Exhibit No. 19

Ameren Missouri – Exhibit 19
Steven M. Wills
Surrebuttal Testimony
File Nos. ER-2021-0240 & GR-2021-0241

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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2021-0240

SURREBUTTAL TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

d/b/a Ameren Missouri

St. Louis, Missouri
November, 2021

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SURREBUTTAL TESTIMONY

OF

STEVEN M. WILLS

FILE NO. ER-2021-0240

Q. Please state your name and business address.

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

Q. Are you the same Steven M. Wills that filed direct and rebuttal testimony in this proceeding?

A. Yes, I am.

I. PURPOSE OF TESTIMONY

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

A. The purpose of my surrebuttal testimony is to respond to several issues raised in the rebuttal testimonies of the Missouri Public Service Commission Staff ("Staff") witnesses Robin Kliethermes and Sarah Lange, the rebuttal testimony of Office of Public Counsel ("OPC") witness Dr. Geoff Marke, and the rebuttal testimony of Missouri Industrial Energy Consumers ("MIEC") witness Maurice Brubaker. Specifically, I will respond to:

- Issues raised by Ms. Kliethermes and Dr. Marke related to the Company's proposed rate switching tracker;
- Dr. Marke's characterization of, and comments on, the Company's Time of Use ("TOU") rate implementation;
- Dr. Marke's comments on the appropriate level of the residential customer charge;

- Dr. Marke's risk sharing proposal associated with the Company's proposed Community Solar program;
- Ms. Lange's criticisms of the Company's Class Cost of Service Study ("CCOSS");
- Mr. Brubaker's and Dr. Marke's recommendation to retain the 12(M) tariff; and
- Dr. Marke's recommendations related to Green Button functionality.

II. THE COMPANY'S RATE SWITCHING TRACKER SHOULD BE APPROVED

Q. Please briefly review the tracker request the Company made through your direct testimony related to rate switching between the new residential rate options, as well as rate switching between Rate 4M – Small Primary Service ("SPS") and Rate 11M – Large Primary Service ("LPS") that may occur pursuant to qualification changes the Company proposed for the LPS tariff.

A. The Company's new optional TOU rate plans present opportunities for residential customers to reduce their electric bills if they manage their usage and demand effectively consistent with their selected TOU schedule and plan parameters. The changes in customer usage profiles should ultimately reduce peak loads on the system, which may result in deferred or avoided investment in distribution, transmission, or generation capacity in the long run, saving long-run costs for all customers.

However, in the short run, the bill reductions will reduce utility revenues immediately with no meaningful cost offsets. As a result, the utility offering these rates is creating revenue erosion that falls to its bottom line as it enrolls customers in these rate options.

Similarly, customers that are able to switch between the SPS and LPS rates, pursuant to the Company's proposal to change the qualification provisions of the LPS tariff, will see reduced bills relative to the billing units used to establish rates in this case. The revenue effect would be similar to residential customers saving on TOU rates.

Q. What is the purpose of the tracker the Company requested?

A. The tracker is designed to help the Company have a more reasonable opportunity to receive revenues that cover its revenue requirement, even while promoting adoption of rates that save customers money. In this way, the tracker aligns the incentives of the utility with helping customers optimize their rate plan selection and their energy usage while taking service under these rates. This is analogous to how certain provisions of the Missouri Energy Efficiency Investment Act ("MEEIA") align utility incentives with helping customers use energy more efficiently by ensuring utilities are not financially harmed in the form of lost revenues when taking actions that benefit customers. The legislation that created MEEIA requires this alignment of incentives for energy efficiency programs. Although such treatment is not legislatively required in the circumstance of rate design, it is good policy for the exact same reasons that the legislature saw fit to create such a requirement for energy efficiency. I discussed additional evidence that demonstrates that policy reasons support approval of the tracker in my rebuttal testimony.

Q. Ms. Kliethermes of Staff proposes additional reasons in her rebuttal testimony that the tracker request be rejected beyond those presented in Staff's Cost of Service Report, which you responded to in your rebuttal testimony. Are the additional reasons she cites for Staff's recommendation good reasons not to provide this alignment of incentives?

A. No. In fact, the concerns Ms. Kliethermes cites reflect misunderstandings about how the proposal works. She largely equates the tracker to being a Revenue Stabilization Mechanism ("RSM "), which is designed to account for the impact on utility revenues of increases or decreases in residential and commercial customer usage due to variations in either weather, conservation, or both. Dr. Marke of OPC makes a similar statement in his rebuttal testimony, characterizing the tracker as a "decoupling" tracker. Decoupling and RSMs are intended to make utilities indifferent to variations in *usage levels*. I explained in detail in my rebuttal testimony that the Company's proposed rate switching tracker simply does not operate that way at all. To reiterate, utility revenues, even with the proposed tracker, will *always* be based on actual usage levels. There is simply no provision in the tracker proposal to true-up usage to a baseline or otherwise break the link between volumes and revenues. The concerns Ms. Kliethermes raises aside from the RSM argument are all either a repackaging of the same arguments I have already addressed at length in rebuttal testimony and just above, or ignore other very pertinent considerations. I will address each concern she raises in turn.

Q. What is Ms. Kliethermes' first objection to the tracker?

A. Ms. Kliethermes raises issues from the Company's "Charge Ahead" case (File No. ET-2018-0132) related to incentives for electric vehicle ("EV") charging.[1] Ms. Kliethermes claims that incremental revenue from new EV load will enhance Company revenues, presumably suggesting that loss of some of that new EV-related revenue due to TOU rate savings is not a problem. Her position ignores two key facts. The first very obvious fact is that the new TOU rates are applicable to all of a customer's usage, not just EV loads. EV load still makes up a very small percent of residential customer usage, and any impact of EVs is not the primary concern of the tracker. The tracker is primarily concerned with all of the existing household usage of adopting residential customers. It is a certainty that *much* more existing residential usage will be subject to

[1] File No. ER-2021-0240, Kliethermes Rebuttal Testimony, p. 2, ll. 14-18.

the new rates than usage associated with new EVs – by an overwhelming margin.[2] The financial losses incurred when serving that pre-existing load on TOU rates will certainly swamp the portion of losses that arise from usage increases associated with new EVs on the system, and will create the disincentive that I discussed above.

Second, I will address the EV-related revenues (small as they might be relative to the totality of residential revenues that could be subject to TOU pricing) on which Ms. Kliethermes focuses. Incremental revenues from new EVs do benefit the Company in the short run. That much is true. But Ms. Kliethermes ignores the fact that the incremental revenues that may arise from increasing number of EVs were a critical element of the business case, and cost recovery solution, that underpinned the Charge Ahead program. Recall that the Company is deferring the up to $11 million cost of that program, and therefore incurring financing charges on the capital spent to defer them while recovering the costs over a multi-year period to be established in future rate cases. The Company volunteered to *not* pass these financing costs on to customers directly by not proposing to include the regulatory asset in rate base (a commitment that is maintained in the Company's current rate filing), based on the expectation that it would earn incremental revenues from new EVs. The incremental revenues that underpinned the Company's proposal were assumed to be at the full retail rate, not a TOU reduced off-peak rate. So to the extent that EV drivers save money on their retail bills by adopting TOU rates and charging during off-peak times, the revenues that were an integral part of the Charge Ahead cost recovery solution, will also be eroded. So while

[2] Per the Company's true-up billing units in this case, the average total household use per residential customer is 12,374 kWh per year. Per the Company's analysis in File No. ET-2018-0132, the estimated usage associated with the addition of an EV is approximately 4,090 kWh per year. Per the Company's reports to the Commission associated with the Charge Ahead Program in File No. ET-2018-0132, there are approximately 7,388 EVs registered in the Company's service territory as of the second quarter of 2021, whereas there are 1,076,624 residential customers on the Company's system based on the Company's true-up billing units. As a result of these facts, not more than 0.7% of residential customers currently have an EV, and of those the EV represents only an estimated 25% of their annual usage (4,090 kWh EV usage / (12,374 kWh of base household usage + 4,090 kWh EV usage) = 25%).

there are certainly incremental revenues from new EVs entering the system, which may be partially attributable to the infrastructure solutions advanced by Charge Ahead, those revenues are intended to compensate the Company for very real program costs that it has volunteered to otherwise not pass on to customers. The fact that the Company would track and eventually recover those revenues is entirely appropriate.

Q. What is Ms. Kliethermes' next objection to the tracker?

A. She indicates that, because customers will only be eligible for TOU rates once they get an Advanced Metering Infrastructure ("AMI") meter, and the rollout of those AMI meters are predictable, there will not be rapid enough adoption of TOU rates to cause significant revenue erosion.[3]

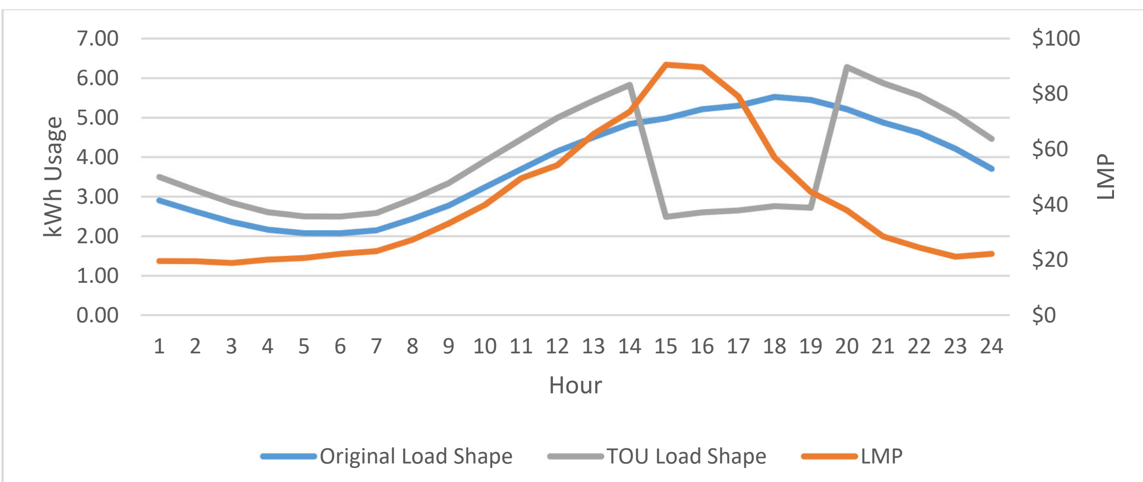
In my direct testimony, I modeled the potential of revenue erosion *factoring in the AMI deployment schedule* and the limits it creates on rate plan adoption. See my direct testimony for details. While TOU adoption rates would have to be relatively robust among those with new AMI meters, the potential for significant revenue losses is real, and the likelihood of those losses increases significantly the more the Company promotes the rates to customers. If Ms. Kliethermes is right that adoption is slow, the impact of the tracker will be minimal on customers and so still no harm will be done. Either way, Ms. Kliethermes did nothing in her testimony to dispute the quantification of revenue at risk to the Company that I provided in my direct testimony. If her presumption that the limits placed on adoption by the pace of TOU rollout mitigate the potential revenue erosion were well founded, she should have been able to explain what was inaccurate about my analysis that quantified the effect.

[3] File No. ER-2021-0240, Kliethermes Rebuttal Testimony, p. 2, ll. 18-21.

Q. Ms. Kliethermes next suggests that the Company will experience reduced purchased power costs if customers shift usage to lower price periods.[4] What is your response?

A. Ninety-five cents of every dollar of such cost reduction will inure to the benefit of customers due to the existence of the Fuel Adjustment Clause ("FAC") with 95/5 sharing of changes in net energy costs. To illustrate the actual financial impact of a customer adopting TOU rates and shifting load to lower priced periods in a way that incorporates avoided energy costs, consider the example in Figure 1 and Table 1 below, which demonstrate the interplay of retail revenue reductions and cost savings associated with a hypothetical customer usage response to TOU rates.

Figure 1 – Load Shape with and without TOU-Induced Shifting and Market Energy Cost



[4] File No. ER-2021-0240, Kliethermes Rebuttal Testimony, p. 2, l. 22 through p. 3, l. 11.

Table 1 – Financial Impacts of TOU-Induced Load Shifting

	Original Load			TOU Shifted Load			
	kWh	Retail Revenue	Energy Cost	kWh	Retail Revenue	Energy Cost	
Off-Peak	22.1	$2.61	$0.46	26.7	$1.50	$0.55	
Intermediate	42.5	$5.02	$2.30	51.2	$4.47	$2.45	
Peak	26.5	$3.13	$1.44	13.2	$3.73	$0.72	
Total	91.1	$10.76	$4.20	91.1	$9.70	$3.72	
TOU Savings					**-$1.054**	-$0.476	
Cost Savings to Customers in FAC						-$0.452	
Cost Savings to Company through FAC Sharing						**-$0.024**	
Net Financial Impact on Company							**-$1.030**

Q. Please interpret Figure 1 and Table 1.

A. Figure 1 is based on actual load and market price data from the test year. The original load shape (blue line) is based on the class average load shape for the summer peak day, scaled to the size of an individual residential customer that may choose to adopt the Company's Smart Savers rate. The TOU load shape (grey line) is a hypothetical load shape that would result if that customer used a programmable thermostat and other behavioral adjustments to reduce its peak period load by 50%, and shifted an equivalent amount of kilowatt-hours ("kWh") to the intermediate and off-peak time periods. The orange line (measured against the right axis) shows the test year normalized market price of energy[5] for the highest price day of the summer,[6] which is what gives rise to the potential cost savings Ms. Kliethermes references.

In Table 1, I calculate the baseline retail revenue and energy cost as the kWh from the original load shape priced at the standard tariff rate and the market prices respectively. Next, I perform the same calculations for the TOU load shape, but using the relevant TOU prices for each period from the Smart Savers rate.

Below those initial calculations, I calculate a comparison of the two scenarios to illustrate the financial impact of the TOU rate adoption and load shifting, and include an analysis of which cost savings will be retained by the Company versus flowed to customers pursuant to the 95/5 sharing of the FAC. Note that this one day of savings for the customer results in a $1.05 reduction in the Company's retail revenue, but in only $0.48 of cost reductions. But that is only the beginning of the story, because the application of the FAC sharing parameters results in the Company retaining only 2 cents of the cost savings (5% of $0.48) in this scenario. The net financial impact on the Company's pre-tax earnings is $1.03, or 98%[7] of the change in revenue. The cost savings Ms. Kliethermes points to offset only *a trivial portion of the revenue loss* incurred by the Company. The point of this analysis is to demonstrate that cost savings retained by the Company are so negligible as to be meaningless in providing the alignment of incentives that the tracker is designed to create.

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[5] Designated in the legend of the graph as "LMP," for Locational Marginal Price – the hourly wholesale market prices that Ameren Missouri is subject to in the MISO market.

[6] The load data and market price data are not from the same day, but are deliberately selected to be the highest load and price days respectively for the summer to test the most extreme scenario that could arise using test year data.

[7] Recall that in an attempt to test the extreme impact that could occur from this effect, I used the highest market prices from any day in the normalized test year. If I had used a more average summer price profile, the result of this analysis would have been that the Company's share of the cost savings would even smaller-- *less than 1 cent, and less than 1% of the revenue loss*.

Q. Next, Ms. Kliethermes mentions that the Company's proposed tracker will reflect variations in revenue attributable to weather rather than just behavioral changes induced by the TOU rate.[8] What is your response?

A. This is the first concern raised by Ms. Kliethermes that has overtones of the RSM argument I mentioned above – frankly, it is the same argument, but just focused on a particular cause of increase or decrease in usage: weather. Consistent with my introductory comments on the topic, I strongly disagree with her concern. Unusually extreme or mild weather will impact customer usage and the corresponding utility revenues whether a customer is on a standard rate or TOU rate. Because the tracker only considers the revenue differences between the actual usage experienced on the TOU schedule and the *same actual usage as if it were on the standard rate* (i.e., it does not incorporate a volumetric decoupling element at all), the tracked difference will only be related to the impact of the TOU rate application (not the weather impact on total usage). In fact, I think that arguably the tracker may only capture a subset of the impact of the TOU rate on Company revenues in this instance. If the TOU rate induced the customer to *reduce* overall weather-related usage rather than just *shift* usage, the lost revenue associated with the TOU-induced usage reduction will not be captured by the tracker and will truly remain lost to the Company. Only those revenues lost due to load shifting and application of different TOU pricing will be incorporated in the tracker. There is simply no consideration of usage changes, whether driven by weather or anything else, that are accounted for by the tracker.

[8] File No. ER-2021-0240, Kliethermes Rebuttal Testimony, p. 3, ll. 12-19.

Q. Ms. Kliethermes makes a similar argument related to TOU-related changes in the load reductions induced by MEEIA energy efficiency programs.[9]

A. The answer to this concern is the same as the previous reply. The rate switching tracker will only measure changes of revenue associated with the application of the TOU rates instead of the standard rate associated with *actual measured usage*. Load reductions associated with MEEIA, which the Company is compensated for in Rider EEIC, will not be double-counted since the rate-switching tracker is only capturing those revenue changes that arise due to the timing of what usage actually occurred and the difference in rates applicable to it but not related to the usage level that would have been experienced but for the MEEIA savings. Any usage that is shifted in time but not reduced, and which therefore is addressed in this tracker, is never addressed in Rider EEIC. There simply is no potential for double counting between these two mechanisms.

Q. Finally, Ms. Kliethermes argues that, somehow, the Company's proposal to differentiate the customer charge between the residential rate plans would create differences in revenue that are not appropriate to capture in the tracker. Do you agree?

A. No. Changes in revenue that arise from customers' election of rate plans should be based on the totality of the revenue impact between the rate plans. Recall that the lower customer charges proposed for the Smart Savers and Ultimate Savers rate are intended to give adopting customers the greatest opportunity to control their bills. That control over bills – including the greater savings associated with the lower customer charge – is creating the customer savings that give rise to the revenue erosion that is addressed by the tracker.

[9] File No. ER-2021-0240, Kliethermes Rebuttal Testimony, p. 3, l. 20 through p. 4, l. 13.

Q. What do you conclude regarding Staff's opposition to the Company's proposed rate switching tracker?

A. Staff's bases for opposition are unfounded. The Commission should approve the tracker to align the incentives of the Company with helping customers optimize their rate plan selection and their energy usage while taking service under the various rates.

III. UPDATE ON THE COMPANY'S PROGRESS ON TOU RATE PLANS' ROLLOUT AND CORRECTION OF OPC'S MISSTATEMENTS THEREON

Q. Dr. Marke of OPC criticizes the delay the Company experienced in rolling out its new TOU rates to customers in his rebuttal testimony.[10] Is his portrayal of the status of the TOU rollout accurate?

A. No. I am afraid that Dr. Marke may have misread my direct testimony, or else is relying on some other source that included inaccurate information as the basis of his statements. Specifically, Dr. Marke said the status of the program is "not good," and goes on to suggest that the TOU rollout and online tools to help customers manage their bills has been postponed until "spring 2022."[11]

As I explained in my direct testimony, the Company did need additional time beyond the originally anticipated January 2021 rollout of the TOU program. However, the delay, which was essential to the development of a smooth launch of these rates, was just a few months. The broad rollout of the TOU program began in earnest in May 2021, with customers being transitioned to the default rate by the beginning of June. Dr. Marke cites my direct testimony where I indicated that only a handful of customers had adopted more advanced TOU rates. This, of course, was because the Company had not started any education efforts related to them yet. The early adopters

[10] File No. ER-2021-0240, Marke Rebuttal Testimony, p. 14.
[11] File No. ER-2021-0240, Marke Rebuttal Testimony, p. 14, ll. 15-26.

had sought out information on their own. But those education efforts began just over a month after the information provided in my direct testimony was presented. At this time, there are several hundred customers on the more advanced TOU rates, with more being added each day, and well over a hundred thousand – approaching two hundred thousand – customers on the default TOU rate. Specifically, as of November 1, 2021, the number of customers on each rate option are as shown in Table 2 below:

Table 2 – Rate Plan Participation

Rate Option	Current Participants
Evening Morning Savers	173,484
Overnight Savers	198
Smart Savers	136
Ultimate Savers	127

Q. Has the Company rolled out the online rate comparison and enhanced usage presentment tools that were included in the TOU program plan?

A. Yes. I included in my rebuttal testimony a screen shot of a customer rate comparison from the new tool. This tool is also providing enhanced AMI usage and energy cost information and usage-related tips to customers with AMI meters. Figures 2 and 3 below show additional views of information that is accessible to customers with AMI meters through the tool that has been released.

Figure 2 – Customer Interval Usage Presentment View

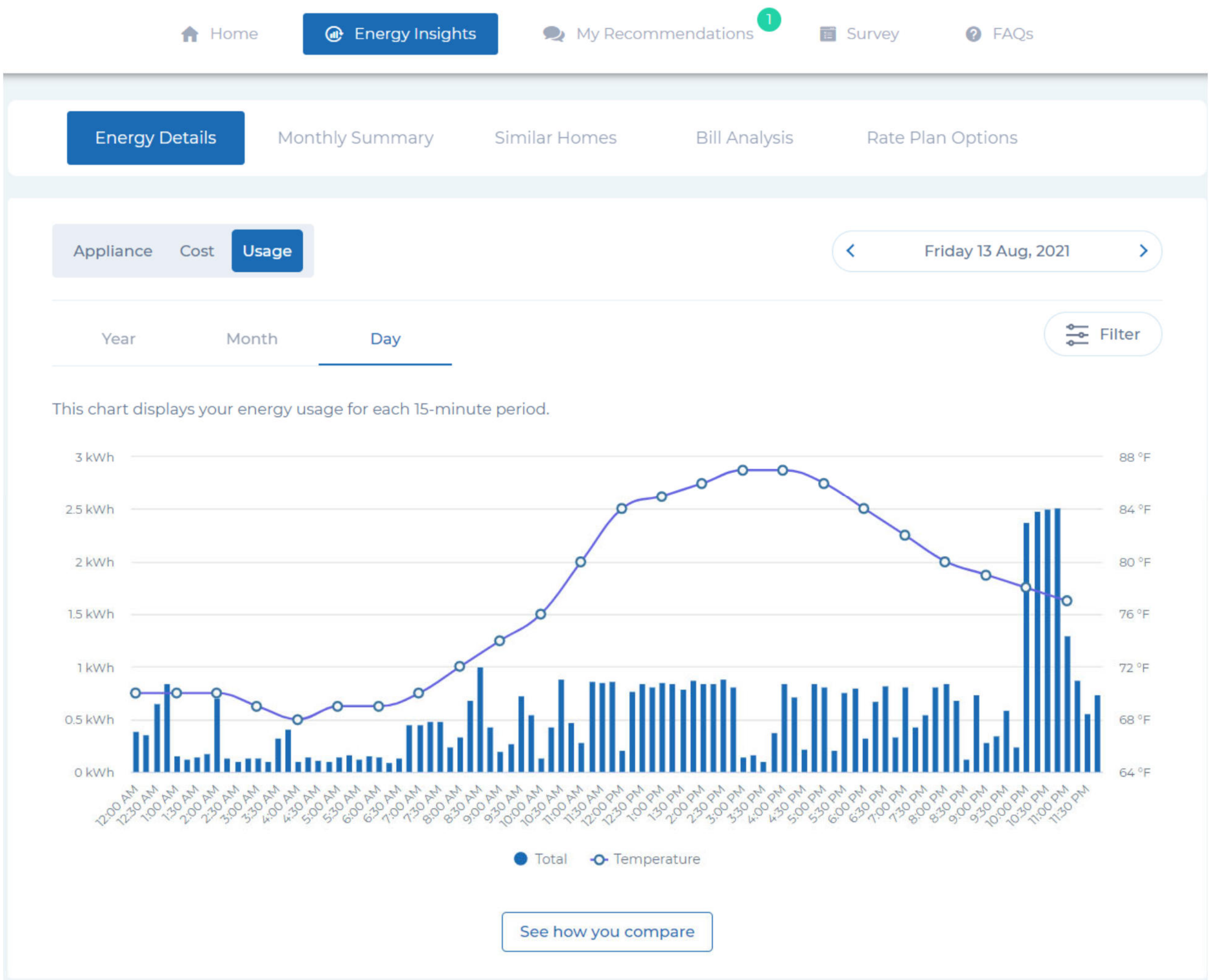
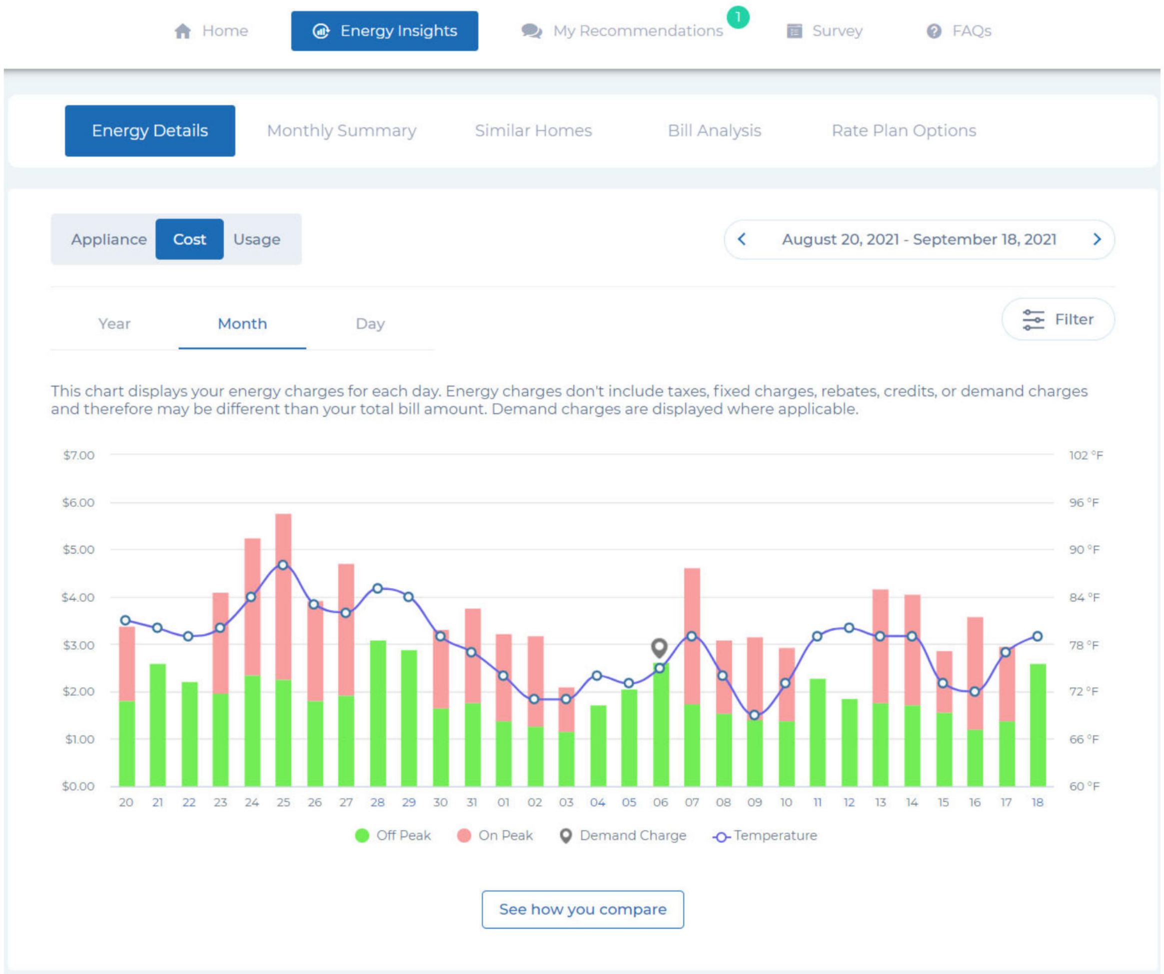


Figure 3 – TOU Customer Daily Cost View



Q. Dr. Marke also endorses Staff's suggestion from its Class Cost of Service Report that the Company should consider renaming its residential rate plan options.[12] How do you respond?

A. Company witness Dr. Ahmad Faruqui and I both addressed Staff's recommendation in our respective rebuttal testimonies. To reiterate briefly, I think that is an extraordinarily bad idea at this time, right as the Company has begun educating customers using the "Savers" rate names,

[12] File No. ER-2021-0240, Marke Rebuttal Testimony, p. 22-23.

to suddenly rebrand the rate plans. I think that is a recipe for creating confusion. I would remind the Commission that the Savers naming convention was proposed by the Company in its last rate case, File No. ER-2019-0335, for the Smart Savers and Ultimate Savers rate plans. No party objected to those names at the time. Subsequent to the settlement of that case, the Company had a series of four monthly meetings with Staff and OPC to discuss the rate education plan, as well as a presentation to the Commission itself at an agenda session. In these meetings, and also in my rebuttal testimony in this case, the Company also explained the primary customer research that it conducted to inform its communication strategy, including the development of certain rate plan names. I am not aware of any concern expressed with the "Savers" convention in any of those settings. I recommend that the Commission decline to order anything related to name changes to the rate plans.

IV. THE COMPANY'S RESIDENTIAL CUSTOMER CHARGE PROPOSALS SHOULD BE APPROVED

Q. Dr. Marke of the OPC recommends maintaining the existing residential customer charge, as opposed to the Company's proposal to implement a modest increase to that charge for customers that do not adopt more advanced TOU rate plans. What costs does Dr. Marke argue should be considered in evaluating the appropriate customer charge?

A. Dr. Marke starts his discussion on this point by saying "customer-related" costs should be reflected in the customer charge. At this point, I agree with him. However, he goes on then to essentially describe only a subset of costs that are classified as customer-related costs by every class cost of service study presented in this case. Essentially, Dr. Marke goes on to suggest that only the *marginal* costs of connecting a new customer should be reflected in the customer charge

Q. Do marginal cost pricing considerations support the need to keep the customer charge low?

A. No. Marginal costs are most relevant in rate design for purposes of trying to develop rates with price signals that help to elicit economically efficient energy consumption decisions from consumers. To the extent that rates are too low, relative to marginal cost, customers may make wasteful energy consuming decisions; whereas to the extent rates are too high relative to marginal cost, customers may have to forego services that they actually value greater than the incremental cost of rendering that service. To achieve economic efficiency, setting rates with some consideration of the relevant marginal cost certainly has merit. But it is critical to recognize – and this is true of rates set routinely by this Commission and virtually every other regulatory authority in the country – that rates must ultimately be set in a manner designed to recover the full, embedded (not just the marginal) costs of the total revenue requirement, which will necessarily result in some or all of the charges not equaling their relevant marginal cost. If that ratemaking condition is going to exist (i.e., at least some rate component, and probably all rate components to a degree, will deviate from marginal cost in part due to the inclusion of fixed distribution costs in the revenue requirement), the question becomes: where is the best place to recover these joint and common fixed costs that will have the least impact on customers' economic choices? Clearly, the answer is the customer charge, which suggests that the determination of the customer charge should be the last rate to price based on marginal cost, and instead should be the home of some of the fixed joint and common system costs.

Q. Why do you say that?

A. The only energy-related decision made by a consumer that could theoretically be influenced by the level of the customer charge is the decision regarding whether to connect to the grid and take electric utility service in the first place. Once that decision is made, the customer charge is fixed and therefore completely irrelevant to the amount and timing of electricity consumption – and therefore any other consumption decision a customer may make. Imagine a customer who is deciding whether to establish service with the local electric utility. Whether the utility's fixed residential monthly customer charge is $9.00 (the current charge) or $11.00 (the Company's proposal for some rate options), I can imagine no residential customer that would factor the $2.00 per month difference into a decision whether they wanted electric service at their residence or not. In effect, it is a forgone conclusion in today's society that everyone will choose to have residential electric service at any plausible level of customer charge, as supported by the CCOSS of any of the parties to this case. The primary purpose of considering marginal cost in rate setting – to drive customer energy-consuming decisions that result in better economic outcomes – is totally irrelevant to the decision to establish residential electric service.[13]

But keep in mind that if we exclude the joint and common (non-marginal) costs that may not be *directly* driven by customer numbers from the customer charge for reasons associated with marginal cost considerations, we must push those same costs, which are *not in any plausible way* driven by energy or demand, into a consumption-based charge. This means, in the case of residential customers, that the non-marginal costs will be included in an energy charge[14] that applies to every kWh consumed. And the inclusion of these fixed costs associated with poles, transformers and conductor in the per-kWh charge drives *that charge farther away from marginal cost*. And that charge – the residential energy charge – is exactly the charge that *can* influence energy consumption decisions with real and meaningful implications for economic outcomes.

[13] It is conceivable that this could change in the future if going "off-grid" becomes a commercially viable option.

[14] Except in the case of the Ultimate Savers rate, where those costs may be reflected in the demand charge. This is a key reason that it may be considered entirely appropriate to maintain a lower customer charge for that rate plan, as the Company has proposed.

Q. Please discuss the economic consequences of inflating the residential energy charge farther above marginal cost than necessary in order to maintain a low customer charge.

A. The first consequence of significance is the impact on electrification efforts. Higher variable energy charges that arise when artificially keeping the customer charge low by pushing fixed distribution costs into the energy charge mean additional cost for electric consumption associated with, for example, Electric Vehicles ("EVs"), among other things. As customers decide whether to electrify their own transportation (or other end uses), the energy rate is an important part of the total cost of ownership equation that many customers are likely to consider, along with the other tradeoffs between EVs and internal combustion engine vehicles. While it might seem counterintuitive at first, raising the customer charge (and by extension reducing the per kWh charge) makes the economics of the electrification case stronger and can drive increasing levels of benefits associated with greater use of electricity relative to direct use of fossil fuels.

This is not a trivial matter. Electrification is increasingly being viewed as an absolutely critical part of the nation's path to decarbonization. This is recognized by parties, jurisdictions, and studies from across the country, and the evidence of the importance of electrification is growing. In Ameren Missouri's service territory, the benefits of electrification will continue to grow as the Company deploys more and more renewable energy in coming years, as contemplated by the Company's generation transition plan reflected in its 2020 Integrated Resource Plan ("IRP").[15]

In order to provide greater economic support for the achievement of the important and broadly recognized benefits of electrification, fixed charges should be a preferred method of recovering fixed costs associated with the joint and common distribution infrastructure rather than

[15] File No. EO-2021-0021.

including them in energy charges that reduce the attractiveness of EVs and other electric end uses that compete with the direct use of fossil fuels.

Q. Dr. Marke focuses on the fact that the customer-related costs you are discussing are not "directly related to the number of customers."[16] Please respond.

A. Again, every CCOSS performed for this case classifies some or all of these costs as customer-related. While certain fixed costs might not vary directly on a one-for-one basis with changes in customer counts, the need to simply connect customers to the grid is what *drives the incurrence of costs* related to distribution infrastructure investment for the types of assets – poles conductor, transformers – that give rise to these costs. These costs (up to the level classified as customer-related in the Company's Minimum Distribution System ("MDS") Study) unquestionably do not vary with changes in demand or energy consumption. If demand goes up at a particular customer's location, we do not need to construct another mile of power lines with a commensurate number of new poles to get the customer connected to the grid.[17]

Q. So what is Dr. Marke's recommendation and rationale for that recommendation for establishing the customer charge?

A. Dr. Marke recommends the customer charge should remain at its current level. He relies on some quotes of the noted rate design author Dr. James Bonbright that essentially suggest that the fixed distribution costs of the minimum system I mentioned above do not have a true and natural home in either the energy charge or customer charge. Dr. Marke therefore suggests that their inclusion in either charge type is somewhat arbitrary, and he therefore relies on his assessment

[16] File No. ER-2021-0240, Geoff Marke Rebuttal Testimony, p. 16.
[17] The size of poles and type of conductor installed may need to increase, and the Company's cost allocation method would appropriately assign the incremental costs of those upgrades to the demand function.

of the likely impact of the customer charge on various types of residential users to inform his recommendation, along with considerations of the pricing principles used by competitive firms.

Q. What is your response?

A. I do not entirely disagree with Dr. Marke's interpretation of Dr. Bonbright. My reading of Dr. Bonbright's work suggests that he does not give definitive guidance on the best charge type to use to reflect these costs of the minimum distribution system. While Dr. Bonbright does not suggest that these costs are customer related, he most certainly does not advocate for them being considered demand or energy related either.

Q. Despite his lack of guidance on which charge should be used to cover shared fixed distribution costs, does Dr. Bonbright provide any support for the notion that recovering the full embedded cost of the revenue requirement will tend to push charges higher than the relevant marginal cost – e.g., that including the costs of the minimum system in an energy charge is likely to increase that charge above the relevant marginal cost?

A. Yes. Dr. Bonbright makes many references that carry the implication that the normal condition of a utility is that rates designed to reflect the relevant marginal costs would not fully recover the embedded cost revenue requirement. For example, he states:

> The usual assumption is that, if the incremental costs of all services, separately measured, were added together, they would fall materially short of covering total costs – an assumption based on the belief that most public utility enterprises operate under conditions of decreasing costs with increasing output. When this assumption is valid, it implies that a public utility cannot cover its total revenue requirements without charging *more* than incremental costs for at least some of its services.[18]

To the extent that this implies that either the customer charge or energy charge is likely to have to be above marginal cost when reflecting these fixed (non-marginal) costs, and if one accepts my previous argument that the improvement in economic efficiency provided for by prices that

[18] James C. Bonbright, *Principles of Public Utility Rates*, p. 299

are informed by marginal costs is much more important for establishment of the energy charge rather than the customer charge, this statement supports the notion that those fixed (non-marginal) distribution costs should be reflected as an increase to the customer charge.

Q. Are there any other points you would like to address regarding Dr. Marke's citations to Dr. Bonbright's work?

A. Yes. Dr. Marke highlights Dr. Bonbright's statement that the most significant marginal costs are long run costs. Dr. Marke uses this idea to suggest that a higher energy price is needed to provide a price signal designed to avoid long run capacity investments. But it is worth exploring Dr. Bonbright's view of the relevant long run costs that should be considered. For example, Dr. Bonbright states:

> For, in actual practice, the more significant marginal costs are those costs which can be expected to persist, not forever or even for twenty years, but rather for those shorter periods that are within the horizon of today's rate makers. As a rule, these are the increments in costs that may be anticipated to result, during the next several years, from increases in rates of output to be accomplished by whatever plant additions and improvements will be warranted in view of the actual layout and actual capacity of the present plant.[19]

Dr. Bonbright puts a finer point on this concept when he later says:

> Hence, the most important marginal costs for purposes of rate control are the normal or persistent marginal costs rather than the very short-lived marginal costs that may fall almost to zero in some brief period of time, only to rise to several times this average total costs soon thereafter. For this purpose, however, "long-run" marginal costs must be given a flexible and frankly indefinite interpretation, since any attempt to fix rates today by reference to cost functions that may not materialize, say, for twenty-five years or more would be utterly foolish. In short, the costs that should be covered by rates are the marginal costs that are "permanent" in the sense used by a dentist when he refers, optimistically, to a permanent rather than a temporary filling.[20]

[19] James C. Bonbright, *Principles of Public Utility Rates*, p. 325
[20] *Id*. at p. 401

With this useful perspective provided by Dr. Bonbright, and thinking about the long-lived poles, conductors, etc. whose cost recovery are at issue in the MDS study, it should be entirely clear that the marginal costs relevant to the determination of the energy charge should exclude these costs associated with the MDS study.

Q. Dr. Marke ultimately looks to competitive enterprises as a model for how the Commission should think about fixed customer charges. Is this a relevant and useful comparison to the business model of a regulated utility?

A. No. Dr. Marke states:

> In competition, a consumer who does not consume a product or service does not nevertheless pay for the mere ability to consume it. Thus, as a general matter, prices should be structured so that, if a consumer chooses not to purchase a good or service, he or she has no residual obligation to pay for some portion of the costs to provide that good or service. In this sense, from the consumer's perspective, costs should be "avoidable."[21]

However, it is critical to understand a key distinction between the competitive firms Dr. Marke references and regulated utilities. A competitive firm does not have an obligation to serve every customer that requests service, at the time and location of that customer's choosing. And, that competitive firm is not required to make substantial customer-specific and shared investments that are necessary to directly connect their services to those customers' residences, which if not paid for by the customer requesting service, will ultimately be borne by its other customers. Those conditions are in fact essential parts of the regulatory compact on which the utility model is premised. If, for example, a competitive taxi cab company were required to have a car for hire parked at each prospective customers' house waiting for them to call for a ride, it would almost certainly charge that customer a standing fee "for the mere ability to consume" its service. Furthermore, other customers of the taxi cab company would certainly demand that the customer

[21] File No. ER-2021-0240, Marke Rebuttal Testimony, p. 19, l. 21 through p. 20, l. 2.

who had the car on standby pay for the costs of that car if the cost was otherwise required to be paid for by them when the first customer did not choose to use its service. While there is a certain intuitive appeal to Dr. Marke's call to consider the competitive model, closer inspection reveals that there are very good reasons that utility pricing is a unique endeavor that cannot be simply extrapolated from the pricing strategies of the nearest retailer or competitive service provider.

Q. What concluding thoughts would you leave on the topic of the residential customer charge?

A. I believe that it is time for the conventional wisdom regarding customer charges to change, and I fully expect it will change across our industry in the coming years, as the focus of decarbonization efforts moves further and further toward an emphasis on electrification. It will be key to make electric transportation, and even other electric end uses, economically competitive to encourage uptake of the equipment and devices that can capitalize on the clean energy transition and help reduce direct fossil fuel use. Removing shared non-marginal system costs from the energy charge helps achieve this goal in a manner that aligns with the economic efficiency objective of rate design.

It is also time for the conventional wisdom regarding customer charges and low-income customers to change. The balance of fixed versus variable charges within rates is a very blunt instrument when it comes to energy affordability, and not well suited to dealing with affordability for vulnerable customers. As I testified in both direct and rebuttal testimony, there are many low-income customers with inefficient homes and appliances, who have quite high levels of overall electric usage. These customers have the highest energy burdens of any customers on the system, and they are unquestionably worse off with a low customer charge that pushes more revenue recovery into the variable charges that are applied to their above average usage.

I close by emphasizing the innovative approach the Company has taken to the customer charge in this case. Differentiating the customer charge by rate option actually helps achieve some progress on a number of the otherwise conflicting rate design objectives that often confound the discussions around the appropriate level of the customer charge. By proposing to maintain a relatively lower customer charge on the more advanced TOU rate structures, which are specifically designed to give customers the opportunity to control their energy bills, the Company has recognized the need to give that control to the customers who desire it. But for those customers that are not willing or able to actively manage their usage, a higher customer charge is an extremely reasonable way to ensure that each customer contributes to the shared customer-related costs of the system – costs that are that are recognized as customer related by every CCOSS presented in this case – while also building the economic case for customers to electrify key end uses.

V. THE OPC'S RISK-SHARING PROPOSAL FOR THE PERMANENT COMMUNITY SOLAR PROGRAM SHOULD BE REJECTED

Q. Dr. Marke argues that the Company's proposal to convert its successful Community Solar pilot program into a permanent program offering should include a risk sharing provision that places the cost of undersubscribed program assets on shareholders. He points to a provision of Evergy's Community Solar tariff and suggests that a similar provision should be put into Ameren Missouri's proposed permanent Community Solar tariff.[22] Does the Company agree that that is an appropriate provision for the Community Solar program?

A. No. Such a provision is both unnecessary and inappropriate. As discussed by Company witness Annemarie Nauert, the success of the Company's Community Solar pilot program and additional customer research the Company has conducted have demonstrated that

[22] File No. ER-2021-0240, Marke Rebuttal Testimony, p. 31.

there is significant demand for voluntary renewable subscription programs here in Missouri. Customers expect their utility to provide options for them to meet their needs for renewable generation. Providing that option to customers should be expected to be a core part of today's electric utility service offerings. And, such core services should be afforded rate making treatment that is commensurate with other core services. Given today's customers' expectations, it is not appropriate to require the utility to bear a substantially higher risk on such program investments in order to be able to provide these services to its customers who are demanding them.

But I would take this point one step further to observe that the risk that Dr. Marke identifies – that some amount of a solar production facility that was developed with subscribers in mind ultimately goes or becomes unsubscribed – is not actually something that should be viewed as a significant negative, even for non-subscribing customers. Keep in mind the Company's 2020 IRP, which identified the need to begin a large-scale transition to wind and solar resources over the coming two decades, with thousands of megawatts of wind and solar resources to be developed and introduced onto the system. To the extent that a small amount of solar generation, originally intended to meet demand for a subscription program, becomes available to utilize on behalf of all customers, it can easily be absorbed into the transition plan and reduce the need for additional system renewables that will otherwise be required to complete the generation transition. Further, the economic benefits associated with any unsubscribed generation – in terms of its energy and capacity value in the market and Renewable Energy Credits ("RECs") that may be needed for Renewable Energy Standard compliance – are likely to largely or entirely offset the cost of those resources. It is entirely unreasonable to make the Company be responsible for the costs of unsubscribed program solar resources while allowing the energy and capacity, and related RECs, to benefit non-subscribing customers.

VI. COUNTER OF STAFF'S CLASS COST OF SERVICE STUDY CRITICISMS

Q. Ms. Lange of Staff criticizes the Company's CCOSS distribution cost allocations in her rebuttal testimony. What are her biggest criticisms?

A. She has two key criticisms: 1) that the Company applied the percent of plant that was classified as customer-related as of the end of the test year to the total investment including amounts installed subsequent to the test year and within the true-up period, and 2) that the Company's minimum system used in its MDS study is a primary system. The issues raised by Ms. Lange directly relate to criticisms that also appeared in Staff's direct case in their CCOS Report. Company witness Tom Hickman provided rebuttal testimony to these points previously. The Company will not rehash all of that testimony, except to observe once again that, with respect to issue one, it is a certainty that some of the new investment (and non-unitized plant) that occurred subsequent to the test year itself has a minimum size and customer-related component that should appropriately be classified as such. While the Company's assumption – which was necessary in order to perform timely analysis for a rate case that is prepared before all of the true-up data is available – that the incremental investment during the true-up phase has a similar makeup to that analyzed as of the test year end is undoubtedly imperfect, it is more reasonable than Ms. Lange's assumption that absolutely none of this incremental investment is customer-related.

As to the second issue, Mr. Hickman explained that the Company's minimum system is not a primary system, but that, due to a lack of certain necessary information for analyzing the minimum size secondary system, the Company treated the entire secondary system as demand-related. Contrary to Staff's assertion that the Company's methods over-allocated distribution costs to the small residential and small commercial classes, this simplifying assumption almost certainly caused costs related to the secondary system to be under-allocated to the smaller residential and commercial customers relative to an analysis that applied the minimum size framework to the secondary system also.

Q. Ms. Lange compares and contrasts some statements from Mr. Hickman's direct testimony with some data request responses he provided during the case. She suggests that there are inconsistencies between the information provided by the Company in these two contexts. Do you agree?

A. Not at all. Ms. Lange appears to read things into Mr. Hickman's testimony and the Company's responses to data requests that are not there. In doing so, Ms. Lange makes claims that she presents as if they are somehow very meaningful or impactful issues in the case, but upon closer inspection, are really a complete non-issue, and reveal no flaw at all in the Company's analysis. Specifically, Ms. Lange observes Mr. Hickman's discussions about how the MDS study was conducted. In testimony, Mr. Hickman explained that the minimum size components for the minimum size study were determined in consultation with Company engineers. But in the data request response in question, Mr. Hickman indicates that his conversations with engineers in the development of this case merely reviewed the reasonableness of the minimum size components that he used for the study. If this can really be called an inconsistency at all, it is frankly a trivial semantic difference between the two descriptions found in testimony and a data request response. The Company's MDS study has been used in substantially similar form for at least three rate cases. When it was first conducted, the Company's engineers were fully engaged in evaluating the minimum size components. Mr. Hickman's characterization of that fact in testimony is completely accurate. While the Company updates the study for any meaningful changes from rate case to rate case, we do not start from scratch and throw out all of our previous work in each case. As Mr. Hickman's testimony explains, the minimum size components for the study were derived from conversations with engineers – those initial conversations just happened to occur in previous rate cases. The data request response, which discusses the specific steps in this case, simply highlight that the conversations in this case were more in the form of reasonableness checks made to validate those previous decisions. The fact that the Company leverages work performed for prior rate cases in the development of a new case is hardly scandalous as Ms. Lange would appear to suggest, nor is it at all inappropriate. The process the Company followed and that Mr. Hickman described in testimony is eminently reasonable.

Q. Ms. Lange cites extensive content from the Regulatory Assistance Project's "Electric Cost Allocation for a New Era – A Manual" ("RAP") Manual in her discussion of the purported flaws in the Company's distribution allocations. Please comment on the reference to the RAP Manual as an authoritative source for determining appropriate cost allocations.

A. The RAP Manual is one perspective on cost allocation, but unlike the National Association of Regulatory Utility Commissioners ("NARUC") Manual, it does not represent a consensus, or even a carefully balanced, view of cost allocation issues in the industry. Maurice Brubaker of MIEC, in a report he attached to his rebuttal testimony, highlighted the fact that the RAP Manual appears to advocate strongly for positions "that small consumer advocates typically make."[23] In contrast, I would simply observe that the NARUC Manual, which describes the minimum size methodology that the Company employs, is a more balanced and authoritative reference which has consistently been relied on to inform the methods utilized for CCOS Studies in front of this Commission for many years, and was recently codified into Missouri law as the authoritative reference work for production cost allocation. Over-reliance on the RAP Manual is

[23] File No. ER-2021-0240, Maurice Brubaker Rebuttal Testimony, Schedule MEB-COS-R-3, p. 1.

inappropriate, and the Commission should continue to recognize the merits of study methods that are derived from the NARUC Manual, such as the Company's MDS study.

Q. In Ms. Lange's conclusion of her rebuttal testimony, she suggests that the Company's study was deficient due to "Ameren Missouri's inability or unwillingness to provide (1) the data necessary to differentiate the costs of primary assets, [high voltage ("HV")] assets, and secondary assets to insulate customers served at HV and primary voltages from the costs of the secondary system."[24] Is this criticism valid and also consistent with the other themes of Ms. Lange's criticisms of the Company?

A. No and no. Ms. Lange has argued that the Company over-allocates costs to residential and small commercial customers. Her concern articulated here that we have not "insulated" HV and primary customers from the secondary system costs is in direct opposition to her otherwise stated concern.

However, this criticism is also not at all accurate. Mr. Hickman and I both discussed in our rebuttal testimonies the Company's "Vandas Study".[25] The Vandas Study is an extraordinarily detailed study that characterizes the voltages at which different equipment operates, and it is used to make sure that the investment in each major distribution account is allocated to customers based on the voltage at which they take service and the voltage at which those assets provide service. Ms. Lange was provided the full workpapers supporting the Vandas Study in the Company's response to data request MPSC 635. The screenshots below, as Figure 4 and Figure 5 respectively, highlight information from Mr. Hickman's workpapers that illustrate some of the voltage level

[24] File No. ER-2021-0240, Sarah Lange Rebuttal Testimony, p. 38.
[25] The special study of distribution assets named for the Company engineer that first conducted it, which determined, among other things, the applicable voltages at which various components operate.

information that was directly employed in the process followed for performing distribution cost allocations in his CCOSS.

Figure 4 – Vandas Allocators on CCOSS

VANDAS STUDY RESULTS

		customer %	Total Demand %	HV	PRI	SEC	Lt	check	
360	land and land rights	0.0%	100.0%	0.41925	0.58075	0	0.0%	100.0%	0.0%
361	structures	0.0%	100.0%	0.41925	0.58075	0	0.0%	100.0%	0.0%
362	substations	0.0%	100.0%	0.41925	0.58075	0	0.0%	100.0%	0.0%
364	poles & fixtures	22.44%	77.56%	0.19886	0.38202	0.19476	0.0%	77.6%	0.0%
365	wires & devices	40.49%	59.51%	0.12827	0.44355	0.02329	0.0%	59.5%	0.0%
366	conduit	67.84%	32.16%	0.02825	0.20356	0.08978	0.0%	32.2%	0.0%
367	cable & devices	67.84%	32.16%	0.02825	0.20356	0.08978	0.0%	32.2%	0.0%
368	line transformers	57.07%	42.93%	0	0.00284	0.42647	0.0%	42.9%	0.0%
369	services						0.0%	0.0%	0.0%
369-01	OH services	40.7%	59.3%	0	0	0.59252	0.0%	59.3%	0.0%
369-02	URD services	94.6%	5.4%	0	0	0.05421	0.0%	5.4%	0.0%
370	meters(1)	100.0%	0.0%	0	0	0	0.0%	0.0%	0.0%
371	customer premises	100.0%	0.0%	0	0	0	0.0%	0.0%	0.0%
373	street lighting	0.0%	100.0%	0	0	1	100.0%	100.0%	0.0%

(1) - see allocation factor 7

Figure 5 – Vandas Allocations in Minimum Size Study of Account 364

Description	Unit of Property	Allocation	Percentage HV	Percentage PRI	Percentage SEC	Dollar HV	Dollar PRI	Dollar SEC	Year	Total Cost	Quantity	Accumulative %	Accumulative Total
E040:EDS-EA:POLE,WOOD,40'	E040	S	3.95%	67.39%	28.65%	$7,212,295.05	$122,903,067.03	$52,254,886.27	Various	$182,370,248.35	231304	24.73%	$182,370,248.35
E035:EDS-EA:POLE,WOOD,35'	E035	S	2.53%	59.01%	38.46%	$2,905,636.69	$67,743,566.94	$44,158,623.59	Various	$114,807,827.23	293330	40.30%	$297,178,075.58
E101:EDS-EA:ANCHOR,COMPLE	E101	P	24.69%	47.47%	27.83%	$23,645,677.62	$45,464,002.12	$26,654,794.97	Various	$95,764,474.70	569571	53.29%	$392,942,550.28
E106:EDS-EA:CROSSARM,7'-11'	E106	P	34.37%	65.63%	0.00%	$22,604,069.17	$43,171,177.44	$0.00	Various	$65,775,246.61	593593	62.21%	$458,717,796.89
E045:EDS-EA:POLE,WOOD,45'	E045	S	22.05%	61.26%	16.69%	$12,700,631.16	$35,283,130.78	$9,614,052.47	Various	$57,597,814.40	63075	70.02%	$516,315,611.29
E030:EDS-EA:POLE,WOOD,30'	E030	S	0.38%	17.06%	82.55%	$186,775.14	$8,311,961.44	$40,211,222.07	Various	$48,709,958.65	152720	76.63%	$565,025,569.94
E065:EDS-EA:POLE,WOOD,65'	E065	S	80.76%	16.10%	3.14%	$18,844,393.18	$3,756,894.84	$733,759.04	Various	$23,335,047.06	11742	79.79%	$588,360,617.00
E050:EDS-EA:POLE,WOOD,50'	E050	S	41.37%	50.47%	8.16%	$9,537,678.26	$11,634,586.69	$1,880,579.77	Various	$23,052,844.71	23926	82.92%	$611,413,461.71
E060:EDS-EA:POLE,WOOD,60'	E060	S	71.26%	24.39%	4.35%	$15,683,301.60	$5,368,461.24	$956,807.25	Various	$22,008,570.09	15042	85.91%	$633,422,031.80
E055:EDS-EA:POLE,WOOD,55'	E055	S	61.32%	33.35%	5.33%	$12,410,693.08	$6,749,970.19	$1,078,922.69	Various	$20,239,585.96	20033	88.65%	$653,661,617.76
E070:EDS-EA:POLE,WOOD,70'	E070	S	82.72%	14.51%	2.77%	$14,901,236.01	$2,614,266.60	$499,414.00	Various	$18,014,916.61	6858	91.09%	$671,676,534.37
E075:EDS-EA:POLE,WOOD,75'	E075	S	86.91%	11.21%	1.88%	$9,306,871.96	$1,200,608.23	$201,256.09	Various	$10,708,736.28	3802	92.55%	$682,385,270.65
E076:EDS-EA:POLE,WOOD,80'	E076	S	86.09%	12.13%	1.77%	$4,820,625.75	$679,458.35	$99,196.92	Various	$5,599,281.02	1571	93.31%	$687,984,551.67
2997:LT:Land-Easements	2997	P	24.69%	47.47%	27.83%	$1,290,286.81	$2,480,859.44	$1,454,486.99	Various	$5,225,633.24	268	94.01%	$693,210,184.91
E105:EDS-EA:CROSSARM,6' ANI	E105	P	34.37%	65.63%	0.00%	$1,740,500.49	$3,324,156.14	$0.00	Various	$5,064,656.63	184471	94.70%	$698,274,841.54
E077:EDS-EA:POLE,WOOD,85'	E077	S	88.75%	9.97%	1.27%	$2,804,282.00	$315,089.81	$40,230.96	Various	$3,159,602.76	913	95.13%	$701,434,444.30
E025:EDS-EA:POLE,WOOD,25'	E025	E	0.00%	0.00%	100.00%	$0.00	$0.00	$2,515,191.92	Various	$2,515,191.92	19485	95.47%	$703,949,636.22
E108:EDS-EA:CROSSARM,17'-29	E108	E	100.00%	0.00%	0.00%	$2,159,325.66	$0.00	$0.00	Various	$2,159,325.66	9789	95.76%	$706,108,961.88
E078:EDS-EA:POLE,WOOD,90'	E078	S	91.48%	7.80%	0.72%	$1,920,752.46	$163,811.36	$15,016.53	Various	$2,099,580.35	488	96.05%	$708,208,542.23
E107:EDS-EA:CROSSARM,12'-16	E107	E	100.00%	0.00%	0.00%	$2,039,754.44	$0.00	$0.00	Various	$2,039,754.44	12341	96.33%	$710,248,296.67
E670:EA:STRUCTURES,STEEL	E670	E	100.00%	0.00%	0.00%	$1,991,863.46	$0.00	$0.00	Various	$1,991,863.46	724556	96.60%	$712,240,160.13
2190:EDS-EA:TOWER,DELTA TA	2190	E	100.00%	0.00%	0.00%	$1,711,294.97	$0.00	$0.00	Various	$1,711,294.97	41	96.83%	$713,951,455.10
2004:EDS-EA:TOWER,TANGENT	2004	E	100.00%	0.00%	0.00%	$1,375,620.66	$0.00	$0.00	Various	$1,375,620.66	46	97.01%	$715,327,075.76
E122:EDS-EA:CROSSARM ASSE	E122	P	34.37%	65.63%	0.00%	$435,265.51	$831,307.17	$0.00	Various	$1,266,572.68	3343	97.19%	$716,593,648.44
E562::PLATFORM,TRANSFORME	E562	E	0.00%	0.00%	100.00%	$0.00	$0.00	$1,249,699.70	Various	$1,249,699.70	473	97.36%	$717,843,348.14
2191:EDS-EA:FOUNDATION,DEL	2191	E	100.00%	0.00%	0.00%	$1,229,183.95	$0.00	$0.00	Various	$1,229,183.95	41	97.52%	$719,072,532.09
E079:EDS-EA:POLE,WOOD,95'	E079	S	92.94%	6.69%	0.37%	$969,538.87	$69,838.38	$3,854.85	Various	$1,043,232.10	185	97.66%	$720,115,764.19
E561::PLATFORM,TRANSFORME	E561	E	0.00%	0.00%	100.00%	$0.00	$0.00	$921,424.90	Various	$921,424.90	869	97.79%	$721,037,189.09
2005:EDS-EA:FOUNDATION,TAN	2005	E	100.00%	0.00%	0.00%	$836,909.94	$0.00	$0.00	Various	$836,909.94	46	97.90%	$721,874,099.03
2124:EDS-EA:TOWER,SUSPENS	2124	E	100.00%	0.00%	0.00%	$654,799.13	$0.00	$0.00	Various	$654,799.13	22	97.99%	$722,528,898.16
2312:EDS-EA:POLE,STEEL STRU	2312	E	100.00%	0.00%	0.00%	$551,954.86	$0.00	$0.00	Various	$551,954.86	36	98.07%	$723,080,853.02
2313:EDS-EA:FOUNDATION,POL	2313	E	100.00%	0.00%	0.00%	$511,945.58	$0.00	$0.00	Various	$511,945.58	33	98.14%	$723,592,798.60
E080:EDS-EA:POLE,WOOD,100'	E080	S	95.20%	4.36%	0.45%	$448,185.96	$20,506.37	$2,114.90	Various	$470,807.23	80	98.20%	$724,063,605.83
2188:EDS-EA:TOWER,RIVER CR	2188	E	100.00%	0.00%	0.00%	$466,544.20	$0.00	$0.00	Various	$466,544.20	2	98.26%	$724,530,150.03
2324:EDS-EA:POLE,SINGLE STE	2324	E	100.00%	0.00%	0.00%	$438,862.69	$0.00	$0.00	Various	$438,862.69	12	98.32%	$724,969,012.72
2319:EDS-EA:FOUNDATION,TWO	2319	E	100.00%	0.00%	0.00%	$410,066.87	$0.00	$0.00	Various	$410,066.87	9	98.38%	$725,379,079.59

Summary | 364 - Step 1 | 364 - Step 2 | 364-Vandas | 365 | 366 | 367 | 368 | query data

In both Figure 4 and 5, the columns with the headings of "HV," "PRI," and "SEC" represent the detailed percentages of the relevant assets or accounts that are, based on Vandas Study results, associated with the High Voltage, Primary, and Secondary systems respectively. Clearly, the Company appropriately utilized voltage information to reasonably allocate the costs of the distribution system to the customer that are using it.

VII. MISCELLANEOUS ISSUES

Q. Dr. Marke[26] and MIEC witness Maurice Brubaker[27] both recommend that the 12(M) tariff, which the Company proposed to discontinue, should remain in effect. What is your response?

A. The 12(M) tariff has been unused for over four years now. It was developed originally for one specific customer – an aluminum smelter not electrically connected to the Company's system – that is no longer taking any service from the Company. It simply does not have a role in the current rate offerings of the Company. The qualification and pricing terms of that tariff were developed specifically for the needs of that customer, and are appropriate for circumstances that are few and far between, and unlikely to arise. I would also note that there has not even been any data with which to calculate CCOSS results for the 12(M) class to determine the extent to which it is still a cost reflective rate.

Mr. Brubaker suggests that the 12(M) rate could be used for other high load factor customers, citing data centers as an example of the type of customer that might use the 12(M) rate. However, my expectation is that if there were such customers seeking such a rate option, their unique needs would differ enough in circumstance from the aluminum smelter that previously occupied the 12(M) rate, such that there would ultimately need to be some changes to the rate to use it for that purpose. If that is the case, it would frankly be much easier and cleaner to propose a new tariff for those circumstances, perhaps outside of a general rate case, than to try to make changes to a dormant tariff – which could likely only be made in the context of a general rate case – to meet the needs of a customer that was never contemplated when the 12(M) rate was created.

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[26] File No. ER-2021-0240, Geoff Marke Rebuttal Testimony, p. 23-24.
[27] File No. ER-2021-0240, Maurice Brubaker Rebuttal Testimony, p. 17.

Q. Dr. Marke also endorses Missouri Energy Consumers Group ("MECG") witness Andrew Teague's direct testimony recommendation for the Commission to order the Company to implement Green Button functionality for customers to be able to access their usage data in some standardized formats.[28] What is your response?

A. It is the same as my rebuttal response to Mr. Teague. The Company is in the process of pursuing Green Button Download My Data functionality, and expects it to be available before the end of 2022. We appreciate and share the interest in getting usage data in the hands of our customers, and fully expect to do so. That said, I do not believe that the Commission should order anything on the topic, as it may create conflict with existing plans and timelines, and create unnecessary cost implications as a result.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

[28] File No. ER-2021-0240, Geoff Marke Rebuttal Testimony, p. 34.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.	)))	Case No. ER-2021-0240

AFFIDAVIT OF STEVEN M. WILLS

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

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

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

/s/ Steven M. Wills
Steven M. Wills

Sworn to me this 3rd day of November, 2021.