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Date 6-15-15 Reporter AT
File No. ER-2014-0370

Exhibit No.:	
Issues:	*Transmission Tracker* *Transmission Expense* *SPP Region-Wide Transmission* *Transmission Wholesale Revenue* *Property Tax Tracker* *Vegetation Management Tracker* *Cyber Security Tracker*
Witness:	*Karen Lyons*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Surrebuttal Testimony*
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MISSOURI PUBLIC SERVICE COMMISSION

REGULATORY REVIEW DIVISION

UTILITY SERVICES - AUDITING

SURREBUTTAL TESTIMONY

OF

KAREN LYONS

KANSAS CITY POWER & LIGHT COMPANY

CASE NO. ER-2014-0370

Jefferson City, Missouri
June 2015

** **Denotes Highly Confidential Information** **

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Q. Please state your name, employment position and business address.

A. Karen Lyons, Utility Regulatory Auditor with the Missouri Public Service Commission ("Commission" or "PSC"), Fletcher Daniels State Office Building, 615 East 13th Street, Kansas City, Missouri 64106.

Q. Are you the same Karen Lyons who contributed to Staff's Revenue Requirement Cost of Service Report and provided rebuttal testimony as part of this rate proceeding?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to the following KCPL witnesses that address several proposed tracking mechanisms and related costs:

- Darrin R. Ives – Transmission Tracker, Property Tax, Vegetation Management, and Cyber Security Tracker
- Tim M. Rush – Transmission Tracker, Property Tax, Vegetation Management, and Cyber Security Tracker
- Melissa Hardesty – Property taxes
- Phelps-Roper – Critical infrastructure protection ("CIP") and cyber security efforts

Specifically, Mr. Ives states beginning on line 5 of page 9 of his rebuttal testimony:

> The historical record unambiguously shows that changes in these costs of service items have caused material earnings shortfalls for KCP&L since current rates took effect in January 2013. The forecasts clearly show that if new rates from this case go into effect without the requested mechanisms to address these costs of service items, KCP&L will shortly thereafter experience material earnings shortfalls.

Staff disagrees that property tax, vegetation management, cyber security and transmission trackers must be approved by the Commission in order for KCPL to earn the Commission authorized ROE. KCPL initially proposed property taxes, vegetation management and cyber security trackers in its direct filing on October 30, 2014. KCPL witnesses Ives and Rush proposed a transmission tracker for the first time in rebuttal testimony filed on May 7, 2015. The trackers proposed by KCPL are for normal cost of service components that KCPL has incurred historically and will continue to incur in the future. Missouri utilities have the ability to file for general rate increases when their revenues are insufficient to cover cost increases like property taxes, transmission, and cyber-security. Staff accounts for increases and decreases in investment, revenue, and expense in its analysis of the cost of service in order to determine the appropriate revenue requirement that allows the utility an opportunity to earn the authorized ROE, taking all factors into consideration. Trackers should only be used in rare circumstances, since cost trackers isolate a specific expense without consideration of other fluctuations in a utility's cost of service. In this case, KCPL identified several areas of its cost of service that have increased since rates were set in its last rate case. To the extent KCPL was not recovering its expenses and was unable to earn its authorize ROE, the appropriate action would have been requesting a rate increase sooner.

In addition to the proposed trackers, I will also respond to KCPL's witness Ronald A. Klote's rebuttal testimony addressing Staff's treatment of transmission expense and Staff's treatment of the investment, costs, and revenues of Southwest Power Pool (SPP) Region-Wide Transmission projects and Wholesale Transmission Revenue. With regard to transmission expense, Mr. Klote suggests that KCPL's transmission expense should be annualized by multiplying the most current monthly data available for transmission expense by twelve.[1] Since May 2015 is the true-up in this case, KCPL requests an annualized transmission expense level based on the transmission expenses incurred during the month of May 2015 multiplied by twelve (12). It is not a normal practice to base ratemaking treatment of revenues or expenses on just one month of data, because it is rare that such a sample from that small a period would fairly represent an ongoing level for the revenue of expense in question. When determining a level of expense in KCPL's cost of service, Staff analyzes several years of data. The analysis involves reviewing all FERC accounts related to the expense, categories of costs included in the FERC accounts, events that may have affected the costs, forecasts, etc. For the true-up in this case (May 2015), Staff will consider all relevant costs and factors affecting transmission expense to determine an appropriate level of expense to include in KCPL's cost of service.

KCPL proposed adjustments to reduce investment, revenue, and expense related to two SPP regional transmission projects. SPP directed KCPL to upgrade the Swissvale-Stilwell Transmission line and the West Gardner Substation, two existing KCPL transmission facilities. Staff included all the investment, revenues, and expenses associated with these transmission upgrade projects in KCPL's cost of service and supported in Staff's Accounting

[1] Ronald A. Klote, Rebuttal Testimony, Page 25, Lines 9-11.

Schedules filed on April 3, 2015. Regarding these projects, in his rebuttal testimony, Mr. Klote states on page 8, beginning on line 20, "The only amount that needs to be included in the retail revenue requirement calculation is the charge that KCP&L receives for its regional Load Ratio Share (<8%) of the cost of the projects, which is booked to Account 565." A common theme in KCPL's direct and rebuttal testimony is to emphasize the expected increase in transmission expense. As a result of the expected increase in transmission expense, KCPL proposes a transmission tracker and a different approach to annualizing transmission expense to ensure that KCPL recovers its incurred transmission expense. On the other hand, the only discussion from KCPL witnesses concerning the transmission revenue it will receive as a result of its SPP transmission activities that will partially offset potential increases in transmission expense is to seek to reduce or eliminate entirely the transmission revenue from reflection in its cost of service. If adopted, KCPL's proposals for transmission expense ensure that its customers will fully be responsible for increased costs but will not receive a proportionate benefit from the related transmission revenues.

Another example of KCPL seeking to give inconsistent treatment to transmission revenues is its proposed adjustment reducing transmission revenues based on the difference between KCPL's Federal Energy Regulatory Commission ("FERC") authorized ROE and the authorized ROE granted by the Missouri Commission in this case. In its direct filing, Staff did not reduce KCPL's transmission revenues as proposed by KCPL instead Staff recommended that if the Commission agrees with KCPL's adjustment to reduce transmission revenues for the difference between the FERC authorized ROE and the Commission authorized ROE in this case, then a corresponding adjustment should be made to KCPL's transmission expense that includes transmission costs based on FERC ROE incentives.

TRANSMISSION TRACKER

Q. What is KCPL's position on a transmission tracker?

A. In its Direct filing, KCPL requested a fuel adjustment clause ("FAC") that included recovery of certain transmission expenses.[2] In rebuttal testimony KCPL requested a transmission tracker if transmission expense is excluded from the FAC or a FAC is not granted by the Commission. Beginning on line 13, page 11, of his rebuttal testimony Mr. Rush states:

> I'd first reiterate my belief that SPP transmission fees need to be included in the FAC, but if that is not possible for some reason, or if an FAC is not authorized for KCP&L, then the Commission should grant tracker treatment for these costs. This is appropriate because basing the rate allowance for SPP transmission fees on historical levels, with no ability to account for changes in those cost levels likely to occur in the future, will lead to a mismatch of costs and revenues with significant detrimental earnings impacts during the future period when rates will be effective.

Q. Is Staff recommending an FAC and if so is Staff recommending the inclusion of all transmission expense in the FAC?

A. No. Staff recommends the Commission deny KCPL's request for a FAC but in the event the Commission grants KCPL an FAC, Staff recommended the exclusion of certain transmission expenses. Staff witness Dana E. Eaves provides Staff's recommendation associated with the structure of any FAC which the Commission may authorize for KCPL.

[2] Ives Direct Testimony, Page 11, line 7.

Q. Does Staff agree with KCPL's request for a transmission tracker outside of an FAC?

A. No. Staff disagrees with certain transmission expense being included in the FAC and disagrees with KCPL's request for a stand-alone tracker for transmission expense if the Commission does not grant KCPL a FAC. Similar to KCPL's request for a property tax, cyber security, and vegetation management tracker, KCPL is attempting to isolate yet another expense without taking into consideration any change in expense or revenue that may offset future increases in transmission expense.

Q. On page 14 of his rebuttal testimony Mr. Rush, with reference to SPP Administrative Fees, states that "[t]hese costs are rising, are out of the Company's control and are necessary to transport electricity to its customers." Do you agree with these comments?

A. No. Although KCPL's transmission costs have increased over the past several years, the SPP Administrative Fees are projected to decrease in the future primarily through actions of SPP members themselves.

Q. What is the evidence that SPP Administrative fees will actually decrease in the future as opposed to increase, as suggested by Mr. Rush?

A. The SPP held a Finance Committee Meeting on October 13, 2014 in Dallas, Texas. The purpose of the meeting was, in part, to discuss SPP's 2015 Administrative Fee budget. Staff obtained the minutes of this meeting from SPP's website.[3] Included in the Finance Committee minutes was the statement that the 2015 SPP Operating budget would decrease from $150.2 million to $142.4 million. In addition to this decrease in the 2015 budget was an indication by several members of the SPP Finance Committee that there would

[3] SPP Finance Committee Meeting Minutes *10/13/14* http://www.spp.org/section.asp?group=245&pageID=27.

be a reduction in the SPP administrative rate charged to SPP members in 2016 and beyond. The SPP Finance Committee Meeting Minutes are attached as Schedule KL-s1. The following excerpt is from SPP's Finance Committee Meeting Minutes dated October 13, 2014 beginning on Page 2:

> 2015 Budget
> SPP staff reviewed, in detail, specific actions it proposes to allow the 2015 operating budget to be fully funded within the existing schedule 1A administrative fee rate cap of 39¢/MWh. Various committee members expressed reservations regarding specific items regarding the appropriateness of the action and/or the impact to members if the action was undertaken.
>
> The actions outlined by SPP staff would reduce the 2015 net revenue requirement from \$150.2 million to \$142.4 million. Committee members noted that none of the actions proposed resulted in cost reductions attributable to LEAN process improvements and that none of the reductions stretched staff to identify cost efficiency improvements. Several Committee members indicated the purpose of these actions were to "smooth" out SPP's administrative fee in anticipation of a reduction in the rate in 2016 and beyond.
>
> Larry Altenbaumer made the following motions, which were seconded by Kelly Harrison:
>
> 1) Establish the 2015 schedule 1A administrative fee rate at 39¢/MWh
>
> 2) Approve the 2015 budget with a net revenue requirement of \$141.2 million, directing SPP management to create an additional \$1.2 million in expense reductions (in addition to the list provided to the committee during the meeting) in the spirit of the proposed cuts which do not transfer costs into future years.
>
> The motions were approved by unanimous voice vote.

Q. Do the minutes of the October 13, 2014 SPP Finance Committee Meeting indicate that SPP's President, Mr. Nick Brown agreed with the fact that the members of the Finance Committee were focusing on SPP costs associated with SPP's Administrative Fee?

A. No. The meeting minutes indicate that Mr. Brown was concerned that the SPP Finance Committee members were focusing on financial management as opposed to solving regional issues and the use of a cap would impact what SPP can accomplish in the future. Members of the Finance Committee that includes Westar Energy, American Electric Power Company, Inc. ("AEP"), Oklahoma Gas & Electric Company ("OG&E"), and KCPL, among others, countered Mr. Brown's concerns with the fact that the restrictions that SPP members are exercising on SPP and its budget are no different than what they experience in their own budgets. The Finance Committee members also indicated there is a renewed focus on utility costs, driven by the increased cost of transmission, which requires changes to how SPP manages itself financially.[4]

Q. Is there additional evidence that, contrary to Mr. Rush's testimony, SPP Administrative Fees will decrease in the future?

A. Yes. On October 1, 2014, Denise M. Buffington and Matthew W. Dority filed a Motion to Intervene, on behalf of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company, both subsidiaries of Great Plains Energy Incorporated, under FERC Docket No. ER14-2850-000 and ER14-2851-000, Southwest Power Pool, Inc. The case involves a September 11, 2014, SPP filing of revisions to its governing documents (Membership agreement and bylaws) in order to facilitate additional SPP members joining SPP as Transmission Owning Members. Included in SPP's filing was the prepared testimony of Carl A. Monroe, SPP's Executive Vice President and Chief Operating Officer. His entire testimony is attached as Schedule KL-s2

[4] SPP Finance Committee Meeting Minutes, October 13, 2014, Pages 2-3.

At page 10 of Mr. Monroe's testimony he included a chart which shows the estimated net present value of the costs and benefits to current SPP Members over the next ten years including the impacts on current Members' Schedule 1A/Membership Fee payments to SPP. At page 11 of his prepared testimony filed in the FERC case, Mr. Monroe stated that the SPP determined that over the next ten years there would be a savings of $185,889,000 in Schedule 1-A charges to current SPP Members (including KCPL) as a result of the new members joining the SPP.

Q. Other than SPP administrative fees, does a KCPL witness address rising SPP regional transmission costs in his rebuttal testimony?

A. Yes. Beginning on line 14 on page 25 of his rebuttal testimony, Mr. Klote states "These transmission expense increases are largely driven by charges to KCP&L under Schedule 11 of the SPP OATT for KCP&L's regional Load Ratio Share of the ATRRs for SPP-directed Base Plan Projects that are subject to region-wide cost allocation."

Q. Is there anything extraordinary about this aspect of KCPL's transmission costs?

A. No. Extraordinary costs are defined as very different from what is normal or ordinary.[5] KCPL's transmission costs are ordinary operating costs. They are normal and recurring costs for KCPL that are, in fact, just the opposite of extraordinary costs.

Q. Has the Commission specifically addressed whether or not KCPL's transmission costs are extraordinary?

A. Yes. In KCPL's most recent rate case, Case No. ER-2012-0174, the Commission made the explicit determination that KCPL's transmission costs are not extraordinary in its Report and Order at Page 31:

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[5] MerriamWebster online dictionary. http://www.merriam-webster.com/dictionary/extraordinary.

> "Rare" does not describe cost increases in the utility business generally. Specifically, Applicants' evidence shows the following as to transmission. Transmission is an ordinary and typical, not an abnormal and significantly different, part of Applicants' activities. Also, Applicants showed that paying more for transmission than in the previous year is a foreseeably recurring event, not an unusual and infrequent event. Thus, "items related to the effects of" transmission cost increases are not rare and, therefore, are not extraordinary.

Q. Mr. Ives, starting on line 10 of page 9 of his rebuttal testimony, states that if KCPL's proposed trackers are not approved, it will not be able to recover costs over which it has little to no control (including but not limited to transmission costs). Does Staff agree?

A. No. Although Staff agrees that transmission expense has increased in recent years, Staff does not agree that KCPL has no control over reducing the impact of increasing transmission expense. As one example, KCPL had the opportunity to mitigate increased transmission expense with increases in transmission revenue. KCPL management had the recent opportunity to construct two regional transmission projects and, instead, transferred the right to construct these regional transmission projects to Transource Missouri, an affiliate of KCPL and KCP&L Greater Missouri Operations ("GMO") pursuant to a Stipulation and Agreement in File Nos. EA-2013-0098 and EO-2012-0367.

Q. Is KCPL seeking special ratemaking treatment for transmission expenses in this rate case because of the increase in transmission costs?

A. Yes. As discussed above, KCPL requests a Fuel Adjustment Clause in its direct filing and in its rebuttal filing requests a transmission tracker. Beginning on line 9 of page 10 of Mr. Ives' rebuttal testimony he identifies increased fuel and purchased power costs, SPP transmission fees, CIP/cyber security costs and property taxes as the reasons why KCPL has not earned its authorized ROE. Beginning on line 16 he states:

> The impact of these items was both significant and volatile such that standard ratemaking treatment using historical figures was clearly inadequate, and resulted in KCP&L revenues falling well short of its costs during the three year period.

KCPL should not be able to use the fact that transmission costs are rising as support for a transmission tracker, since it had every opportunity to mitigate such increases, and such increases are not extraordinary. Consequently, the Commission should deny KCPL's request for a transmission tracker.

TRANSMISSION EXPENSE

Q. In addition to KCPL's proposal for the inclusion of transmission expense in the FAC in its direct testimony and its proposal for a transmission tracker in rebuttal testimony, did KCPL request any other unusual treatment for transmission expense?

A. Yes. KCPL recommends that the level of transmission expense included in the True-Up should be annualized using the most current month of activity. The True-Up date in this case is May 31, 2015. KCPL's recommendation is to annualize transmission expense by using actual transmission expense incurred in May and multiplying the balance by twelve (12).

Q. Please explain how Staff treated KCPL's transmission expense in its direct filing.

A. Staff analyzed KCPL's transmission expense for the period of 2009-2014. Based on a discernable upward trend, Staff included an annualized level of transmission expense based on the 12 month period ending December 31, 2014 and stated in Staff's Revenue Requirement Cost of Service Report that transmission expense would be again be reviewed by Staff in the True -Up.

Q. Does Staff generally use one month of data to annualize any KCPL expense?

A. No. When determining a level of expense in KCPL's cost of service, Staff analyzes several years of data. The analysis involves analyzing all FERC accounts related to the expense, categories of costs included in the FERC accounts, events that may have affected the costs, forecasts, etc. Staff includes a level of costs based on the analysis that could include an average of all the costs, an average of certain categories of costs, an annualization based on 12-months of data, and, in some cases, an annualization based on a shorter period. However, that rarely involves annualizing costs based on one month of data.

Q. How does KCPL justify using one month of transmission expense to develop an ongoing level of costs?

A. Beginning on line 9 of page 25 of his rebuttal testimony Mr. Klote states:

> Transmission expense is forecasted to continue to increase. Therefore, annualizing based on current monthly activity is a more appropriate approach for inclusion of transmission costs in this case. This approach is appropriate for setting the base level of transmission costs, because these costs are forecasted to continue increasing significantly after the true-up period and while rates from this case are effective.

Q. Does Staff agree with Mr. Klote's statements that his approach is appropriate?

A. No. As discussed above, Staff will analyze data based on several factors and not simply because KCPL has forecasted an increase in transmission expenses. In addition, the use of one month to annualize any KCPL expense may not accurately reflect an ongoing level of costs. KCPL is recommending annualizing transmission expense using costs that will occur in May which, at the time of its rebuttal testimony, were not known. In addition, forecasted costs will not necessarily provide an accurate picture of what KCPL will actually incur. KCPL's witness John R. Carlson confirms this in his rebuttal testimony beginning on page 7 when he states the following: "While SPP provides annual projections of *base plan* *funding expenses*, these are only projections and have no bearing on actual expenses." [Emphasis added.] Mr. Carlson also provides a chart for the period of 2010-2017 for SPP's forecast of transmission upgrade costs and the costs that KCPL actually incurred for the period of 2010-2014. Mr. Carlson's own analysis clearly shows ** ________________ ____ ** over this period.

Q. Did Staff perform an analysis to support why using one month to annualize transmission expense is not ideal?

A. Yes. When annualizing expense using one month, the question becomes what month in a calendar year is representative of future ongoing costs. KCPL chose May 2015 because it is the end of the True-Up in this case, but is May 2015 the appropriate month to use to annualize transmission expense?

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Listed above is KCPL's actual monthly transmission expense incurred for the 12 month periods ending 2014. In January 2014, KCPL incurred its ** ____ ** level of transmission expense for the calendar year 2014. The annualized level of transmission expense using January 2014 is ** ________ **. In August 2014 KCPL incurred its ** ____ ** level of transmission expense for the calendar year 2014. The annualized level of transmission expense using August 2014 is ** ________ **. The use of ** ____________

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Q. Are all categories of transmission expense expected to increase?

A. No. A majority of KCPL's transmission costs billed by SPP include point to point transmission costs (SPP Schedules 7 and 8), base plan transmission upgrades that include zonal and region-wide charges (SPP Schedule 11), and tariff administrative fees (SPP Schedule 1-A). The increase in transmission expense is largely due to SPP's base plan transmission upgrades and SPP administrative fees.[6] Although the costs related to SPP's base plan transmission upgrades have increased and are forecasted to increase, there is evidence to support that SPP's administrative fees will decline in the future. As discussed above, SPP filed revisions to its membership agreement and bylaws in order to facilitate additional SPP members joining SPP. The new members represent a 12% load share in the SPP footprint.[7]

[6] Rebuttal Testimony of Ronald A. Klote, Page 25, lines 14-17 and Direct Testimony of Darrin R. Ives, Page 24, lines 10-15.
[7] Direct Testimony of Carl A. Monroe, Page 4, lines 3-4, FERC Docket No. ER14-2850.

Although the new members in this case are transmission owners, meaning KCPL will receive an allocated share of their transmission upgrades made after October 1, 2015[8], the additional load added to the SPP footprint, all other things being equal, will result in a decrease in base plan transmission upgrade costs (Schedule 11) and SPP administrative costs (Schedule 1-A).

Q. Please summarize your testimony concerning annualization of transmission expense.

A. Staff analyzed several years of historical actual transmission expense. The analysis involved reviewing all FERC accounts related to transmission expense, various categories of costs included in the FERC accounts, events that may have affected the costs, forecasts, etc. For its direct filing, Staff included an annualized level of transmission expense based on 12 months ending December 31, 2014 in KCPL's cost of service. Staff fully intends to review KCPL's transmission expense through the true-up, May 31, 2015. At the time of this surrebuttal testimony filing, the amount of actual transmission expense incurred by KCPL through May 31, 2015 is not known. However, as previously mentioned, Staff generally does not use one month of data, as KCPL proposes, to annualize any expense. For the true-up in this case Staff will analyze KCPL's transmission expense and determine an appropriate level of expense at that time.

SPP REGION-WIDE PROJECTS

Q. Please summarize the rebuttal testimony of KCPL witness Klote with regard to the SPP Region Wide Transmission Projects.

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[8] FERC Order Docket No. ER14-2850-000, page 40.

A. KCPL has two SPP base plan transmission projects, the Swissvale-Stilwell Tap project and the Stilwell-West Gardner Substation. KCPL proposed an adjustment to eliminate the investment, expense, and revenue associated with these projects. Mr. Klote states the following beginning on line 15 of page 8 of his rebuttal testimony:

> Without these adjustments 100% of the ratebase [*sic*] and expenses related to these KCP&L-owned projects is being included in the retail revenue requirement calculation and 100% of the revenues related to these projects is being credited in the retail revenue requirement calculation. In addition, the charges for KCP&L's regional Load Ratio Share (<8%) of the projects, which are booked to Account 565 (Transmission by Others) are included in the retail revenue requirement calculation. The only amount that needs to be included in the retail revenue requirement calculation is the charge that KCP&L receives for its regional Load Ratio Share (<8%) of the cost of the projects, which is booked to Account 565.

Mr. Klote indicates Staff's treatment of these projects is flawed because it is not consistent with how SPP allocates the costs of these projects to KCPL.

Q. Did Staff intend to include 100% of the rate base, expense, and revenue related to these projects in KCPL's cost of service?

A. Yes. The upgrades to the Swissvale-Stilwell Tap project and the Stilwell-West Gardner Substation were made to existing KCPL regulated utility assets. As such, all investment, revenue, and expense associated with these projects should be included in KCPL's cost of service. Therefore, Staff did not adopt KCPL's adjustment to eliminate the investment, revenue, and expense related to these projects.

Q. Does SPP allocate the investment, revenue, and expense to other SPP members?

A. Yes. The current SPP transmission cost sharing method is based on the voltage of the transmission line and is reflected in the table below. This method was approved by FERC in June 2010:

Voltage	Paid for by SPP Region	Paid for by Local Zone
"Electricity Highways" 300 kV and above	100%	0%
"Electricity Byways" above 100 kV and below 300 kV	33%	67%
"Electricity Byways" 300 kV and above	0%	100%

Q. Did KCPL receive a Notification to Construct prior to June 2010 for the Swissvale-Stilwell Tap project and the Stilwell-West Gardner Substation and if so how are the costs related to these projects allocated?

A. KCPL received a Notification to Construct on June 19, 2009 for the Swissvale-Stilwell Tap project and on September 3, 2010 for the Stilwell-West Gardner Substation. Both of these projects are 100% allocated to the SPP region. In Staff's rebuttal testimony on page 31, lines 4-6, I incorrectly stated that these projects are allocated 33% to the SPP region and 67% to the zone (KCPL) when in fact these projects are 100% allocated to the SPP region.

Q. Please explain the SPP allocation process for the two projects constructed by KCPL whose costs are assigned to the entire SPP region.

A. SPP members, other than KCPL, pay for approximately 92% of the costs related to the region-wide projects and although the transmission assets are owned by KCPL, KCPL is only responsible for approximately 8% of the costs. The 92% paid by other SPP members is distributed to KCPL by SPP through transmission revenues.

Q. If the projects are 100% allocated to the SPP region why did Staff treat the project investment, expense, and revenue as if the projects were 100% allocated to KCPL?

A. In this case, KCPL has retained ownership of these regulated transmission assets but made a management decision to propose a ratemaking adjustment to eliminate the investment, expense, and revenues from its cost of service. KCPL's adjustment forces KCPL customers to pay for higher transmission expense because of the upgrades but eliminates the revenues that would offset a portion of the expense by virtue of KCPL's ownership of the two projects. Mr. Klote states on page 8, beginning on line 20: "The only amount that needs to be included in the retail revenue requirement calculation is the charge that KCP&L receives for its regional Load Ratio Share (<8%) of the cost of the projects, which is booked to Account 565." There is no ratemaking requirement that Staff is aware of that KCPL must make an adjustment to reduce or eliminate revenues related to these projects.

Q. Is there a negative impact on KCPL's customer if the Commission agrees with KCPL's treatment of the Swissvale-Stilwell Tap and Stilwell-West Gardner Substation region-wide projects?

A. Yes. The value of the Swissvale-Stilwell Tap and Stilwell-West Gardner Substation region-wide projects is approximately $30,000 on a total Company basis. Although this value is minimal, the issue is with how KCPL will treat future SPP-directed transmission projects of a similar nature. For each region-wide project constructed by KCPL, and the subsequent elimination of the costs and revenues of those projects from its cost of service for ratemaking purposes, the seemingly immaterial amount of $30,000 will accumulate as the projects increase, causing KCPL customers to potentially pay materially more in rates.

Q. Please provide a summary of Staff's recommendation for this issue.

A. The investment, expense, and revenue eliminated by KCPL related to the Swissvale-Stilwell and West Gardner projects are associated with KCPL's Missouri regulated utility assets and, therefore, the costs and revenues should remain in KCPL's cost of service.

In this case, several KCPL witnesses discuss in direct and rebuttal testimony KCPL's inability to control increasing transmission expense and earn its authorized ROE, but when given the opportunity to mitigate a portion of the cost increases, KCPL in turn makes an adjustment to eliminate the revenues. Staff recommends the Commission deny KCPL's request to eliminate transmission revenue from its cost of service that can be used to offset a portion of transmission expense; an expense for which KCPL is requesting special treatment in this case.

WHOLESALE TRANSMISSION REVENUE

Q. Please summarize the rebuttal testimony of KCPL witness Klote with regard to wholesale transmission revenue.

A. Mr. Klote recognizes that since KCPL's owned transmission assets are included in rate base and its related transmission expenses are included in the cost of service in this case, transmission revenues received through SPP for use of those same transmission assets by other SPP members should be credited against the revenue requirement.[9] The transmission revenues received from SPP are based on a FERC ROE that is higher than the Commission authorized ROE. As a result, KCPL contends that transmission revenues are overstated if an adjustment is not made to reduce transmission revenues for the difference between the FERC authorized ROE and the Commission authorized ROE. Beginning on Page 5, line 2, of his rebuttal Mr. Klote states:

> When the FERC-authorized ROE is higher than the Missouri Commission authorized ROE, the transmission revenues from other Transmission Customers that are being credited against the retail revenue requirement are greater than that which was calculated in the retail revenue requirement. Essentially Missouri retail customers would be credited back more than they would have been charged.

[9] Ronald A. Klote, Rebuttal Testimony, page 4 lines 12-21.

Q. Does Staff agree?

A. No. KCPL calculates an annual transmission revenue requirement ("ATTR") using KCPL's transmission formula rate ("TFR").[10] The annual transmission revenue requirement is used by SPP to allocate transmission revenue and expense to all transmission owners and transmission customers of SPP. The annual transmission revenue requirement may include available incentives such as ROE adders and CWIP in rate base. Although KCPL can apply for transmission project specific incentives, currently the only incentive that is included in KCPL's annual transmission revenue requirement is a 50 basis point adder for being a member of SPP. Most transmission owners participating in RTO's have requested and received approval from FERC for the 50 basis point adder.[11] The aforementioned incentives are included in transmission revenues KCPL receives from SPP and transmission costs billed from SPP and charged to its customers by KCPL. Staff's treatment of the transmission revenues in this case is to simply recognize all transmission expenses incurred and revenues received by KCPL, including revenues based on a higher FERC ROE. If KCPL customers are expected to pay for transmission expense which includes costs based on a higher FERC ROE, then transmission revenues that are based on a higher FERC ROE should also be included in KCPL's cost of service. If, however, the Commission agrees with KCPL that KCPL's transmission revenues should be reduced for the difference between the FERC authorized ROE and the Commission authorized ROE, then a corresponding adjustment should be made to KCPL's transmission expense since it also includes costs based on a higher FERC ROE.

[10] KCPL Response to Staff Data Request 295 in Case No. ER-2014-0370.
[11] KCPL Response to Staff Data Request 292.1 in Case No. ER-2014-0370.

Q. How does Staff respond to Mr. Klote's statement above, "Essentially Missouri retail customers would be credited back more than they would have been charged."?

A. Mr. Klote argues that since all of KCPL's transmission assets are included in the retail revenue requirement based on a Commission authorized ROE, and transmission revenues received from SPP are based on a higher FERC ROE, an adjustment must be made to reduce revenues; otherwise, according to Mr. Klote, KCPL's Missouri retail customers would be credited back more than they have been charged. Staff contends KCPL's participation in SPP encompasses both financial impacts of KCPL's ownership of transmission assets and the financial impacts of the use of other SPP members' transmission assets. As a SPP transmission customer, if costs of providing transmission service increase for other members of SPP, KCPL's transmission expense will increase. Likewise, as a SPP transmission owner, if KCPL's cost to provide transmission service increases, transmission revenues received from SPP will increase. Transmission revenue and expense must be treated in the same manner to be consistent and fair to KCPL's retail customers.

Q. How did Staff treat KCPL's transmission expense in this case?

A. As described earlier in this testimony, Staff included an annualized level of transmission expense based on the 12 month period ending December 31, 2014. Similar to the transmission revenues, Staff did not eliminate any transmission expense that includes costs calculated using a higher FERC ROE.

Q. Mr. Klote suggests that Staff's rationale to adjust transmission expense for the incentives that are included in the costs that KCPL receives from SPP is flawed.[12] Do you agree that Staff's rationale is flawed and, if not, why not?

[12] Ronald A. Klote, Rebuttal Testimony, Pages 6-7.

A. No, I do not agree that Staff's rationale is flawed. First, Staff's *preferred* treatment of KCPL's wholesale transmission revenues is to include both transmission revenues received from and transmission costs paid to SPP, including FERC incentives. Mr. Klote's suggestion that Staff's rationale is flawed relates to Staff's *alternate* recommendation to reduce transmission expense for the costs that include a higher FERC ROE. Mr. Klote states the following beginning on page 6, line 30 of his rebuttal:

> There would be absolutely no basis, however, for KCP&L to make such an adjustment to the "Transmission but Others" expenses booked in FERC Account 565 that are charged to KCP&L as a transmission customer under the SPP OATT for the allocated use of transmission facilities that are owned by other transmission owners in SPP. These charges are for ATRRs calculated in the other transmission owners' FERC-approved TFRs and charged to transmission customers under the FERC-approved SPP OATT. KCPL has no option to pay any other amounts for the allocated use of transmission owned by other transmission owners. . . .

Staff's treatment of transmission revenues and transmission expenses in this case is consistent. Again, Staff prefers to include all transmission revenue in KCPL's cost of service that includes the higher FERC ROE and to include all transmission expense in KCPL's cost of service that includes costs based on a higher FERC ROE. KCPL would like to recover all transmission expenses that are based on a higher FERC ROE from its rate payers but eliminate transmission revenues that are based on a higher FERC ROE that would mitigate a portion of the rising transmission expense.

Q. Please summarize Staff's position regarding wholesale transmission revenue.

A. KCPL is billed transmission expense from SPP as a transmission customer and receives transmission revenues from SPP as a transmission owner, both of which include ROE incentives. Staff recommends that KCPL treat transmission expense and revenue consistently by reflecting all of KCPL's revenue and expense, including FERC ROE incentives, in its cost of service.

PROPERTY TAX TRACKER

Q. Please summarize KCPL's rebuttal testimony with regard to its request for a property tax tracker?

A. KCPL witnesses Rush and Ives continue to propose a property tax tracker based on historical and forecasted property tax increases, stating that without a tracker, property tax increases will have a negative impact on KCPL's ability to earn the authorized ROE. Mr. Ives states on page 9 of his rebuttal testimony, beginning on line 5:

> The historical record unambiguously shows that changes in these cost of service items have caused material earnings shortfalls for KCP&L since current rates took effect in January 2013. The forecasts clearly show that if new rates from this case go into effect without the requested mechanisms to address these cost of service items, KCP&L will shortly thereafter experience material earnings shortfalls.

In addition, KCPL witness Hardesty states that KCPL's property taxes are expected to increase in 2016 and 2017[13].

Q. What is Staff position on KCPL's proposal for a property tax tracker?

A. Although Staff recognizes property taxes have increased, the use of a tracker is not justified simply because a specific cost has increased. Cost decreases also occur outside of a rate case that may offset a portion of cost increases that a utility may experience. A tracker is typically used in rare circumstances where it is extremely difficult to identify an appropriate level of costs to be included in rates. As explained in further detail in my rebuttal

[13] Melissa Hardesty Rebuttal Testimony, Page 24, lines 7-8.

testimony, property taxes are normal operating costs that will continue to occur every year and an annualized level to include in rates can be reasonably calculated.

Q. Is an increase in normal operating expense a valid reason for a cost tracker?

A. No. Trackers should only be used to address the rare circumstances for which it is difficult to identify the appropriate level of costs to be included in rates. As mentioned above in my surrebuttal testimony, in its Report and Order in Case No. ER-2012-0174 addressing KCPL's request for a transmission tracker, the Commission stated that generally, cost increases for normal operating expenses are not rare. Property taxes are considered a normal operating expense. Consequently, a possible increase in KCPL's future property taxes is not "rare" or unusual and therefore does not justify the use of a property tax tracker.

Q. As discussed above, Mr. Ives states that property tax increases resulted in a negative impact on KCPL's historical earnings and will continue in the future if the Commission does not grant KCPL a property tax tracker as well as the other trackers proposed by KCPL. Do you agree?

A. No. Mr. Ives provides a chart on page 10 of his rebuttal testimony that lists fuel and purchased power cost (net of off system sales), SPP transmission fees, CIP/cyber security costs, property taxes, and the effect of their respective cost increases on historical earnings and future earnings. Mr. Ives' chart fails to identify any offsetting cost decreases that may have occurred historically or could occur in the future. KCPL is quick to point out when costs are increasing and the effect that the cost increases have on their earnings but does not address any cost decreases.

Q. Is Staff aware of any cost decreases that occurred in the past that would offset a portion of the cost increase in historical property taxes?

A. Yes. Over the past several years KCPL has reduced its employee workforce and discontinued incentive compensation for union employees, both of which resulted in significant costs reductions. These are just two examples of cost decreases that occurred and would offset a portion of the increase in property taxes. Staff witness Cary G. Featherstone discusses KCPL's cost reductions in greater detail beginning on page 20 of his rebuttal testimony.

Q. Is Staff aware of any cost decreases that KCPL will incur in the future?

A. As discussed above, there is evidence that SPP administrative fees may decrease in the future. Although Staff cannot point to a specific cost decrease or increase in revenue that will undoubtedly offset future cost increases, Staff can state that while certain costs increase, as KCPL points out, KCPL will also experience decreases in other costs.

Q. Is there anything else that can be concluded from Mr. Ives' chart?

A. Yes. KCPL was aware that property taxes and the other costs included in Mr. Ives' chart increased after rates went into effect in January 2013. This is clear when Mr. Ives states beginning on page 10, line 9 of his rebuttal testimony,

> The rate allowance for fuel and purchased power cost (net of off system sales), SPP transmission fees, CIP/cyber security costs and property taxes was inadequate in the first year of new rates, producing an after-tax earnings shortfall of approximately \$19.8 million (or roughly 180 basis points in reduced ROE). The Year 1 earnings shortfall attributable to these items increased in Year 2, producing and after tax earnings shortfall of \$23.9 million (or roughly 220 basis points in reduced ROE).

When costs increase to a level that is greater than any offset based on other cost decreases, utility companies have an option to file for a rate case. KCPL could have filed another rate case prior to this one to recover the increase in costs identified in Mr. Ives' chart.

KCPL management made a decision to continue to absorb any shortfall in earnings when it did not file a rate case.

Q. Does KCPL's witness Hardesty provide KCPL's projected property taxes for 2016 and 2017?

A. Yes. Ms. Hardesty provides projected property taxes of ** ____ ** million in 2016 and ** ____ ** million in 2017 on page 24, beginning on line 7 of her rebuttal testimony.

Q. Do you agree with Ms. Hardesty projected level of property tax expense?

A. No. The projected expense level provided by Ms. Hardesty includes both property taxes that are capitalized and property taxes that are expensed, but it should only include expensed property taxes. The Commission should disregard the projected property tax expense identified by Ms. Hardesty, as it suggests that KCPL is projected to incur a higher level than it really will, since she provides a projection that includes projected capitalized and expensed property taxes. KCPL is assessed property taxes on plant that has not been placed in service ("CWIP"). These property taxes are capitalized to a specific construction project. When the construction project is completed, all the costs associated with the project, including property taxes, are transferred to plant in service. The capitalized property taxes are then recovered like any other construction cost, through depreciation over the life of the plant. Conversely, expensed property taxes are those that are assessed on plant that has already been placed in service. Historically KCPL recovers these through an annualized level established in a rate case.

Q. Is KCPL requesting a property tax tracker on capitalized property taxes?

A. No. KCPL's request for a property tax tracker is based on property taxes that are expensed. Since Ms. Hardesty's projected property taxes for 2016 and 2017 include capitalized property taxes, the projections are overstated with respect to the level of property taxes that should be tracked using the tracker. By using the higher projections for property tax, Ms. Hardesty gives the impression that expensed property taxes are projected to increase more than they really are. Instead of the projections identified in Ms. Hardesty's testimony, In response to Staff data request 608, KCPL's projected property tax expense should be ** ____ ** million for 2016 and ** ____ ** million for 2017.[14]

Q. Does Staff believe KCPL's projected expensed property taxes over stated?

A. Staff cannot say with certainty that the projected property taxes are overstated however; the following chart compares KCPL's actual property taxes incurred to the projected level of property taxes. The projected level of expensed property taxes for ** ____ ____ **[15]

**

____	____	____	____
____	____	____	____
____	____	____	____
____	____		
____	____		
____	____		

**

[14] KCPL Response to Staff Data Request 608 in Case No. ER-2014-0370.
[15] *Id.*

Q. Please summarize your testimony concerning KCPL's witnesses that address a proposed property tax tracker.

A. The common theme for KCPL's proposed property tax tracker and the other trackers proposed in this case is based on rising costs that prevent KCPL from earning its authorized ROE. Staff does not dispute that property taxes have increased since KCPL's rates were last changed in January 2013. However, increases in property taxes, a normal operating expense, is not a valid reason to warrant a tracker. In addition, if KCPL was not collecting a sufficient level of revenue to earn its authorized ROE, it should have filed a rate case. KCPL's proposed property tax tracker isolates one expense without any consideration for changes in costs or revenues that can mitigate the increase in costs. When setting rates, it is essential to address all increases and decreases in investment, expense and revenue to determine the revenue requirement. Once KCPL determined that revenues collected did not sufficiently cover its expenses and allow it to earn its authorized ROE, it could have filed a rate case but chose instead to absorb the costs.

VEGETATION MANAGEMENT TRACKER

Q. Please summarize KCPL's rebuttal testimony with regard to its request for a vegetation management tracker.

A. Although KCPL witnesses Ives and Rush stated in direct testimony that KCPL's proposal is based on rising costs, now both allege it is not primarily based on raising costs. Mr. Ives states in rebuttal testimony starting on page 12:

> KCP&L-MO is requesting a tracker from vegetation management in order to maximize the benefit of each dollar spent, and to ensure all of our customers are not over- or under-charged for vegetation management efforts.

Mr. Rush states beginning on page 40 of his rebuttal testimony:

> The Company is not requesting a vegetation management tracker primarily because of increasing costs as most trackers may address. Instead, KCP&L Missouri operations are requesting a tracker for two (2) very specific reasons other that *[sic]* traditional increasing costs. First, KCP&L serves both Kansas and Missouri service territories and has an affiliate GMO. These combined service territories all have tree trimming requirements and cover a fairly large geographic territory. In order to maximize the overall efficiencies, the Company believes that it needs to be able to target certain areas of tree trimming. This may result in an imbalance of expenses in one territory over another, but in the overall plan, would balance over time. Under these circumstances, use of a tracker would enable customers to get full credit for each dollar of vegetation management expense built into rates every year. Secondly, the Company is recommending the addition of three program improvements that were addressed in testimony of Jamie Kiley. These new programs are tree-trimming enhancements that should improve reliability.

Q. Is KCPL's proposal for the vegetation management tracker consistent with the purpose of a tracker?

A. No. KCPL's justification for a vegetation management tracker does not meet the conditions generally utilized when establishing a tracker. A tracker is a unique regulatory tool used when it is difficult to accurately determine an annualized level of expense, when there are no historical costs to accurately determine an annualized level of expense, or when a new Commission rule is implemented. Staff witness Mark L. Oligschlaeger discusses the criteria Staff utilizes when evaluating a utility's request for a tracker in greater detail in his rebuttal testimony in this case. Mr. Rush suggests that a vegetation management tracker is necessary based on KCPL's plan to balance costs in all of KCPL's rate districts. Mr. Rush also states in his direct testimony beginning on page 29, line 21, "Use of a tracker for vegetation management costs will enable the Company to schedule and perform this work in the most efficient manner..." A tracker is generally used to reduce the amount of risk associated with significant fluctuation of costs. It is certainly not intended to assist the utility with scheduling and performance efficiencies as Mr. Rush is suggesting. Mr. Rush also justifies a vegetation management tracker based on three program improvements. The proposed programs are entirely up to the discretion of KCPL, are based on projected costs, and are not required by the Commission Vegetation Management rules. Mr. Rush's very specific reasons for the need of a vegetation management tracker that includes balancing the costs for all rate districts and implementation of three new programs do not justify a tracker under the criteria Staff generally uses when evaluating the need for a tracker.

Q. Is KCPL suggesting costs associated with vegetation management are volatile? And if so, does Staff agree?

A. On page 12 of his rebuttal testimony beginning on line 19, Mr. Ives states:

> Because of the variability in jurisdictions, it is sometime necessary to concentrate vegetation management efforts in a certain jurisdiction in a given year, and less so in the following year. This can make the cost of vegetation management by jurisdiction volatile year-over-year.

Staff does not agree with Mr. Ives suggestion that KCPL or GMO's rate districts vegetation management costs are volatile. The following chart identifies KCPL (total company), GMO-MPS and GMO-L&P historical actual vegetation management costs.

	2009	2010	2011	2012	2013	2014
KCPL Total Company	$14,055,887	$14,725,664	$15,657,981	$16,378,377	$16,060,990	$14,966,266
GMO-MPS	$7,164,225	$6,447,295	$7,357,081	$7,017,488	$7,077,845	$7,694,059
GMO-L&P	$1,598,495	$1,862,101	$2,179,293	$1,620,979	$1,449,909	$2,642,667

The costs for KCPL and GMO's rate districts listed above are relatively flat with the exception of the calendar year 2014 for GMO-L&P. In all three rate districts an annualized level can be determined using historical data to represent an ongoing level of expense. If in fact costs increased, such as what occurred in the GMO-L&P district in 2014, Staff would consider the increase when it develops an annualized level of costs to include in its cost of service. In addition, the historical costs for all three rate districts are not material in nature as to result in a negative impact on KCPL's or GMO's earnings.

Q. Does KCPL suggest that vegetation management has a significant negative impact on its earnings?

A. Yes. In his rebuttal testimony, Mr. Ives states on page 12, beginning on line 7:

> The forecasted expense recovery shortfall if the requested mechanisms are not granted by the Commission will be both significant and volatile such that standard ratemaking treatment using historical figures will clearly be inadequate, and will result in KCP&L revenues falling well short of its costs during the two-year period immediately after its rates are increased in this case.

As discussed above, Mr. Ives provides a chart in his rebuttal testimony that provides the impact that specific costs, including vegetation management costs, have on KCPL's earnings. Based on Mr. Ives' chart, vegetation management costs had no impact on earnings following KCPL's last rate case and an immaterial impact on earnings based on the forecast utilized by Mr. Ives.

Q. As discussed above, Mr. Ives states that KCPL's request for a tracker "will ensure all of our customers are not over-or under-charged for vegetation management efforts." Please respond.

A. Missouri utilities are allowed the opportunity to recover their costs in rates established through the rate case process. Utilities and its customers are very rarely reimbursed for any prior under or over-recovery of costs incurred by the utility outside of a rate case. As with all costs incurred by a utility, it is expected that there are times when the utility recovers a cost that is in excess of what is included in rates and times when the utility does not recover the level of a cost imbedded in rates. The use of a tracker should be limited to rare circumstances, not used to recover normal operating expenses that can be addressed through the rate case process.

Q. Please summarize Staff's position on KCPL's proposed vegetation management tracker.

A. Based on its rebuttal testimony, KCPL's primary reason for proposing a vegetation management tracker is based on balancing the costs in its rate districts and implementation of three new programs. In both situations, KCPL's request is based on managing the program and not based on costs that are volatile or fluctuate. Trackers are not intended to allow a utility to recover costs based on proposed programs or assist the utility with scheduling and performance efficiencies. In addition, as with every other tracker proposed by KCPL in this rate case, KCPL asks the Commission to isolate one type of expense without taking into consideration changes in expenses and revenues during the same period that may mitigate in part, if not all, of any cost increase. Staff recommends the Commission deny KCPL's request for a vegetation management tracker.

CYBER SECURITY TRACKER-CRITICAL INFRASTRUTURE PROTECTION ("CIP") OR ("CYBER SECURITY")

Q. Please summarize KCPL's rebuttal testimony with regard to its request for a cyber-security tracker?

A. KCPL witnesses Ives, Rush and Phelps-Roper address cyber-security in their rebuttal testimony. Mr. Ives and Mr. Rush address the negative impact cyber-security costs have had on historical KCPL earnings and will continue to have in the future. Mr. Phelps-Roper addresses historical and projected cyber-security costs and, because of the nature of the costs, KCPL's inability to control the costs.

Staff continues to recommend that the Commission deny KCPL's request for a cyber-security tracker. KCPL's rationale that cyber-security costs will have a negative impact on KCPL's earnings is premature since KCPL witnesses confirm the costs are difficult to forecast, and they do not consider any reductions in other costs or increases in revenues that may mitigate, in part, any cost increases. If the Commission does grant a cyber-security tracker, Staff recommends all labor and capital costs be excluded from the tracker.

Q. What costs does KCPL propose to include in the cyber security cost tracker?

A. On page 11 of Mr. Phelps-Roper's rebuttal testimony he describes the costs intended to be included in KCPL's tracker as follows:

> It should also be noted the CIP/Cyber tracker is envisioned to provide future recovery of O&M costs, and does not include Capital, which provides an incentive for the Company to manage costs.
>
> As part of the true-up process in this rate case, staffing levels as of May 31, 2015 will be included in the revenue requirement calculation. The staffing level at that time will be known and measureable amount and clearly identified in the payroll annualization calculation. The CIP/Cyber tracker requests that incremental positions hired after May 31, 2015, in order to support the CIP/Cyber compliance process, should be included in the proposed tracker. These positions will be incremental to the staffing levels included in base rates as part of the true-up process.

In the quote above, Mr. Phelps-Roper indicates that KCPL's proposed tracker does not include capital costs. However, as I earlier described in my rebuttal testimony beginning on page 24, in his direct testimony Mr. Rush suggests that capital costs are included in KCPL's requested tracker.[16] My rebuttal testimony includes a data request response from KCPL that also reflects an intent that the proposed tracker include capital related costs. No explanation has been supplied for this inconsistency.

Q. Did Staff address the level of cyber-security costs it included in its Accounting Schedules in its rebuttal testimony?

A. Yes. Staff recognizes that cyber-security costs have increased and therefore included the last known level of cyber-security investment and O&M costs, including labor, through December 31, 2014. These costs will also be reviewed through May 31, 2015, the true-up period cut-off date in this case.

Q. As previously mentioned, Mr. Ives provides a chart in his rebuttal testimony that includes the impact of increased cyber-security costs on KCPL's historical and future earnings. Do you agree with his calculations?

A. No. Mr. Ives' chart only depicts certain cost increases and the related impact on earnings. He does not include any reductions in costs or increases in revenues experienced by KCPL that mitigated the cost increases shown. However, when considered in isolation, since KCPL's last rate case in 2012 changes to KCPL's cyber security cost levels did not have a material impact on earnings as Mr. Ives would have the Commission believe.

Q. The chart shows increased cyber-security costs in 2014. How could KCPL mitigate the impact of those increased costs?

[16] Tim M. Rush, Direct Testimony, Page 34, Lines 3-6.

A. When a utility is not earning its authorized ROE, it has the option to file a rate case to capture increased costs in rates. When KCPL's costs rise, as cyber-security costs did in 2014, it could have filed a rate case to reflect the cost increases in rates sooner. Although KCPL points to Missouri's regulatory model as to the reason why it did not earn its authorized ROE and that trackers are now a solution to provide KCPL the opportunity to achieve its authorized return, KCPL's management decision to not file a rate case certainly had a negative impact on its ability to earn its authorized ROE. While Staff applauds KCPL for protecting its customers from frequent rate increases, in an increasing cost environment KCPL has an obligation to protect its shareholders by filing a rate case to recover cost increases as quickly as possible.

Q. KCPL claims it does not have the ability to control the costs related to cyber-security. Do you agree?

A. Staff does not dispute that KCPL is required to comply with CIP/Cyber standards however; Staff believes KCPL has some ability to manage and control the costs. For example, KCPL can manage cyber security costs in the salaries and wages paid to employees and whether contractors are used in lieu of employees. Mr. Phelps-Roper confirms KCPL's control when he describes the numerous governance, project management, and cost control procedures to ensure that CIP/Cyber Security efforts are efficient and cost effective.[17]

Q. Mr. Phelps-Roper compares 2014 actual cyber-security costs to projected 2015 costs and states KCPL will not recover its forecasted 2015 costs.[18] Do you agree?

A. No. Mr. Phelps-Roper cannot make such a statement when the costs are not known and measurable and are difficult to project. To state that KCPL will fall short of

[17] Joshua F. Phelps-Roper, Rebuttal Testimony, Page 10, lines 9-10.
[18] Joshua F. Phelps-Roper, Rebuttal Testimony, Page 9, lines 10-17.

recovering its costs is premature. In addition to comparing 2014 costs to 2015 projected costs, he compares 2014 and projected costs in 2016-2017.[19] My own analysis indicates that a majority of the increases that KCPL projects will occur in 2015 and are largely comprised of new employees and capital additions. As Mr. Phelps-Roper states above, KCPL is arguably not seeking capital costs in its proposed tracker. After 2015, KCPL's projections indicate that the projection for 2017 is very similar to actual incurred costs for the 12-month period ended December 31, 2014. The following chart shows KCPL's actual 2014 cyber-security costs and its projected costs for 2015-2017.[20]

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Q. Are you aware of a utility requesting a cyber-security tracker?

A. A cyber-security tracker has not been requested by a Missouri utility. However, the Public Service Commission of West Virginia Charleston issued an order on May 26, 2015 on the tariff filing of Appalachian Power Company and Wheeling Power

[19] Joshua F. Phelps-Roper, Rebuttal Testimony, Page 3.
[20] KCPL response to Staff Data Request 0331.1 in Case No ER-2014-0370.

Company to increase rates. An excerpt from the Order is attached as Schedule KL-s3. On page 95 of its order, the West Virginia Charleston Commission stated the following:

> The Commission is aware of the increased security dangers presented in the modern world, particularly to the electric utility system. We know that extraordinary steps will become necessary (and may become common), but the Commission concludes that in the absence of concrete plans to implement specific security measures, projected costs, or new regulatory requirements, the projected costs, or new regulatory requirements, the proposal of the Companies to implement a Security Rider is premature.

Q. Please summarize Staff's position on KCPL's proposed cyber security tracker.

A. Costs projected to simply increase are not justification for a tracker. If KCPL were not collecting a sufficient level of revenue to allow it to earn its authorized ROE, it should have filed a rate case. Trackers should only be used in situations when costs are difficult or impossible to predict or when there is no historical data on which to base an appropriate level of ongoing costs. KCPL is requesting to recover specific expenses that can reasonably be calculated. The projected costs identified by KCPL will increase in 2015 largely due to the addition of new employees and capital additions. To the extent these costs will be incurred before May 31, 2015, they will be included in rates. Therefore, Staff recommends the Commission deny KCPL's request for a cyber-security tracker.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2014-0370

AFFIDAVIT

COMES NOW Karen Lyons and on her oath declares that she is of sound mind and lawful age; that she contributed to the attached Surrebuttal Testimony; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Karen Lyons

Karen Lyons

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 4th day of June, 2015.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

SPP Southwest Power Pool

Southwest Power Pool

FINANCE COMMITTEE MEETING

October 13, 2014

DFW Hyatt Regency Hotel
Dallas, TX

• Summary of Action Items •

1. Approved 2015 Budget
2. Approved 2015 schedule 1A and administrative fee rate of 39¢/MWh

• Schedule of Follow-up Items •

1. Establish a scorecard for presentation to MOPC, SPC, and BOD indicating costs associated with member required projects/services.
2. Develop schedule of items that require Committee approval, items that require Committee monitoring, and items that require Committee input.
3. Review of ARR exposures after July 2014.
4. Review SPP's status when a market participant declares bankruptcy.
5. Review any other alternatives to netting ARRs which can mitigate the short window of ARR exposure.
6. Review of credit metrics in September 2014.
7. Investigate potential to increase the exposure calculation for transmission service beyond 50 days.
8. Create comparison of level of financial disclosures contained in RTO annual reports
9. Provide line item detail of expenses expected to be recovered from bidders in the competitive bidding process under Order 1000.

SPP Southwest Power Pool

Southwest Power Pool

FINANCE COMMITTEE MEETING

October 13, 2014

DFW Hyatt Regency Hotel
Dallas, TX

• M I N U T E S •

Administrative Items

SPP Chair Harry Skilton called the meeting to order at 10:30 a.m. The following members of the Finance Committee were in attendance:

Harry Skilton	SPP Director
Larry Altenbaumer	SPP Director
Kelly Harrison	Westar Energy
Sandra Bennett (phone)	AEP
Mike Wise	Golden Spread Electric Coop
Laura Kapustka	Lincoln Electric
Tom Dunn	SPP

Others attending included:

Gretchen Holloway (phone)	ITC
Traci Bender	NPPD
Denise Buffington (phone)	KCPL
Jim Jacoby	AEP
Steve Pittinger	OG&E
Nick Brown	SPP
Carl Monroe	SPP
Lauren Krigbaum	SPP
Stan Chapman (phone)	SPP
Jim Eckelberger	SPP Director
Rick Hannmann	KPMG
Schoen Hertell	KPMG

Minutes from July 10, 2014, September 11, 2014, and September 23, 2014 meetings were reviewed. Kelly Harrison motioned to approve the minutes. The motion was seconded by Sandra Bennett and approved by unanimous voice vote.

The Committee asked a few questions about the August 2014 financial report.

The Committee requested a line item detail of expenses forecast to be recovered from the Order 1000 competitive bidding process.

2015 Budget

SPP staff reviewed, in detail, specific actions it proposes to allow the 2015 operating budget to be fully funded within the existing schedule 1A administrative fee rate cap of 39¢/MWh. Various committee members expressed reservations regarding specific items regarding the appropriateness of the action and/or the impact to members if the action was undertaken.

The actions outlined by SPP staff would reduce the 2015 net revenue requirement from $150.2 million to $142.4 million. Committee members noted that none of the actions proposed resulted in cost reductions attributable to LEAN process improvements and that none of the reductions stretched staff to identify cost efficiency improvements. Several Committee members indicated the purpose of these actions were to "smooth" out SPP's administrative fee in anticipation of a reduction in the rate in 2016 and beyond.

Larry Altenbaumer made the following motions, which were seconded by Kelly Harrison:

1) Establish the 2015 schedule 1A administrative fee rate at 39¢/MWh
2) Approve the 2015 budget with a net revenue requirement of $141.2 million, directing SPP management to create an additional $1.2 million in expense reductions (in addition to the list provided to the committee during the meeting) in the spirit of the proposed cuts which do not transfer costs into future years.

The motions were approved by unanimous voice vote.

Nick Brown, SPP's President, shared concerns regarding the direction being taken by the Committee; specifically steering the Company's focus away from solving regional issues and providing regional benefits and more towards an entity where financial management is the primary concern. SPP management has viewed the annual budget as a forecast to guide the Company's work, not as cap within which the Company must operate. The dynamic of viewing the budget as a cap will impact how SPP accomplishes its work in the future and may also impact what SPP is able to accomplish. Committee members countered that the restrictions they are exercising on SPP and its budget are no different than those they experience in their companies. Additionally, there is renewed focus on utility costs, driven by the increased cost of transmission, which requires changes to how SPP manages itself financially. Staff was encouraged to keep the Committee informed of changes in priorities and/or new initiatives so that the Committee can provide guidance and assistance in managing these issues in concert with the financial limitations established.

2015 Controls Audit Results and Progress

Representatives of KPMG discussed the results of i) the readiness review performed in advance of implementing the Integrated Marketplace; ii) the SOC 1 Type 1 audit of Integrated Marketplace controls conducted as of March 1, 2014; and iii) the SOC 1 Type II audit of SPP's controls environment covering the period March 1, 2014 through October 31, 2014.

The readiness assessment work resulted in clearly defining 34 control objectives and 111 control activities around Integrated Marketplace and Transmission Settlement functions.

The SOC Type 1 audit was issued on August 21, 2014 with an unqualified opinion. The report noted opportunity for improvement in control of program changes.

The SOC Type II audit is ongoing. KPMG has completed their first round of on-site reviews with the second round of on-site review scheduled for late October 2014. No issues have been identified to date.

Future Meetings

The next meeting of the Finance Committee is scheduled for December 8, 2014 at the SPP corporate office in Little Rock, AR beginning at 2:00 pm and concluding at 6:00pm.

There being no further business, Harry Skilton adjourned the meeting at 4:00 pm.

Respectfully Submitted,

Thomas P. Dunn
Secretary

SPP Southwest Power Pool

Southwest Power Pool, Inc.
FINANCE COMMITTEE MEETING
October 13, 2014
DFW – Hyatt Regency Hotel
Dallas, Texas

• AGENDA •

10:30 a.m. – 3:00 p.m.

1. Administrative Items *(15 minutes)* .... Harry Skilton
    a. Minutes
2. 2015 Budget (2 *hours*) .... Tom Dunn
    a. 2015 Detailed Budget
    b. 2015 Administrative Fee Rate
3. 2015 Controls Audit Results and Progress *(60 minutes)* .... KPMG
    a. Readiness Assessment completed as of February 28, 2014
    b. Type I audit completed as of March 1, 2014
    c. Type II audit preliminary findings (March 1 – July 31, 2014)
4. Written Reports
    a. August 2014 Financials
5. Adjourn .... Harry Skilton

SPP Southwest Power Pool

Southwest Power Pool

FINANCE COMMITTEE MEETING

July 10, 2014

DFW Hyatt Regency
Dallas, TX

• Summary of Action Items •

• Schedule of Follow-up Items •

1. Establish a scorecard for presentation to MOPC, SPC, and BOD indicating costs associated with member required projects/services.
2. Develop schedule of items that require Committee approval, items that require Committee monitoring, and items that require Committee input.
3. Review of ARR exposures after July 2014.
4. Review SPP's status when a market participant declares bankruptcy.
5. Review any other alternatives to netting ARRs which can mitigate the short window of ARR exposure.
6. Review of credit metrics in September 2014.
7. Investigate potential to increase the exposure calculation for transmission service beyond 50 days.
8. Create comparison of level of financial disclosures contained in RTO annual reports
9. SPP staff visit with HRC regarding EPL limits

SPP Southwest Power Pool

Southwest Power Pool

FINANCE COMMITTEE MEETING

July 10, 2014

DFW Hyatt Regency Hotel

Dallas, TX

• MINUTES •

Administrative Items

SPP Chair Harry Skilton called the meeting to order at 8:00 a.m. The following members of the Finance Committee were in attendance:

Harry Skilton	SPP Director
Larry Altenbaumer	SPP Director
Kelly Harrison	Westar Energy
Sandra Bennett	AEP
Coleen Wells (phone)	Kansas Electric Power Coop
Mike Wise	Golden Spread Electric Coop
Tom Dunn	SPP

Others attending included:

Laura Kapustka	Lincoln Electric
Rejji Hayes	ITC
Steve Pittenger	OG&E
Lauren Krigbaum	SPP
Larry Middleton	Stephens Capital Management
Larry Lucy	U.S. Bank

Minutes from April 1, 2014 meeting were reviewed. Kelly Harrison motioned to approve the minutes. The motion was seconded by Sandra Bennett and approved by unanimous voice vote.

The Committee reviewed the gap period controls review report prepared by SPP's Internal Audit staff. The report reviewed the effectiveness of SPP's controls for the period November 1, 2013 through February 28, 2014. The review by Internal Audit did not uncover any issues.

The Committee reviewed a document prepared by FERC which outlined numerous potential steps RTOs could implement to enhance the transparency of the RTO budget process. The Committee reached general consensus that SPP's current budget processes met the spirit of the suggestions outlined by FERC with the exception of documenting the budget processes within the SPP regional transmission tariff. The Committee did not see any benefits to including budget processes in the regional transmission tariff.

The Committee reviewed the financial statement disclosures included in SPP's 2013 Annual Report. The review was intended to identify whether or not the disclosures were sufficiently robust for the users of the document. SPP staff was tasked with reviewing the annual report disclosures of other RTOs and prepare a comparison for the Committee.

The Committee reviewed a summary draft of SPP's 2014 Strategic Plan; focusing primarily on the strategic initiatives which listed the Finance Committee as a responsible stakeholder.

SPP staff presented the Southwest Power Pool, Inc. Treasury Investment Policy as requested by the Committee at its April 1, 2014 meeting.

SPP staff presented a memo illustrating forecasted Member's Equity levels through 2023, as requested by the Committee at its April 1, 2014 meeting.

Investment Manager Reports

Stephens Capital Management – Assumed responsibility for management of the assets in the SPP Retirement Plan during 1Q'14. Current portfolio allocation is 74% equity/26% fixed income and complies with the Investment Policy Statement limits. The manager did not foresee any near term changes in the general allocation of the portfolio. Portfolio return is 4.1% for the since manager assumed control (approx. 4 month return), which, when annualized, would exceed the target return of 7% for the portfolio. Two mutual fund holdings are likely to be liquidated in the near future and reinvested in options expected to outperform the existing holdings. The Committee requested more information in future reports covering the following issues:

- Average credit quality of fixed income portfolio
- Calculate the duration of the fixed income portfolio
- Compare benchmark returns versus portfolio returns accounting for volatility
- Highlight any manager concentrations (for mutual fund holdings) and industry concentrations
- Compare portfolio performance versus passive portfolio options

U.S. Bank – Long tenured manager of the SPP Post-retirement Healthcare Fund. Current portfolio allocation 71% equities/29% fixed income and other which is within Investment Policy Statement limits. The five year annualized rate of return for the portfolio is 11.67% net of fees (through 6/30/2014) which exceed the target return of 7%. The portfolio performance trails a 70%/30% passive portfolio of S&P500/Barclays Intermediate Gov't/Corporate by 2.77% annualized per year. No significant changes in the portfolio were implemented in the past 12 months and none are expected in the near future. The Committee requested more information in future reports covering the following issues:

- Clarify annual changes in the portfolio balance segregating increases due to sponsor contributions, realized gains/(loses), unrealized gains/(loses), etc.
- Compare benchmark returns versus portfolio returns accounting for volatility

Investment Policy Statement Review – The Committee reviewed the investment policy statements for both the SPP Retirement Plan and the SPP Post-retirement Healthcare Plan. Several modifications to the documents were suggested. These modifications will be compiled in red-line format and presented to the Committee for approval in September 2014. SPP staff will also compile any modifications suggested by the respective investment managers and present those to the Committee in September 2014. Additionally, the Committee suggested a handful of more substantial changes, as follows:

- Formalize limits on percent of fixed income portfolio that can be invested in below investment grade securities
- Consider limiting the portfolio to long holdings only
- Consider implications of ethic/moral investment limitations (i.e. tobacco, gambling, etc.)
- Ensure Exchange Traded Funds are permitted

D&O Insurance Policy Structure and Limits

SPP staff presented an overview of the Company's existing D&O insurance program identifying: i) What risks are covered, ii) Who is covered, iii) What are the limits of the policy, and iv) Additional indemnification provision. The presentation ended with a recommendation to move the employment practices coverage into a stand-alone policy with a loss limit approximating a worst case scenario.

Staff requested the Committee members review the materials along with their insurance experts and provide input at the September 2014 meeting.

2015 Budget Outlook

SPP staff presented an outlook on the 2015-17 budget which included i) a review of 2014 forecast, ii) review of 2015-16 forecast contained in the 2014 budget, iii) impact of load changes and under-

recoveries in 2013 and 2014 on forecast 2015-16 administrative fees, iv) review of SPP project pipeline including newly proposed 2015 projects and schedule of projects completed in 2014.
Most of the Committee members expressed discomfort with the administrative fee rate forecast for 2015 of 44.5¢/MWh compared with the 2014 rate of 38.1¢/MWh. 70% of the increase for 2015 was disclosed in the 2014 budget and results primarily from increased interest expense and principal retirement; the remaining 30% results primarily from under-recovery in 2013 and forecast under-recovery in 2014. Many Committee members expressed displeasure in SPP forecasting under-recovery in 2014 and implored management to implement actions to cut costs to budget levels in 2014, specifically the Committee members required SPP to eliminate any under-recovery resulting from the bonus approved by the Board in recognition of the successful implementation of the Integrated Marketplace.

Staff further disclosed a forecast illustrating the impact on SPP's administrative fee in 2016 following the addition of the Integrated System to SPP's membership. Specifically, the administrative fee is forecast to decline in 2016 to 36.5¢/MWh versus a forecast of 44.5¢/MWh in 2015. The reduction in rate primarily results from the addition of the load from the Integrated System paying the administrative fee. Committee members urged SPP to develop options which would eliminate the spike in the administrative fee level forecast for 2015.

Mid-year BPI Report
SPP staff presented three reports to the Committee:

- Program Status and Metrics: Report summarized the BPI implementation objectives, timelines, metrics, observations, and accomplishments and challenges
- LEAN Program Value Assessment: Report provided a detailed review of the 19 LEAN initiatives undertaken and/or completed since 2012
- 2Q2014 Cost Avoidance Tracking Report: Summary of avoided costs included in 2014 budget process versus 2014 actual.

SPP staff discussed some of the hurdles experienced in achieving greater success in the LEAN initiatives, with the primary hurdle being a lack of dedicated resources. Committee members shared thoughts on how their firms addressed resource constraints when implementing similar efficiency programs. Certain Committee members shared their disappointment that the LEAN initiatives were not resulting in tracked cost avoidance as indicated in the 2Q2014 Cost Avoidance Tracking Report.

Future Meetings
The next meeting of the Finance Committee will be a teleconference meeting on September 11, 2014 beginning at 3:00 pm with the sole item being Committee members and other providing initial feedback to SPP staff on the 2015 budget. The next face to face meeting is scheduled for September 23, 2014. This meeting is currently schedule to be held in Dallas, TX but the Committee had preliminary discussions to move this meeting to Little Rock, AR so Committee members can participate in the face-to-face meeting of the Credit Practices Working Group as well as attend the Settlements User Group meetings.

There being no further business, Harry Skilton adjourned the meeting at 3:00 p.m.

Respectfully Submitted,

Thomas P. Dunn
Secretary

SPP Southwest Power Pool

Southwest Power Pool

FINANCE COMMITTEE MEETING

September 11, 2014

Teleconference

• Summary of Action Items •

• Schedule of Follow-up Items •

1. Establish a scorecard for presentation to MOPC, SPC, and BOD indicating costs associated with member required projects/services.
2. Develop schedule of items that require Committee approval, items that require Committee monitoring, and items that require Committee input.
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5. Review any other alternatives to netting ARRs which can mitigate the short window of ARR exposure.
6. Review of credit metrics in September 2014.
7. Investigate potential to increase the exposure calculation for transmission service beyond 50 days.
8. Create comparison of level of financial disclosures contained in RTO annual reports

SPP Southwest Power Pool

Southwest Power Pool

FINANCE COMMITTEE MEETING

September 11, 2014

Teleconference

• MINUTES •

Administrative Items

SPP Chair Harry Skilton called the meeting to order at 3:00 p.m. The following members of the Finance Committee were in attendance:

Harry Skilton	SPP Director
Larry Altenbaumer	SPP Director
Kelly Harrison	Westar Energy
Coleen Wells	KEPCo
Mike Wise	Golden Spread Electric Coop
Tom Dunn	SPP

Others attending included:

Laura Kapuska	Lincoln Electric
Jim Eckelberger	SPP Director
Traci Bender	NPPD
Patrick Smith	Westar
Dianne Branch	SPP
Zeynep Vural	SPP
Sherri Dunn	SPP

2015 SPP Budget

The format of the meeting was a "round-table" discussion whereby Committee members and other participants could provide SPP staff with their initial impressions of the 2015 budget document and request additional detail and/or information to be provided at the September 23, 2014 meeting. The discussion yielded the following items where additional information was requested:

a. Provide details of what has changed in the 2014 forecast since the July 2014 Finance Committee meeting
b. Update with the 2015 draft budget information and present the "Activity Chart" from the April 2013 presentation to the RSC
c. Provide historical chart of capital expenditure spending for "Foundation" activities
d. Provide additional detail on the IT "Foundation" capital expenditure spending for 2015-17
e. Detail changes in Outside Services spending between 2014 and 2015
f. Provide historical and forecast headcount chart
g. Discuss changes in workload associated with adding the Integrated System to SPP
h. Provide scenarios illustrating assumptions and impacts related to managing the administrative fee to 39¢/MWh

Future Meetings

The next meeting of the Finance Committee is scheduled for September 23, 2014 at the SPP corporate office in Little Rock, AR beginning at 8:30am and concluding at 3:00pm.

There being no further business, Harry Skilton adjourned the meeting at 4:30 p.m.

Respectfully Submitted,

Thomas P. Dunn
Secretary

SPP Southwest Power Pool

Southwest Power Pool

FINANCE COMMITTEE MEETING

September 23, 2014

SPP Corporate Office
Little Rock, AR

• Summary of Action Items •

1. Approve clarifications to the FERC Order 1000 competitive bidding process tariff language addressing financial requirements when submitting a bid and the period subject to financial review when evaluating bidders
2. Approved format for recovery of the development costs incurred by SPP to develop its FERC Order 1000 competitive bidding process. The development costs will be recognized at a rate of $2,000/bid until fully recovered.

• Schedule of Follow-up Items •

1. Establish a scorecard for presentation to MOPC, SPC, and BOD indicating costs associated with member required projects/services.
2. Develop schedule of items that require Committee approval, items that require Committee monitoring, and items that require Committee input.
3. Review of ARR exposures after July 2014.
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8. Create comparison of level of financial disclosures contained in RTO annual reports

SPP Southwest Power Pool

Southwest Power Pool

FINANCE COMMITTEE MEETING

September 23, 2014

SPP Corporate Office

Little Rock, Arkansas

• MINUTES •

Administrative Items

SPP Chair Harry Skilton called the meeting to order at 8:30 a.m. The following members of the Finance Committee were in attendance:

Harry Skilton	SPP Director
Larry Altenbaumer	SPP Director
Patrick Smith (proxy for Kelly Harrison)	Westar Energy
Sandra Bennett	AEP
Mike Wise	Golden Spread Electric Coop
Tom Dunn	SPP

Others attending included:

Jason Fortik	Lincoln Electric
Gretchen Holloway	ITC
Traci Bender	NPPD
Nick Brown	SPP
Carl Monroe	SPP
Ricky Bittle	Arkansas Electric Cooperative
Bruce Cude	SPS

FERC Order 1000

Ricky Bittle, chair of the SPP Strategic Planning Committee, requested the Finance Committee provide clarification on three issues related to the Order 1000 Competitive Bidding Process:

1) Financial Requirements for bid submissions: The Finance Committee had previously recommended that bidders who did not possesses an investment grade credit rating (or have a guarantor with an investment grade credit rating) would be required to demonstrate the ability to obtain either a letter of credit or performance bond in the minimum amount of their bid plus 30%. The SPP tariff, as drafted, states the l/c or bond must be provided with the bid.

   Sandra Bennett made the following motion: Re-engage the Regional Tariff Working Group to make clarifications in tariff language to only require bidders provide conclusive evidence of their ability to obtain satisfactory l/c or bonding. A letter from bank or bonding agent (who meet SPP's credit requirements as detailed in Attachment X section 7.1.3.2 in the case of a bank, or has a "Financial Strength Rating" of Superior or Excellent from A.M.Best and a policyholder surplus in excess of $500,000,000 in the case of a bonding company. The motion was seconded by Patrick Smith and approved by unanimous voice vote

2) Time Frame for Finance Review: The RFP scoring criteria requires metrics related to liquidity and cash flow be evaluated when reviewing the individual bids. Tariff language didn't specify the period which would be reviewed.

   Sandra Bennett made the following motion: The time frame for review of project financial metrics should be limited to the greater of the expected construction period for the specific facility being evaluated or 5 years. The motion was seconded by Mike Wise and approved by unanimous voice vote.

3) Recover of Order 1000 Development Costs: The tariff provides for full recovery of the costs to administer the Order 1000 Competitive Bidding Process but does not outline the time period for recovery of development costs.

   Larry Altenbaumer made the following motion: Development costs should be included in the annual competitive bidding process costs at a rate equal to $2,000 per bid received until such time as development costs have been fully recovered. The motion was seconded by Mike Wise and approved by unanimous voice vote.

2015 Budget Outlook

SPP staff led a detailed discussion of the SPP 2015 operating and capital budgets. The presentation followed the following main areas:

- Highlighting the value generated by the services provided by SPP; 10:1 benefit to cost ratio
- Review of major capital expenditure programs with deeper dive into ongoing IT spending
- 2015 billing determinant forecast
- 2015 costs by major catagory
- Existing debt structure and contribution to required recovery

SPP staff next reviewed its responses to the questions and information requested at the September 11, 2014 Finance Committee meeting. Significant discussion surrounded the options presented for administrative fee rate for 2015. The Finance Committee members reached consensus that SPP should strive to reduce its costs to maintain an administrative fee rate of 39¢/MWh in 2015.

Future Meetings

The next meeting of the Finance Committee is scheduled for October 13, 2014 at the DFW Hyatt Regency hotel in Dallas, TX beginning at 10:30am and concluding at 3:00pm.

There being no further business, Harry Skilton adjourned the meeting at 2:15 p.m.

Respectfully Submitted,

Thomas P. Dunn
Secretary

SPP Southwest Power Pool

Memorandum

To: SPP Finance Committee

From: Thomas P. Dunn

CC:

Date: October 6, 2014

Re: Adjustments to 2015 Budget to Attain 39¢/MWh Rate

Following is a description of each change proposed by SPP to reduce the costs recovered in 2015 to 39¢/MWh.

2014 Performance Comp Accrual: SPP accrues performance compensation at a rate of 15% of salaries paid during the year. SPP became aware of and resolved an issue where SPP neglected to pay interest on deposits submitted by generation interconnection customers over numerous years. This resulted in SPP needing to pay past generation interconnection study customers approximately $1.8 million. SPP proposes reducing its performance compensation accrual in 2014 by a like amount. This adjustment will eliminate the under-recovery expected in 2014 due to the generation interconnection study interest payments.

Post-retirement Healthcare Fund: SPP's post-retirement healthcare fund was over-funded as of January 1, 2014 by approximately $1.7 million. SPP proposes to eliminate any funding to the account in 2015 ($0.441 million) and transfer $1.0 million from the fund to SPP's operating account to fund O&M costs incurred in 2015. SPP has discussed this approach with the actuary who did not believe these steps would materially impact the plan's funded status.

Delay ITP10 Study: Eliminating work on the ITP20 study for 2015 and delaying the start of the ITP10 study for six months will allow SPP to remove $1.0 million from the 2015 operating budget by reducing the need to engage outside engineering resources to complete the studies. Delay of the ITP10 study for six months will allow the study to consider clearer EPA impacts.

Delay Value of Transmission Study to 2016: This is a discretionary study not required under the SPP tariff or by any regulatory agency. The value of the study is not reduced by waiting until SPP is better able to afford the study within the administrative fee cap.

Increase Vacancy Assumption to 5%: Increasing the vacancy assumption will reduce salary and benefit expenses by $0.7 million. SPP proposes a minimum 90 day vacancy for nearly every position prior to consideration of re-filling the vacant position. This should result in vacancies taking a minimum of 150 days between the day the position becomes open to the day the position is filled.

Pension Funding Reduction: SPP's pension plan is well funded. The plan assets represented 93% of projected benefit obligations at January 1, 2014. Recent changes in pension legislation provide greater flexibility in minimum funding. SPP proposes to reduce 2015 funding from $3.66 million to $3.0 million. SPP has discussed this approach with the actuary who did not believe this would materially impact the plan's funded status.

Create Rebate: SPP participates in an Arkansas Economic Development program whereby the state provides a rebate of salaries paid for new jobs. SPP estimates it will receive $0.5 million in 2015 under this program.

Reductions in IT Consultants and Maintenance: Specific reductions in consultant engagements to augment ongoing staff efforts will remove $0.26 million from the budget. Additionally, changes to maintenance contracts for two applications will reduce the maintenance budget by another $0.16 million

Outside Counsel Reductions in Legal: Reduced forecast engagements of outside attorneys by $0.3 million. SPP typically underspends this budget area.

Outside Service and Travel Reductions in Process Integrity: Reductions include elimination of outside consultants to augment staff efforts in project management post implementation of Project Pinnacle. Elimination of a LEAN expert to review SPP's LEAN implementation and lead an educational seminar will remove $0.035 million in 2015.

Reduce Healthcare: SPP is reviewing alternatives to better manage its pharmacy costs within the self-funded healthcare plan.

Reduce Merit Pool for 2015 to 2%: SPP's Human Resources Committee typically funds a pool for merit compensation changes equivalent to the year over year change in the Consumer Price Index. The Human Resource Committee approved a merit pool equal to 2.3% of salaries; this reduction to 2% will reduce salary and benefit costs by $0.2 million.

Decrease 2014 Staff: SPP management has identified a position that is no longer required by the organization and has eliminated the position.

Decrease 2015 Staff: The Operations Training Working Group has encouraged SPP to develop additional computer based training solutions. SPP had previously engaged consultants to assist with development of these programs. SPP had proposed an incremental position in 2015 to replace the consultant.

Order 1000 Development Cost Recovery: SPP previously proposed recovering all of the Order 1000 development costs from first year bidders. The SPP Finance Committee proposed recovering these costs over several years by charging bidders $2,000/bid. This change reduced Miscellaneous Revenue by $0.3 million.

SOUTHWEST POWER POOL
2015 BUDGET CHANGES
($ millions)

SPP Consolidated Summary	2015 Budget	Changes	2015 Budget
Income			
Tariff Administration Service	$150.6	($8.2)	$142.4
Fees & Assessments	27.6	0.0	27.6
Contract Services Revenue	0.5	(0.0)	0.5
Miscellaneous Income	5.2	0.1	5.3
Total Income	**$183.9**	**($8.0)**	**$175.9**
Expense			
Salary & Benefits	$82.4	($2.4)	$80.0
Employee Travel	2.1	(0.0)	2.1
Administrative	4.8	0.1	4.9
Assessments & Fees	16.4	0.0	16.4
Meetings	1.0	(0.0)	1.0
Communications	4.3	0.0	4.3
Leases	0.2	(0.0)	0.2
Maintenance	14.8	(0.1)	14.7
Services	18.7	(2.9)	15.8
Regional State Committee	0.3	(0.0)	0.3
Depreciation & Amortization	61.2	0.0	61.2
Other Expense	10.2	(0.0)	10.2
Total Expense	**$216.4**	**($5.2)**	**$211.2**
Net Income (Loss)	**($32.5)**	**($2.8)**	**($35.3)**
Headcount	600	(2)	598
Debt Repayment	$24.3	$0.0	$24.3
MW/H Forecast (in millions)	363.5	0.0	363.5
Calculated Net Revenue Requirement	$145.3	($5.5)	$139.8
2013 / 2014 True Up	4.9	(1.3)	3.6
2014 Post-retirement healthcare transfer		(1.0)	(1.0)
2015 Net Revenue Requirement	**$150.2**	**($7.8)**	**$142.4**
Calculated Admin Fee / MWh	**$0.413**	**($0.021)**	**$0.392**
Recommended Admin Fee / MWh	**$0.413**	**($0.023)**	**$0.390**

SOUTHWEST POWER POOL
2015 BUDGET CHANGES
($ millions)

Original 2015 Net Revenue Requirement	**$150.2**
Adjustments	
2014 Performance Comp Reduction	($1.8)
2014 Post-retirement healthcare transfer	(1.4)
Delay in ITP10 Study	(1.0)
Delay Value of Transmission study to 2016	(0.7)
Increase vacancy from 4% to 5%	(0.7)
Pension funding reduction	(0.7)
Add revenue for Create Rebate	(0.5)
Outside Counsel reductions in Legal	(0.3)
Reductions in IT consultants and maintenance	(0.4)
Outside Services & Travel reductions in Process Integrity	(0.3)
Reduce healthcare budget	(0.2)
Reduce merit increase from 2.3% to 2.0%	(0.2)
Decrease 2014 staff (1 Compliance)	(0.1)
Decrease 2015 incremental headcount (1 Training)	(0.1)
Order 1000 Cost recovery revenue reduction	0.3
Total Adjustments	**($7.8)**
Revised Adjusted NRR	**$142.4**
Revised Admin Fee / MWh	**$0.392**
Recommended Admin Fee / MWh	**$0.390**

2015 BUDGET

PREPARED BY ACCOUNTING DEPARTMENT

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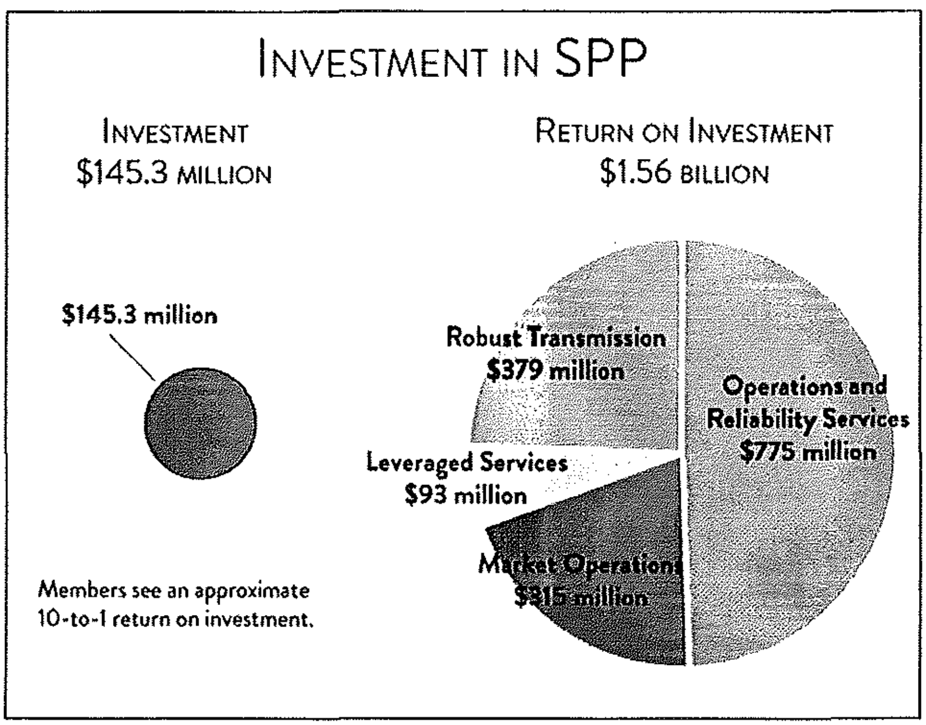
I. Member Value

Southwest Power Pool, Inc. (SPP) ensures the reliable operation of and fair and open access to the high voltage transmission system in its 8-state footprint. SPP's services further ensure reliable least-cost delivered energy to consumers in its footprint. SPP is mandated by the Federal Energy Regulatory Commission to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale electricity prices. In 2015, SPP is expected to provide the eight-state region between $1.2 and $1.9 billion in annual benefits. This range of benefits yields between an 8-to-1 and 13-to-1 return on the annual cost of providing these federally-mandated services. At the proposed 41.3 cents per MWh administrative fee, a residential customer using 1,000 kWh per month would, on average, receive $78 in benefits per year from SPP's services for only $8 in costs.

Another way to view the value SPP provides is to consider SPP's net revenue requirement of $145.3 million (before prior year true-up) as an investment that will yield a $1.56 billion return for the year (midpoint of the range of annual benefits), or a 10.6 times return. That $145.3 million investment provides value in the following areas:

- $775 million in Operations and Reliability Services
- $379 million in Region-Wide Transmission Planning
- $315 million in Open Transparent Energy Market Operations
- $ 93 million in Leveraged, Centralized Services



SPP's services create the opportunity to realize the benefits associated with planning and operating over a larger region. Prior to SPP's evolution to the Regional Transmission Organization (RTO), utilities in the region operated in a decentralized, bilateral market environment. Bilateral power transactions were characterized by physical transmission constraints managed through mechanisms that at times limited the availability of transmission, increased transaction costs, and decentralized unit commitment and dispatch. SPP's market mechanisms now utilize security-constrained, economic dispatch to optimize the use of all the market participants' resources within the region. The resources in the region provide more options and better efficiency to meet the needs of electric customers, both reliably and affordably. SPP's marketplace provides cost savings and enhanced reliability, as well as independent oversight of the region's transmission and generation facilities.

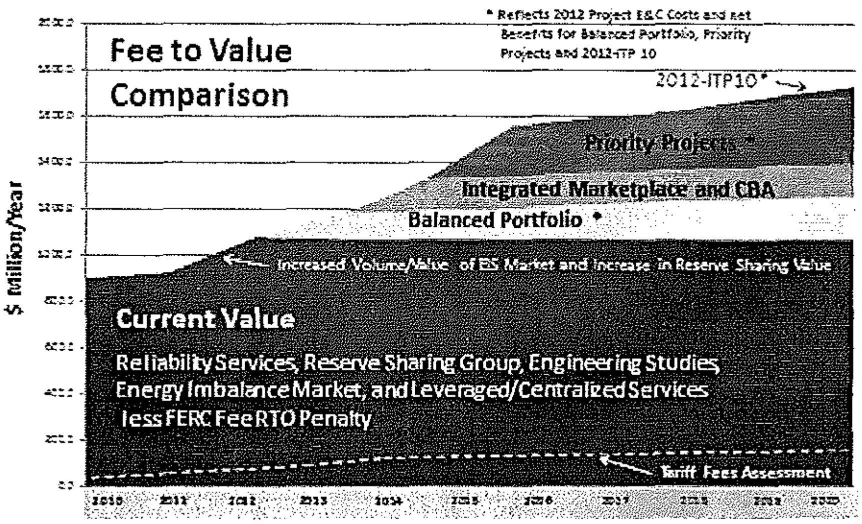
This $145.3 million investment also enables SPP to:

1. Reduce overall costs by operating as a region
2. Provide reliability assurance and predictable operations of the bulk electric system
3. Facilitate effective transmission planning processes that result in building and maintaining an economically optimized transmission system
4. Offer an open and transparent marketplace with economic benefits
5. Optimize market efficiencies and transmission expansion along the seams of other markets and the emerging seam associated with natural gas supply
6. Ensure fair and equitable allocation of transmission expansion costs

Peter Drucker, noted author, management consultant, and educator, once commented, *"Organizations are paid to create value, not to control costs".* The SPP organization, including all of its members, regulators, and staff, has clearly been successful in creating meaningful value throughout its region. SPP has achieved this by remaining guided by its value proposition:

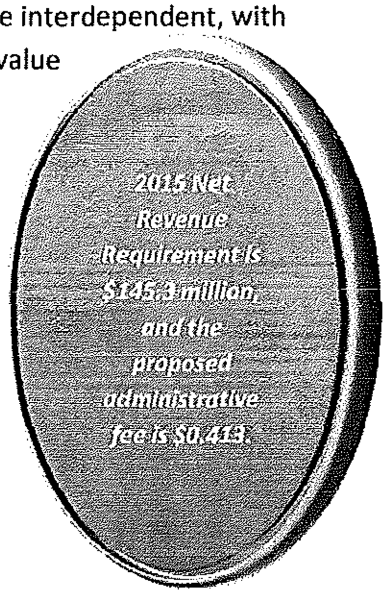
1. Relationship-based
2. Member-driven
3. Independence through diversity
4. Reliability and economics are inseparable
5. Evolutionary versus revolutionary change

MID-RANGE VALUES AND RAMPED FUTURE VALUES



II. 2015 Net Revenue Requirement

SPP continues to focus on the core mission of reliable planning and operation of the grid. A new strategic plan was established during 2014, positioning SPP to fulfill its mission over the next decade and beyond. SPP's activities and initiatives will be guided by the four foundational strategies identified in the new strategic plan which are: reliability assurance, optimizing interdependent systems, maintaining an economical and optimized transmission system, and enhancing member value and affordability. These four strategies are interdependent, with reliability assurance as the basis and the enhancement of member value and affordability as the discipline to drive all SPP strategies.



Total 2015 operating expenses are expected to be $216.5 million, an increase of $15.8 million compared to 2014. Growth in operating expenses results primarily from depreciation of the Integrated Marketplace asset ($11.5 million) and from outside services expense related to various initiatives including: 1) adding the Integrated System to the SPP footprint ($1.4 million), 2) administering the FERC Order 1000 competitive process ($1.3 million), and 3) preparing studies for value of transmission planning ($0.7 million), RCAR Regional Cost Allocation Review ($0.8 million), and clean power plan assessment ($0.3 million). FERC assessments ($1.1 million) also contribute to the increase.

The requested headcount for the current 2015 budget is 600 which compares to 603 in the previous year's budget for 2015. During 2014, SPP reallocated six positions within its approved headcount to meet the changing demands of the business.

The 2015 Net Revenue Requirement (NRR), a component for setting the administrative fee rate, is $145.3 million versus 2014 budget NRR of $132.6 million and 2014 forecast NRR of $136.1 million. The $145.3 million NRR excludes the prior year true up amounts for 2013 and 2014 of $4.9 million. The NRR including prior year true up amounts is $150.2 million. The largest component of the increase in NRR is attributed to the increase in debt payments in 2015. The 2014 actual debt payments were $23 million as compared to the 2015 debt payments of $24.3 million; however, $10 million in 2014 current maturities were funded with new debt proceeds during 2014 and therefore reduced the 2014 NRR by $10 million. The $4.4 million increase in outside services mentioned above represents the remaining increase in the 2015 NRR as compared to the 2014 budget.

Another component used in setting the administrative fee is transmission volume, which SPP projects will increase 4.4% to 363.5 million MWh in 2015 compared to the 2014 budget of 348.2 million MWh. Through July 2014, SPP's members have experienced higher monthly peaks than those recorded in 2013, resulting in a forecast of 351.9 million MWh expected for 2014. Even though year-over-year projections have increased, the base projection for 2015 is equal to the 2014 forecast (351.9 million MWh) due to unseasonably cooler temperatures experienced during the summer months and less point-to-point service sold in 2014. With the addition of the Integrated System load of 11.6 million MWh in the fourth quarter, the estimated total transmission volume is 363.5 million MWh in 2015.

SPP's 2014 budget estimated the 2015 administrative cost/MWh to be 42.6¢/MWh based on an expected NRR of $148.4 million and load of 348.2 million MWh (equal to the 2014 budget). SPP's 2015 budget calculates an administrative cost of 41.3¢/MWh based on an expected 2015 NRR of $145.3 million plus $4.9 million in under-recoveries for 2013 and 2014 and load of 363.5 million MWh.

The 2015 budget identifies capital expenditures totaling $65.5 million for 2015-2017, with $35.3 million expected to be incurred in 2015. These costs are not directly included in SPP's Net Revenue Requirement; however, annual principal and interest payments (net of capitalized interest) for borrowings that fund these capital projects are a component of the Net Revenue Requirement.

In late 2013, SPP began work on Project Pinnacle (previously referred to as Integrated Marketplace Post-Go-Live). Project Pinnacle was originally comprised of three projects mandated by FERC for implementation within one year of the start of SPP's Integrated Marketplace (Market to Market, Regulation Compensation, and Long-Term Transmission Congestion Rights), one significant Member required project (Enhanced Combined Cycle), and several smaller projects addressing grandfather agreements, available flow-gate capacity (AFC) granularity, pseudo-ties, and IT environments.

Work and spending on Pseudo-ties and IT environments will be completed in 2014. Several other projects originally included in Project Pinnacle were not mandated by FERC but rather requested by the SPP membership. As a result of further review and deliberation among staff and the members, the following were canceled and removed from the program scope: AFC granularity changes; Sunset clause for load submittal; Marketplace data for market participants; and GFA Carve Out. The following projects will continue to incur expenditures into 2015 while still targeting a March 1, 2015 implementation date:

- Market to Market
- Regulation Compensation
- Long-Term TCR

Although the 2015 budget continues to reflect projected costs to implement Enhanced Combined Cycle functions, work on the Enhanced Combined Cycle project has been suspended pending further review of the benefits of the project. Prior to placing the project into suspended status, SPP had incurred $1.2 million in capitalized expenses attributed to ECC. Information Technology, Operations and other foundation projects represent $42.6 million during 2015-2017.

Components of 2015 Net Revenue Requirement and Administrative Fee

The following table shows the components and calculation of the administrative fee. The 2015 calculation includes additional funding for under recovery in 2013 and 2014. The $2.8 million 2013 under recovery is the result of higher incentive compensation (18% vs. 15%), pension and self-funded healthcare plan adjustments; and slightly reduced revenues associated with the load ($0.18M). The expected under recovery of $2.0 million in 2014 is related to $1.8 million of interest to be paid on generation interconnection study deposits.

Administrative Fee ($ millions)

	2014 Budget	2014 Forecast	2015 Budget	2015 Prior Year Estimate [2]
Operating Expenses (excluding Depreciation)	$151.0	$148.2	$155.3	$156.3
Debt Service [1]	13.0	13.0	24.3	24.0
Gross Revenue Requirement	$164.0	$161.2	$179.5	$180.3
Less:				
NERC revenue	(11.8)	(9.6)	(11.7)	(12.2)
FERC fee expense	(15.3)	(16.3)	(16.4)	(15.6)
Other Revenues	(4.2)	(5.2)	(6.1)	(4.4)
Net Revenue Requirement (NRR) prior to non-recurring	$132.6	$130.0	$145.3	$148.4
Billing Determinant (MWh millions) [3]	348.2	351.9	363.5	348.2
Calculated Admin Fee/MWh	$0.381	$0.369	$0.400	$0.426
Non-recurring Items & Prior Year Under Recovery/MWh [4]		$0.017	$0.013	
Current/Proposed Admin Fee/MWh	$0.381	$0.387	$0.413	$0.426
Current Tariff Admin Fee Cap	$0.390	$0.390	$0.390	$0.390

(1) 2014 debt payments were $23.0 with $10.0 in current maturities funded with new debt proceeds

(2) Refers to the 2015 estimate made during 2014 budget presentation

(3) Defined as coincident peak for network service and capacity for point to point service in MWh

III. Budget Overview

This budget document provides an overview and outlines details of the cost of services and components of the Net Revenue Requirement, which consists of the following:

- Operating expenses (section IV)
- Capital projects (section VI)
- Debt Service (section VII)

Operating expenses represent the largest component of the Net Revenue Requirement and consist of budgeted costs for ongoing operations. Operating expenses are presented in two different views:

- By resource type (e.g. staffing, facilities) (section IV)
- By division (e.g. Operations, Engineering) (section V)

Capital projects are investments in long-term assets required for SPP to meet its strategic goals and operational requirements. These capital expenditures represent costs incurred to enhance or expand current systems and services, and to maintain existing capabilities.

The budget identifies 12 capital projects impacting 2015, in addition to the foundation projects and Project Pinnacle. Capital projects are discussed in section VI.

Debt service costs are principal payments and interest expense related to various borrowings obtained to fund SPP's capital expenditures. The term of different sources of funding is matched to the estimated useful life of these specific projects. Debt service is discussed in section VII.

Budget Guidance and Assumptions

Budget meetings were held during June 2014 to provide guidance in developing the 2015 budget. Under the direction of the executive team, each department director was tasked to create a zero-based budget for operating expenses. The following major drivers and assumptions were identified during the meetings:

Project Pinnacle Initiatives – During 2014, efforts were focused on the successful development and implementation of the Integrated Marketplace including the design, development and implementation of the following functions:

- Day-Ahead Market
- Transmission Congestion Rights
- Reliability Unit Commitment
- Real-Time Balancing Market
- Operating Reserve Market
- Consolidated Balancing Authority

The 2015 budget identifies capital expenditures and consulting for market-related functionality and enhancements which will go into production in 2015-2016. The major initiatives, referred to as Project Pinnacle, were also included in the 2014 budget projections. They are as follows:

- Enhanced Combined Cycle Functionality
- Regulation Compensation (FERC Order 755)
- Long Term TCRs (FERC required)
- Market to Market (FERC required)

More information on these initiatives can be found in the Capital Projects section VI.

FERC Order 1000 - Order 1000, which was issued by FERC in July 2011, has both regional and interregional planning implications. From the regional perspective, the Order requires removal from regional tariffs of the federal right of first refusal ("ROFR") for "green field" transmission construction. To comply with this requirement, SPP will implement a request for proposal (RFP) process to select qualified transmission owners for construction of approved transmission projects. FERC approved the competitive bidding process for regional transmission projects, which will apply to facilities approved by SPP's Board of Directors beginning January 2015. A key component to the bidding process is awarding incentive points to bidders that submit accepted solutions to cure transmission issues. SPP received over 1,179 submissions to resolve transmission issues in 2014 versus an expected volume of 500-600 submissions. SPP expects the volume of work and costs associated with the competitive bidding process to be significant and costs in the 2015 budget reflect this effort.

In advance of the expected increased workload, SPP added a management position in 2014 to manage Order 1000 RFP administration and to assist with the legal aspects of the RFP process. A second analyst position was also added to assist with the same functions as workload is anticipated to increase for review of qualified participants. The 2015 budget also includes consulting costs related to an Industry Expert Panel to be commissioned for the purpose of evaluating RFP responses ($1.3 million). SPP expects to recover the costs related to the RFP process from entities participating in the bidding process starting in 2015. In 2015, $0.4 million in consulting expense was added to assist in the Definitive Project Proposal (DPP) process and for services associated with the use of cost estimation software by an outside vendor.

From the interregional perspective, the Order most notably increases information sharing and coordination between planning regions for interregional projects, and also calls for the development of joint planning studies between neighboring planning regions. In preparation for implementing the process, three engineering positions were added during 2013 to ensure SPP's compliance with the Order's interregional aspects.

Inclusion of Integrated System (IS) – The SPP footprint is expected to increase in size with the onboarding of the IS entities in the fourth quarter of 2015. Owned by the Western Area Power Administration's Upper Great Plains Region, Basin Electric Power Cooperative, and Heartland Consumers Power District, the IS covers much of North Dakota, South Dakota, and includes parts of Iowa, Minnesota, Montana, and Nebraska. Its 9,848 miles of high-voltage transmission lines would mean a 17 percent increase (to 58,316 miles) in the miles of transmission lines managed by SPP.

Incremental expense associated with the IS integration includes the following:

Integrated Systems Incremental Expense	2015	2016	2017
Incremental staffing (Salaries, benefits and taxes) [1]	$ 0.2	$ 0.3	$ -
Travel and meetings	$ 0.2	$ 0.0	$ 0.0
Maintenance	$ 0.2	$ 0.1	$ 0.1
Consulting - IT / Operations Wind forecasting	$ 0.2	$ 0.1	$ 0.1
Consulting - IT Staff augmentation	$ 0.5	$ -	$ -
Consulting - Engineering planning and analysis	$ 0.5	$ -	$ -
Consulting - IT / Operations (OATI)	$ 0.2	$ -	$ -
Consulting - Settlements	$ 0.1	$ -	$ -
Total Operating Expenses	**$ 1.9**	**$ 0.6**	**$ 0.3**
IT Settlements ETS enhancements	$ 0.3	$ -	$ -
IT Software development	$ 0.3	$ -	$ -
IT Settlements ETSE upgrade	$ 0.3	$ -	$ -
IT Hardware	$ 0.2	$ -	$ -
Total Capital Expenses	**$ 1.0**	**$ -**	**$ -**
Total Expenses	**$ 3.0**	**$ 0.6**	**$ 0.3**

(1) Two incremental positions in Operations added in March 2015 to assist with the implementation and operations of IS. Through maturity of staff and restructuring, two positions will be eliminated by 2017.

Offsetting the costs illustrated above, SPP transmission customers realize a reduction in the administrative fee as a result of the additional MWh load for IS. The IS annual load is estimated at 46.1 MWh, which is a 13% increase over SPP's 2015 base load projection of 351.9 MWh. Since the integration is expected in October 2015, one-fourth of the annual IS load will be captured in SPP's 2015 billing determinants. The Net Income/ (Loss) for SPP Foundation (total budget less IS and the Regional Entity) is shown below.

Income	SPP Foundation	Integrated Systems	Regional Entity	Total 2015 Budget
Tariff Administration Service	$145.8	$4.8	$0.0	$150.6
Fees & Assessments	15.8	0.0	11.8	27.6
Contract Services Revenue	0.5	0.0	0.0	0.5
Miscellaneous Income	5.2	0.0	0.0	5.2
Total Income	**$167.3**	**$4.8**	**$11.8**	**$183.9**
Salary & Benefits	77.7	0.2	4.5	82.4
Depreciation & Amortization	61.2	0.0	0.0	61.2
Communications, Leases & Maint	19.2	0.2	0.0	19.3
Outside Services	15.7	1.4	1.9	19.0
Administrative / Other	15.0	0.0	0.0	15.0
Assessments & Fees	16.4	0.0	0.0	16.4
Travel & Meetings	2.2	0.2	0.7	3.1
Total Expense	**$207.5**	**$1.9**	**$7.1**	**$216.5**
Net Income (Loss)	**($40.2)**	**$2.9**	**$4.7**	**($32.6)**
Debt Repayment				$24.3
MW/H Forecast (in millions)				363.5
Net Revenue Requirement				$145.3
2013 /2014 True Up				$4.9
Recommended Admin Fee / MWh				$0.413

Strategic Outlook

The 2014 strategic plan positions SPP to fulfill its mission statement over the next decade and beyond. The plan recognizes the future is uncertain and that depending upon circumstances, responses must be conditioned upon cooperation, industry knowledge, technology, and the interdependence of neighboring regions, as well as new fuel resources for generation. The 2014 Strategic Plan introduces a new foundational strategy, reliability assurance, as its bedrock. With reliability assurance as its basis, the plan updates the 2010 Strategic Plan, which are anchored in the Mission Statement ("Helping our members work together to keep the lights ... today and in the future") and the five components of SPP's Value Proposition to its members (relationship-based, member-driven, independence through diversity, evolutionary versus revolutionary, reliability and economics are inseparable). The strategic initiatives related to each of the four interdependent foundational strategies will position SPP for the future while balancing operational priorities and financial considerations.

The energy industry remains in a period of dynamic transformation. In developing the strategic initiatives, SPP has considered several of the evolving factors affecting demand, generation resources, and transmission requirements of SPP and its members:

Demand Growth

- SPP has experienced significant pockets of demand increase in certain regions of the footprint caused by the sudden and recent growth of oil and natural gas drilling and transportation industries. The most significant transmission challenges facing portions of the SPP footprint are related to the increase in oil and gas drilling. SPP fully expects that the economic cycles and the energy market pricing fluctuations will produce wide swings in overall demand from year to year.
- Growth in behind-the-meter generation resources by end-use customers, demand response, conservation, and improved efficiencies are expected to continue through 2023; however, the overall impact in meeting the energy and capacity obligations of the SPP region is relatively small.

Generation

- Many competing factors will impact the future mix of generation resources. SPP will stay informed on continuing developments and will incorporate flexibility and adaptability into future plans.
- SPP continues to experience an influx of variable generation resources, leading to operational challenges; however, SPP is enhancing planning processes to better capture the impacts of the oil and gas projects and variable generation.
- Increased usage of renewable resources is becoming a significant factor in the generation mix, and necessitates the development of new tools and capabilities to plan for reliably integrating these resources into the grid. The increase in installed variable generation in the SPP footprint, which is composed almost entirely of wind generation, will continue to cause operational challenges. The SPP RTO Consolidated BA will provide balancing benefits for the widespread installed wind generation.

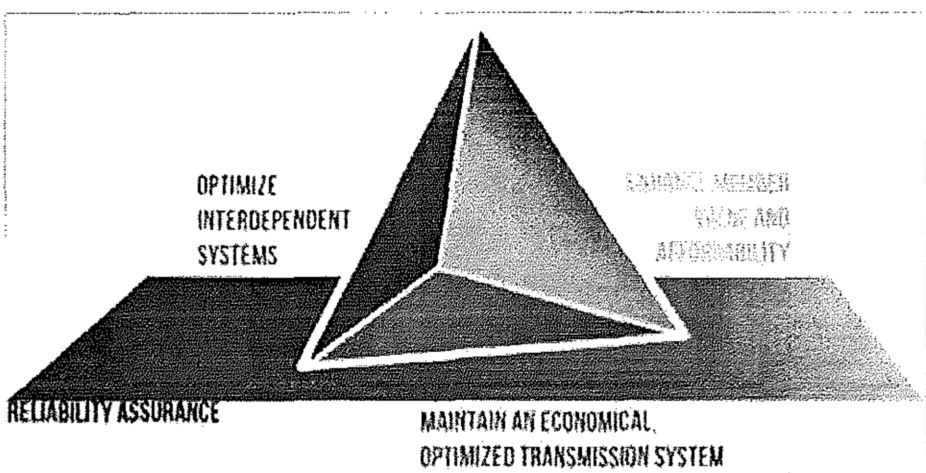
Transmission

- The most significant transmission challenges facing portions of the SPP footprint are related to an increase in oil and gas drilling and environmental policies restricting carbon emissions. New oil and gas drilling facilities are built faster than they can be captured in SPP's planning processes and models. The cumulative effect of environmental regulations on generating capacity may significantly shift the planning for future transmission facilities.

- Expansion of renewable resources will be a major factor impacting the transmission system, as many of these resources are located in areas that are not currently connected to the grid or will require significant capacity expansion.
- The introduction of new types of generation resources into the traditional mix will require greater inter-regional planning and coordination of the transmission system.
- More robust market capabilities will be required in the future, and regional grid operators will need to develop better mechanisms to extend benefits across the seams between market areas.
- Advanced technologies will be available in the future to support robust grid operations, to help end-use customers make more informed decisions about energy use and even providing energy to the grid.
- Land acquisition and "right of way" issues are continually becoming more complex and time-consuming.
- Reliability standards are also becoming more complex and require the ability to manage multiple simultaneous contingencies.

Alignment of 2015 Budget with SPP's Strategic Plan

The Strategic Plan approved by the SPP Board of Directors identifies four foundational strategies to create the capabilities and operational processes needed to fulfill SPP's mission and maintain or improve its value propositions in the face of a rapidly changing environment. These four strategies are interdependent, with reliability assurance as the basis, and the enhancement of member value and affordability as the discipline to drive all SPP strategies. The foundational strategies are long-term, fundamental components of the SPP business model. The plan focuses on four broad strategies to be continued, initiated, and/or completed over the next 10 years.



Reliability Assurance

Reliability is the bedrock of SPP's business. Many changes are taking place simultaneously in the reliability arena requiring SPP to continuously shift and improve planning and operating the system:

- Greater reliance on variable energy resources (wind and solar)
- Shift by consumers to less predictable load patterns
- Reliability implications of environmental policies and regulation
- Continued risk of cyber and physical threats

The following are specific initiatives related to reliability assurance:

- Capacity margin refinement
- Regional resource need and value assessment
- Reliability assessments of environmental rules
- Integration of variable energy resources
- Grid resiliency against cyber and physical threats
- Reliability excellence

Maintain an Economical, Optimized Transmission System

The 2010 SPP Strategic Plan focused on building a robust transmission system, which was described as a system containing an optimal mix of highways (300 kV+) and byways (below 300 kV), and one that minimizes future transmission constraints without over-investing in transmission capacity. A robust system creates immense value for SPP members and end users in the SPP region. In 2013, SPP members completed 112 transmission projects totaling more than $612.7 million. The SPP Board has authorized notices to construct for roughly $8 billion of transmission grid upgrades since the year 2000. This represents the culmination of efforts begun seven years ago to build transmission within SPP's footprint. SPP's strategy going forward includes focusing on maintaining the transmission system in an economical and optimized way.

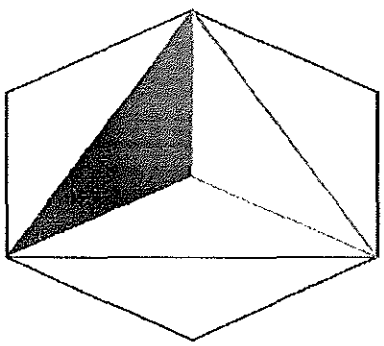
The following are specific initiatives related to maintaining the transmission system:

- Integrated transmission planning check and adjust
- Cost controls on competitive transmission (Order 1000)

- Flexibility to address policy initiatives
- Value pricing: import/export strategy and cost allocation
- Fair and equitable cost/benefit allocation policies

Enhance and Optimize Interdependent Systems

SPP successfully implemented its Integrated Marketplace (IM) on March 1, 2014. Additional enhancements (including member-driven and FERC-directed) are also being made to the Integrated Marketplace and are on track for completion in 2015.



OPTIMIZE INTERDEPENDENT SYSTEMS

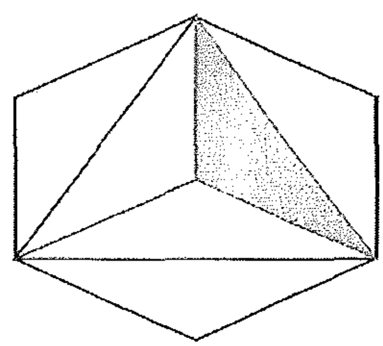
If members are required to move toward more utilization of natural gas as a generation fuel, it will become necessary to coordinate with the natural gas industry to facilitate additional gas transmission pipelines and to develop the operating flexibility allowing the generators to follow load.

Additional value can be derived by optimizing transmission on the boundary seams of the region. This will be a comprehensive effort to focus on inter-regional agreements to plan, allocate cost, optimize usage and provide for fair compensation for the use of transmission across boundaries.

The following are specific initiatives related to enhancing and optimizing interdependent systems:

- Inter-regional coordination of transmission planning and operations
- Optimize market efficiencies along seams
- Optimize natural gas pipeline system seams
- Optimize data seams within SPP and with SPP's members, customers, and external parties
- Integrated Marketplace enhancements

Enhance Member Value and Affordability



ENHANCE MEMBER VALUE AND AFFORDABILITY

SPP continually strives to enhance the value delivered to its members. In addition to the strategic initiatives noted above, SPP will create and continually improve work processes to ensure they are efficient and effective.

SPP recognizes the importance of prioritization of strategic initiatives. SPP will continue to work with it members through the Markets and Operations Policy Committee to share information about the costs and benefits of member-facing project initiatives and regularly provide updates on the entire portfolio.

SPP will further develop processes and a communication strategy to demonstrate to members, regulators, and customers the general inter-zonal equity of costs and benefits for strategic initiatives.

The following are specific initiatives related to enhancing member value and affordability:

- Communication strategy on value/affordability
- Fair and equitable cost/benefit allocation policies
- Project Management Office best practices and rigor in evaluating new projects
- Enhanced market analytics
- Strategic membership expansion and improved stakeholder processes
- Improved communication with and education of stakeholders and external parties

Process Improvements

The SPP staff is conscientious of the need for continuous business process improvements as a strategy to increase the value of services delivered to SPP members at lower costs. SPP has experienced significant growth in the volume and complexity of its service offerings over the past decade. SPP's service offerings in 2005 consisted primarily of:

- Reliability Coordination
- Tariff Administration
- Transmission Scheduling
- Interconnection Studies
- Reliability Studies

Since 2005, SPP has added the following services that provide meaningful benefits to the SPP region:

- Energy Imbalance Services market (retired March 2014)
- Independent Coordinator of Transmission for Entergy (retired December 2012)
- Independent Transmission Operator for Louisville Gas & Electric (retired December 2012)
- Day-ahead Services market
- Real-time Balancing market
- Transmission Congestion Rights market
- Balancing Area services
- Aggregate Study Processes (resulting in over $8 billion in NTCs issued)

SPP was able to provide these new value-added services in a manner satisfying the expectations of the majority of SPP members. As a result, SPP realized a significant increase in its costs of operations. The increased costs were considered in cost/benefit studies for the majority of services.

Many significant challenges still lie ahead as SPP implements Project Pinnacle in early 2015, advances the competitive bidding processes required by FERC Order 1000, and assists the membership in carrying out EPA mandates on environmental protection. SPP's members are under pressure to reduce or keep rates steady, while their rates are burdened with the cost recovery of the SPP regional transmission projects and capital requirements to satisfy environmental mandates on carbon emissions or elimination of coal production.

SPP management is cognizant of the need to reduce operating costs wherever feasible. SPP has challenged management teams to identify real cost reductions in 2015 compared to 2014. Each member of SPP management was required to identify and implement at least one cost reduction for 2015. The reduction was required to be a true savings over what is actually spent in 2014, not simply a reduction in the year-over-year budget.

The following table illustrates the cost reductions, by department, identified during the process. The largest reductions are in areas currently utilizing external consultants, as management reassessed workload in attempts to accomplish more work with the same number of resources, or to do the same amount of work with fewer resources. The savings result from eliminating and/or limiting the 2015 consulting engagements and instead relying on existing staff to absorb expertise and responsibilities. Other savings were identified by reducing travel costs for the company. These reductions take the form of hosting more meetings at SPP's Corporate Center in Little Rock and making broader use of teleconferencing options instead of travelling to attend off-site meetings. In total, the cost savings identified exceed $2.15 million. Individual managers are responsible for tracking the cost savings throughout the year and the savings will be reported to the SPP Finance Committee throughout 2015.

Department	Description of Savings	Savings ($millions)
Operations	Consultants, overtime, travel, licenses expenses, level of backfill positions	$ 0.935
Information Technology	Consultants, eliminate low value licenses, delay staffing backfill, travel	$ 0.857
Project Management	Consultants	$ 0.200
Engineering	In-source reporting, raise billing for services	$ 0.050
Training	Travel, host meetings at member sites or at SPP	$ 0.033
Settlements	Eliminate licenses, reduce SUG meetings	$ 0.024
HR	Change evaluation cycle, change compliance vendor	$ 0.013
Compliance	Increase teleconference vs travel	$ 0.011
Communications	Change service provider	$ 0.010
Facilities	In-source HVAC maintenance	$ 0.009
Internal Audit	Eliminate low-value 3rd party services; reduce travel	$ 0.004
Regulatory	Eliminate subscriptions and travel	$ 0.004
Accounting	Eliminate low-value 3rd party services; lower license expense	$ 0.003
Legal	Overnight delivery	$ 0.002
Customer Relations	Decrease travel	$ 0.001
	Total	$ 2.156

Continuous Improvements LEAN Initiatives

LEAN business thinking continues to form the foundation for SPP's continuous improvement efforts. About half of SPP's workforce has participated in LEAN initiatives to refine processes across at least seven divisions. Among these initiatives:

- Operations implemented improvements to SPP's communication with market participants on wind curtailments and other non-dispatched resources. As a result of more proactive market participant notifications, combined with automated routing and tracking of inquiries, the number of external queries declined and internal productivity increased (estimated at $0.2 million annually). Interested parties can now refer to spp.org for detailed, near-real-time information to better understand the conditions affecting SPP reliability decisions.

- Engineering embarked on an initiative to improve coordination and visibility of transmission facility ratings changes. The team developed an automated approach to identifying and tracking changes with the potential to affect long-term planning models. The initiative, which improved coordination across the operations and planning departments, positions SPP to be better informed of changes that could influence cost allocation decisions. The additional visibility also enhances SPP's ability to maintain effective real-time operation of the grid as well as long-term transmission planning.
- IT determined that changes in provisioning products and services could reduce costs while still maintaining the quality of systems. In the first half of fiscal 2014, IT's change in focus on multi-year agreements and bundling of maintenance costs resulted in projected cost avoidance of the following (realized over three years):
    - $0.6 million based on vendor discounts
    - $0.2 million from internal productivity gains, i.e. negotiating the contract once in a three-year period instead of annually

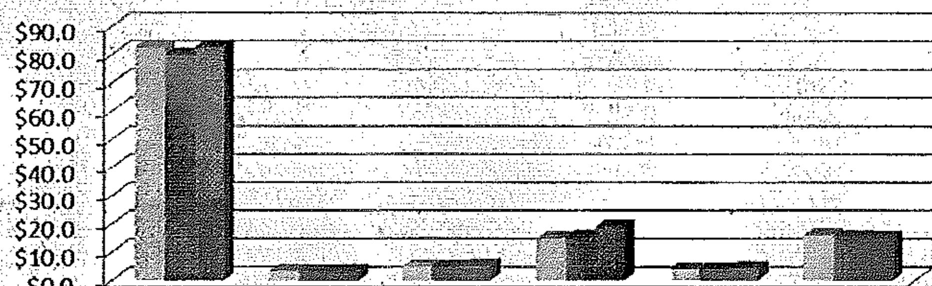
  Additional work is under way to shorten procurement timelines so new or upgraded systems are installed without costly delays.

These examples represent a wide range of activity undertaken in all areas of the company to increase productivity, improve quality and enhance effectiveness. Among the LEAN initiatives identified for 2014 are improvements to SPP's model and ratings processes, quality assurance processes, approach to Settlements information system testing, and coordination of IT requests across applications. The goals behind these efforts are multi-faceted, but true to the LEAN spirit, all are anchored by the desire to increase the value provided to SPP's members and market participants.

IV. 2015 Budget: Resource Utilization View

SPP's 2015 budget encompasses utilization of various resources in driving SPP to meet its strategic goals and organizational objectives. The chart below shows SPP's resources and the corresponding 2015 budget amounts in comparison to 2014 budget and forecast. The 2014 forecast excludes non-recurring items.

2015 Operating Expense Budget by Resource ($ millions)



	Staffing	Travel and Meetings	Admin and Leasing Expenses	Outside Services and Consulting	Comm.	Maint.
2014 Budget	$82.2	$3.1	$4.9	$14.6	$3.9	$15.9
2014 Forecast *	$79.8	$2.8	$4.6	$15.3	$3.8	$15.3
2015 Budget	$82.4	$3.1	$5.0	$19.0	$4.3	$14.8

* 2014 forecast excludes non-recurring items

Staffing: Valuing Work at SPP

SPP's employees are the most valuable and significant resource and the driver of the single largest component of the operating budget. Compensation-related expenses (including salary, benefits, and taxes) total $82.4 million and comprise 64% of the 2015 operating expenses budget (excluding FERC, depreciation and interest), an increase of $0.2 million compared to the 2014 budget. The main factors leading to the increase in staffing costs in 2015 are related to merit and anticipated increases in healthcare costs. These increases are offset by an increase in the vacancy rate from 2% to 4%, which is reflective of the average vacancy rate experienced during 2014. There are five incremental headcount proposed in 2015, resulting in a total staff of 600, which is three less than the prior 2015 forecast.

Merit and Vacancy Rate Assumptions

The Human Resources Committee recommended an overall merit increase of 2.3% for 2015 based on the CPI inflation rate and feedback from SPP members, which contributes to higher salary expenses in 2015. Merit increase was budgeted at 2.4% in 2014. The promotion pool remained consistent with 2014 at 0.75%.

Based on historical trends and expectations, the prior 2014 – 2016 projections included a vacancy factor of 2%. In 2014 vacancy levels fluctuated between 3% and 4% throughout the year. By the end of 2014, headcount is expected to be within 3% of the projected 2014 level (582 of 598). SPP anticipates staff turnover in 2015 to be consistent with trends experienced in 2014. Entering the year with 22 openings and assuming a 90-day period required to backfill open positions, SPP expects a vacancy rate of 3.6% at the beginning of 2015. For purposes of the 2015 budget, SPP utilized a 4% vacancy rate. This equates to turnover averaging 24 open positions during the calendar year.

Healthcare Costs

The net cost of the self-funded medical plan in the 2015 budget is $5.3 million, an increase of 24.7% or $1.1 million compared to the 2014 forecast, and 16% or $0.8 million compared to the 2014 budget. The increase is largely due to the continued increase in medical claims SPP has been experiencing since late 2012. This upward trend is expected to continue throughout 2015, resulting in higher healthcare expenses.

Approximately 92% of employees participate in the medical plan currently. The average number of participants in 2015 is estimated to be 532, compared to the projected average of 528 employees in 2014. Total gross claims are estimated to be $5.6 million in 2015, compared to a forecast of $4.6 million in 2014, an increase of 22.9%. SPP pays fees to the insurance provider to cover administrative costs and insure against excessive losses at both the participant and corporate level. These fees are estimated to be $1.0 million in 2015, compared to a forecast of $0.9 million in 2014, an increase of 9.8%. In 2014, SPP managed to mitigate the increase in fees that normally would have been incurred due to the growth in claims by increasing the deductible on per participant losses. Employee contributions to the medical plan offset the overall cost and are estimated to be $1.3 million in 2015, compared to a forecast of $1.2 million in 2014 as a result of a planned increase of 6.0% in contributions per participant. The net cost of the medical plan to SPP per participant is expected to be $835/month, compared to $724/month in 2014, mainly due to the increase in claims. SPP's Human Resource Committee targets to maintain an 80/20 cost ratio between employer and employee. The following table illustrates total healthcare costs using various cost ratio percentages.

Healthcare Costs ($ millions)

Cost Ratio	80/20	75/25	70/30	60/40
Employer	$5.3	$4.9	$4.6	$3.9
Employee	$1.3	$1.6	$2.0	$2.6
Total	**$6.6**	**$6.6**	**$6.6**	**$6.6**

Staffing Levels

SPP's management continuously assesses and evaluates SPP's staffing levels across all areas of the organization. In 2014, SPP's forecast for headcount was reduced from 598 to 595 with the elimination of an open position in the Regional Entity (RE) and two positions within IT. The RE position had been open for more than 12 months, and it was determined that existing staff was sufficient to cover the workload. Due to reassignment of responsibilities, an IT manager position and an IT specialist position were eliminated after a retirement and resignation. Staff reductions in other areas within SPP were also the result of absorbing responsibilities as positions became vacant due to turnover, retirements or internal transfers; however, four of the six positions were reallocated to IT, with three of the four used to establish a 24x7 on-site shift of IT programmer/analysts. This shift provides immediate response to system issues within the Operations center, 24 hours a day.

2014 Staffing Reallocation	IT	Engineering	Settlements	Regional Entity	Corporate Svcs	Operations	Training/Cust Svc	TOTAL
Reductions in Engineer in Rotation program, positions transferred to IT	2	(2)						0
Settlement Analyst resignation, position transferred to IT	1		(1)					0
Executive Assistant retirement, position transferred to IT	1				(1)			0
Restructure between Engineering and Operations		(1)				1		0
Operations Customer Liason position transferred from Operations to Customer Service						(1)	1	0
Learning Mgmt System (LMS) Admin position transferred from Training to Corporate Svcs					1		(1)	0
IT Manager and IT Specialist, open positions eliminated	(2)							(2)
Regional Entity Compliance Enforcement Attorney, open position eliminated				(1)				(1)
Net change	2	(3)	(1)	(1)	0	0	0	(3)

Three of the four IT positions were included in the 2015 forecast (during the 2014 three-year budget planning), so there is no impact to the previous 2015 headcount total (i.e. 2015 incremental in prior forecast was removed). The prior 2015 forecast included three incremental positions in IT, one in Training and one in Engineering. Training resubmitted the position in the current 2015 budget; however, Engineering did not resubmit a request for incremental headcount in 2015. Market Design submitted a Market Analyst position to eliminate the ongoing use of a consultant for staff augmentation, and Operations requested one incremental position for market support and two to address the expanded responsibilities related to the addition of the Integrated System. The incremental positions in Operations are considered interim, as Operations plans to eliminate two positions by 2017 as a result of attrition.

Prior 2015 Incremental Positions		
598	2014 Budget Headcount	
1	IT	Accelerated to 2014 due to restructuring
2	IT	Accelerated to 2014 due to restructuring
3	IT	Accelerated to 2014 due to restructuring
4	Train	Approved in 2015 Forecast
5	Eng	Approved in 2015 Forecast
603		

Current 2015 Incremental Positions		
595	2014 Forecast Headcount	
1	Mkt	Reduces ongoing consulting costs
2	Ops	Reduces ongoing consulting costs
3	Ops	Restructure for elimination in 2017
4	Ops	Restructure for elimination in 2017
5	Train	Repurposed from 2015 Forecast
600		

The table below shows the staff numbers by executive division:

Headcount by Division	2014 Budget	2014 Forecast	2015 Budget	2016 Budget	2017 Budget
Operations	157	157	160	160	158
Information Technology	144	146	146	146	146
Engineering	76	73	73	73	73
Process Integrity	47	47	48	48	48
Finance	39	38	38	38	38
Compliance, Communications, and MMU	30	30	30	30	30
Corporate Services	29	29	29	29	29
Regulatory Policy and Legal	26	26	26	26	26
Officers	10	10	10	10	10
Market Design	6	6	7	7	7
Interregional Relations	3	3	3	3	3
Subtotal	567	565	570	570	568
Regional Entity	31	30	30	30	30
Total Headcount	598	595	600	600	598

SPP strives to attract and retain a highly educated and skilled employee base to provide the highest level of service and value for its members. Compensation and benefits are regularly monitored to ensure SPP remains a competitive and attractive employer. SPP administers an in-house Engineer in Rotation program, which seeks the most talented engineering graduates for an expansive training program. This program has been reduced from six to four in 2015, with two of the positions being repurposed for IT. The rotating staff of engineers gain experience through on-the-job training and are placed in permanent roles as positions become available through normal employee turnover.

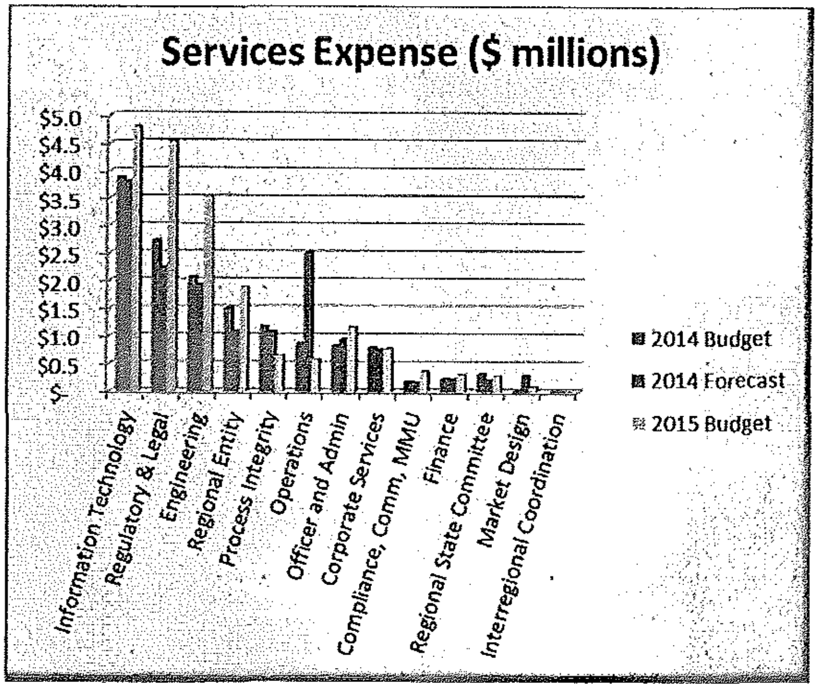
The staffing budget for 2015 includes funding for staff compensation (base salary, performance compensation, and overtime pay), benefits and payroll taxes, relocation, and tuition reimbursement. The base salary budget includes a merit increase of 2.3% and promotion increase of 0.75%, which is a pool of funds for company-wide promotions overseen by the Human Resources department. Performance compensation is budgeted at the target level of 15.0% of base salary and is paid in February of the following year.

The budget for benefits and payroll taxes includes medical, dental, and life insurance benefits, retirement plan contributions, relocation expenses, employee events, payroll taxes, and continuing education. Insurance benefits are budgeted based on projected per participant costs. Funding for 401(k) matching contribution is estimated at 4% of the salary expense based on recent company trends. Below is a breakdown of various employee benefits and taxes:

Benefits and Payroll Taxes ($ millions)	2014 Budget	2014 Forecast	2015 Budget
Performance Compensation	$8.4	$8.4	$8.7
Medical Benefits	4.6	4.3	5.3
Dental Benefits	0.4	0.4	0.4
Life Insurance Benefits	0.2	0.2	0.3
Retirement Plans (401k and Pension)	7.3	6.6	6.7
Payroll Taxes	4.7	4.2	4.7
Continuing Education	1.0	0.8	0.8
Other Employee Benefits	0.3	0.4	0.4
Total Before Non-Recurring Items	**$26.9**	**$25.3**	**$27.2**
Non-Recurring Items	0.0	4.3	0.0
Total Benefits and Payroll Taxes	**$26.9**	**$29.6**	**$27.2**

Outside Services

Outside services consist of third-party expertise to assist SPP in deploying various services, providing legal representation and advice, and satisfying audit requirements. Outside service expenses are estimated to be $18.7 million in 2015 representing an increase of $4.4 million compared to the 2014 budget, and $3.6 million compared to the 2014 forecast. This comprises 15% of the total 2015 operating expenses (excluding FERC fees, depreciation and interest).



Outside Services by Division ($ millions)	2014 Budget	2014 Forecast	2015 Budget	2015 Budget Over / (Under): 2014 Budget	2015 Budget Over / (Under): 2014 Forecast
Information Technology	$ 3.9	$ 3.8	$ 4.8	$ 0.9	$ 1.0
Regulatory Policy and Legal	$ 2.7	$ 2.3	$ 4.5	$ 1.8	$ 2.3
Engineering	$ 2.1	$ 1.9	$ 3.5	$ 1.5	$ 1.6
Regional Entity	$ 1.5	$ 1.1	$ 1.9	$ 0.4	$ 0.8
Officer and Admin	$ 0.8	$ 1.0	$ 1.2	$ 0.3	$ 0.2
Corporate Services	$ 0.8	$ 0.8	$ 0.8	$ (0.0)	$ 0.0
Process Integrity	$ 1.2	$ 1.1	$ 0.7	$ (0.5)	$ (0.4)
Operations	$ 0.9	$ 2.5	$ 0.6	$ (0.3)	$ (1.9)
Compliance, Communications, and MMU	$ 0.2	$ 0.2	$ 0.4	$ 0.2	$ 0.2
Finance	$ 0.2	$ 0.2	$ 0.3	$ 0.1	$ 0.1
Market Design	$ 0.0	$ 0.3	$ 0.1	$ 0.1	$ (0.2)
Interregional Coordination	$ -	$ -	$ -	$ -	$ -
Total Outside Services Expense	**$ 14.3**	**$ 15.1**	**$ 18.7**	**$ 4.4**	**$ 3.6**

Outside services expenses have increased from the 2014 budget and forecast in various areas.

By engaging consultants for various staff augmentation needs, the IT **department** incorporates $4.8 million in outside services expense, representing 25% of the total and approximately a $1.0 million increase over the 2014 budget and forecast. As SPP staff works on delivering new functionality required as part of Project Pinnacle and the IS Integration project, the contractors assist with the extra workload required to support systems. The IS Integration project represents $0.9million of consulting expense, accounting for over 90% of the increase from 2015 to 2014.

The **Regulatory and Legal department** represents 24% of the 2015 outside services budget. Outside legal counsel is utilized for various litigation matters throughout the year and remains relatively consistent with the 2014 budget and forecast ($2.5 million). Outside FERC counsel provides unique legal expertise on specific and strategic FERC matters. FERC counsel allows SPP to leverage their existing relationships with FERC staff and their knowledge of RTO-specific development.

The budget includes costs for Order 1000 Industry Expert Panel (IEP) of $1.3 million, which will be recovered in revenue from the participants in the proposal process. Since the process begins in 2015, the costs are incremental to the 2014 budget and forecast. The budget also includes incremental consulting costs of $0.8 million related to recently required studies. A provision in the Tariff (OATT) requires SPP to perform a Regional Cost Allocation Review (RCAR) to evaluate the reasonableness of the base plan allocation methodology and associated factors. The RCAR report was approved by the stakeholders and Board of Directors to begin once the ITP10 is completed in January 2015. In order to provide efficiencies in modeling and analysis, the stakeholders and Board of Directors elected to engage the Rate Impact Task Force (RITF) for analysis to be completed in parallel with the RCAR.

The **Engineering department** represents over 18% of the 2015 outside services budget ($3.5 million) and has increased by approximately $1.5 million over the 2014 budget and forecast. SPP engages consultants for many aspects of the engineering planning processes. Generation Interconnection study requests are numerous, and consulting services are engaged to complete these studies when requests are greater than SPP staff can accommodate. As appropriate, the consulting costs in these studies are passed through to the participants in the process.

Engineering has three new initiatives and two Order 1000 efforts driving the increase in outside services to be engaged in 2015. These originate from Board of Directors requests, new legislation, and SPP's strategic directive for member expansion and member value. Each came into focus after the 2014 budget was complete.

- $0.7 million – The **Value of Transmission** initiative is a Market Operations and Policy Committee (MOPC) action item directed from the Board of Directors in January 2014. The main focus of this effort is to determine benefits attributable to transmission development in the SPP region. The study will provide realized and future benefits of transmission using real-time planning models, historical data, forecasts, and other sensitivities not included in SPP's ITP or RCAR benefit studies. The results of the study will benefit members in quantifying new transmission projects that will complete in the next two years with their regulatory commissions and validate the benefits to consumers of transmission beyond that of reliability. This study is in line with SPP's new strategic initiatives of maintaining an economical, optimized transmission system while providing member value with a communication strategy on value/affordability.

- $0.5 million – After reviewing the efforts involved in onboarding the **Integrated System**, SPP determined additional resources are required to provide the planning and analysis to bring the IS into our planning processes. Since membership expansion is a strategic priority, the effort will be done in parallel to Engineering's existing Integrated Transmission Planning (ITP) efforts and will include the ITP Near-Term (ITPNT), a new ITP10, and the Order 1000 requirements for the DPP windows in those studies.
- $0.3 million – One of the most critical regulatory items for SPP Transmission Planning in the next five years is the **EPA's Clean Power Act Rule 111(d)** draft issued in June 2014. This act has a broad impact on SPP members, stakeholders, and electric consumers within the SPP footprint. The changes to generation resources based on this ruling could have a landmark effect on SPP's planning processes. In order to determine how transmission planning will adjust for resources impacted by Rule 111(d), multiple studies must be done on many of the aspects of the Clean Power Act, including outage impacts, regional versus state qualification, reliability analysis, economic analysis, and the effects on the ITP planning cycle. These issues will be addressed in the near term so SPP can work with its members on all the possible impacts of the Clean Power Act to make decisions with greater knowledge and confidence.
- $0.3 million – **FERC Order 1000** was implemented January 2014. Many of the aspects of Order 1000, such as Detailed Project Proposals (DPP) and PROMOD support for ITP10, were accounted for in the original 2014 and 2015 budget forecasts; however, these solutions must be processed in a timely manner in order to stay within the ITP schedule and provide submitters the opportunity to cure any deficiencies in the proposals. With this short-term duration and high volume of work, SPP will engage highly skilled technical analysts on a short-term contract basis rather than hiring a permanent resource or issuing a long term consulting contract.

The 2015 budget includes outside services and consultants in various other areas including the following:

- $1.9 million – Regional Entity: audits and hearings
- $1.2 million – Officer and Administrative: board fees, legislative consulting
- $0.8 million – Corporate Services: facility and employee services
- $0.7 million – Process Integrity: audit and project management
- $0.6 million – Operations : Integrated System OATI changes
- $0.4 million – Communications and Market Monitoring: reporting/data services
- $0.3 million – Finance: financial audits, credit services, IS Settlement consultant

- $0.1 million – Market Design: market consultant

Maintenance

The maintenance expense budget includes expenses to maintain SPP's IT hardware and applications and for maintaining corporate facilities.

Maintenance Expense ($ millions)	2014 Budget	2014 Forecast	2015 Budget	Prior 2015
IT Software & Equipment	$ 15.2	$ 14.5	$ 14.1	$ 15.2
General Plant Maintenance	$ 0.7	$ 0.7	$ 0.7	$ 0.7
Total	**$15.9**	**$15.3**	**$14.8**	**$15.9**

The IT maintenance budget increased significantly between 2013 and 2014 due to an increase in the IT operating environment to support Integrated Marketplace. The IT department is now focused on maximizing the value of ongoing hardware/software maintenance agreements by leveraging multi-year terms to align with the technical life of the asset (as appropriate). This will provide price protection and reduce the overall annual maintenance cost for the respective products, while also reducing annual renewal activities therefore improving SPP staff productivity.

In addition to multi-year agreements, the maintenance budget is positively affected by the replacement of older IT hardware technology. The new equipment will carry a warranty, thereby eliminating maintenance costs during the warranty period. As a result, certain IT maintenance expenses are projected to decrease during 2015 by approximately $1.1 million as compared to the 2014 budget and $0.5 million as compared to the 2014 forecast.

Maintenance Expense ($ millions)	2014 Budget	2014 Forecast	2015 Budget	Prior 2015
Support-IT Foundation	$ 7.8	$ 7.4	$ 7.1	$ 7.9
Market	$ 2.8	$ 2.7	$ 1.9	$ 2.9
Leveraged Services	$ 1.7	$ 1.8	$ 1.7	$ 1.5
Reliability	$ 1.4	$ 1.4	$ 1.5	$ 1.3
Support-Project/Other	$ 0.9	$ 0.8	$ 1.4	$ 1.2
General Plant Maintenance	$ 0.7	$ 0.7	$ 0.7	$ 0.7
Transmission	$ 0.5	$ 0.5	$ 0.5	$ 0.5
Total	**$ 15.9**	**$ 15.3**	**$ 14.8**	**$ 15.9**

Other maintenance costs include various facility expenses such as janitorial expense, landscape maintenance, and preventive maintenance. The facilities maintenance budget remains comparable to the 2014 budget and forecast.

Administrative and Leasing Expenses

Administrative and leasing expenses are expected to increase by $0.1 million in 2015 compared to the 2014 budget, with the most notable change due to the categorization of $0.3 million for network hardware adapters as expense versus capital, as previously budgeted. This increase is offset by modest decreases in dues & donations ($0.1 million) and utilities ($0.1 million).

The largest component of the Administrative expense is insurance expense ($1.1 million). The various components are listed here. The next largest component is property taxes, which are based on the value of SPP's assets ($1.0 million).

Dues are budgeted for professional or technical licenses and/or memberships in certain professional organizations where membership is related to employment by SPP, will maintain the employee's professional standing, or is otherwise beneficial to SPP. In addition to such employee dues, $0.3 million of the $0.6 million budget is related to Electric Power Research Institute (EPRI) membership for access to research conducted on issues related to the electric power industry.

Utilities, office and leases expenses make up the remaining administrative expense and remain reasonably consistent with previous projections in 2015.

Communications

Communications expense includes all expenditures related to SPP's internal and external networks and telecommunications. In 2015, network communication expenses are expected to be $4.3 million. This increase of 13% over the 2014 forecast is primarily due to additional capacity required for growth and the Integrated Marketplace. Other factors contributing to the increase are expected increases in NERCnet expenses due to a change in provider (initiated by NERC), addition of a SERC hotline to provide a direct link for critical reliability issues, and an increase in OATI frame relay costs to increase capacity arising from bandwidth saturation.

Communications Expense ($ millions)	2014 Budget	2014 Forecast	2015 Budget	Prior 2015
Network	$ 3.8	$ 3.5	$ 4.0	$ 4.0
Cellular, Satellite, Long Distance	$ 0.1	$ 0.3	$ 0.3	$ 0.1
Total	$ 3.9	$ 3.8	$ 4.3	$ 4.1

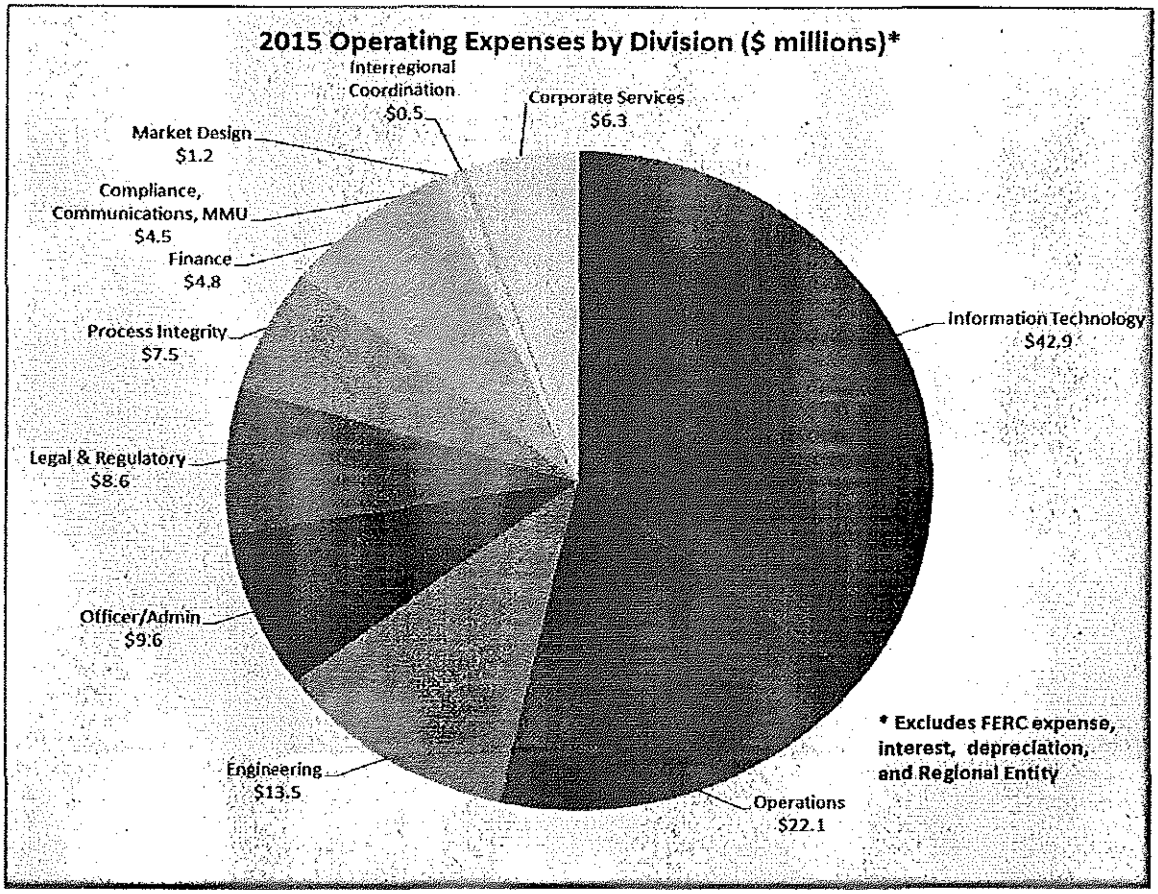
Travel and Meetings

Travel and meetings expenses are expected to increase by $0.3 million in 2015 as compared to the 2014 budget and increase by $0.6 million as compared to the 2014 forecast. The largest component of the increase is in the Regional Entity, where travel is budgeted at $0.2 million higher than the 2014 forecast. Additionally, travel and meetings associated with onboarding the Integrated System makes up $0.2 million of the increase over the 2014 forecast.

When planning for external meetings, usage of SPP's corporate facilities for various meetings, as well as utilization of member facilities is encouraged. In efforts to reduce travel and meeting expenses, SPP encourages all organizational groups to include Little Rock in the rotation for working group meetings.

V. 2015 Budget: Division View

The 2015 operating budgets of the ten divisions are shown below.



Information Technology

The primary mission of IT is to develop, deploy, integrate and support applications and infrastructure for SPP's operational and corporate systems. IT has a total of 148 employees with a proposed 2015 budget of $42.9 million. This division has three main groups: and IT Executive (which includes maintenance), IT Enterprise Operations, and IT Applications.

The IT Executive department has a budget of $15.5 million and includes compensation for a Chief Architect and IT Sourcing Team, as well as equipment and software maintenance for company-wide IT systems ($14.1 million).

The **IT Applications** department provides 24x7 support for existing systems including transmission, reliability and the Integrated Marketplace. In addition, the department is responsible for coordinating all software development efforts related to the Integrated Marketplace enhancements as part of the Project Pinnacle. IT Applications plays an integral role in nearly all new projects, including creating requirements/test/rollback plans; developing software; providing technical leadership; defining, implementing and reviewing architecture; and providing ongoing maintenance and support for these systems. The IT Applications group also tests and implements all software upgrades.

Based on recent workload requirements, along with anticipated increases in future workloads, management performed a review of current staffing levels. As a result, it was determined that current IT Applications staffing is adequate for 2015, supplemented by contractor resources to handle extra workload driven by projects such as the IS Integration. During 2014, six positions (three from within the IT department and three from existing vacancies outside of IT) were reallocated to support a new 24x7 on-site shift of IT programmer/analysts, referred to as the FIRST). This new team will provide immediate IT response to system issues by staffing a support desk within the Operations center 24 hours a day. The IT Applications department is comprised of 95 employees with a budget of $15.8 million.

The **IT Enterprise Operations** department provides 24x7-support for all communications and networking systems, and all computer hardware and environmental needs for the SPP data centers. Each is critical to SPP's transmission, market, and business processes. IT Enterprise Operations provides technical direction, leadership, and architectural design for the communications, network, storage, backup/recovery, and computing platforms for all aspects of the IT infrastructure utilized within SPP. IT Enterprise Operations has maintained a consistent headcount level for the past three years, while accepting a significant increase in workload (number of servers, increases in storage, etc.). The department has been able to absorb the increased workload without adding staff as a result of maintaining a highly qualified staff that is significantly leveraged across various technical platforms and disciplines as well as increasing automation processes. The department historically has not utilized contractor resources to fulfill its responsibilities, and does not anticipate doing so during 2015-2017. The department is currently comprised of 48 employees with a budget of $11.6 million.

Operations

The Operations group administers SPP's Tariff and performs reliability coordination throughout SPP's footprint. The department has a total budget of $22.1 million for 2015, including staff of 158. The group achieves this strategically important goal with a highly-trained staff of professionals in the following departments:

- The **Systems Operations** department is responsible for ensuring 24x7 monitoring of the bulk grid in the SPP region and ensuring operators and support staff are properly trained and in compliance with NERC standards. Outside consultants assisted throughout the transition to the Integrated Marketplace go-live date; however, SPP presently utilizes operators' expertise and has eliminated the need for further consulting services for day-to-day operations. As a Reliability Coordinator, SPP is required by NERC to share in the cost of the Interchange Distribution Calculator (IDC) tool. Annual consulting expense of $0.5 million is included in the Systems Operation's budget for use of this tool. The department has 74 positions, including a department director, two managers, and seven shift supervisors.

- The **Markets Administration** department is comprised of a staff of 27 employees and is divided into two main groups that reflect the fundamental structure of real-time and day-ahead markets. Included are operators and engineers who oversee the operation of the Day Ahead market, optimizing energy and capacity on a daily basis. Duties include providing data integrity in real-time and performing data analyses after the fact to optimize the benefits for SPP's membership and market participants. No additional consulting is included in the Markets Administration budget and there are no plans to increase staffing levels beyond 2015.
- The **Operations Support** department provides support services to the Operations division in areas such as outage coordination, load forecasting, modeling and data validation, and market data and registration, as well as extensive customer interaction and support. Two Engineer positions were added in 2015 to assist with the additional workload associated with the IS integration; however, through normal turnover, two positions will be eliminated by 2017. As a result of adding IS less than $0.1 million was included for outside consulting for OATI software, and for interchange and market changes. This group has a staff of 59 employees, with no additional headcount anticipated beyond 2015.

Engineering

The Engineering division's mission is to facilitate SPP's strategic goal of continued development of a robust transmission system within the SPP footprint, while creating optimum value for stakeholders, members, and customers. This division has a total budget of $13.5 million for 2015 with 73 employees.

The Engineering division is comprised of four departments:

- The **Engineering Planning** department is primarily involved in transmission planning studies and the Integrated Transmission Planning (ITP) process. As discussed in the Outside Services section (IV) four new initiatives are planned for 2015. The department added one position in the 2015 budget for the steady state planning function. A primary goal of the department is increasing the skill and knowledge level of its staff through intensive training, and developing its employees to meet the goals for 2015 and SPP's strategic plans. The various planning studies conducted by the planning department produce revenues for SPP, which serve to reduce SPP's Net Revenue Requirement. Revenue expected from studies is $2.5 million in 2014. This group has a staff of 43 employees.

- The **Modeling** department creates and maintains the power flow models used by the transmission planning and tariff studies groups and continuously coordinates with members to ensure accuracy of the models, a critical step in planning investments in the region's transmission grid. This department has a staff of 11 employees, with no new headcount planned for 2015 – 2017.
- The main goal of the **R&D and Special Studies** department is to assess new approaches and tools to refine performance objectives that align with future needs surrounding renewable resources, which are expected to drive the future of the power grid. To achieve this goal, the department is budgeting for extensive research and information tools, such as publications and membership in Electric Power Research Institute (EPRI), and for increased consulting services from industry experts to bring proven solutions into SPP to improve the planning process. SPP's goal is to conduct centralized R&D activities that will benefit SPP's stakeholders as a region. This department has a staff of 9 employees, including four in the Engineer in Rotation program.
- The **Support and Resource Planning** department provides business solutions and efficiencies, and resource coordination and allocation for engineering projects. The resource coordination and time tracking initiative has produced the ability to provide mitigation plans and track work efforts to produce long-term resource plans that can more accurately predict staffing needs. This department has a staff of 10 employees.

Compliance, Communications, and Market Monitoring

The Compliance, Communications, and Market Monitoring division has a staff of 30 employees with a budget of $4.5 million. No additional headcount is anticipated for 2014-2016.

- The main goals for the **Compliance** department are enhancing member outreach services at the request of the Board Oversight Committee, and providing IT security and risk mitigation functions to the SPP organization, which includes cyber-vulnerability assessments, security monitoring, threat evaluation, and incident response. Improved processes, member outreach planning, and staff capabilities has allowed existing staff to address current and future member evidence reviews and associated outreach needs. The department has a budget of $1.7 million with a staff of 12.
- The focus of the **Communications** department is to build and execute a communication strategy that educates, creates trust, and protects the organization. The department will continue to execute this strategy through various deliverables in 2015, especially involving communicating the value of transmission to stakeholders. The department has a budget of $0.6 million with a staff of 4.
- The main focus of the **Market Monitoring** department is to refine and implement analytical tools and monitoring screens, and continually develop staff to effectively monitor the Integrated Marketplace. The department has a budget of $2.3 million with a staff of 14.

Process Integrity

This division has a total staff of 48, with a proposed budget of $7.5 million for 2014.

- The **Project Management Office (PMO)** department is responsible for overseeing and coordinating the design, development, and implementation of projects within SPP. The department's focus is concentrated on the Project Pinnacle development and implementation. Project resource requirements in 2015 exceed internal resource availability; therefore, contractor resources will be utilized as staff augmentation. The department has a budget of $2.1 million with a staff of 13.
- The **Stakeholder Services** group encompasses two departments, **Customer Service and Customer Training**. Customer Service will concentrate on customer interactions related to the Integrated Marketplace in 2015, as the volume of inquiries, requests, and outreach has increased significantly. Four of the ten staff members are dedicated to the Integrated Marketplace customer interactions. Customer Training will increase services and product delivery in response to demand for additional reliability-related training, new and/or updated operator tools, and Integrated Marketplace. An e-Learning Specialist position was added in 2015 to help mitigate travel and meeting costs to SPP and members by increasing computer based training initiatives. The department has a budget of $2.9 million with a staff of 22.
- The mission of the **Internal Audit** department is to provide independent and objective assurance and advisory services that are designed to add value and improve SPP's operations. The department maintains and implements a risk-based audit schedule for SPP's business and IT units and functions. A critical function of the Internal Audit

department is the coordination of the annual SSAE 16 audit, which evaluates SPP's internal controls as a service organization. With the successful launch of the Integrated Marketplace, the focus going forward is ensuring the effectiveness and reliability of SPP's internal controls supporting Integrated Marketplace functions. The department has a budget of $1.1 million with a staff of 6.

- The **Business Process Improvements** department originated as a result of SPP's organization-wide commitment to continuous improvement. The main focus of the department is to continue to implement the LEAN program throughout the SPP organization, to identify opportunities for process improvements, and to improve effectiveness and efficiencies. The department also focuses on SPP's business continuity planning, which is critical as a result of increased risks associated with the Integrated Marketplace. The department currently includes a staff of 3 and a budget of $0.5 million.
- The goal of the **Interregional Affairs** department is increased involvement in the industry-wide standard development efforts by serving in leadership roles in both NERC and NAESB. The Reliability Standards staff provides SPP leadership in the national effort to develop meaningful and achievable reliability standards. Working with other SPP staff, members, and industry experts, the department works to ensure the standards necessary to maintain a reliable bulk electric system are in place, with clear, effective, reasonable, and measurable requirements. The staff is comprised of 4, with a budget of $0.8 million.

Market Design and Development

This department is responsible for the evolution of the energy and capacity markets, which is achieved through interactions and cooperation with members and other stakeholders while creating and enhancing markets in a member-driven way. Other goals of market design are to maintain reliability and pursue innovative ways to increase reliability through economics.

The department has three key responsibilities:

- Create and modify the SPP regional market design through a member-driven process

- Conduct quality assurance functions to ensure implemented processes and systems are consistent with the market design
- Support other market-related initiatives

With the implementation of the new market, the Market Design workload has increased. The volume of market design changes has increased significantly beyond those anticipated, and there are also increased requests from both internal and external stakeholders to analyze market design issues from a holistic approach. Replacing the continued use of a consultant for staff augmentation, a Market Design Analyst position is included in the 2015 budget to cover the increased workload. The Market Design department has a 2014 budget of $1.2 million and a total staff of 7 employees.

Interregional Coordination

The **Interregional Coordination** department expects seams coordination activity to increase significantly over the next three-year period. The staff is working closely with SPP's neighboring entities to ensure compliance with the interregional requirements of Order 1000. Enhanced efforts with MISO and other neighbors on seams issues and joint operating agreements have become increasingly important. The department will also continue to support efforts to bring new members into SPP. This department has a staff of 3 employees and a budget of $0.5 million.

Legal and Regulatory Policy

The division for Legal and Regulatory Policy is comprised of a staff of 26 FTEs with a total budget of $8.6 million for 2014.

- The **Legal** department continues to evolve into a value-added internal resource with the goal of significantly reducing costs for and dependency on outside counsel, especially in FERC matters. Over the past three years, the outside legal services budget has decreased; however, Integrated Marketplace filings continue to require third party services. The department has a staff of 12 and a budget of $4.2 million.

- **The Regulatory Policy** department is expected to have increased responsibility regarding regulatory filings related to the Integrated Marketplace protocols and tariff implementation. Outside services expense has increased $1.3 million as a result costs for the Order 1000 Industry Expert Panel (IEP), which will be recovered in revenue from the participants in the proposal process. A provision in the Tariff (OATT) requires SPP to perform a Regional Cost Allocation Review (RCAR). Consulting costs of $0.8 million are included to assist with this review. The department has a staff of 14 and a budget of $4.1 million.

Finance

The Finance division is comprised of the Settlements, Credit and Risk Management, and Accounting and Purchasing departments. This division has a 2015 budget of $4.8 million with a total staff of 38 FTEs.

- The **Settlements** department is comprised of two primary areas to support market and transmission settlements. Recent software upgrades, process improvements, efficiency metrics tracking, and the cross training of staff resulted in cost savings by being able to absorb the increased workload associated with the Integrated Marketplace. Additionally, the departmental headcount was reduced by one, as the result of reallocating duties when a Settlement

Analyst position became vacant as the result of a resignation. The position was repurposed from Settlements to the IT department and assigned to perform technical work on the Settlements systems. The department has a budget of $2.9 million with a staff of 24.

- The **Credit and Risk Management** department administers the extension of credit to market participants and works to protect the market participants and members from losses through diligent underwriting and collection efforts. The products within the Integrated Marketplace are much more complex and represent a significant increase in default risk to all market participants. As a result, the department's goal is to carefully monitor the increased risk and respond as necessary to continually protect the market participants and members. The department has a budget of $0.6 million with a staff of 4.
- The **Accounting and Purchasing** department is responsible for invoicing, cash management, payment processing, internal and external reporting, budgeting and forecasting, corporate accounting, and end-to-end procurement services. The department has a budget of $1.3 million with a staff of 10.

Corporate Services

The Corporate Services division is comprised of Human Resources, Corporate Facilities, and Corporate Administrative Services departments. These teams provide support services to SPP employees and members and offer a work environment supporting SPP's business model and culture. The Corporate Services division has a total staff of 29 FTEs and a 2015 budget of $6.3 million.

Officer and Administrative

This group of nine officers is comprised of SPP's CEO and President, COO, and seven executives overseeing the overall business operations and providing strategic direction to SPP as a whole. Overall vacancy is reflected in the Administrative department (4% and $3.4 million in 2015 as compared to 2% and $1.1 million in 2014). Also included are certain corporate administrative costs such as corporate insurance expenses, pension plan and retiree healthcare funding, and property taxes.

With a staff of 10 (9 executives and 1 Assistant Corporate Secretary), the total budget for 2015 for this division is $9.6 million.

VI. Capital Projects

Beginning in January, a comprehensive list of new and on-going projects was compiled for consideration for the 2015 – 2017 Budget under the direction of the Project Review and Prioritization Committee (PRPC) and in collaboration with staff from the Project Management Office (PMO), Accounting and IT departments. The PRPC worked closely with Project Managers, IT Directors, and vendor managers to scope and estimate anticipated workload associated with the implementation of the projects. The Integrated Marketplace Post-Go-Live projects ("Project Pinnacle") mandated by FERC remain the highest priority and consume significant resource capacity. Therefore, consulting costs were incorporated into the operating budget to supplement for expertise and/or staffing constraints as deemed necessary.

2015 - 2017 Capital Expenditures by Year ($ millions)

	Prior	2015	2016	2017	Total
Project Pinnacle	10.9	4.5	-	-	15.4
Enhanced Combined Cycle (suspended)	1.2	8.0	-	-	9.2
Phase I Deferred Enhancements	1.0	-	-	-	1.0
Netezza	2.6	0.2	-	-	2.8
Transmission Settlements Upgrade ETSE3.0	-	3.0	1.2	-	4.2
EMS Upgrade	-	-	1.0	0.5	1.5
Other	0.1	0.6	-	-	0.7
New Projects	n/a	3.7	0.3	-	4.0
Total Non-Foundation Projects	15.8	19.9	2.5	0.5	38.7
Foundation Projects	n/a	15.4	13.2	14.0	42.6
Total Capital Budget	15.8	35.3	15.7	14.4	81.3
2015 - 2017 Budget (excluding prior years)					***65.5***
2014 - 2016 Budget (excluding prior years)					***62.0***

The three-year budget identifies $65.5 million in total capital expenditures with $22.9 million tied to specific projects and initiatives and $42.6 million in foundation related capital expenditures. SPP expects 2015 capital expenditure spending to slightly exceed $35 million, with $19.9 million in specific projects and $15.4 million related to foundation capital spending. During the 2014 budget cycle in 2013, a total of ten projects were classified as "Integrated Marketplace Post Go-Live", which were either mandated by FERC or requested by SPP members. Subsequently, a number of the projects that were not mandated by FERC but requested by SPP membership were canceled and removed from the program scope as a result of further review and deliberation among SPP and its members (AFC Granularity Changes, Sunset Clause for Load Submittal, Marketplace Data for MPs, and GFA Carve Out). The removal of these programs resulted in a $2.0 million reduction in the overall Integrated Marketplace Post-Go-Live budget.

During its meeting in July 2014, the Board of Directors decided to suspend the Enhanced Combined Cycle project, which is a member-requested project within Project Pinnacle, due to unforeseen difficulties encountered in the design and prototype test phase which resulted in a significant increase in projected costs for completion. The Board asked staff to conduct a detailed cost-benefit analysis by October 2014 before any further project work is performed.

The chart below illustrates the aggregate annual administrative fee impact of the projects.

Project Summary	Total Current Project Budget	Asset Life (Years)	Annual Admin Fee Impact	Aggregate Admin Fee Impact
Marketplace Post Go-Live:				
Pinnacle Project	15.4	10	$0.0042	$0.0042
Phase I deferred enhancements	1.0	10	$0.0003	$0.0045
Total Marketplace Post Go-Live Projects	**$16.4**		**$0.0045**	
Other Projects:				
Transmission Settlements Upgrade ETSE 3.0	4.2	5	$0.0023	$0.0068
Netezza	2.8	5	$0.0016	$0.0084
EMS Upgrade	1.5	5	$0.0008	$0.0092
Other	0.7	5	$0.0004	$0.0096
Total - Other	**$9.2**		**$0.0050**	
2015 New Projects	**$4.0**	5	**$0.0022**	**$0.0118**
IT Foundation	**$33.1**	5	**$0.0303**	**$0.0421**
Ops Foundation	**$8.0**	5	**$0.0073**	**$0.0494**
Foundation - Other	**$1.5**	5	**$0.0014**	**$0.0508**
Enhanced Combined Cycle (suspended)	**$9.2**	10	**$0.0025**	**$0.0533**
Total Capital Project Budget	**$81.3**		**$0.0533**	

The following section describes the Project Pinnacle and other noteworthy projects in greater detail. A complete list of initiatives and associated capital and operating budgets appear in the Supplementary Schedules section.

Project Pinnacle

The post-go-live projects represent post-implementation enhancements to the Integrated Marketplace that are mandated by FERC. As explained earlier, a number of member-driven post-go-live projects that were included in the previous year's budget were eliminated, and the Enhanced Combined Cycle project is currently suspended. The remaining mandated projects (Long-term TCRs, Regulation Compensation – FERC Order 755, Market-to-Market, and Pseudo Tie-Out of Assets, along with the required build-out of IT environments for successful testing and implementation which is also managed as a separate project) are projected to cost a total of $15.4 million. These projects are well underway and expected to be completed by the March 1, 2015 deadline.

Regulation Compensation (FERC Order 755)

FERC Order 755 requires RTOs to provide a two-part payment to resources providing regulation service in the Integrated Marketplace. Tariff changes, protocol changes, and software changes are required to comply with this Order.

Long-Term Transmission Congestion Rights (LTTCRs)

FERC Order 681 requires Load Serving Entities (LSEs) to have priority in the allocation of long-term firm transmission rights. FERC expects most transmission organizations to be able to use their current allocation/auction systems to allow LSEs to nominate source-to-sink transmission rights on a longer-term basis than what is currently available. This project will consist of enhancements to the existing software systems and will establish a process providing LSEs the ability to nominate LTTCRs for more than one year.

Market-to-Market

Market-to-market coordination logic is required as an addition to the Integrated Marketplace system software to manage congestion appropriately and efficiently between SPP and neighboring markets. This project adds functionality to the market clearing engine enabling market-to-market coordination. This provides the ability for each market to request re-dispatch of generation to solve a constraint at a lower cost, therefore reducing the overall cost of congestion.

Combined Cycle Enhancements

These enhancements will allow market participants to submit resource offers for each configuration of a combined cycle unit. Each configuration will be modeled in the market-clearing engine as a separate resource in order to select the most economic configuration for unit commitment and dispatch.

Other Projects

Foundation / Other Capital Expenditures by Year ($ millions) [1]

	Prior Yr(s)	2015	2016	2017	Total
Upgrades / System Replacements					
Transmission Settlements ETSE	-	3.0	1.2	-	4.2
EMS Upgrade / Readiness	-	-	1.0	0.5	1.5
Netezza	2.6	0.2	-	-	2.8
Other	0.1	0.6	-	-	0.7
New Projects					
Gas / Electric Harmonization	-	2.0	-	-	2.0
IS Integration	-	1.0	-	-	1.0
Other	-	0.7	0.3	-	1.0
Foundation [2]					
IT Systems Admin Foundation		5.4	2.6	4.2	12.2
IT Network-Telecom Foundation		5.0	5.0	3.7	13.7
IT Applications Foundation		1.3	1.8	2.7	5.8
IT Service Management Foundation		0.2	0.5	0.5	1.2
IT Environmental Ops Foundation		0.2	-	-	0.2
Operations Marketplace Enhancements		2.0	2.1	1.8	6.0
Operations Legacy Applications Foundation		0.7	0.7	0.6	2.0
Other		0.6	0.5	0.5	1.5
Total	**2.7**	**22.9**	**15.7**	**14.4**	**55.8**

(1) Excludes Integrated Marketplace Post Go-Live Projects

(2) Foundation projects are reforecast during each budget cycle and do not include any carry-over funds.

IT Systems Administration Foundation

IT Systems Administration foundation projects include the technology refresh (replacement) of systems no longer covered under existing warranties and where extending warranties is not technologically or economically feasible. IT Systems Administration Foundation projects also include incremental projects necessary to ensure the growth and high availability needs of IT systems can be met. Virtualization technology is deployed to maximize the utilization of hardware and software wherever possible. Based on SPP's experience during the implementation of the Integrated Marketplace platforms, there will be a continuous need for additional data storage, information security, back-up, recovery, and archiving solutions.

During the 2014 budget cycle, storage needs were forecast at approximately 115 TB by the end of 2014, growing to 172 TB in 2015, and 229 TB in 2016. However, subsequent to the Integrated Marketplace implementation, SPP is experiencing the data growth across various systems to be higher than anticipated. Additional projects, such as Project Pinnacle and the IS Integration, have also contributed to higher data storage needs. Currently SPP forecasts that the data storage needs will reach 172 TB of data by the end of 2014, 271 TB in 2015, 396 TB in 2016, and 440 TB by the end of 2017. The IT management team has evaluated different types of storage and is utilizing less expensive types of storage for less critical data storage requirements. Long-term data storage (i.e. data retention) requirements are also being evaluated similarly with a focus on optimizing needs, benefits, and cost. Lastly, IT management continuously exercises diligence in aligning growth requirements with technology refreshes, in order to maximize the value of the storage assets. Data storage growth accounts for roughly 45% of this budget category.

Additional items accounted included in this budget category include hardware and software that are necessary for SPP to enhance the security of its systems. Much of this is driven by the required compliance with Version 5 of the NERC CIP Standards (CIP V5) by April 1, 2016. Approximately 30% of this budget category pertains to protecting SPP's infrastructure from cyber-attacks and/or complying with CIP V5.

The third major component of the IT Systems Administration Foundation budget is technology refresh. As SPP plans for future needs, staff consistently reviews existing hardware and, where appropriate, plan for hardware replacements. Though hardware maintenance is often extended out to five years, technology refreshes become mandatory once these components reach the end of their usable life and/or maintenance for older hardware becomes unavailable or unaffordable. Roughly 25% of this budget category is attributed to technology refreshes and related support activities.

IT Network Telecom Foundation

Items in the Telecom/Network/Security (TNS) Foundation budget are requested for various reasons, the most prominent being improvements to existing network architecture to achieve the highest level of system availability and performance, which is required by a Centralized Balancing Authority and the Integrated Marketplace. Equipment planned for replacement has either been in service for over three years, has an increased risk of failure, and/or lacks feature sets conducive to achieving the availability required by the Integrated Marketplace and other high availability projects. Approximately 61% of the funds in this budget category are allocated to upgrading the network capabilities in SPP's data centers to meet existing and future performance, growth, and security needs.

Additional dollars in this budget category include the cost of hardware to isolate the Chenal and Maumelle Electronic Security Perimeter (ESP) environments into separate core infrastructures. At present, certain core infrastructure is leveraged across multiple environments, which introduces the risk of external issues to impact systems within the ESP. This project allows for a more secure design for this critical infrastructure. This accounts for roughly 25% of this budget area.

Regular technology refreshes for network equipment are also included within this budget category. Similar to the hardware in the Systems Administration budget, there are various network and security components that are required to be refreshed as they will have reached the end of their useful life by the end of 2015. Technology refreshes and related activities amount to roughly 14 % of the IT Network Telecom Foundation budget.

Foundation – IT Applications

The primary components of this particular budget category include hardware and software licenses to keep up with the growth and demand for SPP's Enterprise Analytic Data Store (EADS) and Data Warehouse. EADS has become a critical system relied upon by many of SPP's real-time Operations systems (Integrated Marketplace) as well as the systems used for after-the-fact processing such as Settlements and Market Monitoring. Anticipating the data growth and consumer needs is essential in providing the data services that have become core to our infrastructure.

Additional funding within this budget area will support anticipated software development projects, primarily driven by MPRRs (Market Protocol Revision Requests), which require subject matter expertise that is not maintained in-house.

Operations- Marketplace Enhancements

During the months leading up to implementation of the Integrated Marketplace, SPP identified several items in the market systems being developed by Alstom that could be deferred until after the launch of the Integrated Marketplace. These enhancements are a combination of member requests, MPRRs (Market Protocol Revision Requests), and SPP requests. These deferrals are needed to alleviate manual workarounds being performed and improve the overall quality of the Market solution and results. There have also been additional enhancements identified since the start of the market which will improve the Market system and the Markets UI/API (User Interface/Application Programming Interface), and allow for efficiencies in SPP and MP processes. The total amount being requested for 2015-2017 is $6 million. This includes an additional $1 million in 2016 and 2017 to allow for the implementation of MWG approved Market Design enhancements.

Gas – Electric Harmonization

Getting the gas and power markets "in sync" has become an important concern in the past few years as the electric grid's dependence on gas-fired generation has steadily increased. This project addresses SPP Market's system timeline changes required due to FERC order for the Gas

Industry to change their Gas Nomination periods and Gas day to create better coordination and synchronization between the gas and electric power industries. The SPP Market timeline is currently outside of the NAESB (North American Energy Standards Board) proposed start of the Gas Day and nomination cycles. FERC requires SPP to respond to NAESB rule changes for Gas Nominations by ensuring the SPP market is fair and just to Market Participants scheduling Gas for power generators.

Integrated System (IS) Integration

In preparation for the IS entities becoming part of SPP in the 4th quarter of 2015, certain upgrades and enhancements are required to be performed on SPP markets and settlements systems to ensure seamless integration of systems with the new entities, along with additional investment in hardware and equipment to accommodate the associated growth in data exchange and storage needs.

VII. Debt Service

SPP secures funds from financial institutions and investors to finance its capital projects. Costs of the capital projects are paid directly from the funds provided by the borrowings. These costs are not directly included in SPP's Net Revenue Requirement; however, annual principal and interest payments for borrowings (net of capitalized interest) are considered in the Net Revenue Requirement calculation. SPP's outstanding borrowings are projected to equal $272.3 million as of January 1, 2015. Interest and principal payments included in the 2015 Net Revenue Requirement are shown in the table below.

SPP's policy is to capitalize a portion of interest expense for projects that meet SPP's capitalization threshold criteria. According to U.S. GAAP, the historical cost of acquiring an asset should include all costs incurred to bring it to the condition and location necessary for its intended use. Financing costs incurred for an asset during the construction or development period are considered part of the asset's historical acquisition cost. In accordance with GAAP, SPP's policy is to capitalize interest costs for assets meeting certain criteria to obtain a measure of acquisition cost that more closely reflects SPP's total investment in the asset. Projects with anticipated costs exceeding $5.0 million with an anticipated duration of greater than 18 months are subject to interest capitalization. During 2015, the amount of capitalized interest related to development of software assets for Project Pinnacle (including the Enhanced Combined Cycle project) is estimated to be $0.2 million.

During 2014, SPP issued new debt of $37 million to fund its capital projects. As a result of the ongoing favorable interest rate environment and SPP's credit rating of "A" for senior unsecured debt and "A+" for senior secured debt, SPP was able to secure an interest rate of 3.8% on this new loan. Also in 2014, SPP signed a loan agreement to borrow up to $33 million. This loan is currently not funded, however SPP expects to start drawing from this loan on a monthly basis in early 2015 based on capital spending needs.

The schedule below shows the principal amounts outstanding for each borrowing at the beginning and end of the 2015-2017 budget periods, as well as annual principal payments.

Future Debt Repayments ($ millions)

	Issue Date	Issue Amount	Due Date	Balance 1/1/2015	2015 Principal Payments	2016 Principal Payments	2017 Principal Payments	Balance 12/31/2017
5.45% notes due 2016	7/23/2009	$30.0	7/23/2016	$9.0	($6.0)	($3.0)	$0.0	$0.0
5.51% notes due 2027	3/23/2007	$5.1	2/1/2027	$3.5	($0.2)	($0.2)	($0.2)	$2.9
4.82% construction notes due 2042 (2010A, 2010B)	10/31/2010 & 12/28/2010	$65.0	12/30/2042	$63.0	($1.1)	($1.1)	($1.2)	$59.5
3.55% integrated markets notes due 2024 (2010C)	3/30/2011	$70.0	3/30/2024	$64.8	($7.0)	($7.0)	($7.0)	$43.8
3.00% capital funding notes due 2024 (2012D-1)	5/30/2012	$50.0	3/30/2024	$46.3	($5.0)	($5.0)	($5.0)	$31.3
3.25% capital funding notes due 2024 (2012D-2)	11/30/2012	$50.0	9/30/2024	$48.8	($5.0)	($5.0)	($5.0)	$33.8
3.8% capital funding notes due 2025 (2014E-1)	3/21/2014	$37.0	12/31/2025	$37.0	$0.0	$0.0	$0.0	$37.0
4.95% capital funding notes due 2025 (2014E-2)	3/10/2014	$33.0	3/30/2024	$0.0	$0.0	($2.3)	($3.0)	$27.8
Total		**$340.1**		**$272.3**	**($24.3)**	**($23.6)**	**($21.4)**	**$235.9**

VIII. Supplemental Analysis and Schedules

Income Statement 2014-2015 Comparison
($ millions)

Income Statement 2015-2017
($ millions)

SPP Consolidated Summary	2015 Budget	2016 Budget	2017 Budget
Income			
Tariff Administration Service	$150.6	$146.0	$146.3
Fees & Assessments	27.6	29.6	30.3
Contract Services Revenue	0.5	0.5	0.5
Miscellaneous Income	5.2	4.5	4.6
Total Income	**$183.9**	**$180.7**	**$181.6**
Expense			
Salary	$55.2	$56.4	$57.5
Benefits & Taxes	26.5	27.1	27.5
Continuing Education	0.8	0.8	0.8
Salary & Benefits	$82.4	$84.3	$85.8
Employee Travel	2.1	2.4	2.4
Administrative	4.8	4.8	4.5
Assessments & Fees	16.4	16.7	17.0
Meetings	1.0	1.0	1.0
Communications	4.3	4.4	4.4
Leases	0.2	0.2	0.2
Maintenance	14.8	16.6	19.2
Services	18.7	16.0	15.6
Regional State Committee	0.3	0.3	0.3
Depreciation & amortization	61.2	62.4	34.8
Other Expense	10.2	10.5	9.8
Total Expense	**$216.5**	**$219.4**	**$195.0**
Net Income (Loss)	**($32.6)**	**($38.8)**	**($13.4)**
Debt Repayment	$24.3	$23.6	$21.4
MW/H Forecast (in millions)	363.5	398.0	398.0
Net Revenue Requirement	$145.3	$146.0	$146.3
2013 /2014 True Up	$4.9	$0.0	($0.0)
Calculated Admin Fee / MWh	$0.413	$0.367	$0.367
Recommended Admin Fee / MWh	$0.413	$0.367	$0.367
Tariff Cap on Admin Fee	$0.390	$0.390	$0.390
Capital Expense	$35.3	$16.4	$19.6
Headcount	600	600	598

Balance Sheet
($ millions)

	12/31/2014	12/31/2015
ASSETS		
Current Assets		
Cash & Equivalents	$42.5	$42.0
Restricted Cash Deposits	201.1	211.2
Accounts Receivable (net)	$15.5	$16.8
Other Current Assets	14.3	16.3
Total Current Assets	273.5	286.4
Total Fixed Assets	180.7	154.7
Total Other Assets	2.8	2.7
Investments	1.6	1.7
TOTAL ASSETS	$458.5	$445.4
LIABILITIES & EQUITY		
Liabilities		
Current Liabilities		
Accounts Payable (net)	$23.6	$25.6
Customer Deposits	201.1	211.2
Current Maturities of LT Debt	24.3	23.6
Other Current Liabilities	35.5	36.1
Deferred Revenue	3.5	1.4
Total Current Liabilities	288.0	298.0
Long Term Liabilities		
US Bank Floating Senior Note - 2014	0.0	0.0
US Bank 5.45% Senior Notes - 2016	3.0	0.0
US Bank Maumelle Mortgage - 2027	3.3	3.1
Campus 4.82% Senior Notes - 2042	61.9	60.7
Integrated Marketplace 3.55% Senior Notes - 2024	57.8	50.8
Capital Funding 3.00% - 2024	41.3	36.3
Capital Funding 3.25% - 2024	43.8	38.8
Capital Funding 3.8% - 2025	37.0	34.8
Capital Funding (Line of Credit)		33.0
Other Long Term Liabilities	5.4	5.5
Total Long Term Liabilities	253.3	262.9
Net Income	(42.0)	(32.6)
Members' Equity	(40.9)	(82.9)
Total Members' Equity	(82.9)	(115.4)
TOTAL LIABILITIES & EQUITY	$458.5	$445.4

Cash Flow Forecast 2015-2017

($ millions)

Capital Projects List
($ millions)

Outside Services by Function
($ millions)

Analysis of 2014 Fees & Assessments
($ millions)

Fees & Assessments, Revenue and Expense	2014 Forecast	2014 Budget	Variance Fav/(Unfav)	Note
SPP Regional Entity Revenue	$9.6	$11.8	($2.2)	(a)
FERC Fee Assessments (Sch.12)	$15.2	$14.9	0.3	(b)
Fees & Assessments Revenue*	24.8	26.8	(1.9)	
Fees & Assessments Expense	**$16.3**	**$15.3**	**$1.0**	(c)

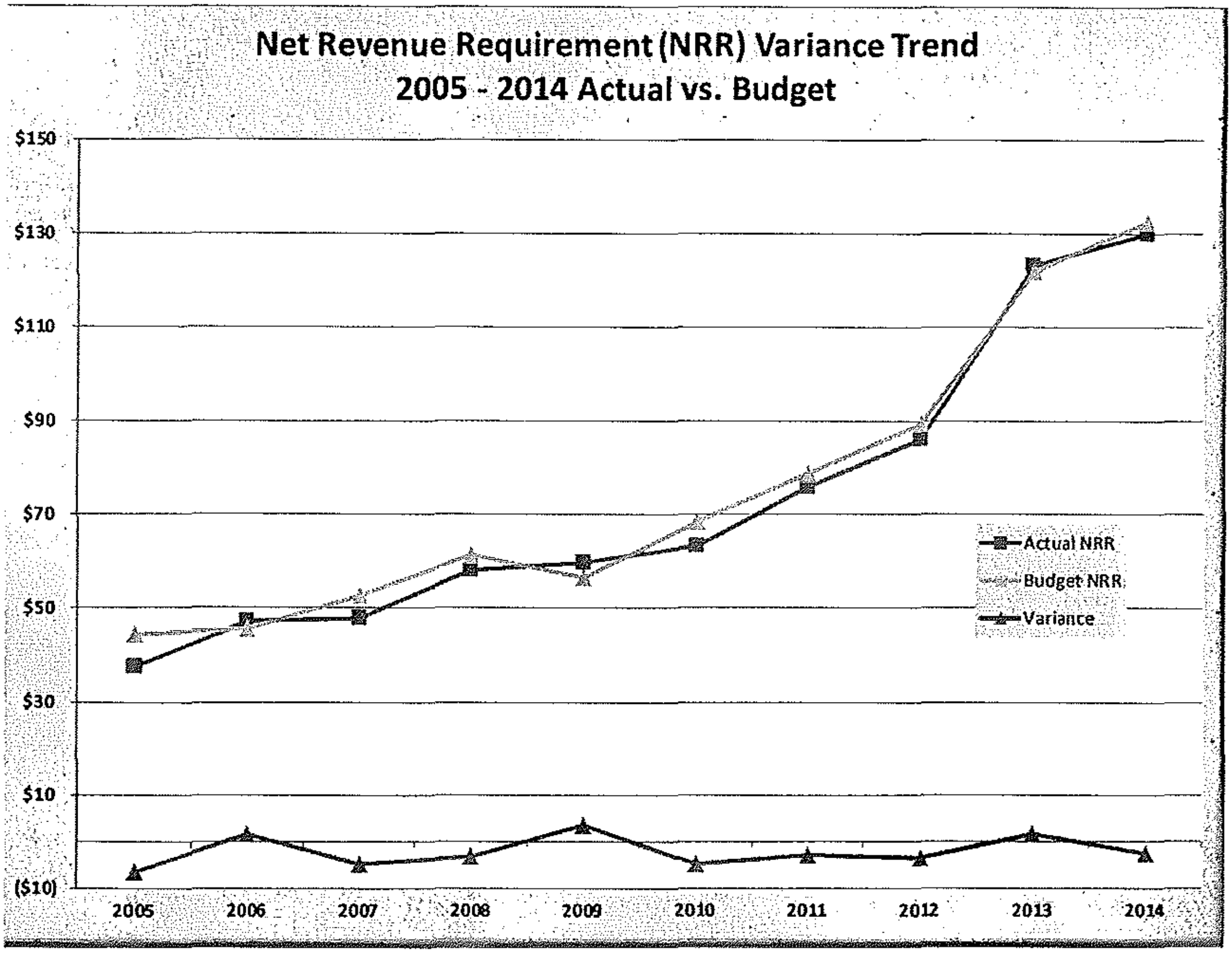
* Total Fees & Assessments revenue includes annual non-load dues, which are $0.5 million and $0.4 million for the 2014 Forecast and Budget, respectively.

(a) Revenue for SPP RE is recognized on a monthly basis based on direct RE expenses and an hourly charge for indirect expenses. In 2014, the RE expects to be favorable in comparison to their total expense budget, resulting in lower corresponding revenues for SPP.

(b) FERC Fee Assessment revenue is recognized monthly when billed to transmission customers.

(c) FERC Fees & Assessments expense is estimated based on prior year assessment plus a growth rate. The current year monthly accrual amount is adjusted once the annual bill is received in June.

Net Revenue Requirement Variance History
($ millions)



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Actual NRR	$37.7	$47.1	$48.0	$58.1	$59.8	$63.5	$75.8	$86.1	$123.3	$130.0 *
Budget NRR	$44.4	$45.7	$52.8	$61.5	$56.5	$68.4	$78.6	$89.6	$121.8	$132.6
Variance	($6.7)	$1.5	($4.8)	($3.4)	$3.4	($4.9)	($2.9)	($3.5)	$1.5	($2.6)
	(15%)	3%	(9%)	(6%)	6%	(7%)	(4%)	(4%)	1%	(2%)

The graph and table above highlight the range of variance between SPP's actual and budgeted Net Revenue Requirement (NRR) by year. As SPP's NRR has increased over the years, the variances between actual and budget remain relatively small.

** The 2014 NRR represents the forecast as of July 2014 and excludes non-recurring items of $6.1 million.*

Prior Year Budget Comparisons
($ millions)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Net Revenue Required Estimations										
2008 Budget - NRR Estimations	$61.5	$64.5	$71.2							
2009 Budget - NRR Estimations		$56.5	$68.4	$75.1						
2010 Budget - NRR Estimations			$68.4	$90.1	$94.9					
2011 Budget - NRR Estimations				$78.6	$86.7	$94.6				
2012 Budget - NRR Estimations					$89.6	$98.6	$113.6			
2013 Budget - NRR Estimations						$121.8	$141.4	$145.0		
2014 Budget - NRR Estimations							$132.6	$148.4	$145.2	
2015 Budget - NRR Estimations (1)								$145.3	$146.0	$146.3
Actual NRR	*$58.1*	*$59.8*	*$63.5*	*$75.8*	*$86.1*	*$123.3*	*$130.0*			

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Billing Unit Estimations										
2008 Budget - Billing Units Estimations	312.5	319.1	325.8							
2009 Budget - Billing Units Estimations		331.4	346.4	353.4						
2010 Budget - Billing Units Estimations			333.5	338.1	342.7					
2011 Budget - Billing Units Estimations				343.0	345.0	349.8				
2012 Budget - Billing Units Estimations					353.5	359.8	366.3			
2013 Budget - Billing Units Estimations						360.9	371.7	382.9		
2014 Budget - Billing Units Estimations							348.2	348.2	348.2	
2015 Budget - Billing Units Estimations								363.5	398.0	398.0
Actual Billing Units	*296.1*	*328.2*	*329.6*	*341.4*	*361.0*	*358.1*	*351.9*			

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Administrative Fee Estimations										
2008 Budget - Admin Fee Estimations	$0.190	$0.200	$0.200							
2009 Budget - Admin Fee Estimations		$0.170	$0.170	$0.170						
2010 Budget - Admin Fee Estimations			$0.195	$0.270	$0.280					
2011 Budget - Admin Fee Estimations				$0.210	$0.255	$0.280				
2012 Budget - Admin Fee Estimations					$0.255	$0.280	$0.300			
2013 Budget - Admin Fee Estimations						$0.338	$0.380	$0.379		
2014 Budget - Admin Fee Estimations							$0.381	$0.433	$0.424	
2015 Budget - Admin Fee Estimations (1)								$0.413	$0.367	$0.367
Actual Admin Fee	*$0.196*	*$0.182*	*$0.193*	*$0.222*	*$0.238*	*$0.337*	*$0.387*			

(1) 2014 actual NRR and admin fee excludes non-recurring items of $6.1 million.

The purpose of this schedule is to quantify the year-to-year changes in SPP's three year projections made during each budget cycle as required by the membership agreement. Accuracy of these projections can be significantly influenced by both internal and external pressures such as board and committee directives, incremental membership, environmental factors, etc.

Member Value Category Descriptions

Operations and Reliability services include SPP's reliability coordination and reserve sharing. SPP is responsible for operating the regional wholesale power grid under rules and regulations from NERC and FERC. The SPP-RC monitors the grid 24x7 to maintain electrical reliability and to mitigate grid emergencies. The objectives of SPP's efforts are to maximize the availability of the power grid to support scheduled transmission while minimizing the negative impacts of transmission congestion and unplanned grid disturbances or outages. Being a member of an RTO provides a higher degree of grid availability, or average Transmission System Availability (TSA), than would be achieved as a standalone utility. Being a member of SPP's Reserve Sharing Group (RSG) enables an SPP member to share reserve resources across the group on a pro-rata basis. SPP's RSG will reserve 150% of the single largest generation contingency in the group. All members share in the cost of providing this reserve capacity as a function of their pro-rata peak loads. Absent the RSG, each entity would have to provide a reserve for its largest single contingency. The difference between the standalone versus the RSG reserve obligation is the value of the RSG to each participant.

Region-Wide Transmission Planning includes: 1) the value of region-wide transmission projects before the Highway/Byway cost sharing was implemented, 2) the net value of the SPP balanced portfolio transmission projects approved by the Board in April 2009, 3) the net value of the Board approved priority project transmission project, and 4) the value of Engineering Studies provided by SPP.

The Engineering Department provides a series of Engineering Studies to ensure planned member actions (generation, transmission, etc.) do not create issues when integrating into the current power grid. SPP is positioned as the unbiased protector of the grid integrity and operation. If SPP were not in existence, the expert witness and the objective study functions would need to be replaced with a combination of consultants and/or engineering staff from the requesting utility.

Market Operations includes the net trade benefits associated with the operation of the EIS (Energy Imbalance Service) market operation as a result of the regional security-constrained economic dispatch (SCED). Additionally, Market Operations includes the net trade benefits from operating a real-time, day ahead and Ancillary services market. Finally, Market Operations includes the value of operating a Consolidated Balancing Authority.

Leveraged, Centralized Services include savings associated with SPP's performance of certain functions that would otherwise have to be contracted individually and therefore represent a savings to the members. Specifically, Leveraged Centralized services include centralized training, Tariff and scheduling service administration, regulatory services, and compliance and settlement services.

SPP's Training Department, through leveraged centralized resource and expertise acquisition, curriculum development and class offerings, allows for substantial cost avoidance to the SPP stakeholder base. SPP administers a regional tariff and its Tariff Administration group provides a centralized reservations "one-stop shopping" for reserving transmission on the power grid. In addition to administering and maintaining the OASIS reservations system, SPP provides the engineering staff to ensure that transmission service requests are valid and will not compromise the integrity of the power grid. If SPP did not exist, the 15 Balancing Authorities and Transmission owners would have to provide these functions for themselves. In addition, there would be a greater number of bilateral transmission agreements, which would be more difficult to administer. A centralized regulatory group administers a single Open Access Tariff. If SPP were not providing this centralized function for the consolidated group of members, each Balancing Authority would have to administer a broader scoped Tariff than it currently is responsible for administering, thereby increasing its cost. Finally, the SPP Compliance function and Settlement function provides compliance information, education and outreach services to our members. These centralized services provide annual cost avoidance value to SPP's members.

Southwest Power Pool, Inc.

FINANCE COMMITTEE

Recommendation to the Board of Directors

October 28, 2014

2015 Budget

Organizational Roster

The following persons are members of the Finance Committee:

Harry Skilton	Director
Larry Altenbaumer	Director
Mike Wise	Golden Spread Electric Coop
Sandra Bennett	American Electric Power
Kelly Harrison	Westar Energy

Background

Section 6.5 of the SPP Bylaws identifies establishment of annual and long-term budgets as a primary duty of the Finance Committee.

Analysis

SPP's management proposed a 2015 budget to include expenditures as follows:

	$000,000
Operating Expense (incl. dep. & am.)	$201.0
Debt Repayment	$24.3
FERC Assessments	$16.4
Capital Expenditures	$35.3

SPP management utilized a "zero-based" budget approach to prepare the 2015 budget.

The most significant cost drivers for 2015 are the scheduled retirement of debt obtained to fund the development of the Integrated Marketplace and other capital expenditure projects.

Recommendation

The Finance Committee recommends the SPP Board of Directors approve the 2015 SPP operating and capital budgets as submitted.

Approved: Finance Committee

Action Requested: Approve Recommendation

Southwest Power Pool, Inc.

FINANCE COMMITTEE

Recommendation to the Board of Directors

October 28, 2014

2015 Administrative and Assessment Fee Rate

Organizational Roster

The following persons are members of the Finance Committee:

Harry Skilton	Director
Larry Altenbaumer	Director
Mike Wise	Golden Spread Electric Coop
Sandra Bennett	American Electric Power
Kelly Harrison	Westar Energy

Background

Section 8.4 of the SPP Bylaws requires SPP to annually develop an assessment rate based on budgeted expenditures for the upcoming fiscal year and estimated billing determinants for that year.

Analysis

The 2015 SPP operating budget indicates a net revenue requirement ("NRR") for the year of $142.4 million (inclusive of 2013 under-recovery of $2.8 and 2014 forecast under-recovery of $0.7, and net of $1.0 transfer from overfunded post-retirement healthcare fund) and estimated billing determinants of 363,500,000 MWh. The rate is determined by dividing the NRR by the estimated billing determinants which results in a rate of 39.2¢/MWh. NRR is derived by adjusting SPP's gross cash outflows (exclusive of capital expenditures) by all non administrative fee revenue forecast to be earned in the year. The billing determinants are calculated by analyzing the current year to date transmission usage and estimating usage through the remainder of the year.

Billing determinants are estimated based on the billing criteria detailed in the SPP tariff. Presently, network integration transmission service is charged the SPP schedule 1A administrative fee based on the average 12 monthly peaks from the previous year; point-to-point transmission service is charged the SPP schedule 1A administrative fee based on the reserved transmission capacity. Through August 2013, SPP has realized year-over-year increase in average monthly peaks of 2.7%. Point to Point transmission sales are down 8.3% year over year through August. SPP forecasts the addition of the Integrated System in October 2015 which will add roughly 46,000,000 MWh of billing determinants annually. SPP is holding its forecast of load level with 2014 and adding 25% of the annual Integrated System load to arrive at the forecast billing determinants of 363,500,000.

Recommendation

The Finance Committee recommends the SPP Board of Directors establish an assessment rate and tariff administrative fee (schedule 1-A) of 39¢/MWh beginning on January 1, 2015.

Approved: Finance Committee

Action Requested: Approve Recommendation

SPP Southwest Power Pool

Memorandum

To: SPP Officers / Directors / Managers
From: Sheri Dunn / Cindy Goodwin
Date: September 26, 2014
RE: August 2014 Financial Package

Attached are the August 2014 monthly financial reports.

SPP Southwest Power Pool

2014 Financial Commentary
August 31, 2014
(in thousands)

Summary

	2014 FY Forecast	2014 FY Budget	Fav/(Unfav) Variance	
Revenues	$163,618	$163,166	$452	0.3%
Expenses	205,554	200,692	(4,862)	(2.4%)
Net Income/(Loss)	($41,936)	($37,526)	($4,410)	(11.8%)

Revenue

	2014 FY Forecast	2014 FY Budget	Fav/(Unfav) Variance	
Tariff Administration Service	$133,921	$132,600	$1,321	1.0%
FERC Fees & Assessments	14,866	14,500	366	2.5%
NERC ERO Regional Entity Rev	9,650	11,824	(2,174)	(18.4%)
Miscellaneous Income	4,273	3,350	923	27.5%
Contract Services Revenue	453	453	2	0.0%
Annual Non-Load Dues	456	440	16	3.6%
Total Revenue	$163,618	$163,166	$452	0.3%

In preparation of the 2014 budget for **Tariff Administration Service** revenues, SPP estimated network service billing determinants utilizing January - August 2013 actual results, which were running 3% below 2012 actuals, and applied that same reduction to the September - December 2013 estimates. The SPP region realized a significant reversal of the trend for the September -December 2013 period. The 2014 MWh forecast is anticipated to be approximately 352 million MWh as compared to the budget of 348 million.

	2012 Actual	2014 Budget	2013 Actual
Network Service (GWh)	325,356	307,106	318,980
Point-to-Point	36,000	41,094	38,555
	361,356	348,200	357,535

SPP expects to collect approximately $1,321 more than budgeted for Schedule 1A administrative fees during 2014.

NERC ERO Regional Entity revenue is based on Regional Entity (RE) budgeted expenditures and anticipated pass-thru expenses for SPP resources outside the RE. The primary drivers of the unfavorable revenue variance relate to compensation and pass-thru expense associated with outside services and SPP resource time. Although the budget assumed the RE would be fully staffed at the beginning of the year, currently 4 of the 31 budgeted positions remain vacant (with 1 position removed from the RE 2015 budget). The services variance is related to fewer audit and hearings expenses. The revenue forecast has been reduced to align with the current revenue trend for 2014. The net impact associated with both RE revenue and expense is unfavorable by $620.

Southwest Power Pool

2014 Financial Commentary
August 31, 2014
(in thousands)

Expense

	2014 FY Forecast	2014 FY Budget	Fav/(Unfav) Variance	
Salary & Benefits	$83,916	$82,247	($1,670)	(2.0%)
Assessments & Fees	16,323	15,300	(1,023)	(6.7%)
Communications	3,754	3,916	161	4.1%
Maintenance	15,182	15,866	684	4.3%
Outside Services (Including RSC)	15,522	14,640	(882)	(6.0%)
Administrative & Leases	4,666	4,858	192	3.9%
Travel & Meetings	2,834	3,112	278	8.9%
Depreciation & Amortization	51,217	49,718	(1,499)	(3.0%)
Other Expenses	12,139	11,035	(1,104)	(10.0%)
Total Expense	$205,554	$200,692	(4,862)	(2.4%)

Salary & Benefits expenses represent an unfavorable variance to budget primarily resulting from an unbudgeted performance payout to SPP staff which was proposed and approved by the SPP Board of Directors and Members Committee. The impact of the performance payout has been mitigated somewhat by lower staffing levels (average 4% vacancy resulting in approximately $1,000 reduction in expenses), decreased contributions to retirement plans ($650 reduction), and lower than budgeted expenditures for continuing education ($300 reduction).

SPP received its annual assessment invoice from FERC in June and immediately recognized a $240 charge to true-up the prior year under-accrual in **Assessments and Fees** expense. The current year accrual was increased by $740 in recognition of the increased FERC costs now expected for 2014 (to be paid in 2015).

Outside Services exceeds budget as a result of classifying several of the consultants engaged in Integrated Marketplace as operating expenses instead of capital expenses as they were budgeted. These activities were primarily the expected post go-live support activities ($1,810 increase). Additionally, a supplement to the 2013 State of the Market report was approved by the SPP Oversight Committee out of budget at a cost of $200. Conversely, outside services trail budget across several departments, with the main contributors found in Regional Entity ($450), Legal ($400), Internal Audit ($125), Regulatory ($190), Engineering ($80) and IT ($45). The Regional Entity variance relates to fewer audit and hearings expenses. Year-to-date outside legal fees related to the Integrated Market were lower than expected, but this decrease was partially offset by higher than anticipated expenses related to the MISO contested docket. Internal Audit expense trails budget as a result of restructuring the Type 1 audit. This change resulted in part of the Type 1 audit items being included in the 2013 Readiness Assessment.

Travel expenses fall below budget across most departments, with the most notable variances in the Regional Entity ($80), Training ($50), and Operations ($30). This is partially due to lower headcount. Various working group meetings trail budget, contributing to the favorable variance in **Meetings** expense ($87).

Depreciation for the Integrated Marketplace was budgeted to begin April 1st instead of March 1st and therefore results in an unfavorable variance in depreciation expense; however this variance is non-cash and has no impact on cost recovery.

The estimated interest payout for study deposits was added to the forecast in **Interest expense** ($1,800).

SPP Southwest Power Pool

Southwest Power Pool
Monthly Overview
August 31, 2014
(in thousands)

	Actual Jan-14	Actual Feb-14	Actual Mar-14	Actual Apr-14	Actual May-14	Actual Jun-14	Actual Jul-14	Actual Aug-14	Fcst Sep-14	Fcst Oct-14	Fcst Nov-14	Fcst Dec-14	FY 2014 Forecast	FY 2014 Budget	Variance Fav/(Unfav)	FY 2013 Actual	Variance Fav/(Unfav)
Income																	
Tariff Administrative Service	11,613	10,265	11,348	10,970	11,338	11,079	11,436	11,425	11,112	11,193	10,901	11,243	$133,921	132,600	$1,321	112,624	$21,298
Fees & Assessments	2,483	2,122	1,789	1,982	1,748	2,115	2,207	2,353	2,218	2,018	1,918	2,018	24,971	26,764	(1,792)	25,188	(216)
Contract Services Revenue	36	36	38	38	38	38	38	38	38	38	38	38	453	453	0	425	28
Miscellaneous Income	380	191	231	362	301	430	296	265	286	286	286	961	4,273	3,350	923	4,502	(229)
Total Income	14,512	12,615	13,406	13,352	13,425	13,661	13,977	14,080	13,654	13,534	13,142	14,259	163,618	163,166	452	142,738	20,880
Expense																	
Salary & Benefits	6,489	6,737	6,646	6,806	10,919	6,646	6,530	6,779	6,572	6,562	6,604	6,625	83,916	82,247	(1,669)	79,660	(4,256)
Employee Travel	106	135	150	153	168	167	195	206	204	212	153	153	2,002	2,192	190	1,868	(135)
Administrative	188	344	207	533	255	539	465	345	236	854	243	281	4,490	4,675	185	3,967	(524)
Assessments & Fees	1,300	1,300	1,300	1,300	1,300	1,645	1,363	1,363	1,363	1,363	1,363	1,363	16,323	15,300	(1,023)	14,699	(1,624)
Meetings	91	72	77	80	67	84	50	64	69	76	71	31	831	919	88	930	98
Communications	374	318	308	305	305	308	297	305	308	309	309	309	3,754	3,916	161	3,665	(90)
Leases	13	12	16	18	12	15	15	15	15	15	15	15	176	183	7	432	256
Maintenance	1,013	1,012	1,144	1,270	1,787	1,447	1,103	1,184	1,281	1,270	1,257	1,412	15,182	15,866	684	11,301	(3,881)
Services	837	1,261	1,857	1,155	2,156	973	1,204	1,312	1,215	1,165	1,121	1,053	15,310	14,313	(998)	15,870	559
Regional State Committee	11	15	15	14	20	15	13	17	23	23	23	23	212	328	116	207	(5)
Depreciation & Amortization	1,750	1,736	4,517	4,511	4,403	5,731	4,677	4,673	4,790	4,790	4,800	4,840	51,217	49,718	(1,499)	19,398	(31,819)
Total Expense	12,171	12,942	16,238	16,146	21,391	17,570	15,911	16,264	16,076	16,640	15,960	16,106	193,415	189,657	(3,758)	151,995	(41,420)
Other Income/(Expense)																	
Other Income/Expense	(41)	58	(36)	(18)	34	31	(21)	55	-	-	-	-	62	-	62	5,651	(5,589)
Interest Income	2	2	3	4	4	6	5	4	-	-	-	-	31	-	31	223	(192)
Interest Expense	(837)	(886)	(841)	(962)	(930)	(1,034)	(855)	(917)	(901)	(1,784)	(1,782)	(884)	(12,613)	(12,195)	(418)	(10,540)	2,073
Capitalized Interest	-	-	221	12	-	78	-	(68)	44	-	-	61	349	1,160	(811)	2,777	2,428
Change in Valuation of Swap	-	-	27	-	-	7	-	-	-	-	-	-	34	-	34	923	889
Net Other Income (Expense)	(875)	(826)	(627)	(964)	(893)	(912)	(871)	(925)	(857)	(1,784)	(1,782)	(823)	(12,139)	(11,035)	(1,104)	(910)	(448)
Net Income (Loss)	**$1,465**	**($1,153)**	**($3,459)**	**($3,758)**	**($8,858)**	**($4,821)**	**($2,804)**	**($3,109)**	**($3,280)**	**($4,890)**	**($4,600)**	**($2,669)**	**($41,936)**	**($37,526)**	**($4,410)**	**($10,168)**	**($31,768)**
2014 Headcount Forecast	569	570	573	576	575	573	573	570	573	575	579	582	582 *				
2014 Headcount Budget	597	598	598	598	598	598	598	598	598	598	598	598	598				
Over / (Under) Budget	(28)	(28)	(25)	(22)	(23)	(25)	(25)	(28)	(25)	(23)	(19)	(16)	(16)				
Headcount Vacancy	-5%	-5%	-4%	-4%	-4%	-4%	-4%	-5%	-4%	-4%	-3%	-3%	-4%				
NRR Over / (Under) Recovery	$3,193	$501	($1,825)	$4,041	($4,153)	$1,350	$1,846	$1,365	($4,032)	$63	$412	($5,056)	($2,294)	$0	($2,294)	($10,712)	$8,419

* The 2014 forecast assumes a vacancy average of 3% for October - December.

SPP Southwest Power Pool

Southwest Power Pool
Actual Results Overview
August 31, 2014
(in thousands)

	Current Month Compared to Forecast			YTD Actual Compared to YTD Budget			YTD 2014 Compared to YTD 2013		
	Aug-2014 Actual	Aug-2014 Forecast	Variance Fav/(Unfav)	Aug-2014 Actual	Aug-2014 Budget	Variance Fav/(Unfav)	Aug-2014 Current Year	Aug-2013 Prior Year	Variance Fav/(Unfav)
Income									
Tariff Administrative Service	$11,425	$11,595	($170)	$89,473	$88,400	$1,073	$89,473	$75,091	$14,382
Fees & Assessments	$2,353	$2,218	135	$16,799	$18,222	(1,423)	$16,799	$16,870	(70)
Contract Services Revenue	$38	$38		$301	$301		$301	$280	21
Miscellaneous Income	$265	$286	(21)	$2,455	$2,233	222	$2,455	$2,603	(148)
Total Income	14,080	14,136	(56)	109,028	109,156	(128)	109,028	94,844	14,184
Expense									
Salary & Benefits	6,779	6,880	$100	57,553	55,013	($2,540)	57,553	51,365	($6,188)
Employee Travel	206	176	(30)	1,280	1,446	166	1,280	1,307	27
Administrative	345	275	(71)	2,877	2,962	85	2,877	2,540	(337)
Assessments & Fees	1,363	1,363	-	10,871	10,200	(671)	10,871	9,847	(1,024)
Meetings	64	67	2	585	640	54	585	654	69
Communications	305	308	4	2,518	2,610	92	2,518	2,385	(134)
Leases	15	15		115	122	7	115	366	251
Maintenance	1,184	1,262	78	9,961	10,600	639	9,961	7,324	(2,637)
Services	1,312	1,117	(195)	10,756	9,803	(952)	10,756	9,762	(994)
Regional State Committee	17	23	6	119	235	116	119	130	11
Depreciation & Amortization	4,673	4,765	92	31,997	29,884	(2,114)	31,997	12,815	(19,183)
Total Expense	16,264	16,251	(13)	128,633	123,516	(5,118)	128,633	98,494	(30,139)
Other Income/(Expense)									
Gain or Loss on Sale of Fixed Asset	()	-	()	()	-	()	()	58	(58)
Other Income/Expense	55	-	55	62	-	62	62	55	7
Interest Income	4	-	4	31	-	31	31	133	(103)
Interest Expense	(917)	(903)	(14)	(7,262)	(8,150)	888	(7,262)	(7,071)	(191)
Capitalized Interest	(68)	-	(68)	243	996	(753)	243	1,519	(1,275)
Change in Valuation of Swap	-	-	-	34	-	34	34	592	(559)
Net Other Income (Expense)	(925)	(903)	(22)	(6,893)	(7,154)	261	(6,893)	(4,714)	(2,179)
Net Income (Loss)	($3,109)	($3,018)	($91)	($26,498)	($21,514)	($4,984)	($26,498)	($8,364)	($18,134)
Headcount	570	571	(1)	570	598	(28)	570	579	(9)

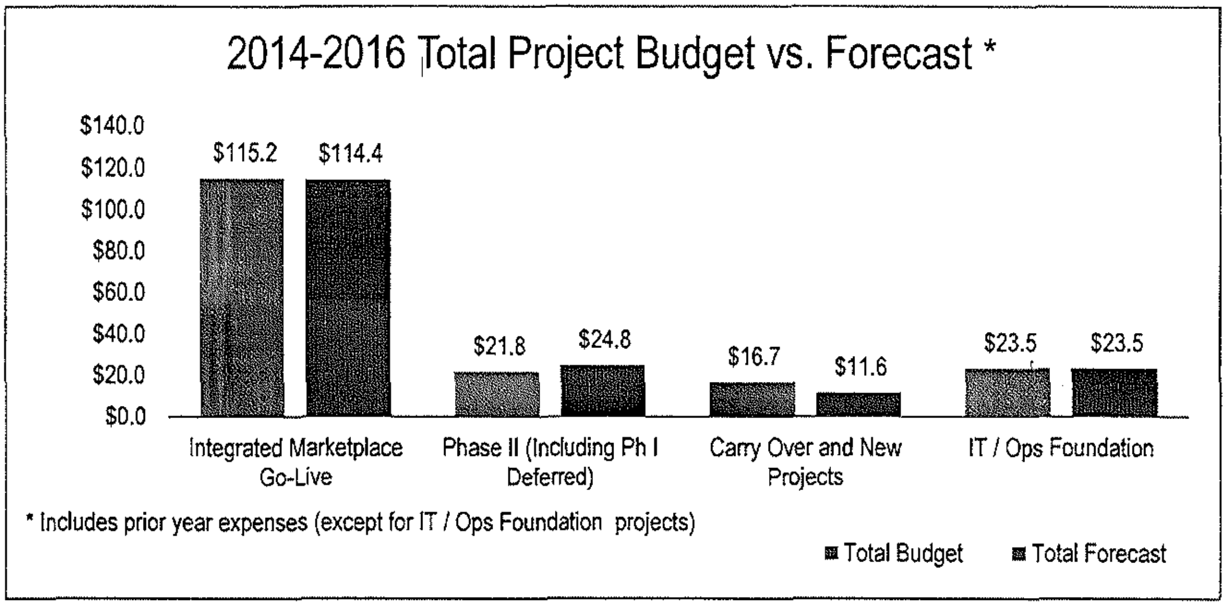
SPP Southwest Power Pool

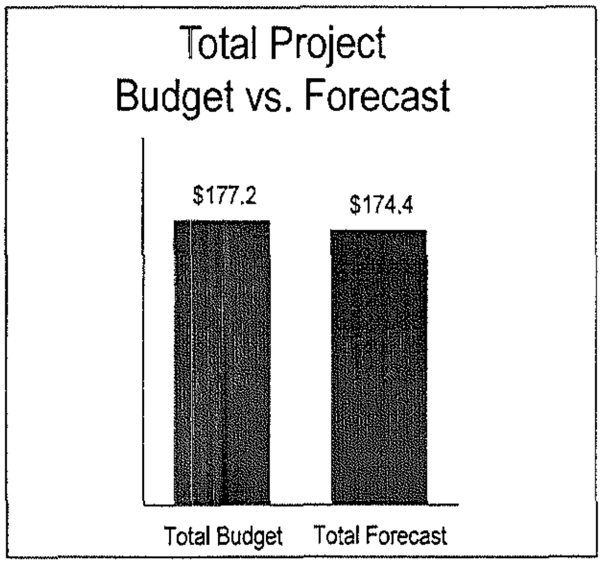
Southwest Power Pool
Balance Sheet
August 31, 2014
(in thousands)

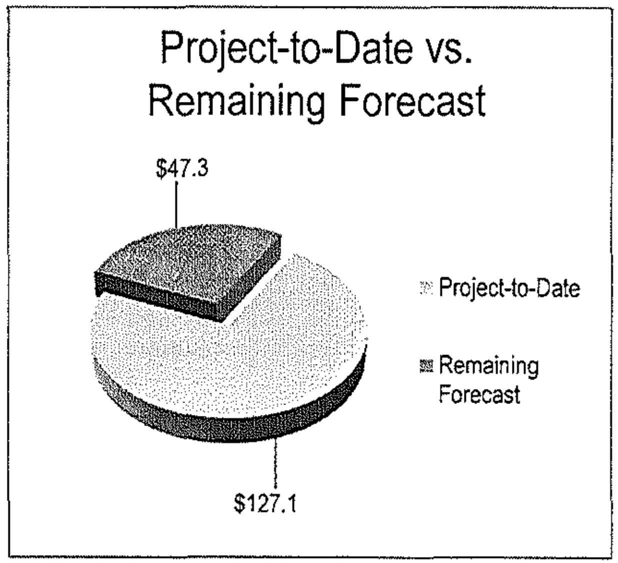
	8/31/2014	12/31/2013	Net Change
ASSETS			
Current Assets			
Cash & Equivalents	$44,149	$34,874	$9,275
Restricted Cash Deposits	205,139	76,712	128,427
Accounts Receivable (net)	31,375	24,134	7,240
Other Current Assets	12,379	6,966	5,412
Total Current Assets	**$293,041**	**$142,687**	**$150,354**
Total Fixed Assets	184,932	204,259	(19,327)
Total Other Assets	2,780	3,158	(378)
Investments	1,461	1,305	156
TOTAL ASSETS	$482,213	$351,409	$130,804
LIABILITIES & EQUITY			
Liabilities			
Current Liabilities			
Accounts Payable (net)	$19,995	$15,953	$4,042
Customer Deposits	205,140	76,713	128,428
Current Maturities of LT Debt	25,774	22,998	2,775
Other Current Liabilities	28,734	29,038	(304)
Deferred Revenue	4,604	5,919	(1,315)
Total Current Liabilites	**284,247**	**150,620**	**133,627**
Long Term Liabilities			
US Bank 5.45% Senior Notes - 2016	6,000	9,000	(3,000)
US Bank Maumelle Mortgage - 2027	3,392	3,547	(154)
Campus 4.82% Senior Notes - 2042	62,423	62,963	(540)
Integrated Marketplace 3.55% Senior Note - 2024	61,250	64,750	(3,500)
Senior Notes - 2024	90,000	95,000	(5,000)
Senior Notes - 2025	37,000	-	37,000
Other Long Term Liabilities	5,295	6,425	(1,130)
Total Long Term Liabilities	**265,360**	**241,685**	**23,676**
Net Income	(26,498)	(10,168)	(16,330)
Members' Equity	(40,896)	(30,728)	(10,168)
Total Members' Equity	**(67,394)**	**(40,896)**	**(26,498)**
TOTAL LIABILITIES & EQUITY	$482,213	$351,409	$130,804

Capital Project Dashboard

(in millions)







Complete Project List
Total Project-to-Date and Remaining Forecast Compared to Budget
As of August 31, 2014
(in thousands)

	Total Budget	Project-to-Date Actual	Remaining Forecast	Total Forecast	Over/(Under) Budget
Integrated Marketplace Go-Live	**$115,173**	**$114,413**	**-**	**$114,413**	**($761)**
Phase I Deferred (Budget found in Ph II contingency)		957	$43	$1,000	$1,000
Phase II					
Market to Market	7,033	1,600	4,789	6,389	(644)
Regulation Compensation	3,211	1,076	2,351	3,427	215
Long-Term Congestion Rights (LTCRs)	4,322	707	2,910	3,617	(705)
Enhanced Combined Cycle	4,599	1,376	7,603	8,979	4,380
Pseudo Tie In/Out	169	253	-	253	84
AFC Granularity Changes for TSRs	1,363	-	-	-	(1,363)
Sunset Clause for Load Submittal for Legacy Bas	156	-	-	-	(156)
Marketplace Date for MPs Post Go-Live	50	-	-	-	(50)
IT Environments Buildout for Marketplace	608	874	311	1,185	577
Grandfather Agreement (GFA) Carve Out (cancelled)	259	-	-	-	(259)
Phase I Deferred (Included in Phase II Budget)	-	-	-	-	-
Unallocated Program Costs (TBD)	-	-	-	-	-
Phase II (Project Pinnacle), Including Phase I Deferred	**$21,770**	**$6,842**	**$18,007**	**$24,849**	**$3,079**
Carry Over and New Projects					
OPS DTS Upgrade to TTSE (cancelled)	4,400	-	-	-	(4,400)
Transmission Settlements Upgrade ETSE3.0 (2015)	3,775	-	4,187	4,187	412
Netezza Upgrade	3,038	2,646	172	2,818	(220)
EMS Upgrade	1,696	-	1,498	1,498	(198)
EMS Readiness	728	889	-	889	161
Data Center Migration	720	264	450	714	(6)
Aurea ESB Replacement	706	-	475	475	(231)
Project Server Upgrade	300	44	42	86	(213)
Miscellanous Facilities	318	72	176	248	(70)
Alstom ETS Foundation	225	-	-	-	(225)
QA ICCP Buildout	180	108	87	195	15
TAGIT Database Enhancement	150	-	150	150	-
Cost Allocation SQL Database	50	-	50	50	-
Engineering App Store	25	-	25	25	-
FERC Order 1000 Regional RFP	165	-	165	165	-
EIS Sunset (costs will not be capitalized)	150	-	-	-	(150)
Rate Impact Automation (2015)	75	-	75	75	-
2013 Carryforward - Centralized Modeling Tool	-	7	-	7	7
2013 Carryforward - Credit Stacking	-	2	-	2	2
2014 Unbudgeted - Engineering POM License	-	25	-	25	25
Carry Over and New Projects	**$16,700**	**$4,056**	**$7,551**	**$11,607**	**($5,092)**
IT / Ops Foundation *					
IT Systems Foundation	8,154	48	8,107	8,154	0
IT Network Telecom	7,596	742	6,854	7,596	0
IT Applications Foundation	2,799	-	2,844	2,844	45
IT Service Management Foundation	901	107	739	846	(55)
IT Environment Foundation	173	-	118	118	(55)
Operations Foundation	3,889	853	3,049	3,902	13
IT / Ops Foundation	**$23,513**	**$1,750**	**$21,710**	**$23,461**	**($52)**
Total Capitalized Project Expense	**$177,156**	**$127,062**	**$47,269**	**$174,330**	**($2,826)**

* IT / Operations foundation projects are reforecast during each budget cycle and do not include any carry-over funds. Project-to-Date reflects only 2014 year-to-date actual results for both IT and Ops foundation projects. The remaining forecast includes 2015 and 2016 forecast.

SPP Southwest Power Pool

Southwest Power Pool
Heaecount Analysis
August 31, 2014

	Current Month Actual vs. Budget			Full Year Forecast vs. Budget		
	Actual Aug-14	Budget Aug-14	Over/(Under) Budget	FY 2014 Forecast	FY 2014 Budget	Over/(Under) Budget
Administration	0	0	0	(12)	0	(12)
Officers	10	10	0	10	10	0
Accounting	10	10	0	10	10	0
Credit	4	4	0	4	4	0
Settlements	24	25	(1)	24	25	(1)
aeministration	48	49	(1)	36	49	(13)
Corporate Services	29	29	0	29	29	0
Inter-Regional Affairs	4	4	0	4	4	0
Project Management	12	13	(1)	13	13	0
Training	11	13	(2)	11	13	(2)
Customer Service	10	9	1	10	9	1
Process Management	3	2	1	3	2	1
Internal Audit	6	6	0	6	6	0
Process Integrity	46	47	(1)	47	47	0
SPP Compliance	12	13	(1)	12	13	(1)
Communications	4	3	1	4	3	1
Market Monitoring	12	14	(2)	14	14	0
Compliance & Market Monitoring	28	30	(2)	30	30	0
SPP Regional Entity	27	31	(4)	30	31	(1)
Information Technology	137	144	(7)	146	144	2
Markets	6	6	0	6	6	0
Interregional Relations	3	3	0	3	3	0
Operations	150	157	(7)	154	157	(3)
Engineering Planning	39	41	(2)	43	41	2
Engineering Other	31	35	(4)	32	35	(3)
Regulatory Policy & General Counsel	26	26	0	26	26	0
TOTAL HEADCOUNT	570	598	(28)	582	598	(16)

* The 2014 forecast assumes a vacancy average of 4% for September - December.

Exhibit No. SPP-3

Prepared Direct Testimony of Carl A. Monroe

Exhibit No. SPP-3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
	)	
	)	
SOUTHWEST POWER POOL, INC.	)	Docket No. ER14-___-000
	)	
	)	
	)	

PREPARED DIRECT TESTIMONY

OF

CARL A. MONROE
EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER
SOUTHWEST POWER POOL, INC.

ON BEHALF OF SOUTHWEST POWER POOL, INC.

SEPTEMBER 11, 2014

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

SOUTHWEST POWER POOL, INC.	)	Docket No. ER14-____-000

PREPARED DIRECT TESTIMONY

OF

CARL A. MONROE

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Carl A. Monroe. My business address is 201 Worthen Drive, Little Rock, AR 72223.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by Southwest Power Pool, Inc. ("SPP") as Executive Vice President and Chief Operating Officer ("COO").

Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. I am responsible for the implementation and management of a regional operations center (including security operations); for regional transmission tariff administration for the SPP Open Access Transmission Tariff ("OATT" or "Tariff"); for oversight of engineering, information technology, and interregional affairs; and for the development, analysis, and operation of all markets. I also oversee staff support for all SPP technical organizational groups.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I earned a Bachelor's Degree in Electrical Engineering from Auburn University. Prior to being named Executive Vice President and COO of SPP, I served as SPP's Vice President of Operations and, before that, as Director of Operations and Manager of Information Technology. I was previously employed by Entergy Corporation and Union Electric (d/b/a Ameren) in various management, engineering and operations positions. I am a professional engineer registered in the State of Missouri.

Q. PLEASE GIVE A BRIEF SUMMARY OF SPP'S ORGANIZATION AND OPERATIONS.

A. SPP came into existence in 1941, when eleven companies joined together voluntarily to serve critical national defense needs during World War II. When the war ended in 1945, SPP's Executive Committee decided the organization should be retained to further the benefits of the coordinated operation of their electric systems. As a result of the Northeast power interruption in late 1965, a number of reliability councils were organized. In 1968, SPP joined with twelve other entities to form the National Electric Reliability Council, now known as the North American Electric Reliability Corporation ("NERC"). SPP incorporated as a non-profit corporation in 1994.

SPP is a Federal Energy Regulatory Commission ("FERC" or "Commission") approved Regional Transmission Organization ("RTO"). It is an Arkansas non-profit corporation with its principal place of business in Little Rock, Arkansas. SPP currently has 76 members in nine states and serves more than 6 million households in a 370,000 square-mile area. SPP's members include 14 investor-owned utilities, 11 municipal systems, 13 generation and transmission cooperatives, 5 state agencies, 11 independent power producers, 12 power marketers and 10 independent transmission companies. SPP, in its role as an RTO, currently administers transmission service over 48,000 miles of transmission lines covering portions of Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. These services include reliability coordination, tariff administration, regional scheduling, transmission expansion planning, market operations, compliance, and training.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am submitting this testimony to: (1) provide an overview of the changes to the SPP Tariff, as well as to the SPP Membership Agreement and SPP Bylaws ("Governing Documents") that SPP is proposing in light of Basin Electric Power Cooperative ("Basin Electric"), Western Area Power Administration – Upper Great Plains Region, a Federal power marketing agency ("PMA") ("Western-UGP"), and Heartland Consumers Power District ("Heartland", and collectively, with Basin Electric and Western-UGP, the "IS Parties") joining SPP as Transmission Owning Members; (2) describe the background and context of the activities SPP has undertaken with respect to the IS Parties joining SPP; (3) explain the benefits of the IS Parties joining SPP that current SPP members have recognized which manifested in stakeholder approval of this filing; and (4) briefly introduce an arrangement for SPP to provide certain services for the administration of limited facilities owned by the IS Parties in the Western Interconnection. The Integrated

System ("IS") geography includes: North and South Dakota; portions of Iowa, Minnesota, and Nebraska; and through a Direct Current ("DC") connection with the Western Interconnection, facilities in Montana. The IS Parties would represent an approximately 12% load ratio share of the combined SPP and IS footprint.

Q. PLEASE IDENTIFY THE PORTIONS OF THE SPP TARIFF THAT SPP PROPOSES TO AMEND.

A. There are proposed changes to the Tariff in Articles I, III, and IV, Schedules 7, 8, 9, 11 and 12, Attachments H, J, K, L, M, T, V, W, AE, AG, AN and AP. There are also proposed changes to the Governing Documents. A complete list of all sections containing proposed changes to the SPP Tariff and Governing Documents can be found in Exhibit Nos. SPP-1 and SPP-2 to this filing.

In addition to this filing, on or about December 1, 2014, SPP will submit for Commission acceptance a non-conforming Network Integration Transmission Service Agreement and Network Operating Agreement for each IS Party. On or about April 1, 2015, SPP will submit for Commission acceptance Annual Transmission Revenue Requirements ("ATRR") associated with the transmission facilities of Western-UGP, Basin Electric and Heartland.

Q. WHO ARE THE OTHER WITNESSES PROVIDING PREPARED DIRECT TESTIMONY IN SUPPORT OF THE PROPOSED CHANGES TO THE SPP OPEN ACCESS TRANSMISSION TARIFF AND GOVERNING DOCUMENTS?

A. The other witnesses who have provided prepared direct testimony are Bruce Rew, John Knofczynski, Michael Risan, David Raatz, Lloyd Linke, Jody Sundsted, and Steven Sanders.

II. IS PARTIES' INTEREST IN SPP MEMBERSHIP AND SPP STAKEHOLDER PROCESS

Q. CAN YOU BRIEFLY EXPLAIN HOW THE IS PARTIES BECAME INTERESTED IN SPP MEMBERSHIP?

A. SPP's relationship with the IS Parties has evolved over the last several years. Western-UGP has participated in the SPP Reserve Sharing Group ("RSG") since December, 2009. In April 2012, SPP and Western-UGP, on behalf of the entire IS, developed, and filed with FERC, a Joint Operating Agreement ("JOA") to improve coordinated operations, congestion management, and planning across the seam.[1] Western-UGP became a Market Participant in SPP effective April 1, 2014. Western-UGP participated in the SPP organizational groups as they designed and developed protocols for the Integrated Marketplace which provided Western-UGP with a deeper understanding of SPP market operations prior to making its decision to join SPP.

In September, 2012, the IS Parties engaged The Brattle Group to conduct an analysis ("Brattle Study") to determine which was the preferred RTO to join, either SPP or the Midcontinent Independent System Operator, Inc. ("MISO"). SPP staff had extensive

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[1] *See* Submission of Joint Operating Agreement Between Southwest Power Pool, Inc. and Western Area Power Administration of Southwest Power Pool, Inc., Docket ER12-1586-000 (Apr. 20, 2012). FERC conditionally accepted the JOA on September 18, 2012 (*See Sw. Power Pool, Inc.*, 140 FERC ¶ 61,199 (2012)). SPP submitted its compliance filing on October 18, 2012 (*See* Compliance Filing Revising Joint Operating Agreement of Southwest Power Pool, Inc., Docket No. ER12-1586-002 (Oct. 18, 2012)).

discussions with the IS Parties and The Brattle Group and provided information about SPP, including the design of the Integrated Marketplace. This analysis was completed by The Brattle Group in March, 2013.

On September 20, 2013, and on October 16, 2013, respectively, SPP entered into Memorandums of Understanding with Basin Electric and Heartland that formalized the commitment to investigate membership in SPP and committed SPP to provide information necessary for a complete evaluation of the potential costs and benefits of SPP membership. On November 1, 2013, Western-UGP published a notice in the Federal Register of its recommendation to pursue membership in SPP, and on January 10, 2014, the Administrator for Western Area Power Administration issued a press release announcing his authorization for staff to pursue formal negotiations with SPP for official membership. In April 2013, Basin Electric's Board of Directors authorized the Basin Electric staff to support Western-UGP in its federal process to join SPP and to negotiate terms and conditions of joining with SPP as a Transmission Owning Member.

Q. PLEASE DESCRIBE THE STAKEHOLDER PROCESS SPP USED TO EVALUATE THE PROPOSED MEMBERSHIP.

A. In 2011, the SPP Strategic Planning Committee ("SPC"), began discussing the possible membership of the IS Parties, based on the agreed-to process for new member interest. As a result, the SPC formed a group of SPP members in September 2012 to assist SPP staff and to provide a forum for Member input on any discussions with the IS Parties regarding membership in SPP. Included in subsequent SPC meetings were reports by SPP staff on the meetings of the small group of members of the SPC and any other meetings between the SPP staff and the IS Parties. During these meetings the SPC gave Member input on the IS's potential integration into SPP. Also, preliminary reports on the costs and benefits of the IS Parties joining SPP were presented. Some of the discussions included the issues that would need to be resolved in order to integrate the IS Parties into the SPP Tariff and Governing Documents. The Regional State Committee ("RSC") was informed of the IS Parties' interest in joining SPP in July 2013 and again in October 2013. The members of the RSC were notified via email about the Western-UGP's November 1st announcement on November 3, 2013. This subject was also presented and discussed at meetings of the RSC on January 27, 2014, March 6, 2014, April 4, 2014, April 28, 2014 and May 27, 2014.

Subsequent to the announcement by the IS Parties of their intent to pursue membership in SPP, SPP had a number of meetings with its stakeholders to consider and discuss the IS Parties' potential membership, which included the following:

A Stakeholder meeting on February 24, 2014 solely for the purpose of considering the IS Parties' membership;

Regional Tariff Working Group meetings on February 20, 2014, March 27, 2014, April 23-24, 2014, May 8, 2014, May 14, 2014, and May 21-23, 2014;

Process Improvement Tariff Task Force meetings on March 12, 2014, March 18, 2014, April 9, 2014, April 30, 2014, May 6, 2014, and May 13, 2014;

Corporate Governance Committee ("CGC") meetings on February 27, 2014, March 31, 2014, April 11, 2014, and May 1, 2014;

Cost Allocation Working Group meetings on April 2, 2014, and May 8, 2014; and

Strategic Planning Committee Meetings on January 16, 2014, and April 16, 2014.

The proposed changes to the Tariff and the Governing Documents were presented to the Markets and Operation Policy Committee ("MOPC") on June 2, 2014 and were approved with only one "no" vote and six abstentions. On June 9, 2014, the SPP Board of Directors ("SPP Board") approved the same.

Q. AS PART OF THE STAKEHOLDER PROCESS, DID SPP PERFORM ANY STUDIES?

A. Yes. SPP has analyzed both the reliability and economic impacts of the IS Parties joining SPP. A study was performed by SPP staff with direction and input from the Transmission Working Group ("TWG"), which SPP has referred to as the TWG Study. The TWG Study was used to evaluate the reliability impacts of the IS Parties joining SPP. SPP also performed cost benefit analysis of the impacts on Members, which considered the impacts on the SPP Tariff's Schedules 1, 1-A, 7, 8 and 11, Reserve Sharing Group ("RSG") benefits, and Integrated Marketplace Benefits. This analysis is discussed further in Section III, herein.

Q. PLEASE DESCRIBE THE TWG STUDY.

A. As an RTO, ensuring reliability is SPP's priority. The TWG Study was intended to be a reliability analysis of the IS Parties' current and planned transmission system and to establish the timing of the IS Parties' planned transmission projects. The analysis was performed using the same base case powerflow models and assumptions that were developed through the stakeholder process for the 2013 Integrated Transmission Plan ("ITP")-Near Term assessment. The models which had already been vetted and approved by SPP stakeholders were provided to the IS Parties for their review and input similar to the review process provided to all SPP stakeholders. Next, SPP conducted a reliability analysis to assess the IS System for potential NERC Transmission Planning ("TPL") violations and for adherence to the SPP Criteria.[2] SPP, following its internal process requested mitigations, as needed, for the potential issues identified and then confirmed that the mitigations provided by the IS Parties addressed the potential issues identified in the reliability analysis. The TWG was presented with the results of the study on October 23, 2013, and endorsed the study as being performed in accordance with SPP planning criteria.[3]

III. ECONOMIC BENEFITS OF THE IS PARTIES' MEMBERSHIP IN SPP

Q. PLEASE ELABORATE ON SPP'S ANALYSIS OF THE ECONOMIC BENEFITS OF THE IS JOINING SPP.

A. SPP performed an analysis to assess the estimated ten-year costs and benefits to SPP's current Members upon the integration of the IS into SPP. This analysis included an assessment of the SPP Tariff's Schedules 1, 1-A, 7, 8, and 11, RSG benefits, and Integrated Marketplace benefits.[4]

Q. WAS THIS ANALYSIS PRESENTED TO SPP STAKEHOLDERS AND MADE PUBLICALLY AVAILABLE?

A. Yes. The economic benefits of the IS joining SPP were presented to SPP Stakeholders on a number of occasions. These presentations were provided to SPP Stakeholders on:

[2] SPP Criteria is available at: http://www.spp.org/section.asp?group=215&pageID=27.
[3] *See* TWG October 23, 2013 Minutes at Agenda Item # 3 posted at: http://www.spp.org/publications/TWG%2010.23.13%20Minutes%20&%20Attachments.pdf.
[4] The analysis related to the cost and benefits, of Schedules 1, 1-A, 7, 8, and 11 as well as RSG benefits were conducted internally by SPP Staff. The only part of SPP's analysis from the information The Brattle Group provided to SPP separate from the IS Parties' Brattle Study was the Integrated Marketplace benefits.

February 24, 2014 at an all-stakeholder meeting; January 16, 2014, April 16, 2014, and May 1, 2014, at the SPC meetings; and January 27, 2014, April 4, 2014, April 28, 2014, and May, 27, 2014, at the RSC meetings. This analysis is posted on the SPP Website in those meeting materials.

Q. WHAT WAS THE RESULTS OF SPP'S ECONOMIC ANALYSIS?

A. The analysis determined the following:

May 20, 2014 Update

Effect of IS Joining SPP ($000)		
Metric	**10 Year Total**	**NPV @ 8% over 10 Years**
Schedule 1-A	**$185,889**	**$119,875**
Schedule 1, 7 & 8	**($50,830)**	**($34,107)**
Schedule 11	**($107,698)**	**($76,522)**
Reserve Sharing Benefits	**$34,380**	**$23,069**
Integrated Marketplace Benefits	**$272,375**	**$187,408**
Benefit	**$334,116**	**$219,723**

1) Positive Value is a Benefit to Current SPP
2) Apr 24, 2014 Update to Sch 1-A
3) May, 2014 Update to Sch 11 (added HPILS Projects)

The chart above shows the estimated net present value of the costs and benefits to current SPP Members over the next ten years. Specifically, the impacts on current Members were analyzed in the following areas:

Schedule 1A/Membership Fee payments to SPP (calculated based on a forecast of the SPP revenue requirement and taking into account the load ratio share of the IS).

> Schedules 1, 7 and 8 Point-to-Point revenue allocations from Point-to-Point Transmission Service ("PTP") (excluding any impact of additional Point-to-Point transactions that might be purchased if the IS Parties were to join).

> Schedule 11 Base Plan Funding cost allocations (including extra high voltage ("EHV")) taking into account an exemption for Western-UGP's load obligations under Federal statute.

> Integrated Marketplace savings (based on the results of the Brattle Study; SPP staff reviewed the input assumptions and the results for reasonability).

> Reserve Sharing Group – If the IS Parties do not join SPP then their alternative is to join MISO. As such there is a cost to SPP if the IS does not join SPP. This cost was estimated as the increased reserves that the current SPP Members would have to carry times the opportunity cost (Locational Marginal Price ("LMP")) that is lost by having to withhold those reserves from the real-time market. This estimate was based on only 10% of the hours being affected by these lost revenues.

The result of SPP staff's analysis indicates there is a net positive benefit to current SPP Members as a result of the IS Parties' membership. Specifically, SPP determined that over the next ten years there would be a savings of $185,889,000 in Schedule 1-A charges to current SPP Members. With respect to charges under Schedules 1, 7 and 8, there would be a cost of $50,830,000 to current SPP Members, as well as a cost to current SPP Members of $107,698,000 under Schedule 11. SPP conservatively estimates that there will be Reserve Sharing Benefits to current SPP Members in the amount of $34,380,000. The net result is a benefit of $61,741,000 to current SPP Members over the next ten years. Using benefits provided from the results of the Brattle Study performed on behalf of the IS Parties, SPP also analyzed the projected benefits from the IS Parties' participation in SPP in the Integrated Marketplace, and determined that there were projected benefits to current SPP Members in the amount of $272,375,000. When considering the Integrated Marketplace benefit, the net benefits to current SPP Members increase to $334,116,000 over the next ten years.

Q. ARE THERE ANY ADDITIONAL QUALITATIVE BENEFITS TO CONSIDER?

A. Yes. There are benefits that SPP did not find to be quantifiable; however, those benefits should not be disregarded simply because they are not readily quantifiable. Although not quantified, the incorporation of the IS Parties should benefit grid reliability and congestion management through the ability to commit and dispatch generation that impacts the 345 kV flows through and out of Nebraska. Those flows impact generation curtailment on the western side of the SPP region. The ability to commit and dispatch all generation impacting the west to east flows and the north to south flows on the western edge of SPP is expected to increase the availability of lower-priced energy throughout the region through reduced curtailment of generation. In addition, any excess generation of Western-UGP beyond what is needed to meet the needs of its Statutory Load Obligation customers will result in access to lower-cost hydro resources for SPP Members.

Another non-quantifiable factor is that if the IS were to not join SPP or did join MISO, costs would also increase for SPP loads using generation in the IS based on rate pancaking and the MISO Through-and-Out rate.

IV. <u>PROPOSED TARIFF CHANGES</u>

Q. IN THE PROPOSED TARIFF CHANGES YOU MENTIONED EARLIER, YOU IDENTIFIED SCHEDULE 11 AS A PORTION OF THE TARIFF THAT WOULD REQUIRE CHANGES. COULD YOU PLEASE ELABORATE ON WHAT THOSE CHANGES ARE?

A. Schedule 11 of the SPP Tariff contains the Base Plan Zonal Charges and the Region-Wide Charges paid by Transmission Customers. There are two main areas of changes proposed to Schedule 11: (i) the Federal Service Exemption and (ii) how the IS Parties will enter into regional cost sharing under the allocation of Base Plan Upgrade costs.

Q. THE FIRST PROPOSED CHANGE YOU MENTIONED WAS THE FEDERAL SERVICE EXEMPTION. COULD YOU EXPLAIN WHAT THAT IS?

A. The Federal Service Exemption was developed because Western-UGP has stated that its proposed membership in SPP is subject to: (i) its statutorily mandated obligations to deliver federal hydro generation to categorically-defined Statutory Load Obligation Customers; (ii) the fixed nature of the generation resources committed to the Statutory Load Obligation customers of Western-UGP; and (iii) the sufficiency of existing transmission that Western-UGP owns to meet its requirements. Accordingly, Western-UGP has requested the Federal Service Exemption to meet those requirements. The Federal Service Exemption is set forth in proposed Section 39.3(e) of the Tariff and includes modifications to Schedule 11 and Attachment AE of the Tariff. Specifically, Western-UGP would be exempt from Schedule 11 Region-wide Charges for Western-UGP's delivery of federal hydro generation to Western-UGP's Statutory Load Obligations. In addition, Western-UGP would be exempt from congestion and marginal loss charges in accordance with Attachment AE for deliveries from federal hydro generation to Western-UGP's Statutory Load Obligations as well as excluded from obtaining the Auction Revenue Rights ("ARRs") and Transmission Congestion Rights ("TCRs") that are available for their transmission usage. Western-UGP will also be excluded from receiving any redistribution of the over-collection of marginal losses.

However, Western-UGP will be responsible for its share of Schedule 11 Base Plan Zonal Charges and for providing the Transmission Provider average losses for the energy delivered under the Federal Service Exemption at the loss factor for Zone 19 listed in Attachment M, Appendix 1 of the Tariff.

The Federal Service Exemption applies only to Western-UGP's delivery of power from federal hydro generation to Western-UGP's Statutory Load Obligation customers. The Federal Service Exemption will not apply to Basin Electric or Heartland or any other entities embedded in the IS that may become SPP Members or Transmission Customers. Any Western-UGP power marketing activity (purchases to meet its Statutory Load Obligation or sales from the excess of its resources) that does not involve providing Federal resources to Federal load will be subject to all transmission service charges under the SPP Tariff, including Schedule 11 Region-wide Charges and Attachment AE requirements. The Direct Testimony of Jody Sundsted addresses the need for the Federal Service Exemption in greater detail. In addition, the Prepared Direct Testimony of Bruce Rew will address the changes to Attachment AE of the Tariff.

Q. DO YOU BELIEVE THE FEDERAL SERVICE EXEMPTION IS REASONABLE?

A. Yes. SPP believes that the basis Western-UGP cites for the Federal Service Exemption is a reasonable interpretation of the applicable statutes.

Q. THE SECOND CHANGE TO SCHEDULE 11 THAT YOU MENTIONED WAS THE INTEGRATION OF THE IS PARTIES INTO REGIONAL COST SHARING. COULD YOU EXPLAIN THAT IN MORE DETAIL?

A. The second main area of change to Schedule 11 is how the IS Parties will enter into SPP's regional cost sharing under the allocation of Base Plan Upgrade costs under the Highway-Byway cost allocation methodology.[5] The Tariff changes in Schedule 11 propose a change to the definition of Base Plan Upgrades whereby the IS Parties and SPP will begin regional cost sharing for projects needed on or after October 1, 2015, in both SPP and the IS Parties' respective transmission planning processes. Throughout the SPP stakeholder process, this has frequently been referred to as the "need-by date." This need-by date proposal is consistent with how other SPP members entered into regional cost sharing under the SPP Tariff, and as the analysis I have previously described shows, this proposal still results in an overall net benefit to SPP's current Members. Any facilities with a need-by date prior to October 1, 2015 would be allocated to either SPP or the IS Parties as it is today.

Q. WHAT IS THE PROPOSED CHANGE TO THE DEFINITION OF BASE PLAN UPGRADE?

A. The Base Plan Upgrades in Zones 1 through 18 identified by the Transmission Provider with a need-by date prior to October 1, 2015 shall not be allocable to Zone 19. The upgrades in Zone 19 identified by the Transmission Provider with a need-by date prior to October 1, 2015, shall not constitute Base Plan Upgrades. The facilities identified in Schedule 2 to Attachment J of the Tariff are expressly deemed to be Base Plan Upgrades pursuant to Attachment J, Section III.A.2.ii.

[5] The Commission issued an order accepting SPP's Highway-Byway cost allocation methodology in Docket No. ER10-1069-000 on June 17, 2010. *Sw. Power Pool, Inc.*, 131 FERC ¶ 61,252 (2010).

Q. PLEASE ELABORATE ON WHAT THIS PROPOSED CHANGE MEANS.

A. When SPP first began regional cost sharing through Base Plan Funding, its Members regionally shared costs on a going-forward basis. In other words, they each had their legacy transmission systems, and there was no attempt to regionally share costs for these legacy facilities. In fact, if there were facilities that were needed by the Member before SPP started regional cost sharing, that Member was responsible for the cost of those facilities in addition to their legacy facilities even if the facility could not be implemented before the start of regional cost sharing. Regional cost sharing through allocation of Base Plan Upgrade costs was implemented for new facilities receiving a notification to construct on or after June 19, 2010. SPP has applied this same philosophy to the proposed integration of the IS Parties. Additionally, this was the same type of offer that was extended to Entergy Services, Inc. when it was considering membership in SPP.

The IS Parties have an existing legacy system as well as projects planned with need-by dates in the future. Those facilities, as well as any planned facilities with a need-by date prior to October 1, 2015, have been and will continue to be fully funded by the IS Parties. SPP Members will not regionally share the costs for these existing facilities. Likewise, existing facilities constructed by SPP Members and those planned facilities with a need-by date prior to October 1, 2015, will be fully paid for by current SPP Members and not cost-shared with the IS Parties. Instead, costs will be shared for projects in both the IS and the current SPP footprint with need-by dates beginning with the proposed date of integration — October 1, 2015.

Q. HOW WAS THE OCTOBER 1, 2015 DATE DETERMINED?

A. This date was proposed by the IS Parties and found to be reasonable by SPP. This October 1, 2015 date allows time for the SPP stakeholder process, approval by the respective boards or management of SPP and the IS Parties, regulatory approvals, and sufficient time for completing all of the necessary steps for integration into SPP. Additionally, Western-UGP was obligated to undergo a public process before it could finalize its decision to join SPP.

Q. **DID SPP CONDUCT ANY ANALYSIS REGARDING THE APPLICATION OF REGIONAL COST SHARING TO THE IS PROJECTS AND THE PROPOSED NEED-BY DATES?**

A. Yes. The purposes of the TWG Study I mentioned above were two-fold: (i) to confirm that the IS Parties were bringing a reliable system for integration into SPP that was in compliance with NERC and SPP standards and (ii) to confirm the need-by date of projects that the IS Parties have planned, according to SPP Criteria and eligibility for allocation of Base Plan Upgrade costs.

The TWG Study looked out as far as 2019, consistent with the 2013 ITP Near-Term study, to identify reliability needs and confirmed that the planned IS projects met the needs identified in the TWG Study for both potential TPL or SPP criteria violations. The TWG Study then timed the need-by dates in accordance with when the reliability needs were identified in the models, exactly as SPP would for SPP members in the ITP Near-Term process.

Basin Electric's projects with an SPP need-by date on or after October 1, 2015 are identified in Schedule 2 to Attachment J.

Q. HOW WILL SPP'S REGIONAL COST ALLOCATION REVIEW ("RCAR") IMPACT THIS PROCESS?

A. When the Commission approved the allocation of Base Plan Upgrade costs with a notification to construct after June 19, 2010, it also approved a regional review of such cost sharing to be performed every three years. To implement this regional review, SPP created the Regional Allocation Review Task Force ("RARTF") which developed the RCAR methodology and the RCAR Report. The RARTF will consider how to incorporate the IS Parties into the RCAR process. The subsequent RCAR analysis will determine if the way the IS Parties proposed to enter into regional cost sharing results in the IS Parties benefiting from SPP facilities in such a way that the benefits are not commensurate with the costs to SPP Members. In the event this becomes an issue, the RARTF has provided a list of possible remedies and the RCAR process will identify the specific remedies that are expected to correct this situation over time.

Q. DO YOU BELIEVE THAT THE CHANGES TO SCHEDULE 11 REGARDING REGIONAL COST SHARING ARE JUST AND REASONABLE?

A. Yes. SPP believes that the proposed changes to integrate the IS Parties into regional cost sharing are just and reasonable.

Q. YOU STATED THAT THERE ARE PROPOSED CHANGES TO SCHEDULE 12 TO THE SPP TARIFF. WOULD YOU PLEASE DESCRIBE THOSE CHANGES?

A. Schedule 12 of the Tariff contains the mechanisms for SPP to collect the funds necessary to pay the annual charges for the FERC Assessment that is assessed to SPP's Transmission Customers and Transmission Owners by the Commission for all energy delivered under PTP and Network Integration Transmission Service ("NITS") and to all energy delivered under Bundled Retail and Grandfathered Loads transmitted in interstate commerce during a calendar year. As proposed, Western-UGP will not pay charges under Schedule 12. The Direct Testimony of Jody Sundsted explains that Schedule 12 charges are not applicable because the FERC Assessment does not include the costs of regulating Federal PMAs. Western-UGP is the only IS owner that will not be assessed Schedule 12 costs for PTP or for NITS that is provided to Western-UGP.

Q. ARE THE CHANGES TO SCHEDULE 12 JUST AND REASONABLE?

A. Yes. SPP believes that Western-UGP's basis for an exemption from Schedule 12 charges is reasonable.

Q. YOU STATED THAT THERE ARE PROPOSED CHANGES TO SCHEDULES 7, 8, AND 9 OF THE TARIFF. WOULD YOU PLEASE DESCRIBE THOSE CHANGES?

A. Schedules 7 and 8 contain the rates for PTP. Schedule 7 contains the rates to calculate charges to be paid by transmission customers for long-term and short-term firm PTP on the SPP system. Schedule 8 contains the charges to be paid by Transmission Customers for non-firm PTP. Upon Commission approval, SPP's calculation of the zonal rate for PTP will include the IS Parties' zone, identified as Zone 19 (Upper Missouri Zone or UMZ). The rates sheet for Zone 19 is contained in Attachment T and is described in more detail below.

Schedule 9 provides that Transmission Customer shall compensate SPP for NITS. The compensation includes a zonal rate. The revisions to Schedule 9 are necessary to include

Zone 19, similar to the proposals for Schedules 7 and 8. However, SPP proposes a different calculation methodology for Zone 19. SPP proposes to retain the current provision for Zones 1 through 18. For network customers in Zone 19 that are interconnected to an external entity, the Zone 19 demand charge is applicable rather than the lowest zonal charge.

Q. ARE THE CHANGES TO SCHEDULES 7, 8, AND 9 JUST AND REASONABLE?

A. Yes. SPP believes the inclusion of the Upper Missouri Zone (UMZ or Zone 19) in these rate schedules is just and reasonable in order to integrate Zone 19 into the ratemaking process under the Tariff.

Q. YOU STATED THAT THERE ARE PROPOSED CHANGES TO ATTACHMENTS H AND T OF THE TARIFF. WOULD YOU PLEASE DESCRIBE THOSE CHANGES?

A. Attachment H contains the ATRR for SPP Transmission Owning Members that have placed their transmission facilities under the Tariff and have Commission accepted stated rates or formula rates for recovery of the ATRR. The components of the Transmission Owner ATRR include the Zonal ATRR, Base Plan Zonal ATRR (before and after June 19, 2010), ATRR reallocated to the Balanced Portfolio Region-wide ATRR, and the Base Plan Zonal ATRR to pay Upgrade Sponsors of transmission upgrades. These components are used by SPP to compute the Region-wide charges under Schedule 11. The changes to Schedule 11 necessary to integrate Western-UGP are discussed above.

SPP proposes in this filing to also revise Attachment H in anticipation of SPP filing on behalf of the IS Parties individual filings to incorporate a stated or formula rate into

Attachment H. Changes to Attachment H include the addition of Zone 19, and respective sub-zones within the zone to represent the IS Parties' ATRR. Zone 19 is divided into separate sub-zones for Western-UGP (Zone 19a), Basin Electric (Zone 19b), and Heartland (Zone 19c) with references to SPP's Revenue Requirements and Rates ("RRR") File similar to other established Transmission Owners.

Additionally, Attachment H is revised to include a Table 2-B to specify the Region-wide ATRR for network upgrades needed on or after the October 1, 2015 date as discussed in this testimony. Table 2-A will continue to represent current information for Network Upgrades needed prior to October 1, 2015.

An Attachment T rate sheet for the Upper Missouri Zone is included in the filing for PTP service in Zone 19. These rates will be set forth in the RRR file. Attachment T for the Upper Missouri Zone will include the rates for each of the IS Parties for firm and non-firm PTP and an adjustment clause for balanced portfolio reallocations in accordance with Attachment J. Similar to attachment H, SPP will make future filings to incorporate the IS Parties' rates into the tariff to allow SPP to populate the RRR file with the IS Parties' ATRR.

Q. ARE THE CHANGES TO ATTACHMENTS H AND T JUST AND REASONABLE?

A. Yes. For the same reasons stated for Schedules 7-9 and 11 above, SPP believes the modifications to Attachments H and T are required to integrate the IS Parties.

Q. YOU STATED THAT THERE ARE PROPOSED CHANGES TO ATTACHMENTS J AND L TO THE SPP TARIFF. WOULD YOU PLEASE DESCRIBE THOSE CHANGES?

A. Attachments J and L of the Tariff dictate the recovery of costs associated with new facilities and the treatment of transmission revenues, respectively. Each attachment is revised to recognize the requirements of Western-UGP as a Federal PMA. Further justification for this requirement will be provided in the Direct Testimony provided by Jody Sundsted and Steven Sanders.

Attachment J will also include a Schedule 2 to Attachment J to identify the base plan upgrades specifically designated for cost allocation under Attachment J when the IS Parties' facilities are included in the SPP system.

Attachment L currently provides in Section II.B.2(f) that revenues collected from network customers for load outside the SPP transmission system under Section 31.3 of the Tariff shall be distributed among Transmission Owners on the same basis as revenues collected for PTP. This section will not apply to the Upper Missouri Zone. Rather, Attachment L will include a new section II.B.2(h) to provide that for load outside the SPP transmission system designated prior to October 1, 2015, revenues that SPP collects shall be distributed amongst the Transmission Owners of Zone 19 only. The Direct Testimony of Lloyd Linke explains the reasons for this proposed change.

Q. ARE THE CHANGES TO ATTACHMENTS J AND L JUST AND REASONABLE?

A. Yes. SPP believes Western-UGP's requirements for Attachment J are consistent with Western-UGP's interpretation of its responsibilities under its governing statutes. SPP has reviewed Mr. Linke's explanation for the proposed revisions to Attachment L and has concluded that the proposed change is just and reasonable.

Q. YOU STATED THAT THERE ARE PROPOSED CHANGES TO ATTACHMENT M TO THE SPP TARIFF. WOULD YOU PLEASE DESCRIBE THOSE CHANGES?

A. Attachment M provides the Loss Compensation Procedure under the Tariff for the determination of losses for which Transmission Customers (both NITS and PTP) are responsible. Any loss compensation to be provided by Western-UGP that is associated with network service to serve its Statutory Load Obligations will be calculated in accordance with Attachment M, but are subject to the requirements of the Federal Service Exemption identified in Section 39.3(e)(ii) of the Tariff. The proposed changes will identify the loss factors to be utilized to calculate Western-UGP's responsibility for its network load to serve its Statutory Load Obligations in accordance with the Federal Service Exemption. The Direct Testimony of Jody Sundsted addresses the need for the Federal Service Exemption in greater detail.

Q. ARE THE CHANGES TO ATTACHMENT M JUST AND REASONABLE?

A. Yes. SPP believes that the basis Western-UGP cites for the Federal Service Exemption is a reasonable interpretation of the applicable statutes and the revisions to Attachment M are consistent with that interpretation.

Q. YOU STATED THAT THERE ARE PROPOSED CHANGES TO ATTACHMENT AN TO THE SPP TARIFF. WOULD YOU PLEASE DESCRIBE THOSE CHANGES?

A. Attachment AN is the *pro forma* agreement between SPP and the participants in the SPP Balancing Authority ("SPP BA") ("SPP BA Agreement") that delineates the division of responsibilities, rights and obligations between SPP and the former Balancing Authorities that were consolidated with the implementation of the Integrated Marketplace. SPP and sixteen (16) former Balancing Authorities are currently signatories and participants in the SPP BA. When the IS Parties integrate into SPP, the Western-UGP WAUE Balancing Authority (which operates on behalf of the IS Parties) will become part of the SPP footprint. Western-UGP has proposed revisions to the SPP BA Agreement as necessary to allow Western-UGP WAUE to become a signatory under the SPP BA Agreement, and to integrate the IS Parties into the SPP footprint. The other signatories to the SPP BA Agreement participated in the review and modification of the terms and conditions being filed.

The changes being proposed to Attachment AN are consistent with the changes proposed to other sections of the Tariff, specifically the proposed revisions to Section 39.3 of the Tariff and the application of federal law, to recognize the requirements of Western-UGP as a Federal PMA. The general Federal requirements applicable to Western-UGP are being addressed in the Prepared Direct Testimony of Jody Sundsted.

Q. ARE THE CHANGES TO ATTACHMENT AN JUST AND REASONABLE?

A. For similar reasons underlying the justification for the Tariff changes being proposed, SPP believes that the changes to Attachment AN are just and reasonable.

Q. YOU STATED THAT THERE ARE PROPOSED CHANGES TO ATTACHMENT AP TO THE SPP TARIFF. WOULD YOU PLEASE DESCRIBE THOSE CHANGES?

A. Attachment AP contains the allocation of costs associated with reliability penalty assessments against SPP. This attachment provides notice to all Market Participants, Members, and Terminated Members that they may be potentially responsible for penalties levied against SPP due to confirmed violations of mandatory Reliability Standards of NERC. Western-UGP has asserted that it is not subject to Reliability Penalties that may be levied against it or SPP's penalty costs due to SPP or Western-UGP violations. Therefore, Attachment AP is being revised to recognize that Western-UGP, by becoming a SPP Member, does not waive or concede any defense it may have against liability for reliability penalty costs levied against SPP by an enforcement authority to which it would not be liable except for membership in SPP. Likewise, SPP does not concede or accept responsibility for any portion of penalty or fine attributable to Western-UGP. The purposes and justification for the changes to Attachment AP is being addressed in greater detail in the Direct Testimony of Lloyd Linke.

Q. ARE THE CHANGES TO ATTACHMENT AP JUST AND REASONABLE?

A. Western-UGP has stated this is a limitation that must be addressed in the Tariff and Governing Documents and is a condition of membership. SPP believes that in light of

Western-UGP's position, the proposal to identify such amounts to the Commission as uncollectable is just and reasonable.

V. CONTRACT FOR ADMINISTRATIVE SERVICES FOR IS FACILITIES IN THE WESTERN INTERCONNECTION

Q. THERE ARE SOME WESTERN-UGP AND BASIN ELECTRIC FACILITIES THAT ARE IN THE WESTERN INTERCONNECTION. ARE THOSE FACILITIES BEING INTEGRATED INTO SPP?

A. No. Those are Western-UGP and Basin Electric facilities that are not being placed under the Tariff based on the membership of those IS Parties. SPP and Western-UGP intend to enter into a contract for SPP to undertake administration of those facilities. Such facilities are located across the Miles City DC Tie and comprise a small amount of load and generation. Participation in the SPP Integrated Marketplace is not feasible for the Western Interconnection facilities because those facilities are in a separate interconnection, and comprise a small amount of facilities and load. It is anticipated that the contract will be similar to the contract between SPP and the Southwestern Power Administration.[6] Western-UGP' WAUW will continue to operate as the Balancing Authority for facilities in the Western Interconnection. It is expected this contract will be completed before October 1, 2015.

VI. PROPOSED CHANGES TO GOVERNING DOCUMENTS TARIFF

[6] The currently effective Tariff Administration Agreement between Southwestern Power Administration and SPP is located in Attachment AD of SPP's Tariff.

Q. WHAT ARE THE CHANGES PROPOSED TO THE MEMBERSHIP AGREEMENT AND THE SPP BYLAWS?

A. The majority of the changes SPP has proposed to its Governing Documents are to accommodate the membership of the IS Parties, which is addressed in the Direct Testimony of Lloyd Linke and Jody Sundsted. However, there are also proposed changes to the SPP Bylaws regarding the number of seats on the Members Committee and the CGC that are not directly a result of the IS Parties' decision to join SPP.

Q. CAN YOU ELABORATE ON THE RESPONSIBILITIES AND SCOPE OF THE MEMBERS COMMITTEE?

A. The Members Committee is currently comprised of 19 members. Presently, four of the representatives are from investor-owned utilities Members, four representatives are from cooperatives Members, two representatives are from municipals Members (including municipal joint action agencies), three representatives are from independent power producers/marketers Members, two representatives are from state/federal power agencies Members, two representatives are from alternative power/public interest Members, one representative is from a large retail customer Member; and one representative is from a small retail customer Member. The Members Committee meets with the SPP Board and Members Committee representatives sit at the table with the SPP Board during such meetings. Prior to a vote of the SPP Board, the Members Committee is polled and takes a non-binding vote, thus indicating the voice of the SPP Members to the SPP Board.

As set forth in Section 5.1 of the SPP Bylaws, the duties of the Members Committee include the following:

(a) Provide individual and collective input to the Board of Directors, including but not limited to a straw vote from the Members Committee representatives as an indication of the level of consensus among Members, on all actions pending before the Board of Directors;

(b) Serve on committees reporting to the Board of Directors as appointed by the Board of Directors; and

(c) Provide input with the Board of Directors to the Regional Entity Trustees on SPP Regional Reliability Standards presented by the MOPC to the Trustees or otherwise developed under the auspices of the Trustees for submission to the ERO for its approval.

Q. WHAT ARE THE PROPOSED CHANGES TO THE MEMBERS COMMITTEE?

A. The proposed changes to Section 5.1.1 of the SPP Bylaws increase the number of representatives on the Members Committee from 19 to 24. The number of representatives from investor-owned utilities is being increased from four to six, the number of cooperative representatives is being increased from four to five, a seat is being added for a representative from a Federal PMA, and a seat is being added for a representative from an independent transmission company (defined as having assets under the Tariff and no affiliate relationships in the other categories of SPP membership). If membership of the IS Parties does not materialize, neither the additional seat for a cooperative representative nor the Federal PMA seat will be added. The addition of two seats for investor-owned utilities is based upon their percentage of the SPP membership and a growing interest in participation. The addition of a seat for a representative from an independent transmission company is based upon the growth of these Members in the SPP footprint. These changes were approved by the SPP Membership and SPP Board on June 9, 2014.

Q. CAN YOU ELABORATE ON THE RESPONSIBILITIES AND SCOPE OF THE CORPORATE GOVERNANCE COMMITTEE?

A. As set forth in Section 6.6 of the SPP Bylaws, the CGC is responsible for the overall governance structure, including nominations, for the company for: Board of Directors (as identified by an independent executive search firm) for consideration by SPP Membership; Regional Entity trustees for consideration by SPP Membership; Members Committee Representatives for consideration by SPP Membership; and filling vacancies for Organizational Groups in accordance with the SPP Bylaws. The CGC is also charged with the responsibility of monitoring the composition of the SPP Board to ensure balance, independence, and qualification under applicable laws, avoidance of conflicts of interest and periodic review of the criteria for independence and recommending changes, as appropriate. The CGC is also responsible for determining the criteria governing the overall composition of the SPP Board and Regional Entity Trustees, and for coordinating an annual review and assessment of the SPP Board's and the Regional Entity Trustee's effectiveness, structure and process. The full scope of the CGC is posted on the SPP Website at: http://www.spp.org/publications/CGC%20Scope%202013.FINAL.pdf.

Currently, the membership of the CGC is comprised of the following: the President of SPP who will serve as the Chair; the Chairman of the Board, (unless his/her position is under consideration, in which case the Vice Chairman of the Board would fill that role); a representative from an investor-owned utilities Member; a representative from a co-operatives Member; a representative from a municipals Member; a representative from an independent power producers/marketers Member; a representative from a state/federal power agencies Member; a representative from an alternative power/public interest Member; and a representative selected by large/small retail Members.

Q. WHAT ARE THE PROPOSED CHANGES TO THE CGC?

The proposed changes to Section 6.6 of the SPP Bylaws change the current seat on the CGC that "shall be representative of and selected by state/federal power agencies Members" to a representative of and selected by state power agencies Members. In addition, a seat on the CGC is added for a member that "shall be representative of and selected by a Federal Power Marketing Agency Member(s)." In the event that membership of the IS does not materialize, these changes will not be made.

Q. ARE THE PROPOSED CHANGES TO THE GOVERNING DOCUMENTS JUST AND REASONABLE?

A. Yes. The proposed changes to the SPP Governing Documents are just and reasonable.

VII. <u>WITHDRAWAL</u>

Q. PLEASE EXPLAIN THE WITHDRAWAL PROVISIONS AS APPLICABLE TO THE IS ENTITIES.

A. Under the proposed revisions to the Governing Documents, Western-UGP, Basin Electric, or Heartland would be able to withdraw from SPP membership with less than the currently required period of notice if the Commission does not approve all of the proposed revisions or if SPP subsequently changes the terms of the revisions or fails to adhere to them. In addition, if Western-UGP were to withdraw under one of those scenarios, the agency would not be responsible for the financial obligations otherwise required upon a member's withdrawal. Basin Electric and Heartland would still have to meet such financial obligations. The Direct Testimony of Lloyd Linke addresses this in greater detail.

Q. WHY ARE THE WITHDRAWAL PROVISIONS FOR WESTERN-UGP DIFFERENT FROM THOSE FOR BASIN ELECTRIC AND HEARTLAND?

A. The distinction is based on Western-UGP's status as a Federal agency and its inability to undertake financial obligations that conflict with the Federal statutes that govern its actions.

Q. PLEASE ELABORATE ON THE BASIS FOR WESTERN-UGP'S PROPOSED EXEMPTION FROM FINANCIAL OBLIGATIONS UPON WITHDRAWAL.

A. While Mr. Linke addresses this issue in more detail, it is apparent that Western-UGP, as the first Federal PMA to pursue RTO membership under the authority of EPAct 05, is proceeding cautiously and with the aim of prudent management of appropriated Federal funds. Western-UGP has stated the specific Tariff and Governing Documents revisions at issue are necessary to permit the agency to participate as a Member of SPP and still comply with its statutory obligations. Accordingly, Western-UGP has advised it must withdraw as a Member if the revisions it deems necessary are not approved by the Commission or are subsequently changed by SPP.

Q. WHAT STATUTORY OBLIGATIONS ARE AT ISSUE HERE?

A. Western-UGP has cited many of the same statues on which the Federal Service Exemption is based. EPAct 05, on which Western-UGP's proposed membership is premised, states in Section 1232(c) that the agency will still be subject to the obligations and limitations of its existing statutory authority and contracts. Western-UGP has identified the payment and funding commitment restrictions of the Anti-Deficiency Act (31 U.S.C. §1341) and the Purpose Statute (31 USC §1301) as well as the minimum rate requirements imposed by Federal reclamation law in Section 9(c) of the Reclamation Project Act of 1939 and Section 5 of the Flood Control Act of 1944.

Q. CAN YOU ELABORATE ON THE FINANCIAL RESTRICTIONS IMPOSED BY THESE STATUTES?

A. Again, Mr. Linke addresses this issue more directly, but under the Anti-Deficiency Act, Western-UGP states that it is unable to obligate itself in advance for an amount that is open-ended or unknown and thus has not been the subject of appropriations.

Q. WHAT IF NONE OF THE SPECIFIED TRIGGERING EVENTS OCCUR, BUT WESTERN-UGP NONETHELESS DECIDES TO WITHDRAW? WOULD THE AGENCY BE RESPONSIBLE FOR PAYMENT OF FINANCIAL OBLIGATIONS UNDER THOSE CIRCUMSTANCES?

A. Under the revisions as proposed, Western-UGP would only be relieved from paying financial obligations upon withdrawal triggered by the specified events (i.e. the Commission does not approve the proposed revisions at issue, SPP changes them unilaterally, or SPP fails to adhere to them). In this context, Western-UGP proposes to distinguish between a withdrawal triggered by the actions of third parties and a withdrawal Western-UGP may plan and undertake after sufficient appropriations have been made for expenses such as financial obligations associated with withdrawal.

Q. ARE THE PROPOSED TERMS OF WITHDRAWAL JUST AND REASONABLE?

A. Yes, I believe that they are.

VIII. CONCLUSION

Q. DO YOU BELIEVE THAT SPP'S PROPOSED CHANGES TO THE TARIFF AND GOVERNING DOCUMENTS ARE JUST AND REASONABLE?

A. I do. There were a number of stakeholder meetings in which the proposed membership of the IS Parties was discussed in detail, and a number of meetings dedicated to developing the proposed language in the Tariff and Governing Documents. The TWG Study was conducted using stakeholder developed models and was endorsed by the TWG and the cost benefit analysis was presented to and considered by SPP's stakeholders. The proposed Tariff changes required to integrate the IS Parties into SPP were approved by the MOPC, the Members Committee and the SPP Board. The proposed changes to the Governing Documents were approved by the MOPC, the SPP Membership, the Members Committee and the SPP Board. In addition, on July 9, 2014, the Administrator of the Western Area Power Administration approved and directed Western-UGP to take the necessary actions to complete full membership with SPP. Heartland's Board of Directors passed resolutions on July 8, 2014, approving its participation as an SPP Member. On July 17, 2014, Basin Electric's Board of Directors authorized integration with SPP by October 1, 2015. The proposed revisions have been carefully scrutinized by all of the affected parties, and have been found to be necessary or appropriate to integrate the IS Parties into SPP. Consequently, the revisions are just and reasonable.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

VERIFICATION

Pursuant to 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing testimony is true and correct to the best of my information, knowledge and belief.

Executed this 8th day of September, 2014.

Carl A. Monroe
Executive Vice President and Chief Operating Officer
Southwest Power Pool, Inc.

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

Case Nos. 14-1152-E-42T and 14-1151-E-D

APPALACHIAN POWER COMPANY
and WHEELING POWER COMPANY

COMMISSION ORDER ON THE TARIFF FILING
OF APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY TO INCREASE RATES,
and PETITION TO CHANGE DEPRECIATION RATES.

May 26, 2015

On cross-examination, Mr. Melton agreed that, under traditional ratemaking, the ratepayer would pay more than actual storm costs in some years and less than actual costs in other years. Tr. 1/23 at 88. Under the Companies' proposal, the Companies would not under-recover, and ratepayers would not pay for more than actual expenses. Id. at 88-89.

The Commission will not authorize a Major Storm Tracking ratemaking mechanism. As described earlier, the Commission has built into base rates a reasonable, normalized level of ongoing storm expense and a significant amount of rate recovery for the VMP. Given the presence of these two rate recovery mechanisms the Commission is not persuaded that an additional deferral mechanism for major storm damage expenses is warranted or appropriate at this time. If the Companies experience extraordinary storm expenses above the normalized level built into the rates authorized in this case, they can make the appropriate decisions regarding whether they should defer those expenses and seek recovery for those costs in a future base rate case where the necessity and prudence of its expenditures can be examined by all interested parties.

D. Security Rider

The Companies proposed approval of a security rider in the tariff to create a regulatory mechanism to track the Companies' investment and costs to defend against possible attacks on physical infrastructure and on computer and information systems. Companies witness Patton stated that security-related expenses may be required on short notice or even on an emergency basis to respond to attacks. Companies Exh. CRP-D at 11-14. Mr. Patton testified that the Companies must be prepared to respond to actual attacks against their generation, transmission, distribution, and other physical facilities, attacks on their systems in cyberspace, and to implement protective security measures. Id. at 14. Mr. Patton stated that in the future the North American Electric Reliability Corporation (NERC) and other authorities will mandate implementation of security measures. The security rider to track and defer capital and O&M costs will allow the Companies flexibility to respond. The Companies would request recovery of deferred costs in subsequent base rate proceedings. The Companies asked that capital investments in security be subject to carrying charges at the Companies' weighted average cost of capital and to any applicable depreciation expense. Id. at 14.

In response to the Staff and WVEUG objections to the Security Rider, Mr. Patton stated that the nature of terrorist activities and cyber-security threats is such that they cannot be known or measurable. Terrorists and wrong-doers constantly seek out new ways of causing harm. Companies Exh. CRP-R at 5-6 (responding to Staff Exh. TRE-D at 19-20; WVEUG Exh. LK-D at 38-41). A flexible mechanism for addressing these activities is required. Mr. Patton stated that implementing new security measures will require significant sums of money, the amount will fluctuate, and the amounts will exceed amounts spent in the past on traditional security measures. Id. at 6. Mr. Patton asked the Commission not to adopt a wait and see policy on emerging threats. Id.

In their brief, the Companies' argued that the Security Rider would not predetermine a Commission treatment of security investments and expenditures. It would, however, enable the Companies to make security investments and expenditures in a timely fashion.

WVEUG witness Kollen stated that the Companies did not support the request for approval of a Security Rider with projected costs, a statement of the security costs already in base rates, a methodology to determine incremental costs, or a date that an associated rate change would go into effect. WVEUG Exh. LK-D at 38-40. Mr. Kollen objected that the Companies did not consider that existing rate base investments in security will continue to depreciate. Mr. Kollen argued that the Companies should not be allowed to recover increment costs through a surcharge or defer costs for future base rate recovery while retaining the savings from the ongoing reductions in its revenue requirement. Id. at 39-40.

Staff witness Eads also opposed the Security Rider. Mr. Eads stated that although there may be increased requirements related to security, the requirements are speculative at this time and the associated costs are not known. Mr. Eads stated that the request to defer costs is premature, but that the Companies may raise the issue at a later date when they can demonstrate costs. Staff Exh. TRE-D at 20. In the Staff brief, Staff argued that the Commission should reject the Companies Security Rider proposal because it lacks sufficient detail to support it. Staff argued that even if the Companies reasonably believe they will incur increased investment and costs to implement security measures, the normal regulatory process should not be bypassed. Citing Hope Gas, Inc., dba Dominion Hope, Case No. 08-1783-6-42T, Commission Order November 20, 2009 at 5. Staff argued that if the Companies receive notice of upcoming regulations related to security, they are free to once again propose a security rider and would likely be better able to describe the magnitude of the costs associated with compliance. Staff Init. Br. at 59-60.

The Commission is aware of the increased security dangers presented in the modern world, particularly to the electric utility system. We know that extraordinary steps will become necessary (and may become common), but the Commission concludes that in the absence of concrete plans to implement specific security measures, projected costs, or new regulatory requirements, the proposal of the Companies to implement a Security Rider is premature.

E. Economic Development Rider

The Companies proposed the addition of an Economic Development Rider with this case filing. CRP-D at 12. Staff and WVEUG took issue with the lack of specificity in the Companies' proposal. In Mr. Patton's rebuttal testimony, he withdrew the Companies' request for the Economic Development Rider in this case. Companies Exh. CRP-R at 7.

TARIFF TERMS AND CONDITIONS

Electric Rules Personal Contact Requirement

162. The Commission should balance the interests of the customers with the safety of the Companies employees.

163. The majority of the Companies' requests regarding termination rules are appropriate for consideration in Case No. 15-0469-E-G-GI.

164. In view of the escalating concerns expressed by the Companies and their employees about customer aggression, employees of the Companies should not be required to make premises visits to customers that the Companies have documented to have 1) been verbally or physically aggressive/abusive to employees or utility facilities, 2) threatened to set loose vicious animals, or 3) brandished or made reference to weapons. The Companies have labeled these customers as C1 or CU customers.

165. Although Case No. 15-0469-E-G-GI is the appropriate case in which to consider permanent amendments to the Electric Rules applicable to terminations, it is reasonable in this case to grant the Companies a blanket waiver of personal contact with respect to C1 and CU customers on an interim basis until the conclusion of Case No. 15-0469-E-G-GI, or a subsequent rulemaking.

Tariff Terms and Conditions of Service

166. To ensure adequate public notice, the Companies should pursue the requested amendments relating to retention of security deposits; discontinuing the offer to waive the deposit requirement when a new customer enters into the Checkless Payment Plan; implementing charges to provide two or more estimates of the cost to relocate facilities; increased costs for installation of underground service; changes in responsibility for securing right-of-way easements and permits for residential extensions; changes in responsibility for right-of-way clearing costs associated with residential extensions; implementing a customer investigation charge; amending the returned check charge; increasing the reconnection charge; new provisions regarding customers' use of energy; an average monthly billing plan; eliminating the special reconnect option; and adding provisions for credit card bill payments, by filing a petition to amend their tariffs.

167. The future filing should be docketed as a "T" case.

ORDER

IT IS, THEREFORE, ORDERED that the Commission authorizes an overall increase in rates of $123.5 million as set out in the cost of service calculation, attached and incorporated herein as Appendix A, which Appendix A is hereby established as the cost of service and revenue requirement approved in these proceedings for APCo/WPCo for providing electric utility service to its customers in West Virginia.

IT IS FURTHER ORDERED that the overall increase to be in effect after the phase-in described herein consists of an increase in base rates of $78.986 million or 5.76 percent, annually as set out in the authorized base rate allocation attached hereto and incorporated herein as Appendix C.

IT IS FURTHER ORDERED that in addition to the base rate increase shown in Appendix C (less $25 million for the residential class phase-in discussed herein), the Commission authorizes the Companies to implement a VMP Surcharge that initially produces an additional $44.472 million, or 3.24 percent, annually.

IT IS FURTHER ORDERED that the Companies shall file a formal petition for annual review and true-up of the VMP surcharge on or before the first business day of March 2016, and for each year thereafter, until further order of the Commission.

IT IS FURTHER ORDERED that the VMP surcharge review filing true-ups will be determined using the (i) RoE, (ii) federal and state income tax rates, (iii) tariff allocations and (iv) new depreciation rates approved in this Order until such time as the Commission issues a future order changing those cost of service elements.

IT IS FURTHER ORDERED that no later than ten days from the date of this Order, the Companies must prepare and file with the Commission revised tariff schedules that reflect (i) the increase to base rates by tariff classification as shown on Appendix C (less $25 million for the residential class) and consistent with the Commission decisions contained in section VIII. Rate Design of this Order and (ii) the VMP Surcharge in accordance with the Commission decision discussed in section VII.A. Ratemaking Mechanisms of this Order.

IT IS FURTHER ORDERED that the costs associated with the Dresden Plant and the Amos Unit 1 scrubber that are currently recovered through the Construction Surcharge on APCo Tariff Sheet No. 27 are moved into the base rates approved in this case and Tariff Sheet No. 27 is eliminated.

IT IS FURTHER ORDERED that the Companies request to eliminate the personal contact requirement of Electric Rule 4.8.a.1 is denied and should be taken up as part of the review of Electric Rules in Case No. 15-0469-E-G-GI; provided, however, the Commission grants the Companies a blanket waiver of personal contact with respect to C1 and CU customers, on an interim basis, until the conclusion of Case No. 15-0469-E-G-GI.

IT IS FURTHER ORDERED that the Companies should pursue tariff changes related to: retaining security deposits; discontinuing the offer to waive the deposit requirement when a new customer enters into the Checkless Payment Plan; implementing charges to provide two or more estimates of the cost to relocate facilities; increasing costs for installation of underground service; changing responsibility for securing right-of-way easements and permits for residential extensions; changing responsibility for right-of-way clearing costs associated with residential extensions; implementing a customer investigation charge; amending the returned check charge; increasing the reconnection charge; adding provisions regarding customers' use of energy; providing for an average monthly billing plan; eliminating the special reconnect option; and adding provisions for credit card bill payments by filing a petition to amend their tariffs. If the Companies make such filing it shall be docketed as a "T" case.

IT IS FURTHER ORDERED that on or before 180 days after the date of this Order, the Companies shall make a closed entry filing in this case stating the number of linemen that have been hired and that have left employment after the date of this Order, and the status of the number of lineman. If the Companies have not hired the twenty additional linemen within 180 days, the Companies shall explain their efforts to do so and provide the expected date each of those additional positions will be filled.

IT IS FURTHER ORDERED that the Companies shall modify the depreciation accounting for the Disposition Plants after retirement. This modification will require the Companies to keep sufficient records to create subaccounts to Account 182 in order to identify the extraordinary losses due to retirement of the undepreciated plant values.

IT IS FURTHER ORDERED that on entry of this Order this case shall be removed from the Commission's docket of open cases.

IT IS FURTHER ORDERED that the Executive Secretary of the Commission serve a copy of this Order by electronic service on all parties of record who have filed an e-service agreement, and by United States First Class Mail on all parties of record who have not filed an e-service agreement, and on Commission Staff by hand delivery.

A True Copy, Teste,

Ingrid Ferrell

Ingrid Ferrell
Executive Secretary

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