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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. EC-2002-1

REBUTTAL TESTIMONY

OF

RICHARD A. VOYTAS

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

Exhibit No. 103
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St. Louis, Missouri
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** **Denotes Highly Confidential Information** **

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REBUTTAL TESTIMONY

OF

RICHARD A. VOYTAS

CASE NO. EC-2002-1

I. <u>INTRODUCTION</u>

Q. Please state your name and business address.

A. My name is Richard A. Voytas. My business address is 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. By whom and in what capacity are you employed?

A. I am employed by Ameren Services Company as Manager of the Corporate Analysis section in the Corporate Planning Department.

Q. How long have you held your position, and what are your responsibilities?

A. The attached Appendix A summarizes my educational background, work experience and the duties of my position.

Q. What is the purpose of your testimony?

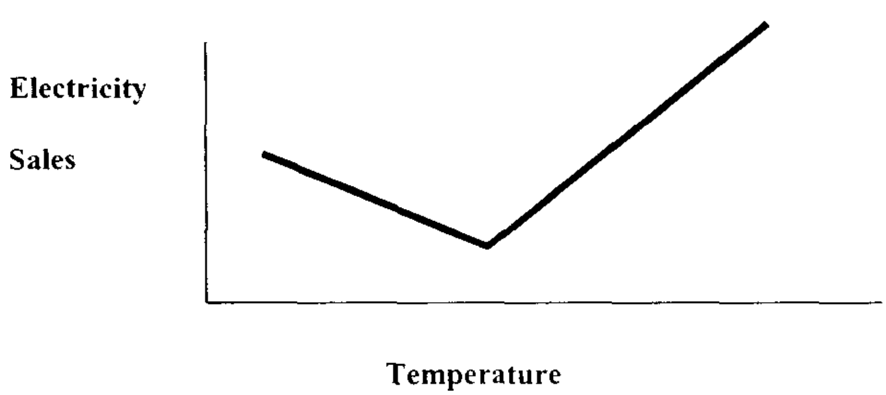
A. The purpose of my testimony is twofold. First, I will address issues related to the weather normalization in the direct testimony of Lena M. Mantle in Case No. EC-2002-1. Second, I will address issues related to capacity to meet reserves in the direct testimony of Michael S. Proctor in the same case. In addition, as part of my testimony, I have prepared an **Executive Summary** attached hereto as Appendix B.

II. WEATHER NORMALIZATION

A. Weather Normalization Adjustment to Customer Usage

Q. Why is it necessary for the Commission to adopt a weather normalization adjustment to Union Electric Company d/b/a AmerenUE's (AmerenUE or Company) test year sales in this case?

A. As Ms. Mantle points out in her direct testimony, electricity use in the Company's service area is very sensitive to weather conditions (Mantle Direct p. 3, lines 1-4). During the summer months, the hotter the weather, the greater the sales of electricity due primarily to the widespread use of air conditioning by the Company's customers. In the winter, colder weather causes greater sales of electricity due to customers' use of electric space heating and electric blowers in conjunction with gas space heating. In graphical form, the relationship between temperature and electricity sales can be expressed as follows:



Because electricity sales are directly related to temperature, in establishing rates for an electric utility it is necessary for the Commission to make an adjustment to account for any abnormal weather experienced during the test year being used for the case. In other words, the Commission must adjust test year sales of electricity to reflect the sales that the Company would have experienced if normal weather had prevailed. In this case, the weather normalization adjustment is expected to be a reduction to test year sales. The issue is the magnitude of the weather's impact on sales during the test year and the methodology used to calculate the magnitude of the weather adjustment.

Q. Has the Staff calculated a weather normalization adjustment in this proceeding?

A. Yes. Ms. Mantle has calculated an adjustment to the Company's test year kilowatthour (kWh) sales to account for abnormal weather experienced during the test year, and Staff witness Janice Pyatte has priced the kWh sales adjustment provided to her by Ms. Mantle to develop a dollar adjustment to the Company's test year revenues. However, Ms. Mantle has used a flawed methodology to minimize the weather adjustment and thereby overstate the Company's normalized test year revenues by approximately $19 million. As a consequence, the Staff's weather normalization adjustment improperly reduces the Company's annual revenue requirement by that amount.

Q. How did Ms. Mantle calculate her weather normalization adjustment to test year kilowatthour sales in this case?

A. In her direct testimony, Ms. Mantle states that she did not independently perform a weather impact analysis on customer usage in this case, and that she simply reviewed the results of the Company's weather analysis for the test year and found those adjustments to be reasonable. Furthermore, she states that she has worked closely with the Company in the development of its weather normalization methods and inputs, and the Staff has used the same method in four of the Company's rate cases (Mantle Direct, p. 3, lines 11-13). Consequently, Ms. Mantle finds the results of the analysis provided to her by the Company to be reasonable.

Q. Is it fair or appropriate for Ms. Mantle to characterize her own weather normalization adjustment as an analysis sponsored by or supported in any way by the Company?

A. Absolutely not. As I will explain later in my testimony, the Company believes that the Staff's methodology for calculating its proposed weather adjustment contains significant flaws and is improperly designed to minimize the weather adjustment rather than calculate the most accurate adjustment to test year kWh sales and revenues. Not only do I not support Ms. Mantle's weather normalization methodology, I believe it is an unreasonable and inaccurate method for weather normalizing sales.

Q. Did AmerenUE provide Ms. Mantle with the calculation she is using for her weather normalization adjustment?

A. Yes. AmerenUE utilizes a computer program (the "Hourly Electric Load Model" or "HELM") to model its electric loads. At the Staff's specific request, this computer program was designed to weather normalize monthly sales using Staff's preferred methodology, among others. In this case, in response to a Staff data request, the Company provided the Staff with the output from the HELM model incorporating the Staff's methodology for calculating normal weather for each month of the test year. However, the fact that the Company provided this data to the Staff should not be interpreted as any kind of endorsement by the Company of the Staff's flawed weather normalization methodology.

Q. Why is the Staff's weather normalization methodology flawed?

A. At the heart of all weather normalization methodologies is a comparison between the temperature experienced on each day of the test year with the "normal" temperature for that day. Once the difference between actual temperature on a given day and normal temperature for that day is determined, the appropriate adjustment to electric sales can be calculated.

Under weather normalization methodologies that in my experience are universally utilized by everyone but the Missouri Public Service Commission Staff, the normal temperature for a particular day is calculated based on an average of the temperatures experienced during a selected base period. For example, if the base period is 30 years (as it is in this case using both the Staff's and the Company's methodologies), the normal temperature for January 1 would be the average of the temperatures experienced on January 1 during the 30-year base period. Various entities from local weather reporters to the National Oceanic and Atmospheric Administration (NOAA) calculate normal temperatures using some variation of this basic averaging methodology. This is the methodology that I am supporting for use in calculating the weather adjustment for this proceeding.

The Staff, on the other hand, does not use such a direct and obvious method for calculating the normal temperature for each calendar day. Instead, the Staff has invented a new method for calculating normal weather, which it has named the "ranking" methodology. Under this methodology the days in each year of the 30-year base period are ranked from hottest to coldest, and then an average temperature for each ranked day is calculated. For example, the Staff calculates the average temperature for the hottest day in each of the last 30 years, the average for the second hottest day in each of the last 30 years, etc. Then the Staff ranks the days in the test year according to temperature and matches each ranked day against the ranked 30-year averages. However, the highest and lowest ranked temperatures for a particular month are never assigned to a weekend day or holiday.

Q. What is the impact of the Staff's use of this unconventional methodology to calculate normal temperatures?

A. As Ms. Mantle openly admits, the effect of the Staff's methodology is to minimize the Staff's weather normalization adjustment (Mantle direct p. 10, line 5). In this case, as a consequence of that minimization, the Company's revenue requirement has been reduced by approximately $19 million per year. The Company believes that minimization of the weather normalization adjustment is completely inappropriate in this or any other proceeding in which rates for a utility are being established. The goal of all of the parties, and the Commission, should be to calculate a weather normalization adjustment to test year sales that is as accurate as possible, not one that either minimizes or maximizes the adjustment.

Q. Ms. Mantle implies that the Staff's unconventional weather normalization adjustment has been consistently adopted by the Commission since it was first invented by the Staff. Is that true?

A. No. Although Ms. Mantle provides a list of electric cases in which she states that the Staff's weather normalization method was used on Schedule 5 of her direct testimony, as she admitted in her deposition on April 17, 2002, in all but one of the cases where the Staff proposed its weather normalization methodology the issue was settled (Mantle Deposition, April 17, 2002 pp. 35-36). The Commission has never adopted the Staff's weather normalization methodology in a litigated case involving AmerenUE. Moreover, as Ms. Mantle admitted in her deposition, the Commission does not use this weather normalization methodology for other types of utilities for which weather normalized sales must be calculated, such as gas utilities and some water utilities. Instead, the Commission uses a methodology similar to the methodology I am proposing in this case to weather normalize sales for other types of utility companies. (Deposition, April 17, 2002, pp. 31-32.) In short, contrary to the implication in Ms. Mantle's testimony, use of the Staff's unusual methodology for weather normalizing sales of electricity is not supported by consistent Commission practice.

Q. Are you aware of any other jurisdictions that utilize Staff's ranking methodology, or any similar methodology, to calculate a weather normalization adjustment to test year sales for ratemaking purposes?

A. No. I participate, along with other Company representatives, on several industry-wide energy forecasting committees and working groups including the Electric Power Research Institute (EPRI), the Association of Edison Illuminating Companies (AEIC), Edison Electric Institute (EEI), Eastern Utilities Forecasting Forum (EUFF) and the MetrixND Users' Group. The topic of weather normalization is discussed frequently. In my experience no one, outside of representatives of Missouri investor owned electric utilities, has ever heard of Staff's ranking method of calculating normal weather. To the best of my knowledge, other jurisdictions that weather normalize sales universally use an average method similar to the method used by NOAA to calculate normal weather for ratemaking purposes. In her deposition, Ms. Mantle admitted that she did not look at the weather normalization methodologies used by other jurisdictions and had no knowledge of any other jurisdiction that used Staff's method. (Deposition, November 20, 2001 pp. 81-82).

Q. Is there any support for the Staff's ranking methodology in academic literature?

A. Ms. Mantle admitted that she is unaware of any support for the Staff's methodology in academic literature, and to the best of my knowledge, no such support exists. (Deposition, November 20, 2001, p. 82).

Q. What methodology did you use to calculate the normal weather that is used in the weather normalization adjustment to the Company's test year sales?

A. I used the NOAA method. NOAA defines normal as the arithmetic mean of a climatological element over a long time period. As a result of international agreements, NOAA determined that the appropriate time period to use for calculating normal temperature is three consecutive decades. To compute normal temperatures for any given day in the test year, I used the average of each daily temperature during the 1961-1990 thirty year base period. This is the same base period used by the Staff to calculate its weather adjustment.

At my direction, my Staff developed the weather adjustment to monthly sales for the test year by using the HELM model and inputting test year monthly bill cycle sales data and the NOAA temperature data for St. Louis Lambert Field weather station. This is the same sales data, temperature data and computer model used in the calculation of the

Staff's proposed monthly weather adjustment. The only difference is that at my direction, my Staff selected the NOAA method for calculating normal temperatures rather than the Staff's ranking method.

Q. What is the difference in magnitude of the weather adjustment to the Company's test year sales, using Staff's ranking method to calculate normal temperatures versus the standard NOAA method?

A. The differences in the magnitude of the monthly weather adjustments by rate class for Missouri sales are shown in my Schedule 1. Staff's ranking method of calculating normal weather adjusts the weather impact on sales for the 12 months ending June 30, 2001 by 329,554 MWh less than the NOAA method of calculating normal weather used by the Company.

Q. Please provide additional explanation of why Staff's ranking method of calculating normal weather produces a smaller weather adjustment to sales than the NOAA method.

A. There are several reasons. The NOAA daily normal temperatures are developed by taking the average of calendar daily temperatures for 30 years (1961-1990). This means that normal temperatures are based on the natural daily temperature pattern of each calendar year. Staff's ranking method artificially develops daily normal temperatures according to the actual weather pattern of a specific rate case test year. This minimizes the weather adjustment for all months of the year. Staff's ranking method of calculating normal weather also changes the amount of weather normalization of sales on weekdays and weekends because the highest and lowest daily "normal" values are always assigned to weekdays rather than weekends or holidays.

Q. How does Staff's ranking method of calculating normal weather impact the magnitude of the weather adjustment during the milder weather months or "shoulder" months?

A. The largest differences in weather adjustments to sales between Staff's ranking method of calculating normal temperature and NOAA's average method occurs during the shoulder months or Fall and Spring months. During shoulder months, the weather is normally mild and the monthly sales of electricity are less than for summer and winter months. The normal weather pattern for shoulder months should be rather flat due to mild weather that typically occurs during these months. However, if abnormal hot or cold weather occurs, sales in shoulder months will jump. On a percentage basis, the weather impact on heating and cooling during the shoulder months can play a larger role if abnormally hot or cold temperatures occur than in summer and winter months. Staff's ranking method of calculating normal temperature minimizes the difference between actual and Staff's reordered "normal" temperature. The magnitude of that differential has much more weight in the shoulder months. Consequently, Staff's ranking method of calculating normal temperatures during shoulder months further exacerbates the minimization of the weather impact on sales.

Q. Is it necessary for Staff to use its ranking methodology to weather normalize monthly sales solely because Staff also weather normalizes hourly net system loads?

A. In her deposition, Ms. Mantle defended the Staff's use of the ranking methodology to weather normalize electric sales, despite the fact that it creates an inaccurate, minimized picture of the appropriate weather adjustment to monthly sales, because the ranking methodology facilitates the Staff's ability to model hourly load shapes for use in Mr. Bender's production cost model. (Deposition, November 20, 2001, p. 75). However, the Staff's desire for consistency between these calculations is no justification to use a minimized adjustment to monthly sales, that will cost the Company $19 million in annual revenue requirement. The fact is that even under the Staff's own analysis, the Staff is required to calibrate the weather normalized hourly net system loads to the weather normalized monthly sales. My only point is that regardless of what methodology Staff may use to weather normalize hourly net system loads, the results should be calibrated to weather normalized monthly sales that are not artificially high due to the use of the ranking weather normalization methodology..

Q. Are you aware of other analyses by Staff the outcome of which was to adjust the impact of weather on sales in a way that reduces the Company's revenue requirements?

A. Yes. In Case Nos. EO-96-14 and EM-96-149 Staff witnesses Dennis Patterson and Dr. Steve Qi Hu submitted testimony in which they attempted to adjust actual recorded historical St. Louis temperatures to account for alleged changes in temperature recording devices at the official weather station at St. Louis Lambert Airport. As with the Staff's ranking method of calculating normal temperatures, the adjustments to actual recorded historical temperatures that Staff recommended had the effect of reducing the difference between normal temperatures and actual temperatures. This in turn reduced the impact of weather on sales, which thereby reduced the Company's revenue requirement in that case in the range of $20 million per year.

Q. What is your recommendation regarding the weather adjustments to test year sales in this case?

A. I recommend that the Commission adopt the weather adjustments to test year monthly customer sales proposed in the attached Schedule 2, which are based on the widely accepted NOAA method of calculating normal temperatures. The Company's use of the NOAA method is reasonable because it neither minimizes nor maximizes monthly weather adjustments. The Staff's ranking method of calculating normal weather, on the other hand, should be rejected since it is purposely biased to minimize weather adjustments to sales.

B. Normalization Adjustments To Hourly Net System Loads

Q. Ms. Mantle also weather normalized hourly net system loads. What are net system loads?

A. Net system loads represent the hourly generation output that is necessary to serve AmerenUE native load customers.

Q. Why is it necessary to normalize hourly net system loads?

A. It is necessary to normalize hourly net system loads for the same reasons it is necessary to weather normalize monthly sales, that is, to account for abnormal weather in the operation of AmerenUE's generating plants.

Q. How are hourly net system loads used in this case?

A. Normalized hourly loads calculated by Ms. Mantle are used by Staff witness Leon C. Bender to determine AmerenUE's production costs. The monthly peak hour load can also be used in rate design calculations.

Q. How does Staff define normal hourly loads?

A. In Staff's view, normal hourly loads closely match actual hourly loads.

Q. Do you agree with Ms. Mantle calculation of normalized hourly loads?

A. No. In addition to the bias introduced in Staff's method of calculating normal temperatures, Ms. Mantle's work in estimating normalized hourly loads is filled with flawed assumptions, numerical and technical mistakes, and inconsistencies.

Q. Discuss Ms. Mantle's flawed assumptions.

A. Ms. Mantle attempted to weather normalize hourly loads for both AmerenUE and Ameren Energy Marketing Company (AEM). The reason for weather normalizing AEM net system loads is to take into account the impact of the joint dispatch agreement (JDA) between AmerenUE and AEM on AmerenUE's production costs. In her normalization of AEM hourly loads, Ms. Mantle made the assumption that the temperatures in the AEM service area in central Illinois are the same as in the AmerenUE service area, which is predominantly in Missouri. A simple review of the temperatures of the two service areas shows that AEM experiences significantly cooler temperatures than AmerenUE. In fact, a comparison of cooling degree-days (CDD) shows that AEM's CDDs are more than 50% less than those of AmerenUE. Schedule 3 compares heating degree-days (HDD) and CDD for AmerenUE and CIPS.

Q. At what point does a difference in CDD between the AEM service territory and the AmerenUE service territory become significant in the analysis done by Ms. Mantle?

A. Ms. Mantle stated in her deposition that any difference in HDD or CDD that exceeds 20% might have significant impact on her analysis, and a difference of 30% would almost certainly have a significant impact. (Deposition, November 20, 2001, pp. 119-120.)

Q. Please discuss numerical and technical mistakes in Ms. Mantle's attempt to weather normalize hourly loads.

A. One of the technical errors is Ms. Mantle's use of the output of two totally different models to estimate the weather normalized hourly loads for AmerenUE. She used a regression model developed by Staff to weather normalize hourly loads. Then she calibrated the sum of the hourly loads to the weather normalized monthly sales as calculated by the Company using the Hourly Electric Load Model. Inconsistencies are created by the different ways each model determines how much to adjust sales for non-normal weather.

Q. Do you know the magnitude of the difference between the annual energy for the test year calculated by Staff's hourly model as compared to the Company's HELM monthly sales model?

A. During the Company's deposition of Ms. Mantle on April 17, 2002, Ms. Mantle indicated that the difference was in the 1% range (Deposition, April 17, 2002, pp. 30-31).

Q. Is one percent a significant number?

A. AmerenUE's Missouri total actual weather sensitive class sales are on the order of magnitude of 32,000,000 MWH for the 12 months ending June 2001. One percent of 32,000,000 MWH is 320,000 MWH. 320,000 MWH at an average retail rate in the range of $0.06/kwh (which approximates the Company's average retail rate) equates to approximately $19 million in annual revenue requirement. In my opinion, this is a significant dollar difference.

Q. What other technical flaws are contained in Ms. Mantle's work?

A. Ms. Mantle uses an average annual energy loss multiplier provided by Staff Witness Alan J. Bax to calculate hourly net output for the AmerenUE generating plants. Line losses are the energy that is dissipated in the form of heat as electricity flows from the generators through the transmission and distribution lines to the end users. Line losses consist of components that vary with the hourly load as well as components that are fixed. Hourly demand loss multipliers are significantly different than average annual system energy loss multipliers. There are significant differences in loss multipliers by rate class, voltage level, month and hour as explained in detail in the rebuttal testimony of Company witness Richard J. Kovach. Ms. Mantle should have used hourly loss multipliers in her normalization of net system hourly loads.

Q. Did you conduct any reasonableness checks on Ms. Mantle's calculation of weather normalized AmerenUE net system loads for the test year?

A. Yes. I did some rather simple checks of her work and found major inconsistencies. To check the magnitude and direction of the monthly weather adjustment to usage, it is reasonable to compare the actual HDD or CDD for a month to normal. For a summer month, if the actual CDD is greater than normal there should be a negative weather adjustment to usage to account for the hotter than normal weather. For AmerenUE June 2001 actual CDD were 306. Normal CDD for June is 286. Since temperatures in June were hotter than normal, Ms. Mantle should have calculated a negative weather adjustment for that month. Yet, Ms. Mantle shows a relatively large positive weather adjustment of 64,461 MWh in her Schedule 3. Both the magnitude and the direction of her weather adjustment for June 2001 as shown in her Schedule 3 directly contradict her statement on page 2 line 18 of her testimony that June 2001 was "hotter than normal." The June weather adjustment, which is incorrect in both in magnitude and direction, is a significant mistake in Ms. Mantle's work.

Q. What other reasonableness checks should be done on Ms. Mantle's proposed hourly normalized loads for AmerenUE?

A. The normalized system peak load is the most important of all the hourly loads. The system peak load drives resource planning and has significant implications in terms of capital investments and expenses associated with acquiring the generation capacity to meet the peak load. One obvious reasonableness check is to compare the normalized system peak load calculated by Ms. Mantle with the normalized system peak load the Company is required to use for resource planning purposes.

Q. What determines the normalized system peak load that the Company is required to use for system planning purposes?

A. The Company is required to use criteria specified by the Mid America Interconnected Network, Inc. (MAIN) Guide No. 4 to weather normalize the system peak demand. MAIN is one of the regional electric reliability councils, which comprise the North America Reliability Council (NERC). The purpose of MAIN is to promote the reliable use of the interconnected electric systems with due regard for safety, environmental protection, and economy of service through cooperation, planning, construction, operation, and maintenance. MAIN's regular members include investor-owned utilities, cooperative systems, independent power producers, power marketers and municipal systems in Missouri, Illinois and Wisconsin. All MAIN members use peak normalization methodologies based on MAIN Guide No. 4 for reliability planning purposes. At AmerenUE, the peak weather adjustment is designed to determine the expected load at an 89° F two-day weighted mean temperature. The 89° F two-day weighted mean temperature standard is based on analysis of historical data for the years 1980 to 1999. The data indicates that the design standard of 89° F is achieved or exceeded in 50% of the summers for which weather data was analyzed. To determine the temperature corrected summer peak, the summer weekday peak loads are plotted against the corresponding two-day weighted temperatures. The load versus temperature plot resembles the shape of an "S". The "S" shape curve illustrates the effect of non-temperature sensitive load or base load at moderate temperatures and the loss of diversity of air conditioning demands at higher temperatures. A curve is drawn through the points on the plot. The intersection of the curve with the 89° F two-day weighted mean temperature standard is defined as the temperature corrected summer peak.

Q. How did Ms. Mantle determine the weather normalized peak demand for the test year in this case?

A. Ms. Mantle utilized the Staff procedure for weather normalizing hourly loads. Staff again calculated normal daily weather using the Staff's ranking methodology.

Q. Have you identified any problems with Ms. Mantle's calculation of peak demand?

A. Yes. There are inconsistencies in Ms. Mantle's work, which Ms. Mantle has not explained. In Ms. Mantle's July 2001 testimony for the test year of calendar year 2000 she attached a Schedule 4 which showed an actual peak demand of 8023 MW that occurred in August 2000. However, she showed a normalized peak demand of 7869 MW that occurred in a different month--July 2000. In Ms. Mantle March 2002 testimony that covers the test year ending June 2001, she shows an actual peak demand of 8084 MW that occurred in August 2000 and a weather normalized peak demand of 8051 MW that occurred in July 2000. Obvious questions are: (1) What is the basis for changing the actual peak demand for August, 2000 from 8023 to 8084 MW? (2) How did the 61 MW (8084-8023 = 61) increase in her calculation of the actual peak equate to a 182 MW (8051-7869 = 182) increase in her calculation of the normal peak? (3) If the actual peak occurred in August 2000, how can the weather normalized peak occur in July? For the test year, the AmerenUE peak occurred on August 30, 2000. Using the MAIN Guide No. 4 procedures, the Company calculated a normalized system peak demand of 8033 MW. Schedule 3 in Ms. Mantle's testimony shows that Ms. Mantle calculated a normalized system peak demand of 8051 MW.

Q. Staff's and AmerenUE's weather normalized peaks for August, 2000 are relatively close. Why is there a problem with Staff's procedure?

A. It appears to be the luck of the draw that the Staff weather normalized peak demand is close to the normalized peak demand the Company is required to use for resource planning purposes. As I showed in my prior answer, Ms. Mantle developed two completely different weather normalized peak demands for the same month in the two versions of her testimony. Earlier in my testimony I have also shown that the direction of the Staff's weather adjustment to the AmerenUE June 2001 peak demand is wrong. Given such glaring inconsistencies in the Staff's results, the fact that Staff's weather normalized peak demand is close to the normalized peak calculated in accordance with the MAIN standards is pure coincidence. The Staff's methodology certainly cannot be relied upon to consistently produce results that match the MAIN standards.

Q. Why is it critical to be consistent and use a single peak demand for production cost modeling and resource planning?

A. The Company has a need to acquire additional generation resources in the future. The Staff original peak demand of 7869 MW is 164 MW less than the Company peak demand. Peaking capacity currently costs in the range of $500/kW. Consequently, a differential of 164 MW or 164,000 kW may be equivalent to either making or not making a capital expenditure of $82 million. System reliability must also be considered. If generation resources are acquired on the basis of the Staff normalized hourly peak load which varies from model run to model run, the system may experience reliability problems. The bottom line is that there should be one normalized system peak number that is used for both production costing and resource planning. The potential for inconsistencies between Ms. Mantle's calculation of weather normalized peak demand and the weather normalized peak demand used by the Company for system reliability purposes is a significant deficiency in her analysis.

III. CAPACITY RESERVES

A. Overview

Q. What is Dr. Proctor's recommendation regarding UE meeting its capacity reserve requirement for the summer of 2001?

A. Dr. Proctor recommended that the expenses incurred by UE for the cost of power purchases to meet UE's reserve requirements for its summer 2001 peak be replaced by a lesser amount. Dr. Proctor would allow UE a lesser amount consisting of the cost of building, operating and maintaining combustion turbine generators (CTGs) identical to those brought on line in 2001 by Ameren Energy Generating Company (AEG) at Columbia, Missouri and Pinkneyville, Illinois. Dr. Proctor supported his recommendation by contending that affiliate abuse occurred when UE purchased a portion of its capacity needs (450 MWs) from its affiliate, AEM, through a competitive bidding process for the summer of 2001. In doing so, he contended that UE should purchase power from an affiliate at the lower of cost or market.

Dr. Proctor did not mention that UE also purchased 50 MWs of capacity and energy from American Electric Power (AEP) through the same competitive bidding process for summer 2001. Based on the cost of the capacity and energy of the 500 MWs that UE purchased from AEM and AEP for summer 2001, as compared to the costs associated with the CTGs, Dr. Proctor's recommendation results in a downward adjustment to UE's cost of service in the amount of $10.2 million. The $10.2 million reduction is the difference between $48 million (which is Missouri's allocation of the $54.7 million in purchased power costs) and $37.8 million (which is Staff's proposal to add the costs of 500 MWs of CTG costs). See my Schedule 4 for a detailed breakdown of Staff's proposal.

As noted on Schedule 4, and below in my testimony, Dr. Proctor understated by $2.3 million the fixed production expenses associated with the CTGs which he recommended as a substitute for UE's power purchases. When the correct amount of fixed production expenses is added to Dr. Proctor's recommended amount, the effect is a downward adjustment of UE's cost of service in the amount of $7.9 million.

Q. Do you agree with Dr. Proctor's recommendation?

A. Absolutely not. In fact, I was very surprised at Dr. Proctor's recommendation mainly because he was actively involved in developing the Request For Proposal (RFP) for capacity and energy for UE's needs for the summer of 2001 which was designed to prevent affiliate abuse from occurring. I was also surprised at the after the fact, hindsight review which he has applied to examine the reasonableness of UE's process for procuring capacity for the summer of 2001. Dr. Proctor's testimony illustrates in the most clear manner the regulatory uncertainty which UE faces in procuring additional generating resources for its customers.

Q. Why were you so surprised at Dr. Proctor's testimony?

A. One of my responsibilities is to manage the resource planning process for UE. We have a long standing way of doing business with Staff and the Office of Public Counsel (OPC) that is based on "no surprises." We meet and correspond on a regular basis to seek their guidance as well as to insure that they are aware of the status of our resource planning work. Attached as Schedule 5 is a chronology of the more significant meetings and correspondence we have had with Staff and OPC over the past 2-3 years.

Portions of Schedule 5 contain Highly Confidential information concerning the Company's resource planning needs.

Q. What do your meetings and correspondence with Staff cover?

A. Issues discussed include UE's capacity position and options to meet future capacity needs, optimum planning reserve margin, peak and sales forecast, weather normalization, low income energy efficiency programs, resource acquisitions, unit upgrades, AEG generation related activities, transmission issues, RFP development, bid evaluations, electric market products, market pricing, transfer of service territories, the Joint Dispatch Agreement, plant retirement/refurbishment analysis, energy efficiency and energy conservation.

Q. In spite of the fact that you had extensive meetings and correspondence with Staff, particularly Dr. Proctor, please explain further why you were surprised at his testimony.

A. Perhaps it would be helpful to begin by addressing the facts surrounding the development of the RFP for capacity and energy for UE for the summer of 2001.

B. <u>RFP Requirements</u>

Q. Is there a Missouri Public Service Commission (Commission) order concerning the process for developing an RFP for capacity and energy for UE?

A. Yes. There is a Unanimous Stipulation and Agreement (Stipulation) which the Commission approved in Case No. EA-2000-37. The Stipulation prescribed the process that UE was required to follow before purchasing power from an affiliate.

In particular, the Stipulation provided as follows (at section 3.b. on p. 14):

> AmerenUE agrees that any future purchased power contract with Genco or its marketing affiliate will only be entered into if Genco is determined to be the most cost effective offer, giving due consideration to reliability and financial viability, through a competitive bidding process in which all bidders, including Genco or its marketing affiliate, are provided with equal information and bidding opportunities.

"Genco" referred to Ameren's new generation affiliate, which became AEG. "Marketing affiliate" referred to Ameren's new wholesale and retail marketing company, which became AEM. (Stipulation, p. 2)

Q. Please cite the specific wording of the Stipulation which required that Staff and OPC review and comment on a draft RFP before it is issued.

A. The wording in the Stipulation was as follows (at p. 14):

> AmerenUE agrees to the following informational requirements associated with competitive bidding Requests for Proposals ("RFPs") made available to Genco or Marketing Company for purposes described in subsection (3)(b) above. (1) Prior to the first time an RFP is made available to Genco or Marketing Company, AmerenUE will provide to the Staff and OPC a draft copy of the RFP. Within 20 days of receiving a draft copy of the RFP, the Staff and OPC will review said RFP and provide AmerenUE with comments.

As discussed below, the Company followed these requirements and worked closely with Staff and OPC in doing so.

Q. What was your understanding as to the purpose behind the requirement for an RFP?

A. As I understood it, the RFP was designed to require UE to solicit bids from eligible suppliers in order to prevent affiliate abuse which might otherwise occur if an Ameren affiliate would sell to UE with no competitive bidding process.

C. Development of RFP For Summer 2001

Q. Did the Company develop an RFP to obtain resources for 2001?

A. Yes. The Company issued an RFP in January of 2001 for the purpose of obtaining 500 MWs of capacity and energy for the summer of 2001 to meet the reserve margin requirements of the MidAmerica Interconnected Network (MAIN) in order to provide reliable service.

Q. Please explain the circumstances which prompted the Company to develop this RFP.

A. UE's preferred option to meet its capacity needs through 2004 was to transfer its Metro East service area to Central Illinois Public Service Company (AmerenCIPS or CIPS) thereby freeing up approximately 600 MWs of low cost generation capacity for UE Missouri customers. UE filed a pleading with the Commission on October 6, 2000 requesting expedited treatment to transfer its Metro East service area to CIPS. (Case no. EM-2001-233) The pleading requested expedited treatment by February 15, 2001 in lieu of buying capacity and energy for summer 2001. On November 9, 2000 the Staff filed a pleading in response. Staff recommended against expedited treatment and projected that resolution of all issues would take at least six months. In addition to regulatory approvals, the proposed transfer of the UE Metro East service area required the approval of AmerenCIPS and its power supplier AEM. As time elapsed, AEM became unwilling to forego other market opportunities while waiting for all applicable regulatory approvals. As a result, UE requested an order from the Commission requesting leave for UE to withdraw the UE Metro East transfer application. The Commission granted the request by order dated May 3, 2001.

As a result of the unsuccessful attempt to transfer the UE Metro East service territory to CIPS, UE's options to acquire capacity and energy were limited to going to the market for summer 2001. Since UE needed time to analyze its long term resource planning options, the RFP was limited to the capacity and energy needs for summer 2001.

Q. Did Staff review the draft RFP for summer 2001 capacity and energy?

A. Yes, several times. From the chronology of events in Schedule 5, Dr. Proctor reviewed and commented on several drafts between December 8, 2000 and January 4, 2001. So did the OPC. We incorporated into the RFP all of Staff's and OPC's comments.

Q. Did Staff review and approve the final draft of the RFP?

A. Yes. On January 4, 2001 Dr. Proctor sent us an e-mail message approving the final version of the RFP.

Q. What protections did the Company discuss with Staff and OPC, and then implement, to guard against any potential affiliate abuse issues?

A. The Company hired Burns & McDonnell to handle the entire bid evaluation process. Burns & McDonnell is an independent consulting firm with experience in evaluating offers from energy suppliers. All bids were submitted directly to them. All questions by bidders were directed to them. Burns & McDonnell was instructed to do the following work: to determine if the bids met the minimum criteria set forth in the RFP; to evaluate the credit and performance of each bidder; to evaluate the resources used by each bidder to provide the services offered; and to evaluate the ability of the capacity offered to meet MAIN requirements. In addition, the Company asked Burns & McDonnell to submit a written report that described the bid evaluation process, and that provided a ranking of the offers received. All of this was designed to ensure that Ameren's affiliates would not have any influence or involvement in the evaluation of bids submitted in response to the RFP.

The Company provided Staff and OPC with a copy of the scope of work for the services of Burns & McDonnell as well as the final report and recommendations of Burns & McDonnell.

A copy of this report dated April 11, 2001 is attached to my testimony as Highly Confidential Schedule 6. The information contained in this report is confidential in that bidders would not want to reveal to their competitors the prices which they offered in response to the RFP. Further, it involves market specific information relating to services offered in competition with others.

Q. Did either Staff or OPC give you any indication that the RFP which you developed was inadequate or insufficient in any way?

A. No. In fact, as mentioned above, we were left with the impression that both Staff and OPC had approved the RFP prior to its being sent to eligible suppliers.

Q. What happened next?

A. After the Staff and OPC had signed off on the RFP, we issued it on January 5 of 2001. We sent it to 41 suppliers which we had reason to believe would be interested in submitting a bid. UE's power trading affiliate, Ameren Energy (AE), helped us in determining the list of bidders. Prior to the issuance of the RFP, we had submitted the list of 41 bidders to Staff and OPC. Neither Staff nor OPC expressed any objection to the Company about the list of suppliers.

Q. What product was the Company seeking in the RFP?

A. The Company sought peaking capacity and energy in an amount up to 500 MWs for the period June 1, 2001 through September 30, 2001. The capacity had to meet the Company's planning reserve margin requirements and MAIN's accreditation requirements. The bids were due February 1, 2001. The RFP specified that only fixed price offers would be accepted. A copy of the RFP is attached to my testimony and marked as Schedule 7.

Q. Please address further the type of energy product that the Company sought in the 2001 RFP.

A. The RFP clearly stated that UE requested capacity with firm energy at a fixed price. The energy requirement was for "16 hour on peak schedules". This meant that suppliers were being asked to submit bids whereby they would supply firm energy for a 16 hour period each day from Monday through Friday from 7:00 a.m. to 10:00 p.m. UE would purchase the energy for this period whether it needed the energy or not. This "5 x 16 product" as it was known was the standard product for on-peak fixed price energy being offered in the market at the time.

Q. During the RFP development process did you meet with Staff to explain why the RFP requested this particular product?

A. Yes. We met on numerous occasions prior to the development of the RFP to discuss this matter. At a resource planning briefing session on July 29, 1999 the president of AE discussed with Staff the various capacity and energy products offered in the market. We discussed the fact that there is a very visible, actively traded short-term market with well-defined prices. We continued the market product and pricing discussion at the August 8, 2000 resource planning briefing session. At this meeting the AE Director of Pricing & Analysis discussed the various electronic platforms and internet sites that were available for viewing market prices. He also discussed the market requirements to get fixed price contracts for peaking capacity and energy, i.e., to obtain must-take energy provisions through 5 x 16 on peak schedules.

D. Results of the 2001 RFP

Q. Please discuss the results of the RFP.

A. Nine bidders responded to the RFP of which two were eliminated from further analysis because their bids did not comply with the basic requirements of the RFP. Based on information provided by Burns & McDonnell, this response rate was typical for this type of offering, and indicates an active and competitive market for electric power supplies.

Q. Please discuss the analysis by Burns & McDonnell of the bids that were received.

A. Burns & McDonnell calculated the total cost of energy to the Company and ranked the bidders on a cost per block basis in 50 MW increments, with the capacity charge determined by finding the product of the price per MW month and the energy demand for each month. Their primary focus was on the delivered price. The availability of energy—the assurance that it would be online when needed—served as the secondary factor.

All bids reflected the forward price curve for July and August 2001 firm energy as of the day on which the bid was submitted. There were many ways for the bidders to structure their bids to reflect the known market prices. For example, the energy charges could be set low, and the capacity pricing set high, or vice versa. However, the total amount of the bid, representing the "all in" costs of each bid, would be reflective of known market conditions at the time the bid was submitted.

Q. How did Burns & McDonnell rank AEM's bid?

A. Burns & McDonnell placed AEM in the middle of its initial ranking finding AEM's proposal to be very competitive in some blocks and competitive in all others. (Schedule 6, pp. 2-3)

Q. Did the Company undertake its own analysis of the bids?

A. Yes. Burns & McDonnell provided the Company with copies of all bids received. We then undertook a benchmark analysis to determine whether the bids were reasonable and consistent with market conditions. A copy of our benchmark analysis of AEM's bid is attached on Schedule 7. It shows that AEM's bid was consistent with market prices available at the time that AEM submitted its bid. This benchmark analysis contains Highly Confidential information containing market specific information relating to services offered in competition with others.

Q. Who were the successful bidders?

A. UE entered into a contract for 450 MWs with AEM and a contract for 50 MWs with American Electric Power (AEP).

Q. Did AEM file the UE-AEM contract with the Federal Energy Regulatory Commission (FERC)?

A. Yes. AEM filed the contract on April 17, 2001 seeking authority to charge UE a market rate as reflected in the contract.

Q. What was FERC's response?

A. The FERC issued an order on June 14, 2001 accepting the contract for filing and authorizing AEM to charge UE a market rate as reflected in the contract. A copy of the FERC order is attached as Schedule 9.

FERC specifically found that there was no affiliate abuse based on the RFP and the benchmark evidence of other relevant prices presented by AEM and UE. Concerning the RFP, FERC concluded that the Missouri Commission and the OPC "had a role in the development and/or execution of the RFP". Concerning the benchmark evidence, FERC was satisfied with AEM's demonstration as to the reasonableness of the prices stated in the power contract. (Schedule 9, pp. 9-10)

E. <u>Allegations of Affiliate Abuse</u>

Q. In his testimony, Dr. Proctor criticized UE for failing to perform an analysis regarding the RFP that "must-take" energy would be the least-cost purchase (at p. 21). Please respond.

A. There is no basis for his criticism. As Dr. Proctor pointed out, "must-take" energy is energy that the buyer must purchase whether the energy is needed or not. He contended that had the Company performed the analysis referenced above "it would have requested bidders to submit proposals that did not require must-take energy and made a comparison". (at p. 21)

The Company did not request such proposals for two reasons. First, the Company sought a product with a fixed price to avoid exposing UE to market prices for energy in an extremely volatile market. This would have been too risky for the Company and for ratepayers. As Dr. Proctor acknowledged, at the time the RFP was issued natural gas prices were high and future prices for must-take energy were also high. As a result, had the Company requested that suppliers submit a bid for a product without a fixed cost it would have been of no value to the Company because it would have elicited bids which priced energy which fluctuated with the market. This would have afforded UE no protection from the high volatility of the market that produced day ahead prices for on-peak energy as high as $1,750/MWh during the summer of 1999.

Second, the Company sought a must-take product because it was the standard product being offered by suppliers at that time. As I previously discussed, the standard product for peaking capacity and energy was for 5 days a week and 16 hours a day whereby the buyer was obligated to pay whether it took the energy or not. Further, suppliers were imposing a significant premium for a non-standard product which did not have a must-take provision. This premium rendered the non-standard product to be non-competitive at the time.

It should be relatively evident why suppliers at that time would impose a premium for a product that did not have a must-take component. The demand for fixed price energy as of February of 2001, when the bids were due, was high. This was reflected in the prices submitted in response to UE's RFP. Further, the demand was such that suppliers knew that the standard product obligated the buyer to purchase for 16 hours a day, and for 5 days a week. Thus, suppliers were assured of revenues based on such durations. Power marketers, like any marketer, charge a premium for a customized product or service. The market considers fixed price but non "must-take" energy to be a customized product. The concept of customization-- implying higher cost-- is clearly evident in the sole non must-take but fixed price energy bid that UE received from

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(Schedule 6, Table 1, comparing baseload and peaking bids)

At his deposition, Dr. Proctor appeared to acknowledge that given a sufficient level of demand, a much higher price was an economic reality when a non must-take product is offered as compared to a must-take product. (pp. 147, 155)

Therefore, the "comparison" that Dr. Proctor believes that UE should have made, was made and was reported in the Burns & McDonnell report. In any case, the comparison was of limited use to the Company because it compares a standard product offered by suppliers to a non-standard product for which a significant premium was imposed.

Q. On page 21, line 13 Dr. Proctor stated that "Instead, after receiving a first-round of bids that did not explicitly require must-take energy bids, Corporate Planning issued a second RFP in which it explicitly required all bidders to submit bids on the basis of must-take energy." Please respond.

A. This contention is not correct. First of all, we did not issue a second RFP. The RFP requested bids for capacity and firm fixed price energy for 16 hours per day, on peak, for the four summer months of June through September of 2001. In an attempt to reduce the total cost of the bids, and to reflect the importance of fixed price energy for the peaking months of July and August, Corporate Planning asked Burns & McDonnell to call the bidders and ask them if they would be willing to bid on a firm fixed price energy product for only July and August 2001.

Q. Were the products requested in both rounds exactly the same?

A. Yes. This is the second point I would like to make. The Company did not change the product that it was seeking. When Burns & McDonnell called the bidders the Company continued to solicit bids for the same fixed price energy product with a 5 x 16 on peak schedule. As stated above, the only difference that Burns & McDonnell provided to bidders pertained to the duration: initially, the request was for four months, July through September; later, the request was for two months, July and August only. For both rounds, the Company sought the same product: a firm fixed price energy bid.

Q. Did the modification requesting two months of must-take energy, as opposed to four months, save UE from additional purchase power expenses?

A. Yes. Restricting the fixed price energy requirement from June through September to July and August saved UE in the range of $20-$30 million.

Q. In the Company's deposition of Dr. Proctor on April 17, 2002, Dr. Proctor stated that one supplier, **______________________________ bid a non "must-take" but fully dispatchable product as an option in its original bid. Please comment.**

A. **____

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Q. Is the analysis of the **___ alternative bids clearly shown in the Burns & McDonnell RFP evaluation and recommendation final report?**

A. Yes. Table 1 attached to the Burns & McDonnell report is a summary cost sheet of the original bids. An analysis of both of **_____** bids are clearly shown.

Q. Does Dr. Proctor have a copy of the report?

A. Yes.

Q. What did Dr. Proctor conclude from the Company's decision not to perform the "comparison" which he recommended regarding must-take energy?

A. He contended that "this is an example of where affiliate abuse by AEG/AEM occurs". (p. 22) His apparent solution is to have UE buy power from an affiliate at cost rather than at market, assuming that cost is lower than market. He explained as follows: "If AEG/AEM were required to provide electricity at cost rather than at market price, then UE could have acquired the needed capacity at cost with little or no concern about what electricity markets might do during the July and August peak months". (p. 22)

Q. Please respond to Dr. Proctor's contention that there was affiliate abuse in that UE did not buy from an affiliate at cost.

A. I strongly disagree and, as before, I am surprised by his contention. At no time during the development of the RFP, or even later, did Dr. Proctor or any member of the Staff (or anyone from OPC) ever state that UE's purchase from an affiliate would be subject to a cost standard. As I understood it, the purpose of the RFP process as set forth in the Stipulation was to protect against the possibility of affiliate abuse. Accordingly, before UE purchased power from an affiliate it had to establish a competitive bidding process where each bidder got the same information. This is what we did, with Dr. Proctor's apparent approval. Now, he has in effect imposed additional conditions upon the RFP process after the fact. I find this to be extremely frustrating, and submit that it is unfair and creates uncertainty about the Company's resource planning process that will harm not only the Company but also its customers.

Q. In your view, were the bids from AEM and AEP which led to contracts that UE entered into for the summer of 2001 the most cost effective alternatives resulting from the RFP process?

A. Yes, for all of the reasons discussed in my testimony, in the Burns & McDonnell report, our benchmark analysis, and in the FERC order approving the UE-AEM contract.

Q. Dr. Proctor contended at p. 7 that "a transparent market for electricity does not exist today". He then defined transparent to mean a market "where the price at which electricity sells, is determined by an independent market facilitator, and that price is published for everyone to see". Please respond.

A. I agree with Dr. Proctor that there is no transparent hourly market for electricity. However, I disagree with him with regard to a forward market for electricity involving a time frame longer than an hour for up to 18 months. The product that we sought with the RFP for the 2001 summer is actively traded in this market. As referenced above, Ameren's experience is that there is a very visible, actively traded short-term market with well-defined prices for this kind of product.

Q. Were marketers willing to sell cost-based products for summer 2001 in January 2001 when the UE RFP was issued?

A. No. This point was stressed numerous times to Staff by AE. Around February 1, 2001 UE began to receive bids from the RFP. On February 1, 2001 the July/August forward price curve was approximately $147/MWh. This meant that buyers were willing to buy a 5 x 16 product (a set capacity amount for each of the five weekdays in a month for 16 hours per day) for the months of July and/or August for $147/MWh. With market prices at this level, Power Marketers were not willing to sell capacity and energy at cost because they could earn more by selling to the market.

At a resource plan briefing session with Staff on March 28, 2001 we covered this analysis in detail. Dr. Proctor contended at that time that some of the bids offered fixed prices for energy without must-take provisions. I tried to explain that his contention was not correct with regards to the bids for fixed price energy bids for July and August 2001. We offered to bring the bidders to meet with Dr. Proctor to explain their bids. At the subsequent resource plan briefing session on May 10, 2001, we reviewed the summer 2001 bid evaluation for the final time. Dr. Proctor adhered to his contention about fixed price market products and the concurrent must-take provisions. We brought the AE Senior Executive Vice President to this meeting to further explain the various bids and the must-take energy requirement for fixed price bids.

Q. Does the fact that the **___** alternative bid for "non must-take" energy which was higher than any "must-take" energy bid support the fact that there are known visible forward market prices which bidders mark their bids to?

A. That is correct. **____ ____ ____** As I have stated throughout my testimony, there is a very visible and liquid forward market for energy for up to 18 months into the future. All serious bids will come in close to the market price. Customized products should be expected to be bid above market prices for standard products.

Q. Concerning other allegations of affiliate abuse, Dr. Proctor contended that Ameren has elected to build new generation capacity within its non-regulated subsidiary rather than within its regulated utility. He appeared to base this allegation on Schedule 3-2 that shows that AEM intended to increase generation to a high planning reserve margin in 2005. (pp. 19-20) He also contended that "UE would not have had to purchase from the market had it built peaking capacity as regulated generation units." (p. 18) Please respond.

A. I strongly disagree with Dr. Proctor's implication that there has been affiliate abuse on the grounds that AEG has built new generation and UE has not. The information he presented was simply not accurate.

In particular, Dr. Proctor did not mention in his testimony that the information in his Schedule 3-2 is dated January 2000, which is more than two years old. Dr. Proctor has the current capacity position of AEG. The last version was sent to him in

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February 2002. AEG actually installed about half the generation that was projected to be installed in 2000. The AEM marketing organization was not fully staffed until summer 2000. Subsequent to January 2000, AEM continuously entered into new power supply agreements with customers. Significant new AEM agreements that Dr. Proctor is or should be aware of include the following: 300 MWs with a major Illinois retail industrial customer; 300 MWs with a major Illinois electric coop; 50 MWs with a major neighboring electric utility; and many, many power supply agreements below 50 MWs. Finally, we've discussed with Dr. Proctor on numerous occasions both UE and AEM plan to maintain an **__**% planning reserve margin rather than the higher level that Dr. Proctor sets forth in his testimony. The Company considers its and AEM's reserve margins to be Highly Confidential. Disclosure of this information would compromise the Company's (and AEM's) ability to buy and sell electricity at reasonable prices.

Moreover, at his deposition Dr. Proctor acknowledged that he has more current data on AEG's reserve margin but chose not to use it. (p. 129) Dr. Proctor presumably was aware that his testimony relied on obsolete data that was no longer accurate.

F. "Normalized" Cost for 2001 Capacity and Energy

Q. Dr. Proctor proposed that the "normalized" cost for capacity that UE purchased to meet reserve margin requirements for June, July, August and September of 2001 be based on the cost of the generation capacity of the new peaking units that were built by AEG. P. 22. Please comment.

A. As Ms. Mantle did with the concept of weather normalization of hourly loads, Dr. Proctor has invented a totally new concept that he calls the "normalized cost of

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generation capacity" without citation to any source or authority. I have never heard of this term in my more than 25 years of experience in the electric utility business.

Presumably, by "normalized" cost he means a representative cost for generation capacity at a certain time and under a given set of conditions. In any case, Dr. Proctor arbitrarily assigned the installed cost of $490/kW based on the installed cost of the AEG FT-8 model CTG units, and ignored the installed costs of the other 1100 MW of CTGs that AEG recently installed. Further, he completely ignored the evidence from the wholesale power market, and therefore did not take into account the price of purchased power that UE could have acquired. Perhaps the most frustrating aspect is that Dr. Proctor never told us that the normalized cost of capacity, from Staff's perspective, is the cost of the new peaking units that were built by AEG. Had we known this, we might have decided not to undertake the thousands of man-hours and dollars that the Company, our consultant, the bidders and the MPSC and OPC Staffs spent on RFP development, bid preparation, negotiations, bid evaluation and report writing. This is what we believed was necessary to establish accurate and representative prices for power for the summer of 2001. All of this effort might have been avoided if we had known that Staff would later contend that it was not relevant to establishing a "normalized cost" for the summer of 2001.

Q. Do you agree with Dr. Proctor's inclusion of non-fuel O&M expenses of $2.45/kW as an adder to the installed cost of $490/kW for normalized capacity planning reserves?

A. No. This represents yet another example of Dr. Proctor's assignment of a normalized cost that is unsubstantiated by analysis of any type. At his deposition, Dr. Proctor was under the impression that the CTGs which UE has had in operation were mostly gas fired. (p. 162) This is not correct. In fact, most of UE's existing CTGs use oil as the fuel.

To be exact, UE's fleet of CTGs consists of the following units:

Plant	Net Capability (MW)	Fuel
Venice	25	Oil
Howard Bend	43	Oil
Meramec 1	55	Oil
Fairgrounds	55	Oil
Mexico	55	Oil
Moberly	55	Oil
Moreau	55	Oil
Meramec 2	53	Oil/Gas
Kirksville	13	Gas
Viaduct	25	Gas

Of the 434 MWs of CTGs listed above, only 38 MWs are fueled solely by natural gas.

Dr. Proctor used a three-year average of the O&M expenses associated with UE's oil-fired CTGs. However, the Columbia CTGs, which Dr. Proctor used to represent the normal cost of planning reserves, are natural gas fired. Oil is significantly more expensive than natural gas. As a result, to minimize operating costs, the Company would have dispatched and operated the hypothetical gas fired turbines selected by

Dr. Proctor more often than the Company would have dispatched and operated oil fired turbines.

Consequently, the Columbia gas fired CTGs would have operated more frequently than the oil-fired CTGs on which Dr. Proctor based his non-fuel O&M expenses. Since non-fuel O&M expenses are driven by the frequency and duration of operation, non-fuel O&M expenses for the Columbia CTGs can reasonably be expected to be much higher than $2.45/kW. In addition, the UE oil-fired CTGs were constructed, or began construction, prior to the time when the units became subject to New Source Performance Standards from the Environmental Protection Agency (EPA). Thus, new CTGs constructed would have additional environmental costs which these oil-fired units do not have. In fact, AEG has site specific O&M agreements in place for its new peaking plants. The O&M agreement for the AEG Columbia, MO CTG specifies a value of approximately **___________** for non-fuel O&M. Documentation concerning O&M expenses for the Columbia CTG is attached as Schedule 10. This documentation is Highly Confidential consisting of market specific information relating to services offered in competition with others.

Thus, in the event that the Commission accepted Dr. Proctor's recommendation regarding the use of the AEG turbines as a proxy for the cost of UE's 2001 capacity needs, the associated non-fuel O&M expenses for gas fired CTGs would be an appropriate match. However, as noted above, I strongly disagree with Dr. Proctor's recommendation on the use of the AEG turbines as a lower of cost or market proxy for the AEM-UE power contract.

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Q. What is the dollar effect of Dr. Proctor's use of non-fuel O&M expenses for the gas fired CTGs which he used to represent the "normalized" cost of capacity for 2001?

A. The effect is an understatement of UE's costs of approximately $2.3 million per year, again assuming the Commission accepts Dr. Proctor's recommendation. This is derived by taking the difference between the non-fuel O&M expenses associated with gas fired CTGs and those with oil fired CTGs **___________ ________** and then multiplying this difference by the 500 MWs representing the total amount of the CTGs used as the proxy for the 500 MW purchases from AEM and AEP and by the UE-Missouri allocation factor of 0.85.

G. RFP for 2002

Q. Dr. Proctor compared and contrasted UE's RFP for capacity and energy for summer 2002 with summer 2001. Dr. Proctor stated "To fulfill its capacity need for the coming summer of 2002, UE has issued Requests For Proposals (RFPs), received bids, evaluated these bids and entered into completely different contracts that are at a lower cost." Please respond.

A. I disagree with Dr. Proctor's testimony in which he compared and contrasted the UE RFPs of 2001 and 2002. Just as the Company did with the summer 2001 RFP, the Company worked closely with Dr. Proctor in the development of the RFP for capacity and energy for the period 2002-2011. We met with Dr. Proctor and Staff from July 12, 2001 to August 10, 2001 in developing the RFP.

I would like to point out some additional facts which are critical to an understanding of the second RFP for 2002. First, as discussed more fully below, the

August 10, 2001 RFP was for a 10-year term as opposed to last year's RFP which was limited to the summer of 2001. Second, and of critical importance, the market price forward curve for electricity plummeted after August of 2001. While the July/August prices in February 2001 for the summer 2001 RFP were in the \$147/MWh range, market prices for July/August 2002 plummeted to the \$40/MWh range in February 2002. A combination of oversupply of new peaking generation throughout the country plus two prior summers of relatively mild weather drove prices to the lowest levels in recent history. Based on this second fact alone, it is not appropriate or meaningful to compare the prices resulting from the first RFP to those resulting from the second RFP conducted about a year later.

Q. How was the 2002-2011 RFP structured?

A. Bidders were encouraged to be creative and bid a variety of products for any portion or the entire term of the RFP. Again, Burns & McDonnell was retained to perform an independent assessment of the bids received.

Q. What type of products were bid?

A. The vast majority of bids were for a "tolling" product. A tolling product is similar to a lease where the buyer incurs a fixed cost to have full use of a generator. The buyer incurs the fuel price risk whenever the buyer elects to operate the generator. Bidders did not bid fixed price energy market products. The reason is that forward market prices had fallen to the point where bidders were willing to simply recover a portion of the costs of their generation investments.

Q. Did market prices and length of contract determine the type of products that power marketers were willing to bid?

A. Yes. The analysis of the bids to both RFPs for the summer 2001 and 2002-2011 proves that point.

Q. In his testimony, Dr. Proctor specifically stated "To fulfill its capacity need for the coming summer of 2002, UE has issued a Request For Proposal...". This implies that there was a RFP issued for summer 2002 only. Please explain.

A. As referenced above, the Company originally developed the second RFP to cover a ten year period from 2002 to 2011. UE first presented the results of the evaluation of the bids for the 2002-2011 period to the Division Directors and Managers of the Commission Staff and OPC on January 15, 2002. In addition to the 2002-2011 bids, UE presented additional options on a confidential basis to meet its capacity needs. These additional options would likely not be completed prior to the summer of 2002. Therefore, assuming that one of the options was selected, UE would still be required to make purchases to meet its capacity needs for summer of 2002.

Q. Why were additional options presented?

A. There are two reasons. First, UE was very concerned about recommendations in Staff testimony in a Utilicorp United Inc. proceeding. (Case No. ER-2001-672) The specific testimony came from Staff witness Mark L. Oligschlaeger. In 1999 Staff recommended approval of a power purchase agreement (PPA) between Utilicorp's MPS subsidiary and Utilicorp's power marketing affiliate, Aquila. In 2001, Staff reversed its earlier recommendation and recommended that part of the PPA be disallowed on the theory that if MPS had built a plant it would now be partially depreciated and the all-in cost of this theoretical plant would now be less than the PPA cost. As we viewed it, the fact that Staff recommended reversing a decision which the Commission had previously approved concerning a market purchase by a utility highlighted an aspect of regularity uncertainty in the state of Missouri that electric utilities must confront.

Q. What was the second reason for the Company presenting additional options for UE's 2002-2011 capacity and energy needs to the Staff?

A. ** ______________________________ **

Q. Explain the first option that UE presented to Staff to meet its future capacity needs.

A. ** ______________________________ **

Q. Explain the second option that UE presented to Staff to meet its future capacity needs.

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A. ** **

Q. What was the outcome of the January 15, 2002 meeting between the Company and Staff?

A. ** **

Q. What happened next?

A. ** **

Q. Did UE and Staff reach any understanding as to what would constitute a reasonable approach for meeting UE's capacity and energy need for summer 2002?

A. Yes. UE had bids to its 2002-2011 RFP for capacity and energy. None of the suppliers bid solely for the year 2002. UE and Staff agreed that it would be

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reasonable for UE to contact the lowest cost bidders and ask them to re-bid on a summer 2002 contract only.

Q. The preceding testimony explains how the 2002-2011 RFP for capacity and energy evolved into a summer 2002 only RFP. What was the outcome of asking the lowest cost bidders to re-bid for summer 2002?

A. The three lowest bids in order of least cost to highest costs were as follows: AEM, AEP, and Reliant.

Q. Does Dr. Proctor have a copy of the analysis of the summer 2002 only bids?

A. Yes. UE sent Dr. Proctor a summary of the analysis of all bids on February 8, 2002.

Q. How much lower is the AEM bid for summer 2002 than the other two bids?

A. The AEM bid is 19% below the AEP bid and 22% below the Reliant bid.

Q. Does the AEM bid for UE's summer 2002 capacity and energy requirements support the possibility of affiliate abuse as Dr. Proctor suggested in his testimony?

A. I believe that it is obvious that it does not. What is does show is that market conditions dictate AEM's pricing strategies with all customers. Affiliate abuse was not an issue for the 2002 RFP and was not an issue for the 2001 RFP. AEM did not receive from UE or Burns & McDonnell any more information than was given to the other bidders. This is true for both the 2001 RFP and the 2002 RFP.

Q. What is the status of the AEM-UE contract for the summer of 2002?

A. On March 20, 2002, AEM and UE entered into a contract under which UE would purchase 200 MWs from AEM. On April 1, AEM filed the contract with the FERC requesting authorization to charge UE the market-based rates set forth in the contract.

H. Regulatory Uncertainty for Future Resources

Q. In light of Dr. Proctor's recommendation that the normalized cost of capacity for meeting reserve requirements should be $490/kW, do you have a better idea of how to meet planning reserve margin requirements in the future?

A. Yes, but only if Dr. Proctor's normalized cost of $490/kW could be relied on for some future time period. If so, then building or owning generating assets that cost no more than $490/kW apparently is the answer for meeting planning reserve margin requirements. Since by definition a normal cost is an average cost, I assume the principle of fairness would require that to the extent that the Company can meet its planning reserve margin requirement for less than $490/kW in a rate proceeding those costs will be normalized upward to reflect "normal" costs. At his deposition, Dr. Proctor acknowledged that this upward adjustment could be appropriate. (p. 119) However, he also stated that his normalized cost could change in the future. (p. 113) Thus, the Company apparently can not rely on the $490/kW figure on a going forward basis.

Q. Is it realistic to think that UE may be able to meet its planning reserve margin requirements for less than $490/kW?

A. To the extent that UE's capacity needs are of a peaking nature, there is the possibility that UE can secure capacity for less than $490/kW. The bids for UE's summer 2002 capacity and energy needs have an equivalent price that is less than $490/kW. However, market conditions have changed and those prices may now differ.

Q. Please discuss UE's activities in building new generation since January of 2000.

A. The regulatory uncertainty surrounding cost recovery has slowed construction of generation capacity by investor-owned electric utilities in the state of Missouri. At UE, we look for reasonable opportunities to meet our capacity requirements that do not expose us to the regulatory uncertainty so clearly illustrated in Dr. Proctor's testimony. Examples include the transfer of UE wholesale customer load to AEM. ** ____ ______** The strategy to free up load and thereby release more capacity for UE Missouri customers clearly has been UE's preferred method of meeting additional capacity needs in the near term. However, UE has not hesitated to build additional capacity when the situation warranted it. For example, UE did not hesitate to build 240 MWs of new peaking generation scheduled for commercial operation in June 2002 when concerns of transmission congestion and market price volatility were raised. UE has also discussed its balanced portfolio approach of both buying and building to meet its anticipated future capacity and energy requirements with Staff at numerous meetings.

Q. Are there any other issues that you wish to address in Dr. Proctor's testimony?

A. Yes. I must emphasize that I believe it would be extremely unfair if the Commission adopted Dr. Proctor's contention that purchases from AEM should be at cost or market, whichever is lower, and that sales to AEM should be at cost or market

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whichever is higher. This philosophy means that affiliates lose 100% of the time and regulated utilities win 100% of the time. Obviously, AEM will always be a loser under such unfair circumstances and will cease doing business with UE. As evidenced by the 2002 RFP, UE customers will lose. Had AEM known that it would be subject to a lower of cost or market standard it surely would not have bid on UE's summer 2002 capacity and energy requirements. No rational supplier will sell at cost if it can make more money selling at market. However, AEM did submit a bid for the 2002 RFP and AEM's bid was 19% lower than then next lowest bid. Staff's approach would remove AEM as a competitive source of supply for UE. Loss of competitive bidders has the potential to increase costs to customers. UE may also be forced to buy from less reliable sources of supply.

Further, on a procedural matter, as Dr. Proctor acknowledged at his deposition, the "lower of cost or market" principle which he applied to the Company's purchase in 2001 from AEM comes from the Commission's affiliate rules. However, Dr. Proctor further acknowledged that the Company is not currently subject to these rules based on the appeal that it has filed, and the Stay that it has received. (Deposition, pp. 127-128) It should be obvious that it is extremely unfair for the Staff to apply rules to the Company when the Company is not subject to them.

I. Conclusion

Q. What do you recommend using as the cost to meet UE's reserve margin requirements for the summer of 2001?

A. I recommend using exactly the amount that UE spent to meet its planning reserve margin requirement. As my testimony shows, UE's power purchase costs are an accurate and fair representation of the market at the time the power supply agreements were signed. UE-Missouri paid about $48 million to AEM and to AEP under the two contracts. Dr. Proctor, on the other hand, only recommended that UE get approximately $38 million for the cost of the CTGs used as a proxy for the power purchase contracts. As referenced above, the derivation of both cost estimates are attached in Schedule 4.

Q. Are there circumstances under which you could agree with Dr. Proctor's recommendation to use $490/kw as the normalized cost to meet reserve margin requirements?

A. Yes. When UE's generation needs are of a peaking nature, if Dr. Proctor is willing to be consistent in his application of $490/kW (with appropriate escalation) as the normalized cost to meet reserve margin requirements in future rate cases, this will mitigate a portion of the regulatory uncertainty associated with Staff reversing its position on the normalized cost of planning reserves.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

AFFIDAVIT OF RICHARD A. VOYTAS

STATE OF MISSOURI)
) **ss**
CITY OF ST. LOUIS)

Richard A. Voytas, being first duly sworn on his oath, states:

1. My name is Richard A. Voytas. I work in St. Louis, Missouri and I am employed by Ameren as Manager, Corporate Analysis.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 51 pages, Appendices A through B and Schedules 1 through 10, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Richard A. Voytas
Richard A. Voytas

Subscribed and sworn to before me this 7th day of May 2002.

Debby Anzalone
Notary Public

My commission expires:

DEBBY ANZALONE
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: April 18, 2006

APPENDIX A: QUALIFICATIONS OF RICHARD A. VOYTAS

My name is Richard A. Voytas and my business address is 1901 Chouteau Avenue, St. Louis, MO 63103. I reside in Waterloo, Illinois.

My educational background consists of a Bachelor of Science degree in Mechanical Engineering from the University of Missouri-Rolla in 1975 and a Masters In Business Administration from St. Louis University in 1979. I am a registered professional engineer in the state of Missouri.

I was employed full time by Union Electric beginning in May of 1975. Effective with the merger of Union Electric Company and Central Illinois Public Service Company into the Ameren Corporation, I assumed employment with Ameren Services. My work experience started at Union Electric as an Assistant Engineer in the Engineering and Construction function. I worked as an Assistant Engineer from 1975 to 1977. In 1977 I was promoted to Fuel Buyer in the Supply Services Function. In 1981 I transferred to the Engineering Department at Union Electric's Rush Island Plant. In 1982 I accepted a position in the coal marketing department at Cities Service Company in Tulsa, OK. In late 1982 I left Cities Service Company and returned to Union Electric as an Engineer in the Corporate Planning Department. From 1982 through 1992 I worked as an Engineer in the Corporate Planning Department, Engineer in the Quality Improvement Department and Engineer in the Rate Engineering Department. In 1993 I was promoted to Senior Engineer in the Corporate Planning Department. In 1995 I was promoted to Supervising Engineer in the Demand-Side Management section of Corporate Planning. In July 1998 the Resource Planning, Forecasting, Load Research and Demand-Side Management sections were combined into one section of Corporate Planning and I was named Supervisor of that section known as the Corporate Analysis department. Today, Corporate Analysis is divided into four subgroups, which are Resource Planning, Market Modeling, Load Analysis and Forecasting, and Load Research. In October 2001 I was promoted to my present position as Manager-Corporate Analysis.

My duties as Manager of Corporate Analysis include overseeing the preparation of the Ameren capacity position both on an annual and weekly basis, preparation of resource plans, development and evaluation of requests and proposals for capacity and energy for Ameren operating companies, preparation of the annual sales and peak demand forecasts, development of the Ameren forward view of electric energy market prices, and the collection, editing and analysis of monthly load research data.

I have submitted testimony concerning least cost planning and weather normalization of sales before the Missouri Public Service Commission and the Illinois Commerce Commission.

EXECUTIVE SUMMARY

Richard A. Voytas

Manager, Corporate Analysis, Corporate Planning Department

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Overview

My testimony responds to Staff witness Lena M. Mantle's testimony concerning weather normalization and Staff witness Michael S. Proctor's testimony concerning capacity reserves. The result of both Ms. Mantle and Dr. Proctor's seriously flawed work is a total reduction in the Company's annual revenue requirement of approximately $30 million.

Weather Normalization

A. Weather Normalization Adjustment to Test Year Sales

Ms. Mantle is sponsoring the Staff's adjustment to normalize the Company's test year sales of electricity to account for abnormal weather experienced during the test year. Although she proposes to reduce test year sales to account for unusual weather, she has not reduced those sales sufficiently, due to her use of an unconventional and inappropriate method of calculating the normal temperature for each day of the test year. The Staff invented this "ranking" method of calculating normal temperatures for the specific purpose of minimizing the weather normalization adjustment for electric utilities. In this case, use of the Staff's method of calculating normal temperatures reduces the Company's revenue requirement by approximately $19 million per year.

Under the Staff's flawed methodology for calculating normal temperatures, all the days in each year of a 30-year base period are ranked from hottest to coldest. Then the Staff calculates an average temperature for the hottest day in each year, the second hottest day in each year, etc. Finally, the weather normalization adjustment is developed by comparing these ranked averages to the temperatures during each ranked day of the test year. This convoluted procedure has the effect of minimizing the adjustment.

The Company's proposed method for calculating normal temperature, on the other hand, is based on the common sense notion that the average temperature for each day should be the average temperature experienced on that day during each year of the 30-year base period. In other words, the average temperature for January 1 is the average temperature experienced on January 1 during the base period. This straightforward methodology for determining normal temperatures is endorsed by the National Oceanic and Atmospheric Administration (NOAA), and it is widely accepted throughout the country. This method of calculating normal temperature neither minimizes nor maximizes the weather normalization adjustment, and is therefore more reasonable than the Staff's methodology.

No authorities on weather normalization other than the Staff, and no jurisdictions outside Missouri, endorse the unconventional and punitive weather normalization methodology proposed by the Staff in this case. In fact, the Commission does not use the methodology to weather normalize the sales of gas and water utilities in Missouri. Moreover, Ms. Mantle has provided no support whatsoever for her weather normalization adjustment to test year sales. In less than two pages of direct testimony addressing the subject, she states only that she agrees with the calculation of the weather adjustment provided to her by the Company. At Ms. Mantle's request, the Company ran its Hourly Electric Load Model ("HELM") computer program to calculate test year weather normalized sales using the Staff's preferred weather normalization methodology, but the Company did not and does not endorse that methodology. Consequently, Ms. Mantle's weather normalization adjustment is completely unsupported and must be rejected.

B. Weather Normalization of Hourly Net System Loads

Ms. Mantle is also supporting the weather normalization of hourly net system loads using the Staff's own computer model on hourly load data provided by the Company. The Staff calibrated the results of the weather normalized hourly system loads to correspond with Ms. Mantle's proposed weather normalized sales developed from the HELM model. The hourly net system loads were then used by Staff Witness Leon C. Bender in his production cost model.

Ms. Mantle's calculation of weather normalized hourly loads is fraught with errors. First of all, as part of her analysis, she used St. Louis temperatures to weather normalize Ameren Energy Marketing Company's (AEM) Illinois loads, even though temperatures in the territory where AEM operates are significantly cooler. Ms. Mantle admitted that a temperature difference of this magnitude would almost certainly have a significant impact on her analysis. Second, as part of her analysis, she calibrated the output of two inconsistent models—the HELM model and the Staff model used to weather normalize the hourly load data. This resulted in an adjustment of approximately 1% to the hourly load data, which is a significant adjustment given the size of the loads on the Ameren system. Ms. Mantle also used an incorrect energy loss multiplier in her calculations. Finally, she failed to perform adequate checks on the reasonableness of her results. For example, even a cursory review of her testimony shows that the weather normalization adjustment for June, 2001 is in the wrong direction. In addition, the test year weather normalized system peak she has calculated for AmerenUE is significantly different between her July 2001 testimony and her March 2002 testimony. Her method of calculating system peak demand is also inconsistent with the method the Company is required to use to calculate system peak for resource planning purposes by the Mid-America Interconnected Network Guide No. 4. For all these reasons, Ms. Mantle's weather normalization adjustments should be rejected, and the Company's proposed normalization adjustment should be adopted.

Capacity To Meet Reserves for 2001

Dr. Proctor has engaged in an improper, hindsight attack on the Company's power contract for 2001 with its affiliate, Ameren Energy Marketing Company (AEM). The impact of his proposal on AmerenUE is approximately $10 million.

Dr. Proctor contended that the AEM-UE contract involved affiliate abuse, and that as a result UE should pay AEM the lower of cost or market. Dr. Proctor's contentions amount to an improper, hindsight attack on the power contract because the contract was the result of a competitive bidding process, which Staff helped develop, and because the contract was approved by the FERC.

This contract was the result of a Request for Proposal (RFP) in full compliance with a prior order of the Missouri Commission. Dr. Proctor reviewed the RFP prior to its issuance, and led the Company to believe that it was adequate. The AEM-UE contract was also approved by the FERC which concluded 1) that there was no affiliate abuse and 2) that the market prices reflected in the contract were appropriate.

Surprisingly, Dr. Proctor chose to ignore the multitude of evidence pointing to a reasonable RFP process and a fair evaluation of all bids received. This evidence included the following: 1) the use of an independent outside consultant to receive, analyze, and evaluate all bids; 2) the FERC approval of the UE-AEM contract; 3) benchmark analysis which the Company performed showing that the prices in the AEM contract were reasonable compared to other market alternatives; 4) the fact that UE also entered into a power supply agreement with a non-affiliate with similar provisions; and 5) Dr. Proctor's direct involvement in the development of the RFP.

To correct the alleged affiliate abuse, Dr. Proctor recommended that a lower of cost or market standard be applied to the cost of the capacity and energy purchased from AEM. Dr. Proctor contended that the "normalized" cost of the capacity and energy to meet UE's planning reserves during the test year was the cost of certain combustion turbine generators (CTGs) that the Company's affiliate, Ameren Energy Generating Company (AEG) built. Costs of other CTGs built by AEG during the same period, as well as market conditions and prices, were totally ignored by Dr. Proctor in his assessment of the normalized cost of planning reserves.

Dr. Proctor further acknowledged that his lower of cost or market principle derived from the Commission's affiliate rules, which are not yet effective as to the Company. Dr. Proctor specifically acknowledged that he in effect applied the affiliate rules to the Company when the Company is not currently subject to them. Further, the lower of cost or market proposal in effect amounts to an additional condition imposed on the Company beyond the RFP requirement in the Commission's prior order.

Dr. Proctor's after the fact, hindsight attack on the AEM-UE contract for 2001 is not only improper but it also creates regulatory uncertainty for the Company in its efforts to acquire generation resources. The Commission should reject Dr. Proctor's lower of cost or market recommendation as fundamentally unfair and improper in this case.

Response to DR No. TMB-34

Total Weather Senstive Classes

	31,576,614	30,607,533	30,277,979	(969,081)	(1,298,635)	-3.07%	-4.11%	

Residential - Missouri

	Actual	Normal Ranked	Unranked	Weather Adj Ranked	Unranked	% Adj Ranked	Unranked	
Jul-00	1,209,755	1,233,269	1,175,306	23,514	(34,449)	1.94%	-2.85%	57,963
Aug-00	1,253,135	1,146,915	1,257,351	(106,220)	4,216	-8.48%	0.34%	(110,436)
Sep-00	1,289,006	1,065,611	957,018	(223,395)	(331,988)	-17.33%	-25.76%	108,593
Oct-00	794,542	742,979	674,376	(51,563)	(120,166)	-6.49%	-15.12%	68,603
Nov-00	731,164	712,979	711,553	(18,185)	(19,611)	-2.49%	-2.68%	1,426
Dec-00	1,115,076	1,014,429	1,028,465	(100,647)	(86,611)	-9.03%	-7.77%	(14,036)
Jan-01	1,444,118	1,358,127	1,308,750	(85,991)	(135,368)	-5.95%	-9.37%	49,377
Feb-01	1,098,165	1,144,041	1,194,405	45,876	96,240	4.18%	8.76%	(50,364)
Mar-01	988,979	995,673	992,825	6,694	3,846	0.68%	0.39%	2,848
Apr-01	795,559	771,279	765,618	(24,280)	(29,941)	-3.05%	-3.76%	5,661
May-01	740,588	670,976	623,269	(69,612)	(117,319)	-9.40%	-15.84%	47,707
Jun-01	890,070	823,482	773,422	(66,588)	(116,648)	-7.48%	-13.11%	50,060
Total	12,350,157	11,679,760	11,462,358	(670,397)	(887,799)	-5.43%	-7.19%	217,402
Summer	4,641,966	4,269,277	4,163,097	(372,689)	(478,869)	-8.03%	-10.32%	106,180
Other	7,708,191	7,410,483	7,299,261	(297,708)	(408,930)	-3.86%	-5.31%	111,222

LGS

	Actual	Normal Ranked	Unranked	Weather Adj Ranked	Unranked	% Adj Ranked	Unranked	
Jul-00	649,197	651,845	644,648	2,648	(4,549)	0.41%	-0.70%	7,197
Aug-00	660,177	648,848	660,610	(11,329)	433	-1.72%	0.07%	(11,762)
Sep-00	669,990	643,902	634,885	(26,088)	(35,105)	-3.89%	-5.24%	9,017
Oct-00	591,812	581,064	577,774	(10,748)	(14,038)	-1.82%	-2.37%	3,290
Nov-00	591,817	574,825	563,489	(16,992)	(28,328)	-2.87%	-4.79%	11,336
Dec-00	609,153	588,264	586,534	(20,889)	(22,619)	-3.43%	-3.71%	1,730
Jan-01	726,600	703,840	684,987	(22,760)	(41,613)	-3.13%	-5.73%	18,853
Feb-01	562,077	571,401	578,790	9,324	16,713	1.66%	2.97%	(7,389)
Mar-01	563,723	567,299	563,247	3,576	(476)	0.63%	-0.08%	4,052
Apr-01	543,746	535,469	527,755	(8,277)	(15,991)	-1.52%	-2.94%	7,714
May-01	576,059	553,153	536,664	(22,906)	(39,395)	-3.98%	-6.84%	16,489
Jun-01	640,250	626,402	629,838	(13,848)	(10,412)	-2.16%	-1.63%	(3,436)
Total	7,384,601	7,246,312	7,189,221	(138,289)	(195,380)	-1.87%	-2.65%	57,091
Summer	2,619,614	2,570,997	2,569,981	(48,617)	(49,633)	-1.86%	-1.89%	1,016
Other	4,764,987	4,675,315	4,619,240	(89,672)	(145,747)	-1.88%	-3.06%	56,075

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SGS

	Actual	Normal Ranked	Unranked	Weather Adj Ranked	Unranked	% Adj Ranked	Unranked	Diff
Jul-00	319,410	321,973	317,234	2,563	(2,176)	0.80%	-0.68%	4,739
Aug-00	323,220	311,281	324,857	(11,939)	1,637	-3.69%	0.51%	(13,576)
Sep-00	329,280	304,492	293,460	(24,788)	(35,820)	-7.53%	-10.88%	11,032
Oct-00	266,356	258,158	252,147	(8,198)	(14,209)	-3.08%	-5.33%	6,011
Nov-00	255,833	247,826	244,473	(8,007)	(11,360)	-3.13%	-4.44%	3,353
Dec-00	308,341	291,647	292,457	(16,694)	(15,884)	-5.41%	-5.15%	(810)
Jan-01	361,516	347,347	338,267	(14,169)	(23,249)	-3.92%	-6.43%	9,080
Feb-01	304,625	312,573	320,805	7,948	16,180	2.61%	5.31%	(8,232)
Mar-01	282,555	284,979	281,879	2,424	(676)	0.86%	-0.24%	3,100
Apr-01	253,856	248,699	245,139	(5,157)	(8,717)	-2.03%	-3.43%	3,560
May-01	259,019	244,144	231,087	(14,875)	(27,932)	-5.74%	-10.78%	13,057
Jun-01	280,676	270,094	266,793	(10,582)	(13,883)	-3.77%	-4.95%	3,301
Total	3,544,687	3,443,213	3,408,598	(101,474)	(136,089)	-2.86%	-3.84%	34,615
Summer	1,252,586	1,207,840	1,202,344	(44,746)	(50,242)	-3.57%	-4.01%	5,496
Other	2,292,101	2,235,373	2,206,254	(56,728)	(85,847)	-2.47%	-3.75%	29,119

LP

	Actual	Normal Ranked	Unranked	Weather Adj Ranked	Unranked	% Adj Ranked	Unranked	Diff
Jul-00	323,637	324,025	323,657	388	20	0.12%	0.01%	368
Aug-00	382,590	379,992	381,549	(2,598)	(1,041)	-0.68%	-0.27%	(1,557)
Sep-00	361,028	358,138	356,418	(2,890)	(4,610)	-0.80%	-1.28%	1,720
Oct-00	317,576	315,813	315,956	(1,763)	(1,620)	-0.56%	-0.51%	(143)
Nov-00	317,576	316,248	314,914	(1,328)	(2,662)	-0.42%	-0.84%	1,334
Dec-00	325,502	325,226	324,722	(276)	(780)	-0.08%	-0.24%	504
Jan-01	298,063	297,888	297,684	(175)	(379)	-0.06%	-0.13%	204
Feb-01	320,562	320,805	320,948	243	386	0.08%	0.12%	(143)
Mar-01	259,982	260,163	259,943	181	(39)	0.07%	-0.02%	220
Apr-01	295,100	292,751	291,766	(2,349)	(3,334)	-0.80%	-1.13%	985
May-01	314,986	311,159	309,389	(3,827)	(5,597)	-1.21%	-1.78%	1,770
Jun-01	336,562	335,109	334,952	(1,453)	(1,610)	-0.43%	-0.48%	157
Total	3,853,164	3,837,317	3,831,898	(15,847)	(21,266)	-0.41%	-0.55%	5,419
Summer	1,403,817	1,397,264	1,396,576	(6,553)	(7,241)	-0.47%	-0.52%	688
Other	2,449,347	2,440,053	2,435,322	(9,294)	(14,025)	-0.38%	-0.57%	4,731

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SP

	Actual	Normal Ranked	Unranked	Weather Adj Ranked	Unranked	% Adj Ranked	Unranked	Diff
Jul-00	398,836	399,950	398,456	1,114	(380)	0.28%	-0.10%	1,494
Aug-00	395,694	391,201	395,478	(4,493)	(216)	-1.14%	-0.05%	(4,277)
Sep-00	396,030	385,929	382,443	(10,101)	(13,587)	-2.55%	-3.43%	3,486
Oct-00	365,963	361,724	360,373	(4,239)	(5,590)	-1.16%	-1.53%	1,351
Nov-00	365,962	360,057	356,274	(5,905)	(9,688)	-1.61%	-2.65%	3,783
Dec-00	352,782	349,555	348,784	(3,227)	(3,998)	-0.91%	-1.13%	771
Jan-01	372,954	370,342	368,318	(2,612)	(4,636)	-0.70%	-1.24%	2,024
Feb-01	506,526	508,810	510,778	2,284	4,252	0.45%	0.84%	(1,968)
Mar-01	262,612	263,545	262,573	933	(39)	0.36%	-0.01%	972
Apr-01	350,767	347,135	343,739	(3,632)	(7,028)	-1.04%	-2.00%	3,396
May-01	313,358	304,897	300,292	(8,461)	(13,066)	-2.70%	-4.17%	4,605
Jun-01	362,521	357,786	358,396	(4,735)	(4,125)	-1.31%	-1.14%	(610)
Total	4,444,005	4,400,931	4,385,904	(43,074)	(58,101)	-0.97%	-1.31%	15,027
Summer	1,553,081	1,534,866	1,534,773	(18,215)	(18,308)	-1.17%	-1.18%	93
Other	2,890,924	2,866,065	2,851,131	(24,859)	(39,793)	-0.86%	-1.38%	14,934

Schedule 1-3

Union Electric Company

2 Month Weather Normalization Analysis

Staff Adjustment vrs UEC Adjustment

	MPSC Staff 12 Mos Ended 6/30/01 (*)		UEC 12 Mos Ended 6/30/01		Difference	
	MWH Adj.	Revenue Adj.	MWH Adj. (W/O line losses)	Revenue Adj.	MWH Adj.	Revenue Adj.
Residential	(670,397)	$ (47,477,368)	(887,799)	$ (62,527,311)	(217,402)	$ (15,049,943)
Small General Service	(101,474)	(6,956,193)	(136,089)	(9,130,816)	(34,615)	(2,174,623)
Large General Service	(138,289)	(4,489,852)	(195,380)	(6,133,831)	(57,091)	(1,643,979)
Small Primary Service	(43,074)	(1,363,537)	(58,101)	(1,774,729)	(15,027)	(411,192)
Large Primary Service	(15,847)	(386,382)	(21,266)	(513,691)	(5,419)	(127,309)
Total Missouri	(969,081)	$ (60,673,332)	(1,298,635)	$ (80,080,378)	(329,554)	$ (19,407,046)

Schedule 2

Heating Degree Days
AmerenUE (with New adjustment)

Month	Normal	2,000 Actual	2,000 Actual/Normal	2,001 Actual	2,001 Actual/Normal	2,001 2001/2000
January	1,129	964	-15%	1,019	-10%	6%
February	900	616	-32%	813	-10%	32%
March	645	473	-27%	700	8%	48%
April	304	277	-9%	145	-52%	-48%
Total	2,978	2,329	-22%	2,677	-10%	15%

AmerenCIPS

Month	Normal*	2,000 Actual	2,000 Actual/Normal	2,001 Actual	2,001 Actual/Normal	2,001 2001/2000
January	1,179	1,106	-6%	1,159	-2%	5%
February	928	718	-23%	896	-3%	25%
March	701	562	-20%	795	13%	41%
April	344	367	7%	200	-42%	-45%
Total	3,151	2,753	-13%	3,050	-3%	11%

* CIPS Normal is updated 1965-2000 Average.

Schedule 3-1

Cooling Degree Days
AmerenUE (with New adjustment)

Month	Normal	2000 Actual	2000 Actual/Normal	2001 Actual	2001 Actual/Normal	2001/2000
April	32	9	-71%	117	265%	1148%
May	108	183	70%	183	69%	0%
June	293	270	-8%	310	6%	15%
July	433	420	-3%	510	18%	21%
Total	867	883	2%	1,120	29%	27%

AmerenCIPS

Month	Normal	2000 Actual	2000 Actual/Normal	2001 Actual	2001 Actual/Normal	2001/2000
April	14	0	#N/A	58	318%	#N/A
May	82	97	18%	105	28%	8%
June	250	190	-24%	227	-9%	20%
July	371	292	-21%	375	1%	28%
Total	717	579	-19%	765	7%	32%

Schedule 3-2

Cooling Degree Days
AmerenUE (with New Adjustment)
One-day-Average Temperature

Month	Normal	2000 Actual	2000 Actual/Normal	2001 Actual	2001 Actual/Normal	2001/2000
June	293	270	-8%	#NAME?	#NAME?	#NAME?
July	433	420	-3%	#NAME?	#NAME?	#NAME?
August	365	508	39%	#NAME?	#NAME?	#NAME?
September	180	218	21%	#NAME?	#NAME?	#NAME?
Total	1272	1416	11%	#NAME?	#NAME?	#NAME?
October	35	78	124%	#NAME?	#NAME?	#NAME?

AmerenCIPS
One-day-Average

Month	Normal	2000 Actual	2000 Actual/Normal	2001 Actual	2001 Actual/Normal	2001/2000
June	250	190	-24%	227	-9%	20%
July	371	292	-21%	375	1%	28%
August	306	341	12%	339	11%	-1%
September	142	132	-7%	109	-23%	-17%
Total	1068	955	-11%	1050	-2%	10%

Schedule 3-3

Heating Degree Days
AmerenUE (with New adjustment)
One-day-Average Temperature

Month	Normal	2000 Actual	2000 Actual/Normal	2001 Actual	2001 Actual/Normal	2001/2000
September	48	51	6%	#NAME?	#NAME?	#NAME?
October	265	164	-38%	230	-13%	40%
November	592	688	16%	331	-44%	-52%
December	988	1315	33%	752	-24%	-43%
Total	1893	2218	17.2%	#NAME?	#NAME?	#NAME?

AmerenCIPS
One-day-Average Temperature

Month	Normal	2000 Actual	2000 Actual/Normal	2001 Actual	2001 Actual/Normal	2001/2000
September	63	56	-11%	76	22%	37%
October	299	251	-16%	319	7%	27%
November	652	448	-31%	420	-36%	-6%
December	1,016	938	-8%	850	-16%	-9%
Total	2029	1693	-17%	1666	-18%	-2%

Schedule 3-4

Staff's Adjustment to AEM - UEC Contract for 2001 and Addition of CT

	Total	Allocation	Missouri
AEM Contract			
Eliminate June Capacity (Cassidy; S-10.3)	($1,800,000)	90.2135%	($1,623,843)
Add CT for Capacity			
Cost of CT in Plant (Proctor; Meyer; P-30)	245,000,000	90.2135%	$221,023,075
Return and Income Taxes on Plant (Bible)	33,983,803		30,657,978
Production Exp. For CT (Proctor; S-6.5)	1,225,000	87.5384%	$1,072,345
Amortization of CT (Meyer)	6,125,000	90.2135%	$5,525,577
Adjust Property Tax for CT (Meyer; S-30.3)	2,414,937	90.2135%	$2,178,599
Total Revenue Requirement of Added CT	$43,748,740		$39,434,499.58
Net Impact of Staff's Proposal on Revenue Requrement			$37,810,656.58
Correction for Non-fuel O&M Expenses			
Using Gas-fired CTs	$3,900,000	87.5384%	$3,413,998
Less Oil-fired Expense per Proctor	($1,225,000)	87.5384%	($1,072,345)
Incremental Amount			$2,341,652
Plus Net Impact on Revenue Requirement			$37,810,657
Total Corrected Impact on Revenue Requirement			$40,152,309
Amount Proposed by Company			
Amounts spent for AEM & AEP contracts	$54,767,600		$48,053,697
Energy	$50,617,600	87.5384%	$44,309,837
Capacity	$4,150,000	90.2135%	$3,743,860
Summary			
Differential Between UE Expenses and Corrected Staff Proposal ($48,053,697 - $40,152,309)			$7,901,389
Differential Between UE Expenses and Uncorrected Staff Proposal ($48,053,697 - $37,810,657)			$10,243,041

HIGHLY CONFIDENTIAL

CHRONOLOGY OF MEETINGS WITH MPSC STAFF ON RESOURCE PLANNING RELATED ISSUES

Date	Event	Significance	Documentation
04/01/1999	MPSC Case No. EO-99-365	Replace IRP filing with bi-annual meetings with Staff	Order
04/01/1999	New Ameren CTG discussion	Technical details/scheduling/ownership	Teleconference notes between R. Smith/ D. Elliott
07/29/1999	UE/MPSC Resource Planning Briefing Session	Focus on discussion of electric market products	Powerpoint Presentation Meeting notes
01/21/2000	UE/MPSC Resource Planning Briefing Session	Discussion of deficiencies of RFP process	Powerpoint Presentation Meeting notes
03/01/2000	Notification of resource acquisition letter	New 48 MW CTG at Meramec Plant	Letter
08/04/2000	UE/MPSC Resource Planning Briefing Session	Discussion of RFP process and market products	Powerpoint presentation Meeting notes
09/07/2000	UE/MPSC Meeting	Load research sample design/historical temperature series	Meeting handouts
10/01/2000	MPSC Case No. EA-2000-37	Ameren Genco stipulation & agreement defining RFP process	Order
10/06/2000	MPSC Case No. EM-2001-233 UE Metro East Transfer	UE requested expedited treatment by 2/15/2001 in lieu of buying capacity and energy for summer 2001	Pleading
11/01/2000	UE/MPSC Meeting	Meeting called by Staff to express multiple concerns with transfer request	E-mail summary of meeting

NOTE: The documentation referred to by this chronology has previously been provided to Staff and OPC. There are no additional workpapers beyond such documentation which I used or relied on in developing my rebuttal testimony.

HIGHLY CONFIDENTIAL

CHRONOLOGY OF MEETINGS WITH MPSC STAFF ON RESOURCE PLANNING RELATED ISSUES

Date	Event	Significance	Documentation
11/09/2000	MPSC Staff pleading in Case No. EM-2001-233	No expedited treatment; resolution expected to take at least six months	Pleading
12/08/2000	Draft RFP for up to 500 MW of capacity and energy for summer 2001 sent to Staff	Start of RFP development process	RFP draft
12/15/2000	UE/MPSC teleconference on draft RFP	UE makes changes to draft at Staff's suggestion	RFP draft no. 2
12/20/2000	UE sends Staff draft no. 2 of RFP and the draft scope of work for a third party consultant to receive and evaluate all bids		
01/03/2001	Final draft of RFP sent to M. Proctor		Draft
01/04/2001	M. Proctor approves RFP		E-mail
01/26/2001	Copy of RFP and bidder list sent to M. Proctor		RFP letter and bidder list
02/01/2001	Forward view of market prices for July/August 2001	5x16 prices at $160/MWh	Market price quotes
03/15/2001	CIPS withdraws offer to accept transfer of the UE-IL service territory	Market prices changes	Letter
03/28/2001	UE/MPSC Resource Planning Briefing Session	Review bids for summer 2001. UE tells Staff that it will withdraw its offer to transfer the UE Metro East service area to CIPS. AEM withdrew their offer. UE reviews future resource planning focus.	PowerPoint presentation. Meeting notes.
04/17/2001	AEM files PSA agreement with UE with FERC	Request approval for market based rates	Pleading
04/25/2001	Notification of resource acquisition letter	UE/AEM 350 MW PSA Summer 2001	Letter w/attachments

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CHRONOLOGY OF MEETINGS WITH MPSC STAFF ON RESOURCE PLANNING RELATED ISSUES

Date	Event	Significance	Documentation
05/03/2001	Case No. EM-2001-233	MPSC order granting leave for UE to withdraw UE-IL transfer application	
05/10/2001	UE/MPSC Resource Plan Briefing Session	Summer 2001 bids analyzed. Joe Hopf, AE, leads discussion on electric market products with must-take energy provisions. Scope of work for a planning reserve margin valuation study discussed.	Powerpoint presentation. Meeting notes.
06/20/2002	Development of new weather normalization model for Ameren	Meeting at UE. Dennis Patterson from MPSC staff attends	
06/07/2001	C. Nelson letter to MO Governor's Energy Policy Task Force	Addresses impact of MPSC regulatory uncertainty on resource planning	Letter
06/14/2001	FERC approves AEM contract	Commission objects	FERC order
06/22/2001	RAV meeting with M. Proctor on planning reserve margin study	Staff assists in development of scope of work; provides list of potential bidders	
07/24/2001	Notification of resource acquisition letter	Add 100 MW to 350 MW PSA with AEM	letter
07/25/2002	M.Proctor e-mails list of potential bidders on planning reserve study to UE		e-mail
07/26/2001	Draft RFP For Capacity and Energy For 2002 - 2011 For UE Sent To MPSC Staff	Long-term RFP requesting bidders to be creative and to bid a variety of products	RFP document
07/31/2001	UE/MPSC Meet To Discuss RFP	UE Made 100% Of Changes Suggested By Staff	
08/01/2001	Draft RFP comments from Mike Proctor		
08/06/2001	CDN letter to MO Governor Energy Policy Task Force	Links regulatory uncertainly to generation additions in MO	letter

Schedule 5-3

HIGHLY CONFIDENTIAL

CHRONOLOGY OF MEETINGS WITH MPSC STAFF ON RESOURCE PLANNING RELATED ISSUES

Date	Event	Significance	Documentation
08/06/2001	Notification of resource acquisition letter	Purchase of 50 MW of capacity and energy from AEP for summer 2001	
08/07/2001	UE sends Staff revised RFP		
08/07/2001	Teleconference between UE and Lena Mantle, and Dave Elliott of MPSC staff on section 7.2 of RFP		
08/08/2001	OPC asks UE for RFP bidders list		
08/08/2001	OPC provides comments on RFP		
08/09/2001	MPSC Staff provides final comments on RFP		
08/09/2001	OPC Staff asks that 6 additional bidders be added to list		
08/09/2001	Notification of resource acquisition letter	UE to build 48 MW CTG @ Venice Plant	
08/10/2001	RFP mailed to bidders (Staff copied)		
08/14/2001	New weather normalization model presented to all potential users	D. Patterson from MPSC staff in attendance	RER Presentation
08/29/2001	Notication of resource acquisition letter	UE to build 192 MW CTG @ Peno Creek	
09/12/2001	Kickoff meeting with contractor, M.S. Gerber, on planning reserve margin study		M.S. Gerber presentation
01/15/2002	Meeting With MPSC and OPC Division Directors & Managers to present executive summary of UE 2002-2011 RFP evaluation	**______________________________ ______________________________**	Powerpoint presentation

NHC
Schedule 5-4

HIGHLY CONFIDENTIAL

CHRONOLOGY OF MEETINGS WITH MPSC STAFF ON RESOURCE PLANNING RELATED ISSUES

Date	Event	Significance	Documentation
01/17/2002	UE/Staff meeting on Venice Plant status	Repowering/retirement/reburbishment (Meeting actually focused on Venice fire and insurance reimbursement and depreciation/plant life assumptions)	
01/18/2002	** ______________ **	** ______________ **	Spreadsheets
01/22/2002	UE/Staff meeting on 2002-2011 RFP evaluation		4-inch binder of evaluation
01/24/2002	UE/Staff meeting on UE asset mix optimization work	Study needs to be be updated with latest information.	Powerpoint presentation
01/25/2002	Meeting with MPSC Staff to present results of planning reserve margin study	** ______________ **	Final report
01/28/2002	M. Proctor provides comments on planning reserve study		
01/31/2002	** ______________ ______ **	** ______________ **	
02/01/2002	** ______________ ______________ **		
02/08/2002	UE/MPSC Staff meeting on Venice repowering options		
02/11/2002	** ______________ ______ **		
02/13/2002	UE/Staff meet to discuss Venice transmission	Staff looking for reasons why transmission upgrades were made after Venice fire	No handouts - confidential transmission info.
02/15/2002	** ______________ ______ **		

NHC
Schedule 5-5

HIGHLY CONFIDENTIAL

CHRONOLOGY OF MEETINGS WITH MPSC STAFF ON RESOURCE PLANNING RELATED ISSUES

Date	Event	Significance	Documentation
02/15/2002	**______________________ ________**		
02/28/2002	Teleconference call with M. Proctor to discuss his comments on planning reserve study		
03/01/2002	UE provides response to M. Proctor's comments on planning reserve margin study		

NHC
Schedule 5-6

Schedule 6-1

through

Schedule 6-12

Schedule 6 has been deemed Highly Confidential in its entirety.

January 3, 2001

AmerenUE – Request For Proposal
Capacity and Energy

Introduction

Burns & McDonnell will assist AmerenUE in evaluating offers for the procurement of capacity and energy for AmerenUE during the months of June 2001 through September 2001.

RFP Schedule and Contacts

Offers Due:	February 1, 2001
Short List Determined:	February 15, 2001
Final Selection Date:	March 1, 2001
Contact:	Mr. Kiah Harris Principal Burns & McDonnell 9400 Ward Parkway Kansas City, MO 64114-3319 (816) 822-3174 Fax. (816) 822-3027 kharris@burnsmcd.com

Supply Requirements

Term:	June 1, 2001 through September 30, 2001
Volume:	Up to 500 MW (minimum of 50 MW increments)
Delivery Point:	Ameren border (offer should include the cost of firm transmission for the entire period). Ameren must be able to secure network service transmission from the delivery point(s).
Firmness:	Capacity - Meets AmerenUE planning reserve margin requirements and MAIN accreditation requirements. Supplier must specify generating source (unit (s) or system). Energy – LD for 16 hour on peak schedules. System firm for any off peak (2 by 16 or 7 by 8) schedules.
Pricing:	Only fixed price offers will be considered.

Ameren will accept offers until 4 p.m., Feb 1, 2001. Offers received after this date and time shall be returned unopened. Faxed offers are acceptable. Award of the contract shall be contingent on the approval of firm transmission delivery to the Ameren system and approval of network service within the Ameren system. Bidders shall propose a mechanism for any adjustments to the energy component of the offer they deem necessary between the bid due date and the time of transmission service approvals, at which point the energy price shall become firm. Final contract terms shall include firm pricing for energy through the term of the contract. Bid evaluation shall include consideration of any proposed adjustment mechanism on energy pricing.

AmerenUE reserves the right to reject any and all offers, for any reason whatsoever, and to enter into separate negotiations with any party for the purchase of capacity and energy. AmerenUE shall not be obligated to purchase any capacity and energy unless a definitive agreement is executed between authorized representatives of the parties negotiating the transaction. Expenses associated with preparation of a proposal and negotiating an agreement (if applicable) that are incurred by the party responding to this request shall be the sole responsibility of the responding party.
AmerenUE agrees to maintain confidentiality with respect to any offers received.

Note: This evaluation of offers to this RFP complies with the requirements of the Missouri Public Service Commission in Case No. EA-2000-37 which states, among other things, that:

> **"AmerenUE agrees that any future purchased power contract with Genco or its marketing affiliate will only be entered into if Genco is determined to be the most cost effective offer, giving due consideration to reliability and financial viability, through a competitive bidding process in which all bidders, including Genco or its marketing affiliate, are provided equal information and bidding opportunities."**

Schedule 8

Schedule 8 has been deemed Highly Confidential in its entirety.

95 FERC ¶ 61,397
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Curt Hébert, Jr., Chairman;
William L. Massey, and Linda Breathitt.

Ameren Energy Marketing Company | Docket No. ER01-1810-000 and ER01-1810-001

ORDER CONDITIONALLY ACCEPTING FOR FILING
PROPOSED POWER SALES AGREEMENT
AND GRANTING, IN PART, CONFIDENTIAL TREATMENT

(Issued June 14, 2001)

In this order, we will conditionally accept for filing, effective June 1, 2001, without hearing or suspension, the proposed market-based power sales agreement (PSA) filed by Ameren Energy Marketing Company (AEM), an affiliate of Union Electric Company d/b/a AmerenUE (AmerenUE). The request to deny confidential treatment of the rates under the PSA is moot. We will grant the request for confidential treatment of the supporting documentation. We will also grant the request for waiver of the Commission's regulations relating to the filing of certain cost information.

I. Background

On April 17, 2001, AEM submitted for filing a PSA with AmerenUE which provides for the sale of capacity and energy by AEM to AmerenUE, at market-based rates. The PSA was the result of a request for proposal (RFP) for supplies by AmerenUE. While AEM has authorization to make sales at market-based rates, it is submitting the PSA for approval because it involves the market-based sale to an affiliate with a franchised service area.[1] AmerenUE, a public utility serving retail customers located in Missouri and Illinois and wholesale customers in Missouri, and AEM, a power marketer, are subsidiaries of Ameren Corporation (Ameren). According to AEM's application, the PSA is necessary in order for AmerenUE to meet its planning reserve margin

[1] AEM was granted market-based rate authority in Madison Gas & Electric Company, et al., 90 FERC ¶ 61,115 at 61,350 (2000).

requirements and MAIN accreditation requirements for summer 2001. AEM will use power from Ameren Energy Generating Company (AEG), an exempt wholesale generator and affiliate of AEM, to serve AmerenUE under the PSA and will also rely on "certain generation units owned by Electric Energy Inc.," a partially owned subsidiary of Ameren.

AEM requests confidential treatment of the PSA until June 1, 2001. AEM argues that the Commission should conditionally allow the terms of the PSA to remain confidential, at least until the remaining potential supplier has had an opportunity to procure transmission service, so that negotiations between AmerenUE and other suppliers are not adversely affected by the public filing of this information. In support of this argument AEM states that the Commission has granted privileged treatment in the past when necessary to protect similar information.[2] In addition, in a May 14, 2001 filing, AEM requests confidential treatment beyond June 1, 2001, for Attachment 1 to the Voytas Affidavit[3] on the basis that the document contains commercially sensitive information submitted to AmerenUE in strict confidence. AEM states that this document reveals the prices at which other suppliers responding to the RFP are willing to provide power, the public release of which could place AmerenUE at a disadvantage in contract negotiations. On June 1, 2001, AEM and AmerenUE submitted public copies of the PSA and of Attachment 4 to the Voytas Affidavit (containing a benchmark price analysis) that AmerenUE included confidentially in its motion to intervene.

The proposed PSA resulted from a selection process initiated by AmerenUE's issuance of an RFP for suppliers to provide AmerenUE with power for the summer of

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[2] Applicant cites to Texas Gas Transmission Corporation, 83 FERC ¶ 61,239 at 62,040 (1998), Western Systems Power Pool, 59 FERC ¶ 61,249 at 61,906 (1992) and Jersey Central Power & Light Company, 87 FERC ¶ 61,014 at 61,040 (1999).

[3] Attachment 1 to the Voytas Affidavit is the report issued by Burns & McDonnell which describes and evaluates the bids received in response to the request for proposal.

2001. AEM claims that the "process that resulted in the PSA was designed to ensure that any contract would be awarded through an unbiased, competitive bidding and evaluation process in which unaffiliated suppliers competed, and which was structured to ensure that all bidders were provided equal information and bidding opportunities." In support of its position, AEM cites to several prior Commission orders. See, e.g., Boston Edison Re: Edgar Electric Energy Company, 55 FERC ¶ 61,382 (1991) (Edgar), Ocean State Power II, 59 FERC ¶ 61,360 (1992), reh'g denied, 69 FERC ¶ 61,146 (1994).

The RFP was designed as a two-step process. Once bids for power were submitted and evaluated, the bidders on the short list were then told to arrange for transmission service to the Ameren border and AmerenUE would submit to the Ameren OASIS requests for network transmission service for the transmission of energy within the Ameren system. The RFP provided that an independent consulting firm would be evaluating offers for the procurement of capacity and energy during the months of June 2001 through September 2001. The RFP required the offer to include the cost of firm transmission for the entire period and that Ameren must be able to secure network service transmission from the delivery point(s). The RFP stated that only fixed price offers would be considered and that award of the contract will be contingent upon the approval of firm transmission delivery to the Ameren system and approval of network service within the Ameren system. The RFP also specified that bidders propose a mechanism for an adjustment to the energy component of the offer they deem necessary between the bid due date (February 1, 2001) and the time of transmission service approvals, at which point the energy price will become firm. The RFP provided that the bid evaluation would include consideration of any proposed adjustment mechanism on energy pricing. Finally, the RFP included a note stating that the evaluation of the offers of the RFP was intended to comply with the requirements of the Missouri Commission order in Case No. EA-2000-37.[4]

AEM states that it submitted a proposal in response to the RFP, was notified it was the successful bidder and subsequently entered into the proposed PSA. After arriving at the terms of the PSA with AEM, AmerenUE undertook its own benchmark analysis to determine the market value of the energy and capacity underlying the PSA and to verify that the pricing terms were fair and reasonable. The term of the PSA is from June 1,

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[4]Union Electric Company, d/b/a AmerenUE, Missouri Commission Case No. EA-2000-37, Order approving Unanimous Stipulation and Agreement, Making Findings Under the Public Utility Holding Company Act, and Closing Case (January 13, 2000) (Missouri Commission Order).

2001 through May 31, 2002. The PSA provides for the sale of up to 450 MW of firm capacity and energy, establishes fixed prices for capacity through the entire term of the contract, and a fixed price for energy during the months of July and August 2001. During all other periods, the energy price will be the current market price.

AEM requests a waiver of the Commission's notice requirements to allow an effective date of June 1, 2001. AEM also requests a waiver of the Commission's regulations relating to the filing of cost information, along with any other regulations that are customarily waived in connection with market-based sales.

II. Notice of Filing

Notice of AEM's filing was published in the Federal Register, 66 Fed. Reg. 21,134 (2001), with comments, protests and interventions due on or before May 8, 2001. On April 27, 2001, AmerenUE filed a motion to intervene in support of the filing. In that motion, confidential treatment was requested for Attachments 1 and 4 of the Affidavit of Mr. Richard A. Voytas.[5] On May 8, 2001, the Missouri Public Service Commission (Missouri Commission) and Missouri Office of the Public Counsel (Public Counsel) separately filed protests. The Missouri Commission and Public Counsel both raise concerns as to whether there was direct head-to-head competition between AEM and other power sellers due to the inability of other power sellers to obtain transmission service. Missouri Commission states that it does not seek rejection of the contract and requests that the Commission reject the proposed market-based rates and set for hearing the appropriate level of cost-based rates or, in the alternative, set for hearing whether AEM has demonstrated that its proposed market-based rates will be just and reasonable. On May 14, 2001, AEM requested continued confidential treatment for Attachment 1 beyond June 1, 2001 and for Attachment 4 until June 1, 2001. On May 23, 2001, AEM and AmerenUE filed answers to the protest and comments of the Missouri Commission and Public Counsel. AEM and AmerenUE request confidential treatment of the attachment to the affidavit of Mr. Richard A. Voytas submitted with the answer.

[5] As noted above, Attachment 1 is the report issued by Burns & McDonnell which describes and evaluates the bids received in response to the RFP. Attachment 4 is the benchmark price analysis of AEM's PSA.

III. Discussion

A Procedural Matters

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2000), the timely, unopposed motions of AmerenUE, Missouri Commission, and the Public Counsel make them parties to this proceeding. Although Rule 214 generally prohibits an answer to a protest, in light of the various representations made by AEM and AmerenUE in their Answers that assist us in our resolution of the issues raised, the Commission finds that good cause exists to accept the Answers of both AEM and AmerenUE.

B. Proposed Market-Based Power Sale to Affiliate

1 Competitive Bidding Process and Benchmarking Analysis

Transactions between traditional public utilities, such as AmerenUE, and an affiliated power marketer, such as AEM, can raise concerns of cross-subsidization and market power gained through the affiliate relationship. In Edgar,[6] the Commission held that in analyzing market rate transactions between an affiliated buyer and seller, the Commission must ensure that the buyer has chosen the lowest cost supplier from among the options presented, taking into account both price and non-price terms (i.e., that the buyer has not preferred its affiliate without justification). The Commission noted several ways for a utility to show it has not unduly favored its affiliates, two of which are relied upon in this case by AEM: (1) evidence of direct head-to-head competition between the seller and competing unaffiliated suppliers in either a formal solicitation or an informal negotiation process; and (2) benchmark evidence of the price and terms and conditions, of contemporaneous sales made by non-affiliated sellers for similar services in the relevant market.[7]

[6]See 55 FERC ¶ 61,382 at 62,168-69. See also Aquila Energy Marketing Corp., 87 FERC ¶ 61,217 at 61,857 (1999) and MEP Pleasant Hill, LLC, 88 FERC ¶ 61,027 (1999).

[7]When such evidence is presented, the Commission seeks assurance that (1) the solicitation was designed and implemented without undue preference for the affiliate, (2)

the analysis of the bids or responses did not favor the affiliate, particularly with respect to evaluation of non-price factors, and (3) the affiliate was selected based on some reasonable combination of price and nonprice factors. Id. at 62,168.

In support of its filing, AEM states that the bidding process initiated by AmerenUE involved the participation of AEM and many other bidders[8] and that an independent consultant evaluated the bids. AEM claims that the PSA resulted from a competitive bidding process and that there is benchmark evidence of market value of contemporaneous sales by non-affiliate sellers for similar services in the relevant market. AEM asserts that this satisfies the Commission's concerns about affiliate abuse.

The Missouri Commission and Public Counsel raise essentially two concerns. First, they argue that AEM did not participate in head-to-head competition because AEM had an advantage over competitors that had to acquire transmission service. They believe that AEM may have market power due to transmission constraints on the Ameren transmission system. In support of their contention, Missouri Commission and Public Counsel both state that Ameren acknowledges that the reason AmerenUE did not pursue any of the other short listed bidders was because of their inability to obtain the transmission services necessary to support the transactions.[9]

Second, Missouri Commission states that it is difficult to evaluate whether the benchmark transactions offered by AmerenUE are appropriate and whether comparable

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[8]AmerenUE, in its motion to intervene in support, states that the RFP was sent to 41 power sellers with whom AmerenUE, or a subsidiary, had past contracts or believed to be capable of meeting contractual obligations. Of the 41, nine responded; three of the nine were eliminated due to non-compliance with the requirements or being the high bid.

[9]Missouri Commission cites AmerenUE's Comments at 7(citing Voytas Affidavit).

transactions exist by which to evaluate whether the rates in the PSA are as low as those charged by non-affiliate sellers,[10] because the information was filed under seal, the transaction is inherently unusual, and the industry's preference for confidential contracts makes public data scarce. Missouri Commission states that, for example, because there is no readily available transparent market for capacity, AmerenUE had to base its benchmark analysis on its "past market experience and its knowledge as a power seller and purchaser." Public Counsel adds that it is not convinced that there is sufficient competition in Midwest power markets to allow benchmarking of the prices in the PSA against market prices in regional markets to protect against affiliate abuse.

To the first concern, AEM responds that the Missouri Commission reviewed the RFP and understood at that time the transmission advantage of AEM as a result of its network resources. In addition, AEM states that the mere existence of constrained transmission into Ameren does not evidence reduced competition within the Ameren service area, but rather clearly demonstrates the maximized utilization of the Ameren system by numerous third party competitors. With respect to the second concern that Missouri Commission and Public Counsel are unable to evaluate the appropriateness of the benchmark transactions, AEM responds that in calculating the energy price bid, it relied on "the active, competitive and transparent "Into-Cinergy" market and the state-approved pricing methodology to determine an "Into Ameren" energy market price. AEM believes that this removes any potential for affiliate abuse.

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[10] AmerenUE filed its benchmark analysis under seal, explaining that the analysis contains confidential information "about the prices at which AmerenUE is willing to enter into contracts in response to the RFP." See AmerenUE Comments at 8; Voytas Affidavit at 9.

The Missouri Commission, Public Counsel, and independent consultant had a role in the development and/or execution of the RFP. On the basis of the independent RFP process in conjunction with the benchmark evidence offered by the independent consultant, as well as that of AmerenUE, as discussed below, we find that there is no affiliate abuse. AEM offers benchmark evidence as described in the Voytas Affidavit that shows AEM's price is at or below the "Into-Cinergy" market price adjusted for "Into Ameren" (June 1, 2001 filing).[11] AEM states that in calculating its energy bid price, AEM relied on prices for the "Into-Cinergy" market and then adjusted this market price to capture the differential between the Cinergy and Ameren markets. According to AEM, the methodology used in determining the differential is the same one as approved by the Illinois Commerce Commission in proceedings related to retail choice. In addition, AmerenUE undertook its own benchmark analysis in which it compared energy bids it received (including AEM's bid) to pricing information available for contracts for deliveries for the same period, as posted on EnronOnline.[12] For capacity bids, both AEM

[11]In addition, the independent consultant performed an analysis that involved calculating the total cost of energy to Ameren and ranking the bidders on a cost per block basis in 50MW increments.

[12]AEM Answer at 7.

and AmerenUE explain that there is a lack of a transparent capacity market, but offer that an existing contract with a non-affiliated party should serve as evidence of lack of affiliate abuse. AEM in its response provided further support for its capacity bid offering that discussions with non-affiliates that commenced in December 2000 for multi-year transactions, including July and August 2001, entailed price levels higher than those in the PSA.[13]

We agree with the Missouri Commission that the benchmark evidence was hard to evaluate in large part because of the complexity of the transaction. However, we are satisfied with AEM's demonstration of the stated prices for the capacity. The capacity charges were compared to the value of capacity based on an agreement between AEM and a non-affiliate and were compared to two offers that were in the process of being negotiated with third parties during the same time period AEM was preparing its bid. The capacity charges in the PSA are lower than these other offers.

As for the energy prices for July and August 2001, AEM relies on "Into-Cinergy" market and a state-approved pricing methodology to determine an "Into-Ameren" energy market price. AEM's bid was evaluated independently by both the independent consultant and AmerenUE. Furthermore, AmerenUE states that one of the competing bidders (Supplier A) in the RFP has received transmission service to the Ameren border for June 2001 through September 2001 and is finalizing pricing terms and conditions for the sale to AmerenUE during that period. AmerenUE offers that the energy prices in the AEM and Supplier A contracts were based on neutral and transparent market indicia at the time the pricing in each contract was agreed upon, and, therefore, the energy prices under each contract reflect the market prices to be expected in an arm's-length transaction between non-affiliates.

2 Pricing of Capacity and Energy in the PSA

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[13] Id. at 7-8

As stated above, the PSA establishes fixed prices for capacity through the entire term of the contract, and a fixed price for energy during the months of July and August 2001. During all other periods, the energy price will be the current market price. The Commission has repeatedly held that prices resulting from affiliate transactions by ~~reference to competitive prices at recognized market hubs~~ is an effective mechanism to prevent affiliate abuse.[14] However, AEM has not identified any market index that will determine the market price for energy.[15] AEM is directed to file a revised PSA to specify the market index that will determine the market price for energy.

3 Request for Confidential Treatment of Supporting Information

The request of AEM and AmerenUE for confidential treatment of the PSA and the Affidavits of both Mr. Serri and Mr. Voytas is moot. As stated above, AEM requested that the information be held confidentially until June 1, 2001. That date has since passed. In any event, the Commission has required companies to file their long-term service agreements (one year or more) in an unredacted, non-confidential form.[16] The request for confidential treatment of AmerenUE's benchmark price analysis, included as Attachment 4 to Mr. Voytas' Affidavit, under 18 C.F.R. § 388.112, is also moot per AEM and AmerenUE's June 1, 2001 filing in which Attachment 4 and the PSA were made public.

In addition, we will grant the request for confidential treatment of all portions of the Burns & McDonnell report, included as Attachment 1 to Mr. Voytas' Affidavit. No

[14]We note that the Commission previously approved inter-affiliate sales for Ameren Operating Companies based on use of an established, relevant index (NYMEX "Into-Cinergy"). See Ameren Services Co., 86 FERC ¶ 61,212 (1999). See also First Energy Trading Services, Inc., 88 FERC ¶ 61,067 (1999); AYP Energy, Inc., 87 FERC ¶ 61,009 at 61,022 (1999).

[15]We note that Applicant's use of "Into-Ameren" and "Into-Cinergy" were used to benchmark the July and August 2001 energy prices in the PSA and are not offered as an index for prices after August 2001.

[16]See AES Huntington Beach, L.L.C., AES Alamitos, L.L.C. and AES Redondo Beach, L.L.C., 83 FERC ¶ 61,100 (1998), reh'g denied, 87 FERC ¶ 61,221 (1999).

party has contested the request. Moreover, we note that these materials are not FERC-jurisdictional rate schedules.[17]

C. Other Matters

The request for waiver of the Commission's notice regulations is granted to allow an effective date of June 1, 2001. We also grant the request for waiver of the Commission's regulations related to the filing of cost-of-service information, as set forth in the ordering paragraphs, consistent with those waivers granted to other sellers of power at market-based rates.

The Commission orders:

(A) The PSA submitted by AEM is hereby accepted for filing, subject to modification, as discussed in the body of this order, to become effective on June 1, 2001

(B) AEM and AmerenUE's requests for confidential treatment are hereby granted.

(C) AEM's request for waiver of the provisions of Subparts B and C of Part 35 of the Commission's regulations, with the exception of sections 35.12(a), 35.13(b), 35.15 and 35.16, is hereby granted.

By the Commission.

[17] See Jersey Central Power & Light Company, et al., 87 FERC ¶ 61,014 (1999).

S E A L)

Linwood A. Watson, Jr.,
Acting Secretary.

COLUMBIA RECURING O&M EXPENSES

Schedule 10 has been deemed Highly Confidential in its entirety.

NHC
Schedule 10