Exhibit No.:	
Issue(s):	Rush Island Energy Center; Rate Switching Tracker; Rate Design; CCOS; TOU; Smart Energy Plan
Witness:	Steven M. Wills
Type of Exhibit:	Surrebuttal Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2022-0337
Date Testimony Prepared:	March 13, 2023

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2022-0337

SURREBUTTAL TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

d/b/a Ameren Missouri

St. Louis, Missouri
March, 2023

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SURREBUTTAL TESTIMONY

OF

STEVEN M. WILLS

FILE NO. ER-2022-0337

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. My surrebuttal testimony responds to several witnesses' and parties' rebuttal testimony, including that of Missouri Public Service Commission Staff ("Staff") witnesses Claire Eubanks and Keith Majors on the topic of the Company's obligation to explain the prudence of its actions leading to the decision to retire the Rush Island Energy Center; Staff witness Sarah Lange on the topics of the Company's proposed rate switching tracker, the residential customer charge, and certain rate design and class cost of service considerations; Renew Missouri witness James Owen on the incompatibility of the Company's residential Time of Use ("TOU") rate plans with net metering under the Missouri legal requirements for net metering and on the appropriate level of the residential customer charge; and Staff witness Eubanks, again, on the topic of the Smart Energy Plan.

II. THE COMPANY MET ITS OBLIGATION TO EXPLAIN THE PRUDENCE OF ITS ACTIONS LEADING TO THE RETIREMENT OF THE RUSH ISLAND ENERGY CENTER

Q. Staff witnesses Eubanks and Majors discuss issues related to the prudence of the Company's decision to retire the Rush Island Energy Center. Has Staff recommended a prudence adjustment to the revenue requirement in this case?

A. No. Staff has proposed an adjustment to the revenue requirement in this case related to Rush Island but has made it clear that the basis for that adjustment relates solely to the fact that the plant is operating less as a system support resource ("SSR") than it had historically. The adjustment is not based on an allegation of imprudence. As a result, there is no issue in this case that requires the Missouri Public Service Commission ("Commission") to determine whether the retirement decision, and the decisions that led to it, were prudent. That said, these Staff witnesses do go into some detail about the events at Rush Island and suggest that they believe that there may have been imprudent decisions made regarding Rush Island. Staff then indicates that the future securitization case that the Company has indicated it intends to file related to Rush Island is the appropriate case in which to consider whether there was any imprudence on the Company's part relating to Rush Island. While not asking the Commission for any action, Staff goes into a fairly lengthy rebuttal discussion of some of the Company's direct testimony regarding the prudence of the decisions related to Rush Island, and expresses its viewpoint that the Company did not meet its commitment to explain the prudence of the circumstances in its direct testimony.[1]

While the prudence issue is not presented in a manner that impacts the issues that the Commission is asked to evaluate in this case, the Company will provide a limited response to

[1] ER-2022-0337, Claire Eubanks Rebuttal Testimony, p. 18 l. 25 – p. 19, l. 19, February 15, 2023.

Staff's allegations in this case in order to clarify the record on these issues. Company witnesses Holmstead and Moor provide that response in their surrebuttal testimonies. I will briefly discuss Staff's claim that the Company did not meet the burden of its requirement to explain the prudence of the events that led to the present circumstance.

Q. What is the basis of Staff's claim that the Company did not fully explain the prudence of its decisions that led to the retirement of Rush Island?

A. Witness Eubanks identifies additional potential decision points, beyond those discussed in the Company's direct testimony, that Staff believes should have been addressed.

Q. Do you agree that the Company's explanation of prudence was incomplete?

A. No. The Company presented four pieces of witness testimony – over 100 pages of fact-heavy content – that provided a tremendous amount of detail regarding the bases for the Company's key decisions that led to the eventual decision to retire Rush Island. The two watershed decisions were the decisions to pursue the projects that led to the New Source Review ("NSR") litigation without pursuing permits, and the decision to retire the plant rather than add additional pollution controls following the final and unappealable order regarding the NSR cases. The detail presented in testimony about those decisions clearly demonstrates what the Company understood at the time the key decisions were made – which is what the prudence standard demands be considered.

These two key decisions are the two things that clearly and directly led to the present circumstances, as the Company was ordered to address. Staff seems to imply that to meet its burden to explain its decisions, it would be necessary for the Company to identify and analyze each and every circumstance and tactical decision that may have created an opportunity to change course, which could have occurred across an entire almost decade-and-a-half time period between the first relevant decision and the final closure decision. Of course, it's true that over a decade and a half, there were various phases of litigation, day-to-day and year-to-year circumstances that took place or arose, and that, in theory, the Company could have attempted to change course from the decisions that it had made pre-2010 when it concluded that it did not need to obtain permits before proceeding with the projects at issue. However, the over-riding factor that guided the Company's actions through those many years and potential incremental decision points, was its belief about the lack of need for permits for the project – as explained fully in our direct testimony. The Company's explanation was exactly what the Commission ordered it to do – an explanation of what decisions led to the present circumstances – not what other decisions the Company did not make, but could have theoretically made, over time. If Staff believes that there were additional milestones arising from potential interim points where the Company could have changed its mind that rise to the level of imprudence, it can identify them, and explain how they result in imprudence, if and when Staff decides to take that position in the securitization case. If that happens, the Company will respond to any such allegations as appropriate. For purposes of this case, the Company has done exactly what it was tasked to do.

III. THE COMPANY'S PROPOSED RATE SWITCHING TRACKER SHOULD BE APPROVED

Q. Staff recommends that the Commission reject the Company's request to track the revenue impacts of rate switching by residential customers adopting more advanced Time of Use ("TOU") rate options, which is proposed in order to provide an alignment of the Company's incentives with those of its customers. Please discuss the important considerations that should guide the Commission's decision on this topic.

A. The alignment of utility incentives with the interest of its customers is an important regulatory concept, which has been recognized by the Commission in many settings. There are many examples of ways that utility regulation generally, and this Commission specifically, try to achieve positive outcomes for customers by creating incentives for the utility that, when acted upon, promote the interest of customers. Examples include the 95/5 sharing of variations in net energy costs in Missouri utilities' Fuel Adjustment Clauses ("FACs"), the mechanisms under the Missouri Energy Efficiency Investment Act ("MEEIA") that allow utilities to avoid negative financial impacts and create earnings when helping customers reduce their usage and bills, and the simple operation of regulatory lag that encourages utilities to manage their costs efficiently, to name just a few. In the case of TOU rates, regulatory lag creates an incentive for the utility that is misaligned with customers' interests in saving money and reducing their bills (much like occurs with MEEIA, customer bill savings directly reduce utility earnings, which in the case of MEEIA is addressed through Commission approved MEEIA plans). When considering Staff's arguments on this topic, I urge the Commission not to get bogged down in the minutiae of technical arguments that amount to little more than quibbling about the valuation of that disincentive around its edges. Rather, the Commission should consider two important questions; Are the Company's interests aligned with its customers' interests on the topic of promoting TOU rates in the absence of a tracker?; and, Do you want them to be? I will address the specifics of the minutiae that Staff goes into demonstrating that the arguments are themselves red herrings. Irrespective of the merits of the issues, none of them are of a significance that could even fundamentally change the fact that the alignment of incentives does not exist in the way that it could and should, through the simple adoption of a tracker.

Q. What are the reasons that Staff gives for their recommendation?

A. First, Staff suggests that the Company has not quantified the benefits to all customers of an individual customer's decision to take service on a TOU rate, and potentially shift its usage away from peak periods,[2] suggesting that the promotion of TOU rates may not be beneficial for all customers, and by logical extension, that the Commission should not even want to encourage more TOU adoption. Next, Staff makes a related suggestion that there is no benefit generally to the Commission adopting policies that encourage the Company to pursue additional rate modernization proposals.[3] In furtherance of this point, Staff alleges that there is no evidence that the TOU rates better align customers' bills with the Company's cost of serving them,[4] nor that customers are shifting their usage away from periods of high demand in response to the TOU rates.

Next, Staff goes on to argue that the Company's proposed approach to calculating the revenues to be tracked is inappropriate. Staff articulates three reasons that it believes this is the case.[5] Those reasons include Staff's suggestion that customers on TOU rates will increase their usage due to certain changes in the utilization of existing equipment and/or due to the addition of

[2] ER-2022-0337, Sarah Lange Rebuttal Testimony, p. 7. ll. 16-21 February 15, 2023.
[3] *Id.*, p. 8, ll. 19-22
[4] *Id.*, p. 10, ll. 3-4.
[5] *Id.*, p. 11, ll. 12-16.

new electric consuming end uses (particularly electric vehicles "EVs"), as well as Staff's claim that the Company will recover some of the revenue losses through the operation of its FAC.

Next, Staff argues that the analogy that I offered in my direct testimony comparing the rate switching tracker to certain provisions of the MEEIA cost recovery framework is an inappropriate comparison.[6]

Finally, Staff suggests that if the tracker is approved, any future rate impacts arising from the application of the amounts to be recovered from customers should be recovered from the TOU customers that created the revenue shortfall.

Q. Please discuss each of these issues, starting with the first issue of whether TOU rates create benefits for all customers.

A. Staff's testimony asks the question whether real benefits arise from TOU customers shifting usage under the Company's rate plans, and then the answer starts: "No….Ameren Missouri…has done no analysis to quantify any changes in existing residential load that the Company projects will be caused by continued operation of these plans."[7]

Q. Does Staff's initial answer of "no" reasonably answer the question that was asked in the testimony, given the rationale postulated in the next sentence – meaning does Staff's answer support its initial claim reflected in its response that suggests real benefits do not arise from TOU rates?

A. No. Staff posits the question of whether benefits arise from TOU rates, but then answers definitively that there are no benefits based only on its observation that those benefits have not already been quantified. Staff provides no evidence or analysis of its own to support its answer of "no" to that question, and provides no reason to believe that TOU rates should not be

[6] *Id.*, p. 13, ll. 5-21.
[7] ER-2022-0337, Sarah Lange Rebuttal Testimony, p. 7, ll. 18-21, February 15, 2023.

expected to be generally beneficial. In fact, Staff's claim that there are no benefits is a very bold and unsubstantiated allegation that is highly probable to be untrue. If Staff felt that TOU rates were not beneficial, why would Staff propose new TOU rate structures for non-residential customers, and also propose accelerated timelines to move residential customers to TOU rates in this case?

Over the course of several rate reviews that have included discussion of the Company's TOU program, the general categories of benefits that are expected to arise from a robust TOU program have been discussed extensively, notably including reducing peak loads that drive capacity investments in generation, transmission and distribution over time, and also shifting usage in ways that may help reliably integrate higher levels of renewable generation that may exist in the Company's future resource mix. Dr. Ahmad Faruqui, of the Brattle Group prior to his recent retirement, testified to the Commission regarding the percentage reduction in peak period customer usage that is expected to occur under each of the Company's rate plans. While the Company has not calculated a number that quantifies the precise economic benefits of its current TOU rate plans, the Data Request ("DR") responses that Staff cites in its testimony make it clear that we anticipate benefits and intend to build more specific analysis that can be used to quantify those benefits into our upcoming Integrated Resource Plan, to be filed later in 2023. But the general fact that TOU rates are expected to be good for the system is really not something that should be considered speculative, or even controversial, in any way.

As I just mentioned, Dr. Faruqui estimated, based on his decades of experience as one of the most recognized and respected rate design experts in the field and his specific study of hundreds of TOU rate programs over that time, that the peak demand reductions associated with the Company's various rate plans are likely to be as shown in Table SMW-S1 below, which is a reproduction of Table 4 from my direct testimony in this case.

Table 1 – Load Shifting Potential of TOU Rate Plans

	Peak/Off-peak Ratio		Expected Peak Load Reduction	
	Summer	Winter	Summer	Winter
Evening/Morning Savers	1.04	1.03	0.3%	0.2%
Overnight Savers	2.53	1.63	6.8%	3.5%
Smart Savers	5.04	3.42	11.8%	9.0%
Ultimate Savers	5.86	3.59	12.9%	9.3%

Given these expected usage reductions during peak periods, and the fact that the peak periods themselves cover the time periods when the Company's peak demands are typically set, therefore driving the incurrence of capacity costs, there can be very little doubt that benefits do and will arise from these plans in the long-term. Significantly, reductions in peak demand, which we have a high level of confidence will result from our rate plans based on Dr. Faruqui's analysis, are explicitly recognized in the cost effectiveness tests calculated to justify the Company's MEEIA energy efficiency and demand response programs as driving avoided capacity, transmission, and distribution costs. The exact same rationale that applies to the quantification of benefits for MEEIA peak demand reductions apply to peak demand reductions that are likely to arise from the adoption of TOU rates.

I would add one further note to this discussion. Staff's DRs and testimony suggest that it is somehow a meaningful criticism of the TOU program that we do not expect it to result in the retirement of any existing distribution, transmission, or generation capacity.[8] I have no idea why Staff thinks that is a relevant point to raise. The goal of peak demand reductions is to avoid *incremental* investments that may be needed to meet future peak loads, not to retire *existing* equipment that is used and useful in serving customers. I recall no instance when Staff has

[8] ER-2022-0337, Sarah Lange Rebuttal Testimony, p. 8, ll. 1-9, February 15, 2022.

suggested we stop running MEEIA programs because they are not contributing to the retirement of existing distribution infrastructure.

Q. What is your response to Staff's claim that "there is no grounds for an assumption the resulting bills [of customers on TOU rates] are closer to the cost of service[9]"?

A. That claim is simply not true. This was the topic of my direct testimony in File No. ER-2019-0335 ("the 2019 case"), in which the Company's TOU rate plans were initially proposed, and eventually approved by the Commission. Attached to my testimony as Schedule SMW-S1 is an excerpt from my direct testimony in that case, where the Company provided an extensive analysis of the cost of service of individual residential customers, and compared those costs to bill outcomes under different rate structures being considered in that case. See the attached schedule for supporting details of the study that was conducted in the 2019 case. Here is a summary of the findings from my direct testimony in that case:

> **Q. Please summarize your findings.**
> A. There is a very clear continuum, quantitatively demonstrated, where, as the rates are increasingly grounded in cost of service analysis, they improve in performance with respect to the equity and economic efficiency they promote. The ranking of the candidate rate structures across the metrics calculated in my analysis, from the most equitable and economically efficient rate, to the least, is as follows:
>
> 1. 3 Part Rate with Demand Charge
> 2. Time of Use ("TOU") Energy Charge
> 3. Cost Based Two Part Rate
> 4. Status Quo
> 5. Inclining Block Rate[10]

The first two rates in the list are the rates that were the basis for the eventually adopted "Ultimate Savers" rate and "Smart Savers" rate.

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[9] *Id.*, p. 10, ll. 3-4
[10] File No. ER-2019-0335, Steven Wills Direct Testimony, p. 6, ll. 3 – 16.

Q. Did Staff provide any rebuttal to the Company's analysis in the 2019 case that you just described, in effect suggesting what they now claim, specifically that the rates do not reflect the cost of service to customers' bills?

A. No. They provided no response to this analysis in that case.

Q. Does Staff acknowledge that analysis in this case when they make the claim that the Company's TOU rates do not reflect the cost of service to customers' bills, or offer any criticisms of that study from the 2019 case?

A. No. The Staff's claims that the rates are not cost based are utterly unsupported and completely without merit. The Staff offers nothing but conclusory statements backed with no evidence, nor even a stated rationale for why they claim the rates are not cost based. As I will discuss later in this testimony, my sense is that Staff is only considering marginal costs of wholesale energy for purposes of determining whether a rate is cost-based – despite the fact that both the Class Cost of Service Study ("CCOSS") and the rates established in the case are designed to analyze and produce revenues to cover the Company's full embedded cost of providing service. The TOU rates are in fact reflective of the utility's embedded cost structure as the Company demonstrated in the 2019 case.

Q. Please move on to Staff's claim that the calculations the tracker would be based on are inappropriate.

A. Staff claims that, because it was able to come up with two anecdotes about how a customer might use more energy when taking service subject to a TOU rate,[11] it is self-evident that customers will use more total energy on the TOU rate than they otherwise would. While Staff never does follow that line of thought through to conclusion to explain why it matters, it is safe to

[11] ER-2022-0337, Sarah Lange Rebuttal Testimony, p. 11, l. 17 – p. 12, l. 5, February 15, 2023.

assume that the point it is making is that some of the losses the Company incurs due to reduced bills on TOU rates will be made up in the form of higher electric energy sales to these customers that are purportedly increasing their usage.

Q. Do you agree with Staff that these two anecdotes demonstrate TOU customers use more energy?

A. No. In fact, the first anecdote about a customer running their clothes dryer in "fluff" mode all night long so that they can dry their clothes at off-peak rates is entirely unrealistic. The notion that a customer that is so interested in saving money that they will make the effort to adjust the timing of their appliance usage, but will then run the appliance for many extra hours while they sleep, should not be taken seriously.

Next, Staff discusses changes in thermostat programming that it claims may result in increased energy usage. At least this anecdote is grounded in reality, by suggesting customers may program their thermostats to "pre-cool" their homes before the peak period, and let the temperature rise in the home during the peak hours. This is exactly the type of customer behavior that we hope TOU rates will elicit – although I would not necessarily recommend to customers to set the thermostat quite as high during peak periods as Staff assumes in its example. That said, the obviousness of the load-shifting potential reflected in this example does suggest to me that Staff's earlier claim that there are no load-shifting benefits associated with TOU rates is likely to be patently wrong, and that Staff itself does in fact fully understand many of the reasons that beneficial load shifting is likely to occur, despite its claims to the contrary. But, as pertains to Staff's claim that this thermostat behavior will result in increased electricity usage – that is entirely speculative. Whether such use of a smart thermostat to "pre-cool" before peak hours, and let the temperature rise during peak hours, would result in more or less total usage would likely depend on a number of factors, such as the efficiency of the air conditioner, the quality of insulation in the home, and the ambient weather conditions outside day to day. It is in fact a certainty that the air conditioner would run less during the peak hours. Whether it would have to run more in other hours by enough to offset the peak period reductions is unknown. Staff provides no evidence that this would systematically increase electric usage.

What Staff also fails to do is acknowledge that there are an equal or greater number of anecdotes one could come up with that suggest reasons that customers on TOU rates might use less energy than they did when on a non-time differentiated rate, further eroding Company revenues, rather than supplementing them as Staff presupposes is happening. Those anecdotes are easy to imagine as well, such as people just having increased awareness of energy consumption and practicing greater levels of energy *conservation* during peak periods instead of just shifting load. This could happen as a result of such simple things as turning off lights more diligently or cooking more meals on an outdoor grill to avoid peak electric usage of their stove. But none of the anecdotes – whether relating to increases or decreases in usage – are significant enough to suggest that a systematic change in total consumption will result from the adoption of a TOU rate, or more importantly, that some hypothetical possibility of such increased sales mean that the Company's incentives are already aligned with customers' interests in using TOU rates to reduce their bills.

Q. What about Staff's other claim about customers increasing their electric usage, which I will paraphrase as – customers will buy more EVs as a result of their adoption of TOU rates, and the additional electricity sales to power those vehicles will make up for the TOU-related revenue losses?

A. Staff raises issues from the Company's "Charge Ahead" case[12] (File No. ET-2018-0132) related to incentives for EV charging, claiming that incremental revenue from new EV load will enhance Company revenues, presumably suggesting that the new revenues will make up for the revenue shortfall from customers saving on TOU rates. While it is true that any incremental revenues from new EVs do benefit the Company in the short run, it is also true that these EV-related revenues represent a very small amount of total usage as compared to the total household usage of residential customers that may be adopting TOU rates and creating customer savings (and utility revenue shortfalls as a result).[13] But even more importantly, Staff ignores the fact that any incremental revenues that may arise from an 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

[12] File No. ER-2022-0337, Sarah Lange Rebuttal Testimony, p. 12, ll. 8-10.

[13] Per the Company's true-up billing units in this case, the average total household use per residential customer is 12,233 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 11,996 EVs registered in the Company's service territory as of the third quarter of 2022, whereas there are 1,084,328 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 1.1% 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 / (12,233 kWh of base household usage + 4,090 kWh EV usage) = 25%).

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. While there are certain to be some amount of 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, and their existence does little or nothing to offset the real disincentive that exists for the Company to encourage higher levels of advanced TOU rate adoption.

Q. Staff next claims that the Company will recover some of its losses from reduced revenue associated with TOU adoption through the Company's five percent share of reduced wholesale market energy costs in the FAC. Is this a meaningful contributor towards aligning the Company and customers incentives?

A. No. Ninety-five cents of every dollar of such cost reduction will inure to the benefit of customers due to the nature of the FAC's 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 and FAC sharing, consider the example in Figure 1 and Table 2 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

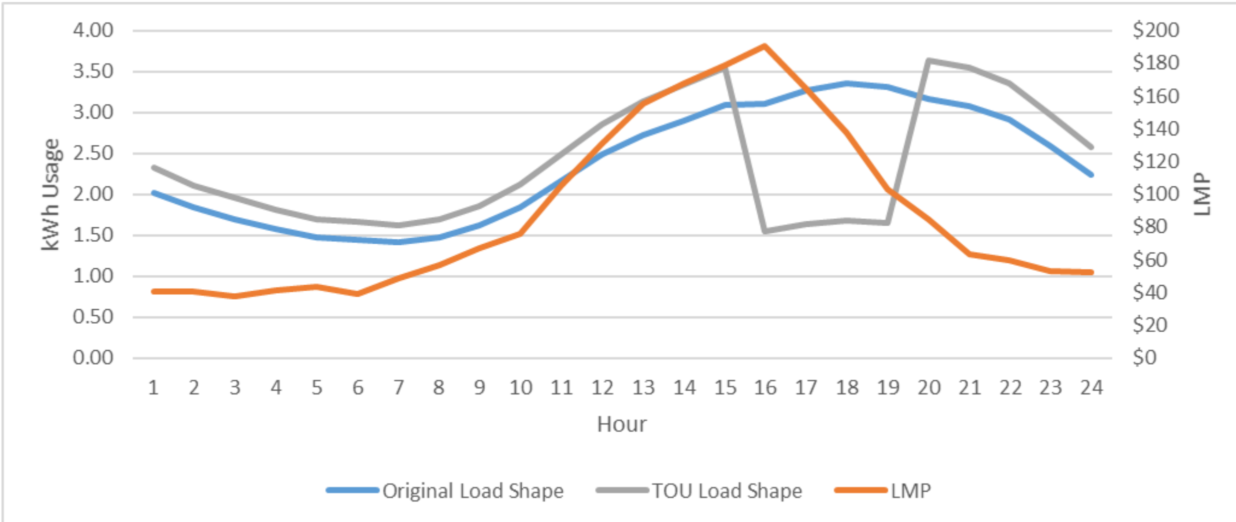

Table 2 – Financial Impacts of TOU-Induced Load Shifting

	Original Load			**TOU Shifted Load**		
	kWh	**Retail Revenue**	**Energy Cost**	**kWh**	**Retail Revenue**	**Energy Cost**
Off-Peak	14.9	$1.93	$0.66	17.1	$1.09	$0.76
Intermediate	28.9	$3.74	$3.05	33.2	$3.34	$3.51
Peak	13.0	$1.69	$1.93	6.5	$2.19	$0.97
Total	56.8	$7.36	$5.65	56.8	$6.62	$5.23
TOU Savings					**-$0.739**	-$0.412
Cost Savings to Customers in FAC						-$0.391
Cost Savings to Company through FAC Sharing						**-$0.021**
Net Financial Impact on Company						

Q. Please interpret Figure 1 and Table 2.

A. Figure 1 is based on normalized load and market price data from an historical day associated with the updated test period in this case. 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[14] for the highest price day of the summer,[15] which is what gives rise to the potential cost savings Staff references.

In Table 2, 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 $0.74 reduction in the Company's retail revenue, but in only $0.41 of cost reductions. However, that is only the beginning of the story, because the application of the FAC sharing parameters results in the

[14] Designated in the legend of the graph as "LMP" is Locational Marginal Price, which is the hourly wholesale market prices that Ameren Missouri is subject to in the MISO market.
[15] 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 a recent summer to test an extreme scenario.

Company retaining only 2 cents of the cost savings (5% of $0.41) in this scenario. The net financial impact on the Company's pre-tax earnings is $0.72, or 97%[16] of the change in revenue. The cost savings Staff points to offset only *a trivial portion of the revenue loss* incurred by the Company. This analysis demonstrates 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.

Q. Staff questions the analogy that you used in your direct testimony on this issue that compared the alignment of incentives provided by MEEIA for energy efficiency programs and the potential for a similar alignment of incentives associated with the TOU program. Do you have any observations related to Staff's comments on this analogy?

A. Yes. Staff's comments reflect Staff drawing a distinction without a difference. Staff states:

> Ameren Missouri's MEEIA program is designed to recover a "Throughput Disincentive," which relies on various assumptions to estimate the value of revenues avoided due to implementation of certain utility-funded measures.[17]

Somehow Staff tries to draw a distinction between the TOU scenario and the energy efficiency scenario and ends up illustrating their incredible similarity. The Throughput Disincentive mechanism under MEEIA does, as Staff explains, rely on various assumptions to *estimate the value of revenues avoided due to implementation* of utility-funded measures, and in fact creates the opportunity for the Company to recover those revenues. Whereas the rate switching tracker *estimates the value of revenues avoided due to the implementation* of utility-offered rate plans, and then creates the opportunity for the Company to recover those revenues. The analogy is

[16] 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 a recent summer. 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*.
[17] ER-2022-0337, Sarah Lange Rebuttal Testimony, p. 13, ll. 16-18, February 15, 2023.

apt, obviously. Staff makes the conclusory statement, supported by no evidence or rationale, that this analogy is not a good reason to approve the tracker, when Staff's own testimony illustrates why the tracker creates an almost perfectly analogous outcome to the sound policy outcome that occurs under MEEIA for energy efficiency programs.

Q. Staff claims that, if the tracker is approved, any revenues recovered under it should only be recovered from the customers that saved money under the TOU plans. Does this make any sense at all?

A. Absolutely not. There is no point in even having a TOU program if you are going to create savings for a group of customers who take beneficial actions for the system, and then charge the savings back to only those same customers. That absurd suggestion, which would completely remove all incentive for customers to choose a TOU rate, should be dismissed out of hand.

IV. THE NET METERING STATUTE DOES NOT APPROPRIATELY ALLOW FOR NET METERING OF TOU RATES

Q. Renew Missouri witness James Owen discusses the fact that the Company does not make all of its TOU rate plans available to customers who are net metered. Why is that the case?

A. As an initial point of historical context, Renew Missouri has not raised this issue in either of the Company's two general rate cases since default TOU rate options have been at issue. In the Corrected Non-Unanimous Stipulation and Agreement in the Company's 2019 general rate case, File No. ER-2019-0335, Renew Missouri indicated that it did not object to the settlement. And, at the on-the-record presentation of the stipulation in the Company's 2019 general rate case, Commissioner Holsman asked Renew's representative, counsel Opitz, about net metering and advanced TOU rate options and the following response was provided:

> COMMISSIONER HOLSMAN: Yes. Was there any discussion concerning the net metered customers and the prohibition on their ability to have time-of-use?
>
> MR. OPITZ: Commissioner, I don't want to get into any discussions that would be considered settlement discussion. I will say that for Renew Missouri's perspective the net metering customers were – some class of customers were very concerned about potentially being forced on to certain rates in the future. Whether they would be prohibited was not something we specifically identified within our positions we've taken.[18]

In File No. ER-2021-0240, Renew Missouri was a signatory to both stipulations and agreements, and Mr. Owen did not raise this issue in his rebuttal testimony.

The Net Metering and Easy Connect Act, which is the legal basis of net metering in Missouri, is drafted in a manner that does not contemplate the application of TOU rates, and when applied as written, does not allow the billing of TOU rates in an economically-rational manner. Specifically, the statute requires that all energy consumed by a customer-generator from the grid during a billing period be netted with all energy produced and delivered to the grid by the customer-generator during the same billing period. This means that any kWh of energy produced can net with any kWh of consumption – i.e., these kWh's must be economically valued equally - irrespective of the time (peak vs. off-peak, etc.) they occur. This dynamic is completely counter to the concept of TOU rates, which makes it clear that kWh have unique economic values during different time periods. Witness Owen mentions the DR responses that the Company provided further explaining its concerns on the topic. Two attachments from the response to DR Renew-MO 2.2 are attached to my testimony as Schedule SMW-S2. For more detail related to the

[18] File No. ER-2019-0335, p. 251, l. 25 – p. 252, l. 10.

Company's concerns, and specific examples of economically-irrational outcomes, please see that schedule.

Q. Witness Owen claims that parties could work through these issues and come up with a means to resolve them in order to create appropriate mechanisms to bill net metering on TOU rates. Do you agree?

A. Conceptually, yes, if Missouri's net metering statute were different. However, it's not, and the kind of solutions witness Owen would likely want to see cannot, based upon advice of counsel, be implemented without a statutory change. The Company has sincere interest in making these rates available to net metering customers but believes that is only appropriate if the proper statutory changes were made.

Q. Witness Owen also implies that it is inconsistent with the statute to exclude net metering customers from these rate options. Do you agree?

A. No. The language he cites is reproduced below:

> "A retail electric supplier shall:… (2) Offer to the customer-generator a tariff or contract that is **identical** in electrical energy rates, **rate structure**, and monthly charges *to the contract or tariff that the customer would be assigned* if the customer were not an eligible customer-generator…"[19]

Witness Owen notes the words that he highlights in bold font, which indicate that the rate offered to net metering customers must be identical to the rate offered to traditional (non-generating) customers. He fails to note, though, that later in that sentence (highlighted in italics) it qualifies what must be offered to net metering customers in a way that limits the application of this provision to the "contract or tariff that the customer would be assigned if the customer were not an eligible customer-generator." This clearly indicates that the default rate – the rate a customer

[19] File No. ER-2022-0337, James Owen Rebuttal Testimony, p. 6, ll. 5-8 (Emphasis supplied by witness Owen in bold, Emphasis I have provided in italics).

would otherwise be assigned to – must be identically available to the customer-generator. It says nothing about optional rates that a non-generating customer can *elect* to enroll in. None of the advanced TOU rates in question with respect to the TOU applicability issue are rates that the Company would ever assign a customer to. They are rates that a customer themselves chooses and opts into. As witness Owen observes, the Evening/Morning Savers rate, which is a default rate for customers with an advanced meter, and to which the Company does and would "otherwise assign" customers, is available to a net metered customer on identical terms to those available to a non-generating customer.

Q. Witness Owen notes the problems that exist for offering net metering customers advanced TOU rates also exist on the default Evening/Morning Savers TOU rate plan. Do you agree, and if so, why does the Company allow net metered customers on this rate plan?

A. I do agree with witness Owen on that point. The Company allows net metering in connection with the Evening/Morning Savers rate because the Evening/Morning Savers is a rate to which we would otherwise assign net metered customers, and as such we are legally obliged to offer it to net metered customers, as I just described above. However, we are concerned that the issues we have identified with net metering and TOU rates do apply in this circumstance as well. Fortunately, the peak/off-peak pricing differentials in the Evening/Morning Savers rate are small enough that the irrational nature of the economic outcomes of offering the rate to net metered customers are not highly impactful. If a default rate with a wider rate differential were available in the future, I would have serious concerns about the appropriateness of that, due to the fact that the Company would need to offer it to net metered customers under its statutory interpretation.

V. NON-RESIDENTIAL RATE DESIGN AND CLASS COST OF SERVICE CONSIDERATIONS

Q. Missouri Industrial Energy Consumers ("MIEC") witness Brubaker and Midwest Energy Consumers Group ("MECG") witness Chriss both comment on Staff's proposal in this case to make significant changes to non-residential rate plans, including the introduction of a TOU "overlay" on each of the non-residential rate schedules. Do you have any observations based on the comments of these witnesses?

A. Yes. I fully agree with witness Brubaker:

> [T]he amount of time allowed for customers to consider potential impact and offer counterproposals is completely inadequate. If Staff wishes to explore further refinements to rates applicable to large customers, then such changes should be considered in a separate proceeding, or there should be a collaboration among Staff, Ameren Missouri and interested parties that would take place between now and the next rate case filing. Only by this approach (which is followed by Evergy) will all parties have a fair and reasonable opportunity to consider impacts and be heard on their concerns and solutions.[20]

Q. Like witness Brubaker, MECG witness Chriss recommends that Staff's proposal be deferred to a future collaborative process to evaluate non-residential rate designs. He also highlights a specific issue with Staff's proposed rate that he says could be more fully vetted in such a process. Do you agree with witness Chriss's concerns about Staff's rate?

A. Yes, and witness Chriss makes an excellent point that this issue could be more fully vetted in a future collaborative process. Witness Chriss highlights that Staff seems to focus almost exclusively on market based marginal costs – MISO LMPs[21] – to define what makes up a cost-based TOU rate. He mentions the fact that as a vertically-integrated utility, the Company's

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[20] ER-2022-0337, Maurice Brubaker Rebuttal Testimony, p. 12, l. 18 – p. 13, l. 2, February 15, 2023.
[21] MISO stands for Midcontinent Independent System Operator; LMP stands for Locational Marginal Price.

embedded costs are an appropriate basis for setting rates. This really is a key point. And the issue shows up in multiple places in Staff's analysis with respect to rate design and class cost of service. Staff seems content to inappropriately set aside traditional embedded cost principles in examining production cost allocation in the class cost of service ("CCOS") process and in TOU rate design, in favor of focusing almost exclusively on marginal costs associated with the Company's involvement in MISO. Staff went so far as to claim that – with respect to CCOS – that the Company's participation in MISO has rendered traditional production cost allocation methodologies irrelevant. I will discuss just below why that perspective is a gross exaggeration.

Q. Prior to addressing that last point, does the concern raised by witness Chriss highlight any additional considerations for non-residential rate designs that you believe are important for the Commission to consider, which can and should be addressed in this docket?

A. Yes. There has been discussion by all of the parties to this case who have provided any testimony on non-residential rate design issues that a future case, potentially proceeded by a collaborative working docket, should focus on exploring changes to non-residential rate design. And the Company agrees with that. However, I have some reservations that the stark and dramatic differences in CCOS philosophy between Staff and all of the other parties that have offered testimony on CCOS in this case could make that future case very contentious and confusing to navigate for everyone. Company witness Hickman's rebuttal testimony provided insights into just how radically Staff's CCOS approach in this case, and the CCOS results it suggests, deviate(s) from national norms and historical practices in this state. As witness Hickman has alluded to, while CCOS is often times considered a blend of art and science where reasonable studies can disagree, Staff's approach in this case has strayed so far from the norm, and presents such a radically different outcome, that it is basically impossible for both the Staff's and Company's CCOS results to be considered reasonable outcomes at the same time. Of course, I believe that, for reasons articulated by witnesses Hickman, Brubaker, and Chriss, the Company's approach is unquestionably the reasonable one of the two. But either way, if these stark philosophical differences are left unaddressed by the Commission's final order in this case, I think collaboration may become increasingly strained in the future rate design setting (working case or rate case), because parties will be approaching the issue without anything close to a common framework for understanding the cost structure of the utility, which is critical to the process of designing or re-designing rates. I would note that it is not uncommon for the Commission to decide not to rule on the merits of different CCOS approaches in rate cases like this one, if it is not necessary in order to determine class revenue allocations (for example, if the inter-class revenue allocation is a settled issue, or if the outcome of CCOS disputes would not significantly alter the inter-class revenue allocation proposals of the parties). In this case, I would strongly suggest that, if the Commission is interested in a constructive future rate design process to address these non-residential rate issues, that it specifically evaluate the competing CCOS approaches in its order in this case and provide clear direction for the future by determining in its Report and Order which CCOS study is reasonable. Allowing the stark differences in CCOS study outcomes to co-exist will not provide the context for a productive dialogue on future rate designs.

Q. Are there also energy policy reasons for the Commission to explicitly consider CCOS in its order in this case, and more specifically, for the Commission to find that the Staff's approach to CCOS is unreasonable?

A. Yes. Staff's approach to CCOS, as described by witnesses Hickman (Company), Chriss (MECG), and Brubaker (MIEC) is conceptually flawed in many significant ways, but also results in radical outcomes. Staff's increasing divergence from well-recognized cost causation principles has been a source of significant conflict in many recent utility rate cases. The testimony from all parties that tread into the CCOS topic is becoming increasingly pointed, and the amount of discovery around CCOS issues has been extremely high, necessitating many objections and requiring countless hours in each case to produce ever-increasing levels of detail and data that no party except Staff finds useful in arriving at a reasonable allocation of costs to the various rate classes. The resources that are being poured into both the creation of massive amounts of data being requested by Staff, and into arguing about Staff's incessant demands to create even larger amounts of data yet, are increasing costs for all parties (which ultimately impacts customers), with little apparent benefit. All of the new and additional data provided to Staff pursuant to its attempts to reinvent economic principles that are sound and have been time tested are being used to produce results that are patently unreasonable, and bad for energy policy in Missouri.

Note that in witness Hickman's surrebuttal testimony, he illustrates what the effect would be of fully embracing Staff's CCOS theories, by analyzing how the Company's current rates, by customer type, compare to national average rates. Then he shows how the Company's rates, by those same customer types, would compare to national averages if Staff's CCOS were the basis of those rates. His illustration shows that, following Staff's CCOS, the Company would have overall average rates *over 10% below the national average*, but industrial rates that are over *10% above the national average*, and residential rates *more than 20% below the national average*. That 30% differential between the relationship of industrial rates and residential rates to the national averages demonstrates how out of the mainstream Staff attempts to take Missouri regulation, and would also represent a significant negative impact on large industrial customers (employers) in the service territory that would ultimately have the potential to discourage economic development, and potentially drive existing employment out of the state. It is time to recognize that enough is enough when it comes to Staff's misguided attempts to turn the concept of CCOS on its head. I encourage the Commission to find that Company's CCOS approach is reasonable, and to reject Staff's CCOS study and its additional demands for more data in this case.

Q. Please return to the point about Staff's claim that the MISO market has made traditional production cost allocation methodologies (i.e., the 4 Non-Coincident Peak ("NCP") Average and Excess ("A&E") Method used by the Company) irrelevant.

A. As I just mentioned, this claim by Staff is a gross exaggeration. MISO does operate an integrated wholesale energy and capacity market that the Company participates in (and has since 2005), and the advent of the MISO market had significant operational ramifications for the Company and utilities in the region. But its biggest impact was not that it fundamentally altered the economic paradigm of vertically-integrated electric utilities, as Staff's CCOS comments would suggest, but simply that it increased the efficiency and transparency of wholesale market transactions and mechanisms that have existed for years. Prior to the advent of the MISO market, the Company would still dispatch its units in a manner that was informed by wholesale market prices. If the market could provide energy cheaper than the Company could produce it, the Company would back down the production from the more expensive generating unit(s), and purchase energy from the market. If the Company could produce excess energy at a cost lower than the prevailing market price of energy, then it would dispatch up its unit(s) above the level needed to meet its own load obligations and sell the excess energy off-system. The *exact* same dynamics exist with MISO – except that, as I said above, the market is more efficient and transparent in achieving these outcomes when a central agent publishes prices and accepts standardized bids and offers to buy and sell energy, and even sends dispatch instructions to the unit operators consistent with the offers that cleared in the market. Yet Staff suggests that the existence of MISO somehow suddenly rendered the traditional economic paradigm of utility cost allocation irrelevant. The MISO market's improved transparency makes it very clear what the Company's *marginal* cost of energy and capacity are, but it does little if anything to change the *embedded* cost of the Company's generation fleet that it has constructed to meet its customers' energy and capacity requirements pursuant to its integrated resource planning process – and the embedded costs of which are the basis of the rates that are being established in this proceeding. As witness Hickman describes further in his surrebuttal testimony, traditional production cost methodologies like 4NCP A&E are as relevant today as they have been historically. This is particularly true of methodologies like the 4NCP A&E that already inherently recognize that the Company's generation fleet is designed to meet both the energy and capacity needs of the Company's customers.

Similarly, when Staff suggests that the Company's TOU rates are not cost based simply because they do not exclusively reflect wholesale energy cost differences between different time periods, which is wrong for the reasons I discussed much earlier in my testimony, it is also a gross--oversimplification of the interplay of marginal and embedded cost principles that influence the structure of rates for retail electric service. In summary, Staff's suggestions should be rejected.

VI. THE RESIDENTIAL CUSTOMER CHARGE SHOULD VARY ACROSS RATE PLANS

Q. Renew Missouri witness Owen criticizes the Company's proposal to vary the residential customer charge across rate plans. In the course of doing so, he suggests that part of the Company's rationale for this proposal was to encourage the adoption of new energy-related technologies like distributed energy resources,[22] but that he believes the proposal will instead discourage adoption of those types of resources.[23] Do you agree with his characterization of the Company's motivation for proposing this treatment of the customer charge?

A. No. Witness Owen correctly refers to my direct testimony as discussing such emerging technologies as an important contextual consideration for evaluating rate design, including the customer charge. But it is definitely not the case that I or the Company think that a utility's rate design should be structured in a manner intended to promote or discourage any technology. In fact, it is quite important in my opinion that the rate design itself should be technology agnostic. What the rate design should do is send appropriate price signals that reflect the cost structure of the utility. That critical factor will encourage customers to choose the technologies that they value in a manner that results in more economically efficient and equitable outcomes for all customers. And that is the point I made in my direct testimony, which I believe witness Owen may have misinterpreted. If adoption of technologies is to be encouraged, that is best accomplished through specific programs or rebates, such as the statutorily-mandated rebate that is currently available to the Company's customers for the installation of distributed solar generation facilities. The goal of rate design is simply to reflect cost, so that technologies compete

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[22] File No. ER-2022-0337, James Owen Rebuttal Testimony, p. 14, ll. 11-13
[23] File No. ER-2022-0337, James Owen Rebuttal Testimony, p. 154, ll. 2-5

on a level playing field, and so that a customer's adoption decision does not result in unintended subsidization, whether that be subsidization of technology adopters by non-adopters, or vice versa.

Q. Witness Owen also mentions several other reasons he opposes the Company's residential customer charge proposal. What is your response to those reasons?

A. Each of the other arguments brought forth by witness Owen is substantially similar to arguments made by Consumers Council of Missouri witness Jacqueline Hutchinson in her direct testimony. I responded to each of those in my rebuttal testimony. Please see that testimony for my response to those issues.

Q. Staff also offers rebuttal testimony opposing the Company's proposal related to the residential customer charge. What is the first reason that Staff recommends that the Commission reject the customer charge increase applicable to certain rate plans under the Company's proposal?

A. Staff relies on the Commission's order in File No. ER-2014-0258 as a reason that the Commission should reject the Company's proposal in this case. However, I am advised by counsel that the Commission is not bound by precedent from prior orders. Further, and more importantly, the circumstances in that case were unquestionably quite different than they are today, and the record in that case was very different also. I described in my direct testimony in this case how the existence of different residential rate plans that did not exist in that prior case – different rate plans for different customers with different preferences – provides the opportunity to balance the sometimes competing objectives of various regulatory stakeholders related to the determination of the appropriate level of the customer charge. For example, maintaining the ability for a customer to manage their bill is often cited as reason to keep the customer charge low. However, under the Company's proposal, customers interested in managing their bill can choose a rate plan with a low customer charge and TOU and other rate parameters that give them a *greater* opportunity to manage their bill than any customer had at the time of the case Staff cites. Parties also often argue that low use customers are hurt by high customer charges. Again, under the Company's current proposal, low use customers can elect a more cost reflective advanced rate plan in order to gain access to a lower customer charge. Assuming these parties' hypothesis that low use customers have a lower cost of service is accurate (i.e., the low use customers don't also happen to have disproportionately high peak demands or peak period usage that impose costs on the system that would be reflected on their bills as a part of TOU energy charges or demand charges), these customers will have lower bills under the rate plans available for them to opt into. If they do have higher proportional peak demands or peak period usage, the higher bill that would arise under a higher customer charge (or higher peak energy charges and demand charges under advanced TOU rates) is not fairly characterized as a penalty to the low use customer, but simply represents a more accurate reflection of the cost to serve that customer.

Q. Staff also alleges that the Company's minimum distribution system study, which is used to allocate costs to the customer classification, and ultimately the customer charge, is flawed and should not be used to establish the level of the customer charge. Is that a valid criticism?

A. No. Company witnesses Hickman and Craig Brown offer surrebuttal testimony to explain why Staff's criticisms of the Company's CCOS study have little merit. Staff's views on distribution cost allocation are far out of the mainstream and result in allocations that are unreasonable.

Q. Staff also states that "Ameren Missouri bases this request on finding the cost for rebuilding every inch of its distribution system at primary voltage, including every device, and then deciding each customer in each class should pay the same share of that total."[24] Is this an accurate characterization of the Company's approach to establishing its recommended customer charge?

A. It's not even close to accurate. This is another example of Staff's fixation on, or lack of understanding of the difference between, marginal versus embedded costs. Staff's statement implies, by saying the Company's study reflects the cost of "rebuilding" the system, that the study is a marginal cost study. It is not. Maybe Staff thinks that's what the Company did because Staff itself is overly reliant on marginal cost study and considerations for its rate design (and CCOS) analysis. Again, that is simply not what the Company studied to recommend its customer charge proposal. Never in the course of our study do we determine the cost of new construction for a line (i.e. the marginal cost of "rebuilding" the system) at any point in time. The Company analyzed its *embedded costs* of providing service – and specifically analyzed the embedded customer-related costs – i.e., that are driven by the existence of customers irrespective of the amount of demand they place on the system or of the total amount of energy they consume over time for purposes of informing its customer charge recommendations.

[24] ER-2022-0337, Sarah Lange Rebuttal Testimony, p. 55, ll. 5 – 7, February 15, 2023.

VII. SMART ENERGY PLAN

Q. Staff witness Eubanks' rebuttal testimony discusses the process that the Company, Staff, and Office of the Public Counsel ("OPC") have undertaken to develop an evaluation framework for projects conducted under the Company's Smart Energy Plan ("SEP"). What recommendations does Staff make in its rebuttal testimony?

A. Witness Eubanks recognizes the progress the parties have made in developing an agreeable framework for evaluating projects across six categories of distribution infrastructure investments.[25] Staff notes that OPC has raised questions in this case about two specific types of investments under its Smart Grid category: Private LTE and Tripsavers.[26] Witness Eubanks recommends additional conversations among the parties related to evaluation methodologies for these two specific investment categories.[27]

Next, witness Eubanks recommends that the Company continue to provide quarterly project documentation on all of the categories of SEP investments consistent with the provisions of the Stipulation and Agreement in File No. ER-2021-0240 ("2021 Stipulation").

Q. Does the Company agree with Staff's recommendations?

A. Yes. The Company is willing to engage in additional discussions on the Private LTE and Tripsavers investments, and also to continue with its documentation and reporting commitments from the 2021 Stipulation.[28]

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

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[25] ER-2022-0337, Claire Eubanks Rebuttal Testimony, p. 20, l. 18 – p. 21, l. 9, February 15, 2023.
[26] *Id.*, p. 21, ll. 10-14
[27] *Id.*, p. 21, ll. 18-19.
[28] *Id.*, p. 21, ll. 20-22.

Exhibit No.:	046
Issue(s):	Rate Design
Witness:	Steven M. Wills
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2019-0335
Date Testimony Prepared:	July 3, 2019

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2019-0335

DIRECT TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
July 2019

will deploy in the future. The current AMR meters are generally programmed to just collect aggregate energy consumption. These AMR meters deliver daily meter readings for most customers, but do not record demand or subdivide usage on an hourly basis or into TOU periods by default. They can be programmed to collect these things, but in order for this to be implemented each meter must be reprogrammed or replaced, which requires a site visit for every meter that is to be used to bill that new rate. As such it is currently both costly and logistically challenging to deploy widespread TOU rates, or a three part rate with demand charges, which I previously described to be the most cost reflective rate design. Given this limitation to only two relatively static rate elements – the customer charge and a non-time varying energy charge – the existing rate structure is generally well aligned with the cost of serving customers. An improvement in this rate structure could be made by increasing the fixed monthly customer charge to recover the full customer-related costs and possibly even a portion of the demand-related costs.[4] However, further improvements to align rates with cost of service and provide more economically efficient price signals require either time varying energy charges, demand charges, or both.

Q. Is it possible to quantify how well a given rate structure reflects the cost of service?

A. Yes, and I will do so for a variety of candidate rate structures in order to compare and contrast them. However, to perform this analysis, it is necessary to have detailed customer usage data that allows the calculation of the customer-specific cost of

[4] When there is no demand charge in a rate structure, it is fair to consider which available charge type (customer or energy) is most appropriate to cover those demand-related costs. Conventional wisdom is that they should be covered by energy charges. To the extent there is a declining block energy charge, it may be the best available solution. But given a flat energy charge (such as Ameren Missouri's summer residential rate structure), the nature of demand is best reflected by allocating part of the demand-related costs to the customer charge, and part to the energy charge.

service, as well as the calculation of bills under a variety of candidate rate structures. For the general population of customers, such data is not available due to the limitations of AMR meters that I previously discussed. However, hourly load research data exists for a sample of customers that is used in developing the Company's CCOSS. While this sample is traditionally used in the CCOSS just to develop class-level load characteristics that can help analyze the cost of serving one class vs. another, the individual customer load characteristics can similarly be used to analyze the cost of serving one customer vs. another within a class. In anticipation of this analysis, the Company expanded its load research program prior to the test year to include a very large, simple random sample of 800 residential customers[5] upon which this analysis is based. I asked Mr. Hickman to identify appropriate allocation factors for individual customers in order to extend his CCOSS analysis[6] to calculate the cost of service of each of these 800 individual residential customers. He describes the process he undertook to accomplish this task in his direct testimony. Next I compute the bills that each of these customers would have experienced under each candidate rate design. By comparing the bills that customers experience to their cost of service, it is possible to draw conclusions about which rate designs best reflect the cost of service to customers. The rate designs that I analyzed are shown in

[5] 1,000 load research meters were originally randomly selected with the knowledge that not all AMR meters set to record load research data have sufficient communication with the AMR network to reliably deliver complete interval data sets. When data was collected, 800 meters were identified with substantially complete hourly load data that were included in this analysis.

[6] The COSS reflected in this analysis was based on a revenue requirement of $3,030,813,000, which would have been a decrease from present revenues of $772,000. A slight change in the revenue requirement analysis and COSS occurred after my analysis was finalized, resulting in a filed revenue requirement, as outlined in the direct testimony of Company witness Laura M. Moore, of $3,030,811,000, or a decrease from present revenues of $774,000. This slight change is immaterial to my analysis given that it reflects a difference of just 0.00008 percent.

Table 1 below:

Table 1: Candidate Rate Designs Analyzed

Rate Design	Description
Status Quo	Based on the Company's current two part rate with a monthly fixed charge and a seasonal energy charge. The summer energy charge is a flat rate and the non-summer energy charge is a declining block with a lower price for usage exceeding 750 kWh.
Cost Based Two-Part Rate	Similar to the status quo, but with the customer charge increased from its present level of $9 per month to match the full customer-related costs
TOU Energy Rate	A two part rate (customer & energy charge) with time varying energy prices featuring 3 pricing tiers designed to reflect the cost structure of electricity in the summer and winter period.
Inclining Block Rate ("IBR")	A two part rate (customer & energy charge) with a summer inclining block with a higher price for usage exceeding 750 kWh and a flat non-summer energy charge.
3 Part Rate w/Demand Charge	A three part rate with a customer, demand, and time varying energy charge.

Q. Please provide a high level description of how you developed each of the candidate rate structures and share the actual rate values that were tested.

A. The status quo rate design is simply the Company's existing rate structure.[7] Each of the other rates, with one exception, was developed by mapping the functionalized and classified costs to the most appropriate available charge type. Table 2 on the following page describes the mapping of each category of cost to the charge type and season in which it is designed to be reflected in the candidate rates.

[7] Because the other candidate rates are being developed based on hypothetical billing units derived from the expanded residential load research sample, the existing rate structure was adjusted slightly to ensure it would produce consistent total revenues with the other rates when using these hypothetical billing units. But the structure and the general relationship of the charges is unchanged from the Company's present rates.

Table 2 – Mapping of Cost Categories to Rate Elements

	Cost based two part rate	TOU Energy Rate	3 Part Rate w/Demand Charge
Customer-related costs	Customer charge	Customer charge	Customer charge
Distribution demand-related costs	Complex allocation to summer and non-summer energy charges	Complex allocation to summer and non-summer peak and intermediate energy charges	Complex allocation to summer vs. non-summer demand charges
Transmission demand-related costs	Equally to all kWh based energy charges for MISO expenses and complex allocation to summer and non-summer block 1 energy charges for all other costs	Equally to all kWh based energy charges for MISO expenses and complex allocation to peak energy charges for all other costs	Equally to all kWh based energy charges for MISO expenses and complex allocation to peak energy charges for all other costs
Production demand-related costs	Complex allocation to summer and non-summer block 1 energy charges	Complex allocation to summer and non-summer peak period energy charges	Complex allocation to summer and non-summer peak period energy charges
Production energy-related costs	Equally to all kWh based energy charges	Equally to all kWh based energy charges	Equally to all kWh based energy charges

The exception to this allocation process for developing candidate rates to evaluate was the IBR rate. There is not a logical rationale from the CCOSS to map any costs to a higher second summer pricing tier, as this rate design is generally not rooted in cost of service analysis, but rather policy considerations. As such, an IBR was developed that would limit bill impacts for 95% of customers to 15%.[8]

The rates calculated for each candidate rate design, applicable to the theoretical billing units derived from the load research sample, are shown below in Table 3.

Table 3 – Candidate Rates for Analysis

	Status Quo		Cost Based Two Part		TOU Energy		IBR		3 Part w/Demand	
	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer	Summer	Non-Summer
Customer Charge	$9.00	$9.00	$24.85	$24.85	$24.85	$24.85	$9.00	$9.00	$24.85	$24.85
Energy Charge	$0.118	N/A	$0.106	N/A	N/A	N/A	N/A	$0.071	N/A	N/A
Block 1 Energy Charge	N/A	$0.082	N/A	$0.067	N/A	N/A	$0.082	N/A	N/A	N/A
Block 2 Energy Charge	N/A	$0.056	N/A	$0.042	N/A	N/A	$0.158	N/A	N/A	N/A
Peak Energy Charge	N/A	N/A	N/A	N/A	$0.379	$0.151	N/A	N/A	$0.352	$0.140
Intermediate Energy Charge	N/A	N/A	N/A	N/A	$0.062	$0.046	N/A	N/A	N/A	N/A
Off-Peak Energy Charge	N/A	N/A	N/A	N/A	$0.035	$0.035	N/A	N/A	$0.035	$0.035
Demand Charge	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$4.11	$1.49

Q. Can you please describe the analysis you undertook and share the results and any conclusions that you draw from those results?

A. As I mentioned previously, my analysis is predicated on comparing the hypothetical bills of individual customers based on the various candidate rate designs shown above to the cost of serving those individual customers as calculated by Mr. Hickman. This analysis was performed individually for each of the 800 residential

[8] I will discuss later the IBR rate that the Company developed pursuant to its commitments in the 2016 Stipulation. That rate was limited to a 5% bill impact for 95% of customers. My understanding of the proposals that led to that stipulation provision, though, is that this 5% limitation on customer bill impacts that arise from a single rate case is intended to facilitate a gradual rate transition, but that the ultimate goal would be to eventually feature a more severe incline. In order to assess the potential end state of the IBR rate design, it makes the most sense to test something closer to that eventual end state rate for its ability to reflect cost. For this purpose, I assumed three rate case cycles with 5% bill impact constraints in each accumulating to a total impact of approximately 15%.

customers in the expanded load research sample. When the bill that was calculated using a given rate design closely matches the cost of service for that customer, the rate design accurately reflects cost of service to that customer. For a rate design that produces a bill that is more divergent from the cost of service, that rate design does not accurately reflect cost of service to the customer. By looking at this comparison for each pricing paradigm for all 800 customers, we can get a good sense of which rate designs tend to perform better than others in terms of reflecting cost, and therefore create more equitable outcomes and tend to provide more economically efficient price signals. For each sample customer and for each candidate rate design, I will calculate the difference between the bill and the cost of service, and refer to this value as the Pricing Inaccuracy that is inherent in that rate for that customer. I will summarize into both graphical depictions, and descriptive statistics, the Pricing Inaccuracy of each rate design across the entire sample of customers. I calculate the following statistics for each rate design (with description of the interpretation of that statistic shown):

- Mean Absolute Deviation ("MAD") – the average of the absolute value of the Pricing Inaccuracy variable. This tells how close the average bill is to cost of service without regard for the direction of the error (i.e. the bill being $50 above or below the cost of service is treated equally as being inaccurate by a magnitude of $50)
- Standard Deviation – similar in concept to the MAD, but imposes a penalty on extreme outcomes where individual customers have bills that deviate from their cost of service by a large amount.

- Median, 10th, and 90th percentiles – The outcomes where the stated percentage (50% for median) of customers have a higher value of Pricing Inaccuracy. These statistics help determine whether the distribution of the Pricing Inaccuracy is symmetrical or skewed and how wide the distribution is (i.e. whether there are similar numbers of customers with bills that are lower than cost of service to those higher than cost of service, or whether there are more extreme outcomes in general, or more extreme outcomes on one side of the distribution or the other).

In general, for each variable, a smaller value (or smaller absolute value for percentile statistics) indicates a better agreement between the sample customers' bills and their cost of service.

Table 4 shows the descriptive statistics associated with each candidate rate design. Figures 3 through 7 on the following pages show the distribution of the Pricing Inaccuracy associated with each candidate rate design. Rate designs that look like a normal distribution – the classic bell curve – have large numbers of customers reflected in the center of the graph, indicating good agreement between bills under that rate design and their cost of service.

The wider and more skewed (i.e., the more the largest numbers of customers are not in the center of the graph) a distribution is, the more inequitable that rate design is.

Table 4 – Summary Statistics of Pricing Inaccuracy Variable Associated with Candidate Rate Designs

	MAD	StDev	10th percentile	Median	90th percentile
IBR	$247	$372	-$304	-$87	$380
Status Quo	$163	$229	-$229	-$29	$258
Cost Based Two-Part Rate	$127	$174	-$207	$0	$199
TOU Energy Rate	$116	$164	-$180	-$12	$181
3 Part Rate w/Demand Charge	$111	$153	-$173	-$7	$177

Figure 3 – Distribution of Bill Impacts for Inclining Block Rate

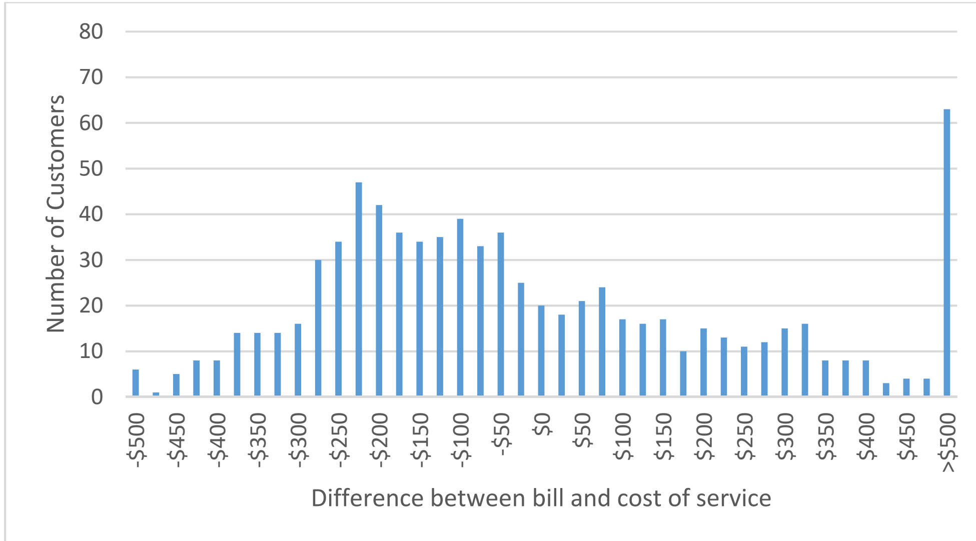


Figure 4 – Distribution of Bill Impacts for Status Quo Rate

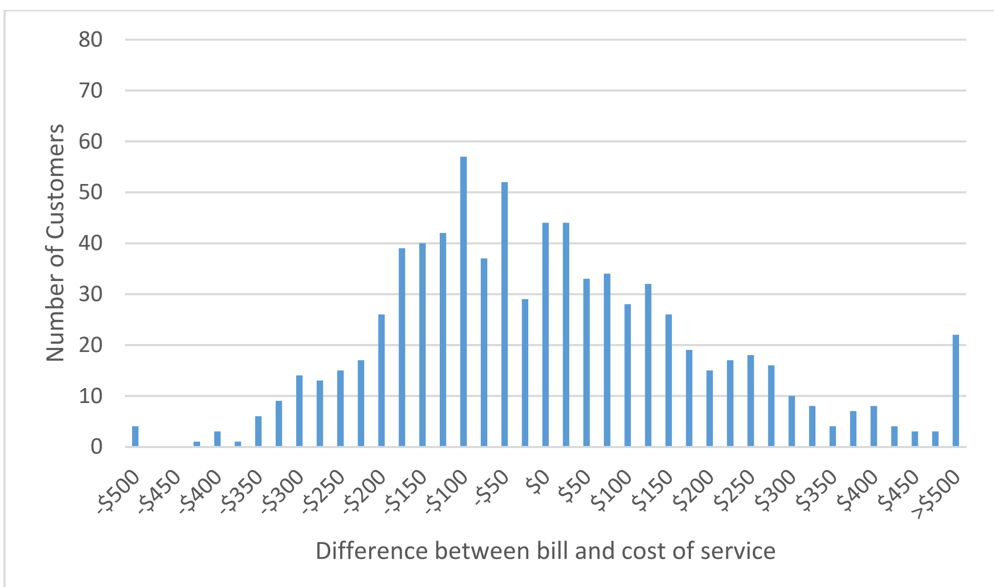


Figure 5 – Distribution of Bill Impacts for Cost Based Two-Part Rate

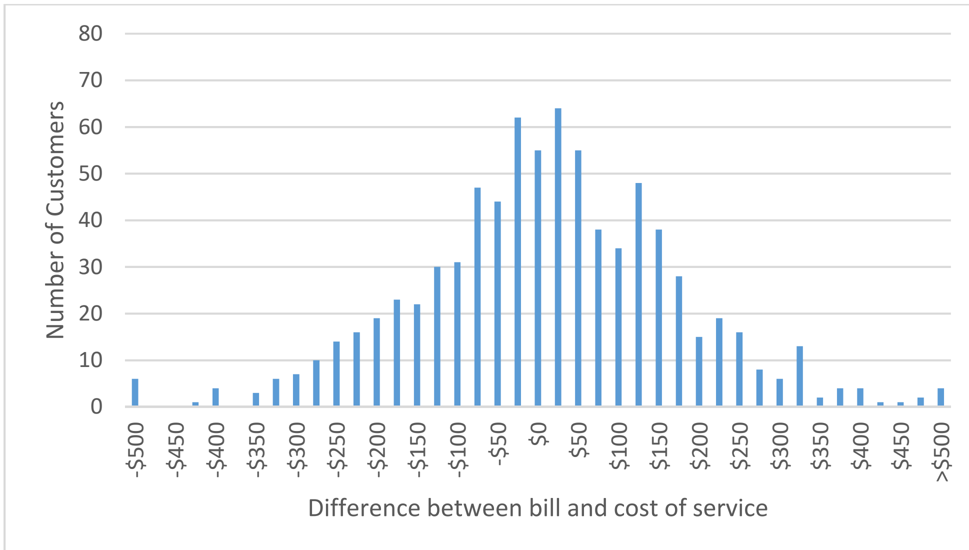


Figure 6 – Distribution of Bill Impacts for TOU Energy Rate

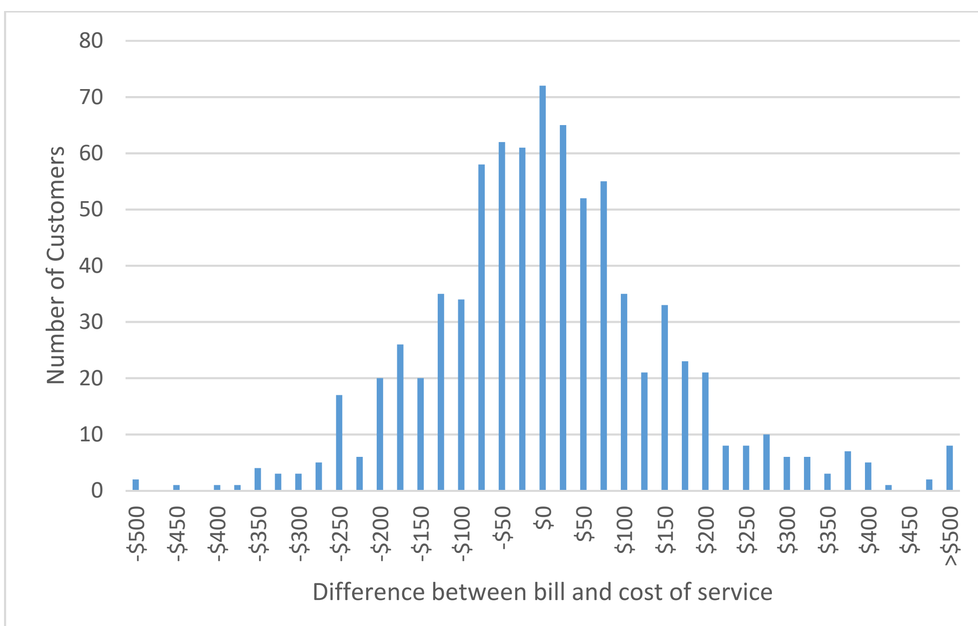
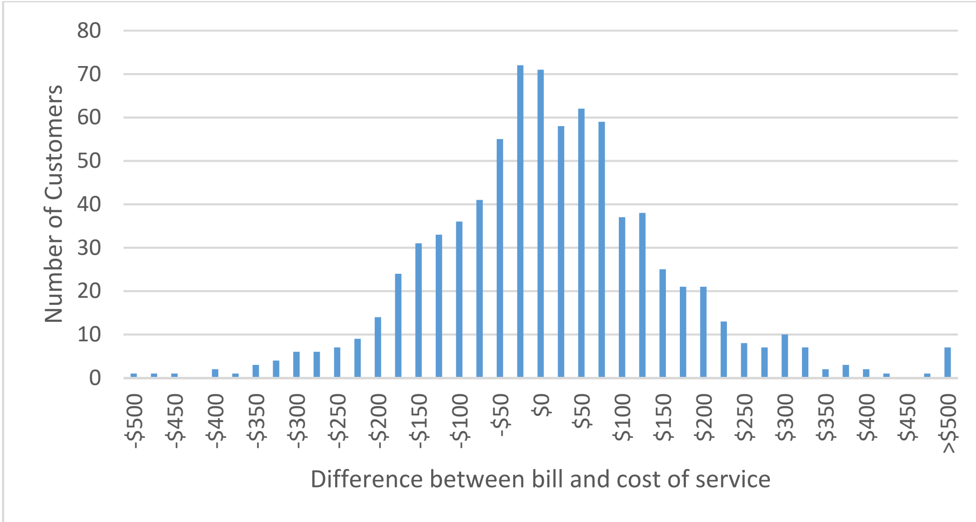


Figure 7 – Distribution of Bill Impacts for 3 Part Rate w/Demand Charge

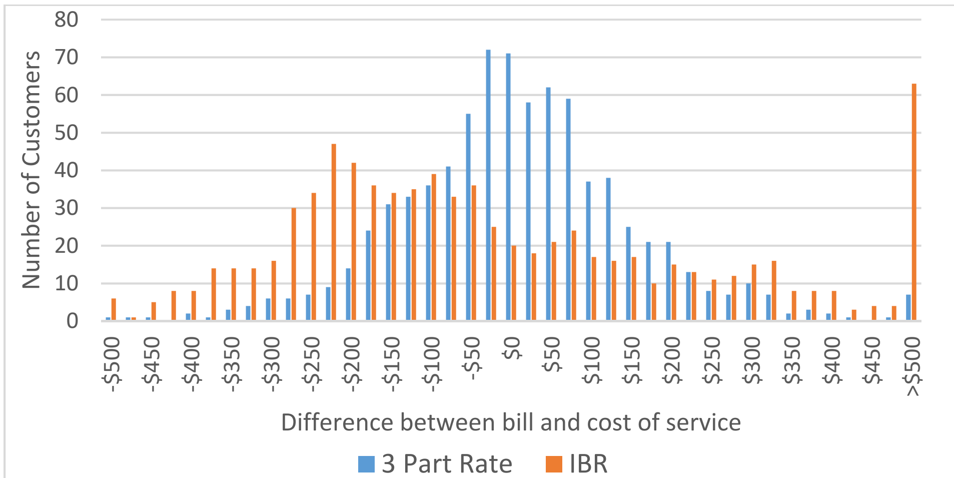


Q. Please comment on the results shown in Table 4 and Figures 3-7.

A. The results are completely consistent with the expectations that rates that are designed based on the principles I discussed earlier – specifically that costs should be collected in the charge type that corresponds to their classification – are far better at reflecting the cost of service in customers' bills. There is essentially a continuum, starting from the status quo rate and then moving to the cost based two-part rate, and next to the TOU energy rate, and finally to the 3 part rate with demand charge, where the rates continue to more and more accurately reflect cost on the bills of individual customers. This is evident virtually universally in each of the statistics related to the Pricing Inaccuracy variable, as well as in the graphical depiction of the distribution of that variable for each rate design.

The IBR, however, is markedly worse than any of the other rate designs across all statistics. The 90th percentile statistic suggests that 10% of customers pay at least $380 per year more than the cost to serve them, and the result is more than half of customers failing to cover their cost of service by $87 per year or more. The contrast between the IBR and the most cost reflective rate, the 3 part rate with demand charge, is perhaps best illustrated by overlaying the distributions associated with those two rate designs in a single graph. I have done that in Figure 8 below:

Figure 8 – IBR vs. 3 Part Rate w/Demand Charge



The 3 Part Rate distribution is a nearly perfect bell curve, whereas under the IBR, there are more customers in the category that pay at least $500 per year more than the cost of serving them than in any other part of the distribution. These observations are a compelling example of the benefits provided by modern rate designs that reflect the cost of service in the form of improved equity between customers versus outcomes under Inclining Block Rates, and even versus the Status Quo rate, albeit to a much lesser extent.

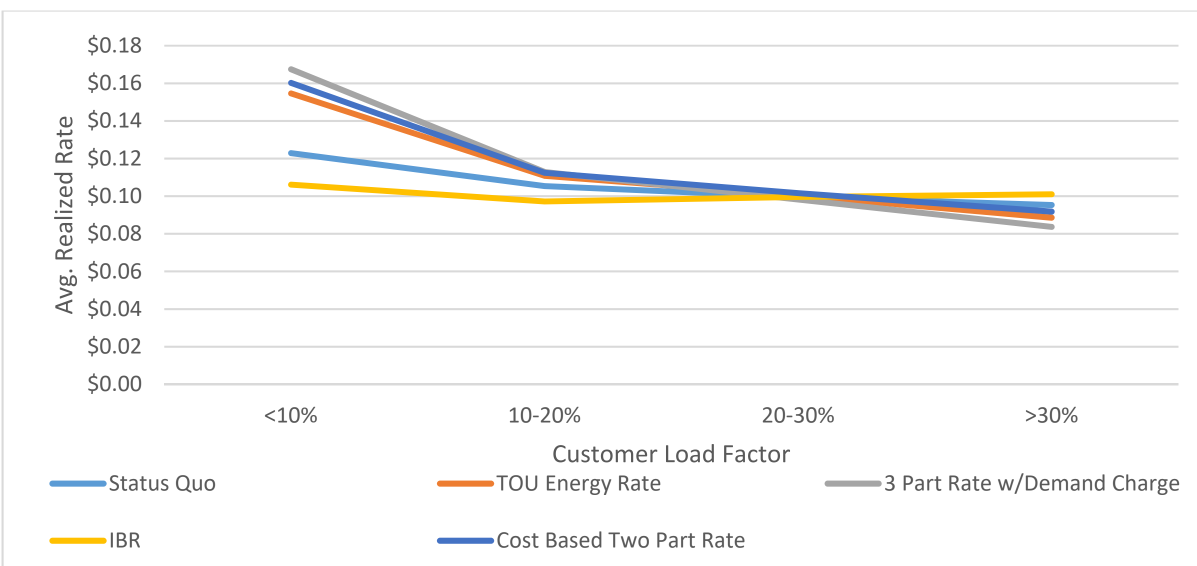
Q. You mentioned previously the concept that customer classes with better load factors that use infrastructure more efficiently tend to pay lower realized rates per kWh than those with poorer load factors who cause significant underutilized infrastructure. You suggested that under a cost based rate design, this phenomenon should apply at the individual customer level as well. Under the various candidate rate structures, how well does the comparison of load factor to realized rate exhibit this characteristic?

A. To illustrate this, I used the results of my previous analysis to calculate the realized rate for each of the 800 customers in the load research sample based on each candidate rate design. Next I calculated each of those customers' load factor based on the load research data. Finally I grouped the customers with similar load factors, and calculated the average realized rate for the customers in each grouping. The results of this analysis are shown in Table 5 and Figure 9 below:

Table 5 – Average Realized Rate by Customer Load Factor

Load Factor	<10%	10-20%	20-30%	>30%
IBR	$0.106	$0.097	$0.100	$0.101
Status Quo	$0.123	$0.105	$0.100	$0.095
Cost Based Two Part Rate	$0.160	$0.112	$0.102	$0.092
TOU Energy Rate	$0.155	$0.111	$0.100	$0.089
3 Part Rate w/Demand Charge	$0.167	$0.113	$0.098	$0.084

Figure 9 – Average Realized Rate by Customer Load Factor



Q. What conclusions do you draw from the results reflected in the figure and table above related to the relationship between load factor and realized rate?

A. It is important to recall the discussion earlier related to class load factor and realized rates for those classes. It is almost universally true – certainly true in the case of all of Ameren Missouri's rate classes – that the better a customer class's load factor is, the lower their realized rate will be. This was illustrated previously when I compared the residential and LGS class rates and load factors. And as I discussed at that time, this phenomenon is a completely appropriate outcome due to the more efficient utilization of infrastructure that allows the fixed customer- and demand-related costs to be spread out over more kWh of usage. There is absolutely no reason that individual outcomes within a customer class should be any different. Higher load factor customers use infrastructure more efficiently, resulting in more kWh of consumption over which to spread the fixed customer- and demand-related costs attributable to that customer. Rates that equitably reflect the cost of service will result in lower realized rates for those customers. It is noteworthy, then, that, once again there is a progression across the rate designs, where the rate designs that reflect the cost structure of the electric system in more detail generally exhibit this trait the most strongly. Again it is notable that the IBR is the outlier. In fact, the realized rate associated with the IBR *increases* as the customer load factor *increases* from 10-20% to 20-30%, and again for customers over 30%. This outcome is counter to the expectations of a sound cost-based rate. The effect of the IBR on residential customers is akin to a situation where the Company proposed higher rates for its largest industrial customers than for residential and small commercial customers – something that would run counter to long established ratemaking principles and typical outcomes associated with them, and which would undoubtedly draw considerable attention from a variety of stakeholders.

This analysis, along with the Pricing Inaccuracy analysis discussed just above, speaks most directly to the equity reflected by these rates – i.e., they characterize how well a given rate design reflects the cost of service to each customer. The results clearly suggest a continuum where the 3 Part Rates with Demand Charges are consistently the most equitable and cost-reflective rates. Such equitable rates also generally reflect economically efficient price signals well, but there is a further analysis that I conducted to understand the interplay of these rates with customer decisions about new and emerging technologies in order to gain deeper insights into the economic efficiency of the price signal that each rate sends to customers.

Q. Please describe that analysis.

A. I returned to the cost of service analysis, and asked Mr. Hickman to use his model to calculate the incremental cost of service that arises from a residential customer adopting an EV, Solar PV, or Solar PV that is paired with a battery. Next, I calculated the incremental impact that the adoption of each of those technologies would have on a residential customer's bill under each candidate rate design. Where the customer's incremental bill change is similar to the incremental effect on the cost of serving that customer, the customer is receiving an economically efficient price signal from the rate that aligns the economic incentives of that customer with those of the customers that share the use of the grid with them. Where the difference between the incremental bill impact and cost of service impact is large, an inefficient price signal is being sent that will likely result in subsidization of or by the adopting customer by or of all other customers. The customer may not have a personal stake in making an overall cost effective decision in the latter case and therefore may end up causing costs that end up being borne by other customers or, equally problematic, passing up good opportunities to create net economic benefits.

Q. Please describe the hypothetical technological investments that you modeled.

A. I determined the cost of service and billing impacts of the following types of customer investments:

- A customer investment in an EV that is driven approximately 34 electric powered miles per day.[9]
- A customer investment in 4 kW of Solar PV, with output that is consistent with other existing solar installations in the region.[10]
- A home battery pack deployed along with Solar PV with the specifications in the bullet above, but that on its own can store 10 kWh and charge/discharge at a rate of up to 5 kW.[11]

Q. Please describe the results of your analysis comparing the cost of serving each of these technologies to the bill impact experienced by a customer deploying them under the various candidate rate designs.

A. Table 6 on the following page shows, for each technology analyzed, the change in the average cost of service for the customers in the 800 customer load research sample when the load changes associated with that technology are overlaid on their existing

[9] With charging taking place in a manner that is consistent with the pattern reflected in the control group load shape reflected in Figure 11 below.

[10] Based on capacity factor and generation pattern data observed at Company Solar PV installations.

[11] For this analysis I assume the battery is charged in the late morning/early afternoon when solar irradiance is generally abundant, and is discharged in the late afternoon or early evening when load is still high but solar irradiance is in sharp decline.

load.[12] Next the table shows the average change in the sample customers' bills as a result of the hypothetical implementation of the technology.

Table 6 – Change in Bills vs. Cost Associated with Technology Implementation

	EV	Solar PV	Solar PV + Battery	Difference Between Change in Cost and Change in Bill			
Change in Cost of Service	$213	-$402	-$752				
Change in bill under….				**EV**	**Solar PV**	**Solar PV + Battery**	**Avg Absolute Difference Across Technologies**
IBR	$393	-$545	-$545	$180	-$143	$207	$177
Status Quo	$340	-$507	-$507	$126	-$105	$245	$159
Cost Based Two Part Rate	$283	-$435	-$435	$69	-$33	$317	$140
TOU Energy	$292	-$357	-$483	$78	$45	$269	$131
3 Part Rate w/Demand Charge	$268	-$419	-$690	$55	-$17	$62	$44

There are several observations that can be drawn from Table 6:

- For *every* technology, the 3 part rate with demand charge results in a bill change that is closest to the cost of service change associated with that technology, and no other rate structure really comes close to it - i.e., it sends the most accurate price signal in all cases

[12] For the Solar PV analysis, and the Solar PV with battery storage analysis, only 702 of the sample customers were analyzed, because the remaining customers' loads were too small to install 4 kW of Solar PV and qualify for net metering treatment.

- Under *every* rate structure, the change in bill associated with the addition of an EV is greater than the change in the cost of service, suggesting the addition of EVs is likely to drive down rates for all customers regardless of the rate design.
- Under the IBR rate, the EV adopting customer's bill approaches double the level of the change in the cost of serving them, discouraging efficient electrification of transportation.
- The IBR rate provides the poorest price signals on average of all of the rate designs across technologies, including being the worst performer by far for the standalone EV and Solar PV technologies.
- Solar PV lowers the cost of service of an average customer by $402 per year, but that increases to $752 per year when a battery is paired with it, suggesting that battery storage can significantly enhance the value of Solar PV to the grid.
- Despite the evident value of adding a battery to Solar PV, the bills for customers deploying battery storage along with Solar PV are identical to the bills for customers deploying solar PV without battery storage for all of the rates that do not feature time varying energy charges or demand charges. This suggests that batteries, a technology that provides demonstrated value to the grid, cannot create any value for a customer deploying it without the implementation of modern rate designs that reflect the cost structure of electricity.

Q. What conclusions do you draw from these results?

A. The best price signals are clearly conveyed by the 3 part rate that includes a demand charge. This is not surprising at all, as it most clearly reflects the cost structure of electricity. Of the remaining rates, the TOU rate fares best on average in this analysis, also due to its improved alignment between retail prices reflected to customers and the underlying cost structure of the electric system. The status quo rate design, which as discussed previously, is reasonably equitable to customers given the constraints on it, is not nearly as economically efficient in terms of its price signals as the more modern rate designs are. It is modestly improved when the customer charge is increased to match the customer-related cost of service, but under any formulation it is still clearly superior to the IBR option.

Q. Based on all of the analysis you have performed to understand the strengths and weaknesses of each candidate rate design, what recommendations do you make regarding the rate structure to adopt in this case?

A. My answer must be grounded in the realities of the AMR metering capabilities that exist today, but also cognizant of the coming AMI technology. As such, for the default residential rate, which must be able to be billed timely and cost effectively to over a million customers using AMR meters immediately upon the conclusion of this case, I recommend the status quo rate design, but, keeping the principle of gradualism in mind, with a modest increase to the customer charge designed to move toward the Cost Based Two Part Rate option. Specifically, I recommend increasing the customer charge from its current level of $9 per month up to $11 per month. The energy charges I recommend are based on the existing seasonal and block structure, but adjusted slightly lower to offset the increased revenues realized from the higher recommended customer charge.

Next, in order to begin on the journey of modernizing Ameren Missouri's residential rate offerings and provide new cost-based rate options for customers, I also recommend the adoption of two new "flavors" of TOU rates that the Company has developed. First, because the soon-to-be-deployed AMI meters are expected to enable the billing of more complex rate structures for many customers in the near future, the Company is proposing to offer a rate similar to the three-tiered TOU rate analyzed above. Second, I recommend another TOU rate that is focused on the needs of EV drivers in order to help realize the benefits of efficient electrification of transportation in the Company's service territory.

TOU RATES

Q. Please discuss the TOU offerings that you propose for implementation in this case.

A. Consistent with the Company's goal of advancing innovative new rate offerings to give customers more choices to align with their preferences and greater opportunities to control their energy bills, the Company is proposing two new optional TOU rates to be available to customers. Each is designed with a specific goal in mind and should appeal to a different segment of customers based on their energy usage behaviors and preferences. One of these rates is also designed specifically to comply with provisions of the 2016 Stipulation, which states at paragraph 5.M referring to Time-of-Use Rates that:

> Ameren Missouri agrees…to file a proposed amendment to its residential Time-of-Use rates in its next general rate case, after reviewing the results of existing studies and soliciting input from interested stakeholders. Ameren Missouri agrees that such Time-of-Use rates shall be developed and proposed with the following goals: to shift usage to off-peak hours during all months of the year; to be structured to allow interested customers to opt in; to be compatible with existing Automated Meter Reading technology; and to encourage off-peak electric vehicle charging.

EV SAVERS RATE

Q. Please describe the Company's "EV Savers" Time of Use rate proposal.

Net metering TOU examples

February – Net positive on-peak usage, net negative intermediate usage, net positive off-peak usage, net positive total usage

Net metering statute tells us that we should be billing the net kWh consumed in the billing period, which in February is 158 kWh. What TOU period are those 158 kWh assigned to? Is the excess from intermediate netted against off-peak kWh? Against peak kWh? Need business rules that are not contemplated in existing statute.

Move to….

April - Net positive on-peak usage, net negative intermediate usage, net positive off-peak usage, **net negative total usage**

Net metering statute tells us that this customer, who is a net producer in April, should pay only the customer charge (zero energy charge) and receive an avoided cost credit for their excess generation. In order to achieve a zero retail energy charge, net over-production in the intermediate period **must** offset net consumption in peak period. This allows customer to generate during a lower priced period to offset actual usage in a premium priced period, which totally negates the price signal intended by the rate structure to reduce usage during the peak period. It will not benefit this customer to shift peak usage to intermediate, because the excess intermediate generation is already required to offset the peak usage. So no price signal for peak consumption exists in this scenario.

Move to….

July – Net negative on-peak usage, net negative intermediate usage, net positive off-peak usage, net positive total usage

Net metering statute tells us that we should be billing the net kWh consumed in the billing period, which is 95. Presumably these would be billed at off-peak, since this is the only period with net positive usage, but that is inferred and not clear in the statute.

What if one suggests billing negative usage in one period at the applicable TOU retail rate, and positive usage in another period at its applicable TOU rate? Then move to….

August– Net negative on-peak usage, net negative intermediate usage, net positive off-peak usage, **net negative total usage**

Under prior scenario of allowing negative usage to be billed (credited) at retail TOU rates….we know that the net metering statute tells us that 56 kWh of excess generation should receive the avoided cost credit. But we have two time periods contributing excess kWh – peak and intermediate. Which kWh of excess go to avoided cost rate vs. which go to being credited at the retail rate? Also, the net metering statute tells us the retail bill should be only the customer charge and an avoided cost credit in this net excess monthly condition, but retail credits for on-peak will not net financially to zero against net off-peak consumption. Therefore, the bill would be the customer charge plus some retail credit, and then some avoided cost credit. The retail kWh would have to be valued equally (i.e., **not have different TOU prices applied to them**) in order to achieve the statutorily required outcome of zero retail energy charges.

Further wrinkle….add a 300 kWh energy shift between peak and off-peak time periods achieved with a battery (recall Sunrun CEO recently said that within a few years all rooftop solar will be paired with battery storage).

Notice that, if we pay a retail credit for excess on-peak generation, this customer just arbitrage the Company's own energy generated during off-peak period by storing it in a battery and discharging it back to the grid during on-peak. This energy at 28 cents is **way more expensive** than what the Company could acquire on-peak energy in wholesale markets (hence, excess generation should only be credited at avoided cost – the statute acknowledges this on a whole billing period basis – it needs to acknowledge this within TOU periods too). Also note the "duck curve" effect that this customer already exhibited got exacerbated by the energy arbitrage. The distortion of the price signal by allowing excess on-peak generation to be credited at retail TOU rates caused the customer to deploy its battery in the least helpful way possible for the system.

Net Metering and Easy Connect Act

Provides basic rate protections for customer-generators with solar PV

TOU rates were not prevalent in Missouri when the statute was written

Mechanics of the rate protections as written – which likely didn't contemplate the types of rates being offered in Missouri today - present challenges for pairing net metering with TOU rate structures

- Netting all energy for the billing month – kWh lose identity as peak or off-peak
- Zero retail energy charge when net zero or negative total usage in billing month, regardless of when usage may occur (e.g., peak)

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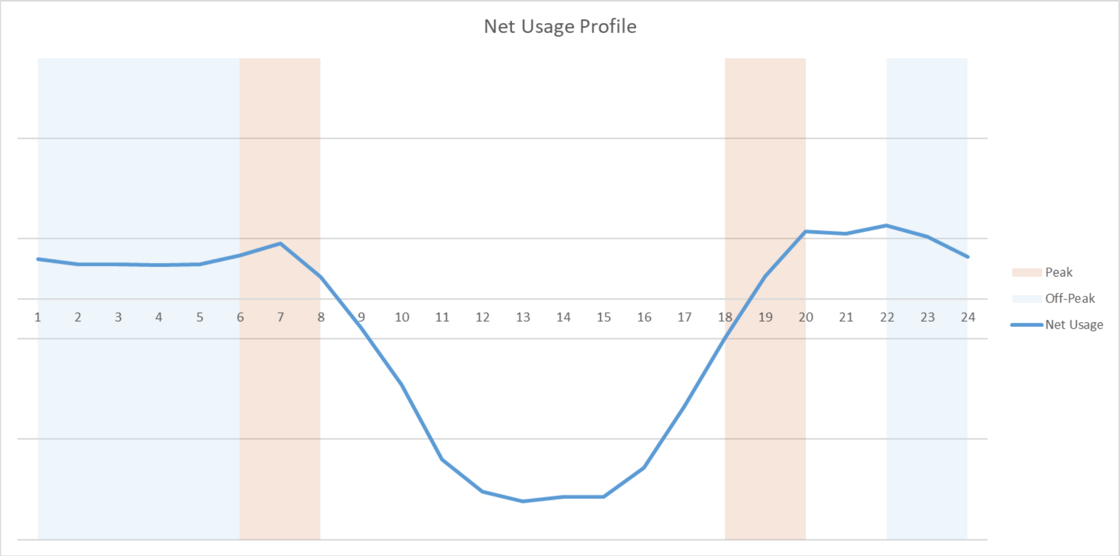
Net Metering TOU Example #1 - April

This customer is a net generator for the month, with excess generation in the intermediate time period and net consumption in the peak and off-peak times

	Raw Net Usage (kWh)
Peak	54
Intermediate	-591
Off-Peak	162
Retail Total	0
Avoided Cost Credit	-375
Total Bill	-375



Netting across the billing month would allow peak usage to be offset by lower value excess generation, eliminating peak period price signal.

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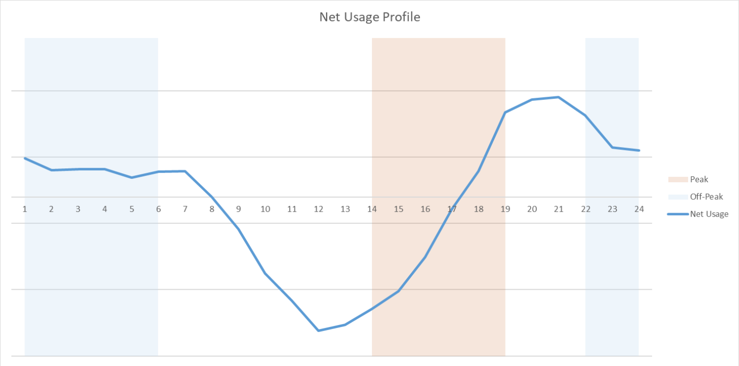
Schedule SMW-S2

Net Metering Example #2 – August – Battery Arbitrage

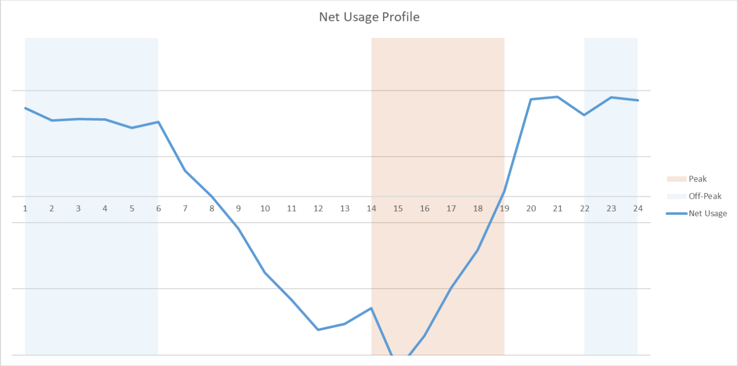
Under TOU rates with net metering with netting over the entire billing period, battery storage could allow customers to arbitrage the utility's power against the rate structure, while creating a less favorable load profile

Original Profile



	Raw Net Usage
Peak	-19
Intermediate	-235
Off-Peak	198
Retail Total	0
Avoided Cost Credit	-56
Total Bill	-56

After Battery Arbitrage Profile



	Raw Net Usage
Peak	-319
Intermediate	-235
Off-Peak	498
Retail Total	0
Avoided Cost Credit	-56
Total Bill	-56

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Schedule SMW-S2

Framework That Would Resolve Net Metering/TOU Issue

Netting should occur **within TOU periods**

- This would require the net metering legal framework to define the measurement of net consumption over the billing month **within each applicable rate period**

Net kWh in a lower priced time period (e.g., off-peak, intermediate) cannot offset usage in a premium time period (e.g., peak) **without significantly distorting the TOU price signal for consumption**, thereby frustrating the primary purpose of the rate structure

Net excess kWh exported to the grid within a TOU period should receive an applicable avoided cost rate, or at most, offset usage at a retail rate associated with a lower priced TOU time period

- Such kWh **do not offset any peak usage** of the customer, but **displace other energy supply** the utility would otherwise produce or purchase for its other customers during that time period
  - This displaced production or purchase would have occurred at a significantly lower cost than the peak retail rate in the overwhelming majority of cases (i.e., avoided cost)

Ameren MISSOURI

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 Adjust Its Revenues for Electric Service.	)))	Case No. ER-2022-0337

AFFIDAVIT OF STEVEN M. WILLS

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

Steven M. Wills, being first duly sworn states:

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

/s/ Steven M. Wills
Steven M. Wills

Sworn to me this 13th day of March, 2023.