EXHIBIT:	
WITNESS:	**DENNIS W. GOINS**
TYPE OF EXHIBIT:	**DIRECT TESTIMONY**
ISSUES:	**COST OF SERVICE, REVENUE SPREAD**
SPONSORING PARTY:	**U.S. DEPT. OF ENERGY**
CASE:	**ER-2012-0174**

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2012-0174

IN THE MATTER OF KANSAS CITY POWER & LIGHT COMPANY'S REQUEST FOR AUTHORITY TO IMPLEMENT A GENERAL RATE INCREASE FOR ELECTRIC SERVICE

DIRECT TESTIMONY OF DR. DENNIS W. GOINS ON BEHALF OF THE U.S. DEPARTMENT OF ENERGY

August 16, 2012

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INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Dennis W. Goins. I operate Potomac Management Group, an economics and management consulting firm. My business address is 5801 Westchester Street, Alexandria, Virginia 22310.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Ph.D. degree in economics and a Master of Economics degree from North Carolina State University. I also earned a B.A. degree with honors in economics from Wake Forest University. Following graduate school I worked as a staff economist at the North Carolina Utilities Commission (NCUC). During my tenure at the NCUC, I testified in numerous cases involving electric, gas, and telephone utilities on such issues as cost of service, rate design, intercorporate transactions, and load forecasting. While at the NCUC I also served as a member of the Ratemaking Task Force in the national Electric Utility Rate Design Study sponsored by the Electric Power Research Institute (EPRI) and the National Association of Regulatory Utility Commissioners (NARUC).

Since leaving the NCUC, I have worked as an economic and management consultant to firms and organizations in the private and public sectors. My assignments focus primarily on market structure, policy, planning, and pricing issues involving firms that operate in energy markets. For example, I have conducted detailed analyses of product pricing, cost of service, rate design, and interutility planning, operations, and pricing issues; prepared analyses related to utility mergers, transmission access and pricing, and the emergence of competitive markets; evaluated and developed regulatory incentive mechanisms applicable to utility operations; and assisted clients in analyzing and negotiating interchange agreements and power and fuel supply contracts. I have also assisted clients on electric power market restructuring issues in Arkansas, New Jersey, New York, South Carolina, Texas, and Virginia.

I have submitted testimony and affidavits and provided technical assistance in nearly 200 proceedings before state and federal agencies as an expert in competitive market issues, regulatory policy, utility planning and operating practices, cost of service, and rate design. These agencies include the Federal Energy Regulatory Commission (FERC), the Government Accountability Office, state courts in Iowa, Montana, and West Virginia, and regulatory agencies in Alabama, Arizona, Arkansas, Colorado, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Wyoming, and the District of Columbia. Additional details of my educational and professional background are presented in the Appendix.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am testifying on behalf of the U.S. Department of Energy (DOE), representing the Federal Executive Agencies (FEA)—that is, all federal facilities served by Kansas City Power & Light Company (KCPL). The largest FEA facility currently served by KCPL is the Bannister Federal Complex, with annual electricity costs exceeding $7 million. Ownership of the Bannister complex is divided between DOE's National Nuclear Security Administration (NNSA) and the General Services Administration. At the Bannister complex, NNSA operates the Kansas City Site Office and Kansas City Plant (KCP), a high-tech research production facility that specializes in science-based manufacturing. In 2014 NNSA will complete its move from the Bannister Federal Complex to a new facility in the Kansas City area served by KCPL's affiliate, KCP&L Greater Missouri Operations Company (GMO).

Q. WHAT ASSIGNMENT WERE YOU GIVEN WHEN YOU WERE RETAINED?

A. I was asked to undertake two primary tasks:

1. Review and evaluate KCPL's application for an increase in base rates, in particular the method KCPL proposes to allocate its cost of service among retail rate classes.
2. Identify any major deficiencies in KCPL's cost analyses, and suggest recommended changes.

Q. WHAT INFORMATION DID YOU REVIEW IN CONDUCTING YOUR EVALUATION?

A. I reviewed KCPL's filing, testimony, exhibits, and selected responses to requests for information. I also reviewed information (including information on prior regulatory cases) found on web sites operated by this Commission, and by KCPL and its parent company, Great Plains Energy.

CONCLUSIONS

Q. WHAT CONCLUSIONS HAVE YOU REACHED?

A. On the basis of my review and evaluation, I have concluded the following:

1. KCPL's Cost of Service. In this case, KCPL initially conducted a jurisdictional separation study in which it allocated and/or assigned total company test-year costs to each regulatory jurisdiction in which it operates (including the Missouri retail jurisdiction).[1] In addition, KCPL conducted a class cost-of-service study (COSS) in which it allocated its Missouri retail costs to various rate classes.[2] KCPL's cost studies are significantly deficient in at least two major areas—the allocation of demand-related (fixed) production costs, and the allocation of nonfirm off-system sales margins.[3]

2. Production Cost Allocation. In its jurisdictional separation study, KCPL allocated demand-related production costs on the basis of contributions to KCPL's system coincident peaks in the four summer months of June through September (the 4CP Method). However, in its class COSS, KCPL allocated demand-related production costs assigned to the Missouri retail jurisdiction on the basis of various measures of each class' relative use of production plant and equipment classified as base, intermediate, and peak (the BIP Method). I agree with the 4CP Method KCPL used in its

[1] The costing approaches KCPL used in its jurisdictional separation study are described primarily in the direct testimony of KCPL witness John P. Weisensee (Weisensee Direct).

[2] KCPL's class COSS is described in the direct testimony of KCPL witness Paul M. Normand (Normand Direct). The test year for both the jurisdictional and class cost studies is the 12 months through September 2011, adjusted for known and measurable changes through August 2012.

[3] Although my testimony focuses on these two problem areas, my decision not to address other allocation issues or elements in the jurisdictional and class cost studies should not be construed as my implicit endorsement of the methods and approaches KCPL took in addressing those issues.

jurisdictional study. However, in my opinion, the BIP Method does not result in a reasonable allocation of demand-related production costs to KCPL's retail rate classes. The BIP Method has never been approved by this Commission (to my knowledge), nor has it been widely used by regulatory commissions in other states to allocate fixed production costs. In particular, the BIP Method:

- Is inconsistent with the 4CP Method that KCPL used to allocate fixed production costs in its jurisdictional separation study. Even though KCPL used class contributions to its 4CP demands to allocate fixed production costs to the Missouri retail jurisdiction, it then used the markedly different BIP Method to allocate jurisdictional fixed production costs to Missouri rate classes. As a result, customer loads (demand and energy) used to allocate fixed production costs to the Missouri retail jurisdiction do not match customer loads used to allocate these jurisdictional costs among Missouri retail rate classes in KCPL's BIP cost study. This mismatch between the allocation of fixed production costs to the Missouri retail jurisdiction and the allocation of those costs among customer classes in the state ensures that customer loads that cause KCPL to incur such costs are not assigned responsibility for them. Moreover, KCPL's different jurisdictional and class allocation methods reflect fundamentally different concepts about cost drivers and cost responsibility. The 4CP Method emphasizes contributions to system peak demands, while the BIP Method emphasizes energy consumption with little recognition of demand.
- Classifies production plant by operating characteristics and assumed dispatch order, and then relies on an implicit,

complex, and indirect linkage between plant classification and customer cost responsibility using an array of nontraditional allocation factors.

- Allocates all baseload capacity costs on the basis of minimum class average demands—that is, energy (kWh) use. This approach fails to recognize any meaningful capacity value of baseload plants that were constructed to meet peak demands throughout the year.
- Fails to align allocated plant and fuel costs properly by base, intermediate, and peaking category. The BIP Method allocates a disproportionately large share of expensive baseload plant costs to high load factor classes compared to low load factor classes. KCPL's underlying rationale for this allocation is the assumption that it only built higher cost baseload plants (relative to the cost of peaking and intermediate capacity) to gain the lower relative fuel cost of baseload capacity. However, KCPL combined this BIP allocation of fixed production costs by specific capacity type with an allocation of *average* monthly fuel costs for all capacity types—not an allocation of fuel costs that reflected each class' use of a particular capacity type. As a result, high load factor classes were allocated a disproportionately large share of expensive baseload plant costs, but were not allocated a corresponding share of lower baseload fuel costs. In other words, under KCPL's BIP Method, higher load factor classes get to pay a disproportionate share of KCPL's baseload plant costs without getting a fair share of the fuel cost savings from these plants. Similarly, under KCPL's proposed BIP Method and average fuel cost allocation, a low load factor class with predominately peak usage gets the benefit of lower fuel costs from baseload

units, but is not allocated a fair and reasonable share of baseload plant costs.

3. Off-System Sales Margin Allocation. In prior rate cases, the Commission approved allocating off-system sales margins on the basis of class energy use. However, in this case, KCPL allocated off-system sales margins using a modified 12CP allocator (factor DEM1B in KCPL's BIP COSS)—the same factor KCPL used to allocate fixed production costs classified as Intermediate.[4] In my opinion, KCPL's arguments supporting the DEM1B allocation do not justify overturning Commission precedent and allocating off-system margins using anything other than an energy allocator that the Commission previously found just and reasonable.[5]

4. Revenue Spread. KCPL proposed spreading its proposed $105.7 million (15.1 percent) rate increase on a uniform, across-the-board percentage basis to each class. This proposal is reasonable given the unreliability of results from KCPL's BIP class COSS and the need to temper class rate increases during tough economic times. As I show later, correcting the two major allocation problems in KCPL's BIP COSS that I have highlighted results in significantly different cost responsibility assigned to each class relative to class cost responsibility identified in KCPL's cost study.

RECOMMENDATIONS

Q. WHAT DO YOU RECOMMEND ON THE BASIS OF THESE CONCLUSIONS?

A. I recommend that the Commission:

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[4] In KCPL's class cost study, Factor DEM1B is designated the 12CP Remaining allocator, and equals each class' 12CP demand (average of each class' monthly test-year coincident peak demand) less the class' Base demand (lowest average monthly test-year demand).

[5] KCPL also used the DEM1B factor to allocate the capacity component of firm bulk sales in Account 447.

1. Reject KCPL's BIP Method for allocating fixed production costs to rate classes. Instead, KCPL should be required to use the 4CP Method.
2. Reject KCPL's proposed allocation of off-system sales margins. Instead, the energy component of such margins should be allocated using loss-adjusted kWh (energy) for each class.
3. Approve an across-the-board revenue spread of any rate increase granted to KCPL. An across-the-board spread is both reasonable and fair in this case.

ALLOCATING DEMAND-RELATED PRODUCTION COSTS

Q. HOW DID KCPL ALLOCATE DEMAND-RELATED PRODUCTION COSTS IN THIS CASE?

A. As I noted earlier, KCPL allocated these costs using the 4CP Method in the jurisdictional separation study, and the BIP Method in the Missouri retail class COSS. The Commission approved the 4CP Method in KCPL's 2006 Missouri rate case (Case No. ER-2006-0314) for allocating jurisdictional fixed production (as well as transmission) costs, even though KCPL proposed a 12CP allocation method. The Commission in that case rendered no decision regarding the appropriate method for allocating fixed production costs in KCPL's class COSS.[6] In 2010 KCPL filed a Missouri retail class cost-of-service study based on the BIP Method in Case No. ER-2010-0355. The Commission's *Report and Order* in that case did not

[6] Almost all class cost-of-service and rate design issues in the case were resolved in a nonunanimous stipulation and agreement that did not specify a methodology for allocating fixed production costs among customer classes. The Commission approved this stipulation and agreement in its *Report and Order* issued on December 21. 2006.

specify a methodology for allocating KCPL's fixed production costs among Missouri retail customer classes.[7]

Q. IS THE 4CP METHOD APPROPRIATE FOR ALLOCATING JURISDICTIONAL FIXED PRODUCTION COSTS?

A. Yes. KCPL is predominately a summer peaking utility, with system peaks most likely in June through September.[8] As a result, the 4CP Method properly reflects the principal factor—coincident peak demands—driving KCPL's need for production capacity, and assigns responsibility for fixed production costs to classes that create those peak demands.

Q. SHOULD THE 4CP METHOD ALSO BE USED TO ALLOCATE FIXED PRODUCTION COSTS AMONG MISSOURI RETAIL RATE CLASSES?

A. Yes. As I will discuss in more detail, the 4CP Method is superior to KCPL's BIP Method for allocating fixed production costs in the Missouri retail class COSS. Moreover, using the 4CP Method to allocate fixed production costs in both the jurisdictional and class cost studies ensures consistency in linking customer demands that drive KCPL's need for production capacity with the cost responsibility for fixed production costs ultimately assigned to each rate class.

Q. ARE CONSISTENT ALLOCATION METHODS DESIRABLE IN JURISDICTIONAL AND CLASS COST STUDIES?

A. Yes. In general, consistency in jurisdictional and class production cost allocation methods is desirable to ensure a direct linkage between customer demands that determine how fixed production costs are allocated

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[7] Class cost-of-service and rate design issues were resolved in a nonunanimous stipulation and agreement approved by the Commission in its *Report and Order* issued on April 12, 2011.

[8] KCPL's June-September test-year system peak loads were significantly greater than system peak loads in other months.

to the Missouri retail jurisdiction and customer demands that are then used to allocate jurisdictional costs to Missouri rate classes. In its filing, KCPL raised the issue of cost recovery problems arising when jurisdictions use different methods to allocate fixed production (and other) costs.[9] KCPL's principal fix for these problems is to promote consistent cost allocation methods among jurisdictions—hence, its arguments supporting the 4CP Method for jurisdictional allocation. A similar problem arises when a different method is used to allocate fixed production costs assigned to a jurisdiction among customer classes in that jurisdiction. More specifically, using different jurisdictional and retail class cost-of-service allocation methods may allow customers responsible for costs assigned to KCPL's Missouri retail jurisdiction to avoid paying for those costs through retail rates. As I noted, the 4CP Method that KCPL used in its jurisdictional separation study and the BIP Method it used in its Missouri retail class COSS reflect fundamentally different concepts about cost drivers and cost responsibility.[10] As a result, under the BIP Method a low load factor class with high summer peak demands (for example, residential customers) will pay only a fraction of fixed production costs assigned to the Missouri retail jurisdiction on the basis of the class' 4CP demand. The BIP Method simply shifts responsibility for these costs to higher load factor classes. This result is both unfair and unreasonable—an outcome that KCPL could have easily avoided by using consistent allocation methods in its jurisdictional and class cost studies.

[9] Weisensee Direct at 5:10-16.

[10] As I noted earlier, the 4CP Method emphasizes system coincident peak demands as the key factor driving KCPL's need for production capacity, while the BIP Method emphasizes energy consumption.

Q. DO YOU SUPPORT KCPL'S BIP METHOD FOR ALLOCATING FIXED PRODUCTION COSTS IN ITS CLASS COSS?

A. No. The BIP Method is described in detail in KCPL's filing.[11] This allocation method received some national attention in the late 1970s and early 1980s following enactment of the Public Utility Regulatory Policies Act of 1978 (PURPA). However, the BIP method was subsequently overshadowed by probability of dispatch (POD) methods that facilitated the analysis of time-differentiated embedded (accounting) costs. Both the BIP and the POD allocation methods have fallen out of favor with cost analysts and regulators. In my opinion, the lack of enthusiasm for these cost allocation methods is due largely to their intensive data requirements and suspect data manipulations required to develop allocation factors.

Q. DOES THE BIP METHOD DIRECTLY ASSIGN FIXED PRODUCTION COSTS ON THE BASIS OF OBSERVABLE FACTORS DRIVING THESE COSTS?

A. No. In general, the BIP Method requires multiple assumptions and mathematical manipulations of demand and energy measures necessary to develop class allocation factors for plant and equipments costs that have been assigned to Base, Intermediate, and Peaking categories. By ignoring the importance of peak demands, the BIP Method produces class allocations of fixed production costs that are largely unrelated to key observable measures (peak demands) driving a utility's need for production capacity.

Q. DOES THE BIP METHOD PROPERLY RECOGNIZE THE CAPACITY VALUE OF BASELOAD PLANTS?

A. No. In my opinion, the BIP Method's most serious problem is its allocation of baseload capacity costs on the basis of class energy use (minimum average demand).[12] This approach implicitly assumes that baseload plants have little or no capacity value, and are built solely to provide energy on a year-round basis. As a result, higher load factor classes are assigned a disproportionate share of these costs relative to lower load factor classes. I agree that baseload plants are planned and designed to operate during most hours of the year, and higher load factor customers use energy from such plants during many of those hours. However, this fact does not automatically lead to the conclusion that baseload capacity must be allocated on an energy basis. System peak demands drive the need for production capacity—and customer contributions to system peaks should be the principle component of factors used to allocate fixed production costs.

Whether higher load factor customers benefit disproportionately from cheaper baseload and intermediate plant energy is an empirical question that KCPL has not addressed in this case. Moreover, in addressing this question, the method used to allocate energy-related costs must be considered. For example, if production plant costs are allocated on the basis of average energy use, then low load factor customers receive the benefits of cheaper baseload (and intermediate) energy without paying a fair share of the capital costs for these plants.

Q. IS THE RELATIVE USE OF PARTICULAR TYPES OF PRODUCTION CAPACITY A GOOD INDICATOR OF CLASS COST RESPONSIBILITY FOR THAT CAPACITY?

A. No. Yet the BIP Method rests on this assumption. Production capacity is built (or acquired) to meet system peak demands—not average demands. Building capacity to meet average demand would be a recipe for blackout disaster. Once capacity is built to meet system peaks, its fixed (sunk) costs

[11] Normand Direct at 8-11.

do not change because of the intensity of its use. How we allocate those costs should be linked to peak demands that the capacity was built to serve.

Q. DOES KCPL'S BIP METHOD PROPERLY ALIGN ALLOCATED BASELOAD CAPACITY AND FUEL COSTS?

A. No. Recall the BIP Method's general premise—utilities trade off higher baseload capacity costs (relative to peaking capacity costs) in exchange for fuel cost savings. The logical consequence of this trade-off is that high load factor customers that are allocated a disproportionately large share of baseload capacity costs should get a disproportionately large share of fuel-cost savings from the baseload capacity. This would require matching baseload fuel costs assigned to a class with a class' relative use of baseload capacity. However, in its BIP Method, KCPL did not separately identify fuel costs by capacity type. Instead, KCPL allocated average monthly fuel costs on the basis of class energy (kWh) use—*ignoring any matching of fuel costs and customer energy use by capacity type*. This average cost approach to fuel cost allocation in KCPL's BIP Method ensures that higher load factor classes pay a disproportionately large share of expensive baseload plant costs without getting the corresponding benefit of lower baseload fuel costs.

Q. DOES THIS MISMATCH OF ALLOCATED CAPACITY AND FUEL COSTS DISTORT RESULTS IN KCPL'S CLASS COST STUDY?

A. Yes. KCPL's mismatch of BIP-allocated capacity and fuel costs also means that a low load factor class with predominately peak usage receives the benefit of lower baseload fuel costs without being allocated a

[12] Average demand is total kWh used in a period divided by the number of hours in the period. KCPL uses factor DEM1A to allocate Base capacity costs in its BIP cost study.

corresponding share of baseload plant costs. As a result, cost of service for lower load factor classes is understated in KCPL's BIP cost study, and overstated for higher load factor classes.

ALLOCATING OFF-SYSTEM SALES MARGINS

Q. HOW DID KCPL ALLOCATE OFF-SYSTEM SALES MARGINS?

A. In the jurisdictional study, KCPL allocated non-firm sales using an energy allocator.[13] In the class cost study, KCPL allocated off-system sales margins using the same modified 12CP allocator (factor DEM1B in KCPL's BIP cost study) that it used to allocate fixed production costs classified as Intermediate.[14]

Q. DO YOU AGREE WITH KCPL'S PROPOSED MARGIN ALLOCATIONS?

A. No. This Commission has generally found that off-system sales margins should be allocated on the basis of energy. For example, in Case No. ER-2006-0314, the Commission rejected KCPL's proposed allocation of off-system sales and related margins (specifically, sales and margins related to the energy component of firm transactions and all nonfirm sales) using a demand-based allocation factor (unused energy). In its final order in the case, the Commission said:

> Staff recommends that the Commission continue to use the energy allocator for revenues from non-firm off-system sales of energy, including the margin component thereof. ***This is the time-tested and widely accepted method for allocating such revenues in this state*** because it is appropriate for allocating

[13] Weisensee Direct at Schedule JCW-7.
[14] Normand Direct at 15:4-13.

> revenues and associated costs that are purely variable with the amount of energy sold.[15] (Emphasis added.)
>
> The only costs assigned to non-firm off-system sales is the fuel and purchased power costs – the variable costs – hence the appropriateness of using the energy allocator. This is consistent with the way KCPL itself allocates the costs relating to the energy portion of firm capacity contracts – using the energy allocator. The reason is simple – the energy allocator is used to allocate variable costs of fuel and purchased power costs relating to retail sales. Using the same rationale, the energy allocator is equally appropriate to use as the allocation factor for both energy of firm (as KCPL does) and non-firm off-system sales. The demand based unused energy allocator should not be used to allocate off-system sales – either energy from firm capacity sales contracts or non-firm off-system sales....[16]

KCPL adhered to this precedent in its jurisdictional separation study, but ignored it in the BIP class cost study. However, even KCPL witness Normand (who sponsors the BIP cost study) is not convinced that allocating off-system sales margins on the basis of energy is wrong. For example, regarding the allocation of off-system sales margins, he says:

> These margins should follow and be consistent with the allocation of production plant. More importantly, these sales are made subsequent to KCP&L providing service to its firm service customers. Therefore, ***both an energy and 12CP allocation*** would reflect an equitable class allocation consistent

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[15] Case No. ER-2006-0314, *Report and Order* (December 21, 2006) at 38.
[16] *Id*. at 39-40.

> with the associated production plant allocation.[17] (Emphasis added.)

Despite acknowledging that allocating off-system margins on the basis of energy is reasonable, witness Normand chose a demand-based (12CP) allocation method. Two points are important regarding his position:

- The Commission's prior decision to allocate off-system margins was reasonable.
- KCPL's decision to reject allocating margins on energy is premised on the assumption that its capacity-based allocation method is superior to an energy allocation approach. In my opinion, this assumption is ill-founded and cannot withstand scrutiny. The Commission reached a similar conclusion in Case No. ER-2006-0314.

Q. SHOULD THE COMMISSION CONTINUE REQUIRING KCPL TO ALLOCATE OFF-SYSTEM SALES MARGINS ON THE BASIS OF ENERGY?

A. Yes. The Commission got it right when it previously required an energy allocation of off-system sales margins. KCPL's arguments for a capacity-based allocation method are not sufficient to justify overturning Commission precedent and allocating off-system margins using anything other than an energy allocator.

[17] Normand Direct at 15:15-18.

CORRECTING KCPL'S COST STUDIES

Q. DO THE TWO MAJOR PROBLEM AREAS IN KCPL'S COST STUDIES THAT YOU JUST DISCUSSED HAVE A SIGNIFICANT EFFECT ON RETAIL CLASS COST RESPONSIBILITY?

A. Yes. Because KCPL used improper methods to allocate demand-related production costs and off-system sales margins, results from its Missouri retail class COSS do not properly identify the cost responsibility of each customer class. To determine the magnitude of these errors, I ran KCPL's class cost-of-service model using the 4CP Method instead of KCPL's BIP Method to allocate fixed production costs. I also used an energy allocator to assign revenues and margins from off-system sales (that is, the energy component of firm transactions, plus all nonfirm transactions) to Missouri rate classes. Summary results from my cost analysis are presented in Schedule DWG-1, and shown in Table 1 below.

Table 1. Rates of Return (Present Rates)

	DOE 4CP		KCPL BIP	
Class	**ROR**	**RORI**	**ROR**	**RORI**
Residential	2.70%	0.49	5.43%	0.98
Small GS	10.21%	1.84	10.97%	1.98
Medium GS	7.25%	1.31	7.09%	1.28
Large GS	7.41%	1.34	5.80%	1.05
Large Pwr	7.08%	1.28	3.01%	0.54
Lighting	31.24%	5.64	6.19%	1.12
Total Retail	5.54%	1.00	5.54%	1.00

Source: Schedule DWG-1. RORI = rate of return index.

As shown in Table 1, the two major problems in KCPL's BIP class COSS produce misleading results regarding how well present rates recover KCPL's cost of serving each class.[18] For example, KCPL's BIP study indicates that revenues from present rates for residential customers just about recover KCPL's cost of serving these customers, but are far below

[18] The class rate of return (RORI) is the rate of return (ROR) earned from each class, divided by

cost of service for Large Power Service (LPS) customers. In contrast, DOE's 4CP cost study—which corrects the improper allocation of fixed production costs and off-system sales margins in KCPL's BIP study—shows that present rates for residential customers are far below KCPL's cost of service, while LPS rates are significantly above cost of service. These dramatic differences highlight the importance of relying on widely accepted cost allocation methods and Commission precedent instead of KCPL's arcane BIP Method to assign class cost responsibility.

Q. DO THE DOE 4CP AND KCPL BIP COST STUDIES INDICATE THAT SIMILAR RATE CHANGES WOULD BE NECESSARY FOR EACH CLASS UNDER KCPL'S PROPOSED RATE INCREASE?

A. No. As shown in Schedule DWG-2 and summarized in Table 2 below, the two cost studies show widely disparate rate increases by customer class are necessary if rates based on KCPL's proposed revenue increase are set equal to cost of service—that is, rates at which KCPL earns the same rate of return from each class. For example, residential rates would have to increase by about 34 percent to recover costs assigned under DOE's 4CP Method versus 15 percent under KCPL's BIP Method. In contrast, KCPL's BIP Method indicates a 31-percent increase in LPS rates is necessary, versus a 6.5-percent increase under DOE's 4CP Method.

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the system average (Missouri Retail) ROR.

Table 2. DOE 4CP Method vs KCPL BIP Method: Sales Revenue Increase Required at Equal Rates of Return

Rate Class	DOE 4CP	KCPL BIP
Residential	34.07%	15.30%
Small Gen Serv	-6.27%	-8.89%
Med Gen Serv	6.28%	7.14%
Large Gen Serv	5.36%	13.98%
Large Pwr Serv	6.55%	31.14%
Lighting	-38.86%	9.95%
MO Retail	15.00%	15.00%

Source: Schedule DWG-2, lines 9 and 16.

Q. WHY IS CORRECTLY ASSIGNING COST RESPONSIBILITY IMPORTANT?

A. Results from a Commission-approved cost-of-service study should be a principal guide in setting the revenue requirement and rates for each customer class in a general rate case. If the allocation methods used in a COSS are not reasonable, then results from the cost study do not provide a reasonable approximation of the utility's cost of serving each class. As a result, rates based on results from an ill-structured cost study (such as KCPL's BIP analysis) will provide improper, non-cost-based price signals to customers, promote inefficient electricity use and investments in electric equipment, and create inter- and intraclass subsidy problems.

Q. DOES THE DOE 4CP METHOD GIVE A FREE RIDE TO CUSTOMERS WITH PREDOMINATELY OFF-PEAK USAGE?

A. No. Fundamental economic principles support allocating little if any demand-related production costs to customers whose loads occur primarily in off-peak periods. Off-peak loads simply utilize production capacity that was built to serve peak demands. The 4CP Method recognizes the importance of peak demands, and does not arbitrarily shift cost to off-peak consumers. In contrast, KCPL's BIP Method systematically ignores any capacity value of baseload plant and fails to assign appropriate cost responsibility to customers whose peak loads drive KCPL's need for production capacity. As a result, KCPL's BIP Method creates a real and significant free rider problem by subsidizing on-peak consumption.

Q. DID YOU TEST YOUR 4CP COSS RESULTS USING ANOTHER WIDELY RECOGNIZED AND ACCEPTED METHOD FOR ALLOCATING FIXED PRODUCTION COSTS?

A. Yes. I also conducted a cost-of-service analysis using the average and excess demand (AED) methodology to allocate demand-related fixed production costs. The AED methodology uses allocation factors that reflect test-year kWh energy usage and contributions to maximum class peak demands. More specifically, the AED allocation factor for each class is comprised of two main elements:

- Average demand component that reflects test-year kWh usage.
- Excess demand component related to the difference between each class's test-year maximum diversified demand (that is, noncoincident peak) and its average demand.[19]

Q. WHAT WERE THE RESULTS OF YOUR AED COST STUDY?

A. The results are presented in Schedules DWG-3 and DWG-4, and summarized in Tables 3 and 4 below. The AED results shown in Table 3 are consistent with results from my 4CP cost study (see Table 1)—that is, they show that present rates residential customers are far below cost of service, while present rates for all other classes are significantly above cost of service.

[19] Coincident peak demands can also be used in an AED cost study.

Table 3. Rates of Return (Present Rates)

	DOE AED		KCPL BIP	
Class	**ROR**	**RORI**	**ROR**	**RORI**
Residential	2.35%	0.42	5.43%	0.98
Small GS	10.95%	1.98	10.97%	1.98
Medium GS	8.18%	1.48	7.09%	1.28
Large GS	7.61%	1.37	5.80%	1.05
Large Pwr	7.63%	1.38	3.01%	0.54
Lighting	12.77%	2.31	6.19%	1.12
Total Retail	5.54%	1.00	5.54%	1.00

Source: Schedule DWG-3. RORI = rate of return index.

The AED cost study also indicates (consistent with my 4CP study) that rates for residential customers would have to be increased more than 30 percent to recover KCPL's cost of service under its proposed revenue increase. (Compare Table 4 with results shown in Table 1.)

Table 4. DOE AED Method vs KCPL BIP Method: Sales Revenue Increase Required at Equal Rates of Return

Rate Class	DOE AED	KCPL BIP
Residential	37.10%	15.30%
Small Gen Serv	-8.78%	-8.89%
Med Gen Serv	1.76%	7.14%
Large Gen Serv	4.41%	13.98%
Large Pwr Serv	4.02%	31.14%
Lighting	-12.92%	9.95%
MO Retail	15.00%	15.00%

Source: Schedule DWG-4, lines 9 and 16.

Q. WHY IS THE CONSISTENCY OF RESULTS FROM YOUR 4CP AND AED COST STUDIES IMPORTANT?

A. The consistency of results implies that KCPL's arcane BIP cost analysis is unreliable and should not be used as a guide in setting class revenue requirements and rates. My 4CP study relies on summer coincident peak demands to allocate fixed production costs, while my AED study relies on average demand (energy) and noncoincident peak demands. Despite major differences in the 4CP and AED allocation methodologies, they produce similar results regarding class cost responsibility—unlike KCPL's BIP Method. This consistency despite differences implies that both methods (4CP and AED) produce fair and reasonable assignments of cost responsibility to customer classes unlike KCPL's BIP Method.

Q. ARE YOU RECOMMENDING THAT THE COMMISSION ADOPT YOUR AED ALLOCATION METHODOLOGY?

A. No. As I noted earlier, I presented the AED cost study only to show that it produced results similar to and consistent with my recommended 4CP allocation methodology. However, if the Commission decides not to adopt my recommended 4CP Method, then I would recommend my AED Method or an AED variant based on coincident peak demands. The AED allocation methodology is certainly a more reasonable and reliable indicator of cost responsibility than KCPL's BIP Method.

REVENUE SPREAD

Q. HOW DID KCPL PROPOSE SPREADING ITS REQUESTED REVENUE INCREASE ACROSS RATE CLASSES?

A. KCPL proposed an across-the-board revenue spread.[20] That is, KCPL proposed that each class receive an increase equal to the system average increase.

Q. DO RESULTS FROM KCPL'S BIP CLASS COSS INDICATE THAT IT EARNS THE SAME RATE OF RETURN FROM EACH CLASS?

A. No. As shown in Table 2, results from KCPL's BIP cost study indicate that rate increases necessary for KCPL to earn its proposed system average rate of return from each rate class would be well-above average for the

LPS class, well-below-average for small and medium general service and lighting customers, and about average for the residential and large general service classes.

Q. ARE SIGNIFICANT SHIFTS IN CLASS REVENUE REQUIREMENTS ALSO INDICATED BY RESULTS FROM DOE'S 4CP CLASS COSS?

A. Yes. However, unlike KCPL's BIP cost study, the DOE 4CP cost study shows that an above-average increase is only necessary to move the residential class closer to cost of service. Below-average rate increases or decreases are necessary to move all other classes closer to cost of service. (See Table 2.) In general, results for the DOE 4CP cost study demonstrate why relying on KCPL's cost analyses to address revenue spread and rate design issues is problematic. My analysis of KCPL's costs supports rejecting KCPL's proposed BIP Method and capacity-based allocation of off-system sales and replacing them with the costing approaches I have recommended. I urge the Commission to do so in this case.

Q. WHY DO YOU SUPPORT AN ACROSS-THE-BOARD REVENUE SPREAD EVEN THOUGH YOUR 4CP COST STUDY SHOWS THAT MAJOR INTERCLASS REVENUE SHIFTS ARE NECESSARY TO MOVE CLASSES CLOSER TO COST OF SERVICE?

A. Results from the DOE 4CP cost study show that significant revenue shifts to lower load factor classes are required to move rates closer to cost of service. However, I support an across-the-board revenue spread in this case. In particular, an across-the-board spread is appropriate because current economic conditions do not justify a dramatic above-average increase for any class. Moreover, the Commission has not yet decided

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[20] *See* the direct testimony of KCPL witness Tim M. Rush at 9:18-20.

how key cost items (in particular fixed production costs) should be allocated among rate classes. The Commission's decisions on various allocation issues will have a significant impact on the types and forms of rates necessary to track costs assigned to each class. As a result, an across-the-board revenue spread is both reasonable and prudent at this time.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

MISSOURI PUBLIC SERVICE COMMISSION

IN THE MATTER OF	§	
KANSAS CITY POWER & LIGHT COMPANY'S	§	CASE NO. ER-2012-0174
REQUEST FOR AUTHORITY TO IMPLEMENT A	§	
GENERAL RATE INCREASE FOR ELECTRIC SERVICE	§	

AFFIDAVIT

Commonwealth of Virginia)
County of Fairfax) SS

Dennis W. Goins, being first duly sworn, on his oath states:

1. My name is Dennis W. Goins. I operate Potomac Management Group, an economics and management consulting firm. My business address is 5801 Westchester Street, Alexandria, Virginia 22310.
2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of the United States Department of Energy which I prepared in written form for introduction into evidence in the above-captioned docket.
3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information, and belief.

Dennis W. Goins

Subscribed and sworn to me this 14 day of August 2012.

Joshua J. Toth

Notary Public

JOSHUA J. TOTH
Notary Public
Commonwealth of Virginia
7206060
My Commission Expires Jun 30, 2016

My Commission Expires: 6/30/16

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2012-0174

IN THE MATTER OF
KANSAS CITY POWER & LIGHT COMPANY'S
REQUEST FOR AUTHORITY TO IMPLEMENT A GENERAL
RATE INCREASE FOR ELECTRIC SERVICE

SCHEDULES TO THE
DIRECT TESTIMONY OF
DR. DENNIS W. GOINS
ON BEHALF OF THE
U.S. DEPARTMENT OF ENERGY

August 16, 2012

Rates of Return at Present Rates: DOE 4CP vs KCPL BIP

Customer Class	DOE 4CP		KCPL BIP	
	ROR	RORI	ROR	RORI
Residential				
Regular	2.67%	0.48	5.96%	1.08
Time of Day	2.09%	0.38	5.04%	0.91
All Electric	2.77%	0.50	4.16%	0.75
Separately Metered	2.90%	0.52	2.96%	0.53
Total	2.70%	0.49	5.43%	0.98
Small GS				
Primary & Secondary	10.20%	1.84	11.15%	2.01
Other	12.64%	2.28	10.06%	1.82
All Electric	9.44%	1.70	8.33%	1.50
Separately Metered	10.38%	1.87	9.43%	1.70
Total	10.21%	1.84	10.97%	1.98
Medium GS				
Primary	11.03%	1.99	9.12%	1.65
Secondary	7.29%	1.32	7.30%	1.32
All Electric	6.66%	1.20	5.29%	0.96
Separately Metered	7.29%	1.32	7.26%	1.31
Total	7.25%	1.31	7.09%	1.28
Large GS				
Primary	8.59%	1.55	7.00%	1.26
Secondary	7.47%	1.35	6.49%	1.17
All Electric	6.94%	1.25	4.49%	0.81
Separately Metered	8.44%	1.52	7.32%	1.32
Total	7.41%	1.34	5.80%	1.05
Large Power Service				
Primary	7.59%	1.37	3.60%	0.65
Secondary	6.95%	1.26	3.44%	0.62
Substation	6.63%	1.20	1.88%	0.34
Transmission	5.29%	0.96	0.93%	0.17
Total	7.08%	1.28	3.01%	0.54
Total Lighting	31.24%	5.64	6.19%	1.12
MISSOURI RETAIL	5.54%	1.00	5.54%	1.00

Revenue Requirements at Equal Rates of Return (KCPL Proposed 8.596%): DOE 4CP vs KCPL BIP

	Operating Revenue	Missouri Retail	Residential	Small Gen Service	Medium Gen Service	Large Gen Service	Large Pwr Service	Total Lighting
	Present Rates[1]							
1	Retail Sales	699,636,961	259,806,177	47,984,116	94,385,415	163,335,353	125,295,179	8,830,722
2	Other	49,051,908	20,541,166	2,685,054	6,146,409	11,613,438	7,794,948	270,892
3	Total	748,688,868	280,347,343	50,669,170	100,531,823	174,948,792	133,090,127	9,101,614
	KCPL BIP - KCPL Proposed Rates[2]							
4	Retail Sales	804,589,191	299,564,033	43,719,236	101,120,148	186,166,461	164,309,683	9,709,630
5	Other Retail Sales[3]	736,370	273,447	50,503	99,341	171,911	131,874	9,294
6	Other	49,051,908	20,541,166	2,685,054	6,146,409	11,613,438	7,794,948	270,892
7	Total	854,377,469	320,378,646	46,454,794	107,365,897	197,951,810	172,236,505	9,989,816
8	Change - Operating Rev (8.596% ROR)	105,688,600	40,031,304	(4,214,376)	6,834,074	23,003,019	39,146,378	888,202
9	Change - Retail Sales Revenue	15.00%	15.30%	-8.89%	7.14%	13.98%	31.14%	9.95%
10	Change - Total Operating Rev	14.12%	14.28%	-8.32%	6.80%	13.15%	29.41%	9.76%
	DOE 4CP - KCPL Proposed Rates[4]							
11	Retail Sales	804,589,191	348,309,991	44,974,929	100,315,914	172,085,717	133,503,508	5,399,133
12	Other Retail Sales[3]	736,370	273,447	50,503	99,341	171,911	131,874	9,294
13	Other	49,051,908	16,235,912	2,449,557	6,247,662	12,397,619	11,237,452	483,706
14	Total	854,377,469	364,819,349	47,474,990	106,662,916	184,655,247	144,872,833	5,892,133
15	Change - Operating Rev (8.596% ROR)	105,688,600	84,472,007	(3,194,179)	6,131,093	9,706,455	11,782,706	(3,209,481)
16	Change - Retail Sales Revenue	15.00%	34.07%	-6.27%	6.28%	5.36%	6.55%	-38.86%
17	Change - Total Operating Rev	14.12%	30.13%	-6.30%	6.10%	5.55%	8.85%	-35.26%

(1) See KCPL Missouri Jurisdiction class-cost-of service, Schedule PMN-2, lines 4-6.
(2) See direct testimony of KCPL witness Paul Normand.
(3) Other Retail Sales Revenue related to amortization of a loss margin refund.
(4) Fixed production costs allocated using 4CP method; off-system sales margins allocated on energy.

Rates of Return at Present Rates: DOE AED vs KCPL BIP

Customer Class	DOE AED ROR	DOE AED RORI	KCPL BIP ROR	KCPL BIP RORI
Residential				
Regular	2.66%	0.48	5.96%	1.08
Time of Day	2.28%	0.41	5.04%	0.91
All Electric	1.93%	0.35	4.16%	0.75
Separately Metered	-0.18%	(0.03)	2.96%	0.53
Total	2.35%	0.42	5.43%	0.98
Small GS				
Primary & Secondary	11.39%	2.06	11.15%	2.01
Other	12.38%	2.24	10.06%	1.82
All Electric	5.65%	1.02	8.33%	1.50
Separately Metered	4.76%	0.86	9.43%	1.70
Total	10.95%	1.98	10.97%	1.98
Medium GS				
Primary	9.08%	1.64	9.12%	1.65
Secondary	8.64%	1.56	7.30%	1.32
All Electric	5.36%	0.97	5.29%	0.96
Separately Metered	6.17%	1.11	7.26%	1.31
Total	8.18%	1.48	7.09%	1.28
Large GS				
Primary	9.49%	1.71	7.00%	1.26
Secondary	8.37%	1.51	6.49%	1.17
All Electric	6.08%	1.10	4.49%	0.81
Separately Metered	8.66%	1.56	7.32%	1.32
Total	7.61%	1.37	5.80%	1.05
Large Power Service				
Primary	8.09%	1.46	3.60%	0.65
Secondary	7.76%	1.40	3.44%	0.62
Substation	7.28%	1.31	1.88%	0.34
Transmission	5.36%	0.97	0.93%	0.17
Total	7.63%	1.38	3.01%	0.54
Total Lighting	12.77%	2.31	6.19%	1.12
MISSOURI RETAIL	5.54%	1.00	5.54%	1.00

Revenue Requirements at Equal Rates of Return (KCPL Proposed 8.596%): DOE Average and Excess Demand vs KCPL BIP

	Operating Revenue	Missouri Retail	Residential	Small Gen Service	Medium Gen Service	Large Gen Service	Large Pwr Service	Total Lighting
	Present Rates[1]							
1	Retail Sales	699,636,961	259,806,177	47,984,116	94,385,415	163,335,353	125,295,179	8,830,722
2	Other	49,051,908	20,541,166	2,685,054	6,146,409	11,613,438	7,794,948	270,892
3	Total	748,688,868	280,347,343	50,669,170	100,531,823	174,948,792	133,090,127	9,101,614
	KCPL BIP - KCPL Proposed Rates[2]							
4	Retail Sales	804,589,191	299,564,033	43,719,236	101,120,148	186,166,461	164,309,683	9,709,630
5	Other Retail Sales[3]	736,370	273,447	50,503	99,341	171,911	131,874	9,294
6	Other	49,051,908	20,541,166	2,685,054	6,146,409	11,613,438	7,794,948	270,892
7	Total	854,377,469	320,378,646	46,454,794	107,365,897	197,951,810	172,236,505	9,989,816
8	Change - Operating Rev (8.596% ROR)	105,688,600	40,031,304	(4,214,376)	6,834,074	23,003,019	39,146,378	888,202
9	Change - Retail Sales Revenue	15.00%	15.30%	-8.89%	7.14%	13.98%	31.14%	9.95%
10	Change - Total Operating Rev	14.12%	14.28%	-8.32%	6.80%	13.15%	29.41%	9.76%
	DOE AED - KCPL Proposed Rates[4]							
11	Retail Sales	804,589,191	356,204,221	43,771,008	96,043,396	170,544,568	130,336,083	7,689,916
12	Other Retail Sales[3]	736,370	273,447	50,503	99,341	171,911	131,874	9,294
13	Other	49,051,908	16,325,802	2,435,849	6,199,011	12,380,070	11,201,385	509,791
14	Total	854,377,469	372,803,470	46,257,359	102,341,748	183,096,548	141,669,341	8,209,001
15	Change - Operating Rev (8.596% ROR)	105,688,600	92,456,128	(4,411,810)	1,809,925	8,147,757	8,579,214	(892,613)
16	Change - Retail Sales Revenue	15.00%	37.10%	-8.78%	1.76%	4.41%	4.02%	-12.92%
17	Change - Total Operating Rev	14.12%	32.98%	-8.71%	1.80%	4.66%	6.45%	-9.81%

(1) See KCPL Missouri Jurisdiction class-cost-of service, Schedule PMN-2, lines 4-6.
(2) See direct testimony of KCPL witness Paul Normand.
(3) Other Retail Sales Revenue related to amortization of a loss margin refund.
(4) Fixed production costs allocated using average and excess demand (1NCP) method; off-system sales margins allocated on energy.

APPENDIX

QUALIFICATIONS OF

DENNIS W. GOINS

DENNIS W. GOINS

PRESENT POSITION

Economic Consultant, Potomac Management Group, Alexandria, Virginia.

AREAS OF QUALIFICATION

- Competitive Market Analysis
- Costing and Pricing Energy-Related Goods and Services
- Utility Planning and Operations
- Litigation Analysis, Strategy Development, Expert Testimony

PREVIOUS POSITIONS

- Vice President, Hagler, Bailly & Company, Washington, DC.
- Principal, Resource Consulting Group, Inc., Cambridge, Massachusetts.
- Senior Associate, Resource Planning Associates, Inc., Cambridge, Massachusetts.
- Economist, North Carolina Utilities Commission, Raleigh, North Carolina.

EDUCATION

College	Major	Degree
Wake Forest University	Economics	BA
North Carolina State University	Economics	ME
North Carolina State University	Economics	PhD

RELEVANT EXPERIENCE

Dr. Goins specializes in pricing, planning, and market structure issues affecting firms that buy and sell products in electricity and natural gas markets. He has extensive experience in evaluating competitive market conditions, analyzing power and fuel requirements, prices, market operations, and transactions, developing product pricing strategies, setting rates for energy-related products and services, and negotiating power supply and natural gas contracts for private and public entities. He has participated in nearly 200 cases as an expert on competitive market issues, utility restructuring, power market planning and operations, utility mergers, rate design, cost of service, and management prudence before the Federal Energy Regulatory Commission, the General Accounting Office (now the Government Accountability Office), the First Judicial District Court of Montana, the Circuit Court of Kanawha County, West Virginia, the Linn County District Court of Iowa, and regulatory commissions in Alabama, Arizona, Arkansas, Colorado, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Wyoming, and the District of Columbia. He has also prepared an expert report on behalf of the United States regarding pricing and contract issues in a case before the United States Court of Federal Claims.

PARTICIPATION IN REGULATORY, ADMINISTRATIVE, AND COURT PROCEEDINGS

1. Kentucky Utilities, Inc., before the Kentucky Public Service Commission, Case No. 2012-00221 (2012), on behalf of the Kentucky Industrial Utility Customers, re interruptible rates.
2. Louisville Gas and Electric Company, Inc., before the Kentucky Public Service Commission, Case No. 2012-00222 (2012), on behalf of the Kentucky Industrial Utility Customers, re interruptible rates.
3. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 479 (2012), on behalf of Nucor Steel-Hertford, re cost of service and retail rate design.
4. Kansas City Power & Light Company, before the Missouri Public Service Commission, Case No. ER-2012-0174 (2012), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.
5. Potomac Electric Power Company, before the Maryland Public Service Commission, Case No. 9286 (2012), on behalf of the General Services Administration, re retail cost recovery.
6. Indiana Michigan Power Company, before the Indiana Utility Regulatory Commission, Cause No. 44075 (2012), on behalf of Steel Dynamics, Inc., re retail cost-of-service and fuel and purchased power cost recovery.
7. Entergy Texas, Inc., before the Public Utilities Commission of Texas, PUC Docket No. 39896 (2012), on behalf of Texas Cities, re cost of service and retail rate design.
8. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1087 (2012), on behalf of the General Services Administration, re retail cost recovery.

9. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 474 (2011), on behalf of Nucor Steel-Hertford, re fuel rate adjustments.
10. Mid-Kansas Electric Company, before the Kansas Corporation Commission, Docket No. 11-GIME-597-GIE (2011),on behalf of Kansas Electric Power Cooperative, Inc., re local delivery service and operating agreements.
11. Duke Energy Corporation *et al*., before the Federal Energy Regulatory Commission, Docket No. EC11-60-000 (2011), on behalf of the North Carolina Electric Membership Corporation, re merger-related market power issues.
12. Resale Power Group of Iowa *et al*., before the Linn County District Court of Iowa, Case No. LACV 054271 (2011), on behalf of Central Iowa Power Cooperative, re compensation for unauthorized transmission access.
13. Columbus Southern Power Company *et al*., before the Public Utilities Commission of Ohio, Case No. 11-346-EL-SSO *et al*., (2011), on behalf of the OMA Energy Group., re standard service offer electric security plan rate design issues.
14. Appalachian Power Company and Wheeling Power Company, dba American Electric Power, before the Public Service Commission of West Virginia, Case No. 11-0274-E-GI (2011), on behalf of Steel of West Virginia, Inc., re expanded net energy cost rate issues.
15. Rocky Mountain Power Company, before the Wyoming Public Service Commission, Docket No. 20000-384-ER-10 (2011), on behalf of Cimarex Energy Company, QEP Field Services Company, and Kinder Morgan Interstate Gas Transmission, re utility rates, cost-of-service, and resource acquisition issues.
16. Duke Energy Indiana, Inc., before the Indiana Utility Regulatory Commission, Cause No. 43955 (2011), on behalf of Nucor Steel and Steel Dynamics, Inc., re utility-sponsored energy efficiency programs.
17. Kansas City Power & Light Company, before the Missouri Public Service Commission, Case No. ER-2010-0355 (2010), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.
18. Appalachian Power Company and Wheeling Power Company, dba American Electric Power, before the Public Service Commission of West Virginia, Case No. 10-0699-E-42T (2010), on behalf of Steel of West Virginia, Inc., re cost-of-service and rate design issues.

19. Entergy Arkansas, Inc., before the Arkansas Public Service Commission, Docket No. 10-010-U (2010), on behalf of Arkansas Electric Energy Consumers, Inc., re industrial opt out of utility-sponsored energy efficiency programs.

20. Indiana Michigan Power Company, before the Indiana Utility Regulatory Commission, Cause No. 38702 – FAC 62-S1 (2010), on behalf of Steel Dynamics, Inc., re fuel and purchased power cost recovery.

21. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 459 (2010), on behalf of Nucor Steel-Hertford, re cost of service and retail rate design.

22. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 461 (2010), on behalf of Nucor Steel-Hertford, re fuel rate adjustments.

23. Entergy Texas, Inc., before the Public Utilities Commission of Texas, PUC Docket No. 37744 (2010), on behalf of Texas Cities, re cost of service and retail rate design.

24. Kentucky Utilities, Inc., before the Kentucky Public Service Commission, Case No. 2009-00548 (2010), on behalf of the Kentucky Industrial Utility Customers, re interruptible rates.

25. Louisville Gas and Electric Company, Inc., before the Kentucky Public Service Commission, Case No. 2009-00549 (2010), on behalf of the Kentucky Industrial Utility Customers, re interruptible rates.

26. Ohio Edison *et al*., before the Public Utilities Commission of Ohio, Case No. 09-1948-EL-POR *et al*., (2010), on behalf of Nucor Steel Marion, Inc., re energy efficiency and peak demand reduction portfolios.

27. Kauai Island Utility Cooperative, before the Hawaii Public Utilities Commission, Docket No. 2009-0050 (2010), on behalf of Kauai Marriott Resort & Beach Club, re retail cost allocation and rate design issues.

28. Entergy Arkansas, Inc., before the Arkansas Public Service Commission, Docket No. 09-024-U (2009), on behalf of Arkansas Electric Energy Consumers, Inc., re power plant environmental retrofit.

29. Appalachian Power Company, before the Virginia State Corporation Commission, Case No. PUE-2009-00030 (2009), on behalf of Steel Dynamics, Inc., re retail cost allocation and rate design issues.

30. Ohio Edison *et al*., before the Public Utilities Commission of Ohio, Case No. 09-906-EL-SSO (2009), on behalf of Nucor Steel Marion, Inc., re market rate offer.

31. Dominion North Carolina Power, before the North Carolina Utilities Commission, Docket No. E-22, Sub 456 (2009), on behalf of Nucor Steel-Hertford, re fuel cost adjustment.
32. Appalachian Power Company, before the Virginia State Corporation Commission, Case No. PUE-2009-00068 (2009), on behalf of Steel Dynamics, Inc., re demand response programs.
33. Indiana Michigan Power Company, before the Indiana Utility Regulatory Commission, Cause No. 43750 (2009), on behalf of Steel Dynamics, Inc., re wind power purchased power agreement.
34. Entergy Arkansas, Inc., before the Arkansas Public Service Commission, Docket No. 07-085-TF (2009), on behalf of Arkansas Electric Energy Consumers, Inc., re energy efficiency cost recovery.
35. CenterPoint Energy Arkansas Gas, before the Arkansas Public Service Commission, Docket No. 07-081-TF (2009), on behalf of Arkansas Gas Consumers, Inc., re energy efficiency cost recovery.
36. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2009-261-E (2009), on behalf of CMC Steel-SC, re DSM cost recovery surcharge.
37. Duke Energy Indiana, Inc., before the Indiana Utility Regulatory Commission, Cause No. 38707 FAC81 (2009), on behalf of Steel Dynamics, Inc., re fuel and purchased power cost recovery.
38. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1076 (2009), on behalf of the General Services Administration, re retail cost allocation and standby rate design issues for distributed generation resources.
39. Appalachian Power Company, before the Virginia State Corporation Commission, Case No. PUE-2009-00039 (2009), on behalf of Steel Dynamics, Inc., re environmental and reliability cost recovery.
40. Indiana Michigan Power Company, before the Indiana Utility Regulatory Commission, Cause No. 38702 – FAC 63 (2009), on behalf of Steel Dynamics, Inc., re fuel and purchased power cost recovery.
41. Appalachian Power Company, before the Virginia State Corporation Commission, Case No. PUE-2009-302-00038 (2009), on behalf of Steel Dynamics, Inc., re fuel and purchased power cost recovery.
42. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2008-302-E (2008), on behalf of CMC Steel-SC, re fuel and purchased power cost recovery.

43. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2008-196-E (2008), on behalf of CMC Steel-SC, re base load review order for a nuclear facility.
44. Ohio Edison *et al*., before the Public Utilities Commission of Ohio, Case No. 08-935-EL-SSO *et al*. (2008), on behalf of Nucor Steel Marion, Inc., re standard service offer via an electric security plan.
45. Ohio Edison *et al*., before the Public Utilities Commission of Ohio, Case No. 08-936-EL-SSO (2008), on behalf of Nucor Steel Marion, Inc., re market rate offer via a competitive bidding process.
46. Alabama Power Company, before the Alabama Public Service Commission, Docket No. 18148 (2008), on behalf of CMC Steel Alabama, Nucor Steel Birmingham, Inc., and Nucor Steel Tuscaloosa, Inc, re energy cost recovery.
47. Entergy Texas, Inc., before the Public Utilities Commission of Texas, PUC Docket No. 35269 (2008), on behalf of Texas Cities, re jurisdictional allocation of system agreement payments.
48. Duke Energy Indiana, Inc., before the Indiana Utility Regulatory Commission, Cause No. 43374 (2008), on behalf of Nucor Steel and Steel Dynamics, Inc., re alternative regulatory plan.
49. Entergy Gulf States Inc., before the Public Utilities Commission of Texas, PUC Docket No. 34800 (2008), on behalf of Texas Cities, re affiliate transactions.
50. Commonwealth Edison Company, before the Illinois Commerce Commission, Docket No. 07-0566 (2008), on behalf of Nucor Steel Kankakee, Inc., re cost-of-service and rate design issues.
51. Ohio Edison *et al*., before the Public Utilities Commission of Ohio, Case No. 07-0551-EL-AIR *et al*. (2008), on behalf of Nucor Steel Marion, Inc., re cost-of-service and rate design issues.
52. Appalachian Power Company dba American Electric Power, before the Public Service Commission of West Virginia, Case No. 06-0033-E-CN (2007), on behalf of Steel of West Virginia, Inc., re power plant cost recovery mechanism.
53. Oncor Electric Delivery Company and Texas Energy Future Holdings Limited Partnership, before the Public Utilities Commission of Texas, PUC Docket No. 34077 (2007), on behalf of Nucor Steel - Texas, re acquisition of TXU Corp. by Texas Energy Future Holdings Limited Partnership.
54. Arkansas Oklahoma Gas Company, before the Arkansas Public Service Commission, Docket No. 07-026-U (2007), on behalf of West Central Arkansas Gas Consumers, re gas cost-of-service and rate design issues.

55. Idaho Power Company, before the Idaho Public Utilities Commission, Case No. IPC-E-07-08 (2007), on behalf of the U.S. Department of Energy (Federal Executive Agencies), re cost-of-service and rate design issues.
56. Potomac Electric Power Company, before the District of Columbia Public Service Commission, Formal Case No. 1056 (2007), on behalf of the General Services Administration, re demand-side management and advanced metering programs.
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