Exhibit No.:	
Issues:	Fuel Adjustment Clause, Off-system sales sharing; MISO Cost Allocations
Witness:	Shawn E. Schukar
Sponsoring Party:	Union Electric Company
Type of Exhibit:	Rebuttal Testimony
Case No.:	ER-2007-0002
Date Testimony Prepared:	February 5, 2007

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2007-0002

REBUTTAL TESTIMONY

OF

SHAWN E. SCHUKAR

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

St. Louis, Missouri
February 5, 2007

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REBUTTAL
TESTIMONY
(ON FUEL ADJUSTMENT CLAUSE ISSUES)
OF
SHAWN E. SCHUKAR
CASE NO. ER-2007-0002

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Shawn E. Schukar. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63166-6149.

Q. Are you the same Mr. Schukar that filed Direct and Supplemental Direct Testimony in this proceeding?

A. Yes, I am. I also filed rebuttal testimony on January 31, 2007 ("January 31 Rebuttal Testimony"), which addressed various parties' December 15, 2006 testimony about wholesale power prices and other issues related to off-system sales.

Q. What is the purpose of your rebuttal testimony filed today?

A. My rebuttal testimony filed today is in response to various parties' December 29, 2006, direct testimonies addressing AmerenUE's proposed fuel adjustment clause ("FAC"). In particular, I will: (1) respond to claims that the "passive nature" of off-system sales in today's market obviates the need for off-system sales ("OSS") incentives; (2) respond to parties' concerns about AmerenUE's proposed treatment of OSS margins, including issues related to the sharing of OSS margins, in the context of the proposed FAC; and (3) address concerns over and clarify the allocation of fuel and purchased power costs, including Midwest Independent Transmission System Operator, Inc. ("MISO") charges, between native load and off-system sales.

Q. Before you address these issues, please summarize the OSS treatment and incentives that AmerenUE has proposed or offered for consideration in combination with its FAC proposal.

A. In combination with its FAC proposal, AmerenUE has (1) proposed the traditional "fixed" base rate treatment of OSS margins; and (2) offered for consideration an alternative OSS sharing mechanism.

Under its proposed "fixed" treatment, the traditional regulatory treatment would continue to apply to OSS margins. This involves reducing the Company's test-year revenue requirement by the value of normalized off-system sales; that is, test-year OSS margins create a "fixed offset" to base rates. The costs subject to true-up through the FAC would consequently only involve the fuel and purchased power costs the Company incurs in supplying its native load. As explained in the rebuttal testimonies of AmerenUE witnesses Mr. Martin J. Lyons and Professor John Mayo, this treatment of native load fuel costs (through the FAC) and OSS (through base rates) preserves important incentives to maintain or improve generating plant performance, which creates efficiencies that directly benefit customers.

AmerenUE has also offered for further consideration an alternative treatment of OSS in the form of an OSS margin sharing mechanism. I have presented a possible sharing grid in my direct testimony under which customers would (1) receive a guarantee of $120 million of OSS margins through a credit to AmerenUE base revenue requirement; (2) receive an additional 80% of realized OSS margins in excess of $120 million up to $180 million[1] per year; (3) receive an additional 50% of realized OSS margins in excess of $180 million up to $360 million per year; and (4) receive an additional 100% of any realized OSS margins in excess of $360 million

per year. As Mr. Lyons explained in his direct testimony, the Company is also offering for further consideration this sharing mechanism grid in combination with the proposed FAC.

II. MISO MARKETS DO NOT OBVIATE THE NEED FOR OSS INCENTIVES.

Q. MIEC Witness James Dauphanais contends in his December 29, 2006 testimony that the relatively passive nature of MISO off-system sales obviates any need for incentives. [Dauphanais Direct Testimony, December 29, 2006, p. 8. l. 17-20]. Is he correct?

A. No, not at all. It is true that the MISO Day 2 Market has, in some sense, made it easier to make off-system sales by simply bidding generation into the MISO day-ahead or real-time market. However, Mr. Dauphanais totally overlooks the fact that the availability and production cost of AmerenUE's generation fleet will significantly affect the Company's ability to sell into the MISO market. Making OSS margins in the MISO energy market is relatively "easy" only if a Company has a cost-effective, well-performing fleet of generation that can sell power at the MISO market-clearing prices. As Professor Mayo and Mr. Lyons explain in their rebuttal testimonies, AmerenUE's proposed treatment of OSS will give the Company the incentive to optimize plant performance so as to maximize OSS.

Moreover, Mr. Dauphanais implicitly assumes that all of AmerenUE's OSS would occur in the MISO day-ahead spot markets. This is not the case. AmerenUE has explored and will continue to explore opportunities to sell various generation products in short- and long-term bilateral forward markets. Both marketing and negotiations are required to make sales in bilateral markets for energy, capacity, or other wholesale products (such as full or partial requirements sales). In addition, Ameren Energy exerts significant effort to manage the

[1] After updating budgeted figures for the last three months of the test year to actual figures in my September 29, 2006 Supplemental Direct Testimony, the $180 million figure originally included in my July 7, 2006

placement of load and generation into the market to both reduce the costs associated with serving native load, reduce MISO charges, and improve OSS sales. Passing through all of the costs and OSS margins as suggested by Mr. Dauphanais would eliminate the incentives associated with the management of costs and the improvement in margins.

III. ANALYSIS OF ALTERNATIVE FAC AND OSS SHARING PROPOSALS.

Q. Mr. Brubaker has proposed in his December 29, 2006, testimony an alternative FAC and OSS sharing mechanism. Please describe what Mr. Brubaker has proposed.

A. Mr. Brubaker proposes an FAC in which under- or over-recovery of fuel costs would be shared between AmerenUE ratepayers and shareholders. Mr. Brubaker would eliminate the OSS incentive by netting all OSS revenues against AmerenUE's fuel and purchased power costs to determine the Company's "net" or baseline fuel cost. There would be a $10 million deadband around the baseline level of fuel costs (*i.e.*, rates would not be adjusted if fuel costs deviated from the baseline by less than $10 million). Outside of the deadband, the next $50 million of change in net fuel costs would be shared 90% to customers and 10% to shareholders. Beyond $60 million, the next $50 million would be shared 80% to customers and 20% to shareholders. Beyond this $110 million, there would be a full flow through to customers of any changes in net costs. (Brubaker Direct Testimony, December 29, 2006, p. 9, l. 2-20).

Q. Do you believe Mr. Brubaker's proposal is an appropriate sharing mechanism?

A. No. While Mr. Brubaker's proposal to share net fuel costs around a base level may appear reasonable at first blush, it has several problems that would make it an inappropriate and ineffective regulatory policy.

Direct Testimony became $183 million.

First, the proposal is heavily biased against AmerenUE given that fuel costs have been increasing and despite being uncertain, as Mr. Neff explains in his February 5, 2007 rebuttal testimony, are expected to increase further in the next several years. In addition, AmerenUE's continued load growth will not only further increase total fuel costs, but it will also reduce OSS margins by reducing the amount of generation available for OSS. This combination of increasing fuel costs and declining OSS margins means that it is much more likely that AmerenUE will have to *absorb* fuel cost and OSS margin changes (i.e., face net fuel costs in excess of Mr. Brubaker's baseline) than it would be able to share the benefit of net fuel costs below Mr. Brubaker's baseline. In other words, Mr. Brubaker's suggestion would almost certainly result in an immediate deterioration in AmerenUE's ROE versus that allowed by the Commission and likely necessitate a rate case shortly after the end of this rate case. This means Mr. Brubaker's proposal would defeat one of the main objectives of an FAC, that is, to reduce the need for frequent rate proceedings due to fuel cost changes that are largely outside the control of AmerenUE and other utilities. This would not only impose the significant administrative costs of more frequent rate cases on the Commission and all stakeholders, but would simultaneously reduce the incentives the Company would otherwise have to control non-fuel-related costs, as explained in the rebuttal testimonies of Professor Mayo and Mr. Lyons.

Second, Mr. Brubaker's proposal fails to recognize the fact that AmerenUE's fuel costs are largely outside of the Company's control and that there are areas where the Company has significantly more control (e.g., plant performance and availability) that have a much larger effect on its OSS. Fuel costs are for the most part driven by market forces that affect the price of delivered fuel (i.e., commodity and transportation) which are largely outside the utility's control. In contrast, factors such as plant availability and plant operating efficiency, over which

AmerenUE (like other utilities) has substantially more control, have a much larger affect on OSS because OSS are only made on the generation that remains available after supplying native load. By lumping OSS together with native load fuel costs, Mr. Brubaker creates a mechanism that puts the Company at risk for factors that are largely outside its control while allowing it to share only a small portion of the benefits associated with factors it can more readily control. Mr. Brubaker's design in effect reduces the incentives that not only allow AmerenUE to benefit through OSS, but that also benefit ratepayers through lower fuel costs that need to be recovered in the FAC. This is inconsistent with the considerations about the design of incentive mechanisms for effective fuel adjustment clauses discussed in Professor Mayo's rebuttal testimony.

Third, it provides only modest incentives. This is because outside the $10 million deadband, shareholders would only receive (or be at risk for) between 10% and 20% of fuel and OSS variances from the baseline, which provides only very muted incentives.

Based on these considerations, I strongly recommend against Mr. Brubaker's proposal. AmerenUE's recommendation to apply the FAC only to its retail load fuel and purchase power costs while maintaining the traditional regulatory treatment of OSS margins is a far more effective proposal.

Q. Please comment on the FAC and OSS treatment recommended by Mr. Binz in his December 29, 2006 testimony.

A. Mr. Binz, testifying on behalf of AARP, opposes implementation of an FAC altogether. That aspect of his testimony is addressed in Mr. Lyons' rebuttal testimony. If an FAC is implemented, however, he recommends that deviations from fuel costs be either shared equally around the base rate amount (pp. 25-26), or that such sharing of fuel cost deviations be

based on various sharing bands around the base amount, similar to a mechanism that was recently implemented in Wyoming to address purchased power costs of a Pacificorp subsidiary (pp. 27-28). This proposal for the sharing of fuel costs has at least three of the problems I noted about Mr. Brubaker's proposal: (1) it is biased against the Company in today's increasing fuel and transportation cost environment; (2) it contains ineffective incentives because it attempts to hold the Company responsible for costs that are largely outside its control; and (3) it would still likely require the Company to file more frequent rate cases, which would reduce efficiency incentives with respect to non-fuel costs and impose added administrative burden on the Commission and other parties.

With respect to OSS, Mr. Binz promotes the retention of the traditional regulatory treatment, which is consistent with AmerenUE's proposal. In fact, he stresses "that it is perfectly defensible to continue the practice of including a fixed level of margin revenue in base rates" (p. 30) and that the OSS "margin sharing mechanism can have a different structure than the FAC" (p. 30). I agree.

Q. If an OSS sharing mechanism were to be considered, Mr. Binz recommends that the sharing should be centered around the "base level" of OSS margins "set on the basis of the best evidence of likely future value [which] is at least $183 million in this case" (p. 30). How do you respond?

A. Mr. Binz does not make a specific recommendation about how OSS margins would be shared around the $183 million base amount. Rather, he recommends that the implementation details be left to negotiations between the parties. I believe this would be a feasible approach. With respect to his recommendation to use the base level of OSS margins and his general discussion of FAC and OSS sharing principles, it appears Mr. Binz might be

suggesting a sharing proposal similar to that recommended by Mr. Higgins in his December 15, 2006 testimony.

Mr. Higgins proposes a 50/50 sharing of OSS margins for both positive and negative deviations above and below the $183 million base line. As I noted in my January 31 response to Mr. Higgins, such symmetric 50/50 sharing of OSS margins would be feasible if the FAC were implemented because the FAC would allow sharing credits to flow both ways. While even without an FAC a positive sharing amount could be distributed to customers as a bill credit, it would require an FAC or similar rate adjustment mechanism to collect through retail rates any negative sharing amount. As I also noted in my January 31 response, sharing symmetrically both positive and negative deviations from the $183 million baseline is an alternative sharing structure that could provide benefits similar to the sharing grid I proposed in my direct testimony.

IV. COST ALLOCATIONS AND MISO CHARGES.

Q. Two witnesses (Mr. Brubaker and Mr. Dauphanais) contend that the Company's proposed treatment of OSS margins could allow AmerenUE to shift costs associated with OSS to native load sales and to similarly shift revenues from native load sales to OSS. What is your response to these cost allocation concerns?

A. I believe this should not be a concern. AmerenUE has long had to allocate costs and revenues between native load sales and OSS under the Joint Dispatch Agreement ("JDA"). These allocation processes are well established and ensure that the lowest cost resources are allocated to native load. In fact, the cost allocations performed under the JDA were significantly more complex because the JDA also required allocations between AmerenUE and other Ameren subsidiaries. The December 31, 2006 termination of the JDA should make this process easier going forward. Moreover, as explained in the direct testimony of Mr. Lyons, there are extensive

minimum filing requirements associated with an FAC and in the subsequent true-up proceedings. AmerenUE will provide exhaustive monthly surveillance data during the period that the FAC is in effect and there will be a detailed annual review and reconciliation of FAC-related costs. Thus, there will be extensive documentation of AmerenUE's fuel and energy costs.

Q. Mr. Dauphanais contends that the methods to allocate fuel and purchased power costs between AmerenUE native load and off-system sales are not sufficiently clear and detailed. What is your response?

A. I recognize that there appears to be some confusion as to what costs, including MISO costs, will be included in the FAC and how they are allocated between AmerenUE's native load and its off-system sales. I will consequently attempt to clarify both native load cost allocations and MISO charge issues. Schedule SES-12 describes the proposed allocations in detail. The principles used for these allocations have been applied for many years under the JDA, and the proposed allocation methods related to MISO issues also have been in place, for the most part, since the start of the MISO market on April 1, 2005. The allocations for AmerenUE will be significantly simplified with the elimination of the JDA.

Q. Would you please summarize at a higher level than Schedule SES-12 how AmerenUE will allocate fuel- and power-related costs between native load and off-system sales on a going-forward basis?

A. The overriding principle behind the allocation of fuel and MISO-related costs to native load and off-system sales is that the least expensive resources in AmerenUE's supply stack are allocated to native load. The principle of allocating the cheapest resources to native load has been applied under the JDA for nearly a decade.

Q. How does AmerenUE ensure that the least expensive resources are allocated to native load?

A. Computer software is used to allocate AmerenUE supply resources between native load and OSS. This software was developed and applied for JDA cost allocations. The software's allocation methodology is based on logic that, on an hourly basis, "stacks" all of AmerenUE's resources (generation and purchases) from lowest cost to highest cost and matches this resource stack with AmerenUE's native load and off-system sales obligations. As such, while the basic allocation process has been used for many years, it needed to be modified somewhat in 2005 to reflect MISO Day 2 operations.

These hourly allocations are conducted on a daily and end-of month basis to ensure that the most up-to-date prices and metered values are reflected in the transactions. A monthly report is then created to summarize the MWhs by generator assigned to AmerenUE native load and to OSS. Actual fuel costs are then applied by generator to calculate the actual fuel costs used to serve AmerenUE native load and OSS.

Q. How do you respond to Mr. Dauphanais' specific concern that the MISO Day 2 Market makes such allocations more complex?

A. His concern is overstated. While I agree that MISO issues are sometimes seemingly complex and involve a lot of detail and individual charge types, I think this concern is mostly due to the relative newness of MISO operations, particularly MISO Day 2 operations. Most market participants have been adapting their accounting and cost allocation systems to the new market structure. AmerenUE has been doing so as well. A clear allocation of MISO charges between AmerenUE native load and off-system sales will be needed for management reporting purposes irrespective of whether the proposed FAC and OSS treatment is implemented.

In addition, it is important to recognize that most other utilities in the MISO region have FACs and presumably have found a way of satisfactorily allocating MISO costs in their FAC, base rates, or other rate adjustment mechanism.

Q. Please explain in more detail how AmerenUE will allocate MISO charges and credits between native load and off-system sales?

A. As noted, allocation methods related to MISO issues have been in place, for the most part, since the start of the MISO market on April 1, 2005, as they were necessary to administer the JDA. Again, the termination of the JDA allowed significant simplification of the allocation process for MISO charges and credits on a going-forward basis. The basic principle for the allocation of MISO charges and credits is to follow, to the maximum extent possible, the cost causation method MISO uses to calculate the respective invoice items. Otherwise, the MW contributions of native load and OSS ("MW-hour ratio") on an hourly basis are used to allocate MISO charges and credits.

With respect to the MISO charges and credits incurred by AmerenUE, two methods will be used to allocate the charges/credits between AmerenUE native load and OSS:

- *Cost-causation method*: Charges/credits are directly assigned based on the method MISO uses to determine the charge. Charges/credits appearing under the "UELSE" asset owner (i.e., AmerenUE as the MISO "load serving entity") will be directly assigned to native load under this method since the UELSE asset owner is only used for AmerenUE load. This method is also utilized for FTR revenue credits of "UEGEN" (i.e., AmerenUE as the owner of generating facilities).

- *MW ratio method*. Charges/credits are assigned based on the ratio of the resource MWs assigned to native load or the resource MWs assigned to OSS and the total resource MWs. The resource MWs assigned to native load or OSS are based on the hourly results of the software. With the exception of UEGEN's FTR revenue credits, this MW ratio will be applied to all other UEGEN charges and credits.

Q. Have you prepared an illustration of what these MISO allocations between AmerenUE's native load and its off-system sales would look like?

A. Yes. Table 1 included in Schedule SES-12 covers the over 30 MISO invoice items and groups them into eight MISO charge and credit categories: congestion, deviations, inadvertent distributions, administrative, losses, revenue neutrality, and revenue sufficiency guarantee charges. For each of these MISO invoice items, the table shows AmerenUE's proposed allocations of MISO charges and credits associated with load (UELSE) and generation (UEGEN). To illustrate the magnitude of the MISO invoice categories and their approximate allocations between AmerenUE native load and OSS, this table also shows how AmerenUE's combined MISO charges and credits for 2006 would have been allocated based on these principles in the absence of the JDA and reflecting 2007 operating conditions. For the purpose of setting base rates and FAC rates in this case, AmerenUE will finalize these allocations of 2006 MISO charges and credits with other revenue requirement items as part of the true-up data to be provided under the Procedural Schedule in this case.

Q. How have these MISO costs related to off-system sales been considered in your $183 million baseline OSS margin?

A. They are not considered in the $183 million OSS baseline. The Company's revenue requirement currently has allocated all test-year MISO costs to native load. Given that 2006 MISO charges related to off-system sales amount to approximately $3.4 million (see Table 1 in Schedule SES-12), this means native load-related costs are overstated by $3.4 million and OSS costs were understated by $3.4 million. While this leaves the total revenue requirement the same (because the $183 million OSS margin is credited against native load-related costs), it does mean that the $183 million OSS margin baseline also is overstated by the $3.4 million in OSS-related MISO charges that were not considered in the determination of the OSS margin.

Q. Mr. Dauphanais raises several specific concerns associated with the allocation of certain MISO payments. For example, on pages 20-21 of his December 29 testimony he states that it is not clear whether AmerenUE is properly netting RSG Make Whole Payments allocated to native load from RSG Distribution amounts. What is your response?

A. I concur with Mr. Dauphanais. After reviewing the allocation of RSG Make Whole payments, AmerenUE has revised its proposed allocation (as reflected in Table 1 of Schedule SES-12) to assign these payments to both AmerenUE native load and OSS, based on the MW ratio of the resources assigned to AmerenUE native load and OSS.

Q. On pages 20-21 of his December 29 testimony, Mr. Dauphanais lists two additional examples of MISO settlement amount allocations that he states are "clearly unreasonable." What are his concerns and how do you respond?

A. His first concern is that allocating MISO adjustments to previously incurred MISO charges should be booked as an offset to Account 555 charges, rather than assign them to Account 457. Mr. Dauphanais is correct that the benefit can either be to native load or to OSS,

but his concern is unfounded since AmerenUE's proposal is actually more beneficial to native load. Consider two scenarios. In the first scenario, the prior period adjustment is a credit to a 400 series account, which is netted against current period charge (500 series account). This would result in the native load receiving a reduced 500 account charge (i.e., a benefit to native load). In the second scenario, the prior period adjustment is a debit to a 500 series account, which is netted against current period credit (a 400 series account). This would result in native load *not* receiving the charge adjustment and OSS receiving a reduced 400 account credit. In both instances, AmerenUE's proposed netting benefits native load and is a detriment to OSS.

Second, Mr. Dauphanais notes that it appears to be unreasonable to allocate MISO FTR settlement amounts between native load and off system sales on the basis of sales activity. He recommends that FTR settlement amounts should be allocated between native load and off-system sales based on the volume of FTRs obtained on behalf of native load and off-system sales. I believe his comments reflect a misunderstanding of AmerenUE's proposal. The AmerenUE proposal allocates FTR settlement amounts based on the purpose of the FTR. If the FTR is associated with transmission between generation and native load, the FTR settlement amount will be allocated to native load. If the FTR is associated with a point-to-point transmission service associated with OSS, the FTR settlement is allocated to OSS. This is highlighted in Table 1 of Schedule SES-12. I believe this is consistent with Mr. Dauphanais' recommendation.

Q. Does this conclude your rebuttal testimony?

A. Yes.

FAC and Off-System Sales Allocations

Guiding Principals used for the Allocation Methodology

The proposal to allocate Fuel and Purchase Power Costs and MISO charges/credits to AmerenUE Native Load (defined below) and Off-system sales from AmerenUE generation ("OSS") is based on the following principles:

- AmerenUE will fully participate in the MISO market by selling available generation into the market and buying load obligations from the market
- The lowest cost resources committed and operated in the MISO market will first be allocated to Native Load obligations and then to OSS
- MISO Charges/credits will be allocated to AmerenUE Native Load and OSS based on the cost-causation method used by MISO to calculate the charge/credit, if possible, or by the MW contributions by Native Load and OSS ("MW-hour ratio")

The principle of allocating the lowest cost resources to Native Load has been applied for many years under the Joint Dispatch Agreement ("JDA"); the proposed allocation methods related to MISO issues have been in place, for the most part, since the start of the MISO market on April 1, 2005. The allocations of these costs and charges for AmerenUE are significantly simplified with the termination of the JDA. As used in this document, Native Load includes both AmerenUE's Missouri-jurisdictional retail load and its Missouri wholesale loads (e.g.,municipalities supplied by AmerenUE under full-requirements contracts). Fuel, Purchase Power and MISO costs (net of credits) are allocated between MO retail and MO wholesale loads based on the variable allocation factor (i.e.,kWh sales).

Fuel Cost Allocations

Energy settled in the MISO market is allocated between Native Load and OSS using a computerized program that matches resources (generation, purchases) to obligations (Native Load, sales) on an hourly basis. The stacking logic used is based on the following general rules:

1. Generation committed in the MISO must operate at least at the minimum safe operating range ("Minimum Load"). The Minimum Load is placed in the resource stack first, ordered by the calculated incremental dispatch cost (based on the currently available fuel cost and heat rates).
2. Following the Minimum Load stacking, all remaining generation and purchase resources are stacked in the resource stack by dispatch cost or purchase cost from the lowest to the highest cost.
3. Native Load is placed first in the obligation stack, thus ensuring that the lowest cost resource available is allocated to Native Load. OSS are then placed in the obligation stack after the Native Load.

While the steps necessary to complete the process have changed as the market structure has changed (e.g., MISO), the overall guiding principle that Native Load should receive the least expensive energy resource has remained unchanged since the start of the JDA and has been in use for nearly a decade.

The following discussion outlines the processes being utilized to apply these principles to AmerenUE's power purchase and sale transactions as they occur today in the MISO marketplace: The proper allocation of costs associated with the principles listed above requires the identification of incremental purchases and sales to and from the MISO associated with the Day Ahead ("DA") and Real Time

("RT") commitment and dispatch processes. To determine the incremental MISO transaction in the DA process, all of the physical resources that clear in the DA market and all of the physical obligations in the DA market are matched to determine if incremental purchases or sales are necessary in the DA process. The DA resources include AmerenUE generation and physical purchases and DA obligations include cleared load and physical sales. If the DA cleared resources are greater than the DA cleared obligations, then MISO DA sales are identified to be included in the actual obligation stack. If the DA cleared resources are less than the DA cleared obligations, then MISO DA purchases are identified to be included in the actual resource stack. These MISO purchases/sales are priced at the DA market clearing price.

In the RT process, like the DA process, all of the physical resources that clear in the RT market and all of the physical obligations that clear in the RT market are matched to determine if incremental RT MISO purchases or sales are needed. RT resources include the following: (1) RT generation output that exceeds the DA generation awards ("Positive RT Generation Deviation"), (2) RT physical purchases and (3) actual load consumption that is less than the DA awarded load bids ("Negative RT Load Deviation"). RT obligations include the following: (1) RT load that exceeds the DA awarded load bids ("Positive RT Load Deviation"), (2) RT physical sales, and (3) RT generation output that is less than the DA generation awards ("Negative RT Load Deviation"). If the RT cleared resources are greater than the RT cleared obligations, then MISO RT sales are identified to be included in the actual obligation stack. If the RT cleared resources are less than the RT cleared obligations, then MISO RT purchases are identified to be included in the actual resource stack. These MISO purchases/sales are priced at the RT market clearing price.

It is then necessary to net DA and RT loads and DA and RT generation to ensure that the stack represents the actual load and generation. Net Load obligations are determined by adding the DA load with the Positive and Negative RT Load Deviations. Net Generation is determined on a unit-by-unit basis by adding the DA Generation with the Positive or Negative RT Generation Deviations.

Once all of the resources and obligations have been identified and the DA and RT netting of load and generation is completed, it is then necessary to stack up all of the resources and obligations to determine the cost allocation. The obligation stack contains the Net Load, RT physical sales, DA physical sales, DA MISO sales and RT MISO sales. The Obligation Stack is as follows with the Net Load always being first in the stack.

RT MISO Sales
RT Physical Sales
DA MISO Sales
DA Physical Sales
Net Load

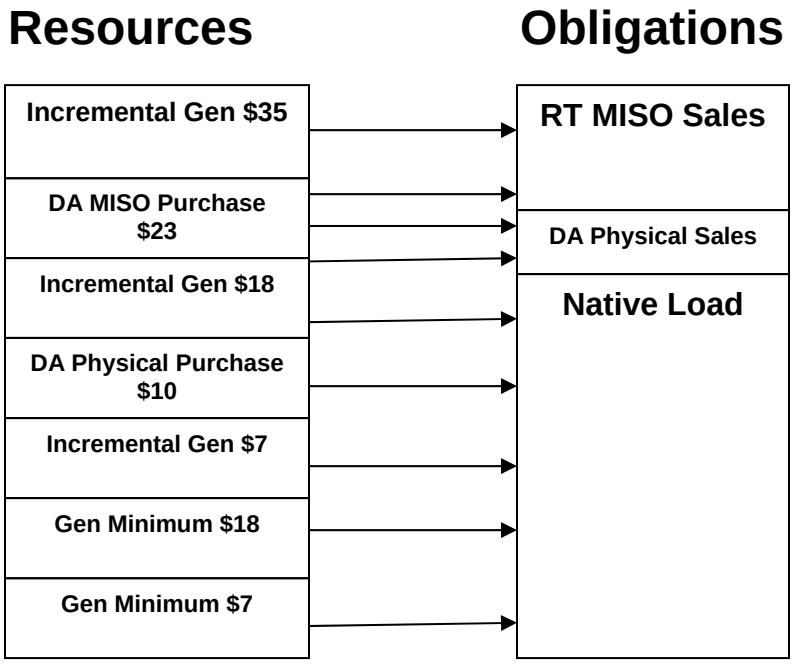
The resource stack contains the Net Generation, DA physical purchases, DA MISO Purchases, RT physical purchases, and RT MISO Purchases. The Net Generation resource is identified unit by unit. In addition the Net Generation for each unit is separated between Generation Minimum and incremental generation where the Generation Minimum is the safe minimum operating level for each unit and the incremental generation is the difference between the Net Generation and the Generation Minimum. Since the Generation Minimum is required for any unit that is on and operating, the Generation Minimum is always placed first in the resource stack. The rest of the resources are then stacked

according to the cost of the resource with the lowest cost resource being placed first in the stack. The following shows the resource stack:

RT MISO Purchases
RT Physical Purchases
DA MISO Purchases
DA Physical Purchases
Incremental Generation
Generation Minimums*

* Generation Minimums are always the lowest in the stack and other resources are stacked by cost

Once the resource and obligation stacks are determined, the hourly obligations that are lowest in the stack are matched with the lowest cost available resources for that hour. The following example shows the matching of obligations with resources (assume resource costs are stacked lowest cost to highest cost



Monthly Closing Process for Fuel Cost Allocations

The DA, RT and Actual allocation are created on a daily basis and re-created again at the end of the month to ensure that the most up-to-date prices and metered values are reflected for the transactions. A monthly report is created to summarize the MWhs by generator assigned to AmerenUE Native Load and to OSS. Actual fuel costs are then applied by generator to calculate the actual fuel costs used to serve AmerenUE Native Load and OSS. These values are then recorded on the General Ledger.

MISO Virtual Transactions

MISO virtual transactions are purely financial instruments that do not affect the stacking of physical power within the allocation program. Virtual transactions on MISO Asset Owner UELSE are for the benefit of AmerenUE Native Load and are directly assigned to AmerenUE. However, the virtual transactions conducted under MISO Asset Owner UEGEN are for UE's generation fleet which may be allocated to load or OSS. As a result the UEGEN virtual transactions are allocated on an hourly basis based on the ratio of UE generation used to supply AmerenUE Native Load versus OSS.

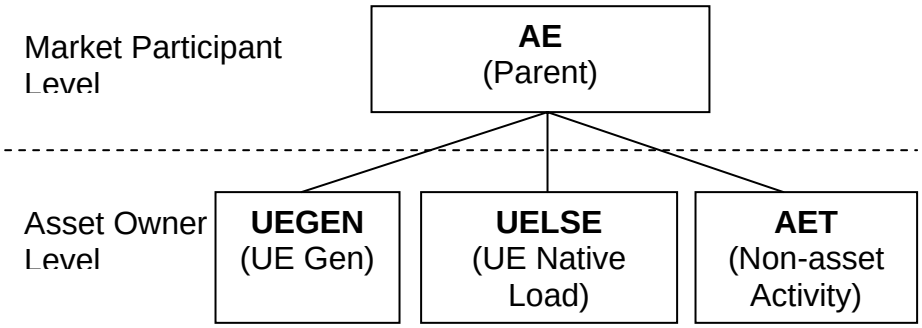
Allocation of Financial Hedges

AmerenUE's hedging policy allows Ameren Energy to lock-in forward prices on sales of excess generation positions and purchases to cover Native Load when generation is forecast to be short of meeting such obligations. Forward financial sales are made to hedge the excess generation position and the financial hedge is therefore considered an OSS transaction. When forward financial purchases are made to cover Native Load due to a short generation position these purchases are considered a Native Load cost.

Allocation of MISO Charges/Credits

Starting January 1st, 2007 Ameren modified the Market Participant structure of UE and Ameren Energy to consolidate their market activities under one consolidated Market Participant (AE). Rolling up to AE in a hierarchal format are the MISO Asset Owners UELSE , UEGEN (for UE generation) and AET (Ameren Energy non-asset based activity).

Ameren's MISO Market Participants (Jan07)



Using these separate and clearly defined Asset Owners will enable us to clearly distinguish the cause of MISO charges and credits between load, generation and other trading activity because MISO settles the markets at the asset owner level (invoices at the market participant level).

Ameren will allocate MISO charges/credits between AmerenUE load and OSS for the costs that appear on the UELSE and UEGEN asset owners. The AET asset owner will only incur cost related to non-asset activities in the market thus they will not impact AmerenUE Native Load or OSS. The Asset, Non-Asset and Virtual energy charges will be allocated using the methods described in the "Fuel Cost Allocations" and "MISO Virtual Transactions" sections of this document.

Two methods will be used to allocate the charges/credits between AmerenUE Native Load and OSS:

1. Cost-causation method: Charges/credits are directly assigned based on the method MISO uses to determine the charge. Charges appearing under the UELSE asset owner will be directly assigned to Native Load under this method because the UELSE asset owner is only used for AmerenUE Native Load;
2. MW- hour ratio method: Charges/credits are assigned based on the hourly ratio of resource MWs assigned to Native Load or resource MWs assigned to OSS and the total resource MWs. The resource MWs assigned to Native Load or OSS are based on the rules described in the "Fuel Cost Allocations" section. This allocation methodology will be applied to most of the charges/credits under the UEGEN asset owner to properly allocate the charges/credits associated with generation in the same manner the energy from these resources are allocated to AmerenUE Native Load and OSS.

Any resettlements of the MISO charges/credits will be allocated based on the same allocation method and ratios used during the actual operating month the charge/credit was incurred.

Table 1 shows the allocation method for each charge/credit and the corresponding estimated allocation of 2006 actual charges/credits. Due to the JDA rules and the asset owner configuration in 2006, these allocations are only approximations of the breakdown of the charges/credits between AmerenUE Native Load and OSS.

Table 1: MISO Charge Allocations for FAC and OSS

Category	Category includes these MISO Charges:	2007 Allocation Method		Estimated Allocation of 2006 Actuals		
		UELSE asset owner	UEGEN asset owner	2006 Total	Native Load*	OSS
Congestion:				**$ 17,908,587**	**$ 16,564,193**	**$ 1,344,394**
	DA Congestion Rebate on Option B GFA	Cost Causation (100% load)	MW-hour Ratio Method			
	RT Financial Bilateral Transaction Congestion Amount	Cost Causation (100% load)	MW-hour Ratio Method			
	RT Congestion Rebate on Carve-out GFA	Cost Causation (100% load)	MW-hour Ratio Method			
	DA Financial Bilateral Transaction Congestion Amount	Cost Causation (100% load)	MW-hour Ratio Method			
	DA Congestion Rebate on Carve-out GFA	Cost Causation (100% load)	MW-hour Ratio Method			
Deviation:				**$ 97,654**	**$ 90,323**	**$ 7,331**
	RT Uninstructed Deviation Amount	Cost Causation (100% load)	MW-hour Ratio Method			
FTR:				**$ (13,447,208)**	**$ (12,437,729)**	**$ (1,009,479)**
	FTR Hourly Allocation Amount	Cost Causation (100% load)	**Cost Causation (100% OSS)			
	FTR Monthly Allocation Amount	Cost Causation (100% load)	**Cost Causation (100% OSS)			
	FTR Transaction Amount	Cost Causation (100% load)	**Cost Causation (100% OSS)			
	FTR Yearly Allocation Amount	Cost Causation (100% load)	**Cost Causation (100% OSS)			
Inadvertent Distribution:				**$ (550,734)**	**$ (509,391)**	**$ (41,343)**
	RT Net Inadvertent Distribution Amount	Cost Causation (100% load)	MW-hour Ratio Method			
Administrative:					**Not included in FAC**	**$ 520,500**
	DA Market Administration Amount	Cost Causation (100% load)	MW-hour Ratio Method			
	FTR Market Administration Amount	Cost Causation (100% load)	MW-hour Ratio Method			
	RT Market Administration Amount	Cost Causation (100% load)	MW-hour Ratio Method			
	DA Schedule 24 Allocation Amount	Cost Causation (100% load)	MW-hour Ratio Method			
	RT Schedule 24 Allocation Amount	Cost Causation (100% load)	MW-hour Ratio Method			
	RT Schedule 24 Distribution Amount	Cost Causation (100% load)	MW-hour Ratio Method			
Losses:				**$ 23,253,071**	**$ 21,507,468**	**$ 1,745,603**
	DA Financial Bilateral Transaction Loss Amount	Cost Causation (100% load)	MW-hour Ratio Method			
	DA Loss Rebate on Option B GFA	Cost Causation (100% load)	MW-hour Ratio Method			
	RT Financial Bilateral Transaction Loss Amount	Cost Causation (100% load)	MW-hour Ratio Method			
	RT Distribution of Losses Amount	Cost Causation (100% load)	MW-hour Ratio Method			
	RT Loss Rebate on Carve-out GFA	Cost Causation (100% load)	MW-hour Ratio Method			
	DA Loss Rebate on Carve-out GFA	Cost Causation (100% load)	MW-hour Ratio Method			
RNU:				**$ 6,836,984**	**$ 6,323,733**	**$ 513,251**
	RT Revenue Neutrality Uplift Amount	Cost Causation (100% load)	MW-hour Ratio Method			
RSG:				**$ 7,357,027**	**$ 6,988,645**	**$ 368,381**
	DA Revenue Sufficiency Guarantee Distribution Amount	Cost Causation (100% load)	MW-hour Ratio Method			
	DA Revenue Sufficiency Guarantee Make Whole Payment Amount	Cost Causation (100% load)	MW-hour Ratio Method			
	RT Revenue Sufficiency Guarantee First Pass Dist Amount	Cost Causation (100% load)	MW-hour Ratio Method			
	RT Revenue Sufficiency Guarantee Make Whole Payment Amount	Cost Causation (100% load)	MW-hour Ratio Method			
				$ 41,455,381	**$ 38,527,244**	**$ 3,448,637**

**** - FTRs under UEGEN are those allocated to Point-to-Point transmission reservations and used for OSS**

*** - Native Load includes both AmerenUE's Missouiri-jurisdictional retail load and its Missouri wholesale loads (e.g., municipalities supplied by AmerenUE under full requirements contracts)**

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Natural Gas Service Provided to Customers in the Company's Missouri Service Area.	)))))	Case No. ER-2007-0002

AFFIDAVIT OF SHAWN E. SCHUKAR

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

Shawn E. Schukar, being first duly sworn on his oath, states:

1. My name is Shawn E. Schukar. I work in the City of St. Louis, Missouri, and I am employed by Ameren Energy, Inc. as Vice President.

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 14 pages and Schedule SES-12, 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.

Shawn E. Schukar

Subscribed and sworn to before me this 5th day of February, 2007.

D. Bradley
Notary Public

My commission expires:

D. Bradley - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #06923315
My Commission Expires 8/6/2010