2013 State of the Market

19 May 2014

SPP Market Monitoring Unit

Southwest Power Pool

Table of Contents

List of Figures

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Executive Summary

A. Purpose

The Market Monitoring Unit (MMU) is the independent market monitor for the Southwest Power Pool (SPP) Regional Transmission Organization (RTO) and is responsible for providing an annual report of electricity market conditions to the SPP Board of Directors, the Federal Energy Regulatory Commission (FERC), the SPP Regional State Committee, and other interested stakeholders. FERC requires *State of the Market Reports* from all RTO and Independent System Operator MMUs. This report fulfills that obligation.

B. Overview of the SPP Footprint

SPP Energy Imbalance Service (EIS) Market added two new Market Participants in 2013. Capacity increased 4.6% to 74,390 MW and reserve margin was at 47%. A reserve margin of this size has positive implications for both reliability and for mitigation of the potential exercise of market power. Capacity additions during 2013 totaled 1,791 MW with the majority in the form of small gas plants that were previously behind the meter and new wind farms.

Demand for electricity was slightly higher in 2013 than the previous year although the summer peak load was lower. Market system coincident peak load in 2013 was 45,256 MW occurring on August 30, approximately 4% lower than the peak load in 2012. The SPP load factor in 2013 was 58.2%, up from 55.2% in the previous year. According to the weather analysis, summer temperature patterns in 2013 were close to normal and winter patterns were colder than normal. This is in contrast to the summer temperatures in 2011 and 2012 that were significantly above normal.

During 2013, the majority of the SPP energy production continued to come from coal-fired plants. Gas power plant production decreased from 26% in 2012 to 20% in 2013 of the total system energy production due to the higher gas prices, lower summer peak load and increase wind generation.

Wind generation increased substantially in 2013, from 8% of the total generation to about 11%. October 10, 2013 saw a record generation from wind capacity of 6,467 MW. Wind energy as a percent of load reached a maximum of 33.4% on April 6, up from 27.3% in 2012. Because wind generation is three times more volatile than load, wind generation of this magnitude has a significant impact on transmission congestion management.

C. EIS Market Performance

The energy purchased and sold through the SPP EIS Market was approximately 26.6 million MWh, a slight decrease from the previous year. However, settlements increased by 13% to about 675 million dollars due to higher average market prices.

SPP electric price remains highly correlated with natural gas prices. The average Panhandle Eastern natural gas price was $3.57/MMBtu in 2013, up from $2.63/MMBtu in 2012. The SPP electric price increased to $25.95/MWh in 2013 from $22.29/MWh in 2012. SPP prices are generally lower than the system prices in neighboring RTOs and this continued to be the case in 2013. In 2013 the yearly average for Electric Reliability Council of Texas (ERCOT) was $30.62/MWh and the Midcontinent Independent System Operator (MISO) price was $31.40/MWh. SPP price volatility was also lower than ERCOT and MISO.

Price differentials between SPP Market Participants were higher in 2013 than in 2012 but less than prior years. Again, 2012 was an unusual year because of the very low gas prices. While the SPP average regional price was $25.95/MWh, average Market Participant prices ranged from a low of $22.29/MWh to a high of $28.56/MWh. These price differences reflect transmission congestion in the SPP footprint. If no congestion existed in the SPP region, the prices at all points would be identical.

Using a relatively simplistic investment calculation it appears that SPP EIS Market prices would have supported a new coal power plant investment in 2013. This is not the case for either combined cycle or combustion turbine power plants. This does not necessarily mean there is sufficient justification for the construction a new coal plant or that there is no rationale for investment in new combined cycle or combustion turbine generation. Regulatory requirements, reliability demands, shifts in generation technology, fuel supply and price forecasts, and load growth patterns are a few of the numerous non-electricity price factors that impact new generation construction decisions.

SPP was a net exporter more than 90% of the time in 2013. Periods during which SPP was a net importer mainly occur in summer months when load was high. The highest net hourly export was 1,986 MWh and the highest net import was 716 MWh. During the highest 10% of load periods, SPP was a net importer 57% of the time. During the lowest 75% of the load periods, SPP was a net exporter more than 95% of the time.

Estimated EIS Market production benefits for 2013 were strong. Benefits were estimated to be $182 million, an increase from $167 million in 2012. Benefits to coal plant asset owners increased in 2013 because of the increasing differential between coal and gas prices and shows up in the higher net revenue category, about 37% higher than estimated for 2012. Gas asset owner benefits increased about $14 million with the increase distributed evenly in the net savings for simple cycle units and combined cycle units. Benefits accruing to wind assets decreased slightly despite increases in the volume of wind generation and electric prices. This appears to be the result of increased bilateral sales represented by wind schedules and less reliance on the EIS Market.

Common market power measures, such as Herfindahl-Hirschman Index (HHI) indicate that the SPP market continues to be competitive and is becoming less concentrated with the addition of new Market Participants in 2013. The MMU monitors for market manipulation by using various metrics including economic withholding, physical withholding, and uneconomic production screens. Overall, the MMU found no evidence of market power abuse or manipulation during 2013.

D. Energy Delivery

Total 2013 transmission owner revenue was approximately $1,171 million. This is a 15% increase from $1,017 million in 2012. Transmission owner revenue has been increasing for many years. Growth in transmission revenue is caused by increases in transmission rates, the addition of new members and associated transmission lines, and higher utilization of the transmission system.

Transmission congestion by most measures declined dramatically in the first five years of the SPP EIS market, 2007 through 2011. Breached intervals declined from about 7.5% of all intervals to just over 4%. Cost of congestion measured by Congestion Revenue and System Redispatch Payments both declined by about 50% during that period. SPP implementation of better congestion management procedures and Market Participants' increased unit flexibility parameters are some of the factors that resulted in a decline in congestion on the SPP system.

This trend changed in 2012 and 2013 with breached intervals increasing to about 6% of total intervals in 2012 and about 7% in 2013. System Redispatch Payments increased about 45% in 2013 over 2012 while Congestion Revenue remained flat. This increased congestion appears to be the result of a dramatic increase in wind generation, increased utilization of the transmission system, increased line outage resulting from new transmission investments, and an increase in external impacts from adjacent systems. Major new transmission investments with commercial operation dates starting in mid-2014 should have a significant positive impact on congestion resulting in a reversal of this trend.

Transmission curtailments are another aspect of congestion where transmission service is reduced in response to a transmission capacity shortage as a result of system reliability conditions. Both firm and non-firm curtailments declined in 2013 from 2012 while firm curtailments were higher than what was experienced in 2011. Overall, firm curtailments are relatively low at only 0.05% of total scheduled energy. This is an indication of effective congestion management where the market is providing efficient congestion relief thereby minimizing the need for transmission operator intervention requesting curtailments.

The Texas Panhandle and Omaha-Kansas City corridors continue to be the most constrained areas in the SPP system. Limited transfer capability across the Panhandle area restricts the movement of low cost energy from the north to load centers to the south and resulting in heavy congestion and significant price divergence across the region. The Omaha-Kansas City corridor is impacted by the large amount of low cost generation to the north and the limited transfer capability to the rest of the SPP market. The other major factor is external impacts caused by flows from outside the SPP system. An unexpected factor affecting the Kansas City area in 2013 was the change in congestion caused by the installation of the Eastowne transformer. This new element is an incremental step in the process of addressing congestion in the Kansas City area. This change has resulted in localized congestion in the south to north directions. A second upgrade to this limiting element is scheduled for mid-spring 2014, which should mitigate some of the unexpected impacts of the initial transformer.

As a Regional Transmission Organization, SPP has a responsibility to develop transmission expansion plans that will ensure both the long and short-term reliability of the system, as well as ensure that the system is cost effective. A number of large transmission lines were under construction during 2013 though no new lines entered service during that period of time. One line did enter service late in 2012 that appears to have relieved some of the congestion between western Nebraska and the balance of the EIS Market. The most prominent projects scheduled to be completed in 2014 are the Spearville to Thistle to Woodward to Tuco set of 345 kV lines. These projects are expected to provide significant additional capacity to the Texas Panhandle corridor there by reducing congestion in the area. The Iatan to Nashua 345 kV line is scheduled to be completed in mid-2015 and should reduce congestion in the Omaha-Kansas City corridor.

SPP has developed several Transmission Expansion Plans in past years and 2013 was no exception. The 2014 SPP Transmission Expansion Plan (STEP), published in January 2014, highlights many key areas of transmission development and provides an outline of forecast capital outlays necessary to ensure that the transmission system remains adequate for both current and future needs. The 2014 plan provides details on projects that impact future development of the SPP transmission grid. Ten distinct areas of transmission planning are discussed in the report, each of which are critical to meeting mandates of either the 2013 SPP Strategic Plan or the nine planning principles in FERC Order 890 and 1000.

The 2014 STEP consists of 386 transmission upgrades throughout the SPP region with a total cost of $6.2 billion dollars. Costs are shown below by project type:

$99 million for Generation Interconnection projects
$86 million for Transmission Service projects
$535 million for Balanced Portfolio projects
$1.38 billion for High Priority projects
$4.13 billion for ITP projects

Potential investments to reduce congestion on highly constrained flowgates are continually being evaluated through the STEP process. For more details see the *2014 SPP Transmission Expansion Plan Report*.

E. Conclusions

The overall market performance was strong in 2013 continuing a long stretch of increasingly effective market rules, vigorous participation by resource owners, and substantial market benefits. Significant near term concerns with regard to SPP markets appear to be appropriately addressed by SPP. However, one long standing concern continues to be the seams problem along the SPP eastern border, which has intensified with Entergy joining MISO in December 2013. SPP continues to pursue solutions to this issue.

I. Overview of SPP Market Footprint

To ensure a consistent methodology, exhibits in this report have been formulated using only the EIS Market footprint unless otherwise expressly stated. Historical data has been provided where applicable to illustrate trends across time.

A. Brief Overview of SPP

SPP is a 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/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 market operations. This report focuses on 2013 EIS Market.

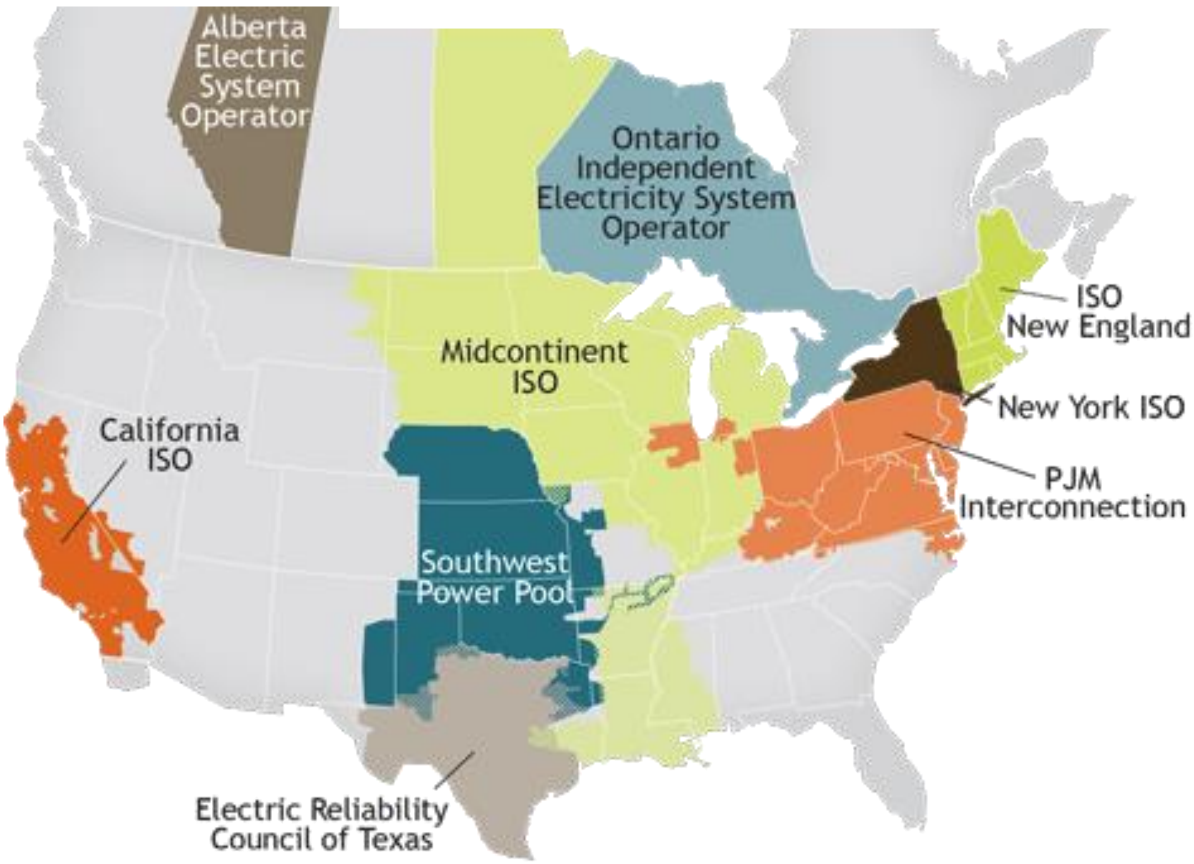
In 2007, SPP launched a real-time EIS Market, comprised of participants that agreed to operate under the SPP Tariff and Market Protocols. The market does not include all SPP members, only those that have agreed to the above terms and provisions. The Market Participants' respective areas collectively form the EIS Market footprint. Unless otherwise stated, the EIS Market footprint is used for the exhibits in this report.

EIS Market ended on February 28, 2014 and the Integrated Marketplace started on March 1, 2014. The EIS Market was a real time nodal market with security constrained dispatch. The Integrated Marketplace is a full Day-Ahead Market with Transmission Congestion Rights and virtual trading, a Reliability Unit Commitment process, a Real-Time Balancing Market, and a price-based Operating Reserves market.

SPP Location

SPP is located in the southwest 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) and the SERC Reliability Corporation (SERC). Figure I.1 shows the operating regions of the nine ISOs and RTOs in the United States and Canada.

Figure I.1 ISO RTO Operating Regions

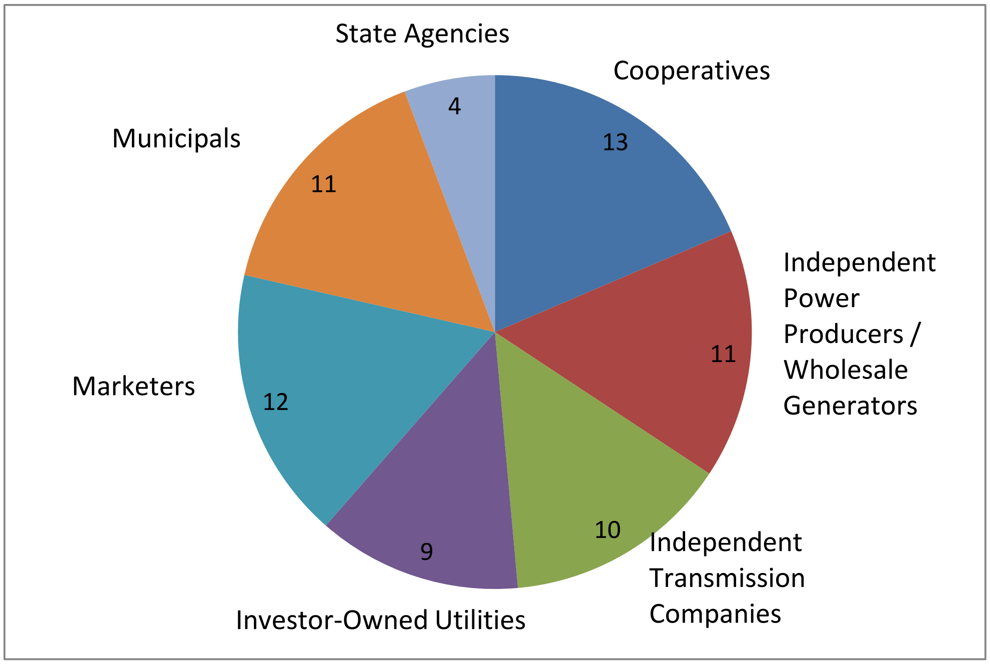


Source: ISO/RTO Council

SPP Membership

At the end of 2013, SPP had 70 members in nine states that serve load, provide generation, and own or use transmission facilities. SPP members include cooperatives, municipals, state agencies, independent transmission companies, investor-owned utilities, independent power producers, and power marketers. For a list of all SPP members, visit SPP.org/About/Members.

Figure I.2 Members as of December 31, 2013

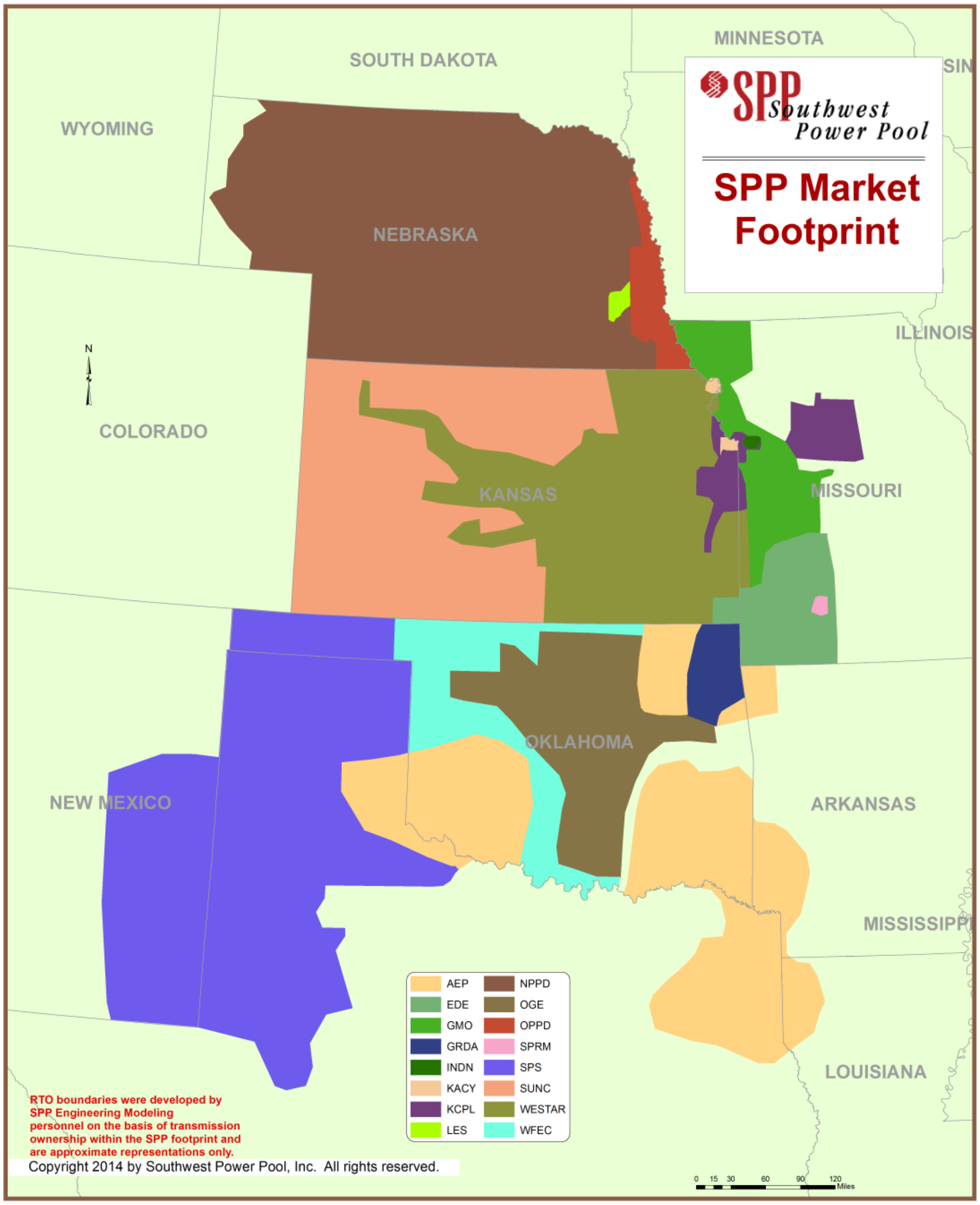


Note: SPP Reliability Footprint

SPP Balancing Authorities

The SPP EIS market footprint is comprised of 16 Balancing Authorities, which are operated by investor-owned utilities, cooperatives, municipals, and state agencies. A Balancing Authority is responsible for managing the minute-to-minute supply and demand for electricity within a specific territory. A rough graphical approximation of these Balancing Authorities is depicted in Figure I.3.

Figure I.3 Map of SPP Balancing Authorities



B. Capacity in SPP

Installed Capacity

Figure I.4 depicts the EIS Market installed generating capacity[1] by Balancing Authorities at the peak load day for 2013. The peak day was chosen because capacity is most relevant when load is at its highest. Total generating capacity in the SPP EIS Market region was 74,390 MW, a 4.6% increase over 2012.

Figure I.4 Installed Generation Capacity by Balancing Authority for 2013

Balancing Authority		Capacity (MW)	Capacity (%)
AEP	American Electric Power West (CSWS)	17,573	24%
OGE	OG&E Electric Services	10,795	15%
SPS	Southwestern Public Service	9,345	13%
WR	Westar Energy	9,270	12%
KCPL	Kansas City Power and Light	6,577	9%
NPPD	Nebraska Public Power District	4,214	6%
OPPD	Omaha Public Power District	3,806	5%
GMOC	KCP&L Greater Missouri Operations	2,934	4%
EDE	Empire District Electric	2,141	3%
WFEC	Western Farmers Electric Cooperatives	1,893	3%
GRDA	Grand River Dam Authority	1,465	2%
SUNC	Sunflower Electric Power	1,456	2%
SPRM	City Utilities of Springfield	1,057	1%
LES	Lincoln Electric System	757	1%
KACY	Kansas City Board of Public Utilities	711	1%
INDN	Independence Power and Light	396	1%
Total		**74,390**	

Note: Capacity is based on name plate rating

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 name plate rating. In 2013[2], the SPP resource margin was 47%, as shown in Figure I.5, which was nearly 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 I.5 are lower than the value shown in Figure I.4. Higher capacity

[1] Installed capacity is calculated as the sum of nameplate rating of all the resources registered in the SPP EIS Market.

[2] Figure I.5 differs from figure I.4 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.

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 I.5 Resource Margin by Year for 2008 – 2013

Year	Capacity (MW)	Peak Load	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%

Capacity Additions in 2013

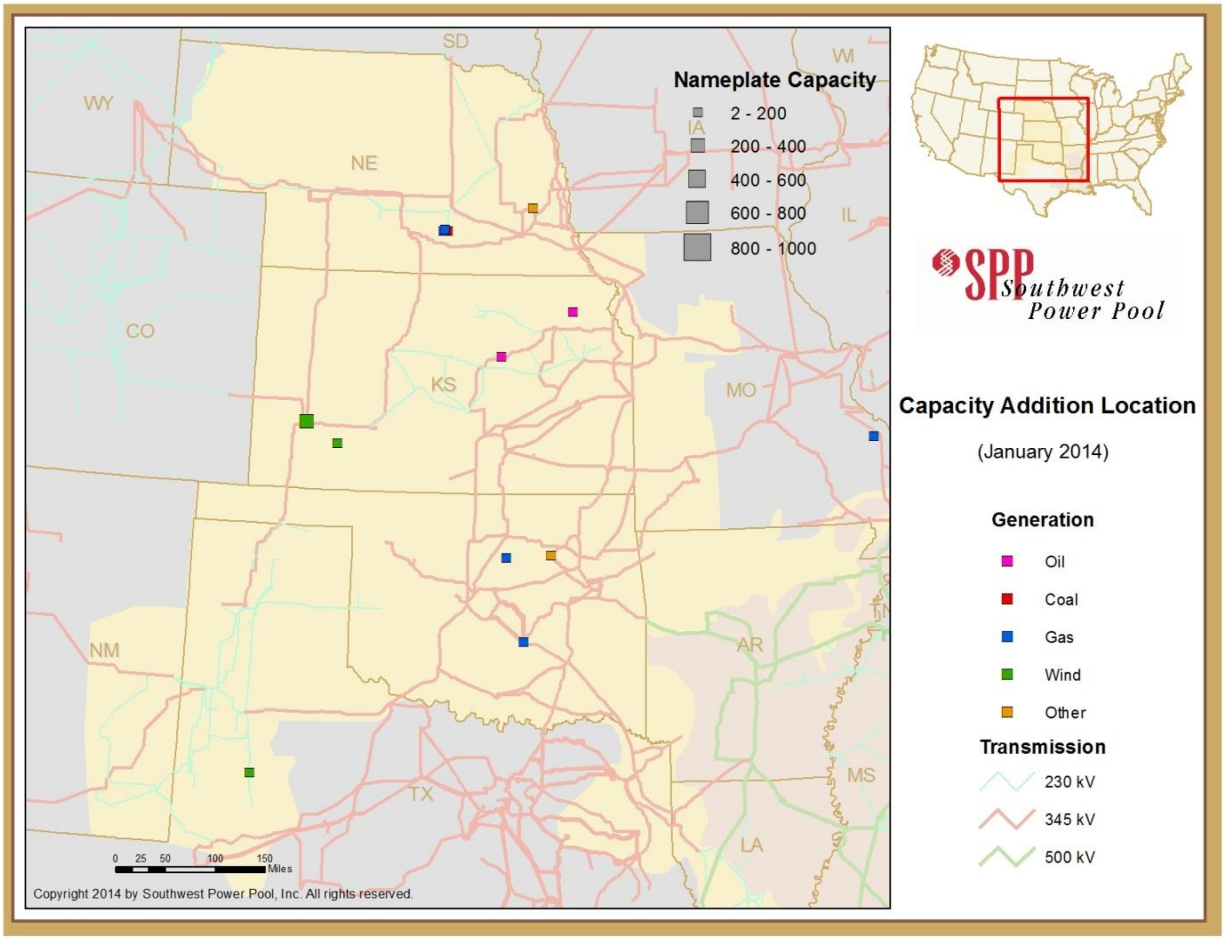
Figure I.6 shows the total amount of installed capacity by fuel type that was added to the SPP market in 2013. These additions came from two sources: generation from new Market Participants and the construction of new generation by the existing members. Most of the capacity increase was small coal and gas units that were previously behind the meter and are now registered market resources. New capacity from wind was 648 MW, significantly less than the 3,091 MW additions in 2012. SPP also had 564 MW of capacity retirement during 2013, most of which was small coal and gas units. For reporting purposes, capacity additions were counted at the end of the calendar year.

Figure I.6 Capacity Additions by Fuel Type for 2013

Fuel Type	Capacity Addition MW
Coal	407
Gas	716
Oil	12
Wind	648
Other	8
Total	1,791

Figure I.7 shows the location, fuel type, and relative size of the resources that registered in the market during 2013. The largest single resource addition (250 MW) was a wind farm in western Kansas.

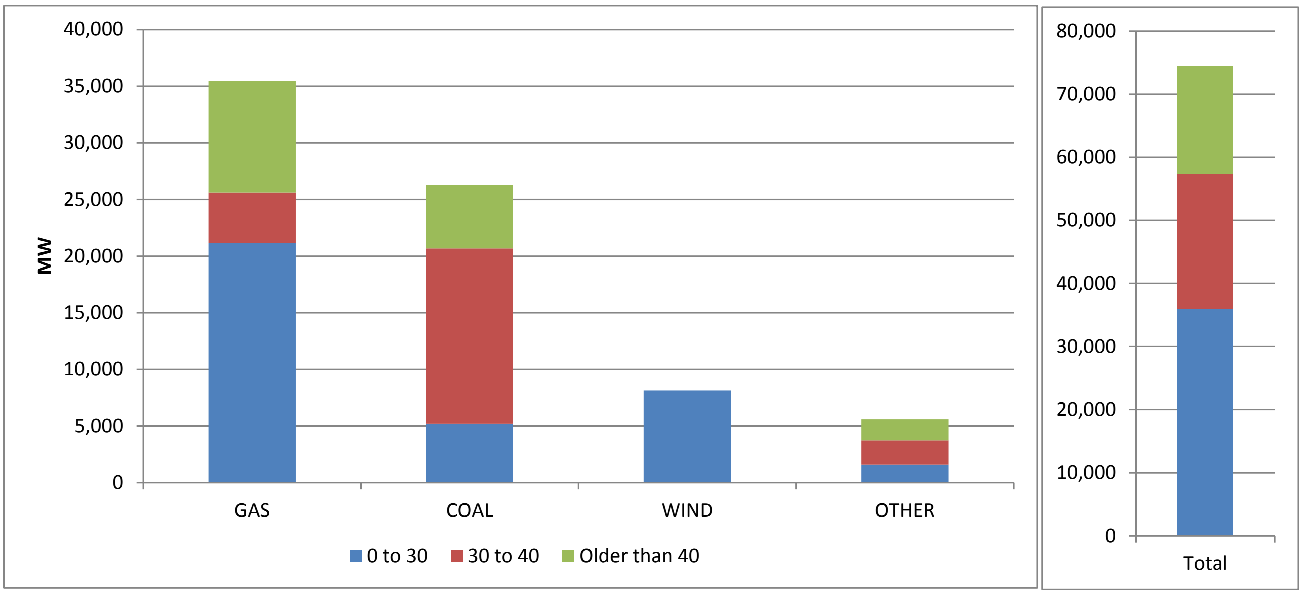
Figure I.7 Capacity Additions Detail



Capacity by Age

Figure I.8 illustrates that, overall, SPP has an aging generation fleet. About 50% of SPP's fleet is over 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. A number of coal generation units have been or could be retrofitted with emission controls to comply with EPA regulations. Investments like this sometimes include efficiency improvements which could significantly extend the economic useful life of the plants well beyond the normal retirement point.

Figure I.8 Capacity by Age of Resource



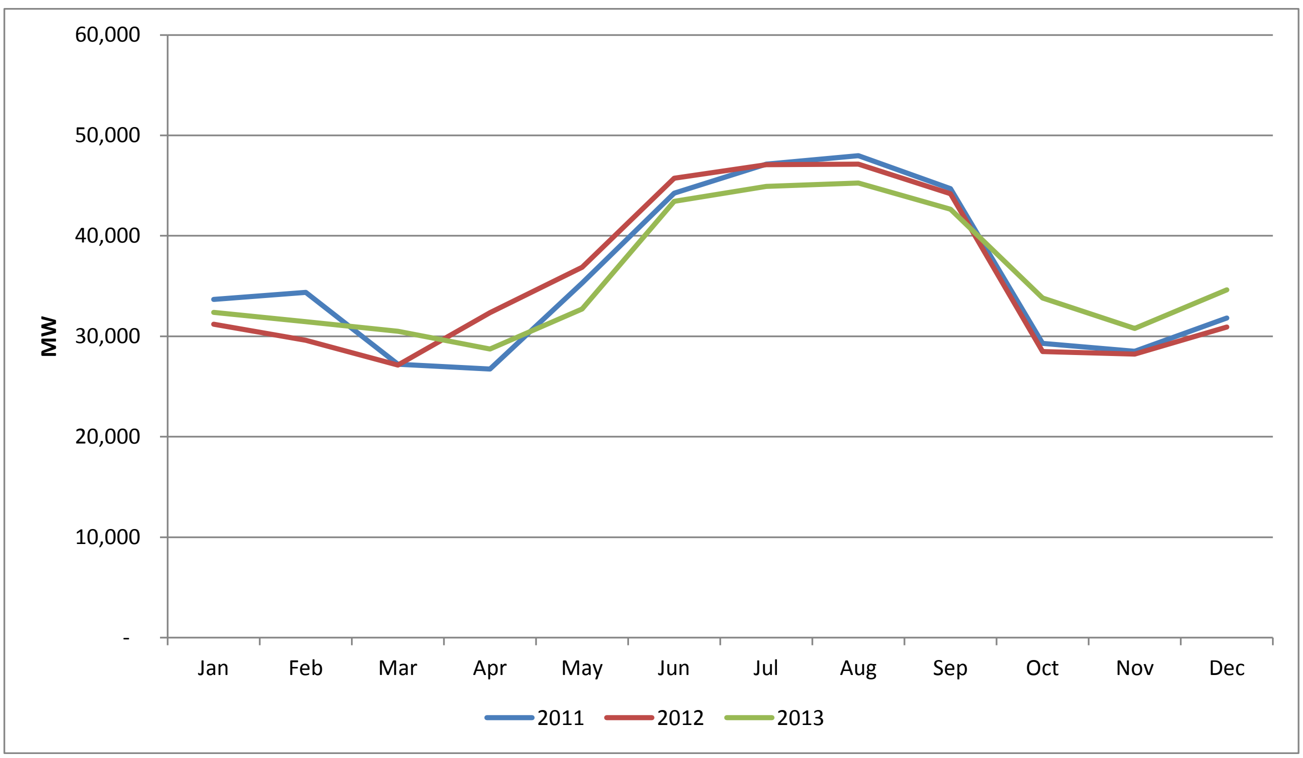
C. Electricity Demand and Energy in SPP

The SPP EIS Market is comprised of Market Participants who 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, there have been only minor changes in SPP's market footprint. The peak value reviewed in this section is described as coincident peak, representing total dispatch across all balancing authorities 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.

System Peak Demand

The SPP system coincident peak demand in 2013 was 45,256 MW on August 30, a decrease of approximately 4% from 2012. Figure I.9 shows a month-by-month comparison of monthly peak day demand for the last three years. Summer monthly peaks in 2013 were lower than in 2012 but peaks in the fourth quarter were higher than 2012. SPP load factor in 2013 was 58.2%, an increase from 55.2% in 2012. The load factor increase was driven by both a lower peak demand and a slight increase in energy.

Figure I.9 Monthly Peak Electric Energy Demand for 2011 – 2013



Market Participant Demand and Energy for Load

Figure I.10 depicts 2013 total energy consumption, the percent of energy consumption attributable to a Market Participant, and Market Participants' peak loads. 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.

Figure I.10 Market Participant Energy Usage

Market Participant Name	2013 Energy Consumed (GWh)	2013 Percent of System Total	2012 Energy Consumed (GWh)	2012 Percent of System Total
AMERICAN ELECTRIC POWER	43,828	19.0%	43,322	19.0%
OKLAHOMA GAS AND ELECTRIC	29,965	13.0%	29,685	13.0%
SOUTHWESTERN PUBLIC SERVICE COMPANY	27,202	11.8%	27,577	12.1%
WESTAR ENERGY	24,187	10.5%	24,876	10.9%
KANSAS CITY POWER AND LIGHT, CO	16,048	7.0%	16,298	7.1%
THE ENERGY AUTHORITY, NPPD	13,923	6.0%	14,407	6.3%
OMAHA PUBLIC POWER DISTRICT	12,249	5.3%	12,153	5.3%
KANSAS CITY POWER & LIGHT GMOC	8,841	3.8%	8,746	3.8%
WESTERN FARMERS ELECTRIC COOPERATIVE	8,632	3.7%	7,991	3.5%
GOLDEN SPREAD ELECTRIC COOPERATIVE INC.	5,944	2.6%	5,085	2.2%
SUNFLOWER ELECTRIC POWER CORPORATION	5,631	2.4%	5,572	2.4%
EMPIRE DISTRICT ELECTRIC CO., THE	5,306	2.3%	5,219	2.3%
GRAND RIVER DAM AUTHORITY	4,925	2.1%	4,808	2.1%
ARKANSAS ELECTRIC COOPERATIVE CORPORATION	3,571	1.5%	3,645	1.6%
LINCOLN ELECTRIC SYSTEM MARKETING	3,532	1.5%	3,483	1.5%
THE ENERGY AUTHORITY, CU	3,314	1.4%	3,352	1.5%
OKLAHOMA MUNICIPAL POWER AUTHORITY	2,529	1.1%	2,656	1.2%
KANSAS CITY BOARD OF PUBLIC UTILITIES	2,426	1.1%	2,465	1.1%
KANSAS POWER POOL	2,011	0.9%	2,137	0.9%
MIDWEST ENERGY INC.	1,547	0.7%	1,545	0.7%
TENASKA POWER SERVICE CO.	1,125	0.5%	94	0.0%
MISSOURI JOINT MUNICIPAL ELECTRICAL UTILITY COMMISSION	1,067	0.5%		
CITY OF INDEPENDENCE	1,066	0.5%	1,119	0.5%
MUNICIPAL ENERGY AGENCY OF NEBRASKA	807	0.3%	761	0.3%
BASIN ELECTRIC POWER COOPERATIVE	797	0.3%	958	0.4%
KANSAS MUNICIPAL ENERGY AGENCY	373	0.2%	18	0.0%
CITY OF CHANUTE	32	0.0%		
System Total	**230,879**		**227,972**	

SPP System Demand and Energy

Figure I.11 shows the monthly system energy consumption. Total SPP system energy consumption in 2013 increased slightly from 2012. Although summer consumption was not as high as 2012, the majority of the remaining months had higher load.

Figure I.11 Monthly System Energy Consumption for 2011 – 2013

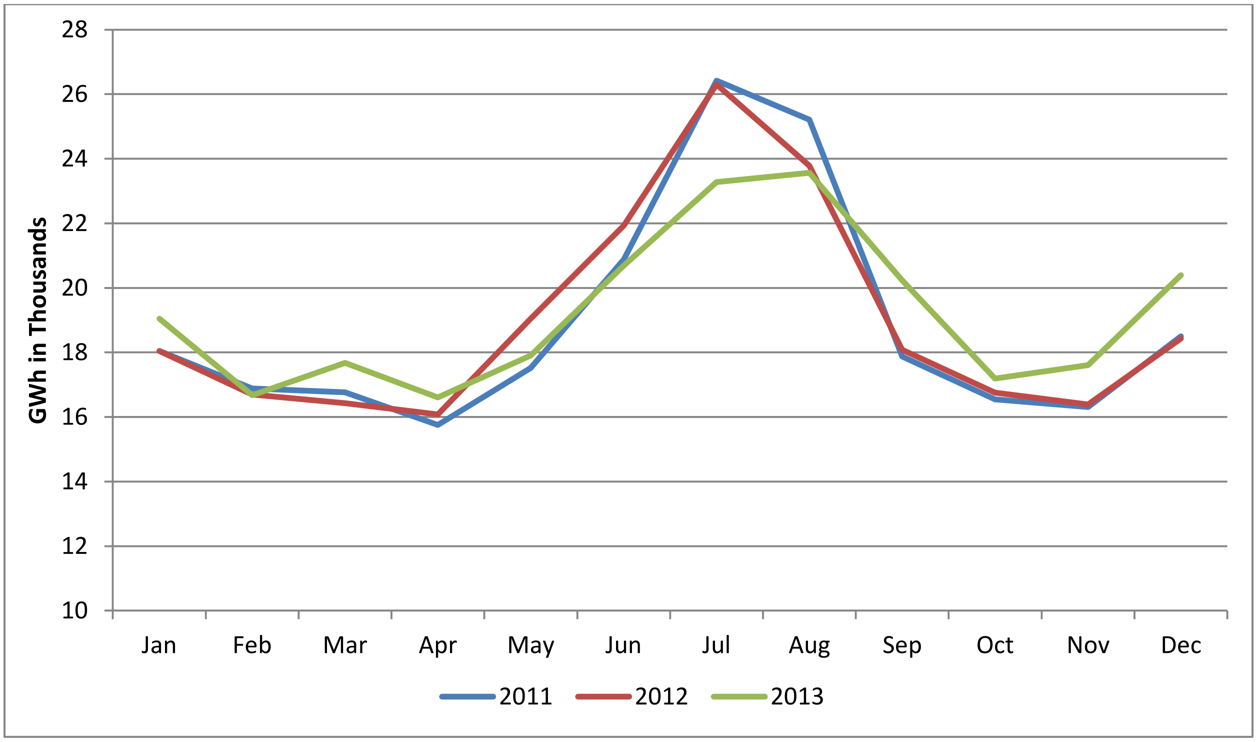


Figure I.12 presents the average minimum and maximum daily demand for each month for 2011 through 2013. Minimum and maximum daily peak values for 2013 were both higher than in 2012. The difference between the minimum and maximum daily demand decreased by 5% from 2012 to 2013.

The highest daily spread between minimum and maximum load was 14,956 MW, which occurred in August. This is expected because of the high demand during the summer season driven by the daily cyclical pattern of air conditioning load.

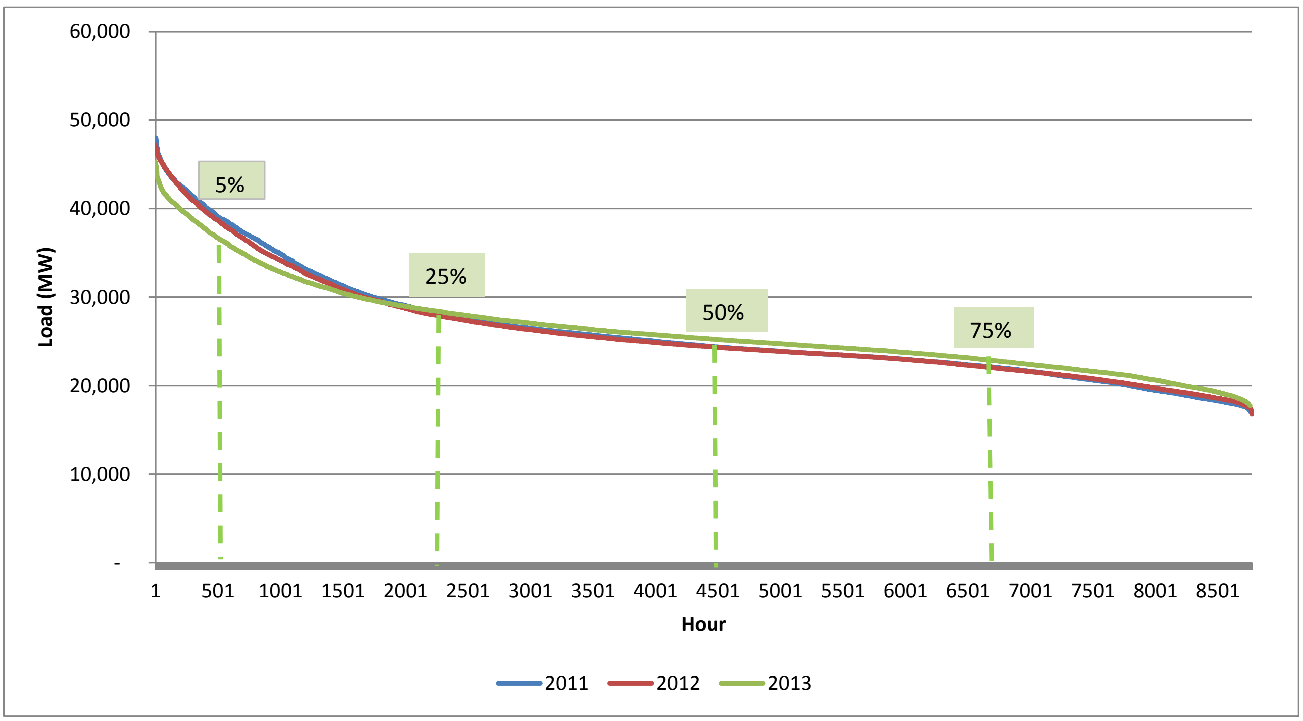
Figure I.12 Daily Minimum and Maximum Electric Energy Demand

Load Duration Curve

Figure I.13 depicts load duration curves for 2011 to 2013. 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 2013 the total system peak load hour was 45,256 MW and the minimum was 17,729 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 slight increase of load in 2013 for the lower 75% load levels. The one difference to note is lower peak loads for 2013 compared to 2011 and 2012. This implies a different weather pattern during the summer peak period which is covered in the next section.

Figure I.13 Electric Load Duration Curve for 2011 – 2013



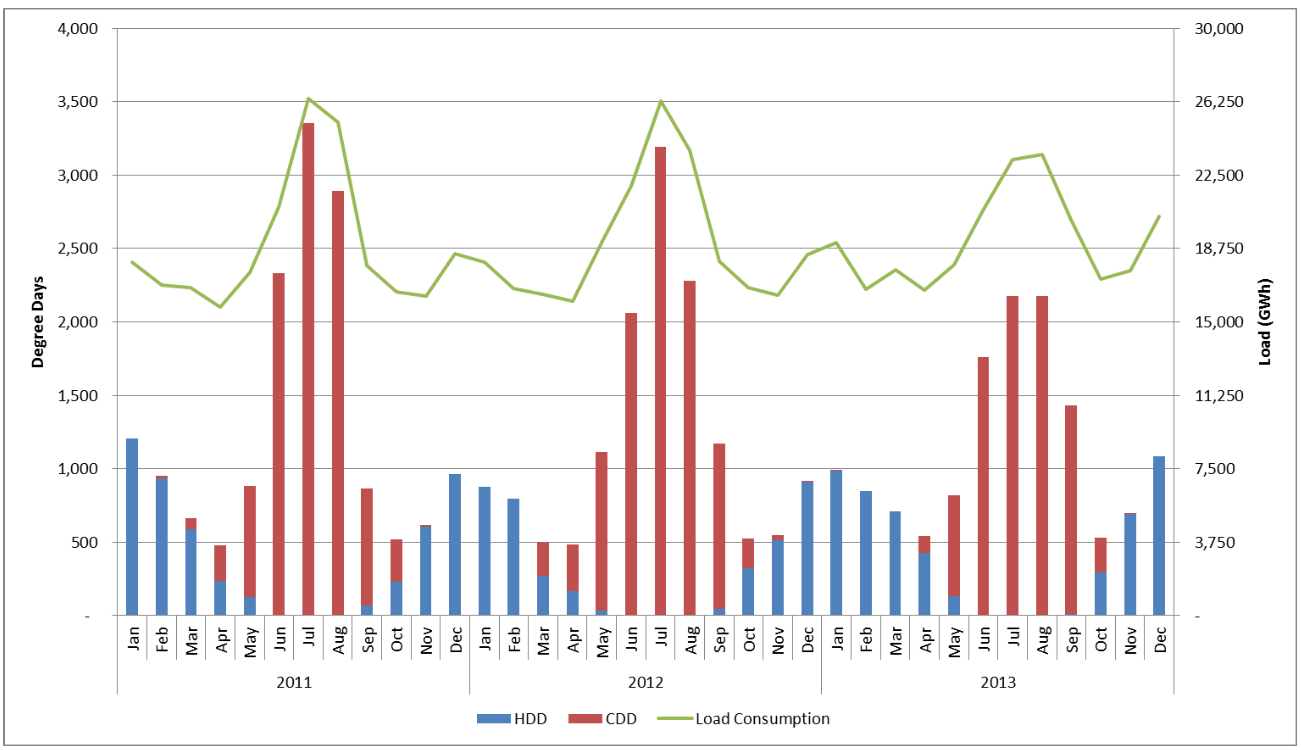
Heating and Cooling Degree Days

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.

In order to determine HDD and CDD for SPP, five representative locations[3] in the SPP market were chosen to calculate system daily average temperatures[4]. 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 because of the higher saturation of electric cooling than electric heating. HDD values were adjusted to reflect load impact differences.

Figure I.14 illustrates fewer cooling degree days in 2013 than the previous two years and is reflected in the lower peak load level in 2013.

Figure I.14 Monthly Heating Degree Days and Cooling Degree Days



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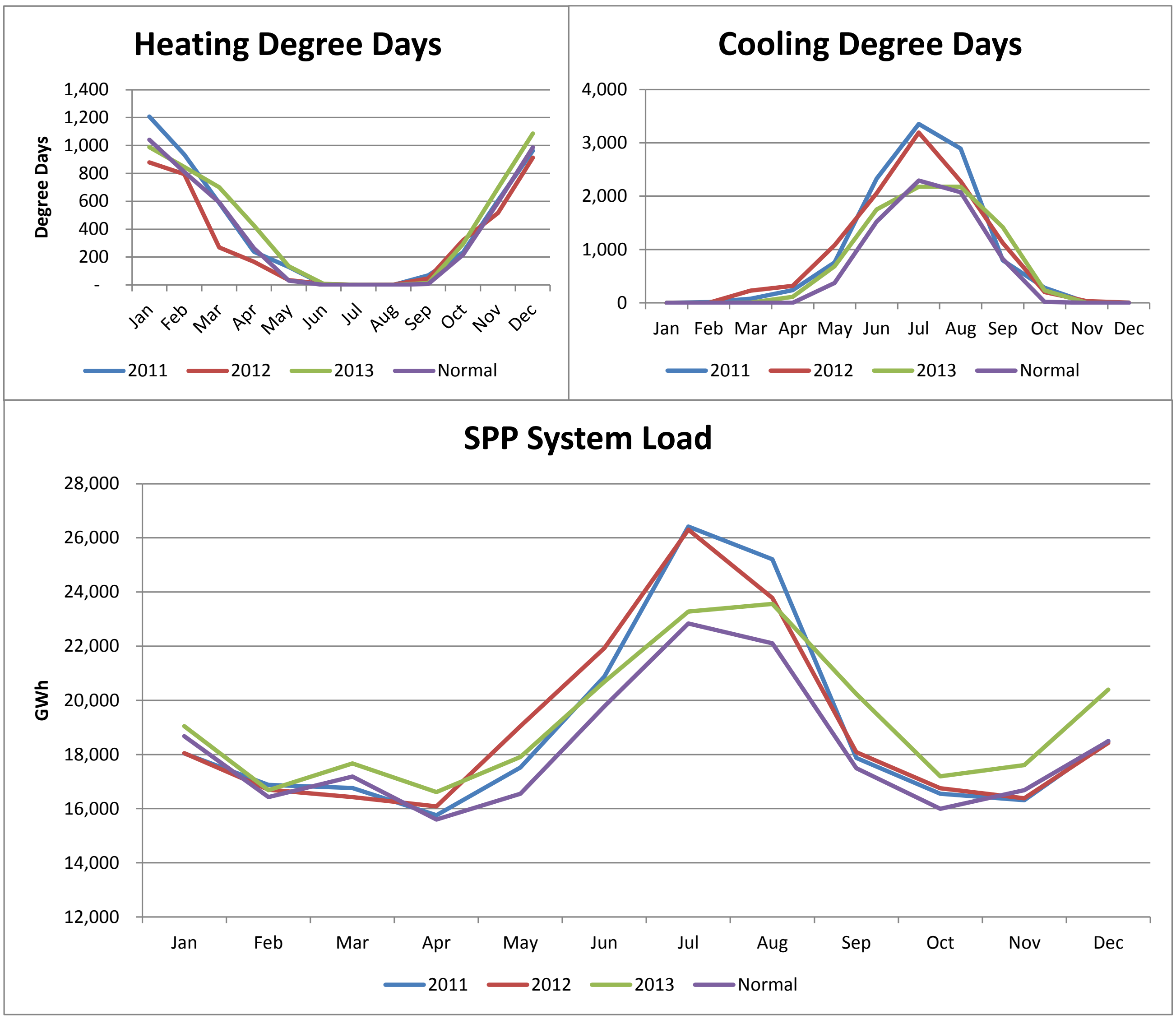
[3] Amarillo TX, Topeka KS, Oklahoma City OK, Tulsa OK and Lincoln NE.

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

Figure I.15 shows the numbers of HDD, CDD and load levels in 2011, 2012, 2013 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.

2013 was a mild summer, resulting in fewer cooling degree days. Summer temperatures in 2013 were close to that of a normal year. However, fall/winter 2013 was colder than normal and had more heating degree days than the previous two years. Therefore, load in 2013 was lower in summer months and higher in winter months than the previous two years.

Figure I.15 Yearly Degree Days and Loads Compared with a Normal Year



D. Electricity Supply in SPP

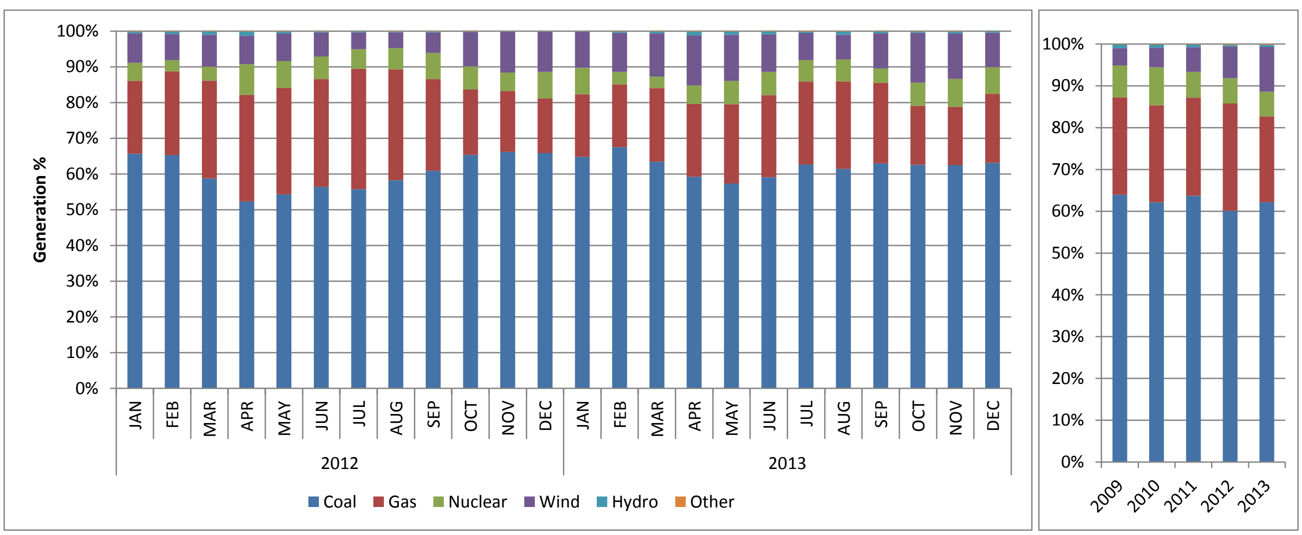
Generation by Fuel Type

An analysis of fuel types utilized in the SPP EIS Market 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 I.16 depicts 2013 generation percentage in the SPP EIS Market by fuel type[5]. Generation from gas has decreased from 26% in 2012 to 20% in 2013. The significant increase in gas prices in 2013 was a major factor in the shift away from gas generation. Coal market share increased 2% from the level in 2012 to 62% of all generation. Wind generation increased from 8% of the total generation in 2012 to 11% in 2013.

The usual seasonal fluctuations can be identified in the chart below. When loads increase above a certain level as experienced in the SPP footprint during the summer period, coal units supply a smaller percent of the higher load. This is because more coal units are running at maximum capacity thereby unable to increase generation. Gas generation, which is generally at a higher cost than coal, is then used to meet the balance of the load. This is reflected in the higher gas generation percentages in the summer months.

Figure I.16 Percent Generation by Fuel Type



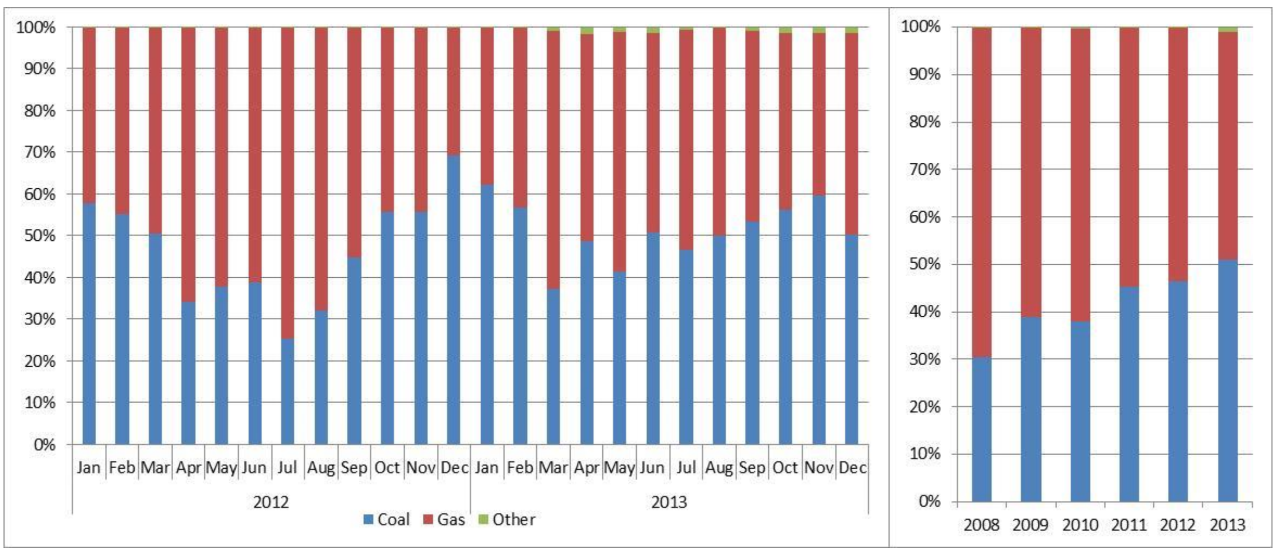
[5] "Other" category includes oil and solar.

Generation on the Margin

The system marginal price is calculated as the price of the next MW available after the total system demand was met. The LIP is the system marginal price plus any congestion charges associated with the pricing node. Figure I.17 illustrates which fuel was on the margin in SPP, thus setting market prices. For a generator to set the system marginal price, the resource must be: (a) in "available" status, (b) not at the resource plan minimum or maximum, and (c) not ramp limited.

As highlighted in Figure I.16, generation from coal-fired resources was responsible for about 62% 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 operation flexibility as compared to other fuel types such as certain gas units.

Figure I.17 Generation on the Margin



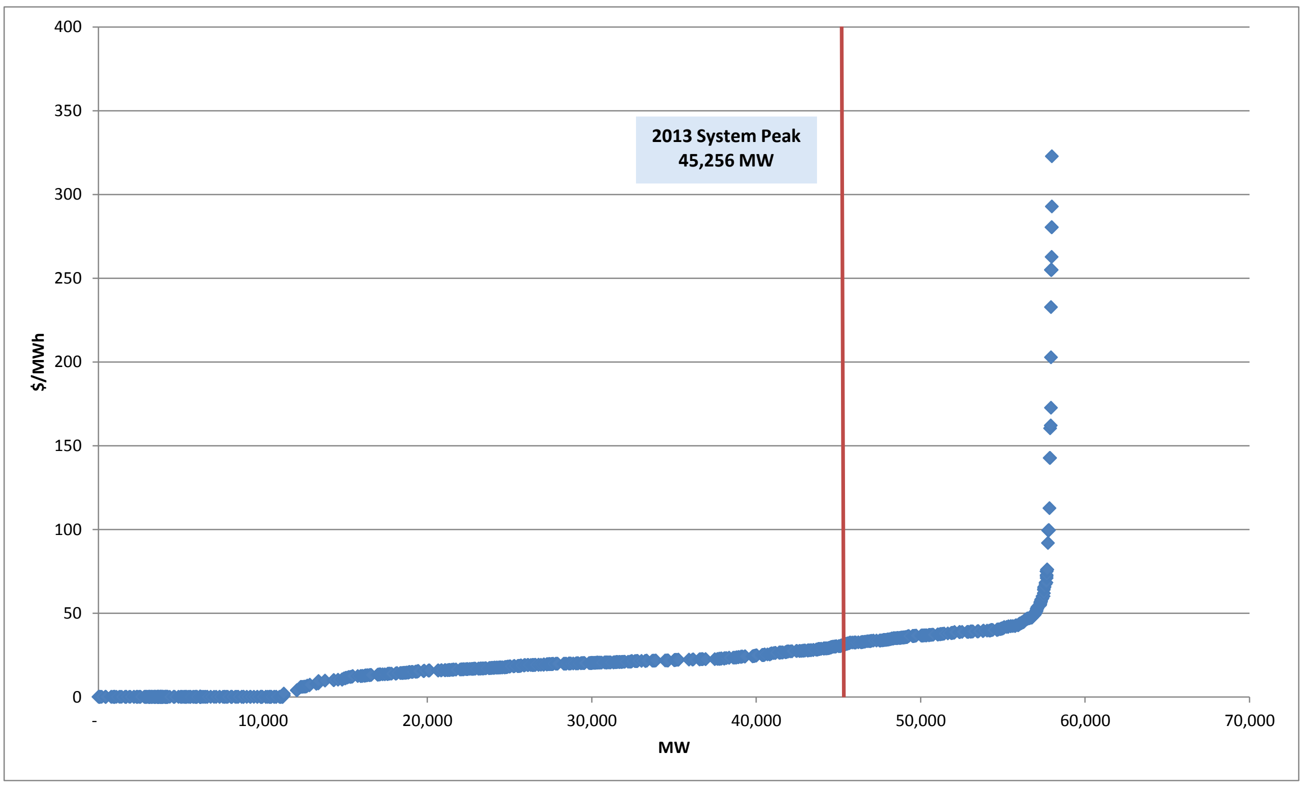
Typically, coal is on the margin more often in low load months, while gas is on the margin more often in high load months. Natural gas units in the SPP region are normally used for load following, and historically been on the margin more than coal. During 2013, percentage of natural gas on the margin has decreased by more than 5%, from 53.5% in 2012 to 48.0% in 2013. Lower summer load, higher wind generation, and higher gas prices are some of the factors causing the decrease. Coal was on the margin 51% of the time, a significant increase from the 2012 level of 46%. A notable development in 2013 was that the "Other" category set marginal prices about 1% of the time comparing to near zero level in previous years. This increase was mainly contributed by wind resources being in "available" status.

Coal on the margin has been increasing steadily over the last five years from a low of about 30% in 2009 to the current level of over 51%. There are long-term factors driving this change. Firstly, market participants have increased the flexibility of their coal plant offers reflecting their confidence in the SPP Market. Secondly, the increase in wind generation as a low cost generator is displacing the highest cost fuel which is natural gas. This moves coal up the supply curve increasing the time coal is on the margin. Wind generation has increased from about 4% of total generation in 2009 to an average of 11% in 2013.

Supply Stack at Peak Hour

The yearly peak load occurred on August 30, 2013 at hour ending 17:00. Figure I.18 compiled offers from all generation resources online during the peak hour. Online resources in a status other than "available" or "quick start" were assumed to have an offer of zero. The vertical line represents the load level in the peak hour. The market price produced by the EIS Market was $45/MWh; the supply and demand curve in the chart intersects at $31/MWh which reflects the price under the perfect conditions, such as no congestion in the system, no ramp limitation, no forced outage, and precise dispatch following.

Figure I.18 Supply Curve by Fuel during the 2013 Peak Hour

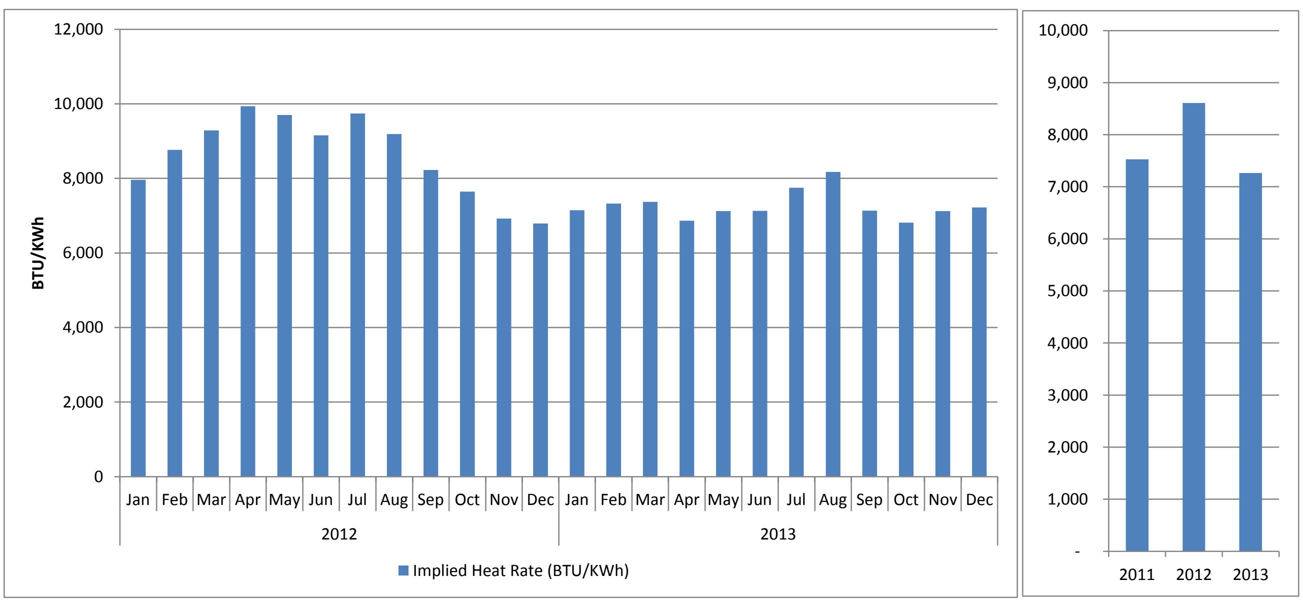


Implied Heat Rate

A useful way of assessing the relative impact of a region's scarcity pricing is to study the Implied Heat Rate. The implied heat rate is the ratio of the natural gas price to the system's electricity price. If the price of natural gas was $4.50/MMBtu, and the LIP was $40.00/MWh, the implied heat rate would be (40.00/4.5) = 8.888 MMBtu/MWh (8888 Btu/KWh). This implied heat rate shows the relative efficiency required of a generator to convert gas to electricity and cover the variable costs of production, given system prices.

Figure I.19 shows the monthly implied heat rate for 2012 and 2013. The chart shows a general decrease from 2012. The high summer rates were mainly caused by the fact that electric prices increase significantly in the summer but gas prices remain stable. Usually the more electric prices are set by coal generation, the lower the implied heat rate will be. This effect is very strong when gas and coal price differences are large and diminishes as the two prices approach parity. For systems like SPP where coal generation sets electric price as often as 47% of the time, this cross fuel impact on implied heat rate can be significant. The increase in implied heat rate in 2012 shown in the annual value of Figure I.19 is directly related to very low gas prices. With gas prices back to more normal level in 2013, implied heat rate values are more in line with historical values.

Figure I.19 Implied Heat Rate



Generation Interconnection

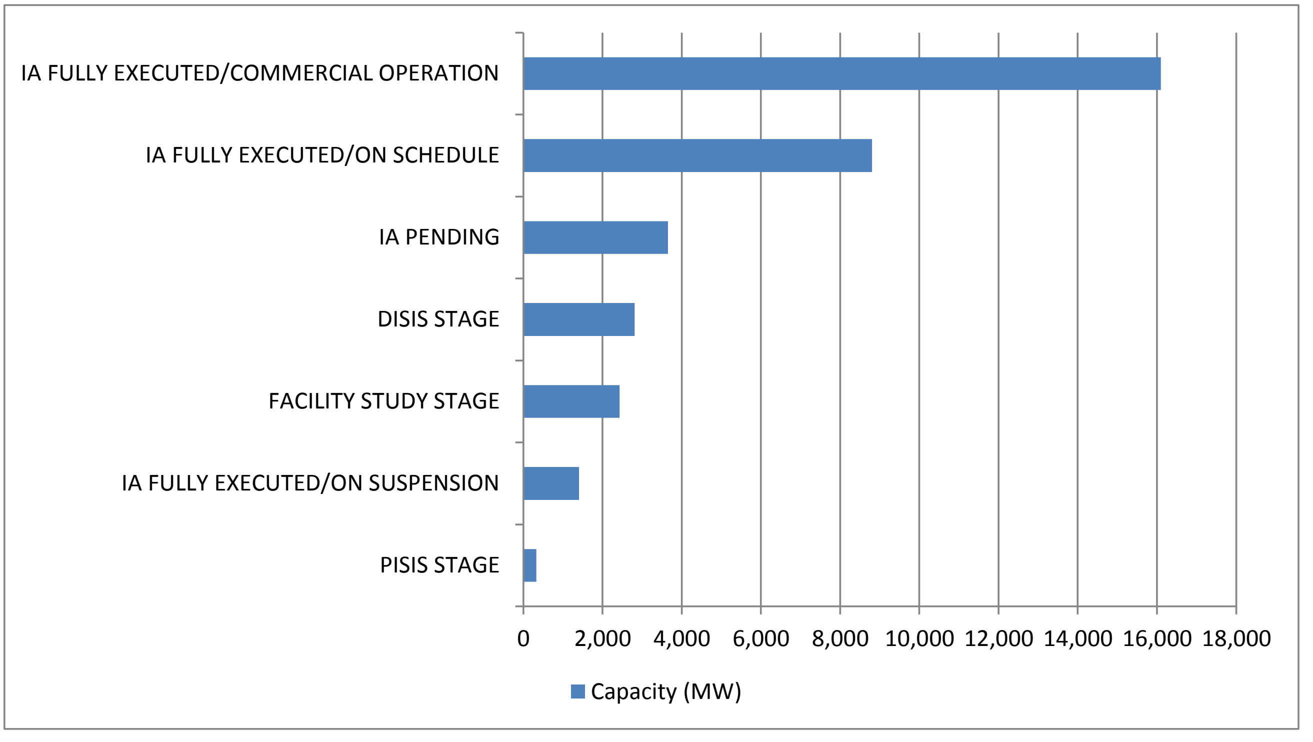
SPP is responsible for performing engineering studies to determine if the interconnection of new generation within the SPP footprint is feasible and to identify any transmission development that would be necessary to facilitate the proposed generation. Types of engineering studies include:

- Feasibility
- Preliminary Interconnection System Impact Study (PISIS)

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

The MWs of capacity included in the proposed generation interconnection requests necessitating engineering studies is displayed in Figure I.20. 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.

Figure I.20 Generation Interconnection Requests by Category (MW)



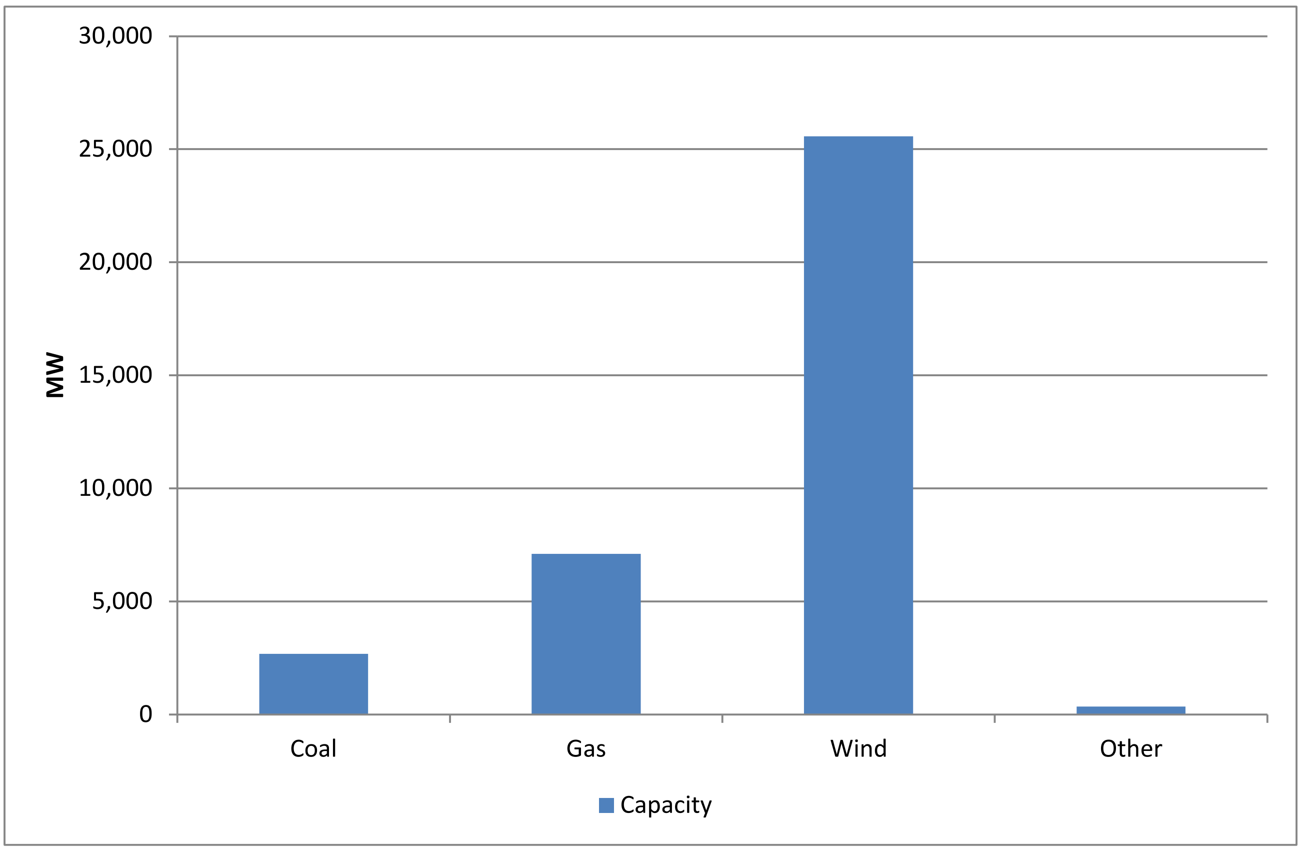
A brief description of the study types and interconnection categories is provided below.

- Feasibility Study Stage – Initial assessment of the practicality and cost involved in adding generation to the SPP transmission system.
- PISIS – More detailed analysis of the proposed interconnection with cost allocations for necessary transmission upgrades (if any)
- DISIS - More detailed analysis of the proposed interconnection with cost allocations for necessary transmission upgrades (if any), and system response modeling with updated interconnection parameters
- Facility Study Stage – Final analysis of proposed interconnection including detailed cost planning data, complete analysis of system integration impacts highlighting necessary upgrades.
- Interconnection Agreement (IA) Pending – The Customer, SPP and the Transmission Operator are in the process of negotiating aspects of the Generation Interconnection Agreement

- Interconnection Agreement Fully Executed/On Schedule – A generation interconnection agreement has been executed and the construction of the facility as outlined in the agreement is under way
- Interconnection Agreement Fully Executed/On Suspension - A generation interconnection agreement has been executed and the construction of the facility as outlined in the agreement has been suspended

Sorting requests in the generation interconnection queue by fuel type and summing the capacity yields Figure I.21. As can be seen in the figure, wind accounts for the vast majority of proposed generation interconnection, over 25,000 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 I.21 Generation Interconnection Requests by Fuel Type (MW)



E. Growing Impact of Wind on SPP System

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 over the last five years. The wind speed map below shows an abundance of locations with a high potential for wind development in SPP. In 2012, SPP saw an influx of wind resources due to the expected expiration of that federal tax credits at the end of the year. However, congress extended the wind energy tax credit in early 2013. SPP continues to see an increase of wind capacity but at a slower pace.

Figure I.22 US Wind Speed Map

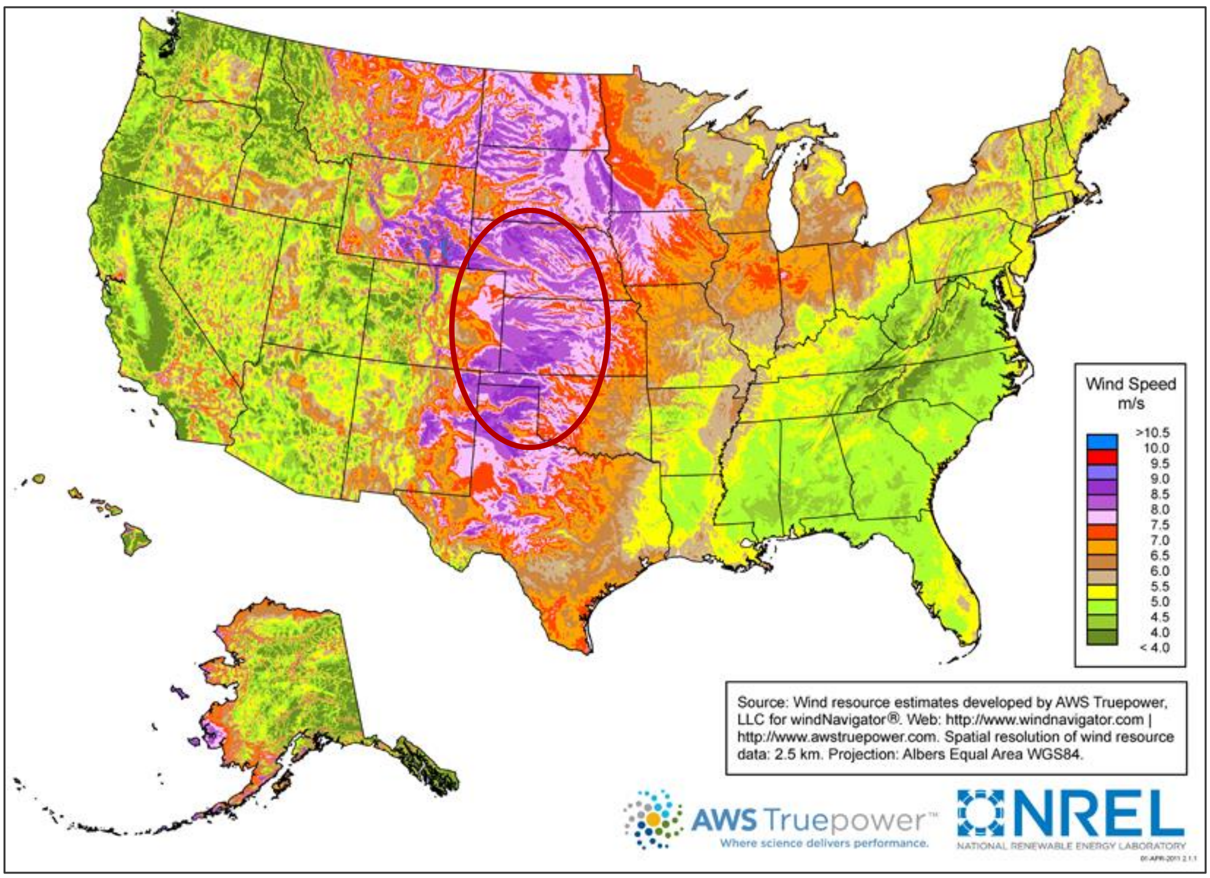
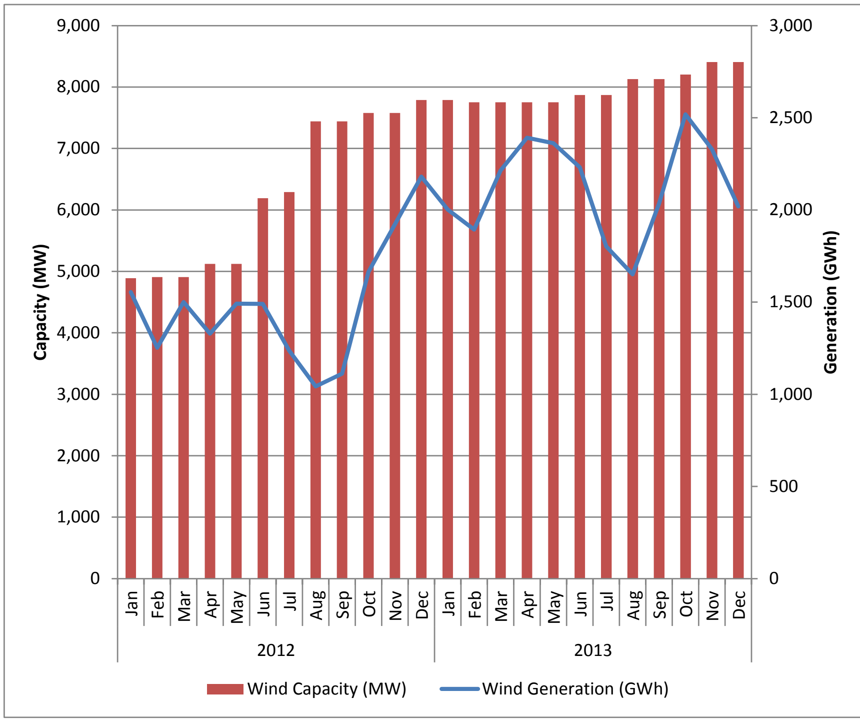


Figure I.23 depicts monthly capacity and total generation from wind facilities for the previous two years and annual values for the last five years. Total registered wind capacity at the end of 2013 was 8,405 MW, an 8% increase from 2012. Wind generation continues to increase but lags capacity added because capacity values are based on the resource registration date, which may precede actual unit startup by several months. Wind generation fluctuates seasonally, where summer is usually the low wind season and spring and fall are the high wind seasons.

Figure I.23 Wind Capacity and Generation



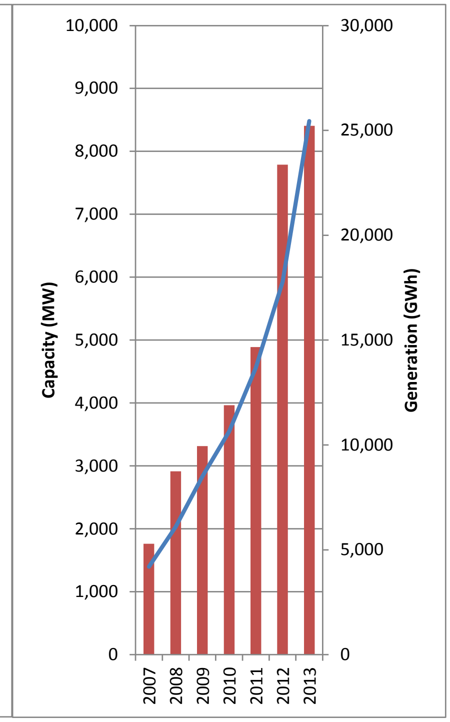
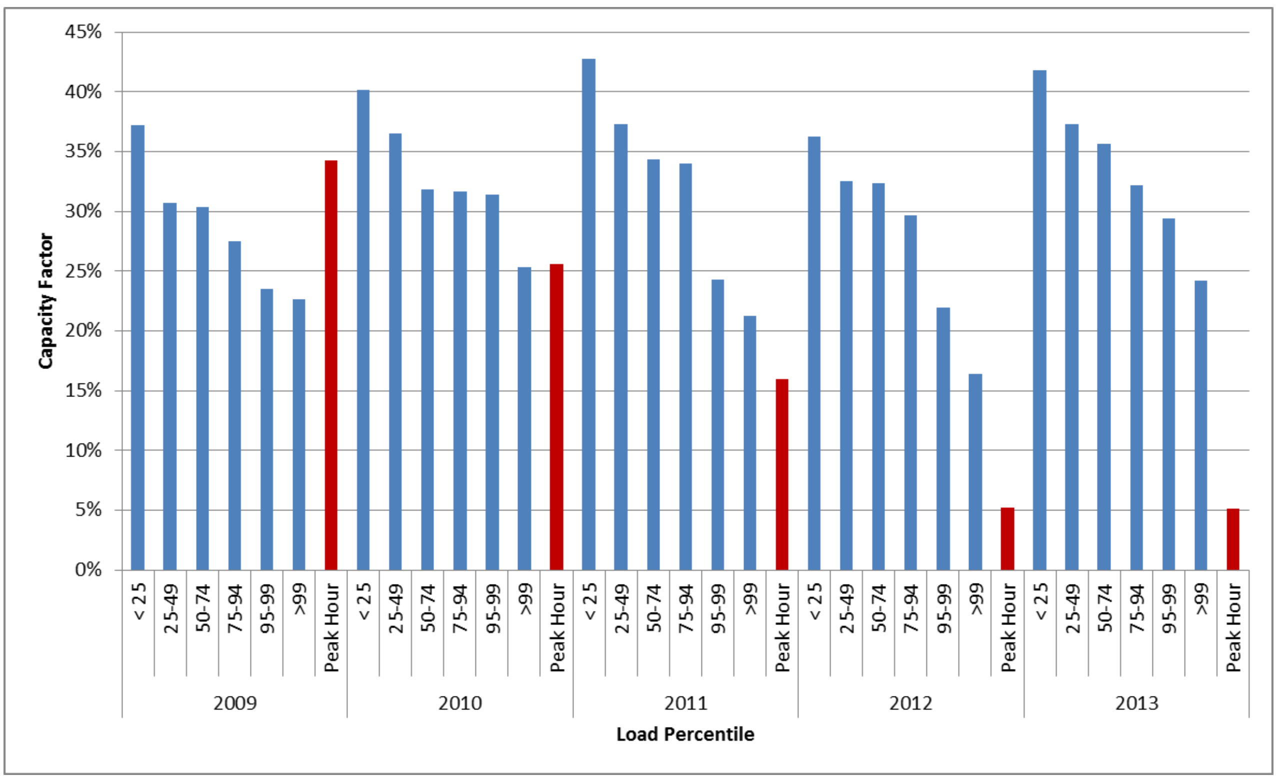


Figure I.24 compares the wind capacity factor to load percentiles. Capacity factor is a ratio of the actual to potential output of generators over a period of time. The potential output is assumed to be the maximum at full nameplate capacity for the entire time period in question. SPP area is similar to most US regions in that there is an inverse relationship between wind production and load. Generally, as load increases wind production decreases. This counter-cyclical pattern results from wind production patterns where the highest production is during fall and spring periods and during the night time periods. Both times are when electricity demand is generally low.

The five years shown in the graphic below illustrate the wind to load relationship for the SPP market. The peak hour values across years vary significantly because the sample size for each year is only one. All the other periods contain a larger sample size thereby showing a more consistent value across time. The very different values of 5% for the 2013 peak hour and 25% for 2010 do illustrate the high variability of wind production.

Figure I.24 Wind Capacity Factor Compared to Load Percentiles 2009 – 2013



Wind Impact on the System

Wind generation increased from 8% of the total generation in 2012 to 11% in 2013. The highest level of wind generation, 6,467 MW, occurred in the market footprint on October 10, 2013. Wind as a percent of load reached a maximum value of 33.4% on April 6. This magnitude of wind is causing operational issues with regard to managing transmission congestion and resolution of ramp constraints. Figure I.25 shows the annual average and the hourly maximum wind generation as a percent of load for the last seven years illustrating a dramatic increase since the start of the EIS Market in 2007.

In 2013 wind units were the generation source for up to 33% of total load in the EIS Market. Because of the high volatility and limited controllability of wind generation, levels this high have a comparable impact on system as all of load. This is because wind is three times more volatile than load.

Figure I.25 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%

Figure I.26 shows duration curves which represent wind generation as a percent of load for years 2012 and 2013. The significant shift up in the curve for 2013 shows wind's increasing contribution to serving load all year long.

Figure I.26 Duration Curve by Interval - Wind as a Percent of Load

Wind Integration

There are a number of issues in dealing with substantial wind capacity. One is managing the impact of production volatility. Wind energy output varies by season and by 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. All these factors create challenges for grid operators to balance total generation to total load and to manage congestion.

In 2013 SPP Operations focused on implementing processes and procedures to automate curtailment of Non-Dispatchable Resources (NDR) for the EIS Market. Substantial effort was also placed on developing processes and procedures for managing Dispatchable Variable Energy Resources (DVER) and Non-Dispatchable Variable Energy Resources (NDVER) in the SPP Integrated Marketplace.

Protocol revisions PRR240/242 were implemented in March 2013 which allowed for a more systematic approach to curtailment of a subset of NDRs based on impacts and transmission service priority. NDRs that have an interconnection agreement executed on or prior to May 21, 2011 and operated commercially prior to October 15, 2012 were exempt from this curtailment process though still subject to manual directives. These dates are in line with those used in the Integrated Marketplace. This implementation provided a more systematic approach to NDR curtailments and maintaining transmission rights of the resource though it was still not part of the economic solution. The solution for curtailment of DVERs in the Integrated Marketplace appear to be more effective though NDVER curtailments (OOME) will still require SPP Operations to make decisions that are outside the economic solution.

The increase in transmission capability serving wind producing regions starting in 2014 will help address concerns related to high wind production. This increased capability will directly reduce localized congestion creating a more integrated system with higher diversity and greater flexibility in managing high levels of wind production.

II. EIS Market Performance

A. EIS Market Overview

The SPP EIS Market began operating on February 1, 2007, and settles real-time imbalances between generation and load. The EIS Market is comprised of participants that have agreed to operate under the SPP Tariff, Market Protocols, and other governing documents. There are 16 Balancing Authorities and 48 Market Participants in the Market footprint. A list of all SPP Market Participants is found at SPP.org>About>Fast Facts>Footprints. Unless otherwise stated, the SPP EIS Market footprint is the reference area for this report.

B. Market Sales and Purchases

A sale in the EIS Market is made when either a resource generates more than was scheduled, or a load consumes less than was scheduled. A purchase is made when a resource generates less than was scheduled or a load consumes more than what was scheduled. Figure II.1 and Figure II.2 show the total volume of EIS sales and purchases that occurred in the SPP region in 2012 and 2013. These figures show that Market Participants sold and purchased less MWh in the EIS Market in 2013 compared to 2012. Market Participants sold and purchased approximately 26.6 million MWh in 2013 versus 27.1 million in 2012. An important aspect of pricing information is that the total magnitude of dollars for purchases and sales is driven by the marginal cost of energy in the SPP region and the volume of energy, MWh. As the price of energy changes so does the EIS total cost of energy. Because of this relationship, a change in dollars received by Market Participants may not reflect any actual increase or decrease in overall market activity, but instead may reflect a change in the market price in the SPP area.

During 2013, SPP market participants received approximately $675 million for sales from the EIS Market and paid approximately $676 million for purchases (Figure II.2). These numbers were higher than the market settlement values in 2012. Less MWh were sold and purchased in the Market though more money was settled through the Market. This higher dollar value reflects the higher market prices in 2013 primarily the results of higher natural gas prices.

Figure II.1 Electricity Sales in the EIS Market by Month for 2012– 2013

	2012		2013	
Month	MWh Sold by Market Participants (in Millions)	Dollars Received by Market Participants (in millions)	MWh Sold by Market Participants (in millions)	Dollars Received by Market Participants (in millions)
Jan	2.22	45.63	2.20	50.34
Feb	2.00	42.10	1.83	42.35
Mar	2.39	45.87	1.91	49.50
Apr	2.12	41.47	2.08	59.51
May	2.10	45.67	2.12	56.39
Jun	2.36	50.03	2.65	65.41
Jul	2.58	68.33	2.55	67.74
Aug	2.59	64.06	2.60	68.22
Sep	2.15	46.62	2.31	56.29
Oct	2.04	48.15	1.99	45.45
Nov	2.11	48.90	2.03	46.48
Dec	2.35	50.25	2.32	67.37
Total	**27.02**	**597.07**	**26.60**	**675.05**

Figure II.2 Electricity Purchases in the EIS Market by Month for 2012 – 2013

	2012		2013	
Month	MWh Purchased by Market Participants (in millions)	Dollars Received by Market Participants (in millions)	MWh Purchased by Market Participants (in millions)	Dollars Received by Market Participants (in millions)
Jan	2.22	46.62	2.18	49.32
Feb	2.02	42.61	1.83	42.89
Mar	2.41	46.42	1.91	50.38
Apr	2.18	41.88	2.10	59.05
May	2.11	45.32	2.12	57.21
Jun	2.37	50.25	2.63	65.14
Jul	2.57	68.85	2.54	66.64
Aug	2.58	64.30	2.59	66.61
Sep	2.12	47.22	2.33	56.65
Oct	2.04	46.88	2.01	47.48
Nov	2.14	49.23	2.04	47.58
Dec	2.35	50.34	2.29	67.05
Total	**27.11**	**599.93**	**26.57**	**676.02**

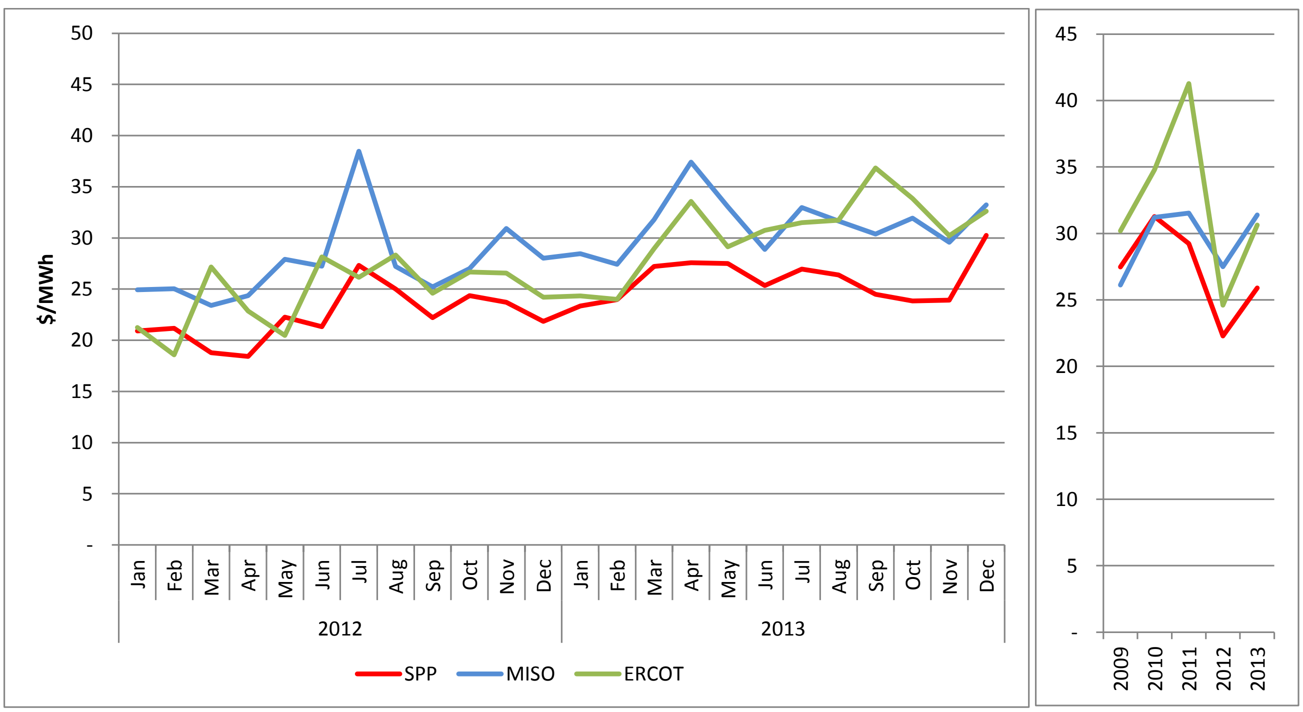
C. Market Prices

Regional Price Comparison

A useful measure of basic market competitiveness is the comparison of prices between SPP and its neighboring regions. If prices in neighboring regions are generally in line with prices in the SPP region, then basic market operations are yielding similar results. It is not realistic to expect prices to be identical across the regions, as market structures vary, resource fleet technologies and fuel mixes are different, and fuel supply costs are dissimilar. For this review, SPP prices are compared to prices in MISO and ERCOT, the two electric wholesale markets adjacent to SPP.

Figure II.3 shows 2013 monthly and yearly system average prices for SPP, MISO and ERCOT. In general, the SPP monthly system prices were lower than other regions[6] for the last three years. Some of the drivers for the low EIS Market prices include relative proximity to inexpensive Powder River Basin coal, substantial low cost capacity consisting of coal, wind, and nuclear, and a high reserve margin.

Figure II.3 Regional Monthly and Yearly Prices Comparison



Another useful means of comparing prices across regions is to review overall price stability. The volatility shown in Figure II.4 represents the average volatility for the system-wide hourly prices.

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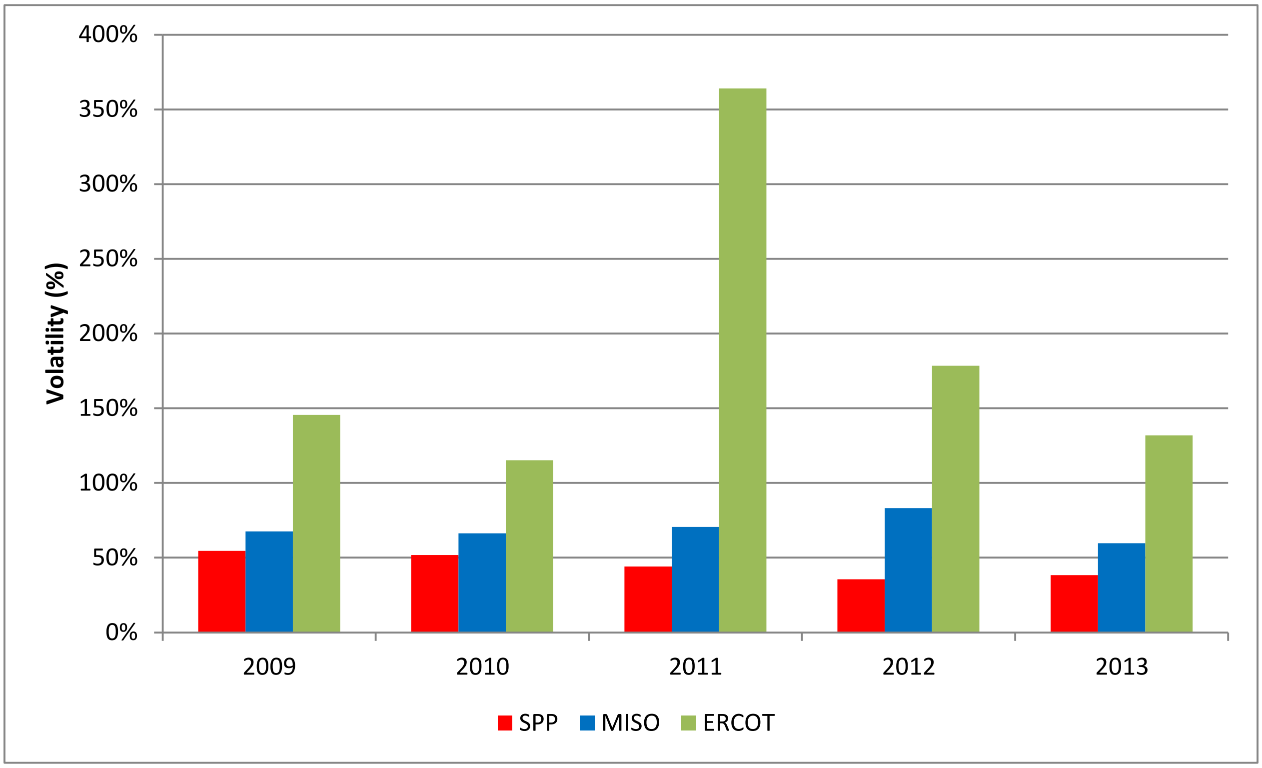
[6] SPP market prices do not include the loss component while MISO and ERCOT market prices include the loss component.

The volatility is calculated by dividing the standard deviation of hourly regional prices by the mean of the hourly regional prices, which yields the coefficient of variation. This value represents the relative movement of prices across time. If volatility is high, prices tend to spread out across the ranges. If volatility is low, prices tend to concentrate near the system average, or near the mean of the price distribution curve. Volatilities in MISO and ERCOT have decreased in 2013 from 2012, while SPP volatility has increased slightly. However, the magnitude of volatility in SPP is still significantly lower than the other two markets.

Figure II.4 Regional Electricity Price Volatility Comparison for 2009 – 2013

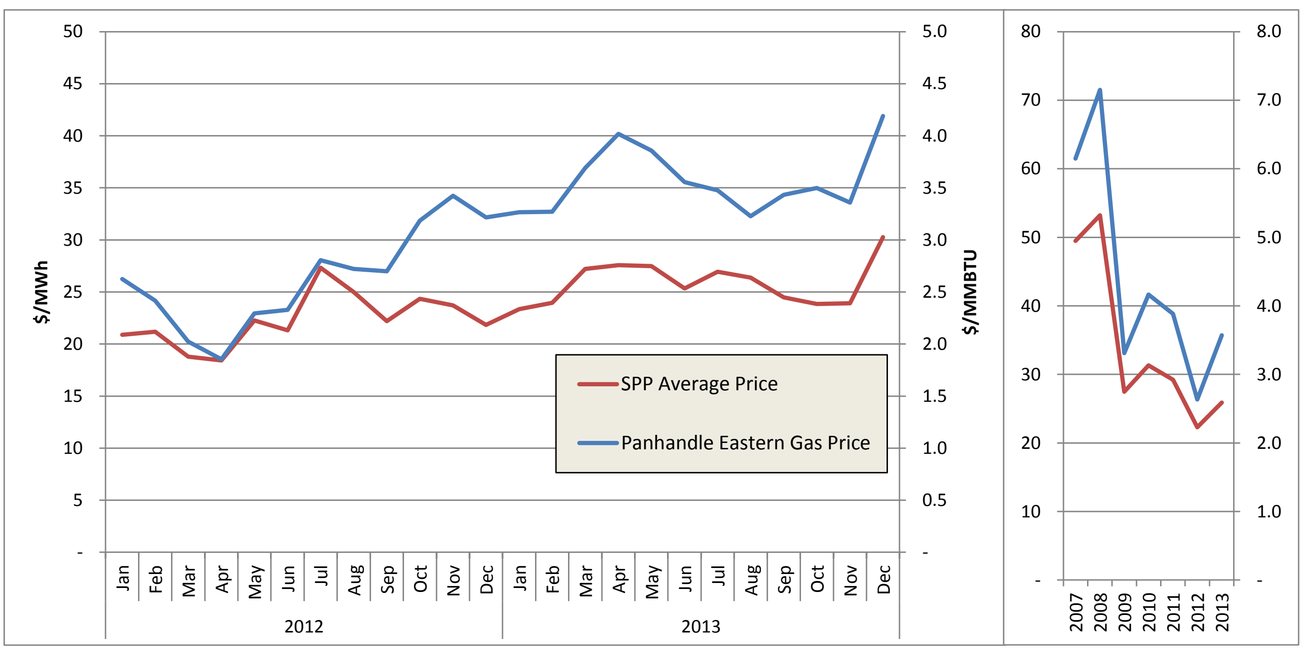


Electric and Natural Gas Price Comparison

Figure II.5 shows the monthly average price for natural gas sold at the Panhandle Eastern gas price hub and the SPP monthly average price for 2012-2013. Gas prices are closely correlated with average system prices in the SPP region. This is to be expected since gas units are often the marginal resource that set the market price. In 2013, gas prices fluctuated in a range from a low of $3.23 per MMBtu in August to a high of $4.19 per MMBtu in December. The average annual price of gas increased from $2.63 in 2012 to $3.57 in 2013, a change of 36%.

Electric prices follow a similar pattern but change only about half as much as natural gas prices. This can be seen in both the monthly and the annual numbers. The relationship between gas prices and electric prices is driven by what fuel type generation is on the margin and thereby setting electric market price. In 2013 gas was on the margin about 50% of the time, as discussed above. Coal prices are relatively stable compared to gas price thereby moderating the volatility of electric prices because coal plants are setting market price about half the time.

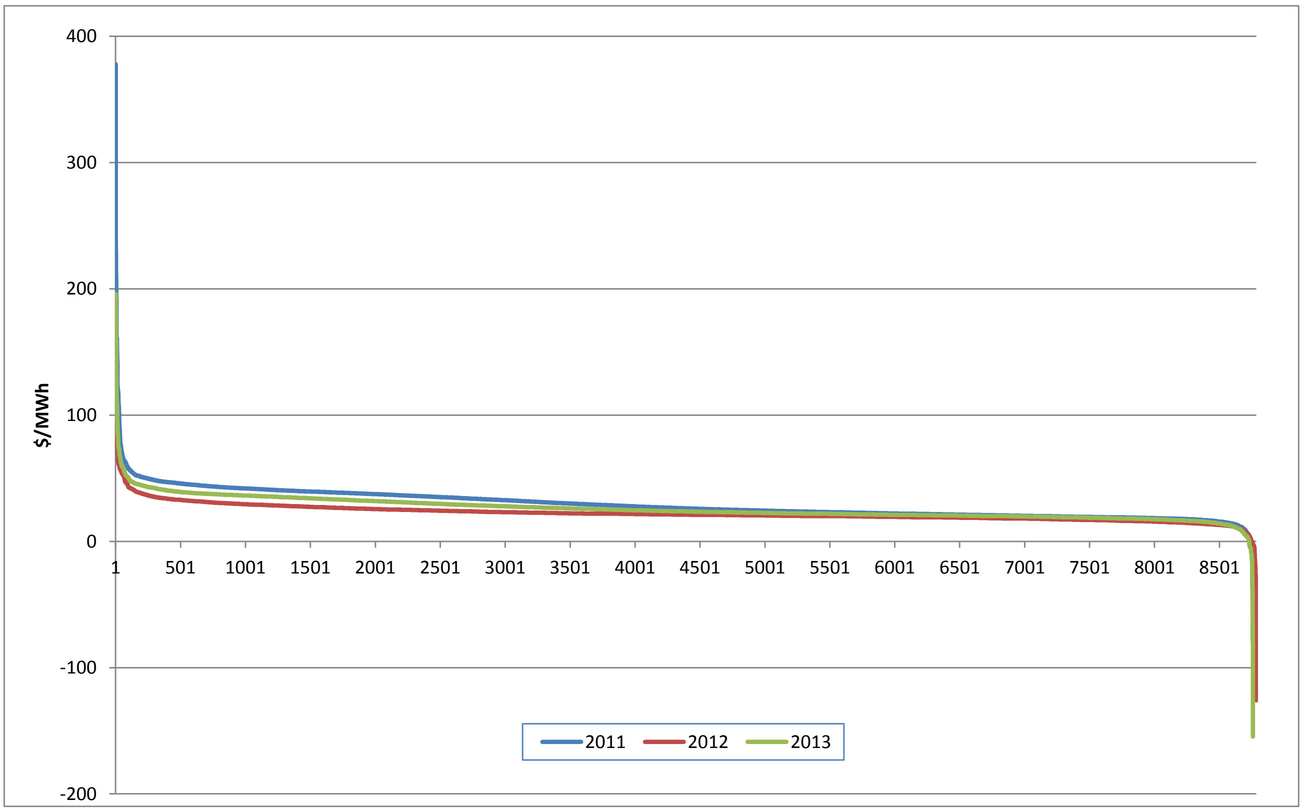
Figure II.5 Comparison of Average Monthly SPP Prices and Panhandle Natural Gas Prices



Price Duration Curve

A final look at system prices is illustrated in Figure II.6, a price duration curve arranging all hourly prices for each year from the highest to the lowest. There were 27 hours in 2011 with market prices over $100/MWh. The number dropped to 8 hours in 2012 and increased slightly to 12 hours in 2013. The entire price duration curve in 2013 is higher than that of 2012, indicating an overall prices increase. This was primarily driven by the higher natural gas prices in 2013. The highest system average hourly price in 2013 was $196, about the same as that experienced in 2012 at $195, but less than the $378 price experienced in 2011. These relatively low peak prices and limited hours above $100 illustrate minimal scarcity events over the last three years.

Figure II.6 Annual Price Duration Curve – 2011 through 2013

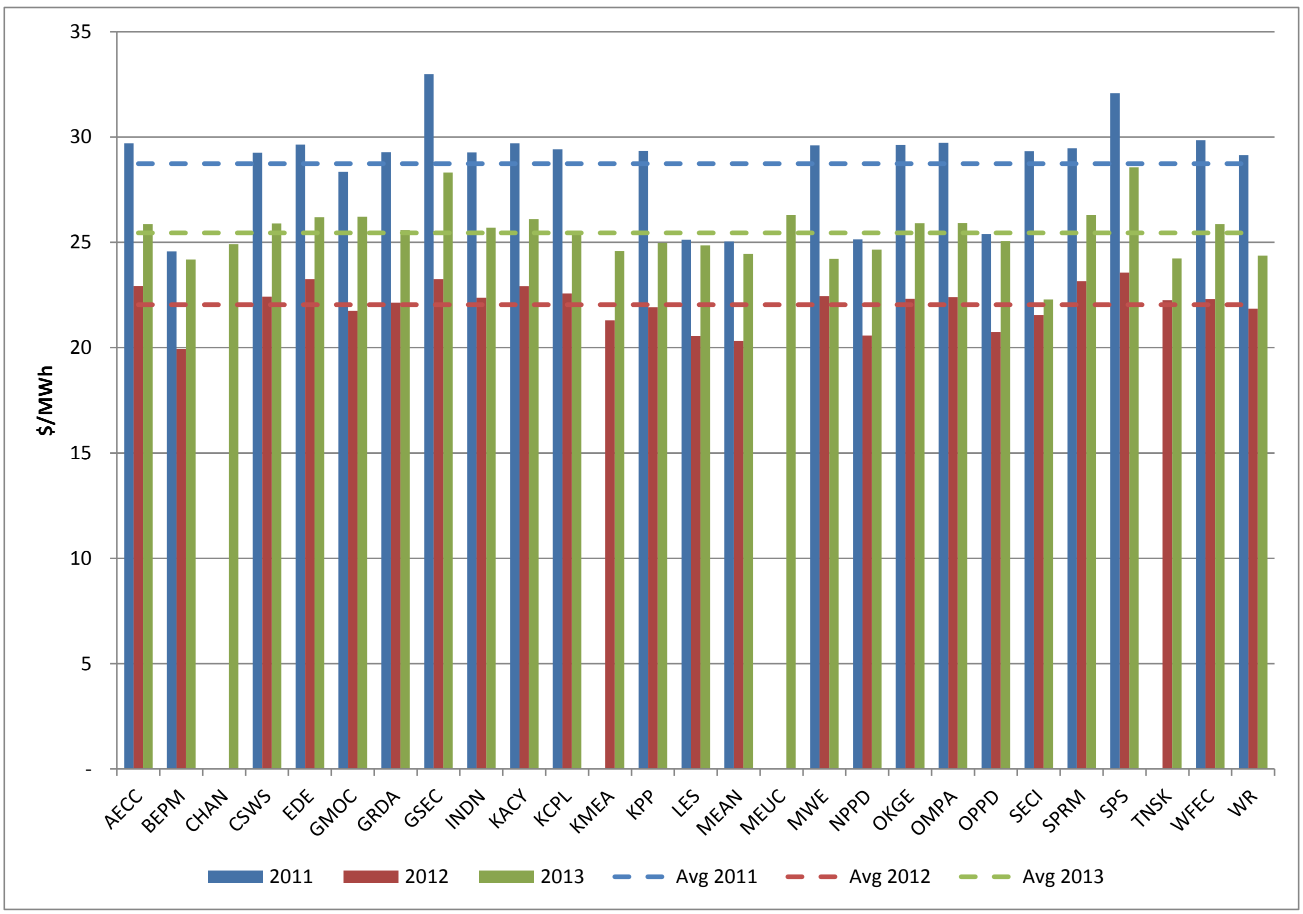


Market Participant Price Comparisons

While pricing comparisons between SPP and its neighboring regions show the relative consistency of the regional markets, it does not represent price volatility experienced by individual participants within the region. To better understand the intricacies of price changes across the SPP region, it is necessary to illustrate price variances at the individual Market Participant level. The remaining metrics in this section provide the analytic framework to review this issue.

Figure II.7 illustrates annual average prices for SPP's Load Serving Entities using load weighted settlement prices. The prices in 2013 for all Load Serving Entities were higher than that experienced in 2012. In 2013, the Southwestern Public Service (SPS) area experienced the highest average prices of $28.56/MWh, while the Sunflower Electric Power (SECI) area experienced the lowest average prices of $22.29/MWh. Prices for these two participants represent the SPP region's extremes for 2013. The driver of the relative price differences is congestion costs applied to Market Participants' respective areas. With SPS and SECI being adjacent to each other and experiencing the two pricing extremes is illustrative of the intensity of the congestion in that region of the SPP market.

Figure II.7 Average Annual Price by Market Participant

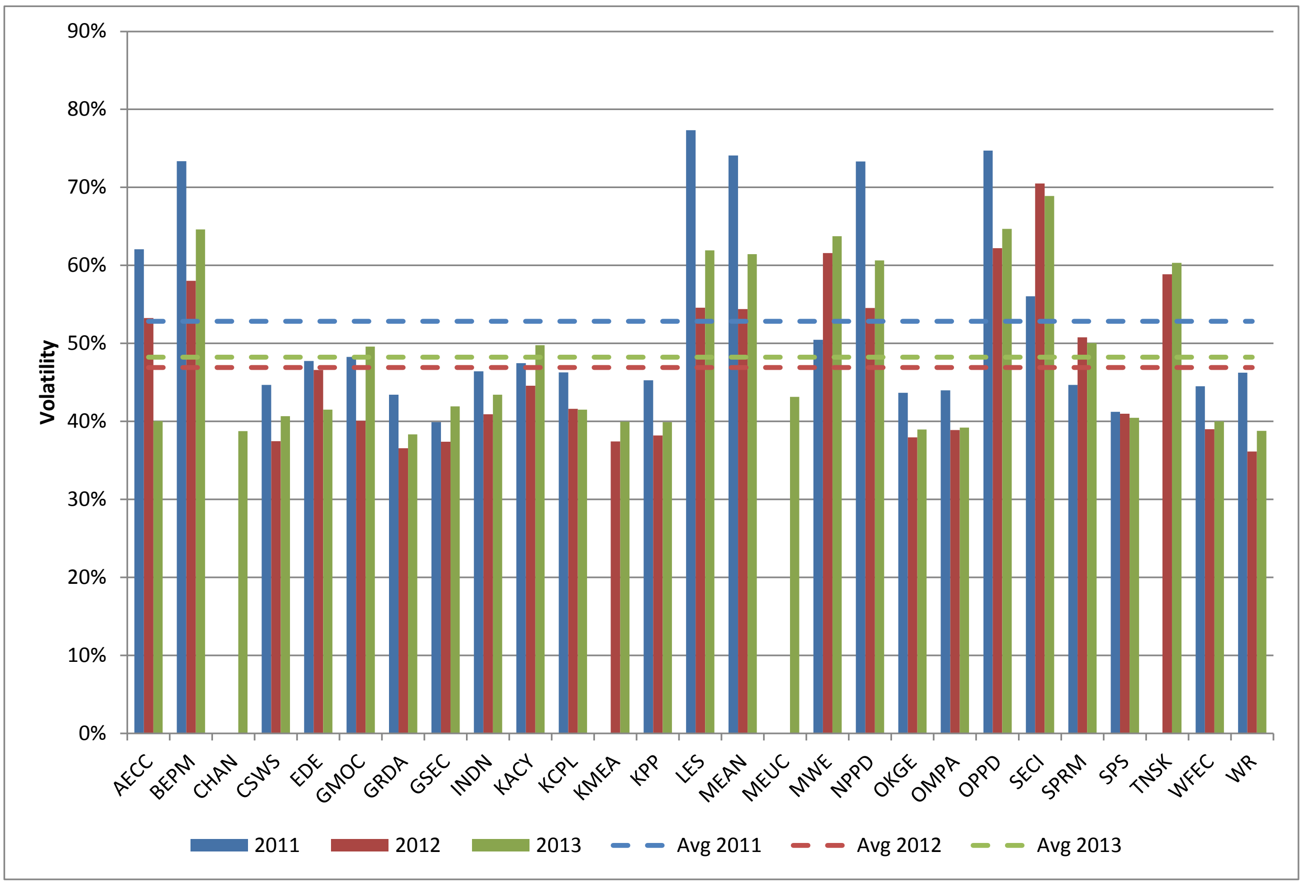


Price Volatility

Market Participant's average prices, discussed in the previous section, provide a high level assessment of price conformity. Another useful perspective is to review price volatility for individual participants. Figure II.8 delineates Market Participants' volatility using load settlement prices. High levels of volatility present long-run problems and may discourage open participation in the SPP EIS Market.

The majority of the Market Participants experienced a small increase in price volatility for 2013 mostly driven by higher energy price, which raised the dollar impact of congestion. Other factors include transmission outages, new transmission investments, and the increase in wind generation. The regions with the highest volatility continue to be Nebraska and western Kansas.

Figure II.8 Annual Price Volatility by Market Participant



Re-pricing in EIS Market

Interval prices from the Market Operations System may be revised if there is a software problem or a data input error. There were very few hours of significant correction in 2013 as was the case in previous years. The most significant re-priced event was on 6/26/2013, which accounted for about 30% of the yearly total impact. This incident was caused by a Market Participant's ICCP link that lead to a total loss of SCADA and backup SCADA from this Market Participant. The incident caused a change in the EIS deployment resulting in a breached flowgate state significantly effecting market prices.

Figure II.9 details the percentage of hours per year that were re-priced in 2009-2013. Approximately 3% of all hours were re-priced in 2013, a decrease from 4.6% in 2012. Although the number of the re-priced hours decreased, the dollar value increased. In 2013, only 0.2% of EIS Market settlement value was changed as a result of re-pricing. This continued low level of re-pricing indicates a high level of price certainty, which is an important aspect of an efficient and effective market.

Figure II.9 Percent of Re-priced Hours and Dollar Impact

	Number of Repriced Hours	Annual Hours	Percent of the Repriced Hours	Repriced Dollar Amount (in Millions)	Total EIS Market Purchase (in Millions)	Percent of the Repriced Dollars
2009	456	8,760	5.21%	$5.0	565	0.88%
2010	295	8,760	3.37%	$1.4	641	0.22%
2011	341	8,760	3.89%	$3.0	646	0.46%
2012	408	8,784	4.64%	$0.67	600	0.11%
2013	285	8,760	3.25%	$1.33	676	0.20%

2013 Price Contour Map

A final look at prices is provided in Figure II.10 and Figure II.11, price contour maps for 2012 and 2013 respectively. Calculations for these graphics were derived by averaging prices at each pricing node for the year. Blue areas indicate relatively low annual average prices and the yellow to red shades indicate higher prices.

Comparing 2012 and 2013 maps indicate that Nebraska prices are starting to converge with the balance of the market. The distinct price divergence at the Kansas/Nebraska state line is not present in the 2013 map. The graphics also show an increase in congestion in the Kansas City area and in the Texas Panhandle area. The new pattern is likely caused by several factors: new transmission investments, higher gas prices, increased wind generation to highlight a few, and changes in external impacts on the Omaha-Kansas City corridor. These issues are discussed in more detail in the congestion section of this report.

Several existing patterns continued in 2013. Western Kansas, western Oklahoma and the northern part of the Texas Panhandle had the lowest prices due to abundant wind generation and limited export capability. The southern part of the Texas Panhandle had the highest prices in the footprint because of limited import capability.

Figure II.10 Price Contour Map for 2012

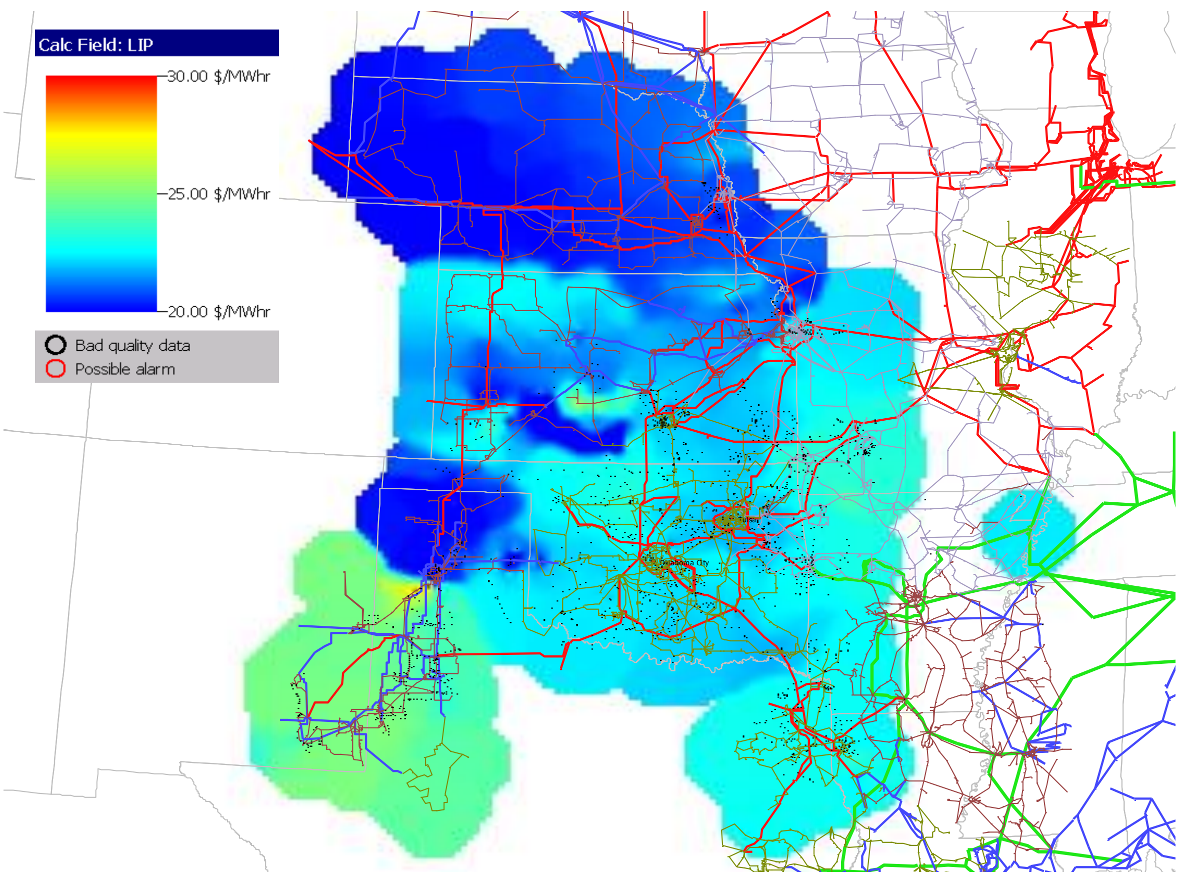
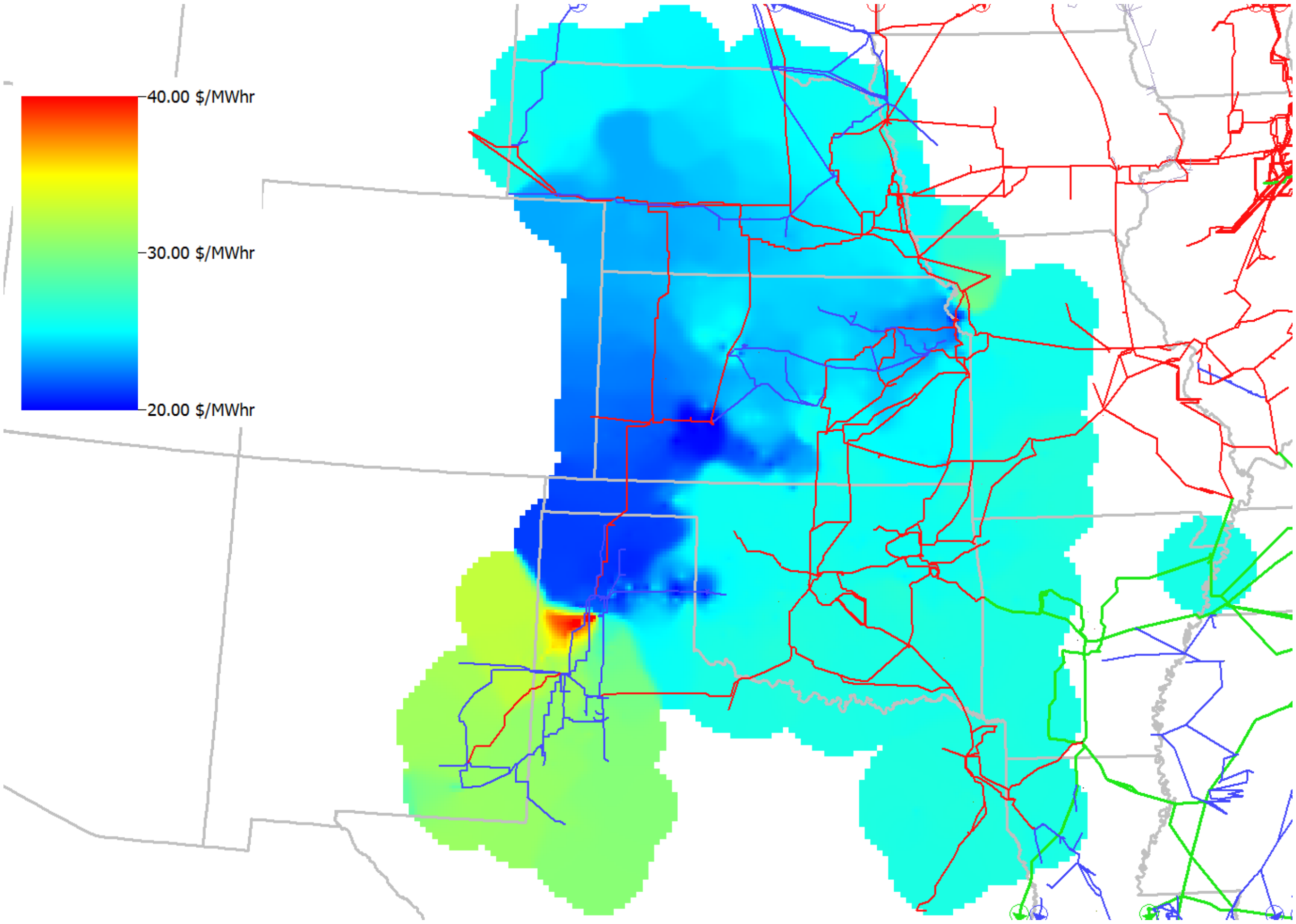


Figure II.11 Price Contour Map for 2013



D. Revenue Neutrality Uplift

SPP is required by its tariff to remain revenue neutral in the markets it operates. The total dollars paid to Market Participants for a given hour must equal the amount collected from Market Participants. Market conditions may result in instances in which there is a difference between net dollars either paid or collected by SPP. When this occurs, SPP must either uplift the deficiency to all Market Participants or distribute the over-collection back to Market Participants by including an adder in the hourly settlement price.

There are five components to Revenue Neutrality Uplift (RNU):

(a) Energy Imbalance Service (EIS) payments,
(b) Self-provided losses (SP loss),
(c) Over-scheduling charges (O/S),
(d) Under-scheduling charges (U/S), and
(e) Uninstructed deviation charges (UD).

Positive numerical results represent an over-collection by SPP and a payment to Market Participants. Negative numerical results represent an under-collection by SPP and require a payment to SPP from Market Participants. EIS results may be either positive or negative; SPP may either under or over collect depending on market results. Self-provided losses may also be positive or negative, depending on the nature of the market solution. Over-scheduling charges, under-scheduling charges, and uninstructed deviation charges are always paid by Market Participants, which means they will always be negative as can be seen in the chart below, Figure II.12.

EIS payments are calculated as EIS volume in MWh multiplied by the appropriate price at the settlement location (LIP). EIS volume is the difference between the metered MW value and the scheduled MW value. The LIP used is the appropriate settlement location LIP. For a given operating hour, the EIS component is the net of all sales and purchases. If SPP collects less revenue from Market Participants than it paid out, the EIS component of RNU is positive. Positive RNU is an indicator that SPP has a revenue shortfall and must collect additional revenue from Market Participants to remain revenue neutral. If SPP collects more revenue than it paid, the EIS component of RNU is negative and SPP has a surplus, which must be distributed back to Market Participants in order to remain revenue neutral.

Transmission losses are a reality of the electrical grid and must be accounted for when considering power flows throughout the SPP region. Losses associated with transactions wholly within the SPP region are already accounted for using the SPP EIS Market. Losses associated with transactions that source from a non-SPP region and sink into SPP are also accounted for using the SPP EIS Market. Losses from transactions that source or sink outside of SPP are accounted for using an alternate method to the SPP EIS Market.

There are two ways Market Participants may handle losses for the aforementioned transactions. They may settle these losses financially, or they may self-provide the loss amount. Financial settlement of losses requires the Market Participant to pay for all loss costs associated with the transaction. If a Market Participant chooses to self-provide for its losses, the Market Participant assigns a Designated Balancing Authority, which is billed the loss amount times the LIP. The Transmission Owners are then compensated for the loss costs as a result of the transaction based on their LIP prices and the Transmission Owner Loss Matrix (posted on the Open Access Same-time Information System). If these amounts are not equal, RNU is necessary for SPP to remain revenue neutral.

Over scheduling happens when a Market Participant schedules more load than actually occurs in its area in an attempt to profit from price differentials between its resource and load LIP values. Under scheduling happens when a Market Participant schedules less load than actually occurs to profit from price differentials between its load and resource LIP values. To mitigate under scheduling, SPP's market software looks for instances in which a Market Participant's actual load exceeds its scheduled load by 4% or 2 MW, whichever is greater. Additionally, the Market Participant must have a LIP value at its load settlement location that is less than the LIP value at its generators. If these conditions are met, the software automatically calculates the total amount to be disgorged from the Market Participant. The over scheduling logic works in much the same way. If the Market Participant's actual load is greater than the scheduled load by 4% or 2 MW, whichever is greater, and LIP at the generators is less than LIP at the load, the Market Participant is subject to disgorgement of any undue revenue.

The Over and Under Scheduling charges outlined above were established to automatically mitigate instances of either over or under scheduling. These charges are levied against the Market Participants meeting the listed criteria and are distributed to all Market Participants according to the established RNU procedures. Under and over scheduling penalties are shown in the following RNU table as negative values because they are penalties levied against Market Participants and require payment from the same.

Uninstructed Deviation (UD) is the difference between a Market Participant resource's dispatch instruction and actual output for a given interval. Market Participants are expected to operate their resources within an allowable tolerance range. Deviation from this range can cause adverse market impacts, as the market must adjust to resources not being where they were instructed.

The tolerance range for a resource is set at 10% above and below the dispatch instruction, limited to a lower limit of 5 MW, and an upper limit of 25 MW. Up and Down Regulation is then added to the tolerance range to determine a total allowable deviation range for the resource.

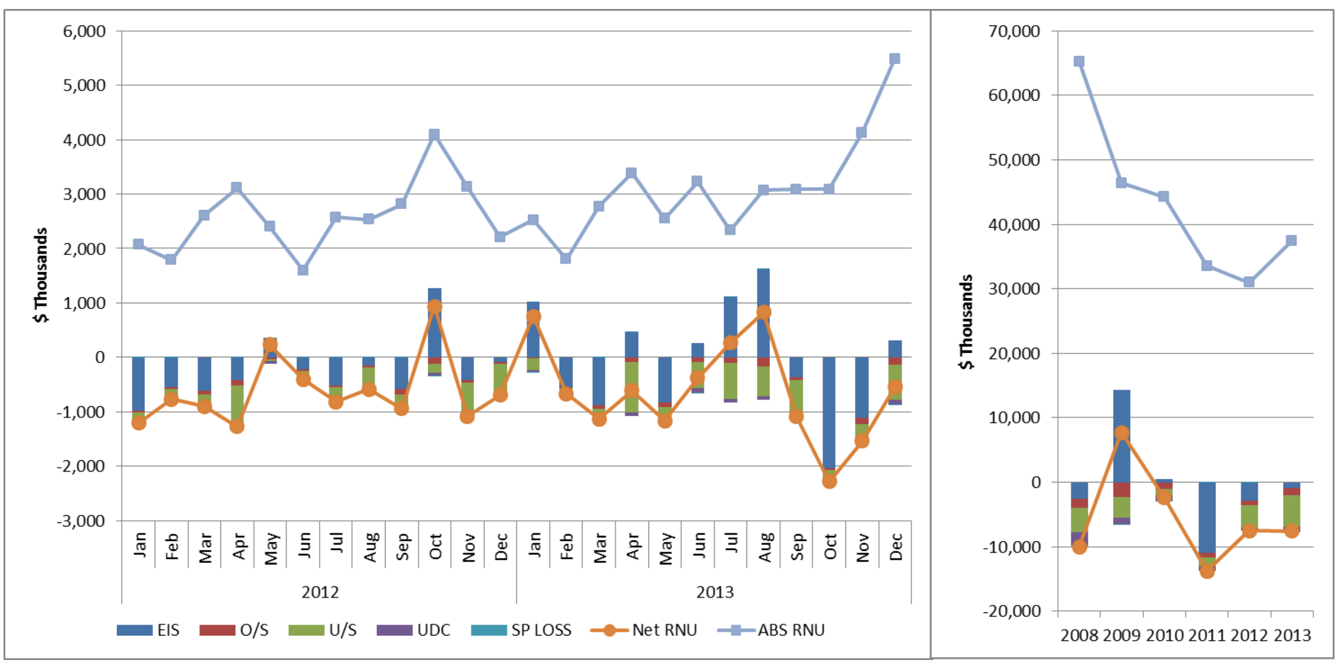
Deviation outside the total allowable deviation range is charged against the Market Participant. If the deviation is between zero and 25 MW, the charge is (MW deviation amount * LIP * 10%). If the deviation is greater than 25 MW, the charge is the sum of the previous calculation for 25 MW plus (deviation in excess of 25 MW * LIP * 25%). The absolute value of the interval deviation as calculated previously is then averaged across the hour for each resource. This yields the hourly uninstructed deviation total. Uninstructed deviation charges are levied against Market Participants and represent a payment required from the participant to SPP in the RNU chart.

RNU Results

Figure II.12 shows the RNU values for each month in 2012 and 2013 by component. The EIS component of RNU represents approximately 80% of total RNU for 2013. Positive RNU results in SPP applying an uplift procedure to collect additional dollars to remain revenue neutral. Negative RNU results in SPP distributing excess revenue back to Market Participants.

Figure II.12 includes both the net and absolute value of the RNU. For net RNU, positive uplift in a given hour may offset negative uplift from a different hour resulting in the "netting out" of hourly impacts for the monthly total. The net RNU shows a decreasing trend in 2013. The absolute RNU shows the total magnitude of all RNU charges that occurred during the month. During 2012 and 2013, monthly absolute RNU fluctuated around a range of about two million dollars. The exception appears to be December when the absolute RNU increased to about five million dollars. This may be the result of unusually cold weather.

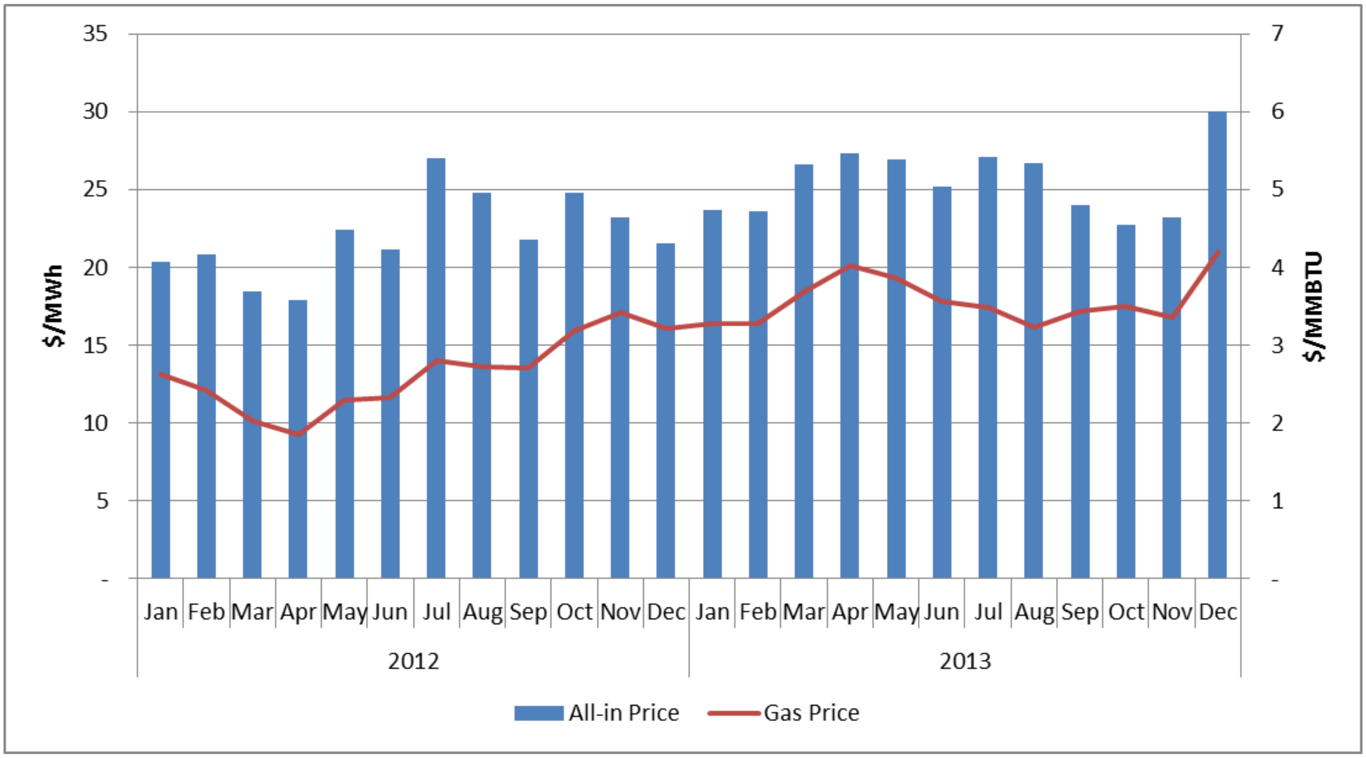
Figure II.12 Components of RNU by Month for 2012 and 2013



All-in Price

Figure II.13 shows the all-in price by month for 2012 and 2013. The all-in price is the load-weighted SPP average price adjusted for net RNU. The net RNU adjustment is the total RNU divided by total EIS MWh. The largest negative RNU adjustment was -$1.14/MWh in October 2013, an approximately 4.7% adjustment to the system average price. The magnitude of RNU adjustments is relatively low and consistent with what would be expected for an effective market.

Figure II.13 All-In Price by Month for 2012 and 2013



E. Revenue Adequacy

An important concept behind the wholesale electric market is the notion that it provides economic signals to encourage long term investments when existing resources are insufficient to meet system demand. This section focuses on full cost recovery for three technology types: scrubbed coal, advanced gas combined cycle, and advanced combustion turbine, which represent the most common generation capacity in the SPP region. “Net Revenue” calculation was used in this analysis to evaluate whether market prices support new generator construction. If the Net Revenue is higher than the Annual Revenue Requirement the investment would be deemed profitable.

Critical to the theory of full cost recovery is the baseline selection mechanism which determines the investment cost of new generation. To reduce the complexity of the process, several simplifying assumptions were made and where possible, data from the Electricity Market Module published by the Energy Information Administration[7] was used. Key assumptions from the Electricity Market Module can be found in Figure II.14.

Figure II.14 Key Assumptions in Revenue Adequacy Formulation

Descriptor	Scrubbed Coal	Advanced Gas/Oil Combined cycle	Advanced Combustion Turbine
Size (MW)	1,300	400	210
Total Overnight Cost ($/kW)	2,844	1,003	666
Variable O & M ($/MWh)	4.25	3.11	9.87
Fixed O & M ($/kW-yr)	29.67	14.62	6.70
Heat rate (Btu/kWhr)	8,800	6,430	9,750

Figure II.15 shows the net revenue requirement and the potential revenue the SPP market would provide for the representative set of new generation facilities. The differences between the net revenue requirement and the annual market revenue determine if an investment in a new generating facility is plausible. The annual revenue requirement includes an assumed 10% return on equity.

Among the three generator types, only scrubbed coal shows the potential to fully recover costs for new investments given SPP system marginal prices in 2013. The revenue of an advanced gas/oil combined cycle and advanced combustion turbine units both fell short of the annual revenue requirement. However, this does not mean there is no rationale for investment in new combined cycle or combustion power plants. Regulatory requirements, reliability demands, shifts in generation technology emphasis, and loading patterns may require new generation investments. What may be

[7] “Assumptions to the Annual Energy Outlook 2013” – Electricity Market Module

inferred is that generation additions from independent entrants based purely on economic incentives may not be warranted at this time for these two technologies.

Figure II.15 Revenue Adequacy Results

Technology	Marginal Cost ($/MWh)	Net Revenue from SPP Market ($/Year)	Annual Revenue Requirement	Able to Recover
Scrubbed Coal	9.53	188,073,249	177,992,100	Yes
Adv Gas/Oil Combined Cycle	26.07	11,547,104	21,143,467	No
Adv Combustion Turbine	44.68	592,258	6,675,900	No

Some SPP Market Participants experienced higher prices than others due to localized congestion. Prices for specific Market Participants were used to calculate revenue adequacy values to determine if congestion changed the results. Figure II.16 summarizes the revenue adequacy results for those Market Participants. Full recovery for advanced gas/oil combined cycle and advanced combustion turbine generation were not possible for any Market Participants. Prices for several Market Participants were high enough to generate needed revenue to cover the cost of a scrubbed coal generation investment.

Figure II.16 Revenue Adequacy Results for Select Market Participants

Selected Participant	Net Revenue from SPP Market ($/Year)					
	Scrubbed Coal	Able to Recover	Adv Gas/Oil Combined Cycle	Able to Recover	Adv Combustion Turbine	Able to Recover
AEP	185,517,293	Yes	11,088,967	No	618,136	No
KCPL	174,226,312	No	9,817,172	No	531,000	No
NPPD	175,291,077	No	13,185,150	No	1,611,722	No
OGE	185,401,255	Yes	14,879,415	No	536,060	No
SPS	204,413,157	Yes	15,019,099	No	713,248	No
WR	168,848,498	No	8,253,526	No	430,512	No

F. Imports & Exports

Figure II.17 examines the amount of time, on an hourly basis, that SPP was either a net exporter or net importer. SPP was a net exporter over 90% of the time in 2013, the highest level in the last five years. The pattern shown in the chart below is typical for SPP market with net exports decreasing in summer time.

Figure II.17 Net Import and Export Interval Percentage

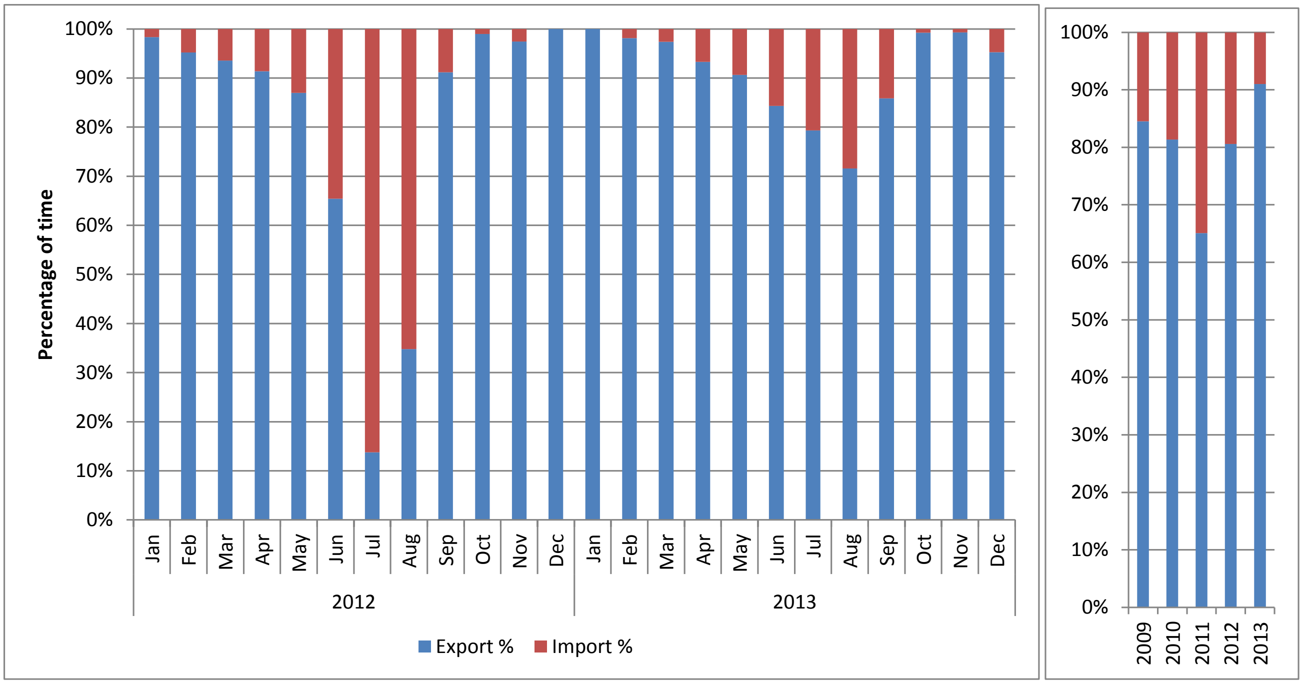
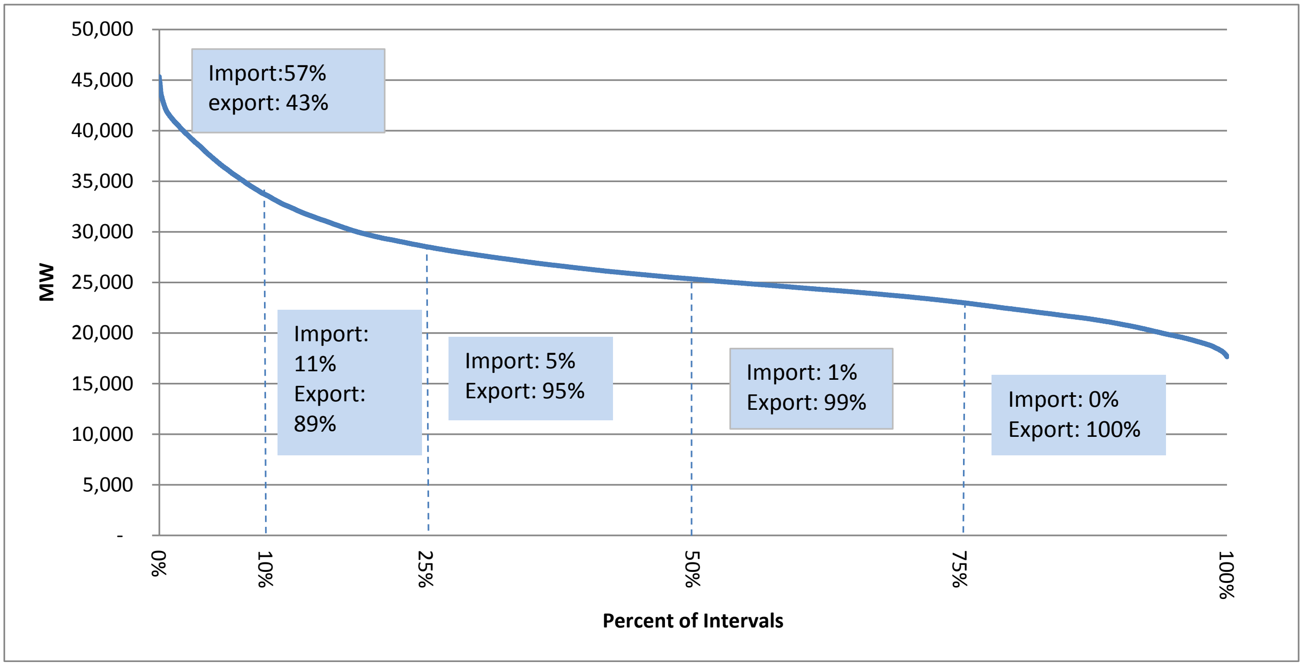


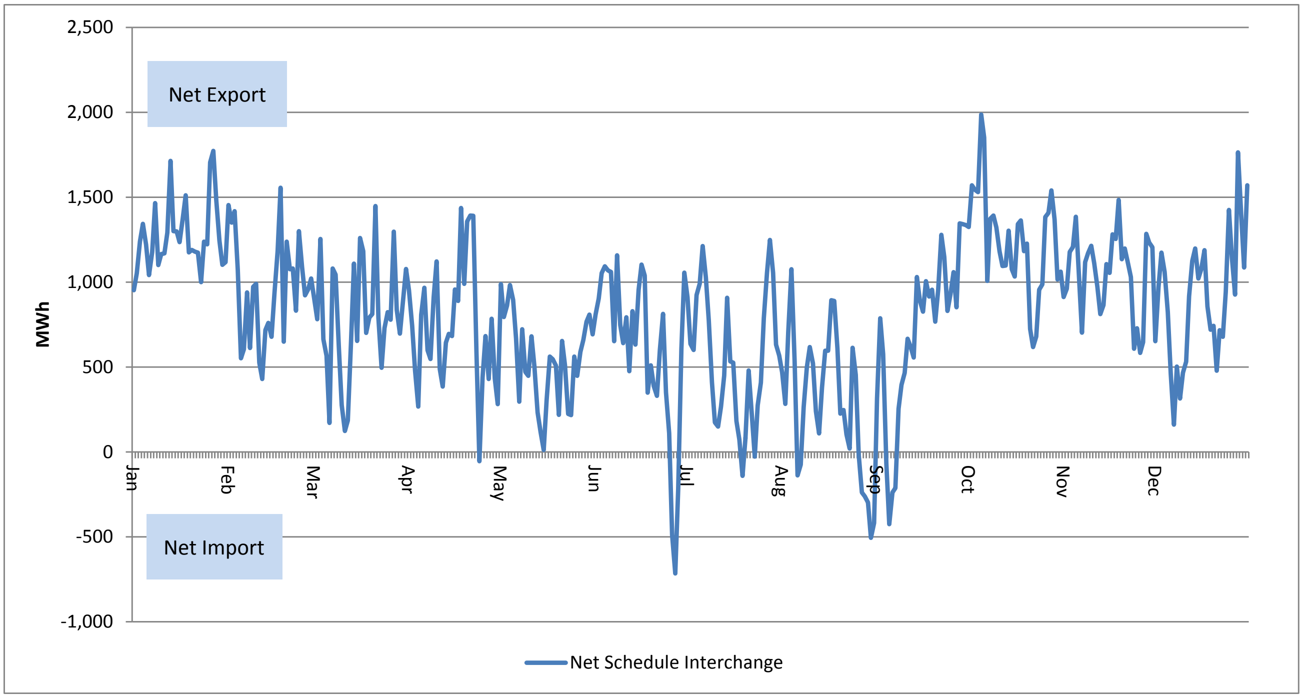
Figure II.18 is a load duration curve divided in quartiles with net exporter and importer percentages superimposed on the chart. During the highest 10% of load, SPP was a net importer 57% of the time, compared to 92% in 2012. As discussed before, summer load in 2013 was lower than 2012. The lower the load, the less time that SPP was likely to be a net importer. As load level decreased, SPP exporting time increased. During the lowest 75% of the load, SPP was a net exporter 95% of the time.

Figure II.18 Imports and Exports Trend for 2013



The magnitude of net imports and exports is shown in figure II.19. The highest daily average net export was 1,986 MWh while the highest daily average net import was 716 MWh.

Figure II.19 Daily Average NSI for 2013



G. Market Participation

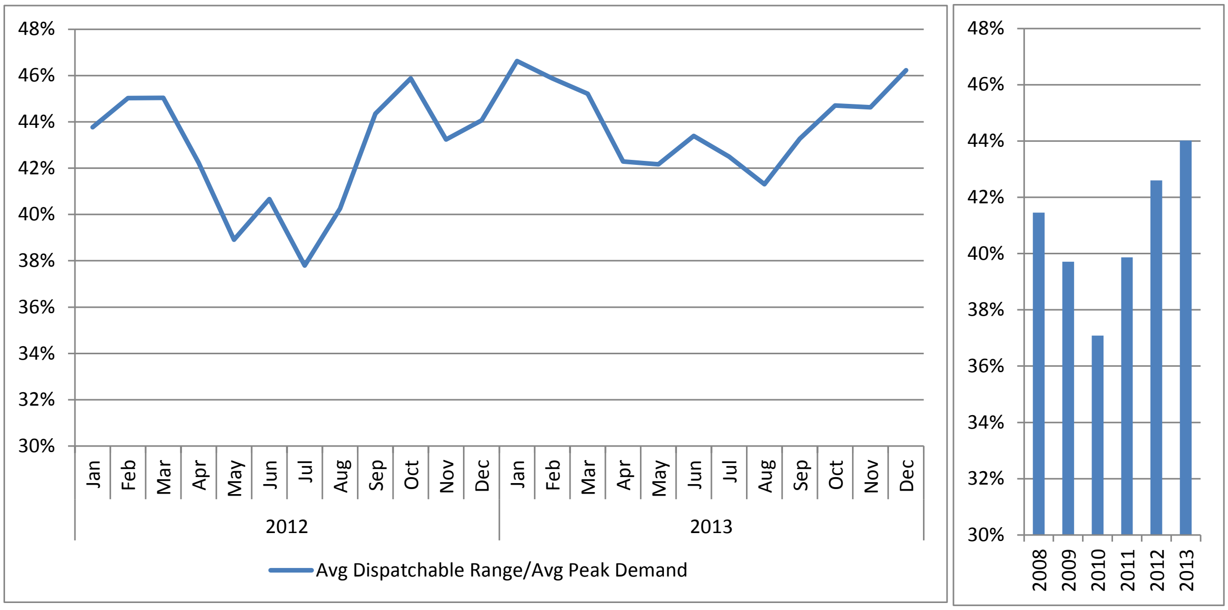
Settling imbalances in the EIS Market is mandatory and automatic. However, the level of participation in the SPP EIS Market is voluntary. Market Participants individually decide how to best manage their resources through appropriate scheduling, resource offers, and resource control parameters. Specifically, Market Participants may modify the control parameters of their resources by changing any or all of the following: dispatchable range, resource minimums, resource maximums, ramp rates, price offers, resource status, etc. Market Participants also engage with the market as they set schedules to manage price risk. The following charts and descriptions depict some key components of the resource parameters.

Dispatchable Range

Dispatchable range is a measure of the difference between the economic minimum and maximum for a resource. If a unit has a 500 MW maximum and a 100 MW minimum output level, the dispatchable range is 400 MW. If a resource is allocated Spinning or Up/Down Regulation service, the total dispatchable range would be decreased by the amount of the service. Limiting the dispatchable range of resources diminishes the EIS Market benefits generally and reduces market value to the specific resource. Reduced dispatchable range also increases incidences of extreme pricing events because the market would not be able to respond to the sudden market condition changes.

Figure II.20 represents the monthly dispatchable range of available resources for 2012 and 2013 as well as annual values for the last six years. There was a noticeable upward trend in the total dispatchable range available to the SPP system in the last three years. Dispatchable range was at the highest in 2013 since the market start. This upward trend is a positive development and a significant contribution to a more flexible and efficient market.

Figure II.20 Dispatchable Range of Available Resources

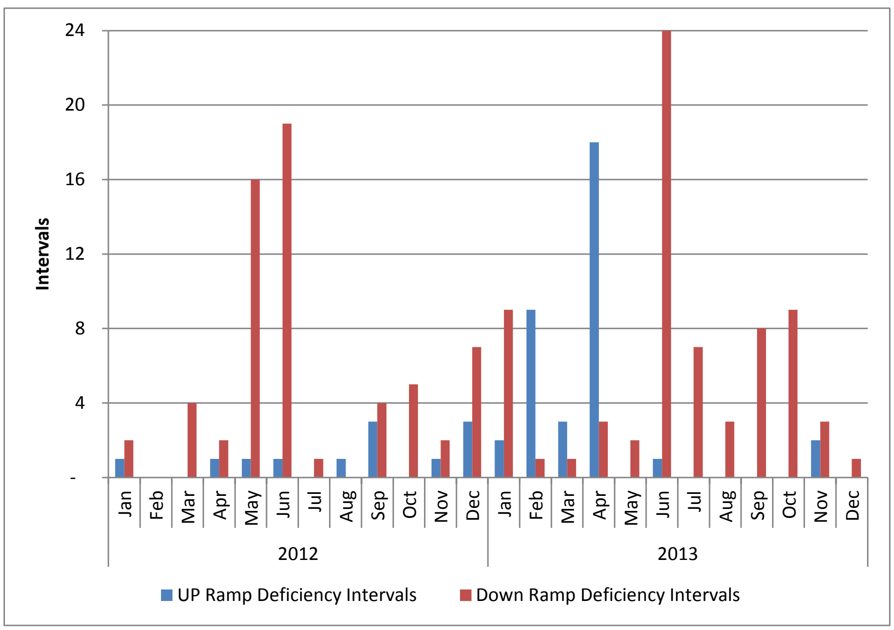


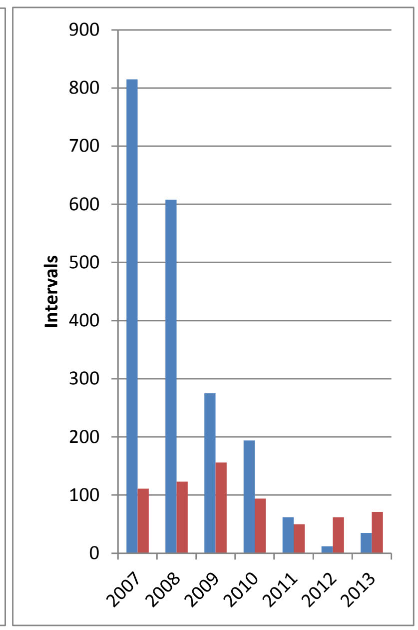
Ramp Rates

Ramp rates play a key role in EIS Market operations because they establish how quickly units can respond to changes in load and address congestion problems. As load increases or decreases, units must move accordingly to maintain the proper balance between supply and demand. Also, when flowgates are fully loaded or overloaded, units must be re-dispatched to prevent damage to transmission assets. If ramp rates are too low, the market cannot respond quickly enough to manage system changes and ramp deficiencies will occur. Deficiencies result in price spikes and increase overall price volatility.

Figure II.21 shows the monthly and yearly number of intervals with a ramp deficiency. Up ramp deficiency intervals and down ramp deficiency intervals both increased slightly in 2013. The highest number of up-ramp deficiencies occurred in April. The highest number of down-ramp deficiencies occurred in June. Variability of load and wind output, generation outages, and import and export changes contributed to these deficiency intervals. The annual graph shows the number of ramp deficiencies overall to be down dramatically since the start of the market.

Figure II.21 Ramp Deficiency Intervals

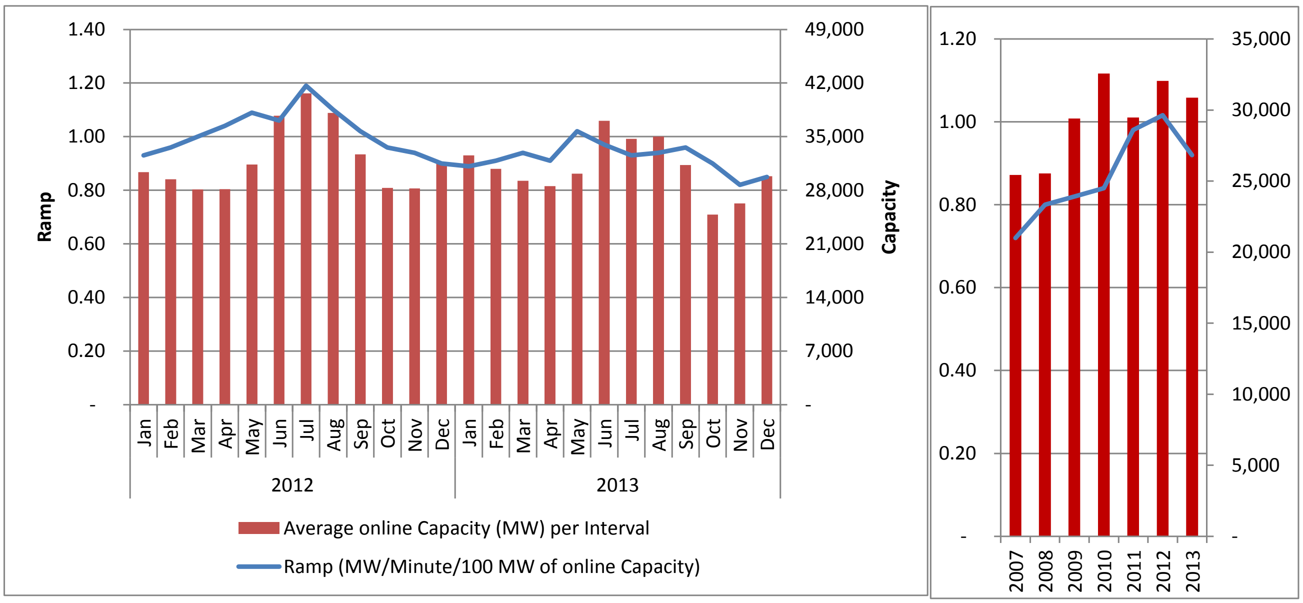




Ramp and Capacity

A composite view of ramp in the SPP EIS Market can be seen in Figure II.22, which shows ramp available to the system as normalized by available capacity. The normalized system ramp decreased slightly in 2013, but was still significantly higher than the early years of the EIS market. The cyclical nature of available ramp is shown in the monthly values. Available ramp is usually highest in summer because more gas units are on line to meet summer peak requirements and this capacity generally has a higher ramping.

Figure II.22 Ramp and Average Online Capacity



Resource Utilization by Status

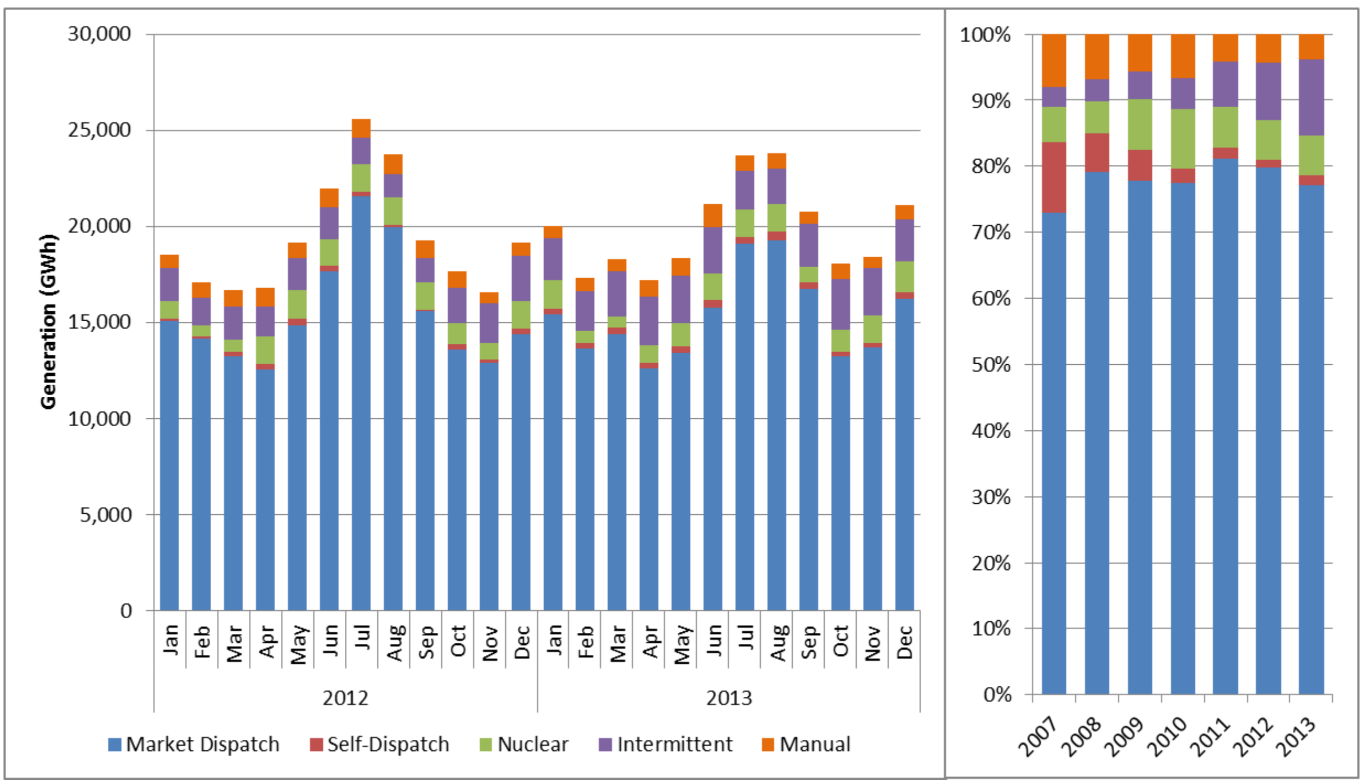
A Market Participant can modify the manner in which a resource functions in the market by selecting a specific status type. Available (also referred to as "Market Dispatch") is the only status type which allows the market to fully utilize a resource by changing the resource output and allowing it to set system price. Available status units are essential to the market in that these units are used to resolve congestion and alleviate other operational constraints. Available units are also central to achieving least cost market dispatch solutions. Resources using a status other than Available cannot be directed to move by the market system. Other status types include: Manual, Self-scheduled, Unavailable, and Supplemental.

- Manual status was discontinued in late February 2011 and replaced with the following options: Exigent Conditions, Intermittent, Qualifying Facility, Quick Start, Shut Down, Start Up and Testing. Resources in these statuses cannot set price and are dispatched to the last known output level.
- Intermittent status can be used by resources registered with SPP as intermittent. Use of this status indicates that the resource is online and unable to follow dispatch instructions due to the uncontrollable nature of the resource output.

- Self-scheduled resources are dispatched according to their sum of schedules for that resource. Market Participants essentially pre-determine an output level, regardless of overall market conditions. Dispatch levels for these resources can be changed by the RTO Reliability desk through the TLR schedule curtailment process.
- Unavailable status indicates the resource is offline and not available for use by either the market or the Market Participant.
- Supplemental status indicates the resource is offline but available to come online within ten minutes.

Figure II.23 illustrates generation from resources operating in various status types. Generation from market available resources was down slightly from 80% in 2012 level to about 77% in 2013. The use of manual statuses – startup, shutdown, exigent conditions and testing – and self-scheduled status continue to be low. The use of intermittent status has increased dramatically from the beginning of the market and was the only status to increase in 2013, from 8.6% in 2012 to 11.5%. With the growth in wind resources in SPP, this increased use of intermittent status is to be expected.

Figure II.23 Generation by Status Type



H. Market Competitiveness Assessment

Herfindahl-Hirschman Index for Market Participant Capacity

Herfindahl-Hirschman Index (HHI) is a common measure of competitiveness used to identify relative levels of market concentration. The U.S. Department of Justice is a predominant user of the HHI as part of its approval process for mergers or acquisitions. A market with a HHI at or under 1,000 is traditionally considered to be competitive and/or unconcentrated. A HHI between 1,000 and 1,800 indicates moderate concentration and raising some concerns but can be reasonably competitive. A HHI over 1,800 is said to indicate a highly concentrated market and is unlikely to be competitive.

The system wide HHI analysis discussed in this section is only relevant when the market is uncongested. When there is congestion in the market, limited transmission capacity restricts competition resulting in significant localized market power.

Figure II.24 shows the HHI for 2009-2013 calculated from total generation capacity shares. The HHI has declined as more Market Participants have been added to the EIS Market footprint. HHI values at this level indicate that no individual Market Participant can dominate the market and that the overall market is competitive. This does not preclude the possibility of localized market power concerns, but does indicate that an individual participant is unlikely to successfully manipulate the system by withholding capacity under non-congested conditions.

Figure II.24 HHI Market Participant Capacity

Herfindahl-Hirschman Index	
2009	970
2010	954
2011	916
2012	858
2013	797

Herfindahl-Hirschman Index for Uncommitted Capacity

Figure II.25 shows the HHI for 2009-2013 for uncommitted capacity by Market Participants. Uncommitted capacity is calculated as the installed capacity at the summer peak plus market participant's net purchase minus the maximum load obligation. In the case of an independent power producer, the entire capacity is considered uncommitted. As can be seen in the figure, the HHI values generally trend downward across time as more participants join the EIS Market. The HHI in 2013 was similar to that of 2012. As with the HHI results for Market Participant capacity, the HHI for Uncommitted Capacity suggests that an individual Market Participant is unlikely to successfully manipulate the system.

Figure II.25 HHI Uncommitted Capacity

Herfindahl-Hirschman Index	
2009	883
2010	810
2011	674
2012	680
2013	684

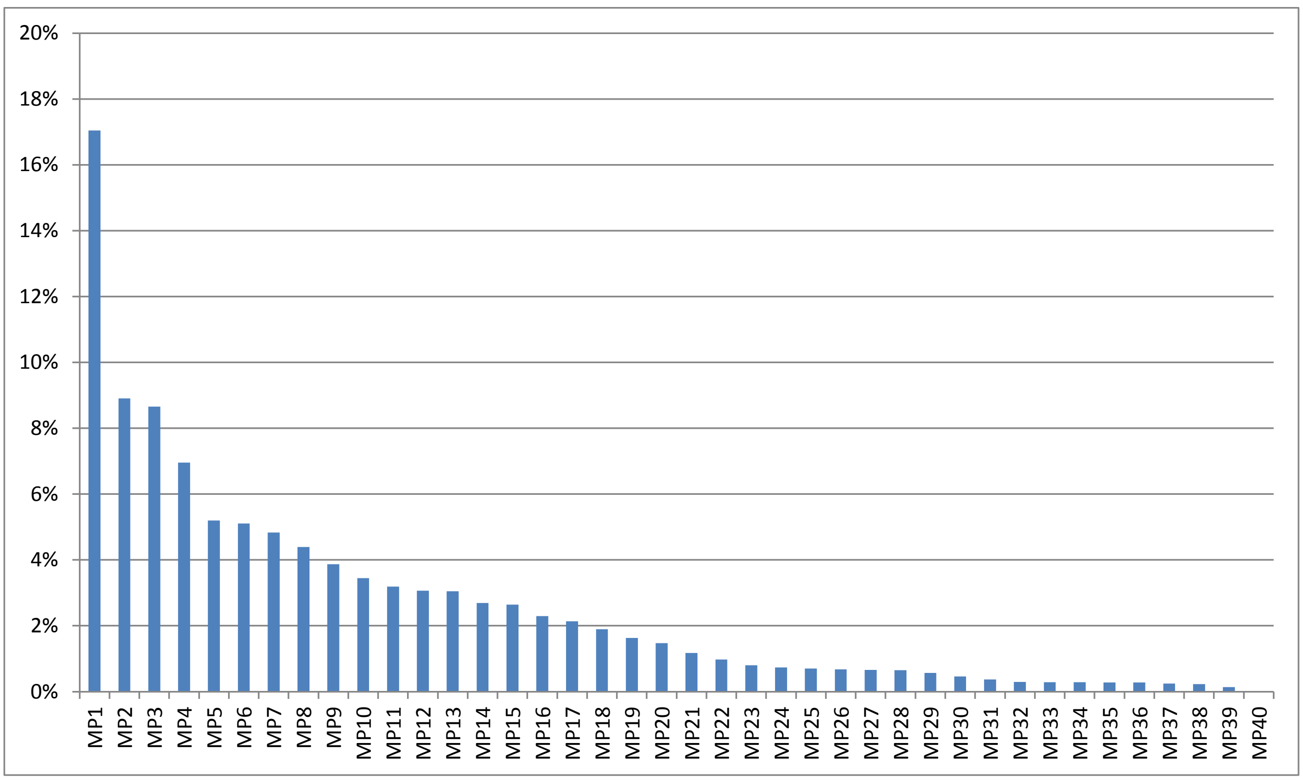
The Market Participant Capacity and Uncommitted Capacity calculations of the HHI yield similar results. HHI values since the start of the EIS market have been close to or under the 1,000 threshold indicating a very competitive market under non congested conditions.

Wholesale Uncommitted Capacity

The wholesale market capacity metric is a measurement of the uncommitted capacity in the market held by each market participant. FERC uses this measure as one of the screens for Market Based Rates authorization. If a market participant has control of less than 20% of the total uncommitted capacity, then they pass this market power test.

The uncommitted capacity is the market capacity remaining after subtracting any capacity that is committed to serving contracted load. For the purposes of this calculation contracted load is defined as that serving franchise load obligations. Firm sales to other parties are normally included in this calculation but not included here because this information is not readily available. Figure II.26, Uncommitted Capacity Market Shares in 2013, clearly highlights the limited impact attributable to individual market participants. Moreover, as no individual market participant exceeds the 20% threshold of uncommitted capacity, the likelihood of successful market power manipulation was low.

Figure II.26 Uncommitted Capacity Market Shares 2013



I. Market Power Monitoring and Mitigation

The MMU is directly charged by FERC with monitoring and reporting three types of potential market power abuse occurrences: Economic Withholding, Physical Withholding and Uneconomic Overproduction. The MMU monitors the impact of the mitigation system to detect possible market behavior issues and also conducts monitoring through the development and implementation of screening procedures and market behavior analysis tools that search out potential market power abuse. Given the result of active monitoring for market power abuse and the minimal impact on prices by the offer cap system as discussed below, there is little evidence market power abuse is a problem in the SPP EIS Market.

Economic Withholding

Economic withholding is defined as actions taken by a seller that maintains prices above competitive levels through the systematic reduction of output by providing offers above marginal cost. An entity exercising withholding experiences a reduction in sales but higher profits from inflated market prices. Economic withholding is addressing in the SPP EIS Market through active intervention in market through an offer cap system and by daily monitoring by the MMU.

The SPP offer cap is an automated system in which offers are capped when a set of conditions are met. The specific conditions are:

(a) Congestion is present in the system;
(b) Resources are in a position to wield potential market power as measured by their Generator to Load Distribution Factor being greater in magnitude than 5%;
(c) Capping of a specific resource results in the capping of all affiliated resources.

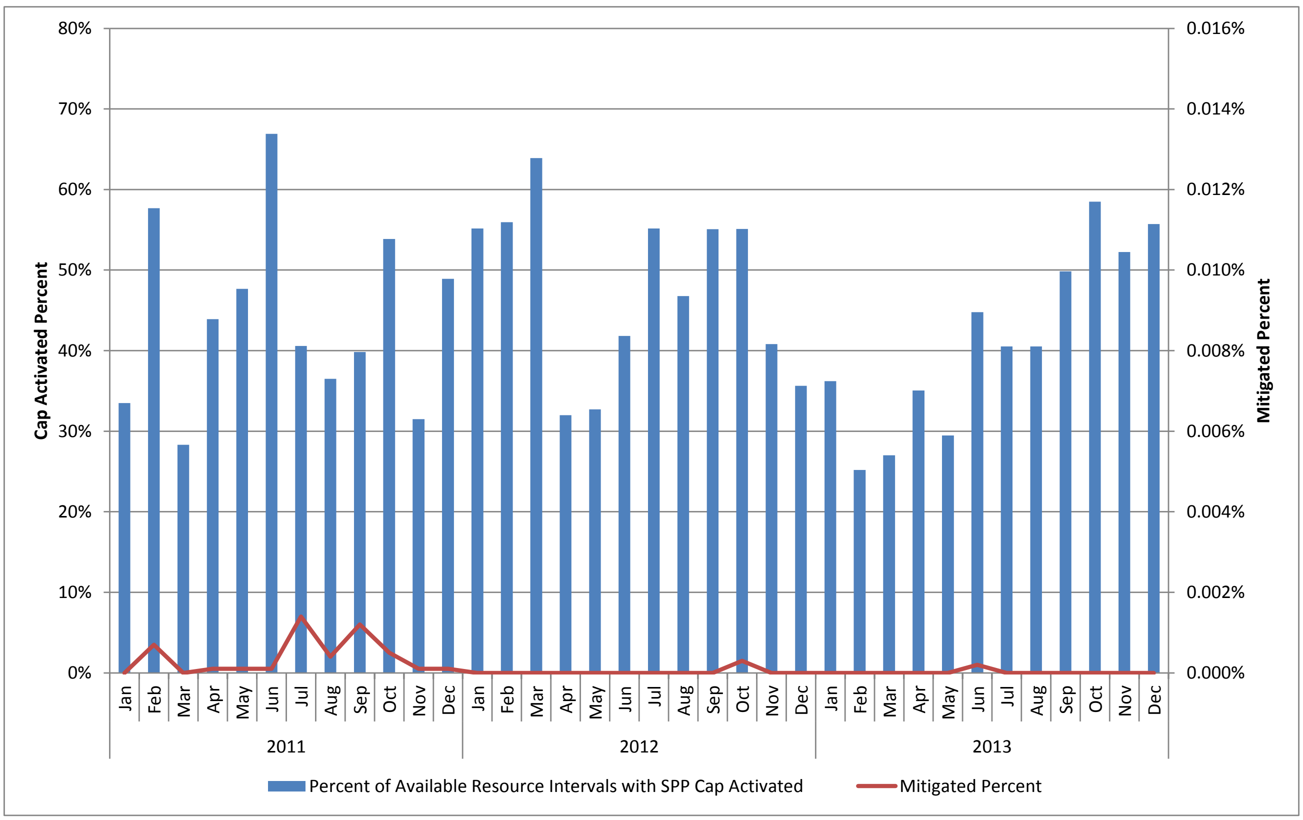
A second type of offer cap required by FERC establishes an absolute maximum offer regardless of market conditions. This limits the value of submitted offers and often referred to as the "safety net cap". The current value is $1,000 for this cap. Neither the safety net cap nor SPP offer caps limit the price any market participant may receive. Prices are set through the use of the System Pricing and Dispatch model, which may yield prices greater than any individual capped offer.

Figure II.27 shows when the SPP offer cap was in effect and how often the cap actually affected prices for the previous three years. The SPP offer cap impacts prices when:

1) An offer is greater than the SPP offer cap,
2) The LIP is greater than the SPP offer cap,
3) The LIP is less than the original offer, and
4) There is a non-zero imbalance volume (EIS energy was sold/bought at the LIP)

Without all four conditions present, EIS prices are not affected. Figure II.26 indicates the SPP offer caps rarely affected prices, only one month in 2013.

Figure II.27 Effect of SPP Offer Caps in 2011 – 2013



The System Marginal Prices and corresponding LIPs are derived from the offer curves submitted by the Market Participants. Because these offer curves are the principal drivers of overall system prices, it is necessary to carefully monitor participant offers to identify the outliers and mitigate potentially abusive offer submissions. The principal concern is that a Market Participant may submit offers that are substantially higher than what is appropriate, causing the market clearing price to increase above what is warranted. The EIS Market employs an "offer cap" to mitigate potential Economic Withholding. The RTO is responsible for managing the offer cap systems to mitigate potential Economic Withholding.

Physical Withholding

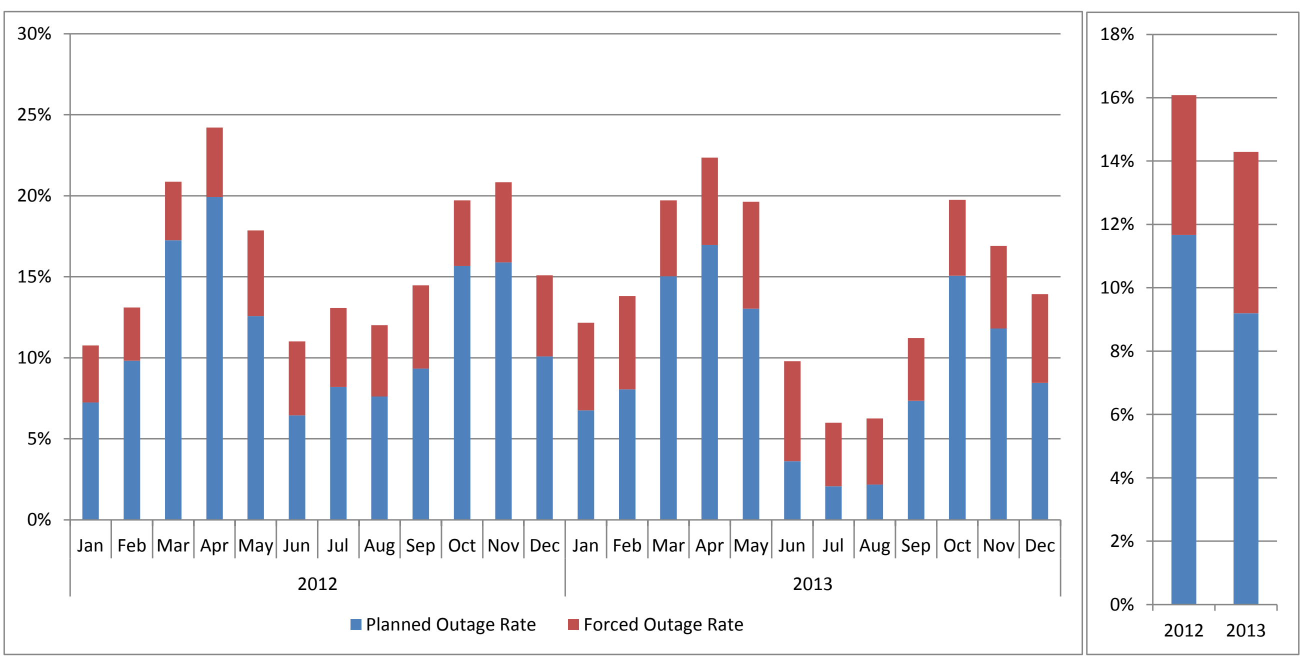
The most common form of physical withholding is to falsely declare generation outages. Generation outages typically fall into two categories – forced and planned. Forced outages occur when a generator is unable to function at full capacity due to an unforeseen circumstance, or it has otherwise been rendered inoperative. Planned outages occur when the owner schedules and SPP approves a generator or associated facility to be out for maintenance.

Figure II.28 shows monthly forced and planned generation outage rates for the past two years. Also included is the yearly average planned and forced outage rate. Outage rate is the percentage of the capacity that is in an outage compared to the total market capacity. Only full outages are included in the calculation.

Outages typically follow a seasonal pattern, with increased planned outages in spring and fall and increased forced outages during summer and winter peaks. Forced outages increase along with the increased utilization of units during high demand summer and winter peak periods as would be expected.

The annual outage rate based on records from the outage reporting tool decreased in 2013 over 2012. Figures from prior years were not included due to SPP implementing a new outage reporting tool (Control Room Operations Window) in late 2011. Only outage numbers in 2012 and 2013 are from the same database and therefore directly comparable. The most noticeable change was that the summer time planned outage rates in 2013 were much lower than in 2012, 3.8% compared to 7.8%.

Figure II.28 Generation Outages Rate by Status



Uneconomic Production

Uneconomic production refers to resources that are producing power when its cost of production is higher than the market price. This is considered a problem when two additional conditions are met. First, the unit is not ramp limited or at minimum capacity. Second, there is congestion affecting the resource. Cases of interest are when Market Participants lose money on the exporting side of the congestion while collecting unreasonable profits on the importing side. Units in either Available or Self-Schedule status could potentially cause problems by creating or increasing congestion which in turn causes price distortions. Other types of conduct identified and monitored include:

- Higher than normal Resource minimums
- Unusually low downward ramp rate offers
- Offers below expected true marginal cost

In 2013 there were a small number of periods when uneconomically production was identified. Each case was evaluated and all issues were resolved.

Behavior Studies

The MMU conducted numerous behavior studies and inquiries during 2013. The areas covered were physical withholding, economic withholding, uneconomic overproduction, operation efficiency, wind generation impact, transmission reservation and scheduling practice, as well as other miscellaneous cases.

Some studies raised market power concerns; some revealed questionable market behaviors; some indicated new market trends; and others exposed inefficient operation guidelines and market rules. MMU shared these findings and results when appropriate and relevant with FERC, the SPP Board of Directors, Market Working Group, relevant RTO staff, Market Participants, and other interested stakeholders.

Given the result of this analysis and continuous review of other market power screens, there is little evidence of any market power abuse in the SPP EIS Market.

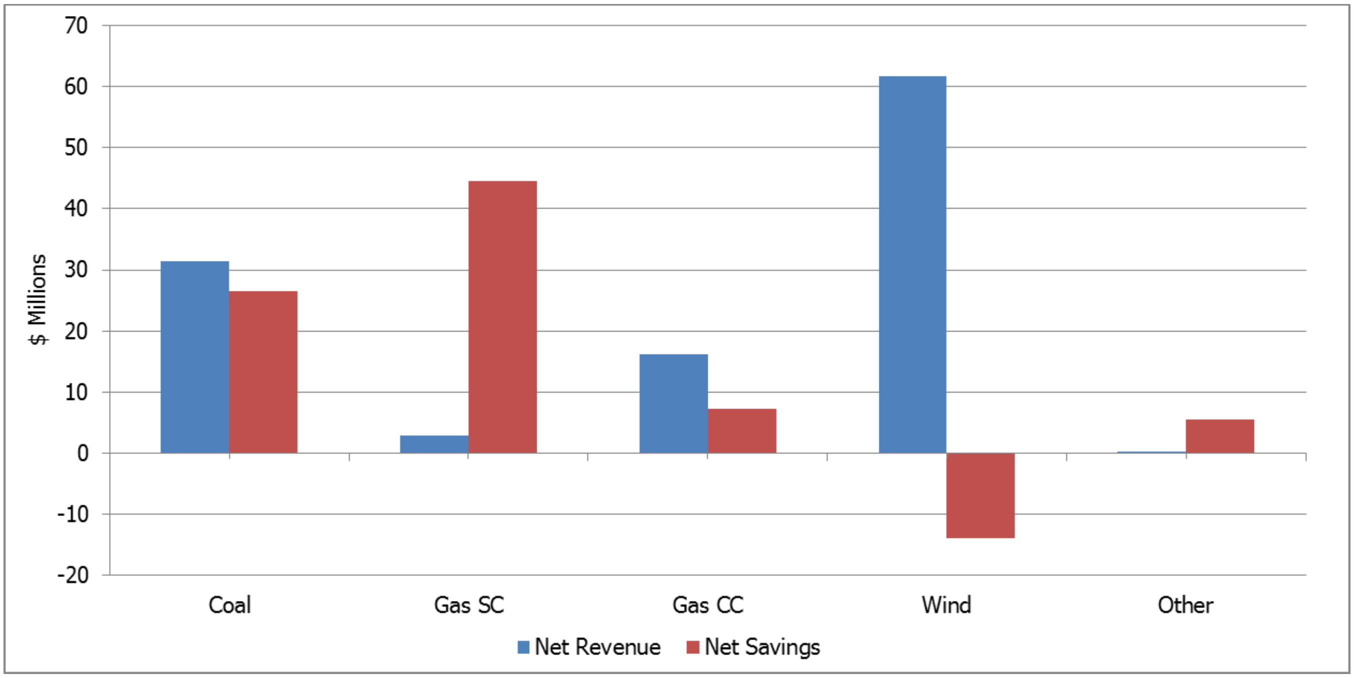
J. Production Benefit Estimates

An estimate of production benefits for the EIS Market shows savings increased from $167 million in 2012 to $182 million in 2013. Factors accounting for this increase were higher natural gas and electricity prices and Market Participants' continued increase in EIS Market participation. These results indicate the market is efficient and providing effective price signals.

Figure II.29 illustrates benefits by fuel type and primary mover technology. Net Revenue is defined as benefits to low cost generation resulting from market imbalance times the difference between marginal cost and LIP. When imbalance is positive (selling) net revenue is positive and when imbalance is negative (buying) net revenue is negative. Net Savings is defined as benefits to high cost generation resulting from imbalance times the difference between marginal cost and LIP. When imbalance is negative (buying) net savings are positive and when imbalance is positive (selling) net savings are negative.

Benefits to coal plant asset owners increased in 2013 because of the increasing differential between coal and gas prices. This shows up as higher net revenue, about 37% higher than estimated for 2012. Gas asset owner benefits increased about $14 million with the increase evenly distributed in the net savings for simple cycle units and combined cycle units. Benefits accruing to wind assets decreased slightly due to increased wind scheduling[8] despite increases in the volume of generation and electric prices.

Figure II.29 Production Benefits for 2013



EIS Market Performance Conclusion

All indications are that the SPP market was competitive and efficient in 2013. Broad metrics like HHI indicate the EIS Market was unconcentrated. Larger dispatchable range and fewer planned outages during the summer enhanced market efficiency. Market benefits have increased significantly in 2013. The offer cap impact metric showing that the offer cap system had virtually no impact on prices is another indication of a very competitive market. Nevertheless, time periods and regions experiencing congestion were monitored closely for localized market power through Economic Withholding, Physical Withholding and Uneconomic Overproduction screens followed by behaviors studies and investigations.

[8] According to the formula used to calculate production benefits, higher levels of scheduling decreases EIS benefits.

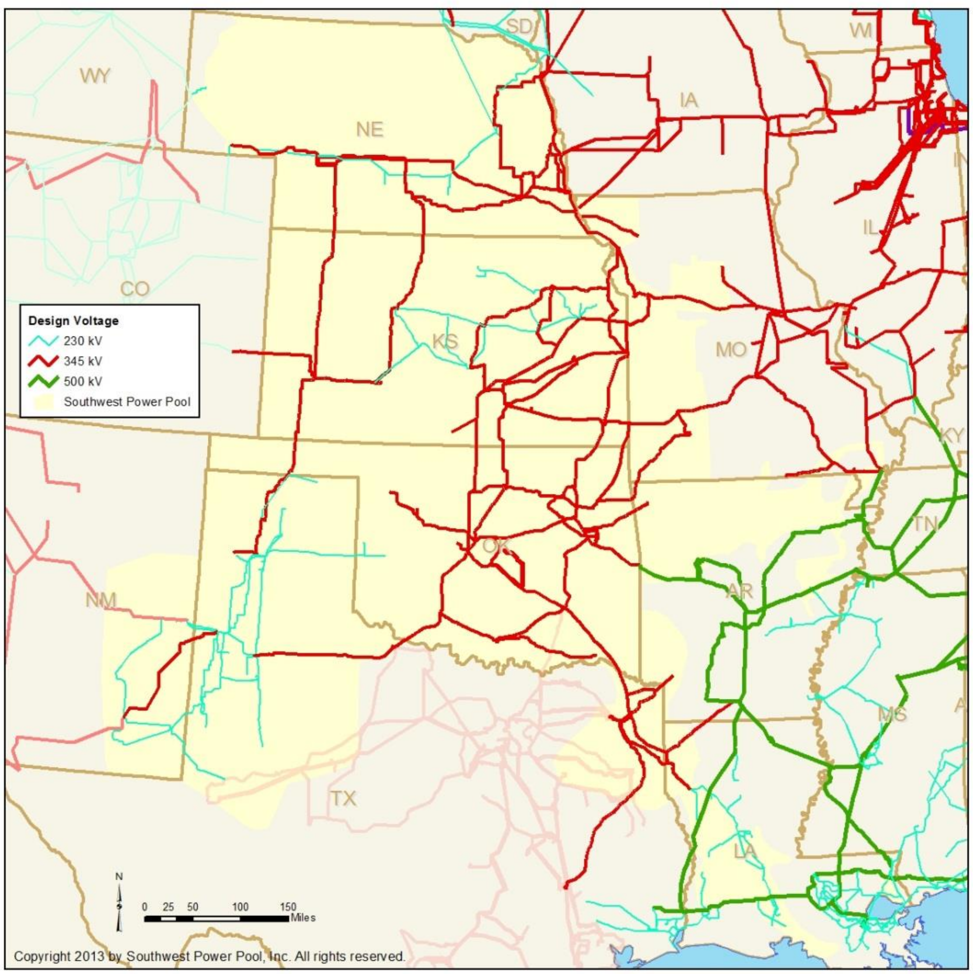
III. Energy Delivery

A. Transmission System

Transmission System Characteristics

Six primary transmission voltages are used in the SPP region: 69 kV, 115 kV, 138 kV, 161 kV, 230 kV, and 345 kV. Transmission owners in the SPP region use differing voltage levels as the backbone of their respective systems. 345 kV is the predominant voltage for much of SPP's eastern portion. 230 kV is the backbone voltage in much of the western part of the region, most notably in the Southwestern Public Service area. Regardless of the voltage, most of the SPP region uses the 69 kV as the cutoff for step-down between transmission and distribution systems. Figure III.1 shows the major transmission elements in the SPP region.

Figure III.1 Major Transmission System Elements in the SPP Region



Transmission project developers in the SPP region continue to make progress in constructing substantial transmission lines and other infrastructure. Projects close to completion that hold the most promise of relieving congestion in the SPP market are as follow:

- Tuco to Woodward 345 KV line has an expected in-service date of June 2014. This project will provide import capability to the highly congested load area in the southwest area of the market that has experienced high prices. This project will also providing export capacity to the congested generation area in the Southwest Kansas – Oklahoma – Texas Panhandle region that has experienced low prices. This region has been the most congested area in the SPP footprint for most of the last five to six years.
- Spearville to Thistle to Woodward set of 345 KV lines has an expected in-service date of December 2014. These lines will also serve the generation pocket of Southwest Kansas – Oklahoma – Texas Panhandle area helping to address the limited export capacity for generation in this area.
- Iatan to Nashua 345 KV line has an expected in-service date of June 2015. This project will help alleviate congestion in the Kansas City area.

Inter-grid Connection Points

In addition to the alternating current grid, there are six direct current (DC) ties with other interconnections. These DC ties serve as interconnection points to other grids by converting power through AC-DC-AC interfaces. Two unique characteristics of this type of interface are its controllability and stability. Energy transfers are known, easily identifiable, and tightly controlled. A list of the DC ties is provided in Figure III.2.

Two of the DC ties connect the SPP region with the ERCOT area: ERCOT East and ERCOT North. Four DC ties connect the SPP region to the Western Electricity Coordinating Council area: Lamar, Eddy County, Blackwater, and Sidney. Tie capability is also depicted in Figure III.2.

Figure III.2 DC Tie Transmission Capability

DC Tie Name	Transmission Capability (MW)
ERCOT East	600
ERCOT North	210
Lamar	210
Eddy County	200
Blackwater	200
Sidney	200

B. Transmission Service

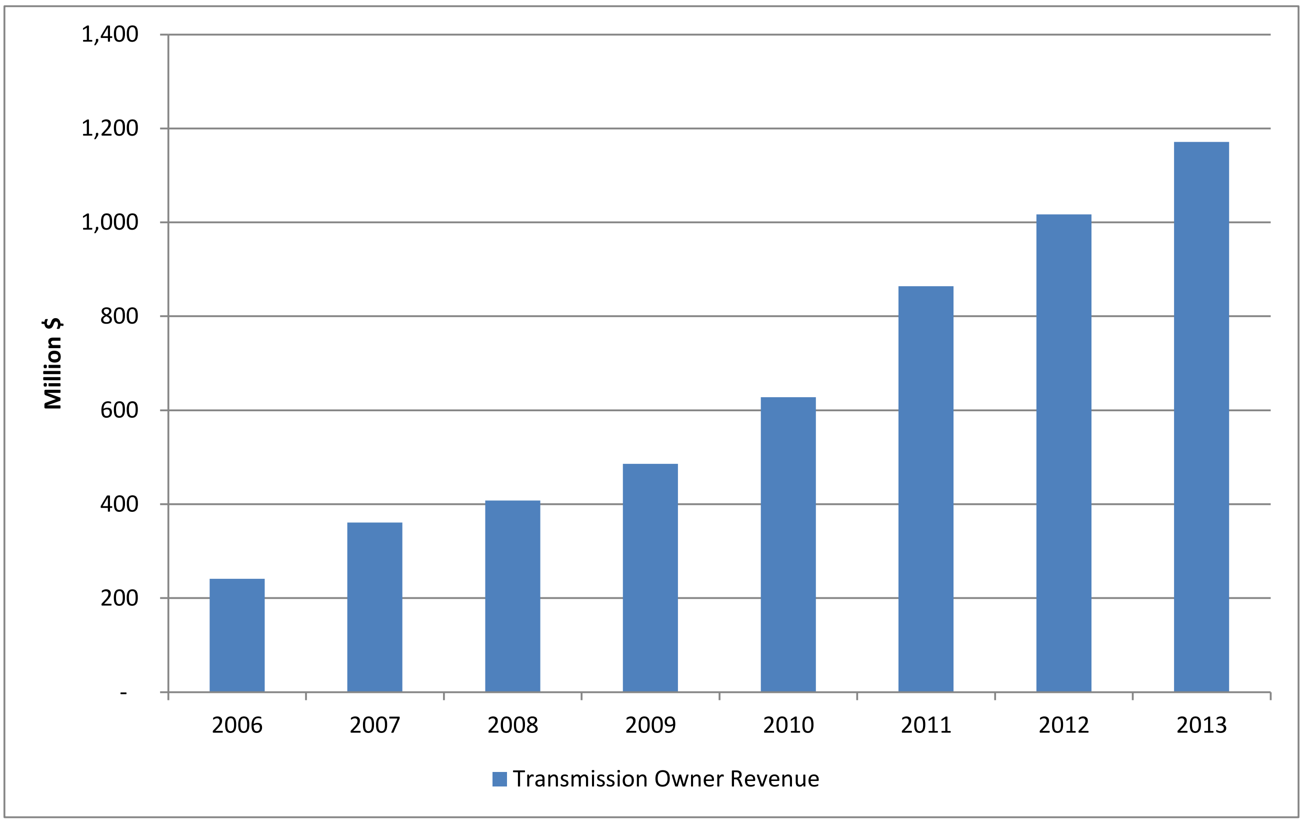
The SPP Regional Transmission Organization is obligated by FERC to manage and regulate the flow of energy across the transmission system within its territory. SPP member companies have agreed to allow SPP to administer their component transmission systems and place these transmission facilities under provisions of the SPP Open Access Transmission Tariff. The Tariff contains regulations that describe how transmission owners are paid for use of the transmission system, as well as rules pertaining to use of the transmission system itself.

Participants who want to use the transmission system must follow specific provisions outlined in SPP's Tariff, Market Protocols, and Business Practices. Market Participants work with SPP to ensure the maximum amount of transmission service requests are approved, while maintaining system reliability and security. Changes in demand patterns via transmission system flows can indicate larger economic shifts or the need for transmission system modifications. The following metrics illustrate these types of change.

Transmission Owner Revenue

Members that own transmission elements in the SPP system are entitled to revenues from use of those elements as facilitated by SPP. Figure III.3 shows total yearly revenue generated from use of the transmission system since 2006. The revenue continued to grow in 2013. Total 2013 revenue was approximately $1,171 million, a 15% jump from $1,017 million in 2012. Growth in transmission revenue is due to an increase in transmission rates. Transmission rates have been increasing in SPP in recent years due to increases in Annual Transmission Revenue Requirement. As base plan projects receive a Notice-To-Construct, the cost of these new transmission upgrades plus a reasonable return must be recovered through transmission service rates.

Figure III.3 Annual Transmission Owner Revenue

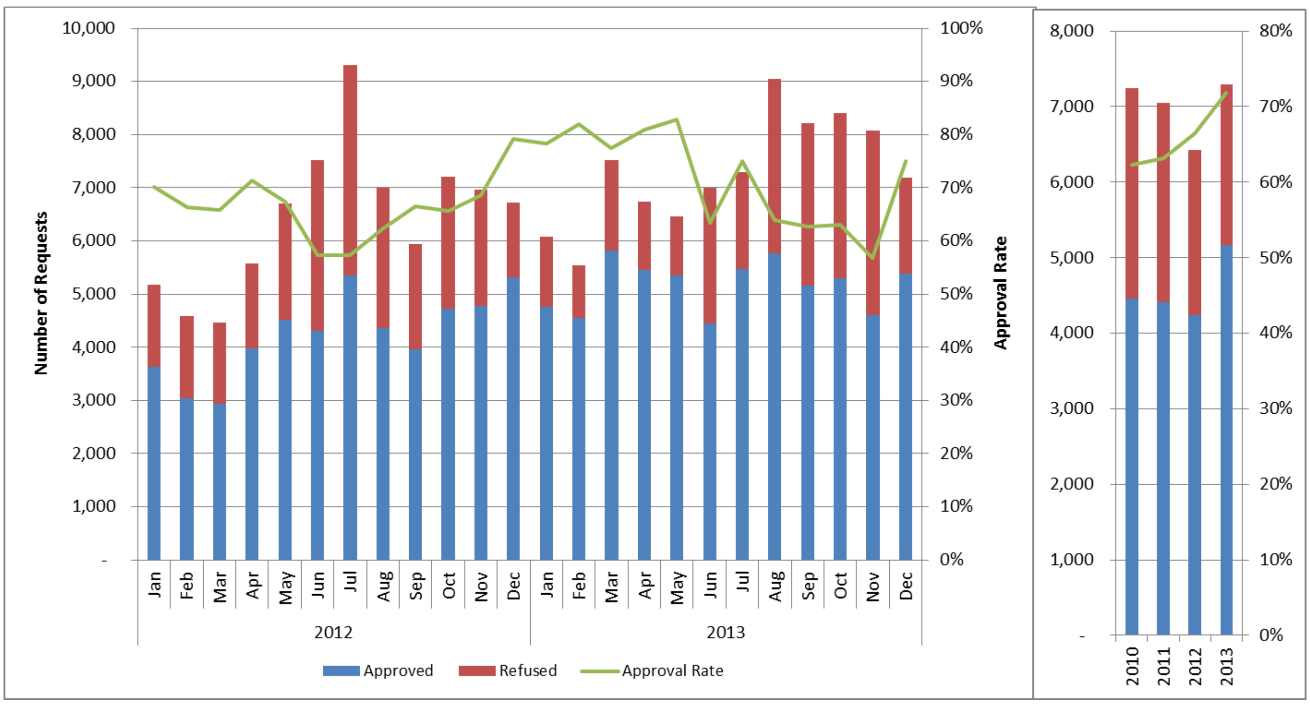


Transmission Service Request Approval Rate

Transmission Service Requests (TSRs) are made by a Participant for transmission service over SPP designated facilities. A request can be for either short-term or long-term service over a defined path for a specific megawatt amount. SPP evaluates each request and determines if it can be accommodated, then approves or denies the request accordingly. TSR approval rates and volumes are examined below.

Figure III.4 depicts the monthly and annual number of TSRs and approval rates, (number of requests approved/total number of requests). This is a measure of SPP transmission system availability. The number of TSRs submitted increased by 13% in 2013 and the approval rate increased from 67% in 2012 to 72% in 2013.

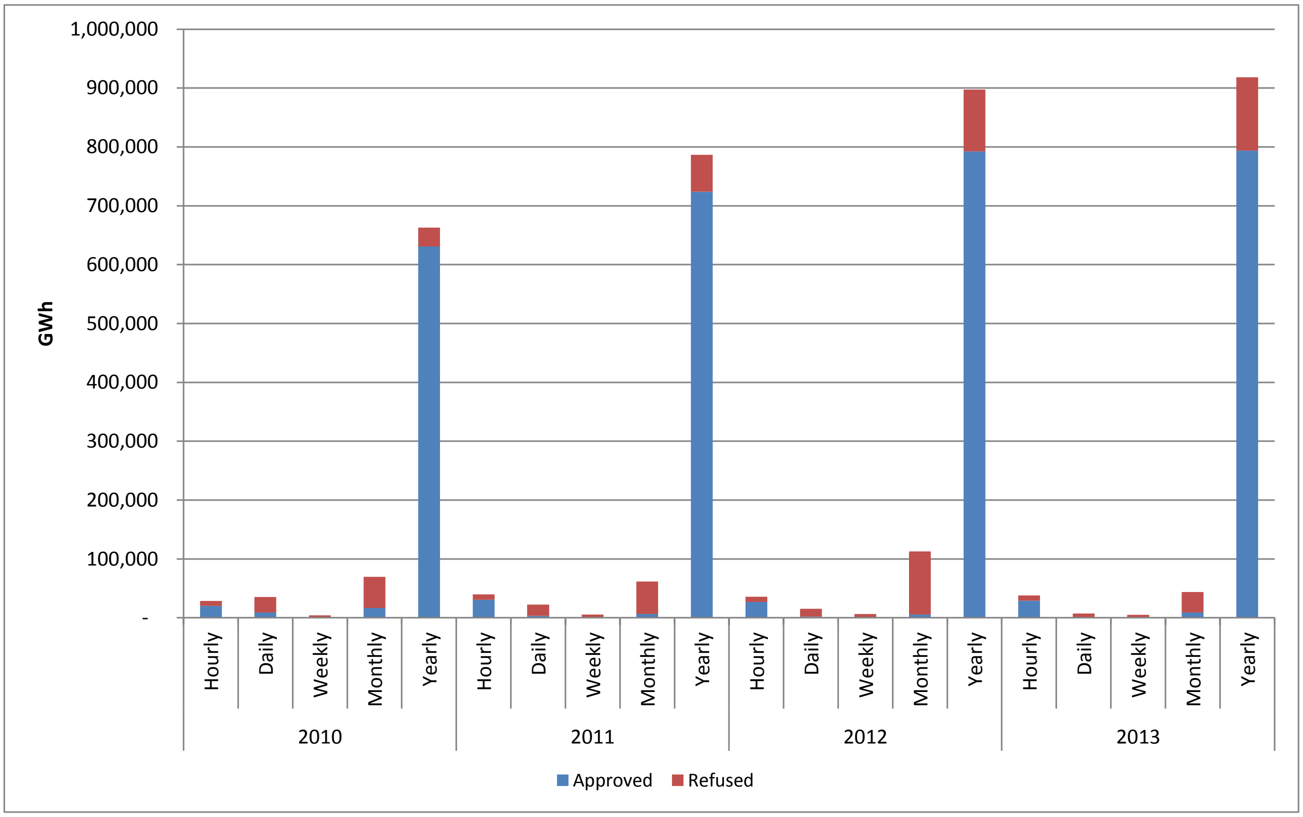
Figure III.4 SPP Transmission Availability



Transmission Service Request Volume

TSRs vary in capacity requested and duration, so it is important to look at both through a review of a volume measure combining these two elements. TSR Volume is calculated as capacity requested multiplied by the duration. Figure III.5 shows the volume of approved and refused TSRs by service increments. The yearly requests account for about 95% of the total volume. The volume of approved TSRs increased and refused TSRs decreased in 2013. The majority of the “daily” and “monthly” TSRs were refused due to failed Available Transmission Capacity evaluation.

Figure III.5 Transmission Service Requests Volume



C. Transmission Congestion

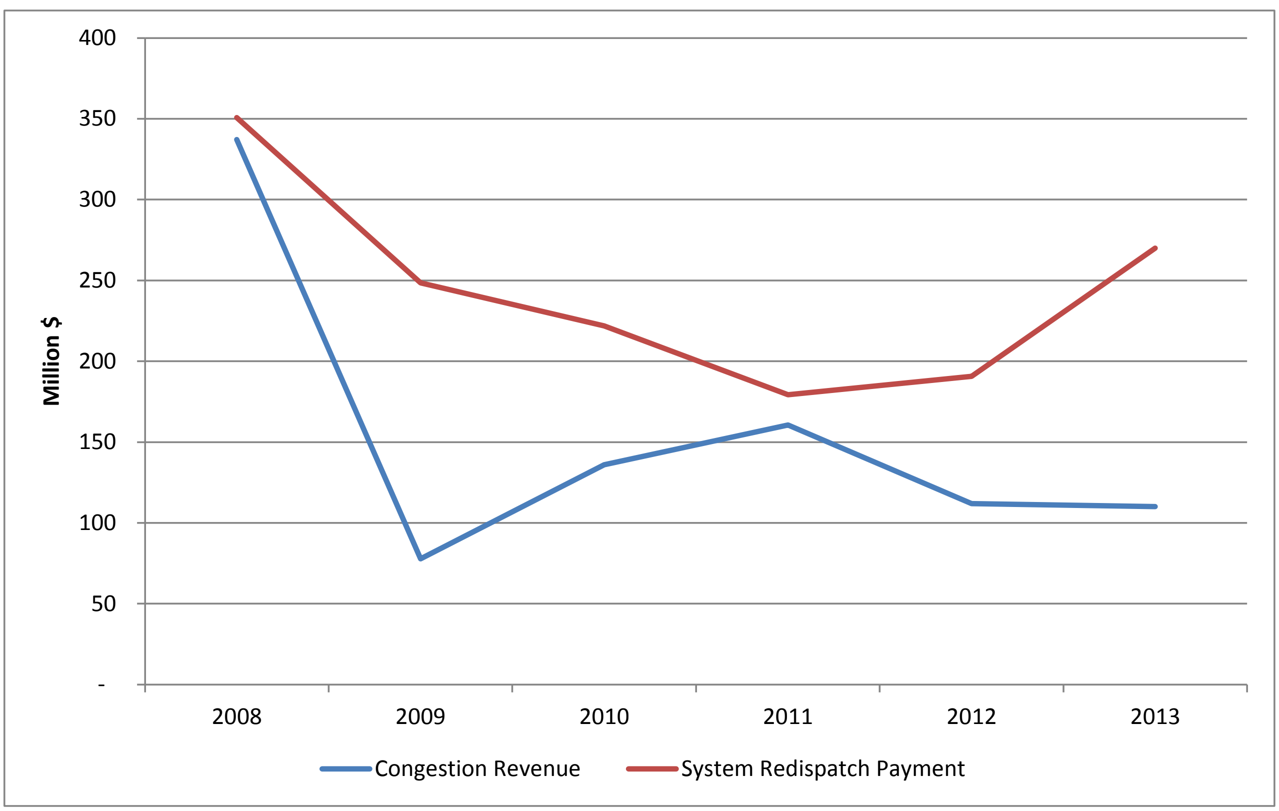
Transmission Congestion Market Impact

Ideally, the transmission system would be robust enough to allow the transfer of all economical energy to supply demand eliminating congestion. However, building such a grid would be extremely expensive and costs would exceed benefits for the interconnected system.

Transmission congestion exists on all interconnected grids. There are two measurements to assess the magnitude of congestion on the system. The first is Congestion Revenue, which is the difference between what is collected from loads and what is paid out to generators. This is the revenue that is used to compensate TCR (Transmission Congestion Rights) holders in the Integrated Marketplace. The second is System Redispatch Payment, which is the production cost reduction that would occur if increased energy transfer across congested paths were allowed.

Congestion Revenue was highest in 2008 and lowest in 2009 with little change between 2012 and 2013. Higher congestion prices were offset by less congestion on the system, resulting in stable congestion revenue. System Redispatch Payments were in steep decline from 2007 to 2011 as a result of higher level of participation by our members, more efficient congestion management procedures implemented by SPP operations, and more transmission investments. System Redispatch Payments increased significantly in 2013. Some potential causes related to congestion impacts are generation and transmission outages, loop flow, and more intermittent generation.

Figure III.6 Congestion Revenue & System Redispatch Payment

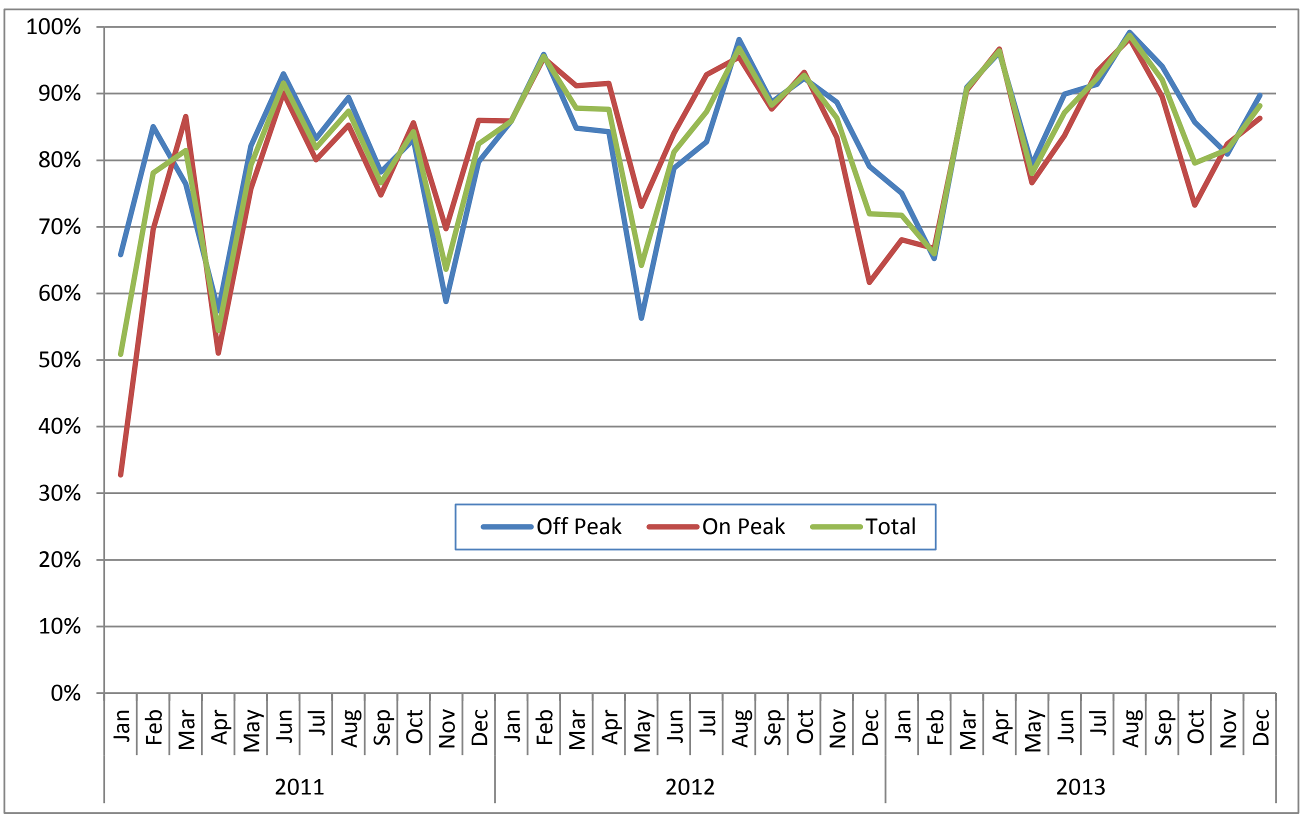


Flowgate Congestion by Time

An important consideration in analyzing overall market health is to study the transmission system congestion levels across the footprint and across time. Flowgates are used to monitor the transmission system in real-time to ensure reliability and maintain maximum efficiency. A flowgate is a transmission element or combination of elements representing a section of the transmission system over which energy flows are monitored and controlled. SPP monitors and controls flow over these flowgates to manage congestion.

Figure III.7 shows the percentage of on-peak, off-peak, and total intervals in which there was at least one congested flowgate. In 2013, at least one flowgate was congested an average of 85% of the time, a slight decrease from 2012. Transmission congestion is an indication that the transmission system is fully utilized for a specific corridor. High levels of congestion with significant price impacts could identify areas where additional transmission development would be beneficial or signal temporary conditions that are caused by transmission or generation outages. Sustained congestion indicates that new transmission investments would facilitate efficient transfer of lower cost energy.

Figure III.7 Percent Congestion by Time Status



Breached and Binding Flowgates

Another way to analyze transmission congestion is to study the total incidence of intervals in which a flowgate was either breached or binding. A breached condition is one in which the load on the flowgate exceeds the allowable limit. A binding flowgate is one in which flow over the element has reached but not exceeded its allowable limit.

Figure III.8 shows the total percent of intervals by month and year in which a flowgate was breached. The declining number of breaches between 2007 and 2011 was driven by SPP implementation of improved congestion management procedures and Market Participant's increased unit flexibility. This trend reversed in 2012 and 2013 as new problems emerged. Issues driving this change include: increasing wind generation, line outages related to transmission upgrades, and unaccounted flows from adjacent systems. The increase in breached periods is a concern since it causes an increase in price spikes and reduces dispatch efficiency. The number of breached conditions is likely to decline as significant new transmission investments are completed in 2014 and 2015.

Figure III.8 Percent of Intervals with Breached Flowgates

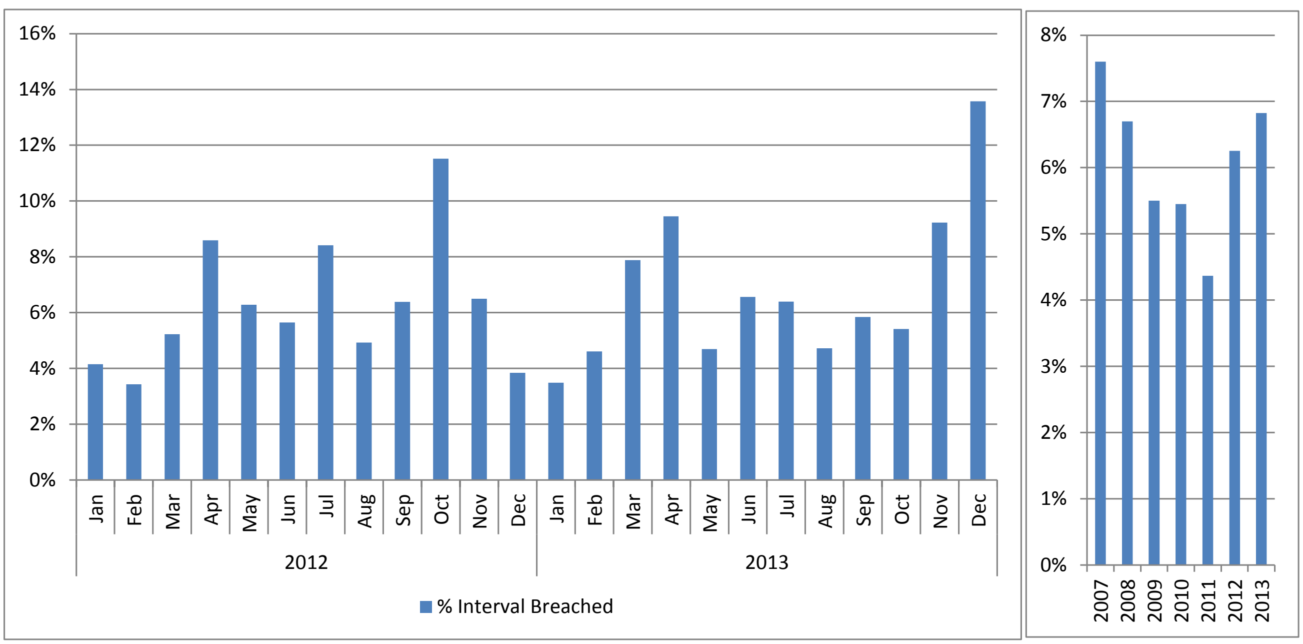
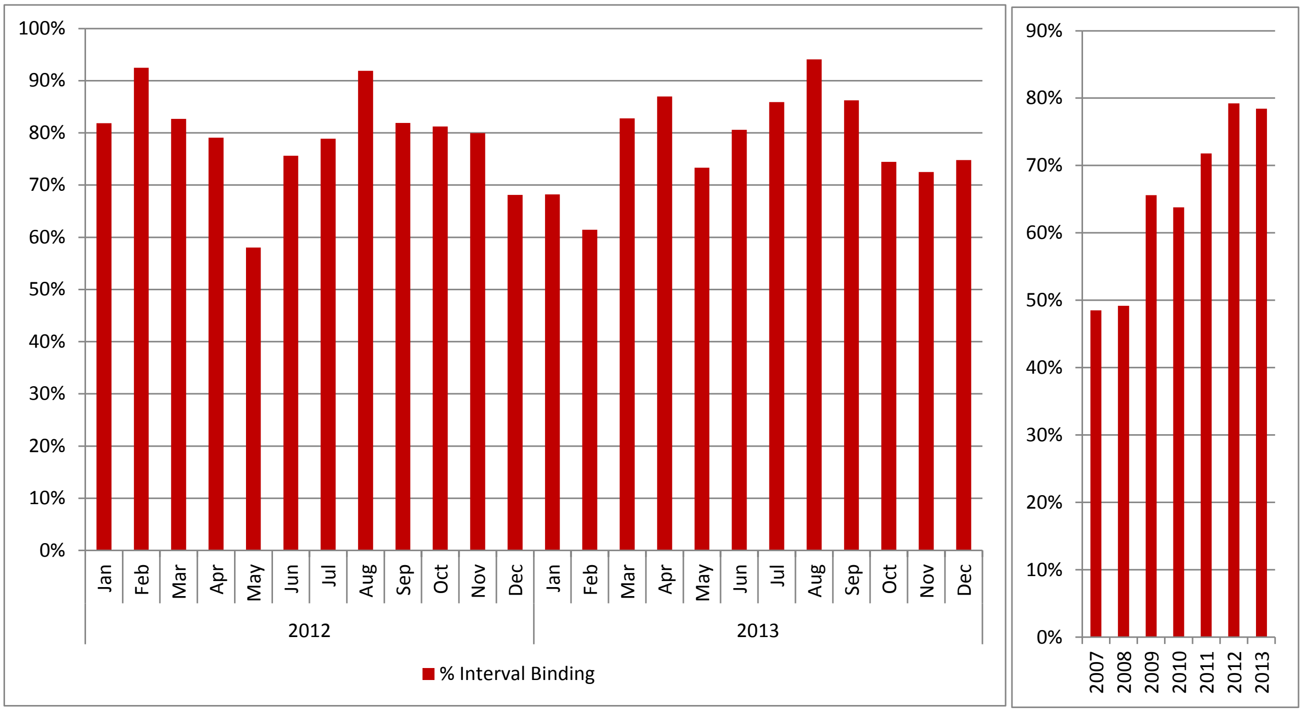


Figure III.9 displays the total percent of intervals by month and year in which a flowgate was binding. Binding flowgates compared to breached flowgates are less of a concern in that binding intervals indicates that the market is using re-dispatched capacity to manage the congestion while minimizing the cost of the constraint. A breached flowgate on the other hand indicates that the system does not have any capability to redispatch generation capacity to manage congestion. The percent of binding flowgates stayed at a high level in 2013.

Figure III.9 Percent of Intervals with Binding Flowgates



Constrained Flowgates by Shadow Price

Figure III.10 details the most congested transmission corridors and their associated flowgates in the SPP footprint. Shadow prices reflect the intensity of congestion on the pathway represented by the flowgate. Binding status has a modest impact on shadow price and breached status has a large impact on the shadow prices and the delivered price of market electricity near each respective flowgate. The figure includes a list of transmission projects that are proposed or under construction that will help alleviate the congestion. SPP Transmission Planning reports posted on the SPP web page provide detailed information on each of the individual projects.

Higher shadow prices in 2013 were caused in part by increased gas prices and resulting higher electric prices. The Texas Panhandle corridor continues to be the most congested area with the Osage Switch – Canyon East flowgate continuing to experience the highest shadow price: $44.13 during 2013, up from $12.16 in 2012. Limited import capability and low cost power north of the constraint continue to be the key factors driving this congestion. Some congestion relief is expected with the completion of Tuco to Woodward 345 kV line in mid-2014 and the Castro County to Newhart 115 kV in 2015.

The Omaha-Kansas City corridor is the second most congested area and is represented by three flowgates. This corridor is impacted by the large amount of low cost generation to the north and the limited transfer capability to move that power to the rest of the SPP market. Unaccounted for flow from outside the SPP system is another major factor. Historically this flow has been from the north to the south. The Eastowne Transformer flowgate was created to manage congestion that appeared in that Kansas City area when the transformer was installed in mid-2013. The shadow price for this flowgate was the second highest even though it only existed for half the year.

The remaining flowgates in the top-ten list are located in western Nebraska, eastern Oklahoma, and Tulsa areas and all have relatively low annual shadow price values.

Figure III.10 Principal Congested Flowgates by Area

Region	Flowgate Name	Flowgate Location (kV)	Average Hourly Shadow Price ($/MWh)	Total % Intervals (Breached or Binding)	Projects Expected to Provide Some Positive Mitigation (Estimated In Service Date – Upgrade Type)
Texas Panhandle	**OSGCANBUSDEA**	Osage Switch - Canyon East (115) ftlo Bushland - Deaf Smith (230) [SPS]	$44.13	36.7%	• Tuco Int. – Woodward 345 kV line (May 2014 - Balanced Portfolio) • Castro County Int. – Newhart 115 kV line (April 2015 - Regional Reliability) • Tuco Int. – Amoco – Hobbs 345 lines (Currently on hold – ITP10)
	GRAXFRSWEELK	Grapevine Xfmr (230/115) [SPS] ftlo Sweetwater – Elk City (230) [WFEC]	$5.97	5.0%	• Bowers – Howard 115 kV line (June 2016 – ITPNT) • Grapevine Transformer (June 2014)
	SHAXFRELKXFR	Shamrock Xfmr (115/69) [CSWS} ftlo Elk City Xfmr (230/138) [WFEC]	$2.76	1.5%	• Elk City – Gracemont 345 kV line (March 2018 – ITP10) • Potter Co. – Tolk 345 kV line (December 2018)
	SPSNORTH_STH	5 element PTDF flowgate north to south through west Texas	$2.71	10.5%	• Randall County Interchange – Amarillo South Interchange 230 kV line (May 2013)
Kansas City – Omaha Corridor	**EASXFREASSTJ**	Eastowne Xfmr (345/161) ftlo Eastowne-St. Joe (345) [GMOC]	$13.15	7.7%	• Iatan – Nashua 345 kV (June 2015 - Balanced Portfolio)
	PENMUN87TCRA ***PENMUNSTRCRA*** *(see note below)*	Pentagon – Mund (115) [WR] ftlo 87th Street – Craig (345) [WR-KCPL]	$12.73	8.8%	• Tap existing Swissvale – Stilwell 345 kV line at West Gardner (in service December 2012) • Iatan – Nashua 345 kV (June 2015 - Balanced Portfolio)
	SUBTEKFTCRAU	Sub 1226 - Tekamah (161) ftlo Fort Calhoun - Raun (345) [OPPD/MEC]	$2.70	0.5%	• SUBTEKFTCRAU is a reciprocal coordinated flowgate with MISO. There are no planned projects to provide positive mitigation.
Western Nebraska	**VICXFRWAYSTE**	Victory Hill Xfmr (230/115) [NPPD} ftlo Wayside-Stegall (230) [WAUE]	$3.23	0.8%	• Victory Hill Transformer (December 2016) • Scottsbluff – Stegall 115 kV (June 2014)
Eastern Oklahoma	**TAHH59MUSFTS**	Tahlequah-Highway 59 (161) [GRDA-OGE] ftlo Muskogee-Fort Smith (345) [OGE]	$3.05	0.9%	• Muskogee – Seminole 345kV (December 2013 - Balanced Portfolio) • Gore – Muskogee 161 kV (June 2018) • Gore – Sallisaw 161 kV (June 2018)
Tulsa Area	**OKMHENOKMKEL**	Okmulgee – Henryetta (138) ftlo Okmulgee – Kelco (138) [CSWS]	$2.70	1.7%	• Muskogee – Seminole 345kV (December 2013 - Balanced Portfolio)

Note: PENMUN87TCRA replaced PENMUNSTRCRA on 4/1/13. Their history has been combined and is reflected as one entry on this table.

Transmission Curtailments

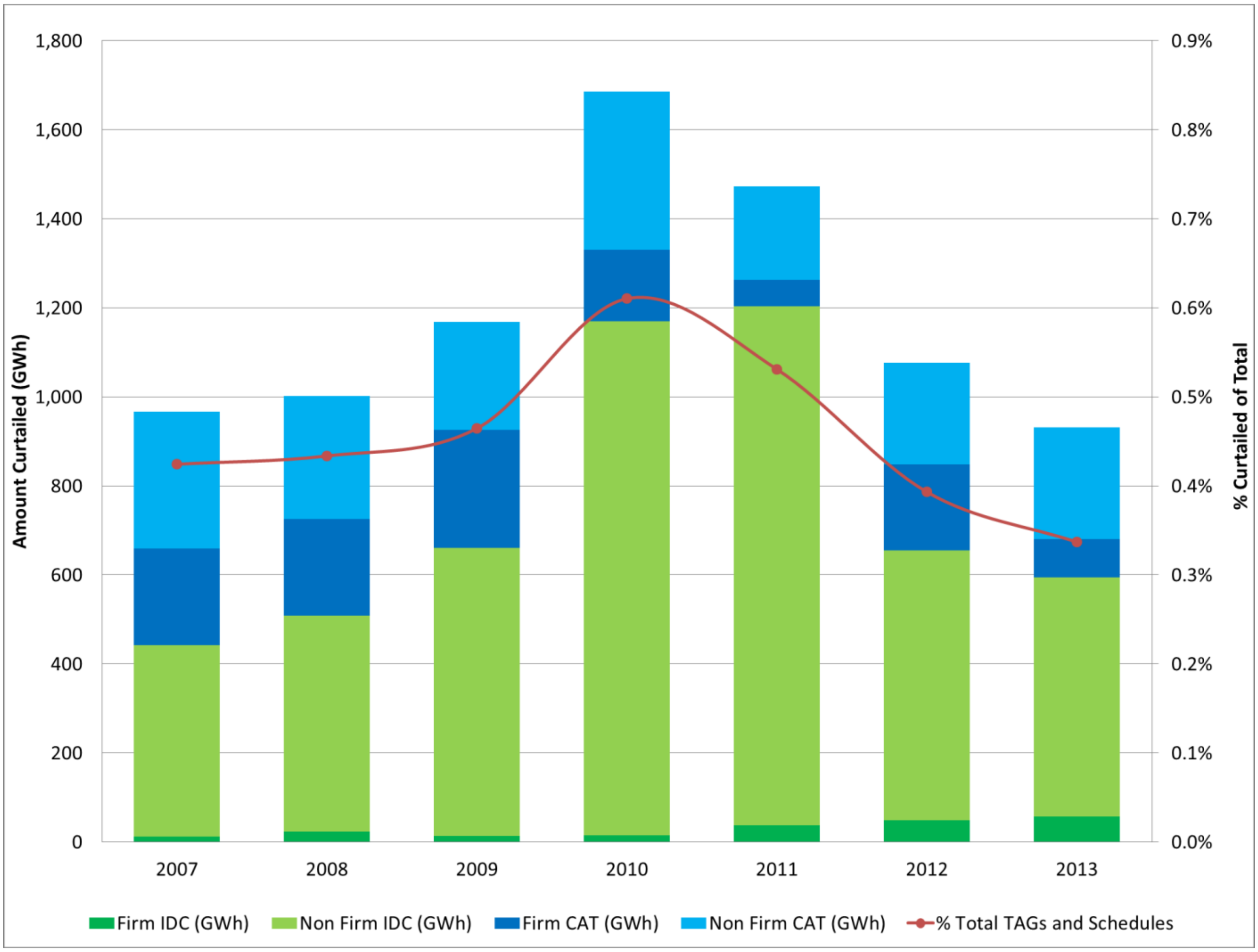
Transmission curtailments are a reduction in firm or non-firm transmission service in response to a system reliability concern. SPP EIS Market utilizes two types of transmission curtailment mechanisms: NERC Interchange Distribution Calculator (IDC) curtailments and SPP Curtailment Adjustment Tool (CAT) curtailments. NERC IDC Curtailments affect tagged Interchange Transactions (tags) that leave or enter SPP Market footprint, tagged Interchange Transactions from Self-Dispatched units, other Tagged Transactions external to SPP and Network and Native Load (NNL) external to SPP market footprint. SPP CAT Curtailments/Adjustments affect tagged Interchange Transactions from units that are not Self-Dispatched (Inter Control Area), intra-BA Schedules from Market-Dispatched units (NLS or tagged), and intra-BA Schedules from Self-Dispatched units (NLS or tagged).

Curtailments can occur when either Transmission Loading Relief (TLR) or Congestion Management Event (CME) is issued. The IDC curtailments can only occur when TLRs are issued, but the CAT curtailments can occur from TLRs and/or CME are issued. Both types curtail non-firm transmission services before firm transmission services.

For the purpose of this review, CAT curtailments are not limited to SPP flowgates. This includes curtailments on any flowgate defined in SPP EMS and MOS. The impact of non-SPP flowgates on CAT curtailments is expected to be low. The amount of IDC curtailments includes curtailments for TLR's issued by SPP and not the curtailments of SPP Members due to TLRs issued by other Reliability Coordinators. The total volume of tags/schedules in MOS does not include the parallel tags from other entities curtailed by IDC for SPP TLR events.

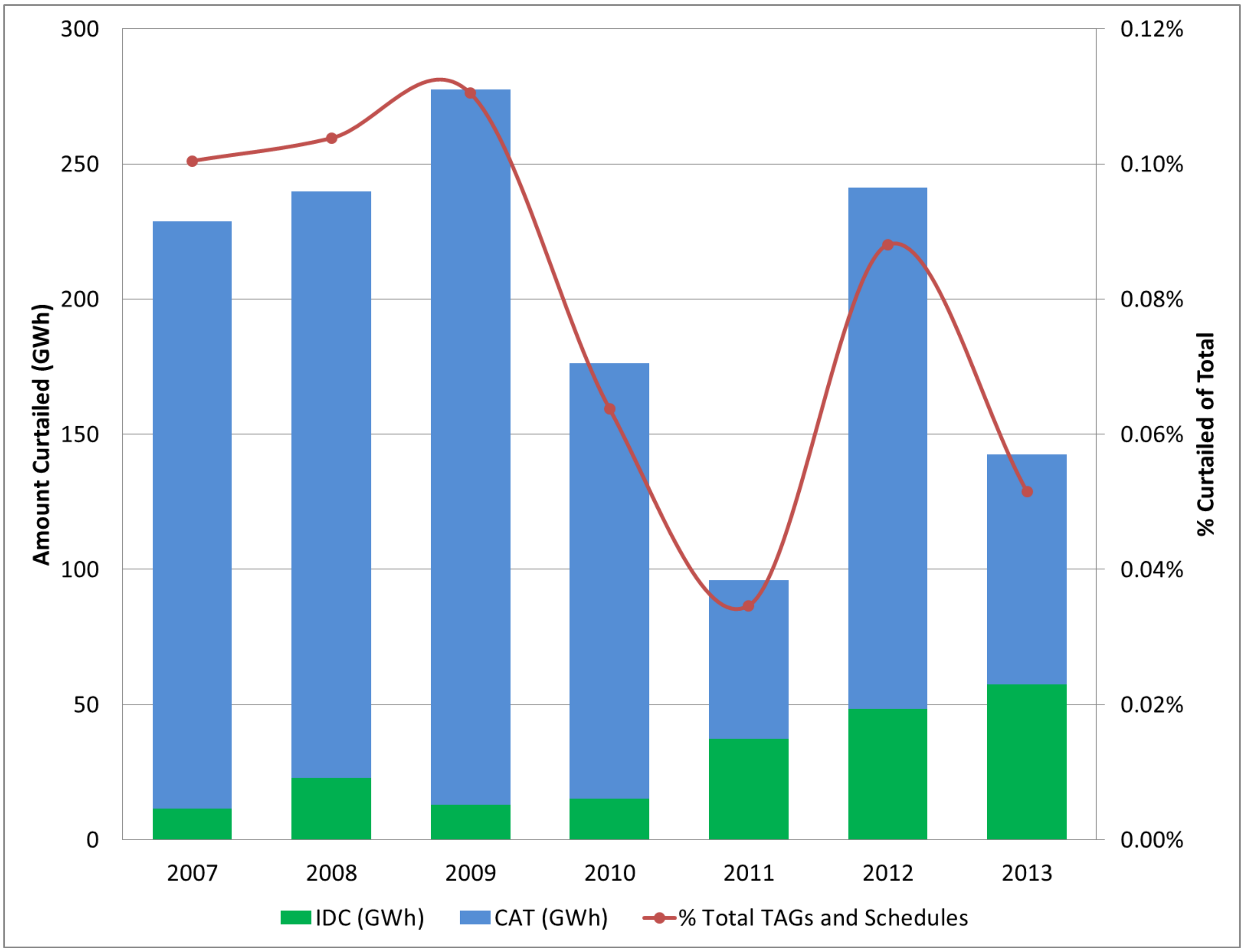
Figure III.11 shows the yearly firm and non-firm curtailments (GWh) normalized as a percent of total tags and schedules. Non-firm curtailments account for the majority of the GWh curtailed. Total amount curtailed has decreased 13.5% from the previous year with non-firm curtailments decreasing by 5.7% and firm curtailments decreasing by 41%.

Figure III.11 Total Curtailments by Year



Firm curtailments are an indication that congestion is severe. Figure III.12 shows the yearly firm curtailments (GWh) over the past several years, normalized as a percent of total TAGs and schedules. The chart reveals that firm curtailments have decreased 41% from 2012. This is similar to what was experienced between 2009 and 2011 when firm curtailments dropped almost 40% each year compared to the 150% increase in 2012. Fewer firm curtailments indicate that fewer firm customers were subjected to congestion prices.

Figure III.12 Firm Curtailments by Year



D. Transmission Outages

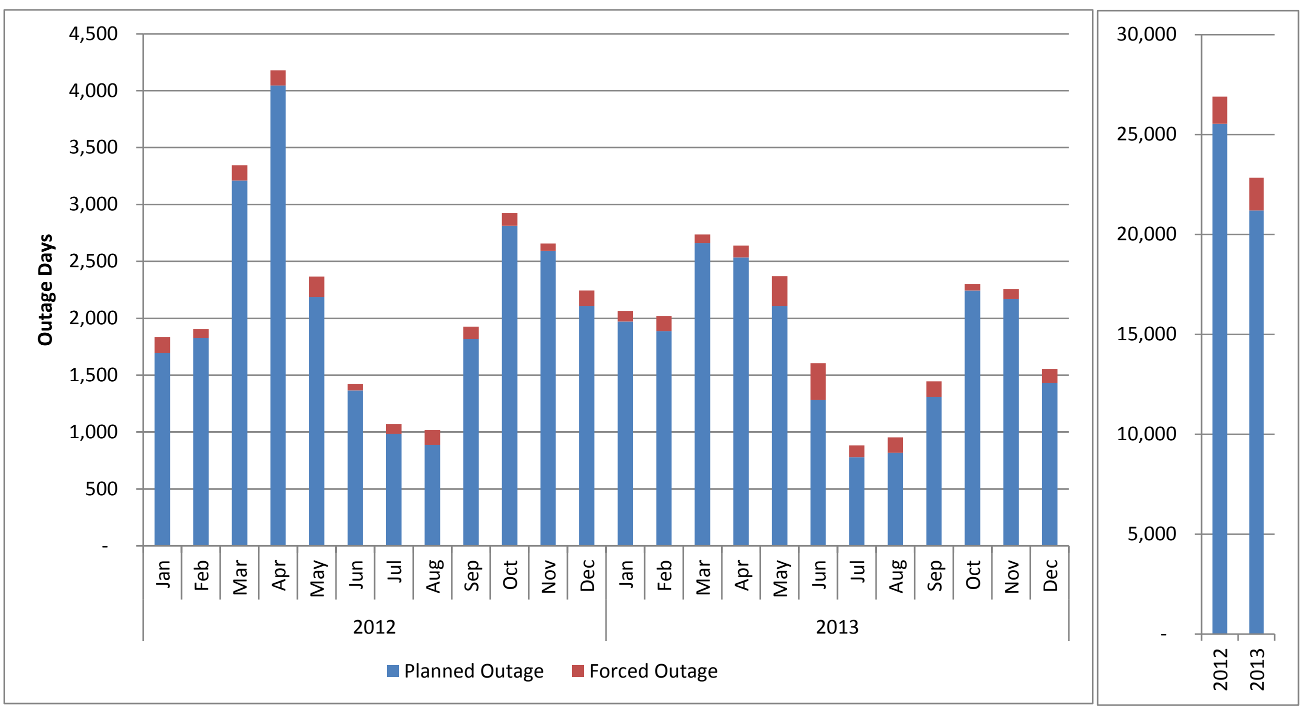
Transmission elements experience outages for a number of reasons. Outages may be the result of maintenance or some other scheduled unavailability, or may be caused by unforeseen circumstances such as storm damage, accidents, fires, and equipment malfunction.

Transmission Outage Days

Figure III.13 shows total transmission outage days for 2012 and 2013. A transmission outage day is the total number of days in which a transmission element is out of service. For instance, if two transmission elements are out of service for one week, the number of transmission outage days would be {(2 elements X 7 days outage) = 14 transmission outage days}.

Between 2012 and 2013, the number of transmission outage days decreased. Numbers from earlier years are not included in this analysis because SPP implemented a new outage reporting tool (Control Room Operations Window) in late 2011. Data for earlier years are not from the same database and therefore not directly comparable. Similar to generation outages, transmission outages follow a seasonal pattern. More planned outages are taken in the shoulder months and fewer planned outages are taken during summer peak months. Forced outages are random; therefore there is no typical pattern. Planned transmission outage days decreased by 17% while forced transmission outages increased by 21% in 2013.

Figure III.13 Total Transmission Outage Days for 2012 and 2013



E. Transmission Investment

SPP as a Regional Transmission Organization has a responsibility to develop transmission expansion plans that will ensure both the long and short-term reliability of the system, as well as ensure that the system is cost effective and adequately robust. SPP has developed several Transmission Expansion Plans in past years; 2013 was no exception. The 2014 SPP Transmission Expansion Plan highlights many key areas of transmission development and provides an outline of forecast capital outlays necessary to ensure that the transmission system remains adequate for both current and future needs.

The 2013 SPP Transmission Expansion Plan (STEP), published in January 2014, summarized 2013 activities that impact future development of the SPP transmission grid. Ten distinct areas of transmission planning are discussed in the report, each of which are critical to meeting mandates of either the 2013 SPP Strategic Plan or the nine planning principles in FERC Order 890 and 1000. These areas are:

- Transmission Services
- Generation Interconnection
- Balanced Portfolio
- High Priority Studies
- Sponsored Upgrades
- Sub-region Planning
- Transmission Congestion and Top Flowgates
- Interregional Coordination
- Project Tracking

The 2014 STEP consists of 386 transmission upgrades throughout the SPP region with a total cost of $6.2 billion dollars. Costs were allocated by project type:

- $99 million for Generation Interconnection projects
- $86 million for Transmission Service projects
- $535 million for Balanced Portfolio projects
- $1.38 billion for High Priority projects
- $4.13 billion for ITP projects

Potential investments to reduce congestion on highly constrained flowgates are continually being evaluated through the STEP process. For more details see the *2014 SPP Transmission Expansion Plan Report that is posted on the SPP web page*.

IV. Market Developments

The following issues are related to the SPP market but not directly represented by other metrics. This section highlights noteworthy events, macro trends and significant market changes that have effected or may affect the SPP region.

A. Natural Gas Development

Natural gas supplies in the U.S. continue to expand as shale gas reserves are developed. Shale development is the primary reason total imports of energy declined in 2013 to the lowest level in more than two decades. Most of this decline is due to the increase in domestic crude oil production. In 2013 oil production grew 15%. Natural gas production continues to expand but at a much lower rate, about 1% in 2013 as compared to 5% in 2012 and 7% in 2011.

The dramatic increase in natural gas production and proven reserves associated with shale formations is having a lesser impact on the SPP electric market than on the industry as a whole. The very low average annual gas prices of $2.64 per MMBtu in 2012 resulted in some displacement of coal by natural gas. This impact was short lived as natural gas prices increased to an average of $3.58 per MMBtu in 2013. Because most coal supplies in the SPP region originate in the low cost Powder River Basin, the gas price needs to be in the $2.00 range before gas generation begins to directly displace coal generation. This actually occurred during late spring and early summer in 2012 resulting in the lowest level of coal generation as a percent of total generation since the start of the EIS Market.

With gas prices increasing about 34% in 2013, gas and coal shares of total generation returned to more normal historical levels. Coal generation increased to about 62% of total SPP generation in 2013 from a historic low of about 60% in 2012, though less than 64% experienced in 2011. Gas generation decreased from 26% in 2012 to 20% of total generation in 2013. The dramatic increase in wind production appears to be displacing simple cycle gas generation more than gas combine cycle or coal generation.

The most likely impact of relatively low gas prices and the dramatic increase in proven reserves will be on long-term decisions to build new generation. The substantial proven natural gas reserves will reduce the risk of fuel supply disruptions and long term price volatility for combine cycle and simple cycle gas turbine generation. The reduced supply risk along with lower capital cost requirement and lower environmental risk are factors that are going to favor gas generation investment for the foreseeable future. This outlook with regard to gas generation investments is not likely to influence investments in new generation in the near term because of the relatively high reserve margin in the SPP region. Generation investments other than wind plants are likely to be very limited. Investments in transmission infrastructure that are reducing congestion are also reducing the incentive for new generation projects.

B. SPP Seams Issue

SPP continued to focus on the eastern border of the SPP footprint specifically the December 19, 2013 integration of the Entergy utilities into the Midcontinent Independent System Operator (MISO) because of the concern of additional external impacts. This integration could eventually result in an additional 4,000 MW of transfer between the MISO Midwest and South areas resulting in increased flows across SPP and other neighboring areas. To allow a transitional period for MISO and neighboring areas (Joint Parties) to gain experience with changing flow patterns, a temporary seams agreement was developed known as the Operations Reliability Coordination Agreement (ORCA.) Parties in this agreement are:

- Associated Electric Cooperative Inc.
- Louisville Gas and Electric Company
- Midcontinent Independent System Operator
- PowerSouth Energy Cooperative
- Southern Company
- Southwest Power Pool
- Tennessee Valley Authority

Key aspects of the ORCA include a phased-in approach allowing increasing flow between the MISO Midwest and South areas and developing methodology for measuring this flow between areas known as the Dispatch Flow Limit.

> Phase 1: Dispatch Flow Limit = 2000 MW through April 19, 2014 (1500 MW during times of congestion)
> Phase 2: Dispatch Flow Limit set with two day ahead process through October 1, 2014
> Phase 3: Dispatch Flow Limit set with one day ahead process through April 1, 2015

All phases are subject to completion of testing and validation as outlined in the ORCA.

In addition to the development of this reliability agreement, debate continued through 2013 on the appropriate transmission rights obtained by MISO to transfer above its base transmission capacity of 1000 MW between the Midwest and South regions. On December 3, 2013, the United States Court of Appeals for the District of Columbia Circuit vacated and remanded FERC’s 2011 order pertaining to Section 5.2 of the MISO-SPP Joint Operating Agreement which MISO argues allows the sharing of transmission paths between SPP and MISO which would allow for transfers to exceed 1000 MW. SPP maintains that use of the system above the 1000 MW transmission capacity is subject to compensation under a Service Agreement. The integration on December 19 has seen Dispatch Flow Limits reported by MISO to be in excess of their obtained 1000 MW transmission rights for which SPP expects compensation for the intentional flow. FERC ruled in early 2014 that four related dockets regarding the SPP-MISO dispute will be consolidated for FERC settlement decisions or at hearing before a FERC Administrative Law Judge.

SPP and MISO issued a Memorandum of Understanding in October 2013 to establish a process for the 2011 Alternative Dispute Resolution regarding Market Flow calculations. The main focus was to address the methodologies used to account for import and export transactions which were contingent upon similar requirements being incorporated into the MISO-PJM JOA. All three RTOs discussed these changes to Market Flow calculations by introducing consistency between Market Flow, Firm Flow Entitlement, and Interchange Distribution Calculator calculations. The changes to the pertinent JOAs will be filed to be effective 1 June 2014; however, there are remaining differences in methodologies amongst the RTOs. MISO and PJM will change to a Marginal Zone method for modeling of transactions for all the aforementioned calculations while SPP will remain with the Point of Receipt/Point of Delivery concept.

In June 2013, SPP and MISO filed revisions to the JOA to reflect market-to-market (M2M) terms and conditions. Many aspects of the SPP-MISO M2M are modeled after the MISO-PJM M2M. SPP and MISO began coordinating efforts on M2M in 2013 and have a scheduled implementation date of March 1, 2015. SPP also continued coordination with adjacent areas in the development of Tariff language regarding FERC Order 1000's transmission planning and cost allocation. Also announced in November 2013 was the Integrated System's recommendation to pursue formal negotiations to join SPP. The Integrated System consists of the Upper Great Plains Region of Western Area Power Administration, Heartland Consumers Power District, and Basin Electric Power Cooperative.

C. Access to Market Information

Previous ASOM reports pointed out the benefits of SPP providing more information to Market Participants. Transparency is important since it is one of the theoretical conditions required for a free market to be efficient. Buyers and sellers must have a high level of trust and thereby confidence in the market in order for them to actively participate in the market. SPP has made significant strides in expanding market data available to Market Participants as part of the Integrated Marketplace startup. The new market is not the focus of this report, however, it is worth noting that a substantial amount of Integrated Marketplace data is now available. The data is accessible at SPP.org/Integrated Marketplace/Public.

E. Integrated Marketplace Design – Phase II

With the successful launch of the Integrated Marketplace, SPP has begun the process to incorporate additional features into the Marketplace design, some required by FERC and others at the request of members. This section will provide a brief description of the new design features that will have direct impacts on market efficiency.

Market-to-Market: A Market-to-Market process is scheduled for implementation by March 1, 2015. The process is governed by a joint operating agreement between SPP and the Midcontinent ISO (MISO). The process allows for one RTO to relieve the congestion on the other's system and be compensated for the congestion relief. For example, if MISO is experiencing congestion on a transmission facility and an analysis shows that it is more economical for SPP generators to provide congestion relief, then through the Market-to-Market process, the SPP generators will be re-dispatched to provide congestion relief and in this example, MISO will compensate SPP generators for providing the relief. This process will allow for more efficient congestion relief on the seams and should also contribute to the convergence of the energy prices at the seams.

Regulation Compensation: SPP will implement a new pricing mechanism for the procurement of regulation. This change is to comply with FERC Order 755. The new pricing mechanism will incorporate performance measures that account for generators' differences in ramping capabilities as well as the ability to accurately respond to regulation deployment. This change will provide better price signals and improve the efficiency of the regulation market.

Long-Term Congestion Rights: Long-Term Congestion Rights (LTCR) will be implemented in October 2014. This is in response to FERC Order 681. Long-Term Congestion Rights are used to hedge long-term supply arrangements. The term length of a Long-Term Congestion Right can range from one year to the length of service for a corresponding transmission service reservation. This compliments the standard Transmission Congestion Right which has durations of one year or less. Long-Term Congestion Rights will reduce congestion cost uncertainty and incentivize long-term power supply arrangements.

Enhance Combined Cycle: The enhanced combined cycle logic will allow the SPP commitment process to consider multiple combined cycle configurations and choose the configuration that is most efficient. Additionally, the new logic will model the cost of transitioning between configurations which will incorporate more flexibility to the commitment process. For example, an optimal commitment of a combined cycle generator may call for one configuration for a first part of a commitment period, and then a transition to a second configuration for the remaining hours of commitment. This change will lead to more efficient commitment of combined cycle generators.

V. 2013 Conclusions and Concerns

Market Participation

Market Participants continued a long stretch of increasing participation in the SPP wholesale electric market. Self-Dispatch status continues to hover around 1%, down from about 15% when the market started. Manual status (start up, shut down, test, etc.) continues to be at about half the level experienced during the first few years of this market. Ramp rate and dispatchable range offers continue a positive long term trend of increasing. All of these activities increase the responsiveness of the market in managing congestion and increase the efficiency of the market. SPP continues to add Market Participants to the rolls as well. These are all positive indications that the market is effective, efficient and provides incentives for increased participation in the EIS Market.

Market Structure

The EIS Market continues to be highly competitive with measures indicating low levels of market concentration. The very low impact of the offer caps on prices is an additional indication that the market is very competitive. A resource margin in the 47% range also indicates that there is reduced risk of the possibility of abusive practices. These positive indicators in no way diminish the obligation for diligent market monitoring.

Market Performance

The increase in estimated production benefits for 2013 continues to indicate strong market performance. The increase was 9% above 2012 to about $186 million. Low levels of Revenue Neutrality Uplift and very low financial impact of re-pricing are other indications that the market is effective and that prices are reliable. Market Participants received payments based on prices that were very close to what was indicated when production was committed to the market.

Price volatility across the SPP footprint increased slightly in 2013 as compared to 2012 but remains at a level significantly less than most prior years. The Nebraska area continues to be more volatile than the rest of the market with the western Kansas region now experiencing increased price volatility. This is consistent with other trends in the market mostly driven by the significant increase in wind generation in the western-central part of the market footprint. SPP price volatility continues to be significantly less than that experienced in adjacent markets when measured on an hourly system price. This price stability creates confidence in the market and encourages higher levels of market participation improving overall market performance. Continued market price stability is contrary in some ways to other metrics that indicate congestion is increasing such as the increase in breached interval and the increase in flowgate shadow prices.

Concerns

Highly Congested Areas – Congestion in the Omaha-Kansas City corridor is as persistent as it is complex. Historic prevailing flow in this transmission corridor is from north to south driven by low cost production in Nebraska in the form of coal generation using low cost Powder River Basin coal, base load nuclear power, and hydro. The economic optimum flow of this low cost power at times exceeds the capacity of the transmission system. As stated in previous reports, this corridor is also impacted by unaccounted for flow from outside the SPP Market Footprint. This flow from adjacent regions has been predominantly from the north to the south. In 2013 the external impact has been more varied. Most of the time the external flow was from the north but for a substantial amount of time the flow was from south to north. The magnitude continues to be high causing significant impacts. As reported in previous years, high levels of unaccounted flow on a congested corridor can result in inequities when curtailments are required. Entergy joining the MISO market in late 2013 and the installation of the Eastowne Transformer in mid-2013 are adding to the complexity and intensity of congestion in the Kansas City area.

The Texas Panhandle area continues to be the most congested region of the SPP footprint. This poses a concern considering the concentration of generation ownership in a high priced area and reduced efficiencies resulting from high levels of congestion. The level of congestion in this corridor increased substantially in 2013 as reflected in the flowgate shadow prices. The Osage Switch – Canyon East flowgate annual average shadow price was $44 compared to the next highest level of $13 for the Eastowne Transformer flowgate in the Kansas City area. Several 345 KV transmission lines currently under construction will begin serving the Panhandle region in 2014. The new lines will provide much needed import capability into the southwest region of the market footprint and at the same time provide export capability to the wind producing region of western Kansas and the Panhandle region.

Transmission corridors that are frequently constrained have an adverse impact beyond increasing overall cost of production and causing price divergence across the congested flowgate. Congestion can actually be a barrier to accessing the diversity in the market reducing operational flexibility. When the only generation unit with available ramp capability for meeting load change is behind a congested flowgate, the result may be a ramp shortage. Highly constrained flowgates have had a detrimental impact by causing more frequent price spikes which are sometimes driven by ramp breaches. The new transmission investments in the Oklahoma/Texas Panhandle region of the SPP market will have a significant positive impact by making the SPP market more fully integrated. Nowhere is this more important than in the Texas Panhandle area.

Wind Generation - Wind production continued to increase dramatically in 2013 accounting for 11% of total annual generation and at times 33% of generation for a specific hour. This level of generation from a source that is more volatile than load and less controllable than conventional generation capacity is having adverse impacts on the system. This is highlighted by the fact that in some years wind production at system peak is at 34% of wind nameplate capacity and other years it is at 5%.

A number of corrective actions were implemented in 2013 and others are close to being implemented to help address concerns about wind generation. In 2013, SPP Operations implemented new processes and procedures that resulted in fewer generation reduction directives even though wind generation increased from 2012. Implementation of market rules in 2013 that require Variable Energy Resources that were commercially operational after October 2012 to be dispatchable was also an important step. Establishing SPP as the consolidated balancing authority for the entire market footprint as part of the Integrate Marketplace implementation was also another important step by increasing the diversity across the region and reducing the local impact of wind. As mentioned earlier, the new transmission investments with a commercial operations date of mid-2014 will improve overall market operations by reducing the barriers to accessing market diversity.

Definitions of Select Terms

Alternating Current - the movement of electric charge that periodically reverses direction

Balancing Authority- The responsible entity that integrates resource plans, maintains load-interchange-generation balance, and supports Interconnection frequency

British thermal unit - amount of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit

Congestion Management Event - process by which the market recognizes flowgate limits and dispatches resources accordingly, used chiefly when no curtailable transactions in the IDC are present

Direct Current - the movement of unidirectional electric charge

Energy Imbalance Service - the real time balancing between scheduled generation and load

Energy Imbalance Service Market - the overall market structure surrounding the provision of EIS

Flowgate - A designated point on the transmission system which serves as a monitoring point for energy flows, and through which the interchange distribution calculator calculates the power flow interchange transactions

Generator to Load Distribution Factor - a numerical representation of the relative impact a generator has on a flowgate. If a GLDF is .1, for any 100 MW change in output there is a corresponding effect on the flowgate of 10 MW

Gigawatt hour - 1 thousand MWh or a measure of electrical energy equal to an accumulation of 1,000,000,000 watts in a one hour period

Independent System Operator - Responsible for coordinating, monitoring and controlling the operation of the electric system within its territory

Kilovolt – 1,000 volts

Locational Imbalance Price - The point specific price that results from the market operations system

MM (mm) - Equivalent Roman numeral representation of one thousand thousand, or 1,000,000

Market Operating System - The SPP system that creates Locational Imbalance Price (LIP) and deployment instructions for participating resources

Market Participant - As defined in the SPP Tariff

Megawatt - an instantaneous measure of electrical energy equal to 1,000,000 Watts

Megawatt hour - A measure of electrical energy equal to an accumulation of 1,000,000 watts in a one hour period

Open Access Transmission Tariff - SPP's transmission tariff as posted on SPP's website

Revenue Neutrality Uplift - Process used to ensure that SPP remains revenue neutral in every market interval by either adding a surcharge or distributing money back to participants

Regional Transmission Organization - Organization responsible for moving electricity over large areas, commonly at higher voltages and over larger areas than covered by an ISO

Transmission Loading Relief - A process used to reduce loading on lines which are at risk for an overload

Common Acronyms

Acronym	**Term**
AC	Alternating current
AECC	Arkansas Electric Cooperative Corporation
AECI	Associated Electric Cooperative Inc.
AEPW	American Electric Power
AFC	Annual Fixed Cost
BA	Balancing Authority
BTU	British thermal unit
CLEC	Cleco Power LLC
CME	Congestion management event
CT	Combustion Turbine
DC	Direct Current
DISIS	Definitive Interconnection System Impact Study
DOE	Department of Energy
EHV	Extra High Voltage
EIA	Energy Information Administration
EIS	Energy Imbalance Service
EMDE	Empire District Electric Co.
ENTR	Entergy, Incorporated
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GLDF	Generator to Load Distribution Factor
GMOC	Greater Missouri Operations Company
GRDA	Grand River Dam Authority
GWh	Gigawatt Hour
HHI	Herfindahl-Hirschman Index
IA	Interconnection Agreement
INDN	City Power & Light, Independence, Missouri
IOU	Investor-Owned Utility
IPP	Independent Power Producer
ISO	Independent System Operator
KACY	Board of Public Utilities, Kansas City, Kansas
KCPL	Kansas City Power & Light
kV	Kilovolt (1,000 volts)
LAFA	City of Lafayette, Louisiana
LEPA	Louisiana Energy & Power Authority
LES	Lincoln Electric System
LIP	Locational Imbalance Price
LNG	Liquefied Natural Gas

Continued from previous

(Acronym	**Term)**
MIDW	Midwest Energy, Inc.
MISO	Midcontinent Independent Transmission System Operator
MKEC	Mid-Kansas Electric Company
MM	Thousand Thousand
MMBtu	Thousand Thousand British Thermal Units (1,000,000 Btu)
MMU	Market Monitoring Unit
MOS	Market Operating System
MP	Market Participant
MPS	Missouri Public Service
MRO	Midwest Reliability Organization
MW	Megawatt (1,000,000 watts)
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NPPD	Nebraska Public Power District
O&M	Operation and Maintenance
OASIS	Open Access Same-time Information System
OATT	Open Access Transmission Tariff
O/S	Over-Scheduling
OKGE	Oklahoma Gas & Electric
OMPA	Oklahoma Municipal Power Authority
OPPD	Omaha Public Power District
PISIS	Preliminary Interconnection System Impact Study
RE	Regional Entity
RNU	Revenue Neutrality Uplift
RTO	Regional Transmission Organization
SERC	SERC Reliability Corporation
SMP	System Marginal Price
SPP	Southwest Power Pool, Inc.
SPS	Southwestern Public Service Company
SECI	Sunflower Electric Power Corporation
SWPA	Southwestern Power Administration
TLR	Transmission Loading Relief
TRE	Texas Regional Entity
UD	Uninstructed Deviation
U/S	Under-Scheduling
VRL	Violation Relaxation Limit
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WERE	Westar Energy, Incorporated
WFEC	Western Farmers Electric Cooperative