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CASE NO.: ER-2010-____

DIRECT TESTIMONY

OF

LARRY W. LOOS

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
June 2010

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KANSAS CITY POWER & LIGHT COMPANY

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DIRECT TESTIMONY

OF

LARRY W. LOOS

Case No. ER-2010-____

I. QUALIFICATIONS

Q. Please state your name and business address.

A. Larry W. Loos, 11401 Lamar, Overland Park, KS 66211.

Q. What is your occupation?

A. I am an engineer and consultant employed by Black & Veatch Corporation (Black & Veatch). I currently serve as a Director in Black & Veatch Management Consulting.

Q. How long have you been with Black & Veatch?

A. Black & Veatch has employed me continuously since 1971.

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. Yes, I am a registered Professional Engineer in the State of Missouri, as well as the states of Colorado, Indiana, Iowa, Kansas, Louisiana, Nebraska, and Utah.

Q. To what professional organizations do you belong?

A. I am a member of the American Society of Mechanical Engineers, the National Society of Professional Engineers, the Missouri Society of Professional 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. We specialize 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 10,000 people.

Q. Have you previously appeared as an expert witness?

A. Yes, I have. I have presented expert witness testimony before this Commission ("PSC" 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, Kansas, Minnesota, New Mexico, New York, North Carolina, Pennsylvania, South Carolina, Texas, Utah, Vermont, and Wyoming. I have also presented expert witness testimony before state trial 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. INTRODUCTION

Q. For whom are you testifying in this matter?

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

Q. What is the purpose of your direct testimony?

A. KCP&L asked me to recommend the most appropriate basis for functionally classifying and allocating production and transmission related costs between jurisdictions (Missouri, Kansas, and FERC). In this regard, KCP&L requested that I focus on the allocation of fixed production and transmission costs, margin associated with off-system sales, and environmental control costs.

Q. Have you previously submitted testimony on behalf of KCP&L regarding these issues?

A. Yes, I have. I filed direct, rebuttal, and surrebuttal testimony in KCP&L's most recent case before this Commission, Case No. ER-2009-0089. In addition I filed direct testimony in December 2009 in KCPL's rate case before the Kansas Corporation Commission ("KCC") in Docket No. 10-KCPE-415-RTS.

Q. Is your testimony in the instant case similar to that you submitted in Case No ER-2009-0089?

A. Yes, it is. It is also similar to the testimony I filed in December with the KCC.

Q. In KCP&L's prior rate cases, how were production and transmission fixed costs allocated?

A. I understand that historically fixed production and transmission costs in Missouri have been allocated based on the average of the four-monthly coincident peak demands ("4CP"). This is different from the average of the twelve-monthly coincident peak demands ("12CP") allocation basis that KCP&L has used in its recent Kansas rate cases[1]. In its 2006 Missouri rate case (Case No. ER-2006-0314), KCP&L proposed, but the PSC rejected using a 12CP allocator. Instead, the Commission adopted a 4CP allocation of production and transmission fixed (capacity) cost.

Q. In KCP&L's prior rate cases, how have margins associated with off-system sales been allocated?

A. I understand that as a result of the Stipulation and Agreement approved by the KCC in Docket No. 07-KCPE-905-RTS ("905 S&A") the "unused energy allocator" is used as the basis to credit off-system sales margin to Kansas jurisdictional customers.

In KCP&L's Missouri rate case No. ER-2006-0314, the Company proposed to allocate margin associated with off-system sales on "unused energy." The PSC rejected KCP&L's proposal in favor of an energy allocator. In that case, I understand, much of the argument opposing the use of the unused energy allocator was that it is not an

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[1] In Docket No. 04-KCPE-1025-GIE KCP&L entered into a stipulation and agreement ("1025 S&A") which provides for (among other things) agreement among the parties to use the 12CP method. I understand the rate case KCP&L filled with the KCC in December 2009 represents the final rate case covered by the 1025 S&A.

industry recognized method for allocating off-system sales margins, and that it had not been accepted for purposes of allocating off-system sales margins.

In KCP&L's most recent Missouri rate case, No. ER-2009-0089, the Company proposed allocating off-system sales margin following my recommendation. In that case I recommended allocating off-system sales margins in the same manner as the fixed costs associated with the generation resources KCP&L uses to generate the energy sold off-system. The case was settled, so the issue was not resolved.

Q. In KCP&L's prior rate cases, how were costs associated with environmental controls allocated?

A. Based on my reading of KCC and PSC orders and my discussions with KCP&L professionals, in the Company's prior cases the allocation of pollution control related costs was not an issue. Examination of the Company's jurisdictional cost study (in cases preceding Case No ER-2009-0089) shows that the Company classified the fixed capital and operating costs associated with pollution control equipment as capacity-related. The Company classified variable operating costs associated with commodities (consumables such as limestone) used in pollution control equipment as energy-related. A 4CP allocator (12CP in Kansas) has been used to allocate capacity-related costs and energy deliveries (adjusted for losses) to alloeate energy-related costs. In Case No ER-2009-0089, I recommended classifying these costs as energy-related and allocating them based on energy deliveries adjusted for losses. However, this case was settled, therefore, this issue was not resolved.

Q. Does use of the different allocation factors in the Missouri and Kansas 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. Currently, KCP&L does not recover its entire revenue requirement because of the different allocation bases.

The Missouri jurisdiction operates at a higher load factor than the other jurisdictions (Kansas and FERC). A 4CP capacity (demand) allocator will nearly always allocate less cost to the higher load factor jurisdiction than use of a 12CP allocator. Likewise, the energy allocator allocates a higher portion of off-system sales margin to the higher load factor jurisdiction than an unused energy allocator will. As I will subsequently demonstrate, neither the unused energy allocator nor the energy allocator are appropriate for allocating off-system sales margins.

The Company fails to recover about $5.6 million in costs because Missouri uses the energy allocator while Kansas uses the unused energy allocator to allocate off-system sales margins.[2] The use of the unused energy allocator results in a higher overall level of margins allocated to the lower load factor jurisdiction than the use of an energy allocator

[2] I develop these amounts in Schedule LWL2010-5, Sheet 2, based on test period cost levels after adjustment for the added investment at Iatan.

and vice versa.[3] The use of different allocation bases results in KCP&L returning approximately 105.38 percent[4] of its off-system sales margin to customers. By that I mean that for every dollar of off-system sales margin that the Company realizes from selling energy off-system, it costs the Company $1.05, or a loss of five cents on the dollar. This does not make any sense and serves as an economic disincentive for the Company to pursue off-system sales.

The Company fails to recover about $4.09 million because in Missouri a 4CP allocation basis is relied on, whereas in Kansas a 12CP allocation is used.

The effect of the different allocation methods used in Missouri and Kansas results in the Company failing to recover $9.71 million of its total revenue requirement. This under-recovery results in the Company actually earning (all other factors being equal) less than the authorized return on equity.

Q. What recommendations are you proposing in this case to address these allocation deficiencies?

A. My specific recommendation in this regard is to allocate off-system sales margins based on the allocation of the fixed costs[5] associated with the generating stations used to generate the energy sold off-system. I made this same recommendation in Case No 2009-0089 and in the Company's current Kansas rate case. While I believe that the 12CP

[3] An energy allocation of off-system sales margin will result in a higher level of margin allocated to the higher load factor jurisdiction (Missouri). An unused energy allocation of off-system sales margin will result in a higher level of margin allocated to the lower load factor jurisdiction (Kansas). Since off-system sales and sales margins are credited to cost of service, the use of these allocation bases results in both jurisdictions enjoying use of the allocation that minimizes cost to that jurisdiction. Obviously, if both the Missouri and Kansas jurisdictions are allocated costs in a manner that minimizes cost to that jurisdiction, the Company subsidizes retail customers.

[4] This and the following amounts are based on test period costs adjusted to reflect the added investment at Iatan.

[5] Throughout my testimony, when I refer to fixed costs, I am referring to costs allocated among jurisdictions. Fixed costs related to directly assigned investment should be excluded in any allocation base.

methodology is not to be addressed in the case currently filed with the KCC because of the 1025 S&A, I do recommend in that case that the "unused energy" allocator be changed to reflect an appropriate allocation methodology. I recommend that margins be allocated on the same basis as the fixed costs of the generating stations used to generate the energy sold off system.

Q. In prior responses, you refer to "fixed" costs and to "demand" costs. Is there a difference?

A. Yes, there is. "Fixed" costs represent costs that do not tend to vary because of changes in sales levels. For the most part, I consider electric utility costs fixed, except for fuel, fuel-related costs, purchased power energy charges, and some consumables used in environmental control equipment. I define demand (or capacity) related costs to be those costs (predominantly fixed) which by their nature are related to, and are appropriately allocated based on some measure of customers' maximum demand (12CP or 4CP).

Variable costs on the other hand are those costs that I do not consider fixed. Variable costs tend to vary in response to changes in sales. I define energy-related costs as those costs (whether fixed or variable) which by their nature are related to, and are appropriately allocated based on energy sales.

Q. In your prior response, you refer to alternative allocation and classification bases. What do you mean by classification?

A. Jurisdictional allocations involve a three-step process even though many practitioners only show one. The first step is the functionalization of cost based on the nature of the cost. The functions typically used in jurisdictional cost allocations include categories such as production (power supply), transmission, and direct assignment. These broad functions may be further separated into "sub-functional" components such as base, intermediate, and peaking resources.

The second step involves the classification of functional costs into capacity, energy, customer, and direct costs. These functionally classified costs correspond to the basic allocation factors used to allocate cost.

The final step is the application of appropriate capacity, energy, customer, or direct allocation factors to the functionally classified costs. Many applications collapse this three-step process into just one-step by allocating costs associated with individual accounts on some basis. This one-step process usually works reasonably well; however, when a plant or operation and maintenance expense account includes costs associated with more than one function or classification, this one-step process can become somewhat cumbersome.

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

A. I will first outline considerations and criteria, which I believe one should objectively use to evaluate the reasonableness and equity of alternative allocation and classification bases. Considering these criteria, I will then evaluate the merits of a number of bases for allocating and/or classifying:

1) Margin associated with off-system sales;
2) Pollution control related costs;
3) Boiler maintenance;
4) Capacity-related power supply costs; and
5) Transmission system costs.

I will also address the merits of alternative measures of maximum demand (4CP and 12CP) for the KCP&L system.

I conclude my direct testimony with recommendations for allocating costs to jurisdictions in this and future rate cases.

Q. Do you sponsor any Schedules?

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

- Schedule LWL2010-1 – Generating Station Cost Characteristics – Example
- Schedule LWL2010-2 – Characteristics of KCP&L Generating Stations
- Schedule LWL2010-3 – KCP&L Smoothed Hourly Load Curve
- Schedule LWL2010-4 – Power Supply Revenue Requirements
- Schedule LWL2010-5 – Impact of Current Allocation Methods
- Schedule LWL2010-6 – Alternative Measures of Maximum Demand
- Schedule LWL2010-7 – Impact of Properly Classifying and Allocating Off-System Sales Margin
- Schedule LWL2010-8 – Impact of Properly Classifying and Allocating Off-System Sales Margin and Environmental Costs
- Schedule LWL2010-9 – Impact of Properly Classifying and Allocating Off-System Sales Margin, Environmental Costs, and Boiler Maintenance
- Schedule LWL2010-10 – Impact of Single CP and 12CP Allocation of Power Supply Capacity Related Costs
- Schedule LWL2010-11 – Summary of Allocation Results
- Schedule LWL2010-12– Impact of Recommended Method

Q. Do you sponsor the jurisdictional allocation proposed by the Company in this case?

A. No, I do not. My testimony is limited to the reasonableness of alternative allocation (and classification and functionalization) bases. Premised on the considerations I outline, I recommend the bases to functionally classify and allocate costs in this case. Company witness John P. Weisensee uses the bases I recommend to allocate costs to jurisdictions in this case.

In this regard, I must emphasize that for evaluation purposes, I develop an estimate of transmission and power supply revenue requirements for the sole purpose of estimating the implications of various allocation and classification scenarios. The use of these estimated revenue requirements is solely for measuring the relative impact of alternatives. The allocation presented by Mr. Weisensee represents the definitive recommendation of the Company based on the Company's claimed total revenue requirement.

Q. What recommendations do you provide Mr. Weisensee?

A. I recommend the following allocation bases:

1) Allocate capacity-related power supply costs based on each jurisdiction's contribution to the system peak demands during the four summer months, that is, on a 4CP basis.
2) Allocate energy-related power supply costs based on energy deliveries adjusted for losses.
3) Classify and allocate margin associated with off-system sales in the same manner as the fixed costs (excluding costs related to direct assignments) of the generating resources used to generate the energy sold off-system.
4) Classify the fixed and variable costs associated with steam plant environmental control equipment as energy-related and allocate accordingly.

5) Classify the non-labor cost of steam plant boiler maintenance expense as variable and allocate based on energy deliveries adjusted for losses.

6) Classify and allocate transmission cost based on the classification and allocation of power supply fixed cost (excluding costs related to direct assignments).

In KCP&L's current Kansas rate case (filed in December 2009), I limited my recommendations to items 2, 3, and 6 above. Because of the 1025 S&A, I did not recommend items 1, 4, and 5, but I indicated to the KCC that I plan to do so in KCP&L's next Kansas rate case filing. Because of the implication of changes in the classification of costs (environmental control and boiler maintenance) on the level of costs allocated to Kansas jurisdictional customers, I recommended a change only in the method to allocate off-system sales margin in the Company's current Kansas rate case. Changing the classification of the environmental costs and boiler maintenance at the same time as changing to a 4CP allocation basis reduces the impact on Kansas customers with no material adverse impact on Missouri customers.

In order to be consistent in this case with the Company's proposed allocation in Kansas, my recommendation is the same. Namely, for allocating costs in this case, I recommend above items 1, 2, 3, and 6. The only change in allocation that I recommend the Commission adopt in this case is the allocation of off-system sales margin. Consistent with my recommendation in Kansas, I plan to recommend above items 4 and 5 in the Company's next rate case.

<u>III. CONSIDERATIONS AND CRITERIA</u>

Q. What criteria do you use to evaluate the reasonableness of jurisdictional allocations?

A. The criteria that I use include:

1) Taken as a whole, is the resulting allocation fair?

2) Does the allocation approach reasonably consider the "cost drivers" associated with the specific items allocated?

3) Does the allocation treat various cost elements consistently?

4) Does the allocation unreasonably affect or unjustly "enrich" one or more jurisdictions or the utility?

5) Are the data required to develop the allocation reasonably available?

6) Will the allocation basis produce relatively stable results from one period to the next?

7) Are the results unduly disruptive?

FAIRNESS

Q. How do you evaluate the fairness of an allocation?

A. Generally, most people consider an allocation that recognizes both the nature of costs and the cost drivers to be fair. I generally agree, provided the nature of the cost and the cost drivers are indeed <u>fully recognized</u>.

Regardless of the nature of costs and cost drivers, an allocation that does not permit the utility a reasonable opportunity to earn its allowed rate of return is patently unfair. Because of differences in the allocation bases currently relied upon in Missouri and Kansas, KCP&L finds itself in this situation today.

Q. Are there certain costs that the Missouri Commission does not allow KCP&L to recover that other jurisdictions do?

A. Yes, there are. There are also costs that the Missouri Commission allows that other jurisdictions do not.

The fact that one commission may deny recovery of a specific cost is not the issue I address. The issue I address is the opportunity for the Company to recover fully all of the costs for which the jurisdiction does permit recovery. The true test of this issue is whether the sum of the allocation factors used by the various jurisdictions to allocate a cost (recoverable by all jurisdictions) equals 100 percent.

Q. Do you believe that because the KCC uses a 12CP allocation basis, the Missouri Commission should adopt a 12CP allocation in the interest of keeping the Company whole?

A. No, I do not. Nor do I expect the KCC to adopt a 4CP allocation basis solely to keep the Company whole.

I do believe, however, that when either commission (Missouri or Kansas) evaluates allocation alternatives, one consideration should be whether using that allocation allows (or increases the probability that) the Company will recover all of its costs. After all, whether it is Missouri or Kansas making the allocation, it is the same total pool of costs. The allocation of that pool of costs needs to be such that the Company recovers 100 percent of them. Otherwise, the Company does not have a reasonable opportunity to earn the rate of return that the Commission finds just and reasonable. Conversely, the allocation should not result in the Company over-recovering its costs.

CONSIDERATION OF COST DRIVERS

Q. You refer to "cost drivers." What do you mean by this term?

A. "Cost drivers" represent those factors which tend to influence cost levels. For example, sales of energy drive fuel costs. As sales increase, fuel costs increase. However, fuel costs also depend on the mix of the generating units used (the cost drivers) to generate energy. This mix generally relates to overall load levels, time of day, season, availability of generating units, etc.

Q. What cost drivers should the Commission consider in evaluating alternative allocation bases?

A. Many costs are dependent on multiple factors. A classic example is in the natural gas pipeline industry, where historically the FERC recognized that "pipelines are built to supply service not only on the few peak days but on all days throughout the year. In proving the economic feasibility of the project in certificate proceedings, reliance is placed upon the annual as well as the peak deliveries."[6] FERC continues to recognize distance of haul, as well as capacity considerations in setting pipeline rates.

In the electric industry, one generally considers that transmission system costs are dependent on the capability (capacity) of the transmission system to move power. As a result, normally, transmission system costs are typically classified as capacity and are allocated on some basis solely related to the maximum system demand[7].

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[6] Consolidated Gas Supply Corp. v. FPC, 520 F.2d 1176, 1181 (D.C. Cir. 1975).

[7] Unless otherwise specified, my use of the term maximum system demand includes any allocation basis that reflects coincidental peak demands, whether single coincident peak ("1CP"), 4CP, or 12CP. Likewise, unless otherwise specified, my reference to coincidental peak allocation bases refers to 1CP, 4CP, and 12CP allocators.

Q. Does use of a CP-based allocator recognize transmission system "cost drivers"?

A. Yes, in large part. The size of the conductor, capacity of substations, equipment ratings, and other elements that contribute to costs are designed in consideration of the capacity necessary to meet maximum load requirements placed on those elements to move power and energy. However, to some extent, capacity requirements depend on the "foot-print" of the transmission system. As the size of the "foot-print" increases, costs also increase because of the additional distances (length of conductor and associated line losses) that are required to interconnect the system. Thus, transmission system costs depend in part on the proximity of generating stations and interconnections to load centers.

With regard to electric generating facilities, the classification of 100 percent of fixed power supply costs to capacity and allocation on the basis of coincidental peak allocators (whether 1CP, 4CP, or 12CP) is based on the assumption that the <u>sole</u> determinant of the fixed costs of electric generation is the capacity of the generating stations used to serve customers. This fails to recognize other cost drivers. Electric utilities such as KCP&L require a mix of generating resources to meet customers' power and energy requirements economically and reliably. KCP&L's mix includes nuclear, coal-fired steam, wind, and combustion turbine (combined-cycle and simple-cycle) resources. Each type of generating station has different fixed and variable cost characteristics. The different fixed and variable cost characteristics allow electric utilities to manage total supply costs while meeting customers' requirements. The capacity to meet customers' maximum demands (plus allowance for reserves) drives (determines) the <u>combined capacity of all power supply resources</u> (generation and purchases) needed. The <u>mix of the various types</u>

of generating station capacity depends not on the total capacity required but how most economically to meet customers' annual energy requirements.

Q. Can you demonstrate how an electric utility can minimize costs through the mix of generating station capacity while meeting system capacity and energy requirements?

A. Yes, I can, through use of a simplified example. I show this example in Schedule LWL2010-1. In Schedule LWL2010-1, I assume in my example that there are two types of generating equipment available. One is a base load resource, such as a large coal-fired steam generating station. The other is a peaking resource, such as a simple cycle combustion turbine ("CT") generating unit.

In Schedule LWL2010-1, I assume that construction costs for base load and peaking resources amount to $1,500 and $500 per kW installed, respectively (Sheet 1, Line 2). I further assume that variable costs amount to $0.015 and $0.120 per kWh, respectively (Line 5).

To calculate annual fixed cost (Line 4), I apply an "all-in fixed charge rate" (Line 3) to the capital cost associated with each type of generating resource. This all-in fixed charge rate includes allowance for all fixed costs including depreciation, return, taxes, and fixed operation and maintenance expenses. I use a higher fixed charge rate for the base load resource to recognize the higher fixed operating costs relative to a peaking resource (simple cycle CT). As I show on Line 4 of Sheet 1, given these assumptions, the annual fixed costs associated with the base load resource are $300 per kW-year. The annual fixed cost for the peaking resource is $90 per kW-year.

I then calculate the total annual cost at various assumed capacity factors. Based on the estimated cost levels I use, I show in Sheet 1 (Lines 6 through 17) annual cost per kW of capacity at various capacity factors. On Lines 18 through 29, I show the annual cost per kWh. I plot these values in the graphs that I show to the right of the tabular data.

Q. What do these graphs show?

A. The upper graph shows the total annual cost per kW (Y-axis) at various capacity factors (X-axis) for both the base load and peaking resource. The lower graph shows the annual cost per kWh. In both curves, I show (based on my assumed cost levels) that when operating at capacity factors <u>lower</u> than about 22.5 percent[8] (2,000 hours) the peaking unit represents the least cost resource. Conversely, so long as the unit operates at a capacity factor <u>higher</u> than about 22.5 percent, the base load resource represents the least cost option.

Q. How do you minimize cost in your example?

A. In Schedule LWL2010-1, Sheet 2, I show a simplified illustrative load duration curve. A load duration curve shows the number of intervals (X-axis – typically an hour in the electric industry) that load equals or exceeds a specific level (Y-axis), over a specified period (typically one year). In my previous example, I find that the peaking plant operated at less than 2,000 hours is more economical than the base load plant operated at less than 2,000 hours. My illustrative load duration curve shows that load exceeds 600 MW, 2,000 hours during the year. Therefore, I minimize cost with 600 MW of base load capacity and 400 MW of peaking capacity. Based on my assumed cost levels, total plant

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[8] 2,000 hours divided by 8,760 hours = 22.83%

Base Load	$300/kW + $0.015/kWh *2,000 hours = $330/kW
Peaking	$90/kW + $0.120/kWh * 2,000 hours = $330/kW

costs in my example would amount to $1.1 billion ($1,500/kW * 600 MW + $500/kW * 400 MW) and total annual fixed and variable cost would amount to $327.79 million.

Q. Can you demonstrate that this mix represents the minimum cost?

A. Yes, I can. In Schedule LWL2010-1, Sheet 3, I show an example of construction cost and annual costs (fixed and variable) to serve a 1,000 MW system peak. In my example, I assume 600, 700, and 500 MW of base load resources and 400, 300, and 500 MW of peaking resources. In each of these three scenarios total capacity amounts to 1,000 MW. As I show in Sheet 3, Line 12, total annual costs amount to $327.79 million when 600 MW of base load and 400 MW of peaking resources are used. This annual cost increases by about 1 percent to $330.42 million if 700 MW of base load and 300 MW of peaking resources are used (Scenario 2, Lines 14 through 21). If 500 MW each of base load and peaking capacity are used, the annual cost in my example increases by about 4 percent to $339.66 million (Scenario 3, Lines 22 through 29).

Q. Does your example recognize real world considerations?

A. Yes, it does. Admittedly, I use a simple example whereas actual conditions include a number of complicating factors I did not attempt to model. Some of these complicating factors include:

1) Reserve requirements;
2) Implications of existing resources (sunk costs);
3) Implications of adding resources in "lumps";
4) Inability to exactly match the capacity required with installed capacity;
5) Uncertainty associated with actual construction and operating costs; and
6) Uncertainly associated with future load (annual and peak) growth.

Though my simple example does not capture all the dynamics of power supply planning, it does capture the implications of the fundamental trade-off in costs between base load and peaking resources.

Q. What conclusions do you reach based on the example you show in Schedule LWL2010-1?

A. With regard to the economic selection of generating resources, both system maximum demand <u>and</u> capacity (load) factor are cost drivers. Coincident peak demand drives the total capacity required (in my simplified example, 1,000 MW) regardless of the cost characteristics of the generating resources. Capacity (load) factor drives the mix of generating resources (in my example, 600 MW of base and 400 MW of peaking). This generation mix minimizes total cost by:

1) Trading off higher fixed cost against lower variable cost for generating resources operated at higher capacity factor, and
2) Trading off lower fixed cost against higher variable cost for generating resources operated at lower capacity factor.

CONSISTENCY

Q. What do you mean by internally consistent allocations?

A. Very simply, interrelated costs must be allocated on a consistent basis. I will address this concept more fully in connection with my discussion of the classification and allocation of off-system sales margins and environmental costs.

UNJUST ENRICHMENT

Q. How can an allocation unreasonably "enrich" one jurisdiction?

A. Jurisdiction A is unjustly enriched when costs reasonably associated with serving that jurisdiction (for example, Missouri) are assigned through the allocation process to Jurisdiction B (for example, Kansas). This approach causes either Jurisdiction B or the Company to subsidize Jurisdiction A which is not a fair result.

AVAILABILITY OF DATA

Q. Why is the availability of data a consideration in the evaluation of alternative allocation bases?

A. The ability to allocate costs fairly and accurately requires reliable data. When data are not available, reasonable results can sometimes be achieved through synthesis. More often, the allocation needs to be modified to accommodate data limitations.

On the other hand, the fact that data which is reliable or accurate to the fifth decimal point may not be available is no reason to abandon an allocation approach. When reasonable unbiased estimates can be used to develop relative relationships, those estimates should be relied upon. In many instances, relative relationships are known, but cannot be measured absolutely. I believe that it is much more important to recognize and accommodate known relationships than it is to measure these relationships to the nearest penny.

A case in point is the simple example I present in Schedule LWL2010-1. Whether the cost of base load generation is $1,500 per kW, $1,250 per kW, or $2,000 per kW does not affect the conclusion reached. We may not know exactly what base load or peaking resources cost; however, we do know with absolute certainty that the capital cost of base load resources substantially exceeds the capital cost of peaking resources, and conversely, that the variable cost of peaking resources substantially exceeds the variable cost of base load resources.

STABILITY

Q. Why do you consider it important that the allocation produce relatively stable results?

A. Once an allocation basis is established and adopted by all jurisdictions, that method should continue to be applied until circumstances change. Allocations that produce substantially different results from year to year may result in substantial shifts in costs that are unduly disruptive and inherently inequitable to customers and the Company. Further, changes in jurisdictional allocation bases should not be unduly disruptive to customers in any jurisdiction.

IV. KCP&L POWER SUPPLY

Q. Do you use Company cost levels to evaluate the implications of the alternatives you evaluate?

A. Yes, I do. In order to evaluate the impacts of alternative allocation and classification basis, I developed the total revenue requirement associated with the Company's power supply and transmission functions. To develop this revenue requirement, I rely on the Company's 2008 operating results using a 7.86 percent return on rate base. I separated the revenue requirement into nuclear, steam, wind, other generation, purchased power, and off-system sales sub-functions.

As I previously discussed, I developed this revenue requirement for the sole purpose of evaluating the impacts of alternative allocation basis. The Company's claimed revenue requirement and jurisdictional allocation is sponsored by Mr. Weisensee.

Q. Does the addition of generating resources over time affect the economics of power supply?

A. Yes, it does. The ultimate mix of resources reflects the evolution of KCP&L's growth in load and generation. As KCP&L added resources, the economics, load, forecast load growth, and other factors at the time of planning for an addition controlled the decision of the size and kind of generation asset KCP&L should add at each point in time.

Q. Have you prepared a schedule that shows some of these different characteristics?

A. Yes, I have. In Schedule LWL2010-2, Sheet 1, I show data related to each of KCP&L's generating resources that I obtained from KCP&L's 2008 FERC Form 1.

Q. Do you have any observations based on examination of the information you show in Schedule LWL2010-2, Sheet 1?

A. Yes, I do. These are:

1) For the most part, the original cost per kW (Line 17) of the Wolf Creek Nuclear Station and the Spearville Wind Farm are more than three times the original cost (per kW) of the other generating resources. I would expect this high original cost because of the technologies involved and the recent construction of the Spearville facility.

2) The variable cost for Wolf Creek ($4.57 MWh) and Spearville (zero) are less than half the lowest variable cost (Iatan Unit 1, $10.88 per MWh) of the other plants.

3) The original cost associated with Hawthorn Unit 5 is considerably in excess of what I would expect given its date of initial installation, and the original cost of the other

steam plants. I understand that this much higher cost relative to other steam generating units is attributable to the explosion and rebuild of the unit in 2001.

In Schedule LWL2010-2, Sheet 2 I have prepared a graph that shows on a relative basis:

1) The original cost per kW of capacity;
2) The variable cost per kWh actually generated; and
3) The capacity factor for each station.

In order to place values into perspective, and manage scale, I show the values for each plant relative to the KCP&L average. For example, the fuel cost at Iatan Unit 1 amounts to $10.88 per MWh (Schedule LWL2010-2, Sheet 1, Line 24 Column F), whereas the system average fuel cost amounts to $13.03 per MWh (Line 24, Column P). Thus, Iatan Unit 1 fuel cost amounts to 83 percent of the system average (10.88 / 13.03 = 83%). This 83 percent value is what I show in Schedule LWL2010-2, Sheet 2.

Q. Based on examination of the information you show in Schedule LWL2010-2, do you reach any conclusions?

A. Yes, I do. In Schedule LWL2010-2, I demonstrate that based on KCP&L's power supply cost and operating characteristics:

1) KCP&L's original cost varies dramatically from about $100 per kW (Northeast) to $2,300 per kW (Wolf Creek).
2) The construction costs of KCP&L's steam generation amounts to about $542 per kW (Sheet 1, Column E, Line 17) which amounts to over 2 times the $252 per kW associated with KCP&L's CT plants.[9] With the exception of the Northeast internal

[9] In my testimony, unless otherwise indicated, my reference to combustion turbine based resources includes KCP&L's simple-cycle units, as well as the internal combustion units (Northeast), and the combined-cycle

combustion units, the CT plants were placed into service within the last 9 years. On the other hand, the steam plants are generally over 30 years old. If the implications of inflation are eliminated, the cost of the steam plants would be 3 to 4 times that of the CT's.

3) KCP&L's variable cost varies even more dramatically from zero for Spearville, to $4.57 per MWh for nuclear generation to about $150 per MWh for Hawthorn Units 7 & 8. For KCP&L's CT based generation, variable costs amount to about $75.00 per MWh or over five times the variable costs of KCP&L's steam-fired generating plants of about $14.16 per MWh.

4) Variable costs ($/kWh) tend to decline as plant costs ($/kW) increase. Other generating plant (CT) variable costs are over five times that of steam plant variable costs whereas current steam plant construction costs about three to four times that of the CT based plants.

5) Capacity factor for the various resources tends to increase as construction (fixed) costs increase and variable costs decrease.

The inescapable conclusion based on the information shown in Schedule LWL2010-1 and confirmed in Schedule LWL2010-2 is that there is a trade-off between fixed and variable costs. The variable costs associated with high capital cost generating resources are substantially less than from lower capital cost resources. KCP&L incurs high capital costs in order to have resources available to meet capacity requirements <u>as well as</u> to generate energy economically. KCP&L incurs the higher variable costs as a trade off

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units (Hawthorn 6 and 9). All of these CT resources are gas-fired, except for the internal combustion units at Northeast which are oil-fired.

against the lower capital costs associated with resources needed solely to meet peak period requirements.

As I show on Line 15, the capacity factor of KCP&L's steam plants (66.91%) is over 20 times that of the CT based plants (2.93%).

In simple terms, KCP&L incurred high capital costs to make energy (MWhs). Conversely, KCP&L did not incur these high capital costs to make MWs (meet peak period requirements) because other lower cost resources are available to use relatively infrequently to meet those needs. In other words, KCP&L pays a premium for generating resources that can generate energy economically.

Q. Can you further demonstrate this concept?

A. Yes, I can by reference to Schedule LWL2010-3. Schedule LWL2010-3 consists of three sheets. In Sheet 1, I show KCP&L's actual load duration curve. In this graph, I show:

1) Load associated with Kansas (lower curve);
2) Load associated with Missouri (immediately above Kansas);
3) Total native load (center curve); and
4) Total load including off-system sales (upper curve).

Note that native load is equal to Missouri plus Kansas. Note also that sales to the FERC jurisdiction is too small to show on the scale used in Schedule LWL2010-3. While not evident in the graph, there is a small increase in the difference between Missouri and Kansas load as native load decreases. This is evidence of the somewhat higher load factor for sales in Missouri.

Q. Do the load curves you show in Schedule LWL2010-3 represent actual deliveries by KCP&L during 2008?

A. Yes, they do. I did, however, average hourly loads over certain ranges in order to "smooth" the curves. In preparing these curves, I first ranked native load from highest to lowest. For the hour with the highest native load, I plot the Kansas, Missouri, total native load, and total load.[10] For the hour with the second highest native load, I plot the Kansas, Missouri, total native load, and total load. I do this for each of the 8,784 hours in 2008, averaging values over various ranges in order to eliminate some of the hourly variations ("noise") from the graph. The resulting load curves are an accurate representation of the hourly Kansas, Missouri, and total loads corresponding to the duration of native load.

Q. What do you show in Schedule LWL2010-3, Sheet 2?

A. In Sheet 2, I start with the native load and total load curves I show in Sheet 1. To those curves, I add generation from KCP&L's various power stations. The order in which I show the various resources corresponds to how well hourly generation from that station correlates to the total hourly native load. This "stacking" order generally corresponds from lowest to highest variable cost (highest to lowest fixed and construction cost).

For example, I show Wolf Creek and Spearville as the bottom curve. As a wind farm, Spearville is unable to follow load. Hourly generation from the Wolf Creek nuclear unit has the lowest correlation to KCP&L's hourly native load. In 2008, Wolf Creek was connected to load 7,271 hours. The average load amounted to 549 MW during those 7,271 hours. The maximum load amounted to 568 MW. In 2008, the Wolf Creek plant

[10] Total native load is equal to the sum of sales to Kansas, Missouri, and FERC jurisdictional customers. Total load is equal to native load and non-firm energy sold off-system.

operated solely as a base load resource, and did not generate in response to changes in native load demands.

Above Wolf Creek and Spearville, I show Iatan Unit 1.[11] The output from Iatan Unit 1 has a very low correlation with native load. When connected to load, Iatan Unit 1 operated at an 87.8 percent capacity factor. Thus, I consider Iatan Unit 1 to also to operate as a base load resource.

Above Iatan Unit 1, I plot LaCygne Units 1 and 2 and Hawthorn Unit 5. These plants correlate somewhat with native load, Montrose has a higher correlation, and the other generating resources and purchases have the highest correlation.

Based on the stacking order I show in Sheet 2, I conclude that:

- Wolf Creek, Spearville, and Iatan Unit 1 operate as base load resources;
- LaCygne Units 1 and 2 and Hawthorn Unit 5 operate as base/intermediate load resources;
- Montrose and purchases operate somewhere between intermediate and peaking resources; and
- CT based generation represents peaking resources that KCP&L relies on to meet native load in excess of capacity from base and intermediate load units.

Q. What do you show in Sheet 3?

A. Sheet 3 is the same as Sheet 2 except that I have included in the generation mix, the dispatch of Iatan Unit 2. Sheet 3 depicts load duration curves forecast for the first full year Iatan Unit 2 is in service.

[11] The values plotted in Schedule LWL2010-3, Sheet 2 (and Sheet 3) are cumulative. For example, the curve labeled Iatan Unit 1 represents the sum of Wolf Creek, Spearville, and Iatan 1.

V. IMPACT OF CURRENT ALLOCATION BASES

Q. Have you evaluated the implications of the different allocation bases used in Kansas and Missouri?

A. Yes, I have. To do so, I developed an estimate of KCP&L's total revenue requirement for its power supply and transmission functions based on 2008 operations and a 7.86 percent return on rate base.[12] I summarize this development in Schedule LWL2010-4. In this schedule, I show that total fixed cost (revenue requirement) associated with power supply amounts to $436.17 million and total power supply variable cost amounts to $235.72 million (Line 24). Both of these values represent revenue requirements net of revenues associated with off-system sales. I also show the revenue requirement associated with the transmission function amounts to $61.71 million (Column D).

These estimated values are before adjustment for the implication on revenue requirements of the improvements at Iatan Unit 1 and the addition of Iatan Unit 2 to rate base. In Sheet 2 of Schedule LWL2010-4, I show my development of revenue requirements (for the power supply function) adjusted to reflect the improvements at Iatan Unit 1 and the addition of Iatan Unit 2.

In Schedule LWL2010-5, Sheet 1, using the unadjusted revenue requirement levels I developed for evaluation purposes in Schedule LWL2010-4, Sheet 1, I show the allocation of power supply and transmission cost to the various jurisdictions (Missouri,

[12] As I previously discussed, I developed this revenue requirement solely for the purpose of evaluating the impact of alternative allocation and classification scenarios. Mr. Weisensee is responsible for sponsoring the Company's claimed revenue requirement.

Kansas, and FERC) based on the allocation basis currently employed by each jurisdiction.[13]

In Lines 1 through 11, I summarize revenue requirements by type of generation, along with the credit for off-system sales[14]. As shown, the total power supply revenue requirement prior to the credit for off-system sales amounts to $885.52 million. Of this $885.52 million, $518.65 million represents fixed costs and $366.87 million represents variable costs. After crediting revenues from off-system sales of $213.63 million, net revenue requirements amount to $671.89 million. Of the $213.63 million of revenues from off-system sales, $131.15 million represents the out-of-pocket or variable cost associated with generating the energy sold. The balance ($82.49 million) represents the margin (revenues in excess of cost) associated with off-system sales. This margin represents a contribution to power supply fixed costs. I therefore credit the variable portion of revenues from off-system sales to variable cost. I classify margin from off-system sales separately to accommodate the implications of the unused energy allocator used in Kansas.

On Lines 12 through 15, I show the allocation to the Missouri jurisdiction using the allocation basis recently used in Missouri. This allocation includes the allocation of:

1) Fixed (capacity-related) transmission and power supply costs based on the average of the 4 monthly coincident peak demands (4CP),
2) Variable (energy-related) costs based on energy deliveries, and

[13] The Company has not had a FERC rate case recently. For the FERC jurisdiction, I use a 12CP capacity cost allocator and allocate off-system sales margin based on the 12CP allocator.

[14] In the balance of my testimony, my reference to off-system sales and off-system sales margins, include miscellaneous revenues of $25,541, see Schedule LWL2010-4, Sheet 1, Lines 22, 23, and 33, and Sheet 2, Line 13.

3) Margin associated with off-system sales based on energy.

On Lines 16 through 19, I show the allocation to the Kansas jurisdiction using the allocation basis recently used in Kansas. This allocation includes the allocation of:

1) Fixed (capacity-related) transmission and power supply costs based on the average of the 12 monthly coincident peak demands (12CP),
2) Variable (energy-related) costs based on energy deliveries, and
3) Margin associated with off-system sales based on "unused energy."

On Lines 20 through 23, I show the allocation of costs to the FERC jurisdiction allocating fixed costs and off-system sales margin using a 12CP allocator and allocating variable costs based on energy deliveries.

On Lines 27 through 37, I show the derivation of the various allocation factors that I use in Lines 12 through 23.

Q. Do you reach any conclusions based on review of Schedule LWL2010-5?

A. Yes, I do. As I show on Line 25, because of the different allocation methods employed by the Kansas and Missouri jurisdictions, KCP&L fails to recover over $9 million of its revenue requirement.

Q. What do you show in Sheet 2 of Exhibit LWL2010-5?

A. Sheet 2 is identical to Sheet 1 except that the total revenue requirement includes an estimate of the costs associated with the improvements at Iatan (including the addition of Iatan 2) , and the allocation factors reflect weather normalized sales for the 12-month period ended August 31, 2009. As I show on Line 25, after the addition of this investment, the unrecovered amount increases from $9 million to $9.7 million. Clearly, the different allocation methods used in Missouri and Kansas represent a problem to KCP&L. Further, the addition of Iatan 2 increases the impact of that problem.

VI. CAPACITY COST ALLOCATOR – 1CP vs 4CP vs 12CP

Q. **You show in Schedule LWL2010-5, Sheet 2, that the difference in capacity cost allocator results in unrecovered transmission cost of nearly $0.31 million and unrecovered power supply fixed cost of $3.78 million. Have you evaluated the merits of KCP&L using a 4CP versus a 12CP allocator?**

A. Yes, I have. I prepared Schedule LWL2010-6 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. As I will discuss later, in addition to the merits of the 4CP versus 12CP allocators, I believe that the traditional manner in which costs are classified as capacity should be re-evaluated.

Q. **Please describe Schedule LWL2010-6.**

A. Schedule LWL2010-6 consists of three sheets that show monthly maximum coincident demands and corresponding monthly deliveries to native load customers. Sheet 1 shows monthly coincident peak demands for 2008 and the number of hours that load equals or exceeds that level. Sheet 2 shows monthly coincident peak demands for 2008 and monthly deliveries by jurisdiction. Sheet 3 shows monthly coincident peak demands for the 2006, 2007, and 2008 calendar years along with monthly energy deliveries to native load customers.

Q. **Do you have any observations based on your examination of the information you show in Sheet 1?**

A. Yes, I do. These observations include:

1) In 2008, any measure of maximum coincidental demand must clearly include August and July.

2) To a lesser degree, coincidental demands in June, and, to a somewhat lesser degree, in September, can reasonably be included as measures of maximum demand.

3) The maximum coincident demand in May might be considered unusually high.[15]

4) The maximum coincident demands during the winter months (December, January, and February) fall in a relatively small range 25 to 30 percent below the maximum demands during July and August.

5) Demands during the spring and fall months (except for May) are considerably below those during the winter and summer.

6) Demands during the eight months other than June through September never exceed the accredited capacity of the Company's base load generating resources. This means that, except during outages, peaking capacity is not required to meet native load during the non-summer months.

7) Demands during the four summer months equal or exceed accredited capacity in the Company's base load resources during 258 hours or about nine percent of the time.

Based on the foregoing, I believe that the measure of maximum demand reasonably includes the four summer months of June through September.

Q. What observations do you have regarding Sheet 2?

A. In Sheet 2 I include coincident peak demands and monthly deliveries by jurisdiction for 2008. In this sheet, I focus on monthly load factors. System load factor during the four

[15] Considering the weather patterns in mid to late May in the Kansas City area and the low load factor, the coincident demand for May is expected.

summer months ranges in the low 60 percent range (59.45 to 65.81 percent). Except for May, system load factor during the other months exceeds 73 percent.

Based on these load factors, I 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.

Q. What observations have you made regarding Sheet 3?

A. In Sheet 3 I include coincident peak demands and monthly deliveries for the 2006 through 2008 calendar years. I also show monthly deliveries to native load customers and the rank, from highest to lowest, of the three-year average.

Based on examination, I have grouped months into the four summer months (June through September), the three winter months (December through February), and the remaining five months.

Some observations include:

1) System load factor during the four summer months ranges in the low 60 percent range (59.45 to 65.81 percent).
2) In 2006 and 2007, the annual system maximum demand occurred in July, instead of August as it did in 2008.
3) While the average maximum demand in September is somewhat lower than the other three summer months, in 2007 the maximum demand in September was only 13 percent below the annual maximum. In 2006 and 2008, the September demand was 16 to 18 percent below the maximum.

4) The average maximum in September is about 15 percent less than July, whereas during the three winter months it is 23 to 34 percent less. During the other months, except for May, the maximum demand is 30 to 44 percent less than July.

5) The average monthly load factors also distinguish the four summer months from the remainder of the year. During the summer months monthly load factor ranges from 56 to 66 percent, whereas for the other months (except May) load factor ranges from 63 to 80 percent.

Q. What do you conclude from your analyses in LWL2010-6?

A. KCP&L is clearly a summer peaking utility. Summer demands dominate. As a result, I believe that the only reasonable measure of maximum demand is the average of the four monthly coincident peaks June through September. As an indication of the dominance of the four summer months, the average monthly demand during July and August exceeds the maximum coincidental demand during March and April.

Q. Based in the forgoing, what is your recommendation?

A. Because KCP&L is a summer peaking utility, I recommend that capacity related costs be allocated on the basis of each jurisdiction's contribution to the four summer month maximum coincidental demand.

VII. OFF-SYSTEM SALES

Q. How were margins associated with off-system sales allocated in the prior case?

A. The Company proposed the use of "unused energy" as the basis to allocate these margins in Case No. ER-2006-0314, but the Commission rejected this proposal in favor of an allocation based on energy sales. The Kansas Commission accepted the "unused energy" method in Docket No. 07-KCPE-905-RTS.

Q. Do you believe an unused energy allocation is reasonable?

A. No, I do not. While I believe it has some philosophical foundation and produces a more reasonable result than an energy allocation, the presumption underlying the premise upon which it is based does not appear valid.

Q. What is the philosophical basis for using unused energy to allocate off-system margins?

A. First, it is important to understand what off-system sales margins represent. Off-system margins are revenues, derived from the sale of power and energy off-system, in excess of KCP&L's out-of-pocket cost of generating or purchasing the energy sold off-system. These margins represent a contribution to the fixed cost of the generation resources used to make such sales.

Through the demand allocator, each jurisdiction is allocated power supply fixed costs in proportion to the capacity cost allocator (4CP or 12CP). Margins realized from off-system sales represent a contribution to the fixed cost of the generating resources paid for by native load customers in proportion to their coincident peak demands.

Following the unused energy allocation basis, these credits to fixed costs are allocated in proportion to "available energy," where "available energy" represents the total capacity paid for by a jurisdiction less the average energy used by that jurisdiction.

The unused energy allocator is premised on the presumption that as native load declines, available energy increases and hence off-system sales increase. However, as I demonstrate in Schedule LWL2010-3, Sheet 2, that presumption does not appear valid.

The level of off-system sales does not increase in proportion to the decline in native load.[16]

Thus, the fundamental underlying premise supporting the unused energy allocator is not validated.

Q. Is the use of an unused energy allocator a recognized method to allocate cost?

A. No, it is not. I am unaware of any instance where this method has been employed except for KCPL. In some instances an energy allocator is used to allocate off-system sales and sales margins. In other instances off-system sales margins are allocated as I recommend here, i.e., the margin is allocated on the same basis or in proportion to the fixed costs of the generating units used to generate the electricity sold off-system.

However, the allocation approach used for other utilities should be given little weight. For most utilities, it doesn't make that much difference. However for KCP&L it does. The magnitude of KCP&L's off-system sales and sales margins is considerably greater than for most electric utilities. In addition, the relative balance of the load and the difference in load factor between the two predominant jurisdictions is unusual. These characteristics all tend to increase the importance of jurisdictional allocations (including the allocation of off-system margins) to KCP&L and its customers.

Q. In your opinion, did the parties err when they agreed to use of the unused energy allocator to allocate margins associated with off-system sales in Kansas?

A. Yes. I believe that KCP&L proposed the unused energy allocator without sufficient study of its implications and reasonableness. Since the unused energy allocator allocates

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[16] In Schedule LWL2010-3, Sheets 2 and 3, the difference between total load and native load represents off-system sales.

more off system sales margins (and hence lower overall costs) to the Kansas jurisdiction, the other parties may not have devoted the resources to study its reasonableness. Based on the analysis that I present here, I believe that the unused energy allocator is not an appropriate method for allocating off-system sales margins.

The result in both Missouri and Kansas is that the allocation of off-system sales margins does not align with the responsibility for power supply fixed costs. This problem is magnified because Missouri allocates these margins based on energy sales, while Kansas uses the unused energy allocator.

Q. What is the philisophical foundation of using an energy allocator to allocate off-system sales margin?

A. I'm not sure there is one. Even though off-system sales do not increase in proportion to the decrease in native load, the fact remains that each kWh sold to native load customers is a kWh that cannot be sold off system. The more energy sold to native load customers,. the less energy is available to sell off system.

Q. In your opinion, did the PSC err when it ordered use of an energy allocator to allocate margins associated with off-system sales?

A. That is a difficult question. I believe the Commission decision may be reasonable based on my understanding of the evidence presented for the Commission's consideration. On the other hand, the collective result in Missouri and Kansas is that the allocation of off-system sales margins does not align with the responsibility for power supply fixed costs, and the methods relied on represent approaches that allocate the highest margin (least net overall cost) to each jurisdiction.

Q. What factor determines whether an allocation of off-system sales margins is reasonable?

A. The most critical factor for assessing the reasonableness of the classification and allocation of margin from off-system sales is the extent to which it is internally consistent with the allocation basis used to allocate fixed costs associated with the Company's generating resources.

The credit (revenues) from off-system sales consists of two components. One is the recovery of the out-of-pocket costs associated with generating the energy sold off-system. The second is the revenue in excess of out-of-pocket cost (margin). This margin represents a contribution toward the fixed costs of the Company's generating resources. The <u>allocation of this sales margin must align with the allocation of fixed production costs</u> to reasonably allocate the margins back to the jurisdiction paying the fixed costs. Subsidization results, if this allocation does not align with the allocation of the fixed production costs these margins offset.

Q. What are the implications of crediting margin associated with off-system sales to energy related costs?

A. Margins associated with off-system sales represent revenues less out-of-pocket costs. Of the total revenues associated with off-system sales of $205.34 million, $100.89 million represents the variable (energy) cost associated with generating the energy sold. As I show in Schedules LWL-4 and LWL-5 (Sheet 2), I have credited this $100.89 million to variable cost in order to eliminate the costs associated with making the off-system sales from the costs I allocate among native load customers. Since I recovered the variable costs associated with the sales, the remainder of $104.45 million represents a contribution to fixed costs. Since there are no fixed costs included in variable or energy related costs, there are no fixed costs for the off-system sales margin to offset. Therefore, to the extent I reduce variable or energy related cost by off-system sales margin, I subsidize the sale of energy to native load customers by selling energy below cost. Whether I credit margin from off-system sales to energy or allocate margin based on energy, the result is the same. I sell energy below cost.

Q. **In lieu of an unused energy or energy allocator, what do you recommend?**

A. The unused energy allocator is premised on the concept that each jurisdiction is charged fixed costs in proportion to the maximum use of capacity by that jurisdiction. Off-system sales margin represents a contribution to the fixed cost of that capacity. Hence, the more direct (and certainly more equitable) method to allocate these off-system sales margins is in proportion to the allocation of fixed costs to each jurisdiction associated with the generating resources used to generate the energy sold off-system.

Examination of Schedule LWL2010-3, Sheet 2 and Sheet 3 (along with the detail underlying the graphs shown in those two sheets) shows that KCP&L makes off-system sales primarily from its coal-fired steam generating stations. In fact, based on load levels adjusted to reflect Iatan Unit 2 in the dispatch, 97.5 percent of non-firm off-system sales are made from KCP&L's coal-fired resources. KCP&L makes nearly all of the remaining 2.5 percent from its gas-fired CT based resources. Since nearly all sales are made from KCP&L's coal-fired generation, I recommend that margin from off-system sales be allocated in the same manner as (in proportion to) steam plant fixed costs.

Q. Have you evaluated the implications of the allocation of these sales margins?

A. Yes, I have. In Schedule LWL2010-7, I show the impact of the classification and allocation of off-system sales margin to the Missouri jurisdiction when this sales margin is allocated on the same basis as the fixed costs of the power supply resources from which the energy sold off system is generated. I use the adjusted revenue requirement levels I summarize in Schedule LWL2010-4, Sheet 2. In Lines 1 through 10, I summarize revenue requirements by type of generation, along with the credit for off-system sales[17]. As shown, the total revenue requirement prior to the credit for off-system sales amounts to $1.032 billion. Of this $1.032 billion, $751.45 million represents fixed costs and $281.38 million represents variable costs. After crediting revenues from off-system sales of $205.34 million, net revenue requirements amount to $827.48 million. Of the $205.34 million of revenues from off-system sales, $100.89 million represents the out-of-pocket or variable cost associated with generating the energy sold. The balance ($104.45 million) represents the margin (revenues in excess of cost) associated with off-system sales. This margin represents a contribution to power supply fixed costs. I therefore credit the variable portion of revenues from off-system sales to variable cost and margin from off-system sales to fixed power supply revenue requirements.

On Lines 11 through 19, I show the allocation of power supply costs to the Missouri jurisdiction, if I allocate margin associated with off-system sales based on energy. As I show on Line 17, this treatment results in a total credit for off-system sales revenues of $117.06 million applicable to the Missouri jurisdiction. Following this treatment, I

17 In the balance of my testimony, my reference to off-system sales and off-system sales margins includes miscellaneous revenues of $25,541. See Schedule LWL2010-4, Sheet 1, Lines 22, 23, and 33, and Sheet 2, Line 13.

allocate a total of $442.98 million or 53.53 percent of total power supply related costs to the Missouri jurisdiction.

On Lines 20 through 28, I show the allocation of power supply costs to the Missouri jurisdiction if I classify margin associated with off-system sales correctly as capacity-related and allocate capacity-related costs using the 4CP.[18] As I show in Line 26, this treatment results in a total credit for off-system sales revenues of $113.06 million applicable to the Missouri jurisdiction. Following this treatment, I allocate a total of $446.97 million or 54.02 percent of total power supply related costs to the Missouri jurisdiction.

On Lines 29 through 38, I show the development of the capacity and energy allocation factors I use.

VIII. ENVIRONMENTAL COSTS

Q. What are environmental costs?

A. As I use the term in my testimony, environmental costs represent all costs (fixed and variable) associated with the capital and the operation and maintenance of equipment used in the Company's coal-fired steam generating stations to reduce, control, or monitor plant emissions. These costs include:

1) Fixed investment costs (including depreciation, return, and taxes) associated with:

- Flue gas desulphurization (FGD or scrubbers) equipment;
- Selective catalytic reduction (SCR) equipment;
- Other NO_x control equipment;

[18] In Schedule LWL2010-7, I classify all fixed production costs as demand related and allocate them using the 4CP allocator. In this instance, the 4CP allocator when applied to production related fixed costs, is the same as the production plant allocation basis.

- Particulate control equipment; and
- Facilities, equipment, land, and improvements associated with the disposal of products produced by the equipment identified above;

2) Variable costs associated with consumables used by the facilities and equipment listed in 1) above;
3) Fixed operation and maintenance expenses associated with the operation and maintenance of the facilities and equipment listed in 1) above;
4) Allowances purchased; and
5) Allowances sold (which operate as a credit).

Q. What do you recommend as the basis to classify and allocate these environmental costs?

A. Environmental costs, both fixed and variable, should be allocated on a basis that recognizes the nature of these costs.

Q. What is the nature of these costs?

A. KCP&L incurs environmental control costs in connection with the generation of electricity from its coal-fired steam generating stations. KCP&L does not incur these costs in order to supply power to customers for four hours or even twelve hours a year.[19] As I discussed previously, the cost of this equipment relates to the need by customers for economical energy. As a result, these costs are energy-related and should be allocated accordingly.

[19] As I previously discussed in connection with Schedule LSL2010-6, Sheet 1, in 2008 native load exceeded accredited base load capacity in only 258 hours.

Q. Are there any factors that demonstrate the energy-related nature of these costs?

A. Yes, there are. In lieu of incurring capital costs to control emissions, KCP&L could purchase allowances. The cost of purchasing allowances is directly related to the kWh generated because for each additional kWh generated, KCP&L would need to purchase an additional fraction of an allowance.

Q. Have you evaluated the implications of classifying environmental costs as energy?

A. Yes, I have. In Schedule LWL2010-8, I show the impact of the classification and allocation of environmental costs based on energy sales to the Missouri jurisdiction. Lines 1 through 24 of Schedule LWL2010-8 are identical to Lines 1 through 19 of Schedule LWL2010-7 with the exception that I have split the revenue requirement associated with steam generation into fixed environmental costs and other steam generation costs. In this regard, I estimate that fixed environmental costs amount to 24.44 percent of total steam fixed costs.

I show in Lines 25 through 37 of Schedule LWL2010-8 the classification and allocation of fixed environmental costs based on annual energy sales. In this allocation I have used the 4CP allocation factor and have classified the margin on off-system sales as capacity-related, and allocated accordingly.

Q. Line 22 of Schedule LWL2010-7 shows capacity-related off-system sales margin of $104.45 million, whereas Line 29 of Schedule LWL2010-8 shows capacity-related off-system sales margin of $78.93 million. Why do these credits differ?

A. Recall that I recommend allocating the margin associated with off-system sales on the same basis as the fixed costs associated with the resource(s) supplying the power and energy sold. In Schedule LWL2010-7, I classify all power supply fixed costs as capacity-related and allocate these capacity costs based on coincidental peak demand (4CP). In Schedule LWL2010-8, however, I do not classify all power supply fixed costs as demand-related. In Schedule LWL2010-8 (Line 28), I classify $118.31 million of fixed power supply costs (environmental) as energy-related. During 2008 (adjusted to reflect the addition of Iatan Unit 2), the credit for off-system sales margin amounts to 21.57 percent of total steam plant fixed costs. I have therefore classified off-system sales margin equal to 21.57 percent of the fixed environmental costs as energy-related. This treatment recognizes that I have now classified certain fixed costs as energy-related, and that associated off-system sales margin should follow. I classify the remaining margin associated with off-system sales ($78.93 million) as capacity-related.

On Lines 25 through 37, I show the allocation of power supply costs to the Missouri jurisdiction using the 4CP allocator and classifying fixed environmental cost as energy related and margin associated with off-system sales on the same basis as fixed power supply costs. As I show in Line 37, this results in allocating 54.44 percent ($450.52 million) of power supply costs to the Missouri jurisdiction.

IX. BOILER MAINTENANCE

Q. How are expenses associated with boiler maintenance usually allocated?

A. These maintenance expenses are nearly always considered fixed, classified as demand-related, and allocated based on peak demands.

Q. Do you agree with this treatment?

A. No. I believe that for the most part, boiler maintenance activities represent a variable cost. By variable cost, I mean a cost that tends to change in response to the energy generated by steam produced by the boiler.

Q. Please explain.

A. Boiler maintenance requirements (and to some degree boiler life) tend to vary depending on the total steam produced. One of the biggest factors that affects the need for maintenance relates to erosion of boiler tubes from the inside by the water and steam flowing through them and from the outside by the particles of combustion and flue gas. As a result, in large part, maintenance requirements depend on the total energy generated.

Q. Do you consider all boiler maintenance expenses variable in nature?

A. No, I do not. Boiler maintenance consists of KCP&L labor and non-labor components (materials and non-KCP&L labor). The KCP&L labor component represents the cost of KCP&L employees performing maintenance activities. This labor cost is relatively fixed since the employees used to perform boiler maintenance activities are involved in other activities during periods when the boiler is not undergoing maintenance.

The other component relates to maintenance contracts and materials used in maintenance activities. These costs relate directly to the need for maintenance. If maintenance were not required, these costs would not be incurred.

Q. Why do you consider these maintenance costs variable?

A. With regard to both the boiler and turbine, one of the principal needs for maintenance relates to erosion. Erosion is the process of weakening a material (in this case steel) because of material, water, and products of combustion wearing it away. In order to keep this equipment running, maintenance is required to replace eroded boiler tubes and turbine vanes. Much like the automobile manufacturers' requirement to change oil in cars based on mileage, boiler and turbine manufacturers typically base maintenance schedules and maintenance contracts on the number of hours connected to load.

Manufacturers also base maintenance schedules and contracts on the number of starts a plant undergoes. Starting and stopping plants introduces thermal stresses due to the heating and cooling of parts. These thermal stresses also increase maintenance requirements. Because of the frequent starts and stops experienced by peaking facilities, the number of starts tends to govern maintenance requirements of peaking equipment.

For large steam plants operated as base load resources, it is the number of hours loaded that controls the need for maintenance. Base load units are not subject to frequent starts. Thus boiler maintenance is properly related to the energy produced by steam generating units and should be allocated accordingly.

Q. Are there energy-related maintenance requirements associated with power supply equipment other than boilers?

A. Yes, to some degree. Manufacturers typically base maintenance schedules associated with steam turbines and CTs on the number of starts and/or number of hours connected to load. Since KCP&L uses its CT based equipment to meet peaking requirements, maintenance of these peaking units is based on the number of starts, and are appropriately allocated based on peak period demands. With regard to steam plants, maintenance associated with equipment other than boilers is relatively minor.

Therefore, I recommend that non-labor boiler maintenance costs be classified as energy and allocated based on energy sales.

Q. Have you evaluated the implications of classifying the non-labor component of boiler maintenance expenses on energy?

A. Yes, I have. In Schedule LWL2010-9, I show the impact of the classifying and allocating the non-labor portion of boiler maintenance expenses as energy-related and allocate such expenses based on energy deliveries. The schedule also reflects recognition of the nature of the margin on off-system sales and environmental costs, and uses the 4CP allocator.

Lines 1 through 27 of Schedule LWL2010-9 are identical to Lines 1 through 19 of Schedule LWL2010-7 with the exception that I have split the gross revenue requirement associated with steam generation into boiler maintenance, environmental cost, and other.

I show on Lines 28 through 34 of Schedule LWL2010-9 the classification of the non-labor portion of boiler maintenance expenses ($22.48 million) as energy-related.

As with Schedule LWL2010-8, because of changing the classification of fixed power supply costs, the classification of margin on off-system sales changes accordingly.

On Lines 35 through 42, I show the allocation of power supply costs to the Missouri jurisdiction, if I classify the non-labor portion of boiler maintenance and fixed environmental cost as energy, allocate margin associated with off-system sales on the same basis as fixed power supply costs, and use the 4CP allocator. As I show on Line 42, this treatment results in allocating 54.53 percent of power supply costs to the Missouri jurisdiction.

X. CAPACITY-RELATED POWER SUPPLY COSTS

Q. What are capacity-related power supply costs?

A. When I refer to capacity-related power supply costs, I am referring to fixed costs that are allocated on some basis that recognizes maximum demands placed on the system. Peak demands -- whether 1CP, 4CP, 12CP, or NCP (non-coincident peak demands) -- are measures of maximum demand usually used to allocate capacity-related costs. The PSC has used 4CP method in KCP&L's prior rate cases, whereas the KCC uses the 12CP method. Based on my analysis of actual KCP&L load levels and patterns, I recommend use of the 4CP method in both Missouri and Kansas.

Q. Have you evaluated the implications of using these various coincidental peak allocation bases?

A. Yes, I have. In Schedules LWL2010-7, LWL2010-8, and LWL2010-9, I show the impact of using the coincident peak demand for the four summer months to allocate capacity-related costs. In Schedule LWL2010-10, I show the impact of using the contribution to the maximum annual peak demand (1CP, Sheet 1) and the contribution to each month's maximum demand (12CP, Sheet 2).

Q. What are the implications of using the 1CP method?

A. As I show in Schedule LWL2010-10, Sheet 1, Line 14, using a single CP allocator and assuming an energy allocation of off-system sales and a capacity allocation of environmental and boiler maintenance cost, the cost responsibility allocated to the Missouri jurisdiction amounts to $443.15 million, or 53.55 percent of the total power supply net revenue requirement.

Assuming the allocation recognizes the nature of off-system sales, environmental cost, and boiler maintenance, the cost responsibility allocated to the Missouri jurisdiction amounts to $451.32 million (Line 29), or 54.54 percent of the total power supply net revenue requirement.

Q. What are the implications of using the 12CP method?

A. As I show in Schedule LWL2010-10, Sheet 2, Line 14, assuming an energy allocation of off-system sales and a capacity allocation of environmental and boiler maintenance costs, the cost responsibility allocated to the Missouri jurisdiction amounts to $446.75 million, or 53.99 percent of the total power supply net revenue requirement.

Assuming the allocation recognizes the nature of 1) off-system sales, 2) environmental cost, and 3) boiler maintenance, the cost responsibility allocated to the Missouri jurisdiction using the 12CP allocator amounts to $453.89 million (Line 29), or 54.85 percent of the total power supply net revenue requirement.

Q. **Which of these approaches do you consider most applicable?**

A. As I previously stated, I believe that the 4CP method best reflects the load characteristics and cost drivers of KCP&L.

Q. **Earlier in your testimony you indicated that to reasonably allocate power supply cost, the allocation method must recognize the fact that KCP&L pays a premium for resources that can generate energy economically. Does the 4CP allocation basis you recommend explicitly recognize this premium?**

A. No, it does not, however, neither does the 1CP or 12CP allocation basis. Nonetheless, by properly classifying and allocating environmental control costs based on energy deliveries, some recognition of the premium paid for resources that can generate energy economically is included in the allocation.

Q. **In Case No. ER-2009-0089 did you evaluate alternative allocation bases that provide more explicit recognition of the premium paid for resources that can generate energy resources economically?**

A. Yes, I did. However, in this case I elected not to present the impact of these alternatives because the impact on Missouri customers would be too disruptive.

XI. SUMMARY OF ALTERNATIVES

Q. Did you summarize the results of the various approaches that you have discussed above?

A. Yes, I have. In Schedule LWL2010-11, I show this summary.

As I show in Schedule LWL2010-11, the Missouri jurisdictional responsibility for power supply costs based on the eight approaches I discuss ranges from 53.53 ($442.98 million) to 54.85 percent ($453.89 million). If the 4CP approach is used and the nature of the off-system sales margin, environmental costs and boiler maintenance is recognized, the Missouri cost responsibility amounts to 54.53 percent.

Q. Do you believe that the 4CP method produces reasonable results?

A. Yes, it does, provided some recognition is given to the premium paid for resources that can generate energy economically. Using the 4CP method and properly treating off-system sales margin, environmental, and boiler maintenance costs provide some recognition. This results in a Missouri jurisdictional responsibility of 54.53 percent, which represents total costs allocated to the Missouri jurisdiction of $451.20 million. This is an increase of $8.22 million or 1.86 percent above the level reflected in the method underlying the existing rates.

Properly treating off-system sales, environmental cost, and non-labor boiler maintenance, and using the 4CP in both Kansas and Missouri will eliminate the $9.71 million revenue shortfall that KCP&L experiences due to the different allocation bases currently relied on.

Because of the settlement reached in the 1025 S&A, the Company did not recommend a change from the 12CP approach in its current Kansas rate case. However, by maintaining the 12CP method and by properly classifying and allocating off-system margin, the under-collection that the Company presently experiences is slightly reduced. I therefore recommended in the Company's current Kansas case using a 12CP allocator, classifying off-system sales margin as a fixed cost, and allocating such margin in the same manner as the fixed costs associated with the resources used to generate the energy sold off-system.

XII. ALLOCATION OF TRANSMISSION SYSTEM COSTS

Q. How are transmission system costs usually allocated?

A. Transmission costs are typically allocated based on capacity requirements. Most often, the basis used to allocate transmission system costs is the same as the allocator used for fixed production costs.

Q. Do you believe this treatment is reasonable?

A. Yes, allocating transmission system cost based on the allocation of power supply fixed costs has merit. The transmission system serves to link the power supply to the load centers. To the extent that fixed power supply costs are considered energy-related, transmission costs should be treated similarly.

The benefit of transmission is two-fold. First, the transmission system tends to reinforce the distribution system. Second, the transmission system serves to link remotely located large central station generating plants to load centers. These large stations are often remotely located due to the difficulty in siting them near major load centers. The primary benefit of these large stations is the relatively low cost of energy produced. To the degree the transmission system serves to connect the large generating stations to load centers, the allocation of transmission system costs should recognize the benefits of those stations. Therefore, I recommend that transmission system costs be allocated based on the allocation of fixed power supply costs (excluding directly assigned cost).

XIII. RECOMMENDED ALLOCATION BASES

Q. Based on your investigation in this case, what jurisdictional allocation bases do you recommend the Commission adopt?

A. Because of the 1025 S&A, I limited my recommendations in this case and in the Company's current Kansas case to the classification and allocation of off-system sales margins in the same manner as the fixed costs of the generating units used to generate the energy sold off-system. In the two cases, I do not recommend a change in the capacity cost allocator or to the classification of environmental costs and boiler maintenance,

However, in future rate cases (in both Missouri and Kansas) I plan to recommend 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) Allocate energy related power supply costs based on energy deliveries adjusted for losses.
3) Classify and allocate margin associated with off-system sales in the same manner as the fixed costs (excluding costs directly assigned) of generating resources used to generate the energy sold off-system.
4) Classify fixed and variable costs associated with steam plant environmental protection and control as energy-related and allocate accordingly.

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

6) Classify and allocate transmission system costs on the same basis as the classification and allocation of fixed power supply costs (exclusive of costs directly assigned).

Q. Have you evaluated the impact of your recommendation in this case?

A. Yes, I do so in Schedule LWL2010-12. This schedule shows, based on the adjusted 2008 revenue requirements, the implications of the recommendations I make in this rate case and in the Company's current rate case in Kansas. As I show, if my recommendations are adopted in full in both cases, the $9.71 million under-collection KCP&L currently suffers as a result of different allocation methods used in Kansas and Missouri (see Schedule LWL2010-5 Sheet 2) will be reduced by about two-thirds to $3.56 million.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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. ER-2010-____

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 20th day of May, 2010.

Notary Public

My commission expires: June 8, 2011

DONNA ATKINS
NOTARY PUBLIC ARIZONA
MARICOPA COUNTY
My Commission Expires
June 8, 2011

KCP&L - Missouri
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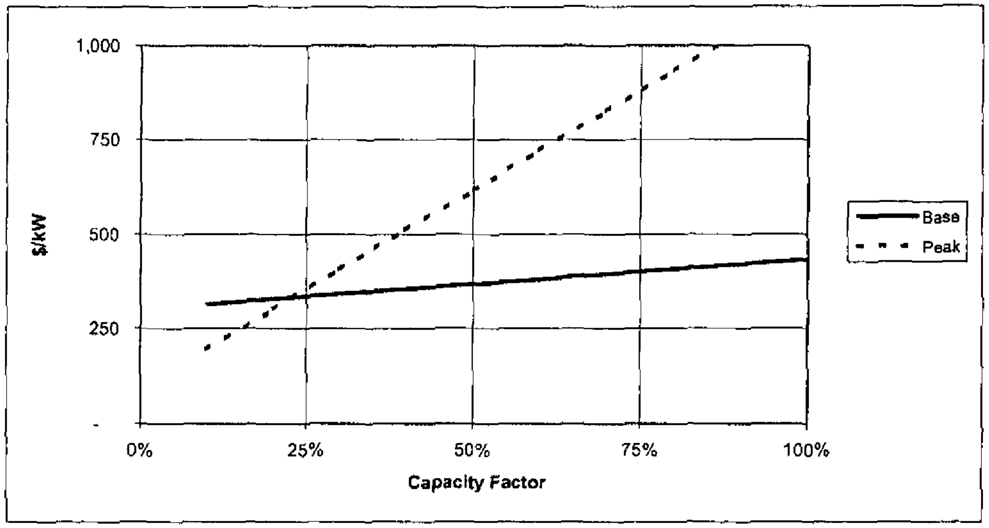
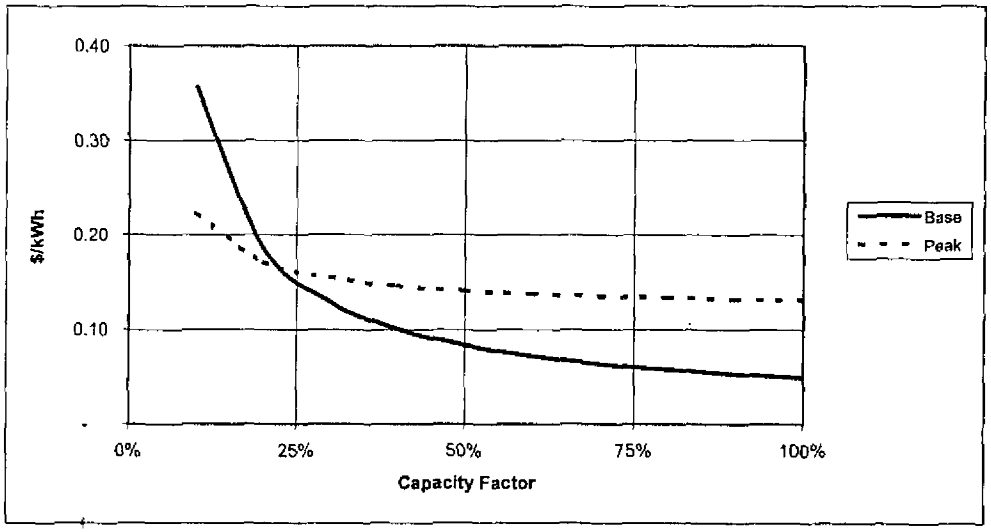
5/19/2010

Schedule LWL2010-1
Sheet 1

Kansas City Power Light Company
Generating Station Cost Characteristics
Example

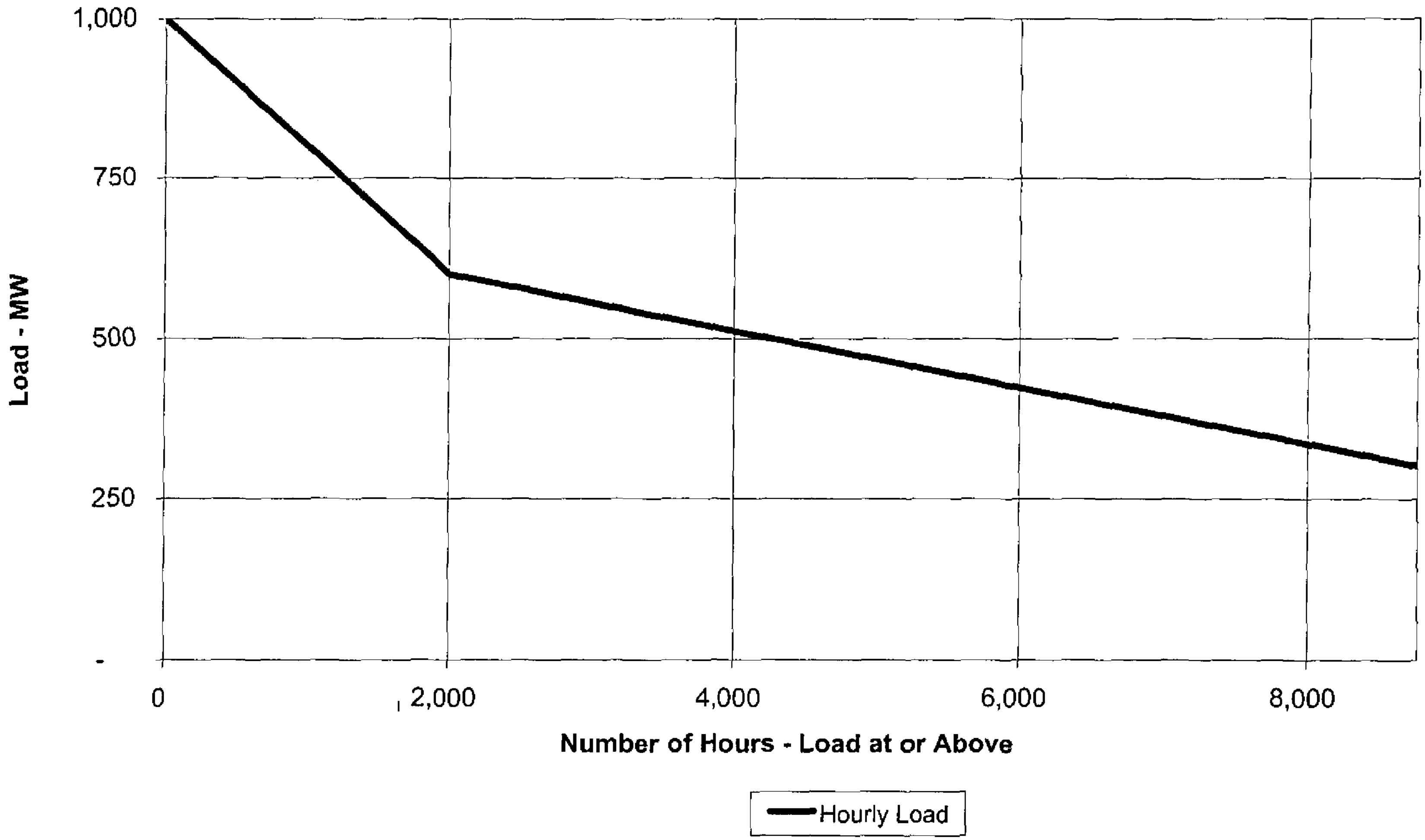
Line No.	[A] Description	[B] Base Resource	[C] Peaking Resource
1	Cost Characteristics - Estimated		
2	Construction Cost - $/kW	1,500	500
3	Annual Fixed Charge Rate	20%	18%
4	Annual Fixed Costs - $/kW	300	90
5	Variable Operating Cost - $/kWh	0.0150	0.1200
6	Annual Cost - $/kW		
7	Capacity Factor		
8	10%	313	195
9	20%	326	301
10	30%	340	406
11	40%	353	512
12	50%	366	617
13	60%	379	722
14	70%	392	828
15	80%	405	933
16	90%	419	1,039
17	100%	432	1,144
18	Annual Cost - $/kWh		
19	Capacity Factor		
20	10%	0.36	0.22
21	20%	0.19	0.17
22	30%	0.13	0.15
23	40%	0.10	0.15
24	50%	0.08	0.14
25	60%	0.07	0.14
26	70%	0.06	0.13
27	80%	0.06	0.13
28	90%	0.05	0.13
29	100%	0.05	0.13





Kansas City Power & Light Company
Hourly Load Curve Example

Schedule LWL2010-1
Sheet 2

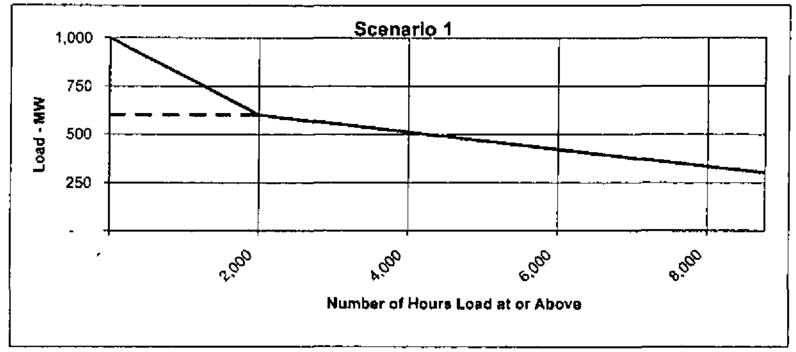


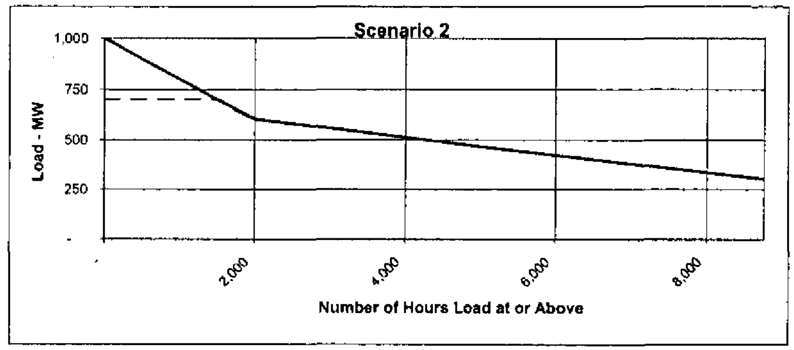
5/19/2010

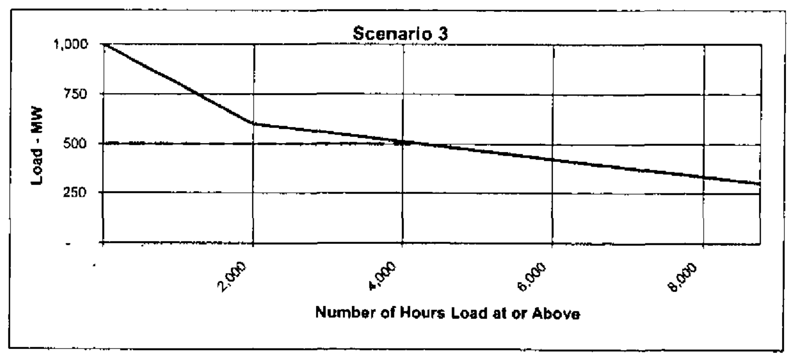
Schedule LWL2010-1
Sheet 3

Kansas City Power Light Company
Generating Station Cost Characteristics
Example of Uneconomic Generation Mix

Line No.	[A] Description	[B] Base Resource	[C] Peaking Resource	[D] Total
1	Cost Characteristics			
2	Construction Cost - $/kW	1,500	500	
3	Annual Fixed Charge Rate	20%	18%	
4	Annual Fixed Costs - $/kW	300	90	
5	Variable Operating Cost - $/kWh	0.0150	0.1200	
6	Scenario 1			
7	Capacity -MW	600	400	1,000
8	Energy - MWH	4,252,750	400,000	4,652,750
9	Capacity Factor	80.69%	11.38%	52.97%
10	Fuel Cost	63,791,250	48,000,000	111,791,250
11	Fixed Costs	180,000,000	36,000,000	216,000,000
12	Total Cost - $	243,791,250	84,000,000	327,791,250
13	Unit Cost - $/kWh	0.0573	0.2100	0.0705
14	Scenario 2			
15	Capacity -MW	700	300	1,000
16	Energy - MWH	4,427,750	225,000	4,652,750
17	Capacity Factor	72.01%	8.54%	52.97%
18	Fuel Cost	66,416,250	27,000,000	93,416,250
19	Fixed Costs	210,000,000	27,000,000	237,000,000
20	Total Cost - $	276,416,250	54,000,000	330,416,250
21	Unit Cost - $/kWh	0.0624	0.2400	0.0710
22	Scenario 3			
23	Capacity -MW	500	500	1,000
24	Energy - MWH	3,939,700	713,050	4,652,750
25	Capacity Factor	89.70%	16.24%	52.97%
26	Fuel Cost	59,095,500	85,566,000	144,661,500
27	Fixed Costs	150,000,000	45,000,000	195,000,000
28	Total Cost - $	209,095,500	130,566,000	339,661,500
29	Unit Cost - $/kWh	0.0531	0.1831	0.0730







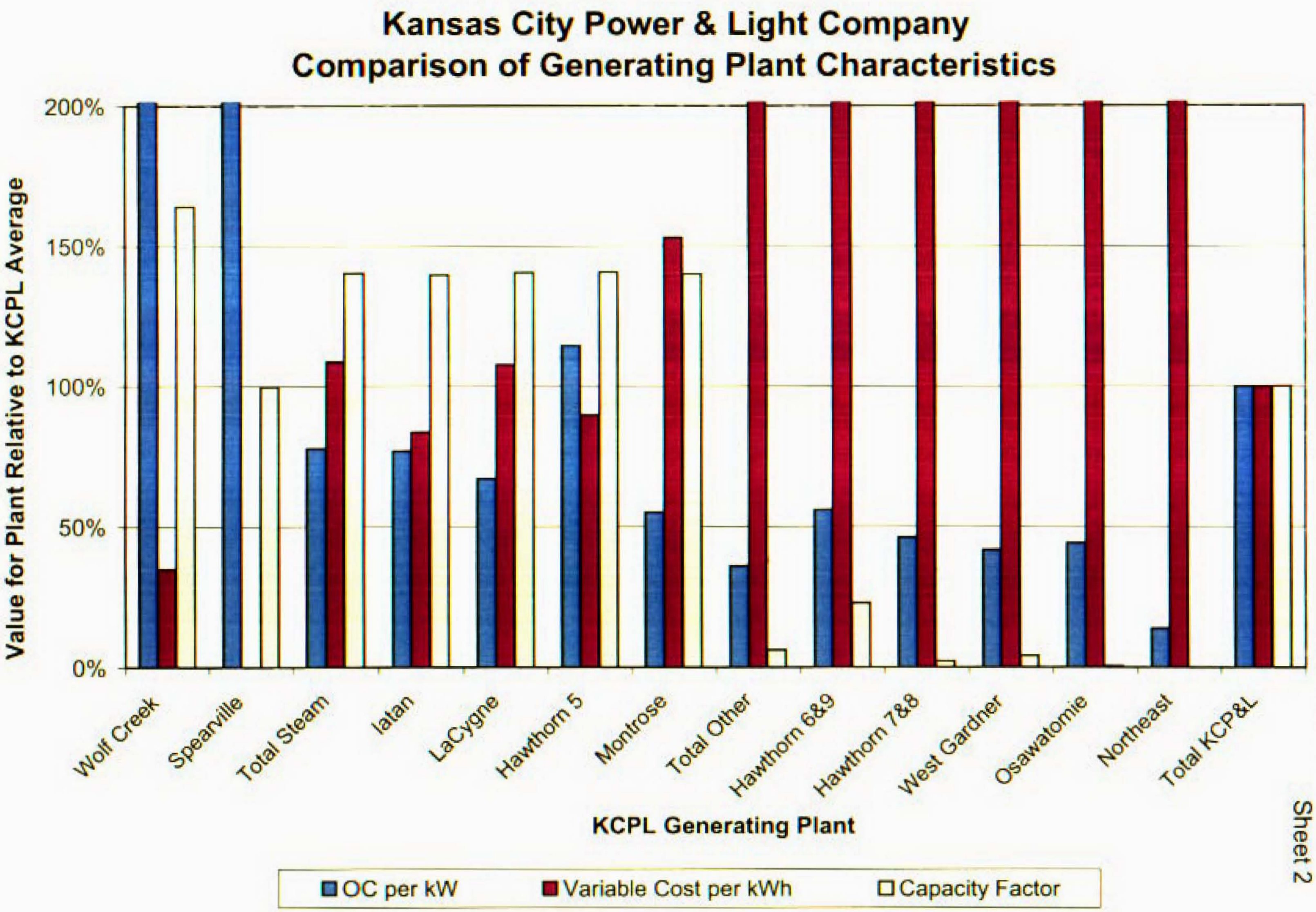
5/19/2010

Kansas City Power Light Company
Characteristics of KCPL Generating Stations

Schedule LWL2010-2
Sheet 1

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]
Line No.	Description	Reference	Wolf Creek	Spearville	Total Steam	Iatan	LaCygne	Hawthorn 5	Montrose	Total Other	Hawthorn 6&9	Hawthorn 7&8	West Gardner	Osawatomie	Northeast	Total KCP&L
1	Plant Type	LN 1 Form 1	Nuclear	Wind		Steam	Steam	Steam	Steam		Combined Cycle	Gas Turbine	Gas Turbine	Gas Turbine	Internal Combustion	
2	Year Originally Constructed	LN 3 Form 1	1985	2006		1980	1973	1969	1958		2000	2000	2003	2003	1972	
3	Year Last Unit Was Installed	LN 4 Form 1	1985			1980	1977	1969	1964		2000	2000	2003	2003	1977	
4	Capacity															
5	Installed Capacity - MW	LN 5 Form 1	581	101	2,492	508	827	594	563	1,466	301	164	408	102	491	4,640
6	Net Peak Demand on Plant - MW	LN 6 Form 1	588	104	2,283	482	716	567	518	1,174	293	183	362	85	251	4,129
7	Accredited Capacity - MW	LN 32	545	15	2,238	456	709	563	510	1,250	266	151	308	76	449	4,048
8	Hours Connected to Load	LN 7 Form 1	7,271	8,784	7,669	6,666	7,995	7,227	8,561	973	3,747	319	493	40	84	5,527
9	Generation															
10	Gross		4,160,773	419,037	15,652,400	3,144,925	5,266,944	3,684,921	3,555,610	400,219	302,111	16,690	75,342	2,417	3,659	20,832,429
11	Net Generation - MWH	LN 12 Form 1	3,993,647	419,037	14,646,383	2,972,879	4,869,862	3,501,092	3,302,550	377,619	288,943	15,363	73,002	1,878	(1,567)	19,436,685
12	Connected Average - MW	LN 11 / LN 8	549.26	47.70	1,909.84	445.98	609.11	484.45	385.77	388.04	77.11	48.16	148.08	46.95	(18.66)	3,516.37
13	Capacity Factor	LN 12 / LN 5	94.54%	47.47%	76.64%	87.79%	73.65%	81.56%	68.52%	26.47%	25.62%	29.37%	36.29%	46.03%	-3.80%	75.79%
14	Annual Average - MW	LN 11 / 8784	454.65	47.70	1,667.39	338.44	554.40	398.58	375.97	42.99	32.89	1.75	8.31	0.21	(0.18)	2,212.74
15	Capacity Factor	LN 14 / LN 5	78.25%	47.47%	66.91%	66.62%	67.04%	67.10%	66.78%	2.93%	10.93%	1.07%	2.04%	0.21%	-0.04%	47.69%
16	Original Cost - $	LN 17 Form 1	1,372,490,693	147,247,934	1,351,171,366	272,231,497	387,532,746	474,754,497	216,652,626	369,172,528	117,589,067	52,836,081	119,104,884	31,518,619	48,123,877	3,240,082,521
17	OC Per kW Installed - $/kW	LN 16 / LN 5	2,362	1,465	542	536	469	799	385	252	391	322	292	309	98	698
18	Operating Expenses									31,453,374						
19	Fuel Cost - $	LN 20 Form 1	18,244,344	-	207,407,971	32,344,968	68,319,392	40,878,363	65,865,248	27,660,082	16,103,436	2,248,957	8,395,264	284,335	628,090	253,312,397
20	Other Production Expenses - $	LN 21 - LN 19	61,804,612	2,055,733	78,737,392	14,643,070	20,278,234	26,542,025	17,274,063	3,793,292	2,323,472	239,593	578,946	67,558	583,723	146,391,029
21	Total O&M Expenses - $	LN 34 Form 1	80,048,956	2,055,733	286,145,363	46,988,038	88,597,626	67,420,388	83,139,311	31,453,374	18,426,908	2,488,550	8,974,210	351,893	1,211,813	399,703,426
22	Unit Cost									31,965,291						
23	Per kWh Generated (net)															
24	Fuel - $/MWh	LN 19 / LN 11	4.57	-	14.16	10.88	14.03	11.68	19.94	73.25	55.73	146.39	115.00	151.40	171.66	13.03
25	Total O&M - $/MWh	LN 21 / LN 11	15.48	4.91	5.38	4.93	4.16	7.58	5.23	10.05	8.04	15.60	7.93	35.97	159.53	7.53
26	Per kW Installed															
27	Other Expenses - $/kW	LN 20 / LN 5	106.38	20.46	31.60	28.82	24.52	44.68	30.68	2.59	7.72	1.46	1.42	0.66	1.19	31.55
28	Primary Fuel	LN 34	Nuclear	Wind		Coal	Coal	Coal	Coal		Gas	Gas	Gas	Gas	Oil	
29	Heat Rate - BTU/kWh	LN 44 Form 1	10,339			10,066	10,294	10,182	10,765		8,704	15,265	13,912	17,275	(37,134)	

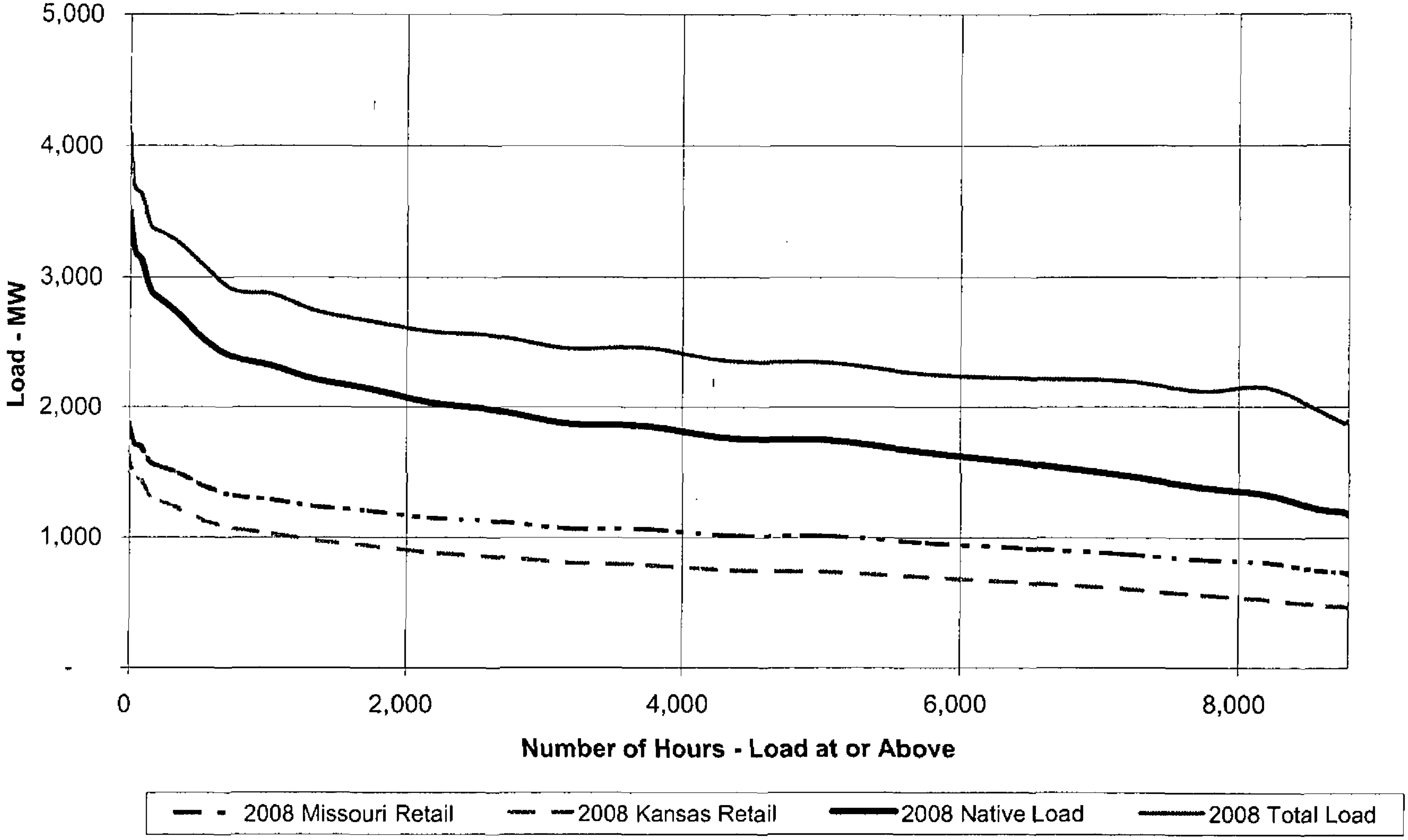
30 Reference:
31 All Data from KCP&L FERC Form No. 1, Pages 402 and 403, Unless Otherwise Specified
32 LN 7 = Accredited Summer Capacity - Provided by KCPL
33 LN 15, COLs [E], [J], and [P]: Weighted Based on LN 5
34 LN 28: Based on Examination of FERC Form 1, Lines 36 through 44
35 COL [D]: FERC Form 1, Page 410 and 411
36 COL [C]: KCP&L's 47% Interest
37 COL [F]: KCP&L's 70% Interest
38 COL [G]: KCP&L's 50% Interest
39 LN 24 & 25 - Column N - Northeast - Unit cost based on gross generation



Schedule LWL2010-2
Sheet 2

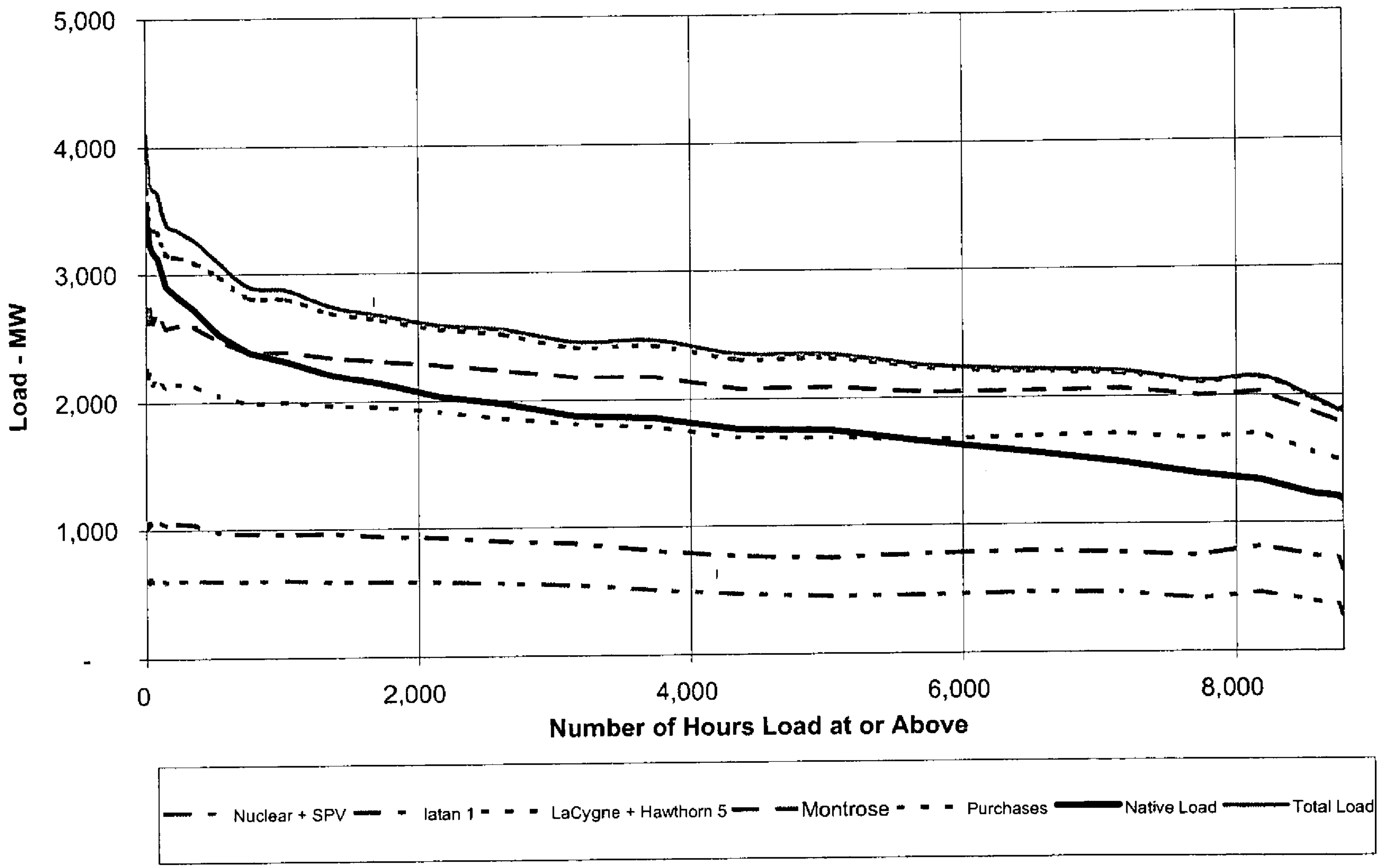
Schedule LWL2010-3
Sheet 1

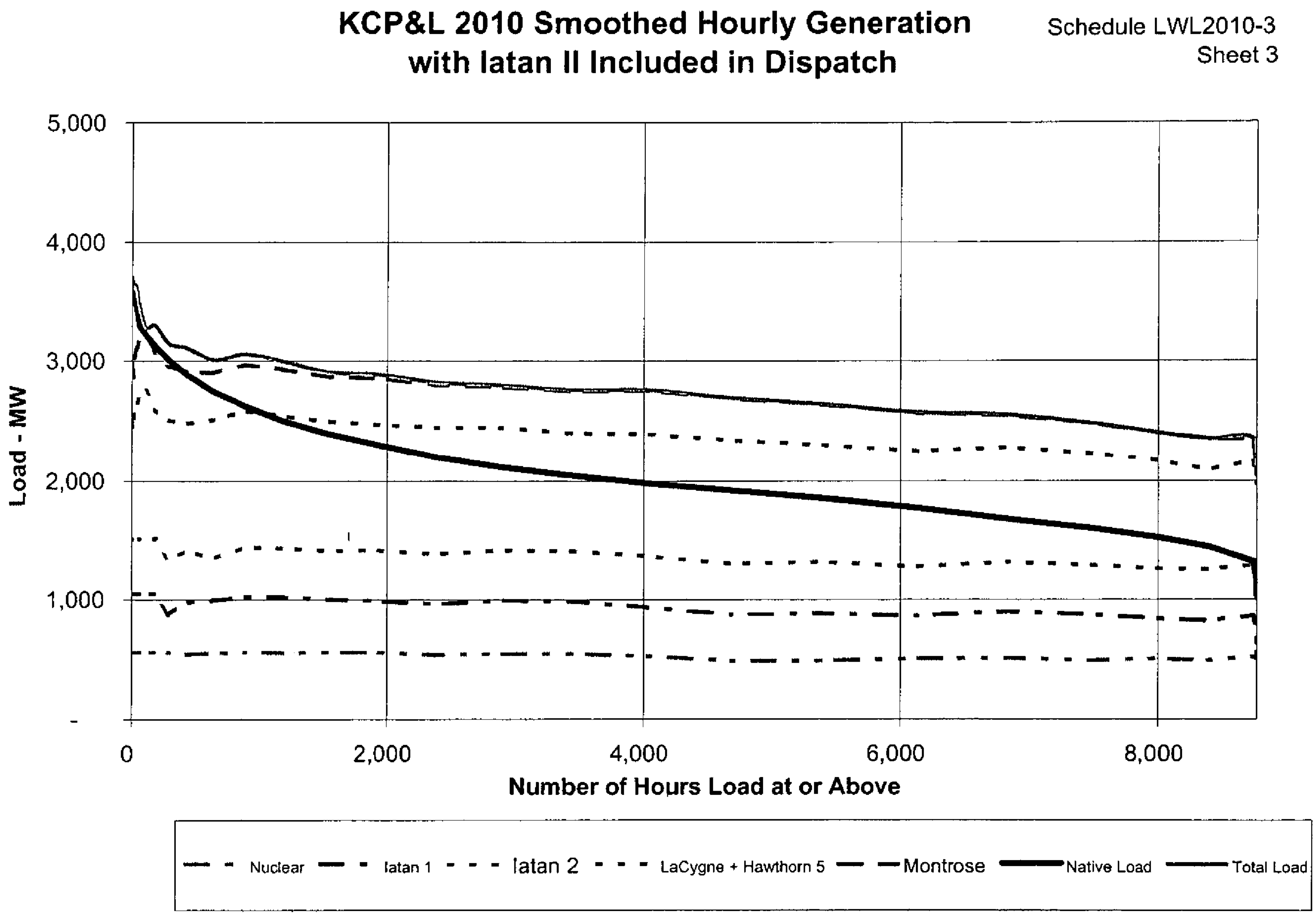
KCP&L Smoothed 2008 Hourly Load Curve



KCP&L 2008 Smoothed Hourly Generation

Schedule LWL2010-3
Sheet 2





KCP&L 2010 Smoothed Hourly Generation
with Iatan II Included in Dispatch
Schedule LWL2010-3
Sheet 3
5,000
4,000
3,000
2,000
1,000
-
Load - MW
0
2,000
4,000
6,000
8,000
Number of Hours Load at or Above
Nuclear
Iatan 1
Iatan 2
LaCygne + Hawthorn 5
Montrose
Native Load
Total Load

Kansas City Power Light Company
Power Supply Revenue Requirements
2008 Unadjusted

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Description	Total KCPL	Other	Transmission	Power Supply Fixed Cost	Power Supply Variable Cost
		$	$	$	$	$
1	Rate Base					
2	Electric Plant in Service	5,633,953,541	1,979,726,949	407,071,090	3,244,187,029	2,968,474
3	Accumulated Depreciation	(2,550,274,090)	(718,794,409)	(151,799,945)	(1,677,587,999)	(2,091,737)
4	Net Plant in Service	3,083,679,451	1,260,932,540	255,271,144	1,566,599,030	876,737
5	Working Capital	115,914,405	(2,127,254)	(1,504,620)	25,770,625	93,775,606
6	Other Rate Base Additions	37,949,174	25,996,155	567,358	10,727,969	657,692
7	Accumulated Deferred Income Taxes	(590,104,617)	(199,533,783)	(43,087,578)	(379,850,643)	32,367,387
8	Other Rate Base Reductions	(169,667,631)	(83,179,049)	-	-	(86,488,582)
9	Total Rate Base	2,477,770,782	1,002,088,608	211,246,304	1,223,246,982	41,188,841
10	Revenue Requirements					
11	Fuel	253,172,424	(1,345,306)	-	739,759	253,777,971
12	Purchased Power	125,784,180	-	-	8,969,483	116,814,697
13	Other O&M Expenses	411,354,427	126,964,612	33,831,254	245,917,643	4,640,918
14	Depreciation Expense	138,217,243	44,895,477	10,097,282	83,224,484	-
15	Amortization Expense	44,101,580	38,973,526	760,571	4,135,554	231,929
16	Interest on Customer Deposits	484,888	484,888	-	-	-
17	Taxes Other than Income Taxes	72,844,511	24,138,665	4,841,881	43,497,419	366,546
18	Return @ 7.8567%	194,670,230	78,731,491	16,597,023	96,107,284	3,236,097
19	State and Federal Income Taxes	56,511,422	26,255,338	6,393,415	36,060,725	(12,197,009)
20	Gross Revenue Requirements	1,297,140,906	339,098,691	72,521,425	518,652,350	366,871,149
21	Revenue Credits					
22	Miscellaneous Revenues	(18,221,709)	(7,383,010)	(10,813,158)	(25,541)	-
23	Off-System Sales	(213,606,478)	-	-	(82,459,979)	(131,146,499)
24	Net Revenue Requirements	1,065,312,718	331,715,681	61,708,267	436,166,831	235,724,650
25	Revenue Requirements by Type of Generation					
26	Nuclear				194,427,647	22,712,445
27	Steam				243,914,238	213,723,257
28	Purchase Power				8,965,059	116,757,085
29	Wind				28,839,383	(14,905,471)
30	Subtotal				476,146,327	338,287,315
31	Other Generation (Peaking)				42,506,024	28,583,834
32	Gross Revenue Requirements				518,652,350	366,871,149
33	Off-System Sales (Includes Miscellaneous Revenues)				(82,485,520)	(131,146,499)
34	Net Revenue Requirements				436,166,831	235,724,650

5/19/2010

Schedule LWL2010-4
Sheet 2

Kansas City Power Light Company
Power Supply Revenue Requirements
Detail by Plant
2008 Adjusted

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
Line		Unadjusted			Adjustments			Adjusted		
No.	Function/Plant	Total	Fixed	Variable	Total	Fixed	Variable	Total	Fixed	Variable
		$	$	$	$	$				
1	Nuclear	217,140,092	194,427,647	22,712,445	10,791,653	-	10,791,653	227,931,745	194,427,647	33,504,098
2	Wind	13,933,911	28,839,383	(14,905,471)	-	-	-	13,933,911	28,839,383	(14,905,471)
3	Steam								-	-
4	Iatan	77,916,489	44,501,695	33,414,794	282,980,478	240,256,383	42,724,095	360,896,967	284,758,078	76,138,889
5	LaCygne	127,830,996	57,542,455	70,288,541	(6,175,844)		(6,175,844)	121,655,152	57,542,455	64,112,696
6	Hawthorn 5	142,705,990	100,216,216	42,489,774	2,737,580		2,737,580	145,443,570	100,216,216	45,227,354
7	Montrose	109,184,019	41,653,871	67,530,148	(11,000,555)		(11,000,555)	98,183,464	41,653,871	56,529,593
8	Total Steam	457,637,495	243,914,238	213,723,257	268,541,658	240,256,383	28,285,275	726,179,153	484,170,621	242,008,532
9	Purchase Power	125,722,144	8,965,059	116,757,085	(116,176,650)	(7,458,914)	(108,717,736)	9,545,494	1,506,145	8,039,349
10	Subtotal	814,433,642	476,146,327	338,287,315	163,156,661	232,797,469	(69,640,808)	977,590,304	708,943,796	268,646,508
11	Other Generation (Peaking)	71,089,858	42,506,024	28,583,834	(15,852,259)	-	(15,852,259)	55,237,599	42,506,024	12,731,575
12	Gross Revenue Requirements	885,523,501	518,652,350	366,871,149	147,304,402	232,797,469	(85,493,067)	1,032,827,903	751,449,820	281,378,082
13	Off-System Sales	(213,632,019)	(82,485,520)	(131,146,499)	8,288,466	(21,966,395)	30,254,861	(205,343,553)	(104,451,915)	(100,891,638)
14	Net Revenue Requirements	671,891,482	436,166,831	235,724,650	155,592,868	210,831,074	(55,238,206)	827,484,350	646,997,905	180,486,444

Kansas City Power Light Company
Impact of Current Allocation Methods
2008 Unadjusted

	[A]	[B]	[C]	[D]	[D]	[E]	[F]
Line No.	Functional Revenue Requirements - Schedule LWL-4	Total Production and Transmission	Total Transmission	Power Supply Total Production	Fixed Cost	Variable Cost	Off System Sales
		$	$	$	$	$	$
1	Transmission	72,521,425	72,521,425				
2	Power Supply by Type of Generation						
3	Nuclear	217,140,092		217,140,092	194,427,647	22,712,445	
4	Steam	457,637,494		457,637,494	243,914,238	213,723,257	
5	Purchase Power	125,722,144		125,722,144	8,965,059	116,757,085	
6	Wind	13,933,911		13,933,911	28,839,383	(14,905,471)	
7	Subtotal	886,955,067	72,521,425	814,433,642	476,146,327	338,287,315	-
8	Other Generation (Peaking)	71,089,858		71,089,858	42,506,024	28,583,834	
9	Gross Revenue Requirements	958,044,925	72,521,425	885,523,500	518,652,350	366,871,149	-
10	Off-System Sales (Includes Miscellaneous Revenues)	(224,445,177)	(10,813,158)	(213,632,019)		(131,146,499)	(82,485,520)
11	Net Revenue Requirements	733,599,748	61,708,267	671,891,481	518,652,350	235,724,650	(82,485,520)

	Allocation to Jurisdiction	Total Production and Transmission	Transmission Capacity	Power Supply Total	Capacity	Energy	Off System Sales
				$	$	$	$
12	Allocation to Missouri						
13	Allocation Basis		LN 30		LN 30	LN 34	LN 34
14	Allocation Factor		53.55%		53.55%	57.01%	57.01%
15	Missouri Portion	398,166,179	33,047,185	365,118,994	277,758,575	134,384,762	(47,024,344)
16	Allocation to Kansas						
17	Allocation Basis		LN 32		LN 32	LN 34	LN 36
18	Allocation Factor		44.83%		44.83%	42.37%	46.68%
19	Kansas Portion	321,557,315	27,665,102	293,892,213	232,522,660	99,875,238	(38,505,685)
20	Allocation to FERC						
21	Allocation Basis		LN 32		LN 32	LN 34	LN 32
22	Allocation Factor		0.66%		0.66%	0.62%	0.66%
23	FERC Portion	4,766,502	409,242	4,357,259	3,439,645	1,464,650	(547,035)
24	Total Recovered	724,489,997	61,121,530	663,368,467	513,720,880	235,724,650	(86,077,063)
25	Total Unrecovered	9,109,751	586,737	8,523,014	4,931,471	-	3,591,544
26	Percent Unrecovered	1.24%	0.95%	1.27%	0.95%	0.00%	4.35%

	Allocation Bases	Total	Missouri	Kansas	FERC
27	Coincident Peak Demand				
28	Single CP - MW	3,495	1,869	1,603	23
29	Capacity Responsibility	100.00%	53.47%	45.88%	0.65%
30	Four CP - Average MW	3,261	1,746	1,494	20
31	Capacity Responsibility	100.00%	53.55%	45.83%	0.62%
32	Twelve CP - Average MW	2,636	1,437	1,182	17
33	Capacity Responsibility	100.00%	54.50%	44.83%	0.66%
34	Annual Deliveries - MWH	16,219,965	9,246,874	6,872,310	100,781
35	Energy Responsibility	100.00%	57.01%	42.37%	0.62%
36	Unused Energy - MWH	21,595,155	11,364,154	10,080,997	150,005
37	Unused Energy Allocator	100.00%	52.62%	46.68%	0.69%

Kansas City Power Light Company
Impact of Current Allocation Methods
2008 Adjusted

Line No.	[A] Functional Revenue Requirements - Schedule LWL-4	[B] Total Production and Transmission	[C] Total Transmission	[D] Power Supply: Total Production	[D] Power Supply: Fixed Cost	[E] Power Supply: Variable Cost	[F] Power Supply: Off System Sales
		$	$	$	$	$	$
1	Transmission	72,521,425	72,521,425				
2	Power Supply by Type of Generation						
3	Nuclear	227,931,745		227,931,745	194,427,647	33,504,098	
4	Steam	726,179,153		726,179,153	484,170,621	242,008,532	
5	Purchase Power	9,545,494		9,545,494	1,506,145	8,039,349	
6	Wind	13,933,911		13,933,911	28,839,383	(14,905,471)	
7	Subtotal	1,050,111,729	72,521,425	977,590,304	708,943,796	268,646,508	-
8	Other Generation (Peaking)	55,237,599		55,237,599	42,506,024	12,731,575	
9	Gross Revenue Requirements	1,105,349,328	72,521,425	1,032,827,903	751,449,820	281,378,083	-
10	Off-System Sales (Includes Miscellaneous Revenues)	(216,156,711)	(10,813,158)	(205,343,553)		(100,891,638)	(104,451,915)
11	Net Revenue Requirements	889,192,617	61,708,267	827,484,350	751,449,820	180,486,445	(104,451,915)

Line No.	Allocation to Jurisdiction	Total Production and Transmission	Transmission Capacity	Power Supply: Total	Power Supply: Capacity	Power Supply: Energy	Power Supply: Off System Sales
				$	$	$	$
12	Allocation to Missouri						
13	Allocation Basis		LN 30		LN 30	LN 34	LN 34
14	Allocation Factor		53.18%		53.18%	57.01%	57.01%
15	Missouri Portion	475,793,010	32,817,270	442,975,739	399,630,926	102,889,453	(59,544,640)
16	Allocation to Kansas						
17	Allocation Basis		LN 32		LN 32	LN 34	LN 36
18	Allocation Factor		45.64%		45.64%	42.36%	47.70%
19	Kansas Portion	397,757,416	28,162,812	369,594,605	342,951,453	76,461,858	(49,818,706)
20	Allocation to FERC						
21	Allocation Basis		LN 32		LN 32	LN 34	LN 32
22	Allocation Factor		0.68%		0.68%	0.63%	0.68%
23	FERC Portion	5,935,629	417,987	5,517,641	5,090,024	1,135,134	(707,516)
24	Total Recovered	879,486,055	61,398,069	818,087,985	747,672,402	180,486,445	(110,070,862)
25	Total Unrecovered	9,706,562	310,198	9,396,365	3,777,417	-	5,618,947
26	Percent Unrecovered	1.09%	0.50%	1.14%	0.50%	0.00%	5.38%

Line No.	Allocation Bases	Total	Missouri	Kansas	FERC
27	Coincident Peak Demand				
28	Single CP - MW	3,703	1,970	1,707	26
29	Capacity Responsibility	100.00%	53.20%	46.10%	0.70%
30	Four CP - Average MW	3,474	1,847	1,604	22
31	Capacity Responsibility	100.00%	53.18%	46.18%	0.64%
32	Twelve CP - Average MW	2,739	1,471	1,250	19
33	Capacity Responsibility	100.00%	53.68%	45.64%	0.68%
34	Annual Deliveries - MWH	16,120,868	9,189,983	6,829,497	101,389
35	Energy Responsibility	100.00%	57.01%	42.36%	0.63%
36	Unused Energy - MWH	25,664,638	13,242,150	12,240,839	181,649
37	Unused Energy Allocator	100.00%	51.60%	47.70%	0.71%

5/19/2010

Schedule LWL2010-6
Sheet 1

Kansas City Power Light Company
Alternative Allocation Bases
1CP vs 4CP vs 12CP
2008 Hourly Load

	[A]	[B]	[C]	[D]	[E]	[F]	[G]
Line No.	Description	Rank	Total KCP&L MW	Ratio to Annual	Hours - Load at or Above Summer Hours	Winter Hours	Other Hours
1	Monthly Coincident Peak Demands						
2	*08/04/08 15:00*	1	3,495	100.00%	1	-	-
3	07/21/08 16:00	2	3,428	98.08%	5	-	-
4	06/25/08 16:00	3	3,194	91.39%	40	-	-
5	09/02/08 14:00	4	2,924	83.66%	164	-	-
6	12/15/08 17:00	5	2,670	76.39%	374	1	-
7	05/30/08 17:00	6	2,626	75.14%	409	3	1
8	01/24/08 07:00	7	2,523	72.19%	534	19	5
9	02/11/08 18:00	8	2,472	70.73%	592	35	5
10	03/07/08 19:00	9	2,209	63.20%	1,020	324	33
11	11/20/08 18:00	10	2,149	61.49%	1,131	470	40
12	10/28/08 07:00	11	1,980	56.65%	1,464	992	103
13	04/12/08 11:00	12	1,956	55.97%	1,508	1,064	122
14	Accredited Capacity		2,798	80.06%	258	-	-
15	Base Load Resources						
16	Total Hours in Period		8,784		2,928	2,928	2,928
17	Months in Period				August	December	May
18					July	January	November
19					June	February	October
20					September	March	April

Kansas City Power Light Company
Alternative Allocation Bases
1CP vs 4CP vs 12CP
2008 Monthly Load

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Description	Rank	Total KCP&L MW	Missouri MW	Kansas MW	FERC MW
1	Monthly Coincident Peak Demands					
2	08/04/08 15:00	1	3,495	1,869	1,603	23
3	07/21/08 16:00	2	3,428	1,830	1,576	22
4	06/25/08 16:00	3	3,194	1,726	1,450	18
5	09/02/08 14:00	4	2,924	1,559	1,347	18
6	12/15/08 17:00	5	2,670	1,430	1,220	20
7	05/30/08 17:00	6	2,626	1,421	1,192	14
8	01/24/08 07:00	7	2,523	1,365	1,139	19
9	02/11/08 18:00	8	2,472	1,351	1,103	18
10	03/07/08 19:00	9	2,209	1,210	982	17
11	11/20/08 18:00	10	2,149	1,200	934	15
12	10/28/08 07:00	11	1,980	1,114	853	13
13	04/12/08 11:00	12	1,956	1,163	780	13
14	Average					
15	1CP		3,495	1,869	1,603	23
16	Portion of Total		100.00%	53.47%	45.88%	0.65%
17	4CP		3,260	1,746	1,494	20
18	Portion of Total		100.00%	53.55%	45.83%	0.62%
19	4 Winter Months		2,469	1,339	1,111	19
20	Portion of Total		100.00%	54.24%	45.01%	0.75%
21	4 Spring and Fall Months		2,178	1,224	940	14
22	Portion of Total		100.00%	56.22%	43.15%	0.62%
23	12CP		2,636	1,436	1,182	17
24	Portion of Total		100.00%	54.50%	44.83%	0.66%
25						
26						
27	Average Monthly Deliveries					
28	Aug 08	2	2,153	1,218	922	13
29	Jul 08	1	2,256	1,271	972	13
30	Jun 08	3	2,040	1,156	872	12
31	Sep 08	7	1,738	1,006	723	10
32	Dec 08	4	1,953	1,099	840	13
33	May 08	10	1,618	938	671	9
34	Jan 08	5	1,929	1,094	821	14
35	Feb 08	6	1,909	1,084	811	13
36	Mar 08	9	1,664	957	696	11
37	Nov 08	8	1,670	966	694	10
38	Oct 08	11	1,584	925	650	9
39	Apr 08	12	1,575	919	646	10
40	Annual		1,841	1,053	777	11
41	Portion of Total		100.00%	57.19%	42.19%	0.62%
42	Load Factor					
43	Aug 08		61.60%	65.20%	57.49%	55.56%
44	Jul 08		65.81%	69.45%	61.66%	60.90%
45	Jun 08		63.88%	66.99%	60.18%	62.63%
46	Sep 08		59.45%	64.54%	53.64%	53.85%
47	Dec 08		73.14%	76.85%	68.87%	67.71%
48	May 08		61.63%	66.02%	56.35%	65.22%
49	Jan 08		76.46%	80.18%	72.11%	70.57%
50	Feb 08		77.22%	80.28%	73.56%	72.53%
51	Mar 08		75.32%	79.07%	70.87%	65.68%
52	Nov 08		77.70%	80.48%	74.23%	70.62%
53	Oct 08		79.98%	83.01%	76.16%	69.82%
54	Apr 08		80.50%	78.99%	82.87%	73.79%
55	Annual		52.68%	56.35%	48.45%	49.87%

Kansas City Power Light Company
Alternative Allocation Bases
1CP vs 4CP vs 12CP
2006 - 08 Monthly Load

Line No.	[A] Description	[B] Rank	[C] Average MW	[D] 2006 MW	[E] 2007 MW	[F] 2008 MW
1	Monthly Coincident Peak Demands - MW					
2	July	1	3,575	3,609	3,689	3,428
3	August	2	3,470	3,480	3,436	3,495
4	June	3	3,298	3,267	3,431	3,195
5	September	4	3,046	2,970	3,243	2,924
6	December	6	2,579	2,623	2,443	2,670
7	January	7	2,553	2,550	2,588	2,522
8	February	8	2,445	2,438	2,425	2,473
9	May	5	2,650	2,564	2,761	2,625
10	October	9	2,308	2,392	2,552	1,981
11	November	10	2,298	2,505	2,239	2,150
12	March	11	2,198	2,187	2,197	2,209
13	April	12	2,123	2,110	2,301	1,957
14	Ratio to Annual Maximum Demand					
15	July		100.00%	100.00%	100.00%	98.08%
16	August		97.05%	96.42%	93.13%	100.00%
17	June		92.23%	90.51%	93.00%	91.42%
18	September		85.18%	82.31%	87.89%	83.66%
19	December		72.13%	72.69%	66.22%	76.39%
20	January		71.41%	70.66%	70.15%	72.16%
21	February		68.39%	67.54%	65.72%	70.76%
22	May		74.11%	71.04%	74.83%	75.11%
23	October		64.56%	66.27%	69.16%	56.68%
24	November		64.27%	69.42%	60.68%	61.52%
25	March		61.47%	60.60%	59.55%	63.20%
26	April		59.36%	58.46%	62.36%	55.99%
27	Monthly Average Demands - MW					
28	July	1	2,286	2,267	2,336	2,254
29	August	2	2,206	2,195	2,274	2,150
30	June	3	2,035	2,017	2,051	2,037
31	September	7	1,786	1,788	1,834	1,737
32	December	5	1,884	1,832	1,870	1,951
33	January	4	1,906	1,871	1,920	1,926
34	February	6	1,837	1,777	1,829	1,906
35	May	10	1,636	1,619	1,672	1,616
36	October	11	1,588	1,568	1,614	1,583
37	November	8	1,660	1,653	1,658	1,668
38	March	9	1,641	1,634	1,625	1,663
39	April	12	1,551	1,518	1,562	1,573
40	Monthly Load Factor					
41	July		63.92%	62.81%	63.32%	65.75%
42	August		63.58%	63.08%	66.19%	61.52%
43	June		61.71%	61.73%	59.77%	63.76%
44	September		58.65%	60.19%	56.58%	59.39%
45	December		73.07%	69.83%	76.55%	73.07%
46	January		74.64%	73.37%	74.20%	76.38%
47	February		75.14%	72.90%	75.43%	77.08%
48	May		61.73%	63.17%	60.55%	61.58%
49	October		68.81%	65.55%	63.26%	79.90%
50	November		72.23%	65.99%	74.08%	77.60%
51	March		74.65%	74.72%	73.97%	75.26%
52	April		73.07%	71.93%	67.87%	80.39%

5/19/2010

Kansas City Power Light Company
Impact of Properly Classifying and Allocating
Off-System Sales Margin
2008 Adjusted

Schedule LWL2010-7
Sheet 1

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Revenue Requirements	Reference	Total KCP&L	Fixed Cost	Variable Cost	
			$	$	$	
1	Revenue Requirements by Type of Generation					
2	Nuclear	LWL-4	227,931,745	194,427,647	33,504,098	
3	Wind	LWL-4	13,933,911	28,839,383	(14,905,471)	
4	Steam	LWL-4	726,179,153	484,170,621	242,008,532	
5	Purchase Power	LWL-4	9,545,494	1,506,145	8,039,349	
6	Subtotal	LWL-4	977,590,304	708,943,796	268,646,508	
7	Other Generation (Peaking)	LWL-4	55,237,599	42,506,024	12,731,575	
8	Gross Revenue Requirements	LWL-4	1,032,827,903	751,449,820	281,378,083	
9	Off-System Sales	LWL-4	(205,343,553)	(104,451,915)	(100,891,638)	
10	Net Revenue Requirements	LWL-4	827,484,350	646,997,905	180,486,445	

Line No.	Allocation to Jurisdiction	Reference	Total	Capacity	Energy	Off-System Sales
			$	$	$	$
11	Energy Allocation of Off-System Sales					
12	Gross Revenue Requirements	LN8	1,032,827,903	751,449,820	281,378,083	
13	Off-System Sales	LN9	(205,343,553)		(100,891,638)	(104,451,915)
14	Net Revenue Requirements	SUM	827,484,350	751,449,820	180,486,445	(104,451,915)
15	Missouri Portion					
16	Gross Revenue Requirements	LN12 * LN34,36&36	560,035,421	399,630,926	160,404,495	-
17	Off-System Sales	LN13 * LN34,36&36	(117,059,682)	-	(57,515,042)	(59,544,640)
18	Net Revenue Requirements	SUM	442,975,739	399,630,926	102,889,453	(59,544,640)
19	Missouri Portion of Total	LN18 / LN14	53.53%	53.18%	57.01%	57.01%
20	Allocation Recognizing Nature of Off-System Sales					
21	Gross Revenue Requirements	LN8	1,032,827,903	751,449,820	281,378,083	
22	Off-System Sales	LN9	(205,343,553)	(104,451,915)	(100,891,638)	
23	Net Revenue Requirements	SUM	827,484,350	646,997,905	180,486,445	
24	Missouri Portion					
25	Gross Revenue Requirements	LN21 * LN34&36	560,035,421	399,630,926	160,404,495	
26	Off-System Sales	LN22 * LN34&36	(113,063,948)	(55,548,906)	(57,515,042)	
27	Net Revenue Requirements	SUM	446,971,473	344,082,020	102,889,453	
28	Missouri Portion of Total	LN27 / LN23	54.02%	53.18%	57.01%	

Line No.	Allocation Factors	Reference	Total	Missouri	Other
29	Coincident Peak Demand - MW				
30	12 CP (Average)		2,739.28	1,470.56	1,268.73
31	Capacity Responsibility	LN30	100.00%	53.68%	46.32%
32	Coincident Peak Demand - MW				
33	4 CP (Average)		3,473.67	1,847.34	1,626.33
34	Capacity Responsibility	LN33	100.00%	53.18%	46.82%
35	Annual Deliveries - MWH		16,120,868	9,189,983	6,930,886
36	Energy Responsibility	LN35	100.00%	57.01%	42.99%
37	Unused Energy - MWH		25,664,638	13,242,150	12,422,488
38	Unused Energy Responsibility	LN37	100.00%	51.60%	48.40%

Kansas City Power Light Company
Impact of Properly Classifying and Allocating Off-System Margin and Environmental Costs
2008 Adjusted

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Description	Reference	Total KCP&L	Fixed Cost	Variable Cost	
			$	$	$	
1	Revenue Requirements by Type of Generation					
2	Nuclear	LWL-4	227,931,745	194,427,647	33,504,098	
3	Wind	LWL-4	13,933,911	28,839,383	(14,905,471)	
4	Steam - Fixed Environmental Cost		118,307,423	118,307,423		
5	Steam - Other	LWL-4	607,871,730	365,863,198	242,008,532	
6	Purchase Power	LWL-4	9,545,494	1,506,145	8,039,349	
7	Subtotal	LWL-4	977,590,304	708,943,796	268,646,508	
8	Other Generation (Peaking)	LWL-4	55,237,599	42,506,024	12,731,575	
9	Gross Revenue Requirements	LWL-4	1,032,827,903	751,449,820	281,378,083	
10	Off-System Sales (Includes Miscellaneous R	LWL-4	(205,343,553)	(104,451,915)	(100,891,638)	
11	Net Revenue Requirements	LWL-4	827,484,350	646,997,905	180,486,445	
			Total	Capacity	Energy	Off-System Sales
			$	$	$	
12	Energy Allocation of Off-System Sales					
13	Gross Revenue Requirements					
14	Excluding Environmental Costs	Balance	914,520,480	633,142,396	281,378,083	
15	Environmental Costs	LN5	118,307,423	118,307,423	-	
16	Off-System Sales	LN10	(205,343,553)		(100,891,638)	(104,451,915)
17	Net Revenue Requirements	LN11	827,484,350	751,449,820	180,486,445	(104,451,915)
18	Missouri Portion					
19	Gross Revenue Requirements					
20	Excluding Environmental Costs	LN14 * LN43,45&45	497,117,973	336,713,478	160,404,495	-
21	Environmental Costs	LN15 * LN43,45&45	62,917,448	62,917,448	-	-
22	Off-System Sales	LN16 * LN43,45&45	(117,059,682)	-	(57,515,042)	(59,544,640)
23	Net Revenue Requirements	SUM	442,975,739	399,630,926	102,889,453	(59,544,640)
24	Missouri Portion of Total	LN23 / LN17	53.53%	53.18%	57.01%	57.01%
25	Allocation Recognizing Nature of Off-System Sales and Environmental Costs					
26	Gross Revenue Requirements					
27	Excluding Environmental Costs	Balance	914,520,480	633,142,396	281,378,083	
28	Environmental Costs	LN5	118,307,423		118,307,423	
29	Off-System Sales	LN10	(205,343,553)	(78,929,018)	(126,414,535)	
30	Net Revenue Requirements	LN11	827,484,350	554,213,379	273,270,971	
31	Missouri Portion					
32	Gross Revenue Requirements					
33	Excluding Environmental Costs	LN27 * LN43&45	497,117,973	336,713,478	160,404,495	
34	Environmental Costs	LN28 * LN43&45	67,443,215	-	67,443,215	
35	Off-System Sales	LN29 * LN43&45	(114,040,308)	(41,975,493)	(72,064,816)	
36	Net Revenue Requirements	SUM	450,520,880	294,737,985	155,782,895	
37	Missouri Portion of Total	LN36 / LN30	54.44%	53.18%	57.01%	
	Allocation Factors		Total	Missouri	Other	
			MW	MW	MW	
38	Coincident Peak Demand - MW					
39	12 CP (Average)		2,739	1,471	1,269	
40	Capacity Responsibility	LN39	100.00%	53.68%	46.32%	
41	Coincident Peak Demand - MW					
42	4CP (Average)		3,474	1,847	1,626	
43	Capacity Responsibility	LN42	100.00%	53.18%	46.82%	
44	Annual Deliveries - MWH		16,120,868	9,189,983	6,930,886	
45	Energy Responsibility	LN44	100.00%	57.01%	42.99%	
46	Unused Energy - MWH		25,664,638	13,242,150	12,422,488	
47	Unused Energy Responsibility	LN46	100.00%	51.60%	48.40%	

5/19/2010

Kansas City Power Light Company
Impact of Properly Classifying and Allocating
Off-System Sales, Environmental Costs, and Boiler Maintenance
2008 Adjusted

Schedule LWL2010-9
Sheet 1

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Description	Reference	Total KCP&L	Fixed Cost	Variable Cost	
			$	$	$	
1	Revenue Requirements by Type of Generation					
2	Nuclear	LWL-4	227,931,745	194,427,647	33,504,098	
3	Wind	LWL-4	13,933,911	28,839,383	(14,905,471)	
4	Steam - Non-Labor Boiler Maintenance		22,475,258	22,475,258		
5	Steam - Fixed Environmental Cost	LWL-9	118,307,423	118,307,423		
6	Steam - Other	LWL-4	585,396,472	343,387,940	242,008,532	
7	Purchase Power	LWL-4	9,545,494	1,506,145	8,039,349	
8	Subtotal	LWL-4	977,590,304	708,943,796	268,646,508	
9	Other Generation (Peaking)	LWL-4	55,237,599	42,506,024	12,731,575	
10	Gross Revenue Requirements	LWL-4	1,032,827,903	751,449,820	281,378,083	
11	Off-System Sales (Includes Miscellaneous Revenues)	LWL-4	(205,343,553)	(104,451,915)	(100,891,638)	
12	Net Revenue Requirements	LWL-4	827,484,350	646,997,905	180,486,445	

Line No.	Description	Reference	Total	Capacity	Energy	Off-System Sales
			$	$	$	
13	Energy Allocation of Off-System Sales					
14	Gross Revenue Requirements					
15	Excluding Environmental & Boiler	Balance	892,045,222	610,667,138	281,378,083	
16	Boiler Maintenance (Non-Labor Portion)	LN4	22,475,258	22,475,258	-	
17	Environmental Costs	LN5	118,307,423	118,307,423	-	
18	Off-System Sales	LN11	(205,343,553)		(100,891,638)	(104,451,915)
19	Net Revenue Requirements	LN12	827,484,350	751,449,820	180,486,445	(104,451,915)
20	Missouri Portion					
21	Gross Revenue Requirements					
22	Excluding Environmental & Boiler	LN15 * LN47,49&49	485,165,334	324,760,839	160,404,495	-
23	Boiler Maintenance (Non-Labor Portion)	LN16 * LN47,49&49	11,952,639	11,952,639	-	-
24	Environmental Costs	LN17 * LN47,49&49	62,917,448	62,917,448	-	-
25	Off-System Sales	LN18 * LN47,49&49	(117,059,682)	-	(57,515,042)	(59,544,640)
26	Net Revenue Requirements	SUM	442,975,739	399,630,926	102,889,453	(59,544,640)
27	Missouri Portion of Total	LN24 / LN18	53.53%	53.18%	57.01%	57.01%
28	Allocation Recognizing Nature of Off-System Sales, Environmental Costs, and Boiler Maintenance					
29	Gross Revenue Requirements					
30	Excluding Environmental & Boiler	Balance	892,045,222	610,667,138	281,378,083	
31	Boiler Maintenance	LN4	22,475,258	-	22,475,258	
32	Environmental Costs	LN5	118,307,423		118,307,423	
33	Off-System Sales	LN11	(205,343,553)	(74,080,347)	(131,263,205)	
34	Net Revenue Requirements	LN12	827,484,350	536,586,791	290,897,559	
35	Missouri Portion					
36	Gross Revenue Requirements					
37	Excluding Environmental & Boiler	LN30 * LN47&49	485,165,334	324,760,839	160,404,495	
38	Boiler Maintenance	LN31 * LN47&49	12,812,414	-	12,812,414	
39	Environmental Costs	LN32 * LN47&49	67,443,215	-	67,443,215	
40	Off-System Sales	LN33 * LN47&49	(114,225,791)	(39,396,906)	(74,828,885)	
41	Net Revenue Requirements	SUM	451,195,172	285,363,933	165,831,239	
42	Missouri Portion of Total	LN39 / LN33	54.53%	53.18%	57.01%	

Line No.	Allocation Factors	Reference	Total	Missouri	Other
			MW	MW	MW
43	Coincident Peak Demand - MW				
44	12 CP (Average)		2,739	1,471	1,269
45	Capacity Responsibility	LN44	100.00%	53.68%	46.32%
43	Coincident Peak Demand - MW				
46	4 CP (Average)		3,474	1,847	1,626
47	Capacity Responsibility	LN46	100.00%	53.18%	46.82%
48	Annual Deliveries - MWH		16,120,868	9,189,983	6,930,886
49	Energy Responsibility	LN48	100.00%	57.01%	42.99%
50	Unused Energy - MWH		25,664,638	13,242,150	12,422,488
51	Unused Energy Responsibility	LN50	100.00%	51.60%	48.40%

5/19/2010

Kansas City Power Light Company
Impact of Single CP Allocation of Capacity Costs
2008 Adjusted

Schedule LWL2010-10
Sheet 1

Line No.	[A] Description	[B] Reference	[C] Total	[D] Capacity	[E] Energy	[F] Off-System Sales
			$	$	$	$
1	Energy Allocation of Off-System Sales and Capacity Allocation of Environmental Cost and Boiler Maintenance					
2	Gross Revenue Requirements					
3	Excluding Environmental & Boiler	LWL-10	892,045,222	610,667,138	281,378,083	-
4	Boiler Maintenance	LWL-10	22,475,258	22,475,258	-	-
5	Environmental Costs	LWL-10	118,307,423	118,307,423	-	-
6	Off-System Sales	LWL-10	(205,343,553)	-	(100,891,638)	(104,451,915)
7	Net Revenue Requirements	LWL-10	827,484,350	751,449,820	180,486,445	(104,451,915)
8	Missouri Portion					
9	Gross Revenue Requirements					
10	Excluding Environmental & Boiler	LN3 * LN33,35&35	485,306,927	324,902,432	160,404,495	-
11	Boiler Maintenance	LN4 * LN33,35&35	11,957,850	11,957,850	-	-
12	Environmental Costs	LN5 * LN33,35&35	62,944,880	62,944,880	-	-
13	Off-System Sales	LN6 * LN33,35&35	(117,059,682)	-	(57,515,042)	(59,544,640)
14	Net Revenue Requirements	SUM	443,149,975	399,805,162	102,889,453	(59,544,640)
15	Missouri Portion of Total	LN12 / LN6	53.55%	53.20%	57.01%	57.01%
16	Allocation Recognizing Nature of Off-System Sales, Environmental Cost, and Boiler Maintenance					
17	Gross Revenue Requirements					
18	Excluding Environmental & Boiler	LWL-10	892,045,222	610,667,138	281,378,083	
19	Boiler Maintenance	LWL-10	22,475,258	-	22,475,258	
20	Environmental Costs	LWL-10	118,307,423	-	118,307,423	
21	Off-System Sales	LWL-10	(205,343,553)	(74,080,347)	(131,263,205)	
22	Net Revenue Requirements	LWL-10	827,484,350	536,586,791	290,897,559	
23	Missouri Portion					
24	Gross Revenue Requirements					
25	Excluding Environmental & Boiler	LN18 * LN33&35	485,306,927	324,902,432	160,404,495	
26	Boiler Maintenance	LN19 * LN33&35	12,812,414	-	12,812,414	
27	Environmental Costs	LN20 * LN33&35	67,443,215	-	67,443,215	
28	Off-System Sales	LN21 * LN33&35	(114,242,968)	(39,414,083)	(74,828,885)	
29	Net Revenue Requirements	SUM	451,319,588	285,488,349	165,831,239	
30	Missouri Portion of Total	LN27 / LN21	54.54%	53.20%	57.01%	

Line No.	Description	Reference	Total	Missouri	Other
			MW	MW	MW
31	Coincident Peak Demand (1CP) - MW				
32	1 CP (Average)		3,703	1,970	1,733
33	Capacity Responsibility	LN32	100.00%	53.20%	46.80%
34	Annual Deliveries - MWH		16,120,868	9,189,983	6,930,886
35	Energy Responsibility	LN34	100.00%	57.01%	42.99%
36	Unused Energy - MWH		25,664,638	13,242,150	12,422,488
37	Unused Energy Responsibility	LN36	100.00%	51.60%	48.40%

5/19/2010

Schedule LWL2010-10
Sheet 2

Kansas City Power Light Company
Impact of Twelve CP Allocation of Capacity Costs
2008 Adjusted

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Description	Reference	Total	Capacity	Energy	Off-System Sales
			$	$	$	$
1	Energy Allocation of Off-System Sales and Capacity Allocation of Environmental Cost and Boiler Maintenance					
2	Gross Revenue Requirements					
3	Excluding Environmental & Boiler	LWL-10	892,045,222	610,667,138	281,378,083	-
4	Boiler Maintenance	LWL-10	22,475,258	22,475,258	-	-
5	Environmental Costs	LWL-10	118,307,423	118,307,423	-	-
6	Off-System Sales	LWL-10	(205,343,553)	-	(100,891,638)	(104,451,915)
7	Net Revenue Requirements	LWL-10	827,484,350	751,449,820	180,486,445	(104,451,915)
8	Missouri Portion					
9	Gross Revenue Requirements					
10	Excluding Environmental & Boiler	LN3 * LN33,35&35	488,235,060	327,830,565	160,404,495	-
11	Boiler Maintenance	LN4 * LN33,35&35	12,065,618	12,065,618	-	-
12	Environmental Costs	LN5 * LN33,35&35	63,512,161	63,512,161	-	-
13	Off-System Sales	LN6 * LN33,35&35	(117,059,682)	-	(57,515,042)	(59,544,640)
14	Net Revenue Requirements	SUM	446,753,157	403,408,343	102,889,453	(59,544,640)
15	Missouri Portion of Total	LN14 / LN7	53.99%	53.68%	57.01%	57.01%
16	Allocation Recognizing Nature of Off-System Sales, Environmental Cost, and Boiler Maintenance					
17	Gross Revenue Requirements					
18	Excluding Environmental & Boiler	LWL-10	892,045,222	610,667,138	281,378,083	
19	Boiler Maintenance	LWL-10	22,475,258	-	22,475,258	
20	Environmental Costs	LWL-10	118,307,423	-	118,307,423	
21	Off-System Sales	LWL-10	(205,343,553)	(74,080,347)	(131,263,205)	
22	Net Revenue Requirements	LWL-10	827,484,350	536,586,791	290,897,559	
23	Missouri Portion					
24	Gross Revenue Requirements					
25	Excluding Environmental & Boiler	LN18 * LN33&35	488,235,060	327,830,565	160,404,495	
26	Boiler Maintenance	LN19 * LN33&35	12,812,414	-	12,812,414	
27	Environmental Costs	LN20 * LN33&35	67,443,215	-	67,443,215	
28	Off-System Sales	LN21 * LN33&35	(114,598,181)	(39,769,296)	(74,828,885)	
29	Net Revenue Requirements	SUM	453,892,508	288,061,269	165,831,239	
30	Missouri Portion of Total	LN29 / LN22	54.85%	53.68%	57.01%	

			Total	Missouri	Other
			MW	MW	MW
31	Monthly Coincident Peak Demand - MW	-			
32	12 CP (Average)		2,739	1,471	1,269
33	Capacity Responsibility	LN32	100.00%	53.68%	46.32%
34	Annual Deliveries - MWH		16,120,868	9,189,983	6,930,886
35	Energy Responsibility	LN34	100.00%	57.01%	42.99%
36	Unused Energy - MWH		25,664,638	13,242,150	12,422,488
37	Unused Energy Responsibility	LN36	100.00%	51.60%	48.40%

5/19/2010

Kansas City Power Light Company
Summary of Allocation Results

Schedule LWL2010-11
Sheet 1

	[A]	[B]	[C]	[D]	[E]
				Applicable to Missouri	
Line No.	Description	Reference Schedule	Total	Amount	Of Total
			$	$	%
1	Total KCPL Power Supply Revenue Requirement	LWL 8	827,484,350		
2	4 CP Allocation of Demand Costs				
3	No Recognition of Nature of Off-System Sales, etc.	LWL 7		442,975,739	53.53%
4	Recognizing Nature of:				
5	Off-System Sales	LWL 7		446,971,473	54.02%
6	Off-System Sales and Environmental Costs	LWL 8		450,520,880	54.44%
7	Off-System, Environmental, and Boiler Maintenance	LWL 9		451,195,172	54.53%
8	No Recognition of Nature of Off-System Sales, etc.				
9	1 CP	LWL 10, Sheet 1		443,149,975	53.55%
10	12 CP	LWL 10, Sheet 2		446,753,157	53.99%
11	Allocations Recognizing Nature of Off-System, Environmental, & Boiler Maintenance				
12	1 CP	LWL 11, Sheet 1		451,319,588	54.54%
13	12 CP	LWL 11, Sheet 2		453,892,508	54.85%
14	Basic Allocation Factors				
15	4CP		3,474	1,847	53.18%
16	Annual Sales		16,120,868	9,189,983	57.01%

C:\Documents and Settings\loo02421\My Documents\Project Files\KCPL\KCPL - MO - ER-2010-\KCPL - MO - LWL Exhibits and Workpapers.xls LWL-11, Sheet 1

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Kansas City Power Light Company
Impact of Recommended Method
2008 Adjusted

Schedule LWL2010-12
Sheet 1

	[A]	[B]	[C]	[D]	[E]	[F]
Line No.	Functional Revenue Requirements - Schedule LWL-4	Total Production and Transmission	Total Transmission	Power Supply Total Production	Power Supply Fixed Cost	Power Supply Variable Cost
		$	$	$	$	$
1	Transmission	72,521,425	72,521,425			
2	Power Supply by Type of Generation					
3	Nuclear	227,931,745		227,931,745	194,427,647	33,504,098
4	Steam	726,179,153		726,179,153	484,170,621	242,008,532
5	Purchase Power	9,545,494		9,545,494	1,506,145	8,039,349
6	Wind	13,933,911		13,933,911	28,839,383	(14,905,471)
7	Subtotal	1,050,111,729	72,521,425	977,590,304	708,943,796	268,646,508
8	Other Generation (Peaking)	55,237,599		55,237,599	42,506,024	12,731,575
9	Gross Revenue Requirements	1,105,349,328	72,521,425	1,032,827,903	751,449,820	281,378,083
10	Off-System Sales (Includes Miscellaneous Revenues)	(216,156,711)	(10,813,158)	(205,343,553)	(104,451,915)	(100,891,638)
11	Net Revenue Requirements	889,192,617	61,708,267	827,484,350	646,997,905	180,486,445
12	Classification Adjustments					
13	Environmental				-	-
14	Boiler Maintenance				-	-
15	Off-System Sales			-	-	-
16	Reclassified Total	889,192,617	61,708,267	827,484,350	646,997,905	180,486,445

Line No.	Allocation to Jurisdiction	Reference	Total Production and Transmission	Transmission Capacity	Power Supply Total Production	Power Supply Capacity	Power Supply Energy
					$	$	$
17	Allocation to Missouri						
18	Allocation Basis			LN 35		LN 35	LN 39
19	Allocation Factor			53.18%		53.18%	57.01%
20	Missouri Portion	LN16 * LN 19	479,788,744	32,817,270	446,971,473	344,082,020	102,889,453
21	Allocation to Kansas						
22	Allocation Basis			LN 37		LN 37	LN 39
23	Allocation Factor			45.64%		45.64%	42.36%
24	Kansas Portion	LN11 * LN 23	399,905,693	28,162,812	371,742,881	295,281,023	76,461,858
25	Allocation to FERC						
26	Allocation Basis			LN 37		LN 37	LN 39
27	Allocation Factor			0.68%		0.68%	0.63%
28	FERC Portion	LN11 * LN 27	5,935,629	417,987	5,517,641	4,382,508	1,135,134
29	Total Recovered		885,630,065	61,398,069	824,231,996		
30	Total Unrecovered		3,562,552	310,198	3,252,354		
31	Percent Unrecovered		0.40%	0.50%	0.39%		

Line No.	Allocation Bases	Total	Missouri	Kansas	FERC
32	Coincident Peak Demand				
33	Single CP - MW	3,703	1,970	1,707	26
34	Capacity Responsibility	100.00%	53.20%	46.10%	0.70%
35	Four CP - Average MW	3,474	1,847	1,604	22
36	Capacity Responsibility	100.00%	53.18%	46.18%	0.64%
37	Twelve CP - Average MW	2,739	1,471	1,250	19
38	Capacity Responsibility	100.00%	53.68%	45.64%	0.68%
39	Annual Deliveries - MWH	16,120,868	9,189,983	6,829,497	101,389
40	Energy Responsibility	100.00%	57.01%	42.36%	0.63%
41	Unused Energy - MWH	25,664,638	13,242,150	12,240,839	181,649
42	Unused Energy Allocator	100.00%	51.60%	47.70%	0.71%