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MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

TARIFF/RATE DESIGN DEPARTMENT

DIRECT TESTIMONY

OF

J LUEBBERT

UNION ELECTRIC COMPANY, d/b/a Ameren Missouri

CASE NO. EO-2023-0136

Jefferson City, Missouri
March 1, 2024

** Denotes Confidential Information **

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DIRECT TESTIMONY

OF

J LUEBBERT

UNION ELECTRIC COMPANY,
d/b/a Ameren Missouri

CASE NO. EO-2023-0136

Q. Please state your name and business address.

A. My name is J Luebbert. My business address is P. O. Box 360, Suite 700, Jefferson City, MO 65102.

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

A. I am the Tariff/Rate Design Department Manager for the Missouri Public Service Commission ("Commission").

Q. Please describe your educational background and work experience.

A. I graduated from the University of Missouri in Columbia, Missouri, with a Bachelor of Science in Biological Engineering, in May 2012. My work experience prior to becoming a member of the Missouri Public Service Commission Staff includes three years of regulatory work for the Missouri Department of Natural Resources. Prior to holding my current position, I was employed as Case Manager of the Commission Staff Division and as an Associate Engineer in the Energy Resources and Engineering Analysis Departments of the Industry Analysis Division of Commission Staff.

Throughout my positions with Staff, I have experience in various aspects of utility functions including, but not limited to, Missouri Energy Efficiency Investment Act ("MEEIA") programs, resource planning, general rate cases, risk-sharing mechanisms, Certificate for

Convenience and Necessity ("CCN") applications, and prudence reviews of electric investor-owned utilities ("IOU").

Q. Have you previously filed testimony before the Commission?

A. Yes, numerous times. Please refer to Schedule JL-d1, attached to this Direct Testimony, for a list of the cases in which I have assisted and filed testimony with the Commission.

EXECUTIVE SUMMARY

Q. How is Staff's direct testimony organized?

A. Mr. Fortson provides an overview of Staff's position and a listing of issues addressed by each Staff witness. Ms. Lange's testimony provides an overview of MEEIA and the MEEIA statute, and identifies areas where details complicate those basic premises. My testimony further explains those details that were flagged in Ms. Lange's testimony, as well as additional topics explained briefly below.[1]

Q. What is the purpose of your direct testimony?

A. My testimony will explain that reasonable avoided cost estimates must be the initial building blocks to design a portfolio of programs that comply with Commission rules and the MEEIA statute. Once reasonable avoided cost estimates are established, my testimony will describe how a MEEIA portfolio could be designed to comply with the MEEIA statutory requirements as described in more detail in the direct testimony of Staff witness Sarah L.K. Lange.

Q. Please provide a high-level overview of the remainder of your testimony.

[1] Mr. Brad J. Fortson also addresses Earnings Opportunities if a fourth MEEIA cycle is authorized and Ms. Lange also addresses avoided revenues if a fourth MEEIA cycle is authorized.

A. The concept behind MEEIA is that all customers pay certain amounts today with an expectation that all customers will avoid potential costs in the future. The basic premise of MEEIA is that all customers may benefit from avoided costs in the future in exchange for socializing energy efficiency costs and utility incentives today. If the avoided costs used to evaluate MEEIA programs are not reasonable estimates of the benefits realized by ratepayers through demand-side programs, the underlying premise falls apart.

Identification of the specific costs targeted for avoidance or deferral through energy and demand savings should be the starting point for any MEEIA portfolio. If future investment is not reduced, deferred, or avoided, then no foregone earnings opportunity will have been achieved through the demand-side portfolio implementation, i.e. shareholders will still have an opportunity to earn a return on future supply-side investment.

It is not reasonable for the Commission to order that ratepayers compensate Ameren Missouri shareholders for avoiding generation-related earnings opportunities while Ameren Missouri spends billions of dollars on generation-related investments.

Through the operation of the FAC, even if the avoided energy sales reduce (rather than increase) the FAC rates, those benefits are socialized across all customers. Analysis of whether a demand-side program is cost-beneficial must include consideration of the extent to which avoided costs (or facilitated capacity revenues) flow through the Ameren Missouri FAC, which complicates the Commission's statutory directive to fairly apportion the costs and benefits of MEEIA among classes. These MISO revenues are functionally similar to avoided costs in terms of MEEIA program design, but do not provide any avoided earnings opportunity.

Ameren Missouri's currently adopted preferred resource plan includes investments in supply-side resources that are driven by factors other than capacity planning. Ameren Missouri intends to invest billions of dollars in new generation, transmission, and distribution assets over the next decade.

It is bad public policy and against the spirit of the MEEIA statute to assume benefits associated with avoided generation, transmission, and distribution investments, and award Ameren Missouri millions of dollars in earnings opportunities for MEEIA programs while the Company is simultaneously seeking a return on investments in generation, transmission, and distribution plant that will not be reduced or avoided as a result of MEEIA Cycle 4. There is no way that the result of this double compensation could lead to just or reasonable rates and Staff recommends that the Commission prevent this exact scenario from happening.

If the objectives of MEEIA are not met by the programs included in a MEEIA application, the program should be rejected, redesigned, and reassessed.

AVOIDED COSTS

Q. Why are avoided costs important to MEEIA?

A. The concept behind MEEIA is that all customers pay certain amounts today with an expectation that all customers will avoid potential costs in the future. The basic premise of MEEIA is that all customers may benefit from avoided costs in the future in exchange for socializing energy efficiency costs and utility incentives today. The avoided costs assumptions used to support a MEEIA application must be reasonable estimates of the benefits realized by ratepayers through demand-side programs.

Q. What potential costs can be avoided in the future?

A. With targeted program implementation of demand-side resources, a supply-side resource may be avoided or deferred, distribution costs may be deferred, and transmission costs may be deferred.

Q. Are there costs that can be avoided now through a well-designed demand-side program?

A. Yes. The cost of acquiring energy at wholesale can be reduced through targeted programs. Additionally, through operation of the MISO planning reserve auction, it is possible that enabled revenues – as opposed to a literal avoided cost – can be created through well-designed demand-side programs. Avoided variable costs (or enabled revenues) are possible for energy, capacity, and transmission expenses.[2]

Q. What is the starting point for developing programs to avoid costs in creating a MEEIA portfolio?[3]

A. Identification of the specific costs targeted for avoidance or deferral through energy and demand savings should be the starting point for any MEEIA portfolio. An iterative process is necessary. Discrete avoidable costs should be identified and quantified. That quantification of avoided costs then sets an initial budget for programs designed and target to avoid those costs. The initial avoided cost estimate should also act as a preliminary ceiling to overall portfolio cost. The overall portfolio should be further refined through program design to be the most cost-effective and beneficial for all customers, regardless of participation. Because this process is likely to result in changes in avoided costs due to investment timing and magnitude, the initial avoided cost estimate must be refined to account for the differences.

[2] As I will discuss below in the section "MEEIA and the FAC," the interaction of these two mechanisms must also be considered in quantifying avoided costs, and in determining the benefits of a given program to a particular class of customers.

[3] Throughout my testimony I will generally refer to a set of MEEIA programs as a portfolio. I will also generally refer to series of available energy efficiency measures implemented under a set of program specific tariff sheets as MEEIA programs. Energy efficiency measures are specific pieces of equipment that can be installed at a customer premise that may alter energy usage characteristics. Energy efficiency measures are a subset of an overarching program. Programs are a subset of an approved portfolio.

However, on its face, it's clear that an initial budget should never be set higher than the avoided costs identified.

Q. Are there complications to this analysis?

A. Yes. As I will discuss below, timing, certainty, and fairness among customers in the allocation of costs and benefits all come into play.

Q. Are avoided costs for purposes of MEEIA defined by Commission rule?

A. Yes. 20 CSR 4240-20.092 (1)(C) provides:

> (C) Avoided costs or avoided utility costs means the **cost savings obtained by substituting demand-side programs for existing and new supply-side resources.** Avoided costs include avoided utility costs resulting from demand side programs' **energy savings and demand savings associated with generation, transmission, and distribution facilities including avoided probable environmental compliance costs.** The utility shall use the integrated resource plan and risk analysis used in its most recently adopted preferred resource plan to calculate its avoided costs; [**Emphasis added**.]

Generation facility avoidable costs

Q. Can the cost of a generation facility be avoided with a MEEIA portfolio?

A. Yes. If a utility needs generation capacity, but due to a demand-side program that generation facility can be avoided, then the revenue requirement that would have occurred can be avoided by customers.

Q. Are facility costs associated with generation capacity requirements the only type of avoided generation facility costs a demand-side program can target?

A. No. Another example of a generation facility that could be reduced, deferred, or avoided through a properly designed MEEIA portfolio are facilities that would be built for compliance with the Missouri Renewable Energy Standard.[4] It is possible that a utility plans

[4] 20 CSR 4240-20.100.

to build additional renewable generation to comply with the rule because it reasonably projects to be short on Renewable Energy Credits, which it must have in an amount equal to 15% of all energy sales. It is possible that a well-designed demand-side program would allow the utility to reduce, defer, or avoid the new renewable investment.

Q. If implementing a specific demand-side portfolio will not impact the size or timing of a generation facility, what avoided generation costs are created by that demand-side portfolio?

A. None. To determine avoided costs associated with generation facilities, first, specific generation facility investments to consider for reduction, avoidance, or deferral should be identified.

Next, the timing of demand-side measures to enable that reduction, avoidance or deferral should be identified, including specific magnitude (i.e. number of MW) at what time (both in terms of years, and time of year), should be identified. For example, if summer peak demand in the year 2030 causes the need for a new generation facility, a program to reduce wintertime usage at night in the years 2025 – 2027 will not affect the need for that facility.

If the programs in a MEEIA application are not expected to result in avoided generation facility costs through reduced, deferred or avoided investments, then the avoided costs for a generation facility are zero.

Distribution facility cost

Q. Can distribution facility costs be avoided with a MEEIA portfolio?

A. There are circumstances where a well-designed portfolio can avoid distribution costs. Avoiding distribution system costs requires a targeted, location specific, approach to demand reductions.

Q. Why must distribution avoided costs be the result of targeted, location specific programs?

A. There are variations in the timing of peak load on distribution system equipment, and there are variations in the current loading of distribution system equipment. Reducing current loading on the distribution system will not result in replacing existing infrastructure with cheaper infrastructure with less capacity-carrying ability.[5]

However, if a particular area on the distribution system is expected to be replaced due to meeting or exceeding loading limitations, targeted reductions in the loads of customers served by that equipment could result in life extension of the existing equipment, then those distribution costs could be deferred or avoided.

Q. Would system-wide energy efficiency programs cause distribution facility cost avoidance?

A. It is unlikely, to the point of improbability, that system-wide energy efficiency would appreciably avoid distribution costs. Distribution costs are specific to the location and the associated system characteristics that the facilities are built. Many distribution system components are long lived and new assets are often initially oversized to accommodate future growth. Once the investment in a distribution system asset occurs and is included in rates, there are no distribution system costs savings obtainable through demand-side resources. Unless a demand reduction allows a specific asset's useful life to be extended, it is unlikely that demand-side programs substitute existing or new distribution system resources.

Q. How should avoided distribution facility costs be determined for purposes of a MEEIA application?

[5] Nor would it be cost-effective or prudent to do so in most situations.

A. First, areas of the distribution system projected to require upgrading should be identified. Then, potential programs to reduce, defer, or avoid the need for those upgrades should be considered. Except for targeted, location specific programs designed to address existing distribution constraints, there are no avoided distribution costs to consider for a fourth MEEIA cycle.

Transmission facility cost

Q. Can transmission facility costs be avoided with a MEEIA portfolio?

A. Yes, under the correct circumstances, if a program has been carefully designed to do so. Similar to distribution facility costs, avoiding transmission investments requires a sustained, targeted approach with respect to time periods of reductions and location. This category of costs is unlikely to result in completely avoiding an investment, but costs can conceivably be deferred or reduced.

Avoided Costs are Portfolio Specific

Q. How can the Commission easily assign value to each avoided cost category for purposes of determining whether a proposed MEEIA portfolio provides benefits for all customers in a class, regardless of whether the programs are utilized by all customers?[6]

A. Unfortunately, to have a reasonable analysis, it is not possible to create generic avoided costs levels to use across programs. For the statutory analysis, avoided cost estimates serve as a proxy for the expected benefits of demand-side programs. A given energy efficiency or demand response program will have differences in the timing of expected reductions within a given day, season, and year, but also the time period that reductions will persist. Consider two hypothetical alternative MEEIA portfolios:

[6] 393.1075.4.

Option 1 includes programs that <u>are not expected</u> to result in demand reductions targeting time periods of customer needs for increased infrastructure investment and the energy savings <u>do not persist</u> for a long period of time. The <u>demand reductions</u> regularly occur during time periods that <u>coincide with some of the lowest MISO purchased power costs</u>. Option 1 does not result in avoided investments, meaning that base rates are likely to increase for all ratepayers when the investments in supply-side resources are included. Participants may see some temporary bill reductions based on measure installation energy savings, but those savings will be short-lived and offset by future rate increases. Non-participants are likely to see cost increases as a result of the programs, with little, if any benefit.

Option 2 includes programs with <u>targeted demand reductions that persist</u> for many years and have the ability to reduce, defer, or <u>avoid additional infrastructure investment</u>. The <u>demand reductions</u> also regularly occur during time periods that <u>coincide with the highest MISO purchased power costs</u>. Option 2 is expected to result in the deferral of supply-side infrastructure investment. Participants will see some net bill reductions based on measure installation energy savings for a relatively longer period of time than Option 1. By deferring the investment, rates will be lower during the time of supply-side investment deferral, all else being equal. The lower rates are realized by all ratepayers, regardless of participation.

These two portfolios cannot not be evaluated for purposes of approval and cost-effectiveness utilizing the same avoided cost assumptions because the potential cost savings and the potential for avoided investment will not be the same.

As I will discuss below in the section “MEEIA and the FAC,” the interaction of these two mechanisms must also be considered.

EARNINGS OPPORTUNITY

Q. What is the difference between avoided costs and avoided earnings opportunities?

A. At the simplest level, avoided costs are the revenue requirement of a supply-side resource that will not be built, and avoided earnings opportunities are the portion of avoided revenue requirement that shareholders would have received as their return on their investment.

Q. Is the difference between these concepts important to understanding MEEIA?

A. Yes. A subset of avoidable cost is the revenue requirement of avoidable investment. A portion of the revenue requirement of avoidable investment is the return on the investment that shareholders expect to receive. Attached as Schedule JL-d2, I provide an example walking through a supply side investment deferral. While somewhat lengthy, an understanding of the interplay of avoided costs and potential earnings opportunity is foundational to understanding how ratepayers and shareholders are impacted by MEEIA.

Q. When and with what level of certainty do shareholders receive return on investments in supply side resources?

A. Shareholders have an opportunity to receive a return on investments in supply side resources after an investment in a supply side resource has been included in ratebase to continue over the useful life of that resource.

Q. What is an Earnings Opportunity in a MEEIA cycle?

A. The intent of the Earnings Opportunity as a component of a MEEIA mechanism should be to compensate shareholders for return not earned on investments not made. The EO should be designed to result in utility shareholders receiving compensation to approximate the present value of the earnings opportunity on capacity-related investments that they would receive if the utility did not facilitate DSM programs, all else being equal.

Q. How should the potential Earnings Opportunity component of a MEEIA mechanism be quantified for particular MEEIA programs?

A. As I described above, it is necessary to first identify avoidable supply-side investments, and the timing of those investments. Once the avoided investments are identified and quantified for a specific MEEIA portfolio, the net present value of the shareholder's return on equity (and an allowance for income tax) is the risk-free earnings opportunity.

Q. Are all avoidable costs for ratepayers accompanied by earnings opportunities for shareholders?

A. No. If future investment is not reduced, deferred, or avoided, then no foregone earnings opportunity will have been achieved through the demand-side portfolio implementation. Variable avoided costs, including enabled capacity revenues, do not result in avoided earnings opportunities.

Q. The MEEIA statute requires that a MEEIA mechanism provide timely earnings opportunities associated with cost-effective measurable and verifiable efficiency savings.[7] Can a MEEIA cycle that does not include an EO mechanism comply with this statutory requirement?

A. Yes. To the extent that a MEEIA cycle is not reducing, deferring, or avoiding future investment opportunities, then no EO is appropriate. Even if a MEEIA cycle was initially assumed to reduce, defer, or avoid investment opportunities, and an EO mechanism was included in the initial program design, if those avoided investments cannot be reasonably

[7] 393.1075.3.

established through measured and verified efficiency savings, then the award of an EO is inappropriate.

Lessons Learned Regarding Ameren Missouri Generation Ratebase

Q. Has Ameren Missouri avoided earnings opportunities on capacity-related investments due to promotion of energy efficiency in prior MEEIA cycles?

A. No. Ameren Missouri has grown its gross and net ratebase related to generation capacity while reducing its MW of accredited capacity.[8]

Q. How have Ameren Missouri's net capacity-related investment and its "UCAP"[9] changed over time?

A. Ameren Missouri's net ratebase has increased, the UCAP has decreased, and the $/UCAP MW have increased. Essentially, Ameren Missouri has increased its investment opportunities in generation facilities, while ratepayers have been paying more for less usable capacity. These values are provided below in the Confidential table and illustration below:

**

[redacted]

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[8] Capacity accreditation accounts for the ability of a given resource to provide energy during the hour(s) of peak demand.

[9] MISO determines Unforced Capacity (UCAP) values for all qualified Capacity Resources, Load Modifying Resources and Energy Efficiency Resources annually, prior to the Planning Resource Auction for each Planning Year. MISO converts the installed nameplate capacity of a resource to UCAP to reflect a resource's distinct operating characteristics and expected availability, including deliverability to load, during the coincident peak period. Source: https://cce-help.misoenergy.org/knowledgebase/article/KA-01119/en-us

**

[redacted]

**

Q. Simply put – do ratepayers have more or less available usable capacity than they had in 2013?

A. Less. And rates have increased.

Q. Simply put – do investors have more or less capacity-related investment opportunities than they had in 2013?

A. More. And earnings have increased.

Ameren Missouri's shareholders have gained earnings opportunities due to management decisions to "transform," utility investment in generating assets. This management decision is emphasized from the very first page of its September 26, 2023, Integrated Resource Plan filing,[10] as stated below in the "Executive Summary," under the heading "Ensuring a Reliable and Affordable Transformation."

> Last year, Ameren Missouri announced our plan to accelerate the transformation of our generation portfolio to one with cleaner and more diverse energy resources. The 2022 Preferred Resource Plan included the

[10] EO-2024-0020.

addition of renewable resources to eventually reach 5,400 megawatts (MW) total, consisting of 2,700MW each of new wind and solar generation, along with 800 MW of new battery storage, the accelerated retirement of coal and gas-fired generation, and the addition of 1,200 MW of new and efficient natural gasfired generation. As the Company has continued to execute on that plan, we have also continued to update our planning to include changes in the planning environment. These include changes in policy, such as the Inflation Reduction Act (IRA) passed by Congress in 2022, which provides increased incentives for the deployment of clean energy sources. They also include changes in the utility industry and power markets. Over the last year, we have seen increasing concerns regarding reliability and the sufficiency of resources to meet customer needs, especially during extreme weather events. We have also seen changes in the costs of different resource options, which are a key consideration that can affect the nature and cost of our portfolio transition. In light of these changes, Ameren Missouri has further refined its plan to transition its portfolio in a responsible fashion and ensure reliability and affordability during that transition. Our new plan includes additional on-demand resources to ensure that we can meet our customers' energy needs in all hours, even during extreme weather events. At the same time, we have accelerated planned investments in renewable resources and energy storage resources to take advantage of tax incentives in the IRA that reduce costs to customers while also providing greater energy diversity and availability. Our plan ensures a reliable and affordable transition that results in reductions in CO2 emissions of 60% by 2030 and 85% by 2040, both based on 2005 levels, and net zero emissions by 2045, based on expected development of viable clean dispatchable generation technologies (e.g., hydrogen, carbon capture and sequestration, advanced nuclear, and long-duration energy storage) and does so at the lowest cost to customers. In doing so, we will also support the decarbonization of our region's economy through efficient electrification of transportation and other sectors that currently require fossil fuels. The timeline on page 2 highlights the key elements of our plan.

Q. What is Ameren Missouri's stated intent regarding capacity at this time?

A. Ameren Missouri's executive summary to its 2023 IRP filing,[11] at pages 9 – 10, includes a section titled "Near-Term Implementation," which states:

As mentioned previously, the transformation of our portfolio will involve actions taken by Ameren Missouri and its customers. For example, Ameren Missouri has already secured certificates of

[11] EO-2024-0020.

convenience and necessity (CCN) for two solar projects and applied for CCNs for another four solar projects. Together, these six projects total 900 MW of the 1,800 MW we plan to add to our portfolio by 2030. We continue to pursue additional solar projects to meet our customers energy needs. We also expect to issue another RFP for wind resources in the near term to identify projects that will fulfill our planned addition of 1,000 MW of wind resources by 2030.

In addition, Ameren Missouri has received approval to extend its current energy efficiency and demand response programs through 2024. That extension continues many existing programs for residential and business customers, while also offering business demand response customers the option to opt-out. Programs will retain continuity through 2024 while allowing for the DSM planning team to account for various factors, such as the Inflation Reduction Act, as the next MEEIA cycle is under discussion.

As Ameren Missouri's coal-fired energy centers approach the end of their useful lives, a key step in retiring the units is the assessment of resultant transmission infrastructure needs and the construction of that infrastructure. Our Rush Island Energy Center will be retired by the end of 2024, and the process of putting new transmission system infrastructure in place to support grid reliability needs is underway. With the retirement of our Sioux Energy Center by the end of 2032, we have initiated a similar process to support its retirement. Continued expansion of transmission infrastructure will also be key to integrating renewable wind and solar generation as we transform our portfolio over the next twenty years.

We have also started to take steps for the implementation of the gas-fired simple cycle (800 MW by 2027) and combined cycle (1,200 MW by 2032) generation we are adding to our portfolio to partner with renewable resources and our existing fleet to ensure reliable energy service. Implementation steps over the next three years include design, engineering, procurement, permitting, and securing interconnection rights in MISO as well as efforts to ensure staffing continuity as coal units are retired and gas generators are added.

As we implement these key steps in our portfolio transformation, we will also continue to monitor conditions that may affect our longer-term plans. This includes continually assessing the power market conditions that affect the economics of our planned generation portfolio, such as prices for coal, natural gas, nuclear fuel, and electric power. Similarly, it also includes monitoring expected customer demand and the adequacy and reliability of our portfolio resources to meet our customers' needs. It also includes advocating for constructive energy and economic policies, including those that address investment in energy infrastructure,

> climate change, incentives for clean energy technologies, and environmental regulations. New technologies will be critical to achieving our goal of net-zero CO2 emission by 2045, so we will be continuing to actively participate in efforts to help advance the development of emerging technologies such as carbon capture and sequestration (CCS), the use of hydrogen fuel for electric production and energy storage, next generation nuclear, and large-scale long-duration battery energy storage.

It is not reasonable for the Commission to order that ratepayers compensate Ameren Missouri shareholders for avoiding generation-related earnings opportunities while Ameren Missouri makes billions of dollars of generation-related investments.

Impact of Ameren Missouri's decision to accelerate the transformation of its generation portfolio on Avoidable Costs and Avoidable Earnings Opportunities

Q. Ameren Missouri's currently adopted preferred resource plan includes adding gigawatts of renewable energy resources over the next decade. How does that impact the assumptions of avoided costs associated with MEEIA programs?

A. Renewable energy resources have very low avoidable costs. Renewable energy resources:

1. Are primarily capitalized costs that are set at the time of inclusion in rates;
2. Do not consume any fuel to operate; and
3. Have minimal, if any, operations and maintenance costs that are dependent on the level of generation or dispatch.

Once the capitalized costs are included in rates, there are minimal, if any, costs associated with the assets that can be avoided through MEEIA programs.

An example of the avoidable costs of low- or no-variable cost generation is provided in Schedule JL-d2.

Q. How does Ameren Missouri's management decisions related to supply-side resources effect avoided costs and avoided investments attributable to MEEIA programs.

A. Ameren Missouri's currently adopted preferred resource plan includes investments in supply-side resources that are driven by factors other than capacity planning. Ameren Missouri intends to invest billions of dollars in new generation facilities over the next decade. It is nonsensical to assume benefits associated with avoided generation investments and award Ameren Missouri millions of dollars in earnings opportunities for MEEIA programs while the Company is simultaneously seeking a return on billions of dollars of investments in supply-side resources that extend beyond the needs of supplying ratepayers with safe and adequate service. It is hard to imagine how the result of this double compensation could lead to just or reasonable rates.

Q. How does Ameren Missouri's management decisions related to transmission and distribution resources effect avoided costs and avoided investments attributable to MEEIA programs?

A. Since Ameren Missouri elected Plant-in-Service Accounting ("PISA") treatment, the Company has increased actual and planned capital expenditure on transmission and distribution facilities.[12] According to Ameren Missouri's response to Staff Data Request No. 0030 in this case,

> Based on the analysis outlined above, no projects shown in "exh 1 2023-27 capital investment plan confidential.pdf" are expected to be eliminated or reduced in budget if MEEIA 4 occurs at this time.

It is bad public policy and against the spirit of the MEEIA statute to assume benefits associated with avoided transmission and distribution investments and award Ameren Missouri

[12] An excerpt from Ameren Missouri's most recent 5-year capital investment plan is attached as Schedule JL-d3.

millions of dollars in earnings opportunities for MEEIA programs while the Company is simultaneously seeking a return on investments in transmission and distribution plant that will not be reduced or avoided as a result of MEEIA Cycle 4. There is no way that the result of this double compensation could lead to just or reasonable rates and Staff recommends that the Commission prevent this exact scenario from happening.

Q. Is the rate impact of investments in renewable supply-side resources and the transmission and distribution system included in the revenue requirement impact cap associated with PISA?

A. Yes.

Q. Is the rate impact of the costs associated with a MEEIA portfolio, including earnings opportunities, included in the revenue requirement impact cap associated with PISA?

A. No. The costs recovered through a utility's demand-side investment mechanism are not considered base rates.

ADDITIONAL FACTORS COMPLICATING MEEIA

Q. Ms. Lange mentions and briefly describes additional complications of designing MEEIA cycles, citing your testimony for additional context. Please provide a brief list of those complications that will be addressed in this section of your testimony.

A. This section of my testimony will address additional context, as referenced in Ms. Lange's testimony and necessary to understand MEEIA, and how to effectively implement the MEEIA statute.

Benefits to all customers in a class regardless of whether the programs are utilized by all customers

Q. Does Ameren Missouri's IRP provide a transparent view of the impact of a given MEEIA portfolio application?

A. No. This is due to several factors.

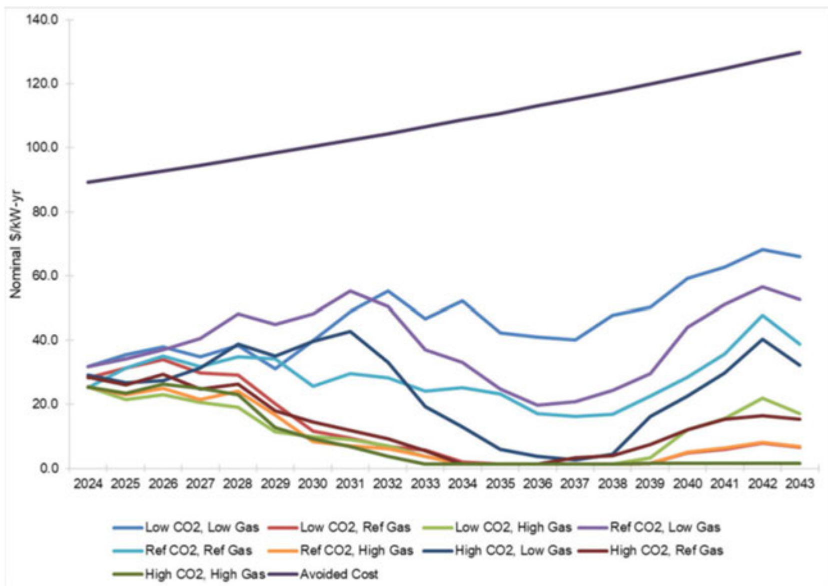
First, Ameren Missouri does not typically include modeling of specific MEEIA cycles as discrete alternatives for comparisons. Most alternative resource plans assume a level of demand-side programs being implemented over a 20-year planning horizon. In essence, these scenarios assume that Ameren Missouri has Cycle 4 through Cycle 11, assuming 3-year cycles continue, approved at a given level of energy and demand savings. To the extent that a supply-side resource appears to be deferred by comparing alternative resource plans with and without demand-side resources, it is not reasonable to assume that the deferral is the result of implementing MEEIA Cycle 4.

A second factor is the energy and demand savings from MEEIA programs have finite lives which are highly dependent on numerous factors, including baseline energy usage, baseline energy efficiency standards, and actual installation of measures.

A third factor is that absent specifically identifying a supply-side resource that can be deferred via a specific MEEIA cycle, i.e. MEEIA Cycle 4, a MEEIA EO may cause Ameren Missouri shareholders to recover "foregone earnings opportunities" for the same plant across multiple cycles resulting in over recovery.

A fourth factor is that the IRP assumes a package of demand-side measures that will not coincide with the measures that are actually installed over time. Most MEEIA applications have included, and the utility has received, a great deal of flexibility how the approved budgets are spent on demand-side programs. All energy efficiency measures have distinct savings attributes and likewise the resulting benefits, or detriments, of implementation will vary as the actual measure installations vary.

A fifth factor is that Ameren Missouri's IRP models demand-side programs preferentially when compared to supply-side resources. The graphic below is an excerpt from Ameren Missouri's 2023 IRP which represents Ameren Missouri's "Capacity Price Assumptions".



The Avoided Cost line is the set of values that Ameren Missouri utilizes for screening demand-side programs for inclusion in the alternative resource plans. The avoided cost value does not account for the seasonal nature of MISO's PRA and is clearly an outlier in terms of assumed value even when comparing to the highest cost alternative pricing assumptions. The result of this overestimated avoided cost in the screening results in flawed assumptions of cost-effectiveness.

Finally, Ameren Missouri does not allow the modeling software used in the IRP to select, size, or optimize demand-side programs being included within alternative resource plans.

The alternative resource plans will select a "level" of demand-side management for the entirety of the planning horizon. There are not thresholds included for adding additional demand-side resources near times of greatest need, nor slowing demand-side management when the timing or size of supply-side resources are not effectively altered.

MEEIA and the FAC

Q. At a high level, how does Ameren Missouri's FAC operate?

A. A simple example of the Base Factor calculation is provided below.

Fuel Cost	$ 1.50
Purchased Power Costs	$ 2.00
Purchased Power Revenue	$ (1.65)
Total/Net	$ 1.85
Energy Sales	100
FAC Base Factor:	$ 0.01850

In this example, when rates are set in a general rate case, Ameren Missouri incurred $1.50 of fuel expense to meet MISO's dispatch instructions, for which it received $1.65 in revenue. At the same time, Ameren Missouri's load required 100 kWh, and the cost of obtaining the energy at wholesale to serve its load was $2.00. These amounts net to $185, and dividing that net cost by the 100 kWh of load results in an FAC base factor of $0.0185 per kWh.

As time goes on, Ameren Missouri keeps track of its actual fuel costs, its actual purchased power revenues, and its actual purchased power costs. When it is time for an FAC filing, the net of these amounts is divided by the actual load during the same time period.

	Base Factor		Actuals
Fuel Cost	$ 1.50		$ 1.20
Purchased Power Costs	$ 2.00		$ 1.90
Purchased Power Revenue	$ (1.65)		$ (1.26)
Total/Net	$ 1.85		$ 1.84
Energy Sales	100		95
		Net Energy Cost:	$ 0.01937
		Difference from Base Factor:	$ 0.00087
		New FAC Rate:	$ 0.00083

Under the FAC sharing calculation, 95% of the difference between the actual net energy cost per kWh and the base factor is then billed as the new FAC rate.[13]

Q. How is the FAC's operation relevant to MEEIA?

A. The FAC operation is relevant to MEEIA in several ways.

First, because of the FAC, while avoiding energy sales may nominally create avoided costs, the relative cost of the energy avoided determines whether any benefit or detriment accrues to Ameren Missouri's customer base.

Second, because of the FAC, even if avoiding an energy sale does create a benefit, that benefit may not be fairly apportioned among the customer classes.[14]

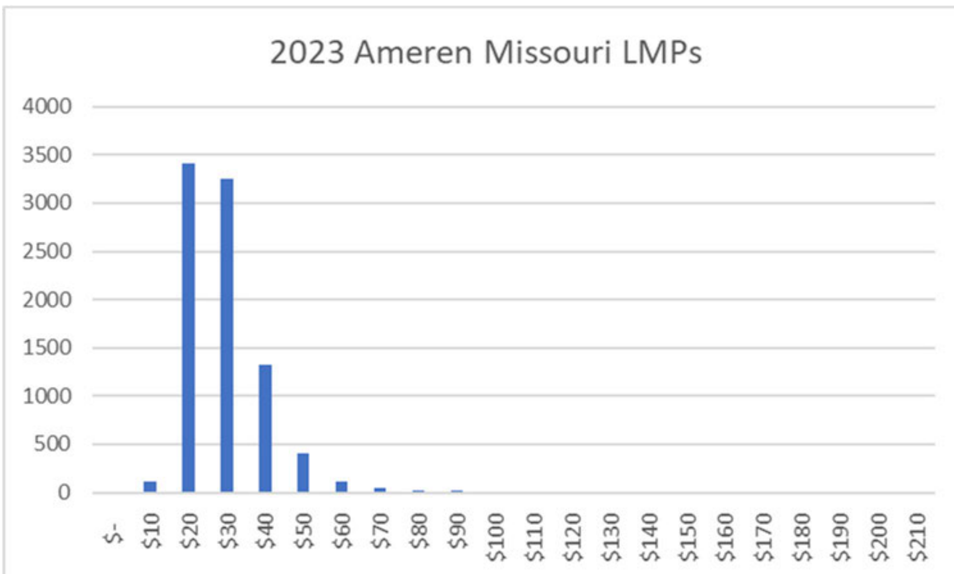
Third, because of the FAC, while a DSM program may enable capacity revenues, the enabled revenue may not be fairly apportioned among the customer classes.

[13] The FAC rate would apply to customer usage on their bill.
[14] Section 393.1075.5, "In setting rates the commission shall fairly apportion the costs and benefits of demand-side programs to each customer class except as provided for in subsection 6 of this section," and Section 393.1075.4, "Recovery for such programs shall not be permitted unless the programs are approved by the commission, result in energy or demand savings and are beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers."

Through operation of the FAC, unless the avoided energy sales are of above-average cost per kWh, the avoided energy sales will result in an increase in the FAC rates, which will offset the benefits received by all customers.

Q. Does the cost of energy at wholesale vary over time?

A. Yes. The graph below illustrates the number of hours that the Ameren Missouri Day Ahead Location Marginal Pricing (DA-LMP) was at various dollar values during the year 2023.



Q. Can you provide a simple illustration of how the FAC operates with regard to avoiding a sale of a kWh at retail associated with a relatively high cost kWh?

A. Yes. For this simplified example assume exactly one kWh is avoided, and that kWh sale would have otherwise occurred in an hour when the cost of energy at wholesale is above the average cost of energy at wholesale.

Fuel Cost	$ 1.50		$ 1.50
Purchased Power Costs	$ 2.00	$ (0.03)	$ 1.97
Purchased Power Revenue	$ (1.65)		$ (1.65)
Total/Net	$ 1.85		$ 1.82
Energy Sales	100	(1)	99
		Net Energy Cost:	$ 0.01838
		Difference from Base Factor:	$(0.00012)
		New FAC Rate:	$(0.00011)

In this example, the only thing that has changed from the initial base factor calculation is that one less kWh is required for Ameren Missouri's load, and that kWh that was avoided had a cost at wholesale that was higher than the average cost of a kWh. The benefit of that avoided kWh is passed to Ameren Missouri's customers through the new FAC rate, which is a reduction to customer bills.

Q. Can you now provide an example where the kWh avoided is a relatively low cost kWh?

A. Yes.

Fuel Cost	$ 1.50		$ 1.50
Purchased Power Costs	$ 2.00	$ (0.01)	$ 1.99
Purchased Power Revenue	$ (1.65)		$ (1.65)
Total/Net	$ 1.85		$ 1.84
Energy Sales	100	(1)	99
		Net Energy Cost:	$ 0.01859
		Difference from Base Factor:	$ 0.00009
		New FAC Rate:	$ 0.00008

Here, avoiding a sale of a relatively inexpensive kWh causes the FAC to increase the bills of all of Ameren Missouri's customers.

Q. Is the Day Ahead energy market the only relevant consideration?

A. No. The Real Time market, transmission costs assessed through Ameren Missouri's load-ratio share, and the Planning Reserve Auction for capacity are also relevant.

Q. Does avoiding a sale of a kWh at retail avoid a sale of a kWh at wholesale, and avoid the expense of the fuel for that generation?

A. It may, if an Ameren Missouri unit is the marginal generating unit, and if the unit has fuel costs that can be reduced or avoided by reducing its output.

Q. Is it Staff's position that because of the FAC no energy costs can ever be avoided for Ameren Missouri's retail customers?

A. No. It is Staff's position that the FACs operation cannot be ignored in attempting to quantify the avoided costs associated with a given MEEIA program. Consideration should be given to, at a minimum, (1) the relative value of wholesale energy purchases expected to be avoided by a given measure, and (2) as discussed in the following two sections, the classes that benefit from avoided costs, and the classes that pay for the creation of the avoided costs through demand-side programs.

Q. What consideration should be given to the relative value of wholesale energy purchases when designing programs?

A. A program expected to avoid purchase of high-cost kWh is much more likely to produce benefits for all customers in a class (regardless of if they participate in that program) than a program that is expected to avoid purchases of average or low-cost kWh. While Ameren Missouri's load shape does not correlate perfectly with the MISO LMP pricing, in general programs that reduce energy consumption at times when energy consumption is high are much more likely to produce net benefits than programs that reduce energy consumption around the clock or in primarily low-usage hours.

Q. With this premise in mind, are there potential low-cost, high-reward programs that could warrant evaluation?

A. Yes. Broadcast or text "peak alert" programs have been employed by cooperative and municipal utilities in Missouri for decades. Generally speaking, such programs notify customers of time periods with exceptionally high costs and request reduced energy usage during that time period.

Through the operation of the FAC, even if the avoided energy sales reduce (rather than increase) the FAC rates, those benefits are socialized across all customers.

Q. Section 393.1075.4 states "Recovery for such programs shall not be permitted unless the programs are approved by the commission, result in energy or demand savings and are beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers." Similarly, Section 393.1075.5 requires "In setting rates the commission shall fairly apportion the costs and benefits of demand-side programs to each customer class except as provided for in subsection 6 of this section." How does the operation of the FAC complicate analysis of whether a program is beneficial to all customers in the customer class in which the program is proposed?

A. Consider the FAC example discussed above, where exactly 1 kWh was avoided, and that kWh was a relatively high-cost kWh. For that program, the customer benefit calculation is provided below:

	$/kWh	kWh	$
Customer benefit	$ 0.00011	99	0.01093

If the cost to produce that 1 kWh of avoided energy sales was exactly 1 cent, the cost to benefit ratio would be as follows:

	Pre-program kWh	Program Costs	Post-program kWh	Customer Benefits	Benefits : Costs
All Customers	100	$ 0.01	99	$ 0.01093	1.0925

Because the ratio of benefits to costs is greater than one, the program is beneficial to all customers, regardless of whether the programs are utilized by all customers. However, the analysis required by statute is whether the program is beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers. Therefore, the next step is to review the costs and benefits of the program on a class level.

	Pre-program kWh	Program Costs	Post-program kWh	Customer Benefits	Benefits : Costs within Class
Class A	10	$ 0.01	9	$ 0.00099	0.099318
Class B	90	$ -	90	$ 0.00993	#DIV/0!

Note that for Class A, which is responsible for the program costs, the customer benefits are lower than the program costs, and therefore the ratio of benefits to costs within the class is less than 1.

Q. What does "#DIV/0!" mean for the ratio of benefits to costs for Class B?

A. This display indicates that a number is divided by zero, which is mathematically impossible. For Class B, there are $0 in program costs, yet there are benefits.

Q. This example considers only avoided energy costs, will this same result occur if avoided energy costs are considered?

A. It depends. Avoided capacity costs will be discussed in the following section. At a high level, the FAC distorts the allocation of potential benefits to customer classes in a manner that is not consistent with the recovery of the cost of demand-side programs. To the extent that a significant source of benefits are derived from avoided energy costs, the interaction of the FAC with the assumed benefits must be considered. This is particularly important for the statutory requirement under that Section 393.1075.5 that "In setting rates the commission shall fairly apportion the costs and benefits of demand-side programs to each customer class except as provided for in subsection 6 of this section."

Q. What are some of the limitations that exist for achieving costs savings through reduced MISO energy purchases to serve retail load?

A. First, a reduction in the purchased power cost through MISO may not be efficient in all hours of the year. Cost savings can only be obtained if the average cost of the MEEIA programs' energy reductions is less than the locational marginal price of energy for a specific kWh saved. There will undoubtedly be hours within each year that it is cheaper to purchase additional energy through MISO than it is to save energy via MEEIA programs. Next, the time periods that can achieve the greatest cost savings must be analyzed and targeted in order to maximize cost reductions. These time periods are subject to change from time to time and the magnitude of the cost reductions is variable over time. Finally, because of the interaction of the FAC, the flow of benefits to the customer classes must be analyzed when evaluating whether a program is cost-beneficial to all customers in a customer class, regardless of participation. This is especially true when some of the reductions in purchased power costs will be achieved in a manner that may not be cost effective (i.e. it costs more to reduce energy consumption than the reduction in purchased power costs that are achieved).

Reductions in capacity can cause new capacity revenues through the integrated marketplace, but those revenues are generally socialized through all customers through the FAC.

Q. Based on MEEIA experience to date, is it more likely that demand side management programs result in avoided production ratebase, or in potential RTO capacity revenues?

A. Potential RTO capacity revenues (or reduced RTO capacity costs) are more likely to occur than avoidance or significant deferral of a generation facility.

Q. Section 393.1075.5 requires "In setting rates the commission shall fairly apportion the costs and benefits of demand-side programs to each customer class except as provided for in subsection 6 of this section." To the extent that the benefits of demand-side programs include avoided RTO capacity costs, or created RTO capacity revenues, how would those benefits flow to the customer classes?

A. Those benefits flow to the customer classes on the basis of loss-adjusted class energy.[15] This result

Q. Does reduced energy usage always result in reduced production from existing supply-side resources, and subsequently reduced emissions from those assets?

A. No. A reduction of a Missouri IOU's load does not necessarily result in a reduction in generation from that IOU's generation facilities.[16]

Q. What are some of the limitations that exist for increased revenues through increased capacity sales through the MISO PRA?

[15] Ameren Missouri's FAC tariff at sheet 71.28 under the MISO energy and operating settlement charges includes "RT resource adequacy auction amount" and at sheet 71.18 it states under purchased power: "Generation capacity acquired in MISO's capacity auction or market; provided such capacity is acquired for a term of one year or less."
[16] In fact, unless the IOUs generating unit is the marginal unit in a specific time period for setting marginal energy cost component when the load is reduced, the utility is unlikely to see any reduction in generation dispatch instructions from the RTO.

A. First, the sales of capacity are uncertain. If demand reductions allow for additional sales of capacity through the PRA, there must be a price taker at a given price. Next, additional revenues are only beneficial if the average cost of the MEEIA programs' demand reductions is less than the cleared price of capacity for a given season. Furthermore, the structure of the MISO PRA complicates this matter. The MISO PRA has shifted to a seasonal construct, which includes four distinct seasons for each planning year.[17] Each PRA season includes a cleared price that can be different from other seasons. The determination of capacity required for each season and the availability of existing Ameren Missouri generation resources is distinct for each season. The cleared PRA prices are currently effective for a single planning year and are variable over time.

Q. Does this mean that demand-side programs can never be cost-beneficial within a customer class to the extent that Ameren Missouri's classes do not consume energy uniformly?

A. No. It means that analysis of whether a demand-side program is cost-beneficial must include consideration of the extent to which avoided costs (or facilitated capacity revenues) flow through the Ameren Missouri FAC. It may also mean that apportionment of program costs among customer classes may need to recognize how the FAC will work to apportion benefits among the customer classes.

Aligning utility financial incentives with helping customers use energy more efficiently

Q. Are there additional aspects that must be considered when reviewing an application for a MEEIA portfolio?

[17] Staff witness Jordan T. Hull's direct testimony discusses MISO's shift to a season PRA.

A. Yes. I will address several topics that provide needed additional context for understanding MEEIA.

Reliability of TRM

Q. How is the reliability of a TRM related to an application for approval of a MEEIA portfolio?

A. A TRM includes energy and demand savings estimates for energy efficiency measures. Energy and demand savings vary by measure and those savings will likely change over time. Different energy efficiency measures that fall within the same category, e.g., appliances, can have very different energy usage profiles, baseline energy consumption estimates, and measure lives. Each of these components can, and likely will, change over time. The reliability of energy and demand savings from a TRM is crucial to accurately estimating the expected energy and demand savings of a MEEIA portfolio.

Estimation of margin rates by measure

Q. How does estimation of margin rates relate to an application for approval of a MEEIA portfolio?

A. To the extent that a marginal rate calculation is included in a throughput disincentive mechanism, it is important that the calculations of net marginal revenues are accurate. As discussed more thoroughly in the testimony of Staff witnesses Justin Tevie and Hari Poudel, the introduction of time of use rates further complicates the existing calculation methods. More granularity and specificity are likely necessary to avoid future over or under recovery if net marginal rates continue as part of a throughput disincentive mechanism.

Differences in expected versus actual measure installations

Q. When past MEEIA cycles have been approved, have the actual installations of energy efficiency measures matched those used to support a given application?

A. No. Past MEEIA cycles have included flexibility of the utility to spend approved budgets. Utilities often request approval of a TRM and incentive ranges that include measures that are not included within the workpapers that support a given application. The measures that have actually been installed differ from those used to support the application.

EM&V

Q. As discussed by Mr. Fortson, in developing prior MEEIA cycles, the benefits used as a part of the cost-effectiveness calculation are the energy and demand savings multiplied by the deemed avoided costs. EM&V, as conducted to date, determines the product of a reviewed level of savings and multiplies that level of savings by the deemed avoided costs, but does not evaluate, measure, or verify costs actually avoided. Must this be the case?

A. No. A relatively simple improvement to EM&V would be to multiply the savings by the DA-LMPs[18][19] as existed in real time while the measures were in place. While review of enabled capacity revenues would be more complicated, some analysis using real capacity auction results would be more meaningful than current practices. The disbursement of these avoided costs through the FAC would have to be considered. This would provide a more meaningful opportunity for the Commission to review whether or not the statutory

[18] Day-ahead Locational Marginal Prices.

[19] Locational Marginal Pricing (LMP) is a market-based pricing mechanism used in electricity markets to determine the cost of electricity at a specific location on the power grid. It reflects the cost of supplying electricity at a particular point, taking into account the cost of generation, transmission losses, and congestion on the power grid. LMP is used to allocate the costs of electricity generation, transmission, and distribution to different locations and to serve as the basis for settling energy transactions. Changing every five minutes or less, LMP reflects changes in supply and demand on the power grid. https://www.misoenergy.org/meet-miso/market-basics/

requirement that a MEEIA portfolio is beneficial to all customers in the customer class in which the programs are proposed regardless of whether the programs are utilized by all customers has been satisfied.

Cost recovery mechanism must align utility actions with customer benefits

Q. Why is the design of the MEEIA cost recovery an important consideration for approval of MEEIA application?

A. My testimony has described the variable nature of many of the assumptions that are included to support a given MEEIA application, as well as the interaction of the FAC on the allocation of some of the benefits. It is imperative that any approved cost recovery mechanism appropriately align utility actions associated with MEEIA programs with the realization of ratepayer benefits. As I discussed earlier in the section titled "Earnings Opportunity", shareholder earnings must be tied to an expected deferral or avoidance of infrastructure investments. Ms. Lange describes Staff's proposed solution to the problems that exist with the current throughput disincentive mechanism.

DESIGNING A MEEIA COMPLIANT PORTFOLIO

Q. What steps should be taken to design a MEEIA compliant portfolio?

A. The design of a reasonable MEEIA portfolio must begin with an achievable outcome that is aligned with statutory and Commission rule requirements.

Identify Avoided Costs and Foregone Earnings Opportunity

Q. Where would you start in designing a MEEIA compliant portfolio?

A. As discussed in the section of my testimony titled "Avoided Costs", the first step to designing a compliant MEEIA portfolio is the identification of investments that can be reduced, deferred, or avoided in order to benefit all ratepayers, including non-participants.

A crucial step in this identification is the specific nature of the investment, the timing of investment, and identification of the determinant of the required investment. Reduction, deferral, or avoidance of these investments are the ultimate end-goals of the MEEIA process. A simplified example of this identification process follows:

1. A utility's capacity expansion modeling establishes that construction of a 300MW simple cycle natural gas plant is appropriate in the year 2027 due to a capacity shortfall occurring during the summer peak hours.
2. The utility identifies that a peak demand reduction of 50 MW in 2027, 100 MW in 2028, and 150 MW in 2029 would allow the plant to be deferred until 2030, and that this deferral would reduce net present value of revenue requirement by $1 million, of which $400,000 is associated with Return on Equity.
3. The utility considers what kinds of programs may produce the identified peak demand reductions, among program options that would cost ratepayers less than $600,000.
4. The utility performs its capacity expansion modeling again, with the program modeled, to determine whether the capacity expansion model delays the plant investment more, less, or the same as assumed in Step 1.
5. The utility considers the impact of the FAC on the costs and benefits of the program to ratepayers over the life of the program, and weighs it against the changes in NPVRR associated with the delayed plant investment.[20]
6. The utility now has a reasonable estimate of the avoidable costs and the avoidable earnings opportunity of the MEEIA program identified.

[20] The variable avoided costs identified should reflect the time variant nature of the costs.

Selection and Review of Programs and Measures

Q. At a class and program or measure level, using the avoided costs identified above, the utility analyzes whether or not the program is beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers.[21] What would be done next?

A. Next the utility would explore the ability to achieve energy and demand savings through demand-side programs as follows:

Once reasonable estimates of avoidable costs and avoidable earnings opportunities are identified, the structure of the portfolio of programs, benefits, and costs can then be derived to maximize the potential ratepayer benefits.

Through this process, the utility can identify programs that do not achieve the end goal of summer peak hour demand reductions as cost effectively as others. The selection of programs should be designed in a manner that maximizes ratepayer benefits, minimizes free-ridership, and ensures that the measures that are incentivized cause summer peak demand savings within the utility service territory. Any program measures that may induce load building should be eliminated or restricted to avoid this adverse outcome.

Finalizing the Portfolio

Q. After eliminating measures and programs that are not ideal fits to achieve the end goal, the utility can develop a portfolio that it expects will defer the investment of a resource until 2030. What would the utility then do?

A. The utility would then:

[21] 393.1075.4.

1. Identify the finalized expected costs for implementing the demand-side programs, including all associated costs such as incentive costs, administrative costs, implementer costs, labor costs, and the costs to measure and verify the demand reductions.
2. Determine the expected demand reductions and cost recovery of each program by rate class and ensure that the demand savings estimates are reasonable, accurate, measurable, verifiable, and obtainable prior to the otherwise required investment.
3. Determine whether the programs will be beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers. This analysis should recognize the allocation of potential benefits and the expected cost recovery of the programs, including operation of the FAC. If the programs will not meet this requirement, the programs should be redesigned and reassessed.
4. Fully develop plans for each program, including key performance indicators and alternatives if savings estimates and expected cost avoidance are not being achieved. The development of any earnings opportunity should be tied to achieving investment reduction, deferral, or avoidance.
5. Fully develop plans for measurement and verification of demand savings for each program.
6. Develop tariffs that will be submitted along with an application for approval of the programs and cost recovery.

7. Develop an application that:
    a. Fully describes each program;
    b. Provides a comprehensive view of the development of the programs;
    c. Identifies and quantifies the specific benefits that the portfolio is expected to provide ratepayers, including those ratepayers that do not participate;
    d. Fully supports all assumptions for the estimation of all energy and demand savings including page specific citations;
    e. Includes all source material utilized to support assumptions;
    f. Includes all workpapers used to support the application and program development;
    g. Includes a guide to the cross-references between workbooks used in support of the application;
    h. Fully describes how the demand savings will be measured and verified to achieve the end goal of supply-side investment deferral;
    i. Complies with all Commission rules with minimal waivers or variances;
    j. Complies with all statutory requirements.

Tariff Development

Q. What level of detail is needed for the tariff that authorize special rate recovery through a Commission-approved MEEIA portfolio?

A. The tariff related to a MEEIA portfolio includes three general sections: Demand-side investment mechanism tariff sheets, program tariff sheets, and portfolio level tariff sheets.

The DSIM tariff sheets should clearly define the treatment, calculation, recovery mechanism, and billing of all applicable charges for the three possible program components, as applicable.[22]

The program tariff sheets should clearly explain the funding, purpose, availability, descriptions, incentive amounts, and implementation details necessary to provide transparency and certainty to ratepayers, the utility, third party administrators, other stakeholders, and the Commission.

The portfolio level tariff sheets should include the required definitions, opt-out provisions, and other terms established in the order authorizing the portfolio that are necessary to provide transparency and certainty to ratepayers, the utility, third-party administrators, other stakeholders, and the Commission. Definitions and use of terminology across programs should be clear and consistent to avoid unnecessary confusion.

Q. How will inclusion of specific information for programs within the tariff aid the Commission in future prudence reviews of the programs?

A. Including detailed requirements within the tariff provides a clear and legally binding framework for reviewing compliance with the approved portfolio. If information is included within the tariff, the review for imprudent actions and expenditures within the context of a prudence review can be more efficiently administered and leaves less room for interpretation of appropriateness after the fact.

Q. Please provide some recent examples of the improved efficiency that would result from more detail being included within the tariff.

[22] Program costs, avoided revenue, and earnings opportunity.

A. The first example is an issue of how budgets are spent once a MEEIA portfolio is approved. Staff and OPC have recognized that in some instances a larger percentage of the budgeted spend has occurred for administration of certain MEEIA programs than the actual incentives provided to program participants. The current Commission rules that govern MEEIA do not explicitly state the percentage of costs that should be utilized for program administration versus program incentive levels. However, this is an aspect of a given MEEIA application that the Commission should consider in deciding whether to approve the application or order modification. MEEIA applications to date have not included detailed information about how a program will be administered, how costs will be minimized, nor how benefits will be achieved and maximized. Requiring more detail in the tariff sheets will mean that the Commission, Staff, and other stakeholders have that information with the application and proposed tariff sheets at the start, making the overall process more efficient going forward.

Staff recommends that if any MEEIA programs are approved, that the Company be ordered to file tariff sheets for each approved program that includes at least the following information:

1. Description of the purpose of the program including the desired outcome of implementation,
2. Descriptions of availability for each program,
3. Clear definitions of terms of the program,
4. Program level budget, by year, broken down by cost categories, such as incentive amounts, administration, labor, measurement and verification,
5. Energy efficiency measures that are available through each program,
6. Incentive amount for each measure available through each program,

7. Description of the recovery of program administration, purpose, availability, descriptions, incentive amounts, applicable rates, restrictions, etc.

8. Explanation of the evaluation of each program including, but not limited to, how achieved savings will be measures or verified and the determination of goals achieved through program implementation.

CONCLUSION

Q. Please briefly summarize your testimony.

A. Identification of specific costs that can be avoided or deferred through energy and demand savings should be the starting point for any MEEIA portfolio. More specifically, investments that can be avoided or deferred are the starting point for determining an earnings opportunity for utility shareholders in return for facilitating ratepayer-funded demand side programs. Analysis of whether a demand-side program is cost-beneficial must include consideration of the extent to which avoided costs (or facilitated capacity revenues) flow through the Ameren Missouri FAC, which complicates the Commission's statutory directive to fairly apportion the costs and benefits of MEEIA among classes.

It is bad public policy and against the spirit of the MEEIA statute to assume benefits associated with avoided generation, transmission, and distribution investments and award Ameren Missouri millions of dollars in earnings opportunities for MEEIA programs while the Company is simultaneously seeking a return on investments in generation, transmission, and distribution plant that will not be reduced or avoided as a result of MEEIA Cycle 4. There is no way that the result of this double compensation could lead to just or reasonable rates and Staff recommends that the Commission prevent this exact scenario from happening.

If the objectives of MEEIA are not met by the programs included in a MEEIA application, the program should be rejected, redesigned, and reassessed. If any program is approved, Staff recommends detailed compliance tariff sheets be ordered by the Commission as discussed in the section "Tariff Development" of my testimony.

Q. Does this conclude your Direct 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	)))))	Case No. EO-2023-0136

AFFIDAVIT OF J LUEBBERT

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW J LUEBBERT and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Direct Testimony of J Luebbert*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

J LUEBBERT

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 28th day of February 2024.

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: July 18, 2027
Commission Number: 15207377

Dianna L. Vaught
Notary Public

Case Participation of
J Luebbert

Case Number	Company	Issues
EO-2015-0055	Ameren Missouri	Evaluation, Measurement, and Verification
EO-2016-0223	Empire District Electric Company	Integrated Resource Planning Requirements
EO-2016-0228	Ameren Missouri	Utilization of Generation Capacity, Plant Outages, and Demand Response Program
ER-2016-0179	Ameren Missouri	Heat Rate Testing
ER-2016-0285	Kansas City Power & Light Company	Heat Rate Testing
EO-2017-0065	Empire District Electric Company	Utilization of Generation Capacity and Station Outages
EO-2017-0231	Kansas City Power & Light Company	Utilization of Generation Capacity, Heat Rates, and Plant Outages
EO-2017-0232	KCP&L Greater Missouri Operations Company	Utilization of Generation Capacity, Heat Rates, and Plant Outages
EO-2018-0038	Ameren Missouri	Integrated Resource Planning Requirements
EO-2018-0067	Ameren Missouri	Utilization of Generation Capacity, Heat Rates, and Plant Outages
EO-2018-0211	Ameren Missouri	Avoided Costs and Demand Response Programs
EA-2019-0010	Empire District Electric Company	Market Protection Provision
GO-2019-0115	Spire East	Policy
GO-2019-0116	Spire West	Policy
EO-2019-0132	Kansas City Power & Light Company	Avoided Cost, SPP resource adequacy requirements, and Demand Response Programs
ER-2019-0335	Ameren Missouri	Unregulated Competition Waivers and Class Cost Of Service
ER-2019-0374	Empire District Electric Company	SPP resource adequacy
EO-2020-0227	Evergy Missouri Metro	Demand Response programs
EO-2020-0228	Evergy Missouri West	Demand Response programs
EO-2020-0262	Evergy Missouri Metro	Demand Response programs
EO-2020-0263	Evergy Missouri West	Demand Response programs
EO-2020-0280	Evergy Missouri Metro	Integrated Resource Planning Requirements

cont'd J Luebbert

Case Number	Company	Issues
EO-2020-0281	Evergy Missouri West	Integrated Resource Planning Requirements
EO-2021-0021	Ameren Missouri	Integrated Resource Planning Requirements
EO-2021-0032	Evergy	Renewable Generation and Retirements
GR-2021-0108	Spire Missouri	Metering and Combined Heat and Power
ET-2021-0151	Evergy	Capacity costs
ER-2021-0240	Ameren Missouri	Market Prices, Construction Audit, Smart Energy Plan, AMI
ER-2021-0312	Empire District Electric Company	Construction Audit, Market Price Protection, PISA Reporting
EO-2022-0193	Empire District Electric Company	Retirement of Asbury
ER-2022-0129	Evergy Missouri Metro	MEEIA annualization
ER-2022-0130	Evergy Missouri West	MEEIA annualization, Schedule SIL revenue and incremental costs
EF-2022-0155	Evergy Missouri West	Customer event balancing
EC-2022-0315	Evergy Missouri West	Compliance with Stipulation and Agreement, Commission Order, and Schedule SIL
GR-2022-0179	Spire Missouri	Compressed Natural Gas
EA-2022-0244	Ameren Missouri	Huck Finn Solar CCN
EA-2022-0245	Ameren Missouri	Boomtown Solar CCN
EA-2022-0328	Evergy Missouri West	Persimmon Creek CCN
ER-2022-0337	Ameren Missouri	Billing determinant adjustments
EA-2023-0286	Ameren Missouri	Solar CCNs
EO-2024-0002	Evergy Missouri West Evergy Missouri Metro	Data retention

Hypothetical explanation of foregone earnings opportunity

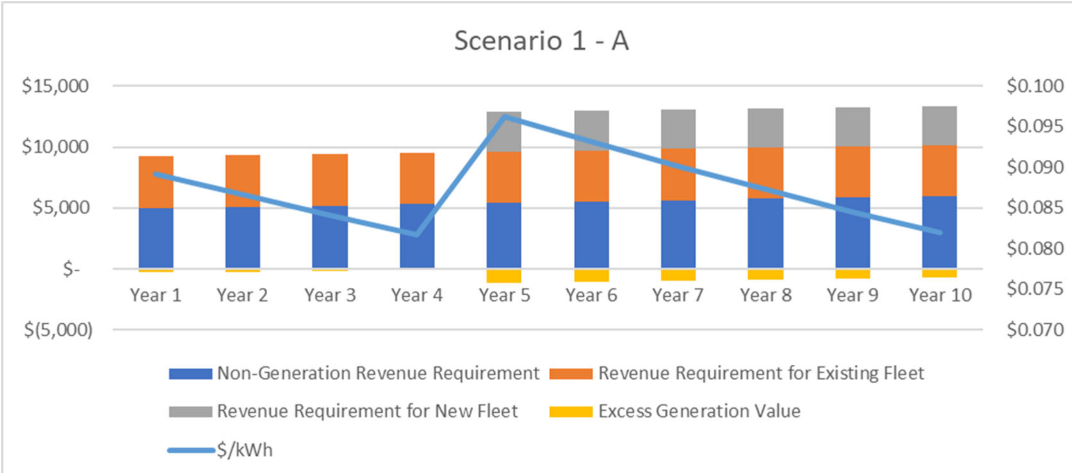
Q. Could you walk through an illustration of the theory behind MEEIA?

A. Yes. In the first scenario of this simplified example, we will assume that our example utility anticipates a need to install a new power plant in planning year 5. The table below illustrates the existing revenue requirement, including detailed line items for the existing generation revenue requirement, and detailed line items for the revenue requirement associated with the additional generation to be added in planning year 5:

Scenario 1 - A	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Generation Capability	120,000	120,000	120,000	120,000	200,000	200,000	200,000	200,000	200,000	200,000
Annual Load	100,000	105,000	110,250	115,763	121,551	127,628	134,010	140,710	147,746	155,133
Generation-related Ratebase	$ 1,000	$ 967	$ 933	$ 900	$ 867	$ 833	$ 800	$ 767	$ 733	$ 700
Generation-related Depreciation	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33
Generation-related Return on Equity	$ 50	$ 48	$ 47	$ 45	$ 43	$ 42	$ 40	$ 38	$ 37	$ 35
Generation-related Cost of Debt	$ 25	$ 24	$ 23	$ 23	$ 22	$ 21	$ 20	$ 19	$ 18	$ 18
Generation-related Income Tax	$ 10	$ 10	$ 9	$ 9	$ 9	$ 8	$ 8	$ 8	$ 7	$ 7
Fuel Costs	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400
Generation-Related O&M	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700
Additional Generation-related Ratebase					$ 3,000	$ 2,900	$ 2,800	$ 2,700	$ 2,600	$ 2,500
Additional Generation-related Depreciation					$ 100	$ 100	$ 100	$ 100	$ 100	$ 100
Additional Generation-related Return on Equity					$ 150	$ 145	$ 140	$ 135	$ 130	$ 125
Additional Generation-related Cost of Debt					$ 75	$ 73	$ 70	$ 68	$ 65	$ 63
Additional Generation-related Income Tax					$ 30	$ 29	$ 28	$ 27	$ 26	$ 25
Additional Fuel Costs					$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600
Additional Generation-Related O&M					$ 1,300	$ 1,300	$ 1,300	$ 1,300	$ 1,300	$ 1,300
Excess Generation Value	$ (300)	$ (225)	$ (146)	$ (64)	$ (1,177)	$ (1,086)	$ (990)	$ (889)	$ (784)	$ (673)
Non-Generation Revenue Requirement	$ 5,000	$ 5,100	$ 5,202	$ 5,306	$ 5,412	$ 5,520	$ 5,631	$ 5,743	$ 5,858	$ 5,975
Total Revenue Requirement	$ 8,918	$ 9,091	$ 9,268	$ 9,452	$ 11,697	$ 11,885	$ 12,080	$ 12,282	$ 12,491	$ 12,708
$/kWh	$ 0.0892	$ 0.0866	$ 0.0841	$ 0.0817	$ 0.0962	$ 0.0931	$ 0.0901	$ 0.0873	$ 0.0845	$ 0.0819

The summary of this revenue requirement calculation is provided below, as a table and an illustration:

Scenario 1 - A	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Non-Generation Revenue Requirement	$ 5,000	$ 5,100	$ 5,202	$ 5,306	$ 5,412	$ 5,520	$ 5,631	$ 5,743	$ 5,858	$ 5,975
Revenue Requirement for Existing Fleet	$ 4,218	$ 4,216	$ 4,213	$ 4,210	$ 4,207	$ 4,204	$ 4,201	$ 4,199	$ 4,196	$ 4,193
Revenue Requirement for New Fleet	$ -	$ -	$ -	$ -	$ 3,255	$ 3,247	$ 3,238	$ 3,230	$ 3,221	$ 3,213
Excess Generation Value	$ (300)	$ (225)	$ (146)	$ (64)	$ (1,177)	$ (1,086)	$ (990)	$ (889)	$ (784)	$ (673)
Total Revenue Requirment	$ 8,918	$ 9,091	$ 9,268	$ 9,452	$ 11,697	$ 11,885	$ 12,080	$ 12,282	$ 12,491	$ 12,708
$/kWh	$ 0.089	$ 0.087	$ 0.084	$ 0.082	$ 0.096	$ 0.093	$ 0.090	$ 0.087	$ 0.085	$ 0.082



Q. What is the takeaway from Scenario 1 – A?

A. Scenario 1 – A demonstrates that adding the example power plant in Year 5 increases overall revenue requirement and average $/kWh.

Q. What will you illustrate in Scenario 2 – A?

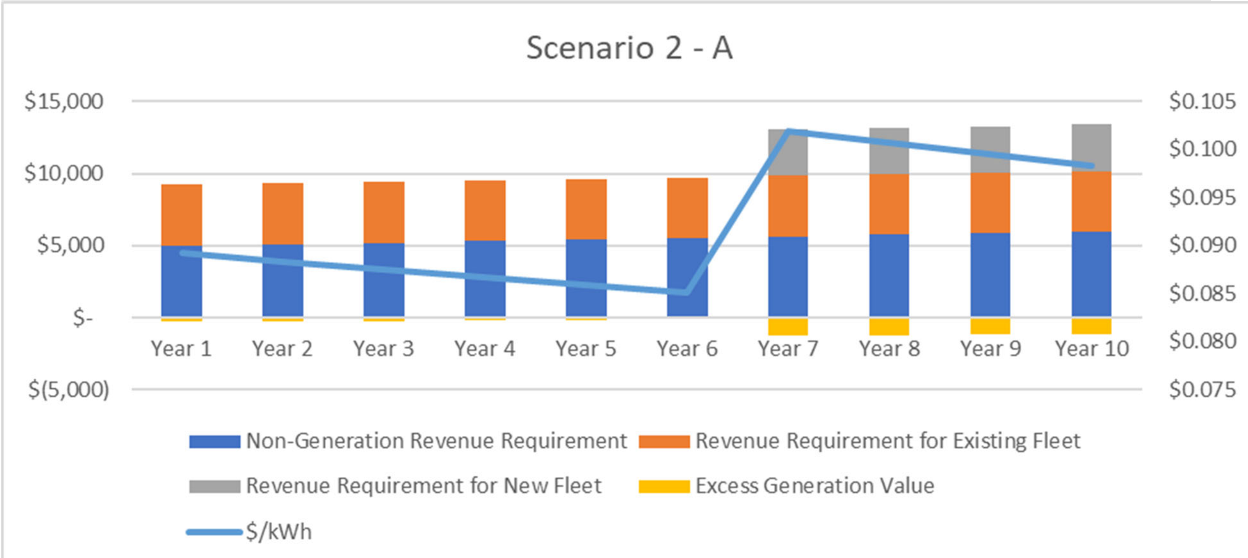
A. Scenario 2 – A will illustrate a two-year plant deferral. In Scenario 2 - A, the annual load growth is half of the load growth assumed in Scenario 1 – A.[1] As a result, the need for the plant is pushed back to Planning Year 7. The detailed revenue requirement is set out below:

Scenario 2 - A	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Generation Capability	120,000	120,000	120,000	120,000	120,000	120,000	200,000	200,000	200,000	200,000
Annual Load	100,000	102,500	105,063	107,689	110,381	113,141	115,969	118,869	121,840	124,886
Generation-related Ratebase	$ 1,000	$ 967	$ 933	$ 900	$ 867	$ 833	$ 800	$ 767	$ 733	$ 700
Generation-related Depreciation	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33
Generation-related Return on Equity	$ 50	$ 48	$ 47	$ 45	$ 43	$ 42	$ 40	$ 38	$ 37	$ 35
Generation-related Cost of Debt	$ 25	$ 24	$ 23	$ 23	$ 22	$ 21	$ 20	$ 19	$ 18	$ 18
Generation-related Income Tax	$ 10	$ 10	$ 9	$ 9	$ 9	$ 8	$ 8	$ 8	$ 7	$ 7
Fuel Costs	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400	$ 2,400
Generation-Related O&M	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700	$ 1,700
Additional Generation-related Ratebase							$ 3,000	$ 2,900	$ 2,800	$ 2,700
Additional Generation-related Depreciation							$ 100	$ 100	$ 100	$ 100
Additional Generation-related Return on Equity							$ 150	$ 145	$ 140	$ 135
Additional Generation-related Cost of Debt							$ 75	$ 73	$ 70	$ 68
Additional Generation-related Income Tax							$ 30	$ 29	$ 28	$ 27
Additional Fuel Costs							$ 1,600	$ 1,600	$ 1,600	$ 1,600
Additional Generation-Related O&M							$ 1,300	$ 1,300	$ 1,300	$ 1,300
Excess Generation Value	$ (300)	$ (263)	$ (224)	$ (185)	$ (144)	$ (103)	$ (1,260)	$ (1,217)	$ (1,172)	$ (1,127)
Non-Generation Revenue Requirement	$ 5,000	$ 5,100	$ 5,202	$ 5,306	$ 5,412	$ 5,520	$ 5,631	$ 5,743	$ 5,858	$ 5,975
Total Revenue Requirement	$ 8,918	$ 9,053	$ 9,191	$ 9,331	$ 9,475	$ 9,622	$ 11,827	$ 11,971	$ 12,120	$ 12,271
$/kWh	$ 0.0892	$ 0.0883	$ 0.0875	$ 0.0866	$ 0.0858	$ 0.0850	$ 0.1020	$ 0.1007	$ 0.0995	$ 0.0983

The simplified revenue requirements summation, as a table and as an illustration, is provided below:

[1] The same overall load shape is assumed, such that the relationship between capacity requirements and annual load is consistent across scenarios.

Scenario 2 - A	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Non-Generation Revenue Requirement	$ 5,000	$ 5,100	$ 5,202	$ 5,306	$ 5,412	$ 5,520	$ 5,631	$ 5,743	$ 5,858	$ 5,975
Revenue Requirement for Existing Fleet	$ 4,218	$ 4,216	$ 4,213	$ 4,210	$ 4,207	$ 4,204	$ 4,201	$ 4,199	$ 4,196	$ 4,193
Revenue Requirement for New Fleet	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,255	$ 3,247	$ 3,238	$ 3,230
Excess Generation Value	$ (300)	$ (263)	$ (224)	$ (185)	$ (144)	$ (103)	$ (1,260)	$ (1,217)	$ (1,172)	$ (1,127)
Total Revenue Requirment	$ 8,918	$ 9,053	$ 9,191	$ 9,331	$ 9,475	$ 9,622	$ 11,827	$ 11,971	$ 12,120	$ 12,271
$/kWh	$ 0.089	$ 0.088	$ 0.087	$ 0.087	$ 0.086	$ 0.085	$ 0.102	$ 0.101	$ 0.099	$ 0.098



Q. What are the revenue requirement differences between Scenarios 1-A and 2-A?

A. The differences on an annually and present-valued basis are provided below:

		1	2	3	4	5	6	7	8	9	10
Scenario 1	Total Revenue Requirement	$ 8,918	$ 9,091	$ 9,268	$ 9,452	$ 11,697	$ 11,885	$ 12,080	$ 12,282	$ 12,491	$ 12,708
Scenario 2	Total Revenue Requirement	$ 8,918	$ 9,053	$ 9,191	$ 9,331	$ 9,475	$ 9,622	$ 11,827	$ 11,971	$ 12,120	$ 12,271
		$ -	$ 38	$ 78	$ 121	$ 2,223	$ 2,264	$ 254	$ 311	$ 372	$ 437
$ 3,933	NPVRR Difference		$ 32	$ 63	$ 91	$ 1,548	$ 1,467	$ 153	$ 174	$ 194	$ 212

Q. It appears that the differences between Scenarios 1 and 2 save ratepayers money, is this accurate?

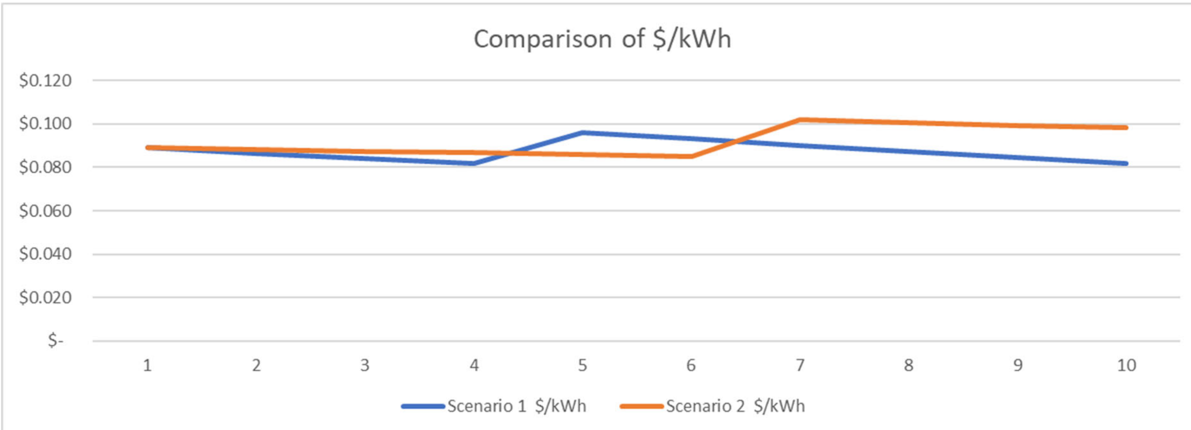
A. Generally, yes. However, as an initial matter, note that I did not include the full life revenue requirement of the generation addition, as it is assumed to be in service for 30 years. As such, Scenario 1 – A includes 6/30 years of the plant's revenue requirement, while Scenario 2 – A includes only 4/30 years.

Q. All else being equal, if a generation addition can be avoided or delayed, will it save ratepayers money?

A. Yes, and this is the fundamental concept of MEEIA.

Q. Is all of the difference between the two scenarios savings to ratepayers?

A. No. This is best illustrated by looking at the differences in the average $/kWh over time.



During the early years, Scenario 2 costs ratepayers more per kWh for the kWh consumed, because there are fewer kWh added each year over which to spread non-energy revenue requirement. Additional complications include the existence of the fuel adjustment clause and of the MISO integrated energy market as discussed in the subsection of my testimony titled "MEEIA and the FAC". Additionally, rate case timing and various regulatory treatments such as PISA,[2] the RESRAM, and various renewable programs such as community solar and voluntary green programs complicate perfect calculations, much less simplified examples.

Q. This example is far from simple, can you further simplify it?

A. Unfortunately, no. MEEIA is an incredibly complex concept and relies on a series of mechanisms and assumptions to place utility shareholders in a position in the near term comparable to the position utility shareholders would be in in the long term, if the shareholders had not facilitated DSM programs with ratepayer funds.

Q. In this example, what earnings opportunity are shareholders foregoing by facilitating DSM programs with ratepayer funds?

[2] Plant in service accounting.

A. In this example, the earnings opportunity shareholders are foregoing by facilitating DSM programs with ratepayer funds is the difference between Scenario 1 – A and 2 – A during years 5 – 10, for specific revenue requirement lines.

Q. Which revenue requirement lines illustrate the foregone earnings opportunity for years 5 – 10?

A. For shareholders, only the "Additional Generation-related Return on Equity" would be considered in calculation of a foregone earnings opportunity in years 5 – 10.

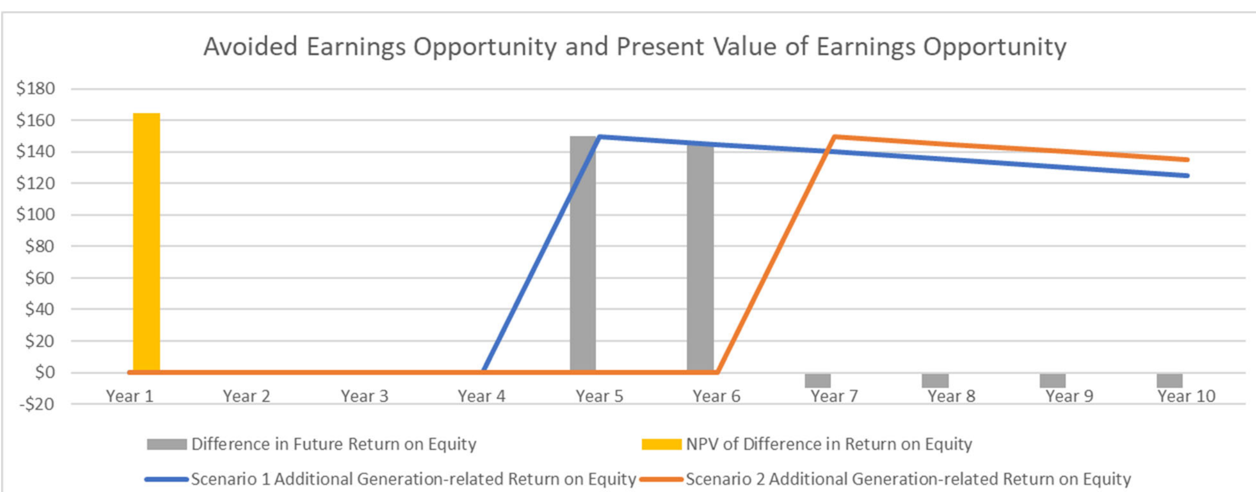
		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Scenario 1	Additional Generation-related Return on Equity	$ -	$ -	$ -	$ -	$ 150.00	$ 145.00	$ 140.00	$ 135.00	$ 130.00	$ 125.00
Scenario 2	Additional Generation-related Return on Equity	$ -	$ -	$ -	$ -	$ -	$ -	$ 150.00	$ 145.00	$ 140.00	$ 135.00
	Difference	$ -	$ -	$ -	$ -	$ 150	$ 145	$ (10)	$ (10)	$ (10)	$ (10)

Q. Are there additional costs that would be payable by ratepayers, but not retained by shareholders associated with a foregone earnings opportunity in years 5 – 10?

A. Yes. Shareholders would not retain the "Additional Generation-related Income Tax," but ratepayers would pay revenue requirement for that expense.

Q. Can you illustrate the equivalent difference in future earnings opportunity and a compensation for that earnings opportunity if it occurred in Year 1?

A. Yes. The compensation for earnings opportunity is typically designed to occur in years 4 – 5; given the simplicity of this example, I will illustrate the equivalent values in Year 1.



Q. What does this hypothetical illustration show?

A. This illustrates that if shareholders facilitate ratepayer funded DSM programs today, shareholders will forgo an earnings opportunity around $200 as a return on investment in years 5 and 6.[3] However, to compensate shareholders today for foregone future earnings, a payment of about $164 today would put shareholders in the same position they would have been in if the shareholders had not facilitated ratepayer-funded DSM.

Q. Is the NPV amount in year 1 taxable as income?

A. Yes. It is my understanding that the NPV compensation for future earnings opportunity is taxable as income, just as the actual earnings on actual rate base in year 5 and beyond would be taxable as income.

Q. If shareholders are provided with a payment of $164 plus an allowance for income tax today, are they in the same or better position than they would be if shareholders had an investment opportunity to earn a return worth about $200 in years 5 & 6, plus an allowance for income tax?

A. Frankly, shareholders are in a better position under this approach, in that the recovery of $164 is guaranteed and is subject to true-up down to the penny. However, if shareholders actually support investment in years 5 and 6, the shareholders will only have an opportunity to recover the awarded return on equity through rates, which is a risk for which the awarded RoE compensates. The $200 includes compensation for the shareholders of the risk of non-recovery, although recovery of the $164 is certain. In any case, shareholders are in at least the same position as if they had not facilitated ratepayer funding of DSM programs.

[3] As discussed above, this is a simplified example. If this illustration were expanded out to 40 years, shareholders would earn more return on equity in Scenario 2 than in Scenario 1 in years 35 and 36. However, when this difference is discounted to the net present value, the differences in years 5 and 6 are worth more than the offsetting differences in years 35 and 36.

Q. If ratepayers provide shareholders with a payment of $164 plus an allowance for income tax today,[4] are they in the same or better position than they would be if they provided a return on equity of about $200 in years 5 & 6, plus an allowance for income tax?

A. With regard to only the return aspect, and setting aside intergenerational equity considerations, ratepayers are in the same position whether the lesser amount is paid today, or the greater amount in a few years. The intergenerational equity concerns grow the more distant a deferred investment is in time.

Q. Are there other aspects in this example where ratepayers are better off due to providing funds for the utility to facilitate DSM?

A. Yes. The ratepayers are able to avoid (or defer) revenue requirement associated with the additional depreciation, the additional cost of debt, and additional generation-related O&M. Setting aside complexities of the FAC and the IM, for purposes of this example, additional fuel costs and net margins are also avoided or deferred. These calculations are illustrated below:

		1	2	3	4	5	6	7	8	9	10
Scenario 1	Total Revenue Requirement	$ 8,918	$ 9,091	$ 9,268	$ 9,452	$ 11,697	$ 11,885	$ 12,080	$ 12,282	$ 12,491	$ 12,708
Scenario 2	Total Revenue Requirement	$ 8,918	$ 9,053	$ 9,191	$ 9,331	$ 9,475	$ 9,622	$ 11,827	$ 11,971	$ 12,120	$ 12,271
		$ -	$ 38	$ 78	$ 121	$ 2,223	$ 2,264	$ 254	$ 311	$ 372	$ 437
$ 3,618	NPVRR Difference		$ 32	$ 60	$ 86	$ 1,443	$ 1,348	$ 139	$ 156	$ 171	$ 184
Scenario 1	$/kWh	$ 0.089	$ 0.087	$ 0.084	$ 0.082	$ 0.096	$ 0.093	$ 0.090	$ 0.087	$ 0.085	$ 0.082
Scenario 2	$/kWh	$ 0.089	$ 0.088	$ 0.087	$ 0.087	$ 0.086	$ 0.085	$ 0.102	$ 0.101	$ 0.099	$ 0.098
Scenario 1	Avoidable	$ -	$ -	$ -	$ -	$ 2,078	$ 2,161	$ 2,248	$ 2,340	$ 2,437	$ 2,539
Scenario 2	Avoidable	$ (300)	$ (263)	$ (224)	$ (185)	$ (144)	$ (103)	$ 1,995	$ 2,030	$ 2,066	$ 2,103
		$ 300	$ 263	$ 224	$ 185	$ 2,223	$ 2,264	$ 254	$ 311	$ 372	$ 437
$ 3,965	NPVRR Difference		$ 221	$ 173	$ 131	$ 1,443	$ 1,348	$ 139	$ 156	$ 171	$ 184
Scenario 1	Transfer to EO	$ -	$ -	$ -	$ -	$ 180	$ 174	$ 168	$ 162	$ 156	$ 150
Scenario 2	Transfer to EO	$ -	$ -	$ -	$ -	$ -	$ -	$ 180	$ 174	$ 168	$ 162
		$ -	$ -	$ -	$ -	$ 180	$ 174	$ (12)	$ (12)	$ (12)	$ (12)
$ 197	NPVRR Difference		$ -	$ -	$ -	$ 117	$ 104	$ (7)	$ (6)	$ (6)	$ (5)
		NPV	**Actuals**								
	Total Avoidable	$ 3,965	$ 6,095								
	Transfer to EO	$ 197	$ 306								
	Difference	$ 3,768	$ 5,789								

Q. What is the point of all of this?

[4] $197 with an allowance for income tax.

A. The underlying premise of MEEIA is that, based on the assumptions and quantities in these examples, ratepayers are better off providing shareholders with $164 plus an allowance for income tax today to avoid around $5,789 in revenue requirement in the future, to compensate shareholders for facilitating ratepayer-funded DSM programs, so long as the total cost of facilitating those DSM programs is less than $3,768. This premise does not hold when investments in generation assets are not deferred or avoided.

Problem with creating budget for program costs if there's no avoided O&M like with renewables

Q. In the "Scenario 1 – A and Scenario 2 – A examples above, did the deferred generation facility have fuel and variable operating costs?

A. Yes.

Q. If a plant to be deferred does not have fuel costs or variable operating costs, or those costs are very low, - such as solar or wind facilities – does this effect the maximum amount for ratepayers to break even in facilitating DSM programs?

A. Yes. Under identical assumptions to Scenarios A, but with fuel costs removed and variable operating costs drastically lowered, the $3,768 figure from the first set of examples is reduced to $830, as shown below.

		1	2	3	4	5	6	7	8	9	10
Scenario 1	Total Revenue Requirement	$ 8,918	$ 9,091	$ 9,268	$ 9,452	$ 9,337	$ 9,525	$ 9,720	$ 9,922	$ 10,131	$ 10,348
Scenario 2	Total Revenue Requirement	$ 8,918	$ 9,053	$ 9,191	$ 9,331	$ 9,475	$ 9,622	$ 9,467	$ 9,611	$ 9,760	$ 9,911
		$ -	$ 38	$ 78	$ 121	$ (137)	$ (96)	$ 254	$ 311	$ 372	$ 437
$ 680	NPVRR Difference		$ 32	$ 60	$ 86	$ (89)	$ (57)	$ 139	$ 156	$ 171	$ 184
Scenario 1	$/kWh	$ 0.089	$ 0.087	$ 0.084	$ 0.082	$ 0.077	$ 0.075	$ 0.073	$ 0.071	$ 0.069	$ 0.067
Scenario 2	$/kWh	$ 0.089	$ 0.088	$ 0.087	$ 0.087	$ 0.086	$ 0.085	$ 0.082	$ 0.081	$ 0.080	$ 0.079
Scenario 1	Avoidable	$ -	$ -	$ -	$ -	$ (282)	$ (199)	$ (112)	$ (20)	$ 77	$ 179
Scenario 2	Avoidable	$ (300)	$ (263)	$ (224)	$ (185)	$ (144)	$ (103)	$ (365)	$ (330)	$ (294)	$ (257)
		$ 300	$ 263	$ 224	$ 185	$ (137)	$ (96)	$ 254	$ 311	$ 372	$ 437
$ 1,027	NPVRR Difference		$ 221	$ 173	$ 131	$ (89)	$ (57)	$ 139	$ 156	$ 171	$ 184
Scenario 1	Transfer to EO	$ -	$ -	$ -	$ -	$ 180	$ 174	$ 168	$ 162	$ 156	$ 150
Scenario 2	Transfer to EO	$ -	$ -	$ -	$ -	$ -	$ -	$ 180	$ 174	$ 168	$ 162
		$ -	$ -	$ -	$ -	$ 180	$ 174	$ (12)	$ (12)	$ (12)	$ (12)
$ 197	NPVRR Difference		$ -	$ -	$ -	$ 117	$ 104	$ (7)	$ (6)	$ (6)	$ (5)
		NPV	**Actuals**								
	Total Avoidable	$ 1,027	$ 1,375								
	Transfer to EO	$ 197	$ 306								
	Difference	$ 830	$ 1,069								

If the plant being deferred through MEEIA programs is a renewable facility, it will be more difficult for ratepayers to benefit from the deferred investment by paying for the MEEIA programs today.

Ameren Missouri 5-Year Electric Customer-Focused Capital Investment Plan

$ - Thousands

Category 1	2023 Actual	2024	2025	2026	2027	2028	Grand Total
Smart, Reliable Grid Operations	795,164	706,217	695,065	747,925	729,451	727,887	3,606,545
Smart Meter Program	65,715	34,310	9,487	-	-	-	43,797
Non-Nuclear Generation & Environmental	97,214	173,246	143,541	177,788	194,863	210,415	899,853
Nuclear Generation	104,992	108,931	113,688	97,414	99,495	96,980	516,508
Hydro Generation	31,692	42,087	49,598	48,414	11,977	6,282	158,358
Renewable & Gas Turbine Generation*	63,621	1,069,146	622,011	1,222,463	938,532	717,023	4,569,175
*New Renewable Generation***	*30,010*	*1,028,875*	*407,759*	*859,119*	*565,209*	*483,776*	*3,344,738*
New Dispatchable Generation	*2,522*	*14,001*	*186,989*	*338,584*	*361,162*	*226,308*	*1,127,044*
Secure & Reliable Transmission	308,406	295,449	278,556	283,205	286,172	285,164	1,428,546
Cyber & Technology Upgrades	176,555	144,000	146,530	162,605	203,186	208,277	864,598
Operational & Customer Support Facilities	64,518	77,636	67,822	80,582	42,944	43,258	312,242
Innovative Opportunities	7,377	7,910	2,231	1,902	1,902	1,900	15,845
Grand Total - Capital	**1,715,254**	**2,658,932**	**2,128,529**	**2,822,298**	**2,508,522**	**2,297,186**	**12,415,467**

Renewable Asset Acquisitions	905
Grand Total, Including Renewable Asset Acquistions	**1,716,159**

*Renewable & Gas Turbine Generation is inclusive of New Renewable Generation & New Dispatchable Generation

** New Renewable Generation Plan for 2024-2028 may include both self-built projects and acquired renewable assets, pending future regulatory proceedings