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Issue(s):	Production Cost Model
Witness:	S. Hande Berk
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2019-0335
Date Testimony Prepared:	July 3, 2019

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2019-0335

DIRECT TESTIMONY

OF

S. HANDE BERK

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

****DENOTES CONFIDENTIAL INFORMATION****

St. Louis, Missouri
July 2019

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OF

S. HANDE BERK

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I. INTRODUCTION

Q. Please state your name and business address.

A. S. Hande Berk, One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

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

A. I am employed by Ameren Services Company ("Ameren Services") as Manager, Electric Resource Planning. Ameren Services provides various corporate support services to Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company") and its affiliates such as accounting, finance, treasury, human resources, and planning, including resource planning.

Q. Please describe your educational and professional background.

A. I received a Bachelor of Science degree in Economics from Orta Doğu Teknik Üniversitesi in Ankara, Turkey in June of 2000 and a Master of Science degree in Economics and Finance from Southern Illinois University Edwardsville in August of 2002. I joined the Corporate Planning Department of Ameren Services as a Forecasting and Load Research Specialist in July of 2003. I was responsible for electricity and gas sales and peak demand forecasts, weather normalization, load research data management and analysis to support cost of service studies and electric rate design, and monthly economic outlook reports for senior management. In September of 2008, I became a Corporate Planning

Analyst. My responsibilities included fuel budgeting for Ameren Missouri's generating fleet, benchmarking and calibrating the MIDAS tool used for long-term resource planning analysis to Ameren Missouri's fuel budget, and modeling and analyzing the alternative resource plans in Ameren Missouri's 2011 Integrated Resource Plan ("IRP") filing. I was promoted to Senior Corporate Planning Analyst in October of 2011, and I led the efforts for Ameren Missouri's 2012 IRP Annual Update in that capacity. I became a Senior Corporate Model Specialist in December of 2011. My duties included financial forecasting, monthly margin analysis, analysis support for Ameren Corporation's divestiture of Ameren Energy Resources and project evaluation. I was transferred back to the Corporate Analysis group in June of 2013 as a Senior Corporate Planning Analyst. I was the project lead on Ameren Missouri's 2014 and 2017 IRP filings. I developed the revenue requirements model that replaced MIDAS, in addition to overseeing all of the assumptions and analyses used in the filings. I was promoted to Manager, Electric Resource Planning in January of 2019 and am responsible for long-term resource planning-related analyses and fuel budgeting.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

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 the delivered cost of nuclear fuel, coal, oil, and natural gas associated with producing electricity from the Ameren Missouri generation fleet, plus the variable component of net purchased power.

Ameren Missouri witness Andrew Meyer is also filing direct testimony to address other FAC components, including net off-system sales revenues which are netted against the costs that I have modeled and used by Ms. Moore in determining NBEC, and he also addresses the transmission charges and revenues to be included in the FAC.

My testimony will also include the determination of a real-time load and generation deviation adjustment that has been included in the determination of NBEC over the last several Ameren Missouri electric rate cases.

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 $650.1 million and net purchased power costs are $21.6 million.

The normalized annual value for the real-time load and generation deviation adjustment is a credit (reduction of cost) of $9.4 million.

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 tariff sheets.[1] As noted, the NBEC is discussed in Ms. Moore's direct testimony.

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

A. 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 analyses, 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 are: 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.

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

A. The major outputs are: 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. In this manner, 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 the Company's market settlements with the Midcontinent Independent System Operator, Inc.'s ("MISO") markets. In actual operations, the Company purchases energy for its entire load from the MISO market and separately sells all of the MWhs generated by its 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 exceeds 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 January 1, 2018 through December 31, 2018.

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 SHB-D1 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 as compared to the modeling submitted in the Company's last electric rate case?

A. Yes. Minimum load levels for Labadie Units 1-2 have been lowered, while minimum load levels for Meramec Unit 4, Rush Island Unit 2, and Sioux Units 1-2 have been increased based on recent operating experience. A second change is that the Kirksville combustion turbine generator ("CTG") has been excluded from modeling as a result of its retirement in 2018. Additionally, the methodology used by Staff witness Shawn Lange in Ameren Missouri's last electric rate proceeding, File No. ER-2016-0179, for hourly hydroelectric generation profiles was adopted to estimate Keokuk and Osage hourly generation.

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 SHB-D2. 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 January 1, 2013 and December 31, 2018. The outage assumption for the Callaway Energy Center was based on an annualized average of the four most recent re-fueling outages: outages 19 through 22.

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 SHB-D3. 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 January 1, 2013 and December 31, 2018, and is reflected in Schedule SHB-D4.

A unit de-rate occurs when a generating unit cannot reach its maximum output due to operational considerations. The magnitude of the de-rating 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 January 1, 2013 and December 31, 2018, and is reflected in Schedule SHB-D5.

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, 2018;
- The nuclear fuel cost assumption is based on the average nuclear fuel cost associated with Callaway Refuel 23;
- The incremental coal cost assumptions are based on the average spot market prices for the 36-month period ending December 31, 2018; and
- The average (accounting) coal cost assumptions reflect coal and transportation costs based upon coal and transportation prices that will be effective for 2020.

We have not included a cost assumption for landfill gas, as 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, 2019. 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.

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

A. The deviation was calculated in a manner consistent with what was used in File No. ER-2016-0179, using data for the 36 months ending December 31, 2018. As with the calculation in File No. ER-2016-0179, 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 that occur separately from the economic dispatch process, and for which they receive Revenue Sufficiency Guarantee Make-Whole Payments.

The Taum Sauk Energy Center is excluded from the calculation due to the manner in which these generating 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[2] to pump water back up 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 a result, 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. Does this complete your direct testimony?

A. Yes, it does.

[2] 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.

SCHEDULE SHB-D1

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SCHEDULE SHB-D2

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SCHEDULE SHB-D3

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SCHEDULE SHB-D4

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SCHEDULE SHB-D5

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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 Decrease Its Revenues for Electric Service.	)))	File No. ER-2019-0335

AFFIDAVIT OF S. HANDE BERK

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

S. Hande Berk, being first duly sworn on her oath, states:

1. My name is S. Hande Berk. I work in the City of St. Louis, Missouri, and I am employed by Ameren Services Company as Manager, Electric Resource Planning.

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 11 pages and Schedule(s) SHB-D1 to SHB-D5, 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.

Sefika Hande Berk
S. Hande Berk

Subscribed and sworn to before me this 27th day of June, 2019.

Geri A. Best
Notary Public

My commission expires:

GERI A. BEST
Notary Public - Notary Seal
State of Missouri
Commissioned for St. Louis County
My Commission Expires: February 15, 2022
Commission Number: 14839811