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Witness: H. Edwin Overcast
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Case No. ER-2014-0351
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Before the Public Service Commission
Of the State of Missouri

Rebuttal Testimony

of

H. Edwin Overcast

March 2015

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OF
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ON BEHALF OF
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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS AFFILIATION.

A. H. Edwin Overcast, Director, Enterprise Management Solutions, a Black & Veatch Company.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS CASE BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes. I filed direct testimony in this case on behalf of The Empire District Electric Company ("Empire").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I reviewed the Rate Design and Class Cost-of-Service Report and supporting direct testimony filed by the Staff of the Commission ("Staff") on February 11, 2015, the direct testimony of the Office of the Public Counsel ("OPC") witnesses Dismukes and Mantle, and the direct testimony of Midwest Energy Consumers Group ("MECG") witness Maini. My rebuttal testimony addresses issues raised in the aforementioned testimony related to the appropriate cost of service study, rate design policy, and Empire's fuel adjustment clause ("FAC").

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I conclude that the testimony of the other witnesses on the appropriate cost of service methodology fails for two fundamental reasons. First, the methods supported by Staff, OPC, and MECG do not reflect cost causation, because, in some respects, they are not grounded in the engineering, planning, and operating reality of Empire or any electric utility. Second, the cost of service studies filed by the other parties requires assumptions that are false or unrealistic as to the nature of the costs to be allocated and to the classification of these costs. I also conclude that the proposed rate designs result in rates that are not just and reasonable, fail to provide the utility an opportunity to earn its allowed return, and, in the case of the residential rate, continue a pattern of undue discrimination within the residential class. This later issue must be addressed to remedy the excess portion of costs collected from larger customers to provide a subsidy to smaller customers within the rate class. Finally, I conclude that there is no rationale for eliminating Empire's FAC and that all of the costs associated with fuel transportation and transmission charges from the Southwest Power Pool ("SPP") should be included in Empire's FAC.

SECTION 1- COST OF SERVICE ISSUES RAISED BY OTHER PARTIES

Q. IS THERE A COMMON THEME AMONG THE COST STUDIES SUBMITTED BY THE OTHER PARTIES?

A. Yes. All parties including Empire base their cost of service as it relates to production plant on one of the various methodologies that fall into the same category as average and excess demand ("AED") method. Since the production plant is the largest component of rate base, it is useful to have agreement on this fundamental concept. The debate around AED is about which of a number of versions is most appropriate. As I stated in my direct testimony, there is a best cost of service methodology for each utility. That methodology is the one that matches cost causation to cost allocation for the portion of the system being allocated. Cost causation is the key element to selecting an appropriate allocation factor. This has been the standard by which an allocation method is evaluated, and it continues to be the gold standard for assessing cost allocation. For example, the U.S. Court of Appeals for the District of Columbia Circuit has defined the cost causation principle as follows: "[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."[1] The U.S. Court of Appeals for the Seventh Circuit recently quoted and elaborated on that definition, stating:

> All approved rates must reflect to some degree the costs actually caused by the customer who must pay them. Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party. To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed.[2]

The D.C. Circuit hears appeals from the Federal Energy Regulatory Commission ("FERC") and, has significant expertise related to cost of service matters.

[1] K N Energy, Inc. v. FERC, 968 F.2d 1295, 1300 (D.C. Cir. 1992) (K N Energy).

[2] Illinois Commerce Comm'n v. FERC, 576 F.3d 470, 476 (7th Cir. 2009) (Illinois Commerce Commission) (citing K N Energy, 968 F.2d at 1300; Transmission Access Policy Study Group v. FERC, 225 F.3d 667, 708 (D.C. Cir. 2000); Pacific Gas & Elec. Co. v. FERC, 373 F.3d 1315, 1320-21 (D.C. Cir. 2004); Midwest ISO Transmission Owners v. FERC, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (Midwest ISO Transmission Owners); Alcoa Inc. v. FERC, 564 F.3d 1342 (D.C. Cir. 2009); Sithe/Independence Power Partners, L.P. v. FERC, 285 F.3d 1, 4-5 (D.C. Cir. 2002) (Sithe); 16 U.S.C. 824d).

Q. IF THERE IS GENERAL AGREEMENT AS TO THE ALLOCATION METHODOLOGY FOR PRODUCTION PLANT, WHY ARE DIFFERENT METHODS PROPOSED BY THE OTHER PARTIES?

A. Each party to a rate proceeding has its own objectives in developing a cost of service study. For example, a party may be trying to benefit only one group of customers. The important issue is how the selected method matches cost causation. In furthering his or her own objective, an analyst may depart from the underlying cost causation. For example, MECG witness Maini suggests that it is appropriate to use only six peaks to calculate the excess demand portion of the AED methodology. Witness Maini bases this conclusion on the peak loads of customers and notes that the system is both winter and summer peaking for load. This analysis of load defines load too narrowly, as I discuss in my evaluation of peak demand on pages 17-18 of my direct testimony. If one understands the planning and operation of the power system, there is no question that loads are not the only demand on the system resources. Power systems must maintain a level of reserves necessary to assure reliability at all times, because of the variability of both loads and the availability of generation plants. It is these operational constraints that cause the aggregate demand on the system capacity and not just load. When unit maintenance, forced outage rates, and unit deratings are added to load, the total system load for Empire flattens out, so the valleys in the customer load are the times when the utility schedules maintenance outages and thus raised the full load of the system. Using only six peaks based solely on load does not adequately represent either how the system is planned or how the system is operated to minimize the total cost of power supply services including reserves. In essence, this variant of AED proposed by MECG witness

Maini does not come close to reflecting cost causation and should be rejected for application to Empire.

Q. ARE THERE ADDITIONAL WAYS THAT THE OTHER PARTIES, DESPITE USING A VARIANT OF AED, FAIL TO REFLECT COST CAUSATION?

A. Yes. OPC witness Dismukes provides an alternative average and peak cost allocation which is classified as an energy weighting form the same as AED. There are two fundamental problems with the average and peak that cause it not to reflect cost causation. First, the method double counts the average demand in developing the allocation factor. This is because the average demand is part of the peak demand allocation factor and receives a judgmental weighting of 50% for average and another 50% for the peak factor. The following expansion of the average and peak methodology illustrates this point.

Average Demand = Total energy for a class/ 8760 hours in a year

12 CP = Average Demand + Excess demand based on the average of 12CPs

Average and peak = .5(Average Demand) + (.5(Average Demand) + .5 (Excess Demand), the latter term equaling 12CP.

Second, the arbitrary weighting of average and peak bears no resemblance to how costs are incurred or to how plants are planned and operated. It is just a simple average of two components. The underlying concept of cost causation requires a detailed explanation of how this method reflects cost causation, but no such explanation is provided by OPC. There simply is no theoretical, planning, or operating consideration that forms the basis of support for the arbitrary nature of the average and peak methodology.

Q. PLEASE CONTINUE.

A. The Staff also uses a method that is arbitrary and suffers from incorrect assumptions and arbitrary weightings. The Base – Intermediate - Peaking ("BIP") method is based on the assumption that the capacity costs of production facilities can be assigned to different components of the load - base load, intermediate load, and peaking load. While it is true that plants have different characteristics in terms of the duration of hours when they operate, the implicit assumptions of the model are not valid in terms of the operating reality, the economics of the plant, or the planning of the capacity additions. It is not correct to assume that all of the costs of a baseload plant are incurred solely to meet the average load of the system. When planners add capacity to the system, it is added in a way to meet two basic objectives: (1) adequate capacity to meet the system maximum demand on generation resources with adequate reserve margins for reliability; and (2) to provide the lowest possible annual operating costs consistent with meeting objective number one. Simply, since baseload plants are operating at the system peak, they are also providing a system peaking resource. The BIP method incorrectly assumes that all of the capacity costs of baseload plants are incurred solely to meet the baseload energy requirements. The fundamental problem with the base allocation on average demand fails to recognize that some portion of that total capacity cost is incurred to have adequate resources at the peak. The same conclusion also holds for intermediate capacity. That is, all capacity has some component of cost that is caused by the need to meet peak loads reliably. The BIP method does not reflect this cost causation principle. Further, plants may change from baseload to intermediate load, as plants age and the generation mix changes. Intermediate plants also provide peak capacity as well. It is also incorrect to assume that peaking plants only run during peak periods. Peaking plants may be dispatched for many reasons because of their particularly valuable operating characteristics. For example, given their quick start properties, these plants may be run to respond to changes in the generation of solar PV or wind because of their lower reliability. In that case we may find peaking plants operating at night and on the weekend to assure system reliability and to provide supplemental operating reserves at any time.

Q. ARE THERE OTHER ISSUES WITH THE BIP METHODOLOGY THAT DO NOT REFLECT COST CAUSATION?

A. Yes. The concept of averaging the class' baseload equally over all baseload hours is not a reasonable assumption. For example, the residential class has two segments with different load shapes. Electric heating customers have much higher base loads than other residential customers because of the significant night and weekend loads in the winter. At the same time, base loads for all of the residential class are substantially lower in the spring and fall when baseload units are out of service for maintenance. In fact, as system load factor increases, the system reaches a point when capacity would be needed just to have adequate reserves during maintenance outages. In planning the system, load duration measured by total demand on the system (not just customer load) is critical to determining the required capacity and the mix of that capacity. The BIP method is an inaccurate picture of the factors that cause costs because it cannot recognize even basic realities of system operation. For this reason alone, the Staff's proposed cost of service study should be rejected as the evidence does not support the use of the study.

Q. ARE THERE OTHER AREAS OF DISAGREEMENT RELATIVE TO THE COST OF SERVICE STUDIES?

A. Yes. There is disagreement relative to the allocation of distribution costs in the costs study. Both the Staff and OPC classify distribution costs in accounts 360-368 based solely on demand. This classification is not consistent with cost causation. To adequately cover the objections to the use of the minimum system classification of costs between demand and customer, I will address the arguments of OPC witness Dismukes separately from the Staff arguments.

Q. PLEASE DISCUSS THE ERRORS IN THE TESTIMONY OPC WITNESS DISMUKES RELATED TO THE USE OF THE MINIMUM SYSTEM.

A. OPC witness Dismukes begins his criticism of the method by stating "the MSS study is based upon a straw man of hypotheticals that hinge on a number of unverifiable assumptions." This statement is factually incorrect. The data used in the minimum system classification of distribution cost is neither hypothetical nor does it require any unverifiable assumptions. This argument shows a fundamental lack of understanding of the rigorous documentation used by engineers who design the distribution system and the necessary accounting data to determine the costs associated with the design of that system by component. Perhaps OPC witness Dismukes has not been exposed to the myriad of distribution standards used by distribution engineers when they design various components of the system. These mandated engineering standards are designed to provide a safe and reliable electric system for serving each premise on the system regardless of the load actually being served[3]. These documents include approved line extension policies in the utility tariff as well as distribution standards from IEEE such as

[3] For example, there is minimum size of pole that can be installed to assure adequate clearance between the energized conductor and persons or vehicles passing underneath.

the Transmission and Distribution Standards[4]. In addition, utilities have their own operating standards designed to assure that the utility meets all applicable codes and standards and follows good engineering practices. Thus, a competent distribution engineer knows the smallest (minimum size) of each system component installed. A simple example will illustrate this concept. It is not practical or economically efficient to stock every size of a particular component of the distribution system. As a result, different utilities determine the optimum size for the smallest transformer they install. The minimum size will differ from system to system for a variety of factors, such as expected minimum loads for residential customers, and other factors that impact transformers, such as ambient temperatures. A similar analysis applies to each component taking into account numerous factors necessary for safe operation of the system. The minimum system represents actual facilities being installed by the utility not hypothetical installations or assumed installations. The costs of these facilities are based on actual costs for the typical installation that is recorded in the plant accounts of the utility. There are no data limitations for determining the classification in a rigorous and sound manner.

Q. PLEASE CONTINUE.

A. OPC witness Dismukes also cites academic literature in his opposition to the use of the minimum system. Witness Dismukes uses a quotation from Principles of Public Utility Rates by Bonbright, Danielsen and Kamerschen, which refers to the system as a

[4] With a focus on power transmission and distribution, this popular subscription provides access to over 270 IEEE T&D standards, drafts, IEEE Redline Versions of Standards, and archived standards known throughout the T&D industry today. The standards in this growing online collection address the design, performance, installation operation, and maintenance of overhead and underground systems that carry electricity via AC or DC lines from generating sources and substations to service areas. These standards include: network systems; switching surges; electric and magnetic fields; towers, insulators and hardware; safety and environmental impact; and power quality.

"phantom system"[5]. As noted above, the minimum system analysis for Empire is based on actual facilities installed - not some phantom equipment. Further, Witness Dismukes truncates the first paragraph in his quotation and goes on to include a second paragraph that references "this last-named cost imputation" which is a reference to the zero-intercept method in the 1988 edition[6]. The zero intercept method is not used in this study. Additionally, the last portion of that paragraph citing a 1980 study represents material added by Danielsen and Kamerschen. The conclusion of the study that there is no statistical association between distribution costs and the number of customers is not in dispute in this case, because the minimum system is used to classify costs between customer and demand. The demand component remains the larger share of distribution costs. Further, it is obvious that as the system expands (regardless of density), new poles, wires and transformers must be added to attach the customers at the periphery of the system or even internally when land use options change. Fortunately, the minimum system analysis actually accounts for density with measures such as conductor miles and number of poles and transformers. The academic arguments are not well founded when viewed in the light of actual utility experience in a modern utility.

Q. PLEASE CONTINUE.

A. Finally, I should note that OPC witness Dismukes is quite selective in quoting academic literature. In the same Bonbright, et, al. text, we find that these costs also cannot be allocated on demand as suggested by witness Dismukes and in practice "the vast majority of utilities use some form of the minimum system to classify costs.[7]" Thus, the literature

[5] James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates, 1988 Edition, p. 491.
[6] Op. cit. p. 491
[7] Op. cit. p. 492

actually indicates that this method is reasonable and to include the role of density would not produce uniform rates for the whole service territory. Also, in the text Public Utility Accounting: Theory and Application written by James E. Suelflow states as follows:

> *Similarly, distribution transformers and primary and secondary distribution lines including conductors and devices (Account 365, "Distribution Plant") and poles and towers (Account 364, "Distribution Plant"), all contain capacity and customer costs.*[8]

All of this is to say that cost of service studies to be reasonable must reflect cost causation, and the minimum system classification of distribution costs reflects cost causation both in theory and, more importantly, in the operating practices of the utility as they relate to the distribution system.

Q. PLEASE DISCUSS THE STAFF'S PROPOSED CLASSIFICATION OF DISTRIBUTION COSTS IN ACCOUNTS 364-368.

A. The Staff report incorrectly classifies all of these costs as demand. The report does not explain why they chose to classify costs only to demand and have provided no evidence of any analysis that it is solely demand that causes these costs. In the discussion of the distribution demand allocation issue, the Staff report discusses the role of diversity and how it changes from the substation to the transformer. Despite this correct discussion that recognizes that diversity decreases in closer proximity to customers, the Staff report uses the same class NCP allocation factor for all of the components of the distribution system starting with substations. Where demand is used as the allocation factor, it must be recognized that the appropriate NCP allocation factor changes as the load moves

[8] Public Utility Accounting: Theory and Application, James E. Suelflow, The Institute of Public Utilities, Michigan State University, 1974, p. 241

closer to the customer. Thus, for the most local facilities such as secondary conductor and transformers, it is no longer the class NCP driving the cost. Instead, it is the sum of the customer NCPs. For example, the class NCP has diversity based on a system wide set of socio-economic and demographic factors that impact diversity. Those factors change as the facilities move closer to the load. The net result is that there is much more delivery capacity in installed transformers than there is in substation transformers. This capacity is needed to serve the maximum loads of the customers served from the transformer. This is the reality of the distribution system as may be illustrated by a single residential customer served off a transformer. The transformer must be large enough to meet the NCP of the customer. Even if we add a second customer to that transformer, there is a high probability of coincident NCPs if the premises have the same end use load characteristics. The Staff report thus under allocates cost of distribution to secondary service customers. The simple solution to that issue is proper use of the minimum system to classify a portion of the system as customer related. Failure to use the minimum system classification means that the cost study has deviated significantly from the gold standard of cost of service - cost causation.

Q. PLEASE COMMENT ON THE ALLOCATION OF THE INCREASED REVENUE REQUIREMENTS AMONG THE CLASSES.

A. In my view, the proposed revenue allocation based on either the Empire proposal or the Staff proposal is reasonable. On the other hand, the recommendations from OPC and MECG are self-serving recommendations and do not properly balance all of the information before the Commission. The OPC and MECG revenue requirement allocation recommendations should be rejected.

Q. DO YOU HAVE OTHER COMMENTS RELATED TO THE COST OF SERVICE STUDIES?

A. Yes. The Staff notes at two occasions in their report that results of cost of service studies are not precise[9]. OPC witness Dismukes also recognizes this caveat relative to the cost of service. I agree with this point in principle because cost studies provide useful directional information related to class returns and the overall allocation of revenue requirements. This conclusion does not, however, apply to use of the unbundled costs for specific services provided by the utility. Cost of service studies are more important for the information related to the unbundled costs of the services the utility provides. In this context, the cost study is useful in rate design, because it guides the determination of various rate components such as the customer charge and the facilities charge to recover distribution demand costs. The view that cost of service is a guide for rate design is sound when the costs are unbundled for specific components of cost that are well defined.

<u>SECTION 2- RATE DESIGN ISSUES</u>

Q. WHICH PARTIES HAVE RECOMMENDED RATE DESIGNS IN THIS CASE?

A. OPC witness Dismukes recommends rate designs for all classes of customers, as does the Staff Report. MECG witness Maini accepts the principles recommended by Empire related to fixed cost recovery and only recommends rate designs for larger customers.

Q. PLEASE DISCUSS THE RATE DESIGN RECOMMENDATIONS BY OPC WITNESS DISMUKES.

A. OPC witness Dismukes takes issue with the general recommendation to collect more fixed costs in fixed charges. In fact, he recommends putting more cost on the energy charge for all rate schedules based on promoting economic efficiency. It is surprising

[9] STAFF'S RATE DESIGN AND CLASS COST-OF-SERVICE REPORT at page 6, lines 12-13 and page 11, line 5

that witness Dismukes reaches this conclusion without even mentioning that economically efficient price signals should be based on marginal cost not average revenue requirements. The only rationale for increasing the energy charge would be if the marginal cost of generating the power is greater than the current rate. Since there is no evidence that this is the case, there is no efficiency argument that can support further increasing the variable charge. The opposite conclusion would follow if the marginal cost is less than the current rate. That is, the variable charge should be reduced and even more cost recovered in the fixed charge than Empire has recommended under the principle of Ramsey pricing or an optimal two part rate. There are, however, many other reasons for increasing the customer charge that witness Dismukes chooses to ignore. First, the Empire residential rate serves both regular and all-electric customers. Under any circumstances and any cost allocation, all-electric customers are less costly to serve on a kilowatt hour basis. They have a higher load factor that results in lower unit recovery of fixed cost. They have a larger share of lower energy and production capacity cost based on winter load and, in addition, a larger share of off-peak load than regular use residential customers. From a cost of service perspective, they have lower unit costs for distribution investment because of large economies of scale[10]. In short, using the same kWh charge for these larger customers causes them to subsidize other residential customers and creates a case of undue discrimination relative to the cost to serve the load. The proposed rate design of witness Dismukes exacerbates the discrimination rather than moving to correct this issue. The two-part rate referenced in witness Dismukes testimony has its theoretical foundation in Ramsey pricing and the constraint of 19th century

[10] See the detailed analysis in my direct testimony supporting these conclusions at pages 19 and 20.

metering technology[11]. Further, as the electric industry is evolving to a market of mixed competition and monopoly service, it is even more critical that the pricing of electric services be unbundled to charge separately for the services actually provided.[12]

Q. HAVE YOU EXPLAINED THE ELEMENTS OF AN UNBUNDLED RATE IN THIS CASE?

A. Yes. I have provided a detailed explanation of the components of unbundled rates in my direct testimony. By moving in the direction of unbundled rates in this case and subsequent cases, the Commission can more adequately address the issues of mixed monopoly and competition model. Just as an example, moving in this direction is a critical component of creating adequate rates for partial requirements customers such as combined heat and power ("CHP") customers, as discussed in the direct testimony of Missouri Department of Economic Development - Division of Energy witness Schroeder. The provision of service to CHP customers is complex and requires more rate design tools than exist for Empire currently. Partial requirements customers have characteristics that do not neatly fit in the context of current rate designs. By using the tools of unbundling, rate designs can be much more efficient and provide better price signals for customers who elect to use different services from the utility. Both OPC witness Dismukes and the Staff have proposed rate designs that do little or actually harm the transition from 19th century rates to smart rates for the 21st century.

[11] See for example my article "To Modernize the Grid, We Must Forget Everything We Know About Rate Structures" in **greentechgrid,** October 24, 2014

[12] This evolution is being driven by the availability of distributed generation (DG) to provide a portion of the customers' generation requirements.

Q. PLEASE COMMENT ON THE TESTIMONY PROVIDED BY OPC WITNESS DISMUKES RELATED TO REGIONAL CUSTOMER CHARGES IN SCHEDULE DED-11.

A. First, the testimony does not represent all of the customer charges in the region or even in the state of Missouri. Schedule HEO-R-1 attached to this testimony provides the customer charges for 40 Missouri electric cooperatives who serve customers in areas adjacent to the Empire service area and throughout the state. Schedule HEO-R-1 shows that the average customer charge for the member owned and member regulated electric utilities is over $24.00 per month and the median value and the mode for the cooperatives is $25.00. This amount is above the Empire proposed charge. Moreover, this is far more instructive for the Commission as to the correct level of a customer charge because it represents the customer charge that citizens of Missouri who own and operate their own utility view as appropriate.

Q. PLEASE CONTINUE.

A. OPC witness Dismukes also fails to point out that three of the higher customer charges from Wisconsin - Madison Gas and Electric, Wisconsin Electric Company, and Wisconsin Public Service Corp. - represent the latest decisions on the magnitude of the charge and were approved in the most recent decisions on the matter. The trend in utility rate design is to move to higher fixed charges to provide better price signals and provide the utility with a more realistic opportunity to earn the allowed return. In addition, higher customer charges are needed to provide appropriate price signals in the mixed monopoly and competition model that has arisen with the availability of distributed generation ("DG") at economic prices when viewed in the context of net metering where customers may avoid essentially the embedded cost of service in total (less the customer charge) but continue to cause at least the same cost for delivery and potentially more delivery costs as well.

Q. DOES OPC WITNESS DISMUKES PROPERLY DESCRIBE THE EMPIRE PROPOSED RATE DESIGN?

A. No. OPC witness Dismukes first characterizes the rate design as a straight fixed-variable ("SFV") based rate design proposal. That is not a correct characterization, and, even if it were, this Commission has adopted SFV rate designs for natural gas delivery service. Thus there is some precedent for using SFV rate design in Missouri. There are a number of theoretical and practical errors in the OPC testimony regarding SFV rate design. For example, OPC witness Dismukes references the SFV rate design approved by the FERC for gas pipelines as an example of SFV rates. In this case, Empire is only proposing to increase the customer charge by an amount less than the revenue requirement increase, leaving some dollars and still most of the fixed costs to be collected in the kWh charge. The FERC SFV rate did not even contain a customer charge but, instead, collected the fixed costs in a 100% ratcheted demand charge. Although Empire proposes to increase the customer charge to a level that is less than the full customer related costs, there is no demand charge proposed. At some point in rate unbundling, that will be a necessary element of the rate design to recover facilities costs just as in other rate classes. OPC witness Dismukes states that "the Company's rate design proposals are inconsistent with energy efficiency." That statement is not correct either practically or theoretically. Economic theory is unambiguous that economic efficiency in energy, or in any product for that matter, results when the price of the product is equal to short-run marginal cost.

In that sense, the relevant value for Empire is closely related to the marginal cost of fuel and would not include, for example, customer costs not recovered in the customer charge, the sunk cost of distribution, transmission, and generation capacity, all of which is recovered today in the kWh charges for customers without a demand charge. In fact, none of the distribution costs are avoided for customers who adopt DG, and, in some cases, even those who adopt various conservation measures. Thus, the prices that are inconsistent with economic efficiency are those proposed by the OPC that depart even further from economically efficient prices. OPC witness Dismukes goes on to say "…in the extreme case of an SFV rate design, customers will pay the same charge regardless of their usage level. As a result, inefficient customers would pay the same monthly utility bill as relatively more efficient customers, negating all incentive to seek greater efficiency." This statement is also incorrect. First, the concept of a fixed charge within a utility's rate structure is much more than its traditional monthly customer charge. To be clear, the definition of a fixed charge under SFV does not equate to the concept of a customer charge alone[13]. Rather, it also includes a variety of demand charges to recognize the different utility services provided to customers. Attempting to recover fixed costs for all of the utility services used by customers through a single fixed charge is not feasible and could never produce a reasonable result. It is also clear that Empire did not make such a proposal. Moreover, a single fixed charge cannot provide efficient price signals for customers. I have developed, filed, and had approved SFV rates, and I am very familiar with the components of such rates. SFV rates recover fixed costs in both customer and demand charges. Customers under SFV rates will never pay the same

[13] In the case of gas distribution the customer charge recovers all of the costs for smaller customers for whom the minimum system will serve the customer's maximum design day demand. That does not alleviate the need for a demand charge for peaking capacity such as LNG plant costs.

costs regardless of usage, as witness Dismukes claims. Customers even under SFV rates pay more for more usage through both the variable charge and through the demand charge if that differs with volumetric usage. Further, by definition, more inefficient users will pay higher fixed charges as a result of recovering fixed costs through demand charges. The importance of the increase in fixed charges is noted in the highlighted quotation from the National Action Plan for Energy Efficiency where SFV rates better reflect the costs.

Q. WHY IS A BETTER REFLECTION OF COSTS IMPORTANT?

A. The most important element of an efficient decision about the consumption of electricity, either as an increase or a decrease, is providing the customer with a cost based price signal. When the rate structure properly reflects costs there is a match between the change in the customer's bill and the change in the utility's revenue. Absent this match, deviations from the consumption in the test year either deny the utility the opportunity to earn the allowed return or penalize the customer by providing the utility unjust enrichment when rates are not reflective of actual costs. This matching principle is an integral part of sound regulation, regardless of the form rates take to provide matching. The Empire proposal for rate design is a conservative and reasonable step toward such matching, while the OPC proposal exacerbates the mismatch to the detriment of both customers and Empire.

Q. HOW DOES THE ISSUE OF AFFORDABILITY ENTER INTO THE ARGUMENTS RELATED TO RATE DESIGN?

A. The issue of affordability is not significant, since the proposed customer charge increase is only about $0.20 per day. When one considers all the value of the services derived from access to the electric service, the customer charge increase is miniscule. In addition, the analysis of affordability is not a basis for rejecting efficient and rational rate designs that result in significant welfare gains for society. Rather, the issue of affordability should be addressed directly for only those customers who would require assistance in affording electric service. Most states handle this issue separate from the adoption of a particular rate design. The use of targeted rates for those who have issues with affordability is much more effective as a policy tool than distorting the price signals for every customer on the basis of those limited number of customers who have legitimate affordability concerns.

Q. BOTH THE COMMISSION STAFF AND OPC WITNESS DISMUKES CITE THE COMMISSION'S DECISION IN THE AMEREN MISSOURI RATE CASE, CASE NO. ER-2012-0166, AS THE BASIS FOR LIMITING THE INCREASE TO THE RESIDENTIAL CUSTOMER CHARGE. PLEASE COMMENT ON THAT RATIONALE.

A. I did not participate in that case and am not familiar with all the facts before the Commission in that case. As a general matter, the Commission is not bound by any prior decision in the current Empire case, because the facts and evidence in this case must be the basis for any decision. The overriding issue is that the rates adopted for Empire must be both just and reasonable and not unduly discriminatory based on the evidence in this case. The issue of undue discrimination is important in this case because a single rate serves both regular and all-electric residential customers. As I have discussed, current rates cause all electric customers to bear a disproportionate share of the cost of service, no matter what cost study is the basis for the analysis. This is the most significant element of the discussion related to the magnitude of the customer charge. Failure to increase the customer charge as proposed by Empire, means that energy charges increase, thus further impacting large customers who by and large are all electric customers. Even the Empire proposal does not eliminate the undue discrimination in the residential rates. It does, however, reflecting the principle of gradualism, take a critical step toward rates that are just and reasonable and not unduly discriminatory. All of the other residential rate design proposals create more discrimination - not less. There is no precedential value for a decision that would continue the practice of undue discrimination within the residential class. Additionally, the advent of the mixed competitive and monopoly market for residential electric service makes it incumbent on the Commission to eliminate the cross subsidy between small and large customers in order to avoid substantially larger increases to customers who remain captive to the utility service. While this issue is not a major one for Empire currently, it is only a matter of time before these issues move from western states such as California, Arizona, and Hawaii to states in the Midwest. Adopting policies that unbundle rates and recover fixed costs in fixed charges (both customer and demand charges) and start with increasing the customer charge as proposed in this case is the first important step for rationalizing residential rates. It is also important to set the facilities demand charge equal to the cost of service. The issues in this case fully support the proposed gradual move to better rates.

Q. DOES THE CONSERVATION PRICE SIGNAL ARGUMENT DISCUSSED IN THE STAFF REPORT SUPPORT LIMITING THE CUSTOMER CHARGE INCREASE?

A. The answer depends entirely on the definition of conservation. If conservation means an absolute reduction in electric use, then the limitation on the customer charge would in fact promote a reduction of utility generated kWh[14]. I do not believe that conservation in any context just means the absolute reduction of the use of resources. Conservation is the act of preserving, guarding, or protecting; wise use of electricity. In the economic context it means using resources efficiently. The current residential rate designs do not accomplish this objective, because the bill savings under those rates exceed the actual savings of the resources used to provide service. As I noted above, this mismatch between price savings and cost savings is wasting resources - not conserving them. As I have discussed in my direct testimony, there are additional opportunities to improve Empire's rates.[15] It is these rate design changes that would efficiently promote conservation - not the Staff rate design proposal.

SECTION 3- PROPOSED FUEL CLAUSE CHANGES

Q. HAVE THE PARTIES PROPOSED CHANGES TO THE FAC?

A. Yes. OPC witness Mantle and MECG witness Maini both propose that the clause be eliminated or, in the alternative, changes made to the clause. The Staff recommends the continuation of the FAC with certain modifications.

Q. HAVE YOU DISCUSSED THE FAC IN YOUR DIRECT TESTIMONY?

A. Yes. I have discussed the role of the FAC in unbundled rates. In my testimony, I recommend a full tracking FAC that recovers all fuel, purchase power, and other variable costs such as transportation costs and environmental chemicals outside of the base rates and recovers these costs based on loss adjusted seasonal and as appropriate time of use

[14] It would also require an elasticity adjustment to test period sales to provide a reasonable opportunity to earn the allowed return.
[15] See my Direct Testimony at pages 27-29 for example.

rates. A properly designed, unbundled fuel clause also promotes economic efficiency. For example, customers would know the seasons when fuel costs are higher and under time of use even the hours of the highest fuel cost. Having fuel in base rates distorts this signal and comingles these costs with costs that do not vary with seasons or even with time of use. Further, it is axiomatic that if some costs are over or under recovered, the price signal is always wrong even on average. This mismatch of revenues and costs is both inefficient and costly.

Q. PLEASE EXPLAIN WHY EMPIRE NEEDS TO HAVE A FUEL CLAUSE.

A. Basically, the fuel clause allows a utility to recover the prudently incurred costs for the energy and energy related production and purchase costs of providing kWhs to customers. The costs of fuel and purchased power are not within the direct control of management in many regards. First, fuel costs are determined in competitive markets and change based on market conditions beyond any control by management short of an approved hedging program that may fix costs for some portion of fuel but also include the risk of paying more than the market cost of fuel. Second, there is variability in the cost to be recovered unrelated to the cost of fuel. Schedule HEO-R-2 provides the output of the Ozark Beach Hydroelectric station for just the last three years. The table shows that on an annual basis there is not a lot of volatility in the annual output. As a run of the river plant, output is entirely dependent on water conditions each month of the year. The monthly timing of that generation is important because it determines the expected marginal cost of replacing those MWh of generation from thermal capacity. April of 2012 had the highest generation of any month and September of 2013 had the lowest generation. Seasonal volatility is quite large suggesting that the impact on thermal operations will deviate substantially from the normalized data used in an historic test year as the basis for fuel costs in base rates. In addition to the variability of hydroelectric output, there is also a significant component of wind generation that introduces volatility for fuel prices in several ways. Wind generation may cause low cost coal plants to reduce production because of the must take nature of wind generation. This means that the plant operates at a higher point on the heat rate curve and thus at a higher cost per kWh. As wind generation is subject to regular changes in output, combustion turbines may be used to meet the fluctuations in generation in a different pattern than the test year normalized operation that supports the fuel cost for the system. This means higher fuel costs in total even if fuel prices remain unchanged. Third, factors far beyond the Empire system may result in highly volatile settlement costs within SPP. This impacts not only the costs but also the value of off system sales that pass through the fuel clause. In a normalized test year, the costs are based on normalized weather, normalized outage rates and unit heat rate curves. When these factors differ from the test year to the rate year,[16] any one of the factors may cause costs to differ on an annual basis even if fuel costs are on average the same. Fuel and purchased power costs are also volatile based on the applicable transmission rates for services from SPP where rates are formula based rates and change annually under FERC approved formulas[17]. In addition, fuel delivery rates for both coal and pipeline natural gas are also subject to federal ratemaking jurisdiction and determination. All of these charges should likewise be recovered in the FAC as beyond the reasonable control of Empire. Simply, there are too many variables associated with the FAC related costs to develop a reasonable forecast based on a test

[16] The first twelve months after new rates are effective.
[17] As a practical matter these costs should pass through based on the principle of Federal preemption. If they do not pass through the state would be denying the utility a reasonable opportunity to recover prudently incurred costs.

year to reasonably estimate the actual costs during the rate effective period. A properly designed and monitored FAC is the best practice regulation for recovery of fuel, purchased power costs, and other components of the FAC. Finally, recognizing that the test year estimate is based on normal use, it is likely that actual fuel costs in total and fuel costs per kWh will vary in the rate year. Hot summers and cold winters will cause a different dispatch of resources and have different impacts on the fuel mix and the average heat rates for units. Even if weather on average is normal, the pattern of that weather may be different than assuming each month is normal and would result in costs that differ from the test year to the rate year. For example cold weather in March and April when baseload units are out for maintenance would mean more operation of peaking assets than would be considered in the normal dispatch. The simple conclusion is that the costs recovered in the FAC may change both up and down beyond the control of utility management and the FAC should not allow either windfall gains or losses for the utility so long as the system is operated prudently. FACs assures that customers' rates reflect the changing cost of this major component of variable costs. This is a necessary condition for efficient rates and for efficient regulation.

Q. HOW IS A FULL TRACKING FAC JUST AND REASONABLE FOR CUSTOMERS?

A. An FAC is reasonable for customers, because as long as the utility is monitored for prudence and the costs that pass through are prudent there is no unjust enrichment for shareholders through recovering more than the expense, and customers do not pay less than the actual cost of the service provided. Since there is no profit associated with expenses, customers are assured that the costs and revenues are appropriately matched over the rate effective period through the balancing account and reconciliation process. Importantly, utilities exposed to under recovery of prudent costs are exposed to credit downgrades that increase the capital cost for the utility at the expense of customers. During periods of high fuel clause related volatility, utilities would be required to file more frequent rate cases at an additional cost for customers and for taxpayers. There is simply no justification for imposing higher costs on customers when the FAC eliminates these costs in entirety.

Q. DO YOU AGREE WITH OPC WITNESS MANTLE'S STATEMENTS REGARDING THE FAC AND SINGLE ISSUE RATEMAKING?

A. No. OPC witness Mantle states that the FAC is a deviation from the Commission's "prohibition of single issue rate making." This point of view is totally undermined by the fact that the legislature has provided the Commission with this rate making tool to be used to allow rates to be just and reasonable and to allow the utility an opportunity to earn the allowed return. Moreover, it is not single issue ratemaking when the Commission carves out costs from the basic revenue requirements formula in a rate case and establishes a separate formula, the FAC, to recover the actual costs incurred to provide the service. Under the operation of the FAC formula as approved by the Commission, costs are recovered through a separate part of the basic revenue requirements formula while still remaining subject to the review of those cost for prudence. A formula rate established as part of the whole ratemaking procedure and implemented through a rate case is not single issue ratemaking. In fact, it is consistent with all of the other issues in this case under even more stringent scrutiny because of the provision for both audit and prudence review and the requirement to refile for approval at least every five years. There is no such standard for the other parts of the revenue requirements formula as approved in a general rate case. Furthermore, the FAC is a requirement for just and reasonable rates under the standard of providing the utility an opportunity to earn its allowed return because expense reduce earned return before taxes on a dollar for dollar basis.

Q. DO YOU AGREE WITH OPC WITNESS MANTLE'S STATEMENT THAT THE FAC SHIFTS THE RISK OF COSTS RECOVERED UNDER THE FAC TO CONSUMERS?

A. No. Ms. Mantle's view that it is shifting risk is very telling. The FAC only shifts risk to customers if fuel costs are higher in the rate year than they would be in a normalized test year. If the costs were lower, there would be a benefit for customers. Since only risk is mentioned, it would be reasonable to infer that the OPC witness assumes that costs are likely to be higher in the rate year. If that is the case, the proposal to do away with the FAC obviously violates the Supreme Court mandate that utilities should be allowed a reasonable opportunity to actually earn the allowed return.[18] Further, the use of an FAC or other means of recovering actual fuel and purchase power expenses is found almost universally among both regulated and unregulated electric utilities across the country. The FAC recognizes that, as I note above, there are benefits for customers when these costs are recovered in a timely manner based on the actual prudent costs incurred. Absent an FAC, the matching cannot occur and in particular where the only way to reasonably estimate these costs cannot possibly result in an accurate estimate of what the costs will be in the rate year based on a normalized and annualized historic test year.

[18] Missouri ex rel. Southwestern Bell Tel. Co. v. Public Service Commission, 262 U. S. 276, 290-291 (1923).

Q. IS THERE ANY REASONABLE BASIS FOR ELIMINATING THE EMPIRE FAC IN THIS CASE AS PROPOSED BY OPC WITNESS MANTLE AND SUPPORTED BY MECG WITNESS MAINI?

A. No. The Empire FAC is a valuable and fundamental part of the revenue requirements equation that is necessary for just and reasonable rates for customers and investors. A proper, full tracking and unbundled FAC provides for the very balancing of interests that are fundamental to the responsibility of the Commission.

Q. DO YOU SUPPORT OPC'S ALTERNATIVE PROPOSAL OF AMENDEDING THE FAC?

A. No. There are two issues with the OPC witness Mantle's fallback position. The first issue is the issue of the amount of the cost changes to be recovered, and the second issue is the definition of the costs to be recovered in the FAC. As far as the issue of a well-defined formula for cost inclusion, I support that view with the caveat that the costs included in base rates should match dollar for dollar the costs excluded from FAC recovery. The principle of matching costs and revenues is fundamental to a reasonable rate. With respect to the issue of changing the sharing mechanism and calling this an incentive, I cannot agree. The current and the proposed sharing mechanism is not an incentive. It is really a means to disallow prudently incurred costs under the guise of an incentive. This view is both unjust to Empire and its customers. Practically, it means that either Empire will have a windfall gain or a windfall loss based solely on the quality of the forecast of the base fuel costs included in the rates. There is no basis for the proposal to disallow prudently incurred cost before they are incurred. For example, in the same Supreme Court case that stands for the principle of allowing the utility an opportunity to earn the allowed return, Justice Brandeis in a concurring opinion said with respect to rate base that it should be assumed that investments are made based on the "exercise of reasonable judgment."[19] There is no reason to believe that the same principle should not apply to expenses as other courts have found. The only available rationale for excluding these costs from recovery is if Empire management acted imprudently in the generation and purchase of the required kWhs to serve the loads of customers. There is not one piece of evidence that Empire has been or is intending to be imprudent in meeting its utility obligation, and the basic utility compact requires that Empire recover all of its fuel costs without arbitrary exclusion of those costs in any magnitude. I conclude that the FAC should be set to match dollar for dollar the expenses properly included in the clause, absent an evidentiary showing of imprudence. It is this type of fuel cost adjustment clause that promotes economic efficiency by a dollar for dollar matching of production costs and fuel clause revenues.

Q. DO YOU AGREE WITH THE POSITION OF OPC WITNESS MANTLE THAT THE EXISTENCE OF AN FAC "REMOVES THE INCENTIVE TO REDUCE FUEL AND PURCHASED POWER COSTS"?

A. No. The regulatory process is about incentives, but so is the market process. The utility is always looking for ways to minimize the cost to consumers so that consumers perceive good value for the dollars they pay for that service. Fuel and purchased power represents the largest operating expense for the utility and has the largest potential for managing the overall cost of service to customers. There is never a valid reason to incur unnecessary costs that impact customers and the market negatively. Being inefficient in any regard

[19] Missouri ex rel. Southwestern Bell Tel. Co. v. Public Service Commission, 262 U. S. 276, n.1 (1923) (concurring opinion).

exposes the utility to lost base rate revenues[20], because customers have other options for end-use services and, also, new premises have even more options for substituting other energy sources that erode long-term earnings potential. Currently, the mixed monopoly and competition model is a good example of the impact of not managing costs. If the utility is wasteful in its purchase of fuel and purchased power (excluding of course any mandated purchases that cannot be avoided), its competitive position relative to the potential for DG is eroded. The longer term issues of stranded costs and earnings erosion associated with customer opportunities provides more than adequate incentives for utilities to manage fuel costs efficiently even with a fuel clause. Further, the OPC position about incentives with an FAC are wholly contrary to the very principle of sound utility management absent a showing otherwise. OPC witness Mantle makes no such showing other than her improper speculation about behaviors she cannot and has not observed.

Q. IS THE REQUIREMENT TO PROVE A UTILITY ACTED IMPRUDENTLY AFTER THE FACT AN UNREASONABLE BURDEN?

A. No. Prudence cannot be known before the action occurs. It is always an after the fact process. This is the way the regulatory process is consistent with the requirements for the determination of just and reasonable rates. OPC witness Mantle essentially wants to find the utility guilty beforehand and disallow costs without recourse for the utility to prove it was prudent in order to recover the costs. The OPC knows full well that the utility has no right to go back and recover the unrecovered fuel costs. The shareholders or the

[20] There is no profit in fuel cost recovery. If higher fuel costs result in reduced consumption the lost base rate revenue all reduces operating margin and thus ultimately earnings. No rational utility wants to make this tradeoff.

customers are punished under the OPC proposal without regard to reasonable standards of regulation as determined both by statute and by judicial mandates.

Q. PLEASE COMMENT ON OPC WITNESS MANTLE'S VIEW THAT THE FAC IS NOT A RIGHT.

A. The fundamental regulatory compact that all utilities operate under establishes a system of rights and obligations for the utility. The very first of those rights for a utility is the right to a reasonable return. In return, the utility has an obligation to provide safe and reliable service at just and reasonable rates. In order to have the opportunity to earn a reasonable return, the utility has a right to recover all prudently incurred expenses. Under a sound regulatory model that provides a framework for recovering a reasonable return, regulatory mechanisms must recognize and allow for the revenue requirements formula to be adjusted for costs that cannot be reasonably estimated based on an historic test year. Fuel costs are one such cost. Although the authorization of an FAC is not statutorily mandated, the right to a fuel clause is an essential element of the basic right to a reasonable return, since historic normalized and annualized costs are not a good measure of the actual costs in the rate year.[21]

SECTION 4 – SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have explained in detail the reasons that alternative costs studies do not reflect cost causation principles. The role of understanding cost causation is critical to developing a reasonable cost of service study. Departures from the way the system is planned and

[21] The use of the Interim Energy Charge (IEC) mechanism is an example of the Commissions view that the test year cost of fuel and purchased power was inadequate for estimating the costs in the rate year prior to the availability of the FAC option. That mechanism itself was inadequate in some respects as recognized by the financial analysts covering Empire.

operated result in unreliable cost allocation results. A sound cost study requires a multi-discipline approach to understanding cost causation. The cost study views of the OPC, Staff and MECG lack the rigor necessary to demonstrate cost causation. The Company's study meets the test of cost causation and should be adopted as the preferred method for Empire. It should not set any precedent for utilities that may have different cost causation factors. In fact the use of a standard method for multiple utilities demonstrates that a careful review of cost causation has not occurred in the preparation of the cost study.

I have also shown that opposition to the Empire proposed rate design is not well founded. In the new mixed competition and monopoly model, sound rate design requires unbundled rates. This view is consistent with economic efficiency, conservation and importantly provides a better opportunity for the utility to earn its allowed return. This latter conclusion is particularly important in the context of a historic test year. I have also shown that the residential class rates are not just and reasonable under the current design. Regardless of the amount of rate relief granted, the proposed level of the residential customer charge should be approved if rates are going to move away from the discrimination that exists within the class.

Finally, I also discuss the appropriate form of a fuel adjustment clause. I point out that all fuel should be removed from base rates and that all fuel and fuel related variable costs should be recovered in a full tracking fuel adjustment clause. Both the current adjustment clause and the OPC proposed changes rely on faulty analysis and illogical assumptions. Sound rates must allow prompt recovery of cost changes that are beyond the reasonable control of management. The full tracking fuel clause is an appropriate tool for minimizing long term costs to customers and providing efficient and timely price signals as well.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

	Column1
Mean	24.27
Standard Error	0.78
Median	25.00
Mode	25.00
Standard Deviation	4.92
Sample Variance	24.25
Kurtosis	0.72
Skewness	0.02
Range	24.00
Minimum	14.00
Maximum	38.00
Sum	970.62
Count	40.00

Cooperative	Fixed Charge	
Atchison-Holt Electric Cooperative	$15.50	
Barry Electric Co-op	$25.00	
Barton County Electric Co-op, Inc.	$25.00	
Black River Electric Cooperative	$23.00	
Boone Electric Co-op	$20.00	
Callaway Electric Cooperative	$30.00	
Central Missouri Electric Cooperative	$14.00	
Citizens Electric Corp.	$25.00	
Co-Mo Electric Cooperative, Inc.	$29.00	
Consolidated Electric Co-op	$27.50	
Crawford Electric Cooperative, Inc.	$25.00	
Cuivre River Electric Co-op, Inc.	$15.00	$.50 per day
Farmers Electric Cooperative, Inc.	$23.00	
Gascosage Electric Cooperative	$25.00	
Grundy Electric Cooperative, Inc.	$25.00	
Howard Electric Cooperative	$26.50	
Howell-Oregon Electric Cooperative, Inc.	$25.00	
Intercounty Electric Cooperative Assn.	$26.35	$0.85 per day
Laclede Electric Co-op	$15.79	
Lewis County REC	$27.00	
Macon Electric Cooperative	$30.00	
Missouri REC	$30.00	
New-Mac Electric Cooperative, Inc.	$25.00	
North Central Missouri Elec. Co-op	$25.00	
Osage Valley Electric Co-op Assn.	$25.00	
Ozark Border Electric Cooperative	$22.00	
Ozark Electric Co-op	$20.00	
Pemiscot-Dunklin Electric Cooperative	$22.00	
Platte-Clay Electric Cooperative, Inc.	$25.38	
Ralls County Electric Cooperative	$38.00	
Sac Osage Electric Cooperative, Inc.	$25.00	
Se-Ma-No Electric Co-op	$21.60	$0.72 per day
SEMO Electric Cooperative	$18.00	
Southwest Electric Co-op	$20.00	
Three Rivers Electric Co-op	$23.00	
Tri-County Electric Cooperative Assn.	$30.20	
United Electric Cooperative	$31.80	$1.06 per day
Webster Electric Co-op	$18.00	
West Central Electric Cooperative, Inc.	$25.00	
White River Valley Electric Cooperative	$28.00	
	$24.27	

2012		*2013*		*2014*	
Mean	4809.916667	Mean	4787.416667	Mean	5054.333
Standard Error	757.2407693	Standard Error	657.0730029	Standard Error	449.3996
Median	3448.5	Median	4111.5	Median	4536
Mode	#N/A	Mode	#N/A	Mode	#N/A
Standard Deviation	2623.158972	Standard Deviation	2276.167651	Standard Deviation	1556.766
Sample Variance	6880962.992	Sample Variance	5180939.174	Sample Variance	2423520
Kurtosis	-0.742210116	Kurtosis	-1.280350713	Kurtosis	0.547083
Skewness	0.913956365	Skewness	0.515557273	Skewness	0.687786
Range	7711	Range	6486	Range	5770
Minimum	2204	Minimum	1997	Minimum	2580
Maximum	9915	Maximum	8483	Maximum	8350
Sum	57719	Sum	57449	Sum	60652
Count	12	Count	12	Count	12
Largest(1)	9915	Largest(1)	8483	Largest(1)	8350
Smallest(1)	2204	Smallest(1)	1997	Smallest(1)	2580

Monthly Generation for Ozark Beach 2012-2014 (MWH)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total	CF
2012	7,198	7,906	7,778	9,915	3,809	3,088	4,152	2,893	2,885	2,204	3,009	2,882	57,719	41.1%
2013	3,297	2,666	2,707	5,658	7,949	7,603	4,317	5,944	1,997	3,906	2,922	8,483	57,449	41.0%
2014	8,350	4,150	6,497	6,595	2,580	4,417	4,193	5,162	4,655	3,750	4,326	5,977	60,652	43.3%
	6,282	4,907	5,661	7,389	4,779	5,036	4,221	4,666	3,179	3,287	3,419	5,781		

	Summer	Winter	Spring	Fall
2012	13,018	17,986	21,502	5,213
2013	19,861	14,446	16,314	6,828
2014	18,427	18,477	15,672	8,076
Difference	6,843	4,031	5,830	2,863

Summer is J,J,A,S
Winter is D,J,F
Spring is M,A,M
Fall is O,N

AFFIDAVIT OF H. EDWIN OVERCAST

STATE OF GEORGIA)
) ss
COUNTY OF HENRY)

On the 4th day of March, 2015, before me appeared H. Edwin Overcast, to me personally known, who, being by me first duly sworn, states that he is Director of Enterprise Management Solutions Black & Veatch and acknowledged that he has read the above and foregoing document and believes that the statements therein are true and correct to the best of his information, knowledge and belief.

H. Edwin Overcast

H. Edwin Overcast

Subscribed and sworn to before me this 04 day of March, 2015

Himali Patel

Notary Public

My commission expires: 02-15-2016

HIMALI PATEL
MY COMMISSION EXPIRES FEBRUARY 15, 2016
NOTARY PUBLIC
HENRY COUNTY, GEORGIA