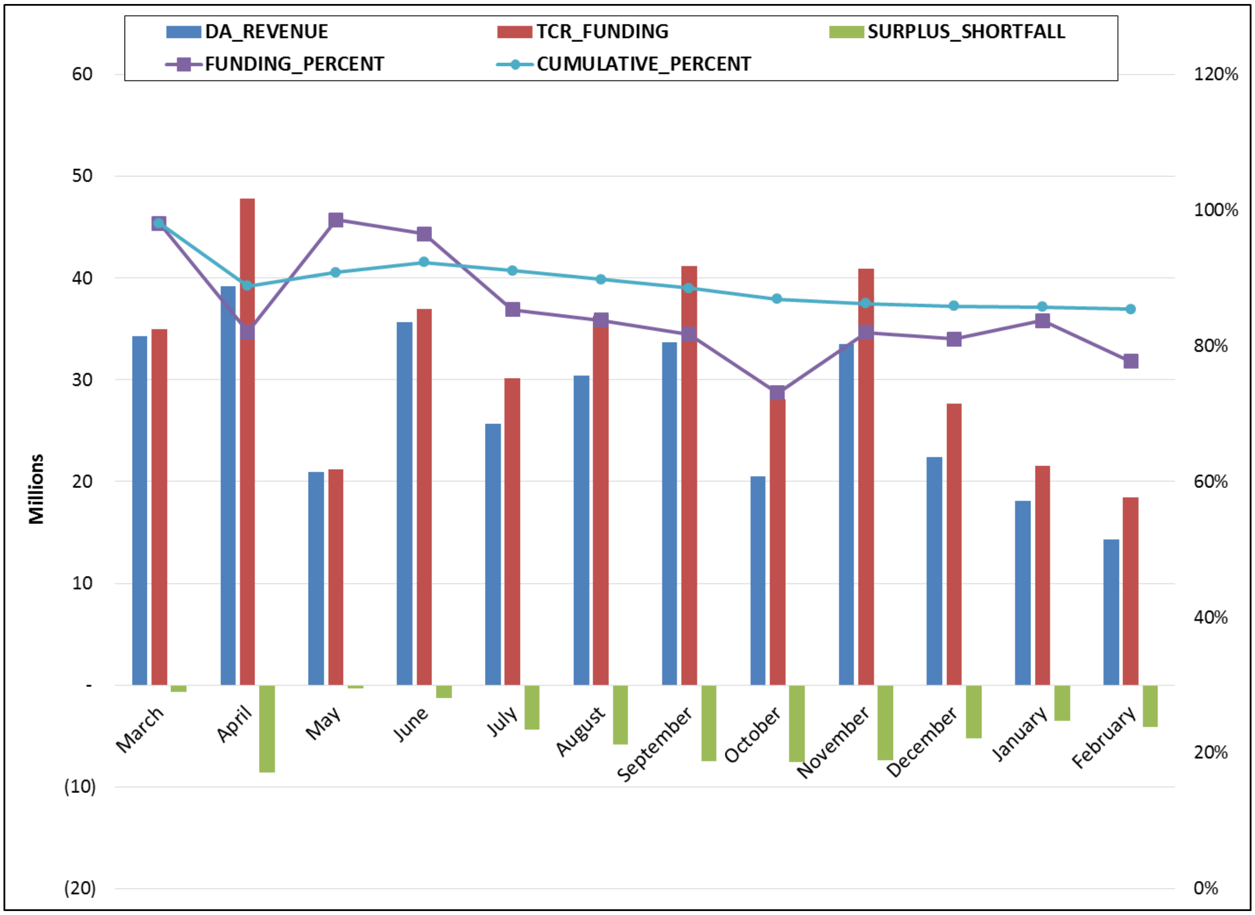
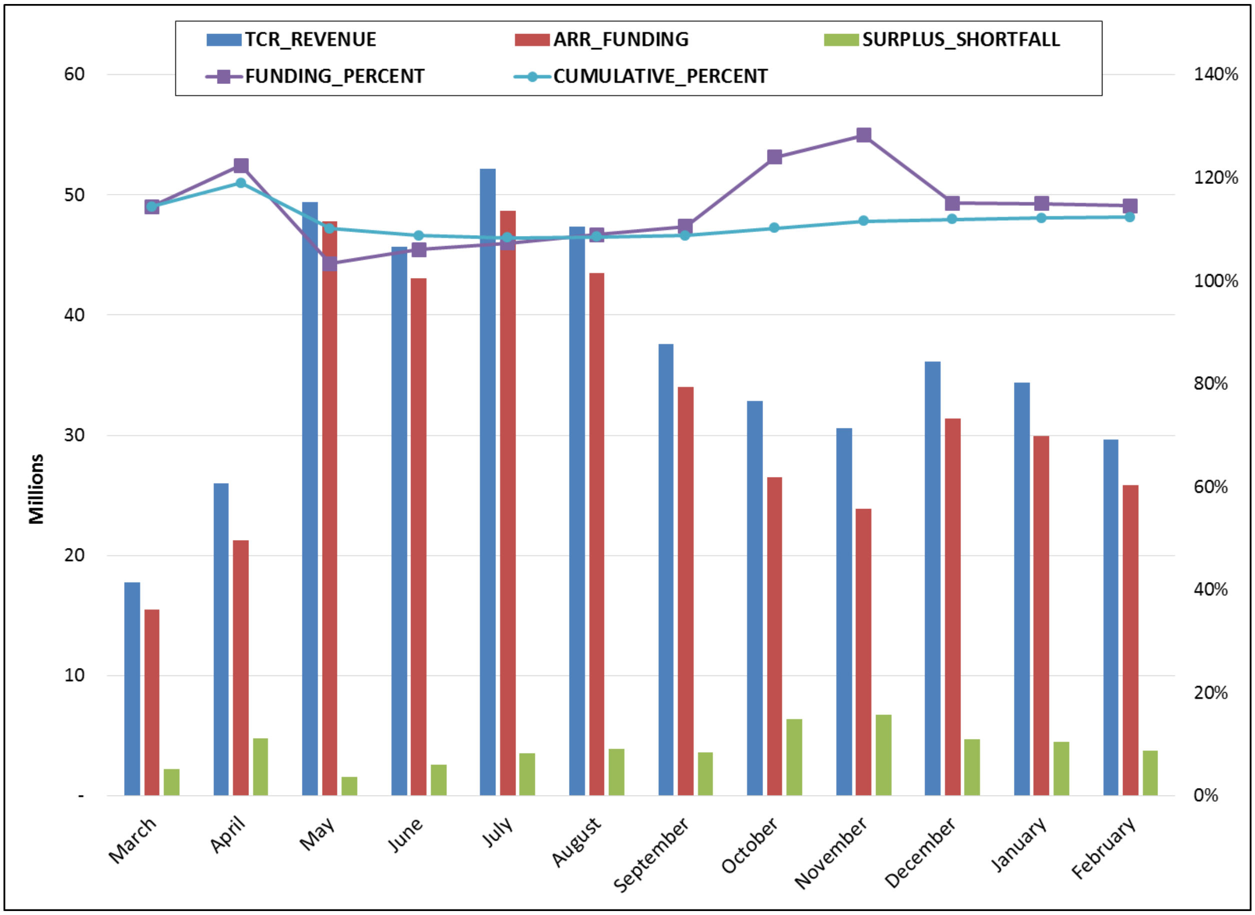


Figure 5–17 Monthly ARR Funding Levels



5.9.6. Awarding ARRs and TCRs Beyond the Transmission System Capability

A contributing factor to 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 market design and the quantity of system capacity that it makes available in the ARR allocations and TCR auctions, which begins with the design of the annual ARR allocation.

In the annual allocation, the full (100%) transmission capability of the SPP system may be awarded to candidate ARR holders for point-to-point service plus sufficient network transmission to serve up to 103% of an LSE's annual peak load for all 12 months of the year. These ARRs may be self-converted into TCRs in the auction process. 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. 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 modelling result in an abundance of TCRs awarded in the annual process.

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 underfunding.

An additional cause of underfunding 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.

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 could achieve further improvement in funding disparity by reducing the full system availability in the annual ARR allocation to match the system availability levels in the annual TCR auction and using lower system scaling factors for the annual TCR auction, monthly ARR allocations, and monthly TCR auctions.

MMU Recommendation 5. TCR and ARR System Availability

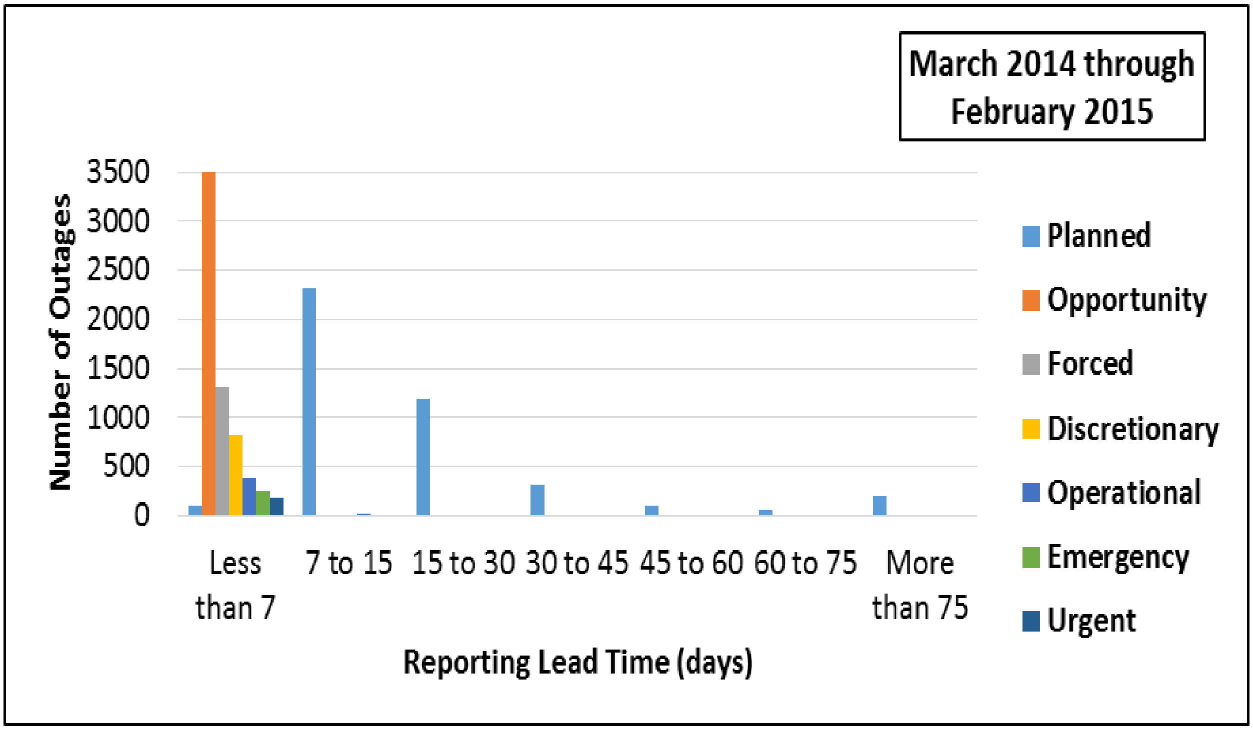
- Match the ARR and TCR system availability in the annual process to eliminate required limit expansion for infeasible ARRs.
- Lower the transmission system capacity available for award in the annual TCR auction.
- Lower the transmission system capacity available for award in the monthly ARR allocations and TCR auctions.

5.9.7. Transmission Outage Reporting and Modelling

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. SPP requires only seven days advance reporting of planned outages. Figure 5–18 shows the lead time of planned transmission outage reporting.

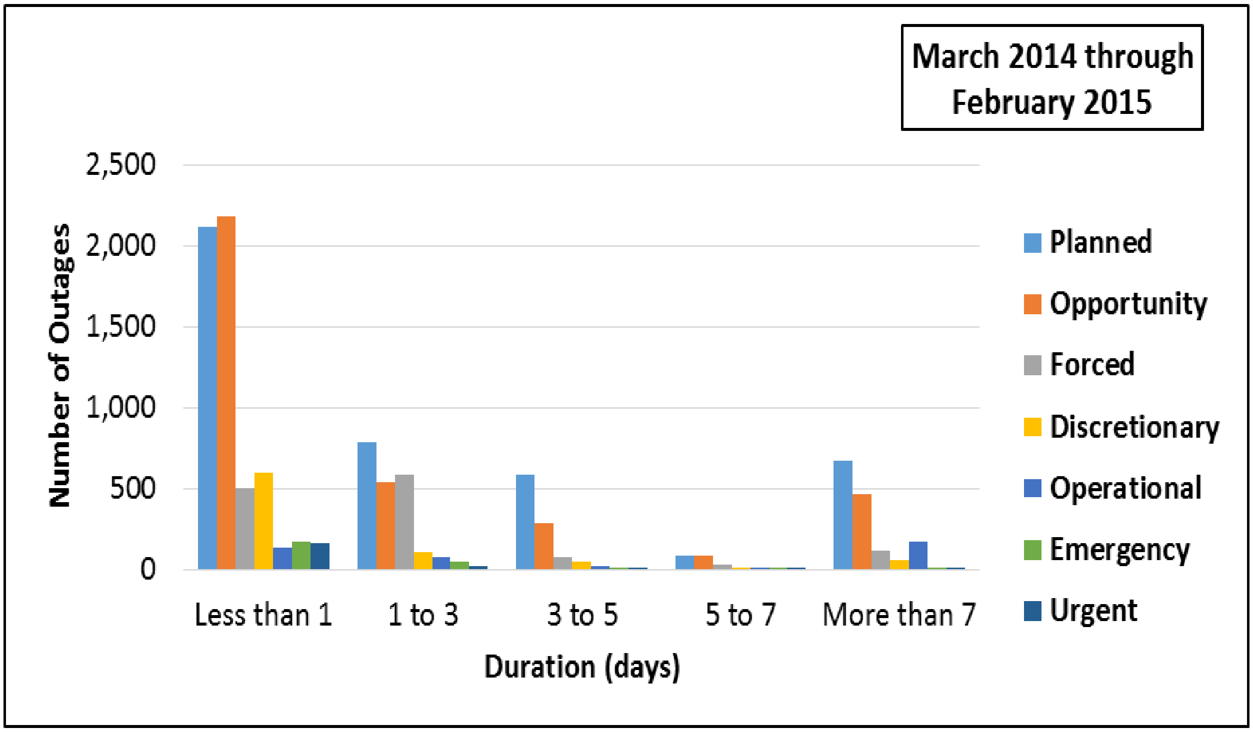
Figure 5–18 Transmission Outages by Reporting Lead Time



SPP transmission operators reported the vast majority of outages in the 7- to 30-day timeframe. They reported less than ten percent of planned outages in the 45- to 75-day timeframe required for reflection in the monthly ARR and TCR models. SPP staff has noted room for improvement and, as of the time of this report, had proposed modifications to historical outage reporting practices to require earlier reporting of planned outages. The MMU supports this effort and its recommendations above; lowering the capacity made available in the allocations and auctions would also mitigate the over-selling 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. In the first interim and annual processes, SPP included most all known outages. With stakeholder feedback, the criteria lengthened to up to a five day minimum duration in late 2014. Figure 5–19 shows that most outages lasted less than three days, and several fell into the 3- to 5-day category.

Figure 5–19 Transmission Outages by Duration



Outage duration does not imply market impact, and SPP at times excluded impactful outages based on their short duration. SPP could add flexibility to its processes to allow for more engineering judgement in the criteria for outage inclusion in ARR and TCR models.

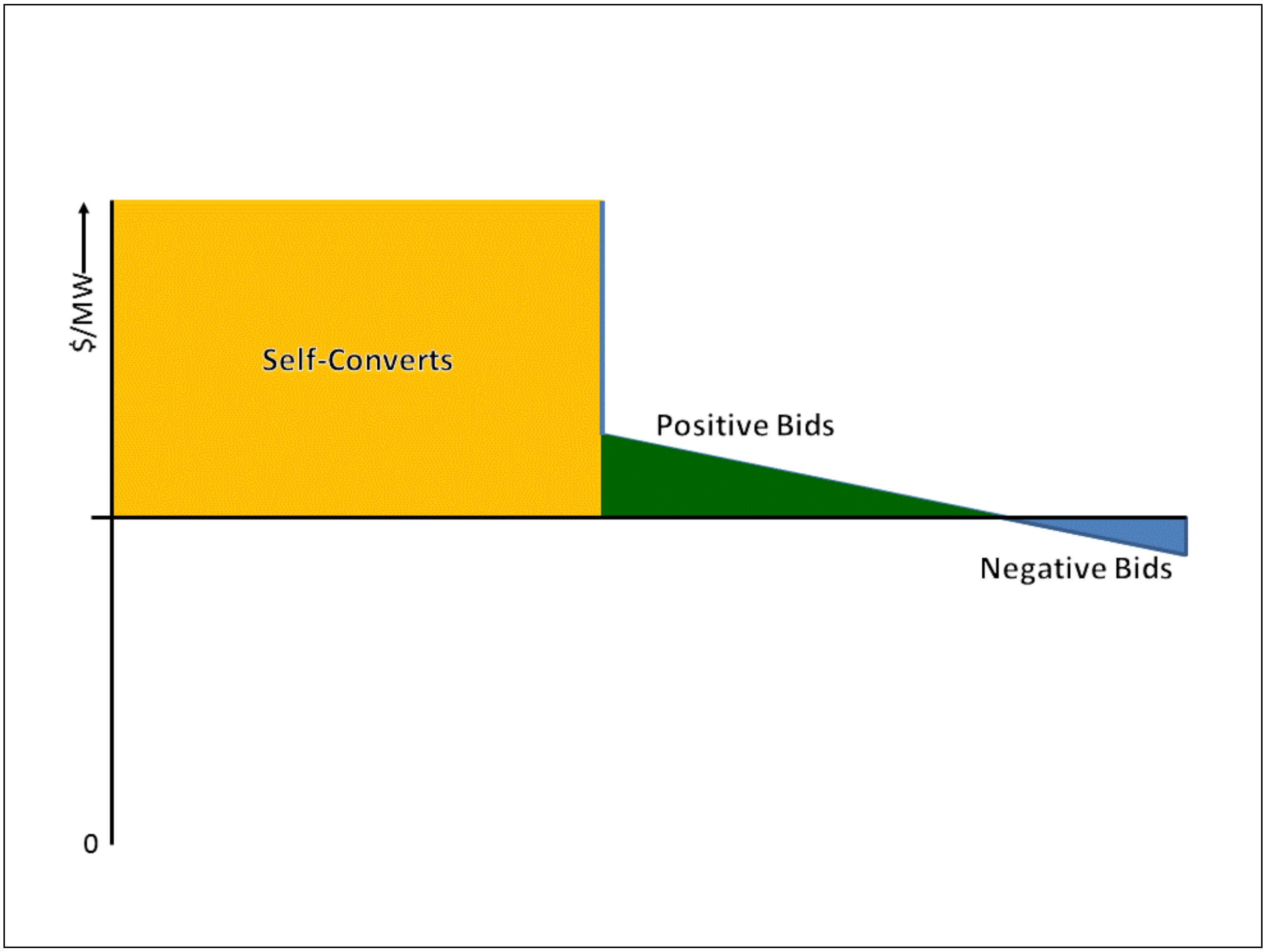
MMU Recommendation 6. Transmission Outage Reporting and Modelling

- Add flexibility to outage inclusion criteria for ARR and TCR modelling.

5.9.8. Self-Convert Modeling

Most 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 5–20 conceptually depicts the ranked bids for TCR MWs in a typical auction. It shows that approximately half of all auction bid MWs represent self-convert ARRs with effectively infinite prices.

Figure 5–20 TCR Bids by Value



SPP and the MMU are evaluating the impact of the self-convert modelling on TCR auction prices and awards, as well as exploring alternative processes used by other RTOs.

5.9.9. Bidding at Electrically Equivalent Settlement Locations

SPP prohibited bidding between pairs of electrically equivalent settlement points, which allow infinite or near-infinite quantities of TCRs to be awarded at zero cost. It publishes the 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. The MMU therefore recommends that the RTO implement appropriate safeties in the Market User Interface to prevent this behavior in the future.

MMU Recommendation 7. TCR Bidding at Electrically Equivalent Settlement Locations

- Impose a systematic block of TCR bidding at electrically equivalent settlement locations to prevent ongoing Tariff violations.

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 5–21 Total Congestion Payments for Load Serving Entities and Non-Load Entities

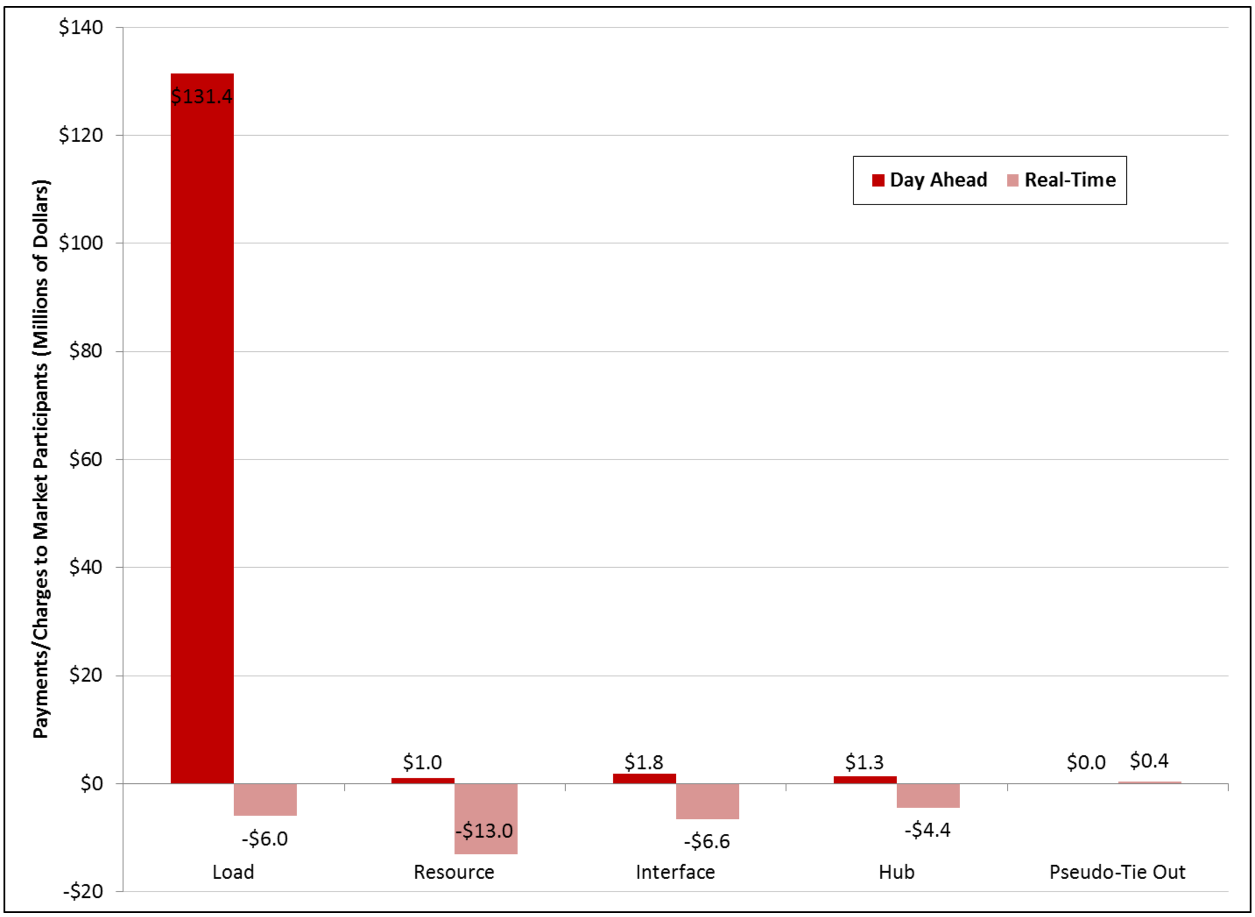
($ millions)	LSEs	Non-LSEs
DA Congestion	(268.8)	(54.0)
RTBM Congestion	(11.1)	42.3
NET CONGESTION	(279.9)	(11.6)
TCR Charges	(360.5)	(65.3)
TCR Payments	268.9	105.3
TCR Uplift	(33.5)	(21.5)
ARR Payment	375.5	3.1
ARR Surplus	45.2	1.2
NET TCR/ARR	295.6	22.9
RTBM Congestion Uplift	(17.9)	(1.4)
NET TOTAL	(1.9)	8.6

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

Both the congestion and loss components of the 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 has taken steps that largely correct the incentive issue.

During the first year of SPP's market, 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 5–22 provides the total over-collected loss distributions and charges by settlement location type for the first 12 months of the market.

Figure 5–22 Over-Collected Losses Totals



Due to high Day-Ahead Market load bids (see Figure 4–2), the load received $131 million, or 118% of all over-collected losses, while RTBM deviations from day-ahead positions paid $20 million, an amount equal to 19% of the over-collected losses. For comparison, RUC make whole payments are also charged to RTBM deviations from the Day-Ahead Market. Total RUC make whole payments for the year were $52.5 million (see Figure 3–29), so the RTBM over-collected loss changes constituted a 38% increase in penalties to deviations. For real-time exports, this implied an average charge of $2.27/MWh with charges sometimes exceeding $1,000/MWh, deterring trading at the SPP interfaces.

The payments at hubs and interfaces, especially in the RTBM, were exaggerated by the weighting of distributions to loss pools, which weight the distributions to settlement areas by the amount of marginal losses paid in that area. The interfaces and hubs constitute a single loss pool, which experiences disproportionate transaction volume in the RTBM. The disproportionate transaction volume occurs largely because cleared virtual offers constitute withdrawals in the RTBM for the purpose of the over-collected losses calculation.

Use of Bilateral Settlement Schedules (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. So long as the BSS does not change the net withdrawal at the location, the charges and credits for losses simply change hands. Where the BSS creates a net withdrawal that would not otherwise exist, it creates charges or credits 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 charge or credit where no energy is withdrawn from the system. The same occurs with the BSS at hubs, where no energy is withdrawn, by definition. The $1 million in distributions at resource settlement locations occurs for this reason, as well as the $1.3 million in credits and $4.4 million in charges 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.

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 May 2015. 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 real-time transactions at interfaces and hubs may continue to be altered due to the use of loss pools, and the BSS continues to create net withdrawals that receive loss distributions where they would not otherwise exist.

MMU Recommendation 8. Allocation of Over-Collected Losses

- Remove Bilateral Settlement Schedule transactions from the over-collected losses distribution calculation.
- Consider over-collected losses distributions to exports relative to interface transaction profit margins to assess potential distortion of market incentives.

6. Market Power and Mitigation

The SPP Integrated Marketplace should provide sufficient market incentives to produce competitive market outcomes despite local market power and regardless of the diverse regulatory policies and business structures of the SPP membership. The Federal Energy Regulatory Commission (FERC) approves market-based rate authority for SPP's Market Participants based upon this supposition. Competitiveness of the current design requires an absence of global market power and an intent on the part of market participants to seek energy market profits. The vertically integrated utility business model predominant in SPP decreases the incentive to capture higher profits through market power. For some utilities, it also substantially alters the ability to increase profits through energy market sales, weakening competitive motivation in the market. Section "3. Energy and Operating Reserve Markets" (page 47) assessed the possibility that prices may have been below efficient market levels in SPP. This section focuses on whether or not prices rose above competitive levels, reflecting market power. The MMU's competitive assessment provides evidence that market outcomes were workably competitive and that the market required mitigation of local market power to achieve those outcomes.

6.1. Competitive Assessment

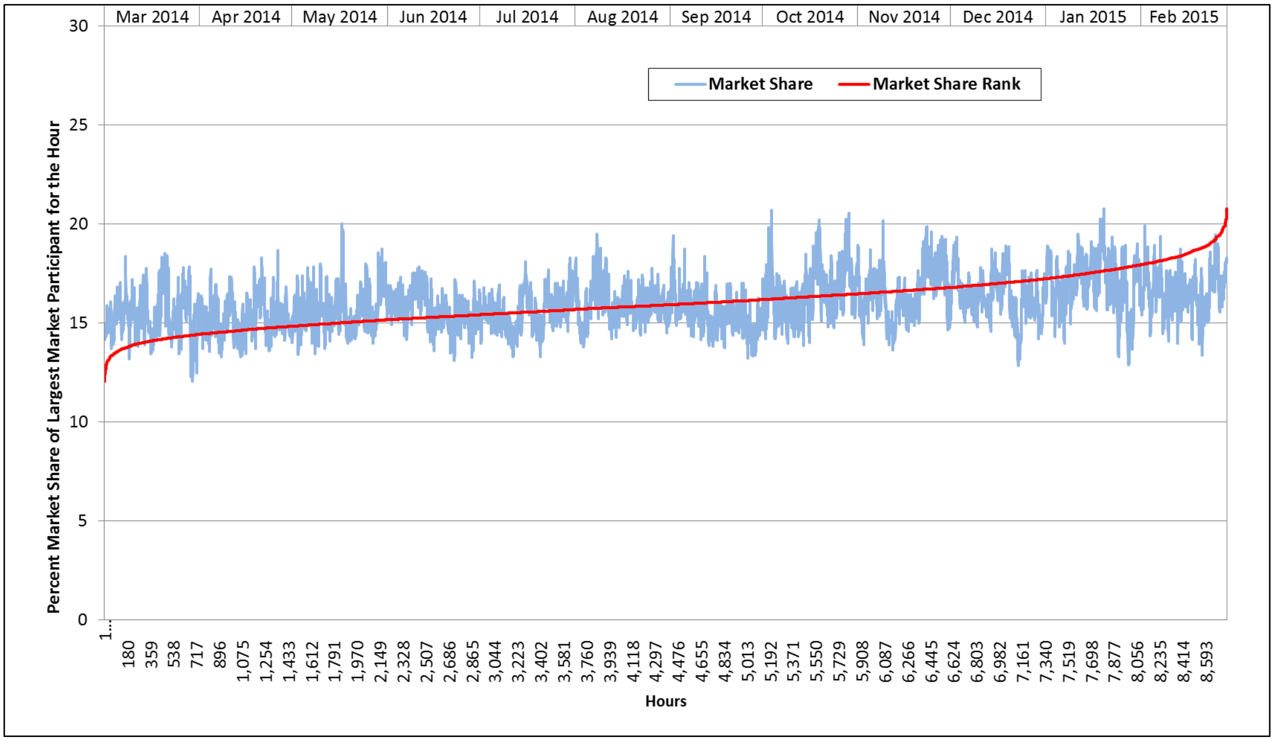
The assessment of the competitive environment during the first year of SPP's Integrated Marketplace first establishes the level of structural market power and then examines market prices for indications of market power impact. Automatic market power mitigation processes limit the ability of generators 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. The following subsection examines the effectiveness of local market power mitigation.

6.1.1. Market Structure

Two core metrics of structural market power are the market share of the largest supplier and the Herfindahl-Hirschman Index (HHI). They both indicate potential structural market power in SPP's energy market.

Figure 6–1 displays the energy output market share of the largest online supplier in the Real-Time Balancing Market by hour for the period March 1, 2014 to February 28, 2014, along with a ranked maximum market share duration curve.

Figure 6–1 Market Share of the Largest Supplier by Hour



It ranged from 12% to 21%, exceeding 20% percent in only 14 hours for the year. The highest market share hours mostly occurred during the off-peak months of the year, with the exception of a couple of consecutive hours in mid-January. Most of these high market share hours occurred in the middle of the night or during the morning ramp up period.

The HHI is a standard measure of structural market power used in merger analysis. It represents the sum of the market shares of all suppliers (*i*),

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

According to FERC's "Merger Policy Statement," 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 the SPP market was unconcentrated almost half of the year and moderately concentrated the other half. HHIs never rose above the 1,800, highly concentrated threshold.

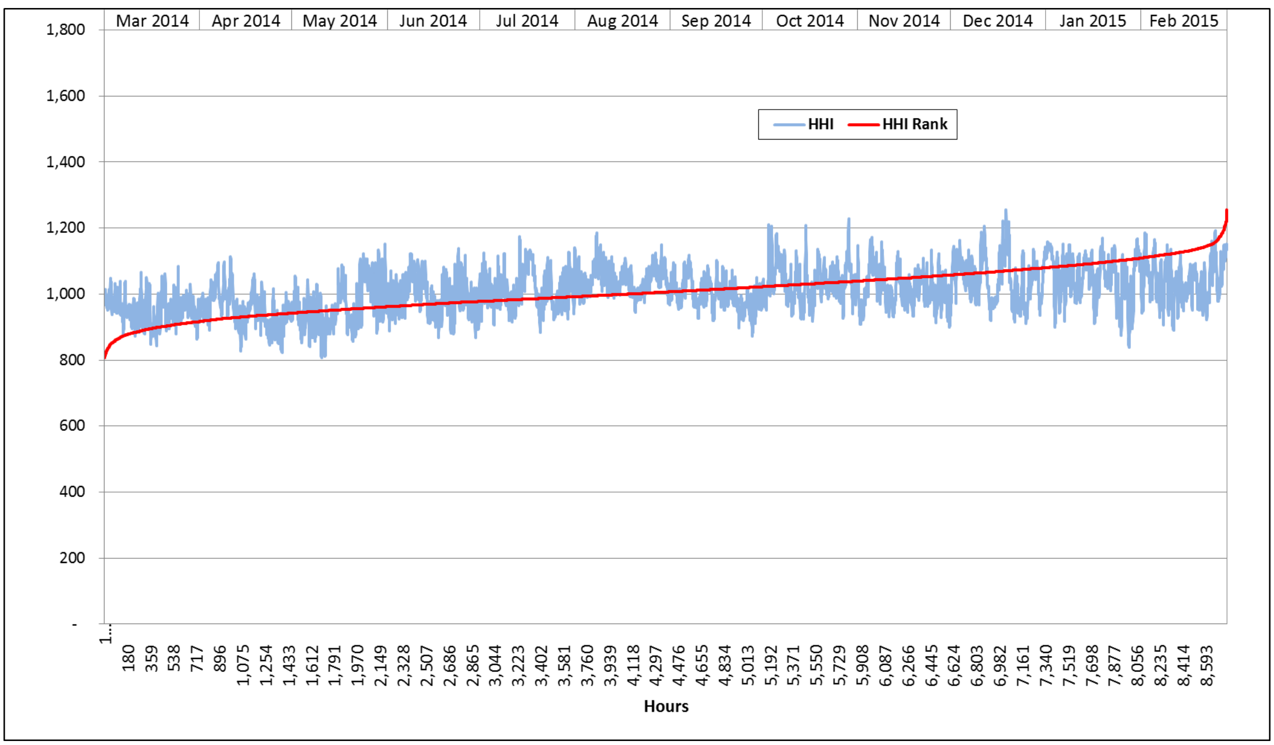
Figure 6–2 Count of RTBM Hours by Market Concentration Level

	HHI Level	Hours	% of Hours
Unconcentrated	Below 1,000	4,102	47%
Moderately Concentrated	1,000 to 1,800	4,658	53%
Highly Concentrated	Above 1,800	0	0%

Measured from March 2014 through February 2015

Figure 6–3 depicts the hourly RTBM HHI for the first year of the Integrated Marketplace along with a ranked HHI duration curve. The hourly HHI ranges from 800 to about 1,200 during the course of the year, with higher concentration levels in the fall and winter months.

Figure 6–3 Hourly HHI



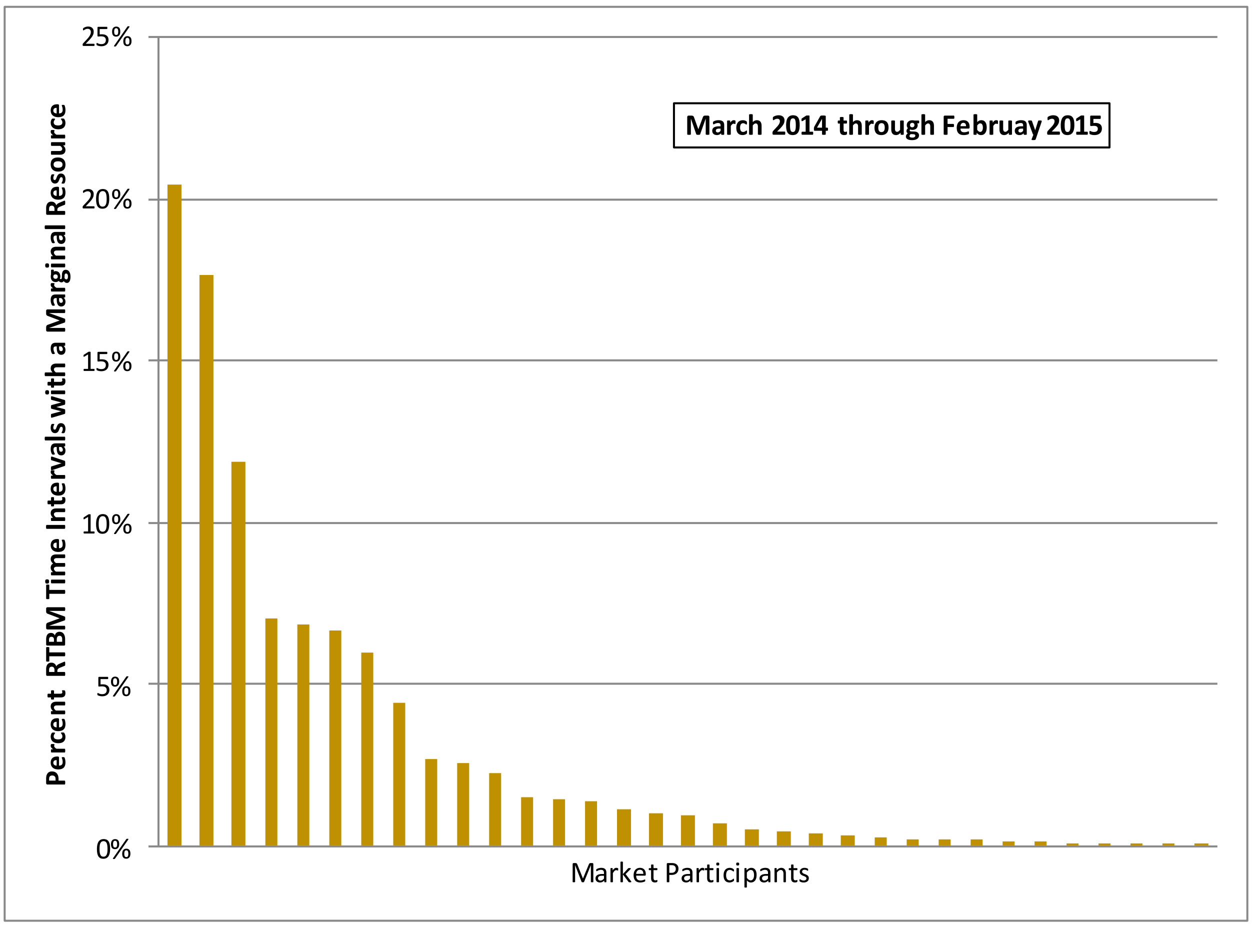
Market structure conditions in SPP change with the fuel mix of online resources. Base load (coal, nuclear, and wind) generation produced about 80% of SPP's energy for the year and these resources often set the marginal price, especially during off-peak hours. Prices rise and the market structure becomes 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 larger. To demonstrate the level of market concentration under these various conditions, Figure 6–4 provides hourly RTBM HHI statistics by supply curve segment. It shows that the intermediate and peaking segments of the market were highly concentrated.

Figure 6–4 Hourly HHI Statistics by Supply Curve Segment

Supply Segment	% of Hours Online	Min. HHI	Avg. HHI	Max HHI
Base load	50 to 100	833	1,035	1,241
Intermediate	10 to 50	921	2,282	9,995
Peaking	0 to 10	1,004	6,568	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 fuel 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 ten percent 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.

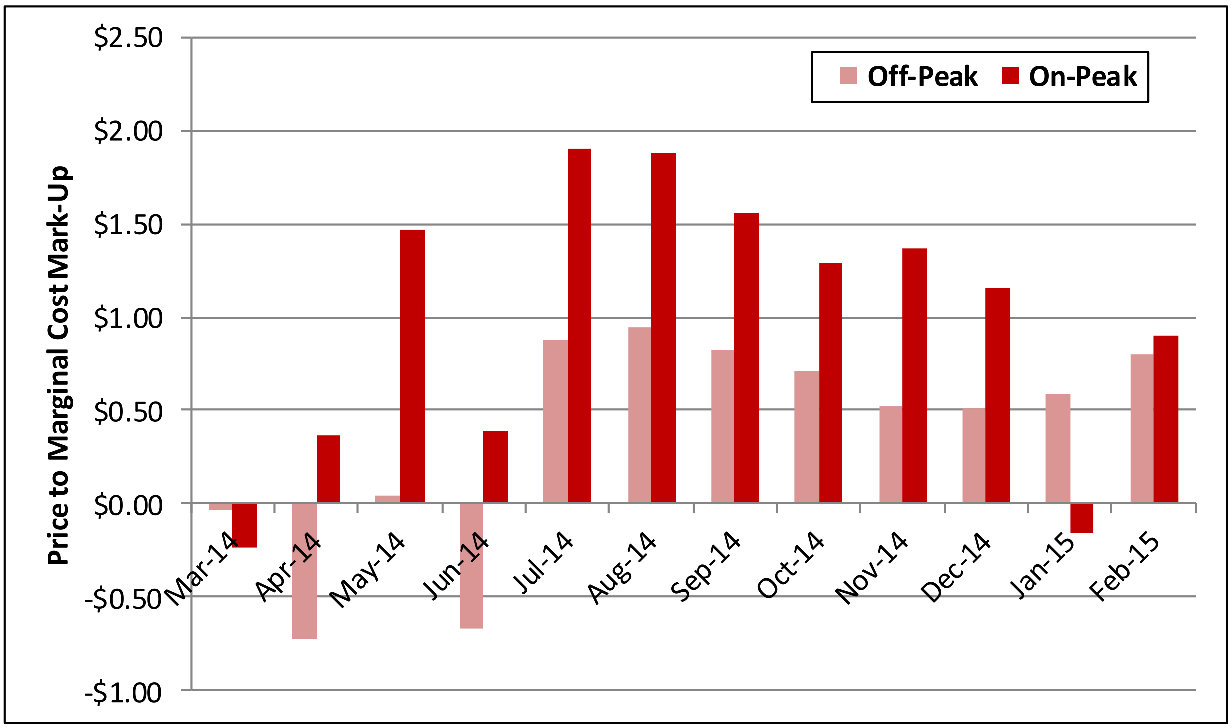
Figure 6–5 Market Participants on the RTBM Margin



6.1.2. Competitive Market Performance

In a competitive market, prices equal the short run marginal cost of production. In SPP's Integrated Marketplace, market participants submit hourly mitigated energy offer curves that represent the short run marginal cost of energy. To assess market performance, the MMU compares the market offer to the mitigated offer for the marginal resources for each RTBM interval. Figure 6–6 provides the average marginal resource mark-ups by month for on-peak and off-peak periods.[18]

Figure 6–6 Monthly Average Mark-Ups



The mark-ups ranged from -$0.72 to $0.94/MWh for off-peak periods and from -$0.24 to $1.90/MWh for on-peak periods. The lowest mark-ups occur in spring 2014 for off-peak hours. These months had the most wind on the margin and were some of the windiest overall. In March 2014, the average on-peak mark-up was also negative. This reflects RTBM offers below mitigated offers in the winter weather event during the first week of the market. Generators may

[18] The MMU calculates a simple average over all marginal resources for an interval. The mark-ups are not weighted to reflect each marginal resources proportional impact on the system marginal price.

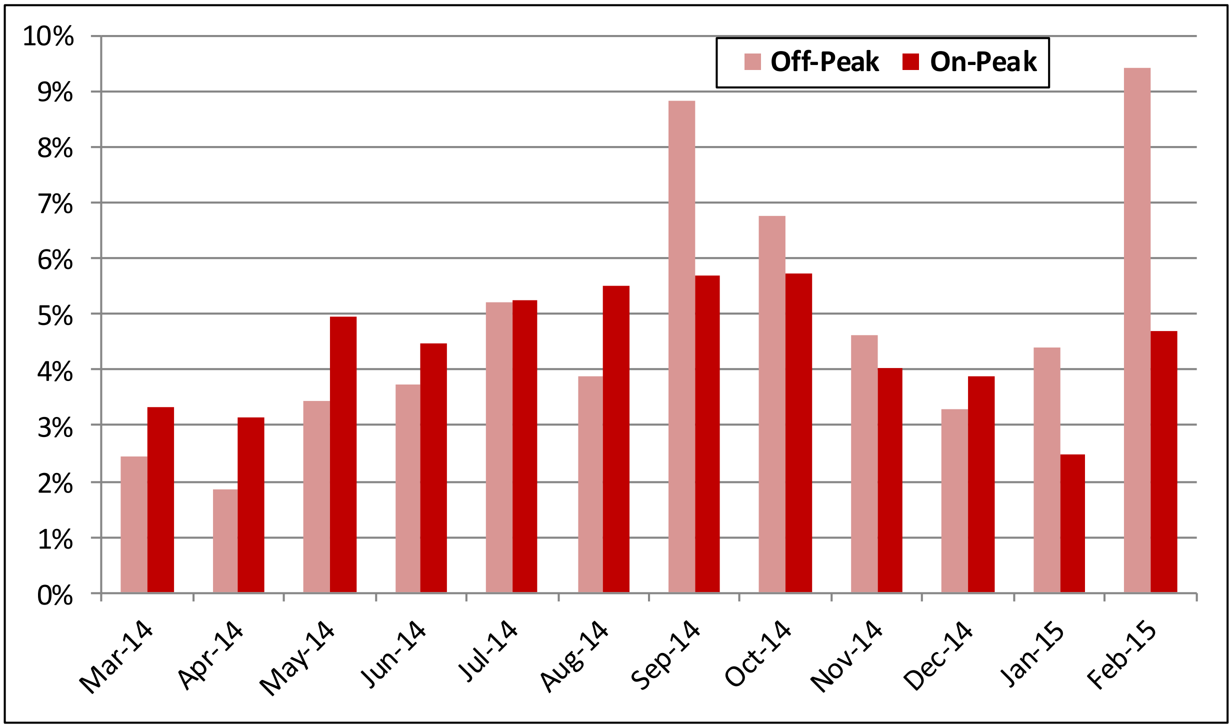
have offered below their marginal cost to maintain commitments or updated real-time offers from day-ahead levels as gas prices fell throughout the week. On-peak mark-ups rose to almost $2/MW during the summer and fell thereafter.[19]

Mark-ups fell with the price of natural gas in the winter in both absolute value and percentages. The negative on-peak average mark-up in January 2015 reflects a month when natural gas resources only set prices 35% of the time, though the natural gas share of total generation did not fall. This occurred because the marginal cost of energy from combined cycle gas fell below the average marginal cost of SPP coal-fired generation. The 35% gas on the margin in January was the least amount for the year, compared to an average of 50% and summer values of 60%. LMPs also fell to their low for the year in this month. The falling mark-up trend breaks in February 2015 when natural gas prices fell a bit more. This coincided with higher average daily loads and more severe weather in February.

[19] It should be noted that some outlier mark-up 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.

Figure 6–7 provides the monthly average mark-up as a percent of LMP. On-peak percent mark-up falls from the 5% range in summer 2014 to as low as 2.5% in January 2015.

Figure 6–7 Monthly Average Mark-Ups as Percentage of LMP



The changing gas price explains the fall in absolute mark-up, but not the fall in percent mark-up. The percentage fall may indicate an increasingly competitive market environment when combined cycle gas came into direct competition with coal-fired generation. The MMU will continue to track this trend. Overall, average mark-up levels in the range of two to ten percent of LMP indicate competitive market pricing outcomes.

6.1.3. Summary Assessment

The structural and performance measures indicate that the market was generally competitive in its first year. However, there are indications that structural conditions were not ripe for competitive market outcomes at all times. HHIs averaged at moderately concentrated levels, and there was a high degree of concentration in the intermediate, mostly natural gas-fired, segment of the market supply curve. Price mark-ups over short run marginal cost rose when this segment of the market set LMPs and fell when this segment came into direct competition with coal-fired generation, reflecting modest impacts of economic withholding. For this reason, the MMU reiterates the importance of market power mitigation and the need to continually reassess its effectiveness. Based on the first 12 months of the market, the MMU does not see a need for mitigation of global market power.

6.2. 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 potentially have local market power due to transmission congestion, and also to instances where there is the potential for cost recovery manipulation due to a manual commitment that guarantees recovery of all cost reflected in the resource's submitted offers.

6.2.1. Mitigation Frequency

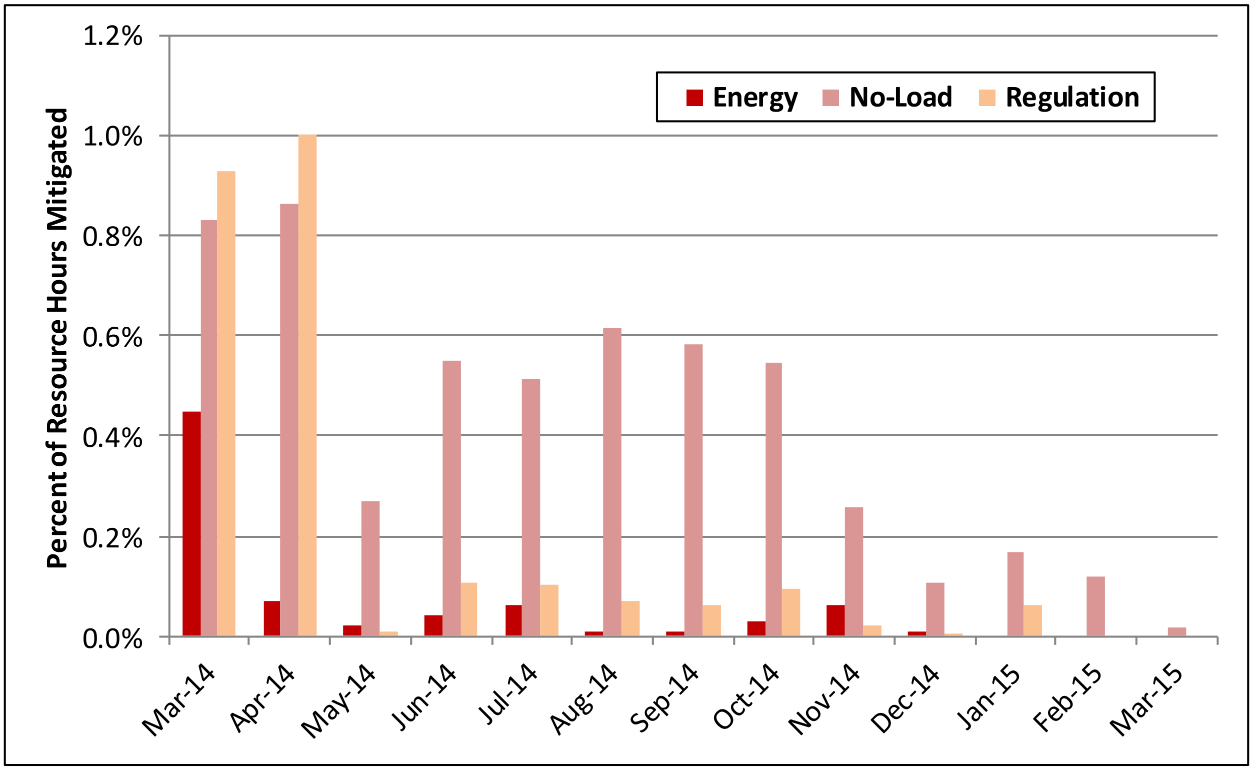
Resources' energy, start-up, no-load, and operating reserve offers are subject to the conduct and impact mitigation plan, and mitigation is applied when the following three circumstances occur simultaneously in a market solution:

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, and a second offer, generally referred to 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 potentially 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.

The mitigation frequency varies across products and markets. Figure 6–8 shows that the mitigation of energy, no-load, and operating reserve products was infrequent in the Day-Ahead Market. The application of mitigation to energy, no-load, and operating reserve offers is below

1% for the first 12 months of the market, with the one exception being the application of mitigation to regulation service offers in 1% of resource-hours in April 2014. The mitigation levels drop below 0.2% over the last few months. The application of mitigation in the RTBM is on average less than 0.1% for the first 12 months of the market. The most mitigated resource in the RTBM for each month of the market has never been more than 2.5% of the resource-intervals.

Figure 6–8 Mitigation Frequency, Day-Ahead Market



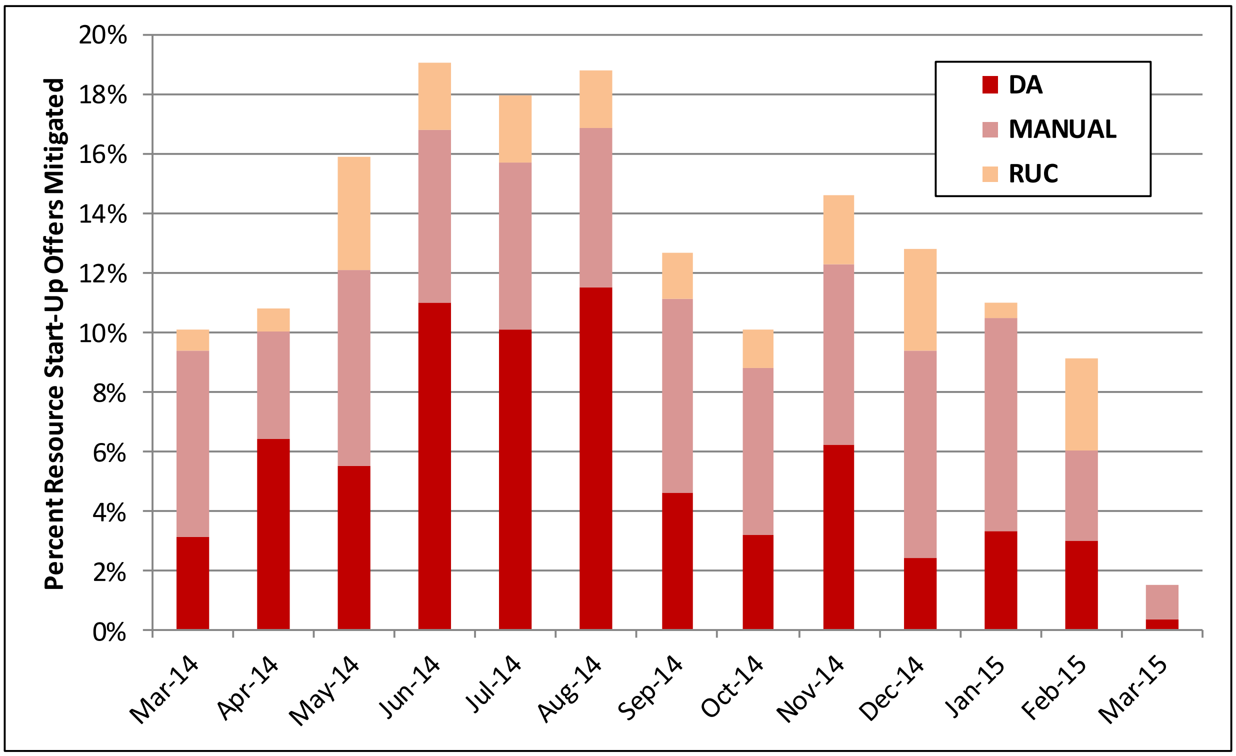
The mitigation of start-up offers has been significant. Figure 6–9 shows the mitigation frequency for start-up offers for the various means of commitment. Mitigation was most prevalent in the summer months with 19% of start-up offers mitigated.

An important take-away from Figure 6–9 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.[20] 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 to address a local reliability issue. Other manual commitments are 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



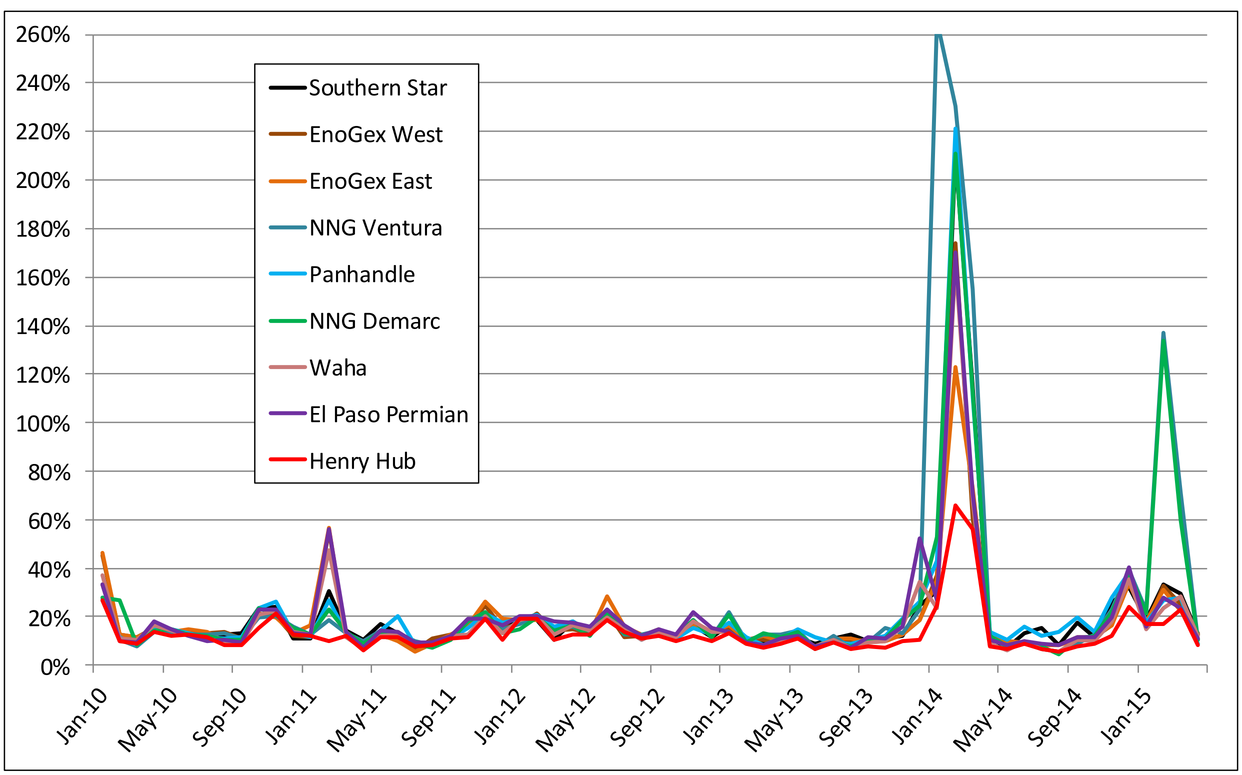
6.2.2. Analysis of Conduct and Impact Thresholds

The Mitigated Offers represent the competitive baseline costs for the generators and as such are held to the short-run marginal cost standard. The conduct thresholds are in place to account for uncertainty in the calculation of the Mitigated Offers, since the Mitigated Offers must be

[20] See FERC Docket ER15-673.

submitted at the close of the Day-Ahead Market at 1100 hours on the day before the operating day, 13 to 37 hours before these cost will be incurred. Therefore, Market Participants must estimate several variables in the calculation of these offers. A large part of the uncertainty is related to fuel cost volatility, and in the original design of the mitigation plan the price volatility of natural gas was used as a guide to an appropriate conduct threshold. Figure 6–10 below is a chart of monthly gas price volatilities for several gas hubs that are used by the Market Monitor as proxies for gas cost for SPP generators. The monthly volatilities are generally below the 25% level, but there are several months where volatility percentages exceed 25% and a few months where the volatilities exceed 50%. The conduct threshold should not be set with the goal of accommodating all circumstances of gas price volatility; rather they should be set with long-term expectations in mind. The most effective way to deal with the extraordinary circumstances, such as the spikes in February 2014 and February 2015, is for the Market Participant to notify the Market Monitor of unexpected high gas cost and the need to make changes to the Mitigated Offer levels.

Figure 6–10 Historical Monthly Price Volatility



The MMU also analyzed how many generators are impacted by the current threshold levels. A generator was determined to be impacted by the threshold level if on average the generator's offers exceed the conduct threshold or are within 1% of the threshold. The reasoning being that a market participant that is truly negatively impacted by the threshold being too low may offer right up to the threshold to avoid the possibility of being mitigated. The analysis shows that energy offers for 39 resources (approximately 9%) are impacted by the conduct threshold levels; no-load offers for 19 resources (approximately 4%) are impacted; and start-up offers for 162 resources (approximately 35%) are impacted by the conduct thresholds.

With respect to start-up offers and regulation offers, the MMU found that a significant source of uncertainty unrelated to fuel price volatility should be included in the evaluation of conduct thresholds. To calculate a competitive start-up offer adhering to the short-run marginal cost standard, Market Participants must estimate the energy revenues that will be earned prior to the start of the commitment period and subtract that amount from the other costs. Factors other than fuel cost that are unknown at the time the offer is submitted and must be estimated include the LMP, fuel usage, and the generation profile from synchronization to the economic minimum capability. While each of these factors adds to the uncertainty of a start-up offer, the LMP is likely a significant source of uncertainty and should be accounted for in the start-up offer conduct threshold level.

Resources that operate with smaller dispatch ranges when cleared for regulation are exposed to a loss of revenue or higher operating costs. The SPP market does not capture these costs, which are referred to as the uncompensated costs of regulation in the Mitigated Offer Development Guidelines. The market participant must estimate the uncompensated costs by forecasting the RTBM LMP and then calculating the difference between the RTBM LMP and the cost of energy in the uncaptured operating range. Price uncertainty between the Day-Ahead Market and Real-Time Balancing Market is at times substantial and the additional uncertainty in the cost of providing regulation should be accounted for in the regulation offer conduct threshold level.

MMU Recommendation 9. Market Power Mitigation Conduct Thresholds

The MMU recommends the start-up offer conduct threshold be increased to address the additional uncertainty that Market Participants face in calculating a start-up offer that is unrelated to fuel cost volatility. The Market Monitor also recommends increasing the regulation-up and regulation-down conduct thresholds to account for the uncertainty in estimating the uncompensated costs that are an input into the applicable mitigated offers. The MMU will present specific recommendations to stakeholders in calendar year 2015.

Finally we note that given the construct of the SPP conduct thresholds, there is not a just reason for tighter conduct thresholds in the Frequently Constrained Areas (FCA). As noted above, the energy offer conduct threshold is tied to fuel price volatility and set at a level that reasonably matches long-term expectations. Market participants with resources in FCAs do not face a lower level of uncertainty. Therefore we recommend that energy offers for resources that designated as being in a FCA be subject to a 25% conduct threshold.

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
DVER	Dispatchable Variable Energy Resource
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

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
VER	Variable Energy Resource
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WR	Westar Energy, Incorporated