Exhibit No.
Issue: Rate Design
Witness: H. Edwin Overcast
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Sponsoring Party: Empire District
Case No. ER-2004-0570

Before the Public Service Commission
of the State of Missouri

Surrebuttal Testimony

of

H. Edwin Overcast

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On behalf of

The Empire District Electric Company

Introduction

Q. Please state your name and business affiliation.

A. H. Edwin Overcast, Vice President R. J. Rudden Associates, Inc.

Q. Are you the same H. Edwin Overcast who previously filed testimony in this case before the Missouri Public Service Commission ("Commission") on behalf of The Empire District Electric Company ("Empire" or "Company")?

A. Yes. I filed direct and rebuttal testimony in this case

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony addresses issues related to the rebuttal testimony of certain Commission Staff ("Staff") witnesses related to proposed rate design, cost allocation and the rationale for the Company's proposals. In addition, my testimony responds to testimony provided by the Office of Public Counsel ("OPC") related to cost of service and rate design.

Q. How is your testimony organized?

A. The testimony devotes a section to each of three issues- cost of service, rate design and the rationale supporting the Company's proposals. Section One discusses cost of service. Section Two discusses appropriate rate design and Section Three provides a summary of the supporting rationale for the Company's proposals.

Section One- Cost of Service

Q. Have you reviewed the testimony of the Staff and OPC regarding the cost studies filed by the parties?

A. Yes. I have reviewed the rebuttal testimony of Ms. Hu of the Staff and the rebuttal testimony of Ms. Meisenheimer of OPC.

Q. Please discuss the theoretical assumptions underlying the cost method employed by Staff and OPC.

A. The Staff and OPC employ a method they describe as a peak and average method. They argue that this method is a reasonable proxy for the Commission's preferred time of use ("TOU") methodology. The theoretical underpinning for a peak and average allocation is that energy is a factor in the determination of plant costs and hence some energy weighting is required to reflect cost causation. Theoretically, lower energy costs require higher capital investment. Typically, lower capacity cost plants have higher fuel cost. The mix of capacity costs and operating costs result in the annual operating costs for different technologies. When operating costs and expected hours of economic dispatch are matched, the resulting cost of alternative technologies becomes the basis for selecting incremental generation for the system and represents a sound basis for evaluation of capacity options. On an embedded cost basis, this marginal type analysis may not hold because of regulatory costing principles and the timing of capacity additions. Older base load units may actually have both lower capacity and energy costs based on the level of accrued depreciation reducing the capacity component of cost. Some of these units may no longer run as base load units further complicating the matching of costs and benefits for various customer classes. Implicit in the allocation of costs is the matching of costs and benefits. That is, a customer should not be allocated costs for assets from which no benefit is provided. Intuitively, for any hour when units are operating or are demanded for outage and maintenance, the unit costs should be allocated to that hour and customers classes should share in that cost based on the amount of service consumed in that hour. This is a correct assessment of time of use allocation. By actually reviewing each unit, one avoids the arbitrary assumption that all base load capacity has higher capacity costs than peaking units. In reality, a new peaking unit may have higher embedded capacity costs than an old base load unit. Both Staff and OPC use a method that ignores the actual costs of the units operating because a single factor allocates the sum of capacity costs for the system without consideration for the actual embedded costs of the units.

Q. Is it possible to illustrate this problem in the Staff and OPC allocation that causes the methodology to fail?

A. Yes. The following table provides a high level summary of information that illustrates the problem in the Staff and OPC methodology. The table provides the jurisdictional gross plant for steam and other generation (Combustion turbines and Combined Cycle) and the accumulated depreciation.

Generation Type	Jurisdictional Gross Plant	Jurisdictional Accumulated Depreciation	Rate Base as a percent of original cost
Steam	$162,666,505	$78,417,774	42%
Other	$244,539,293	$33,157,306	14%

This information related to the capacity cost illustrates that the lowest fuel cost units actually have a lower total embedded cost or average cost then the higher operating cost intermediate and peaking units. If the composite depreciation rate for steam units is applied to the per kW cost for the base load units and the composite for the other units is applied to the intermediate and peaking units, the result is that the revenue requirement per kW is lower for the Iatan unit (the most expensive base load unit on a per kW basis) than for the State Line Combustion Turbine (the most expensive per kW unit in the other classification). This illustrates the vintage problem as it relates to the Staff and OPC assumptions underlying the Peak and Average allocation they propose. The important point is that the Staff and OPC assume a cost relationship that does not exist on an embedded cost basis and then allocate embedded costs. The result is to allocate more capacity cost to high load factor customers despite the fact that these customers use a greater portion of the energy from low cost, base load units. Staff and OPC cannot be assumed to have provided even a proxy for the TOU cost allocation preferred by the Commission.

Q. Is it possible to illustrate this type of time differentiated cost allocation?

A. Yes. This type of analysis requires that in any hour that a plant is operating or out for maintenance (scheduled or forced) the plants capacity cost for one hour is included in the cost to be allocated. Hourly plant capacity cost is the total annual capacity cost divided by operating hours. The sum of the hourly fixed costs of all such plants used in the hour represents the portion of TOU capacity costs to be shared on the basis of the customer class loads adjusted for losses in that hour. A similar calculation must be made for energy to achieve a cost based matching for customers. The result is to match the costs, both fuel and capacity, with the loads in that hour. It is relatively straightforward to develop shares of load in any hour based on load research data. This produces a true TOU allocation. It also provides insight into seasonal average cost differences for generation. The design of the transmission system is fundamentally different than the generation system and as a result the allocation of transmission cannot mirror the allocation of capacity and energy costs.

Q. How is the peak and average allocation factor developed by the Staff and OPC?

A. The allocation factor is developed using an analysis of the class average demand weighted by the system load factor plus a non-coincident peak factor weighted by one minus the system load factor. The non-coincident peak ("NCP") allocation factor results from adjusting the percentage of the class contribution to the sum of monthly NCPs by a factor representing the monthly share of incremental demand.

Q. Is this peak and average allocation identified as a variation of the method in the NARUC Cost Allocation Manual?

A. No. There is no discussion of this method in the NARUC manual. As discussed below, the method is arbitrary and capricious. The method is arbitrary because the calculation of the excess demand depends on the difference between the monthly NCPs and those values are random. It is capricious because the estimate of the factor changes with any change in the actual NCPs for any month or the changing rank of any month. For this reason, it is not surprising that the method is not discussed in the NARUC Manual.

Q. Is the peak and average analysis employed by the Staff and OPC a reasonable proxy for a TOU allocation of costs?

A. No. The cost method is inadequate as a proxy for several reasons. First, both Staff and OPC fail to match the lower fuel cost component of base load units with the allocation of the capacity shares. This occurs because energy cost is allocated on an annual per kWh basis. Second, the method allocates excess capacity and energy costs to off-peak loads. This occurs because of the average cost allocation of energy and the use of NCPs to allocate the demand component of plant costs.

Q. Why does this not represent the TOU costs fairly?

A. The per kWh capacity cost for a baseload unit is lower than the per kWh capacity cost for a peaking unit because of the number of hours of operation. For example, a base load unit that has a capacity cost of $1500 per kW and an annual carrying cost of 20 percent operates 7500 or more hours per year. Its per kWh hour capacity cost is $ 0.04 per kWh or less. A peaking unit that costs $250 per kW and has the same carrying cost operates several hundred hours per year. The cost per kWh of the peaking unit is greater than the base load unit unless the peaking unit operates at least 1250 hours per year. Peaking units are not designed to operate this many hours each year. As a result, compared to an actual TOU allocation, the staff method allocates too much cost to off-peak loads. In addition, as pointed out above, peaking plant costs are higher than base load plant costs exacerbating the excess cost allocation to off peak loads under the staff and OPC methodology.

Q. Are there additional reasons the cost method is an inadequate proxy?

A. Yes

Q. Please continue.

A. The allocation of capacity costs based on the method employed by Staff and OPC results in excess capacity costs being allocated to high load factor customers. This occurs because of the assumption that the energy portion of the Average and Peak allocation factor receives the larger weight while the NCP factor is subject to a lesser weighting. Since there is a statistical relationship between peak demand (defined as either CP or NCP) and load factor, the variables used by Staff and OPC are not independent in the statistical sense.

Q. Why does independence matter?

A. The class load factor is a reasonable predictor of the class NCP. By summing the two as if they were independent, the allocation tends to give an even greater and therefore arbitrary weighting to energy. Also, the calculation of the weights applied to the development of the NCP portion of the allocation factor has no logical basis. There is no rationale in the operation of the system, or in the mix of capacity used to serve load, to define the monthly shares of incremental demand as the Staff has chosen to do. This is an arbitrary calculation and choosing other plausible definitions of the incremental demand alters the allocation factors. For example, incremental demand might be defined as the difference between the low month NCP and the NCP of the current month. This results in a different allocation factor for NCP and an overall different allocation. The NARUC Cost Allocation Manual refers to the traditional Peak and Average method (as distinct from the Staff and OPC non-traditional method) as "judgmentally- established energy weighting". Staff and OPC compound judgment with arbitrary definitions that produce arbitrary allocation factors. Generally speaking, TOU allocations rely on the analysis of system operating characteristics or dispatch models that allow the analyst to match capacity and energy costs and avoid the arbitrary use of factors that may or may not represent costs reasonably. Finally, the Staff and OPC use a single, derived allocation factor applied to both production and transmission costs. This factor cannot represent a TOU factor for generation and fails to reflect the actual cost causing characteristics of the transmission system.

Q. What characteristics of the Transmission system should be considered in an allocation factor?

A. The Transmission system is designed and constructed in three distinct pieces. First, there are local facilities designed to connect generation to the bulk transmission delivery system. These facilities are designed to carry the output of a specific generator or group of generators. The second component of the system is the local facilities designed to connect the bulk system to the distribution substation or the load-serving portion of the system. The remainder of the cost is the bulk system designed to move power within the system, to or from other systems and to deliver power from external systems to external systems. The cost associated with the three pieces of the system is not reflected by an allocation based on peak and average. As a practical matter, the bulk system is designed to meet coincident peak loads. The two local portions are designed to meet the class NCP for delivery to substations and to deliver the maximum capacity of the generator for the other local system. The peak and average allocation does not reflect any of these factors.

Q. How does one determine the best method for allocating capacity costs given the arbitrary nature of cost allocation?

A. Initially, it is imperative to understand the system operating characteristics, the definitions of fixed and variable costs and certain principles of cost allocation, namely that the allocation of cost should reflect factors that cause the costs to be incurred. These issues were discussed in my rebuttal testimony and will not be repeated here. The Staff and OPC fail this test. The following table provides and illustration of the basic methodologies and their relevant theory.

Method	Allocation Factor	Theory
Coincident Peak Allocation	Coincident class demands	System peak determines cost
Average and Excess Allocation	Energy and maximum demand	Capacity costs determined on both peak and energy
Non-coincident Peak Allocation	Class or customer maximum demand	Class or customer peak determines cost

Importantly, no one method is always correct for different systems or even for the same system over time. Further, a sound cost study uses more than one method to reflect the differences in the underlying cost causation factors. For example, distribution costs are a function of the non-coincident peak while the bulk transmission system is a function of the coincident peak. The allocation of the generation component, particularly in light of the Commission's preference for TOU needs to reflect the combination of energy and capacity requirements of the system.

Q. Why does the average and excess allocation used by the Company better allocate demand costs?

A. The average and excess allocation developed by the Company places a greater reliance on the overall demand and energy characteristics of the customer classes. The method explicitly recognizes that the total demand on capacity for the Empire system is relatively flat and that the coincident peak is less important than the relatively uniform monthly peaks. While this method is not strictly a TOU allocation (and neither are the Staff and OPC), the method does rely on the elements that cause the cost for the generation system and allocates generation costs consistent with the basic time of use theory that energy consumption determines in part the fixed capacity costs of the system.

Q. In summary, in response to the rebuttal of the other parties, what recommendations do you make regarding cost of service?

A. I make the following recommendations:

- The Commission should reject the cost studies prepared by Staff and OPC.
- The Commission should accept the cost study prepared by the Company for this proceeding.
- The Commission should further clarify its preference for TOU allocation methodologies by providing opportunity for all parties to develop and present a preferred TOU allocation methodology for generation costs, both fixed and variable, in the next Company rate proceeding.

<u>Section Two- Rate Design</u>

Q. Have you reviewed the Staff and OPC testimony relative to rate design?

A. Yes. I have reviewed the rebuttal testimony of Ms. Pyatte of the Staff and Ms. Meisenheimer of OPC.

Q. How does the Staff characterize the differences between their rate design and the Company proposal?

A. The Staff characterizes the Company proposal as having "primary emphasis … on economic efficiency". In contrast, the Staff says its primary emphasis is cost of service.

Q. Please comment on the rate design characterizations provided by Staff.

A. The Staff mischaracterizes the Company proposal and, importantly, as illustrated below, its own proposal.

Q. Please explain how Staff mischaracterizes both the Company and its own proposal.

A. First, the Company proposal does emphasize economic efficiency, but it does so in the context of more cost-based rate designs as well. That is, the Company proposed rates are cost based and at the same time send better price signals to promote economic efficiency. Second, the Staff rate design proposal does not reflect costs. Simply, the Staff cost study produces over $11.00 per month of residential customer costs excluding facilities rental related demand costs that they propose to collect from other customers as a ratcheted demand charge yet the Staff proposes low customer charges. The staff cannot claim cost-based rates without moving to costs and they have not done so. Third, as discussed in detail below, the Staff rate design proposal is not cost-based on either theoretical or practical grounds.

Q. Please explain why the Staff proposal is not cost based on theoretical grounds.

A. Simply stated, a flat rate, even for the summer, cannot be cost based. That is the cost per kWh for residential customers is not constant over all levels of kWh consumption. This is obvious from a review of the monthly average cost of energy that shows variations from month to month even in the summer season. We also know that energy cost differs between on and off peak hours over the course of a day. As energy consumption increases for any constant level of demand (a higher load factor), a greater portion of the energy is consumed in off peak hours. The declining block rate proposed by the Company collects a portion of the customer costs; fixed demand related distribution costs and fixed demand costs for generation and transmission in the energy charge portion of the rate. It is precisely the declining block nature of both the summer and winter portion of the residential rate that permits the rate to reflect the differences in cost due to diversity, usage characteristics and the need to spread fixed cost recovery over kWh consumption without creating intra-class subsidies, i.e., avoiding undue discrimination.

Q. Please discuss the theoretical basis for the declining block rate.

A. Under the Staff's cost allocation methodology, the cost of energy is a flat rate per kWh on a year round basis. Empire recognizes that a seasonal differential in energy cost is warranted and has proposed that the differential reflect marginal cost. Under the seasonal differential concept, the difference may be based on average cost or marginal cost. The marginal cost difference is greater than the average cost difference and provides a more efficient price signal for consumers. Empire proposes to set the difference at marginal cost. Staff provides no analytical basis for their differential other than the design of a rate that produces the total revenue requirement. There is no valid or logical argument to support the large differential based on costs.

Q. How should seasonal differentials be determined?

A. The energy cost is the only cost that varies with consumption and thus the only basis for a difference on a per kWh basis. Fixed costs do not vary on a per kWh basis. In any case, the energy cost component from the Staff cost study for the residential rate is a flat charge per kWh for each season. If we accept for the moment the simplifying assumption that the energy charge is flat for every hour in the billing month, Figure 1, attached as surrebuttal schedule HEO-1, illustrates the energy cost component as a flat rate equal to e¢ per kWh and is depicted graphically as the horizontal line EE'. The residential rate must recover the remainder of the class revenue requirement consisting of customer and demand related costs. The customer charge in the rate recovers a portion of the allocated customer costs. For the portion of customer cost not recovered in the customer charge, the cost per kWh of this fixed charge is represented by the curve CC' in Figure 1. This curve declines over the entire range of kWh consumption as the fixed cost is spread over the units or kWhs. This declining unit cost is a function of the fixed nature of the cost allocated to the customer component.

Q. How is the demand cost collected?

A. The demand component of cost is illustrated in Figure 1 by the curve DD'. In reality, this demand component is a whole family of curves each corresponding to a different level of demand for each customer. The demand component represents a simplifying assumption that one curve represents the generation, transmission and distribution components of costs. Without the simplifying assumption, there would be a separate curve for each component and the total cost would be the sum of each of the three components. Nevertheless, since these costs are fixed based on the customers demand (the allocation factor for each component) the downward slope of the curve represents the correct view of the cost components of the residential rate. (It might be noted that this shape applies using the results of the Company, Staff or OPC cost study. The only difference is the level of the curve based on the fixed cost allocation.) The total cost for any customer is given by the vertical summation of the three cost curves-customer, demand and energy, for each season.

Q. Is there anything else relevant to the rate design discussion?

A. Yes, several additional observations are relevant at this point. First, larger residential customers (measured in kWh consumption) impose greater demand on the system and hence their demand curve, all else being equal, will be higher than a smaller customer. It is also true that larger customers also exhibit higher coincident and non-coincident load factors than do smaller customers. With the higher load factors, the locus of points that make up the relationship between cost and use for residential customers is downward sloping to the right. Stated another way, if we plotted all of the residential customers on this graph based on their demand and energy characteristics and assumed for the moment that all unit costs are the same, the residential cost curve would slope down and to the right. Figure 2 illustrates the cost curve for a residential customer with a known demand. The appropriate rate is the vertical summation of the energy, customer and demand components of cost for the number of hours-use of that demand by the customer, or the kWh consumption. As Figure 2, attached as surrebuttal schedule HEO-2, illustrates, the cost per kWh declines as additional kWhs are consumed. Figure 2 also illustrates that a flat rate, as proposed by Staff results in almost all customers paying too little or too much.

Q. Why does a flat rate not reflect costs?

A. Added to the problem that a flat rate is nearly always not cost based is the fact that our assumption that demand costs are constant over size is unsupported by the facts. There are significant economies of scale in distribution related to transformers, conductors and other components of the distribution system. In other words, per unit cost of demand for the distribution system is lower the larger the size of the equipment installed. A simple example illustrates this point. A ten Kva transformer costs more per Kva of installed capacity than a 25 Kva transformer. Larger customers permit the Company to install equipment that has a lower cost per unit of demand than the equipment installed for smaller customers. Average cost studies rarely, if ever, recognize this scale effect because of the average nature of the allocation process. The correct representation of this scale effect is to make the composite cost curve for residential service in Figure 2 even steeper than the illustration. Finally, even though a flat energy charge is assumed, higher load factor customers tend to use relatively more energy in the lower cost periods of each day. Using the Commission preferred TOU allocation would result in a weighted cost of energy for the largest customers below that of the average residential customer because of the higher load factor. The net result of a theoretical analysis of cost is that the declining block rate design proposed by the Company is more cost-based than the design proposed by the Staff. There is no evidence to support the

Staff's view that the summer rate should be flat. The flat residential rate is inefficient, unduly discriminatory and creates intra-class subsidies. In contrast, the Company proposal promotes economic efficiency, properly reflects costs, avoids undue discrimination and reduces intra-class subsidies.

Q. Is there evidence that declining block rates are practical for the residential class?

A. Yes. It is common practice to recognize that within a relatively homogeneous customer class such as the residential class, there may be significant cost differences based on the size of the customers measured by kWh consumption. In fact, the Staff supports a declining block rate feature for general service rates. The hours use of demand rate applicable to certain general service customers is specific recognition of the lower unit costs associated with higher load factors. Typically, the highest use residential customers also have the highest load factors. In practice, this means that the declining block rate provides a closer matching of costs and revenues than the proposed flat summer rate and declining block winter rate.

Q. Is it possible to design a flat rate that tracks costs and is also efficient?

A. Yes. The rate would have an energy charge for all kWhs equal to the summer marginal cost in the summer and the winter marginal cost in the winter. The remainder of the residential revenue requirement would be collected through a customer charge. The required customer charge level would be several times as large as the charge proposed by the Company. The proposed Staff rate does not even move toward rates that are more cost based or efficient and should be rejected. The Staff correctly recognizes the nature of distribution cost recovery for large general service customers and proposes a facilities charge to recover distribution costs. This charge has the effect of tracking the downward slope of the unit cost curve since increases in kWh consumption lower average cost per kWh. It is difficult to understand the obvious inconsistency among the Staff proposals unless the Staff does not wish to reflect costs for the residential rate.

Q. Does OPC propose a rate design for residential customers?

A. No. OPC states that increases in the customer charge do not improve efficiency and that any increase in the charge should be limited to $1.00 per month. No evidence is offered that the Company rate design does not represent an efficient rate design. The OPC does state that marginal cost sets the floor for unsubsidized rates. Since subsidies are by definition inefficient, the increase in the Company proposed residential customer charge is actually consistent with the OPC view of marginal cost since marginal customer cost for residential service is over $12.00 per month. The OPC seems to support rates that are not even at the minimum charge they say should be acceptable. It is impossible to reconcile the low customer charges and economic efficiency. It is also impossible to reconcile the proposed limit on the customer charge and cost-based, non-discriminatory rates.

Q. Does OPC provide evidence that fixed cost recovery in fixed charges is not efficient?

A. No. OPC relies on an anecdotal comparison of cost recovery for a fast food restaurant as the basis for arguing that customer and other fixed charges are unnecessary for efficiency. That reliance is misplaced for a variety of economic reasons. Most importantly, there is no real comparison between a fast food establishment and a utility. The utility has an obligation to serve, the restaurant does not; the utility cannot change its prices with market conditions the restaurant does; the utility provides its facilities to the customer in such a way that use by one customer of certain facilities excludes the use of other customers while a restaurant has no facilities dedicated to the use of a single customer and if they do dedicate facilities to a single customer there are separate minimum charges for doing so; the utility cannot exit the business and move to a better location or different clientele while the restaurant may do all of these things. The foregoing list does not address the differences in the cost structure of the two businesses. The utility's costs are largely fixed while the restaurant's costs are largely variable. Even in competitive markets characterized by high fixed costs we find that fixed charges are the common and sometimes predominant method of cost recovery. For example, cell phone service providers use fixed charges, as do rental car companies. The important point in all of this is that economic theory recognizes the importance of fixed charge recovery of the portion of revenue requirement above marginal cost. As a result the OPC position is incorrect and the OPC evidence concedes that the customer charge should not be less than marginal cost. Therefore, the one-dollar proposed maximum increase is not supported by evidence in this case.

<u>Section Three- Summary Rationale for Adopting the Company's Proposed Rates</u>

Q. Please summarize the testimony in support of the Company proposed rates.

A. The Company has proposed a number of changes to rate design that recognize the current cost characteristics of the company and translates those costs into economically efficient, cost-based rates. The evidence demonstrates that the current winter summer rate differential is too large under any cost based determination. Based on the evidence before the Commission, there is nothing to support the current differential on either a cost or efficiency basis. It is also incorrect in light of the evidence to continue the use of a flat summer rate for residential customers. The flat summer energy charge rate is not cost-based and overcharges consumers for consumption in the summer even if one accepts the Staff's erroneous winter/summer cost allocation. The Company provides evidence on both a theoretical and practical basis that the declining block rate structure with higher customer charges is superior to other rate proposals along all of the dimensions under which the Commission evaluates rates. The Company's rates are more nearly cost-based, more equitable in sharing costs within the class and more economically efficient.

Q. Please summarize the rationale for adopting the Company's proposed cost of service study.

A. The Company proposed cost of service study represents the most reliable cost study filed in this proceeding. As discussed at length above, there are numerous problems with the Staff and OPC studies. Neither study actually approximates the Commission preferred TOU allocation. Both studies suffer from judgmental development of allocation factors that cannot possibly be reconciled with the actual cost incurrence of the system on a TOU basis. The actual development of the demand allocation factors applied to generation is arbitrary and capricious. No recognition is given to the mathematical manipulation used to develop the peak portion of the factor. The Company has filed a cost study that relies on both energy and non-coincident peaks to allocate production capacity. The method is well recognized and accepted among cost-of service experts. More importantly, the method is consistent with the underlying operation and cost incurrence on the system. As a result, the Company cost study provides a reasonable, rational and reliable analysis of the cost to serve each customer class. Recognizing that differences in cost of service always occur because of the necessity to allocate joint and common costs does not mean that arbitrarily determined factors provide a sound basis for the allocation of costs. Cost studies must be judged on the basis of the soundness of the underlying theory to match the factors that cause costs to be incurred. The Company cost study is exactly such a study.

Q. Does this conclude your testimony?

A. Yes.