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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EO-2015-0055

SURREBUTTAL TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
April 2015

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OF

STEVEN M. WILLS

FILE NO. EO-2015-0055

Q. Please state your name and business address.

A. Steven M. Wills, Ameren Illinois Company, One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. What is your position with Ameren Illinois?

A. As of April 1, 2015, I am the Director of Rates and Analysis for Ameren Illinois. However, at the time that Ameren Missouri ("Company") prepared and filed its 2016-18 Energy Efficiency Plan (the "MEEIA 2 Plan"), I was the Manager of Quantitative Analytics in the Corporate Planning Department of Ameren Services Company. In that role, I was the primary person in charge of developing the Company's MEEIA 2 Plan. As a transitional activity associated with my previous responsibilities, I am testifying on behalf of Ameren Missouri in this proceeding.

Q. Please describe your educational background and employment experience.

A. I received a Bachelor of Music degree from the University of Missouri-Columbia in 1996. I subsequently earned a Master of Music degree from Rice University in 1998, then a Master of Business Administration ("M.B.A") degree with an emphasis in Economics from St. Louis University in 2002. While pursuing my M.B.A., I interned at Ameren Energy in the Pricing and Analysis Group. Following the completion of my M.B.A. in May of 2002, I was hired by Laclede Gas Company as a Senior Analyst in its

Financial Services Department. In this role, I assisted the Manager of Financial Services in coordinating all financial aspects of rate cases, regulatory filings, rating agency studies and numerous other projects.

In June of 2004, I joined Ameren Services as a Forecasting Specialist. In this role, I developed forecasting models and systems that supported the Ameren operating companies' involvement in the Midwest Independent Transmission System Operator, Inc.'s ("MISO")[1] Day 2 Energy Markets. In November of 2005, I moved into the Corporate Analysis Department of Ameren Services, where I was responsible for performing load research activities, electric and gas sales forecasts, and assisting with weather normalization for rate cases. In January of 2007, I accepted a role I briefly held with Ameren Energy Marketing Company as an Asset and Trading Optimization Specialist before returning to Ameren Services as a Senior Commercial Transactions Analyst in July of 2007. I was subsequently promoted to the position I held until recently, as the Manager of the Quantitative Analytics group.

Q. What were your responsibilities in the position you held while participating in the development of Ameren Missouri's 2016-18 Energy Efficiency Plan?

A. In that position, I managed a group of employees with responsibility for short-term electric load forecasting, long-term electric and gas sales and revenue forecasting, load research, weather normalization, and various other analytical tasks, including the types of analyses embodied in the Demand Side Investment Mechanism ("DSIM") included in the MEEIA 2 Plan.

[1] MISO has since changed its name to the Midcontinent Independent System Operator, Inc.

Q. Have you testified in Missouri Public Service Commission ("Commission") proceedings before?

A. Yes, I have provided testimony in every Ameren Missouri rate case since File No. ER-2008-0318, among others.

Q. What is the purpose of your surrebuttal testimony in this proceeding?

A. The purpose of my testimony is to respond to the rebuttal testimony of Office of the Public Counsel's ("OPC") witness Geoff Marke, Commission Staff's ("Staff") witnesses John Rogers, Sarah Kliethermes, Mark Oligschlager, and David Murray, and National Resources Defense Council's ("NRDC") witness Ashok Gupta. The major topics I will address include the structure, mechanics, and supporting financial calculations of the Company's proposed DSIM, Staff's concerns about whether the Company's proposed energy efficiency plan benefits all customers, NRDC's proposal to utilize an annual revenue adjustment mechanism to address the throughput disincentive in place of the Company's proposed shared net benefits model, and a number of other miscellaneous issues raised throughout the rebuttal testimonies of various witnesses.

Q. How is your testimony organized?

A. I present my testimony by topic, with the following breakdown:

I. 2013-15 DSIM Throughput Disincentive – Net Shared Benefits
II. Programs Benefitting All Customers in the Class
III. 2016-18 DSIM-- Throughput Disincentive
IV. Alternative Proposals to the TD-NSB
V. 2016-18 DSIM – Performance Incentive
VI. Deemed Savings and Contemporaneous Recovery
VII. Miscellaneous Issues

I. 2013-15 DSIM THROUGHPUT DISINCENTIVE – NET SHARED BENEFITS

Q. What issues do Dr. Marke of OPC and Mr. Rogers of Staff raise with respect to the revenues collected under the Throughput Disincentive – Net Shared Benefits[2] ("TD-NSB") component of the Company's 2013-15 DSIM?

A. Both Dr. Marke and Mr. Rogers suggest that the Company may have "over collected" revenues needed to offset the negative financial impacts associated with the throughput disincentive arising from implementation of energy efficiency measures. On page 8 and 9 of his rebuttal testimony, Dr. Marke indicates that the shared net benefits created by the Company in 2013 and 2014 are 149% of the planned net benefits. He seems to imply that this result may be improper in some way and alleges that a cause of this phenomenon is the omission of out-of-pocket participant costs and the utility performance incentives in the Company's calculation of net benefits.

Mr. Rogers, at page 32 of his rebuttal testimony, indicates his belief that 2013 Evaluation, Measurement, and Verification ("EM&V") results suggest that the Company may have received over $4.5 million of pre-tax earnings from its TD-NSB mechanism above and beyond the level required to offset the throughput disincentive.

Q. What is the significance of the discussion of the 2013-15 DSIM results in the testimonies of Dr. Marke and Mr. Rogers with respect to the Company's MEEIA 2 Plan?

A. Because the Company proposes to use a similar mechanism to address the throughput disincentive in its MEEIA 2 Plan (to be in effect 2016-18) as the one that was

[2] For purposes of brevity, I will not explain the underlying concepts associated with the throughput disincentive and offsetting TD-NSB incorporated in the Company's DSIM proposal here, as they were the topic of extensive discussion in the plan filed by the Company in December. Please see that document for a thorough discussion of the matter.

used in the 2013-15 plan, Dr. Marke and Mr. Rogers point to the issues they perceive with the 2013-15 plan results ostensibly to suggest that such issues will plague the 2016-18 plan as well. It should be noted though that Mr. Rogers correctly points out, on page 32 of his rebuttal testimony, the concerns he has do not suggest that revenues already collected by the Company should be refunded or are imprudent in any way. That being said, the suggestion that the Company may have over collected the TD-NSB revenues required to rectify the financial harm caused by the throughput disincentive is based on an incomplete, and in some cases inaccurate, characterization of the 2013-15 results. The 2013-15 TD-NSB mechanism is working exactly as it was designed to work. The results speak for themselves with respect to the alignment of incentives the mechanism has provided and the vigor with which the Company has pursued cost-effective savings in its 2013-15 program implementation.

Q. Please discuss the criticisms leveled by Dr. Marke.

A. First, Dr. Marke's implication that the Company creating 49% more net benefits than planned is in any way a negative outcome is puzzling. This occurred by design. The rationale for adopting a shared net benefits model for energy efficiency programs was to strengthen the incentive for the Company to produce the greatest level of benefits possible, which benefits Ameren Missouri's customers just as it benefits Ameren Missouri, because the increase in net benefits is shared by both. By far the largest reason that the Company has created more net benefits than planned is that the Company has successfully created more energy savings at a lower cost than was planned. This created more benefits for customers than was anticipated at the time of the original MEEIA filing, which should be what all parties want Ameren Missouri to do. But at the same time, greater savings significantly increase the impact of the throughput disincentive on the financial results of the Company because greater savings also result in lower electricity sales than anticipated. Fortunately, by the well-conceived design of the shared net benefits model, the Company's TD-NSB revenues increase with the total net benefits and that increase helps offset the incremental impacts of the throughput disincentive created when the Company achieves greater and greater levels of savings for its customers. The 49% increase in net benefits relative to the plan target resulted from energy savings that exceeded plan targets by 37% for program year ("PY") 2013-14. Dr. Marke's implication that this outcome is inappropriate is clearly misplaced.

Q. Does Dr. Marke's assertion that the 49% increase in net benefits relates to the omission of costs (participant out-of-pocket measure costs and utility incentives) in the calculation of net benefits have any merit?

A. Absolutely not. The Company has followed the terms of the Commission-approved Stipulation and Agreement that resulted in implementation of its 2013-15 programs ("2012 Unanimous Stipulation")[3] precisely in determining the TD-NSB revenues that it is able to collect. Importantly, no party has maintained that there is any imprudence or error in any of the calculations supporting the rates charged under the Energy Efficiency Investment Charge Rider ("Rider EEIC"). To be clear, the Company did not include out-of-pocket participant costs or utility incentives in the net benefits calculation. But it is equally clear from the terms of the 2012 Unanimous Stipulation that such costs were not to be included for this purpose. Despite this fact, Dr. Marke raises

[3] *Unanimous Stipulation and Agreement Resolving Ameren Missouri's MEEIA Filing*, File No. EO-2012-0142, approved by Commission order dated August 1, 2012.

similar concerns with respect to the design of the 2016-18 TD-NSB component of the Company's planned DSIM. I will address those concerns later in my testimony.

Q. You indicated that the 2012 Unanimous Stipulation makes it clear that such costs are not to be included for this purpose. Please explain.

A. I have attached Appendix A from the 2012 Unanimous Stipulation as Schedule SMW-1 to my testimony. That appendix illustrated the calculation of the TD-NSB revenues included in the Company's rates implementing its 2013-15 DSIM. It is clearly marked in that appendix that the planned net benefits used to perform the calculation are $361 million. I will also reproduce below, from page 11 of the 2013-2015 Energy Efficiency Plan which was approved by the Commission with approval of the 2012 Unanimous Stipulation, Table 1.3, which shows the net benefits associated with the Utility Cost Test ("UCT") and the Total Resource Cost Test ("TRC").

Table 1.3 Portfolio Summary – Cost-Effectiveness Analysis ($MM)

	Total		Residential		Business	
	UCT	**TRC**	**UCT**	**TRC**	**UCT**	**TRC**
Avoided Cost Benefits	**$499**	**$499**	**$307**	**$307**	**$192**	**$192**
Program Admin. Cost	$79	$79	$45	$45	$34	$34
Customer Rebates	$55	$55	$31	$31	$24	$24
Net Participant Cost		$106		$60		$46
Total Cost	**$134**	**$241**	**$77**	**$137**	**$58**	**$104**
Net Benefits	**$364**	**$258**	**$230**	**$170**	**$134**	**$88**
Benefit/Cost Ratio	**3.71**	**2.07**	**4.00**	**2.24**	**3.33**	**1.85**

Dr. Marke's contention that participant out-of-pocket costs were intended to be included in the net benefits used in the TD-NSB calculations suggests that the TRC net benefits should have been used in Appendix A. However, the TRC net benefits from the plan of $258 million, are not even close to the $361 million shown in Appendix A from the 2012 Unanimous Stipulation. The $364 million shown above for the UCT net benefits is in extremely close alignment with the $361 million in Appendix A[4]. Clearly the calculations represented in the 2012 Unanimous Stipulation are UCT net benefits, and accordingly exclude participant out-of-pocket costs. The importance of aligning the class of net benefits used to design the DSIM with the net benefits to which the DSIM is ultimately applied is discussed further later in my testimony.

Q. Please respond to the concerns Mr. Rogers raises with respect to the level of 2013-15 TD-NSB revenues.

A. Whereas some of Dr. Marke's assertions were confusing and/or inaccurate, Mr. Rogers' claims are simply out of context and based on an incomplete view of the 2013-15 plan results. A key to understanding this point is a statement made by Mr. Rogers on pages 31-32 of his rebuttal testimony:

> Staff concludes that – ***all else equal*** – for 2013, Ameren Missouri received, through its TD-NSB Share, $4,573,635 more than its actual (as measured and verified through full EM&V) lost margin revenue. (emphasis supplied).

Q. Is "all else equal"?

A. No. And it virtually never is when moving from a modeled, before-the-fact view of the world to an observed, after-the-fact view. There are many assumptions and inputs into the calculations of the TD-NSB. Mr. Rogers has chosen to focus only on the difference between the deemed savings and benefits as compared to the EM&V-based savings and benefits. But, for reasons I will describe later, even that comparison is not sufficient to conclude that the Company "over collected" its throughput disincentive. Even if it were, Mr. Rogers' analysis ignores other critical factors that must be considered

[4] Due to minor changes to the plan that resulted from settlement negotiations, the UCT net benefits were very slightly modified from the original plan for purposes of the 2012 Unanimous Stipulation, but the magnitude of UCT vs. TRC net benefits in the plan clearly demonstrate that Appendix A relates to UCT benefits.

in any reconciliation of TD-NSB collected to throughput disincentive financial impacts incurred.

Q. Please identify other items that may result in differences in the actual magnitude of the throughput disincentive compared to the modeled values used to establish the Company's existing TD-NSB share.

A. A couple of obvious ones immediately come to mind. The most obvious and impactful is rate case timing. As described in detail in the Company's initially-filed report in this docket, the magnitude of the financial impact of the throughput disincentive is very sensitive to the timing of rate cases. Such cases are the permanent remedy to the then-existing throughput disincentive, when the Company's rates are reset based on usage information that includes the energy efficiency savings that give rise to the issue. In the Company's 2013-15 plan, the TD-NSB share was set based on an assumption that the Company would file for rate adjustments every 18 months. The first such case filed by Ameren Missouri during the implementation of the 2013-15 plan (File No. ER-2014-0258, filed July 3, 2014) came 29 months after the Company's previous rate case (File No. ER-2012-0166, filed February 3, 2012). Filing rate cases less frequently than planned will generally exacerbate the throughput disincentive, as energy savings impact the receipt of revenues to cover the Company's fixed costs for the longer time period between cases. Because the throughput disincentive from these programs will not be permanently resolved until the last kilowatt hour of program savings is included in test year revenue in a rate case, we cannot even speculate at this point how much impact rate case timing will ultimately have on the final 2013-15 throughput disincentive incurred. However, the fact that Ameren Missouri assumed a rate case interval of eighteen months between rate cases when the actual interval was twenty-nine months, suggests the possibility that the Company's TD-NSB share may, ***all else equal***, "under-collect" the throughput disincentive associated with the 2013-2015 programs.

Another example of a modeling assumption used to establish the TD-NSB sharing percentage for the 2013-15 plan that differs from reality and impacts the throughput disincentive magnitude is the mix of participating customers that realize the savings. Since residential customers pay the highest rate of any of Ameren Missouri's customer classes, residential energy savings tend to have the largest negative impact on covering the Company's fixed costs. The Company's filed plan was based on an assumption that 63.7% of savings would come from the residential class. But in 2013, 77.9% of actual program savings were derived from the residential class. This factor, taken alone, also suggests, ***all else equal***, the Company's TD-NSB share may "under-collect" the throughput disincentive.

Q. Previously you mentioned that even if all else was equal, the comparison Mr. Rogers makes is not sufficient to conclude that the Company over collected the throughput disincentive. Please explain.

A. Mr. Rogers correctly performs the math to estimate the 2013 impact on the TD-NSB if the calculation were based on EM&V results rather than deemed values. However, to say that this is conclusive evidence of over-collection (even based just on this factor) is a stretch. It is well documented, both in this docket and in File No. ER-2012-0142 in which the 2013 EM&V results were established, that measuring energy that was not consumed but otherwise would have been is at best an inexact science and oftentimes is described as at least part art. Most of the estimation of energy savings is designed using statistical samples intended to achieve 10% precision with 90% confidence.

Many of the components of the net-to-gross adjustments utilized by EM&V, however, cannot be ascribed even this level of statistical precision, or really any particular level of statistical precision at all. Suffice it to say, even with savings "established by" complete retrospective EM&V, the uncertainty around the point estimates of energy savings and net benefits far exceeds the difference between the deemed net benefits that were used to determine the TD-NSB calculation versus the net benefits estimated by EM&V. As such, the TD-NSB revenues earned by the Company are well within the bounds of what constitutes a reasonable estimate of the impact of the Company's properly attributed energy savings on revenues designed to cover the Company's fixed costs. In fact, based on EM&V reports filed by the Company's independent third party evaluators, the savings and net benefits found were much higher than the final numbers referenced by Mr. Rogers and included in the Stipulation and Agreement that resolved the 2013 EM&V issues ("2013 EMV Stipulation") that was approved by the Commission.[5] The 2013 EMV Stipulation clearly indicated:

> This Stipulation is being entered into for the purpose of disposing of the issues that are specifically addressed herein. In presenting this Stipulation, none of the Signatories shall be deemed to have approved, accepted, agreed, consented or acquiesced to any ratemaking principle or procedural principle, including, without limitation, any method of cost or revenue determination or cost allocation or revenue related methodology, and none of the Signatories shall be prejudiced or bound in any manner by the terms of this Stipulation (whether it is approved or not) in this or any other proceeding, other than a proceeding limited to enforce the terms of this Stipulation, except as otherwise expressly specified herein.[6]

[5] *Second Non-Unanimous Stipulation and Agreement Settling the Program Year 2013 Change Requests*, File No. EO-2012-0142, approved by Commission order dated February 25, 2015.
[6] *Id.*, par. 16.

Clearly, the outcome of that proceeding was not intended by the parties to be utilized (nor can it properly be used) for a review of the TD-NSB revenues. The only thing that can be inferred from the 2013 EMV Stipulation is the fact that the savings and net benefits established for purposes of determining the financial performance incentive that will be calculated post-2015 for the entire 2013-15 program cycle were considered reasonable by all of the parties. Nothing in the 2013 EMV Stipulation suggests the parties believed the agreed-upon net shared benefits amount was an exact or precise measurement, and there most certainly is nothing in the 2013 EMV Stipulation that suggests the parties believed the agreed-upon TD-NSB amount resulted in an "over collection" of the throughput disincentive.

Q. Was the 2013-15 TD-NSB share intended to be trued-up, or exactly track the amount of throughput disincentive impacts that if EM&V were "precisely correct" the Company would have actually experienced?

A. No. Keep in mind that the Company quantified the impact of the throughput disincentive in its 2013-15 plan at over $100 million for the three-year cycle of energy efficiency programs. This potential financial loss was identified as one of the most critical issues causing misalignment of incentives between the Company and the interests of its customers in using less energy. The TD-NSB mechanism was adopted to try to achieve that alignment, and it has done so. At no time did anyone portray this as a lost revenue tracker or anything of the sort. In fact, utilization of a share of net benefits implies that in agreeing to this mechanism, stakeholders, as well as Ameren Missouri, found value in linking the recovery of the throughput disincentive to the delivery of benefits to customers. To the extent the Company is able to deliver more benefits than it projected, its TD-NSB revenues increase – exactly as the benefits provided to customers do. But the suggestion that the Company *might have* made about $4 million from a mechanism utilized to rectify a $100 million issue by achieving outstanding results should hardly call into question the efficacy of that mechanism. Moreover, as discussed above, one cannot conclude that the EM&V results are "correct" and thus "prove" that there was an over collection. As also noted, there are other parameters that were assumed that turned out differently that may suggest "under collection."

Q. Please summarize this section of your testimony.

A. While 2013-15 results are not at issue in this case, both Staff and OPC bring them up in an attempt to raise concerns about the TD-NSB mechanism proposed by the Company for its MEEIA 2 Plan. However, the specific concerns raised by OPC and Staff are characterized in a way that is inaccurate and/or incomplete. At this point, it is impossible to estimate how accurately the TD-NSB mechanism is collecting the throughput disincentive, but reviewing all of the relevant assumptions should give the Commission comfort that the mechanism is certainly doing a reasonable job of providing exactly the type of alignment of incentives that the MEEIA legislation and rules call for. Viewed on a stand-alone basis, some factors may suggest that TD-NSB revenues will be slightly too high, while other factors may suggest they will be too low. But there is no credible evidence of any overall systematic bias in the performance of the mechanism. The issues raised with respect to the 2013-15 DSIM should give the Commission no pause whatsoever in approving a similar mechanism for the 2016-18 program period.

II. PROGRAMS BENEFITTING ALL CUSTOMERS IN THE CLASS

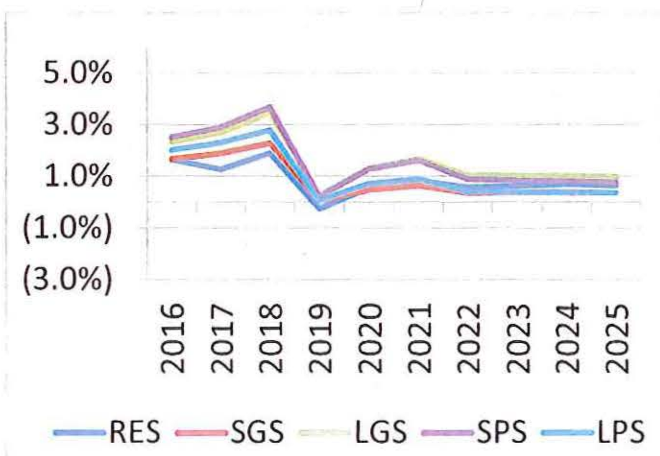
Q. Please describe the next issue you will address.

A. In his rebuttal testimony, Mr. Rogers alleges that the Company's energy efficiency plan fails to provide benefits to all customers in the classes served by the programs. He further alleges that this violates the MEEIA requirement for such benefits, and gives this as a reason that the Commission should reject the Company's plan.

Q. Do you agree with Mr. Rogers' assessment of the plan? Specifically that all customers do not benefit from the plan?

A. No. To make his claim, Mr. Rogers points to Figure 3.8 from the Company's filed energy efficiency plan, which is reproduced below for convenient reference.

Figure 3.8: 2016-18 Portfolio and DSIM Rate Impacts



Because he sees that the rate impacts associated with the plan are positive (meaning rates are higher with the plan than without), he asserts this implies that a non-participating customer will always experience higher bills, and therefore never recognize any benefits. However, it is important to understand what Figure 3.8 is and what it is not. Essentially, Figure 3.8 is an annual view of the Rate Impact Measure ("RIM") Test with utility financial incentives added as a ratepayer cost. This test assesses the stand-alone impact of the energy efficiency plan, with all its attendant costs and benefits and DSIM utility incentive mechanisms on future rates, all else equal. The phrase "all else equal" once again becomes a critical qualifier to a pertinent analysis in this case. Said another way, underlying this figure are the assumptions that current utility rates, cost structures, generation resources, and all other general conditions persist into the future; then costs and benefits specifically attributed to the plan are overlaid on top of those assumptions. The graph is not, however, based on a forecast of future rates with and without energy efficiency that considers all factors that will influence those rates.

For this purpose, it is critical to understand the role of the Integrated Resource Plan ("IRP") in establishing the benefits of energy efficiency. Ameren Missouri witness S. Hande Berk describes this in more detail, but the key is to recognize that energy efficiency competes against supply-side resource options available to the Company. When energy efficiency is selected as a resource in the preferred plan, the need to expend capital on more expensive supply side resources may be deferred or reduced. In a world with no energy efficiency programs, future rates would be impacted by those generation investments that would be needed to meet customer demand. As mentioned previously, those future rate impacts are not included in the analysis in Figure 3.8. Consequently, Figure 3.8 simply does not depict what Mr. Rogers claims.

Q. In his testimony, does Mr. Rogers consider the impacts of generation deferral in the IRP as a potential benefit of energy efficiency?

A. He does, but his conclusion from this review is puzzling.

Q. How so?

A. Mr. Rogers looked at several resource plans that were analyzed in the Company's IRP and compared the projected rates from the preferred plan, which included the Realistic Achievable Potential ("RAP") energy efficiency portfolio ultimately proposed in this proceeding,[7] with rates from a representative resource plan that included no new energy efficiency investments. When he compared the two plans (with and without energy efficiency) on page 28 of his rebuttal testimony, he found that rates were higher at the beginning of the study period under the energy efficiency plan relative to the chosen comparison, but that in the long run, rates would eventually be lower with energy efficiency. He indicates that over the twenty years of the IRP study period, however, the average annual impact of choosing the RAP energy efficiency plan was 0.3% higher rates than the no-energy efficiency plan. This, he suggests, means that there are no long-term overall benefits to non-participating customers that are subjected to the higher average rate level.

Q. Why is that conclusion so puzzling to you?

A. For a number of reasons. First, it's important to review the specific standard that Staff and Mr. Rogers expressly establish for non-participant benefits earlier in Mr. Rogers' testimony.

> Upon the advice of Staff Counsel, Staff interprets 393.1075.4 and 4 CSR 240-20.094(2)(C) to mean that the Commission can only approve DSM programs and a DSIM which are expected to provide some benefits for each customer in each customer class including each customer who does not participate directly in any of the programs. For the customer who never participates directly in any of

[7] The RAP plan in the IRP was subject to certain minor revisions before being filed in this proceeding, but those changes actually lowered the cost relative to what was assumed in the IRP. So the plan as constructed in this docket should be even slightly more cost effective than it is in any IRP analysis.

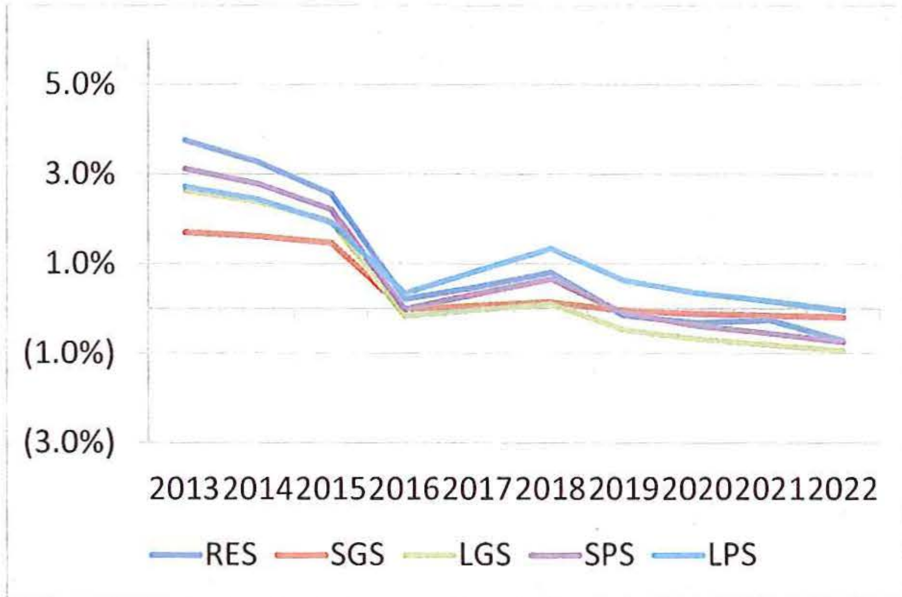
> the DSM programs, benefits will only occur if the impact of the Plan causes rates – **at some point in time** – to be lower than the rates that would have occurred if there were no DSM programs and no DSIM. (Rogers rebuttal, page 19, lines 10-16, emphasis added).

Staff's legal interpretation appears to accept a higher average rate level across the entire study period as long as eventually, ***at some point in time***, the energy efficiency plan reduces rates. In Chart 2 on page 28 of Mr. Rogers' testimony, the impact of the energy efficiency plan relative to a no-energy efficiency plan, results in lower rates in eight of the twenty study years, and significant on-going rate benefits for the years immediately following the twenty-year study. Clearly his own analysis shows that *at some point in time* the plan causes rates to be lower than the rates that would have occurred if there were no DSM programs and no DSIM.

Q. Is there further evidence that Staff has accepted higher average rate levels associated with energy efficiency as long as rates are measurably lower at some point in time?

A. Yes. Mr. Rogers explains how Staff justified finding that the Company's 2013-15 plan benefitted all customers, including non-participants, by showing Figure 2.9 from the 2013-15 plan, which is the counterpart to Figure 3.8 in the 2016-18 plan. That figure is also reproduced here for convenience.

Figure 2.9 Average Annual Rate impact (% Change)



In describing this figure, Mr. Rogers states:

> [T]he *2013-2015 Energy Efficiency Plan* included an expectation that there would be benefits through lower rates for the LGS rate class by 2019 and for all rate classes by 2022. (Rogers rebuttal, page 22, lines 4-6).

However, Mr. Rogers also produced the annual rate impacts in tabular form. By averaging the numbers in the table provided by Mr. Rogers on page 23 of his rebuttal testimony, it is apparent that the average annual rate impact for the residential class is an increase of 0.97% over the entire ten years of the graph. This can be interpreted, over the years, that Mr. Rogers used to justify the non-participant benefits of the 2013-15 plan, residential customers would pay rates that average approximately 1% higher than if the plan had not been implemented.[8] Yet the ongoing lower rates at the end of the study period provided sufficient benefits to meet Staff's legal opinion about the standard for Commission approval of a plan under MEEIA. Applying a similar standard to the

[8] All else equal

2016-18 plan, the many years of lower rates and ongoing lower rates at and beyond the end of the study period presented in Mr. Rogers' Chart 2, on page 28 of his rebuttal, logically address and should satisfy Staff's concerns, and show that the Commission – using Staff's asserted standard can and should approve the Company's plan.

Q. Despite the clear fact that Staff's own analysis should lead to the conclusion that there are non-participant benefits associated with the plan, what would be the implication if the Commission found otherwise and adopted Mr. Rogers' recommendation that the Company "redo" its analysis to ensure the plan is beneficial to all customers?

A. It would likely mean that there would be no meaningful energy efficiency programs in 2016 that could be offered by Ameren Missouri. While Mr. Rogers seems to suggest that a "redo" may make programs more beneficial to the point where they pass Staff's "beneficial" criterion, that is not the case. The purported problem does not lie with the design of the Company's programs or DSIM, but rather with the economics of lower avoided costs due to expected energy and capacity market prices.

To understand why this is the case, consider again Staff's analysis of the 2013-15 plan. Mr. Rogers determined that there were non-participating customers who would benefit several years into the future because at a certain point average rates crossed below the point they would otherwise have been. With that in mind, it is instructive to consider what levers the Company would have to adjust to design the 2016-18 program to achieve that same result for this three-year program period. The answer is none. If the Company made programs more cost effective by delivering savings at a lower cost, it would only lower rates during the three years of program implementation, the point at which the rate impacts shown in Mr. Rogers' chart are the highest. No amount of reduced delivery costs would ever result in lower rates during the time that the customers are paying the full program costs in exchange for future avoided cost benefits. Alternatively, what if the Company expanded its efficiency portfolio to have more savings in the future to generate more benefits? Under this scenario, there would indeed be more benefits to apply downward pressure to future rates. But, there would also be additional upward pressure on future rates as billing units declined further due to the increased energy savings and the fact that fixed costs would be spread over less usage in future rate cases. Because the avoided costs are as low as they are (and out of the Company's control to influence) avoided cost benefits simply do not overcome the lower billing unit impact on revenues to cover fixed costs to make rates lower[9] no matter how the portfolio is designed or re-designed.

Q. If read literally, what other impacts does Staff's interpretation of the MEEIA legislation have?

A. Staff used great specificity in developing its asserted legal standard for Commission approval of energy efficiency programs, to the point where Staff said *each* customer in *each* class with programs must benefit. To extend that overly-strict reading to a clearly illogical outcome, consider a customer today who might move out of the service territory two years from now. Staff would claim *that particular customer must* benefit from Ameren Missouri's programs in order for those programs to meet the "beneficial" standard and go forward. But since that customer, who does in fact pay for a portion of the programs, moves before the prospect of lower rates is achieved, there

[9] It is very important to keep in mind here that total bills for the class as a whole are still lower due to those higher rates being applied to less usage.

would be no benefits that ever could accrue to that customer. While this example may seem extreme, the point is that energy efficiency (along with almost all resource acquisition strategies and ratemaking decisions) will virtually never benefit all customers equally. However, it also follows a central tenet of rate making: costs (and benefits) following cost (and benefit) causation. Participants create the benefit of avoided costs by taking affirmative action to implement energy efficiency measures, so it is very reasonable that most of the benefits accrue to them. In fact, this sends an economic signal to customers to participate in programs. If customers heed this signal and take up energy efficiency, more benefits are created for everyone. While it is important to keep the relative level of benefits accruing to non-participant versus participant in mind and within a reasonable balance, it is hard to fathom that the intent of the legislation was to guarantee that every single customer on the system (in the classes with programs) would get a lower bill whether or not they participate in energy efficiency programs.

Q. If Staff's reading of the law is unreasonable, can you provide some other perspective on how to view non-participant benefits?

A. Yes. First of all, it is essential that any view of customer benefits be grounded in the IRP. In her surrebuttal testimony, Ms. Berk provides an overview of the way customers benefit when the Company has the tool of energy efficiency available to plan its system. The benefits of energy efficiency can include deferral of higher cost supply side resources, mitigation of various risks, and many others. Beyond that, though, energy efficiency programs provide something else to non-participants; an option to become a participant. Ameren Missouri's programs are available and accessible to all customers[10]. There are low-income programs that provide energy efficiency services to the Company's most vulnerable customers free of charge[11]. Any customer can take action as simple as changing out a few light bulbs and by doing so, recognize long-term bill savings. Should the modest rate impacts resulting from energy efficiency programs become too burdensome, those programs themselves provide the previously non-participating customers with the perfect tools to manage their energy costs by becoming participants. When the Company builds supply-side resources, customers do not have a similar means to control the impact those resources may have on their bill.

III. 2016-18 DSIM: THROUGHPUT DISINCENTIVE

Q. What witnesses and issues will you be responding to with respect to the treatment of the TD-NSB in the Company's proposed DSIM?

A. I will respond to Staff witness Sarah Kliethermes regarding the quantification of the throughput disincentive, OPC witness Geoff Marke regarding his proposal to include participant costs in the net benefits used to calculate the TD-NSB, and Staff witness Mark Oligschlaeger regarding his proposal to perform a true-up of the TD-NSB.

Q. Ms. Kliethermes alleges that the Company's quantification of the throughput disincentive[12] is overstated by two to three times relative to the level that Staff estimates is appropriate. Are Staff's estimates and concerns about this well-founded?

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[10] Except for street lighting customers and those eligible customers who by their own choice opt out, but those customers also do not pay the costs of the programs.
[11] Low-income customers also will benefit by not having to pay for programs following implementation of the low-income exemption agreed to by parties in File ER-2014-0258.
[12] Ms. Kliethermes uses the acronym NTD to represent the throughput disincentive portion of the DSIM mechanism, whereas the Company's filing and my testimony refer to this as TD-NSB.

A. Absolutely not. Ms. Kliethermes has a number of factual errors in her testimony regarding the Company's TD-NSB calculations. In addition, Ms. Kliethermes' proposed corrections to the calculation are completely inappropriate and do not accurately reflect the financial impacts to the Company when implementing energy efficiency programs.

Q. What factual errors does Ms. Kliethermes make in discussing the Company's TD-NSB calculations?

A. She alleges that the Company used average rates instead of marginal rates to estimate the revenue impact of energy savings, and also that the impact of program savings on revenues derived from demand charges may be different from the impact of savings derived from energy charges, and that the Company failed to capture this fact in its analysis. It is puzzling that Ms. Kliethermes raises these points, because the Company went to great length in both the filed report in this docket and the technical conferences held with stakeholders (which Ms. Kliethermes attended) to point out the significant effort the Company made to include in its filing all the detail Ms. Kliethermes claims it is missing. I am not sure how she missed that when we explained (and provided proof of) why the allegations she is making are incorrect in great detail, both in the filing and during the technical conferences.

Q. Can you please provide some references that show where the Company provided the information that Ms. Kliethermes missed?

A. In the Company's filed report that initiated this proceeding titled "2016-18 Energy Efficiency Plan" there is a section, beginning at page 32 and continuing on for over three pages, that describes the detailed study the Company performed to determine marginal rates for the TD-NSB calculations. In fact, that section has a bold heading of "Marginal Rate Analysis." That whole discussion is relevant to this issue, but for brevity, I will reproduce just one paragraph:

> For this filing, the Company determined the *marginal rate* for the average customer in each tariff class. The distinction between the average rate and the marginal rate is that the average rate, as described in the paragraph above, is what customers pay on average for all of their usage. Because of the unique rate structures, customers might pay a different amount for marginal usage or for the last kWh consumed. This is relevant in the context of the throughput disincentive because customers that use less energy due to installation of energy efficient measures experience a reduction on their bill according to the price of the last kWh consumed. Therefore, using marginal rates will be a more precise measurement of the bill savings to participants and of the throughput disincentive to the Company. This is a much more complicated analysis than calculating average rates, since the marginal rate might be different for every individual Ameren Missouri customer. Therefore, to come up with average marginal rates for each tariff class, every bill of every customer needed to be analyzed. (emphasis added).

The excerpt above not only specifically advises the reader that the marginal rate was used (contrary to Ms. Kliethermes' claim that the average rate was used) but also goes on to describe in detail the methodology utilized to perform this study, including a brief discussion of the fact that the Company also analyzed the relationship of demand and energy impacts from savings on bills, also in direct contrast to Ms. Kliethermes' portrayal of the Company's analysis.

Beyond that, there was also a technical conference held with all stakeholders devoted to the topic of the DSIM financial analysis. I have attached the slides that were used in that conference as Schedule SMW-2 to this testimony. Slides 6-10 are all devoted specifically to the marginal rate study, including slide 7, which goes through the discussion of rate blocks for residential customers in a manner very similar to what Ms. Kliethermes recommends in her rebuttal testimony, and slide 9, which discusses demand versus energy impacts. Again, Ms. Kliethermes attended this conference, so I am at a loss to understand how she could have made the claims she did in her rebuttal testimony.

Finally, Ms. Kliethermes mentioned that she reviewed the workpapers provided by the Company. Those workpapers included a number of very large files where every single Ameren Missouri customer bill issued over the course of a year was analyzed for determination of the marginal rates. Had she reviewed those files, it would be hard to miss the fact that the Company undertook the specific analysis she claims it did not.

Q. Can you please describe the issues that you have identified with the additional analysis undertaken by Staff, on which it bases its claim that the TD-NSB revenues as quantified by the Company are overstated by two to three times?

A. Ms. Kliethermes goes to great length to describe and calculate, at a high level, the marginal cost reductions that she claims the Company would experience associated with the energy savings from the efficiency programs. She goes on to indicate her belief that TD-NSB revenues need to be reduced to reflect these cost savings.

Q. Before explaining in detail the true marginal cost reductions the Company experiences with respect to energy savings, can you provide a simple, high level explanation of how Ms. Kliethermes gets this concept wrong?

A. Very simply, the cost reductions Ms. Kliethermes identifies are all net energy-related costs. Because the Company flows 95% of all changes in net energy costs that occur between rate cases to customers through its Fuel Adjustment Clause ("FAC"), the overwhelming majority of cost reductions she identifies are realized by customers, not the Company. It is clearly inappropriate to count on cost reductions that the

Company does not get to keep to rectify a revenue shortfall that the Company otherwise would "keep."

Q. What are the actual cost reductions to the Company associated with these energy savings and how are they already incorporated into the TD-NSB analysis?

A. To understand this, it is best to walk through the cash flows that the Company experiences when load reductions occur due to energy efficiency in some detail. The example below shows my point and includes round numbers for ease of illustration. In this example, I will assume 100,000 MWh of savings from a residential energy efficiency program that occurs in the time period when summer rates are in effect. I will further assume that the relevant wholesale price of energy at the same time is $40.00/MWh. It is also important to have a threshold understanding that when the Company's retail electricity sales decline (as occurs due to energy efficiency), that decline generally does not impact the amount of energy generated at its energy centers. Generation output is a function of market prices, unit availability, and economic dispatch. The Company sells all of its generation output to MISO and buys all of its energy requirements to serve its retail load obligations from MISO. The difference between the energy sales and purchases at any given time is referred to as net off-system sales revenue (when the Company is a net seller) or net power purchases (when the Company is a net purchaser). Based on this understanding, it should be clear that, all other things being equal, when the Company's retail load is reduced due to the successful implementation of energy efficiency measures, the Company's net off-system sales increase[13]. Thus, the key to understanding the impacts to the Company of a reduction in retail load is understanding the mechanics of the FAC with respect to the handling of the increase in net off-system sales revenues.

Q. Please provide an overview of the FAC mechanics and its operation in your example.

A. The critical portion of the FAC for this analysis is the formula and terms reproduced from the tariff below:

Table 1 - FAC Tariff Terms:

$$FAR_{RP} = [(ANEC - B) \times 95\% + I \pm P \pm T]/S_{RP}$$

$$ANEC = FC + PP + E - OSSR$$

$$B = BF \times S_{AP}$$

The first equation shown is the Fuel Adjustment Rate, which is essentially the rate that will be charged or credited to customers in order to provide a true-up of net energy costs incurred to those already being covered through base rates customers pay. The part of the rate equation that is impacted by energy efficiency savings is the term (ANEC – B). The term (ANEC – B) is designed to compare the actual net energy costs incurred by the Company to those costs that are already reflected in base rates in order to determine the extent to which those actual net energy costs are greater or less than the base, and can therefore be subjected to the Fuel Adjustment Rate. ANEC stands for Actual Net Energy Costs, and reflects the fuel ("FC" in the ANEC equation above) and net purchased power ("PP") expense of the Company less the net Off-System Sales Revenue ("OSSR"). The term "B" represents the net energy costs that are reflected in base rates. B is determined by multiplying term BF (which stands for "Base Factor," and represents the amount of

[13] In the alternative, net purchased power decreases. For purposes of this example, I will operate under the simplifying assumption that the Company is a net seller and all load reductions increase net off-system sales rather than reducing net power purchases.

net energy costs that are reflected in base rates from the most recent rate case on a \$/MWh basis) by S_{AP} (the actual retail sales from the time period being reconciled).

Q. Please continue with the example.

A. In the assumptions I identified above, there are two FAC-related impacts of the reduction in retail sales that I am assuming from energy efficiency. First, since the generation output of the Company is unaffected by the retail sales reduction attributable to energy efficiency, net off-system sales revenues increase by \$4 million (100,000 MWh x \$40/MWh). Second, the amount of net energy costs already reflected in base rates is reduced, due to the lower retail sales, by approximately \$1.5 million (100,000 MWh x \$14.96/MWh, which is the Base Factor, or BF, applicable to summer period sales in the currently effective FAC tariff). Thus, through the FAC, customers will experience a credit of approximately \$2.4 million due to the energy reductions associated with the efficiency program impacts. The FAC impacts are summarized in Table 2 below:

Table 2 - FAC Impact of Energy Efficiency

	Description	Source/Calculation	Impact	
Line 1	Hypothetical residential energy efficiency load reduction (MWh) and consequent increase in net off-system sales	Illustrative Example	100,000	
Line 2	Hypothetical Off-System Sales Rate ($/MWh)	Illustrative Example	$40.00	
Line 3	Increase to OSSR (decrease to ANEC)	Line 1 * Line 2	**-$4,000,000**	← Net OSS Revenue From Reduced Energy Purchases from MISO
Line 4	Decrease to S_{AP} due to Energy Efficiency Load Reduction	Line 1	-100,000	
Line 5	BF (Summer Base Factor in current FAC tariff)	FAC Tariff	$14.96	
Line 6	Decrease to B	Line 4 * Line 5	**-$1,496,000**	← Reduction in Net Energy Revenue realized from base rates to be trued-up in FAC
Line 7	ANEC - B impact of load reduction	Line 3 - Line 6	**-$2,504,000**	
Line 8	95% Share of ANEC - B	Line 7 * 95%	**-$2,378,800**	← Net FAC Impact of Load Reduction

Q. Given this impact of energy efficiency savings in the FAC, please summarize the overall financial impact on the Company of the reduction in retail sales.

A. Returning to our original example, a 100,000 MWh reduction in residential sales during the summer period would result in $11.4 million in reduced retail revenues to the Company (the summer rate is $0.1136/kWh). The Company would correspondingly experience an increase in net off-system sales revenue of $4 million due to its reduced energy purchases from MISO. As illustrated above, the FAC calculations would result in approximately $2.4 million flowing from the Company to its customers. The sum of those cash flows is the throughput disincentive from the implementation of these energy efficiency measures, and is summarized in Table 3 below:

Table 3 - Cash Flow Impact to Company of Energy Efficiency Load Reduction:

Line 1	Retail Revenue Loss	-$11,360,000
Line 2	Incremental Net Off-System Sales Revenue	$4,000,000
Line 3	FAC Cash Flows	-$2,378,800
Line 4	Total Company Cash Flows (Line 1 + Line 2 + Line 3)	-$9,738,800

Q. How does this compare with the method Ms. Kliethermes proposes to use in quantifying the throughput disincentive?

A. Ms. Kliethermes' method completely misses the impact of the FAC, which would understate the financial losses incurred by the Company by $2.4 million in my example.

Q. Does the Company's calculation adequately capture all of these effects?

A. Yes. This detailed approach that captured the incremental net off-system sales revenue and the FAC calculations, including the 95/5 sharing, was employed in developing the marginal rates used by the Company to quantify the throughput disincentive.

Q. Ms. Kliethermes also suggests that the TD-NSB revenue calculation should be updated when the result of Ameren Missouri's pending rate case, File No. ER-2014-0258, is known. Is the Company agreeable to this update?

A. Yes, to the extent that the result is known in time to incorporate into the calculation before any final tariffs implementing this energy efficiency plan need to be filed. Since the operation of law date in the pending rate case is May 30, this result should be known in time to incorporate it into the calculations.

Q. Do you have any further evidence to show the Commission that, rather than being overstated by two to three times, the Company's estimate of the throughput disincentive is in a reasonable range?

A. Yes. While the specific circumstances of every utility are different and the impact of energy efficiency is affected by a myriad of factors that may differ across utilities, it can still be instructive to look at some information about what other utilities across the country collect from their customers to address the impacts of their energy efficiency programs. To that end, I will compare the Company's TD-NSB revenue estimates, on a $/MWh of savings basis, to the lost revenue recoveries of some other utilities below.

Q. What utilities have you gathered information for and how are energy efficiency impacts on company financial results accounted for in their jurisdictions?

A. I have compiled information for Duke Energy in North Carolina and Entergy Arkansas in Arkansas. I only present two utilities because this type of analysis is at a more granular level than that provided in many industry reports that summarize energy efficiency policies, so I had to research it and assemble available data on a state by state basis, which can be quite a time consuming process. My preliminary research suggests to me, though, that if more information were studied for utilities in vertically-integrated states like Missouri, the results there would be similar.

Duke and Entergy both have lost revenue recovery[14] as a part of their state-approved energy efficiency business models. In North Carolina, Duke is allowed to collect lost revenues for a period of three years from measure implementation or until it has a general rate case. In Arkansas, lost revenues are collected for the entire energy efficiency measure life, or until a rate case. Reviewing the latest filings of both utilities, I have estimated the lost revenues that will be collected by each utility for a recent year (2014 programs for Duke and 2013 programs for Entergy Arkansas). Entergy's filing only shows a single year's lost revenue collections at a time, but Entergy collects those same lost revenues on a recurring annual basis until it has a new rate case. In order to make Entergy's lost revenues comparable to Duke's and Ameren Missouri's numbers, I will assume that Entergy collects those revenues for a three year period before it has a rate case and resets its lost revenue mechanism.

Q. What are the lost revenues collected per MWh of energy savings in these jurisdictions and in Ameren Missouri's plan?

A. Ameren Missouri's plan includes a TD-NSB mechanism designed to collect $44 million associated with 426,382 MWh of savings, or approximately $103/MWh saved. Duke's program year 2014 savings and lost revenue recovery will produce approximately $97/MWh, but excluding its residential behavioral program[15], Duke will realize $108/MWh. Entergy Arkansas, for its 2013 programs, realized $47/MWh for one year of lost revenues. Assuming Entergy continues to collect at the

[14] These states use the term lost revenues, but it is not the same as the definition of lost revenues in Missouri's rules. In fact, their utilization of the term means almost exactly the same thing as the term throughput disincentive as reflected in the Company's filings.
[15] Ameren Missouri does not have a similar program, and the lost revenue impact of this program for Duke is disproportionate to other programs, presumably because Duke assumes that the savings from this program do not persist from year to year.

same rate for two additional years before a rate case, it could collect up to $142/MWh of savings.

Q. What do you conclude from this comparison?

A. Ameren Missouri's proposal to collect TD-NSB revenues estimated at $44 million for the 2016-18 program years is not at all out of line with peer utilities. Because each utility's lost revenues are uniquely calculated based on their specific circumstances, this should not be ascribed more weight than it is due. But, generally this type of benchmarking can give the Commission a sense of comfort that the mechanism it approves will yield results similar to those in other states with vertically-integrated utilities.

Q. What is the issue raised by Dr. Marke relating to the TD-NSB proposal that you will address?

A. Dr. Marke asserts the net benefits that are shared by the utility to offset the throughput disincentive should be based on the TRC calculation, which includes program participants' out-of-pocket costs, rather than the UCT calculation, which only contemplates utility costs.

Q. How do you respond to this concern?

A. While I disagree with Dr. Marke's preference for the TRC for this purpose, the larger issue here is that Dr. Marke misses the point of the TD-NSB mechanism and mischaracterizes the consequence of the decision to use the UCT versus the TRC.

Q. How so?

A. Dr. Marke alleges that by calculating the TD-NSB sharing percentage using the UCT, the Company may "over-collect" the throughput disincentive. This is simply not true. The TD-NSB is specifically designed to collect a particular dollar amount, which is the amount of financial losses expected to be incurred by the utility due to the throughput disincentive associated with the implementation of energy efficiency. In this case, that number is $44 million. To the extent that we choose a different set of net benefits, for example the TRC benefits instead of UCT, the sharing percentage itself will be adjusted to target the same level of dollar recovery that is provided by the 32.57% sharing percentage applied to the UCT net benefits. Put another way, the percentage would be adjusted and would still be designed to collect the same $44 million.

Q. Please provide an example of this.

A. Dr. Marke correctly identifies in his rebuttal testimony the net benefit numbers associated with each cost effectiveness test. The UCT net benefits are expected to be $135 million, whereas the TRC net benefits, due to the inclusion of additional costs borne by participants, are expected to be $91 million. The 32.57% share of net benefits proposed by the Company is simply based on the impact of the throughput disincentive ($44 million) divided by the UCT net benefits ($135 million), $44/$135 = 32.57%. If Dr. Marke's proposal to use the TRC net benefits were adopted, the appropriate thing to do would be to take the same $44 million impact of the throughput disincentive, but divide it by the $91 million of TRC net benefits to come up with a new sharing percentage, $44/$91 = 48.42%.

The key to this mechanism working as designed is that the net benefits used to establish the sharing percentage are calculated using the same cost effectiveness measure as the benefits that are ultimately applied to that percentage to determine the revenues to be collected by the utility. If the Commission approved a sharing percentage of 32.57% based on the expected UCT net benefits, but then applied that percentage to the TRC net benefits the Company achieved (assuming the Company achieves the planned \$91 million), the Company would collect only \$29.6 million, well short of the actual \$44 million impact of the throughput disincentive. Conversely, if the Commission approved a 48.42% sharing percentage based on the TRC net benefits, but then applied that to UCT net benefits of \$135 million, the Company would recover \$65.4 million, which would be significantly more than the impact of the throughput disincentive. When Dr. Marke alleges that using the UCT net benefits for the sharing percentage will cause the Company to over collect the throughput disincentive, that is only true if there is a mismatch between the version of benefits used to establish the sharing percentage relative to the version of achieved benefits to which the sharing percentage is eventually applied. The same version should be used for both.

There are only two things that the Commission should really be concerned about relative to the TD-NSB issue. First, is the \$44 million a reasonable representation of the financial impact of the throughput disincentive? As discussed above in response to Staff's concerns, I submit that it is. Secondly, that the version of net benefits used to calculate the sharing percentage is clearly identified, and that the same version of net benefits is used for purposes of calculating the Company's actual TD-NSB revenues.

I mentioned earlier that Dr. Marke criticized the Company's 2013-15 DSIM, suggesting that the Company had "over collected" the throughput disincentive due to this very issue; specifically application of the sharing percentage to UCT net benefits that excluded participant costs. In my response to that concern, I indicated that the Company had properly followed the 2012 Unanimous Stipulation in determining its TD-NSB revenues. The 2012 Unanimous Stipulation established the sharing percentage for use in the 2013-15 programs based on the UCT net benefits. Given this discussion, it should now be apparent that if the Company had included participant costs (i.e., used the TRC net benefits) to calculate its TD-NSB revenues for 2013-15, it would have dramatically "under collected" the throughput disincentive.

Q. What issue does Staff witness Mark Oligschlaeger raise with respect to the Company's proposed TD-NSB mechanism included in its DSIM?

A. Mr. Oligschlaeger primarily expresses concern over the use of assumptions in the establishment of the TD-NSB sharing mechanism that will not later be trued-up. He identifies, and to some extent challenges, the assumptions used to establish the TD-NSB sharing rate proposed by the Company, and indicates his concern that they may result in the Company "over collecting" the throughput disincentive that is actually incurred.

Q. Does the Company still believe that the assumptions included in its initially filed TD-NSB analysis are appropriate?

A. Yes. Based on the best available information, the Company believes the expectations embodied in the assumptions made in the TD-NSB are completely reasonable. However, Mr. Oligschlaeger does correctly identify, and the Company acknowledged in its initial filing, that regardless of the assumptions made, there is uncertainty about future outcomes that could impact the magnitude of the throughput disincentive.

Q. Given that fact, does the Company accept the Staff's proposal to true-up the TD-NSB calculations?

A. No. Ameren Missouri witness Lynn Barnes discusses the accounting rules that govern the Company's ability to record revenues associated with mechanisms like the TD-NSB. She provides information that demonstrates that, if subjected to a full true-up of the kind Mr. Oligschlaeger advocates, the TD-NSB revenues would not be able to be recorded as revenues on Company financial statements, even if the Company was billing those amounts to customers presently. This would cause the Company's earnings to suffer at the time energy efficiency measures are installed. This earnings impact would serve as a disincentive to the Company for pursuing aggressive energy efficiency, which in turn would mean that the Commission could not satisfy one of the obligations MEEIA imposes on it – to ensure that the utility's incentives are aligned with helping its customers use energy more efficiently.

Q. Are there any other reasons the Commission might consider foregoing a true-up of the TD-NSB mechanism?

A. Yes. While it is a fine objective to have the mechanism attempt to collect the throughput disincentive very precisely, there are at least two reasons that it may not be feasible or even desirable from the Commission's perspective.

First, as discussed earlier regarding the 2013-15 TD-NSB, measurement of energy efficiency savings includes estimation of factors that can have considerable uncertainty, and in the case of attribution (i.e., net-to-gross) are often quite subjective. Attempting to have an after-the-fact true-up of TD-NSB would only serve to raise the stakes associated with EM&V. This may result in more contentious interactions between stakeholder groups trying to get the TD-NSB amounts precisely "correct" even though the "correct" value can never be determined. Getting the result to be within a reasonable range is likely the optimal thing to do.

Secondly, truing up the TD-NSB completely may be impractical because, as Mr. Oligschlaeger correctly points out, the timing of future rate cases can materially impact the true-up process. Imagine a scenario where the Company had a rate case test year that ended in mid-2018 (the final year of programs under this three-year plan), and then managed to stay out of rate cases for a substantial period of time, say three years. The savings generated by measures installed under this plan in late 2018 would never become reflected in rates, resolving the throughput disincentive associated with this cycle of programs, until 2022[16]. The final true up of the 2016-18 programs, then, would not be made until as late as 2023.

IV. ALTERNATIVE PROPOSALS TO THE TD-NSB

Q. What alternative proposals were presented by parties in rebuttal testimony as remedies to the throughput disincentive?

A. Staff witness Sarah Kliethermes proposed that the Company should apply for a lost revenue mechanism as that term is defined by the Commission's MEEIA rules and NRDC witness Ashok Gupta proposed an annual revenue adjustment mechanism.

[16] Three years beyond a 2018 test year would mean a 2021 test year, with rates likely implemented in the following year.

Q. Does the Company see a lost revenue mechanism as a viable solution to the throughput disincentive?

A. Not as "lost revenue" is currently defined in the Commission's rules. The Commission's definition of lost revenue is insufficient to align the incentives of the utility with its customers' interest in using energy more efficiently, as the MEEIA statute requires.

Q. Why is that?

A. The Commission's definition of lost revenue encompasses only a subset of the throughput disincentive. Basically, it represents the amount of the throughput disincentive experienced in some future time period, but only allows recovery when actual sales experienced during that time period are lower than the level of sales used to set the billing units in the last rate case of the utility. This leaves the potential for material impacts to utility earnings from the throughput disincentive in the event sales are otherwise higher than the historical test year used to set rates.

Q. But, if sales are otherwise higher than the historical test year, wouldn't that suggest the utility is "over earning" and can afford to lose those revenues and still earn its authorized return, even while pursuing energy efficiency?

A. No. There are many reasons that the utility might not be "over earning" despite higher sales. Increased expenses and the addition of capital investments not reflected in current rates are but two examples. In addition, there are clearly asymmetric impacts that result from this type of mechanism that favor "under earning" over time associated with energy efficiency under the Commission's lost revenue rule.

Q. Why might the utility not have excess revenues that cause it to "over earn" under a scenario where sales increase from the test year?

A. In a rate case, rates are set employing the "matching principle," where historical revenues and historical costs are aligned. But, after new rates are implemented, both costs and revenues inevitably change. Recent history points to inclining costs in the utility industry generally and at Ameren Missouri specifically. Therefore, achieving or exceeding historical levels of sales is no guarantee a utility will recover all of its costs or earn a reasonable return on its investments. If increasing sales are driven by new customers on the system, there are likely to be incremental costs incurred and investments made to serve them. To that extent, taking the beneficial revenues from regulatory lag associated with load growth to offset losses incurred due to energy efficiency would leave the utility with no chance at recovery for the regulatory lag on those cost increases.

Further, the term "over earning" is itself misleading. The Commission sets the level of a reasonable return in the Company's rate cases, but actual earnings can and do fluctuate both above and below that level, and are expected to do so. While achieved returns exceeding the recently authorized return seem to have a stigma that it is inappropriate, in reality, if earned returns sometimes fall below the authorized return but are never allowed to exceed it, in the long run, utilities will always fall short of earning their authorized returns. However, whether earning at, above, or below the authorized return, the opportunity to experience higher levels of earnings associated with higher sales levels (by not encouraging customers to use less of its product) will always create a conflict between a utility's desire to maximize profits and competing interests, such as energy efficiency. This inherent conflict is what the throughput disincentive is designed to eliminate, or at least mitigate. The bottom line is that the use of "lost revenues" as proposed by Staff will mean that the Company's earnings will be lower *with* energy efficiency than without energy efficiency. That not only does not align incentives as required by MEEIA, it dis-aligns them. Ms. Barnes also addresses this problem in her surrebuttal testimony.

Q. How else might a lost revenue mechanism create the potential for asymmetric impacts of the throughput disincentive on utility earnings over time?

A. The Commission's definition of lost revenues relies on a comparison of actual sales experienced during the time when energy efficiency measures are in place to the level of normalized and annualized sales used in the test year of the last rate case. While I have already discussed reasons any sales growth experienced since the last rate case may be needed to offset rising costs in order to support a reasonable opportunity to achieve the authorized rate of return, the other thing that comes into play is the impact of weather on the actual sales included in the Commission's test for lost revenue recovery.

Imagine a scenario where the Company implemented a set of energy efficiency programs that caused it to incur $10 million in throughput disincentive each year for two years. The total losses incurred would be $20 million. Now imagine that weather-normalized sales were equal to the test year sales from the most recent rate case, implying that load has neither grown nor declined. Finally, assume the first year was impacted by more extreme weather than normal, producing $10 million in additional revenues relative to the normalized test year, and the second year was impacted by milder than normal weather, causing a decline in revenues by $10 million relative to the prior test year.

Table 4 below demonstrates the impact of this set of outcomes on the Company's earnings:

Table 4 - Impact of Abnormal Weather on Lost Revenue Mechanism vs. TD-NSB:
Lost Revenue Mechanism Illustration (Dollars in Millions)

	Year 1	Year 2	Total
Throughput Disincentive	-$10	-$10	-$20
Load Growth Revenue Impact	$0	$0	$0
Weather Revenue Impact	$10	-$10	$0
Lost Revenue Mechanism Recoveries	$0	$10	$10
Total Earnings Impact	$0	-$10	-$10
Approximate Basis Points of ROE	0.0	-16.9	-8.5
TD-NSB Illustration (Dollars in millions)			
Throughput Disincentive	-$10	-$10	-$20
Load Growth Revenue Impact	$0	$0	$0
Weather Revenue Impact	$10	-$10	$0
TD-NSB Impact	$10	$10	$20
Total Earnings Impact	$10	-$10	$0
Approximate Basis Points of ROE	16.9	-16.9	0.0

Q. What do you conclude from the scenario represented in Table 4?

A. In this scenario, the Company is unable to offset the impact of the throughput disincentive in the year that featured extreme weather. However, the following year, when the Company had negative financial impacts from mild weather, there was no recourse for the Company to remedy the situation. In essence, the Company would be required to give up any positive weather impacts it experiences while implementing energy efficiency, but must absorb the negative impacts from unfavorable weather. Over time, this mechanism, which by design is one-sided, is virtually guaranteed to produce an asymmetrical result where the Company experiences losses that it is never able to recoup.

Q. In summary, does a mechanism consistent with the Commission's definition of lost revenue align the utility's incentive with its customers' interests in

using energy more efficiently in a manner that is consistent with the requirements imposed by MEEIA?

A. No. The issues identified above show the fundamental flaws inherent in any mechanism based on the Commission's definition of lost revenue. By its very nature, energy efficiency is an unusual business model in that it requires a for-profit business to encourage its customers to buy less of its product. Rational businesses do not operate that way under normal circumstances. The DSIM proposed by Ameren Missouri creates the circumstances that allow aggressive pursuit of energy efficiency and overcomes this dynamic. It also does so in a manner that is fully consistent with MEEIA. Simply put, the Commission's lost revenue mechanism does not.

Q. What is the Company's response to the NRDC proposal to implement an annual Revenue Adjustment Mechanism ("RAM")?

A. I will refer to the RAM proposal interchangeably as decoupling, which is the commonly used industry vernacular for the type of mechanism that I understand the NRDC proposal to represent. While I am not a lawyer, I am advised by counsel that decoupling is not currently authorized under Missouri law because it requires that rates be adjusted outside of a rate case. My understanding is that rate adjustments outside of a rate case in the state of Missouri must be explicitly authorized by statute. No such statutory authority exists for decoupling at this time.

Q. If it were lawful, would Ameren Missouri support a decoupling proposal?

A. Ameren Missouri does not take a position on this issue at this time. While the Company would be willing to engage in discussions about decoupling proposals if they were authorized, the specifics of any particular proposal would have to be analyzed thoroughly and weighed on its merits.

V. 2016-18 DSIM – PERFORMANCE INCENTIVE

Q. Please discuss the comments made by Dr. Marke regarding the Company's proposed performance incentive.

A. Dr. Marke indicates that the Company has defended the requested level of performance incentive by citing incentives in eight other states. He then goes on to provide various criticisms of this benchmarking information.

Q. Was this benchmarking with other states the primary justification for the level of performance incentive proposed by the Company?

A. No. Similar to the benchmarking I provided earlier in this testimony when comparing the TD-NSB to lost revenues allowed in other states, the benchmarking Dr. Marke refers to is just to provide some context to the Commission regarding what is happening around the country. This benchmarking clearly shows that the Company's request is not out of line with incentives authorized in many other jurisdictions. However, the primary and undisputed analysis on which the Company bases its request is grounded in Integrated Resource Planning and is tied to the incentive structure implicit in the existing regulatory model.

Q. Please summarize what that analysis showed.

A. The analysis is discussed thoroughly in the 2016-18 Energy Efficiency Plan filed by the Company at the outset of this case. The premise is that utilities generate earnings by investing capital in useful infrastructure to serve their customers. In the traditional regulatory model, without energy efficiency, this is indeed the only means by which a utility can earn returns. By substituting demand-side resources, which require no capital to be deployed, for traditional supply-side resources that the utility builds and finances, there is no escaping the fact that utility earnings will be materially lower over time because of the lowered investment in capital resources. The Company quantified the expected reduction in earnings associated with such deferred or avoided supply-side construction. This is really the earnings opportunity cost to the Company for pursuing energy efficiency. The analysis demonstrated that in order to replicate the earnings from supply-side resources, the incentive needed would amount to $23.3 million per year (almost $70 million for the three-year plan). Despite this analysis, the Company requested a far lower amount for its performance incentive. Specifically, the Company proposed an incentive of $25 million for achieving 100% of the three-year savings target, which amounts to an average of $8.3 million per program year.

Q. If the Company's analysis supported the need for $23.3 million per year, why is the proposal for $8.3 million per year?

A. There are numerous factors that have to be balanced in assessing the appropriate performance incentive. The biggest issue from the Company's perspective was the rate impacts on its customers. The 2013-15 DSIM provided for a targeted incentive of $6.25 million per program year. To jump from that level all the way to $23.3 million would have been quite an increase for customers. Additionally, the analysis that produced the $23.3 million is very sensitive to changes in the type and timing of resources the Company would need to construct absent its investment in energy efficiency. Because the Company recognized the foregone earnings value associated with supply-side investment may change over time as circumstances change, the Company chose a more conservative level of incentive than the full $23.3 million.

Q. If that is the basis for the proposed incentive level, why even provide the level available to utilities in other jurisdictions?

A. To be clear, Ameren Missouri does not believe Missouri policy should be dictated by other states when robust Company-specific analysis is available. However, it is also important that the Commission be provided with information to put the Company's analysis in some context. The information from other states was provided in an effort to give that context.

Q. Do the criticisms Dr. Marke makes of the chosen benchmarks suggest that the Company's request is out of line with the other states?

A. I do not believe so. Dr. Marke makes the false claim that when looking at the other states Ameren Missouri's proposal would be "by far the most generous" (Marke rebuttal, page 27, lines 7-8) as compared to the benchmarks identified. But there are at least two states on the list that would have more generous incentives than those proposed by the Company. Minnesota's incentive of up to 9 cents per kWh is clearly higher than the Company's proposal (which at its maximum level would be approximately 7 cents per kWh), as is Oklahoma's primary incentive mechanism of 25% of net economic benefits (as compared to Ameren Missouri's proposal that caps out just over 17% of net benefits). While the remaining states benchmarked by the Company do not have incentives higher than Ameren Missouri's proposal, they are in a similar general range and support the conclusion that the Company's proposal, if adopted by the Commission, would be by no means an outlier.

Q. Dr. Marke identifies which of the states Ameren Missouri chose for comparisons that operate under Energy Efficiency Resource Standards (EERS). What is the relevance of that?

A. I am not really sure. He seems to imply that a utility operating under an EERS should have a larger incentive, but that is counter-intuitive to me. Rather than impose a mandate for utilities to achieve some pre-defined amount of energy efficiency, Missouri, through MEEIA, clearly decided to focus on utilizing alignment of incentives to drive savings results. States with EERS drive results, at least in part, by dictating the level of savings that utilities will pursue and potentially use other means to drive compliance. It makes little sense for a state that relies entirely on incenting the utility to drive the desired energy efficiency outcomes to provide lesser incentives than states that already have some other type of enforcement of the goals that they have established. Given the lack of an EERS in Missouri, the incentive implicit in the supply-side alternative identified in the IRP should have heightened importance in the Commission's consideration of the appropriate performance mechanism to adopt.

Q. Dr. Marke and NRDC witness Phil Mosenthal also suggest that the performance incentive is too high given the concerns they have about the size of the Company's portfolio and their perception that the goals will be too easy to meet. How do you respond to those concerns?

A. It is important again for the Commission to consider the Missouri-specific and Company-specific information that was used in developing the potential study that informed those goals. Ameren Missouri witnesses Rick Voytas and Ingrid Rohmund testify to the robust analysis that supports the potential study estimates. The Company's goals are well grounded in a rigorous analysis of primary market research and represent appropriate goals for the Commission to adopt for purposes of the incentive mechanism being proposed.

VI. DEEMED SAVINGS AND CONTEMPORANEOUS RECOVERY

Q. What issues do the parties raise with respect to the Company's proposal to base its performance incentive on deemed savings?

A. Staff witness John Rogers indicates Staff's belief that this proposal is counter to MEEIA's and the Commission's rules requirement that any earnings opportunity associated with a DSIM be associated with cost effective measurable and verifiable savings. Staff interprets measurable and verifiable to mean that after-the-fact determination of net-to-gross factors is a threshold requirement for the performance incentive.

Q. Do you agree with Staff's interpretation of the rule?

A. No. Staff's assertion that measurable and verifiable means that after-the-fact, net-to-gross evaluation must occur is based on reading something into the rule that simply is not there. First of all, the language "measurable and verifiable" is distinctly different than "measured and verified," which would at least have some implication of something occurring after-the-fact. But, even if one believes that the measurement and verification must take place before the performance incentive is finally determined, deeming is a valid form of measurement and verification. Deemed values used in all facets of EM&V (measure savings, NTG, etc.) are grounded in the best and most updated studies available with the most locally relevant data available, usually primary data about the Company's service territory.

Q. Please explain how deemed values are used in the EM&V process.

A. To understand this in more depth, it is instructive to consider the types of work that are a part of EM&V studies and what is not a part of it. Consider the EM&V for the Company's 2013-15 programs. For purposes of the TD-NSB, all savings are deemed based on the Technical Resource Manual ("TRM") approved by the Commission for this purpose. Actual measures installed are verified, but the savings ascribed to them are based on calculations, algorithms, and engineering equations in the TRM. Those forms of measurement are informed by the most recent and best studies available at the time the TRM was created.

For purposes of determining the performance incentive, full "after-the-fact" EM&V is performed. As a part of that review, certain items are singled out each year for new metering studies, survey work, and other research. But, by no means are all elements of the TRM or net-to-gross calculations subjected to a complete annual review. The items that are not specifically studied in a given year are generally still measured using the values and equations in the TRM. Implicit in this process is the fact that the after-the-fact EM&V that Staff values relies to a large extent on deeming. There has been no argument that the 2013-15 savings do not constitute "measurable and verifiable savings" by any party.

Q. Can you provide some specific examples of items that have been deemed and considered "measurable and verifiable"?

A. Certainly. In 2013, the Company's residential EM&V contractor installed lighting loggers at a sample of customers' homes to evaluate the hours of use for lighting in homes to determine the savings associated with efficient lighting technologies. The study was not completed until well into 2014. For 2013 EM&V, the TRM-based, deemed hours of use were used for lighting savings, even in the after-the-fact EM&V results. For 2014 EM&V, the new hours' use information was available and used in the EM&V. Under the method proposed for the Company's 2016-18 plan, the only difference would be that the deemed value, which every party accepted without any concern in 2013, would also have been used for 2014 and the updated hours' use would have been applied prospectively for future years. The 2014 EM&V, by using deemed hours of use, would have been no less "measurable and verifiable" than was the 2013 EM&V. And the Company's proposal to update the TRM annually for new information would have meant that the hours of use would still be used prospectively on a timely basis.

Similarly, the residential EM&V contractor performed a Market Effects study in 2013. The plan includes another such study in 2015, but due to the cost of such studies, an additional study was not performed in 2014. For the 2014 EM&V, the evaluation contractor used information from the 2013 study to, in essence, deem the Market Effects value for one year of EM&V, and then would use a new study result for 2015.

The point is this: EM&V, by its very nature, routinely relies on past studies, engineering algorithms, and calculations all of which are or produce deemed values. This is deeming.[17] Directly measuring every single kilowatt-hour saved is simply impossible, and even if it were possible, would not be cost effective. Application of the TRM would not prevent EM&V from occurring; it would simply apply results of new studies on a moderate lag relative to the Staff's preferred approach.

[17] Black's Law Dictionary defines "deem" as "[t]o hold; consider; adjudge; believe; condemn; determine; treat as if; construe."

Q. Are there any benefits of applying the research performed for EM&V purposes prospectively rather than retrospectively that support subjecting the use of such information to a slight lag?

A. Yes. First, as Mr. Rogers points out in his testimony, this allows the Company to reduce the EM&V budget from approximately 5% of the total program costs to 3% of program costs. These reduced costs will accrue as savings to customers. Given a budget of $135 million for the 2016-18 period, this could save customers almost $3 million.

Secondly, "after-the-fact" EM&V has the potential to produce extremely contentious stakeholder interactions with the potential for time intensive and costly litigation. This is evidenced by the 2013 EM&V process associated with the Company's first program year under MEEIA. That process produced multiple change requests,[18] multiple rounds of testimony, negotiations, stipulations and agreements, and nearly went to full hearing almost a year after the results at issue had been achieved. Prospectively deeming results is very likely to significantly reduce, and maybe entirely eliminate, the need for such a contentious process. Pursuing such a contentious process is costly, and ultimately those costs impact the Company's ratepayers.

Finally, even by utilizing after-the-fact EM&V, there is no guarantee that the result is any more accurate, and the process for determining the performance incentive associated with the 2013 programs illustrates this point. A case can be made that it creates perverse incentives with all parties to not even seek an accurate result. For purposes of the 2013 TD-NSB, the net benefits were deemed based on a net-to-gross

[18] A change request is essentially the process by which a Stakeholder can dispute the findings of the EM&V report.

value of one, and the calculation was a complete non-event with respect to any associated litigation. For purposes of the performance incentive associated with 2013 programs though, as mentioned just above, there was a long and drawn out process. As a part of that process, Staff calculated all of the combinations of outcomes that could result from the positions of the various parties. Staff's spreadsheet contained 24 possible outcomes, with net-to-gross outcomes ranging from 89.4% to 116.9%. After that spreadsheet was produced, Dr. Marke suggested further *new* adjustments in surrebuttal testimony that would double the number of possible outcomes and increase the range of results those outcomes represented. Based on this evidence, had a hearing been held, the Commission would have had to choose an NTG result with probably over 30% variability in the outcome at stake. And of course the center of that range was one, which was already used without controversy for the TD-NSB calculations. While the Company believes its positions had great merit, it felt compelled to settle the issue rather than go to a hearing on a complex issue for which the *"true"* answer can never be known or proven with certainty. However, the fact that the application of this result to the performance incentive would result in more or fewer dollars going to the Company, the argument lingered on and for some time escalated.

With all that history as context, imagine if the results of that very same EM&V work were used prospectively only. Every party could focus on getting a reasonable set of results to use going forward, at a time when no dollars were at stake. Since the Company's plan would increase its savings targets if the EM&V suggested that measure savings were higher than the TRM indicates, then the future results would also reflect those new assumptions and there would be no financial incentive whatsoever to assure more "conservative" or "aggressive" assumptions were used for the EM&V work.

Q. Given the fact that EM&V findings would only be applied prospectively, how does the Company's plan protect customers' interest in making sure the savings targeted by the Company are not associated with high levels of free-ridership after the prospective net-to-gross values are established?

A. The issue of net-to-gross is really the concern of using energy efficiency budgets efficiently. If a program participant would buy a measure regardless of the availability of any utility incentive (i.e., free ridership), then the incentive dollars have been essentially wasted. It is reasonable to look back at the positions taken in the 2013 EM&V process and conclude that, rather than focusing on directly assessing the customer value delivered by providing incentives to customers, the process focused on complex statistical analyses of which application could be subjective (self-reporting surveys); on abstruse and theoretical academic concepts (the rebound effect); and the very real, but hard to measure, phenomenon of market effects. The Company's 2016-18 plan avoids those constructs in favor for a common-sense, but meaningful assessment of the market for energy efficient products. The market assessments Ameren Missouri proposes ask one simple question; what is the market share of an efficient technology? The implication of this question is the heart of net-to-gross assessment. If a product has significant market share, it is probably well established in customers' minds and does not require large subsidies to ensure adoption. However, if a product that has real energy saving benefits is available but experiencing low market share (which suggests people are not adopting it for whatever reason), utility incentives can make a meaningful contribution to the widespread deployment of that technology.

Q. Please summarize your testimony on this topic.

A. Staff's concern that the legal standard stated in MEEIA and the Commission's rules require after-the-fact, net-to-gross assessment does not hold up based on the plain wording of the statute and rules or on a comparison to the practices that have been accepted in the EM&V industry generally, or specifically in Ameren Missouri's 2013 programs. Deeming is a mainstay of EM&V processes and is clearly a valid form of measurement of savings. The after-the-fact approach advocated by Staff and OPC carries with it few benefits relative to deeming, and those benefits are clearly outweighed by the costs of increased budgets and more litigation that does little to increase (and perhaps decrease) the ultimate accuracy of the result. In contrast, adopting the Company's streamlined and prospectively applied EM&V process will save customers money, reduce the likelihood of litigation, and ensure that all parties to the process are motivated first and foremost to get as accurate of an answer as possible. Such deeming may ultimately become necessary to ensure program savings can be used to comply with CO_2 emissions' regulations that may be promulgated by the Environmental Protection Agency, depending on the specific form of the regulations enacted.

VII. MISCELLANEOUS ISSUES

Q. What is the first additional issue you wish to address?

A. In support of his assertion that there is more energy efficiency potential than the Company estimates, Dr. Marke uses historic Company sales data to suggest that total customer load has grown significantly since 2012, despite the implementation of the

2013-15 energy efficiency programs. However, Dr. Marke's use of this sales data is completely misleading. This is because the variability in load from year to year, as measured by reported total sales, is overwhelmingly driven by variability in the weather experienced. It is well understood in the utility industry that, in order to make any meaningful comparison of sales from one time period to another, it is absolutely essential to first weather normalize those sales statistics. This is clear from the Commission's own review of test year sales data in every electric rate case that I have ever been a part of or reviewed. It is clear from a review of utility financial communications with the investor community, as well as countless internal management reports that provide information to utility decision makers. For my entire career at Ameren, I have been directly involved in load forecasting and weather normalization of sales, and I can say definitively and without hesitation that the numbers presented in Table 11 on page 21 of Dr. Marke's rebuttal testimony are not suitable for assessing the systematic (i.e., weather normalized) changes in load between 2012 and 2014, upon which inferences about energy efficiency potential can be drawn.

Q. Please describe, at a high level, the reason sales need to be weather normalized for purposes of analyses like that presented by Dr. Marke.

A. The level of consumption of some of the largest end uses of electricity, especially for the residential class, are highly sensitive to weather conditions experienced in the Company's service territory. As winter weather gets colder or summer weather gets hotter, space heating and cooling equipment, respectively, must run longer to keep homes and businesses at a comfortable temperature. Consequently, energy use tends to rise with more extreme seasonal temperatures. Changes to sales as a result of this phenomenon, however, reveal nothing about future energy efficiency potential.

Estimation of potential is necessarily based on an assessment of the existing stock of end use appliances and the projected adoption of more efficient technologies that can provide the same level of service while consuming less energy. Some forms of observed load changes, therefore, are indicative of more or less energy efficiency potential. For example, if there are more new homes built in the Company's service territory causing an increase in observed customer counts, this will likely cause both load and energy efficiency potential to grow. New customer additions would also mean that new air conditioners (for example) and all kinds of other energy consuming devices are likely in use by customers. With a larger stock of appliances in use, the pool of equipment that can be upgraded with more efficient technologies is expanded; hence greater energy efficiency potential. To that end, observed load growth *can* be indicative of increasing energy efficiency potential.

The factors discussed above are clearly not the underlying cause of the majority of the changes in sales in Dr. Marke's Table 11, however. The changes in load from 2012 to 2014 are primarily a function of the increasing utilization of existing equipment due to more extreme weather. In the customer growth example, load changes were indicative of a larger pool of appliances that could be replaced with more efficient technologies. When load changes are driven by weather, the pool of end use appliances that can be impacted by energy efficiency programs is unchanged. These load changes tell us nothing about what additional energy savings we may be able to incent next year relative to last year, because the changes were transient and are not expected to persist under whatever weather conditions prevail in the future. It is simply impossible to devise any useful information about changes to energy efficiency potential by looking at two isolated years' sales without weather normalizing.

Q. Were the weather conditions in 2012 and 2014, the years compared by Dr. Marke, similar?

A. Not at all. 2012 was one of the warmest years, both summer and winter, experienced in the history of the Company's service territory. To the contrary, 2014's winter was among the coldest in recent memory, while the summer was much closer to normal. Table 5 below shows the Heating Degree Days ("HDD") and Cooling Degree Days ("CDD") for the two years in question:

Table 5 – 2012 vs. 2014 Degree Days

	HDD	CDD
2012	3,551	2,173
2014	5,009	1,698
Difference	1,459	-475

Q. Can you provide a view of weather-normalized sales for the years Dr. Marke reports on to provide a more instructive comparison?

A. Yes. The Company's IRP filing made in October 2014 included historical weather-normalized sales for the years 2004-2013. I have updated that information with 2014 weather-normalized sales information, and I show the trends for the residential class and total sales[19] in Figures SMW-1 and SMW-2 respectively below:

[19] In the total sales graph, I have excluded the load associated with the Noranda aluminum smelter because it introduces volatility that has nothing to do with changes in energy efficiency potential.

Figure SMW-1 – Residential Weather Normalized Usage 2004- 2014

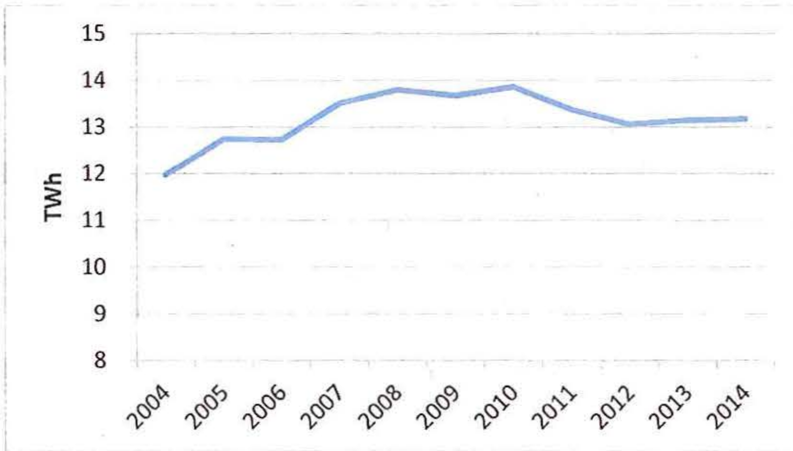
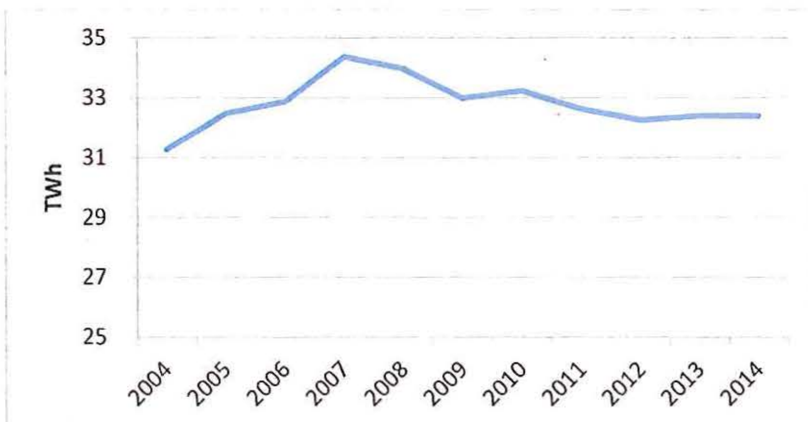


Figure SMW-2 – Total Weather Normalized Usage 2004- 2014



From these charts, it is clear that both total load and residential load have been generally flat to declining since 2009. While part of this effect is clearly associated with the economic downturn experienced in the 2008-2009 timeframe, the Company's energy efficiency programs, which ramped up significantly beginning at about that same time, have undoubtedly been a meaningful contributor. Regardless of the reason for the lack of load growth, though, it is clearly not the case that sales are growing in a way that supports Dr. Marke's conclusion that there is increasing potential based on observed load trends.

Q. What is the next issue you will address?

A. Staff witness Sarah Kliethermes indicated in her rebuttal testimony that the Company had failed to provide a customer notice and sample bill with its filing. The Company has subsequently provided that information to Staff. The language for the customer notice and a sample bill are attached to this testimony as Schedules SMW-3 and SMW-4 respectively.

Q. Staff witness David Murray indicated in his rebuttal testimony that there was an error in the Company's reported credit metrics in its initial filing. How do you respond to that issue?

A. Mr. Murray is correct. In the 2016-18 Energy Efficiency Plan filed to initiate this docket, Table 3.6 (on page 54) contained the Company's assessment of the impact of the plan on key credit metrics. In that table, the data in the lines labeled "Baseline Credit Metrics" and "Credit Metrics w/MEEIA 2016-18 Plan" were inadvertently transposed. The corrected table is attached to my testimony as Schedule SMW-5.

Q. Are there any other issues raised by Mr. Murray that you would like to address?

A. Yes. Mr. Murray discusses the impact of the plan on the Company's business risk. I would first like to highlight a very valid point he makes with respect to this issue. Mr. Murray points out that lowering the utility's ROE in a rate case due to any perceived changes in risk associated with the DSIM would run counter to the intent of the DSIM, which is to encourage utilities to pursue energy efficiency on the same basis as it pursues supply-side alternatives. If the Commission grants a DSIM that gives the utility an opportunity to earn up to 23 basis points per program year[20] as an incentive to pursue programs, but in the next rate case reduces the authorized ROE, it will have removed much of the positive incentive it just gave the Company. Such action would, I believe, be inconsistent with MEEIA's mandate to align the Company's incentives behind the pursuit of energy savings and to otherwise approve plans that allow utilities to value demand-side and supply-side investments equally.

Q. Do you agree also with Mr. Murray's assessment that, despite the point made above, the DSIM does reduce the Company's risk?

A. No. On a stand-alone basis, the DSIM may reduce the Company's risk compared to pursuing energy efficiency without a DSIM. However, such pursuit of energy efficiency without a DSIM would very obviously increase the Company's business risk because it would be subjected to the full impact of the throughput disincentive and foregone earnings opportunities associated with supply-side investments. The DSIM just rectifies those situations in a way that leaves the overall business risk of the Company in a similar place to where it would be without energy efficiency as a part of its business model. The plan first increases risk by taking actions that in and of themselves would be counter to the utility's business interests, then reduces those same risks by addressing the issues that give rise to them. Regardless, it is inappropriate to look at the DSIM on a stand-alone basis. To set Ameren Missouri's rate of return, the Commission compares the Company's business and financial risks, in total, to those of comparable utilities. To the extent those comparable utilities are protected from the negative impacts of energy efficiency programs by a DSIM or some similar

[20] This number is presented by the Company in its original filing and is validated by Mr. Murray's calculation in his rebuttal testimony.

mechanism, that circumstance is already reflected in the Company's authorized rate of return. Without a complete analysis of how Ameren Missouri's risk compares to the utilities who were studied to set the current rate of return, neither Mr. Murray nor the Commission can make an informed decision about whether the DSIM increases or decreases the Company's risk, and if so by how much.

Q. Do you have any last observations to share about Mr. Murray's analysis?

A. Yes. Mr. Murray correctly points out a couple of interesting facts about the DSIM that are important points for the Commission to understand. He mentions that the earnings associated with the performance mechanism are earned with no capital being deployed. He also points out that, depending on the incentive achieved, due to the timing of the recognition of the earnings, it could produce 27 to 69 basis points of earnings in a given year. The Commission should recognize the ability to achieve superior returns on existing capital investment by excelling at the delivery of energy efficiency is a design feature of the DSIM that, consistent with MEEIA, levels the playing field between supply-side and demand-side resources. If the utility had invested in supply-side resources, capital would have been deployed, rate base would have been increased, and the absolute level of earnings would have been higher, even if the earned returns did not exceed the targeted return. In fact, the opportunity to earn higher rates of return, albeit on a smaller base of capital, is a consideration that made the Company more comfortable with its proposal to set the performance incentive lower than the absolute level of earnings associated with the foregone supply-side investment.

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 2nd Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by MEEIA.	))))	File No. EO-2015-0055

AFFIDAVIT OF STEVEN M. WILLS

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

Steven M. Wills, being first duly sworn on his oath, states:

1. My name is Steven M. Wills. I work in the City of St. Louis, Missouri, and I am employed by Ameren Services Company as Manager of Quantitative Analytics in the Corporate Planning Department.

2. Attached hereto and made a part hereof for all purposes is my Surrebuttal Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 62 pages and Schedule(s) SMW-1 thru SMW-5, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

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

Steven M Wills
Steven M. Wills

Subscribed and sworn to before me this 24th day of April, 2015.

Julie Irby
Notary Public

My commission expires:

Julie Irby - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #13753418
My Commission Expires 1/15/2017

Calculation of Ninety Percent of Ameren Missouri TD-NSB Share

From DSMore

NPV Program Costs	$136,204,652
NPV Benefits	$496,985,976
NPV Net Benefits	$360,781,324

NPV Throughput Disincentive ($8 RES Cust. Charge, $MM) $95.05

Sharing Percentage 26.34%

Net Benefit (PV)	$360.78			
Initial Sharing Percent	26.34%			
Initial Sharing Amount (PV)	$95.05			
Class	RES	BUS	Low Inc.	Total
MWh (3-Year Cum.)	491,803	287,633	13,666	793,102
Percent Allocation	62.0%	36.3%	1.7%	100.0%
Before-Tax Rev. Req. (PV)	$58.94	$34.47	$1.64	$95.05
Revenue Requirement (3-Year Annuity)	$20.98	$12.27	$0.58	$33.83
Percent in Rates	90.0%	90.0%	90.0%	
Final Revenue Requirement (ER-2012-0166)	$18.88	$11.04	$0.52	$30.45

Throughput Disincentive Check

	Total	100% TD
2013	$8.39	$33.83
2014	$22.69	$33.83
2015	$39.38	$33.83
2016	$25.77	0
Total	$109.34	$101.50
NPV	$95.045	$95.045
check	-	-

Discount Rate 6.95%

Sample Calculation of Year 1 Ameren Missouri TD-NSB Share

From DSMore

NPV Program Costs	$36,116,713	
NPV Benefits	$149,095,793	0.3
NPV Net Benefits	$112,979,080	

NPV Throughput Disincentive ($8 RES Cust. Charge, $MM)

Sharing Percentage

Net Benefit (PV)	$112.98			
Initial Sharing Percent	26.34%			
Initial Sharing Amount (PV)	$29.76			
Class	RES	BUS	Low Inc.	Total
MWh (3-Year Cum.)	159,478	75,122	5,797	240,397
Percent Allocation	66.3%	31.2%	2.4%	100.0%
Before-Tax Rev. Req (PV)	$19.74	$9.30	$0.72	$29.76

Discount Rate 6.95%

Appendix A

Sample Calculation of Year 2 Ameren Missouri TD-NSB Share

From DSMore		
NPV Program Costs	$80,175,300	
NPV Benefits	$323,040,885	0.65
NPV Net Benefits	$242,865,584	

NPV Throughput Disincentive ($8 RES Cust. Charge, $MM)

Sharing Percentage

Net Benefit (PV)	$242.87				
Initial Sharing Percent	26.34%				
Initial Sharing Amount (PV)	$63.98				
Class	RES	BUS	Low Inc.	Total	
MWh (3-Year Cum.)	323,186	162,330	10,326	495,842	
Percent Allocation	65.2%	32.7%	2.1%	100.0%	
Before-Tax Rev. Req (PV)	$41.70	$20.95	$1.33	$63.98	$34.22 Year 2 amount (PV)
					$36.60 Year 2 nominal amount

Discount Rate 6.95%

Sample Calculation of Year 3 Ameren Missouri TD-NSB Share

From DSMore	
NPV Program Costs	$136,204,317
NPV Benefits	$496,985,976.26
NPV Net Benefits	$360,781,659.08

NPV Throughput Disincentive ($8 RES Cust. Charge, $MM)

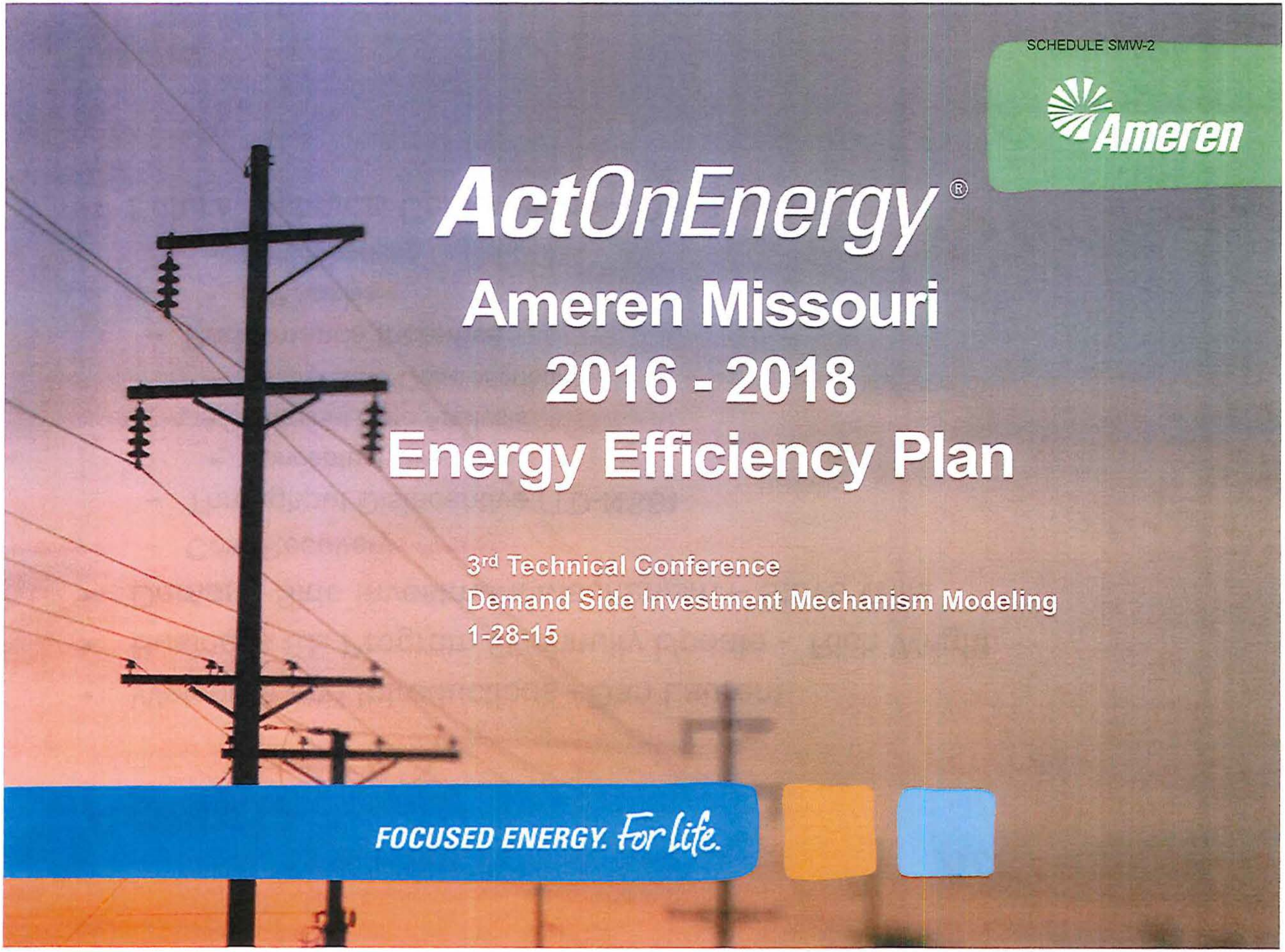
Sharing Percentage

Net Benefit (PV)	$360.78				
Initial Sharing Percent	26.34%				
Initial Sharing Amount (PV)	$95.05				
Class	RES	BUS	Low Inc.	Total	
MWh (3-Year Cum.)	491,803	287,633	13,666	793,102	
Percent Allocation	62.0%	36.3%	1.7%	100.0%	
Before-Tax Rev. Req (PV)	$58.94	$34.47	$1.64	$95.05	$31.06 Year 3 amount (PV)
					$35.53 Year 3 nominal amount

Discount Rate 6.95%

CHECK

	2013	2014	2015	NPV
EXAMPLE	$29.76	$36.60	$35.53	$95.05
In Rates	$33.83	$33.83	$33.83	$95.05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2016 - 2018
Energy Efficiency Plan
3rd Technical Conference
Demand Side Investment Mechanism Modeling
1-28-15
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Agenda

- Welcome and Introductions –Dan Laurent
- Business EE Program Continuity Update - Rich Wright
- Demand Side Investment Mechanism – Steve Wills
  - Cost Recovery
  - Throughput Disincentive (TD-NSB)
    - Conceptual Overview
    - Marginal Rate Analysis
    - Future Rate Case Modeling
  - Performance Incentive
    - IRP Analysis
    - Benchmarking
- Future Technical Conferences – Dan Laurent

Cost Recovery

- Program costs recovered dollar for dollar through Rider EEIC 1618
  - Forecast costs for coming year
  - Include forecasted cost in determination of rate for Rider EEIC 1618
  - True-up actual program costs incurred to program costs billed under the rider and incorporate over- or under-recoveries in subsequent Rider filing including short-term interest expense

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Throughput Disincentive - Conceptual Overview

- The throughput disincentive arises from the fact that a majority of the fixed costs of the Company's system are collected through variable charges
- Decreases in usage impact revenues without reducing the fixed costs incurred
- The recovery of the cost of equity capital is based on the remaining revenues that are available after all of the other costs and taxes are paid – so losing revenue on the margin causes earnings erosion
- The immediate impact of energy savings on utility earnings acts as a disincentive to promoting energy efficiency
  - MEEIA legislation recognizes this misalignment of incentives

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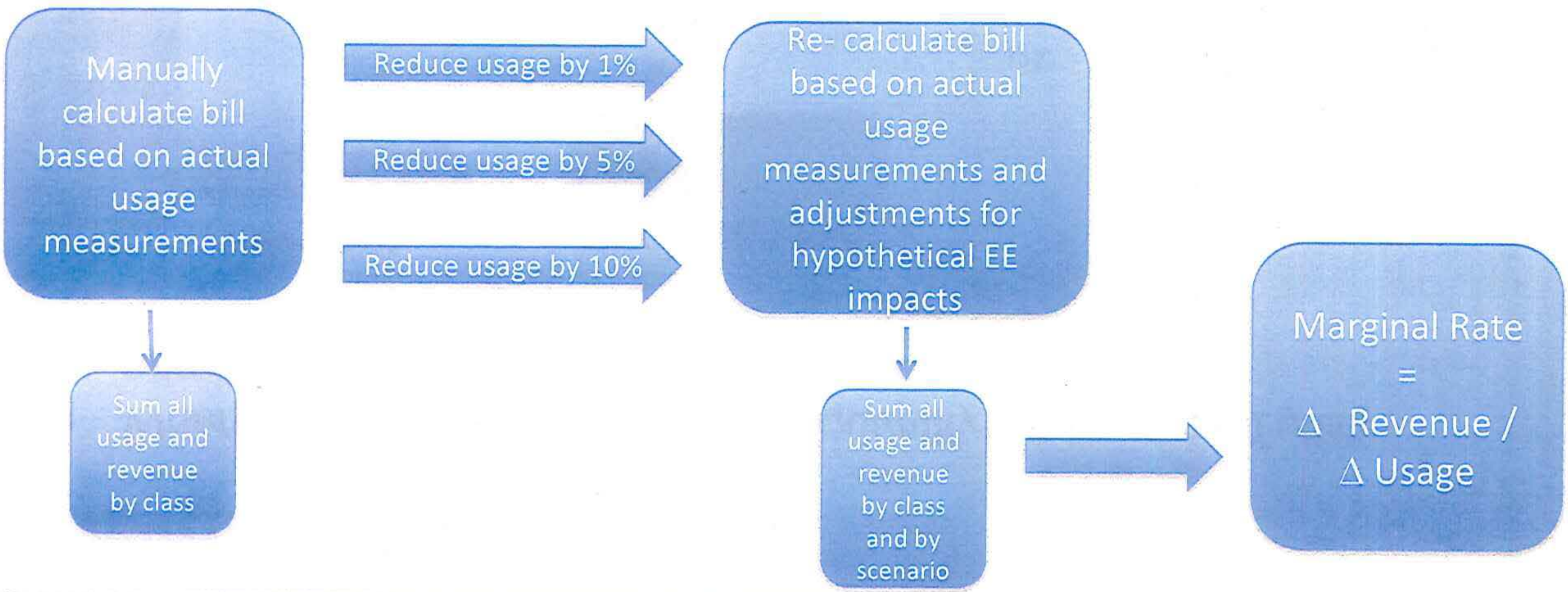
Throughput Disincentive – Marginal Rate Analysis

- When a kWh is saved, how do we quantify the impact on utility earnings?

Throughput Disincentive – Marginal Rate Analysis

- All applicable rates [1(M), 2(M), 3(M), 4(M), 11(M)] have some complex structures – meaning not every kWh is priced equally
  - Marginal rate impact study
- Downloaded all bills for the 12 month period ended March 2014



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Sample Bill Calculation – Residential Non-Summer Bill

	Usage (kWh)	Block 1 Usage	Block 1 Rate	Block 1 Revenue	Block 2 Usage	Block 2 Rate	Block 2 Revenue	Total Revenue	Δ Revenue	Δ Sales	Average Rate	Marginal Rate
Original Bill	800	750	$0.0808	$60.60	50	$0.0538	$2.69	$63.29			$0.0791	
1% EE Impact	792	750	$0.0808	$60.60	42	$0.0538	$2.26	$62.86	-$0.43	-8	$0.0794	$0.0538
5% EE Impact	760	750	$0.0808	$60.60	10	$0.0538	$0.54	$61.14	-$2.15	-40	$0.0804	$0.0538
10% EE Impact	720	720	$0.0808	$58.18	0	$0.0538	$0.00	$58.18	-$5.11	-80	$0.0808	$0.0639

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Residential Billing Analysis for 12 Months Ended March 2014

	Actual Bills		1% Energy Reduction Case				
	Class Usage (MWh)	Class Revenue ($MM)	Average Rate	Change in Usage (MWh)	Change in Revenue ($MM)	Marginal Rate	Marginal Rate vs Average Rate
Summer	4,662,650	$530	$0.114	-46,589	-$5.3	$0.114	100%
Non-Summer	9,325,760	$634	$0.068	-93,250	-$5.5	$0.059	86%
Annual	13,988,410	$1,164	$0.083	-139,839	-$10.8	$0.077	93%

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Demand Charges

- Some revenues are collected based on billing demand
- Billing demand is impacted by EE also
- Demand impact may be different from energy usage impact for various EE measures, depending on the end use characteristics
- Change in billing demand was calculated using 2013 deemed energy vs. demand savings results in conjunction with class load research

	Class Energy (kWh)	Coincident Peak Demand (kW)	Load Factor	Demand Impact vs. Energy Impact
LPS 11(M) Load Research for 2013	4,148,055,142	599,715	78.96%	
Deemed 2013 Savings	6,156,424	1,163	60.42%	
Class load after EE	4,141,898,718	598,552	78.99%	
% EE Reduction	0.15%	0.19%		130.68%

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Marginal Rate Study: Results

- Demand vs. Energy impact differences can produce marginal rate higher than the average rate
- Unique feature of SGS rate design (dynamic rate block) pushes marginal rate above average rate

Marginal Rate as a % of Average Rate

Class	Summer	Winter	Annual
RES	100.0%	86.3%	92.5%
SGS	100.0%	103.3%	101.8%
LGS	95.3%	96.4%	95.9%
SPS	103.9%	102.8%	103.3%
LPS	105.7%	100.7%	103.0%

Variable Costs

- The marginal rate study assesses the impact of EE on total revenues – a portion of which collect variable costs
- The variable costs being collected in rates are identified in the Fuel Adjustment Clause Tariff term BF (Base Factor)
- BF indicates the level of net energy costs that are embedded in permanent rates on a per kWh basis (including kWh of line losses)
- Earnings impact of EE is the revenue erosion based on marginal rate, less the loss adjusted rate BF
- Throughput Disincentive Model also picks up incremental Off-System Sales revenues made possible by EE and credits the 5% share of the incremental revenues retained by the Company through the FAC against the margin erosion

Throughput Disincentive: Future Rate Case Modeling

- Rate cases assumed to occur every 30 months
- Margin rate increase assumed to be 5.5% (as filed) in ER-2014-0258 and 4% in future rate cases (assumes approximately 1.5% per year cost increases and 30 months of increase)
- Test year and update period relationship to date of new rates consistent with recent cases
- EE savings annualized in test year update period in all rate cases with MEEIA 2016-18 impacts
  - This was done for pre-MEEIA EE savings in case ER-2012-0166

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Test Year Annualization Illustration from 2012 Rate Case

Illustrative Actual and Annualized Test Year kWh for CFL Installed in July 2011						
Test-Year Month	Annualized kWh Savings	Monthly Usage Pattern	Monthly Savings (kWh)	Measure Installed in Test Year?	Actual Savings (kWh)	Annualization Adjustment (kWh)
10/01/2010		8.4%	2.77	No	0	
11/01/2010		9.3%	3.06	No	0	
12/01/2010		10.0%	3.28	No	0	
01/01/2011		10.4%	3.43	No	0	
02/01/2011		9.3%	3.07	No	0	
03/01/2011		9.0%	2.95	No	0	
04/01/2011		8.2%	2.68	No	0	
05/01/2011		7.6%	2.5	No	0	
06/01/2011		6.7%	2.2	No	0	
07/01/2011		6.6%	2.16	Half-Month	1.08	
08/01/2011		7.1%	2.32	Yes	2.32	
09/01/2011		7.4%	2.43	Yes	2.43	
Total	32.85	100.0%	32.85		5.83	-27.02

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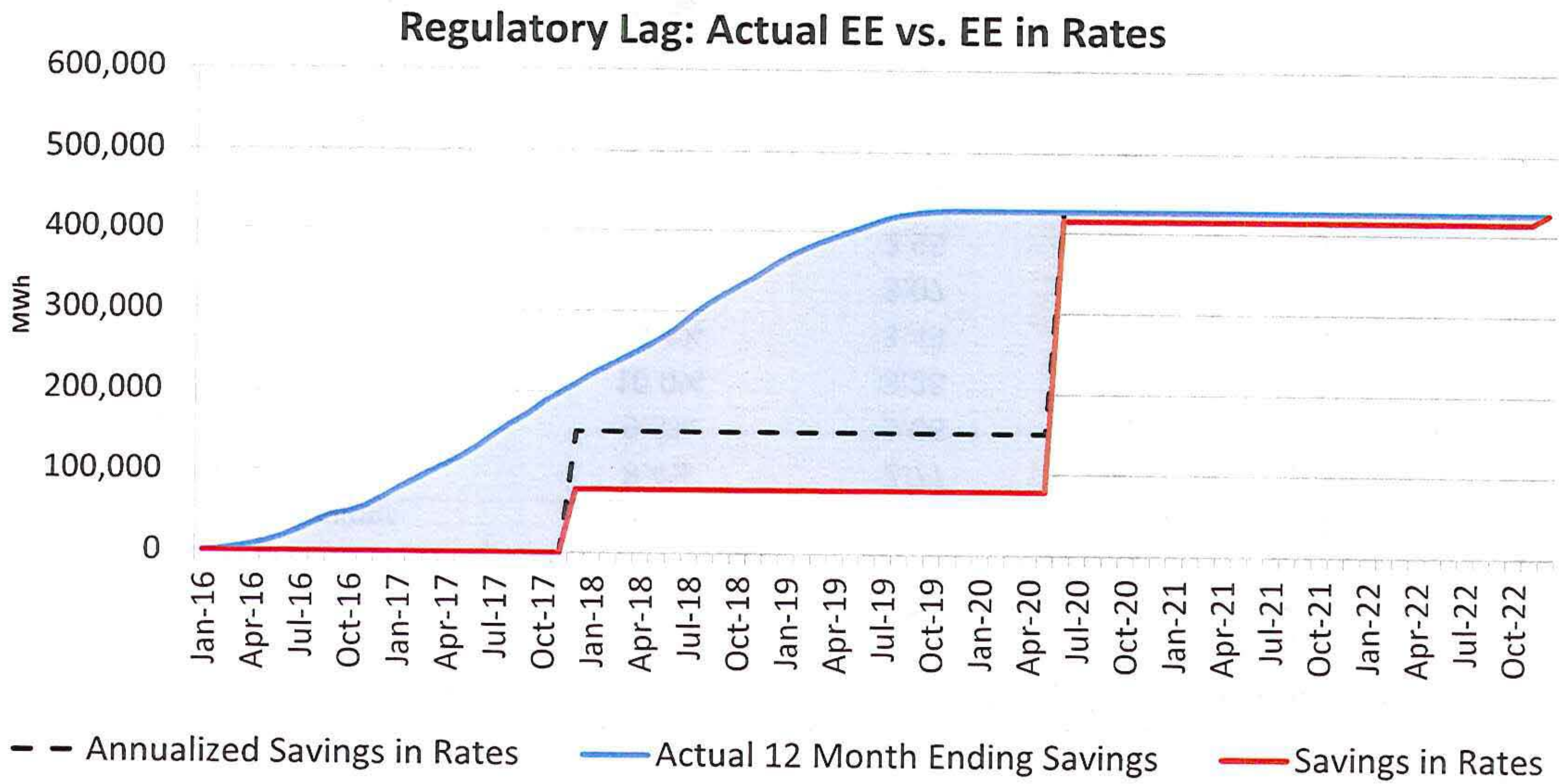
Throughput Disincentive Illustration



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TD-NSB Share

- Based on the aforementioned assumptions, the 2016 NPV of the throughput disincentive impact on pre-tax earnings is $44 million
- The total 2016 NPV of net benefits of the plan are $135.1 million
- TD-NSB Share = $44 / $135.1 = 32.57%
- The source of the $44 million in throughput disincentive is customer savings on the fixed cost portion of bills
  - The reduction in customer bills benefits customers
  - These benefits are not reflected in the avoided costs used to assess cost effectiveness (TRC, UCT)
    - To truly assess the customer impact of the TD-NSB, the fixed cost bill savings need to be considered along with the TD-NSB payments they will make
  - Participants recognize the fixed cost bill savings; all customers (excluding opt-out) pay TD-NSB
    - All customers have the opportunity to be participants

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Financial Performance Incentive: IRP Analysis

- Grounded in MEEIA law/rule requirement to encourage utility decision makers value supply side and demand side resources equally
  - 2014 IRP
    - Without energy efficiency, additional supply side resources would be needed earlier in the planning period
      - Combined Cycle plants in 2023, 2031, and 2034 (in addition to renewable additions)
    - With energy efficiency, supply side resources as identified in the preferred plan
      - Combined Cycle plant in 2034 (in addition to renewable additions)
  - Earnings on the capital investment associated with the 2023 and 2031 combined cycles are opportunity cost to the utility making EE investments

SCHEDULE SMW-2

Financial Performance Incentive: IRP Analysis

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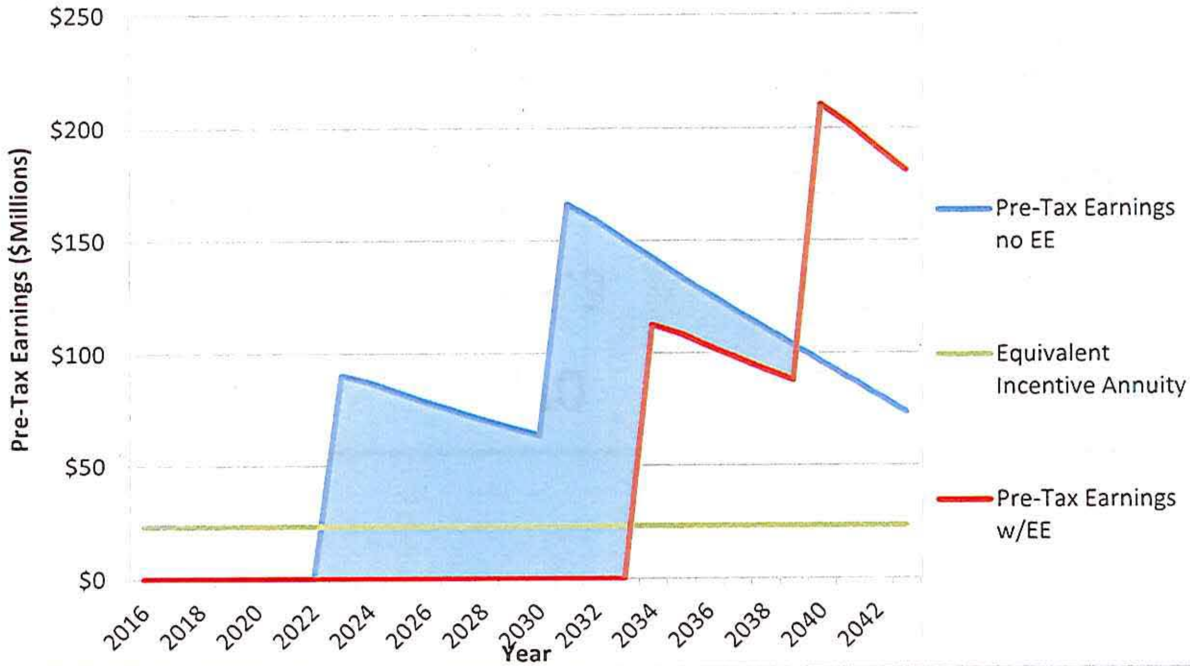
- Differential in future utility earnings with and without EE depicted below
- NPV of the green line equals the difference in NPVs of the blue and red line
- Annuity of $23 million



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Financial Performance Incentive: Benchmarks

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% of Goal Achieved	70	100	130
Incentive per Program Year	$5.3	$8.3	$13.3
3-Year Total Incentive	$16.0	$25.0	$40.0
2016 NPV of Incentive	$12.1	$18.9	$30.2
% of Net Benefits	12.8%	14.0%	17.2%
% of Program Costs	9.6%	15.0%	23.9%
$/kWh Achieved Incentive	$0.054	$0.059	$0.072
ROE Basis Points	9	14	23

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Technical Conferences

- *1st Technical Conference – 1/16/15 Filing Overview*
- *2nd Technical Conference – 1/22/15 - EE Potential Study and IRP DSM Portfolio Selection*
- **3rd Technical Conference**
  - Wednesday, January 28 at 1:00 pm
  - Topics: Business Program Continuity & Demand Side Investment Mechanism
- **4th Technical Conference**
  - Wednesday, February 4 at 3:00 pm
  - Topics: Multi-Family and Future New Programs
- **5th Technical Conference**
  - Wednesday, February 18 at 10:30 am
  - Topics?
- **6th Technical Conference**
  - Wednesday February 25 at 2:00 pm

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List of Acronyms Used

- MEEIA – Missouri Energy Efficiency Investment Act
- DSIM – Demand Side Investment Mechanism
- NTG – Net to Gross
- TRM – Technical Resource Manual
- NPV – Net Present Value
- EM&V – Evaluation, Measurement, & Verification
- EEIC – Energy Efficiency Investment Charge
- RAP – Realistic Achievable Potential
- TRC – Total Resource Cost
- UCT – Utility Cost Test
- IRP – Integrated Resource Plan
- TDNSB – Throughput Disincentive Net Shared Benefits
- PINSB – Performance Incentive Net Shared Benefits
- MW - Megawatt
- MWH – Megawatt-Hour
- C&I – Commercial and Industrial
- EE – Energy Efficiency
- DSM – Demand Side Management

RES - Residential
SGS – Small General Service
LGS – Large General Service
SPS – Small Primary Service
LPS – Large Primary Service

ENERGY EFFICIENCY INVESTMENT CHARGE NOTICE

Ameren Missouri has filed tariff sheets with the Missouri Public Service Commission (MPSC) pursuant to the Missouri Energy Efficiency Investment Act (MEEIA) to make changes to the "Energy Efficiency Investment Charge." Ameren Missouri proposes to implement a suite of residential and business energy efficiency programs designed to help customers reduce their energy consumption in order to manage their electric bills. An explanation of each program can be found at www.actonenergy.com.

In its filing with the MPSC, Ameren Missouri explained that it expects the energy efficiency programs to generate more utility cost savings ($261 million) than the implementation costs collected from customers ($126 million). Because these programs are designed to lower energy sales, Ameren Missouri proposes that it receive a share (32.57%) of the net benefits generated by the programs in order to recover operating costs not covered due to lower sales. Additionally, the Company requests an opportunity to recover a performance incentive (up to 17.19% of net benefits).

If approved by the MPSC, the cost of offering those programs and the utility's portion of net benefits will be recovered through the "Energy Efficiency Investment Charge." The charge will be collected based on the amount of energy consumed each month and will remain on customer bills for the future years 2016, 2017, and continue until at least 2018. Under the Company's proposal, the rate can be updated semi-annually to correct for under or over-collections. Monthly charges will vary. A residential customer using 1000 kWh of electricity a month will see an increase of approximately $1.67 per month in 2016.

The Company has not requested its application be ruled upon by the MPSC by any specific deadline, but a decision is anticipated by this summer. The MPSC Case Number is EO-2015-0055.

Comments and questions for Ameren Missouri with respect to its Application can be directed to the customer contact center.
Phone: 1-800-552-7583
email: Answers@ameren.com

The Office of the Public Counsel is actively reviewing the Application and accepting public comments. Please see the contact information listed below:

Office of the Public Counsel
P.O. Box 2230
Jefferson City, MO 65102
Phone: (866) 922-2959
Fax: (573) 751-5562
email: mopco@ded.mo.gov

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- AmerenMissouri.com
- 1.800.552.7583
- PO Box 790352 St. Louis, MO 63179-0352

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Current Charge Detail for Statement 11/20/2014

Electric Charge - Residential	$68.58
Fuel Adjustment Charge	$3.49
Energy Efficiency Investment Charge	$2.58
St Louis Co Municipal Charge	$3.93
Current Charge	**$78.58**
Budget Bill Adjustment	$17.29
Budget Bill Amount	**$95.87**
Amount Due	**$95.87**

AMOUNT DUE $95.87

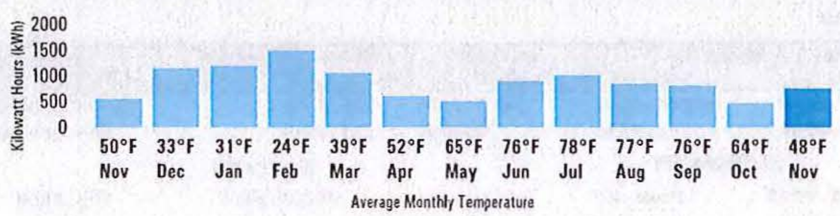
Due Date:	**12/03/2014**
Account Number	[redacted]
Service Address	[redacted]
Previous Bill	$105.00
Last Payment - 11/04/2014	$105.00

Your Budget Billing amount was reviewed this month and it will change to $97.00 effective with your next bill.

Electric Service from 10/19/2014 - 11/18/2014 — 30 Days

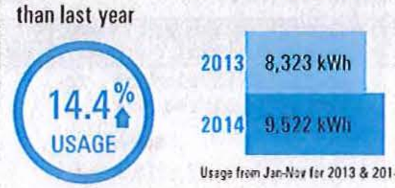
	Meter Number	Current Reading	Previous Reading	Current Usage	Reading Type
E	18967959	048722	047979	743 kWh	Actual

Electric Usage History



Electric Usage Summary

So far this year, you're using **14.4% more** than last year



33748 34465 34432 13073
04691 2118965 004692 009383 0001/0001
INTERNAL USE ONLY

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Get paid to save energy with Ameren Missouri's ActOnEnergy® programs. We offer rebates on a variety of energy efficient products and more. Visit **AmerenMissouri.com/ActOnEnergy** to start saving today!

TAKE CONTROL AND SAVE! Check out the back of your energy statement for energy-saving tips and cash-back rebates.

> > See reverse for messages

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Please return this portion with your payment.

☐ Check if you have address changes on back.

AMOUNT DUE	Due Date
$95.87	December 03, 2014
Amount After Delinquent Date 12/12/2014	**Account Number**
$97.31	[redacted]

Amount Enclosed: $

>004691 2118965 0001 092139 20Z
04691 2 AV 0.381 5-D 63125
[redacted]

AMEREN MISSOURI
PO BOX 88068
CHICAGO IL 60680-1068

5220000 0045241063309 00095870 00095870 00095870

Ameren
MISSOURI

Please Return This Portion With Your Payment.

AMOUNT DUE	DUE DATE
$3,352.34	Dec 3, 2014
AMOUNT PAYABLE AFTER Dec 12, 2014	ACCOUNT NUMBER
$3,402.63	[redacted]

SCHEDULE SMW-4

Amount
Enclosed $ ____________

[redacted]

Ameren Missouri
P.O. Box 88068
Chicago, IL 60680-1068

80600000 0017080500105 000003352340 000003352340

Keep This Portion For Your Records

ACCOUNT NUMBER	[redacted]
NAME	[redacted]
SERVICE AT	[redacted] SAINT LOUIS, MO 63123

BILL DATE	Nov 20, 2014

TOTAL AMOUNT DUE BY	Dec 3, 2014	$3,352.34
DELINQUENT AFTER	Dec 12, 2014	$3,402.63

Payment Received on Nov 10, 2014 $3,539.39

TYPE OF READING	METER NUMBER	SERVICE FROM TO	NO. DAYS	METER READING PREVIOUS	METER READING PRESENT	READING DIFFERENCE	METER MULTIPLIER	THERM FACTOR	USAGE	R D
Total kWh	05571668	10/19-11/18	30	42863.0000	43266.0000	403.0000	120.0000		48360.0000	A
Peak kW	05571668	10/19-11/18	30	0.0000	0.9000	0.9000	120.0000		108.0000	A

SUMMARY

	Service To			Service To	
Total kWh	11/18/2014	48360.0000	Peak kW	11/18/2014	108.0000
Total Billing Demand	11/18/2014	108.0000	October Winter Base kW	11/18/2014	100.0000
Winter Base Demand	11/18/2014	100.0000	Base kWh Ratio	11/18/2014	0.9259
Base kWh (HUD)	11/18/2014	44777.0000	Seasonal kWh (HUD)	11/18/2014	3583.0000

METERED ELECTRIC SERVICE BILLING

Rate 3M Large General Service — Service From 10/19/2014 To 11/18/2014

Seasonal Energy Charge	3,583.00 kWh	@	$.03630000	$130.06	
Demand Charge	108.00 kW	@	$1.71000000	$184.68	
Base Energy Chg / Hours Used	15,000.00 kWh	@	$.06230000	$934.50	
Base Energy Chg / Hours Used	20,000.00 kWh	@	$.04620000	$924.00	
Base Energy Chg / Hours Used	9,777.00 kWh	@	$.03630000	$354.91	
Customer Charge				$88.82	
Fuel Adjustment Charge	48,360.00 kWh	@	$.00470000	$227.29	
Energy Efficiency Pgm Charge	48,360.00 kWh	@	$.00050000	$24.18	
Energy Efficiency Invest Chg	48,360.00 kWh	@	$.00237200	$114.71	
Total Service Amount					$2,983.15
Missouri State Sales Tax				$126.04	
Missouri Local Sales Tax				$86.15	
St Louis Co Municipal Charge				$157.00	
Total Tax Related Charges					$369.19

Current Amount Due	$3,352.34
Prior Amount Due	$0.00
Total Amount Due	$3,352.34

The ActOnEnergy® BizSavers® program has CASH INCENTIVES available for your next energy efficiency project! Everything from lighting to controls to new construction. Visit ActOnEnergy.com/BizSavers to learn more.

A late payment charge of 1.5% will be added for any unpaid balance on all accounts after the delinquent date.

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