Exhibit No.:	
Witness:	James R. Dauphinais
Type of Exhibit:	Surrebuttal Testimony
Issue:	Off-System Sales Margin and Fuel Adjustment Clause
Sponsoring Parties:	Missouri Industrial Energy Consumers
Case No.:	ER-2007-0002

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**

Surrebuttal Testimony of

James R. Dauphinais

On Behalf of

Missouri Industrial Energy Consumers

February 27, 2007
Project 8632

Brubaker & Associates, Inc.
St. Louis, MO 63141-2000

"NON-PROPRIETARY" Version

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

Affidavit of James R. Dauphinais

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

1. My name is James R. Dauphinais. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141. We have been retained by the Missouri Industrial Energy Consumers in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my surrebuttal testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2007-0002.

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

James R. Dauphinais

Subscribed and sworn to before me this 26th day of February, 2007.

CAROL SCHULZ
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: Feb. 26, 2008

Notary Public

My Commission Expires February 26, 2008.

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<u>Table of Contents to the Surrebuttal Testimony of James R. Dauphinais</u>

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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**

Surrebuttal Testimony of James R. Dauphinais

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A My name is James R. Dauphinais and my business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, MO 63141.

Q ARE YOU THE SAME JAMES R. DAUPHINAIS THAT FILED DIRECT TESTIMONY ON REVENUE REQUIREMENT ISSUES AND FUEL ADJUSTMENT ISSUES IN THIS PROCEEDING?

A Yes, I am.

Q ON WHOSE BEHALF ARE YOU PRESENTING THIS SURREBUTTAL TESTIMONY?

A This testimony is presented on behalf of the Missouri Industrial Energy Consumers (MIEC).

I. Introduction

Q WHAT IS THE SUBJECT OF YOUR SURREBUTTAL TESTIMONY?

A My surrebuttal testimony responds to the rebuttal testimony of AmerenUE's witnesses on the subjects of the off-system sales margin component of AmerenUE's revenue requirement and AmerenUE's proposed Fuel Adjustment Clause (FAC). Specifically, I respond to Messrs. Finnell and Schukar in regard to off-system sales margin issues, Mr. Finnell on operating reserve issues, and Messrs. Schukar and Lyons in regard to FAC issues. None of what these witnesses have offered conceptually changes the recommendations I made in my direct testimonies on AmerenUE's proposed off-system sales margin and FAC. However, I have updated the dollar amounts and some of the details in my recommendations to reflect some new information introduced in these witnesses' rebuttal testimonies and recent discovery. The fact I do not address an issue should not be interpreted as approval of any position taken by AmerenUE or any other party to this proceeding.

This all said, the proper determination of AmerenUE's appropriate off-system sales margin and the allocation of fuel and purchased power costs between native load customers and off-system sales is a very complicated matter. The principal point of my testimony in this proceeding is that these determinations could be significantly simplified by: (1) not setting a fixed value for AmerenUE's off-system sales margin, and (2) sharing AmerenUE's off-system sales margin between AmerenUE and its native load customers in the same manner fuel and purchased power costs are shared between AmerenUE and its native load customers. Mr. Brubaker's fuel adjustment proposal does precisely this.

Q PLEASE SUMMARIZE YOUR UPDATED RECOMMENDATIONS.

A I recommend that the Missouri Public Service Commission (Commission):

1. Not set a fixed off-system sales margin component for AmerenUE's revenue requirement due to a lack of a post-Joint Dispatch Agreement (JDA) benchmark of AmerenUE's production cost model, the huge discrepancy between AmerenUE's proposed off-system sales margin versus that in its 2007 Budget Forecast, and the incentives that would be created to shift costs to, and revenues from, native load customers if AmerenUE were authorized an FAC with a fixed off-system sales margin.

2. Require AmerenUE to rerun its production cost simulations with wholesale electricity prices that reflect average market prices no lower than the historic spot market prices that occurred during January through December of 2006. Alternatively, the Commission should increase AmerenUE's off-system sales margin (or off-system sales margin baseline) by no less than $23.5 million, which is my estimate of the impact of rerunning the simulations with these prices. This would amount to a reduction of no less than $22.6 million to AmerenUE's proposed revenue requirement. (This adjustment is only for wholesale prices, and does not consider changes in the volume of sales, which would be in addition to my adjustment.)

3. I also recommend that, if the Commission floats the off-system sales margin level through AmerenUE's proposed FAC, that any sharing of the off-system sales margin deviation from its baseline be shared between AmerenUE and native load customers in the same manner as any deviation in native load fuel and purchased power cost from its baseline is shared between AmerenUE and native load customers.

4. If despite my recommendation, the Commission approves an FAC for AmerenUE and chooses either to set a fixed off-system sales margin or share off-system sales margin deviations differently than native load fuel and purchased power cost deviations, I recommend the Commission:

   a. Require AmerenUE to make a compliance filing to update AmerenUE's Schedule SES-12 to:

      i. Ensure AmerenUE's generation minimum amounts are stacked economically with AmerenUE's incremental generation and purchased power with no priority assignment of generation minimums to native load.

      ii. Ensure AmerenUE generator Locational Marginal Pricing (LMP) revenues associated with generators assigned to native load obligations during AmerenUE's economic stacking process are assigned to native load and passed through the FAC to native load customers.

      iii. Ensure the document clearly indicates which specific LMP is used for the market clearing price for each component in AmerenUE's resource and obligation stacks.

iv. Ensure it is clear that all MISO adjustments to MISO charges passed through AmerenUE's FAC are also passed through AmerenUE's FAC.

v. Ensure it is clear that all MISO Revenue Sufficiency Guarantee (RSG) Make Whole Payments assigned to native load are passed through the FAC to native load customers.

vi. Ensure it is clear why AmerenUE's estimate of the 2006 allocation of MISO charges and credits deviates from AmerenUE's proposed allocation method and why AmerenUE believes its assumption reasonably approximates conformance to its proposed allocation method.

b. As part of the FAC reconciliation process, conduct detailed audits of AmerenUE's conformance to the Commission's approved allocation method for AmerenUE's fuel and purchased power cost, including MISO charges and credits.

5. Require AmerenUE to rerun its production cost simulations with January 1, 2007 operating reserve levels of 43 MW for spinning reserve, 50 MW for regulating reserve and 63 MW for quick start (or non-spinning) reserve. Alternatively, the Commission should reduce AmerenUE's revenue requirement by $2.0 million, which is my rough estimate of the impact of the reduction of the operating reserve requirement.

6. If the Commission floats AmerenUE's off-system sales margin and/or grants an FAC for AmerenUE, require AmerenUE to include an adjustment for the impact Taum Sauk would have had on AmerenUE's actual fuel costs, purchased power costs and off-system sales margin, as applicable, if Taum Sauk had still been operational.

II. Response to AmerenUE Witness Finnell in Regard to Off-System Sales Margin Issues

Q HAVE YOU REVIEWED THE REBUTTAL TESTIMONY OF MR. FINNELL?

A Yes.

Q MR. FINNELL INDICATES THAT ONCE A CALIBRATION OF THE PROMOD PRODUCTION COST MODEL IS DONE, THE MODELER CAN BE CONFIDENT THAT HIS WELL-CALIBRATED MODEL WILL PRODUCE REASONABLE PREDICTIONS OF RESULTS BASED UPON A DIFFERENT SET OF CONDITIONS (FINNELL REBUTTAL TESTIMONY AT 25). HOW DO YOU RESPOND?

A This is true within the bounds of the limitations of the model used. However, if a model is used outside the bounds of its limitations it will not produce an accurate result. Production cost simulations such as PROMOD contain a very large number of assumptions both in the modeling done in the software and the input data applied. For this reason, a calibration performed let us say 5 years ago cannot be relied on to show the model is still valid today because a substantial number of changes may have happened to the utility's operation over those 5 years. Recognition of this is implicit in the common practice of providing a new calibration or benchmark production cost run in each new rate proceeding.

As I discussed in my direct testimony on off-system sales margin (Revenue Requirement Direct Testimony of Dauphinais at 3-4), the end of the JDA will significantly change the operation of AmerenUE. Therefore, reliance on a pre-JDA calibration raises doubt in regard to the validity of the model to portray a post-JDA condition especially since, as my colleague Mr. Brubaker noted in his direct testimony on revenue requirement (Revenue Requirement Direct Testimony of Brubaker at 10-11), AmerenUE's production cost simulations performed for this rate proceeding are producing off-system sales volumes that are substantially lower than AmerenUE has experienced in recent years. Thus, I continue to hold my opinion that there is uncertainty in regard to the ability of AmerenUE's current production cost model to reasonably estimate AmerenUE's fuel and purchased power costs and its off-system sales revenues.

Q MR. FINNELL INDICATES HISTORICAL DATA IS USEFUL FOR DEVELOPING A BENCHMARK, BUT HAS LITTLE VALUE WHEN COMPARED TO NORMALIZED OUTPUTS FROM THE PROMOD MODEL (FINNELL REBUTTAL TESTIMONY AT 29). DO YOU AGREE?

A No. While a deviation from the historical off-system sales volume adjusted for known changes is not alone a conclusive indicator of the reasonableness of the PROMOD projection of off-system volumes, it is a reasonable sanity check, which when failed, casts doubt on the results and indicates that a more detailed examination is warranted. As it turns out, recent information provided by AmerenUE in regard to its 2007 Budget projections has significantly increased my skepticism associated with the validity of AmerenUE's off-system sales projections in this proceeding.

Q PLEASE EXPLAIN WHAT AMERENUE'S 2007 BUDGET PROJECTIONS SHOW.

A ******. Therefore, AmerenUE's own projections of off-system volumes outside of this rate proceeding are significantly higher than those it made within this proceeding. Thus, I continue to recommend that the Commission not set a fixed off-system sales margin component for AmerenUE's revenue requirement. If despite my recommendation the Commission does set a fixed off-system sales margin, the Commission should be very cautious considering the wide range of outcomes that AmerenUE's own projections provide.

III. Response to AmerenUE Witness Schukar on Off-System Sales Margin

Q DOES MR. SCHUKAR IN HIS REVENUE REQUIREMENT REBUTTAL TESTIMONY DISAGREE WITH YOUR PROPOSED USE OF 2006 WHOLESALE ELECTRICITY PRICES WHEN DETERMINING AMERENUE'S OFF-SYSTEM SALES MARGIN?

A Yes. He argues it is important to take an average across several years to reduce the potential impact associated with unusual seasonal weather variations and to otherwise remove normal volatility in prices. He further argues this is especially true because the average monthly level and seasonal pattern of load used in AmerenUE and Staff's production cost modeling is weather-normalized in order to derive normalized test-year fuel costs and off-system sales margins. He also argues that by relying on a single year's power prices, there is a significant risk that the power prices will be significantly overstated (or somewhat understated vis-à-vis normalized loads). Finally, he argues if a single year with unusual peaks and valleys is used in combination with weather normalized loads, abnormal prices will be matched with normal loads resulting in a distortion of off-system sales margins. (Revenue Requirement Rebuttal Testimony of Schukar at 5-6).

Q HOW DO YOU RESPOND TO MR. SCHUKAR?

A While I agree with the need to synchronize prices and loads by using a normalized hourly price <u>profile</u> with a similarly normalized hourly load profile, I strongly disagree with the use of three-year normalized hourly prices without an adjustment to reflect price trends. AmerenUE does not use three-year normalized hourly loads in its PROMOD model. Instead, <u>weather</u> normalized sales for the test year are applied to a historic load pattern. This is because AmerenUE's load is forecasted to grow and it is unlikely AmerenUE's native load sales levels will fall back to levels of two or three years ago barring unusual weather. Thus, if AmerenUE simply used its normalized hourly loads, it would be understating its native load sales.

This same issue exists with the hourly wholesale electricity prices used in AmerenUE's PROMOD production cost runs upon which AmerenUE's proposed off-system sales margin is based. AmerenUE used normalized hourly wholesale electricity priced based on averaging prices from 2003 through 2005 with downward adjustments to 2005 values to remove the impact of hurricanes and rail disruptions. To use such hourly prices without further adjustment is to assume wholesale electricity prices will remain static at the adjusted average price of the three-year period. However, AmerenUE in this proceeding has not produced any evidence that supports the notion that wholesale electricity prices will return to 2003 and 2004 levels in the foreseeable future. Wholesale electricity prices in 2006, while lower than in 2005 due to the abatement of the influence of the 2005 hurricanes and rail disruptions, were significantly higher than prices in 2003 and 2004 as shown in Table 1 - Surrebuttal.

Table 1 - Surrebuttal
Comparison of Cinergy On-Peak and Off-Peak Prices
(per MWh)

On-Peak				Off-Peak			
2003	2004	2005	2006	2003	2004	2005	2006
$37.51	$43.35	$63.74	$51.78	$19.62	$24.44	$35.46	$32.14

Source: Platts *Megawatt Daily*

Q IS THERE ANY OTHER EVIDENCE THAT A RETURN TO 2003 AND 2004 WHOLESALE ELECTRICITY PRICE IS UNLIKELY?

A Yes, as I discussed in my revenue requirement direct testimony, forward prices for electricity for calendar year 2007 reported in late 2006 were significantly higher than historical prices for 2006. With 2006 closed, I can now report that historical on-peak Cinergy prices for 2006 averaged $51.78 per MWh while the average forward on-peak Cinergy price for 2007 on the last five trading days of 2006 was $53.57 per MWh (Platts *Megawatt Daily* reported closing prices for December 21-28, 2006). Furthermore, current Cinergy on-peak forward trading for calendar years 2008 and 2009 at the <u>lowest</u> single daily market close in the first 57 days of 2007 was $57.50 per MWh for calendar year 2008, $57 per MWh for calendar year 2009 and $56.50 per MWh for calendar year 2010 (Platts *Megawatt Daily*, January 30, 2007). ******. Clearly, even AmerenUE for budgeting purposes believes it is very unlikely we will see a return to 2003 and 2004 wholesale electricity prices anytime soon. Therefore, if the adjusted normalized wholesale prices developed by Mr. Schukar for AmerenUE are used as is they will understate the wholesale market price for electricity.

Consistent with my revenue requirement direct testimony, at a minimum, AmerenUE's adjusted normalized wholesale prices need to be scaled up to the average wholesale electricity prices experienced by AmerenUE's generation during January through December of 2006.

Q MR. SCHUKAR ARGUES EARLY 2006 PRICES WERE STILL IMPACTED BY 2005 SUPPLY DISRUPTIONS AND CITES A FERC REPORT, A CONGRESSIONAL RESEARCH SERVICE REPORT AND ANALYSIS BY COMMISSION STAFF WITNESS DR. PROCTOR (REVENUE REQUIREMENT REBUTTAL TESTIMONY OF SCHUKAR AT 6-7). HOW DO YOU RESPOND?

A The evidence Mr. Schukar presents does suggest there was some impact from the 2005 supply disruption on early 2006 prices. However, this has to be viewed in the context of recent historical prices and current forward prices. Table 2-Surrebuttal compares average historical Locational Marginal Price (LMP) at the Ameren (now UE) MERAMEC1 pricing node for January and the first 23 days of February 2006 to the same period for 2007. It can clearly be seen that the historic 2007 prices in this comparison are significantly higher than historic 2006 prices for the same period. The higher 2007 prices in part may be explained by February 2007 being colder on average than February 2006, but the fact remains that current prices to date in 2007 have been higher on average than historical prices for the same period in 2006.

Table 2 - Surrebuttal
To Date Comparison of 2006 and 2007 Historic
Wholesale Block of Prices at AMRN.MERAMEC1
(per MWh)

	Day-Ahead	Real-Time
January 1 – February 23, 2006	$39.88	$38.85
January 1 – February 23, 2007	$43.05	$43.84

Source: www.midwestiso.com

In addition, as I have already discussed, even at the lowest market close to date for 2007, forward market prices for 2008, 2009 and 2010 are trading higher than historic prices for 2006. Considering all of this evidence, I do not believe any adjustment to remove any lingering effect of 2005 supply disruptions from historical early 2006 wholesale electricity prices is warranted. The use of these historical prices is still conservative versus what current forward prices suggest will be likely.

Q MR. SCHUKAR INDICATES THAT WHILE YOU USED A MISO GENERATION LMP FOR AN AMERENUE FACILITY, IT WOULD HAVE BEEN MORE APPROPRIATE TO UTILIZE THE AVERAGE OF THE LMPS AT THE AMERENUE GENERATOR NODES THAT TYPICALLY PROVIDE OFF-SYSTEM SALES (REVENUE REQUIREMENT REBUTTAL TESTIMONY OF SCHUKAR AT 26). DO YOU AGREE?

A Yes. However, note that I did not have ready access to a list of AmerenUE generator nodes that typically provide off-system sales. Therefore, I instead conservatively used the lowest priced AmerenUE generation node for the period of my evaluation of historic prices. If the Commission adopts my recommendation to use hourly wholesale electricity prices that average to the historical LMPs that occurred between January 2006 and December 2006, the historical LMPs that are used should be calculated from an average of the LMPs at generator nodes where AmerenUE typically makes off-system sales.

Q MR. SCHUKAR ALSO INDICATES IT WOULD BE NECESSARY TO UTILIZE THE DAY-AHEAD AND REAL-TIME LMPS AT THESE GENERATOR NODES AT THE RATIO THAT AMERENUE NORMALLY SELLS INTO THE DAY-AHEAD AND REAL-TIME MARKETS (*ID.*). DO YOU AGREE?

A Yes. However, note that the majority of AmerenUE's off-system sales are likely made into the day-ahead market rather than the real-time market as a very high percentage of MISO load clears in the day-ahead market. Nevertheless, if the Commission adopts my recommendation to use hourly wholesale electricity prices that average to historical LMPs for January 2006 through December 2006, day-ahead and real-time LMPs at the aforementioned generation nodes at the ratio that AmerenUE normally sells into the day-ahead and real-time markets should be utilized.

Q MR. SCHUKAR INDICATES IT WAS INAPPROPRIATE FOR YOU TO USE A PRICE AVERAGE THAT ONLY INCLUDES 11 MONTHS OF THE YEAR BECAUSE IT LEAVES OFF-PEAK MONTH OUT, WHICH OVERSTATES THE AVERAGE PRICE. HE ALSO STATES THAT AS A MINIMUM YOU SHOULD ALSO USE DECEMBER 2006 PRICES TO DEVELOP A 12-MONTH AVERAGE PRICE (REVENUE REQUIREMENT REBUTTAL TESTIMONY OF SCHUKAR AT 26). HOW DO YOU RESPOND?

A Mr. Schukar has apparently misunderstood my usage of an 11-month average and missed that my recommendation was that the Commission require AmerenUE to rerun its PROMOD model with hourly wholesale electricity prices that average to historical prices for January 2006 through <u>December</u> 2006. In Tables 1 and 2 on pages 7 through 8 of my Revenue Requirement Direct Testimony, I used 11 months of 2006 historical data in comparison to 11 months of AmerenUE's adjusted normalized wholesale electricity prices because December 2006 data was not yet available and December 2005 had above normal prices due to the 2005 supply disruptions.

The comparisons I made were appropriate as I compared a January to November historical period to AmerenUE's numbers for a January to November period. In regard to my estimate of the dollar impact of my recommendation that was detailed in Schedule JRD-1 of my Revenue Requirement Direct Testimony, I have updated it in Schedule JRD-Surrebuttal-1 to use average wholesale electricity prices for January 2006 through December 2006 based on AmerenUE's rebuttal testimony PROMOD runs and assuming a 90% day-ahead market and 10% real-time market split. Note that I am no longer adjusting fuel oil and natural gas prices since AmerenUE witness Mr. Finnell adopted historical 2006 natural gas prices in his revenue requirement rebuttal testimony (Revenue Requirement Rebuttal Testimony of Finnell at 34).

My updated estimate of the impact of rerunning AmerenUE's PROMOD simulations with hourly wholesale electricity prices that average to the historic wholesale electricity prices AmerenUE's generation experienced during January through December of 2006 would increase AmerenUE's proposed off-system sales margin by $23.5 million, which would decrease its proposed revenue requirement by $22.6 million after deducting the increased cost of purchased power. (Note that this adjustment relates only to price levels and that adjustments to sales volumes would be added to my adjustment.)

Q MR. SCHUKAR NOTES YOU USED CINERGY DAY-AHEAD PRICES IN TABLE 1 ON PAGE 7 OF YOUR REVENUE REQUIREMENT REBUTTAL TESTIMONY. HE ALSO INDICATES THE CINERGY DAY-AHEAD PRICE WOULD NOT BE AN APPROPRIATE PRICE TO USE FOR AMERENUE'S OFF-SYSTEM SALES (REVENUE REQUIREMENT DIRECT TESTIMONY OF SCHUKAR AT 27). HOW DO YOU RESPOND?

A This is a red herring. I have not suggested the day-ahead Cinergy price be used for AmerenUE without a basis differential being applied to bring the Cinergy price back to the AmerenUE generation nodes. My estimate of the impact of using 2006 historical wholesale electricity prices in fact applied MISO prices for AmerenUE's Meramec1 generation node not Cinergy prices. In regard to Table 1 of my revenue requirement direct testimony, even if the day-ahead Cinergy prices in the table were reduced by the basis differential of $1.51 per MWh that Mr. Schukar mentions, they are still significantly higher than AmerenUE's adjusted normalized hourly wholesale electricity prices.

Finally, note that Cinergy is the most relevant trading hub for electricity for AmerenUE. Therefore, the price trend at Cinergy is a valid indicator of the likely price trend at AmerenUE's generation nodes. Thus, if forward prices at Cinergy are higher than historic prices at Cinergy, forward prices at AmerenUE generation nodes are likely higher than historic prices at AmerenUE's generation nodes.

Q MR. SCHUKAR ARGUES FORWARD CONTRACTS FOR ELECTRICITY ARE IN ESSENCE A COMBINATION OF THE AVERAGE EXPECTED SPOT PRICE FOR A DELIVERY LOCATION AND A HEDGE AGAINST SPOT PRICE VOLATILITY, WHICH RESULTS IN A RISK PREMIUM OR DISCOUNT BEING ASSOCIATED WITH THE CONTRACT. HE THEN ALSO ARGUES THAT AN ESTIMATE OF THE RISK PREMIUM WITHIN FORWARD PRICES MUST BE REMOVED TO YIELD A PRICE COMMENSURATE TO WHAT AMERENUE CAN EARN (REVENUE REQUIREMENT REBUTTAL TESTIMONY OF SCHUKAR AT 27-28). HOW DO YOU RESPOND?

A I disagree with the concept that you must carve out a risk premium or discount from a forward price. Forward prices effectively reflect the market consensus regarding probable outcomes of future spot prices. If a subsequently realized spot price is below a corresponding forward price, it does not necessarily follow that the forward price contained a premium, but rather that some possible outcome (e.g., price spike due to extreme weather event) was unrealized. To extract from the forward price a "premium" would in essence assign a probability of zero to higher spot price overcomes. Such an assumption would understate spot prices since there is always some probability that price spikes could occur and such an occurrence would provide an opportunity for AmerenUE to earn a higher off-system sales margin. Therefore, no risk premium needs to be removed from the forward price nor any risk discount added back into the price. ******.

Q MR. SCHUKAR INDICATES THAT AFTER LARGE JUMPS IN MARKET PRICES LIKE THE PRICE SPIKES THAT WERE SEEN IN 2005 FROM THE HURRICANES AND RAIL DISRUPTIONS, FORWARD PRICES WILL TEND TO HAVE A SIGNIFICANT BUILT-IN RISK PREMIUM, WHICH MEANS FORWARD PRICES WILL EXCEED THE EXPECTED SPOT PRICES (REVENUE REQUIREMENT REBUTTAL TESTIMONY OF SCHUKAR AT 28). HOW DO YOU RESPOND?

A For the reasons I have just discussed, such increases do not mean forward prices will exceed expected spot prices. Instead, it means spot prices higher than in the past were anticipated because the long-term impact of the supply disruptions were not known. As the true long-term impact of the disruptions became clear, forward prices retreated to lower levels as market expectations of future spot market prices changed. Regardless, it is important to note that the forward prices that I have cited here and in my revenue requirement direct testimony closed in the forward market after the very mild hurricane season of 2006 and long after the 2005 rail disruptions. There is no reason to believe current forward market prices are a product of unrealistic assessments of future spot prices.

Q MR. SCHUKAR INDICATES THAT YOU SEEM TO HAVE LEAPED TO THE CONCLUSION THAT JUST BECAUSE AMERENUE IS SEEING AN INCREASE IN FUEL COST, THE BALANCE OF THE MARKET IS SEEING THE SAME COST INCREASES, RESULTING IN INCREASED ENERGY PRICES. HE FURTHER INDICATES THERE IS NOT NECESSARILY A STRONG RELATIONSHIP BETWEEN AMERENUE'S PRICE OF FUEL AND POWER PRICES (REVENUE REQUIREMENT REBUTTAL TESTIMONY OF SCHUKAR AT 29). HOW DO YOU RESPOND?

A I never suggested there is a relationship between wholesale electricity prices and AmerenUE's average cost of fuel and purchased power. What I objected to in my Revenue Requirement Direct Testimony was AmerenUE making an adjustment to reflect 2007 coal and nuclear fuel costs without making a similar adjustment for wholesale electricity prices when there is substantial information supporting significantly higher spot market prices for wholesale electricity than the adjusted normalized prices for 2003 through 2005 that AmerenUE used in its production cost simulations (Revenue Requirement Direct Testimony of Dauphinais at 9-10).

Q MR. SCHUKAR ASSERTS THAT THE FUEL PRICES AMERENUE UTILIZED FOR ITS PRODUCTION COST MODELING WERE CONSISTENT WITH ELECTRICITY PRICES THAT AMERENUE USED (REVENUE REQUIREMENT REBUTTAL TESTIMONY OF SCHUKAR AT 30). DO YOU AGREE?

A No. As I have indicated, it is inappropriate to make an adjustment for fuel costs while not making a similar adjustment to wholesale electricity prices as this distorts the estimated off-system sales margin produced in the production cost simulations.

Q MR. SCHUKAR INDICATES THAT THE WHOLESALE ELECTRICITY PRICE AMERENUE WOULD BE ABLE TO REALIZE WOULD BE AN AVERAGE 5-10% LESS THAN THE PRICE IT WOULD RECEIVE IF IT WERE ABLE TO SELL ITS OUTPUT AT THE FIXED HOURLY AMOUNTS REQUIRED IN FORWARD CONTRACTS BECAUSE THE AMOUNT OF POWER IT HAS AVAILABLE TO SELL IN EACH HOUR CAN VARY SIGNIFICANTLY (REVENUE REQUIREMENT REBUTTAL TESTIMONY OF SCHUKAR AT 30-31). HOW DO YOU RESPOND?

A I do not necessarily disagree, but the production cost simulations inherently reflect this when they calculate AmerenUE's off-system sales. To reduce the wholesale electricity prices input into the model would be to double compensate for the fact AmerenUE makes significantly varying amounts of off-system sales amounts in each hour. In addition, my estimate of rerunning AmerenUE's production cost simulations with hourly wholesale electricity prices that average to 2006 historical prices inherently addresses this as well because the method I used for the estimate scales AmerenUE's already implicitly reduced off-system sales revenues by the ratio of the average of 2006 wholesale electricity prices to AmerenUE's adjusted normalized wholesale electricity prices. It is also important to note that AmerenUE's adjustments to normalized wholesale electricity prices did not involve a 5-10% reduction of prices.

Q CAN YOU SUMMARIZE YOUR FINAL THOUGHTS ON THE SUBJECT OF AMERENUE'S OFF-SYSTEM SALES MARGIN?

A Yes. AmerenUE's witnesses on rebuttal have not provided any new information that would conceptually change the recommendations in my direct testimony. Because of great uncertainty associated with the level of AmerenUE's off-system sales margin, I recommend the Commission not set a fixed value for AmerenUE's off-system sales margin.

Regardless, AmerenUE should be required to rerun its production cost simulations using hourly wholesale electricity prices that average to the historical wholesale electricity prices experienced by AmerenUE at its generation nodes during January 2006 through December 2006 or alternatively the Commission should increase AmerenUE's off-system sales margin (or off-system sales margin baseline) by a minimum of $23.5 million which is my estimate of the impact of such a rerun.

IV. Response to AmerenUE Witness Schukar on Fuel Adjustment Clause Issues

Q MR. SCHUKAR INDICATES IN HIS FUEL ADJUSTMENT CLAUSE REBUTTAL TESTIMONY THAT IN YOUR FUEL ADJUSTMENT CLAUSE DIRECT TESTIMONY YOU TOTALLY OVERLOOK THAT THE AVAILABILITY AND PRODUCTION COST OF AMERENUE'S GENERATION FLEET WILL SIGNIFICANTLY AFFECT THE COMPANY'S ABILITY TO SELL INTO THE MISO MARKET (FUEL ADJUSTMENT CLAUSE REBUTTAL TESTIMONY OF SCHUKAR AT 3). HOW DO YOU RESPOND?

A My testimony went to the issue of whether AmerenUE needs incentives to make off-system sales, not whether AmerenUE needs incentives to maximize the availability of its generation and minimize its production cost of that generation. This latter issue was addressed by my colleague Mr. Brubaker. Nevertheless, let me say the introduction of a fuel adjustment clause in general reduces the incentives a utility would have to maximize the availability of its generation, minimize the production cost of its generation and minimize its purchased power costs. These incentives can be restored by sharing all fuel and purchased power costs and off-system sales revenues between native load customers and AmerenUE in a manner like that proposed by Mr. Brubaker. However, it is critical that any such sharing mechanism share native load fuel and purchased power costs and off-system sales margin in a similar manner, otherwise incentives will be introduced for AmerenUE to shift costs to native load customers and revenues to off-system sales. Mr. Brubaker's proposal addresses this concern.

Q MR. SCHUKAR ASSERTS YOU IMPLICITLY ASSUME THAT ALL OF AMERENUE'S OFF-SYSTEM SALES WILL OCCUR IN THE MISO DAY-AHEAD SPOT MARKETS (FUEL ADJUSTMENT CLAUSE REBUTTAL TESTIMONY OF SCHUKAR AT 3). DID YOU?

A No. ******. Moreover, Mr. Schukar himself has generally discounted the ability of AmerenUE to make bilateral sales. For example, in his Revenue Requirement Rebuttal Testimony, Mr. Schukar discounts the ability of AmerenUE to make forward contract sales because AmerenUE only sells power after native load requirements have been met and the amount that is available to be sold each hour of a period can vary significantly and can in fact be zero (Revenue Requirement Rebuttal Testimony of Schukar at 31).

Moreover, AmerenUE's method of projecting its off-system sales in its PROMOD production cost model implicitly assumes all of AmerenUE's off-system sales will be sales into the day-ahead and real-time markets. While certainly AmerenUE will have the opportunity to make bilateral off-system sales and should be availing itself of those opportunities, for the foreseeable future such bilateral sales will only make up a very small percentage of AmerenUE's total off-system sales volume.

Finally, to the extent any incentive is warranted in this area, it is adequately addressed through Mr. Brubaker's proposal for sharing native load fuel and purchased power costs and off-system sales margin between native load customers and AmerenUE.

Q MR. SCHUKAR INDICATES THAT HE DOES NOT BELIEVE A SHIFTING OF COSTS TO NATIVE LOAD CUSTOMERS AND REVENUES TO OFF-SYSTEM SALES SHOULD BE A CONCERN BECAUSE AMERENUE'S COST AND REVENUE ALLOCATION PROCEDURES ARE WELL ESTABLISHED AND ENSURE THAT THE LOWEST COST RESOURCES ARE ALLOCATED TO NATIVE LOAD (FUEL ADJUSTMENT CLAUSE REBUTTAL TESTIMONY OF SCHUKAR AT 8). HOW DO YOU RESPOND?

A I strongly disagree. First, until this proposal there has not been an ongoing need to scrutinize the allocation of costs and revenues between native load and off-system sales because AmerenUE has not had an FAC and both native load fuel and purchased power costs and off-system sales margin were allocated to native load customers in an identical fashion. Therefore, the quality of AmerenUE's previous allocations of costs and revenues between native load and off-system sales is really unknown.

Second, AmerenUE completely failed to address this cost and revenue allocation issue in its direct case and the issue may very well have been "swept under the rug" but for me raising it in my fuel adjustment clause direct testimony.

Third, based on Mr. Schukar's fuel adjustment clause rebuttal testimony, what little AmerenUE provided in discovery in regard to the allocation was incomplete and apparently inaccurate.

Fourth, Mr. Schukar's Fuel Adjustment Clause Rebuttal Testimony revealed that the Company in its proposed revenue requirement in this proceeding misallocated $3.5 million in MISO costs to native load because it assigned <u>no</u> MISO costs to off-system sales (Fuel Adjustment Clause Rebuttal Testimony of Schukar at 12-13).

While AmerenUE's allocation can be scrutinized during reconciliations of FAC-related costs, the complexity of such reconciliations would be significantly increased if the Commission chooses to allow a sharing of off-system sales margin in a manner different than how native load fuel and purchased power costs are shared.

Q MR. SCHUKAR ASSERTS YOUR CONCERN THAT THE MISO DAY 2 MARKET MAKES THE ALLOCATION OF COSTS AND REVENUES MORE COMPLEX IS OVERSTATED. HE ALSO ASSERTS IT IS IMPORTANT TO RECOGNIZE OTHER UTILITIES IN THE MISO REGION HAVE FACS AND PRESUMABLY HAVE FOUND A WAY OF SATISFACTORILY ALLOCATING MISO COSTS IN THEIR FAC, BASE RATES AND OTHER RATE ADJUSTMENT MECHANISMS (FUEL ADJUSTMENT CLAUSE REBUTTAL TESTIMONY OF SCHUKAR AT 10-11). HOW DO YOU RESPOND?

A I am not overstating the concern. Post-JDA, the cost allocation will be significantly more complicated than it would have been post-JDA without the MISO Day 2 markets. In addition, as I previously noted, since in the past both native load fuel and purchased power costs and off-system sales margin both flowed the same way through fixed rates for AmerenUE, the need to carefully scrutinize AmerenUE's allocation of costs and revenues between native load and off-system sales was not present. Finally, satisfactory allocation of MISO costs under an FAC has been a significant issue in other jurisdictions in the region where native load fuel and purchased power costs are shared differently than off-system sales margin.

Q CAN YOU PROVIDE SOME EXAMPLES OF WHAT HAS BEEN AN ISSUE IN OTHER JURISDICTIONS WITHIN THE MISO FOOTPRINT?

A Yes. I have been involved in FAC proceedings in Indiana and Power Supply Cost Recovery (PSCR) factor proceedings in Michigan. In Indiana, the utilities within the MISO regulated by the Indiana Utility Regulatory Commission (IURC) each have an FAC and the off-system sales margin is either set at a fixed value or shared under an off-system sales tracker. Despite the fact the IURC conducted an extensive proceeding in IURC Cause No. 42865 in regard to the allocation of MISO Day 2 market costs and revenues, the allocation of these costs and revenues between native load customers and off-system sales has become a significant issue of contention that has resulted in contested proceedings in PSI Energy, Inc. Cause No. 38707-FAC67-S1, Indianapolis Power and Light Company Cause No. 38703-FAC71-S1 and Northern Indiana Public Service Company Cause No. 38706-FAC71-S1.

This strongly contrasts with my experience in Michigan. In Michigan, native load fuel and purchased power costs and off-system sales margin are shared in the same manner through the PSCR factor. As a result, the allocation of MISO costs and revenues has not become a contested issue in the PSCR reconciliations I have been involved with concerning Detroit Edison Company and Wisconsin Electric Power Company. Based on my experience, in my opinion FAC reconciliations for AmerenUE will be more complicated and contentious if off-system sales margin is not shared between native load customers and AmerenUE in the same manner as native load fuel and purchased power costs.

Q HAS AMERENUE PRESENTED AN UPDATE TO ITS DOCUMENTS ADDRESSING THE ALLOCATION OF FUEL AND PURCHASED POWER COSTS, INCLUDING MISO COST AND REVENUES, BETWEEN NATIVE LOAD AND OFF-SYSTEM SALES?

A Yes. As part of his Fuel Adjustment Clause Rebuttal Testimony, Mr. Schukar has sponsored and provided supporting testimony for a new Schedule SES-12 which updates AmerenUE's proposed allocation of fuel and purchased power costs, including MISO charges and credits, between native load and off-system sales.

Q HAVE YOU REVIEWED AMERENUE SCHEDULE SES-12 AND MR. SCHUKAR'S SUPPORTING TESTIMONY?

A Yes. AmerenUE has addressed my concern in regard to AmerenUE deeming the information confidential by publicly filing Schedule SES-12. In addition, Schedule SES-12 is a measurably clearer document than the documents previously provided by AmerenUE in discovery, which I had attached to my Fuel Adjustment Clause Direct Testimony as Schedules JRD-FAC-2 and JRD-FAC-3. However, there are still significant shortcomings in Schedule SES-12 such that it fails to meet my call for AmerenUE to file a clear, complete, corrected and detailed allocation method for all fuel and purchased power costs, including MISO charges and credits (Fuel Adjustment Clause Direct Testimony of Dauphinais at 2).

Q CAN YOU WALK US THROUGH THE REMAINING SHORTCOMINGS TO SCHEDULE SES-12 THAT YOU HAVE BEEN ABLE TO IDENTIFY?

A Yes. In the time since AmerenUE filed Schedule SES-12, I have identified the following remaining shortcomings:

- AmerenUE's proposed assignment of generation minimum amounts to native load allows expensive AmerenUE gas-fired generation committed by the MISO to unreasonably displace lower cost AmerenUE incremental coal-fired generation dispatched by the MISO and lower cost power purchases from the MISO.

- AmerenUE has not identified whether the LMP revenue earned by a generation minimum or incremental generation assigned to native load will be allocated to native load in addition to fuel cost to offset any LMP charges assessed by MISO to native load.

- AmerenUE has not provided adequate assurance that non-asset activity conducted by AmerenEnergy through the MISO AET Asset Owner is de minimus and/or is not of a nature that would lead to AmerenEnergy acting in a manner that increases costs or decreases revenues due to native load.

- AmerenUE has not adequately explained which market clearing prices are used for pricing MISO purchases and sales.

- AmerenUE has not adequately addressed the passing through the FAC of MISO adjustments to MISO charges that have been previously passed through the FAC to native load customers.

- AmerenUE's approximate estimate of 2006 actual MISO credits and charges does not conform to its proposed allocation method for those charges.

Q WHAT IS A GENERATION MINIMUM AMOUNT?

A A generation minimum amount is the minimum MWh output at which a generator must operate in a given hour in order to be on-line. On occasion the MISO will commit and dispatch AmerenUE generation on an out-of-merit order basis for reliability purposes or in anticipation of needing to economically dispatch that generator at a higher level during a later hour. When this happens the fuel cost of the generator in question can exceed the Locational Marginal Price (LMP) at its generation node.

Q DOES MISO MAKE THESE GENERATION COMMITMENTS SPECIFICALLY FOR AMERENUE NATIVE LOAD OR OFF-SYSTEM SALES?

A No. The MISO commits and dispatches generation for its entire footprint. It does not commit and dispatch generation for particular MISO market participants or asset owners.

Q DOES THE MISO PROVIDE ANY COMPENSATION FOR THESE COSTS ABOVE THE LMP?

A Yes. The MISO provides Revenue Sufficiency Guarantee (RSG) Make Whole Payments. However, under AmerenUE's proposed allocation method these payments will be allocated in each hour between native load and off-system sales on the basis of the hourly ratio of native load MWh and off-system sales MWh to total MWh. (Schedule SES-12 at 5-6 and Fuel Adjustment Clause Rebuttal Testimony of Schukar at 13). AmerenUE is not allocating these payments on the basis of how its specific generators are allocated each hour between native load and off-system sales.

Q WHAT IS THE PROBLEM WITH AMERENUE'S PROPOSED ASSIGNMENT OF GENERATOR MINIMUMS TO NATIVE LOAD PRIOR TO AMERENUE'S LOWEST COST INCREMENTAL GENERATION AND PURCHASED POWER (SCHEDULE SES-12 AT 1-3)?

A The MISO may commit expensive AmerenUE gas-fired generation out-of-merit order. Under AmerenUE's Schedule SES-12, the higher cost for this out-of-merit order generation would be targeted to native load and displace lower cost incremental generation and purchased power from native load to off-system sales. This would increase AmerenUE's off-system sales margin at the expense of increasing native load's fuel and purchased power cost.

Q WHAT DO YOU RECOMMEND TO ADDRESS THIS ISSUE?

A AmerenUE's generation minimum amounts should be stacked economically with AmerenUE's incremental generation and purchased power with no priority assignment of generation minimums to native load customers.

Q PLEASE EXPLAIN YOUR CONCERN WITH AMERENUE NOT IDENTIFYING HOW THE LMP REVENUE EARNED BY GENERATION ASSIGNED TO NATIVE LOAD IS ALLOCATED.

A All of AmerenUE's native load will be cleared at the LMP for the AmerenUE load zone and be assessed energy charges by the MISO at these LMPs. If in AmerenUE's stacking process only the fuel cost associated with generation assigned to native load is allocated to native load, native load will be unreasonably assigned both MISO LMP charges at the AmerenUE load zone and fuel costs. Instead, both the LMP revenue earned by the native load assigned generator and the fuel cost of that generator needs to be assigned to native load. This would net to fuel cost plus the difference between the AmerenUE load zone LMP and the generator's LMP. This difference between the two LMPs is the MISO's marginal congestion and transmission loss charge to move the assigned power from the generator to native load.

Q HAVE YOU BROUGHT THIS PARTICULAR CONCERN TO THE ATTENTION OF AMERENUE PERSONNEL?

A Yes. Subsequent to AmerenUE's fuel adjustment clause rebuttal testimony I spoke with AmerenUE's Mr. Schukar. He indicated at that time it is AmerenUE's intent to assign generator LMP revenues to native load in the manner comparable to that I have just discussed. However, this needs to be explicitly spelled out by AmerenUE in Schedule SES-12.

Q WHAT DO YOU RECOMMEND IN REGARD TO THIS ISSUE?

A The Commission should require AmerenUE to modify Schedule SES-12 so that it explicitly assigns generator LMP revenues received by generation assigned to native load in AmerenUE's stacking process to native load.

Q PLEASE EXPLAIN YOUR CONCERN IN REGARD TO THE IDENTIFICATION OF WHICH MARKET CLEARING PRICES ARE USED FOR PRICING MISO PURCHASES AND SALES.

A Page 2 of Schedule SES-12 mentions MISO purchases and sales are priced at market clearing prices. However, AmerenUE has not detailed which specific market clearing prices would apply. In conversations I have had with AmerenUE's Mr. Schukar subsequent to AmerenUE's rebuttal testimony, Mr. Schukar has indicated that MISO purchases would be priced at the AmerenUE load zone LMP, MISO sales at the LMPs of the generators assigned to the sale through AmerenUE's stacking process, and generator minimums and incremental generator MISO revenues assigned to native load at each generator's LMP. This needs to be detailed in Schedule SES-12.

Q WHAT DO YOU RECOMMEND?

A AmerenUE be required to modify its Schedule SES-12 to specifically spell out the market clearing prices that will be used for each component in its resource and obligation stacks.

Q WHAT IS YOUR CONCERN WITH THE PASS-THROUGH OF MISO ADJUSTMENTS TO THOSE MISO CHARGES THAT ARE PASSED THROUGH THE FAC?

A As I discussed in my Fuel Adjustment Clause Direct Testimony, the MISO on occasion makes downward adjustments to charges during the resettlement period and under AmerenUE's accounting these credits could get assigned to a FERC 400 series account that is not passed through the FAC (Fuel Adjustment Clause Direct Testimony of Dauphinais at 16-17). I also had this same concern in regard to assuring MISO RSG Make Whole Payments, which are also credits, are assigned to native load through the FAC. I found Mr. Schukar's Rebuttal Testimony on this matter to be confusing (Fuel Adjustment Clause Rebuttal Testimony of Schukar at 13-14). However, in conversations with Mr. Schukar after AmerenUE filed its rebuttal testimony, he indicated that it was not AmerenUE's intent to block the flow of such credits to native load customers through the FAC. In addition, he advised me AmerenUE would clarify its intention in regard to the FAC pass-through of these credits in his surrebuttal testimony. I welcome this development.

Q WHAT DO YOU RECOMMEND?

A That the Commission require AmerenUE to modify Schedule SES-12 to make it clear that all MISO adjustments to MISO charges passed through AmerenUE's FAC also pass through AmerenUE's FAC. In addition, the Commission should require Schedule SES-12 be modified to assure all MISO RSG Make Whole Payments received by AmerenUE and assigned to native load are passed through AmerenUE's FAC to native load customers.

Q PLEASE EXPLAIN YOUR CONCERN WITH AMERENUE'S ESTIMATE OF ACTUAL 2006 MISO CHARGE AND CREDIT ALLOCATIONS (AMERENUE SCHEDULE SES-12 AT 6).

A The indicated allocations do not entirely correspond to AmerenUE's proposed allocation of MISO costs and credits. For example, FTR revenues were allocated on a MWh ratio basis in the 2006 estimate, but AmerenUE's actual proposal presented in Mr. Schukar's fuel adjustment clause rebuttal testimony is direct assignment UELSE Asset Owner FTR revenues to native load and UEGEN Asset Owner point-to-point FTRs to off-system sales. In addition, the amounts AmerenUE has identified for marginal congestion and marginal losses will not on a going forward basis actually appear in the bilateral transaction line items as they would have in 2006.

Q HOW DO YOU RECOMMEND THE COMMISSION ADDRESS THIS ISSUE?

A AmerenUE should be required to explain why the estimate does not fully conform to its proposed allocation method and why the assumptions AmerenUE has made reasonably approximate conformance with its proposed allocation method, if at all.

Q WHAT IS YOUR FINAL RECOMMENDATION IN REGARD TO AMERENUE'S PROPOSED ALLOCATION METHOD FOR FUEL AND PURCHASED POWER COSTS INCLUDING MISO CHARGES AND CREDITS?

A The Commission should adopt the same sharing approach for off-system sales margin as it does for sharing native load fuel and purchased power cost. However, if despite my recommendation the Commission adopts a different sharing approach for off-system sales than for native load fuel and purchased power cost, the Commission should require AmerenUE to make a compliance filing update of AmerenUE's Schedule SES-12 with the corrections I have just discussed. In addition, as I noted in my fuel adjustment clause direct testimony, during FAC reconciliations the Commission should conduct detailed audits of AmerenUE's conformance to the compliance version of Schedule SES-12 as approved by the Commission.

V. Response to AmerenUE Witness Finnell on <u>Revenue Requirement Issues Related to Operating Reserves</u>

Q MR. FINNELL ASSERTS THAT YOU DO NOT UNDERSTAND OPERATING RESERVES BECAUSE YOU DID NOT MENTION THE REGULATING COMPONENT OF OPERATING RESERVE (REBUTTAL TESTIMONY OF FINNELL AT 4). HOW DO YOU RESPOND?

A I have testified on numerous occasions before the Federal Energy Regulatory Commission (FERC) and various state commissions on the subject of ancillary services including regulation, spinning reserve and supplemental (i.e., non-spinning or quick start) reserves. I misunderstood Mr. Finnell's direct testimony because he made an uncommon use of the term "spinning reserve." It is now clear from Mr. Finnell's rebuttal testimony and AmerenUE's response to Data Request MIEC 21-6 that when Mr. Finnell used the term "spinning reserve" in his direct testimony (Direct Testimony of Finnell at 10) he was referring to spinning reserve and regulating reserve together rather than spinning reserve alone. This is a very uncommon usage of the term "spinning reserves" since spinning reserve proper is associated with responding to contingencies and regulating reserve is associated with maintaining system frequency and moment-to-moment balance between generation, load and losses. It is noteworthy that Mr. Finnell separately states regulating reserve from spinning reserve in his rebuttal testimony. To avoid further confusion, the term "spinning reserves" should be used without the inclusion of regulating reserves, consistent with Mr. Finnell's usage in his rebuttal testimony.

Q MR. FINNELL INDICATED IN HIS DIRECT TESTIMONY HE MODELED IN PROMOD A 101 MW SPINNING RESERVE VALUE AND A 101 MW NON-SPINNING RESERVE VALUE (DIRECT TESTIMONY OF FINNELL AT 10). MR. FINNELL INDICATED IN HIS REBUTTAL TESTIMONY HE MODELED IN HIS DIRECT TESTIMONY 58 MW OF SPINNING RESERVE, 53 MW OF REGULATING RESERVE AND 101 MW OF QUICK START RESERVE (REBUTTAL TESTIMONY OF FINNELL AT 30-31). CAN YOU RECONCILE THESE DIFFERENCES?

A Yes. In response to Data Request MIEC 21-6, AmerenUE indicated the value of spinning reserve was incorrectly stated as 58 MW in Mr. Finnell's rebuttal testimony. AmerenUE modeled 48 MW of spinning reserve, 53 MW of regulating reserve and 101 MW of quick start reserve in its direct testimony PROMOD runs (AmerenUE Response to Data Request MIEC 21-6).

Q MR. FINNELL AGREES WITH YOUR TESTIMONY THAT AMERENUE'S TOTAL OPERATING RESERVE REQUIREMENTS BECOME LOWER ON JANUARY 1, 2007. HE GOES ON TO INDICATE THE 2007 OPERATING RESERVE COMPONENTS WILL BE SPINNING, 43 MW; REGULATING, 50 MW; AND QUICK START, 63 MW (REBUTTAL TESTIMONY OF FINNELL AT 30). DO YOU AGREE WITH MR. FINNELL'S NUMBERS?

A Yes. The 106 MW of operating reserve for 2007 only included spinning reserve and quick start reserve. Due to my misunderstanding of Mr. Finnell's uncommon usage of the term "spinning reserve" in his direct testimony, I was not aware Mr. Finnell had included 53 MW of regulating reserve in the 101 MW of "spinning reserve" he discussed in his direct testimony. Based on the clarifications provided by Mr. Finnell in his rebuttal testimony and AmerenUE in its response to Data Request MIEC 21-6, it is now clear that on January 1, 2007 AmerenUE's combined spinning and regulating reserve requirement fell from 101 MW to 93 MW and AmerenUE's non-spinning reserve requirement fell from 101 MW to 63 MW.

Q FOR HIS REBUTTAL TESTIMONY, DID MR. FINNELL RERUN AMERENUE'S PROMOD PRODUCTION COST MODEL WITH THE NEW VALUES FOR SPINNING RESERVE, REGULATING RESERVE AND NON-SPINNING RESERVE THAT WENT INTO EFFECT ON JANUARY 1, 2007?

A No. Mr. Finnell left the combined spinning and regulating reserve total at 101 MW and the non-spinning reserve value at 101 MW (Direct Testimony of Finnell at 31).

Q WHY DID AMERENUE FAIL TO MODEL THE NEW OPERATING RESERVE VALUES?

A For spinning and operating reserve AmerenUE continued to use 101 MW rather than the new value of 93 MW because it claimed there are additional "stranded MW" that exist when a generating unit is used for regulation that must be addressed. In regard to non-spinning reserves, AmerenUE continued to use 101 MW rather than the new value of 63 MW because in its opinion the quick start requirement is not a major factor in production cost modeling because AmerenUE has numerous generating units with quick start capability (*Id.*).

Q DO YOU AGREE WITH AMERENUE'S REASONING?

A No. AmerenUE has admitted in response to Data Request MIEC 21-6f that it has never in the past accounted for "stranded MW." Furthermore, AmerenUE has admitted in response to Data Request MIEC 21-6g that it is not aware of any other utility which accounts for "stranded MW." In regard to quick start reserves, AmerenUE admitted in response to Data Request MIEC 21-7a&b that AmerenUE on occasion meets its quick start reserve requirement with spinning reserves. More significantly, AmerenUE admitted in response to Data Request MIEC 21-7e that during hours when the per MWh market price for power exceeds the per MWh operating costs of AmerenUE's quick start generation, a reduction in AmerenUE's non-spinning (i.e., quick start) operating reserve could potentially provide AmerenUE the opportunity to make additional off-system sales. To summarize, AmerenUE has not justified why it did not perform its rebuttal testimony PROMOD runs with 2007 operating reserve values of 92 MW for spinning and regulating reserve and 63 MW for non-spinning reserve.

Q WHAT DO YOU RECOMMEND?

A I recommend that the Commission require AmerenUE to use the 2007 spinning regulating and non-spinning reserve values without "stranded MW" in any rerun of the PROMOD model that is ordered by the Commission. If a PROMOD rerun is not performed, AmerenUE's proposed revenue requirement should be increased by approximately $2.0 million which is my updated estimate of the rough impact of a PROMOD rerun with 2007 operating reserve values. My updated estimate is detailed in Schedule JRD-Surrebuttal-2.

VI. Response to AmerenUE Witness Lyons in <u>Regard to Fuel Adjustment Issues Involving Taum Sauk</u>

Q HAS AMERENUE RESPONDED TO YOUR CONCERN IN REGARD TO THE HANDLING OF TAUM SAUK UNDER THE PROPOSED FAC?

A Yes. Mr. Lyons indicates AmerenUE proposes to make an adjustment through the FAC formula's "R" factor to hold customers harmless from the effects of Taum Sauk not being available. AmerenUE proposes to make either a fixed adjustment of a set amount or to calculate an update adjustment amount annually through PROMOD production cost simulations (Fuel Adjustment Clause Rebuttal Testimony of Lyons at 31-33).

Q IS EITHER METHOD PREFERABLE OVER THE OTHER?

A Ideally, refreshing the adjustment annually would be the best approach as it is the most accurate method. However, there is merit to avoiding additional production cost simulations, if possible. My recommendation is that a fixed set adjustment be applied unless a party to a reconciliation proceeding, including AmerenUE, petitions that production cost simulations be run. I believe this is a reasonable approach considering the dollar amount involved and the FAC requirement that AmerenUE file a new rate case every four years.

VII. <u>Conclusion</u>

Q CAN YOU PLEASE SUMMARIZE YOUR FINAL CONCLUSIONS?

A Nothing offered in AmerenUE's rebuttal testimony or recent discovery responses conceptually changes the recommendations I made in my direct testimonies. However, this new information does impact some of my dollar values in my recommendations and the details of my recommendation on AmerenUE's allocation of fuel and purchased power cost, including MISO charges and credits, between native load and off-system sales under AmerenUE's proposed FAC.

Q PLEASE SUMMARIZE YOUR UPDATED RECOMMENDATIONS.

A I recommend that the Missouri Public Service Commission (Commission):

1. Not set a fixed off-system sales margin component for AmerenUE's revenue requirement due to a lack of a post-Joint Dispatch Agreement (JDA) benchmark

of AmerenUE's production cost model, the huge discrepancy between AmerenUE's proposed off-system sales margin versus that in its 2007 Budget Forecast, and the incentives that would be created to shift costs to, and revenues from, native load customers if AmerenUE were authorized an FAC with a fixed off-system sales margin.

2. Require AmerenUE to rerun its production cost simulations with wholesale electricity prices that reflect average market prices no lower than the historic spot market prices that occurred during January through December of 2006. Alternatively, the Commission should increase AmerenUE's off-system sales margin (or off-system sales margin baseline) by no less than $23.5 million, which is my estimate of the impact of rerunning the simulations with these prices. This would amount to a reduction of no less than $22.6 million to AmerenUE's proposed revenue requirement. (This adjustment is only for wholesale prices, and does not consider changes in the volume of sales, which would be in addition to my adjustment.)

3. I also recommend that, if the Commission floats the off-system sales margin level through AmerenUE's proposed FAC, that any sharing of the off-system sales margin deviation from its baseline be shared between AmerenUE and native load customers in the same manner as any deviation in native load fuel and purchased power cost from its baseline is shared between AmerenUE and native load customers.

4. If despite my recommendation, the Commission approves an FAC for AmerenUE and chooses either to set a fixed off-system sales margin or share off-system sales margin deviations differently than native load fuel and purchased power cost deviations, I recommend the Commission:

   a. Require AmerenUE to make a compliance filing to update AmerenUE's Schedule SES-12 to:

      i. Ensure AmerenUE's generation minimum amounts are stacked economically with AmerenUE's incremental generation and purchased power with no priority assignment of generation minimums to native load.

      ii. Ensure AmerenUE generator Locational Marginal Pricing (LMP) revenues associated with generators assigned to native load obligations during AmerenUE's economic stacking process are assigned to native load and passed through the FAC to native load customers.

      iii. Ensure the document clearly indicates which specific LMP is used for the market clearing price for each component in AmerenUE's resource and obligation stacks.

      iv. Ensure it is clear that all MISO adjustments to MISO charges passed through AmerenUE's FAC are also passed through AmerenUE's FAC.

      v. Ensure it is clear that all MISO Revenue Sufficiency Guarantee (RSG) Make Whole Payments assigned to native load are passed through the FAC to native load customers.

vi. Ensure it is clear why AmerenUE's estimate of the 2006 allocation of MISO charges and credits deviates from AmerenUE's proposed allocation method and why AmerenUE believes its assumption reasonably approximates conformance to its proposed allocation method.

b. As part of the FAC reconciliation process, conduct detailed audits of AmerenUE's conformance to the Commission's approved allocation method for AmerenUE's fuel and purchased power cost, including MISO charges and credits.

5. Require AmerenUE to rerun its production cost simulations with January 1, 2007 operating reserve levels of 43 MW for spinning reserve, 50 MW for regulating reserve and 63 MW for quick start (or non-spinning) reserve. Alternatively, the Commission should reduce AmerenUE's revenue requirement by $2.0 million, which is my rough estimate of the impact of the reduction of the operating reserve requirement.

6. If the Commission floats AmerenUE's off-system sales margin and/or grants an FAC for AmerenUE, require AmerenUE to include an adjustment for the impact Taum Sauk would have had on AmerenUE's actual fuel costs, purchased power costs and off-system sales margin, as applicable, if Taum Sauk had still been operational.

Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A Yes, it does.

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Missouri Public Service Commission
Case No. ER-2007-0002

Union Electric Company
d/b/a AmerenUE

Estimate of the Impact of Adjusting AmerenUE's Wholesale Electricity Spot Prices to Historic 2006 Levels

Line	Description	Amount	Notes
1	Total Production Cost Model Non-APL Purchased Power Cost	***	From AmerenUE's response to Data Request MIEC 21-09
2	Total Production Cost Model Off-System Sales Revenue	***	From AmerenUE's response to Data Request MIEC 21-09
3	Average Production Cost Model Wholesale Electricity Price	*** per MWh	From AmerenUE's response to Data Request MPSC - 0140
4	Average Historic January - December 2006 MISO Electricity Price for AMRN.MERAMEC1 (90% Day-Ahead, 10% Real-Time Weighted Average)	*** per MWh	From www.midwestiso.org
5	Estimated Increase in AmerenUE Off-System Sales Revenue	***	Line 3 * (Line 8 / Line 5) - Line 3
6	Estimated Increase in AmerenUE Purchased Power Cost	***	Line 2 * (Line 8 / Line 5) - Line 2
7	Estimated Net Decrease to AmerenUE's Revenue Requirement	***	Line 9 - Line 10 - Line 11

James R. Dauphinais
Schedule JRD-Surrebuttal-1

Missouri Public Service Commission
Case No. ER-2007-0002

Union Electric Company
d/b/a AmerenUE

Rough Estimate of the Impact of Adjusting Down AmerenUE's Operating Reserve Levels to Those as of January 1, 2007

Line	Description	Amount	Notes
1	Production Cost Model AmerenUE Spinning and Regulating Reserve Level	*** MW	From AmerenUE's response to Data Request MIEC 4-06
2	Production Cost Model AmerenUE Non-Spinning Reserve Level	*** MW	From AmerenUE's response to Data Request MIEC 4-06
3	AmerenUE's Estimated Midwest Reserve Sharing Group Contingency Operating Reserve Level as of January 1, 2007	*** MW	From AmerenUE's response to Data Request MIEC 4-06
4	AmerenUE Estimated Regulating Reserve Level as of January 1, 2007	*** MW	Rebuttal Testimony of Tim Finnell at 30
5	Reduction of AmerenUE Operating Reserve Level as of January 1, 2007	*** MW	(Line 1 + Line 2) - Line 3 - Line 4
6	Percentage of Total Operating Reserve Reduction Associated with AmerenUE's Coal Fired Generation	*** %	Assumption
7	Estimated Reduction in Operating Reserve Carried by AmerenUE's Coal Fired Generation as of January 1, 2007	*** MW	Line 5 * Line 6
8	Production Cost Model Average Cost of Coal Generation	*** per MWh	From AmerenUE's response to MPSC - 0140
9	Average Wholesale Electricity Price	*** per MWh	From Schedule JRD-Surrebuttal-1, Line 4
10	Rough Estimate of Decrease to AmerenUE's Revenue Requirement	***	Line 7 * 8760 Hours * (Line 9 - Line 8)