Exhibit No.:	
Issue:	SPP Transmission Expansion Planning Process and Federal Energy Regulatory Commission ("FERC") Jurisdiction
Witness:	Todd E. Fridley
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company
Case No.:	EO-2012-0367
Date Testimony Prepared:	August 31, 2012

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: EO-2012-0367

DIRECT TESTIMONY

OF

TODD E. FRIDLEY

ON BEHALF OF

**KANSAS CITY POWER & LIGHT COMPANY
AND
KCP&L GREATER MISSOURI OPERATIONS COMPANY**

**Kansas City, Missouri
August 2012**

I. Introduction

Q: Please state your name and business address.

A: My name is Todd E. Fridley. My business address is 1200 Main Street, Kansas City, Missouri 64105.

Q: By whom and in what capacity are you employed?

A: I am employed by Kansas City Power & Light Company ("KCP&L") as Director – Transmission Partnerships. In addition to my position with KCP&L, I also hold the position of Vice President of Transource Energy, LLC ("Transource") and Transource Missouri, LLC ("Transource Missouri"). Transource is a newly formed joint venture between Great Plains Energy Incorporated ("GPE") and American Electric Power Company, Inc. ("AEP"). Transource Missouri is a wholly-owned subsidiary of Transource.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of KCP&L and KCP&L Greater Missouri Operations Company ("GMO"), which are both subsidiaries of GPE (collectively referred to as the "Companies").[1]

Q: What are your responsibilities?

A: My responsibilities on behalf of the Companies include: (1) development of corporate transmission policy in relation to the Federal Energy Regulatory Commission

[1] GPE is a public utility holding company that does not own or operate any significant assets other than the stock of its operating subsidiaries KCP&L and GMO. KCP&L, through its employees and resources, is currently taking steps to move forward on the Projects, addressed in this testimony, on behalf of itself, as well as on behalf of GMO, pursuant to the terms and conditions set forth in the October 10, 2008 Joint Operating Agreement between KCP&L and GMO. Subsequent references in this testimony to GMO's responsibilities with respect to the Projects are made in this context.

("FERC") policy and orders associated with transmission and energy markets; (2) development of corporate policymaking and decisions for the Southwest Power Pool, Inc. ("SPP") Regional Transmission Organization ("RTO") activities through participation in SPP committees and working groups of the stakeholders; and (3) development of corporate transmission investment strategy. My responsibilities on behalf of Transource and Transource Missouri are similar to those for the Companies, in that I focus on policy development and transmission investment strategy in SPP.

Q: Please describe your education, experience and employment history.

A: I received a Bachelor of Science degree in Electrical Engineering from the University of Missouri – Rolla in 1983.

I have 29 years of experience in the electric utility business and joined KCP&L's Engineering Division in 1983. I have had responsibilities for transmission and substation engineering, transmission system operations, generation system operations and distribution operations. In 2000, I assumed the Superintendent of Distribution Control Center position with responsibility for managing KCP&L's distribution operations and restoration functions. In 2005, I returned to a transmission role and assumed a Senior Manager position managing the Companies' regional and federal transmission policy, SPP RTO activity, FERC and North American Electric Reliability Corporation ("NERC") compliance, transmission investment strategy and transmission energy accounting. In 2010, FERC and NERC compliance responsibilities were redirected to another division for governance purposes. In April 2012, after the closing of the transaction that initiated the Transource joint venture, I assumed my responsibilities with Transource and will transition certain transmission policy and SPP RTO activities for the Companies to others in the near future.

Q: Please describe your participation in industry organizations.

A: I participate in a wide range of SPP RTO activities and serve as vice-chairman of the SPP Markets and Operations Policy Committee ("MOPC") as a voting member for KCP&L. The MOPC is responsible for all decisions related to transmission expansion, energy markets, reliability, and transmission tariffs. This committee reports to the SPP Board of Directors. I serve as chairman of the Edison Electric Institute ("EEI") Transmission Policy Task Force responsible for policy work on a wide range of industry issues related to the bulk electric system. I represent the Companies at the North American Transmission Forum organization, which is engaged in developing best practices, peer reviews, event analysis and improvements related to compliance matters for the bulk electric system. I previously participated as a member of the EEI Reliability Executive Advisory Committee where decisions and policymaking occur for a variety of transmission issues including bulk-power reliability, transmission tariff, and compliance. I also have served on a wide variety of NERC committees related to operations, engineering and compliance.

Q: Have you previously testified in a proceeding before the Missouri Public Service Commission ("Commission" or "MPSC")?

A: No. However, I have submitted prepared written testimony before FERC in Docket No. ER10-230-000.[2]

[2] Kansas City Power & Light Co. and KCP&L Greater Missouri Operations Co., 130 FERC ¶ 61,009 (2010).

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to: (1) provide an overview of transmission rates and policy; (2) provide background regarding transmission planning and expansion, transmission cost allocation, and integrated planning functions within the SPP RTO; and (3) discuss the development and selection of the Companies' current regional transmission projects. The first projects Transource plans to build are two existing SPP regional projects for which the Companies have received notifications to construct ("NTCs") from SPP. The projects are the Iatan-Nashua 345kV transmission project ("Iatan-Nashua Project") and the Sibley-Nebraska City 345kV transmission project ("Sibley-Nebraska City Project") (collectively described herein as the "Projects").

II. Overview of Transmission Rates and Policy

Q: Please describe the history and emergence of open access transmission service.

A: Electricity is an extremely dynamic force and by nature must be instantaneously managed in order to match, with a high degrees of accuracy, the balance between supply and demand. Traditionally, public utilities have met customer demand and energy through strategic investments within or near their respective retail service areas by way of local generation connected to their high voltage transmission grid. Throughout the history of the development of the electric transmission grid, public utilities have also leveraged the synergies of neighboring systems through interconnections and exchanged capacity and energy in order to effectively serve their respective customer loads. As each electric utility system acts as its own control area, certain physical constraints such as generator or transmission outages can create needs for inter-control area wholesale transactions in order to support economical and reliable service to customers. The rates, terms and conditions for both interstate transmission and wholesale energy sales are governed under FERC's authority within the Federal Power Act. Therefore, FERC jurisdictional utilities maintain their established rates and terms for their transmission and wholesale energy sales through the appropriate FERC-approved tariffs. Fundamentally, this regulatory construct provides uniform oversight for rates, terms and conditions across all investor-owned public utility systems and gives single-source jurisdiction for proceedings pertaining to such rates, terms and conditions. As such, individual state jurisdictions do not govern rates, terms, and conditions for interstate transmission and wholesale energy. Rather, individual state jurisdictions govern other core public utility functions such as, but not limited to, generation adequacy levels, siting and construction of generation assets, local distribution of electricity, and the bundled rates, terms and conditions for sales of electric energy to retail customers. Also, in some states there are state statutes governing transmission routing and siting.

In the mid-1990s, following the passage of the Energy Policy Act of 1992,[3] FERC concluded that there remained fundamental inefficiencies regarding the use of transmission, and in particular identified discriminatory practices that hindered the

[3] Energy Policy Act, 42 U.S.C. § 13201 (1992).

efficient use of available transmission capacity. To address such issues, on April 24, 1996, FERC issued landmark transmission policy with Order No. 888,[4] and Order No. 889,[5] requiring that all public utilities that own and operate transmission provide open access non-discriminatory transmission service for transmission customers, and in doing so, abide by a detailed public posting information system. As a result, all providers of transmission service were to apply FERC's *pro forma* Open Access Transmission Tariff ("OATT" or "Tariff"), which included a host of requirements that would facilitate non-discriminatory transmission service to transmission customers. This also effectively established a functional unbundling of transmission service and operations from market activities such that utilities performing both functions were required to separate the two functions in order to provide non-discriminatory transmission service. This policy of open access transmission enabled new competitive wholesale power markets, thereby ushering in significant growth in wholesale energy trading activity throughout the period following the mid-1990s.

Q: Please describe the history and emergence of RTOs.

A: As a result of high levels of energy transactions on the nation's transmission grid, FERC identified evidence that traditional management of the transmission grid by

---

[4] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in part and remanded in part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002) (codified at 18 C.F.R. § 35.28).

[5] Open Access Same-Time Information System and Standards of Conduct, Order No. 889, FERC Stats. & Regs. ¶ 31,035 (1996), order on reh'g, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049 (1997), order denying reh'g, Order No. 889-B, 81 FERC ¶ 61,253 (1997), aff'd in substantial part sub nom. Transmission Access Policy Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002) (codified at 18 C.F.R. pt. 37).

vertically integrated electric utilities was inadequate to support the efficient and reliable operation needed for continued development of competitive electricity markets. FERC found evidence of continued discrimination in the provision of transmission services by vertically integrated utilities, which was impeding fully competitive electricity markets. As a precursor to the development of RTOs, Independent System Operators ("ISO") first grew out of Orders No. 888 and 889, where FERC suggested the concept of an ISO as one way to satisfy the requirement of providing non-discriminatory access to transmission.

In FERC Order No. 2000,[6] FERC went further by developing and proposing independent RTOs that would more effectively address impediments to efficient grid operation and electricity market competition and that would consequently benefit consumers through lower electricity rates resulting from a wider choice of services and service providers. In Order No. 2000, FERC provided the requirements, structure and minimum functions for establishing the nation's RTOs, including the following characteristics and functions.

Minimum Characteristics:

1. Independence
2. Scope and Regional Configuration
3. Operational Authority
4. Short-term Reliability

Minimum Functions:

1. Tariff Administration and Design

[6] Regional Transmission Organizations, Order No. 2000, 89 FERC ¶ 61,285 (1999), order on reh'g, Order No. 2000-A, 90 FERC ¶ 61,201 (2000), appeals dismissed sub nom. Public Utility District No. 1 v. FERC, 272 F.3d 607 (D.C. Cir. 2001) (per curiam) (codified at 18 C.F.R. § 35.34).

2. Congestion Management

3. Parallel Path Flow

4. Ancillary Services

5. OASIS and Total Transmission Capability

6. Market Monitoring

7. Planning and Expansion

8. Interregional Coordination

FERC indicated in Order No. 2000 that it encouraged transmission-owning entities in the United States to place their transmission facilities under the control of an appropriate RTO, and as a result of a voluntary approach, encouraged jurisdictional utilities to form RTOs.

Since the time of Order No. 2000, there have been seven (7) RTOs established, including the SPP RTO in which the Companies have membership. SPP obtained conditional approval from FERC on February 10, 2004 for establishing SPP as an RTO,[7] and SPP was recognized under full approval by FERC as an RTO on October 1, 2004.[8]

Q: Please describe the impacts of the Energy Policy Act of 2005.

A: Through the Energy Policy Act of 2005 ("EPAct 05"),[9] Congress gave further clarity and direction to FERC concerning the planning and expansion of the nation's

---

[7] Southwest Power Pool, Inc., 108 FERC ¶ 61,003 (2004).

[8] Southwest Power Pool, Inc., 109 FERC ¶ 61,009 (2004).

[9] Energy Policy Act, 42 U.S.C. § 15801 (2005).

transmission system. In Section 1233 of EPAct 05, Section 217 was added to the Federal Power Act[10] to include, among other things:

> Any load-serving entity described in paragraph (1) is entitled to use the firm transmission rights, or, equivalent tradable or financial transmission rights, in order to deliver the output or purchased energy, or the output of other generating facilities or purchased energy to the extent deliverable using the rights, to the extent required to meet the service obligation of the load-serving entity.
>
> and
>
> The Commission shall exercise the authority of the Commission under this Act in a manner that facilitates the planning and expansion of the transmission facilities to meet the reasonable needs of the load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable of financial rights) on a long-term basis for the long-term power supply arrangements made, or planned, to meet such needs.

Therefore, EPAct 05 solidified and further clarified FERC's authority to direct and enforce the transmission planning and expansion responsibilities of RTOs and public utilities for meeting the obligations of load-serving entities.

Q: Were there other transmission policy changes enacted by EPAct 05?

A: Yes. Through EPAct 05, Congress also directed FERC to provide rules that would strengthen transmission investment in the United States that would support electric power reliability, reduce transmission congestion, and improve energy market efficiencies that benefit consumers. In Section 1241 of EPAct 05, the Federal Power Act was amended to add a new Section 219[11] that included, among other things:

> 1) promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the

[10] Federal Power Act, 16 U.S.C. § 824q.

[11] Federal Power Act, 16 U.S.C. § 824s.

transmission of electric energy in interstate commerce, regardless of the ownership of the facilities;

2) provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies);

3) encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities.

As a result, on July 20, 2006, FERC issued Order No. 679,[12] establishing the following rate treatments:

a) incentive rates of return on equity for new investment;

b) full recovery of prudently incurred construction work in progress;

c) full recovery of incurred pre-commercial operations costs;

d) full recovery of prudently incurred costs of abandoned facilities;

e) use of hypothetical capital structures;

f) accumulated deferred income taxes for transcos;

g) adjustments to book value for Transco sales/purchase;

h) accelerated depreciation;

i) deferred cost recovery for utilities with retail rate freezes; and

j) higher rate of return on equity for utilities that join and/or continue to be members of RTOs.

[12] Promoting Transmission Investment through Pricing Reform, Order No. 679, FERC Stats. & Regs. ¶ 31,222, order on reh'g, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2007), order on reh'g, 119 FERC ¶ 61,062 (2007).

Q: Please describe the issues related to continued transmission service discrimination after the issuance of Order No. 888.

A: Although FERC Order No. 888 set initial criteria for ensuring non-discriminatory transmission service, certain deficiencies were recognized, such as the lack of partial firm or "conditional firm" service that could enable renewable resources, and continued evidence of undue discriminatory activity. Therefore, on February 16, 2007, FERC issued Order No. 890,[13] which amended and revised provisions of Orders No. 888 and 889, setting forth the following:

a) Consistent and transparent Available Transmission Capacity calculations;

b) Nine (9) regional planning principles - including economic planning studies and cost allocation for new projects;

c) Documentation of designated resources;

d) Modification to long-term firm transmission service including planning redispatch and conditional firm service;

e) Extension of rollover rights from one (1) year to five (5) years;

f) Tracking and posting of transmission service performance metrics; and

g) Established terms and conditions for energy and generator imbalances.

Beyond the primary impetus for Order No. 890, namely preventing undue discriminatory activity, the amendments further strengthened the role of transmission planning and expansion activities in order to capture regional efficiencies and benefits

[13] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, FERC Stats. & Regs. ¶ 31,241 (2007), order on reh'g and clarification, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), order on reh'g and clarification, Order No. 890-B, 123 FERC ¶ 61,299 (2008), order on reh'g and clarification, Order No. 890-C, 126 FERC ¶ 61,228 (2009), order on clarification, Order No. 890-D, 129 FERC ¶ 61,126 (2009) (codified at 18 C.F.R. pts. 35, 37).

inherent in competitive energy markets. It also provided more flexibility in transmission service options for customers to better serve their needs.

Q: Please describe the emergence of the competitive elements of the transmission industry.

A: While FERC had established a favorable environment for competitive energy markets and an open non-discriminatory transmission service, FERC concluded that it should encourage more regional transmission solutions that could enable additional market efficiencies. Without sufficiently developed regional cost allocation mechanisms, regional transmission plans were remaining just that – regional plans only and not actual transmission projects in construction. Also, in connection with the RTO transmission planning process, FERC received complaints that non-incumbent transmission developers were being treated unfairly with respect to the ability to build new regional transmission. The complaints arose from the existing planning process and the existence of OATT provisions containing rights of first refusal for incumbent utilities, affording them priority in building projects resulting from the regional planning process. FERC viewed this practice as discriminatory. As a result, on July 21, 2011, FERC issued Order No. 1000,[14] which contained the following key elements:

a) Requires each public utility transmission provider to participate in a regional transmission planning process;

---

[14] Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, 136 FERC ¶ 61,051 (2011), order on reh'g and clarification, Order 1000-A, 139 FERC ¶ 61,132 (2012), reh'g pending (codified at 18 C.F.R. § 35.28).

b) Requires each public utility transmission provider to develop its transmission planning process to consider and include public policy requirements;

c) Removes any form of federal right of first refusal within tariffs and agreements with certain exceptions;

d) Directs regions to develop interregional transmission plans with neighboring regions;

e) Directs regions to develop regional cost allocation methodologies for the cost of new transmission facilities selected in regional plans for the purpose of cost allocation; and

f) Directs regions to develop interregional cost allocation methodologies for new transmission facilities located in two or more neighboring transmission planning regions.

As a result, Order No. 1000 directed new levels of planning criteria and the corresponding regional cost allocation to be developed necessary to ensure project costs are applied in a manner roughly commensurate to the benefits from the project.

In addition, Order No. 1000 created a fundamental shift in the rights that utilities previously held to build and own transmission lines which connected to facilities within their respective retail service territories. Several regions, including SPP and the Midwest Independent Transmission System Operator, Inc. ("MISO") in which Missouri utilities hold RTO membership, do have a right of first refusal element within their transmission tariff or membership agreements, which provided the rights to build projects proposed in the region. Order No. 1000 established that all transmission providers must remove any reference to a federal right of first refusal from the process of selecting who should build transmission facilities that are selected in a regional transmission plan for purposes of regional cost allocation. Rather, FERC directed regions to formulate a process that would allow non-incumbents the ability to participate in regional planning and would ensure that non-incumbent transmission developers have the same ability as incumbent utilities to build such regional transmission facilities.

III. <u>Overview of Southwest Power Pool</u>

Q: Please describe the history of the SPP.

A: SPP began as a consolidated organization of eleven (11) utilities in 1941, resulting from the cooperation by those utilities to meet dramatic rises in electric demand for bauxite mining operations and defense plant operations in Arkansas during the World War II efforts. The organization proved valuable for supporting ongoing electric reliability and operations coordination for the region, and therefore the organization was maintained after the war.

On November 9, 1965, the United States and Canada experienced the largest grid-wide blackout in history, which caused approximately 30 million people to be without power in the northeastern United States and Southeastern Canada. In 1967, the Federal Power Commission (FERC's predecessor agency) proposed the formation of a council on power coordination and on June 1, 1968, SPP joined other regional reliability organizations to form the NERC. The regions and NERC worked together through the years since NERC's inception to develop and implement operating guides and criteria to support robust, reliable bulk power grid operations.

In the mid to late 1990s, SPP began developing additional services to members primarily as a result of FERC Order No. 888. A key benefit was reliability coordination functions that allowed SPP to monitor in real-time the region's electric transmission grid and generators status in order to give region-wide analysis for maintaining bulk power grid reliability. With the advent of open access, the volume of transactions on the grid was high and no one single utility could maintain a full and comprehensive view of grid reliability. By 2001, SPP had developed reliability coordination services, transmission and tariff administration services, and regional scheduling services.

Q: Please describe SPP's energy market history and activity.

A: In February of 2004, SPP obtained conditional approval from FERC for establishment of RTO status, and received final approval as an RTO on October 1, 2004.[15] Because of SPP's approval as an RTO, utilities were subsequently able to comply with FERC Order No. 2000 by submitting functional control of their transmission facilities to the SPP RTO. This provided a number of advantages for utilities including a centralized one-stop shop and non-pancaked transmission rates for energy transactions in the SPP region. As a result, the SPP Open Access Transmission Tariff ("SPP Tariff") provided the region's rates, terms, and conditions for transmission customers' use of the SPP region's transmission facilities. It also afforded utilities the ability to capture synergies in the administrative efforts to manage transmission tariffs, transmission schedules, and transmission planning requirements. For instance, in 2011, SPP

[15] Southwest Power Pool, Inc., 108 FERC ¶ 61,003, order on compliance filing, 109 FERC ¶ 61,009 (2004).

processed 8,500 transmission transactions per month on average with a total of $945 million in transmission service value for the region.

In February of 2007, SPP launched the Energy Imbalance Service ("EIS") market consistent with provisions in FERC Order No. 2000 requiring RTOs to provide energy market functions with real-time energy imbalance services and independent market monitoring. SPP's EIS market allows market participants to buy and sell wholesale electricity in real-time with subsequent energy imbalance services. In doing so, market participants can use the EIS market to obtain the least cost energy from other utilities. Therefore, these energy imbalance differences are met by the market in real-time and provide the most advantageous and economical energy transaction. SPP facilitates the market, ensures the least expensive energy is used to meet demand, and monitors the balance of supply and demand. At the same time, SPP ensures that the transmission system, which supplies the means for the transactions, is stable and reliable.

Additional enhanced market functions will be implemented in 2014, termed the "Integrated Marketplace," to enable SPP to have a true day-ahead market whereby all generating resources within SPP will be utilized on a regional basis to meet the region's forecasted demand or load for the next day.

Q: Please describe the history and activity surrounding SPP transmission planning and the associated cost allocation.

A: As a transmission provider and administrator for an OATT, SPP must adhere to all transmission planning rules outlined in NERC standards and FERC Orders No. 888, 889, 890, and most recently 1000. These requirements, as mentioned earlier in this testimony, have continued to shape the policy and practices governing what SPP must perform as it pertains to transmission planning and associated cost allocation. Specifically these are: (a) develop robust and flexible transmission plans that sufficiently meet instantaneous, near-term and long-term grid reliability needs of the region; (b) develop economically beneficial projects sufficient to support specific benefit to cost ratios; (c) incorporate public policy provisions (such as renewable wind resources); (d) develop effective allocation methods for application to transmission projects; and (e) review and revise comprehensive transmission plans on a regular basis to meet emerging developments in public policy and fundamental driver changes, such as generating resources, load, and grid topology.

Q: How did SPP engage in traditional transmission planning?

A: SPP for many years has performed traditional load flow study analysis to identify limitations of network elements on the transmission system. Transmission planners use the information from these studies to develop effective solutions necessary to meet specific reliability criteria. NERC planning and operating standards govern the levels of reliability that must be met by the transmission plans. SPP also performs planning studies necessary for new generation interconnection and transmission services related to the connection and use of the transmission system. These activities also create additional transmission plans necessary to meet ongoing needs of transmission customers.

Q: How did SPP initially approach cost allocation for transmission projects constructed under SPP direction?

A: SPP, like many other RTOs, recognized that cost allocation for transmission expansion is very complex. This complexity is due to the fact that the transmission system delivers power from a widely dispersed set of generators to widely dispersed set of local load centers. The transmission system itself serves the primary purpose of transferring energy from the generators to load centers, and it does so within a complex network that supports other critical components to grid operations. Because each member's system is neither isolated nor independent, the transmission grid also supports regional voltage and regional reliability characteristics inherent within its operation. In addition, when projects are developed to resolve reliability issues in the region, they generally resolve reliability issues for more than a single member's zone. As a result, in 2005, SPP developed and obtained FERC approval within the SPP Tariff for a cost allocation methodology that directs one-third (1/3) of the costs of regional projects to the entire region and the remaining two-thirds (2/3) of the costs directed to the local members' zones using a methodology based on line impacts.[16]

Q: Please explain the roles and involvement of the SPP Markets and Operations Policy Committee, SPP Regional State Committee, and SPP Board.

A: The SPP governing documents generally provide for an open stakeholder process for all activity within the SPP.

The SPP Markets and Operations Policy Committee ("MOPC") governs much of the SPP activities, with a variety of subcommittees, working groups and task forces

[16] SPP Tariff, Attachment J, Section III - Base Plan Upgrades.

comprised of SPP members in order to accomplish work in their respective areas concerning RTO issues. The MOPC reports directly to the SPP Board and maintains a full membership representation from the SPP members. As designed, MOPC develops and approves transmission planning and expansion functions, transmission operations, energy market design, energy market implementation, energy market operation, SPP's tariff revisions and administration, business practices, and solutions to operational and reliability activities. Decisions requiring SPP Board approval are presented to the Board in the form of recommendations from the MOPC which carries with it a full background of membership discussion and decision-making. Other non-approval items are given to the SPP Board as informational items for their consideration along with membership discussions or decisions.

The Regional State Committee ("RSC") plays a significant role in the SPP processes in determining issues such as but not limited to: transmission cost allocation; remote generation transmission needs; allocations for financial transmission rights; and resource adequacy for the region. The composition of the RSC is made up of a designated commissioner or other official representing each state that:

a) Has authority to regulate the retail electricity or distribution rates or approve retail service areas of transmission-owning members or transmission-dependent utility members of SPP; or
b) Serve as the primary regulatory agency responsible for siting electric transmission facilities in states where there are transmission-owning members of the SPP.

The RSC primarily relies on the SPP's Cost Allocation Working Group ("CAWG") to develop and recommend solutions to cost allocation and other issues. The CAWG is made up of each state's regulatory or governing agencies' staff members who deal directly with economic and ratemaking areas for the state's electric utility sector.

The SPP Board is made up of seven (7) independent directors including the SPP CEO. The Board's duties include, but are not limited to: direct all activities of SPP organization groups; approve budgets; authorize substantive contracts; authorize filings with regulatory bodies; and approve regional criteria related to planning and operating standards. The SPP Board holds meetings in conjunction with the Members Committee, which is a representative group of the members based on individual industry sectors. The Board solicits input from the Members Committee during its meetings and in advance of decisions and actions taken through discussions and straw vote actions by Members in order to understand Member positions.

Q: Please discuss how transmission projects are awarded to transmission owners in the SPP.

A: Under existing SPP Tariff provisions, transmission projects that are identified and selected through the SPP planning process are designated for construction to those transmission owning members to which the proposed facilities connect. The designated transmission owners ("DTOs") are issued a NTC. If those facilities are owned by two different transmission owners, the parties must work together to determine who will build each portion of the line. In notifying transmission owners, SPP issues notifications to construct the facilities that carry a 90-day response deadline for indicating whether the transmission owner will commit to construct the project, and if so, a preliminary construction cost estimate and schedule for the project.[17]

Q: Please discuss how transmission projects are novated to other transmission owners in the SPP.

A: The SPP Tariff[18] and SPP Tariff Business Practices[19] provide transmission owners the ability to novate a project to another transmission owner. The SPP Tariff Business Practice 7070 Assignment and Novation is attached hereto as Schedule TEF-1. The novation process includes review by stakeholders of certain criteria, and approval by the SPP Board, outlined in Schedule TEF-1. Novations provide much needed flexibility for the construction of regional transmission projects. SPP recognized that regional transmission projects are typically significant in scale and can result in considerable capital constraints or project scale that exceeds the capabilities of the entity receiving the NTC. Novation provides relief of these constraints upon the DTO and ensures that the project remains on course to meet the scheduled in-service date.

IV. SPP's Balanced Portfolio and Identification of the Iatan-Nashua Project

Q: Please describe SPP's Balanced Portfolio transmission planning initiative.

A: In early 2008, SPP began to review the potential for transmission projects that would unlock and enable market benefits. These benefits could be realized by increasing the

---

17 SPP Tariff, Attachment O, Section VI – Construction of Transmission Facilities.

18 SPP Tariff, Attachment O, Section VI – Construction of Transmission Facilities ("At any time, a Designated Transmission Owner may elect to arrange for another entity or another existing Transmission Owner to build and own all or part of the project in its place subject to the qualifications in Subsections i, ii, iii, and iv above.").

19 SPP Tariff Business Practices, 7070 Assignment and Novation, Schedule TEF-1.

capacity of transmission facilities in the region and also reducing known congestion bottlenecks on the transmission grid. By removing these constraints on the transmission system, the existing generation resources can be used more efficiently and are able to meet the region's energy needs at a lower cost. These reductions in generation costs and improved wholesale trade benefits, termed "adjusted production costs," were identified as resulting from the proposed transmission upgrades.[20]

As a result of these efforts, in April 2009 SPP approved the Balanced Portfolio,[21] which contained seven (7) transmission projects that provide expected benefits greater than costs for the region. The SPP Balanced Portfolio Report is attached hereto as Schedule TEF-2. The Balanced Portfolio represents transmission projects that improve regional long-term reliability, reduce regional transmission congestion, and provide economical trade and production benefits. The fundamental premises in selecting projects to be included in the Balanced Portfolio was that the projects should provide net benefits to the region, benefit a large number of SPP member companies, and meet threshold benefit-to-cost ratios.

Q: Did the Companies receive NTCs for any of the Balanced Portfolio projects from SPP?

A: Yes. The Companies received and accepted NTCs for two projects: (a) the Iatan-Nashua Project, which is a 345kV transmission line between KCP&L's Iatan and Nashua substations in Missouri and (b) a 345kV tap connection from the Swissvale-Stilwell line into the KCP&L's West Gardner substation in Kansas. The Iatan-

---

[20] SPP Tariff, Attachment O, Section IV – Other Planning Studies, 3) Evaluation of Potential Balanced Portfolios.

[21] SPP Balanced Portfolio Report, Schedule TEF-2.

Nashua Project is one of the two Projects that are the subject of this Application. Brent C. Davis will discuss the Iatan-Nashua Project in greater detail in his Direct Testimony.

Q: Did SPP develop new cost allocation methodologies in coordination with the Balanced Portfolio transmission planning initiative?

A: Yes. New cost allocation techniques were developed in anticipation of the Balanced Portfolio development to take into consideration the impact of the economic foundations for the project set. SPP's CAWG developed a cost allocation methodology that provided for 100% of the project costs to be allocated to all members in the region. This methodology was ultimately approved by the SPP RSC and the SPP Board and incorporated into the SPP Tariff after FERC approval.[22] It also included specific provisions for reducing transmission charges (by transferring those charges to other members) to members for whom the overall benefit of the portfolio was insufficient to support allocated costs.

V. SPP's Priority Projects and Identification of the Sibley-Nebraska City Project

Q: Please describe SPP's Synergistic Planning Project Team and Principles.

A: SPP realized during the development of the Balanced Portfolio that in order to properly develop a set of fully comprehensive transmission plans that included additional elements beyond simple reliability based projects, a broader scope of planning principles needed to be developed. Therefore, in January 2009, the SPP Board directed a team termed the Synergistic Planning Project Team ("SPPT") to research and develop principles for transmission planning that would address these

[22] SPP Tariff, Attachment J, Section IV – Approved Balanced Portfolios.

issues. The SPPT consisted of utility stakeholders, state regulatory commissioners and SPP staff. In April 2009, the SPPT Report[23] was completed, and is attached as Schedule TEF-3, and the following guiding principles were identified to formulate a new comprehensive transmission planning process termed SPP's Integrated Transmission Plan ("ITP"):

a) Develop transmission plans on a regional basis with three (3) sets of ongoing planning stages: Near-Term Study performed annually, 10-Year Study performed every three (3) years, and 20-Year Study performed every three (3) years.

b) Develop the transmission system to serve SPP loads with SPP resources in a cost-effective manner with the following goals.

    i. Enhance interconnections between SPP's western and eastern regions.

    ii. Strengthen existing ties to the Eastern Interconnection.

    iii. Provide future coordination to the Western Electricity Coordinating Council and Electric Reliability Council of Texas systems.

c) Base transmission plan modeling upon a 20-year physical model and a 40-year financial analysis timeframe; and

d) Position SPP to proactively prepare for and respond to national priorities while providing flexibility to adjust expansion plans.

[23] SPP Synergistic Planning Project Team Report-v6-1 (Apr. 23, 2009), Schedule TEF-3.

With the completion of the SPPT work, a new framework was developed at SPP that would shape future transmission planning and incorporate not only a long-term vision, but also a more comprehensive set of drivers and needs that would meet the reliability and economic goals of the region. The SPPT Report also recommended that SPP develop a set of regional priority projects to address near-term planning needs based on the new planning principles and that SPP develop a more comprehensive set of cost allocation methods.

Q: Please describe the development of SPP's Priority Projects.

A: From April 2009 when the SPPT completed its report to April 2010 when the Priority Projects were approved, SPP worked with stakeholders to develop a comprehensive set of Priority Projects and a new regional cost allocation methodology that would meet the objectives outlined in the SPPT Report.

For the transmission planning efforts, SPP solicited proposed projects from the stakeholders, who were primarily the local utilities' transmission planning departments, in order to begin developing analysis and development of a regional set of transmission solutions. Extensive input and assumptions work was vetted thoroughly with stakeholders through the various SPP committees and working groups. These inputs included: study period, fuel prices, wind modeling, regional interconnections, environmental costs, generator planned and forced outages, operating reserves, hurdle rates, load forecasts, and market structure. A critical input for the SPP regional studies has been modeling new wind generation resources which relate directly to several of the states' mandates of renewable energy standards. For the Priority Project studies, these cumulative effects of geographically constrained wind generation were considered at both the current state mandate levels and also with sensitivities for additional wind potential within a proposed federal renewable standards policy framework. For Missouri utilities, including the Companies, the state renewable mandates are defined by Missouri Revised Statutes (2000) Section 393.1030.

The following quantifiable metrics were used for study outputs, and the results were used for the final set of Priority Projects:

a) Adjusted Production Cost – measured impacts of production cost savings by Locational Marginal Price (LMP) as well as purchases and sales of economic interchange;

b) Energy Loss Savings – measured the capacity and energy savings from lower transmission line losses;

c) Reliability Impact – measured the ability to defer or eliminate needs for future transmission projects due to reliability needs met by larger-scale projects in the portfolio; and

d) Wind Revenue Impact – measured the additional production cost benefits from wind resources being modeled as load reductions rather than a true generating units.

SPP developed the final Priority Project Report with SPP Board approval on April 27, 2010[24] and is attached as Schedule TEF-4.

[24] SPP Priority Projects Phase II Final Report, (Apr. 27, 2010), Schedule TEF-4.

Q: Did the Companies receive notifications to construct for any of the Priority Projects from SPP?

A: Yes, the final Priority Projects include a 345kV line from Nebraska City, Nebraska, to Maryville, Missouri, to Sibley, Missouri (the "Sibley-Nebraska City Project"). GMO received and accepted an NTC for the Missouri portion of the Sibley-Nebraska City Project, which includes approximately 170 miles of 345kV line and an associated 345kV substation near Maryville, Missouri. Mr. Davis discusses the Sibley-Nebraska City Project in greater detail in his Direct Testimony.

Q: Please describe the development and results of SPP's new cost allocation methodology, often referred to as "Highway-Byway."

A: In conjunction with the development of the Priority Projects, SPP's CAWG, with guidance from Dr. Mike Proctor, the former Chief Economist of the Commission, worked in 2009 to develop the requisite new cost allocation methodology recommended within the SPPT Report. The rate design goals for the new cost allocation were:

a) Balance cost allocation among:
   i. Beneficiaries and cost causers; and
   ii. Transmission access and transmission use
b) Eliminate 'free riders' and 'late comers';
c) Differentiate regional versus local facilities; and
d) Simplify transmission accounting processes.

The CAWG developed a conceptual framework that considered the primary function and use of transmission facilities. The rate design called for load to bear the costs, rather than generators or a combination of generators and load. In the Highway segment, there would be regional facilities whose primary function would be to transmit power from distant generation resources to load centers. The benefits of access and the use of regional or Highway facilities include energy transfers, access to regional markets, reliable transmission service, access to renewable resources, and resource adequacy.

'Byway' facilities would provide generators and loads access to one another and access for both generators and loads to the Highway transmission facilities. The benefits of access and the use for the local or Byway facilities include energy transfers including market activity, exports and imports, access for local generators to serve local load through the Highway, access for local load access to the Highway, and local generation access to the Highway.

SPP performed a Transmission Distribution Factor analysis to determine which facilities in SPP contribute to regional functions supporting the Highway concept and which facilities in SPP contribute to local functions supporting the Byway concept. The analysis results showed that a majority of the Extra High Voltage ("EHV") system (the portion of the system above 300kV) was primarily responsible for delivering a series of 182 test transmission service transactions on both new EHV projects and existing EHV infrastructure. Separately, SPP performed Injection-Withdrawal Transmission Utilization Analysis to estimate the proportion of local utilization versus other utilization of EHV lines in the SPP region. In this analysis applied to new EHV projects, a minority of usage was attributed to the EHV system.

As a result of the rate design and cost allocation analysis work, the CAWG recommended the following cost allocation methodology: (1) EHV 300kV and higher would receive 100% regional allocation; (2) 100kV to 299kV would receive one-third (1/3) regional and two-thirds (2/3) zonal allocation; and (3) less than 100kV would receive 100% zonal allocation.

The new Highway-Byway regional cost allocation was approved on October 26, 2009 by the SPP RSC and by the SPP Board on October 27, 2009 for use in SPP's Priority Projects and future ITP planning process[25]. The new Highway-Byway regional cost allocation was subsequently approved by FERC on June, 17, 2010.[26]

Q: Please summarize the SPP cost allocation methodology that applies to the Iatan-Nashua Project and the Sibley-Nebraska City Project.

A: They are subject to the Highway-Byway methodology that will allocate the costs associated with new regional transmission lines at 300kV and above to all members based on load ratio share.

Under this methodology, the transmission owner who completes the project, either will apply to FERC for a new fixed revenue requirement based on the actual cost of the project, or will reflect the project cost in its FERC formula rate. Because the constructor of the project is a transmission owning member of SPP, the resulting new revenue requirement is incremental to and included for cost recovery under SPP's Tariff. The resulting annual transmission revenue requirement is allocated by SPP as a charge to each member based on each member's load ratio share. The load

25 SPP Tariff, Attachment J, Section III – Base Plan Upgrades.

26 Southwest Power Pool, Inc., 131 FERC ¶ 61,252 (2010).

ratio share in SPP for the Companies' combined Missouri retail load is approximately 8%.

Therefore, whether the Companies build the Projects or other transmission owning members in SPP build the Projects, the resulting revenue requirement, determined through the federal ratemaking process, will be allocated as a cost to members by load ratio share to each member's load in the SPP region.

Q: Does this conclude your testimony?

A: Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company Regarding Arrangements for the Construction of Certain Transmission Projects.	)))))	Case No. EO-2012-0367

AFFIDAVIT OF TODD E. FRIDLEY

STATE OF MISSOURI)
) **ss**
COUNTY OF JACKSON)

Todd E. Fridley, being first duly sworn on his oath, states:

1. My name is Todd E. Fridley. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Director – Transmission Partnerships.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company consisting of thirty (30) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Todd E. Fridley
Todd E. Fridley

Subscribed and sworn before me this 31st day of August, 2012.

Nicole A. Wehry
Notary Public

My commission expires: Feb. 4 2015

NICOLE A. WEHRY
Notary Public - Notary Seal
State of Missouri
Commissioned for Jackson County
My Commission Expires: February 04, 2015
Commission Number: 11391200