Exhibit No.:	
Issue:	*Regulatory Lag & Jurisdictional Allocation Factors*
Witness:	*Cary G. Featherstone*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Rebuttal Testimony*
Case No.:	*ER-2014-0370*
Date Testimony Prepared:	*May 7, 2015*

MISSOURI PUBLIC SERVICE COMMISSION

REGULATORY REVIEW DIVISION

UTILITY SERVICES - AUDITING

REBUTTAL TESTIMONY

OF

CARY G. FEATHERSTONE

KANSAS CITY POWER & LIGHT COMPANY

CASE NO. ER-2014-0370

Jefferson City, Missouri
May 7, 2015

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

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REBUTTAL TESTIMONY

OF

CARY G. FEATHERSTONE

KANSAS CITY POWER & LIGHT COMPANY

CASE NO. ER-2014-0370

Q. Please state your name and business address.

A. Cary G. Featherstone, Fletcher Daniels State Office Building, 615 East 13th Street, Kansas City, Missouri.

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

A. I am a Regulatory Auditor with the Missouri Public Service Commission ("Commission").

Q. Are you the same Cary G. Featherstone who filed direct testimony in this proceeding?

A. Yes, I am. I filed direct testimony in this case on April 3, 2015, sponsoring Staff's revenue requirement cost of service report ("COS Report") for Kansas City Power & Light Company's ("KCPL" or "Company") rate case filed on October 30, 2014. I also provided testimony in the COS Report on various topics specifically identified in the report.

Q. What is the purpose of your rebuttal testimony?

A. I address the regulatory lag aspects of the direct testimony of the following KCPL witnesses:

Scott H. Heidtbrink, KCPL's Executive Vice President and Chief Operating Officer—direct testimony, pages 14 to 20;

Darrin R. Ives- KCPL's Vice President – Regulatory Affairs— direct testimony, pages 2 to 12; and, Tim M. Rush- KCPL's Director of Regulatory Affairs— direct testimony, pages 5 to 9.

Specifically, in his testimony Mr. Ives states that KCPL experiences regulatory lag because Missouri uses historical costs when setting rates (KCPL refers to this as the "regulatory model in Missouri"). Regarding this model, KCPL contends:

- "This model not only ignores cost increases that have occurred between the historical test year used and the date rates are effective..." (Ives direct, Page 4)
- "In certain cost of service categories, costs can vary significantly from year-to-year and when such costs are a material cost of service component they can have a dramatic impact to the Company as a result of regulatory lag." (Ives direct, page 5)
- "From a capital investment perspective, when a utility is in a substantial capital investment cycle, as is occurring at KCP&L and across the industry today, significant regulatory lag is produced." (Ives direct, page 5)
- "Another factor significantly contributing to regulatory lag for KCP&L is that the Company is experiencing little or no growth in its Missouri sales . . . " (Ives direct, page 6)
- In an environment where costs are increasing rapidly and billing determinants that drive revenues . . . " " . . . are flat to declining, the opportunity for utilities to earn a fair return is severely compromised by regulatory lag." (Rush direct, page 5)

KCPL's direct testimony contends current costs are increasing and it is in a cycle of making capital investments while at the same time KCPL is not experiencing sufficient customer load growth.[1]

KCPL's discussion on regulatory lag is specifically intended to support its requests for regulatory deferrals for certain costs structures. These are known as deferral mechanisms, or more commonly "trackers" or "tracking devices."

[1] Direct Testimony of Darrin R. Ives on Behalf of Kansas City Power & Light Company; page 4 - 6 Case No. ER-2014-0370.

My testimony will address the negative, unbalanced view of regulatory lag that KCPL presents and discuss how regulatory lag is also an important mechanism in ensuring efficiency and fair rates.

I also address the direct testimony of Company witness Ronald A. Klote on KCPL's use of the 12 coincident peak (CP) method of developing a demand allocation factor for assigning investment costs and expenses to the Missouri retail jurisdiction.

Q. Are other Staff members expanding on your testimony in these areas?

A. Yes. Staff witness Charles R. Hyneman is testifying in rebuttal on regulatory lag. Staff witness Mark L. Oligschlaeger is providing an overview on the subject of the deferral mechanisms proposed by KCPL, the trackers, in his testimony. Staff witnesses Karen Lyons of the Commission's Auditing Unit, Daniel I. Beck of Energy Engineering Analysis, and Randy S. Gross of Energy Resource Analysis are providing rebuttal testimony on the three deferral mechanisms requested by the Company relating to cyber security, property taxes and vegetation management:

Staff Witness	**Deferral Area**
Mark L. Oligschlaeger	Overview
Karen Lyons	Cyber Security Property Taxes Vegetation Management
Daniel I. Beck	Vegetation Management
Randy S. Gross	Cyber Security

EXECUTIVE SUMMARY

Q. Would you please summarize your rebuttal testimony?

A. KCPL claims it is experiencing a level of regulatory lag in its operations in the recent past. However, KCPL, in the past ten years, dramatically increased its construction cycle, directly resulting in an increased cost of service. Other cost increases KCPL has faced include fuel and freight cost increases and higher maintenance costs at its power plants, most significantly at the Wolf Creek nuclear plant. The depressed economy of the last ten years and the success of conservation efforts contributed to limited growth in revenues, as well. Still, Staff does not agree the reason for KCPL's difficulties in earning its authorized returns lies solely on what it calls the regulatory model used in Missouri or that the solution is the exclusive responsibility of KCPL's customers. Rather KCPL should take greater responsibility to manage its limited resources, particularly in the administrative and general expense category. Shifting the risk of cost increases solely to customers through the many tracking mechanisms sought in this case is not an appropriate solution to KCPL's earnings shortfall.

KCPL is coming out of its ten year construction cycle with the completion of the environmental upgrades at the La Cygne generating station and infrastructure replacements at Wolf Creek Nuclear Generating Station. While there are always construction projects for a utility the size of KCPL, the significant increases in construction costs experienced by KCPL will decline as this current construction cycle wraps up, putting less pressure on earnings. Furthermore, KCPL has mechanisms in place to capture declines in sales and usage through conservation with its Missouri Energy Efficiency Investment Act (MEEIA) surcharge that the Commission approved in June of 2014 and the Company implemented starting July 2014.

The Commission already allows KCPL to fully recover costs associated with energy efficiencies from customers and declines in usage through lost revenues. Finally, KCPL has the highest administrative and general ("A&G") costs of the Missouri electric utilities. Those high costs contribute to KCPL's difficulties in earning its authorized returns. With these considerations in mind, the Commission should reject KCPL's proposals to minimize the negative impacts of regulatory lag on earnings.

REGULATORY LAG

Q. What is regulatory lag?

A. Generally, regulatory lag is the period of time between when an increase or decrease in expenses or revenues and investment costs is incurred and when they are recognized in rates. Regulatory lag can benefit the utility or can work to its detriment. When costs decline to levels below what is included in rates, as they often do, the utility enjoys the benefits of those savings until rates change. An example of beneficial regulatory lag is when employee levels are reduced, such is the case since the last KCPL rate case in 2013, Case No. ER-2012-0174. After the cost cut-off date agreed to in that case, KCPL reduced the number of employees from the levels included in the payroll expense calculation as of the end of the true-up period of August 31, 2102—the level included in rates. Each employee reduction below the level included in rates represents a cost savings to KCPL until rates are changed in this case. Those reduced employee costs offset increases in costs in other cost categories. When costs increase over levels built into rates, the utility absorbs those costs to the extent that other cost declines or revenue growth will not make up the differences. This situation is a detriment to the utility as earnings would decline. An example of adverse regulatory lag is when transmission costs increase over levels included in rates. KCPL has also experienced this type of negative regulatory lag. KCPL absorbs those transmission cost increases unless it can offset them with other cost decreases. These cost increases will continue until rates change unless decreases in costs or increases in revenues do not materialize. When costs increase to a materially greater level than other cost declines can offset, then utility companies file for rate increases.

Q. What is KCPL's position concerning regulatory lag in this case?

A. KCPL believes it has not had opportunity to earn its authorized return on equity because of what is referred to as "regulatory lag." Mr. Ives states at page 4 of his direct testimony:

> From a cost of service prospective, the process utilizes historical test year costs, trued-up for known and measurable changes. Regardless of the true-up period, this model results in rates being set on historical costs that were incurred in a range anywhere from 5 months to 27 months prior to the date rates are effective. This model not only ignores cost increases that have occurred between the historical test year used and the date rates are effective, it also ignores the fact that in a rising cost environment, costs to serve our customers continue to increase from the date rates are effective, with little ability to synchronize recovery with costs incurred other than to initiate another expensive and time-consuming rate case.

Q. KCPL witness Ives asserts that Missouri's use of historical information for setting utility rates results in "regulatory lag" that harms KCPL.[2] Do you agree?

A. No. I described in my direct testimony the various methods used to develop rates in a forward-going way. While in Missouri actual historical costs are used as the starting point for determining what a utility's future cost to serve its retail customers is, those historical costs are often normalized and annualized to reflect the most current information

[2] Direct Testimony of Darrin R. Ives on Behalf of Kansas City Power & Light Company, pg. 4 Case No. ER-2014-0370.

available. Adjustments for known and measurable changes are made to the test year (in this case the 12 months ending March 31, 2014); updated to a point in time closer to when new rates take effect (here updated through December 31,2014); and trued-up to an even later point in time, in this case May 31, 2015.

Q. KCPL believes it is unable to earn its authorized return because rates are developed using historical cost information incurred as far as 27 months from the date new rates take effect, according to Mr. Ives. Does Staff agree with this assessment?

A. No. While there is some lag from when costs increases are incurred and when they are recognized in rates, in this case that "lag" is only four months from the May 31, 2015 true-up to the late September date for the change in rates. Just because historical cost information is used does not mean the costs are dated as far back as two full years or 27 months as Mr. Ives asserts on page 4 of his direct testimony.

The purpose of a true-up is to bring costs as close to the time rates are in effect as possible. In fact, both KCPL and Staff use a variety of methods to bring revenues, costs and rate base investment to levels representative of the time when new rates will be in effect. For example, when the true-up is completed, fuel costs and payroll costs will be included in rates at the May 31, 2015 levels. Those costs levels are not known at the time of this rebuttal filing, but they will be at the time of the true-up date. Current plant and depreciation reserve levels will also be reflected in rates at the May 31, 2015 true-up date.

Q. How are adjustments made to reflect changes for the true-up?

A. Various techniques are used to make the adjustments in a rate case. For example, if the costs vary year-to-year a multi-year average may be used or, if they are increasing or decreasing year-after-year, end of period costs are used.

Q. Did Staff use any averages to normalize the costs used for developing its cost of service and resulting revenue requirement recommendation for KCPL?

A. Yes. In its fuel model, Staff used a multi-year average for forced outage rates for KCPL's generating units. Those averages may be over a five, six or even a seven-year period of time and smooth out fluctuations of outages occurring at power plants, in particular the scheduled outages for extended periods to accomplish major overhaul and repair work. These averages use historical information to represent a typical annual period of power plant production with on-going operations. Both KCPL and Staff employed averages in their rate increase models. Averages capture unusual or abnormal events and reflect on-going normal levels of operation. This means KCPL also used historical data in their own models.

Revenues, like costs, are normalized and annualized to reflect the most current levels of customers at the current rates to capture the most current revenues. The true-up process captures any reductions, as well as increases, in revenues. Both KCPL and Staff used a 30-year weather normalized average to determine the proper adjustment for weather sensitive customers.

Q. Are annualized costs historical costs?

A. No, but they are based on historical information. While actual cost inputs are used as the basis to develop the levels of costs included in rates, the annualized levels of costs are by no means historical costs. For example, Staff used January 1, 2015 fuel prices to reflect both increases and decreases based on existing fuel and freight contracts. These prices are actual contracted prices and do not in any way relate to historical costs. The January 1, 2015 prices will be updated for the May 31, 2015 contracted prices in the true-up. The May 31, 2015 fuel and freight contract prices will produce an annualized fuel cost level that are not historical test year results, but rather the actual cost basis going forward. This annualized fuel costs will have no relationship to test year results, nor calendar year 2014 results. The May 31, 2015 contract fuel and freight prices are also used in the fuel model with many other inputs to determine the needed fuel costs consistent with the annualized and normalized level net system input load requirements of KCPL's Missouri jurisdictional operations. These inputs use a variety of techniques to determine the amount of fuel costs included in rates expected to be incurred on a forward going basis—not looking backward in time. In the true-up, KCPL and Staff will use the same May 31, 2015 fuel prices to determine the annualized fuel amount which rates will be based.

Payroll costs are determined the same way as fuel costs by using actual cost information, such as actual employee levels and the most current wage rates, to determine annualized payroll costs, in this case through the May 31, 2015 true-up. Payroll costs calculations, then, do not relate to historical cost levels even though the basis for the payroll calculations is actual cost information. The payroll costs annualized in rate case are forward looking costs—not historical costs. The annualized level of payroll reflects payroll costs expected to be representative of the period when new rates take effect.

Q. What is the reason for any costs being left at test year levels during the ratemaking process?

A. While the majority of costs such as fuel and purchased power, payroll, property taxes are included in the cost of service calculation at current levels, under certain circumstances, test year levels are deemed appropriate and no adjustments are proposed. This means when a cost is left at test year level, it is believed those costs represent the level necessary for those expenditures going forward. Just because a cost is based on historical actual cost does not mean those costs are "dated" or somehow not reflective of on-going costs and cannot be used to set rates.

Q. Based on the usage of actual cost information, is it fair to say that rate cases ignore "cost increases that have occurred between the historical test year used and the date rates are effective . . . " as Mr. Ives claims?[3]

A. No. As described above, annualizations are based on actual costs and the most current cost trend information, having little to do with the test year results. The discussion on payroll and fuel costs are examples of cost methodology unrelated to test year. Test year results serve as a starting point, with adjustments made to bring the major cost components to annualized levels. The actual operating results for the periods after the test year are unrelated to either KCPL's or Staff's proposed levels that are actually included in the cost of service recommendations. For example, the recommended annualized level for payroll is not the amount for the 12 months ending update period of December 31, 2014 or the true-up of May 31, 2015. The annualized payroll level as of May 31, 2015 reflects the most current wages paid to the most current number of employees as of that point in time and is different than the 12 month ending payroll amounts. The fuel annualization, as well as the other annualized and normalized levels included in the cost of service calculations made in the rate case, is not related to test year or any other 12 month ending period.

The Missouri model, as KCPL refers to this cost of service calculation, in no way ignores either cost increases or decreases " . . . that have occurred between the historical test year used and the date rates are effective . . . " as Mr. Ives contends.[4] Those cost increases

[3] Direct Testimony of Darrin R. Ives on Behalf of Kansas City Power & Light Company, pg. 4. Case No. ER-2014-0370.
[4] Direct Testimony of Darrin R. Ives on Behalf of Kansas City Power & Light Company, pg 4. Case No. ER-2014-0370.

and decreases occurring through May 31, 2015 are the basis used to develop revenue increases. To the extent KCPL believes the cost increases are not timely reflected in rates, the rate case could be filed sooner to capture the costs KCPL believes are being ignored.

Q. Did KCPL have to consider the timing for when to file this rate request?

A. Yes. Because of the completion of the construction projects at Wolf Creek and La Cygne station, this rate case had to be filed to consider the in-service dates of those generating units. However, to the extent other costs were increasing, KCPL could have filed another rate case prior to this one to recover the increases in costs identified in testimony for transmission, fuel and property taxes. For instance, if fuel prices are expected to increase materially, KCPL can plan the timing of the case in the same way it has timed this case around the construction project completion dates.

Q. Do you agree with Mr. Ives's that what he refers to as the Missouri model ". . . ignores the fact that in a rising cost environment, costs to serve our customers continue to increase from the date rates are effective, with little ability to synchronize recovery with costs incurred other than to initiate another expensive and time-consuming rate case?"[5]

A. No. KCPL, like any other large utility, has many opportunities to manage its costs. KCPL negotiates labor contracts that determine the salaries and wages paid to its employees and decides the employee benefits to offer; the Company negotiates fuel supply and transportation agreements; it determines the most efficient generation mix to meet customer load requirements; along with deciding a host of many other cost considerations to operate its electric system. If KCPL believes its costs are increasing sufficiently to justify a rate increase, then one option is to file a rate case to meet its operational commitments. Rate

[5] Direct Testimony of Darrin R. Ives on Behalf of Kansas City Power & Light Company, pg. 4, Case No. ER-2014-0370.

increase requests are one of many options the Company has to meet its operational commitments. For example, KCPL can contain costs and enhance revenues through growth of the system to offset rising costs.

Q. Does Mr. Ives suggest in his direct testimony that Missouri regulation for KCPL has not worked well for its Missouri operations, specifically referencing pages 4 through 7 and pages 9 and 11?

A. Yes. Mr. Ives states at page 11 ". . . the current regulatory model in Missouri has not kept pace with the changing operating environment faced by KCP&L and the other Missouri utilities." He further criticizes the Missouri regulatory climate referencing a January 2014 publication that Missouri " . . . is currently ranked in the bottom quarter of 53 regulatory jurisdictions as assessed by Standard and Poor's . . . " Mr. Ives also references KCPL's rate of return witness Hevert's view that ". . . given Missouri's ranking, the financial community appears to attribute higher regulatory risk to KCP&L than to other utilities." Yet, Mr. Hevert is recommending the same 10.3% return on equity in KCPL's pending Kansas rate case as he is recommending in Missouri, despite his belief Missouri has a higher risk due to its poor regulatory climate.

Q. Has KCPL received benefits that suggest that it has a good regulatory climate to operate in, contrary to Mr. Ives' view?

A. Yes. Both KCPL, and its affiliate, KCP&L Greater Missouri Operations ("GMO") have received recent upgrades to its credit ratings. The minutes to the Great Plains, KCPL and GMO's Board of Directors meeting and the minutes to the Audit Committee of the Boards of Great Plains, KCPL, and GMO meetings identified reasons for the credit rating upgrades by the analysts. Mr. Kevin E. Bryant, then Great Plains and KCPL's Vice

President- Investor Relations and Strategic Planning and Treasurer made a presentation to the Board of Directors to each of the Great Plains companies:

> Mr. Bryant discussed Moody's recent one notch credit rating upgrades of Great Plains Energy, KCP&L and KCP&L Greater Missouri Operations Company ("GMO"). **Moody's cited a constructive regulatory environment that continues to provide adequate cost recovery as one of their rationales for the upgrade.**
> [Source: Great Plains, KCPL and GMO February 10-11, 2014 Board Minutes; emphasis added]

Mr. Bryant also addressed the constructive regulatory nature of the Missouri Commission at the May 5, 2014 Audit Committee of the Great Plains Board identified in the minutes to that meeting:

> Mr. Bryant indicated that in January 2014, Moody's upgraded Great Plains Energy, KCP&L and KCP&L Greater Missouri Operations ("GMO") by one notch, citing constructive regulatory relationships in Missouri and Kansas. In May 2014, Standard & Poor's Rating Services ("S&P") also raised the credit ratings of Great Plains Energy, KCP&L and GMO by one notch **due to continuation of the regulated utility business model with supportive cost recovery**.
> [Source: Great Plains, KCPL and GMO May 5, 2014 Board Minutes of the Audit Committee; emphasis added]

In the Great Plains Energy Incorporated ("Great Plains") 2014 Annual Report to Shareholders[6] it was stated that ". . . efforts to strengthen key-credit metrics and further solidity our credit profile were validated by ratings upgrades by both Standard and Poor's and Moody's Investor Service. These ratings reduce borrowing costs, which also help us manage customer rates."

Q. Was this first time KCPL received positive support from the investment community?

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[6] 2014 Great Plains Energy Annual Report, pg. 2, located at *http://phx.corporate-ir.net/phoenix.zhtml?c=96211&p=irol-reportsannual*.

A. No. During the time of the construction of Iatan 2, KCPL received positive support for novel way in which it achieved enhanced cash flows and positive credit metrics. In Case No. EO-2005-0329, the Commission approved KCPL's Alternative Regulatory Plan ("Regulatory Plan") that allowed it to seek up to four rate cases during the period of 2006 to 2010 to address variety of matters, the most significant was the construction of Iatan 2 and an environmental upgrade to La Cygne 1, wind generation and various demand side management programs. KCPL was allowed to collect in rates during the course of those four rate cases an amount that accumulated to $183.4 million enhancement to cash flow. These amounts were referred to as Additional Amortizations and they were specifically identified in Staff's Cost of Service Report at page 173.

The investment community looked upon the Additional Amortizations favorably and viewed the Commission as supportive of KCPL's construction projects.

Q. Has KCPL's parent company, Great Plains Energy, experienced benefits from the operations of KCPL and GMO?

A. Yes. Great Plains also received upgrades in its credit ratings. Great Plains authorized increases in dividends paid to its shareholders, four times in five years, even with the alleged poor rates on return and skyrocketing costs claimed in KCPL's witness testimony. The following represents the dividends paid to Great Plains shareholders in 2009 through 2014[7]:

continued on next page

[7] 2014, 2013, 2012, 2011, 2010, 2009 Great Plains Energy Annual Report, located at *http://phx.corporate-ir.net/phoenix.zhtml?c=96211&p=irol-reportsannual*.

Common Stock Dividend

QUARTER	2014	2013	2012	2011	2010	2009
Total	$0.935	$0.8825	$0.855	$0.835	$0.83	$0.83

Great Plains total shareholder return, a key financial indicator to Great Plains, was 21% in 2014 and over the last two years, a 51% return.[8]

Q. What is the relationship of Great Plains' Missouri operations to its other jurisdictions?

A. Between KCPL and GMO combined, Great Plains' Missouri operations comprise approximately 71% of total Great Plains based on retail revenues over the last three years with Kansas and the FERC jurisdiction comprising the remaining 29%. Over the last three years based on retail revenues, KCPL's Missouri's operations comprise approximately 55%, compared to 45% in Kansas[9]. With sufficient total shareholder returns experienced by Great Plains the last two years, KCPL's Missouri operations and GMO contributed the vast majority of this return since both entities make up 71% of Great Plains retail revenues.

Q. Mr. Ives indicated that KCPL's Missouri's revenue growth is flat.[10] Is this expected to continue?

A. KCPL expects its service territory to grow. At the Great Plains November 4, 2014 Board meeting, KCPL discussed its operating plan for 2015 and 2016:

[8] 2014 Great Plains Energy Annual Report, pg. 2, located at http://phx.corporate-ir.net/phoenix.zhtml?c=96211&p=irol-reportsannual.
[9] 2014 Great Plains Shareholder Report – pages 7 and 9.
[10] Direct Testimony of Darrin R. Ives on Behalf of Kansas Power & Light Company, pg. 6 Case No. ER-2014-0370.

** ____ **

[Source: November 4, 2014 Minutes of the Great Plains Board of Directors; emphasis added]

KCPL service area is experiencing some improvement in the economy with the second consecutive year of positive demand growth as noted in the 2014 Shareholders Report .[11]

Q. Mr. Ives indicates that if the Commission allows the use of “alternative regulatory mechanisms . . .” it will reduce the risk of KCPL and therefore, will result in access to low-cost capital.[12] Has KCPL had trouble accessing low cost capital?

A. Not to my knowledge. KCPL accessed capital markets to meet its substantial financing needs for funding of the construction projects for Iatan 2 and all the environmental upgrades at Iatan 1 and La Cygne 1 and 2. In fact, KCPL significantly reduced its debt costs since 2011 during the time it operated in the supposedly less than adequate regulatory environment in Missouri. The table below identifies the reduction in interest expense resulting from the reduction in financing costs:

continued on next page

[11] 2014 Great Plains Energy Annual Report, pg. 1, located at http://phx.corporate-ir.net/phoenix.zhtml?c=96211&p=irol-reportsannual.
[12] Direct Testimony of Darrin R. Ives on Behalf of Kansas Power and Light Company, pg. 12 Case No. ER-2014-0370.

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Type of Debt	**Amount of Debt-original interest rate**	**Maturing**	**Refinanced/ Remarketed & interest rate**	**Annual Interest Savings**	**Savings since 2013 to Sept 2015—assume two full years**	**KCPL Missouri Share-approximate 53%**
Series 1992 EIRR bonds	$31 million at 5.25%	2017	2013-remarketed at 1.25%	$1,240,000		
Series 1993A bonds	$40 million at 5.25%	2023	2013-remarketed at 2.95%	920,000		
Series 1993B bonds	$39.5 million at 5.00%	2023	2013-remarketed at 2.95%	809,750		
Series 2007B bonds	$73.25 million at 5.375%	2035	2013-remarketed at 0.753%	3,385,615		
Series 2007A bonds	$73.25 million at 5% and 5.125%	2035	2013-remarketed at 0.753%	3,189,990		
Series 2008 State EIERA	$23.4 million at 4.90%	2038	2013-remarketed at 2.875%	473,850		
Interest Costs Savings				**$10,019,205**	**$20,038,410**	**$10,620,357**
Senior Note	$150 million at 6.50%		2011-refinanced at 5.30%	$1,800,000		
TOTAL				**$11,819,205**		

Source: KCPL's response to MECG Data Request Question 11-11— Michael Brosch direct- Schedule MLB-5

continued on next page

On-going future annual savings of $1.6 million (page 12, line 22) refinancing of interest rates made up of:

Type of Debt	Amount of Debt-original interest rate	Maturing	Refinanced/ Remarketed & interest rate	Annual Interest Savings	Savings since 2015 to next effective date—assume two full years	KCPL Missouri Share-approximate 53%
Series 2005 La Cygne bonds	$21.94 million at 4.65%	2035	Sept 1, 2015-remarketed at 3.50%	$252,310		
Series 2005 Burlington bonds	$50 million at 4.65%	2035	Sept 1, 2015-remarketed at 3.50%	575,000		
Series 1992 State EIERA bonds & 2007 Senior Note	$31 million at 1.25% and $250 million at 5.85%	June 2017	Q2 2017-remarketed at 5.05%	822,000		
TOTAL				**$1,649,310**	**$3,298,620**	**$1,748,269**

Source: KCPL's response to MECG Data Request Question 11-12— Michael Brosch direct- Schedule MLB-5

The identified cost savings assumes KCPL retained the interest cost reductions for two full years from the time the debt costs were refinanced to the change in its electric rates resulting from this case, September 30, 2015. Some of the refinancing cost reductions occurred early in 2013 giving KCPL well over two years of cost savings between rate cases.

Construction Projects

Q. What is the status of KCPL's construction projects?

A. With the completion of the La Cygne environmental upgrades and Wolf Creek's replacement of its water system, KCPL's current construction cycle of over ten years nears an end. KCPL's construction expenditures are expected to decrease as this construction cycle wraps up. Great Plains stated the following in its 2014 Annual Report:

> By the end of 2015, all of our large base-load coal-fired power plants will have state-of-the-art emission-reduction equipment installed and will comply with existing environmental rules.
> [Source: 2014 Annual Shareholder Report, page 1]

Q. What impact will the completion of the construction cycle have on KCPL?

A. It should reduce the need for future financing and reduce costs as construction expenditures decrease. The completion of the construction projects should reduce the pressure on earnings from reduced financing costs and will enhance cash flow from the inclusion of depreciation on the newly installed plant.

Cost Savings

Q. Does Mr. Ives identify the reasons he believes caused KCPL not to earn its authorized return?

A. Yes. At page 7 of his direct testimony, Mr. Ives provides several items he terms "material" as the cause for the earnings shortfall in Missouri. Mr. Ives indicates KCPL has not earned its authorized return " . . . since new rates became effective in early 2013 because actual experience for certain cost items was materially higher than the amounts used for such items in the rate setting process in Missouri." Mr. Ives states the reasons impacting KCPL earnings in 2013 are:

- Retail revenues were down nearly $14.5 million and wholesale sales were down $7.9 million;
- Fuel and purchased power costs were up $13.7 million;
- Transmission costs were up $6.9 million
- Non-Fuel Operations and Maintenance expenses were up $6.0 million;
- Depreciation expense was up $3.3 million;
- General taxes (Property) were up $3.9 million; and
- Rate base increased $78.2 million

Q. Are there other cost impacts that should be considered in KCPL's analysis?

A. Yes. Several cost reductions occurred since the last rate case, allowing KCPL to enjoy the benefits of those savings until rates change in this case.

1. As noted above, KCPL has benefited from interest expense savings through refinancing its long-term debt. On a Missouri basis, KCPL reduced financing costs by $10.6 million over two years – over $5.3 million per year since interest rates changed in January 2013. KCPL's Missouri customer have not received the benefit of those financing savings for over two years and won't until rates change in September 2015. (see above discussion on refinancing savings)

2. In KCPL's last rate case (ER-2012-0174), the Commission ordered the use of Great Plains' capital structure which contained substantially higher equity and lower debt than the actual capital structure for 2013.

3. Since the last rate case, KCPL reduced the number of employees by at least 140 and as many as 160 employees—the latter referenced by Mr. Ives at the first local public hearing (held April 23, 2015). This was the second time between rate cases KCPL significantly reduced payroll costs through employee reductions having done so after rates were determined in the 2010 rate case.

4. KCPL retained payroll savings between rate cases relating to incentive compensation paid to its union employees.

5. KCPL experienced a reduction in nuclear storage fees paid to the Department of Energy (DOE fees).

6. KCPL retained cost savings from amortizations that expired during various times since the last rate case.

7. KCPL also had other cost reductions in its cost of service from the time of the last case for increases in accumulated deferred income taxes and reduction in depreciation expense for plant retirements.

<u>Great Plains Capital Structure</u>

Q. How did KCPL obtain cost savings relating to Great Plains capital structure?

A. In KCPL's last rate case, the Commission ordered the use of Great Plains actual consolidated capital structure as of August 31, 2012, the date of true-up in that case. The actual capital structure used to set rates in Case No. ER-2012-0174, effective January 26, 2013, consisted of common equity of 52.56%, preferred stock of 0.60% and long-term debt of 46.84%. However, the 2013 and 2014 actual Great Plains capital structure resulted in a higher debt ratio which is less costly. KCPL collected higher electric rates than what would have resulted if the higher debt and lower equity ratio would have been used. Typically, debt is the less costly form of financing because the interest from the debt cost is tax deductible while equity is not deductible. In other words, there was and continues to be a cost savings to KCPL, which will continue until rates are changed, by virtue of the lower equity ratio of Great Plains for both 2014 and 2015. The table below identifies the actual 2013 and 2014 Great Plains capital structure compared to the Commission ordered capital structure used to determine rates in the last case:

Great Plains Energy	**2014 Actual Capital Structure Percentage**	**Total Equity**	**2013 Actual Capital Structure Percentage**	**Total Equity**	**Commission Ordered Capital Structure in Case ER-2012-0174**	**Total Equity**
Common Equity	50.42%		49.43%		52.56%	
Preferred	0.55%	50.96%	0.55%	49.98%	0.600%	53.16%
Long-term Debt	49.04%		50.02%		46.84%	
Total	100%		100%		100%	

Source: Great Plains 2013 10-K, page 53
Source: Commission Order- page 26 and 2014 10-K, page 51

The work sheet is attached as Rebuttal Schedule CGF-R1.

Q. What is the capital structure recommended in this case?

A. Staff recommends a capital structure based on a 50.31% for common equity, a 0.55% preferred stock and 49.14% long-term debt. This recommended level is still a lower cost capital structure than what was used to determine rates in KCPL's 2012 rate case. KCPL recognized immediate cost savings from reduction in the capital structure from the time of the last rate case right up to the effective date of rates in this case, a period of over 2½ years. The capital structure with reduced equity ratio is consistent with the capital structure currently being recommended by Staff in the 2015 rate case.

Payroll Cost Savings

Q. Have employee reductions resulted in cost savings?

A. KCPL's employee levels have been declining over the last several years. The table below identifies the total employees compared to the dates of the individual true-ups used in the last two rate cases forming the basis of payroll costs included in rates:

Year	KCPL Employees	Date of True-up in the 2010 and 2012 Rate Cases	Effective Date of Rates
2008	3,259		
2009	3,197		
2010	**3,188**	December 31, 2010 true-up ER-2010-0355	May 4, 2011 ER-2010-0355
2011	3,053 downsizing		
2012	**3,090**	August 31, 2012 true-up ER-2012-0174	January 26, 2013 ER-2012-0174
2013	2,964 downsizing		
2014	2,935		

Source: Great Plains and KCPL Annual Form 10Ks for period 2008 to 2014

KCPL had higher payroll costs included in rates than what was actually incurred during the time those rates were effective. KCPL benefited from these savings during the time rates were in effect for the last two rate cases.

The payroll savings resulting from employee reductions on total KCPL basis is $34.9 million, or approximately $18.6 million on a Missouri basis through the effective date of rates in this case of September 29, 2015. The table below identifies the approximate savings at December 31, 2014, update period, May 31, 2015, the true-up date and September 29, 2015, the effective date of rates:

Begin Date of Savings	**End Date of Savings**	**Total Savings**	**Benefit & Tax Factor**	**Total Savings**	**Total KCPL Savings**	**Missouri Jurisdictional Savings**
September 1, 2012	December 31, 2014	$22.0 million	0.6	$35.2 million	$23.1 million	**$12.3 million**
September 1, 2012	May 31, 2015	$28.2 million	0.6	$45.1 million	$29.7 million	**$15.8 million**
September 1, 2012	September 29, 2015	$33.2 million	0.6	$53.1 million	$34.9 million	**$18.6 million**

The work sheet is attached as Rebuttal Schedule CGF-R2.

Q. Have KCPL's customers benefited from the reduced employee levels?

A. No. Customers will not benefit from these employee reductions until rates change in this case, expected around September 29, 2015.

Q. Has KCPL experienced other payroll related cost savings since the last rate case?

A. Yes. KCPL retained savings between rate cases relating to incentive compensation paid to its union employees. Existing rates include those costs since they were included in the cost of service calculation performed in last rate case, Case No. ER-2012-0174. When KCPL discontinued that benefit in a subsequent labor agreement in March 2013, it recognized savings of $3.2 million benefit on a total KCPL basis, of which Missouri's share is $1.7 million, through the effective date of rates in this case of September 29, 2015.

The following table identifies the cost savings relating to the discontinued incentive compensation once paid to union employees at December 31, 2014, update period, May 31, 2015, the true-up date and September 29, 2015, the effective date of rates:

Begin Date of Savings	End Date of Savings	Total Savings	Total KCPL Savings	Missouri Jurisdictional
March 8, 2013	December 31, 2014	$3.5 million	$2.3 million	**$1.2 million**
March 8, 2013	May 31, 2015	$4.3 million	$2.8 million	**$1.5 million**
March 8, 2013	September 29, 2015	$4.9 million	$3.2 million	**$1.7 million**

The work sheet is attached as Rebuttal Schedule CGF-R3.

<u>Department of Energy—Nuclear Storage Fees</u>

Q. Are there other recent KCPL cost reductions not reflected in current rates?

A. Yes. The Department of Energy assessed fees for nuclear storage for the consumed fuel at Wolf Creek, paid by Wolf Creek's owners. Congress required the DOE to stop assessing those fees. The fees were based on the generation of electricity at Wolf Creek and were included in the fuel expense annualization in past rate cases. KCPL is collecting in current rates an amount to cover those DOE costs. On May 16, 2014, KCPL no longer was required to pay the DOE fees for operating Wolf Creek. However, the current rate structure still reflects the DOE fees. KCPL is collecting amounts for the DOE fees from its customers but does not make any payments to the federal government. KCPL retains the costs savings relating to these fees and will continue to do so until rates change.

Q. Is Staff proposing an adjustment in this case to pass the DOE savings to customers?

A. Yes. Staff recommends the amount KCPL over collected for the DOE fees be returned to customers over a five-year period. The savings are identified from the time the fees were no longer required to be paid through the effective date of rates, September 29, 2015, which is a total KCPL savings of $6.2 million, a Missouri basis of $3.5 million.

The following table identifies the cost savings relating to the DOE fees at December 31, 2014, update period, May 31, 2015, the true-up date and September 29, 2015, the effective date of rates:

Begin Date of Savings	**End Date of Savings**	**Total Savings**	**Missouri Jurisdictional**
May 16, 2014	December 31, 2014	$2.8 million	**$1.6 million**
May 16, 2014	May 31, 2015	$4.7 million	**$2.7 million**
May 16, 2014	September 29, 2015	$6.2 million	**$3.5 million**

The work sheet is attached as Rebuttal Schedule CGF-R4.

Q. Did Staff file an application with the Commission addressing the reduction in KCPL's costs for the DOE fees?

A. Yes. On October 9, 2014 Staff requested the Commission approve an Accounting Order to defer the cost savings for the DOE fees. This Accounting Order request was designated as Case No. EU-2015-0094, and specifically ask the Commission to order KCPL to record these cost reduction as a regulatory liability based on the annualized level included in rates for this cost as of January 26, 2013, the effective date in rates for Case No. ER-2012-0174.

Through a combined stipulation concerning another deferral request made by KCPL for continuation of construction accounting for La Cygne Station's environmental cost upgrades, identified as Case No. EU-2014-0255, the request to defer the cost savings for DOE fee reductions was to be treated as part of this rate case. Staff is recommending the cost savings be amortized back to customers as a reduction to fuel expense over a five-year period.

Expiring Amortizations

Q. Has KCPL retained any other savings since the rates were established in the last rate case?

A. Yes. KCPL retained cost savings from amortizations that expired during various times since the last rate case. Those amortizations represent a real savings to KCPL because it continues to recover in rates amounts for each of these amortizations, even though it no longer is charging to expense those amounts. In essence, KCPL receives a cash benefit- this is a positive cash flow with KCPL receiving the benefit to earnings. The following table represents the amount of expired amortizations and the calculated amounts as of December 31, 2014- the update period, at May 31, 2015- the true-up period and through September 2015- the time when rates will change from this case:

Regulatory Asset	End Date of Amortization	Annual Amortization	Overcollection at December 31, 2014	Overcollection at May 31, 2015	Overcollection at September 2015
2010 Rate Case Expense – Vintage 1	April 2014	$1,294,629	$863,086	$1,402,515	$1,834,058
Wolf Creek Refueling No. 16	August 2014	$314,116	$104,705	$235,587	$340,292
Economic Relief Pilot Program (ERPP)	April 2014	$85,642	$57,095	$92,779	$121,326
R&D Tax Credit Expenses	August 2014	$78,846	$26,282	$59,134	$85,416
Total Net		**$1,773,233**	**$1,051,168**	**$1,790,015**	**$2,381,092**

Q. Did KCPL consider any of these cost savings in its testimony?

A. No. While KCPL identified significant cost increases over levels built into current rates that it presented as support for its ratemaking proposals in direct testimony, the Company did not include or discuss in its testimony any of the savings retained from cost decreases that occurred since the last rate case.

The cost reductions achieved by KCPL are as important to address in any discussion on regulatory lag as cost increases. It is inconsistent to exclude the cost savings. All the elements of the cost of service should be included in any fair discussion of how rates are determined. In a rate request, payroll reductions are considered along with plant additions and increases for transmission costs and property taxes. If KCPL's costs increased to a greater degree than the cost reductions it achieved, then it had the option of filing for a rate increase sooner.

Other Cost Reductions

Q. Are there other cost reductions KCPL does not consider in its discussion on regulatory lag?

A. Yes. KCPL has had significant cost reductions in its cost of service for increased accumulated deferred income taxes, or deferred taxes. Deferred taxes are accounted for as an offset to rate base. Since the rate base determined by the Commission in its order in Case No. ER-2012-0174, deferred taxes have increased over $122.8 million from $510.2 million at August 31, 2012 true-up levels to $633 million through December 31, 2014, the update period in this case.[13] The increase in rate base for deferred taxes is approximately $12 million to $18 million savings to the revenue requirement on a Missouri jurisdictional basis (assuming a 10% to 15% rate base conversion). Deferred taxes will further increase

[13] See Accounting Schedules in Case Nos. ER-2014-0370 (balance at December 31, 2014) and ER-2012-0174 (balance at August 31, 2012), Schedule 2- Rate Base for Accumulated Deferred Income Tax Amounts.

significantly for the true-up in this at May 31, 2015. The increase in deferred taxes from the true-up level at August 31, 2014 has occurred throughout the entire period of rates determined in KCPL's 2012 rate case.

Q. Have there been other cost reductions since the last time rates changed?

A. Yes. Just as KCPL has indicated there are increases rate base for plant additions over levels found in last case, there have been plant retirements. Just as increases in plant caused higher depreciation expense, plant retirements cause a reduction.

Administrative and General Costs

Q. Does Mr. Ives discuss the high costs incurred by KCPL to deliver electric services to Missouri customers in his direct testimony?

A. Yes. At pages 4 through 12 of Mr. Ives' direct testimony, he references many cost increases KCPL experienced since its last rate case in 2012. However, in his testimony, Mr. Ives does not address the fact that KCPL has also incurred significantly higher administrative and general costs compared to other utilities. These high administrative costs contribute to the increased costs faced by KCPL and place strain on its ability to earn authorized returns.

Q. Did Staff do an analysis with respect to KCPL's administrative and general costs?

A. Yes. Staff witness Keith Majors contributed an analysis in Staff's Cost of Service Report at pages 234 through 239.

Q. What were the results of Staff's analysis regarding KCPL's A&G costs?

A. The analysis clearly shows KCPL has high A&G compared to other Missouri companies; on the basis of A&G costs compared to per customers, per megawatt hour sold and per electric operating revenues.

Q. Will the high A&G costs experienced by KCPL impact its earning levels?

A. Yes. The A&G costs, like any other cost, impacts KCPL's ability earn its authorized return. KCPL's A&G costs are significant and are sufficiently higher than other Missouri utilities to cause pressure on KCPL's financials where it is difficult to earn a return close to authorized levels. While KCPL indicated it achieved savings in some of its costs identified in the direct testimony of KCPL witness Heidtbrink, at pages 16 through 18, the high A&G costs incurred place an earnings drag on the Company.

<u>Conclusion for Regulatory Lag</u>

Q. What is the conclusion from your testimony on regulatory lag?

A. Staff does not dispute the fact KCPL has experienced a level of cost increases from the cost of service level determined from the last rate case in January 26, 2013—almost 2½ years. Of course, it is common for a utility seeking rate relief to experience increased costs or expect to increase costs, often due to increases in rate base due to plant additions, or cost increases for such items as transmission and fuel costs. However, KCPL has presented a very limited and one-sided analysis respecting its view of regulatory lag in its direct testimony. The Company is quick to point out all the costs that have increased since its last rate case. But KCPL has ignored any cost reductions that have occurred since the rates determined in KCPL's 2012 rate case have been in effective. Staff, in presenting the rebuttal testimonies of various witnesses, is attempting to identify some of the cost savings and benefits KCPL has not recognized in its request concerning regulatory lag and the deferral mechanisms. Staff disputes the need for these various single issue ratemaking mechanisms requested by the Company in this case. To the extent costs are increasing faster than cost benefits creating positive revenue requirements, KCPL should request a change in its rates after maintaining strenuous efforts towards cost containment.

If KCPL really believed it is not earning a reasonable and fair return for its shareholders, then it should have filed for rate relief much earlier than it did.

The regulatory model used in Missouri is not broke or somehow obsolete. It has worked well for over a century as evidenced by the healthy financial condition KCPL finds itself and recognized by the rating agencies, who early last year increased KCPL's and GMO's credit ratings, specifically citing the constructive regulatory support from the Missouri Commission as reason for this increase. As further evidence of Great Plains current earning levels, total shareholder returns have been solid the last two years—2013 and 2014—since the time of the existing rates determined by the Commission in January 2013 for the KCPL Missouri and GMO operations.

JURISDICTIOANAL ALLOCATION FACTORS

Q. How did KCPL allocate investment costs and expenses in its direct filing?

A. KCPL witness Ronald A. Klote describes at page 7 of his direct testimony that "[t]he Demand allocator used for this case is a 12-month weather normalized average of the coincident peak demands for the Missouri and Kansas retail jurisdictional customers and the firm wholesale jurisdiction which covered the period April 2013 to March 2014."

The demand allocation factor is used to allocate production, transmission and fixed capacity costs and revenues among federal and state jurisdictions. The demand allocation factor is determined by examining its system peak, which refers to the maximum monthly demand load requirements placed on the electrical system by the utility's customers. The coincident peak (CP) are the monthly peak contributions made by the respective jurisdictions relative to the total system peaks—in this case the Kansas retail jurisdiction, Missouri retail jurisdiction and wholesale jurisdiction peaks compared to—or coincide with—KCPL's total Company peak demand.

Q. Did KCPL justify why it applied the 12 coincident peak method?

A. No. KCPL simply declared it was using the 12 coincident peak (12 CP) method.

Q. Did KCPL identify why using the appropriate allocation methodology was important?

A. Mr. Klote indicates the importance of the using the proper method of allocations in the following exchange found at page 6 of his direct testimony:

> Q. Why is the method by which allocation are made critical?
>
> A. First, the method of allocation is critical to ensure that the rates charged to each jurisdiction of customers reflect the full cost of serving those customers but not the cost of serving customers in other jurisdictions. Second, and very important, is the method of allocation must allow the Company the opportunity to recover fully its imprudently incurred costs of serving those customers. That is, if the sum of the allocation factors allowed in each jurisdiction is less than 100%, then the Company is unable to recover its prudently incurred cost of service and return on rate base. The allocation factors presented in this case accomplish this.

While I agree in general, with the premise of what Mr. Klote is conveying in his direct testimony that KCPL should have opportunity to recover all its costs when it operates multiple jurisdictions as the Company does. However, I do not agree the purpose of the allocation process, and the ultimate method chosen to allocate costs between the various jurisdictions, is to make the utility whole. Each jurisdiction must make its own independent judgment as to the most appropriate method to use to assign the proper costs based on the operating characteristics of the utility in each of the multiple jurisdictions it operates in.

Q. What is the purpose of allocations process?

A. For utilities operating in multiple jurisdictions, the allocation process is used to assign costs to the various jurisdictions based on how those costs were incurred. The allocation method used should be based on the source of those costs, e.g. the cause of the cost should pay for the cost. The allocation methodology must result in the most appropriate allocation factors so costs incurred for the provision of service to a specific jurisdictional service territory are assigned the proper costs.

Q. Has KCPL addressed the need to use the most appropriate method to determine allocation factors based on the circumstances?

A. Yes. KCPL witness Darrin R. Ives, currently KCPL's Vice President – Regulatory Affairs, testified in the KCPL's 2015 rate case that the facts should be the determining factor in making decision the proper allocation method to use in a rate case. Mr. Ives stated in the Kansas in 2012:

> **Q: Are you saying that the Commission should choose an allocation methodology simply because it matches what another jurisdiction's commission determined?**
>
> A: No, absolutely not. The Commission is charged with balancing the interests of customers and utilities. **In determining the appropriate allocation methodology, the Commission should rely on the facts and theory supporting how such methods should be fairly and appropriately applied to a utility.** Just as the Commission should not be forced to choose a methodology solely based on the choice of another jurisdiction commission's decision, neither should the Commission choose a methodology solely because it benefits either the customer or the utility. **The basis for the choice of**

> **allocator should be the appropriate theory surrounding such allocation and the specific facts and nature of the utility's business. The most appropriate methodology on this issue is the 4CP method** as established by the direct testimony of Mr. Loos.
>
> [Source: Ives Direct, page 11, Kansas Docket 12-KCPE-764-RTS; emphasis added]

Q. Does KCPL's proposed use of the 12 CP methodology shift costs to the Missouri jurisdiction?

A. Yes. Mr. Klote's recommendation in his direct testimony shifts disproportionate costs to Missouri and lessens the allocation to Kansas. KCPL's use of the 12 CP method of allocation apportions more generation and transmission plant costs to Missouri than the 4 CP method consistently chosen by Staff and adopted by the Commission. Staff's method of determining the demand allocation factor is identified as the 4 CP method and is defined in the Cost of Service Report at pages 179 to 189, specifically page 180.

Q. Why did Staff use the 4 CP method to allocate costs with KCPL?

A. As noted in the Cost of Service Report referenced above, Staff relies on the 4 CP method because it properly allocates the costs of KCPL's Missouri jurisdiction based on the peak demands for the four summer months of all its jurisdictions in relation to KCPL's total system peak. KCPL's peak demand has the highest concentration of electricity being consumed in the four summer months and no other months or combination of months come close to those summer months which is why the 4 CP method is the appropriate method for KCPL's operations in both Missouri and Kansas. When the actual peaks are examined, KCPL's four peak demands *always* occur in the summer months—June, July, August and September. Therefore, the 4 CP method is accurately determines KCPL's actual jurisdictional peak demands of the four summer months compared to all the months in the year. Applying the 12 CP method improperly determines the peak demand requirements needed to meet demands of the summer months because it relies on all the months of the year. No other combinations of months result in the relationship the summer months have to the rest of the year which is why the 4 CP method is considered to be the most appropriate allocation method to use for summer peaking utility like KCPL. It is the concentration of the four summer months peak demands in relation to the other months of the year that forms the basis for using the 4 CP method to allocate costs among the jurisdictions.

Q. What is the result of using the 12 CP method to allocate costs on a demand factor basis?

A. Using the 12 CP method allocates more costs to Missouri than if the 4 CP method is applied, meaning KCPL's Missouri retail customers will be charged for services consumed by other jurisdictions. The 12 CP method allocates less costs to the Kansas jurisdiction.

Q. Has the Commission decided the appropriate method of determining the demand allocation factor in previous KCPL rate cases?

A. Yes. In KCPL's 2006 rate case filed as Case No. ER-2006-0314, the Commission found that the proper method of determining the demand factor to allocate production and transmission plant costs and related expenses was the 4 CP method. The Commission states:

> KCPL operates in both Kansas and Missouri. Instead of maintaining separate systems, KCPL's sole system serves both jurisdictions. To set just and reasonable rates for each jurisdiction requires allocating various generation and transmission capital costs property between these states. KCPL and other parties disagree over which coincident peak method to use to allocate those costs.

> Coincident peak refers to the load of each jurisdiction that coincides with the hour of a utility's overall system peak. KCPL asserts that its operating and capacity planning realities, which take into account all hours of the year, and not just peak hour or seasonal peak needs, dictate use of the 12 CP demand allocator. **Staff and other parties assert that KCPL has historically used the 4 CP method, that the 12 CP method would allocate more plant investment and costs to Missouri and less to Kansas, and that KCPL's high peak demand from June until September is more akin to a 4 CP than a 12 CP system.**
>
> The Commission finds that the competent and substantial evidence supports Staff's position, and finds this issue in favor of Staff. As on all issues, KCPL bears the burden of proof.
>
> . . .
>
> . . . not only Staff, but Praxair, Ford, and Missouri Industrial Energy Consumers support the 4 CP methodology. Their evidence showed that a 4 CP methodology for a utility such as KCPL is appropriate because its non-summer peak demands are significantly lower than the summer peak demands. Moreover, Praxair witness, Maurice Brubaker, has testified hundreds of times on cost allocation issues, and his testimony was that the Commission should use the 4 CP method.
> [emphasis added]

The Commission rejected the use of the 12 CP method in KCPL's 2006. Yet KCPL has provided no justification for wanting to the Commission to adopt its 12 CP proposal and, more importantly, provided no reasoning for the Commission to reverse itself in the use of the 4 CP method to allocate demand related costs.

Q. Has Staff used the 4 CP method for KCPL rate cases in the past?

A. Yes. Staff has used the 4 CP method to determine the demand allocation factor in all the rate cases filed by KCPL since 2006. In fact, Staff has consistently used the 4 CP methodology since it changed from the single peak, or 1 CP method in the 1985 Wolf Creek rate case—Case No. EO-85-185. In the Wolf Creek rate case, KCPL filed its case based on a 4 CP demand allocation factor. Staff agreed to use the 4 CP method proposed by KCPL moving away from its 1 CP method. Staff has used the 4 CP method in all KCPL rate cases since.

Q. Has KCPL proposed the use of the 4 CP method for the demand allocation factor since the Wolf Creek rate case?

A. Yes, in Missouri. While KCPL filed for the 12 CP method in the 2006 rate case, after the Commission rejected this methodology, KCPL presented the 4 CP method in every subsequent rate case filed in Missouri until it proposed the 12 CP in this case. KCPL filed the demand factor based on the 4 CP method in Case No. ER-2007-0291 (the 2007 rate case), Case No. ER-2009-0089 (the 2009 rate case), Case No. ER-2010-0355 (the 2010 rate case) and Case No. ER-2012-0174 (the 2012 rate case). As indicated above, KCPL first proposed the use of the 4 CP method to determine the demand factor in the 1985 Wolf Creek rate case—Case No. ER-85-185.

Q. What method of allocation has KCPL proposed be used to determine the demand factor in Kansas?

A. KCPL is proposing to use the 12 CP method of allocating demand costs in its 2015 Kansas rate case even though KCPL proposed the use of the 4 CP in its last Kansas rate case filed in 2012—Docket No. 12-KCPE-764-RTS. KCPL has consistently used the 4 CP method in Missouri since its 2007 rate case with exception of the 2015 Missouri case. KCPL switched its allocation method once again in one of its jurisdictions by proposing the 12 CP method in the current Kansas rate case filed January 2, 2015.[14]

[14] Klote direct testimony, page 7 in Kansas case—Docket No. 15-KCPE-116-RTS.

Q What allocation factors are being used in the Missouri and Kansas 2015 rate cases?

A. KCPL used the following demand allocation factors based on the 12 CP method for Missouri, Kansas and the whole sale jurisdiction compared to what Staff determined based on the 4 CP method:

Jurisdiction	**Staff** **Missouri Rate Case—filed April 3, 2015 ER-2014-0370 based on June to September 2014**	**KCPL** **Missouri Rate Case—filed October 30,2014 ER-2014-0370 based on April 2013 to March 2014**	**KCPL** **Kansas Rate Case— filed January 2, 2015 15-KCPE-116-RTS based on July 2013 to June 2014**
Allocation Method	4 Coincident Peak	12 Coincident Peak	12 Coincident Peak
Missouri	53.17%	53.5748%	53.5494%
Kansas	46.59%	46.2047%	46.2293%
Whole Sale	0.0024%	0.2204%	0.2213%
Total	100%	100%	100%

Source: KCPL work paper D 1 Allocator for KCPL's Missouri and Kansas 2015 rate cases and Staff Cost of Service Report, page 181.

Q. Has KCPL used the 4 CP method to determine the demand allocation factor in Kansas?

A. Yes. Consistent with filing the 4 CP method several times since its 2007 Missouri rate case, excepting for this 2015 rate case, KCPL filed its 2012 Kansas rate case using the 4 CP method to calculate the demand factor.

Mr. Ives, stated at page 9 of his direct testimony filed in the 2012 Kansas rate case supported the use of the 4 CP method as the basis for the demand allocation factor in Kansas:

> Q. What is KCP&L recommending as the appropriate jurisdictional allocator for capacity-related costs in this case?

> A: The 4CP method allocates costs using the four highest months of demand on KCP&L's system, namely June through September, whereas the 12CP method considers an entire year, which includes the lower non-summer usage months. **Because KCP&L is a summer peaking business, we are recommending the 4CP method as a more accurate allocator of these costs between the Company's Kansas and Missouri jurisdictions.** Mr. Loos provides extensive testimony regarding how to discern the appropriate allocation method for a particular utility. **His analysis clearly identifies the 4CP method as appropriate for KCP&L. As such, KCP&L is requesting that the Commission change the method used in recent KCP&L cases for calculating the demand allocator, the 12CP method, to a 4CP method based upon the specific parameters of KCP&L's business as a summer-peaking utility.**
>
> **The basis for the choice of allocator should be the appropriate theory surrounding such allocation and the specific facts and nature of the utility's business. The most appropriate methodology on this issue is the 4CP method** as established by the direct testimony of Mr. Loos.
>
> [Source: Ives Direct, pages 9-11, Kansas Docket 12-KCPE-764-RTS selected pages attached as Rebuttal Schedule CGF-R5; emphasis added]

Finally, Mr. Terry Bassham, KCPL's President and Chief Operating Officer, testified in his direct testimony in the 2012 Kansas rate case the 4 CP method was the most appropriate allocation method to use for both jurisdictions:

> **KCP&L will demonstrate in this case that the 4CP method is the more appropriate method for allocation of these costs between the Company's jurisdictions, given that it operates a summer peaking business.**
>
> [Source: Bassham Direct, page 4, Kansas Docket 12-KCPE-764-RTS selected pages attached as Rebuttal Schedule CGF-R6; emphasis added]

Q. Did KCPL have any other witnesses support the use of the 4 CP demand allocation factor?

A. Yes. KCPL hired a consultant from Black & Veatch named Larry W. Loos who provided expert testimony regarding the proper use of the 4 CP method in the 2012 Kansas rate case. Mr. Loos also filed testimony in the 2009 and 2010 Missouri rate cases concerning the proper use of the 4 CP allocation factor. Mr. Loos, as an independent consultant, testified that based on his analysis supported by several FERC tests, that KCPL system requirements were those consistent with the use of a 4 CP.

Mr. Loos stated the following at page 19 of his direct Kansas testimony filed in the 2012 rate case:

> Q. Based on examination of the data set forth in Schedule LWL-7, what do you conclude?
>
> A. Based on the tests set forth in various FERC orders, **without question the 12CP method is not appropriate for use to allocate capacity costs among the jurisdictions served by KCP&L. I therefore recommend that the [Kansas] Commission order the Company use the four (4) coincident peak demands during the months of June through September to allocate capacity costs among jurisdictions.**
> [emphasis added]

Attached as Rebuttal CGF-R7 is the complete direct testimony of Mr. Loos filed by KCPL in the 2012 Kansas rate case which the Company supported the use of the 4 CP method of determining the demand allocation factor.

In addition, KCPL responded to a Staff data request submitted in the Company's 2010 rate case

> 1c. The Kansas Regulatory Plan ("Reg Plan") requires the use of a 12CP allocator for plant and related O&M expense. Therefore, the Company could not propose consistent plant/O&M allocation methods for the two jurisdictions in the current rate cases, since the Missouri allocation is based on 4CP. **Mr. Loos recommends 4CP in both jurisdictions in future rate cases.**
> [Source: KCPL's response to Data Request 0415 in Case ER-2010-0355]

Q. Did Mr. Loos ever testify before the Missouri Commission that the use of the 12 CP method to determine the demand allocation factor should not be used?

A. Yes. Mr. Loos did not believe the 12 CP was a proper allocation method to use for a predominate summer peaking utility such as KCPL. KCPL's system load requirements have substantial peaks occurring in the summer months of June through September each year. Mr. Loos believed through his extensive analysis that the use of the 4 CP method was the proper approach to determining the demand allocator.

Q. Did Mr. Loos support the use of a 12 CP allocation method in any previous KCPL rate case?

A. No. Mr. Loos testified he could not support the use of the 12 CP method—the method proposed by KCPL in its 2015 rate case in Missouri. Despite Mr. Loos' expert opinion that the 12 CP method is improper for use in KCPL's state jurisdictions it has presented this method in both Kansas and Missouri 2015 rate cases. KCPL also proposed the 12 CP method in its 2006 rate case in Missouri that was rejected by the Commission. Mr. Loos has said that he would not recommend in Kansas or Missouri use of the 12 CP method to allocate KCPL's costs among the Missouri, Kansas and FERC jurisdictions. In his deposition taken on March 18, 2009, Mr. Loos testified he did not support and would not use the 12 CP allocation method to determine the demand allocator as follows:

> Q. In this case, NO. ER-2009-0089, did you recommend the use of the twelve coincident peak allocation basis to allocate KCPL costs between the Missouri, Kansas and FERC jurisdictions?
>
> A. I did not.
>
> Q. Why not?
>
> A. As I indicated before**, I prefer an allocation that better recognizes the maximum demand place on the system by customers, which is single CP, 4 CP, sometimes 3 CP**.

> Q. **In your opinion would the twelve coincident peak allocation basis be an appropriate basis for allocating KCPL costs between Missouri, Kansas and FERC jurisdictions for a rate case before the Kansas Corporation Commission?**
>
> A. **I wouldn't recommend it.**
>
> Q. And why not?
>
> A. Because **I believe that there are methods that are preferable to it, either single or 4 CP**, yeah.
>
> Q. The same reasons that you wouldn't recommend it in this case?
>
> A. Uh-huh. Yes.
>
> Q. Do you know the circumstance where you would ever recommend the use of the twelve coincident peak allocation basis for allocating costs among State and Federal jurisdictions for ratemaking purposes?
>
> A. If the -- if the utility loads are relatively constant -- or essentially constant over twelve months, it would make a little difference. And under that situation it could capture and allocate additional amounts to perhaps some classes we didn't want to allocate it to.
>
> [Loos March 18, 2009 deposition, pages 31 and 32; emphasis added]

In this case, KCPL is proposing to use the very allocation method its expert opposed in testimony filed in several Kansas and Missouri rate cases presented during the period 2009 through 2012. Yet KCPL, making no attempt to refute their own experts and providing no evidence to support the application of the 12 CP allocation method, based its 2015 rate cases in both Kansas and Missouri using this wrong methodology.

Q. What does Staff recommend regarding what allocation method to use in this rate case?

A. Staff continues to support the 4 CP method of determining the demand allocation factor used to assign the production and transmission investment costs in rate base along with the related expenses to the various jurisdictions KCPL operates in. It is important that KCPL pursue consistent allocation treatment in its jurisdictions. KCPL should continue to pursue more consistent allocation treatment in its Kansas jurisdiction to apply a more accurate methodology. KCPL's Missouri customers should not be expected to pay in their rates any short-fall caused by the Kansas jurisdiction's refusal to use the very method of allocation KCPL's own witnesses have supported in past rate Missouri cases and the most recent Kansas case.

Q. Mr. Klote states at page 7 of his direct testimony that the demand factor used by KCPL was based on ". . . a 12-month weather normalized average of the coincident peak demands for the Missouri and Kansas retail jurisdictional customers . . ." Has the Commission used weather normalized average peaks in determining a demand factor in Missouri?

A. No, because weather normalized average peaks do not properly identify the actual maximum peak demand on the system. The allocation of the production and transmission plants are based on *actual* loads placed on KCPL's electric system. The generating and transmission facilities are required to provide *maximum hourly usage* by customers regardless of the weather conditions. It is not proper to weather normalize the monthly coincident peaks to determine the appropriate demand factor. Power plants must generate sufficient power and transmission plants must have the capacity to transmit the power to meet the hottest days of the year. It is the *actual electric loads* placed on the KCPL system, not the weather normalized loads, that the production and transmission facilities must be capable of fulfilling.

Q. Did KCPL provide any justification in its direct testimony for using the "weather normalized" average peaks to support the determination of the demand factor in this case?

A. No. KCPL did not identify any reasons for determining the demand factor using weather normalized average peaks.

<u>Jurisdictional Allocations- Conclusion</u>

Q. What should the Commission do respecting the allocation method to use in this case for demand costs?

A. The Commission should use Staff's proposed 4 CP method of allocating costs because it properly apportions costs among multiple jurisdictions for a summer peaking utility, such as KCPL. The Commission should reject KCPL's proposal to allocate demand costs using the 12 CP method because the method improperly apportions costs associated with serving other jurisdictions to Missouri retail customers. The 4 CP demand allocation method was first proposed by KCPL and was adopted by the Commission in the 1985 Wolf Creek rate case—and that method has been applied by Missouri in every KCPL rate case since.

KCPL's own witnesses in the 2012 Kansas rate case directly refute the use of the 12 CP method for determining the demand factor. In the 2012 Kansas case, KCPL's officers and its expert witness testified that the use of the 12 CP was not proper for a summer peaking utility and that the appropriate method for determining the demand allocation factor was using the 4 CP method. In fact, each of KCPLs witnesses in the 2012 Kansas rate case testified against the 12 CP method, the very method KCPL is proposing be used in Missouri in this case. Further, KCPL's 2012 Kansas testimony made it abundantly clear the 4 CP is the appropriate allocation method to use to allocate costs based on demand. Equally important, KCPL has failed to provide any justification or explanation that supports the use of the 12 CP method in this current Missouri rate case. The Commission should continue to base the rates in this case using the 4 CP method to determine the demand allocation factor.

Q. Does this conclude your rebuttal 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 OF CARY G. FEATHERSTONE

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Cary G. Featherstone, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Rebuttal Testimony in question and answer form, consisting of 44 pages to be presented in the above case; that the answers in the foregoing Rebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of his knowledge and belief.

Cary G. Featherstone

Cary G. Featherstone

Subscribed and sworn to before me this 6th day of May, 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

Kansas City Power and Light Company
Case No. ER-2014-0370

Great Plains Energy Incorporated
Capitaliation - Capital Structure

Great Plains Energy	**2014 Actual**			**2013 Actual**			**Commission Order in Case ER-2012-0174**	
Common Equity	$ 3,586,100,000	50.42%	50.96%	$ 3,474,400,000	49.43%	49.98%	52.56%	53.16%
Preferred	39,000,000	0.55%		39,000,000	0.55%		0.600%	
Long-term Debt	3,488,000,000	49.04%		3,515,700,000	50.02%		46.84%	
	$ 7,113,100,000	100.00%		$ 7,029,100,000	100.00%		100.00%	

source: 2013 10-K, page 53
2014 10-K, page 51

source: Commission Order- page 26

Rebuttal Schedule CGF

Kansas City Power & Light Company

Payroll Savings-- Employee Reductions

Begin Data of Savings	End Date of Savings	Net Payroll Savings (1)	Benefit & Tax Adder (2)	Total Savings	Total KCPL Savings (3)	Missouri Jurisdictional Savings (4)
Septerber 1, 2012	December 31, 2014	$ 22,019,105	0.6	$ 35,230,567	$ 23,142,959	$ 12,349,083
September 1, 2012	May 31, 2015	$ 28,211,533	0.6	$ 45,138,453	$ 29,651,450	$ 15,822,014
September 1, 2012	September 29, 2015	$ 33,173,678	0.6	$ 53,077,885	$ 34,866,863	$ 18,604,958

(1) Terminations less hires through July 31, 2014 -- 140 employees

(2) KCPL estimate of payroll taxes and benefits, Case No. ER-2012-0174-- 61% (rounded to 60%)

(3) KCPL share of payroll , Case No. ER-2012-0174- 65.69% (remainder allocated to GMO)

(4) Missouri aggregate payroll jurisdictional factor, Case No. ER-2012-0174- 53.36%

Rebuttal Schedule CGF

Kansas City Power & Light Company

Payroll Savings- Union Incentive Compensation

Begin Data of Savings	End Date of Savings	Total Savings	Total KCPL Savings (1)	Missouri Jurisdictional Savings (2)
March 8, 2013	December 31, 2014	$ 3,492,264	$ 2,294,068	$ 1,224,115
March 8, 2013	May 31, 2015	$ 4,287,637	$ 2,816,549	$ 1,502,910
March 8, 2013	September 29, 2015	$ 4,924,988	$ 3,235,225	$ 1,726,316

(1) KCPL share of payroll, Case No. ER-2012-0174-- 65.69%-- remainder allocated to GMO

(2) Missouri aggregate payroll jurisdictional factor, Case No. ER-2012-0174-- 53.36%

Rebuttal Schedule CGF

Kansas City Power & Light Company

Department of Energy Nuclear Storage Fees

Begin Data of Savings	End Date of Savings	Total Savings		Missouri Jurisdictional Savings (1)	
May 16,2014	December 31, 2014	$	2,826,275	$	1,614,368
May 16,2014	May 31, 2015	$	4,681,786	$	2,674,236
May 16,2014	September 29, 2015	$	6,156,365	$	3,516,515

(1) Using Energy Allocation Factor from Case No. ER-2012-0174 of 57.12%

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Kansas Corporation Commission
/S/ Patrice Petersen-Klein

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

Received
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by
State Corporation Commission
of Kansas

DIRECT TESTIMONY OF

DARRIN R. IVES

ON BEHALF OF
KANSAS CITY POWER & LIGHT COMPANY

IN THE MATTER OF THE APPLICATION OF
KANSAS CITY POWER & LIGHT COMPANY
TO MAKE CERTAIN CHANGES IN
ITS CHARGES FOR ELECTRIC SERVICE

DOCKET NO. 12-KCPE-764-RTS

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Darrin R. Ives. My business address is 1200 Main, Kansas City, Missouri 64105.

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

A: I am employed by Kansas City Power & Light Company ("KCP&L" or the "Company") as Senior Director – Regulatory Affairs.

Q: What are your responsibilities?

A: My responsibilities include oversight of the Company's Regulatory Affairs Department, as well as all aspects of regulatory activities including cost of service, rate design, revenue requirements, regulatory reporting and tariff administration.

KCP&L's customers since late 2010. KCP&L is now requesting that the cost of this asset, $50.6 million (Kansas jurisdictional share), be placed into rate base and recovered through our retail rates.

This facility and the in-service criteria and test results are discussed in more detail in the Direct Testimony of KCP&L witness Mr. Bell.

VI. JURISDICTIONAL ALLOCATION OF CAPACITY-RELATED COSTS

Q: Please discuss the allocation issue raised by the Company in this case.

A: As discussed in the Direct Testimony of Company witness Mr. Larry Loos in KCP&L's last rate case, the 415 Docket, KCP&L agreed in the Stipulation and Agreement in Docket No. 04-KCPE-1025-GIE ("1025 S&A") to utilize a 12CP allocation method to allocate its capacity-related (also referred to as demand-related) costs to its Kansas and Missouri jurisdictions. The 1025 S&A has expired and KCP&L asks the Commission to revisit the appropriate allocation method to apply to the Company's capacity-related costs for jurisdictional allocation.

Q: What is KCP&L recommending as the appropriate jurisdictional allocator for capacity-related costs in this case?

A: The 4CP method allocates costs using the four highest months of demand on KCP&L's system, namely June through September, whereas the 12CP method considers an entire year, which includes the lower non-summer usage months. Because KCP&L is a summer peaking business, we are recommending the 4CP method as a more accurate allocator of these costs between the Company's Kansas and Missouri jurisdictions. Mr. Loos provides extensive testimony regarding how to discern the appropriate allocation method for a particular utility. His analysis clearly identifies the 4CP method as appropriate for KCP&L. As such, KCP&L is requesting that the Commission change the method used in recent KCP&L cases for calculating the demand allocator, the 12CP method, to a 4CP method based upon the specific parameters of KCP&L's business as a summer-peaking utility.

Q: Are there other issues surrounding this allocation methodology that the Commission should consider?

A: At times, Kansas and Missouri have ordered different allocators be used in each state for a certain set of costs. This use of differing allocators to assign a single set of costs can lead to an allocation of more than or less than 100% of the costs in question. Significantly impacting the Company, and the only jurisdictional allocator difference addressed in this case, is the allocation of capital investment in facilities between the states where Kansas currently allocates these costs based upon a 12CP method and Missouri currently allocates these same costs based upon a 4CP method. The amount of cost recovery lost by the Company as a result of Kansas and Missouri utilizing these different methods has increased substantially as a result of the large capital investments the Company has made over the last few years. As explained further in the testimony of Mr. Loos, the inconsistency in this particular allocation leaves KCP&L unable to recover a significant amount of its costs.

Q: Are you saying that the Commission should choose an allocation methodology simply because it matches what another jurisdiction's commission determined?

A: No, absolutely not. The Commission is charged with balancing the interests of customers and utilities. In determining the appropriate allocation methodology, the Commission should rely on the facts and theory supporting how such methods should be fairly and appropriately applied to a utility. Just as the Commission should not be forced to choose a methodology solely based on the choice of another jurisdiction commission's decision, neither should the Commission choose a methodology solely because it benefits either the customer or the utility. The basis for the choice of allocator should be the appropriate theory surrounding such allocation and the specific facts and nature of the utility's business. The most appropriate methodology on this issue is the 4CP method as established by the direct testimony of Mr. Loos.

VII. DEPRECIATION RATES

Q: The Commission addressed depreciation expense in the Company's last rate case. Why is KCP&L raising the issue again in this case?

A: One primary reason is that the depreciation study used to set rates in the 415 Docket was based on 2008 data. Since that time, KCP&L's plant in service has increased by approximately $900 million. A new depreciation study is warranted when there has been such a large change in the underlying data. A substantial portion of the increase in depreciation expense requested in this case is attributable to the increased capital investment occurring since the study used to set depreciation rates in our last case. Depreciation expense for new investments since the audit cut-off in our last case is included in our request in the case. The additional investments occurring since the study used to set depreciation rates in our last case also are a driver in the increase in certain depreciation rates, particularly in the production asset class.

Additionally, in the 415 Docket, the Company's depreciation study supported a decrease of over $12 million to its depreciation expense (which translates directly to its revenue requirement), and KCP&L proposed that decrease in its application in that case.

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/S/ Patrice Petersen-Klein

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

Received
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of Kansas

DIRECT TESTIMONY OF

TERRY BASSHAM

ON BEHALF OF
KANSAS CITY POWER & LIGHT COMPANY

IN THE MATTER OF THE APPLICATION OF
KANSAS CITY POWER & LIGHT COMPANY
TO MAKE CERTAIN CHANGES IN
ITS CHARGES FOR ELECTRIC SERVICE

DOCKET NO. 12-KCPE-764-RTS

I. INTRODUCTION AND OVERVIEW

Q: Please state your name, occupation and business address.

A: My name is Terry Bassham. I am President and Chief Operating Officer ("COO") of Kansas City Power & Light Company ("KCP&L" or "Company") and of KCP&L Greater Missouri Operations Company ("GMO"). I am also a member of the Board of Directors of Great Plains Energy Incorporated ("Great Plains Energy" or "GPE"), the holding company of KCP&L and GMO. Effective June 1, 2012, I will also assume the role of Chief Executive Officer replacing Michael Chesser who recently announced he will retire at that time. My business address is 1200 Main Street, Kansas City, Missouri 64105.

requests recovery of its investment in additional wind generation capacity at its Spearville site built to meet that requirement.

Third, the Company requests a modification to the Commission's method of allocating capacity-related costs to the Company's Kansas and Missouri jurisdictions from a 12 monthly coincident peak demand ("12CP") basis to a 4 monthly coincident peak demand ("4CP") basis. KCP&L will demonstrate in this case that the 4CP method is the more appropriate method for allocation of these costs between the Company's jurisdictions, given that it operates a summer peaking business. While KCP&L is basing this request on the fact that 4CP is the correct jurisdictional allocator for KCP&L's business, I would add that consistent allocators between the states is also important so that the Company has the opportunity to recover all of its costs. Missouri presently recognizes that the 4CP method is appropriate for KCP&L.

Fourth, KCP&L requests that its proposed updated depreciation rates be applied to the Company's capital investment. An updated depreciation study and new depreciation rates are necessary at this time due to the large increase in plant investment occurring since the last study was performed.[2] The Company is requesting depreciation rates that fairly and accurately assign asset costs to the appropriate generation of customers who benefit from those assets.

Finally, KCP&L requests certain rate design changes.

There are other reasons supporting KCP&L's filing for a rate increase at this time, as discussed in the Direct Testimony of Mr. Ives, but the five items outlined above are the key drivers.

---

[2] The depreciation study included with KCP&L's application in Docket No. 10-KCPE-415-RTS was based upon data from the 12-month period ending December 31, 2008.

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in Its Charges for Electric Service	))))	Docket No.: 12-KCPE- -RTS

AFFIDAVIT OF TERRY BASSHAM

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Terry Bassham, being first duly sworn on his oath, states:

1. My name is Terry Bassham. I work in Kansas City, Missouri, and I am President, Chief Operating Officer, and a member of the Board of Directors of Great Plains Energy Incorporated, the holding company of Kansas City Power & Light Company ("KCP&L"). I am also the President and Chief Operating Officer of KCP&L.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of KCP&L consisting of twenty (20) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

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

Terry Bassham

Subscribed and sworn before me this 18th day of April, 2012.

Nicole A. Wehry
Notary Public

My commission expires: Feb. 4, 2015

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

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/S/ Patrice Petersen-Klein

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DIRECT TESTIMONY OF

LARRY W. LOOS

KANSAS CITY POWER & LIGHT COMPANY

DOCKET NO. 12-KCPE-764-RTS

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BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

DIRECT TESTIMONY OF

LARRY W. LOOS

ON BEHALF OF
KANSAS CITY POWER & LIGHT COMPANY

IN THE MATTER OF THE APPLICATION OF
KANSAS CITY POWER & LIGHT COMPANY
TO MODIFY ITS TARIFFS TO CONTINUE THE
IMPLEMENTATION OF ITS REGULATORY PLAN

DOCKET NO. 12-KCPE-____-RTS

I. INTRODUCTION AND OVERVIEW

Q. Please state your name and business address.

A. My name is Larry W. Loos. My address is 42830 W. Kingfisher Drive, Maricopa, Arizona 85138.

Q. What is your occupation?

A. Prior to my retirement from full-time employment in May 2011, Black & Veatch Corporation (Black & Veatch) employed me for 41 years. While at Black & Veatch, I served in the Company's Management Consulting Division as an engineer, project engineer, project manager, partner, vice president, and director. In this engagement, I serve as a consultant and independent contractor to Black & Veatch.

Q. For whom are you testifying in this matter?

A. I am testifying on behalf of Kansas City Power & Light Company ("KCP&L" or the "Company").

Q. What is the purpose of your direct testimony?

A. In this case, I will be recommending the basis for allocating capacity-related costs among the Company's jurisdictions. Specifically, I will focus on whether the 12 monthly coincident peak demands ("12CP") or the 4 monthly coincident peak demands ("4CP") is the more appropriate allocation methodology to allocate capacity-related costs between the Company's Kansas and Missouri customers. My conclusion is that the 4CP is the more appropriate allocation methodology for KCP&L. This allocation change represents an increase in revenue requirement of $10.4 million, as set forth in the testimony of Company witness, Mr. John Weisensee.

Q. Have you previously submitted testimony on behalf of KCP&L regarding this issue?

A. Yes, I have. I addressed this issue as well as other jurisdictional allocation issues in KCP&L's prior rate case, Docket No. 10-KCPE-415-RTS ("415 Docket"), before this Commission. I also addressed jurisdictional allocation issues in KCP&L's rate cases before the Missouri Public Service Commission, Case Nos. ER-2009-0089 and ER-2010-0355.

Q. What is your educational background?

A. I am a graduate of the University of Missouri at Columbia, with a Bachelor of Science Degree in Mechanical Engineering and a Masters Degree in Business Administration.

Q. Are you a registered professional engineer?

A. No, currently I am not registered.

Q. To what professional organizations do you belong?

A. I am a member of the American Society of Mechanical Engineers and the Society of Depreciation Professionals.

Q. What is your professional experience?

A. I have been responsible for numerous engagements involving electric, gas, and other utility services. Clients served include both investor-owned and publicly owned utilities; customers of such utilities; and regulatory agencies. During the course of these engagements, I have been responsible for the preparation and presentation of studies involving cost classification, cost allocation, cost of service, allocation, rate design, pricing, financial feasibility, weather normalization, normal degree-days, cost of capital, valuation, depreciation, and other engineering, economic and management matters.

Q. Please describe Black & Veatch.

A. Black & Veatch has provided comprehensive construction, engineering, consulting, and management services to utility, industrial, and governmental clients since 1915. The Company specializes in engineering and construction associated with utility services including electric, gas, water, wastewater, telecommunications, and waste disposal. Service engagements consist principally of investigations and reports, design and construction, feasibility analyses, cost studies, rate and financial reports, valuation and depreciation studies, reports on operations, management studies, and general consulting services. Present engagements include work throughout the United States and numerous foreign countries. Including professionals assigned to affiliated companies, Black & Veatch currently employs approximately 9,000 people.

Q. Have you previously appeared as an expert witness?

A. Yes, I have. I have presented expert witness testimony before this Commission ("KCC" or "Commission") on a number of occasions. I have also testified before the Federal Energy Regulatory Commission ("FERC") and regulatory bodies in the states of

Colorado, Illinois, Indiana, Iowa, Missouri, Minnesota, New Mexico, New York, North Carolina, Pennsylvania, South Carolina, Texas, Utah, Vermont, and Wyoming. I have also presented expert witness testimony before courts in Colorado, Iowa, Kansas, Missouri, and Nebraska; and before the Courts of Condemnation in Iowa and Nebraska. I have also served as a special advisor to the Connecticut Department of Public Utility Control.

II. BACKGROUND ON KCP&L'S ALLOCATION METHODOLOGY

Q. What methodology has KCP&L historically used to allocate capacity-related costs to its Kansas customers?

A. KCP&L has been using the 12CP method.

Q. Does the stipulation and agreement approved by the Commission in Docket No. 04-KCPE-1025-GIE ("1025 S&A") provide that the parties agree to use the 12CP method to allocate capacity costs to the Kansas jurisdiction during the term of that agreement?

A. Yes, it does. I understand that the 415 Docket was the final rate case controlled by the 1025 S&A and that KCP&L's filings in this and future rate filings are not subject to that agreement.

Q. In your testimony in the 415 Docket, what jurisdictional allocation basis did you indicate that you would recommend to the Commission in this case?

A. I indicated that I planned to recommend in this case a jurisdictional allocation that includes the following:

1) Allocate capacity-related power supply costs based on each jurisdiction's contribution to the four summer month coincident peak demands (4CP).

2) Classify and allocate the margin associated with off-system sales in the same manner as the fixed costs associated with KCP&L's generating resources used to generate the energy sold off-system.

3) Classify production costs related to environmental protection and control as energy-related and allocate accordingly.

4) Classify boiler maintenance expense excluding KCP&L labor as energy-related and allocate accordingly.

5) Classify and allocate transmission system costs on the same basis as the classification and allocation of fixed production related costs.

I made these recommendations in the Company's 2009 and 2010 Missouri rate cases (Case Nos. ER-2009-0089 and ER-2010-0355, respectively). These cases were settled without the Missouri Commission specifically addressing jurisdictional allocation issues.

Q. **Are your recommendations in this case the same as those you indicated to the Commission that you planned to make?**

A. No, they are not. The Company decided not to address jurisdictional allocation issues in its current Missouri rate case. The Company asked that in this Kansas case, I limit my recommendation to the appropriate basis (4CP or 12CP) to allocate capacity-related costs among jurisdictions.

Q. **How have capacity-related costs been allocated to KCP&L's Missouri customers in KCP&L's prior rate cases in Missouri?**

A. Historically, Missouri has used a 4CP allocator.

Q. Does use of the different allocation factors in the Kansas and Missouri jurisdictions result in any problem?

A. Yes, it does. For multi-jurisdictional utilities, the use of different jurisdictional allocation bases usually results in the company either not recovering its entire revenue requirement or over recovering its revenue requirement. This result (over- or under-recovery) is determined through the consequences of the actions of the Commissions. In KCP&L's situation, the Company does not recover its entire revenue requirement because of the use of different allocation bases in each of its jurisdictions, including different capacity cost allocators.

The Kansas jurisdiction operates at a lower load factor than the other jurisdictions (Missouri and FERC). A 12CP capacity (demand) allocator will nearly always allocate lower cost to the lower load factor jurisdiction than use of a 4CP allocator. For example, the capacity cost responsibility for the Kansas jurisdiction amounts to 46.86 percent using a 4CP allocator whereas the cost responsibility for the Kansas jurisdiction amounts to 45.64 percent using a 12CP allocator. Thus, the lower cost allocated to the Kansas jurisdiction by using the 12CP allocator amounts to 1.22 percent of capacity-related cost.

Conversely, the Missouri jurisdiction operates at a higher load factor than the other jurisdictions (Kansas and FERC). A 12CP capacity (demand) allocator will nearly always allocate more cost to the higher load factor jurisdiction than use of a 4CP allocator. For example, the capacity cost responsibility for the Missouri jurisdiction amounts to 53.69 percent using a 12CP allocator whereas the cost responsibility for the Missouri jurisdiction amounts to 52.49 percent using a 4CP allocator. Thus, the lower cost allocated to the Missouri jurisdiction by using the 4CP allocator amounts to 1.20 percent of capacity-related cost.

Thus, the implication of using the 12CP allocator in Kansas and using the 4CP allocator in Missouri is KCP&L's failure to recover from retail customers about 1.2 percent of its capacity-related costs.

Q. How do you organize the balance of your direct testimony?

A. The sole issue that I address is whether the 4CP or 12CP allocation basis is more appropriate for KCP&L. I will describe the analyses that I rely on to determine that KCP&L has a dominant summer peak and thus the more appropriate basis to allocate capacity-related costs is the 4CP allocator. In this regard, I will analyze:

1) Monthly system peak demands for the calendar years 2006 through 2011;
2) Hourly load for calendar year 2011;
3) Monthly coincident demands by jurisdiction for calendar year 2011;
4) Monthly system peak demands for the calendar years 2006 through 2011 by season; and
5) Various system demand tests relied on by the FERC.

Q. Do you sponsor any Schedules?

A. Yes, I do. I sponsor the following Schedules:

- Schedule LWL-1 – Monthly System Peak Demands (2006-11)
- Schedule LWL-2 – Monthly System Peak Demands versus System Hourly Load (2011)
- Schedule LWL-3 – Monthly Coincidental Peak Demands by Jurisdiction (2011)
- Schedule LWL-4 – Monthly System Peak Demands by Season (2006-11)

- Schedule LWL-5 – Chapter 5 of A Guide to FERC Regulation and Rate Making of Electric Utilities and Other Power Suppliers
- Schedule LWL-6 – Excerpts from FERC Opinion No. 501
- Schedule LWL-7 - FERC System Demand Tests

III. HISTORICAL MONTHLY SYSTEM PEAK DEMANDS

Q. Have you evaluated the merits of KCP&L using a 4CP versus a 12CP allocator?

A. Yes, I have. I prepared Schedules LWL-1 through LWL-7 to aid in evaluating the merits of alternative measures of maximum demand. I refer to the 4CP and 12CP allocators as measures of maximum demand.

Q. Please describe Schedule LWL-1

A. Schedule LWL-1 consists of a single sheet that shows monthly maximum system demands for the 2006 through 2011 calendar years. In Lines 1 through 13, I show the monthly system demands. In Lines 14 through 26, I show the rank for each month relative to the other months in that year. In Lines 27 through 39, I show for each month, the ratio of that month's peak demand to the annual system demand.

In Columns B through G, I show monthly data for the 2006 through 2011 calendar years. In Column H, I show the median value over the six-year period. In Columns I and J, I show the six-year minimums and maximums.

Q. Do you have any observations based on examination of the information you show in Schedule LWL-1?

A. Yes, I do. My observations are:

1) Clearly, any measure of maximum demand must include July and August because with one exception (2009) demands in these two months exceed all other monthly demands. In 2009, June had the highest demand of the year.[1]

2) To a lesser degree, coincidental demands in June, and to a somewhat lesser degree September, can reasonably be included as measures of maximum demand. With one exception (September 2009) during the six-year period (2006 – 2011), the four highest monthly demands occurred during the June through September period. Demands for the three months, June through August, exceed, without exception, 90 percent of the annual system peak. With one exception (September 2009), the demand reported for September exceeds 80 percent of the annual system peak demand. Demand in no other month exceeds 80 percent of system peak demand during the six-year period.

3) The maximum coincident demands during the winter months (December, January, and February) generally rank as the sixth through eighth highest monthly demands during the year. Maximum demands during these winter months are generally 25 to 35 percent less than the maximum annual demand.

4) Demands during the spring and fall months (March, April, October, and November) are considerably below demands during the winter and summer, and with two exceptions (November 2006 and October 2007) have the four lowest monthly maximum demands during the year. Maximum demands during these four spring and fall months are generally 35 to 45 percent less than the maximum annual demand.

[1] Note that over the six-year period the lowest monthly demand for the months of February, May and July through November occurred in 2009.

5) Demands during the month of May are usually the fifth or sixth highest of the year and are generally 20 to 30 percent below the system annual demand. In many respects, the load levels exhibited in May are similar to loads during the three winter months. However, considering climate conditions in the Kansas City area, the load characteristics in May are more closely aligned with the spring and summer months than with the winter months. Therefore, for analysis purposes, I will include May with the other spring months.

Q. What conclusions do you reach based on your observations of the data set forth in Schedule LWL-1?

A. For purposes of analyzing monthly system peak demands, there are three periods of analysis. The maximum demands occur in the summer months of June through September. The lowest demands occur during the spring and fall months (March, April, May, October, and November). Demands during the winter months (December, January, and February) fall someplace in between.

IV. ANALYSIS OF HOURLY LOADS

Q. Please describe Schedule LWL-2.

A. Schedule LWL-2 is a single page and shows a summary comparison of 2011 monthly system peak demands with hourly demands.

In Column A, I show the date and time of the monthly system peak demands ranked from highest to lowest. For example, the maximum annual demand occurred at 16:00 on August 1, whereas the second highest monthly demand occurred at 16:00 on July 27.

In Column D, I show the ratio of the monthly system peak demand to the annual system peak.

In Columns E, F, and G, I show the number of hours during the summer, winter, and other months that hourly load equals or exceeds the level shown for the maximum in Column C. For example, during the summer months, in only one hour did the system hourly load equal or exceed the annual system peak demand of 3,689 MW recorded at 16:00 on August 1. On the other hand, the lowest monthly system peak demand of 1,882 MW (reported at 16:00 on April 10) was equaled or exceeded 1,811 hours during the four summer months; 1,051 hours during the three winter months; and 350 hours during the five other months.

In Lines 14 through 20, I show similar information regarding the number of hours that hourly load equaled or exceeded accredited base load capacity. In Lines 22 through 26, I show the months that are included in each period.

Q. What observation do you make on examination of Schedule LWL-2?

A. The information on Schedule LWL-2 shows conclusively the dominance of KCP&L's summer peak demands. As shown, during 2011, hourly loads during the summer months equaled or exceeded the maximum load in the non-summer months (May - 2,828 MW) during 469 hours. These 469 hours represent 16 percent of the hours during the summer period and over 5 percent of the annual hours.

Hourly loads during the summer months equaled or exceeded the maximum monthly demand occurring during the winter months (February 8 - 2,646 MW) during 668 hours, whereas during the other months (May) this level was exceeded during only 10 hours.

When compared to the maximum monthly demand occurring during the spring and fall months, other than May (October 7 - 2,107 MW), hourly loads during the summer months equaled or exceeded 2,107 MW during 1,417 hours, or about 48 percent of the time. During the winter months, hourly loads equaled or exceeded the 2,107 MW October monthly maximum, during 406 hours (14 percent of the time).

Q. How do hourly loads compare to the Company's accredited capacity?

A. As I show in Line 18, the Company has accredited base load capacity of 3,263 MW (88.45 percent of 2011 maximum annual demand). During the summer, monthly hourly load equaled or exceeded this 3,263 MW level during 146 hours. Hourly load never exceeded this level in any month other than during the four summer months.

As I show in Line 20, considering the maintenance requirement associated with the Company's largest base load unit, the Company has capacity totaling 2,700 MW or about 73 percent of annual system demand. During the four summer months, the hourly load exceeded this level during 611 hours (21 percent of the time). Other than during the four summer months, this level was exceeded during only 7 hours in the month of May.

Q. What conclusions do you reach based on examination of Schedule LWL-2?

A. As with Schedule LWL-1, the inescapable conclusion is that any measure of maximum demand reasonably includes the four summer months of June through September. Further, due to the dominance of load levels during these four summer months any reasonable measure of maximum demand does not include demands during other months.

V. JURISDICTIONAL LOAD LEVELS

Q. PLEASE DESCRIBE SCHEDULE LWL-3.

A. Schedule LWL-3 consists of a single sheet that shows each jurisdiction's contribution to the 2011 monthly maximum demands.

In Lines 1 through 13, I show monthly coincident demands in the same order that I show in Schedule LWL-2. In Lines 14 through 26, I show averages over various periods.

In Lines 27 through 39, I show average monthly deliveries, and in Lines 40 through 53, monthly and annual load factors.

Q. What observation do you make on examination of Schedule LWL-3?

A. In this Schedule, I focus on monthly load factors. System load factor during the four summer months falls below 71.33 percent. The system load factor for these four summer months is less than for any other month except for May. This same relationship generally holds for both the Kansas and Missouri jurisdictions.

Based on these load factors, I again believe that the measure of maximum demand reasonably includes the four summer months. Maximum demands in the non-summer months do not reasonably belong with the four summer months.

VI. MONTHLY SYSTEM PEAK DEMANDS BY SEASON

Q. PLEASE DESCRIBE SCHEDULE LWL-4.

A. Schedule LWL-4 consists of a single sheet that shows monthly system peak demands by season for the 2006 through 2011 calendar years. The data shown in this Schedule is similar to that shown in Schedule 1, except the order in which I present the data, reflects the grouping of the monthly data as I described previously.

In Lines 1 through 17, I show monthly maximum demands. In Lines 18 through 34, I show the ratio of the monthly maximum demand to the annual maximum. In Lines 35 through 52, I show monthly average demands and in Lines 53 through 70, I show monthly load factors. In Lines 14 through 17, 31 through 34, 48 through 51, and 66 through 69, I show averages for the four summer months, the three winter months, the five spring and fall months, and the five spring and fall months excluding May. In Lines 52 and 70, I show annual averages.

In Columns C through H, I show data for each of the calendar years 2006 through 2011. In Column I, I show the average over the six-year period.

Q. **What observation do you make on examination of Schedule LWL-4?**

A. As with Schedules LWL-1, LWL-2, and LWL-3, examination of Schedule LWL-4 leads to the inescapable conclusion that the dominance of the summer period demands requires a measure of capacity responsibility that reflects conditions during the summer period (4CP). Measures of capacity responsibility that include the implications of the other months (12CP) are not appropriate. For example:

- During the four summer months, the average (six-year) monthly maximum demand amounts to over 92 percent of the annual maximum (Line 31, Column I).
- During the three summer months (June through August), the monthly maximum demand exceeds 90 percent of the maximum annual demand (Lines 19 through 21, Columns C through H).
- With the exception of September 2009, the maximum demand in September exceeds 81 percent of the system annual demand (Line 22). In 2011, the maximum demand in September amounts to nearly 95 percent of the maximum annual demand.
- During the three winter months, the monthly maximum demands never exceed 78 percent of the annual maximum and on only 4 occasions (December 2008 and 2009 and January 2009 and 2010) exceed 75 percent of annual maximum demand (Lines 23 through 25).
- Monthly demands (six-year average) during the three winter months are over 29 percent less than the annual maximum demand (Column I, Line 32).

- On average, monthly demands during the five spring and fall months are over 37 percent less than the annual maximum demand (Line 33, Column I).

The data I show in this Schedule again demonstrate that KCP&L is clearly a summer peaking utility. Summer demands dominate. As a result, the only reasonable measure of maximum demand is demands during the summer months. As an indication of the dominance of demands during the summer months, over the six-year period the monthly demand during July and August exceeds the maximum demand during March, April, and October.

VII. FERC SYSTEM DEMAND TESTS

Q. Has the Federal Energy Regulatory Commission (FERC) provided any guidance regarding the appropriate measure of peak period responsibility to use in the allocation of capacity cost?

A. Yes, FERC has addressed this issue on a number of occasions. In Schedule LWL-5, I have included a copy of Chapter 5 of a publication authored by Michael E. Small entitled *A Guide to FERC Regulation and Ratemaking of Electric Utilities and Other Power Suppliers* Third Edition (1994). As shown in this material the FERC has used a variety of tests, in a number of cases, to decide the issue of whether to use the 12CP or 4CP (and on occasion 3CP) method. In Schedule LWL-6, I have included excerpts from FERC Opinion No. 501 (123 FERC ¶ 61,047) which sets forth an even more definitive criteria for use of the tests set forth in Schedule LWL-5.

Q. What criteria does FERC rely on to determine the appropriate manner in which to allocate capacity cost?

A. FERC has generally found that if a utility's system demand (monthly peak demand) is relatively flat from month to month, the use of a 12CP allocator is appropriate. Conversely, if the "utility experiences a pronounced peak during "one, three, or four consecutive months, then under FERC precedent use of another CP method would be supported." As I have previously demonstrated, KCP&L experiences a pronounced peak during the summer period. With this pronounced peak, use of 12CP is not appropriate.

Q. Does Mr. Small identify tests that the FERC has relied on to determine whether a utility has a pronounced peak demand?

A. Yes, he did. Examination of the material I have included in Schedule LWL-5 indicates four different tests. The tests identified that FERC has relied are:

- Test 1 - Difference between 1) the average of the system peaks during the purported peak period divided by the annual peak and 2) the average of the system peaks during the purported off-peak period divided by the annual peak.
- Test 2 - The lowest monthly peak divided by the annual peak.
- Test 3 - The average of the twelve monthly peaks divided by annual peak.
- Supplemental Test - The extent to which peak demands in the purported non-peak months exceed the peak demands during the purported peak months.

Q. Have you evaluated KCP&L's demands using these various tests?

A. Yes, I have. I show the results of my analyses in Schedule LWL-7.

Q. Please describe Schedule LWL-7.

A. Schedule LWL-7 consists of a single sheet in which I evaluate KCP&L's monthly system peaks using each of the four tests identified by Mr. Small. In Lines 1 through 14, I show monthly maximum demands and the average of the monthly maximum demands. Unlike Schedules LWL-2 through LWL-4, the order in which I show the monthly maximum demands correspond to the calendar months, January through December. In Lines 15 through 27, I show the average of monthly peak demands over various assumed peak periods and the corresponding assumed off-peak period. I also show the ratio of the assumed off-peak period divided by the assumed peak period. Beginning in Line 28, I show the calculation of the various test identified by Mr. Small.

In Columns B through G, I show data and analyses for each year 2006 through 2011. In Column H, I show the median for the six-year period and in Columns I and J, the minimum and maximum.

Q. Please describe Test 1.

A. Test 1 is the difference between the ratio of the average purported peak period demands divided by the annual peak less the ratio of the average of the purported off-peak period demands divided by the annual peak. FERC has held that large differences support use of something other than the 12CP method. As I show in Line 37, assuming a 3-month peak period (June through August) the median of this difference amounts to 28.45 percent and ranges from 26.87 percent to 30.18 percent. In Line 40, I show that assuming a 4-month peak period the median difference amounts to 26.87 percent and ranges from

22.61 percent to 33.33 percent. As shown in Schedule LWL-5, FERC has found that differences above 20 percent support use of a method other than 12CP.[2]

Thus, for KCP&L, FERC Test 1 without question supports use of some method other than the 12CP method.

Q. Please describe Test 2.

A. Test 2 is the ratio of the lowest monthly peak demand divided by the maximum annual peak. FERC has found that the higher this ratio the greater the support for the 12CP. As I show in Schedule LWL-6, over the six-year period, the median of this ratio amounts to 56.09 percent (Line 46, Column H) and ranges from 51.02 to nearly 59.55 percent. Of the 14 cases cited by Mr. Small, in all cases with a ratio in excess of 70 percent the FERC found the 12CP method appropriate.[3] With one exception, all cases with a ratio of less than 70 percent the FERC found the 3CP or 4CP method appropriate. That one exception relates to an Illinois Power case in which the Test 1 difference amounted to 19 percent and the Test 2 ratio to 66 percent. In that case the FERC found use of the 12CP method appropriate.

Thus, for KCP&L, FERC Test 2 without question supports use of some method other than the 12CP method.

Q. Please describe Test 3.

A. Test 3 is the average of the 12-monthly peak demands as a percentage of maximum annual demand. As shown in Line 55, during the six-year period, this ratio ranged from

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[2] In Opinion No. 501 (Schedule LWL-6), FERC shows that the 12CP is appropriate when this ratio is equal to or less than 19 percent.

[3] In Opinion No. 501 (Schedule LWL-6), FERC shows that the 12CP is appropriate when this ratio is equal to or greater than 66 percent.

73.68 to 75.49 percent. FERC has generally found that where this percentage is below 81 percent something other than the 12CP method should be used.[4]

Thus according to FERC Test 3, the 12CP method should not be used.

Q. Please describe what you refer to in Schedule LWL-7 as the Supplemental Test.

A. Another test Mr. Small identifies is the extent to which monthly system peak demands in the "non-peak" months exceed system peaks during the "peak" months. As I show in Line 51 of Schedule LWL-7, if the four summer months are considered the peak period, on three occasions in 2009, monthly "off-peak" demands exceed monthly "peak" period demands. The three months of December, January, and February 2009 exceed the maximum demand for September 2009. The maximum demand for September 2009 was about 600 MW below the six-year median for September and over 550 MW below the second lowest demand during the 2006 through 2011 period. Clearly, the maximum demand for September 2009 does not represent normal conditions.

Thus for KCP&L, this supplemental test supports use of the 4CP method.

Q. Based on examination of the data set forth in Schedule LWL-7, what do you conclude?

A. Based on the tests set forth in various FERC orders, without question the 12CP method is not appropriate for use to allocate capacity costs among the jurisdictions served by KCP&L. I therefore recommend that the Commission order the Company use the four (4) coincidental peak demands during the months of June through September to allocate capacity costs among jurisdictions.

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4 In Opinion No. 501 (Schedule LWL-6), FERC shows that the 12CP is appropriate when this ratio is equal to or greater than 81 percent.

Q. What are the implications of using a 4CP to allocate capacity costs among jurisdictions?

A. Mr. Weisensee informs me that changing the capacity cost allocator from 12CP to 4CP results in an increase in costs allocated to the Kansas jurisdiction of $10.4 million.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of	)	
Kansas City Power & Light Company	)	Docket No.: 12-KCPE- -RTS
to Make Certain Changes in	)	
Its Charges for Electric Service	)	

AFFIDAVIT OF LARRY W. LOOS

STATE OF ARIZONA)
) **ss**
COUNTY OF PINAL)

Larry W. Loos, being first duly sworn, deposes and says that he is the witness who sponsors the accompanying testimony entitled, "Direct Testimony of Larry W. Loos"; that said testimony and schedules were prepared by him and/or under his direction and supervision; that if inquiries were made as to the facts in said testimony and schedules, he would respond as therein set forth; and that the aforesaid testimony and schedules are true and correct to the best of his knowledge.

Larry W Loos
Larry W. Loos

Subscribed and sworn before me this 11th day of April, 2012.

Notary Public

DANIELA MARIA GALINDO
Notary Public - Arizona
Pinal County
My Commission Expires
April 12, 2015

My commission expires: April 12, 2015

Kansas City Power and Light Company
Case No. ER-2014-0370

Kansas City Power Light Company
Monthly System Peak Demands
2006 - 2011 Calendar Years

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
Line No.	Description	2006	2007	2008	2009	2010	2011	Median	Minimum	Maximum
		MW	MW	MW	MW	MW	MW	MW	MW	MW
1	Monthly System Peak Demands - MW									
2	January	2,550	2,588	2,522	2,631	2,811	2,548	2,569	2,522	2,811
3	February	2,438	2,425	2,473	2,390	2,445	2,646	2,441	2,390	2,646
4	March	2,187	2,197	2,209	2,235	2,113	2,058	2,192	2,058	2,235
5	April	2,110	2,301	1,957	2,031	2,018	1,882	2,025	1,882	2,301
6	May	2,564	2,761	2,625	2,363	2,825	2,828	2,693	2,363	2,828
7	June	3,267	3,431	3,195	3,448	3,398	3,377	3,388	3,195	3,448
8	July	3,609	3,689	3,428	3,182	3,412	3,593	3,511	3,182	3,689
9	August	3,480	3,436	3,495	3,238	3,603	3,689	3,487	3,238	3,689
10	September	2,970	3,243	2,924	2,389	2,947	3,491	2,959	2,389	3,491
11	October	2,392	2,552	1,981	1,937	2,086	2,107	2,097	1,937	2,552
12	November	2,505	2,239	2,150	2,071	2,220	2,080	2,185	2,071	2,505
13	December	2,623	2,443	2,670	2,620	2,442	2,316	2,532	2,316	2,670
14	Monthly System Peak Demands - Rank									
15	January	7	6	7	4	6	7	6	4	7
16	February	9	9	8	6	7	6	8	6	9
17	March	11	12	9	9	10	11	9	9	12
18	April	12	10	12	11	12	12	12	10	12
19	May	6	5	6	8	5	5	5	5	8
20	June	3	3	3	1	3	4	3	1	4
21	July	1	1	2	3	2	2	1	1	3
22	August	2	2	1	2	1	1	2	1	2
23	September	4	4	4	7	4	3	4	3	7
24	October	10	7	11	12	11	9	11	7	12
25	November	8	11	10	10	9	10	10	8	11
26	December	5	8	5	5	8	8	7	5	8
27	Monthly System Peak Demands - Percent of Maximum Annual									
28	January	70.66%	70.15%	72.16%	76.31%	78.02%	69.07%	71.41%	69.07%	78.02%
29	February	67.54%	65.72%	70.76%	69.32%	67.86%	71.73%	68.59%	65.72%	71.73%
30	March	60.60%	59.55%	63.20%	64.82%	58.65%	55.79%	60.07%	55.79%	64.82%
31	April	58.46%	62.36%	55.99%	58.90%	56.01%	51.02%	57.24%	51.02%	62.36%
32	May	71.04%	74.83%	75.11%	68.53%	78.41%	76.66%	74.97%	68.53%	78.41%
33	June	90.51%	93.00%	91.42%	100.00%	94.31%	91.54%	92.27%	90.51%	100.00%
34	July	100.00%	100.00%	98.08%	92.29%	94.70%	97.40%	97.74%	92.29%	100.00%
35	August	96.42%	93.13%	100.00%	93.91%	100.00%	100.00%	98.21%	93.13%	100.00%
36	September	82.31%	87.89%	83.66%	69.29%	81.79%	94.63%	82.99%	69.29%	94.63%
37	October	66.27%	69.16%	56.68%	56.18%	57.90%	57.12%	57.51%	56.18%	69.16%
38	November	69.42%	60.68%	61.52%	60.06%	61.62%	56.38%	61.10%	56.38%	69.42%
39	December	72.69%	66.22%	76.39%	75.99%	67.78%	62.78%	70.23%	62.78%	76.39%

3/26/2012 Schedule LWL-2

Kansas City Power Light Company
Monthly System Peak Demands
Versus
System Hourly Load
Calendar Year 2011

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Description	Rank	Total KCP&L	Ratio to Annual	Hours - Load at or Above Summer	Winter	Other
			MW		MW	MW	MW
1	Monthly System Peak Demands - MW						
2	08/01/11 16:00	1	3,689	100.00%	1	-	-
3	07/27/11 16:00	2	3,593	97.40%	10	-	-
4	09/01/11 16:00	3	3,491	94.63%	43	-	-
5	06/30/11 16:00	4	3,377	91.54%	87	-	-
6	05/10/11 16:00	5	2,828	76.66%	469	-	1
7	02/08/11 18:00	6	2,646	71.73%	668	1	10
8	01/13/11 07:00	7	2,548	69.07%	780	6	18
9	12/05/11 18:00	8	2,316	62.78%	1,099	112	40
10	10/07/11 15:00	9	2,107	57.12%	1,417	406	66
11	11/28/11 18:00	10	2,080	56.38%	1,461	464	75
12	03/09/11 18:00	11	2,058	55.79%	1,495	526	90
13	04/10/11 16:00	12	1,882	51.02%	1,811	1,051	350
14	Accredited Base Load Capacity						
15	Wolf Creek		545				
16	Steam		2,703				
17	Wind		15				
18	Total		3,263	88.45%	146	-	-
19	Largest Unit (Hawthorne 5)		563				
20	Total Less Largest Unit		2,700	73.19%	611	-	7
21	Total Hours in Period				2,928	2,904	2,928
22	Months in Period				June	December	March
23					July	January	April
24					August	February	May
25					September		October
26							November

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Kansas City Power and Light Company
Case No. ER-2014-0370

3/26/2012

Kansas City Power Light Company
Monthly Coincidental Peak Demands
2011 by Jurisdiction

Schedule LWL-3

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Description	Rank	Total KCP&L	Missouri	Kansas	FERC
			MW	MW	MW	MW
1	Monthly Coincident Peak Demands					
2	08/01/11 16:00	1	3,689	1,929	1,737	23
3	07/27/11 16:00	2	3,593	1,893	1,677	24
4	09/01/11 16:00	3	3,491	1,828	1,640	23
5	06/30/11 16:00	4	3,377	1,778	1,577	22
6	05/10/11 16:00	5	2,828	1,536	1,277	15
7	02/08/11 18:00	6	2,646	1,421	1,202	23
8	01/13/11 07:00	7	2,548	1,372	1,156	20
9	12/05/11 18:00	8	2,316	1,263	1,036	17
10	10/07/11 15:00	9	2,107	1,181	915	11
11	11/28/11 18:00	10	2,080	1,154	910	16
12	03/09/11 18:00	11	2,058	1,143	899	16
13	04/10/11 16:00	12	1,882	1,014	858	10
14	Average					
15	1CP		3,689	1,929	1,737	23
16	Portion of Total		100.00%	52.30%	47.07%	0.62%
17	4CP		3,538	1,857	1,658	23
18	Portion of Total		100.00%	52.49%	46.86%	0.65%
19	3 Winter Months		2,503	1,352	1,131	20
20	Portion of Total		100.00%	54.00%	45.20%	0.80%
21	5 Spring and Fall Months		2,191	1,206	972	13
22	Portion of Total		100.00%	55.03%	44.36%	0.61%
23	12CP		2,718	1,459	1,240	18
24	Portion of Total		100.00%	53.69%	45.64%	0.67%
25	Annual		1,854	1,057	786	12
26	Portion of Total		100.00%	56.97%	42.36%	0.66%
27	Average Monthly Deliveries					
28	Aug 11		2,265	1,264	987	15
29	Jul 11		2,563	1,414	1,132	17
30	Sep 11		1,682	967	704	10
31	Jun 11		2,131	1,197	922	13
32	May 11		1,629	939	680	10
33	Feb 11		1,903	1,083	805	15
34	Jan 11		1,972	1,114	843	15
35	Dec 11		1,773	1,014	747	13
36	Oct 11		1,563	913	640	9
37	Nov 11		1,612	936	664	11
38	Mar 11		1,652	957	684	12
39	Apr 11		1,498	875	614	9
40	Load Factor					
41	Aug 11		61.41%	65.52%	56.82%	63.17%
42	Jul 11		71.33%	74.69%	67.54%	70.66%
43	Sep 11		48.17%	52.92%	42.92%	44.62%
44	Jun 11		63.11%	67.30%	58.44%	58.54%
45	May 11		57.59%	61.14%	53.25%	63.38%
46	Feb 11		71.90%	76.20%	66.98%	63.64%
47	Jan 11		77.41%	81.22%	72.91%	76.56%
48	Dec 11		76.55%	80.26%	72.08%	73.55%
49	Oct 11		74.16%	77.32%	69.92%	87.91%
50	Nov 11		77.48%	81.14%	72.99%	68.37%
51	Mar 11		80.27%	83.71%	76.02%	73.52%
52	Apr 11		79.61%	86.31%	71.51%	95.93%
53	Annual		50.27%	54.76%	45.24%	53.55%

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3/26/2012

Schedule LWL-4

Kansas City Power Light Company
Monthly System Peak Demand
2006-11 Calendar Years by Season

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
Line No.	Description	Rank	2006 MW	2007 MW	2008 MW	2009 MW	2010 MW	2011 MW	Average MW
1	Monthly Peak Demands - MW								
2	June	3	3,267	3,431	3,195	3,448	3,398	3,377	3,353
3	July	2	3,609	3,689	3,426	3,182	3,412	3,593	3,486
4	August	1	3,480	3,436	3,495	3,238	3,603	3,689	3,490
5	September	4	2,970	3,243	2,924	2,389	2,947	3,491	2,994
6	December	7	2,623	2,443	2,670	2,620	2,442	2,316	2,519
7	January	6	2,550	2,588	2,522	2,631	2,811	2,548	2,608
8	February	8	2,438	2,425	2,473	2,390	2,445	2,646	2,469
9	March	11	2,187	2,197	2,209	2,235	2,113	2,058	2,166
10	April	12	2,110	2,301	1,957	2,031	2,018	1,882	2,050
11	May	5	2,564	2,761	2,625	2,363	2,625	2,828	2,661
12	October	10	2,392	2,552	1,981	1,937	2,086	2,107	2,176
13	November	9	2,505	2,239	2,150	2,071	2,220	2,080	2,211
14	Average Summer		3,331	3,450	3,261	3,064	3,340	3,538	3,331
15	Average Winter		2,537	2,485	2,555	2,547	2,566	2,503	2,532
16	Average Spring/Fall		2,352	2,410	2,184	2,127	2,252	2,191	2,253
17	Excluding May		2,299	2,322	2,074	2,069	2,109	2,032	2,151
18	Ratio to Annual Maximum Demand								
19	June	3	90.51%	93.00%	91.42%	100.00%	94.31%	91.54%	93.46%
20	July	2	100.00%	100.00%	98.08%	92.29%	94.70%	97.40%	97.08%
21	August	1	96.42%	93.13%	100.00%	93.91%	100.00%	100.00%	97.24%
22	September	4	82.31%	87.89%	83.66%	69.29%	81.79%	94.63%	83.26%
23	December	7	72.69%	66.22%	76.39%	75.99%	67.78%	62.78%	70.31%
24	January	6	70.66%	70.15%	72.16%	76.31%	78.02%	69.07%	72.73%
25	February	8	67.54%	65.72%	70.76%	69.32%	67.86%	71.73%	68.82%
26	March	11	60.60%	59.55%	63.20%	64.82%	58.65%	55.79%	60.43%
27	April	12	58.46%	62.36%	55.99%	58.90%	56.01%	51.02%	57.12%
28	May	5	71.04%	74.83%	75.11%	68.53%	78.41%	76.66%	74.10%
29	October	10	66.27%	69.16%	56.68%	56.18%	57.90%	57.12%	60.55%
30	November	9	69.42%	60.68%	61.52%	60.06%	61.62%	56.38%	61.61%
31	Average Summer		92.31%	93.50%	93.29%	88.87%	92.70%	95.89%	92.76%
32	Average Winter		70.30%	67.36%	73.10%	73.87%	71.22%	67.86%	70.62%
33	Average Spring/Fall		65.16%	65.31%	62.50%	61.70%	62.51%	59.39%	62.76%
34	Excluding May		63.69%	62.94%	59.35%	59.99%	58.54%	55.08%	59.93%
35	Monthly Average Demands - MW								
36	June	3	2,017	2,051	2,039	2,078	2,226	2,131	2,090
37	July	2	2,267	2,336	2,256	2,021	2,332	2,563	2,296
38	August	1	2,195	2,274	2,152	2,030	2,389	2,265	2,216
39	September	4	1,788	1,834	1,738	1,668	1,796	1,682	1,751
40	December	7	1,832	1,870	1,953	1,943	1,893	1,773	1,877
41	January	6	1,871	1,920	1,929	1,936	2,025	1,972	1,942
42	February	8	1,777	1,829	1,908	1,757	1,941	1,903	1,852
43	March	11	1,634	1,625	1,664	1,636	1,662	1,652	1,646
44	April	12	1,518	1,562	1,575	1,587	1,541	1,498	1,547
45	May	5	1,619	1,672	1,619	1,603	1,672	1,629	1,635
46	October	10	1,568	1,614	1,585	1,565	1,521	1,563	1,569
47	November	9	1,653	1,658	1,670	1,572	1,616	1,612	1,630
48	Average Summer		2,067	2,124	2,047	1,949	2,186	2,160	2,089
49	Average Winter		1,827	1,873	1,930	1,879	1,953	1,883	1,891
50	Average Spring/Fall		1,824	1,875	1,919	1,847	1,983	1,938	1,897
51	Excluding May		1,593	1,615	1,624	1,590	1,585	1,581	1,598
52	Average Annual		1,813	1,855	1,841	1,784	1,885	1,854	1,839
53	Monthly Load Factor								
54	June	3	61.73%	59.77%	63.83%	60.28%	65.50%	63.11%	62.37%
55	July	2	62.81%	63.32%	65.81%	63.52%	68.34%	71.33%	65.86%
56	August	1	63.08%	66.19%	61.58%	62.68%	66.30%	61.41%	63.54%
57	September	4	60.19%	56.58%	59.45%	69.83%	60.95%	48.17%	59.19%
58	December	7	69.83%	76.55%	73.15%	74.16%	77.51%	76.55%	74.62%
59	January	6	73.37%	74.20%	76.48%	73.60%	72.04%	77.41%	74.52%
60	February	8	72.90%	75.43%	77.17%	73.50%	79.38%	71.90%	75.05%
61	March	11	74.72%	73.97%	75.34%	73.20%	78.64%	80.27%	76.02%
62	April	12	71.93%	67.87%	80.49%	78.15%	76.36%	79.61%	75.74%
63	May	5	63.17%	60.55%	61.66%	67.82%	59.18%	57.59%	61.66%
64	October	10	65.55%	63.26%	79.99%	80.78%	72.92%	74.16%	72.78%
65	November	9	65.99%	74.08%	77.69%	75.92%	72.81%	77.48%	73.99%
66	Average Summer		62.03%	61.57%	62.77%	63.62%	65.44%	61.07%	62.75%
67	Average Winter		72.00%	75.37%	75.54%	73.76%	76.11%	75.21%	74.66%
68	Average Spring/Fall		77.56%	77.80%	87.83%	86.80%	88.04%	88.43%	84.41%
69	Excluding May		69.31%	69.54%	78.27%	76.87%	75.15%	77.82%	74.49%
70	Annual		50.22%	50.28%	52.69%	51.74%	52.32%	50.27%	51.25%

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Chapter Five—Functionalization, Classification, and Allocation

In allocating costs to a particular class of customers, there are three major steps (if all cost of service issues have been resolved): (1) functionalization, (2) classification, and (3) allocation. FERC has indicated that a guiding principle for this step is that the allocation must reflect cost causation. *See, e.g.*, *Kentucky Utilities Co.*, Opinion No. 116-A, 15 FERC ¶61,222, p. 61,504 (1983); *Utah Power & Light Co.*, Opinion No. 113, 14 FERC ¶61,162, p. 61,298 (1981).[133]

A. Functionalization

Generally, plant or expense items are first functionalized into five major categories:

(1) Production;

(2) Transmission;

(3) Distribution;

(4) General and Intangible; and

(5) Common and Other.

See 18 C.F.R. §35.13(h)(4)(iii) (plant); 18 C.F.R. §35.13(h)(8)(i) (O&M expenses). Each plant or expense item will be segregated into the category with which it is most closely related.

While functionalization for most items is relatively straightforward, and not usually litigated, problems do arise with respect to the functionalization of administrative and general expenses (A&G)[134] and general plant expenses.[135] FERC stated that:

> The Commission normally requires that A&G and General Plant expenses be allocated on the basis of total company labor ratios. Under such allocation method, A&G and General Plant expense items are 'functionalized,' or segregated into...

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133 Where a company has significant non-jurisdictional business, the above cost incurrence principle is important in keeping FERC within its jurisdictional constraints. *See Panhandle Eastern Pipe Line Co. v. FPC*, 324 U.S. 635, 641-42 (1945) ("the Commission must make a separation of the regulated and unregulated business...Otherwise the profits or losses...of the unregulated business would be assigned to the regulated business and the Commission would transgress the jurisdictional lines which Congress wrote into the Act").

134 A&G expenses include salaries of officers, executives, and office employees, employee benefits, insurance, etc.

135 General plant includes office furniture and equipment, transportation vehicles, lockers, tools, lab equipment, etc.

> production, transmission, distribution, customer accounts, customer service, information, and sales. This 'functionalization' is in proportion to the ratio of the labor cost in each major function to total labor costs less A&G and General Plant labor. Each functionalized component is allocated to customer groups.

Utah Power & Light Co., Opinion No. 308, 44 FERC ¶61,166, p. 61,549 (1988). *See also Minnesota Power & Light Co.*, Opinion No. 20, 4 FERC ¶61,116, p. 61,268 (1978) (general plant will be functionalized by labor ratios unless it is shown that the use of labor ratios produces unreasonable results). In many cases, FERC has allowed labor ratios to be used to functionalize general plant. *See, e.g., Utah Power & Light Co.*, Opinion No. 308, 44 FERC at 61,549; *Kansas City Power & Light Co.*, 21 FERC ¶63,003, p. 65,034 (1982), *aff'd*, 22 FERC ¶61,262 (1983); *Delmarva Power & Light Co.*, 17 FERC ¶63,044, p. 65,204 (1981), *aff'd*, Opinion No. 185, 24 FERC ¶61,199 (1983); *Philadelphia Electric Co.*, 10 FERC ¶63,034, pp. 65,355-56, *aff'd*, 13 FERC ¶61,057 (1980). Similarly, FERC has required that most A&G expenses be functionalized on the basis of labor ratios. *Missouri Power & Light Co.*, Opinion No. 31, 5 FERC ¶61,086, pp. 61,137–38 (1978); *Kansas City Power & Light Co.*, 21 FERC at 65,035; *Delmarva Power & Light Co.*, 17 FERC at 65,204. An exception to this has been established for property insurance which has been functionalized on plant ratios. *Pacific Gas & Electric Co.*, 16 FERC ¶63,004, pp. 65,015-16 (1981), *aff'd*, Opinion No. 147, 20 FERC ¶61,340 (1982); *Kansas-Nebraska Natural Gas Co.*, Opinion No. 731, 53 FPC 1691, 1722 (1975).

Common plant and intangible plant also have been analogized to general plant and functionalized on the basis of labor ratios. *Kansas City Power & Light*, 21 FERC at 65,035; *Delmarva Power & Light Co.*, 17 FERC at 65,204; *Philadelphia Electric*, 10 FERC at 65,355-56.

Another issue that has arisen is the calculation of the labor ratios. Usually, the labor ratio consists of total labor costs in the denominator with the labor costs associated with a particular category in the numerator. In a number of proceedings, companies have attempted to change the ratio by only including production, transmission, and distribution-related labor costs in the denominator, thereby excluding customer service related labor costs. FERC rejected this in at least one case. *Kansas City Power & Light*, 21 FERC at 65,033–34.

B. Classification

After functionalizing, the next step is to classify those expenses or costs into one of three categories (1) demand, (2) energy, or (3) other. *See* 18 C.F.R. §35.13(h)(8)(ii)(A).

FERC's Staff for a number of years has used the predominance method for classifying production O&M accounts. Under this method if an account is *predominantly* (51–100%) energy-related, it will be classified as energy. The same also is true with respect to demand related costs. FERC has accepted this method in a number of cases. *See, e.g., Arizona Public Service Co.*, 4 FERC ¶61,101, pp. 61,209-10 (1978); *Illinois Power Co.*, 11 FERC ¶63,040, pp. 65,255-56 (1980), *aff'd*, 15 FERC ¶61,050, p. 61,093 (1981); *Kansas City Power & Light*

Co., 21 FERC ¶63,003, p. 65,037 (1982), *aff'd*, 22 FERC ¶61,262 (1983); *Minnesota Power & Light Co.*, Opinion No. 86, 11 FERC ¶61,312, pp. 61,648-49 (1980).[136]

In addition to FERC's adoption of Staff's predominance method, FERC also has adopted Staff's classification index of production O&M accounts. *Arizona Public Service Co.*, 4 FERC at 61,209-10; *Kansas City Power & Light*, 21 FERC at 65,037; *Minnesota Power & Light Co.*, 11 FERC at 61,648-49. In *Montaup Electric Co.*, Opinion No. 267, 38 FERC at 61,864, FERC rejected a proposed rate tilt, finding that the "proposal is inconsistent with the classification table of predominant characteristics for operation and maintenance accounts used by Staff, which has been approved by the Commission." In *Southern Company Services*, Opinion No. 377, 61 FERC ¶61,075, p. 61,311 (1992), *reh. denied*, 64 FERC ¶61,033 (1993), FERC, however, stated that the Staff index is not mandatory. FERC accepted a departure from the Staff's index, though it held that a party proposing a departure has the burden of justifying that departure.

C. Allocation

After classifying costs to demand, energy, and customer categories, the next step is to allocate these costs to the various classes to determine their respective cost responsibilities. In the past, the most hotly litigated allocation issue involved demand cost allocation. Typically, FERC has allocated demand costs on a coincident peak (CP) method. *Houlton v. Maine Public Service Co.*, 62 FERC ¶63,023, p. 65,092 (1992) ("Maine Public has cited a legion of Commission decisions affirming the use of a coincident peak demand allocator.... And, it denies knowledge of '*any* decision, involving an electric utility since the FERC came into existence in 1977, where FERC did not follow a coincident peak method of allocating demand costs' "). In *Lockhart Power Co.*, 4 FERC ¶61,337, p. 61,807 (1978), FERC stated that its "general policy is to allocate demand costs on the basis of peak responsibility as is demonstrated by the overwhelming majority of decided cases." *See also Houlton v. Maine Public Service Co.*, 62 FERC at 65,092. Under a CP method, the demands used in the allocation are the demands of a particular customer or class occurring at the time of the system peak for a particular time period. The basic assumption behind this method is that capacity costs are incurred to serve the peak needs of customers.

1. Coincident Peak Allocation

In most cases, FERC has accepted one of four CP methods—1 CP, 3 CP, 4 CP, and 12 CP, with the largest number of companies using a 12 CP allocation. Under a 1 CP method, the allocator for a particular wholesale class will be developed by dividing the wholesale class's CP for the peak month by the total company system peak. Similarly, for 3, 4, and 12

136 If a company is able to justify a percentage split, such as 70-30, in an account, then FERC may accept that split. However, in light of FERC precedent on this subject, any party proposing a deviation from the predominance method likely will have the burden of justifying its proposed split.

CP companies the numerator would consist of the average of the wholesale class's coincident peaks for each of the peak months, while the denominator would consist of the average of the total system peaks for each of the peak months. FERC has held that interruptible loads should not be reflected in this demand allocation.[137] *See Delmarva Power & Light Co.*, Opinion No. 189, 25 FERC at 61,121; *Delmarva Power & Light Co.*, Opinion No. 185, 24 FERC ¶61,199, p. 61,462 (1983).

While FERC has not established a hard and fast rule for determining which allocation method is appropriate, it has stated that the following factors should be considered:

> [T]he full range of a company's operating realities including, in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments. (footnote omitted).

Carolina Power & Light Co., Opinion No. 19, 4 FERC ¶61,107, p. 61,230 (1978); *Commonwealth Edison Co.*, 15 FERC ¶63,048, p. 65,196 (1981), *aff'd*, Opinion No. 165, 23 FERC ¶61,219 (1983); *Illinois Power Co.*, 11 FERC ¶63,040, pp. 65,247-48 (1980), *aff'd*, 15 FERC ¶61,050 (1981). *See also Houlton v. Maine Public Service Co.*, 62 FERC at 65,092 (applying FERC's various tests in finding that a 12 CP was appropriate).

a. System Demand Tests

If a utility's system demand curve is relatively flat, then that supports the use of a 12 CP method under FERC precedent. If a utility experiences a pronounced peak during one, three, or four consecutive months, then under FERC precedent the use of another CP method would be supported.

In determining whether a utility experiences a pronounced peak during a particular time period, FERC considers a number of tests. First, FERC has compared the average of the system peaks during the purported peak period, as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak. FERC has held that large differences between these two figures lends support to using something other than a 12 CP method, while a smaller difference supports 12 CP, as shown below:[138]

(1) *Louisiana Power & Light Co.*,
Opinion No. 813,
59 FPC 968 (1977)
(31% difference—4 CP);

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137 FERC ordered that the revenues from the interruptible loads be credited to the cost of service. *Delmarva Power & Light Co.*, 28 FERC ¶61,279, p. 61,510 (1984).

138 *See also Houlton v. Maine Public Service Co.*, 62 FERC ¶63,023, p. 65,092 (1992) (the ALJ stated that "using established Commission tests that compare average monthly peaks with the annual peak, lowest monthly peak to the annual peak, average monthly demand peaks of the peak season to the monthly demand peaks of the off-peak service" Maine Public is a 12 CP company).

(2) *Louisiana Power & Light Co.*,
Opinion No. 110,
14 FERC ¶61,075 (1981)
(26% difference—4 CP);

(3) *Lockhart Power Co.*,
Opinion No. 29,
4 FERC ¶61,337 (1978)
(18% difference—12 CP);

(4) *Illinois Power Co.*,
11 FERC at 65,248,
(19% difference—12 CP);

(5) *Commonwealth Edison Co.*,
15 FERC at 65,196
(16.4-24.9% differences—4 CP);

(6) *Southwestern Public Service Co.*,
18 FERC at 65,034
(average difference of 22.9%; high of 28.3%—3 CP).

FERC also has used a second test involving the lowest monthly peak as a percentage of the annual peak. The higher the percentage, the greater the support for 12 CP. This test has been used in the following cases:

(1) *Louisiana Power & Light Co.*,
Opinion No. 813,
59 FPC 968 (1977)
(56%—4 CP);

(2) *Idaho Power Co.*,
Opinion No. 13,
3 FERC ¶61,108 (1978)
(58%—3 CP);

(3) *Southwestern Electric Power Co.*,
Opinion No. 28,
4 FERC ¶61,330 (1978)
(55.8%—4 CP);

(4) *Lockhart Power Co.*,
Opinion No. 29,
4 FERC ¶61,337 (1978)
(73%—12 CP);

(5) *Southern California Edison Co.*,
Opinion No. 821,
59 FPC 2167 (1977)
(79%—12 CP);

(6) *Alabama Power Co.*,
Opinion No. 54,
8 FERC ¶61,083 (1979)
(75%—12 CP);

(7) *Illinois Power Co.*,
11 FERC at 65,248
(66%—12 CP);

(8) *Commonwealth Edison Co.*,
15 FERC at 65,198
(64.6-67.8%—4 CP);

(9) *Louisiana Power & Light Co.*,
Opinion No. 110,
14 FERC ¶61,075 (1981)
(61.9%—4 CP);

(10) *El Paso Electric Co.*,
Opinion No. 109,
14 FERC ¶61,082 (1981)
(71%—12 CP);

(11) *Carolina Power & Light Co.*,
Opinion No. 19,
4 FERC ¶61,107 (1978)
(72%—12 CP);

(12) *New England Power Co.*,
Opinion No. 803,
58 FPC 2322 (1977)
(80%—12 CP);

(13) *Southwestern Public Service Co.*,
18 FERC at 65,034
(on average, almost 67 percent—3 CP); and

(14) *Delmarva Power & Light Co.*,
17 FERC at 65,201
(71.4%—12 CP).

Another test that has been utilized by FERC is the extent to which peak demands in non-peak months exceed the peak demands in the alleged peak months. In *Carolina Power & Light Co.*, Opinion No. 19, 4 FERC at 61,230, FERC adopted a 12 CP approach where the monthly peaks in three nonpeak months exceeded the peaks in two of the alleged peak months. In *Commonwealth Edison Co.*, 15 FERC at 65,198, FERC adopted a 4 CP method where over a four year period, a peak in one of the 4 peak months was exceeded only once by a peak from a non-peak month. *See also Southwestern Public Service Co.*, 18 FERC at 65,034 (monthly peak in any non-peaking month exceeded the monthly peak in peak month only once and 3 CP adopted).

A last test involves the average of the twelve monthly peaks as a percentage of the highest monthly peak and has been used in the following cases:

(1) *Illinois Power Co.*,
11 FERC at 65,248-49
(81%—12 CP);

(2) *El Paso Electric Co.*
Opinion No. 109,
14 FERC ¶61,082 (1981)
(84%—12 CP);

(3) *Lockhart Power Co.*,
Opinion No. 29,
4 FERC ¶61,337 (1978)
(84%—12 CP);

(4) *Southern California Edison Co.*,
Opinion No. 821,
59 FPC 2167 (1977)
(87.8%—12 CP);

(5) *Louisiana Power & Light Co.*,
Opinion No. 110,
14 FERC ¶61,075 (1981)
(81.2%—4 CP);

(6) *Commonwealth Edison Co.*,
15 FERC at 65,198
(79.4-79.5%—4 CP);

(7) *Southwestern Public Service Co.*,
18 FERC at 65,035
(80.1%—3 CP); and

(8) *Delmarva Power & Light Co.*,
17 FERC at 65,202
(83.3%—12 CP).

b. Tests Relating to Reserves/Maintenance

To the extent a utility uses the off-peak months to perform its scheduled maintenance, FERC has found that supportive of the use of a 12 CP method. *Alabama Power Co.*, Opinion No. 54, 8 FERC ¶61,083, p. 61,327 (1979); *Illinois Power Co.*, 11 FERC at 65,249; *New England Power Co.*, Opinion No. 803, 58 FPC 2322, 2338 (1977); *Delmarva Power & Light Co.*, 17 FERC at 65,202. *But see Commonwealth Edison*, 15 FERC at 65,199.[139]

However, the scheduled maintenance must be considered together with the reserves available after the maintenance. To the extent the reserve margins are fairly stable after maintenance, then a 12 CP method is supported. If the reserve margins drop substantially to marginal levels during certain months, then a method other than 12 CP may be supported. *See, e.g., Illinois Power Co.*, 11 FERC at 65,249 (46 percent reserves after maintenance non-summer months and 34.5 percent for summer months—12 CP); *Commonwealth Edison Co.*, 15 FERC at 65,200 (for 1979 36.63 percent reserves after maintenance for 8 non-summer months and 22.15 percent for 4 summer months—4 CP).

c. Projection of CP and Total System Demands

In a number of cases, parties and the FERC Staff have challenged the filing company's estimated coincident peak or total system demand estimates.[140] While FERC appears to have established few hard and fast rules, the following cases provide some guidance. First, parties have challenged projections on the basis that the historical periods used were not representative. In some cases, FERC has held that multiple years of historical data should be

139 In *Southwestern Public Service Co.*, Opinion No. 337, 49 FERC ¶61,296, p. 62,132 (1989), FERC declined to depart from the 3 CP method based on "monthly load patterns and reserve margins as affected by scheduled maintenance" which "show that Southwestern's capacity requirements are largely determined by the peak demands imposed on the system during a three-month summer period."

140 In *Blue Ridge Power Agency v. Appalachian Power Co.*, Opinion No. 363, 55 FERC ¶61,509, p. 62,788 (1991), FERC accepted the Staff's method for deriving a coincident peak estimate. The Staff asserted that the noncoincident peak estimate must be divided by the diversity factor to convert each noncoincident peak demand into a comparable coincident peak demand. 55 FERC at 62,788-89. The "diversity factor is the noncoincident peak demand divided by the coincident peak demand." 55 FERC at 62,788 n. 87. FERC, however, stated that "[n]ormally, we would calculate the coincident peak demand for the sales for resales group by looking at its consumption at the time of Appalachian's peak. In this case, however, we have the forecasted monthly noncoincident peak demands for the customer group" and that "[u]sing the historical diversity factor for the group, we can derive the calculated coincident peak." *Id.*

used in developing the estimate and not just one year. *See, e.g., Otter Tail Power Co.*, Opinion No. 93, 12 FERC ¶61,169, p. 61,429 (1980); *Commonwealth Edison Co.*, 15 FERC at 65,190, *aff'd*, Opinion No. 165, 23 FERC ¶61,219 (1983) (3 year average adopted); *Southern California Edison Co.*, Opinion No. 359-A, 54 FERC at 62,020 (accepted system peak demand and energy sales forecasts based on 1967-1981 data and 1981 coincidence factors). In other cases, FERC, however, has adopted CP projections based on the use of one year's data. *See, e.g., Carolina Power & Light Co.*, Opinion No. 19, 4 FERC at 61,229-30.

Second, FERC has expressed concern that the numerator and the denominator be developed on similar bases. In *Otter Tail Power Co.*, Opinion No. 93, 12 FERC at 61,429, FERC modified a demand allocator to provide for the use of the same number of years data in the derivation of both the numerator and the denominator.

Finally, FERC has held that billing demands should be consistent with the demands used in the demand allocator. *See El Paso Electric Co.*, Opinion No. 109, 14 FERC ¶61,082, p. 61,147 (1981).

123 FERC ¶ 61,047
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 501

Golden Spread Electric Cooperative, Inc. Lyntegar Electric Cooperative, Inc. Farmers' Electric Cooperative, Inc. Lea County Electric Cooperative, Inc. Central Valley Electric Cooperative, Inc. Roosevelt County Electric Cooperative, Inc.	Docket No. EL05-19-002
v.	
Southwestern Public Service Company	
Southwestern Public Service Company	Docket No. ER05-168-001

Issued: April 21, 2008

123 FERC ¶ 61,047
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Golden Spread Electric Cooperative, Inc.
Lyntegar Electric Cooperative, Inc.
Farmers' Electric Cooperative, Inc.
Lea County Electric Cooperative, Inc.
Central Valley Electric Cooperative, Inc.
Roosevelt County Electric Cooperative, Inc.

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OPINION NO. 501

OPINION AND ORDER ON INITIAL DECISION

(Issued April 21, 2008)

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I. Introduction

1. This case arises in part out of a complaint, filed on November 2, 2004, by several cooperatives (the Cooperative Customer Group, CCG, or complainants).[1] These cooperatives purchase requirements service from Southwestern Public Service Company (SPS).[2] SPS, a subsidiary of Xcel Energy Inc., is an operating utility engaged primarily in the generation, transmission, distribution and sale of electricity. SPS serves approximately 386,000 electric customers in portions of Texas and New Mexico, and also operates in Oklahoma and Kansas.

2. The complaint, filed under section 206 of the Federal Power Act (FPA),[3] alleges that SPS has historically violated, and continues to violate, the fuel cost adjustment clause (FCAC) provisions of its wholesale customers' rate schedules and the Commission's FCAC regulations. Complainants assert that SPS may be flowing through

[1] When the complaint was filed, CCG included Golden Spread Electric Cooperative, Inc. (Golden Spread), Lyntegar Electric Cooperative, Inc. (Lyntegar), Farmers' Electric Cooperative, Inc. (Farmers'), Lea County Electric Cooperative, Inc. (Lea County), Central Valley Electric Cooperative, Inc. (Central Valley), and Roosevelt County Electric Cooperative, Inc. (Roosevelt County). However, since that time, Golden Spread and Lyntegar have resolved with SPS all issues except one in a settlement filed on December 3, 2007 (Settlement Agreement). Therefore, in this order, CCG will only include Farmers', Lea County, Central Valley, and Roosevelt County.

[2] All of the cooperatives involved in this proceeding are full requirements customers, except Golden Spread, which is a partial requirements customer.

[3] 16 U.S.C. § 824e (2000).

> Because the ROE in this case will apply to a diverse group of companies, the entire range of results yielded by the subset is relevant here. Thus, we find that using the midpoint is the most appropriate measure for determining a single ROE for all Midwest ISO [transmission operators], since it fully considers that range. Selecting the most refined measure of central tendency, as might be achieved with use of the median, is not the Commission's goal in this case, given that we are not selecting a ROE for a single utility of average risk.[129]

64. Here, we are determining the just and reasonable ROE for a single utility of average risk and find the median to be appropriate for setting the ROE. In *Transcontinental Gas Pipe Line Corp.*,[130] the Commission determined that setting the ROE at the median of the zone of reasonableness lessens the impact of any single proxy company whose ROE is atypically high or low. While there are no concerns of extremes here, using the median also has the advantage of taking into account more of the companies in a proxy group rather than only those at the top and bottom. We decline to place SPS in the upper half of the zone of reasonableness because we conclude, based on the S&P Safety Rank and Business Profile factors, SPS does not have any higher risk than the proxy group, despite SPS' arguments to the contrary.[131] SPS cites *Southern California Edison*, a case in which the Commission placed the utility in the upper half of the zone of reasonableness because it found the company to be more risky than the proxy group.[132] Unlike in *Southern California Edison*, here we find that SPS is not more risky than the proxy group. Accordingly, we affirm the use of the median in establishing the ROE for SPS.

65. We reverse the ALJ's finding that there should be a 37 basis point interest rate adjustment. Instead, the adjustment should be 6 basis points, because the rates at issue here are for a locked-in period. Therefore, the ROE should be 9.33 percent (9.27 plus 6 basis points). As CCG correctly noted, where the rate under consideration is "locked-in" (that is, the rate being litigated has been superseded or is otherwise no longer in

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[129] *Midwest ISO*, 106 FERC ¶ 61,302 at P 10.

[130] 84 FERC ¶ 61,084, *aff'd* Opinion No. 414-B, 85 FERC ¶ 61,323 (1998).

[131] Trial Staff Brief Opposing Exceptions at 23-25.

[132] *Southern California Edison*, 92 FERC ¶ 61,070, at 61,266 (2000) ("[W]e find that SoCal Edison is more risky than the comparison group. Therefore, the appropriate ROE for SoCal Edison should be above the midpoint of returns indicated for the comparison group").

effect),[133] the Commission updates the equity allowance for the locked-in period based on the change in average yields on ten-year constant maturity U.S. Treasury bonds.[134] Instead of following the Commission's methodology for adjustments applicable to locked-in period rates, the ALJ used the Commission's method for updating based on open-ended rates. This was inconsistent with Commission policy, as the rates at issue here were for a locked-in period. Accordingly, we adopt the adjustment required by Commission precedent for locked-in rates, 6 basis points instead of 37 basis points.

B. Coincident Peak Basis (3 CP v. 12 CP)[135]

66. Demand allocation refers to the method of apportioning fixed capacity costs among customer classes. The Commission typically uses a coincident peak method to allocate demand costs, in which demand costs are allocated based on the customer class' demand at the time of (coincident with) the system peak demand.[136] The coincident peak may be based, for example, on a single peak month (1 CP), the average of three peak months (3 CP), or the average of peaks in twelve months (12 CP). A company that has a relatively flat demand curve throughout the year would typically allocate demand on a 12 CP basis, which assumes that a utility's demand is relatively constant throughout all twelve months of the year. A summer (or winter) peaking company would more typically allocate demand on a 3 CP basis, which assumes demand will peak during the three peak usage months.

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[133] As noted, the rates at issue here are for the locked-in period from January 1, 2005 to July 1, 2006.

[134] *E.g., Jersey Cent. Power & Light Co.*, Opinion No. 408, 77 FERC ¶ 61,001, at 61,009-10 (1996).

[135] Initial Decision at P 10-24 (Issue I.A). We note that the issue of the Coincident Peak Basis is the sole issue that the Settling Parties did not resolve in the Settlement Agreement. Therefore, this portion of the order applies to both the Settling Parties and non-settling parties.

[136] *See generally Delmarva Power & Light Co.*, 17 FERC ¶ 63,044, at 65,199-203 (1981), *aff'd in relevant part*, Opinion No. 185, 24 FERC ¶ 61,199 (1983) (*Delmarva Initial Decision*) (discussing method of demand cost allocation).

1. Initial Decision

67. The ALJ concluded that SPS remains a 3 CP system,[137] not a 12 CP system as Cap Rock, SPS, and CCG propose. The ALJ cited *Louisiana Power & Light Co.*,[138] in rejecting calls for changing SPS' demand allocation method. *Louisiana P&L*, the ALJ explained, states that the demand allocation method should not be changed except when there are changed circumstances or a change in policy.[139] The ALJ concluded that the data suggest modest changes but not "major shifts" in the load curve.[140] The ALJ further observed that one of the factors that may have caused the movement in the direction of a flatter demand curve – the increase in intersystem sales caused by the availability of excess power due to the shift of Golden Spread to a partial requirements customer – has run its course.[141] Moreover, the ALJ found that one cannot assume the continuation of whatever flattening of the demand curve occurred.[142]

2. Briefs on Exceptions

68. CCG,[143] Cap Rock,[144] and SPS[145] argue that SPS is now a 12 CP system, and they disagree with the ALJ's conclusion that SPS remains a 3 CP system. They claim that SPS' peak load ratios and other operating realities have changed substantially since the Commission last examined the SPS system in 1989. They claim that analyses by Cap Rock, SPS, and others in the proceeding take into account factors besides the availability of excess power due to the shift of Golden Spread to a partial requirements customer,

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[137] *Cf. Southwestern Pub. Serv. Co.*, Opinion No. 162, 22 FERC ¶ 61,341, at 61,589-591, *reh'g denied*, 23 FERC ¶ 61,406 (1983) (Opinion No. 162) (affirming that SPS is a 3 CP system); *Southwestern Pub. Serv. Co.*, Opinion No. 337, 49 FERC ¶ 61,296, at 62,132 (1989), *reh'g denied,* Opinion No. 337-A, 51 FERC ¶ 61,130 (1990) (Opinion No. 337) (same).

[138] Opinion No. 110, 14 FERC ¶ 61,075, at 61,128, *reh'g denied,* 15 FERC ¶ 61,297 (1981) (Opinion No. 110 or *Louisiana P&L*).

[139] Initial Decision at P 22.

[140] *Id.* P 24.

[141] *Id.*

[142] *Id.*

[143] CCG Brief on Exceptions at 3-23.

[144] Cap Rock Brief on Exceptions at 12-61.

[145] SPS Brief on Exceptions at 61-65.

such as large retail customers seeking to firm up service previously taken on an interruptible service basis and SPS' rapidly increasing growth in high load factor oil field load. They state that the evidence clearly establishes that SPS is now a 12 CP system.

69. For example, CCG states that during the hearing they introduced updated analyses of various aspects of SPS' system demand curve and other system characteristics, based on data from recent years, to show the appropriate wholesale demand cost allocator in light of current conditions, and that, in total five witnesses concluded that SPS has now become a 12 CP system.[146] CCG argues that the Initial Decision does not discuss or dispute this evidence, undermining its ruling that a 3 CP allocator should continue to be used.[147]

70. CCG, Cap Rock, and SPS also claim that the burden of proof for a change in methodology is satisfied by a just and reasonable standard, and that the ALJ broke with precedent set in *Louisiana P&L* by ruling that "there should be a strong reason for changing allocation methodologies," and parties seeking to do so must show "major shifts in the load curve."[148] They claim that Opinion No. 110[149] states that the demand allocator should not be changed "except where there are changed circumstances or a change in policy."

3. Brief Opposing Exceptions

71. Golden Spread argues that the Initial Decision was correct in concluding that SPS' operating realities remain consistent with a 3 CP system.[150] Golden Spread submits that its demand allocation testimony demonstrates that SPS remains a 3 CP system, and that its evidence complies with the requirements set forth in *Illinois Power Co.*[151] Golden Spread asserts that Cap Rock, CCG, and SPS failed to meet the burden of proof, and shifting to a 12 CP would impose a significant cost shift on the sole entity that has done anything of significance on the system to curtail summer demand. Golden Spread claims that the ALJ recognized its comprehensive analysis and correctly concluded that "there

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[146] CCG Brief on Exceptions at 4.

[147] *Id.* at 4-5, 7-11.

[148] Initial Decision at P 24.

[149] 14 FERC ¶ 61,075.

[150] Golden Spread Brief Opposing Exceptions at 17-22.

[151] *Id.* at 17 (citing *Illinois Power Co.*, 11 FERC ¶ 63,040, at 65,247-48 (1980), *aff'd in relevant part*, 15 FERC ¶ 61,050, at 61,093 (1981) (*Illinois Power*)).

should be a strong reason for changing allocation methodologies, given the impact on customers' expectations and the shifting price signal effects associated with a change in methodology."[152]

72. Golden Spread claims that what little change has occurred in the SPS system in metrics can be attributed to the response by Golden Spread to the 3 CP price signal. Golden Spread states that it built a highly efficient generating facility that tempered the growth of the SPS summer peak, limiting cost increases to the SPS ratepayers, and providing significant energy cost savings. Golden Spread states that affirming the ALJ would ensure that customers will not be penalized for merely responding to price signals and reducing the burden they impose on a summer peaking system.

73. Golden Spread points out that the Trial Staff witness who advocated the switch to 12 CP in prefiled testimony was not as certain during the hearing, and admitted that a 12 CP would probably produce a price signal that would not discourage customers to reduce their summer load, but rather have the opposite effect.[153]

4. <u>Commission Determination</u>

74. We reverse the Initial Decision's finding that the 3 CP methodology remains the correct demand cost allocator for the SPS system. Although the Commission previously determined that SPS was a 3 CP system, we find that the ALJ misapplied the *Louisiana P&L* standard and overlooked numerical data in concluding that demand changes on the SPS system do not provide a "strong reason" for shifting the demand allocator to a 12 CP methodology.[154]

75. While the Commission has not established hard and fast rules for determining whether the 3 CP or 12 CP allocation method is appropriate, we have explained that the following factors should be considered when determining which allocation to use: "[t]he full range of a company's operating realities including, in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments."[155]

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[152] Initial Decision at P 24.

[153] Tr. 2469:2-10 (Sammon).

[154] Initial Decision at P 9.

[155] *Carolina Power & Light Co.*, Opinion No. 19, 4 FERC ¶ 61,107, at 61,230 (1978); *Illinois Power*, 11 FERC ¶ 63,040 at 65,247-48; *see also Delmarva Initial Decision*, 17 FERC ¶ 63,044 at 65,199-203 ("The Commission has not adopted any one

(continued...)

76. Historically, the Commission has considered three tests in determining whether a system is better characterized as 3 CP or 12 CP. First, the Commission compares the average of the system peaks during the purported peak period, as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak – the On and Off Peak test. Generally, the Commission has held that a nineteen percentage point or less difference between these two figures supports using the 12 CP method.[156] The second test, the Low-to-Annual Peak test, involves the lowest monthly peak as a percentage of the annual peak. The Commission considers a range of sixty-six percent or higher as indicative of a 12 CP system.[157] The third test is the Average to Annual Peak test, and it computes the average of the twelve monthly peaks as a percentage of annual peak. Generally, the range for a utility to be considered 12 CP is eighty-one percent or higher.[158]

77. The Commission is persuaded by testimony and evidence submitted by SPS, Cap Rock, the full requirements customers,[159] and Golden Spread that substantive changes have occurred on the SPS system since the Commission last addressed the issue in 1989. The chart below is a comparison of previously accepted ratios from the peak tests indicative of a 12 CP system to the ratios submitted as evidence by various parties at trial regarding SPS' system. Differences in ratio values can be attributed to the inclusion or exclusion of interruptible loads, off-system sales, and the number of years used to calculate the average ratios shown below. The chart illustrates that applying the same

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method . . . its determination of the appropriate allocation method has rested on the facts of each case.").

[156] *See, e.g., Illinois Power*, 11 FERC ¶ 63,040 at 65,248-49 (comparing average summer peak of ninety-four percent of annual peak to eight-month average peak of seventy-five percent of annual peak, a difference of nineteen percentage points).

[157] *Id.* (approving 12 CP where lowest monthly peak as percentage of annual peak was sixty-six percent); *Delmarva Initial Decision,* 17 FERC ¶ 63,044 at 65,201 (stating that Commission favors 12 CP method and citing 12 CP cases with low monthly peaks).

[158] *See, e.g., Illinois Power*, 11 FERC ¶ 63,040 at 65,249 (approving 12 CP where average monthly peak for five-year period was eighty-one percent); *Lockhart Power Co.*, Opinion No. 29, 4 FERC ¶ 61,337, at 61,807 (1978) (approving 12 CP where average monthly demand was eight-four percent of annual system peak); *El Paso Elec. Co.*, Opinion No. 109, 14 FERC ¶ 61,082, at 61,147 (1981) (approving 12 CP where twelve-month average was eighty-four percent of maximum peak).

[159] Central Valley Electric Cooperative, Inc., Farmers' Electric Cooperative, Inc., Lea County Electric Cooperative, Inc., and Roosevelt County Electric Cooperative, Inc.

analytical criterion that was primarily used in Opinion Nos. 162 and 337 to determine that SPS was a 3 CP system now clearly demonstrates it is a 12 CP utility. Even Golden Spread's witness Linxwiler's ratios, who testified in support of SPS remaining a 3 CP utility, meet the acceptable range.

	Lowest-To-Peak	On-Peak-Off-Peak	Average-To-Peak
Historical Commission Range for 12 CP	66% or higher	19% or less	81% or higher
Heintz, SPS-37 at 16	68%	19%	82%
Saffer FRC-2 Pro Forma	70%	18%	84%
Linxwiler, GSL – 1 at 9-10	67.55%	19%	82.05%
Diller, CRE-1 at 18	70%	18%	84%

78. In addition, in the years since Opinion Nos. 162 and 337, Golden Spread switched from a full-requirements, high summer-peaking customer on SPS' system to a partial requirements customer with a year-around, fixed contract. SPS testified that this and other factors have increasingly flattened its load profile to a point inconsistent with a 3 CP utility, as illustrated by the peak ratio percentages submitted by SPS and others.[160] We agree and will reverse the ALJ's finding that SPS is a 3 CP utility and conclude that use of the 12 CP demand allocation methodology appropriately reflects SPS' system.

C. Demand Cost Allocation Factors[161] and Post Test Year Adjustments[162]

1. Initial Decision

79. The ALJ determined that the interruptible load deductions[163] issue was resolved in the Joint Trial Stipulation, and that Cap Rock is free to further pursue the matter in

[160] *See* SPS Brief on Exceptions at 64 (citing Tr. 1560:3-9).

[161] Initial Decision at P 108-113 (Issue I.J).

[162] *Id.* P 114-119 (Issue I.K).

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Kansas City Power Light Company
Merits of Alternative Capacity Cost Allocation Bases
FERC System Demand Tests

Line No.	[A] Description	[B] 2006 MW	[C] 2007 MW	[D] 2008 MW	[E] 2009 MW	[F] 2010 MW	[G] 2011 MW	[H] Median MW	[I] Minimum MW	[J] Maximum MW
1	Monthly Coincident Peak Demands - MW									
2	January	2,550	2,588	2,522	2,631	2,811	2,548	2,569	2,522	2,811
3	February	2,438	2,425	2,473	2,390	2,445	2,646	2,441	2,390	2,646
4	March	2,187	2,197	2,209	2,235	2,113	2,058	2,192	2,058	2,235
5	April	2,110	2,301	1,957	2,031	2,018	1,882	2,025	1,882	2,301
6	May	2,564	2,761	2,625	2,363	2,825	2,828	2,693	2,363	2,828
7	June	3,267	3,431	3,195	3,448	3,398	3,377	3,388	3,195	3,448
8	July	3,609	3,689	3,428	3,182	3,412	3,593	3,511	3,182	3,689
9	August	3,480	3,436	3,495	3,238	3,603	3,689	3,487	3,238	3,689
10	September	2,970	3,243	2,924	2,389	2,947	3,491	2,959	2,389	3,491
11	October	2,392	2,552	1,981	1,937	2,086	2,107	2,097	1,937	2,552
12	November	2,505	2,239	2,150	2,071	2,220	2,080	2,185	2,071	2,505
13	December	2,623	2,443	2,670	2,620	2,442	2,316	2,532	2,316	2,670
14	Average	2,725	2,775	2,636	2,545	2,693	2,718	2,706	2,545	2,775
15	Average Monthly Coincident Peak Demands									
16	Jul - Aug	3,544	3,563	3,462	3,210	3,508	3,641	3,499		
17	Other Months	2,561	2,618	2,471	2,412	2,531	2,533	2,508		
18	Ratio	72.25%	73.48%	71.37%	75.12%	72.15%	69.58%	72.20%	69.58%	75.12%
19	Jun - Aug	3,452	3,519	3,373	3,289	3,471	3,553	3,462		
20	Other Months	2,482	2,527	2,390	2,296	2,434	2,440	2,410		
21	Ratio	71.91%	71.83%	70.87%	69.81%	70.13%	68.66%	70.50%	68.66%	71.91%
22	Jun - Sep	3,331	3,450	3,261	3,064	3,340	3,538	3,336		
23	Other Months	2,421	2,438	2,323	2,285	2,370	2,308	2,342		
24	Ratio	72.67%	70.68%	71.26%	74.56%	70.96%	65.25%	71.11%	65.25%	74.56%
25	May - Sep	3,178	3,312	3,133	2,924	3,237	3,396	3,207		
26	Other Months	2,401	2,392	2,280	2,274	2,305	2,234	2,291		
27	Ratio	75.54%	72.22%	72.77%	77.76%	71.21%	65.79%	72.50%	65.79%	77.76%
28	**FERC Test 1 - On-Peak less Off-Peak**									
29	**Average of the Monthly System Peaks During the On-Peak Months as a Percentage of the Annual Peak, less**									
30	**Average of the Monthly System Peaks During the Off-Peak Months as a Percentage of the Annual Peak**									
31	Ratio to Annual System Peak									
32	Jul & Aug	98.21%	96.56%	99.04%	93.10%	97.35%	98.70%	97.78%	93.10%	99.04%
33	Other Months	70.95%	70.96%	70.69%	69.94%	70.23%	68.67%	70.46%	68.67%	70.96%
34	Difference	27.26%	25.61%	28.35%	23.16%	27.12%	30.03%	27.19%	23.16%	30.03%
35	Jun - Aug	95.64%	95.37%	96.50%	95.40%	96.34%	96.31%	95.98%	95.37%	96.50%
36	Other Months	68.78%	68.51%	68.39%	66.60%	67.56%	66.13%	67.97%	66.13%	68.78%
37	Difference	26.87%	26.87%	28.11%	28.80%	28.78%	30.18%	28.45%	26.87%	30.18%
38	Jun - Sep	92.31%	93.50%	93.29%	88.87%	92.70%	95.89%	93.00%	88.87%	95.89%
39	Other Months	67.09%	66.08%	66.48%	66.26%	65.78%	62.57%	66.17%	62.57%	67.09%
40	Difference	25.22%	27.42%	26.81%	22.61%	26.92%	33.33%	26.87%	22.61%	33.33%
41	May - Sep	88.06%	89.77%	89.65%	84.80%	89.84%	92.05%	89.71%	84.80%	92.05%
42	Other Months	66.52%	64.83%	65.24%	65.94%	63.97%	60.55%	65.04%	60.55%	66.52%
43	Difference	21.53%	24.93%	24.41%	18.86%	25.87%	31.49%	24.67%	18.86%	31.49%
44	**FERC Test 2 - Lowest to Peak**									
45	**Lowest Monthly Peak as a Percentage of the Annual Peak**									
46	Minimum Peak/Maximum	58.46%	59.55%	55.99%	56.18%	56.01%	51.02%	56.09%	51.02%	59.55%
47	**FERC Test 3 - Average ot Peak**									
48	**Average of 12-Monthly Peak Demands as a Percentage of the Maximum Annual Demand**									
49	Average/Maximum	75.49%	75.22%	75.41%	73.80%	74.75%	73.68%	74.99%	73.68%	75.49%
50	**Supplemental FERC Test**									
51	**Number of Monthly Demands in Off-Peak Months Which Exceed Montly Demands During the On-Peak Months**									
52	Jul & Aug	-	-	-	1	-	-			
53	Jun - Aug	-	-	-	-	-	1			
54	Jun - Sep	-	-	-	3	-	-			
55	May - Sep	1	-	1	3	-	-			

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