MAY 20 2002

Exhibit No.:	
Issues:	Revenue Requirement Capacity Planning Alt Reg Plan Rate Design
Witness:	Mark Drazen
Sponsoring Party:	Missouri Energy Group
Type of Exhibit:	Rebuttal Testimony
Case No.:	EC-2002-1
Date Testimony Prepared:	May 16, 2002

AmerenUE

Case No. EC-2002-1

Before the Missouri Public Service Commission

Rebuttal Testimony of Mark Drazen

on Behalf of the Missouri Energy Group

****DENOTES NON-PROPRIETARY INFORMATION****

Exhibit No. 110 NP
Date 7/10/02 Case No. EC-2002-1
Reporter Ken

Project 011253
May, 2002

DRAZEN
CONSULTING GROUP

NP

AmerenUE

Case No. EC-2002-1

Affidavit of Mark Drazen

STATE OF MISSOURI)
)
COUNTY OF ST. LOUIS)

Mark Drazen, being of lawful age and duly affirmed, states the following:

1. My name is Mark Drazen. I am a consultant in the field of public utility economics and regulation and a member of Drazen Consulting Group, Inc.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony consisting of Pages 1 through 27, Appendix A and Schedules 1 through 6 filed on behalf of the Missouri Energy Group.

3. I have reviewed the attached direct testimony and schedules and hereby affirm that my testimony is true and correct to the best of my knowledge and belief.

Mark Drazen

Mark Drazen

Duly affirmed before me this 16th day of May, 2002.

Sheryl M. Fenelon

Notary Public

My commission expires on December 29, 2002.

NOTARY SEAL STATE OF MISSOURI

SHERYL M. FENELON
St. Louis County
My Commission Expires
December 29, 2002

AmerenUE

Missouri Public Service Commission
Case No. EC-2002-1

<u>**Rebuttal Testimony of the Missouri Energy Group**</u>

Section I—Introduction and Overview

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Mark Drazen, 7730 Forsyth Boulevard, St. Louis, Missouri.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility economics and regulation and a member of Drazen Consulting Group, Inc.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have worked in this field since 1972 in rate cases, project planning and negotiations throughout the United States and Canada. Our firm has been in this field since 1937. I have degrees in mathematics and engineering from the Massachusetts Institute of Technology. Details are given in Appendix A.

Q ON WHOSE BEHALF ARE YOU SUBMITTING THIS EVIDENCE?

A I am presenting it on behalf of the Missouri Energy Group (MEG), which comprises manufacturers and hospitals who are customers of AmerenUE.

Q WHAT TOPICS ARE COVERED IN THIS TESTIMONY?

A The topics are:

- Test year revenue requirement and cost trends of AmerenUE;
- Planning and rate issues that will affect AmerenUE's costs going forward;
- AmerenUE's proposed Alternative Regulation Plan; and
- Rate design.

Q PLEASE SUMMARIZE THE MAIN POINTS IN THIS TESTIMONY.

A **Revenue Requirement**—The refunds under the EARP (Experimental Alternative Regulation Plan) and the rate reduction recommended by the Commission Staff reflect AmerenUE's ability to control costs as its sales have increased over the last several years. An analysis of the underlying reasons suggests that this pattern will likely continue into the future. In particular, AmerenUE's cost of supply from its existing generation plants has been decreasing and should continue doing so in the future. AmerenUE says that the issues in this proceeding should be viewed in a broader context, including industry developments. I offer some comments on this topic.

Planning—The trend of future generation costs will be affected by decisions made at this time. Over the next several years, additional capacity will be needed to meet growing demand in the AmerenUE Missouri service area. The need for and cost of additional supply can be reduced by AmerenUE decisions in several areas, including service options that AmerenUE can create or enhance at this time. These include rates to encourage additional interruptible and price-responsive load, customer-owned distributed generation and "dedicated" generation supply procured by customers. The best time to consider these is now, *before* AmerenUE embarks on a capacity acquisition program.

Alternative Regulation Plan—AmerenUE has recommended a new "Alt Reg Plan" for the three-year period starting in July, 2002. We agree with AmerenUE on the principle of a new Alt Reg Plan. We suggest that the Commission consider a different (lower) starting point and a different sharing arrangement.

Rate Design—The Staff has recommended a distribution of the rate increase based on the results of the 1996 class cost of service study presented in EO-96-15. The recommendation is that (1) the first $9.8 million of the decrease be allocated only to non-residential, non-lighting customers, and (2) the balance be allocated by an equal percentage to all classes. AmerenUE's class cost of service analysis (based on its calculation of total cost) shows that non-residential rates are above cost and residential below, and therefore supports a different spread of any decrease.

Section II—Analysis of Cost Trends

Q WHAT IS THE PURPOSE OF ANALYZING COST TRENDS?

A One reason is to evaluate the reasonableness of test year data. The purpose of using "test year" data, including adjustments for known changes and normalization, is to set rates that are expected to recover (prudent) costs that will be incurred while the rates are in effect. AmerenUE's costs and revenues have changed quite a bit over the last five years and will continue to change. Analyzing how and why costs have changed in the last several years will help us understand how they may change in the next few years, and for how long the rates set in this case will be reasonable.

Second, AmerenUE has proposed a new Alternative Regulation Plan, which would share future cost savings between ratepayers and shareholders. To evaluate the reasonableness of this, we should have information about expected costs.

Finally, the electric utility industry is moving toward a more market-based environment and it is useful to know how AmerenUE will be positioned in that environment. In 2000, AmerenUE supported legislation that would have facilitated the transfer of its regulated plants to an unregulated subsidiary. The MEG and others were concerned about the potential for lost "residual" value (the opposite of "stranded" cost) if the plants are transferred. This proceeding illustrates the importance to customers of the current regulatory arrangement and provides an opportunity to understand the tradeoffs that may occur under restructuring.

Analysis of Costs: 1996 to 2001

Q HOW HAVE COSTS CHANGED SINCE 1996?

A Table 1 shows the total cost of service as calculated by the Staff and by AmerenUE for the test year (June, 2001 updated through September for Staff) and for the test year ended September, 1996 (as used in EO-96-15).

Table 1

Missouri Jurisdictional Cost of Service

		2001-Staff		AmerenUE
	1996	w/out I/S	with I/S	2001
Net plant-Prod	$2,606.3	$2,814.7	$2,814.7	$2,630.1
Net plant-Trans	221.9	255.8	255.8	262.9
Net plant-Dist	1,357.5	1,525.9	1,525.9	1,524.9
Net plant-Gen'l	303.3	274.4	274.4	277.0
Other	(665.2)	(754.2)	(749.3)	(699.9)
Total rate base	$3,823.8	$4,116.7	$4,121.6	$3,995.0
Rate of return	x 10.125%	x 8.600%	x 8.600%	x 10.137%
Return	$387.2	$354.0	354.4	405.0
Income taxes	204.7	134.4	134.6	230.9
Deferred ITC		(14.6)	(14.6)	(14.3)
O&M-Prod	533.5	609.7	759.1	620.8
O&M-Trans	9.6	15.6	15.6	19.1
O&M-Dist	75.7	100.5	100.5	106.0
O&M-Cust	51.8	54.6	54.6	56.0
O&M-Gen	154.4	222.6	222.6	245.5
Total O&M	825.0	1,003.1	1,152.4	1,047.4
Operating taxes	98.1	99.1	99.1	96.2
Depreciation	209.7	180.7	180.7	280.0
Subtotal cost	$1,724.6	$1,756.7	$1,906.7	$2,045.1
Less sys. rev.	(17.6)	(69.3)	(308.9)	(44.9)
Net cost	$1,707.0	$1,687.4	$1,597.8	$2,000.2

Q HOW HAVE UNIT COSTS CHANGED?

A Table 2 shows the change in unit costs.

Table 2

AmerenUE Unit Costs

	1996	2001	% Change
Production			
Net investment/kW	$378	** **	** **
Fuel cost/kWh	1.02¢	** **	** **
Transmission			
Net investment/kW	$34	** **	** **
O&M expense/kWh	0.27¢	** **	** **
Distribution			
Net investment/customer	$1,286	** **	** **
O&M expense/customer	$72	** **	** **
Customer service			
O&M expense/customer	$8.2	** **	** **

Source: AmerenUE 1996 and 2001 Form 1.

Details of the calculation are on Schedule 1. Although the total dollar amount of most costs is higher, the various measures of usage—peak demand, energy sales and number of customers—are, too, as shown in Table 3.

Table 3

AmerenUE Usage

	1996	2001	Increase
System			
Peak demand (MW)	7,621	** **	** **
Energy sales (MWh)	43,730,831	** **	** **
Customers	1,133,556	** **	** **
Missouri Jurisdictional			
Peak demand (MW)	6,548	** **	** **
Energy sales (MWh)	27,953,067	** **	** **
Customers	1,055,269	** **	** **

Source: AmerenUE Form 1 reports; AmerenUE cost study in EO-96-15; Staff filing in this proceeding.

Notes: System data on a calendar year basis; Missouri data on a test-year basis.

Q WHY HAVE GENERATION UNIT COSTS DECREASED?

A This results from efficiencies in operation, reduced fuel costs and depreciating book value of existing plant. Base load coal unit output has increased:

Table 4

AmerenUE Base Load Generation

	1996 GWh	1999 GWh	2001 GWh
Labadie	12,248	13,425	** **
Sioux	3,874	4,690	** **
Rush Island	6,830	7,552	** **
Meramec	1,584	3,092	** **
Subtotal	24,536	28,759	** **
Callaway	8,890	8,587	** **
Total	33,427	37,346	** **

Schedule 2 contains details of generation amounts and cost for 1996-2001.

Next, AmerenUE has been successful in reducing coal costs:

Table 5

Ameren Coal Costs
Price Per Ton

Year	Labadie	Sioux	Rush Island	Meramec	Four Plants
1995	$23.09	$22.09	$20.17	$32.87	$22.59
1996	20.57	23.10	17.12	33.43	20.59
1997	17.64	21.92	16.72	28.69	18.91
1998	16.77	19.85	16.08	27.01	17.88
1999	16.84	21.16	15.17	24.92	17.88
2000	16.53	19.83	14.80	22.39	17.09
**					**

Source: AmerenUE Form 1 reports.

Q HAVE YOU ANY COMMENTS ON AMERENUE'S REBUTTAL TESTIMONY?

A AmerenUE criticized the Staff for "its failure to consider economic and regulatory conditions in the electric industry generally and in the Midwest" (Testimony of Dr. Fox-Penner, Page 3). I agree that looking at the test year in isolation of industry trends and cost trends may not give the best picture of what is reasonable.

From our preliminary review, it appears that AmerenUE's testimony suffers from this focus on the "here and now" to some extent. For example, several AmerenUE witnesses discuss in general terms the benefits of the proposed "Alt Reg Plan," under which AmerenUE will have incentives to achieve more savings, which will then be shared with customers. There is little information, though, about what AmerenUE's costs are likely to be in the next few years. The testimony refers to increased investment, but says little about expected cost reductions. AmerenUE takes exception to the Staff's proposed reduction in depreciation rates. For generating plants, the industry has seen a trend toward longer economic lives and increased potential for upgrades, expansions and repowering. There is also the potential for higher profits from wholesale sales.

Finally, an issue of particular contentiousness is the treatment of the purchased power cost for the summer of 2001. This is an example of the cost that, by AmerenUE's own testimony, is not representative of current conditions.

Q PLEASE EXPLAIN THE SUMMER, 2001 COST OF PURCHASED POWER.

A Until early 2001, AmerenUE had planned to transfer its "Metro East" Illinois load to Ameren Energy. This would have made available enough capacity from existing plant to meet AmerenUE needs in Summer, 2001. In early 2001, Ameren cancelled the proposed transfer. This forced AmerenUE to purchase power to meet its summer demand.

AmerenUE satisfied much of this need by purchasing 450 MW of "must take" energy for the months of July and August. The cost of the energy was ** **. AmerenUE was required to buy ** **, for a total cost of ** ** (Response to Staff Request No. 85). AmerenUE takes the position that it should be allowed to recover this cost because it was prudently incurred, as demonstrated by the involvement of Staff and the Office of Public Counsel (OPC) in the procurement process and testing the cost against other market offers. But even if the cost is deemed to be prudent, it is certainly not representative of current or future conditions. For Summer, 2002, Ameren arranged purchases that do not require "must take" energy and are priced much lower.

Analysis of Cost Trends After 2001

Q WHAT IS THE EXPECTED TREND OF COSTS IN THE FUTURE?

A For generation, the cost of supply from existing resources will decline, as greater output is obtained and as plant is further depreciated. Although AmerenUE will need additional capacity for peak times, the existing base load units provide most of the energy needed to meet load. AmerenUE's Power Operations Division *Strategic Plan Development* (February 5, 2002), provided in response to OPC Request No.668, states that AmerenUE plans to reduce fuel and other production costs and to increase availability and, therefore, output. The goals include reducing average production cost by over ** **, increasing Equivalent Availability to ** ** from the 2001 average of about ** ** and increasing annual output by about ** **.

The performance of the coal plants, as measured by standard measures such as Capacity Factor (ratio of average output to capacity) and Equivalent Availability Factor (percent of capacity available) show that AmerenUE is realistic in expecting continued improvement:

**

**

New supply will be more expensive than existing supply. However, as discussed below, the cost of new supplies can be affected by AmerenUE's decisions on service offerings.

Transmission investment will increase. AmerenUE says it will need additional transmission capacity. According to AmerenUE, the next big step would be an investment of ** ** to increase import capacity by ** **. This increase in transmission capacity could also provide opportunities for AmerenUE to import energy at a lower cost than its peaking resources and/or to increase exports of its own low-cost base load energy. Thus, the cost of the transmission facilities might be offset to some extent by lowering the net generation cost.

Distribution will increase with customer growth, but at a rate similar to the past. AmerenUE has forecast that it will invest about ** ** in new distribution facilities over the period 2002-2006. Since 1996, annual net additions of distribution plant have averaged $125 million.

Section III—Generation Planning

Q WHY IS GENERATION PLANNING A RELEVANT ISSUE?

A AmerenUE's rebuttal testimony repeatedly emphasizes the need for sufficient cash flow and financial strength to finance new generation. According to Mr. Randolph, AmerenUE plans to invest ** ** in generation capacity over the period 2002-2006. Therefore, it is relevant to explore possibilities for reducing the cost of meeting capacity needs.

Q WHAT PLANNING ISSUES WILL AFFECT THE COST OF GENERATION?

A The critical questions are the amount of new capacity that will be needed and the sources of that capacity.

Q WHY IS ADDITIONAL CAPACITY NEEDED?

A AmerenUE will not have sufficient capacity to meet its anticipated peak load plus planning reserve margin.

This is primarily a need for peaking capacity. Schedule 2 shows the output of AmerenUE's generating units for the period 1996-2001. Note that the (low-cost) energy output from the coal and nuclear plants meets virtually all of AmerenUE's needs. In 2001, energy output from the nuclear and coal plants in 2001 was about ** **; AmerenUE's retail and "requirements" sales, plus associated losses, were about ** **. The peaking plants are rarely run.

Q WHAT IS THE BASIS FOR AMERENUE'S CAPACITY PLANNING?

A Ameren's planning is based on a reserve margin of ** **, as discussed in the testimony of Mr. Voytas. Mr. Nelson's testimony includes an AmerenUE load and capacity forecast and is reproduced in Schedule 3 of this testimony. According to this, by 2006 AmerenUE will require ** ** of additional capacity by 2006.

Q WHAT ACTIONS COULD REDUCE THE NEED FOR ADDITIONAL CAPACITY?

A Factors that can affect the need for new capacity include: (1) the planning reserve margin; (2) increases in interruptible load; and (3) transfer of the Illinois Metro load to AmerenCIPS.

Q PLEASE EXPLAIN THE ISSUE REGARDING THE PLANNING RESERVE MARGIN.

A It is not clear why AmerenUE is using an ** ** margin target. In 2001, Ameren commissioned a reserve margin study from a consultant (see the response to OPC Request No. 653), who recommended an optimal reserve margin of ** **. Some earlier projections by AmerenUE used a ** ** reserve margin (see Schedule 4, from response to OPC Request Nos. 508-509). A 1% reduction in the planning reserve margin reduces capacity requirements by approximately ** **.

Q HOW DOES INTERRUPTIBLE AND PRICE-RESPONSIVE LOAD AFFECT THE NEED FOR NEW CAPACITY?

A For this, it is useful to look at a more detailed version of the load/capacity projection. One such version is reproduced in Schedule 5. This shows the interruptible loads as a deduction from the peak demand. AmerenUE's load/capacity forecast does not appear to anticipate any increase in the amount of price-responsive or interruptible load. Nor does it include any provision for other sources of capacity, such as (customer-owned) distributed generation and customer-procured independent supply.

Ms. Hu, of the Office of Public Counsel (OPC), recommends the implementation of a residential time-of-use rate as a way to reduce peak demands. Our recommendations are made in the same vein.

Q PLEASE EXPLAIN THE "METRO EAST" EFFECT.

A AmerenUE had planned to transfer its "Metro East" (Illinois) customers to AmerenCIPS. The generation supply for that load would come from Ameren Energy. This would have had the effect of freeing up AmerenUE capacity to serve additional Missouri load. The Illinois load is about 600 MW. With the planning reserve margin, this is equivalent to about 700 MW of additional capacity. In March, 2001, AmerenUE decided against the transfer. The explanation, provided in response to OPC Request No. 520, was given in a memorandum from Mr. Rainwater to Mr. Mueller that said (in its entirety):

> *This is to notify you that CIPS is no longer prepared to accept the transfer of UE's Illinois service area to CIPS, as I had proposed in April 2000. Power markets have moved significantly against the economics of the transfer in the last year, to the point that the transfer would now result in unacceptable financial losses to AmerenCIPS.*

Mr. Voytas states that transferring this load from AmerenUE to AmerenCIPS was the "preferred option to meet its capacity needs through 2004" (Testimony, Page 24) and apparently remains such (Testimony, Page 49).

Interruptible and Price-Responsive Load

Q PLEASE EXPLAIN THE USE OF INTERRUPTIBLE AND PRICE-RESPONSIVE LOAD.

A Interruptible service requires the customer to reduce its load upon request by the utility. It is a standard way of reducing peak load and, therefore, reducing capacity requirements. Usually, the rate provides a capacity credit to the customer in exchange for the right to interrupt the customer's load. Price-responsive service offers customers a credit for reducing load at a time when market prices are very high.

Q HAS AMERENUE OFFERED THESE TYPES OF SERVICE?

A Yes. AmerenUE had a typical interruptible service offering in its Missouri service territory under a closed rate schedule, Rate 10 (M). It had 40 MW of load served on the rate. AmerenUE chose not to continue the rate when it expired in 2000.

AmerenUE currently has two forms of price-responsive service, Rider L and Rider M. As shown on Schedule 5, AmerenUE anticipates the continuation of about ** ** of interruptible load. Riders L and M are called "voluntary curtailment" riders. The customer is not required to interrupt load, but has an incentive to do so if wholesale market prices are very high.

Q WHY DID AMERENUE TERMINATE ITS INTERRUPTIBLE SERVICE RATE?

A The utility argued that cheaper sources of capacity were available. The cost was $60/kW/year, in exchange for which AmerenUE had the right to curtail the customer during peak times and system emergency times.

Q ARE THE VOLUNTARY CURTAILMENT RIDERS APPROPRIATE SUBSTITUTES FOR THE INTERRUPTIBLE RATE?

A Not entirely. These price-responsive rates serve a somewhat different function than the traditional interruptible rate.

In a single control area, with a competitive market, we would expect market prices to be highest when demand is highest. If this correlation exists, the two rates may serve a similar function because the expectation is that price-responsive loads will self-curtail when the load is highest. However, this correlation does not necessarily hold for AmerenUE. It is possible for AmerenUE to hit a new peak at times when market prices are not particularly high, and it is possible for market prices to be very high at a time other than Ameren's peak. Thus, neither type of rate alone is sufficient. As long as AmerenUE continues to use a planning reserve margin based on its peak load, traditional interruptible service serves a useful purpose.

Q WHAT WOULD BE REQUIRED IN ORDER TO MAKE INTERRUPTIBLE SERVICE COST-EFFECTIVE FOR THE UTILITY AND ATTRACTIVE TO CUSTOMERS?

A The credit to the customer would have to be large enough to compensate the customer for the inconvenience (e.g., lost production) during periods of interruption.

The cost to the utility would have to be economic relative to other sources of capacity that the utility could install or acquire.

Q **WHAT CAPACITY COST IS OFFSET BY INTERRUPTIBLE LOAD?**

A AmerenUE's interruptible load is a substitute for peaking capacity. One measure is the rate that AmerenUE has paid for peaking capacity. Another is the cost of installed peaking capacity.

If the utility uses an ** ** reserve margin, each kW of interruptible load reduces capacity requirements by ** **.

The Staff has estimated that the capacity cost of new CTs is $490/kW and the non-fuel operating cost is ** **. If the capital recovery factor (a levelized rate to cover return, income taxes and depreciation) is 10%, the annual cost of this capacity is about ** **, calculated thus:

**

**

This is higher than the $60/kW credit in the rate that AmerenUE terminated. Using AmerenUE's estimate that the annual O&M cost is ** **, the effective annual offset is ** **.

Most interruptible rates specify the terms for interruption and/or a limit on the amount of interruptions allowed. In practice, this should not be a problem, inasmuch as most peaking capacity is run for 1% of the time or less (see Schedule 2). AmerenUE's load duration curve shows that the top 50 hours account for ** ** of demand. See Schedule 6.

Distributed Generation

Q WHAT IS "DISTRIBUTED GENERATION?"

A Distributed generation (DG) refers to generation units that are located at customer load sites. Such on-site generation is particularly cost-effective in cogeneration applications, where a single fuel can be used to produce electricity and another useful form of energy (usually steam).

Q WHAT ARE THE BENEFITS OF DISTRIBUTED GENERATION TO THE UTILITY?

A There are several potential benefits of DG to the utility. *First*, the utility need not raise capital to invest in the generation. *Second*, because the generation is located closer to load, losses are reduced. *Third*, for a similar reason, transmission requirements are reduced. This may be particularly applicable to AmerenUE, because transmission constraints limit the ability to bring additional power from outside the AmerenUE load area.

Q WHAT ARE THE BENEFITS OF DISTRIBUTED GENERATION TO CUSTOMERS?

A In cogeneration applications, where the customer has the need for steam as well as electricity, the combined cost of steam and electricity from on-site generation can be lower than the cost of separate services. Even when the cost of generation from an on-site unit is higher than the utility's generation cost, other savings can make the total package attractive. For example, the customer may need less transmission and distribution service. In some cases, on-site generation can provide higher reliability, which is a consideration for sites that have large data processing operations (e.g., brokerage houses).

Q **WHAT IS NECESSARY IN ORDER TO MAKE DISTRIBUTED GENERATION COST-EFFECTIVE FOR CUSTOMERS?**

A The utility must offer interconnection and backup/supplemental rates on reasonable terms. Further, the utility should be willing to purchase excess generation on reasonable terms.

Q **DOES AMERENUE HAVE SUCH RATES?**

A Yes, but new versions of these rates are needed. AmerenUE has proposed changes to Rider E, to recognize the character of backup service. These are described in the testimony of Mr. Kovach.

Q **DO YOU AGREE WITH THE PROPOSED REDESIGN OF RIDER E FOR SUPPLEMENTAL AND BACKUP SERVICE TO CUSTOMER-OWNED GENERATION?**

A The structure of the rate is appropriate, but some of the charges are too high.

Q WHAT STRUCTURE HAS AMERENUE PROPOSED?

A Rider E has unbundled charges for generation, wires, energy and reactive demand. The charges are:

Table 9

Proposed Rider E Charges

	Summer	Winter
Customer	$445/mo	$445/mo
Production Demand	$10.09/kW	$5.05/kW
Generator Backup Demand	$1.82/kW	$0.91/kW
Wires	$4.43/kW	$2.21/kW
Energy	2.70¢/kWh	2.35¢/kWh
Reactive Power	$0.24/kVAr	$0.24/kVAr

The Generation Backup Demand is a monthly charge that applies to the nameplate rating of the customer's self-generation equipment. When a customer experiences an outage, the Production Demand charge is charged on a daily basis for the maximum demand that would normally be served by the customer-owned generation. The Wires charge is applied to the maximum demand supplied by the combination of AmerenUE power and customer-owned generation. The Energy charges include an adder of 0.5¢/kWh, which Mr. Kovach says is to account for the higher incremental cost of energy to supply these loads.

Q ARE THESE CHARGES APPROPRIATE FOR BACKUP SERVICE?

A As described, the rates are unnecessarily high.

The Generator Backup Demand charge is calculated at 18% of the "production demand cost that is embedded in the Large Primary Service Rate" (Kovach Testimony, Page 106). However, the demand cost that is embedded in that rate already includes the cost of reserve capacity—that is, for each kW of load demand, the cost is based on ** ** of capacity. The appropriate charge for the Generator Backup Demand should be calculated using a ratio of ** ** of the LPS demand cost charge. This gives monthly charges of $1.54/kW (summer) and $0.77/kW (winter).

Second, from the language in the Rider, it appears that the Generator Backup Demand charge applies to the full nameplate capacity of all installed capacity. Some customers may wish to install multiple units to provide some self-backup. It is not necessary to charge the Generator Backup Demand charge on the full nameplate capacity of all the units, only on the amount of capacity that is expected to be serving site load.

Third, the Production Demand charge is applied essentially on a daily basis during actual customer outages. However, the cost of providing normal backup service is already covered in the Generator Backup Demand charge. That is, this monthly charge covers the cost of backup capacity that is expected to be used for a normal level of outages. An additional charge during actual outages is appropriate only to the extent that the customer-owned capacity experiences outages at a rate greater than the outage rate for utility-owned capacity. (This also means that if the customer-owned capacity is more reliable, it should pay a lower rate.) The Equivalent Forced Outage Rates of AmerenUE's major coal plants are:

**

**

Q **YOU ALSO SAID THAT UTILITIES SHOULD BE WILLING TO PURCHASE EXCESS GENERATION ON REASONABLE TERMS. PLEASE EXPLAIN.**

A At present, AmerenUE will purchase power only from very small generators (100 kW or less) at rates that average less than 1.5¢/kWh. The rates are stated in AmerenUE's tariffs, Schedule No. 1, Sheet No. 1(M). The maximum purchase rate, for weekday on-peak deliveries is 1.74¢ in the summer and 1.51¢ in the winter. Just as AmerenUE has rates that effectively "purchase" power from Rider L and M customers based on spot market prices, it should be willing to purchase power from DG owners at spot market prices.

Customer-Procured Dedicated Supply

Q WHAT DO YOU MEAN BY "DEDICATED" SUPPLY?

A This is a program under which a customer arranges supply from an outside party (e.g., another utility or an independent generator), assigns that contract to the host utility (AmerenUE) and then receives power under a rate that recovers the cost of that dedicated generation supply, plus the costs of transmission and distribution necessary to provide delivery.

Q IS THIS SERVICE FEASIBLE WITH THE CURRENT INDUSTRY STRUCTURE?

A Yes. In fact, it is a service that AmerenUE proposed in late 1999 to offer to customers at the time that Senate Bill 455 was being considered.

Q HOW WOULD DEDICATED SUPPLY ARRANGEMENTS BENEFIT AMERENUE?

A If a customer can arrange for additional supply and commits to paying the cost, that relieves AmerenUE from having to do so.

Q WHAT CHANGES WOULD BE NECESSARY IN ORDER TO MAKE THIS TYPE OF SERVICE FEASIBLE?

A AmerenUE would have to develop rates that unbundle delivery cost from the generation component. This has already been done by AmerenUE to develop the new Rider E. Further, terms and conditions would have to be developed to ensure accountability of the customer and the supplier.

Section IV—Alternative Regulation Plan

AmerenUE Proposal

Q WHAT IS AMERNEUE'S PROPOSED "ALT REG PLAN?"

A The main features, as described in Mr. Baxter's testimony, are:

- Three-year duration (July, 2002 to June, 2005);
- Immediate rate reduction of $15 million, effective April, 2002;
- One time rate credit of $15 million;
- 10.5% return on equity (RoE) threshold;
- Credit of $15 million if AmerenUE RoE reaches 10.5%;
- Refunds to customers if AmerenUE earns above 12.5% RoE:
  - 55% of income above 12.5% RoE
  - 90% of income above 15.0% RoE
  - 100% of income above 16.0% RoE
- Donations and credits to low income assistance programs.

Q WHAT ARE YOUR COMMENTS ON THE PROPOSAL?

A Two areas that bear further investigation are the starting point and the sharing mechanism.

Q WHAT SHOULD BE THE STARTING POINT?

A An incentive plan, like the proposed Alt Reg Plan, makes sense if it motivates the Company to "stretch" beyond the otherwise-expected results. In other words, the starting point for the utility should be the level of costs which would normally be expected under good management.

As discussed above, AmerenUE's testimony and exhibits provide little information about the expected level of costs in the next few years. As that information is developed, it will become easier to determine a reasonable starting point.

Q HOW MIGHT THE SHARING MECHANISM BE CHANGED?

A The proposed Alt Reg Plan, like the former EARP, has a "progressive to the customer" sharing arrangement. This means that the customers get progressively larger shares of the savings, culminating in a 100% share of any earnings over a 16.0% return on equity.

A "progressive to the utility" approach should be considered instead. The reason for this is that the easy savings come first and that there should be greater incentives for the Company to push harder and harder. This approach does not put a cap on the return on equity that the utility can earn, because it will keep the larger share of any extraordinary accomplishments.

Q WHAT MIGHT THIS SHARING ARRANGEMENT LOOK LIKE?

A A possible sharing matrix is:

Table 11

Sharing Matrix

	AmerenUE Plan		Alternative	
	Customers	Utility	Customers	Utility
12.5%-15.0%	55%	45%	80%	20%
15.0%-16.0%	90%	10%	50%	50%
>16.0%	100%	0%	30%	70%

Section V—Rate Design

Interclass Allocation—Staff Recommendation

Q WHAT HAS THE STAFF RECOMMENDED REGARDING THE ALLOCATION OF THE DECREASE AMONG CUSTOMER CLASSES?

A Their recommendation, presented by Mr. Watkins, is that the first $9.83 million of the decrease be distributed to the non-residential and non-lighting rate classes and the balance be allocated by an equal percentage of current revenues, based on the Stipulation and Agreement in rate design Case No. EO-96-15. In that case, the recommendation to rebalance rates of return on classes could not be fully realized.

Interclass Allocation—Analysis

Q DO YOU AGREE WITH THE STAFF'S PROPOSAL?

A No. Given the changes in costs over the last five years, it would be preferable to base the rebalancing on an updated cost of service study. AmerenUE has prepared such a study, which shows that commercial and industrial rates are well above cost and residential below. This result is consistent with the observations that unit generation costs have decreased over the last few years. Because generation is the largest component of the large industrial rate, the result would be that the industrial rates are further above cost than they were at the conclusion of Case No. EO-96-15.

Conclusion

Q DOES THAT CONCLUDE YOUR TESTIMONY?

A Yes.

Experience of Mark Drazen

Mr. Drazen has worked since 1972 on economic analysis of energy and utility service, pricing in regulated and deregulated utility markets, contract negotiations, and strategic planning throughout the United States and Canada. His experience covers electric, natural gas, oil pipeline, telecommunications, transportation, waste and water utilities in 40 states in the U.S. (Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Louisiana, Maine, Massachusetts, Michigan, Minnesota, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin and Wyoming) and in seven Canadian Provinces (Alberta, British Columbia, Newfoundland and Labrador, Nova Scotia, Ontario, Québec and Saskatchewan).

He has appeared as an expert witness before courts, federal, state, and provincial regulatory agencies (including the Federal Energy Regulatory Commission, the National Energy Board, the Federal Communications Commission and the Canadian Radio and Telecommunications Commission) in most of the above jurisdictions.

Drazen Consulting Group offers economic, strategic planning and regulatory consulting services to clients that include industrial utility users, municipalities, schools, hospitals, utilities and government agencies. The founding firm (Michael Drazen and Associates) was established in 1937.

The firm's work covers all aspects of utility regulation (and deregulation), including revenue requirements, cost of capital, cost analysis, pricing, valuation, performance-based regulation and industry restructuring.

Mr. Drazen is a graduate of the Massachusetts Institute of Technology, with the degrees of Bachelor of Science in Mathematics, Master of Science in Electrical Engineering, and Electrical Engineer.

AmerenUE Costs and Units

	1996	2001
Production		
Gross Plant (inc. Additions and Retirement)	$4,576.2	***
Accumulated Depreciation	1,654.76	***
Net Investment	2,921.43	***
Net Demand on Plant - kW	7,720,900	***
Net Investment $/kW	$378.4	***
Fuel Cost	$342.3	***
Plant Generation - kWh	33,457,297,300	***
Cost ¢/kWh	1.02	***
Transmission		
Gross Plant (inc. Additions and Retirement)	$423.8	***
Accumulated Depreciation	165.64	***
Net Investment	258.18	***
System Peak - kW	7,621,000	***
Net Investment $/kW	$33.9	***
O&M Expense	$11.9	***
Total Sales-MWh	43,730,831	***
O&M Expense ¢/kWh	0.27	***
Distribution		
Gross Plant (inc. Additions and Retirement)	$2,507.6	***
Accumulated Depreciation	1,049.70	***
Net Investment	1,457.86	***
Total # of Customers	1,133,556	***
Net Investment per Customer	$1,286.1	***
O&M Expense	$81.6	***
Total # of Customers	1,133,556	***
O&M Expense $/customer	$72.0	***
Customer Service		
Customer Service Expense	$9.3	***
Total # of Customers	1,133,556	***
Expense per Customer	$8.25	***

Source:
Plant information from 1996 and 2001FERC Form 1 page 204.
O & M expense from 1996 and 2001 FERC Form 1 page 320.
*** Denotes proprietary information.

NON-PROPRIETARY

	1996				2001			
Plant	Net Demand On Plant	Production	Fuel Cost	System Peak	Net Demand On Plant	Production	Fuel Cost	System Peak
Callaway	1230	8,241,833,000	41,913,529		***	***	***	
Rush Island	1340	6,105,649,000	67,030,280		***	***	***	
Labadie	2261	12,924,992,000	160,600,801		***	***	***	
Sioux	940	3,350,084,000	43,174,212		***	***	***	
Meramec	848	1,366,989,000	25,440,941		***	***	***	
Venice	288	46,490,300	2,378,036		***	***	***	
Meramec CT	56	4,168,000	241,317		***	***	***	
Moreau CT	66	6,918,700	298,166		***	***	***	
Kirksville CT	15	860,100	77,946		***	***	***	
Fairgrounds CT	68.3	3,315,400	207,148		***	***	***	
Viaduct CT	30.6	1,823,600	73,825		***	***	***	
Moberly CT	70	5,275,700	336,662		***	***	***	
Mexico CT	65	4,816,300	302,804		***	***	***	
Venice CT	29	245,700	63,875		***	***	***	
Howard Bend	52	2,531,800	153,950		***	***	***	
Osage	227	482,055,500	-		***	***	***	
Keokuk	135	909,249,200	-		***	***	***	
Total	7720.9	33,457,297,300	342,293,492	7,621	0	-	-	***

Source:
Data from 1996 and 2001 FERC Form 1, pages 402 -403 and 406.
Net Demand - line 6
Production - line 12
Fuel Cost - line 19
System Peak Demand page 401b, line 35

Number of Customers

Rate Schedule	1996	2001
Residential	994,252	***
Commercial	131,564	***
Insutrial	6,145	***
Public Street/Municipal	1,594	***
Other Public Authorities	1	***
Total	1,133,556	***
Total Sales MWh	43,730,831	***

Source: FERC Form 1, page 304, lines 5, 14, 22,29 and 35, page 401a, line 20.
*** Denotes proprietary information.

NON-PROPRIETARY

AmerenUE

Generation Supply 1996

Name	Fuel	Capability (MW)	Energy Output (MWh)	Energy Output (%)	Fuel Cost (¢/kWh)	% of Time Run
Labadie *	Coal	2,389	12,261,398		1.17¢	
Sioux	Coal	1,099	3,874,490		1.28	
Rush Island	Coal	1,242	6,829,880		1.06	
Meramec	Coal	923	1,584,391		1.70	
Venice	Coal	474	40,576		8.40	1.0%
		6,127	24,590,735	70.5%	1.21	
Callaway	Nuclear	1,236	8,890,377	25.5%	0.50	
Venice	GT	38	1,629		12.11	0.5%
Kirksville	GT	15	811		7.45	0.6%
Fairground	GT	68	1,557		8.98	0.3%
Viaduct	GT	31	2,594		6.03	1.0%
Moberly	GT	61	2,735		8.75	0.5%
Mexico	GT	61	3,587		6.31	0.7%
Howard Bend	GT	47	2,775		7.16	0.7%
Meramec	GT	68	1,988		6.48	0.3%
Moreau	GT	61	2,563		8.63¢	0.5%
Subtotal		450	20,239	0.1%		
Osage	Hydro Stg.	208	482,056			
Keokuk	Hydro RoR	125	909,249			
Subtotal		333	1,391,305	4.0%		
Subtotal		8,146	34,892,656	100.0%		
Taum Sauk	Pump Stg.	468	(75,385)			

Source: FERC Form 1

* Note: Labadie energy output from form EIA-906

NON-PROPRIETARY

AmerenUE

Generation Supply 1997

Name	Fuel	Capability (MW)	Energy Output (MWh)	Energy Output (%)	Fuel Cost (¢/kWh)	% of Time Run
Labadie	Coal	2,389	12,908,866		1.05¢	
Sioux	Coal	1,099	4,564,137		1.23	
Rush Island	Coal	1,242	6,527,403		1.03	
Meramec	Coal	923	2,146,300		1.59	
Venice	Coal	474	90,427		6.00	2.2%
		6,127	26,237,133	71.8%	1.14	
Callaway	Nuclear	1,236	8,954,604	24.5%	0.50	
Venice	GT	38	466		24.85	0.1%
Kirksville	GT	15	351		6.67	0.3%
Fairground	GT	68	2,488		10.41	0.4%
Viaduct	GT	31	303		22.03	0.1%
Moberly	GT	61	3,337		9.10	0.6%
Mexico	GT	61	3,147		9.44	0.6%
Howard Bend	GT	47	987		8.82	0.2%
Meramec	GT	68	2,254		7.77	0.4%
Moreau	GT	61	4,087		8.23¢	0.8%
Subtotal		450	17,420	0.0%		
Osage	Hydro Stg.	208	572,746			
Keokuk	Hydro RoR	125	784,464			
Subtotal		333	1,357,210	3.7%		
Subtotal		8,146	36,566,367	100.0%		
Taum Sauk	Pump Stg.	468	(47,430)			

Source: FERC Form 1

NON-PROPRIETARY

AmerenUE

Generation Supply 1998

Name	Fuel	Capability (MW)	Energy Output (MWh)	Energy Output (%)	Fuel Cost (¢/kWh)	% of Time Run
Labadie	Coal	2,389	13,797,154		1.01¢	
Sioux	Coal	1,099	4,973,644		1.15	
Rush Island	Coal	1,242	7,783,780		1.00	
Meramec	Coal	923	2,420,078		1.58	
Venice	Coal	474	103,535		4.98	2.5%
		6,127	29,078,191	73.5%	1.09	
Callaway	Nuclear	1,236	8,516,773	21.5%	0.51	
Venice	GT	38	1,742		10.32	0.5%
Kirksville	GT	15	994		5.66	0.8%
Fairground	GT	68	8,951		5.70	1.5%
Viaduct	GT	31	3,495		4.11	1.3%
Moberly	GT	61	9,908		5.99	1.9%
Mexico	GT	61	10,283		5.58	1.9%
Howard Bend	GT	47	7,215		5.19	1.8%
Meramec	GT	68	8,729		4.85	1.5%
Moreau	GT	61	9,994		5.71¢	1.9%
Subtotal		450	61,311	0.2%		
Osage	Hydro Stg.	208	1,034,947			
Keokuk	Hydro RoR	125	882,278			
Subtotal		333	1,917,225	4.8%		
Subtotal		8,146	39,573,500	100.0%		
Taum Sauk	Pump Stg.	468	(78,363)			

Source: FERC Form 1

NON-PROPRIETARY

AmerenUE

Generation Supply 1999

Name	Fuel	Capability (MW)	Energy Output (MWh)	Energy Output (%)	Fuel Cost (¢/kWh)	% of Time Run
Labadie	Coal	2,389	13,424,957		1.01¢	
Sioux	Coal	1,099	4,690,216		1.15	
Rush Island	Coal	1,242	7,552,365		0.94	
Meramec	Coal	923	3,091,730		1.54	
Venice	Coal	474	97,473		5.38	2.3%
		6,127	28,856,741	73.8%	1.09	
Callaway	Nuclear	1,236	8,586,646	22.0%	0.50	
Venice	GT	38	998		13.09	0.3%
Kirksville	GT	15	737		7.37	0.6%
Fairground	GT	68	7,062		7.51	1.2%
Viaduct	GT	31	1,705		5.99	0.6%
Moberly	GT	61	5,336		6.38	1.0%
Mexico	GT	61	5,213		6.80	1.0%
Howard Bend	GT	47	3,864		6.41	0.9%
Meramec	GT	68	6,086		4.67	1.0%
Moreau	GT	61	6,469		6.52¢	1.2%
Subtotal		450	37,470	0.1%		
Osage	Hydro Stg.	208	707,001			
Keokuk	Hydro RoR	125	898,487			
Subtotal		333	1,605,488	4.1%		
Subtotal		8,146	39,086,345	100.0%		
Taum Sauk	Pump Stg.	408	(113,144)			

Source: FERC Form 1

NON-PROPRIETARY

AmerenUE

Generation Supply 2000

Name	Fuel	Capability (MW)	Energy Output (MWh)	Energy Output (%)	Fuel Cost (¢/kWh)	% of Time Run
Labadie	Coal	2,389	14,936,049		0.99¢	
Sioux	Coal	1,099	5,219,423		1.02	
Rush Island	Coal	1,242	7,895,566		0.94	
Meramec	Coal	923	3,038,540		1.39	
Venice	Coal	474	40,934		10.53	1.0%
		6,127	31,130,512	73.7%	1.03	
Callaway	Nuclear	1,236	9,991,845	23.7%	0.43	
Venice *	GT	38				
Kirksville	GT	15	553		12.59	0.4%
Fairground	GT	68	5,952		9.98	1.0%
Viaduct	GT	31	933		8.62	0.3%
Moberly	GT	61	3,353		9.79	0.6%
Mexico	GT	61	4,768		10.36	0.9%
Howard Bend	GT	47	1,224		8.87	0.3%
Meramec	GT	130	6,130		7.20	0.5%
Moreau	GT	61	4,859		9.58¢	0.9%
Subtotal		512	27,770	0.1%		
Osage	Hydro Stg.	208	176,813			
Keokuk	Hydro RoR	125	884,558			
Subtotal		333	1,061,371	2.5%		
Subtotal		8,208	42,211,498	100.0%		
Taum Sauk	Pump Stg.	408	(192,095)			

Source: FERC Form 1

* Note: FERC Form 1 shows negative net output

AmerenUE

Generation Supply 2001

Name	Fuel	Capability (MW)	Energy Output (MWh)	Energy Output (%)	Fuel Cost (¢/kWh)	% of Time Run
Labadie	Coal	2,389	***		***	
Sioux	Coal	1,099	***		***	
Rush Island	Coal	1,242	***		***	
Meramec	Coal	923	***		***	
Venice	Coal	474	***		***	
		6,127	***	***	***	***
Callaway	Nuclear	1,236	***		***	***
Venice *	GT	38	***		***	
Kirksville	GT	15	***		***	***
Fairground	GT	68	***		***	***
Viaduct	GT	31	***		***	***
Moberly	GT	61	***		***	***
Mexico	GT	61	***		***	***
Howard Bend	GT	47	***		***	***
Meramec	GT	130	***		***	***
Moreau	GT	61	***		***	***
Subtotal		512	***	***	***	
Osage	Hydro Stg.	208	***			
Keokuk	Hydro RoR	125	***			
Subtotal		333	***	***		
Subtotal		8,208	***	***		***
Taum Sauk	Pump Stg.	408	***			

Source: FERC Form 1

NON-PROPRIETARY

AmerenUE Forecast of Peak Demands And System Capability at Time of Peak (2001 - 2010)

Schedule 3

(MEGAWATTS)

	ACTUAL	FORECAST									
Demand at Time of Peak	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Gross Instantaneous Peak Demand											
Net Integrated Peak Demand											
Capability At Time Of Peak											
Callaway											
Fossil Steam											
Combustion Turbine & Diesel Generation											
Approved Generation Upgrades											
Approved Generation Additions											
Hydro Plant Generation											
Pumped Storage Generation											
Total Installed Generating Capability - Net											
Installed Station Service											
Total Installed Generating Capability - Gross											
Purchase - Net Electric Energy Inc. (2)											
Percent Reserves											
Unreserved Purchases (+) / Sales (-):											
Non-Utility Generation											
Total Capability At Time Of Peak - Gross	0	0	0	0	0	0	0	0	0	0	0
Installed Station Service (-)	0	0	0	0	0	0	0	0	0	0	0
Total Adjusted Capability At Time Of Peak	0	0	0	0	0	0	0	0	0	0	0
Percent Reserves											

NON-PROPRIETARY

Schedule 4

AmerenUE Forecast of Peak Demands And System Capability at Time of Peak (2001 - 2010)

With Metro East Transfer - 2002

(MEGAWATTS)

	ACTUAL	FORECAST									
Demand at Time of Peak	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Gross Instantaneous Peak Demand											
Net Integrated Peak Demand											
Wholesale Contracts											
Temperature Normalization											
Normalized Net Integrated Peak Demand											
Option Curtailments											
Voluntary Curtailment Rider											
Voltage Reduction											
Interruptible Load (1)											
Net Integrated Adjusted Demand											
Capability At Time Of Peak (Based on July Capabilities)											
Callaway											
Fossil Steam											
Combustion Turbine & Diesel Generation											
Approved Generation Upgrades											
Approved Generation Additions											
Hydro Plant Generation											
Pumped Storage Generation											
Total Installed Generating Capability - Net											
Installed Station Service											
Total Installed Generating Capability - Gross											
Percent Reserves											
Unreserved Purchases (+) / Sales (-):											
Non-Utility Generation											
Total Capability At Time Of Peak - Gross											
Installed Station Service (-)											
Total Adjusted Capability At Time Of Peak											
Percent Reserves											
Purchases Required (-) or Sales Allowed (+) to Meet 15% Reserve Margin											
Purchases Required (-) or Sales Allowed (+) to Meet 18% Reserve Margin											

NON-PROPRIETARY

AmerenUE Forecast of Peak Demands And System Capability at Time of Peak (2001 - 2010)

(MEGAWATTS)

	ACTUAL	FORECAST									
Demand at Time of Peak	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Gross Instantaneous Peak Demand											
Net Integrated Peak Demand											
Wholesale Contracts											
Temperature Normalization											
Normalized Net Integrated Peak Demand											
Option Curtailments											
Voluntary Curtailment Rider											
Voltage Reduction											
Interruptible Load (1)											
Net Integrated Adjusted Demand											
Capability At Time Of Peak (Based on July Capabilities)											
Callaway											
Fossil Steam											
Combustion Turbine & Diesel Generation											
Approved Generation Upgrades											
Approved Generation Additions											
Hydro Plant Generation											
Pumped Storage Generation											
Total Installed Generating Capability - Net	0	0	0	0	0	0	0	0	0	0	0
Installed Station Service											
Total Installed Generating Capability - Gross	0	0	0	0	0	0	0	0	0	0	0
Percent Reserves											
Unreserved Purchases (+) / Sales (-):											
Non-Utility Generation											
Total Capability At Time Of Peak - Gross											
Installed Station Service (-)											
Total Adjusted Capability At Time Of Peak											
Percent Reserves											
			0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0

NON-PROPRIETARY

AmerenUE Load for Test Year Ended June 30, 2001
Top 50 Hours