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Witness:	Timothy D. Finnell
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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2007-0002

REBUTTAL TESTIMONY

OF

TIMOTHY D. FINNELL

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

St. Louis, Missouri
January, 2007

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TIMOTHY D. FINNELL

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Q. Please state your name and business address.

A. My name is Timothy D. Finnell. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63166-6149.

Q. Are you the same Mr. Finnell that filed Direct Testimony in this proceeding?

A. Yes, I am.

I. INTRODUCTION AND SUMMARY

Q. What is the purpose of your Rebuttal Testimony in this proceeding?

A. My rebuttal testimony has five principal purposes. First, I identify errors or unreasonable modeling assumptions associated with the Missouri Public Service Commission's Staff (Staff or MPSC Staff) production cost modeling and quantify the impact of those problems to the extent possible. Second, I respond to certain other parties' criticisms of AmerenUE's production cost modeling which was performed using AmerenUE's PROSYM production cost model, as discussed in my direct testimony filed on July 7, 2006. Third, I respond to the MPSC Staff's suggestion that heat rate data used in AmerenUE's modeling is somehow inaccurate. Fourth, I respond to the Missouri Industrial Energy Consumer's (MIEC) vague and unsupported "suggestion" that AmerenUE's model results understate the megawatt hours (MWhs) produced by AmerenUE's generating units. Fifth, I explain why MIEC witness James R. Dauphanais' criticisms of the operating reserve requirements modeled by AmerenUE are unfounded. Finally, I update the normalized fuel, variable purchase power costs and off-system sales revenues supplied in my direct testimony using more recently available data, including more recent data used by the MPSC Staff in its production cost modeling filed with its direct testimony on December 15, 2006.

Q. Please outline the problems you have identified with the MPSC Staff modeling results.

A. I have identified at least ten errors or unreasonable modeling assumptions that I will address in further detail in my rebuttal testimony. I want to point out that it is my understanding, based upon my work with the MPSC Staff in recent weeks, that the MPSC Staff is aware of and possibly addressing items 1 through 5 below. Consequently, my rebuttal testimony on those items may be unnecessary. However, given that at this point the MPSC Staff has made no filing to correct the concerns relating to these items, as reflected in the MPSC Staff's December 15, 2006 filing, I address those items, and others, below. The 10 errors or unreasonable assumptions are as follows:

1. Planned outages at the Company's Callaway Plant were poorly and unrealistically scheduled.

2. Forced outages at the Callaway Plant were modeled in an inappropriate and unorthodox manner.

3. Coal blending that is necessary for optimal plant operations at the Sioux Plant was modeled improperly.

4. Hourly load profiles and hourly energy market prices are not adequately synchronized.

5. Line losses were improperly calculated.

6. Unit availability rates are inaccurate.

7. The MPSC Staff's model introduced unrealistically high levels of off-system sales volumes.

8. Staff's levels of normalized prices are overstated, as explained in Mr. Schukar's rebuttal testimony, also leading to overstated off-system sales margins.

9. The modeling of output from Electric Energy, Inc. (EEInc.) that the Company is not receiving overstates off-system sales volumes in the MPSC Staff's model.

10. An alternative method for valuing off-system sales in the MPSC Staff's production model would have produced lower margins, even without correcting the other MPSC Staff production cost modeling problems.

Q. Please summarize your response to certain other parties' criticisms of the Company's PROSYM modeling which underlies its direct filing in this case.

A. One criticism, alleged in various forms in the testimonies of MPSC Staff witness Michael Rahrer, Office of Public Counsel (OPC) witness Ryan Kind, and MIEC witness James Dauphanais, is that the AmerenUE PROSYM model cannot be reliably calibrated to actual conditions, due to the significant changes in the marketplace. As I discuss later in my rebuttal testimony, AmerenUE's model follows industry-standard practices in ensuring reliability of its results. Moreover, AmerenUE's model has been calibrated using actual data from historical periods. Once such a calibration is done, one can be confident that the model can produce reasonable results in terms of predicting variable production costs in the future based upon a set of modeling assumptions designed to represent expected future conditions. Indeed, that is precisely what models do.

Q. Please summarize your response to the MPSC's Staff's suggestion that perhaps the Company's heat rate data is inaccurate.

A. It is apparent that the MPSC Staff witness sponsoring this "suggestion" has no understanding of how AmerenUE's heat rate data is derived, and indeed admits he has no evidence whatsoever that the heat rate data is inaccurate in any way. The Company's heat rate data is current and accurate, having been updated in June 2006, just prior to the filing of this case.

Q. Please summarize your response to MIEC witnessess' Messrs. Dauphanais and Brubaker who criticize AmerenUE's levels of generation output.

A. In short, their criticism of the level of generating unit output is vague and unsupported.

Q. Mr. Dauphanais also raises an issue regarding the Company's modeling of operating reserves. Please summarize your response.

A. Mr. Dauphanais' testimony makes clear that he does not understand operating reserve requirements because he has not mentioned the regulating component of operating reserves. The operating reserve components that impact production cost modeling (i.e., spinning and regulating reserves) were modeled correctly.

Q. What are the fuel cost updates that you propose?

A. There are seven fuel cost updates that need to be made, all of which are minor adjustments discovered in the course of the MPSC Staff's audit in this case, as follows: (1) the removal of the magnesium hydroxide expense from the Labadie fuel costs; (2) the reclassification and update of urea costs at the Sioux Plant from a fuel expense item to an operating and maintenance (O&M) expense; (3) the Sioux Plant generation profile has been revised to reflect an 83%PRB/17% Illinois coal blend; (4) use of the same coal price updates for fuel costs used by the MPSC Staff in its modeling (as of November 21, 2006); (5) updating the nuclear fuel costs using information provided in the Rebuttal Testimony of AmerenUE's witness Mr. R. J. Irwin; (6) updated natural gas prices to reflect 2006 prices; and (7) updating the dispatch costs for the Sioux, Rush, and Meramec generating units to correct a modeling input error.

II. MPSC STAFF PRODUCTION COST MODELING ERRORS OR UNREASONABLE ASSUMPTIONS

Q. Earlier you listed ten errors or unreasonable modeling assumptions discovered in the MPSC Staff's final production cost modeling. Did these production cost modeling problems exist in the MPSC benchmark run?

A. No. In an attempt to promote the accurate modeling of AmerenUE's production costs for a normalized test year, the MPSC Staff had its production cost modeler, Mr. Rahrer, "benchmark" the RealTime model used by Staff and developed by Mr. Rahrer's company against AmerenUE's PROSYM model used to support AmerenUE's direct case filing. As discussed below, this kind of benchmarking was unusual and less accurate than benchmarking against actual data. However, most of the 10 errors or unreasonable modeling assumptions I have outlined above were caused by specific inputs or assumptions that the MPSC Staff directed Mr. Rahrer to use. As Mr. Rahrer indicated, he did not exercise his discretion in deciding if a particular assumption or input he was given was correct, and indeed, he was, in his words, "just a mechanic here" when it came to producing modeling results for the MPSC Staff. (Rahrer Deposition, Jan. 16, 2007, p. 26, l. 20-25; p. 27, l. 1-2; Deposition Exh. 1, p. 39).

Q. Please address the first problem, the poor and unrealistic scheduling of planned outages at the Callaway Plant.

A. The MPSC Staff used the same planned outages used by AmerenUE at all of AmerenUE's generating units except, curiously, at the Callaway Plant. At Callaway, the MPSC Staff reduced the length of the Callaway outage modeled by AmerenUE and then moved the outage scheduled by AmerenUE from the Spring to the Fall.

Q. Why is this a concern?

A. Outages must be planned to take into account operating requirements (e.g., because of the every-18-month refueling needs at a nuclear plant, Callaway's outages always occur at approximately 18-month intervals) and by taking into account planned outages at other major units. This is because planned outages across major units must be balanced so that not too many units are out of service at one time, both due to reliability considerations and operating limitations. When the MPSC directed Mr. Rahrer to move the planned Callaway outage from the Spring to the Fall, and left the planned outage schedule for the other units the same,[1] the MPSC Staff produced an unbalanced outage schedule which results in higher reserve margins in the Spring and lower reserve margins in the Fall. As Mr. Rahrer testified in his deposition, it is normal to spread outages among major units between the Spring and the Fall, as opposed to scheduling a large number of major units to be out of service in one season or the other. (Rahrer Deposition, Jan. 16, 2007, p. 121, l. 9-13). Yet, the MPSC Staff, by requiring Mr. Rahrer to model a Callaway planned outage in November, recommended a schedule that departed from this norm and that created potential reliability concerns. Indeed, Mr. Rahrer did nothing to verify whether it was reasonable or feasible to model planned outages in this way, save to ask the MPSC Staff "for their opinion." (Rahrer Deposition, Jan. 16, 2007, p. 125, l. 9-25).

Schedule TDF-9 illustrates Staff's scheduling of planned outages and shows how the scheduling produces significant reserve imbalances. Page 1 of the schedule shows how Staff scheduled outages for AmerenUE's major plants. Note the clustering of significant outages across the bulk of AmerenUE's baseload generation during the September - December time

[1] "Isn't it a fact that you were not able to avoid the coincidence of some other major unit planned outages in November? A. That's correct * * * So you've got Labadie 1, Sioux 1 and Callaway all out at the same time in your modeling, right? A. That's what it looks like, yes." (Rahrer Deposition, Jan. 16, 2007, p. 124, l. 13-16; l. 24-25; p. 125, l. 1).

period. As shown on this calendar, there are just approximately 804,000 MWh of outages during the four-month period of February through May, but over *four times* that amount (about 3.2 million MWh) during the four-month period of September through December.

Page 2 of the schedule shows the result of Staff's assumptions on AmerenUE's resulting reserves. The shaded area quantifies the average hourly availability of AmerenUE resources under Staff's assumptions. The line plots the peak hourly load during each week of the year. The significant valley in the shaded area between September and October is a direct result of Staff's decision to schedule too many major overhauls simultaneously. AmerenUE's planned schedules avoid this significant reserve imbalance that is illustrated on Schedule TDF-9-2.

The MPSC Staff also ignored, and it appears failed to consider, other important factors that must be considered when developing an annual planned outage schedule for a fleet of generating units, including as follows: whether enough contractors and other support personnel are available for coincident planned outages at multiple units; whether parts and other materials are available; and the elapsed time since the last planned outage. There is no evidence that Staff took any of these factors into account when instructing Mr. Rahrer to change the planned outage schedule. Finally, as Dr. Proctor confirmed in his deposition, an outage scheduled during the relatively lower-priced Fall period yields higher off-system sales margins than if the outage would have been scheduled during the higher-priced Spring period. (Proctor Deposition, Jan. 12, 2007, p. 90, l. 20-25). Thus, Staff's change, like other mistakes and unreasonable modeling assumptions Staff directed Mr. Rahrer to make or use, was biased in favor of creating higher off-system sales margins by an estimated $3.5 million and thus lowered the Company’s revenue requirement.

Q. What changes would you recommend to levalize the reserve margins?

A. I recommend that the planned outage schedule used by AmerenUE be maintained. However, if the Callaway outage were to be scheduled in the Fall period, then it would be necessary to move another unit's planned outage from the Fall to the Spring. Moving the Labadie outage would make the most sense in that event.

Q. Please identify the second modeling problem associated with the Callaway unplanned outages.

A. Mr. Rahrer states that the unplanned outages for Callaway were assigned to specific dates given to him by the MPSC Staff, rather than using his RealTime model, as is normal, to randomly generate unplanned outages throughout the period under study. (Rahrer Deposition, Jan. 16, 2006, p. 54, l. 10-14; p. 127, l. 7-25; p. 128, l. 9-12). The unplanned outages include partial outages or derates, forced outages, and short term maintenance outages used to repair equipment problems. Schedule TDF-10 shows the months where the unplanned outages were assigned, as well as the monthly market energy price used by the MPSC Staff in its model. The focus of this Schedule is to show the impact of Staff's unplanned outage assumptions, so I have removed the scheduled outage from the highlighted columns of November and April. This schedule indicates that the MPSC Staff results are a function of how the MPSC Staff required Mr. Rahrer to model unplanned outages, and are biased. The bias results in either understating the cost to serve native load or overstating revenues from off-system sales. In either case, the bias understates AmerenUE's revenue requirement. I estimate the annual impact of this error to be $1.3 million. What the MPSC Staff should have done is to model unplanned outages at Callaway based on randomly generated outages as was done for the Company's other generating units, and as Mr. Rahrer himself agrees is the normal method of modeling unplanned outages.

Q. What is the third problem you found related to Sioux coal blending in the MPSC final run?

A. Before identifying the problem, it is important to have a general understanding of why coal is blended at the Sioux Plant and how the coal blending affects its operation and output. The Sioux Plant can burn both Powder River Basin, Wyoming (PRB) and Illinois coal. The Illinois coal has a much higher heat content and is much more expensive on a per-ton basis, and also has much higher sulfur content. Consequently, there are environmental impacts (or economic impacts created by sulfur content) related to the percentage of Illinois coal that can be burned at the Sioux Plant.

AmerenUE seeks to use an optimal blend of PRB and Illinois coal at the Sioux Plant so that the Sioux Plant's variable production costs are kept at the lowest possible level. This means that the cost of the coal, the economics of consuming more SO2 allowances when burning more of the higher sulfur content Illinois coal, and market prices for electricity all must be considered in determining what blend of coal to use during given times of the Sioux Plant's operation.

When the MPSC Staff modeled the operation of the Sioux Plant, they used a coal blend during certain time periods that was unsupported by the economics of running the plant, and that also created operational problems. The end result was that Staff's model predicted approximately 449,000 megawatt hours (MWhs) more output from the Sioux Plant than could actually be achieved given these economic and operational considerations. The estimated impact of this error is $11.6 million.

Q. **Please elaborate further.**

A. Schedule TDF-11 shows a load duration curve for Sioux Unit No. 1 for calendar year 2005, versus a curve for the MPSC Staff modeling results. Schedule TDF-11 shows a large difference between how the units are actually operated and how the units were modeled by Staff. This large difference is almost certainly due to the coal blending that is done at the Sioux Plant. The Sioux Plant burns, depending on economic/operational conditions, three different blends of PRB and Illinois coal. Each of the coal blends results in a different generation level. The capacity limits for each coal blend are listed in Schedule TDF-12. For example, under normal operating conditions, 80% of the coal burned at Sioux is PRB. Under that coal blend, the plant's maximum capacity is at 452 MW. At a 50% PRB/50% Illinois coal blend, the plant's maximum capacity is 504 MW. Given that the average blend (shown on Schedule TDF-12) is an 83% PRB/17% Illinois coal blend, that blend is the proper blend to use in modeling the Sioux Plant's output.

Q. Is the 83% PRB / 17% Illinois coal blend a fixed constraint?

A. No, but the 83% PRB / 17% Illinois blend is an expected annual average blend , although it could change due to a number of factors such as: coal quality, market conditions, and plant operating considerations. For the purposes of this case, AmerenUE (and Staff, as discussed below) have now assumed that a coal blending strategy of 83% PRB/17% Illinois coal is optimal and have used a unit rating schedule which produces an annual blend of 83 % PRB/17% Illinois coal blend. The example illustrated in Schedule TDF-13 supports this assumption.

Q. Did AmerenUE use this blending assumption in its modeling?

A. Yes. The AmerenUE variable production costs for the Sioux Plant were calculated using an 83% PRB/17% Illinois coal blend. We arrived at this blend after optimizing the use of the fuel. The optimization took into account coal supply limits, the minimum or maximum time constraints that may exist for certain coal blends, the maximum capacity for each coal blend, and the energy prices. Schedule TDF-13 is an example of the economics used to determine when a coal blend switch should be made.

This schedule illustrates how expected profit margins are used to determine when it is economic to switch to a premium coal blend. On page 1 of the schedule, I provide an example where market prices for power are expected to be low ($35.00/MWh). While a premium coal blend allows greater output, the greater output comes at a much higher cost. In this example, the profit margins under a coal blend for normal operating conditions (left-hand panel) far exceed the profit margins under a premium coal blend (right hand panel). Thus, it would make no economic sense to switch to a premium blend if market prices were expected to be around the $35/MWh level.

Page 2 of this schedule presents another example where market prices are expected to be much higher ($67/MWh). In this case, the extra revenues from greater output under the premium blend generate margins that are slightly higher than the blend used under normal operating conditions. Thus, one would need to expect market prices around $66 - $67 to justify switching to a premium coal blend. Otherwise, Sioux would be more profitable under the blend used for normal operating conditions.

Given that market energy prices are generally more likely to be well below this $66 to $67 threshold,[2] it is not surprising that that the expected average annual blend is near the blend used for normal operating conditions (80% PRB).

Q. Did Staff incorporate the Sioux coal blending constraint in its production cost model?

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[2] Staff would certainly agree, given that even Dr. Proctor's higher estimated energy prices ($30.63/MWh in the off-peak and $54.51/MWh in the on-peak) are much lower than $67/MWh.

A. No. As I noted earlier, the MPSC Staff omitted the coal blending constraints and simply assumed that the Sioux Plant could be operated at the generation level that would exist if a 50% PRB/50 % Illinois coal blend was burned most of the time. If the plant were to operate at this level, the fuel mix and fuel costs would have to be modified to reflect this type of blending strategy. The economics for fuel blending, as illustrated in Schedule TDF-13, show that costs under a premium coal blending strategy are much higher and require a consistent expected price of above $65/MWh to justify that decision. Any time market prices are below that level, operating at a premium blend would result in lost profits relative to operating under a normal blend. Since Staff did not adjust their fuel costs to line up with their premium coal blending strategy, they vastly understated the costs of generation from Sioux.

Q. Is it your understanding that Staff now agrees that it should have modeled the Sioux Plant using the 83% PRB/17% Illinois coal blend?

A. Yes, it is my understanding that Staff is making this model change.

Q. Please address the fourth problem you identified in the MPSC Staff's production cost modeling, which relates to the failure of the MPSC Staff to properly synchronize hourly loads and off-system sales prices.

A. The MPSC Staff used a normalized hourly load pattern developed for the test year period (i.e., for the period July 1, 2005 through June 30, 2006). However, they matched that particular 12-month period with an hourly off-system sales price pattern from a *different* period (i.e., a period reflective of the three-year adjusted average prices used by AmerenUE witness Shawn Schukar in his recommendations relating to prices to use for off-system sales). Since the two time series cover different periods, the known relationship between loads and prices is lost under Staff's approach. Mr. Rahrer recognized a potential problem of poor correlation between loads and prices and raised the issue with Staff before Staff filed its direct case. Inexplicably, he was told by Staff that his "concerns were not their concerns." (Rahrer Deposition, Jan. 16, 2007, p. 142, l. 13-25; p. 143, l. 1-15). In fact, both Mr. Rahrer and Dr. Proctor both agree that the right way to model production costs is to preserve the relationship between loads and prices by using loads for a particular 12-month period and prices from that same 12-month period. (Rahrer Deposition, Jan. 16, 2007, p. 142, l. 13-20) (Proctor Deposition, Jan. 12, 2007, p. 64, l. 15 – 25; p. 65, l. 1-5).

Q. Before addressing the need to maintain the load/price relationship further, does the use of a three-year adjusted average of prices cause a problem in and of itself?

A. Yes. A three-year average hourly price may unrealistically smooth out the hourly price profile. By smoothing out the hourly prices, the extremes of high and low prices that can actually occur from hour-to-hour are missed, thus creating some potential inaccuracy in the production cost model.

Q. Does Staff's load profile also follow a three-year adjusted average?

A. No. The Staff's normalized load profile was based on actual load data for the period July 1, 2005 through June 30, 2006.

Q. Why did the Staff use load profiles and price profiles for different periods?

A. Apparently because Staff's load and price profiles were prepared separately by two different witnesses. Each person used their own methodology to generate the profile that they were responsible for. However, no one took on the responsibility to synchronize or coordinate both sets of data. The lack of synchronization between loads and prices serves to exacerbate the smoothing problem in Staff's model.

Q. How did AmerenUE avoid these smoothing and synchronization problems in its production cost model?

A. While using normalized levels of both prices and loads, AmerenUE fits those levels to actual hourly load and market price patterns from a *common* time period, which in the modeling used for this case was calendar year 2005.

Q. Please describe how the normalized levels of prices and loads are assigned a common and actual hourly pattern?

A. The normal load and price data were fitted to actual 2005 patterns using tools which ratio the actual data up or down to meet normalized loads and prices. For example, the average actual on-peak electricity price for June weekdays was calculated for 2005. Then, the average on-peak normal electricity price for June weekdays was also calculated. The ratio of these two averages was then applied to actual hourly prices for June weekdays in 2005. As a result, the levels of prices are set to the normalized levels sponsored by Mr. Schukar, but the peaks and valleys (i.e., the shapes) from the actual time period were maintained. This procedure was done for monthly on-peak and off-peak electricity prices, as well as for loads.

Q. What is the impact of Staff's failure to use loads and prices that are properly synchronized?

A. I estimate that this will overstate off-system sales margins by $7.6 million.

Q Please describe the fifth problem associated with the line loss calculation done by MPSC Staff Witness Erin Maloney.

A. I identified two errors associated with the purchase power data used in the line loss calculation. First, the June data utilized by Staff was estimated by using a secondary data source. The second error was the omission of system energy transfers or purchases of power received during the test year under the now-terminated Joint Dispatch Agreement (JDA). Adjusting for these errors results in a line loss rate of 5.97% (rounded to 6.0%) versus the MPSC line loss rate of 4.5%. Schedule TDF-14 shows the actual line loss results for the test year.

Q. How does the line loss error impact AmerenUE's overall variable production costs?

A. Using the correct line losses means that additional energy from the AmerenUE generators will be used to supply the line losses associated with the sales to the AmerenUE native load customers. A 1.5% line loss change on the MPSC Staff sales forecast of 39,310,653 MWh results in 589,000 MWh of additional generation required by the native load customers. The fuel costs associated with the extra energy will result in higher native load fuel costs. Another result of the increase in generation to supply native load customers is a decrease in generation that would be available for off-system sales, thus reducing off-system sales margins. I estimate that the impact of this error to be $24.1 million.

Q. The sixth main problem you identified relates to the accuracy of availability factors in Staff's model. Please describe this problem.

A. The equivalent availability factors utilized by the MPSC Staff are too high. Schedule TDF-15 compares the availability rates between AmerenUE's PROSYM model and the MPSC Staff model. Also included in the tables is the total amount of outages categorized by plant. Note that the MPSC Staff results show fewer outage MWh for both Callaway and AmerenUE's coal-fired plants. As described earlier in this rebuttal testimony, the MPSC Staff incorrectly handled outages at the Callaway Plant, and this largely explains the significant variation in available nuclear generation. However, because of the significant divergence in planned outage assumptions between the MPSC Staff and AmerenUE models, it is difficult to determine directly if there are modeling concerns regarding equivalent availability factors at Callaway.

Q. Is your concern related to accurate availability factors confined to nuclear generation?

A. No. My review of equivalent availability factors and available generation for the coal units indicates a small variation at all of the coal generating units. Even though the variations at each unit appear small, taken together, the sum of variations for all twelve coal units results in a substantial amount of extra available generation (842,233 MWh). This is yet another example of a systemic upward bias in the MPSC Staff's modeling results that overstate available MWhs and thus overstates off-system sales margins. Since Mr. Rahrer testified that he used the same outage data for the coal units (Rahrer Deposition, Jan. 16, 2007, p. 89, l. 22-25), the variation is most likely due to the availability algorithm used in the RealTime production cost model.

Q. What are the consequences of having extra generation available in a production cost model?

A. The extra generation will either result in lowering costs to serve native load or increasing revenues from extra off-system sales volumes. Here, it overstates off-system sales volumes.

Q. What suggestions do you have to resolve the potential inaccuracies in Staff's availability assumptions?

A. I am not familiar enough with the RealTime model to suggest a specific model fix. However, my experience with other production cost models that use similar availability modeling algorithms suggests that additional model iterations may minimize the problem. My experience using the multiple iteration approach for the Company's PROSYM production cost model indicates that a *minimum* of 20 iterations is necessary to produce acceptable equivalent availability factors (EAF). Mr. Rahrer indicated in his deposition (Rahrer Deposition, Jan. 16, 2007, p. 96, l. 13-14) that he used only sixteen iterations. Mr. Rahrer agrees that by using more iterations, the modeler is attempting to reduce sampling error which can produce unacceptable EAFs. (Rahrer Deposition, Jan. 16, 2007, p. 98, l. 9-15). Thus, Mr. Rahrer may be able to eliminate this modeling problem by using more iterations. If the difference in model EAFs cannot be fixed, I recommend that the Staff reduce the generation volumes and costs and off-system sales volumes and revenues by an amount equal to the excess available generation from the MPSC Staff's modeling, which related to the coal units is approximately 844,233 MWh. The impact of such an adjustment would be to reduce off-system sales margins by approximately $23 million.

Q. Are there any other concerns regarding the availability modeling done by Mr. Rahrer?

A. Yes there is. Schedule TDF-15 lists the EAFs for the coal units in both the MPSC Staff Benchmark Run and the MPSC Staff run which underlies their direct testimony. The EAFs for all of the units changed between the two runs. As mentioned earlier, some of the small variations may be minimized or eliminated by having the RealTime model perform more iterations. Alternatively, the model may be set up to use the exact same outage sequence for each model run. My main concern is the large difference in the EAFs at Rush Island Unit No. 2 and Labadie Unit No. 4. Mr. Rahrer stated in his deposition that he had to modify the RealTime Model availability inputs used in his MPSC Benchmark Run in order to calibrate the RealTime Model. (Rahrer Deposition, Jan. 16, 2007, p. 50, l. 9-12, 22-25). He also stated that he switched back to the original availability data for the MPSC Staff's final run. (Rahrer Deposition, Jan. 16, 2007, p. 51, l. 2-7). These statements suggest that there is either a problem with the availability modeling or some other possible model input that is incorrect

Q. Your seventh identified problem relates to the volumes of off-system sales resulting from Staff's model. Please explain.

A. As can be seen from the other problems already identified, there appears to be a systemic overstatement of off-system sales volumes resulting from Staff's modeling because each modeling mistake or problem relating to unreasonable modeling assumptions has the effect of causing the modeling results to show more MWhs available for sale. This seems indicative of a general bias in the MPSC Staff's modeling toward higher than reasonable off-system sales. Consistent with this bias seems to be the inclusion in the MPSC Staff's modeling of arbitrarily high volume limits for off-system sales -- 8,000 MW -- and this limit was never hit. (Rahrer Deposition, Jan. 16, 2007, p. 133, l. 19-24). Keep in mind that AmerenUE's coal and nuclear capacity is only 6,701 MW. Arbitrarily setting the off-system sales limits at such high levels as those used in the MPSC Staff's model created unreasonable expectations for off-system sales volumes and margins. A review of the off-system sales data produced by Mr. Rahrer shows one hour when off-system sales exceed 4,000 MW and over 200 hundred hours when the sales exceeded 3,500 MW. These large volumes of off-system sales could be a result of the problems with synchronization of hourly loads and prices; however, they may also be the result of unreasonable model assumptions. Sales levels produced by the MPSC Staff's model just don't pass a "sanity check."

Schedule TDF-16 compares off-system sales volumes between AmerenUE's model and actual 2006 data. Staff's volumes are consistently above AmerenUE's actual results. An analysis of AmerenUE's actual data results in an off-system sales limit of 2,700 MW. The schedule shows that Staff's model produces volumes that are well above 2,700 MW and in one case as high as 4,000 MW. It should be noted that the MPSC Staff model included 400 MW of EEInc. energy, thus based upon their position on EEInc. (with which we do not agree) a sales limit of 3,100 MW could theoretically be used as a limit in their model. A 4,000 MW limit is unsupported. The impact of not limiting sales results in $1.0 million of unrealistic off-systtem sales margins.

Q. Do you believe that the model should impose a limit on off-system sales?

A. Yes I do. The production cost model does not perform a complete market analysis. Rather, it looks only at AmerenUE load and generation data in relative isolation. A complete market analysis would include data for all of the surrounding areas to determine the proper level of off-system sales. This type of analysis is very difficult to do, thus alternative approaches are often used to simplify production cost modeling.

Q. What alternative approach can be performed?

A. Ideally, one would use actual historical transaction levels to assess the validity of volumes, but due to the existence of the JDA, historical transaction level data is difficult to obtain. An alternative, feasible approach estimates off-system sales levels by comparing actual hourly load to actual generation and purchases. Any excess of generation and purchases over native load can be defined as an off-system sale. This was the approach used to develop the actual 2006 off-system sales volumes as shown in Schedule TDF-16, and that reasonably establishes that limits should be included in the production cost modeling and that sets a reasonable limit as discussed above.

Q. Your eighth problem relates to Staff's off-system sales margins being overstated due to excessive power price assumptions. Please explain.

A. I understand, from Mr. Schukar's rebuttal testimony, that correcting Dr. Proctor's regression analysis and gas prices produces normalized power prices that are lower than the recommendations from Staff's direct testimony. Since Staff's power prices are too high, off-system sales margins are overstated. As shown in Mr. Schukar's rebuttal testimony, Dr. Proctor's normalized prices are $30.63, $59.78, and $52.72 for the off-peak, summer peak and other season peak time periods, respectively. Using data from an early run of AmerenUE's production cost model, I estimate that 54% of off-system sales volumes occur in the off-peak periods, 10% of the volumes occur in the summer peak periods, and 36% of the volumes occur in the other season peak periods. This implies a crudely-weighted off-system sales price of $41.49, if one were to otherwise accept Dr. Proctor's prices. Mr. Schukar's corrections to Dr. Proctor's approach reduce Dr. Proctor's normal price levels to $28.42, $55.70, and $46.76 for the off-peak, summer peak and other season peak time periods, respectively. The resulting weighted, corrected price is $37.73 ($3.76 less than used in the MPSC Staff's model). Assuming an off-system sales volume of 13.2 million MWhs, as Staff does,[3] I estimate the error caused by Staff's inaccurate prices, if corrected Dr. Proctor prices are used, to be approximately $50 million per year in off-system sales margins. Assuming an off-system sales volume of 9.1 million MWh, as AmerenUE's model does, the error is still approximately $34 million.

Q. Please describe the ninth problem related to the inclusion of EEInc. purchases in Staff's model.

[3] Which I believe to be too high, both for reasons discussed herein and because it includes energy the Company is not receiving from EEInc.

A. The inclusion of EEInc. in Staff's production cost model leads to overstated off-system sales volumes of approximately 3,014,256 MWh. Other witnesses address the merits, or lack thereof, of including power from EEInc. in the MPSC Staff's modeling. Based upon the Staff's energy price assumptions, the extra off-system sales margins relating to energy from EEInc. that the Company will in fact not receive are approximately $78 million.

Q. Please describe the final identified problem related to Staff's methodology for calculating off-system sales margins from its production cost model.

A. One can use data produced in Mr. Rahrer's original work papers to estimate the off-system sales margins resulting from the MPSC Staff's production cost model. Margins for off-system sales can be calculated by the following steps: (1) obtain revenues from off-system sales, (2) calculate the cost of off-system sales by subtracting the fuel and purchase power cost from the "no sales" case from the fuel and purchase power cost from the "with sales" case, and (3) calculate margins by subtracting costs from revenues. Based on my review of MPSC Staff witness John Cassidy's work papers, I believe that Staff used that approach to quantify off-system sales margins in its accounting schedules. There is a problem with this approach because the MWh to serve native load is different in the "with sales" case and the "no sales" case. The "with sales" case had a native load value of 40,947,981 MWh and the "no sales" case had a native load value of 41,264,824 MWh. This difference in the size of the native load for each case results in a higher cost for native load and a lower cost for off-system sales. The lower cost for off-system sales results in an overstatement of off-system sales margins. In response to a data request, Mr. Rahrer identified an alternative and more accurate method for quantifying margins that the MPSC Staff, even if one otherwise accepted the Staff's modeling assumptions, should have used. This alternative approach appears to produce off-system sales margins that are $10 million lower than the levels included in Staff's accounting schedules.

Q. Please explain further the alternate method for calculating off-system sales margins using Mr. Rahrer's model.

A. In response to data request TDF-Staff-16, Mr. Rahrer explains: "The Staff run Without Sales could be used to approximate the cost of serving native load, but since sales are a natural part of the AmerenUE system, it is not the best way to determine the cost of serving native load. A preferred method is to make a RealTime run of the Staff Run model and set the sale contract's charge method to "margin". The "margin" setting instructs the model to sell power at the exact cost of generation." Thus, the most precise method for estimating margins from the model is to conduct a version of Staff's run where generation is sold at cost as opposed to the market prices prepared by Dr. Proctor. Comparing the sales revenues between this run and the original Staff run also produces a more precise estimate of off-system sales margins. This calculation produces an alternative margin estimate of approximately $355 million. Thus, Staff's methodology for valuing off-system sales margins produced a normalized level of margins over $10 million higher than what would result from Mr. Rahrer's preferred methodology. This, like many other modeling problems and modeling assumptions, biases Staff's case toward unreasonably high off-system sales margins.

Q. You have presented a variety of estimated dollar amounts associated with the errors and unreasonable modeling assumptions you have identified. Should Staff's estimated off-system sales margins be reduced by the sum of these adjustments?

A. No. They are simply order of magnitude estimates for each error or unreasonable modeling assumption taken in isolation. Correcting one of these problems may change the estimated dollar impact of other problems. The only reliable way to quantify the total impact of the errors and unreasonable modeling assumptions employed by Staff is to rerun the RealTime production model correcting all of the problems I have identified in this testimony. To summarize the individual dollar impact of the problems I presented, I have prepared Schedule TDF-17, which summarizes all of the errors in one schedule, plus an error discussed below relating to Mr. Rahrer's benchmark run for Staff.

III. RESPONSE TO OTHER PARTIES' CRITICISMS OF AMERENUE'S MODELING

Q. Please summarize your response to other parties' criticisms.

A. I will respond to various intervenors' criticisms of assumptions or approaches used in AmerenUE's production cost model. One criticism, found in various forms in the testimonies of Staff witness Michael Rahrer, OPC witness Ryan Kind, and MIEC witness James Dauphanais, is that the AmerenUE model cannot be reliably benchmarked to actual conditions, due to the significant changes in the marketplace. I will respond to this criticism and show that AmerenUE's model follows industry-standard practices in ensuring reliability of its results.

Q. Briefly describe the criticism of your model calibration.

A. Several witnesses imply that changes in the marketplace make it impossible to calibrate AmerenUE's model to reality. Mr. Dauphanais claims that the termination of the JDA at the end of 2006 will produce dramatically different operating conditions. He alleges that since actual data related to these conditions have not been compiled, there is no post-JDA benchmark to test the accuracy of AmerenUE's model. (Dauphanais Direct Testimony, pp. 3-4). Mr. Kind echoes this point when he identifies the significant changes that are occurring in the marketplace and the need for OPC to carefully scrutinize production cost models in that light (Kind Direct Testimony, pp. 5-6). Mr. Rahrer testifies that benchmarking of AmerenUE's model is impossible since "test year data being used by RealTime has already been processed and synthesized by AmerenUE and can no longer be compared against an unbiased objective." (Rahrer Direct Testimony, p. 11).

Q. Mr. Rahrer is the only one of these witnesses who ran a production cost model for this case. Please comment on his criticisms first.

A. Several things are surprising about Mr. Rahrer's criticisms. First, he states in his deposition that he had no criticisms of my model calibration, as discussed in my direct testimony; in fact, he had failed to evaluate my calibration at all, although he knew that the Company's model had been calibrated. (Rahrer Deposition, Jan. 16, 2007, p. 70, l. 25; p. 71, l. 1-12). It thus seems odd that he would testify that benchmarking against actual data cannot be done at all. Second, Mr. Rahrer testified that he would himself normally calibrate his model against actual results and that indeed, *for this rate case*, his opinion all along was that his model should be calibrated against actual data. (Rahrer Direct Testimony, p. 11; Rahrer Deposition, Jan. 16, 2007, p. 60, l. 5-6, 11-14; p. 62, l. 24-25; p. 63, l. 1-6). For reasons not clear to me, the MPSC Staff, from the very beginning, apparently would not let him calibrate his model to actual data. (Rahrer Deposition, Jan. 16, 2007, p. 60, l. 21-25). The bottom line is that the Company's model has been calibrated against actual data. Staff could have done the same with their model and this is indeed the appropriate thing to have done, but Staff made no attempt to do so.

Q. Do changes in the marketplace like those cited by witnesses Dauphanais and Kind render the calibration of AmerenUE's model impossible?

A. No. First, it may be helpful to define model calibration, as I did in my original testimony at page 4: "Model calibration is done by using inputs that reflect actual (i.e. not normalized) data for a specific time period and comparing the simulated results produced by the model to the actual generation performance and costs for that time period. Production cost model outputs that should be compared to actual data to properly calibrate the model include: unit generation totals for the period being evaluated; hourly unit loadings; unit heat rates; number of hot and cold starts; and off-system sales volumes and prices." While I agree that certain changes in the marketplace are occurring, none of these changes should preclude the calibration of the production cost model. As long as the inputs and outputs are gathered from the same time period, and that time period's operating conditions are modeled correctly, one can test if the model is accurately predicting outcomes for some historical time period. Once such a calibration is done, the modeler can be confident that his well-calibrated model can then model changes to arrive at reasonable predictions of results based upon a different set of conditions to aid in predicting future results, which is how both the Company and the MPSC Staff are using their models in this case.[4] Indeed, if one were to accept Messrs. Dauphanais' and Kind's argument, models would be useless because it is apparently their view that if conditions change the model would be unable to model those changes. Of course, the very reason we need and use models is because of the need to model differences (changes) between actual conditions known to exist in a particular period (typically a particular 12-month period) and some other period. The fact is that they have no evidence of any material inaccuracy in AmerenUE's modeling in this case, and neither does Mr. Rahrer.

Q. Would you expect to be able to obtain meaningful and reasonably reliable estimates of net fuel, variable purchase power costs, and off-system sales revenues without the use of a production cost model?

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[4] Mr. Rahrer agrees that the reason we have models is so we can model changes (i.e., such as those occurring during the test year in this case) and that if you have a good model, it can produce reasonably accurate results. (Rahrer Deposition, Jan. 16, 2007, p. 74, l. 3-10).

A. No. I am not aware of any reliable method for determining normalized net fuel, variable purchase power costs, and off-system sales revenues that do not include the use of a production cost model.

Q. What about Mr. Rahrer's point that since the actual data have already been processed, it is impossible to benchmark AmerenUE's model to reality?

A. I agree that without actual inputs and outputs from a historical time period, one cannot benchmark a model to actual conditions. However, Mr. Rahrer's deposition made it clear that he thought it would have been preferable to benchmark both models to actual data. Nevertheless, Staff instructed him to benchmark the model to AmerenUE's run instead, as noted earlier. Had Staff requested the actual inputs I used to perform my benchmarking run, I would have provided them and Mr. Rahrer could have performed a standard benchmarking exercise. As it turns out, Mr. Rahrer was never given access to that input data by Staff, and had no evidence that Staff ever requested that data from AmerenUE. (Rahrer Deposition, Jan. 16, 2007, p. 69, l. 17-20; p. 70, l. 7-12).

Q. Does Mr. Rahrer's failure to benchmark his model against actual data concern you?

A. Yes. After completing his benchmark run, we know that the variable production costs he generated, which should have essentially matched AmerenUE's modeling results, since he was supposed to be benchmarking his model against AmerenUE's model, were approximately 1.5% too low. (Rahrer Deposition, Jan. 16, 2007, p. 96, l. 7-9). This means that 1.5% or approximately $9 million of AmerenUE's variable production costs (calculated by Staff to be approximately $624 million), were in effect removed or omitted from Staff's modeling since Staff's benchmark results – the baseline from which Staff ran its ultimate modeling – understated costs by 1.5%. In other words, Staff ran its model, which underlies its direct testimony, starting from a point that automatically ignored $9 million of costs.

Q. Please summarize your response to others parties' criticisms of AmerenUE's modeling.

A. There criticisms are unfounded and based on no evidence of inaccuracies or bias in AmerenUE's modeling. AmerenUE's model has been benchmarked to actual data; Staff's model has not and indeed, the failure to do so apparently created a $9 million error detrimental to the Company in Staff's modeling, before Staff even attempted to model test year conditions.

IV. AMERENUE'S HEAT RATES

Q. Is Mr. Rahrer correct in his assertion that the AmerenUE model does not use updated plant heat rates?

A. No. In fact, given that Mr. Rahrer knew absolutely nothing about the heat rates used by AmerenUE when he made this assertion, I am surprised he would make such an assertion.

Q. Why do you say he knew absolutely nothing about the heat rates used by AmerenUE?

A. Because in his deposition it was clear that he had never been involved in heat rate testing with any utility, knew nothing about the frequency of AmerenUE's heat rate testing, didn't know how heat rate testing was done, didn't know what factors affect a unit's heat rate, and had no evidence that the heat rate curves used in AmerenUE's production cost modeling were not reflective of current heat rates at each of AmerenUE's plants. (Rahrer Deposition, Jan. 16, 2007, p. 77, l. 4 to p. 79, l. 24; p. 81, l. 11-15).[5]

[5] As just one example of his lack of knowledge, he testified as follows: "You really don't have any evidence that their heat rate curves are inaccurate in any way; is that fair? A. No, I guess I don't."

Q. Please explain why AmerenUE's heat rate curves are up-to-date and accurate.

A. AmerenUE uses an Efficiency Deviation Factor (EDF) to update each generating unit's Input/Output (I/O) curve. A generating unit's I/O curve is the relationship between the amount of fuel it consumes (input) and its generation (output) level. A unit's heat rate is determined by dividing the fuel burn by its output; thus updating a unit's I/O curve by applying an EDF is the same as updating a unit's heat rate.

Q. What is an Efficiency Deviation Factor (EDF)?

A. The EDF is the ratio of the actual BTUs used by a generating unit divided by the theoretical BTUs used at a generating unit. The actual BTUs are obtained *from accounting records for a period of time being evaluated*, usually twelve months. The theoretical BTUs are calculated using an I/O curve which determines the BTUs used to generate a specific plant output (MW). Since the BTUs vary with the generating unit's load level and the actual generating unit's load level frequently varies, the theoretical BTUs are calculated for each hour of the period being analyzed. The EDF factor used in the PROSYM run was updated *for this case* in June 2006. Thus, the heat rate curves used in AmerenUE's model were prepared following industry conventions using actual, up-to-date AmerenUE accounting data.

Q. Mr. Dauphanais (Dauphanais Direct, pp. 3 – 4) and Mr. Brubaker (Brubaker Direct, pp. 10 - 12) state that historical off-system sales volumes are much higher than the levels models by AmerenUE. Do these witnesses sponsor a specific adjustment to volumes?

A. No. They simply refer to historical data and suggest that the modeled levels are not consistent with historical trends.

Q. As a general principle, do you believe historical data is a reasonable check of the production cost model's normalized outputs?

A. No. Historical data is useful for developing a benchmarking run as I described in this testimony, but has little value when compared to normalized outputs. Mr. Dauphanais and Mr. Brubaker have compared *actual* off-system sales volumes for the recent past to a *normalized* level of off-system sales resulting from AmerenUE's model. I can think of several reasons why these historical snapshots may not be equal to normalized outputs. For example, prior to 2007, the AmerenUE and Ameren Energy Generating Company (AEG) units operated under the JDA in a single control area. During this time most of AmerenUE's spinning reserve and regulating requirements were often supplied by the AEG units. This allowed the AmerenUE units to run near their maximum rating while the AEG units were off-loaded to provide spinning and regulating reserves for AmerenUE customers. With the termination of the JDA the AmerenUE units must be off-loaded to meet the AmerenUE spinning reserve and regulating requirements. Other reasons include volumes of purchased power to support off-system sales and the impact that fuel cost changes at the AmerenUE generating units may have on the level of off-system sales from those units.

Q. Specifically, Mr. Brubaker points out that AmerenUE's normalized off-system sales levels are 4.1 million MWh lower than the actual levels in the test year. He argues that known adjustments between the model run and actual conditions do not justify this reduction. What is your response?

A. In short, Mr. Brubaker argues that the actual off-system sales volumes experienced for 12 months ending June 2006 (13.2 million MWh) should be close to the volumes used for normalized off-system sales. There are several reasons why this number is not a reasonable expectation of normal levels of off-system sales volumes. First, this time period included exceptionally high availability of plants that is not expected to be normal. The equivalent availability factor (EAF) for the base load coal and nuclear units was 88.2% for twelve months ending June 2006. The EAF for the normalized year was based on a six year average, which was 85.4%. The difference in EAF results in 1.6 million MWh of reduced generation which would directly reduce off-system sales. Second, during the test year, AmerenUE purchased 4.7 million MWh and in the normalized year AmerenUE's purchase power estimate is just 1.5 million MWh. Lower volumes of purchase power will also result in lower off-system sales volumes. A third factor is the increased use of the AmerenUE generating units to meet spinning and regulation requirements. During the test year, AmerenUE operated under the JDA and the spinning and regulating requirements were distributed between the AmerenUE units and the AEG units. During this time, the AEG supplied a large share of AmerenUE's spinning and regulating requirements. I have estimated that AmerenUE generation will be reduced by 440,000 MWh due to the requirement that AmerenUE plants supply their full share of the spinning and regulating requirements.

V. ISSUES RELATED TO MODELING OF OPERATING RESERVES

Q. Please respond to Mr. Dauphanais' criticism that AmerenUE modeled an operating reserve level that is too high (202 MW) (Dauphanais Direct, p. 15)?

A. Mr. Dauphanais is correct in stating that the operating reserve requirements will be different in 2007. Operating reserves consist of spinning and quick start requirements. The 2007 Operating Reserve Requirement is 156 MW. The 2007 operating reserve components are spinning, 43 MW, regulating, 50 MW, and quick start 63 MW. The operating reserve components used in my original direct testimony filed on July 7, 2006 were spinning, 58 MW, regulating, 53 MW, and quick start, 101 MW.

Q. Which of the operating reserve components are most important for production cost modeling?

A. The spinning and regulating requirements are important because they result in reduced outputs of the generating units used to supply these requirements. For the new operating reserve levels, there are 93 MW held back for operating reserves. The quick start requirement is not a major factor in production cost modeling because AmerenUE has numerous units that are quick start capable, Osage, Taum Sauk, and several CTGs. Consequently, the model largely ignores the 101 MW of quick start reserves resulting in modeling that effectively holds back just 101 MW of operating reserves.

Q. Are there any operational issues that need to be considered along with the spinning and regulating requirements?

A. Yes, an operating issue that must be addressed along with the MW held back for regulation are the additional stranded MWs that exist when a generating unit is used for regulation. A unit on regulation may not be designed to regulate at a range that coincides with its maximum rated capacity. Consequently, there is often 5 to 15 MW of capacity that cannot used to generate power when the unit is regulating. Thus, the production cost model should withhold between 98 MW and 108 MW of generation (42 MW for spinning, 50 MW for regulating, and 5 to 15 stranded MW).

Q. So given changes in 2007, was the modeling of operating reserves correct?

A. Yes. Since the quick start reserves have no material impact on the modeling and the sum of the 2007 spinning, regulating and stranded MWs is virtually identical to the 101 MW of non-quick start reserves originally modeled, the model results are accurate.

VI. UPDATES TO FUEL COSTS

Q. What are the fuel cost updates that you propose?

A. There are seven fuel cost updates that need to be made, all of which are minor adjustments discovered in the course of the MPSC Staff's audit in this case, as follows: (1) the removal of the magnesium hydroxide expense from the Labadie fuel costs; (2) the reclassification and update of urea costs at the Sioux Plant from a fuel expense item to an operating and maintenance (O&M) expense; (3) the Sioux Plant generation profile has been revised to reflect an 83%PRB/17% Illinois coal blend; (4) use of the same coal price updates for fuel costs used by the MPSC Staff in its modeling (as of November 21, 2006); (5) updating the nuclear fuel costs using information provided in the Rebuttal Testimony of Ameren UE's witness Mr. R. J. Irwin; (6) updated natural gas prices to reflect 2006 prices; and (7) updating the dispatch costs for the Sioux, Rush, and Meramec generating units to correct a modeling input error.

Q. Why is an adjustment being made to remove the magnesium hydroxide expense from the Labadie fuel costs?

A. The original fuel cost for Labadie Plant included an expense of $4,521,000 associated with a fuel additive called magnesium hydroxide. Magnesium hydroxide is expected to improve the boiler performance when burning PRB coals. Field testing of magnesium hydroxide is ongoing and a final recommendation and implementation plan have not been completed, thus the associated expenses have been removed from all cost categories in this case.

Q. Why is the urea expense at Sioux plant being reclassified?

A. The fuel cost for Sioux Plant originally included an expense of $4,244,000 for urea. Urea is a chemical injection that is used as part of the Rich Reagent Injection Selective Non- Catalytic Reduction (RRI SNCR) system used to reduce NOx at Sioux Plant. It has been determined that urea is an emission control expense, not a fuel expense. Thus the urea expense is being moved from the Sioux fuel costs and included as a plant O&M expense. Also, the urea fuel expense calculation has been updated and was reduced to $3.5 million.

Q. What changes have been made to the generation profile for the Sioux Plant?

A. As mentioned earlier in my testimony the Sioux generation level is directly related to the coal quality which is burned at the plant. The generating unit rating pattern has been updated to reflect the coal blend used to determine the Sioux coal prices, which is 83% PRB/17% Illinois coal. Schedule TDF-12 illustrates the revised generating unit and coal blending schedule included in the updated production cost model run.

Q. Why are coal prices being updated?

A. The original coal costs were based on pricing data available in April 2006, which was the most recent data available when the production cost modeling that underlies the Company's original filing was done. In November, the MPSC Staff was provided more current coal cost information for use in their production cost model. Thus, the PROSYM model is being updated using the same fuel cost data used by the MPSC Staff. It should be noted that the coal costs will be updated one more time based on a true-up for actual coal costs as of January 1, 2007.

Q. What changes have been made to Callaway fuel costs?

A. The Callaway fuel costs are being updated to reflect the fuel cost update being sponsored in rebuttal testimony from AmerenUE witness Mr. R. J. Irwin. The fuel costs were updated to reflect the fuel costs from fuel cycle 16, updated Department of Energy (DOE) changes for spent fuel, and updated DOE decommissioning and dismantling charges.

Q. What change was made to the prices of natural gas?

A. The natural gas prices were updated to reflect the actual prices for 2006.

Q. Why are the dispatch prices for Rush, Sioux, and Meramec units being updated?

A. The dispatch coal prices used in AmerenUE's production cost model included adjustments which eliminated the impact of the coal supply disruptions which occurred during the period August through December 2005. The PROSYM model used the Labadie coal cost adjustment factor for all of the plants, but more properly should have used a specific coal adjustment factor for each of the four coal plants. I have thus calculated individual plant adjustments and applied the appropriate adjustments to the dispatch prices for the other coal fired plants: Rush, Sioux, and Meramec.

Q. What is the impact of all of these changes to the normalized fuel, variable component of purchase power cost and off-system sales for this case?

A. Re-running AmerenUE's PROSYM model with the updates described above results in normalized fuel, variable purchase power costs, and off- system sales revenues of $573 million, $28 million, and $307 million, respectively (versus the values in the Company's September 29, 2006 supplemental filing of $598 million, $26 million, and $317, million respectively).

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

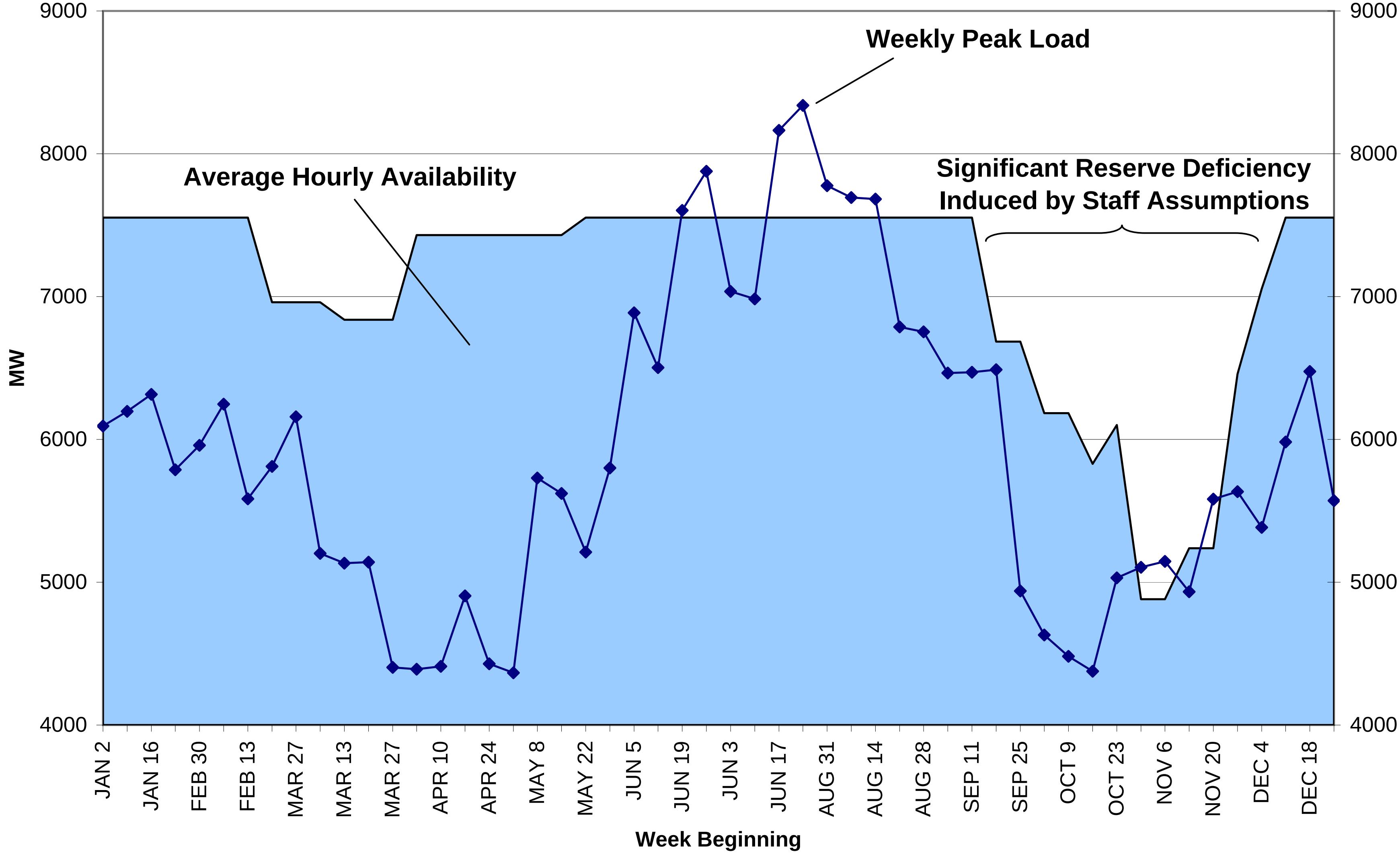
STAFF'S PROPOSED PLANNED OUTAGES

804,384 FEB - MAY OUTAGE MWh

SEP - OCT Outage MWh 3,231,648

Mws	DMQ 2005	JAN (2, 9, 16, 23)	FEB (30, 6, 13, 20)	MAR (27, 6, 13, 20, 27)	APR (3, 10, 17, 24)	MAY (1, 8, 15, 22)	JUN (29, 5, 12, 19, 26)	JUL (3, 10, 17, 24)	AUG (31, 7, 14, 21, 28)	SEP (4, 11, 18, 25)	OCT (2, 9, 15, 23)	NOV (30, 6, 13, 20, 27)	DEC (4, 11, 18, 25)	DMQ 2005
1220	CAL 1											CALLY(29 days)		CAL 1
593	RUSH 1		RUSH #1 (41 days)											RUSH 1
592	RUSH 2													RUSH 2
597	LAB 1									LABADIE #1 (78 days)				LAB 1
595	LAB 2													LAB 2
613	LAB 3													LAB 3
511	LAB 4										c			LAB 4
500	SX 1										SIOUX #1 (68 days)			SX 1
503	SX 2													SX 2
123	MER 1			MERAMEC #1 (68 days)										MER 1
125	MER 2													MER 2
273	MER 3									MER #3 (33 days)				MER 3
356	MER 4										MER #4 (26 days)			MER 4
440	TAUM SK													TAUM SK

AmerenUE Available Resources under Staff's Planned Outage Assumptions



Schedule TDF-9-2

Staff Treatment of Callaway Outage

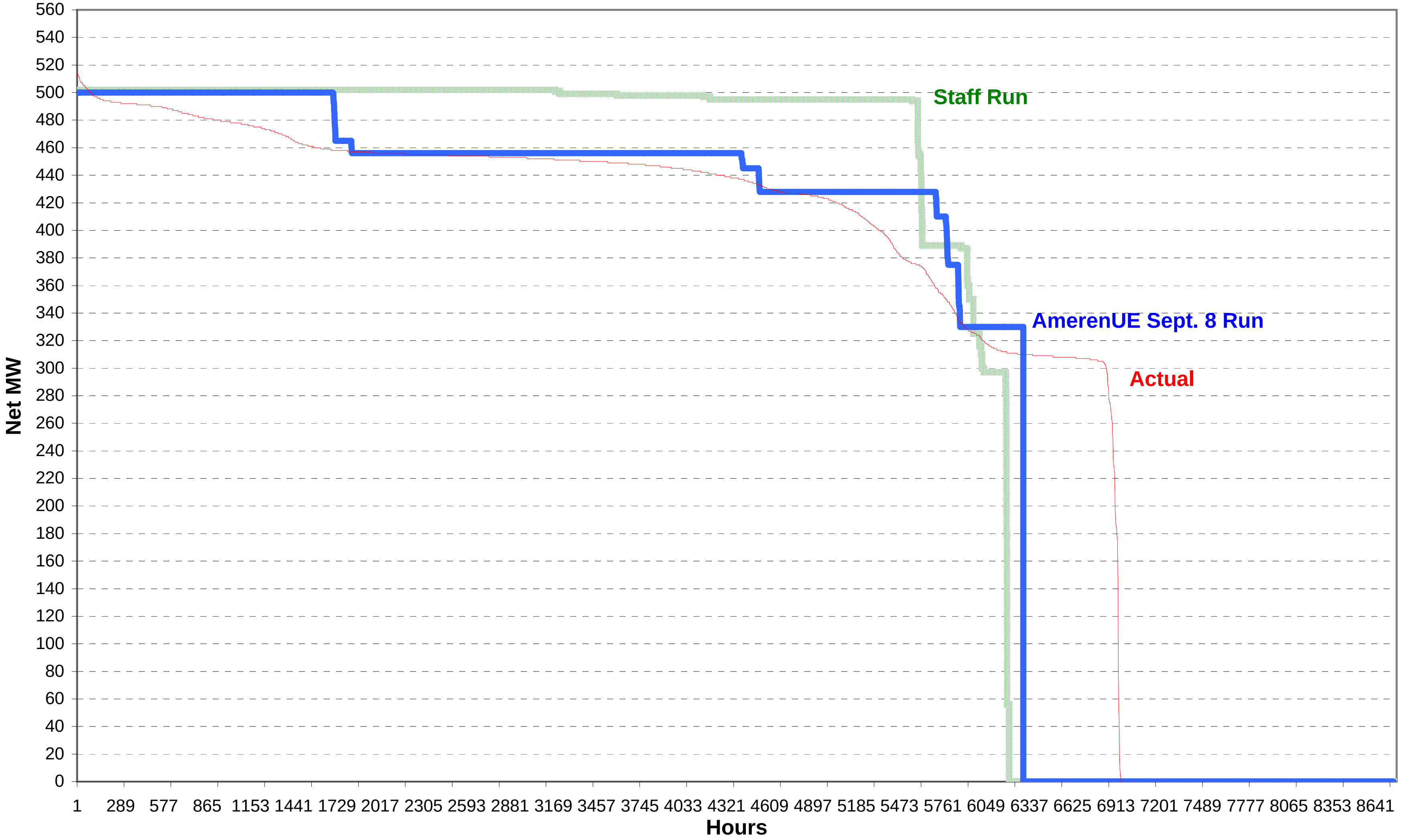
Source	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total
Callaway Forced Outage Hours	0	0	16	155	**0**	143	23	35	54	**0**	146	53	625
Unit Rating	1220	1220	1220	1220	**1220**	1220	1220	1220	1220	**1220**	1220	1220	1220
MWH Out	-	-	19,520	189,100	**-**	174,460	28,060	42,700	65,880	**-**	178,120	64,660	762,500
OSS PRICE	$ 47.31	$ 45.09	$ 37.20	$ 36.61	**$ 37.54**	$ 43.16	$ 44.08	$ 45.61	$ 46.62	**$ 42.64**	$ 36.50	$ 41.43	
$ Impact	$ -	$ -	$ 726,057	$ 6,922,225	**$ -**	$ 7,530,010	$ 1,236,985	$ 1,947,724	$ 3,071,089	**$ -**	$ 6,501,277	$ 2,678,611	$ 30,613,977

Proper Treatment of Callaway Outage

Source	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Total
Callaway Forced Outage Hours	56.8	56.8	56.8	56.8	**57**	56.8	56.8	56.8	56.8	**0**	56.8	56.8	625
Unit Rating	1,220	1,220	1,220	1,220	**1220**	1,220	1,220	1,220	1,220	**1220**	1,220	1,220	1,220
MWH Out	69,318	69,318	69,318	69,318	**69,318**	69,318	69,318	69,318	69,318	**-**	69,318	69,318	762,500
OSS PRICE	$ 47.31	$ 45.09	$ 37.20	$ 36.61	**$ 37.54**	$ 43.16	$ 44.08	$ 45.61	$ 46.62	**$ 42.64**	$ 36.50	$ 41.43	
$ Impact	$ 3,279,225	$ 3,125,478	$ 2,578,329	$ 2,537,472	**$ 2,602,163**	$ 2,991,898	$ 3,055,792	$ 3,161,889	$ 3,231,365	**$ -**	$ 2,530,074	$ 2,871,581	$ 31,965,266

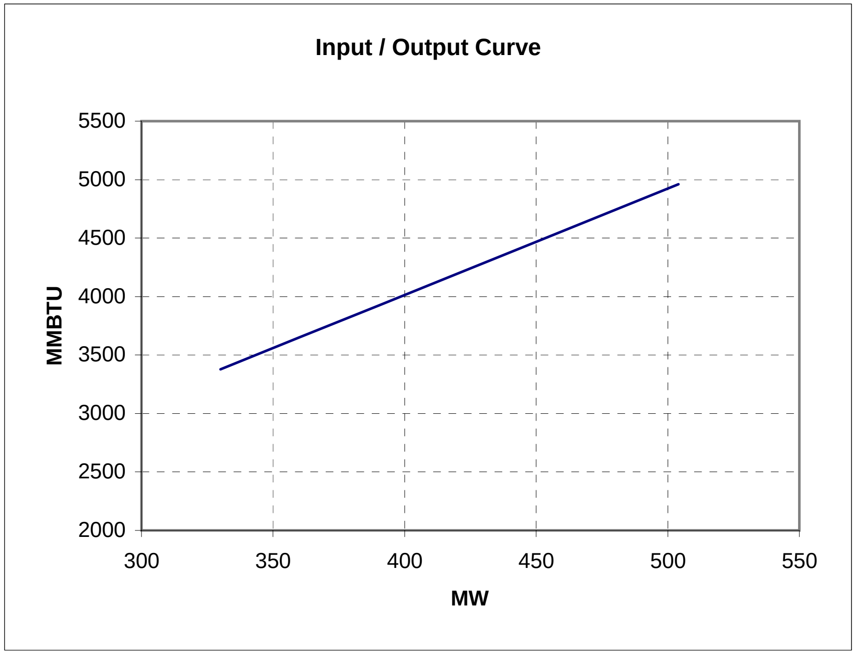
Impact of Timing of Callaway Forced Outages $ 1,351,289

Modeled and Actual Sioux #1 Load Duration Curves



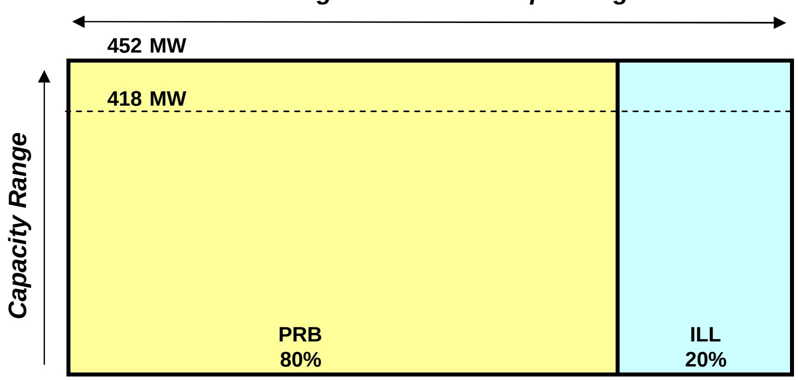
Operating Conditions under Various Sioux Coal Blends

Blend Description	PRB Share of Coal Burned	Maximum Capacity Given PRB Blend	Btu/lb	Tons / hour	Fraction of Generation at Specified Blend
Off-Peak	100.0%	418	8,800	237	23.4%
Normal Operating	80.0%	452	9,460	237	71.5%
Premium	50.0%	504	10,450	237	5.1%
Average Blend =	83.2%				

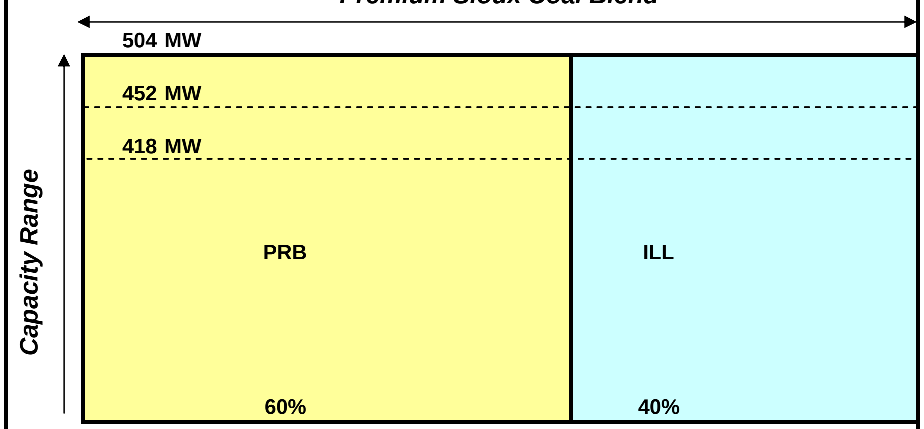


ECONOMICS OF SIOUX COAL BLENDING ASSUMING LOW MARKET PRICES

Sioux Coal Blending Under Normal Operating Conditions



Premium Sioux Coal Blend



Expected Plant Profitability

% PRB	MW	MMBTU	$ / MMBtu	COST	MARKET PRICE	REVENUE
80%	452	4,486	$2.075	$9,311	**$35.00**	$15,820
[1a]	[2a]	[3a]	[4a]	[5a]=[3a]x[4a]	**[6a]**	[7a]=[2a]x[6a]

MARGIN (Normal Blend) = $6,509 [8a]=[7a]-[6a]

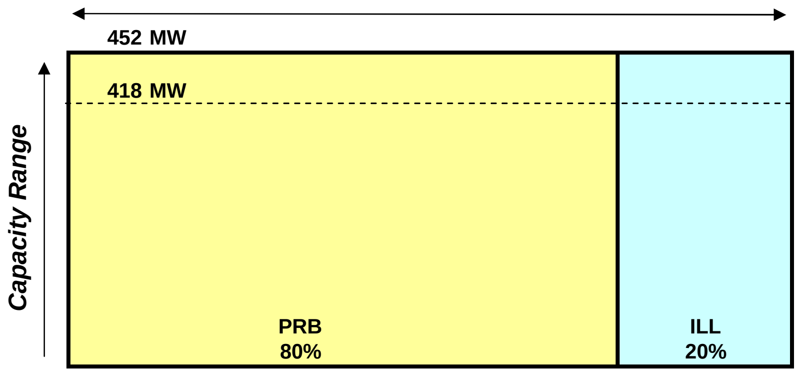
Expected Plant Profitability

% PRB	MW	MMBTU	$ / MMBtu	COST	MARKET PRICE	REVENUE
60%	504	4,959	$2.558	$12,688	**$35.00**	$17,640
[1b]	[2b]	[3b]	[4b]	5b]=[3b]x[4b]	**[6b]**	[7b]=[2b]x[6b]

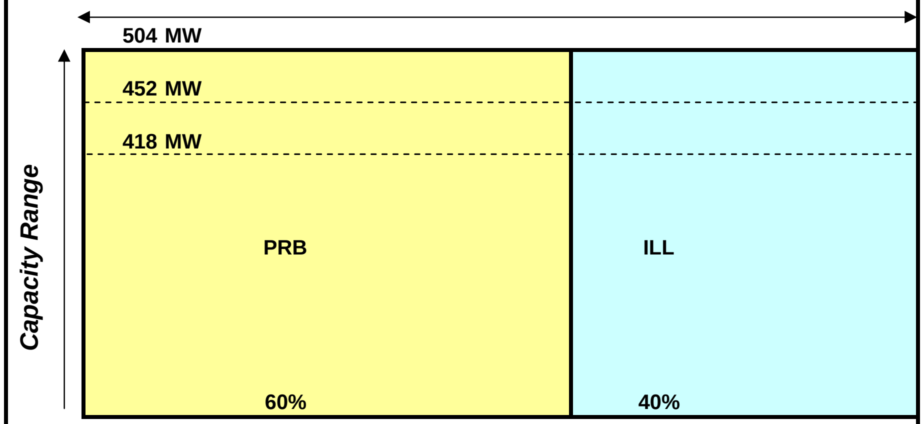
MARGIN (Premium Blend) = $4,952 [8b]=[7b]-[6b]

ECONOMICS OF SIOUX COAL BLENDING ASSUMING HIGH MARKET PRICES

Sioux Coal Blending Under Normal Operating Conditions



Premium Sioux Coal Blend



Expected Plant Profitability

% PRB	MW	MMBTU	$ / MMBtu	COST	MARKET PRICE	REVENUE
80%	452	4,486	$2.075	$9,311	**$67.00**	$30,284
[1a]	[2a]	[3a]	[4a]	[5a]=[3a]x[4a]	**[6a]**	[7a]=[2a]x[6a]

MARGIN (Normal Blend) = $20,973 [8a]=[7a]-[6a]

Expected Plant Profitability

% PRB	MW	MMBTU	$ / MMBtu	COST	MARKET PRICE	REVENUE
60%	504	4,959	$2.558	$12,688	**$67.00**	$33,768
[1b]	[2b]	[3b]	[4b]	[5b]=[3b]x[4b]	**[6b]**	[7b]=[2b]x[6b]

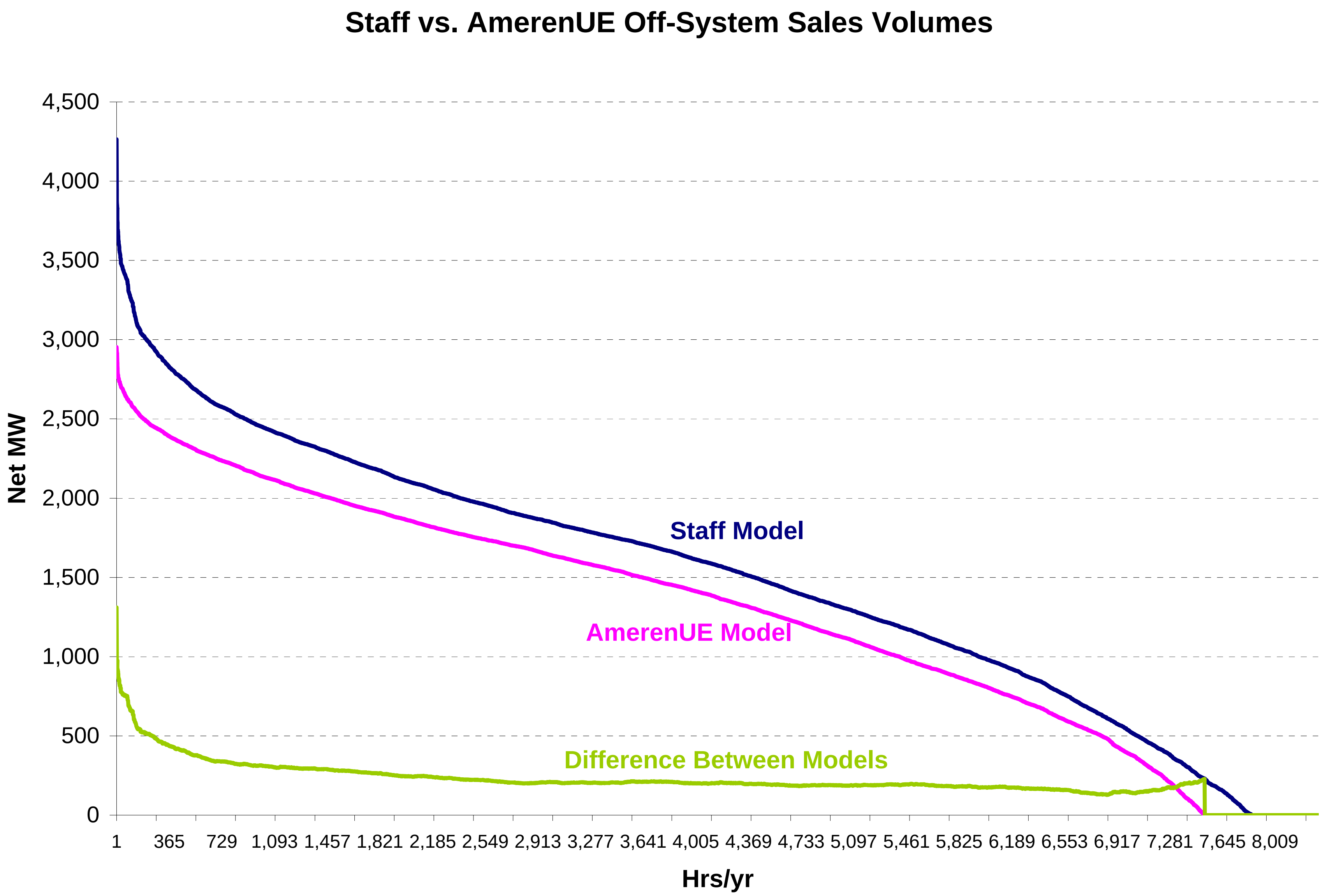
MARGIN (Premium Blend) = $21,080 [8b]=[7b]-[6b]

Support for Line Loss Ratio

	YEAR ENDING 30-Jun-06 ACTIVITY
TOTAL NET GENERATION	48,948,206
PURCHASED POWER	4,706,599
SALES FOR RESALE - INTERCHANGE	(13,221,180)
TOTAL OUTPUT FOR LOAD	40,433,625
NATIVE SALES OF ELECTRIC ENERGY	38,018,866
LINE LOSSES AND COMPANY USE	2,414,759
LINE LOSS RATIO	**6.0%**

Comparison of AmerenUE and Staff Production Cost Model Annual Equivalent Availability Factors (EAFs) and Outages

	Annual Unit Equivalent Availability Factors							***Annual MWH of Outages***				
	Unit Rating	AmerenUE	Rahrer's Benchmark	Rahrer - UE Benchmark	Staff's Model	Staff - UE Model		AmerenUE	Rahrer's Benchmark	Rahrer - UE Benchmark	Staff's Model	Staff - UE
Callaway	1,220.0	83.1	83.1	-	88.6	5.5		1,806,137	1,806,137	-	1,218,555	(587,582)
Labadie 1	597.0	72.6	73.7	1.0	74.5	1.9		1,431,846	1,377,090	(54,756)	1,333,840	(98,006)
Labadie 2	595.0	89.8	91.8	2.0	91.6	1.8		529,194	426,723	(102,472)	437,929	(91,265)
Labadie 3	613.0	91.9	91.7	(0.1)	92.2	0.3		435,351	443,122	7,771	418,528	(16,823)
Labadie 4	611.0	86.4	93.0	**6.6**	88.8	2.4		729,976	375,093	(354,883)	602,033	(127,943)
Meramec 1	123.0	72.4	75.8	3.4	75.4	3.1		297,675	261,106	(36,569)	264,737	(32,938)
Meramec 2	125.0	93.7	95.1	1.4	96.2	2.4		68,579	53,524	(15,056)	41,851	(26,728)
Meramec 3	273.0	76.2	79.3	3.1	81.2	5.0		568,987	494,630	(74,357)	450,555	(118,432)
Meramec 4	356.0	80.3	83.0	2.7	83.7	3.4		614,650	530,810	(83,840)	509,697	(104,952)
Rush 1	593.0	74.4	78.0	3.6	77.6	3.2		1,328,130	1,140,544	(187,586)	1,161,530	(166,600)
Rush 2	592.0	87.4	91.8	**4.4**	88.3	0.9		653,161	425,971	(227,189)	607,375	(45,786)
Sioux 1	500.0	71.0	70.5	(0.6)	72.4	1.3		1,268,294	1,293,545	25,251	1,211,026	(57,268)
Sioux 2	503.0	93.7	94.5	0.8	92.7	(1.0)		278,340	241,332	(37,008)	322,848	44,508
Totals	6,701.0	82.9	84.9	1.9	**85.4**	**2.4**	Totals	10,010,321	8,869,627	(1,140,694)	**8,580,505**	**(1,429,816)**



Staff vs. AmerenUE Off-System Sales Volumes
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Net MW
Staff Model
AmerenUE Model
Difference Between Models
1
365
729
1,093
1,457
1,821
2,185
2,549
2,913
3,277
3,641
4,005
4,369
4,733
5,097
5,461
5,825
6,189
6,553
6,917
7,281
7,645
8,009
Hrs/yr

QUANTIFICATION OF STAFF'S ERRORS OR UNREASONABLE ASSUMPTIONS

ERROR OR UNREASONABLE ASSUMPTION	*DOLLAR IMPACT OF REDUCED REVENUE REQUIREMENT*
Planned Outage Assumptions	**$ 3,485,000**
Forced Outage Assumptions	**$ 1,351,000**
Sioux Coal Blending	**$ 11,671,667**
Synchronization of Loads and Prices	**$ 7,557,000**
Line Losses	**$ 24,104,959**
Availability Rates	**$ 23,203,529**
Off-System Sales Volumes	**$ 1,056,625**
Forward Price Curve	**$ 49,644,066**
EEInc.	**$ 78,641,939**
Off System Margin Calculation Error (THIS HAS NO IMPACT ON ACTUAL CASE)	**$ 10,000,000**
Cost Error in Rahrer Benchmarking Run	**$ 9,000,000**

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 Electric Service Provided to Customers in the Company's Missouri Service Area.	)))))	Case No. ER-2007-0002

AFFIDAVIT OF TIMOTHY D. FINNELL

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

Timothy D. Finnell, being first duly sworn on his oath, states:

1. My name is Timothy D. Finnell. I work in St. Louis, Missouri and I am employed by Ameren Services Company as Supervising Engineer in the Corporate Planning Function.

2. Attached hereto and made a part hereof for all purposes is my rebutttal Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 35 pages and Schedules TDF- 9 through TDF - 17, 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.

Timothy D. Finnell
Timothy D. Finnell

Subscribed and sworn to before me this 31st day of January, 2007.

Carolyn J. Woodstock
Notary Public

My commission expires: May 19, 2008

CAROLYN J. WOODSTOCK
Notary Public - Notary Seal
STATE OF MISSOURI
Franklin County
My Commission Expires: May 19, 2008