Exhibit No.:	
Issues:	Weather Normalization; Capacity Reserves; Joint Dispatch Agreement; Resource Planning; Alternative Regulation Plan; Off-System Sales
Witness:	Michael S. Proctor
Sponsoring Party:	MoPSC Staff
Type of Exhibit:	Surrebuttal Testimony
Case No.:	EC-2002-1
Date Testimony Prepared:	June 24, 2002

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

SURREBUTTAL TESTIMONY

OF

MICHAEL S. PROCTOR

UNION ELECTRIC COMPANY d/b/a AMERENUE

CASE NO. EC-2002-1

Exhibit No. 54NP
Date 7/10/02 Case No. EC-2002-1
Reporter KRM

Jefferson City, Missouri
June, 2002

** **Denotes Highly Confidential Information** **

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BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

The Staff of the Missouri Public Service Commission, Complainant,	)	
vs.	)	Case No. EC-2002-1
Union Electric Company, d/b/a AmerenUE, Respondent.	)	

AFFIDAVIT OF MICHAEL PROCTOR

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Michael Proctor, of lawful age, on his oath states: that he has participated in the preparation of the following written Surrebuttal Testimony in question and answer form, consisting of 64 pages of testimony to be presented in the above case, that the answers in the attached written Surrebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true to the best of his knowledge and belief.

Michael S Proctor
Michael Proctor

Subscribed and sworn to before me this 21st day of June, 2002.

DAWN L. HAKE
Notary Public – State of Missouri
County of Cole
My Commission Expires Jan 9, 2005

Dawn L. Hake
Notary Public

My commission expires My Commission Expires Jan 9, 2005

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SURREBUTTAL TESTIMONY

OF

MICHAEL S. PROCTOR

UNION ELECTRIC COMPANY

d/b/a AMERENUE

CASE NO. EC-2002-1

Q. What is your name and business address?

A. My name is Michael S. Proctor. My business address is 200 Madison Street, P.O. Box 360, Jefferson City, Missouri 65102-0360.

Q. Are you the same Michael S. Proctor who submitted direct testimony in the instant case, EC-2002-1?

A. Yes, I am.

Q. What is the purpose of your surrebuttal testimony?

A. I will address the rebuttal testimony of several of AmerenUE witnesses on issues related to:

1) Weather Normalization – Normal Weather;
2) Capacity Reserves;
3) Joint Dispatch Agreement;
4) Resource Planning;
5) Alternative Regulation Plan - Generation and Transmission Expansion;
6) Significant Problems with Off-System Sales Profit Margins; and
7) Alternative Regulation Plan - The Role of Regulation in Today's Electric Industry.

WEATHER NORMALIZATION – NORMAL WEATHER

Q. Which AmerenUE witness testified on Weather Normalization?

A. Mr. Richard A. Voytas is the AmerenUE witness on Weather Normalization?

Q. What is Mr. Voytas' position on Normal Weather?

A. Mr. Voytas and the Staff are using the same thirty-year mean temperature data for the specification of normal weather (1961 – 1990). However, Mr. Voytas is averaging the weather on each calendar date to obtain daily normal temperatures; while the Staff first ranks the temperatures from highest to lowest and averages all the highest temperatures, next highest temperatures and so forth.

Q. Do you agree with Mr. Voytas' method of averaging the weather on each calendar date?

A. If electricity use responded to temperature by a constant factor, then I would agree with Mr. Voytas. However, electricity does not respond to temperature by a constant factor. Mr. Voytas claims to be using the National Oceanic and Atmospheric Administration (NOAA) method, but he is wrong. NOAA has always recognized the problem that energy does not respond by a constant factor to temperature and has instituted degree-day measures - heating degree days (HDD) and cooling degree days (CDD) as a way to recognize the difference between heating and cooling response to temperature. Every decade NOAA produces HDD and CDD normals based on the most recent thirty year history. NOAA has two methods for calculating these normals, neither of which use Mr. Voytas' method of first averaging daily temperatures for a given date.

Q. Why does NOAA not use average daily temperatures for a given date in its calculation of normal HDD and CDD?

A. The reason is quite simple. Degree day calculations use a base of 65 degrees. If the daily mean temperature is below 65 degrees, the difference between 65 degrees and the daily mean temperature measures HDD. If the daily mean temperature is above 65 degrees, the difference between the daily mean temperature and 65 degrees is CDD. As an illustration, suppose in one year, on a specific date, that the daily mean temperature is 59 degrees (6 HDD) and in the next year on that same date the daily mean temperature is 71 degrees (6 CDD). If the temperature is averaged over these two years, the average is 65 degrees, giving zero HDD and zero CDD. But if the HDD and CDD are averaged from the two years, the results are 3 HDD and 3 CDD. These average degree days represent the average of energy usage for the two years; while the average temperature method used by Mr. Voytas misrepresents energy use by indicating zero heating and cooling response.

Q. Which method is used by the Staff and Local Distribution Companies for weather normalizing natural gas sales?

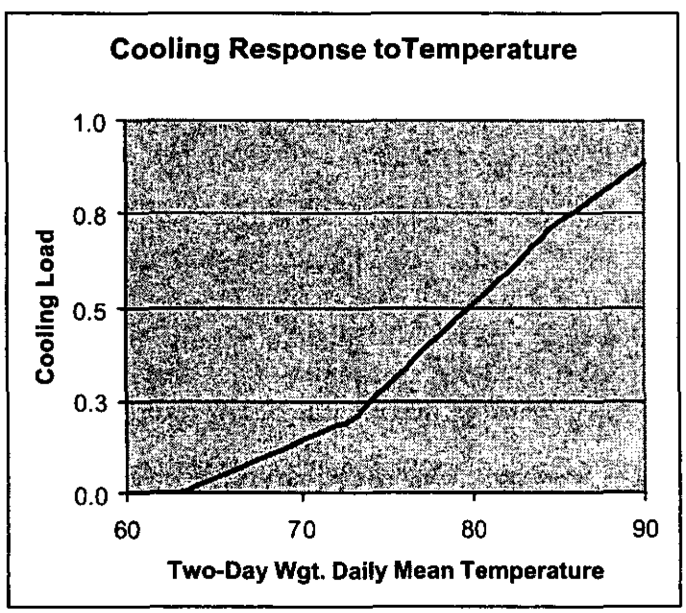
A. The NOAA method of first calculating HDD for each of the thirty years and then averaging HDD is used for normalizing natural gas sales.

Q. How serious is the low estimate of normal electricity use resulting from the method used by Mr. Voytas?

A. The method of averaging temperatures for the same date will significantly underestimate normalized electricity use. The extent of this underestimate can be measured by comparing degree days derived from first averaging temperatures on each day of the year and then calculating degree days (Voytas method) versus first calculating degree days and then averaging the degree days (NOAA method). For these calculations two-day weighted daily mean temperatures were used to be consistent with AmerenUE's weather methods. The Voytas' method produced 4,786 HDD and 1,265 CDD. The NOAA method produced 4,934 HDD and 1,413 CDD. Thus, Mr. Voytas' method is short 148 HDD and 148 CDD. For heating this is only a 3% shortage, but for cooling, the shortage of CDD is over 10%.

Q. Is the shortage in electricity use using Mr. Voytas' method limited to the shortage in CDD?

A. No, the problem with Mr. Voytas' method is compounded on the cooling side by the fact that the electricity response to temperature increases at an increasing rather than a constant rate. This cooling response is characterized by an "S-shaped" curve having three segments as shown in the figure below. The lower segment (from 63



degrees to 73 degrees) is relatively flat having a lower response of electricity to weather. The second segment (from 73 degrees to 85 degrees) has over twice the response of electricity to weather as more and more air conditioners respond to higher thermostat settings. In the top segment the electricity response is less than in the second segment due to saturation of air conditioning loads, but is still higher than in the first segment.

Q. How does this cooling response cause Mr. Voytas' method of averaging daily temperatures on a specific date to underestimate electricity use for cooling?

A. Mr. Voytas' method of averaging daily temperatures on a specific date results in moving the daily temperatures to the middle of the temperature distribution. Thus, his method significantly moves temperatures from the middle segment of the cooling response curve to the lower segment of that curve that has half the electricity response. The following table shows how both the Voytas' method and the ranking method used by the Staff compared to CDD (base 63 degrees) using the NOAA method of averaging degree days.

Table 1
Cooling Degree Days by Segments

	NOAA	Voytas	Staff
63 to 73	1,210	1,177	1,215
73 85	481	368	492
85 and above	14	0	8
	1,706	1,545	1,716

Table 1 clearly indicates that Mr. Voytas' method falls short overall in calculating CDD (1,545 vs. 1,706), while the Staff's ranking method is very close (1,716 vs. 1,706). In addition, Mr. Voytas' method underestimates the CDD in the most critical, middle segment of the cooling response curve, from 73 degrees to 85 degrees. With the load response being twice as much in this segment, Mr. Voytas underestimate of 113 CDD (481 – 368) can be doubled to a 226 CDD shortage in estimating electricity response for normal cooling.

CAPACITY RESERVES

Q. Which AmerenUE witness testified on Capacity Reserves?

A. Mr. Richard A. Voytas is the AmerenUE witness on Capacity Reserves.

Q. What is Mr. Voytas' position on Capacity Reserves for the updated test year?

A. Mr. Voytas estimates a Staff's adjustment of $10.2 million by replacing contracts AmerenUE had for 500 MWs of capacity and associated must-take energy ($48 million) with 500 MWs of combustion turbine capacity ($37.8 million). Staff witness, Mr. Greg R. Meyer will provide surrebuttal testimony that the $37.8 million estimate presented by Mr. Voytas is too high. Mr. Voytas also states that the non-fuel O&M expenses for these 500 MWs of combustion turbines is understated by $2.3 million, which if corrected would reduce the Staff's adjustment to $7.9 million.

Q. Do you agree with Mr. Voytas' calculation of $10.2 to $7.9 million difference between Staff and AmerenUE for the cost of the 500 MWs of reserve capacity?

A. No, these numbers overstate the differences. Mr. Voytas makes his calculations on Schedule 4 attached to his rebuttal testimony. However, for the months of July and August, Mr. Voytas compares 1) capacity (non-fuel) costs proposed by the Staff to 2) both capacity and energy costs incurred by AmerenUE. A correct comparison would include the additional fuel costs included in the Staff's fuel run for July and

August to replace the must-take energy (168,000 MWh in July and 184,000 MWh in August) included in the AmerenUE power purchase contracts. The Staff's fuel run included just over $10.2 million in fuel expense associated with the July and August generation to replace the must-take energy (352,000 MWh) from the power purchase contracts entered into by AmerenUE. Schedule 1 attached to this surrebuttal testimony is the spreadsheet calculation of this fuel cost for the must-take energy. As shown at the bottom of Schedule 1, the average cost of replacing the must-take energy was $29.18/MWh, and Missouri retail customer's share of this cost is $9 million. This is the fuel cost of the must-take energy that should be added to the $37.8 million that Mr. Voytas calculated as the Staff's substitute capacity costs for the 500 MWs of contract power. This reduces the difference from $10.2 million to $1.2 million.

Q. Is the fact that the two numbers are very close surprising to you?

A. No it is not. By placing the combustion turbines in rate base, the Staff included the first-year costs for these units, and first-year costs are the highest costs that will be experienced for those units. Moreover, in most cases of a one-year contract, market price will be at or below the first-year costs of combustion turbines.

Q. Is the issue creating a material difference between AmerenUE and Staff's cost of service in the instant case?

A. Although I do not consider the dollar difference between the Staff and AmerenUE significant, particularly when compared to the dollar value of other issues in this case, I will respond to the rebuttal testimony of AmerenUE on capacity reserves because the principles involved are very important to this case. As stated in my direct testimony, the Staff made the adjustment because of 1) the high market prices at the time

AmerenUE entered into these contracts (i.e., a normalization adjustment would be appropriate if the transaction were prudent); and 2) the must-take nature of the purchased power contracts entered into by AmerenUE for the July and August months for 2001 (i.e., the transaction was an imprudent decision at the time it was made).

Q. Does Mr. Voytas testify that these contracts represent recurring expenses for AmerenUE?

A. No, as a matter of fact, Mr. Voytas' rebuttal testimony is exactly the opposite. Based on the following quotes from Mr. Voytas' rebuttal testimony, it should be very clear to the Commission that the purchase power contracts for the must take energy for the summer months of July and August of 2001 are not representative of the cost of purchased power, represent circumstances that are not likely to recur and as stated in my direct testimony, should be subject to a normalization adjustment.

> The Company did not request such proposals for two reasons. First, the Company sought a product with a fixed price to avoid exposing UE to market prices for energy in an extremely volatile market. This would have been too risky for the Company and for ratepayers. As Dr. Proctor acknowledged, at the time the RFP was issued natural gas prices were high and future prices for must-take energy were also high. As a result, had the Company requested that suppliers submit a bid for a product without a fixed cost it would have been of no value to the Company because it would have elicited bids which priced energy which fluctuated with the market. This would have afforded UE no protection from the high volatility of the market that produced day ahead prices for on-peak energy as high as $1,750/MWh during the summer of 1999. [Voytas Rebuttal, pp. 30-31]

> It should be relatively evident why suppliers at that time would impose a premium for a product that did not have a must-take component. The demand for fixed price energy as of February of 2001, when the bids were due, was high. [Voytas Rebuttal, p. 31]

> … First, as discussed more fully below, the August 10, 2001 RFP was for a 10-year term as opposed to last year's RFP which was limited to the summer of 2001. Second, and of critical importance, the market price

> forward curve for electricity plummeted after August of 2001. While the July/August price in February 2001 for the summer 2001 RFP were in the $147/MWh range, market price for July/August 2002 plummeted to the $40/MWh range in February 2002. A combination of oversupply of new peaking generation throughout the country plus two prior summers of relatively mild weather drove prices to the lowest levels in recent history.... [Voytas Rebuttal, pp. 42-43]

Q. What does the first quote from Mr. Voytas state concerning the test year costs for capacity reserves?

A. Market prices for power for the summer of 2001 were volatile and high. I agree with this characterization of the futures electricity markets for the summer of 2001.

Q. What does the second quote from Mr. Voytas state concerning the test year costs for capacity reserves?

A. The market for fixed-priced energy for the summer of 2001 was high. I agree with this characterization of the futures electricity markets for the summer of 2001.

Q. What does the third quote from Mr. Voytas state concerning the test year costs for capacity reserves?

A. Around February of 2001 and 2002, at about the time when bids were received and evaluated by AmerenUE for the upcoming summers, the prices for fixed-priced energy for the summer of 2002 were much lower than for the summer of 2001. I agree with this comparison of the forward electricity prices for both summers.

Q. If Mr. Voytas acknowledges that forward electricity prices were unusually high for the summer of 2001, and this resulted in high costs for contracts in effect for the summer of 2001, why is AmerenUE unwilling to make an adjustment for these unusually high prices?

A. There is no indication in Mr. Voytas' rebuttal testimony as to why AmerenUE does not believe that some form of adjustment is appropriate. Instead, Mr. Voytas' rebuttal testimony expresses frustration that "Dr. Proctor never told us that the normalized cost of capacity, from Staff's perspective, is the cost of the new peaking units that were built by AEG." [Voytas Rebuttal, p. 39]

The logic of making such an adjustment seems clear to me.

1. For the summer of 2001, AmerenUE needed capacity reserves - there was no disagreement on this fact.
2. If AmerenUE builds its capacity reserves, they are best met with combustion turbines – there should be no disagreement on this fact.
3. If the utility is "surprised" by its need for capacity reserves and does not have time to build, then it must purchase the capacity reserves and will be subject to the "whims of the market" – Mr. Voytas' rebuttal testimony supports this fact.
4. To include an adjustment to test year costs when they are both "high" and "volatile" is to be expected – it appears that here is where Mr. Voytas and the Staff disagree.

Q. In his rebuttal testimony, Mr. Voytas has included much detail regarding the RFP process that AmerenUE used for the contracts entered into for the summer of 2001. Do you believe that anything done in this RFP process was imprudent?

A. As stated in my direct testimony, my only concern with AmerenUE's RFP process is that it narrowed the requests and evaluation to must-take energy for the on-peak hours for the summer months of July and August. Mr. Voytas describes this "standard energy product" in the following way:

> The RFP clearly stated that UE requested capacity with firm energy at a fixed price. The energy requirement was for "16 hour on peak schedules". This meant that suppliers were being asked to submit bids whereby they would supply firm energy for a 16-hour period each day from Monday through Friday from 7:00 a.m. to 10:00 p.m. UE would purchase the energy for this period whether it needed the energy or not. This "5 x 16 product" as it was known was the standard product for on-peak fixed price energy being offered in the market at the time. [Voytas Rebuttal, p. 27]

I disagree with the initial statement made by Mr. Voytas that the RFP "clearly" stated the requirements. What the RFP specifically asked for is: [Voytas Rebuttal, Schedule 7-1]

Firmness: Capacity - Meets AmerenUE planning reserve margin requirements and MAIN accreditation requirements. Supplier must specify generating source (unit(s) or system).

Energy - LD for 16 hour on peak schedules. System firm for any off peak (2 by 16 or 7 by 8) schedules.

Pricing: Only fixed price offers will be considered.

When I reviewed this language of the RFP I read "LD" to stand for liquidated damages and "16 hour on peak schedules" meant that the liquidated damages portion of the contract was limited to the 16 on-peak hours of from 7:00 a.m. through 10:00 p.m. Liquidated damages means that if the provider cannot meet the contract obligation then that provider would have to pay for substitute energy which AmerenUE would either have to produce or purchase at a higher price than the fixed price. Nothing in this language indicated to me that AmerenUE was asking for a must-take energy product.

Q. When did you become aware that the product being requested by AmerenUE was must-take energy for the on-peak hours of the two summer months of July and August?

A. I became aware that AmerenUE had sought a must-take energy product when I first read the evaluation report submitted to AmerenUE by Burns & McDonnell. Mr. Voytas discussed this at the bottom of page 32 and the top of page 33 of his rebuttal testimony. However, Mr. Voytas' characterization of the contact made with bidders after the initial RFP did not include a discussion of the two parts of the Burns & McDonnell report. The lead paragraphs for each part of the report are:

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HC-----------------------------** [Voytas Rebuttal, HC Schedule 6-2]

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HC----------------------**. [Voytas Rebuttal, HC Schedule 6-5]

After reading these two parts of the Burns & McDonnell report, it appeared to me that AmerenUE had changed the types of products it was seeking, and had made that change without contacting the Staff or Office of Public Counsel. Subsequently, when the Staff met with AmerenUE, I expressed my concern and was told that the language of the original RFP was also asking for a standard product, which includes must-take energy.

I am not disputing AmerenUE's claim that "LD for 16 hour on peak schedules" means "must-take energy" for the on peak hours. Regardless, respecting "LD for 16 hour on peak schedules," this interpretation was not my understanding at the time I reviewed the Initial RFP, and that when the "Alternate RFP" went out to the short list of six bidders, according to the Burns & McDonnell evaluation, the must-take nature of the product was made clear. The only importance to whether or not I understood that AmerenUE was seeking a must-take energy product at the time I reviewed the RFP is that had I known that it was seeking bids on only must-take energy products at that time, I would have objected to the RFP on grounds that it was not seeking a full range of products.

Q. Now that you know that AmerenUE was seeking must-take energy products in its initial bid, do you have any additional concerns?

A. Yes, I do. Mr. Voytas indicates in his rebuttal testimony that the reason for AmerenUE to restrict its request to must-take energy products was that "it was the standard product being offered by suppliers at the time," and "suppliers were imposing a significant premium for non-standard product which did not have a must-take provision." [Voytas Rebuttal, p. 31] Apparently, Mr. Voytas became aware that this was the condition of the forward electricity markets through discussion with Ameren Energy, a non-regulated affiliate of AmerenUE. In addition to the issue of discussing the matter with a non-regulated affiliate before the RFP was issued, AmerenUE should not have presumed that must-take energy was a market condition without discovering it through the RFP process.

Q. What do you mean by forward electricity markets?

A. Forward electricity markets involve bilateral contracts for electricity between a buyer and a seller for a transaction that is to be scheduled at a future date. These are distinct from the futures electricity markets involving financial transactions that may or may not result in physical delivery of electricity at the future date.

Q. How should AmerenUE receive specific information regarding the nature of the forward electricity markets?

A. As Mr. Voytas points out in his rebuttal testimony, "the process that UE was required to follow before purchasing power from an affiliate" is set out in a Unanimous Stipulation and Agreement approved by the Commission in Case No. EA-2000-37. [Voytas Rebuttal, p. 22] However, purchasing power from an affiliate is only one concern that an RFP for competitive power is meant to address. An RFP process is one in which the buyer discovers what is the condition of the forward market for electricity. If the buyer too narrowly restricts the RFP, then the amount of information that is received from the market is likewise restricted. One such restriction – a fixed price – is clearly acceptable when facing a tight market. However, it remains my testimony that confining the RFP to must-take energy was too restrictive, and AmerenUE should not have presumed that must-take energy was a market condition without discovering it through the RFP process.

Q. Despite AmerenUE's request for must-take power in the Alternate RFP, did it receive a bid for a fixed price, non-must-take product?

A. Yes it did. In Mr. Voytas' rebuttal testimony he discusses such a bid received from one of the final six bidders. This was a bid from ** HC---------------- HC----------- ** for ** HC------- ** with a capacity charge of ** HC---------------- HC------------------ ** for each of the four summer months, and an energy charge of ** HC--------**for dispatchable energy that was required to be scheduled a day ahead.

Q. Having reviewed Mr. Voytas' rebuttal testimony, do you agree with his statement that the comparison to a non-must-take product was performed in the evaluation process?

A. No, I do not. Mr. Voytas refers to a comparison shown on Table 1 of Schedule 6 attached to his rebuttal testimony. Despite AmerenUE's insistence on a must-take energy product, the bid submitted for capacity and dispatchable energy at a firm price but not must take was included by Burns & McDonnell in its evaluation. However, there was a major error made in that evaluation. Specifically, this bid was evaluated as if it were a must-take bid, and the comparison made by Burns & McDonnell assumed that energy would be taken on a must-take basis for 44 days at 16 hours per day (704 hours) during July and August of 2001. Under these assumptions, this bid is higher cost, but if the hours of take are reduced based on the number of hours AmerenUE would expect to take the energy on a non-must-take basis, it would be a lower cost option. For example, a spreadsheet calculation attached as HC Schedule 2 to my surrebuttal testimony shows that the non-must-take option is cheaper for hours of use of 286 hours or less for the summer months of July and August of 2001. This number of hours is more than sufficient to provide AmerenUE with the protection it required against high spot-market prices for electricity.

In its analysis of the responses to the Initial RFP, both AmerenUE and Burns & McDonnell should have made the calculations for this non-must-take bid and requested similar bids from all of the bidders on the short list in the Alternate RFP.

If on February 7, 2001, AmerenUE had requested a non-must take, but fixed price bid from all of the bidders, it then would have been clear that Burns & McDonnell would have had to perform a different type of evaluation. In its RFP Evaluation Procedures and Guidelines, Burns & McDonnell states

2) ** HC---

HC---

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HC----------------------------------** [Voytas Rebuttal, Schedule 6-1]

Because an hourly production model representing Ameren's system would be required to make an evaluation of a non-must take (dispatchable) capacity alternative, this statement by Burns & McDonnell makes it very clear that it did not include an evaluation of a product that was non-must take (dispatchable) capacity reserves.

Q. Is it still your testimony that AmerenUE should have requested and evaluated non-must-take energy options for which the energy from the regulatory capacity is dispatchable?

A. Yes, that is my testimony regarding the AmerenUE RFP process.

Q. With respect to the situation that put AmerenUE in a position where it was forced to purchase capacity for the summer of 2001, Mr. Voytas criticizes you for using AmerenUE and AmerenCIPS/GENCO planning reserve margin forecasts dated January 2000. Why did you not use updated reserve margin forecasts?

A. The purpose of using the planning reserve margin forecasts dated January 2000 was to show how AmerenUE was forced into the position of having to purchase capacity for the summer of 2001 based on the information available at that time. I went back to the latest point at which a decision could have been made to build peaking capacity for AmerenUE that would have been in place in time to meet its need for capacity reserves for the summer of 2001. Any later planning reserve margin forecasts would have been too late for that decision. Using an updated reserve margin forecast would not be of any value with respect to the reserve margin position AmerenUE was in prior to the summer of 2001.

Q. Did Mr. Voytas correctly interpret your use of the reserve margin forecasts dated January 2000?

A. No, he did not. Mr. Voytas misinterpreted my use of these reserve margin forecasts to be an indication that I was seeking to show Ameren has an ongoing bias to build capacity in its non-regulated subsidiary (Ameren Energy Generating Company or AEG) and thereby force AmerenUE to have to purchase all future capacity additions from AEM. That was not the intention of including the reserve margin forecasts from January 2000 in my direct testimony. Rather, it was to show that this is what happened at that particular time. Moreover, if the decision had been made in January 2000 to build peaking capacity for AmerenUE, it would not have been in the position of having to purchase capacity for the summer of 2001.

Q. Did Mr. Voytas discuss other circumstances that contributed to AmerenUE's deficit in capacity reserves for the summer of 2001?

A. Yes, at pages 24 and 25 of his rebuttal testimony, Mr. Voytas discussed some of the details related to AmerenUE's request to transfer its Illinois service territory and customers to AmerenCIPS (Case No. EM-2001-233). Mr. Voytas' rebuttal testimony infers that had the Staff not "recommended against expedited treatment and projected that resolution of all issues would take at least six months," AmerenUE might not have found itself in a position of having to purchase capacity reserves for the summer of 2001. [Voytas Rebuttal, p. 24] The complete story is that the Staff reviewed the filing made by AmerenUE in Case No. EM-2001-233 and found that AmerenUE had omitted both fixed operation and maintenance (O&M) costs and reallocation of overhead costs in its analysis. Without the inclusion of these costs, the Staff could not recommend the transfer of AmerenUE's Illinois service territory and customers to AmerenCIPS.

Q. Ultimately, what caused AmerenUE to withdraw its request to transfer AmerenUE's Illinois service territory and customers to AmerenCIPS?

A. Mr. Voytas describes the cause of the withdrawal in the following way: "As time elapsed, AEM became unwilling to forego other market opportunities while waiting for all applicable regulatory approvals." [Voytas Rebuttal, pages 24-25] This is not my understanding of what happened. At the time AmerenUE withdrew its application, Mr. Craig D. Nelson, Vice President – Corporate Planning of Ameren Services Company, told the Staff, including me, that AEG was unwilling to enter into the transfer because it had determined that with the rate caps in Illinois, it would earn a very low rate of return on its generation from serving the Illinois customers that were to be transferred and was therefore unwilling to go forward with the transfer. My recollection is that the low rate of return that he mentioned was ** HC-----------**.

Q. Do other AmerenUE witnesses present rebuttal testimony on this issue of capacity reserves?

A. Yes. AmerenUE witnesses Dr. Peter Fox-Penner and Mr. Craig D. Nelson present rebuttal testimony on this issue. Dr. Fox-Penner believes that if AmerenUE purchases power from a non-regulated affiliate, it should always pay market price and opposes the Staff position of requiring the price to be the minimum of market or cost. Mr. Nelson characterizes the Staff as having used "hindsight" in making this adjustment. I will respond to Mr. Nelson in the next section of my surrebuttal testimony.

Q. What is your response to Dr. Fox-Penner's position that market price should always be the basis for transactions between regulated and non-regulated subsidiaries?

A. My first response is that Dr. Fox-Penner is responding to the concept rather than to the specific circumstances for AmerenUE. Moreover, nowhere in Dr. Fox-Penner's rebuttal testimony does he give recognition to the fact that AmerenUE is selling energy to AEG/AEM at cost rather than market price via the Joint Dispatch Agreement (JDA). When there is a cost-based transaction of energy between regulated and non-regulated affiliated generation entities, and that transaction occurs when the non-regulated affiliate would otherwise have to purchase that energy at a higher price, then for the non-regulated affiliated entity to turn around and charge the regulated affiliated entity higher than cost for capacity and energy imposes an asymmetric constraint on the regulated affiliate.

With respect to this asymmetric constraint, the Staff determined, by using its fuel model run, that had AmerenUE been able to sell to the market the energy that it transferred to AEG/AEM under the JDA, it would have earned an additional $102 million dollars in profits from off-system sales during the test year. To give up this amount of earnings and then have the non-regulated generation affiliate require market price from the regulated affiliate when market price is above cost is affiliate abuse. This is shown on Schedule 3 attached to this testimony. On Schedule 3, the imbalance between the two companies is very clear. AmerenUE gives up over $105 million in profits by transferring electricity to AEG/AEM, while AEG/AEM gives up less than $3 million in profits when it transfers electricity to AmerenUE.

Q. Would you agree with Dr. Fox-Penner's position of always trading at market price between affiliates if this condition is imposed symmetrically to all transactions?

A. Because the issue in the instant case involves a purchase power contract, I will limit my response to power transactions. I do not agree that in every circumstance trading power (energy and/or capacity) at market price will ensure the lack of affiliate abuse, but it would be a much more reasonable position if AEG/AEM had been required in the JDA to purchase energy from AmerenUE at market price instead of cost.

Another problem with Dr. Fox-Penner's position is relying on the Federal Energy Regulatory Commission's (FERC's) test for lack of affiliate abuse. Unfortunately, in the criteria used by the FERC, it failed to consider the circumstances that led to AmerenUE having to purchase power from AEG/AEM. In this specific instance, AmerenUE was put into the position of having to go to the market because of an earlier decision to build capacity in the non-regulated affiliate (AEG/AEM), and that affiliate later refused to accept transfer of the AmerenUE Illinois load to its generation system, thereby forcing AmerenUE into the position of an immediate need for capacity. This is clearly a case of affiliate abuse. I would never support market price as the sole basis for a transaction in circumstances where the non-regulated affiliate is buying energy from the regulated utility affiliate at cost and the non-regulated generation affiliate has the power to force the regulated utility affiliate to the market in which the non-regulated generation affiliate wants to participate as a seller. In these circumstances, the proper criterion is the minimum of market price or embedded cost.

Q. Returning to the cost included for non-fuel related O&M expenses for the combustion turbines included as capacity reserves in the Staff's direct case, what is Mr. Voytas' objection to these costs?

A. Mr. Voytas believes the costs included for non-fuel O&M expenses are too low because they are representative of those costs for oil-fired combustion turbines rather than for gas-fired combustion turbines. Mr. Voytas is correct at page 40 of his rebuttal testimony with respect to the fuels used to operate the various combustion turbines listed as "UE's fleet of CTGs" (Combustion Turbine Generators). In the Staff's fuel run, 91 MWs of the 434 MWs or 21% of combustion turbine capacity are fired by natural gas with the remaining 79% being fired by oil.

Q. Do you agree with Mr. Voytas that "O&M Agreements" that AEG has in place for new combustion turbines is an appropriate measure to use as the basis for AmerenUE's non-fuel O&M expenses for similar type combustion turbines?

A. No. As a result of reading Mr. Voytas' rebuttal testimony, it appears that his concern is with the increase in O&M cost that will come from running the combustion turbines fired by natural gas more than combustion turbines that are fired by oil. This is a variable O&M charge. Checking AmerenUE's dispatch of generation, I found that it includes a $2/MWh variable O&M charge for all of its combustion turbines. In the Staff fuel model, the new gas-fired combustion turbines ran for 126,278 MWh. At $2/MWh, this would add $252,556 to the O&M charges included by Staff in its direct filing.

Q. Did you review Schedule 10 submitted by Mr. Voytas as support for a higher non-fuel O&M charge for the new combustion turbines?

A. Yes, I have reviewed Mr. Voytas Schedule 10. What Schedule 10 represents is an estimate of O&M costs, not actual experience. This is not adequate support for an additional variable O&M charge of $2.3 million as proposed by Mr. Voytas. Moreover, because these new units are gas fired and will run more often, adding $2.3 million to historical levels of non-fuel O&M implies variable O&M charges in the range of $18/MWh, more than it takes to operate a coal-fired unit and about half of the fuel cost to operate a gas-fired unit. Such a variable O&M charge is unreasonably high.

JOINT DISPATCH AGREEMENT

Q. Which AmerenUE witness submitted rebuttal testimony on the Joint Dispatch Agreement (JDA)?

A. Mr. Craig D. Nelson is AmerenUE's witness on the JDA.

Q. What is Mr. Nelson's position on the JDA?

A. Mr. Nelson's position is that the cost of service in this case should not reflect my recommendation for an additional $3.7 million in profit margin to be allocated to AmerenUE from Ameren's off-system wholesale sales of electricity from the test year.

Q. What is the basis for Mr. Nelson's position?

A. Mr. Nelson states that "as a matter of policy and fairness," the current JDA should be followed because: 1) "parties should not be encouraged to disregard an approved contract;" and 2) "contracts should be followed until they terminate according to their terms or until they are changed after all regulatory approvals are obtained." [Craig Nelson Rebuttal, p. 12]. While Mr. Nelson states that his rebuttal testimony would address the specifics of my proposed change to the allocations of off-system profits, he instead returns to the same argument, citing previous opportunities by the Staff to object to the allocation of off-system profits in the JDA, but never addresses the issue of whether allocating off-system profits using share of load versus share of generation is more equitable. In brief, Mr. Nelson's only rebuttal testimony is that it is unfair for the Staff to make a recommendation to change the JDA in the instant case.

Q. Do you agree with Mr. Nelson's position that once an individual item like the JDA is included as part of an overall approval of something like a merger or a transfer of generation assets in Illinois, that the individual item may not be subject to future regulatory review and change for purposes of ratemaking?

A. No, I do not agree. The best that regulators can do in the context of a merger case or an asset transfer case, is to review the overall benefits and costs to make a recommendation about whether or not the proposed merger or asset transfer is not detrimental to the public interest. Moreover, if the Staff were forced into the position of having to review and approve every allocation method for every proposed benefit and cost, it would take an unreasonable amount of time to complete this review. Instead, in the Union Electric Company (UE) merger with Central Illinois Public Service Company (CIPS) the following language is included as a part of the Stipulation And Agreement in Case No. EM-96-149.

> Electric Contracts Required to be Filed with the FERC. All wholesale electric energy or transmission service contracts, tariffs, agreements or arrangements, including any amendments thereto, of any kind, including the Joint Dispatch Agreement, between UE and any Ameren subsidiary or affiliate required to be filed with and/or approved by the Federal Energy Regulatory Commission ("FERC"), pursuant to the Federal Power Act ("FPA"), as subsequently amended, shall be conditioned upon the following without modification or alteration: UE and Ameren and each of its affiliates and subsidiaries will not seek to overturn, reverse, set aside, change or enjoin, whether through appeal or the initiation or maintenance of any action in any forum, a decision or order of the Commission which pertains to recovery, disallowance, deferral or ratemaking treatment of any expense, charge, cost or allocation incurred or accrued by UE in or as a result of a wholesale electric energy or transmission service contract, agreement, arrangement or transaction on the basis that such expense, charge, cost or allocation has itself been filed with or approved by the FERC, or was incurred pursuant to a contract, arrangement, agreement or allocation method which was filed with or approved by the FERC. [Stipulation and Agreement, Case No. EM-96-149, Section 8: State Jurisdiction Issues, Item e, pages 25-26] [Craig Nelson Rebuttal, Schedule 1-50 and 1-51]
>
> No Pre-Approval of Affiliated Transactions. No pre-approval of affiliated transactions will be required, but all filings with the SEC or FERC for affiliated transactions will be provided to the Commission and the OPC. The Commission may make its determination regarding the ratemaking treatment to be accorded these transactions in a later ratemaking proceeding or a proceeding respecting any alternative regulation plan. [Stipulation And Agreement, Case No. EM-96-149, Section 8: State Jurisdiction Issues, Item g, page 30] [Craig Nelson Rebuttal, Schedule 1-52]
>
> None of the signatories to this Stipulation And Agreement shall be deemed to have approved or acquiesced in any question of Commission

> authority, accounting authority order principle, cost of capital methodology, capital structure, decommissioning methodology, ratemaking principle, valuation methodology, cost of service methodology or determination, depreciation principle or method, rate design methodology, cost allocation, cost recovery, or prudence, that may underlie this Stipulation And Agreement, or for which provision is made in this Stipulation And Agreement." [Stipulation And Agreement, Case No. EM-96-149, Section 13: No Acquiescence, page 36] [Craig Nelson Rebuttal, Schedule 1-61]

When AmerenUE requested that the Commission make the Public Utility Holding Company Act of 1935 (PUHCA) Section 32(c) determinations respecting the transfer of assets from CIPS to a Exempt Wholesale Generator (GENCO), it signed off on the following as a condition in the Unanimous Stipulation And Agreement in Case No. EA-2000-37.

> AmerenUE agrees that all substantive proposed changes to the JDA between AmerenUE, AmerenCIPS and Genco [(later named "AmerenEnergy Generating Company")] shall be submitted to the Missouri Commission for approval. Non-substantive changes to the JDA do not need Missouri Commission authorization, but all proposed changes to the JDA must be submitted to the Staff and the OPC for their determination whether the proposed changes are substantive. Proposed changes to the JDA which either the Staff or the OPC deem to be substantive must be submitted to the Commission for approval. All proposed changes to the JDA which AmerenUE asserts to be non-substantive must be submitted to the Staff and OPC in advance of said changes being filed with the FERC. AmerenUE's filing with the Commission for Commission approval shall occur prior to or concurrent with AmerenUE's analogous filing for approval with the FERC, which FERC filing shall include notification that approval of the Missouri Commission has been obtained or is being sought contemporaneously. A determination by AmerenUE either that a general change or that a particular change in the JDA does not require FERC approval will not control whether Missouri Commission authorization is required. Any changes to the JDA approved or required by another administrative agency shall not supersede or void the need for Ameren to fulfill all of the terms and conditions approved or required by the Missouri Commission respecting the JDA. Any approval by the Commission respecting the JDA, as identified in this Unanimous Stipulation and Agreement, shall not be deemed to constitute a ratemaking determination. [Unanimous Stipulation And Agreement, Case No. EA-2000-37, Conditions Section 1:

Joint Dispatch Agreement (JDA) Conditions, Item a, pages 9-10] [Craig Nelson Rebuttal, Schedule 2-22 and 2-23]

By receiving or reviewing the material provided, neither Staff nor the OPC, nor any other party shall be precluded in any future rate case, earnings complaint case or second alternative regulation plan or sharing credit calculation proceeding from contesting the ratemaking treatment to be afforded the purchase of capacity. [Unanimous Stipulation And Agreement, Case No. EA-2000-37, Conditions Section 3: Resource Planning Conditions, Item f, page 15] [Craig Nelson Rebuttal, Schedule 2-28]

Regulatory conditions applicable to Ameren, AmerenUE, Genco, Marketing Company and any AmerenUE marketing company, which are contained in the July 12, 1996 Stipulation And Agreement in Case No. EM-96-149, include, but are not limited to, the provisions in said Stipulation And Agreement set out below for illustrative purposes (nothing in the conditions agreed to by AmerenUE in the instant proceeding, Case No. EA-2000-37, reduces the requirements contained in the Stipulation And Agreement in Case No. EM-96-149): [Unanimous Stipulation And Agreement, Case No. EA-2000-37, Conditions Section 5: Regulatory Conditions In Case No. EM-96-149, Item 5, page 16] [Craig Nelson Rebuttal, Schedule 2-29]

AmerenUE agrees that a Commission Order containing the findings required by PUHCA with respect to Genco shall in no way be binding on the Commission or preclude any party to a future rate case, earnings complaint case or second alternative regulation plan sharing credit calculation proceeding from contesting the ratemaking treatment to be afforded transactions relating to AmerenCIPS, Genco, Marketing Company, AmerenUE marketing company, Ameren Energy, or any affiliate, associate, mutual service, subsidiary or holding company. [Unanimous Stipulation And Agreement, Case No. EA-2000-37, Section 6: Additional Conditions, Item b, page 19] [Craig Nelson Rebuttal, Schedule 2-32]

AmerenUE agrees that it will not seek to overturn, reverse, set aside, change or enjoin, whether through appeal or the initiation or maintenance of any action in any forum, a decision or Order of the Commission which pertains to recovery, disallowance, deferral or ratemaking treatment of any expense, charge, cost or allocation incurred or accrued by AmerenUE in or as a result of the JDA on the basis that such expense, charge, cost or allocation has itself been filed with or approved by the FERC, or was incurred as a result of the Commission making findings pursuant to 15 U.S.C.A. Section 79z-5a(c) (Section 32(c) of PUHCA). [Unanimous Stipulation And Agreement, Case No. EA-2000-37, Section 6: Additional

Conditions, Item c, pages 19-20] [Craig Nelson Rebuttal, Schedule 2-32 and 2-33].

Q. What does this type of language say about the conditions of "policy" and "fairness" related to keeping contracts as referred to by Mr. Nelson in his rebuttal testimony?

A. First, AmerenUE has agreed to each of these statements. Second, each of these statements is relevant for the allocations included in the JDA. The first statement regarding the Stipulation And Agreement in the merger case says AmerenUE cannot oppose future ratemaking by the Commission of an allocation method approved by the FERC.

The second statement regarding the Stipulation And Agreement in the merger case says that the Commission can make ratemaking determinations at any future date regarding an affiliate transaction. The JDA is an affiliate transaction between AmerenUE and AEG/AEM.

The third statement says that the signatories of the Stipulation And Agreement in the merger case have neither approved nor acquiesced to future ratemaking treatment related to the merger. The allocations contained within the JDA are clearly part of ratemaking treatment with respect to the merger.

The final set of statements regarding the transfer of CIPS generation assets to GENCO state that AmerenUE agrees to not protest any future ratemaking proposals from any party based on the fact that they supported the approval of the transfer of the CIPS generation assets to GENCO. Since the revision of the JDA (involving substituting "GENCO" for "CIPS") was a part of this transfer, AmerenUE has agreed not to protest any future ratemaking proposal respecting the JDA on the grounds that it was included in the Unanimous Stipulation And Agreement in Case No. EM-2000-37. Moreover, Mr. Nelson's rebuttal testimony in the instant case appears to be a violation of the agreements entered into by UE and AmerenUE in those two respective cases. If violation of signed contracts and agreements are the basis for determination of lack of fairness and equity, then AmerenUE's rebuttal position in the instant case should be found to be unfair and inequitable.

Q. Is it your position that the JDA must be changed because AmerenUE does not benefit from the current JDA?

A. No. I have never contended that there are no benefits to AmerenUE from the JDA. Equity is not about the lack of benefits; rather it is about the fair allocation of those benefits among the various parties. As I stated earlier in my surrebuttal testimony, Mr. Nelson's rebuttal fails to address any aspects of why the Staff's proposal for allocating profits from off-system sales is not more fair or reasonable than the allocation currently set out in the JDA.

Q. On a going forward basis, is it your position that the JDA will continue to provide benefits to AmerenUE?

A. No. This is because AmerenUE may have more attractive options that promote its interest better than the JDA. These options would be clearly pursued if AmerenUE were not affiliated with AEG.

If the Standard Market Design being proposed by the FERC is implemented, the current JDA will be detrimental to AmerenUE. In the Standard Market Design each owner of generation will bid that generation into a transparent hourly wholesale market in which a market-clearing price will be determined. For the generation bid at or below the market-clearing price, the owner will be paid the market-clearing price for that generation. In essence AmerenUE will bid its generation separate from AEG. AmerenUE and AEG will be paid the market-clearing price for their individual generation, and instead of transfers taking place at incremental cost, those transfers will take place at the market-clearing price.

Based on the Staff's analysis of the JDA, AmerenUE will significantly benefit from the implementation of the FERC's Standard Market Design. As a part of Mr. Bender's production cost model of the JDA, a spreadsheet was developed in which the MWh's transferred and the incremental cost of these transfers were calculated for both AmerenUE and AEG. The incremental costs of the transfers were compared to Mr. Bender's prices for Off-System Purchases. Whenever the price of the Off-System Purchases were above the incremental cost, the difference was multiplied by the MWh transferred to measure the opportunity loss of making the transfer via the requirements of the JDA. As indicated earlier in this testimony and on Schedule 3, these calculations show that if AmerenUE sells into the market rather than transferring at incremental cost, it would increase its profit margins from these sales by over $100 million per year. If this one-year snap shot is an indication of the future market potential for AmerenUE's generation resources, then on this basis alone it would be imprudent for AmerenUE to continue its participation in the JDA agreement beyond the time at which the FERC's Standard Market Design is implemented.

Q. Have you reviewed the rebuttal testimony of Office of Public Counsel's witness Mr. James R. Dittmer?

A. Yes, I have. Mr. Dittmer proposes to change the JDA to a shared savings approach versus the current JDA transfers taking place at incremental cost.

Q. Is Mr. Dittmer's claim correct that his proposed shared savings approach is equivalent to the JDA that you proposed for the two UtiliCorp (now Aquilla) divisions of Missouri Public Service and St. Joseph Light & Power?

A. Yes. I proposed that UtiliCorp calculate stand-alone costs for each division, subtract the joint dispatch cost from the stand-alone costs to measure joint dispatch savings and share that joint dispatch savings based on each division's share of stand-alone cost. This is a more equitable recognition of JDA savings than making transfers at incremental cost.

RESOURCE PLANNING

Q. Which AmerenUE witness submitted rebuttal testimony on Resource Planning?

A. Mr. Craig D. Nelson is the AmerenUE witness on Resource Planning.

Q. What is Mr. Nelson's position regarding Resource Planning?

A. Mr. Nelson's position is that because Staff introduced testimony that adjusted for the high cost power supply contract that AmerenUE entered into for the summer of 2001 and challenged the fairness of the JDA allocation of off-system profits, this has introduced "considerable amount of uncertainty concerning the future regulatory treatment of AmerenUE's resource planning process and the decisions resulting from that process," and creates "uncertainty for the Company which undermines the resource planning process and inhibits the Company's ability to confidently provide for customers' needs." [Craig Nelson Rebuttal, p. 17]

Q. What is the current status of resource planning for investor-owned electric utilities in Missouri?

A. The current status of electric resource planning is determined by Missouri law, including the established rules for electric resource planning per 4 CSR 240-22 (Electric Resource Planning Rules) from which variances were granted in Case No. EO-99-544, pursuant to a Joint Application For Variance. First, Missouri is not a pre-approval state; i.e., the Commission does not have a statutory mandate to pre-approve the resource plans of the investor-owned, electric utilities. Second, when the Electric Resource Planning Rules were developed and adopted by the Commission, the issue of pre-approval was thoroughly debated and the Commission chose not to engage in proceedings whereby the electric utility's resource plans would be pre-approved. Third, as noted above, when the electric utilities filed to rescind these rules, an agreement was reached by which the utilities would meet with the Staff and the Office of the Public Counsel twice per year to provide information on anticipated resource plans. The argument for waiving the filing requirements of the Electric Resource Planning Rules was that plans were changing too rapidly for a filing every three years to be meaningful. In addition, the filings associated with the Electric Resource Planning Rules were viewed by the utilities as another regulatory cost, and absent pre-approval, appeared to have few if any benefits for the utilities.

This describes the current status of electric resource planning for investor-owned utilities in Missouri and is the system of regulatory oversight for resource planning that was in effect during the test year and update period for the instant case and will remain in place until either the Legislature changes the statutes or the Commission changes the procedures that the Commission accepted in Case No. EO-99-544.

Q. What is Mr. Nelson's position regarding this current system of regulatory oversight for resource planning?

A. Mr. Nelson complains that AmerenUE is subject to high levels of regulatory risk through "improper hindsight attacks," and "it frustrates the ability of the Company to make decisions based on what it believes to be the appropriate criteria at the time the decision is made." [Craig Nelson Rebuttal, p. 25]. Specifically, Mr. Nelson claims that the Staff's "recommendation on the JDA and the AEM-UE power contract for 2001 constitute improper hindsight attacks on these approved agreements." [Craig Nelson Rebuttal, p. 25]. As my surrebuttal testimony has already indicated, Mr. Nelson's concept of "approved agreements" is in direct conflict with the language included in those agreements.

Q. What is your response to Mr. Nelson's accusation of the Staff applying hindsight by its adjustments for capacity reserves and the JDA?

A. Hindsight is the application of judgment to conditions that were not knowable to the utility at the time a decision was made. Absent a pre-approval process that precludes subsequent review, any discovery by the Staff of facts that were in place at the time AmerenUE made its decisions is not hindsight. The fact that Staff was not aware of these facts at the time the decision was made by the utility would only be relevant to a pre-approval regulatory process. As stated previously, such a process can take a very long time to implement in order to engage in discovery of all relevant facts.

Q. Is it your belief that Mr. Nelson is asking for a change in the system of regulatory oversight for resource planning?

A. This appears to be the case; however, it is not clear to me that Mr. Nelson has taken into account the changes that would be required in order to implement pre-approval of resource planning decisions.

Q. What do you mean by pre-approval of resource planning decisions?

A. Specifically, pre-approval of resource planning decisions means that at the time a decision is made to acquire resources and before the costs associated with those resources are included in rates, the Commission would approve the decision to acquire those resources. Pre-approval does not mean that the Commission would approve the levels of the costs associated with the resources acquired until those costs are known and measurable. Thus, for example, the decision to build a plant rather than purchase power could be approved, but the costs associated with the power plant would not be approved until those costs have been incurred by the utility.

Q. From a regulatory perspective, what are the challenges for this type of pre-approval process?

A. If the regulators are meeting on a regular basis with the electric utilities and the utilities are open, cooperative and timely in providing information, then the specifics of decisions by the electric utility to acquire resources usually should not be a surprise. I believe that generally we currently have this level of communication with the investor-owned utilities in Missouri. Even when the element of surprise is managed, there remains a major challenge with pre-approval: for the regulators to review all of the details and assumptions that go into the analysis performed by a utility in making the decision in question. The Commission's Electric Resource Planning Rules describe in great detail the type of risk analysis required for a utility to prudently make a decision. In a pre-approval type of regulatory oversight system, the Electric Resource Planning Rules would need to be rewritten to set up a regulatory process for obtaining pre-approval of the proposed resource acquisition (filings, filing requirements, intervention, hearings, etc.). My major concern is that if the pre-approval process were to be done correctly, it would simply slow down the electric utilities' resource acquisition process, resulting in delays that could be unacceptable to the utilities.

Q. Absent a pre-approval process for resource acquisition, does this leave the utility with a higher regulatory risk of disallowance than it would have with pre-approval?

A. Yes, it does. To explain my answer, consider three alternatives. Alternative 1 is pre-approval, as I have previously defined it. This alternative has a high regulatory cost, but a low risk related to future disallowances (regulatory risk). Alternative 2 is the current system in Missouri with no pre-approval and low regulatory cost, but a higher regulatory risk related to future disallowances. Alternative 3 is what Mr. Nelson appears to be asking for in his rebuttal testimony: no explicit pre-approval process to avoid the high regulatory cost of pre-approval, but a low risk for future disallowances. While Alternative 3 is a good alternative for the utility company, it is not a good alternative for ratepayers. This is because the regulatory costs from Alternative 1 and the regulatory risk from Alternative 2 that are avoided by Alternative 3 have now been shifted to ratepayers in terms of lack of regulatory oversight to insure prudent resource acquisition.

Q. Are there any other alternatives beside the three you just discussed?

A. Yes there are. For the past two decades, economists have been searching for better "models" that provide some degree of regulatory oversight by focusing on results rather than the decision making process. These models have many descriptions depending on the specific application; the most familiar are Performance Based Ratemaking and Incentive Regulation Plans. These are a subset of Alternative Regulation Plans (ARPs) in which performance targets are set and the utility is allowed to keep a share of the savings when performance is better than the target, but must pay for a share of the losses when performance is worse than the target.

Q. Are performance-based ARPs a viable alternative in Missouri?

A. No, they are not. In order for the Commission to implement a performance-based ARP, it must be done as an experimental ratemaking plan and must be acceptable to the utility. In essence this means that the only performance-based ARP that can ever be approved is one that is designed by the utility that is suppose to be regulated.

If Mr. Nelson truly wants to impact the way in which AmerenUE is regulated in Missouri, then he should encourage his company to work on developing legislation that would allow the Commission to adopt performance-based ARPs that are not subject to the approval of the utility being regulated as a condition for implementation. The ability of the Commission to independently determine the performance-based ARP is of key importance because it is in the utility's interest to only accept ARPs that most closely reflect Alternative 3 (no regulatory cost for pre-approval, no regulatory risk of disallowances) and that have minimal incentives for good performance. It is this type of ARP that has been submitted by AmerenUE in the instant case.

ALTERNATIVE REGULATION PLAN

GENERATION AND TRANSMISSION EXPANSION

Q. Which AmerenUE witnesses testified on Generation and Transmission Expansion?

A. Mr. Garry L. Randolph is the AmerenUE witness on Generation Expansion, and Mr. David A. Whiteley is the AmerenUE witness on Transmission Expansion.

Q. What is Mr. Randolph's position regarding Generation Expansion?

A. Mr. Randolph testifies that AmerenUE intends to invest $1.74 billion in generation improvements and additions from now through 2006. Mr. Randolph argues that the Staff's proposal in this case threatens AmerenUE's ability to finance these projects and that AmerenUE's ARP provides a reasonable rate of return and regulatory certainty needed in order to implement the Generation Expansion necessary over the next three years.

Q. What is Mr. Whiteley's position regarding Transmission Expansion?

A. Mr. Whiteley testifies to $400 million of transmission investment by AmerenUE that will increase the import capability of AmerenUE by 1,300 MWs by the year 2005. Mr. Whiteley then argues for adequate cost recovery and incentives that will encourage these Transmission Expansion projects.

Q. Is AmerenUE asking for pre-approval for its Generation and Transmission Expansion plans?

A. I'm not sure, but I don't think so. Instead, both witnesses appear to be arguing for an ARP that will provide sufficient cash flow over the next three years to keep AmerenUE's financing costs at current levels. If this is the case, there is significant testimony missing from the AmerenUE filing.

Q. What is missing from the AmerenUE filing in regard to Generation and Transmission Expansion as it relates to an ARP?

A. Generation and Transmission Expansion are the decision variables that determine the amount of investment that will occur over the next several years. Schedule 4-1 to this surrebuttal testimony is a graphic illustration of this process. The level of capacity reserves drives Generation Expansion, and Transmission Expansion is driven by the level of import capability. These decision variables are shown in the box at the top of the graphic. The lower boxes show some of the key uncertainties that AmerenUE faces in making these decisions.

The first area of uncertainty deals with generation plant performance. I listed this area first, because AmerenUE is planning to undertake significant investment in power plant improvements, which should have a significant impact on generation plant performance. While the expected impact of these investments can be estimated, the exact impact cannot be determined because the plant heat rates and forced outage performances are subject to random outcomes. However, investments in power plant improvements are designed to reduce a portion of this uncertainty, as well as increase the levels of generation plant performance.

The second area of uncertainty is the market prices that AmerenUE will face both as a potential buyer and seller of electricity. Changing electricity prices in the wholesale markets have an impact on the year-to-year costs of AmerenUE. The level of reserves and import capability are key determinants in how frequently AmerenUE will go to the market to purchase electricity versus going to the market to sell electricity. AmerenUE will purchase from the market whenever the market price is below its incremental cost of generation and when there is sufficient import capability. During times of high prices, AmerenUE will be in a better position to sell into that market if it holds higher levels of reserves.

The third, fourth and fifth areas of uncertainty deal with forecasts for load requirements, fuel costs and capacity costs for both generation and transmission. These are more traditional types of uncertainties that have been included in decision making prior to the development of market-based pricing in the wholesale electric markets.

Q. What is shown below each of these key uncertainties in your graphic illustration on Schedule 4-1?

A. With uncertainties, there is a distribution of outcomes as shown by the probability distribution graphs on Schedule 4-1. These outcomes may vary by year as shown for years 1, 2 and 3 in Schedule 4-1. When all of these uncertainties are taken together, the result is a distribution of production and transmission costs as is shown on Schedule 4-2. This probability distribution of production and transmission costs has an expected value, but the distribution shows that there may be a wide range of production and transmission costs that could occur even when the reserve requirement and import capability levels are predetermined.

Q. How is the probability distribution of production and transmission costs important to the financial requirements of the utility?

A. The wider and flatter the production and transmission costs distribution, the higher the business risk faced by the utility. The more narrow and spiked the distribution, the lower the business risk faced by utility. Business risk is a key determinant in the design of the sharing grid for an ARP. However, AmerenUE has failed to provide information on the business risk profile that it faces over the next several years with respect to its investment decisions for Generation and Transmission Expansion.

Q. Can you give a specific example of the type of business risk that AmerenUE faces?

A. This may best be illustrated through a scenario. Suppose AmerenUE decides to hold only 13% in reserve requirements. If the weather is very hot in the summer, but everyone's generation plants stay on line, the market price for electricity is not likely to spike. But if there is a generation capacity shortage in the region, combined with a hot summer, market prices will spike. Yet, AmerenUE will be able to keep its generation costs down if it does not experience any forced outages on it generation units. However, if one of AmerenUE's large coal-fired units goes down, a 13% capacity reserve margin may put AmerenUE in a position where it has to purchase from the wholesale electricity market at very high prices. This is a business risk that AmerenUE can hedge by increasing its capacity reserve margin.

Q. How does AmerenUE determine its hedging strategy with respect to its capacity reserve margin?

A. The graphic on Schedule 4-3 illustrates one way in which such a hedging strategy is determined. At each capacity reserve margin level there are expected annual production and transmission costs. There will be a capacity reserve margin level at which these expected costs are minimized. Assuming that the business risks do not decrease with increasing expected costs, the capacity reserve margin level at which expected costs are minimized determines the optimal strategy for AmerenUE to deal with its business risks.

Q. In Schedule 4-3 what do the three curves represent?

A. Each curve represents the expected annual production and transmission costs for the next three years. Notice that the costs are increasing from year 1 to year 2 to year 3. This illustrates the situation in which the utility is facing "increasing costs" over the next several years. Typically, an increasing cost utility is not interested in an ARP that sets rates at current cost-of-service levels.

Q. Does AmerenUE face increasing costs?

A. Because AmerenUE has not presented that information as a part of its filing for an ARP, the Staff does not know for sure. However, there is some information from AmerenUE's rebuttal filing in the instant case that indicates either:

1) AmerenUE is facing decreasing costs;
2) The cost-of-service filed by AmerenUE is not representative of its true costs; or
3) The ARP filed by AmerenUE will not meet its expected revenue requirement needs over the next three years.

Q. What information from AmerenUE's filing leads you to these alternative conclusions?

A. AmerenUE filed a cost of service that shows a need for a rate increase of approximately $148 million for the test year, and then offers an ARP over the next three years involving a $15 million dollar rate decrease. If a $148 million increase truly represents AmerenUE's cost of service, then in order to have a $15 million rate decrease meet AmerenUE's revenue requirements over the three years of its proposed ARP, the costs for the next three years of that ARP must be significantly below the costs represented by the $148 million increase.

Q. Of these three alternatives, which is the most likely to be true?

A. I would eliminate option 3 as inconsistent with the quality of analysis that I have seen performed by AmerenUE over the past 25 years. With the magnitude of expenditures that AmerenUE rebuttal witnesses Mr. Garry Randolph and Mr. David Whiteley are proposing, I find it difficult to comprehend that AmerenUE would willingly accept the risk that it can realistically decrease its cost by the magnitude involved in a short time period. Therefore, I eliminate option 1. Thus, I am led to the conclusion that option 2 (the test year cost of service filed by AmerenUE in the instant case is not representative of its true costs) must be true. Moreover, with respect to production costs, AmerenUE did not start with the test year of 12 months ending June 30, 2001 updated through September 30, 2001. Instead, AmerenUE started with booked production expenses for the twelve months ending September 30, 2001 and therefore never addressed the question of that, because these booked expenses were abnormal, there needed to be significant adjustments to the test year of the twelve months ending June 30, 2001 for production expenses that were booked for the months of July, August and September of 2001.

SIGNIFICANT PROBLEMS WITH OFF-SYSTEM SALES

PROFIT MARGINS FOR JULY, AUGUST AND SEPTEMBER, 2001

Q. Are there problems with interchange revenues and costs booked by AmerenUE for the twelve months ending September 30, 2001?

A. Yes, in fact, there are significant problems. In comparing expenses related to interchange sales for the twelve months ending September 30, 2001 to the twelve months ending June 30, 2001 (which includes the months of July, August and September of 2000), expenses were up $12.7 million and revenues from interchange sales were down $16.1 million, leaving a decrease in margin from interchange sales of $28.8 million. With a base level profit margin from interchange sales of around $96 million per year, this change is highly significant and AmerenUE should have provided an explanation of this difference. Yet, AmerenUE provides no explanation in its testimony for this significant difference.

The apparent reason that AmerenUE offers no explanation for this difference is that AmerenUE did not treat it as an adjustment. Instead, AmerenUE apparently assumed that updating from the twelve months ending June 30, 2001 through September 30, 2001 simply means moving its books three months. But this is not correct. Every difference from what was booked in the months of July, August and September of 2000 (which are in the test year of the twelve months ending June 30, 2001) to those same months for 2001 is an adjustment to the test year that AmerenUE should have explained. Instead, AmerenUE has ignored these differences.

Q. Have you attempted to determine an explanation for the significant difference in the expenses and revenues related to interchange sales?

A. Yes, I have. I went back to the records for Interchange Electricity Sales that are provided to Staff on a monthly basis by AmerenUE, pursuant to 4 CSR 240-20.080. These records indicate that in the area of Off-System Sales, for the peak summer months of July and August, revenues decreased by almost one half from 2000 to 2001. This decrease in revenues from Off-System Sales was derived from a greater than one half fall in sales and a significant increase in the average price of power sold by AmerenUE. When sales decrease but prices increase, this indicates that AmerenUE was not able to sell at lower prices because it needed the lower cost generation to meet its native load. This can occur when either there is a hotter summer (higher native load) or when a large base load generating plant is out of service. In the summer of 2001, AmerenUE faced both of these circumstances for the months of July and August with: (1) cooling degree days (CDD) up from 867 CDD in July and August of 2000 to 938 CDD in July and August of 2001; and (2) the Rush Island Unit 2 forced out of service for 712 hours in the month of July and down for maintenance for 117 hours in the month of August. On the other hand, September 2001 sales were comparable to those from September 2000, but Off-System Sales' revenues were down because of lower prices.

Q. Were there any problems with booked revenues and costs for Interchange Sales for the month of July through September of 2001?

A. Yes, there were. First, there is a difference between Off-System Sales and Interchange Sales. Interchange Sales include the revenues from Off-System Sales plus the revenues from transfers to AEG/AEM and revenues from transmission sales. On the cost side, Interchange Sales include the costs for making Off-System Sales plus the costs of the electricity transferred from AmerenUE to AEG/AEM. Thus, when looking at profits in Interchange Electricity Sales, the revenues from transmission sales must first be removed. The resulting profits combine both Off-System Sales and transfers from AmerenUE to AEG/AEM.

For the months of July through September of 2001, once transmission revenues are removed, revenues from Interchange Electricity Sales were only $377,233 above Interchange Expenses for AmerenUE. This is virtually a zero margin, and this is impossible when including transfers because the transfers should include a slight margin of $3/MWh for incremental operating and maintenance expense and emissions allowances.

In response to a Staff data request, AmerenUE provided information concerning an adjustment that was made to the AmerenUE books in August 2001. After making this adjustment, the revenues booked from Interchange Electricity Sales for July through September 2001 increased by $5.3 million. But this only came to a profit margin of $2.97/MWh, which is still slightly less than the mark-up of $3/MWh for transfers.

The low level of profits recorded for July through September of 2001 is not due alone to a downward swing in the electricity market, rather it is either an error in the accounting entries or the inclusion of additional adjustments for other months in the entries for these three months. In either case, the entries for July, August and September of 2001 are not representative of AmerenUE's normal levels for profit margins from Interchange Sales.

Q. Do you have a recommendation concerning the books and records related to AmerenUE's revenues and expenses from Interchange Sales for the twelve months ending September 30, 2001?

A. Yes, I do. The Commission should not believe that the amounts shown on AmerenUE's books for the months of July, August and September 2001 are accurate and should reject those amounts as not being typical of AmerenUE's profits from Off-System Sales. However, AmerenUE's records show an $8,292,255 adjustment to the months of January through June 2001, which are in the test year that was adopted by the Commission in this case and is the test year on which my direct testimony is based. This amount should be subtracted from revenues for Interchange Sales in the Staff's test year, dropping the test year profit margin from $96,321,367 [Proctor Direct, Schedule 2] to $88,029,255. All of this adjustment comes out of the profits for Off-System Sales, reducing these profits from $47,647,186 [Proctor Direct, Schedule 2] to $39,354,931. The Staff adjustment from allocating profits for Off-System Sales by Resource Output rather than by Load Share should accordingly be reduced from $3,725,146 to $3,076,842.

Q. Are there other factors that could have increased the profits for Off-System Sales for the test period?

A. Yes. An adjustment could have been made to increase Off-System Sales because of the Callaway refueling outage that occurred during the test year, and an adjustment could have been made to increase Off-System Sales because of Ameren's coal conservation program that took place during the spring of 2001 in the test year. Both of these adjustments would have increased the level of Off-System Sales included in the Staff's test year or AmerenUE's test year. Neither the Staff nor AmerenUE made adjustments for these abnormal test year conditions.

ALTERNATIVE REGULATION PLAN

THE ROLE OF REGULATION IN TODAY'S ELECTRIC INDUSTRY

Q. Which AmerenUE witnesses testified on the Role of Regulation in Today's Utility Industry?

A. Mr. Warner L. Baxter, Dr. Mark N. Lowry, Dr. Dennis L. Weisman, Dr. Peter S. Fox-Penner and Ms. Suedeen G. Kelly have all testified on what they view as the proper role for regulation in today's electric industry.

Q. Would you please summarize your understanding of Mr. Baxter's position on the proper role for regulation in today's electric industry?

A. My summary of Mr.Baxter's position on the proper role for regulation is based on the following statements from his rebuttal testimony:

1. Sound energy policy and regulation is critically important in today's energy market to create the reliable energy infrastructure so necessary to maintain favorable economic conditions in the State. [Baxter Rebuttal, p. 3]

2. Such innovative approaches to the State's energy and regulatory policy are even more imperative now, because utilities must operate in an increasingly complex, and volatile industry environment. [Baxter Rebuttal, p. 4]

3. Rising customer demands and maintaining high levels of reliability require significant energy infrastructure investment over the next five years. These infrastructure investments require strong cash flows and ready access to the capital markets. [Baxter Rebuttal, p. 6]

4. … I simply cannot understand the Staff's punitive $245 million to $285 million rate reduction recommendation and its willingness to abandon the farsighted EARP framework, in favor of the traditional regulatory model. [Baxter Rebuttal, p. 6]

My summary of Mr. Baxter's position is that the business risks now facing a regulated utility have significantly increased and the traditional regulatory model is no longer able to properly deal with those risks. Therefore, this Commission should move away from the traditional regulatory model in favor of ARPs.

Q. Would you please summarize your understanding of Dr. Lowry's position on the impact of the alternative regulation sharing plan for AmerenUE?

A. Dr. Lowry testifies that AmerenUE performed better (lower costs) than what his econometric models predicted that it would perform over the 1995 to 2001 time period. [Lowry Rebuttal, p.p. 8-9]

Q. Would you please summarize your understanding of Dr. Weisman's position on the role of alternative regulation compared to traditional regulation?

A. Dr. Weisman presents extensive testimony on the economic theory of both traditional and alternative regulation. His primary thesis appears to be that alternative regulation is defined by having longer periods between, and set periods for, rate reviews compared to traditional regulation where rate reviews are driven by the utility's earnings. [Weisman Rebuttal, p.p. 23-24] With longer periods between rate reviews that are not driven by the utility's earnings, Dr. Weisman argues that utilities will have greater incentives to implement efficiency (cost savings) measures. [Weisman Rebuttal, p.p. 24-27] Dr. Weisman also testifies that ARPs should focus on rates rather than earnings or narrowly targeted performance benchmarks. [Weisman Rebuttal, p. 74] Finally, Dr. Weisman argues that setting artificially low rates in an attempt to "claw back" some of the earnings that the Staff deemed to be excessive under the previous Experimental Alternative Regulation Plans (EARPs) would breach the Commission's commitment to AmerenUE under these EARPs. [Weisman Rebuttal, p. 78] Moreover, Dr. Weisman argues that AmerenUE should be allowed a higher rate of return because of its performance under the previous EARPs. [Weisman Rebuttal, p. 79]

Q. Would you please summarize your understanding of Dr. Fox-Penner's position on the proper role for regulation in today's electric industry?

A. My summary of Dr. Fox-Penner's position on the proper role for regulation is based on the following statements from his rebuttal testimony:

1. ... the transmission grid is becoming more heavily used, and maintaining grid-level reliability is becoming more of a challenge than it was under the past industry structure. [Fox-Penner Rebuttal, p. 36]

2. ... market-based prices inherently are much more volatile than regulated, cost-based prices. [Fox-Penner Rebuttal, p. 36]

3. Wholesale price volatility increases the risks faced by electric utilities. [Fox-Penner Rebuttal, p. 37]

4. Another impact on Ameren stems from added volatility in the wholesale power markets. Since Ameren is both a buyer and seller of wholesale power, rapid changes in the availability and price of such power makes buying and selling more difficult and more risky than in the past. [Fox-Penner Rebuttal, p. 38]

5. ... in wholesale power markets, generation increasingly is sold at market-based rates, whereas in retail markets, much generation continues to be sold at regulated, cost-based rates. [Fox-Penner Rebuttal, p. 39]

6. Even if a utility with an obligation-to-serve builds a new generating plant under cost-of-service regulation and a state-approved resource plan, it cannot be sure how long it will have an exclusive retail franchise or marketing area. [Fox-Penner Rebuttal, p. 41]

7. Transmission investment also is affected by the uncertain status of retail competition because of split federal/state jurisdiction over transmission rates and the transmission revenue requirement. [Fox-Penner Rebuttal, p. 41]

8. Utilities that have an obligation to serve need to invest in the infrastructure necessary to provide adequate, reliable, and cost-effective service. ... However, the turmoil and uncertainty facing the electric utility industry today is greater than at any time since the 1930s, and this increases the

risk associated with new generation and transmission investments. [Fox-Penner Rebuttal, p. 43]

9. State regulation needs to recognize that the risks, challenges, and opportunities facing electric utilities have changed. These changes need to be considered in the determination of Ameren's rates. [Fox-Penner Rebuttal, p. 49]

10. Rather, it must be recognized that future costs and forecasts of all types are more uncertain than before. In some cases, this calls for a greater range of allowed costs (i.e., a 'buffer'). And it certainly calls for using the most recent actual and best available forecasted data for setting rates. [Fox-Penner Rebuttal, p. 49]

11. For example, well-designed incentive regulation would provide AmerenUE with strong incentives to manage the risk of volatile cost elements, such as fuel and purchase power costs. [Fox-Penner Rebuttal, p. 50]

12. To summarize, when future costs and risks are relatively predictable, cost-of-service regulation and infrequent traditional rate cases have worked well. When costs are volatile and unpredictable, incentive regulation makes more sense. [Fox-Penner Rebuttal, p. 50]

My summary of Dr. Fox-Penner's rebuttal testimony is that with the changes that are taking place at the federal level with respect to market-based pricing of electricity in the wholesale markets and the increased use of the transmission grid, regulated electric utilities are facing greater business risk than in the past. The traditional regulatory model is not well suited for dealing with costs that are volatile, and state commissions should turn to incentive regulation as a viable alternative.

Q. Would you please summarize your understanding of Ms. Kelly's position on the proper role for regulation in today's electric industry?

A. My summary of Ms. Kelly's position on the proper role for regulation is based on the following statements from her rebuttal testimony.

1. … performance based regulation is more important now than ever before because the changes in the industry demand new investment and will reward cost reduction, efficiency and innovation. [Kelly Rebuttal, p. 53]

2. … the Alt Reg Plan eliminates some of the regulatory risks associated with traditional cost of service regulation that current conditions in the industry counsel against incurring. [Kelly Rebuttal, p.p. 53-54]

3. These behaviors include cost reduction, efficiency and innovation. Although such behaviors are desirable in any business, including the utility business, they are particularly important for a business that is facing new demands for infrastructure investment, new ways of doing business because of market changes, and new competitive pressures. [Kelly Rebuttal, p.p. 54-55]

4. In order to strike an appropriate balance of interests, a cost of service study on which rates are based must accurately reflect a utility's costs, including appropriately normalized test year costs and revenues, appropriate depreciation rates, and a reasonable return on equity. [Kelly Rebuttal, p. 59]

My summary of Ms. Kelly's rebuttal testimony is that regulated electric utilities face increasing business risks and at a time when AmerenUE needs to make significant improvements to its production and transmission infrastructure the Commission should adopt an ARP in order to decrease regulatory risk and provide AmerenUE with incentives to make new investment and reward cost reductions, efficiency improvements and innovation.

Q. From a public policy perspective, do you agree with what these witnesses have said about the "failures" of traditional cost-of-service regulation and the "virtues" of ARPs?

A. In part I agree and in part I disagree. First, with respect to traditional cost-of-service regulation, I agree that there is greater volatility in some fuel markets (e.g., natural gas), and wholesale electricity markets. I also agree that there is a great deal of future uncertainty regarding revenues from the sale of "through" Ameren transmission and the availability of "into" transmission for forward contracts of purchased capacity and energy as well as off-system purchases of electricity imported to meet native load. From a regulatory Staff perspective, increased volatility in market prices and available transmission means that traditional test years could be subject to extensive normalization. Clearly the important question for traditional cost-of-service regulation is how best to set normal levels for costs that are subject to a great deal of change.

Where I disagree is that the AmerenUE witnesses appear to believe that an ARP can avoid having to deal with these same normalization issues. Moreover, an ARP must set a base level for rates. Thus, I am troubled with the concept that an ARP is somehow decoupled from the utility's costs as indicated in the rebuttal testimony of Dr. Fox-Penner.

> Incentive regulation differs from cost-of-service regulation in that it partially decouples a regulated firm's rates from its costs and uses explicit financial incentives to motivate the firm's behavior. Under cost-of-service regulation, there is in principle a dollar-for-dollar correspondence between prudently-incurred costs and rates. Under incentive regulation, the link between costs and nates is not as direct in the short term [Fox-Penner Rebuttal, p. 24]

As a clarification, I am more comfortable with the following description: An ARP is still based on the utility's cost of service, but may go beyond a current test year concept for determination of rates that will be in effect over the period of the ARP.

Q. Is this in effect a "forecasted" test year concept?

A. In a general way, forecasts are used. But when the forecast is simply for the expected value for future revenue requirements, such an approach does not fully bring to bear the business risk faced by the utility over the next several years. For example, the utility's forecast of the expected value of wholesale market prices for the next several years gives no indication of the volatility that the utility is facing with respect to costs for off-system purchases and revenues from off-system sales. In order for these forecasts to be of value to the development of the base level(s) for rates, the forecasts should include the distributions of the earnings that are reflective of the business risks faced by the utility for the next several years.

Q. What role do the distributions of earnings reflective of business risk have to do with developing an ARP?

A. Dr. Fox-Penner describes this in two ways.

> 1. A primary purpose of earnings sharing is to align company and consumer interests and to keep a company's earnings at politically and operationally acceptable levels during the plan's term or commitment periods. [Fox-Penner Rebuttal, p. 25]
>
> 2. … it must be recognized that future costs and forecasts of all types are more uncertain than before. In some cases, this calls for a greater range of allowed costs (i.e., a 'buffer'). And it certainly calls for using the most recent actual and best available forecasted data for setting rates. [Fox-Penner Rebuttal, p. 49]

When I first read the words "politically and operationally acceptable level" for earnings, I assumed that Dr. Fox-Penner was referring to the rate cap implicit in the AmerenUE ARP (i.e., 13.33 %). And while this may be a part of what needs to be set as an acceptable level, if the utility is constantly earning at or near that earnings cap, then the base level set in the ARP was not initially set at an acceptable level. It is extremely important to correctly set the base level, otherwise it is impossible to distinguish between successful improvements in efficiency and cost savings versus simply over earning because the base level was set too high.

The second statement from Dr. Fox-Penner hits what I believe is the heart of the matter regarding the role that the distribution of earnings reflective of business risks play in developing an ARP. Faced with greater business risk, Dr. Fox-Penner believes that it is appropriate to build into an ARP a "buffer" that is reflective of the utility's forecasted business risk.

Q. Has AmerenUE submitted any testimony that attempts to measure its distribution of earnings over the period of the ARP?

A. No it has not. This is a major flaw in AmerenUE's request for an ARP. Instead of forecasts of its earnings distribution that would lay the foundation for approving its ARP, all that has been presented to the Commission is an ARP that has no measurable foundation and the testimony of outside consultants that support the need for providing a measurable foundation. Moreover, it appears that the only quantifiable basis for AmerenUE's ARP is a guaranteed, not to exceed rate of return of 13.33%.

Q. Why isn't a guaranteed not to exceed rate of return sufficient grounds for approving AmerenUE's ARP?

A. The level set for base rates in the ARP is critical to the distribution of earnings shared between ratepayers and shareholders. For example, if the rates are set high enough, AmerenUE earns 13.33% under almost any business risk and the credits sent back to ratepayers is simply the over earnings from initially setting the rates too high. This is equivalent to a rate case, with no adjustments to books in which the utility is simply allowed to earn 13.33%. I do not believe that the Commission would approve such a level of rates; yet, in essence, this is what AmerenUE is asking for by its filing in the instant case.

Q. If AmerenUE had submitted this information, what determination would the Commission need to make in order to approve an ARP that would be "politically and operationally acceptable?"

A. First, while there should not be pre-approval of future expenditures for investment in infrastructure, the Commission should determine the need for these improvements. In terms of what I discussed earlier with respect to production and transmission, a proper review would determine whether the specific projects will likely result in a least-cost way of meeting AmerenUE's obligation to serve its customers. For example, the determination that AmerenUE should have X % of capacity reserves and Y MW of import capability and that the proposed methods for meeting these targets are likely to be the least cost.

Second, the Commission should determine that the assumptions going into the determination of the distributions of the key uncertain variables are within a reasonable range. These distributions are key determinants of the business risk that will be shown for future cost-of-service. Setting unreasonably high levels of uncertainty in these distributions will result in higher levels of business risk than the utility will actually face.

Third, based on the expected levels of cost-of-service over the length of the ARP, the Commission should determine the appropriate levels for rates in each year of the plan. Rates, customer growth and weather determine the customer revenue base for calculating expected earnings. With rates fixed, customer growth and weather become the key uncertainties affecting the distribution of revenues from a proposed set of rates. Thus, for proposed rate levels during the ARP, the distribution of earnings and/or rates of return can be determined.

Fourth, based on the distribution of earnings and/or rates of return, an appropriate sharing grid can be developed, subject to Commission approval. This sharing grid along with the distribution of earnings will give the Commission a sound basis for determining the impact of the ARP for both consumers and shareholders of AmerenUE.

Q. Has AmerenUE provided this type of information to the Commission in its rebuttal filing?

A. No, it has not. Moreover, the Commission is missing directly relevant information needed in order to approve the ARP proposed by AmerenUE. When I requested this information from Mr. Baxter in a data request, his response was that "The Company has neither developed a comprehensive forecast of AmerenUE's 'expected' earnings nor calculated a 'probability distribution' for the sole purpose of estimating earnings for each year of the proposed ARP." [Response to Staff D.R. No. 3524] Mr. Baxter's response to Staff Data Request No. 3524 is attached as Schedule 5 to my surrebuttal testimony.

I find Mr. Baxter's response to be remarkable. It is beyond my comprehension that an ARP has been offered by AmerenUE that will determine its earnings over the next three years and there has been no estimate made of what impact that plan will have on AmerenUE's expected earnings for that same period.

Q. Absent this information, do you agree that a comparison of AmerenUE's rates to those of other utilities is sufficient evidence for setting the base rates?

A. I absolutely disagree with the contention that comparing AmerenUE's rate levels with those of other utilities is a sound basis for setting base rates in an ARP. This approach to regulation, in which the individual circumstances of each utility is not taken into account, is a formula for detriment to both ratepayers and utilities. If a utility is facing decreasing costs or lower costs than those utilities being used as the basis of the rate comparison, then the utility is allowed to over earn to the detriment of its ratepayers. If a utility is facing increasing costs or higher costs than those utilities being used as the basis of the rate comparison, then the utility is forced to under earn to the detriment of its shareholders.

Q. Did Mr. Baxter promise to improve AmerenUE's monitoring of performance and service quality?

A. Yes, he did. However, the performance measures proposed by AmerenUE are all related to customer service, while a major portion of infrastructure improvements are related to production and transmission. I am not saying that poor performance in production and transmission will not ultimately impact customer service, rather that with a claim for the need for an ARP being directly linked to these two areas, AmerenUE should have provided specific measures that are directly related to performance in production and transmission; e.g., improvements in unit availabilities, unit heat rates, overall transmission capability and transmission import capability to serve utility load.

Q. Did you review the econometric study of Dr. Lowry?

A. Yes, I reviewed what was included in Dr. Lowry's rebuttal testimony. Dr. Lowry used what is known in economics as a "translog" cost function that is estimated using simultaneous cost-share equations. The basic translog cost function measures costs as a function of output and input prices. In this cross sectional application involving data from several utilities various additional parameters were added to delineate factors that might vary with the costs of a specific utility. Two models were estimated:

1) a trend model having 2 output variables (number of customers and volume of sales), 3 input price variables (labor, capital and energy) and 5 business condition variables (load factor, % electric, miles of overhead lines, % overhead in T&D and % of generation not in hydroelectric); and

2) a cost level model having 2 output variables (same), 3 input price variables (same) and 1 business condition variable (load factor).

The models appear to include both operating and capital costs, where capital costs are evaluated at a hypothetical rental price for capital services rented in a competitive capital services market. With AmerenUE having significant decreases in its capital cost over the period of its EARPs, it is not surprising that the model used by Dr. Lowry would over predict AmerenUE's costs.

Q. Why would AmerenUE have significant decreases in its capital cost over the period of its EARPs?

A. The building of the Callaway nuclear plant placed AmerenUE in an excess situation regarding both capacity and base load generating capability. Because of the excess in base load capability, AmerenUE would only need to add less costly peaking capacity when its load grew enough to absorb the excess capacity from Callaway. In addition, the high capital cost of the Callaway nuclear plant raised AmerenUE's embedded cost for generation above the incremental cost of adding new and much less expensive peaking capacity. During the EARPs, AmerenUE would be realizing the benefits of this situation. It is not clear how Dr. Lowry's econometric models with its hypothetical rental price for capital services would take into account this declining cost situation faced by AmerenUE.

Q. Are there other difficulties that you see in using this specific form of an econometric model to predict utility costs?

A. Yes, there are significant theoretical problems with the form of the models used by Dr. Lowry to estimate the cost function for utilities. First, the model used by Dr, Lowry assumes a perfectly competitive market for all of the inputs. While this might be the case for capital services and energy (fuel input) costs, it is clearly not the case for labor, where labor rates and levels are negotiated between two monopolists (the utility and the labor unions). Second, the model used by Dr. Lowry assumes that the firm will choose inputs to minimize its total costs. It is well documented in economic literature that with a rate of return regulation, in order to maximize profits, utilities will over invest in capital inputs when compared to the minimum cost condition. Third, in **Econometric Methods**, a standard text written by J. Johnston, the author warns:

> "There have been many applications of this cost share approach in recent years. However, a word of caution is required. As the derivation made clear, a basic assumption underlying the derivation of the share equations is that in each observation period in the sample there has been a full and complete adjustment of the input mix to the factor prices ruling in that period so that the minimum cost level C* is achieved. This is an implausible assumption for many production processes, and actual cost shares probably represent various lagged adjustments to changing factor prices. The assumption of instantaneous adjustment is likely to produce seriously biased estimates of the various elasticities." [Econometric Methods, Third Edition, McGraw Hill, 1984, p.p. 336-337]

From my review of Dr. Lowry's testimony and work papers, it does not appear that he has taken into account the potential for lagged adjustments to changing factor prices. While this may not be a problem for energy (fuel input) prices, it is likely to be a significant problem for both labor prices and capital prices.

All three of these problems are likely to produce bias in the parameter estimates for Dr. Lowry's trend model. In the cost level model, Dr. Lowry used three-year averages and this may have helped to eliminate some of the bias.

Q. What do the results of Dr. Lowry's cost level model indicate?

A. If the parameter estimates from Dr. Lowry's cost level model are unbiased, then the predicted growth rate of 2.76% in AmerenUE's costs over the 1995 to 2001 time period can be compared to the actual growth rate in AmerenUE's costs of only 1.09%. Dr. Lowry attributes this difference to the AmerenUE EARPs. While this is a possible explanation, because UE merged with CIPS in the middle of this period, it is more likely that these cost savings were in large part due to merger savings. In fact, it is very important to note that the extension of the EARP for an additional three years was part of the Stipulation And Agreement in the merger case (EM-96-149). Thus, AmerenUE was allowed the opportunity to retain a portion of the merger savings that it asserted it would achieve via its merger with CIPS.

Q. As contended by Dr. Weisman, does a rate freeze over a fixed period of time give utilities additional incentives to reduce costs over that same period of time?

A. If a rate freeze or a rate cap is in place over a long enough period of time and the impact that cost savings will have for future rates beyond the specified period for the rate freeze are known, there can be additional incentives for utilities to find innovative methods for reducing their costs.

Q. Why is a long enough period of time important to incentives for cost savings?

A. If the period is relatively short, then the period of time over which the utility is allowed to retain a portion of the cost savings is also short and this tends to reduce the incentive for seeking out innovative methods for reducing costs. In the case of AmerenUE, the settlement in the merger case allowed AmerenUE to retain merger savings for three years after the merger and extended the entire EARP for a period of six years. While this six-year period may be long enough for implementation of innovative methods for reducing costs, without a specific proposal for AmerenUE to retain a portion of these savings beyond the six years, it is unlikely that many innovative methods for reducing costs beyond consolidation of function from the merger would have been implemented.

Q. Why is the rate treatment of cost savings at the time of the rate review at the end of an ARP important to incentives for cost savings?

A. As Dr. Weisman points out in his rebuttal testimony, if the utility believes that the regulators will incorporate cost savings into future rates, then the only retention of cost savings are those the utility is allowed to keep during the initial ARP. Dr. Weisman essentially argues that AmerenUE should not be held to a cost-of-service standard following the six-years of EARPs because this would be an attempt to "claw back" some of the savings that were achieved during that time. However, it is likely that much of the savings AmerenUE achieved during this time came from the merger. These are not savings achieved from innovative programs to reduce costs, rather they are savings achieved from combining functions of two utility companies into a single workforce that can serve both utilities. This raises a fundamental issue of when and where will AmerenUE's customers receive the benefits from the merger.

Even if some of the savings are from innovative programs to reduce costs, AmerenUE has had a long period of time to retain the earnings from those savings compared to what would occur in a competitive environment. Regarding the sustainability of cost advantage, Professor Michael E. Porter states, "Cost advantage is sustainable if there are entry or mobility barriers that prevent competitors from imitating its sources." [**Competitive Advantage**, The Free Press, 1985, p. 112] In this regard, even innovative methods for saving costs cannot be hidden from competitors for an extended period of time.

Q. How does the fact that competitors are likely to imitate innovative cost savings impact the period of time and the impact that cost savings will have for future rates beyond the specified period for an ARP?

A. First, in a competitive environment, when competitors imitate innovative cost savings, the impact is to lower the price of the product. Second, in ARPs for utilities, the impact is a trade off between the length of the ARP versus how much of the cost savings the utility is allowed to retain beyond the specified period of the ARP. If the ARP is fairly short (3 years or less), then the utility may be allowed to retain as much as 50% of its cost savings. But if the ARP is fairly long (5 years or more), then the percent of savings the utility is allowed to retain should be much less; e.g., 10% to 20%. In addition, the percent of savings the utility is allowed to retain beyond the termination of the ARP should vary with the amount of savings that it is allowed to retain during the ARP.

Q. Do you agree with Dr. Weisman that Staff's allowed rate of return is too low and should be increased because of AmerenUE's performance under the previous EARP?

A. As a general concept, I prefer allowing in rates a portion of measured historical cost savings to allowing a higher rate of return based on historical performance. The difficulty with either approach is in measuring or benchmarking historical performance.

Q. What is benchmarking of historical performance?

A. Benchmarking sets target levels for costs that are similar to utility specific forecasts of its expected costs over the period of the ARP. Much like using price indices in contracts, if the utility can do better than the benchmark, then it is allowed to add a portion of this difference to the costs included in the rates that form the basis of the next ARP, and if it does worse than the benchmark, it must decrease the costs included in these rates.

Q. Has AmerenUE proposed benchmarking as a part of its ARP?

A. No. In addition to critical information regarding forecasted earnings, the AmerenUE proposed ARP lacks a system of benchmarking so that at the end of its proposed three-year plan, there is no basis for measuring performance.

Q. Would Dr. Lowry's econometric models provide a sound basis for benchmarking AmerenUE's costs?

A. Not in their current form. Dr. Lowry's econometric models are essentially cross-sectional models that compare the costs of various utilities at a given point in time. A benchmark should take a given utility's costs, and determine over time the historical relationship of those costs to the same type of driver variables used in Dr. Lowry's model. Based on the forecasting error of such a model, a "dead band" range could be determined in which the difference between actual and forecasted levels could be deemed to simply be statistical error. If the utility's costs dropped below the dead band, then it would be able to add a portion of the cost savings to its cost of service at the time new rate levels are set, and if the utility's cost go above the dead band, then it would have to subtract a portion of the added costs from its cost of service at the time new rate levels are set.

Q. What is your recommendation to the Commission with respect to ARPs?

A. The Commission should reject the ARP submitted by AmerenUE in its rebuttal testimony. However, if the Commission wants to implement an ARP, it should order AmerenUE to submit an ARP that meets the following requirements.

1. Sets out the need for investment in infrastructure and demonstrate that AmerenUE's plan is likely to be the least cost way of meeting this need.
2. Provides forecasts of the distribution of earnings for each year of the proposed ARP.
3. Demonstrates the assumptions going into the determination of the distributions of the key uncertain variables that drive the distribution of earnings are within a reasonable range.
4. Choose rate levels for each year of the ARP and a sharing grid that provide reasonable levels of sharing between customers and AmerenUE over the term of the ARP.

5. Provide specific measures for improvements in plant performance and transmission service to native load.

6. Provide specific benchmarks that can be used to measure AmerenUE's cost performance over the term of the ARP.

7. For the setting of rates that will take place at the end of the proposed ARP, set out proposals for retention of cost savings and penalties for cost overruns compared to benchmarks/dead bands and quality of service measures.

Q. Does this complete your surrebuttal testimony?

A. Yes, it does.

SCHEDULE 1 HAS BEEN

DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY

SCHEDULE 2 HAS BEEN

DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY

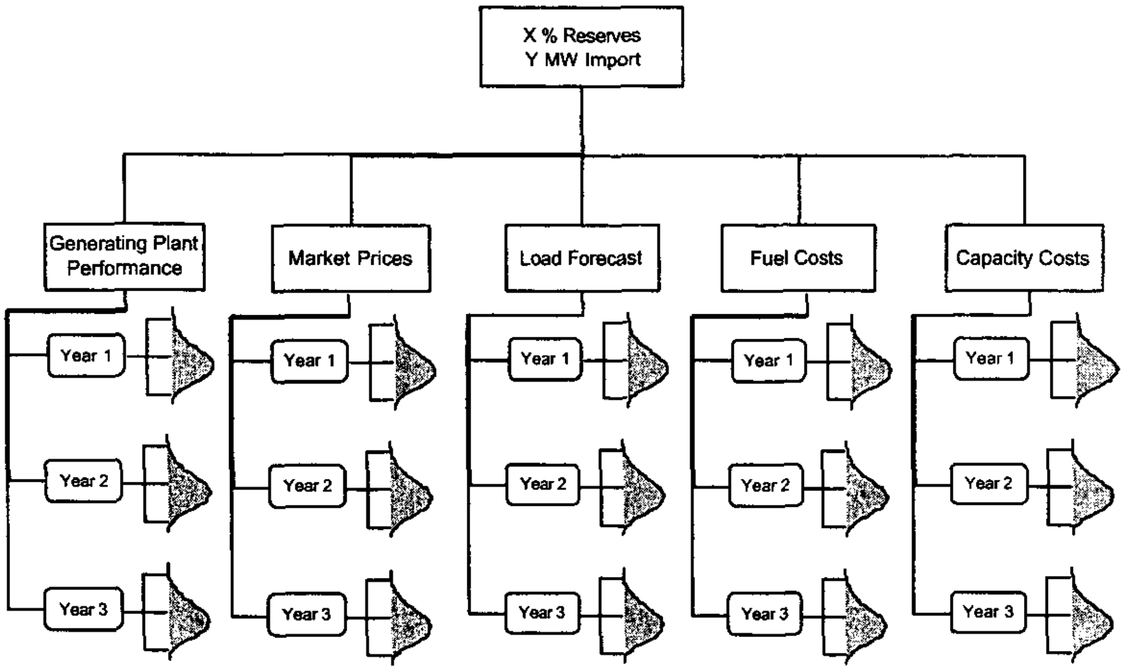
Economic Losses from Transfering at Incremental Cost Rather Than at Market*

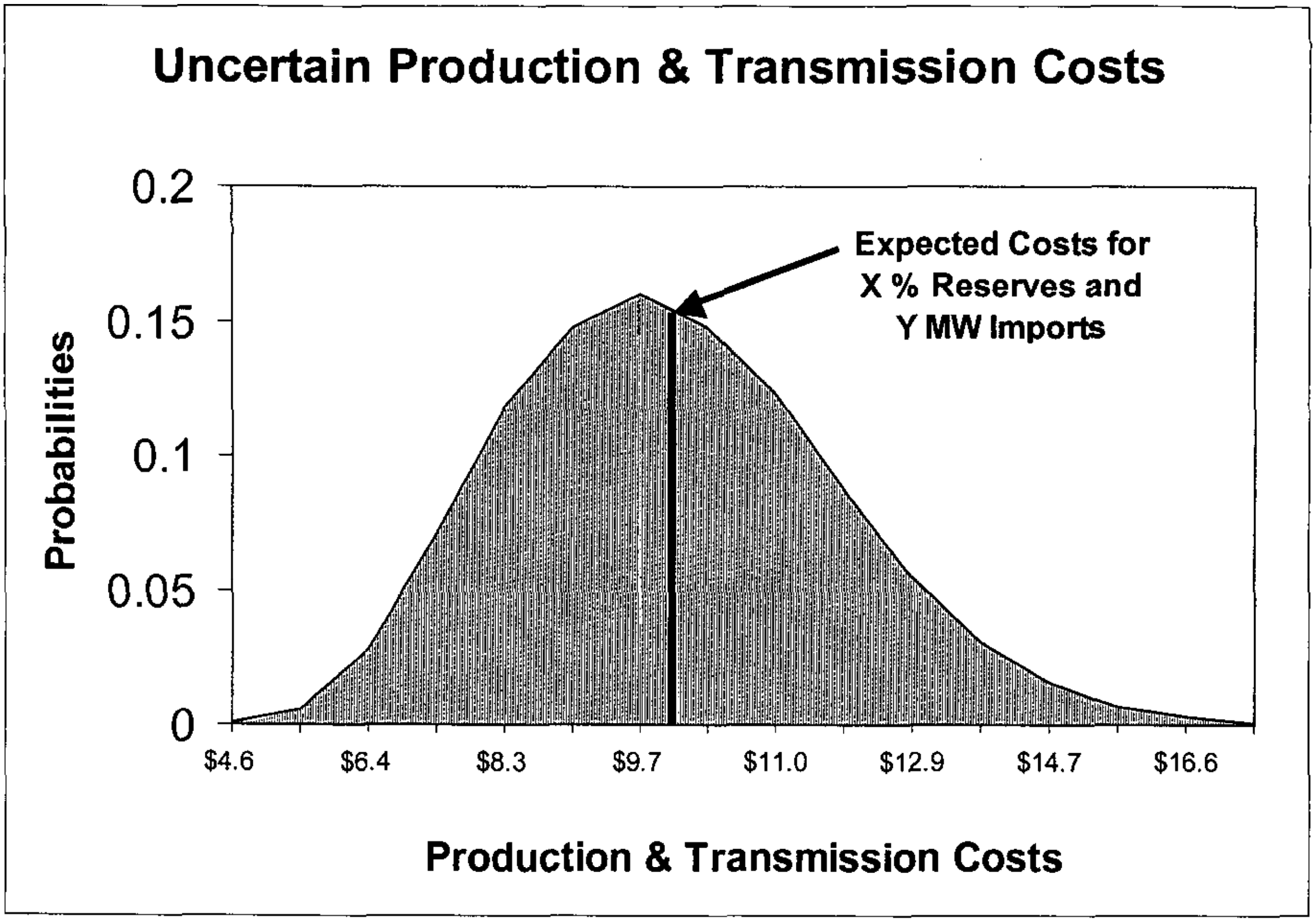
Run	Losses for Transfers Made By: UE to AEG	Losses for Transfers Made By: AEG to UE	Net Losses to UE
1	$105,867,638	$2,489,548	$103,378,089
2	$106,270,708	$3,351,357	$102,919,351
3	$104,724,063	$2,684,960	$102,039,103
4	$105,031,232	$3,627,848	$101,403,383
5	$104,584,784	$3,346,409	$101,238,374
6	$109,596,917	$2,084,384	$107,512,534
7	$101,839,265	$3,066,875	$98,772,390
8	$106,673,636	$1,980,987	$104,692,650
9	$101,712,967	$2,041,888	$99,671,079
10	$105,193,914	$3,193,841	$102,000,073
Avg	**$105,149,512**	**$2,786,810**	**$102,362,703**

* Based on simulation production cost runs made by Staff Witness Leon Bender
- a) Hourly calculation of MWh transferred
- b) Hourly calculation of incremental costs
- c) Hourly comparison of market price to incremental cost
- d) Economic Loss = (market price - incremental cost)(transferred MWh)

Run	UE Transfers to AEG MWh		AEG Transfers to UE MWh
1	6,492,601		116,696
2	6,535,071		129,269
3	6,559,775		114,816
4	6,514,595		152,629
5	6,536,179		134,488
6	6,667,969		91,977
7	6,320,536		153,433
8	6,529,625		91,308
9	6,405,368		104,426
10	6,515,738		140,468
Average	**6,507,746**	**MWh Transferred**	**122,951**
Average	**$66,990,576**	**Incremental Costs**	**$4,521,952**
Average	**$10.29**	**Incremental Cost**	**$36.78**

Generation & Transmission: Decision Making Under Uncertainty

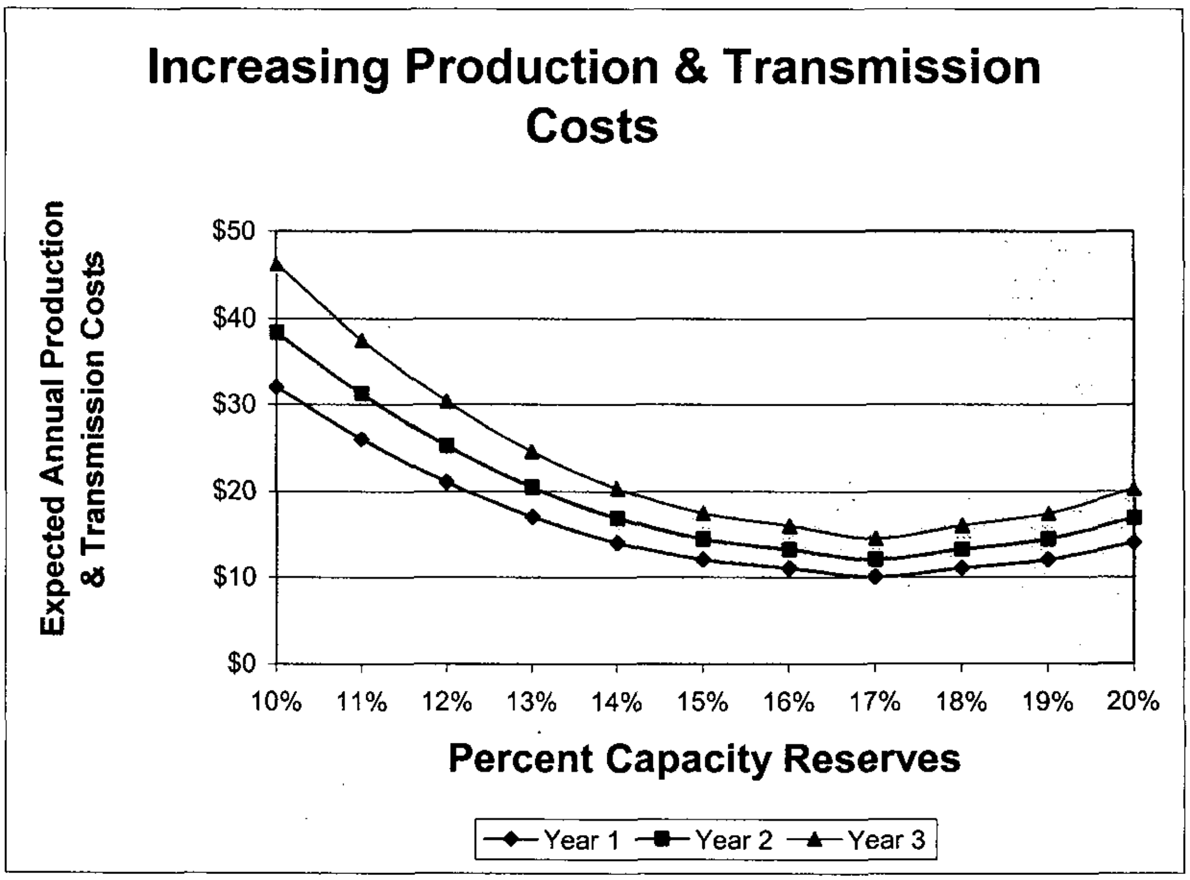



Uncertain Production & Transmission Costs
Expected Costs for
X % Reserves and
Y MW Imports
Probabilities
0.2
0.15
0.1
0.05
0
$4.6
$6.4
$8.3
$9.7
$11.0
$12.9
$14.7
$16.6
Production & Transmission Costs

Annual Revenue Requirements for Production & Transmission

Illustration of an Increasing Cost Situation

Capacity Reserve Requirement	Year 1 Production Costs	Year 2 Production Costs	Year 3 Production Costs
10%	$32	$38	$46
11%	$26	$31	$37
12%	$21	$25	$30
13%	$17	$20	$24
14%	$14	$17	$20
15%	$12	$14	$17
16%	$11	$13	$16
17%	$10	$12	$14
18%	$11	$13	$16
19%	$12	$14	$17
20%	$14	$17	$20



AmerenUE's Response to
MPSC Staff Data Request
Case No. EC-2002-1
Excess Earnings Complaint
Staff of the MPSC v. Union Electric Company d/b/a AmerenUE

No. 3524:

a. Does AmerenUE have a cost-of-service basis for the rates included in its Alternative Regulation Plan? If so, please provide the detailed cost-of-service study that was used? If not, what then is the basis for the rates included in the Alternative Regulation Plan?
b. If AmerenUE's Alternative Regulation Plan is approved by the Missouri Commission, what are AmerenUE"s expected (forecasted) earnings each year of the Alternative Regulation Plan? Please provide backup, including assumptions that are critical to this forecast of earnings (e.g., new investments in production, transmission and distribution and market prices for electricity).
c. In addition to expected earnings for each year of the Alternative Regulation Plan, what is the probability distribution of earnings estimated by AmerenUE for each year of the Alternative Regulation Plan?

Response:

The rates included in AmerenUE's Alternative Regulation Plan are not based on a specific cost of service study. Rather, the rates proposed are consistent with UE's view that its Alternative Regulation Plan Proposal, when viewed in its entirety, balances the interest of all stakeholders in the case. Further, AmerenUE considered its expected future energy infrastructure needs, regulatory plans implemented in other states and other factors when developing its proposals under the Alternative Regulation Plan. The terms "expected earnings" and "probability distribution" of earnings are statistical terms related to the range and averages of possibly future outcomes. The Company has neither developed a comprehensive forecast of AmerenUE's "expected" earnings nor calculated a "probability distribution" for the sole purpose of estimating earnings for each year of the proposed Alternative Regulation Plan.

Signed By: Warner L. Baxter

Prepared By: Warner L. Baxter
Title: Senior Vice President, Finance