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Witness:	Michael S. Proctor
Sponsoring Party:	MoPSC Staff
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MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

TESTIMONY

OF

MICHAEL S. PROCTOR

CASE NO. EC-2002-1

Jefferson City, Missouri
March 1, 2002

Exhibit No. 53NP
Date 7/10/02 Case No. EC-2002-1
Reporter KEM

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

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DIRECT TESTIMONY

OF

MICHAEL S. PROCTOR

UNION ELECTRIC COMPANY

d/b/a AMERENUE

EC-2002-1

Q. What is your name and business address?

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

Q. By whom are you employed and in what capacity?

A. I am employed by the Missouri Public Service Commission (Commission) as Manager of Economic Analysis in the Energy Department.

Q. Have you previously filed direct testimony in this case?

A. No.

Q. What is your education background and work experience?

A. I have Bachelors and Masters of Arts Degrees in Economics from the University of Missouri at Columbia, and a Ph.D. degree in Economics from Texas A&M University. My previous work experience has been as an Assistant Professor of Economics at Purdue University and at the University of Missouri at Columbia. Since June 1, 1977, I have been on the Staff of the Commission and have presented testimony on various issues related to weather normalized energy usage and rate design for both electric and natural gas utilities. With respect to electric issues, I have worked in the areas of load forecasting, resource planning and transmission pricing. In 1997 and 1998, I served as the Staff Vice Chair of the Market Structure and Market Power working group of the Commission's Task Force on Retail Competition. From December of 2000 until the Southwest Power Pool's (SPP's) application as a Regional Transmission Organization (RTO) was rejected by the Federal Energy Regulatory Commission in the summer of 2001, I served as chairman of the Forward Congestion Markets Subgroup of the SPP's Congestion Management Systems Working Group.

Q. What are your current duties in the Energy Department as Manager of Economic Analysis?

A. I supervise the Economic Analysis group within the Energy Department. This group is responsible for various issues related to weather normalization of sales, class cost of service and rate design. I am also responsible for the review of the economic analysis performed by Missouri, investor-owned, electric utilities for their resource plans. In addition to my supervisory role, I have focused my attention on the development and structure of RTOs for the purpose of increasing efficiency and reliability in the competitive supply of electricity. Because of the restructuring of the electric industry toward the increased competitive supply of electricity, I have also focused on the issue of market power within the electric industry.

RECOMMENDATIONS

Q. In this instant case, what is the purpose of your direct testimony?

A. My direct testimony in this case addresses issues with respect to the Ameren Joint Dispatch Agreement (JDA) between Union Electric Company (UE or AmerenUE) and Ameren Energy Generating Company (AEG), the exempt wholesale generator that now owns the generation assets of Central Illinois Public Service Company

(CIPS or AmerenCIPS) and Ameren Energy Marketing (AEM), the marketing representative for AEG. In addition, I will address issues related to how UE met its reserve requirement for the summer of 2001, which the Commission has included in its update period for this case.

Q. What is your recommendation regarding the JDA?

A. The current Ameren JDA is deficient and, as a consequence, its terms should not be followed with respect to setting the revenue requirements for UE's Missouri retail customers. The Ameren JDA allocates the monthly profit margins from Off-System Sales between UE and AEG/AEM, according to UE's and AEG/AEM's share of monthly Load Requirements. As I will further explain in my direct testimony, this is an inequitable allocation of profits from Off-System Sales and therefore, at a minimum, the monthly profit margins from Off-System Sales should be allocated based on the contribution of UE's and AEG/AEM's share of monthly energy from Resources jointly used to meet Load Requirements plus Off-System Sales. In brief, I am recommending that UE's allocation of monthly profit margin be increased because of the lost opportunity to sell into the wholesale electricity market that UE experiences when it transfers electricity from its cheaper resources to meet the Load Requirements for AEG/AEM.

Q. What is your recommendation regarding UE meeting it's capacity reserve requirement for the summer of 2001?

A. The current Ameren JDA has no explicit pricing for capacity transfers between UE and AEG/AEM as may be necessary for each entity to meet a minimum capacity reserve requirement. Reserve requirements are necessary to maintain adequate levels of generation capacity to provide reliable supplies of electricity to Ameren (UE and CIPS) customers at reasonable prices. As will be explained further in my direct testimony, the lack of such conditions, along with an implicit Ameren policy to build new generation capacity in AEG rather than in UE, leads to the possibility of affiliate abuse. Affiliate abuse occurs when such policies place the regulated company (UE), in situations where in order to have adequate capacity, it must purchase capacity and energy from the unregulated affiliate (AEG) or its marketing agent (AEM) at market prices, that are higher than what would otherwise be the regulated cost of that same capacity and energy. Because this situation of paying market price when it is higher than cost occurs for the capacity purchased by UE for June, 2001 through May, 2002, I am recommending that the cost of the capacity purchases made by UE to meet its reserve requirements for its summer 2001 peak be replaced with the cost of building, operating and maintaining combustion turbines identical to those brought on line in 2001 by AEG at Columbia, Missouri and Pinkneyville, Illinois.

JOINT DISPATCH AGREEMENT - ALLOCATIONS

Q. What is a JDA?

A. A JDA is an agreement (contract) that sets out all of the conditions by which two or more (usually affiliate) companies will jointly dispatch their electric supply resources (Resources) and Off-System Purchases to meet their joint load, including both Load Requirements and Off-System Sales. Resources include both Generating Resources and longer-term purchase power contracts for capacity and energy. The Ameren JDA defines: 1) Generating Resources as " all power generating facilities owned by a Party available to meet the capacity and energy needs of the Parties;" 2) Load Requirements as "the demand and energy, which each Generating Party is obligated to serve pursuant to service territory commitments and requirements agreements;" 3) Off-System Purchases as "purchases from a third party of energy and/or associated capacity to reduce costs and/or to provide reliability for the system or as required by law;" and 4) Off-System Sales as "all sales of power and/or energy to third parties other than Load Requirements." Thus, the sum of Load Requirements and Off-System Sales is the total joint demand being served by Ameren at any given time, and the sum of Resources and Off-System Purchases is the total joint supply available to Ameren for use to serve its total joint demand.

The conditions of any JDA primarily focus on how the costs and revenues from the joint operation will be allocated among the various companies. In addition, the JDA can also specify certain conditions required of the joint dispatch function as well as conditions placed on each company with respect to such things as having adequate electricity supply resource capacity to reliably meet its individual Load Requirements. In this section of my direct testimony, I will focus on the Ameren JDA allocations of variable costs and profits from Off-System Sales involving UE and AEG/AEM.

Q. How are the variable costs associated with the Ameren JDA determined?

A. Variable production costs are those costs that change directly with the electricity output from Resources and Off-System Purchases. This variable output of electricity is sometimes called "energy," and the associated variable costs are called "energy costs."

In most JDAs, a joint dispatch means that the lowest variable cost energy available from the Resources are dispatched to meet the joint load irrespective of which company has entitlement to those Resources. In addition, the dispatcher can purchase power from the short-term (e.g., hourly, daily or perhaps weekly) energy market (Off-System Purchases) whenever it is cheaper than the variable cost of the energy from the Resources of either company. These are the basic conditions placed on the joint dispatcher by the Ameren JDA that determine the total variable/energy costs to meet load. In addition, the joint dispatcher can sell into the wholesale electricity market when energy is available from UE or AEG/AEM Resources or Off-System Purchases that is not needed to meet the joint Load Requirements of UE and AEG/AEM.

Q. How are the variable/energy costs associated with this joint dispatch then allocated between UE and AEG/AEM?

A. The conditions of the Ameren JDA determine the allocations of variable costs based on the dispatched energy from each company's Resources and the Load Requirements of each company. If in the joint dispatch, one company is long (energy dispatched from its Resources exceed what is required to meet its Load Requirements) in any given hour, then the highest incremental cost energy from the long company's Resources are allocated to the company that is short (energy dispatched from its Resources are less than what is required to meet its Load Requirements). In this context, allocating the highest incremental cost from the long company to the short company implies that the lowest-cost energy of the long company is allocated to meet the long company's own Load Requirements, and the highest-cost energy of the long company is then residually allocated to meet that portion of the Load Requirements of the short company not being met by energy from its own Resources. Since the joint dispatch rule is to use the lowest overall cost energy to meet the joint load, this transfer of energy and associated costs should never happen unless the highest-cost energy of the long company is still cheaper than the energy available from the Resources of the short company to serve that same increment of load.

Q. In the current Ameren JDA, at what price do the transfers of energy between the two companies take place?

A. In the Ameren JDA, all transfers of energy occur at a price that is equal to the incremental cost of fuel, variable operation and maintenance (O&M) expense and the opportunity cost of emission's allowances. The incremental cost of fuel is the fuel cost associated with the highest-cost resources of the company making the transfer. It is important to note that under the Ameren JDA, the transfer price does not include the opportunity cost of selling the transferred energy to the Off-System Sales market (sales made into the short-term, wholesale electricity market). Instead, on behalf of both companies, the dispatcher makes Off-System Sales jointly, and the Ameren JDA specifies how the profits from such sales are to be allocated between UE and AEG/AEM.

Q. Is it appropriate for the JDA to exclude the opportunity cost of foregone sales to the short-term wholesale electricity market in the determination of the price at which energy is transferred from one company to the other?

A. No, but it is to some extent understandable. With market conditions as they existed at the time the JDA was first written and even for where these markets have evolved to today, it would be difficult to make transfers between two companies at market prices. This difficulty occurs primarily because a transparent market for electricity does not exist today. By "transparent," I mean a market where the price at which electricity sells, is determined by an independent market facilitator, and that price is published for everyone to see. Instead, today's short-term markets are characterized by bilateral transactions, and published prices are based on information from traders that is voluntarily provided to an independent market reporter.

If, at some point in the future, transparent markets for short-term electricity come into existence, such as those currently being proposed in the market design for the Midwest region by the Midwest Independent System Operator (MISO), then using the opportunity cost associated with the hourly market price of electricity could be used to eliminate any of the opportunities lost from transferring energy rather than making Off-System Sales that either company may experience through the Ameren JDA's present method of pricing transfers of energy. As these transparent, hourly electricity markets (both day-ahead and real-time) come into being, the industry practice will be significantly different, and the Ameren JDA will either be discarded or will need to be totally rewritten. In the interim, for ratemaking purposes, the profits from Off-System Sales allocated to UE by the JDA should be treated differently to reflect the lost opportunity in Off-System Sales from the JDA requirement to serve the other company's Load Requirements.

Q. According to the conditions of the Ameren JDA, how are profits from Off-System Sales determined and then allocated between UE and AEG/AEM?

A. All Off-System Sales are served from the highest incremental cost energy used (whether these are company Resources or Off-System Purchases) to meet the sum of Load Requirements and Off-System Sales. In essence, the lower-cost energy from dispatched Resources and Off-System Purchases are allocated to meet Load Requirements; while the higher-cost energy from dispatched Resources and Off-System

Purchases are allocated to meet Off-System Sales. This insures that, at any given time, lower-cost energy from Resources are used to serve the customers that are paying the capacity costs of those Resources, and are not used to inflate profits from Off-System Sales, or for that matter, cover up what would otherwise have been a loss (negative profit; i.e., variable costs are above revenues) from an off-system sale.

The costs associated with this higher-cost energy from dispatched Resources or Off-System Purchases to meet Off-System Sales are then accounted for as the hourly costs to serve the Off-System Sales. At the end of the month, both the revenues and assigned costs for Off-System Sales are allocated between UE and AEG/AEM based on each company's share of "Net Output." The Ameren JDA defines Net Output as: "each Generating Party's monthly total of the energy delivered for Load Requirements." In essence, their relative share of Load Requirements determines UE's and AEG/AEM's shares of profits from Off-System Sales.

Q. Is allocating profits from Off-System Sales in proportion to each company's share of Load Requirements a just and reasonable allocation method?

A. No, it is not. Allocating profits from Off-System Sales in proportion to Load Requirements makes sense only when the energy dispatched from the Resources of each company are "balanced" relative to its Load Requirements. At the end of any given month, if the Resource Output (energy dispatched from Resources held by each party to the JDA) were compared to the Load Requirements of each company, a balanced condition would be represented by Resource Outputs and Load Requirements being nearly equal. If this is not the case, and one of the two companies is a dominant supplier of energy to meet the joint load, then that company is contributing more Resource Output than its Load Requirements' share of energy to the system and is entitled to a higher share of profits from Off-System Sales. Such an imbalanced situation exists with the Ameren JDA.

Q. How do UE's Resource Outputs compare to UE's Load Requirements?

A. Schedule 1-1 shows a comparison of UE's share of Resource Outputs to UE's share of Load Requirements (Net Outputs) for the twelve months ending June 30, 2001. On the average throughout this twelve-month period, UE is providing just over **____** of the Resource Output, but only has **_____** of the Load Requirements. Two periods where this differences are smaller are: 1) the peak summer months of July and August; and 2) the months when the Callaway nuclear plant was down for refueling in April and May of 2001. However, even in these months, UE's Resource Output exceeds its Load Requirements.

Q. Why is a company that is contributing more Resource Output than its Load Requirement's share of energy to the system entitled to a higher share of the profits from Off-System Sales?

A. In simple terms, if one of the two companies is consistently supplying more electricity to the system than what is required to serve its own Load Requirements, then that company is providing excess electricity to serve the Load Requirements of the other utility, as well as providing electricity for Off-System Sales. Under the Ameren JDA, the only compensation that a company receives for providing energy in excess of its load requirements is to cover its incremental fuel cost, variable O&M expense and the opportunity cost of its emission's allowances. While this compensation covers the supplying utility's out-of-pocket costs, the supplying utility should be entitled to greater compensation than just covering its "out-of-pocket" costs since it must forego Off-System Sales opportunities.

Q. How does Schedule 1-1 show that UE's generation is being used to forego Off-System Sales opportunities?

A. Whenever one utility's contribution to Resource Output exceeds its Load Requirements, under the JDA it is either providing electricity to meet the other utility's Load Requirements or to meet Off-System Sales. However, from the perspective of opportunity cost, it does not matter which of these two it is doing, because the excess of Resource Output above Load Requirements is, in effect, first being used to meet Off-System Sales. Let me illustrate why this is true with two examples.

First, suppose the simplest case, where in a given hour UE's Load Requirement is 4,000 megawatts and AEG/AEM's Load Requirement is 2,000 megawatts. Assume that in order to meet joint Load Requirements that UE's Resource Output is 4,000 megawatts and AEG/AEM's Resource Output is 2,000 megawatts; i.e., both companies are in balance. Now, assume that the system has an opportunity to make an Off-System Sale in the same hour for 500 megawatts, and that the next cheapest (incremental) energy is from UE's Resources. In a competitive environment, both UE and AEG/AEM would bid, and because UE's costs are cheaper, it could bid lower than AEG/AEM and would therefore win the bid (i.e., make the sale) and keep the profits. In a cooperative, JDA environment, the bid comes from the joint resources (in this case UE's lower energy cost Resources) and if Ameren wins the bid (i.e., makes the sale), then the profits should be distributed in a fair way between the two utilities. In this simplistic example, it would appear that all of the profits should go to UE because it supplied the generation on which the sale was made. Before jumping to any conclusions, it should be pointed out that the world of joint dispatch can be much more complex than this simple example.

Second, to illustrate this complexity, suppose that instead of the two companies being in balance, UE's Load Requirement is still 4,000 megawatts, UE's Resource Output has increased to 4,500 megawatts, AEG/AEM's Load Requirement is still 2,000 megawatts, but AEG/AEM's Resource Output has decreased to 1,500 megawatts. For purposes of meeting Load Requirements, UE is transferring 500 megawatts to meet 500 megawatts of AEG/AEM's Load Requirement. Now suppose that the joint dispatcher has an opportunity to make 500 megawatts in Off-System Sales and the next cheapest 500 megawatts of energy available is from AEG/AEM Resources. Even though the 500 megawatts of energy to serve Off-System Sales are coming from AEG/AEM Resources, it would be unfair to give AEG/AEM all of the profits from this sale because UE could have made the sale from its cheaper energy had it not been committed to transferring this cheaper energy to meet AEG/AEM's Load Requirements. Specifically, if these two companies were competitors, UE would not have made the transfer and would have instead made the sale to the off-system wholesale market, and AEG/AEM would have had to meet its own Load Requirements with the 500 megawatts that, under the JDA, the joint dispatcher used to make the Off-System Sale.

Q. How do your examples illustrate the unfairness of allocating profits from Off-System Sales using each company's monthly percentage share of Load Requirements?

A. In both examples, UE's Resource Output exceeds its Load Requirement by 500 megawatts, which is identically equal to the amount of the Off-System Sales. In both examples, UE's Load Requirement share is 67% (= 4,000 ÷ 6,000) and UE's Resource Output share is 69% (= 4,500 ÷ 6,500).

Under competitive conditions, UE would be able to keep 100% of the profits from the Off-System Sale. However, under the JDA, UE has an obligation to serve the Load Requirements of AEG/AEM before it can make offers to the Off-System Sales market. This obligation means that UE is required to forego opportunities to sell to the Off-System Sales market, and this obligation is represented by UE's share of Resource Output. However, this obligation to serve the Load Requirements of AEG/AEM before it can make sales to the Off-System Sales market should not also mean that UE must incur a "penalty" through the JDA allocation method for carrying out this obligation. This penalty is the difference between UE's share of Load Requirements and UE's share of Resource Output. In the example, the 2% difference (69% for Resource Output vs. 67% for Load Requirements) is the penalty imposed by the Ameren JDA for using Load Requirements rather than Resource Output as the basis for allocating profits from Off-System Sales.

Q. When compared to share of Load Requirements, why does UE's share of Resource Output more fairly represent what it should be allocated of profits from Off-System Sales?

A. As indicated earlier in my testimony, any excess of Resource Output over Load Requirements is a measure of the amount of electricity that UE is providing to either meet AEG/AEM's Load Requirements or for sale into the Off-System Sales market. To exclude that excess of Resource Output by UE from the calculation of the allocation factor for profits from Off-System Sales is to exclude a contribution from those resources that actually were used to make the Off-System Sale.

Q. Could the resources actually used to make Off-System Sales be calculated on an hourly basis?

A. Yes, they can. Recall that in a given hour, energy from the most expensive sources is accounted for as meeting the megawatt-hour requirement for Off-System Sales. In any given hour, this energy can come either from UE's Resources, AEG/AEM's Resources or Off-System Purchases. If Off-System Sales are made directly from Off-System Purchases, then allocating the profits from those sales on a Load Requirements basis is fair. In fact, the Ameren JDA uses hourly Load Requirements to allocate the cost of Off-System Purchases between UE and AEG/AEM in hours where both entities would benefit from the Off-System Purchases. However, when AEG/AEM's Resources are used to make Off-System Sales, then the megawatt-hour amount for which it is given credit should be netted against the amount of megawatt-hours that UE has transferred to meet AEG/AEM Load Requirements. Conversely, when UE's Resources are used to make Off-System Sales, the megawatt-hour amount for which it is given credit should be netted against the amount of megawatt-hours that AEG/AEM has transferred to meet UE Load Requirements.

Q. Have you made hourly calculations of how many megawatt-hours were supplied to the Off-System Sales market by UE, AEG/AEM and from Off-System Purchases?

A. No, I did not have sufficient time to make such calculations for each hour of the test year. However, as a check of using shares of Resource Output to allocate profits from Off-System Sales, I have made these calculations using monthly data. These monthly calculations should not be used for allocating profits because they are based on the assumption that every hour is like the average hour for the month. However, the monthly calculations can be used to provide a check of reasonableness for using monthly Resource Output rather than monthly Load Requirements as the basis for allocating profits from Off-System Sales.

Q. As a check of reasonableness for using Resource Output for allocating profits from Off-System Sales, what did your monthly calculations indicate?

A. As indicated in Schedule 1-2 attached to my direct testimony, using a monthly calculation of UE's share of Resource Output to serve Off-System Sales results in a much higher allocation to UE than using the share of UE Resource Output to serve the combination of Load Requirements and Off-System Sales. Thus, UE's share of Resource Output is likely to be a conservative (low) estimate of the way profits from Off-System Sales should truly be allocated.

Q. What adjustment do you propose to make to the test-year profits from Off-System Sales allocated to UE?

A. As shown on Schedule 1-2, moving from allocating on the basis of share of Load Requirements to share of Resource Output, would increase the allocation of profits from Off-System Sales to UE from an estimated **____________________ ______** per year.

Q. What is your recommendation for adjustments to interchange revenues (S-5.1) and expenses (S-8.1) for the increased allocation of profits from Off-System Sales to UE?

A. Estimates of the components for test-year profits for Interchange Sales, before and after this adjustment are shown on Schedule 2 attached to my direct testimony. While the adjustment to profits is the critical number for revenue requirements, for accounting purposes, this adjustment to profits is separated between an adjustment to revenues (S-5.1) and an adjustment to expenses (S-8.1).

Q. Why did you have to estimate the profits from Off-System Sales for the test year?

A. UE does not account separately for profits from Off-System Sales. Instead, UE accounts for total revenues and costs for what it calls Interchange Sales. In addition to revenues from Off-System Sales, revenues for Interchange Sales include revenues from transmission sales and revenues from energy transfers from UE to AEG/AEM. In documents that UE sends monthly to the Staff, is a separate accounting of revenues from Off-System Sales and transfers from UE to AEG/AEM. These were subtracted from the revenues for Interchange Sales to arrive at the estimate of revenues for transmission. While the revenues between Off-System Sales and transfers from UE to AEG/AEM are separated in the monthly documents received from the Staff, unfortunately, there appears to exist no such separation for the costs. If the revenues from transfers exactly matched the cost of transfers, this would not pose a problem. But the revenues from transfers include a margin for variable O&M and opportunity cost for emission's allowances, which are not included in the costs for Interchange Sales. Since, it appears that no separate records of margins for transfers are maintained, they must be estimated. In discussions regarding this problem, Ameren employee, Mr. Tim Finnell, told me that **_______** is a good estimate for this margin. Using this **_______** estimate, the margin for transfers along with transmission revenues are removed from the Interchange Sales revenues, and the costs for Interchange Sales are subtracted from the remaining revenues to estimate the profits from Off-System Sales.

Q. Did you estimate profits from Off-System Sales to include the update period for the months of July, August and September of 2001?

A. No, I did not. I could not obtain reasonable estimates for profits from Off-System Sales based on the records for these months. Moreover, it appears that in these months the records that UE sends to the Staff may not be reflective of what actually occurred in those months. Part of the reason for this is that the records include significant adjustments for other months and may be in need of adjustments themselves. Thus, the best information available at this time is from the test year, excluding the update period.

CAPACITY TO MEET RESERVES

Q. What is the issue regarding UE's capacity to meet its reserve requirements for the summer of 2001?

A. In order to meet its reserve requirements for the summer of 2001, UE purchased 450 megawatts from AEG/AEM and an additional 50 megawatts from American Electric Power Co. (AEP). There are four issues that the Staff is raising regarding these purchases.

- These contracts are a one-time purchase and are not representative of UE's power costs on a going forward basis.
- Purchases from UE's affiliate (AEM) were made at market prices rather than at cost.

- Purchases were made for must-take power during the on-peak hours of the summer months of July and August of 2001, and UE failed to perform any analysis that must-take power was the least-cost method for meeting its need for that summer.
- UE would not have had to purchase from the market had it built peaking capacity as regulated generation units.

Q. Why are these contracts not representative of UE's power costs on a going forward basis?

A. These contracts were entered into to meet UE's capacity need for the summer of 2001. To fulfill its capacity need for the coming summer of 2002, UE has issued Requests For Proposals (RFPs), received bids, evaluated these bids and entered into completely different contracts that are at a lower cost.

Q. What is the ratemaking treatment for a prudently incurred cost during a test year that is above the representative (normalized) cost to the utility on a going forward basis?

A. A one-time, non-recurring expense should not be included in revenue requirements on a going forward basis.

Q. Why should a utility buy from a non-regulated affiliate at the lower of market price versus cost?

A. This principle keeps the non-regulated affiliate from abusing its relationship with the regulated utility. This is of extreme importance when the company from which the regulated electric utility is purchasing power is an unregulated generation affiliate, such as is the case for AEG/AEM. If the unregulated generation affiliate were able to sell to the regulated utility at the greater of market price or cost, then the holding company would always decide to have the affiliate build new generation and sell it to the utility as a way of maximizing the unregulated profits of the holding company.

Q. Why is this principle of particular importance to the situation as it exists for UE and AEG/AEM within the corporate structure of Ameren?

A. Under conditions where UE would have independent decision-making authority as a regulated utility, then it would also be able to acquire needed generation capacity at least cost by deciding to build its own generation at times when market price is higher than cost. However, in a holding company environment such as exists with Ameren, the decision making regarding in which company generation will be built is not independent. In fact, in the case of Ameren: 1) the President and Chief Operating Officer (COO) of Ameren is also the President and COO of UE; 2) UE does not have a separate board of directors from Ameren; and 3) the analysis regarding the evaluation of resource options to meet future power supply needs for UE is made by Corporate Planning, a department of Ameren Services, a service company under Ameren.

Q. Did Ameren make the decision to build new generation capacity within its non-regulated subsidiary rather than within its regulated utility?

A. Until recently, this has been the case. In January 2000, AEG planned to build new peaking capacity at: **______________________________

____

____**. After a scheduled resource plan meeting with UE on January 21, 2000, I requested information concerning the ten-year forecast of peak loads and resource plans for both UE and CIPS. The response to this request is attached to my direct testimony as Schedule 3. Schedule 3-2 shows all of the planned additions, none of which were planned additions for UE. Schedule 3-5 [third row up from the bottom row] shows that with forecasted reserve margins of **____ ________________________**, AEG/AEM needed only a fraction of the capacity it was planning to add to serve the needs of its own Load Requirements customers. Subsequent to this plan, AEG/AEM has added **____________________________ ________________________________**.

Q. Were any capacity additions planned by Ameren for UE?

A. Schedule 3-4 shows only minor upgrades to existing generation units and no new capacity additions, even though UE clearly had capacity needs with reserve margins of **____ ____**. [See Schedule 3-4, third row up from the bottom row.] Subsequent to this plan, one peaking unit was added at Meramec (**____________________________ ______________________**). This unit was placed in the UE system **________ ____ ____ ____** [See Schedule 4 attached to my direct testimony 4-10, entitled "Attachment E."] The installation of the **______________________________** had only a minor impact on UE's reserve deficit by raising reserve margins to **________________________ ____________________________________**. [See Schedule 4-9, third row up from the bottom row.]

Q. What was the form of the contract for purchased power that UE entered into for capacity needed for the summer of 2001?

A. For the peak hours of the summer of 2001, the contracts required UE to pay for all the energy from the capacity it purchased to meet its reserve requirement needs. These peak hours are weekday peak hours for the months of July and August that are in the update period adopted by the Commission. This is called "must-take" energy, which must be taken whether or not the energy is needed.

Q. Did Corporate Planning perform an analysis to determine that must-take energy would be the least-cost type of purchase?

A. No, it did not. Had it performed such an analysis, it would have requested bidders to submit proposals that did not require must-take energy and made a comparison. Instead, after receiving a first-round of bids that did not explicitly require must-take energy bids, Corporate Planning issued a second RFP in which it explicitly required all bidders to submit bids on the basis of must-take energy. In an evaluation that is seeking to find the least-cost bid, bids for options other than must-take energy should have been requested and evaluated.

Q. Were there conditions in effect at the time that would have forced UE to purchase must-take energy?

A. At the time, natural gas prices were high and the future prices for must-take energy were also high. Thus, there may have been a concern by Corporate Planning that other than must-take energy would only be bid to be sold at spot prices. If one thinks the spot price is going to be higher than the futures price, then getting a fixed-price forward contract is a way to hedge against having to possibly pay higher prices at the future date. If the only way to obtain this hedge was to enter into a must-take energy contract, then Corporate Planning may have believed that it was necessary to request must-take energy bids and enter into must-take contracts. However, this is an example of where affiliate abuse by AEG/AEM occurs. If AEG/AEM were required to provide electricity at cost rather than market price, then UE could have acquired the needed capacity at cost with little or no concern about what electricity markets might do during the July and August peak months of the update period. Alternatively, had the peaking capacity needed by UE been built within UE, not AEG, the problem of AEG/AEM offering to sell at market price above cost would not have been an issue.

Q. What do you propose as a normalized cost for the 500 megawatts of capacity that UE purchased to meet its reserve requirements for the update period that includes July, August and September of 2001?

A. The normalized cost should be the cost of the generation capacity of the new peaking units that were built by AEG. The newest peaking units have been built at Columbia and Pinckneyville at an installed cost of **__________**. These are FT8 Combustion Turbines with fairly efficient heat rates in the range of **_____ ________**. These generation units are used because they best represent the cost of the 500 megawatts of capacity required to meet UE's need for capacity reserves. Staff witness Leon Bender includes this capacity in his modeling of fuel expense. Staff witness Greg Meyer includes the installed cost of **__________________________ ____** in his calculation of rate base, as well as expenses directly associated with rate base, such as depreciation and property taxes.

Q. In addition to the installed cost of the 500 megawatts of peaking capacity and its associated rate base and fuel expense, are there additional costs that need to be included in the normalization?

A. Yes, there are. Non-fuel O&M expenses of $2.45/kW should be included. Schedule 5, attached to my direct testimony, shows that $2.45/kW is a normalized expense based on expenditures made by UE for non-fuel O&M expenses over the past few years. Specifically, this estimate is based on a rolling three-year average of non-fuel O&M expenses for combustion turbines over the past four years. Three-year averages were used because the maintenance expenses for combustion turbines are incurred on a cyclical basis. It is also slightly higher than the average non-fuel O&M expense experienced by UE over the 1996-2000 time period. With the addition of 500,000 kW at $2.45/kW, $1,225,000 should be added to non-fuel O&M production expenses for the update period.

Q. Does this complete your direct testimony?

A. Yes, it does.

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 foregoing written Direct Testimony in question and answer form, consisting of 23 pages of testimony to be presented in the above case, that the answers in the attached written Direct 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 28th day of February, 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 ____________

SCHEDULES 1-1 AND 1-2

ARE DEEMED TO BE

HIGHLY CONFIDENTIAL

IN THEIR ENTIRETY

Adjustments to Margin from Sales

		Booked 12 months Ending 30-Jun-01
Revenues from Sales		$255,886,515
Expenses for Sales		$159,565,148
Margin (Profits) from Sales		$96,321,367
Margin (Profit) Components		
Transmission		** **
Transfers		** **
Off-System Sales		** **
Total Margin for Sales		** **
Revision to Allocation of Margin from Off-System Sales		
Allocation Based on Resource, not Load		** **
Estimated Adjustments to Revenue from Sales and Costs for Sales		
Revenues from Sales	**Adjustment S-5.1**	** **
Expenses for Sales	**Adjustment S-8.1**	** **
Profits from Sales		** **
Adjusted Revenues from Sales and Costs for Sales		
Revenues from Sales		** **
Expenses for Sales		** **
Profits from Sales		** **

SCHEDULES 3-1 T0 3-5

ARE DEEMED TO BE

HIGHLY CONFIDENTIAL

IN THEIR ENTIRETY

SCHEDULES 4-1 TO 4-10

ARE DEEMED TO BE

HIGHLY CONFIDENTIAL

IN THEIR ENTIRETY

NON-FUEL O&M EXPENSE
UE COMBUSTION TURBINES

Three-Year Averages

Year Ending	Maintenance	Other	kW Capacity	Maintenance	Other	Total
2000	$621,822	$165,014	396,333	$1.57	$0.42	$1.99
1999	$796,353	$125,391	382,000	$2.08	$0.33	$2.41
1998	$764,570	$151,745	381,667	$2.00	$0.40	$2.40
1997	$772,557	$171,365	381,000	$2.03	$0.45	$2.48
1996	$567,190	$236,903	378,667	$1.50	$0.63	$2.12
1995	$394,247	$250,137	376,333	$1.05	$0.66	$1.71
1994	$553,560	$251,870	374,000	$1.48	$0.67	$2.15
1993	$677,012	$260,459	374,000	$1.81	$0.70	$2.51
1992	$666,047	$247,959	374,000	$1.78	$0.66	$2.44
	Average fpr last 4 Three-Year Averages Excluding Maintenance for 2000			$2.04	$0.39	$2.43
	Normal			**$2.05**	**$0.40**	**$2.45**

Five-Year Average

Year	Maintenance	Other	kW Capacity	$/kW Maintenance	$/kW Other	$/kW Total
2000	$510,518	$150,281	424,000	$1.20	$0.35	$1.56
1999	$916,443	$136,434	382,000	$2.40	$0.36	$2.76
1998	$438,505	$208,327	383,000	$1.14	$0.54	$1.69
1997	$1,034,110	$31,412	381,000	$2.71	$0.08	$2.80
1996	$821,095	$215,496	381,000	$2.16	$0.57	$2.72
Total	$3,720,671	$741,950	1,951,000	$1.91	$0.38	$2.29