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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2018-0145

DIRECT TESTIMONY

OF

THOMAS J. SULLIVAN, JR.

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
January 2018

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CASE NO. ER-2018-0145

INTRODUCTION

Q. Please state your name and business address.

A. Thomas J. Sullivan, Jr., 15898 Millville Road, Richmond, Missouri, 64085.

Q. By whom are you employed?

A. I am President and owner of Navillus Utility Consulting LLC.

Q. How long have you been with Navillus Utility Consulting?

A. I started the company in June 2011.

Q. What is your educational background?

A. I received a Bachelor of Science Degree in Civil Engineering Summa Cum Laude from the University of Missouri - Rolla in 1980 and a Master of Business Administration Degree in Business Administration from the University of Missouri - Kansas City in 1985.

Q. Are you a registered professional engineer?

A. Yes, I am a Registered Professional Engineer in the State of Missouri.

Q. To what professional organizations do you belong?

A. I am a member of the American Society of Civil Engineers.

Q. What is your professional experience?

A. Prior to forming Navillus Utility Consulting LLC, I worked for Black & Veatch Corporation. I worked for Black & Veatch for over 31 years as an engineer, project engineer, project manager, vice president, and director. I have been responsible for the preparation and presentation of numerous studies for gas, electric, water, and wastewater utilities. My clients served include investor-owned utilities, publicly-owned utilities, and their customers. The professional studies that I have prepared involve valuation and depreciation, cost of service, cost allocation, rate design, cost of capital, supply analysis, load forecasting, economic and financial feasibility, cost recovery mechanisms, and other engineering and economic matters.

Q. Have you previously appeared as an expert witness?

A. Yes, I have. In Schedule TJS-1, I list cases where I have filed expert witness testimony and appeared as an expert witness. As noted on that schedule, I have appeared before the Missouri Public Service Commission ("Commission") as an expert witness on depreciation rates for Missouri Gas Energy in Case Nos. GR-2001-292, GR-2004-0209, GR-2006-0422, and GR-2009-0355; The Empire District Gas Company in Case Nos. GR-2009-0434 and GR-2016-0023; and, The Empire District Electric Company in Case Nos. ER-2011-0004 and ER-2012-0345. I also served as an expert witness for Aquila, Inc. (natural gas operations) on class cost of service, rate design, and weather normalization in Case No. GR-2004-0072.

Q. For whom are you testifying in this matter?

A. I am testifying on behalf of the Kansas City Power & Light Company ("KCP&L" or "Company"). I would also like to point out that I am filing testimony on behalf of

KCP&L Greater Missouri Operations Company ("GMO") rate case coincident with this filing.

Q. What is the purpose of your direct testimony?

A. I am sponsoring KCP&L's proposed production cost allocation methodology used in its class cost of service ("CCOS") study. My testimony specifically focuses on the classification and allocation of production related costs. Company witness Ms. Marisol Miller is sponsoring the Company's CCOS and her Direct Testimony includes the discussion of the Company's model and actual analyses. In his Direct Testimony, Company witness Mr. Bradley Lutz discusses the recent history of the Company's production cost allocation and the Company decision regarding the methodology to use in this case.

Q. Do you sponsor any schedules with your testimony?

A. Yes. I sponsor the following schedules:

Schedule TJS-1 – Expert Witness Testimony of Thomas J. Sullivan

Schedule TJS-2 – KCP&L's Generating Facilities

Schedule TJS-3 – Comparison of Fuel and Capacity Unit Costs

Schedule TJS-4 – Comparison of Capacity Factors and Capacity Unit Cost

Schedule TJS-5 – Class Coincident Peak Load Factors

Schedule TJS-6 – Operating Characteristics of KCP&L's Generating Assets (Capacity & Load Factors)

Schedule TJS-7 – Unit Costs of KCP&L's Generating Assets

Schedule TJS-8 – Unit Costs of KCP&L's Generating Asset Reflecting System-wide Fuel Cost

Schedule TJS-9 – Comparison of Production Cost Allocations – NARUC

Schedule TJS-10 – Comparison of Production Cost Allocations - KCP&L

The sources of data used to prepare Schedules TJS-2, TJS-3, TJS-4, TJS-6, TJS-7, and TJS-8 are the Company's Federal Energy Regulatory Commission Form No. 1 ("FERC Form 1") for the years 2014 through 2016. Schedule TJS-9 relies upon data in the 1992 National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual ("NARUC Manual"). Schedules TJS-5, TJS-7, TJS-8 and TJS-10 utilize data and analyses from the Company's CCOS Study filed in this case

Q. Do you support the Company's recommended use of the classification and allocation of production related costs using the average and Excess Demand methodology?

A. Yes, I do.

Q. What are the primary reasons you are supporting the use of this methodology?

A. In my opinion the Average and Excess Demand ("A&E") methodology best meets the primary goal of a CCOS Study which is to align cost allocation with cost causation for the following reasons:

1. Lower load factor customers have directly resulted in the Company needing to construct and operate facilities that have higher unit costs.
2. The total unit cost of the facilities built to serve these lower load factor loads are significantly more expensive than the facilities that would be built if the system operated at a much higher load factor.
3. Fuel costs are currently recovered on an energy basis even though the lower load factor generating facilities have much higher fuel costs. Thus, the

recovery of fuel related costs on an energy basis results in a benefit to lower load factor customers.

4. The use of allocation methods that approach an energy based allocation does not give adequate differentiation between the cost associated with higher and lower load factor facilities and higher and lower load factor customers.

5. The A&E or 100 percent demand based allocations produce results that provide a reasonable balance between the energy and capacity function of generating facilities.

Q. Please outline your direct testimony.

A. My direct testimony is broken down in the following sections:

1. Discussion of CCOS principles and definition of terms.
2. Discussion of Production Cost Allocation.
3. Discussion of KCP&L's generating assets and load profile.
4. History of methodologies used in Missouri and Kansas.
5. Discussion of the production cost allocation methodologies.

CLASS COST OF SERVICE PRINCIPLES AND TERMINOLOGY

Q. What is the purpose of a CCOS study?

A. A CCOS study is intended to determine the cost of providing service to the various classes of service provided by the utility. The classes of service are defined as relatively homogeneous groups of customers whose usage characteristics and service requirements are similar. The classes generally align with the various rates the utility charges for service. The costs allocated to the customer classes consist of the various components of rate base and revenue requirements. The primary component of rate base is the net plant investment in the facilities of the utility system. Revenue requirements primarily consist of operation and maintenance expenses, depreciation expenses, return on rate base, and taxes.

The CCOS study is used as a tool or as one of the principle considerations in the design of the rates charged by the utility. While a CCOS study does provide the overall cost of service or overall revenue requirement for each customer class, the real value of the CCOS study is providing detail regarding the cost of the various functions or services that the utility provides. Further, rates generally consist of fixed and variable components that target specific fixed and variable costs. Fixed costs are costs that do not vary with the amount of the product produced or used. Variable costs are costs that do vary directly with the amount of product produced or used. To the extent practical, rates should be designed to reflect the fixed and variable nature of the underlying costs.

Q. Please discuss further the various functions and services provided by an electric utility like KCP&L.

A. The functions provided by an electric utility like KCP&L consist of the following:

<u>Generation or Production</u> – producing electricity.

<u>Transmission</u> – moving electricity from generating resources to general areas of demand.

<u>Distribution</u> – delivery of electricity to the individual customers.

<u>Customer related</u> – providing customer specific services and services related to billing customers and collecting revenues.

For utilities like KCP&L that use the FERC Uniform System of Accounts, investment and operating costs are tracked at a level of detail that follows these functions.

Electric utilities provide service that is available 24 hours a day and 365 days a year whenever the customers demand that service. The electric utility's facilities must be designed to be able to respond to demands of customers over which the utility has no direct control. Therefore, in the CCOS study, functional costs are further classified as demand, commodity, or customer related. Demand related costs are the costs associated with providing the capacity in the system needed to meet both the highest demand of individual customers but also the aggregate requirements of all of its customers with an adequate level of reserves to meet contingencies. Commodity (or energy) related costs are the costs of providing the variable needs of the customers. Customer related costs are those costs incurred to connect and serve a customer independent of the customer's actual demand or usage.

Q. What specific component of the CCOS study is addressed in your direct testimony?

A. My direct testimony will specifically address appropriate allocation of the production or generation function to customer classes.

Q. Please discuss what facilities and costs constitute the production function?

A. The production function for KCP&L consist of the power plants owned by KCP&L and the various components associated with these generating assets up to the point where the electricity is delivered to the electric transmission or distribution systems. A listing of these facilities is shown in Schedule TJS-2.

The production net plant includes the Company's investment less the accumulated depreciation associated with these facilities. Based on the FERC Uniform System of Accounts, these costs are tracked in FERC Accounts 310 through 347. This breakdown provides the detail on plant in service, accumulated depreciation, and depreciation expenses associated with these assets. The direct costs associated with operating and maintaining these facilities are tracked in FERC Accounts 500 through 557.

In addition to these direct costs, the revenue requirement for production also includes the return and income taxes associated with the rate base associated with these facilities as well as allocations of taxes other than income taxes and an allocation of general and administrative costs.

Q. How are electric production related costs classified?

A. Generally, the non-fuel production (function) related costs are classified as demand (capacity) or commodity (energy). Fuel (used in the generating facilities) is usually unbundled from the CCOS study and collected through a separate fuel charge component of the rate or in some manner that directly accounts for fuel. There are several different methodologies that are used to determine what portion of non-fuel production related costs are classified as demand or capacity and commodity or energy. Later in my testimony, I will discuss not only the A&E methodology I am recommending but other methodologies that have been used or considered for use for KCP&L in the recent past.

Q. Once non-fuel production related cost are classified, how are these costs allocated to customer classes?

A. The Production Demand related costs are typically allocated to customer classes based on some measure of the customer class's share of the peak demand of the system. The Production Commodity related costs are allocated to customer classes based on the customer class's share of the annual energy requirements (or total energy production) of the system.

Q. Please define what you mean by commodity or energy requirements.

A. A customer class's commodity or energy requirements are the class's aggregate sales plus energy losses usually measured in kilowatt-hours ("kWh"). In the context of the CCOS study the sales can be annual, monthly, or seasonal. The losses for each customer class represent the amount of energy in excess of what the customer consumes that needs to be inputted into the system in order to account for the energy losses that occur through all of the facilities required to deliver that energy to the customer. For example, each time the energy flows through a transformer, a certain amount of energy is lost (as heat) in the process of increasing or decreasing the voltage. So, all other things being equal, the losses associated with each customer class are generally correlated with the voltage levels at which the customers in that class are served.

Q. Please define what you mean by Capacity or Peak requirements.

A. The customer class's capacity or peak requirements are the class's aggregate rate of energy usage plus losses usually measured in kilowatts (kW). There are several different ways to measure this peak requirement. The rate of energy use can be viewed as the amount of energy used in one hour (or sometimes shorter time periods such as 15 minutes). The peak demands discussed in my testimony will be one hour demands. Class coincident peak ("CP") is the aggregate demand of that class at the time of (coincident with) the system peak. Class non-coincident peak is the maximum aggregate demand of that class that occurs any time during the time period defined. The non-coincident peaks ("NCP") of each of the customer classes do not necessarily occur at the time of the system peak and they do not necessarily occur at the same time as each other (i.e. one class's NCP may not occur at the same time as another class's NCP). CP's and

NCP's can be defined both annually, monthly, seasonally or ranked (the highest 4 CP's for example). For purposes of production cost allocation, the class demands are aggregated for the class. The class demands are the sum of the demands for all of the customers in that class at a given point in time; in other words, for the class, the demands of the individual customers are coincident with each other (i.e. occur at the same time).

Q. Are there some other terms you would like to discuss prior to discussing specific production cost allocation methodologies?

A. Yes. There are four terms I would like to define and discuss because they are particularly important to the discussion of the production cost allocation – Capacity Factor, Load Factor, Coincident Peak, and Non-Coincident Peak.

Q. Please define what you mean by capacity factor.

A. Capacity factor as it relates to an electric utility is defined as the ratio of the average output (kilowatts) of a generating unit over a specified period of time to the rated capacity (kilowatts) of a generating unit over that same time period. Capacity factor is a measure of how efficiently the unit is operated or dispatched. For example, if a generating unit with a rated capacity of 200,000 kilowatts generates 1,314,000,000 kilowatt-hours of electricity over a year for an average output of 150,000 kilowatts (1,314,000,000 kilowatt-hours divided by 8760 hours in a year), that unit had a capacity factor of 75 percent. In other words, the unit produced 75 percent of the energy it could have theoretically produced if it operated 100 percent of the time at its rated capacity.

Q. What factors impact the capacity factor of a generating unit.

A. There are several factors that impact a unit's capacity factor. One factor is the variable operating cost of the unit. The variable operating costs include both the fuel cost of the unit as well as the variable operation and maintenance expenses associated with the unit. When an electric utility's generating units are dispatched, it generally makes the most economic sense to dispatch the available units with the lowest variable cost first. This will generally result in the lowest overall variable cost of operating the facilities. With this in mind, there are factors other than economic dispatch that might impact which units are dispatched at any specific point in time. The second factor is the availability of the unit. The availability of the unit is a function of several factors including the age of the unit, the cycle of regularly scheduled maintenance, and other unplanned outages or unscheduled maintenance and repairs. Further, how the unit is used (i.e. the frequency of restarts) impacts the availability of the unit. Most generating units operate most efficiently if they are operating at or near their rated capacity with minimal fluctuations in output or restarts. Fluctuations in output and restarts are generally caused by variations in system demand. Fluctuations in output and restarts cause stress on equipment that increases operation and maintenances costs and reduces the life of components.

Q. Please define what you mean by load factor.

A. Load factor for an electric utility is defined as average demand divided by peak demand. Load factor is a measure of how efficiently a customer uses the facilities required for service. For example, if a customer uses 8,760 kilowatt-hours over the course of a year, that customer's average demand is 1 kilowatt. However, if the customer used 5 kilowatts during the hour of its maximum demand, the customer's load factor would be 20 percent (1 divided by 5). If this customer's demand also occurred at the same time as the system peak, this 20 percent could further be stated at the customer's coincident peak load factor. If, on the other hand, this demand occurred at a time other than the system peak, this 20 percent would be stated as the customer's non-coincident peak load factor. A customer with a 20 percent load factor, on average used 20 percent of the capacity available to serve their demand; or stated differently, 80 percent of the available capacity was not fully used.

While capacity factor is typically used to measure the output of a generating unit, load factor can be used as either a measure of a customer's load profile or as a measure of how the generating asset is used over a finite period of time. Also, there is a subtle difference between a generating unit's capacity factor and its load factor. Load factor for a generating unit would be based on the unit's peak output whereas capacity factor is based on the unit's rated capacity.

Q. When you use the terms peak or average demand in your testimony, do the figures include allowance for losses?

A. Yes. In my testimony, when I am referring or referencing specific numbers, the class average demands are based on the annual customer class demands including allowance for losses and the class peak demands also include allowance for losses. Therefore, all the figures are assumed to be at the system input level, rather than what is ultimately measured at the meter. So, for example, if a customer uses 1,000 kilowatt-hours in a month, the amount of energy that actually has to be generated is higher than that figure due to the fact that some energy is lost or consumed through the delivery of that energy through the system.

Q. Please define coincident peak.

A. In the context of my testimony, I will use the term Coincident Peak to mean the class peak coincident (occurring at the same time) with the system peak. The coincident peak associated with the single highest system demand is referred to as the 1 CP. I refer to coincident peaks based on the average of multiple months as the number with CP. For example, 3 CP would mean the average of the three highest class coincident peaks in three different months.

Q. Please define Non-coincident peak.

A. In the context of my testimony, I will use the term Non-Coincident Peak to mean the highest demand for the class occurring at any time (may or may not be coincident with the system peak). The non-coincident peak associated with a class' highest demand is referred to as the 1 NCP. I refer to non-coincident peaks based on the average of multiple months as the number with NCP. For example, 3 NCP would mean the average of the three highest class peaks in three different months.

Q. Within a customer class, how is the CP or NCP determined.

A. When I use the term CP or NCP, I am assuming that within a class the peak demands of the individual customers are coincident with each other and the CP and NCP are the aggregated demand of the whole class. There may be demand factors used (on distribution facilities for example) where the term NCP may mean the sum of the individual customer demands that may not be coincident with each other, but in the context of my testimony, I will only be referring to class demands where the demands of the individual customers within the class are coincident with each other.

PRODUCTION COST ALLOCATION

Q. What is the overall goal of cost allocation in general and production cost allocation in particular as it relates to a CCOS study?

A. The goal of a CCOS study is to align the cost with causation to the maximum extent practical. In other words, the cost should be aligned as closely as practical to the customers who result in the cost being incurred. Different types of generating assets are more efficient at serving different types of loads. The utility's decisions regarding what generating assets are to be built are based on analysis of these loads and the relative cost of different types of generating assets that could serve these loads, the goal being to construct facilities that result in the lowest overall cost. The relative unit costs of these different types of generating assets can generally be summarized as follows:

1. Higher capital (fixed) cost facilities generally have lower operating (variable) costs.
2. Lower capital cost facilities generally have higher operating costs.

As such, the lowest overall cost usually results from building the higher fixed cost facilities to operate at high capacity (or load) factors and the lower fixed cost facilities to operate at lower capacity (or load) factors.

As system load factor declines with the corresponding decline in the capacity factors of the generating assets – base load units become less economical and the generation mix turns to intermediate and peaking type units that have lower capital costs but higher operating costs. Overall such units have higher unit costs because their costs correspond with less generation (lower capacity factors). Also, as system load factor declines, the diversity between customer classes generally increases and you start to see the stratification between customer classes. This stratification will manifest itself in increasing differences between average demand and peak demand allocation factors as the spread between class load factors increase.

The allocation of generation costs should then primarily focus on properly allocating costs to the classes that produce the lower load factor and the higher unit cost associated with non-base load generation.

Q. Have you confirmed these relationships as they relate to the Company's generating assets?

A. Yes. In Schedule TJS-3 I provide a graph that shows the fixed cost of KCP&L's principle generating resources in terms of the original cost of the facilities divided by their rated capacity ($/kW) and their average fuel cost ($/kWh) for 2016. As shown in this graph, the variable fuel cost is generally inversely correlated to the fixed capacity cost of the facilities.

In Schedule TJS-4, I show the relationship between capital cost and capacity factor over the 2014-2016 period. The graph shows that the higher capital cost units have higher capacity factors (they are dispatched more). It should be noted that as discussed previously, a unit's capacity factor is also impacted by issues other than cost.

Q. Is there one specific cost allocation methodology that is Generally better at aligning costs to the customer classes causing the cost?

A. No. The methodology used should take into consideration the following:

1. The load characteristics of the customers served by the utility.
2. The generating assets constructed to meet customer requirements.
3. How fuel costs are recovered.

4. Methodologies generally used by similarly situated utilities.

As a secondary consideration, the methodology historically used by the utility should also be taken into consideration primarily from the perspective of the impact the CCOS study may have on the design of rates. In my opinion, the methodology used should not be driven by what has been used in the past. The methodology used should be the methodology that best recognizes the four considerations listed above. However, I do recognize that a change in methodology and full application of this methodology in the design of rates could be disruptive and the reflection of a methodological change in rate design may need to be phased in over time to mitigate disruption.

Q. Is there one specific cost allocation methodology that is recommended by the NARUC Manual?

A. No. The intent of the manual (published in 1992) was to provide a comparison of methodologies in use at the time the manual was published. The manual specifically discusses the following methodologies for production cost allocation:

<u>Peak Demand Methods</u>

1. Single Coincident Peak ("1 CP")
2. Summer and Winter Coincident Peak ("6 CP")
3. Monthly Coincident Peak ("12 CP")
4. Other Multiple Coincident Peaks ("4 CP" would be an example)
5. All Peak Hours ("On-peak Energy")

<u>Energy Weighting Methods</u>

6. Average and Excess
7. Equivalent Peaker

8. Base and Peak

9. Judgmental Energy Weighting (includes Average and Peak)

<u>Time Differentiated Methods</u>

10. Production Stacking

11. Base-Intermediate-Peak

12. Loss of Load Probability ("LOLP")

13. Probability of Dispatch ("POD")

Within these methods there are also hybrids. For example, the energy weighting methods might include either coincident peaks or non-coincident peaks and differing number of peaks (3, 4, 6, or 12, for example).

Q. Is there a common point of comparison between these various methods?

A. Yes. All of these methods use different approaches to determining the relative weighting of capacity (peak) and energy requirements in the allocation of production related costs. Generally speaking, the relative weightings will range from a Single Non-Coincident Peak Method which allocates all the costs on the basis of non-coincident peak demand to methodologies that approach a pure energy allocation. Generally, the higher number of peaks included in the calculation combined with a higher percentage weighting of energy in the allocation will generally produce allocations that near a pure energy allocation.

Q. Are all of the methodologies identified in the NARUC Manual commonly used?

A. No. Based on my review of KCP&L's recent rate cases and recent rate cases filed in Missouri and Kansas, the following methods have generally been used or proposed (with various numbers and types of peaks - CP versus NCP):

1. Average and Excess

2. Average and Peak

3. Base-Intermediate-Peak

In the remainder of my testimony, I will primarily focus on these methodologies. I will also use the 1 NCP and 1 CP method and pure energy allocation method for comparative purposes. Please refer to the direct testimony of company witness Mr. Bradley Lutz for a more detailed history of the recent use of the methods above as they pertain to KCP&L.

Q. Of the methodologies on which you will focus in the remainder of your testimony, please generally discuss the relative weighting of peak demand and energy requirements in those allocation bases.

A. If the three methodologies are considered along a continuum with a 1 NCP or 1 CP method having a zero weighting of energy requirements and a pure energy allocation having a 100 percent weighting of energy requirements, the three methodologies listed above can generally be ranked as follows as they relate to a 1 NCP methodology:

1. 1 NCP
2. 1 CP
3. Average and Excess
4. Average and Peak
5. Base-Intermediate-Peak
6. Energy Only

Later in my testimony, I will provide examples of the allocation bases produced by these methods as discussed in the NARUC Manual and also as they relate to test year analyses in this case.

KCP&L'S LOAD PROFILE AND GENERATING ASSETS

Q. What are the primary considerations in determining the appropriate cost allocation methodology for KCP&L?

A. As stated above, the primary considerations are the Company's load profile and the generating assets constructed to serve that load profile. If a system operated at a very high load factor (say 80 percent or higher), the differences between the load profiles of the customer classes would be small and thus the differences between allocation methodologies would be relatively small. Further, the utility would generally build base load generating facilities that are intended to operate at very high capacity or load factors. There would be a great deal of homogeneity between the generating resources. As system load factor declines, the relative differences between class load profiles and allocation methods increases and the utility relies upon ever increasing investments in peaking units (the homogeneity between generating resources decreases) which have lower capital costs but higher operating and fuel costs. Also, as system load factor declines, the overall utilization rates (capacity factors and load factors) of all of the generating units decline. Base load units are cycled more and peaking units are cycled even more. The core issue in any production cost allocation is who should pay for the higher unit costs that result from the lower utilization of generating units and the greater reliance upon peaking units. In other words, who should pay for the unused or under-utilized capacity? The simple answer is the customers who contribute to the unused or underutilized capacity, or broadly speaking, the customer classes whose usage characteristics contribute to the lower system load factor.

Q. Please explain how load profile should determine the appropriate cost allocation methodology.

A. For systems with very high load factors, the differences in load profile between the classes are relatively small with all of the classes necessarily having very high load factors. In other words, there is a great deal of homogeneity between the load profiles of the various customer classes and also a great deal of homogeneity between the generating assets. As such, it would be difficult to argue that particular classes are contributing to unused capacity since the capacity is being highly utilized. As such, it would be reasonable to utilize methodologies that are more energy based. Also, as a practical matter, there would be little difference in the results produced by different methodologies.

As system load factor declines and differences between class load factors increases (i.e. there is not homogeneity between the customer classes and less homogeneity between generating assets), the differences between a pure peak and a pure energy allocation increase. Most importantly, allocation bases that give higher recognition to energy requirements become less and less appropriate because they fail to adequately recognize which classes are contributing to the lower system load factor and higher cost.

Q. Based on the Test Year Ended June 30, 2017, what are the class load factors for the Customer classes used in KCP&L's CCOS study?

A. Schedule TJS-5 summarizes the derivation of class load factors based on test year coincident peak demand (1 CP) and test year energy requirements. As shown in Schedule TJS-5, the system load factor is 56 percent and the class load factors range from

39 percent for the Residential class to 82 percent for the Large Power Service class. The Large General Service class has a load factor of 67 percent, the Medium General Service class has a load factor of 59 percent, and the Small General Service has a load factor of 57 percent. Based on this analysis, there are significant differences between the class load factors with the Residential class being the primary contributor to the system's relatively low load factor.

Q. Is there a significant diversity in KCP&L's generating resources and how these resources are operated?

A. Yes. As shown in Schedule TJS-6, there is diversity in types of units, fuels used, and in how the units are used. There is a very clear delineation between plants that have high rates of utilization and plants that have low rates of utilization. As shown in Schedule TJS-7, the plants with the highest utilization rates also have the lowest fuel cost and generally the lowest overall unit cost.

Q. What Is the correlation between how KCP&L's Generating resources are operated and customer demands?

A. The high utilization rate and low cost units generally meet the highest load factor demands. In other words, the high consistent customer use is met by these highly utilized and lowest unit cost plants. Conversely, the low utilization rate and higher cost units are used sparingly to meet the lowest load factor demands. These lowest load factor demands are the infrequent higher demands caused by lower load factor customers.

Q. Please generally discuss Fuel Costs and how they are related to the CCOS study.

A. Fuel costs are recovered through a combination of fuel in the base rates plus a separate FAC rider that tracks the difference between the base amount of fuel and the incremental change in fuel costs. As such, fuel costs are tracked separately from the non-fuel portion of base rates. As such the CCOS study generally focuses on the non-fuel related production costs. Generally, fuel costs are recovered from customers on an aggregated basis (system-wide unit cost) with no specific recognition given to the differences in fuel costs between generating units and how the usage characteristics of different customer classes contribute to how generating units with different fuel costs are utilized to meet the different customer class requirements. The primary reason for this is to simplify the application and administration of the fuel cost rider. As shown in Schedule TJS-7, there are significant differences in the fuel costs between the generating units and as shown in Schedule TJS-6, there are significant differences in how the units are utilized. Further, as discussed above, how the units are utilized is directly related to the differing customer requirements.

Q. Is the cost recovery of fuel Costs relevant to the allocation and cost recovery of non-fuel costs?

A. Yes. As indicated above, the unit fuel cost does not reflect the significant differences in fuel cost between generating units and the significant difference in customer requirements that cause these different fuel costs to be incurred. As such, it is important to recognize that this difference exists when considering how the non-fuel production related costs should be allocated to customer classes. While there are a variety of reasons that it makes sense to use a system-wide average fuel cost, that does not mean that differences in fuel costs should be ignored in developing the overall cost to serve customer classes and ultimately in the overall rate design. The CCOS study can and should take into consideration the overall cost of the generating assets.

Q. How can the costs of the generating units reflect the actual treatment of fuel costs?

A. In Schedule TJS-7, I show the actual unit fuel costs for each of the Company's generating units for the 2014-2016 period, as well as the overall unit fuel cost (on Line 15). The total unit costs for each unit shown on Lines 24-47 reflect each generating unit's specific fuel cost. In Schedule TJS-8, I show the unit cost of each unit excluding their fuel costs on Lines 2 through 14 and including the system-wide average fuel cost (in lieu of the unit's specific fuel costs) on Lines 17 through 29. As shown on Lines 15 and 30, the total overall non-fuel cost does not change, only the units' costs of the individual units.

Q. How can the analysis shown in Schedule TJS-8 be used to determine how non-fuel production costs should be allocated to customer classes?

A. On Line 32 of Schedule TJS-8, I show the average unit cost of the five most highly utilized generating units for each year, and on Line 34, I show the average unit cost of the remaining generating units. These unit costs reflect the use of a system-wide unit cost for fuel. A comparison between Lines 32 and 34 shows that the unit cost of the highly utilized generating units is significantly lower than the unit cost of the remaining (lower utilized) generating units. In 2016, this cost difference was $0.0111 per kWh. The differences were higher in 2015 and 2014.

The allocation methodology used to allocate production related costs should recognize both this difference in cost and how the customer classes contribute to this difference in cost. The use of an energy based allocation basis, allocation bases that heavily weight energy, or allocation bases that approximate the result produced by an energy allocation will not adequately reflect these differences in cost and the customer classes whose usage characteristics contribute to these differences.

<u>METHODOLOGIES USED BY OTHER UTILITIES IN MISSOURI AND KANSAS</u>

Q. Would you please discuss production cost allocations recently used in Missouri and Kansas?

A. As I indicated earlier, the production cost allocations used or proposed in recent Missouri and Kansas rate cases include the following:

1. Average and Excess
2. Average and Peak
3. Base-Intermediate-Peak

Mr. Lutz discusses the history of the methodologies used in the Company's recent rate cases. I would like to focus on the methodologies used by the other two large electric utilities in Missouri and Kansas, Ameren and Westar, respectively.

Q. What methodologies were proposed in the most recent Ameren rate case?

A. In its most recent case in Missouri Public Service Commission Docket No. ER-2016-0179, Ameren's witness proposed the use of the A&E Demand methodology using the maximum four monthly non-coincident peaks for the class peak demands. The Missouri Public Service Commission Staff proposed the use of the BIP methodology. The witness for the Missouri Industrial Energy Consumers ("MIEC") proposed the use of the A&E methodology using the two highest summer non-coincident peaks for the class peak demands.

Q. What methodologies were proposed in the most recent Westar rate case?

A. In its most recent rate case in Kansas Corporation Commission ("KCC") Docket No. 15-WSEE-115-RTS, Westar's witness proposed the use of the A&E methodology using the four monthly highest coincident peaks for the class peak demands. The KCC Staff proposed a method that would best be described as average and peak where costs classified as average and peak using the same classification as the A&E methodology but the peak portion is allocated based on the class' four monthly highest coincident peak demands.

Q. Why does it matter what methodologies are used for Ameren and Westar?

A. The primary reason it matters deals with competition and specifically competition for industrial customers. As discussed earlier in my testimony, KCP&L's industrial customers generally have a very high load factor, much higher than the system average and much higher than the other customer classes. As will be discussed in the next section of my testimony, of the three methodologies predominantly recommended in Missouri and Kansas, the A&E methodology is the only method that gives a significant recognition to the relative load factors of the customer classes. Further, when a system is not operating at a very high load factor, the A&E methodology best assigns the higher cost of unused capacity.

If the CCOS study is used as a principle tool in assigning the utility revenue requirement to customer classes and thus rate design, industrial cost responsibility and thus industrial rates for utilities using the A&E methodology will be lower than using either of the other two methodologies, all other things being equal. Thus, if the rates for the two major utilities with which KCP&L competes are using the A&E methodology and KCP&L is not, KCP&L will be at a competitive disadvantage in attracting and retaining industrial load.

Q. Why is it important to attract and retain industrial load?

A. There are numerous reasons why this is important. First, industrial customers have higher load factors that increase the overall efficiency of the electric system, particularly generation and transmission facilities. The loads are stable throughout the day, allowing the utility to invest in lower cost base load generating facilities. Second, industrial customers usually provide a large amount of direct and indirect jobs. The direct jobs are associated with the industrial facility itself. The indirect jobs include the supporting companies that provide materials to the facility and the residential and commercial development supported by the employees of the industrial company.

DISCUSSION OF PRODUCTION COST ALLOCATION METHODOLOGIES

Q. Up to this point you have discussed several production cost allocation methodologies. can you please define these methodologies, starting with the average and Excess Demand methodology?

A. The A&E method is a hybrid method combining average demand and peak demand components. The rationale of hybrid methods is that generating assets serve the function to meet requirements 8,760 hours a year and, also to meet peak hour requirements. The hybrid methods seek to balance these two functions in the allocation.

I generally prefer to view the A&E method as two steps even though the mathematics can be combined into one overall allocation factor. The first step in the application of the A&E method is to determine how much non-fuel cost is classified to the Energy function and how much is assigned to the Capacity (or Demand) function. In the A&E method, the amount classified to the Energy function is equal to the system load factor (based on the annual system peak). One minus the system load factor is then classified as Capacity related.

In the second step, the amount classified to the Energy function is then allocated to customer classes based on the class annual energy requirements or <u>average</u> demand. The amount classified to the Capacity function is allocated to customer classes based on the class peak demand in <u>excess</u> of their average demand (in other words peak demand minus average demand).

Q. Please define the A&P demand methodology.

A. While there may be different iterations of the A&P method, the following is how it will be used in my testimony. This method is similar to the A&E method in that the classification of costs between Energy and Capacity is done the same way. The allocation of the cost classified as Energy is also allocated in the same fashion. The difference is that the Capacity component is allocated to customer classes based on the total class peak demand.

Q. Please define the BIP methodology.

A. The BIP method is based upon assigning generating resources to base, intermediate and peaking components based the type of load the unit primarily serves usually based on the relative operating costs of the units. For example, a base load unit (a unit operating at a high capacity or load factor) runs most of the time and thus serves load during base, intermediate and peaking periods. A peaking unit that has a very low capacity or load factor would generally only operate during peak (or emergency) periods and thus only serves load during peak periods. Once the non-fuel costs are classified as base, intermediate and peaking, there may be a variety of methods used to allocate costs to customer classes. Costs classified as peaking would be allocated based on some measure of demand during peak period, cost classified as intermediate based on some measure of intermediate or shoulder period demand, and base costs allocated on average demand.

Q. Please define the non-Coincident Peak Demand (1 NCP) methodology.

A. While the three methods previously discussed would be considered hybrid methods, the next three methods I discuss would be considered either pure demand or energy methods in that costs are allocated based on either 100 percent peak demand or 100 percent energy (or average demand).

The 1 NCP method assigns 100 percent of the non-fuel costs to the Capacity function and then allocates costs to customer classes based on the class NCP as a percentage of the sum of all the classes NCP. While this method would not typically be used to allocate production related costs, I have included it in my testimony for comparative purposes with the other methods.

Q. Please define the Coincident Peak Demand (1 CP) methodology.

A. The 1 CP method assigns 100 percent of non-fuel costs to the Capacity function and then allocates costs to customer classes based on the class CP contribution to the overall system CP.

Q. Please describe an allocation based on 100 percent energy requirements.

A. As the name implies, this method assigns 100 percent of the non-fuel costs to the Energy function and then allocates costs to customer classes based on annual requirement (or average demand). Like the 1 NCP method, this method is not commonly used to allocate capacity related costs but is include for comparative purposes. However, as previously discussed, the fuel portion of production costs are essentially allocated to customer classes using this allocation.

Q. Please generally contrast each of these methodologies?

A. In Schedule TJS-9, I show an example of the resulting composite allocation (combining the energy and capacity components into one allocation factor) using each of these methods. I have used the example utility used in the NARUC Manual to demonstrate each of the methods. Generally speaking, the results produced by these methods can be segregated into two groups. The single peak and A&E methods tend to produce similar results. Likewise, the pure energy and BIP tend to produce similar results, with the A&P being somewhat towards the midpoint of all the methods.

The single peak and A&E methods tend to allocate more cost to lower load factor customer classes and less to higher load factor customer classes. The BIP method differs very little from a pure energy allocation.

Q. Please discuss the impact of including multiple peaks in the demand allocation factors.

A. Generally, the use of multiple peaks will tend to dilute the impact that peak demand has on the allocation bases and will tend to move the allocation towards a pure energy allocation. This makes some intuitive sense for a couple of reasons. First, as more hours are included in the demand analysis, you by necessity are moving towards an energy allocation basis. Second, as more hours are included, the impact is to reduce the gross demand of lower load factor customer classes since these classes have more variability in their hourly demands than do higher load factor customer classes where demands do not vary significantly from hour-to-hour.

Q. Have you done a comparative analysis of methodologies based on KCP&L?

A. Yes. In, Schedule TJS-10 I compare the resulting allocation factor using a 1 NCP, 1 CP, A&E – 4 NCP, A&E – 4CP, A&P – 4 NCP, and pure energy allocations. The results are very similar to the analysis in Schedule TJS-9 from the NARUC Manual.

Like the single peak methods, the A&E method results in an allocation that specifically differentiates between customer classes with high load factors and low load factors. Further, there is not a great deal of variation between methods for customer classes with load factor near the system average.

Q. What methodology do you believe best achieves the goals you identified earlier in your testimony regarding production cost allocation?

A. The Average and Excess Demand methodology.

Q. Please explain why.

A. As I stated earlier in my testimony, the goal of a CCOS study is to align the cost with causation; cost should be aligned as closely as practical to the customers who result in the cost being incurred. Different types of generating assets are more efficient at serving different types of loads. The utility's decisions regarding what generating assets are to be built are based on analysis of these loads and the relative cost of different types of generating assets that could serve these loads, the goal being to construct facilities that result in the lowest overall cost.

In my opinion the A&E methodology best meets this goal for the following reasons:

1. Lower load factor customers have directly resulted in the Company needing to construct and operate facilities that have higher unit costs.

2. The unit cost of the facilities built to serve these lower load factor loads are significantly more expense than the facilities that would be built if the system operated at a much higher load factor.

3. Fuel costs are currently recovered on an energy basis even though the lower load factor generating facilities have much higher fuel costs. Thus, the recovery of fuel related costs on an energy basis results in a benefit to lower load factor customers.

4. The use of allocation methods that approach an energy based allocation does not give adequate differentiation between the cost associated with higher and lower load factor facilities and higher and lower load factor customers.

5. The A&E or 100 percent demand based allocations produce results that provide a reasonable balance between the energy and capacity function of generating facilities.

Further, as discussed earlier in my testimony, the production cost allocation methodologies used by utilities in the region are an important consideration primarily due to how the cost allocation ultimately impacts rate design, particularly for higher load factor, large industrial customers. Since the other large utilities in Missouri and Kansas use the A&E methodology, designing rates for KCP&L using either the A&P or B-I-P methodologies puts KCP&L at a competitive disadvantage relative to these other utilities. Therefore, using the A&E methodology for cost allocation for KCP&L and using the resultant cost allocation as the basis for rate design is more reasonable than using the methods used in the past for KCP&L since using the A&E methodology results in a better alignment of the basis for KCP&L's rates with these other utilities.

Q. Does this complete your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	)))	Case No. ER-2018-0145

AFFIDAVIT OF THOMAS J. SULLIVAN, JR.

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

Thomas J. Sullivan, Jr., being first duly sworn on his oath, states:

1. My name is Thomas J. Sullivan, Jr. and my business address is Navillus Utility Consulting LLC, 15898 Millville Road, Richmond, Missouri, 64085. I have been retained to serve as an expert witness to provide testimony on behalf of Kansas City Power & Light Company.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Kansas City Power & Light Company consisting of thirty-two (32) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

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

Thomas J. Sullivan, Jr.

Subscribed and sworn before me this 29th day of January, 2018.

Notary Public

My commission expires: 4/26/2021

ANTHONY R WESTENKIRCHNER
Notary Public, Notary Seal
State of Missouri
Platte County
Commission # 17279952
My Commission Expires April 26, 2021

Expert Witness Testimony of Thomas J. Sullivan, Jr.

- *Peoples Natural Gas Company of South Carolina, South Carolina Public Service Commission Docket No. 88-52-G (1988).* Natural gas utility revenue requirements and rate design.

- *Peoples Natural Gas (UtiliCorp United, Inc.), Iowa Utilities Board Docket No. RPU-92-6 (1992).* Natural gas utility class cost of service study and peak day demand requirements.

- *Peoples Natural Gas (UtiliCorp United, Inc.), Kansas Corporation Commission Docket No. 193,787-U (1996).* Natural gas utility class cost of service study, rate design, and peak day demand requirements.

- *Southern Union Gas Company, Railroad Commission of Texas Gas Utilities Docket No. 8878 (1998).* Natural gas utility depreciation rates.

- *Southern Union Gas Company, City of El Paso (1999).* Natural Gas utility depreciation rates.

- *UtiliCorp United, Inc., Kansas Corporation Commission Docket No. 00-UTCG-336-RTS (1999).* Natural gas utility weather normalization, class cost of service, and rate design.

- *Philadelphia Gas Works, Pennsylvania Public Utility Commission Docket No. R-00006042 (2001).* Natural gas utility revenue requirements.

- *Missouri Gas Energy, Missouri Public Service Commission Docket No. GR-2001-292 (2001).* Natural gas utility depreciation rates.

- *Aquila Networks, Iowa Utilities Board Docket No. RPU-02-5 (2002).* Natural gas utility class cost of service study, rate design, and weather normalization adjustment.

- *Aquila Networks, Michigan Gas Utilities, Michigan Public Service Commission Case No. U-13470 (2002).* Natural gas utility class cost of service study, rate design, and weather normalization adjustment.

- *Aquila Networks, Nebraska Public Service Commission Docket No. NG-0001, NG0002, NG0003 (2003).* Natural gas utility weather normalization adjustment.

- *Aquila Networks, Missouri Public Service Commission Docket No. GR-2003 (2003).* Natural gas utility class cost of service study, rate design, annualization adjustment, and weather normalization adjustment.

- *North Carolina Natural Gas, North Carolina Utilities Commission Docket No. G-21-Sub 442 (2003).* Filed intervener testimony on behalf of the municipal customers regarding natural gas cost of service and rates related to intrastate transmission service.

- *Texas Gas Service Company, Division of ONEOK, Railroad Commission of Texas Gas Utilities Docket No. 9465 (2004).* Natural gas utility depreciation rates.

- *Missouri Gas Energy, Missouri Public Service Commission Docket No. GR-2004-0209 (2004).* Natural gas utility depreciation rates.

- *Aquila Networks, Kansas Corporation Commission Docket No. 05-AQLG-367-RTS (2004).* Natural gas utility class cost of service study, rate design, and weather normalization adjustment.

- *Aquila Networks, Iowa Utilities Board Docket No. RPU-05-02 (2005).* Natural gas utility class cost of service study, rate design, grain drying adjustment and weather normalization adjustment.

- *PJM Interconnection, LLC, Federal Energy Regulatory Commission Docket No. ER05-1181 (2005).* Operating cash reserve requirements.

- *Kinder Morgan, Inc., LLC, Wyoming Public Service Commission Docket No. 30022-GR-6-73 (2006).* Natural gas utility weather normalization adjustment, development of load factors, billing cycle adjustment, determination of test year billing units and revenue, and depreciation rates.

- *Missouri Gas Energy, Missouri Public Service Commission Docket No. GR-2006-0422 (2006).* Natural gas utility depreciation rates.

- *Kinder Morgan, Inc., Nebraska Public Service Commission Docket No. NG-0036 (2006).* Natural gas utility weather normalization adjustment, test year billing determinants and revenues under existing rates, customer and usage trends and rate design.

- *Aquila Networks, Kansas Corporation Commission Docket No. 07-AQLG-431-RTS (2006).* Natural gas utility class cost of service study, rate design, irrigation adjustment, and weather normalization adjustment.

- *Aquila Networks, Nebraska Public Service Commission Docket No. NG-0041 (2006).* Natural gas utility jurisdictional and class cost of service study, rate design, and revenue synchronization adjustment.

- *Zia Natural Gas Company, New Mexico Public Regulation Commission Case No. 08-00036-UT (2008).* Natural gas utility billing determinants and revenues, weather normalization adjustment, customer growth adjustment, peak day analysis, revenue requirement, class cost of service study, and rate design.

- *SourceGas Distribution, LLC, The Public Utilities Commission of the State of Colorado Docket No. 08S-0108G (2008).* Natural gas utility weather normalization adjustment, irrigation adjustment, group load factor analysis, therm billing, test year billing determinants and revenues, and trends in customer usage.

- *Black Hills/Iowa Gas Utility Company, LLC (fka Aquila Networks), Iowa Utilities Board Docket No. RPU-08-3 (2008).* Natural gas utility weather normalization adjustment, grain drying adjustment, revenue synchronization adjustment, class cost of service study, and rate design.

- *Black Hills/Colorado Gas Utility Company, LLC (fka Aquila Networks), The Public Utilities Commission of the State of Colorado Docket No. 08S-430G (2008).* Natural gas utility weather normalization, revenue synchronization adjustment, customer reclassification, thermal billing, test year billing determinants, revenues under existing and proposed rates, class cost of service study, and rate design.

- *Wyoming Gas Company, Wyoming Public Service Commission Docket No. 30009-48-GR-8 (2008).* Natural gas utility weather normalization adjustment, test year billing determinants, revenues under existing and proposed rates, rate of return, revenue requirement, class cost of service study, and rate design.

- *Missouri Gas Energy, Missouri Public Service Commission Docket No. GR-2009-0355 (2009).* Natural gas utility depreciation rates.

- *Empire District Gas Company, Missouri Public Service Commission Docket No. GR-2009-0434 (2009).* Natural gas utility depreciation rates.

- *SourceGas Distribution, LLC, Nebraska Public Service Commission Docket No. NG-0060 (2009).* Natural gas utility customer and usage trends and adjustments; weather normalization adjustment, customer change adjustment, use per customer adjustment, and inflation adjustment riders; and competitive factors.

- *Black Hills/Nebraska Gas Utility Company, LLC (fka Aquila Networks), Nebraska Public Service Commission Docket No. NG-0061 (2009).* Natural gas utility jurisdictional and class cost of service study, rate design, and revenue synchronization adjustment.

- *SourceGas Distribution, LLC, Wyoming Public Service Commission Docket No. 30022-148-GR -10 (2010).* Natural gas utility customer and usage trends; use per customer adjustment, inflation adjustment, and uncollectible accounts riders.

- *Black Hills/Nebraska Gas Utility Company, LLC (f.n.a. Aquila Networks) Iowa Utilities Board Docket No. RPU-2010-0002 (2010).* Natural gas utility jurisdictional class cost of service study, rate design, weather normalization adjustment, grain dryer adjustment, annualization adjustment, ethanol plant adjustment, and synchronization adjustment.

- *The Empire District Electric Company, Missouri Public Service Commission Docket No. ER 2011-0004 (2010).* Electric utility depreciation rates.

- *The Empire District Electric Company, Corporation Commission of Oklahoma Cause No. PUD 201100082 (2011).* Electric utility depreciation rates.

- *SourceGas Distribution, LLC, Nebraska Public Service Commission Docket No. NG-0067-RTS (2011).* Natural gas utility jurisdictional and class cost of service study, rate design, customer and usage trends, number of customer change adjustment, use per customer adjustment, and competitive factors.

- *Interstate Power and Light Company, Iowa Utilities Board Docket No. RPU-2012- 0002 (2012).* Natural gas utility class cost of service study and weather normalization adjustment.

- *The Empire District Electric Company, Missouri Public Service Commission Docket No. ER-2012-0345 (2012).* Electric utility depreciation rates.

- *Rocky Mountain Natural Gas Company LLC, Public Utilities Commission of the State of Colorado Docket No. 13AL-0067G (2013).* Intrastate natural gas pipeline cost of service study and rate design.

- *Rocky Mountain Natural Gas Company LLC, Public Utilities Commission of the State of Colorado Docket No. 13AL-067G (2013).* Safety and System Integrity Rider (SSIR).

- *SourceGas Distribution LLC, Public Utilities Commission of the State of Colorado Docket No. 13AL-143G (2013).* Tariff provisions to incorporate Docket No. 13AL-0067G unbundling and tariff changes.

- *Black Hills/Kansas Gas Utility Company, LLC, Kansas Corporation Commission Docket No. 14-BHCG-RTS (2014).* Natural gas utility class cost of service study, rate design, weather normalization adjustment, irrigation adjustment, annualization adjustment, synchronization adjustment, and bypass revenue rider

- *Wyoming Gas Company, Wyoming Public Service Commission Docket No. 30009-57-GI-14 (2015).* Testified at hearing to consider Wyoming Gas Company's motion for relief from filing a general rate case.

- *The Empire District Electric Company, Missouri Public Service Commission Docket No. ER-2016-0023 (2015).* Electric utility depreciation rates.

- *Wyoming Gas Company, Wyoming Public Service Commission Docket No. 30009-60-GR-16 (2016).* Natural gas utility weather normalization adjustment, test year billing determinants, revenues under existing and proposed rates, cost of capital, revenue requirement, class cost of service study, and rate design.

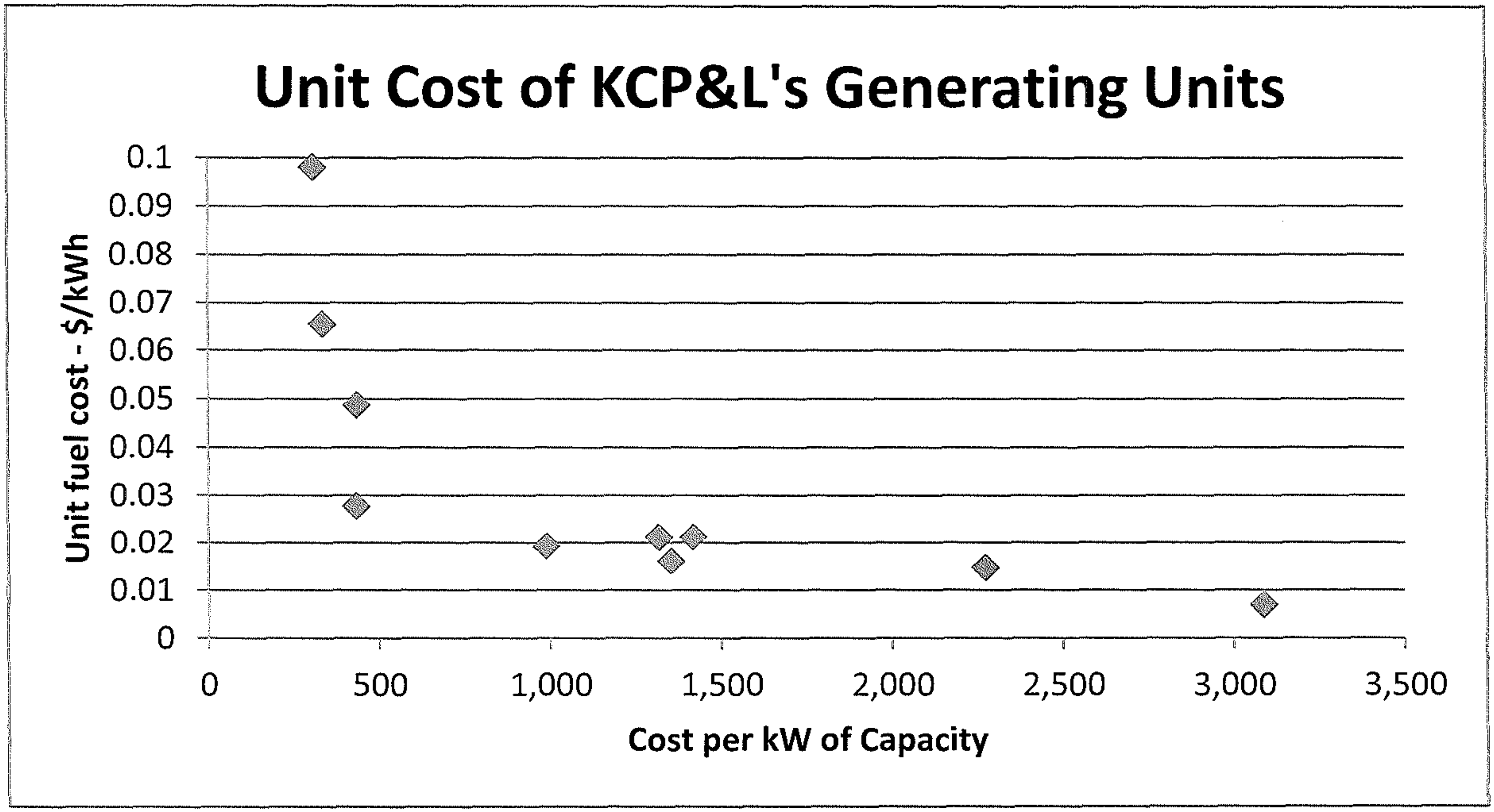
- *The Empire District Electric Company, The Corporation Commission of Oklahoma Cause No. PUD 201600468 (2016).* Electric utility depreciation rates.

Kansas City Power & Light Company
Generating Facilities

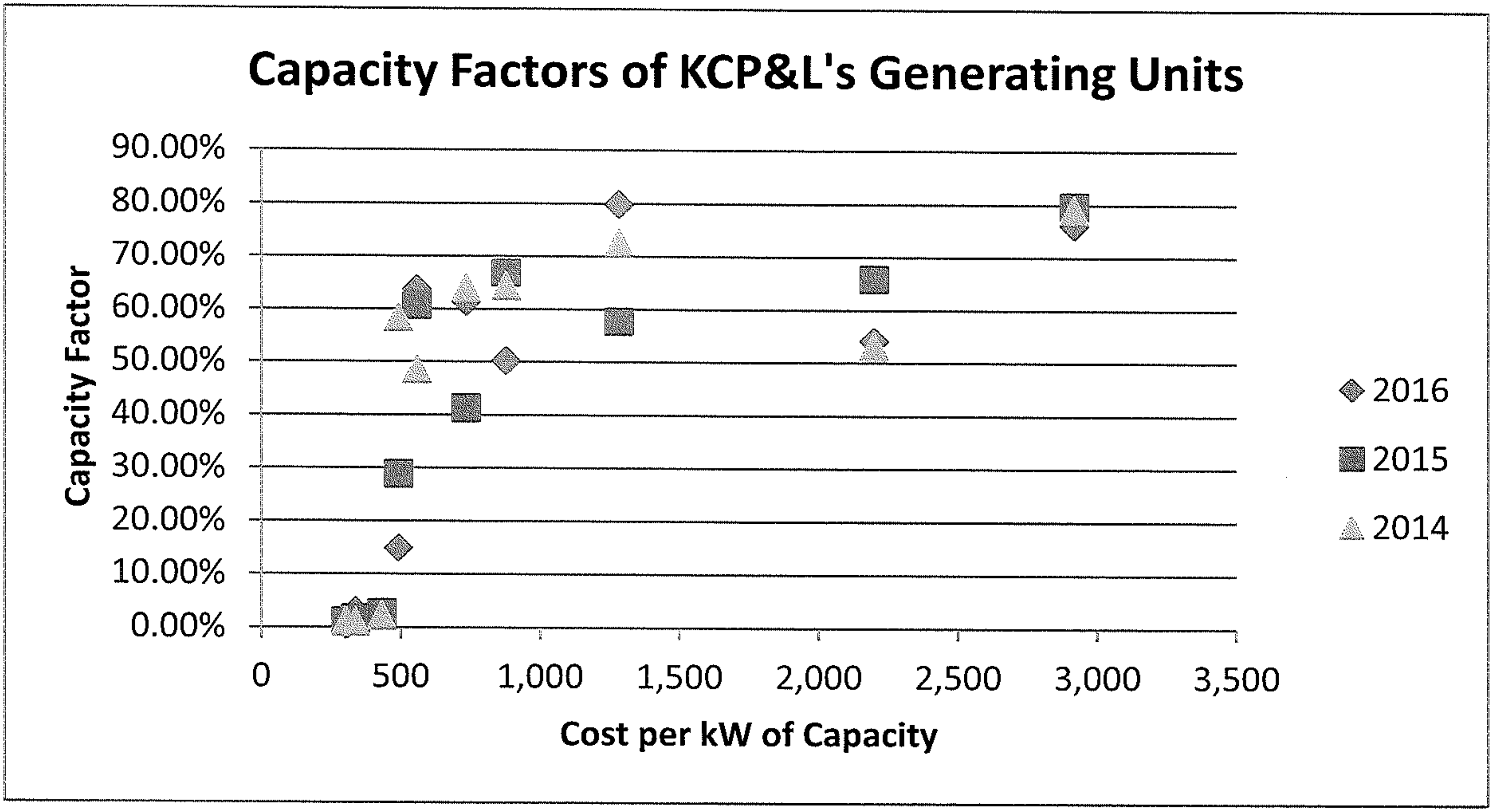
	[A]	[B]	[C]	[D]	[E]
Line No.	Description	KCPL Ownership	Fuel	Plant Type	Generating Capacity (1) MW
1	Montrose	100.00%	Coal/Oil	Steam	563.00
2	Hawthorn 5	100.00%	Coal/Gas	Steam	594.00
3	Hawthorn 6&9	100.00%	Gas	Combined Cycle	301.00
4	Hawthorn 7&8	100.00%	Gas	Gas Turbine	164.00
5	Osawatomie	100.00%	Gas	Gas Turbine	102.00
6	Iatan 1	70.00%	Coal/Oil	Steam	508.00
7	Iatan 2	54.71%	Coal/Oil	Steam	547.00
8	West Gardner	100.00%	Gas	Gas Turbine	408.00
9	Northeast	100.00%	Oil	Internal Combustion	491.00
10	Wolf Creek	47.00%	Nuclear	Nuclear	581.00
11	LaCygne 1	50.00%	Coal/Oil	Steam	436.50
12	LaCygne 2	50.00%	Coal/Oil	Steam	362.93
13	Spearville Wind	100.00%	Wind	Wind Turbine	151.70

14 (1) KCPL's share

Kansas City Power & Light Company
Comparison of Fuel and Capacity Unit Costs



Kansas City Power & Light Company
Comparison of Capacity Factors and Capacity Unit Cost



Kansas City Power & Light Company - MO
Class Coincident Peak Load Factors

	[A]	[B]
Line No.	Customer Class	Load Factor
1	Residential	39.00%
2	Small General Service	57.13%
3	Medium General Service	58.68%
4	Large General Service	66.68%
5	Large Power Service	82.04%
6	Lighting	100.00%
7	Total System	55.64%

Kansas City Power & Light Company
Operating Characteristics of KCP&L's Generating Assets
2014-2016

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Description	Fuel	Type	2016	2015	2014
1	**Capacity Factors**					
2	Montrose	Coal/Oil	Steam	14.76%	28.77%	58.21%
3	Hawthorn 5	Coal/Gas	Steam	50.05%	66.88%	64.25%
4	Hawthorn 6&9	Gas	Combined Cycle	2.19%	2.60%	2.17%
5	Hawthorn 7&8	Gas	Gas Turbine	2.91%	1.54%	0.85%
6	Osawatomie	Gas	Gas Turbine	0.15%	0.40%	1.36%
7	Iatan 1 (70%)	Coal/Oil	Steam	79.80%	57.62%	72.64%
8	Iatan 2 (54.71%)	Coal/Oil	Steam	54.07%	65.85%	53.13%
9	West Gardner	Gas	Gas Turbine	0.34%	0.98%	0.97%
10	Northeast	Oil	Internal Combustion	0.03%	0.02%	0.02%
11	Wolf Creek (47%)	Nuclear	Nuclear	76.15%	79.70%	79.03%
12	LaCygne 1 (50%)	Coal/Oil	Steam	61.34%	41.22%	63.88%
13	LaCygne 2 (50%)	Coal/Oil	Steam	63.68%	60.63%	48.46%
14	Spearville Wind	Wind	Wind Turbine	31.50%	34.70%	35.86%
15	**Load Factors**					
16	Montrose	Coal/Oil	Steam	24.95%	31.70%	64.26%
17	Hawthorn 5	Coal/Gas	Steam	52.53%	72.23%	67.91%
18	Hawthorn 6&9	Gas	Combined Cycle	2.85%	3.20%	3.41%
19	Hawthorn 7&8	Gas	Gas Turbine	3.39%	1.71%	0.94%
20	Osawatomie	Gas	Gas Turbine	0.20%	0.54%	1.98%
21	Iatan 1 (70%)	Coal/Oil	Steam	81.24%	59.86%	74.85%
22	Iatan 2 (54.71%)	Coal/Oil	Steam	60.60%	71.76%	58.35%
23	West Gardner	Gas	Gas Turbine	0.45%	1.42%	1.29%
24	Northeast	Oil	Internal Combustion	0.11%	0.06%	0.08%
25	Wolf Creek (47%)	Nuclear	Nuclear	76.41%	80.11%	79.58%
26	LaCygne 1 (50%)	Coal/Oil	Steam	72.56%	47.11%	73.96%
27	LaCygne 2 (50%)	Coal/Oil	Steam	66.79%	62.87%	52.66%
28	Spearville Wind	Wind	Wind Turbine	34.62%	37.07%	38.05%
29	**Five Highest Load Factors**					
30	Iatan 1			81.24%	59.86%	74.85%
31	Wolf Creek			76.41%	80.11%	79.58%
32	LaCygne 1			72.56%		73.96%
33	LaCygne 2			66.79%	62.87%	
34	Iatan 2			60.60%	71.76%	
35	Hawthorn 5				72.23%	67.91%
36	Montrose					64.26%

Kansas City Power & Light Company
Unit Costs of KCP&L's Generating Assets
2014-2016

	[A]	[B]	[C]	[D]
Line No.	Description	2016	2015	2014
1	**Fuel Cost per kWh**			
2	Montrose	0.0277	0.0265	0.0245
3	Hawthorn 5	0.0192	0.0196	0.0201
4	Hawthorn 6&9	0.0487	0.0483	0.0607
5	Hawthorn 7&8	0.0655	0.0692	0.1214
6	Osawatomie	0.0109	-0.3724	-0.0176
7	Iatan 1 (70%)	0.0161	0.0173	0.0188
8	Iatan 2 (54.71%)	0.0147	0.0152	0.0171
9	West Gardner	0.0980	0.0773	0.0986
10	Northeast	1.0458	1.0924	0.7804
11	Wolf Creek (47%)	0.0069	0.0067	0.0068
12	LaCygne 1 (50%)	0.0210	0.0217	0.0229
13	LaCygne 2 (50%)	0.0211	0.0218	0.0225
14	Spearville Wind	0.0000	0.0000	0.0000
15	Total	0.0160	0.0164	0.0179
16	**Five Lowest Fuel Costs**			
17	Wolf Creek (47%)	0.0069	0.0067	0.0068
18	Iatan 2 (54.71%)	0.0147	0.0152	0.0171
19	Iatan 1 (70%)	0.0161	0.0173	0.0188
20	Hawthorn 5	0.0192	0.0196	0.0201
21	LaCygne 1 (50%)	0.0210	0.0217	0.0229
22	LaCygne 2 (50%)	0.0211	0.0218	0.0225
23	**Total Unit Cost - $/kWh**			
24	Montrose	0.0755	0.0557	0.0390
25	Hawthorn 5	0.0450	0.0372	0.0385
26	Hawthorn 6&9	0.2711	0.2408	0.2945
27	Hawthorn 7&8	0.1737	0.2736	0.4891
28	Osawatomie	2.0432	0.3808	0.2097
29	Iatan 1 (70%)	0.0356	0.0455	0.0389
30	Iatan 2 (54.71%)	0.0606	0.0506	0.0606
31	West Gardner	0.9838	0.3866	0.4048
32	Northeast	6.1386	10.0577	5.2140
33	Wolf Creek (47%)	0.0660	0.0621	0.0650
34	LaCygne 1 (50%)	0.0455	0.0568	0.0370
35	LaCygne 2 (50%)	0.0456	0.0455	0.0389
36	Spearville Wind	0.0558	0.0507	0.0493
37	Total	0.0537	0.0523	0.0486
38	**Five Lowest Total Unit Costs per kWh**			
39	Iatan 1 (70%)	0.0356	0.0455	0.0389
40	Hawthorn 5	0.0450	0.0372	0.0385
41	LaCygne 1 (50%)	0.0455		0.0370
42	LaCygne 2 (50%)	0.0456	0.0455	0.0389
43	Iatan 2 (54.71%)	0.0606	0.0506	
44	Montrose		0.0557	0.0390

Kansas City Power & Light Company
Unit Costs of KCP&L's Generating Assets
Reflecting System-wide Fuel Cost
2014-2016

Line No.	Description	2016	2015	2014
	[A]	[B]	[C]	[D]
1	**Total Unit Cost Less Fuel per kWh**			
2	Montrose	0.0478	0.0291	0.0145
3	Hawthorn 5	0.0258	0.0176	0.0183
4	Hawthorn 6&9	0.2224	0.1925	0.2338
5	Hawthorn 7&8	0.1082	0.2045	0.3676
6	Osawatomie	2.0323	0.7532	0.2273
7	Iatan 1 (70%)	0.0196	0.0282	0.0201
8	Iatan 2 (54.71%)	0.0459	0.0355	0.0434
9	West Gardner	0.8857	0.3093	0.3061
10	Northeast	5.0928	8.9653	4.4336
11	Wolf Creek (47%)	0.0591	0.0554	0.0582
12	LaCygne 1 (50%)	0.0245	0.0351	0.0141
13	LaCygne 2 (50%)	0.0245	0.0237	0.0164
14	Spearville Wind	0.0558	0.0507	0.0493
15	Total	0.0377	0.0359	0.0307
16	**Total Unit Cost Less Average Fuel per kWh**			
17	Montrose	0.0595	0.0392	0.0211
18	Hawthorn 5	0.0290	0.0208	0.0206
19	Hawthorn 6&9	0.2551	0.2244	0.2766
20	Hawthorn 7&8	0.1577	0.2572	0.4712
21	Osawatomie	2.0272	0.3643	0.1918
22	Iatan 1 (70%)	0.0196	0.0291	0.0210
23	Iatan 2 (54.71%)	0.0446	0.0342	0.0427
24	West Gardner	0.9678	0.3702	0.3869
25	Northeast	6.1226	10.0412	5.1961
26	Wolf Creek (47%)	0.0500	0.0456	0.0470
27	LaCygne 1 (50%)	0.0295	0.0404	0.0191
28	LaCygne 2 (50%)	0.0296	0.0291	0.0210
29	Spearville Wind	0.0398	0.0343	0.0314
30	Total	0.0377	0.0359	0.0307
31	Five Highest Load Factor Units			
32	Unit Cost - $/kWh	0.0353	0.0294	0.0272
33	All Other Units			
34	Unit Cost - $/kWh	0.0464	0.0635	0.0425

Comparison of Selected Production Cost Allocations
NARUC Electric Utility Cost Allocaton Manual

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
Line No.	Class or Classification	CP Load Factor	Allocation Methods						
			1 NCP	1 CP	AE-1NCP	AP-1CP	AP-1NCP	BIP	Energy
1	Average				57.98%	57.98%	57.98%		
2	Demand				42.02%	42.02%	42.02%		
3	Domestic	51.53%	36.94%	34.84%	36.46%	32.59%	33.48%	31.55%	30.96%
4	Lighting, Small & Medium Power	52.73%	34.91%	37.25%	34.82%	35.28%	34.30%	34.04%	33.86%
5	Large Power	73.47%	23.34%	24.63%	23.97%	28.44%	27.90%	30.58%	31.21%
6	Agriculture & Pumping	56.82%	3.94%	3.29%	3.88%	3.25%	3.52%	3.12%	3.22%
7	Street Lighting	100.00%	0.87%	0.00%	0.86%	0.43%	0.80%	0.71%	0.74%
8	Total	57.98%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Kansas City Power & Light Company
Comparison of Production Allocations