Exhibit No.:	
Issue(s):	Production Cost Allocations; Class Revenue Requirements; Rate Design; LTS Class (Noranda) and FAC Rate Design
Witness:	Wilbon L. Cooper
Sponsoring Party:	Union Electric Company
Type of Exhibit:	Rebuttal Testimony
Case No.:	ER-2010-0036
Date Testimony Prepared:	February 11, 2010

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2010-0036

REBUTTAL TESTIMONY

OF

WILBON L. COOPER

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

St. Louis, Missouri
February, 2010

REBUTTAL TESTIMONY

OF

WILBON L. COOPER

CASE NO. ER-2010-0036

Q. Please state your name and business address.

A. My name is Wilbon L. Cooper. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, MO 63103.

Q. Are you the same Wilbon L. Cooper who filed direct testimony in this proceeding?

A. Yes, I am.

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

A. The purpose of my testimony is to provide rebuttal comments and evidence that address the direct testimonies on the allocation of production plant and/or class revenue requirements filed by Missouri Public Service Commission Staff ("Staff") witness Michael Scheperle, and Office of the Public Counsel ("OPC") witness Barbara A. Meisenheimer. Additionally, I will provide rebuttal comments and evidence that address the direct testimonies on rate design by Mr. Scheperle, OPC witness Ryan Kind, Charter Communications witness Richard Stenneford, and Noranda Aluminum, Inc. ("Noranda") witness Henry Fayne. Lastly, I will provide rebuttal to certain Fuel Adjustment Clause ("FAC") testimony of Mr. Scheperle. Other Company witnesses will provide additional rebuttal testimony to address certain issues raised by these witnesses. My failure to address a particular witness' position or argument should not be construed as endorsement of same.

I. PRODUCTION PLANT ALLOCATION

Q. Please summarize the position stated by each of the parties in direct testimony in this docket as it relates to the allocation of fixed production plant.

A. The following provides a high level summary of each party's recommendation on the allocation of fixed production plant:

- Company – The Company utilized a four non-coincident peak ("4 NCP") version of the Average and Excess Demand Allocation methodology ("A & E") that gives weight to both a) class peak demands and b) class energy consumption.
- Staff – Staff provided two studies, one using a Judgmental Energy Weighting four coincident peak ("4 CP") method that incorporates judgmentally-established energy weightings into the cost study, and another using a Capacity Utilization Method that gives weight to both a) class peak demands and b) class energy consumption.
- OPC – OPC also utilized two methodologies, first a 4 CP version of the Peak and Average ("P & A") that gives weight to both a) adjusted class peak demands and b) class energy consumption, and second, a Time of Use ("TOU") allocation methodology which assigns demand related fixed production plant investments and associated depreciation reserve to each hour.
- Missouri Industrial Energy Consumers ("MIEC") – MIEC utilized the Company's recommended 4 NCP version of the Average and Excess Demand Allocation methodology.

Q. Have you prepared a table that summarizes the parties' positions on production plant allocation and the associated production plant allocation factors by customer class?

A. Yes, Table 1 depicts this summary.

Table 1

Party	Method	RES	SGS	LGS/SPS	LPS	LTS
Company (UE) & MIEC	4 NCP – A & E	46.7%	11.0%	28.6%	7.8%	5.9%
MPSC Staff 1	Judgmental 4CP	41.1%	10.4%	30.7%	9.2%	8.6%
MPSC Staff 2	Capacity Utilization	40.6%	10.4%	30.9%	9.3%	8.8%
OPC 1	4 CP – P & A	40.7%	10.3%	30.9%	9.5%	8.6%
OPC 2	TOU	38.2%	9.8%	31.7%	10.0%	10.3%

Q. With the exception of the OPC TOU allocation methodology, is there a common element in the remaining production plant allocation methods listed in Table 1?

A. Yes, the common element in all the methods is the use of class kilowatt-hours in the allocation of a portion of production plant. The reference to "A" (Average) in Table 1 for each of the methods is representative of class average demands that are calculated by dividing annual class energy consumption by 8,760 hours, the total number of hours in a year. Said class averages are computed as a percent of the system average demand and then multiplied by the system's annual load factor of approximately 55%. As a result, 55% of the Company's production plant investment is allocated on an energy basis regardless of the method listed in Table 1 (excepting TOU). Differences among the parties lie with the allocation of the remaining one minus system load factor (45%) portion of production plant investment. Such differences are driven by the use of "Excess" demands associated with Non-Coincident Peaks vs. total Non-Coincident or Coincident Peaks.

Q. The Company and MIEC have proposed the use of an A & E method for the allocation of production plant investment, while Staff and one of OPC's allocation methods proposes the use of the Peak and Average method. Please comment on the use of the A & E method vs. the P & A method for the allocation of production plant investment.

A. The use of the P & A method is inherently flawed as it double counts the average demand of customer classes. This double counting results from the previously described use of class average demand for a portion of production plant allocation (i.e., the 55% system load factor weighting piece) and the use of class peak or non-coincident peak demands, which include an average demand component for the remaining allocation of production plant (i.e., 45%). This double counting results in customers with higher load factors being allocated an inequitable share of production plant investment. This result is driven by the high load factor customers demonstrating a better correlation between average demands and peak demands than do lower load factor customers; therefore, higher load factor customers receive a disproportionate share of the non-average demand (i.e., 45%) portion of production plant investment.

The use of the A & E method is more equitable than the P & A method, as it does not suffer from the same double counting flaw. Instead, the A & E method utilizes "Excess" demands (i.e., the difference between class non-coincident or peak demands and class average demands) for application of the remaining 45% of production plant investment, thus avoiding any double counting of demands.

Q. Table 1 also lists the TOU production plant allocation methodology sponsored by OPC witness Meisenheimer. Please comment.

A. The TOU allocation method allocates production plant costs to customer classes over every hour of the year based upon class kWh use in each hour. A summation of the results for each customer class produced the production allocations shown in Table 1. For comparison purposes, the following Table 2 contains the results of Ms. Meisenheimer's TOU analyses for the production plant fixed allocators and also Mr. Kind's production variable (energy) allocator.

Table 2 - OPC Time of Use Fixed Production Allocation Results Compared to the Results of an Energy Allocator

	RES	SGS	LGS/LPS	LPS	LTS
Fixed	38.2%	9.8%	31.7%	10.0%	10.3%
Variable	37.0%	9.8%	32.2%	10.6%	10.4%

Q. Based on Table 2, what observations can be made regarding the results of the TOU allocation methodology for production plant investment?

A. Comparing the percentage share of the variable or running costs and the fixed or capacity costs illustrates how closely the allocation of capacity costs tracks the allocation of variable running costs under the TOU method. In fact, the individual class results for all but the residential class are either very close or virtually the same. Arguably, the application of the TOU method for the allocation of the Company's fixed production plant investment can be replicated with a simple energy allocation methodology.

Q. Does the TOU method promote the improvement of system load factor?

A. No. This method shifts additional costs from on-peak periods to off-peak periods, whenever off-peak usage is added. This will, in fact, have the effect of discouraging any addition of off-peak use while encouraging additional on-peak use. This result is the opposite of that which would produce an improvement in overall system load factor. Reduced demands during system peak periods will reduce or defer future production plant additions, thereby reducing the Company's investment in production plant required to serve its customers.

Additionally, improving load factor through additional off-peak sales will result in greater use of existing production plant capacity.

Q. Please summarize the Company's position on the use of the TOU method for the allocation of fixed production plant.

A. The TOU allocation method does not result in an equitable allocation of fixed production investment, as there is little or no balance between the consideration of energy and capacity associated with the Company providing production capacity. Moreover, this method does not support the important goal of improving system load factor.

Q. Please summarize the Company's overall position regarding the allocation of fixed production plant.

A. The Company's net investment in fixed production assets represents approximately 68% of net original cost rate base in this case. As a result, the variations in allocation of these assets depicted in Table 1 above produce significant differences in class cost of service requirements in this case.

In my opinion, the Company's 4 NCP A & E allocation methodology is superior to other proposals offered by parties in this docket due to its more balanced consideration of both the energy and excess demand requirements for serving each customer class. The consideration of energy is important due to its relevance in the type of generation on the Company's system, while the consideration of demand is also relevant due to its importance in the magnitude of the capacity of the Company's generating facilities. The A & E method assigns a weight of 55% to class energy requirements and 45% to class excess demands, based on the Company's annual system load factor of 55% during the study period. Additionally, the Company has utilized the 4 NCP A & E methodology for its most recent cases before the Commission and the continued use of this allocation methodology will promote cost of service stability. The Company is not suggesting that there is a single methodology for the allocation of these costs which can be deemed as the absolute, correct, and only method for the allocation of fixed production plant. However, it would be desirable to either continue the use of the 4 NCP A & E or to have some reasonable resolution of this particular issue in advance of future rate cases. Moreover, it would be highly advantageous to all parties to have the ability to rely upon a standardized methodology whose results could be reasonably predicted.

II. CLASS REVENUE REQUIREMENTS

Q. Please summarize the Company's position on the allocation of the revenue increase requested in this case.

A. As stated in my direct testimony, the Company is proposing to allocate the requested increase in this case on an across-the-board basis, with an equal percentage increase for all customer classes.

Q. What are the positions of the other parties on class revenue requirements?

A. The following Table 3 depicts a summary of the positions of the other parties:

Table 3

Party	Class Revenue Recommendation
MPSC Staff	Equal Percentage – Across-the-Board with $3M revenue neutral adjustment to Residential and ($3M) revenue adjustment to combined Large General Service/Small Primary Service Classes.
OPC	Equal Percentage – Across-the-Board.
MIEC	20% movement to MIEC's class cost of service study ("CCOSS") results with revenue neutrality at present rates for all classes except LTS; LTS would be moved to CCOSS results. The LTS shortfall would be allocated to remaining classes based on percent of revenues. Any overall change resulting in the case would be applied on an equal percentage across-the board-basis.

Q. Why should the Commission adopt the Company's across-the-board or equal percentage increase for all classes recommendation?

A. The Commission should adopt the Company's recommendation for the following reasons:

- While cost based rates are an important starting point in developing class revenue targets and rate design, there are other factors (e.g., public acceptance (particularly among the Company's largest rate class - residential customers), rate stability, and revenue stability from year to year) that should be considered when determining class revenue requirements and designing rates. Considering today's challenging economic conditions, these other factors take on more importance.
- Despite varying class cost of service study results, Staff (with a minor variation) and OPC are recommending an equal percentage or across-the-board allocation of the increase granted in this case.
- MIEC has not presented any compelling evidence to vary from the across-the-board approach recommended by the other parties.
- The Company's proposal is fairly consistent with the rates approved by the Commission in the Company's last rate case (Case No. ER-2008-0318).

Q. The overwhelming majority of speakers at the local public hearings held in this docket were residential customers expressing their discontent with the impact on their electric bill of the increase being requested in this case. Have you performed an analysis of a mechanism that the Commission could consider to mitigate the impact of a rate increase on residential customers?

A. Yes, I have. I examined the impact of shifting 1% of present revenues from the Company's Service Classification No. 1(M) Residential Service to Service Classification Nos. 11(M) – Large Primary Service and 12(M) – Large Transmission Service (i.e., the Company's service classifications with the lowest cents per kilowatt-hour realizations). Utilizing present class revenues, as updated for twelve months of usage through July 31, 2009 and shifting 1% of the residential class' revenue to the previously identified classes based on percent of combined revenue, the increase would be approximately 3.2% higher for each of these classes than it would be if an across-the-board allocation to all classes were used.

Q. Please continue.

A. The above analysis was performed to provide the Commission information on the impact on class revenues if, as a matter of public policy, the Commission desired to mitigate the rate increase for residential customers given the comments from the public at the local public hearings. In accordance with the Commission's February 10, 2010 *Order Directing the Parties to Address the Concerns Raised by AmerenUE's Low-Income Residential Customers*, the Company will provide additional information to the Commission regarding this important issue when it files direct testimony related to this issue on February 19, 2010.

III. RATE DESIGN

Q. On pages 5 and 6 of his testimony, Mr. Scheperle has five recommendations on rate design. Please comment.

A. Two of Mr. Scheperle's recommendations pertain to class revenue requirements which were addressed above. Mr. Scheperle's remaining three recommendations address "return[ing] non-residential rates schedules to interrelationship uniformity" and the proposed monthly customer charges for the Company's residential and small general service customer classes. With regard to the interrelationship uniformity, the Company's direct testimony in this docket reflects this same uniformity and the Company supports Mr. Scheperle's proposal in the final determination of affected rates in this docket.

Q. Moving now to Mr. Scheperle's recommendations of an increase to the residential monthly customer charge to $8.50 and to increase the small general service customer charges to $9.28 for single phase service and $18.56 for three phase service, do you agree with these recommendations?

A. No. Staff's Cost of Service/Rate Design Report on pages 26-27 indicates that Staff's CCOSS results support: a) a monthly residential customer charge of over two times the existing charge of $7.25 per month and b) a monthly general service customer charge of over $25 per month vs. the existing single phase general service charge of $8.03 per month. As stated in my direct testimony, the Company's CCOSS results supported a residential customer charge of approximately $20 per month and a weighted (i.e., single phase and three phase) general service charge of approximately $21 per month. Due consideration of the Staff's and Company's CCOSS results warrants implementing an above-average increase to the customer charges of these classes. Yet, the Staff's recommendations only represent a modest increase above the present customer charge levels. Also, Mr. Scheperle's Schedule MSS-6 indicates that the Company's residential and single phase general service customer charges are currently the lowest among the five investor-owned utilities in the state. This demonstrates that on an intra-state comparison basis, the Company's residential and single phase general service customer charges are lagging behind similar charges at other utilities, which further validates the CCOSS results. Lastly, due consideration of the expected customer energy use reductions associated with the Company's aggressive energy efficiency and demand response efforts and their impact on affording the Company a more reasonable opportunity to earn its authorized rate of return also provides support for the Company's recommendation. Notably, if the Commission were to approve the Company's recommend level of $10 for residential service and $11 for (single phase) general service, then the Company's levels would be approximately 7% above and 29% below the average tariff residential and general service levels, respectively, of the other electric utility tariffs within the state.

Q. On page 8 of Mr. Kind's testimony, Mr. Kind recommends that any increase should generally be made by making equal percentage changes to all rate elements. Do you agree?

A. Generally, yes. However, my earlier recommendations on interrelationship uniformity and the residential and small general service customer charges would be exceptions to this statement.

Q. On page 8 of Mr. Kind's testimony, Mr. Kind states OPC's belief that declining block charges are no longer an appropriate rate design for customers of Missouri regulated utility providers as they give customers an inappropriate price signal by charging lower per unit prices for higher levels of usage. Please comment.

A. The Company's only "pure" declining block rate is for residential winter energy usage and has been in place for decades. The retention of this declining block rate is warranted for three reasons: 1) to more fully utilize available existing production and transmission capacity installed to meet the higher summer demands for electricity, 2) to reflect the fact that additional winter demand can be served by the Company at a variable cost lower than its average running costs of generation, and 3) the material bill impact of the elimination of same on the Company's much above-average winter's energy use residential customers. Items 1 and 2 provide qualitative cost support for the Company's declining block residential rate, while item 3 addresses the basic rate principles of bill impact and public acceptance.

Q. On pages 9-10 of Mr. Kind's testimony, Mr. Kind states that Missouri consumers should be making investment decisions that impact the level of their future energy usage based on price signals that are generally in accordance with the direction of future utility rate design and, also, that declining block rates will go away in Missouri. Please comment.

A. While I respect Mr. Kind's right to prognosticate on the future of energy prices and energy regulation in Missouri, neither he nor the Company can accurately predict the long term future of energy prices or rate designs in Missouri. This statement is especially true considering, among other things, the uncertainty around carbon regulation or other environmental laws, the impact of renewables or new energy technology, and the evolving energy efficiency rules for the State of Missouri. Therefore, providing customers more than general direction on the long term future prices or rate design would be speculative, at best, and would be a disservice to our customers.

Q. On pages 8-9 of Mr. Stenneford's testimony, Mr. Stenneford proposes that the monthly customer charge for cable television power supplies that are unmetered be set equal to the customer charge contained in the Company's Service Classification No. 6(M) . Do you agree?

A. Yes. These connections are not metered and it is reasonable to assess these accounts the same monthly customer charge as other similarly situated customers. It should be noted that if the Commission approves this recommendation, then test year billing units and revenue will need to be adjusted to reflect this change.

IV. LTS RATE DESIGN AND FUEL ADJUSTMENT CLAUSE

Q. Have you read the testimony of Noranda witness Fayne concerning the Company's proposed take-or-pay rate design for its LTS tariff?

A. Yes, I have.

Q. At pages 7-8, of his direct testimony, Mr. Fayne indicates that if the Commission concludes that the Company's risk of Noranda curtailment should be mitigated, then the Company's fuel adjustment clause ("FAC") can be modified to allow the sales from energy, that otherwise would have been consumed by Noranda, to be excluded from the fuel clause. Please comment.

A. Mr. Fayne is correct. If the Commission is looking for an alternative to the Company's take-or-pay proposal then a modification to the Company's FAC can be made to achieve similar risk mitigation. As I outlined in my direct testimony, the Company's take-or-pay proposal was designed to address the very unusual circumstance of having one customer on the system that in effect requires the output of an entire large coal-fired generating plant, and whose load loss can immediately reduce the Company's return on equity by as much as approximately 300 basis points. It is thus critical that this kind of highly unusual and significant risk be mitigated. Like the take-or-pay proposal outlined in my direct testimony, Mr. Fayne's suggestion would also substantially mitigate this risk in a way that is fair to all customers, and this is apparently more acceptable to Noranda.

Q. Please describe such a modification.

A. The attached Schedule WLC-ER10 reflects modifications to the Company's existing FAC tariff that would implement a mechanism within the FAC such as proposed by Mr. Fayne. Schedule WLC-ER10 also contains a few "housekeeping" changes to the FAC recommended by Mr. Scheperle that I will discuss later. With regard to the Noranda-related modifications to the FAC, these revisions provide that incremental off-system sales revenues made possible by energy not taken by Noranda (but which can then be sold off-system by AmerenUE in the event Noranda's load is reduced) will be retained by AmerenUE to the extent, *but only to the extent* necessary to offset the loss of retail margins from Noranda due to any loss in Noranda load. Under this revision, once AmerenUE has received off-system sales revenues from megawatt hours not taken by Noranda equal to the lost Noranda margin, all additional off-system sales revenues would flow to customers (without any sharing by AmerenUE). As a consequence, customers will in any event be no worse off than they would have been if Noranda's consumption remained at test year load levels, but they are likely to receive additional benefits due to the additional off-system sales revenues that any loss in Noranda load makes possible.

Q. Please describe the FAC tariff changes necessary to implement this mechanism.

A. The revised FAC incorporates three discrete and straightforward changes to the FAC formula to place AmerenUE and its customers in the same position as they would have been had no Noranda load loss occurred. First, the term "OSSR" (Off-System Sales Revenues) has been modified to exclude the revenues from additional off-system sales that would be made possible due to any loss in Noranda load. Second, the term S_{AP} (Supplied kWh) has been modified to include the kilowatt hours that would have been supplied to Noranda (i.e., the test year levels of kWh), if the loss of load had not occurred. Finally, a new factor "N" has been added to the formula to flow through to customers 100% of any incremental margin (beyond the lost Noranda margin) which might be earned by selling the power in the off-system market instead of to Noranda.

Commission approval of these changes to the FAC tariff would afford AmerenUE the same reasonable opportunity to earn its allowed rate of return as the take-or-pay approach, and, at the same time, ensure that other customers are unaffected by any variations from the test year load level of Noranda. In fact, other customers could benefit from any loss of Noranda load once the Company has been made whole (i.e., once the Company has been able to realize the same margin it would have realized had Noranda's load not been lost or reduced).

Q. Please elaborate on why other customers would not be affected by variations in Noranda's load level versus the load level assumed in the test year.

A. Both the Company and the Staff have calculated their revenue requirement recommendations using Noranda's test year load, with the exception that we have ignored the large load reduction that took place due to the devastating ice storm in Southeast Missouri in late January 2009. Consequently, both the Company's and the Staff's revenue requirements assume Noranda at full load, which means that Noranda's load for revenue requirement-setting purposes is assumed to be approximately 440 megawatts at an approximately 98 percent load factor. What this means is that the base rates to be set in this case will assume retail revenues (of approximately $164 million) to the Company from Noranda based upon this load and load factor, will assume a certain level of costs are assigned to Noranda's rate class and away from other rate classes, and will also assume that the power and energy Noranda is assumed to take will not be available for off-system sales, which as the Commission is aware flow through the FAC. If, however, Noranda's load drops again, the Company would immediately lose substantial revenues from Noranda, and would then also immediately increase its off-system sales, which would create a windfall for other customers who, by virtue of Noranda's circumstances (e.g., a huge loss of production due to an ice storm) will see their rates go down. The FAC modifications prevent this windfall, keep all other customers whole, keep the Company whole, and even provide some mitigation of lower revenues at Noranda that a production shortfall at Noranda could cause since Noranda would gain some portion of the potential benefit of additional off-system sales made possible by a load reduction at Noranda. Schedule WLC-ER11 contains an example of the impact of these FAC modifications if it is assumed that some event were to cause Noranda to shut down one of its three "pot lines" and thus reduce its load by approximately one-third.

Q. Earlier you mentioned certain "housekeeping" changes to the FAC tariff recommended by staff with Mr. Scheperle. Please comment.

A. The Company agrees with Mr. Scheperle's housekeeping changes, all of which are reflected in the attached Schedule WLC-ER10.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service.	) Case No. ER-2010-0036) Tracking No. YE-2010-0054) Tracking No. YE-2010-0055

AFFIDAVIT OF WILBON L. COOPER

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

Wilbon L. Cooper, being first duly sworn on his oath, states:

1. My name is Wilbon L. Cooper. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a AmerenUE as Manager, Rates and Tariffs.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 17 pages and Schedules WLC-ER10 through WLC-ER11, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Wilbon L. Cooper
Wilbon L. Cooper

Subscribed and sworn to before me this 10th day of February, 2010.

G L Waters
Notary Public

My commission expires: 4/17/2011

G. L. Waters - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #07452863
My Commission Expires 4/17/2011

~~*~~ RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE

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), 8(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, net of Off-System Sales Revenues (OSSR) (i.e., Actual Net Fuel Costs) and Net Base Fuel Costs (factor NBFC, as defined below), calculated and recovered as provided for herein.

For purposes of this FAC, the true-up year shall be from March 1 through the last day of February of the following year. The Accumulation Periods and Recovery Periods are as set forth in the following table:

Accumulation Period (AP)	Filing Date	Recovery Period (RP)
February through May	By August 1	October through September
June through September	By December 1	February through January
October through January	By April 1	June through May

Accumulation Period (AP) means the historical calendar months during which fuel and purchased power costs, including transportation, net of OSSR for all kWh of energy supplied to Missouri retail customers are determined.

Recovery Period (RP) means the billing months as set forth in the above table during which the difference between the Actual Net Fuel Costs during an Accumulation Period and NBFC are applied to and recovered through retail customer billings on a per kWh basis, as adjusted for service voltage level.

* The Company will make a Fuel and Purchased Power Adjustment (FPA) filing by each Filing Date. The new FPA rates for which the filing is made will be applicable starting with the Recovery Period that begins following the Filing Date. All FPA filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

FPA DETERMINATION

Ninety five percent (95%) of the difference between Actual Net Fuel Costs and NBFC for all kWh of energy supplied to Missouri retail customers during the respective Accumulation Periods shall be reflected as an FPA_C credit or debit, stated as a separate line item on the customer's bill and will be calculated according to the following formulas.

For the FPA filing made by each Filing Date, the FPA_C rate, applicable starting with the Recovery Period following the applicable Filing Date, to recover fuel and purchased power costs, including transportation, net of OSSR, to the extent they vary from Net Base Fuel Costs (NBFC), as defined below, during the recently-completed Accumulation Period is calculated as:

* Indicates ~~Addition~~Change.

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

* $FPA_{(RP)}$ = [[(CF+CPP-OSSR-TS-S) – (NBFC x S_{AP})]x 95% + I + R - N]/S_{RP}

The FPA rate, which will be multiplied by the voltage level adjustment factors set forth below, applicable starting with the following Recovery Period is calculated as:

$$FPA_C = FPA_{(RP)} + FPA_{(RP-1)} + FPA_{(RP-2)}$$

where:

FPA_C = Fuel and Purchased Power Adjustment rate applicable starting with the Recovery Period following the applicable Filing Date.

FPA_{RP} = FPA Recovery Period rate component calculated to recover under/over collection during the Accumulation Period that ended prior to the applicable Filing Date.

$FPA_{(RP-1)}$ = FPA Recovery Period rate component from prior FPA_{RP} calculation, if any.

$FPA_{(RP-2)}$ = FPA Recovery Period rate component from FPA_{RP} calculation prior to $FPA_{(RP-1)}$, if any.

CF = Fuel costs incurred to support sales to all retail customers and Off-System Sales allocated to Missouri retail electric operations, including transportation, associated with the Company's generating plants. These costs consist of the following:

* a) For fossil fuel or hydroelectric plants:

(i) the following costs reflected in Federal Energy Regulatory Commission (FERC) Account Number 501: coal commodity, applicable taxes, 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 (for purposes of factor CF, hedging is defined as realized losses and costs minus realized gains associated with mitigating volatility in the Company's cost of fuel and purchased power, 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), hedging costs associated with SO2 and fuel oil

* Indicates ~~Addition~~Change.

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

adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, ash disposal revenues and expenses, and revenues and expenses resulting from fuel and transportation portfolio optimization activities; and

(ii) the following costs reflected in FERC Account Number 547: natural gas generation costs related to commodity, oil, transportation, storage, capacity reservation charges, fuel losses, hedging costs, and revenues and expenses resulting from fuel and transportation portfolio optimization activities;

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

CPP = 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 (other than relating to the Taum Sauk Plant) to the extent those premiums are not reflected in base rates. Changes in replacement power insurance premiums (other than those relating to the Taum Sauk Plant) 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 (other than those relating to the Taum Sauk Plant) qualifying as assets under Generally Accepted Accounting Principles. Notwithstanding the foregoing, concurrently with the date the "TS" factor is eliminated as provided for in this tariff, the premiums and recoveries relating to replacement power insurance coverage for the Taum Sauk Plant shall be included in this CPP Factor.

OSSR = Revenues from Off-System Sales allocated to Missouri electric operations.

Off-System Sales shall include all sales transactions (including MISO revenues in FERC Account Number 447), excluding Missouri retail sales and long-term full and partial requirements sales, that are associated with (1) AmerenUE Missouri jurisdictional generating units, (2) power purchases made to serve Missouri retail load, and (3) any related transmission.

* Indicates Addition.

*** RIDER FAC**

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

** Off-System Sales shall exclude all revenues derived from the off-system sale of power made possible as a result of reductions in the level of sales billed under Service Classification 12(M) below the level of normalized 12(M) load as determined in Case No. ER-2010-0036.

*TS = The Accumulation Period value of Taum Sauk. This factor will be used to reduce actual fuel costs to reflect the value of Taum Sauk, and will be credited in FPA filings (of which there are three each year as shown in the table above), until the next rate case or, if sooner, until Taum Sauk is placed back in service. This value is ~~$22.7~~$26.8 million ~~annual~~ annually ~~for each true-up year as determined in the rate proceeding in which this FAC was established~~, one third of which (i.e., ~~$7.56~~$8.93 million) will be applied to each Accumulation Period.

S = The Accumulation Period value of Blackbox Settlement Amount of $3 million annually, which shall expire on September 1, 2010. One third of the annual value ($1 million) shall be applied to each Accumulation Period. For the Accumulation Period during which the factor expires, the factor shall be prorated according to the number of days during which it was effective during that Accumulation Period.

**N = The positive amount by which, over the course of the Accumulation Period, (a) revenues derived from the off-system sale of power made possible as a result of reductions in the level of 12(M) sales (as addressed in the definition of OSSR above) exceeds (b) the reduction of 12(M) revenues compared to normalized 12(M) revenues as determined in Case No. ER-2010-0036.

*I = Interest applicable to (i) the difference between Actual Net Fuel Costs (adjusted for Taum Sauk and factor "S") and NBFC for all kWh of energy supplied to Missouri retail customers during an Accumulation Period until those costs have been recovered; (ii) refunds due to prudence reviews (a portion of factor R, below); and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the ~~annual~~ true-up filings provided for herein (a portion of factor R, below). 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.

* Indicates ~~Addition~~Change.

** Indicates Addition.

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

* R = Under/over recovery (if any) from currently active and prior Recovery Periods as determined for the ~~annual~~ FAC true-up adjustments, and modifications due to adjustments ordered by the Commission (other than the adjustment for Taum Sauk as already reflected in the TS factor), as a result of required prudence reviews or other disallowances and reconciliations, with interest as defined in item I.

* S_{AP} = Supplied kWh during the Accumulation Period that ended prior to the applicable Filing Date, at the generation level. Factor S_{AP} shall include the kWh reductions in the level of sales (at the generation level) to 12(M) customers below the level of normalized 12(M) load (at the generation level) as determined in Case No. ER-2010-0036.

S_{RP} = Applicable Recovery Period estimated kWh, at the generation level, subject to the FPA_{RP} to be billed.

* NBFC = Net Base Fuel Costs are the net costs determined by the Commission's order as the normalized test year value (and reflecting an adjustment for Taum Sauk, consistent with the term TS) for the sum of allowable fuel costs (consistent with the term CF), plus cost of purchased power (consistent with the term CPP), less revenues from off-system sales (consistent with the term OSSR), less an adjustment (consistent with the term "S"), expressed in cents per kWh, at the generation level, as included in the Company's retail rates. The NBFC rate applicable to June through September calendar months ("Summer NBFC Rate") is X.XXX cents per kWh. The NBFC rate applicable to October through May calendar months ("Winter NBFC Rate") is X.XXX cents per kWh.

*To determine the FPA rates applicable to the individual Service Classifications, the FPA_C rate determined in accordance with the foregoing will be multiplied by the following voltage level adjustment factors:

Secondary Voltage Service	1.0789~~888~~
Primary Voltage Service	1.0459~~92~~
Large Transmission Voltage Service	1.0124~~47~~

The FPA rates applicable to the individual Service Classifications shall be rounded to the nearest 0.001 cents, to be charged on a cents/kWh basis for each applicable kWh billed.

*Indicates ~~Addition~~Change.

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

*** TRUE-UP OF FAC**

After completion of each Recovery Period, ~~After the completion of each true-up year,~~ the Company will make a true-up filing in conjunction with an adjustment to its FAC, where applicable. The true-up filings ~~make a true-up filing by May 1 of each year (starting by May 1, 2010) with the Commission. Such filings~~ shall be made on the first Filing Date that occurs at least two (2) months after completion of each Recovery Period.~~by May 1 of every subsequent year until all fuel and purchased power costs accumulated during the effective period of the FAC have been recovered and trued-up.~~ Any true-up adjustments or refunds shall be reflected in item R above, and shall include interest calculated as provided for in item I above.

The true-up adjustments shall be the difference between the revenues billed and the revenues authorized for collection during the Recovery Period~~true-up year~~.

****GENERAL RATE CASE/PRUDENCE REVIEWS**

The following shall apply to this Fuel and Purchased Power Adjustment Clause, 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 Missouri Public Service Commission order implementing or continuing this Fuel and Purchased Power Adjustment Clause. The four-year period referenced above shall not include any periods in which the Company is prohibited from collecting any charges under this Fuel and Purchased Power Adjustment Clause, or any period for which charges hereunder must be fully refunded. In the event a court determines that this Fuel and Purchased Power Adjustment Clause is unlawful and all moneys collected hereunder are fully refunded, the Company shall be relieved of the obligation under this Fuel and Purchased Power Adjustment Clause to file such a rate case.

Prudence reviews of the costs subject to this Fuel and Purchased Power Adjustment Clause shall occur no less frequently than every eighteen months, and any such costs which are determined by the Missouri Public Service Commission to have been imprudently incurred shall be returned to customers with interest at a rate equal to the weighted average interest rate paid on the Company's short-term debt.

* Indicatges Change.
** Indicates ~~Addition~~Reissue.

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

Calculation of Current FPA_C Rate:

	Accumulation Period Ending:		mm/dd/yy
1.	Total Energy Cost (CF+CPP-OSSR-TS-S)		$0
2.	Base Energy Cost	-	
	2.1 NBFC ($/kWh)	x	$0.0000
	2.2 Accumulation Period Sales kWh (S_{AP})		0
3.	First Subtotal (1.-2.)		$0
4.	Customer Responsibility	x	95%
5.	Second Subtotal		$0
*6.	Adjustment for Under / Over recovery for Prior Periods Plus Interest less Factor "N" (I + R - N)	±	$0
7.	Third Subtotal		$0
8.	Estimated Recovery Period Sales kWh (S_{RP})	÷	0
9.	FPA_{RP}		$0.0000
10.	FPA_{RP-1}	+	$0.0000
11.	FPA_{RP-2}	+	$0.0000
12.	FPA_C (without Voltage Level Adjustment)		$0.0000
*13.	Voltage Level Adjustment Factor		
	13.1 Secondary	x	1.0789
	13.2 Primary	x	1.0459
	13.3 Large Transmission	x	1.0124
14.	FPA_C (with voltage level adjustment)		
	14.1 Secondary		$0.0000
	14.2 Primary		$0.0000
	14.3 Large Transmission		$0.0000

* Indicates Change.

Illustration of Impact on AmerenUE and Remaining AmerenUE Customers of 1.4 Million MWh of Lost Noranda Load

($ Millions)

	Impacts Without FAC [1]	Impacts Under Current FAC [2]	Impacts Under Proposed FAC [3]
Impact on AmerenUE			
Lost Retail Revenues	-$52.9	-$52.9	-$52.9
Gained OSSR	$50.1	$50.1	$50.1
FAC Adjustment	$0.0	-$30.0	$0.0
Net Impact on AmerenUE	**-$2.8**	**-$32.8**	**-$2.8**
Windfall Benefit to Customers	**$0.0**	**$30.0**	**$0.0**

Notes:

(1) Loss of 1.4 million MWh of Noranda Load at $38.60/MWh (approximately one-third of Noranda's production).

(2) OSSR gain of 1.4 million MWh at $36.59/MWh.

(3) Underlying data for this analysis was extracted from workpapers of AmerenUE Witnesses Timothy Finnell and Gary Weiss