Exhibit No.:	
Issues:	Fuel Adjustment Clause
Witness:	Steven M. Wills
Type of Exhibit:	Surrebuttal Testimony
Case No.:	EO-2010-0255
Date Testimony Prepared:	December 22, 2010

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. EO-2010-0255

SURREBUTTAL TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY d/b/a Ameren Missouri

St. Louis, Missouri
December, 2010

TABLE OF CONTENTS

SURREBUTTAL TESTIMONY

OF

STEVEN M. WILLS

CASE NO. EO-2010-0255

I. INTRODUCTION

Q. Please state your name and business address.

A: Steven M. Wills, Ameren Services Company ("Ameren Services"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri.

Q. What is your position with Ameren Services?

A. I am the Managing Supervisor Quantitative Analytics in the Corporate Planning Department.

Q. What is Ameren Services?

A. Ameren Services provides various corporate, administrative and technical support services for Ameren Corporation ("Ameren") and its affiliates, including Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company").

Q. Please describe your educational background and employment experience.

A. I received a Bachelor of Music degree from the University of Missouri-Columbia in 1996. I subsequently earned a Master of Music degree from Rice University in 1998, then a Master of Business Administration ("M.B.A.") degree with an emphasis in Economics from St. Louis University in 2002. While pursuing my M.B.A., I interned at Ameren Energy in the Pricing and Analysis Group. Following completion of my

M.B.A. in May 2002, I was hired by Laclede Gas Company as a Senior Analyst in its Financial Services Department. In this role I assisted the Manager of Financial Services in coordinating all financial aspects of rate cases, regulatory filings, rating agency studies, and numerous other projects.

In June 2004, I joined Ameren Services as a Forecasting Specialist. In this role I developed forecasting models and systems that supported the Ameren operating companies' involvement in the Midwest Independent Transmission System Operator, Inc.'s ("MISO") Day 2 Energy Markets. The forecasts that I developed were the basis for all of the companies' demand bids into the MISO markets. In November 2005, I moved into the Corporate Analysis Department in Ameren Services, where I was responsible for performing load research activities, electric and gas sales forecasts, and assisting with weather normalization for rate cases. In January 2007, I accepted a role I briefly held with Ameren Energy Marketing Company as an Asset and Trading Optimization Specialist before returning to Ameren Services as a Senior Commercial Transactions Analyst in July 2007. I was subsequently promoted to my present position as the Managing Supervisor of the Quantitative Analytics group.

Q. What are your responsibilities in your current position?

A. In my current position, I supervise a group of employees with responsibility for gas and electric load forecasting, load research, weather normalization, and various other analytical tasks.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present an overview of the treatment of wholesale contracts in Ameren Missouri's Integrated Resource Plan ("IRP") and to address certain claims related to the IRP made by other witnesses in their direct/rebuttal testimony. I will also address other claims made by Missouri Public Service Commission Staff ("Staff") witness Lena Mantle and Missouri Industrial Energy Consumers ("MIEC") witness Henry Fayne.

III. TREATMENT OF WHOLESALE LOAD IN AMEREN MISSOURI'S IRP

Q. Why is it necessary to present an overview of the treatment of wholesale contracts in Ameren Missouri's IRP?

A. The various witnesses supporting Staff's position that the American Electric Power Operating Companies ("AEP") and Wabash Valley Power Association, Inc. ("Wabash") contract revenues should be flowed through the Fuel Adjustment Clause ("FAC") all rely on a particular interpretation of the phrase "long-term full and partial requirements sales." The definition relied upon by several witnesses includes the concept that in order to be classified as a long-term full or partial requirement sale, the load represented by such agreement must be one that the supplier plans to provide for on an ongoing basis and includes in its system resource planning. See Eaves direct/rebuttal, page 10, lines 19-23; LaConte direct, page 5, lines 14-16; Brubaker direct, page 3, lines 15-20; and Fayne direct, page 4, lines 2-4. Because the IRP is a significant and visible part of system resource planning for Ameren Missouri, the treatment of wholesale loads in that process is important to understand.

Q. Does the definition of requirements sales relied upon by the other parties actually provide a means to distinguish the AEP and Wabash contracts from the other municipal contracts that Ameren Missouri is a party to?

A. No, it does not. I would first point out that, as detailed in the surrebuttal testimony of Company witness Jaime Haro, this definition is not the correct definition to apply to contracts for classification in Ameren Missouri's FAC tariff. But even under the definition that these witnesses propose, the distinction that they are trying to draw between the various wholesale contracts does not exist.

Q. Please elaborate on this point.

A. Given the standard that the Staff, MIEC, and the Missouri Energy Group ("MEG") propose for defining requirements sales, there would not be a single wholesale contract which was effective during the accumulation period that would qualify as a full or partial requirements contract, including the contracts with municipal utilities. However, I would note that no party has proposed to include the wholesale contracts with municipal utilities in the adjustment that Staff and the intervenors argue should be made to the FAC recovery calculations.

Q. Why would no contract qualify as a full or partial requirements contract?

A. These contracts would not qualify because the 2008 IRP filing, in Case No. EO-2007-0409, did not include any projection of load for any such agreements after December 31, 2008. Furthermore, Ameren Missouri did not plan to serve those municipal agreements previously in place – (and for which load was projected through December 31, 2008) – beyond their specific termination dates.

Q. Is there any specific evidence that you can provide that Ameren Missouri did not include a projection of load for the municipal contracts in its 2008 IRP and has not planned its system to meet the requirements of the municipal loads on an ongoing basis any more than it has done so for AEP and Wabash?

A. Yes. In its 2008 IRP filing Ameren Missouri included in its load forecast loads associated with six municipal wholesale customers. These customers' loads, however, were only included in the forecast horizon for the duration of the contracts that were in existence at the time of the forecast's preparation. At that time, all wholesale loads served by the Company were expected to cease to be an obligation of Ameren Missouri as of December 31, 2008 when the contracts terminated according to their own terms.

Q. Were the contracts that had associated loads projected through only December 31, 2008 in the 2008 IRP still in effect when Ameren Missouri's Rider FAC took effect?

Q. No. Rider FAC became effective March 1, 2009 after the conclusion of Case No. ER-2008-0318. As of March 1, 2009, Ameren Missouri had only four municipal electric wholesale customers in addition to the newly initiated AEP contract. Although the four municipal customers that were under contract were among the same entities that had been included in the 2008 IRP forecast, they were taking service under new agreements. Their 2009 load requirements were definitely not planned for in the 2008 IRP proceeding.

Q. Was there any clarification of Ameren Missouri's plans for wholesale load as a part of that IRP docket?

A. Yes. When it filed its report on Ameren Missouri's IRP, Staff identified Ameren Missouri's plan regarding serving wholesale customers as an item of concern as noted in the following excerpt from that report:

> From the report and from on-going meetings with AmerenUE, it is unclear what plans AmerenUE has regarding serving Wholesale Customers. AmerenUE should clarify its intentions of serving Wholesale Customers beyond 2008, and these intentions should be reflected in resource planning.

Q. How did Ameren Missouri respond to Staff's concern?

A. On August 12, 2008, Ameren Missouri made a supplemental filing with additional data and discussion intended to address Staff's concerns and deficiencies. As a part of that filing, Ameren Missouri, as requested by Staff, clarified its intention with regard to serving wholesale customers. The supplemental filing indicated,

> AmerenUE intends to offer relatively short-term contracts based on market pricing to Missouri customers seeking wholesale power, subject to projected availability of sufficient excess capacity after serving its retail native load obligations and subject to transmission availability. Wholesale customers have not been included in the base load forecast beyond the expiration of any existing contracts because their status at that point is subject to the competitive landscape and decisions of those customers. **AmerenUE has not planned its resources in order to serve any wholesale customers beyond existing contracts**. (emphasis added)

Based on Ameren Missouri's supplemental filing, it could not be any clearer that there was no intention to serve the municipals beyond the previous contracts on an ongoing basis. Therefore, the fact that the municipal contracts were included in the 2008 IRP cannot be used to distinguish the AEP and Wabash contracts from the municipal contracts. Even further evidence of this can be seen in the fact that two of the six customers that had contracts reflected in the 2008 IRP did not execute new agreements with Ameren Missouri and ceased to take service from the Company.

Q. Nevertheless, the same municipal customers were at least included in the IRP, whereas the AEP and Wabash contracts were not. Doesn't that indicate some different treatments by Ameren Missouri?

A. No. Which contracts were included in the IRP forecast and which were not was merely a function of the timing of the filing. By rule, Missouri utilities must file IRPs every three years. Necessarily, the load forecast submitted with any IRP is a view as of a certain point in time. At the time of the 2008 IRP filing, there were six wholesale customers that had active contracts with Ameren Missouri. The AEP and Wabash contracts had not been entered into at the time. Had they been active agreements, they would have been included in the IRP just like the municipal contracts.

Q. Was the Noranda load that was later impaired by the January 2009 ice storm included in the 2008 IRP filing?

A. Yes. Noranda was included at full load over the entire forecast horizon. Since the AEP and Wabash contracts were executed with the intent of replacing the volumes lost due to Noranda's impairment, as described in the direct testimony of Company witness Jaime Haro, it is actually reasonable to say that the loads served via the AEP and Wabash contracts were included in the system resource plan to a greater extent than that ultimately served under the municipal contracts.

Q. Why is it accurate to say that the energy and capacity used to serve the AEP and Wabash contracts was included in Ameren Missouri's 2008 IRP?

A. Although these specific customers – AEP and Wabash – were not identified as the recipient of the energy and capacity, the Company did plan to serve the volumes in its 2008 IRP that were ultimately taken by AEP and Wabash. Because the ice storm happened, volumes that appeared in the IRP intended for Noranda were later sold to AEP and Wabash. From this point of view, the load taken by AEP and Wabash was represented in the filing, albeit under the name of a different customer.

Q. Please summarize your conclusions with regard to the IRP issues.

A. First, it is clear from the testimony of Mr. Haro that the appropriate definition of long-term full and partial requirements sales does not depend on the IRP process. However, given that the other parties to this case have testified that this is relevant, it is important to understand how the loads associated with the long-term full and partial agreements in place during the accumulation period were represented in the IRP. There were six wholesale contracts that had load associated with them whose revenues were carved out of the off-system sales term in Rider FAC for the recovery periods in question – four municipal contracts plus the AEP and Wabash contracts. None of those contracts had associated load attributed to them in Ameren Missouri's 2008 IRP for those same recovery periods. The distinction that the Staff and interveners are attempting to draw between the municipal contracts and the AEP and Wabash contracts based on the IRP simply does not exist.

IV. <u>RESPONSES TO OTHER WITNESS CLAIMS</u>

Q. Have you reviewed the direct/rebuttal testimony of Staff witness Lena Mantle?

A. Yes, I have.

Q. Do you have any comments about any of the claims she made in her testimony?

A. Yes. Ms. Mantle claims that the first time that Staff became aware of the AEP and Wabash contracts was in the process of their review of Case No. ER-2010-0036. She indicates that Staff had not heard of these contracts until October 14, 2009, when they received the response to a data request Staff submitted to the Company on September 24th of that year.

Q. Is this the first communication that the Company provided to Staff regarding the AEP and Wabash contracts in the case?

A. No. As pointed out in the surrebuttal testimony of Company witness Gary Weiss, there were numerous FAC-related filings that explicitly included AEP and Wabash references. However, even in the case that Ms. Mantle is referencing, the Company clearly communicated all relevant information regarding the new customers from the very beginning. My direct testimony in Case No. ER-2010-0036, filed July 24, 2009, which is attached as Schedule SMW-S1, provided as follows at page 18, lines 3-9:

> **Q. Are there any other changes to the mix of wholesale customers that impact the test year?**
>
> A. Yes. The Company entered two long-term partial requirements contracts with new customers in the spring of 2009. These contracts are effective well in advance of the true-up date in the case and an annualized level of expected sales under these contracts should be included in the test year to appropriately reflect the mix of customers the Company will be serving as of the true-up date in the case.

Although I did not give the names of the customers in my testimony, I clearly indicated that there were new contracts to be considered. Among the workpapers I submitted electronically with the case was an Excel spreadsheet called "Wholesale Annualization – 051209.xls" that included the customer names in addition to contract terms, prices, and volumes, as well as the annualized volumes that I proposed for inclusion in the test year in the case.

Q. Ms. Mantle also claims that Ameren Missouri included AEP and Wabash in the jurisdictional allocation factors in Case No. ER-2010-0036, but not in the net system input. (Mantle direct/rebuttal, page 7 line 19 through page 8 line 3) Is this statement accurate?

A. No. Again, a review of my direct testimony would reveal that appropriate adjustments were made to the net system output (I should note that what Staff refers to as net system input is referred to in Company testimony as net system output) to account for the AEP and Wabash loads. Following the portion of my testimony I quoted above where I indicated that I annualized the wholesale mix, I discuss the adjustments to net system output. That discussion included the following quote:

> Second, I used the adjusted sales in the development of normalized net system output that I provided to Company witness Timothy D. Finnell for production cost modeling.

Q. If Ms. Mantle's assertion had been correct that AEP and Wabash were included in the jurisdictional allocation factors but not in the net input, how would that have impacted the Company's filed request?

A. By including AEP and Wabash in the jurisdictional allocation factors, the Company would have allocated tens of millions of dollars of its costs to these contracts, away from retail load. If the loads had also been excluded from the net system input, the Company would have allowed the generation that served these customers to be credited to customers as off-system sales, thereby reducing retail customers' revenue responsibility. So taken together, this inconsistency would have inappropriately reduced the Company's filed rate request by tens of millions of dollars. In other words, if Ms. Mantle had been correct that the Company filed this way, it would have done so to its own detriment.

Q. Ms. Mantle later goes on to state that "[a]s the case progressed, it became evident to Staff that there was some confusion at Ameren Missouri regarding Ameren Missouri's treatment of the AEP and WVPA contracts." (Mantle direct/rebuttal, page 8, lines 3-5) Was there confusion regarding these contracts' treatment in the case?

A. No. My testimony and workpapers were not ambiguous on the topic. Ameren Missouri was clear, forthright and complete in the information it presented regarding AEP and Wabash in that case and any suggestion to the contrary is not correct.

Q. Mr. Fayne indicates that the AEP and Wabash contracts are more in line with what he calls "opportunity sales" than requirements sales. Do you have any response to that?

A. Yes. Mr. Fayne describes opportunity sales as follows:

> Typically, off-system sales are characterized as opportunity sales. They represent sales of excess power that is not currently required by the utility to meet its firm long-term retail and wholesale load requirement. Such off-system sales may be short term or long term; moreover, they can be configured in numerous ways including bilateral transaction with other utilities, transactions with RTOs, or transactions with other trading counterparties." (Fayne direct, page 3 line 20 through page 4 line 2)

This description of opportunity sales is consistent with the characterization of future municipal contracts that the Company provided in its supplemental response to concerns raised by Staff in the 2008 IRP in which the Company stated that it would offer "contracts…subject to projected sufficient excess capacity after serving its retail native load obligation." So again, there is no distinction between the AEP and Wabash contracts and the Company's contracts with municipalities.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the First Prudence Review of Costs Subject to the Commission-Approved Fuel Adjustment Clause of Union Electric Company, d/b/a AmerenUE.	))))	Case No. EO-2010-0255

AFFIDAVIT OF STEVEN M. WILLS

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

Steven M. Wills, being first duly sworn on his oath, states:

1. My name is Steven M. Wills. I work in the City of St. Louis, Missouri, and I am employed by Ameren Services Company as Managing Supervisor Quantitative Analytics.

2. Attached hereto and made a part hereof for all purposes is my Surrebuttal Testimony on behalf of Ameren Missouri consisting of 12 pages, and Schedule SMW-S1, 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.

Steven M. Wills

Steven M. Wills

Subscribed and sworn to before me this 22 day of December, 2010.

Amanda Tesdall

Notary Public

My commission expires:

Amanda Tesdall - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #07158967
My Commission Expires 7/29/2011

Exhibit No.:
Issues: Weather Normalization
Witness: Steven M. Wills
Sponsoring Party: Union Electric Co.
Type of Exhibit: Direct Testimony
Case No.: ER-2010-_____
Date Testimony Prepared: July 24, 2009

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2010-_____

DIRECT TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

St. Louis, Missouri
July, 2009

TABLE OF CONTENTS

DIRECT TESTIMONY

OF

STEVEN M. WILLS

CASE NO. ER-2010-____

I. INTRODUCTION

Q. Please state your name and business address.

A. Steven M. Wills, Ameren Services Company ("Ameren Services"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri.

Q. What is your position with Ameren Services?

A. I am the Managing Supervisor of Quantitative Analytics in the Corporate Planning Department.

Q. What is Ameren Services?

A. Ameren Services provides various corporate, administrative and technical support services for Ameren Corporation ("Ameren") and its affiliates, including Union Electric Company d/b/a AmerenUE ("Company" or "AmerenUE"). Part of that work is performing important analyses, including weather normalization of test year sales for rate proceedings, which is the subject of my direct testimony in this case.

Q. Please describe your educational background and employment experience.

A. I received a Bachelor's of Music degree from the University of Missouri-Columbia in 1996. I subsequently earned a Master's of Music degree from Rice University in 1998, then a Master's of Business Administration ("M.B.A.") degree with an emphasis in Economics from St. Louis University in 2002. While pursuing my

M.B.A., I interned at Ameren Energy in the Pricing and Analysis Group. Following completion of my M.B.A. in May 2002, I was hired by Laclede Gas Company as a Senior Analyst in its Financial Services Department. In this role I assisted the Manager of Financial Services in coordinating all financial aspects of rate cases, regulatory filings, rating agency studies, and numerous other projects.

In June 2004, I joined Ameren Services as a Forecasting Specialist. In this role, I developed forecasting models and systems that supported the Ameren operating companies' involvement in the Midwest Independent Transmission System Operator, Inc.'s ("MISO") Day 2 Energy Markets. The forecasts that I developed were the basis for all of the companies' demand bids into the MISO markets. In November 2005, I moved into the Corporate Analysis Department of Ameren Services, where I was responsible for performing load research activities, electric and gas sales forecasts, and assisting with weather normalization for rate cases. In January 2007, I accepted a role I briefly held with Ameren Energy Marketing Company as an Asset and Trading Optimization Specialist before returning to Ameren Services as a Senior Commercial Transactions Analyst in July 2007. I was subsequently promoted to my present position as the Managing Supervisor of the Quantitative Analytics group.

Q. What are your responsibilities in your current position?

A. In my current position, I supervise a group of employees with responsibility for short-term electric load forecasting, long-term electric and gas sales forecasting, load research, weather normalization, and various other analytical tasks. My group's day-ahead load forecasts serve as the basis for the Company's demand bids into the MISO energy markets. We also perform forecasts of the Company's electric and gas sales for budgeting and resource planning purposes. Our load research work supports cost of service studies, settlements, and weather normalization, among other things.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe the process AmerenUE used to weather normalize test year sales and net system output, and to present the results of the weather normalization analysis. Additionally, I calculated a days' adjustment for the test year to apply to sales and annualization adjustments for wholesale and Large Transmission Service class sales. Finally, I developed a customer count forecast that was used to project customer growth through the proposed true-up date in the case.

III. WEATHER NORMALIZATION OF TEST YEAR SALES

Q. Are the Company's sales dependent on weather conditions experienced in its service territory?

A. Yes. Weather is one of the most significant factors that can introduce short-term fluctuations in the sales made by the Company. This is primarily due to the large number of customers that heat and cool their premises with electric air conditioning, electric space heating, and gas space heaters that have associated electric blowers. When summer weather is unusually hot, air conditioning equipment must work harder to keep buildings cool. This results in an increase in the Company's sales. Similarly if the summer is particularly mild, air conditioning loads, and therefore electric sales, will decline from expected levels. The converse is true in the winter. Colder temperatures cause increases in space heating-related electric sales, while warm weather reduces them.

Q. What is weather normalization and why is it necessary?

A. Weather normalization is the process of determining the level of sales that the Company should be expected to make on an ongoing basis under normal weather conditions. When changing rates in a rate case, it is important to normalize sales for the impact of unusual weather. This is because the level of test year sales will become the denominator in the development of new electric rates (cents/kilowatt-hour ("kWh")). If the test year included weather-related decreases in sales that are not expected to persist from year to year, the denominator of the rate will be too small and the resulting rate will be too high. In this case the Company would be expected to recover more than its revenue requirement. Conversely, if the weather-related sales are higher than normal, the resultant rate will be too low for the Company to have a reasonable opportunity to recover its revenue requirement. Adjusting sales to a normal level will help develop a final rate that is most likely to permit the Company to collect its revenue requirement accurately.

Q. Please outline the process of weather normalizing electric sales.

A. There are three broad steps involved in the process, each with significant detail involved in them. The first step is to define "normal" weather. The Company has used weather observations from the period of 1971-2000 to develop its normal weather conditions. This is consistent with the National Oceanic and Atmospheric Administration ("NOAA") definition, which states that normal for a climatic element is equal to the arithmetic average of that element computed over three consecutive decades (currently 1971-2000). However, because of the unique nature of the problem of normalizing energy usage, a specific technique that is often referred to as the "rank and average" approach is applied to temperatures from these decades. Application of this procedure is necessary in order to produce realistic levels of normal energy later in the process. This method has been utilized routinely in electric rate cases by the Missouri Public Service Commission Staff ("Staff"), and was used by both the Company and the Staff in the Company's most recent rate case (Case No. ER-2008-0318). I will elaborate further on this methodology later in my testimony.

The second step in the weather normalization process is to develop load-temperature relationships. Accurate statistical models of the response of load to temperature are critical to developing a reasonable level of sales and net system output upon which to develop rates. Using a software package called MetrixND, daily loads at the rate and revenue class level are modeled statistically as a function of calendar and weather variables. These statistical relationships are the basis for the weather adjustments that are made to test year sales and will be discussed in more detail later in my testimony.

The final step in the weather normalization process is to bring together the actual and normal weather data with the statistical relationships of load and weather to calculate the adjustments necessary to bring test year sales to the level expected under normal conditions. This is the point at which we develop the level of sales that will ultimately produce rates that afford the best opportunity to generate revenues in line with the revenue requirement in the case. These calculations will also be described further below.

IV. ACTUAL AND NORMAL WEATHER DATA

Q. What weather data is required for the weather normalization process?

A. It is necessary to obtain actual and normal two-day weighted mean temperatures for each day in the test year that apply to the Company's service territory.

Q. What is a two-day weighted mean temperature ("TDMT")?

A. The TDMT is a temperature measure that is calculated by first taking an average of the high and low temperature reported for each day. This value is referred to as the daily average or mean temperature. Then for each day, the daily mean temperature is averaged with the prior day's daily mean temperature with 2/3 weight on the current day and 1/3 weight on the prior day. This calculation is done because the TDMT is a better predictor of electric loads than the simple daily mean temperature. As an example of why this is the case, electric loads tend to be higher on each successive very hot day. This phenomenon is observable in load data and is largely attributed to heat build-up. When coming off of a very hot day, buildings' internal temperatures are higher than they otherwise would be. Therefore air conditioning units must work harder to cool structures. The TDMT captures this effect by bringing forward the effect of the prior day's temperature into the value being used to explain the current day's electric usage.

Q. What weather station is used to describe the weather in the Company's service territory?

A. Weather readings taken at the NOAA station at the St. Louis International Airport ("Lambert Field") are used in the weather normalization process as representing the Company's service territory. As the St. Louis Metropolitan Area is home to a large majority of the Company's customer base and the entire load served by the Company is located in relatively nearby Missouri counties, this is appropriate. The Company acquires this weather data from the Midwestern Regional Climate Center's ("MRCC") Midwestern Climate and Information System database.

Q. Are there any adjustments made to the temperatures reported by the MRCC before they are used in the weather normalization process?

A. Actual temperatures for the test year are used as reported by the MRCC in the Company's calculations. However, in the calculation of normal weather, it is necessary to make adjustments to the historical readings to account for certain discontinuities in the data that have resulted from known changes made over time in the equipment used at Lambert Field and its location.

Q. Please describe the need to make adjustments to the weather data as mentioned above.

A. Over the time period from 1971-2000, there have been changes made to the weather station at Lambert Field where the temperature measurements are taken. The most significant of these changes occurred in May 1996, when Lambert Field was changed to an Automated Surface Observing System station. At this time, both the equipment used to record temperatures and the location of that equipment changed in order to introduce a system that records weather data continuously and automatically. The new equipment and location resulted in readings that were lower than they would have been with the previous equipment and location.

The most important characteristic of the calculated normal temperature is that it be accurate relative to the test year temperatures. The difference between the normal temperature and the actual temperature should represent climate variability, not artificial differences that can be introduced by changing observation practices. If the temperature readings from 1971-2000 have a known bias when compared with current readings from Lambert Field, the calculated normal temperatures that are based on those readings will not be applicable to the test year.

To illustrate this point, imagine two consecutive days that happen to have identical high and low temperature conditions. At midnight, assume that the weather station is disassembled and reconstructed with new equipment some distance away from where it was. The new equipment happens to read cooler than the equipment it replaced, since it is now in a grassy field instead of near blacktop pavement that absorbs heat. The temperature on the second day now reads more than 1 degree cooler than the first day. It would be inappropriate to use the temperature from the first day without any adjustment in a calculation that will be used on the second day. The adjustment process corrects this problem and allows us to fulfill the objective of having normal temperatures that are accurate relative to the test year temperatures.

Q. How are the magnitudes, direction, and timing of these adjustments determined?

A. The adjustments that the Company makes to the historical temperature data from Lambert Field are based on a collaborative analysis undertaken by Staff and the Company during Case No. EM-96-149. Climatologists engaged by the Company and Staff used a statistical technique called "double-mass analysis" to determine the timing, direction, and magnitude of the necessary adjustments. In the course of this analysis, the climatologists used multiple reference weather stations in close geographic proximity to Lambert Field to identify and characterize the discontinuities in the data. These adjustments were agreed to in Case No. EM-96-149 and were used again by both parties most recently in Case No. ER-2008-0318.

Q. Please describe the specific adjustments you applied to the historical temperatures.

A. There are three adjustments made to the historical temperatures. First, on January 11, 1978, a change occurred at Lambert Field that resulted in readings that were 0.3 degrees warmer than before. Next, on February 1, 1988, a change occurred that resulted in readings that were 0.45 degrees warmer than those prior. Finally, on May 1, 1996, a change occurred that resulted in temperature readings that were 1.69 degrees cooler than before. All adjustments are applied to the temperature readings before the date of the change. This practice brings historical temperatures in line with current readings at Lambert Field so that the normal and actual temperatures are appropriate for comparison.

Q. Now that you have described the source of and adjustments to historical temperature data, please describe the process you use to develop daily normal temperatures for the test year.

A. First, daily TDMTs are calculated for the period from 1971-2000. Next, a technique called "rank and average" is applied to the historical TDMTs in order to develop normal values to use in the test year. The rank and average technique is used so that the resultant normal temperatures produce appropriate levels of electric usage when applied to the statistical models that capture the relationship between load and temperature. The rank and average technique starts by ranking all of the days within a season or year for each year from the highest TDMT to the lowest. Then for that season or year, the warmest day of each of the 30 years is averaged, the second warmest day of each of the 30 years is averaged, and so on until the coolest day of each of the 30 years is averaged. Through this process we get a series of daily temperatures that represent the normal hottest day for the season or year through the normal coldest day for the season or year. This result is desirable because it gives normal temperatures that also exhibit normal levels of extreme temperatures.

Q. Why is it important to have normal levels of extreme temperatures?

A. The response of load to temperature is non-linear. That means that a change in temperature of 1 degree from 40 to 41 degrees has a different impact than a change in temperature from 60 to 61 degrees, which in turn has a different impact than a change from 80 to 81 degrees. Because load behaves differently across the spectrum of possible temperatures, it is important to have a representative number of days in each part of the temperature range in order to reproduce the level of load that would be experienced across a year with normal temperature variability. The rank and average technique achieves this objective.

Q. Are there any other considerations that you make when using this technique?

A. Yes, there are many details to this calculation. In particular, there are various ways to handle certain issues around seasons and days of the week. The Company has performed the calculations consistent with its understanding of the Staff's preferred approach and similar to how the Company and Staff ultimately agreed to perform these calculations in Case No. ER-2008-0318.

V. LOAD – TEMPERATURE RELATIONSHIP

Q. How is the relationship between load and TDMT established?

A. The Company uses a software package called MetrixND to develop statistical models that represent the relationship of load and temperature.

Q. Is this a change from prior cases?

A. The software has changed, but the underlying statistical models are very similar. In past cases, the Company used the Hourly Electric Load Model ("HELM"). MetrixND has functionality that is very similar to HELM and the models employ the same fundamental principles as HELM models.

Q. What are the inputs to the MetrixND models?

A. Hourly loads for each customer rate/revenue class combination to be weather normalized are input into MetrixND. In addition, calendar variables that describe the day of the week and season of the year are utilized. Finally, the model requires actual TDMT for the period being used to develop the model. In the case of a few classes, trend variables were also included.

Q. What is a trend variable and why might it be needed?

A. A trend variable is a variable that grows with time. Every day, the value of this variable is one higher than the prior day's value. This is utilized to capture a load pattern that is growing or declining significantly over time. By controlling for load growth, the underlying weather response is modeled more accurately. This variable was required for a few customer classes because the loads were deteriorating rapidly as economic conditions worsened in the Company's service territory.

Q. Since the Company bills its customers monthly, and therefore reads most of its customers' meters only monthly, how does the Company obtain hourly load data by customer rate and revenue class to input into the model?

A. The Company uses hourly load data developed through its Load Research Program in the model. AmerenUE maintains stratified random samples of customers from each rate class, for which it collects hourly load data. Using the hourly loads from the samples along with calendar month class sales, the Company uses a statistical technique called ratio analysis to generate hourly class level loads. In addition to the rate class level analysis, the Company uses another statistical technique called "domains analysis" to extract revenue class level data. Revenue classes include Residential, Commercial, and Industrial. By subdividing the rate classes into revenue classes, more homogeneous customer groups are available to model.

The class level loads are aggregated, adjusted for transmission and distribution line losses and compared to the system load by hour. The system load is an actual hourly metered value, whereas the class loads are still statistical estimates. The class level loads are calibrated so that they aggregate up to match the known system loads by hour. This ensures that the class level hourly data is consistent with the energy that was consumed on the system. The resultant calibrated loads by rate and revenue class are used in the MetrixND model and become a very important element in the process used to normalize net system output.

Q. Please discuss the modeling process that occurs in MetrixND.

A. In MetrixND, a scatter plot is created with daily TDMTs on the horizontal axis and load on the vertical axis. Using this graph, temperature ranges are identified that have similar load responses to temperature. The ranges become temperature groupings for the model. Additionally, seasons are analyzed graphically to see if the load-temperature response differs seasonally. Variables are then developed to reflect these temperature ranges and seasonal combinations that have similar load-temperature responses. These variables, along with day of week variables and the trend variables mentioned earlier are combined in regression models to explain the variation in daily energy by class.

Q. Please describe how these statistical models represent the load-temperature response.

A. Consider a model that is being fit for which no seasonal variations in the load-temperature response have been identified. Over the course of the year, both heating and cooling equipment may be used by the Company's customers. The model may determine that when the temperature is between 40 and 50 degrees, a particular customer class' usage may increase by 100 megawatt hours ("MWhs") for each degree it gets colder. That means that when the TDMT falls from 42 to 41 degrees, space heating equipment works harder, resulting in 100 MWhs of increased usage. In this case, the MetrixND model would have a coefficient of -100 for the variable or variables that represent that temperature range. This is similar to graphically drawing a line with a slope of -100 over the area between 40 and 50 degrees on the scatter plot that we started with. However, this same model may indicate that from 70 to 80 degrees, the same class' usage increases by 150 MWhs for each degree warmer that it gets. This is because as temperature increased, heating equipment was switched off and air conditioning equipment was switched on. The coefficient of the model for the variable(s) that represent this temperature range will be 150, which is similar to including a line with a slope of 150 on the scatter plot over the load-temperature pairs between 70 and 80 degrees. The model establishes across all relevant temperature ranges what is expected to happen to customer loads as the temperature changes. An example graph displaying a load-temperature scatter plot with the weather response function is attached to my testimony as Schedule SMW-E1.

Q. How are these models used to normalize customer loads?

A. For each day, actual and normal TDMTs have been paired based on the normal weather calculations described above. For a given day, assume that the actual TDMT was 74 degrees and normal is determined to be 78 degrees. We will look to the statistical relationships developed in MetrixND, which may indicate that in this temperature range, each additional degree causes usage to increase by 100 MWhs. So in order to normalize load we will take the number of degrees that the actual temperature deviated from normal (78 degree normal – 74 degree actual = 4 degree adjustment from actual to normal) and multiply it by the usage per degree described by the model (4 degrees x 100 MWhs/degree = 400 MWhs). On that day, normal usage is 400 MWhs higher than the actual usage was.

Q. Are there any other models developed in this fashion?

A. Yes, an identical process is followed to generate statistical models and normal values to represent each customer class' daily peak load. This will be instrumental in developing the normalized net system output.

VI. NORMALIZING BILLED AND CALENDAR SALES

Q. Once you have normalized the energy from the daily loads that you developed in your load research process, how does this translate into normal sales for billing months?

A. The Company's billings for a given month do not necessarily represent all of the energy used within the calendar days of that month. This is because the Company's customers have their meters read in 21 groups (or cycles) each month according to a published schedule. So an August bill for one customer may be based on the period July 14 through August 13, while for another customer the August bill may include usage from July 26 through August 26. Groups of customers that have their meters read on the same date are referred to as sharing a billing cycle. In the weather normalization process, the Company is normalizing each billing cycle independently. We start with billed sales for each billing cycle (group of customers whose meters are read together) for each month. Since we know the dates the meters were read for each billing cycle, it is possible to estimate how much usage occurred on each day. Take for example a hypothetical billing cycle that began on July 14 and ended on August 13. A particular class of customers (e.g., Residential, Commercial Small General Service, etc.) may have been billed for 150,000 MWhs of usage in that period for the customers on that billing cycle. We then look at the total estimated class daily usage from load research for those dates. We may find that the total class used 3,000,000 MWhs over the dates between July 14 and August 13. Perhaps the total class usage on July 14th was 100,000 MWhs. Therefore, 3.33% of the class' usage occurred that day (100,000 MWhs of class daily usage / 3,000,000 MWhs of class usage over the billing period). That 3.33% is applied to the sales of the actual billing cycle that is being normalized (150,000 MWhs x 3.33% = 5,000 MWhs on July 14th). Using this methodology the actual billed sales are estimated by day for each billing cycle. Then for each day, the actual billed sales are adjusted based on the daily normalized loads produced by MetrixND. We know that the total class used 100,000 MWhs on July 14th, and through the MetrixND process the normal load for July 14th was determined to be 110,000 MWhs. So for that day, normal usage was 110% of actual (110,000 MWhs normal load / 100,000 MWhs actual load = 110%). So the billing cycle that used 5,000 MWhs on July 14th has a normal load for that day of 5,500 MWhs (5,000 MWhs actual usage x 110% normal/actual ratio = 5,500 MWhs normal usage). For every customer class, month and billing cycle combination, this calculation is done for each day that falls between the applicable meter reading dates. The sum of the daily billed actual sales across all months and billing cycles tie to the Company's billings for the year for the customer class being normalized. The sum of the daily billed normal sales across all months and billing cycles is the normalized level of the Company's billings for the year.

Q. How are calendar month actual and normal sales estimated in this process?

A. When going through the calculations of actual and normal billed sales, daily actual and normal sales by billing cycle are developed. These sales are then just aggregated according to the days within a calendar month rather than according to meter read schedules to develop calendar month sales.

Q. Please summarize the results of your analysis.

A. The test year was warmer than normal both in the summer and winter. Cooling Degree Days ("CDD"), a quantification of the weather that typically results in air conditioning load, were 2.6% greater than normal. This results in summer sales being normalized downward. Heating Degree Days ("HDD"), a quantification of the weather that typically results in heating load, were 6.3% less than normal. This results in winter sales being normalized upward. Total retail sales for the weather sensitive classes were adjusted up by 0.2% in aggregate. Class-by-class monthly results are reported in Schedule SMW-E2. The schedule also includes the annualized sales for the LTS class as discussed below.

VII. ANNUALIZATION OF WHOLESALE SALES AND REVENUES

Q. Why was an annualization adjustment necessary for AmerenUE's test year wholesale sales?

A. AmerenUE has had a static group of six wholesale customers for several years. These customers are Missouri municipal utilities that were under long-term full requirements power purchase contracts. All of the existing wholesale contracts were originally set to expire December 31, 2008. Four of the six municipal customers signed new contracts to continue on with full requirements service with AmerenUE beyond the test year and true-up date in this case. The two customers that did not sign new contracts are no longer served by AmerenUE. These customers had nine months of sales included in the test year. As this is clearly a known and measurable change that will be reflected in the Company's sales mix going forward, it is appropriate to remove these sales from the test year totals. Additionally, the 4 returning customers are buying power at new contract rates. The revenues associated with these customers were adjusted to reflect the level of revenues that would have been achieved with the new contract rates in effect.

Q. Are there any other changes to the mix of wholesale customers that impact the test year?

A. Yes. The Company entered two long-term partial requirements contracts with new customers in the spring of 2009. These contracts are effective well in advance of the true-up date in the case and an annualized level of expected sales under these contracts should be included in the test year to appropriately reflect the mix of customers the Company will be serving as of the true-up date in the case.

Q. How were the annualization adjustments computed?

A. For the customers whose contracts terminated on December 31, 2008, all usage that was recorded on the books during the nine months of the test year that proceeded that date was removed from the wholesale sales totals. For the new customers, the contracts guided the calculation of the sales to impute into the test year. One contract calls for 100 MW of power (energy and capacity) every hour of the contract term. The other contract calls for 150 MW of energy and capacity, subject to the customer's day-ahead schedule. This contract requires the customer to achieve a minimum of a 76% load factor over the term of the agreement. The appropriate monthly volumes were calculated consistent with the provisions listed above and imputed in the test year to reflect an appropriate annualized wholesale sales level.

Q. What are these adjustments used for?

A. There are two places these adjustments show up in the case. First, I provided the sales adjustments to Company witness Gary S. Weiss to use in the development of allocation factors to assign costs to retail and wholesale load. Second, I used the adjusted sales in the development of normalized net system output that I provided to Company witness Timothy D. Finnell for production cost modeling. I will describe the net system output calculations later in my testimony. The adjustments to the wholesale class sales and revenues are detailed in Schedule SMW-E3.

VIII. ANNUALIZATION OF LTS SALES

Q. Why is an annualization adjustment necessary to the Large Transmission Service ("LTS") class sales?

A. The Large Transmission Service Class is made up of only one customer. This customer is the Company's largest customer by sales volume by a wide margin. The customer in this class experienced an outage of their production capacity related to a winter storm that occurred in January 2009. The last three months of the test year included usage for this customer that was significantly below normal usage by historical standards.

Q. How was the normal annual level of sales to the LTS class determined?

A. The customer that makes up this class has an extremely consistent load when operating under normal conditions. The annual load factor of this class is approximately 98% and the annual sales to this class have not varied by more than 1% in a full year over the last three years. Because the load pattern of this customer is so consistent under normal operations, it is adequate to use sales from the first three months of 2008 to replace January through March sales of 2009. The annualized sales for the

LTS class sales simply replaced the last three months of the test year with the same three months from the prior year.

Q. Were any adjustments made to the prior year's sales at all?

A. Yes. February of 2008 included a leap day. The February 2008 sales volume was reduced by 1/29th to reflect the level of sales that would be expected to occur in a 28 day month, as February 2009 was.

Q. What was the LTS class adjustment used for?

A. I provided this adjustment to Mr. Weiss, again for the development of the variable allocation factor in his cost of service analysis. Also, I provided the annualized sales to Company witness James R. Pozzo for him to use in the development of billing units for the case. Finally, I incorporated the adjusted sales level in the development of the normalized net system output that I provided to Mr. Finnell.

IX. CUSTOMER GROWTH FORECAST

Q. What is the purpose of the customer growth forecast you provided for this case?

A. The Company has proposed to true-up certain items of revenue and expense through February 28, 2010. The basis of the revenue true-up is the forecast of customer counts at that time. To the extent that the customer base continues to grow and use per customer remains unchanged, revenues will grow. The customer forecast was used to true-up revenues to the level expected to be achieved based on growth through that time.

Q. How was the customer forecast created?

A. Using MetrixND, the same statistical software that was used to create the load-temperature response models, econometric forecasts were created for seven customer classes.

Q. Which classes were included and why were they selected?

A. Customer growth was forecast for the Residential, and Commercial and Industrial ("C&I") classifications of the Small General Service, Large General Service, and Small Primary Service classes. The only tariff classes not chosen for a customer growth adjustment were the C&I Large Primary Service ("LPS") classes and the LTS class. The LPS class is a class with a fairly small number of very large customers. This class was reviewed by the Company's rate engineering group for known changes to the existing customer base. The LTS class, as mentioned earlier, only has one customer and has no prospects for change at this time.

Q. Please describe the models used to forecast customer growth.

A. For most customer classes, an appropriate economic driver was selected to explain changes in customer counts over time. The Company receives both historical data and forecasted data on numerous economic data series that are relevant specifically to its service territory from Moody's Economy.com. The drivers selected were all forecasted by this nationally respected service.

For the Residential class, the households variable was selected as the driver variable for its obvious intuitive fit. For the various C&I classes a relevant employment or output (for example, Gross Domestic Product for the Manufacturing sector) was selected as the driver variable. The variable for each particular class was selected based on its having an intuitive relationship with the class being forecast as well as the statistical fit of the variable. In most cases, the model simply consisted of a lagged dependent variable and the driver variable.

Q. What is the purpose of the lagged dependent variable?

A. The lagged dependent variable simply means that the last period's actual customer count is used to predict the customer count for the following period. As customer counts are fairly stable over time, this lends stability to the model and provides for a very good statistical fit. The economic variables then can provide a basis for changes in the growth rate over time.

Q. Were any classes modeled in a different fashion?

A. Yes, the Commercial Small Primary Service class was done with just a time series model. This essentially means that the level and trend across time is just extrapolated into the future.

Q. Why was that done for this class?

A. All of the relevant drivers projected a significant near-term decline in customers due to the poor economic conditions included in Economy.com's forecast. A decline was not evident in the actual customer data yet, so these forecasts were rejected in favor of a time series forecast.

Q. What was done with the results of the customer forecast?

A. I provided forecasted customers for each of the seven classes mentioned above to Mr. Pozzo. He used these customer counts to adjust the test year billing units to the level that is expected to exist as of the requested true-up date.

X. NORMALIZED NET SYSTEM OUTPUT

Q. What is net system output?

A. Net system output is the term the Company uses to describe the total amount of energy generated or purchased to serve its retail and long-term wholesale load, along with the associated distribution system line losses. The Staff frequently refers to this as net system input. The terms may be used interchangeably. The only difference is the perspective on the system. It is system output from the point of view of the generation fleet. It is system input from the point of view of the transmission system.

Q. Why is it necessary to normalize net system output?

A. Earlier I described the need for normalizing test year sales. Because we have normalized sales, it is also essential to normalize net system output. The net system output is the load that will drive the production cost model that determines the fuel and purchased power costs of the Company during the test year. The matching principle dictates that revenues should be matched up with the expenses that were incurred to generate those revenues. Essentially, we are simply treating revenues and expenses equivalently so that the true cost of service of our normalized level of load is reflected in the case.

Q. How is net system output normalized?

A. Much of the work is already done from the process of normalizing sales. We used calibrated load research data for each customer class to build statistical models of daily class energy. As I mentioned when describing the sales normalization, I simultaneously built models to weather normalize the daily peak load for each class. From these models, it is possible to generate hourly weather normalized class loads.

Q. How does normalization of the daily energy and peak produce normal hourly class loads?

A. I used a technique called the "unitized hourly load calculation" that keeps the existing hourly pattern of loads that was experienced in the test year, but adjusts it to the targeted energy and peak levels from the daily weather response functions. This technique is detailed in the Staff's 1990 Draft Report titled "Weather Normalization of Electric Loads."

Q. Once you have computed normalized hourly class loads, how do you create the total system output on a normal basis?

A. This is the reason it was important to point out the calibration process of our load research work. The load research was developed at the customer meter level, then adjusted for transmission and distribution line losses and compared to the actual net system output. Any variation between the sum of our class level estimates and the total system load was allocated to the various customer classes at that time. So the sum of hourly class loads adjusted for losses is equal to the observed system load. Now that we have normalized these loads individually, we can once again sum up the loss adjusted normal hourly loads. The sum of these becomes the normal system load, or net system output.

Q. What is the advantage of the class-by-class, or "bottom-up" method of normalizing net system output that you are proposing in this case?

A. There are at least three advantages of this method. First, the models that are normalizing the energy level of the net system output are the exact same models that are normalizing sales for revenue calculations. That helps to build consistency between these adjustments. Second, the energy models at the rate class level can pick up differences in response to temperature by class and therefore incorporate more useful information about load into the calculation. The higher level of detail should provide a truer representation of the load-temperature relationship. Finally, it helps build consistency across filings to use the bottom-up approach, as a class-by-class hourly weather normalization will be included in Integrated Resource Plan ("IRP") filings made by the Company. Using a similar approach to weather normalization of class and system loads in the rate case and IRP only makes sense. Again, it is worth reiterating that the calibration of the original class level load research ensures consistency between the class level calculations and the system load calculations.

Q. Were any other adjustments made to the class level loads besides the weather normalization calculations?

A. Yes, the annualization adjustments to the LTS and wholesale classes were also reflected in the net system output. Additionally, the sales included in the billing units to reflect expected customer growth through the true-up date were also built into the net system output. Finally, an estimate of transmission losses that will be calculated through the settlement process with MISO was deducted from the net system output.

Q. Why does the estimate of transmission losses need to be based on MISO settlements and why is it deducted from net system output?

A. When the Company interacts with MISO, transmission losses are settled financially. This means that when the Company buys the energy needed to serve its load from the MISO, it does not explicitly buy the associated energy to cover transmission losses. The Company will be paid for all energy it generates by MISO and will pay for all energy it consumes from MISO. The difference between the generation and load will be off-system sales net of power purchases. Since transmission losses are not included in the load purchased from MISO, the load used for the net system output should not include those losses. That way the generation that went to serve transmission losses will appear as off-system sales in the production cost model, which is a reflection of how the Company truly transacts with MISO. Transmission losses are paid for through the Marginal Loss Component of the Locational Marginal Price paid for all load. In order to match this reality, the loss rate that matches MISO's loss estimates is used in the calculation.

Q. How was that loss rate developed?

A. I reviewed the last two years of data from the MISO. For 2007 and 2008, MISO's calculated transmission losses were 2.2% of the metered volume of energy that the Company settled with the MISO.

Q. Once all of the appropriate adjustments are made, what is done with the net system output numbers?

A. I provided them to Mr. Finnell. He uses them in his production cost model to determine the net base fuel cost incurred to serve this load given our generation mix, cost of fuel, and market prices.

XI. <u>DAYS' ADJUSTMENT</u>

Q. What is a days' adjustment?

A. The billed sales in the test year are based on the Company's meter read schedule. This schedule varies from year to year and from billing group to billing group. The effect of this is that customers may be billed for slightly more or less than 365 days over the course of a test year. Since a normal year has 365 days, customer usage is adjusted accordingly.

Q. How did you calculate the days' adjustment?

A. I followed the method that was proposed by the Staff and ultimately agreed to by the Company in Case No. ER-2008-0318. Essentially we look at the difference between the calendar month sales and billing month sales estimated in the weather normalization process above. The difference is provided to Mr. Pozzo so that he can adjust the billing units to match the 365 day usage. Since the calendar month sales are based on exactly 365 days, it reflects the appropriate amount of usage for a test year. A table of the days' adjustment by class is attached to my testimony as Schedule SMW-E4

Q. Are there any other benefits of using this method?

A. Yes. This helps ensure that the matching of revenues and expenses will be accurate. Because the net system output was calculated from hourly data over the calendar months of the test year, using the calendar sales level from the test year to generate the revenue will ensure that the appropriate matching of these components occurs.

Q. Does this conclude your direct testimony?

A. Yes, it does.

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	)))))	Case No. ER-2010-

AFFIDAVIT OF STEVEN M. WILLS

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

Steven M. Wills, being first duly sworn on his oath, states:

1. My name is Steven M. Wills. I work in the City of St. Louis, Missouri, and I am employed by Ameren Services Company as Managing Supervisor of Quantitative Analytics.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 27 pages, Schedules SMW-E1 through SMW-E4, 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.

Steven M. Wills
Steven M. Wills

Subscribed and sworn to before me this 24th day of July, 2009.

Amanda Tesdall
Notary Public

My commission expires:

Amanda Tesdall - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #07158967
My Commission Expires 7/29/2011

Schedule SMW-S1