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Witness:	Larry W. Loos
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Sponsoring Party:	Kansas City Power & Light Company
Case No:	ER-2009-___
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2009-__

DIRECT TESTIMONY

OF

LARRY W. LOOS

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

JEFFERSON CITY, MISSOURI

Kansas City, Missouri
September 2008

TABLE OF CONTENTS

DIRECT TESTIMONY

OF

LARRY W. LOOS

Case No. ER-2009-____

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's Enterprise Management Solutions Division.

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 Iowa, Colorado, Indiana, 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 the Missouri Public Service Commission (the “Commission”) on several 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, Pennsylvania, North Carolina, South Carolina, Texas, Utah, and Vermont. I have also presented expert witness testimony before District Courts in Iowa, Colorado, Kansas, 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.

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. IN KCP&L'S PRIOR RATE CASE, HOW WERE PRODUCTION AND TRANSMISSION FIXED COSTS ALLOCATED?

A. In KCP&L's most recent rate case (Case No. ER-2007-0291), the Company and the Commission Staff continued to allocate fixed production and transmission cost based on the average of the four-summer month's coincident peak demands ("4CP"). This is different from the twelve coincident peak ("12CP") allocation basis that I understand underlies the settlement approved by the Kansas Corporation Commission in KCP&L's most recent rate case filed in Kansas (Docket No.07-KCPE-905-RTS). In its 2006 Missouri case (Docket No. ER-2006-0314), KCP&L requested, but the Commission did not approve, 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 CASE, HOW WAS MARGIN ASSOCIATED WITH OFF-SYSTEM SALES ALLOCATED?

A. In KCP&L's prior Missouri rate case (Case No ER-2006-0314), the Company proposed to allocate margin associated with off-system sales on "unused energy." I understand this allocation basis underlies the settlement approved by the Kansas Commission in KCP&L's most recent rate case filed in Kansas. Again, in its 2006 Missouri case, the Commission did not adopt KCP&L's proposal. Instead, the Commission adopted an allocation based on energy deliveries. In KCP&L's most recent Missouri rate case, Docket No ER-2007-0291, the Company allocated off-system sales margin based on energy deliveries.

Q. IN KCP&L'S PRIOR RATE CASES, HOW WERE COSTS ASSOCIATED WITH ENVIRONMENTAL CONTROL ALLOCATED?

A. Based on my reading of the Commission's order 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 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, the cost of purchasing allowances, and the revenues realized from the sale of allowances as energy related. As I previously discussed, the Commission ordered a 4CP allocator for allocating capacity related costs and energy deliveries (adjusted for losses) for allocating energy related costs.

Q. DOES USE OF DIFFERENT ALLOCATION BASES BY THE MISSOURI AND KANSAS COMMISSIONS TO ALLOCATE COSTS BETWEEN 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. For KCP&L, the different allocations used by the Missouri and Kansas Commissions results in KCP&L not recovering its entire revenue requirement.

The Missouri jurisdiction operates at a somewhat 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. Based on the Company's revenue requirement in this case, the use of a 4CP allocator will result in an allocation to the Missouri jurisdiction of about $1.7 million less than use of a 12CP allocator[1]. Conversely, the use of a 12CP allocator will result in an allocation to the Kansas and FERC jurisdictions of about $1.7 million less than use of a 4CP allocator. Thus, the use of different allocation bases results in the Company failing to recover approximately $1.7 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.

Likewise, allocating the margin associated with off-system sales on an energy basis, as the Missouri Commission has previously required, will result in a lower overall level of cost allocated to the higher load factor jurisdiction than the use of an "unused energy" allocator[2]. These different allocation bases result in KCP&L returning approximately 104 percent of its off-system sales margin to customers in Kansas and Missouri. This amounts to an approximate $ 4 million under recovery by the Company in the current rate case.

[1] Assuming the credit for off-system sales is allocated based on energy.

[2] The allocation of off-system sales based on energy will result in a higher level of off-system sales allocated to the higher load factor jurisdiction (Missouri). Since these off-system sales are credited to cost of service the overall level of cost allocated to the jurisdiction is reduced.

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, customers' maximum loads.

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 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 directly assigned. 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 other 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 other 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. Based on these considerations and criteria, I will then evaluate the merits of a number of allocation bases for allocating and/or classifying:

1) Margin associated with off-system sales
2) Steam plant environmental control equipment costs
3) Steam plant boiler maintenance
4) Capacity related power supply costs
5) Transmission system costs

I conclude my prepared direct testimony with recommendations for allocating costs to jurisdictions in this case.

Q. DO YOU SPONSOR ANY SCHEDULES?

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

- Schedule LWL-1 – Generating Station Cost Characteristics – Example
- Schedule LWL-2 – Characteristics of KCP&L Generating Stations
- Schedule LWL-3 – KCP&L Smoothed 2007 Hourly Load Curve
- Schedule LWL-4 – Power Supply Revenue Requirements - Summary
- Schedule LWL-5 – Impact of Properly Classifying and Allocating Off-System Sales
- Schedule LWL-6 – Impact of Properly Classifying and Allocating Off-System Sales and Environmental Costs
- Schedule LWL-7 – Impact of Properly Classifying and Allocating Off-System Sales, Environmental Costs, and Boiler Maintenance
- Schedule LWL-8 – Impact of Single CP and 12CP Allocation of Power Supply Capacity Related Costs
- Schedule LWL-9 – Allocation Results - Capital Substitution Method
- Schedule LWL-10 – Allocation Results - Base, Intermediate, Peaking Method
- Schedule LWL-11 – Allocation Results - Economic Rents Allocation Method
- Schedule LWL-12 – Allocation Results - Hour-by-Hour Allocation Method
- Schedule LWL-13 – Summary of Allocation Results

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. Based 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.

Q. WHAT RECOMMENDATIONS DID YOU PROVIDE MR. WEISENSEE?

A. I recommend the following:

1) Classify and allocate the margin associated with off-system sales on the same basis as the fixed costs of the generating stations used to generate the energy used to make those sales;
2) Classify the fixed and operating costs associated with steam plant environmental control equipment as energy and allocate accordingly;
3) Classify the non-labor cost of steam plant boiler maintenance expense as energy and allocate accordingly;
4) 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; and
5) Classify and allocate transmission cost based on the classification and allocation of power supply fixed cost.

CONSIDERATIONS AND CRITERIA

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?

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, I believe is patently unfair. KCP&L currently finds itself in this situation.

Q. ARE THERE CERTAIN COSTS THAT THE MISSOURI COMMISSION ALLOWS KCP&L TO RECOVER THAT OTHER JURISDICTIONS DO NOT?

A. Yes, there are. There are also costs other jurisdictions allow that the Missouri Commission does 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%.

Q. DO YOU BELIEVE THAT BECAUSE KANSAS 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 Kansas Commission 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 to recover all of its costs. After all, whether it is Kansas or Missouri making the allocation it is the same total pool of cost. The allocation of that pool of cost needs to be allocated so the Company recovers 100 percent of it.

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."[3] 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 classified as capacity and are allocated on some basis solely related to the maximum system demand[4].

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[3] Consolidated Gas Supply Corp. v. FPC, 520 F.2d 1176

[4] 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 "foot-print" increases, costs 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) based generating 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 cost 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 generating</u>

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 LWL-1. In Schedule LWL-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-generating unit.

In Schedule LWL-1, I assume that construction costs for base load and peaking resources amount to $1,500 and $500 per kW installed, respectively (Line 2). I have further assumed 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 is $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 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 lower than about 25% (2,000 hours) the peaking unit represents the least cost resource. Conversely, so long as the unit operates at a capacity factor higher than about 25%, the base load resource represents the least cost option.

Q. HOW DO YOU MINIMIZE COST UNDER YOUR EXAMPLE?

A. In Schedule LWL-1, Sheet 2, I show a simplified illustrative load duration curve. A load duration curve represents the number of hours (X-axis) that load equals or exceeds a specific level (Y-axis), over a specified period (typically one-year). In my previous example, I found 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 the load exceeds 3,000 MW, 2,000 hours during the year. Therefore, I minimize cost with 3,000 MW of base load capacity and 2,000 MW of peaking capacity. Based on my assumed cost levels, total plant costs in my example would amount to $5.5 billion ($1,500/kW * 3,000,000 kW + $500/kW * 2,000,000 kW) and total annual fixed and variable cost would amount to $1.6 billion.

Q. CAN YOU DEMONSTRATE THAT THIS MIX REPRESENTS THE MINIMUM COST?

A. Yes, I can. In Schedule LWL-1, Sheet 3, I show construction cost and annual costs (fixed and variable) to serve a 5,000 MW system peak. In my example, I assume 2,500, 3,000, and 3,500 MW of base load resources and 2,500, 2,000, and 1,500 MW of peaking resources. In each of these three scenarios total capacity amounts to 5,000 MW. As I show in Sheet 3, Line 12, total annual costs amount to $1.638 billion when 3,000 MW of base load and 2,000 MW of peaking resources are used. This annual cost increases by about 1 percent to $1.651 billion if 3,500 MW of base load and 1,500 MW of peaking resources are used (Scenario 2, Lines 14 through 21). If 2,500 MW each of base load and peaking capacity are used, the annual cost in my example increases by about 4 percent to $1.697 billion (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 LWL-1?

A. With regard to the economic selection of generating resources, both system maximum demand and capacity factor are cost drivers. Coincident peak demand drives the total capacity required (in my simplified example, 5,000 MW) regardless of the cost characteristics of the generating resources. Capacity factor drives the mix of generating resources (in my example, 3,000 MW of base and 2,000 MW of peaking) which will minimize total cost by:

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

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 of off-system sales margins.

Q. HOW CAN AN ALLOCATION UNREASONABLY "ENRICH" ONE JURISDICTION?

A. This represents an element of fairness. Jurisdiction A is unjustly enriched when costs reasonably associated with serving that jurisdiction (say for example, Missouri) are assigned through the allocation process to Jurisdiction B (say for example, Kansas). This approach results in either Jurisdiction B or the Company subsidizing Jurisdiction A.

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 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 made upon which 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 LWL-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 that the capital cost of base load resources substantially exceeds the capital cost of peaking resources, and that the variable cost of peaking resources substantially exceeds the variable cost of base load resources.

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.

KCP&L POWER SUPPLY

Q. DO YOU USE ACTUAL COMPANY COST LEVELS TO EVALUATE THE IMPLICATIONS OF THE ALTERNATIVES YOU EVALUATE?

A. Yes, I do. Based on the Company's 2007 operating results including a 10.75 percent return on equity, I developed the total revenue requirement associated with the Company's power supply and transmission functions. I further separated this total revenue requirement into nuclear, steam, wind, other generation, purchased power, and off-system sales sub functions.

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 LWL-2, Sheet 1 I show data related to each of KCP&L's generating resources that I obtained from KCP&L's 2007 FERC Form 1.

Q. DO YOU HAVE ANY OBSERVATIONS BASED ON EXAMINATION OF THE INFORMATION YOU SHOW IN SCHEDULE LWL-2, SHEET 1?

A. Yes, I do. I identified several anomalies. These are:

1) For the most part, the original cost per kW (Line 20) of the Wolf Creek Nuclear Station and the Spearville Wind Farm are more than 3 times the original cost (per kW) of the other generating resources. I 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 (0.45 cents per kWh) and Spearville (zero) are less than ½ the lowest variable cost (Iatan, $0.96 cents per kWh) of the other plants.

3) Because of the explosion and rebuild of the Hawthorn 5 unit, the original cost associated with this unit is considerably in excess of what I would expect given its date of initial installation and the original cost of the other steam plants.

4) The variable cost at Montrose is somewhat higher than what I would expect in light of the variable costs reported for the other steam plants.

In Schedule LWL-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 amounts to 0.96 cents per kWh (Schedule LWL-2, Sheet 1, Line 28, Column E), whereas the system average fuel cost amounts to 1.19 cents per kWh (Line 28, Column P). Thus, Iatan's fuel cost amounts to 81 percent of the system average (0.96 / 1.19 = 81%). This 81 percent value is what I show in Schedule LWL-2, Sheet 2.

Q. BASED ON EXAMINATION OF SHEETS 1 AND 2 OF SCHEDULE LWL-2, WHAT CONCLUSIONS DO YOU REACH?

A. As I indicated above, there are some dislocations in the information set forth in Sheets 1 and 2. In order to eliminate the implications of these dislocations, for the purpose of my comparisons:

1) I eliminate Wolf Creek and Spearville from the comparison;

2) I restate the original cost of the Hawthorn 5 unit to the estimated original cost balance prior to the explosion and rebuild in 2001; and

3) As with Hawthorn 5, I restate the original cost at Montrose to the estimated original cost in 1998 in recognition of the age of the plant and the implication of interim replacements and additions when developing trended costs based on date of initial construction.

In Sheet 4, I plot the values I show in Sheet 3, in the same fashion as in Sheet 2 for Sheet 1. In addition, in Sheet 4, I added trended costs per kW to the graph.

Q. WHAT IS THE PURPOSE OF TRENDING THE COST LEVELS?

A. I trend all costs to 2007 levels in order to eliminate the implications of inflation when comparing unit costs. By doing so, I eliminate from my comparison differences in construction costs due to when plants were constructed. The trended costs I show represent the approximate cost of construction in 2007. As I show in Sheets 1 and 3, the newest steam plant is Iatan, which KCP&L completed in 1980. KCP&L completed its oldest non-steam plant (excluding the Spearville wind farm, the Wolf Creek nuclear station, and the Northeast Station) in 2000. Since 2000, the cost of combustion turbine based generating equipment has increased by about 20 percent (Line 17 of Sheets 1 and 3), less than 3 percent per year. The cost of this equipment increased by 300 percent between the mid 1970's to today (Northeast Plant, Sheet 1, Line 17, Column N), more than 15 percent per year. Any meaningful cost comparison between the costs of different technologies should consider and eliminate to the extent practical the implications of inflation on the relative values.

Q. BASED ON EXAMINATION OF SHEETS 3 AND 4 OF SCHEDULE LWL-2, DO YOU REACH ANY CONCLUSIONS?

A. Yes, I do. In Schedule LWL-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). If the implications of inflation are eliminated, the construction costs of KCP&L's steam generation amounts to about $1,750 per kW (Sheet 3, Column C, Line 21) which amounts to about 4 times the $400 per kW associated with KCP&L's combustion turbine plants.

2) KCP&L's variable cost varies even more dramatically from zero for Spearville, to $4.53 per MWH for nuclear generation to over $300 per MWH for Northeast. For all of KCP&L's combustion turbine based generation, variable costs amount to about $75.00 per MWH or about 6 times the variable costs of KCP&L's steam-fired generating plants of about $12.35 per MWH.

3) Variable costs ($/kWh) tend to decline as plant costs ($/kW) increase. Other generating plant (combustion turbine) variable costs are about 6 times that of steam plant variable costs whereas steam plant construction (fixed) costs about 4 times that of the combustion turbine based plants.

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

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

As I show on Line 13, the capacity factor of KCP&L's steam plants (68.23%) is 16 times that of the combustion turbine based plants (4.24%).

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.

Q. CAN YOU FURTHER DEMONSTRATE THIS CONCEPT?

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

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

Note that as native load decreases the level of off-system sales tend to increase.

Note also that the Missouri load shape is similar to that of the total native load. There is however, some narrowing of the difference between the Missouri load and total native load as load levels decline. This is evidence of the somewhat higher load factor for sales in Missouri relative to other jurisdictions.

Q. DO THE LOAD CURVES YOU SHOW IN SCHEDULE LWL-3 REPRESENT ACTUAL DELIVERIES BY KCP&L DURING 2007?

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 Missouri load and total load. For the hour with the second highest native load, I plot the Missouri load and total load. I do this for each of the 8,760 hours in 2007, averaging values over various ranges in order to eliminate hourly variations (noise) from the graph. The resulting load curves are an accurate representation of the hourly Missouri and total loads corresponding to the native load.

Q. WHAT DO YOU SHOW IN SCHEDULE LWL-3, SHEET 2?

A. In Sheet 2, I start with the total load curve I show in Sheet 1. To that curve, 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 as the bottom curve. Hourly generation from Wolf Creek has the lowest correlation to KCP&L's hourly native load. In 2007, Wolf Creek generated 8,759[5] hours. The average load amounted to 556 MW. The maximum load amounted to 566 MW and the minimum load was 436 MW. In 2007, the Wolf Creek

[5] The hourly load data I relied on included all 8,760 hours. However, hourly generation data for the hour beginning 11:00 PM December 31, 2007 is missing.

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

Above Wolf Creek, I show Iatan and Spearville. As a wind farm, Spearville does not follow load. I also found that output from Iatan has a very low correlation with native load. Thus, I consider Iatan and Spearville to operate as base load resources. Above Iatan and Spearville, I plot LaCygne and Hawthorn Unit 5. These two plants correlate somewhat with native load, Montrose has a higher correlation, and the other generating resources plus purchases have the highest correlation.

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

- Wolf Creek, Spearville, and Iatan operate as base load resources;
- LaCygne and Hawthorn 5 operate as base/intermediate load resources;
- Montrose operates somewhere between intermediate and peaking resources; and
- Combustion turbine based generation and purchases represent peaking resources that KCP&L relies on to meet peak customer demands in excess of capacity from base and intermediate load units.

OFF-SYSTEM SALES

Q. HOW WERE MARGINS ASSOCIATED WITH OFF-SYSTEM SALES ALLOCATED IN THE PRIOR CASE?

A. The Company proposed use of "unused sales" 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 sales" method in Docket No. 07-KCPE-905-RTS.

Q. DO YOU BELIEVE AN UNUSED SALES ALLOCATION IS REASONABLE?

A. No, I do not. However, compared to some other approaches, it produces a more reasonable result than an energy allocation.

Q. WHAT FACTOR DETERMINES WHETHER AN ALLOCATION OF THESE 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 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 revenues 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> in order for the allocation to be reasonable. Subsidization results, if this allocation does not align with the allocation of the fixed production costs these margins are intended to offset.

Q. IN YOUR OPINION, DID THE COMMISSION 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 is reasonable based on my understanding of the evidence presented for the Commission's consideration. On the other hand, 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.

Q. HAVE YOU EVALUATED THE IMPLICATIONS OF THE ALLOCATION OF THESE SALES MARGINS?

A. Yes, I have. To do so, I developed KCP&L's total revenue requirement based on 2007 operations and a 10.75 percent return on equity. I summarize this development in Schedule LWL-4. In this schedule, I show that total fixed cost (revenue requirement) associated with power supply amounts to $385.7 million and total power supply variable cost amounts to $252.2 million. Both of these values represent revenue requirements net of revenues associated with off-system sales.

In Schedule LWL-5, using the revenue requirement levels I summarize in Schedule LWL-4, I show the impact of the classification and allocation of off-system sales margin to the Missouri jurisdiction. In Lines 1 through 10, I summarize revenue requirements by type of generation, along with the credit for off-system sales[6]. As shown, the total revenue requirement prior to the credit for off-system sales amounts to $868.0 million. Of this $868.0 million, $484.3 million represents fixed costs and $383.7 million

[6] In the balance of my testimony, my reference to off-system sales and off-system sales margins, include miscellaneous revenues of $40,311, see Schedule LWL-4, Lines 22, 23, and 33.

represents variable costs. After crediting revenues from off-system sales of $230.1 million net revenue requirements amount to $638.0 million. Of the $230.1 million of revenues from off-system sales, $131.5 million represents the out-of-pocket or variable cost associated with generating the energy sold. The balance ($98.5 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 classify margin associated with off-system sales as energy related and allocate based on annual sales. This is the treatment ordered by the Commission in the prior case. As I show on Line 17, this treatment results in a total credit for off-system sales revenues of $131.6 million applicable to the Missouri jurisdiction. Following this treatment, I allocate a total of $349.9 million or 54.85% 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 based on coincident peak requirements. As I show in Line 26, this treatment results in a total credit for off-system sales revenues of $128.5 million applicable to the Missouri jurisdiction. Following this treatment, I allocate a total of $353.0 million or 55.33% of total power supply related costs to the Missouri jurisdiction.

On Lines 29 through 37, I show the development of the capacity and energy allocation factors I use. In this regard, for the purpose of Schedule LWL-5 I use a 4CP allocator to allocate capacity costs.

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 $230.0 million, $131.5 million represents the variable (energy) cost associated with generating the energy sold. As I show in Schedules LWL-4 and LWL-5, I have credited this $131.5 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, $98.5 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. To the extent I reduce variable or energy related cost by off-system sales margin, I would subsidize the sale of energy to native load customers by selling energy below cost.

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 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 (depreciation, return, and taxes) associated with:

- Flue gas desulphurization (FGD or scrubbers) equipment;
- Selective catalytic reduction (SCR) equipment;
- Other NO_x control equipment;
- 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 (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 these environmental control cost 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 4 hours or even 12 hours a year. The need for this equipment relates to the total energy generated at each of the stations. As a result, these costs are energy related and should be allocated accordingly.

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 LWL-6, 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 LWL-6 are identical to Lines 1 through 19 of Schedule LWL-5 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 32 percent of total steam fixed costs.

I show in Lines 25 through 37, of Schedule LWL-6 the classification and allocation of fixed environmental costs based on annual energy sales. In this allocation, I have also classified the margin on off-system sales as capacity, and allocated accordingly.

Q. LINES 9 AND 22 OF SCHEDULE LWL-5 SHOWS CAPACITY RELATED OFF-SYSTEM SALES OF $98.5 MILLION WHEREAS, LINE 29 OF SCHEDULE

LWL-6 SHOWS CAPACITY RELATED OFF-SYSTEM SALES OF $79.8 MILLION. WHY ARE THESE CREDITS DIFFERENT?

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 LWL-5, I classify all power supply fixed costs as capacity related and allocate these capacity costs based on coincidental peak demand (4CP). In Schedule LWL-6 however, I do not classify all power supply fixed costs as demand related. In Schedule LWL-6 (Line 28), I classify $75.0 million of fixed power supply costs (environmental) as energy related. During 2007, about 25 percent of power generated by KCP&L went to support off-system sales. I have therefore classified off-system sales margin equal to 25 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. The remaining margin associated with off-system sales ($79.8 million) I classify as capacity related.

On Lines 25 through 37, I show the allocation of power supply costs to the Missouri jurisdiction, if I classify fixed environmental cost as energy and classify 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 55.60 percent ($354.7 million) of power supply costs to the Missouri jurisdiction.

BOILER MAINTENANCE

Q. HOW ARE EXPENSES ASSOCIATED WITH BOILER MAINTENANCE USUALLY ALLOCATED?

A. These maintenance expenses are usually 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 costs that tend 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. This is because, one of the biggest factors that affect 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 and if maintenance were not required, these costs would not be incurred.

Q. WHY DO YOU CONSIDER THIS MAINTENANCE COST 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 and/or number of starts.

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, these activities (boiler maintenance) are 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 turbine generators and combustion turbines 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, hence appropriately allocated based on peak period demands. With regard to steam plants, maintenance associated with equipment other than boilers is relatively minor.

I therefore 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 LWL-7, I show the impact of the classification and allocation of 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.

Lines 1 through 27 of Schedule LWL-7 are identical to Lines 1 through 19 of Schedule LWL-5 (Lines 1 through 24 of Schedule LWL-6) 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 LWL-7 the classification of the non-labor portion of boiler maintenance expenses based on energy. In this regard, for the purpose of this schedule, I estimate that 50 percent of boiler maintenance expenses relate to KCP&L labor and 50 percent to non-labor expenses. I also recognize that a portion of boiler maintenance expense relates to environmental equipment. In this allocation, I have also classified the margin on off-system sales as capacity related and environmental costs as energy related and allocated accordingly.

As with Schedule LWL-6, 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 and classify margin associated with off-system sales on the same basis as fixed power supply costs. As I show on Line 42, this treatment results in allocating 55.64 percent of power supply costs to the Missouri jurisdiction.

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 system demand usually used to allocate capacity related costs.

The Commission adopted the 4CP method in KCP&L's 2006 rate case case (ER-2006-0314), whereas the Kansas Commission has adopted the 12CP method.

Q. HAVE YOU EVALUATED THE IMPLICATIONS OF USING THESE VARIOUS COINCIDENTAL PEAK ALLOCATION BASES?

A. Yes, I have. In Schedules LWL-5, 6, and 7, I show the impact of using the coincident peak demand for the 4 summer months to allocate capacity related costs. In Schedule 8, 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 8, 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 $349.4 million, or 54.77 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 $354.6 million (Line 29), or 55.58 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 8, 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 $351.6 million, or 55.11 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 amounts to $356.1 million (Line 29), or 55.81 percent of the total power supply net revenue requirement.

Q. WHICH OF THESE APPROACHES DO YOU CONSIDER MOST APPLICABLE?

A. For predominately summer peaking utilities, I prefer the single or four coincident peak method to the 12CP method. For the purpose of this case, I recommend use of the 4CP allocation basis. The Missouri Commission relied on the 4CP method in KCP&L's prior two rate cases (ER-2006-0314 and ER-2007-0291). Further, to the extent coincidental peak demands are relied on to allocate demand related cost, I believe that the 4CP is more stable than a single CP allocation basis.

Q. DID YOU EVALUATE ANY OTHER POWER SUPPLY CLASSIFICATION AND ALLOCATION APPROACHES?

A. Yes, I did. I evaluated four other approaches. I refer to these four approaches as the:

1) Capital substitution method;
2) Base, intermediate, peaking method;
3) Economic rents method; and
4) Hour-by-hour method.

Q. PLEASE DESCRIBE WHAT YOU REFER TO AS THE CAPITAL SUBSTITUTION METHOD.

A. As I previously discussed, a utility's fixed power supply cost is determined by two factors. One factor is the maximum system demand. The second factor is the mix of generating resources required to meet its energy requirements economically. The capital substitution method explicitly recognizes both of these factors. It is based on the premise that utilities do not construct expensive base load generating resources to meet system peak demands. In order to meet peak demands, utilities construct less expensive resources. The capital substitution method is based on the straightforward concept that the cost responsibility associated with peak requirements should recognize the cost associated with the facilities the utility actually constructs and uses to meet those demands. Costs in excess of the cost of peaking are then classified as energy and allocated based on annual energy sales.

Q. WHAT ARE THE IMPLICATIONS OF CLASSIFYING COSTS BASED ON USE OF THE CAPITAL SUBSTITUTION METHOD?

A. In Schedule LWL-9, I show the classification of power supply costs into capacity and energy related and the subsequent allocation of costs to the Missouri jurisdiction using the capital substitution method. I allocate costs classified as capacity related based on the Missouri's contribution to the 4CP demand.

In Schedule LWL-9, I first show power supply cost by generating type (Lines 1 through 10). On lines 1 through 8, I show gross revenue requirements before the credit for off-system sales. I next show, on Lines 11 through 18, units of service corresponding to the gross revenue requirements I show in Lines 1 through 8. In this regard, I show in

Column D, KCP&L's accredited summer capacity for each type of generating resource. In Column E, I show annual generation from each type of resource. In Column C, I show "capacity factor" based on annual generation and accredited capacity.

Q. IS ACCREDITED CAPACITY AND CAPACITY FACTOR CRITICAL?

A. Accredited capacity is the measure of the amount of generating resources KCP&L has to meet customers' peak requirements. If accredited capacity is not sufficient to cover customers' peak demands and provide an adequate reserve margin, KCP&L must acquire additional resources. Therefore accredited capacity represents the measure of the total capacity required to meet customers' requirements.

Capacity factor on the other hand provides information regarding which resources are peaking in nature. As I show, the capacity factor (based on accredited capacity) for other generation (peaking) amounts to less than 5 percent, whereas other types of generating resources all exceed 70 percent. A five percent capacity factor clearly relates to resources operated as peaking.

Q. WHAT DO YOU SHOW IN LINES 19 THROUGH 26?

A. In Lines 19 through 26, I show the unit costs for each of the various types of resources. Unit total costs, Column C represents the total costs (fixed and variable) for the resource divided by annual generation. As I show, the unit cost of the peaking resources amounts to nearly 20 cents per kWh, whereas the average for the other resources amounts to about 3.5 cents per kWh.

In Column D, I show unit fixed costs based on accredited capacity. Of particular note is the $53.95 per kW fixed cost of peaking resources. This unit cost represents the unit capacity cost of KCP&L's facilities installed to meet customer's peak period requirements. This $53.95 per kW peaking cost compares to a $136.31 per kW average for KCP&L's other resources.

In Column E, I show unit variable costs for each of the various types of generating resources.

Q. DO YOU USE THESE UNIT COSTS?

A. Yes, I use the unit cost of peaking ($53.95 per kW) to develop capacity related cost. I calculate capacity related cost ($232.4 million, Line 29) as the product of the unit cost of capacity ($53.95 per kW) and KCP&L's total accredited capacity (4,308 MW). I then determine energy related cost as the balance of fixed cost plus variable cost. I reach the same result by reducing the total revenue requirement of $638.0 million by the capacity related cost of $232.4 million.

I show on Line 33, that following the capital substitution method, capacity related costs amounts to $232.4 million and energy related costs amount to $405.5 million. I complete Schedule LWL-9 by allocating capacity related and energy related costs to the Missouri jurisdiction.

I show on Line 39, total cost allocated to the Missouri jurisdiction amounts to $357.7 million or 56.07 percent (Line 35) of total power supply revenue requirements.

Q. IN SCHEDULE LWL-9, YOU SHOW MARGIN ASSOCIATED WITH OFF-SYSTEM SALES AS A FIXED COST. HOW HAVE YOU TREATED ENVIRONMENTAL CONTROL AND BOILER MAINTENANCE COSTS?

A. Following my capital substitution method, the treatment of off-system sales, environmental cost, and boiler maintenance is of no consequence. As I suggested previously, the capital substitution method is in fact a method to classify cost. This method recognizes the fact that fixed costs of power supply are affected not only by the maximum demand placed on the system by customers, but also on the energy requirements of such customers. Using the capital substitution method, there is no issue regarding the classification of margin on off-system sales, environmental cost, and boiler maintenance. In the classification and allocation I show in Schedule 9, I have allocated capacity costs as determined by the unit cost of peaking capacity and KCP&L's accredited capacity based on the maximum demands during the summer months (4CP). I then allocate the balance of power supply costs based on energy sales. To the extent that costs are included in the cost of peaking resources, they are classified as demand related and allocated accordingly. For all other costs, fixed and variable, I consider these to be energy related. Thus following the capital substitution method, the manner in which I classify costs (except for fixed costs associated with peaking resources) has no bearing.

Q. PLEASE DESCRIBE THE BASE, INTERMEDIATE, PEAKING METHOD.

A. The premise underlying the base, intermediate, peaking ("BIP") method is that there are three basic types of generating resources. These resources are operated differently and have differing cost characteristics. The BIP method recognizes these different costs and operating characteristics by allocating costs associated with each type of generation separately according to each jurisdiction's use of that type of generation.

As I previously discussed, base load resources are operated throughout the year. Base load resources are seldom shut down except as a result of forced outage or maintenance. Output from base load resources does not vary materially in response to changes in customers' load. Base load resources are characterized by high capital cost and low operating costs. The benefit of base load resources is the energy produced. Therefore following the BIP method, the costs of base load resources are allocated primarily based on energy requirements. These energy requirements are at the bottom of the load curve. As I show in Schedule LWL-3, Sheet 2, the Wolf Creek nuclear unit, the Spearville wind farm, and the Iatan Unit 1 operate as base load resources.

Peaking resources on the other hand are designed and operated to meet the high demands placed on the system a relatively few hours a year. Peaking resources often will be started and stopped daily or weekly in response to customer loads. As I previously described, peaking generation is characterized by low capital cost but high operating costs. Peaking resources are called upon to meet customers' requirements in excess of requirements met by base load and intermediate resources. Following the BIP approach, I allocate the cost of peaking resources based on customers' requirements in excess of what base and intermediate load resources provide.

Between base load and peaking load resources are what I refer to as intermediate load resources. This generating equipment tends to follow load by increasing or decreasing output throughout the day. Utilities seldom add generating equipment to meet intermediate load service. More often than not, intermediate load service requirements are met by older less efficient generating units which were originally installed to provide base load service. The costs of intermediate load resources tend to fall between the costs of base load and peaking resources.

Q. HAVE YOU EVALUATED THE IMPLICATIONS OF THE BIP METHOD ON THE MISSOURI JURISDICTION?

A. Yes, I have. I show the results of my BIP allocation in Schedule LWL-10.

In reviewing the operation of KCP&L's generating resources, I found that as expected, the Wolf Creek nuclear plant, the Spearville wind farm, and Iatan I all operate as base load resources. None of these resources are used to follow load to any significant extent.

During 2007, the combined output from these three resources at no time exceeded native load. The capacity factor for Wolf Creek exceeded 95 percent whereas the capacity factor for Iatan amounted to about 65 percent. However, Iatan's capacity factor during the hours it was connected to load exceeded 85 percent.

KCP&L uses its LaCygne and Hawthorn 5 units to meet the remainder of customers' base load requirements as well as provide intermediate load service. To some limited degree, these two units follow load and are connected to load nearly continuously (LaCygne – 8,284 hours and Hawthorn 5 – 7,590). When connected to load, the capacity factor for the LaCygne station amounted to about 75 percent where as the capacity factor for the Hawthorn 5 unit amounted to over 80 percent.

KCP&L uses its Montrose plant to meet the remainder of its intermediate load requirements. The plant was connected to load for over 8,000 hours during 2007. However, the capacity factor (based on connected hours) amounted to 67 percent.

Examination of the hourly load curves shows that to some degree KCP&L operates the plant to follow load.

KCP&L operates the remainder of its generating resources to meet customer's peaking requirements. Of these CT and internal engine based resources, no unit was connected to load for over 2,500 hours, and only one (Hawthorn 6 & 9 – 2,471 hours), was connected to load for over 500 hours.

Q. IN DEVELOPING THE BIP ALLOCATION, WHAT WAS YOUR FIRST STEP?

A. I first developed revenue requirements by the four classes of generation I identified (base, base/intermediate, intermediate/peaking, and peaking.) I summarize those revenue requirements on Lines 7 through 12 of Schedule LWL-10. To these revenue requirements, I apply allocation factors which recognize the Missouri jurisdiction's use of each of these resources. As I show on Lines 13 through 17, the Missouri jurisdiction's responsibility ranges from a little over 40 percent for peaking demand related cost to about 61 percent for the cost associated with base load resources.

I show on Line 23 that the Missouri jurisdiction's responsibility amounts to $353.8 million or 55.46 percent.

Q. HOW DO YOU DEVELOP THE ALLOCATION FACTORS YOU SHOW ON LINES 13 THROUGH 17?

A. I develop the allocation factors based on the use of capacity and energy of each type of generation by the Missouri jurisdiction. To do so, I start with the load duration curve I show in Schedule LWL-3, Sheets 1 and 2. Based on that curve, I find that the load on the base load resources at the time of the minimum native load amounts to 904 MW, whereas at the time of the native load's maximum demand the base load resources generated 1,065 MW or 17 percent more than the minimum.

I also find that the minimum native load amounts to 1,114 MW, whereas the Missouri contribution to that native load amounts to 679 MW, or 61.0 percent of minimum native load. The output from the base load resources at the time of the native load's maximum demand is 17 percent higher than the load at the time of the native load's minimum demand. As a result, at the time of the native load peak demand I set the Missouri jurisdiction's load at 17 percent more than the level I determined as the minimum associated with base load resource. Based on the minimum and maximum loads for the Missouri jurisdiction and native load, and the shape of the load curve for the base load resources, I develop load curves for use of base load resources by Missouri and total native load. From these load curves, I determine the energy from base load resources attributable to Missouri as well as the maximum loads.

I repeat this process to determine the Missouri jurisdiction's responsibility for each of the other resources' load at the time of native load maximum demand, as well as the use of energy.

Q. PLEASE DESCRIBE THE ECONOMIC RENTS METHOD.

A. The economic rents method is much like a unit capacity sale. A unit capacity sale is a contractual arrangement where the purchaser, in return for paying X percent of the fixed and variable costs of a generating station, gets X percent of the plant's output. The economic rents approach is based on the same concept. Based on the demand responsibility, each jurisdiction is credited with all of the energy produced.

Q. IF THE MISSOURI JURISDICTION IS CREDITED WITH ENERGY PRODUCED IN PROPORTION TO ITS DEMAND RESPONSIBILITY, IS THERE ENOUGH ENERGY TO MEET MISSOURI CUSTOMERS' REQUIREMENTS?

A. No, there is not. That is why a "transfer pricing mechanism" is required. In this regard, I use the equivalent cost at 100 percent load factor operation. This results in a contribution to the fixed costs charged to the other jurisdictions and the cost of the energy needed by the Missouri jurisdiction as if generation were operated at the 100 percent load factor.

Q. HAVE YOU PREPARED A SCHEDULE SHOWING THE RESULTS OF THIS APPROACH?

A. Yes, I have.

In Schedule LWL-11, I show the application of this method. I begin with the revenue requirements and the total units of service (Lines 1 through 9). On Lines 11 and 12, I show the unit cost per kW and per kWh.

As I indicated above, in order to satisfy Missouri's energy requirements, a transfer pricing is required. In Schedule LWL-11, I used the 100 percent load factor equivalent cost as the transfer price. I calculate this 100 percent load factor equivalent cost by dividing fixed costs per kW by 8,760 hours, and adding the per-unit variable cost. In this regard, based on the 4CP average demands of 3,450 MW, the 100 percent load factor equivalent cost amounts to 3 cents per kWh.

On Line 19, I show the cost responsibility to the Missouri jurisdiction based on the 4CP allocation factor. On Line 20, I show the associated energy.

As I show on Line 20, the energy associated with the 54.10 percent of fixed costs that are allocated to Missouri amounts to 8.8 million MWH. This 8.8 million is deficient in meeting the Missouri jurisdiction's requirements by 504,402 MWH (Line 21). The value (cost) of this 504,402 MWH amounts to $15.2 million dollars based on the 100 percent load-factor equivalent cost of 3.01 cents per kWh. Adding the $15.2 to the $345.1 million responsibility based on the 4CP allocation of all costs results in a cost responsibility to the Missouri jurisdiction of $360.3 million or 56.48 percent.

Q. PLEASE DESCRIBE THE HOUR-BY-HOUR METHOD.

A. The hour-by-hour method is based on the contribution of each generating source to each hour's load. I first allocate the cost of each generating resource to each hour of the year. I do this by dividing the revenue requirements for each resource by the total annual generation from that resource. I then multiply this unit cost by the resource's hourly output to determine the cost in that hour for that generating resource. By adding the costs for all generation in an hour, I develop the total cost for the hour. I allocate this hourly cost to each jurisdiction based on the load of that jurisdiction in that hour.

In Schedule LWL-12, I show the results of this method. As I show on Lines 45 and 46, the annual cost applicable to the Missouri jurisdiction amounts the $362.0 million, or 56.74 percent of the total.

Q. HAVE YOU SUMMARIZED THE RESULTS OF THE VARIOUS ALLOCATION APPROACHES YOU DISCUSSED?

A. Yes, I have. In Schedule LWL-13, I show this summary.

As I show in Schedule LWL-13, the Missouri jurisdictional responsibility based on the 12 approaches I discuss range from 54.77 percent to 56.74 percent.

Of the methods I show in this Schedule, with the exception of the single CP allocation, the lowest responsibility is using the method approved by the Commission in the Company's 2006 case (ER-2006-0314). Giving no consideration to the 1CP and 12CP approaches, the lowest cost responsibility is from use of the 4CP approach. 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 55.64 percent.

Q. DO YOU BELIEVE THAT THE 4CP METHOD PRODUCES REASONABLE RESULTS?

A. The 4CP method, reflecting the proper treatment of off-system sales, environmental and boiler maintenance costs, results in a Missouri jurisdictional responsibility of 55.64 percent. This represents total costs allocated to the Missouri jurisdiction of $354.9 million, an increase of $5.0 million or 1.4 percent above the level reflected in the method underlying the existing rates.

Of the other methods I present, the capital substitution method I believe the most reliable and fair, because of its straight forward simplicity and its explicit recognition of the cost implications associated with the various types of generating resources. Using the capital substitution method would result in an additional increase of $2.8 million (0.8 percent). In order to avoid undue disruption, I recommend that the Commission for the purpose of this case rely on the 4CP method, giving recognition to the nature of off-system sales margins, environmental costs, and non-labor boiler maintenance as I discussed.

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 production fixed costs.

Q. DO YOU BELIEVE THIS TREATMENT REASONABLE?

A. Yes, allocating transmission system cost based on the allocation of power supply fixed costs has merit. The transmission system serves to link power supply to the load centers. To the extent that 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 on the basis of the allocation of fixed power supply costs.

RECOMMENDED ALLOCATION BASES

Q. BASED ON YOUR INVESTIGATION IN THIS CASE, WHAT JURISDICTIONAL ALLOCATION BASES DO YOU RECOMMEND THE COMMISSION ADOPT?

A. I recommend the following:

1) Allocate capacity related power supply costs on the basis of the Missouri jurisdiction's contribution to the four summer month coincident peak demands.

2) To avoid the subsidization of Missouri customers by KCP&L or other jurisdictions, classify the margin associated with off-system sales in the same manner as the fixed costs associated with KCP&L's generating resources used to generate the energy sold off-system. Since most fixed costs associated with generation are classified as capacity and allocated based on peak period demands, most of the margins associated with off-system sales should be classified as capacity.

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

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

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

6) In future rate cases, the Commission should consider allocation approaches that provide explicit consideration to the fact that an electric utility pays a premium for power generating facilities that can produce energy economically.

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	)))	Case No. ER-2009-____

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 13 day of August ~~2008~~.

Notary Public

My commission expires: 12/15/10

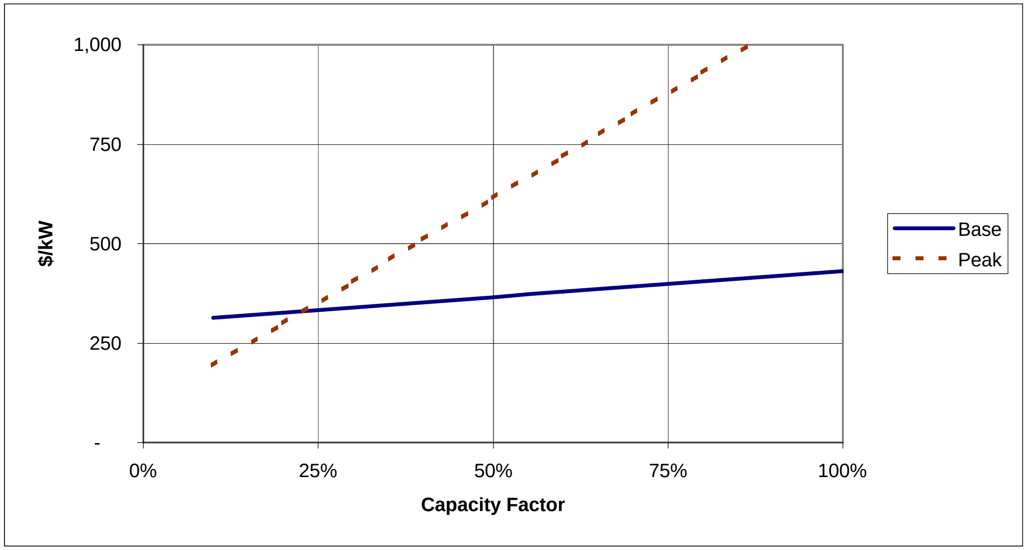
JASON C. MARSH
NOTARY PUBLIC - ARIZONA
PINAL COUNTY
My Commission Expires
December 15, 2010

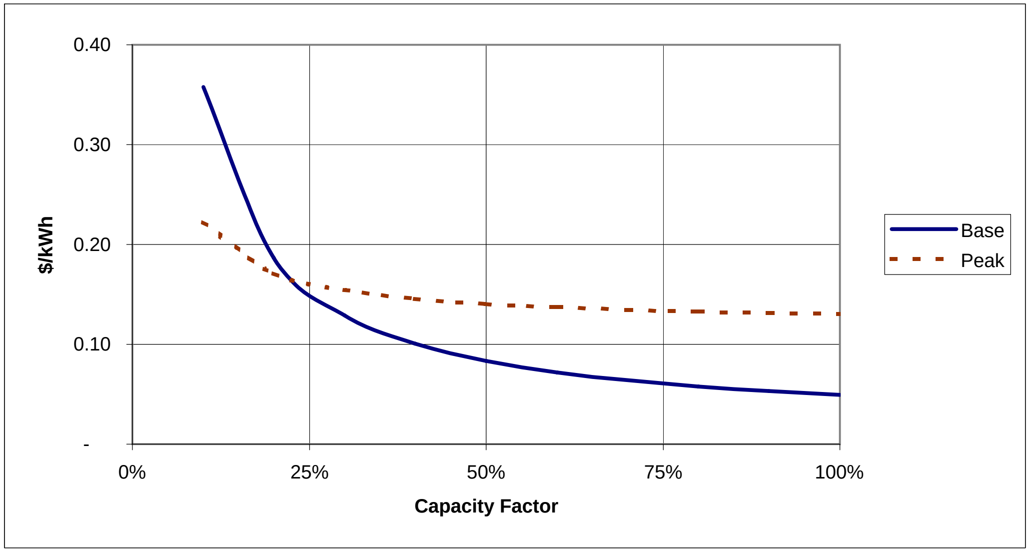
8/11/2008

Kansas City Power Light Company
Generating Station Cost Characteristics
Example

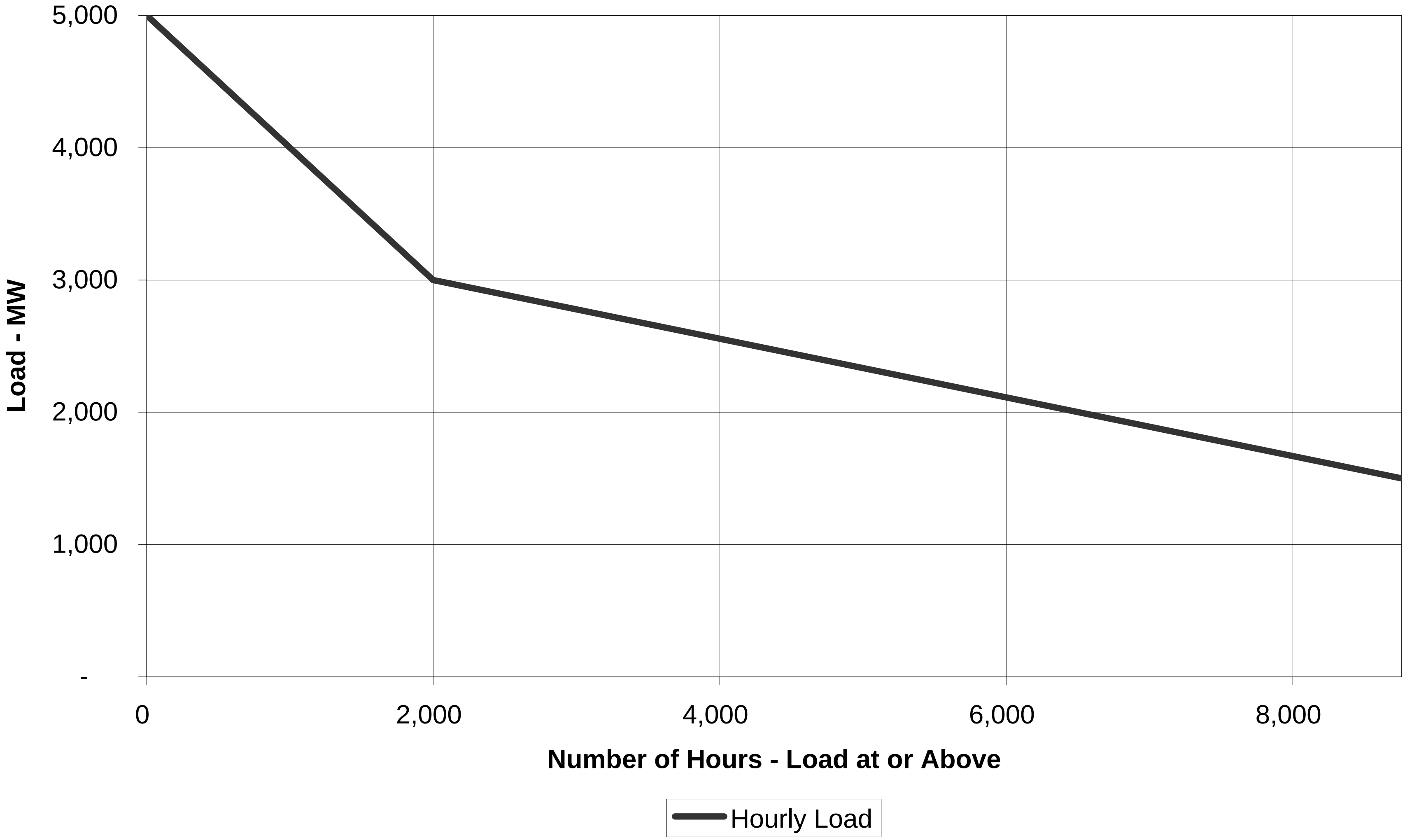
Schedule LWL-1
Sheet 1

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	300
10	30%	339	405
11	40%	353	510
12	50%	366	616
13	60%	379	721
14	70%	392	826
15	80%	405	931
16	90%	418	1,036
17	100%	431	1,141
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



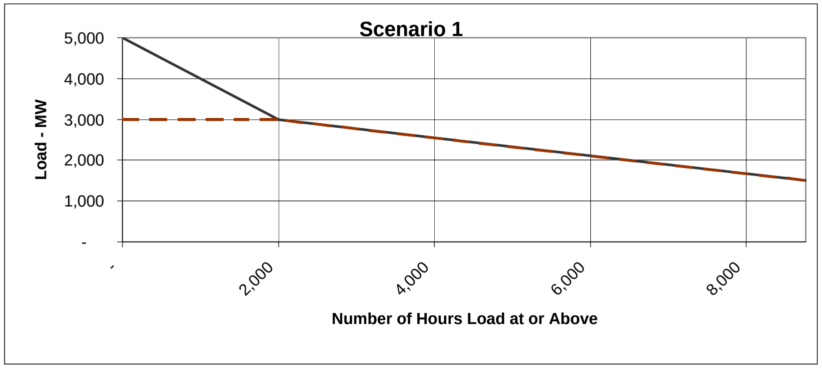


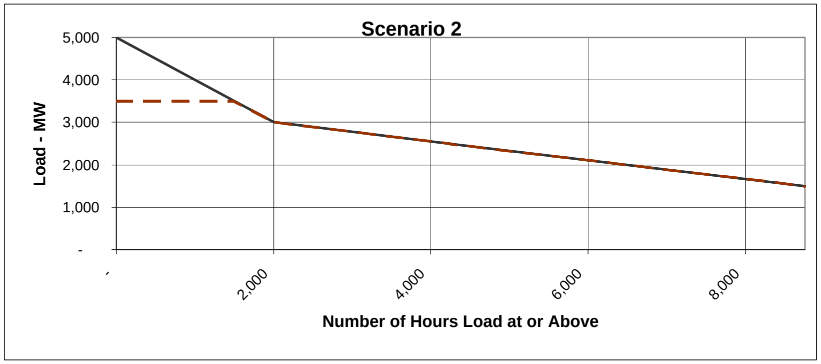
Kansas City Power & Light Company
Hourly Load Curve Example

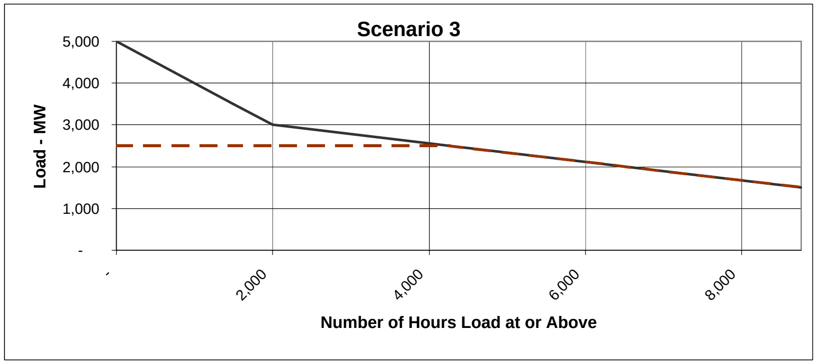


Kansas City Power Light Company
Generating Station Cost Characteristics
Example of Uneconomic Generation Mix

	[A]	[B]	[C]	[D]
Line No.	Description	Base Resource	Peaking Resource	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	3,000	2,000	5,000
8	Energy - MWH	21,210,000	2,000,000	23,210,000
9	Capacity Factor	80.71%	11.42%	52.99%
10	Fuel Cost	318,150,000	240,000,000	558,150,000
11	Fixed Costs	900,000,000	180,000,000	1,080,000,000
12	Total Cost - $	1,218,150,000	420,000,000	1,638,150,000
13	Unit Cost - $/kWh	0.0574	0.2100	0.0706
14	Scenario 2			
15	Capacity -MW	3,500	1,500	5,000
16	Energy - MWH	22,085,000	1,125,000	23,210,000
17	Capacity Factor	72.03%	8.56%	52.99%
18	Fuel Cost	331,275,000	135,000,000	466,275,000
19	Fixed Costs	1,050,000,000	135,000,000	1,185,000,000
20	Total Cost - $	1,381,275,000	270,000,000	1,651,275,000
21	Unit Cost - $/kWh	0.0625	0.2400	0.0711
22	Scenario 3			
23	Capacity -MW	2,500	2,500	5,000
24	Energy - MWH	19,646,667	3,563,333	23,210,000
25	Capacity Factor	89.71%	16.27%	52.99%
26	Fuel Cost	294,700,000	427,600,000	722,300,000
27	Fixed Costs	750,000,000	225,000,000	975,000,000
28	Total Cost - $	1,044,700,000	652,600,000	1,697,300,000
29	Unit Cost - $/kWh	0.0532	0.1831	0.0731







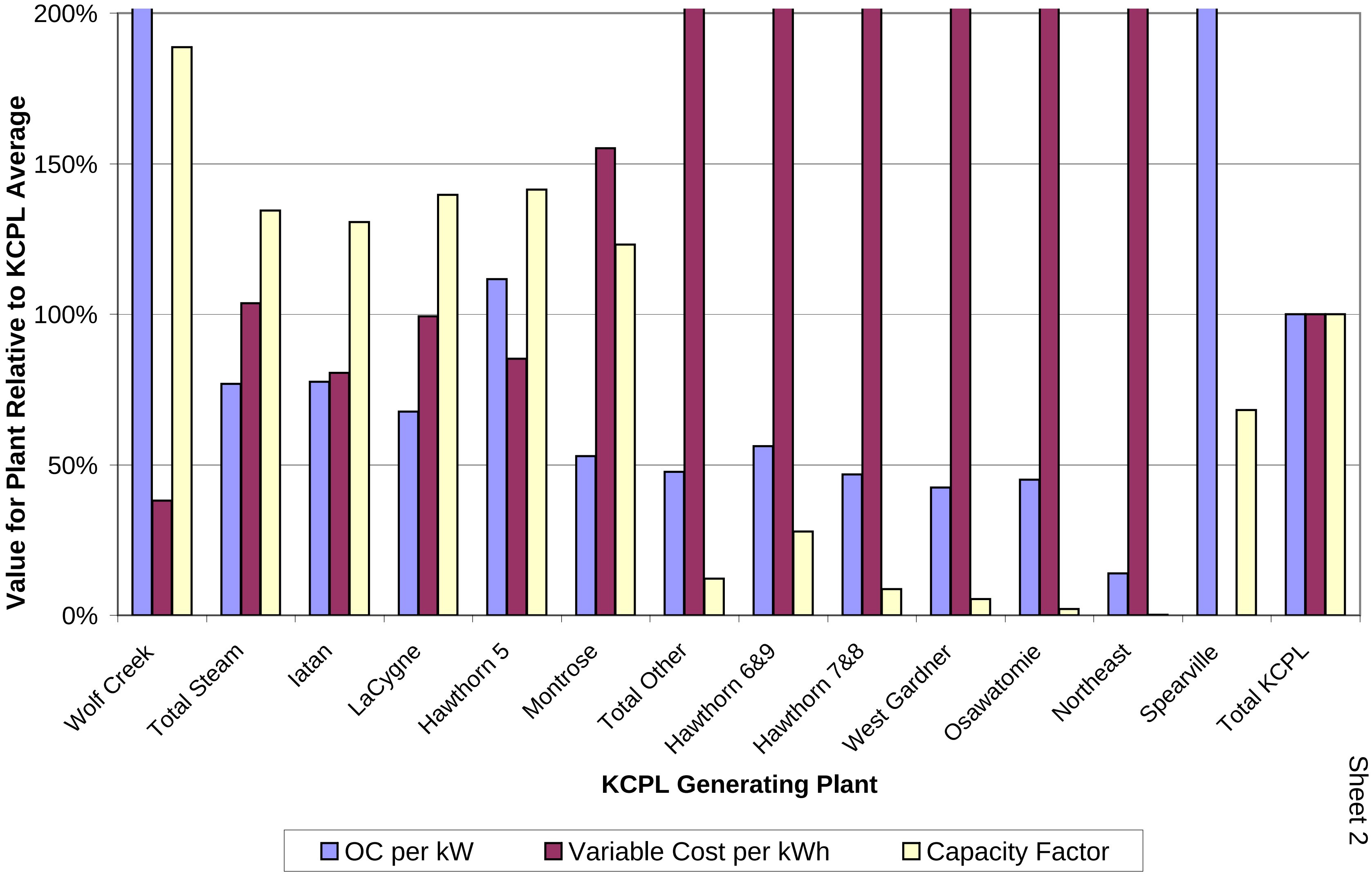
8/11/2008

Kansas City Power Light Company
Characteristics of KCPL Generating Stations

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]
Line No.	Description	Reference	Wolf Creek	Total Steam	Iatan	LaCygne	Hawthorn 5	Montrose	Total Other	Hawthorn 6&9	Hawthorn 7&8	West Gardner	Osawatomie	Northeast	Spearville	Total KCPL
1	Plant Type	LN 1 Form 1	Nuclear		Steam	Steam	Steam	Steam		Combined Cycle	Gas Turbine	Gas Turbine	Gas Turbine	Internal Combustion	Wind	
2	Year Originally Constructed	LN 2 Form 1	1985		1980	1973	1969	1958		2000	2000	2003	2003	1972	2006	
3	Year Last Unit Was Installed	LN 3 Form 1	1985		1980	1977	1969	1964		2000	2000	2003	2003	1977		
4	Capacity															
5	Installed Capacity - MW	LN 5 Form 1	581	2,492	508	827	594	563	1,567	301	164	408	102	491	101	4,640
6	Net Peak Demand on Plant - MW	LN 6 Form 1	586	2,278	477	720	567	514	1,300	321	186	359	90	241	103	4,164
7	Accredited Capacity - MW	LN 36	548	2,238	456	709	563	510	1,265	266	151	308	76	449	15	4,051
8	Hours Connected to Load	LN 7 Form 1	8,760	7,744	6,620	8,284	7,590	8,126	1,250	2,471	451	480	177	95	8,760	5,679
9	Net Generation - MWH	LN 12 Form 1	4,873,482	14,894,358	2,949,806	5,131,864	3,730,866	3,081,822	848,599	372,291	63,718	96,449	9,162	2,264	304,715	20,616,439
10	Connected Average - MWH	LN 9 / LN 8	556.33	1,923.42	445.59	619.49	491.55	379.25	678.70	150.66	141.28	200.94	51.76	23.83	34.78	3,630.61
11	Capacity Factor	LN 10 / LN 5	95.75%	77.18%	87.71%	74.91%	82.75%	67.36%	43.33%	50.05%	86.15%	49.25%	50.75%	4.85%	34.61%	78.25%
12	Annual Average - MWH	LN 9 / 8760	556.33	1,700.27	336.74	585.83	425.90	351.81	96.87	42.50	7.27	11.01	1.05	0.26	34.78	2,353.47
13	Capacity Factor	LN 12 / LN 5	95.75%	68.23%	66.29%	70.84%	71.70%	62.49%	6.18%	14.12%	4.44%	2.70%	1.03%	0.05%	34.61%	50.73%
14	Original Cost - $	LN 17 Form 1	1,359,531,173	1,315,170,313	270,657,507	384,684,005	455,574,752	204,254,049	512,895,532	116,008,959	52,762,478	119,108,011	31,518,619	46,779,390	146,718,075	3,187,597,018
15	Handy-Whitman Index	LN 38	242		203	136	76	63		434	434	439	439	132	529	
16	2007 Handy-Whitman Index	LN 38	489		531	531	531	531		529	529	529	529	529	529	
17	Trend Factor	LN 16 / LN 15	2.02	5.41	2.62	3.90	6.99	8.43	1.41	1.22	1.22	1.21	1.21	4.01	1.00	3.32
18	TOC	LN 14 * LN 17	2,747,151,833	7,114,539,496	707,976,040	1,501,964,755	3,183,028,859	1,721,569,842	721,411,323	141,402,625	64,311,868	143,526,510	37,980,295	187,471,949	146,718,075	10,583,102,652
19	Unit Cost															
20	OC Per kW Installed - $/kW	LN 14 / LN 5	2,340	528	533	465	767	363	327	385	322	292	309	95	1,460	687
21	TOC Per kW Installed - $/kW	LN 14 / LN 5	4,728	2,855	1,394	1,816	5,359	3,058	461	470	392	352	372	382	1,460	2,281
22	Operating Expenses								43,644,918							
23	Fuel Cost - $	LN 20 Form 1	22,067,927	183,733,891	28,305,368	60,659,538	37,830,946	56,938,039	39,707,699	22,582,677	5,994,755	9,255,002	1,042,854	832,411	-	245,509,517
24	Other Production Expenses - $	LN 25 - LN 23	57,673,388	72,790,074	13,674,098	18,985,869	22,789,007	17,341,100	5,433,528	2,481,275	342,687	532,271	162,039	418,947	1,496,309	135,896,990
25	Total O&M Expenses - $	LN 34 Form 1	79,741,315	256,523,965	41,979,466	79,645,407	60,619,953	74,279,139	45,141,227	25,063,952	6,337,442	9,787,273	1,204,893	1,251,358	1,496,309	381,406,507
26	Unit Cost															
27	Per kWh Generated															
28	Fuel - $/kWh	LN 23 / LN 9	0.00453	0.01234	0.00960	0.01182	0.01014	0.01848	0.04679	0.06066	0.09408	0.09596	0.11382	0.36774	-	0.01191
29	Total O&M - $/kWh	LN 25 / LN 9	0.0164	0.0172	0.0142	0.0155	0.0162	0.0241	0.0532	0.0673	0.0995	0.1015	0.1315	0.5528	0.0049	0.0185
30	Per kW Installed															
31	Other Expenses - $/kW	LN 24 / LN 5	99.27	29.21	26.92	22.96	38.37	30.80	3.47	8.24	2.09	1.30	1.59	0.85	14.89	29.29
32	Primary Fuel	LN 40	Nuclear		Coal	Coal	Coal	Coal		Gas	Gas	Gas	Gas	Gas	Wind	
33	Heat Rate - BTU/kWh	LN 44 Form 1	10,268		9,992	10,329	10,241	10,841		8,521	12,997	13,483	14,215	38,373		

34 Reference:
35 All Data from KCPL FERC Form No. 1, Pages 402 and 403, Unless Otherwise Specified
36 LN 7 = Accredited Summer Capacity - Provided by KCPL
37 LN 13, COLs [D], [I], and [P]: Weighted Based on LN 5
38 LN 15 = The Handy Whitman Index of Public Utility Construction Costs - Bulletin No. 166 - North Central Region - at Midpoint Between Date Originally Constructed and Last Unit
39 LN 16 = The Handy Whitman Index of Public Utility Construction Costs - Bulletin No. 166 - North Central Region - July 2007
40 LN 32: Based on Examination of FERC Form 1, Lines 36 through 44
41 COL [O]: FERC Form 1, Page 410 and 411
42 COL [C]: KCPL's 47% Interest
43 COL [E]: KCPL's 70% Interest
44 COL [F]: KCPL's 50% Interest

Kansas City Power & Light Company
Comparison of Generating Plant Characteristics



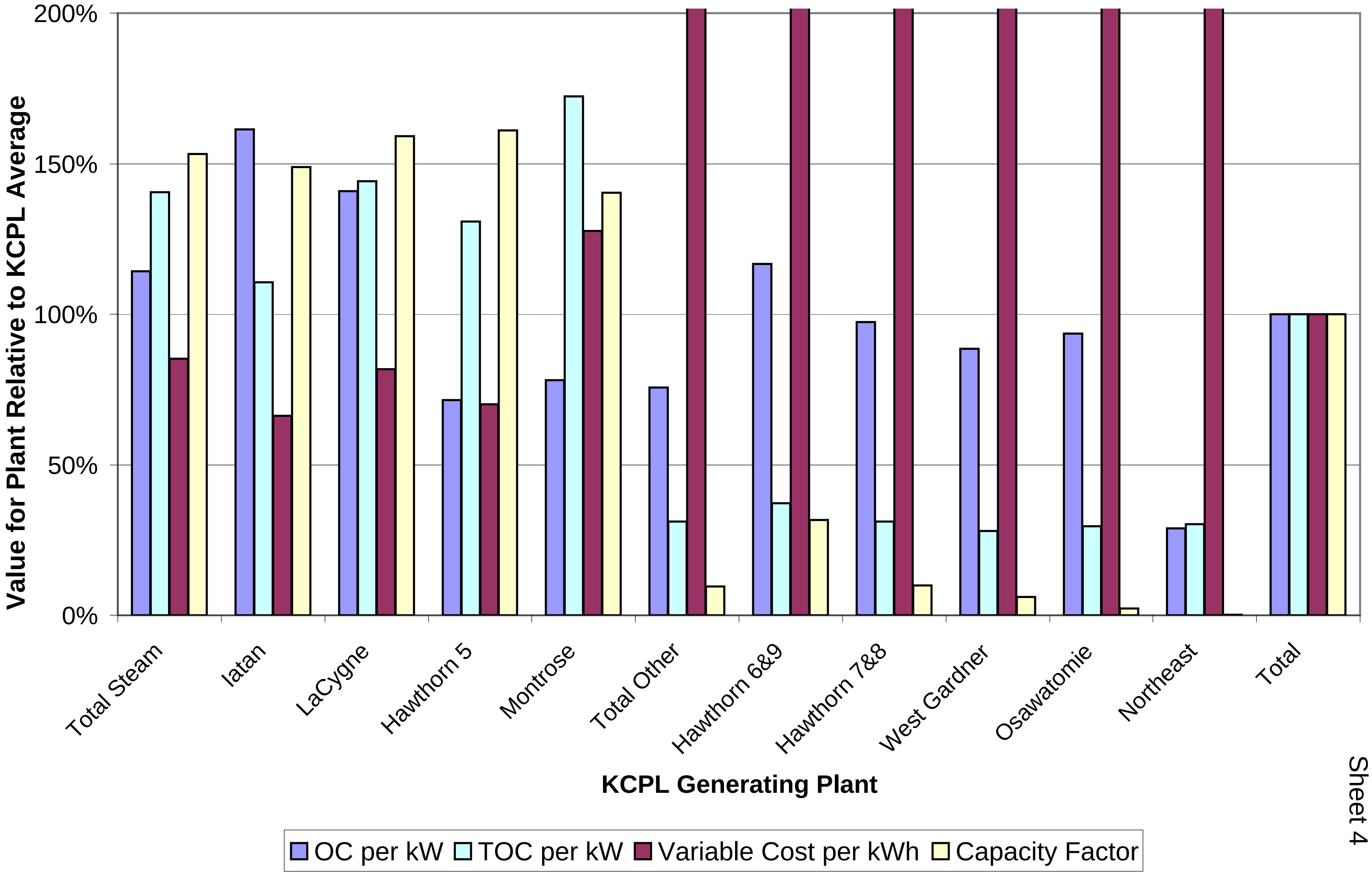
Schedule LWL-2
Sheet 2

Kansas City Power Light Company
Characteristics of KCPL Generating Stations
Excluding Wolf Creek and Spearville
Hawthorn 5 and Montrose Adjusted

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
Line No.	Description	Reference	Total Steam	Iatan	LaCygne	Hawthorn 5	Montrose	Total Other	Hawthorn 6&9	Hawthorn 7&8	West Gardner	Osawatomie	Northeast	Total
1	Plant Type	LN 1 Form 1		Steam	Steam	Steam	Steam		Combined Cycle	Gas Turbine	Gas Turbine	Gas Turbine	Internal Combustion	
2	Year Originally Constructed	LN 2 Form 1		1980	1973	1969	1958		2000	2000	2003	2003	1972	
3	Year Last Unit Was Installed	LN 3 Form 1		1980	1977	1969	1964		2000	2000	2003	2003	1977	
4	Capacity													
5	Installed Capacity - MW	LN 5 Form 1	2,492	508	827	594	563	1,466	301	164	408	102	491	3,958
6	Net Peak Demand on Plant - MW	LN 6 Form 1	2,278	477	720	567	514	1,197	321	186	359	90	241	3,475
7	Accredited Capacity - MW	LN 36	2,238	456	709	563	510	1,250	266	151	308	76	449	3,488
8	Hours Connected to Load	LN 7 Form 1	7,744	6,620	8,284	7,590	8,126	736	2,471	451	480	177	95	5,148
9	Net Generation - MWH	LN 12 Form 1	14,894,358	2,949,806	5,131,864	3,730,866	3,081,822	543,884	372,291	63,718	96,449	9,162	2,264	15,438,242
10	Connected Average - MWH	LN 9 / LN 8	1,923.42	445.59	619.49	491.55	379.25	739.45	150.66	141.28	200.94	51.76	23.83	2,998.92
11	Capacity Factor	LN 10 / LN 5	77.18%	87.71%	74.91%	82.75%	67.36%	50.44%	50.05%	86.15%	49.25%	50.75%	4.85%	75.77%
12	Annual Average - MWH	LN 9 / 8760	1,700.27	336.74	585.83	425.90	351.81	62.09	42.50	7.27	11.01	1.05	0.26	1,762.36
13	Capacity Factor	LN 12 / LN 5	68.23%	66.29%	70.84%	71.70%	62.49%	4.24%	14.12%	4.44%	2.70%	1.03%	0.05%	44.53%
14	Original Cost - $	LN 17 Form 1	940,341,512	270,657,507	384,684,005	140,000,000	145,000,000	366,177,457	116,008,959	52,762,478	119,108,011	31,518,619	46,779,390	1,306,518,969
15	Handy-Whitman Index	LN 38		203	136	76	63		434	434	439	439	132	
16	2007 Handy-Whitman Index	LN 39		531	531	531	531		529	529	529	529	529	
17	Trend Factor	LN 16 / LN 15	4.69	2.62	3.90	6.99	8.43	1.57	1.22	1.22	1.21	1.21	4.01	3.82
18	TOC	LN 14 / LN 17	4,410,241,547	707,976,040	1,501,964,755	978,157,895	1,222,142,857	574,693,248	141,402,625	64,311,868	143,526,510	37,980,295	187,471,949	4,984,934,795
19	Unit Cost													
20	OC Per kW Installed - $/kW	LN 14 / LN 5	377	533	465	236	258	250	385	322	292	309	95	330
21	TOC Per kW Installed - $/kW	LN 14 / LN 7	1,770	1,394	1,816	1,647	2,171	392	470	392	352	372	382	1,259
22	Operating Expenses													
23	Fuel Cost - $	LN 20 Form 1	183,733,891	28,305,368	60,659,538	37,830,946	56,938,039	39,707,699	22,582,677	5,994,755	9,255,002	1,042,854	832,411	223,441,590
24	Other Production Expenses - $	LN 38	72,790,074	13,674,098	18,985,869	22,789,007	17,341,100	3,937,219	2,481,275	342,687	532,271	162,039	418,947	76,727,293
25	Total O&M Expenses - $	LN 34 Form 1	256,523,965	41,979,466	79,645,407	60,619,953	74,279,139	43,644,918	25,063,952	6,337,442	9,787,273	1,204,893	1,251,358	300,168,883
26	Unit Cost													
27	Per kWh Generated													
28	Fuel - $/kWh	LN 39	0.01234	0.00960	0.01182	0.01014	0.01848	0.07301	0.06066	0.09408	0.09596	0.11382	0.36774	0.01447
29	Total O&M - $/kWh	LN 25 / LN 9	0.0172	0.0142	0.0155	0.0162	0.0241	0.0802	0.0673	0.0995	0.1015	0.1315	0.5528	0.0194
30	Per kW Installed													
31	Other Expenses - $/kW	LN 24 / LN 5	29.21	26.92	22.96	38.37	30.80	2.69	8.24	2.09	1.30	1.59	0.85	19.39
32	Primary Fuel	LN 40		Coal	Coal	Coal	Coal		Gas	Gas	Gas	Gas	Gas	
33	Heat Rate - BTU/kWh	LN 44 Form 1		9,992	10,329	10,241	10,841		8,521	12,997	13,483	14,215	38,373	

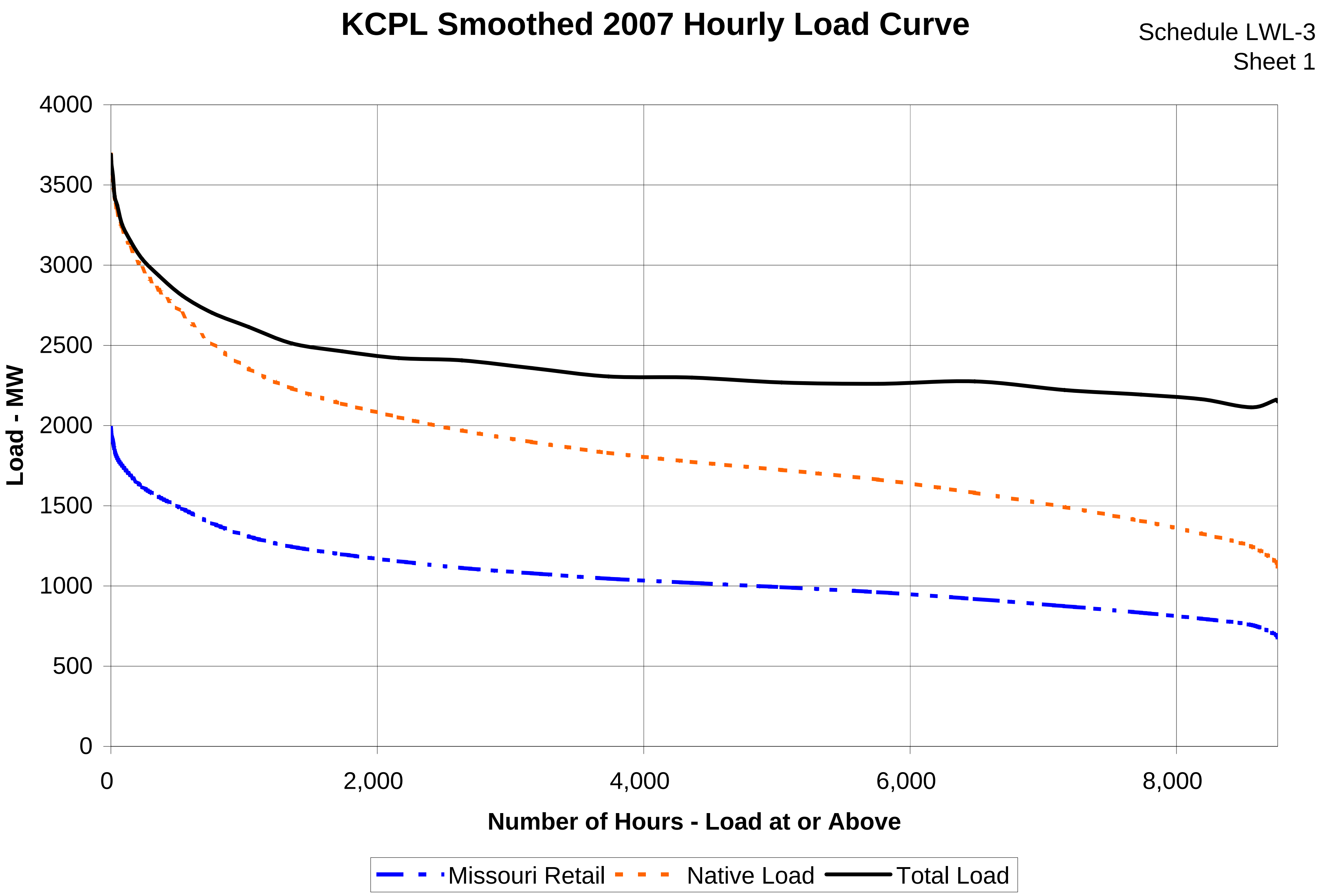
34 Reference:
35 All Data from KCPL FERC Form No. 1, Pages 402 and 403, Unless Otherwise Specified
36 LN 7 = Accredited Summer Capacity - Provided by KCPL
37 LN 13, COLs [C], [H], and [N]: Weighted Based on LN 5
38 LN 15 = The Handy Whitman Index of Public Utility Construction Costs - Bulletin No. 166 - North Central Region - at Midpoint Between Date Originally Constructed and Last Unit
39 LN 16 = The Handy Whitman Index of Public Utility Construction Costs - Bulletin No. 166 - North Central Region - July 2007
40 LN 32: Based on Examination of FERC Form 1, Lines 36 through 44
41 COL [D]: KCPL's 70% Interest
42 COL [E]: KCPL's 50% Interest

Kansas City Power & Light Company
Comparison of Generating Plant Characteristics



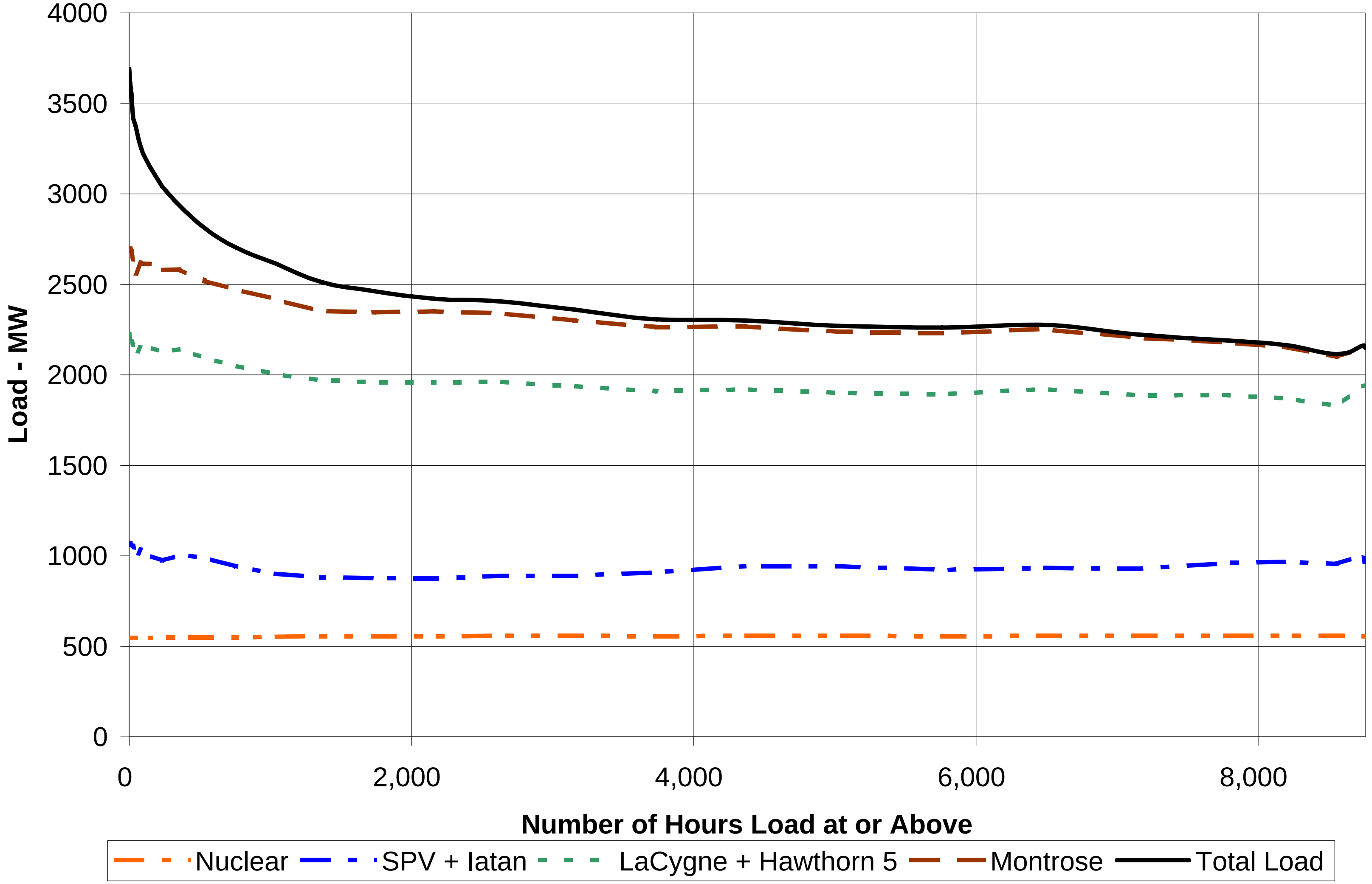
Schedule LWL-2
Sheet 4

Schedule LWL-3
Sheet 1



KCPL 2007 Smoothed Hourly Generation

Schedule LWL-3
Sheet 2



Kansas City Power Light Company
Power Supply Revenue Requirements
Summary

	[A]	[B]	[C]	[D]	[E]	[F]
					Power Supply	
Line No.	Description	Total KCPL	Other	Transmission	Fixed Cost	Variable Cost
		$	$	$	$	$
1	Rate Base					
2	Electric Plant in Service	5,428,690,145	1,835,242,969	387,152,470	3,185,356,167	20,938,540
3	Accumulated Depreciation	(2,476,180,149)	713,777,643	(141,214,346)	(1,605,343,728)	(15,844,431)
4	Net Plant in Service	2,952,509,996	1,121,465,326	245,938,124	1,580,012,438	5,094,109
5	Working Capital	102,501,673	(1,797,943)	(1,264,180)	25,075,986	80,487,799
6	Other Rate Base Additions	51,387,552	32,399,914	836,938	15,953,902	2,196,797
7	Accumulated Deferred Income Taxes	(588,757,716)	(207,295,155)	(41,734,450)	(372,665,065)	32,936,954
8	Other Rate Base Reductions	(97,474,779)	(10,008,978)	-	-	(87,465,801)
9	Total Rate Base	2,420,166,726	934,763,164	203,776,432	1,248,377,261	33,249,858
10	Revenue Requirements					
11	Fuel	245,600,648	(1,144,473)	-	806,618	245,938,502
12	Purchased Power	103,057,496	-	-	8,692,034	94,365,462
13	Other O&M Expenses	391,662,879	116,100,355	31,280,847	207,264,490	37,017,187
14	Depreciation Expense	133,894,123	42,744,722	9,494,315	81,655,085	-
15	Amortization Expense	31,269,406	26,534,320	633,072	2,479,541	1,622,472
16	Interest on Customer Deposits	554,255	554,255	-	-	-
17	Taxes Other than Income Taxes	70,284,556	23,202,150	4,537,598	41,638,443	906,365
18	Return @ 8.5828%	207,717,981	80,229,772	17,489,609	107,145,171	2,853,759
19	State and Federal Income Taxes	76,840,529	33,241,511	7,977,768	34,604,732	1,016,724
20	Gross Revenue Requirements	1,260,881,872	321,462,612	71,413,209	484,286,116	383,720,471
21	Revenue Credits					
22	Miscellaneous Revenues	(17,213,210)	(7,031,731)	(10,141,168)	(40,311)	-
23	Off-System Sales	(230,011,997)	-	-	(98,501,325)	(131,510,672)
24	Net Revenue Requirements	1,013,656,665	314,430,882	61,272,041	385,744,479	252,209,799
25	Revenue Requirements by Type of Generation					
26	Nuclear				160,899,785	36,589,737
27	Steam				231,182,479	211,421,446
28	Purchase Power				8,681,056	94,246,283
29	Wind				16,075,624	597,562
30	Subtotal				416,838,943	342,855,029
31	Other Generation (Peaking)				67,447,173	40,865,442
32	Gross Revenue Requirements				484,286,116	383,720,471
33	Off-System Sales (Includes Miscellaneous Revenues)				(98,541,636)	(131,510,672)
34	Net Revenue Requirements				385,744,479	252,209,799

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

	[A]	[B]	[C]	[D]	[E]
Line No.	Description	Reference	Total KCPL	Fixed Cost	Variable Cost
			$	$	$
1	Revenue Requirements by Type of Generation				
2	Nuclear	LWL-4	197,489,522	160,899,785	36,589,737
3	Steam	LWL-4	442,603,925	231,182,479	211,421,446
4	Purchase Power	LWL-4	102,927,339	8,681,056	94,246,283
5	Wind	LWL-4	16,673,185	16,075,624	597,562
6	Subtotal	LWL-4	759,693,971	416,838,943	342,855,029
7	Other Generation (Peaking)	LWL-4	108,312,615	67,447,173	40,865,442
8	Gross Revenue Requirements	LWL-4	868,006,586	484,286,116	383,720,471
9	Off-System Sales	LWL-4	(230,052,308)	(98,541,636)	(131,510,672)
10	Net Revenue Requirements	LWL-4	637,954,278	385,744,479	252,209,799
			Total	Capacity	Energy
			$	$	$
11	Energy Allocation of Off-System Sales				
12	Gross Revenue Requirements	LN8	868,006,586	484,286,116	383,720,471
13	Off-System Sales	LN9	(230,052,308)		(230,052,308)
14	Net Revenue Requirements	SUM	637,954,278	484,286,116	153,668,162
15	Missouri Portion				
16	Gross Revenue Requirements	LN12 * LN35&37	481,487,452	261,997,423	219,490,028
17	Off-System Sales	LN13 * LN35&37	(131,591,071)	-	(131,591,071)
18	Net Revenue Requirements	SUM	349,896,381	261,997,423	87,898,957
19	Missouri Portion of Total	LN18 / LN14	54.85%	54.10%	57.20%
20	Allocation Recognizing Nature of Off-System Sales				
21	Gross Revenue Requirements	LN8	868,006,586	484,286,116	383,720,471
22	Off-System Sales	LN9	(230,052,308)	(98,541,636)	(131,510,672)
23	Net Revenue Requirements	SUM	637,954,278	385,744,479	252,209,799
24	Missouri Portion				
25	Gross Revenue Requirements	LN21 * LN35&37	481,487,452	261,997,423	219,490,028
26	Off-System Sales	LN22 * LN35&37	(128,535,510)	(53,310,747)	(75,224,762)
27	Net Revenue Requirements	SUM	352,951,942	208,686,676	144,265,266
28	Missouri Portion of Total	LN27 / LN23	55.33%	54.10%	57.20%
			Total	Missouri	Other
			MW	MW	MW
29	Coincident Peak Demand (4CP) - MW				
30	June		3,431	1,847	1,584
31	July		3,689	1,992	1,697
32	August		3,436	1,866	1,570
33	September		3,243	1,761	1,482
34	Average		3,450	1,866	1,583
35	Capacity Responsibility	LN34	100.00%	54.10%	45.90%
36	Annual Deliveries - MWH		16,266,920	9,304,760	6,962,161
37	Energy Responsibility	LN34	100.00%	57.20%	42.80%

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

	[A]	[B]	[C]	[D]	[E]
Line No.	Description	Reference	Total KCPL	Fixed Cost	Variable Cost
			$	$	$
1	Revenue Requirements by Type of Generation				
2	Nuclear	LWL-4	197,489,522	160,899,785	36,589,737
3	Steam - Fixed Enviornmental Cost	LN 48	75,000,000	75,000,000	
4	Steam - Other	LWL-4 - LN3	367,603,925	156,182,479	211,421,446
5	Purchase Power	LWL-4	102,927,339	8,681,056	94,246,283
6	Wind	LWL-4	16,673,185	16,075,624	597,562
7	Subtotal	LWL-4	759,693,971	416,838,943	342,855,029
8	Other Generation (Peaking)	LWL-4	108,312,615	67,447,173	40,865,442
9	Gross Revenue Requirements	LWL-4	868,006,586	484,286,116	383,720,471
10	Off-System Sales (Includes Miscellaneous R	LWL-4	(230,052,308)	(98,541,636)	(131,510,672)
11	Net Revenue Requirements	LWL-4	637,954,278	385,744,479	252,209,799
			Total	Capacity	Energy
			$	$	$
12	Energy Allocation of Off-System Sales & Capacity Allocation of Environmental Cost				
13	Gross Revenue Requirements				
14	Excluding Environmental Costs	Balance	793,006,586	409,286,116	383,720,471
15	Environmental Costs	LN3	75,000,000	75,000,000	-
16	Off-System Sales	LN10	(230,052,308)		(230,052,308)
17	Net Revenue Requirements	LN11	637,954,278	484,286,116	153,668,162
18	Missouri Portion				
19	Gross Revenue Requirements				
20	Excluding Environmental Costs	LN14 * LN44&46	440,912,663	221,422,635	219,490,028
21	Environmental Costs	LN15 * LN44&46	40,574,789	40,574,789	-
22	Off-System Sales	LN16 * LN44&46	(131,591,071)	-	(131,591,071)
23	Net Revenue Requirements	SUM	349,896,381	261,997,423	87,898,957
24	Missouri Portion of Total	LN23 / LN17	54.85%	54.10%	57.20%
25	Allocation Recognizing Nature of Off-System Sales and Environmental Costs				
26	Gross Revenue Requirements				
27	Excluding Environmental Costs	Balance	793,006,586	409,286,116	383,720,471
28	Environmental Costs	LN3	75,000,000		75,000,000
29	Off-System Sales	LN10	(230,052,308)	(79,751,325)	(150,300,983)
30	Net Revenue Requirements	LN11	637,954,278	329,534,790	308,419,487
31	Missouri Portion				
32	Gross Revenue Requirements				
33	Excluding Environmental Costs	LN27 * LN44&46	440,912,663	221,422,635	219,490,028
34	Environmental Costs	LN28 * LN44&46	42,900,375	-	42,900,375
35	Off-System Sales	LN29 * LN44&46	(129,118,156)	(43,145,242)	(85,972,914)
36	Net Revenue Requirements	SUM	354,694,882	178,277,393	176,417,490
37	Missouri Portion of Total	LN36 / LN30	55.60%	54.10%	57.20%
			Total	Missouri	Other
			MW	MW	MW
38	Coincident Peak Demand (4CP) - MW				
39	June		3,431	1,847	1,584
40	July		3,689	1,992	1,697
41	August		3,436	1,866	1,570
42	September		3,243	1,761	1,482
43	Average		3,450	1,866	1,583
44	Capacity Responsibility	LN 43	100.00%	54.10%	45.90%
45	Annual Deliveries - MWH		16,266,920	9,304,760	6,962,161
46	Energy Responsibility	LN 45	100.00%	57.20%	42.80%
47	Reference:				
48	LN 3 = Estimated @ $75,000,000 (Aproximately = 28.61% of Gross Plant and 17.00%of Depreciation Reserve)				

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

	[A]	[B]	[C]	[D]	[E]
Line No.	Description	Reference	Total KCPL	Fixed Cost	Variable Cost
			$	$	$
1	Revenue Requirements by Type of Generation				
2	Nuclear	LWL-4	197,489,522	160,899,785	36,589,737
3	Steam - Non-Labor Boiler Maintenance	LN 53	10,000,000	10,000,000	
4	Steam - Fixed Environmental Cost	LWL-6	75,000,000	75,000,000	
5	Steam - Other	LWL-4 - LN3&4	357,603,925	146,182,479	211,421,446
6	Purchase Power	LWL-4	102,927,339	8,681,056	94,246,283
7	Wind	LWL-4	16,673,185	16,075,624	597,562
8	Subtotal	LWL-4	759,693,971	416,838,943	342,855,029
9	Other Generation (Peaking)	LWL-4	108,312,615	67,447,173	40,865,442
10	Gross Revenue Requirements	LWL-4	868,006,586	484,286,116	383,720,471
11	Off-System Sales (Includes Miscellaneous Revenues)	LWL-4	(230,052,308)	(98,541,636)	(131,510,672)
12	Net Revenue Requirements	LWL-4	637,954,278	385,744,479	252,209,799

			Total	Capacity	Energy
			$	$	$
13	Energy Allocation of Off-System Sales and Capacity Allocation of Environmental Cost and Boiler Maintenance				
14	Gross Revenue Requirements				
15	Excluding Environmental & Boiler	Balance	783,006,586	399,286,116	383,720,471
16	Boiler Maintenance	LN3	10,000,000	10,000,000	-
17	Environmental Costs	LN4	75,000,000	75,000,000	-
18	Off-System Sales	LN11	(230,052,308)		(230,052,308)
19	Net Revenue Requirements	LN12	637,954,278	484,286,116	153,668,162
20	Missouri Portion				
21	Gross Revenue Requirements				
22	Excluding Environmental & Boiler	LN15 * LN49&51	435,502,692	216,012,663	219,490,028
23	Boiler Maintenance	LN16 * LN49&51	5,409,972	5,409,972	-
24	Environmental Costs	LN17 * LN49&51	40,574,789	40,574,789	-
25	Off-System Sales	LN18 * LN49&51	(131,591,071)	-	(131,591,071)
26	Net Revenue Requirements	SUM	349,896,381	261,997,423	87,898,957
27	Missouri Portion of Total	LN24 / LN18	54.85%	54.10%	57.20%
28	Allocation Recognizing Nature of Off-System Sales, Environmental Cost, and Boiler Maintenance				
29	Gross Revenue Requirements				
30	Excluding Environmental & Boiler	Balance	783,006,586	399,286,116	383,720,471
31	Boiler Maintenance	LN3	10,000,000		10,000,000
32	Environmental Costs	LN4	75,000,000		75,000,000
33	Off-System Sales	LN11	(230,052,308)	(77,251,325)	(152,800,983)
34	Net Revenue Requirements	LN12	637,954,278	322,034,790	315,919,487
35	Missouri Portion				
36	Gross Revenue Requirements				
37	Excluding Environmental & Boiler	LN30 * LN49&51	435,502,692	216,012,663	219,490,028
38	Boiler Maintenance	LN31 * LN49&51	5,720,050	-	5,720,050
39	Environmental Costs	LN32 * LN49&51	42,900,375	-	42,900,375
40	Off-System Sales	LN33 * LN49&51	(129,195,676)	(41,792,749)	(87,402,927)
41	Net Revenue Requirements	SUM	354,927,441	174,219,914	180,707,527
42	Missouri Portion of Total	LN39 / LN33	55.64%	54.10%	57.20%

			Total	Missouri	Other
			MW	MW	MW
43	Coincident Peak Demand (4CP) - MW				
44	June		3,431	1,847	1,584
45	July		3,689	1,992	1,697
46	August		3,436	1,866	1,570
47	September		3,243	1,761	1,482
48	Average		3,450	1,866	1,583
49	Capacity Responsibility	LN 47	100.00%	54.10%	45.90%
50	Annual Deliveries - MWH		16,266,920	9,304,760	6,962,161
51	Energy Responsibility	LN 49	100.00%	57.20%	42.80%

52 Reference:

53 LN 3 = Estimated @ $10,000,000 (Aproximately = 50% of Boiler Maintenance, exclusive of 28.61%Applicable to Enviornmental

Kansas City Power Light Company
Impact of Single CP Allocation of
Power Supply Capacity Related Cost

Line No.	Description [A]	Reference [B]	Total [C]	Capacity [D]	Energy [E]
			$	$	$
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-7	783,006,586	399,286,116	383,720,471
4	Boiler Maintenance	LWL-7	10,000,000	10,000,000	-
5	Environmental Costs	LWL-7	75,000,000	75,000,000	-
6	Off-System Sales	LWL-7	(230,052,308)	-	(230,052,308)
7	Net Revenue Requirements	LWL-7	637,954,278	484,286,116	153,668,162
8	Missouri Portion				
9	Gross Revenue Requirements				
10	Excluding Environmental & Boiler	LN3 * LN33&35	435,074,109	215,584,081	219,490,028
11	Boiler Maintenance	LN4 * LN33&35	5,399,238	5,399,238	-
12	Environmental Costs	LN5 * LN33&35	40,494,286	40,494,286	-
13	Off-System Sales	LN6 * LN33&35	(131,591,071)	-	(131,591,071)
14	Net Revenue Requirements	SUM	349,376,562	261,477,604	87,898,957
15	Missouri Portion of Total	LN12 / LN6	54.77%	53.99%	57.20%
16	Allocation Recognizing Nature of Off-System Sales, Environmental Cost, and Boiler Maintenance				
17	Gross Revenue Requirements				
18	Excluding Environmental & Boiler	LWL-7	783,006,586	399,286,116	383,720,471
19	Boiler Maintenance	LWL-7	10,000,000	-	10,000,000
20	Environmental Costs	LWL-7	75,000,000	-	75,000,000
21	Off-System Sales	LWL-7	(230,052,308)	(77,251,325)	(152,800,983)
22	Net Revenue Requirements	LWL-7	637,954,278	322,034,790	315,919,487
23	Missouri Portion				
24	Gross Revenue Requirements				
25	Excluding Environmental & Boiler	LN18 * LN33&35	435,074,109	215,584,081	219,490,028
26	Boiler Maintenance	LN19 * LN33&35	5,720,050	-	5,720,050
27	Environmental Costs	LN20 * LN33&35	42,900,375	-	42,900,375
28	Off-System Sales	LN21 * LN33&35	(129,112,756)	(41,709,830)	(87,402,927)
29	Net Revenue Requirements	SUM	354,581,778	173,874,251	180,707,527
30	Missouri Portion of Total	LN27 / LN21	55.58%	53.99%	57.20%

			Total	Missouri	Other
			MW	MW	MW
31	Coincident Peak Demand (1CP) - MW				
32	July		3,689	1,992	1,697
33	Capacity Responsibility	LN32	100.00%	53.99%	46.01%
34	Annual Deliveries - MWH		16,266,920	9,304,760	6,962,161
35	Energy Responsibility	LN34	100.00%	57.20%	42.80%

Kansas City Power Light Company
Impact of Twelve CP Allocation of
Power Supply Capacity Related Cost

Line No.	[A] Description	[B] Reference	[C] Total	[D] Capacity	[E] Energy
			$	$	$
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-7	783,006,586	399,286,116	383,720,471
4	Boiler Maintenance	LWL-7	10,000,000	10,000,000	-
5	Environmental Costs	LWL-7	75,000,000	75,000,000	-
6	Off-System Sales	LWL-7	(230,052,308)	-	(230,052,308)
7	Net	LWL-7	637,954,278	484,286,116	153,668,162
8	Missouri Portion				
9	Gross Revenue Requirements				
10	Exclude Environ & Boiler	LN3 * LN45&47	436,905,914	217,415,885	219,490,028
11	Boiler Maintenance	LN4 * LN45&47	5,445,115	5,445,115	-
12	Environmental Costs	LN5 * LN45&47	40,838,363	40,838,363	-
13	Off-System Sales	LN6 * LN45&47	(131,591,071)	-	(131,591,071)
14	Net	SUM	351,598,321	263,699,363	87,898,957
15	Missouri Portion of Total	LN14 / LN7	55.11%	54.45%	57.20%
16	Allocation Recognizing Nature of Off-System Sales, Environmental Cost, and Boiler Maintenance				
17	Gross Revenue Requirements				
18	Exclude Environ & Boiler	LWL-7	783,006,586	399,286,116	383,720,471
19	Boiler Maintenance	LWL-7	10,000,000	-	10,000,000
20	Environmental Costs	LWL-7	75,000,000	-	75,000,000
21	Off-System Sales	LWL-7	(230,052,308)	(77,251,325)	(152,800,983)
22	Net Revenue Requirements	LWL-7	637,954,278	322,034,790	315,919,487
23	Missouri Portion				
24	Gross Revenue Requirements				
25	Exclude Environ & Boiler	LN18 * LN45&47	436,905,914	217,415,885	219,490,028
26	Boiler Maintenance	LN19 * LN45&47	5,720,050	-	5,720,050
27	Environmental Costs	LN20 * LN45&47	42,900,375	-	42,900,375
28	Off-System Sales	LN21 * LN45&47	(129,467,162)	(42,064,236)	(87,402,927)
29	Net Revenue Requirements	SUM	356,059,177	175,351,650	180,707,527
30	Missouri Portion of Total	LN29 / LN22	55.81%	54.45%	57.20%

Line No.	Description	Reference	Total	Missouri	Other
			MW	MW	MW
31	Monthly Coincident Peak Demand (12CP) - MW				
32	January		2,588	1,430	1,159
33	February		2,425	1,334	1,091
34	March		2,197	1,223	974
35	April		2,301	1,279	1,022
36	May		2,761	1,488	1,273
37	June		3,431	1,847	1,584
38	Maximum Annual - July		3,689	1,992	1,697
39	August		3,436	1,866	1,570
40	September		3,243	1,761	1,482
41	October		2,552	1,384	1,168
42	November		2,239	1,232	1,006
43	December		2,443	1,300	1,143
44	Average		2,775	1,511	1,264
45	Capacity Responsibility	LN44	100.00%	54.45%	45.55%
46	Annual Deliveries - MWH		16,266,920	9,304,760	6,962,161
47	Energy Responsibility	LN46	100.00%	57.20%	42.80%

Kansas City Power Light Company
Allocation Results
Capital Substitution Method

	[A]	[B]	[C]	[D]	[E]
Line No.	Description	Reference	Total KCPL Power Supply Cost	Fixed Cost	Variable Cost
			$	$	$
1	Annual Revenue Requirements - $				
2	Nuclear	LWL-4	197,489,522	160,899,785	36,589,737
3	Steam	LWL-4	442,603,925	231,182,479	211,421,446
4	Purchase Power	LWL-4	102,927,339	8,681,056	94,246,283
5	Wind	LWL-4	16,673,185	16,075,624	597,562
6	Subtotal (Before Peaking)	LWL-4	759,693,971	416,838,943	342,855,029
7	Other Generation (Peaking)	LWL-4	108,312,615	67,447,173	40,865,442
8	Total Power Supply before Bulk Sales Credit	LWL-4	868,006,586	484,286,116	383,720,471
9	Off-System Sales (Credit)	LWL-4	(230,052,308)	(98,541,636)	(131,510,672)
10	Net Revenue Requirements	LWL-4	637,954,278	385,744,479	252,209,799
			Capacity Factor	Accredited Capacity	Annual Generation
				MW	MWH
11	Units of Service				
12	Nuclear		101.52%	548	4,873,482
13	Steam		75.97%	2,238	14,894,358
14	Purchase Power		70.66%	257	1,590,713
15	Wind		231.90%	15	304,715
16	Subtotal (Before Peaking)		80.87%	3,058	21,663,268
17	Other Generation (Peaking)		4.97%	1,250	543,884
18	Total		58.85%	4,308	22,207,152
			Unit Total Cost	Unit Fixed Cost	Unit Variable Cost
			$/kWh	$/kW	$/kWh
19	Unit Cost				
20	Nuclear	LN 2 / LN 12	0.0405	293.61	0.0075
21	Steam	LN 3 / LN 13	0.0297	103.30	0.0142
22	Purchase Power	LN 4 / LN 14	0.0647	33.78	0.0592
23	Wind	LN 5 / LN 15	0.0547	1,071.71	0.0020
24	Subtotal (Before Peaking)	LN 6 / LN 16	0.0351	136.31	0.0158
25	Other Generation (Peaking)	LN 7 / LN 17	0.1991	53.96	0.0751
26	Total	LN 8 / LN 18	0.0391	112.42	0.0173
			Total	Capacity Related	Energy Related
			$	$	$
27	Unit Cost of Peaking Capacity - $/kW	LN 25		53.96	
28	Functionally Classified Cost - $				
29	Capacity Related	LN 18 / LN 27	232,449,936	232,449,936	-
30	Fixed Costs Classified as Energy Related	LN 31 - LN 29	153,294,543	-	153,294,543
31	Total Fixed Costs	LN 10	385,744,479	232,449,936	153,294,543
32	Variable Costs Classified as Energy Related	LN 10	252,209,799	-	252,209,799
33	Total	SUM	637,954,278	232,449,936	405,504,342
34	Portion Applicable to				
35	Missouri		56.07%	54.10%	57.20%
36	Other		43.93%	45.90%	42.80%
37	Total		100.00%	100.00%	100.00%
38	Allocated Costs - $				
39	Missouri	LN 33 * LN 35	357,705,272	125,754,760	231,950,512
40	Other	LN 33 * LN 36	280,249,006	106,695,176	173,553,830
41	Total	Sum	637,954,278	232,449,936	405,504,342

Kansas City Power Light Company
Allocation Results
Base, Intermediate, Peaking Method

	[A]	[B]	[C]	[D]	[E]
Line No.	Description	Reference	Total KCPL Power Supply	Demand Related	Energy Related
			$	$	$
1	Gross Revenue Requirements Recognizing Nature of Off-System Sales, Environmental Cost, and Boiler Maintenance				
2	Excluding Environmental & Boiler	LWL-7	783,006,586	399,286,116	383,720,471
3	Boiler Maintenance	LWL-7	10,000,000	-	10,000,000
4	Environmental Costs	LWL-7	75,000,000	-	75,000,000
5	Off-System Sales	LWL-7	(230,052,308)	(77,251,325)	(152,800,983)
6	Net Revenue Requirements	LWL-7	637,954,278	322,034,790	315,919,487
7	Net Revenue Requirements by Resource Type				
8	Base (Wolf Creek, Spearville, & Iatan)		263,423,054	167,529,918	95,893,137
9	Intermediate (LaCygne & Hawthorn 5)		160,007,422	78,332,675	81,674,747
10	Montrose & Purchases		119,260,435	21,774,273	97,486,162
11	Peaking		95,263,367	54,397,925	40,865,442
12	Total	SUM	637,954,278	322,034,790	315,919,487
13	Cost Responsibility Applicable to Missouri				
14	Base (Wolf Creek, Spearville, & Iatan)			60.99%	59.53%
15	Intermediate (LaCygne & Hawthorn 5)			60.97%	55.74%
16	Montrose & Purchases			48.40%	53.43%
17	Peaking			40.27%	40.96%
18	Cost Applicable to Missouri				
19	Base (Wolf Creek, Spearville, & Iatan)	LN 8 * LN 14	159,254,917	102,173,214	57,081,703
20	Intermediate (LaCygne & Hawthorn 5)	LN 8 * LN 15	93,287,799	47,760,998	45,526,801
21	Montrose & Purchases	LN 8 * LN 16	62,624,921	10,538,840	52,086,081
22	Peaking	LN 8 * LN 17	38,642,391	21,904,668	16,737,723
23	Total	SUM	353,810,029	182,377,720	171,432,308
24	Missouri Cost Responsibility	LN 23	55.46%	56.63%	54.26%

Kansas City Power Light Company
Allocation Results
Economic Rents Allocation Method

	[A]	[B]	[C]	[D]	[E]
Line No.	Description	Reference	Total KCPL Power Supply Cost	Demand Related	Energy Related
			$	$	$
1	Gross Revenue Requirements Recognizing Nature of Off-System Sales, Environmental Cost, and Boiler Maintenance				
2	Excluding Environmental & Boiler	LWL-7	783,006,586	399,286,116	383,720,471
3	Boiler Maintenance	LWL-7	10,000,000	-	10,000,000
4	Environmental Costs	LWL-7	75,000,000	-	75,000,000
5	Off-System Sales	LWL-7	(230,052,308)	(77,251,325)	(152,800,983)
6	Net Revenue Requirements	LWL-7	637,954,278	322,034,790	315,919,487
7	Total Units				
8	4CP - MW			3,450	
9	Annual Sales - MWH				16,266,920
10	Unit Cost				
11	Fixed Cost - S/kW	LN 6 / LN 8		93.35	
12	Variable Cost - $/kWh	LN 6 / LN 9			0.0194
13	100% Load Factor Equivalent	LN 11 / 8760	0.0301	0.0107	0.0194

Line No.	Description	Reference	Total	Missouri	Other
14	4CP Average Demand - MW		3,450	1,866	1,583
15	Responsibility	LN 14	100.00%	54.10%	45.90%
16	Annual Sales - MWH		16,266,920	9,304,760	6,962,161
17	Responsibility	LN 16	100.00%	57.20%	42.80%
18	Annual Load Factor		53.83%	56.92%	50.19%
19	Cost Responsibility based on 4CP Allocation - $	LN 6 * LN 15	637,954,278	345,131,466	292,822,812
20	Associated Energy - MWH	LN 9 * LN 15	16,266,920	8,800,358	7,466,562
21	MWH Deficiency (Excess)	LN 16 - LN 20	-	504,402	(504,402)
22	Value of MWH Deficiency (Excess)	LN 21 * LN 13	-	15,171,259	(15,171,259)
23	Total Cost Responsibility				
24	Amount	LN 21 + LN 22	637,954,278	360,302,725	277,651,553
25	Percent	LN 23	100.00%	56.48%	43.52%

Kansas City Power Light Company
Allocation Results
Hour-by-Hour Allocation Method

[A] [B] [C] [D] [E] [F] [G] [H] [I] [J] [K]

Line No.	Description	Reference	Gross Revenue Requirements	Boiler Maintenance	Environmental Costs	Off-System Sales	Net Revenue Requirements
			$	$	$	$	$
1	Revenue Requirements						
2	Demand Related	LWL-7	399,286,116	-	-	(77,251,325)	322,034,790
3	Energy Related	LWL-7	383,720,471	10,000,000	75,000,000	(152,800,983)	315,919,487
4	Total	LWL-7	783,006,586	10,000,000	75,000,000	(230,052,308)	637,954,278

Line No.	Description	Reference	Total	Base (Wolf Creek, Spearville, & Iatan)	Intermediate (LaCygne & Hawthorn 5)	Montrose	Peaking	Purchases and Off-System Sales
			$	$	$	$	$	$
5	Net Revenue Requirements by Resource Type							
6	Demand Related		322,034,790	207,717,837	97,123,511	26,997,595	67,447,173	(77,251,325)
7	Energy Related		315,919,487	95,893,137	176,382,442	155,579,449	40,865,442	(152,800,983)
8	Total		637,954,278	303,610,974	273,505,953	182,577,045	108,312,615	(230,052,308)
9	Generation - MWH		16,266,920	8,117,596	8,843,781	3,092,240	540,696	(4,327,393)
10	Unit Cost - $/MWH	LN 8 / LN 9	39.22	37.40	30.93	59.04	200.32	53.16

Line No.	Hours		Missouri Hourly				Base (Wolf Creek, Spearville, & Iatan)	Intermediate (LaCygne & Hawthorn 5)			Purchases and Off-System Sales
12	Number	Total	Cost	Load	Hourly Cost	Native Load			Montrose	Peaking	
13	Hours	Hours	$	MW	$/MWH	MW	MW	MW	MW	MW	MW
14	Smoothed Load Curves										
15	1	1	97,627	1,985	49.19	3,689	1,065	1,161	470	171	822
16	4	5	106,602	1,956	54.51	3,643	1,062	1,152	478	302	649
17	5	10	110,595	1,929	57.34	3,596	1,065	1,159	474	372	526
18	10	20	101,598	1,902	53.41	3,540	1,061	1,154	470	275	580
19	15	35	110,392	1,844	59.86	3,425	1,055	1,112	466	418	375
20	25	60	110,585	1,797	61.55	3,336	983	1,129	451	448	325
21	50	110	103,772	1,750	59.29	3,230	1,034	1,119	462	396	219
22	75	185	100,152	1,688	59.35	3,109	1,004	1,150	458	394	104
23	100	285	92,485	1,618	57.16	2,981	972	1,154	452	341	61
24	150	435	83,330	1,556	53.57	2,847	1,003	1,138	443	270	(7)
25	200	635	76,432	1,483	51.54	2,699	990	1,103	427	226	(47)
26	250	885	68,684	1,391	49.36	2,513	940	1,111	421	187	(146)
27	300	1185	61,361	1,308	46.90	2,353	900	1,102	415	146	(210)
28	350	1535	56,233	1,245	45.17	2,231	881	1,089	382	122	(244)
29	400	1935	50,289	1,198	41.99	2,137	878	1,081	388	80	(288)
30	450	2385	45,555	1,154	39.48	2,052	875	1,083	394	51	(351)
31	500	2885	42,835	1,112	38.52	1,969	890	1,071	379	46	(417)
32	550	3435	41,081	1,080	38.06	1,897	888	1,049	363	44	(447)
33	600	4035	38,715	1,046	37.02	1,830	910	1,001	352	34	(467)
34	650	4685	36,701	1,020	36.00	1,774	942	977	348	28	(519)
35	700	5385	35,198	992	35.47	1,723	943	959	336	25	(540)
36	750	6135	33,164	961	34.50	1,663	922	970	340	21	(591)
37	700	6835	30,498	919	33.18	1,581	933	989	330	22	(692)
38	650	7485	27,957	874	31.99	1,492	929	957	319	17	(729)
39	500	7985	25,115	833	30.15	1,406	959	930	292	12	(787)
40	400	8385	22,991	797	28.86	1,327	967	905	283	10	(838)
41	350	8735	21,577	757	28.50	1,247	955	874	270	14	(867)
42	24	8759	16,607	695	23.88	1,149	1,002	935	213	12	(1,012)
43	1	8760	14,081	679	20.72	1,114	904	1,039	207	-	(1,036)
44	Annual Units - MWH			9,275,983		16,266,920	8,117,596	8,843,781	3,092,240	540,696	(4,327,393)
45	Annual Cost - $		361,971,489		637,954,278	637,954,278	303,610,974	273,505,953	182,577,045	108,312,615	(230,052,308)
46	Ratio		56.74%								

Kansas City Power Light Company
Summary of Allocation Results

	[A]	[B]	[C]	[D]	[E]
Line No.	Description	Reference Schedule	Total	Applicable to Missouri Amount	Applicable to Missouri Of Total
			$	$	%
1	Total KCPL Power Supply Revenue Requirement	LWL 5	637,954,278		
2	4 CP Allocation of Demand Costs				
3	No Recognition of Nature of Off-System Sales, etc.	LWL 5		349,896,381	54.85%
4	Recognizing Nature of:				
5	Off-System Sales	LWL 5		352,951,942	55.33%
6	Off-System Sales and Environmental Costs	LWL 6		354,694,882	55.60%
7	Off-System, Environmental, and Boiler Maintenance	LWL 7		354,927,441	55.64%
8	No Recognition of Nature of Off-System Sales, etc.				
9	1 CP	LWL 8		349,376,562	54.77%
10	12 CP	LWL 8		351,598,321	55.11%
11	Allocations Recognizing Nature of Off-System, Environmental, & Boiler Maintenance				
12	1CP	LWL 8		354,581,778	55.58%
13	12CP	LWL 8		356,059,177	55.81%
14	Capital Substitution - 4CP	LWL 9		357,705,272	56.07%
15	Base, Intermediate, Peaking	LWL 10		353,810,029	55.46%
16	Annual Rents - 4CP	LWL 11		360,302,725	56.48%
17	Hour-by-Hour	LWL 12		361,971,489	56.74%
18	Basic Allocation Factors				
19	4CP		3,450	1,866	54.10%
20	Annual Sales		16,266,920	9,304,760	57.20%