BEFORE THE PUBLIC SERVICE COMMISSION
<u>OF THE STATE OF MISSOURI</u>

In the Matter of the Application of	)	
Kansas City Power & Light Company	)	
For Approval to Make Certain Changes	)	**<u>Case No. ER-2006-0314</u>**
In its Electric Service to Being the	)	
Implementation of Its Regulatory Plan	)	

INITIAL POSTHEARING BRIEF

OF

PRAXAIR, INC.

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COMES NOW Praxair, Inc. ("Praxair"), pursuant to the Commission's March 29, 2006 Order Setting Procedural Schedule, and submits its Initial Posthearing Brief on the issues set forth below. As the Commission is aware, the parties recently executed and submitted a Stipulation and Agreement regarding the class cost of service and rate design issues. With this settlement of these potentially contentious issues between the parties, and subject to the Commission's acceptance of that Stipulation and Agreement, Praxair submits this brief addressing the issues and subissues involving Jurisdictional Allocations and Off-System Sales. Praxair generally supports the revenue requirement positions advanced by the Staff of the Missouri Public Service Commission. Praxair reserved the right to address such issues in the context of its Reply Brief scheduled to be filed on November 27, 2006.

I. INTRODUCTION

To understand the Jurisdictional Allocations and Off-System Sales issues, it is useful to understand not only how an electric utility generates electricity, but also how a utility undertakes the planning and construction of generating assets to meet future growth. So equipped, one can better understand how the issues of jurisdictional allocations and off-systems sales arise and should be resolved.

The electric utility industry marketplace is fundamentally different than the market for other goods or services. Electricity cannot be stored, but must be generated as the demand arises. The delivery of electricity "occurs instantaneously when and in the amount needed by the customer."[1] Furthermore, because electricity cannot be stored, the

[1] Exhibit 602, page 5.

electric utility must plan and construct facilities capable of generating and transmitting electricity to meet the maximum demand imposed by customers on the electric utility.[2]

Maximum generation demand can be met by constructing combinations of: (1) baseload; (2) intermediate or (3) peaking facilities. The overarching principle is for the utility to provide that combination of generating resources that results in the lowest total cost of generation to serve all the utility's load.

II. JURISDICTIONAL ALLOCATIONS

A. What Is The Appropriate Method (4 CP vs. 12 CP) To Use For Allocating Generation And Transmission Costs Among Jurisdictions?

KCPL operates in both Kansas and Missouri and rather than operate separate electric utilities in each jurisdiction, KCPL constructs and operates its generating and transmission facilities in these jurisdictions as a single consolidated entity. Establishing just and reasonable rates for each jurisdiction requires allocation of the various generating and transmission capital costs between these jurisdictions. The issue at hand is the appropriate "demand allocator" to be used in allocating these generation and transmission facilities. The FERC notes that, "demand allocation determines the charge to each [jurisdiction] based upon the [jurisdiction's] contribution to the company's capacity costs."[3]

Realizing that electricity cannot be stored, and must be generated instantaneously to match the demand of the customer, an electric utility must construct generating and transmission facilities sufficient in size to meet the greatest single *peak* demand placed on the system by the customers.

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[2] Exhibit 603, page 3.

[3] *Golden Spread Electric Cooperative et al v. Southwestern Public Service Company.*, 115 FERC ¶63,043, p. 65,172 (2006).

> Peak demand is the largest electric load requirement occurring on a utility's system within a specified period of time (e.g., day, month, season, or year). Since generation units and transmission lines are planned, designed, and constructed to meet a utility's anticipated system peak demands plus required reserves, the contribution of each individual jurisdiction to these peak demands is the appropriate basis on which to allocate the costs of these facilities.[4]

The selection of a demand allocator is ultimately based upon a company's peak demand curve. "Because the capacity of a utility's generation and transmission facilities (plant) is largely determined by peak loads that must be satisfied, the demand costs are assigned to a utility's [jurisdictions] in proportion to the respective demand that each [jurisdiction] imposes upon the system's peak at a concurrent time period of period."[5]

> A company that has a relatively flat demand curve would typically allocate demand on a 12 Coincident Peak (12 CP) basis, which assumes that a utility's fixed costs are related to the demand throughout all twelve months of a year. On the other hand, a summer (or winter) peaking company would typically allocate demand on a [4] CP basis which related demand to the [four] peak usage months.[6]

In *Carolina Power & Light Co.*, the FERC established three quantitative measurements by which an expert could objectively determine the appropriate demand methodology.[7] These quantitative measurements allow for relative comparisons between the utility's monthly / seasonal peaks and the utility's annual peak.[8] Based upon established thresholds, these quantitative assessments will determine the appropriate demand allocator.[9] Expert analysis provided by Staff, Praxair, Ford, and MIEC assert that a 4 CP methodology is the most appropriate method of allocating generating and

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[4] Exhibit 122, page 7.
[5] *In re: Puget Sound Energy, Inc.*, 88 FERC ¶63,002 (1999).
[6] *Golden Spread Electric Cooperative et al.* at p. 65,172.
[7] *Carolina Power & Light Co.*, 4 FERC ¶61,107, p. 61,230 (1978).
[8] Exhibit 122, page 9.
[9] *Id.*

transmission facilities.[10] In fact, the witness for Praxair, Ford and MIEC notes that "[o]ver the last 36 years, I have testified on cost allocation issues on several hundred occasions."[11]

> The 4 CP methodology is appropriate for a utility, such as KCP&L, where the month peak demands during the non-summer months are significantly below the summer monthly peak demands. The lower demand in the non-summer months will have little or no influence on the capacity planning process and it would not be rational to consider all twelve monthly peaks in a jurisdictional allocation methodology when there are such significant statistical variations in the monthly seasonal peaks.[12]

The appropriateness of the 4 CP methodology was recognized by the Commission in KCPL's last rate increase proceeding and has been utilized by KCPL in its surveillance reporting for the past 22 years.[13] FERC decisions place a heavy burden on a utility seeking to change its method of allocating generation and transmission facilities.

> We begin with the fact that Commission precedent supports use of 3 CP. In the Company's last two litigated rate cases, the Commission reached the result that SPS was a summer peaking system, and 3 CP was the appropriate demand allocator. ***The Commission has expressed the view that the demand allocation method used for particular utility should not be changed except where there are changed circumstances or a change in policy.***
>
> I am persuaded that 3 CP remains the correct allocator here. I am influenced by the record evidence that there should be a strong reason for changing allocation methodologies, given the impact on customers' expectations and the shifting price signal effects associated with a change in methodology. Here, the data are not suggestive of major shifts in the load curve in the direction away from summer peak, but reflect more modest changes. These changes lead one closer to the edges of the various ratios relied on historically by the Commission, and some of them carry over in the direction of a flatter demand curve, ***but there is no smoking gun pointing to 12 CP***. . . ***In order to justify a departure from***

[10] Exhibit 122, page 6; Exhibit 603, page 4.
[11] Exhibit 605, page 2.
[12] Exhibit 122, page 8.
[13] *In re Kansas City Power & Light Company*, 75 P.U.R.4th 1 (1986); Tr. 589.

> ***Commission precedent, even a 20 year old precedent, more is needed than a mere step or two in the direction of a flatter curve****. . . .*[14]

In contrast, KCPL recommends that the Commission adopt a 12 CP demand allocator. Unlike the 4 CP methodology advanced by Staff, Praxair, Ford, and MIEC, KCPL's recommendation was not based on any independent expert analysis of KCPL's demand curve. Rather, KCPL's recommendation was based purely on financial considerations, producing a result that "over-allocate[s] costs to the Missouri jurisdiction."[15]

The objective behind KCPL's 12 CP recommended methodology is underscored by the lack of experience and expertise acknowledged by KCPL's witness. As revealed on cross-examination, KCPL's witness: (1) had ***never*** conducted a jurisdictional allocation analysis prior to this proceeding;[16] (2) had ***never*** taken any classes or attended any conferences related to jurisdictional allocations;[17] (3) had ***never*** had any training regarding jurisdictional allocations;[18] (4) had ***not*** consulted any textbooks or treatises related to jurisdictional allocations;[19] (5) had ***not*** reviewed any testimony filed in other jurisdictions related to jurisdictional allocations;[20] and (6) had ***not*** reviewed any FERC decisions on the issue of jurisdictional allocations.[21]

KCPL's witness readily admits that the 12 CP methodology was not the result of any "independent analysis", but rather was a decision made elsewhere in the Company.[22]

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[14] *Golden Spread Electric Cooperative* at p. 65,174. (emphasis added, citations omitted)
[15] Exhibit 603, page 2.
[16] Tr. 573.
[17] *Id.*
[18] *Id.*
[19] *Id.*
[20] Tr. 575.
[21] Tr. 576.
[22] Tr. 577-579.

It turned out that KCPL's 12 CP methodology was no more than an effort to gain some claimed "consistency" between the Missouri and Kansas jurisdictions.[23]

The Commission should reject the 12 CP methodology advanced by KCPL solely for self-serving, financial motivations, and instead adopt the 4 CP methodology recommended by Staff, Praxair, Ford and MIEC. As indicated previously, the 4 CP methodology is: (1) dictated by the use of objective quantitative measurements prescribed by the FERC; (2) is recommended by expert testimony of a witness with experience in hundreds of cost allocation proceedings; (3) reflects the summer peaking nature of KCPL's system; (4) is consistent with over 22 years of Commission precedent and (5) properly provides for the allocation of costs between KCPL's Missouri and Kansas jurisdictions.

<u>B.</u> <u>How Should A&G Expenses Be Allocated To The Missouri Retail, Kansas Retail and FERC Wholesale Jurisdictions?</u>

As with the allocation of generation and transmission facilities, the purpose of the allocation of A&G expenses should be premised on cost-based rates. In order to reach this goal, it is necessary to utilize an allocation mechanism that has a rational relationship to the nature of the costs incurred.

KCPL allocated the costs contained in many of the Administrative and General (A&G) accounts using reasonable allocation mechanisms. However, KCPL recommended allocating the remaining A&G accounts "using the <u>***Energy***</u> allocator."[24] As demonstrated in the record, however, the use of the Energy allocator does not bear a rational relationship to the nature of the costs in these accounts. "Arbitrarily defaulting to

[23] *Id.*
[24] Exhibit 9, page 10. (emphasis added).

an energy allocation factor for these types of costs, when these costs have little of nothing to do with energy, is inappropriate."[25]

As can be seen from the title and definition of some of the various A&G accounts, these accounts are in no way related to the generation of ***energy***. In fact, if the costs were actually related to the generation of energy, the costs would be booked to Power Production Expense accounts (Accounts 500 *et seq.*), rather than to the A&G accounts.

Account 921 (Office Supplies and Expenses): This account shall include office supplies and expenses incurred in connection with the general administration of the utility's operations ***which are assignable to specific administrative or general departments and are not specifically provided for in other accounts***.[26]

Account 923 (Outside Service Employed): This account shall include the fees and expenses of professional consultants and others for general services ***which are not applicable to a particular operating function*** or to other accounts.[27]

Account 930.2 (Miscellaneous General Expenses): This account shall include the cost of labor and expenses incurred in connection with the ***general management*** of the utility not provided for elsewhere.[28]

Account 931 (Rents): This account shall include rents properly includible in utility operating expenses for the property of others used, occupied, or operated ***in connection with the customer accounts, customer service and informational, sales and general and administrative functions of the utility***.[29]

As can be seen, an underlying notion of A&G costs are that those costs not be "chargeable direct to a particular operating function." [30] Therefore, because the costs booked to the A&G accounts are not related to the energy production function, an Energy allocator is not appropriate. Instead, as reflected in the testimony of Praxair Witness Brubaker, "typically, these accounts are allocated on some measure of the costs

[25] Exhibit 602, page 28.
[26] 18 CFR Pt. 101 (Section 921). (emphasis added)
[27] 18 CFR Pt. 101 (Section 923). (emphasis added)
[28] 18 CFR Pt. 101 (Section 930.2). (emphasis added)
[29] 18 CFR Pt. 101 (Section 931). (emphasis added)
[30] 18 CFR Pt. 101 (Section 920). (emphasis added)

associated with all of the other elements of the system, such as salaries and wages or plant in service. I have allocated these accounts on salaries and wages to correct KCPL's misallocation."

In this case, the Commission should utilize a jurisdictional allocator which has a rational relationship to the costs in question. By using the recommended salaries and wages allocator, the Commission can ensure that Missouri ratepayers are not paying for costs more appropriately assigned to the Kansas and wholesale jurisdictions.

<u>III. OFF-SYSTEM SALES</u>

<u>A. What Level Of Off-System Sales Margin Should Be Included In Determining KCPL's Cost Of Service?</u>

As discussed in the introduction, peak load is met by constructing a mix of: (1) baseload; (2) intermediate and (3) peaking facilities. While baseload generating facilities have a high initial capital costs, they are usually coal-fired and have a low operating cost. On the other hand, if the generating plant is only expected to be needed to meet customer demand for a few peak hours throughout the year, the electric utility will likely construct a peaking facility. These peaking facilities are characterized by low initial capital costs, but as a result of being fueled by natural gas, they will have a high operating cost.

Recognizing that an electric utility will not experience a peak load every hour of the day, the utility will be capable of generating and selling energy into the off-system market.

> Off-system sales are sales of energy made by KCPL to other entities in the wholesale power market. Essentially, KCPL sells to other entities, such as utilities and marketers, the energy available from its system, after first having assigned the most economical energy to its native load customers.[31]

[31] Exhibit 601, page 3.

Historically, KCPL has been an active participant in the off-system market. This participation is primarily a result of the prevalence of energy available from KCPL's baseload, coal-fired generating facilities.

> Recognizing its abundance of nuclear and coal-fired generation (according to the latest 10K: 2,788 MWs), KCPL is frequently able to sell energy generated by the lower cost coal-fired generating units at wholesale market prices that are based on higher priced natural gas generation. The difference between the low cost of supplying power and the higher price established by the wholesale market necessarily leads to large off-system margins for KCPL.[32]

Despite historical volatility in the underlying price of natural gas, this volatility has not had a significant effect on KCPL's ability to realize off-system revenues from its low cost coal-fired facilities. "On an historical basis the annual contribution from wholesale margins have been large, but contrary to suggestions by KCPL, these margins are continuing to grow."[33] In fact as recently as August 3, 2006, KCPL reported that off-system sales margins were up from a year ago.[34] This increase continues a trend of increasing off-system sales margins dating at least as far back as 2001. As Staff Witness Traxler indicated, KCPL has seen the following increases in off-system sales margins since 2001:

Year	**Dollars**
2001	**____________**
2002	**____________**
2003	**____________**
2004	**____________**

[32] *Id.* at pages 4-5.
[33] *Id.* at page 5.
[34] *Id.*

2005	**____________**[35]

Further reinforcing the notion that off-system sales margins are expected to increase, KCPL has budgeted the following amounts:

Year	**Dollars**
2006	**____________**
2007	**____________**[36]

Needless to say, many parties to this case were somewhat surprised by the appearance of the issue of off-system sales. These parties, signatories to the KCPL Regulatory Plan, thought that they had fully addressed this issue in the context of the Stipulation and Agreement implementing that Regulatory Plan. As discussed more completely, *infra*, KCPL agreed in that Stipulation and Agreement "that off-system energy and capacity sales revenues and related costs will continue to be treated above the line for ratemaking purposes." Furthermore, KCPL agreed "not to propose any adjustment that would remove any portion of its off-system sales from its revenue requirement determination in any rate case."[37] KCPL's commitment was and is appropriate because "[t]he costs associated with these KCPL generation resources (O&M expense, depreciation, return, etc. are, and always have been, supported by native load customers through the revenue requirement determination process."[38]

Despite this commitment from barely a year ago, KCPL now seeks to retain a portion of the ***expected*** level of off-system sales margin for the benefit of its shareholders. This broken commitment has drawn harsh response from Staff, OPC,

[35] Exhibit 134, page 23.
[36] *Id.* at page 23-24.
[37] Exhibit 143, page 22.
[38] Exhibit 601, page 3.

Praxair, Ford, MIEC, and the Department of Energy. In response, each of these entities has made adjustments to include these revenues in the ratemaking calculation and hold KCPL to its previous commitment.

KCPL attempts to obfuscate its broken commitment by dragging in ancillary issues regarding: (1) the risk of off-system sales margins; (2) the volatility of the wholesale market; and (3) the company's large capital requirements associated with its comprehensive energy plan. Furthermore, rather than analyzing historical data and attempting to deduce a normalized level of off-system margins, KCPL attempts to confuse the issue by presenting its position in terms of complicated, probabilistic statistical analysis of the expected 2007 wholesale market.

Specifically, KCPL statistical analysis of the 2007 wholesale market indicates that KCPL is expected to realize 2007 off-system margins of **____________**.[39] This number is consistent with the 2007 budgeted amount as well as the experienced trend in margins KCPL has realized in the wholesale market. Despite this predicted level of off-system margins, KCPL then proposes to include an amount in rates associated with the 25th percentile in its statistical analysis (**___________**).[40] KCPL readily admits that that it has a 3:1 probability of exceeding this level of off-system margins and pocketing money for its shareholders.[41]

As mentioned, numerous parties presented adjustments designed to include the expected level of off-system sales margins in the revenue requirement determination and reinstate KCPL's commitment to include all off-system margins above the line. In this

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[39] Exhibit 30, page 19. Showing the inherent instability of its modeling, KCPL presented updated results on September 30 of **___________**. (Schnitzer True-Up Rebuttal, Schedule MMS-10, page 5).
[40] Exhibit 3, page 25. Again, showing the inherent instability of its modeling, KCPL updated this result on September 30 to **___________**. (Schnitzer True-Up Rebuttal, Schedule MMS-10, page 5).
[41] Exhibit 3, page 25.

case Praxair believes that it is most appropriate to include a level of off-system sales margins as reflected in KCPL's 2006 budget (**____________**). This level of off-system sales margins: (1) reflects KCPL's best estimate of its 2006 level of off-system sales; (2) is comparable to the amount budgeted for the year that rates will be in effect; (3) is consistent with the most likely level of off-system sales margins as reflected in KCPL's statistical modeling; and (4) reflects KCPL's commitment to include all off-system sales margins above the line and for the benefit of ratepayers.

<u>B.</u> <u>How Should The Off-System Sales Margin Be Allocated To The Missouri Retail, Kansas Retail And FERC Wholesale Jurisdictions?</u>

Historically, KCPL has allocated off-system sales revenues via the use of the energy allocator.[42] Similarly, the cost of generating the energy sold in the off-system sale (primarily fuel) has historically been allocated using the energy allocator.[43] Because off-system sales margins are equal to the off-systems sales revenues minus the costs of generating the *energy* sold in those sales, off-system sales margins have historically been allocated, both by the Commission and by KCPL, with the energy allocator.

Dissatisfied with the revenue result of this historic approach, KCPL has now advanced a unique, and new methodology – the KCPL-christened "unused energy allocator." Like its recommendation of the 12 CP demand allocator, KCPL's allocation methodology for off-system sales margin is designed to lead to higher rates for Missouri customers apparently for the benefit of its Kansas ratepayers, but in actually for the benefit of KCPL. As described in Praxair's testimony, "KCPL allocates what it has identified as profits from off-systems sales using a novel methodology which attempts to

[42] Tr. 640.
[43] Tr. 642.

allocate more profits to the low load factor Kansas jurisdiction than to the higher load factor Missouri jurisdiction."[44]

As demonstrated in testimony and through cross-examination, KCPL's unused energy allocator suffers from numerous fundamental flaws.

> This methodology does not give any consideration at all to sales made from the reserve capacity that is paid for by all customers and carried for the benefit of all customers in proportion to customer loads, rather than in proportion to some ill-defined notion of "unused energy." It also does not recognize scheduled maintenance requirements or forced outage events, nor does it recognize specific class load patterns. It is a rather simplistic, broad bush and unique allocation formula.[45]

In addition, there are lingering questions whether KCPL's unused energy allocator violates the underlying rationale of several provisions of the 2005 Energy Policy Act. Specifically, Section 1252 of the 2005 Energy Policy Act requires Commissions to consider whether to implement time-based metering. This may include options such as seasonal and time-of-day rates, real-time pricing, critical-peak pricing, credits for interruptible peak load and others.[46] The underlying purpose of these time-based metering considerations is to provide appropriate price signals to customers to allow them to move their demands on the utility's system from peak hours to off-peak hours. Effectively, the Energy Policy Act is attempting to shave the peak demand and increase the overall system load factor. Despite the underlying federal goals of the Energy Policy Act, KCPL's unused energy allocator would then penalize the jurisdictions that were able to increase their overall load factor by denying those jurisdictions of their appropriate amount of off-system sales margins.

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[44] Exhibit 603, page 5.
[45] *Id.*
[46] 119 Stat. 962 §1252(B).

Finally, recognizing that KCPL relied upon the same witness to advocate both the unused energy allocator as the 12 CP demand allocator, the unused energy allocator suffers from other similar flaws. As stated previously, KCPL's witness: (1) had ***<u>never</u>*** conducted a jurisdictional allocation analysis prior to this proceeding;[47] (2) had ***<u>never</u>*** taken any classes or attended any conferences related to jurisdictional allocations;[48] (3) had ***<u>never</u>*** had any training regarding jurisdictional allocations;[49] (4) had ***<u>not</u>*** consulted any textbooks or treatises related to jurisdictional allocations;[50] (5) had ***<u>not</u>*** reviewed any testimony filed in other jurisdictions related to jurisdictional allocations;[51] and (6) had ***<u>not</u>*** reviewed any FERC decisions on the issue of jurisdictional allocations.[52]

In this case the Commission should reject KCPL's unique and distorted "unused energy allocator" in favor of the historically accepted energy allocator.

<u>C. What Parameters Does The Commission-Approved Stipulation & Agreement In Case No. EO-2005-0329 Impose On The Treatment Of Off-System Sales Revenue In This Case?</u>

In the Stipulation and Agreement in Case No. EO-2005-0329 KCPL explicitly agreed not to attempt to retain for shareholders any off-system sales. Specifically, KCPL made the following commitment:

> KCPL agrees that off-system energy and capacity sales revenues and related costs will continue to be treated above the line for ratemaking purposes. KCPL specifically agrees not to propose any adjustment that would remove any portion of its off-system sales from its revenue requirement determination in any rate case, and KCPL agrees that it will not argue that these revenues and associated expenses should be excluded from the ratemaking process.[53]

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[47] Tr. 573.
[48] *Id.*
[49] *Id.*
[50] *Id.*
[51] Tr. 575.
[52] Tr. 576.
[53] Exhibit 143, page 22.

Despite this commitment, KCPL advanced a result-driven probabilistic analysis which has the identical effect as an "adjustment that would remove [a] portion of its off-system sales from its revenue requirement determination." Specifically, despite recognizing in its budget and its probabilistic analysis that KCPL has a 3:1 possibility of realizing a greater level of off-system sales, KCPL's "adjusts" its position to reflect a lesser amount of off-system sales in its case; to the detriment of its ratepayers. As such, KCPL's probabilistic analysis put forward by KCPL circumvents the commitment made in the Stipulation and Agreement.

D. Should KCPL's Customers Receive The Benefit Of All Margins Of Off-System Sales Or Should It Be Shared Between Customers And Shareholders? Should A Mechanism Be Adopted To Ensure That The Benefit Is Received By The Appropriate Party Or Parties? If So, What Mechanism?

As reflected in its commitment from the Stipulation and Agreement in Case No. EO-2005-0319, KCPL's customers should receive the entire benefit of margins on off-system sales. The commitment to credit all off-system sales margins to ratepayers is appropriate because all costs associated with these generating plants have been included in KCPL's rate base. Any attempt to implement a mechanism designed to result in a sharing of off-systems sales margins between customers and shareholders would be an explicit violation of the Stipulation and Agreement and would seriously undermine the balancing of interests reflected in KCPL's regulatory plan.

Not only would a sharing mechanism undermine the Regulation Plan commitments, the implementation of any such mechanism would be of inherently questionable legitimacy. Although KCPL mentioned the idea of "risk sharing for off-system sales,"[54] it never provided any substance to this notion. "We have not made a specific proposal in terms of testimony, anything direct in this case. I had anticipated making those proposals in settlement discussions."[55] Recognizing that no party has proposed a sharing mechanism, it would be inappropriate to implement such a mechanism in this proceeding.

Finally, there is some question whether the Commission has the authority to unilaterally issue an order implementing such a sharing mechanism. With all the inherent problems of an off-system sales sharing mechanism, the Commission should instead hold KCPL to its commitment and maintain all off-system sales in the revenue requirement determination.

IV. CONCLUSION

For all of the foregoing reasons, Praxair respectfully requests that the Commission adopt its position as set forth above on each of the issues set forth herein.

[54] Exhibit 3, page 28.

[55] Tr. 771. "[I]t was my intent to propose those alternatives in the settlement discussions. Unfortunately, we didn't get that far in those discussions." Tr. 816-817.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing pleading by email, facsimile or First Class United States Mail to all parties by their attorneys of record as provided by the Secretary of the Commission.

David L. Woodsmall

Dated: November 17, 2006