Exhibit No. 103

Ameren – Exhibit 103
Steven Wills Testimony
Surrebuttal
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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EO-2023-0136

SURREBUTTAL TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
May, 2024

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SURREBUTTAL TESTIMONY

OF

STEVEN M. WILLS

FILE NO. EO-2023-0136

I. INTRODUCTION

Q. Please state your name and business address.

A. Steven M. Wills, Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

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

A. I am the Senior Director of Regulatory Affairs for Ameren Missouri.

Q. Are you the same Steven M. Wills that submitted rebuttal testimony in this case?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q. To what testimony or issues are you responding?

A. I am responding to the rebuttal testimony of several Staff witnesses including Sarah Lange, J Luebbert, and Justin Tevie, as well as to Office of Public Counsel ("OPC") witnesses Lena Mantle and Geoff Marke. I will address a variety of issues including an overall response to these parties' rebuttal testimony, a discussion of Staff's commentary on the Total Resource Cost ("TRC") test and of expected rate impacts from MEEIA, a response to various other Staff criticisms, a brief discussion of the Fuel

Adjustment Clause and its impact on this case, and a response to claims that demand response ("DR") programs can be displaced by Aggregators of Retail Customers ("ARCs") and Time of Use ("TOU") rates.

III. THE COMMISSION IS FACED WITH A STARK CHOICE IN THIS CASE

Q. What is your overall reaction to the rebuttal testimony of Staff and OPC?

A. Staff and OPC erect false barriers to the continuation of MEEIA programming in the state, which, if allowed to impede future offerings will jeopardize the reliability and affordability of electric service throughout the ongoing generation transition. That transition is the result of macro level forces beyond the control of the utilities in the state. It is simply untenable for a vertically integrated utility in today's energy landscape to not be proactively pursuing a diverse mix of cleaner – but still reliable – resources to manage the risks of continued reliance on coal-fired generation. While new renewable resources and natural gas generation for dispatchability are keys to the "new fleet" needed to serve customers and mitigate risks, energy efficiency is absolutely foundational to enabling an orderly transition that maintains the highest levels of reliability and affordability possible for customers. We are in the process of replacing retiring generation systematically, which requires the construction/acquisition of new generation. If we are also faced with increasing load growth, including growth that could otherwise be managed through MEEIA programs, but isn't, then we will have to build additional incremental generation above that amount already planned. Those supply side resources are more costly than demand-side management ("DSM") – more than $4.1 billion more costly on a net present value ("NPV") basis based on the Company's 2023 Integrated Resource Plan

("IRP"). But a further concern is that those resources take significant lead time to plan and construct. The abrupt end of MEEIA programming in 2025 would eliminate at least 183 MW of existing Company resources – that is, all of the capacity provided by our DR programs that would be gone instantaneously, increasing the Company's and its customers' exposure to volatile and tight capacity markets. Further, the increase in load growth from the burgeoning demand from new data centers all across the country (including here in the Company's service territory) has the potential to exacerbate everything I just talked about. While that (data center) growth may not be manageable through MEEIA, there is load growth that *can* be managed. It's imperative that the Company's MEEIA programs persist and create the most stable foundation possible on which to manage the rest of the tangled web of supply-side interactions that are converging during the generation transition, which also includes new environmental regulations recently issued by the Environmental Protection Agency ("EPA").

Q. Why do you say that Staff and OPC are creating false barriers?

A. As I read the rationales of these parties' positions, I see a majority of objections to the Company's MEEIA application arise from either 1) issues that, if true, would have been equally true of *every MEEIA application that this Commission has ever approved,* and which provide no rationale for pausing MEEIA at this critical juncture in the generation transition, or 2) criticisms and logic that can only be described as flat out inaccurate, incorrect, or flawed.

For just a few examples, a non-exhaustive list of contentions of OPC and Staff in this case that are not new or unique to this application and, if true, have been true throughout all of the long and successful history of MEEIA programs, and which would have meant that the Commission should *never* have approved any MEEIA application in the last decade include:

- Evaluation, Measurement, and Verification ("EM&V") is too hard and uncertain;
- There is a "principal/agent" problem;
- There is a rebound effect;
- Energy efficiency creates intergenerational inequity;
- Energy efficiency results in reallocation of the revenue requirement that might cause some customer who had the opportunity to participate in programs but did not do so a higher cost than they otherwise would experience;
- DSM doesn't eliminate all investment that will ever be needed in new generation (or transmission and distribution ("T&D"));
- The Total Resource Cost ("TRC") test should include incentive costs and/or a higher discount rate;
- The Rate Impact Measure ("RIM") test should be positive;
- The throughput disincentive is just too complicated.

These barriers – despite the fact that, to the extent that they are actually issues, they are issues that existed in the past to the *exact same extent* that they exist today - have never been reason to reject a MEEIA application, and they should not be a reason to do so now. In fact, for the reasons I discussed in my answer to the previous question, now is likely the worst time imaginable to halt DSM investment. And recall Figures 1 and 2 from my rebuttal testimony that demonstrated the absolute sea change in load growth that has been ushered in during the "MEEIA era." Given the obvious efficacy of DSM programs in altering the historical trajectory of load when all of the issues above existed during that history, at least to the same extent that they do today, it simply cannot be true that each or any of those issues means that DSM programs cannot or will not be effective in managing load growth in the future.

IV. STAFF FAILS TO UNDERSTAND THE TRC TEST

Q. What is the significance of the TRC test in this case?

A. The MEEIA statute states: "The commission shall consider the total resource cost test a preferred cost-effectiveness test." The statute provides a goal of achieving all cost-effective demand-side savings, and it defines that goal specifically in terms of the TRC as the primary means of determining cost effectiveness.

Q. Does the statute define the TRC?

A. Yes. The statute defines the test as follows:

> "Total resource cost test", a test that compares the sum of avoided utility costs and avoided probable environmental compliance costs to the sum of all incremental costs of end-use measures that are implemented due to the program, as defined by the commission in rules.[1]

Q. Has the Company performed the TRC test consistent with this definition?

A. Yes.

Q. What issue does Staff raise with the TRC calculation?

A. Staff alleges several issues. Staff performs several of its own TRC calculations to address these alleged issues with the Company's calculation. None of Staff's calculations have any merit. Rather, Staff's positions represent the continuation of a

[1] RSMo 393.1075 (6).

disturbing trend where Staff takes increasingly aggressive and unsupported positions, many of which are just objectively wrong, in furtherance of its opposition to the Company's efforts to implement its Preferred Resource Plan ("PRP"). I discussed the importance of the PRP in my rebuttal testimony, indicating it is our plan, and the only plan that any entity has put forward on behalf of the Company's customers (i.e., Staff has not provided an alternative approach), to navigating the complexity of the ongoing and historic transition of generation fleets occurring in the industry broadly, and at Ameren Missouri specifically, in a manner that appropriately balances the important but competing objectives of ensuring reliability, affordability and sustainability (i.e., implementation of cleaner resources with lower emissions and less risk of environmental regulation impacting their ability to perform).

Q. Can you please more specifically identify the flaws in each of Staff's various criticisms of, and/or adjustments to, the Company's calculation of the TRC?

A. Yes. Staff raises alleged issues, and in turn performs new calculations of the TRC five different times in the rebuttal testimony of Sarah Lange. The various iterations of TRC calculations performed by Ms. Lange, which I will reference by number throughout this section of my testimony as shown in the list below, include:

TRC #1 - Staff (based on a complete misunderstanding of the TRC itself) objects to the characterization of incentives paid to customers through the programs as transfer payments that are excluded from the calculation of the TRC and develops two different alternative approaches to incorporating the cost of incentives into the calculation. In the first alternative, Staff adds the cost of incentives to both the costs (denominator) and benefits (numerator) included in the TRC calculation and calculates a TRC of **1.45**.[2]

TRC #2 - Staff's second approach to dealing with the alleged problem of excluding incentives is to include the incentives as only a cost in the TRC calculation (but not also as a benefit). In this iteration, Staff calculates a TRC of **1.16.**[3,4]

TRC #3 - Staff identifies that the Company's TRC calculation included the Earnings Opportunity ("EO") at the target level proposed by the Company rather than the maximum level that could be achieved under the proposal. Staff again identifies two alternative calculations to address this alleged issue. Staff's first such calculation uses their observation about the EO as an excuse to arbitrarily and dramatically recast the entire balance of costs and benefits expected by the MEEA 4 portfolio of programs, resulting in a TRC of **0.93**.[5]

TRC #4 - Staff's second approach to dealing with the alleged understatement of the EO adds additional EO costs into the calculation, resulting in a TRC of **1.07**.[6]

TRC #5 - Staff calculates the TRC using a different (and completely unsupported and inappropriate) discount rate to determine the net

[2] File No. EO-2023-0136, Sarah Lange Rebuttal Testimony, p. 20, ll. 14-17.
[3] Note that in Ms. Lange's testimony she reports this TRC value as 1.16, but in the workpaper that I later reference and attach to my testimony, the calculation of this TRC actually rounds to 1.17.
[4] File No. EO-2023-0136, Sarah Lange Rebuttal Testimony, p. 21, ll. 11-14.
[5] File No. EO-2023-0136, Sarah Lange Rebuttal Testimony, p. 22, ll. 16-17.
[6] File No. EO-2023-0136, Sarah Lange Rebuttal Testimony, p. 23, ll. 1-2.

present value of benefits and costs. This calculation results in a TRC of **0.997**.

TRCs #1 & #2:

Q. Taking Staff's TRC #1 and #2 calculations together, since they both address the treatment of incentive costs as transfer payments, please respond to Staff's allegation.

A. Staff's allegation demonstrates a complete lack of understanding of the basic concept of the TRC and is objectively wrong in its attempt to "correct" an issue in the Company's calculation – an issue that does not exist. Staff witness Lange states:

> "Based on discussions with Ameren Missouri in prior MEEIA cycles, Ameren Missouri believes that dollars obtained from all ratepayers for provision to a subset of ratepayers are both costs and benefits to ratepayers, and can be ignored."[7]

The Company, however, did not base its treatment of incentive costs on a "belief." It based it in on extremely well-established and broadly accepted industry standard definitions of the TRC as well as the sound logic that underlies that industry standard.[8]

Q. What evidence can you provide that the industry standard definition of the TRC treats incentives as transfer payments (neither costs nor benefits in the TRC)?

A. Plenty. First, the California Standard Practice Manual itself, which is generally considered one of, if not the, original authoritative reference(s) on DSM program cost effectiveness testing, says this:

> The primary strength of the Total Resource Cost (TRC) test is its scope. The test includes total costs (participant plus program administrator) and also has the

[7] File No. EO-2023-0136, Sarah Lange Rebuttal Testimony, p. 20, ll. 5-7.
[8] I would also note at this time, and I will return to this point later, that there are certain incentive costs that do get added into the TRC under the Company's, and the industry standard, approach.

> potential for capturing total benefits (avoided supply costs plus, in the case of the societal test variation, externalities). To the extent supply-side project evaluations also include total costs of generation and/or transmission, the TRC test provides a useful basis for comparing demand and supply-side options.
>
> **Since this test treats incentives paid to participants and revenue shifts as transfer payments** (from all ratepayers to participants through increased revenue requirements), the test results are unaffected by the uncertainties of projected average rates, thus reducing the uncertainty of the test results. Average rates and assumptions associated with how other options are financed (analogous to the issue of incentives for DSM programs) are also excluded from most supply-side cost determinations, again making the TRC test useful for comparing demand-side and supply-side options.[9]

This is what it says in a 2008 National Action Plan for Energy Efficiency report titled "Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy Makers" in a case study of Southern California Edison's residential energy efficiency programs:

> The TRC reflects the total benefits and costs to all customers (participants and non-participants) in the SCE service territory. The key difference between the TRC and the PACT is that **the former does not include program incentives, which are considered zero net transfers** in a regional perspective (i.e., costs to the utility and benefits to the customers). **Instead, the TRC includes the net measure costs** of $41 million.[10]

Here is a very nice summary from a different National Action Plan for Energy Efficiency presentation titled "Cost-effectiveness Tests - 'Current Practice'" that presents the appropriate categories of costs and benefits to be included in each cost effectiveness

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[9] California Standard Practice Manual – Economic Analysis of Demand-Side Programs and Projects, 2001, p. 21, https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy_-_electricity_and_natural_gas/cpuc-standard-practice-manual.pdf emphasis added.

[10] Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers, National Action Plan for Energy Efficiency, November 2008, p. 3-7, https://19january2017snapshot.epa.gov/sites/production/files/2015-08/documents/understanding_cost-effectiveness_of_energy_efficiency_programs_best_practices_technical_methods_and_emerging_issues_for_policy-makers.pdf, emphasis added.

test in easy to view tabular form.[11] Note clearly that incentive payments are not identified as a cost or a benefit in the TRC:

Summary of Costs and Benefits

- High level summary of costs and benefits included in each cost test
- Each state adjusts these definitions depending on circumstances
- Details can significantly affect the type of energy efficiency implemented

Component	PCT	PAC	RIM	TRC	SCT
Energy and capacity related avoided costs.	-	Benefit	Benefit	Benefit	Benefit
Additional resource savings	-	-	-	Benefit	Benefit
Non-monetized benefits	-	-	-	-	Benefit
Incremental equipment and install costs	Cost	-	-	Cost	Cost
Program overhead costs	-	Cost	Cost	Cost	Cost
Incentive payments	Benefit	Cost	Cost	-	-
Bill Savings	Benefit		Cost	-	-

5

And this from a Pennsylvania Public Utility Commission order issued in 2019:

> **Incentives to program participants are a transfer payment intended to offset the IMC of efficient equipment. They are a cost to the EDC and a benefit to the participant, so they are neither a cost nor a benefit in the TRC Test.** An exception to this rule occurs when the incentive amount is greater than the IMC. If the incentive amount is greater than the IMC, the incentive amount should be used as the TRC cost instead of the IMC. Incentives may be greater than the IMC when an EDC elects to make the efficient option the lowest cost option for participants (*e.g.*, discounting an LED lighting bulb in retail stores such that the upfront cost of the efficient LED is less than the cost of a comparable halogen or incandescent lamp). Incentives can also exceed incremental cost when there is no clear measure cost, such as for Appliance Recycling programs.[12,13]

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[11] Cost-effectiveness Tests – 'Current Practice', National Action Plan for Energy Efficiency, Snuller Price, E3; https://www.aceee.org/files/pdf/conferences/mt/2009/E2_Price.pdf
[12] Pennsylvania Public Utility Commission, Docket M-2019-3006868, Final Order, p. 77, emphasis added.
[13] Defined acronyms from the order included in this quote: IMC (Incremental Measure Cost), EDC (Electric Distribution Company)

Here is an excerpt from a report issued by the Regulatory Assistance Project in conjunction with Synapse Energy Economics, Inc. titled "Energy Efficiency Cost-Effectiveness Screening":

> The rationale for offering a customer financial incentive is to help the customer overcome the market barriers to energy efficiency. The amount of customer financial incentive (in combination with technical support, education, and other support) thus should be as large as necessary to overcome the market barriers to energy efficiency, but no larger. Once an efficiency measure has been deemed to be cost-effective, the size of the customer financial incentive can be determined based on this principle. **Under both the Societal Cost and the TRC Tests, the amount of the customer financial incentive will not affect the cost-effectiveness results.**[14]

I could go on. There are many more documents from reputable sources and other Commissions (probably hundreds more) that reflect this characterization of incentives in (or rather not in) the TRC. But hopefully these examples are sufficient to illustrate the point that incentive payments (except in special circumstances) do not factor into the TRC. That that is commonly understood in the industry should be abundantly clear.

Q. Why is this generally accepted definition of the TRC, which does not factor program incentives into the categories of costs to be included, entirely appropriate?

A. This is appropriate because the TRC already accounts for the *full incremental cost of the energy efficiency measure* in its calculation. This is clear in the slide above from the National Action Plan for Energy Efficiency that shows "Cost" in the row of the TRC column labeled "Incremental equipment and install costs." It's also clear in the definition of the TRC in this state's enabling statute that I cited above, and which defines

[14] Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for 'Other Program Impacts' and Environmental Compliance Costs, Woolf, Steinhurst, Malone, and Takahashi, Regulatory Assistance Project, Synapse Energy Economics, Inc., Nov. 2012, p. 33, emphasis added.

the TRC as "a test that compares the sum of avoided utility costs and avoided probable environmental compliance costs **to the sum of all incremental costs of end-use measures that are implemented due to the program**, as defined by the commission in rules."

The incentives are generally a subset of the full incremental measure cost. Including both the incremental measure cost *and* the incentive as separate and discrete costs in the TRC would (and does in Ms. Lange's calculations) unquestionably double count those costs and is inconsistent with how the TRC is defined under MEEIA.[15] This double counting potential is also evident in the bolded portion of the excerpt from the Pennsylvania PUC order I cited above where it says "[i]ncentives to program participants are a transfer payment ***intended to offset the I[ncremental] M[easure] C[ost] of efficient equipment*,"** which again confirms that the incentive is a subset of the incremental measure cost.

Consider a very simple example. Imagine a customer is in the process of getting a new air conditioner, and a unit with higher efficiency costs $2,000 more than a lower efficiency unit. That $2,000 difference is the incremental measure cost - the amount of incremental money the customer must spend to gain that efficiency, given that it is already going to purchase at least the less efficient air conditioner – and is the amount that the TRC dictates be included as a cost (and which *is* included as a cost in the TRCs calculated by the Company). Now imagine that a utility program offers a $1,000 incentive to the customer in order to encourage them to make that more efficient choice. That means that the customer only has to come up with $1,000 out of pocket to cover the $2,000 incremental cost and get the more efficient air conditioner. Staff's approach, whereby it would add the incentive cost into the TRC, which already reflects the incremental measure costs, would

[15] RSMo 393.1075 (6).

result in the TRC reflecting $3,000 of cost associated with this customer's selection of the higher efficiency air conditioner - $2,000 from the incremental measure cost and *another* $1,000 from the incentive – even though the incentive went to pay towards the $2,000 incremental cost. There is no world where it makes any sense to count $3,000 of costs in the TRC for this example where the higher efficiency unit only costs an incremental $2,000. And that is exactly what Staff's approach to the TRC under TRCs #1 and #2 does.

Q. Can you demonstrate that Staff in fact does double count incremental measure costs and incentives, exactly as you just described.

A. Yes. I have attached Staff witness Lange's rebuttal workpaper titled "Copy of MEEIA 4 2025-2027_AMOSubmittalTool_w_Sources_2024-01-24 staff markup.xlsx" to my testimony as Schedule SMW-S1 as an operable Excel file with formulas intact. The TRC #2 value of 1.16, which fully double counts incentive costs, is found on the sheet within this workbook labeled "NPV", in cell O1. The formula in this cell shows that the denominator of this benefit/cost ratio (the denominator being the cost) is the sum of two different numbers, which can be traced through the formulas in the spreadsheet to (hardcoded) source data in cells X5 through AJ10. I have included a screenshot of this cell range as Figure 1 below, and notated the columns from this table that are added up into the two inputs Ms. Lange included in the denominator (cost) of the 1.16 TRC that she ultimately calculates as TRC #2.

Figure 1 – Cost (TRC Denominator) Inputs into Witness Lange's TRC #2

X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ
Incentive Payments	**Setup Cost**	**Administrative Cost**	**Marketing Cost**	**Miscellaneous Costs**	**Measure Level TRC Cost**	**Total Education Program Cost****	**Total Pilot/R&D Cost**	**Total EM&V Cost (EE)**	**Total Marketing & Inc Labor Cost**	**Admin. Cost (Potential Study)**	**Earnings Opportunity Requested in Ameren Direct**	**Earnings Opportunity Reflected in Ameren Direc**
$ 64,170,989	$ 1,035,301	$ 40,872,133	$ 1,169,609	$ 14,731,091	$ 79,908,590	$ 1,138,693	$ 3,518,977	$ 3,251,602	$ 2,639,233	$ 1,000,000		$ 15,766,88
$ 68,476,802	$ -	$ 42,344,786	$ 1,183,902	$ 16,426,737	$ 82,497,490	$ 1,151,158	$ 3,687,671	$ 3,394,699	$ 2,765,753	$ 500,000		$ 15,314,81
$ 72,497,642	$ -	$ 42,699,748	$ 1,206,050	$ 18,105,772	$ 84,485,421	$ 1,000,845	$ 3,840,452	$ 3,522,129	$ 2,880,339	$ -	$ 23,626,420	$ 16,810,17
$ 205,145,433	$ 1,035,301	$ 125,916,667	$ 3,559,561	$ 49,263,600	$ 246,891,501	$ 3,290,696	$ 11,047,100	$ 10,168,430	$ 8,285,325	$ 1,500,000	$ 74,912,886	$ 47,891,87
												64

Source of first input into TRC denominator (costs)

Source of second input into TRC denominator (costs) excluding column AI, but including column AC, which is defined as **Measure Level TRC Costs**.

By adding the values in the column labeled "Incentive Payments" to the total Program Costs that included the column labeled "Measure Level TRC Costs", which *are* the incremental measure costs (as appropriately adjusted for incentives that exceed incremental measure cost and incentives paid to free riders, as I will discuss momentarily) of which incentives are a subset, Ms. Lange has explicitly double counted costs in the TRC values she calculated in order to "correct" the Company's treatment of incentives as transfer payments. This is both obviously inappropriate on its face and in direct contravention of every one of the authoritative references I cited above about the appropriate treatment of incentives in the TRC, including Missouri's MEEIA statute.

Q. Are there any additional details of the treatment of incentives in the TRC that you would like to explain just for clarity?

A. Yes. I mentioned above that there are some special situations where incentives are included in the TRC. There are two special cases where this is true. One is where the incentive paid exceeds the incremental cost of the measure. Only that portion of the incentive that exceeds the incremental measure cost is included in the TRC (imagine if the utility had provided a $2,001 incentive to the customer in the example of the air conditioner with an incremental cost of $2,000 – in that case, the extra $1 in the incentive that exceeds the incremental measure cost would appropriately be picked up in the TRC costs), as that does not result in double counting of costs, but rather fully accounts for them. This exception is explicitly referenced in the excerpt cited above from the Pennsylvania PUC order. The Company in fact does include any incentives that exceed incremental measure cost as a program cost in its TRC calculation.

The second exception is that incentives paid to free riders (customers that would have undertaken the efficiency upgrade even without the incentive and therefore do not count as contributing to program savings, as reflected in the net-to-gross ratio) are also included in the TRC. In that case, the incremental measure cost is excluded from the TRC, as are all benefits associated with the measure. But the incentive paid to the free rider, which did not *cause* any energy efficiency savings, but which *is* recovered as a program cost, is counted as a TRC cost. The net-to-gross ratio is applied to the incentives included in the Measure Level TRC Costs calculated by the Company to capture the cost of incentives paid to free riders.

Q. Are there any other clarification points you would like to raise before you move on?

A. Yes. I want to acknowledge that it is possible to find descriptions of how to calculate the TRC that would list incentives as an appropriate cost category for inclusion in the TRC. However, in these instances, incremental measure costs included in the same TRC are redefined to only include the portion of the incremental measure costs that are fully borne by the customer. This is mathematically equivalent to counting the full amount of the incremental measure cost in the TRC and excluding incentives. It is only a semantic difference. Consider our air conditioner example where the incremental cost was $2,000 and the incentive paid to the customer toward that incremental cost was $1,000. One could include $2,000 as the TRC cost and refer to it as the incremental measure cost (this is most common, and also how the Company has performed its TRC), or one could include $1,000 of incentive payment and another $1,000 of participant contribution toward the incremental measure cost, for the exact same total cost in the TRC. In both cases the TRC would appropriately include $2,000 of costs (the same as the incremental measure cost).

For example, in the Regulatory Assistance Project/Synapse paper I cited above, page 12 includes a table titled "Components of the Energy Efficiency Cost-Effectiveness Tests," which describes what categories of costs and benefits get included in which cost effectiveness test. That table describes the TRC in the way I just outlined in the prior paragraph. The table shows that the TRC should contemplate cost categories including "EE Measure Cost: Program Financial Incentive" and "EE Measure Cost: Participant Contribution." The Program Financial Incentive and Participant Contribution add up to the total incremental measure cost. So again, this is just semantics, and regardless of those semantics, both of these definitions include the incremental measure cost without double counting the incentives as Staff has done.

Q. Please summarize your response to Staff's TRC #1 and #2 recalculations.

A. Staff entirely misunderstands the TRC as it is used in practice in the industry, and as Ameren Missouri has calculated it in support of this MEEIA 4 application. In an effort to "correct" a flaw that does not exist, Staff has double counted costs in its calculations that resulted in TRCs #1 and #2 of 1.45 and 1.16 respectively. Staff's recalculations are flat out wrong and must be disregarded.

<u>TRCs #3 & #4</u>

Q. Please turn to the third and fourth issues above, which include Staff's next two attempts to recalculate the TRC. Are there any threshold issues with these calculations that need to be understood right up front?

A. Yes. Just to be 100% clear, the next adjustments that Staff makes to the TRC also include and build on the error from TRC #2 above, meaning that Staff included its double counting of incentive costs in these calculations as well, before making other adjustments to the TRC. That alone is enough to invalidate the calculations of TRC #3 and #4. As a result of the inclusion of this double counting, the differences between the TRCs that Staff calculated related to these issues (.93 and 1.07 respectively) and that calculated by the Company in support of its application do not isolate the impact of the issue Staff is addressing here, but rather compound multiple issues (i.e., they double count incentive costs *and* make other changes related to EO costs).

Q. Please describe the underlying Staff concern that gives rise to TRC #3 and #4.

A. Staff takes exception to the amount of EO the Company included in the TRC costs. The Company included the costs of an EO in its TRC calculation based on the target level of EO it has proposed in its plan. However, the EO proposal also has a maximum payout for higher levels of performance that could be achieved by the Company. Staff asserts that it is this maximum value of the EO that should have been reflected in the TRC.

Q. What is your reaction to Staff's concern?

A. Conceptually, I think it is not unreasonable to consider the maximum EO, and the calculation of a TRC sensitivity with that change would have been a fair thing to do. However, the way Staff approaches adjusting the TRC for this dynamic under TRC #3, which resulted in its calculation of a TRC of 0.93, is completely unsupported and inappropriate. Ms. Lange apparently decided that, since the target EO that the Company used in the TRC is triggered if the Company achieves 80% of planned energy savings from its portfolio, that she should recalculate the TRC with that *80% value also applied in a manner that scales down (reduces) all of the planned benefits, but not applied at all – meaning no reduction to - the costs (including already double counted costs)*. Essentially, with the stroke of the keyboard, Staff slashed the benefits from the programs and left all of the costs unchanged. This calculation is simply not representative of the Company's proposed plan. The costs and benefits modeled by the Company were rigorously studied in the Company's Market Potential Study and informed by a Request for Proposals process from implementation contractors in the industry bidding based on their own market experience. The costs and benefits, and the balance between the two, are rooted in those processes. The makeup of the EO award provides no basis to change the relative relationship of costs and benefits in the plan, and Staff provides no other basis for doing so. Staff's TRC #3 is not representative of the Company's plan. The TRC calculated at 0.93 should be wholly disregarded (recall it also double counts incentives – and without that obvious flaw TRC #3 would still be above 1, as incorrect as it is).

Q. What about TRC #4, which also relates to the EO, and results in a TRC of 1.07?

A. In this iteration of Staff's TRC calculations, Ms. Lange does do what I think could be considered in concept to be a reasonable sensitivity analysis to address Staff's concern, which is to include the additional EO that the Company would be entitled to under its proposal if it achieved the maximum payout in the TRC costs. However, TRC #4 is still wholly inappropriate to represent anything associated with the Company's MEEIA 4 plan, since it also double counts incentive costs. This double counting is also evident in Ms. Lange's workpaper that I have included and already referenced as Schedule SMW-S1. The 1.07 value for TRC #4 is also calculated on the "NPV" tab of the spreadsheet, in cell L39. The denominator of the calculation in that cell adds the additional EO costs on to costs that are exactly equal to the costs in the denominator of TRC #2, which you will recall included a double counting of incentive costs. Also recall that under TRC #2 that the TRC with the incentive costs double counted was 1.16. So, the impact of including the maximum EO in the TRC costs only contributed to the incremental change in the TRC from 1.16 – which is completely wrong due to double counting – down to 1.07 as calculated by Ms. Lange as TRC #4. If the Company's originally (and correctly) calculated TRC had reflected the maximum payout of EO, the TRC would have changed from 1.64 to 1.59. That latter value could be considered a reasonable sensitivity analysis to consider in this case, unlike each of the five TRC iterations calculated by Ms. Lange.

TRC #5

Q. Please address Ms. Lange's calculation of TRC #5.

A. I'll first start by reiterating what I have said about TRCs #3 and #4, and that is Ms. Lange has compounded her errors by double counting incentive costs in TRC #5, as described in my response to TRC #2. With that said, the other major change Ms. Lange makes in her calculation is to change the discount rate used in the determination of the net present value of benefits and costs from the programs. She does this based on a claim that I advocated for such a discount rate in the analysis around the Company's recent application for four Certificates of Convenience and Necessity ("CCNs") in File No. EA-2023-0286 ("solar CCN case"). Ms. Lange misrepresents my testimony from that case and uses it to justify an analysis that is completely opposite from her own position in the solar CCN case.

Q. How does Ms. Lange misrepresent your testimony from that case?

A. She ignored the fact that my overarching argument was that the Company's weighted average cost of capital ("WACC") is ***the*** appropriate discount rate for analysis of the net present value of revenue requirement ("NPVRR") in resource planning analysis and decision-making. Prior to the discussion Ms. Lange cites from my testimony, I highlighted the clarity of the Commission's resource planning rules that dictate that the Company's weighted average cost of capital be used as the discount rate for determining the NPVRR in resource planning analyses. The Company's position is and was that the Company's WACC is the right discount rate to use for such analyses. But because Ms. Lange had already opined in that case in support of alternative discount rates - i.e., she supported an analysis with no discounting at all, and another analysis based on her assessment of a "customer discount rate" – and that the appropriate discount rate from a customer's perspective should be very low (specifically, 2% based on her workpapers in that case), I did proceed to rebut her perspective on customer discount rates – despite my primary argument being that they were not the appropriate measure to be used in resource planning analysis. But certainly, as Ms. Lange observed, I did go to some length to describe my disagreement with Ms. Lange's view that customers have a much lower discount rate than the Company, and instead suggested that customers' discount rate should be expected to be higher than the Company's. I stand by that claim, but I also stand by the more important claim that the right discount rate to use in *both* cases is *the Company's WACC*, consistent with Commission resource planning rules and sound business planning processes. In no way did I or the Company endorse the notion of trying to specifically estimate a customer discount rate, or of applying any discount rate other than the Company's WACC to the analysis in that case. I'll reproduce here exactly what I said in the solar CCN case - about what discount rate should be used for analysis related to resource planning decisions:

> Staff's conclusory statements are outright contradictions of the methods of analysis required by the Commission's resource planning rules, as shown in the cited rule provisions below:
>
> > (2) The fundamental objective of the resource planning process at electric utilities shall be to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies. The fundamental objective requires that the utility shall— …
> >
> > (B) **Use minimization of the present worth of long-run utility costs as the primary selection criterion** in choosing the preferred resource plan, subject to the constraints in subsection (2)(C);[16]
> >
> > …and…

[16] 20 CSR 4240-22.010 (2), emphasis added.

> (B) All present worth and levelization calculations **shall use the utility discount rate** and all costs and benefits shall be expressed in nominal dollars.[17]
>
> …and…
>
> (64) Utility discount rate means the post-tax rate of return on net investment used to calculate the utility's annual revenue requirements.[18,19]

Q. What do you make of Ms. Lange's inclusion of a radically different perspective on which discount rate to analyze in this case versus what she testified to just a few months ago?

A. As I just mentioned, Ms. Lange presented analyses using a 2% customer discount rate in the solar CCN case just a few months ago, and now, purportedly based on my comments in that case, presents an analysis with a 10.5% customer discount rate. It appears Ms. Lange is simply selecting the discount rate in each case that will do the most to bolster her recommendation in that case.

Table 1 below shows the discount rate recommendations of Staff and the Company across the solar CCN case and this MEEIA 4 case. Table 1 is a clear visual of the dramatic shift in Staff's recommendation between the two cases:

Table 1 – Discount rate presented in analysis of resource planning decisions

Case	Staff Discount Rate	Company Discount Rate
EA-2023-0286	2.0%	6.59%
EO-2023-0136	10.5%	6.86%

[17] 20 CSR 4240-22.060 (2)(B), emphasis added.

[18] 20 CSR 4240-22.020 (64). i.e., shall use the utility's weighted average cost of capital ("WACC"), which is exactly what the Company's analyses in this case used.

[19] File No. EA-2023-0286, Steven Wills Surrebuttal Testimony, p. 60 l. 13 through p. 61, l. 7. Citations and emphasis added were both included in that testimony.

So I ask the rhetorical question of which party's position on discount rates in this case is inconsistent with its position in the solar CCN case?

Q. Do you have any other comments on the discount rate issue related to Staff's TRC #5?

A. Yes. Ms. Lange's table that presents the result of this analysis in her rebuttal testimony labels the column with the 10.5% discount rate as being based on "Wills' discount rate." Her testimony is unsupported. Ms. Lange does not and cannot include any specific citation where I said this because there is nowhere in the record of any case where I have ever recommended a 10.5% discount rate. It is evident, in fact, that the selection of the 10.5% rate was actually made as a "breakeven" type analysis, to show what the discount rate would have to be in order for the TRC to fall below 1 (when also double counting incentive costs, as Ms. Lange has done here). Ms. Lange's testimony describes the breakeven nature of this analysis clearly, where she says, "any discount rate at or over 10.5% results in the modeled benefits failing to meet or exceed program costs."[20] Of course this phrase in her testimony should have indicated that it failed to meet or exceed "double counted program costs."

Simply put, consideration of the analysis using the 10.5% discount rate has no foundation in the Commission's resource planning rules or standard business planning practices, and Staff does not suggest any rationale for 10.5% to be considered the or an appropriate discount rate.

Q. Please summarize your testimony regarding Staff's alternative calculations of the TRC.

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[20] File No. EO-2023-0136, Sarah Lange Rebuttal Testimony, p. 48, ll. 15-16.

A. Each and every one of Staff's TRCs #1-5 contain significant errors and should not be considered to be representative of the cost effectiveness of the Company's MEEIA 4 proposal. These TRCs suggest a lack of understanding of the TRC by Staff, as well as an extreme (double counting incentives in all 5 TRC calculations), sometimes arbitrary (cutting benefits by 80% and leaving costs untouched in TRC #3), sometimes argumentative (adopting a discount rate that is completely opposite of its recommendation in the recent solar CCN case in TRC #5 just because the Company criticized Staff's analysis in that case) attempt by Staff to bolster its recommendation to reject the Company's MEEIA application.

Q. You mentioned at the beginning of this section of your testimony that Staff's TRC-related testimony *continued* a trend of **Staff taking unreasonable positions in opposition to the Company's efforts to implement its Preferred Resource Plan ("PRP"). What other recent evidence of this trend exists?**

A. In the solar CCN case that I have referenced several times already in this section of testimony and which gave rise to the discount rate discussion that led Staff to calculate TRC #5, I highlighted the myriad of negative and erroneous positions that Staff appeared to be taking toward the Company's proposal in order to bolster its recommendation in that case to reject the CCNs sought by the Company. The most egregious of those positions by far, however, was Ms. Lange's "threshold analysis", which presented a view of the projected revenue requirement of the solar facilities that included almost ***a billion dollars of obvious and basic errors in revenue requirement construction*** that made the projects appear more costly to customers than they really are.[21] The pattern of errors – large in magnitude and directionally biased against the approval sought by the Company - is noteworthy context for consideration of the Staff recommendation in this case.

V. STAFF'S ATTEMPT TO RECALCULATE MEEIA 4 EXPECTED RATE IMPACTS HAVE NO FOUNDATION AND ARE HIGHLY INACCURATE

Q. What does Staff witness Luebbert say with respect to the expected rate impacts of the Company's MEEIA 4 programs?

A. Mr. Luebbert questions the accuracy of the Company's calculations, saying:

> "The rate impacts are drastically understated. Figure 8 below is a reproduction of Ameren Missouri's rate impact analysis. Figure 9 below replaces Ameren Missouri's overstated avoided cost benefits with the values included in the DSMore files labeled as "Market-Based Avoided Costs" and removing avoided transmission and distribution cost benefits."[22]

Mr. Luebbert then proceeds to display a graph from the Company's original filing juxtaposed against his own attempt to recalculate the content of the graph using what he claims are more reasonable assumptions.

Q. Are Mr. Luebbert's changes to the Company's calculations warranted?

A. No. They are entirely without merit, as are his concerns that gave rise to them, as I will discuss throughout this section of my surrebuttal testimony.

Q. Please identify the changes that Mr. Luebbert makes in order to recalculate the Company's rate impact projection.

[21] See the surrebuttal testimony of Company witness Mitch Lansford in File No. EA-2023-0286 for meticulous documentation of these errors. I also have personal knowledge of the "threshold analysis" errors as documented in Mr. Lansford's testimony and schedules thereto in that case.
[22] File No. EO-2023-0136, J Luebbert Rebuttal Testimony, p. 38 l. 19 through p. 39 l. 2.

A. Mr. Luebbert unreasonably eliminates *all* savings associated with avoided transmission and distribution ("T&D") costs and replaces the avoided capacity costs calculated by the Company with the result of a completely unsupported "market based avoided cost."

Q. Why is it unreasonable to eliminate all avoided T&D costs?

A. Company witness Michels addresses this issue in both his rebuttal and surrebuttal testimonies. I would just add that utilization of avoided T&D costs – despite Staff's claims to the contrary - is typical in the industry, and the values used by the Company are completely in line with the industry. For example, a 2014 benchmarking analysis[23] conducted by the Mendota Group on behalf of Xcel Energy found that, of 35 utilities surveyed, the average avoided distribution cost calculated for purposes of DSM program analysis was \$48.37/kW-year, with a range from \$0-171/kW-year. Avoided transmission costs from the same survey averaged \$20.21/kW-year and ranged from \$0-88.64/kW-year. The Company's 2025 avoided T&D costs of \$22 and \$1.5 per kW-year respectively are not only well within the range of values identified in this benchmarking survey but are also well below the average. The fact that the benchmarking study is aging slightly suggests to me that the relevant benchmarks are likely understated due to the effect of inflation and rising costs in the intervening years since it was conducted.

I would note that Mr. Luebbert has questioned the existence of *any* deferred or avoided T&D (as suggested by his removal of such avoided costs entirely from his analysis) when measures are not locationally targeted to specific areas on the system where

[23] Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments, The Mendota Group, LLC, October 2014, p. 10-12.

specifically identified projects can be deferred or avoided. The Mendota benchmarking study made the following observation related to this point:

> Authors Chris Neme and Rich Sedano categorize the manner in which efficiency programs can defer T&D investments as "passive" or "active". Passive refers to deferred investments in transmission and distribution that occur as a byproduct of EE investments whereas active deferrals are those that result from EE initiatives targeted at specific locations. Active deferrals have the express purpose of deferring T&D investments. **The authors cite a host of reasons as to why active deferrals are uncommon**.
>
> Further to this point, "**passive deferral occurs when the growth in load or stress on feeders, substations, transmission lines, or other elements of the T&D system is reduced as a result of broad-based (e.g., statewide or utility service territory-wide) efficiency programs**." Estimates of savings from EE investments "are typically developed by dividing the portion of forecast T&D capital investments that are associated with load growth (i.e., excluding the portion that is associated with replacement due to time-related deterioration or other factors that are independent of load) by the forecast growth in system load."[24]

Recall from my rebuttal testimony the charts in Figures 1 and 2, which showed the impact that prior MEEIA cycles have had on overall system loads (i.e., hundreds of MW of reduction of load coincident with the system peak that can be expected to drive capacity investments across generation and T&D). Those are exactly the type of reductions in load growth that can and should be expected to create passive deferrals of T&D, and it is implausible to believe that there would not have been more investment in T&D on the Company's system if peak loads were hundreds of MWs higher than they currently are. Simply put, Mr. Luebbert's opinion that passive deferrals do not exist is both unreasonable and inconsistent with industry practice. Avoided T&D absolutely should be included in both cost effectiveness testing and rate impact analysis in this case.

[24] Id. P. 4-5, emphasis added.

Q. Please proceed to discuss Mr. Luebbert's utilization of an alternative to the Company's avoided capacity costs in his very flawed recalculation of MEEIA 4 rate impacts.

A. I'm at a loss to understand how Mr. Luebbert would even consider using the "market-based avoided cost" values he did for purposes of analysis in this case. One of the significant themes in his testimony in this proceeding has been his concern with documentation of sources of data and hard coded numbers in spreadsheets for which he cannot verify the underlying data – it is abundantly clear that Mr. Luebbert prefers rigorous documentation of data that he relies on. His rebuttal testimony uses the word "hardcoded" 14 times in discussing this theme, not including in section headers or schedules (30 times including them).

The "market-based avoided costs" that Mr. Luebbert utilized for this analysis were not just hardcoded – but they were *completely disavowed* by the Company as having been verified or relevant to the case in any way in a Data Request response to Staff – they were simply extraneous data in a workpaper file that is automatically generated by the DSMore program with functionality that the Company does not utilize. In retrospect, it certainly would have been better for the Company to delete this extraneous data from workpapers, but irrespective of that fact, we did make it entirely clear that this data was not prepared for or relevant to this case. A DR response that Mr. Luebbert attached to his testimony demonstrates that he fully knew that these numbers had not been validated by the Company in any way – and the Company objected and clearly indicated that these values were not relevant to this case. There is simply no foundation for the utilization of this data – or the analysis resulting from it - in this case in any way.

Q. Since Mr. Luebbert, by incorporating this data as a part of his analysis that Staff uses to support its recommendation to reject the Company's MEEIA 4 programs, has made the question of the relevance of the "market-based avoided cost" data itself relevant, have you subsequently been able to research the "market-based avoided cost" functionality in DSMore to get a better understanding of what it reflects?

A. Yes. As a result, I can say that it is not appropriate to utilize that data in this case at all. Mr. Luebbert ostensibly uses this data to substitute a different avoided capacity cost for the Company's avoided capacity costs due to his concerns about them – concerns which were fully addressed in witness Michels' rebuttal and surrebuttal testimonies. As it turns out, the "market-based avoided cost" data generated by DSMore includes exactly ***zero*** dollars of avoided capacity costs. Perhaps unknowingly, Mr. Luebbert's solution to his (unfounded) concern about the Company's avoided costs was to remove *all* avoided capacity costs. That is certainly not a reasonable solution, even if a problem existed with the Company's avoided costs (which it doesn't). It appears that Mr. Luebbert believed that the data in a column labeled "Adder/Capacity" included market based avoided capacity costs. It does not.

Q. What evidence can you provide that there are absolutely no avoided capacity costs reflected in Mr. Luebbert's rate impact analysis?

A. Here is an excerpt from a section titled "5.4.1 Market-Based Scenario Inputs (Utility Inputs!G3:G8)" of the DSMore user manual describing features related to the "market-based avoided cost" functionality:

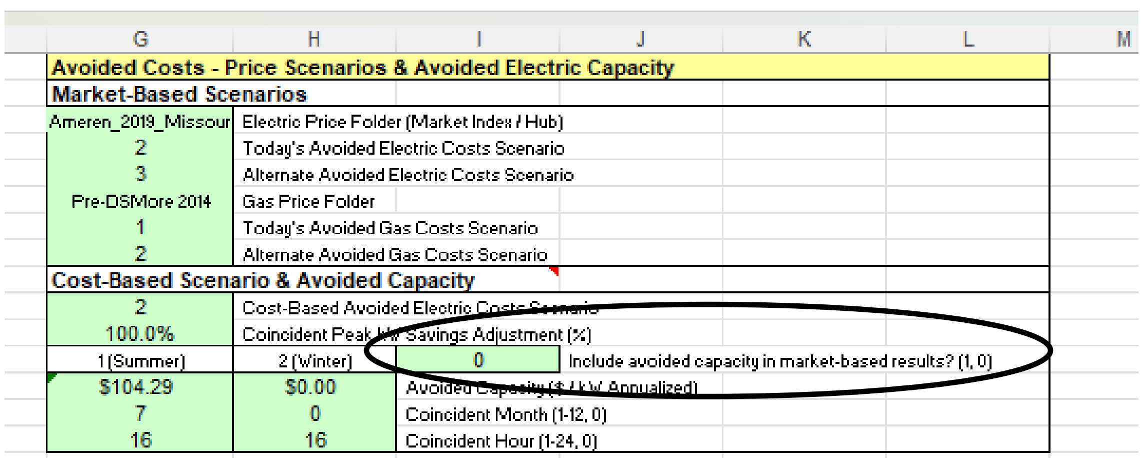
Include avoided capacity in market-based results (I12)

Normally avoided capacity values are **not** included in the market-based results. Entering a“1” will include avoided capacity values in the market-based results.

Q. Did the Company's DSMore input files have a value of "1" entered in the "include avoided capacity…" input area?

A. No. See as Figure 2 below a screenshot of the input file for the Company's DSMore analysis of residential programs in this case, including the black circle that I added around the input where the "include avoided capacity…" is set to zero. This was also the case for the non-residential program input files as well. This means that no avoided capacity costs whatsoever are included in the "market based avoided costs" reported by DSMore.

Figure 2 – DSMore Input File Screenshot



G	H	I	J	K	L
Avoided Costs - Price Scenarios & Avoided Electric Capacity					
Market-Based Scenarios					
Ameren_2019_Missour	Electric Price Folder (Market Index / Hub)				
2	Today's Avoided Electric Costs Scenario				
3	Alternate Avoided Electric Costs Scenario				
Pre-DSMore 2014	Gas Price Folder				
1	Today's Avoided Gas Costs Scenario				
2	Alternate Avoided Gas Costs Scenario				
Cost-Based Scenario & Avoided Capacity					
2	Cost-Based Avoided Electric Costs Scenario				
100.0%	Coincident Peak kW Savings Adjustment (%)				
1 (Summer)	2 (Winter)	0	Include avoided capacity in market-based results? (1, 0)		
$104.29	$0.00	Avoided Capacity ($ / kW Annualized)			
7	0	Coincident Month (1-12, 0)			
16	16	Coincident Hour (1-24, 0)			

Q. What information was in the column labeled "Adders/Capacity" that Mr. Luebbert did include in his calculations in place of avoided capacity costs?

A. The market based avoided cost functionality in DSMore includes certain "adders" that can be included in analysis that relate to the market energy costs – adders that are completely unrelated to capacity costs. The DSMore user manual identifies the following categories of costs – costs which Mr. Luebbert did (presumingly unknowingly) include in his analysis: Ask Adder above Wholesale + Basis Charge (%), Supply, Load Following, and Risk Management Fee (%), Credits and Uncollectibles (%), Operating Retail Costs Avoided (%), and Supplemental Reserve Margin (%). I would go into more detail to describe each of these costs, but that would be unnecessary for purposes of this case, since 1) they are irrelevant since neither the Company nor Staff have argued that any of these "Adder" categories are at issue in this case, and 2) they are not capacity costs, of which Mr. Luebbert was purportedly trying to find an alternate estimate. Figure 3 below is a screenshot of the DSMore input template area where the parameters of each of these adders is fed into the analysis:

Figure 3 – Market Based Avoided Cost Price Scenarios

Avoided Costs - Electric T&D, Electric Adders, & Gas		
Electric		
	$23.10	Avoided Electric T&D ($ / kW)
	Coincident	Savings to Use for Avoided T&D (Coincident, Non-Coincident)
	Summer	Season to Use for Avoided T&D (Summer, Winter)
Peak	Off-Peak	Electric Adders Below Apply To Market-Based Only
47.6%	52.4%	Peak vs. Off-Peak Hours (%)
0.50%	0.50%	Ask Adder above Wholesale + Basis Charge Adder (%)
0.00%	0.00%	Supply, Load Following, and Risk Management Fee Adder (%)
0.00%	0.00%	Credits & Uncollectibles Adder (%)
0.00%	0.00%	Avoided Operating Retail Costs Adder (%)
5.00%	5.00%	Supplemental Reserve Margin Adder (%)

Simply put, Mr. Luebbert replaced the Company's capacity costs with a bucket of irrelevant costs that is not related to or representative of any expectation of capacity costs.

Q. Can you illustrate that these are not closely related to any capacity costs that may be considered in this case?

A. Yes. Mr. Luebbert has repeatedly compared the capacity costs in the DSMore analysis to various capacity forward price scenarios included in the Company's 2023 IRP. As a quick aside, I would first observe that Mr. Michels fully explained the role of each of these types of capacity price curves in his rebuttal testimony, and he further validates the fact that *market-based curves* are used to value capacity revenues associated with DSM resources in the Company's integration analysis *on exactly equal footing* with the way supply side resources are analyzed. In that integration analysis where demand-side and supply-side capacity were valued exactly equally, the resource portfolio reflected in the Company's Preferred Resource Plan and which includes Realistic Achievable Potential ("RAP") demand side management ("DSM") programs was demonstrated to be over $4.1 billion less in NPV of revenue requirement than a portfolio of only supply side resources.

But returning to the chart of capacity price forward curves that Mr. Luebbert repeatedly references, those capacity costs curves would all produce substantially higher totals of avoided capacity costs than the arbitrary avoided cost of "adders" picked up in Mr. Luebbert's analysis. Note the following facts that illustrate this point. From the Company's DSMore workpaper that Mr. Luebbert pulled his "market based avoided cost" numbers from, the total NPV of market based avoided costs associated with the "adders" that Mr. Luebbert conflated with avoided capacity costs is $15,964,955. The "cost based" capacity numbers (those utilized by the Company for its analysis) had an NPV of $309,766,262. The "adder" avoided costs were therefore approximately 5% of the cost based avoided capacity costs used by the Company. Simple visual inspection of the graphs that Mr. Luebbert has repeatedly referenced (for example, Figure 1 on page 17 of his rebuttal testimony) quickly makes it obvious that the market-based capacity price scenarios in the Company's IRP are *far* higher than 5% of the cost-based avoided capacity cost line on that same graph, making any attempt to argue that the avoided cost calculated by DSMore associated with "adders" might offer a reasonable proxy for market base capacity costs impossible. The number adopted by Mr. Luebbert in his rate impact analysis adjusted to exclude avoided T&D and using DSMore "market based avoided costs" are wholly invalid for application to this case in any way.

Q. What is your takeaway related to Staff's calculation of rate impacts based on exclusion of avoided T&D and incorporation of the DSMore calculated "market based avoided costs" to replace avoided capacity costs?

A. Staff's inclusion of no consideration of avoided T&D costs is unreasonable and inconsistent with industry standard practice. Beyond that, the market based avoided cost values reflected in Company workpapers, as was made abundantly clear in our DR response noted by Mr. Luebbert, have no relevance to this case. They fully exclude all consideration of capacity costs and instead include an arbitrary avoided cost associated with "adders" used in the DSMore software associated with categories of cost that no party has argued should be included in this case. The analysis that Staff presents based on this has no foundation and offers no credible evidence of expected rate impacts from the MEEIA 4 programs. I would note that this conclusion is also applicable to Staff witness Sarah Lange's analysis that builds on Mr. Luebbert's analysis, found in SKLK Figure 2 on page 6 of her rebuttal testimony, and which is further referenced periodically throughout her testimony.

VI. STAFF TAKES A VARIETY OF OTHER MERITLESS AND/OR INACCURATE POSITIONS IN OPPOSITION TO THE COMPANY'S MEEIA 4 APPLICATION

Q. What does Staff witness Lange assert with respect to rate increases attributable to the Company's MEEIA 4 plan?

A. Ms. Lange characterizes the amounts to be recovered through the proposed Rider Energy Efficiency Investment Charge ("EEIC") associated with the Company's plan as a 23% rate increase[25]. First, I will say that I disagree with Ms. Lange's calculations of the actual costs (she reports approximately $626 million) that will flow through Rider EEIC. This is because, as I read her workpaper, she includes recovery of all lost revenues net of fuel incurred in the first three years of the programs as a result of the lower sales induced by energy efficiency as being captured in the throughput disincentive ("TD") mechanism and flowing through Rider EEIC, when in reality a significant amount of that cost is likely to be recovered through base rates that are reset in periodic rate cases. But that is really not the issue I take with her rate increase representation at all. The truly stunning issue is that Ms. Lange proceeds to add up costs that her own workpaper shows being recovered over *six years* through Rider EEIC and compares them to the Company's current *single year* revenue requirement to calculate a percentage increase. How it is possible to characterize a *rate increase* (we generally use this phrase in the industry to talk about a comparison of rates applicable in *one period* to rates applicable *in one preceding period* – i.e., an apples to apples comparison of costs incurred by customers across two time periods) by comparing *six years* of costs customers would experience through Rider EEIC associated with the programs to *one year* of cost associated with base rates is beyond me. I wracked my brain to come up with a justification for this characterization and cannot come up with anything that would reasonably explain it.

[25] File No. EO-2023-0136, Sarah Lange Rebuttal Testimony, p. 2, ll. 6-11.

Q. What does Staff witness Lange say with respect to the Rate Impact Measure ("RIM") test?

A. Ms. Lange observes that the RIM test for the Company's MEEIA 4 portfolio is less than 1. This should not be news to anyone and is no different than almost every energy efficiency portfolio that this Commission has ever approved. Ms. Lange claims that this means that the programs cost customers more than it benefits them.[26] This is untrue. The TRC test, discussed at length earlier, is defined as the preferred cost effectiveness test in the state and is well above 1, and it explicitly means that customers do experience significant net benefits from the programs. Ms. Lange's focus on the RIM test appears to be suggesting the displacement of the statutorily defined preferred cost effectiveness test with a test (the RIM test) with a narrower scope. The RIM being lower than 1 ***may*** mean that the benefits do not exceed the costs for a subset of customers – non-participating customers. Hopefully this is a small subset of customers since the Commission has encouraged, and the Company has endeavored to create, programs that are as broad and inclusive as possible to increase participation. And it is certainly true that every single customer has the option to be a participant if they so choose, an option that in and of itself provides value to all customers.

However, even the notion that non-participants will not benefit in the form of lower net costs is speculative, since the cost-effectiveness tests, including the RIM, do not reflect the full impact of energy efficiency, which includes deferred investment in and operation of incremental new generation that would be needed absent the programs – which is only fully and explicitly analyzed in the IRP - as well as significant risk mitigation provided by

[26] File No. EO-2023-0136, Sarah Lange Rebuttal Testimony, p. 24, ll. 2-5.

DSM programs against the need to potentially deploy larger amounts of less cost-effective supply-side resources if load growth is unexpectedly higher than anticipated (a timely risk in today's environment – see my rebuttal testimony for details) or additional environmental regulations that impact existing fossil fueled generation (also a timely risk with the new greenhouse gas and other regulations recently issued by the EPA). The IRP identifies sustained investment in DSM programs as resulting in a revenue requirement more than $4.1 billion lower than what it would be absent DSM programs. *That lower revenue requirement will benefit all customers. So will the significant risk mitigation provided by DSM programs.*

Q. Ms. Lange also observes that the Company relied upon the RIM test to support its proposed Charge Ahead program that included electrification measures and was approved by the Commission in 2019.[27] Does that undermine the Company's MEEIA application in any way?

A. No, not at all. There are several reasons why this makes sense. First, there is no statutory mandate directing the Commission to approve cost-effective electrification programs like exists with MEEIA for DSM programs. The statute tells us the primary metric to use to evaluate a cost-effective DSM program – the TRC, not the RIM. But moreover, because the Company was cognizant that its Charge Ahead request was entirely at the Commission's discretion to approve (i.e., no statutory mandate), it was incumbent upon the Company to systematically build a compelling case that that program was in the public interest from the ground up. Ms. Lange claims that we used the RIM and *not* the TRC in Charge Ahead. The fact is, we used *both* of these tests in concept – although we

[27] File No. EO-2023-0136, Sarah Lange Rebuttal Testimony, p. 24 l. 11 through p. 25 l. 3.

did incorporate a "modification" to the TRC (we referred to this as the mTRC, or modified TRC) to account for savings that our customers experience associated with alternative forms of energy – primarily gasoline and diesel fuel - when adopting electrified measures. The Charge Ahead programs *are* energy efficiency programs, they are not however conventional *electric* energy efficiency programs like MEEIA (the efficiency is observed across multiple fuels). Alternative fuel savings are not incorporated in the typical TRC test, but in explaining how what is often referred to as "beneficial electrification" or "efficient electrification" works, alternative fuel savings are a key part of the story, and we therefore incorporated those alternative fuel savings in the mTRC. However, the Company was aware that passing the mTRC test alone would likely not be considered sufficient justification for the inclusion of costs in the Company's retail electric revenue requirement. If a participant was going to get an electric vehicle and save on their gasoline bill, it would not be likely to be considered justification for all customers to pay the costs of the program through their electric bill to achieve that individual participant's gasoline savings. But the mTRC *in combination with* the favorable RIM results meant that both participating and non-participating customers would be expected to benefit from the Charge Ahead program, which is part of what made the program in the public interest. The public interest of the MEEIA programs in this case are primarily measured by the TRC as required by statute, but also by the Company's IRP which demonstrates that all customers are overwhelmingly better off with the programs than without them.

Q. Staff witness Lange incorporates into her rebuttal testimony a long section discussing "reallocation of the revenue requirement". Please comment on your takeaways from that discussion.

A. Ms. Lange discusses the Company's recovery of the net throughput disincentive ("NTD") – this is lost revenues experienced by the Company that arise from the lower sales levels induced by the Company's DSM programs. Ms. Lange indicates that "[i]t would be reasonable to include an estimate of the cost of the NTD, at a minimum, as a cost in analyzing Ameren Missouri's MEEIA 4 Application, as these amounts will be paid directly by ratepayers." The fact is, though, that absent MEEIA 4, these costs would *still be paid directly by ratepayers* in equivalent amounts. Recall the excerpt from the California Standard Practice Manual in my discussion of the TRC above, which made the point that, "**this test treats** incentives paid to participants and **revenue shifts as transfer payments.**" I previously focused on this quote's emphasis on incentive payments being considered net transfers, but now I would highlight that the exact same is true for "revenue shifts," which characterizes the NTD. These are transfer payments inasmuch as they do not increase or decrease utility net income, they simply reallocate cost recovery between customers. The Company's lost revenues, which it recovers from customers as NTD, exist because of *lower customer bills,* which obviously reduce costs experienced by customers (a benefit to customers). The recovery of those amounts (a cost to customers), in aggregate and in isolation, leaves the Company and customers in the *exact same position* as they would be without MEEIA. If the Company did not have MEEIA programs, the avoidance of NTD charges would not benefit customers in the aggregate, because customers would pay those amounts as a part of their base bills for electric service.

Q. Are there any other points that you would raise about "the reallocation of the revenue requirement"?

A. Yes. Reallocation of the revenue requirement exists in every rate review that is conducted, irrespective of the existence of MEEIA programs. Any changes in customer usage (at least weather normalized usage) between rate cases for any reason results in fixed costs being shifted between customers and between customer classes. That is inherent in utility ratemaking. Customers that are able to reduce their usage between rate cases generally benefit by avoiding paying some amount toward the recovery of fixed costs, and other customers pick up those costs through higher cost allocations and rates as a result. Customers that increase usage between rate cases generally contribute more to fixed cost recovery and result in lower cost allocations and rates for other customers and classes. The fact that the Company is giving its customers tools to manage their usage, and therefore their costs, is a benefit to all customers, because they can all participate at their discretion, and reduce the amount of fixed costs for which they are individually responsible. That the program participants who create the benefits of MEEIA (through lower loads and the avoided energy, capacity, and T&D costs that arise from those lower loads) receive proportionally more of those benefits is not inappropriate. But all customers do receive some level of benefits from cost effective programs as reflected in the TRC, as well as the fact that the IRP analysis demonstrates a more than $4.1 billion reduction in the NPV of revenue requirement associated with a plan that includes RAP level DSM versus the alternative that would include a greater amount of supply side resources.

It's also true that, assuming cost allocation methodologies and ratemaking decisions in rate cases are reflective of the drivers of utility costs, the reallocation of costs from

MEEIA programs for a given rate class should not be expected to negatively impact the other customers within that rate class. The Regulatory Assistance Project's "Electric Cost Allocation for a New ERA" states as follows on the topic:

> [A] program that reduces the loads of one class shrinks its share of the cost pie, increasing other classes' shares of the pie. For the participating class, the reduction in both the size of the pie and the class's share of the pie reduces customers' cost allocation. For each class participating in each program, the program reduces the bills of participants **and the costs allocated to the class**.[28]

This is an important perspective to consider. What this really suggests is that the reallocation of costs that results from, for example, lower residential class sales arising from residential MEEIA programs, should be expected to shift those costs to *other* (i.e., non-residential) rate classes, because the lower residential loads that result from DSM program impacts affect (i.e., reduce) the parameters used to allocate fixed costs to the residential class, and thereby result in lower cost allocations to the class. Under this premise and example, the residential class is unambiguously benefiting from residential class programs once the reallocation of costs has occurred in a subsequent rate review, and it is only customers in other rate classes that would be expected to be impacted at all by the reallocation. This is another perspective through which it can be demonstrated that all customers *within a class* benefit from programs *provided to and for that class*.

[28] Electric Cost Allocation for a New Era – A Manual, Regulatory Assistance Project, Lazar, Chernick, and Marcus, January 2020, p. 167, emphasis added.

Q. Staff makes an "intergenerational equity" argument that suggests that MEEIA programming that has a cost today in exchange for benefits in the future may be considered unfair. How do you respond?

A. To the extent that this is a concern, it has been true of every MEEIA portfolio ever approved by this Commission. But I suggest that the proper lens to view this issue through is the Commission's resource planning rules, which require the valuation of resources on a net present value basis. Future savings are discounted more than current or near-term costs to help mitigate any perceived inequity. Moreover, I think the best way to promote intergenerational equity is to have a sustained commitment to energy efficiency programs that allows customers access to programs at the time of their need in order to help manage their costs when the opportunity arises for them. Staff's proposal to end or pause MEEIA programming at this time could negatively impact a customer who, within the term of the MEEIA 4 programs, is in the market for a new air conditioner, or whatever measure with which the Company could help them achieve higher levels of efficiency. The biggest threat to intergenerational equity that I see is the Staff's proposed starting and stopping of programs to try to "sharpshoot" capacity needs, which will not provide equal opportunity to customers in various stages of their personal investment cycles to participate in the programs that could help to manage their costs.

Q. Staff witness Justin Tevie's rebuttal testimony states, "[a]fter searching through the TRM and related application, I could not find where Ameren Missouri identified specific hours where the greatest savings impact could be achieved. The TRM does not provide such information. It only states a static - not hourly dependent - annual energy savings and coincident factor. This is quite concerning because the

whole premise of MEEIA is based on the concept of avoided cost."[29] What is a coincidence factor?

A. A coincidence factor is a metric that expresses the relationship between energy savings and "the specific hours where the greatest savings impact could be achieved" (i.e., the hour in which the Company's peak load occurs). By virtue of using this coincidence factor that is based on an analysis of the relationship between an end use load shape that may be associated with a given measure and the system peak hour, the Company has done exactly what Mr. Tevie is encouraging it to do with this comment in his testimony.

VII. RESPONSE TO OPC WITNESS MANTLE

Q. What issue is raised by Ms. Mantle?

A. Ms. Mantle characterizes her own testimony as an attempt to clarify the discussion in the direct testimony of Staff witness J Luebbert related to the operation of the Company's Fuel Adjustment Clause ("FAC") and its role in passing the benefits that arise from the Company's MEEIA programs that are the subject of this case to customers. Her testimony indeed does essentially make the same point as Mr. Luebbert's testimony with respect to the FAC's intersection with MEEIA programs. I also addressed this issue in my rebuttal testimony, largely confirming (and making my own effort to clarify) the mechanics of the FAC that Mr. Luebbert described. With minor exceptions that I will note, I think all three of us – that is myself, Ms. Mantle, and Mr. Luebbert – all largely agree on the way the FAC operates to deliver avoided cost benefits from DSM programs to customers.

Q. Are there any portions of Ms. Mantle's discussion of the FAC mechanics that you wish to specifically comment on?

[29] File No. EO-2023-0136, Justin Tevie Rebuttal Testimony, p.7, ll. 11-15.

A. Yes. At page 24 of her rebuttal testimony, Ms. Mantle tries to clarify a point made by Mr. Luebbert, but I believe her clarification is in fact more inaccurate than Mr. Luebbert's original statement. Mr. Luebbert's point, as I understand it, was that, whether energy savings from DSM programs result in higher or lower *FAC* rates depends on the relationship of the market price at the time of the energy savings as compared to the rate established as the Base Factor in the FAC. Ms. Mantle suggests as a point of clarification that this phenomenon is related to how the market price of the energy savings relates to "the average load cost included in the calculation of the base factor in the rate case."[30] Mr. Luebbert's direct testimony correctly identified the Base Factor rate itself, rather than the average cost of load included in the calculation of the Base Factor in the rate case as the key measure for assessing the impact of energy savings on the determination of whether those energy savings will result in higher or lower FAC rates. I explained this phenomenon in great detail in my rebuttal testimony at pages 34-38.

Q. Why is it important to clarify this point?

A. Because I also demonstrated in my rebuttal testimony on pages 38-41, including Tables 2 and 3, that the savings associated with all measure types in the Company's proposed DSM portfolio should be expected to result in lower FAC rates based on a detailed analysis of market prices at the time those measures impact load and a comparison of the measure specific avoided costs that arose from that analysis and the Base Factor in the FAC. This is the proper comparison (i.e., measure specific avoided costs versus Base Factor) to assess potential FAC rate impacts of MEEIA programs. Again, see my rebuttal testimony for details. This analysis and comparison demonstrated that there

[30] File No. EO-2023-0136, Lena M. Mantle Rebuttal Testimony, p. 24, ll. 16-17.

should be no expectation of higher FAC rates arising from implementation of the Company's proposed MEEIA 4 programs – but rather the programs should cause lower future FAC rates than would otherwise exist.

Q. Does Ms. Mantle raise any points in her testimony that further strengthens this conclusion?

A. Yes. Ms. Mantle observes on page 19 of her rebuttal testimony that "Mr. Luebbert did not include the costs or revenues from the capacity market in his examples."[31] This is true, and inclusion of capacity market impacts could only be expected to further lower future FAC rates. To be clear, since MEEIA programs by their very nature reduce peak demand, they can only be expected to reduce capacity costs (lower peak demand means less capacity to be purchased) or increase capacity revenues (or lower peak demand means more Company owned capacity not needed to serve its now lower load is available to sell) – either of those effects reducing net energy costs – that the Company experiences and which pass through the FAC. Changes in capacity costs/revenues have no impact on the calculations associated with the Base Factor, so there is no offsetting effect like there is for changes in total energy consumption that I described in my rebuttal testimony. What this means is that net cost impacts arising from capacity savings from the MEEIA load reductions should only ever *reduce* FAC rates rather than increase them. This further reinforces the conclusion that MEEIA 4 programming should be expected to reduce FAC rates relative to a situation without such programs.

Q. What other comments do you have on Ms. Mantle's characterization of the FAC's role in delivering MEEIA benefits?

[31] File No. EO-2023-0136, Lena M. Mantle Rebuttal Testimony, p. 19, ll. 11-12.

A. Ms. Mantle makes the statement later in her rebuttal testimony that "the majority of benefits of reduced energy usage are realized through Ameren Missouri's FAC".[32] This is not true, as I clearly illustrated in my rebuttal testimony at pages 41-42. As I explained there, the FAC is by its nature a transient mechanism in that it only deals with the recovery from or return to customers of changes in net energy costs that have occurred since the most recent rate case. To that end, the benefits of the long-lived measures of MEEIA are primarily delivered through base rates – in fact, roughly 90% or greater of those benefits will pass through base rates and not the FAC based on the discussion in my rebuttal testimony.

Q. Ms. Mantle, in discussing the capacity market impacts of MEEIA under MISO's seasonal construct, states that "[a]ny MEEIA programs designed using the $236.66 price signal in the 2022-2023 year would not likely impact the fall peak that had the highest price signal in the 2023-2024 year."[33] Is she correct?

A. No. It is a virtual certainty that programs that are designed around the Company's summer peak load would also significantly impact the fall peak load that defines the Company's seasonal capacity obligation. Under MISO's seasonal construct, September is defined as a fall month (MISO's fall season is made up of September, October, and November). The peak for that season is experienced in September an overwhelming majority of the time (in fact, the Company's fall peak, which correlates strongly with MISO's peak, occurred on a hot day in September in each and every one of the last 9 years, which was the number of years of data I had readily available to analyze this phenomenon, on days with average high temperatures in St. Louis of 95 degrees), and is typically on a

[32] File No. EO-2023-0136, Lena M. Mantle Rebuttal Testimony, p. 34, ll. 16-17.
[33] File No. EO-2023-0136, Lena M. Mantle Rebuttal Testimony, p. 17, ll. 4-6.

hot summer-like day where any programs designed around measures that reduce the summer peak load (such as air conditioning measures) would still be affecting the load in a similar manner. Further, the Company's demand response program, even as historically constructed before consideration of seasons other than summer, continues to allow the Company to call DR events through September. Although Ms. Mantle did not mention the spring seasonal capacity market, I would note that spring includes the month of May that also is typically driven by warm weather that would be influenced by those same measures and includes the potential for DR events. It is also worth noting that almost all measures will affect at least some amount of usage at the peak times in most seasons, so Ms. Mantle's blanket statement that programs designed around one season's peak would not impact another season's peak is really an unfair generalization that cannot be expected to be accurate.

VIII. AGGREGATORS OF RETAIL CUSTOMERS ("ARCS") AND TIME OF USE ("TOU") RATES ARE NOT GOOD SUBSTITUTES FOR COMPANY SPONSORED DR PROGRAMS

Q. In describing the potential role of ARCs in providing DR services in the Company's service territory, Dr. Marke of OPC states, "[c]ompetitive ARC's operate in most U.S. states today at no direct cost to ratepayers. Voltus, CPower, or some other ARC do not require ratepayer funds to operate. In this MEEIA proposal though, Ameren Missouri requests that the Commission allow it to continue to fill that free market role through direct subsidies from captive ratepayers."[34] Is there more to the story with respect to ARCs?

[34]File No. EO-2023-0136, Geoff Marke Rebuttal Testimony, p. 7, ll. 8-11.

A. Yes. While it is true that there are no *direct* costs of ARC-sponsored DR programs for non-participating customers, there are also no direct financial benefits from those programs for non-participating customers, as exist with Company-sponsored programs. DR programs are increasingly important in today's tight capacity markets, especially given the current events around the potential for increasing load growth, and also environmental regulations impacting existing generation. They can provide both reliability benefits as well as financial hedges against exposure to spikes in capacity market prices, which we have seen periodically in MISO in recent years. ARC-sponsored programs, to the extent that they perform to expectations, can provide the reliability benefits of DR within MISO. But they provide absolutely zero financial hedge for the Company's customers against exposure to capacity market prices, but rather *increase* exposure to those market prices relative to a world where the same customer would otherwise have enrolled in the Company's program. When a customer of the Company enrolls in the Company's DR program, that customer's load reduction capabilities literally become a resource in the Company's portfolio that improves its capacity position in annual MISO auctions (i.e., we either buy less or sell more capacity as a result of the existence of the DR resource participating in our program), and we obtain that resource at a known price based on the programs that this Commission has approved. When an ARC enrolls a customer of the Company, the capabilities of that Ameren Missouri retail customer to reduce load become a resource owned and controlled by another entity (i.e., the ARC), which, if needed for reliability by the Company, it must buy back at market prices, including potentially elevated market prices that may occur in any given year's capacity auction. Further, when customers participate in Company sponsored programs, the Company has better line of sight to the future expectations with that customer and can be more confident in reliance on that customers' DR capabilities when evaluating future supply side resource needs. Meaning that if a customer is enrolled with an ARC and the Company does not have access to its DR capacity as a resource, the Company may need to build additional supply side resources to shore up any short capacity position, whereas it may not need to do so if the customer was a participant in the Company's DR program where we had high confidence in the stability of that customer and their DR capabilities into the future. Simply put, DR operated through ARCs create a resource for the market. DR operated through MEEIA creates a resource for Ameren Missouri (and its customers).

Q. Dr. Marke also suggests that the existence of DR programs and TOU rates is redundant and amounts to "double dipping." How do you respond to this characterization?

A. This is an inaccurate and unfair characterization. TOU rates and DR programs are both valuable tools for customers, and they can and should co-exist. TOU rates are a very useful but also blunt instrument for reducing peak loads on a specific day (i.e., a peak day where the system is strained). There can be little doubt that the existence of the TOU rates (and customers taking service on them) reduces the Company's load on peak days and creates capacity-related benefits. But there are multiple reasons that DR programs can provide further additional peak load reductions. For example, on a peak day where the system is reaching over-loaded conditions, it is certainly possible for a TOU customer to achieve even higher levels of load reductions than they may naturally create on a daily basis in response to its TOU rate. The incentive in a DR payment, because of the limited time it applies to, can be much larger and therefore more financially enticing for a customer to reduce load than the peak rate that applies every single weekday of the year, and can therefore elicit deeper savings than the TOU rate can. Speaking strictly anecdotally, my household is on a TOU rate – we reduce our peak period usage daily during defined peak hours – and also enrolled in the Peak Time Savings program – *i.e.*, we allow our thermostat to be adjusted by the Company on the rare days when a DR event occurs. On a non-event day, we raise our thermostat by 1 degree during peak hours, but also reduce the operations of large appliances, creating load reductions. On an event day, the program raises our thermostat by approximately 4 degrees, further reducing the operation of our air conditioner and creating higher levels of savings.

But another reason TOU rates and DR programs can be complementary is that not all customers may want to be on a TOU rate. Having different options for how to achieve peak load reductions (TOU rates versus DR) may increase participation by giving customers choice in how to engage in load management. While some customers like the bill savings of TOU rates enough to be willing to live according to the applicable pricing schedule every single day, other customers may not want to manage their load actively on a daily basis. However, many of those non-TOU customers may be more than happy to contribute to system reliability and earn an incentive for load reductions that are only needed on rare occasions throughout the year. It certainly appears with recent experience in the state that optional (rather than mandatory) high differential TOU rates are going to stay the norm in Missouri. So, relying exclusively on TOU to create demand savings may be short-sighted. We should give customers options to manage their usage and costs in multiple different ways that meet customers where they are, and having the option of TOU rates and/or DR programs does exactly that. Further, DR programs can clearly provide greater levels of and more targeted demand reductions than are possible with just TOU rates alone.

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 4th Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by MEEIA.	))))	File No. EO-2023-0136

AFFIDAVIT OF STEVEN WILLS

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

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

My name is Steven Wills and hereby declare on oath that I am of sound mind and lawful age; that I have prepared the foregoing *Surrebuttal Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

/s/ Steven Wills
Steven Wills

Sworn to me this 30th day of May 2024.