Exhibit No.:	
Issue(s):	Policy – Missouri Energy Efficiency Investment Act, Timely Recovery of Program Cost, Achieving Utility and Customer Financial Alignment, Net Shared Benefits & Allocations
Witness:	William R. Davis
Sponsoring Party:	Union Electric Company
Type of Exhibit:	Surrebuttal Testimony
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MISSOURI PUBLIC SERVICE COMMISSION

Case No. EO-2012-0142

SURREBUTTAL TESTIMONY

OF

WILLIAM R. DAVIS

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
May, 2012

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SURREBUTTAL TESTIMONY

OF

WILLIAM R. DAVIS

CASE NO. EO-2012-0142

Q. Please state your name and business address.

A. My name is William R. Davis. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

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

A. I am a Senior Corporate Planning Analyst in the Resource Planning group within the Corporate Planning department for Ameren Services Company ("Ameren Services").

Q. Are you the same William R. Davis who sponsored portions of the Company's *2013 – 2015 Energy Efficiency Plan* ("MEEIA Report") and who also previously filed supplemental direct testimony in this docket?

A. Yes, I am.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to summarize the positions of the parties on the key aspects of our filing and provide additional discussion on the following issues:

I. Valuing Supply-Side and Demand-Side Resources Equally

II. The Proposed Performance Mechanism

III. Program Cost Recovery

IV. Cost Allocations

V. Residential Customer Charge

VI. Customer Benefits and Impacts

I. VALUING SUPPLY-SIDE AND DEMAND-SIDE RESOURCES EQUALLY

Q. What is the significance of comparing supply-side and demand-side resources?

A. The Missouri Energy Efficiency Investment Act ("MEEIA") law is clear that it is the state's policy to value supply-side and demand-side resources equally. The law also directs the Commission to take steps to support this policy. The Commission must provide timely cost recovery, a timely earnings opportunity, and must ensure that the Company's financial interests are aligned with helping customers use energy more efficiently.

As Company witness Warren Wood explains, only when the utility is indifferent between implementing demand-side resources and supply-side resources can it be determined that the two have been valued equally. Mr. Wood further explains that valuing the resources equally does not mean treating them the same from a conceptual or accounting standpoint.

There is a temptation to develop various comparisons between supply and demand-side resources to determine whether the resources are valued equally but those comparisons cannot capture all of the differences between the resource types. A summary of some of the differences follows:

1. Demand-side resources do not have a significant "construction cycle" while supply-side resources can take as long as seven or eight years to place in service.

2. Demand-side resources represent expenditures of the Company engaging in marketing efforts to change customer usage and purchasing behaviors as

opposed to traditional construction projects which result in assets that the Company owns and operates.

3. Demand-side resources directly and contemporaneously cause erosion to Company earnings by reducing sales whereas supply-side resources simply do not.

4. Customer benefits are contemporaneous with demand-side expenditures since the savings are achieved as customer rebates are administered whereas supply-side resources provide benefits over a long period of time after the construction cycle ends and the plant is placed into service.

5. Demand-side resources are a continuous stream of new resources becoming available while supply-side generation projects are large "lumpy" projects, meaning there can be years or decades between projects.

6. The effects of demand-side resources cannot be precisely measured whereas the output of supply-side projects can be easily measured and objectively determined.

Trying to compare supply-side and demand-side resources reminds me of what Albert Einstein once said, “The world we have created today as a result of our thinking thus far has problems which cannot be solved by thinking the way we thought when we created them.” If we keep referring back to the treatment of supply-side resources to solve demand-side resource problems it is unlikely we will get an appropriate solution.

Q. Staff witness Mark Oligschlaeger made several comparisons between supply-side and demand-side resources, some of which are embodied in your summary above. Do you agree with the Staff's comparison?

A. No. The Staff appears to be looking to do nothing more than mimic supply-side cost recovery, without considering the differences between supply-side and demand-side resources.

Q. Could you please elaborate on those differences?

A. Yes. As I noted above, during construction of a generation asset, the Company is not reducing its revenue stream. In contrast, energy efficiency programs immediately reduce the Company's revenue stream collected. This is the most important distinction between supply-side and demand-side resources. It is why the MEEIA statute requires the Commission to address the inherent misalignment between the Company's financial interests and the interest of helping its customers use energy more efficiently, as discussed in the Company's MEEIA Report and in Mr. Wood's surrebuttal testimony. Staff's proposal compares the retrospective recovery of the revenue degradation to the project costs of the supply-side resource. It is incorrect to compare the throughput disincentive to the construction of a supply-side addition.

Q. Why is it incorrect to compare the revenue degradation (i.e., the throughput disincentive) to the supply-side construction costs?

A. Because as Ameren Missouri witnesses Lynn M. Barnes and Stephen M. Ditman explain, the throughput disincentive causes an immediate earnings reduction while earnings are not negatively affected during the relatively long periods of construction of a supply-side resource.

Q. Could you please compare the project costs of supply-side and demand-side resources?

A. For a supply-side resource, the Company finances the construction cost of the resource over whatever period is required to construct the resource and place it "in service" and make it "used and useful." The Company would file a rate case generally designed so that the conclusion of the rate case coincides as closely as possible with the in-service date, and the costs would then be included in rates and collected over the life of the asset. In contrast, demand-side resources do not require a significant "construction cycle" in which the Company is spending money without producing results. This is because the Company is engaging in marketing efforts aimed at changing customer behavior in order to reduce energy consumption and because the installation of demand-side measures by customers typically does not involve delay. To the contrary, it immediately results in a reduction in energy usage. In effect, the demand-side measures (and the energy savings they immediately generate) are a continuous stream of resources that become used and useful as the money is spent.

Q. But shouldn't the Company experience a period of negative cash flow just as it does with a supply-side resource?

A. Without understanding the differences between supply-side and demand-side resources, this position may appear rational. Upon closer examination, however, this idea falls apart quickly. The Staff's argument is that in order to "value supply-side and demand-side resources equally," as MEEIA requires, the resources must be *accounted* for the same. This is false, because it does not result in the two alternative investments being valued equally, as also discussed in Mr. Wood's surrebuttal testimony. As I explained earlier in my testimony, demand-side resources are used and useful contemporaneous with spending so there is no reason to delay program cost recovery. The Staff agrees with contemporaneous recovery of program costs, yet the Staff argues that the throughput disincentive should be recovered retrospectively. However, the throughput disincentive is a consequence of the fact that the demand-side resources are already used and useful, and it is being "incurred' by the Company contemporaneously with the benefits provided by the programs, just as the program costs are. If recovery of the throughput disincentive is delayed the Company is forced into a situation where it incurs financial losses while customers are receiving the benefits of the programs, just as it would be if the Company had to make program expenditures without contemporaneous recovery of them. Those financial losses would not be experienced during supply-side development because there is no throughput disincentive for supply-side resources and the Company earns AFUDC until the asset is in-service, and as I discuss further below, generally has also received it on major supply side additions until they are reflected in rates.

Q. But shouldn’t the Company wait until a rate case for cost recovery just like it would for a supply-side resource?

A. No. For a large generation resource the Company would typically file a rate case at such a time to include it in rates as close to when it becomes used and useful as possible. This strategy, albeit imperfect, generally works for major supply-side resources because they are typically implemented through a large expenditure of capital over a fixed duration prior to being placed in service and they allow adequate time to prepare and file a rate case. However, this strategy is not available for demand-side resources since they are a continuous stream of expenses and result in resources that become operational as these expenses are incurred. It is simply impossible for the Company to time its rate case filings in order to provide a reasonable opportunity of getting costs included in rates similar to supply-side resources.

Q. How is a generation project typically determined to be "used and useful"?

A. A generation project is typically determined to be used and useful once it is "in service". Normally there would be an agreement to the terms under which the generator is determined to be in service. For instance, there may be a requirement to run at various capacity factors over specified time intervals and/or prove shut-down and start-up capabilities. So, in general, there would be a list of criteria that are observable and can be objectively determined.

Q. Does such a concept apply to demand-side resources?

A. No. It appears that the Staff equates Evaluation, Measurement and Verification ("EMV") to the "proof" that might be comparable to in-service criteria. But EMV is proof that the demand-side resource in fact has already been in service for a period of time and has already created benefits for the customer. It is not, in fact, a test that shows that the demand-side resource is now available to be deemed "in-service" going forward.

Q. So how would anyone "prove" the effects of the energy efficiency programs?

A. It may sound a bit cliché, but the fact is that it is not possible to unequivocally measure the effects of the energy efficiency programs in the same way that one can measure how many megawatt-hours a power plant produced or how many tons of coal it burned. All EMV results contain a substantial measure of subjectivity and one evaluator will almost certainly come up with a different answer than another, as Ameren Missouri witness Rick Voytas explains in his surrebuttal testimony. Because of EMV limitations, it is more appropriate to agree to savings estimates up front and then use updated estimates to inform future plans (e.g., refine the deemed values in the Technical Resource Manual prospectively). It is also necessary to take this approach if demand-side expenditures are to be valued equally, for the reasons discussed by Mr. Wood in his surrebuttal testimony. I would also note that Ms. Barnes attests to the importance of objectivity and how it impacts the financial accounting, and explains that a retrospective application of EMV will result in the very earnings degradation that must be avoided if the Company's financial interests are to be aligned with customers' interests.

Q. Do you agree with Staff witness Mark Oligschlaeger's characterization that customers are "prepaying" under the Company's proposal?

A. No. Prepaying implies customers are paying before receiving any value (e.g., I prepay my rent for all of 2012 in September of 2011, but I do not live there until January to December of 2012). In contrast, the Company's proposal is aimed at *contemporaneous* recovery which means paying at the same time as services are being rendered. For the most part, the Company's proposal collects both the program costs and the throughput disincentive contemporaneously with the implementation of the Company's programs and the resulting program benefits (principally energy savings). The Staff offers no basis for objecting to one aspect but not to the other. It is true that in order to adapt to rate case and other timing limitations, there will be some mismatch between the revenue collections and costs. However, the Company has accounted for the time value of money in its analysis to fairly compensate customers for over-recoveries and the Company for under-recoveries. In addition, the Company has also proposed safe guards such as trackers to keep both customers and the Company whole.

Q. Does the Company's proposal include contemporaneous recovery of the earnings incentive?

A. No. The proposal is designed to provide contemporaneous recovery of its program costs and the throughput disincentive, which is entirely consistent with the timing of the costs. The earnings incentive portion of net shared benefits is reserved until the Company has completed its plan and measured its performance against its goal.

II. PERFORMANCE MECHANISM

Q. Can you please summarize the positions of the other parties regarding the Company's performance mechanism proposal?

A. Yes. First I will note that Laclede Gas Company ("Laclede") and the Missouri Industrial Energy Consumers ("MIEC") have not provided rebuttal testimony on Ameren Missouri's proposed incentive level. Staff and the Missouri Department of Natural Resources ("MDNR") support the proposed level of incentive component (4.8% of net shared benefits at the 100% energy savings performance level) while both the Office of the Public Counsel ("OPC") and the Environmental Interveners[1] suggest a lower sharing percentage for the incentive. Staff, MDNR, and the Environmental Interveners support the proposed 15.4% sharing related to the throughput disincentive component while OPC suggests a completely different proposal.

[1]Natural Resources Defense Council, Sierra Club and Renew Missouri.

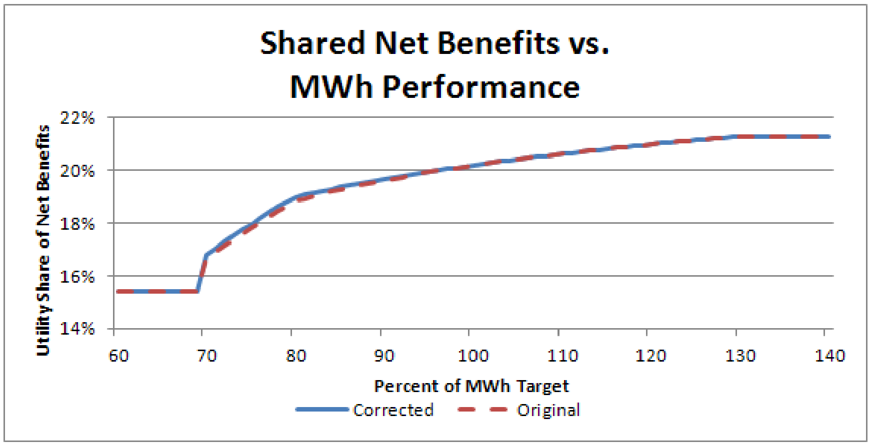
Q. MDNR outright supports the Company's incentive proposal but is concerned that the proposal is not expressed as net shared benefits. Is that concern valid?

A. No. The incentive portion of the performance mechanism is in fact proposed as a percentage of net shared benefits and not in absolute dollars. This is evidenced not only by the Company's MEEIA Report, but also by the Staff and Environmental Interveners' accurate summaries of the Company's incentive proposal as a request for a portion of net shared benefits. The Company's net shared benefits proposal (also called the performance mechanism), which includes the throughput disincentive component and the incentive component, was included in the MEEIA Report as Figure 2.6.

Q. Is there a correction needed to the incentive component of the performance mechanism sharing curve?

A. Yes, while reviewing the calculations for the incentive portion of the performance mechanism, MDNR witness Bickford identified a calculation error that resulted in the sharing percentages required to achieve the designed performance incentive level being understated at performance levels below 100%. In short, the incentive portion was first determined in absolute dollars then converted to net shared benefits. In doing so, the net benefits, which serve as the denominator for the equation, were inadvertently overstated at performance levels below 100% which resulted in an understatement of the sharing percentages. I have subsequently corrected the error. Although the overall impact was relatively minor I certainly appreciate Mr. Bickford's diligence in reviewing the Company's calculations. Figure 1 below shows the original and corrected sharing curve in which you can see a very slight increase in the sharing curve percentages below the 100% performance level. This correction had no impact to the calculation of the 15.4% sharing related to the throughput disincentive and no impact to the absolute level of incentive requested.

Figure 1: Comparison of Corrected and Original Sharing Curve



Q. Environmental Intervener Philip Mosenthal expressed confusion about how Ameren Missouri plans to calculate its performance. Can you please clarify?

A. Yes. As stated in the MEEIA Report, Ameren Missouri's performance goal is 793,100 MWh (excluding line losses and adjustment for actual customer opt-out). In fact, in Figure 2.6 in the MEEIA Report, and in Figure 1 above, the x-axis is labeled as "Percent of MWh Target". Mr. Mosenthal suggests two alternatives for weighting energy and demand savings including: 1) the development of explicit weights and 2) the performance being measured as percent of achievement toward planned net benefits. Although a modification to target net benefits could be implemented, it would be redundant since the Company's ultimate net reward is already dependent on net benefits achieved. For instance, to the extent the Company achieves more or less demand savings, those impacts will be incorporated into the net benefits. Since the Company is not proposing demand response programs, devising an explicit weighting scheme for energy and demand savings goals will provide little value to a cost recovery system that is already complicated.

Q. Have you reviewed OPC witness Ryan Kind's testimony regarding the performance mechanism?

A. Yes.

Q. Do you agree with his conclusions or recommendations?

A. No. Mr. Kind criticizes the performance mechanism in three ways. First, he claims that an American Council for an Energy Efficient Economy ("ACEEE") report suggests that the throughput disincentive component of the performance mechanism (the 15.4% of net shared benefits component) is too high. Second, he suggests that the throughput disincentive should not be addressed as the Company proposes at all. Third, he argues that the incentive portion of the performance mechanism (the 4.8% of net shared benefits; also referred to as the incentive component) should be determined and limited based on a percent of program costs. He also cites the ACEEE report in support of the latter argument.

Q. Is it appropriate to compare the Company's 15.4% sharing that addresses the throughput disincentive to the performance incentive caps Mr. Kind references from the ACEEE report?

A. No. The ACEEE report was clearly focused only on the shareholder incentives (the 4.8% component in our mechanism), as the report indicates:

> This report examines state efforts and experiences with financial incentives for encouraging investor-owned utilities ("IOUs") to provide effective energy efficiency programs for their customers. Two fundamental impediments to improving efficiency in the IOU sector include the existence of: 1) A disincentive to using energy efficiency programs to reduce customer energy consumption because utility revenues will also be reduced. 2) A lack of incentive to spend money on programs to improve customer energy efficiency as compared to making investments in new utility facilities and equipment. Different policy mechanisms address different aspects of the specific problems

> noted above and it is critically important that these measures be considered together as part of an overarching approach to correct longstanding barriers inhibiting utility investments in customer energy efficiency. *<u>This report focuses on one such mechanism, shareholder incentives.</u>*[emphasis added]

Mr. Kind, however, is misusing the report to address that part of the Company's performance mechanism that addresses the throughput disincentive. With respect to the throughput disincentive issue, the ACEEE report Mr. Kind references draws the following conclusion:

> Most states with incentives *also* permit some form of remuneration to utilities from sales that are lost due to decreased demand resulting from efficiency improvements. Both decoupling and lost revenue recovery mechanisms are common; however, a number of states employ these mechanisms on a pilot basis and not uniformly across utilities or sectors (gas and electric) [emphasis added].

Q. Please explain your prior point further.

A. The Company has proposed the 15.4% sharing to remedy the throughput disincentive while the 4.8% is associated with the incentive (earnings opportunity); therefore, Mr. Kind's comparison's based upon the ACEEE report is only relevant (if relevant at all) to the 4.8% sharing component of the performance mechanism and has nothing to do with the 15.4% component.

Q. Mr. Kind's second argument is that the proposed 15.4% sharing to address the throughput disincentive should be eliminated entirely and that the Commission should instead approve a "lost revenue component." How do you respond?

A. Mr. Kind's proposal fails to address the throughput disincentive. Relief from the throughput disincentive is required to align the financial interests of the utility and its customers as discussed by Mr. Wood in his surrebuttal testimony. A lost revenue tracker as advocated by Mr. Kind would not sufficiently address the throughput disincentive because it fails to account for the full impact that the energy savings produced by energy efficiency have on the Company's bottom line. In addition, the Company's proposal sends a strong signal to maximize customer net benefits. To the extent that the Company has its throughput disincentive recovery intertwined with maximizing customer net benefits then the signal is amplified.

Q. Has any other party besides OPC taken issue with the Company's proposal to recover the throughput disincentive with net shared benefits?

A. No. Staff, MDNR, and the Environmental Interveners have all filed testimony that is supportive of the Company's proposed framework and have supported the base level of sharing at 15.4%. The remaining disagreements with those parties are regarding the earnings opportunity level (Environmental Interveners) and the timing of recovery ("Staff"), both of which I address in this testimony.

Q. As you noted, Mr. Kind also attacks the incentive level (the 4.8% at 100% performance component) and advocates that it should be established (and capped) based on program costs. The ACEEE report is relied on by Mr. Kind to justify his proposal. Does the ACEEE report support Mr. Kind's proposal?

A. No, it does not. The ACEEE report contains data from 18 states, the majority of which 10 are restructured states. When one considers the differences between the impact of energy efficiency expenditures by a utility in restructured state versus the impact of energy efficiency expenditures by a utility in a vertically integrated state, like Missouri, coupled with a closer examination of the data, it becomes apparent that the ACEEE report does not support Mr. Kind's argument.

Q. Please explain the point you made regarding the impact of energy efficiency expenditures on a utility in a restructured state versus a utility like Ameren Missouri.

A. A comparison of Ameren Missouri, a vertically integrated utility, and Ameren Illinois Company, a distribution only utility, illustrates the point. One (1) basis point of return on equity ("ROE") for Ameren Missouri is about $555,000 of revenue requirement while one (1) basis point of ROE for Ameren Illinois is about $190,000. However, both utilities are of a similar size, with both Ameren Missouri and Ameren Illinois serving about 1.2 million customers. Because it is vertically integrated, Ameren Missouri's rate base is significantly larger since it includes the generation assets. Ameren Illinois' electric energy efficiency programs are funded at about $45 million annually so a 10% cap for the performance incentive would be $4.5 million. The ROE impact of the $4.5 million for the distribution company is 24 basis points. If Ameren Missouri were under the same incentive constraints, the ROE impact would be just 8 basis points. Put another way, with a 10% cap Ameren Illinois would have three times the incentive as Ameren Missouri. This is a result that one could expect would be typical when comparing distribution only utilities having comparatively smaller rate bases (due to the lack of owned-generation) versus integrated utilities having owned-generation and larger rate bases. For this reason, it is more appropriate to focus on what constitutes a reasonable earnings opportunity as opposed to relying on program expenditure levels as a benchmark.

Q. What about the information in the ACEEE report regarding the vertically integrated states?[2] How does it relate to this issue?

A. There are eight states on ACEEE's list that are vertically integrated. Two of the states have no incentive caps at all. One state has a cap at 30% of program costs while another has a 20% program cost cap. Two states have a 10% program cost cap while one has a 5% (or $4 million cap). Finally, one state has a cap of 150% of savings goals but the report does not convert its meaning to percentage of program costs, so one cannot glean anything from it.

The Company's incentive component proposal is about 21% of program costs at the 100% performance level and 33% of program costs at maximum performance. Although the Company's incentive component request is in fact higher than a few relevant examples from the ACEEE report, it is evident that the Company's proposal is within the relevant range. In summary, of the 18 states in the Report, the data from 14 of the 18 states provides no support for Mr. Kind's proposal.

Q. In addition to claiming that the incentive is too high in comparison to others, which you addressed earlier, do you agree with OPC's rationale to limit the incentive to a percentage of program costs at all?

A. No. Basing the incentive level on a percent of program costs is arbitrary. The Staff and MDNR have testified that the Company's performance mechanism level is reasonable; it is only Mr. Kind who opines that it is completely out of line. To the extent the Company can manage programs that are providing customers with substantial net benefits then there is no reason to arbitrarily limit financial rewards to some percentage of the size of

[2] The vertically integrated states are Colorado, Georgia, Hawaii, Idaho, Kentucky, Minnesota, Washington, and Wisconsin.

the program costs. An appropriate alignment of interests would incent efficient and effective demand-side expenditures, as our filing has done, rather than cap incentives based on programs costs.

Q. Is there much dispute regarding the Company's proposal that the threshold for incentive starts at 70% and then reaches its maximum at 130%?

A. No. OPC seems to think 50% is an appropriate threshold while 150% is an appropriate maximum. It seems that Mr. Mosenthal's threshold was 71% and his maximum was 130%. MDNR supports the Company's proposal. I think it is fair to say that the Company's proposed threshold and maximum are reasonable.

Q. Do you agree with Mr. Mosenthal's characterization that the sharing curve is most generous from 70-80% of performance?

A. No, I do not. In fact, it is the opposite in that the sharing is most punitive in that range. For all performance levels above 80% the slope of the performance curve is constant. However if the Company's performance goes below 80% then the possible incentive is reduced at an increasing pace. If the same slope from the 80-130% were applied to the 70-80% range then the minimum incentive at 70% would be $4 million instead of $2 million.

Q. Do you agree that the forgone earnings opportunity should be based on the deferral of the supply-side resource as opposed to the complete elimination?

A. Yes, at least from a theoretical standpoint.

Q. Has the Company performed any analysis to determine how long "all cost effective demand-side resources" could delay a 600 MW combined cycle power plant?

A. Yes. Table 1 below shows that demand growth is expected to be about 63 MW per year plus 11 MW of reserves by 2030 (or about 0.68% per year based on the Company's 2012 IRP update). Given the Realistic Achievable Potential ("RAP") of 2,092 MW by 2030, if those levels are sustainable then the power plant could be deferred 28 years (2092/74). Realizing the timeframe is so long (starting in 2029 looking out to 2057) the estimate becomes less reliable. The Company's original analysis was simplified to avoid problematic assumptions about time periods beyond its long-term planning horizon.

Table 1: Analysis of Demand-Side Resource Potential

Demand Growth	63
Reserves	17%
Demand Growth Including Reserves	74
RAP EE (2030)	1082
Reserves	17%
RAP EE Including Reserves	1266
RAP DR (2030)	706
Reserves	17%
RAP DR Including Reserves	826
Total DSM After Reserves	2092
Years Delayed	28

*EE: Energy Efficiency, *DR: Demand Response, *RAP: Realistic Achievable Potential

Q. Is Ameren Missouri's analysis of the earnings opportunity an aggressive estimation?

A. Not at all. The Company's analysis compares the pursuit of all cost-effective energy efficiency to a 600 MW combined cycle power plant. A combined cycle plant like the one the Company modeled can be expected to achieve a 52.5% capacity factor which means it would produce 55 million MWh over 20 years. In contrast the RAP energy efficiency portfolio would provide 1,266 MW of capacity by 2030 and about 52 million MWh. Considering another 800 MW of RAP level demand response by 2030 (even waiting until 2016 to start), it is evident that "all cost effective" demand-side resources have the potential to defer significantly more than a single 600 MW combined cycle plant included in Ameren Missouri's analysis.

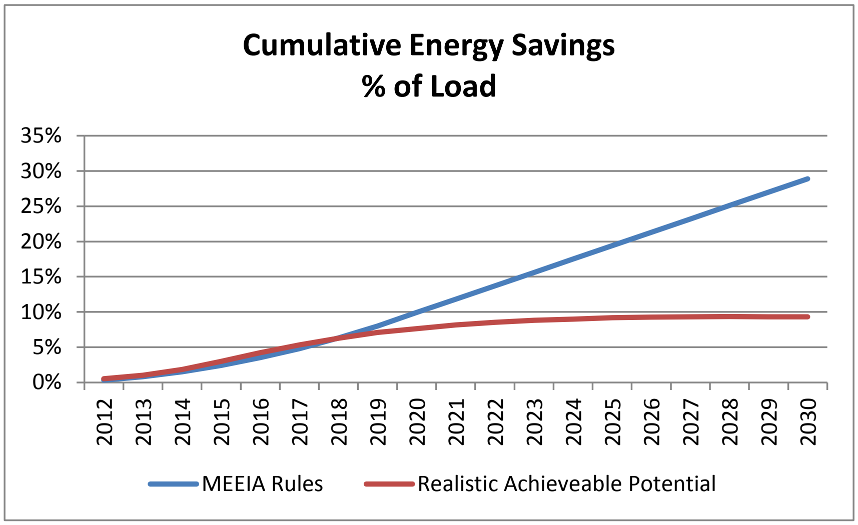
Q. Do you agree with Mr. Mosenthal's proposal to ramp-up Ameren Missouri's performance incentive?

A. No. Mr. Mosenthal's proposal is predicated on the belief that "all cost effective" energy efficiency is only achieved when the 1.9% annual savings goal is met. This is a false comparison. Each year should have the same relative value since each year is achieving all cost-effective energy savings relative to that year's potential, not an arbitrary maximum at some point in the future. Ameren Missouri's plan achieves all cost effective energy efficiency in the implementation period; therefore, the entire award should be available.

Furthermore, Mr. Mosenthal's analysis assumes that the 1.9% savings level is continued indefinitely. Ameren Missouri has repeatedly discussed the realities of diminishing returns and based on its potential study finds that level savings are simply unsustainable.[3] Figure 2 compares the MEEIA goals to the potential study.

[3] Richard Voytas Surrebuttal, Case No. EO-2011-0271, p. 7, l. 8 through p. 14, l. 7.

Figure 2: Comparison of Energy Savings Goals



Q. If Mr. Mosenthal's ramp-up proposal is ignored, what incentive level would be implied?

A. Notwithstanding my other disagreements with Mr. Mosenthal's analysis, if the ramp-up is ignored it is evident that the incentive level based on his analysis would be $8.8 million as opposed to the $4 million he claims. This can be observed because Mr. Mosenthal's analysis concludes that with a 17 year deferral of the combined cycle power plant the present value of lost earnings opportunity of $108 million while the Company's analysis yielded $123 million. The $108 million estimated by Mr. Mosenthal is 88% of the Company's result, and the only other difference in the analysis was Mr. Mosenthal's ramp-up proposal. Therefore, 88% of the Company's $10 million proposal would be $8.8 million. Mr. Mosenthal's claim that the incentive level should be $4 million is mistaken.

Q. Have you reviewed Mr. Mosenthal's incentive recommendation for KCP&L Greater Missouri Operations ("KCPL GMO")?

A. Yes, Mr. Mosenthal recommended KCPL GMO be granted $2 million at 100% performance.

Q. Is there any indication that Mr. Mosenthal has proposed KCPL GMO's incentive award be ramped-up?

A. No.

Q. How would a similar proposal relate to a utility the size of Ameren Missouri?

A. Using Staff's analysis in KCPL GMO's case it is evident that $2 million is approximately 14 basis points of ROE. Therefore the same basis point impact for Ameren Missouri would be about an $8 million incentive for Ameren Missouri, not very different from the amount Ameren Missouri is seeking in this case and considerably more than Mr. Mosenthal claims is appropriate in his surrebuttal testimony.

Q. Is Ameren Missouri's MEEIA plan more aggressive than KCPL GMO's?

A. Yes. From an energy efficiency standpoint, Ameren Missouri has proposed energy savings of 0.6%, 0.7%, and 0.8% of load over the 3-year implementation plan while KCPL GMO has proposed savings of 0.5% of load each year.

Q. Should a more aggressive plan have a higher earnings opportunity?

A. Yes. If not there would be no incentive to propose a more aggressive plan.

Q. Is there any indication in Mr. Mosenthal's testimony that could be used to determine why he is proposing a substantially lower relative incentive for Ameren Missouri as compared to KCPL GMO?

A. No, there is not.

Q. Are there limitations related to analyzing the forgone earnings of a supply-side alternative?

A. Yes. There are several limitations associated with this type of analysis. First, the target resource can change over time. Currently the Company's preferred resource plan has identified a combined cycle unit. However as time passes and uncertainties evolve the Company may prefer a different supply-side resource. For instance, if a nuclear plant becomes the preferred resource option, then the foregone earnings opportunity could increase substantially.

Another limitation for this type of analysis is the timing of resource needs may change considerably. For instance, the Company's 2011 IRP preferred resource plan included a combined cycle unit in 2029. However, in the event that the Meramec coal plant were to be retired earlier, the resource timing would be significantly advanced, which would in turn impact the relative earnings opportunity.

There are other limitations related to the practicality of tracking a "No DSM" plan over time and trying to adjust earnings levels over time to make up for changes in resource types and timing. However, the limitations of the analysis should not cause us to discard the resulting data points. Instead, we should use the analysis to understand reasonableness. The fact remains that, absent demand-side resources, the Company will eventually build a supply-side resource and have the associated earnings opportunity. Therefore one must acknowledge this reality, model it, and utilize the result as a data point in the decision making process.

Q. How did the Staff determine the incentive level to be reasonable?

A. Although disagreeing with the premise of Ameren Missouri's analysis, the Staff nonetheless supports the incentive level requested. Based on the discussion in testimony the approval was based on evaluating the impact to the Company's return on equity which was quantified at slightly less than 20 basis points (at 100% performance). Staff also argues that "timely earnings opportunity" does not mean "potential earnings equity".

Q. There does not seem to be an objective way to conclusively determine the incentive level. In view of that fact, what do you recommend?

A. The testimony thus far provides some data points for the Commission's consideration. Staff and MDNR are in agreement with the Company's proposal of $10 million at 100% and a $16 million maximum award. OPC's proposal is about $4.5 million at 100% and a $6.6 million maximum award. The Environmental Interveners have proposed about $4 million at 100% and about $8 million at 130%. Based on all the testimony as-filed, it is evident that the range at 100% performance is $4-$10 million and $6.6-$16 million for the maximum. However, I have provided evidence that indicates the Environmental Interveners' proposal is half of what their analysis supports and inexplicably half of their recommendation in KCPL GMO's case on an ROE basis, meaning the range (ignoring OPC) is really $8-$10 million at 100% and at least $16 million at the maximum (Mr. Mosenthal's maximum incentive proposal would exceed $16 million once adjusted for the aforementioned factors). This leaves OPC's proposal as a clear outlier; and, for the reasons I discussed earlier, it is inappropriate given the aggressive level of the Company's programs and the fact that the Company is a vertically integrated utility. Because of the inherent deficiencies in both OPC and NRDC's proposals, they should not be given any weight in the Commission's decision.

This leaves the Commission with the fact that the Company's proposed incentive level is outright supported by MDNR and Staff, the fact that the Company is proposing to double its previous three year energy efficiency levels, and the fact that under the Company's proposal customers will retain 91% of the UCT net benefits and 87% of the TRC net benefits. In summary, under the Company's proposal, its customers will realize hundreds of millions of dollars in net benefits while the Company has a strong economic interest in maximizing those net benefits. Therefore, I recommend the Commission approve the Company's incentive proposal (4.8% sharing portion) and its overall performance mechanism.

III. DIRECT PROGRAM COST RECOVERY

Q. Can you please summarize the position of the other parties in the case?

A. Yes. Although Laclede and MIEC did not provide rebuttal testimony on Ameren Missouri's program cost recovery proposal, all of the parties that did, the Staff, OPC, MDNR, and the Environmental Interveners are all generally supportive of the Company's proposal. The Staff proposed a different interest rate be applied to variances in the tracking mechanism and the Environmental Interveners proposed a slight modification to the amount to be included in rates.

Q. Do you agree with Mr. Mosenthal's proposal that the amount to be included in rates should be based on the present value analysis?

A. Yes. Mr. Mosenthal correctly points out that even if Ameren Missouri completes the three year program exactly as planned, the tracker would contain about $1.8 million dollars in interest charges payable to customers. Instead of having an outstanding balance owed to customers at the end, Mr. Mosenthal suggests the anticipated interest credit be built into the rate request so the final tracking balance will be zero if the actual program expenditures are exactly as planned. I agree with Mr. Mosenthal's analysis that the annual level of program costs that should be reflected in rates should be lowered to $47,787,297. This analysis is predicated on using the Company's AFUDC rate. If the Commission were to agree with the Staff's proposal to use the short-term debt rate, then the interest charges would be substantially lower and ultimately would not call for a change to the Company's original proposal.

Q. Do you agree with the Staff's proposal to accrue interest at the Company's short-term debt rate?

A. No. The Staff cites the fact that the Fuel Adjustment Clause ("FAC") accrues interest at the Company's short-term interest rate. But what they fail to mention is that use of the short-term interest rate is mandated by the statute that governs FACs and is not necessarily a reflection of the actual carrying costs.

Q. What is AFUDC and how is it used?

A. AFUDC, or Allowance for Funds Used During Construction, is a weighted average of the pool of debt and equity funds available to the Company which includes using short term only to the point that it can finance construction work in progress. It represents the pool of monies used by the Company to fund efforts that require cash. Financing is typically not secured specifically for a single project; instead, projects are funded from the available financing pool. Use of the AFUDC rate represents the fact that one cannot discern the source of funds for any individual expenditure. Table 2 below shows an example calculation of the Company's AFUDC rate for March 2012. By proposing the use of short-term debt, the Staff is effectively assuming that the total source of funds that are used to pay the program costs is short-term debt. This assumption is not valid because the cost of the funds available to the Company is the overall cost of the entire pool of funds. Table 2 shows that the actual financing costs would be 8% interest yet the Company would only be able to recover 0.13% interest.

Table 2: March 2012 AFUDC Rate Calculation

Source of Funds	Amount ($MM)	Capital Structure Weights	Interest Rate	Short-term Debt Weight	Weighted Interest Rates	Net of Taxes Weighted Rates
Short-term Debt	$0	N.A.	0.13%	0%	0%	0%
Long-term Debt	$3,603	47.62%	5.86%		2.79%	1.72%
Preferred Stock	82	1.08%	4.18%	100%	0.05%	0.05%
Common Stock	3,881	51.30%	10.20%		5.23%	5.23%
AFUDC Rate					8.07%	7.00%

Q. How does the Staff attempt to justify use of the short-term interest rate?

A. Staff indicates that using the AFUDC rate is only appropriate if the Commission wants to make the Company whole[4]. The clear implication of the Staff's position is that use of the short-term interest rate will *not* make the Company whole. The

[4] Oligschlaeger Rebuttal, p. 14, l. 8-12.

Staff in fact points out that accruing interest at the AFUDC rate does reflect compensation to the Company for its time value of money yet curiously argues that the Commission should not do so. In its argument, the Staff says that is not how supply-side generation alternatives are treated and therefore it is not appropriate for demand-side resources.

Q. Is the Staff correct?

A. No. The Company has received treatment for generation alternatives that compensates the Company for the time value of money between the time assets are placed in service and the time they are included in rates including most, it not all, major supply-side projects installed over the past thirty years or so. This includes the Callaway Plant and the Sioux Scrubber. This has also been true for other major supply-side additions for other Missouri utilities: Wolf Creek, Iatan 1, Iatan 1 air quality improvements, and Iatan 2 Plants for Kansas City Power & Light Company and retrofitting what is now KCP&L-GMO's Sibley Plant to burn western coal.

IV. <u>COST ALLOCATIONS</u>

Q. Can you please summarize the positions of the other parties regarding the allocation of the costs and performance mechanism in the Company's proposal?

A. Yes. Both the Staff and MIEC generally support the Company's proposal to allocate program costs and the performance mechanism. Staff witness Michael Scheperle has recommended that there should not be a seasonal differentiation in the Company’s proposed DSIM rates, rather the rates should be the same regardless of the billing season. MIEC has indicated that a longer time period should be used to determine the allocation of the performance mechanism and that the trackers should be applied at the rate class schedule level. Laclede, OPC, MDNR, and Environmental Interveners have not provided rebuttal testimony on Ameren Missouri's proposed cost allocations.

Q. Earlier you stated that Mr. Scheperle recommended that the DSIM rate should not be seasonal. Please comment.

A. The Company believes its original proposal is reasonable, as it is consistent with both the current energy efficiency rates for historical program costs and the Company's longstanding seasonal differentiation on non-DSIM rates. However, as the proposed DSIM rates are nominal, the Company is willing to accept Staff's proposal. Table 3, Table 4, and Table 5, below, show the Company's DSIM proposal if the seasonal DSIM rate is eliminated in favor of a single annual DSIM rate and those tables are respectively comparable to Table 2.5, Table 2.7, and Table 2.8 of the MEEIA Report.

Table 3: Program Cost Revenue Requirements

Rate Class	Revenue Req. ($MM)	Allocation (Class Energy)	Allocated Revenue Req.	Annual $/kWh
RES	$27.65	100%	$27.6	$0.0020
SGS	$20.78	19.8%	$4.1	$0.0012
LGS		46.0%	$9.6	$0.0012
SPS		19.5%	$4.0	$0.0012
LPS		14.7%	$3.1	$0.0012
LTS	*$0*	*100%*	*$0*	*$0.0000*
Lighting	*$0*	*100%*	*$0*	*$0.0000*

Table 4: Performance Mechanism Revenue Requirements

Rate Class	Revenue Req. ($MM)	Allocation (Energy Reductions)	Allocated Revenue Req.	Annual $/kWh
RES	$20.70	100%	$20.7	$0.0015
SGS	$11.78	8.9%	$1.0	$0.0003
LGS		46.2%	$5.4	$0.0007
SPS		24.5%	$2.9	$0.0008
LPS		20.5%	$2.4	$0.0009
LTS	*$0*	*100%*	*$0*	*$0.0000*
Lighting	*$0*	*100%*	*$0*	*$0.0000*

Table 5: Total MEEIA Revenue Requirements

Rate Class	Revenue Req. ($MM)	Allocation	Allocated Revenue Req.	Annual $/kWh
RES	$48.35	100%	$48.4	$0.0036
SGS	$32.56	15.84%	$5.2	$0.0015
LGS		46.07%	$15.0	$0.0018
SPS		21.27%	$6.9	$0.0020
LPS		16.82%	$5.5	$0.0021
LTS	*$0*	*100%*	*$0*	*$0.0000*
Lighting	*$0*	*100%*	*$0*	*$0.0000*

Q. MIEC witness Maurice Brubaker suggests that the performance mechanism allocation should be based on a longer time period. How do you respond to that proposal?

A. Mr. Brubaker's proposal is reasonable and the Company is willing to support such a modification. Table 6 below shows a comparison between the Company's proposal and MIEC's proposal. Both proposals rely on historical energy savings by rate class with the difference driven by the time period chosen for allocation purposes. Mr. Brubaker accurately points out that there is a relatively large project completed in June 2011 that significantly increases the allocation to the Large Primary Service class than if one only considers the 12 month test year in the Company's rate case (ER-2012-0166). This is a reasonable concern and extending the time period is a way to mitigate the impact of a single large project for any rate class. The data indicates that both Large General and Small Primary Service classes have one month of energy savings that is relatively large compared to the 12 month period the Company has proposed; although, not nearly as pronounced as the issue in the LPS class. To avoid trying to "normalize" the historical energy savings by rate class, it may be appropriate to rely on a longer time period for allocation purposes. Table 7 shows the revenue requirement, annual rate, and winter/summer rates based on MIEC's proposal to extend the time period used for allocation purposes.

Table 6: Performance Mechanism Allocation Comparison

Rate Class	Company Proposal	MIEC Proposal
SGS	8.9%	8.2%
LGS	46.2%	49.7%
SPS	24.5%	26.3%
LPS	20.5%	15.8%

Table 7: Performance Mechanism Revenue Requirement (MIEC Proposal)

Rate Class	Revenue Req. ($MM)	Allocation (Energy Reductions)	Allocated Revenue Req.	Annual $/kWh	Summer $/kWh	Winter $/kWh
SGS	$11.78	8.2%	$1.0	$0.0003	$0.0003	$0.0002
LGS		49.7%	$5.4	$0.0007	$0.0010	$0.0006
SPS		26.3%	$2.9	$0.0009	$0.0012	$0.0007
LPS		15.8%	$2.4	$0.0007	$0.0009	$0.0006

Q. MIEC further suggests the Company should apply both the program cost tracker and performance mechanism tracker by rate schedule. Is that a reasonable request?

A. It is possible to examine the recovery at this level of detail, as the Company will have the records to track the program costs and program participation by rate schedule. The Company suggests the direct program costs be tracked at the residential and non-residential level while the performance mechanism is tracked at the rate schedule level.

Direct program costs are allocated based on class energy (adjusted for opt-out) based on the premise that all customers in the classes are eligible to participate. If the costs are tracked at the rate schedule level then the true-up would also need to be based on class energy. Given the fact that the seasonal DSIM rates are almost identical for each business rate class and the annual DSIM rate would be identical (see Table 3 above) for each business rate class, a simpler approach would be to utilize a residential rate and a non-residential rate then apply the tracker at that level. This approach would be consistent with the fact that the Company administers residential and non-residential energy efficiency programs. Table 8 below illustrates what the program cost recovery rates would be if such an approach were adopted. The approach below would yield cost allocations very similar to rate class energy allocators but without more detailed rate schedule tracking.

Table 8: Program Costs - Single Rate for All Business Classes

Rate Class	Revenue Req. ($MM)	Annual $/kWh	Summer $/kWh	Winter $/kWh
RES	$27.65	$0.0020	$0.0027	$0.0017
SGS	$20.78	$0.0012	$0.0015	$0.0010
LGS		$0.0012	$0.0015	$0.0010
SPS		$0.0012	$0.0015	$0.0010
LPS		$0.0012	$0.0015	$0.0010
LTS	*$0*	*$0.0000*	*$0.0000*	*$0.0000*
Lighting	*$0*	*$0.0000*	*$0.0000*	*$0.0000*

Tracking the performance mechanism at the rate schedule level makes more sense because the participation levels from the past may not be as stable of an allocator compared to normalized class energy which is being used to allocate direct program costs. Therefore the Company is amenable to tracking the performance mechanism at the rate schedule level.

Q. Both MIEC and Staff provided rebuttal testimony regarding the allocation of historical energy efficiency program costs; does the Company expect the Commission to determine cost recovery for historical energy efficiency expenditures in this case?

A. No. The Company has not proposed that the Commission determine how to treat historical energy efficiency costs as part of this MEEIA case and agrees with the Staff that the issue should be dealt with in the Company's rate case (Case No. ER-2012-0166).

V. RESIDENTIAL CUSTOMER CHARGE

Q. Can you please summarize the positions of the other parties?

A. Yes. First I will note that Laclede, MDNR, and MIEC have not provided rebuttal testimony on Ameren Missouri's proposed change to the residential customer charge. Staff has not stated its position for or against the proposal but instead recommends the Commission address the issue in Ameren Missouri's rate case (ER-2012-0166). OPC has also cited several concerns about addressing the request in the MEEIA filing as opposed to a rate case. The Environmental Interveners have opposed the request but did not opine about whether the rate case would be a more appropriate forum.

Q. How does a change in the customer charge impact the economics of energy efficiency?

A. An increase in the customer charge will cause a reduction in the volumetric charges if all other factors are held constant. In terms of the standard cost-effectiveness tests, an increase in the customer charge will improve the Ratepayer Impact Measure ("RIM") test and degrade the Participant Cost Test ("PCT"). The PCT is degraded because the decrease in the volumetric charge will reduce the fixed cost bill savings (but not the avoided cost benefits). The RIM test captures the fact that fixed cost savings are not true benefits of energy efficiency and therefore must be recovered as a cost. Since more fixed costs would be collected in the customer charge there would be less fixed costs that need to be recovered from others on the system which in turn improves the RIM test. The Total Resource Cost test ("TRC") and Utility Cost Test ("UCT") do not consider any changes in bill savings because those savings represent a transfer between participants and non-participants, which effectively "cancel out" in the TRC and UCT. A change in the customer charge will not affect the avoided cost benefits or direct program costs; and thus will not affect the TRC or UCT.

Q. Do you share Mr. Mosenthal's concern that increasing the residential customer charge undermines the intent of DSM?

A. I agree that increasing the residential customer charge has an incremental effect that reduces participant bill savings and without context that could seem like it is contradictory to energy efficiency goals. However, I think characterizing the Company's proposal as undermining the intent of DSM is excessive. For instance, Table 9 below shows a comparison of the PCT and RIM tests for all proposed residential programs (the TRC and UCT are unaffected). Notice that the PCT still shows a strong benefit/cost relationship and the overall impact is minor. The improvement to the RIM is very slightly less in percentage terms than the degradation to the PCT (+1.5% RIM vs. -1.7% PCT).

Also, I would note that under both scenarios customers will still incur additional costs for every unit of energy consumed; and, conversely customers will still experience bill savings for every unit of energy not used.

Table 9: Comparison of Residential PCT and RIM

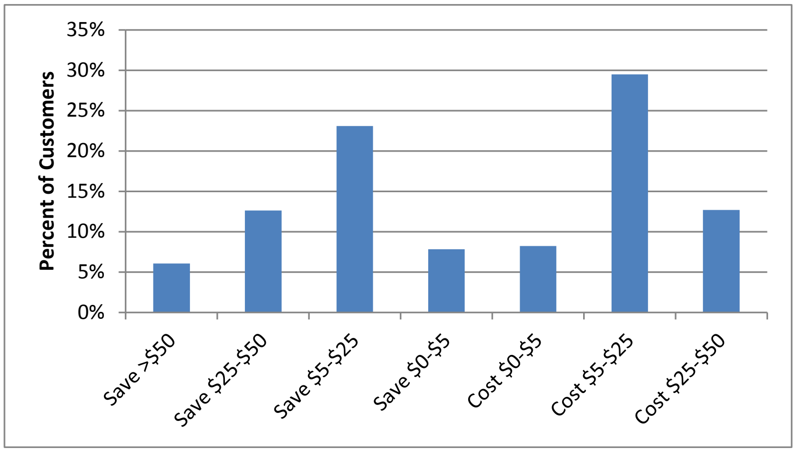
	PCT		RIM	
Program	**$8**	**$12**	**$8**	**$12**
RES-Lighting	10.18	9.95	0.56	0.57
RES-Efficient Products	2.85	2.79	0.62	0.63
RES-HVAC	2.63	2.61	0.94	0.94
RES-Refrigerator Recycling[5]	∞	∞	0.63	0.64
RES-HEP	3.11	3.08	0.68	0.68
RES-New Homes	3.61	3.55	0.57	0.58
RES-Low Income	2.85	2.82	0.43	0.43
RES-TOTAL	**4.68**	**4.60**	**0.68**	**0.69**

[5] Includes correction identified in data request MPSC 0026

Q. Can you explain the impact to customers by changing the customer charge?

A. Yes. Residential customers pay a bill that is based on a monthly customer charge and a volumetric rate. The residential revenue requirement established by the Commission in an electric rate case is designated to be collected by multiplying test year customers counts by the established residential customer charge and then collecting the remainder via volumetric (kWh) charges based on the weather normalized test year sales volumes. The Company's proposal does not remove all fixed costs from its volumetric rates; in fact, a very large proportion (85%) will remain in the volumetric charges. Whenever there is an increase in the customer charge, the high usage customers' bills will be lower, the low usage customers' bills will be higher, and the average usage customers' bills will be the same. As demonstrated earlier in this testimony, the Company's proposed customer charge increase has a negligible impact on the economics of energy efficiency. Figure 3 below shows the annual impact to customers. It is noteworthy that the maximum additional cost to any customer would be $48 over 12 months. This $48 dollar increase would only apply to those customers who have zero usage but pay for electricity service. Figure 3 also shows that most customers who are negatively impacted by the change would experience an annual cost between $5 and $25.

Figure 3: Annual Change in Customer Charge Impacts (from $8 to $12)



Q. If there is a hot summer, will low usage customers be better off with a higher customer charge?

A. Generally speaking, higher monthly customer charges and the resultant lower volumetric charges are less beneficial to lower than average use customers and the converse is also true. However, if a lower than average use customer also uses an air conditioner, then in hot summer conditions the savings from a lower marginal rate could overcome the increase in cost caused by a higher customer charge.

Q. Are rates set based on hot summers?

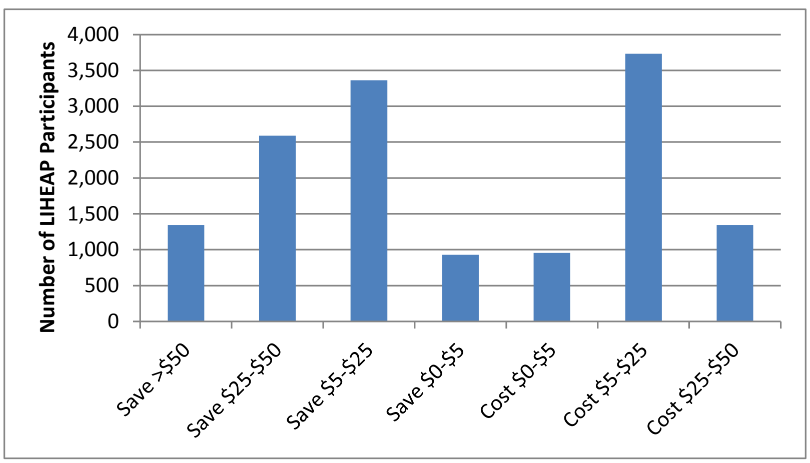
A. No, rates are based on normal weather but that does not preclude the Commission from considering the potential customer benefits under non-normal conditions.

Q. Mr. Kind raises a concern about how low-income customers would be affected by the Company's proposed residential customer charge. Have you performed any analysis to understand those impacts?

A. Yes, I downloaded 12 months (October 2010-September 2011) of actual energy usage data for all of Ameren Missouri's electric customers who have participated in Low Income Home Energy Assistance Program (“LIHEAP”) during that 12 month period

(14,255 total participants). I then calculated all of these customers' bills with the current $8 customer charge and with the proposed $12 customer charge along with the respective volumetric rates. The analysis showed that 58% of the LIHEAP participants would be better off with the $12 customer charge and the LIHEAP participants as an overall group would be slightly better off with the $12 customer charge. The maximum annual cost to a LIHEAP participant was $48 over 12 months while a few LIHEAP participants saved over $200 over 12 months. Figure 3 shows a simple distribution of annual bill savings and costs associated with applying a $12 customer charge to the LIHEAP data set. Conventional wisdom may be that low income customers are also low usage customers but the data suggests that many low income customers would benefit from a higher customer charge.

Figure 3: Annual Bill Impacts to LIHEAP group with $12 Customer Charge



Q. Do you agree with OPC that the Company's request to modify the residential customer charge is entirely out of place?

A. No. It is evident that the customer charge and the net shared benefits are inextricably intertwined. Therefore the Commission must recognize the implications to net shared benefits when approving or disapproving the Company's proposal. Also, as shown above, the impact to customer economics related to energy efficiency is minimal.

Q. Should the Commission wait until the rate case to decide on the Company's request to change the residential customer charge?

A. I would prefer the Commission rule on the issue in this case and merely implement it in the rate case. But it is important to avoid creating a situation in which these types of requests cannot be incorporated into a MEEIA filing. If the Commission prefers to resolve the request in the rate case, then the Commission should issue an order in the MEEIA case that can adapt to the outcome of the rate case.

Q. How can a Commission order issued this summer adapt to a rate case outcome that will be issued in the winter?

A. The Commission order in this case should indicate what levels it is approving if the customer charge remains at $8 or if it is changed to $12 in the rate case. As mentioned in the MEEIA Report, the throughput disincentive sharing percentage associated with keeping the current $8 customer charge would need to increase from 15.4% to 16%. The incremental sharing associated with the earnings opportunity (4.8% at 100% performance) would then be added to the new base sharing of 16%. Since the initial sharing percentage changes based on the customer charge so would the amount of net shared benefits requested to be included in the Company's DSIM to be implemented in the rate case. With approval of the $12 customer charge proposal the revenue requirement is about $32.5 million for three years; whereas, the revenue requirement for an $8 customer charge would increase to $33.8 million for three years. These two data points provide enough information to deduce the appropriate revenue requirement in case there is an outcome other than $8 or $12 in the rate case. Ultimately the Company's DSIM proposal is to be implemented through its pending rate case so the two cases need to be consistent.

VI. CUSTOMER BENEFITS AND IMPACTS

Q. Mr. Mosenthal commented on Table 2.10 of the MEEIA report, can you please explain that table?

A. Yes. Table 10 below (which is a copy of Table 2.10 from the MEEIA Report) shows how the Company's proposal affects customers from a revenue requirements perspective. The first row shows the Company's program cost recovery proposal which would include the collection of program costs over three years. Since Table 10 is a copy of the original it does not include the Company's agreement with Mr. Mosenthal to slightly lower the program cost recovery amount included in rates. The second row (labeled performance mechanism) shows the recovery associated with the Company's net shared benefits proposal. The first three years are recovery for the throughput disincentive while the last three years are the recovery for the performance incentive. The "Retail Non-Fuel Revenues" is the throughput disincentive, which is negative because it represents fixed cost bill savings to customers. The "FAC sharing" is the 5% sharing that accrues to the Company associated with the FAC. The "Net Fuel Savings" includes the increase in off-system energy and capacity sales which are also referred to as "avoided costs". The "Avoided T&D" represents the avoided transmission and distribution costs. Table 10 includes the costs and benefits included in the UCT but also demonstrates that the Company's 15.4% of net shared benefits is designed to offset the throughput disincentive. The "Net Customer Cost" is $331million while the UCT net benefit is $364 million. The difference is associated with the performance incentive (roughly $30 million, i.e. 3 years of $10 million incentive).

Table 10: Total Customer Cost (Revenue Requirements Perspective)

	Lifetime Present Value	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Ongoing (Present Value)
Program Cost Recovery	$136	$48.4	$48.4	$48.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0
Performance Mechanism	$122	$32	$32	$32	$14.5	$13.5	$12.6	$0.0	$0.0	$0.0	$0.0	$0
Retail Non-Fuel Revenues	($94)	($8.2)	($22.4)	($39.0)	($25.7)	($11.7)	($1.5)	$0.0	$0.0	$0.0	$0.0	$0
FAC Sharing	$3	$0.2	$0.6	$1.2	$0.9	$0.5	$0.1	$0.0	$0.0	$0.0	$0.0	$0
Net Fuel Savings	($461)	($3.9)	($13.3)	($26.7)	($43.0)	($52.0)	($60.7)	($66.6)	($70.8)	($71.6)	($78.3)	($130)
Avoided T&D	($37)	($1.0)	($2.4)	($4.6)	($4.7)	($4.8)	($4.9)	($4.9)	($4.6)	($4.3)	($4.2)	($8)
Net Customer Cost	($331)	$68.0	$43.4	$11.8	($57.9)	($54.4)	($54.4)	($71.4)	($75.5)	($75.9)	($82.4)	($138)

Q. Did Mr. Mosenthal agree with the analysis included in Table 2.10 of the MEEIA report?

A. No, Mr. Mosenthal claimed that the table was erroneous and that it is an inaccurate comparison.

Q. Do you agree with Mr. Mosenthal's assessment?

A. Absolutely not. Mr. Mosenthal claims that Table 2.10 mixes apples and oranges. This could not be further from the truth. Table 2.10 is in fact a reconciliation between the Company's DSIM proposal and the UCT. The UCT is the basis for the net shared benefits, therefore it is important to understand how the Company's actual DSIM recovery corresponds to the cost-effectiveness test. The cost-effectiveness analysis in DSMore is based on perfect ratemaking; that is, all of the costs are recovered as they are incurred. Since the DSMore analysis is based on perfect ratemaking it does not incorporate the effects of the throughput disincentive because if ratemaking were truly "perfect," it would not exist. Table 2.10 shows how the Company's proposal would work in reality and proves that customers retain 91% of the net benefits from a revenue requirements perspective. Mr. Mosenthal suggests the table is in error because it excludes customer costs. The table is in fact accurate because it was specifically designed to be consistent with the Commission's definition of net shared benefits and relevant to the discussion of sharing net benefits. Mr. Mosenthal calculates a similar perspective that if customers' out of pocket costs are considered then customers would retain 87% of those net benefits from a TRC perspective rather than the UCT perspective. Mr. Mosenthal's calculation of the TRC perspective is correct. It is befuddling how reconciling the Company's proposal with the standard cost-effectiveness analyses could be characterized as mixing apples and oranges.

Q. Do you agree with Mr. Mosenthal's analysis of customer benefits?

A. No. Mr. Mosenthal seems to be inventing a new test of cost-effectiveness by substituting the benefits included in the TRC with customer bill savings. Table 12 compares the standard cost effectiveness tests to Mr. Mosenthal's analysis. In addition, Mr. Mosenthal fails to recognize the link between the standard cost-effectiveness test results and the real-world modeling of the throughput disincentive. As mentioned earlier, the cost-effectiveness tests are based on perfect ratemaking. Therefore the RIM test assumes that all of the fixed cost bill savings caused by energy efficiency are recovered. If this was reality then the Company would not be facing a financial disincentive. Ameren Missouri's analysis of the throughput disincentive is quantifying the customer bill savings that are not collected through rates as the RIM test assumes. The explanation and quantification of the throughput disincentive is discussed at length in the MEEIA Report starting on page 15 and continuing through page 22. Mr. Mosenthal includes the entire bill savings identified in the RIM test but fails to understand that the throughput disincentive represents bill savings that "fall through the crack" of Missouri ratemaking; that is, those costs that remain unrecovered because of regulatory lag. Mr. Mosenthal's analysis then treats the throughput disincentive recovery as a cost. At that point his analysis becomes internally inconsistent. The throughput disincentive is a subset of bill savings, therefore it is completely inappropriate for Mr. Mosenthal to count the recovery of those bill savings as a cost yet count all bill savings as a benefit. He provided no explanation as to why the subset of bill savings, the throughput disincentive, is counted as both a cost and benefit. Regardless, Mr. Mosenthal ignores the fact that customer bill savings from the throughput disincentive represent costs that are supposed to be recovered through rates and therefore cannot be considered a benefit. Because of regulatory lag, some of these fixed cost bill savings are not incorporated into rates and the throughput disincentive is born. Part of the Company's request is for recovery of the throughput disincentive, which by definition will not impact the UCT or TRC net benefits. This fact has been proven out in the Company's analysis included in Table 2.10.

Further, Mr. Mosenthal then compares his analysis of net benefits to the net benefits of the UCT and TRC. Such a comparison is nonsensical. Table 11 below is a closer look at Mr. Mosenthal's analysis. First consider the last column (Mr. Mosenthal's concept) which ignores the Company's proposal outright. As a starting point Mr. Mosenthal would conclude that customers retain 86% of the UCT net benefits and 122% of the TRC benefits. This does not make sense because when there are zero net shared benefits awarded then one would expect customers to retain 100% of the UCT and TRC net benefits.

Other comparisons are equally nonsensical. Notice that the first column is the same analysis included in Mr. Mosenthal's rebuttal testimony. The second column is

Mr. Mosenthal's premise but recognizes the fact that the throughout disincentive represents bill savings and therefore should not be counted as both a cost and benefit. The last two rows compare the net benefits from Mr. Mosenthal's analysis to the net benefits from the UCT and TRC, which are the standard cost effectiveness tests.

In summary, Mr. Mosenthal's analysis completely ignores the avoided cost benefits which are the true benefits to customers. A comparison between Mr. Mosenthal's calculation of net benefits and the UCT or TRC net benefits has no practical meaning.

Table 11: Closer Look at Mr. Mosenthal's Analysis (Present Value - Million Dollars)

	Net Benefits	Mr. Mosenthal Rebuttal	Mr. Mosenthal fixed TD	Mr. Mosenthal Concept
Bill Savings		$556	$556	$556
Program Cost Recovery		-$136	-$136	-$136
Additional share of benefits given to Ameren		-$122	-$31	$0
Customer Co-Pay		-$106	-$106	-$106
Net Savings		$192	$283	$314
UCT Comparison	$364	53%	78%	86%
TRC Comparison	$258	74%	110%	122%

*TD: Throughput Disincentive

Table 12: Cost Effectiveness Analysis Comparison

Component	**TRC**	**UCT**	**PCT**	**RIM**	**Mr. Mosenthal***
Energy and capacity related avoided costs	Benefit	Benefit		Benefit	
Incremental equipment and installation costs	Cost		Cost		Cost
Program overhead costs	Cost	Cost		Cost	Cost
Customer Rebates		Cost	Benefit	Cost	
Bill Savings			Benefit	Cost	Benefit

*Mr. Mosenthal also includes the throughput disincentive recovery as a cost but not as bill savings contrary to how other bill savings are treated.

Q. Staff witness Mark Oligschlaeger testified that the Company has overstated the costs associated with deferring recovery of the 15.4% net shared benefits. Could you please respond?

A. Mr. Oligschlaeger contends the cost of delay is overstated for two reasons: 1) accruing financing costs at the AFUDC rate instead of the short-term debt rate and 2) using 10.75% ROE in the analysis instead of 10.2% ROE. I have previously explained, and the Staff agrees, that using the AFUDC rate is necessary to make the Company whole for the time value of money. The supplemental testimony analysis was done after the MEEIA report, and in the supplemental testimony I used the Company's requested ROE in its rate case to determine the financing costs associated with amortizing the regulatory asset. If I were to use 10.2% instead of 10.75%, the additional financing costs would be $35 million instead of $36 million. Therefore, it is apparent that the truly significant driver of the cost to delay recovery is whether interest is accrued at the AFUDC rate or the short-term debt rate. To make the Company whole, the AFUDC rate is appropriate and necessary.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Filing to Implement Regulatory Changes Furtherance of Energy Efficiency as allowed by MEEIA.	)))	File No. EO-2012-0142

AFFIDAVIT OF WILLIAM R. DAVIS

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

William R. Davis, being first duly sworn on his oath, states:

1. My name is William R. Davis. I am a Senior Corporate Planning Analyst in the Resource Planning group within the Corporate Planning department for Ameren Services Company ("Ameren Services").

2. Attached hereto and made a part hereof for all purposes is my Surrebuttal Testimony on behalf of Union Electric Company, d/b/a AmerenUE, consisting of 43 pages (and Schedules 0 through 0 if any), all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

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

William R Davis
William R. Davis

Subscribed and sworn to before me this 4th day of May, 2012.

Julie Donohue
Notary Public

My commission expires: 2/17/2013

Julie Donohue - Notary Public
Notary Seal, State of
Missouri - St. Louis City
Commission #09753418
My Commission Expires 2/17/2013