Exhibit No.:
Issues: Rate Design and Class Cost of Service Study
Witness: David E. Dismukes, Ph.D
Sponsoring Party: Public Counsel
Type of Exhibit: Surrebuttal Testimony
Case No.: ER-2014-0351
Date Testimony Prepared: March 24, 2015

MISSOURI PUBLIC SERVICE COMMISSION

SURREBUTTAL TESTIMONY
OF
DAVID E. DISMUKES

EMPIRE DISTRICT ELECTRIC COMPANY
CASE NO. ER-2014-0351

Jefferson City, Missouri
March 24, 2015

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	))))	Case No. ER-2014-0351

AFFIDAVIT OF DAVID DISMUKES

STATE OF MISSOURI)
)
COUNTY OF COLE)

David Dismukes, of lawful age and being first duly sworn, deposes and states:

1. My name is David Dismukes. I am an expert witness for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my surrebuttal testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

David Dismukes
Expert Witness

Subscribed and sworn to me this 20 day of March 2015.

Notary Public
ID No. 133884

My Commission expires At Death

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OF
DAVID E. DISMUKES

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2014-0351

I. INTRODUCTION

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808. I am the same person that provided pre-filed expert witness testimony on the behalf of the Missouri's Office of Public Counsel ("OPC") on February 11, 2015 and March 9, 2015.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the rebuttal testimony of the Empire District Electric Company ('the Company") and the Midwest Energy Consumers Group ("MECG") regarding the class cost of service studies ("CCOSS") and revenue distribution/rate design issues. Additionally, I will provide an update to my recommended revenue distribution and rate design.

Q. HAVE YOU UPDATED ANY SCHEDULES IN SUPPORT OF YOUR TESTIMONY?

A. Yes. I am providing an update to Schedules DED-2, DED-3, DED-8 and DED-9 that reflect all revisions as indicated in my surrebuttal testimony. These updates are included as multiple pages in one composite schedule listed as Schedule DED-S1.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Update Revenue Distribution and Rate Design Recommendations
- Class Cost of Service Study

- Revenue Distribution and Rate Design

II. UPDATED REVENUE DISTRIBUTION AND RATE DESIGN RECOMMENDATION

Q. ARE YOU MAKING ANY REVISIONS TO YOUR REVENUE DISTRIBUTION AND RATE DESIGN RECOMMENDATIONS?

A. Yes. I have changed my recommended revenue distribution and rate design proposals based upon MECG's rebuttal testimony and related discovery responses. I also adjusted Commercial Small Heating for an oversight in the revenue allocation process. The modifications to my testimony include:

- An adjustment to revenues for the Special Transmission Praxair class to account for the $365,712 of interruptible revenue credits. This credit was not included in my direct testimony and recommendations.
- Given the above revenue adjustment, the Special Transmission Praxair class was removed from the first step increase in my proposed revenue distribution but was included in the second step increase of my originally-recommended revenue distribution.

The Commercial Small Heating class was inadvertently included in the first step of the revenue allocation process rather than the second step of the allocation. This has been corrected. This change is reflected on pages 3 and 4 of Schedule DED-S1.

Q. HOW WILL THE INTERRUPTIBLE REVENUE CREDIT ADJUSTMENT IMPACT THE SPECIAL TRANSMISSION PRAXAIR CLASS?

A. Under these revisions, Praxair will not receive a first step increase of 5.99 percent as proposed in my original testimony. Instead, I propose the Special

Transmission Praxair class receive a 2.19 percent increase on the basis of its overall revenues. This will reduce the revenue increase originally-allocated to the Praxair class under the Company's full revenue requirement request by $30,178 and by $6,036 under the revenue distribution at 20 percent of the Company's revenue requirement. This revenue adjustment, however, will only effect the revenue distribution under the AED12CP CCOSS.[1] The revenue distribution under the A12CP will not change since the Special Transmission Praxair class is still under-earning using that CCOSS methodology.

Q. HAVE YOU UPDATED YOUR ORIGINALLY-PROVIDED SCHEDULES TO REFLECT THESE CHANGES?

A. Yes. Schedules DED-2 and DED-3 that were included as part of my original testimony have been updated and reflect the revenue adjustment and updated rate of return and relative rate of return for each class. These updates are provided on pages 1 and 2 of Schedule DED-S1. Additionally, the recommended revenue distribution DED-8 and DED-9 have also been updated to reflect the updated CCOSS results and the updated revenue allocation under the AED12CP CCOSS. These updates are provide on pages 3 and 4 of Schedule DED-S1.

Q. HAVE YOU ALSO UPDATED YOUR RECOMMENDATIONS TO ADJUST FOR THE DISCREPANCY ADDRESSED IN A FOOTNOTE ON PAGE 8 OF THE REBUTTAL TESTIMONY OF MECG WITNESS MAINI?

A. Yes. MECG points out that the total average demand amount in the workpapers used to calculate the AED12CP and A12CP allocation factors contain a formulaic error

[1] There is no change to the revenue distribution under the A12CP CCOSS results as the Special Transmission Praxair class is still under earning as a result of that Alternative CCOSS model.

that was occurring in the calculation of the Alternative A12CP allocation factor for the Miscellaneous Services class. Correcting the calculation has very minor impact on the results of the Alternative A12CP CCOSS model with most classes' overall returns experiencing a change of 0.03 percent, with the exception of the Miscellaneous Services class.[2] However, this correction to the CCOSS will have no impact on the recommended revenue distribution and rate design results.

Q. HAVE YOU MADE ANY UPDATES TO YOUR REBUTTAL TESTIMONY?

A. Yes. At the time my rebuttal testimony was filed there was outstanding discovery regarding the Company's allocation of purchase power costs classified as demand related but allocated on the basis of energy in the Company's CCOSS. Since the filing of my rebuttal testimony the Company provided responses indicating that these costs are demand related but should be allocated on the basis of energy because "the purchase power demand charges cannot be allocated to demand for classes that have no demand charges."[3] I disagree with this rationale. There are a number of instances within a CCOSS where demand related items are allocated on the basis of demand regardless of whether or not a class has a demand charge. The Company has not provided a sufficient reason for treating these costs any differently than other costs that are considered demand-related. Therefore, I have updated the CCOSS in DED-S1 to reflect the allocation of this portion of purchased power on the basis of demand not energy.

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[2] The Miscellaneous Services class's return will increase by 2.49 percent. However, this class is under earning with an overall return of -12.55 percent, after correction.
[3] Company's response to OPC Discovery Request 5091.

III. COST OF SERVICE

Q. WOULD YOU PLEASE RESPOND TO MECG'S DISAGREEMENT WITH THE USE OF 12 COINCIDENT PEAKS IN THE ALLOCATION OF PRODUCTION PLANT?

A. Yes. MECG disagrees with the use of the 12CP stating that "it does not accurately assign costs to cost causers."[4] Instead, MECG advocates an allocation of production plant on the basis of two three-month NCPs.

Q. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. When allocating production plant a number of factors should be considered besides demand. MECG's approach, for instance, ignores other factors which include scheduled maintenance, unscheduled outages, diversity, and reserve requirements. The Company's approach does place some consideration on these factors in choosing an appropriate demand allocation method.[5] However, the Company's load data never shows coincident peaks occurring in more than three consecutive months. My recommended 12CP allocation method considers that periods other than the peak periods are important from the system planning perspective.

Q. ARE THERE ANY TESTS THAT CAN BE EMPLOYED TO DETERMINE IF A UTILITY IS A 12CP SYSTEM?

A. Yes, the Federal Energy Regulation Commission ("FERC") employs three tests to determine whether or not a utility is a 12CP system. These tests analyze the difference between on-peak and off-peak periods; as well as compares the low peak and average peak to the system peak period. The three FERC tests include:

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[4] Kavita Maini, Rebuttal Testimony, 6:10-12.
[5] H. Edwin Overcast, Direct Testimony 18:2-8.

- On and Off Peak Test No. 1: This is a two part test that first, compares the average of the coincidental peaks in the months with the highest system peaks as a percentage of the annual system peak. Second, it compares the average of the lowest monthly coincidental peaks as a percentage of the annual system peak. Generally, a 12 CP allocation is considered appropriate if the difference between these two percentages is 19% or less.
- Low-to-Annual Peak Test No. 2: This test compares the lowest monthly peak as a percentage of the annual system peak. A range of 66% or higher is considered indicative of a 12 CP system.
- Average to Annual Peak Test No. 3: This test compares the average of the twelve monthly peaks as a percentage of the annual system peak. Typically, a system is considered to be 12CP if the results are in the range of 81 percent or higher.[6]

Q. HAVE YOU PERFORMED AN ANALYSIS USING THE FERC'S THREE TESTS IN DETERMINING THE USE OF THE 12CP ALLOCATION FACTOR?

A. Yes, I have conducted an analysis using the three tests described above. The results of this analysis are shown on Schedule DED-S1. Using the three summer and three winter months that MECG has identified as the "peak" months, the results of Test No. 1 is 18 percent, which meets the criteria above. The outcomes of Test No. 2 and Test No. 3 also meet the above-discussed FERC criteria with estimates of 68 percent and 87 percent, respectively. Collectively, these tests indicate that the Company's

[6] *Golden Spread Electric Cooperative et al. v. Southwestern Public Service Company,* 123 FERC 61,047, Opinion No. 501, Issued April 21, 2008, p. 34, ¶ 76.

system is likely reflective of one that should utilize 12CP allocation method consistent with the proposal in my original testimony.

Q. PLEASE RESPOND TO THE CRITICISM OF BOTH MECG AND THE COMPANY THAT THE AVERAGE AND PEAK METHOD DOUBLE COUNTS CLASS ENERGY USAGE.

A. The Average and Peak method is designed to give weight to both the share of average demand and system peak demand as the purpose of the methodology is to recognize that energy loads play an important role in production plant costs. On the other hand, the Average and Excess method focuses on capacity costs and attempts to separate capacity costs into demand related costs incurred to meet average demand and demand related costs incurred to meet the remainder of the system peak demand. The Average and Peak method is not a double counting, rather the basis of the method is to effectively obtain a weighted average of both the average and peak demand components and is not based on the difference of the two demand components.

Q. WOULD YOU ADDRESS THE COMPANY'S STATEMENT THAT THE AVERAGE AND PEAK METHOD USES AN ARBITRARY WEIGHTING METHOD?

A. Yes. The Company argues that the Average and Peak method uses an arbitrary weighting method that "bears no resemblance to how costs are incurred or to how plants are planned and operated."[7] I disagree. In my determination of the Average and Peak allocation factors, the load factor and 1 minus the load factor were used as the weighting factors. The load factor is a measure of electric consumption consistency; it is a reflection of how efficiently a system is operating and a useful tool when estimating

[7] H. Edwin Overcast, Rebuttal Testimony, 5:17-18.

capacity costs. Using the load factor and 1 minus the load factor are not arbitrary weighting methods; these methods are a commonly used for assigning weights, most notably by its use in the determination of the allocation factors in the AED method.[8]

Q. PLEASE RESPOND TO THE COMPANY AND MECG'S CRITICISM OF ALLOCATING DISTRIBUTION PLANT ACCOUNTS 364 – 368 ON THE BASIS OF DEMAND.

A. The Company and MECG disagree with the allocation of the distribution plant accounts 364-368 on the basis of demand, instead both parties advocate for the use of the Company's minimum system study to allocate these distribution plant accounts. The minimum system approach classifies a portion of the costs as being customer-related and as a result makes the assumption that a single household should be assigned the same costs as a large industrial customer. Therefore, the results of minimum system approach often times will assign a disproportionate amount of these costs to small users such as the residential customer class due to the larger amount of customers in this class.

Q. WHAT ARE THE USUAL OUTCOMES OF SUCH AN ANALYSIS?

A. The most noticeable and significant result of the minimum system method is the large increase in the fixed monthly customer costs due to the added customer cost component of these plant accounts as well as the associated O&M expenses. These much higher fixed customer costs stand is stark contrast to the revenues typically collected by most utilities through their monthly customer charges. The large discrepancy between the two could (incorrectly) be used to support an argument that

[8] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, p 49.

monthly fixed customer charges should be increased, and increased in a relatively significant manner. The entire premise of this increase, however, is based upon a faulty cost-estimation approach.

Q. ARE THERE ANY OTHER CRITICISMS OF THE MINIMUM SYSTEM APPROACH?

A. Yes. Another criticism of the minimum system method is that it fails to recognize that even the minimum size distribution system has the capability to carry at least some load which itself could be considered demand-related. Not properly adjusting for this "minimum load" can lead to a disproportionate share of demand-related costs being allocated to certain classes leading to "double counting". Reviewing the Company's CCOSS and minimum system study shows no indication of accounting for the load capabilities of its minimum system in allocating the demand related costs. Therefore, it exposes the possibility that some classes are being allocated a larger share of costs than are necessary.

Q. PLEASE SUMMARIZE THE COMPANY'S CRITICISMS OF YOUR DIRECT TESTIMONY'S RECOMMENDATION AGAINST USE OF THE COMPANY'S MINIMUM SYSTEM STUDY.

A. The Company argues that proposed allocation of distribution plant accounts 364-368 on the sole basis of demand represents "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."[9] The Company also suggests my citation to the seminal work

[9] H. Edwin Overcast, Rebuttal Testimony, 8:13-16.

Principles of Public Utility Rates by Bonbright, Danielsen and Kamerschen incorrectly applies criticisms of zero-intercept studies to minimum system studies. The Company also suggests I did not include references in favor of minimum system studies from Bonbright, et. al. text.

Q. DOES YOUR PROPOSAL TO ALLOCATE DISTRIBUTION PLANT ACCOUNTS 364-368 ON THE SOLE BASIS OF DEMAND REPRESENT A FUNDAMENTAL LACK OF UNDERSTANDING OF DISTRIBUTION SYSTEM PLANNING?

A. No. Minimum system studies by their very nature deal in hypotheticals that often do not exist in the real world. Part and parcel of this is a minimum system study's reliance on a minimum system, an academic construct that attempts to de-link the serving of utility system customers from the serving of utility system customer's load. Minimum systems do not exist in real world setting as utility system planners do not build electrical systems with the intention of not carrying electricity. The service of customers and their electrical energy needs are concepts that are fundamentally linked and cannot be easily separated.

Q. CAN YOU PLEASE PROVIDE AN EXAMPLE OF THE INTERRELATIONSHIP OF CUSTOMERS AND CUSTOMER ENERGY NEEDS IN DISTRIBUTION SYSTEM PLANNING?

A. Yes. The Company in their rebuttal testimony references mandated engineering standards related to minimum size of utility poles to insure adequate clearance between the energized conductor and pedestrians and vehicles underneath. However, the Company fails to note that these standards are in part designed around the concept of line sag. Electric conductors are metallic, and like most metallic substances, expand when exposed to heat. This causes the conductor to droop or sag towards the ground when exposed to heat. This heat may be the result of ambient weather conditions, but is also the result of resistance within the cable; as more electric current is passed through the cable, it encounters more resistance which produces heat. In the absence of any need to transport electricity, utility poles could be safely spaced further apart because of reduced concerns associated with line sag.[10]

Q. CAN YOU PROVIDE AN EXAMPLE OF THE INTERRELATIONSHIP OF CUSTOMERS AND CUSTOMER ENERGY NEEDS IN DISTRIBUTION SYSTEM PLANNING?

A. Yes. Another good example is utility line transformers. The Company assumes that even under a minimum load setting the Company would need 67,365 line transformers and 8,920 pad-mounted transformers to serve all customers on its system. However, when designing primary and secondary distribution feeder circuits, utility personnel must ensure that each transformer has sufficient capacity available to meet the maximum load placed on the transformer.[11] Minimum system studies assume that this task is only handled through the installation of larger transformers, however, in reality there is no restriction on the number of customers each transformer must serve.[12] A transformer can be allocated to a single customer (as often the case with larger commercial and industrial customers) or can serve two or three customers as in the case of most residential customers. Again, the question of serving the customer and

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[10] *See*, Slegers, James (October 18, 2011), "Transmission Line Loading: Sag Calculations and High-Temperature Conductor Technologies," Iowa State University.

[11] *See*, National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, p 97.

[12] [12] *See, for example, "*datasheet 2014v4 proprietary.xls."

serving the customer's energy needs is directly linked from the perspective of the distribution system.

Q. HAS ANYONE ELSE NOTED THE CONCEPTUAL NATURE OF MINIMUM SYSTEM STUDIES?

A. Yes. As I referenced in my Direct Testimony, Dr. James Bonbright and his co-authors in his seminal work on public utility rates raised questions about the use of minimum system studies, noting that they represented "estimated annual costs of a hypothetical system of minimum capacity."[13] The text later refers to this as a "phantom system."[14] It is clear from a reading of Dr. Bonbright's text that he had a similar concern to my own regarding the application of a strictly academic construct to real world rate making.

Q. DOES THE COMPANY AGREE WITH THIS READING OF DR. BONBRIGHT'S SEMINAL WORK ON PUBLIC UTILITY RATES?

A. No. The Company claims that Dr. Bonbright's reference to a "phantom system" is in reference to a zero-intercept regression that was not used in the Company's analysis, suggesting that somehow the citation I provided is not entirely relevant to the issues associated with the Company's minimum distribution cost estimates. I disagree. Professor Bonbright and his colleagues, in this section of their text, generally discuss the issues with minimum system-type approaches. A zero-intercept regression is an alternative statistical analysis that can also be used to estimate customer-related distribution system costs.[15] A zero-intercept study attempts, through a statistical

[13] James C. Bonbright, et al. Principles of Public Utility Rates. 1988 Edition, p. 491, emphasis added.
[14] James C. Bonbright, et al. Principles of Public Utility Rates. 1988 Edition, p. 491.
[15] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, p 92.

regression analysis, to identify the costs associated with a utility system possessing no electrical load. The zero-intercept method uses statistics, in contrast to a more traditional "deterministic" approach, like the one used by the Company, that estimates these costs without any variation. Both methods (one statistical, one deterministic) attempt to estimate the same thing: the cost of a minimum system with no load. In fact, Dr. Bonbright's full reference to a "phantom system" actually references it as a "minimum-sized distribution system."[16] Bonbright et. al. concludes by stating that "the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to us to be clearly indefensible."[17]

Q. DOES THE COMPANY PROVIDE ANY QUOTATIONS THEY BELIEVE ARE SUPPORTIVE OF THIS MINIMUM SYSTEM APPROACH?

A. Yes. The Company argues that there is one reference in the Bonbright text that is supportive of its position providing a quote that "[i]n actual practice the vast majority of utilities utilize some form of minimum system to classify costs, which is in line with the FERC accounts."[18] This quote, however, needs to be placed into some context since the specific sentence is used by Bonbright to explain the incorrect nature of such a practice. Specifically, Bonbright notes:

> In actual practice the vast majority of utilities utilize some form of minimum system to classify costs, which is in line with the FERC Accounts. Sterzinger (1981) is critical of this practice and recommends that to avoid the overcollection of charges from low-use residential customers, regulators should classify distribution costs as demand costs. Neither of these procedures can be justified as a cost allocation in the sense of directly assignable costs, for they are in fact nonassignable.

[16] James C. Bonbright, et al. Principles of Public Utility Rates. 1988 Edition, p. 491.
[17] James C. Bonbright, et al. Principles of Public Utility Rates. 1988 Edition, pp. 491-492.
[18] James C. Bonbright, et al. Principles of Public Utility Rates. 1988 Edition, p. 42.

> Allocation, in whole or in part, would be at least theoretically possible if a customer-density parameter were added to the three traditional cost components. But if this factor were embodied, not only in cost analysis but in the resulting rate differentials, rates would not be uniform throughout a given community and hence would violate a generally accepted tradition.[19]

IV. REVENUE DISTRIBUTION AND RATE DESIGN

Q. PLEASE RESPOND TO THE COMPANY'S CRITICISMS OF YOUR PROPOSED REVENUE DISTRIBUTION.

A. The Company argues that only the Staff provides a reasonable proposed revenue distribution outside those originally-provided by the Company. The Company argues that my proposal, as well as MECG's proposal, are "self-serving recommendations and do not properly balance all the information before the Commission."[20] I disagree with the Company's assertions. My recommendation is not self-serving; since it takes into consideration the principle of gradualism and considers each class' overall rate of return, and each class' relative rate of return, in establishing an overall revenue distribution. Consider that the Staff and the Company's revenue allocations do not allocate any increase to the lighting classes despite the fact that three out of the four light classes are severely under-earning. Moreover, the Company's revenue allocation is not easily replicated with the majority of allocations appearing to result from judgment rather than a specific methodology. There is no clear indication as to why a particular class is receiving a smaller or larger increase than another. Furthermore, by its design the Company's revenue allocation leaves a portion of the revenue increase, $134,000,

[19] James C. Bonbright, et al. Principles of Public Utility Rates. 1988 Edition, p. 492.
[20] H. Edwin Overcast, Rebuttal Testimony, 12:20-22.

unallocated. The Company assigned this increase to the Residential $104,915 and Large Power $29,085 classes, without any explanation.[21]

Q. HAS THE COMPANY MISREPRESENTED YOUR STATEMENTS REGARDING YOUR RATE DESIGN RECOMMENDATIONS?

A. Yes. The Company states that I have recommended allocating more costs to the energy charge for all rate schedules based on promoting "economic efficiency"[22] and further stating that I reach my conclusions "without even mentioning that economically-efficient price signals should be based on marginal cost not average revenue requirements."[23] Unfortunately, Mr. Overcast misread my testimony. I actually stated that the Company's rate design proposals are inconsistent with energy efficiency since it reduces economic incentives for ratepayers to control monthly utility bills through energy efficiency and conservation efforts.[24]

Q. WOULD YOU PLEASE COMMENT ON THE COMPANY'S STATEMENT THAT COLLECTING FIXED COSTS IN THE VOLUMETRIC CHARGE CAUSES ALL-ELECTRIC RESIDENTIAL CUSTOMERS TO SUBSIDIZE OTHER RESIDENTIAL CUSTOMERS?

A. Yes. The Company states that my customer charge recommendation exacerbates this discrimination rather than correcting it.[25] Apparently, the Company believes that customer charges should be increased in order to correct what it claims are intra-class subsidization issues. However, even if the Company's assertions were correct, their

[21] Company's response to OPC Discovery Request 5078. See also Company's workpaper "Rate Design ER-2014-0351".
[22] H. Edwin Overcast, Rebuttal Testimony, 13:22-23.
[23] H. Edwin Overcast, Rebuttal Testimony, 14:1-3.
[24] David Dismukes, Direct Testimony, 34:7-9.
[25] H. Edwin Overcast, Rebuttal Testimony, 14:20-21.

proposed remedy would not fix this purported intra-class subsidization problem since all-electric residential customers would still be subsidizing other residential customers through volumetric rates that do not reflect the "lower unit cost" to serve these customers.[26] Instead, the increasing customer charges will only serve to ensure that the revenue recovery risk is shifted away from the Company (which earns a return on its investment for this risk) to the customer.

Q. PLEASE ADDRESS THE COMPANY'S CRITIQUE OF YOUR REGIONAL CUSTOMER CHARGE SURVEY.

A. The Company takes issue with the fact that my survey of customer charges in the Mid-West focused on investor-owned utilities and did not include electric cooperatives.[27] The Empire District Electric Company is an investor owned utility. The rates of electric cooperatives and municipal electric systems operating in the state of Missouri are not regulated by the Missouri Public Service Commission ("MPSC").[28] Electric cooperatives are privately-owned not-for-profit entities in which its members retain ownership and make decisions that are presumably in their own best interests as both owners and customers. The Company's ratepayers, unlike the rural cooperatives, do not vote, nor have representatives setting rate design or pricing policy decisions.

[26] The Company states the all-electric residential customers have lower unit costs to serve because of greater economies of scale. See the Rebuttal Testimony of H. Edwin Overcast, 14:16-17.
[27] H. Edwin Overcast, Rebuttal Testimony 16:1-7.
[28] Missouri Public Service Commission; *A Snapshot of What We Do;* August 2014.

Q. DO YOU HAVE ANY FURTHER COMMENTS YOU WOULD LIKE TO MAKE REGARDING THE COMPANY'S REBUTTAL TESTIMONY?

A. Yes. The Company believes that I have mischaracterized their rate design as a straight fixed variable ("SFV") rate design.[29] My direct testimony states that it is "similar" to a SFV method of setting rates and in my discussion I discuss the practice of a "modified SFV" in which not all of the fixed costs are collected through the customer charge with some of the fixed costs remaining in the volumetric or variable charges.[30] Even the Company has stated that they are moving towards more fixed costs recovered through fixed charges.[31]

Q. DOES A RATE DESIGN HAVE TO INCLUDE A DEMAND CHARGE IN ORDER FOR IT TO HAVE CHARACTERISTICS SIMILAR TO A MODIFIED SFV?

A. No. A SFV rate design, or modified SFV, is commonly referred to as a generic form of rate design that sets relatively fixed charges for what are represented to be fixed costs. I believe the Company's proposal resembles that of a modified SFV rate design since it is attempting to roll a very large level of what it estimates as fixed customer costs into a customer charge. The Company's statement suggesting that a SFV can only exist with some form of demand charge (as opposed to customer charge) simply confuses the issue to no purpose.[32] Further, it is not entirely accurate since many customer classes with demand charges will see significant increases in their rates. The Company is proposing to increase the facilities demand charge for General Power,

[29] H. Edwin Overcast, Rebuttal Testimony, 17:6-7.
[30] David Dismukes, Direct Testimony, 32:16-17 and 33:6-11.
[31] H. Edwin Overcast, Direct Testimony, 21:5-7.
[32] H. Edwin Overcast, Rebuttal Testimony, 17:16-18.

Total Electric Building, Special Transmission, and Large Power classes.[33] In fact, the Company is proposing to increase the facilities demand charge to the costs reflected in the cost of service study.[34] Furthermore, not only is the Company proposing to increase the facilities demand charges for these classes they are also proposing to increase customer charges to the unit cost reflected in the cost of service study.[35]

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY ON MARCH 24, 2015?

A. Yes.

[33] H. Edwin Overcast, Direct Testimony, 33: 5-6.
[34] H. Edwin Overcast, Direct Testimony, 33: 5-6.
[35] H. Edwin Overcast, Direct Testimony, 33: 10-11.

Revised DED-2: Alternative CCOSS 1 AED12CP Under Recommended Cost Allocation Factors

Account Description	Total Missouri	Residential (RG)	Commercial (CB)	Commercial Small Heating (SH)	General Power (GP)	Special Transmission Praxair (SC-P)	Total Electric Building (TEB)	Feed Mill (PFM)	Large Power (LP)	Miscellaneous Services (MS)	Street Lights (SPL)	Private Lights (PL)	Special Lights (LS)
OPERATING REVENUES													
Utility Sales Revenues	$ 449,170,905	$ 208,264,822	$ 42,245,667	$ 10,278,954	$ 85,561,297	$ 3,894,018	$ 37,556,333	$ 78,524	$ 54,383,272	$ 14,189	$ 2,321,701	$ 4,452,930	$ 119,198
Total Operating Revenues	$ 455,548,995	$ 211,531,819	$ 42,727,957	$ 10,411,570	$ 86,595,752	$ 3,950,168	$ 38,109,759	$ 79,252	$ 55,234,570	$ 14,320	$ 2,321,701	$ 4,452,930	$ 119,198
OPERATING EXPENSES													
Production	$ 171,551,969	$ 74,417,888	$ 13,203,181	$ 3,753,217	$ 34,263,497	$ 2,222,327	$ 15,565,660	$ 18,646	$ 26,829,133	$ 5,206	$ 712,031	$ 536,462	$ 24,721
Transmission	$ 14,494,784	$ 7,107,447	$ 1,145,205	$ 314,898	$ 2,456,329	$ 133,328	$ 1,314,119	$ 1,728	$ 2,021,419	$ 311	$ -	$ -	$ -
Distribution	$ 24,059,213	$ 12,408,328	$ 2,641,202	$ 635,968	$ 3,591,540	$ 4,708	$ 1,852,460	$ 6,420	$ 2,343,727	$ 376	$ 242,725	$ 281,649	$ 50,110
Customer Acctg & Service	$ 11,038,436	$ 8,745,561	$ 1,235,696	$ 208,794	$ 300,338	$ 8,616	$ 136,553	$ 1,292	$ 301,741	$ 4,298	$ 26,756	$ 60,157	$ 8,635
Admin & General	$ 37,863,085	$ 20,745,833	$ 3,713,595	$ 878,587	$ 5,139,572	$ 202,269	$ 2,702,822	$ 6,266	$ 3,990,929	$ 4,214	$ 217,109	$ 233,326	$ 28,562
Total Operating Expenses	$ 259,007,487	$ 123,425,057	$ 21,938,878	$ 5,791,463	$ 45,751,276	$ 2,571,248	$ 21,571,615	$ 34,353	$ 35,486,950	$ 14,405	$ 1,198,621	$ 1,111,594	$ 112,028
DEPRECIATION EXPENSES	$ 62,274,122	$ 32,463,254	$ 5,621,199	$ 1,438,819	$ 9,395,117	$ 295,879	$ 5,074,130	$ 11,099	$ 7,008,326	$ 1,333	$ 427,412	$ 481,332	$ 56,220
TAXES OTHER THAN INCOME TAX	$ 21,833,107	$ 11,325,727	$ 1,964,295	$ 501,798	$ 3,311,908	$ 115,932	$ 1,783,963	$ 3,766	$ 2,506,798	$ 799	$ 141,720	$ 159,101	$ 17,299
INCOME BEFORE INCOME TAXES	$ 112,434,279	$ 44,317,781	$ 13,203,585	$ 2,679,489	$ 28,137,450	$ 967,109	$ 9,680,052	$ 30,034	$ 10,232,495	$ (2,218)	$ 553,947	$ 2,700,903	$ (66,349)
INCOME TAXES													
Income Taxes - Current	$ 21,008,801	$ 10,788,912	$ 1,854,805	$ 481,917	$ 3,244,512	$ 110,630	$ 1,759,557	$ 3,652	$ 2,450,422	$ 456	$ 139,866	$ 157,139	$ 16,933
Provision for Deferred FIT	$ 10,448,853	$ 5,365,930	$ 922,498	$ 239,684	$ 1,613,678	$ 55,023	$ 875,126	$ 1,816	$ 1,218,732	$ 227	$ 69,563	$ 78,154	$ 8,422
ITC Adjustment - Net	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Federal Income Taxes	$ 31,457,654	$ 16,154,842	$ 2,777,304	$ 721,602	$ 4,858,190	$ 165,653	$ 2,634,683	$ 5,469	$ 3,669,154	$ 683	$ 209,429	$ 235,293	$ 25,355
OPERATING INCOME	$ 80,976,625	$ 28,162,940	$ 10,426,281	$ 1,957,888	$ 23,279,260	$ 801,456	$ 7,045,369	$ 24,565	$ 6,563,342	$ (2,901)	$ 344,519	$ 2,465,610	$ (91,704)
Gains/Losses	$ (3,645,260)	$ (1,793,179)	$ (310,146)	$ (81,837)	$ (608,883)	$ (29,551)	$ (304,406)	$ (549)	$ (472,125)	$ (165)	$ (20,979)	$ (21,348)	$ (2,092)
Interest on Customer Deposits	$ (407,085)	$ (323,917)	$ (58,492)	$ (10,171)	$ (9,956)	$ -	$ (4,074)	$ (24)	$ -	$ -	$ -	$ -	$ (451)
NET INCOME	$ 76,924,280	$ 26,045,844	$ 10,057,643	$ 1,865,879	$ 22,660,421	$ 771,905	$ 6,736,890	$ 23,992	$ 6,091,216	$ (3,066)	$ 323,540	$ 2,444,262	$ (94,247)
RATE BASE	$ 1,142,391,460	$ 577,470,247	$ 97,015,650	$ 25,416,781	$ 180,554,405	$ 6,816,079	$ 97,115,042	$ 193,108	$ 139,906,372	$ 26,477	$ 8,041,764	$ 9,024,562	$ 810,972
RETURN ON RATE BASE	6.73%	4.51%	10.37%	7.34%	12.55%	11.32%	6.94%	12.42%	4.35%	-11.58%	4.02%	27.08%	-11.62%
Relative Rate of Return	1.00	0.67	1.54	1.09	1.86	1.68	1.03	1.85	0.65	-1.72	0.60	4.02	-1.73

Revised DED-3: Alternative CCOSS 2 A&12CP Under Recommended Cost Allocation Factors

Account Description	Total Missouri	Residential (RG)	Commercial (CB)	Commercial Small Heating (SH)	General Power (GP)	Special Transmission Praxair (SC-P)	Total Electric Building (TEB)	Feed Mill (PFM)	Large Power (LP)	Miscellaneous Services (MS)	Street Lights (SPL)	Private Lights (PL)	Special Lights (LS)
OPERATING REVENUES													
Utility Sales Revenues	$ 449,170,905	$ 208,264,822	$ 42,245,667	$ 10,278,954	$ 85,561,297	$ 3,894,018	$ 37,556,333	$ 78,524	$ 54,383,272	$ 14,189	$ 2,321,701	$ 4,452,930	$ 119,198
Total Operating Revenues	$ 455,548,995	$ 211,531,819	$ 42,727,957	$ 10,411,570	$ 86,595,752	$ 3,950,168	$ 38,109,759	$ 79,252	$ 55,234,570	$ 14,320	$ 2,321,701	$ 4,452,930	$ 119,198
OPERATING EXPENSES													
Production	$ 171,551,969	$ 72,811,194	$ 13,162,745	$ 3,764,211	$ 35,247,412	$ 2,340,692	$ 15,594,043	$ 18,355	$ 27,334,617	$ 5,486	$ 712,031	$ 536,462	$ 24,721
Transmission	$ 14,494,784	$ 7,107,447	$ 1,145,205	$ 314,898	$ 2,456,329	$ 133,328	$ 1,314,119	$ 1,728	$ 2,021,419	$ 311	$ -	$ -	$ -
Distribution	$ 24,059,213	$ 12,408,328	$ 2,641,202	$ 635,968	$ 3,591,540	$ 4,708	$ 1,852,460	$ 6,420	$ 2,343,727	$ 376	$ 242,725	$ 281,649	$ 50,110
Customer Acctg & Service	$ 11,038,436	$ 8,745,561	$ 1,235,696	$ 208,794	$ 300,338	$ 8,616	$ 136,553	$ 1,292	$ 301,741	$ 4,298	$ 26,756	$ 60,157	$ 8,635
Admin & General	$ 37,863,085	$ 19,994,761	$ 3,694,693	$ 883,727	$ 5,599,518	$ 257,600	$ 2,716,090	$ 6,130	$ 4,227,225	$ 4,345	$ 217,109	$ 233,326	$ 28,562
Total Operating Expenses	$ 259,007,487	$ 121,067,291	$ 21,879,540	$ 5,807,597	$ 47,195,136	$ 2,744,944	$ 21,613,265	$ 33,925	$ 36,228,729	$ 14,817	$ 1,198,621	$ 1,111,594	$ 112,028
DEPRECIATION EXPENSES	$ 62,274,122	$ 30,972,180	$ 5,583,673	$ 1,449,022	$ 10,308,229	$ 405,726	$ 5,100,470	$ 10,828	$ 7,477,435	$ 1,594	$ 427,412	$ 481,332	$ 56,220
TAXES OTHER THAN INCOME TAX	$ 21,833,107	$ 10,792,799	$ 1,950,883	$ 505,445	$ 3,638,265	$ 155,193	$ 1,793,377	$ 3,669	$ 2,674,464	$ 892	$ 141,720	$ 159,101	$ 17,299
INCOME BEFORE INCOME TAXES	$ 112,434,279	$ 48,699,550	$ 13,313,861	$ 2,649,506	$ 25,454,121	$ 644,305	$ 9,602,647	$ 30,829	$ 8,853,942	$ (2,984)	$ 553,947	$ 2,700,903	$ (66,349)
INCOME TAXES													
Income Taxes - Current	$ 21,008,801	$ 10,250,953	$ 1,841,266	$ 485,598	$ 3,573,951	$ 150,261	$ 1,769,060	$ 3,555	$ 2,619,670	$ 550	$ 139,866	$ 157,139	$ 16,933
Provision for Deferred FIT	$ 10,448,853	$ 5,098,372	$ 915,765	$ 241,515	$ 1,777,526	$ 74,733	$ 879,852	$ 1,768	$ 1,302,908	$ 274	$ 69,563	$ 78,154	$ 8,422
ITC Adjustment - Net	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Federal Income Taxes	$ 31,457,654	$ 15,349,325	$ 2,757,031	$ 727,114	$ 5,351,476	$ 224,995	$ 2,648,912	$ 5,323	$ 3,922,578	$ 824	$ 209,429	$ 235,293	$ 25,355
OPERATING INCOME	$ 80,976,625	$ 33,350,224	$ 10,556,830	$ 1,922,392	$ 20,102,645	$ 419,310	$ 6,953,735	$ 25,506	$ 4,931,364	$ (3,807)	$ 344,519	$ 2,465,610	$ (91,704)
Gains/Losses	$ (3,645,260)	$ (1,731,004)	$ (308,581)	$ (82,263)	$ (646,957)	$ (34,131)	$ (305,504)	$ (538)	$ (491,686)	$ (176)	$ (20,979)	$ (21,348)	$ (2,092)
Interest on Customer Deposits	$ (407,085)	$ (323,917)	$ (58,492)	$ (10,171)	$ (9,956)	$ -	$ (4,074)	$ (24)	$ -	$ -	$ -	$ -	$ (451)
NET INCOME	$ 76,924,280	$ 31,295,304	$ 10,189,757	$ 1,829,958	$ 19,445,731	$ 385,179	$ 6,644,157	$ 24,945	$ 4,439,678	$ (3,983)	$ 323,540	$ 2,444,262	$ (94,247)
RATE BASE	$ 1,142,391,460	$ 545,479,480	$ 96,210,533	$ 25,635,688	$ 200,145,074	$ 9,172,829	$ 97,680,163	$ 187,304	$ 149,971,023	$ 32,068	$ 8,041,764	$ 9,024,562	$ 810,972
RETURN ON RATE BASE	6.73%	5.74%	10.59%	7.14%	9.72%	4.20%	6.80%	13.32%	2.96%	-12.42%	4.02%	27.08%	-11.62%
Relative Rate of Return	1.00	0.85	1.57	1.06	1.44	0.62	1.01	1.98	0.44	-1.84	0.60	4.02	-1.73

Revised DED-8: Recommended Revenue Distribution at Company's Proposed Revenue Requirement

		Residential (RG)	Commercial (CB)	Commercial Small Heating (SH)	General Power (GP)	Special Contract Praxair (SC-P)	Total Electric Building (TEB)	Feed Mill (PFM)	Large Power (LP)	Miscellaneous Services (MS)	Street Lights (SPL)	Private Lights (PL)	Special Lights (LS)
Cost of Service Results													
Operating Income	$ 76,924,280	$ 26,045,844	$ 10,057,643	$ 1,865,879	$ 22,660,421	$ 771,905	$ 6,736,890	$ 23,992	$ 6,091,216	$ (3,066)	$ 323,540	$ 2,444,262	$ (94,247)
Rate Base	$ 1,142,391,460	$ 577,470,247	$ 97,015,650	$ 25,416,781	$ 180,554,405	$ 6,816,079	$ 97,115,042	$ 193,108	$ 139,906,372	$ 26,477	$ 8,041,764	$ 9,024,562	$ 810,972
ROR	6.73%	4.51%	10.37%	7.34%	12.55%	11.32%	6.94%	12.42%	4.35%	-11.58%	4.02%	27.08%	-11.62%
Relative Rate of Return	1.00	0.67	1.54	1.09	1.86	1.68	1.03	1.85	0.65	-1.72	0.60	4.02	-1.73
Revenue Requirement Results													
Operating Income	$ 76,924,280	$ 26,045,844	$ 10,057,643	$ 1,865,879	$ 22,660,421	$ 771,905	$ 6,736,890	$ 23,992	$ 6,091,216	$ (3,066)	$ 323,540	$ 2,444,262	$ (94,247)
Rate Base	$ 1,142,391,460	$ 577,470,247	$ 97,015,650	$ 25,416,781	$ 180,554,405	$ 6,816,079	$ 97,115,042	$ 193,108	$ 139,906,372	$ 26,477	$ 8,041,764	$ 9,024,562	$ 810,972
ROR	6.73%	4.51%	10.37%	7.34%	12.55%	11.32%	6.94%	12.42%	4.35%	-11.58%	4.02%	27.08%	-11.62%
Relative Rate of Return	1.00	0.67	1.54	1.09	1.86	1.68	1.03	1.85	0.65	-1.72	0.60	4.02	-1.73
Rate Schedule Specific Revenue Increase Allocation													
Revenue Requirement	$ 23,741,631												
Operating Income Deficiency	$ 14,627,545												
ROR Schedule	6.73%												
Step One Increase													
System ROR	6.73%	6.73%	6.73%	6.73%	6.73%	6.73%	6.73%	6.73%	6.73%	6.73%	6.73%	6.73%	6.73%
Incremental Income	$ 14,627,545	$ 12,838,798	$ (3,524,979)	$ (154,410)	$ (10,502,577)	$ (312,936)	$ (197,534)	$ (10,989)	$ 3,329,545	$ 4,849	$ 217,962	$ (1,836,582)	$ 148,854
Revenue Conversion Factor	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231
Revenue Requirement	$ 23,741,631	$ 20,838,357	$ (5,721,313)	$ (250,619)	$ (17,046,490)	$ (507,920)	$ (320,612)	$ (17,836)	$ 5,404,107	$ 7,870	$ 353,769	$ (2,980,915)	$ 241,602
Percent Increase @ System ROR	5.44%	10.43%	-13.82%	-2.49%	-20.58%	-13.78%	-0.89%	-21.57%	9.75%	57.18%	15.62%	-68.60%	201.21%
Maximum Increase @ 1.10 Times System Average Increase	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%
Required Percentage Increase with Limitation	5.99%	5.99%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	5.99%	5.99%	5.99%	0.00%	5.99%
Initial Increase	$ 15,423,635	$ 11,963,580							$ 3,316,508	$ 824	$ 135,537		$ 7,187
Shortfall in Required Increase	$ 8,317,996												
Step Two Increase													
Basis to Allocate Step Two Increase	$ 178,633,742	$ -	$ 41,395,126	$ 10,052,427	$ 82,846,435	$ 3,685,327	$ 36,226,524	$ 82,683	$ -	$ -	$ -	$ 4,345,220	$ -
Allocation of Shortfall to Remaining Customer Classes	$ 8,317,996	$ -	$ 1,927,544	$ 468,087	$ 3,857,705	$ 171,606	$ 1,686,871	$ 3,850	$ -	$ -	$ -	$ 202,333	$ -
Total Required Increase	$ 23,741,631	$ 11,963,580	$ 1,927,544	$ 468,087	$ 3,857,705	$ 171,606	$ 1,686,871	$ 3,850	$ 3,316,508	$ 824	$ 135,537	$ 202,333	$ 7,187
Proposed Revenue Allocation													
ROR	8.01%	5.79%	11.59%	8.48%	13.87%	12.88%	8.01%	13.65%	5.81%	-9.66%	5.06%	28.47%	-11.08%
Incremental Income	$ 14,627,545	$ 7,370,926	$ 1,187,587	$ 288,395	$ 2,376,785	$ 105,729	$ 1,039,304	$ 2,372	$ 2,043,346	$ 508	$ 83,506	$ 124,660	$ 4,428
Revenue Conversion Factor	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231
Revenue Requirement	$ 23,741,631	$ 11,963,580	$ 1,927,544	$ 468,087	$ 3,857,705	$ 171,606	$ 1,686,871	$ 3,850	$ 3,316,508	$ 824	$ 135,537	$ 202,333	$ 7,187
Final Relative Rate of Return	1.00	0.72	1.45	1.06	1.73	1.61	1.00	1.70	0.73	-1.21	0.63	3.55	-1.38

Revised DED-9: Recommended Revenue Distribution at 20 Percent of Company's Proposed Revenue Requirement

		Residential (RG)	Commercial (CB)	Commercial Small Heating (SH)	General Power (GP)	Special Contract Praxair (SC-P)	Total Electric Building (TEB)	Feed Mill (PFM)	Large Power (LP)	Miscellaneous Services (MS)	Street Lights (SPL)	Private Lights (PL)	Special Lights (LS)
Cost of Service Results													
Operating Income	$ 76,924,280	$ 26,045,844	$ 10,057,643	$ 1,865,879	$ 22,660,421	$ 771,905	$ 6,736,890	$ 23,992	$ 6,091,216	$ (3,066)	$ 323,540	$ 2,444,262	$ (94,247)
Rate Base	$ 1,142,391,460	$ 577,470,247	$ 97,015,650	$ 25,416,781	$ 180,554,405	$ 6,816,079	$ 97,115,042	$ 193,108	$ 139,906,372	$ 26,477	$ 8,041,764	$ 9,024,562	$ 810,972
ROR	6.73%	4.51%	10.37%	7.34%	12.55%	11.32%	6.94%	12.42%	4.35%	-11.58%	4.02%	27.08%	-11.62%
Relative Rate of Return	1.00	0.67	1.54	1.09	1.86	1.68	1.03	1.85	0.65	-1.72	0.60	4.02	-1.73
Revenue Requirement Results													
Operating Income	$ 76,924,280	$ 26,045,844	$ 10,057,643	$ 1,865,879	$ 22,660,421	$ 771,905	$ 6,736,890	$ 23,992	$ 6,091,216	$ (3,066)	$ 323,540	$ 2,444,262	$ (94,247)
Rate Base	$ 1,142,391,460	$ 577,470,247	$ 97,015,650	$ 25,416,781	$ 180,554,405	$ 6,816,079	$ 97,115,042	$ 193,108	$ 139,906,372	$ 26,477	$ 8,041,764	$ 9,024,562	$ 810,972
ROR	6.73%	4.51%	10.37%	7.34%	12.55%	11.32%	6.94%	12.42%	4.35%	-11.58%	4.02%	27.08%	-11.62%
Relative Rate of Return	1.00	0.67	1.54	1.09	1.86	1.68	1.03	1.85	0.65	-1.72	0.60	4.02	-1.73
Rate Schedule Specific Revenue Increase Allocation													
Revenue Requirement	$ 4,748,326												
Operating Income Deficiency	$ 2,925,509												
ROR Schedule	6.73%												
Step One Increase													
System ROR	6.73%	6.73%	6.73%	6.73%	6.73%	6.73%	6.73%	6.73%	6.73%	6.73%	6.73%	6.73%	6.73%
Incremental Income	$ 2,925,509	$ 12,838,798	$ (3,524,979)	$ (154,410)	$ (10,502,577)	$ (312,936)	$ (197,534)	$ (10,989)	$ 3,329,545	$ 4,849	$ 217,962	$ (1,836,582)	$ 148,854
Revenue Conversion Factor	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231
Revenue Requirement	$ 4,748,326	$ 20,838,357	$ (5,721,313)	$ (250,619)	$ (17,046,490)	$ (507,920)	$ (320,612)	$ (17,836)	$ 5,404,107	$ 7,870	$ 353,769	$ (2,980,915)	$ 241,602
Percent Increase @ System ROR	1.09%	10.43%	-13.82%	-2.49%	-20.58%	-13.78%	-0.89%	-21.57%	9.75%	57.18%	15.62%	-68.60%	201.21%
Maximum Increase @ 1.10 Times System Average Increase	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%
Required Percentage Increase with Limitation	1.20%	1.20%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.20%	1.20%	1.20%	0.00%	1.20%
Initial Increase	$ 3,084,727	$ 2,392,716							$ 663,302	$ 165	$ 27,107		$ 1,437
Shortfall in Required Increase	$ 1,663,599												
Step Two Increase													
Basis to Allocate Step Two Increase	$ 178,633,742	$ -	$ 41,395,126	$ 10,052,427	$ 82,846,435	$ 3,685,327	$ 36,226,524	$ 82,683	$ -	$ -	$ -	$ 4,345,220	$ -
Allocation of Shortfall to Remaining Customer Classes	$ 1,663,599	$ -	$ 385,508.90	$ 93,617	$ 771,541.02	$ 34,321	$ 337,374	$ 770	$ -	$ -	$ -	$ 40,467	$ -
Total Required Increase	$ 4,748,326	$ 2,392,716	$ 385,509	$ 93,617	$ 771,541	$ 34,321	$ 337,374	$ 770	$ 663,302	$ 165	$ 27,107	$ 40,467	$ 1,437
Proposed Revenue Allocation													
ROR	6.99%	4.77%	10.61%	7.57%	12.81%	11.64%	7.15%	12.67%	4.65%	-11.20%	4.23%	27.36%	-11.51%
Incremental Income	$ 2,925,509	$ 1,474,185	$ 237,517	$ 57,679	$ 475,357	$ 21,146	$ 207,861	$ 474	$ 408,669	$ 102	$ 16,701	$ 24,932	$ 886
Revenue Conversion Factor	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231
Revenue Requirement	$ 4,748,326	$ 2,392,716	$ 385,509	$ 93,617	$ 771,541	$ 34,321	$ 337,374	$ 770	$ 663,302	$ 165	$ 27,107	$ 40,467	$ 1,437
Final Relative Rate of Return	1.00	0.68	1.52	1.08	1.83	1.66	1.02	1.81	0.66	-1.60	0.61	3.91	-1.65

FERC 12CP System Test Results

	Test 1 On Peak and Off Peak	Test 2 Low to Annual Peak	Test 3 Average to Annual Peak
Results	18%	68%	87%
Conditions under FERC Test	**≤ 19%**	**≥ 66%**	**≥ 81%**

Source: Company Response to OPC Discovery Request 5001, Attachment Datasheet2014v4 PROPRIETARY.xls.