Exhibit No.:
Issues: Energy Losses and Jurisdicational Allocations
Witness: Alan J. Bax
Sponsoring Party: MoPSC Staff
Type of Exhibit: Surrebuttal Testimony
Case No.: EC-2002-1
Date Testimony Prepared: June 24, 2002

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

SURREBUTTAL TESTIMONY

OF

ALAN J. BAX

FILED[3]
JUN 2 4 2002
Missouri Public Service Commission

UNION ELECTRIC COMPANY d/b/a AMERENUE

CASE NO. EC-2002-1

Jefferson City, Missouri
April 2002

NP

****Denotes Proprietary Information****

Exhibit No. 13NP
Date 7/10/02 Case No. EC-2002-1
Reporter Kem

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

The Staff of the Missouri Public Service Commission, Complainant,	)	
vs.	)	Case No. EC-2002-1
Union Electric Company, d/b/a AmerenUE, Respondent.	)	

AFFIDAVIT OF ALAN J. BAX

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Alan J. Bax, of lawful age, on his oath states: that he has participated in the preparation of the following written Surrebuttal Testimony in question and answer form, consisting of 13 pages of testimony to be presented in the above case, that the answers in the attached written Surrebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true to the best of his knowledge and belief.

Alan J Bax
Alan J. Bax

Subscribed and sworn to before me this 23rd day of June, 2002.

Dawn L. Hake
Notary Public

DAWN L. HAKE
Notary Public – State of Missouri
County of Cole
My Commission Expires Jan 9, 2005

My commission expires ____________

TABLE OF CONTENTS

SURREBUTTAL TESTIMONY

OF

ALAN J. BAX

UNION ELECTRIC COMPANY

d/b/a AMERENUE

CASE NO. EC-2002-1

Q. Please state your name and business address.

A. Alan J. Bax, P.O. Box 360, Jefferson City, Missouri, 65102.

Q. Are you the same Alan J. Bax who previously filed Direct Testimony in this case?

A. Yes.

Q. What is the purpose of your Surrebuttal Testimony in the AmerenUE (Company) Complaint Case, Case No. EC-2002-1?

A. The purpose of this testimony is to respond to the Rebuttal Testimony filed by Company witnesses Richard J. Kovach and Gary S. Weiss on certain aspects of the system energy loss percentage and the jurisdictional demand and energy allocation factors that I calculated and presented in my Direct Testimony, filed in this case on March 1, 2002

Q. Do you have any recommendations for the Commission in your testimony?

A. Yes. I recommend that the Commission adopt my average system energy loss percentage of ** P-------** of net system input, my demand allocation factor for the

Company's Missouri retail jurisdiction of ** P------**, and my energy allocation factor of ** P-----** for the Company's Missouri retail jurisdiction.

SYSTEM ENERGY LOSSES

Q. Is there a difference between the Staff's calculation of the average system energy loss percentage and that of the Company?

A. Yes, but the difference between the average system energy loss percentage as calculated by the Company and the Staff is very small. The average system energy loss percentage from my Direct Testimony filed in March 2002 was ** P-------** of net system input. Schedule 1, attached to this Surrebuttal Testimony, contains a spreadsheet received from the Company in response to Staff Data Request No. 2928. This spreadsheet shows the Company's derivation of the various customer class, jurisdictional, and average system energy loss percentages. The Company has calculated two average system energy loss percentages: one based on theoretical loss factors that have been applied to individual customer classes (bottom of column six – ** P-------** of output) and the other based on the actual losses reported by the Company (bottom of column nine – ** P-------** of output). It should be noted that the Staff's use of the term "net system input" is equivalent to the Company's use of the term "% of output". The Company's determination of an average system energy loss percentage using actual recorded data and equal to ** P----- ** of output is ** P---- ** percentage points lower than the corresponding theoretical percentage. Moreover, it represents only a ** P--- ** percentage point difference from the Staff's calculation. Both the Staff's and the Company's calculations are based on data obtained for the twelve months ending September 30, 2001.

Q. Are there any other issues regarding system energy losses?

A. Yes. Mr. Kovach disagrees with the method in which my average system energy loss percentage was incorporated into the analyses performed by Staff witness Lena M. Mantle. Please refer to the Surrebuttal Testimony of Ms. Mantle for further discussion on how the average system energy loss percentage was used. I have applied a loss adjustment to each jurisdiction in my determination of the energy allocation factors based upon the actual losses recorded by the Company. In contrast, the Company has applied adjustments for losses to their corresponding calculation of energy allocation factors based upon overestimated theoretical loss percentages. This will be discussed later in my testimony in the section titled "Energy Allocation Factor."

DEMAND ALLOCATION FACTOR

Q. Have you changed the demand allocation factors that you previously provided in your Direct Testimony filed in March of 2002?

A. Yes. I adjusted the monthly coincident peaks of Union Electric's Missouri Wholesale jurisdiction to account for the transfer of former wholesale customer City of Rolla (Rolla) to Ameren Energy Marketing. In addition, I removed the demands of former Illinois customer Laclede Steel Corporation (Laclede Steel) from the Illinois jurisdictional loads.

Q. What is the result of your calculation after these adjustments?

A. These factors are presented in Schedule 2 and repeated here.

Missouri Retail ** P------**

Missouri Wholesale ** P-----**

Illinois ** P-----**

Q. Why did you make these adjustments to your calculation of the jurisdictional demand allocation factors?

A. In reviewing the Company's filing, it was brought to my attention that I had adjusted my energy allocation factors to account for the transfer of Rolla and had not performed a similar adjustment to the calculation of the demand allocation factors. The adjustment made for Laclede Steel is also appropriate, as it has gone out of business. I became aware of this change only after receiving the Rebuttal Testimony of Richard J. Kovach.

Q. How does your revised Missouri retail allocation factor compare to your previous calculation filed in your Direct Testimony?

A. This current factor (** P------**) is a little larger than the one calculated previously (** P----- **). The result is a higher allocation of costs to Union Electric's Missouri retail jurisdiction.

Q. Did you provide the result of this calculation to another Staff witness?

A. Yes, I provided this result to Staff witness Steve Rackers.

Q. Are the Staff's demand allocation factors now the same as the Company's?

A. No. Both the Company and the Staff support the premise that capacity (demand or fixed) related costs should be allocated using a coincident peak methodology. However, the Company used a four coincident peak (4 CP) methodology in its determination of a demand allocation factor. Schedule 15, attached to the Rebuttal Testimony of Company witness Gary S. Weiss, shows that the Company averaged the sum of the coincident peaks recorded in the months of June through September 2001 in calculating the Company's demand allocation factors. This was in contrast to the Staff's use of the twelve coincident peak methodology (12 CP) in its calculations. Staff averaged the sum of the coincident peaks recorded for each month in the twelve-month period ending September 30, 2001.

Q. Has the Company been using the 4 CP methodology in Missouri?

A. No. As noted by Company witness Gary S. Weiss, "The Company has in the past used the 12 CP method to calculate the fixed allocation factor." (Weiss Rebuttal, Page 27, Lines 5-6).

Q. Has the Company been using the 4 CP methodology in other jurisdictions?

A. The Company's current rate design with the Federal Energy Regulatory Commission (FERC) is based on the 12 CP methodology, as noted by Mr. Kovach in his Rebuttal Testimony (page 72, lines 15 - 18). With respect to the Company's service territory in Illinois, although the Illinois Commerce Commission (ICC), in a 1985 order, opted to continue its endorsement of the 4 CP methodology, the Company argued in support of the 12 CP methodology[1]. Attached to my testimony as Schedule 3 is a page of the ICC order, which was furnished to the Staff by the Company as part of its response to Staff Data Request No. 2936.

Q. When did you become aware that the Company was adopting the use of a 4 CP methodology in Missouri?

A. When the Company filed its rebuttal testimony in this proceeding on May 10, 2002.

[1] *Union Electric Company-Proposed General Increase in Electric Rates*, Ill. Commerce Comm'n, Docket No. 85-0006 (May 1985).

Q. What support does the Company offer for its position that a 4 CP methodology is appropriate in this case?

A. The Company relies solely upon the use of three arithmetical tests used by the FERC as a guide in determining the appropriate methodology. In his Rebuttal Testimony, Mr. Kovach states, "All of these tests in these analyses indicate, conclusively, that the Company is not a 12 CP jurisdictional demand allocation methodology utility" (page 49, lines 18-19). These tests are included in a book entitled A Guide to FERC Regulation and Ratemaking of Electric Utilities and Other Power Suppliers – Third Edition, authored by Michael E. Small, an excerpt of which is attached to Mr. Kovach's testimony as Schedule 3-2 through Schedule 3-2j. Staff has been unable to obtain a copy of this book for its use because it is currently out of print. Therefore, I relied upon the excerpt from Mr. Small's book for information concerning the application of these FERC tests.

Q. Please describe how these FERC tests are used as a guide in the process of determining an appropriate methodology?

A. These FERC tests are arithmetical calculations whose results are compared to specific ranges that suggest which methodology may be more appropriate. It should be noted, however, that these ranges were never specified by the FERC; rather, they resulted from calculations performed in specific cases in gauging various utilities.

Q. Please illustrate these arithmetical relationships and define these specific ranges.

A. **Test 1** - Computes the difference between the following two ratios:

a) The average of the system peaks during the reported peak period as a percentage of the annual peak, and

b) *The average of the system peaks during the remainder of the test* period as a percentage of the annual peak

The result is compared to the following ranges:

18% - 19% - Reflected in cases in which FERC adopted a 12 CP methodology

26% - 31% - Reflected in cases in which FERC adopted a 4 CP methodology

Test 2 – A ratio of the lowest monthly peak to the annual peak.

The result is compared to the following ranges:

66% - 81% - Reflected in cases in which FERC adopted a 12 CP methodology.

55% - 60% - Reflected in cases in which FERC adopted a 4 CP methodology.

Test 3 – A ratio of the average of the twelve monthly peaks in the reporting period as a percentage of the annual peak.

The result is compared to the following ranges:

81% - 88% - Reflected in cases in which FERC adopted a 12 CP methodology

78% - 80% - Reflected in cases in which FERC adopted a 4 CP methodology

Q. Have you performed calculations using these FERC tests?

A. Yes. As illustrated on Schedule 4, I have calculated the following percentages using the demands recorded for the twelve-month period ending September 30, 2001:

Test 1 - 21.48%

Test 2 - 63.90%

Test 3 - 80.39%

Q. Please discuss the significance of these results.

A. The results of all three of these FERC tests fall between the above-indicated ranges of the percentages noted in the FERC decisions identified in Mr. Kovach's Rebuttal Testimony (page 50 – lines 15 to 20) and illustrated in Schedule 3-2e and 3-2f attached thereto. These tests would indicate that these results are, at best, inconclusive as to which methodology is appropriate for this case. However, I would note that the results of the first two tests lie closer to the range suggesting the appropriateness of a 12 CP and the result of the third test leans only minimally toward the 4 CP range. Contrary to Mr. Kovach's suggestion, FERC has never relied solely on any of these tests in determining a coincident peak methodology. Moreover, as illustrated above, the results of the FERC test calculations, taken collectively or individually, are hardly conclusive evidence that the 12 CP methodology should now be abandoned in favor of the 4 CP methodology in the present proceeding. Clearly, additional information is required in order to adopt a methodology that strays from historical practice.

Q. What additional information should be considered?

A. These three FERC tests, relied upon exclusively by Mr. Kovach, are part of a larger set of factors historically utilized by the FERC in its determination of which coincident peak methodology should be used in electric utility cases. The excerpt from Mr. Small's book, attached as part of Schedule 3 to Mr. Kovach's testimony, cites language that appears in a number of FERC decisions, indicating the additional factors that, according to FERC, must be considered in determining the appropriate demand allocation methodology. In a rate case decision involving Carolina Power & Light

Company[2], for example, the FERC states:

> ...it is necessary to consider the full range of a company's operating realities including, in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments (footnote omitted).

In addition, in this case, transfers of energy between the Company and its affiliate, Ameren Energy Marketing (AEM) should be considered. In the adoption of the 12 CP methodology, FERC has cited these operating realities as important to their determination.

Q. How do these operational realities apply to the Company?

A. The majority of the Company's plant costs are associated with base load units. These base load units represent ** P-------** of total generation plant dollars as of December 31, 2001 (as reflected in the Company's FERC Form 1, pages 402 to 407). These units have high capital costs but lower running costs when compared to intermediate or peaking units. These plants are costly to start up and shut down and therefore are in operation well over 90% of the time on average, with necessary maintenance being planned in the spring and fall in the months that have lower demand for energy. There are many hours during the year when the base load plants adequately cover the usage of the Company's native load customers, allowing the Company the opportunity to use the excess power being generated by these base load units for off-system sales or to transfer this low-cost energy to AEM under the Joint Dispatch Agreement (JDA).

Q. Are there other operational realities that should be taken into account?

[2] *Carolina Power & Light Co.*, Opinion No. 19, 4 FERC ¶61,107 at 61,230 (Aug. 1978).

A. Yes. The Company's capacity planning process takes into account all the hours of the year, not just the summer peaks. In their response to Staff Data Request No. 2938, the Company replied that its planning requirement for the Mid-America Interconnected Network, Inc. (MAIN) is a Loss of Load Probability (LOLP) of less than 0.1 days per year. This means that the Company plans its capacity for every hour of the year, not just for the peak hour or seasonal peak.

Q. Has the Company ever invoked these operational realities in order to justify a particular allocation methodology?

A. Yes, it has. In the 1985 Illinois Commerce Commission order, mentioned on page 5 of my testimony, the ICC states:

> Company witness Kovach testified that an examination of cost causation should consider both the total kilowatt capacity and the mix or types of plants which must be determined on the basis of load throughout the year, including non-summer months whose peaks average about two-thirds of the annual peaks.

Q. Please summarize why operational realities justify the use of a 12 CP methodology in calculating jurisdictional demand allocation factors in this case.

A. The determination of proper cost causation involves a process much more involved than any one arithmetical calculation or series of calculations based on monthly or seasonal peaks. Allocation factors should be developed based on the costs associated with the particular facilities one intends to allocate. Using a 4 CP methodology implies that the Company's facilities were constructed as peaking facilities, operating for only a limited number of hours annually. This certainly is not the case with this Company. Earlier in my testimony, I pointed out that the Company's generation mix is overwhelmingly base loaded, and this has certainly been the case ever since the Callaway

Nuclear Plant became operational. Given that there has been minimal change in the Company's generation profile since then, there is no reason for the Commission to adopt a change from a 12 CP methodology to a 4 CP methodology in the present case. For this Company, then, it is these operational realities, not a series of inconclusive arithmetical tests, that leads one to conclude that the 12 CP continues to be the appropriate methodology for allocating demand (fixed) costs. The Commission, therefore, should reject the Company's proposed change to a 4 CP methodology.

ENERGY ALLOCATION FACTOR

Q. Have you made any adjustments to the energy allocation factors filed previously in your Direct Testimony of March 2002?

A. Yes. Mr. Kovach notes several adjustments that he believes should have been considered in the calculation of the energy allocation factors (identified as Adjustments 1 through 7 on Schedule 3-3 of his Rebuttal Testimony, and attached to my Surrebuttal Testimony as Schedule 5). In my previous testimony, I applied adjustments for weather and the transfer of Rolla from AmerenUE to AEM (Mr. Kovach's adjustments 1 and 2). The Staff agrees with Mr. Kovach that the following adjustments should be made:

a. Miscellaneous Adjustment

b. Rate Switching Adjustment

c. A 365 Days Adjustment

d. Customer Growth Adjustment

These are shown as adjustments 3 through 6 in my revised calculations of the energy allocation factors in Schedule 6, attached to this Surrebuttal Testimony. I have not, however, adjusted my factor for Laclede Steel. The energy associated with Laclede Steel was included in the Staff's fuel run and thus remains in my determination of the energy allocation factors. In addition, I applied the appropriate jurisdictional loss factors, shown in Column 10 on Schedule 1 of my Surrebuttal Testimony, to the adjusted kWhs for each corresponding jurisdiction.

Q. In calculating these losses in connection with your Surrebuttal Testimony, did you use the same approach as the Company used in its Rebuttal filing?

A. No, not entirely. Although the Staff and the Company use the same approach with respect to the unadjusted kWhs, the Staff does not agree with the Company's inclusion of <u>theoretical</u> losses with the aforementioned adjustments. Previously in this testimony, I discussed the Company's spreadsheet, attached as Schedule 1 to this Surrebuttal Testimony, illustrating two sets of loss percentage calculations: one based on actual losses reported by the Company and the other based on figures determined theoretically. The Schedule illustrates that the Company applied a theoretical loss percentage (Column 4) to the actual usage recorded at the meters of each of the listed customer classes for the twelve months ending September 30, 2001. According to the Company's response to Staff Data Request No. 2930, these loss percentages were calculated from information contained in the Company's most recent loss study, which was conducted back in 1983 and provided to the Staff in a Company response to Staff Data Request No. 4138. Applying these theoretical loss percentages to each customer class results in an average system energy loss percentage that is ** P----** percentage points (nearly 16%) greater than the average system energy loss percentage calculated using the actual losses reported in the Company's Financial and Statistical

(F&S) statements. Thus, the losses included in the adjustments that the Company incorporated into its calculation of the energy allocation factors are considerably overstated.

Q. Did the Company make the same adjustments as the Staff in its determination of the energy allocation factors?

A. No. The Company did not apply a miscellaneous adjustment, a 365 days adjustment, or a customer growth adjustment. Furthermore, the Company calculated its allocation factor using energy from the twelve months ending September 30, 2001 whereas Staff used the test year. The Company's weather adjustment was also based on the twelve months ending September 30, 2001 and the Company applied an adjustment for unbilled sales as well (Weiss Rebuttal, Schedule 16).

Q. What are the resulting jurisdictional energy allocation factors after applying these additional adjustments?

A. These factors are presented in Schedule 6 and repeated here.

Missouri Retail ** P------**

Missouri Wholesale ** P-----**

Illinois ** P-----**

Q. Did you provide the result of this calculation to another Staff witness?

A. Yes. I provided this result to Staff witness Steve Rackers.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes.

ALAN J. BAX

SCHEDULE 1 HAS BEEN

DEEMED

PROPRIETARY IN ITS ENTIRETY

ALAN J. BAX

SCHEDULE 2 HAS BEEN

DEEMED

PROPRIETARY IN ITS ENTIRETY

The Company urges the Commission to reinstate the 12 CP method for two reasons. First, because the 12 CP approach has been adopted in the other three jurisdictions which regulate the Company, use of the 12 CP method in Illinois would produce consistency among jurisdictions, and would allow the Company to earn a return on its full investment which will not occur if the 4 CP method is used because the 4 CP allocation factor for Illinois is lower than the 12 CP factor. Secondly, UE submits that the 12 CP method better reflects cost causation. Company witness Kovach testified that an examination of cost causation should consider both the total kilowatt capacity and the mix or types of plants which must be determined on the basis of load throughout the year, including non-summer months whose peaks average about two-thirds of the annual peaks. (Resp. Exh. 19, pp. 24, 25) UE contends that methodologies which presume the system was constructed to serve only summer peaks should not be applied to UE's generation and transmission systems which reflect a mix of types of capacity that is not determined by only the level of capacity required by the yearly peak.

Staff witness Lane did not agree with the Company's proposal. He recommended continued use of the 4 CP method. He testified that UE is clearly a summer peaking utility, and has not forecasted a change in this characteristic. He also stated that the 4 CP method is consistent with the strong seasonal differentials exhibited in the Company's Illinois rates which provides signals to customers that electricity is more costly in summer months.

The Commission is of the opinion that the demand allocation factor should continue to be determined by use of the 4 CP method for the reasons given by staff witness Lane. The updated allocation factors presented by the Commission staff should be used in this proceeding.

The Commission observes, however, that for reasons explained above, the use of the 4CP demand allocation factor in Illinois and the 12CP factor elsewhere may have the effect of excluding a portion of the Company's rate base from any jurisdictional rate base. That is, part of the Company's rate base is not eligible to earn a return within a regulated context. In recognition of this problem, the Company should present to the Commission within six months of the issuance of this order a plan for the treatment of this rate base in a competitive manner. One option of the plan could be action which confirms the status quo. The treatment of this rate base should be fair to both the company and its ratepayers and should provide the proper incentives to the Company. In addition, the Commission invites the company to

FERC Test Calculations

			AmerenUE Monthly Peaks (MWs)		
January			5927		
February			5886		
March			5097		
April			5625		
May			6742		
June			7191		
July			7976		
August			7908		
September			7141		
October			5851		
November			5381		
December			6217		
Maximum Peak	=		7976		
Minimum Peak	=		5097		
Summer Month Avg	=		7554		
Other Months Avg	=		5840.75		
12 Month Avg	=		6411.833333		
Ratio 1a = (Summer_Avg) / Max	=		0.947091274		
Ratio 1b = (8-Month_Avg) / Max	=		0.732290622		
FERC Test 1	=	Ratio 1a - Ratio 1b	0.214800652	=	21.48%
FERC Test 2)	=	Min. Peak / Max Peak	0.639042126	=	63.90%
FERC Test 3	=	(12 Month Avg) / Max Peak	0.803890839	=	80.39%

Energy Allocation Factor Adjustments (kWh's)

July 2000 - June 2001

	Missouri Retail Usage (kWh)	Missouri Wholesale Usage (kWh)	Illinois Usage (kWh)	Total Usage (kWh)
Total Usage*	32,009,845,300	854,692,200	3,171,890,900	36,036,428,400
Jurisdictional Losses**	2,462,787,690	32,241,540	183,733,360	2,678,762,590
Adjusted System Input	34,472,632,990	886,933,740	3,355,624,260	38,715,190,990
Adjustment 1	(969,081,000)	(21,481,000)	(53,747,000)	(1,044,309,000)
Losses	(74,522,329)	(809,834)	(3,111,951)	(78,444,114)
Adjustment 2		(153,593,010)		(153,593,010)
Losses		(5,790,456)		(5,790,456)
Adjustment 3			(237,362,400)	(237,362,400)
Losses			(5,127,028)	(5,127,028)
Adjustment 4	(18,103,848)			(18,103,848)
Losses	(1,091,662)			(1,091,662)
Adjustment 5	(60,553,690)			(60,553,690)
Losses	(3,651,388)			(3,651,388)
Adjustment 6	30,352,000			30,352,000
Losses	2,334,068.80			2,334,069
Adjustment 7	287,384,513			287,384,513
Losses	22,099,869			22,099,869
Output for Load	33,687,799,524	705,259,440	3,056,275,881	37,449,334,845
Percentage	89.96%	1.88%	8.16%	100.00%

* Source: Alan Bax Direct Testimony, Schedule 6.
** Adjusted for average jurisdictional losses.

Adjustment 1 - Normalized Weather per Bax, Schedule 6.
Adjustment 2 - Rolla Adjustment per Bax, Schedule 6.
Adjustment 3 - Adjustment to Laclede Steel Sales to reflect bankruptcy operation.
Adjustment 4 - Miscellaneous Adjustment per Pyatte, Schedule 2.
Adjustment 5 - Rate Switching Adjustment per Pyatte, Schedule 2.
Adjustment 6 - 365 Day Normalization Adjustment per Pyatte, Schedule 2.
Adjustment 7 - Customer Growth Adjustment per Pyatte, Schedule 2.

ALAN J. BAX

SCHEDULE 6 HAS BEEN

DEEMED

PROPRIETARY IN ITS ENTIRETY