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Witness: Lena M. Mantle
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Case No.: ER-2012-0166
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MISSOURI PUBLIC SERVICE COMMISSION

REGULATORY REVIEW

SURREBUTTAL TESTIMONY

OF

LENA M. MANTLE

UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI

CASE NO. ER-2012-0166

Jefferson City, Missouri
September 2012

EXHIBIT 224

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service	)))	Case No. ER-2012-0166

AFFIDAVIT OF LENA M. MANTLE

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Lena M. Mantle, of lawful age, on her oath states: that she has participated in the preparation of the following Surrebuttal Testimony in question and answer form, consisting of 18 pages of Surrebuttal Testimony to be presented in the above case, that the answers in the following Surrebuttal Testimony were given by her; that she has knowledge of the matters set forth in such answers; and that such matters are true to the best of her knowledge and belief.

Lena M Mantle
Lena M. Mantle

Subscribed and sworn to before me this 16th day of September, 2012.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Susan L Sundermeyer
Notary Public

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UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI

CASE NO. ER-2012-0166

Q. Would you state your name and your business address?

A. My name is Lena M. Mantle. My business address is P.O. Box 360, Jefferson City, Missouri 65102.

Q. What is your present position with the Missouri Public Service Commission ("Commission")?

A. I am manager of the Energy Unit of the Tariff, Safety, Economic, and Engineering Analysis Department, Regulatory Review Division.

Q. Are you the same Lena M. Mantle who provided testimony in Staff's Cost of Service Report ("Staff Report")?

A. Yes, I am.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of Union Electric d/b/a Ameren Missouri ("Ameren Missouri" or "Company") regarding the continuation of the Ameren Missouri's fuel adjustment clause ("FAC"). In particular, I will respond to Ameren Missouri witnesses:

- Wilbon L. Cooper with respect to the base factor proposal
- Steven M. Wills with respect to proposed FAC tariff sheet language
- Robert K. Neff with respect to the future impact of the FAC sharing mechanism

- Jaime Haro with respect to the impact of the FAC sharing mechanism on off-system sales
- Lynn M. Barnes with respect to the impact of the FAC sharing mechanism.

Q. Do you have recommendations for the Commission?

A. In addition to the Staff recommendations in the Staff Report, Staff recommends that to avoid any confusion in the future, accounts and subaccounts of costs and revenues that flow through the FAC should be listed to the extent that they currently are not, on the FAC tariff sheets. In addition, the FAC tariff sheets should list the MISO schedule costs that are allowed to flow through the FAC. Any additional charges and/or revenues should only be added in a rate case where all parties have an opportunity to provide comment to the Commission.

Staff also recommends that the Commission require Ameren Missouri to provide account and subaccount detail in its monthly FAC submissions.

<u>Response to the Rebuttal Testimony of Jaime Haro</u>

Q. What is your overall response to Mr. Haro FAC rebuttal testimony?

A. In the Staff Report, Staff stated that it was recommending changes to the tariff sheet to help clarify the costs and revenues that flow through the FAC. At that point in time, the only driver for this recommendation was the different interpretation of Ameren Missouri and KCP&L Greater Missouri Operations Company ("GMO") FAC tariff sheets that became evident in Staff's FAC prudence reviews. One of those recommendations was that Ameren Missouri's tariff sheets clarify that only the transmission associated with off-system sales and purchased power be allowed to pass through the FAC. Only after the Staff Report was filed did Staff learn that Ameren Missouri was stating on its website regarding the Lutesville to

Heritage Transmission line[1] that Ameren Missouri intended to pass its costs of building the Lutesville to Heritage transmission line through the FAC. Mr. Haro defends passing the costs of building transmission lines through the FAC in his rebuttal testimony.

Q. How does Ameren Missouri intend to pass the costs of building the Lutesville-Heritage transmission line through the FAC?

A. In response to Staff data request no. 473, Ameren Missouri replied that:

> The MISO charges are assessed under Schedule 26 of the MISO's Tariff and are recorded in Account 565. Under the FAC tariff, costs recorded in Account 565 are included in the FAC calculations as part of Factor CPP.

Q. What is Factor CPP?

A. As stated in the currently effective tariff, CPP is defined as:

> Costs of purchased power reflected in FERC Account Numbers 555, 565, and 575, excluding MISO administrative fees arising under MISO Schedules 10, 16, 17, and 24, and excluding capacity charges for contracts with terms in excess of one (1) year, incurred to support sales to all Missouri retail customers and Off-System Sales allocated to Missouri retail electric operations. Also included in factor "CPP" are insurance premiums in FERC Account Number 924 for replacement power insurance to the extent those premiums are not reflected in base rates. Changes in replacement power insurance premiums from the level reflected in base rates shall increase or decrease purchased power costs. Additionally, costs of purchased power will be reduced by expected replacement power insurance recoveries qualifying as assets under Generally Accepted Accounting Principles.

Q. Did Staff ever agree that the costs of building transmission lines should flow through the FAC?

A. No, it did not. It is the position of Staff that the costs that flow through the FAC be fuel and purchased power costs incurred to provide energy to its customers. It is not a mechanism to flow transmission costs through.

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[1] http://www.lhtransmission.com/FAQs.htm

Q. How did Mr. Haro justify passing the costs of building transmission lines through the FAC?

A. On page 22 Mr. Haro states:

> …we are required to take network service from the MISO to serve our load and as part of taking that service we are billed certain transmission charges by the MISO, which are based upon the amount of load which we serve.
>
> Network service enables us to transmit energy acquired from the MISO market (including that injected by our own generators) to our customers. That service is governed by the MISO tariff and there are a variety of charges from the MISO which may be incurred as the result of utilizing that service. These charges are not ala carte – we cannot pick and choose which ones we have to pay. Even though they exist as distinct schedules, they are required charges if one is using the system to serve load, which we do.

Q. Just because MISO enables the transmission of energy to Ameren Missouri's customers, should Ameren be allowed to pass the cost of building transmission through the FAC?

A. No, it should not. Just because a cost is incurred to deliver energy to Ameren Missouri customers, does not mean the cost should flow through the FAC. There are other costs that Ameren Missouri incurs to deliver energy to its customers that do not pass through the FAC. A case could be made that easement and franchise fees are necessary for delivery of energy but, to Staff's current knowledge, these costs are not flowed through the FAC. MISO costs to deliver energy are included in Staff's revenue requirement in this case.

Q. Does Mr. Haro give any other reasons for including such MISO costs?

A. Yes, he does. On page 23 he states:

> As net sellers, we expect to obtain a net margin for our excess generation which we could not reasonably expect to obtain as a stand-alone entity or as a member of another entity without an organized market. Since the revenues from these sales are credited against our fuel costs, our customers are receiving the benefit (or 95% of the benefit) of these enhanced sales. Fluctuations in these revenues from those used to establish the base NBFC are properly accounted for in the FAC.

> I am unaware of anyone arguing for, or even hinting at removing from the FAC the benefits which exist because of our MISO membership. However, the Staff's proposed language may reflect a suggestion that we should now cease accounting for some subset of transmission charges within the FAC, even though MISO transmission charges are required as a function of the very same market participation that is delivering the market-based benefits to customers. That is inequitable and unreasonable.

Q. Just because MISO enables Ameren Missouri to make revenues from off-system sales which are then passed through to customers, should Ameren be allowed to pass the cost of building transmission through the FAC?

A. No, it should not. Just because a MISO is necessary to make revenues from off-system sales that are passed on to Ameren Missouri customers, does not mean the cost of building transmission should flow through the FAC. There are other costs that Ameren Missouri incurs to make off-system sales that do not pass through the FAC. Ameren Missouri uses the services of several Ameren Services employees to make off-system sales but, to Staff's current knowledge, these costs are not flowed through the FAC.

Q. Is Staff seeking to exclude all MISO charges?

A. No, it is not. Staff is recommending that the Commission not allow cost of building transmission lines flow through the FAC.

Q. Does Staff agree with Mr. Haro that the charges from Entergy to serve Ameren Missouri's customers in the bootheel should flow through the FAC?

A. No, it does not. It is the position of Staff that the costs that flow through the FAC be fuel and purchased power costs incurred to provide energy to its customers. It is not a mechanism to flow transmission costs through to its customers. Entergy costs are included in Staff's revenue requirement in this case and are recovered by Ameren Missouri through its permanent rates.

Q. Mr. Haro on page 21 states that Staff hasn't provided enough clarity to determine what transmission costs should be allowed. Can you provide additional clarity?

A. Yes. Staff recommends that only the following transmission costs be allowed:

1) The transmission costs other than MISO costs that are necessary for the purchase of energy; and

2) The transmission costs other than MISO cost to make a cost-effective off-system sale.

For example, KCPL offers to sell Ameren Missouri some energy at a price lower than the cost of energy in the MISO market. Ameren Missouri can include the transmission cost of bringing KCPL's energy into MISO. Another example would be if Ameren Missouri can sell energy to Associated Electric Cooperative, Inc. but as a condition of the sale it must pay some transmission costs. If the transaction is still cost-effective with the addition of the transmission costs, then that transmission costs can be flowed through the FAC.

Q. Is there language in the attached tariff sheets that would effect this change?

A. No, there is not. However, Staff will be glad to work with Ameren Missouri to get the correct language in the FAC tariff sheets.

Q. Is Staff recommending the removal of all MISO costs from the FAC?

A. No. However, instead of what MISO schedule costs should not be allowed to flow through the FAC as stated in the current tariff sheet, Staff recommends that the MISO schedule costs that are allowed to flow through the FAC be on the tariff sheet. Explicitly stating what items of expense and revenue are "included" in the FAC, provides assurance that the Commission will have the opportunity to approve each item of expense and revenue before its inclusion in the FAC and prior to each item beginning to flow through the FAC. To allow items of expense and revenue to flow through the FAC simply because these items have not been explicitly "excluded" from the FAC is not sound regulatory policy.

Q. Which MISO schedules should be included?

A. According to Ameren Missouri's response to Staff Data Request 0518, Ameren Missouri provided which MISO schedules costs it currently flows through the FAC and which schedules it does not. These MISO schedules are attached to this testimony as Schedule LMM-S1. Of these, Staff recommends that only Schedule 02 - Reactive Supply and Voltage Control and Schedule 33 - Blackstart Service be included in the FAC.

Q. Do you have any recommendations to help Staff and other parties monitor what flows through the FAC?

A. Yes, I do. Staff has requested a detailed list of the accounts and subaccounts of costs and revenues that Ameren Missouri flows through the FAC. Staff recommends that to avoid any confusion in the future, these accounts and subaccounts should be listed to the extent that they currently are not, on the FAC tariff sheets. In addition, the tariff should list the MISO schedule costs that are allowed to flow through the FAC. Any additional charges and/or revenues should only be added in a rate case where all parties have an opportunity to provide comment to the Commission.

Staff also recommends that the Commission require Ameren Missouri to provide account and subaccount detail in its monthly FAC submissions.

Q. Is there anything else in Mr. Haro's testimony that you would like to respond to?

A. Yes, there is. Mr. Haro states on page 2, line 10, that Staff's proposal assumes that it is possible to accurately predict the power price in the production cost model.

Q. Is he correct?

A. No such assumption was made by Staff.

Q. Is he correct when he states on page 2, line 14, that Staff's proposal assumes that the Company has not been prudently pursuing available opportunities for off-system sales?

A. No such assumption was made by Staff.

Q. Would that be why Staff didn't provide evidence that supports these two statements as Mr. Haro states on page 2 of his rebuttal testimony?

A. Yes, it is.

Q. Is it your theory as Mr. Haro states on page 3, line 6, of his rebuttal testimony "that a change in the sharing percentage will create a greater incentive to better predict what power prices will be when rates are in effect – i.e., in the future."

A. No, it is not. But I do believe that it will provide an incentive to Ameren Missouri to look for better predictors.

Q. Should it surprise Mr. Haro as he states on page 7 that Staff believes that there may be better methods for predicting purchases power prices?

A. No, it should not. A good analyst should always be looking for better ways to do their work.

Q. Is he correct when he states on page 11, line 16, that you contend that Ameren Missouri's use of a three-year average to estimate market prices reflects a "lack of incentive to get it right"?

A. No, he is not correct.

Q. Is he correct when he states on page 14, line 11, that you "would have the Company put into a position of failing to recover even more of the prudently incurred fuel and purchase power costs it must incur to serve its customers simply based on the fortuity that [Ameren Missouri was] unable to accurately predict future power prices."?

A. No, he is not correct.

Q. Is he correct when he states on page 15, line 4, that you are "suggesting that if we had an adequate incentive to "get it right," we would more accurately predict what the price of energy will be a year or two from now."?

A. No, he is not correct.

Q. Mr. Haro states on page 15, beginning on line 19, that: "We already sell all of our available, "in-the- money" generation. Doing so is simply a function of the MISO market. We don't have to seek out counter-parties to make sure that our generation is economically dispatched. As the parties to this case are well aware, we offer our units into the MISO market, and the MISO clears these units when their cost of generation is lower than the market price." Does this mean that Ameren Missouri has no control at all over off-system sales?

A. No, it does not. A key phrase in Mr. Haro's statement is "we offer our units into the MISO market."

Q. Are you asserting that Ameren Missouri has not always offered its generation into the market when it was economically beneficial?

A. No, I am not. I am merely pointing out that Ameren Missouri does play a role in the off-system sales revenues that it generates.

Response to the Rebuttal Testimony of Wilbon L. Cooper

Q. With respect to the FAC, what did Mr. Cooper address in his rebuttal testimony that you are addressing in this surrebuttal testimony?

A. I am addressing Mr. Cooper's discussion on pages 17 through 20 regarding Staff's requested clarification changes to the FAC tariff sheets and proposed some additional changes and the seasonality of the FAC base factor ("BF").

Q. Does Staff agree with the clarification changes in the FAC tariff sheets that Mr. Cooper proposed?

A. Staff had a conference call with Ameren Missouri since Mr. Cooper filed his rebuttal testimony to discuss Ameren Missouri's proposals. Schedule LMM-S2 contains what Staff believes that Ameren Missouri and Staff agreed to in that phone call. The highlighted sections are where issues still exist but will be resolved by Commission order. Most of these will be addressed later in this surrebuttal testimony. These tariff sheets do not reflect my earlier recommendations that all accounts and subaccounts be listed and that only MISO schedule 2 and 33 costs be flowed through the FAC. Staff had not yet developed these recommendations when it talked with Ameren Missouri about the tariff sheets.

Q. Are there any sections highlighted that you would like to address?

A. Yes. One of the issues that I did not find addressed in Ameren Missouri's testimony is what hedging costs should be included in the FAC. It is Staff's position that only hedging gains and losses associated with mitigating volatility in its fuel costs and allowances for SO_2 and NO_x emissions should flow through Ameren Missouri's FAC and that no other hedging gains and losses be allowed through Ameren Missouri's FAC without Ameren Missouri first proposing that they do so in a general rate proceeding where all parties have an opportunity to make recommendations to the Commission regarding the appropriateness of doing so. In the currently effective FAC tariff sheets, hedging is mentioned with respect to fossil fuel, SO_2, fuel oil, and natural gas. However, in its proposed tariff sheets, Ameren

Missouri added hedging gains and losses for purchased power and off-system sales revenue. At this time Staff does not have a sufficient understanding of how or why Ameren Missouri hedges purchased power and off-system sales revenue. Therefore, Staff recommendation remains that only hedging gains and losses associated with mitigating volatility in its fuel costs and allowances for SO_2 and NO_x emissions flow through Ameren Missouri's FAC and that no other hedging gains and losses be allowed through Ameren Missouri's FAC.

Secondly, Ameren Missouri added a paragraph on the fourth page that allows items to remain in the FAC if the Federal Energy Regulatory Commission ("FERC") requires the item to be recorded in an account different than the account listed in the tariff sheets. Staff agrees with this provision. However, Staff proposes to add the following sentence to that paragraph:

> In the month that Ameren Missouri begins to record items in a different account or in accounts not listed at all, Ameren Missouri will file with the Commission the previous account number, the new account number and what costs or revenues that flow through the FAC are to be recorded in the account.

Q. Does this address all of the highlighted portions of the proposed tariff sheets?

A. No, it does not. I address other provision in the proposed tariff sheets in this testimony response to other Ameren Missouri witnesses.

Q. Does Staff agree with Mr. Cooper's analysis regarding the seasonality of the base factor?

A. Staff does not disagree with the analysis conducted by Mr. Cooper regarding the impact of a single base factor as compared to seasonal base factors. However, Staff's preliminary seasonal base factors show a higher base factor for summer than the base factor for the non-summer months. Ameren Missouri's summer base factor is lower than the base factor for the non-summer months. If the actual net energy costs occur as modeled by Staff and Ameren Missouri's seasonal base factors are used, the difference between actual energy costs and net base fuel costs will be even greater than what Mr. Cooper shows in his testimony. For this reason, Staff proposed a single annual base factor. However, Staff is agreeable to using seasonal base factors calculated using the trued-up of costs and revenues that are included in the FAC.

Response to the Rebuttal Testimony of Steven M. Wills

Q. With respect to the FAC, what did Mr. Wills address in his rebuttal testimony that you are addressing in this surrebuttal testimony?

A. On pages 30 through 32, Mr. Wills addresses two FAC language issues. The first is regarding the definition of the terms S_{AP} and S_{RP}. Staff had removed the words "the retail component of" from the definitions of these terms that identify the energy used in the calculation of the net base energy costs and the fuel adjustment rates. Staff agrees with Mr. Wills that these words should not be removed. This phrase is included in the definitions of S_{AP} and S_{RP} in Schedule LMM-S2.

The second issue Mr. Wills addresses is a proposed modification of the definition of S_{AP} to account for energy generated by the Company's landfill gas plant, the Maryland Heights Energy Center. Staff agrees that failure to add the output of the Maryland Heights Energy Center would understate the calculation of collected costs and the definition needs to be modified. However, Ameren Missouri's proposal would only take into account generation operated as a "behind the meter" resource owned by Ameren Missouri. Staff recommends modifying the language proposed by Ameren Missouri to include generation that operated "behind the meter" that may be owned by an entity other than Ameren Missouri. Staff proposes that the phrase "plus the metered net energy output of any generating station operating within its certificated service territory as a behind the meter resource in MISO" be appended to the end of the definition of S_{AP}.

Response to the Rebuttal Testimony of Robert K. Neff

Q. With respect to the FAC, what did Mr. Neff address in his rebuttal testimony that you are addressing in this surrebuttal testimony?

A. On pages 6 through 8, Mr. Neff responds to Staff's recommendation to change the sharing mechanism to 85%/15% from 95%/5%. He characterizes the proposed 15% sharing of the fuel cost as a "penalty" stating on page 6, lines 20 through 21, that "[t] he 15% sharing would penalize Ameren Missouri for proactively complying with the CSAPR regulations." He also proposes a method of more accurately estimating net base fuel costs.

Q. Is the proposed 15% sharing a "penalty" for Ameren Missouri for proactively complying with the CSAPR regulations?

A. No, it is not. Ameren Missouri would actually receive a benefit, because it has an FAC of recovering 85% of all of its prudently incurred fuel costs above what is included in the net base fuel costs. Absent the FAC, Ameren Missouri would recover 0% of all of its prudently incurred fuel costs, above what is included in the net base fuel costs - whether it be for fuel purchased to comply with CSAPR regulations or not. For every $10 million of increased costs, Ameren Missouri would actually enjoy the benefit of being able to bill its customers for $8.5 million of that increase. Without a FAC, Ameren Missouri would not be able to bill for any of the increase in fuel costs.

Q. On page 7 of his rebuttal testimony, Mr. Neff provides some estimates of the impact of the 15% on Ameren Missouri's coal commodity cost. Are his estimates correct?

A. Given his assumptions, I have no reason to believe that his calculations are not correct. However, they are miss-leading. He calculates the average increase over the term of the contract and then applies 5% and 15% to that amount. In practice, the increases in the initial years would be less than those in the later years resulting in a lower dollar impact in the initial years. These amounts would be even less if Ameren Missouri continues to request rate increases as frequently as it has done since 2007, because the net base energy costs would include the fuel costs that had escalated since the previous rate case,

Mr. Neff also remarks on lines 7 and 13 that if Ameren Missouri does not file a rate case for several years the losses would multiply. To continue its FAC, Ameren Missouri is required to file a general rate case with effective dates no later than four years after the effective date of the Commission order implementing FAC rates. I am not sure what Mr. Neff meant by "several years" but the time between new FAC rates is shorter than the term of the contract he is referring to.

Q. What is the method that Mr. Neff proposes to more accurately estimate net base fuel costs for in the FAC?

A. Mr. Neff states on page 8, lines 9 and 10, that "the Company will increase its fuel costs as part of its true-up filing to reflect the January 1, 2013 delivered coal cost increases."

Q. What is Staff's response to this proposal?

A. Including the fuel costs as of January 1, 2013, may seemingly result in the most accurate fuel costs as of rates going into effect on January 2. 2013. However, the exact impact of all changes in fuel costs through January 1, 2013, are not known and measureable at this time. In addition, these costs will be incurred past the true-up date agreed to by the Company and established by the Commission in this case. Including these costs is beyond the traditional regulatory practice as set out by the Commission in its procedural schedule order and may violate the matching principle relied upon by all parties in this case. In addition, the

Company's request is untimely and Staff and all other parties will not have the opportunity to review all relevant factors prior to the true-up filing date.

Response to the Rebuttal Testimony of Lynn M. Barnes

Q. With respect to the FAC, what did Ms. Barnes address in her rebuttal testimony that you are addressing in this surrebuttal testimony?

A. Ms. Barnes provided a response to Staff's proposal to change the incentive mechanism to 85%/15% and the five areas that Staff considered in developing its proposal. I will respond to some of her comments regarding this proposal.

Q. What would you like to address first?

A. On page 6, lines 12 and 13, Ms. Barnes states that Staff did "not explain[] how increasing this sharing percentage would improve the efficiency or cost-effectiveness of the Company's fuel procurement activities." This is really very simple - when more responsibility for the payment of an item is put on a company, the more care it is going to take in the purchase of an item. For example, if someone goes to buy a car with their own money, it is more likely that they will carefully research so that they can get the most car for their money than if someone gave them money for the car. In the same way, if Ameren Missouri is responsible for more of the increase in fuel costs it will take great care to keep that increase as small as possible.

Q. Ms. Barnes states on page 9, lines 8 through 10, and again on page 10, lines 9 through 11, that Ameren Missouri cannot control the fuel and power markets that it operates in. Is this good justification for not adopting Staff's proposal?

A. No, it is not. If these markets are uncontrollable and hard to predict as Ms. Barnes testifies on page 10, line 7, it makes it even more critical for Ameren Missouri to have a stake in the costs that it incurs to meet its customer's needs. With no stake or very little, such as the current 5%, the impact on Ameren Missouri of less efficient or cost-effective fuel procurement activities is minimal while it could be very great on Ameren Missouri's customers.

Q. On page 7, lines 1 through 10, Ms. Barnes discusses the "heavy burden" that Staff's proposal would put on Ameren Missouri. Do you agree with her characterization?

A. Ms. Barnes uses Mr. Neff's testimony to demonstrate the "heavy burden that the proposal would put on Ameren Missouri. I have already explained above that his calculations are likely too high. While Ms. Barnes states the amount that Ameren Missouri has had to absorb since the last case (approximately $29 million), she fails to mention the amount that Ameren Missouri has been able to bill the customers for that it would not have been able to absent the FAC (approximately $490 million)[2]. While $29 million was a burden on Ameren Missouri, the $490 million was a burden on Ameren Missouri's customers. A simple calculation of the impact on Ameren Missouri's 1.2 million customers is that it has cost each customer $408.[3] To many customers, that has been a heavy burden.

The "approximately $29 million" provided by Ms. Barnes in her rebuttal testimony assumes that all else remained the same. The amount may have been lower had the sharing percentage actually been 15% and the burden on Ameren Missouri's customers would also have been less.

Q. On page 7, of her rebuttal testimony, Ms. Barnes states: "It is inappropriate to separate the OSS margins from the fuel and purchased power costs, as Ms. Mantle has attempted to do, because the sharing percentage is applied to changes in the net fuel costs

[2] For this estimate Staff did not independently calculated the numbers used. It used the numbers provided in Ms. Barnes rebuttal testimony.
[3] This was calculated by dividing $409 million by 1.2 million.

(fuel and purchased power costs net of OSS margins) and not individually to fuel/purchased power costs of OSS margins." Do you agree with Ms. Barnes?

A. I agree that the sharing percentage is applied to changes in the net fuel costs. However, I do not agree that the Commission should not look at individual components of the FAC. While Ms. Barnes states that it is improper for Staff, Ms. Barnes herself along with Ameren Missouri witnesses Mr. Neff and Jaime Haro also look at specific components of fuel costs and off-system sales. By reviewing the components of the FAC the Commission will better understand what the "net fuel costs" consists of and how volatile each component actually is.

Q. On page 10 of her testimony, Ms. Barnes quotes from your deposition in the last rate case. If asked any of these questions would you respond differently today?

A. No, I would not. I still believe that the ability of the Commission to take away the FAC is a powerful incentive if the Company is misusing the privilege of the FAC. However, Staff is not proposing the Commission take away that privilege. Staff is merely proposing changes that, short of taking away the privilege, would provide Ameren Missouri more incentive to manage its net fuel cost efficiently and cost-effectively.

Q. Ms. Barnes states that if you are serious about the importance of setting the net fuel cost as accurately as possible then you should agree to include "the approximately $39 million of delivered coal cost increases we can calculate today, that were known and measurable as of the July 31, 2012 true-up date" in net base cost. Do you agree with Ms. Barnes?

A. Ms. Barnes proposal is interesting. As I previously stated in response to Mr. Neff's similar proposal, including the fuel costs as of January 1, 2013 may seemingly result in the most accurate fuel costs as of rates going into effect on January 2. 2013. However, the "we" Ms. Barnes refers to in "we can calculate today" must mean what Ameren Missouri has calculated, because Staff has not calculated the impact of future changes in fuel costs. As I previously stated, this request is untimely and Staff and all other parties will not have the opportunity to review all relevant factors prior to the true-up filing date. In addition, these costs will be incurred past the true-up date agreed to by the Company and established by the Commission in this case. So, although I am serious about the importance of setting the correct net base energy cost, Staff cannot commit to including these future costs.

Q. Ms. Barnes states on page 14, lines 1 and 2, of her testimony that "it is clear that changing the sharing percentage would not have any impact on our ability to forecast these market prices." Do you agree?

A. I do not know if it would or not. On the continuum of possible percentage sharing mechanisms we only have information on two different points – 95%/5% and 0%/100%. I do believe that Ameren Missouri was able to keep all of the off-system sales margin it would have a great incentive to maximize to find the best forecasting methodologies and hire the best employees to increase the off-system sales margins and if it did not get to keep any of the off-system sales margin, there would be little incentive. While I do not have "proof" that Ameren Missouri would act differently than it currently does, the Commission cannot get "proof" without changing the sharing mechanism.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

SCHEDULE 1 Scheduling, System Control And Dispatch Service

Version: 1.0.0 Effective: 1/1/2011

SCHEDULE 1

Scheduling, System Control and Dispatch Service

I. GENERAL

Scheduling, System Control and Dispatch Service associated with the Transmission Provider is to be provided directly by the Transmission Provider except in the case of ITC Service, Scheduling System Control and Redispatch Service may, at the election of the ITC, be provided by the ITC in accordance with the ITC Control Area Service and Operations Tariff. This service is required to schedule the movement of power through, out of, within or into the Midwest ISO Balancing Authority Area and is provided by the operators of the Local Balancing Authority Area(s) of the Transmission Provider. To the extent the Local Balancing Authorities perform this service to the Transmission Provider, the charges collected under this Schedule shall represent a pass-through of the costs incurred by the Local Balancing Authorities. The Transmission Customer must purchase this service from the Transmission Provider, or, as applicable the ITC.

II. RATES

Service under this Schedule shall be at a single, system-wide rate. Amounts to be recovered under this Schedule 1 shall not include any amounts recovered pursuant to Schedule 24 including amounts shown in any separate sub-account to Account No. 561 established pursuant to Schedule 24-A to Schedule 24 of this Tariff. The annual rate for this service will be calculated as follows:

(1-2) divided by 3

Where:

1= The sum of all costs booked to FERC Account Nos. 561.1, 561.2, and 561.3 for the Transmission Owners and ITCs (or the equivalent account(s) for Coordinating Owners, Transmission Owners, and ITCs that do not use FERC Account Nos. 561.1, 561.2, and 561.3) in the prior calendar or fiscal year[1].

2= The sum of all charges under this Schedule assessed to firm transactions of less than one year, all non-firm transactions, and any other transactions whose loads are not included in the Divisor on Page 1 of Attachment O for Drive-Out and Drive-Through Transmission Service.

3 = The Divisor on Page 1 of Attachment O for Drive-Out and Drive-Through Transmission Service.

Such rate shall be calculated and put into effect on January 1 and June 1 of each year in concert with Attachment O rate postings.

III. CHARGES

The charges for Transmission Customers taking Point-To-Point Transmission Service under Module B of the Tariff shall be calculated by multiplying the appropriate rate calculated above by each megawatt of Reserved Capacity.

The charges for Transmission Customers taking Network Integration Transmission Service under Module B of the Tariff shall be calculated by multiplying the Monthly Rate calculated above by each megawatt of Network Load determined in accordance with Section 34.2 of the Tariff.

Notwithstanding the foregoing, charges for ITC Service shall be governed by the applicable ITC Control Area Service and Operations Tariff.

IV. ALLOCATION OF SCHEDULE 1 REVENUES

In order to provide for full recovery of each Transmission Owner's and ITC Participant's Schedule 1 revenue requirement, the total Schedule 1 revenues to be distributed to Transmission Owners and ITC Participants shall include the Schedule 1 charges that would be payable by any Transmission Owner and ITC Participant covered by the exclusion from Midwest ISO billing of

Schedule 1 in Section 37.3 of the Tariff, or by a similar exclusion in a Service Agreement with the Transmission Provider ("imputed revenues"). These total Schedule 1 revenues shall be distributed pro-rata among Transmission Owners and ITC Participants based on their contribution to the amount of the total Schedule 1 revenue requirement [(1-2) as calculated in Section II of this Schedule 1]. In distributing Schedule 1 revenues to Transmission Owners and ITC Participants, the Transmission Provider shall deduct the imputed revenues from charges attributed to each such Transmission Owner and ITC Participant from the total Schedule 1 revenues that are due to that Transmission Owner or ITC Participant.

Notwithstanding the foregoing, in the case of ITC Service, such service may be governed by the ITC Control Area Services and Operations Tariff. Revenue distribution under this schedule to an ITC shall be limited to the portion of revenues associated with transactions under this Tariff that do not take place under the applicable ITC's Rate Schedule.

Costs booked to a sub-account to Account No. 561 pursuant to Schedule 24 shall not be included in the sum of all costs booked to Account No. 561 for the purposes of this formula.

SCHEDULE 2 Reactive Supply and Voltage Control From Generation or Other Version: 0.0.0 Effective: 7/28/2010

SCHEDULE 2

Reactive Supply And Voltage Control From

Generation or Other Sources Service

I. GENERAL

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, Generation Resources and non-generation resources capable of providing this service that are under the control of the Local Balancing Authority are operated to produce or absorb reactive power. Thus, service under this Schedule 2 - Reactive Supply and Voltage Control from Generation or other sources service must be provided for each transaction on the Transmission System. The amount of Reactive Supply and Voltage Control from Generation Resources or other service that must be supplied with respect to the Transmission Customer's transaction will be determined by the Transmission Provider based on the reactive power support necessary to maintain transmission voltages within the voltage range and the resulting reactive power range that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or other sources service is to be provided by the Transmission Provider by making arrangements with the Local Balancing Authority(s) that acquires this service for the Transmission Provider's Transmission System, except that, in the case of ITC Reactive Supply and Voltage Control from Generation Sources Service, the service may, at the election of the ITC, be acquired by the ITC in accordance with the ITC Control Area Services and Operations Tariff and the standards for qualification of

Generation Resources set out in this Schedule 2. The Transmission Customer must purchase this service from the Transmission Provider or from the ITC, as appropriate. The charges for such service by the Transmission Provider or the ITC will be based on the rates set forth below.

II. QUALIFIED GENERATOR

A. **General Qualifications:** All existing Generation Resources collecting charges for Reactive Supply and Voltage Control from Generation Sources Service under a Commission approved cost-based rate schedule as of May 1, 2004, are deemed to be Qualified Generators. Any other Generation Resource may collect charges associated with its Reactive Supply and Voltage Control from Generation Sources Service capability under this Schedule 2, where the Transmission Provider determines that the Generation Resource is a Qualified Generator based on the requirements of paragraphs 1-4 in Section II.B. The Transmission Provider shall have the right to review the Qualified Generator status of any Generation Resource at a subsequent time and revoke the Qualified Generator status of Generation Resources that do not meet the requirements of paragraphs 1-4 of Section II.B below. For the purposes of this Schedule 2, the revenue distribution provisions in Section III shall apply to all Qualified Generators under this Schedule 2, regardless of whether the Qualified Generator actually provided the service.

B. **Technical Qualifications:** If a Generation Resource meets the qualifications as stated below, it shall be recognized as a Qualified Generator.

1. The Generation Resource (i) operates with its voltage regulators in automatic mode and responds to voltage schedules of the Transmission

Provider or Local Balancing Authority for the pricing zone in which the Generation Resource is located; (ii) is able to maintain voltage support within its design limits; and (iii) is capable of a reactive power range of 95% leading to 95% lagging at the Point of Interconnection unless otherwise stated in the Generation Resource's Generator Interconnection and Operating Agreement;

2. The Generation Resource (i) can respond to changes in voltage on the system and to changes in voltage schedules if the facility is operating; or (ii) will provide voltage control specified by the Transmission Provider or Local Balancing Authority immediately, if intra-day system conditions require additional reactive power supply to maintain reliability, or as instructed by the Transmission Provider prior to the Operating Day based on forecasted system conditions, taking into consideration the unit's operating characteristics, and whether the Generation Resource is not operating at the time of the request as a result of an unscheduled or planned outage;

3. The Generation Resource has met the testing requirements for voltage control capability required by the Regional Reliability Council where the Generation Resource is located within the past five years; and

4. The Generation Resource has submitted a request to the Transmission Provider for Qualified Generator status as outlined in Section II.C below.

C. **Notification to Transmission Provider of Qualified Generator Status and Notification of Filing of Revenue Requirement:** To be eligible to receive compensation for its voltage control capability, a Generation Resource shall submit a request to the Transmission Provider certifying its compliance with paragraphs 1 - 4 of Section II.B and stating its cost-based revenue requirement as filed and accepted by the Commission. Any Generation Resource seeking compensation under this Schedule 2 shall be responsible for making all appropriate filings with the Commission to justify its cost-based revenue requirements for the provision of the reactive supply and voltage control service. The Transmission Provider will not make any determination or assertions concerning whether the cost-based revenue requirements sought by the Generation Resource are just and reasonable, as these determinations will be made by the Commission. If the Transmission Provider does not notify the Generation Resource of a deficiency to the certification within fifteen (15) days, Qualified Generator status is effective on the first day of the month immediately following acceptance of the revenue requirement by the Commission or the first day of the month if Commission acceptance of such revenue requirement is on the first day of the month.

III. RATES, CHARGES, AND REVENUE DISTRIBUTION

The Transmission Provider shall calculate rates for Reactive Supply and Voltage Control from Generation Sources Service for each pricing zone in the Transmission System. The charges collected under this Schedule 2 shall represent a pass through of costs, based on the annual cost-based revenue requirements or cost-based rates of those Qualified Generators providing service pursuant to this Schedule 2. For those pricing zones where more than one entity is deemed to be a Qualified Generator providing the service described under this Schedule 2, the Transmission

Provider will pass through the revenue it receives directly to each individual Qualified Generator based on the revenue requirements specified in Section III.D or cost-based rates. The Qualified Generators shall be responsible for filing their annual cost-based revenue requirement and/or cost-based rates for voltage control capability with the Commission.

A. Rates for Reactive Supply and Voltage Control from Generation Sources Service provided to Load within the Transmission System

The Transmission Provider shall determine the rates by:

1. Summing the annual revenue requirements for voltage control capability, as determined pursuant to Section III.D.1, including any amounts to be collected pursuant to Section III.D.2, for all Qualified Generators in the respective pricing zone to determine the annual reactive power revenue requirement~~; then~~
2. Multiplying the annual reactive power revenue requirement determined in step 1 above by one-twelfth (1/12) to obtain the monthly reactive power revenue requirement for the pricing zone; and then
3. Dividing the monthly reactive power revenue requirement determined in step 2 above by the Attachment O, Page 1, Line 15 rate divisor for each pricing zone to derive a monthly rate; and deriving from that monthly rate the rates for weekly, daily and hourly service. For those pricing zones not utilizing Attachment O to derive rates for base Transmission Service, the Transmission Provider shall use the same rate divisor used in calculating base transmission rates for Schedule 7, the Midwest ISO Single System-Wide Rates, or use a divisor specified by Commission order as the Schedule 2 rate divisor.

4. For those Qualified Generators having a cost-based rate schedule on file with the Commission that does not include an annual revenue requirement (*i.e.*, a stated rate), the Transmission Provider will calculate the rates in respective pricing zone by adding the incremental rates as calculated in steps 1-3 above to the stated rates.

5. The Transmission Provider will recalculate the rates annually effective the beginning of June and the beginning of any month subject to any change in the reactive power revenue requirements or rate divisor for a pricing zone.

B. Rates for Reactive Supply and Voltage Control from Generation Sources Service for transactions exiting the Transmission System

The rate for Reactive Supply and Voltage Control from Generation Sources Service for Transmission Customers with loads located outside the Transmission Provider's Transmission System shall be calculated using an average rate. The average rate shall be calculated by:

1. Summing the annual revenue requirements determined in Section III.A.1 for all of the pricing zones; and
2. Dividing the annual revenue requirement determined in step 1 above by the Attachment O divisor used for calculating the Schedule 7, Part (2) Single-System Rate, or use a divisor as specified as modified by Commission order, to derive a monthly rate; and deriving from that monthly rate the rates for weekly, daily and hourly service.
3. In those instances where a Qualified Generator has a cost-based rate schedule on file with the Commission that does not include an annual revenue requirement (i.e., a stated rate), the Transmission Provider will calculate the average rate by weighting

the respective rates calculated in Section III.A, together with the stated rates, using the rate divisor previously mentioned in Section III.A.3. The average rate will be the sum of the load weighted rates.

4. The Transmission Provider will recalculate the rates annually effective the beginning of June and the beginning of any month subject to a change in the reactive power revenue requirements or stated rates for a pricing zone.

C. Collection of Charges and Distribution of Revenues

1. Each Transmission Customer shall pay the Transmission Provider a charge for Reactive Supply and Voltage Control from Generating Sources Service determined by multiplying the applicable rate as calculated in Section III.A by the Reserved Capacity for the Transmission Customer taking Point-To-Point Transmission Service or the monthly Firm Point-To-Point Transmission Service rates times the Network Load for a Network Customer taking Network Integration Transmission Service.

2. Each month for Point-to-Point Transmission Service or Network Integration Transmission Service provided to load within a pricing zone within the Transmission System, the Transmission Provider shall distribute to each Qualified Generator owner a *pro rata* allocation of the amounts collected under this Schedule 2 based upon the Qualified Generator's respective share of the relative rates within the pricing zone (*i.e.,* rates of the Qualified Generator divided by the total rates of Qualified Generators in a zone) derived under Section III.A. The *pro rata* allocation of the amounts collected by the Transmission Provider will be reduced for those Qualified Generators with Transmission Customers who are not paying charges under this Schedule 2. The reduction will be calculated by the Transmission Provider based on

the ratio of the subject Transmission Customers' average of their prior calendar year's twelve (12) coincident peaks to the Section III.A.3 rate divisor for the applicable pricing zone times the aggregate gross annual revenue requirement for all Qualified Generators within the pricing zone.

3. Each month for Transmission Service provided to Points of Delivery or loads located outside the Transmission System, the Transmission Provider shall distribute to each Qualified Generation owner a *pro rata* allocation of the amounts collected for its share of its gross annual reactive power revenue requirement among all Qualified Generators providing service under this Schedule 2.

4. The Transmission Provider will allocate revenue to each pricing zone based on the respective load weighted rate for each pricing zone as compared to the average rate. The Transmission Provider will then distribute those revenues allocated to each pricing zone to each Qualified Generator within the pricing zone based on each Qualified Generator's *pro rata* share of the rate for the pricing zone as calculated under Section III.A.4 as described in paragraph C.2 above.

D. Annual Revenue Requirement Rights of Qualified Generators

1. Non-public utilities and/or non-jurisdictional entities are eligible to receive compensation for their provision of Reactive Supply and Voltage Control from Generation Resources Service. Each Qualified Generator, including Generators owned by non-public utilities and/or non-jurisdictional entities, shall file its annual revenue requirement for their Reactive Supply and Voltage Control from Generation Resources Service capability with the Commission. The Qualified Generator possesses the unilateral right under Section 205 of the Federal Power

Act to file to establish or revise its annual cost-based revenue requirement or rates for this Schedule 2 - Reactive Supply and Voltage Control from Generation Sources Service.

2. Nothing in this Tariff interferes with the right of any Generation Resource that is physically located on the Transmission System, including any non-qualified generator, to file with the Commission a rate schedule under its Interconnection and Operating Agreement and consistent with Commission policy providing for compensation for the provision of voltage control capability in excess of that provided by normal operation of voltage control capability and where provided by a Generation Resource at the request of Transmission Provider or Local Balancing Authority.

IV. QUALIFIED GENERATOR STATUS

A. Re-Evaluation of Qualified Generator Status

1. If a Qualified Generator fails to comply with the Local Balancing Authority's voltage control requirements three or more times in a calendar month for reasons other than planned or unscheduled outages, the Transmission Provider shall determine whether the Generation Resource should continue to be a Qualified Generator based on the criteria established in Section II.B of this Schedule 2

2. In making a determination of whether a Generation Resource should continue to be a Qualified Generator, the Transmission Provider will evaluate, among other factors, whether the Generation Resource was operated consistently with its design characteristics, and whether system conditions prevented it from

responding as required by the Local Balancing Authority.

SCHEDULE 25 Cross-Border Allocation Tariff Provisions Version: 0.0.0 Effective: 7/28/2010

SCHEDULE 25

CROSS-BORDER COST ALLOCATION TARIFF PROVISIONS

The following provisions govern (i) the allocation of costs to PJM, on behalf of its customers, associated with Cross-Border Allocation Projects constructed by Midwest ISO Entities; (ii) the mechanism for recovery of costs allocated to Midwest ISO Entities associated with Cross-Border Allocation Projects constructed by PJM Entities; and (iii) the mechanism for distributing revenues received from PJM.

I. DEFINITIONS

The following additional definitions pertain to this Schedule 25.

A. **Coordinated System Plan:** The Plan developed pursuant to Section 9.3.5 of the JOA.

B. **Cross-Border Allocation Projects:** Transmission facilities which are determined to be Cross Border Allocation Projects under Section 9.3 and 9.4 of the JOA.

C. **JOA:** The Joint Operating Agreement between the Midwest ISO and PJM.

D. **Midwest ISO Entities:** Either the entities doing business within the Transmission Provider Region constructing the facilities or the entities within the Transmission Provider Region who will make payments pursuant to Section III of this Schedule 25.

E. **PJM:** PJM Interconnection, LLC.

F. **PJM Entities:** The entities doing business within the PJM region constructing the facilities.

II. ANALYSIS TO DETERMINE IF A FACILITY IS A CROSS-BORDER ALLOCATION PROJECT AND ALLOCATION OF COSTS FROM TRANSMISSION PROVIDER TO PJM

The analysis to determine if a facility is a Cross-Border Allocation Project is performed as provided in Sections 9.3 and 9.4 of the JOA. The allocation of costs between PJM and the Transmission Provider shall be performed consistent with Section 9.4 of the JOA. The Transmission Provider shall bill PJM, on behalf of its customers, for the revenue requirements of Cross-Border Allocation Projects allocated to PJM.. In determining the revenue requirements to be allocated to PJM, the Transmission Provider shall apply the formula in Attachment CC to the costs allocated to PJM determined through the JOA process. The revenue requirements charged to PJM on a monthly basis shall be set forth in Schedule 25-1, with appropriate filings submitted to the Commission to reflect such charges in this Schedule 25-1. The billing and payment provisions of this Tariff shall apply to such charges. The Transmission Provider shall bill PJM each month based upon the charges reflected in Schedule 25-1.

III. COLLECTION OF AMOUNTS ALLOCATED TO THE TRANSMISSION PROVIDER

With regard to amounts charged to the Midwest ISO, on behalf of Midwest ISO Entities, associated with Cross-Border Allocation Projects, the Transmission Provider will recover those amounts from Midwest ISO Entities based on an allocation of the relative contribution of the Load in each of the affected pricing zones to the loading on the constrained facility giving rise to the Cross-Border Allocation Project as determined by the study performed pursuant to Section 9.4.3.2 and 9.4.3.3 of the JOA. The Transmission Provider shall produce a schedule showing the allocation of these amounts and will distribute the schedule to all entities who would be allocated amounts before making any filings to implement the charges. The Transmission Provider shall make publicly available all work papers and supporting back-up for the schedule. The Transmission Provider shall distribute the schedule sufficiently in advance of any filing to allow the affected Midwest ISO Entities time to provide comments on such schedules. After that process, a filing will be submitted to the Commission setting forth the charge to each Midwest ISO Entity arising from this process. These charges will be reflected on Schedule 25-2. Each Midwest ISO Entity shown to be responsible for a charge on Schedule 25-2 shall be responsible for paying the charge consistent with the billing and payment provisions of this Tariff. The Transmission Provider shall pass through to PJM the amounts collected from Midwest ISO Entities associated with Cross-Border Allocation Projects under this Section III.

IV. REVENUE DISTRIBUTION TO MIDWEST ISO ENTITIES

Upon receiving revenues from PJM, the Transmission Provider shall distribute the revenues to the appropriate Transmission Owners and ITCs. The Transmission Provider shall distribute the revenues to each owner of each Cross-Border Allocation Project as follows:

TOR= TORR/ALLTORR * (Monthly dollars received from PJM)

TOR= Monthly revenues to be received by a Transmission Owner or ITC under this Schedule.

TORR=The monthly revenue requirements of all Cross-Border Allocation Projects owned by the Transmission Owner or ITC referred to in the TOR definition.

ALLTORR=The sum of all monthly revenue requirements of Cross-Border Allocation Projects owned by all Transmission Owners and ITCs.

SCHEDULE 26 Network Upgrade Charge From Transmission Expansion Plan Version: 4.0.0 Effective: 1/1/2012

SCHEDULE 26

NETWORK UPGRADE CHARGE FROM TRANSMISSION EXPANSION PLAN

The Transmission Customer shall compensate the Transmission Provider the current Network Upgrade Charge ("NUC") for Reserved Capacity at the sum of the applicable charges set forth below in addition to all other charges for Transmission Service for which the Transmission Customer is responsible under this Tariff. The rates are calculated using the formula included in Attachment GG of this Tariff.

The charges under this Schedule 26 shall be in addition to any charges under Schedules 7, 8, 9, and 26-A. Grandfathered Agreements, including the provision of Transmission Service, shall not be charged this Schedule 26.

1) **Pricing Zone Rates:** The Transmission Customer shall pay the zonal rate as calculated under Attachment GG, per kW of Reserved Capacity, based upon the pricing zone where the load is located for Transmission Service (1) where the generation source is outside the Transmission Provider Region and the load is located within the Transmission Provider Region and (2) where both the generation source and the load are located within the Transmission Provider Region. The Network Customer shall pay the monthly rate as calculated under Attachment GG for the prizing zone where the load is located based on it Network Load. The rate for each pricing zone will be determined in accordance with the provisions of Attachment GG. All pricing zones will include a system-wide rate component of the NUC, as provided under Section 2 of Attachment GG and designated pricing zones will include an additional NUC rate component.

   The pricing zones are as follows:

Zone 1:	ITC Midwest LLC
Zone 2:	American Transmission Company LLC
Zone 3A:	Ameren Illinois
Zone 3B:	Ameren Missouri
Zone 4:	[Reserved]
Zone 5:	Duke Energy Indiana, Inc. (includes Indiana Municipal Power Agency and Wabash Valley Power Association)
Zone 6:	City of Columbia, Missouri
Zone 7:	City Water, Light & Power (Springfield, Illinois)
Zone 8:	Great River Energy
Zone 9:	Hoosier Energy
Zone 10:	International Transmission Company
Zone 11:	Indianapolis Power & Light Company
Zone 12:	Lincoln Electric (Neb.) System AVAILABILITY SUSPENDED
Zone 13:	Michigan Joint Zone (Michigan Electric Transmission Company LLC, Michigan Public Power Agency and Wolverine Power Supply Cooperative, Inc.)
Zone 13A:	Michigan Joint Zone Subzone
Zone 14:	Minnesota Power, Inc.
Zone 15:	Montana-Dakota Utilities Co.
Zone 16:	NSP Companies
Zone 17:	Northern Indiana Public Service Company
Zone 18:	Otter Tail Power Company

Zone 19: Southern Illinois Power Cooperative

Zone 20: Southern Minnesota Municipal Power Agency

Zone 21: Aquila, Inc. – Kansas (West Plains Energy) **AVAILABILITY SUSPENDED**

Zone 22: Aquila, Inc. – Missouri (St. Joseph Light & Power and Missouri Public Service Co.) **AVAILABILITY SUSPENDED**

Zone 23: Vectren Energy

Zone 24: MidAmerican Energy Company

Zone 25: Muscatine Power and Water

Zone 26: Dairyland Power Cooperative

Zone 27: Big Rivers Electric Corporation

Additional zones may be added if a) additional Transmission Owners transfer control of their facilities to the Transmission Provider. Such additional zones may be added only if consistent with the requirements of Schedules 7, 8 and 9 of this Tariff.

2) **NUC Out and Through Rate:** The Transmission Customer shall pay the rate specified under Attachment GG for Transmission Service (1) where the generation source is located within the Transmission Provider Region and the load is located outside of the Transmission Provider Region; and (2) where both the generation source and the load are located outside of the Transmission Provider Region.

3) **Rates to the PJM Interconnection, LLC:** In accordance with the Commission's November 18, 2004 Order in Docket Nos. ER05-6, EL04-135, EL02-111 and EL03-212, *Midwest Independent Transmission System Operator, Inc.* 109 FERC ¶ 61,168 (2004), the charge under Section 2 above for Points of Delivery at the border of the Transmission Provider Region for reservations pursuant to requests made on or after November 17,

2003, for service commencing on or after April 1, 2004, shall not apply to transactions to serve load within the area served under the open access transmission tariff on file with the Commission of the PJM Interconnection, LLC where transmission service is taken under the PJM Interconnection, LLC open access transmission tariff. Beginning April 1, 2006, the charge under Section (1) above for Points of Delivery at the border of the Transmission Provider Region shall not apply to all transactions to serve loads within the area served under the open access transmission tariff on file with the Commission of PJM Interconnection, LLC, where transmission service is taken under the PJM Interconnection, LLC open access transmission tariff.

4) **Rate Caps:** The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the weekly rate times the highest amount in kW of Reserved Capacity in any day during such week. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the daily rate times the highest amount in kW of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the weekly rate above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Credit for Charges During Transmission Loading Relief (TLR) Events:** In the event that the Transmission Provider initiates Curtailment of confirmed Point-To-Point Transmission Service on the Transmission System due to a TLR event in accordance with Attachment Q, credit will be given to the Transmission Customer(s) that are actually requested to curtail their energy schedules associated with the confirmed Point-To-Point Transmission Service. No credits will be given for: (1) TLR events external to the

Transmission System; (2) Non-Firm Secondary Point-To-Point Transmission Service under a Firm Point-To-Point reservation; or, (3) Next-Hour Transmission Service. Under no circumstances shall the amount credited exceed the amount the customer was actually curtailed nor will credit be given for any hours other than those in which the Curtailment was requested.

6) **Discounts:** Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same Point(s) of Delivery on the Transmission System.

7) **Compliance with Agreements:** If the Commission has allowed agreements to become effective which require a waiver of any of the charges under this Schedule, then such charges shall be waived.

8) **Revenue Distribution to Transmission Owners and ITCs:** As and to the extent that the Transmission Provider collects revenues from Transmission Customers, it shall remit such revenues to the Transmission Owner and/or ITC's in proportion to their annual pro-rata share of the total NUC revenue requirement as determined under Attachment GG.

SCHEDULE 26A
MULTI-VALUE PROJECT USAGE RATE

The Multi-Value Project Usage Rate ("MUR") is a Midwest ISO System-wide rate charged to Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules. The rates are calculated using the formula included in Attachment MM of this Tariff. The charges under this Schedule 26-A shall be in addition to any charges under Schedules 7, 8, 9, and 26. Grandfathered Agreements, except as permitted under Schedule 40, and Export Schedules and Through Schedules for deliveries that sink in the transmission system operated by PJM Interconnection, LLC shall not be charged this Schedule 26-A.

1. **Rates:** Except as provided above, Monthly Net Actual Energy Withdrawals, Export Schedules, and Through Schedules shall pay the MUR rate as calculated under Attachment MM.
2. **Revenue Distribution to Transmission Owners and ITCs:** As and to the extent that the Transmission Provider collects revenues from Market Participants, it shall remit such revenues to the Transmission Owner and/or ITC's in proportion to their annual pro-rata share of the total MVP revenue requirement as determined under Attachment MM.

SCHEDULE 33 Blackstart Service Version: 0.0.0 Effective: 7/28/2010

SCHEDULE 33

Blackstart Service

Blackstart Service is necessary to facilitate reliable and complete system restoration following a shut down of the bulk power Transmission System. Blackstart Service enables Transmission Operators to designate specific generation facilities as Blackstart Units whose location and capabilities are required to assist in re-energizing a specific portion of the Transmission System following a system-wide blackout.

I. SERVICE OBLIGATIONS

All Transmission Customers are subject to charges for Blackstart Service provided pursuant to this Schedule 33. The Transmission Provider and Transmission Operators will work with the applicable Regional Entity to determine the Blackstart Service required for complying with NERC reliability standards. The Transmission Provider will distribute revenues collected under this Schedule 33 to Blackstart Unit Owners in accordance with this Schedule 33.

A Blackstart Unit Owner must be a Tariff Customer to qualify for payments under this Schedule 33. A qualifying Blackstart Unit Owner or a Transmission Operator may contract with an entity inside or outside of the Transmission Provider Region for supply of Blackstart Service if such Blackstart Service is consistent with the Transmission Operator's System Restoration Plan, NERC reliability standards, and the minimum requirements of this Schedule 33. Payments will be made by the Transmission Provider to such a Blackstart Unit Owner or Transmission Operator as reimbursement for the Commission approved costs of the contract, in accordance with Section V of this Schedule. The Blackstart Unit Owner or the Transmission Operator is responsible for all reporting to the Transmission Provider and the contract must provide that all requirements of the Tariff including Schedule 33 are to be met.

II. PROVISION OF BLACKSTART SERVICE

A Blackstart Unit shall be considered capable of providing Blackstart Service when it meets the criteria established by NERC and the applicable Regional Entity, has been included in the Transmission Operators System Restoration Plan and/or entered into the database of the applicable Regional Entity's Blackstart Capability Plan. Notwithstanding the foregoing, a Blackstart Unit must meet the minimum requirements of Section III of this Schedule 33 to be eligible for compensation.

The Transmission Operators are responsible for identifying to the Transmission Provider the Blackstart Units that are included in each of their individual System Restoration Plans and that are required for the reliable restoration of the Transmission System in each of the Transmission Pricing Zones. Blackstart Units will be identified by the Transmission Operators pursuant to criteria established by NERC and the applicable Regional Entity, and in conjunction with the coordination of the Transmission Operators' System Restoration Plans by the Transmission Provider acting in its capacity as the Reliability Coordinator.

To be eligible for compensation under this Schedule 33, Blackstart Unit Owners initially shall commit to provide Blackstart Service for a minimum term of a continuous three-year period either by submitting an executed Service Agreement to the Transmission Provider using Attachment NN to the Tariff or by entering into an agreement for such service with a Transmission Operator, and submitting an executed Service Agreement to the Transmission Provider using Attachment NN to the Tariff. Subject to the terms of the applicable contract, a Blackstart Unit Owner may terminate this three-year commitment only upon written notice to the

Transmission Operator and Transmission Provider, given at least two years before the date the commitment period ends, absent an event of Force Majeure as defined in Section 10.1 of the Tariff. A Transmission Operator may terminate a Blackstart Unit's designation by providing written notice of such termination to the Blackstart Unit Owner and the Transmission Provider at least two years before the date the commitment period ends.

In the event that neither the Blackstart Unit Owner nor the Transmission Operator exercises its right to terminate by providing a two year written notice of termination, the commitment to provide Blackstart Service will be extended automatically for an additional year to maintain a rolling three-year commitment. In the event that a Blackstart Unit Owner fails to fulfill its three year rolling commitment to provide Blackstart Service, the right to receive Blackstart Service revenues associated with the non-performing Blackstart Unit shall cease effective upon the date that such commitment ceases.

III. PERFORMANCE STANDARDS AND OUTAGE RESTRICTIONS

To be eligible for compensation under this Schedule 33, Blackstart Units must demonstrate the minimum performance capabilities for Blackstart Units in accordance with the criteria set forth in the NERC System Restoration and Blackstart reliability standards and any applicable Regional Entity standards, as such standards may be revised from time to time, and must remain in effect for the duration of the Blackstart Unit Owner's commitment to provide Blackstart Service.

Each Blackstart Unit Owner must maintain procedures for the start-up of the Blackstart Units consistent with the procedures established by NERC and the applicable Regional Entity.

Planned outages at Blackstart Units within a Transmission Pricing Zone may be restricted based on Transmission Operator requirements for Blackstart Service availability. Such restrictions must be predefined and approved by the Transmission Provider acting in its capacity as Reliability Coordinator in accordance with the Regional System Restoration Plan.

A service agreement entered into between a Black Start Unit Owner and a Transmission Operator for Black Start Service may contain additional terms and conditions consistent with the minimum requirements of this Section III.

IV. TESTING

To verify that a Blackstart Unit can be started and operated without being connected to the Transmission System, Blackstart Units shall be tested periodically in accordance with the NERC System Restoration and Blackstart reliability standards.

To be compensated for providing Blackstart Service, a Blackstart Unit Owner must provide the Transmission Provider by May 1 with all data necessary to demonstrate that it has met all applicable NERC and Regional Entity Blackstart criteria, standards and requirements. The Blackstart Unit Owner must also affirm that it will continue to meet the requirements of this Schedule 33 for the next 12 months.

To receive Blackstart Service compensation, a Blackstart Unit must have a successful periodic test on record with the Transmission Provider within the preceding 36 months and also meet all applicable NERC and Regional Entity Blackstart standards and requirements as set forth in this Schedule 33.

A service agreement entered into between a Black Start Unit Owner and a Transmission Operator for Black Start Service may contain additional terms and conditions consistent with the minimum testing requirements of this Section IV.

V. DETERMINATION OF REVENUE REQUIREMENT FOR A BLACKSTART UNIT

1. A Blackstart Unit Owner shall be compensated for Blackstart Service under this Schedule 33. Compensation shall be based on the annual revenue requirements associated with each Blackstart Unit. The Blackstart Unit Owner possesses the unilateral right under Section 205 of the Federal Power Act to file to establish or revise its annual cost-based revenue requirement for this Schedule and shall be responsible for making all appropriate filings with the Commission.

2. Blackstart Service revenue requirements shall be calculated using the formula set forth below, or as determined by the Commission in an order issued pursuant to paragraph 5 of this Section V. Commission approved changes to the Blackstart Service revenue requirements may be made once each year with written notice to the Transmission Provider no later than May 1 for the revised revenue requirements to be included in charges effective the following June 1.

3. The formula for calculating a Blackstart Unit's annual Blackstart Service revenue requirement shall represent a pass through of costs that a Blackstart Unit Owner incurs to provide Blackstart Service (*i.e.*, costs that would not otherwise be incurred, but for providing Blackstart Service capabilities, including, but not limited to, costs related to all applicable NERC Reliability Standards) from a Blackstart Unit. The Blackstart Service revenue requirement shall be the sum of the following three (3) elements: **Fixed Blackstart Service Costs + Variable Blackstart Service Costs + Training and compliance Costs.**

Fixed Blackstart Service Costs: shall include the annual amortized fixed costs that a Blackstart Unit Owner incurs to be able to provide Blackstart Service. If the Transmission Operator terminates a Blackstart Unit's designation pursuant to Section II (and the Blackstart Equipment was installed in response to a request by a Transmission Operator to provide Blackstart Service under this Tariff), the Blackstart Unit Owner shall be entitled, upon termination, to full recovery over a ten year period of any unamortized fixed capital costs (including its financing costs of capital), that the Blackstart Unit Owner invested in the Blackstart Equipment. A terminated Blackstart Unit shall provide information regarding fixed costs to the Transmission Provider consistent with information filed with the Commission in support of its revenue requirements.

Variable Blackstart Service Costs: shall include the reasonable operating, maintenance and costs to maintain sufficient fuel inventory that can be attributed to supporting Blackstart Service for a Blackstart Unit.

Training and Compliance Costs: shall include those training and compliance costs that are reasonably incurred to enable a Blackstart Unit Owner's employees to efficiently operate the Blackstart Service capabilities of the Blackstart Unit, including costs incurred to comply with NERC reliability standards applicable to Blackstart Units such as, but not limited to, Critical Infrastructure Protection standards.

Each Blackstart Unit Owner shall certify in writing under penalty of perjury that all of the data and information provided to the Transmission Provider is complete and accurate.

4. A Transmission Operator contracting for Blackstart Unit services shall be compensated for Blackstart Service under this Schedule 33 if the bilateral agreement for blackstart service with a Blackstart Unit Owner meets the minimum term and technical capability requirements of this Schedule 33. Compensation paid to the Transmission Operator shall be based on the Commission approved contract associated with each Blackstart Unit to the extent the costs are consistent with the calculation of the annual revenue requirement set forth in this Section V. A Transmission Operator otherwise entitled to compensation as set forth in this Section may elect to have the Transmission Provider compensate the Black Start Unit Owner in

the amount that would otherwise be paid to the Transmission Operator pursuant to this Schedule 33, if permitted by the agreement between the Transmission Operator and the Black Start Unit Owner.

5. Nothing in this Tariff interferes with the right of any Black Start Unit Owner that is physically located on the Transmission System to file with the Commission, individually or in connection with an agreement to provide Blackstart Service to a Transmission Operator, a rate schedule consistent with Commission policy providing for compensation for the provision of Blackstart Service. If the Black Start Unit Owner meets the eligibility requirements of this Schedule 33, the revenue requirement established by the Commission for that Black Start Unit Owner will be the revenue requirement used by the Transmission Provider for determining the rate to be charged for Blackstart Service under Section VI of this Schedule 33.

VI. CALCULATION OF BLACKSTART SERVICE CHARGES

The Transmission Provider shall calculate rates for Blackstart Service for each Transmission Pricing Zone in the Transmission System. The charges collected under this Schedule 33 shall represent a pass through of Blackstart Service costs, based upon the annual cost-based revenue requirements of those Blackstart Units providing service pursuant to this Schedule 33, that have been approved by the Commission. For those Transmission Pricing Zones where more than one entity is deemed to be a Blackstart Unit Owner providing the service described under this Schedule 33, the Transmission Provider will pass through the revenue it receives directly to each individual Blackstart Unit Owner based on the revenue requirements specified in Section V.

A. Rates for Blackstart Service provided to Load within the Transmission System

The Transmission Provider shall determine the rates for each Transmission Pricing Zone within the Transmission System through the following steps:

1. Summing the annual revenue requirements for Blackstart Service, as determined pursuant to Section V for Blackstart Units in each respective Transmission Pricing Zone, less revenue allocated to each Transmission Pricing Zone's Blackstart Units from transactions exiting the Transmission System for the prior 12-month calendar period, to determine the yearly Blackstart Service revenue requirement;

2. Multiplying the annual Blackstart Service revenue requirement determined in step 1 above by one-twelfth (1/12) to obtain the monthly Blackstart Service revenue requirement for the Transmission Pricing Zone; and

3. Dividing the monthly Blackstart Service revenue requirement determined in step 2 above by the Attachment O, Page 1, Line 15 rate divisor for each Transmission Pricing Zone to derive a monthly rate; and deriving from that monthly rate the rates for yearly, weekly, daily and hourly service. For those Transmission Pricing Zones not utilizing Attachment O to derive rates for base Transmission Service, the Transmission Provider shall use the same rate divisor used in calculating base transmission rates for Schedule 7 (the Midwest ISO Single System-Wide Rates) unless an alternate divisor is specified by a Commission order as the Schedule 33 rate divisor.

For those Blackstart Unit Owners having a cost-based rate schedule on file with the Commission that does not include an annual revenue requirement (*i.e.*, a stated rate), the Transmission Provider will calculate the rates in the respective Transmission Pricing Zone by adding the incremental rates as calculated in steps 1-3 above to the stated rates.

The Transmission Provider will calculate the rates annually effective June 1. Rates will be calculated as soon as reasonably practicable for any new Blackstart Units with Commission approved Blackstart revenue requirements. In accordance with Section V of this Schedule, the Transmission Provider will assign Blackstart charges and distribute revenue in the billing cycle following the effective date of any new or revised rates.

B. Rates for Blackstart Service for Transactions Exiting the Transmission System

The Transmission Provider shall determine the appropriate rate for Transmission Customers with Loads located outside the Transmission Provider's Transmission System by:

1. Summing the annual revenue requirements for Blackstart Service, as determined pursuant to Section V for all Transmission Pricing Zones to determine the yearly system-wide Blackstart Service revenue requirement; and

2. Dividing the annual system-wide revenue requirement determined in step 1 above by the Attachment O divisor used for calculating the Schedule 7, Part (2) Single-System Rate, or use a divisor as specified by Commission order, to derive a monthly rate; and deriving from that monthly rate the rates for yearly, weekly, daily and hourly service.

In those instances where a Blackstart Unit has a cost-based rate schedule on file with the Commission that does not include an annual revenue requirement (*i.e.*, a stated rate), the Transmission Provider will calculate the average rate by weighting the respective rates calculated in Section V together with the stated rates, using the rate divisor previously mentioned in Section VI.A.3. The average rate will be the sum of the load weighted rates.

The Transmission Provider will calculate the rates annually effective June 1. Rates will also be calculated as soon as reasonably practicable for the addition of any new Blackstart Units with Commission approved Blackstart revenue requirements. In accordance with Section V the Transmission Provider will assign Blackstart charges and distribute revenue in the billing cycle following the effective date of any new or revised rates.

VII. COLLECTION OF CHARGES AND DISTRIBUTION OF REVENUES

1. Each Transmission Customer shall pay the Transmission Provider a monthly charge for Blackstart Service determined by multiplying the applicable rate as calculated in Section VI.A or VI.B either: (1) by the Reserved Capacity for the Transmission Customer taking Point-To-Point Transmission Service, or (2) by the Network Load for a Network Customer taking NITS.

2. Each month for Point-to-Point Transmission Service or NITS provided to load within a Transmission Pricing Zone within the Transmission System, the Transmission Provider shall distribute to each Blackstart Unit Owner a *pro rata* allocation of the amounts collected under this Schedule 33 based upon the Blackstart Unit Owner's respective share of the relative rates within the Transmission Pricing Zone (*i.e.*, rates of the Blackstart Units divided by the total rates of Blackstart Units in a Transmission Pricing Zone) derived under Section VI.A.

3. Each month for Transmission Service provided to Points of Delivery or Loads located outside the Transmission System, the Transmission Provider shall distribute to each Blackstart Unit Owner a *pro rata* allocation of the amounts collected for its share of its gross annual Blackstart Service revenue requirement among all Blackstart Unit Owners providing service under this Schedule 33.

4. Each month the Transmission Provider shall distribute to each Transmission Operator that has contracted for Blackstart Service and is eligible for compensation pursuant to Section V of this Schedule 33, a *pro rata* allocation of the amounts collected for its share of its Blackstart Service contract payment among the gross annual Blackstart Service revenue requirement of all Blackstart Unit Owners providing service under this Schedule 33.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

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

~~Eighty~~ Ninety five percent (~~85~~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.

**Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

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

$$FAR_{RP} = [(ANEC - B) \times \cancel{85}\underline{95}\% + I \pm P \pm T]/S_{RP}$$

Where:

ANEC = FC + PP + E - OSSR

B = BF x S_{AP}

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

a) For fossil fuel plants:

(i) the following costs and revenues (including applicable taxes) reflected in Federal Energy Regulatory Commission (FERC) Account Number 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

(ii) the following costs and revenues reflected in FERC Account Number 502 for: consumable costs related to Air Quality Control System (AQCS) operation, such as urea, limestone and powder activated carbon; and

(iii) the following costs and revenues reflected in FERC Account Number 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;

b) Costs and revenues in FERC Account Number 518 (Nuclear Fuel Expense).

**Indicates Change.

DATE OF ISSUE ______ DATE EFFECTIVE ______

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

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

PP = Costs and revenues for purchased power reflected in FERC Account Numbers 555, 565, and 575, including those associated with hedging, but excluding MISO administrative fees arising under MISO Schedules 10, 16, 17, and 24, and excluding capacity charges for contracts with terms in excess of one(1) year. Also included in factor "PP" are insurance premiums in FERC Account Number 924 for replacement power insurance to the extent those premiums are not reflected in base rates. Additionally, costs of purchased power will be reduced by expected replacement power insurance recoveries qualifying as assets under Generally Accepted Accounting Principles.

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

OSSR = Revenues in FERC Account 447, including those associated with hedging.

**Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

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.

For purposes of factors FC, PP, 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 and purchased power 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.

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 or that are not listed in such factors at all, such items shall nevertheless be included in factor FC, PP, E or OSSR.

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.

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 energy output of any Company generating station operating within its certificated service territory as a behind the meter resource in MISO.

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 energy output of any Company generating station operating within its certificated service territory as a behind the meter resource in MISO.

**Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

BF = The Base Factor, 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 $0.01529 per kWh. The BF applicable to October through May calendar months (BF_{WINTER}) is $0.01553 per kWh.

T = True-up amount as defined below.

P = Prudence disallowance amount, if any, 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 and Purchased Power Adjustment rate starting with the applicable Recovery Period following the FAR filing.

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

$FAR_{(RP-1)}$ = FAR Recovery Period rate component from other prior FAR_{RP}.

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.

**Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

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.

**Indicates Change.

MO.P.S.C. SCHEDULE NO. 5 ________ SHEET NO. __

CANCELLING MO.P.S.C. SCHEDULE NO. 5 ________ SHEET NO. __

APPLYING TO **MISSOURI SERVICE AREA**

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Calculation of Fuel Adjustment Rate for [month, day, year] through [month, day, year])**

Calculation of Current Fuel Adjustment Rate (FAR):

	Accumulation Period Ending:		Month, Day, Year
1.	Actual Net Energy Cost (ANEC) (FC+PP+E-OSSR)		$
2.	Net Base Energy Cost (B)	-	$
2.1	Base Factor (BF)	x	$0.00000
2.2	Accumulation Period Sales (S_{AP}))		XXXXXX kWh
3.	Total Company Fuel & Purchased Power Difference	=	$
3.1	Customer Responsibility	x	~~85~~95%
4.	Fuel & Purchased Power Amount to be Recovered	=	$
4.1	Interest (I)	+	$
4.2	True-Up Amount (T)	±	$
4.3	Prudence Adjustment Amount (P)	±	
5.	Fuel and Purchased Power Adjustment (FPA)	=	$
6.	Estimated Recovery Period Sales (S_{RP})	÷	kWh
7.	Current Period Fuel Adjustment Rate (FAR_{RP})	=	$/kWh
8.	Prior Period Fuel Adjustment Rate (FAR_{RP-1})	+	$/kWh
9.	Fuel Adjustment Rate (FAR)	=	$/kWh
10	Secondary Voltage Adjustment Factor (VAF_{SEC})		1.0575
11.	FAR for Secondary Customers (FAR_{SEC})		$/kWh
12.	Primary Voltage Adjustment Factor (VAF_{PRI})		1.0252
13.	FAR for Primary Customers (FAR_{PRI})		$/kWh
14.	Transmission Voltage Adjustment Factor (VAF_{TRAN})		0.9917
15.	FAR for Transmission Customers (FAR_{TRAN})		$/kWh

** Indicates Change.

DATE OF ISSUE ____________ DATE EFFECTIVE ____________

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