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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2012-0166

DIRECT TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
February, 2012

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DIRECT TESTIMONY

OF

STEVEN M. WILLS

CASE NO. ER-2012-0166

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 63103.

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 Ameren Missouri ("Company" or "Ameren Missouri"). Part of that work is performing important analyses, including weather normalization of test year sales for rate proceedings, which is the primary subject of my direct testimony in this case.

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. 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.

II. PURPOSE OF TESTIMONY

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

A. The primary purpose of my testimony is to describe the process Ameren Missouri 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 an adjustment to annualize the impact of the Company's energy efficiency programs on sales. Finally, I calculated weather normalized class demands for the class cost of service study.

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 heating with 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 would be expected to have made in the test year if normal weather conditions had prevailed. 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 circumstance the Company would be expected to recover more than its revenue requirement, all other things being equal. 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. At a high level, there are three basic steps involved in the process, each with significant details involved in them. The first step is to define "normal" weather. The Company has used weather observations from the period 1981-2010 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 1981-2010). 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 sales 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 Staff in the Company' most recent rate case (Case No. ER-2011-0028). 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 do you use to perform weather normalization?

A. I use 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, reflecting the fact that 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' 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") Applied Climate 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 as reported by the MRCC are used 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 1981-2010, 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 must 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 1981-2010 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 simultaneously reconstructed with new equipment some distance away from where it previously 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 one 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 in at least the last four Ameren Missouri electric rate cases, most recently in Case No. ER-2011-0028.

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

A. There are two adjustments made to the historical temperatures. First, on February 1, 1988, a change occurred that resulted in readings that were 0.45 degrees warmer than those prior. Second, on May 15, 1996, a change occurred that resulted in temperature readings that were 1.69 degrees cooler than before. These 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. It should be noted that the original agreed upon adjustments to the Lambert Field temperature data included an additional adjustment made for the period preceding January 11, 1978. Since the period used to calculate normal temperatures has been updated to begin in 1981, this adjustment is no longer needed, since it applies to a period that is not included in the data.

Q. Now that you have described the source of and adjustments to the 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 1981-2010. Next, a technique referred to as "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 warmest day for the season or year through the normal coolest 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. Is there any additional information regarding the rank and average calculations that warrants discussion?

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 Staff's preferred approach and similar to how the Company and Staff ultimately agreed to perform these calculations in Case No. ER-2011-0028.

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. What are the inputs to the MetrixND models?

A. Daily 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, TDMTs for the time period being used to develop the model are input.

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

A. The company develops hourly load data (which is aggregated into daily data) through its Load Research Program. Ameren Missouri 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 rate classes into revenue classes, more homogeneous customer groups are available to model.

As a part of the load research process, class level loads are aggregated, adjusted for transmission and distribution line losses, and then compared to the observed system load by hour. The system load is an actual hourly metered value, whereas the class loads are 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 an important input in the process used to normalize net system output and the class peaks used in the class cost of service study.

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, ranges are identified that have similar load responses to changes in temperature. These 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 month or season variables are combined in regression models to explain the variation in daily energy consumption 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 and class demands.

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 bill 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, where 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 = 3.33%). 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 MWh (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 sales across all months and billing cycles ties 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 as described above. These sales are then just aggregated according to the days within a calendar month rather than according to meter read schedule dates to develop calendar month sales.

Q. Please summarize the results of your analysis for the test year in this case.

A. The test year was warmer than normal, both in the winter and the summer. Cooling Degree Days ("CDD"), a quantification of the weather that typically results in air conditioning load, were 29.3% greater than normal. The summer of 2011 was among the most extreme summers St. Louis has experienced in recorded history, and consequently, load must be normalized down by a significant amount in the summer. Heating Degree Days ("HDD"), a quantification of the weather that typically results in heating load, were 2.4% less than normal. This results in winter sales being normalized slightly upward. Total retail sales for the weather sensitive classes were adjusted down by 3.2% in aggregate. Class-by-class monthly results are reported in Schedule SMW-E2.

Q. What do you do with the final weather normalized sales numbers?

A. I provide them to Company witness James R. Pozzo for him to use in the development of the billing units for the case.

VII. ANNUALIZATION OF ENERGY EFFICIENCY PROGRAM IMPACTS

Q. Please describe the adjustment you are sponsoring to annualize the impact of the Company's energy efficiency programs on test year sales.

A. During the test year, Ameren Missouri spent significant sums of money on programs designed to help its customers use energy more efficiently. The natural result of these programs is a decline in the sales made by the Company relative to the level of sales that would be made absent the programs. Because Ameren Missouri's programs were successful in generating significant customer energy savings, the impact of the efficient measures installed in the test year should be annualized to reflect the full impact that those measures have on the Company's sales.

Q. Since the measures installed in the test year necessarily affect test year sales already, why is it necessary to further adjust sales to fully reflect the impact of these programs?

A. A simple example should help to explain the issue. Imagine that as a result of a Company program, a customer installs a 15-watt Compact Fluorescent Light ("CFL") bulb in a light fixture in their home. But assume this installation took place late in September 2011, the last month of the test year, and it replaced a 60-watt incandescent bulb. All throughout the test year, this particular customer may have been using the incandescent bulb for 2 hours per day. So in the test year the customer's light from this fixture consumed 43.8 kWh (365 days * 2 hours / day * 60 watts = 43,800 Watt-hours or 43.8 kWh). Just prior to the end of the test year, the CFL is installed. Going forward, the same light fixture, with the same utilization pattern will consume 10.95 kWh (365 days * 2 hours / day * 15 Watts = 10,950 Watt-hours or 10.95 kWh). On an annual basis, using this hypothetical example that is illustrative of what is happening in reality, a customer's annual consumption is reduced by 32.85 kWh due to the energy efficiency actions promoted by the Company. The change took place during the test year, but its impact (in the extreme example of a measure installed right at the test year-end) is only reflected in a tiny fraction of the test year loads. Now imagine this effect being multiplied by nearly a million bulbs and various similar effects coming from numerous other measures at various times throughout the test year. Because the Company has documented records of the measures installed in the test year, the annualized energy savings of those measures, and the installation dates of the measures, it is appropriate to reflect the full energy impact of the measures in the test year. This is a known and measurable change in energy consumption that occurred before the end of the test year and it should be annualized.

Q. Are there any analogous adjustments made to test year sales for other changes in consumption that typically occur in a rate case?

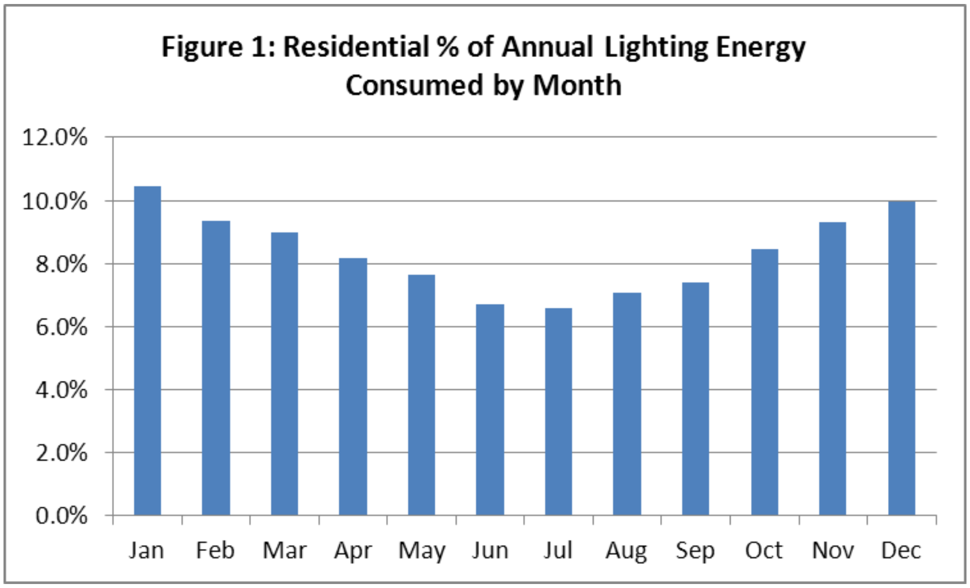
A. Yes. Sales are typically annualized for changes in customer counts during the test year. During the test year, typically customer counts are growing because of new customer connections exceeding the number of customers that disconnect from the system (since the recent recession and housing market slump, this has not always been the case, but it is a fairly ordinary course of events historically speaking). In the process of developing normalized billing units, both the Company and Staff typically adjust the test year sales to produce a level of sales that would have occurred if every customer on the system at the end of the test year had been on the system for the entire test year. This has most often increased the billing units above the level of sales that actually occurred in the test year. It is no different to annualize energy consumption such that the consumption pattern of light bulbs (and various other program measures) that are in place at the end of the test year in fixtures that were utilized during the test year are reflected in the level of sales made throughout the test year.

Q. Please describe how you calculated this adjustment.

A. Using tracking reports maintained by the Company and its implementation contractors, we assessed the number of each type of measure installed in each month, and obtained the annualized kWh impact of those measures. For the measures installed in a given month, we calculated the actual impacts of that measure on the test year sales and compared them to the annualized impacts from the tracking reports.

Q. How were the actual impacts calculated?

A. Again, this is probably best described through use of an illustrative example. Assume the CFL bulb from the previous example was installed in a residential lighting fixture in July 2011, replacing an incandescent bulb. Assume that the tracking report identified annualized savings of 32.85 kWh associated with this bulb, consistent with our previous example. The 32.85 kWh were allocated to months in the calendar year. The allocation reflects the best information the Company has regarding the utilization pattern of the measure. For example, residential lighting tends to be used more in the winter than in the summer due to the shorter hours of daylight that occur that time of year. The pattern of consumption for each end use was based on the end use load forecast modeling from the company's most recent Integrated Resource Plan ("IRP") load analysis and forecasting work. In the case of our lighting example, the pattern used is shown in Figure 1 below:



Once the annualized energy is allocated to months using the measure specific shape, then the energy from the months where the measure was already installed during the test year are summed to calculate the actual savings associated with the measure in the test year. For the month that the measure is installed, it is assumed that it is installed mid-month[1], and therefore half of the energy savings allocated to that month are classified as actual savings[2]. Figure 2 below illustrates the full calculation for our 32.85 kWh saving CFL installation:

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[1] For Business Programs, actual installation dates are available in the measure tracking reports utilized, so the actual usage in the month of installation is prorated based on the actual installation date rather than assuming a mid-month installation, as is done with the Residential class.

[2] For an individual measure like our lighting example, that assumption may not be entirely accurate, but when considering thousands of light bulbs being installed across the service territory, on average the half-month assumption is very realistic. This is because some of the bulbs would have been installed early in the month and others late, but the average bulb installation date should be very nearly mid-month given a large and diverse set of measure installations.

Figure 2: Illustrative Actual and Annualized Test Year kWh for CFL Installed in July 2011						
Test-Year Month	Annualized kWh Savings	Monthly Usage Pattern	Monthly Savings (kWh)	Measure Installed in Test Year?	Actual Savings (kWh)	Annualization Adjustment (kWh)
Oct-10		8.4%	2.77	No	0.00	
Nov-10		9.3%	3.06	No	0.00	
Dec-10		10.0%	3.28	No	0.00	
Jan-11		10.4%	3.43	No	0.00	
Feb-11		9.3%	3.07	No	0.00	
Mar-11		9.0%	2.95	No	0.00	
Apr-11		8.2%	2.68	No	0.00	
May-11		7.6%	2.50	No	0.00	
Jun-11		6.7%	2.20	No	0.00	
Jul-11		6.6%	2.16	Half-Month	1.08	
Aug-11		7.1%	2.32	Yes	2.32	
Sep-11		7.4%	2.43	Yes	2.43	
Total	**32.85**	100.0%	32.85		**5.83**	**-27.02**

As is evident in Figure 2, the CFL installed in July produced actual savings in two and a half months of the test year. The inefficient incandescent bulb that was replaced by the CFL was installed and using power during nine and a half months of the test year. So the annualization adjustment is made to reduce test year sales by 27.02 kWh, which is the difference between the 32.85 kWh of annualized savings and the 5.83 kWh of actual savings.

Q. Can you please summarize the adjustment you are proposing to annualize the impact of all Company energy efficiency programs that operated in the test year?

A. Yes. Residential test year sales should be reduced by 65,173,172 kWh to annualize the impact of the Company's residential energy efficiency programs. The remaining rate classes' test year sales should be reduced by 64,581,767 kWh to annualize the impact of the Company's business energy efficiency programs. Schedule SMW-E3 shows the impacts by month and by rate class. I have provided these numbers to Mr. Pozzo to include them in the calculation of the test year billing units.

Q. Will these numbers be trued-up?

A. Yes. There are two things that will need to be trued-up. First, the numbers should be trued-up to be consistent with final Evaluation, Measurement, and Verification ("EM&V") reports that were not available at the time this case was prepared. The numbers in this filing are based on the most current tracking reports available at the time of preparation, but the final EM&V results should replace these numbers. Second, if the parties to the case or the Commission should decide to update test year sales beyond September 2011 when developing billing units (as has been done by Staff and the Company in each of the last two rate cases), the results should be recalculated over the new twelve month period that becomes the basis for the billing units using the best information available (EM&V where possible and current tracking reports otherwise).

VIII. NORMALIZED NET SYSTEM OUTPUT

Q. What is net system output?

A. Net System Output ("NSO") is the term the Company uses to describe the total amount of energy generated or purchased to serve its retail load including the energy associated with distribution system line losses.

Q. Commission rule 4 CSR 240-3.190 requires electric utilities to submit monthly data reporting, among other things, Net System Input ("NSI"). How does this relate to NSO you described above?

A. The Company uses these terms interchangeably. Both are describing the amount of electric supply required to serve the utility's ultimate consumers. This includes line losses. This can be thought of as NSO when viewed from the generator's point of view. NSO is the amount of electrical output of the Company's generators used to serve customer load (including purchased power). NSI is the amount of electric supply input into the Company's electrical grid (from its own generation along with power purchases) that is used to serve customer load. As long as they are measured at the same point, there is really no difference between the two. Since Ameren Missouri began operating as a part of the MISO Day 2 Energy market in April 2005, NSO and NSI have been measured at the transmission level (i.e. including distribution losses but excluding transmission losses). This is because, as described more fully below, Ameren Missouri is not responsible for the physical energy that is lost on the transmission system under MISO's market construct.

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

A. Earlier I described the need for normalizing test year sales. Because the Company has normalized sales (and consequently test year revenues), 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 in a manner that is consistent with the calculated normalized revenues.

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 net system output on a normal basis?

A. Quite simply, we adjust the normalized class hourly loads for losses and sum across the classes to develop normalized net system output.

Q. Do the details of the load research process described earlier provide any benefits at this point in the process?

A. Yes, 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 finally compared to the actual observed system loads. 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. All energy generated and purchased for load is necessarily accounted for in these values. Using the normalized version of these calibrated loads and adjusting for losses using the same loss rates as before ensures that the normalized net system output also accounts for all energy that would be generated or purchased to serve the normalized level of load from the test year.

Q. What are the advantages of the class-by-class, or "bottom-up" method of normalizing net system output?

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 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 increased 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 the results of a class-by-class hourly weather normalization will be utilized in 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 of energy efficiency program impacts was 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, as was the annualization of large customer load changes and of the Owensville load that will be served by the Company as described in the testimony of Mr. Pozzo. 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 the Company buys the energy needed to serve its load from MISO, but does not explicitly buy the associated energy to cover transmission losses (energy associated with distribution losses is purchased from MISO). 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 sold and the load purchased is equal to off-system energy 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. What is done with the normalized net system output number in the Company's filing?

A. I provide the hourly net system output to Company witness Mark J. Peters so it can be used in production cost modeling. Additionally, I provide the annual MWh of net system output to Company witness Gary S. Weiss and he uses it in the calculation of the Net Base Fuel Cost ("NBFC") in the Fuel Adjustment Clause tariff.

IX. DAYS' ADJUSTMENT

Q. Please describe the need for a days' adjustment.

A. The billed sales in the test year are based on the Company's meter reading schedule. This schedule varies from year to year and from billing group to billing group. The effect of this is that groups of 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 employed by Staff and the Company most recently in Case No. ER-2011-0028. Essentially we look at the difference between the calendar month sales and the billing month sales estimated in the weather normalization process as described 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 benefits of using this method for the days' adjustment?

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.

X. WEATHER NORMALIZED CLASS DEMANDS

Q. Please describe the class demand data you prepared for the case.

A. The load research performed by my group provides a key input to the class cost of service study. We provide the demand of each rate class that occurs coincident with the system peak demand. We also provide the class peak demand for the year on a non-coincident basis. Finally we provide the class non-coincident demands, which represent an aggregate of the estimated peak usage of each member of the class.

Q. How is this data utilized in the class cost of service study?

A. The specific details are covered by Company witness William M. Warwick. In short, though, this data is used to develop allocation factors to assign various costs to the customer classes responsible for causing them.

Q. Did you weather normalize this demand data?

A. Yes. Because the net system output calculations detailed above include an hourly normalization calculation for each rate class, normalized demands were available. I provided these normalized class demands to Mr. Warwick.

Q. What is the benefit of weather normalizing class demands?

A. Class demand data that has not been weather normalized can be influenced by extreme weather experienced in the test year. Absent weather normalization of the class demands, allocation factors could change from case to case based on nothing more than the prevailing weather conditions at the time of peak during the test year. Normalizing these demands will help produce more stable allocation factors that will only change when there is a true change in the usage characteristics of the various customer classes.

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 Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.	)))	Case No. ER-2012-0166

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 a Managing Supervisor of the Quantitative Analytics group.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 29 pages, and 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

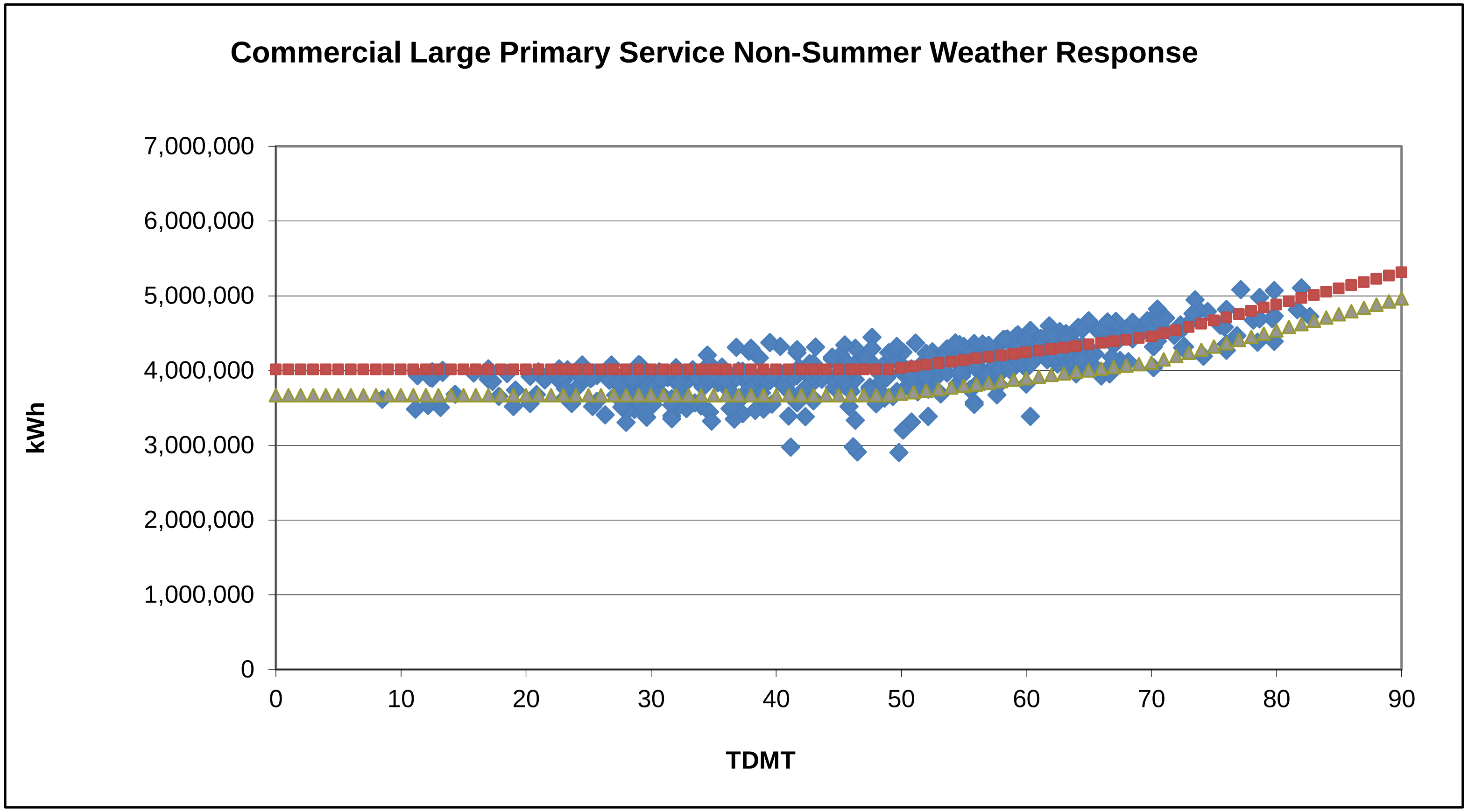
Subscribed and sworn to before me this 2nd day of February, 2012.

Mary Hoyt

Notary Public

My commission expires: 4-11-2014

Mary Hoyt - Notary Public
Notary Seal, State of
Missouri - Jefferson County
Commission #10397820
My Commission Expires 4/11/2014


Commercial Large Primary Service Non-Summer Weather Response
kWh
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5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
0
10
20
30
40
50
60
70
80
90
TDMT

Ameren Missouri - Residential Test Year Sales (kWh) - Revenue Month			
Month	Actual	Normal	Ratio
10	852,687,428	845,035,626	99.1%
11	786,862,035	805,241,390	102.3%
12	1,268,796,179	1,279,518,896	100.8%
1	1,647,040,683	1,569,214,098	95.3%
2	1,433,678,742	1,407,678,814	98.2%
3	1,095,005,472	1,120,291,924	102.3%
4	908,611,572	936,351,666	103.1%
5	798,778,804	792,650,700	99.2%
6	1,121,929,048	993,799,194	88.6%
7	1,443,119,939	1,238,175,783	85.8%
8	1,650,096,035	1,411,617,941	85.5%
9	1,262,058,762	1,143,763,166	90.6%
Total	14,268,664,699	13,543,339,196	94.9%

Ameren Missouri - Small General Service Test Year Sales (kWh) - Revenue Month			
Month	Actual	Normal	Ratio
10	270,516,503	266,810,295	98.6%
11	246,444,205	246,456,175	100.0%
12	298,641,275	299,729,285	100.4%
1	357,213,394	345,631,035	96.8%
2	322,070,100	317,843,377	98.7%
3	276,605,259	279,691,456	101.1%
4	254,519,563	258,699,993	101.6%
5	248,352,183	247,866,288	99.8%
6	294,259,675	280,004,765	95.2%
7	339,720,267	315,094,158	92.8%
8	367,179,686	336,653,649	91.7%
9	321,045,214	306,037,885	95.3%
Total	3,596,567,324	3,500,518,361	97.3%

Ameren Missouri - Large General Service Test Year Sales (kWh) - Revenue Month			
Month	Actual	Normal	Ratio
10	672,072,360	664,511,940	98.9%
11	622,186,531	619,726,834	99.6%
12	665,034,393	663,999,341	99.8%
1	734,528,231	713,608,808	97.2%
2	669,510,963	662,391,364	98.9%
3	620,435,085	626,245,281	100.9%
4	608,734,172	611,411,682	100.4%
5	628,768,136	625,784,884	99.5%
6	713,769,140	690,597,387	96.8%
7	773,570,461	730,294,956	94.4%
8	829,566,664	778,460,202	93.8%
9	765,754,461	739,801,164	96.6%
Total	8,303,930,597	8,126,833,845	97.9%

Ameren Missouri - Small Primary Service Test Year Sales (kWh) - Revenue Month			
Month	Actual	Normal	Ratio
10	289,923,998	287,330,400	99.1%
11	298,918,765	296,470,209	99.2%
12	288,272,878	287,491,236	99.7%
1	313,040,293	311,835,535	99.6%
2	297,825,183	297,351,251	99.8%
3	275,780,910	275,645,586	100.0%
4	273,433,501	272,598,373	99.7%
5	290,525,503	288,953,915	99.5%
6	320,453,711	314,426,824	98.1%
7	336,386,565	324,293,652	96.4%
8	353,230,426	337,335,507	95.5%
9	355,784,727	347,598,762	97.7%
Total	3,693,576,460	3,641,331,249	98.6%

Ameren Missouri - Large Primary Service Test Year Sales (kWh) - Revenue Month			
Month	Actual	Normal	Ratio
10	319,440,744	316,966,679	99.2%
11	316,302,463	313,230,730	99.0%
12	309,063,491	308,560,078	99.8%
1	297,712,504	297,875,557	100.1%
2	275,721,397	275,578,526	99.9%
3	270,852,633	269,762,493	99.6%
4	321,365,937	319,719,205	99.5%
5	298,464,920	296,031,326	99.2%
6	339,621,704	336,309,676	99.0%
7	347,904,912	340,577,077	97.9%
8	352,165,433	341,765,894	97.0%
9	376,752,043	370,824,884	98.4%
Total	3,825,368,181	3,787,202,125	99.0%

Test Year Savings from DSM Programs (kWh)					
Year	Month	Rate Class	Annualized	Actual	Adjustment
2010	10	RES	11,740,810	510,280	-11,230,530
2010	11	RES	12,944,608	1,909,339	-11,035,269
2010	12	RES	14,124,934	3,620,550	-10,504,385
2011	1	RES	14,801,054	5,228,875	-9,572,179
2011	2	RES	13,032,338	5,987,125	-7,045,213
2011	3	RES	12,608,262	7,183,459	-5,424,803
2011	4	RES	11,325,650	7,616,523	-3,709,127
2011	5	RES	10,785,184	8,226,281	-2,558,903
2011	6	RES	10,105,733	8,389,353	-1,716,380
2011	7	RES	10,428,256	9,142,461	-1,285,795
2011	8	RES	10,848,242	10,031,800	-816,442
2011	9	RES	10,648,018	10,373,870	-274,149
Test Year		RES	143,393,090	78,219,917	-65,173,172
2010	10	SGS	937,550	27,982	-909,568
2010	11	SGS	906,204	103,598	-802,606
2010	12	SGS	939,606	176,109	-763,497
2011	1	SGS	925,495	295,621	-629,873
2011	2	SGS	837,540	324,397	-513,143
2011	3	SGS	928,320	435,845	-492,475
2011	4	SGS	898,841	497,724	-401,116
2011	5	SGS	929,461	678,086	-251,375
2011	6	SGS	872,412	678,759	-193,652
2011	7	SGS	904,228	764,543	-139,685
2011	8	SGS	907,452	829,017	-78,435
2011	9	SGS	877,362	824,929	-52,433
Test Year		SGS	10,864,469	5,636,611	-5,227,859
2010	10	LGS	4,761,407	147,741	-4,613,667
2010	11	LGS	4,375,268	403,139	-3,972,129
2010	12	LGS	4,536,025	664,878	-3,871,147
2011	1	LGS	4,467,814	933,664	-3,534,150
2011	2	LGS	4,043,193	1,061,697	-2,981,495
2011	3	LGS	4,558,619	1,586,267	-2,972,351
2011	4	LGS	4,401,829	1,978,599	-2,423,230
2011	5	LGS	4,910,287	2,506,982	-2,403,305
2011	6	LGS	4,892,311	2,780,814	-2,111,496
2011	7	LGS	5,218,773	3,428,708	-1,790,064
2011	8	LGS	5,619,047	4,134,189	-1,484,858
2011	9	LGS	4,810,901	4,234,885	-576,015
Test Year		LGS	56,595,474	23,861,566	-32,733,908

Test Year Savings from DSM Programs (kWh)					
Year	Month	Rate Class	Annualized	Actual	Adjustment
2010	10	SPS	2,533,601	32,730	-2,500,871
2010	11	SPS	2,353,238	238,617	-2,114,621
2010	12	SPS	2,439,564	435,727	-2,003,836
2011	1	SPS	2,402,908	658,426	-1,744,482
2011	2	SPS	2,174,528	777,675	-1,396,854
2011	3	SPS	2,442,855	942,411	-1,500,444
2011	4	SPS	2,360,288	1,193,055	-1,167,233
2011	5	SPS	2,592,123	1,476,842	-1,115,281
2011	6	SPS	2,555,038	1,600,366	-954,672
2011	7	SPS	2,710,580	1,873,565	-837,015
2011	8	SPS	2,881,189	2,130,014	-751,176
2011	9	SPS	2,523,291	2,166,548	-356,743
Test Year		SPS	29,969,204	13,525,976	-16,443,228
2010	10	LPS	1,937,830	163,975	-1,773,855
2010	11	LPS	1,449,255	426,866	-1,022,389
2010	12	LPS	1,502,364	511,437	-990,927
2011	1	LPS	1,479,799	527,895	-951,904
2011	2	LPS	1,339,152	483,178	-855,974
2011	3	LPS	1,628,079	574,205	-1,053,875
2011	4	LPS	1,553,644	694,846	-858,798
2011	5	LPS	2,274,846	859,649	-1,415,197
2011	6	LPS	2,655,586	1,497,558	-1,158,028
2011	7	LPS	3,028,964	2,954,038	-74,927
2011	8	LPS	3,752,113	3,731,432	-20,681
2011	9	LPS	2,467,536	2,467,318	-218
Test Year		LPS	25,069,168	14,892,396	-10,176,772

Class	Days' Adjustment (kWh)
RES	-78,248,115
SGS	-14,357,698
LGS	-28,563,229
SPS	-2,303,824
LPS	10,739,281