Exhibit No.:	
Issue:	Rate Design
Witness:	James R. Dauphinais
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Noranda Aluminum, Inc.
Case No.:	EC-2014-____
Date Testimony Prepared:	February 7, 2014

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Noranda Aluminum, Inc.'s Request for Revisions to Union Electric Company d/b/a Ameren Missouri's Large Transmission Service Tariff to Decrease its Rate for Electric Service	)	**Case No. EC-2014-____**

Direct Testimony and Schedules of

James R. Dauphinais

On behalf of

Noranda Aluminum, Inc.

February 7, 2014

BRUBAKER & ASSOCIATES, INC.

Noranda Exhibit No. 13
Date 6-16-14 Reporter XF
File No. EC-2014-0224

Project 9851

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Noranda Aluminum, Inc.'s Request for Revisions to Union Electric Company d/b/a Ameren Missouri's Large Transmission Service Tariff to Decrease its Rate for Electric Service)	Case No. EC-2014-____

STATE OF MISSOURI)
) SS
COUNTY OF ST. LOUIS)

Affidavit of James R. Dauphinais

James R. Dauphinais, being first duly sworn, on his oath states:

1. My name is James R. Dauphinais. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by Noranda Aluminum, Inc. in this proceeding on its behalf.

2. Attached hereto and made a part hereof for all purposes are my direct testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. EC-2014-____.

3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things that they purport to show.

James R. Dauphinais
James R. Dauphinais

Subscribed and sworn to before me this 6th day of February, 2014.

MARIA E. DECKER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis City
My Commission Expires: May 5, 2017
Commission # 13706793

Maria E. Decker
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Noranda Aluminum, Inc.'s Request for Revisions to Union Electric Company d/b/a Ameren Missouri's Large Transmission Service Tariff to Decrease its Rate for Electric Service	Case No. EC-2014-____

Direct Testimony of James R. Dauphinais

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Managing Principal of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A This testimony is presented on behalf of Noranda Aluminum, Inc. ("Noranda").

Q HAVE YOU PRESENTED TESTIMONY IN PRIOR PROCEEDINGS BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION ("COMMISSION")?

A Yes. I have been involved in a number of proceedings before the Commission including, but not limited to, Case Nos. ER-2007-0002, ER-2008-0318, ER-2010-0036, ER-2011-0028 and ER-2012-0166, where I testified with respect to the fuel cost, off-system sales and transmission revenues and expenses of Union Electric Company ("Ameren Missouri").

Q WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A The purpose of my direct testimony is to present my estimate of the annual reduction in Actual Net Energy Cost ("ANEC") that Ameren Missouri would experience if Noranda's New Madrid facilities were to shut down. This reduction in ANEC would partially offset the retail revenues Ameren would lose from such a shutdown. A shutdown of the Noranda facilities would eliminate Ameren Missouri's need to generate and purchase power to serve those facilities. Essentially, this would increase the revenues Ameren Missouri receives from off-system sales and decrease its purchased power and transmission service expenses.

These increased revenues and decreased expenses will manifest themselves through a reduction in Ameren Missouri's ANEC. However, as shown in Mr. Brubaker's direct testimony, this cost reduction is significantly less than the retail revenues Ameren Missouri would lose from a shutdown of the Noranda facilities.

Q PLEASE EXPLAIN THE TERM ANEC.

A ANEC is the term used in Ameren Missouri's Rider FAC to describe the portion of its revenue requirement that is tracked through its Fuel Adjustment Clause ("FAC"). Ameren Missouri's ANEC consists of four major components:

1. **FC** – Fuel costs for Ameren Missouri's generation facilities (as detailed on Sheet 72.1 of Rider FAC).

Plus

2. **PP** – Purchased power costs and revenues including non-administrative Midcontinent Independent System Operator, Inc. ("MISO") market purchase settlements and transmission settlements (as detailed on Sheets 72.1 through 72.3 of Rider FAC).

Plus

3. **E** – Costs and Revenues for SO_2 and NO_X emission (as detailed on Sheet 72.4 of Rider FAC).

Less

4. **OSSR** – Off-system sales revenues (as detailed on Sheet 72.4 of Rider FAC).

For the convenience of the Commission, I have provided a complete copy of Ameren Missouri's Rider FAC that is currently in effect (FAC Rider Sheets 72 and 72.1 through 72.9) in Schedule JRD-1.

Q WHAT IS YOUR ESTIMATE OF THE ANNUAL REDUCTION IN ANEC THAT AMEREN MISSOURI WOULD EXPERIENCE IF NORANDA'S NEW MADRID FACILITIES WERE SHUT DOWN?

A I estimate that Ameren Missouri's ANEC would be reduced by approximately $112.8 million per year if Noranda's New Madrid facilities were shut down.[1] This is an ANEC savings to Ameren Missouri of approximately $27.05 per MWh of reduced retail sales to Noranda.

Q PLEASE EXPLAIN HOW YOU DEVELOPED THIS ESTIMATE.

A I assumed electric sales to Noranda of approximately 4,169,000 MWh per year with a load factor of 98% and a coincidence factor of 100%. I next made a conservative simplifying assumption that market clearing prices in the MISO (including Locational

[1]This includes approximately $111.02 million in reduced net energy, transmission loss and congestion costs ("Net Fuel Cost"); approximately $0.20 million in reduced net capacity costs; and approximately $1.54 million in reduced regional transmission service costs.

Marginal Prices) would be negligibly affected by the loss of these retail sales by Ameren Missouri. I then estimated the annual dollars Ameren Missouri would avoid by not having to clear these retail sales in its market and transmission settlements with MISO for its load. In doing so, I used recent historical MISO market clearing prices and the current forecasted regional transmission charge rates for 2014 under the MISO Tariff. The details of my calculations are presented in Schedule JRD-2.

Q DID YOU PERFORM ANY PRODUCTION COST SIMULATIONS TO DEVELOP OUR ESTIMATE?

A No. Because of Ameren Missouri's participation in the MISO market and my conservative simplifying assumption that MISO market clearing prices would be negligibly affected by Ameren Missouri's loss of its retail sales to Noranda, it was not necessary to use production cost simulations to estimate the reduction in ANEC that Ameren Missouri would experience from the loss of its retail sales to Noranda. It can instead be estimated by applying recent historical MISO market prices and current forecasted MISO regional transmission rates for 2014 to the MW and MWh sales to Noranda.

Q PLEASE EXPLAIN WHY THIS IS SO.

A As a participant in the MISO Regional Transmission Organization ("RTO"), Ameren Missouri must clear all of its generation and all of its load in the MISO market. Ameren Missouri's generation clears in the MISO market based on the offer price Ameren Missouri submits for each of its generators to produce energy (or provide capacity) and the market prices set by MISO. Those market prices are set by MISO based on: (i) the generation offers of Ameren Missouri and all other MISO market participants; and (ii) the total load within the MISO market that needs to be served. As a result, the clearing of Ameren Missouri's generation facilities in the MISO market (including the commitment and dispatch of those generation facilities) would not be affected by Ameren Missouri's loss of retail sales to Noranda unless MISO market prices changed enough to influence that clearing as a result of the loss of those retail sales by Ameren Missouri.

Because the loss of Ameren Missouri's retail sales to Noranda would negligibly affect MISO market clearing prices in most hours of the year and act to lower those prices when there is more than a negligible effect, it can be reasonably and conservatively assumed that Ameren Missouri's market settlements for its generation facilities are unaffected by the loss of those retail sales. Thus, the reduction in Ameren Missouri's ANEC can be reasonably and conservatively estimated as the cost avoided by Ameren Missouri by not having to clear the Noranda retail sales in its MISO market and transmission settlements for its load. This can be calculated using recent historical MISO market prices and current forecasted regional transmission rates for 2014 under the MISO Tariff.

Q **CAN YOU PROVIDE A SIMPLE EXAMPLE TO ILLUSTRATE YOUR EXPLANATION?**

A Yes. Let us examine a simple example (that neglects transmission losses) involving the energy market in a single hour. Assume a utility has a retail load in this hour of 1,000 MW and the utility is participating in an RTO energy market that has a total load of 20,000 MW in this hour. Further, assume the utility has a single 1,000 MW generator that it is offering into the RTO market at $20 per MWh based on the fuel cost of that generation. Finally, assume that based on its 20,000 MW total load in that hour, the generation offer from the utility and the generation offers it receives from other market participants, the RTO sets the clearing price for energy (or Locational Marginal Price) in that hour at $30 per MWh and there is no transmission congestion in that hour.

Under these assumptions, the utility's generation facility would be fully dispatched (i.e., cleared) in that hour at 1,000 MW since its offer price of $20 per MWh is less than the Locational Marginal Price of $30 per MWh. In addition, the utility will in this hour have neither net purchased energy costs nor off-system energy sales revenues since in this hour the utility's cleared generation (1,000 MW) equals its cleared load (1,000 MW).

The utility's resulting generation settlements in that hour would be as follows:

RTO Generation Revenue = 1,000 MWh x $30 per MWh = $30,000

The utility's load settlements in that hour would be:

RTO Load Expense = 1,000 MWh x $30 per MWh = $30,000

The utility's fuel cost for its generation facility would be:

Generation Fuel Cost = 1,000 MWh x $20 per MWh = $20,000

The utility's Net Fuel Cost (generation fuel cost plus net purchased energy cost less off-system energy sales revenues) in that hour would be:

Generation Fuel Cost	$20,000
plus RTO Load Expense	$30,000
less RTO Generation Revenue	<u>$30,000</u>
Net Fuel Cost	$20,000

Now, assume the utility had 100 MWh lower retail sales in that hour. Also, now assume the resulting 100 MWh drop of the RTO's total load in that hour from 20,000 MWh to 19,900 MWh did not change the $30 per MWh Locational Marginal

Price in that hour. In this case, the utility's generation would still be fully dispatched at 1,000 MW of output because its $20 per MWh offer price is still less than the $30 per MWh Locational Marginal Price. As a result, the utility's MISO generation revenue of $30,000 and generation fuel cost of $20,000 would remain unchanged despite the utility losing 100 MWh of retail sales. The only thing that would change is that the utility will clear 900 MWh of retail load rather than 1,000 MWh of retail load in the RTO market. The utility will continue to have no net purchased energy cost, but will now have a 100 MWh net off-system energy sale because in this hour it is clearing 1,000 MWh of generation but only clearing 900 MWh of retail load. Thus, the utility's load settlement in the RTO market for this hour will become:

RTO Load Expense = 900 MWh x $30 per MWh = $27,000

And, the utility's Net Fuel Cost in this hour will become:

Generation Fuel Cost	$20,000
plus RTO Load Expense	$27,000
less RTO Generation Revenue	<u>$30,000</u>
Net Fuel Cost	$17,000

This is a $3,000 reduction in the utility's Net Fuel Cost for the hour that results from the utility's loss of 100 MWh of retail sales in that hour in this example. In the utility's accounting in this example, the $3,000 amount would appear as $3,000 of additional off-system energy sales margins.

Q **WOULD THE NET FUEL COST SAVINGS ALWAYS APPEAR AS AN INCREASE IN OFF-SYSTEM ENERGY SALES MARGINS FOR THE UTILITY?**

A No. In my example, off-system energy sales increased by 100 MWh. If the same retail sales reduction in another hour decreased the utility's net purchase of energy by

100 MWh, the net fuel cost savings would appear in the utility's accounting as a reduction in the utility's net purchased energy costs rather than an increase in the utility's off-system energy sales. Thus, the Net Fuel Cost portion of my estimated $112.7 million reduction in Ameren Missouri's ANEC will manifest itself through the year as a combination of increased off-system energy sales margins and decreased net purchased energy costs.

Q ARE THE PRINCIPLES EXHIBITED IN THIS EXAMPLE FOR THE ENERGY MARKET GENERALLY APPLICABLE TO OTHER MISO MARKETS SUCH AS CAPACITY AND FOR MISO REGIONAL TRANSMISSION SERVICE CHARGES?

A Yes. With regard to capacity, the MISO conducts an annual capacity auction (the MISO Planning Resource Auction or "PRA"). Assuming a utility self-schedules all of its generation capacity into that auction, all of that utility's generation and load will clear in that auction at the capacity market clearing price. To the extent the utility has generation capacity in excess of its load requirements (including planning reserve margin and transmission losses), the loss of retail sales by that utility would increase its off-system capacity sales margins based on the capacity market clearing price. To the extent the utility has a deficit of generation capacity to meet its load requirements (including planning reserve margin and transmission losses), the loss of retail sales by that utility would decrease the utility's net purchased capacity cost based on the capacity market clearing price.

With regard to regional transmission service charges, the cost savings will be the lost retail sales applied to current MISO regional transmission rates. These savings will always appear in the utility's accounting as a reduction in the utility's regional transmission charges.

Q IS IT TRULY REASONABLE AND CONSERVATIVE TO ASSUME, AS YOU HAVE, THAT THE SHUTDOWN OF NORANDA'S NEW MADRID FACILITIES WOULD HAVE A NEGLIGIBLE EFFECT ON MISO MARKET PRICES?

A Yes, in the context of how my estimate is being utilized in this proceeding it is reasonable and conservative. Specifically, the loss of Ameren Missouri's sales to Noranda due to a shutdown of Noranda's New Madrid facilities would remove the load associated with those sales from the Ameren Missouri load zone in the MISO market. If such a reduction in demand had any impact on market prices, it would be to lower the market prices in the Ameren Missouri load zone, the market prices at the generation nodes of Ameren Missouri's generation facilities and potentially market prices at other generation nodes and load zones within MISO.

As a result, an assumption that market prices will remain unchanged by a shutdown of Noranda's New Madrid facilities may slightly overstate the ANEC reduction that would be experienced by Ameren Missouri. However, this is conservative in the context of this proceeding because my estimate of ANEC is being subtracted by my colleague, Mr. Brubaker, from the lost retail revenues in order to estimate the resulting loss of contribution to Ameren Missouri's fixed costs that would result from a Noranda shutdown. As a result, any overstatement of a reduction in Ameren Missouri's ANEC translates into an understatement of lost contribution from Noranda toward Ameren Missouri's fixed costs.

In addition, it is likely that the loss of retail sales to Noranda has a negligible effect on prices except during very high (or very low) load hours in the MISO market or when transmission congestion is significantly elevating or depressing prices in the Ameren Missouri load zone and at the Ameren Missouri generation nodes. The reason is that Noranda's peak demand of just under 500 MW is less than 0.4% of the total annual system peak load of the MISO market which is in excess of 125,000 MW.[2] As a result, in most hours of the year the loss of the Noranda sales will have a negligible impact on MISO market prices. Only during hours when there is significant transmission congestion or MISO-wide scarcity (due to either near annual MISO peak load conditions or near annual MISO minimum load conditions) will there likely be a significant drop in the relevant MISO market prices due to the loss of just under 500 MW of load demand.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

[2]The historical MISO market region peak load (inclusive of the new MISO South area) was 126,337 MW on July 20, 2011 (*MISO Corporate Information*, January 2014).

Qualifications of James R. Dauphinais

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017, USA.

Q **PLEASE STATE YOUR OCCUPATION.**

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q **PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I graduated from Hartford State Technical College in 1983 with an Associate's Degree in Electrical Engineering Technology. Subsequent to graduation I was employed by the Transmission Planning Department of the Northeast Utilities Service Company as an Engineering Technician.

While employed as an Engineering Technician, I completed undergraduate studies at the University of Hartford. I graduated in 1990 with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation, I was promoted to the position of Associate Engineer. Between 1993 and 1994, I completed graduate level courses in the study of power system transients and power system protection through the Engineering Outreach Program of the University of Idaho. By 1996 I had been promoted to the position of Senior Engineer.

In the employment of the Northeast Utilities Service Company, I was responsible for conducting thermal, voltage and stability analyses of the Northeast

Utilities' transmission system to support planning and operating decisions. This involved the use of load flow, power system stability and production cost computer simulations. It also involved examination of potential solutions to operational and planning problems including, but not limited to, transmission line solutions and the routes that might be utilized by such transmission line solutions. Among the most notable achievements I had in this area include the solution of a transient stability problem near Millstone Nuclear Power Station, and the solution of a small signal (or dynamic) stability problem near Seabrook Nuclear Power Station. In 1993 I was awarded the Chairman's Award, Northeast Utilities' highest employee award, for my work involving stability analysis in the vicinity of Millstone Nuclear Power Station.

From 1990 to 1996, I represented Northeast Utilities on the New England Power Pool Stability Task Force. I also represented Northeast Utilities on several other technical working groups within the New England Power Pool ("NEPOOL") and the Northeast Power Coordinating Council ("NPCC"), including the 1992-1996 New York-New England Transmission Working Group, the Southeastern Massachusetts/Rhode Island Transmission Working Group, the NPCC CPSS-2 Working Group on Extreme Disturbances and the NPCC SS-38 Working Group on Interarea Dynamic Analysis. This latter working group also included participation from a number of ECAR, PJM and VACAR utilities.

From 1990 to 1995, I also acted as an internal consultant to the Nuclear Electrical Engineering Department of Northeast Utilities. This included interactions with the electrical engineering personnel of the Connecticut Yankee, Millstone and Seabrook nuclear generation stations and inspectors from the Nuclear Regulatory Commission ("NRC").

In addition to my technical responsibilities, from 1995 to 1997, I was also responsible for oversight of the day-to-day administration of Northeast Utilities' Open Access Transmission Tariff. This included the creation of Northeast Utilities' pre-FERC Order No. 889 transmission electronic bulletin board and the coordination of Northeast Utilities' transmission tariff filings prior to and after the issuance of Federal Energy Regulatory Commission ("FERC" or "Commission") FERC Order No. 888. I was also responsible for spearheading the implementation of Northeast Utilities' Open Access Same-Time Information System and Northeast Utilities' Standard of Conduct under FERC Order No. 889. During this time I represented Northeast Utilities on the Federal Energy Regulatory Commission's "What" Working Group on Real-Time Information Networks. Later I served as Vice Chairman of the NEPOOL OASIS Working Group and Co-Chair of the Joint Transmission Services Information Network Functional Process Committee. I also served for a brief time on the Electric Power Research Institute facilitated "How" Working Group on OASIS and the North American Electric Reliability Council facilitated Commercial Practices Working Group.

In 1997 I joined the firm of Brubaker & Associates, Inc. The firm includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business. Since my employment with the firm, I have filed or presented testimony before the Federal Energy Regulatory Commission in Consumers Energy Company, Docket No. OA96-77-000, Midwest Independent Transmission System Operator, Inc., Docket No. ER98-1438-000, Montana Power Company, Docket No. ER98-2382-000, Inquiry Concerning the Commission's Policy on Independent System Operators, Docket No. PL98-5-003, SkyGen Energy LLC v. Southern Company Services, Inc., Docket No. EL00-77-000, Alliance Companies, et al., Docket No. EL02-65-000, et al., Entergy Services, Inc., Docket No.

ER01-2201-000, and Remedying Undue Discrimination through Open Access Transmission Service, Standard Electricity Market Design, Docket No. RM01-12-000, Midwest Independent Transmission System Operator, Inc., Docket No. ER10-1791-000 and NorthWestern Corporation, Docket No. ER10-1138-001, et al. I have also filed or presented testimony before the Alberta Utilities Commission, Colorado Public Utilities Commission, Connecticut Department of Public Utility Control, Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the Kentucky Public Service Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the Missouri Public Service Commission, the Montana Public Service Commission, the Council of the City of New Orleans, the Public Utility Commission of Texas, the Wisconsin Public Service Commission and various committees of the Missouri State Legislature. This testimony has been given regarding a wide variety of issues including, but not limited to, ancillary service rates, avoided cost calculations, certification of public convenience and necessity, cost allocation, fuel adjustment clauses, fuel costs, generation interconnection, interruptible rates, market power, market structure, off-system sales, prudency, purchased power costs, resource planning, rate design, retail open access, standby rates, transmission losses, transmission planning and transmission line routing.

I have also participated on behalf of clients in the Southwest Power Pool Congestion Management System Working Group, the Alliance Market Development Advisory Group and several working groups of the Midcontinent Independent System Operator, Inc. ("MISO"), including the Congestion Management Working Group and Supply Adequacy Working Group. I am currently an alternate member of the MISO Advisory Committee in the end-use customer sector on behalf of a group of industrial end-use customers in Illinois. I am also the past Chairman of the Issues/Solutions Subgroup of the MISO Revenue Sufficiency Guarantee ("RSG") Task Force.

In 2009, I completed the University of Wisconsin-Madison High Voltage Direct Current ("HVDC") Transmission course for Planners that was sponsored by MISO. I am a member of the Power and Energy Society ("PES") of the Institute of Electrical and Electronics Engineers ("IEEE").

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

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RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE

(Applicable To Service Provided On January 2, 2013 And Thereafter)

APPLICABILITY

This rider is applicable to kilowatt-hours (kWh) of energy supplied to customers served by the Company under Service Classification Nos. 1(M), 2(M), 3(M), 4(M), 5(M), 6(M), 7(M), 11(M), and 12(M).

Costs passed through this Fuel and Purchased Power Adjustment Clause (FAC) reflect differences between actual fuel and purchased power costs, including transportation and emissions costs and revenues, net of off-system sales revenues (OSSR) (i.e., Actual Net Energy Costs (ANEC)) and Net Base Energy Costs (B), calculated and recovered as provided for herein.

The Accumulation Periods and Recovery Periods are as set forth in the following table:

Accumulation Period (AP)	Recovery Period (RP)
February through May	October through May
June through September	February through September
October through January	June through January

AP means the four (4) calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate (FAR).

RP means the billing months during which the FAR is applied to retail customer usage on a per kWh basis, as adjusted for service voltage.

The Company will make a FAR filing no later than sixty (60) days prior to the first billing cycle read date of the applicable Recovery Period above. All FAR filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

FAR DETERMINATION

Ninety five percent (95%) of the difference between ANEC and B for each respective AP will be utilized to calculate the FAR under this rider pursuant to the following formula with the results stated as a separate line item on the customers' bills.

Issued pursuant to the Order of the MoPSC in Case No. ER-2012-0166.

DATE OF ISSUE May 31, 2013 DATE EFFECTIVE June 30, 2013

ISSUED BY Warner L. Baxter President & CEO St. Louis, Missouri
NAME OF OFFICER TITLE ADDRESS

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On January 2, 2013 And Thereafter)

FAR DETERMINATION (Cont'd.)

For each FAR filing made, the FAR_{RP} is calculated as:

$$FAR_{RP} = [(ANEC - B) \times 95\% + I \pm P \pm T]/S_{RP}$$

Where:

ANEC = FC + PP + E − OSSR

FC = Fuel costs and revenues associated with the Company's generating plants. These consist of the following:

1. For fossil fuel plants:
   A. the following costs and revenues (including applicable taxes) reflected in Federal Energy Regulatory Commission (FERC) Account 501 for: coal commodity, gas, alternative fuels, fuel additives, Btu adjustments assessed by coal suppliers, quality adjustments related to the sulfur content of coal assessed by coal suppliers, railroad transportation, switching and demurrage charges, railcar repair and inspection costs, railcar depreciation, railcar lease costs, similar costs associated with other applicable modes of transportation, fuel hedging costs, fuel oil adjustments included in commodity and transportation costs, oil costs, ash disposal costs and revenues, and revenues and expenses resulting from fuel and transportation portfolio optimization activities; and
   B. the following costs and revenues reflected in FERC Account 502 for: consumable costs related to Air Quality Control System (AQCS) operation, such as urea, limestone and powder activated carbon; and
   C. the following costs and revenues reflected in FERC Account 547 for: natural gas generation costs related to commodity, oil, transportation, storage, capacity reservation , fuel losses, hedging, and revenues and expenses resulting from fuel and transportation portfolio optimization activities; and
2. Costs and revenues in FERC Account 518 (Nuclear Fuel Expense), including nuclear fuel commodity and waste disposal expense, and nuclear fuel hedging costs.

PP = Purchased power costs and revenues and consists of the following:

1. Costs and revenues for purchased power reflected in FERC Accounts 555 and 575, excluding all charges under Midwest Independent Transmission System Operator, Inc. ("MISO") Schedules 10, 16, 17 and 24 (or any successor to those MISO Schedules), and excluding generation capacity charges for contracts with terms in excess of one (1) year. Such costs and revenues include:

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On January 2, 2013 And Thereafter)

FAR DETERMINATION (Cont'd.)

A. MISO costs or revenues for MISO's energy and operating reserve market settlement charge types and capacity market settlement clearing costs or revenues associated with:
   i. Energy;
   ii. Losses;
   iii. Congestion management including:
      a. Congestion;
      b. Financial Transmission Rights; and
      c. Auction Revenue Rights;
   iv. Generation capacity acquired in MISO's capacity auction or market; provided such capacity is acquired for a term of one (1) year or less;
   v. Revenue sufficiency guarantees;
   vi. Revenue neutrality uplift;
   vii. Net inadvertent energy distribution amounts;
   viii. Ancillary Services, including:
      a. Regulating reserve service (MISO Schedule 3, or its successor);
      b. Energy imbalance service (MISO Schedule 4, or its successor);
      c. Spinning reserve service (MISO Schedule 5, or its successor);and
      d. Supplemental reserve service (MISO Schedule 6, or its successor); and
   ix. Demand response, including:
      a. Demand response allocation uplift; and
      b. Emergency demand response cost allocation (MISO Schedule 30, or its successor);

B. Non-MISO costs or revenues as follows:
   i. If received from a centrally administered market (e.g. PJM/SPP), costs or revenues of an equivalent nature to those identified for the MISO costs or revenues specified in subpart A of part 1 above;
   ii. If not received from a centrally administered market:
      a. Costs for purchases of energy; and
      b. Costs for purchases of generation capacity, provided such capacity is acquired for a term of one (1) year or less; and

Schedule JRD-1
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RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On January 2, 2013 And Thereafter)

FAR DETERMINATION (Cont'd.)

C. Realized losses and costs (including broker commissions and fees) minus realized gains for financial swap transactions for electrical energy that are entered into for the purpose of mitigating price volatility associated with anticipated purchases of electrical energy for those specific time periods when the Company does not have sufficient economic energy resources to meet its native load obligations, so long as such swaps are for up to a quantity of electrical energy equal to the expected energy shortfall and for a duration up to the expected length of the period during which the shortfall is expected to exist; and

2. Insurance premiums in FERC Account 924 for replacement power insurance. Costs of purchased power will be reduced by expected replacement power insurance recoveries qualifying as assets under Generally Accepted Accounting Principles; and

3. All transmission service costs reflected in FERC Account 565 and all transmission service revenues reflected in FERC Account 456.1. Such transmission service costs and revenues include:
   A. MISO costs and revenues associated with:
      i. network transmission service (MISO Schedule 9 or its successor);
      ii. point-to-point transmission service (MISO Schedules 7 and 8 or their successors);
      iii. System control and dispatch, (MISO Schedule 1 or its successor);
      iv. Reactive supply and voltage control (MISO Schedule 2 or its successor);
      v. MISO Schedule 11 or its successor;
      vi. MISO Schedules 26, 26A, 37 and 38 or their successors; and
      vii. MISO Schedule 33;
   B. Non-MISO costs associated with:
      i. network transmission service;
      ii. point-to-point transmission service;
      iii. System control and dispatch; and
      iv. Reactive supply and voltage control.

Schedule JRD-1
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RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On January 2, 2013 And Thereafter)

FAR DETERMINATION (Cont'd.)

E = Costs and revenues for SO_2 and NO_x emissions allowances in FERC Accounts 411.8, 411.9, and 509, including those associated with hedging.

OSSR = Costs and revenues in FERC Account 447 for:

1. Capacity;
2. Energy;
3. Ancillary services, including:
   A. Regulating reserve service (MISO Schedule 3, or its successor);
   B. Energy Imbalance Service (MISO Schedule 4, or its successor;
   C. Spinning reserve service (MISO Schedule 5, or its successor); and
   D. Supplemental reserve service (MISO Schedule 6, or its successor);
4. Make-whole payments, including:
   A. Price volatility; and
   B. Revenue sufficiency guarantee; and
5. Hedging.

Adjustment For Reduction of Service Classification 12(M) Billing Determinants:

Should the level of monthly billing determinants under Service Classification 12(M) fall below the level of normalized 12(M) monthly billing determinants as established in Case No. ER-2012-0166, an adjustment to OSSR shall be made in accordance with the following levels:

a) A reduction of less than 40,000,000 kWh in a given month

- No adjustment will be made to OSSR.

b) A reduction of 40,000,000 kWh or greater in a given month

- An adjustment excluding off-system sales revenue from OSSR will be made equal to the lesser of (1) all off-system sales revenues derived from all kWh of energy sold off-system due to the entire reduction, or (2) off-system sales revenues up to the reduction of 12(M) revenues compared to normalized 12(M) revenues as determined in Case No. ER-2012-0166.

Issued pursuant to the Order of the MoPSC in Case No. ER-2012-0166.
DATE OF ISSUE May 31, 2013 DATE EFFECTIVE June 30, 2013

ISSUED BY Warner L. Baxter President & CEO St. Louis, Missouri
NAME OF OFFICER TITLE ADDRESS

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On January 2, 2013 And Thereafter)

FAR DETERMINATION (Cont'd.)

For purposes of factors FC, E, and OSSR, "hedging" is defined as realized losses and costs (including broker commissions and fees associated with the hedging activities) minus realized gains associated with mitigating volatility in the Company's cost of fuel, off-system sales and emission allowances, including but not limited to, the Company's use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps.

Costs and revenues not specifically detailed in Factors FC, PP, E, or OSSR shall not be included in the Company's FAR filings; provided however, in the case of Factors PP or OSSR the market settlement charge types under which MISO or another centrally administered market (e.g., PJM or SPP) bills/credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the MISO or another centrally administered market (e.g. PJM or SPP) implement a market settlement charge type not listed in Exhibit H of the Non-Unanimous Stipulation and Agreement Regarding Class Kilowatt-Hours, Revenues And Billing Determinants, Net Base Energy Costs, and Fuel Adjustment Clause Tariff Sheets approved in Case No. ER-2012-0166 (a "new charge type"):

A. The Company may include the new charge type cost or revenue in its FAR filings if the Company believes the new charge type cost or revenue possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR, as the case may be, subject to another party's right to challenge the inclusion (or failure to include) as outlined in E. below;

B. The Company will include in its monthly reports required by the Commission's fuel adjustment clause rules notice of the new charge type no later than 60 days prior to the Company including the new charge type cost or revenue in a FAR filing. Such notice shall identify the proposed accounts affected by such change, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR as the case may be, and identify the preexisting market settlement charge type(s) which the new charge type replaces or supplements;

C. The Company will also provide notice in its monthly reports required by the Commission's fuel adjustment clause rules that identifies the new charge type costs or revenues by amount, description and location within the monthly reports;

D. The Company shall account for the new charge type costs or revenues in a manner which allows for the transparent determination of current period and cumulative costs or revenues; and

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On January 2, 2013 And Thereafter)

FAR DETERMINATION (Cont'd.)

E. If the Company includes a new charge type cost or revenue in a FAR filing and a party challenges the inclusion (or if the Company does not include a new charge type cost or revenue and a party challenges the failure to include it), such challenge will not delay approval of the FAR filing. To challenge the inclusion of a new charge type, a party shall make a filing with the Commission based upon that party's contention that the new charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. To challenge the failure to include a new charge type, a party shall make a filing with the Commission based upon that party's contention that the new charge type costs or revenues at issue should have been included, because they do possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. In the event of a challenge, the Company shall bear the burden of proof to support its decision to include or exclude or its failure to include or exclude a new charge type in a FAR filing. Should such challenge be upheld by the Commission, any such costs will refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P.

Should FERC require any item covered by factors FC, PP, E or OSSR to be recorded in an account different than the FERC accounts listed in such factors, such items shall nevertheless be included in factor FC, PP, E or OSSR. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through this Rider FAC are to be recorded in the account.

B = BF x S_{AP}

BF = The Base Factor, which is equal to the normalized value for the sum of allowable fuel costs (consistent with the term FC), plus cost of purchased power (consistent with the term PP), and emissions costs and revenues (consistent with the term E), less revenues from off-system sales (consistent with the term OSSR) divided by corresponding normalized retail kWh as adjusted for applicable losses. The normalized values referred to in the prior sentence shall be those values used to determine the revenue requirement in the Company's most recent rate case. The BF applicable to June through September calendar months (BF_{SUMMER}) is \$0.01496 per kWh. The BF applicable to October through May calendar months (BF_{WINTER}) is \$0.01454 per kWh.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On January 2, 2013 And Thereafter)

FAR DETERMINATION (Cont'd.)

S_{AP} = kWh during the AP that ended immediately prior to the FAR filing, as measured by taking the retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node), plus the kWh reductions up to the kWh of energy sold off-system associated with the 12(M) OSSR adjustment above plus the metered net energy output of any generating station operating within its certificated service territory as a behind the meter resource in MISO, the output of which served to reduce the Company's load settled at its MISO CP node (AMMO.UE or successor node).

S_{RP} = Applicable RP estimated kWh representing the expected retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node) plus the metered net energy output of any generating station operating within its certificated service territory as a behind the meter resource in MISO, the output of which served to reduce the Company's load settled at its MISO CP node (AMMO.UE or successor node).

I = Interest applicable to (i) the difference between ANEC and B for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews ("P"), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings ("T") provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest rate paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

P = Prudence disallowance amount, if any, as defined below.

T = True-up amount as defined below.

The FAR, which will be multiplied by the Voltage Adjustment Factors (VAF) set forth below is calculated as:

$$FAR = FAR_{RP} + FAR_{(RP-1)}$$

where:

FAR = Fuel Adjustment Rate applied to retail customer usage on a per kWh basis starting with the applicable Recovery Period following the FAR filing.

FAR_{RP} = FAR Recovery Period rate component calculated to recover under- or over-collection during the Accumulation Period that ended immediately prior to the applicable filing.

$FAR_{(RP-1)}$ = FAR Recovery Period rate component for the under- or over-collection during the Accumulation Period immediately preceding the Accumulation Period that ended immediately prior to the application filing for FAR_{RP}.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On January 2, 2013 And Thereafter)

FAR DETERMINATION (Cont'd.)

To determine the FAR applicable to the individual Service Classifications, the FAR determined in accordance with the foregoing will be multiplied by the following Voltage Adjustment Factors (VAF):

Secondary Voltage Service (VAF_{SEC})	1.0575
Primary Voltage Service (VAF_{PRI})	1.0252
Large Transmission Voltage Service (VAF_{TRAN})	0.9917

The FAR applicable to the individual Service Classifications shall be rounded to the nearest $0.00001 to be charged on a $/kWh basis for each applicable kWh billed.

TRUE-UP

After completion of each RP, the Company shall make a true-up filing on the same day as its FAR filing. Any true-up adjustments shall be reflected in T above. Interest on the true-up adjustment will be included in I above.

The true-up adjustments shall be the difference between the revenues billed and the revenues authorized for collection during the RP.

GENERAL RATE CASE/PRUDENCE REVIEWS

The following shall apply to this FAC, in accordance with Section 386.266.4, RSMo. and applicable Missouri Public Service Commission Rules governing rate adjustment mechanisms established under Section 386.266, RSMo:

The Company shall file a general rate case with the effective date of new rates to be no later than four years after the effective date of a Commission order implementing or continuing this FAC. The four-year period referenced above shall not include any periods in which the Company is prohibited from collecting any charges under this FAC, or any period for which charges hereunder must be fully refunded. In the event a court determines that this FAC is unlawful and all moneys collected hereunder are fully refunded, the Company shall be relieved of the obligation under this FAC to file such a rate case.

Prudence reviews of the costs subject to this FAC shall occur no less frequently than every eighteen months, and any such costs which are determined by the Commission to have been imprudently incurred or incurred in violation of the terms of this rider shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in P above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in I above.

Issued pursuant to the Order of the MoPSC in Case No. ER-2012-0166.
DATE OF ISSUE May 31, 2013 DATE EFFECTIVE June 30, 2013

ISSUED BY Warner L. Baxter President & CEO St. Louis, Missouri
NAME OF OFFICER TITLE ADDRESS

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

(Applicable To Calculation of Fuel Adjustment Rate for the Billing Months of February 2014 through May 2014)

*Calculation of Current Fuel Adjustment Rate (FAR):

Accumulation Period Ending:			September, 30, 2013
1.	Actual Net Energy Cost (ANEC) (FC+PP+E-OSSR)		$258,851,360
2.	Net Base Energy Cost (B)	-	$205,416,214
	2.1 Base Factor (BF)	x	$0.01496
	2.2 Accumulation Period Sales (S_{AP})		13,731,030,352 kWh
3.	Total Company Fuel and Purchased Power Difference	=	$53,435,146
	3.1 Customer Responsibility	x	95%
4.	Fuel and Purchased Power Amount to be Recovered	=	$50,763,390
	4.1 Interest (I)	+	$36,815
	4.2 True-Up Amount (T)	+	$105,339
	4.3 Prudence Adjustment Amount (P)	-	$26,667,727
5.	Fuel and Purchased Power Adjustment (FPA)	=	$24,237,817
6.	Estimated Recovery Period Sales (S_{RP})	÷	25,164,951,073 kWh
7.	Current Period Fuel Adjustment Rate (FAR_{RP})	=	$0.00096/kWh
8.	Prior Period Fuel Adjustment Rate (FAR_{RP-1})	+	$0.00159/kWh
9.	Fuel Adjustment Rate (FAR)	=	$0.00255/kWh
10.	Secondary Voltage Adjustment Factor (VAF_{SEC})		1.0575
11.	FAR for Secondary Customers (FAR_{SEC})		$0.00270/kWh
12.	Primary Voltage Adjustment Factor (VAF_{PRI})		1.0252
13.	FAR for Primary Customers (FAR_{PRI})		$0.00261/kWh
14.	Transmission Voltage Adjustment Factor (VAF_{TRAN})		0.9917
15.	FAR for Transmission Customers (FAR_{TRAN})		$0.00253/kWh

* Indicates Change.

Ameren Missouri
Missouri Public Service Commission Case No. EC-2014-____

Estimate of the Annual Reduction in Ameren Missouri's Actual Net Energy Cost ("ANEC")
Under a Noranda Shutdown

Major Components of Ameren Missouri Actual Net Energy Cost ("ANEC") Affected by Loss of Retail Sales to Noranda	Applicable Billing Units for Retail Sales to Noranda	Historical Market Price	Forecasted Rate	Estimated Annual Reduction in Ameren Missouri ANEC
Net Energy, Transmission Loss and Congestion Costs	4,169,000 MWh	$ 26.63 per MWh		$ 111,020,470
Net Capacity Costs	194,377 MW-days	$ 1.05 per MW-day		$ 204,096
MISO Tariff Schedule 26-A Multi-Value Project Usage Rate	4,169,000 MWh		$ 0.37 per MWh	$ 1,544,893
Total				$ 112,769,459
Total per MWh of sales to Noranda				$ 27.05 per MWh

Sources:

The Historical Market Price of $26.63 per MWh used for the Net Energy, Transmission Loss and Congestion Cost savings estimate is the around-the-clock average of the day-ahead hourly LMPs for the AECI.AMMO Node for the 12 months ending October 31, 2013 as posted on the MISO website.

The Historical Market Price of $1.05 per MW-day used for the Net Capacity Cost savings estimate is the market clearing price for Zonal Resource Credits (ZRCs) for Local Resource Zone 5 (Missouri) in the MISO's Planning Resource Auction for the MISO 2013/2014 Planning Year as reported by MISO on its website at https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=150145.

The Forecasted MISO Tariff Schedule 26-A rate of $0.37 per MWh is MISO's indicative Multi-Value Project (MVP) Schedule 26-A Annual Charge estimate for the Ameren Missouri Transmission Pricing Zone for 2014 as of August 6, 2013 as posted on the MISO website at www.misoenergy.org.

Notes:

Noranda Retail Sales assumed to be 4,169,000 MWh annually with a 98% Load Factor and 100% Annual Coincidence Factor.

194,377 MW-days = 4,169,000 MWh / 8,760 hours per year / 98% (Load Factor) / 100% (Annual Coincidence Factor) x 107.3% (UCAP Planning Reserve Margin) x 102.2% (MISO Transmission Losses) x 365 days per year

MISO Schedule 26-A charges are different than MISO Schedule 26 (Network Upgrade Charge From Transmission Expansion Plan) charges. A reduction in MISO Tariff Schedule 26 charges was not included in the ANEC savings estimate above because most of this MISO charge for Ameren Missouri currently consists of the cost recovery for Ameren Missouri's own transmission projects that are included in this rate whose costs are nearly entirely allocated to Ameren Missouri under MISO Schedule 26. As a result, unlike with MISO Schedule 26-A, the loss of retail sales to Noranda would only allow Ameren Missouri to avoid a very limited portion of MISO Schedule 26 charges.

There are other MISO market settlement charges that have not been included in the above estimate of ANEC savings. They were excluded either because they would not likely be significantly reduced for Ameren Missouri with the loss of retail sales to Noranda or they net to a small value when taken in aggregate with other smaller market settlement charges.