Exhibit No.:	
Issue(s):	*Storm Reserve, Injuries and Damages Reserve, Jurisdictional Allocations*
Witness:	*Keith Majors*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Rebuttal Testimony*
Case No.:	*ER-2026-0143*
Date Testimony Prepared:	*August 11, 2026*

MISSOURI PUBLIC SERVICE COMMISSION

FINANCIAL AND BUSINESS ANALYSIS DIVISION

AUDITING DEPARTMENT

REBUTTAL TESTIMONY

OF

KEITH MAJORS

EVERGY METRO, INC., d/b/a EVERGY MISSOURI METRO

CASE NO. ER-2026-0143

Jefferson City, Missouri
August 2026

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Q. Please state your name and business address.

A. My name is Keith Majors, Fletcher Daniels Office Building, 615 East 13th Street, Room 201, Kansas City, Missouri 64106.

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

A. I am a Utility Regulatory Audit Unit Supervisor employed by the Staff ("Staff") of the Missouri Public Service Commission ("Commission").

Q. Are you the same Keith Majors who previously provided testimony in this case?

A. Yes. I provided direct testimony in this case on June 30 concerning Pensions and Other Post-Employment Benefits, Supplemental Executive Retirement Plan, miscellaneous expenses, insurance settlement proceeds, and rail litigation proceeds.

<u>EXECUTIVE SUMMARY</u>

Q. What is the purpose of your rebuttal testimony?

A. The purpose of by rebuttal testimony is to respond to the following Evergy Missouri Metro ("EMM") topics and witnesses in their direct testimonies:

- Injuries and Damages Reserve
    - Kevin D. Gunn direct testimony – pages 21-22
        - Ronald A. Klote direct testimony – pages 31-32

- Storm Reserve
    - Kevin D. Gunn direct testimony – page 22
    - Ronald A. Klote direct testimony – pages 32-34
    - Ryan P. Mulvany direct testimony – pages 16-17

- Jurisdictional Allocations
    - Kevin D. Gunn direct testimony – pages 18-19
    - John Wolfram corrected direct testimony – all

Specific to EMM's proposal for a Storm Reserve and Injuries and Damages ("I&D") Reserve, EMM is requesting the Commission to establish reserves for these amounts to address "the inherent unpredictability and magnitude of the costs."[1] Mr. Klote also suggests that the I&D Reserve is necessary "rather than trying to predict precisely when and in what amount these costs will be incurred."[2] When developing a revenue requirement in a general rate case, regulatory principles such as annualizations and normalizations are used with the intention to match the relationship with a utility investment, revenue, and expense. This relationship, also known as the matching principle, is a bedrock foundation of utility ratemaking and is anticipated to continue in the foreseeable future. Precisely predicting a specific cost to include in a utility's revenue requirement, as suggested by Mr. Klote, is done infrequently. Instead, regulatory principles are used to develop a level of costs that maintain the relationship with a utility's investment, revenue and expense. EMM's requests for the I&D and Storm Reserves cause an inconsistency with this relationship and places additional risks on

[1] Gunn Direct, page 21, line 20.
[2] Klote Direct, Page 32, lines 3-4.

EMM's ratepayers. In addition, EMM's proposed reserves violate the known and measurable concept since it is asking its customers to pay in advance for events that may not materialize in the future. Staff recommends the Commission deny EMM's proposal for a Storm Reserve and I&D Reserve.

Q. Is EMM requesting another regulatory mechanism, also known as a "tracker" for another expense in this case?

A. Yes. EMM is requesting a Critical Infrastructure Protection ("CIP") and Cyber Security tracker. Staff witness Karen Lyons addresses this request in her rebuttal testimony.

Q. Has Staff prepared updated accounting schedules?

A. Yes. I sponsor these schedules, and they are being filed concurrently with this testimony. The accounting schedules include various corrections of errors or omissions that were noted in consultation with EMM.

<u>STORM RESERVE</u>

Q. Please explain EMM's proposed storm reserve.

A. EMM proposes to set the storm reserve using a three-year average of storm costs to determine the level of storm costs to include in the storm reserve. Mr. Klote states the following beginning on page 33, line 15 of his direct testimony:

> The Company is proposing to set a reserve level and annualized level based upon a three-year average of storms costs (12-months ending December 2022, 2023, and 2024), where the costs related to individual storms were greater than $250,000. An annual amount equal to the three-year average has been included in the revenue requirement on an on-going basis. This is needed to continue to cover expenses paid out of the

> reserve over time due to the unpredictable and sporadic nature of storm events. The implementation of this reserve will be used to cover intermediate to large storms by using a $250,000 minimum storm level, but in the event a storm is very significant and impactful to Company operations, this request does not preclude the Company from requesting an Accounting Authority Order if the magnitude of the storm warrants the request, as has been done historically.

EMM's proposal would add $1,092,086 of additional annual expense to the revenue requirement. This amount is 100% Missouri jurisdictional.

Q. Does Staff support EMM's proposed storm reserve?

A. No. EMM is asking its customers to pay in advance of potential storms occurring in the future. It is Staff's opinion that rate case adjustments such as annualizations and normalizations can be used to determine an appropriate level of these costs. Listed below are the reasons Staff opposes EMM's proposed storm reserve.

- Although it is a certainty that storms will occur, the proposal is for unknown future storm costs.
- The threshold of $250,000 described by Mr. Klote is not material when compared to EMM's total operating expenses.
- Alternative regulatory mechanisms are available to EMM when significant storm costs are incurred. These alternative mechanisms provide ratepayers and shareholders sufficient protection from sporadic storm costs. A storm reserve would only serve to provide shareholders additional protection from storm risk.
- Storm costs are included in Staff's normalized level of distribution maintenance expense.
- The Commission has rejected a proposal to establish a storm reserve for EMM in a prior rate case.

Q. What is the amount that EMM is proposing for the storm reserve in this case?

A. EMM's proposed annual amount for the storm reserve is $1,092,086. This amount is 100% Missouri jurisdictional. This amount is in addition to the normalized level of $27,937,268 for distribution maintenance expense proposed by EMM.

Q. Is EMM's proposed storm reserve based on the regulatory concept of known and measurable storm costs?

A. No. Known and measurable costs are amounts that are known and can be calculated with a high degree of accuracy. Mr. Klote states. "The establishment of a storm reserve would allow EMM to collect in rates the cost of storms that are significant in nature that are likely to occur in the future."[3] Potential future storm costs do not meet the known and measurable standard.

Q. Do you consider the storm threshold of $250,000 to be material?

A. No. The $250,000 threshold of non-labor storm costs compared to EMM's operating expenses is infinitesimal. It equates to less than one half of one percent of EMM's total operating expenses.[4]

Q. What alternative regulatory mechanisms are available in the event a significant storm occurs?

A. EMM may file an Accounting Authority Order ("AAO") application with the Commission. Typically, AAOs have been used to allow utilities to capture certain unanticipated and extraordinary costs that are not included in their ongoing rate levels.

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[3] Klote Direct Page 32, lines 20-22.

[4] $250,000/$790,434,429=0.03%. Source: Staff Direct Filed EMS, Income Statement Detail, Line 310.

An example is the occurrence of a natural disaster, such as a wind or ice storm that may impact a utility's service territory.

Q. EMM witness Ryan Mulvany asserts that, "[t]he [storm] reserve benefits customers by smoothing major storm expenses year-over-year for recovery in rates over time."[5] Do ratepayers need storm costs to be smoothed out?

A. No. Year-to-year storm costs are considered in Staff's analysis of historical maintenance expenses. In the event that storms cause annual costs to fluctuate, costs can be smoothed out with an appropriate normalization (i.e. average) of historical actual costs. It is unlikely that Staff would recommend rates that reflect a cost inflated by an abnormal storm, not only because Staff's analysis would remove abnormal events, but a large storm would possibly be addressed separately in an AAO.

Q. How did Staff account for EMM's storm costs in its recommended revenue requirement filed with its direct testimony on June 30, 2026?

A. Consistent with prior EMM general rate cases, Staff normalized non-labor distribution expense. In this case, Staff recommends a three-year average (calendar years 2023, 2024, and 2025) of distribution costs for EMM including FERC Account 593-Maintenance of Overhead Lines where the majority of storm-related costs are recorded. The chart below depicts Staff's recommended annual level for distribution expense by FERC account.

[5] Mulvany Direct, page 17, lines 4-5.

Description	FERC Account	2022	2023	2024	2025	3-yr Average (2023,2024,2025)
Maintenance of overhead lines	593	22,637,050	26,741,014	27,078,051	25,108,429	26,309,165

Q. Does EMM record storm costs in additional FERC accounts?

A. Yes. EMM records storm costs in several FERC accounts. However, the majority of storm costs are recorded in FERC account 593.

Q. Does Staff recommend an adjustment for storm costs EMM records in other FERC accounts?

A. No. Storm costs recorded in other FERC accounts are immaterial when compared to the storm costs recorded in FERC account 593. In addition, the costs are relatively flat. In other words, there is so substantial fluctuation with these costs, and Staff's normalized level is an increase of about $1.2 million over the last known full calendar year. Using the data in Staff's historical analysis, Staff used a three-year average as representative of ongoing costs.

Q. Has the Commission rejected a Storm Reserve proposal for EMM?

A. Yes. In Case No. EO-85-185 ("the Wolf Creek Case")[6], the Office of the Public Counsel ("OPC") recommended that the Commission establish a storm damage reserve account to recover the cost of future storm related expenses. I have attached the relevant pages of the Commission's Report and Order in that case as Schedule KM-r1.

In that case, EMM[7] and Staff agreed to a five-year amortization of expenses associated with the March 1984 ice storm. OPC opposed recovery of the March 1984 ice

[6] The initial Wolf Creek Case was designated as ER-85-128. Due to schedule changes of the Wolf Creek in-service date, the tariffs were refiled with EO-85-185 remaining as the lead case.
[7] At that time, EMM operated as Kansas City Power & Light.

storm expenses on the grounds that such recovery constituted retroactive ratemaking.[8] The Commission rejected OPC's proposal in favor of amortizing the March 1984 ice storm expenses over five years. OPC's proposal would have added $970,079 of additional expense based on a normalization of storm expenses occurring from 1973-1985. OPC's proposal in the Wolf Creek Case and EMM's proposal in this case are substantially the same.

Q. Has EMM used its ability to file for an AAO for past significant storm costs?

A. Yes. The most recent storm specific AOO for EMM was Case No. EU-2002-1048. As noted in EMM's Application which is attached as Schedule KM-r2:[9]

> 4. In the past, the Commission has approved the deferral of incremental costs related to extraordinary events including a wind storm in 1982, an ice storm in 1984, flooding in 1993 and a snow storm in 1996. The January 30-31, 2002, ice storm caused more damage to KCPL's property and equipment than any of these previous events.
>
> 5. On January 30 and 31, a severe ice storm hit KCPL's system. Accumulations of up to two inches of ice on trees, lines and equipment caused unprecedented damage and destruction to KCPL's facilities. At the peak of the storm, over 305,000 of KCPL's approximate 450,000 customers had lost electric service. Almost 200 of KCPL's 550 metro circuits were completely out at some point in the storm. In order to restore service as quickly as practicable, KCPL utilized 447 outside utility and contractor crews and 314 outside tree crews, in addition to the 200 KCPL and local contract crews. Personnel from eleven utilities and ten contractors from sixteen states were used in the restoration efforts.

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[8] Report and Order, page 46, attached as Schedule KM-r1.
[9] Case No. EU-2002-1048, Application of Kansas City Power & Light Company for an Accounting Authority Order Regarding Accounting for Extraordinary Cost Relating to Storm Damage.

There are two main points discerned from the 2002 ice storm AAO. First, EMM has the ability to file an AAO and has when the storm damage costs are substantial, and second, EMM experienced several major storms and did not request a storm reserve until the 2022 rate case , Case No. ER-2022-0129. Staff was supportive of the AAO in EU-2002-1048 and the Commission ordered deferral of the costs and amortization over five years.

Q. Please summarize Staff's position on EMM's proposed storm reserve.

A. Staff opposes EMM's proposal to establish a storm reserve for potential future storms. EMM's proposal violates the known and measurable concept by asking its customers to pay in advance to fund a storm reserve for storms that may or may not occur in the future. Staff utilized normal ratemaking methods by including a normalized level of maintenance expense and, to the extent EMM incurs significant storm costs in the future, other regulatory mechanisms are available for possible recovery, such as an AAO.

<u>INJURIES AND DAMAGES RESERVE</u>

Q. Please explain EMM's proposed I&D reserve.

A. To determine the level of I&D costs to include in the reserve, Mr. Klote states the following on page 32, lines 13-15 of his direct testimony:

> The Company is proposing to begin establishing the reserve by increasing operating expense equal to the annual amount calculated from a five-year average of claims experience incurred over a three-year period.

Q. What is the proposed I&D balance for EMM?

A. The proposed I&D reserve balance for EMM is $1,523,633, total EMM.[10] This amount is above the normalized level proposed by EMM. This amount would be collected every year by EMM.

Q. Does Staff support EMM's proposed I&D reserve?

A. No. Similar to EMM's request for a storm reserve, EMM is asking its customers to pay in advance for costs related to certain events that have not occurred, in this case costs related to I&D claims. These costs are not known and measurable and regulatory concepts such as normalizations and annualizations can be used to determine an appropriate level to include in EMM's cost of service. Also, like EMM's proposed storm reserve, its request for an I&D reserve simply transfers the risk of potential I&D claims from EMM and its shareholders to ratepayers to the detriment of customers.

Q. How did Staff account for EMM's I&D costs in its recommended revenue requirement filed with its direct testimony on June 30, 2026?

A. Consistent with prior EMM general rate cases, Staff normalized I&D costs. In this case, Staff recommends a four-year average (calendar years 2022, 2023, 2024, and 2025) of I&D costs for EMM. Staff witness Sydney Ferguson addresses I&D expense in her direct testimony.

Q. Is there a difference between Staff and EMM with regard to the normalization of I&D costs?

A. The difference is due to timing and period of normalization. Specifically, EMM used the three-year average of 12 months ending periods of June 2023, June 2024,

[10] This amount is allocated 53.09% to Missouri.

and test year June 2025 that results in a normalized level of $4,570,899. On the other hand, Staff used the four-year period of calendar years 2022, 2023, 2024, and 2025 that results in a normalized level of $5,797,885, a difference of $1,226,986. Therefore, with Staff's updated normalized level of I&D expense, the difference is $296,647, or about $157,490 Missouri jurisdictional without the addition of an amount for the reserve.

Q. Mr. Klote suggests that the I&D reserve is necessary to address unpredictability of these costs, "rather than trying to predict precisely when and in what amount these costs will be incurred."[11] Do you agree?

A. No. As previously discussed, when developing a revenue requirement in a general rate case, regulatory principles, such as annualizations and normalizations, are used with the intention to match the relationship with a utility investment, revenue,

and expense. The goal is to maintain the relationship, not to precisely predict one cost over the other. When the relationship no longer exists, the utility can request a rate increase.

Q. Mr. Klote states the I&D reserve "will provide a smoothing of annual expenses associated with I&D claims which are volatile year to year."[12] Do you agree this is necessary?

A. No. Normalizing these costs as Staff recommends smooths out the rate impact of any fluctuations in these costs. Establishing an I&D reserve does not lead to an I&D cost that is more normal than a five-year normalization adjustment.

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[11] Klote Direct, page 32, lines 3-4.
[12] Ibid, lines 5-7.

Q. Please summarize Staff's position on EMM's proposed I&D reserve.

A. Staff opposes EMM's proposal to establish a I&D reserve for potential future I&D claims. EMM's proposal violates the known and measurable concept by asking its customers to pay in advance for claims that have not occurred. Normal ratemaking methods can be used to determine an appropriate level of I&D expense when developing a revenue requirement.

JURISDICTIONAL ALLOCATIONS

Q. What is Staff's recommendation regarding jurisdictional allocations, specifically the demand allocation factor for EMM?

A. Staff recommends use of the four coincident peak ("4CP") methodology in calculating the demand factor. The Commission should disregard in its entirety EMM unprincipled and unsupported use of an average of the 4CP and 12CP methods. Staff witness Alan Bax supports the calculation of the 4CP in his direct and rebuttal testimonies in this case. Staff's use of the 4CP methodology is based on objective evidence proving it is the correct method to assign costs between the Missouri, Kansas, and wholesale jurisdictions.

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

A. EMM witness John Wolfram describes at page 9 of his direct testimony that "the Company proposes to allocate demand in this case using the arithmetic average of the 4 CP and 12 CP calculations, except for transmission, which will use 12 CP."[13] The average of 4CP and 12CP is what I refer to as the "Wolfram methodology" as it is

[13] Wolfram direct, page 9 lines 8-10.

subjective and not based on any objective evidence other than it is EMM's solution to a problem it has exacerbated over the last 40 years.

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 peaks (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 – EMM's total company peak demand.

Q. Did EMM justify why it applied an average of the 4CP and 12CP methods?

A. No, other than to enable "jurisdictional harmony". Mr. Wolfram disregarded the results of the FERC tests that suggested a seasonal peak determination was more appropriate than using a 12CP allocation method. For various reasons, including an attempt at allocation parity in Kansas, Mr. Wolfram contrived a new allocation methodology.

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

A. Mr. Wolfram indicates the importance of the using the proper method of allocations in the following exchange found at page 4 of his direct testimony:

> **Q. WHY IS THE METHOD BY WHICH THE ALLOCATIONS ARE MADE IMPORTANT?**
>
> A. The method of allocation is critical to ensure that the rates charged to customers in each jurisdiction reflect the actual cost of serving those customers without reflecting the cost of serving customers in other jurisdictions. Simultaneously, the method of allocation should allow the Company the opportunity to fully recover its prudently incurred costs of serving those customers. Regulated utilities are entitled to a reasonable opportunity to recover their prudently incurred costs and are entitled to earn a fair and reasonable rate of return on their capital investments. If the sum of the allocation factors allowed in each jurisdiction is less than 100%, then the Company will not have the opportunity to recover its prudently incurred cost of service and return on rate base.

I generally agree with the premise of what Mr. Wolfram is conveying in his direct testimony that EMM should have opportunity to recover all its costs when it operates multiple jurisdictions. I do not agree the primary 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 in which it operates. In Missouri, Staff has consistently relied on objective evidence to support the jurisdictional allocation process.

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 Evergy addressed the need to use the most appropriate method to determine allocation factors based on the circumstances?

A. Yes. Evergy witness Darrin R. Ives, currently EMM's Senior Vice President – Regulatory and Government Affairs, testified in EMM's 2012 Kansas 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 his direct testimony in the Kansas Rate Case 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.[14] [emphasis added]

I have attached selected pages of this testimony as Schedule KM-R3.

[14] Ives Direct, page 11, Kansas Docket 12-KCPE-764-RTS; emphasis added.

Q. Does EMM's proposed use of the Wolfram methodology shift costs to the Missouri jurisdiction?

A. Yes. Mr. Wolfram's recommendation in his direct testimony shifts disproportionate costs to Missouri and lessens the allocation to Kansas. Generally, EMM's use of the Wolfram method of allocation apportions more generation and transmission plant costs to Missouri than Staff's method. Staff's method of determining the demand allocation factor is identified as the 4CP method, which it has consistently used, and the Commission has consistently adopted.

Q. Why did Staff use the 4CP method to allocate costs for EMM?

A. Staff relies on the 4CP method because it properly allocates the costs of EMM's Missouri jurisdiction based on the peak demands for the four summer months of all its jurisdictions in relation to EMM's total system peak. EMM'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 4CP method is the appropriate method for EMM's operations in both Missouri and Kansas. When the actual peaks are examined, EMM's four peak demands *always* occur in the summer months—June, July, August, and September. Therefore, the 4 CP method accurately determines EMM's actual jurisdictional peak demands for the four summer months compared to all the months in the year. Even Mr. Wolfram admits that "the [FERC] test results indicate that using a seasonal peak determination is more appropriate than using 12 CP for determining the Demand allocator. This is the case in every scenario for all jurisdictions…”[15] Applying the Wolfram 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 combination of months results in the relationship the summer months have to the rest of the year, which is why the 4CP method is considered to be the most appropriate allocation method to use for summer peaking utility like EMM. 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 4CP method to allocate costs among the jurisdictions.

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

A. Generally, using the Wolfram method allocates more costs to Missouri than if the 4CP method is applied, meaning EMM’s Missouri retail customers will be charged for services consumed by other jurisdictions. The Wolfram method does allocate more costs to the Kansas jurisdiction than the 12CP method if that were to be adopted by the Kansas Corporation Commission (“KCC”) for Kansas jurisdiction rates.

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

A. Yes. In EMM’s 2006 rate case, 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 4CP method. The Commission stated:

[15] Wolfram Direct, page 13, lines 11-13.

> 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 12CP method in EMM's 2006 rate case. Yet EMM has provided no justification for wanting the Commission to adopt the Wolfram methodology other than to achieve "jurisdictional harmony" and, more importantly, provided no reasoning for the Commission to reverse itself in the use of the 4CP method to allocate demand related costs, which it has consistently used for nearly 40 years.

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

A. Yes. Staff has used the 4CP method to determine the demand allocation factor in all the rate cases filed by EMM since 1985. In fact, Staff has consistently used the 4CP methodology since it changed from the single peak, or 1 CP method following the 1985 Wolf Creek rate case – Case No. EO-85-185. In the Wolf Creek rate case, EMM filed its case based on a 4CP demand allocation factor. The Commission ordered use of the 4CP method proposed by EMM rejecting Staff's 1CP method. Staff has used the 4CP method in all EMM rate cases since.

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

A. Yes, in Missouri. While EMM recommended the 12CP method in the 2006 rate case, after the Commission rejected this methodology, EMM presented the 4CP method in every subsequent rate case filed in Missouri until it proposed the 12CP in the 2014 Rate Case. EMM filed the demand factor based on the 4CP method in Case Nos. 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, EMM proposed the use of the 4CP method to determine the demand factor in the 1985 Wolf Creek rate case—Case No. EO-85-185.

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

A. EMM proposed to use the 12CP method of allocating demand costs in its 2015 and 2018 Kansas rate cases even though EMM proposed the use of the 4CP in the

2012 Kansas Rate Case, Docket No. 12-KCPE-764-RTS. EMM has consistently used the 4CP method in Missouri since its 2007 rate case with exception of the 2014 Missouri Rate Case, the 2022 Missouri Rate Case and the current rate case. EMM switched its allocation method once again in one of its jurisdictions by proposing the 12CP method in the 2015 and 2018 Kansas rate cases.

Mr. Ives, at page 9 of his direct testimony filed in the 2012 Kansas rate case, supported the use of the 4CP 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.**[16]

[16] Ives Direct, pages 9-11, Kansas Docket 12-KCPE-764-RTS selected pages attached as Rebuttal Schedule KM-r3; emphasis added.

Finally, Mr. Terry Bassham, at that time Evergy's President and Chief Operating Officer, testified in his direct testimony in the 2012 Kansas rate case the 4CP 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.[17]

Q. Did EMM sponsor any other witness testimony in past cases that support the use of the 4CP demand allocation factor?

A. Yes. EMM hired a consultant from Black & Veatch named Larry W. Loos who provided expert testimony regarding the proper use of the 4CP 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 4CP demand allocation factor. Mr. Loos, as an independent consultant, testified that based on his analysis supported by several FERC tests that EMM system requirements were those consistent with the use of a 4CP.

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**

[17] Bassham Direct, page 4, Kansas Docket 12-KCPE- 764-RTS selected pages attached as Rebuttal Schedule KM-r4; emphasis added.

> **September to allocate capacity costs among jurisdictions.** [emphasis added]

Attached as Rebuttal KM-r5 is the complete direct testimony of Mr. Loos filed by KCPL in the 2012 Kansas rate case in which EMM supported the use of the 4CP method of determining the demand allocation factor.

In addition, KCPL responded to a Staff data request submitted in its 2010 rate case as follows:

> 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.**[18]

Q. Did Mr. Loos testify before the Missouri Commission in the 2010 Rate Case that the use of the 12CP method to determine the demand allocation factor is inappropriate?

A. Yes. Mr. Loos did not believe the 12CP was a proper allocation method to use for a predominately summer peaking utility such as EMM. EMM'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 4CP method was the proper approach to determining the demand allocator.

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

[18] KCPL's response to Data Request 0415 in Case ER-2010-0355, emphasis added.

A. No. Mr. Loos testified he could not support the use of the 12CP method, — the method proposed by EMM in its 2014 rate case in Missouri. Despite Mr. Loos' expert opinion that the 12CP method is improper for use in EMM's jurisdictions, EMM presented this method in both Kansas and Missouri 2014 rate cases, and now in modified form with the Wolfram methodology. EMM also proposed the 12CP method in its 2006 rate case in Missouri, which was rejected by the Commission. Mr. Loos has previously said that he would not recommend, in Kansas or Missouri, use of the 12CP method to allocate EMM costs among the Missouri, Kansas, and wholesale jurisdictions. In his deposition taken on March 18, 2009, Mr. Loos testified he did not support and would not use the 12CP 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.[19]

In this case, EMM is proposing to use a variation on the method its expert opposed in testimony filed in several Kansas and Missouri rate cases presented during the period 2009 through 2012. Yet EMM makes no attempt to refute their own past experts and provides no evidence to support the application of the 12CP allocation method or the Wolfram methodology, in the current rate case.

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

A. Staff continues to support the 4CP 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 EMM operates in. It is based on sound, objective evidence in the form of the FERC tests that overwhelmingly support the 4CP methodology. It is important that EMM pursue consistent allocation treatment in its jurisdictions. EMM should continue to pursue more consistent allocation

[19] Loos March 18, 2009, deposition, pages 31 and 32; emphasis added.

treatment in its Kansas jurisdiction to apply a more accurate methodology should it desire to do so. EMM'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 EMM's own witnesses have supported in past rate Missouri cases and the most recent Kansas case.

Q. Mr. Wolfram states at page 4 of his direct testimony that the demand factor used by EMM was based on weather normalized coincident peak demands. 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 EMM'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 EMM system, not the weather normalized loads, that the production and transmission facilities must be capable of fulfilling.

Q. Did EMM 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. EMM did not identify any reasons for determining the demand factor using weather normalized average peaks.

Q. On page 16 of his direct testimony, Mr. Wolfram references Liberty Utilities d/b/a The Empire District Electric Company ("Liberty") using the 12CP methodology in both Missouri and Kansas. Should this fact have any bearing on EMM's allocation methodology?

A. No. Liberty serves only two rural counties in Kansas. As I understand it, Liberty has substantial winter electric loads primarily driven by electric space heating due to lack of natural gas service. Moreover, Staff uses the same FERC test methodology in determination of cost of service and those results prove a 12CP allocation is the most appropriate for Liberty.

EMM's witness Larry W. Loos noted this fact in his rebuttal testimony in the 2012 Kansas Rate Case:

> Empire District Electric Company ("Empire") provides retail electric service in the States of Missouri, Kansas, Arkansas, and Oklahoma. Because neither summer nor winter loads dominate on Empire's system, each of the four jurisdictions relies on a 12-CP allocator to allocate capacity costs to that jurisdiction.

Q. In Mr. Wolfram's testimony in Case No. ER-2022-0129, on pages 17-20, Mr. Wolfram references EMM's participation in SPP Integrated Marketplace as some of the justification for using a different allocation methodology. How do you respond?

A. This argument is without merit and should be rejected wholesale. In the same testimony, he clearly states that SPP is responsible for SPP capacity. EMM has been a member of SPP since at least 2006 and the Integrated Marketplace ("IM") has been active since March 2014. These circumstances have no impact on the objective FERC test determination used by Staff and Mr. Wolfram. EMM filed three cases in Missouri prior to the current case since March 2014 and not once mentioned SPP capacity planning or the SPP IM as a reason for adopting any jurisdictional allocation methodology.

Q. Concerning "jurisdictional harmony," has EMM consistently sought to harmonize Missouri and Kansas allocation methodologies?

A. No. Aside from differences of methodologies concerning the demand factor, EMM also sought to utilize the "unused energy allocator", a novel, unique allocation factor for off-system sales, or interchange sales, revenue, beginning in the 2006 Rate Case in Missouri. The Unused Energy Allocator, used exclusively in Kansas, is derived from the Demand and Energy allocators. It is calculated by subtracting the actual energy usage from the "available energy". The available energy is defined as the average of the 12 coincident peak demands multiplied by the total hours in the test period. The Missouri Commission rejected the use of the unused energy allocator in the 2006 Rate Case, but it was adopted in the 2006 Kansas Rate Case. This methodology benefited Kansas over Missouri and resulted in the return of more than 100% of off-system sales revenue credits to Kansas and Missouri customers. This allocation methodology was invented by EMM and was used nowhere else.

Q. Is the "unused energy allocator" still used in Kansas?

A. No. It is my understanding that EMM nor the KCC uses this flawed allocation methodology. This is likely due to the inappropriate, and unfair, result of recognizing off-system sales revenue credits in excess of actual results between the various jurisdictions. As noted by Mr. Ives in Case No. EU-2021-0283, the difference in allocation methodologies resulted in $13.6 million of revenue credits greater than the off-system sales revenues that were actually realized.

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

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

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

Q. Does this conclude your rebuttal testimony?

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2026-0143

AFFIDAVIT OF KEITH MAJORS

STATE OF MISSOURI)
) ss.
COUNTY OF Jackson)

COMES NOW KEITH MAJORS and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Rebuttal Testimony of Keith Majors*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Keith Majors

KEITH MAJORS

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Jackson, State of Missouri, at my office in Kansas City, on this 10th day of August 2026.

TINA PETERSON
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
MY COMMISSION EXPIRES MARCH 4, 2030
JACKSON COUNTY
COMMISSION #26812480

Tina Peterson

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the matter of Kansas City Power & light Company of Kansas City, Missouri, for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the Company, and the determination of in-service criteria for Kansas City Power & Light Company's Wolf Creek Generating Station and Wolf Creek rate base and related issues.	Case No. EO-85-185
In the matter of Kansas City Power & Light Company, a Missouri corporation, for determination of certain rates of depreciation.	Case No. EO-85-224

REPORT AND ORDER

Date Issued: April 23, 1986

Date Effective: May 5, 1986

197.

Company's agreement with respect to the amortization; (2) the amortization of this extraordinary tree trimming expense does not constitute retroactive ratemaking. When approved, the program was designed to improve safe and adequate service in the future and not to recover past expenses or losses due to the imperfect matching of rates with expenses.

Based on the foregoing the Commission determines that Staff's position should be accepted and, therefore, only the test year level for tree trimming expenses will be allowed.

H. 1984 Ice Storm Expense

The Company and the Staff agree to a five-year amortization of expenses associated with the March, 1984 ice storm. Staff, however, recommends that one-half of the ice storm expense be disallowed because of the Company's failure to pursue its 1982 three-year tree trimming program. The annualized amount from the five-year amortization is $530,943 under Staff's recommendation and $1,061,886 under the Company's recommendation.

Public Counsel opposes any recovery of ice storm expense on the ground that such recovery constitutes retroactive ratemaking. Public Counsel cites 393.140(5)and Section 393.140(5), RSMo 1978, for the proposition that ratemaking be prospective as opposed to retroactive.

The Commission agrees that retroactive ratemaking is prohibited and the Supreme Court of Missouri has so found. State ex rel. Util. Consumers Council, etc. v. P.S.C., 585, S.W.2d 41 (Mo. banc 1979) (hereinafter UCCM). The UCCM Court found a fuel adjustment clause to be unlawful and in rejecting Public Counsel's request to remand to the Commission to order a refund of the excess amounts collected under the fuel adjustment clause the court stated:

> [17] However, to direct the commission to determine what a reasonable rate would have been and to require a credit or refund of any amount collected in excess of this amount would be retroactive ratemaking. The commission has the authority to determine the rate to be charged, § 393.270. In so determining it may consider past excess recovery insofar as this is relevant

to its determination of what rate is necessary to provide a just and reasonable return in the future, and so avoid further excess recovery, see State ex rel. General Telephone Co. of the Midwest v. Public Service Comm'n, 537 S.W.2d 655 (Mo.App.1976). It may not, however, redetermine rates already established and paid without depriving the utility (or the consumer if the rates were originally too low) of his property without due process. See Arizona Grocery Co. v. Atchison, Topeka & Santa Fe R. Co., 284 U.S. 370, 389-90, 52 S.Ct. 183, 76 L.Ed. 348 (1932); Board of Public Utility Commissioners v. New York Telephone Co., 271 U.S. 23, 31, 46 S.Ct. 363, 70 L.Ed 808 (1926); Lightfoot v. City of Springfield, 361 Mo. 659, 236 S.W.2d 348, 353 (1951). UCCM supra at 58.

In finding the fuel surcharge unlawful the court stated:

> [19,20] The utilities take the risk that rates filed by them will be inadequate, or excessive, each time they seek rate approval. To permit them to collect additional amounts simply because they had additional past expenses not covered by either clause is retroactive rate making, i.e., the setting of rates which permit a utility to recover past losses or which require it to refund past excess profits collected under a rate that did not perfectly match expenses plus rate-of-return with the rate actually established, Board of Public Utility Commissioners v. New York Telephone Co., 271 U.S. at 31, 46 S.Ct. 363; Lightfoot vs. Springfield, 236 S.W.2d at 353. UCCM at 59.

Public Counsel cites Narragansett Electric Co. v. Burke, 415 A.2d 177 (R.I. 1980) for an explanation of the policy concerns underlying the prohibition against retroactive ratemaking.

> The rule against retroactive ratemaking serves two basic functions. Initially, it protects the public by ensuring that present consumers will not be required to pay for past deficits of the company in their future payments....
>
> . . . .
>
> The rule also prevents the company from employing future rates as a means of ensuring the investments of its stockholder. Georgia Ry. & Power Co. v. Railroad Commission of Georgia, 278 F. 242 (D.C.Ga. 1922). If a utility's income were guaranteed, the company would lose all incentive to operate in an efficient, cost-effective manner, thereby leading to higher operating costs and eventual rate increase. Id. at 179-180. (emphasis added).

What Public Counsel does not mention in his argument is the fact that the Narragansett Court specifically considered ice storm expenses in light of the rule against retroactive ratemaking and concluded that the rule did not apply. The Rhode Island Supreme Court said at pp. 179-180:

[2] The application of the rule against retroactive ratemaking to prevent the company from recovering the extraordinary cost of the ice storm would serve neither of the policies expressed above. Because of the unpredictable and severe nature of the storm, it is unlikely the company officials, in planning their operational expenses, could take into account the cost of repairing the widespread damage that occurred on January 14, 1978. The existing rates, moreover, as the commission indicated in its decision, were "not in any fashion [based on] the extraordinary expenses of restoration of service after the ice storm." Since the company incurred highly extraordinary expenses not covered by existing rates in combating this freakish storm, it is difficult to perceive how the future efficiency of the utility would be furthered by the application of the rule in this instance.

We have also noted that the rule serves to protect present customers from paying for a utility's past operating deficits. This aspect of the rule must be weighed against the interest of providing immediate service to customers when a destructive, unexpected storm occurs. On such an occasion the public interest in quickly restoring heat and electricity to the homes of customers must prevail.

. . . .

The next time a storm of this magnitude occurs, the company would have no incentive to hire outside line and tree crews to restore service efficiently and swiftly to customers if no reimbursement for extraordinary expenses would be forthcoming. Thus, application of the rule to expenses related to such an emergency situation so inextricably related to the public health and safety would serve to thwart the goal of effective customer service.

The plethora of cases from other jurisdictions permitting a utility to recover the extraordinary costs associated with an unusually severe storm indicate that the rule against retroactive ratemaking does not come into play in such instances. [citations omitted]

The Narragansett holding was cited with approval by this Commission in KCPL's last rate case as support for the recovery and amortization of the cost associated with the Company's Hawthorn 5 outage. See Re: Kansas City Power & Light Company 26 Mo. P.S.C. (N.S.) 104, 120 (1983).

Considering the foregoing, the Commission determines that the rule against retroactive ratemaking does not apply to expenses incurred which are associated with extraordinary events. Such expenses are not associated with "imperfectly matching of rates with expenses" or a "redetermination of rates already established and paid".

In contrast to underrecovery of fuel expenses established in previous rates which was the subject of the UCCM case, ice storm expenses do not involve the question of underrecovery since the previously established rates do not include expenses associated with extraordinary events.

In the Commission's opinion it has the discretion to recognize extraordinary events and allow for amortization of the expenses on a prospective basis over a reasonable period of time.

Finally, the Commission determines that Staff's position should be rejected. Although it is true and the Company admits a correlation exists between large limb overhangs and ice storm damage, the extent of the correlation has not been shown in this record. Thus, the Commission is unable to find that the reduction of overhead tree trimming for one-half of the three-year tree trimming program warrants a disallowance of one-half of ice storm related expenses. The Commission believes that the netting of ice storm expenses against capacity sales as discussed in Phase IV, Section IV-H below eliminates the inequities raised by the Staff in this matter.

I. Advertising and Related Expenditures

1. New York Rule

The Commission has traditionally applied the "New York Rule" to gas and electric utilities to determine whether costs of advertising and promotional practices should be included in rates. "As applied by this Commission, the rule first excludes all political and promotional advertising and then allows all other advertising, including good will advertising, up to an amount equal to one-tenth of one percent of the utility's revenues." Re: Union Electric Company, 25 Mo. P.S.C. (N.S.) 194, 200 (1982).

Staff, Public Counsel and Company are all recommending elimination of the New York Rule as it has been applied by this Commission. Staff asserts the rule is deficient because it allows institutional advertising which does not benefit the ratepayers, it arbitrarily excludes promotional advertising regardless of benefit to

In the Commission's opinion the O&M savings at issue are not comparable to one-time non-recurring extraordinary expenditures. The Company's rates which have been previously set by this Commission are designed to recover O&M expenses among other expenses and a return on the Company's investment. The Company apparently did not incur O&M expenses at the level that was built into previous rates. The Commission finds that DOE's proposal involves returning past profits to ratepayers in violation of the prohibition against retroactive ratemaking and, therefore, should be rejected.

C. Storm Damage Reserve

The Public Counsel recommends that the Commission establish a storm damage reserve account to recover the cost of future storm related expenses. Public Counsel proposes $970,079 on an annual basis based upon a normalization of expenses associated with significant storms occurring since 1973. The Public Counsel contends that this approach legally addresses extraordinary storm expenses and avoids Public Counsel's claim that the amortization treatment of storm-related expenses constitutes retroactive ratemaking.

Since the Commission has rejected Public Counsel's retroactive ratemaking argument and found the amortization method to be appropriate, the Commission finds that Public Counsel's proposal to establish a storm damage reserve account should be rejected.

D. Test Year Revenues

The Company adjusted its test year revenues to reflect known and measurable changes, including the annualization of test year kilowatt hour sales and revenues, to reflect the projected number of customers as of July 31, 1985. Company's calculated test year revenue level is approximately $359.8 million. The Company's approach is consistent with the method proposed and adopted in Case No. ER-83-49.

The Staff proposes to normalize and annualize test year kwh sales by applying to the Company's actual test year Missouri load factor the base case

FISCHER & DORITY
PROFESSIONAL CORPORATION

James M. Fischer
Larry W. Dority

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April 24, 2002

FILED[3]
APR 2 4 2002
Missouri Public Service Commission

Mr. Dale Hardy Roberts
Chief Regulatory Law Judge/Secretary
Missouri Public Service Commission
200 Madison Street, Suite 100
P.O. Box 360
Jefferson City, Missouri 65102

RE: Kansas City Power & Light *Company*
Case No.

Dear Mr. Roberts:

Enclosed for filing in the above-referenced matter is an original and eight (8) copies of the Application of Kansas City Power & Light Company for an Accounting Authority Order.

Thank you for your attention to this matter.

Sincerely,

James M. Fischer

James M. Fischer

Enclosures
cc: Office of the Public Counsel
Dana K. Joyce

FILED[3]

APR 2 4 2002

Missouri Public Service Commission

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company for an Accounting Authority Order Regarding Accounting for Extraordinary Cost Relating to Storm Damage.	)	Case No. ___________

APPLICATION OF KANSAS CITY POWER & LIGHT COMPANY FOR AN ACCOUNTING AUTHORITY ORDER REGARDING ACCOUNTING FOR EXTRAORDINARY COST RELATING TO STORM DAMAGE

Comes now Kansas City Power & Light Company ("KCPL"), pursuant to Section 393.140(4), RSMo, and 4 CSR 240-2.060 and 2.080, and respectfully applies for an Accounting Authority Order regarding KCPL's accounting for extraordinary costs relating to a severe ice storm that destroyed KCPL's property and equipment on January 30 and 31, 2002. KCPL requests that these extraordinary costs be deferred to Account 182.3 and amortized over a five-year period. In support thereof, KCPL states:

1. KCPL is a corporation duly organized and existing under and by virtue of the laws of the State of Missouri, with its principal office located at 1201 Walnut, Kansas City, Missouri 64106: e-mail: www.kcpl.com; telephone: (816) 556-2200; fax (816) 556-2787. KCPL is an "electrical corporation" and a "public utility" as defined in Sections 386.020(12) and (32), RSMo. KCPL is engaged in the generation, transmission, distribution and sale of electric energy to the public in portions of Kansas and Missouri.

2. KCPL has filed its Certificate of Good Standing in Case No. EF-2002-315, which is incorporated herein by reference.

3. Communications and correspondence in regard to this Application should be addressed to:

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4. In the past, the Commission has approved the deferral of incremental costs related to extraordinary events including a wind storm in 1982, an ice storm in 1984, flooding in 1993 and a snow storm in 1996. The January 30-31, 2002, ice storm caused more damage to KCPL's property and equipment than any of these previous events.

5. On January 30 and 31, a severe ice storm hit KCPL's system. Accumulations of up to two inches of ice on trees, lines and equipment caused unprecedented damage and destruction to KCPL's facilities. At the peak of the storm, over 305,000 of KCPL's approximate 450,000 customers had lost electric service. Almost 200 of KCPL's 550 metro circuits were completely out at some point in the storm. In order to restore service as quickly as practicable, KCPL utilized 447 outside utility and contractor crews and 314 outside tree crews, in addition to

the 200 KCPL and local contract crews. Personnel from eleven utilities and ten contractors from sixteen states were used in the restoration efforts.

6. The January, 2002, ice storm threatens financial hardship to KCPL because rates in Missouri are set on a prospective basis, and no allowance is included for the possibility of unusual expenses related to a natural disaster such as this storm. The storm has increased costs beyond what KCPL should, in its normal course of business, be expected to bear in a single year.

7. KCPL thus asks that the Commission permit incremental costs directly related to the ice storm including, but not limited to, labor costs, material purchases and repairs be deferred to Account 182.3, Other Regulatory Assets. Such deferral is consistent with previous regulatory procedures in Case Nos. ER-77-118, ER-83-49, EO-85-185, ER-94-197 and EO-97-224. In these cases, the Commission approved the deferral and subsequent amortization of extraordinary costs. In Case No. EO-85-185, the Commission allowed KCPL to include in its rates deferred costs associated with the 1984 ice storm. KCPL will seek recover of the unamortized portion of these deferred costs in future rate proceedings.

8. KCPL requests an order from the Commission authorizing the deferral of incremental storm costs to Account 182.3. KCPL also requests that these deferrals be amortized for financial reporting beginning with receipt of the Commission's Accounting Authority Order and continue over a five year, or sixty month, period.

9. KCPL has no pending action or final unsatisfied judgments or decisions against it from any state or federal agency or court which involve customer service or rates which has occurred within three (3) years of the date of the Application, except as identified on Exhibit A, attached hereto and incorporated herein. No annual report or assessment fees are overdue.

WHEREFORE, KCPL respectfully requests an Accounting Authority Order that allows both for the deferral of extraordinary storm costs and for their subsequent amortization over five years as described above.

Respectfully submitted,

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and

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Attorneys for
Kansas City Power & Light Company

EXHIBIT A

The following is a listing of Applicant's pending actions or final unsatisfied judgments or decisions against it from any state or federal agency or court which involve customer service or rates, which action, judgment or decision has occurred within three (3) years of the date of this application:

1. GST Appeal of Missouri Public Service Commission Decision; Case No. EC-99-553 in the Circuit Court of Cole County, Missouri; Docket No. 00CV324891; further appealed to the Court of Appeals of the Western District of Missouri by GST.

2. Hawthorn Station Incident Investigation before the Missouri Public Service Commission; Case No. ES-99-581

CERTIFICATE OF SERVICE

I do hereby certify that a true and correct copy of the foregoing Application has been hand-delivered or mailed, First Class mail, postage prepaid, this 24th day of April, 2002, to:

Office of the Public Counsel
P.O. Box 7800
Jefferson City, MO 65102

Dana K. Joyce, General Counsel
Missouri Public Service Commission
P.O. Box 360
Jefferson City, MO 65102

James M. Fischer

James M. Fischer

2012.04.20 16:26:22
Kansas Corporation Commission
/S/ Patrice Petersen-Klein

**BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

Received
on

APR 20 2012

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.

2012.04.20 16:26:47
Kansas Corporation Commission
/S/ Patrice Petersen-Klein

**BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

Received
on
APR 2 0 2012
by
State Corporation Commission
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.

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[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.

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Kansas Corporation Commission
/S/ Patrice Petersen-Klein

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by
State Corporation Commission
of Kansas

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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 to Make Certain Changes in Its Charges for Electric Service	))))	Docket No.: 12-KCPE- -RTS

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

My commission expires: April 12, 2015

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

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%

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

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

Line No.	[A] Description	[B] Rank	[C] Total KCP&L	[D] Missouri	[E] Kansas	[F] 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%

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	2007	2008	2009	2010	2011	Average
			MW	MW	MW	MW	MW	MW	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	3,428	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	2,825	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	2,218
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%

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.

v. Docket No. EL05-19-002

Southwestern Public Service Company

Southwestern Public Service Company Docket No. ER05-168-001

OPINION NO. 501

OPINION AND ORDER ON INITIAL DECISION

(Issued April 21, 2008)

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Paragraph Number

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

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[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.

[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. <u>Brief Opposing Exceptions</u>

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).

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

	[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 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	-	-			