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Witness:	Mark J. Peters
Sponsoring Party:	Union Electric Company
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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2016-0179

DIRECT TESTIMONY

OF

MARK J. PETERS

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
July 2016

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DIRECT TESTIMONY

OF

MARK J. PETERS

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I. INTRODUCTION

Q. Please state your name and business address.

A. Mark J. Peters, Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. What is your position with Ameren Missouri?

A. I am Manager, Asset & Trading Optimization in the Corporate Planning Function.

Q. Please describe your educational background and employment experience.

A. I received a Bachelor of Arts degree in Liberal Arts & Sciences (Concentration in Economics) in August of 1985 from the University of Illinois (Urbana-Champaign). My current duties include supervision and guidance of the group responsible for developing fuel budgets, reviewing and updating economic dispatch parameters for the generating units owned by Ameren Missouri, running production cost model studies supporting power plant project-justification studies, and performing other special studies, including those supporting our rate cases.

I began employment with Illinois Power Company in August of 1985, holding a variety of roles prior to its acquisition by Ameren Corporation ("Ameren"). Following

Illinois Power's acquisition, I was a member of the Strategic Initiatives group of Ameren Services Company, concentrating on Ameren's Illinois utility subsidiaries' post-2006 energy supply acquisition process. In December of 2007, I accepted the position of Managing Supervisor, Asset & Trading Optimization in the Commercial Transactions section of Corporate Planning. In that role, I was initially responsible for the guidance and supervision of a group that provided analytical support to the Ameren Missouri trading group, which is now managed by Ameren Missouri witness Andrew Meyer. In December 2011, I added the duties noted in the beginning of this section.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. The purpose of my direct testimony is to sponsor the determination of the normalized value for the sum of allowable fuel costs plus the cost of net purchased power, which was used by Company witness Laura Moore in determining Ameren Missouri's revenue requirement for this case and in calculating the Net Base Energy Costs ("NBEC") utilized in the Company's Fuel Adjustment Clause ("FAC"). These costs consist of nuclear fuel, coal, oil, and natural gas costs associated with producing electricity from the Ameren Missouri generation fleet, plus the variable component of net purchased power.

Mr. Meyer's testimony will address net off-system sales revenues which are netted against these costs in the determination of NBEC.

My testimony will also include the determination of the real-time load and generation deviation adjustment, as well as the percentage of transmission cost to be included in the FAC.

Q. Please summarize your testimony and conclusions.

A. Ameren Missouri's normalized annual fuel costs and net purchased power costs were calculated using the PROSYM production cost model.

The normalized annual fuel costs are $825.1 million and net purchased power costs are $20.3 million.

The normalized annual value for the real-time load and generation deviation adjustment is a credit (reduction of cost) of $0.7 million.

The percentage of transmission charges to be included in the FAC is 1.86%.

III. PRODUCTION COST MODELING

Q. What is a production cost model?

A. A production cost model is a computer application used to simulate an electric utility's generation system and load obligations. One of the primary uses of a production cost model is to develop production cost estimates used for planning and decision making, including the development of a normalized level of net energy costs upon which a utility's revenue requirement can be based.

"Net energy costs" as used in this testimony are the normalized values for the sum of allowable fuel costs, including transportation, plus the cost of net purchased power. These are a subset of the total fuel and net purchased power costs, including transportation and emissions costs and revenues and net of net off-system sales revenues, which are used to establish NBEC in the Company's Rider FAC tariffs.[1] As noted, the NBEC is discussed in Ms. Moore's direct testimony.

[1] There are other components of NBEC that are not produced by the production cost modeling, as discussed by Mr. Meyer and Ms. Moore in their direct testimonies.

Q. How long has PROSYM been used as a production cost model by Ameren Missouri?

A. It is my understanding that PROSYM has been used to model Ameren Missouri's system since 1995.

Q. How is PROSYM used by Ameren Missouri?

A. PROSYM is used by Ameren Missouri to model generation output. The results of this modeling are used for operational, financial and regulatory purposes. The model's output provides information used in developing budgets and financial forecasts, fuel burn projections, emissions estimates, and other generation station project analysis, and is used in the preparation of and as evidentiary support for rate cases, such as this one.

Q. What are the major inputs to the PROSYM model run used for calculating a normalized level of net energy costs?

A. The major inputs include normalized hourly loads, unit operating characteristics, unit availabilities, prices for the primary variable cost components (fuel by type and by plant, variable operating and maintenance costs, opportunity cost of emissions), and the market price of electrical energy.

Q. What are the major outputs of the PROSYM model run used for calculating a normalized level of net energy costs?

A. The major outputs include: generation output by unit expressed in megawatt-hours ("MWh"), millions of British thermal units ("MMBtu"), and the cost in dollars; net purchases of energy, expressed in both MWh and dollars; and net off-system sales of energy, expressed in both MWh and dollars.

Q. Please generally describe how net off-system sales and net purchases of energy are determined by the model.

A. For any given hour, the model increases the generation output for units that have a dispatch cost below the hourly market price for energy and decreases the output for those units whose dispatch cost is above the hourly market price. The model accomplishes this while recognizing the unit operating limits and characteristics and presuming the units are available for dispatch in that period. As such, the model determines the output of each generator in MWh for each hour. This output is then compared to the load assumption in MWh for each hour to determine whether there is a net purchase or a net off-system sale for that period.

In that regard, the model emulates our market settlement with the Midcontinent Independent System Operator, Inc.'s ("MISO") markets. In actual operations, we purchase energy for our entire load from the MISO market and we separately sell all of the MWhs generated by our generating units into the MISO market. However, it is my understanding that the Federal Energy Regulatory Commission ("FERC") requires that these amounts be netted against each other for each hour for reporting purposes. This netting results in the recording of either a net off-system sale or a net power purchase for that hour, depending on whether the volume of total sales exceeds total purchases (net off-system sale) or if the volume of total purchases exceed total sales (net power purchase). A $1 increase in off-system sales has the same impact on NBEC as a $1 reduction in purchased power (and vice versa).

IV. PRODUCTION COST MODEL INPUTS

Q. What load data assumptions were used in the PROSYM model run used for calculating a normalized level of net fuel costs?

A. We used normalized hourly loads, including applicable losses, developed from the actual loads for the test year of April 1, 2015, through March 31, 2016, as adjusted to remove the Industrial Aluminum Smelter ("IAS") loads.

Q. Why were the normalized loads adjusted to remove IAS loads?

A. The reason for their removal for all purposes for which normalized loads are utilized in this case is discussed in the testimony of Ameren Missouri witness William R. Davis. To ensure consistency, the same loads must be used for production cost modeling as are used for all other aspects of developing the revenue requirement and rates in this case.

Q. What operational data assumptions were used in the PROSYM model run used for calculating a normalized level of net energy costs?

A. Operational data assumptions reflecting the characteristics of the generating units were used for this purpose, including: unit input/output curve, which calculates the fuel input required for a given level of generator output; unit minimum and maximum load levels; ramp rates; minimum up and down times; unit commit status; identification of specific fuel used for startup and generation, including the ratio of those fuels if more than one for a given unit; and fuel blending. Schedule MJP-1 lists the operational data used for this case.

Q. Are there any changes of note in the unit operating characteristics included in the PROSYM model?

A. Yes. The first such change is that the model has been updated to reflect the recent switch at Meramec Units 1 and 2 to natural gas operation from coal. The second is that the minimum load levels for Labadie Units 1-3, Meramec Unit 4, Rush Island Unit 1, and Sioux Unit 2 have all been lowered based on recent operating experience (testing on the remaining coal units is on-going and any resulting change in unit minimums will be included in the true-up modeling). The third such change is the exclusion of the Howard Bend combustion turbine generator ("CTG") from modeling as a result of its retirement in 2015.

Q. Have any inputs been normalized to remove the impact of the "Polar Vortex" period of January through March 2014, as was done in File No. ER-2014-0258?

A. Yes. We have normalized values for natural gas by replacing the values for January through March 2014 with the average values for those same months for 2015 and 2016. The three-year normalized market price of energy discussed in Mr. Meyer's testimony has also been normalized to account for the "Polar Vortex."

Q. What unit availability data assumptions were used in the PROSYM model run used for calculating a normalized level of net energy costs?

A. Unit availability data assumptions were developed to annualize planned outages, unplanned outages and de-ratings. Planned outages are major unit outages that are scheduled in advance. The length of the scheduled outage depends on the type of work being performed. Planned outage intervals vary due to factors such as type of unit, unplanned outage rates during the maintenance interval, and plant modifications. A normalized planned outage length was used for this case, as reflected in Schedule MJP-2.

The lengths of the planned outage assumptions, except for the Callaway Energy Center, are based on a six-year average of actual planned outages that occurred between April 1, 2010 and March 31, 2016. The outage assumption for the Callaway Energy Center was based on an annualized average of the four most recent re-fueling outages: outages 18 through 21. As re-fueling outage 21 was not completed at the time that the model was run, the expected length of this outage was used. The final length of Refuel 21 will be reflected in the true-up calculation.

In addition to the length of the planned outage, the time period when the planned outage occurs is also important. The planned outage schedule assumption used in modeling Ameren Missouri's generation with the PROSYM model in this proceeding is shown in Schedule MJP-3. This assumption was developed in consideration of historical practices and market prices, whereby such outages are generally scheduled in the spring and fall, when the negative financial consequences of removing a unit from service are lower.

Unplanned outages are short outages when a unit is completely off-line, which are not scheduled in advance. These outages typically last from one to seven days and occur between the planned outages. Unplanned outages by definition are unforeseen events whose timing cannot be predicted, and thus are modeled as random events. The normalized unplanned outage rate assumption for this proceeding is based on a six-year average of unplanned outages that occurred between April 1, 2010 and March 31, 2016, and is reflected in Schedule MJP-4.

A unit de-rate occurs when a generating unit cannot reach its maximum output due to operational considerations. The magnitude of the de-rate varies based on the operating issues involved. As with the unplanned outage assumption, these are unforeseen events whose timing cannot be predicted, and thus are modeled as random events. The de-rate assumption used in this case is based on a six-year average of de-rates that occurred between April 1, 2010 and March 31, 2016, and is reflected in Schedule MJP-5.

Q. What fuel data assumptions were used in the PROSYM model run used for calculating a normalized level of net energy costs?

A. Ameren Missouri's units burn four general types of fuel: nuclear fuel, coal, natural gas (including landfill gas), and oil. The specific fuels (and the applicable ratio of those fuels if more than one) used by each generating unit for both normal generation and unit startup are identified in the model, and an incremental and average cost assumption is developed for each. The incremental cost assumptions are used by the model in its dispatch logic—determining when and at what output level a specific unit should run. Average costs represent the accounting costs incurred for the fuel consumed by generation and are used to calculate the fuel cost for each generating unit.

The natural gas and oil price assumptions are based on the average daily spot market prices for the 36-month period ending December 31, 2016,[2] using 28 months of historical data and 8 months of forward prices. The nuclear fuel cost assumption is based on the average nuclear fuel cost associated with Callaway Refuel 21.

The incremental coal cost assumptions are based on the average spot market prices for the 36-month period ending December 31, 2016, using 29 months of historical data and 7 months of forward prices.

[2] December 31, 2016 is the true-up cutoff date proposed for this case.

The average (accounting) coal cost assumptions reflect coal and transportation costs based upon coal and transportation prices that will be effective for 2017.

We have not included a cost assumption for landfill gas, as I have been advised that those costs represent Renewable Energy Standard ("RES") compliance costs and are accounted for in the RES cost re-base operations and maintenance expense portion of the revenue requirement.

Q. What market price of energy assumptions were used in the PROSYM model run used for calculating a normalized level of net energy costs?

A. The model was run using average hourly energy prices for the 36-month period ending December 31, 2016, adjusted for the Polar Vortex weather anomaly. The development of these prices is discussed in Mr. Meyer's testimony.

Q. Are there costs and revenues other than those established by the PROSYM production cost model which should be considered in the determination of NBEC?

A. Yes. In addition to the real-time load and generation deviation adjustment discussed below, there are other costs and revenues that should be considered in determining NBEC, which are addressed in Mr. Meyer's and Ms. Moore's testimonies.

Q. Please list the items that are modeled in PROSYM that should be trued-up using data as of the end of the anticipated true-up date in this case.

A. The following PROSYM input assumptions should be updated as of the applicable true-up date: Ameren Missouri's retail kilowatt-hour ("kWh") sales and distribution line losses; coal, nuclear, natural gas, and oil costs; unit availability factors;

energy prices; and known and measurable changes to unit operating characteristics, if any.

V. REAL-TIME LOAD AND GENERATION DEVIATION ADJUSTMENT

Q. Please describe the purpose of the real-time load and generation deviation adjustment.

A. The real-time load and generation deviation adjustment is intended to capture the difference in revenue (or expense) between the production cost model (which is a day-ahead only model) and the operation of the MISO market, which has both a day-ahead and real-time component. This difference is reasonably expected to continue into the future, and the inclusion of the adjustment is also reasonably expected to improve the accuracy of the NBEC calculation when taken in combination with the adjustments for Real- Time Revenue Sufficiency Guarantee Make-Whole Payment ("RT-RSG-MWP") margins, physical bilateral transaction margins and swap transaction margins.

Q. Please describe how the real-time load and generation deviation was calculated.

A. The deviation was calculated in a manner consistent with that used in File No. ER-2014-0258 using data for the 36 months ending December 31, 2015. Since this period overlapped with the true-up period for that case, I used the results from that case for the first two years with the exception of the "Polar Vortex" period of January through March of 2014. I then calculated the values for the remaining months. The "Polar Vortex" period was normalized by replacing the values for those months with the average values for the applicable month using 2013 and 2015 data (e.g., the value for January 2014 was set to the average of the January 2013 and January 2015 value).

As with the calculation in File No. ER-2014-0258, the CTGs and Taum Sauk were excluded. I recommend that this calculation be updated as part of the true-up process.

Q. What is the rationale for excluding the CTGs and Taum Sauk?

A. The CTGs are excluded due to the high number of reliability starts required by the MISO which occur separately from the economic dispatch process and the associated Revenue Sufficiency Guarantee Make-Whole Payments.

The Taum Sauk Energy Center is excluded from the calculation due to the manner in which these units are offered and cleared in the MISO market. As a pumped hydroelectric unit, the incremental cost basis for generating at the Taum Sauk facility is the cost of purchasing energy from the MISO market at the applicable Taum Sauk CpNode[3] to pump water back into the reservoir. Neither MISO market operations nor settlements consider this pumping energy to constitute load that could be cleared as part of Ameren Missouri's load in the day-ahead market. Rather, MISO considers pumping energy to constitute "negative generation" at the facility. Negative generation cannot be offered or cleared in the day-ahead market. As such, pumping energy is only cleared in the real-time market. It is not possible to determine what pumping cost would have been had Taum Sauk's output exactly matched its day-ahead award in any given hour.

Q. Was your real-time load and generation deviation adjustment also modified to account for the change in the IAS load assumption?

A. No. I did not adjust this factor as the IAS loads were not discretely forecasted on a daily basis. As a result, unlike the generator and total load day-ahead

[3] A CpNode or Commercial Pricing Node, is a component of the MISO commercial model used to schedule and settle market activity at a specified location.

awards, I do not have a known day-ahead value for the IAS load. Further, these loads have historically been very consistent in nature day-to-day and thus it is unlikely that there was an appreciable difference between their actual loads and the amount that would have been included in Ameren Missouri's day-ahead forecast for our entire load obligation provided to the MISO.

VI. PERCENTAGE OF TRANSMISSION COST INCLUDED IN FAC

Q. With respect to transmission charges recorded in Account 565, have you determined what portion of these charges should be included in the determination of NBEC used to determine the Base Factors ("BFs")?

A. Yes. I have determined that amount to be 1.86%. Those amounts excluded from the calculation of NBEC and BF should be included in base rates.

Q. Is this the same percentage that should be utilized to determine the portion of total transmission charges to be included in the FAC in any given period?

A. Yes.

Q. How was the 1.86% determined?

A. 1.86% is the result obtained by dividing the total MWh of net purchased power in the production cost model run for this case by the total load assumption used in that model. This calculation is consistent with that performed by Missouri Industrial Energy Consumers ("MIEC") witness James Dauphinais in File No. ER-2014-0258 and ultimately utilized by the Commission in that case to determine the percentage of transmission charges included in NBEC, base rates, and in the operation of the FAC tariff in that proceeding.

Q. Does this complete 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-2016-0179

AFFIDAVIT OF MARK J. PETERS

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

Mark J. Peters, being first duly sworn on his oath, states:

1. My name is Mark J. Peters. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a Ameren Missouri as Manager, Asset & Trading Optimization in the Corporate Planning Function.

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 14 pages, and Schedules MJP-1 HC through MJP-5 HC, 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.

Mark J. Peters

Subscribed and sworn to before me this 1st day of July, 2016.

Julie Irby
Notary Public

My commission expires:

Julie Irby - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #13753418
My Commission Expires 1/15/2017

Schedules MJP 1-5 HC

are **HIGHLY CONFIDENTIAL**

in their entirety

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