BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION	)	
OF OKLAHOMA GAS AND ELECTRIC	)	
COMPANY FOR COMMISSION	)	
AUTHORIZATION OF A PLAN TO	)	
COMPLY WITH THE FEDERAL CLEAN	)	CAUSE NO. PUD 201400229
AIR ACT AND COST RECOVERY; AND	)	
FOR APPROVAL OF THE MUSTANG	)	
MODERNIZATION AND COST	)	
RECOVERY	)	

Direct Testimony of
Jennifer B. Tripp

On Behalf of
Sierra Club

Public Version

December 16, 2014

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I. INTRODUCTION

Q: Please state your name, title, affiliation, and business address.

A: My name is Jennifer B. Tripp. I am an Executive Consultant and Managing Director of Transmission and Delivery with nFront Consulting, Inc., an energy consulting firm based in Florida.

Q: Please describe nFront Consulting, Inc.

A: nFront Consulting, LLC ("nFront") is an energy consulting firm that includes experienced engineers, analysts, and consultants providing consulting services to utilities, financial institutions, governmental entities, independent power producers, and other entities that transact in the energy industry. My business address is 2465 Southern Hills Court, Oviedo, Florida 32765. My physical address is in Evergreen, Colorado.

Q: On whose behalf is your testimony offered?

A: This testimony was prepared on behalf of Sierra Club.

Q: What is your role in this proceeding?

A: I have been asked to review the Oklahoma Gas & Electric ("OG&E") Environmental Compliance Plan ("ECP") Filing ("OG&E Filing") and supporting documents to assess the reasonableness of OG&E's decision not to consider wind resources because of transmission delivery considerations and capacity value, to review the ProMOD[1] modeling done by OG&E, and to analyze any reliability considerations.

Q: Please briefly describe your education background and professional experience as it relates to your role in this proceeding.

A: I have a Bachelor of Science from the University of Cincinnati in Electrical Engineering and a Masters of Business Administration from Thunderbird School of Global

[1] ProMOD, licensed by ABB/Ventyx, is a production cost software model, which can simulate full security constrained economic dispatch in its "SCED" or nodal mode using its Transmission Analysis Module ("TAM"). For more information on this module, see http://www.ventyx.com/~/media/files/brochures/promod_technical_overview_data_sheet.ashx

Management in Global Business Administration. I have over twenty-five years of experience in the energy industry, which has included work as an employee of a utility, Ohio Edison Company, now named FirstEnergy, as a Principal and Vice President of R.W. Beck/SAIC, as an Executive Consultant working for BP Wind (via Clover Global Solutions), and in my current position as Managing Director of Transmission and Delivery at nFront Consulting. I am a registered professional engineer in the state of Arizona. I have testified in a number of state utility regulatory commission and Federal Energy Regulatory Commission ("FERC") proceedings on various issues, including timing and need for transmission and generation assets and alternatives to proposed asset additions.

Throughout my career, I have focused on various technical, transmission, market, financing, and regulatory issues in the energy industry, including at nFront and R.W. Beck, where I managed a team of transmission planning, security constrained economic dispatch, and market analyses professionals. Technical efforts I have led include examinations of nodal-based congestion, also referred to as security constrained economic dispatch ("SCED"),[2] and curtailment analyses of variable energy resources, cost benefit analyses, timing and need for transmission and generation facilities, interconnection, transmission service, transmission rate recovery, portfolio analyses, and transmission expansion planning.

I have been involved in electricity restructuring and wholesale markets since the inception of Order No. 888, supporting numerous clients on the evolution of transmission and generation requirements, independent system operator markets, contractual arrangements, integration of variable energy resources, financing of power assets, transmission expansion, congestion risks and curtailment mitigation. I also have extensive experience in issues of reliability planning, inter-regional planning, and

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[2] FERC definition of security constrained economic dispatch, or SCED was adopted from Section 1234 of EPAct 2005 as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." Page 4 of the December 2014 FERC document (http://www.ferc.gov/legal/staff-reports/2014/AD14-14-operator-actions.pdf) describes that unit dispatch is determined through a security constrained economic dispatch (SCED) optimization process. The phrase "security constrained" denotes the fact that the unit commitment and economic dispatch decisions are made subject to the condition that transmission system constraints are not violated and resource supply offer parameters and operating characteristics are honored.

operational planning, and have led transmission and delivery risk assessments for financing about two hundred renewable and fossil generating assets.

Q: Describe your experience specific to the SPP regional transmission organization.

A. I have worked for SPP load-serving entities since the early 2000's, providing counsel on strategic planning for power supply, timing and need for transmission facilities, and generator siting; I have counseled natural gas and wind generating plant developers in the areas of resource siting, market need, interconnection, transmission service, and transmission delivery risks; and I have counseled the lender community on financing generating plant assets, providing detailed evaluation of the transmission cost, service, congestion, curtailment, and market risks presented by proposed developments.

In 2011, I took a full-time contract position with BP Wind in Houston. I was recruited initially to lead BP's transmission risk assessment for financing of its 470 MW Flat Ridge II wind farm, located within the Southwest Power Pool ("SPP"). Beyond that, I also evaluated the impact of transmission expansion plans, supported BP Wind's transition to the SPP Integrated Marketplace ("IM"), developed congestion and curtailment assessments for various wind resources within SPP, evaluated risks associated with firm energy delivery outside of SPP, was integral in the development of BP Wind's transmission congestion rights strategies, and led curtailment mitigation strategies for wind plants outside of SPP.

Q: Have you ever testified before the Oklahoma Corporation Commission?

A: No, I have not, but I filed testimony in a proceeding before the Oklahoma Corporation Commission that was settled prior to going to hearing.

Q: Does your curriculum vitae, which is attached as JBT-1, and the experience described above fairly and accurately represent your experience?

A: Yes.

Q: Have you reviewed the OG&E ECP Filing?

A: In preparing this testimony, I have reviewed OG&E's Application, portions of its 2014 Integrated Resource Plan ("IRP"), and the testimony and exhibits of Leon Howell and John Reed, and OG&E responses to numerous data requests.

Q: What other materials and information did you review in preparing your testimony?

A: I also reviewed the OG&E's ProMOD modeling, which it provided in response to Sierra Club Data Request 2-4, the SPP's Market Protocols, market data, transmission expansion plans, generation interconnection queue, flowgate information and other associated information, including wind plants under power purchase agreements.

II. <u>OUTLINE OF TESTIMONY</u>

Q: Please provide an outline of your testimony.

A: In my testimony, I first provide background on how the SPP functions, particularly with respect to responding to congestion. This background section describes tools load-serving entities can use to address congestion risk. Next, I evaluate how much wind OG&E could reasonably and reliably purchase, in light of how much wind its neighboring utilities have pursued and historically low wind power purchase agreements prices. I then respond to two major justifications OG&E provides to support its refusal to consider wind: 1) its claim that it did not receive reasonable responses to its Request for Information regarding available wind power purchase agreements ("PPAs") because wind generators would not assume 100% of curtailment risk, and 2) its claim that the capacity value of wind is limited to 5% of the resource's nameplate capacity. Next, I evaluate OG&E's ProMOD modeling used to produce "market prices." Finally, I address how the Commission can evaluate compliance options, such as retirement of the Sooner plant, without fear of creating reliability issues.

III. SUMMARY OF OG&E'S APPLICATION WITH RESPECT TO WIND.

Q Does OG&E analyze whether it would be more economical to replace the energy from the Sooner units with wind generation than it would be to retrofit the units?

A No. OG&E excludes wind from its analysis altogether, stating that in two years it will re-evaluate wind as a resource.

Q What reasons does OG&E provide for this decision?

A OG&E offers three primary justifications for this decision: first, it claims that transmission constraints prevent it from investing in additional wind at present; second, it claims that it did not receive any attractive offers for wind in response to its 2013 Request for information; and third, that wind does not provide sufficient capacity value to offer a suitable replacement for the Sooner units.

I will address each of these claims in turn.

IV. ANALYSIS OF THE AVAILABILITY OF TRANSMISSION TO RELIEVE CONGESTION CONSTRAINTS IN OG&E'S TERRITORY

Q: One of the justifications OG&E cites to support its decision not to evaluate wind is transmission constraints in SPP. OG&E states that it will "[d]efer expanding wind energy for at least two years, or until transmission constraints are relieved and there is greater certainty as to the value of wind in the SPP IM."[3] Does your analysis suggest that OG&E's decision is reasonable?

A: No. As explained below,

- While congestion has existed in SPP in the area of some of OG&E's existing wind plants, several new transmission lines went into service in late 2014 and OG&E already has approval to construct for a final major 345 kV line in the area.
- While OG&E declined to accept attractive wind plant bids, its neighbors Public Service Company of Oklahoma ("PSO") and Southwestern Public Service ("SWPS") both added wind contracts, for total contracted capacity at or near 25% of their peak demand.
- I also conclude that OG&E could reliably and economically integrate 20 to 25% of its peak demand with wind resources or up to about 1,500 MW of wind.

[3] See 2014 IRP.

A. Background on the Framework of the Southwest Power Pool

Q: Please briefly describe the SPP market.

A: As a Regional Transmission Organization, SPP is mandated by FERC to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity. In order to ensure reliable operations and competitive wholesale electricity prices, SPP operates and administers Energy and Operating Reserve Markets and Transmission Congestion Rights Markets (described in Section IV.B.). On March 1, 2014, SPP restructured its energy markets by implementing the Integrated Marketplace ("IM"). The SPP IM includes a day-ahead market with transmission congestion rights, a real-time balancing market, and a consolidated balancing authority with a centralized dispatch of resources. The IM is not a capacity market so all market participants, including OG&E, still must independently meet their capacity and ancillary service obligations. SPP developed Market Protocols and provide background information, guidelines, business rules, and processes for the operation and administration of the SPP IM.[4]

SPP is considering expanding its territory to include the Integrated System consisting of Western Area Power Administration Upper Great Plains East, Basin Electric, and Heartland. This change would enlarge the footprint of SPP to include the remainder of Nebraska and most of South and North Dakota, and limited other areas of the eastern interconnect near those states. Each of the companies in the Integrated System has proposed to join SPP by October 31, 2015. It is unknown as of the date of this testimony whether the Integrated Systems will join SPP, but in November 2014, FERC approved the majority of the SPP tariff changes required for such integration.

Q: Please describe how the transmission system generally operates.

A. Serving electricity consumers requires a combination of electric power generators, a transmission grid, and a distribution network, which predominantly provides a delivery mechanism from the transmission grid to retail consumers of electricity. System demand

[4] Pages 57 and 58 of the SPP Market Protocols
http://www.spp.org/publications/Integrated%20Marketplace%20Protocols%2022.pdf

is the aggregate customer electricity usage. The system demand varies as electricity usage changes, such as the increase that typically occurs each morning as consumers wake up and use more electricity. From a transmission terminology standpoint, the system demand is distributed into loads, which represent the aggregate of consumers demand served from that point on the transmission network.

The transmission system itself is a physical network of transmission lines, substations, transformers, and other associated equipment. The transmission system is typically operated in a "normal" configuration, with all transmission facilities in service. Understanding the impact of power transfers, from generation to load, on a transmission system requires understanding an important characteristic of an alternating current system: for any given system configuration and generation dispatch, power is delivered from generation to load in precisely the most efficient manner by distributing flow (in proportions that can be calculated mathematically) over all paths between the generator and the load. As a result of this physics, each generator (injecting energy) and loads (withdrawing energy) contributes some amount to the power flow of each transmission facility making up the path. The closer (in electrical terms, which does not have to do with physical distance but instead with electrical "distances" represented by impedance) a generator or load is to a specific transmission facility, the greater the flow impact it will have on that facility. Regardless of electrical distance, it is possible to calculate the contribution to flow from dispatch of a generator or alteration of a load, on any individual transmission line or transformer on the interconnected grid. The contribution to flow of a generator on a transmission line is referred to as a "generator shift factor."

A second characteristic of alternating current transmission systems is that, when a transmission line or transformer goes off-line unexpectedly (i.e., trips), power transfers automatically, and essentially instantaneously, to the remaining parallel facilities on the grid. This has the inherent benefit that when a transmission facility is forced (or scheduled) out of service, power instantaneously redistributes itself. Transmission systems are planned with a reliability margin to account for the planned or unexpected outage of transmission facilities. This is important to understand because transmission constraints do not necessarily occur when the transmission line (or transformer) actual reaches it thermal or operating limit, but instead can become constrained when a forward-looking analytical model determines that the reliability limit would be reached if, not when, the loss of any other transmission line or transformer occurred. The reason for this is complex, but the critical issue is that, if the outage did occur, the transmission line and associate equipment could be physically damaged if this operating margin was not in effect.

The reliability of grid operations and the ability to manage transmission flows through altering (redispatching) the output of generating resources (based on the ability calculate the contribution to flow of a generating resource on any transmission line), provides the foundation of a locational marginal pricing ("LMP") system. Each "load" point on the transmission system, as well as each point where a generating plant interconnects is referred to as a "node." For load-serving entities, each load point within the load serving entities' area is aggregated into a single load price, which is referred to as a load zone. In the context of the LMP market, it is a "pricing node," as described in the following section.

Q: How do these characteristics of the transmission system factor into a location marginal pricing system?

A. The fundamental attribute of an LMP-based market is the imposition of transmission costs on electricity generators depending on their location during periods of constrained transmission. As generation is dispatched to serve the system demand, transmission facilities providing the delivery mechanism between generating resources and load are an integral part of the wholesale electricity markets, not only for reliable service to load but also for economic reasons. Altering transmission flows requires a change in the generation dispatch or a change in the load profile. While demand-side management procedures can alter the distribution of load on a more localized level, they are rarely used for system-wide management of transmission flows. Instead, redispatch of generation is the tool primarily used for managing transmission constraints. Because it is possible to calculate the generator shift factor on any transmission line, it is possible to identify the most effective unit to increase (or decrease) flow on a given segment of line.

However, changing the dispatch of the larger contributor to flow may not be (and in fact often is not) the most economic solution.

Q: How is the LMP impacted by congestion or transmission constraints?

A: Delivering generation to load in the most economic manner requires an unconstrained transmission system. Transmission is constrained when the level of flow on the transmission facility or group of facilities (generally referred to as a flowgate) reaches a thermal limit (a flow limit that, if not reduced, can damage the transmission facility or cause other reliability issues) or operating limit (a limit that is set somewhere lower than the thermal limit for reliability reasons). A grid without transmission constraints allows the grid operator to dispatch the generation on an "economic" basis with the lowest cost units dispatched first, followed incrementally by increasingly more expensive units, up to the level necessary to meet system demand, taking into account operating reserves and other operating limitations. This "economic" order of dispatch is referred to as "merit order" from the lowest priced unit to the highest priced unit necessary to meet the system demand.

When a constraint occurs, however, the flow on the constrained section of transmission must be reduced to alleviate the overload. As discussed previously, changing the flow requires reducing the dispatch (energy output) of a generating unit that increases flow over the constrained transmission section (export side of the constraint). However, to maintain a level of generation matching the system load, that also means increasing the output of generation elsewhere on the system. The decision of which generating plants to dispatch up and dispatch down is a function of both the contribution to flow on the constraint and the "price" (bid or offer) of the generating unit. A security constrained economic dispatch model will select the least-cost solution to alleviate the constraint. However, the overall system generation dispatch cost has increased because of the constraint. This incremental system dispatch cost is referred to as a "congestion" cost. The LMP is the marginal cost of supplying, at least cost, the next increment of system demand at a specific location (node) on the electric power network taking into account this congestion at each node on the system.

When the system is unconstrained, the marginal energy (or reference) price is the same across SPP and is equal to the offer of the most expensive unit dispatched in the merit order. When the congestion cost is introduced, LMPs across the system diverge with some nodes moving higher (those that would reduce flow on the constraint or constraints) and others moving lower (those that would increase flow on the constraint or constraints). The impact of a constraint on the market can be illustrated by its shadow price, which reflects the intensity of congestion on the constraint. The shadow price indicates the marginal value of an additional megawatt of relief on a given constraint in reducing the total production costs.

B. Tools for Addressing Congestion and Transmission Constraints in the SPP.

1. Managing Congestion Risk: Transmission Congestion Rights

Q: What is the process for integrating new resources into the transmission system?

A. SPP administers the Open Access Transmission Tariff which includes procedures for generator interconnection and transmission service. Generating plants desiring to interconnect with the SPP system must file a generator interconnection request under the Open Access Transmission Tariff. The generator interconnection process does not include determination of need, but instead provides the technical studies to determine the transmission upgrades required to interconnect the resource. Delivering the output of the resource requires transmission service. Load serving entities ("LSEs") can file a transmission service request for network integration transmission service which, when granted, allows the LSE to designate the resource as a designated network resource.

Q: Please explain how a transmission service request for network integration transmission service can serve to manage congestion risk for delivery of generating resources.

A. Network integration transmission service, subject to any redispatch limitations, is eligible for auction revenue rights that can be converted to transmission congestion rights ("TCRs"). The denomination of a TCR is in megawatts between a specified source (e.g., a designated network resource node) to a specified sink (e.g., the load zone of the TCR holder), and the TCR provides the TCR holder the value of the congestion cost (difference in marginal congestion component of the source and the sink) times the megawatts held, a value which can be positive or negative (as explained below). TCRs are financial instruments and are independent from the amount of megawatts scheduled from the source to the sink. TCRs are a tool that can be used in hedging (or managing) congestion between the designated network resource point of interconnection and the LSE’s load zone or between other eligible points on the system. The SPP Market Protocols describe the process in detail, but the amount of TCRs’ megawatts is not a fixed quantity over the year but can vary between months or seasons (periods) and on-peak or off-peak (class).[5] The charges and credits to TCR holders are calculated on a daily basis and included on the settlement statements consistent with the timing of the Energy and Operating Reserve Markets settlement as described under SPP Market Protocols Section 4.5.9.24.

Q: Please explain the pros and cons of using TCRs as a tool to manage congestion costs.

A. Congestion costs, described in more detail later, can be positive or negative, and holding a TCR can at times create an incremental cost as opposed to a benefit. A TCR entitles its owner to be charged or receive compensation when there is congestion between specific points on SPP's transmission grid in the day-ahead market. Likewise, the process of managing auction revenue rights and transmission congestion rights decisions requires effort, targeted analytics, and a solid understanding of the IM. Determining the megawatt amount of transmission congestion rights to “hold” to manage congestion associated with delivery of variable energy resources, such as wind resources, can increase the analytical complexity.

Q: Please explain how auction revenue rights and transmission congestion rights can be used to manage congestion associated with variable energy resources.

A. A variable energy resource differs from typical fossil fueled generating resources, such as coal or natural gas plants, in that its dispatch is not controlled in the same manner, e.g., set to a certain megawatt output level. Therefore, the amount of TCR megawatts has to account for the variable energy resources production over the applicable period as well as potential production deviations between day-ahead schedules and real-time balancing

[5] Periods and Class are described on pages 577 and 578 of the SPP Market Protocols, Revision 22

market production. Still, TCRs are an effective tool for managing congestion costs for transactions from resources, including variable energy resources. As a result, SPP publicly posts considerable data to support market participants in the required analytics, such as the "Reference Price"[6] for each source/sink combination for each TCR product, historical pricing information, and even the ProMOD production models that SPP uses for planning. TCRs are not a tool to mitigate the congestion cost in each hour as the TCR level is fixed for each class (on or off-peak) period (month or season) and resource dispatch changes. TCR holders thus consider the congestion cost over the applicable period in terms of a net gain or loss.

Q: You discussed TCRs relative to SPP network integration transmission service. Please discuss the likely availability of this type of transmission service.

A. Transmission service is requested via SPP's open access same time information system ("OASIS"). SPP studies groupings of requests that are received within certain time frames and posts the results of the transmission service study on its OASIS following each study iteration.[7] The process is iterative since certain transmission service requests withdraw and the remaining grouping is re-studied. For an OG&E network integration transmission service request, the sink would be specified at the OG&E load zone, and the source as the generating plant node. SPP reports the request based on the transmission owner at the source, i.e., for a generating plant location interconnected to the OG&E system the transmission service request would be posted as OG&E to OG&E. A recent grouping, 2013 aggregate grouping 3 iteration 4 (AG3-4) has three transmission service requests from OG&E to OG&E all of which show transmission service is available March 1, 2015 without a dispatch requirement. This demonstrates the availability of transmission service and in turn the ability to manage congestion using TCRs.

2. Curtailment Risk

Q: So, the SPP IM has tools to manage congestion risk for delivery of generating resources. Does SPP provide tools to manage curtailment risk?

A. SPP does not provide tools per se, but it does provide procedures described in the Market Protocol to curtail generation in a non-discriminatory manner and will provide access to

[6] https://marketplace.spp.org/web/guest/tcr-market-pub
[7] http://sppoasis.spp.org/documents/swpp/transmission/TRPAGE.CFM

its ProMOD/TAM models under certain restrictions. A person with nodal modeling experience can assess future curtailment risk using these analytical tools.

Q: Please provide an example of SPP Market Protocols applicable to understanding curtailment risk in the IM.

A. The energy output from all dispatchable resources, (e.g., dispatchable variable energy resources and fossil energy resources) can be "curtailed" economically based on the unit's resource offer compared with the price at its pricing node. "Economic curtailment" occurs when the LMP at the pricing node drops below the resource offer price of the generating unit. There are many economic and operating factors which go into a generating unit's resource offer price, but in simple terms the minimum offer price can be considered equal to the cost for the generating unit to produce one megawatt of energy (may be referred to as the variable cost). The energy cost is a function of the fuel cost and the efficiency (heat rate) of the unit. For example, when natural gas prices are $4/MMBTU[8] the variable cost for a natural gas-fired combined cycle generating plant is in the order of $28 per megawatt hour, i.e., it will cost a minimum of $28 for that plant to produce a megawatt of energy based on the fuel cost and efficiency of the generating plant. Therefore, the minimum offer price for this plant can be assumed for modeling purposes at $28 per megawatt hour. A wind generating plant, on the other hand, has no fuel cost so its variable cost is equal to $0 per megawatt hour. However, to incentivize development of renewable energy, for eligible wind generating plants and typically for the initial ten years of operation of the plant, the federal government has for a number of years provided a production tax credit[9] for each megawatt hour of wind energy produced by the plant. Since a wind generating plant has no variable cost, the production tax credit actually allows a wind plant to set a minimum offer price at a level less than $0 per megawatt hour. An LMP will fall below $0 when the marginal congestion component at the node reduces the price by more than the SPP marginal cost of energy.

Returning to the market protocol example, a wind plant that has a minimum offer price of $0 would be "economically" curtailed when the LMP at its pricing node fell below $0,

[8] One million British thermal units
[9] Additional detail located at http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F

whereas a different wind plant with the same LMP and which had a minimum offer price of -$10 would not be curtailed (unless the LMP fell below -$10).

At times, there are transmission constraints that cannot be mitigated (at least in a reliable manner) via economic means, and SPP follows specified procedures to respond to those situations. For example, per SPP Market Protocols Section 4.4.2.5, SPP may issue reliability directives via a manual dispatch instruction to any on-line resource to resolve a reliability issue the market system cannot resolve (referred to in the system as "out-of-merit energy") or to resolve an emergency condition. The out of merit energy dispatch instructions will specify the megawatt level the resource is expected to produce until the constraint can be resolved. SPP is required to select the generating resources that receive out of merit energy dispatch instructions in a non-discriminatory manner. Where the constraint requires out-of-merit energy dispatch for reliability reasons, but does not require SPP to declare an emergency condition, curtailment occurs pro rata across all generation that contributes 5% or more to the constraint. Where the constraint requires an out-of-merit energy emergency declaration (which SPP expects to occur only infrequently), due to time limitations SPP may instead instruct the largest contributor to the constraint to curtail first, followed by the next largest, as applicable, but will return to pro rata curtailment or a solution based on market economics as soon as it is practicable considering reliability.

3. Transmission Build-Out in the SPP.

Q: You mentioned that developing reasonable future scenarios is required to effectively evaluate generating resource curtailment risk. Please explain how development of scenarios is implemented.

A: Beyond the tools available for addressing congestion risk that I've discussed above, expansion of the transmission grid can alleviate congestion. OG&E Witness Leon Howell indicated that OG&E has "concerns about the low SPP prices in areas where the addition of wind generation has caused those prices to be depressed due to congestion charges. Transmission lines are under construction that may relieve the congestion on the transmission system."[10] Likewise, OG&E Witness John Reed indicates that "[w]ind

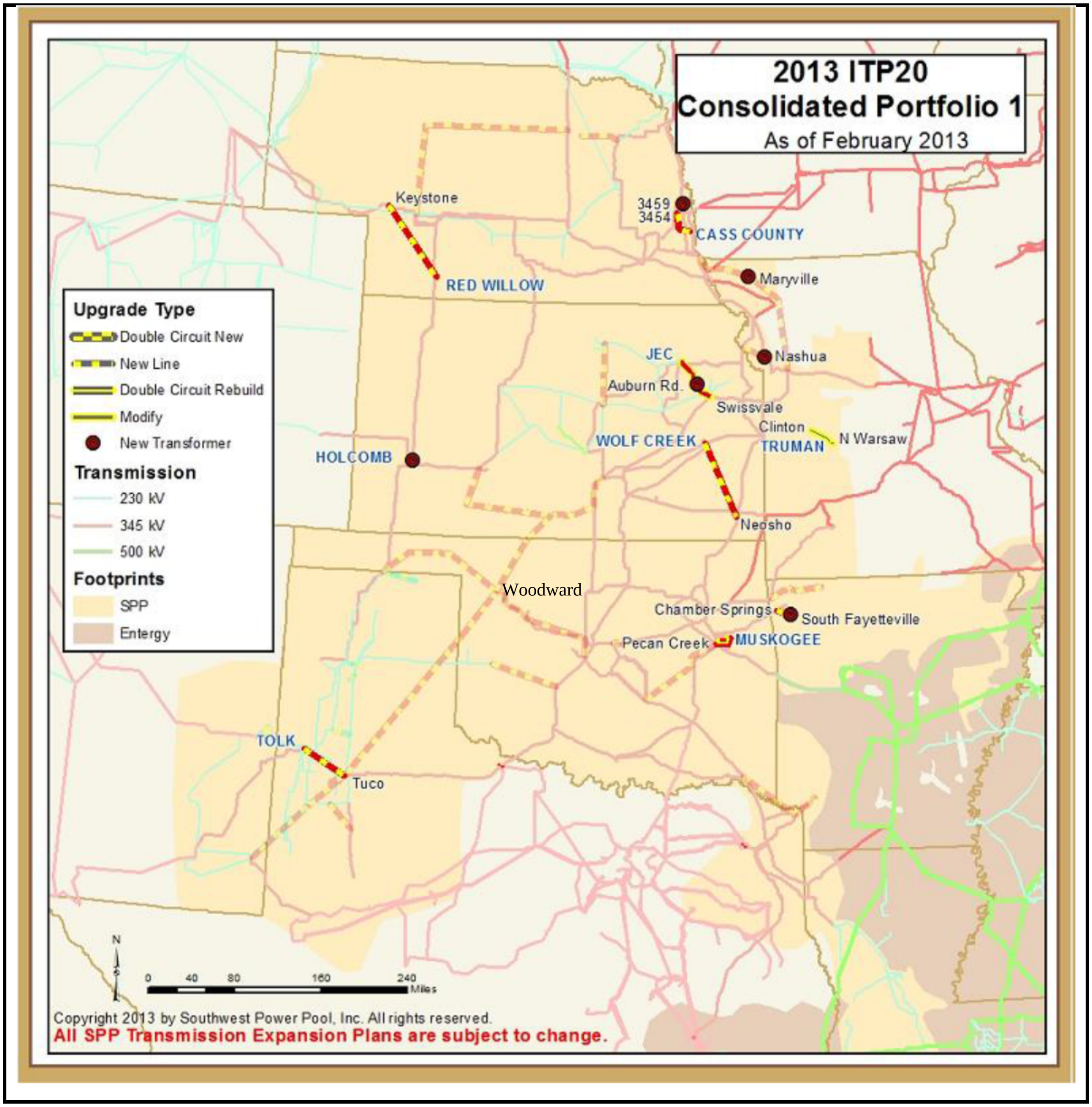
[10] Direct Testimony of Leon Howell page 20, lines 13 to 17

energy can be accommodated by an IRP although it often requires transmission investments to deliver it to market areas."[11] As I discussed previously, power flows and, in turn, transmission constraints are a function of the configuration of the transmission network (how all the transmission components interconnect to form the network), the dispatch of generation and the distribution of system demand. Further, I explained how generating plants and loads are located at specific points, or nodes, on the transmission system. Among other variables, changing the configuration of the transmission network by adding new transmission lines, adding new generating plants at new points on the network, or altering the distribution of the system demand will change how power flows over the transmission network from generating plants to the consumers.

SPP provides extensive information relative to transmission expansion, a queue of generation interconnection requests, and transmission network models that identify new load points on the network. SPP performs coordinated transmission expansion planning, which integrates its traditional 10-year reliability assessments with the Extra High Voltage studies, the Generator Interconnection Process, the Balanced Portfolio, Integrated Transmission Plans, and its Transmission Service Study Process. SPP documents the transmission expansion plans (SPP Transmission Expansion Plan or STEP) in reports which it posts on the SPP website. Figure 1 [12] from a recent planning report, shows previous SPP board approved transmission expansion projects in the background (lighter dashes) with the recommended projects in that plan shown in darker dashed lines.

[11] Direct Testimony of John Reed page 11, lines 17 to 19
[12] Page 49, http://www.spp.org/publications/2014_STEP_Report_Final_20140205.pdf

Figure 1: SPP Transmission Expansion



Transmission projects identified in the planning process and meeting defined criteria are submitted on an annual basis to the SPP Board of Directors for approval. Approved projects are given a notice to proceed and can recover the transmission costs. As shown in Figure 1, previously approved transmission expansion plans include several 345 kV transmission lines within and throughout Oklahoma. SPP updates the status of approved transmission projects on its website quarterly.[13]

Q: Describe the completed and planned transmission expansion plans occurring in OG&E's territory.

A. Despite the comments regarding transmission expansion by OG&E Witnesses Howell and Reed, the OG&E system is almost done with the process of adding a series of new 345 kV transmission lines shown in Figure 1. The 345 kV line from the Southwestern Public Service's Tuco substation to OG&E's Woodward Substation was completed in September 2014. OG&E's double circuit 345 kV Woodward line into Kansas was completed in November 2014, and other associated 345 kV line sections were completed in June 2014. These 345 kV lines were part of SPP's high priority projects to integrate wind resources into the SPP grid. For instance, Woodward is where OG&E owns or has PPAs for several wind generating plants. These recently added transmission lines plus additional approved lines should reduce transmission constraints in the OG&E system.

SPPs integrated transmission planning process has also identified another 345 kV upgrade: a new 345 kV line from the Woodward District Extra High Voltage to Tatonga to Matthewson to Cimarron – which is officially expected to be online by 2021. This online service date can occur sooner as OG&E already has a notice to construct (#200223) and, historically, once a notice to construct is issued the actual in service date may occur even years before scheduled.[14]

Q: What conclusions do you draw from your review of transmission expansion plans in OG&E's territory?

A: Several 345 kV transmission lines, designed as part of the SPP priority projects to integrate new wind resources and interconnecting the OG&E system to other regional utility systems, went into service in late 2014. With these facilities in service, transmission congestion should be reduced. Likewise, there is another major 345 kV transmission line already approved and a notice to construct already issued to OG&E.

[13] http://www.spp.org/section.asp?group=1867&pageID=27

[14] As an example, Western Resources' Viola 345/138 transformer, Viola to Gill and Viola to Clearwater 138 kV transmission upgrades (notice to construct #200228) were originally approved with a June 1, 2018 in service date, but Western Resources moved the date forward to June 1, 2016.

This approved, yet to be constructed, line provides a second circuit along one of the known critical transmission "N-1" contingency outages, the same line outage that results in the special protection scheme discussed in Section VII. So – to the extent congestion has not been completely addressed by the transmission lines which entered service in 2014, OG&E has the authorization to proceed with construction of the additional transmission line.

4. Generator Interconnection Data

Q: You indicated that SPP also provides a generator interconnection queue. How did you use information from this queue to support your evaluation of available wind projects?

A. SPP posts the substantial information regarding generator interconnection requests on its website,[15] including generation interconnection studies. From this information, one can identify the size (in megawatts) of new generation resources, the location (nearest town or county and/or substation or transmission line), status of the request in the interconnection process, the interconnection costs (once the study is completed), and whether the generator has a generator interconnection agreement.

Q: In evaluating future congestion and curtailment risk, would you add all the projects in the generator interconnection request queue into your analysis?

A. No. History shows that many project in the queue will later be withdrawn. For a base case analysis of the impact of new resources on curtailment and congestion risks, I would only add projects already under construction and projects with PPAs. In all cases, one should develop a stress test scenario in which other plants are added to the particular area of interest to "bound" the congestion and curtailment risks.

SPP also provides access to other data that can aid in understanding and assessing congestion and curtailment risks as discussed in the following section.

[15] http://sppoasis.spp.org/documents/swpp/transmission/studies.cfm

5. Other Available SPP Data

Q: Please discuss other relevant data available for the SPP system.

A. SPP posts information on existing transmission constraints, LMP for each pricing node, and non-dispatchable resource curtailment logs.

Flowgates are transmission constraints that are identified based on historical operation. SPP reports permanent flowgates and temporary flowgates on an ongoing basis. Temporary flowgates may be due to transmission outages, such as those required for line maintenance, or simply may not yet have a sufficient history of occurrence to warrant inclusion in the permanent flowgate list. Not all flowgates have been recently constrained. One can identify the flowgates that have been constrained using the SPP posted binding constraints information, inclusive of the SPP IM shadow price.[16] SPP also posts the out of merit order dispatch of non-dispatchable resources. The posting identifies the flowgate constraint causing the out of merit energy dispatch instruction, when it occurred, duration, and the number of non-dispatchable resources impacted. SPP also posts both its day-ahead and real-time LMPs for each pricing node including the load nodes that are aggregated for each utility. Utilities and other stakeholders can use this information to understand existing congestion and curtailment risks.

Q: Please explain how you used LMP information to better understand congestion issues in OG&E's territory.

A. To better understand the congestion issues related to OG&E load and generating resources, I had historical hourly LMP data compiled[17] for OG&E generating resource nodes and the OG&E load zone from the period starting March 1, 2014, the start date for the Integrated Marketplace, through December 10, 2014. I also had actual hourly generation compiled the available OG&E units. This hourly production data is available on a quarterly basis, so it was compiled from March 1, 2014 through September 30, 2014.

Table 1 presents the simple average LMP for the OG&E load zone pricing and each OG&E generating resource that is owned or contracted for under a power purchase

[16] https://marketplace.spp.org/web/guest/markets
[17] Data was compiled from SNL Energy, to which nFront has a license

agreement. For purposes of comparison, I also added to the table the load prices for two of OG&E's neighbors, Southwestern Public Service ("SWPS") and American Electric Power's Public Service of Oklahoma ("PSO") and Southwestern Electric Power Company, reported by SPP as an aggregate price for the American Electric Power utilities. To understand congestion relative to each of the plants, I also calculated the average price at each OG&E generator node compared to the OG&E load LMP.

Additionally, even though load-serving and generating operations are effectively separate in the Integrated Marketplace, congestion cost applies to both generating plant nodes and load zones. OG&E load will buy its energy at the OG&E load zone price and its network generators will be paid the LMP at the generator node. I have added a column in Table 1 which applies the difference in the LMP between the OG&E load zone and the generator nodes based on the actual hourly production (LMP difference times the megawatts of production in the hour). This cost data represents how much less (a negative value) or more (a positive value) OG&E generators were paid due to marginal congestion and marginal losses than the price paid by OG&E load. This data is useful because it shows the impact of congestion which is not reflected in a zonal analysis discussed in Section VI. For example, the dispatch of Sooner 1 to an OG&E load price (as opposed to use of a security constrained economic dispatch analysis reflective of operation of the SPP IM) would result in the analysis showing approximately $3.7M in revenues for the plant that would not occur in the SPP IM, and that is for over just a 10.5 month period.

Table 1
Integrated Marketplace OG&E LMP and Congestion

Node	**Day Ahead Average LMP ($/MWh) 3/1-12/10**	**Real Time Average LMP ($/MWh) 3/1-12/10**	**Day Ahead % of OG&E Load LMP 3/1-12/10**	**Real Time % of OG&E Load LMP 3/1-12/10**	**Production Weighted Congestion Cost ($) 3/1 - 9/30**
OKGE Load	36.58	37.07			
AEP Load	35.81	35.76			
SWPS Load	37.86	38.85			
Congestion Cost[2]					(28,635,028)
Average of OG&E Gen Nodes	35.39	36.00	96.7%	97.1%	
Muskogee 4	34.77	35.11	95.0%	94.7%	(4,092,432)
Muskogee 5	34.80	35.15	95.1%	94.8%	(5,000,381)
Muskogee 6	34.82	35.17	95.2%	94.9%	(2,483,274)
Sooner 1	35.53	36.32	97.1%	98.0%	(3,748,604)
Sooner 2	34.61	35.07	94.6%	94.6%	(5,251,620)
Horseshoe Lake 6	36.40	37.23	99.5%	100.4%	(218,486)
Horseshoe Lake 8	36.39	37.25	99.5%	100.5%	(361,637)
Mustang 1	37.04	37.75	101.3%	101.9%	4,154
Mustang 2	36.94	37.64	101.0%	101.6%	21,502
Mustang 3	37.05	37.75	101.3%	101.8%	67,025
Mustang 4	36.91	37.63	100.9%	101.5%	(47,838)
Seminole 1	35.36	36.48	96.7%	98.4%	(425,079)
Seminole 2	35.43	36.42	96.9%	98.3%	(172,640)
Seminole 3	35.41	36.41	96.8%	98.2%	(538,140)
Horseshoe Lake 7	36.38	37.22	99.4%	100.4%	(364,600)
McClain 1	36.39	36.96	99.5%	99.7%	(282,682)
McClain 2	36.39	36.96	99.5%	99.7%	(276,128)
McClain ST 1	36.39	36.96	99.5%	99.7%	(1)
Redbud 1	35.31	35.52	96.5%	95.8%	(1,000,876)
Redbud 2	35.31	35.52	96.5%	95.8%	(1,609,315)
Redbud 3	35.30	35.49	96.5%	95.7%	(1,566,015)
Redbud 4	35.30	35.49	96.5%	95.7%	(1,196,007)
Horseshoe Lake 9	36.39	37.17	99.5%	100.3%	(41,465)
Horseshoe Lake 10	36.39	37.17	99.5%	100.3%	(50,489)
Mustang 5A (Tink5 1)	36.46	37.20	99.7%	100.4%	(1)
Mustang 5B (Tink5 2)	36.46	37.20	99.7%	100.4%	(1)
Seminole 1GT	35.36	36.48	96.7%	98.4%	(1)
AES Shady Point 2	33.78	33.51	92.3%	90.4%	(1)

AES Shady Point 3	33.78	33.48	92.3%	90.3%	(1)
PowerSmith	36.98	37.64	101.1%	101.6%	(1)
FPL Wind	41.92	45.97	114.6%	124.0%	(1)
Keenan	27.69	26.29	75.7%	70.9%	(1)
Taloga	34.69	35.64	94.8%	96.2%	(1)
Blackwell	36.57	37.10	100.0%	100.1%	(1)
Centennial	26.73	25.13	73.1%	67.8%	(1)
OU Spirit	27.57	26.18	75.4%	70.6%	(1)
Crossroads	33.94	34.53	92.8%	93.1%	(1)

(1) Hourly operations data not available or not found.

(2) This calculation of the congestion cost ignored the marginal losses component, assuming the congestion between the OG&E load zone and its generating units was equal to the difference in LMP. Likewise, the OG&E hourly load was not available, so the production from the OG&E network resources could be higher or lower than the OG&E load, and therefore, the summation of congestion costs are for illustrative purposes only.

Q: What conclusions do you derive from the data shown in Table 1?

A. First, since the IM began, Muskogee, Sooner and AEP Shady Point have been the most congested OG&E fossil generating plants, with congestion comparable to that of OG&E's three newest wind plants. Second, even when there is an LMP higher than the OG&E load, it may not result in a significant positive impact in terms of overall OG&E congestion. For example, OG&E's Mustang plant has an average LMP that is higher than OG&E load, but its production is so low that the congestion benefit over time (the incremental price it would receive in the market due to congestion) is small in comparison to the negative congestion cost impacts of other fossil generating plants, such as Muskogee and Sooner. Third, congestion varies greatly between the OG&E owned or contracted for wind generating plants, with one wind plant, FPL Wind, having by far the highest congestion benefit and three other wind plants, all located near Woodward substation, having the highest congestion cost. Since the new 345 kV lines connecting to Woodward substation were not in service until November 2014, only a month of the lines' congestion alleviation benefits is reflected in this data. Fourth, the newest OG&E wind plants (Blackwell, Taloga and Crossroads) have average LMPs approximately that of the OG&E coal plants--Muskogee, Sooner and the contracted for AES Shady Point plants. In other words, these wind plant LMPs reflect congestion at their pricing nodes commensurate with the OG&E coal plants. Finally, the average nodal price (not weighted for production) for even the lowest LMP wind plant nodes exceeds the approximately $22/MWh average wind purchase contract price[18] reported by OG&E to be available. This means that energy from these wind plants, paid at the LMP in the IM, exceeds their PPA prices, meaning OG&E and its customers reap a financial benefit.

V. WIND RESOURCES IN SPP

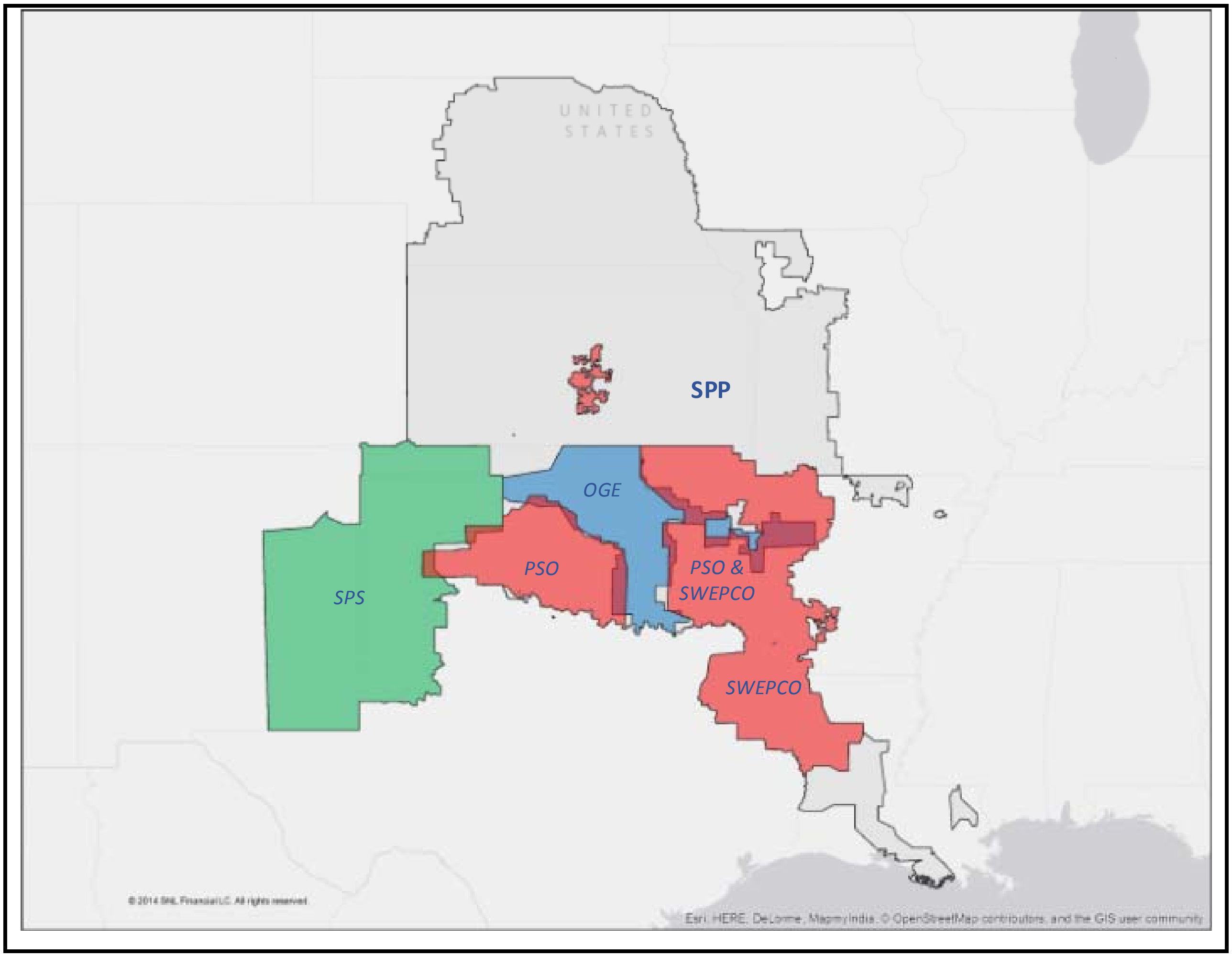
A. Wind Power Purchases by OG&E Neighboring Utilities

Q: Please describe other utilities in the vicinity of OG&E.

A. Neighboring utilities to OG&E include Southwestern Public Service Company ("SWPS"), Public Service of Oklahoma ("PSO") and Southwestern Electric Power Company ("SWEPCO") as shown in Figure 2.

[18] Page 30 of OG&E's 2014 IRP, regarding the 2013 RFI, indicated that "[b]ase pricing averaged approximately $22/MWh."

Figure 2: Regional Utility Territories



Q: Please explain why it is useful to examine wind purchases by OG&E's neighboring utilities?

A: I reviewed wind power purchases by OG&E's neighboring utilities to determine whether OG&E's wind portfolio is comparable to these similarly situated utilities. This information is helpful in assessing the reasonableness of OG&E's decision not to expand its wind resources and to determine a comparative percentage of owned or contracted for wind as a percentage of peak demand.

Q: How does the peak demand of these utilities compare to OG&E?

A. American Electric Power reports the combined loads for its subsidiaries Public Service of Oklahoma and Southwestern Electric Power Company. However, Table 1-1 of the State of Oklahoma 12th Electrical System Planning Report dated April 2013[19] reported the Public Service of Oklahoma peak demand for 2011 as 4,468 MW and OG&Es as 5,815 MW. The ProMOD models provided by OG&E in response to Sierra Club 2-4 included a 2015 peak load for OG&E of 5,798 MW and 6,177 MW for Southwestern Public Service Company. I also reviewed the 2013 FERC 714 load filing which reported an actual hourly peak load in 2013 for Southwestern Public Service Company of 5,909 MW. Based on the available load information, the Southwestern Public Service Company load is slightly larger than OG&E and Public Service Company of Oklahoma's load is approximately 80% of OG&E's.

Q: Considering the similarity in size, proximity to OG&E, and for PSO, the location within Oklahoma, how do these utilities compare to OG&E in the amount of installed wind plants either owned or contracted for under a power purchase agreement?

A. Using the hourly peak demand supplied by OG&E in its ProMOD model, OG&E's owned and contracted for wind plants equal about 14% of its peak demand (840 megawatts of wind divided by 5,800 megawatts of peak demand. As summarized in Table 2, Southwestern Public Service contracts with wind plants for about 26.5% of its peak demand—almost double that of OG&E.[20]

[19] 2013 Oklahoma ESPR, dated May 2013 http://digitalprairie.ok.gov/cdm/ref/collection/stgovpub/id/216158, attached as Exhibit JBT-3.
[20] Assuming the output of qualified facilities (QFs) is counted. The percentage is 23.6% if the 181 MW of QFs is excluded.

Table 2
SWPS Wind PPA and Peak Demand

Wind Plant Name	ISD	Status	MW	Type	PPA Start	PPA End	Term (Years)
Llano Estacado-NM (Texico)	1999	IS	2	QF			
Llano Estacado Wind Ranch	2001	IS	80	PPA	Jun-02	Jun-17	15
Aeolus Wind	2003	IS	3	QF			
Caprock Wind Ranch	2004	IS	80	PPA	Dec-04	Dec-24	20
San Juan Mesa Wind	2005	IS	120	PPA	Dec-05	Dec-25	20
Exelon Wind 1-11 (10MW each)	2006	IS	110	QF			
Wildorado Wind Ranch	2007	IS	161	PPA	May-07	May-27	20
High Plains Wind Power	2008	IS	10	QF			
Mesaland's Campus	2008	IS	1.5	QF	Dec-08		
Diamond Shamrock Wind	2009	IS	14.4	QF	Sep-09		
Majestic Wind Farm	2009	IS	79.5	PPA	Jan-09	Jan-29	20
Little Pringle One	2010	IS	10	QF	Oct-10		
Ralls Wind Farm	2011	IS	10	QF	Jun-11		
DeWind Frisco (Frisco Wind)	2012	IS	20	QF	Feb-12		
High Majestic Wind II	2012	IS	79.6	PPA	Aug-12	Aug-32	20
Spinning Spur Wind Ranch	2012	IS	161	PPA	Dec-12	Dec-27	15
Palo Duro Wind	2014	UC	249.9	PPA	Dec-14	Dec-34	20
Mammoth Plains Wind	Dec-14	UC	198.9	PPA	Dec-14	Dec-34	20
Roosevelt Wind Ranch	Dec-15	2015	250	PPA	Dec-15	Dec-35	20
SWPS 2016 Wind PPA Total			**1641**				

SWPS Peak Demand = 6,177 MW
SWPS Installed wind as % of peak demand including QFs = 26.5% or 23.6% without QFs

Likewise, Public Service of Oklahoma also has a much higher percentage of installed wind to peak demand. After recently entering into PPAs for 598.7 megawatts of new wind plant output, Public Service of Oklahoma will have 1,157 megawatts[21] of installed wind in 2016. Using the actual Public Service of Oklahoma 2011 load data of

[21] The Oklahoma Corporation Commission final order no 621229 in Cause No. PUD 201300188 indicates that with the new PPA's PSO at the start of 2016 will have 1,288.5 MW (page 7 of 10) minus 151.2 MW due to the expiration of the Blue Canyon II PPA (page 3 of 10) in 2015. Entered the contracts in 2013 and approved by the Oklahoma Corporation Commission in 2014, attached as Exhibit JBT-4.

4,468 megawatt and conservatively escalating it 2% per year provides a 2016 installed wind to peak load of about 23.5%.

Q: Besides the fact that OG&E has committed to only a fraction of the wind megawatts compared to its neighbors, what other considerations undermine OG&E's statements that congestion necessitates halting investment in additional wind?

A. First, other utilities have contracted for wind resources in areas that OG&E claims are too congested to support wind development. This suggests that such investments are in fact economical. For example, SWPS's 2013 wind power purchase contacts for Mammoth Plains, Palo Duro, and Roosevelt are located in OG&E's territory. Mammoth Plains interconnects to the same location, Tatonga 345 kV substation, as OG&E's Crossroad wind plant; Palo Duro interconnects with a new substation, Beaver County, which is located one substation away from OG&E's Woodward substation, the location of the OG&E wind plants with the most congestion, as summarized in Table 1. Likewise, in Table 1, since the start-up of the IM, Southwestern Public Service Company has had an average day-ahead LMP of $37.86 compared to OG&E's of $36.58/MWh. So, while congestion certainly does, or at least did, exist in the Woodward area, Southwestern Public Service Company contracted for approximately 450 megawatts from plants located in the same area with an even higher average load zone LMP.

Likewise, of the three recent wind power purchase agreements entered into by Public Service of Oklahoma: (1) Balko (about 200 megawatt) is at the same location as the Southwestern Public Service Company contracted for Palo Duro wind plant; (2) the interconnection location for Goodwell (about 200 megawatt) is one substation to the west of the substation to which Balko and Palo Duro interconnect; and (3) Seiling (about 200 megawatt) is also at the same interconnection location of OG&E's existing Crossroads wind plant.

Q: What can you conclude from your comparison of OG&E installed wind (contracted and owned) with that of its two closest neighbors of comparable size?

A. This data shows that neither Southwestern Public Service Company nor Public Service of Oklahoma were "afraid" to enter into power purchase agreements from wind plants in the same area as many of OG&E's existing wind plants. In fact, these utilities have contracted for wind plants at a level approximating 25% of their peak demand compared, far exceeding OG&E's 14%. While congestion has historically existed in the area of Woodward (per the summary in Table 1), the historical congestion did not cause Southwestern Public Service Company and Public Service of Oklahoma to avoid contracting for the output of new wind resources, which are (or will be) located in that same area.

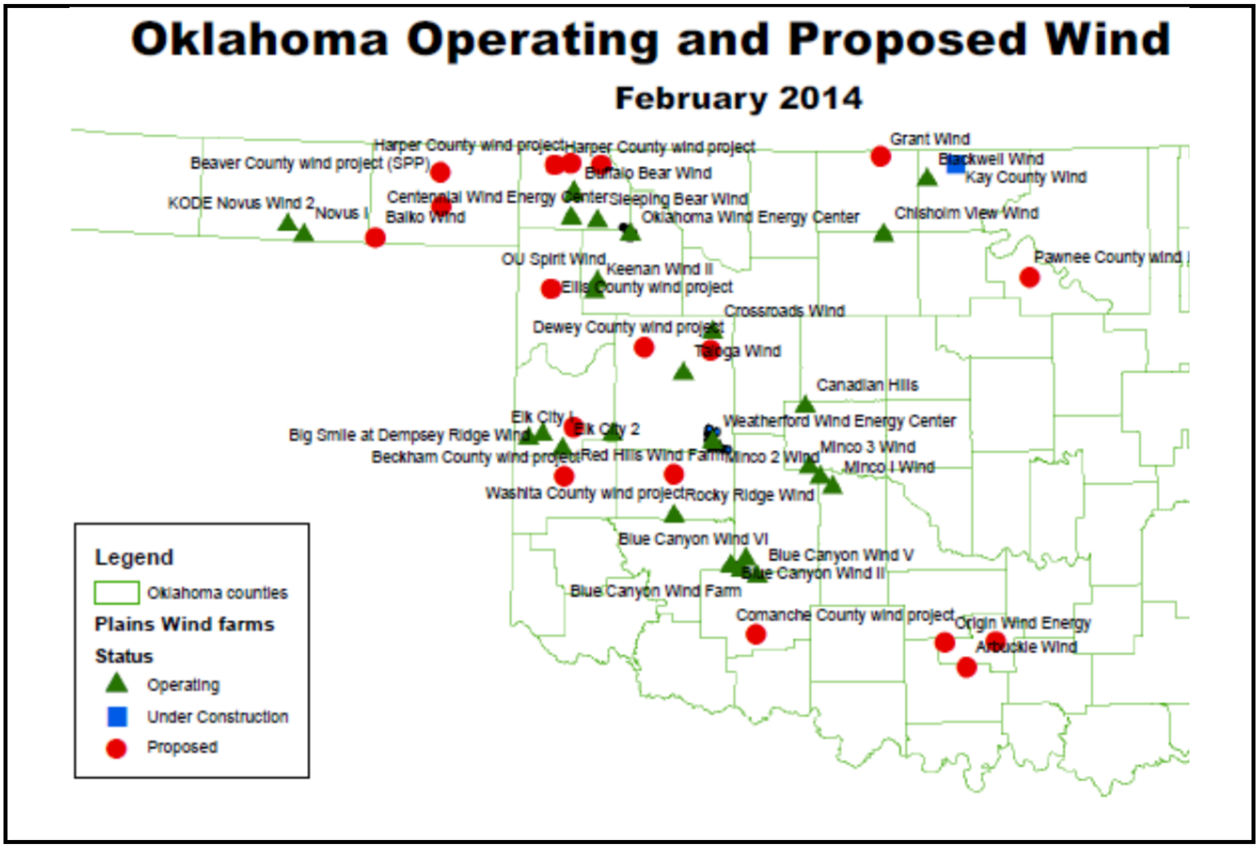
Based on the above, OG&E could reliably and economically integrate 20% to 25% of its peak demand with wind resources or up to about 1,500 megawatts of wind.

Q: Is it possible that all available wind plants were contracted for by the other companies, and therefore no additional wind plants are available to OG&E?

A. No. The SPP queue includes many wind generation projects with generator interconnection agreements that do not yet have power purchase agreements. Figure 3 shows the location of existing, under construction, and proposed Oklahoma wind plants as of February 2014.[22] While some of the wind plants identified as proposed are now under power purchase agreements, there are many wind plants that have generator interconnection agreements (as reported in the SPP generation interconnection queue). Based on a review of the SPP queue, power purchase agreement reported by SNL energy and available commission rulings such as for the power purchase agreements for Southwestern Public Service, I estimate that there are in excess of 3,500 MW of wind plants within the SPP footprint with generator interconnection agreements and no known power purchase agreements. Thus, OG&E has significant opportunity to add available wind to its system.

[22] http://www.kansasenergy.org/documents/OK_WindFarms.pdf
Plant names and size detail located at http://kansasenergy.org/wind_projects_OK.htm, attached as Exhibit JBT-5.

Figure [ ]: Oklahoma Wind



Q: What other information in the record supports the availability of additional wind for purchase?

A: In the 2014 IRP, OG&E reported that it received multiple bids to contract for the output of new wind plants.

B. Power Purchase Agreements

Q: Does the ability of wind developers to sell wind directly into the SPP undermine OGE&'s ability to enter PPAs for wind?

A. OG&E indicates on page 49 of its 2014 IRP update that "[a]nother change created by the SPP IM is that wind developers may now construct wind farms and sell the energy output directly into the SPP IM without an agreement with OG&E." While it is true that wind resources and other types of generating plants for that matter can sell energy output directly in the SPP IM without a power purchase agreement, the majority of existing wind plants and those under construction are under power purchase agreements. The fact that OG&E received multiple responses to its solicitation is further evidence that numerous wind generation developers continue to desire to contract under long term power purchase agreements. Likewise, the SPP IM LMPs summarized in Table 1 show that the LMP at OG&E wind plant nodes is generally well in excess of the power purchase agreement bid prices. OG&E as the off-taker under a power purchase agreement would typically be responsible for the congestion cost; however, based on the market data to date, the wind plant LMPs would benefit OG&E. Each megawatt hour of energy output from the plant would "sell" to the SPP IM at the node price (money received by OG&E as the off-taker) and OG&E in turn would pay the power purchase agreement price to the wind plant, thus a net benefit to OG&E even considering congestion costs. OG&E Witness John Reed cites an additional benefit as "[w]ind energy has limited capacity value but does act as a hedge against natural gas price increases and the potential for carbon regulation."[23]

C. Congestion

Q: Was it reasonable for OGE to dismiss all responses to its RFI because they did not assume congestion and curtailment (economic) risk?

A: No. OG&E indicates on page 49 of the IRP update that "[b]ased on recent experience with wind energy there is considerable SPP IM price risk and the respondents to our 2013 RFI declined to assume this risk. We expect that this price risk will diminish as new transmission capacity is placed in service and will monitor this risk."

As shown in Table 1, it is true that congestion exists within SPP, and it is also true that it exists at most of OG&E generating plant nodes. However, it is not reasonable for OG&E to reject wind proposals on the basis that they do not assume all congestion risk. I am not aware of any wind developers that would contractually obligate themselves to "open-ended" risk.

Bids accepted by neighboring utilities are similar to those received by OG&E, and they assume considerable economic congestion and curtailment risk. For example, the

[23] Direct Testimony of John Reed page 15, lines 16 to 18

Recommended Decision of the New Mexico Commission in Case No. 13-00233-UT, dated October 30, 2013 (attached as Exhibit JBT-2) provides approval for the SWPS power purchase contracts for Mammoth Plains and Palo Duro wind plants (discussed previously). The first year contract price for Mammoth Plains was $19.18 per megawatt hour and a first year contract price for Palo Duro was $21.10 per megawatt hour.[24] [redacted].[25] Additionally, the contracts specify for "Allowable Curtailment," which allows Southwestern Public Service Company to curtail each wind plant for up to 30,000 megawatt hours per year for the first six years of the power purchase agreement for any reason and not compensate the wind plant. Extrapolating from the wind plant sizes of 199 MW and 250 MW, respectively, the Allowable Curtailment provision alone means that the wind plants accepted 3.6% and 2.9% uncompensated curtailment respectively (assuming 47% net capacity factor). It is therefore difficult for me to believe that wind plants responding to the OG&E RFI were not also open to accepting a level of economic risk.

Considering the numerous other wind plant power purchase agreement contracts entered into by other load serving entities, including two of OG&E's neighboring utilities, it is difficult to understand OG&E's decision to reject all of the wind bids. Given the disconnect between OG&E and the neighboring utilities, OG&E appears to be the entity with the unrealistic expectations that will preclude it from entering reasonable contracts for wind. Any contract negotiation includes give and take, and it is difficult for me to believe that at least some of the respondents were not willing to accept a reasonable level of economic risk, such as reflected in the amount of risk shouldered by the developers of the Mammoth Plains and Palo Duro wind projects.

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[24] Id. at pg. 9.
[25] OIEC 5-8_Confidential, Attachment ("Please see OIEC 5-8_Att_Confidential for the prices, price escalation rates, contract nameplate capacity and delivery term for each response to OG&E's 2013 Wind RFI")

Q: In your experience, is it reasonable for OG&E to ask a wind developer to take on all congestion risk?

A. No. I have been involved in financing of a couple hundred wind and fossil projects and have never seen a project take on 100% of congestion/curtailment risk.

Transmission risks impacting a wind plant's financials vary from project to project but may include compensable or non-compensable curtailment, congestion cost, transmission service cost, transmission service curtailment and other market factors. Prior to receiving financing, these risks are assessed in the context of the contractual arrangements, market structure, transmission system capability, and future considerations such as transmission expansion and generation additions or retirements. To secure financing, the lenders must be able to quantify the congestion and curtailment risks in the context of the power purchase agreement and the IM Market Protocols. For example, under the Mammoth and Palo Duro power purchase agreement terms discussed above, even though the contract allows uncompensated Allowable Curtailment over six years of 180,000 megawatt hours, lending institutions can quantify the value of that curtailment, and thus the risk associated with the provision is understood. What cannot be quantified is open ended congestion and curtailment risk, such as I can only presume was desired by OG&E in its 2013 RFI.

An example of a more reasonable provision that would still protect OG&E would be that OG&E could curtail the output of the wind plant and not compensate the wind plant for the curtailment for any reason with a maximum number of curtailment hours set per year.

D. OG&E understates the value of wind from a capacity perspective

Q: OG&E on page 48 of the IRP Update indicates that "SPP only recognizes approximately 5% of nameplate wind generation capability for capacity margin purposes." Does this statement accurately reflect wind capacity accreditation in the SPP?

A. No, while it is true that SPP has historically recognized only 5% of nameplate wind generation capability for capacity purposes, SPP's accreditation processes are undergoing revision. In fact, in the first years of operation the capacity value for a wind plant can be as low as 3%. However, this value is low compared with other similar markets. As

OG&E is aware,[26] "[o]n April 16, 2014, SPP changed the criteria regarding wind capacity credit at a meeting of the SPP Market Operations Policy Committee ("MOPC")." SPP will now accredit capacity for wind projects on a project-by-project basis going forward.[27] SPP estimates that it will increase capacity value to an average of 10%. The information presented by SPP includes an initial screening of 17 wind plants representing 2,072 MW of SPP wind plants, or about one fourth of the wind plants currently operational in SPP. The wind plants were not identified, but one can assume that the sample plants covered a broad region of SPP. The results showed wind plant capacity credit values ranging from a low of 2.2% to a high of 26.9%.

Similarly, in MISO, the wind capacity average is 14.1% with individual plants ranging from 0 to 25.3%.[28]

Q: Please provide additional detail on SPP's proposed change in methodology to be used in calculating capacity margin credit for wind resources.

A. The Criteria Changes Wind Accreditation by Generation Working Group states that SPP will set the capacity credit using the following method: the wind energy production from a project will be evaluated based on the highest 22 hours of production in the peak load month, based on a 60% probability that the wind plant output will be that level or higher.

Q: Have you performed any analyses using SPP hourly wind and load data to explore the potential impacts of the wind capacity criteria changes?

A. I do not have access to actual hourly output for individual wind plants. However, SPP reports forecasted and actual hourly demand for the SPP system as well as forecasted and actual hourly wind output. I had this data compiled[29] and the result for the top 22 load hours in August and July of 2014 are shown in Table 3.

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[26] See OG&E's Response to Sierra Club DR 1-29.

[27] See OG&E's Response to Sierra Club DR 1-29, Att. 2, Criteria Changes Wind Accreditation by Generation Working Group

[28] MISO 2014 Wind Capacity Credit Report[28], dated December 2013 Page 4, attached as Exhibit JBT-6. https://www.misoenergy.org/Library/Repository/Study/LOLE/2014%20Wind%20Capacity%20Report.pdf

[29] nFront utilized the short term wind forecast for the SPP market that was available from the SPP marketplace website given every hour in five minute increments. nFront then aggregated the five minute intervals into each hour to get the forecasted vs the actual wind production average of every hour in 2014 to November 24th. nFront also pulled the Mid-Term Load Forecast (MTLF) for SPP of the hourly actual vs forecasted from the operational data at the same site nFront used for the wind forecast shown below.

Table 3

SPP Actual Wind Production in 22 Heaviest Load Hours									
2014 August (actual peak hour reported)					2014 July				
Top 22 Load Hours	Date/Time	Hourly Market Load (MW)	Actual Wind in Hour (MW)	Wind MW in hour as % of installed wind(2)	Top 22 Load Hours	Date/Time	Hourly Market Load (MW)	Actual Wind in Hour (MW)	Wind MW in hour as % of installed wind(2)
1	08/21/2014 17:00	45,223	3,657	47.5%	1	7/22/2014 17:00	44,545	1,900	24.7%
2	08/21/2014 18:00	44,802	3,344	43.4%	2	7/22/2014 16:00	44,272	2,553	33.2%
3	08/21/2014 16:00	44,698	4,283	55.6%	3	7/22/2014 18:00	44,170	1,830	23.8%
4	08/22/2014 16:00	44,604	3,797	49.3%	4	7/25/2014 17:00	44,030	2,050	26.6%
5	08/22/2014 17:00	44,500	2,971	38.6%	5	7/25/2014 18:00	43,619	2,287	29.7%
6	08/25/2014 17:00	44,096	1,362	17.7%	6	7/25/2014 16:00	43,552	2,508	32.6%
7	08/22/2014 15:00	43,969	4,367	56.7%	7	7/22/2014 15:00	43,489	2,573	33.4%
8	08/21/2014 19:00	43,794	3,800	49.4%	8	7/22/2014 19:00	43,422	1,899	24.7%
9	08/20/2014 17:00	43,772	4,061	52.7%	9	7/21/2014 17:00	43,224	883	11.5%
10	08/21/2014 15:00	43,766	4,234	55.0%	10	7/21/2014 18:00	43,016	677	8.8%
11	08/25/2014 16:00	43,750	1,545	20.1%	11	7/25/2014 19:00	42,730	2,278	29.6%
12	08/19/2014 17:00	43,646	4,711	61.2%	12	7/21/2014 16:00	42,632	1,167	15.2%
13	08/25/2014 18:00	43,644	1,002	13.0%	13	7/7/2014 17:00	42,556	1,128	14.6%
14	08/22/2014 18:00	43,528	2,656	34.5%	14	7/22/2014 14:00	42,515	2,441	31.7%
15	08/20/2014 18:00	43,365	3,869	50.2%	15	7/25/2014 15:00	42,468	2,665	34.6%
16	08/20/2014 16:00	43,321	4,562	59.2%	16	7/21/2014 19:00	42,317	603	7.8%
17	08/19/2014 18:00	43,289	4,804	62.4%	17	7/7/2014 18:00	42,286	1,119	14.5%
18	08/19/2014 16:00	43,159	5,172	67.2%	18	7/7/2014 16:00	42,268	1,451	18.8%
19	08/22/2014 14:00	43,084	4,710	61.2%	19	7/22/2014 20:00	42,214	1,960	25.5%
20	08/25/2014 15:00	42,988	1,555	20.2%	20	7/26/2014 18:00	41,826	910	11.8%
21	08/25/2014 19:00	42,642	843	10.9%	21	7/7/2014 19:00	41,625	1,050	13.6%
22	08/21/2014 14:00	42,606	4,197	54.5%	22	7/7/2014 15:00	41,573	1,685	21.9%
SPP Installed Wind (MW):(1)			7,700		SPP Installed Wind (MW):(1)			7,700	
Min. Wind in Top 22 Hrs (MW):			843	10.9%	Min. Wind in Top 22 Hrs (MW):			603	7.8%
Avg. Wind Top 22 Hrs (MW):			3,432	44.6%	Avg. Wind Top 22 Hrs (MW):			1,710	22.2%

Note 1: Installed wind, net of pseudo-tied resources has been estimated from the 2013 State of Market (SOM), dated 5/19/2014. The 2013 SOM indicated approximately 8,500 MW of wind installed in SPP at the end of 2013, and the 2014 Spring SOM, quarterly ,dated July 14, 2014, indicated that as of the start-up of the IM, SPP net pseudo-tied resources from the reported wind production. Pseudo-ties have been assumed for the output of Cimarron (165 MW to TVA), Chishom View (235 MW to Alabama Powre), Buffalo Dunes (250 MW to Alabama Power) and Caney River (200 MW to TVA). 8,500 minus the 850 MW of assumed pseudo-tied wind resources is approximately 7,700 MW

Note 2: Wind production as a percentage of installed wind (at P50, actual, levels). P60 will be lower.

Table 3 shows that wind produced energy at a capacity factor of approximately 47% in the reported peak load hour in August, and had an average production over 22% in July and almost 45% in August during the top 22 load hours.

Q: What can you conclude from the available information, including the Table 3 analyses and the information in the Criteria Changes Wind Accreditation by Generation Working Group reporting?

A. I conclude that it appears likely that the capacity credited to wind resources on average is likely to be considerably higher than 5%. This is based on the actual SPP average data I presented in Table 3, capacity credits for the MISO system, and the results of SPP's own preliminary studies showing capacity factors for some plants in excess of 25%.[30] Portions of Kansas and Oklahoma have extremely good wind potential. Responses to OG&E's 2013 Wind RFI provided capacity values ranging from 43% to 57%.[31] A high capacity factor for a wind plant indicates that it produces more on average throughout the year. With the capacity factor range identified by OG&E in its 2013 Wind RFI, it is possible that wind resources available to OG&E will have a capacity factor credit considerably higher than 5%. In light of these changes to SPP's capacity accreditation process and actual capacity values of these resources, OG&E understates the likely capacity factor credit it could receive from additional wind investments.

Q: What are your thoughts regarding attractive wind PPA prices within the SPP market?

A. First, there is excellent wind potential in the SPP area as demonstrated by the power purchase agreement prices and capacity values received in response to the 2013 RFI. Second, Congress is on the verge of extending the federal production tax credit ("PTC") for wind energy, which will encourage further wind development. Under the 2013 PTC extension, wind plants could receive the credit if construction was completed by 2016 and it either started construction before the end of 2013 or had spent at least 5% of the wind plant cost prior to the end of 2013 to be eligible for the PTC. The United States House of Representatives has passed a one year extension which applies the same terms to wind plants through December 2014 and moves the in service date back to 2017. The U.S. Senate is expected to pass this bill and the President is expected to sign it.

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[30] See OG&E's Response to Sierra Club DR 1-29, Att. 2, Criteria Changes Wind Accreditation by Generation Working Group

[31] OG&E's Response to Sierra Club DR 4-4

VI. PROMOD MODELING

A. OG&E Modeling for ECP

Q: You have indicated that you have reviewed OG&E's ProMOD modeling provided in response to Sierra Club Data Request 2-4. Please discuss your findings in reviewing the data.

A. OG&E indicates in the Executive Summary of the OG&E 2014 IRP that "[t]his IRP also reflects the recently implemented SPP IM, which went live on March 1, 2014. The SPP IM includes a Day Ahead market and several other features that will commit and dispatch resources and transmission flows to serve electricity loads across the multi-state SPP footprint. While OG&E is still required to own or control sufficient generation capacity to meet SPP planning reserve requirements, the Company now obtains all of its energy through the SPP IM rather than relying on its own resources. As a consequence, the evaluation of OG&E's prospective resource needs incorporates an analysis of generation resources, transmission constraints and market conditions for the entire SPP region." Given this statement, I was surprised to find that OG&E performed the ProMOD analysis in zonal rather than nodal mode[32].

Q: Please explain why OG&E running in zonal mode surprised you.

A. Evaluating the impact of congestion, and the resulting impact on production cost, requires a tool that can simulate grid operation, including commitment of generating resources, dispatch of generation to serve load, calculation of flows on the transmission system, and redispatch of generation necessary to alleviate transmission constraints. While grid operators such as the SPP have customized software programs, there are various "off-the-shelf" security constrained economic dispatch software programs which are used to calculate LMPs and estimate the impacts of changes on the system. These programs can generally be run in "zonal" mode, which greatly simplifies the transmission representation and as a result is not appropriate for many purposes, or nodal mode, which includes the full transmission network model.

[32] See OG&E's response to Sierra Club data request 4-8

OG&E's claim that its analysis reflects inclusion in the SPP IM is a partial-truth at best as its ProMOD analysis does not account for a critical component of the IM, the impact of congestion on the individual generator LMPs, discussed in Section IV. As shown in Table 1, several OG&E generators have experienced significant congestion as reflected in their LMPs since the startup of the SPP IM, including the Muskogee and Sooner plants. A zonal analyses will not reflect the impact of congestion on the generating plant nodes, as a zonal model only produces a single "market" price for each zone modeled. OG&E's claims that it did not pursue wind resource additions because of congestion risk are belied by the fact that OGE completely ignored the impact of congestion on its own fossil fuel generating units.

Q: What were some of your other findings from your review of the OG&E ProMOD modeling?

A. First, the OG&E zonal ties were not correct in its ProMOD model as there is no tie between the OG&E and Southwestern Public Service (SWPS) systems.[33] A critical first step in modeling is to update the model. OGE did not do this, at least not for ties from its load area to other areas. As of the end of 2014, the thermal limit of the SWPS ties to OG&E totals 1792 MW[34]. As discussed in the Transmission to Relieve Congestion in Section IV., the major transmission lines that came into service in 2014 tied SWPS and OG&E. By failing to include this 1792 MW transmission tie the market price for the OG&E load zone is inaccurate.

Second, the zonal transmission limits for all transmission ties within SPP do not change over 30 years even though SPP has an approved transmission expansion plan with some additional major 345 kV lines going into service (impacting the OG&E area) between 2018 and 2022.

Third, OG&E only ran the SPP footprint, thus excluding areas outside of SPP. While the IM only applies within SPP, SPP is not a stand-alone area. The entire eastern interconnect is an interconnected electrical grid from Florida to eastern Texas (where the non-

[33] . nFront pulled the Ventyx zonal model as delivered, and this was a flaw in the ProMOD zonal model delivered from Ventyx. However, there are typically many flaws in the model as delivered by ProMOD.

[34] The tie value is from the SPP 2014 Series 2015 Summer Peak 2014MDWG_Final_15S.raw power flow case model. nFront did not calculate a transfer limit which would be lower.

synchronous Electric Reliability Council of Texas is located), to the Dakotas, into Manitoba Canada, through Ontario Canada into New York and New England, and everything in between. For security constrained economic dispatch analyses, modeling the entire eastern interconnect generally overloads the capability of the program. Fortunately, it is generally not necessary to model the entire eastern interconnect, because including the entire region generally will not significantly alter modeling results assuming the other factors addressed herein are adequately addressed. Instead, based on the evaluation and purpose of the study, one determines a reasonable "footprint", i.e., the amount of the system which is to be modeled in detail. The footprint for SPP would generally include Associated Electric Cooperative ("AECI"), the Integrated System (likely soon to be part of SPP) and the Mid-continent ISO ("MISO") at a minimum.

Q. Do you think OG&E's assumptions regarding wind resources that it included in its ProMOD analysis were reasonable?

No. OG&E modeled about 9,700 MW of total SPP wind in 2015 and did not add any more wind additions throughout the study. First, OG&E's assumption about how much wind would be added to the SPP over the next 30 years is unreasonable as SPP has already achieved the assumed levels. The 2013 State of the Market Report states that approximately 8,400 MW of wind generation was installed in SPP at the end of 2013.[35] None of the new SWPS and PSO wind PPAs, discussed in Section IVa. were in service at the end of 2013. Adding just those new wind plants essentially equals the maximum amount that OG&E modeled for wind. Since wind energy has no fuel cost, it is generally referred to as a "price-taker" in the market, i.e., with its ability to bid $0 or below, a wind plant typically is not "setting" the marginal energy price. Therefore, wind energy displaces energy from the "marginal" plants setting the market price and in turn can lower the marginal energy price for the system.

Second, the capacity factors that OG&E uses for wind resources is low and not reflective of new wind plants in the Kansas and Oklahoma areas. As with not installing as much wind MWs as is likely to be developed within SPP, using low capacity factor also understates the wind energy delivered to the SPP IM that would reduce the amount of

[35] See 2013 State of the Market Report at pg. 34, available at http://www.spp.org/section.asp?group=642&pageID=27. Attached as Exhibit JBT-7.

energy required from fossil resources. OG&E modeled capacity factors for its owned or contracted for wind units between 34 and 39.39%, and modeled the new generic wind plants with capacity factors ranging from 35.7 to 38.2%, despite the capacity factors identified by OG&E from the responses to its 2013 request for information (RFI) ranging from 43% to 57%. Much lower modeled capacity values such as these could significantly impact hourly market prices, especially during high wind hours.

Q: What conclusions have you reached regarding the OG&E ProMOD modeling?

A. I conclude that the OG&E prices produced from ProMOD are the compilation of many data flaws combined with use of ProMOD in a zonal mode manner which does not reflect the SPP IM. As a result, I conclude that the results, an hourly stream of OG&E load zone prices, introduced a substantial error to any analysis performed using the ProMOD generated prices.

Q: Have you performed an analysis indicating what the impact of the ProMOD modeling errors could be on the ECP?

A. No, I have not. OG&E has the responsibility under the ECP to support its analyses, which it has not done.

B. nFront Supplemental ProMOD cases

Q: Have you performed other analyses using the ProMOD model provided by OG&E in response to Sierra Club 2-4?

A. Yes. In support of the testimony of Tyler Comings and Rachel Wilson of Synapse Energy Economics, nFront personnel under my direction produced two additional scenarios using the OG&E provided ProMOD data. For consistency, I made no attempt to correct the flaws in the OG&E modeling, but simply followed the methodology it used. The resulting hourly stream of OG&E zone prices were provided to Witnesses Rachel Wilson and Tyler Comings, the results of which are addressed in their testimonies.

Q: Please describe the process you used to produce the hourly OG&E zone prices?

A. OG&E provided the PROMOD input files[36] (Sierra Club Response 2-4) for seven cases. The seven ".xml" files ("OG&E ProMOD cases") were the Base Case, CO2 Cost Case, Gas Price (+50%) Case, Gas Price (-25%) Case, High Coal to Gas Conversion Case, Load (-10%) Case, and Low Coal to Gas Conversion Case. nFront began with the Base Case by importing the supplied data into ProMOD to create an unaltered ProMOD Base Case in which to benchmark against the OG&E Base Case prices provided in OG&E's response to Sierra Club 1-37, Attachment 1-37_Att1_Confidential. Since nFront made no changes to the ProMOD Base Case data supplied, the expectation was that when ProMOD was run, the hourly prices would be identical to the OG&E Base Case pricing provided in Attachment 1-37_Att1_Confidential Base Scenario. The nFront ProMOD Base Case results were not identical although reasonably close in most hours. We were unable to identify the exact reasons since no changes were made to the OG&E input data.

However, since there were not substantial material differences, nFront created two new cases; a Base Case with EPA CO_2[37] and a Low Gas[38] with EPA CO_2. nFront ran the two new cases using ProMOD in zonal mode, i.e., making no other changes to the ProMOD data or methodology used by OG&E and for the same period from 2015 through 2044. nFront supplied the OG&E prices from all three ProMOD runs (nFront ProMOD cases), the "benchmarked" Base Case, the Base Case with EPA CO_2 and the Low Gas with EPA CO_2 to Witnesses Rachel Wilson and Tyler Comings. In addition to the prices from the three nFront ProMOD cases, I also provided an hourly wind pattern to Witness Tyler Comings for use in his modeling of new wind plants. The hourly wind profile was selected from the National Energy Renewable Laboratory[39] Eastern dataset which has over 1,300 wind patterns across the eastern interconnect including 82 in Oklahoma. nFront selected and supplied the NREL site pattern number 365 representing a site in Beaver County, Oklahoma with a 46.5% capacity factor. This pattern is reasonable, and

[36] The input files are in .xml format and include all the ProMOD model inputs, e.g., fuel, hourly demand, zone definitions, generating resources and characteristics, etc.
[37] . nFront replaced the National CO2 effluent forecast with in the OG&E Base Case was set to $0 with an annual CO2 forecast provided by Witness Tyler Comings.
[38] nFront created a layer lowering the three natural gas forecasts EIA SPP North NG, EIA SPP South NG, and EIA MRC West NG by 25% for the full 2015-2044 IRP analysis.
[39] http://www.nrel.gov/electricity/transmission/eastern_wind_dataset.html

in fact conservative, representation of wind energy that OG&E could contract for under power purchase agreements.

VII. RELIABILITY CONSIDERATIONS

Q: In Section III beginning on page 9 of this testimony, you described characteristics of an alternating current (AC) electrical system as it pertains to locational marginal pricing. Does your discussion within that section cover all the aspect of reliable planning and operation of the transmission grid?

A. Certainly not. The analytical tool must fit the purpose of the study. A power flow program is the primary tool for reliability planning. Section III of my testimony addresses issues of relevance to constraint management in an LMP system. A nodal program, such as ProMOD/TAM contains the inputs and processes to evaluate economics, not reliability. Unlike power flow programs,[40] security constrained economic dispatch models generally use a linear (direct current) transmission solution, and therefore, the models have no ability to evaluate voltage impacts.

Q: If a security constrained economic dispatch model cannot account for voltage impacts then how do transmission operators, such as SPP use such a program for reliable operation of the system?

A. Similar to the discussion in Section IIIc. pertaining to out of merit order dispatch instructions where there are defined procedures in place (e.g., curtailing the output of generating plants contributing 5% or more to the flow on the constraint), reliability issues, such as actions which are required to avoid voltage collapse under certain system conditions are identified and put in place beforehand (based on "reliability" analyses using power flow, short circuit and voltage and dynamic stability analyses).

An example of a reliability procedure is use of a special protection scheme. A special protection scheme is developed in advance in the process of reliability planning and applied in day-to-day operation of the grid based on the criteria defined. An example within SPP is a special protection scheme which will trip OG&E's Crossroad wind

[40] Examples include Siemens/PTI's PSS/E program, General Electric's PSLF program of PowerGem's TARA program.

plant[41] if the event specified in the special protection scheme occurs. Procedures such as these show the coordination between reliability planning and operations.

Q: Are there similar procedures in place relative to the interconnection or new generation, or alternately the retirement of generation?

A. Yes. As discussed in Section IVB., the SPP open access transmission tariff has a specific generation interconnection process. The reliability studies identified as part of the generator interconnection process will specify the transmission upgrades required to reliably integrate the new generation. Likewise, transmission operators, such as MISO[42] and PJM, have defined procedures in place for evaluating retirement of generation units to assure reliability. Although SPP has not yet posted specific generating plant retirement procedures, as the reliability coordinator it is responsible for maintaining reliability.

Q: Are you familiar with the EPA Clean Power Plan?

A. While I have not studied the plan in detail, I am aware of goals of the EPA Clean Power Plan.[43] EPA proposed carbon pollution regulations under Clean Air Act Section 111(d). Implementation of the Clean Power Plan is expected to lead to the retirement of certain coal-fired generating plants.

Q: How will EPA's Clean Power Plan impact reliability?

A. SPP and other balancing authorities will maintain reliability but it will require planning.

As of June 18, 2007, FERC granted the National American Electric Reliability Corporation ("NERC") the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the bulk power system and made compliance with those standards mandatory and enforceable. In November 2014, NERC released a report entitled "Potential Reliability Impact of EPA's Proposed Clean Power Plan."[44] Page 1 of the Executive Summary states "The preliminary review of the proposed rule,

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[41] http://www.spp.org/publications/SPCWG%2011%2012%2010%20Minutes.pdf , attached as Exhibit JBT-8.
[42] https://www.misoenergy.org/Library/Repository/Communication%20Material/One-Pagers/SSRs.pdf, attached as Exhibit JBT-9.
[43] http://blog.epa.gov/epaconnect/2014/06/understanding-state-goals-under-the-clean-power-plan/
[44] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf

assumptions, and transition identified that detailed and thorough analysis will be required to demonstrate that the proposed rule and assumptions are feasible and can be resolved consistent with the requirements of BPS reliability. This assessment provides the foundation for the range of reliability analyses and evaluations that are required by the ERO *(electric reliability organizations)*, RTOs *(regional transmission organizations)*, utilities, and federal and state policy makers to understand the extent of the potential impact. Together, industry stakeholders and regulators will need to develop an approach that accommodates the time required for infrastructure deployments, market enhancements, and reliability needs if the environmental objectives of the proposed rule are to be achieved." While NERC concludes the report by indicating that "NERC supports policies that include a reliability assurance mechanism to manage emerging and impending risks to the BPS *(bulk power system)*, and urges policy makers and the EPA to ensure that a flexible and effective reliability assurance mechanism is included in the rule's implementation," the reality is that NERC's is obligated to ensure the grid remains reliable.

As one with an extensive background in transmission planning, I am not trying to make light of the effort and planning that SPP, NERC, and others will invest to ensure grid reliability. For example, SPP put considerable effort and detail into the OG&E Crossroad wind plant special protection scheme to address one transmission outage event. Implementation of the EPA Clean Power Plan will be done in a manner where grid reliability is maintained. This means that retirements will not occur haphazardly, but rather after adequate addition of energy and capacity sources, transmission expansions, and modifications to relevant operating procedures to ensure reliability.

Q: Do you have any final thoughts relative to grid reliability of relevance to this case?

A. Planning for reliable operation is the responsibility of utilities, transmission operators, across regional transmission organizations (under FERC Order 1000) and other stakeholders. The final ECP will require reliability planning. However, no matter what the final ECP consists of reliability will be maintained.

VIII. CONCLUSIONS

Q: Does that conclude your testimony?

A: Yes.

Background and Experience of

JENNIFER B. TRIPP

Educational Background:

MBA Global Business Administration
Thunderbird School of Global Management, Glendale, AZ, 2009

Bachelor of Science Degree in Electrical Engineering
University of Cincinnati, Cincinnati, OH, 1986

Professional Registration:

Registered Professional Engineer State of Arizona since 1993

Registered Professional Engineer State of Ohio 1990 – 2011 (currently inactive)

Professional Experience:

nFront Consulting, Evergreen, Colorado **May 2013 – Present**

Management Consulting in the Energy Sector with Specialty in Transmission and Markets

Managing Director – Transmission and Delivery

- Manage transmission and delivery sector which includes technical evaluations using power flow (PowerGem's TARA) and security constrained economic dispatch (Ventyx's ProMOD with the Transmission Access Module)
- Lead intermittent resource curtailment and congestion risk assessments to evaluate/support power purchase agreement provisions and for financing of power projects
- Lead evaluations of the impact of transmission expansion on resource delivery
- Support utilities, developers and resource owner/operators with decisions affecting their strategies and financial decisions
- Provide expert witness testimony for transmission and resource delivery related issues

BP Wind (via Clover Global Solutions), Evergreen, Colorado **September 2011 – January 2014**

Renewable Power Development, Financing/ Operations with Specialty in Transmission, Markets and Financial Risks

Executive Consultant Project Advisor

- Transmission lead for financing team and development of confidential information memorandum for 470 MW wind farm
- Supported protests and comments in the SPP Integrated Marketplace Docket No. ER12-1179-000
- Developed congestion profiles for wind resource off-takers under power purchase agreeements

- Managed development of congestion, curtailment and transmission cost inputs for wind plant pro forma models
- Lead investigator of causes of reliability curtailment on operating wind portfolio and oversee development of mitigation plan
- Advisor on greenfield site development, solar portfolio, wind plant acquisitions and market outlooks

SAIC/R. W. Beck, Inc. (acquired by SAIC in 2009), Scottsdale, Arizona **1991 – September 2011**

Management Consulting and Engineering in the Energy Sector with Specialty in Electric Power and Renewables

Trusted presenter, client manager, business developer and successful project manager providing client focused solutions to developers, banks/equity investors and utilities primarily focused on impacts of electric transmission, markets, and regulation on clients' financial, development, reliability, planning and economic decisions for generation and transmission assets.

- Leadership positions including Vice President, Principal, National Director, Board of Directors
- Provided testimony in sixteen transmission and resource dockets, including timing and need for assets
- Managed transmission markets consulting which included technical evaluations using power flow and security constrained economic dispatch
- Demonstrated ability to identify market trends and develop strategies in challenging and changing markets to deliver results
- Track record of growing business, substantially exceeding sales, project management and revenue metrics through identifying opportunities and value, client relations, skillful negotiation, mentoring, and leadership through disciplined project execution
- Multiple live interviews on CNN following the August 2003 Northeast Blackout
- Elected to the R. W. Beck Board of Directors in 2003 - 2004

Ohio Edison Company, Akron, Ohio **August 1986 – November 1990**

Engineer in the Electric Utility Sector with Specialty in System Operations, Production Costing and Transmission

Employed by Ohio Edison Power Company, Akron, Ohio. Served as an engineering cooperative education employee from 1983 to 1985 in the positions of Distribution Operations, Transmission Design, Telecommunications and Generating Resource Operations. Served as a Substation Design Engineer from 1986 to 1988 and as a System Operations Engineer at the system control center from 1988 to end of 1990. The operations experience included real-time security analysis program studies, short-term production costing and economic dispatch analyses, power quality evaluations, and transmission wheeling scheduling and contract administration.

ATTACHMENT A (CONTINUED) – LITIGATION EXPERIENCE

Record of Testimony & Affidavits Submitted By
JENNIFER B. TRIPP

Line No.	Utility	Proceeding (Docket Nos.)	Subject of Testimony	Before	Client	Year
1	Public Service Company of New Mexico	ER95-1800 ER96-1462 ER96-1551 EL95-75	Open Access and Power and Energy Sales Tariffs	Federal Energy Regulatory Commission	Navajo Tribal Utility Authority	1996(1)
2	Niagara Mohawk Power Corporation	OA96-194-000	Open Access Transmission Tariff	Federal Energy Regulatory Commission	Sithe/Independence Power Partners, L.P.	1996-1998
3	New York Power Exchange/ Independent System Operator	ER97-1523-000 ER97-986-000 OA97-470-000 ER97-4234-000	Affidavit Transmission Rates and Losses	Federal Energy Regulatory Commission	Sithe/Independence Power Partners, L.P.	1997-2000(1)
4	Pacific Gas & Electric Company	ER98-2351-000 ER972358-000	Credit for Transmission Facilities	Federal Energy Regulatory Commission	Public Systems	1999(1)
5	Niagara Mohawk Power Corporation	EL99-65-000	Affidavit Transmission Rates and Losses Under Section 206 of the Federal Power Act	Federal Energy Regulatory Commission	Sithe/Independence Power Partners, L.P.	1999-2001(1)
6	Niagara Mohawk Power Corporation - Remand	EL95-38-000	Affidavit Transmission Rates and Losses	Federal Energy Regulatory Commission	Sithe/Independence Power Partners, L.P.	1999-2001(1)
7	-	L-000000-00-0099	Certificate of Environmental Compatibility	Arizona Siting Committee	Gila River, L.P.	03/2000
8	-	L-00000B-00-0105	Certificate of Environmental Compatibility	Arizona Siting Committee	Salt River Project – Santan Expansion	10/2000

Record of Testimony & Affidavits Submitted By
JENNIFER B. TRIPP

Line No.	Utility	Proceeding (Docket Nos.)	Subject of Testimony	Before	Client	Year
9	-	L-00000B-00-0112	Certificate of Environmental Compatibility	Arizona Siting Committee	Toltec Power Station	5/2001
10	-	L-00000B-00-0113	Certificate of Environmental Compatibility	Arizona Siting Committee	Toltec Power Station	7/2001
11	Arizona Public Service Company	L-00000B-00-0115	Certificate of Environmental Compatibility	Arizona Siting Committee	Arizona Public Service Southwest Valley 500 kV Transmission Line	2001-2002
12	-	L-00000B-00-0118	Certificate of Environmental Compatibility	Arizona Siting Committee	Bowie Power Station	10/2001
13	-	01-F-0761	Article X Certificate of Environmental Compatibility and Public Need	New York State Board on Electric Generation Siting	S.H.A.R.E.D.	2002
14	Sierra Pacific Resources Operating Company	ER03-1328-000	Transmission Rates and Planning	Federal Energy Regulatory Commission	Indicated Customers	2004 (1)
15	Oklahoma Gas and Electric	PUD 200300564	Resource Acquisition	Oklahoma Corporation Commission	PowerSmith Cogeneration	2004 (1)
16	Rayburn County Electric Cooperative	SOAH Docket No. 473-07-0218; PUC Docket No. 32707	Certificate of Convenience and Necessity	Public Utility Commission of Texas	Rayburn County Electric Cooperative	2007-2008
17	NV Energy Operating Companies	ER13-1605-000 ER13-1607-000	Transmission Rates and Planning	Federal Energy Regulatory Commission	Las Vegas Power Company, LLC	2013 (1)
18		13-T-0292	Article VII Certificate of Environmental Compatibility and Public Need	New York State Board on Electric Generation Siting	Town of Cortland, Riverkeeper, Scenic Hudson, Inc	2014 (2)

(1) Case was settled.
(2) Applicant's Article VII Application was rescinded with intent to refile, prior to Intervener direct testimony filing

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION FOR APPROVAL AND AUTHORITY TO: (1) ENTER INTO SEPARATE PURCHASED POWER AGREEMENTS WITH NEXTERA ENERGY RESOURCES' MAMMOTH PLAINS AND PALO DURO WIND ENERGY CENTERS AND INFINITY WIND POWER'S ROOSEVELT WIND RANCH FOR WIND ENERGY; AND (2) RECOVER THE ASSOCIATED ENERGY COSTS THROUGH ITS FUEL AND PURCHASED POWER COST ADJUSTMENT CLAUSE,	)	CASE NO. 13-00233-UT
SOUTHWESTERN PUBLIC SERVICE COMPANY, APPLICANT.	)	

RECOMMENDED DECISION

October 30, 2013

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Frances I. Sundheim, Hearing Examiner in this case, submits this Recommended Decision to the New Mexico Public Regulation Commission ("Commission") pursuant to NMSA 1978, Section 8-8-14, and Commission Rules of Procedure 1.2.2.29D(4) and 1.2.2.37B NMAC. The Hearing Examiner recommends that the Commission adopt the following statement of the case, discussion, findings of fact, conclusions of law and decretal paragraphs in an Order.

I. STATEMENT OF THE CASE

On July 10, 2013, Southwestern Public Service Company ("SPS") filed an Application under NMAC 17.9.551 requesting that the Commission enter an order authorizing SPS to:

(1) enter into a purchased power agreement with NextEra Energy Resources' ("NextEra") Mammoth Plains Wind Project Holdings, LLC ("Mammoth") for the purchase of 199 MW of wind energy beginning no later than December 31, 2014 and continuing for twenty years ("Mammoth PPA");

(2) enter into a purchased power agreement with NextEra's Palo Duro Wind Project Holdings, LLC ("Palo Duro") for the purchase of 249 MW of wind energy beginning no later than December 2014 and continuing for twenty years ("Palo Duro PPA");

(3) enter into a purchased power agreement with Infinity Wind Power's Roosevelt Wind Ranch, LLC ("Roosevelt") for the purchase of 250 MW of wind energy beginning no later than December 31, 2015 and continuing for twenty years ("Roosevelt PPA"); and

(4) recover through its fuel and purchased power cost adjustment clause ("FPPCAC") the New Mexico retail customer jurisdictional share of

the cost of energy purchased under these three purchased power agreements ("PPAs").[1]

Concurrent with the Application, and in support of the Application, SPS submitted the pre-filed direct testimony and exhibits of Bennie F. Weeks and Jessica L. Collins.

On July 16, 2013, the Commission issued an order designating Carolyn R. Glick as Hearing Examiner to preside over this case. A prehearing conference was held on July 29, 2013. At the prehearing conference, the Hearing Examiner requested that SPS file supplemental testimony. In response to the Hearing Examiner's request, SPS filed the Supplemental Direct Testimony of Bennie F. Weeks on August 12, 2013.

On August 1, 2013, a Procedural Order and attached Notice to SPS Customers was issued establishing a schedule for the case, requiring SPS to publish and post notice of this proceeding, and setting a public hearing for October 15-16, 2013.

Motions to Intervene were filed by the Coalition for Clean Affordable Energy ("CCAE") and Occidental Permian, Ltd. ("Occidental"). The motions were not opposed.

On August 29, 2013, SPS filed SPS's Notice of Publication and Filing of Affidavit showing that SPS published and posted the Notice to SPS Customers as required by the Procedural Order.

On September 9, 2013, the Commission issued an order designating the undersigned as Hearing Examiner to preside over this case.

On September 16, 2013, Utility Division Staff ("Staff") of Commission submitted the pre-filed direct testimonies and exhibits of Charles W. Gunter and Bruno E. Carrara, P.E.

On September 24, 2013, SPS filed the Rebuttal Testimony of Bernie F. Weeks.

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[1] SPS's Application at p. 2-3.

As allowed under 17.9.551.10 NMAC, the Parties[2] filed a Joint Motion to Vacate Hearing and Approve SPS's Modified Application for Long Term Purchased Power Agreements ("Joint Motion"),[3] on October 3, 2013. The Parties concur with the Joint Motion, do not require a formal hearing, waive cross-examination, and waive the filing of additional testimony or discovery.

On October 8, 2013, the undersigned Hearing Examiner issued an order vacating the hearing because there were no contested issues, and admitting into evidence the testimony submitted by SPS and Staff.

On October 21, 2013, the parties filed a Joint Proposed Recommended Decision.

No public comments were filed in this case.

The Parties concur with and support this Recommended Decision.

II. DISCUSSION

A. Legal Standard

Section 17.9.551.8 NMAC of the Commission's rules states that electric utilities may not become irrevocably obligated under a long term PPA without first obtaining the Commission's written approval. The rule requires utilities to file an application for the Commission's review and approval of a long term PPA within thirty days after execution of the agreement. 17.9.551.8(B) NMAC.

The rule establishes filing requirements for long term PPA applications, including the following:

[2] "Parties" refers to SPS, Staff, CCAE, and Occidental.
[3] SPS's Application requested that the Commission grant "all other approvals, authorizations, waivers, or variances that the Commission determines are necessary to implement and effectuate the relief granted in this case." Staff did not concur with this request. Because no such approvals, authorizations, waivers, or variances were identified, SPS's request was rendered unnecessary. SPS's Application was modified accordingly by the Rebuttal Testimony of Bennie F. Weeks.

(1) a copy of the PPA;

(2) an explanation of the key terms and conditions of the PPA containing:

(a) the term of the PPA including any options to extend the agreement;

(b) the size in MW of capacity and the amount of energy in MWh or kWh per month and any conditions regarding the minimum or maximum amount of energy or capacity made available or required to be purchased;

(c) the price or pricing formula under which the electric utility will pay for the power and energy contracted for, including identification of when charges begin to be incurred, any price reopeners and any price escalation provisions;

(d) obligations by the electric utility to pay for any fixed or variable administrative, transactional or operation and maintenance costs incurred through the operation of the generation facility, including start-up costs, taxes, insurance, environmental or reclamation-related costs, fuel costs and any other costs that the electric utility may incur; and

(e) provisions relating to non-performance by the counter-party and the remedies provided;

(3) a description of transmission costs the electric utility will incur or pay to receive the purchased power, which may include the costs of third-party transmission wheeling, or construction of transmission to facilitate purchases under the PPA or both;

(4) an explanation of how the electric utility proposes to recover from ratepayers the costs incurred and an estimate of the effect on rates to customers;

(5) a general description of:

(a) the generating facility or facilities that will generate the purchased power; or

(b) if the power is to be generated from one or more specific generating units to be constructed outside New Mexico, a description of the anticipated siting of the generating unit, expected construction time and the expected commercial operation date; and

(c) if the power is to be generated from one or more specific generating units to be constructed within New Mexico, a description of:

(i) the approvals required to construct and operate the generating unit, including air quality and other environmental permits;

(ii) the expected construction time;

(iii) the expected commercial operation date;

(iv) the fuel type and supply sources; and

(v) other provisions addressing the electric utility's ownership options for the generating unit during or after the term of the agreement;

(6) evidence that entering into the PPA is consistent with the provision of safe and reliable electric utility service at the lowest reasonable cost, considering both short and long-term costs and all other relevant factors;

(7) evidence of the PPA's impact on the electric utility's financial condition and financial metrics;

(8) evidence that the PPA is consistent with the electric utility's most recent commission-accepted integrated resource plan unless, as described in Section 17.7.3.10 NMAC, material changes that would warrant a different course of action by the electric utility have occurred; in which case, the testimony shall include justification for deviation from the integrated resource plan;

(9) evidence addressing whether a utility-owned generation resource could have been constructed as an alternative to the PPA with greater benefit to ratepayers;

(10) evidence addressing the methodology and criteria by which the purchased power agreement was selected; and

(11) any other information or evidence that the electric utility believes will assist the commission in its review of the PPA.

17.9.551.8(D) NMAC.

The rule provides that the following ratemaking treatment will apply to PPAs unless the utility requests and/or the Commission requires otherwise:

(1) energy costs incurred under a purchased power agreement are recoverable through a fuel and purchased power cost adjustment clause ("FPPCAC") according to the provisions of the FPPCAC approved for the electric utility; and

(2) capacity costs and fixed costs incurred under a purchased power agreement, as well as energy costs incurred by an electric utility without an approved FPPCAC, may be recoverable through base rates when the commission issues an order authorizing a change in base rates that includes recovery of the capacity costs and fixed costs, and energy costs in the case of an electric utility without an approved FPPCAC.

17.9.551.9 NMAC.

The rule requires the Commission to issue a final order on the application within six months after the date the application was filed. Otherwise, the application will be deemed to be approved. 17.9.551.10(B) NMAC. The Commission may approve an application without a formal hearing if no protest is filed within sixty days after the date notice is given pursuant to a Commission order. 17.9.551.10(A) NMAC.

B. SPS's Application

1. Description of the Facilities

The Mammoth Plains facility is a new 199 MW capacity wind project that will be located in Dewey and Blaine Counties, Oklahoma. Construction is expected to take up to 9 months, and the facility is expected to be fully operational by December 2014. SPS expects the project to produce approximately 996,000 MWh of wind energy per year.

The Palo Duro facility is a new 249 MW capacity wind project that will be located in Hansford and Ochiltree Counties, Texas. Construction is expected to take up to 9 months, and the facility is expected to be fully operational by December 2014. SPS expects the project to produce approximately 1.18 million MWh of wind energy per year.

The Roosevelt facility is a new 250 MW capacity wind project that will be located in Roosevelt County, New Mexico between the towns of Dora and Elida. Construction is expected to take up to 24 months, and the facility is expected to be fully operational by December 2015. SPS expects the project to produce approximately 1.06 million MWh of wind energy per year.

SPS's testimony identifies the governmental approvals, licenses, and authorizations that will be obtained by NextEra and Infinity. The testimony also includes a construction schedule for each facility.

2. Key Terms of the PPAs

a. Mammoth and Palo Duro PPAs

The Mammoth and Palo Duro PPAs are 20-year contracts for SPS to purchase the energy generated by the Mammoth and Palo Duro facilities. There are no provisions in the contracts to extend the purchase arrangement beyond the 20-year terms. The Mammoth and Palo Duro PPAs provide for the purchase of an "energy only" product. The PPAs do not provide for the purchase of capacity. The contracts include a provision that allows SPS to purchase Renewable Energy Certificates ("RECs") at a future date.

Under the Mammoth PPA, the price for the first year of commercial operation will be $19.18 per megawatt-hour ("MWh"). The price escalates at a rate of 2% each year until 2020. Under the Palo Duro PPA, the price for the first year of commercial operation is $21.10 per MWh and escalates at the rate of 1.8% annually until the end of 2020. The price is then reset to $22.20 and escalates at the rate of 1.8% annually.

The Mammoth and Palo Duro PPAs provide for a block of "Allowable Curtailment" hours, *i.e.*, curtailments that can be initiated by SPS for any reason without an obligation to compensate the seller. Under these contracts, SPS is not required to compensate the Seller for up to 30,000 MWhs of curtailments per year during the first six (6) Commercial Operation Years.

The Mammoth and Palo Duro PPAs permit SPS to commission a transmission study outside of the normal SPP transmission service study process to estimate expected transmission service upgrade costs, timing, and related curtailment risks.

Guaranteed Mechanical Availability Percentage ("GMAP") ensures that generating equipment is available to produce energy at least 90% of the time (adjusted for predefined allowable downtime) during each contract year. Failure to achieve the GMAP of 90% is an event of default and results in payment of damages to SPS. If Mammoth Plains or Palo Duro fails to achieve the GMAP in 3 consecutive Contract Years, or 4 of 6 consecutive Contract Years, or achieve an actual availability of less than 65% in a contract year, SPS may terminate the contract.

In addition, SPS is entitled to recover damages if NextEra fails to perform in accordance with its obligations under the PPAs.

The Mammoth and Palo Duro PPAs contain a joint ownership purchase option that allows SPS or a wholly-owned affiliate of Xcel Energy Inc. to purchase up to 50% of the facility interests anytime before the facility achieves commercial operation. These PPAs also permit SPS to purchase the facilities at any time after the 15th anniversary of the commercial operation date ("COD") with 120 days notice.

b. Roosevelt PPA

The Roosevelt PPA is a 20-year contract for SPS to purchase the energy generated by the Roosevelt facility. There are no provisions in the contract to extend the purchase arrangement beyond the 20-year term. The PPA provides for the purchase of an "energy only" product. The PPA does not provide for the purchase of capacity. The contract includes a provision that allows SPS to purchase RECs at a future date.

The price under the Roosevelt PPA is $20.15 for the first year of commercial operation and escalates at a rate of 2.0% annually.

Under the Roosevelt PPA, the facility must produce at least 85% of the committed energy over any rolling 24-month period. Production below 85% is considered an event of default. Roosevelt may remedy such a default by curing or initiating a cure within 30 days or through payment of replacement energy costs to bring the total MWh to the committed level. The payment of replacement energy costs to cure this default may exceed the applicable damage cap established in the contract. If Roosevelt chooses not to exceed the damage cap to make such payments, SPS may terminate the contract. Additionally, if Roosevelt fails to produce at least 65% of the committed energy over a rolling 24-month period, SPS may terminate the contract.

SPS will accept and pay for energy delivered up to and including 115% of committed energy level at the contract price. In the event that energy in any year exceeds 115% of the committed level, SPS will have the option to either (i) pay Roosevelt at the current contract price for all energy delivered or (ii) elect not to accept any the energy. If SPS elects not to accept the excess energy, Roosevelt may sell that energy to a third party.

SPS is entitled to recover damages if Infinity fails to perform in accordance with its obligations under the PPA.

SPS has the right to purchase the facility after the COD under the right of first offer provisions.

3. Transmission Costs

It is uncertain whether SPS will incur transmission costs for delivery of the wind energy under the PPAs, but the projected savings under the agreements is expected to outweigh any such costs. SPS has not submitted a request to the Southwest Power Pool ("SPP") for firm transmission service for the Roosevelt project but believes that this facility is situated such that very little, if any, transmission congestion will occur.[4]

For the Mammoth Plains and Palo Duro projects, SPS submitted requests for firm transmission service to the SPP on May 31, 2013. At this time, SPS does not know what the transmission cost impacts will be.[5] SPS negotiated 30,000 MWh of non-compensable curtailment during the first six (6) years for the Mammoth Plains PPA and Palo Duro PPA. SPS believes that with the non-compensable curtailments and the use of the SPP Transmission Congestion Rights ("TCR") market to manage potential congestion, it will be protected from any

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[4] B. Weeks Direct Testimony at 27.
[5] B. Weeks Direct Testimony at 26.

additional costs related to transmission.[6] Additionally, contract terms allow SPS to terminate the PPAs if studies indicate that transmission impacts are significant.

4. Cost Recovery and Bill Impact

SPS requests Commission approval to recover the contract costs of the purchased power through SPS's monthly FPPCAC in accordance with Rules 550 and 551. SPS estimates that the PPAs will result in savings of up to $590 million (total company) net present value over the term of the PPAs, of which SPS's New Mexico retail customers are expected to benefit in the amount of approximately $100 million (based upon current jurisdictional allocations). SPS projects the monthly bill of a residential customer using 800 kilowatt-hours ("kWh") per month would decrease by 60¢, or 0.88%, assuming current base rates and projected 2015 energy purchases under the PPAs. Of the projected 60¢ per month savings, approximately 3¢ is attributable to the Roosevelt PPA, 28¢ is attributable to the Palo Duro PPA, and 29¢ is attributable to the Mammoth PPA. The relatively low contribution to the 2015 savings from the Roosevelt PPA occurs because that facility is not expected to be fully operational until the end of 2015.

5. RFP Process

During 2011 and 2012, SPS received unsolicited bids for sales of wind generation resources. The proposed prices were favorable and trending downward due to wind resource developers attempting to acquire and secure bilateral agreements to take advantage of Production Tax Credits ("PTCs") that were scheduled to expire December 2012.[7] On January 2, 2013, legislation extending the PTCs for one year was signed. With the extension of the PTCs and the

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[6] B. Weeks Direct Testimony at 26.
[7] B. Weeks Direct Testimony at 16.

indication that wind energy prices were economical and beneficial for SPS's customers, SPS issued its 2013 Wind RFP.

SPS's 2013 Wind RFP was issued on March 15, 2013, seeking wind generation beginning on or after January 1, 2014, but no later than December 2015. The 2013 Wind RFP asked bidders to provide SPS terms and conditions under which the environmental benefits and renewable energy certificates associated with the energy would be included in the purchase and a proposal under which the bidder would retain ownership of the REC. The RFP sought bids for a minimum amount of 10 MW, and required the facilities to interconnect directly to the SPP's transmission system or alternatively, the bidder would be responsible for directing energy from a system outside of the SPP and for associated costs. Bid proposals were due on April 12, 2013, and the evaluation, due diligence, and PPA negotiations were conducted during the months of April – June, 2013.

SPS received responses from eighteen (18) bidders that included over seventy five (75) proposals. SPS performed an initial screening of the bids to assess compliance with the RFP, and then analyzed the bids and sought clarification from the bidders when necessary. First, SPS calculated the levelized cost of each bid to determine its rank. After the rank was determined, SPS consulted with its internal operations, transmission, purchased power, and regulatory personnel to discuss any issues that might arise due to existing unit operations, transmission constraints, transmission service requests, PPA exceptions provided by the bidders, and REC strategy.

SPS then narrowed the selection to five bids. These bids were weighted based on six criteria: 1) price; 2) congestion management; 3) generation interconnection status; 4) ability to facilitate execution of the PPA; 5) balancing authority location; and 6) financial plan. The bids were then narrowed to the final three. Potential savings under the final three bids were calculated using SPS's avoided cost.

SPS used the production costing model, *Strategist*, to determine the avoided energy cost. *Strategist* constructs the generation stack of available resources to serve the load at the lowest cost, taking system constraints into consideration. *Strategist* was used to simulate the system dispatch necessary to meet SPS's forecasted system load for a twenty-year period. Next, *Strategist* was rerun with an additional resource, a 750 MW intermittent resource at a $0 cost per megawatt hour ("MWh"). This second run resulted in a lower cost than the initial run due to the additional resource that was included at $0/MWh. The annual costs resulting from the second optimization run with the 750 MW intermittent resource were subtracted from the annual costs resulting from the program results without the intermittent resource (first run). The differences in total system costs are the avoided energy costs that were used to determine the economic effectiveness of the selected projects.

Based on this information, SPS determined that the Mammoth Plains PPA, Palo Duro PPA, and Roosevelt PPA provide the best wind energy alternatives to add to SPS's resource portfolio. The total system net present value savings for these PPAs is $590.4 million based on SPS's most current 20-year levelized gas price forecast of $6.84/MMBtu.

SPS states that the PPAs will not have any significant impact on its financial condition or metrics.[8]

6. Consistency with SPS's Integrated Resource Plan

SPS's 2012 integrated resource plan ("IRP") incorporated the conclusions from its 2009 IRP, which indicated that the optimized model runs were as follows: (1) combined-cycle

[8] B. Weeks Direct Testimony at 29.

capacity and energy appeared in each of the optimized cases, shifting only slightly forward or backward in time; and (2) some amount of wind proved to be economic in virtually all of the runs (except for the no carbon and low gas cases). SPS's 2012 IRP evaluated additional purchases of wind energy assuming that PTCs for the development of wind energy would expire at the end of 2013. The exclusion of the PTCs caused wind energy to be uneconomic. The extension of the PTCs in January of 2013 resulted in favorable and economic wind prices. Based on current projections, the energy procured under the PPAs will be economic energy that will replace higher cost energy that would otherwise be generated or purchased.[9] Although these three PPAs were not specifically included in SPS's 2012 IRP, they are consistent with the IRP.

7. Renewable Energy Certificates

SPS has not purchased RECs under the PPAs because it has sufficient RECs to comply with its Renewable Portfolio Standard requirements. The price SPS has negotiated for the wind energy under the PPAs reflects that SPS will not be purchasing the RECs. Should SPS's needs change in the future, SPS has negotiated the option to purchase available RECs under the agreements.

C. Staff's Recommendation

Staff testified that SPS's Application and supporting testimonies and exhibits provided the information required by Rule 551 and that SPS has provided information in supplemental testimony as ordered by the Hearing Examiner. In Staff's opinion, SPS has demonstrated that the three proposed PPAs will provide fuel and purchased power cost savings with little risk to SPS or its customers, and that it is appropriate for SPS to recover through its FPPCAC the New Mexico retail customer jurisdictional share of purchased power costs under the three PPAs.

[9] B. Weeks Supplemental Direct Testimony at 14.

Staff recommends that the Commission approve SPS's requests to enter into the Palo Duro, Mammoth, and Roosevelt PPAs and to authorize SPS to recover through its FPPCAC the New Mexico retail jurisdictional share of the cost of energy purchased under the three PPAs.[10]

D. Analysis and Recommendations

The Hearing Examiner recommends that the Commission approve the Mammoth, Palo Duro, and Roosevelt PPAs. SPS has provided the information required by Rule 17.9.551.8 NMAC and has shown that the PPAs are consistent with the provision of safe and reliable electric utility service at the lowest reasonable cost. There is no evidence to indicate that the PPAs will have a negative impact on SPS's financial condition and metrics. The PPAs are consistent with SPS's most recent Commission-accepted IRP, and the evidence indicates that a utility-owned generation resource could not be constructed as an alternative to the PPAs with greater benefit to ratepayers. Further, the RFP process that resulted in SPS's decision to proceed with the PPAs appears to have been reasonably conducted.

The Hearing Examiner also recommends that the energy costs paid by SPS under the PPAs be approved for recovery through SPS's FPPCAC. The Commission's rule on PPA approvals provides for the recovery of such costs through a utility's FPPCAC unless a reason is shown to do otherwise, and no such reason exists here. *See* 17.9.551.9(A)(1) NMAC.

III. FINDINGS OF FACT AND CONCLUSIONS OF LAW

The Hearing Examiner recommends that the Commission find and conclude as follows:

1. The foregoing statement of the case, discussion, and all findings and conclusions contained therein, whether or not separately stated, numbered, or designated as findings and

[10] Charles W. Gunter Direct Testimony at 15-16; Bruno E. Carrara, P.E. Direct Testimony at 3; and Joint Motion.

conclusions, are hereby incorporated by reference as findings of fact and conclusions of law of the Commission.

2. The Commission has jurisdiction over the subject matter of the proceedings and the Parties.

3. Reasonable, proper, and adequate notice of this case has been given.

IV. DECRETAL PARAGRAPHS

The Hearing Examiner recommends that the Commission order as follows:

A. The findings, conclusions, rulings and determinations made and construed herein are hereby adopted and approved as the findings, conclusions, rulings and determinations of the Commission.

B. SPS's request for approval of the Mammoth, Palo Duro, and Roosevelt PPAs under 17.9.551.8 NMAC is granted.

C. SPS's request for approval pursuant to 17.9.551.9 NMAC to recover the amounts paid for purchased power under the Mammoth, Palo Duro, and Roosevelt PPAs through SPS's FPPCAC is granted.

D. This Order is effective immediately.

E. Copies of this Order shall be sent to all persons on the attached Certificate of Service.

F. This docket is closed.

ISSUED at Santa Fe, New Mexico, on **October30, 2013.**

NEW MEXICO PUBLIC REGULATION COMMISSION

Frances I. Sundheim, Hearing Examiner

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION FOR APPROVAL OF THREE LONG-TERM PURCHASED POWER AGREEMENTS AND OF COST RECOVERY THROUGH ITS FUEL AND PURCHASED POWER COST ADJUSTMENT CLAUSE.	)))))))	**Case No. 13-00233-UT**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing ***Recommended Decision,*** issued this **30th** day of October 2013, was sent by electronic mail to the individuals listed below:

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DATED this **30th** day of October, 2013.

NEW MEXICO PUBLIC REGULATION COMMISSION

Elizabeth Saiz, Law Clerk

The State of Oklahoma's 12th Electric System Planning Report

Prepared by the Oklahoma Corporation Commission's Public Utility Division

April 2013

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2012 Electric System Planning Report - Page 1

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This publication, printed by the Oklahoma Corporation Commission (hereafter “Commission” or OCC”), is issued by the OCC as authorized by Title 17 Okla. Stat., § 157. The Public Utility Division “PUD” has prepared 30 copies and distributed them at a cost of $73.90. This publication may also be found on the OCC’s website at **www.occeweb.com** under the Industry/Electric Utility tab.

EXECUTIVE SUMMARY

The Oklahoma Legislature, through 17 Okla. Stat., § 157, requires the Oklahoma Corporation Commission ("Commission" or "OCC") to perform the following:

> prepare a 10-year assessment of the electrical power and energy requirements of this state and assess the need for additional or replacement generating facilities and the associated costs of such facilities to the electric consumers of this state. . . Such assessments shall not constitute official Commission certification or approval of any proposed generating facilities.

As stated, §157 mandates the OCC to assess the need for additional or replacement generating facilities and the estimated costs of such facilities to the electric consumers of this state. Oklahoma's seven major electric suppliers provided data on their existing and proposed transmission facilities and substation upgrades. This data shows that many existing transmission lines will need to be upgraded over the next decade. In addition, new transmission lines and substations will be required to serve Oklahoma's growing demand for electrical energy. Therefore, transmission concerns will continue to be an issue, especially as new wind facilities are built that require new or modernized transmission facilities. Further, there are cost recovery issues, which regulators must address. There are also siting concerns on the part of landowners, which could delay the full development of western and central Oklahoma's extensive wind resource. Oklahoma's wind energy will not only contribute to Oklahoma's growing energy requirements, wind energy will also provide a boost to Oklahoma's economy through new jobs. Other states with less renewable opportunities will also benefit from Oklahoma's wind, assuming that transmission facilities will be in place to support this valuable Oklahoma resource.

Of the seven major electric suppliers, only OG&E and OMPA are planning to construct new generating capacity. The expected expenditure for the next 10 years will be $842 million. While Oklahoma ratepayers may not directly assume responsibility for any Independent Power Producers ("IPPs") in the State, the IPPs may install as much as $5.9 billion in new wind capacity in the coming decade. Under the new Integrated Transmission Planning process, the Southwest Power Pool expects to add $2.0 billion in new transmission projects. The cost of environmental compliance will add another $839 million to electric power cost. Oklahoma's seven major electric suppliers estimate the total cost of new plant for the next 10 years will be approximately $3.7 billion.

CHAPTER ONE: PREFACE AND INTRODUCTION

This is the 12th Edition of the Electric System Planning Report ("ESPR") prepared by the Commission's Public Utility Division ("PUD"). The current report is the accumulation and evaluation of extensive statistical data submitted to the PUD by the electric utilities in Oklahoma. PUD gathered data for this presentation based on the years ending December 2010 and December 2011. PUD made its projections from this data looking forward for the next 10 years. PUD used many resources to procure this information including, but not limited to, the following: utility and various other websites, annual reports, Integrated Resource Plan's ("IRP's"), and company state and federal jurisdictional filings.

While PUD prepared this report, neither the contents of the report nor the analysis used to produce the report constitute official Commission policy. PUD, at its discretion, may place any element of this report (including conclusions and recommendations) before the Commission to request endorsement or other actions within the jurisdiction of the Commission.

The purpose of this report is two-fold. The first aim is to survey and report the electrical power capacity available in Oklahoma during 2010 and 2011. The second is to project maximum available capacity, firm power purchases, peak energy demand, and capacity margins over the next 10 years, i.e., from 2012 to 2012. As part of this projection, PUD reviewed newly proposed transmission lines and substations as well as upgrades to existing transmission lines and substations.

Oklahoma Providers

The State of Oklahoma has seven major electric suppliers operating within the state. Of these seven suppliers, six actually own and/or operate electric generation facilities, or portions of generation facilities, within the borders of Oklahoma. This report refers to these seven electric suppliers collectively as the "Providers". The Providers' generation systems vary in their power and energy production capabilities.

Oklahoma Gas & Electric Company ("OG&E") is the largest Provider in the state. In addition, OG&E is the largest investor owned electric utility ("IOU") in Oklahoma, in terms of generation capacity, energy generation capability and retail customers. OG&E is followed by American Electric Power Company ("AEP") and Public Service Company of Oklahoma ("PSO"). Grand River Dam Authority ("GRDA") and Western Farmers Electric Cooperative ("WFEC") are essentially identical in terms of their generation capacity and energy generation capability. Next are KAMO Electric Cooperative (KAMO) and the Oklahoma Municipal Power Authority ("OMPA"), who have similar capacity totals. In comparison, OMPA purchases nearly one-third of its capacity while KAMO self generates almost 90 percent of its required capacity (which it sells to Associated Electric Cooperative Inc., ("AECI"). All of the Providers have generation in Oklahoma except the Empire District Electric Company ("Empire"), servicing approximately 4,700 customers in Oklahoma. All of Empire's generation facilities are located in the states of Missouri, Kansas and Arkansas. Empire is the smallest investor owned electric utility operating in Oklahoma, with over 166,000 electric customers throughout its system. Empire is significant in terms of its total generation with approximately 1,500 MW of total capacity.

Generation System Capability

The generation capability of an electrical generation system is defined as the total net megawatt generation capacity of the units operating on the system. The watt is the unit of measurement used to quantify the power generating capacity of electrical generators. A kilowatt (kW) is one thousand (1,000) watts, while a megawatt (MW) is one million (1,000,000) watts. This means that the measurement of the kilowatts or megawatts available from an electrical generation system tells us how much power is available from that system. Typically, electrical generation systems are designed so that the power output of the system meets, or exceeds, the maximum demand for power expected to be placed on the system.

Generation Fuels[1]

Nearly all generation units the Providers operate use fossil fuels. The exceptions are the hydroelectric facilities operated by Empire District Electric in Missouri and the hydroelectric operations in Oklahoma owned by GRDA and OMPA, along with the wind generation owned by OG&E in western Oklahoma. Other non-fossil fuel generation facilities exist in the state. These facilities include the hydro plants operated by the Southwestern Power Authority and various wind generation facilities located predominately in the western portions of the state. These non-fossil fuel facilities generally sell their output to most, if not all, of the Providers.

[1] This discussion is limited to a review of the fuels used by the Providers' generation systems during 2010 and 2011.

In 2010 and 2011, coal-fired generation capacity owned by the Providers comprised 5,419 MW and 5,858 MW, respectively. In 2010, Providers had 8,128 MW of natural gas-fired generation capacity and 8,855 MW in 2011. Oil-fired generation remained at 25 MW for years 2008 through 2011, while hydro generation capacity was 519 MW for 2010 and 469 MW for 2011. Renewable capacity, which dealt primarily with wind, was 256 MW for 2010 and 55 MW for 2011.

Table 1-1
Actual Peak Demand for the Providers (megawatts)

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
Provider	**Year**	**Coal Peak**	**Natural Gas Peak**	**Hydro Peak**	**Oil Peak**	**Renewable**	**Peak Purchase Power**	**System Peak Demand** (C)+(D)+(E)+(F)+(G)+(H)	**Actual Peak DSM**	**Adjusted Peak Demand** (I+J)	**Total Power Capacity (Generation and Purchases)**	**Reserve Margin** (L)-(K)	**Reserve Margin With Purchases** (M)/(K)	**Reserve Margin Without Purchases** (M-H/K)
AEP/ PSO	2010	920	2,336	0	0	112	815	4,168	41	4,209	4,183	-26	-0.62%	-19.98%
	2011	905	2,646	0	0	27	1,459	4,425	43	4,468	5,037	587	13.20%	-19.60%
EMPIRE	2010	346	771	14	0	10	69	1,210	-11	1,199	1,313	114	9.51%	3.76%
	2011	527	635	14	0	10	20	1,206	-8	1,198	1,463	265	22.12%	20.44%
GRDA	2010	718	301	227	0	0	13	1,259	10	1,269	1,806	537	42.32%	41.29%
	2011	542	398	185	0	0	107	1,232	10	1,242	1,806	564	45.41%	36.80%
KAMO	2010	821	685	74	12	0	0	1,592	0	1,592	1,807	215	13.50%	13.50%
	2011	901	934	80	13	0	0	1,928	0	1,928	2,144	216	11.20%	11.20%
OG&E	2010	2,153	3,179	0	0	39	417	5,371	0	5,371	5,788	417	7.76%	0%
	2011	2,390	3,412	0	0	13	435	5,815	0	5,815	6,250	435	7.48%	0%
OMPA	2010	104	342	29	0	1	128	604	0	604	777	173	28.64%	7.45%
	2011	187	274	0	0	3	157	621	0	621	790	169	27.21%	1.93%
WFEC	2010	357	514	175	0	94	365	1,505	0	1,505	1,868	363	24.09%	-0.17%
	2011	406	556	190	0	2	384	1,538	0	1,538	1,943	405	26.30%	1.33%
TOTAL	**2010**	**5,419**	**8,128**	**519**	**12**	**256**	**1,792**	**16,126**	**40**	**16,166**	**19,574**	**3,408**	**21.08%**	**10.00%**
	2011	**5,858**	**8,855**	**469**	**13**	**55**	**1,950**	**17,200**	**45**	**17,245**	**19,898**	**2,653**	**15.39%**	**4.08%**

Looking at actual electrical energy available to Providers in 2010 and 2011 by fuel type, coal-fired generation was 33,307,134 MWh for 2010, and 36,565,823 MWh for 2011. Natural gas-fired generation was 24,361,258 MWh for 2010, and 22,988,139 MWh for 2011. Hydro generation was 2,017,267 MWh for 2010, and decreased to 1,413,997 MWh for 2010. Empire accounted for nearly all fuel oil generation, which was 5,755 MWh for 2010 and 5,763 MWh in 2011. Empire uses fuel oil as a starter fuel for its coal units.

Table 1-2
Actual Energy Available from the Providers (megawatt hours)

A	B	C	D	E	F	G	H	I
Provider	**Year**	**Coal**	**Natural Gas**	**Hydro**	**Oil**	**Renewables**	**Annual Purchased Energy**	**Annual Provider Energy** (C+D+E+F+G+H)
AEP/PSO	2010	6,616,000	7,761,000	0	0	2,027,000	4,435,000	20,839,000
	2011	7,663,000	7,161,000	0	0	2,617,000	3,601,000	21,042,000
EMPIRE	2010	2,634,278	1,576,082	84,369	5,755	867,682	1,219,888	6,388,054
	2011	2,791,674	1,492,778	48,898	5,763	925,609	943,995	6,208,717
GRDA	2010	4,991,403	1,915,495	1,037,667	0	0	319,830	8,264,395
	2011	5,508,842	1,782,658	720,770	0	0	441,569	8,453,839
KAMO	2010	1,273,537	0	0	0	0	7,405,114	8,678,651
	2011	1,297,514	0	0	0	0	8,056,078	9,353,592
OG&E	2010	14,192,859	10,317,547	0	0	939,886	2,382,564	27,832,856
	2011	15,618,055	10,128,374	0	0	1,651,838	2,208,039	29,606,306
OMPA	2010	836,000	1,067,000	110,000	0	150,000	922,000	3,085,000
	2011	807,000	1,116,000	26,000	0	141,000	989,000	3,079,000
WFEC	2010	2,763,057	1,724,134	785,231	0	718,491	1,813,817	7,804,730
	2011	2,879,738	1,307,329	618,329	0	756,266	2,513,841	8,075,503
TOTAL	2010	33,307,134	24,361,258	2,017,267	5,755	4,703,059	18,498,213	82,892,686
	2011	36,565,823	22,988,139	1,413,997	5,763	6,091,713	18,753,522	85,818,957

Electric generation by renewable sources (predominately wind) for 2010 was 4,703,059 MWh, and 2011 was 6,091,713 MWh. Renewable energy generation continued to increase significantly for most companies over the two-year period primarily due to the abundance of wind in Oklahoma. With the addition of needed transmission facilities, wind energy should continue to play a significant role in Oklahoma's future energy picture. In 2010, the Oklahoma Legislature passed two bills related to wind energy, i.e., HB 3028 and HB 2973. HB 3028 established a renewable energy standard of 15 percent for the state, which means that 15 percent of the state's generation in 2015 would be from renewable energy sources. HB-2973 set a standard for the decommissioning of wind turbines and wind farms.

CHAPTER TWO: PROVIDER OVERVIEWS

This chapter presents a brief overview of the Providers in the state and the service territory of each. This Report arranges the overviews according to the relative number of customers and sales of the Providers, starting with OG&E and PSO, followed by Empire, GRDA, OMPA, WFEC and KAMO Electric Cooperative.

The Providers serve distinctive groups of customers in Oklahoma, with some over-lapping of those groups. Private power companies such as OG&E and PSO generally provide service to customers in non-rural areas of the state, (e.g., Oklahoma City, Tulsa, Lawton, Muskogee, and Enid). WFEC (and the 19 distribution cooperatives which govern Western Farmers) and KAMO Power (and the seventeen cooperatives which sit on the KAMO governing board) serve primarily rural areas. The GRDA serves both rural and non-rural areas of the state, while the OMPA provides power to municipalities that voluntarily become members of the Authority. Empire has approximately 167,000 electric customers in a four state area, (i.e., Arkansas, Kansas, Missouri and Oklahoma). However, most of Empire's customers and their operations are Missouri, with only 4,700 customers in Oklahoma.

Historical Overview

Oklahoma Gas and Electric Company ("OG&E")

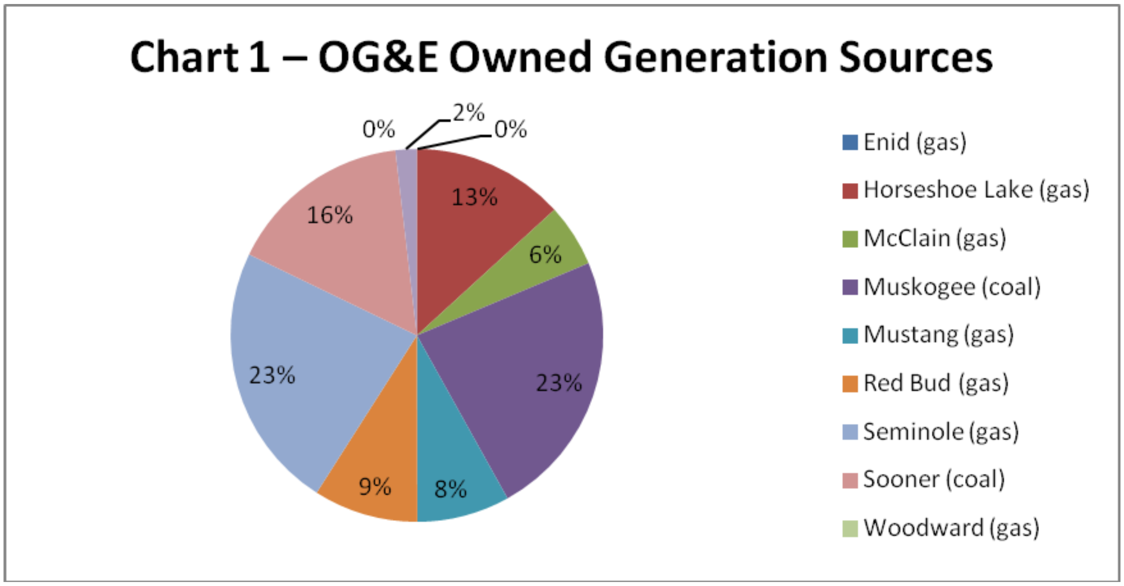
OG&E is an investor-owned public utility engaged primarily in the generation, transmission, and distribution of electricity to retail and wholesale customers in Oklahoma and Arkansas. OG&E is the largest electric utility in Oklahoma. In 1928, OG&E sold its retail gas business and has since been a provider of only retail and wholesale electricity. OG&E's electric generation system consists of nine interconnected fossil fuel generating stations, most with multiple units, and two wind farms located in western Oklahoma. OG&E's headquarters are in Oklahoma City. OG&E serves more than 789,000 retail customers in Oklahoma and western Arkansas, along with a number of wholesale customers[2] throughout the region. OG&E generates electricity from natural gas, western coal[3], and wind, resulting in approximately 6,800 MW of generation capacity. OG&E's electric transmission and distribution systems span some 30,000 square miles.

Table 2-1
OG&E Owned Generation Sources

Plant Name	Location	Megawatt Capacity
Enid (gas)	Garfield, OK	0
Horseshoe Lake (gas)	Oklahoma City, OK	858
McClain (gas)	Newcastle, OK	353
Muskogee (coal)	Muskogee, OK	1,510
Mustang (gas)	Oklahoma City, OK	523
Red Bud (gas)	Luther, OK	589*
Seminole (gas)	Seminole, OK	1,501
Sooner (coal)	Red Rock, Ok	1,038
Woodward (gas)	Woodward, OK	0
Centennial (wind)		120
Sooner Spirit (wind)		101

*OG&E ownership capacity
For more information about OG&E refer to: http://www.oge.com/investorrelations/Pages/InvestorRelations.aspx

[2] OG&E is ending its wholesale contracts. All of the Company's wholesale contracts should end by 2015.
[3] Coal from the Powder River Basin in Wyoming has a low sulfur content.

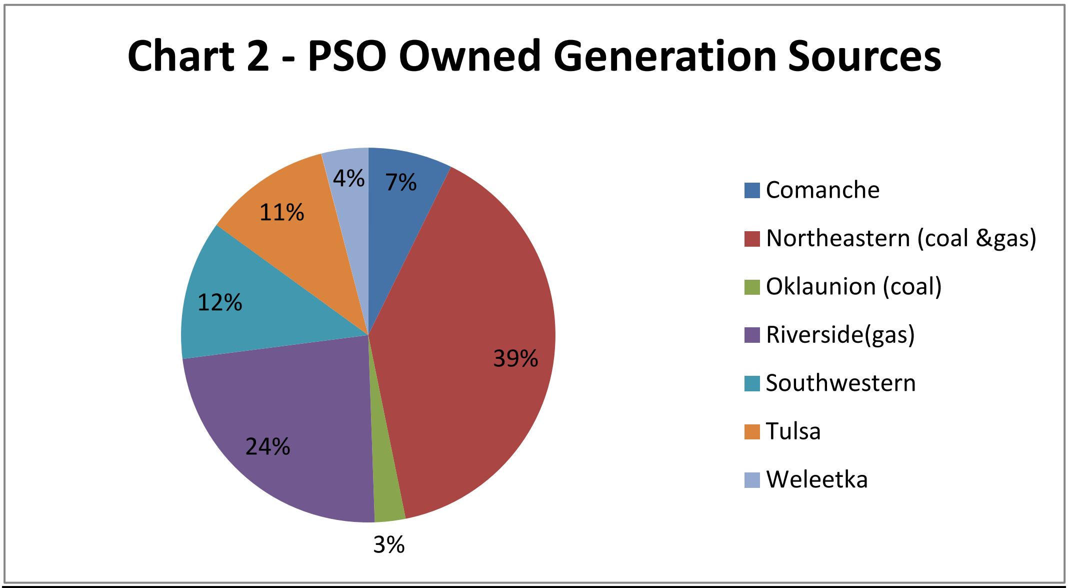


Public Service Company of Oklahoma ("PSO")

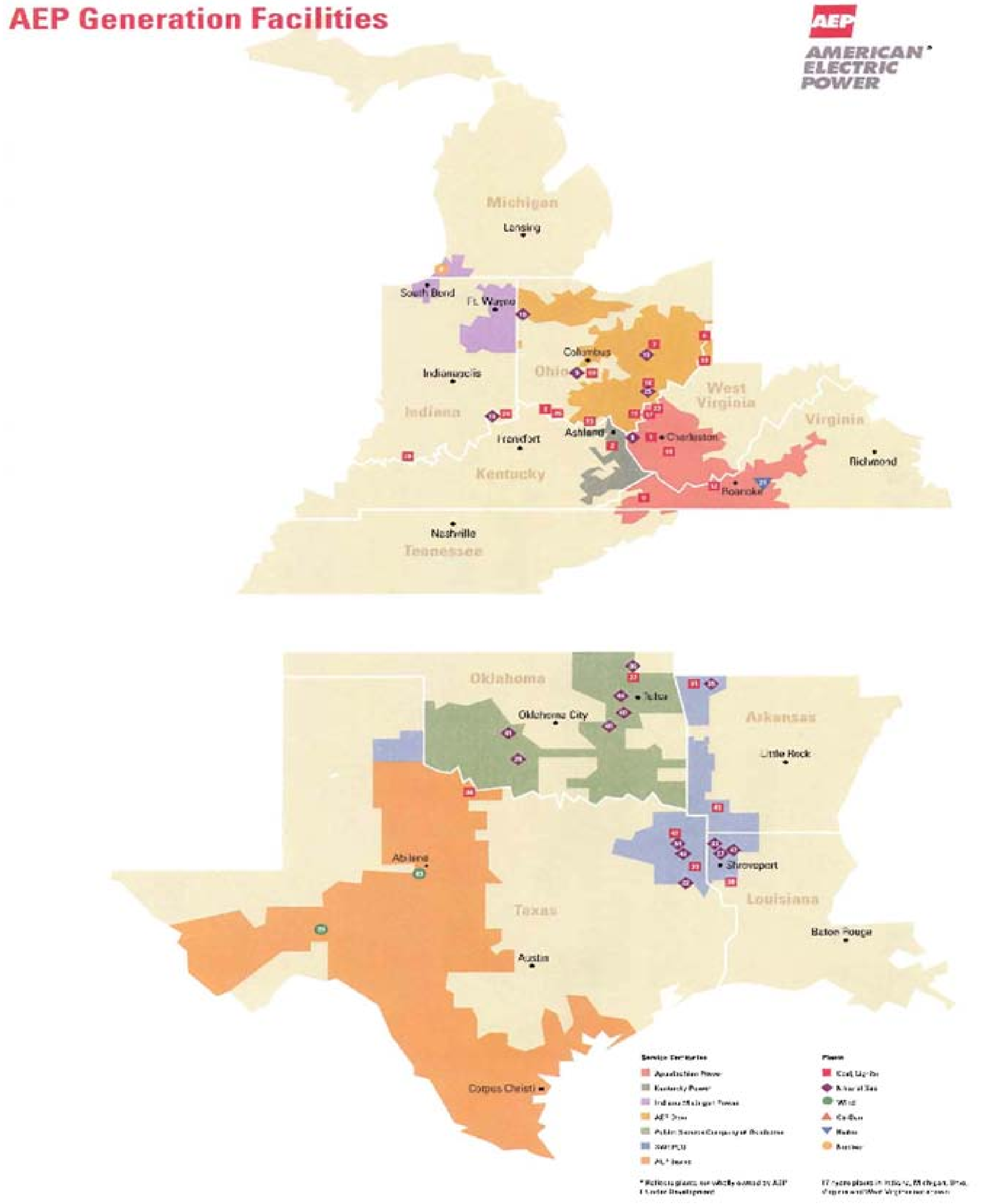
PSO is a subsidiary of American Electric Company ("AEP"). PSO headquarters are located in Tulsa with regulatory and external affairs offices in Oklahoma City. AEP's corporate headquarters are located in Columbus, Ohio. AEP is one of the largest electric utilities in the United States, delivering electricity to more than five million customers in 11 states. AEP ranks among the nation's largest generators of electricity, owning nearly 38,000 MW of generating capacity in the U.S. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765-kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined. With approximately 4,034 MW of capacity and nearly 1,700 employees, PSO serves approximately 527,000 customers in 230 cities and towns across 30,000 square miles of eastern and southwestern Oklahoma. PSO's distribution operations are organized into three districts: Tulsa, Lawton, and McAlester.

Table 2-2 PSO Owned Generation Sources		
Plant Name	**Location**	**Megawatt Capacity**
Comanche	Comanche, OK	294
Northeastern (coal & gas)	Rogers, OK	1,594
Oklaunion (coal)	Vernon, TX	107*
Riverside(gas)	Tulsa, OK	949
Southwestern	Caddo, OK	485
Tulsa	Tulsa, OK	443
Weleetka	Okfuskee, OK	163

* PSO's power allocation of the total plant capacity based on ownership percentage.
For more information about AEP/PSO, refer to http://www.aep.com/



PSO's Service Territory


AEP Generation Facilities
AEP
AMERICAN ELECTRIC POWER
Michigan
Lansing
South Bend
Ft. Wayne
Columbus
Ohio
Indianapolis
Indiana
West Virginia
Virginia
Frankfort
Ashland
Charleston
Kentucky
Richmond
Roanoke
Nashville
Tennessee
Oklahoma
Tulsa
Oklahoma City
Arkansas
Little Rock
Abilene
Shreveport
Texas
Louisiana
Baton Rouge
Austin
Corpus Christi

The Empire District Electric Company ("Empire")

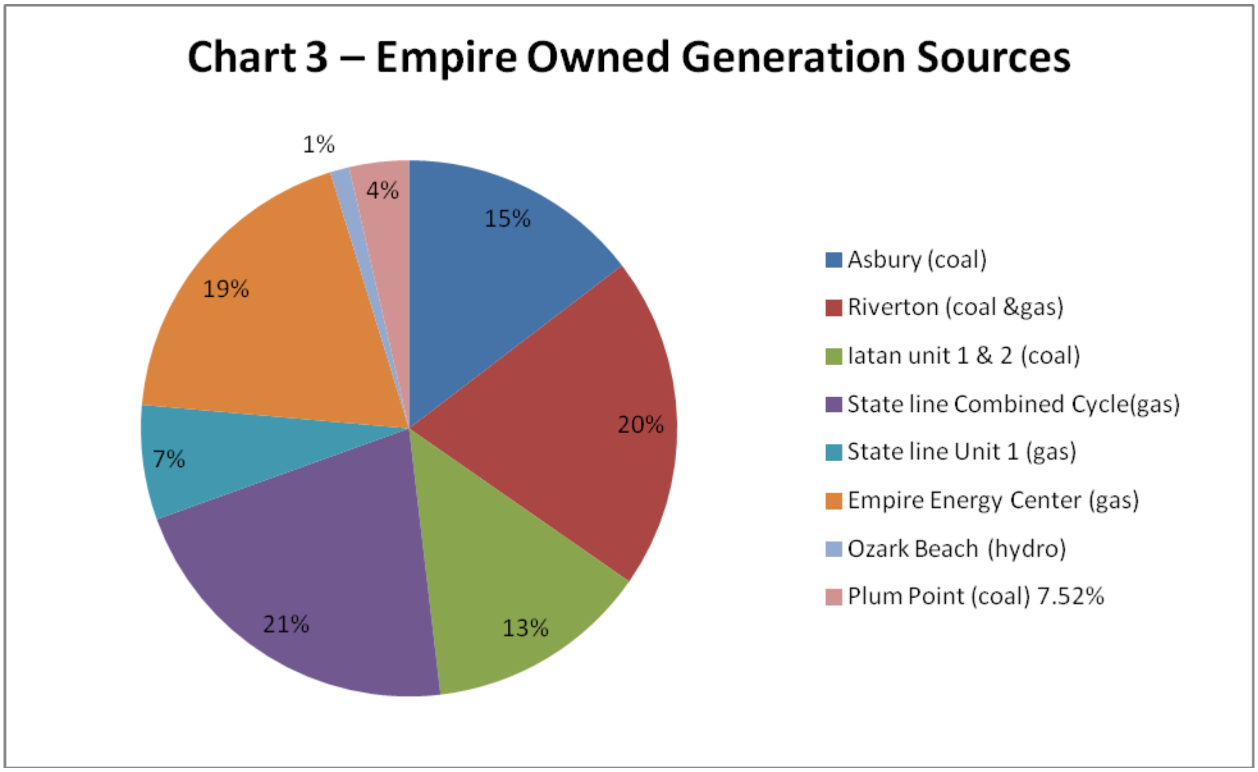
Empire is an investor-owned public utility headquartered in Joplin, Missouri, and operating in Arkansas, Kansas, Missouri, and Oklahoma. All but two of Empire's generation facilities, and most of its electric power sales, are in Missouri. Empire operates seven generation plants, of mostly in Missouri. Empire has generation facilities located at Riverton, Kansas and the Plum Point facility located near Osceola, Arkansas. Empire's Oklahoma customers (4,700) account for approximately 2.8 percent of Empire's total demand and approximately 3.3 percent of the total on-system sales on the Empire system. Empire's Oklahoma electric power sales account for about 0.2 percent of the total electric demand in the state of Oklahoma.

Empire serves approximately 167,000 electric customers in Arkansas, Kansas, Missouri and Oklahoma. Empire's Oklahoma operation is limited to portions of the far northeastern counties of Craig, Delaware and Ottawa. Empire also provides natural gas service (through its wholly owned subsidiary The Empire District Gas Company) and water service, with approximately 214,000 total customers in Missouri, Kansas, Oklahoma, and Arkansas. A subsidiary of Empire also provides fiber optic services.

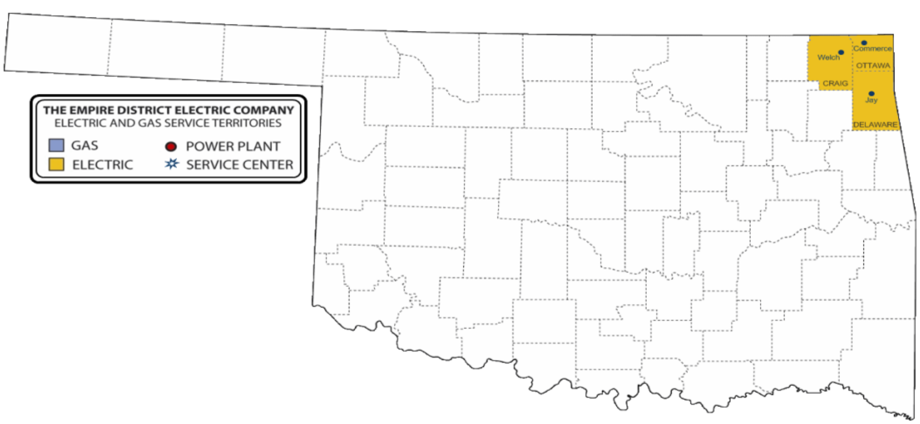
Table 2-3: Empire Owned Generation Sources

Plant Name	Location	Megawatt Capacity
Asbury (coal)	Asbury, MO	203
Riverton (coal &gas)	Riverton, KS	279
Iatan unit 1 & 2 (coal)	Western, MO	187*
State line Combined Cycle(gas)	Joplin, MO	297*
State line Unit 1 (gas)	Joplin, MO	96
Empire Energy Center (gas)	LaRussell, MO	262
Ozark Beach (hydro)	Ozark Beach, MO	16
Plum Point (coal) 7.52%	Osceola, AR	50*

*Empire's ownership capacity
For more information about Empire refer to: https://www.empiredistrict.com/



Empire's Service Territory in Oklahoma



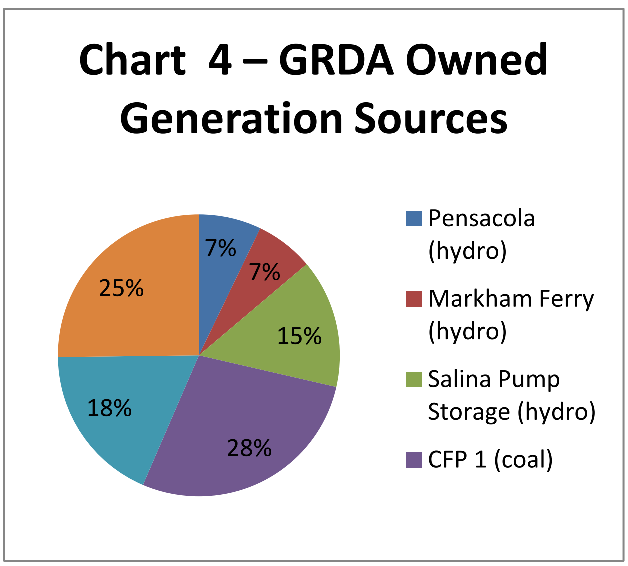
Grand River Dam Authority ("GRDA")

The Grand River Dam Authority headquartered in Vinita, Oklahoma, is an Agency of the State of Oklahoma organized and existing pursuant to Oklahoma Statute, Title 82, Sections 861 *et seq*. The GRDA owns and operates electric generation and transmission facilities mainly within the northeastern part of the state. GRDA is a major supplier of electricity not only in Oklahoma, but regionally as well.

Table 2-4
GRDA Owned Generation Sources

Plant Name	Location	Megawatt Capacity
Pensacola (hydro)	Langley, OK	126
Markham Ferry (hydro)	Locust Grove, OK	117
Salina Pump Storage (hydro)	Salina, OK	260
CFP 1 (coal)	Chouteau, OK	490
CFP 2 (coal) 62%	Chouteau, OK	322*
Redbud (gas) 36%	Luther, OK	443*

*GRDA's ownership capacity
For more information about GRDA, refer to https://www.grda.com/



Grand River Dam Authority Map of Customers and Facilities

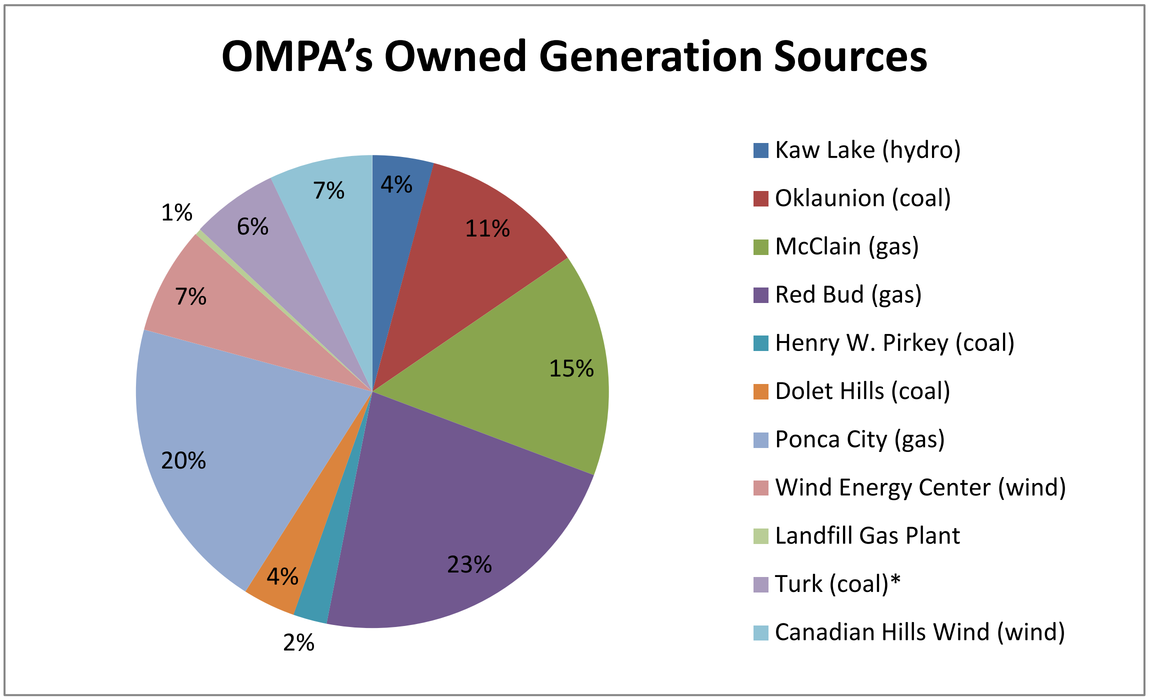
Oklahoma Municipal Power Authority ("OMPA")

OMPA is a joint action agency created by the Oklahoma Legislature in 1981, and headquartered in Edmond, Oklahoma. OMPA is composed of 39 of the state's 63 municipally owned electric utilities. Its member municipal power companies are located throughout the state. OMPA cooperates with local control to create a public power agency that is able to economically plan, build, and operate electric generation and transmission facilities for the benefit of all the member municipalities. Prior to the existence of OMPA, most municipalities in Oklahoma obtained electric power from private power companies. An 11-member board made up of city officials who manage or operate municipal electric systems governs OMPA. The primary aim of OMPA is "to provide an adequate, reliable, and affordable supply of electricity to member cities."

Table 2-5
OMPA's Owned Generation Sources

Plant Name	Location	Megawatt Capacity
Kaw Lake (hydro)	Ponca City, OK	29 MW
Oklaunion (coal)	Vernon, TX	78 MW*
McClain (gas)	Newcastle, OK	106 MW*
Red Bud (gas)	Luther, OK	155 MW*
Henry W. Pirkey (coal)	East TX	16 MW*
Dolet Hills (coal)	DeSoto, LA	25 MW*
Ponca City (gas)	Ponca City, OK	140 MW
Wind Energy Center (wind)	Woodward, OK	51 MW
Landfill Gas Plant	Sand Springs, OK	3 MW First Part of 2013
Turk (coal)*	Texarkana, AR	41 MW Starting late 2012
Canadian Hills Wind (wind)	El Reno, OK	49 MW Starting late 2012

*OMPA ownership capacity.
For more information about OMPA refer to: https://www.ompa.com/



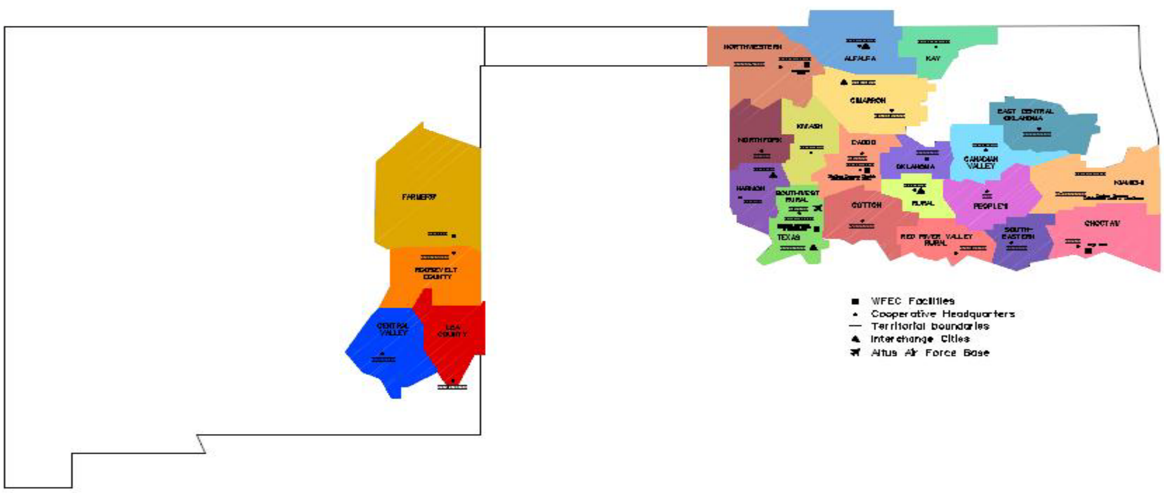
Western Farmers Electric Cooperative ("WFEC")

WFEC is a consumer-owned, regional electric generation and transmission cooperative with its headquarters in Anadarko, Oklahoma. WFEC generates electric power from self-owned generation and transmission facilities. WFEC delivers power to a 60,000 mile square area including 23 distribution electric cooperatives, Altus Air Force Base and several communities across Oklahoma and New Mexico. The service area includes all but the northeast quarter of Oklahoma, several counties in Kansas adjacent to northwestern Oklahoma, a small area of Texas bordering southwestern Oklahoma and New Mexico, and an area that includes southeastern New Mexico, bordering the Texas panhandle on the west.

With the generating plants located at Mooreland, Anadarko and Hugo, WFEC has total power capacity of more than 1,700 megawatts when the purchased hydropower is included. Purchased power includes SWPA hydro; several wind farms, GRDA and others. WFEC signed an energy purchase agreement for up to 74.25

megawatts of the Blue Canyon Wind Project in 2003. This wind farm has been operational since December 2003. Because of inherent uncertainty in wind power, WFEC currently does not recognize any capacity from this project. WFEC contracted with Buffalo Bear in 2008 and with Red Hill in 2009 for 19.8 MW and 123.5 MW, respectively. WFEC augmented its wind power portfolio in 2012 with 150 MW from Rocky Ridge and 29 MW from Wild Cat. Cumulative total wind generation was 397 MW in 2012.

WFEC Members' Service Area

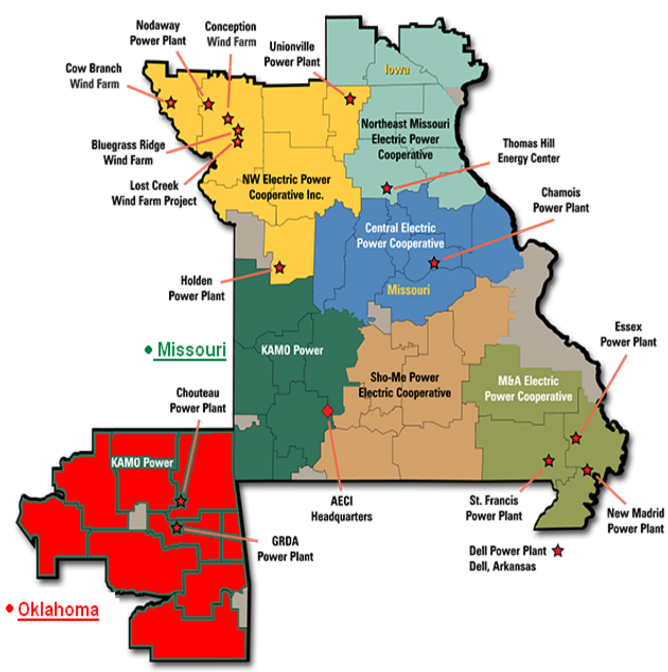


For more information about WFEC, refer to https://www.wfec.com/

KAMO Power

KAMO Electric Cooperative is a generation and transmission electric cooperative serving 17 member distribution cooperatives in northeastern Oklahoma and southwestern Missouri, with its headquarters in Vinita, Oklahoma. Eight distribution cooperatives are located in Oklahoma. In terms of generation sources, KAMO's Oklahoma and Missouri operations are largely independent of one another. This report includes both the Missouri and Oklahoma operations of KAMO. KAMO does not operate any generation facilities in Oklahoma; however, KAMO has partial ownership of the Grand River Dam Authority coal fired unit No. 2. KAMO's ownership accounts for approximately 38 percent of the unit or 198 MW of this facility's output. This unit has a nameplate capacity of 520 MW. KAMO purchases its power requirements from the Associated Electric Cooperative Inc.

AECI and Affiliated Cooperatives Service Areas



CHAPTER THREE: RESOURCE PROJECTIONS AND FORECASTS

Introduction

One of the most critical foundations of planning new generation resources is forecasting expected loads and peak demand. Each utility in Oklahoma prepares an Integrated Resource Plan ("IRP") to assess its expected peak loads for the forthcoming decade. Recent market developments at the federal level have increased the inclusion of transmission planning in the IRP process as many view transmission as a substitute for generating resources. The forecasting and resource planning process has an added dimension of complexity owing to pending environmental regulation and enforcement at all levels of government. Generation planning, transmission expansion, and environmental regulation all deserve attention when ascertaining electric needs for the next 10 years.

Generation

The most notable observation of generation planning is how few power projects the incumbent energy providers will undertake. IPPs have replaced the traditional utility company in building new electric capacity. This trend is true nationally, but particularly so in Oklahoma. PSO, for one, intends to replace its plant retirements with purchased power contracts. On the other hand, OG&E has promised in its "20/20 Plan" pledging to construct no new fossil fuel projects until the year 2020. In addition to examining the plans of the major IOUs of Oklahoma, prudence dictates including an examination of the proposed projects of IPPs in the state.

Statewide Oklahoma

The notable additions to generating capacity in the state are wind farms. Wind farms will increase capacity from 2,745.6 MW in 2012 to 4,290.6 MW in 2019[4]. Fossil-fuel capacity may decline because of PSO's potential retirement of one of its coal units.[5] Forecasted coal capacity will decrease from 5,792.9 MW in 2012 to 5,332.9 MW in 2019.[6] Fossil additions are likely to use natural gas as a fuel source which predictions show a slight increase of approximately 100 MW from 2012 to 2019.[7] Other generating resources, biomass, fuel oil, and hydropower, should not experience a change.[8]

Table 3-1: Expected Generation Capacity Additions for Oklahoma in MW

Year	Biomass	Coal	Gas	Oil	Other Nonrenewable	Water	Wind
2012	73.6	5,792.9	13,213.6	69.3	227.0	1,114.2	2,745.6
2013	73.6	5,792.9	13,213.6	69.3	227.0	1,114.2	3,285.6
2014	73.6	5,792.9	13,213.6	69.3	227.0	1,114.2	4,290.6
2015	73.6	5,792.9	13,316.6	69.3	227.0	1,114.2	4,290.6
2016	73.6	5,332.9	13,316.6	69.3	227.0	1,114.2	4,290.6
2017	73.6	5,332.9	13,316.6	69.3	227.0	1,114.2	4,290.6
2018	73.6	5,332.9	13,316.6	69.3	227.0	1,114.2	4,290.6
2019	73.6	5,332.9	13,316.6	69.3	227.0	1,114.2	4,290.6

Source: SNL.com

Oklahoma Gas & Electric Company

Electric Demand & Energy Forecast

OG&E's load forecasting framework relies on independently produced forecasts of service area economic and population growth, actual and normal weather data, and projections of electricity prices for price-sensitive customer classes. The final energy and demand forecast includes Federal Energy Regulatory Commission (FERC) jurisdictional wholesale contracts as post-modeling adjustments.

[4] SNL Power Plant Database, www.snl.com.
[5] *IRP,* AEP Public Service Company of Oklahoma, submitted August 2012, Section 3.4, p.25 and Section 6.4, p. 55.
[6] SNL Power Plant Database, www.snl.com.
[7] Ibid.
[8] Ibid.

OG&E bases the retail energy forecast on retail sector-level econometric models representing OG&E's Oklahoma and Arkansas service territories. The Center for Applied Economic Research at Oklahoma State University provided the historical and forecast economic variables (drivers).[9]

Table 3-2
OG&E's Energy Sale Forecast in GWh

Year	Wholesale	Retail	Total	Retail Growth
2013	1,372	26,494	27,866	1.2%
2014	1,166	26,849	28,015	1.3%
2015	578	27,138	27,716	1.1%
2016	0	27,495	27,495	1.3%
2017	0	27,835	27,835	1.2%
2018	0	28,177	28,177	1.2%
2019	0	28,536	28,536	1.3%
2020	0	28,950	28,950	1.4%
2021	0	29,408	29,408	1.6%
2022	0	29,662	29,662	0.9%

Source: Table 1, OG&E Integrated Resource Plan

The load responsibility forecast relies on an hourly econometric model and reflects the following:

1. Impact of different weekdays on hourly system load;
2. Impact of different summer months on hourly system load;
3. Influence of heat buildup during heat waves;
4. Impact of the combined effects of humidity and warm temperatures; and
5. Non-linearity in the load and temperature relationships at very high temperatures.

Weather-adjusted retail energy sales are the main driver for the peak demand.[10]

[9] *Integrated Resource Plan,* Oklahoma Gas & Electric Company, October 2012, p. 8.
[10] Ibid.

Table 3-3
OG&E's Peak Demand Forecast in MW

Year	Wholesale	Retail	Total	Retail Growth
2013	334	5,933	6,267	1.3%
2014	314	5,998	6,312	1.1%
2015	0	6,051	6,051	0.9%
2016	0	6,105	6,105	0.9%
2017	0	6,187	6,187	1.3%
2018	0	6,248	6,248	1.0%
2019	0	6,318	6,318	1.1%
2020	0	6,380	6,380	1.0%
2021	0	6,488	6,488	1.7%
2022	0	6,526	6,526	0.6%

Source: Table 3, OG&E Integrated Resource Plan

As shown in Table 3-3, OG&E forecasts an average annual energy sales growth of 1.3 percent until 2022.[11] The Company also predicts an annual increase of 1.1 percent of peak demand until 2022.[12]

Needs Assessment

The Southwest Power Pool ("SPP") establishes the basis for a minimum capacity planning reserve margin for SPP members. The SPP requires that generation reliability assessments examine the regional ability to maintain a loss of load expectation standard of one day in every 10 years. This sets the capacity margin of OG&E to 12 percent.[13] Capacity margins compare the Company's Total Resources available to its net demand. Total Resources consist of OG&E owned generation and purchased power agreements ("PPAs"). Net Demand is the difference between forecasted loads and the sum of Energy Efficiency and Demand Response. OG&E has predicted that it will need to acquire resources through either construction or contract starting in 2020.

[11] OGE Strategy and Planning Department, "2011 OG&E Load Forecast: Final Report," August 24, 2011, p. 4.
[12] Ibid, p. 7.
[13] Section 4.3.5 of the SPP Criteria.

Generation Additions

Based on its model estimates, OG&E plans to begin adding new capacity in 2020 using natural gas combined cycle technology as its source.[14] OG&E contracted with the engineering firm Sargent & Lundy to determine estimate unit cost. The firm's study anticipates the construction of a 562 MW facility at a cost of $1,320 per kilowatt or $742 million.[15]

Public Service Company of Oklahoma

Load and Energy Forecasts

The AEP Economic Forecasting Group developed the internal PSO long-term energy and peak demand estimates in April 2011. The process examined the consumption of electricity at aggregate levels. PSO's process begins with a long term economic forecast through third-party arrangement with Moody's Analytics and includes particulars on the PSO's service territory. The AEP Economic Forecasting Group applies End-Use models that account for the demographics of the residential and commercial classes. It includes the effects of growth in incomes and energy efficiency as well as the impact of current environmental and energy regulations.[16] PSO anticipates an annual growth in peak from 4,233 MW in 2012, to 4,350 MW in 2021, reflecting an annual growth rate of -0.03 percent, essentially flat. The Company predicts that annual energy usage will increase at annual rate of 0.22 percent from 18,824 GWh in 2012, to 19,670 in 2021.[17] See Table 3-4.

[14] "Table 17: CC and CT Expansion Plans," *Integrated Resource Plan,* Oklahoma Gas & Electric Company, October 2012, p. 33.
[15] "Table 9: New Supply Side Resources," ibid, p. 20.
[16] "2.1 Load and Demand Forecast-Process Overview," *Integrated Resource Plan,* AEP Public Service Company of Oklahoma, August 2012, pp. 11-13.
[17] "Table 1-1: PSO Peak Demand and Internal Load," ibid, p. 4.

Table 3-4 PSO Peak Demand and Energy Forecasts		
Year	Peak (MW)	Energy (GWh)
2013	4,265	18,889
2014	4,283	18,994
2015	4,282	19,067
2016	4,285	19,155
2017	4,292	19,241
2018	4,303	19,343
2019	4,318	19,458
2020	4,326	19,558
2021	4,350	19,670
2022	4,366	19,781

Source: Table 1-1, PSO IRP 2012

Generation Additions

With little to no growth in both demand and energy requirements, PSO anticipates no additions to its thermal fleet of power plants. PSO's Capability, Demand and Reserve estimates show that its total capability (power plants and purchased power agreements) will decline from 4,824 MW in 2012, to 4,561 MW in 2022. Likewise, net system demand (peak demand plus demand side management measures) will decrease from 4,275 MW in 2012 to 4,053 MW in 2022.[18]

Table 3-5 PSO Capability, Demand and Reserve (CDR)							
	Capability			Demand			Reserve
Year	**Plant Capacity**	**Purchased Power**	**Total Capability**	**Peak with Passive DSM**	**Active DSM**	**Firm Demand**	**Margin**
2012	4,268	556	4,824	4,207	77	4,130	16.8%
2013	4,268	556	4,824	4,227	77	4,150	16.2%
2014	4,268	554	4,822	4,235	77	4,158	16.0%
2015	4,268	554	4,822	4,226	77	4,149	16.2%
2016	3,793	814	4,607	4,222	99	4,123	11.7%
2017	3,793	812	4,605	4,212	129	4,083	12.8%
2018	3,793	812	4,605	4,208	132	4,076	13.0%
2019	3,793	815	4,608	4,210	134	4,076	13.1%
2020	3,793	814	4,607	4,207	136	4,071	13.2%
2021	3,793	814	4,607	4,220	139	4,081	12.9%
2022	4,264	307	4,571	4,234	142	4,092	11.7%

Source: Figure 7-1, PSO IRP 2012

[18] "Figure 7-1: Capability, Demand and Reserve (CDR)," ibid, p. 59.

The Company plans to take four steps over the next five years to meet its demand and load obligations.

1. Retire Northeastern Unit 4 by end of April 2016;
2. Retrofit Northeastern Unit 3 with DSI technology, ACT and fabric filter bag house by end of April 2016;
3. Replace with approximately 260MW of load capacity (PPA) beginning June 2016; and
4. Implement 2013-2015 Demand Portfolio currently pending before the OCC in PUD 201200128.[19]

The retirement of Northeastern Unit will reduce PSO system capacity by 470 MW.[20]

Other Oklahoma Providers

Oklahoma Municipal Power Authority has announced the construction of the Charles D. Lamb Energy Center. It will be a 103 MW natural gas combustion turbine with and expected in service date on 2015. The estimated cost will be $87 million.

Independent Power Producers

The State of Oklahoma is the location of a sizable amount of power projects proposed by IPPs. The IPPs will use wind power to add to the state's portfolio of renewable energy. Currently, nine different firms propose to construct 2,849 MW of merchant generation at an investment of $5.8 billion.[21] See Table 3-6. It is important to note that many of these projects are in preliminary stages and may not see fruition.

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[19] "7.3 Five Year Action Plan", ibid, pp. 57-58.
[20] Table 3-2, ibid, p. 23.
[21] SNL Power Plant Database, www.snl.com.

Table 3-6
Independent Power Producers' Projects

Project Name	Project Owner(s)	Capacity (MW)	Primary Fuel Group	Year in Service	Status	Estimated Construction Cost (000)
25 Mile Creek Wind Farm	Berrendo Energy	200.00	Wind	-	Announced	$440,000
Acciona Wind Farm 66	Acciona Energy North America	150.00	Wind	-	Announced	$330,000
Cherokee Chilocco Wind Project	PNE Wind USA	70.00	Wind	-	Early Development	$154,000
Eva Wind I	Chermac Energy Corp	80.00	Wind	2013	Early Development	$160,240
Eva Wind II	Chermac Energy Corp	80.00	Wind	2013	Early Development	$160,240
Eva Wind III	Chermac Energy Corp	80.00	Wind	2013	Early Development	$160,240
Goodwell Wind I	Chermac Energy Corp	80.00	Wind	2014	Early Development	$176,000
Goodwell Wind II	Chermac Energy Corp	80.00	Wind	2014	Early Development	$160,240
Goodwell Wind III	Chermac Energy Corp	80.00	Wind	2014	Early Development	$160,240
Hugo Lake Dam Water Power Project (FFP 105)	Free Flow Power Corp	8.00	Water	-	Announced	$12,000
Kay County Wind Project	Apex Wind Energy	300.00	Wind	-	Announced	$660,000
Kingfisher Wind Farm	Apex Wind Energy	300.00	Wind	-	Early Development	$460,000
Mustang Run Wind Project	TradeWind Energy LLC	150.00	Wind	-	Early Development	$300,000
NoMans Land (East Guymon) Wind	Chermac Energy Corp	150.00	Wind	2013	Announced	$300,450
North Buffalo Wind	Gestamp North America Inc.	765.00	Wind	2014	Announced	$1,532,295
Novus Wind Project	Dewind Co, Novus Windpower	250.00	Wind	-	Early Development	$550,000
Oologah Lake Dam Hydro Plant	Free Flow Power Corp	20.00	Water	-	Announced	$30,000
Pine Creek Lake	Broken Bow City	6.40	Water	-	Announced	$9,600
Total		**2,849**				**$5,800,000**

Source: SNL Power Plant Database

Transmission

Since the Eleventh ESPR, the responsibility of planning transmission has shifted from the utility companies to the ("SPP").[22] As a FERC-designated Regional Transmission Organization, one of SPP's responsibilities is to create regional transmission expansion plans.[23] With its members, regulators, and stakeholders, SPP creates planning models and studies that determine what new transmission is needed to meet our region's long- and near-term needs and create a cost-effective, flexible, and robust transmission network. SPP does not own or build transmission, though its Open Access Transmission Tariff contains rules that govern transmission planning.[24]

SPP's Integrated Transmission Plan ("ITP") is a three-year study process that assesses long and near-term infrastructure needs of the SPP Transmission System. Along with the Highway/Byway cost allocation methodology, the ITP promotes transmission investment that will meet reliability, economic, and public policy needs.[25] This report documents the portion of that assessment that focused on SPP's long-term regional needs in the upcoming 10-year horizon.[26] The total expected cost of transmission investment for upcoming 10 years is approximately $1,993,469,021.

Highway/Byway Cost Allocation

FERC Docket Order ER10-1069-000 approved the cost allocation method for new transmission in the SPP region. FERC has assigned cost responsibility in a proportionate manner according to the operating voltage (measured in kilovolts or kV) of

[22] FERC ER-10-1069-000.
[23] Ibid.
[24] http://www.spp.org/section.asp?pageID=128
[25] The Highway/Byway cost allocation approving order is *Sw. Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010). The approving order for ITP is *Sw. Power Pool, Inc.*, 132 FERC ¶ 61,042 (2010).
[26] Southwest Power Pool, "2012 Integrated Transmission Plan 10-Year Assessment Report," January 31, 2012, p. 9.

the project between "Region" and "Zone". The Region is all of SPP's operating territory. The Zone is a control area that more close resembles the utility company's operating territory[27]. Because high voltage projects and the nature of transmission serve the broader wholesale market, the Highway/Byway rule assigns their cost to all members of SPP. Lower voltage transmission serves primarily to supplement the distribution level of the utility, so the Zone bears responsibility.

- Above 300 kV – Full Cost allocation to the Region
- Between 100 kV and 300 kV – One-third cost to the Region; Two-thirds to the zone
- Below 100 kV – Full Allocation to the Zone

Proposed Transmission Projects

The highway/byway rule segregates projects into three categories: Above 300 kV, Between 100 kV ands 300 kV, and Below 100 kV.

Above 300 kV

SPP assigns Oklahoma based utilities with the responsibility for 40.8 percent[28] of all costs associated with higher voltage transmission. SPP has planned 86 projects for a total of $3,464,222,728. Oklahoma Providers are responsible for $1,413,402,895. See Table 3-7.

[27] The delineation is a simplification. The actually practice is more subtle.
[28] Allocated share of Oklahoma based providers for transmission in ATTACHMENT H, "Annual Transmission Revenue Requirement for Network. Values chosen are according to Zonal ATRR, Southwest Power Pool.

Table 3-7 Proposed Transmission Above 300 kV	
Owner	**Cost Estimate**
American Electric Power	$442,650,163
CLECO	$0
Greater Missouri KC P&L	$445,488,362
Grand River Dam Authority	$8,019,000
ITC Great Plains	$330,935,451
Kansas City Power & Light	$16,361,081
Mid Kansas Electric Cooperative	$19,612,658
Nebraska Public Power Authority	$433,854,343
Oklahoma Gas & Electric	$958,004,219
Omaha Public Power Authority	$19,796,666
Prairie Wind (Mid-Kansas)	$180,500,000
Sunflower Electric	$12,116,815
Southwestern Public Service	$461,219,920
Westar Energy	$135,664,104
Total	$3,464,222,782
Oklahoma Allocated Cost	**$1,413,402,895**

Source: 2nd Quarter 2013 SPP Project Tracking Report

Between 100 kV and 300 kV

SPP assigns Oklahoma based utilities with the responsibility for one-third of all costs associated with medium voltage transmission outside their operating zones and for their own load responsibilities. SPP has planned 169 projects for a total of $1,124,096,791. With the split allocation rule, Oklahoma Providers are responsible for $152,877,164. See Table 3-8.

Table 3-8
Proposed Transmission Between 100 kV - 300 kV
Outside of Oklahoma

Owner	Cost Estimate
CLECO	$5,000,000
Deep East Texas Electric Cooperative	$29,212,960
Greater Missouri KC P&L	$9,557,672
GRIS	$3,937,500
ITC Great Plains	$6,473,443
Kansas City Power & Light	$10,370,550
Louisiana Energy & Power Authority	$1,000,000
Lincoln Electric Service	$41,355,777
Midwest Energy	$25,377,960
Mid-Kansas Electric Cooperative	$94,837,879
Nebraska Public Power Authority	$35,307,261
Oklahoma Municipal Power Authority	$30,000
Omaha Public Power Authority	$11,067,000
Rayburn Country Electric Cooperative	$4,218,750
Sunflower Electric	$6,025,790
Southwestern Public Service	$635,652,518
Southwest Power Authority	$5,520,000
Westar Energy	$203,460,481
Total	$1,124,096,791
Oklahoma Allocated Cost	**$152,877,164**

Source: 2nd Quarter 2013 SPP Project Tracking Report

SPP assigns Oklahoma based utilities with the responsibility for two-thirds of all costs associated with medium voltage transmission for their own load responsibilities.[29] SPP has planned 77 projects for a total of $372,168,571. With the split allocation rule, Oklahoma Providers are responsible for $248,112,381. See Table 3-9.

[29] See FERC ER-10-1069-000.

Table 3-9 **Proposed Transmission Between 100 kV - 300 kV** **Inside Oklahoma**	
Owner	**Cost Estimate**
American Electric Power	$207,665,892
Grand River Dam Authority	$23,813,200
Oklahoma Gas & Electric	$57,492,379
Western Farmers Electric Cooperative	$83,197,100
Total	$372,168,571
Oklahoma Allocated Cost	$248,112,381

Source: 2nd Quarter 2013 SPP Project Tracking Report

Below 100 kV

Each Oklahoma based utility bears the responsibility of all costs associated with lower voltage transmission. SPP has planned 37 projects for a total of $179,076,582. Oklahoma is responsible for $179,076,582. See Table 3-10.

Table 3-10 **Proposed Transmission Below 100 kV** **Inside Oklahoma**	
Owner	**Cost Estimate**
American Electric Power	$109,194,518
Empire District Electric Company	$1,500,000
Grand River Dam Authority	$3,907,403
Oklahoma Gas & Electric	$1,115,338
Southwestern Public Service	$38,280,573
Western Farmers Electric Cooperative	$28,791,250
Total	$179,076,582
Oklahoma Allocated Cost	$179,076,582

Source: 2nd Quarter 2013 SPP Project Tracking Report

Environmental Issues

The Environmental Protection Agency ("EPA") has been actively proposing emission standards on fossil fuel generation power plants nationwide. Fossil fuel (coal and natural gas) generation facilities in Oklahoma were included in three EPA rules:

- Regional Haze Rule ("RHR") – reducing emissions that contribute to regional haze from certain sources.
- Cross-State Air Pollution Rule ("CSAPR") [30] - reducing power plant emissions that contribute to ozone and particulate matter pollution in other states.
- Mercury and Air Toxics Standards ("MATS") – establishing emission standards for Mercury and certain hazardous air pollutants from electric generating units.

Currently the RHR is pending litigation, the CSAPR has been remanded and the MATS rule will become effective in 2016. The financial and economic impact of compliance with these environmental regulations adds considerable costs to the generation of electricity.

Oklahoma Gas & Electric Company

OG&E is proposing to install Low NO_x[31] burners on seven of its units to comply with current regulations at an estimate cost of $122 million. Further, the Company anticipates the cost of Dry Sorbent Injection technology on five units to add another $126 million. OG&E also plans to retrofit five units with Activated Carbon Injection ("ACI") equipment, costing $21 million. The total cost of OG&E's environmental controls equipment over the next five years will be $279 million.[32]

Public Service of Company of Oklahoma

Environmental regulation has had a steeper impact on PSO. AEP, as an agent for PSO, has negotiated with the EPA a settlement in principle around PSO's Northeastern coal units. Under the agreement, PSO would meet certain emission control equipment on one of the Northeastern coal units in 2015, and retire the other

[30] On August 21, 2012, DC Circuit Court vacated and remanded CSAPR and ordered the EPA to continue to administer CAIR until it promulgates a replacement to CSAPR.
[31] "NO_x" is the abbreviation for nitrogen oxides.
[32] "Table 14: Environmental Equipment Installation Plans," *Oklahoma Gas & Electric: Integrated Resource Plan,* October 2013, p.28.

unit in 2016. PSO plans to retire the retrofitted unit in 2025.[33] The Company has proposed installing DSI technology, a fabric filter bag house, and ACI equipment on Unit No. 3.[34] PSO's estimates the cost of the retrofit will be $560 million.[35]

Total Environmental Cost for Oklahoma's Providers

The expected cost of environmental compliance for Oklahoma's Providers will be $839 million over the next 10 years.

Projected Costs

Recalling that OG&E and OMPA are the only Oklahoma providers planning to construct new generating capacity, the expected expenditure for the next 10 years will be $842 million. While Oklahoma ratepayers may not directly assume responsibility for any IPPs in the State, the IPPs may install as much as $5.9 billion in new wind capacity in the coming decade. Under the new Integrated Transmission Planning process, the SPP expects to add $2.0 billion in new transmission projects. The cost of environmental compliance will add $839 million to electric power cost. The Providers estimate the total cost of new plant for the next 10 years will be $3.7 billion.

Table 3-11: Proposed Total Cost For New Electric Investment

Segment	Estimate (Millions)
Independent Power Producers	$5,900
Generation	$842
Transmission	$1,993
Environmental Compliance	$839
Estimated Investment	**$3,674**

33 "1.5 EPA Settlement (Northeastern 3 & 4) Settlement," *Integrated Resource Plan,* PSO, August 2012, p. 6.
34 "Table 6-2," ibid, p. 51.
35 "Table 6-4," ibid, p. 53.

CONCLUSION

After accumulating and evaluating statistical data submitted to the PUD by the electric utilities in Oklahoma, PUD has concluded the following:

- Over the last two years, all electricity providers have sustained a steady growth in demand for their power; however, no provider has had any substantial increase in its generation facilities during the timeframe covered by this report.
- The resulting actual capacity margins are beginning to shrink since the Commission's last ESPR report. During the report period, the Providers continued to rely on additional purchase power to meet their margin needs. However, capacity in excess of 12 percent is decreasing.
- Statewide renewable energy generation increased in 2010 and diminished significantly in 2011 than in the previous ESPR report. One attributing factor reflected the lack of renewal of the federal production tax credit, which stimulated investment in wind power — from the manufacturing of equipment to the construction and maintenance of the turbines that are now a common sight in western Oklahoma.
- Almost all the electricity providers operate or have plans to operate some type of demand-side management ("DSM") programs. Of the major Oklahoma electricity providers, KAMO and OMPA currently do not operate DSM programs.

Regarding future resource changes and additions, PUD concludes:

- Projected reserve margins indicate that providers continue to rely on wholesale purchased power rather than on new construction of generation facilities. PSO plans to retire one of its coal plants by 2016 reducing the company's operating capability. OG&E may add new generation in 2020 at cost of $742 million.
- Expansion of the electric power transmission grid with over $2 billion over the next ten years may drive industry costs.
- Environmental regulations and compliance to maintain the current fleet of electric generation may add up to $839 million under current regulations.
- Wind power project slated for development over the next ten years may add 2,849 megawatts of nameplate capacity at a potential investment of $5.8 billion

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

JLM
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APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA ("PSO") TO RECOVER ALL COSTS INCURRED FROM THREE WIND POWER RESOURCE CONTRACTS THROUGH THE FUEL COST ADJUSTMENT RIDER AND TO RECOVER THE COST OF THE INDEPENDENT EVALUATOR	CAUSE NO. PUD 201300188 ORDER NO. 621229

HEARING: January 23, 2014, in Courtroom B
2101 North Lincoln Boulevard, Oklahoma City, Oklahoma 73105
Before James L. Myles, Administrative Law Judge

APPEARANCES: Jack P. Fite and Joann T. Stevenson, Attorneys, *representing* Public Service Company of Oklahoma
Judith L. Johnson, Senior Attorney, *representing* the Public Utility Division, Oklahoma Corporation Commission
William L. Humes, Nicole A. King and Jerry J. Sanger, Assistant Attorneys General, Office of Attorney General, State of Oklahoma
Jennifer H. Castillo, Thomas P. Schroedter, and James D. Satrom, Attorneys, *representing* Oklahoma Industrial Energy Consumers
Lee Paden, Attorney, *representing* Quality of Service Coalition

FINAL ORDER

BY THE COMMISSION:

This Cause comes before the Oklahoma Corporation Commission ("Commission") for consideration and action on the merits of the Application filed in this Cause.

I. PROCEDURAL HISTORY

On October 24, 2013, Public Service Company of Oklahoma ("PSO") filed its Application and the direct testimony of its witnesses in support of the Application, Jay F. Godfrey and Jon R. Maclean. An Amended Application was filed October 29, 2013.

Also on October 24, 2013, PSO filed its Motion for Procedural Schedule and Motion for Protective Order.

On October 28, 2013, the Attorney General of the State of Oklahoma ("AG") filed an Entry of Appearance ("EOA") which was followed by an EOA filed by Oklahoma Industrial Energy Consumers ("OIEC") on October 29, 2013, and an EOA by the Quality of Service Coalition ("QOSC") on November 4, 2013.

On November 12, 2013, this Commission issued an Order Granting Motion for Protective Order, Order No. 617961.

On November 26, 2013, this Commission issued an Order Establishing Procedural Schedule, Order No. 618556, which, among other items, set a hearing on the Merits for 1:30 p.m. on January 23, 2014.

On December 11, 2013, the responsive testimony of OIEC's witness, Scott Norwood, was filed. Also on December 11, 2013, the responsive testimony of Frank Mossburg and Sam Choi, on behalf of the Commission's Public Utility Division ("PUD") and the AG was filed.

All witnesses also filed summaries of their respective testimonies on either January 15 or January 16, 2014.

On January 23, 2014, the Application, as amended, came on for hearing before the undersigned Administrative Law Judge ("ALJ"). No party appeared in opposition to the Application. After all testimony was presented, Counsel for QOSC stated that QOSC was supportive of the three wind contracts PSO had entered into and recommended the approval of those contracts by the Commission. After hearing the testimony of the witnesses and statements of Counsel, the ALJ announced that he would recommend approval of the Application to the Commission.

II. RECOMMENDATIONS OF THE PARTIES

A. Public Service Company of Oklahoma:

Public Service Company of Oklahoma recommended that the Commission issue an Order prior to March 31, 2014, authorizing recovery of all costs incurred from three Renewable Energy Purchase Agreements entered into on October 9, 2013, between: (1) PSO and Balko Wind, LLC, (2) PSO and Goodwell Wind Project, LLC, and, (3) PSO and Seiling Wind, LLC (the "Renewable Energy Purchase Agreements") through the Fuel Cost Adjustment Rider. PSO further recommended that the recovery of the costs associated with the Independent Evaluator utilized by PUD and the AG in this cause be recovered in PSO's next base-rate case.

B. Oklahoma Corporation Commission Public Utility Division and the Office of the Attorney General:

Witnesses for the Oklahoma Corporation Commission Public Utility Division and the Office of the Attorney General recommended that the Commission approve the Renewable Energy Purchase Agreements.

C. Oklahoma Industrial Energy Consumers:

OIEC recommended that the Commission approve PSO's request for recovery of the costs of the Renewable Energy Purchase Agreements through PSO's Fuel Cost

Adjustment Rider using PSO's Production Demand Allocator. OIEC further recommended that the Commission encourage PSO and other Oklahoma utilities to evaluate the prudence of additional wind energy purchases.

III. CONTESTED ISSUES

There were no contested issues.

IV. SUMMARY OF EVIDENCE

A summary of the testimony of each witness is set forth below:

Jay F. Godfrey - Public Service Company of Oklahoma

Mr. Jay F. Godfrey, Managing Director - Renewable Energy for American Electric Power Service Corporation, testified on behalf of PSO.

Mr. Godfrey's testimony supported PSO's request for cost recovery approval of three contracts entered into on October 9, 2013, between PSO and Balko Wind, LLC, PSO and Goodwell Wind Project, LLC, and PSO and Seiling Wind, LLC. According to Mr. Godfrey, these contracts were entered into with non-affiliated companies pursuant to a transparent and fair competitive solicitation, conducted consistent with the Commission's competitive bidding rules, OAC 165:35-34-1 et seq. (Subchapter 34, Competitive Procurement). He also supported PSO's request for recovery of the cost of consulting services provided to the Commission Staff and the Attorney General's Office by Boston Pacific Company Inc., the Independent Evaluator appointed by Commission Staff for the 2013 Wind Energy Resources Request for Proposal (RFP) in its next base rate case.

Mr. Godfrey testified that PSO had two primary objectives behind the issuance of the RFP (See Exhibit JFG-1). The first objective was to find a replacement resource for the existing Blue Canyon II REPA (151.2 MW) expiring at the end of 2015. In addition to the replacement of the Blue Canyon II, PSO had an interest in gaining current market intelligence on the wind energy industry in Oklahoma given the fact that Section 45 Production Tax Credit (PTC) was set to expire at the end of 2013.

Mr. Godfrey testified regarding the bid eligibility requirements of the wind Request for Proposal; the timeline for the RFP; the information bidders were required to submit; and the response received by the company from the RFP.

Mr. Godfrey further testified and described the evaluation process that was used as well as the final decision and the role of the independent evaluator.

Mr. Godfrey then described the three contracts and the benefits that PSO's customers will receive from those contracts.

According to Mr. Godfrey, the REPAs were secured through a fair and transparent competitive solicitation conducted in accordance with the Commission's competitive bidding rules, OAC 165:35-34-1 et seq. (Subchapter 34, Competitive Procurement). The pricing under the REPAs is fair, reasonable and based on the Company's economic analysis, and is beneficial to PSO's customers according to Mr. Godfrey.

Mr. Godfrey testified that PSO was requesting that the Commission issue an Order prior to March 31, 2014, authorizing recovery of all costs incurred from the REPAs through the Fuel Cost Adjustment Rider. PSO was further requesting the recovery of the costs associated with the Independent Evaluator in PSO's next base rate case.

Jon R. MacLean - Public Service Company of Oklahoma

Jon R. MacLean, Manager of Resource Planning in the Corporate Planning & Budgeting Department of the American Electric Power Service Corporation, testified on behalf of PSO.

Mr. MacLean's testimony described the Step 4 Revenue Requirement Impact analysis discussed in PSO Witness Jay Godfrey's Direct Testimony filed in this proceeding that supports PSO's request for cost recovery approval of three contracts entered into on October 9, 2013, between PSO and Balko Wind, LLC, PSO and Goodwell Wind Project, LLC, and PSO and Seiling Wind, LLC.

According to Mr. MacLean, the costs and avoided costs associated with each proposal were evaluated under two market price scenarios – base case and low band as indicated in Exhibit JRM-1. Exhibits JRM-2 and JRM-3 provide the results of the base case analyses and low band analyses.

Mr. MacLean testified that four main cost savings categories were evaluated: (1) energy, (2) capacity, (3) integration, and (4) transmission service

Mr. MacLean testified that Exhibit JRM-1 provided an overall summary and ranking of the proposals and their respective revenue requirement impacts for the base and low band analyses. The capacity, energy, capacity factor, 2016 contract price, and levelized 20-year impact on PSO revenue requirements were provided for each of the projects and combinations of projects that were evaluated.

As a result of the attractive pricing of the proposals, the analysis for each of the projects yielded a reduction in projected net revenue requirement. The Balko, Goodwell, and Seiling proposals offered the lowest \$/MWh prices and also the greatest reduction in PSO revenue requirement. The greatest reduction in revenue requirement is provided by combination of the Balko, Goodwell, and Seiling projects.

Mr. MacLean testified that the Balko, Goodwell, and Seiling Contracts were economically justified because according to the net revenue requirement analyses, using a fundamental forecast of avoided energy and capacity prices, the Balko, Goodwell and Seiling proposals were estimated to lower revenue requirement each year of the contracts through 2035.

Frank Mossburg - Office of Attorney General/Public Utility Division

The purpose of my testimony is to assess Public Service Company of Oklahoma's (PSO) request for approval of three Renewable Energy Purchase Agreements (REPAs) for approximately 600 MW of supply from three new wind projects.

Boston Pacific served the Public Utility Division and the Office of the Attorney General as the Independent Evaluator for PSO's 2013 Wind RFP. We oversaw each step of the procurement from the bidder's conference through the receipt of bids, selection of the Initial and Final Shortlists, selection of winning bidders and contract negotiations. We reviewed all proposals submitted, all analysis prepared by PSO as well as all related analysis produced by the Southwest Power Pool (SPP). My colleague, Sam Choi, and I jointly led Boston Pacific's efforts. Mr. Choi's testimony focuses on the issuance of the RFP, review of the qualification of bidders and selection of the Initial Shortlist. My testimony concerns the selection of the Final Shortlist, selection of winning bidders and negotiation of final contracts.

My recommendation is that the Commission should approve all three REPAs. I say so for several reasons. First, the RFP was conducted fairly; all bidders were treated equally and according to the rules laid out in the RFP. Second, the RFP was substantially in compliance with the Commission's competitive procurement rules. Third, the evaluation of offers was transparent. Ultimately, the three winning bidders were the three bidders who offered the lowest prices. This "price only" or "price mostly" style of evaluation is the most transparent and fair form of evaluation. Fourth, the RFP was competitive. In total, the RFP received 18 bids from nine different bidders offering a total of 2,942.4 MW, or more than 14 times the advertised need. Having offers far in excess of need helps ensure that evaluators were able to get a good deal for ratepayers by choosing among many competing offers. Fifth, the projects are projected to achieve significant net benefits for PSO's ratepayers. PSO estimates that the three projects will provide cost reductions of $89.5 million on a levelized annual basis under base case assumptions.

These net benefits are primarily energy cost savings from buying wind power instead of market purchases.

In addition, the selected resources bring more fuel diversity to PSO's system, protecting against increases in the price of natural gas as PSO begins to retire its existing coal-fired generation and allow PSO to capture the significant benefits of the federal production tax credit before it was set to expire at the end of 2013. Moreover, the REPAs ensure that ratepayers will generally only pay when they receive power from the units.

Finally, additional analysis does not reveal any issues with adding more wind to the system. PSO's Strategist planning model runs confirm that additional wind power is beneficial and is generally used to reduce reliance on market purchases.

Sam Choi - Office of Attorney General/Public Utility Division

The purpose of my testimony is to provide my opinion and assessment of the Request for Proposals (RFP) issued by Public Service Company of Oklahoma (PSO) seeking long-term contracts for wind energy resources.

Boston Pacific was hired to assist the Public Utility Division of the Oklahoma Corporation Commission and the Office of the Attorney General of Oklahoma by providing expert witness services regarding PSO's 2013 Wind RFP. My colleague, Frank Mossburg, and I jointly led Boston Pacific's efforts to monitor this RFP. We were both active in all phases of the procurement from the Bidder Technical Conference through the receipt of bids, selection of the initial and final shortlists, and selection of winning bidders to contract negotiations. An explanation of our evaluation is included in Boston Pacific's testimony and presented in two parts. My testimony focuses on the receipt of bids, review of the qualification of bidders and selection of the Initial Shortlist. Mr. Mossburg's testimony concerns the remainder of the RFP process including the selection of the Final Shortlist, selection of winning bidders and negotiation of final contracts.

My conclusion is that the RFP process from bid submission to the selection of the Initial Shortlist was fair, transparent, and competitive for the following reasons. First, the RFP was substantially in compliance with PUD's competitive procurement rules. Second, the RFP was competitive. In total the RFP received 18 bids from nine different bidders offering a total of 2,942.4 MW, or over 14 times the advertised need. Having offers far in excess of need helps ensure that evaluators were able to get a good deal for ratepayers by choosing between many competing offers. No offers were received from bidders affiliated with PSO. Third, the qualification of bids was conducted in a fair and transparent manner according to the rules of the RFP. Fifteen of the 18 bids qualified for potential initial shortlisting. Fourth, the evaluation of the bids for the Initial Shortlist was fair and transparent with bids ranked by price. Finally, the Initial Shortlist was properly constructed such that the lowest cost bids were selected first while additional bids were selected to account for potential differences in transmission system integration costs.

Scott Norwood - Oklahoma Industrial Energy Consumers

My name is Scott Norwood. I am President of Norwood Energy Consulting, L.L.C. I am a consultant specializing in the areas of electric utility regulatory consulting, resource planning, and energy procurement. I have over 30 years of experience in electric utility regulatory consulting, resource planning and energy procurement. I have testified in a number of past base rate and fuel proceedings before the Oklahoma Corporation Commission ("OCC" or "Commission"), including Public Service Company of Oklahoma's ("PSO" or "Company") 2008 and 2009 fuel prudence cases, the Company's application for approval of the Red Rock coal-fired generating station, PSO's application for approval of the MINCO Renewable Energy Purchase Agreement, and the Company's application for approval of an Southwest Power Pool Transmission Cost tariff.

I am testifying on behalf of Oklahoma Industrial Energy Consumers ("OIEC"). OIEC is an association which represents the interests of industrials or other large energy consumers. Many industries in Oklahoma purchase substantial quantities of electric power which are important to their operations. Electric power costs can constitute a significant percentage of industrial operating costs. These electric power supplies are generally purchased from utilities pursuant to standard tariffs filed at the Commission. Industries served by PSO often operate in highly competitive business environments and, thus, are interested in the Commission determining rates for PSO that achieve reliable power supply at the lowest and most reasonable costs possible under the circumstances. OIEC historically has supported the acquisition of power supply resources that enhance fuel diversity and which meet the Commission's "lowest reasonable cost" standard. In this regard, OIEC has supported wind energy resources acquired by PSO and Oklahoma Gas and Electric Company ("OG&E") that have met the lowest reasonable cost standard.

The purpose of my testimony is to present my analysis and recommendations regarding: (i) PSO's request for approval to recover from ratepayers the costs of three new long-term wind energy purchase contracts and, (ii) PSO's allocation of such costs to its various customer classes.

The three wind contracts at issue in this case (hereinafter referred to as "Wind Energy Contracts") were acquired by PSO through a Request for Proposal ("RFP") process which was initiated on June 18, 2013. The Company's RFP sought proposals for long-term supply of up to 200 MW of renewable energy for service beginning January 1, 2016. PSO engaged Boston Pacific Company, Inc. as the Independent Evaluator of the RFP and bid evaluation process. In response to the RFP, the Company received 18 wind energy proposals for 16 different wind projects with an aggregate name-plate capacity totaling 2,692 MW. PSO conducted an economic analysis of the bids and used the Southwest Power Pool ("SPP") Long-Term Service Request study process to evaluate related transmission service costs for shortlisted bids. After significant analysis, the Company entered into three contracts for the purchase of approximately 600 MW of wind energy over a 20 year term beginning in January of 2016. The three suppliers selected by PSO are Balko Wind, LLC, Goodwell Wind Project, LLC, and Seiling Wind, LLC.

The 598.7 MW supplied from the new Wind Energy Contracts will increase PSO's total wind energy ownership to 1,288.5 MW. The Company expects to receive approximately 2.65 million MWh of additional wind energy annually from the new contracts, which is equivalent to roughly 13% of PSO's total forecasted 2016 energy requirements. When this new wind energy is added to energy supplied under PSO's existing wind contracts, the Company's wind energy is expected to be over 20% of the Company's total energy requirements in 2016.

I reviewed the terms of the proposed Wind Energy Contracts and found them to be reasonable. The three contracts provide for delivery of wind energy to PSO over a twenty year term starting on January 1, 2016. Contract pricing reflects an "around the clock" base price per

Megawatt-hour based on the initial year price plus an annual escalator. The contracts include performance guarantees that ensure that each wind project provides a minimum specified energy level with performance penalties to compensate PSO in the event performance falls before the specified levels. The contracts provide that PSO retains the environmental and renewable energy credits ("RECs") associated with energy purchased under each contract, and the Company has indicated that it intends to continue to monetize such RECs in accordance with prior Commission Orders.

I also reviewed PSO's cost/benefit analyses for the proposed Wind Energy Contracts and found these analyses to be reasonable. PSO's analyses appropriately include the cost of certain new high voltage transmission upgrades that are expected to be required to allow firm delivery of the energy to PSO's system. However, PSO's analyses conservatively do not include other benefits of the Wind Energy Contracts including the monetized value of RECs, environmental benefits from reduced emissions, and indirect economic benefits which arise from Wind Energy Contracts. These additional benefits serve to increase the economic advantage of the Wind Energy Contracts to PSO's customers over other energy alternatives.

The proposed contracts are expected to benefit PSO's customers by enhancing fuel diversity and by providing a guaranteed low cost source of energy for twenty years which will serve to significantly reduce PSO's system energy costs. In fact, according to PSO's base case analysis, the Wind Energy Contracts are forecasted to provide $723.9 million of net energy savings (on a present value basis) when compared to an alternative scenario without additional new wind energy additions. These forecasted savings reflect the fact that the price of energy from the Wind Energy Contracts is at historically low levels and is expected to remain far lower than the cost of natural gas-fired generation and market energy purchases which the wind energy is expected to displace. In fact, the price of energy from the Wind Energy Contracts is competitive when compared to the current cost of coal-fired energy, which is by far PSO's lowest cost energy resource.

Moreover, it is important to note that the level of PSO's wind energy purchases is largely independent of the Company's decisions with regard to future operations of its coal-fired generating units. PSO's economic analysis indicates that the wind energy purchases under these new contracts will displace very little of the energy produced from the Company's coal-fired plants. Therefore, whether PSO prematurely retires its Northeastern coal-fired generating units as the Company proposes to do under terms of its settlement with EPA, or whether it continues to operate its coal-fired units, the Wind Energy Contracts would provide essentially the same benefits to PSO's customers.

I also reviewed PSO's proposal that costs of the proposed Wind Energy Contracts be assigned to PSO's customer classes on a production demand allocator basis and recovered through PSO's fuel adjustment clause, and find this proposal to be reasonable and consistent with the Commission's most recent orders regarding the appropriate ratemaking treatment of wind energy costs in Cause Nos. PUD 200900031 and PUD 201000092.

In summary, PSO should be commended for increasing its level of planned wind energy purchases in response to the low prices it received from bidders in its renewable power RFP. I recommend that the Commission approve PSO's new Wind Energy Contracts and the Company's proposal to recover the costs of such contracts through the Company's FAC Rider using PSO's production demand allocator. Furthermore, I recommend that the Commission encourage PSO and other Oklahoma utilities to evaluate the prudence of additional wind energy purchases at this time due to the historically low level of wind energy prices and for other reasons addressed in my testimony. Although potential operational and reliability impacts of higher level of wind purchases must be carefully evaluated, at the current wind energy price levels, maximizing wind energy purchases appears to be a clear win-win proposition for Oklahoma industry and all other electric consumers.

V. FINDINGS OF FACT AND CONCLUSIONS OF LAW

THE COMMISSION FINDS it has jurisdiction in this Cause pursuant to Art. 9, §18 of the Oklahoma Constitution and 17 O.S. §§ 151, 152, 153, 250 *et. seq.* and 286.

THE COMMISSION FURTHER FINDS that notice was proper in the cause and in accordance with Commission Rules and Oklahoma law.

THE COMMISSION FURTHER FINDS that PSO's Request for Proposal that resulted in the Renewable Energy Purchase Agreements was conducted fairly with all bidders being treated equally and according to the rules contained within the Request for Proposal;

THE COMMISSION FURTHER FINDS that the Request for Proposal was substantially in compliance with the Commission's Competitive Procurement Rules;

THE COMMISSION FURTHER FINDS that the Renewable Energy Purchase Agreements will provide significant net benefits for PSO's customers such as enhancing fuel diversity and providing a guaranteed low-cost source of energy for 20 years, and will provide primarily energy costs savings from buying wind power instead of market purchases.

THE COMMISSION FURTHER FINDS that the costs of the Renewable Energy Purchase Agreements entered into on October 9, 2013, between: (1) PSO and Balko Wind, LLC, (2) PSO and Goodwell Wind Project, LLC, and, (3) PSO and Seiling Wind, LLC, should be approved.

THE COMMISSION FURTHER FINDS that the costs of the Renewable Energy Purchase Agreements should be recovered through the Fuel Cost Adjustment Rider using PSO's Production Demand Allocator;

ORDER

IT IS THEREFORE THE ORDER OF THE COMMISSION that the Renewable Energy Purchase Agreements are hereby approved for cost recovery through Public Service Company of Oklahoma's Fuel Cost Adjustment Rider using PSO's Production Demand Allocator.

IT IS FURTHER THE ORDER OF THE COMMISSION that the cost of the Independent Evaluator shall be a regulatory asset with the manner of cost recovery to be determined in Cause No. PUD 201300217, PSO's pending base rate case.

THIS ORDER SHALL BE EFFECTIVE immediately.

CORPORATION COMMISSION OF OKLAHOMA

Patrice Douglas

PATRICE DOUGLAS, Chairman

Bob Anthony

BOB ANTHONY, Vice Chairman

Dana L. Murphy

DANA L. MURPHY, Commissioner

CERTIFICATION

DONE AND PERFORMED by the Commissioners participating in the making of this Order, as shown by their signatures above, this 4th day of February, 2014.

[Seal]

Peggy Mitchell

PEGGY MITCHELL, Secretary

REPORT OF THE ADMINISTRATIVE LAW JUDGE

The foregoing findings, conclusions and order are the report and recommendations of the undersigned administrative law judge.

James L. Myles

JAMES L. MYLES
Administrative Law Judge

January 28, 2014

Date

Exhibit JBT-5
OCC Cause No. PUD 201400229

Oklahoma Wind Farms

Oklahoma Wind Projects

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Operating Oklahoma Wind Farms

Projects are listed in order of commercial operation)

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Operating Oklahoma Wind Farms					
Name	County	Size (MW)	Turbine type	Turbine Model	First Year of Operation
Oklahoma Wind LLC	Harper, Woodward	102	GE	1.5	2003
Blue Canyon	Caddo, Comanche	74.0	Vestas	NM72, 1.65	2003
Blue Canyon II	Caddo, Comanche	150.0	Vestas	V80, 1.8	2005
Weatherford	Custer, Washita	147	GE	1.5	2005
Centennial Wind Farm	Harper	120	GE	sle 1.5	2007
Sleeping Bear	Harper	94.5	Suzlon	S88, 2.1	2008
Buffalo Bear	Harper	19.0	Suzlon	S88, 2.1	2008
Red Hills Wind	Roger Mills, Custer	123.0	Acciona	1.5	2009
Blue Canyon V	Caddo, Comanche	99.0	GE	sle 1.5	2009
OU Spirit Windfarm	Woodward	101.2	Siemens	SWT-2.3-93	2009
Elk City I	Roger Mills, Beckham	98.9	Siemens	2.3	2009
Elk City II	Roger Mills, Beckham	100.8	GE	1.5 & 1.6	2010
Keenan II Renewable Energy	Woodward	151.8	Siemens	SWT-2.3-101	2010
Minco Wind	Grady	99.2	GE	1.6	2010
Minco Wind II	Grady, Caddo	100.8	GE	xle 1.5	2011
Blue Canyon VI	Caddo	99.0	Vestas	1.8	2011
Taloga Wind	Dewey	129.6	Mitsubishi	MWT95 2.4 MW	2012
Rocky Ridge	Kiowa, Washita	150.0	GE	1.6	2012
Crossroads	Dewey	228.0	Siemens	SWT 2.3 & 3.0	2012
Big Smile Wind Farm	Roger Mills, Beckham	132.0	Acciona	*NA*	2012
Chisholm View	Garfield, Grant	235.0	GE		2012
Canadian Hills	Canadian	300.0	Mitsubishi REPower	MWT102 2.4 MM92 2.05	2012

1

Blackwell	Kay	60.0	*NA*	*NA*	2012
DeWind Novus	Texas	80	DeWind	D9.2, 2.0	2012
DeWind Novus II	Texas	80	DeWind	D9.2, 2.0	2012
Minco 3	Canadian, Caddo	101	GE	1.6	2012
Total		3,175			
Oklahoma Wind Farms Under Construction					
Origin	Murray & Carter	150	*NA*	*NA*	2014
Total		150			
Oklahoma Wind Farms with PPA's					
Osage County Wind	Osage	150	GE	1.6	2014
Kay County Wind	Kay	200	*NA*	*NA*	2015
Balko Wind	Beaver	300	*NA*	*NA*	2015
Arbuckle Wind	Murray, Carter	100	*NA*	*NA*	2016
Goodwell	Texas	200	*NA*	*NA*	
Seiling	Dewey	198.9	*NA*	*NA*	
Mammoth Plains	Dewey/Blaine	199	*NA*	*NA*	
Total		1,247.9			

NEW **Map of Operating & Proposed Wind Projects in Oklahoma** Source: Kansas Energy Information Network, February 2014 (PDF, 230 kB)

Wisconsin Wind Projects.

Nebraska Wind Projects.

Map of Operating Oklahoma wind farms, Source: Oklahoma Dept. of Commerce, Dec. 2009.

Oklahoma Wind Energy Center

Harper & Woodward Counties, Oklahoma - This 102 MW project of Florida Power and Light (FPL, now known as NextEra Energy Resources) of Juno Beach, Florida was the first commercial wind farm in Oklahoma. This wind farm reached commercial operation in September 26, 2003 and consists of 68 GE 1.5MW wind turbines. Half of the power (51 MW) is sold to Oklahoma Municipal Power Authority, while the other half is sold to Oklahoma Gas & Electric. (October 2012)

- **Oklahoma Wind Energy Center Quick Facts** - Oklahoma Municipal Power Authority
- **Oklahoma Wind Energy Center Facts** - NextEra Energy Resources

Blue Canyon Wind Farm

Caddo and Comanche Counties, Oklahoma - This is a 74 MW project of **Horizon Wind Energy** of Houston, TX (now EDP Renewables of Madrid, Spain). This wind farm reached commercial operation in December 2003 and consists of 45 Vestas NM72 1.65 MW wind turbines. The energy is sold to Western Farmers Electric Cooperative. (October 2009)

- **Blue Canyon Wind Farm** - Western Farmers Electric Cooperative Video

Blue Canyon II Wind Farm

Caddo and Comanche Counties, Oklahoma - This project has a capacity of 150 MW and was also developed by **Horizon Wind Energy** of Houston, TX (now EDP Renewables of Madrid, Spain). This wind farm reached commercial operation in December 2005 and consists of 84 Vestas V80 1.8 MW turbines. The energy is sold to Public Service Company of Oklahoma . (October 2009)

- **Blue Canyon II Wind Farm** - Horizon Wind Energy Fact Sheet
- **Blue Canyon II Wind Farm Project Summary** - Public Service Company of Oklahoma

Weatherford Wind Farm

Custer and Washita Counties, Oklahoma - This project has a capacity of 147 MW and was developed by NextEra Energy Resources (formerly FPL Energy) of Juno Beach, Fla. who owns and operates the wind farm. The Weatherford wind farm reached commercial operation in April 2005 and consists of 98 GE 1.5 MW turbines. 41.5 MW are sold to Public Service Company of Oklahoma. (October 2009)

- **Weatherford Wind Farm Fact Sheet** - NextEra Energy Resources
- **Weatherford Wind Farm Project Summary** - Public Service Company of Oklahoma

Centennial Wind Farm

Harper County, Oklahoma - This project, located just north of Woodward, is owned and operated by Oklahoma Gas & Electric (OG&E), which also uses the power. There are 80 GE wind turbines with a total capacity of 120 MW. The project was originally developed by Chermac Energy Corp and taken to completion by Invenergy Wind in 2007. (October 2012)

- **Centennial Wind Farm Fact Sheet** - OG&E
- **Centennial Wind Farm Info** - Invenergy
- Centennial Wind Farm - Wikipedia

Sleeping Bear Wind Farm

Harper County, Oklahoma - This project, located just north of Woodward, is owned and operated by Edison Mission Group. There are 45 Suzlon wind turbines with a total capacity of 94.5 MW. The project was originally developed by Chermac Energy Corp and commissioned in 2007. AEP Public Service of Oklahoma is the power off-taker. (October 2012)

- Sleeping Bear Wind Farm - The Windpower (database)
- Sleeping Bear Wind Farm - Open Energy Information

Buffalo Bear Wind Farm

Harper County, Oklahoma - This project was developed by Chermac Energy Corp and later bought and brought to completion by Edison Mission Group, which continues to own and operate it. This facility consists of nine (9) Suzlon 2.1 wind turbines for a total capacity of 18.9 MW. It went on-line in December 2008. Western Farmers Electric Coop buys the power.(October 2012)

- **Elk City I & II Wind Energy Center Fact Sheet** - NextEra Energy Resources
- Next Era to develop 100MW Oklahoma project, *Wind Power Monthly*, June 22, 2010

Red Hills Wind Farm

Custer and Roger Mills Counties, Oklahoma - The Red Hills Wind Farm came on-line in June 2009 with a capacity of 123 MW. The project was developed by Acciona North America of Spain, which also owns and operates the facility. The Red Hills wind farm reached commercial operation in March 2009 and consists of 82 Acciona windpower 1.5 MW turbines. Western Farmers Electric Coop buys the power under a 20-year purchase agreement. (September 2012)

- **Red Hills Wind Farm Fact Sheet** - Acciona North America
- **Red Hills Wind Farm** - TerraPass Inc.
- Elk City wind farm to be dedicated today
  (*The Oklahoman*, June 20, 2009)

Blue Canyon V Wind Farm

Caddo and Comanche Counties, Oklahoma - This is a 99 MW project of **Horizon Wind Energy** of Houston, TX (now EDP Renewables of Madrid, Spain) went on-line Oct. 23, 2009. The project consists of 66 GE sle 1.5 MW wind turbines with the energy sold to Public Service Company of Oklahoma (PSO). (September 2012)

- **Blue Canyon V Wind Farm** - White Construction Fact Sheet
- Horizon Wind Energy Dedicates Blue Canyon V Wind Farm, Press Release, Nov. 5, 2009

Taloga Wind Farm

Dewey County, Oklahoma - This 129.6 MW project was developed by RES Americas and later bought and built by Edison Mission Group of Santa Ana, California. The project consists of 54 Mitsubishi MWT95 2.4 MW wind turbines and went on-line in March 2012. Power from this project is purchased by Oklahoma Gas & Electric. (September 2012)

- Edison International dedicates Taloga Wind Energy Project in Oklahoma, *Electric Light & Power*, March 26, 2012
- $400 million Taloga wind farm set, *Clinton Daily News*, April 14, 2010 (PDF)

OU Spirit Wind Farm

Woodward County, Oklahoma - This 101.2 MW project was developed by Competitive Power Ventures (CPV) Renewables. The project consists of 66 Siemens SWT-2.3-93 wind turbines (2.3 MW each with a 93 meter rotor diameter) and went on-line in 2010. This project, originally called Keenan I wind farm, was sold outright to Oklahoma Gas & Electric and was renamed OU Spirit wind. (September 2012)

- **OU Spirit and Keenan II Wind Energy Projects** - TetraTech Project Information Sheet

Elk City I & II Wind Farms

Roger Mills & Beckham Counties, Oklahoma - These two wind farms were developed by NJ 101.2 MW project were developed by NextEra Energy Resources (formerly FPL Energy) of Juno Beach, Fla. Elk City I consists of 43 Siemens SWT-2.3 wind turbines for a total capacity of 98.9 MW and went on-line in 2009. Elk City II costs of 48 GE 1.5 MW turbines and 18 GE 1.6 MW turbines for a total capacity of 100.8 MW. Elk City II went on-line in 2010. (October 2012)

- **Elk City I & II Wind Energy Center Fact Sheet -** NextEra Energy Resources
- Next Era to develop 100MW Oklahoma project, *Wind Power Monthly*, June 22, 2010

Keenan II Wind Farm

Woodward County, Oklahoma - This 151.2 MW project was developed by Competitive Power Ventures (CPV) Renewables. The project consists of 66 Siemens SWT-2.3-101 wind turbines (2.3 MW each with a 101 meter rotor diameter) and went on-line in 2010. Phase I of this project was sold outright to Oklahoma Gas & Electric and was renamed OU Spirit wind. Power for this project is sold to OG&E through a 20-year power purchase agreement. (September 2012)

- **OU Spirit and Keenan II Wind Energy Projects -** TetraTech Project Information Sheet
- Keenan 2 Wind Farm Commences Commercial Operation, *Wind Daily*, Dec. 28, 2010
- CPV breaks ground on wind farm, *Woodward News*, May 13, 2010
- CPV REC Closes Keenan II Wind Farm Financing, *Woodward News*, Feb. 17, 2010

Minco Wind Farm

Grady County, Oklahoma - This project has a capacity of 99.2 MW and was developed by NextEra Energy Resources of Juno Beach, Florida. The wind farm consists of 62 GE 1.6 MW turbines and reached commercial operation in 2010. The project was constructed by Blattner Energy Group of Avon, Minn. (October 2012)

- **Minco I Fact Sheet -** Next Era Energy Resources
- **Minco I & II Fact Sheet -** Next Era Energy Resources
- **Facility Study For Generation Interconnection Request GEN-2007-043 -** January 2010, Southwest Power Pool
- **Impact Restudy Study for Generation Interconnection Request GEN–2007–043 -** May 2010, Southwest Power Pool
- **Feasibility Study For Generation Interconnection Request GEN-2007-043 -** April 2008, Southwest Power Pool
- Wind farm moves into south of Minco to harness and create usable energy, *Chickasha Express Star*, Aug. 11, 2010

Minco II Wind Farm

Grady & Caddo Counties, Oklahoma - This project has a capacity of 100.8 MW and was developed by NextEra Energy Resources of Juno Beach, Florida. The wind farm consists of 63 GE xle 1.6 MW turbines and reached commercial operation in 2011. (October 2012)

- **Minco I & II Fact Sheet -** Next Era Energy Resources
- **Facility Study For Generation Interconnection Request GEN-2007-043 -** January 2010, Southwest Power Pool
- **Impact Restudy Study for Generation Interconnection Request GEN–2007–043 -** May 2010, Southwest Power Pool
- **Feasibility Study For Generation Interconnection Request GEN-2007-043 -** April 2008, Southwest Power Pool

Blue Canyon VI Wind Farm

Caddo County, Oklahoma - This is a 99 MW project constructed by RES Americas for developer/owner **Horizon Wind Energy** of Houston, TX (now EDP Renewables of Madrid, Spain). This wind farm reached commercial operation in 2011 and consists of 55 Vestas 1.85 MW wind turbines. The energy is sold to Western Farmers Electric Cooperative. (November 2012)

- **Blue Canyon VI Wind Farm Fact Sheett -** RES Americas

Rocky Ridge Wind Project

Kiowa and Washita Counties, Oklahoma - This project is projected to be a 150 MW wind project of Lenexa, Kan.-based TradeWind Energy has been proposed for North Central Kiowa and South Central Washita Counties near the towns of Hobart, Rocky, and Sentinel, Oklahoma. The project could be expanded up to 300 MW. In June 2011, Enel bought a 51% stake in this project. The project will consist of 93 GE 1.6 MW turbines, while construction began in Fall 2011. (October 2011)

- **Rocky Ridge Wind Project**
  TradeWind Energy Fact Sheet
- New Oklahoma wind farm begins operation

(*The Oklahoman*, July 3, 2012)

- Enel Green Power Starts Construction of a 150 MW Wind Farm in Oklahoma
(*Enel Press Release*, October 11, 2011)
- Enel Green Power Purchases 51% Stake in Oklahoma wind Farm from Tradewind Energy
(*Newswire Today*, June 18, 2011)
- TradeWind Energy expands wind project near Oklahoma-Kansas border
(*Kansas City Business Journal*, May 4, 2011)

Crossroads Wind Farm

Dewey County, Oklahoma - The Crossroads wind farm located near Canton, OK, came on-line in January 2012 with a capacity of 227.5 MW. There are 98 Siemens wind turbines, including 95 Siemens 2.3 MW turbines and three of the new Siemens direct-drive, 3.0 MW generators. RES Americas developed and built the project, while Oklahoma Gas & Electric owns and uses the power from it. The wind farm connects with OG&E's Windspeed transmission line, which was energized in 2010 and delivers wind power across the utility's electric service area. (October 2012)

- **Crossroads Wind Farm Fact Sheett** - RES Americas
- **Rider to recover costs from Crossroads wind farm** - OG&E
- Oklahoma Gas and Electric Co. completes latest wind farm
(*The Oklahoman*, January 21, 2012)

Big Smile Wind Farm at Dempsey Ridge

Custer and Roger Mills Counties, Oklahoma - This project has a capacity of 132 MW and was developed by Acciona North America of Spain. The Big Smile wind farm reached commercial operation in May 2012. (September 2012)

- **Big Smile Wind Farm at Dempsey Ridge Fact Sheet** - Acciona North America

Chisholm View Wind Project

Garfield and Grant Counties, Oklahoma - Lenexa, Kan.-based TradeWind Energy developed this project and announced in Fall 2011 that they had reached agreement with Alabama Power Co. to sell the utility 235 MW of power from the Chisholm View Wind Farm. This project is located 15 miles north and east of Enid, OK and adjacent to Hunter, OK. Through an agreement with TradeWind, Enel Green Power now controls the project and they announced in April 2012 that they had closed an equity partnership agreement with GE Capital. The project will cost around $375 million and will contribute around $5 million annually to the local economy through land rents and taxes. This wind farm came on-line in December 2012 and was officially dedicated in September 2013. (September 2013)

- **Chisholm View Wind Project** - TradeWind Energy Fact Sheet
- NEW Gotebo wind project officially dedicated
(*Lawton Constitution*, Sept. 15, 2013)
- NEW Chisholm View Wind Farm Dedicated
(*Enid News and Eagle*, Sept. 11, 2013)
- Alabama Power buys wind power from Oklahoma wind farm
(*Alabama.com*, Dec. 13, 2012)
- Wind energy innovation: Chisholm View project lauded by association
(*Enid News*, Nov. 27, 2012)
- $1.2 million in liens filed against Chisholm View Wind Project
(*Enid News*, Nov. 16, 2012)
- Alabama Power purchases electricity generated by wind in Oklahoma, Kansas
(*The Birmingham News*, Sept. 29, 2012)
- Farming the wind
(*Enid News*, July 10, 2012)
- GE buys stake in new Enel wind power farm
(*Reuters*, April 2, 2012)
- Wind energy firm forging ahead
(*Enid (OK) News & Eagle*, Oct. 13, 2011)
- Oklahoma wind to take indirect route to Alabama
(*The Oklahoman*, Oct. 7, 2011)
- Northwest Oklahoma wind farm will provide power to Alabama
(*The Oklahoman*, Sept. 21, 2011)
- A plan to sell the wind: Company to invest $400M in area wind farms
(*Enid (OK) News & Eagle*, Sept. 19, 2011)
- State Regulators Ok Alabama Power 202-MW Wind PPA
(*Electric Power Daily*, Sept. 8, 2011)

Canadian Hills Wind Farm

Canadian County, Oklahoma - This project has a capacity of 295 MW and was originally developed by Apex Clean Energy of Charlottesville, Virginia with Atlantic Power Corporation of Boston, Mass. buying a majority interest in the project and securing financing. Atlantic Power will own and operate the wind farm.

The project consists of 135 turbines - 62 Mitsubishi MWT102 2.4 MW turbines and 73 REpower MM92

Exhibit JBT-5
OCC Cause No. PUD 201400229

2.05 MW turbines. Construction began on the wind farm in May 2012 and commercial operation is expected later in 2012. Power off-takers for this project will be Southwestern Power Co. and, Grand River Dam Authority, each with 20-year PPA's and Oklahoma Municipal Power Authority with a 25-year PPA. Also of note, Google will be purchasing 48 MW of power from GRDA's portion of this project. (October 2012)

- **Canadian Hills Wind Farm Fact Sheet** - Atlantic Power Corp.
- **Canadian Hills Wind Farm Fact Sheet** - Apex Wind Energy
- Apex Begins Construction of 300 MW Canadian Hills Wind
  (*Apex Wind Energy Press Release*, May 23, 2012)

Blackwell Wind Project

Kay County, Oklahoma - This 60 MW project was developed by local landowners and Brooklyn-based Own Energy. This project was sold to NextEra Energy Resources of Juno Beach, Florida, which constructed the project. Power for this project will be sold to Oklahoma Gas & Electric, who in turn will sell it to Oklahoma State University in Stillwater with a 20 year agreement. (January 2013)

- **Blackwell Wind Farm Fact Sheet** - Own Energy, April 2012
- Kay County Wind farm is planned to supply Oklahoma State University
  (*Tulsa World*, Dec. 9, 2011)

NEW *DeWind Novus Wind Project*

Texas County, Oklahoma - This 80 MW project was acquired by DeWind of Korea in 2011 with rights for 160 MW of a 370 MW development. Phase I of this project came on-line in late-2012 with forty DeWind D9.2, 2.0 MW turbines. Phase II of this project was constructed at the same time as Phase I and was the same size. It came on-line in January 2013. (October 2013)

Oklahoma Projects Under Construction

NEW *Origin Wind Project*

Carter & Murray counties, Oklahoma - Enel Green Power of Rome, Italy started construction on this 150 MW project in November 2013. Originally developed by RES Americas, Enel plans to self-finance the project and sell power to Arkansas Electric Cooperative Corp. through a 20-year power purchase agreement. (November 2013)

- Arkansas Co-ops Buy Oklahoma Wind Power
  (*Electric Co-Op Today*, Dec. 1, 2014)
- Enel takes helm at 150MW Origin
  (*reNews*, Nov. 21, 2013)
- Constructions begins on $250 million Oklahoma wind farm to supply energy to Arkansas co-op
  (*Franklin (IN) Daily Journal*, Nov. 21, 2013)
- Arkansas Electric Cooperative Corp. adds additional 150 MW of wind energy
  (*AECC News Release*, July 19, 2013)

Oklahoma Projects with PPAs

NEW *Balko Wind Project*

Beaver County, Oklahoma - Charlottesville, Virginia-based Apex Clean Energy is developing a 300 MW wind project in Beaver County, which is located in the Oklahoma panhandle. In October 2013, it was announced that the company had signed a PPA for 200 MW to be sold to Tulsa-based Public Service Company of Oklahoma. In November 2013, it was announced that 100 MW of power would be sold to Western Farmers Electric Cooperative. This project is expected to come on-line in 2015. (November 2013)

- **Balko Wind Project** - Apex Wind Energy
- Apex sells wind energy from 300 MW wind power project
  (*Electric Light & Power*, Nov. 13, 2013)
- 2 New Wind Farms Planned in Oklahoma Panhandle
  (*Public Radio Tulsa*, October 12, 2013)
- PSO Signs 600 MW of New Wind Power Agreements
  (*PSO News Release*, October 11, 2013)
- Apex Clean Energy signs 200 MW Renewable Energy PPA with PSO
  (*Apex Wind News Release*, October 11, 2013)

Arbuckle Mountain Wind Farm

Murray & Carter Counties, Oklahoma - Lincoln Electric Services (LES) utility in Lincoln, Neb. announced in July 2013 that it had signed a 20 year PPA with EDP Renewables of Madrid, Spain for wind power from the Arbuckle Mountain Wind Farm in Oklahoma. Delivery of electricity from this project is scheduled to begin in January 2016 and the total will boost LES renewable resource portion to 12%. Construction on this project will begin in 2013 to take advantage of the Federal PTC. This project is located approximately 12 mile north of Ardmore, OK. (July 2014)

- **Arbuckle Mountain Wind Project** - Burns & McDonnell
- Lincoln Electric Systems to add wind energy
(*Omaha World-Herald*, July 20, 2013)
- LES to acquire additional 100 megawatts of wind energy
(*LES News Release*, July 19, 2013)

Kay County Wind Project

Kay County, Oklahoma - Charlottesville, Virginia-based Apex Clean Energy is in the process of developing a 300 MW wind farm in northern Kay County, just south of the OK-KS state line (and south of Cowley & Sumner Counties, KS), according to March 2012 obstruction evaluation filings with the FAA. In May 2013, Apex announced they would break ground by the end of 2013. In November 2013, it was announced that Westar Energy of Kansas had signed a PPA for 200 MW of power from this project. This project is slated for completion by the end of 2015. (November 2013)

- **Kay Wind Project** - Apex Wind Energy
- Westar wind farm first in wave to beat tax credit deadline
(*Wichita Eagle*, November 6, 2013)
- Westar to increase wind energy use from farm under construction
(*Topeka Capital-Journal*, November 6, 2013)
- Kay Wind Farm project announced
(*The Newkirk Herald Journal*, May 30, 2013)

Goodwell Wind Project

Texas County, Oklahoma - Lenexa, Kan.-based TradeWind Energy is developing a 200 MW wind project near the town of Goodwell, southwest of Guymon, Oklahoma. It was announced that power from this project will be sold to Tulsa-based Public Service Company of Oklahoma. This project was initially developed by Chermac Energy Corp before being purchased by d by TradeWind Energy. (October 2013)

- 2 New Wind Farms Planned in Oklahoma Panhandle
(*Public Radio Tulsa*, October 12, 2013)
- PSO Signs 600 MW of New Wind Power Agreements
(*PSO News Release*, October 11, 2013)
- TradeWind Energy signs deal with Public Service Company of Oklahoma to provide low-cost power from a new 200-MW wind project
(*Windpower Engineering*, October 11, 2013)

Mammoth Plains Wind Project

Dewey & Blaine Counties, Oklahoma - This 199 MW wind farm is owned by NextEra Energy Resources of Juno Beach, FL. Originally developed by Infinity Wind Power of Santa Barbara, Cal., a PPA is in place between NextEra and Southwestern Public Service Company (SPS), an Xcel Energy company. (November 2013)

- Xcel Energy to double wind buys
(*Amarillo Globe-News*, November 15, 2013)
- New Mexico regulators approve Xcel Energy wind purchases
(*Xcel Energy News Release*, November 15, 2013)

Seiling Wind Project

Dewey County, Oklahoma - Juno Beach, Florida-based NextEra Energy Resources is developing a 198.9 MW wind project project in Northwest Oklahoma. It was announced that power from this project will be sold to Tulsa-based Public Service Company of Oklahoma. (October 2013)

- Xcel Energy to double wind buys
(*Amarillo Globe-News*, November 15, 2013)
- PSO Signs 600 MW of New Wind Power Agreements
(*PSO News Release*, October 11, 2013)

Proposed Oklahoma Wind Projects

(Projects are listed alphabetically by county)

Kingfisher Wind Project

Canadian & Kingfisher Counties, Oklahoma - Charlottesville, Virginia-based Apex Clean Energy is in the process of developing a 300 MW wind farm in northern Canadian and southern Kingfisher Counties, north of Highway 3, according to their web-site between the towns of Piedmont and Okarche. Around 7,000 acres are currently leased for the project. This project experienced some community opposition, but came to an agreement in December 2013, that will allow the project to proceed. Apex has announced that they plan to break ground by the end of 2013. (June 2013)

- **Kingfisher Wind Project** - Apex Wind Energy
- **Kingfisher Wind Project Blog** - Apex Wind Energy
- Settlements pave way for Kingfisher wind farm between Piedmont and Okarche
(*Oklahoma City Oklahoman*, Dec. 11, 2013)
- Apex Wind Energy holds public meetings about planned Kingfisher wind farm
(*The Oklahoman*, March 14, 2013)
- Winds of change coming to Kingfisher
(*KFOR-TV, OKC Channel 4*, January 31, 2013)
- Against the Wind: Large wind farm met with blowback
(*KFOR-TV, OKC Channel 4*, October 24, 2012)
- Company plans Okarche area wind farm
(*Kingfisher Times & Free Press*, September 30, 2012)
- Proposed wind farm includes many unknowns
(*Piedmont Daily*, August 24, 2012)

NEW *Beckham County Wind Project*

Beckham County, Oklahoma - A company called North Rim Wind Land Holdings, LLC of Sayre, OK has filed 157 turbine locations with the FAA for obstruction evaluations in June 2013. The location is south of the town of Erick in Beckham County. KEIN does not have any other info on this project at this time. (October 2013)

NEW *Craig County Wind Project*

Craig County, Oklahoma - EDP Renewables of Madrid, Spain is developing a wind project project in Northeast Oklahoma, just south and east of the town of Centralia. Locations for 59 turbines were filed with the FAA for obstruction evaluations in March 2013. (October 2013)

25 Mile Creek Wind Project

Ellis County, Oklahoma - Boulder-based Berrendo Energy is in the process of developing a ~200 MW wind farm north of the town of Gage, OK, according to an October 2012 obstruction evaluation filings with the FAA. This project is located on private land used for grazing and farming. (November 2013)

Breckenridge Wind Project

Garfield County, Oklahoma - Lenexa, Kan.-based TradeWind Energy is in the process of developing a wind farm north and west of the small town of Breckenridge, according to Sept. 2012 obstruction evaluation filings with the FAA. Plans are for a 29 turbine project producing 98.8 MW. (December 2013)

- New wind farm proposed in Garfield County
(*Tulsa World*, Dec. 12, 2013)

Chilocco Wind Project

Kay County, Oklahoma - Chicago-based PNE Wind USA, a subsidiary or German wind developer PNE Wind AG, is partnering with the Cherokee Nation and four other tribes to develop a wind farm in northern Kay County, just south of the OK-KS state line (and below Cowley County, KS). The plans are for 45 turbines to be placed on 3,000 acres owned by the Cherokee tribe near the Chilocco Indian Agricultural School and another 45 turbines located on 3,000 acres owned by the Kaw Nation, Otoe-Missouria Tribe, Pawnee Nation and Ponca Nation. Info on this project first appeared in Sept. 2012 obstruction evaluation filings with the FAA. (November 2013)

- Tribe pushes forward with wind farm
(*Cherokee Phoenix*, May 24, 2013)
- Cherokee Nation To Operate Largest Wind Farm On Tribal Land
(*North American Windpower*, May 15, 2013)

Osage County Wind Project

Osage County, Oklahoma - This is a 150 MW, construction-ready project of Wind Capital Group of St. Louis, MO. Located west of Pawhuska, Oklahoma in Osage County, WCG has a PPA with Missouri-based Associated Electric Cooperative, Inc., which will buy all the power from the site. General Electric (GE) was awarded a contract to supply 94, GE 1.6 MW wind turbines to the project. At the same time, the Osage Nation tribe has opposed the project, arguing that the wind farm would interfere with their mineral rights in the county. In December 2013 it was announced that WCG had sold this project to TradeWind Energy, which also has a project in this count - See Below. (December 2013)

- **Osage County Wind Farm Fact Sheet** - Wind Capital Group
- Osage County denies wind farm permit for TradeWind Energy
(*Tulsa World*, May 9, 2014)
- Wind energy facility in Oklahoma draws rare coalition
(*Tulsa World*, May 8, 2014)
- Osage Nation drops appeal in wind farm case

(*Osage News*, Feb. 27, 2012)

- Wind farms a "go" in Osage County
(*KJRH, Tulsa Channel 2*, Dec. 16, 2011)
- Judge turns down injunction request in Osage County wind farm trial
(*Tulsa World*, Dec. 15, 2011)
- Hearing Set for December in Osage v. Wind Capital Project
(*Pawhuska Journal-Capital*, November 8, 2011)
- The Energy War in Osage County
(*This Land (OKC)*, November 8, 2011)
- BIA and Osage Minerals Council prepare to fight wind farm project
(*Osage News*, Sept. 26, 2011)
- Osage County Board Approves Wind Farm Plan
(*Tulsa World*, Aug. 12, 2011)
- Osage Nation chief opposes proposed wind farm near tallgrass prairie
(*Tulsa World*, June 13, 2011)

Mustang Run Wind Farm

Osage County, Oklahoma - Lenexa, Kan.-based TradeWind Energy is developing a 136 MW, wind project approximately 13 miles west of Pawhuska, Oklahoma. Like the Osage County Wind Farm proposed by Wind Capital Group, this project has been opposed by the Osage Nation tribe. (November 2012)

- **Mustang Run Wind Project -** TradeWind Energy Fact Sheet
- Wind Farm Controversy In Pawhuska
(*KTUL Tulsa Channel 8*, April 10, 2014)
- Zoning Board Holds Meeting For Osage County Wind Farm Project
(*Tulsa News on 6*, April 10, 2014)
- Eagle conservation, renewable energy projects at odds over federal rule extension
(*Oklahoma City Oklahoman*, December 12, 2013)
- Osage Nation chief opposes proposed wind farm near tallgrass prairie
(*Tulsa World*, June 13, 2011)
- Osage County approves ordinance on wind farm turbines
(*Tulsa World*, April 13, 2011)

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Exhibit JBT-6
OCC Cause No. PUD 201400229

Planning Year 2014-2015 Wind Capacity Credit

December 2013

Contents

Reason for Revision	Revised by:	Date:
Draft Posted	MISO Staff	11/25/2013
Final Posted	MISO Staff	12/17/2013

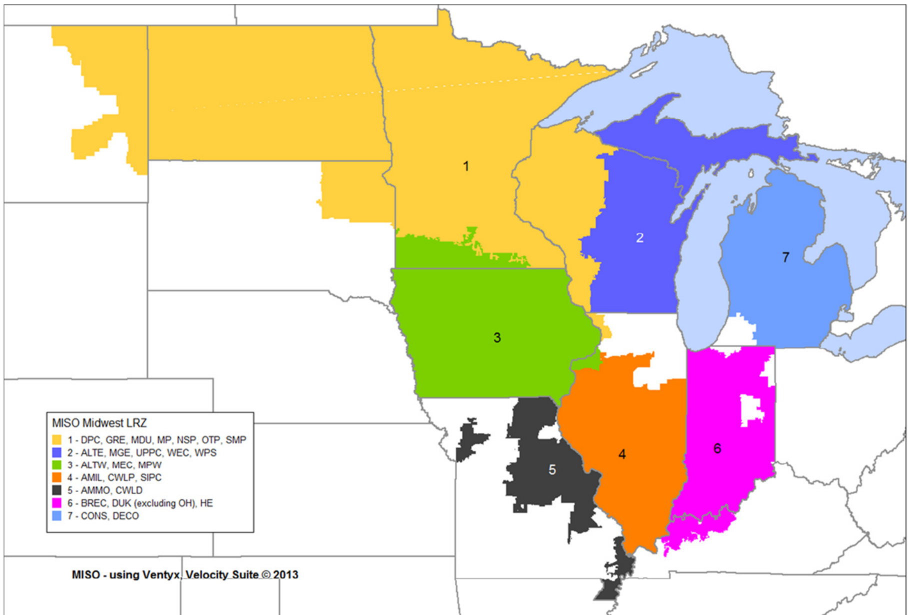
1 Executive Summary

The MISO system-wide wind capacity credit for the 2014-2015 planning year is 14.1 percent. Since 2009 MISO has embarked on a process to determine the capacity value for the increasing fleet of wind generation in the MISO system. The MISO process as developed and vetted through the MISO stakeholder community consists of a two-step method. The first-step utilizes a probabilistic approach to calculate the MISO system-wide Effective Load Carrying Capability (ELCC) value for all wind resources in the MISO footprint. The second-step employs a deterministic approach using the historical output of each wind resource, which considers each wind resource's location. The MISO system-wide ELCC value is then allocated across all wind Commercial Pricing Nodes (CPNodes) in the MISO system to determine a wind capacity credit for each wind CPNode.

As of June 30th, 2013, the MISO system had 12,239 MW (176 CPNodes) of registered wind capacity. This means 1,723 MW (12,239 MW x 14.1%) of unforced wind capacity potentially qualifies under Module E-1 of MISO's tariff. To the extent that the 1,723 MW of unforced wind capacity is deliverable at the individual wind CPNodes, the unforced capacity megawatts may be converted to Zonal Resource Credits (ZRC) to meet Resource Adequacy obligations. Based on the Network Resource Interconnection Service (NRIS) of each wind CPNode, approximately 75% of the 2013 unforced wind capacity would qualify to be converted to ZRC's in the 2014-2015 Planning Resource Auction.

The capacity credit at the 176 individual wind CPNodes is proprietary information, however, the percent credit across all wind CPNodes ranged from zero to 25.3 percent. Section 3 describes the details of allocating the total 1,723 MW to the 176 wind CPNodes. Upon request to MISO, the capacity credit details for individual wind CPNodes are available to the associated Market Participants. Figure 1-1 geographically illustrates the seven MISO Midwest Local Resource Zones (LRZ). The table in Figure 1-1 shows the most detailed results that MISO can share. All LRZs have multiple market participants with wind CPNodes with the exception of LRZ 5. Therefore, the values for LRZ 5 shown in Figure 1-1 were combined with LRZ 4 so that proprietary information would not be revealed.

One thing to consider about future planning year studies is that a lower penetration level of wind will be observed than the current 13 percent. This will be due to the addition of MISO South in December 2013 to the MISO system. MISO South will bring a substantial amount of load to the MISO footprint with very little to no wind capacity. This will decrease the wind penetration in MISO as compared to the 2014-2015 planning year.



Metric	MISO	Zone 1	Zone 2	Zone 3	Zone 4 and Zone 5	Zone 6	Zone 7
Registered Max (MW)	12,239	3,941	627	5,932	514	282	943
UCAP (MW)	1,723	622	76	811	48	22	145
ELCC %	14.1%	15.8%	12.1%	13.7%	9.3%	7.8%	15.4%
Wind CPnode Count	176	67	10	72	7	4	16

Figure 1-1: MISO Midwest Local Resource Zones (LRZ) And Distribution of Wind Capacity

2 MISO System-Wide Wind ELCC Study

2.1 Probabilistic Analytical Approach

The probabilistic measure of load not being served is known as Loss of Load Probability (LOLP) and when this probability is summed over a time frame, e.g. one year; it is known as Loss of Load Expectation (LOLE). The accepted industry standard for what has been considered a reliable system has been the "Less than 1 Day in 10 Years" criteria for LOLE. This measure is often expressed as 0.1 days/year, as that is often the time period (1 year) over which the LOLE index is calculated.

Effective Load Carrying Capability (ELCC) is defined as the amount of incremental load a resource, such as wind, can dependably and reliably serve, while considering the probabilistic nature of generation shortfalls and random forced outages as driving factors to load not being served. Using ELCC in the determination of capacity value for generation resources has been around for nearly half a century. In 1966, Garver demonstrated the use of loss-of-load probability mathematics in the calculation of ELCC[1]

To measure the ELCC of a particular resource, the reliability effects need to be isolated for the resource in question from those of all the other sources. This is accomplished by calculating the LOLE of two different

[1] Garver, L.L.; , "Effective Load Carrying Capability of Generating Units," Power Apparatus and Systems, IEEE Transactions on , vol.PAS-85, no.8, pp.910-919, Aug. 1966

5

cases: one “With” and one “Without” the resource. Inherently, the case “with” the resource should be more reliable and consequently have fewer days per year of expected loss of load (smaller LOLE).

The new resource in the example shown in Figure 2-1 made the system 0.07 days/year more reliable, but there is another way to express the reliability contribution of the new resource besides the change in LOLE. This way requires establishing a common baseline reliability level and then adjusting the load in each case “With” and “Without” the new resource to this common LOLE level. A common baseline that is chosen is the industry accepted reliability standard of 1 Day in 10 Years (0.1 days/year) LOLE criteria.

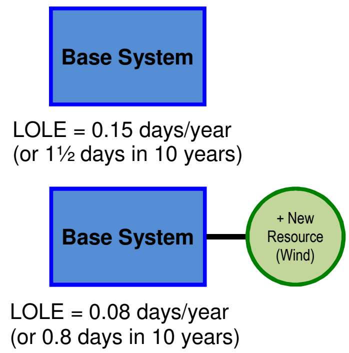


Figure 2-1: Example System “With” & “Without” New Resource

With each case being at the same reliability level, as shown in Figure 2-2, the only difference between the two cases is that the load was adjusted. The difference is the amount of ELCC expressed in load or megawatts, which is 300 MW (100 minus -200) for the new resource in this example. Sometimes this number is divided by the Registerd Maximum Capacity (RMax) of the new resource and then expressed in percentage (%) form. The new resource in the ELCC Example Figure 2-2 has an ELCC of 30 percent of the resource’s nameplate capacity.

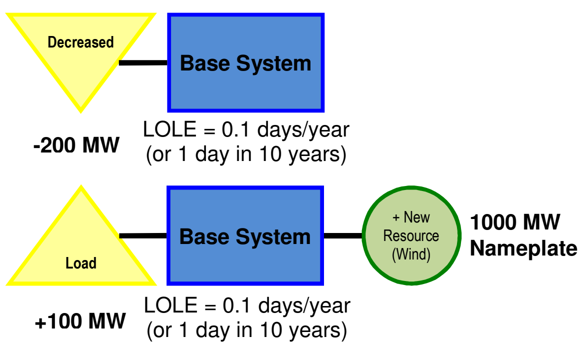


Figure 2-2: ELCC Example System at the same LOLE

The same methodology illustrated in the simple example of Figure 2-2 was utilized as the analytical approach for the determination of the 2014 MISO system-wide ELCC of the wind resources in the much more complex MISO system. Using ELCC is the preferred method of calculation for determining the capacity value of wind[2].

2.2 LOLE Model Inputs & Assumptions

MISO applies the ELCC calculation methodology by utilizing the Multi-Area Reliability Simulation (MARS) program by GE Energy to calculate LOLE values with and without wind resources modeled. This model consists of three major inputs:

1. Generator Forced Outage Rates (FOR)
2. Actual Historic Hourly Load Values
3. Actual Historic Hourly Wind Output Values

Forced outage rates are used for the conventional type of units in the LOLE model. These FOR are calculated from the Generator Availability Data System (GADS) that MISO uses to collect historic operation performance data for all conventional unit types in the MISO system.

For the 2014 ELCC Study, the actual 2013 historical hourly concurrent load and wind output at the wind CPNodes is used to calculate the ELCC values for the wind generation in MISO on a system-wide basis. The second to last column of Table 2-1 illustrates the ELCC results for the past 9 years.

2.3 MISO System Wide ELCC Results

MISO calculated ELCC percentage results for historical years 2005 through 2013 and at multiple scenarios of penetration levels, corresponding to 10 GW, 20 GW and 30 GW of installed wind capacity. This creates an ELCC penetration characteristic for each year, as illustrated by the different curves in Figure 2-3. The ELCC characteristic of each year can be represented by a trend line equation that has an R squared coefficient of no less than 0.999. This is the basis for achieving accuracy with sparse or few years of data. The initial left most data point for each curve is at the lowest penetration point and represents the actual annual ELCC for that year. These values are shown in the second to last column of Table 2-1. The values along each year's characteristic curve at the higher penetration levels reflect what that year's wind resources would have as an ELCC if more capacity had been installed over the same year and footprint. The high end 30 GW level of penetration (approximately 30 percent on x-axis of Figure 2-3) is an estimate of the amount of wind generation that could result in MISO, as the Load Serving Entities (LSE) collectively meet renewable resource mandates of the various MISO States. Figure 2-3 illustrates the ELCC versus penetration characteristic of each of the nine years, and how those characteristics from multiple years were merged to establish the current 14.1 percent wind capacity credit.

[2] Keane, A.; Milligan, M.; Dent, C.J.; Hasche, B.; D'Annunzio, C.; Dragoon, K.; Holttinen, H.; Samaan, N.; Soder, L.; O'Malley, M.; , "Capacity Value of Wind Power," Power Systems, IEEE Transactions on , vol.26, no.2, pp.564-572, May 2011

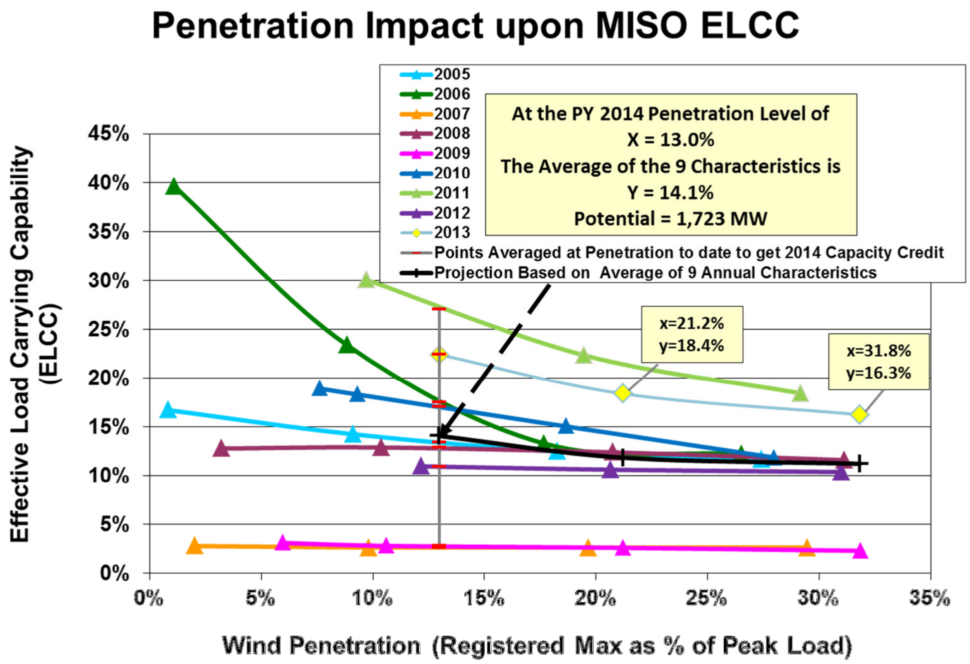


Figure 2-3: Nine Years of Historical ELCC Penetration Characteristics

The Planning Year (PY) 2014 wind capacity credit is determined by averaging the nine ELCC values found along each year's ELCC-and-penetration characteristic curve. The averaging is done at the penetration level that corresponds to the penetration level at the end of the 2nd Quarter 2013. The registered amount of capacity at the end of the 2nd Quarter is the convention used to set the capacity going into the summer season. The penetration level at the end of the 2nd Quarter 2013 was 13.0 percent. The historical 2013 penetration level is calculated by dividing the 2nd Quarter 12,239 MW (from column 4 of Table 2-1) by the 94,298 MW peak load (column 1 of Table 2-1). The peak load is defined as the highest average integrated hourly load for the year. The vertical line called out in the legend of Figure 2-3 as "Points Averaged at penetration to date to get 2014Capacity Credit" illustrates where each of the nine ELCC values from each year's characteristic curve intersect with the most recent 13.0 percent historical penetration level. The legend of Figure 2-3 also indicates that the average of the intersected values is the 14.1 percent system-wide ELCC for PY 2014. The black projection line in Figure 2-3 starts with the PY 2014 14.1 percent, and is more clearly observed as the current 14.1 percent point and forward projection in Figure 2-4.

The resulting wind capacity credit is expressed in Unforced Capacity (UCAP) megawatts. If the individual CPNodes were to have full deliverability via the Generator Interconnection process, the system-wide capacity rating could represent as much as 1,723 MW of UCAP in 2014. MISO calculates the associated UCAP at each wind CPNode and provides it to the appropriate Market Participant on a requested confidential basis. The capacity credit values can also be viewed in the Module E Capacity Tracking (MECT) tool. For the 2014-2015 planning year, a total UCAP of 1,723 MW is allocated among 176 wind CPNodes, up from 169 CPNodes in planning year 2013. Section 3 shows the details of the allocation method. The amount at each node that can qualify under Module E-1 is subject to the specific deliverability limit for each location.

Market-wide Operational Tracking							
Peak Load (MW)	Planning Year (PY)	Metered Wind at Peak Load[1] (MW)	Registered Maximum Capacity[2] (MW)	Peak Day RMax[2] (%)	Historical Penetration (%)	Annual Historical ELCC (%)	MISO Capacity Credit (%)
109,473	2005	104	908	11.5%	0.8%	16.7%	N/A
113,095	2006	700	1,251	56.0%	1.1%	39.6%	N/A
101,800	2007	44	2,065	2.1%	2.0%	2.8%	N/A
96,321	2008	384	3,086	12.4%	3.2%	12.8%	N/A
94,185	2009	86	5,636	1.5%	6.0%	3.1%	20.0%
107,171	2010	1,770	8,179	21.6%	7.6%	18.9%	8.0%
102,804	2011	4,421	9,996	44.2%	9.7%	30.1%	12.9%
96,764	2012	1,152	11,774	9.8%	12.2%	11.0%	14.7%
94,298	2013	6,439	12,239	52.6%	13.0%	22.4%	13.3%
Pending	2014	Pending	Pending	Pending	Pending	Pending	14.1%

Notes: 1 Curtailed and Dispatchable Intermittent Resources (DIR) MW have bee added to settlement MW
2 Registered Maximum (Rmax)

Table 2-1: Historical Tracking of Wind Related Metrics

The current method to set the capacity credit was developed at the LOLE Working Group, and was first applied to planning year 2011. Table 2-2 shows the consistency of that method's results over five Planning Years, which includes the PY 2010 value if the current method had also been applied. Again, the black curve in Figure 2-4 is the projection going forward, where the influence of future annual ELCC characteristics are still pending. For related study work that require hourly wind and load patterns, such as required in PROMOD ® simulations, MISO has indicated that the historical 2005 wind and load shapes are typical patterns to use at MISO. The appropriateness of continuing to use 2005 as a typical year is confirmed in Figure 2-3 since the black trend line that reflects all history lies nearly on top of the blue line representing the single year 2005. The left portion of Figure 2-4 demonstrates the increasing volatility that would have resulted if the current calculating process had been applied to successively fewer sets of historical annual ELCC penetration characteristics. Figure 2-4 also repeats the 2014 point and the extension to future higher penetration levels from Figure 2-3.

Table 2-2: Consistent and Responsive System-Wide ELCC Method Demonstrated by Applying it Over Five Planning Years

Planning Year	Wind Penetration	ELCC
PY 2010	6.0%	12.4%
PY 2011	7.6%	12.9%
PY 2012	9.7%	14.7%
PY 2013	12.2%	13.3%
PY 2014	13.0%	14.1%

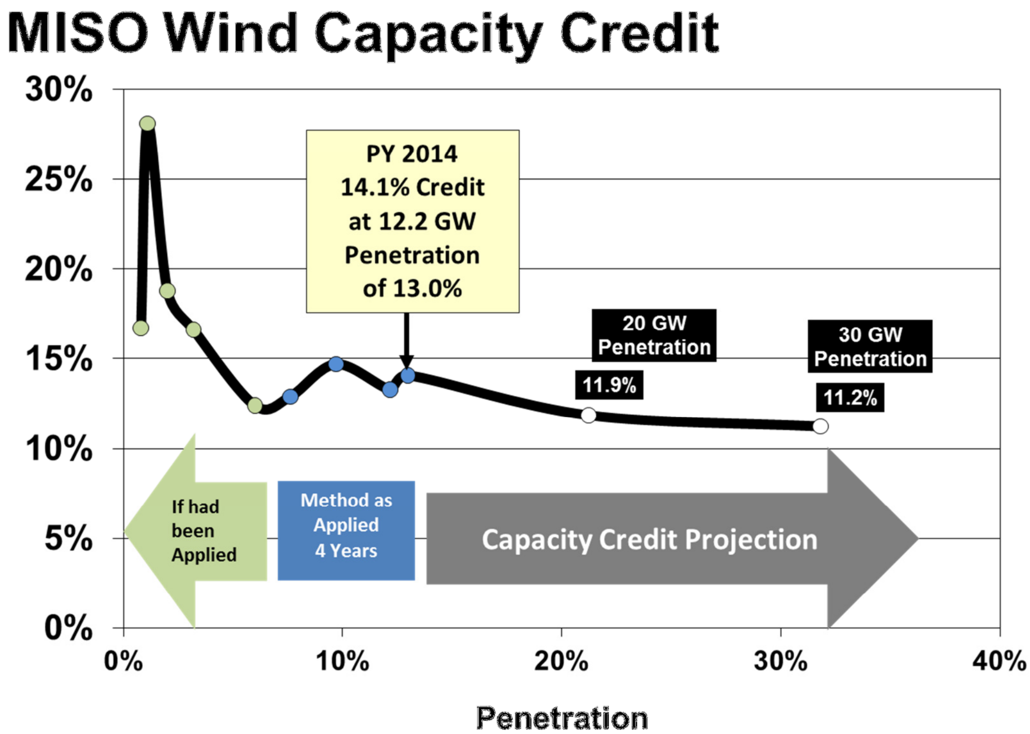


Figure 2-4: Demonstration of Applying Capacity Credit Method Starting with PY 2006

3 Details of Wind Capacity by CPNode

3.1 Deterministic Analytical Technique

Since there are many wind CPNodes throughout the MISO system (176 in 2013), a deterministic approach involving a historic-period metric is used to allocate the single system-wide ELCC value of wind to all the registered wind CPNodes. While evaluation of all CPNodes captures the benefit of the geographic diversity, it is also important to assign the capacity credit of wind at the individual CPNode locations, because in the MISO market the location relates to deliverability due to possible congestion on the transmission system. Also, in a market it is important to convey the correct incentive signal regarding where wind resources are relatively more effective. The location and relative performance is a valuable input in determining the tradeoffs between constructing wind facilities in high capacity factor locations that typically require more transmission investment versus locating wind generating facilities at less effective wind resource locations that may require less transmission build-out.

For the 2014-2015 planning year, the system-wide wind ELCC value of 14.1 percent times the 2013 registered maximum wind capacity (RMax) of 12,239 MW (2nd Quarter 2013) results in 1,723 MW of system-wide capacity. The 1,723 MW is then allocated to the 176 different CPNodes in the MISO system. The historic output has been tracked for each wind CPNode over the top 8 daily peak hours for each year 2005 through 2013. The average capacity factor for each CPNode during all 72 (8-hours x 9-years) historical daily peak hours is called the "$PKmetric_{CPNode}$" for that CPNode. The capacity factor over those 72 hours and the RMax at each CPNode are the basis for allocating the 1,723 MW of capacity to the 176 CPNodes. If the start date of the CPNode's name was after 2005, then the average capacity factor over fewer years is used. MISO has developed business practice rules for the handling of new wind CPNodes that do not have historical output data. Table 3-1 is a listing of the total system wind output at the time of 72 daily peak loads. These 72 peaks are the top nine daily peaks over the past nine summers.

Tracking the top 8 daily peak hours in a year is sufficient to capture the peak load times that contribute to the annual LOLE of 0.1 days/year. For example, in the LOLE run for year 2013, all of the 0.1 days/year LOLE occurred in the month of July, but only 5 of the top 8 daily peaks occurred in the months of July. Therefore, no more than 5 of the top daily peaks contributed to the LOLE. Other years have LOLE contributions due to more than 5 days, however 8 days was found sufficient to capture the correlation between wind output and peak load times in all cases. If many more years of historical data were available, one could simply utilize the single peak hour from each year as the basis for determining the $PKmetric_{CPNode}$ over multiple years. Using the top 8 daily peak days will be evaluated each year as more data is received.

Table 3-1 - Wind Output for 9 Years
At Time of 8 Top Daily Load Peaks each Year

END_TIME of Daily Peak (EST)	Wind Registered Max (MW)	Estimated Curtailment and DIR (MW)	Wind Output at Daily Peak Load [1] (MW)	Wind Output % of Registered Max at Daily Peak Load [1]	Daily Peak Load (MW)	Year	Planning Year Daily Peak Rank
6/27/05 15:00	908	0	291	32.1%	105,353	2005	6
7/21/05 16:00	908	0	92	10.2%	104,998	2005	7
7/25/05 15:00	908	0	89	9.8%	108,558	2005	3
8/1/05 17:00	908	0	58	6.4%	106,949	2005	5
8/2/05 16:00	908	0	211	23.2%	109,099	2005	2
8/3/05 16:00	908	0	104	11.5%	109,473	2005	1
8/8/05 17:00	908	0	396	43.6%	104,011	2005	8
8/9/05 16:00	908	0	282	31.1%	107,615	2005	4
7/17/06 16:00	1,251	0	430	34.4%	110,011	2006	4
7/18/06 16:00	1,251	0	63	5.1%	102,742	2006	5
7/19/06 16:00	1,251	0	378	30.2%	101,744	2006	7
7/25/06 17:00	1,251	0	53	4.3%	100,948	2006	8
7/28/06 16:00	1,251	0	471	37.6%	102,161	2006	6
7/31/06 16:00	1,251	0	700	56.0%	113,095	2006	1
8/1/06 16:00	1,251	0	139	11.1%	110,947	2006	2
8/2/06 16:00	1,251	0	36	2.9%	110,499	2006	3
6/26/07 15:00	2,065	0	363	17.6%	97,413	2007	8
7/9/07 15:00	2,065	0	45	2.2%	98,049	2007	6
7/31/07 17:00	2,065	0	352	17.0%	98,955	2007	5
8/1/07 16:00	2,065	0	64	3.1%	101,496	2007	2
8/2/07 16:00	2,065	0	45	2.2%	101,268	2007	4
8/6/07 17:00	2,065	0	76	3.7%	97,435	2007	7
8/7/07 17:00	2,065	0	59	2.9%	101,306	2007	3
8/8/07 16:00	2,065	0	44	2.1%	101,800	2007	1
7/16/08 16:00	3,086	0	455	14.8%	95,982	2008	2
7/17/08 16:00	3,086	0	423	13.7%	95,592	2008	3
7/18/08 16:00	3,086	0	97	3.1%	93,144	2008	5
7/29/08 16:00	3,086	0	384	12.5%	96,321	2008	1
7/31/08 17:00	3,086	0	402	13.0%	92,544	2008	7
8/1/08 16:00	3,086	0	405	13.1%	93,422	2008	4
8/4/08 17:00	3,086	0	178	5.8%	92,245	2008	8
8/5/08 16:00	3,086	0	212	6.9%	93,089	2008	6
6/22/09 16:00	5,636	0	527	9.4%	87,846	2009	5
6/23/09 15:00	5,636	0	720	12.8%	91,671	2009	3
6/24/09 17:00	5,636	0	300	5.3%	92,402	2009	2
6/25/09 14:00	5,636	0	86	1.5%	94,185	2009	1
6/26/09 16:00	5,636	0	1,082	19.2%	87,355	2009	6
8/10/09 14:00	5,636	0	167	3.0%	89,039	2009	4
8/14/09 16:00	5,636	0	2,126	37.7%	87,023	2009	7

8/17/09 15:00	5,636	0	1,132	20.1%	85,593	2009	8
7/23/10 16:00	8,179	0	692	8.5%	102,995	2010	8
8/3/10 16:00	8,179	0	365	4.5%	103,646	2010	4
8/4/10 16:00	8,179	0	948	11.6%	103,527	2010	6
8/9/10 16:00	8,179	0	383	4.7%	103,571	2010	5
8/10/10 16:00	8,179	30	1,770	21.6%	107,171	2010	1
8/11/10 16:00	8,179	0	129	1.6%	104,075	2010	3
8/12/10 16:00	8,179	25	1,788	21.9%	106,653	2010	2
8/13/10 16:00	8,179	0	2,072	25.3%	102,996	2010	7
6/7/11 17:00	9,996	57	5,624	56.3%	94,933	2011	7
7/18/11 15:00	9,996	0	991	9.9%	98,177	2011	4
7/19/11 16:00	9,996	0	1,880	18.8%	101,076	2011	2
7/20/11 17:00	9,996	197	4,421	44.2%	102,804	2011	1
7/21/11 16:00	9,996	158	961	9.6%	99,601	2011	3
7/22/11 16:00	9,996	71	1,192	11.9%	93,759	2011	8
8/1/11 15:00	9,996	0	2,427	24.3%	95,703	2011	5
8/2/11 16:00	9,996	64	2,613	26.1%	95,169	2011	6
6/28/12 17:00	11,774	8	1,387	11.8%	93,031	2012	6
7/2/12 16:00	11,774	80	3,668	31.1%	92,605	2012	7
7/5/12 16:00	11,774	0	659	5.6%	92,473	2012	8
7/6/12 16:00	11,774	75	2,397	20.4%	95,262	2012	3
7/16/12 17:00	11,774	2	4,336	36.8%	94,727	2012	4
7/17/12 15:00	11,774	8	1,159	9.8%	96,102	2012	2
7/23/12 16:00	11,774	0	1,152	9.8%	96,794	2012	1
7/25/12 17:00	11,774	63	4,276	36.3%	93,408	2012	5
7/15/13 16:00	12,239	14	1,734	14.2%	88,517	2013	8
7/16/13 17:00	12,239	23	1,798	14.7%	90,807	2013	4
7/17/13 17:00	12,239	17	1,478	12.1%	93,190	2013	2
7/18/13 16:00	12,239	212	6,439	52.6%	94,298	2013	1
7/19/13 16:00	12,239	51	3,606	29.5%	91,097	2013	3
8/26/13 17:00	12,239	124	4,515	36.9%	89,196	2013	7
8/27/13 17:00	12,239	93	2,776	22.7%	89,456	2013	6
8/29/13 16:00	12,239	16	1,849	15.1%	89,642	2013	5
System-Wide Average Peak Metric				**17.39%**			
Note 1 **Curtailed and DIR MW have been added to settlement MW**							

3.2 Wind CPNode Equations

Registered Maximum (RMax) is the MISO market term for the installed capacity of a resource. The relationship of the wind capacity rating to a CPNode's installed capacity value and Capacity Credit percent is expressed as:

$$(\text{Wind Capacity Rating})_{\text{CPNode n}} = \text{RMax}_{\text{CPNode n}} \times (\text{Capacity Credit \%})_{\text{CPNode n}} \qquad (1)$$

Where $\text{RMax}_{\text{CPNode n}}$ = Registered Maximum installed capacity of the wind facility at the CPNode n. The right most term in expression (1), the $(\text{Capacity Credit \%})_{\text{CPNode n}}$, can be replaced by the expression (2) :

$$\text{K} \times (\text{PKmetric}_{\text{CPNode n}} \%) \qquad (2)$$

Where "K" for Year 2013 was found by obtaining the PKmetric at each CPNode over the 9 year period, and solving expression (3):

$$\text{K} = \frac{\text{ELCC}}{\sum_{1}^{176} \text{RMax}_{\text{CPNode n}} \times \text{PKmetric}_{\text{CPNode n}}} \qquad (3)$$

This results in the sum of the MW ratings calculated for the CPNodes equal to the system wide ELCC 1,723 MW. The values in (3) are:

ELCC = 1,723 MW

$\sum$ $\text{RMax}_{\text{CPNode n}}$ x $\text{PKmetric}_{\text{CPNode n}}$ = 2,723 MW

Therefore: K = 0.6329 = 1,723 / 2,723

3.3 Wind CPNode Capacity Credit Results & Example

The individual $\text{PKmetric}_{\text{CPNode}}$ of the CPNodes ranged from zero to 40.0%. The individual Capacity Credit percent for CPNodes therefore ranged from zero to 25.3%, by applying expression (2).

Example: RMax = 100 MW

PKmetric = 25%

K = 0.6329

Capacity Credit (MW)	=	RMax * PKmetric * K
	=	100 * 0.25 * 0.6329
	=	15.82 MW
Capacity Credit (%)	=	Capacity Credit (MW)/RMax
	=	15.82/100
	=	15.82%

Figure 3-1 shows how the system-wide 14.1percent capacity credit percent compares with the individual capacity credit percents for the 176 active CPNodes as of 2nd quarter 2013. This reflects implementing the formulas referred to earlier in this section to allocate the total system 1,723 MW to the 176 CPNodes. The CPNodes have been sorted by their capacity credit percentages. Along with the specific identity of CPNodes, a given market participant is provided only the results, or selected bars on the chart that correspond to their CPNodes. The percentage is applied to the node's RMax and provides the CPNodes capacity credit in megawatts for the market participant. The CPNode's deliverability status determines the amount of the capacity credit MW that qualifies for LRZ credits in Module E-1.

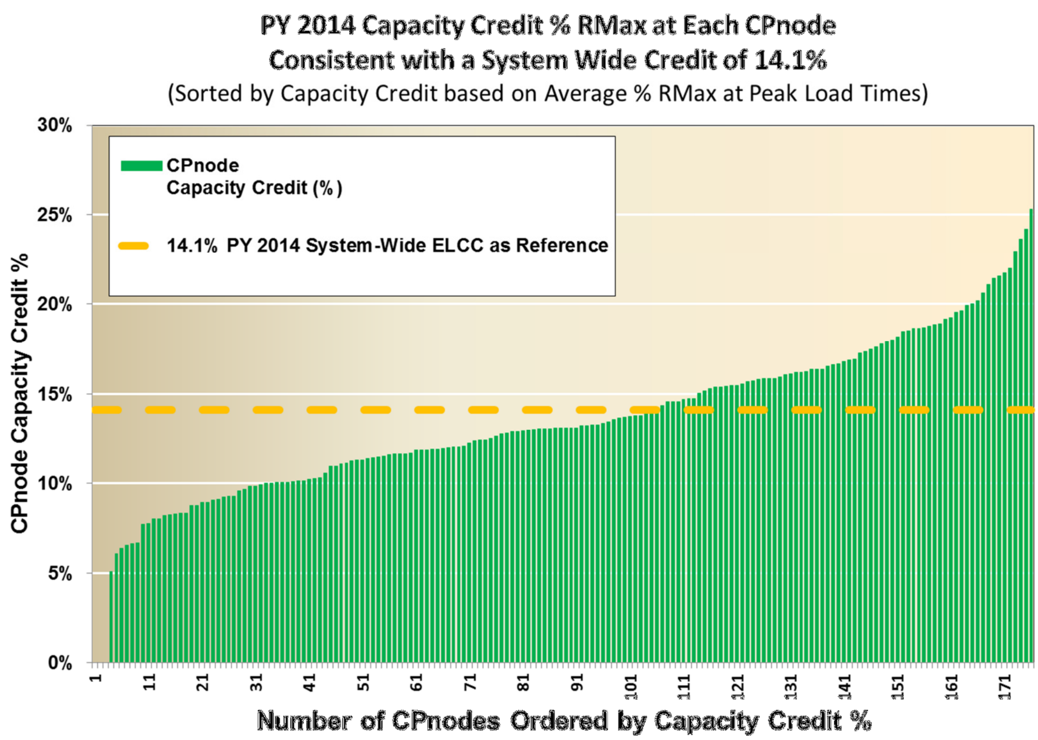


Figure 3-1 – Allocation of Capacity Credit % over 176 CPNodes Consistent with a System-Wide Credit of 14.1%

2013 State of the Market

19 May 2014

SPP Market Monitoring Unit

Southwest Power Pool

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Disclaimer

The data and analysis in this report are provided for informational purposes only and shall not be considered or relied upon as market advice or market settlement data. All analysis and opinions contained in this report are solely those of the SPP Market Monitoring Unit (MMU), the independent market monitor for Southwest Power Pool, Inc. ("SPP"). The MMU and SPP makes no representations or warranties of any kind, express or implied, with respect to the accuracy or adequacy of the information contained herein. The MMU and SPP shall have no liability to recipients of this information or third parties for the consequences that may arise from errors or discrepancies in this information, for recipients' or third parties' reliance upon such information, or for any claim, loss or damage of any kind or nature whatsoever arising out of or in connection with:

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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.

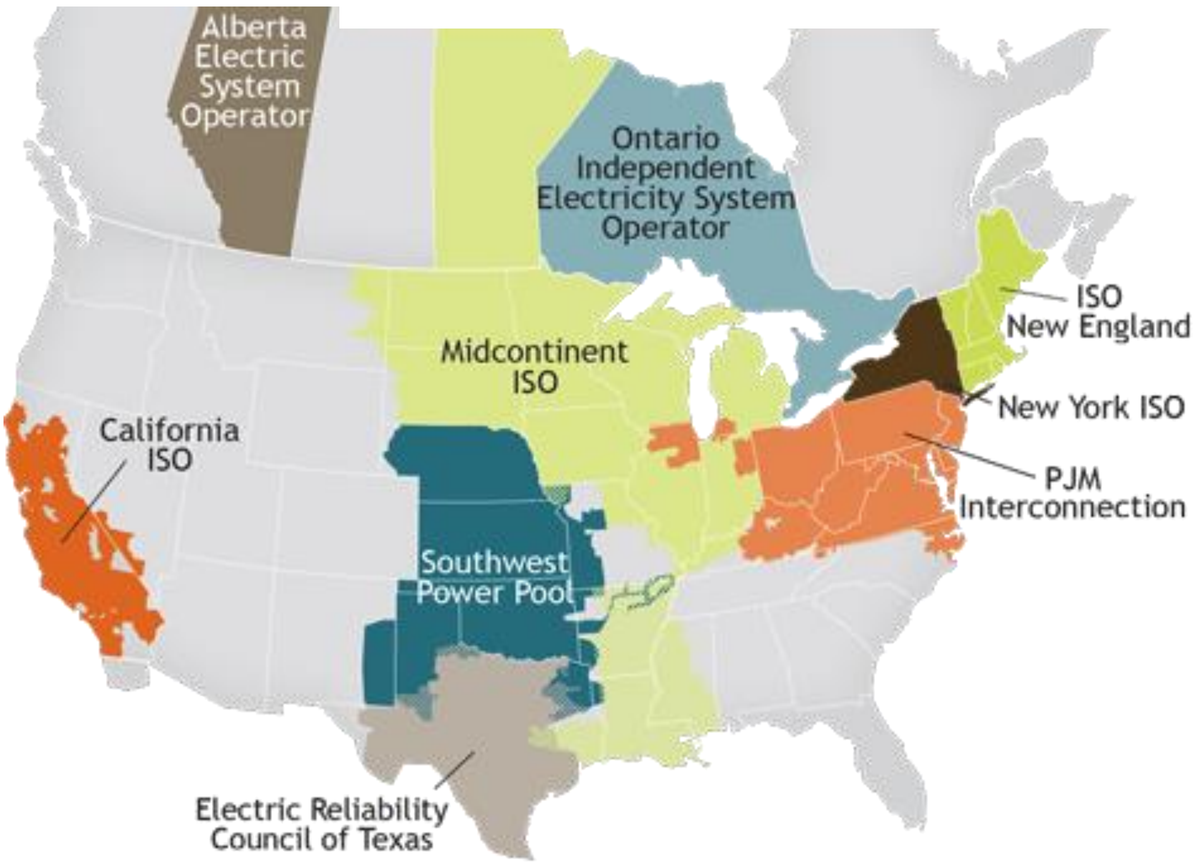
In 2007, SPP launched a real-time EIS Market, comprised of participants that agreed to operate under the SPP Tariff and Market Protocols. The market does not include all SPP members, only those that have agreed to the above terms and provisions. The Market Participants' respective areas collectively 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

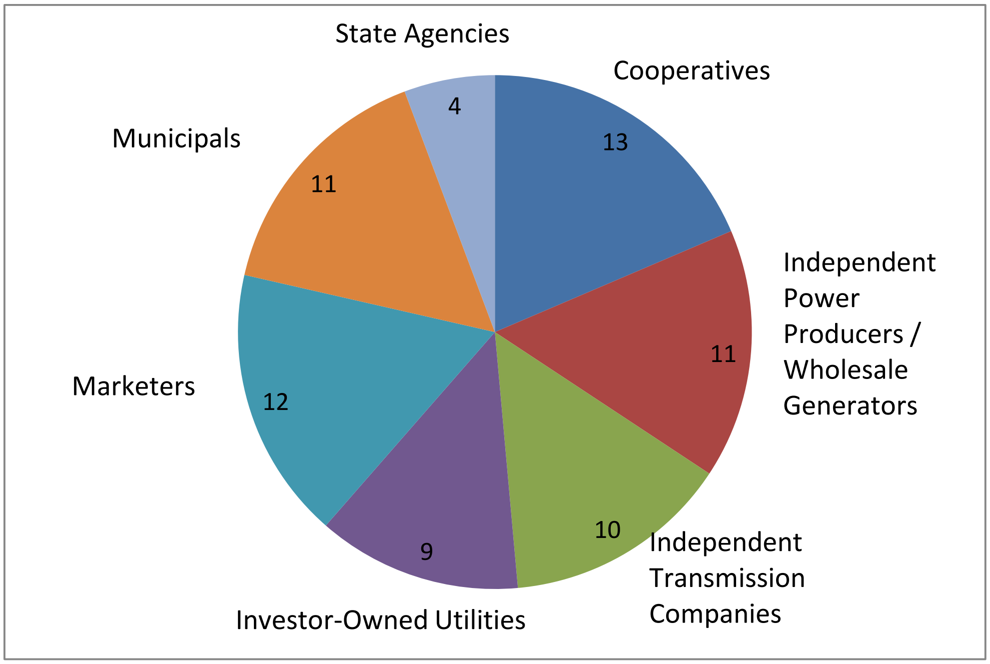


Source: ISO/RTO Council

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

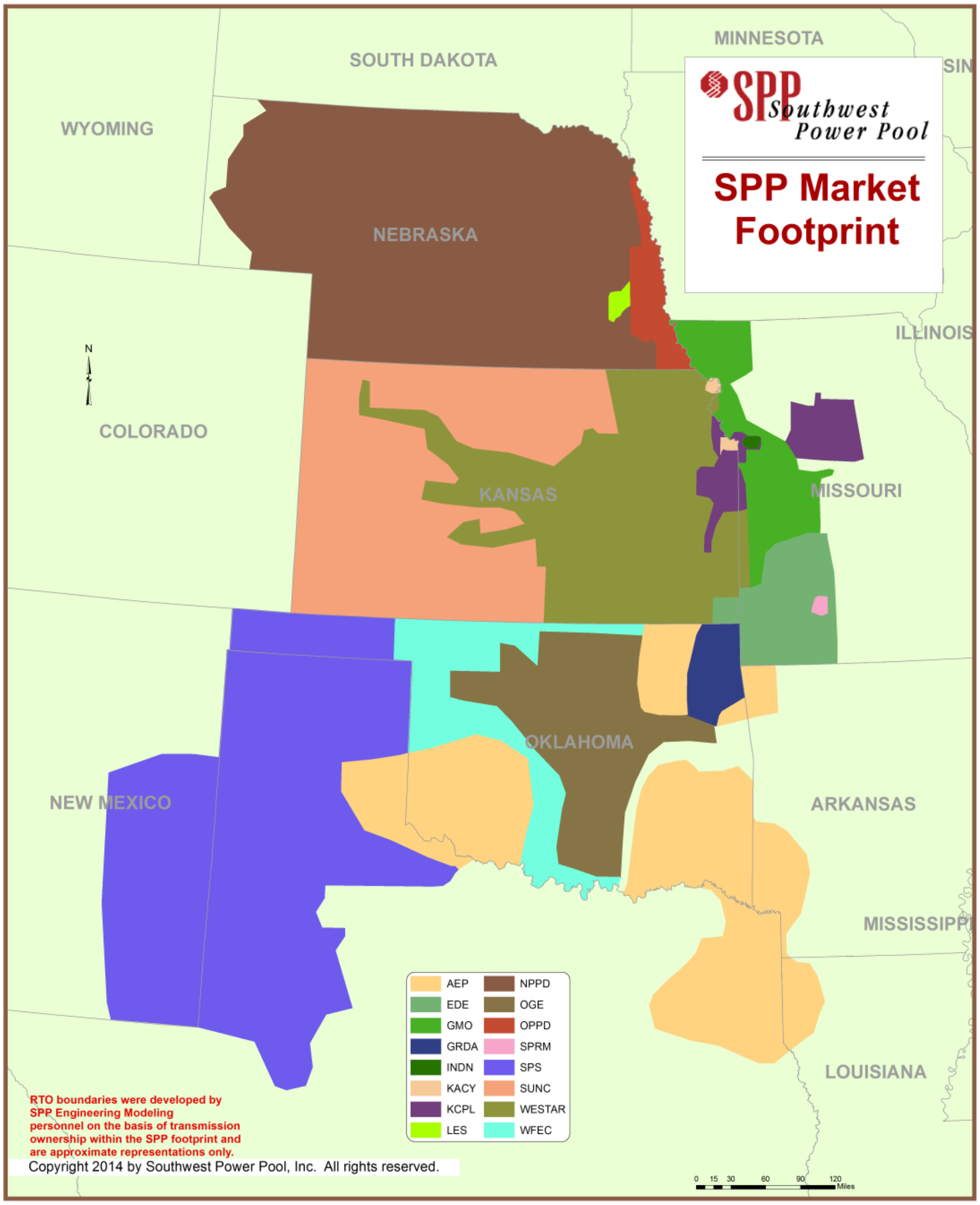


Note: SPP Reliability Footprint

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

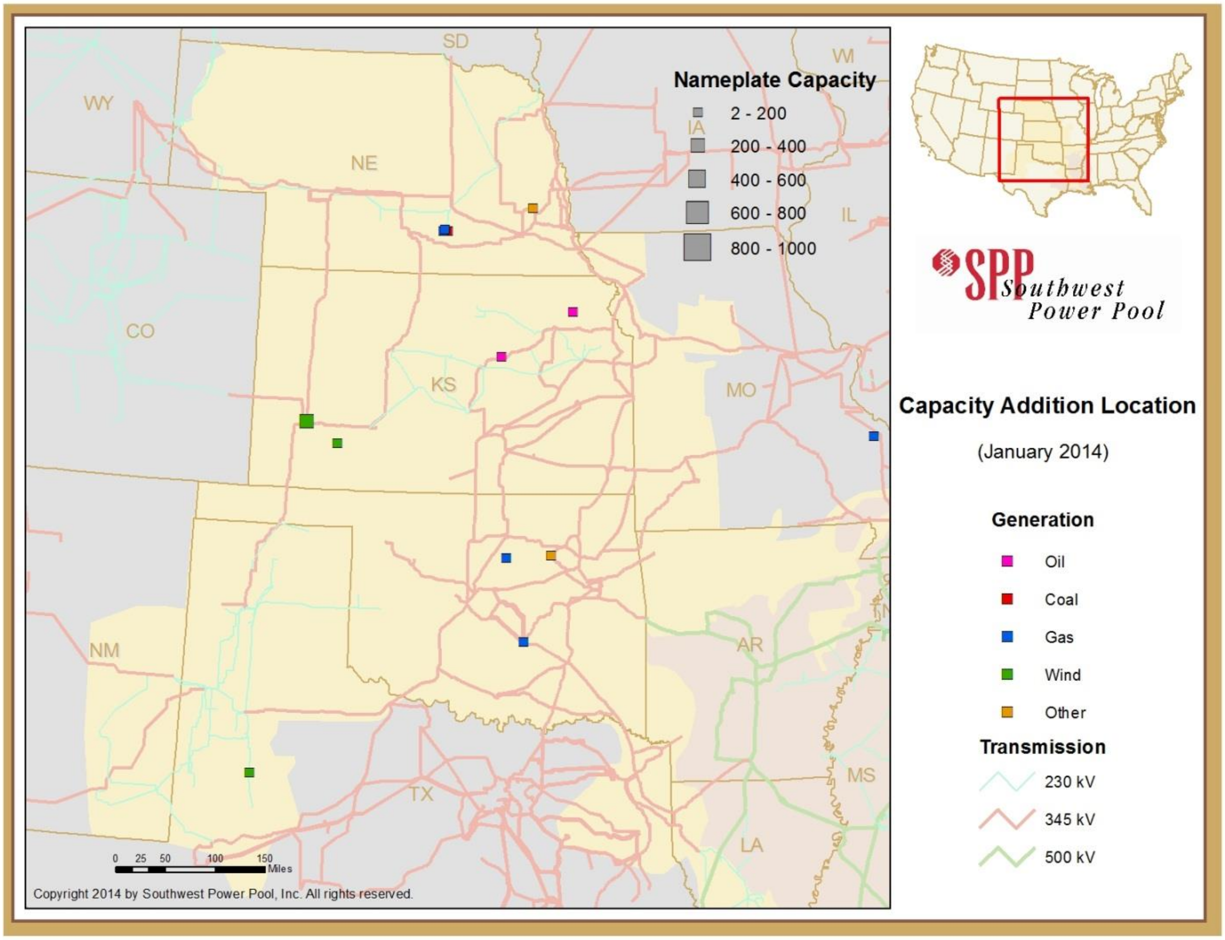
Figure I.6 shows the total amount of installed capacity by fuel type that was added to the SPP market in 2013. These additions came from two sources: generation from new Market Participants and the construction of new generation by the existing members. Most of the capacity increase was small coal and 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.

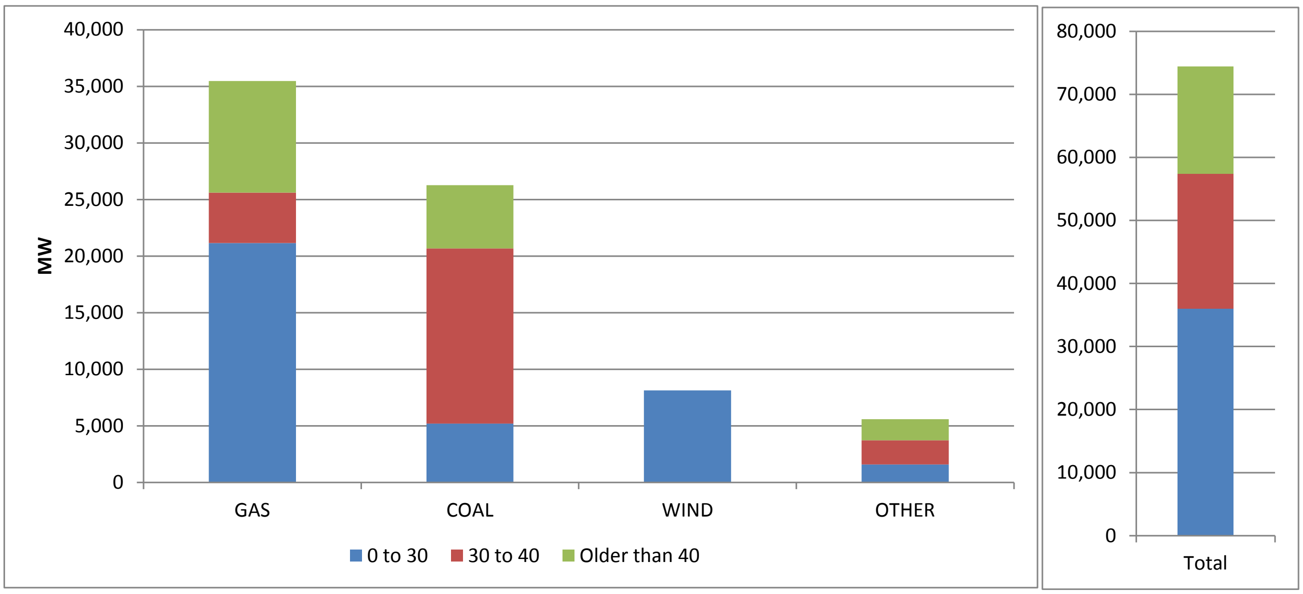
Figure I.7 Capacity Additions Detail



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



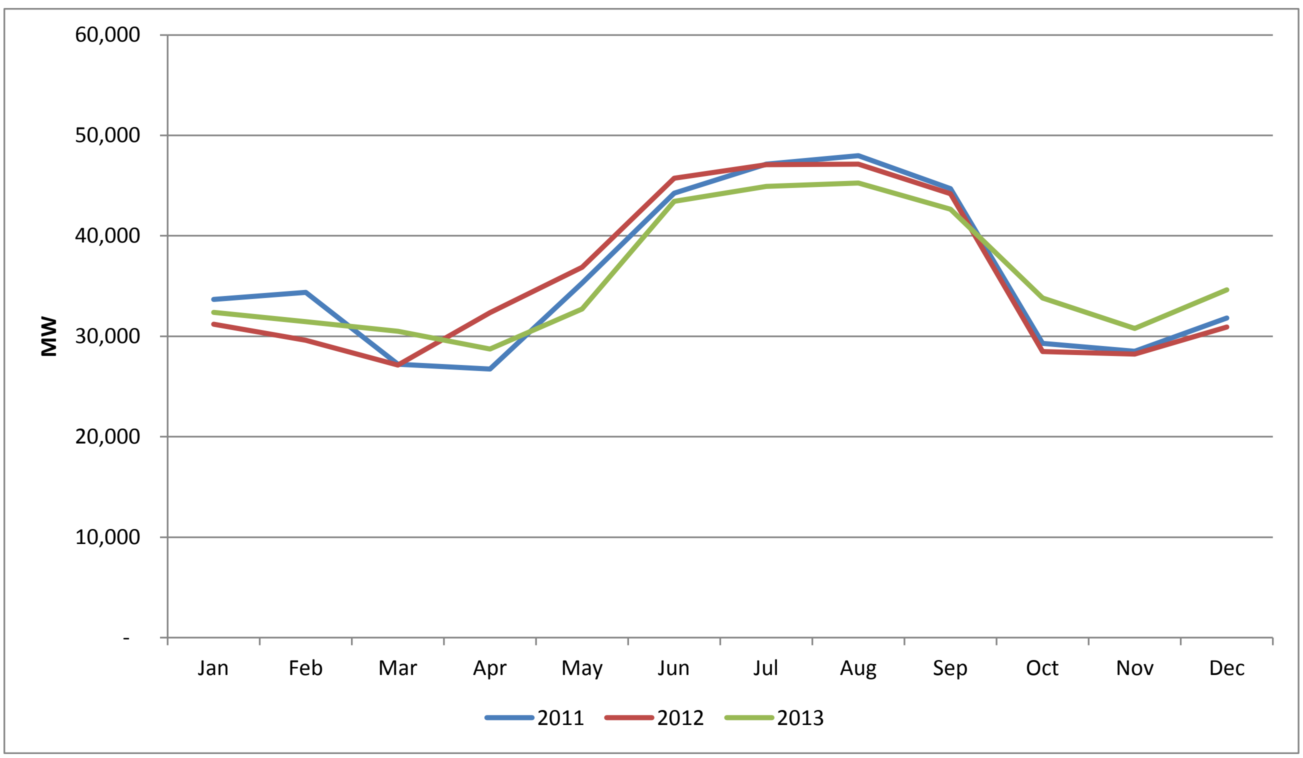
C. Electricity Demand and Energy in SPP

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

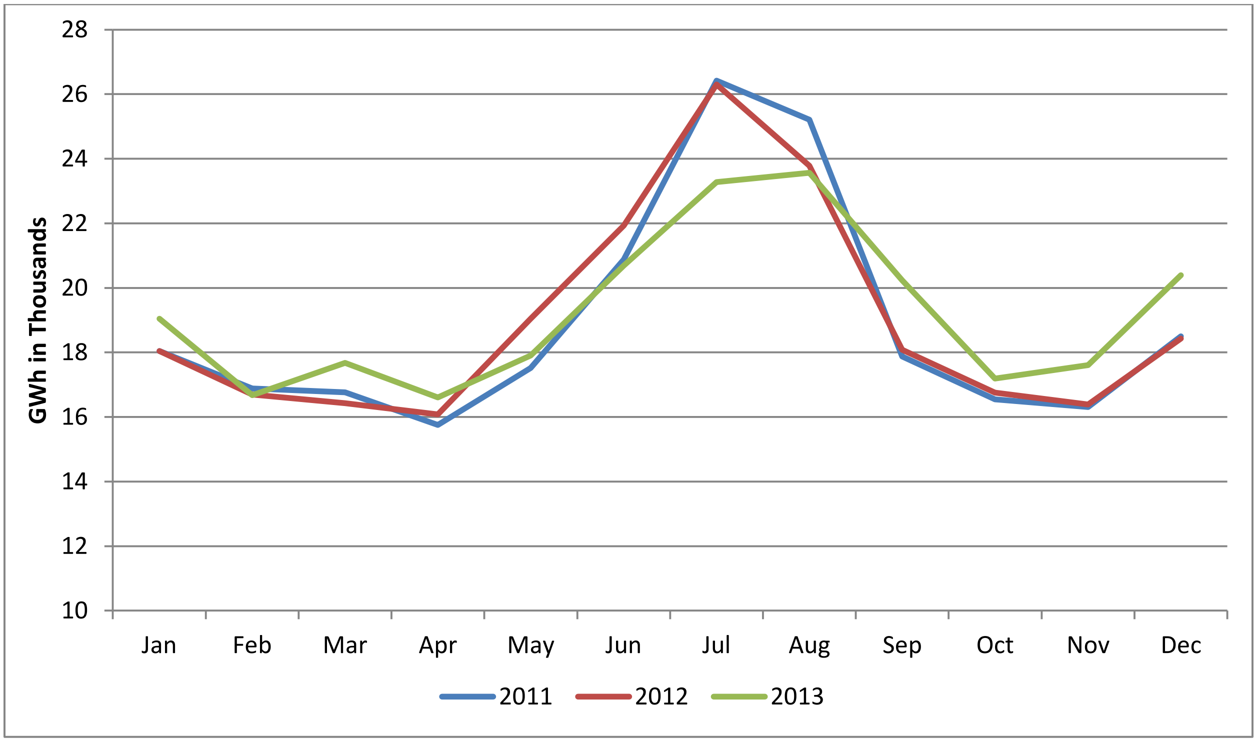
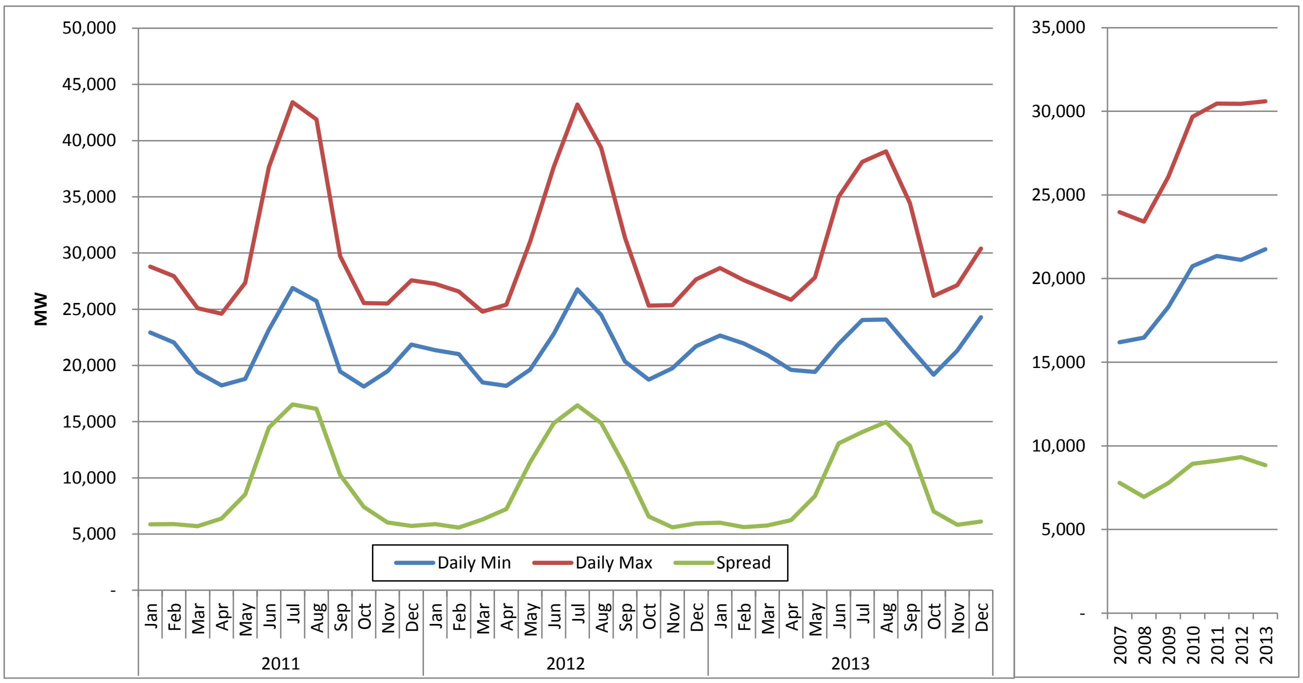


Figure I.12 presents the average minimum and maximum daily demand for each month for 2011 through 2013. Minimum and maximum daily peak values for 2013 were both higher than in 2012. The difference between the minimum and maximum daily demand decreased by 5% from 2012 to 2013.

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

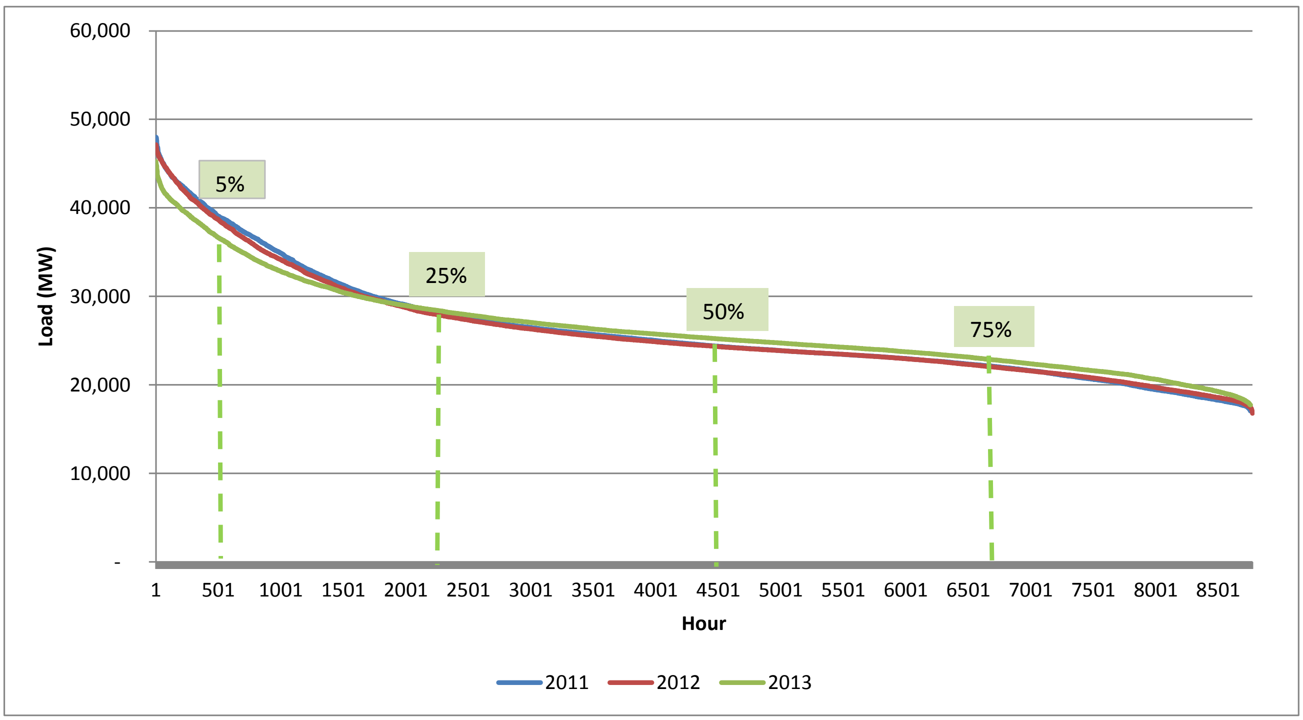


Load Duration Curve

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



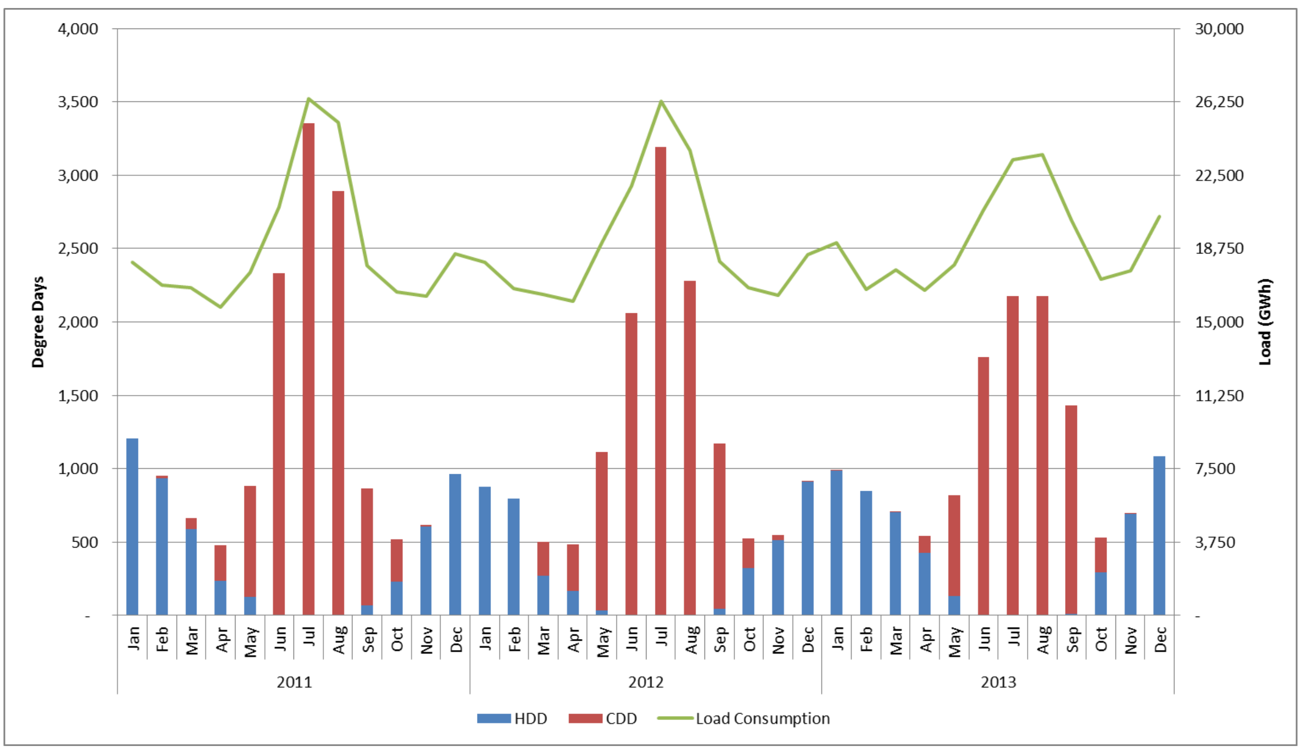
Heating and Cooling Degree Days

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

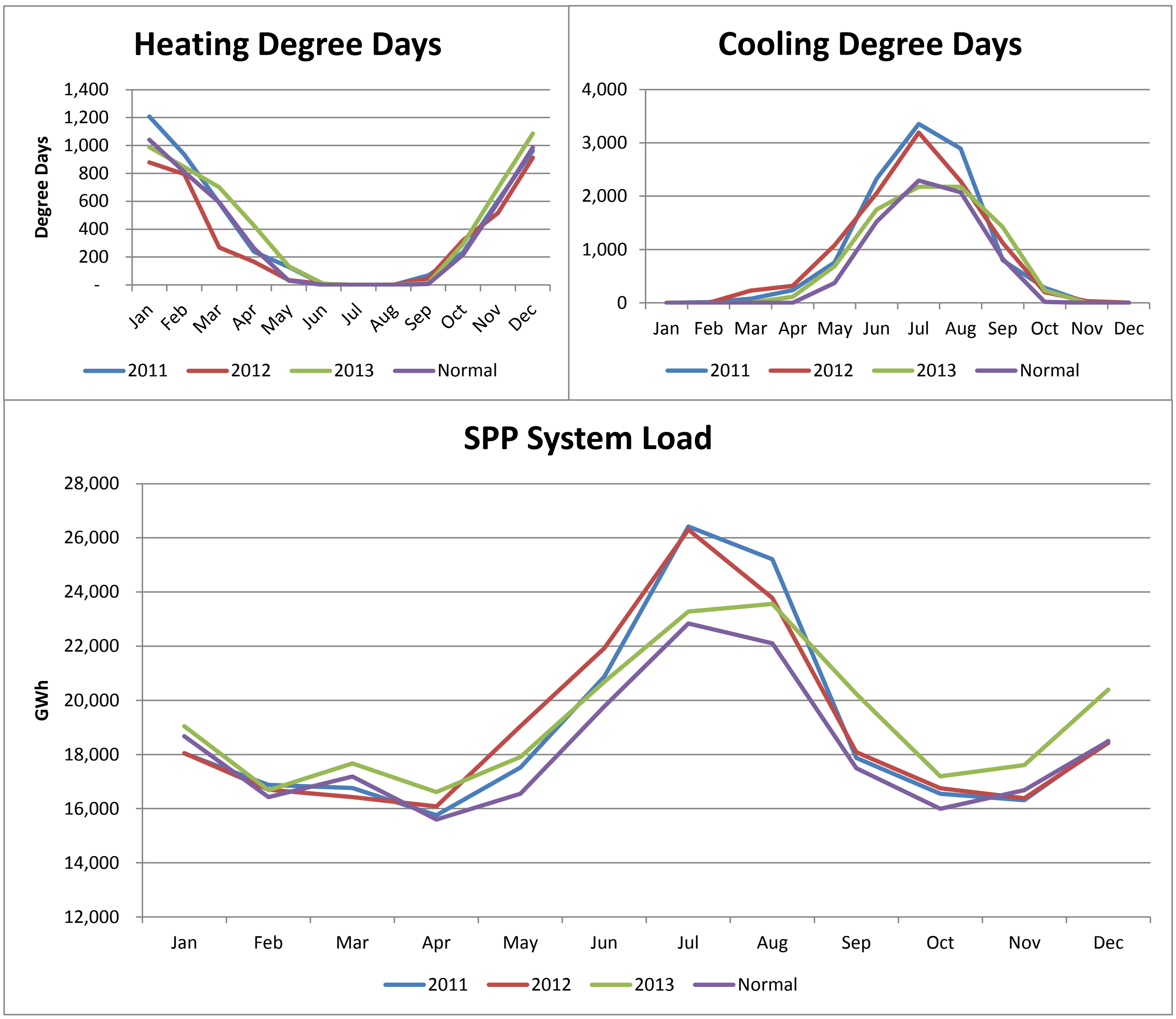


[3] Amarillo TX, Topeka KS, Oklahoma City OK, Tulsa OK and Lincoln NE.
[4] Daily average temperature is calculated as the average of the daily lowest and highest temperatures. The source of the temperature is NOAA.

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

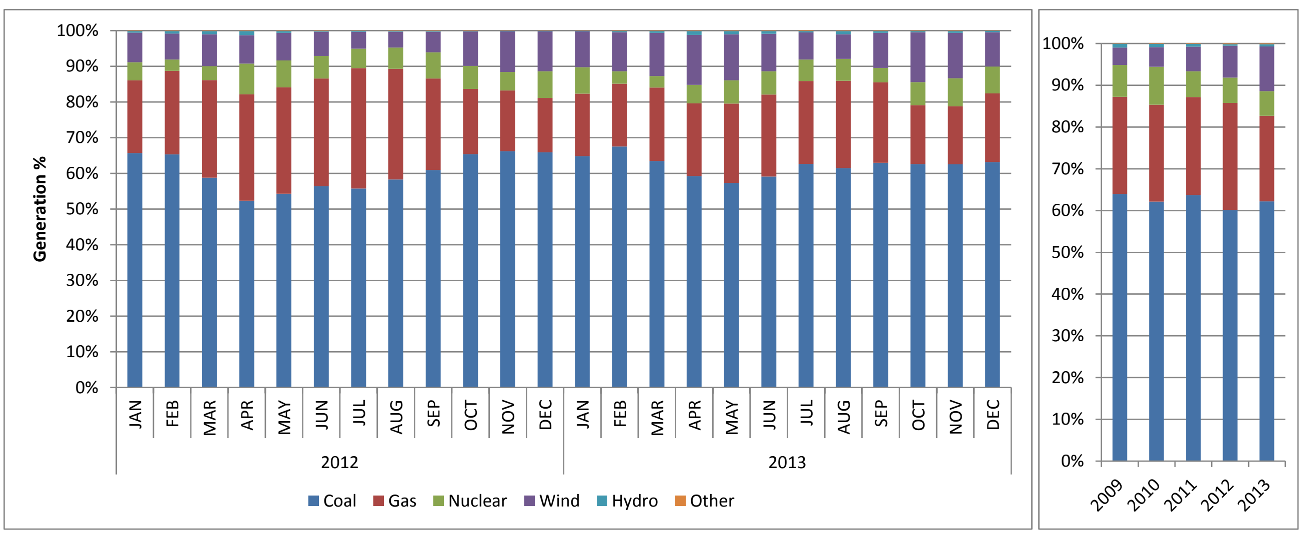
Generation by Fuel Type

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



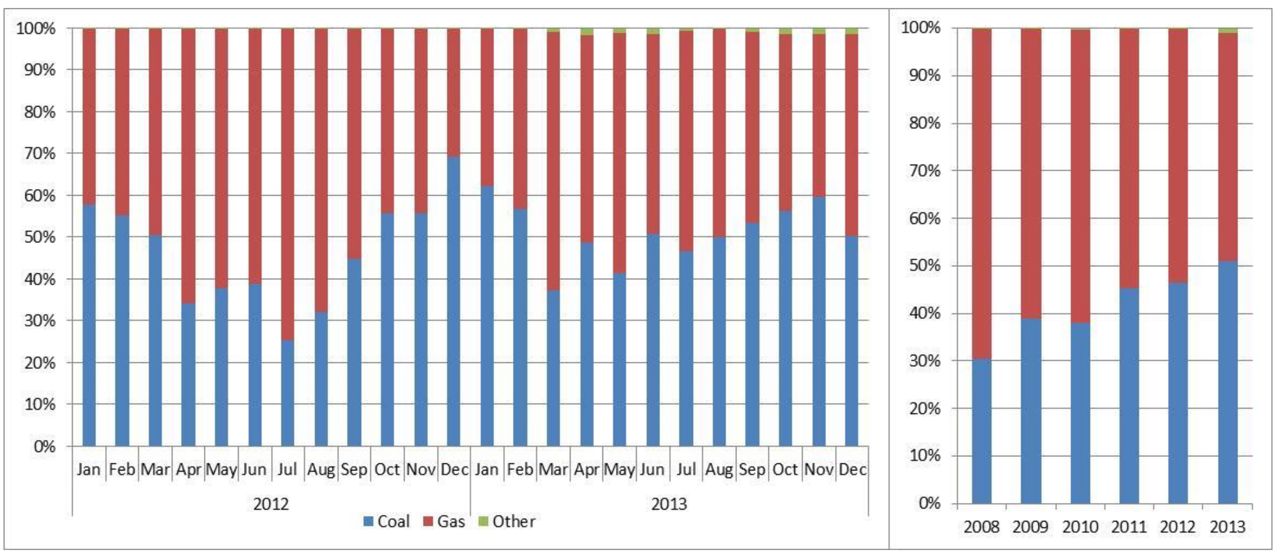
[5] "Other" category includes oil and solar.

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



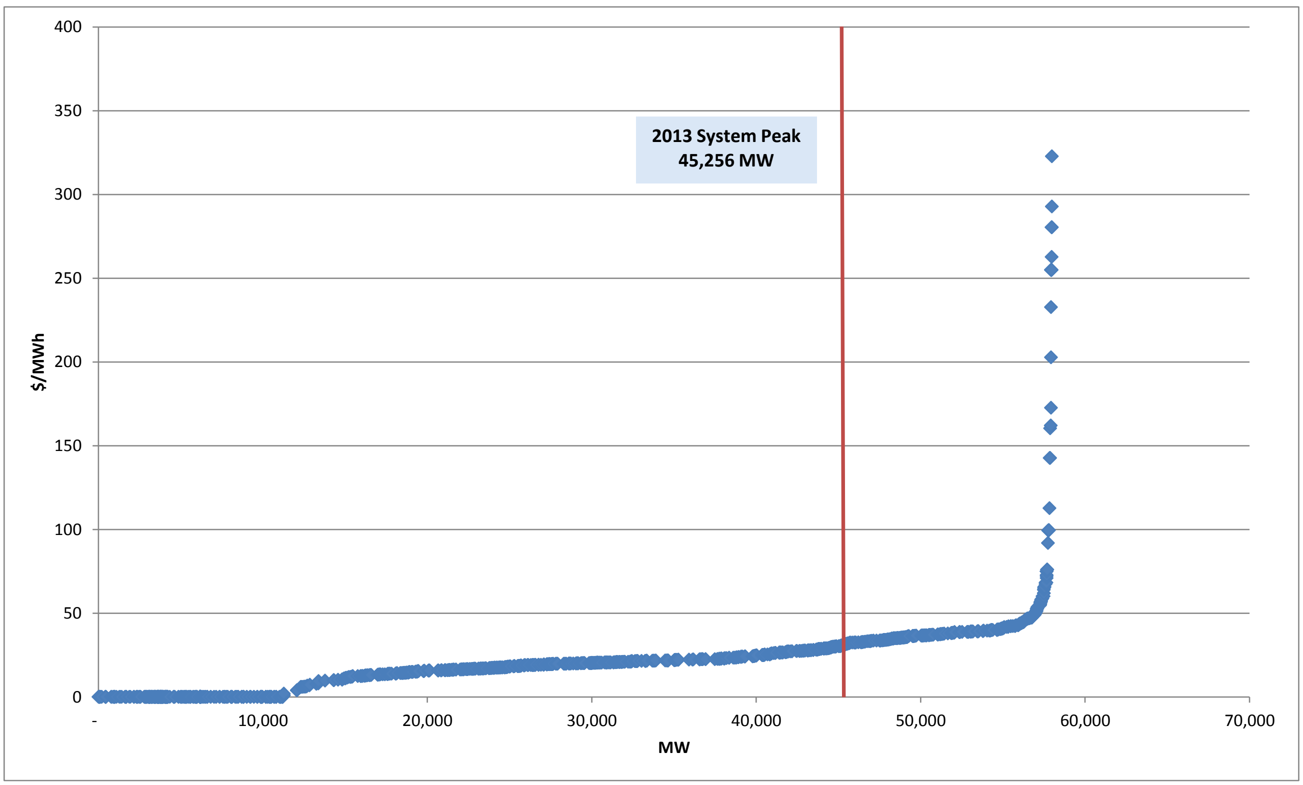
Typically, coal is on the margin more often in low load months, while gas is on the margin more often in high load months. Natural gas units in the SPP region are normally used for load following, and historically been on the margin more than coal. During 2013, percentage of natural gas on the margin 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

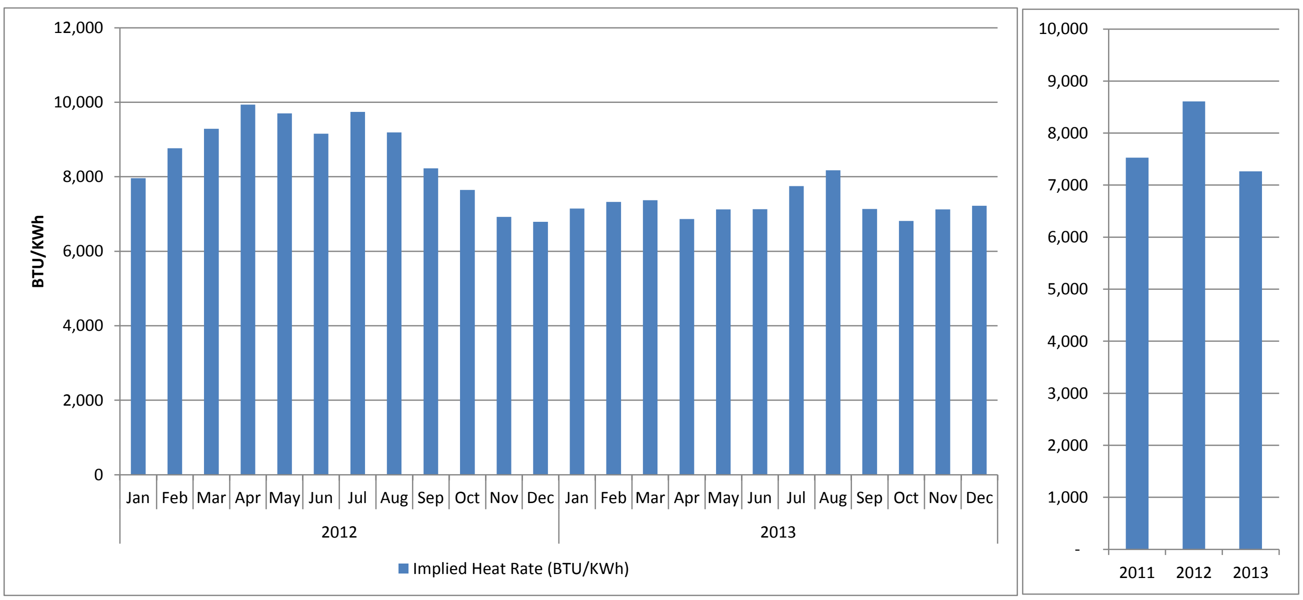


Implied Heat Rate

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

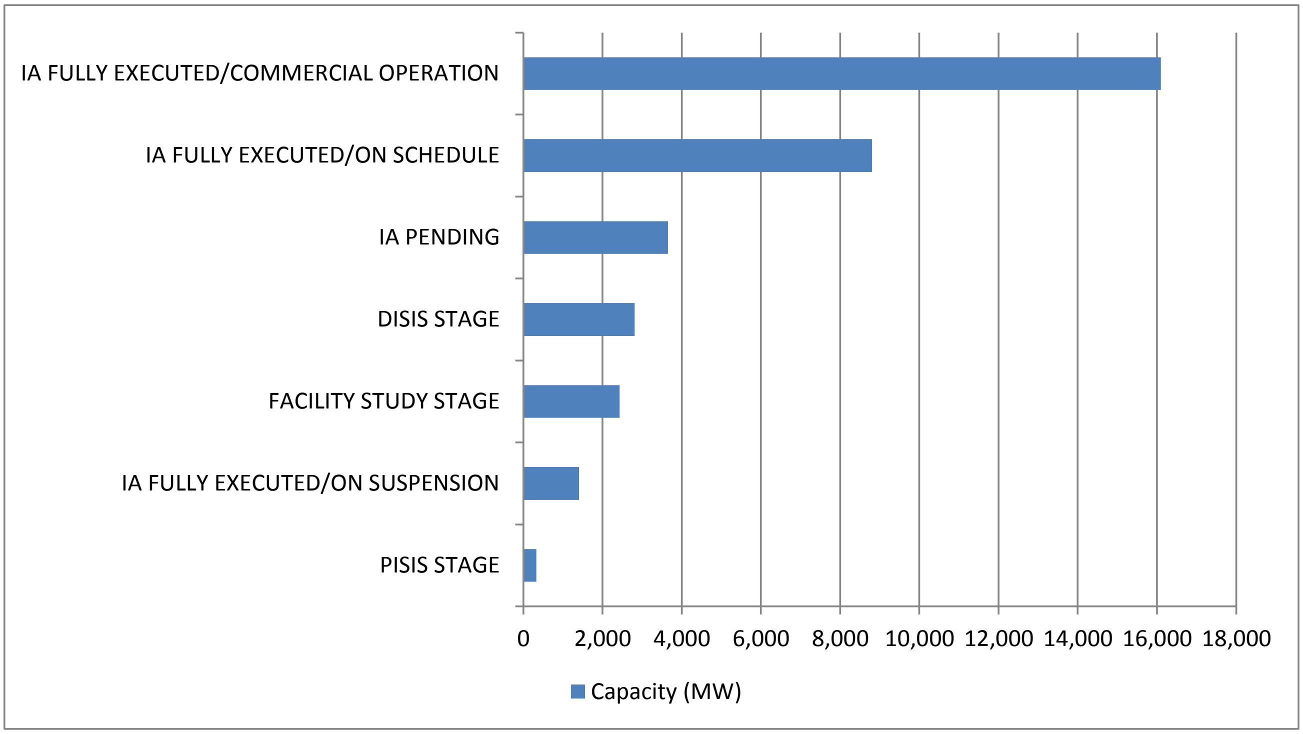
SPP is responsible for performing engineering studies to determine if the interconnection of new generation within the SPP footprint is feasible and to identify any transmission development that would be necessary to facilitate the proposed generation. Types of engineering studies include:

- 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)



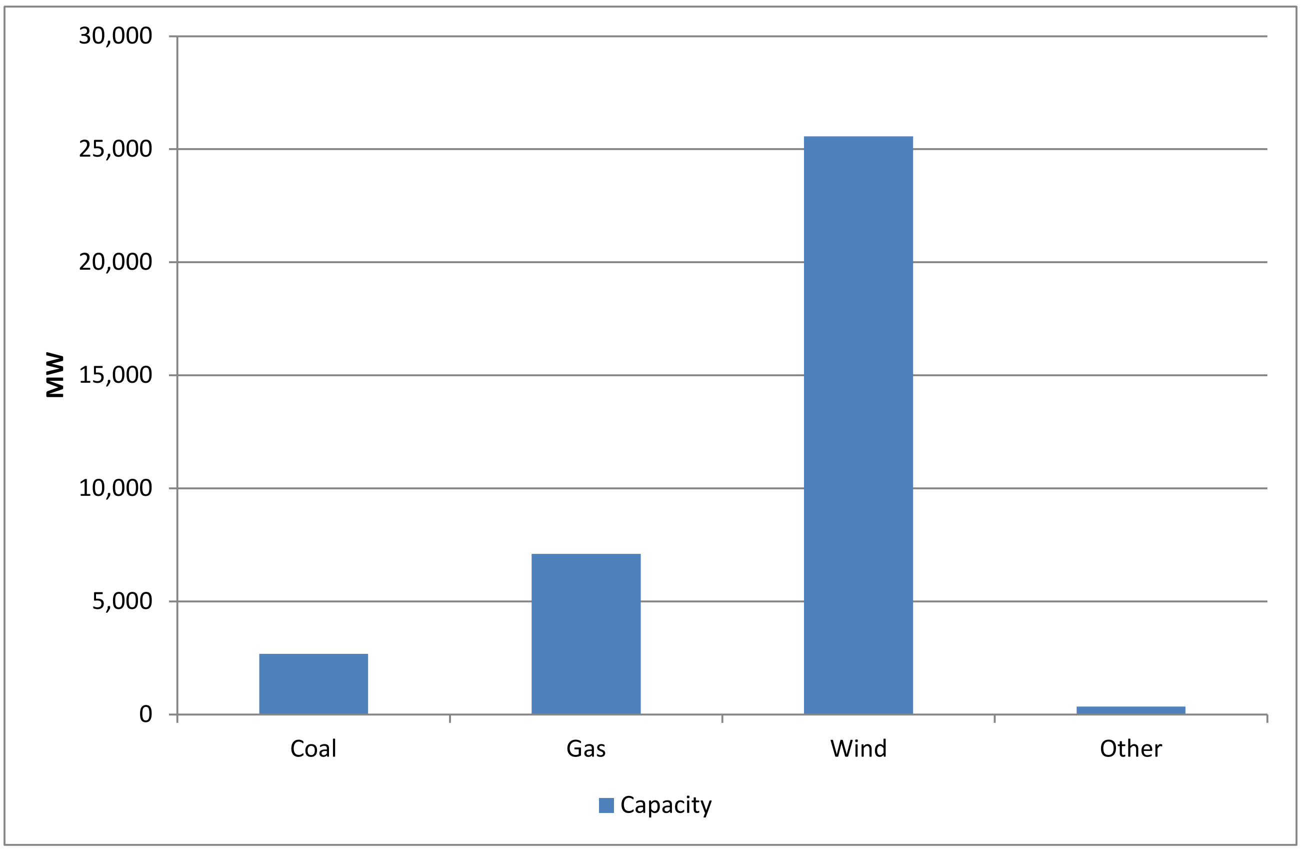
A brief description of the study types and interconnection categories is provided below.

- 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

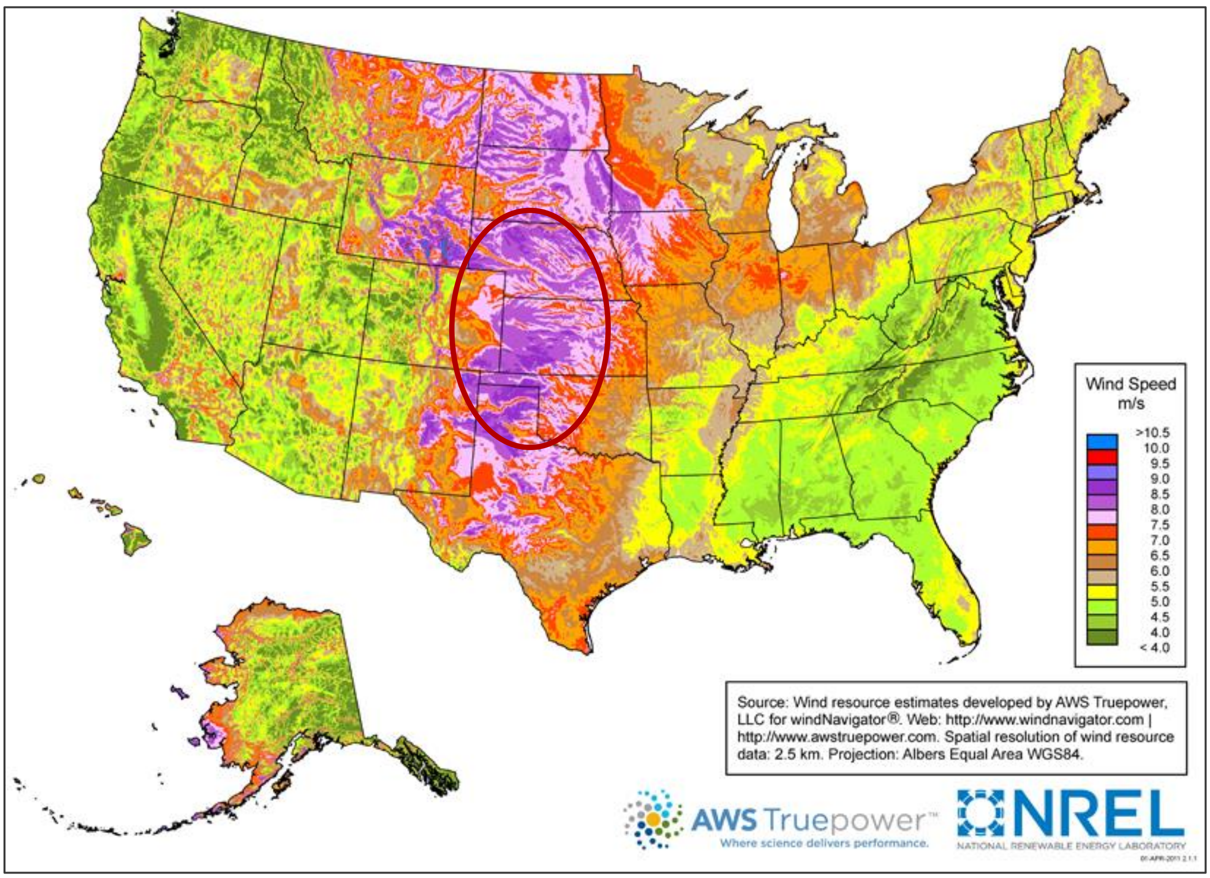


Figure I.23 depicts monthly capacity and total generation from wind facilities for the previous two years and annual values for the last five years. Total registered wind capacity at the end of 2013 was 8,405 MW, an 8% increase from 2012. Wind generation continues to increase but lags capacity added 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

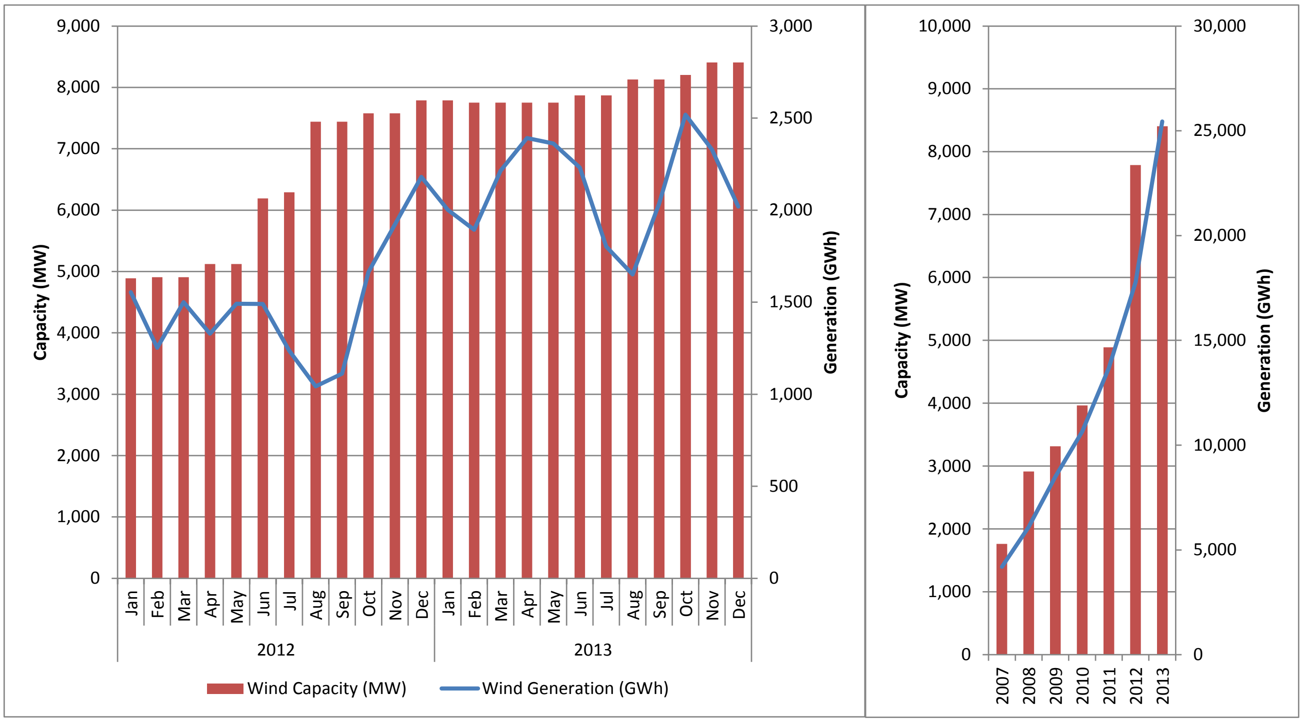
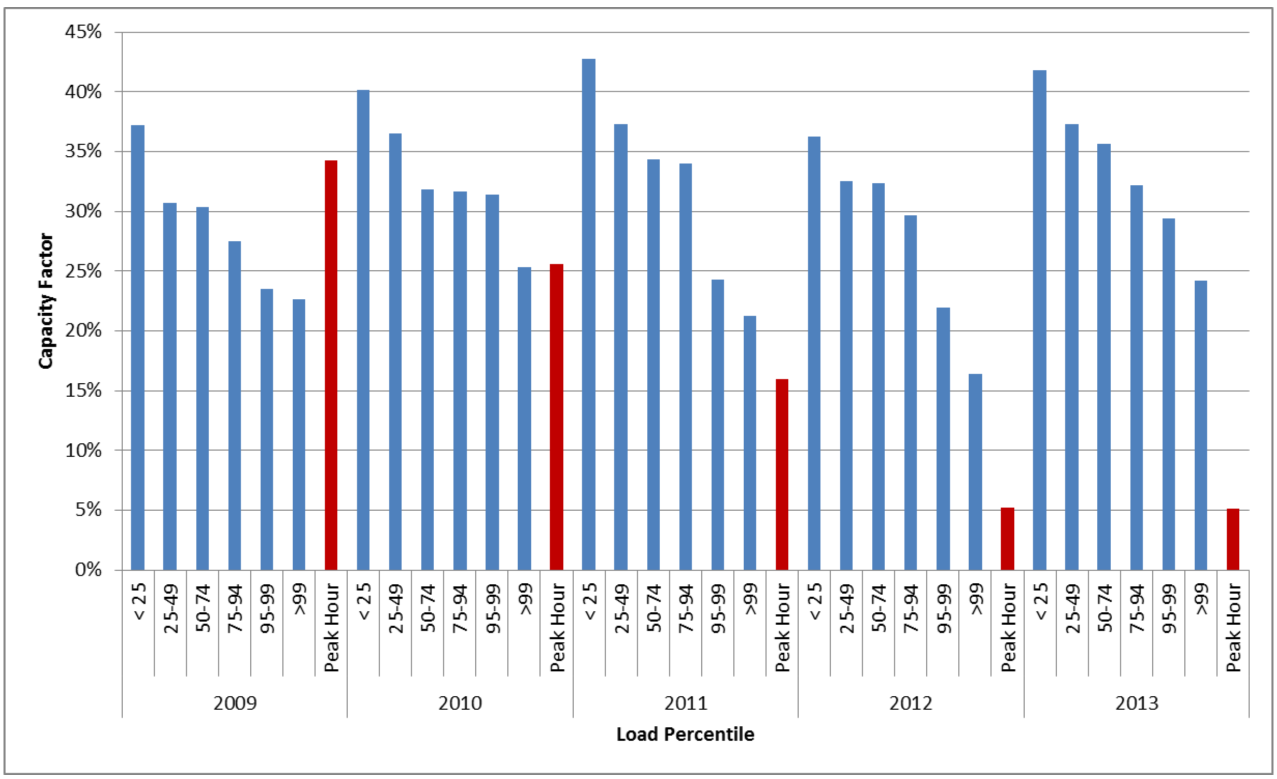


Figure I.24 compares the wind capacity factor to load percentiles. Capacity factor is a ratio of the actual to potential output of generators over a period of time. The potential output is assumed to be the maximum at full nameplate capacity for the entire time period in question. SPP area is similar 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**

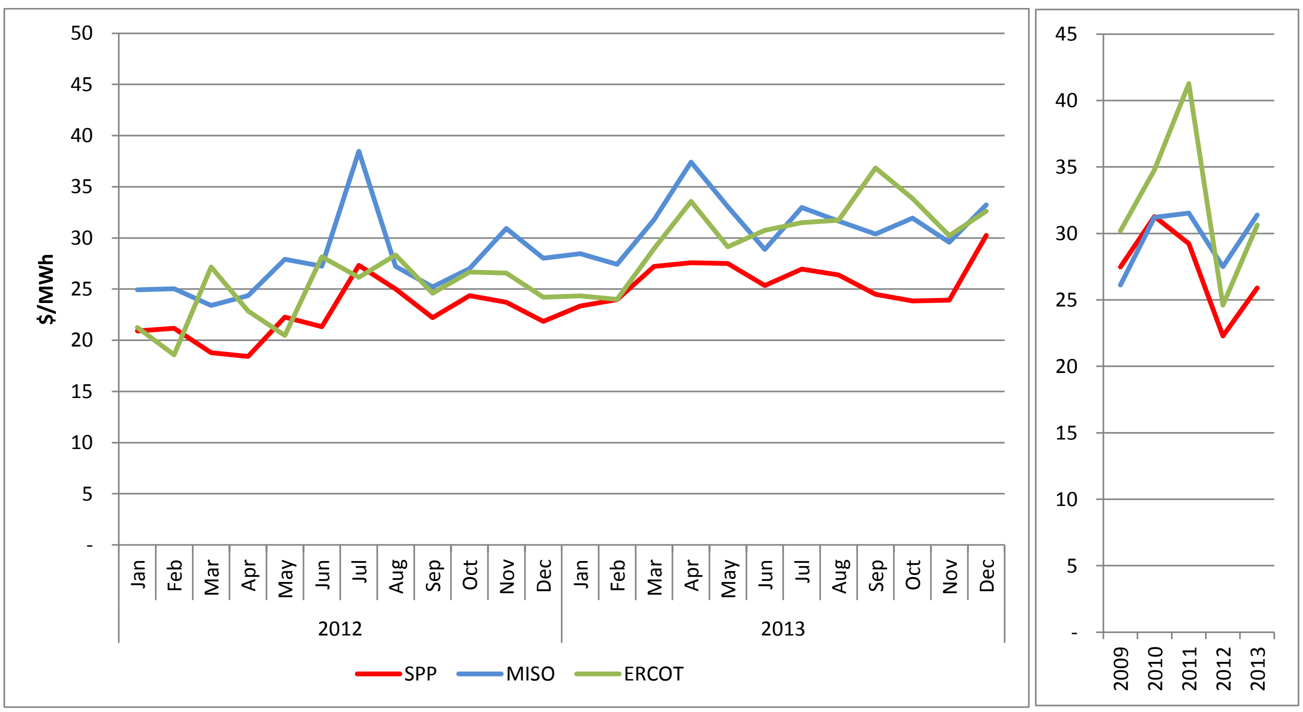
C. Market Prices

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

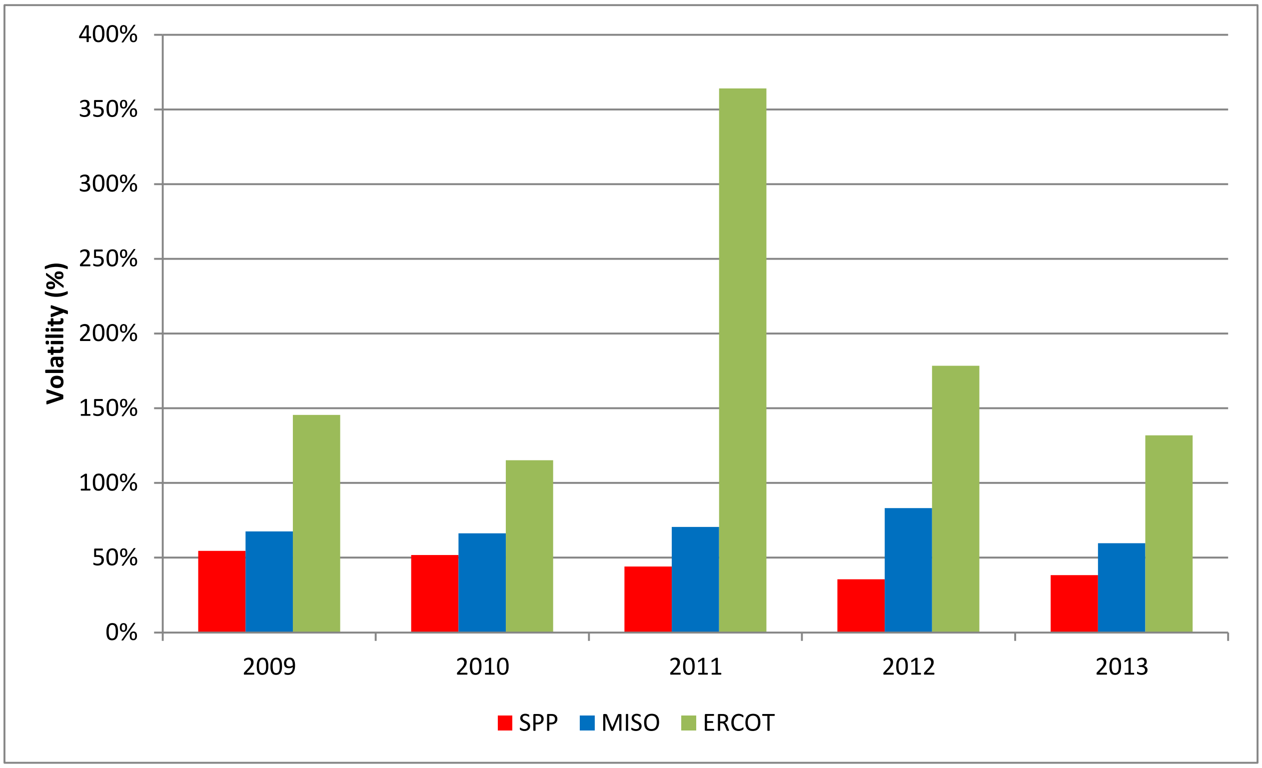


Another useful means of comparing prices across regions is to review overall price stability. The volatility shown in Figure II.4 represents the average volatility for the system-wide hourly prices.

[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

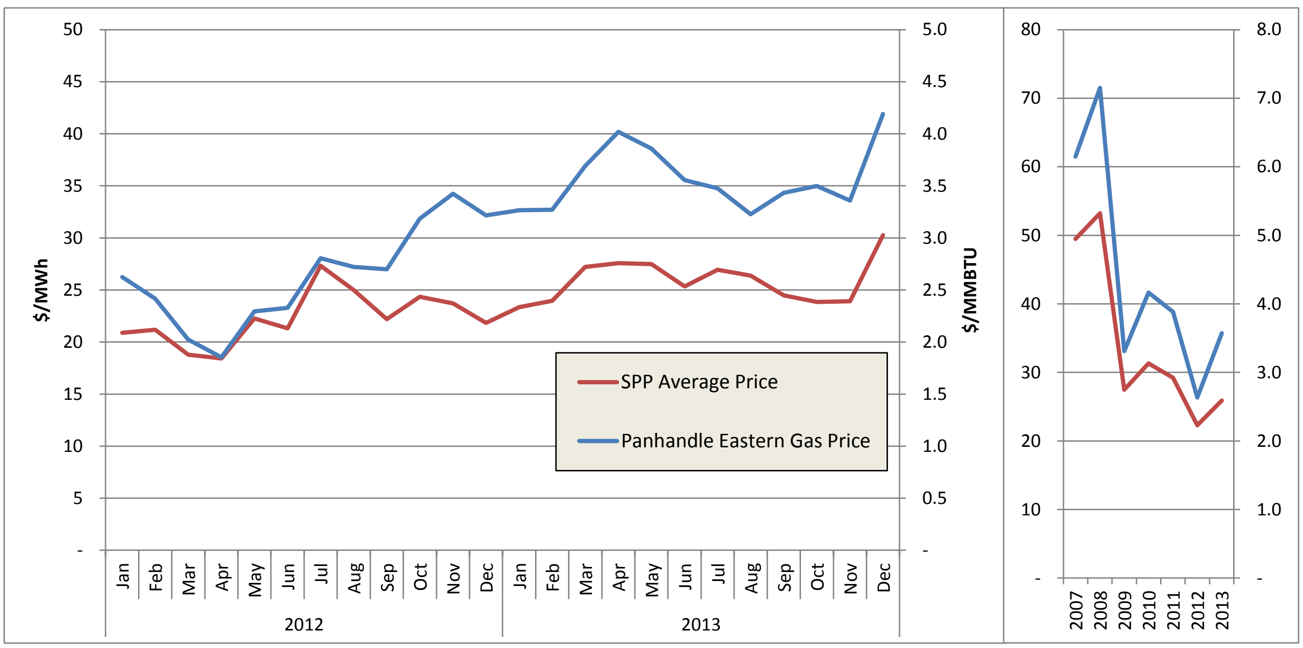


Electric and Natural Gas Price Comparison

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.

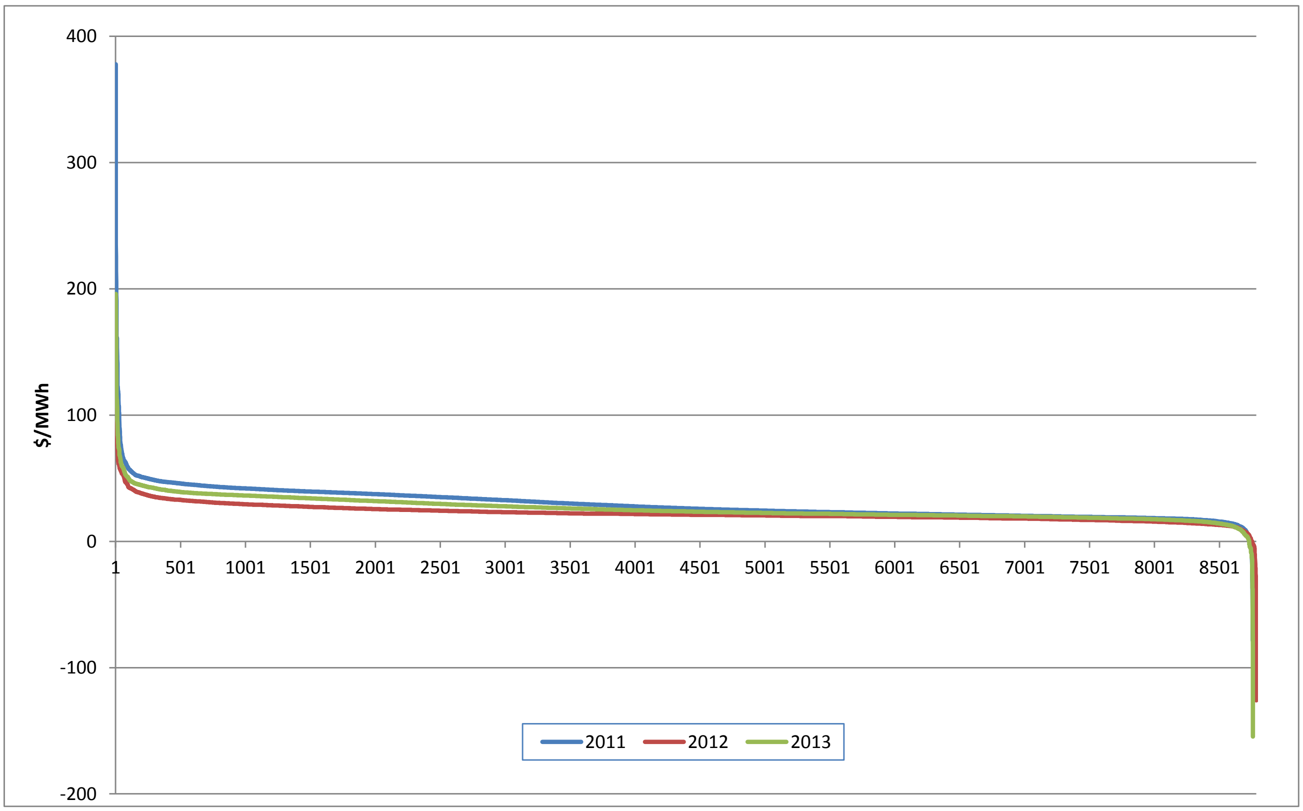
Figure II.5 Comparison of Average Monthly SPP Prices and Panhandle Natural Gas Prices



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

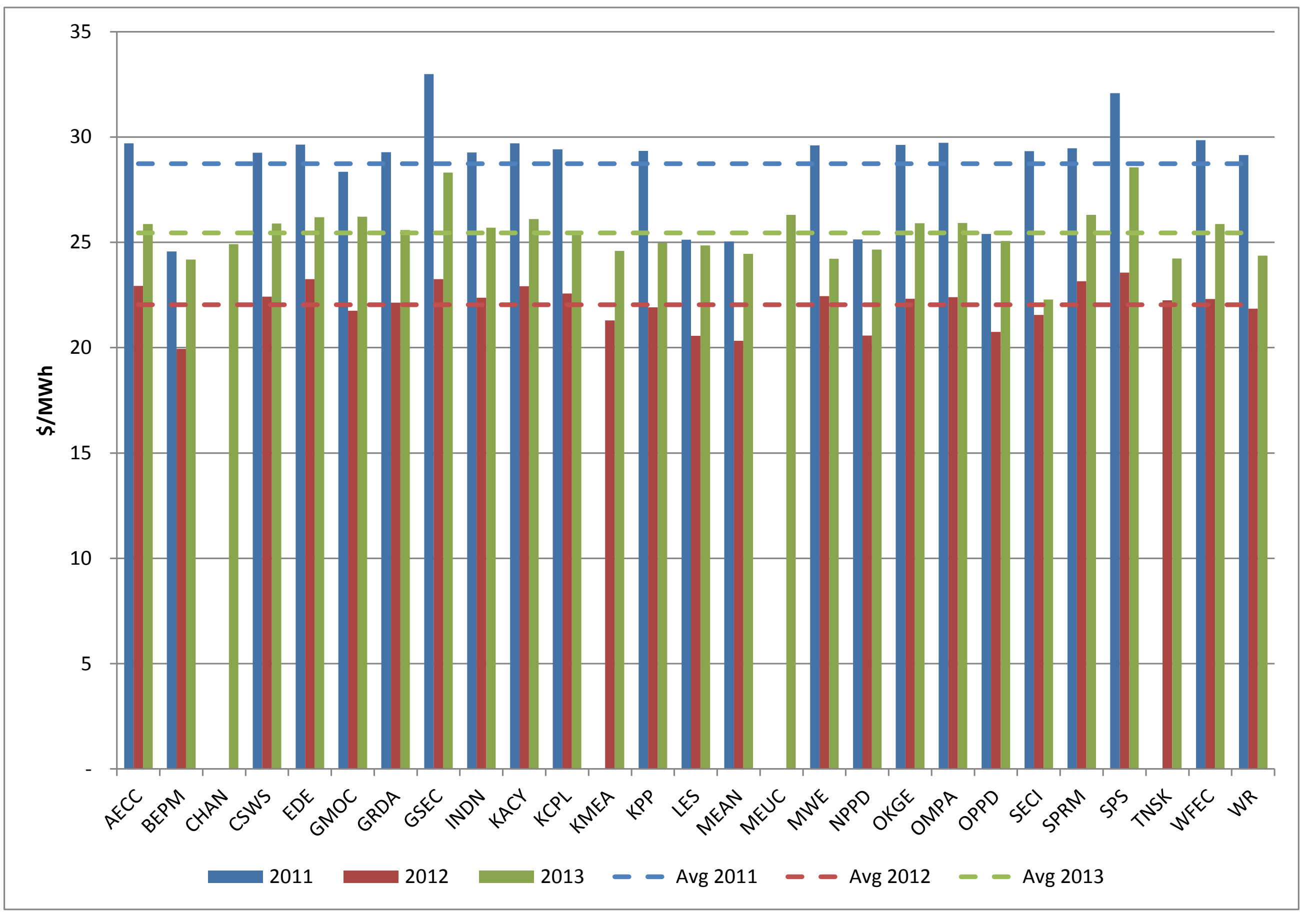


Market Participant Price Comparisons

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

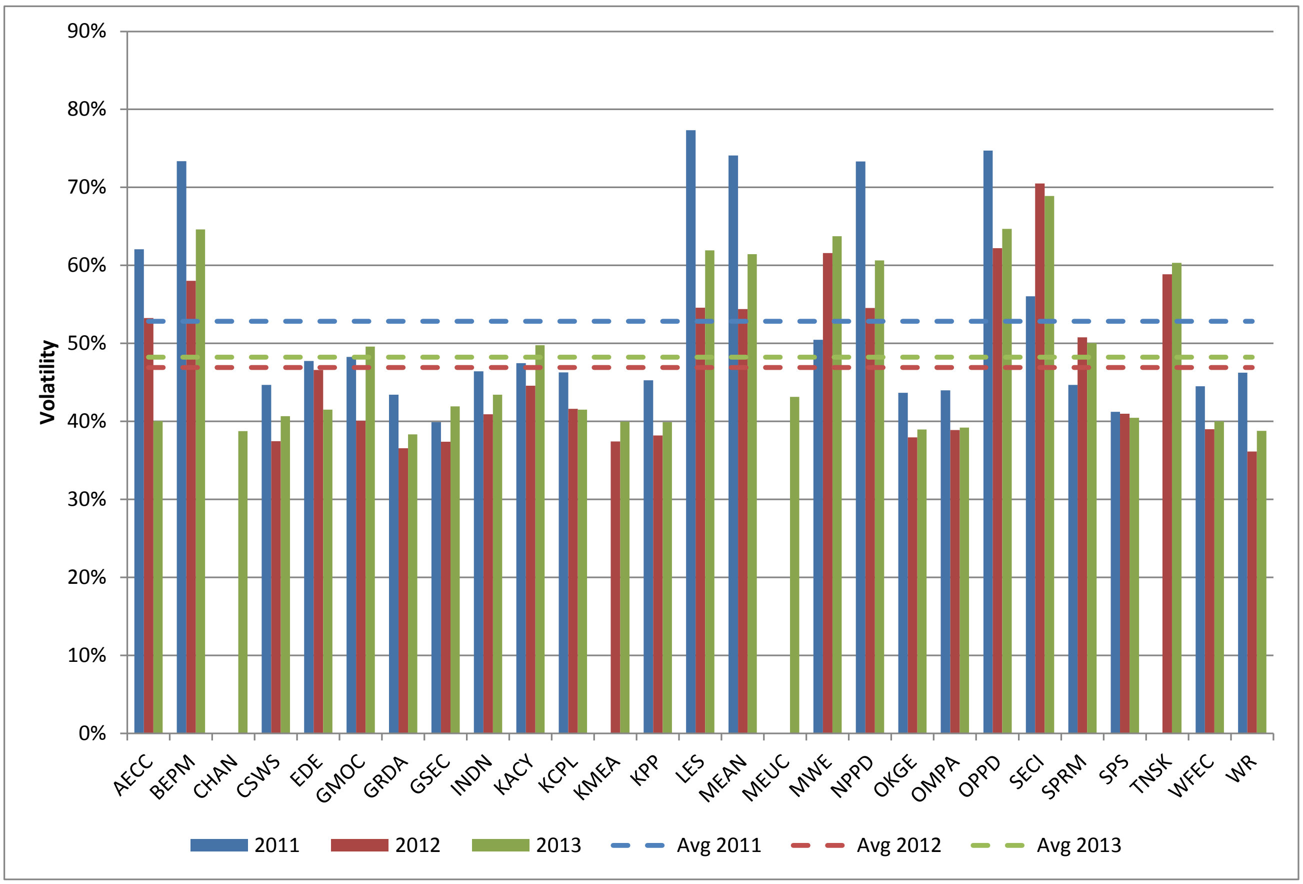


Price Volatility

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

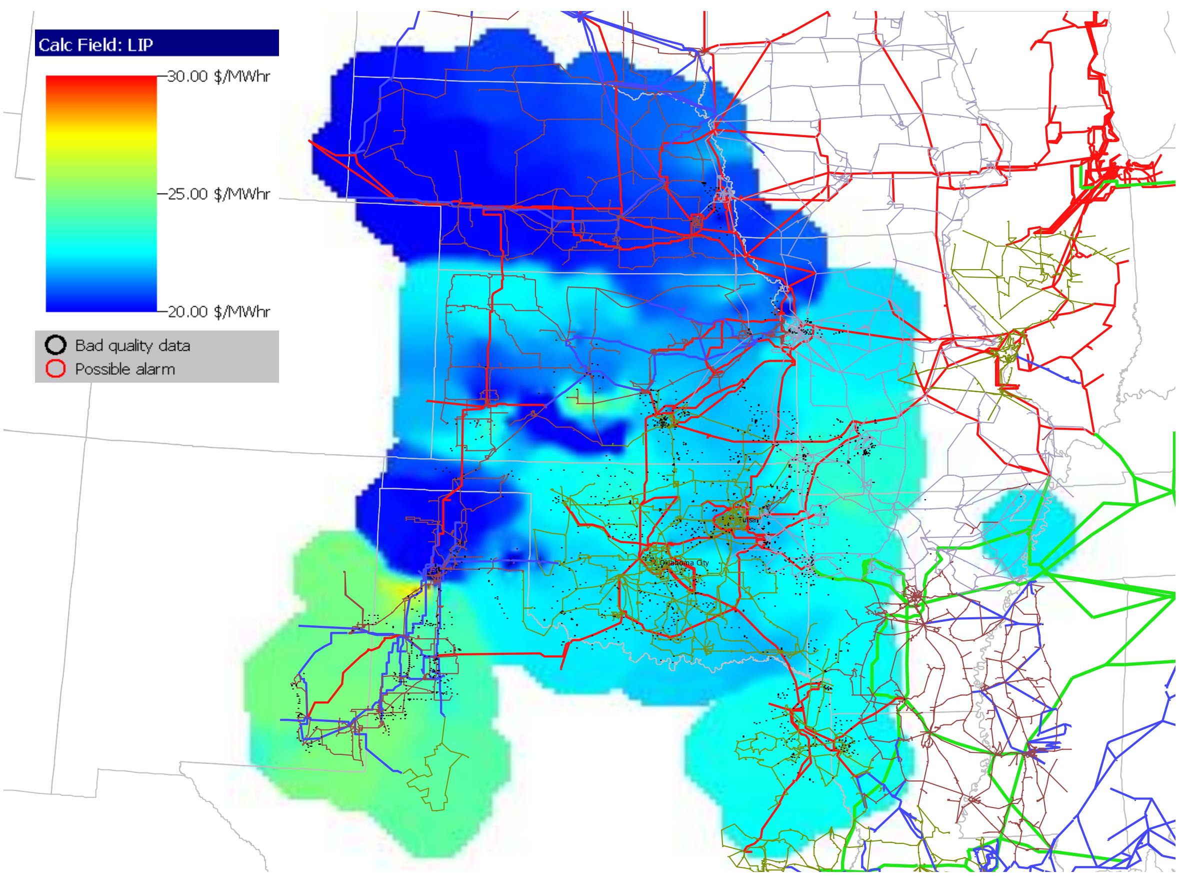
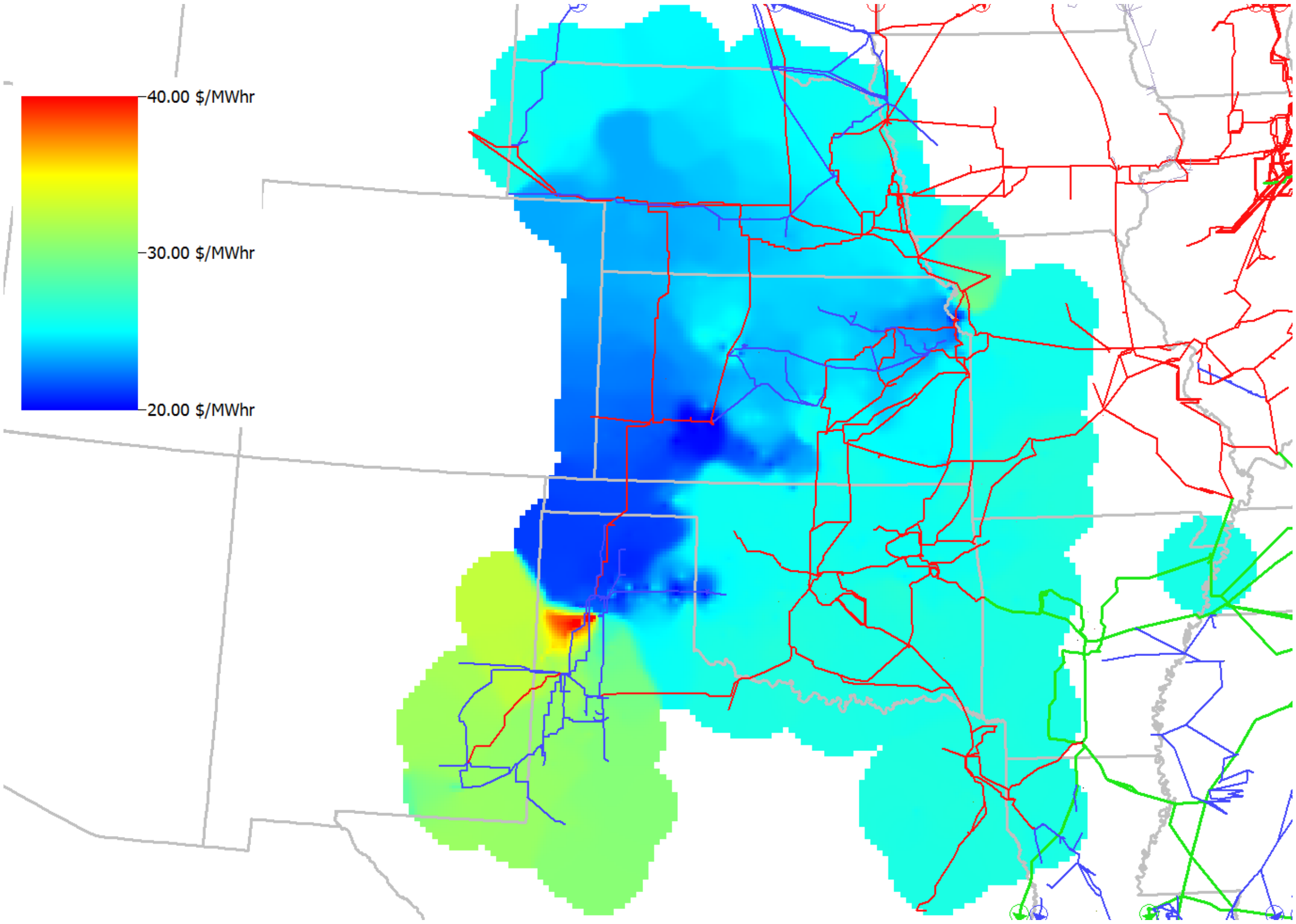


Figure II.11 Price Contour Map for 2013



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.

<u>Over scheduling</u> 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. <u>Under scheduling</u> 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.

<u>Uninstructed Deviation (UD)</u> 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.

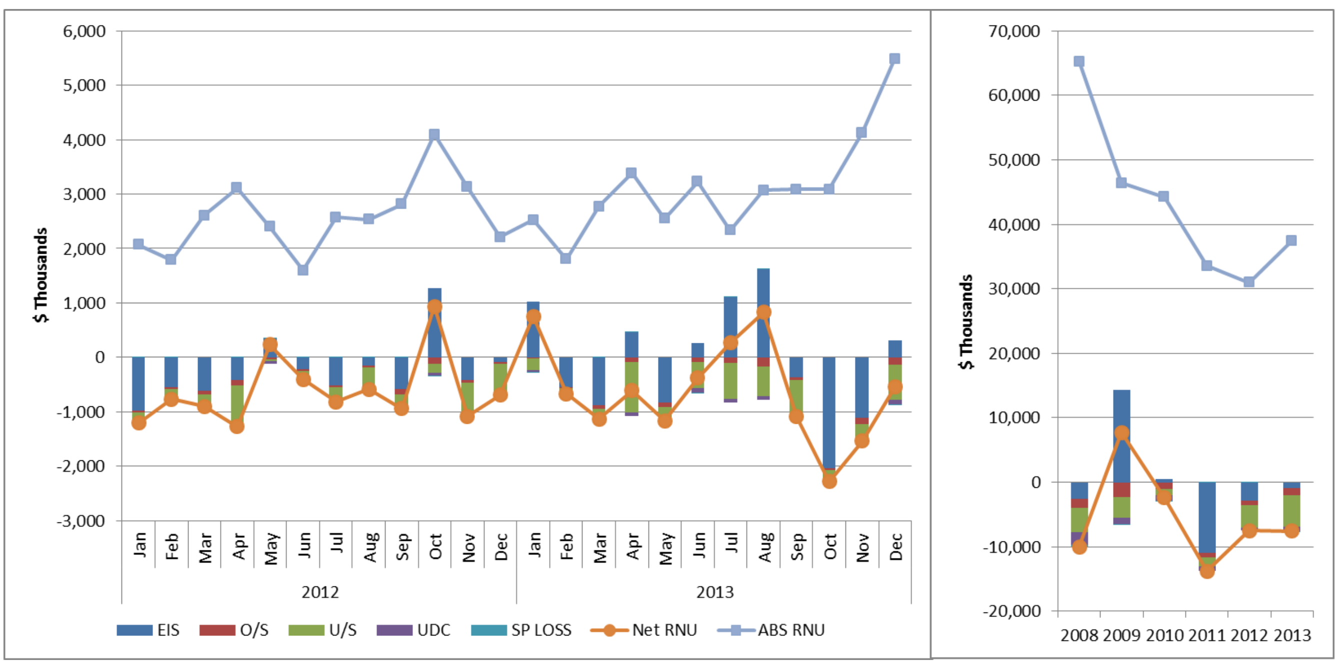
Deviation outside the total allowable deviation range is charged against the Market Participant. If the deviation is between zero and 25 MW, the charge is (MW deviation amount * LIP * 10%). If the deviation is greater than 25 MW, the charge is the sum of the previous calculation for 25 MW plus (deviation 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.

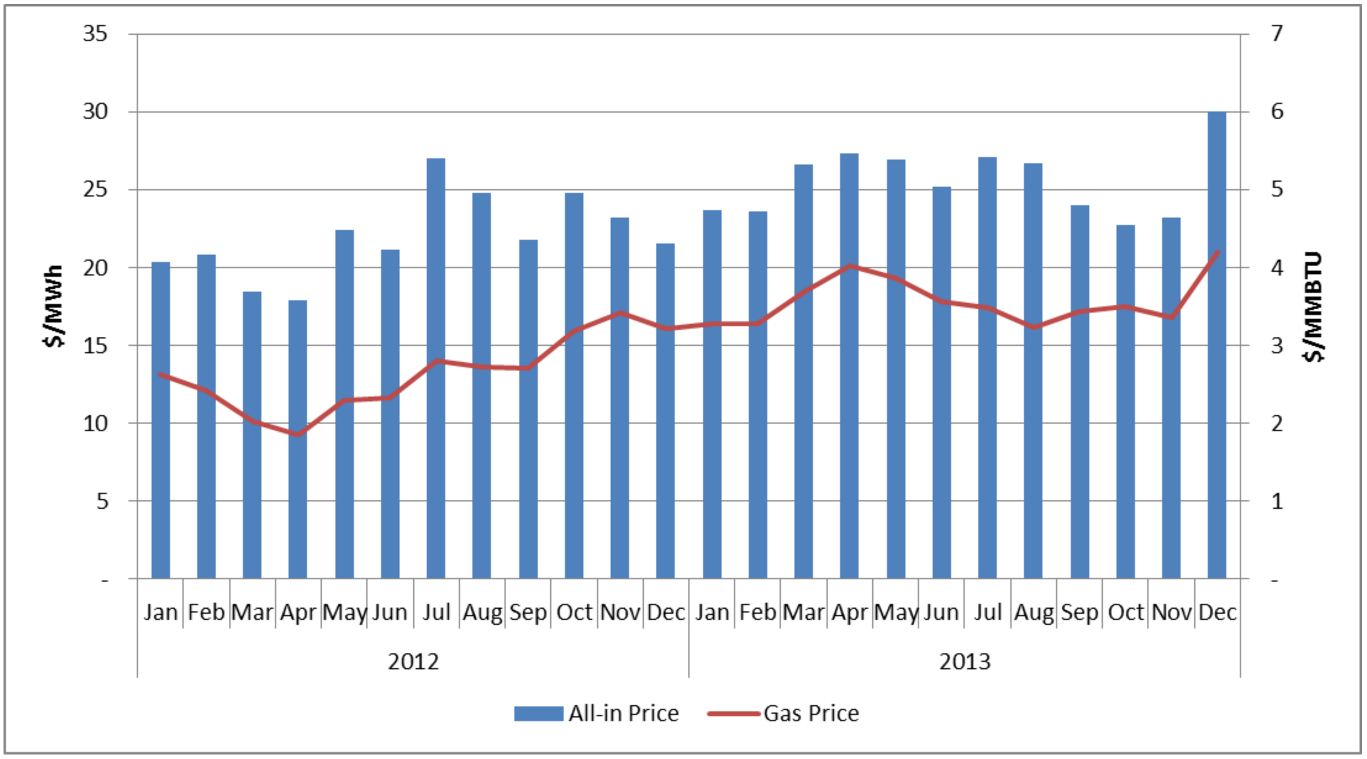
Figure II.12 Components of RNU by Month for 2012 and 2013



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.

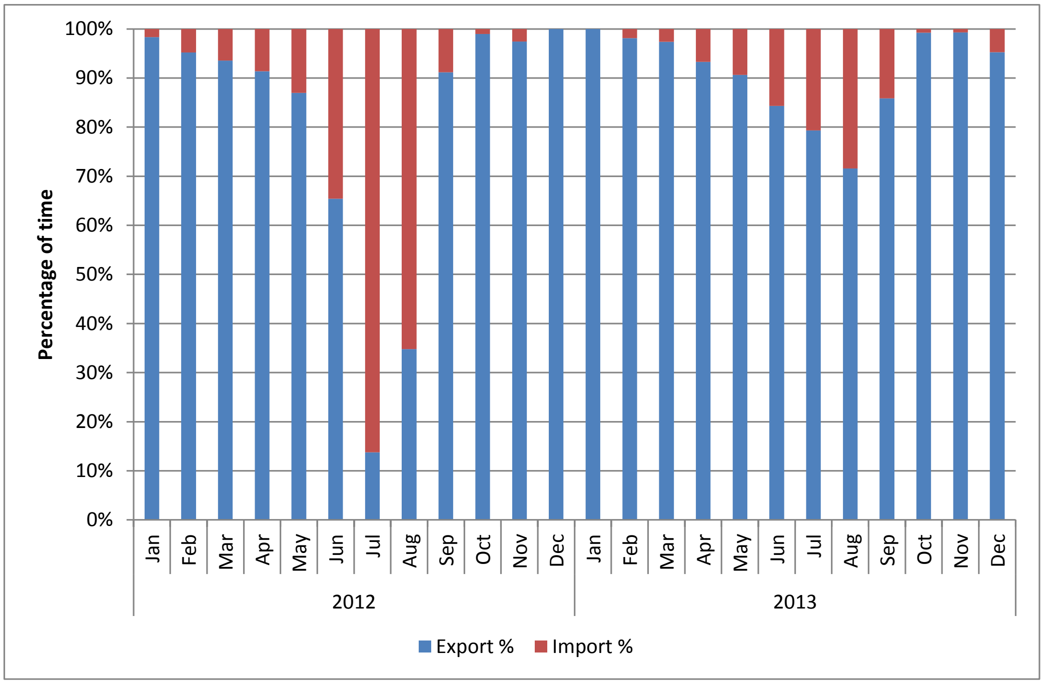
Figure II.16 Revenue Adequacy Results for Select Market Participants

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



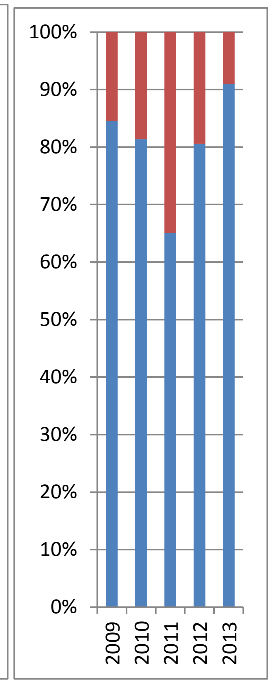
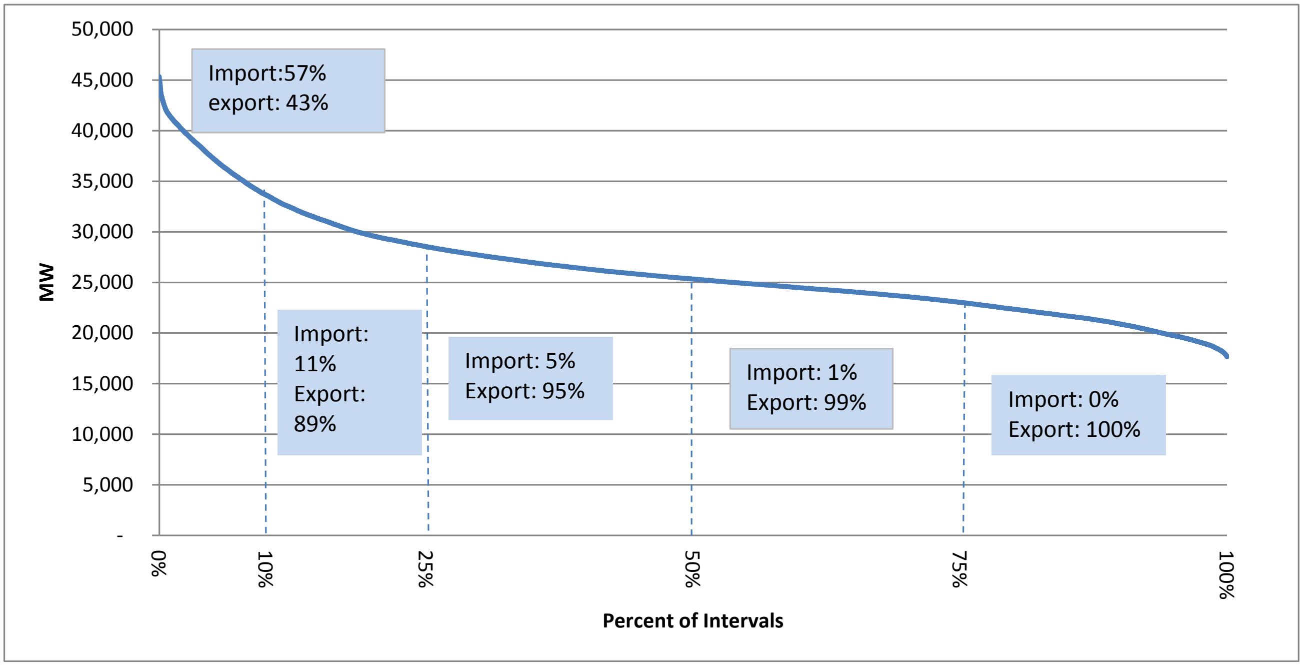


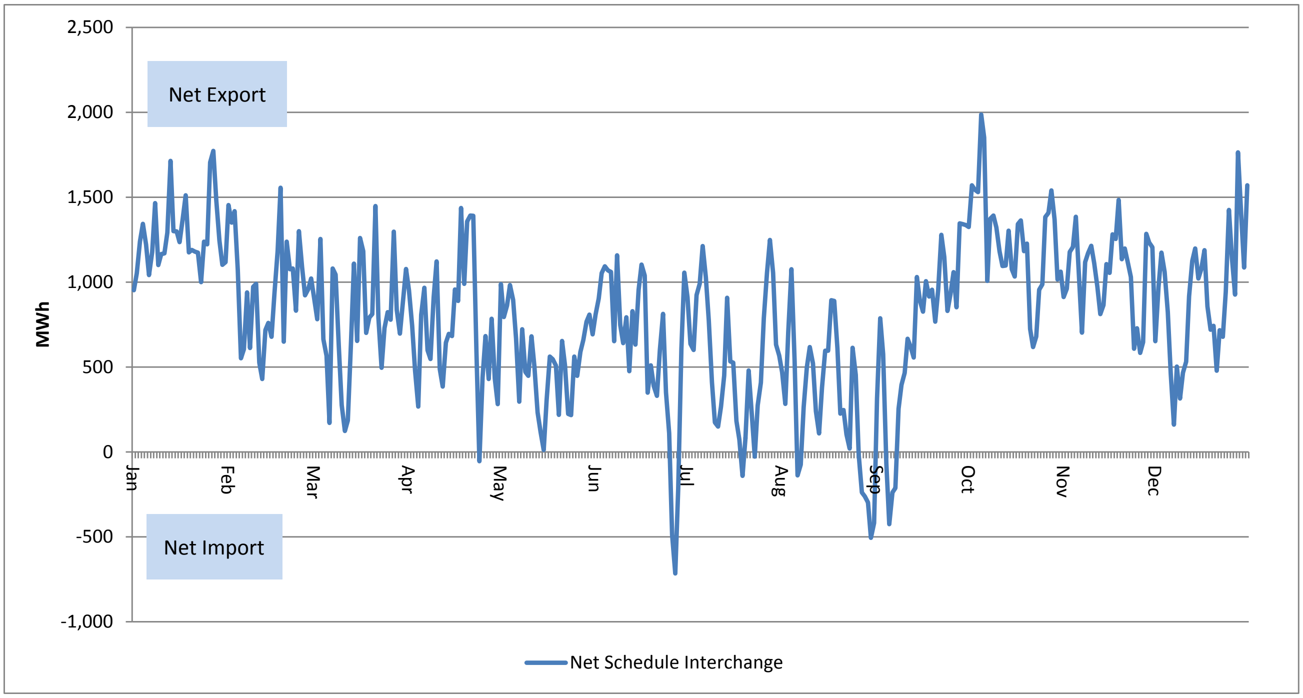
Figure II.18 is a load duration curve divided in quartiles with net exporter and importer percentages superimposed on the chart. During the highest 10% of load, SPP was a net importer 57% of the time, compared to 92% in 2012. As discussed before, summer load in 2013 was lower than 2012. The lower the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

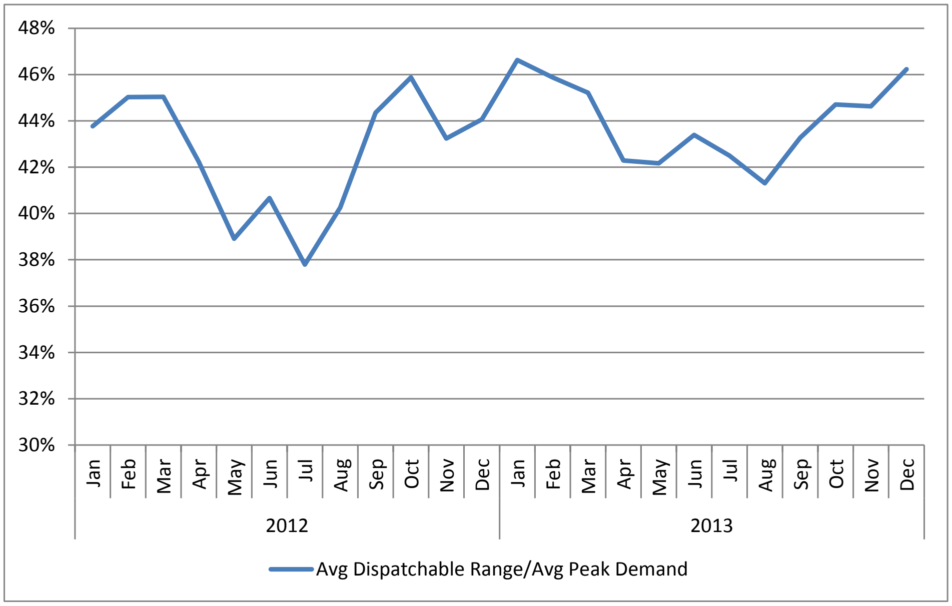
Settling imbalances in the EIS Market is mandatory and automatic. However, the level of participation in the SPP EIS Market is voluntary. Market Participants individually decide how to best manage their resources through appropriate scheduling, resource offers, and resource control parameters. Specifically, 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.

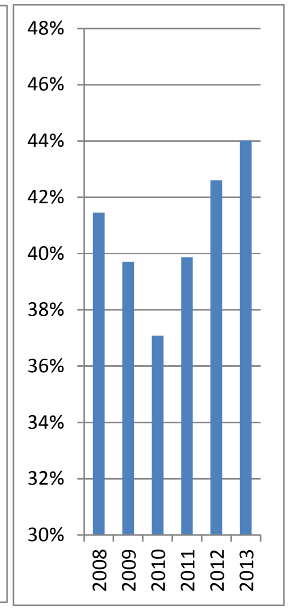
Dispatchable Range

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



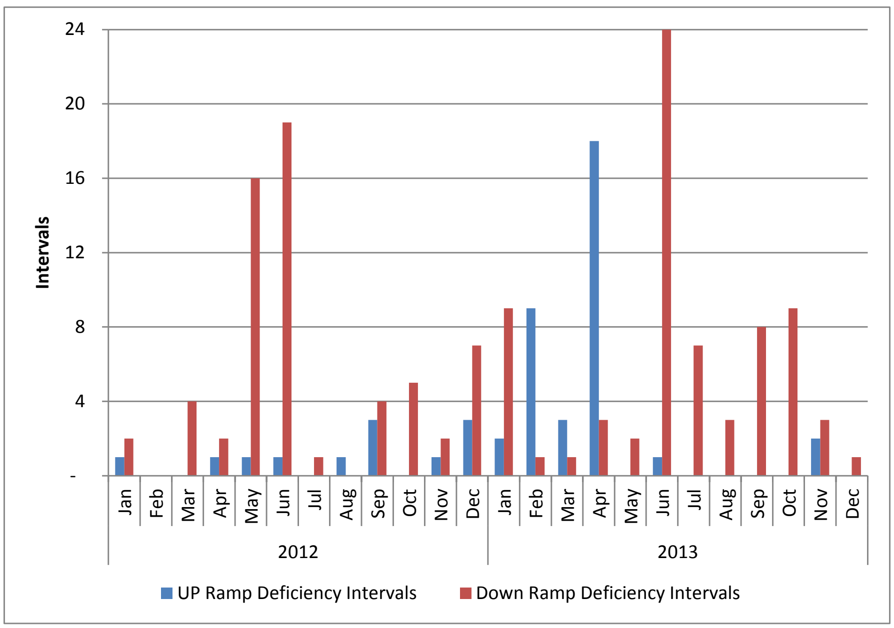


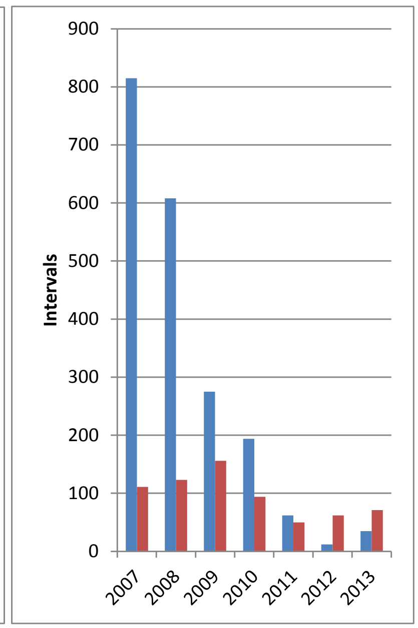
Ramp Rates

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

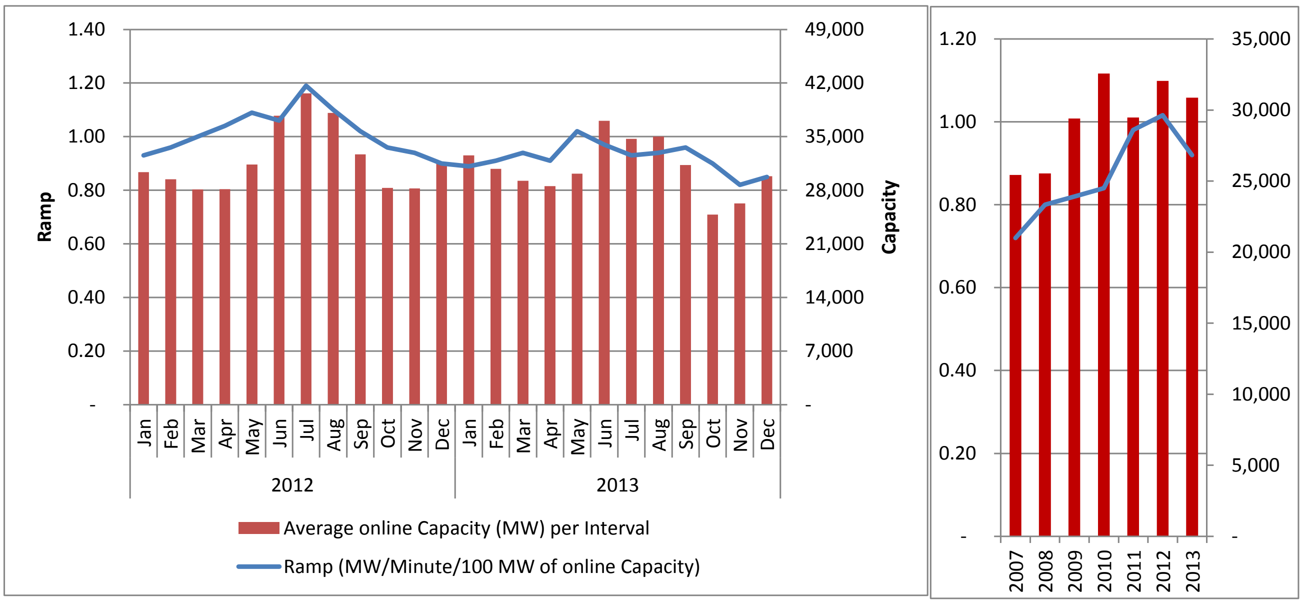




Ramp and Capacity

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

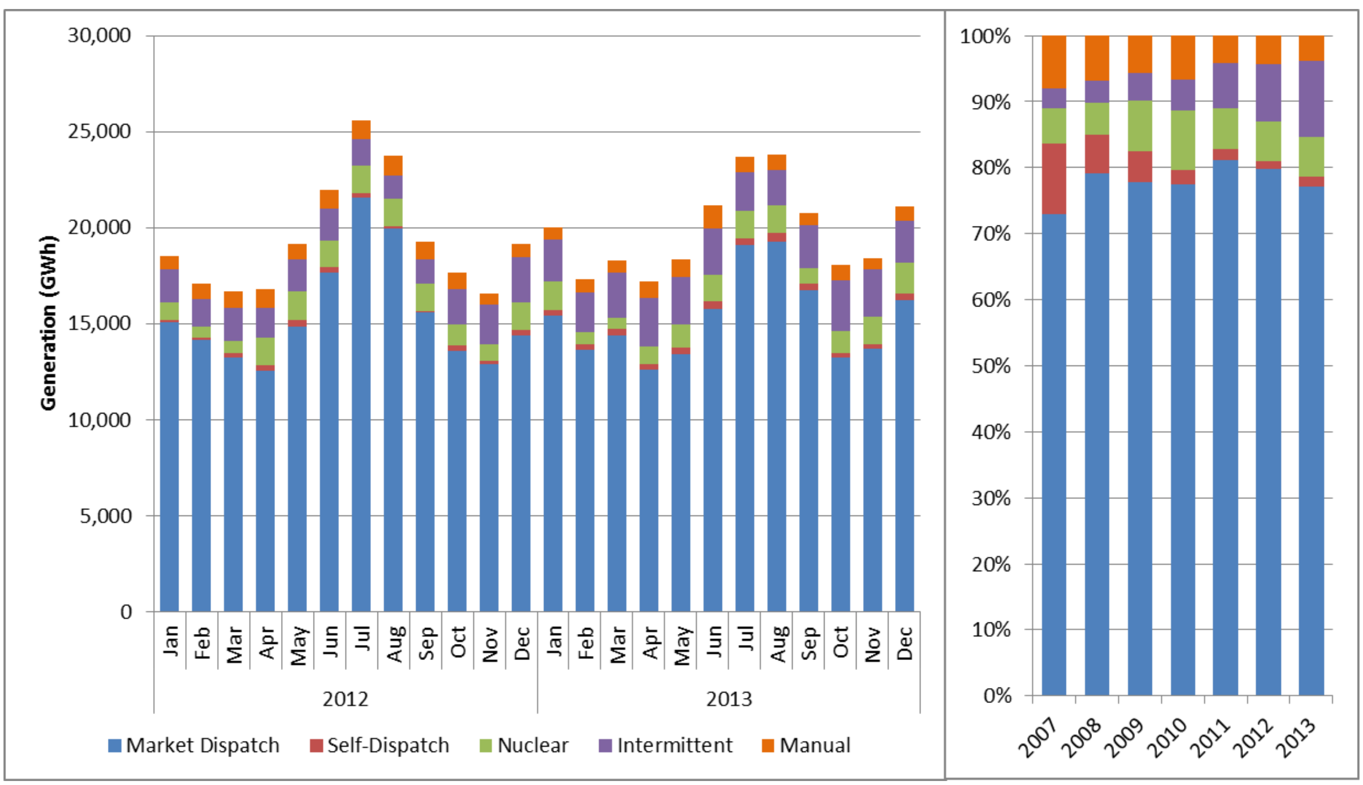
A Market Participant can modify the manner in which a resource functions in the market by selecting a specific status type. Available (also referred to as "Market Dispatch") is the only status type which allows the market to fully utilize a resource by changing the resource output and allowing it to 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

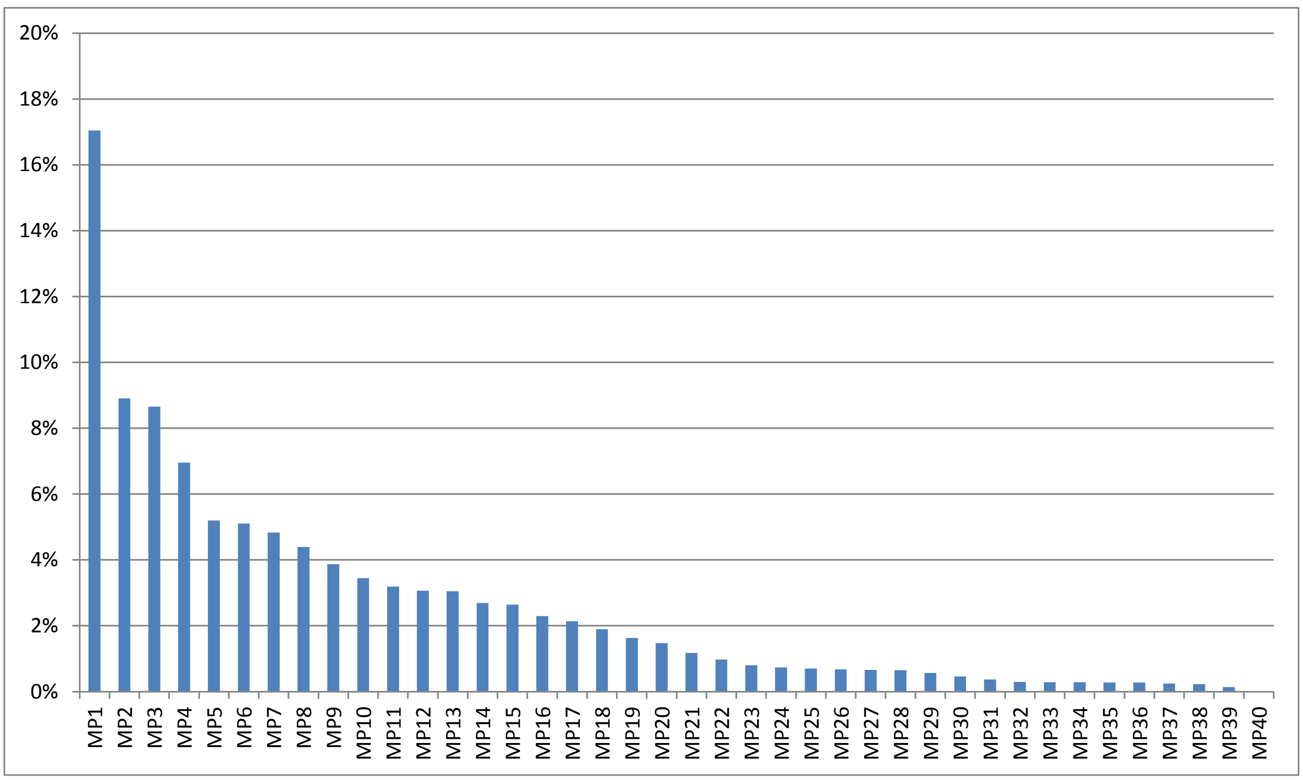
The Market Participant Capacity and Uncommitted Capacity calculations of the HHI yield similar results. HHI values since the start of the EIS market have been close to or under the 1,000 threshold indicating a very competitive market under non congested conditions.

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.

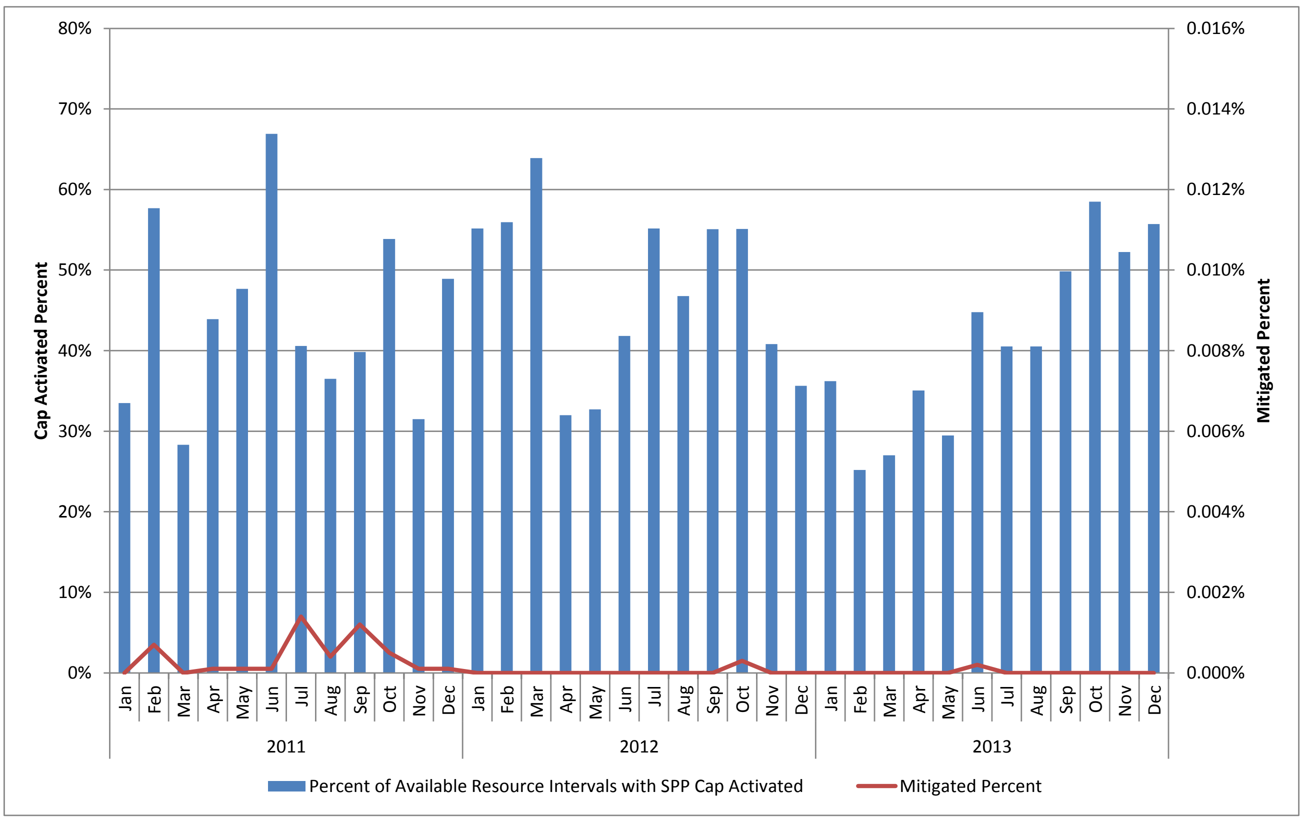
A second type of offer cap required by FERC establishes an absolute maximum offer regardless of market conditions. This limits the value of submitted offers and often referred to as the “safety net cap”. The current value is $1,000 for this cap. Neither the safety net cap nor SPP offer caps limit the 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

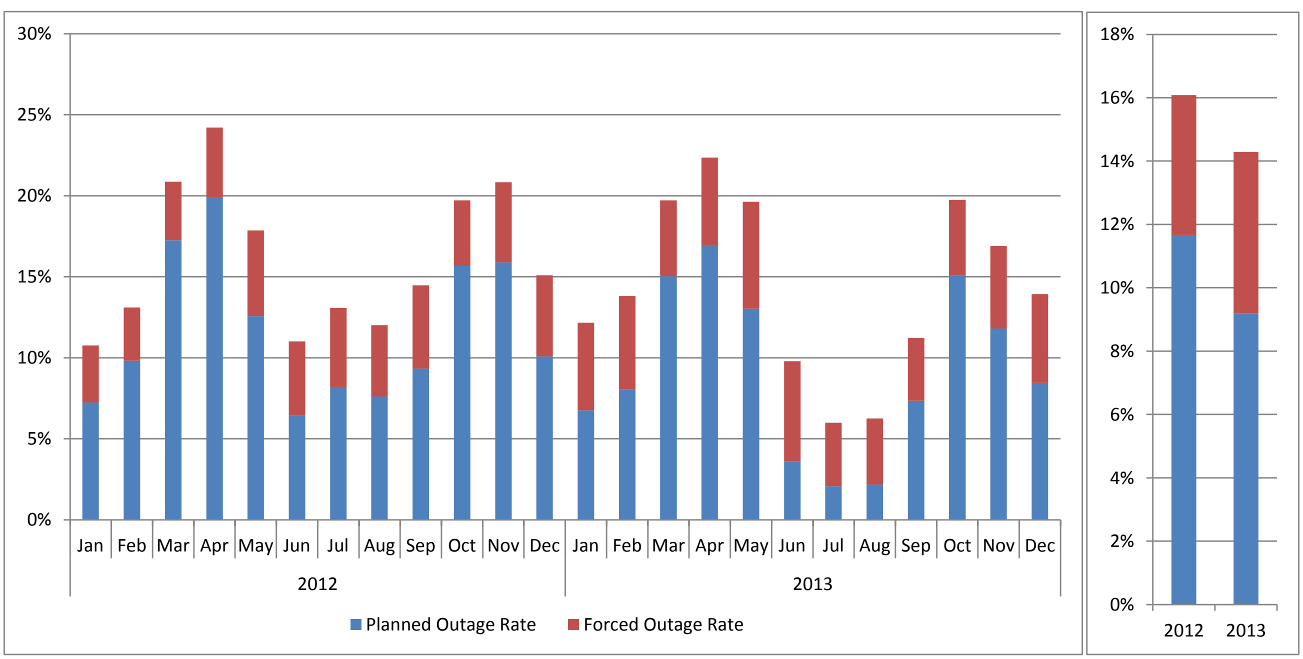
The most common form of physical withholding is to falsely declare generation outages. Generation outages typically fall into two categories – forced and planned. Forced outages occur when a generator is unable to function at full capacity due to an unforeseen circumstance, or it has otherwise been rendered 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.

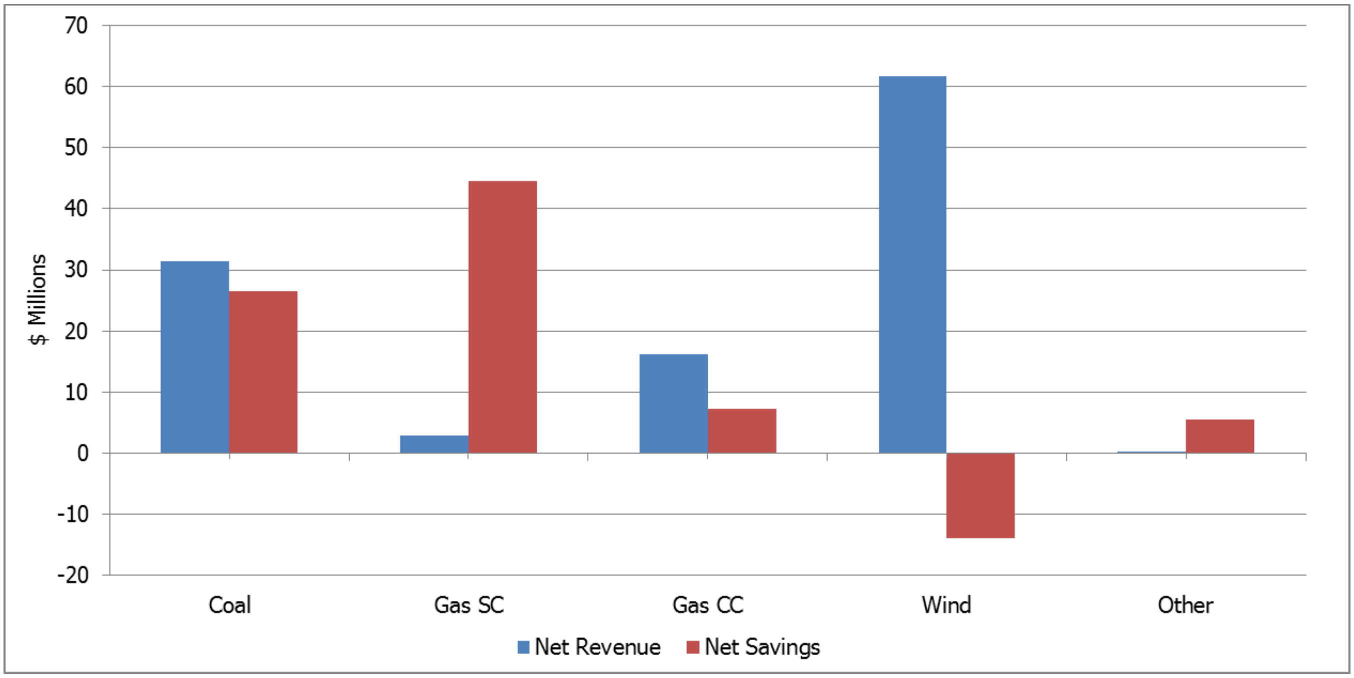
J. Production Benefit Estimates

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.

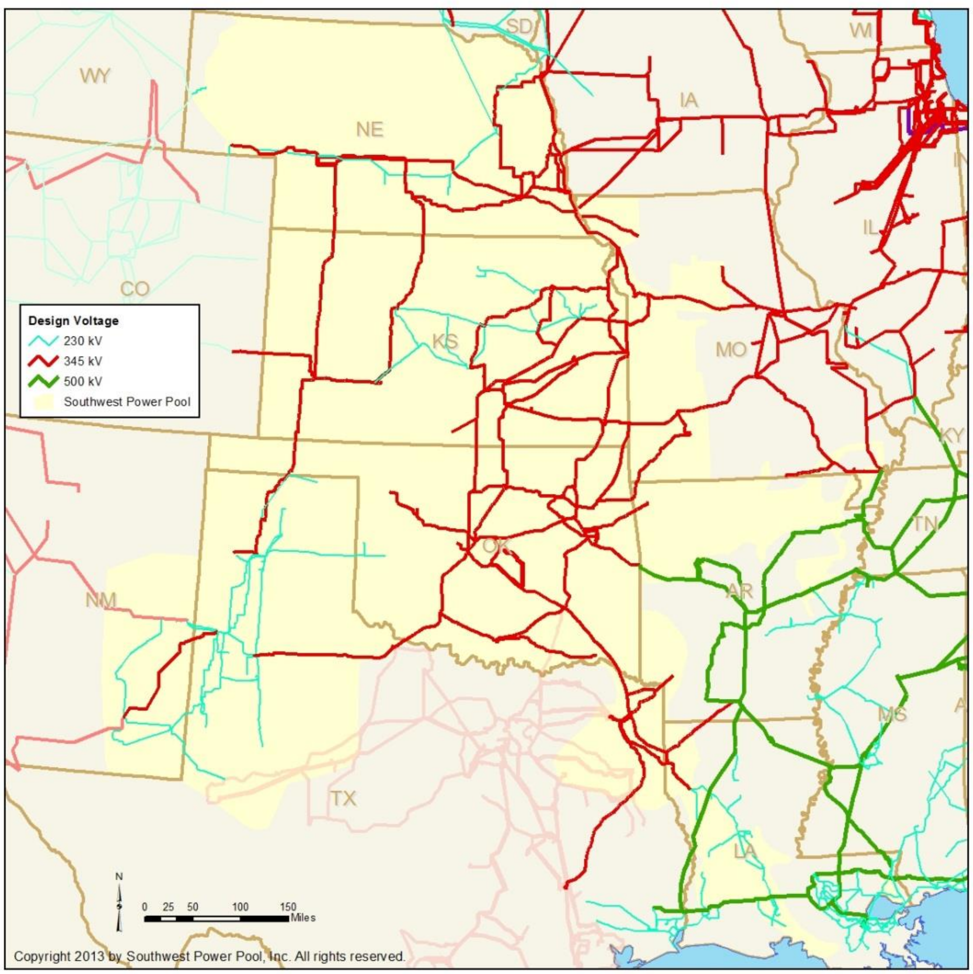
III. Energy Delivery

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

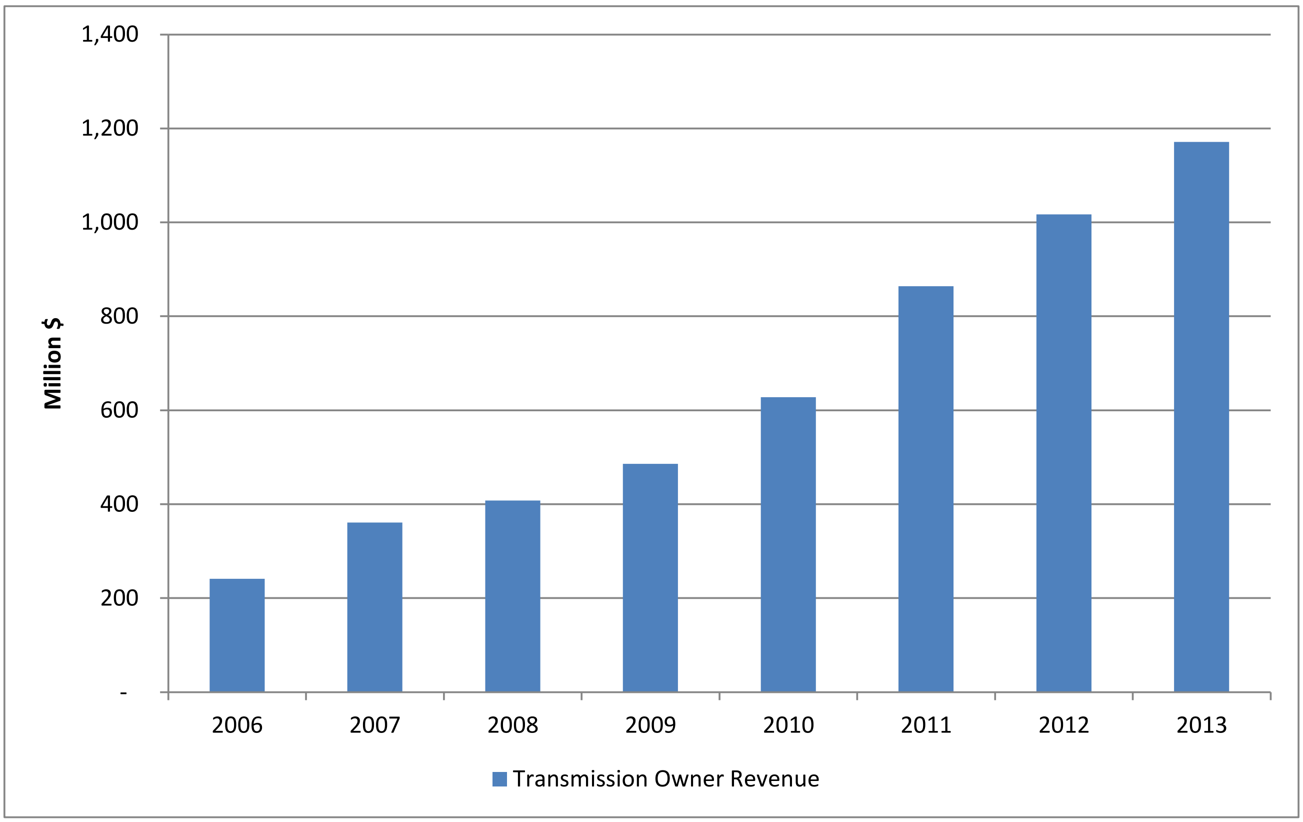
The SPP Regional Transmission Organization is obligated by FERC to manage and regulate the flow of energy across the transmission system within its territory. SPP member companies have agreed to allow SPP to administer their component transmission systems and place these transmission facilities under 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

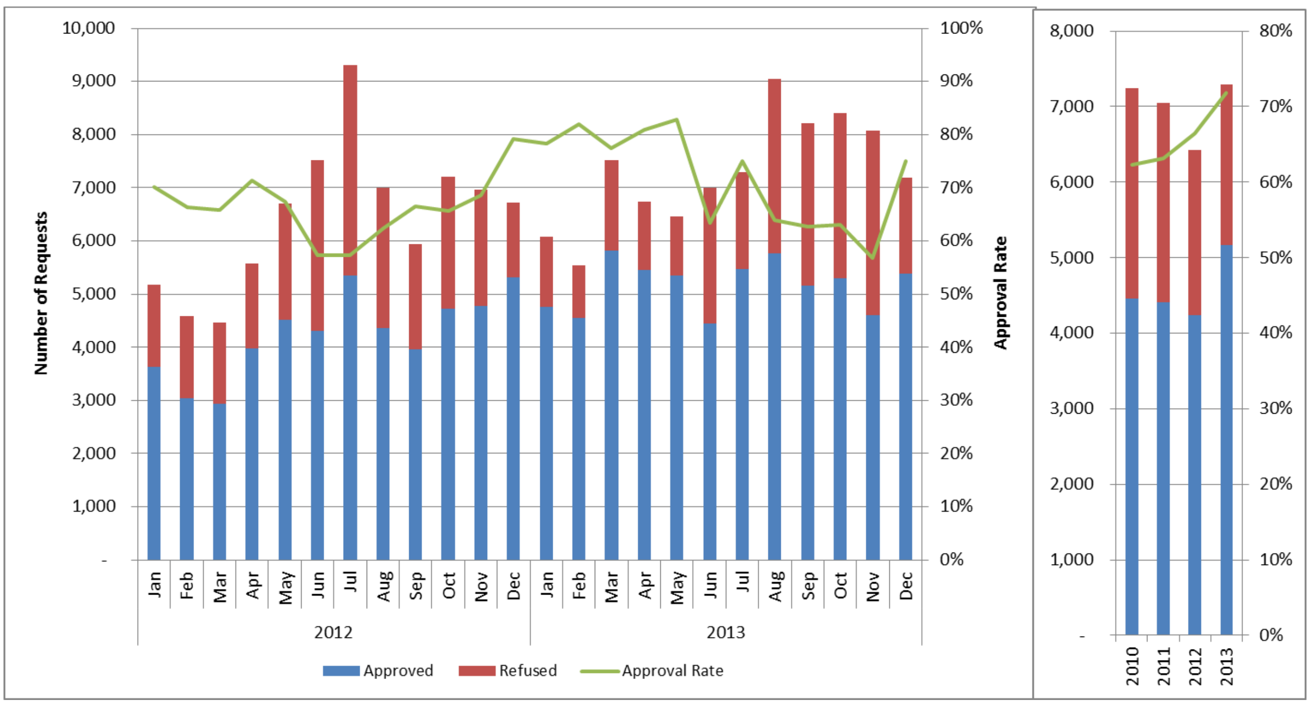


Transmission Service Request Approval Rate

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.

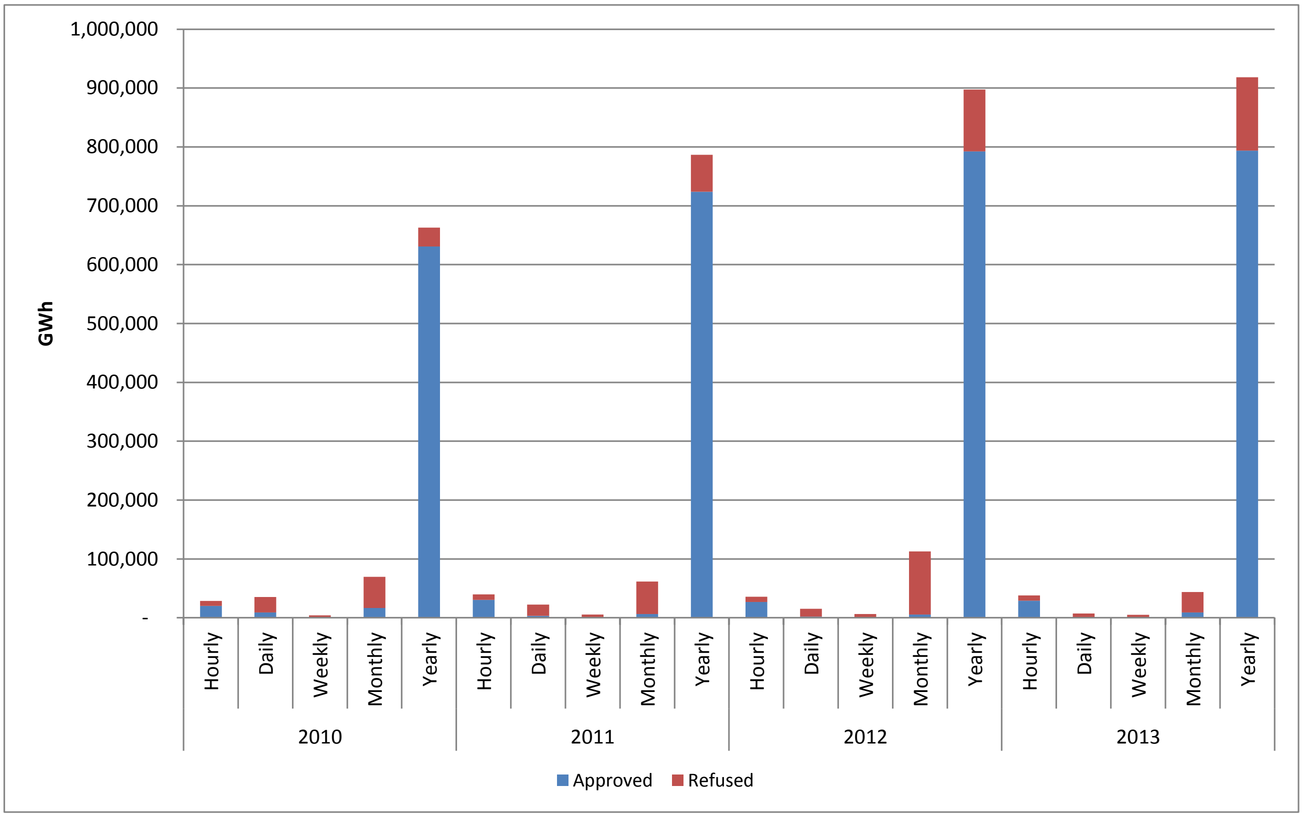
Figure III.4 SPP Transmission Availability



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

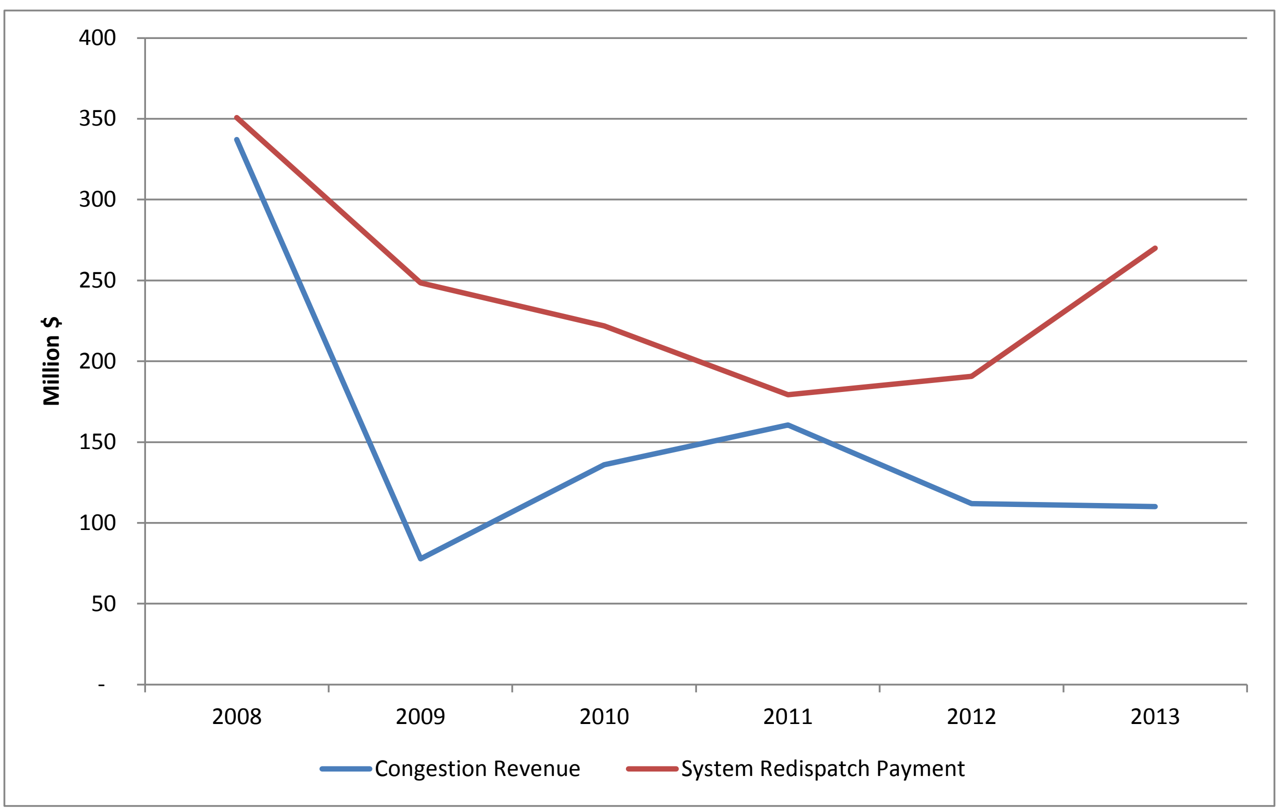
Transmission Congestion Market Impact

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

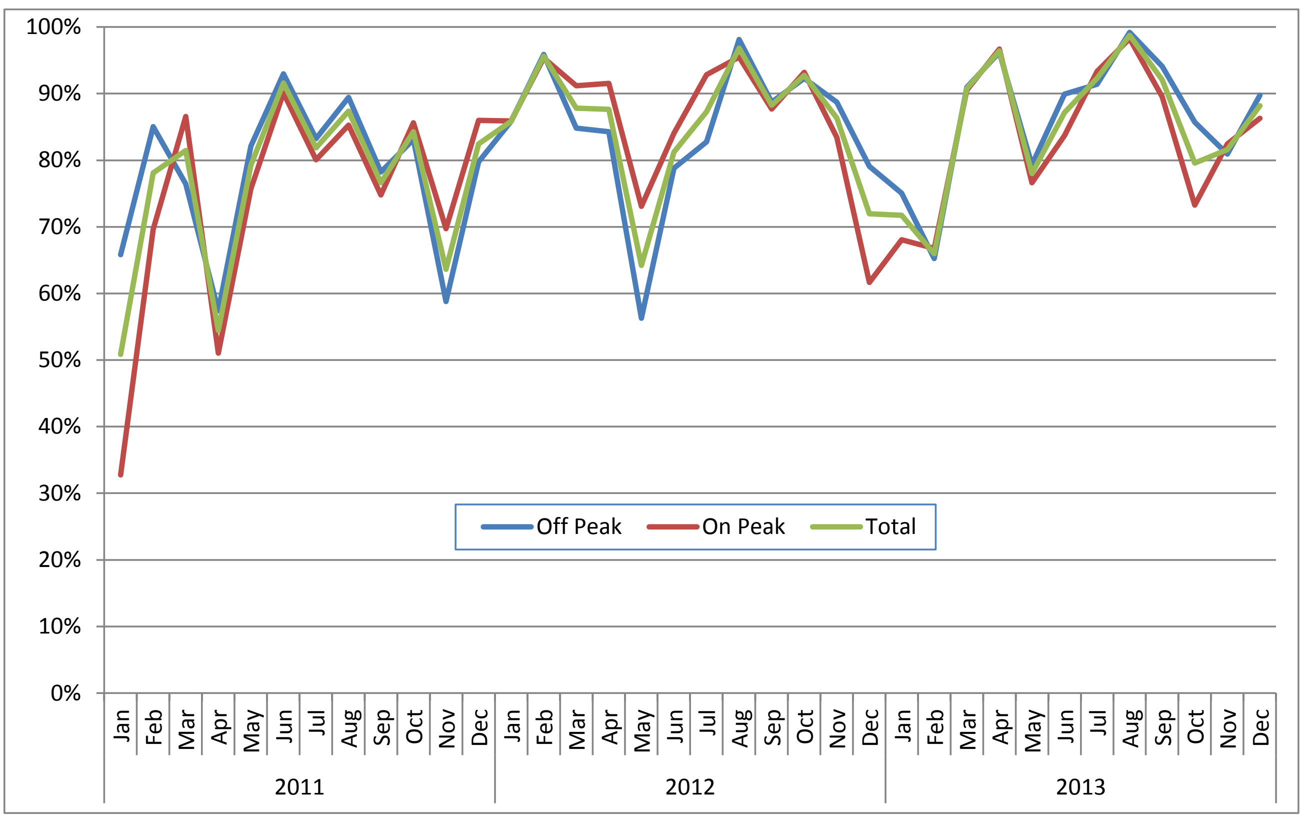


Flowgate Congestion by Time

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

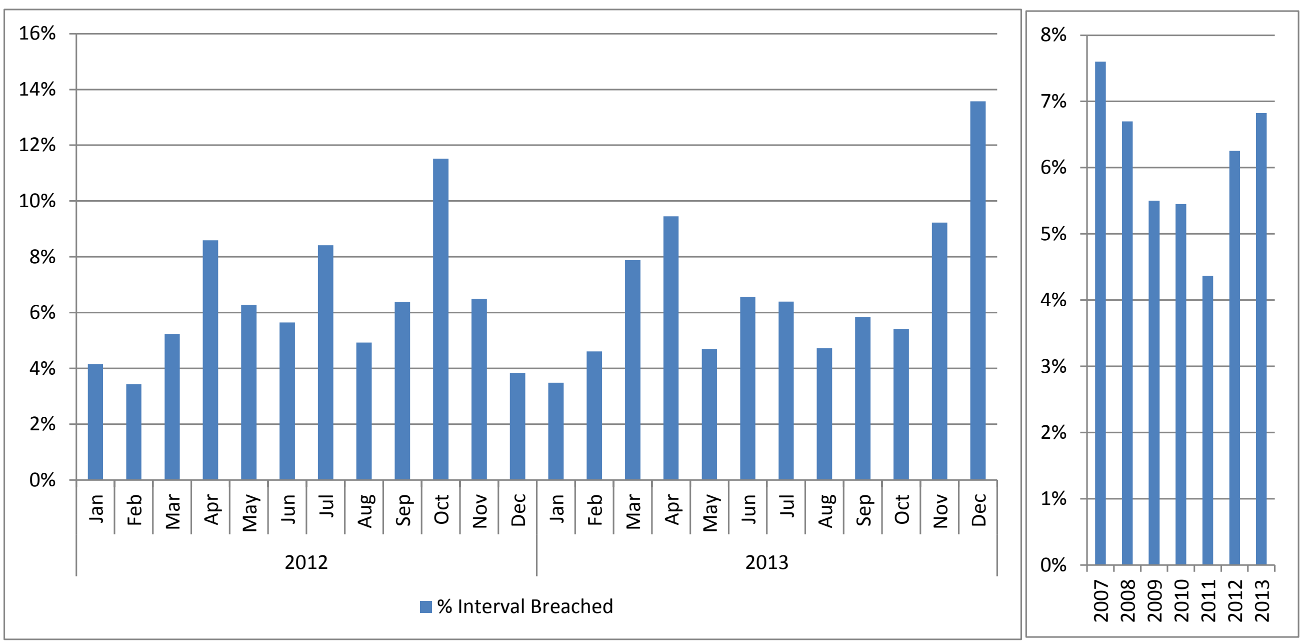
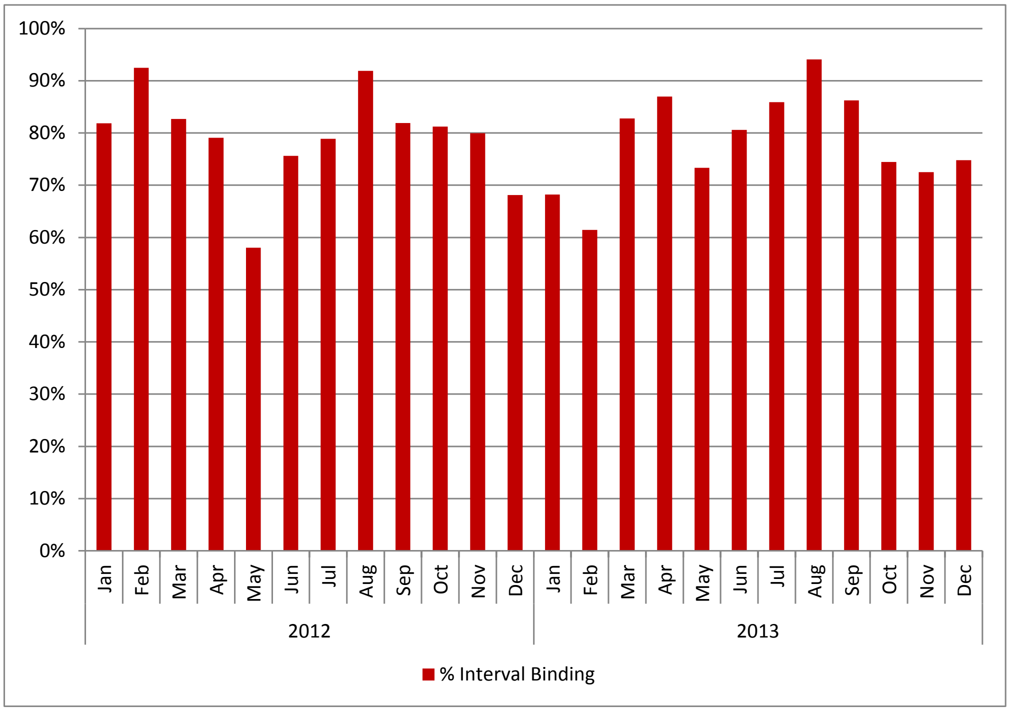
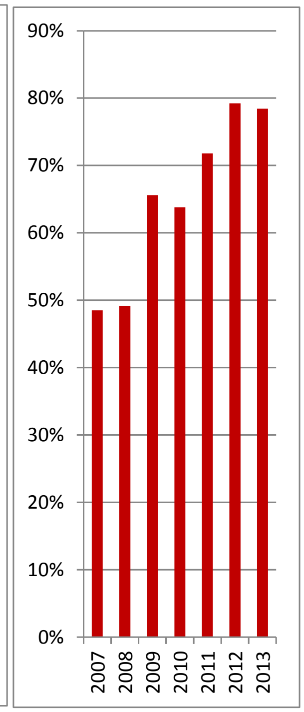


Figure III.9 displays the total percent of intervals by month and year in which a flowgate was binding. Binding flowgates compared to breached flowgates are less of a concern in that binding intervals indicates that the market is using re-dispatched capacity to manage the congestion while minimizing 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)
Texas Panhandle	**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)
Texas Panhandle	**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)
Texas Panhandle	**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)
Kansas City – Omaha Corridor	**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)
Kansas City – Omaha Corridor	**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

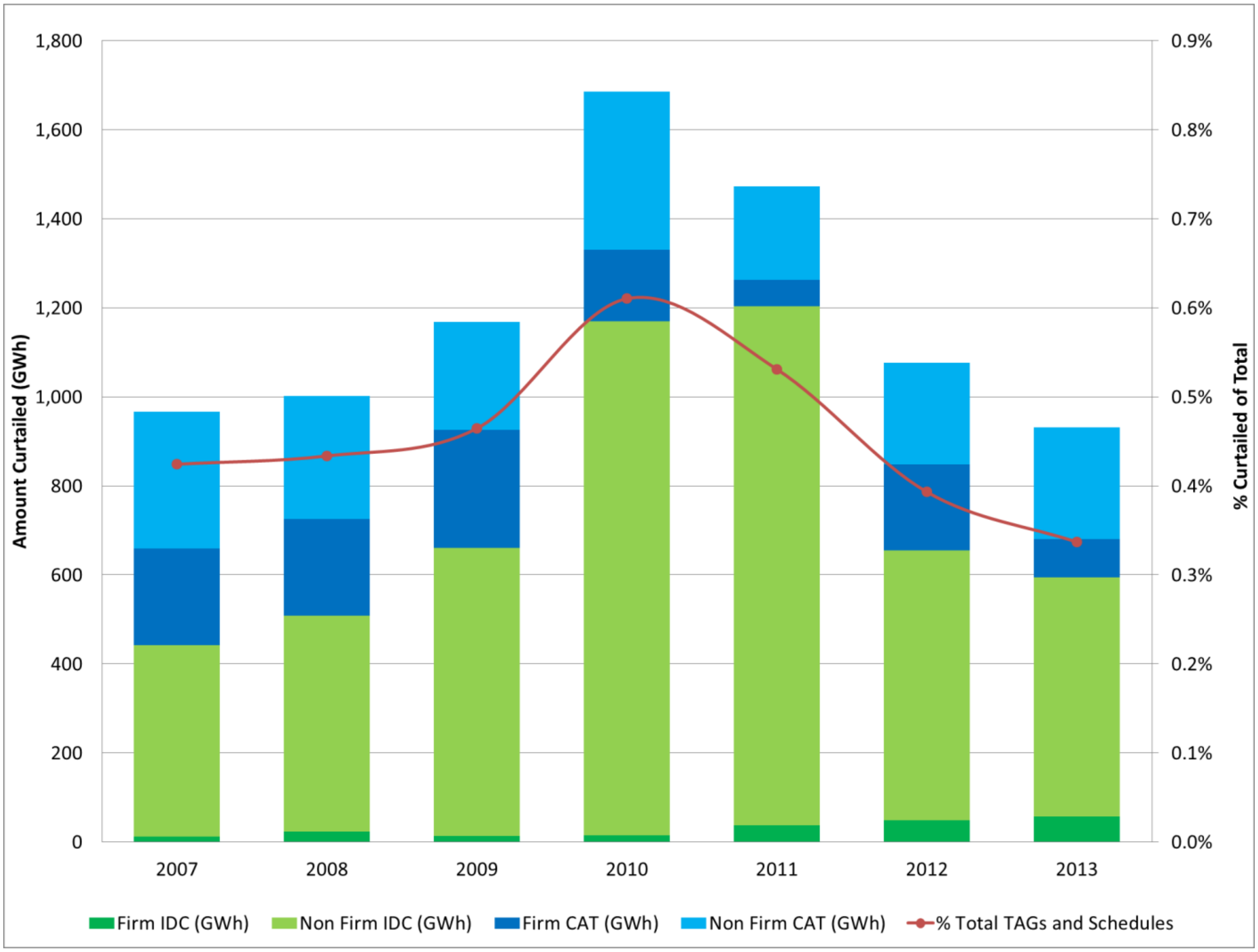
Transmission curtailments are a reduction in firm or non-firm transmission service in response to a system reliability concern. SPP EIS Market utilizes two types of transmission curtailment mechanisms: NERC Interchange Distribution Calculator (IDC) curtailments and SPP Curtailment Adjustment Tool (CAT) 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.

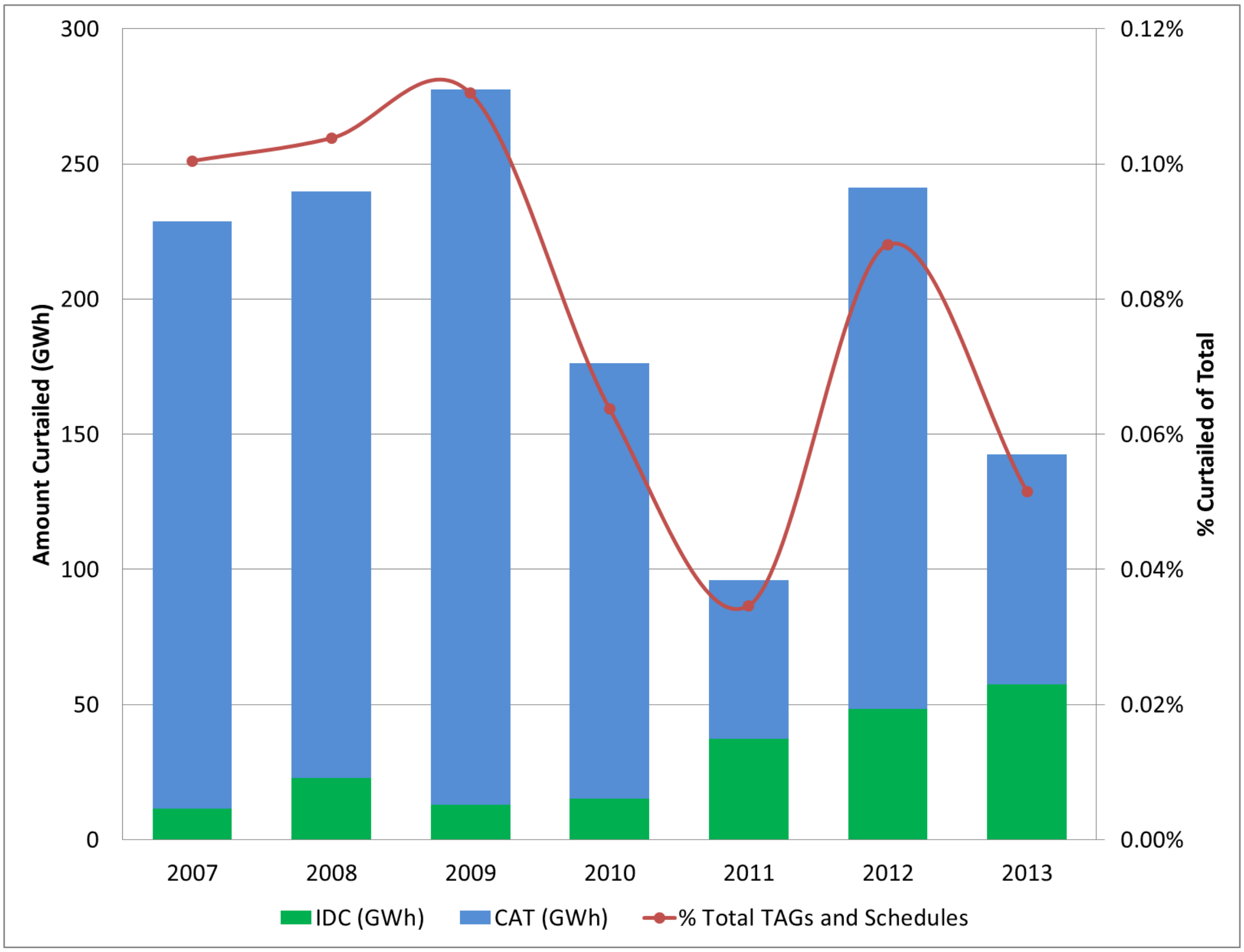
Figure III.11 shows the yearly firm and non-firm curtailments (GWh) normalized as a percent of total tags and schedules. Non-firm curtailments account for the majority of the GWh curtailed. Total amount curtailed has decreased 13.5% from the previous year with non-firm curtailments decreasing by 5.7%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

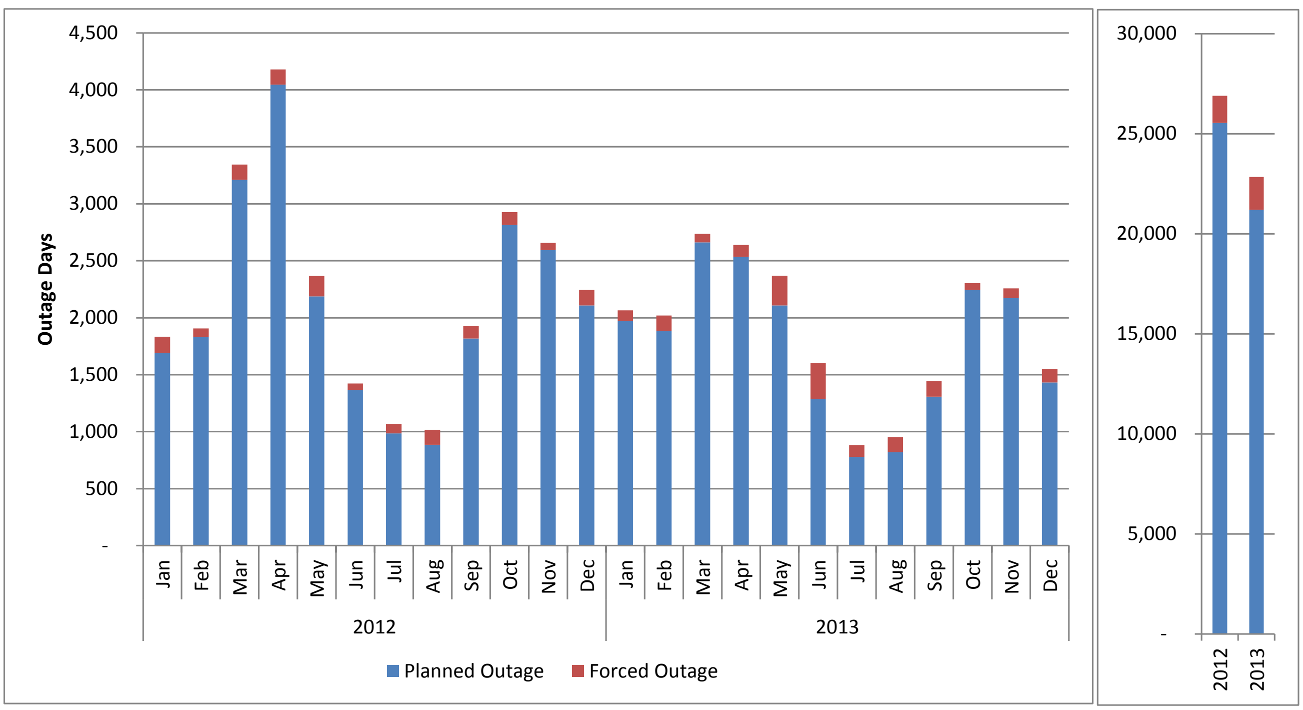
Transmission elements experience outages for a number of reasons. Outages may be the result of maintenance or some other scheduled unavailability, or may be caused by unforeseen circumstances such as storm damage, accidents, fires, and equipment malfunction.

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

Southwest Power Pool
SYSTEM PROTECTION AND CONTROL WORKING GROUP and SPP UFLS
Standard Drafting Team Meeting
MINUTES
November 12, 2010
9:00 a.m. – 11:00 a.m.
Net conference

Item 1 – Administrative:

Shawn Jacobs, Chairman, called the System Protection and Control Working Group (SPCWG) meeting to order at 9:00 a.m. The agenda was approved (Attachment 1 – Agenda).

Following members were available for this meeting:

Shawn Jacobs	: OG&E
Heidt Melson	: SPS
Tim Hinken	: KCPL
Ken Zellefrow	: SPRM
Ron McIvor	: OPPD
Bud Averill	: GRDA
Mathew Thykkuttathil	: SUNC
Brent Carr	: AECC
Lynn Schroeder	: WERE
Steve Wadas	: NPPD
Louis Guidry	: CELE
Jason Speer	: SPP Staff

Other meeting attendees were:

David Kelley	: SPP Staff
Charles Hendrix	: SPP Staff
Travis Hyde	: OG&E
John Pasierb	: GDS Associates

Item 2: Crossroads Interconnect SPS

Shawn Jacobs led the discussion on the Crossroads Special Protection Scheme (SPS). The SPS states that if the Tatonga – Northwest 345kV line trips, then the Crossroads Windfarm would have to be curtailed. Bud Averill made a motion that the Crossroads SPS be approved for 3 years. Lynn Schroeder seconded the motion which was passed unanimously. (Attachment 2 – Crossroads SPS)

The SPCWG also talked about the Generation Interconnection SPS policy. The policy was discussed and was conditionally approved by the SPCWG based on the following changes to the policy document.

1) Rename the title to "Generation Interconnection Special Protection Scheme Policy" – just to make it clear that this policy does not apply to all SPS's.

2) On point #1, add the word "new" so that the policy starts with "Any new Special Protection Scheme…" – emphasizes the fact that already approved SPS's are not subject to this policy.
3) On point #2, need to add verbiage to allow a possible re-approval of the SPS after the three year timeframe is over.
4) On point #11, it needs to state that the TWG and the ORWG need to approve the SPS as well as the SPCWG and MOPC which are already listed. It needs to stay consistent with the SPP criteria.

Lynn Schroeder made the motion to conditionally approve this SPS policy with the following changes. Steve Wadas seconded the motion which was approved unanimously. (Attachment 3 – Generation Interconnection Special Protection Scheme Policy)

Item 2a: PowerTech UFLS Study

The Standard Drafting Team talked about the addendum to the previous UFLS study that was conducted by PowerTech. It was decided that PowerTech would perform a 30% generator deficiency study with all load shedding and circuit tripping relays operating with 30 cycles tripping time and 6 cycle breaker time delays. All generator under-frequency tripping relays will be set according to Attachment 1 in the latest PRC-006-SPP-01 standard.

PowerTech will perform a second study as detailed above with 40 cycles relay tripping times provided that the 30 cycle study results identify secure system operation. In case that the 30 cycle study results identify an unsecure system operation, PowerTech will perform the second study with 20 cycles relay tripping times.

Item 3: SPP UFLS Standard

This agenda item was not discussed at this meeting.

Item 4: Closing Administrative Duties

The next net conference has been scheduled for November 16 (2pm-4pm).

The net conference was adjourned at 11:00 a.m.

Respectfully submitted,

Jason Speer, Secretary

Southwest Power Pool

SOUTHWEST POWER POOL
SYSTEM PROTECTION AND CONTROL WORKING GROUP and SPP REGIONAL STANDARD DEVELOPMENT MEETING
November 12, 2010 (9:00 a.m. till 11:00 a.m.)
Net Conference

- AGENDA -

Item 1 – Administrative
- Call to order
- Proxies
- Approve agenda

Item 2 – Crossroads Interconnect SPS (Shawn)

Item 2a – PowerTech UFLS Study (Shawn)

Item 3 – SPP UFLS Standard (All)
- Homework Assignments (Measures and Violation Severity Levels)
- 4th Draft
- Responses to comments received for 3rd Draft

Item 4 – Closing Administrative Duties
- Next meeting place & date
- Upcoming meeting topics
- Adjourn meeting

Crossroads Wind Farm Special Protection System (SPS)

The Problem

Tatonga Substation is going to be expanded to a three-breaker ring, 345KV switching station, located northwest of Oklahoma City. Presently, there is one 345KV transmission line to Northwest Substation in Northwest Oklahoma City and one 345KV transmission line to Woodward District EHV Substation in Woodward, Oklahoma. Both lines are protected by primary and back up relaying and breaker failure. An SEL-311L relay is used for primary relaying utilizing DCB and an SEL-421 relay for backup relaying using a POTT scheme. Two frequency wave trap and Power line carrier type UPLC are installed on each line for relaying communication. A third 345KV breaker is being installed in the ring bus to provide for termination of the 345KV Crossroads Wind Farm Line. The transmission line to Crossroads Wind Farm is equipped with OPGW shield wire and an SEL-311L for primary relaying utilizing DCB and Line Differential and an SEL-421 for backup relaying utilizing a POTT scheme.

If the 345KV Northwest to Tatonga Line breakers (PCB 319 and PCB 381) trip automatically or manually while the Crossroads Wind Farm is generating and with other wind farms such as OU Wind Spirit, Centennial and Keenan Wind, which are already installed and in operation in Woodward, it will cause the 138kV voltage to collapse in the Woodward area. For this contingency, the Crossroads Wind Farm will have to be curtailed immediately.

Proposed Remediation

For a fault on the 345KV Northwest-Tatonga Line the primary and the backup line relays will trip all three 345KV circuit breakers (PCB 311, PCB 319 and PCB 381) at Tatonga Substation. To provide redundancy, the primary and backup line protection on the Tatonga – Crossroads line will send a Mirrored Bit Direct Transfer Trip (DTT) to trip and latch trip the 345KV breaker at Crossroads Wind Farm. If PCB's 319 and 381 are both opened manually during maintenance or otherwise, it will automatically trip PCB 311 and initiate DTT to Crossroads Wind Farm.

Tatonga Substation will go through its automatic reclosing sequence. PCB 381 will reclose twice automatically on Hot Woodward District EHV Line-Dead Northwest Line. If the reclosing is successful and Northwest Line is picked up through PCB 381, PCB 319 will reclose on Hot Northwest Line-Dead Crossroads Wind Farm Line, a mirrored bit will be sent to Crossroads to unlatch their trip allowing the Wind farm to re-synchronize into the system. PCB 311 will reclose on Hot Crossroads-Hot Woodward District EHV Line in-phase. The substation RTU will monitor and report any operation at Tatonga, including the Mirrored Bit (DTT) to Crossroads, to the Control Center in Oklahoma City. OG&E understands that this is a temporary solution during that contingency. The plans are in place to expand Woodward District EHV Substation to breaker and a half and construct new 345KV transmission lines out of this substation to facilitate the operations of all the wind farms presently connected to the system. This includes new 345KV lines to Hitchland and Kansas.

Scheme Summary

- This special protection scheme (SPS) will eliminate the voltage collapse on the system caused by the outage of 345KV line to Northwest Substation. The scheme will be monitored and reviewed with any improvement to the area transmission system including construction of every new transmission line. Load flows will be run to determine if the scheme is needed to be in service.

- We project this scheme will be in place for maximum of three years. The expansion of Woodward District EHV Substation and construction of the new transmission lines to Hitchline and Kansas will remedy this problem and will eliminate its need.

Special Protection Scheme Policy

1. Any Special Protection Scheme (SPS) that affords the in-service date of a Generating Facility that is the subject of a Generation Interconnection Agreement (GIA) or an Interim Generation Interconnection Agreement (IGIA) to be accelerated ahead of the in service date of its required network upgrades shall be offered on a non-discriminatory basis to any Interconnection Customer under the SPP OATT who meets the following criteria -

    1.1. Interconnection Customers who(se)
        1.1.1. Have requested a Limited Operation Study under GIA 5.9 and have found that Limited Operation is not available until the required network upgrades in the GIA are placed in service; or have requested an IGIA under the OATT and have found that Interim Interconnection Service cannot be granted until the Impact Study required network upgrades are in service; and
        1.1.2. Have had a study completed by Transmission Provider that shows the SPS will be able to facilitate the interconnection of the Generating Facility.

2. SPS will be a temporary measure, not to exceed three years, until such time that the Interconnection Customer's required network upgrades under their GIA can be completed.

3. SPS configurations that will be considered for evaluation will be limited to the items following

    3.1. Removal of Customer's generation from the Transmission System following a disturbance that causes the outage of a transmission line or transformer that terminates at the point of interconnection substation facility (or within a reasonable physical distance from that facility – less than 0.25 mile).
    3.2. Tripping and removal from the Transmission System of a transformer or transmission line that terminates at the point of interconnection substation facility.

4. SPS operation shall not cause the removal of other generation from the Transmission System unless agreed to by the affected generator owners; subject to queue priority listed in Item 10.

5. Operation of an SPS cannot cause the disruption of service to Native Load Customers.

6. Installation of an SPS cannot inhibit the use of the Transmission System for future use (i.e. prevent the addition of points of delivery for Native Load Customers).

    6.1. SPS can be re-evaluated at later time to ensure adherence to this criteria.

7. SPS will not be considered after the execution (or unexecuted filing) of a GIA unless Transmission Provider has determined that the in service date of the required Network Upgrades under the GIA will be delayed.

8. SPS does not relieve Customer from obtaining applicable transmission service or from curtailment under applicable SPP processes.

9. SPS will not be considered in the processing of short term or long term transmission service requests.

10. SPS does not relieve Customer from risk associated with Interim Interconnection Service under the IGIA or Limited Operation under the GIA (i.e. subject to future studies that may require a reduction or pre-emption of service when higher or equally queued customer come on-line)

    10.1. A Customer with higher or equal queue priority proposed SPS and Generating Facility may be accommodated by the removal of a lower queued Customer's SPS and Generating Facility or the pro-rated reduction in service of a Customer with equal queue priority.

11. SPS must be approved by the System Protection and Controls Working Group (SPCWG) and the Market and Operations Policy Committee (MOPC)

Exhibit JBT-9
OCC Cause No. PUD 201400229

System Support Resources
Unit Retirement Process

MISO's robust System Support Resource determination process considers stakeholder solutions while assuring regional reliability.

A System Support Resource – or SSR – is a power plant that must be available for MISO to operate the transmission system within applicable reliability standards. As the regional reliability coordinator, MISO is obligated to maintain reliability of the electric grid. MISO's transmission planning and outage management functions are generally designed to ensure the system can accommodate temporary generation outages. However, the long-term or permanent loss of a generator can affect MISO's ability to operate reliably. Therefore, a power plant owner seeking to retire or suspend a generator must first obtain approval from MISO to remove a plant from operation. Attachment Y of MISO's FERC-approved tariff is the mechanism used for these requests.

Did you know?

- MISO evaluates plant retirement / suspension requests for reliability need; System Support Resource (SSR) designations made where reliability is threatened.
- MISO solicits Stakeholders for alternative solutions; an SSR Agreement results if none exist.
- Load Serving Entities benefiting from SSR pay costs to operate.
- Confidentiality of request and study result required if no SSR designation is made.

SSR Designation

Upon receipt of an Attachment Y application, MISO performs a reliability-based evaluation to determine the impact of the power plant's removal from service. At study completion, the power plant owner decides whether to receive the results or retract the request. If the owner receives the results and MISO finds a plant is needed for reliable operations, it designates the generator as an SSR. MISO provides notice of this designation on its Open Access Same-Time Information System (OASIS). The Attachment Y and study results remain confidential however, if the owner retracts the request, or if MISO does not make an SSR designation.

Exploration of Solutions

Once an SSR designation occurs, MISO reviews the evaluation with stakeholders and solicits alternative solutions – transmission upgrades, new generation, or demand response – that would allow reliability to be maintained without the generator. If an alternative exists, MISO removes the SSR designation and approves the plant's retirement/suspension. If no alternatives exist, MISO and the plant owner negotiate an SSR Agreement.

SSR Agreement and Compensation

SSR Agreements define the terms of the arrangement, including compensation. SSRs receive compensation for their going forward costs resulting from remaining online and available. The parties determine the revenue requirement based on actual historical plant costs. Monies paid to the SSR are net of any energy market revenues earned. MISO collects SSR costs from the Load Serving Entities found during the evaluation to benefit from the plant's operation. Agreements have initial terms of 12 months and require annual reassessment of continued need. MISO files agreements with FERC. If MISO and the plant owner do not reach agreement, unexecuted materials are filed with FERC.

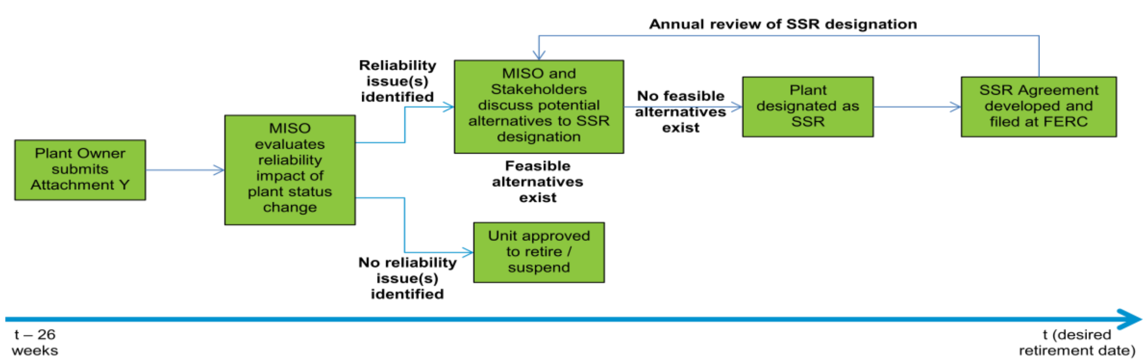


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Table 1 - Long-Term Transmission Service Requests Included in Aggregate Facility Study

Customer	Study Number	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date without interim redispatch	Deferred Stop Date without interim redispatch	Start Date with interim redispatch	Stop Date with interim redispatch	Minimum Allocated ATC (MW) within reservation period	Season of Minimum Allocated ATC within reservation period
AECC	2013-AG3-001	78754116	OKGE	CSWS	150	7/1/2014	7/1/2019	3/1/2015	3/1/2020	3/1/2015	3/1/2020	0	15SP
AECC	2013-AG3-002	78754144	OKGE	OKGE	150	7/1/2014	7/1/2019	3/1/2015	3/1/2020	3/1/2015	3/1/2020	0	15SP
AEPM	2013-AG3-003	78775996	OKGE	CSWS	200	1/1/2016	1/1/2036	1/1/2018	1/1/2038	1/1/2016	1/1/2036	0	16SP
AEPM	2013-AG3-004	78776033	SPS	CSWS	200	1/1/2016	1/1/2036	1/1/2018	1/1/2038	1/1/2016	1/1/2036	0	16SP
AEPM	2013-AG3-005	78776041	OKGE	CSWS	199	1/1/2016	1/1/2036	1/1/2016	1/1/2036	1/1/2016	1/1/2036	0	16SP
ETEC	2013-AG3-006	78774012	CSWS	CSWS	31	1/1/2015	1/1/2024	3/1/2015	3/1/2024	3/1/2015	3/1/2024	0	15SP
GRDX	2013-AG3-007	78753946	CSWS	GRDA	136	10/1/2015	10/1/2020	10/1/2015	10/1/2020	10/1/2015	10/1/2020	0	16SP
GRDX	2013-AG3-008	78773345	MPS	GRDA	240	4/1/2016	4/1/2021	4/1/2016	4/1/2021	4/1/2016	4/1/2021	0	16SP
GRDX	2013-AG3-009	78773355	MPS	GRDA	100	4/1/2016	4/1/2021	4/1/2016	4/1/2021	4/1/2016	4/1/2021	0	16SP
KCPS	2013-AG3-016	78758401	WR	KCPL	50	7/1/2015	1/1/2036	7/1/2015	1/1/2036	7/1/2015	1/1/2036	0	16SP
KCPS	2013-AG3-017	78764630	WR	KCPL	101	7/1/2015	1/1/2036	7/1/2015	1/1/2036	7/1/2015	1/1/2036	0	16SP
KCPS	2013-AG3-018	78764633	WR	KCPL	51	7/1/2015	1/1/2036	7/1/2015	1/1/2036	7/1/2015	1/1/2036	0	16SP
LESM	2013-AG3-021	78773742	OKGE	LES	100	11/26/2015	11/26/2020	1/1/2018	1/1/2023	11/26/2015	11/26/2020	0	16SP
OGE	2013-AG3-024	78759765	OKGE	OKGE	16	10/1/2014	6/1/2030	3/1/2015	11/1/2030	3/1/2015	11/1/2030	0	15SP
OMPA	2013-AG3-025	78697838	OKGE	OKGE	4	10/1/2014	12/1/2040	3/1/2015	5/1/2041	3/1/2015	5/1/2041	0	15SP
SECI	2013-AG3-026	78763050	KCPL	SECI	50	1/1/2015	1/1/2045	6/1/2018	6/1/2048	6/1/2017	6/1/2047	0	15SP
SPSM	2013-AG3-027	78751808	SPS	SPS	250	12/1/2015	12/1/2035	6/1/2020	6/1/2040	6/1/2020	6/1/2040	0	16SP
TEXL	2013-AG3-028	78773933	CSWS	CSWS	50	1/1/2015	1/1/2025	3/1/2015	3/1/2025	3/1/2015	3/1/2025	0	15SP
TEXL	2013-AG3-029	78773967	CSWS	CSWS	27	1/1/2015	1/1/2030	3/1/2015	3/1/2030	3/1/2015	3/1/2030	0	15SP
UCU	2013-AG3-030	78748020	MPS	KCPL	2	5/1/2014	5/1/2019	3/1/2015	3/1/2020	3/1/2015	3/1/2020	0	14SP
UCU	2013-AG3-031	78754546	MPS	MPS	50	7/1/2015	1/1/2036	7/1/2015	1/1/2036	7/1/2015	1/1/2036	0	16SP
UCU	2013-AG3-032	78763378	MPS	MPS	101	7/1/2015	1/1/2036	7/1/2015	1/1/2036	7/1/2015	1/1/2036	0	16SP
UCU	2013-AG3-033	78763386	MPS	MPS	51	7/1/2015	1/1/2036	7/1/2015	1/1/2036	7/1/2015	1/1/2036	0	16SP
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Note 1: Start and Stop Dates with interim redispatch are determined based on customers choosing option to pursue redispatch to start service at Requested Start and Stop Dates or earliest date possible.

Note 2: Start dates with and without redispatch are based on the assumed completion dates of previous Aggregate Transmission Service Studies currently being conducted. Actual start dates may differ from the potential start dates upon completion of the previous studies.

Note 3: Request is unable to be deferred due to fixed stop dates.

Note 4: Transmission customer did not select "remain in the study using interim redispatch" option.