Q. Once these cost tracking relationships have been determined for each of the Company's rate blocks in each of the seasons, what is the next step in the development of the LGS and SGS Rates?

A. As the HU rate blocks in these rates are continuous, and the determined cost responsibilities are single-point determinations, sets of algebraic equations are set up and solved in order to derive the charges for the continuous blocks, while maintaining the derived cost responsibilities. Once these charges are determined for the production and transmission demand related costs are determined, at the primary voltage level for the SGS class, these rates were increased by a loss factor to arrive at the comparable set of rates for the LGS class.

Q. What other costs need to be added to these HU rates for the LGS and SGS Rate classes?

A. The variable production energy costs need to be added to the rates for the demand related costs to arrive at the total HU energy based rates. Based upon my Schedule 10 data, these rates were determined to be 1.78 cents per kilowatthour for LGS and 1.72 cents per kilowatthour for SPS. These variable costs should also be added to each of the rate values determined for the recovery of demand related costs in the HU blocks, in order to arrive at the final values for this component of the Company's LGS and SPS Rates being proposed in this case. Summaries of these rates and the "proof of revenue" for each class are attached as Schedules 14-1 and 14-2 of my testimony.

Large Primary Service Rate

Q. How was the Large Primary Service (LPS) Rate being proposed by the Company in this case developed and designed?

A. The LPS Rate currently consists of a Customer Charge, seasonal Demand and Energy Charges and a Reactive Charge. The proposed LPS Customer Charge was determined in the same manner that I described earlier in my testimony for the LGS and SPS Rate Customer Charges. The customer related costs of $258 million for the LPS Rate class, indicated in my Schedule 10, were divided by the number of annual bills rendered to LPS Rate customers to arrive at a monthly LPS Customer Charge of $385.

Q. How was the proposed LPS Demand Charge determined?

A. The design of the current LPS Rate reflects a single kilowatt demand charge for each of the summer and winter billing seasons established at approximately 85% of the total production, transmission and distribution demand related cost assigned to the LPS Rate class. The 15% balance of such demand-related costs was assigned to the LPS Rate Energy Charge, along with all of the variable cost allocated or assigned to the class. This recovery of a portion of demand costs in the energy component of this rate insures that LPS class customers contribute some margin to demand related costs for every kilowatthour sold to them.

Q. What Demand and Energy Charges for the LPS Rate resulted from the process you just described?

A. Using the functionalized demand related costs contained in my Schedule 10, I allocated 85% of such costs to the demand charge for this rate. I then determined the seasonal demand charges on the basis of the two to one ratio of the summer charge to the winter charge referred to earlier in the design of the LGS and SPS Rate distribution demand charge. The monthly billing demand charges determined for the LPS Rate were $14.74 per kW and $7.36 per kW, respectively, for the summer and winter billing months. The remaining 15% of these demand costs was assigned to summer and winter billing seasons, based upon the previously mentioned 60/40 seasonal split of such costs. These seasonal costs were then converted to a cents per kilowatthour charge and combined with the remaining annual average variable energy cost in cents per kilowatthour that was derived from the LPS energy related production cost in my Schedule 10. This resulted in seasonal Energy Charges of 2.20 cents per kilowatthour in the summer and 1.85 cents per kilowatthour in the winter billing season. The Reactive Charge in both the LPS and SPS Rates was maintained at its current level. A summary of this rate and its "proof of revenue" is attached as Schedule 15 of my testimony.

Lighting Rates

Q. Is the Company proposing any revisions to its street and outdoor area lighting rates in this case?

A. No specific proposals were developed for the lighting rates as a part of this case, as the Company did not perform any cost of service studies for its lighting classes, which constitute approximately 1% of the Company's total Missouri revenues. Rather, the Company accounted for its lighting costs and revenues in the cost of service study performed by Mr. Warwick by employing an approach utilized by the Commission Staff in the Company's past cases involving such studies. This approach consists of allocating all direct lighting costs and other allocated investment and expenses to the non-lighting classes, and offsetting the allocation of such costs by also allocating all lighting revenue to the same non-lighting classes in the same manner. The net effect of such allocations of costs and revenues should be negligible, under the reasonable assumption that the rates for lighting service have been established at or near their cost of service.

Proposed Rider B - Discounts For Customer Owned Substations

Q. Please explain the purpose of Rider B and how it applies to high voltage customers taking service on the Company's SPS and LPS Rates.

A. Rider B is a current tariff that provides for a discount to customers taking service at voltage levels at 34,500 volts and higher. As such customers pay for their service on either the Small or Large Primary Service Rate, and the costs allocated to these rate classes provide for service ranging from 4,160 to 13,800 volts, a rate discount is appropriate for the billing of such high voltage customers. This discount should reflect the Company's avoided substation transformation costs that are not required to provide service to these high voltage customers. These billing discounts are applied to the metered billing demands of the high voltage customers as indicated in Rider B. The discounts are categorized for customers taking service at 138 kV or 34.5/69 kV, with options for metering at either the Company's delivery voltage, or at the lower voltage after transformation by the customer's substation.

Q. Can the appropriate level of such discounts be determined from the Company's class cost of service study?

A. Yes, a sub-analysis of Distribution Account 362 – Station Equipment, in the Company's class cost of service study, was performed to develop a revenue requirement for the substation capacity which the Company avoids installing when serving such higher voltage customers. This account includes both distribution substations that transform power to the 34,500 and 69,000 volt levels and substations that transform power to the 4,160 to 13,800 volt levels of the distribution system, at which most of the Small and Large Primary Rate customers are supplied. Only the investment and expenses associated with the latter group of distribution substations were included in this substation cost analysis study.

Q. Please summarize the results of this study of distribution substation costs and how such costs were used to determine the Company's proposed Rider B discounts.

A. The annual revenue requirement of the distribution substations providing 4,160 to 13,800 volt service to primary service customers was determined to be $6,719,000 from Mr. Warwick's class cost of service study. The annual kilowatt billing demands of the SPS and LPS Rate customers that are not high voltage Rider B customers were 13,140,642 kilowatts during the test year. The monthly cost of such substations calculates to be $0.51 per kW-month based upon this data, which is the appropriate Rider B discount for customers providing their own substations and taking service from the Company at a higher voltage level that allows them to avoid the use of these distribution substations.

Q. Was a similar cost analysis performed for the remaining distribution substations in Account 362 that provide 34,500 to 69,000 volt service?

A. Yes, a comparable analysis for the balance of the distribution substations in Account 362, which transform only to 34,500 to 69,000 volts, determined their annual revenue requirements to be $5,475,000. The annual billing demands of all SPS and LPS Rate customers utilizing these substations were 16,576,798 kilowatts during the test year. The monthly cost of these higher voltage distribution substations calculates to be $0.33 per kW-month, based upon the latter data.

Q. How is this distribution substation cost of $0.33 per kilowatt-month used in determining the Rider B discount for customers taking service at 138,000 volts or higher?

A. The Company avoids the cost of both types of distribution substations describe above when a customer takes service at a voltage of 138,000 volts or higher. Therefore the appropriate Rider B discount for service at this voltage or higher is the summation of these two credits, or $0.84 per kilowatt-month.

Q. Were these two proposed Rider B discounts those used in the development of the Small and Large Primary Service Rates proposed by the Company in this case?

A. Yes, these were both used in arriving at the base rate components required to attain the total annual revenue targets for these two rate classes.

Proposed Rider E

Q. What is the general purpose of Rider E and how is it used?

A. The title of the current Rider E is Supplementary Service. In general terms, this rider is applicable to customers with a source of electrical generation other than that supplied by the Company. The rider is applicable to those situations where such a customer requires an electrical connection to the Company's system to either supplement the output of such generation, or to simply have the Company serve as standby and/or backup to the customer's generation during its forced outage and/or maintenance periods. For safety and reliability purposes, all Rider E customers are required to enter into a parallel operating agreement with the Company and, when required by Company, to provide, install and maintain a circuit breaker of a size and type approved by the Company.

Q. What are the current rates and charges applicable to a Rider E customer?

A. Rider E provides that it is applicable to customers taking service at a primary voltage level, and that such service should be billed under the provisions of a Primary Service Rate (SPS or LPS is not specified). Rider E also specifies a minimum monthly bill for such service to be no less than the bill for actual service or a bill based upon the LPS Demand Charge applied to the customer's Contract Demand. Contract Demand is the kilowatt level initially agreed to by Company (based upon customer's installed generation capacity) or the actual metered demand delivered to customer, whichever is greater.

Q. What decisions must be made by customers that elect to install generation and be subject to the provisions of Rider E?

A. Conceptually, customers that add generation on their premises should be required to make the following decisions regarding electric service from the Company a) the portion of their total electrical requirements they plan to generate (which could range from 0-100%); b) if the answer to (a) is 100%, the customer must decide whether or not to remain connected to the Company's distribution and transmission system; c) if electing to stay connected to the Company's system, the customer must decide what level of distribution and transmission capacity is required, i.e. for the total electrical use at the premises, only what is being purchase from the Company, or some other level; d) the portion, if any, of the customer's generation capacity that needs to be reserved by the Company. Obviously, many of these decisions that should be made by customers adding generation are interrelated.

Q. Do the Company's other customers, that do not own generation, receive all of these services from the Company as a part of their standard monthly bill for electric service?

A. Yes, customers taking their full electrical requirements from the Company receive adequate and reliable distribution, transmission and generation service, including reserve generation service, to meet all of their electrical needs whenever it is called upon. The cost of all such services is included in the rates upon which the monthly bills of such customers are based.

Q. Does it follow then, that customers with owned generation, that are partial requirements customers, should pay these same costs?

A. If such customers expect to be provided all of these same services by the Company, they should pay all of the same costs. That is why the partial requirements customer decisions, I referred to earlier, must addressed. Once the appropriate services are selected, such customers must pay for them, otherwise the full requirements customers will be subsidizing the partial requirements customers through their electric rates.

Q. Please describe some of the costs that you are referring to in more detail.

A. If a generation customer wants to completely disconnect from the Company's distribution system, there is no customer and no costs to be concerned with. The opposite extreme case is a customer that seeks to meet the entire electrical requirements of its premises with generation, but still wants to remain connected to the Company's distribution system so that the Company will stand by to potentially serve all of the Customer's electrical requirements in the event that all of a portion of the customer's generation fails. In the latter instance, the Company must standby, not only with generation capacity, but also with distribution and transmission capacity, to supply electrical usage that may only appear on the system for a few "outage" hours of the year, if at all. Obviously, if there is little or no electrical usage to bill such a customer for, the Company will not come close to recovering the fixed costs associated with these standby services, resulting in such costs being borne (and subsidized) by other full requirements customers.

Q, Is there a way, through a revision of Rider E, to insure that these potential subsidies do not occur or continue?

A. Yes, this can be reasonably addressed through a restructuring of Rider E by unbundling the costs of these various services and charging them to customers with generation in a way that is different than the way in which the Company's standard rates are applied. At this point in time, customer generation is the exception, rather than the rule, on the Company's system and this non-standard service requires something other than the Company's standard rate applications to adequately recover the costs related to such service.

Q. What would be the format and application of the unbundled rates the Company is proposing for such service?

A. Starting with the distribution and transmission system costs, the costs for such facilities were determined in Mr. Warwick's cost of service study and later converted into rate values for the various classes served by the Company. These rate components should be applied to the customer's total electrical requirements (i.e., the Company's main electrical supply meter plus a meter on the customer's generation) on the premises, and be billed each month, if the customer requires full standby service from these facilities. If the generation customer were willing to contract for a physical electrical limitation on such capacity, the Company would be willing to accommodate that customer request.

Q. How should the cost of standby or backup generation capacity be handled for such customers seeking this service?

A. A case can certainly be made that the backup requirement for a customer's single generation unit operation would be a second unit of exactly the same size. However, the Company's generation planning studies have determined that an 18% reserve margin is applicable to the diverse system operated by the Company, with its multiple types of generations and fuel sources. Thus, the Company is willing to provide such service to generation customers based upon the application of this reserve margin to the production demand cost that is embedded in the Large Primary Service Rate the Company is proposing in this case. The application of this resulting generation backup charge to the nameplate capacity of the customer's generator(s) would also be billed each month of the year.

Q. How would the billing for any service used by generation customers be handled on a month to month basis?

A. In addition to the monthly charges discussed above, generation customers would be subject to a monthly Customer Charge, the LPS Reactive charge, and the LPS Demand and Energy charges applied to all use through the customer's main meter. In addition, unless otherwise excluded by the customer, the Generation Backup Charge discussed earlier would also apply each month. Where the customer's generator failed for all or a portion of any billing month, adjustments will be made to the customer's energy and production billing demand quantities to reflect load normally served by such generation. Typically, the additional monthly production billing demand associated with the generator failure would be prorated based on days' use, while the additional energy would be charged at standard rates plus an adder to reflect the Company's higher incremental costs associated with serving such load.

Q. Have you prepared a revised Rider E tariff as a part of the Company's proposed rates in this case?

A. Yes, the Company's proposed Rider E tariff is attached hereto as Schedule 16 of my testimony.

<u>Rider RDC - Reserve Distribution Capacity Rider</u>

Q. What is the intent and purpose of this Rider RDC?

A. Rider RDC is a new optional rider the Company is proposing in response to requests from a number of its commercial and industrial customers for higher reliability distribution service, above that which the Company normally provides under its existing rate structures and charges. The types of customers that have inquired about such a service include customers with large computer data centers and/or computer controlled manufacturing or other industrial processes where interruptions in their electrical supply may significantly disrupt their operations. The purpose of this rider is to respond to these customer requests, where it is feasible to do so, and where the customer making the request agrees to pay the additional cost of the Company's distribution system enhancements under the terms and conditions of the proposed Rider RDC.

Q. Absent this proposed Rider, how does the Company currently respond to such customer requests for additional distribution reserve service?

A. Currently, the Company can only offer such a service under the provisions of Section III.Q. of the Rules and Regulations provisions of its Missouri tariffs. These current tariff provisions require a substantial up-front payment by the customer, additional payment for subsequent changes in facilities and less than a 100% guarantee that such reserve capacity will continue to be available in the future.

Q. What options does the proposed Rider RDC offer to customers that are not covered or contained in the Company's current tariffs?

A. The proposed optional Rider RDC allows customers having demands of 500 kilowatts or more to contract with the Company for any desired level of distribution reserve capacity, not on the customer's property, for an initial five-year period that is renewable thereafter on a year-to-year basis. The customer is required to pay a lower up-front charge for all system improvements necessary to accommodate the request of reserve capacity, and a monthly charge thereafter, based upon existing tariff rates. Duplicate facilities on the customer's property such as second service lines or second reserve transformers, etc. will still be paid for by the customer under the Company's Special Facility tariffs, and these costs are not addressed by the provisions of Rider RDC, which applies only to off-site distribution costs. The specific tariff language the Company is proposing for this tariff is attached hereto as Schedule 17 of my testimony.

Tariff Sheet No. 178 - Deposit Practices

Q. Is the Company also proposing to modify its tariffs in order to index the interest rate that it is currently paying on customer deposits?

A. Yes, the current interest rate in the Company's tariffs applicable to customer deposits is 9.5%, which is far in excess of current market rates for such interest bearing investments such as pass book savings accounts, certificates of deposit, money market funds, etc.

Q. What revision in this tariff is the Company proposing?

A. Rather than having the tariff contain a fixed interest rate which requires both Company and Commission action to make periodic updates, the Company is proposing that the rate of interest on deposits be calculated annually in November of each year, for use during the following calendar year. The rate would be based upon the published interest rate for the average one-year yield on U.S. Treasury securities during the last full week in November, rounded to the nearest one-half of one percent. The specific tariff language being proposed is attached hereto as Schedule 18 of my testimony.

<u>The Company's Proposed Alternative Regulation Plan</u>

Q. The Company has submitted its proposal for an Alternative Regulation Plan as a part of its testimony in this case, is that correct?

A. Yes, this proposed plan is discussed in the testimony of Company witness Warner L. Baxter.

Q. Please describe the general application of the permanent rate reduction the Company is proposing to file as a part of that Plan.

A. The Company's proposal is to file tariffs to implement this rate reduction to be effective on April 1, 2002. It provides for the reduction to apply on an equal percentage basis within and among rate classes (excluding customer and miscellaneous charges) for all Missouri retail electric customers.

Q. Will this proposed general application of the permanent rate reduction contained in the Company's proposed Plan maintain existing rate relationships both between and within each of the Company's rate classes?

A. Yes, it will continue such existing relationships. This proposed methodology is virtually identical to how the Company has implemented some rate reductions in the past.

Q. Does this conclude your 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 RICHARD J. KOVACH

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

Richard J. Kovach, being first duly sworn on his oath, states:

1. My name is Richard J. Kovach. I work in St. Louis, Missouri and I am employed by Ameren Services Company as Manager, Rate Engineering.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 110 pages, Appendices A and B and Schedules 1 through 18, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Richard J. Kovach
Richard J. Kovach

Subscribed and sworn to before me this 7th day of May, 2002.

Debby Anzalone
Notary Public

My commission expires:

DEBBY ANZALONE
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: April 18, 2006

QUALIFICATIONS OF RICHARD J. KOVACH

My name is Richard J. Kovach, and I reside in St. Louis County, Missouri.

I received the degrees of Bachelor of Science in Industrial Engineering in 1962 and Master of Engineering Administration in 1967 from Washington University in St. Louis, Missouri.

I was employed as an Assistant Engineer in the Rate and Statistical Department of Union Electric in January 1963. My work in the Department included assignments relating to the general analysis and administration of various aspects of Union Electric's electric, gas and steam rates. From 1966 to 1970, I held various engineering positions in the Corporate Planning, Transmission and Distribution, Engineering and Construction, and Power Operations functions of the Company. In April 1970, I returned to the Corporate Planning Function and was appointed Supervising Engineer - Rates and Planning in that function in February 1973. In the latter position I was responsible for day-to-day rate and tariff administration, conducting studies relative to utility cost-of-service and participation in Union Electric Company rate case proceedings. I was appointed to my present position of Manager of Rate Engineering in April 1975 and to the same position with Ameren Services in 1998.

I currently have responsibility for the general policies and practices associated with the day-to-day administration and design of Union Electric's electric and gas rate tariffs, riders and rules and regulations tariffs on file with the Missouri Public Service Commission and the Illinois Commerce Commission, and in the participation in various proceedings before these regulatory agencies. In addition, Rate Engineering is responsible for conducting class cost-of-service and rate design studies, and the participation in other projects of a general corporate nature, as requested by the Vice President of Corporate Planning.

I am a registered Professional Engineer in the States of Missouri and Illinois. In addition, I am the Ameren Services representative on the Edison Electric Institute (EEI) Economic Regulation & Competition Committee (the former Rate Research Committee). The EEI Committee provides its membership with current information applicable to various rate design and regulatory concepts, as well as new and proposed state and federal legislation. Its membership consists of the individuals responsible for rate design and administration from virtually every investor-owned utility in the United States. I was also the Company's representative on the Associated Edison Illuminating Companies (AEIC) Load Research Committee from 1988-1998, serving as the Chairman of that Committee from 1993-95.

EXECUTIVE SUMMARY

Richard J. Kovach

Manager, Rate Engineering Department of Ameren Services

* * * * * * * * * *

The purpose of my testimony, and that of my associates, Mr. James R. Pozzo and Mr. William M. Warwick, is to address the Commission Staff's position in several areas of this case, as follows:

- Customer Growth Adjustment - Doyle Gibbs
- Loss Factor Adjustment / Jurisdictional Allocations and Methodology - Alan Bax
- Rate Design-James Watkins and Janice Pyatte / Sales and Revenues-Janice Pyatte

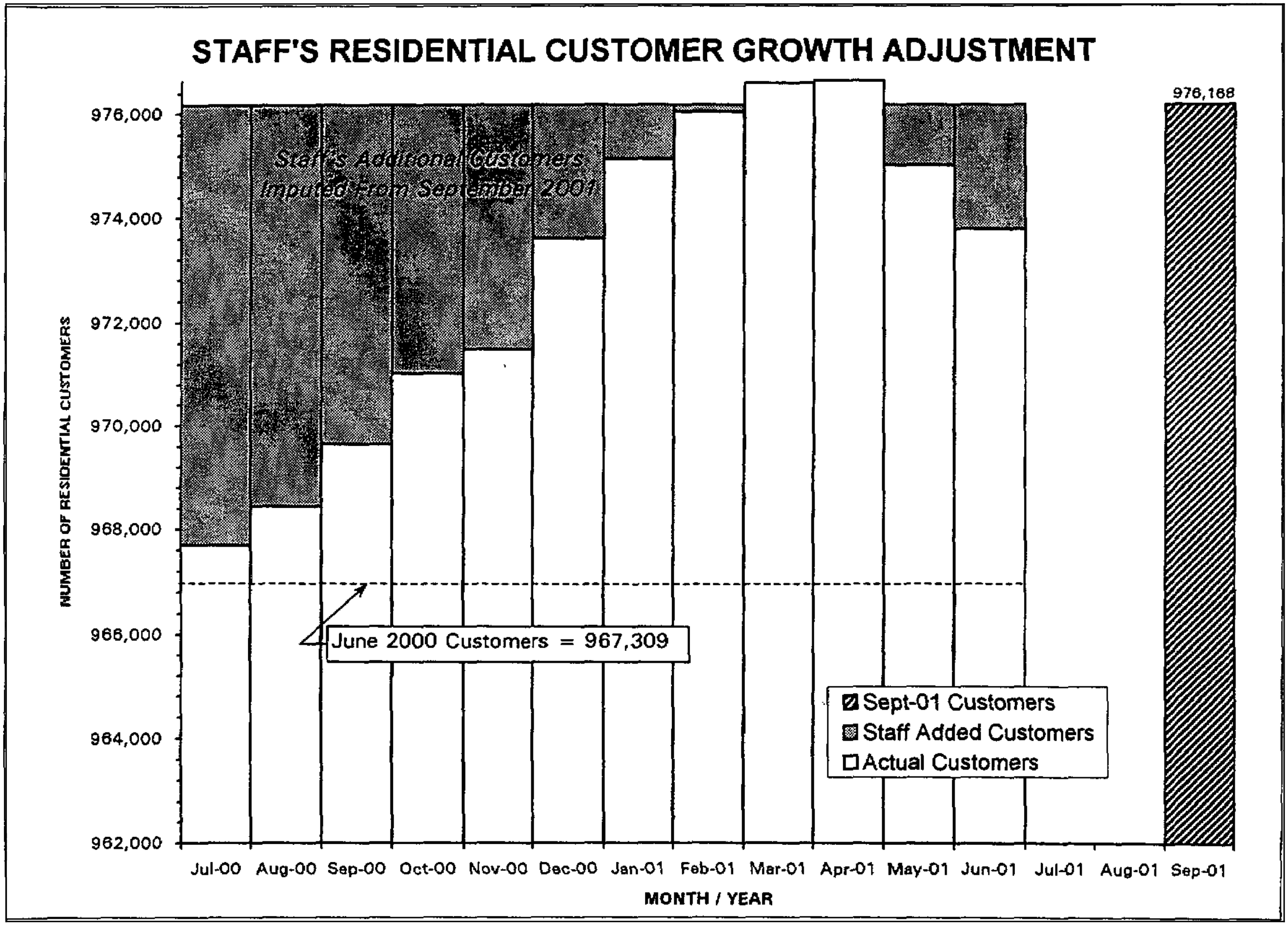
Customer Growth Adjustment - The Staff proposes to increase the test year (July 2000-June 2001) customers to the number of customers on September 30, 2001, and by that adjustment impute $18 million of "phantom" revenues, net of taxes, which the Company did not realize during the test year, and will not realize in total, if at all, until at least September 30, 2002. Staff's cost allowance for serving such additional customers consisted of average fuel expense, ignoring the fact that incremental growth will be supplied at incremental fuel costs that are often twice the magnitude of average costs. In addition, the Staff also ignored numerous other obvious direct costs required to serve additional customers such as meter reading, billing, postage, customer accounting, call center, credit and collection and distribution operating expenses. Significantly, the Staff also excluded any consideration of its customer growth adjustment from its Missouri jurisdictional demand and energy allocation factor calculations, resulting in no demand or energy costs allocated to Missouri for such growth. The Staff's proposed customer growth adjustment violates the test year and update provisions ordered by the Commission in this case as it imputes revenues and sales into the test year that the Company will not fully realize until September 30, 2002, if at all, and should be rejected for that reason alone. Even if considered, however, the growth adjustment suffers from the serious deficiencies of failing to properly provide for the direct costs associated with serving additional customers. Moreover, Staff ignores the impact of their growth adjustment upon both the Missouri jurisdictional demand and energy allocation factors, which totally ignores production and transmission fixed costs and under allocates energy costs to Missouri.

Loss Factor - The kilowatthours associated with the Staff's customer growth adjustment were adjusted only for average losses, which understate losses for the secondary voltage residential and general service customers that constitute most of this adjustment. As a result, the Staff's production cost model used to determine the additional fuel cost of these understated system requirements, also understated the fuel cost for these customers.

Jurisdictional Methodology and Allocations - Staff recommends the use of the twelve monthly system coincident peaks (12 CP) allocation methodology in arriving at the Missouri jurisdictional demand allocation factor. The Company's monthly peak demands that Staff relied upon in making this recommendation do not support the use of this methodology. Using this same data with three standard tests, established by the Federal Energy Regulatory Commission (FERC), demonstrates conclusively that the 12 CP jurisdictional allocation methodology is <u>not</u> appropriate for the Company, but that a 4 CP or 3 CP methodology is appropriate. Significantly, the Staff excluded any consideration of its proposed customer growth adjustment from its Missouri jurisdictional demand and energy allocation calculations, resulting in no allowance for Missouri demand costs and an under allocation of energy costs to Missouri for such growth.

Rate Design - The Staff proposed to allocate any class rate reductions resulting from this case on the basis of a stipulation in the Company's last rate design case. That stipulation is non-binding in this case and was based upon an out of date test year ending September 1996. The Company's overall revenues in this case should be distributed to customer classes by initially equalizing class rates of return, based upon the class cost of service study sponsored by Mr. Warwick, and then assigning any additional revenue adjustments on the basis of the allocated rate base of each class, as also determined by Mr. Warwick's analysis. The results of these steps are outlined in Schedules 6 and 7 of my testimony. The specific class rates that result from the first step of equalizing class rates of return are contained in my Schedules 11-15, based upon the Company's current level of total Missouri revenues. Subsequent schedules reflect a proposed revision of Rider E applicable to customers with generation, a new proposed optional Rider RDC for enhanced distribution system reliability service and a proposed revision to index the rate of interest paid by the Company on customer deposits.

Sales and Revenues - Sales, revenues and rate billing units, for the twelve month ending June 2001 test year, were developed by Mr. Pozzo based upon the Company's weather normalized sales and are provided in his Schedules for use in the subsequent design of final rates as a part of this case. This twelve month test year is in accord with similar work performed by the members of the Staff responsible for rate design, and can be used in the design of any level of class revenues that may be ordered by the Commission in this case. In addition, a sample of the sales and revenue reconciliation report recommended by Staff in this case has been developed and is contained in Schedule 8 of my testimony. The Company plans to continue to work with the Staff to modify this report in an effort to meet all practicable sales and revenue reconciliation requirements.


STAFF'S RESIDENTIAL CUSTOMER GROWTH ADJUSTMENT
Staff's Additional Customers
Imputed From September 2001
976,168
June 2000 Customers = 967,309
Sept-01 Customers
Staff Added Customers
Actual Customers
NUMBER OF RESIDENTIAL CUSTOMERS
976,000
974,000
972,000
970,000
968,000
966,000
964,000
962,000
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Dec-00
Jan-01
Feb-01
Mar-01
Apr-01
May-01
Jun-01
Jul-01
Aug-01
Sep-01
MONTH / YEAR

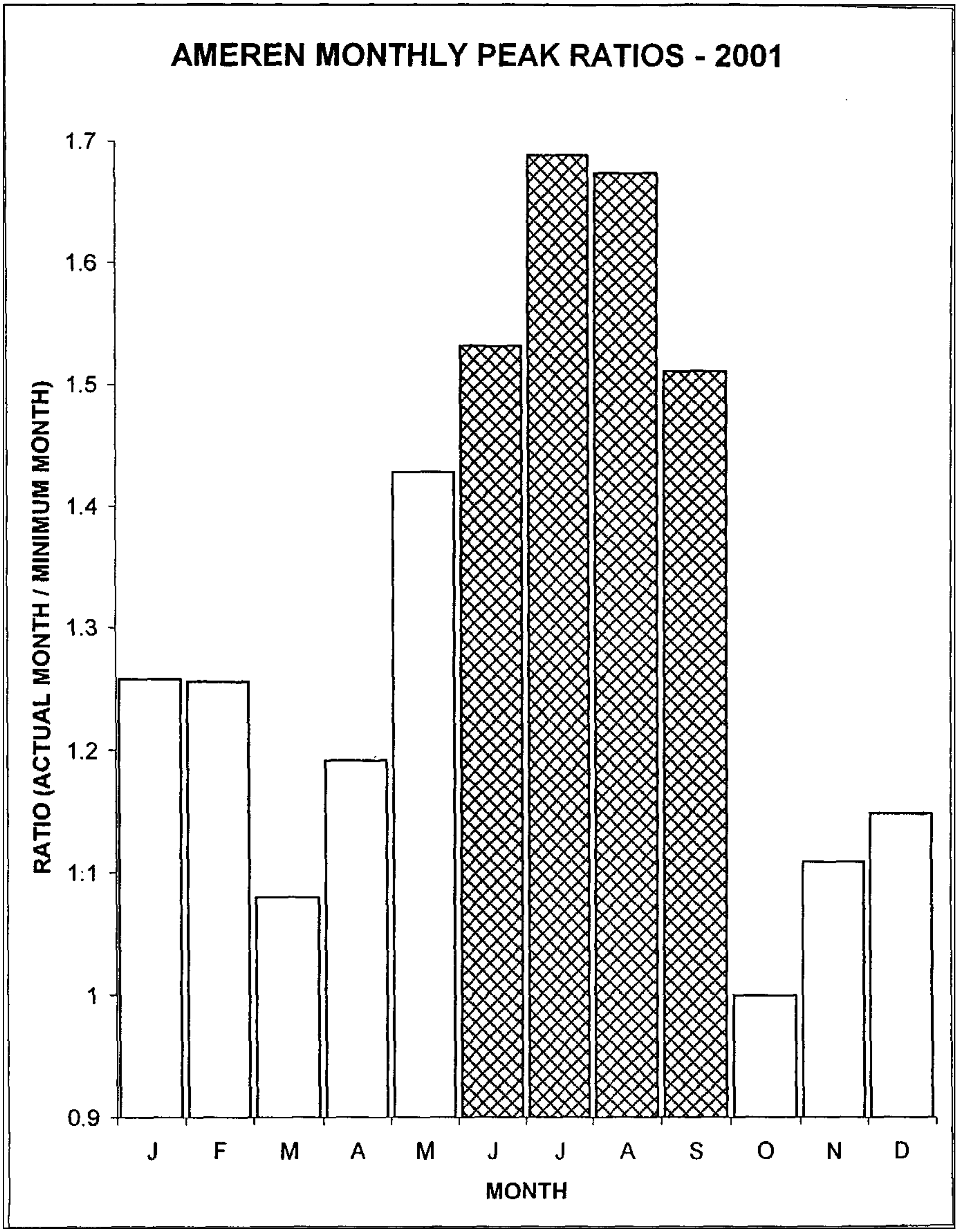
Schedule 1-1

Additional Missouri Coincident Peak (CP) Demands (MW)
Related to Staff's Proposed Customer Growth Adjustment

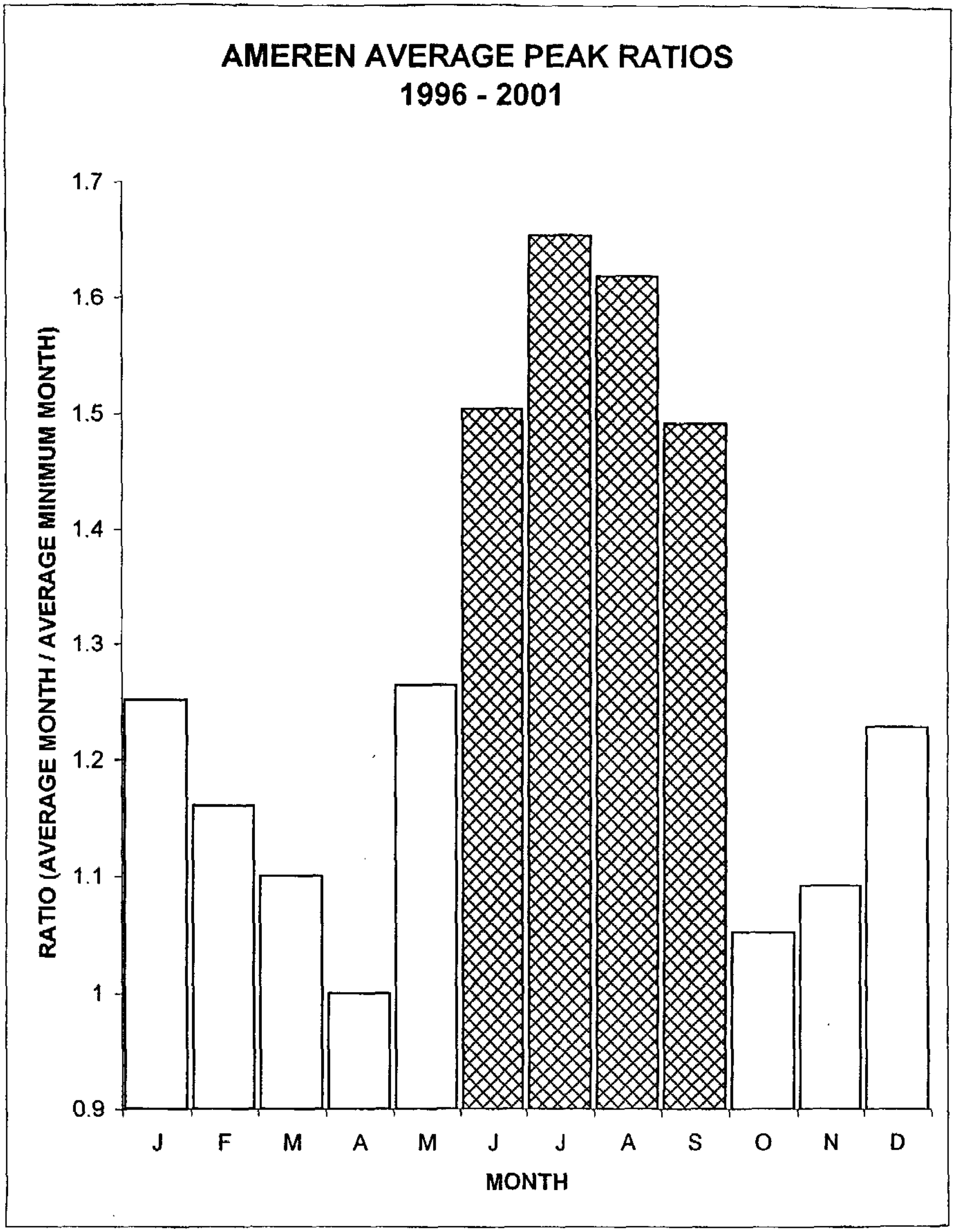
July 2000 - June 2001

	Additional CP	Adjust for Other	Actual CP Demands (MW) (1)		Adjusted CP Demands (MW) (2)(3)	
Month	Demands (MW)(2)	Demands (MW)(3)	MO retail	Total AmerenUE	MO Retail	Total AmerenUE
Jul-00	107.2	-64.3	7038	7727	7145.2	7769.9
Aug-00	92.5	-70.1	7401	8155	7493.5	8177.3
Sep-00	93.2	-70.6	7106	7851	7199.2	7873.7
Oct-00	60.4	-63.6	5318	5916	5378.4	5912.8
Nov-00	51.8	-109.6	4864	5489	4915.8	5431.2
Dec-00	50.1	-140.0	5645	6354	5695.1	6264.1
Jan-01	42.9	-15.6	5359	5943	5401.9	5970.2
Feb-01	20.6	-47.7	5314	5934	5334.6	5906.9
Mar-01	2.0	-7.5	4514	5105	4516.0	5099.5
Apr-01	49.1	-5.4	5091	5631	5140.1	5674.8
May-01	81.3	-5.8	6156	6749	6237.3	6824.5
Jun-01	41.8	-49.1	6547	7240	6588.8	7232.7
CP Totals						
12 CP Totals	692.9	-649.3	70,353	78,094	71,046	78,138
Jurisdictional Factor			90.09%	100.00%	90.92%	100.00%
4 CP Totals	334.7	-254.1	28,092	30,973	28,427	31,054
Jurisdictional Factor			90.70%	100.00%	91.54%	100.00%

(1) Source: Alan Bax Schedule 4.
(2) Actual CP Demands plus Additional CP Demands for Customer Growth.
(3) Adjust for loss of Rolla and Laclede Steel CP Demands.


AMEREN MONTHLY PEAK RATIOS - 2001
RATIO (ACTUAL MONTH / MINIMUM MONTH)
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1
0.9
J
F
M
A
M
J
J
A
S
O
N
D
MONTH

Schedule 2-1



AMEREN AVERAGE PEAK RATIOS
1996 - 2001
RATIO (AVERAGE MONTH / AVERAGE MINIMUM MONTH)
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1
0.9
J
F
M
A
M
J
J
A
S
O
N
D
MONTH

Schedule 2-2

AMERENUE FORM 1 MONTHLY COINCIDENT PEAKS (MW)

	2001	2000	1999	1998	1997	1996	Average	% Minimum
January	5943	5772	6164	5549	6224	6092	5957	1.25
February	5934	5496	5166	5141	5286	6137	5527	1.16
March	5105	4719	5276	5673	4906	5737	5236	1.10
April	5631	4488	4685	4415	4804	4537	4760	1.00
May	6749	6992	5086	6642	4464	6166	6017	1.26
June	7240	6755	7235	7601	7155	6971	7160	1.50
July	7979	7520	8399	8060	7642	7621	7870	1.65
August	7910	7836	8120	7745	7107	7511	7705	1.62
September	7142	7520	7211	7611	6868	6244	7099	1.49
October	4727	5833	4671	4868	5524	4428	5009	1.05
November	5241	5593	5166	4670	5198	5319	5198	1.09
December	5428	6348	5840	5900	5541	6045	5850	1.23

From Mr. Bax's Testimony (Yr. 2001)				
Maximum Demand	7,979	% of Max.		
Minimum Demand	4,727	59.24%	FERC 1st Test (on and off-peak demand test)	94.85% - 70.12% = 24.73%
Summer Average	7,568	94.85%	FERC 2nd Test (Low to Annual peak demand)	4727 MW/ 7979 MW = 59.24%
Winter Average	5,595	70.12%	FERC 3rd Test (Average to Annual peak demand)	6252 MW/ 7979 MW = 78.36%
Average	6,252	78.36%		

Using Averages from Mr. Bax's Testimony				
Maximum Demand	7,870	% of Max.		
Minimum Demand	4,760	60.48%	FERC 1st Test (on and off-peak demand test)	94.77% - 69.17% = 25.6%
Summer Average	7,458	94.77%	FERC 2nd Test (Low to Annual peak demand)	4760 MW/ 7870 MW = 60.48%
Winter Average	5,444	69.17%	FERC 3rd Test (Average to Annual peak demand)	6116 MW/ 7870 MW = 77.71%
Average	6,116	77.71%		

FERC TEST RANGES

	3 or 4 CP	12 CP
FERC 1st Test (on and off-peak demand test)	26% to 31%	18% to 19%
FERC 2nd Test (Low to Annual peak demand)	55.8% to 61.9%	66% to 80%
FERC 3rd Test (Average to Annual peak demand)	79.4% to 81.2%	81% to 88%

Schedule 3-1

A Guide To FERC Regulation and Ratemaking of Electric Utilities and Other Power Suppliers

Third Edition

Michael E. Small

Edison Electric Institute
WASHINGTON, DC

Schedule 3-2

About the Author

Michael E. Small is a partner in the law firm of Wright & Talisman, P.C., Washington, D.C., which has one of the oldest and largest energy practices in Washington. Mr. Small, who also holds a B.S. in Nuclear Engineering, has been involved in hundreds of FERC cases, both as an employee of the FERC and as an outside lawyer. Mr. Small has over fourteen years of experience in matters involving FERC and about seventeen years of experience in the energy area.

While at FERC, Mr. Small was one of the first FERC staff trial supervisors in the electric utility area through his position as a Special Assistant to the Deputy General Counsel for Litigation and Enforcement. He also supervised gas pipeline rate litigation and represented FERC in electric and gas pipeline cases before federal courts.

At Wright & Talisman, P.C. (since 1985), Mr. Small has represented electric utilities and gas pipelines in proceedings at FERC, before U.S. Court of Appeals, and before the U.S. Supreme Court. Mr. Small currently is the general counsel to the Western Systems Power Pool and previously either has represented or performed work for the Edison Electric Institute and for the Interstate Natural Gas Association of America. Mr. Small also has represented and advised clients involved in the development of qualifying facilities.

On the subject of electric utility ratemaking, Mr. Small previously authored *A Guide to FERC Electric Utility Ratemaking* (AIS 1989), the "FERC Electric Rate Primer," 5 Energy Law Journal 1, p. 107 (1984), and the *Federal Energy Regulatory Commission Electric Utility Handbook* (FERC 1983). Mr. Small also has written on natural gas pipeline rate and natural gas production regulation and has taught courses on both electric and gas pipeline rate regulation.

Chapter Five—Functionalization, Classification, and Allocation

In allocating costs to a particular class of customers, there are three major steps (if all cost of service issues have been resolved): (1) functionalization, (2) classification, and (3) allocation. FERC has indicated that a guiding principle for this step is that the allocation must reflect cost causation. *See, e.g., Kentucky Utilities Co.*, Opinion No. 116-A, 15 FERC ¶61,222, p. 61,504 (1983); *Utah Power & Light Co.*, Opinion No. 113, 14 FERC ¶61,162, p. 61,298 (1981).[133]

A. Functionalization

Generally, plant or expense items are first functionalized into five major categories:

(1) Production;

(2) Transmission;

(3) Distribution;

(4) General and Intangible; and

(5) Common and Other.

See 18 C.F.R. §35.13(h)(4)(iii) (plant); 18 C.F.R. §35.13(h)(8)(i) (O&M expenses). Each plant or expense item will be segregated into the category with which it is most closely related.

While functionalization for most items is relatively straightforward, and not usually litigated, problems do arise with respect to the functionalization of administrative and general expenses (A&G)[134] and general plant expenses.[135] FERC stated that:

> The Commission normally requires that A&G and General Plant expenses be allocated on the basis of total company labor ratios. Under such allocation method, A&G and General Plant expense items are 'functionalized,' or segregated into...

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133 Where a company has significant non-jurisdictional business, the above cost incurrence principle is important in keeping FERC within its jurisdictional constraints. *See Panhandle Eastern Pipe Line Co. v. FPC*, 324 U.S. 635, 641-42 (1945) ("the Commission must make a separation of the regulated and unregulated business...Otherwise the profits or losses...of the unregulated business would be assigned to the regulated business and the Commission would transgress the jurisdictional lines which Congress wrote into the Act").

134 A&G expenses include salaries of officers, executives, and office employees, employee benefits, insurance, etc.

135 General plant includes office furniture and equipment, transportation vehicles, lockers, tools, lab equipment, etc.

Schedule 3-2b

> production, transmission, distribution, customer accounts, customer service, information, and sales. This 'functionalization' is in proportion to the ratio of the labor cost in each major function to total labor costs less A&G and General Plant labor. Each functionalized component is allocated to customer groups.

Utah Power & Light Co., Opinion No. 308, 44 FERC ¶61,166, p. 61,549 (1988). *See also Minnesota Power & Light Co.*, Opinion No. 20, 4 FERC ¶61,116, p. 61,268 (1978) (general plant will be functionalized by labor ratios unless it is shown that the use of labor ratios produces unreasonable results). In many cases, FERC has allowed labor ratios to be used to functionalize general plant. *See, e.g., Utah Power & Light Co.*, Opinion No. 308, 44 FERC at 61,549; *Kansas City Power & Light Co.*, 21 FERC ¶63,003, p. 65,034 (1982), *aff'd*, 22 FERC ¶61,262 (1983); *Delmarva Power & Light Co.*, 17 FERC ¶63,044, p. 65,204 (1981), *aff'd*, Opinion No. 185, 24 FERC ¶61,199 (1983); *Philadelphia Electric Co.*, 10 FERC ¶63,034, pp. 65,355-56, *aff'd*, 13 FERC ¶61,057 (1980). Similarly, FERC has required that most A&G expenses be functionalized on the basis of labor ratios. *Missouri Power & Light Co.*, Opinion No. 31, 5 FERC ¶61,086, pp. 61,137-38 (1978); *Kansas City Power & Light Co.*, 21 FERC at 65,035; *Delmarva Power & Light Co.*, 17 FERC at 65,204. An exception to this has been established for property insurance which has been functionalized on plant ratios. *Pacific Gas & Electric Co.*, 16 FERC ¶63,004, pp. 65,015-16 (1981), *aff'd*, Opinion No. 147, 20 FERC ¶61,340 (1982); *Kansas-Nebraska Natural Gas Co.*, Opinion No. 731, 53 FPC 1691, 1722 (1975).

Common plant and intangible plant also have been analogized to general plant and functionalized on the basis of labor ratios. *Kansas City Power & Light*, 21 FERC at 65,035; *Delmarva Power & Light Co.*, 17 FERC at 65,204; *Philadelphia Electric*, 10 FERC at 65,355-56.

Another issue that has arisen is the calculation of the labor ratios. Usually, the labor ratio consists of total labor costs in the denominator with the labor costs associated with a particular category in the numerator. In a number of proceedings, companies have attempted to change the ratio by only including production, transmission, and distribution-related labor costs in the denominator, thereby excluding customer service related labor costs. FERC rejected this in at least one case. *Kansas City Power & Light*, 21 FERC at 65,033-34.

B. Classification

After functionalizing, the next step is to classify those expenses or costs into one of three categories (1) demand, (2) energy, or (3) other. *See* 18 C.F.R. §35.13(h)(8)(ii)(A).

FERC's Staff for a number of years has used the predominance method for classifying production O&M accounts. Under this method if an account is *predominantly* (51–100%) energy-related, it will be classified as energy. The same also is true with respect to demand related costs. FERC has accepted this method in a number of cases. *See, e.g., Arizona Public Service Co.*, 4 FERC ¶61,101, pp. 61,209–10 (1978); *Illinois Power Co.*, 11 FERC ¶63,040, pp. 65,255–56 (1980), *aff'd*, 15 FERC ¶61,050, p. 61,093 (1981); *Kansas City Power & Light*

Schedule 3-2c

Co., 21 FERC ¶63,003, p. 65,037 (1982), *aff'd*, 22 FERC ¶61,262 (1983); *Minnesota Power & Light Co.*, Opinion No. 86, 11 FERC ¶61,312, pp. 61,648-49 (1980).[136]

In addition to FERC's adoption of Staff's predominance method, FERC also has adopted Staff's classification index of production O&M accounts. *Arizona Public Service Co.*, 4 FERC at 61,209-10; *Kansas City Power & Light*, 21 FERC at 65,037; *Minnesota Power & Light Co.*, 11 FERC at 61,648-49. In *Montaup Electric Co.*, Opinion No. 267, 38 FERC at 61,864, FERC rejected a proposed rate tilt, finding that the "proposal is inconsistent with the classification table of predominant characteristics for operation and maintenance accounts used by Staff, which has been approved by the Commission." In *Southern Company Services*, Opinion No. 377, 61 FERC ¶61,075, p. 61,311 (1992), *reh. denied*, 64 FERC ¶61,033 (1993), FERC, however, stated that the Staff index is not mandatory. FERC accepted a departure from the Staff's index, though it held that a party proposing a departure has the burden of justifying that departure.

C. Allocation

After classifying costs to demand, energy, and customer categories, the next step is to allocate these costs to the various classes to determine their respective cost responsibilities. In the past, the most hotly litigated allocation issue involved demand cost allocation. Typically, FERC has allocated demand costs on a coincident peak (CP) method. *Houlton v. Maine Public Service Co.*, 62 FERC ¶63,023, p. 65,092 (1992) ("Maine Public has cited a legion of Commission decisions affirming the use of a coincident peak demand allocator.... And, it denies knowledge of '*any* decision, involving an electric utility since the FERC came into existence in 1977, where FERC did not follow a coincident peak method of allocating demand costs' "). In *Lockhart Power Co.*, 4 FERC ¶61,337, p. 61,807 (1978), FERC stated that its "general policy is to allocate demand costs on the basis of peak responsibility as is demonstrated by the overwhelming majority of decided cases." *See also Houlton v. Maine Public Service Co.*, 62 FERC at 65,092. Under a CP method, the demands used in the allocation are the demands of a particular customer or class occurring at the time of the system peak for a particular time period. The basic assumption behind this method is that capacity costs are incurred to serve the peak needs of customers.

1. Coincident Peak Allocation

In most cases, FERC has accepted one of four CP methods—1 CP, 3 CP, 4 CP, and 12 CP, with the largest number of companies using a 12 CP allocation. Under a 1 CP method, the allocator for a particular wholesale class will be developed by dividing the wholesale class's CP for the peak month by the total company system peak. Similarly, for 3, 4, and 12

136 If a company is able to justify a percentage split, such as 70-30, in an account, then FERC may accept that split. However, in light of FERC precedent on this subject, any party proposing a deviation from the predominance method likely will have the burden of justifying its proposed split.

CP companies the numerator would consist of the average of the wholesale class's coincident peaks for each of the peak months, while the denominator would consist of the average of the total system peaks for each of the peak months. FERC has held that interruptible loads should not be reflected in this demand allocation.[137] *See Delmarva Power & Light Co.*, Opinion No. 189, 25 FERC at 61,121; *Delmarva Power & Light Co.*, Opinion No. 185, 24 FERC ¶61,199, p. 61,462 (1983).

While FERC has not established a hard and fast rule for determining which allocation method is appropriate, it has stated that the following factors should be considered:

> [T]he full range of a company's operating realities including, in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments. (footnote omitted).

Carolina Power & Light Co., Opinion No. 19, 4 FERC ¶61,107, p. 61,230 (1978); *Commonwealth Edison Co.*, 15 FERC ¶63,048, p. 65,196 (1981), *aff'd*, Opinion No. 165, 23 FERC ¶61,219 (1983); *Illinois Power Co.*, 11 FERC ¶63,040, pp. 65,247–48 (1980), *aff'd*, 15 FERC ¶61,050 (1981). *See also Houlton v. Maine Public Service Co.*, 62 FERC at 65,092 (applying FERC's various tests in finding that a 12 CP was appropriate).

a. System Demand Tests

If a utility's system demand curve is relatively flat, then that supports the use of a 12 CP method under FERC precedent. If a utility experiences a pronounced peak during one, three, or four consecutive months, then under FERC precedent the use of another CP method would be supported.

In determining whether a utility experiences a pronounced peak during a particular time period, FERC considers a number of tests. First, FERC has compared the average of the system peaks during the purported peak period, as a percentage of the annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak. FERC has held that large differences between these two figures lends support to using something other than a 12 CP method, while a smaller difference supports 12 CP, as shown below:[138]

(1) *Louisiana Power & Light Co.*,
Opinion No. 813,
59 FPC 968 (1977)
(31% difference—4 CP);

[137] FERC ordered that the revenues from the interruptible loads be credited to the cost of service. *Delmarva Power & Light Co.*, 28 FERC ¶61,279, p. 61,510 (1984).

[138] *See also Houlton v. Maine Public Service Co.*, 62 FERC ¶63,023, p. 65,092 (1992) (the ALJ stated that "using established Commission tests that compare average monthly peaks with the annual peak, lowest monthly peak to the annual peak, average monthly demand peaks of the peak season to the monthly demand peaks of the off-peak service" Maine Public is a 12 CP company).

(2) *Louisiana Power & Light Co.*,
Opinion No. 110,
14 FERC ¶61,075 (1981)
(26% difference—4 CP);

(3) *Lockhart Power Co.*,
Opinion No. 29,
4 FERC ¶61,337 (1978)
(18% difference—12 CP);

(4) *Illinois Power Co.*,
11 FERC at 65,248,
(19% difference—12 CP);

(5) *Commonwealth Edison Co.*,
15 FERC at 65,196
(16.4-24.9% differences—4 CP);

(6) *Southwestern Public Service Co.*,
18 FERC at 65,034
(average difference of 22.9%; high of 28.3%—3 CP).

FERC also has used a second test involving the lowest monthly peak as a percentage of the annual peak. The higher the percentage, the greater the support for 12 CP. This test has been used in the following cases:

(1) *Louisiana Power & Light Co.*,
Opinion No. 813,
59 FPC 968 (1977)
(56%—4 CP);

(2) *Idaho Power Co.*,
Opinion No. 13,
3 FERC ¶61,108 (1978)
(58%—3 CP);

(3) *Southwestern Electric Power Co.*,
Opinion No. 28,
4 FERC ¶61,330 (1978)
(55.8%—4 CP);

(4) *Lockhart Power Co.*,
Opinion No. 29,
4 FERC ¶61,337 (1978)
(73%—12 CP);

(5) *Southern California Edison Co.*,
Opinion No. 821,
59 FPC 2167 (1977)
(79%—12 CP);

(6) *Alabama Power Co.*,
Opinion No. 54,
8 FERC ¶61,083 (1979)
(75%—12 CP);

(7) *Illinois Power Co.*,
11 FERC at 65,248
(66%—12 CP);

(8) *Commonwealth Edison Co.*,
15 FERC at 65,198
(64.6–67.8%—4 CP);

(9) *Louisiana Power & Light Co.*,
Opinion No. 110,
14 FERC ¶61,075 (1981)
(61.9%—4 CP);

(10) *El Paso Electric Co.*,
Opinion No. 109,
14 FERC ¶61,082 (1981)
(71%—12 CP);

(11) *Carolina Power & Light Co.*,
Opinion No. 19,
4 FERC ¶61,107 (1978)
(72%—12 CP);

(12) *New England Power Co.*,
Opinion No. 803,
58 FPC 2322 (1977)
(80%—12 CP);

(13) *Southwestern Public Service Co.*,
18 FERC at 65,034
(on average, almost 67 percent—3 CP); and

(14) *Delmarva Power & Light Co.*,
17 FERC at 65,201
(71.4%—12 CP).

Another test that has been utilized by FERC is the extent to which peak demands in non-peak months exceed the peak demands in the alleged peak months. In *Carolina Power & Light Co.*, Opinion No. 19, 4 FERC at 61,230, FERC adopted a 12 CP approach where the monthly peaks in three nonpeak months exceeded the peaks in two of the alleged peak months. In *Commonwealth Edison Co.*, 15 FERC at 65,198, FERC adopted a 4 CP method where over a four year period, a peak in one of the 4 peak months was exceeded only once by a peak from a non-peak month. *See also Southwestern Public Service Co.*, 18 FERC at 65,034 (monthly peak in any non-peaking month exceeded the monthly peak in peak month only once and 3 CP adopted).

A last test involves the average of the twelve monthly peaks as a percentage of the highest monthly peak and has been used in the following cases:

(1) *Illinois Power Co.*,
11 FERC at 65,248–49
(81%—12 CP);

(2) *El Paso Electric Co.*
Opinion No. 109,
14 FERC ¶61,082 (1981)
(84%—12 CP);

(3) *Lockhart Power Co.*,
Opinion No. 29,
4 FERC ¶61,337 (1978)
(84%—12 CP);

(4) *Southern California Edison Co.*,
Opinion No. 821,
59 FPC 2167 (1977)
(87.8%—12 CP);

(5) *Louisiana Power & Light Co.*,
Opinion No. 110,
14 FERC ¶61,075 (1981)
(81.2%—4 CP);

(6) *Commonwealth Edison Co.*,
15 FERC at 65,198
(79.4–79.5%—4 CP);

(7) *Southwestern Public Service Co.*,
18 FERC at 65,035
(80.1%—3 CP); and

(8) *Delmarva Power & Light Co.*,
17 FERC at 65,202
(83.3%—12 CP).

b. Tests Relating to Reserves/Maintenance

To the extent a utility uses the off-peak months to perform its scheduled maintenance, FERC has found that supportive of the use of a 12 CP method. *Alabama Power Co.*, Opinion No. 54, 8 FERC ¶61,083, p. 61,327 (1979); *Illinois Power Co.*, 11 FERC at 65,249; *New England Power Co.*, Opinion No. 803, 58 FPC 2322, 2338 (1977); *Delmarva Power & Light Co.*, 17 FERC at 65,202. *But see Commonwealth Edison*, 15 FERC at 65,199.[139]

However, the scheduled maintenance must be considered together with the reserves available after the maintenance. To the extent the reserve margins are fairly stable after maintenance, then a 12 CP method is supported. If the reserve margins drop substantially to marginal levels during certain months, then a method other than 12 CP may be supported. *See, e.g., Illinois Power Co.*, 11 FERC at 65,249 (46 percent reserves after maintenance non-summer months and 34.5 percent for summer months—12 CP); *Commonwealth Edison Co.*, 15 FERC at 65,200 (for 1979 36.63 percent reserves after maintenance for 8 non-summer months and 22.15 percent for 4 summer months—4 CP).

c. Projection of CP and Total System Demands

In a number of cases, parties and the FERC Staff have challenged the filing company's estimated coincident peak or total system demand estimates.[140] While FERC appears to have established few hard and fast rules, the following cases provide some guidance. First, parties have challenged projections on the basis that the historical periods used were not representative. In some cases, FERC has held that multiple years of historical data should be

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139 In *Southwestern Public Service Co.*, Opinion No. 337, 49 FERC ¶61,296, p. 62,132 (1989), FERC declined to depart from the 3 CP method based on "monthly load patterns and reserve margins as affected by scheduled maintenance" which "show that Southwestern's capacity requirements are largely determined by the peak demands imposed on the system during a three-month summer period."

140 In *Blue Ridge Power Agency v. Appalachian Power Co.*, Opinion No. 363, 55 FERC ¶61,509, p. 62,788 (1991), FERC accepted the Staff's method for deriving a coincident peak estimate. The Staff asserted that the noncoincident peak estimate must be divided by the diversity factor to convert each noncoincident peak demand into a comparable coincident peak demand. 55 FERC at 62,788-89. The "diversity factor is the noncoincident peak demand divided by the coincident peak demand." 55 FERC at 62,788 n. 87. FERC, however, stated that "[n]ormally, we would calculate the coincident peak demand for the sales for resales group by looking at its consumption at the time of Appalachian's peak. In this case, however, we have the forecasted monthly noncoincident peak demands for the customer group" and that "[u]sing the historical diversity factor for the group, we can derive the calculated coincident peak." *Id.*

Schedule 3-2i

used in developing the estimate and not just one year. *See, e.g., Otter Tail Power Co.*, Opinion No. 93, 12 FERC ¶61,169, p. 61,429 (1980); *Commonwealth Edison Co.*, 15 FERC at 65,190, *aff'd*, Opinion No. 165, 23 FERC ¶61,219 (1983) (3 year average adopted); *Southern California Edison Co.*, Opinion No. 359-A, 54 FERC at 62,020 (accepted system peak demand and energy sales forecasts based on 1967-1981 data and 1981 coincidence factors). In other cases, FERC, however, has adopted CP projections based on the use of one year's data. *See, e.g., Carolina Power & Light Co.*, Opinion No. 19, 4 FERC at 61,229-30.

Second, FERC has expressed concern that the numerator and the denominator be developed on similar bases. In *Otter Tail Power Co.*, Opinion No. 93, 12 FERC at 61,429, FERC modified a demand allocator to provide for the use of the same number of years data in the derivation of both the numerator and the denominator.

Finally, FERC has held that billing demands should be consistent with the demands used in the demand allocator. *See El Paso Electric Co.*, Opinion No. 109, 14 FERC ¶61,082, p. 61,147 (1981).

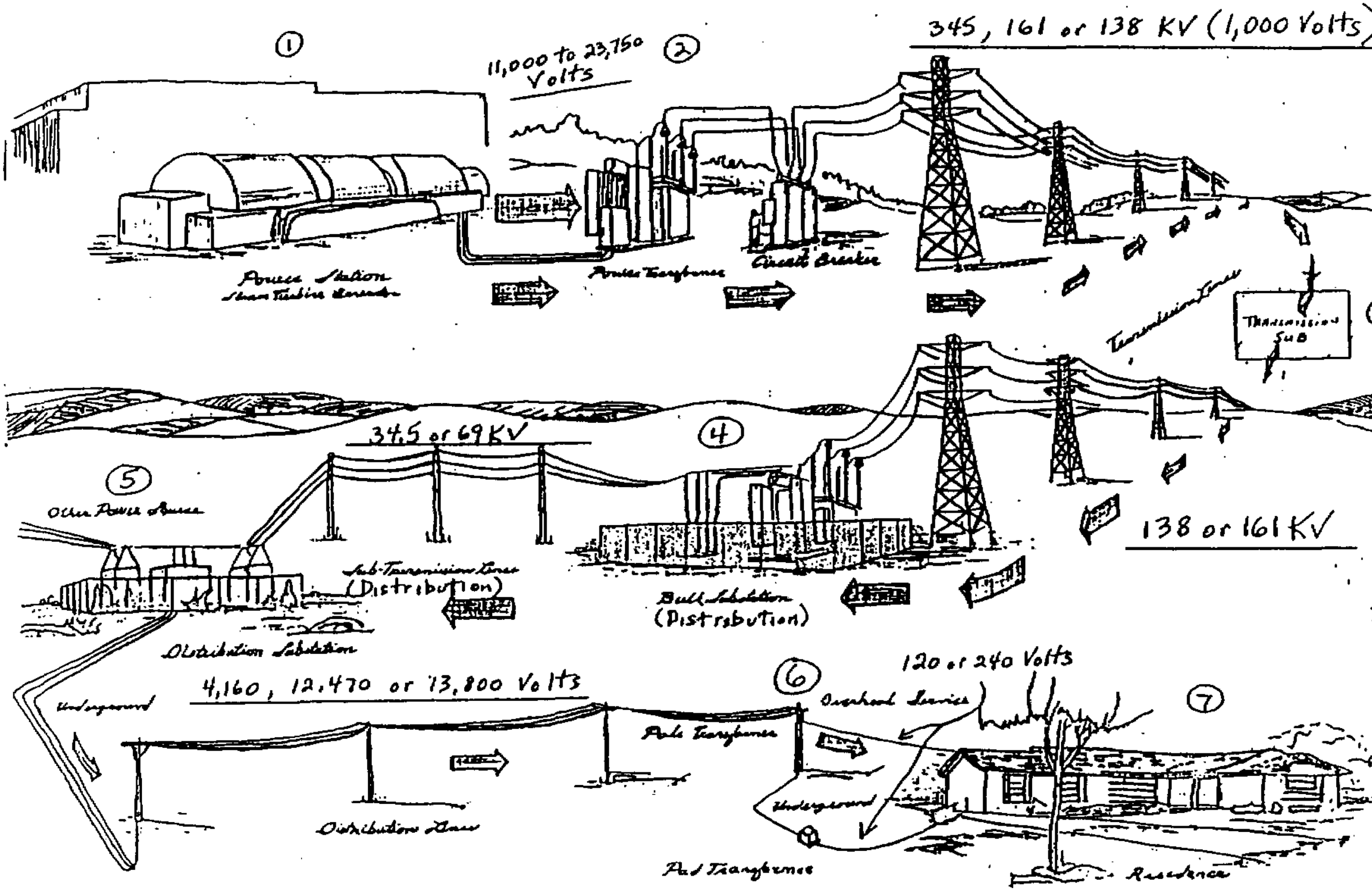
Energy Allocation Factor Adjustments (kWh's)

July 2000 - June 2001

	Missouri Retail Usage (kWh)	Missouri Wholesale Usage (kWh)	Illinois Usage (kWh)	Total Usage (kWh)
Total Usage*	32,009,845,300	854,692,200	3,171,890,900	36,036,428,400
Jurisdictional Losses**	2,462,787,690	32,241,540	183,733,360	2,678,762,590
Adjusted System Input	34,472,632,990	886,933,740	3,355,624,260	38,715,190,990
Adjustment 1	(969,081,000)	(21,481,000)	(53,747,000)	(1,044,309,000)
Losses	(74,522,329)	(809,834)	(3,111,951)	(78,444,114)
Adjustment 2		(153,593,010)		(153,593,010)
Losses		(5,790,456)		(5,790,456)
Adjustment 3			(237,362,400)	(237,362,400)
Losses			(5,127,028)	(5,127,028)
Adjustment 4	(18,103,848)			(18,103,848)
Losses	(1,091,662)			(1,091,662)
Adjustment 5	(60,553,690)			(60,553,690)
Losses	(3,651,388)			(3,651,388)
Adjustment 6	30,352,000			30,352,000
Losses	2,334,068.80			2,334,069
Adjustment 7	287,384,513			287,384,513
Losses	22,099,869			22,099,869
Output for Load	33,687,799,524	705,259,440	3,056,275,881	37,449,334,845
Percentage	89.96%	1.88%	8.16%	100.00%

* Source: Alan Bax Direct Testimony, Schedule 6.
** Adjusted for average jurisdictional losses.

Adjustment 1 - Normalized Weather per Bax, Schedule 6.
Adjustment 2 - Rolla Adjustment per Bax, Schedule 6.
Adjustment 3 - Adjustment to Laclede Steel Sales to reflect bankruptcy operation.
Adjustment 4 - Miscellaneous Adjustment per Pyatte, Schedule 2.
Adjustment 5 - Rate Switching Adjustment per Pyatte, Schedule 2.
Adjustment 6 - 365 Day Normalization Adjustment per Pyatte, Schedule 2.
Adjustment 7 - Customer Growth Adjustment per Pyatte, Schedule 2.



1
11,000 to 23,750 Volts
2
345, 161 or 138 KV (1,000 Volts)
Power Station
Power Transformer
Circuit Breaker
Transmission Lines
Transmission Sub
3
4
138 or 161 KV
34.5 or 69 KV
5
Other Power Source
Sub-Transmission Lines
(Distribution)
Bulk Substation
(Distribution)
Distribution Substation
4,160, 12,470 or 13,800 Volts
6
120 or 240 Volts
Overhead Service
7
Underground
Pole Transformer
Distribution Lines
Pad Transformer
Residence

Schedule 4

UNION ELECTRIC COMPANY
ELECTRIC COST OF SERVICE ALLOCATION STUDY
TEST YEAR: 12 MONTHS ENDED JUNE 2001

	TITLE: SUMMARY ($000's)	MISSOURI	RESIDENTIAL	SMALL GEN SERV	LARGE GEN SERV	SMALL PRIMARY	LARGE PRIMARY
1	BASE REVENUE	$ 1,773,763	$ 786,445	$ 226,660	$ 393,395	$ 204,361	$ 162,901
2	OTHER REVENUE	$ 73,128	$ 40,919	$ 7,826	$ 13,203	$ 6,028	$ 5,153
3	LIGHTING REVENUE	$ 25,633	$ 13,246	$ 3,175	$ 5,334	$ 2,120	$ 1,758
4	SYSTEM REVENUE	$ (3,744)	$ (1,892)	$ (453)	$ (787)	$ (339)	$ (272)
5	RATE REVENUE VARIANCE	$ 626	$ 323	$ 78	$ 130	$ 52	$ 43
6	TOTAL OPERATING REVENUE	$ 1,869,405	$ 839,040	$ 237,285	$ 411,275	$ 212,222	$ 169,582
7							
8	TOTAL PROD., T&D, CUST., AND A&G EXP.	$ 971,740	$ 455,212	$ 115,777	$ 204,379	$ 105,788	$ 90,583
9	TOTAL DEPR. AND AMMORT. EXP.	$ 278,979	$ 144,806	$ 34,774	$ 57,982	$ 22,637	$ 18,780
10	REAL ESTATE AND PROPERTY TAXES	$ 78,116	$ 40,683	$ 9,750	$ 16,210	$ 6,273	$ 5,201
11	INCOME TAXES	$ 162,739	$ 84,096	$ 20,159	$ 33,864	$ 13,459	$ 11,161
12	PAYROLL TAXES	$ 16,944	$ 8,387	$ 1,996	$ 3,449	$ 1,681	$ 1,430
13	FEDERAL EXCISE TAX	$ (117)	$ (56)	$ (14)	$ (27)	$ (11)	$ (9)
14	REVENUE TAXES	$ -	$ -	$ -	$ -	$ -	$ -
15	TOTAL OPERATING EXPENSES	$ 1,508,401	$ 733,129	$ 182,442	$ 315,857	$ 149,826	$ 127,146
16							
17	NET OPERATING INCOME	$ 361,003	$ 105,911	$ 54,843	$ 95,418	$ 62,395	$ 42,436
18							
19	GROSS PLANT IN SERVICE	$ 8,145,416	$ 4,242,096	$ 1,016,695	$ 1,690,221	$ 654,097	$ 542,307
20	RESERVES FOR DEPRECIATION	$ 3,518,877	$ 1,833,165	$ 436,650	$ 732,878	$ 282,314	$ 233,870
21	NET PLANT IN SERVICE	$ 4,626,539	$ 2,408,931	$ 580,045	$ 957,343	$ 371,782	$ 308,437
22							
23	MATERIALS & SUPPLIES - FUEL	$ 125,294	$ 47,899	$ 14,244	$ 30,042	$ 17,701	$ 15,408
24	MATERIALS & SUPPLIES -LOCAL	$ 17,020	$ 10,316	$ 2,233	$ 2,954	$ 855	$ 661
25	CASH WORKING CAPITAL	$ 34,382	$ 16,106	$ 4,096	$ 7,231	$ 3,743	$ 3,205
26	CUSTOMER ADVANCES & DEPOSITS	$ (23,301)	$ (9,918)	$ (7,755)	$ (3,398)	$ (714)	$ (1,515)
27	ACCUM. DEFERRED INCOME TAXES	$ (810,067)	$ (421,879)	$ (101,111)	$ (168,094)	$ (65,050)	$ (53,933)
28	TOTAL NET ORIGINAL COST RATE BASE	$ 3,969,867	$ 2,051,454	$ 491,753	$ 826,080	$ 328,317	$ 272,264
29							
30	RATE OF RETURN	9.094%	5.163%	11.153%	11.551%	19.005%	15.586%

UNION ELECTRIC COMPANY
MISSOURI
CASE NO. EC-2002-1
CLASS REVENUE REQUIREMENTS AT EQUAL RATES OF RETURN
($000's)

Customer Class	Current Base Revenue	Proposed Base Revenue	Required Revenue Adjustment	% Change
Residential	$ 786,445	$ 867,085	$ 80,640	10.25%
Small General Service	$ 226,660	$ 216,535	$ (10,125)	-4.47%
Large General Service	$ 393,395	$ 373,097	$ (20,298)	-5.16%
Small Primary Service	$ 204,361	$ 171,822	$ (32,539)	-15.92%
Large Primary Service	$ 162,901	$ 145,223	$ (17,678)	-10.85%
Total	$ 1,773,762	$ 1,773,762	$ -	0.00%

UNION ELECTRIC COMPANY
EQUALIZED CLASS RATES OF RETURN ANALYSIS
TEST YEAR: 12 MONTHS ENDED JUNE 2001

	TITLE: SUMMARY EQUAL ROR ($000's)	MISSOURI	RESIDENTIAL	SMALL GEN SERV	LARGE GEN SERV	SMALL PRIMARY	LARGE PRIMARY
1	BASE REVENUE	$1,773,763	$ 867,085	$ 216,535	$ 373,097	$ 171,822	$ 145,223
2	OTHER REVENUE	$ 73,128	$ 40,919	$ 7,826	$ 13,203	$ 6,028	$ 5,153
3	LIGHTING REVENUE	$ 25,633	$ 13,246	$ 3,175	$ 5,334	$ 2,120	$ 1,758
4	SYSTEM REVENUE	$ (3,744)	$ (1,892)	$ (453)	$ (787)	$ (339)	$ (272)
5	RATE REVENUE VARIANCE	$ 626	$ 323	$ 78	$ 130	$ 52	$ 43
6	TOTAL OPERATING REVENUE	$1,869,405	$ 919,680	$ 227,160	$ 390,977	$ 179,682	$ 151,905
7							
8	TOTAL PROD., T&D, CUSTOMER, AND A&G EXP.	$ 971,740	$ 455,212	$ 115,777	$ 204,379	$ 105,788	$ 90,583
9	TOTAL DEPR. AND AMMOR. EXPENSES	$ 278,979	$ 144,806	$ 34,774	$ 57,982	$ 22,637	$ 18,780
10	REAL ESTATE AND PROPERTY TAXES	$ 78,116	$ 40,683	$ 9,750	$ 16,210	$ 6,273	$ 5,201
11	INCOME TAXES	$ 162,739	$ 84,096	$ 20,159	$ 33,864	$ 13,459	$ 11,161
12	PAYROLL TAXES	$ 16,944	$ 8,387	$ 1,996	$ 3,449	$ 1,681	$ 1,430
13	FEDERAL EXCISE TAX	$ (117)	$ (56)	$ (14)	$ (27)	$ (11)	$ (9)
14	REVENUE TAXES	$ -	$ -	$ -	$ -	$ -	$ -
15							
16	TOTAL OPERATING EXPENSES	$1,508,401	$ 733,129	$ 182,442	$ 315,857	$ 149,826	$ 127,146
17							
18	NET OPERATING INCOME	$ 361,003	$ 186,551	$ 44,718	$ 75,120	$ 29,856	$ 24,759
19							
20	GROSS PLANT IN SERVICE	$8,145,416	$ 4,242,096	$1,016,695	$1,690,221	$ 654,097	$ 542,307
21	RESERVES FOR DEPRECIATION	$3,518,877	$ 1,833,165	$ 436,650	$ 732,878	$ 282,314	$ 233,870
22							
23	NET PLANT IN SERVICE	$4,626,539	$ 2,408,931	$ 580,045	$ 957,343	$ 371,782	$ 308,437
24							
25	MATERIALS & SUPPLIES - FUEL	$ 125,294	$ 47,899	$ 14,244	$ 30,042	$ 17,701	$ 15,408
26	MATERIALS & SUPPLIES -LOCAL	$ 17,020	$ 10,316	$ 2,233	$ 2,954	$ 855	$ 661
27	CASH WORKING CAPITAL	$ 34,382	$ 16,106	$ 4,096	$ 7,231	$ 3,743	$ 3,205
28	CUSTOMER ADVANCES & DEPOSITS	$ (23,301)	$ (9,918)	$ (7,755)	$ (3,398)	$ (714)	$ (1,515)
29	ACCUMULATED DEFERRED INCOME TAXES	$ (810,067)	$ (421,879)	$ (101,111)	$ (168,094)	$ (65,050)	$ (53,933)
30							
31	TOTAL NET ORIGINAL COST RATE BASE	$3,969,867	$ 2,051,454	$ 491,753	$ 826,080	$ 328,317	$ 272,264
32							
33	RATE OF RETURN	9.094%	9.094%	9.094%	9.094%	9.094%	9.094%

Schedule 7

AmerenUE Missouri - Commission Verification Report
for Revenue Month January 2002

Revenue Class/Rate Class	Number of Customers	Billed Sales (kWh) from CSS CURST 235	Net Rate Revenue($) Excludes GRT from CSS CURST235	Revenue Credits	GRT Taxes (CURST 233-235)	Gross Rate Revenue($) Includes GRT from CSS CURST233	Booked Sales (kWh) from Gen Acct	Booked Revenue ($) from GA	Variance Sales (kWh)	Variance Revenue ($)
Residential	980,458	1,255,325,410	$67,433,229		$2,647,009	$70,080,238	1,255,325,410	$70,080,237	0	$1
COMMERCIAL										
2(M) Small General Svc	2,926						NOTE GL TOTALS LISTED IN SUMMARY LINE			
Single Phase		2,849,238	$159,374		$6,548	$165,922				
TOU Single Phase		5,449	$300		$15	$315				
Three Phase		32,506,219	$1,781,797		$117,297	$1,899,094				
TOU Three Phase		146,400	$7,381		$358	$7,739				
Unmetered		560	$50		$5	$55				
3(M) Large General Svc	7,397									
LGS		513,239,329	$22,179,528		$1,426,855	$23,606,383				
TOU Demand		116,354	$6,214		$412	$6,626				
4(M) Small Primary Svc	434									
Substn Disc		8,033,886	$280,292		$18,373	$298,665				
Sm Prim Ele		206,586,389	$7,932,787		$522,865	$8,455,852				
11(M) Large Primary Svc	20									
Substn Disc		7,618,722	$271,145		$8,766	$279,911				
Lg Prim		70,672,417	$2,501,959		$224,122	$2,726,081				
Other			$15		$2	$17				
3, 4, 11 M Blended Tax		663,100	$24,597		$2,368	$26,965				
RF Commercial	132,755	273,856,728	$16,031,306		$894,905	$16,926,211				
COMMERCIAL SUMMARY	143,532	1,116,294,791	$51,176,745		$3,222,891	$54,399,636	1,121,399,242	$54,424,528	-5,104,451	-$24,892
INDUSTRIAL										
2(M) Small General Svc	268						NOTE GL TOTALS LISTED IN SUMMARY LINE			
Single Phase		36,229	$2,117		$649	$2,766				
Three Phase		3,181,157	$164,019		$9,832	$173,851				
TOU Three Phase		0	$0		$0	$0				
Three Phase Sub Disc		202,495	$10,109		$954	$11,063				
3(M) Large General Svc	1,128									
LGS		135,515,558	$3,600,458		$235,462	$3,835,920				
TOU Demand		54,489	$2,257		$119	$2,376				
4(M) Small Primary Svc	200									
Substn Disc		22,151,507	$814,926		$48,286	$863,212				
Sm Prim Ele		108,103,038	$4,257,852		$270,715	$4,528,567				
11(M) Large Primary Svc	37									
Substn Disc		96,458,693	$3,349,198		$116,411	$3,465,609				
TOU Substn Disc		5,426,979	$193,941		$8,728	$202,669				
Lg Prim Elec		129,285,031	$4,641,182		$229,117	$4,870,299				
RF Industrial	3,618	11,018,556	$615,660		$33,787	$649,447				
INDUSTRIAL SUMMARY	6,251	511,433,732	17,651,719		$954,060	$18,605,779	442,785,975	$18,577,502	68,647,757	$28,277
STREET & HWY LIGHTING										
5(M) Lighting (Company Owned)	[illegible]						NOTE GL TOTALS LISTED IN SUMMARY LINE			
442 Comp Own - Muni		[illegible]	[illegible]		[illegible]	[illegible]				
44? Comp Own - Muni		[illegible]	[illegible]		$16,590	[illegible]				
6(M) Lighting (Customer Owned)	[illegible]									
442 Cust Own Unmtr		5,973	[illegible]		$0	[illegible]				

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Schedule 8-1

AmerenUE Missouri - Commission Verification Report
for Revenue Month January 2002

Revenue Class/Rate Class	Number of Customers	Billed Sales (kWh) from CSS CURST 235	Net Rate Revenue($) Excludes GRT from CSS CURST235	Revenue Credits	GRT Taxes (CURST 233-235)	Gross Rate Revenue($) Includes GRT from CSS CURST233	Booked Sales (kWh) from Gen Acct	Booked Revenue ($) from GA	Variance Sales (kWh)	Variance Revenue ($)
[redacted]										
TOTAL MISSOURI RETAIL	1,130,825	2,896,482,147	$137,348,299		$6,844,726	$144,193,025	2,831,385,119	$144,087,378	65,097,028	$105,647
WHOLESALE	10	52,828,004	$1,551,383		$0	$1,551,383	52,828,004	$1,527,601	0	$23,782
TOTAL MISSOURI	1,130,835	2,949,310,151	$138,899,682		$6,844,726	$145,744,408	2,884,213,123	$145,614,979	65,097,028	$129,429

Table 4 (Updated)
Relative Changes of Union Electric's Retail Rate during the EARP Period

Rate Comparison by Customer Class		Average Retail Rates (includes customer credits) in cents/kWh 1994	1999	2000	Percent Change in Average Retail Rates 1994-1999	1994-2000
UE-MO	Residential	7.53	7.22	7.06	-4.1%	-6.2%
	Commercial	6.23	5.94	5.69	-4.7%	-8.7%
	Industrial	5.06	4.72	4.73	-6.7%	-6.5%
	Ultimate	6.48	6.17	6.04	-4.8%	-6.8%
West North Central	Residential	7.49	7.44	7.48	-0.7%	-0.1%
	Commercial	6.36	6.11	6.08	-3.9%	-4.4%
	Industrial	4.36	4.39	4.38	0.7%	0.5%
	Ultimate	5.80	5.83	5.84	0.5%	0.7%
East North Central	Residential	8.52	8.25	8.09	-3.2%	-5.0%
	Commercial	7.37	7.15	6.94	-3.0%	-5.8%
	Industrial	4.76	4.57	4.29	-4.0%	-9.9%
	Ultimate	6.59	6.44	6.21	-2.3%	-5.8%

Notes:

1 - 1994-1999 results have been presented in Table 4 of the *Whitepaper on Incentive Regulation: Assessing Union Electric's Experimental Alternative Regulation Plan,* February 1, 2001.

2 - Based on data and weighted averages reported by EEI. Note that average rates by customer class may be based on fewer data points in cases in which customer class data is not available for all of the utilities that report company-wide average rates. The average across all customer classes, thus, may not be fully consistent with the averages reported for individual customer classes.

Sources:

2000 data - EEI Typical Bills and Average Rates Report, Winter 2001.

1999 data - EEI Typical Bills and Average Rates Report, Winter 2000.

1994 data - EEI Typical Bills and Average Rates Report, Winter 1997.

Schedule 9

<u>UNION ELECTRIC COMPANY</u>
UNBUNDLED ELECTRIC COST OF SERVICE ANALYSIS
TEST YEAR: 12 MONTHS ENDED JUNE 2001

				Unbundled Base Revenue ($000's)		
	Total Missouri	Residential	Small Gen Serv	Large Gen Serv	Small Primary	Large Primary
Customer	$ 164,587	$ 130,171	$ 23,871	$ 8,826	$ 1,460	$ 258
Production -- Demand	$ 701,333	$ 333,223	$ 85,492	$ 159,629	$ 66,846	$ 56,142
Production -- Energy	$ 521,885	$ 199,480	$ 59,320	$ 125,147	$ 73,745	$ 64,192
Transmission -- Demand	$ 36,080	$ 17,200	$ 4,129	$ 7,921	$ 3,665	$ 3,166
Distribution -- Demand	$ 349,877	$ 187,010	$ 43,722	$ 71,574	$ 26,105	$ 21,465
Total Base Revenue	$ 1,773,762	$ 867,085	$ 216,535	$ 373,097	$ 171,822	$ 145,223

Schedule 10

Residential Service Rate Comparison
AmerenUE - Missouri
Weather Normalized-12 months ending June 2001

Billing Components		Present	Proposed
Summer (June - September)			
Customer Charge	Per Month	$7.25	$11.30
Energy Charge:			
All Kwh	Cents per Kwh	8.130 ¢	9.48 ¢
Winter (October - May)			
Customer Charge	Per Month	$7.25	$11.30
Energy Charge:			
0- 750 Kwh	Cents per Kwh	5.770 ¢	5.41 ¢
All Kwh Over 750	Cents per Kwh	3.891 ¢	3.70 ¢

Proof of Revenue

	Units	Rate	$1,000	Rate	$1,000
Summer					
Customer Charge	3,879,496	$ 7.25	$ 28,126	$ 11.30	$ 43,838
Mwh	4,162,714	$0.08130	$ 338,429	0.0948	$ 394,625
			$ 366,555		$ 438,464
Winter					
Customer Charge	7,786,657	$ 7.25	$ 56,453	$ 11.30	$ 87,989
0-750 Mwh	4,115,087	$0.05770	$ 237,441	0.0541	$ 222,626
Over 750 Mwh	3,236,523	$0.03891	$ 125,933	0.0370	$ 119,751
Total MWH	11,514,324		$ 419,827		$ 430,367
			$ 786,382		$ 868,830
Res TOD	987		$ 63		$ 63
	11,515,311		$ 786,445		$ 868,893

Schedule 11

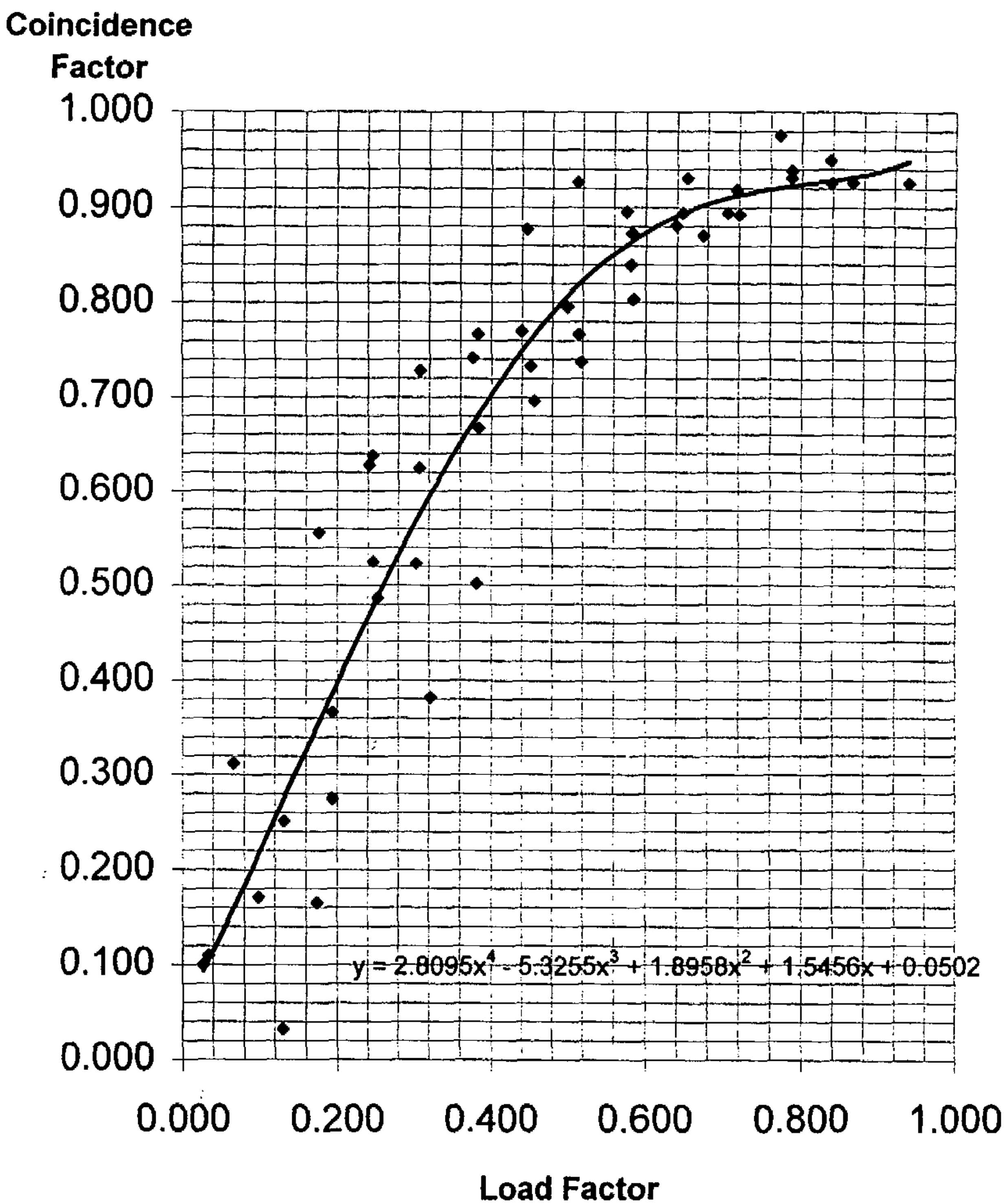
Small General Service Rate Comparison
AmerenUE - Missouri
Weather Normalized-12 months ending June 2001

Billing Components		Present	Present
Summer (June - September)			
Customer Charge:			
Single Phase Service	Per Month	$7.25	$12.75
Three Phase Service	Per Month	$15.10	$25.50
Energy Charge:			
All Kwh	Cents per Kwh	7.99 ¢	8.46 ¢
Winter (October - May)			
Customer Charge:			
Single Phase Service	Per Month	$7.25	$12.75
Three Phase Service	Per Month	$15.10	$25.50
Energy Charge:			
Base Use	Cents per Kwh	5.96 ¢	4.59 ¢
Seasonal Use	Cents per Kwh	3.45 ¢	2.90 ¢

Proof of Revenue

	Units	Rate	1000's	Rate	1000's
Summer					
Customer Charge - Single Phase	369,500	$7.25	$ 2,679	12.75	$ 4,711
Customer Charge - Three Phase	126,756	$15.10	$ 1,914	25.50	$ 3,232
Mwh	1,193,680	$0.0799	$ 95,375	0.0846	$ 100,985
			$ 99,968		
Winter					
Customer Charge - Single Phase	739,977	$7.25	$ 5,365	12.75	$ 9,435
Customer Charge - Three Phase	254,195	$15.10	$ 3,838	25.50	$ 6,482
Winter Base Mwh	1,687,310	$0.0596	$ 100,564	0.0459	$ 77,448
Winter Seasonal Mwh	490,599	$0.0345	$ 16,926	0.0290	$ 14,227
Winter Total MWH	2,177,909		$ 126,693		
Total	3,371,589		$ 226,660		$ 216,520

Large G. S. & Small Prim. Rates



Large General Service Rate Comparison
AmerenUE - Missouri
Weather Normalized-12 months ending June 2001

Billing Components		Present	Proposed
Summer (June - September)			
Customer Charge	Per Month	$66.00	$89.46
Energy Charge (¢ per kWh)			
First 150 kWh per KW		7.84 ¢	7.04 ¢
Next 200 kWh per KW		5.91 ¢	5.47 ¢
All over 300 kWh per KW		3.96 ¢	2.72 ¢
Demand			
Per KW of Billing Demand		$3.79	$4.94
Winter (October - May)			
Customer Charge	Per Month	$66.00	89.46
Energy Charge (¢ per kWh)			
First 150 kWh per KW		4.91 ¢	3.67 ¢
Next 200 kWh per KW		3.68 ¢	3.11 ¢
All over 300 kWh per KW		2.86 ¢	2.11 ¢
Seasonal Energy Charge		2.86 ¢	2.11 ¢
Demand			
Per KW of Billing Demand		$1.35	$2.47

Proof of Revenue

	Units	Rate	$1,000	Rate	$1,000
Summer					
Customer Charge	32,755	$66.00	$ 2,162	$89.46	$ 2,930
Summer Energy Mwh					
0-150 hours	1,011,872	$0.0784	$ 79,331	$0.0704	$ 71,236
151-350 hours	1,112,083	$0.0591	$ 65,724	$0.0547	$ 60,831
Over 350 hours	405,723	$0.0396	$ 16,067	$0.0272	$ 11,036
Demand	7,190,823	$3.79	$ 27,253	$4.94	$ 35,523
			$ 190,537		$ 181,555
Winter					
Customer Charge	65,908	$66.00	$ 4,350	$89.46	$ 5,896
Winter Energy Mwh					
0-150 hours	1,689,758	$0.0491	$ 82,967	$0.0367	$ 62,014
151-350 hours	1,840,091	$0.0368	$ 67,715	$0.0311	$ 57,227
Over 350 hours	607,001	$0.0286	$ 17,360	$0.0211	$ 12,808
Seasonal	374,402	$0.0286	$ 10,708	$0.0211	$ 7,900
Demand	14,635,445	$1.35	$ 19,758	$2.47	$ 36,150
			$ 202,858		$ 181,994
	7,040,930		$ 393,395		$ 363,550

Small Primary Service Rate Comparison
AmerenUE - Missouri
Weather Normalized-12 months ending June 2001

Billing Components		Present	Proposed
Summer (June - September)			
Customer Charge	Per Month	$210.00	$190.20
Energy Charge (¢ per kWh)			
First 150 kWh per KW		7.45 ¢	6.72 ¢
Next 200 kWh per KW		5.62 ¢	5.22 ¢
All over 300 kWh per KW		3.76 ¢	2.59 ¢
Demand			
Per KW of Billing Demand		$3.01	$4.04
Billing Kvars		24 ¢	24 ¢
Rider B 34kv			
Per KW		81 ¢	51 ¢
Rider B 138kv			
Per KW		95 ¢	84 ¢
Winter (October - May)			
Customer Charge	Per Month	$210.00	$190.20
Energy Charge (¢ per kWh)			
First 150 kWh per KW		4.69 ¢	3.53 ¢
Next 200 kWh per KW		3.49 ¢	2.98 ¢
All over 300 kWh per KW		2.73 ¢	2.02 ¢
Seasonal Energy Charge		2.73 ¢	2.02 ¢
Demand			
Per KW of Billing Demand		$1.10	$2.02
Billing Kvars		24 ¢	24 ¢
Rider B 34kv			
Per KW		81 ¢	51 ¢
Rider B 138kv			
Per KW		95 ¢	84 ¢

Proof of Revenue

	Units	Rate	$1,000	Rate	$1,000
Summer					
Customer Charge	2,559	$210.00	$ 537	$190.20	$ 487
Summer Energy Mwh					
0-150 hours	492,233	$0.0745	$ 36,671	$0.0672	$ 33,078
151-350 hours	612,369	$0.0562	$ 34,415	$0.0522	$ 31,966
Over 350 hours	410,066	$0.0376	$ 15,418	$0.0259	$ 10,621
Demand	3,328,507	$3.01	$ 10,019	$4.04	$ 13,447
Billing Kvars	699,337	$0.24	$ 168	$0.24	$ 168
Rider B 34kv	273,075	$0.81	$ (221)	$0.51	$ (139)
Rider B 138kv	8,932	$0.95	$ (8)	$0.84	$ (8)
			$ 96,999		$ 89,619
Winter					
Customer Charge	5,117	$210.00	$ 1,075	$190.20	$ 973
Winter Energy Mwh					
0-150 hours	808,956	$0.0469	$ 37,940	$0.0353	$ 28,556
151-350 hours	1,013,868	$0.0349	$ 35,384	$0.0298	$ 30,213
Over 350 hours	781,677	$0.0273	$ 21,340	$0.0202	$ 15,790
Seasonal	176,166	$0.0273	$ 4,809	$0.0202	$ 3,559
Demand	6,251,204	$1.10	$ 6,876	$2.02	$ 12,627
Billing Kvars	1,435,459	$0.24	$ 345	$0.24	$ 345
Rider B 34kv	572,138	$0.81	$ (463)	$0.51	$ (292)
Rider B 138kv	0	$0.95	$ -	$0.84	$ -
			$ 107,305		$ 91,771
	4,295,335		$ 204,304		$ 181,391

Large Primary Service Rate Comparison
AmerenUE - Missouri
Weather Normalized-12 months ending June 2001

Billing Components		Present	Proposed
Summer (June - September)			
Customer Charge	Per Month	$210.00	$385.00
Demand Charge	Per KW of Billing Demand	$15.67	14.74
Energy Charge:			
All Kwh	Cents per Kwh	2.62 ¢	2.20 ¢
Reactive Charge	Cents per kVar	24 ¢	24 ¢
Rider B 34kv	Per KW	81 ¢	51 ¢
Rider B 138kv	Per KW	95 ¢	84 ¢
Winter (October - May)			
Customer Charge	Per Month	$210.00	$385.00
Demand Charge	Per KW of Billing Demand	$7.11	$7.36
Energy Charge:			
All Kwh	Cents per Kwh	2.31 ¢	1.85 ¢
Reactive Charge	Cents per kVar	24 ¢	24 ¢
Rider B 34kv	Per KW	81 ¢	51 ¢
Rider B 138kv	Per KW	95 ¢	84 ¢

Proof of Revenue

	Units	Rate	1000's	Rate	1000's
Summer					
Customer Charge	219	$210.00	$ 46	385	$ 84
Summer Mwh	1,359,800	$0.0262	$ 35,627	0.022	$ 29,916
Demand	2,460,780	$15.67	$ 38,560	14.74	$ 36,272
Billing Kvars	322,622	0.24	$ 77	0.24	$ 77
Rider B 34kv	719,623	0.81	$ (583)	0.51	$ (367)
Rider B 138kv	181,932	0.95	$ (173)	0.84	$ (153)
			$ 73,555		$ 65,829
Winter					
Customer Charge	451	$210.00	$ 95	385	$ 174
Winter Mwh	2,521,685	$0.0231	$ 58,251	0.0185	$ 46,651
Demand	4,536,307	$7.11	$ 32,253	7.36	$ 33,387
Billing Kvars	654,748	$0.24	$ 157	0.24	$ 157
Rider B 34kv	1,335,100	$0.81	$ (1,081)	0.51	$ (681)
Rider B 138kv	345,556	$0.95	$ (328)	0.84	$ (290)
			$ 89,346		$ 79,398
	3,881,485		$ 162,901		$ 145,227

RIDER E
SUPPLEMENTARY AND BACKUP SERVICE

1. Rate Application

Supplementary and Backup Service consist of the standard service supplied by Company that is also available in the event of failure or shutdown of customer's private plant service or any other source of electrical energy or motive power through electrical or mechanical means or by means of operational procedure, or where this service in effect serves to relieve, sustain or augment any other source of power.

2. Availability

Supplementary and Backup Service will be supplied whenever it is available from the Company at the customer's location and is desired by the customer, as indicated by the customer's connection to the Company's Delivery System and self-generation is available and operable on the customer's side of the meter. Customer's generating equipment shall not be operated in parallel with Company's service except when such operation is approved by Company and permitted under a written Parallel Operating Agreement with Company.

Supplementary and Backup Service will be delivered to customer under the Large Primary Service Rate at a service voltage to be selected by Company. All provisions of the Large Primary Service rate under which supplementary and backup service is to be supplied shall remain in effect, except as hereinafter specifically provided

Unless otherwise described herein, all other provisions, Rules and Regulations provided within the tariff and applicable to the Large Primary Service classification are also applicable to this Rider. Rider B credits are only applicable to the Wires and Energy Charges contained herein. Except as noted herein, no other credits or Riders are applicable to customers served under the provisions of this Rider.

3. General Provisions

Company shall install meter(s) and/or recording device(s) to register the output of the Customer's self-generation. Such metering shall be 15-minute interval metering and recording devices that are compatible with the Company's main revenue meter(s). The installation charge for the additional or nonstandard meter(s) and/or recording device(s) required to administer this Rider, in addition to any other applicable additional facilities, shall be determined by the provisions of Section III.Q, Special Facilities.

4. Rate for Service

All Electric service shall be billed under the provisions of this Rider. The monthly bill to be paid by customer for Supplementary and Backup Service shall be:

	Summer	Winter
Customer Charge	$445.00	$445.00

Monthly meter readings from Company's main meter:

	(June - September) Summer	(October - May) Winter
Energy Charge: (1)	2.20¢/kWh	1.85¢/kWh
Wires Charge: (2)	$4.43/KW	$2.21/KW
Production Demand: (3)	$10.09/KW	$5.05/KW
Generator Backup Demand: (4)	$1.82/KW	$0.91/KW
Reactive Power: (5)	$0.24/kVar	$0.24/kVar

(1) The energy charge is based on the meter readings through the company's main meter. All main metered energy usage associated with load normally supplied through customer's generator shall be priced as above plus 0.5¢/kWh.

(2) The Wires Demand shall be the 15-minute maximum coincidized demand reading of the Company's main meter and the customer's self-generation meter except for contractual agreements limiting the demand available through the Company's meter.

(3) The Production Demand quantity shall be the 15-minute maximum demand reading through the Company's meter. Such reading may be adjusted for periods when customer demonstrates an outage to the Company's satisfaction. For such occurrences, when the Monthly Demand Share is 50% or lower, the 15-minute maximum demand reading shall be the greater of 1) maximum main meter demand outside outage period, or 2) highest main meter reading minus load normally served by customer's generator during the generator outage. The Production Demand charge shall also be applicable to the Monthly Demand Share times the load normally served by customer's generator.

(4) The Generator Backup Demand is the nameplate rating of the customer's self-generation equipment expressed in KW.

(5) The Reactive Power kVar as defined in the Large Primary Service Classification.

5. Definitions

Self-Generation Meter(s) - Meter(s) installed and read by Company to measure output of customer's self-generation device(s).

Company Main Meter(s) - Meter(s) installed by Company to measure consumption of KW and kWh's by customer from Company.

Self-Generator Outage - Outage of customer's self-generation equipment, as reported by customer to Company with supporting documentation acceptable to Company. Customer shall indicate duration of outage, nameplate rating of generator, and shall report when outage has ended and unit placed back in service. Outage must be reported to the company as soon as practicable, but in no event more than 30 days after the billing cycle.

Monthly Demand Share - For periods when customer can demonstrate to Company's satisfaction that a generator outage has occurred, the number of days of outage (excluding weekends and holidays) divided by twenty (20). Such fraction shall be used to determine the outage related prorated Production Demand KW. A 24-hour day starting at midnight will be assumed for purposes of this Rider.

RESERVE DISTRIBUTION CAPACITY RIDER
RIDER RDC

1. Purpose - The purpose of this Rider is to provide reserve capacity on the Company's distribution system to customers that request a reserve distribution service connection for the delivery of electricity from distribution facilities other than the standard or preferred distribution supply facilities designated by Company.

2. Applicability - This optional Rider is limited to customers who qualify for service under the Company's Service Classification 3 (M) Large General Service Rate, 4 (M) Small Primary Service Rate, or 11 (M) Large Primary Service Rate, with a minimum monthly metered demand of 500 kilowatts or greater. This Rider shall expire on December 31, 2006 and no further requests for service under this Rider will be accepted after that time. All contracts in existence as of December 31, 2006 shall remain in force per the terms of those agreements.

3. Availability - The availability of reserve distribution supply service to a customer shall be contingent upon Company's engineering studies of the impact of providing reserve distribution service to a customer and the Company's current and projected system distribution capacity needs.

4. Description of Reserve Distribution Service - When provided, Company will designate the reserve distribution capacity on its electric distribution system that will be available to the customer upon a single contingency failure of the preferred or "standard" supply to the customer. Such reserve service is subject to the following conditions:

   The determination of delivery circuits and routes to provide sufficient single contingency distribution reserve capacity will be made by Company and will be subject to change as operating conditions change.

   Company will make all reasonable efforts to provide reserve distribution service on an adequate and continuous basis, but will not be liable for service interruptions, deficiencies or imperfections which result from conditions which are beyond the reasonable control of the Company. The Company cannot guarantee the service as to continuity, freedom from voltage and frequency variations. The Company will not be responsible or liable for damages to customer's apparatus resulting from failure or imperfection of service beyond the reasonable control of the Company. Where such failure or imperfection of service might damage customer's apparatus, customer should install suitable protective equipment.

   Company does not commit to reserve supplies from different substations and reserves the right to designate the preferred & reserve supplies and limit switching of customer's load from one service supply to the other.

RESERVE DISTRIBUTION CAPACITY RIDER
RIDER RDC (Cont'd.)

5. Customer Requirements - The customer and Company shall contract for the level of electrical load for which the Company is providing electric distribution reserve capacity.

6. Contribution and Rates for Electric Distribution Reserve Service - The customer shall pay, in advance of construction, to Company its estimated cost to extend or reinforce the reserve portion of the additional distribution supply back to a point on the Company's system where the Company reasonably expects adequate distribution capacity will exist. Said payment shall be non-refundable. If the customer's load increases above their contracted capacity, and/or they request additional reserve capacity for new load and the Company must install additional distribution reserve capacity facilities, an additional customer payment will be required. Said payment shall be in advance and be equal to the Company's total estimated costs as described above to modify or expand Company's distribution system to accommodate the increased load. The cost of all transformers and switchgear included as part of the reserve capacity shall include the estimated costs to install and remove said facilities.

Additionally, the following monthly rates for electric distribution reserve capacity shall apply, based on the lowest voltage level at which distribution reserve facilities are provided, regardless of the voltage of the customer's standard or preferred supply.

For Second Supply Voltage of:	Monthly Rate per kW of Billing Demand**
120 - 600 volts	Large General Service Total Billing Demand Charges
601 - 15,000 volts	Small Primary Service Total Billing Demand Charges
15,001 - 69,000 volts	Small Primary Service Total Billing Demand Charges less Rider B Demand Discount Credit (Line 4)
69,001 - 345,000 volts	Small Primary Service Total Billing Demand Charges less Rider B Demand Discount Credit (Line 2)

** - Same Billing Demand As Metered and Delivered Via Customer's Designated Standard Connection

7. Duplicate On-Site Supply Facilities - Requests for duplicate supply facilities on the customer's premises, such as a second transformer or a second primary extension from a single supply feeder, shall be provided under provisions of the Company's Special Facilities tariff, Section III.Q.

8. Term - Customer shall be required to sign a contract for an initial term of ten (10) years, cancelable by customer at any time after one (1) year with six (6) months' written notice to Company. Absent such

RESERVE DISTRIBUTION CAPACITY RIDER
RIDER RDC (Cont'd.)

cancellation during the initial term, the contract shall be automatically renewed for successive terms of one (1) year each, subject to termination by the giving of written notice, by either Company or customer, of at least six (6) months prior to the expiration of any renewal term.

Said contract shall be based on the Form of Contract included with this Rider RDC tariff and provided within ten days of execution to the Missouri Public Service Commission "Commission" Staff for informational purposes. The Company will file a revised Form of Contract tariff with the Commission before any significant modifications are made to said Contract.

9. General Rules and Regulations - In addition to the above specific rules and regulations, all of the Company's General Rules and Regulations shall apply to the supply of service under this Rider.

FORM OF CONTRACT

This Agreement is entered into as of this _____ day of ________, 20__, by and between AmerenUE(d/b/a Union Electric "Company") and ________________________________ (Customer) for the providing of a second or reserve distribution connection to serve Customer's load not to exceed _______ kilowatts.

WITNESSETH:

Whereas, Company has on file with the Public Service Commission of the State of Missouri (Commission) a certain Reserve Distribution Capacity Rider (Rider), and;

Whereas, Customer has satisfied the Availability and Applicability provisions of the Rider, and;

Whereas, Customer wishes to take electric service from the Company, and the Company agrees to furnish electric service to the Customer under this Rider and pursuant to all other applicable tariffs of the Company;

The Company and Customer agree as follows:

1. Service to the Customer's Facilities shall be pursuant to the Rider, all other applicable tariffs, and the Company's General Rules and Regulations Applying to Electric Service, as may be in effect from time to time and filed with the Commission.

2. Customer acknowledges that this Agreement is not assignable voluntarily by Customer, but shall nevertheless inure to the benefit of and be binding upon the Customer's successors by operation of law.

3. Customer shall be required to sign a contract for an initial term of ten (10) years, cancelable by customer at any time after one (1) year with six (6) months' written notice to Company. Absent such cancellation during the initial term, the contract shall be automatically renewed for successive terms of one (1) year each, subject to termination by the giving of written notice, by either Company or customer, of at least six (6) months prior to the expiration of any renewal term.

4. This Agreement shall be governed in all respects by the laws of the State of Missouri (regardless of conflict of laws provisions), and by the orders, rules and regulations of the Commission as they may exist from time to time. Nothing contained herein shall be construed as divesting, or attempting to divest, the Commission of any rights jurisdiction, power or authority vested in it by law.

In witness whereof, the parties have signed this Agreement as of the date first above written.

Union Electric Company

____
Customer

By ________________________________ By ________________________________

Current Interest on Deposit Language for Sheet No. 178, paragraph 3.

Interest paid on deposits - Interest at the rate of 9.5 percent per annum, compounded annually, will be credited annually upon the account of the customer or paid upon the return of a residential deposit, whichever occurs first. Simple interest at the rate of 9.5 percent per annum will be payable upon the return of a non-residential deposit held by the Company for six months or longer. Interest shall not accrue on a cash deposit after the date the deposit is applied to the customer's account, or Company has made a reasonable effort to return the deposit to customer by mailing the deposit to customer's last known address.

Proposed Interest on Deposit Language for Sheet No. 178, paragraph 3.

Interest paid on deposits – Interest at the rate of the one-year yield on United States' Treasury securities for the last full week in November in a given calendar year, compounded annually, will be credited annually upon the account of the customer or paid upon the return of a residential deposit, whichever occurs first. Simple interest at the same rate per annum will be payable upon the return of a non-residential deposit held by the Company for six months or longer. Interest shall not accrue on a cash deposit after the date the deposit is applied to the customer's account, or Company has made a reasonable effort to return the deposit to customer by mailing the deposit to customer's last known address.