Exhibit No. 17

Ameren Missouri – Exhibit 17
Steven M. Wills
Direct Testimony
File Nos. ER-2021-0240 & GR-2021-0241

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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2021-0240

DIRECT TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
March, 2021

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DIRECT TESTIMONY

OF

STEVEN M. WILLS

FILE NO. ER-2021-0240

I. INTRODUCTION

Q. Please state your name and business address.

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

Q. What is your position with Ameren Missouri?

A. I am the Director of Rates & Analysis.

Q. Please describe your educational background and employment experience.

A. I received a Bachelor of Music degree from the University of Missouri-Columbia in 1996. I subsequently earned a Master of Music degree from Rice University in 1998, then a Master of Business Administration ("M.B.A.") degree with an emphasis in Economics from St. Louis University in 2002. While pursuing my M.B.A., I interned at Ameren Energy in the Pricing and Analysis Group. Following completion of my M.B.A. in May 2002, I was hired by Laclede Gas Company as a Senior Analyst in its Financial Services Department. In this role, I assisted the Manager of Financial Services in coordinating all financial aspects of rate cases, regulatory filings, rating agency studies and numerous other projects.

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

In April 2015, I accepted a position with Ameren Illinois as its Director, Rates & Analysis. In this role, I was responsible for the group that performed Class Cost of Service, revenue allocation, and rate design activities for Ameren Illinois, as well as maintained and administered that company's tariffs and riders. In December 2016, I accepted a position with the same title at Ameren Missouri.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. My testimony in this case will largely focus on residential rate design. As the Commission is aware, in the Company's last general rate proceeding, File No. ER-2019-0335 ("the 2019 case"), the Company proposed a number of new innovative rate

[1] Now known as the Midcontinent Independent System Operator, Inc.

designs to begin to introduce our residential customers to time-of-use ("TOU") rates. Through the process of negotiating a unanimous settlement of the issues in that case, the Company, the Missouri Public Service Commission Staff ("Staff"), and other parties to the case agreed on parameters of those new optional rates, as well as on a plan to educate customers about TOU rates and default them onto a more moderate form of TOU rate that had been proposed by Staff. In testimony in that case, I characterized the Company's proposal as a journey to modernize our rates in order to provide customers with more choice and control about how they manage their energy usage and costs. This effort is being facilitated by the Company's deployment of Advanced Metering Infrastructure ("AMI") that is currently underway.

In this testimony, I will update the Commission on the early stages of this rate transition and continue the dialogue about its next steps. Specifically, I will discuss the reasons that the new optional and default rates should continue in largely the same form as they were approved in the last case, while the AMI rollout and customer TOU education initiatives mature. I will also discuss some tweaks to the rates that can be incorporated in this case to make modest progress on the rate modernization front without disrupting that rate education process. Those tweaks will include proposals to adjust the fixed monthly customer charge for certain of the rate options, and to make a small adjustment to the peak period definition of one rate structure. I will also discuss the interaction of TOU rates with net metering, which is a topic that the Commission expressed interest in during the on-the-record discussion of the settlement in the 2019 case.

Q. Are there any other Company witnesses that also discuss residential rate design?

A. Yes. Dr. Ahmad Faruqui, a Principal with The Brattle Group, also shares his perspectives on modernizing residential rates, with focus on the journey the Company is undertaking. Dr. Faruqui is a noted expert in electric utility rate design, and provided testimony in the 2019 case.

Q. Are there issues other than residential rate design that you will also discuss?

A. Yes. I will also discuss a number of other topics. First, I will explain the Company's request for the Commission to authorize a new tracker to account for impacts to the Company's revenues that will arise as residential customers switch between the various optional rates and certain large, non-residential customers potentially move from rate 4(M) to rate 11(M). Next, I will discuss the interaction of the rates and tariffs in this case with the Company's Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM") rate and tariff. I will also evaluate the Company's rate proposal with respect to its compliance with the rate caps associated with its election of Plant-in-Service Accounting ("PISA") under Section 393.1400, RSMo. Finally, I describe a proposed change to the Company's Keeping Current program tariff.

III. RESIDENTIAL RATE DESIGN – OVERVIEW

Q. Please provide an overview of the different residential rate plans that the Company now offers as a result of the 2019 case.

A. The settlement of the 2019 case resulted in the Company offering its residential customers five distinct rate plans, spanning a spectrum from simple rates to quite advanced rates. Since that settlement, the Company has arrived on a naming strategy for the rates that are framed in terms of customer lifestyle. I will refer to each rate by the name now used in customer-facing education and communications.[2] Each rate option currently includes a $9 per month fixed charge, and seasonally differentiated energy rates. The details of the five rate plans are described in Table 1 below:

Table 1 – Summary of Current Residential Rate Plans

Rate Plan	TOU Periods	Peak/Off-Peak Price Differential	Demand Charge?	Load Shift Savings Potential
Anytime User	None	None	No	None
Evening/Morning Savers	**Peak:** 9 a.m. to 9 p.m. daily **Off-Peak**: 9 p.m. to 9 a.m. daily	Small	No	Low
Overnight Savers[3]	**Peak:** 6 a.m. to 10 p.m. daily **Off-Peak:** 10 p.m. to 6 a.m. daily	Moderate	No	Moderate
Smart Savers[3]	**Summer Peak:** 2 - 7 p.m. weekdays **Non-summer Peak:** 6 - 8 a.m. and p.m. weekdays **Off-Peak:** 10 p.m. to 6 a.m. daily **Intermediate:** All other hours	Large	No	High
Ultimate Savers	**Summer Peak:** 3 - 7 p.m. weekdays **Non-summer Peak:** 6 - 8 a.m. and p.m. weekdays **Off-Peak:** All other hours	Large	Yes	Highest

The far right column of Table 1, labeled "Load Shift Savings Potential," is a key to understanding the level of impact the rate may have on customers' bills and with respect to the their enhanced ability to manage their energy costs on that rate. The potential for bill impacts – as well as the potential to save on energy costs – arises from higher TOU rate

[2] In the tariffs filed to implement the rates proposed in this case, the tariff names of the rate plans have been aligned with these customer-facing names.
[3] Includes an option to participate in TOU pricing during the summer only.

differentials[4] associated with the more advanced rates, as well as from the presence of the demand charge in the Ultimate Savers rate. Those same features of those more advanced rate plans, however, do create the risk of higher bills for customers that adopt these rates if their load characteristics are not well suited to the rate structure and they are unable or unwilling to adjust their consumption patterns. Because of that, customers who are not engaged in managing their energy costs and prefer more certainty regarding their bill may prefer rates closer to the top of the list, with little or no savings potential, but also little risk of increased cost. Customers that are satisfied with their current experience and who want to continue to not worry about when they use energy may be perfectly happy with the Anytime User option. Customers that are interested in managing their bill – perhaps they already watch their energy usage closely, have invested in enabling technology like programmable thermostats, or are budget conscious and willing to make extra effort to use energy at times that allow them to save money – may choose to engage with an advanced rate and make the adjustments needed to lower their bills. These rate options allow residential customers to have more control over their energy costs.

Q. What is the status of the implementation of the new rates?

A. The rate that most of our customers have been on for years, now referred to as the "Anytime User" rate plan, is still applicable to almost all of the Company's residential customers. The settlement of the 2019 case called for a staged implementation of a new

[4] Rate differential refers to the difference between the per kWh charge during different defined time periods, such as on-peak and off-peak periods. For example, the current Smart Savers rate has a peak summer rate of approximately 28 cents/kWh, and an off-peak rate of just over 5 ½ cents/kWh, for a peak to off-peak price ratio of approximately 5:1. This large price differential creates more savings when customers shift usage to the off-peak period, but could increase costs for a customer that has significant usage during the 28 cents/kWh on-peak periods that they are unable or unwilling to shift.

default rate, now referred to as "Evening/Morning Savers." Customers served through a legacy Automated Meter Reading ("AMR") meter will continue to be assigned to the Anytime User rate plan[5] until receiving an AMI meter. Once customers receive their AMI meter, they are to be defaulted to the Evening/Morning Savers rate after six months. Each customer also has the choice to opt in to any of the new TOU rates, or back to the Anytime User rate at any time after their AMI meter is installed, which will obviate the rate defaulting process for that particular customer.

The settlement agreement in the 2019 case also recognized that the new plan to default customers to TOU rates, and to provide detailed rate comparison information for each rate plan for each customer, represented a major change to the Company's billing system. It required substantial investments in enhanced digital capabilities and tools by the Company. In October 2020, the Company requested additional time to complete the transformation of its billing system to support the default process, rate comparisons, and implementation of certain of the new rates.[6]

The Company did not ask for this additional time lightly. The Company is aware of, and very much shares, the Commission's keen interest in advancing the adoption of TOU rates that will help customers save money while adjusting their usage to create a more efficient electric system. However, the Company is also keenly aware that rushing the TOU rollout process and failing to "get it right" could undermine the acceptance of TOU rates by customers and hinder the long-term level of customer adoption. The scope of the changes to digital systems and customer communications needed to "get it right" is difficult

[5] There are a small number of customers on a legacy Time of Day pilot rate. Customers served through AMR may also elect one of the new TOU rates – Overnight Savers – for an incremental fee of $1.50 per month.
[6] File No. EE-2021-0103.

to overstate. These new TOU-enabling processes require fundamental changes to the billing system and carry implications for a huge number and variety of customer interactions, as well as many digital systems operated by the Company. By taking this extra time to go through a robust process to analyze and define the going-forward business processes and build its foundational capabilities thoughtfully, the Company has made it a priority to "get it right."

As a result, with the filing of this proceeding, customers have not begun to be automatically placed on (or defaulted to) the Evening/Morning Savers rate plan, nor have they begun to receive rate comparisons, or have access to the digital tools that will enable greater levels of informed adoption of the more advanced TOU rates. The release of these tools is currently slated to occur this spring. Customers that have not opted for another rate will begin to be assigned to the Evening/Morning Savers rate plan no later than June 1st.

Q. Have any customers migrated to any of the new TOU rate plans yet?

A. Yes, but only just a few. The number of customers on these rates remain very small, as should be expected given the revised timeline for rolling out the new digital tools and customer education pieces that will provide customers with insights to make well-informed rate selections. As of March 1, 2021, there are approximately 170,000 residential customers that are currently being served through AMI meters. Of those customers,[7] 5 are currently taking service on the Overnight Savers rate, and 14 customers on the Smart Savers rate. This handful of early adopters are either customers who proactively researched the new rate options on their own, or customers that had participated in the legacy Time of

[7] Overnight Savers also includes customers adopting that rate option through a legacy AMR meter and paying the incremental $1.50 per month fee.

Day ("TOD") rate pilot prior to receiving their AMI meter.[8] Much more significant levels of voluntary adoption of the advanced TOU rates are anticipated after the release of rate comparison tools and the initiation of the customer education and rate defaulting processes.

Q. Does the Company have specific forecasts of, or targets for, the number of customers that will eventually take service on each available rate plan?

A. No, not at this time. Ultimately, which customers are on which rates will come down to a matter of customer preference. Customers will be able to choose between five plans. Through customer education, customers will be empowered to choose the best rate option for their lifestyle and understand how they may control their energy costs.

But as our customers learn how to be successful on these rates, the Company will also be learning – learning about customers' preferences, as well as their capabilities to adjust their lifestyles to save more on the rates that are advanced. As we see additional data about rate plan adoption and load shifting response of different types of customers, we will be able to develop well-informed plans to help customers find the rate that is best for them, while simultaneously achieving the long-term system benefits that can arise from large numbers of customers shifting their loads in response to the rates. We fully expect over time to achieve robust adoption of the more advanced rates.

Q. Please provide an overview of the education and communication plan that will accompany the process of placing customers automatically on the Evening/Morning Savers rate plan.

[8] Customers taking service under the pilot TOD rate are immediately placed onto the Smart Savers rate plan, which is the most similar rate to the pilot TOD rate. They may then elect to remain on that rate, or choose to transition to any of the other available rate plans.

A. The settlement of the 2019 case called for certain TOU-related education and information to be provided to customers by the Company. The Company has endeavored earnestly to meet and even exceed the requirements of that agreement. Ameren Missouri has made it a high priority to create a seamless customer experience around the new TOU rates that educates and empowers customers to take control of their usage, and consequently of their energy costs.

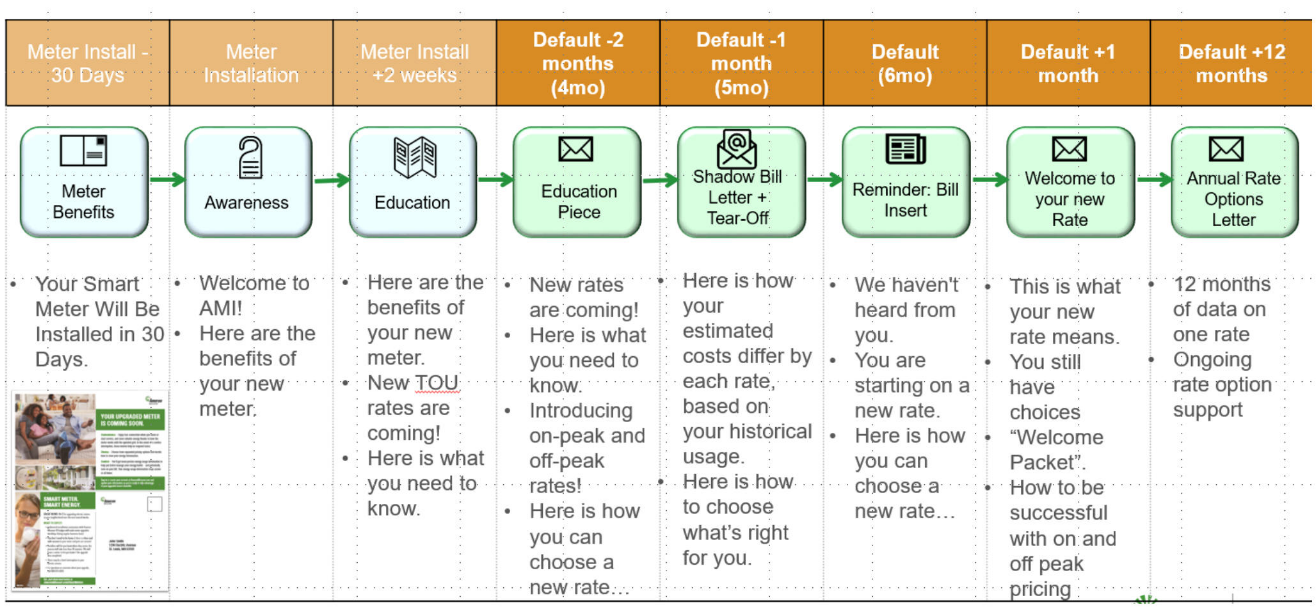
The customer-specific activities called for in this plan begin thirty days prior to AMI meter installation, when each residential customer will get a notice of the scheduled meter change. That notice will include a very high level description of the benefits of their new meter, including a reference to the new rate options. Customers who are interested in learning more about the benefits of smart meters, which include these new rate options, will be directed to Ameren Missouri's smart meter webpage. Next, on the day of meter installation, a "leave behind" door hanger will again reference the benefits of their new meter. Two weeks after installation, customers will be mailed a "benefits mailer" with more information about their new meter, including the first direct piece of education about TOU rates, including a description of on-peak and off-peak pricing, and a link to the new rate options webpage.[9]

Four months after meter installation, the customer will get an additional educational piece about TOU rates and their new options. At five months after installation, customers will get a mailer that includes customized bill comparison[10] to illustrate the potential impacts of TOU rates on their bill given their own historical consumption pattern, along

[9] AmerenMissouri.com/RateOptions
[10] The comparison will show the average bill on the Anytime User and Evening/Morning Saver rate plans over the first four months that the customer had a smart meter, and also direct them to a website to see the bill impacts on all of the other available rate plans.

with a tear-off postcard that will allow them to opt out of defaulting if they are not comfortable making a change at that time. At this point in time, the online tool will have in-depth comparisons of all available rates, along with more information and tools customers can use to make their rate selections. At month six, customers will receive a bill insert notifying them that their next bill will be on the Evening/Morning Savers rate, and again directing them to the Company's options for selecting another rate if they prefer to do so. The full suite of direct communications that customers will experience is illustrated in the timeline represented in Figure 1 below:

Figure 1 – Customer TOU Communications Timeline



Customers who elect to change rates will be able to do so conveniently through the Company's website, with rate selection links built into the rate comparison page, or by calling the call center. Customers that want to retain their old rate may do so by mailing in a form attached to the five month communication letter that they will receive from the Company. The whole experience is focused on convenience for our customers, as well as on providing options for customers with different communications preferences.

Q. Is the Company recommending substantial changes to the rate structure of any of the plans to advance the modernization of its residential rates?

A. Not at this time.[11] Recall that in the 2019 case I represented the Company's proposal as the beginning of a journey to modernize our residential rates. It is natural as the next rate case comes about – this being that case – to think about sprinting along this path in an effort to rapidly advance to a state where most of the Company's customers are on an advanced TOU rate or even more advanced dynamic prices. But it is also very important to step back and recognize what a dramatic paradigm change the 2019 case represented, both for the Company and for its customers – and just how new these rate structures are for Missouri customers. This first step is a *big* step – and it takes time to execute it well. It is critical, in my view, to allow this paradigm change to take root and mature while the Company and its customers gain experience with these rates prior to trying to introduce additional changes to the rate plans and education efforts.

During the on-the-record presentation of the settlement of the 2019 case, some Commissioners questioned whether the default rate should feature a more consequential peak/off-peak differential on a quicker time scale. While the Company understands and appreciates that perspective, and ultimately believes that the time will come to ensure that more customers are participating in rates with enhanced price signals, now is not the time. Making substantial changes to the default rate structure in a case that is taking place just as the Company is beginning to educate customers about what a time-varying rate is, and what their rate options are, would be disruptive to the message and education customers are in the process of receiving.

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[11] Later in my testimony, I will discuss a couple of proposals to make some very modest tweaks to certain rate elements, but I would not characterize them as substantial changes.

Q. How would changing the default rate structure in this case disrupt the customer messaging and education effort that the Company is making pursuant to the settlement of the 2019 case?

A. As I mentioned above, due to the timeline required to develop the foundational changes to billing systems and online tools needed to support the default TOU rate plan, no customers have experienced the Evening/Morning Savers rate plan as of the time of filing of this testimony. Shortly after this testimony is filed, the very first customers will be automatically placed on the Evening/Morning Savers rate plan, and a significant number of customers will begin to learn its parameters and will learn directly what it means for their bills based on their own usage patterns. The introduction of significant changes to the parameters of this rate plan when this case is resolved – less than a year after the first customers are exposed to Evening/Morning Savers, and *just a few weeks or months* since tens or hundreds of thousands of customers were educated about how this rate works and impacts their bills – would make all of the educational information, including those customer-specific rate comparisons that customers relied on for their decision whether to participate in the default process, irrelevant. In fact, those customer-specific rate comparisons could paint an inaccurate picture of the experience on which they are about to embark. Participants in the new rate would have to receive a whole new sequence of educational and informational communications – and ideally a new customized analysis of the impacts the now revised rates are likely to have on their bills. Not only would this be costly and time-consuming to develop and mail these new education and rate comparison pieces, but the sudden change of a message coming immediately on the heels of the then-out-of-date original educational materials, would understandably be a source of potentially significant customer confusion and frustration. I believe making substantial changes to the default rate in this case – given the nascent status of the TOU initiative – would be a key risk to long-term success of TOU rates in Missouri. Dr. Faruqui further expounds on this topic in his direct testimony.

Q. Are there other reasons to avoid changing the parameters of the default rate?

A. Yes. Beyond the confusion that would be created for customers that recently were assigned to the then-out-of-date default rate, it is also true that most of the Company's residential customers have not yet been exposed to the "training wheels" effect proposed by Staff for this rate. By the time rates take effect from this case, it is estimated that approximately 475,000 customers will have AMI meters. But that means that at least 600,000 still will not. If a more advanced form of default TOU rate were adopted in this case, all of those 600,000 customers' first experience with TOU would come in an environment with a substantially higher risk of adverse bill impacts. The risk of adverse bill impacts as a result of defaulting customers to TOU rates with a larger peak price differential could be particularly challenging for vulnerable customers that don't opt out of the rate defaulting process, such as low-income, fixed-income and elderly customers. These customers may have more limited technology options to control their usage, less flexibility in their ability to shift usage, and lower tolerances for unexpectedly higher bills.

Finally, the lingering impacts of the pandemic make it a potentially more difficult time to think about defaulting customers to a more advanced TOU rate. While there is hope that the effects of the pandemic will be waning in the coming months, they are still with us today, as are the changes to lifestyles have taken place in response to it. Higher rates of working from home, both now and potentially in the future as employers find that remote working is perhaps a more viable permanent option than they previously thought, may make it more challenging for some customers to adjust to TOU rates. Customers may be less certain about whether they will be working in the home versus outside of it, and the lingering effects of those who worked from home and had children learning from home, temporarily will make rate comparisons based on recent historical usage a less useful predictor of future success on a TOU rate.

For all of the foregoing reasons, it makes good sense to let the TOU education and the transition process that has been put into place mature. Getting more AMI meters installed, and therefore more customers educated about and exposed to TOU concepts, as well as getting distance from the depths of the pandemic, will provide a better foundation to progress even further toward modernizing our rate plan offerings, while avoiding unnecessary confusion and frustration from customers that might otherwise receive conflicting messages about their rate plan shortly after they adopt (or are assigned to) it.

Q. With little change in rate plans proposed in this proceeding, what do you see as the future steps in enhancing the residential rate experience?

A. The most important next step in the immediate future is to allow the significant paradigm change that we have already embarked on to mature and take root, and for the Company's AMI implementation to be completed so that all customers begin to have access to and learn about their usage patterns and TOU rates. Because all customers are expected to have an AMI meter by the end of 2024 and therefore would have gone through the rate selection/defaulting process by the first half of 2025, my suggestion is that we maintain stability of the rate offerings through that time. That said, the Company will be evaluating uptake of the rates and the customer experience. With our new online tools for engaging customers, we can check and adjust our communications efforts on an ongoing basis to ensure that these rates are being used by increasing numbers of customers.

After all customers have AMI meters, the time will be right to contemplate further changes needed to communication strategies, or more structural changes to the rate plans themselves, to ensure that we achieve robust levels of adoption of beneficial and cost-reflective TOU rates. Options at that point might include adjusting the default rate to have a wider pricing differential and shorter peak period in order to push large numbers of customers that have stayed with the default rate toward a more modern rate design that elicits more load shifting, or to ramp up marketing efforts further to achieve higher levels of voluntary enrollment in the advanced rates. The data and customer experience observed between now and then will help inform the selection of the path forward.

Additionally, that will be a good time to contemplate options to create even greater levels of load flexibility – which will be critical to reliably integrating higher levels of renewable generation which I discuss further below – by exploring even more dynamic rates and/or other load management programs. Options like Critical Peak Pricing ("CPP"), Variable Peak Pricing ("VPP"), or Peak Time Rebates ("PTR") would be logical considerations to add to the rate and/or demand response portfolio of the Company. CPP, VPP, and PTR are all methods to dynamically adjust rates, or provide bill credits, to encourage customers to use less power during defined events when the system experiences the conditions of highest demand and stress. It will also be appropriate to consider during the years following full AMI deployment whether forms of Real Time Pricing, or other more advanced demand side management programs, are appropriate options to further build load flexibility. Dr. Faruqui discusses future options as well.

IV. RESIDENTIAL RATE DESIGN – MONTHLY FIXED CHARGE

Q. Please provide some context for consideration of the parameters of the Company's residential rate options.

A. In the 2019 case, I discussed at length the changes in the electric utility industry that are driving the need for, and the capability of utilities to offer, updated modern rate plans that better reflect the cost structure of the utility. Those changes include adoption of electric vehicles ("EVs"), increasing penetration of intermittent renewable generation (both behind the meter and at utility scale), and technologies like smart thermostats and other home automation that increase customers' ability to control their electric usage. Additionally, battery technology continues to evolve and may become increasingly economic for customers to deploy in their homes – paired with solar generation or on its own – in the not too distant future. These changes are increasingly familiar to the Commission and stakeholders. On the utility side, deployment of AMI systems are enabling the billing and communications capabilities needed to offer such rates and help customers succeed on them. With the increasing prevalence of such new energy-related technologies, many of which can represent significant investments on the part of customers, and which can also have significant impacts on the way customers interact with the electric grid and may correspondingly cause different costs to be incurred or avoided by the utility, therefore it is increasingly important for electric rates to reflect the cost structure of the utility. Cost-based rates help to promote equity between customers and also promote economic efficiency of the electric system. These are two of the important goals of electric rate design originally spelled out by the widely recognized and often cited rate design authority Dr. James C. Bonbright in his *Principles of Public Utility Rates*.

The modern rates that the Company introduced in its last case feature price signals that are intended to encourage decisions around the adoption of the technologies I described above by customers in a manner that promotes the economic efficiency of the electric system. Once adopted, it promotes fairness between customers where the bills of customers choosing these new technologies reasonably reflect the cost of serving them, avoiding the creation of undue cross-subsidies between customers.

Q. Given the heightened importance of equitable and economically efficient rates in today's environment, can you please describe the considerations that go into developing a cost basis for such rates?

A. Yes. Truly cost based rates can only be developed with the aid of a detailed class cost of service study ("CCOSS"). Company witness Thomas Hickman's direct testimony supports the Company's CCOSS. He provides detail regarding the functionalization, classification, and allocation of costs to the various customer classes.

I will elaborate on this process to some degree, particularly regarding how the principles used to allocate costs to customer classes can and should be extended in order to allocate costs appropriately on an intra-class basis to individual customers, by using the class cost of service information to inform the design of the specific rate elements used to bill those customers. In doing so, it is first instructive to review the process of classifying costs in the CCOSS and how those classifications relate to the various rate design elements used to price electric service.

Costs are classified as either customer-related, demand-related, or energy-related based on an assessment of the activities and investments that give rise to those costs. The key costs to consider for the fixed monthly customer charge are those that are customer-related.

Q. What costs are classified as customer-related?

A. The costs of assets dedicated to individual customers, such as meters and service lines that directly connect to the customer premises and billing costs, are classified as customer-related costs. Beyond the basic costs of customer connections and billing, the costs of the minimum distribution system are included in the customer-related classification, which Mr. Hickman discusses further. Mr. Hickman also describes the other major cost classifications – energy and demand – in more detail.

Q. How do the three cost classifications – customer, demand, and energy – relate to rate design?

A. These classifications of cost, which are used to reflect costs in the CCOSS to the various customer classes that cause them, are also useful for reflecting cost causation down to the bills of different individual customers within the class. This is based on their load characteristics in a way that is an extension of the cost allocation concept as applied at the class level. The rate designs employed by electric utilities, including Ameren Missouri for many rate classes, are often times described as three-part rates. The three parts relate back directly to the three categories identified for classification of costs in the CCOSS: customer, demand, and energy. Under the three-part rate structure, there is a logical mapping of costs from the classifications of the CCOSS to the rate design. Customer charges are generally used to collect customer-related costs; demand charges generally collect demand-related costs; and energy charges generally collect energy-related costs. Rate designs based on these relationships tend to result, at the individual customer level, in outcomes similar to those that occur when the results of the CCOSS are followed for allocating the revenue requirement at the class level. That is to say, when this mapping of costs to charge types is followed, customer bills tend to be more reflective of the cost to serve them. In general, while there are still a considerable number of details to consider[12] and decisions to make when designing equitable cost-based rates, it is fair to say the practice of collecting costs in the charge type that corresponds to the classification of those costs generally promotes cost-based rates.

Q. Do the residential rate plans approved in the 2019 case reflect the costs identified in the CCOSS accurately?

A. Generally, yes, but to varying degrees depending on the rate plan. I analyzed that in depth in my testimony in the 2019 case, and found that the Ultimate Savers rate, which is the only plan that features a demand charge, along with a significant time-varying energy charge, produced individual customer bills most aligned with the cost of serving them. The Smart Savers rate does not have a demand charge, but does feature significant time-variation in the energy charge, which is aligned around the times that give rise to costs on the electric system. This results in the Smart Savers rate being the second most cost-reflective rate offered by the Company based on my analysis from the 2019 case.

The other rate plans are for the most part about as cost reflective as can be achieved using simpler rate structures with no demand charge and no or modest time-variation in the

[12] For example, while mapping energy costs to energy charges generally is a critical step for creating cost based rates, a detail that can enhance the extent to which rates reflect cost is further consideration of the time that customers use energy through differentiated TOU charges.

energy charges. This cost alignment is generally achieved through seasonal energy charges and the declining block winter structure reflected in the Anytime Users and Evening/Morning Savers rate plans, and the more modest time-variation of energy charges reflected in the Overnight Savers and Evening/Morning Savers rate plans. For customers that are not ready for more advanced rates and/or do not have an AMI meter that enables the billing of the advanced rates, these are generally appropriate cost-based rates. However, across the board for all of the rate plans, but most significantly with respect to the less advanced rate plans, better alignment between bills and the cost of service could be achieved by reflecting more of the customer-related costs in the customer charge.

Q. What is the current monthly residential customer charge, and what does the CCOSS study suggest it should be?

Q. For all residential rate plans, the fixed monthly customer charge is currently $9. However, the process I discussed above of mapping the customer-related costs from the CCOSS to the customer charge suggests that a residential customer charge that truly reflects customer-related costs would be approximately $24.34 per month. At this level, the customer charge would be designed to cover the customer-related costs: meters and service lines that directly connect to the customer premises, billing costs, as well as an equitable allocation of the fixed costs of the shared distribution grid that are incurred irrespective of the demand or energy requirements of customers, and which are simply necessary to construct and operate a functional electric grid and connect customers to it.

Q. Why is the customer charge so much lower than the customer-related costs suggest it should be?

A. The determination of the customer charge is often a source of significant disagreement between parties and perspectives in rate cases. While the policy considerations of promoting the rate design goals of equity and economic efficiency are very important – which I have argued in past cases, and still believe, that they should be the primary determinative factors of the optimal customer charge – there are policy considerations that others have argued as supporting a lower customer charge. Through settlement agreements and Commission orders in past cases, some of those policy considerations have resulted in the customer charge remaining at a very low level.

Q. What are the policy considerations that some argue support the lower customer charge?

A. Generally, because customer charges are fixed and cannot be avoided by customers, they are viewed as limiting customers' ability to manage their bill by reducing usage. It is also sometimes argued that higher fixed charges reduce customers' incentive to invest in energy efficiency measures, and that they may have an outsized impact on low-use customers, which are often perceived to include many low-income customers.

I believe, however, that the existence of a portfolio of residential rate plans that are available to customers allows us to think a little bit differently about the issue of the customer charge in this case relative to how it has been discussed in the past, and perhaps represents an opportunity to reconsider, and better balance, the sometimes competing policy objectives that go into establishing the customer charge.

Q. What opportunity does the existence of different rate plans create for the reconsideration of the residential customer charge?

A. Ameren Missouri now offers five distinct rate plans with unique characteristics, which may appeal to different customers with different energy-related preferences and priorities. I discussed previously how customers with an interest in actively managing their energy cost by changing consumption behaviors should gravitate toward the more advanced rate plans, where their actions to shift energy usage can create significant bill savings. These rates – with significant time-variation in their energy charges, and in one case the existence of a demand charge – already inherently reflect the cost structure of the electric system better than the other rates. The less advanced rates with flat, or more moderate TOU energy charges, are appropriate for customers that do not want to or are unable to engage as seriously with changing their energy usage to manage their bills. These rates are also currently less fully reflective of the cost structure of the electric system.

I think this creates the opportunity to differentiate the customer charge across the rate plans in order to improve the extent to which the less advanced rates reflect cost, and also to meet the objectives of the customers that may utilize different rate plans based on their preferences for engaging in controlling their usage and bills.

Q. How do you propose to differentiate the customer charges of the different rate plans?

A. Table 2 below summarizes the customer charges that I proposed for the various residential rate plans. I will discuss further below the rationale for these specific recommendations.

Table 2 – Proposed Customer Charge by Rate Plan

Rate Plan	Peak/Off-Peak Price Differential	Demand Charge?	Load Shift Savings Potential	Proposed Fixed Monthly Customer Charge
Anytime User	None	No	None	**$11**
Evening/Morning Savers	Small	No	Low	**$11**
Overnight Savers	Moderate	No	Moderate	**$11**
Smart Savers	Large	No	High	**$10**
Ultimate Savers	Large	Yes	Highest	**$9**

As is shown in Table 2, I propose maintaining the existing $9 per month fixed monthly charge for the Ultimate Savers rate plan. This rate plan already creates the best alignment between customer bills and the cost of serving them. Said another way, although it is not perfect, it is already a highly cost-reflective rate plan. The existence of the demand charge provides more assurance that customers will fairly contribute revenues that cover the fixed costs of the shared minimum distribution system. While I still think that the minimum distribution system costs are best reflected in a customer charge for purposes of promoting equity and economic efficiency, in recognition of the other rate design policy considerations discussed in relation to customer charges, the Company is proposing to maintain the $9 level and reflect those additional minimum distribution system costs in the demand charge. The elegant part of this solution is that the rate plan designed for customers that *want* to actively manage their bills will create the *greatest opportunity* to do so, not only because of the demand and TOU elements, but also because of the lower fixed charge with correspondingly larger variable charges that may be avoided by customers that manage their usage well.

I observed previously that the Smart Savers rate plan is the second most cost-reflective rate design, and also affords customers a significant opportunity to control their bills by adjusting their usage. It is, however, not as cost-reflective as Ultimate Savers with its demand charge, and customers on this rate are less certain to share in covering the fixed costs of the minimum distribution system. For this reason, I propose a small increase in the monthly fixed charge, from $9 to $10. This will modestly improve alignment of bills with the cost of serving customers, but still afford a great opportunity for customers to create savings by managing their energy consumption.

The other three rate plans – Anytime Users, Evening/Morning Savers, and Overnight Savers – are not as sophisticated as the other two advanced rate plans. They are a little less cost reflective, and more prone to outcomes where certain customers may not contribute equitably to the minimum distribution system fixed costs. These circumstances can be partially remedied with a little bit larger increase in the fixed monthly charge. And because these rates are positioned in the portfolio of rates offered to residential customers to be more attractive to customers that are *less* active in managing their whole house energy usage[13] and more interested in *certainty of energy costs* – regardless of when they use electricity – the higher fixed charge, and lower variable charges, will produce more stable bills and will align well with the goals of the adopters of these rates. This is the outcome that is created by increasing the customer charge for these specific rate plans – because the higher customer charge is offset on a revenue neutral basis by lower variable charges. This increase of the portion of the bill that is associated with fixed (stable) charges, and the corresponding reduction of the portion of the bill derived from variable energy charges, creates an environment where these customers who may be more interested in bill stability, will be able to achieve this outcome.

[13] Overnight Savers was originally designed to give EV owners a path to a rate that allows savings for charging an EV at night without negatively impacting the cost of electricity for customers who were unwilling or unable to make the other changes needed to avoid higher on-peak charges throughout the day.

Customers who prefer a lower fixed customer charge in order to manage their bills will have the option to move to the Ultimate Savers or the Smart Savers rate plans – giving them an even more enhanced ability to control their bills.

At this point in time, I am only recommending a modest increase in the fixed charge for these rate plans – Anytime Users, Evening/Morning Savers, and Overnight Savers - from $9 per month to $11 per month.

Q. If the CCOSS suggests $24.34 per month is a fully cost based customer charge, why only increase the customer charge on the more basic rates by $2 in this case?

A. The primary reason is that the Anytime Users rate is still applicable to almost all customers being served through a legacy AMR meter. AMI meters will not be fully deployed and all customers will not have access to the advanced rates until sometime in 2024. With that in mind, I think it is important to still follow a path of gradualism with respect to rate design changes that impact a rate plan that is applicable to, and the only realistic option for, hundreds of thousands of customers. Keeping in mind that the energy charge will be reduced by a commensurate amount, an $11 customer charge will have a quite modest bill impact on customers – including those AMR metered customers that do not have as many rate plan choices yet. In time, the customer charge for these rates may be further differentiated as all customers get AMI meters and they have the option to adopt any of the five rate plans.

Q. How will an increased customer charge impact customers' savings associated with the adoption of electric energy efficiency measures?

A. The impact will be negligible. In the Company's 2016 electric rate case, File No. ER-2016-0179, the Company analyzed the impact of its proposed Energy Grid Access Charge on the participant payback of various energy efficiency measures. First, it is noteworthy that the Company's proposal in that case included an almost $5 increase in monthly fixed charges, whereas the pending proposal in this case for certain rate plans is only for a $2 per month increase. But even with that larger increase, the payback for the average energy efficiency measure in the Company's residential programs only increased from one year and ninety days to one year and one hundred fifteen days. It is hard to imagine that a customer that is willing to invest in an energy efficiency measure with just over a year payback would forego that same investment when the payback took just twenty-five days longer. And again, the impact of the proposal in the current case on measure paybacks would likely be less than half of that magnitude, given the requested increase in the fixed charge for certain rate plans is only $2 versus the almost $5 underlying that analysis. That said, to the extent that there is *any* negative impact on the economic case for customers to adopt *electric* energy efficiency measures associated with an increased fix charge, there will also be a *positive* impact on economics of the adoption of *efficient electrification* measures that promote overall energy efficiency. And I will reiterate that the impact of the change in paybacks of measure adoption associated with modest changes in the fixed charge is *quite* small. But that said, it almost certainly represents a more significant favorable total dollar impact on customers adopting efficient electrification measures like EVs than it represents a negative impact on customers adopting electric energy efficiency measures, simply because EVs are such a large energy consuming end use and there are therefore more marginal kilowatt-hours ("kWh") to benefit from the slightly lower variable rate.

Q. How does a higher customer charge support the economics of clean efficient electrification?

A. By shifting revenue recovery to a fixed charge, the variable price seen by residential electric customers will be lower than it otherwise would be. That means marginal usage of customers will be less costly than if the fixed charge were lower (and variable charges a commensurate amount higher). Adoption of EVs represents a significant source of marginal residential electricity usage – but a source that generally drives overall efficiency of total energy costs in addition to improved environmental outcomes. A higher fixed charge and lower variable charge can, if just slightly, enhance the economics of electrification and help encourage the adoption of EVs.

This tradeoff between fixed and variable charges also supports the economic efficiency goal of rate design more generally. The most actionable charge with respect to customers' energy consumption decisions is by far the energy charge. By building recovery of the shared fixed costs of the distribution system into energy charges, as happens with basic and traditional rate designs, energy charges are typically much higher than the marginal cost of energy. This potentially discourages consumption – such as that associated with efficient electrification – that has real value to customers and potential benefits to the energy system and environment, and therefore reduces overall economic efficiency and slows progress on environmental issues.

Q. Would low-use customers be negatively impacted by this proposal?

A. No, I do not believe they would be negatively impacted at all. Customers who are truly low users can gain the benefits of a lower fixed charge by adopting the Ultimate Savers or Smart Savers rate. If those customers' lifestyles are not a good fit for those rates, it can only be true because they have high peak period usage, or a high peak demand that would establish their demand charge. It is fair to say, then, that the cost of serving those customers must also be commensurately higher. Allowing them to remain on a flat rate with a lower customer charge would almost certainly result in that customer being unfairly subsidized by the rest of the residential customer base, rather than being unfair to them.

Q. What about the impact on low-income customers?

A. With respect to low-income and other vulnerable customers, I believe the focus on fixed monthly charges has been misplaced. Regardless of whether low-income customers are low-users on average or not, it is certain that there are substantial numbers of low-income customers all across the usage spectrum, including many with very high usage. This is empirically true, and logical as well, as many low-income customers have inefficient homes and appliances and do not have the resources to make needed efficiency upgrades to reduce their usage.

Reducing the customer charge, then, has a disparate impact on the bills of low-income customers. A lower customer charge reduces bills for some low-users at the expense of *increasing* the bills of higher users. But this much is certain: the low-income customers that are negatively impacted by lower fixed charges – those high usage low-income customers, many of whom rely on electricity to heat their homes in the winter –

are those customers who already have the *highest electric energy burdens*. Energy burden is a metric used to assess the percent of a household's income that is dedicated to their energy costs. High users by definition have higher bills and a higher energy burden than low users at similar income levels. High using low-income customers by definition have the highest energy burdens of any customers on the system. An artificially low customer charge, and correspondingly higher variable charge, exacerbates the problem for these higher using low-income customers and increases the energy burden on those who have the highest energy burden to begin with.

V. RESIDENTIAL RATE DESIGN – SMART SAVERS PEAK PERIOD

Q. What changes are you proposing to the Smart Savers rate plan parameters?

A. I am proposing a very modest reduction of the hours that make up the on-peak period. Currently, Smart Savers features peak hours from 2 to 7 p.m. on non-holiday weekdays during the summer months (June – September), and 6 to 8 a.m. and p.m. on non-holiday weekdays in the non-summer months. Going forward, I suggest reducing the peak hours for the summer months by excluding the 2 o'clock hour and making the peak period span from 3 to 7 p.m. There are no changes proposed to the non-summer peak period.

Q. Why do you suggest removing the 2 o'clock hour from the definition of the peak period for this rate plan?

A. Essentially, it is to begin to take steps to future-proof the rate by considering the customer usage behaviors that will help integrate the higher levels of solar generation that are anticipated in the future, including the additions called for in the Company's 2020

Integrated Resource Plan ("IRP"),[14] while still reasonably reflecting the hours that currently have the highest system loads, which drive the demand-related costs of the system.

Q. How does rate design impact the integration of renewable resources?

A. Historically, and to a very large degree still today, the Company's system and the generation mix in the regional power markets in which the Company participates, have been dominated by dispatchable fossil fuel resources that are able to follow load, and produce energy whenever customers wanted to use that energy. The transition to greater levels of renewable generation called for in the 2020 IRP is a needed and welcome change, but it does bring new challenges with it. Obviously, solar and wind generation are not fully dispatchable on demand. The sun has to be shining, or the wind blowing, to have access to the resource. The integration of renewables has to recognize their intermittency and develop solutions to balancing available supply with customer demand for electricity 24 hours a day, 7 days a week.

A part of that balancing solution will be, at least for a number of years to come, continued operation of some traditional dispatachable resources to follow load and fill in the gaps in the availability of the intermittent resources. But increasingly the balance will likely have to come from increased levels of energy storage, and importantly for this discussion, more flexible load that can be shifted to the time periods with greater levels of resource availability. That is where TOU rates, and other forms of more dynamic pricing, come into the picture. The TOU rates offered by the Company are designed to begin the process of building flexible demand, and enabling customers to be a part of the solution to

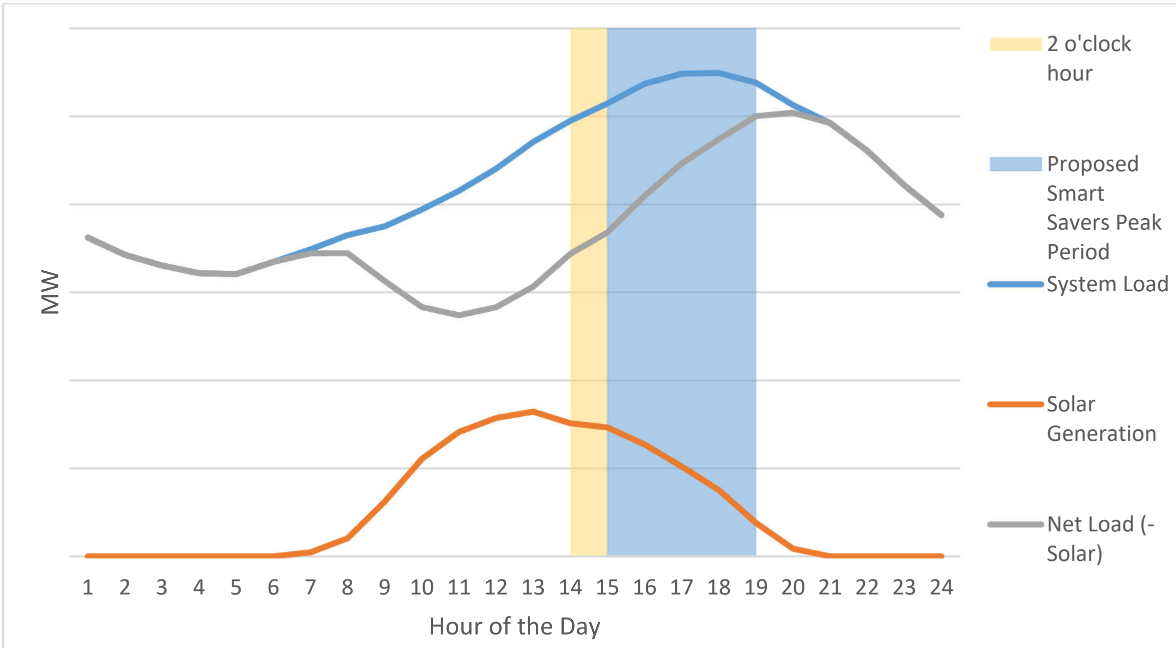
[14] File No. EO-2021-0021.

integrating renewables by cost-effectively managing their usage to the price signals reflected in the TOU rates. To accomplish this, the energy pricing periods in TOU rates should be based not solely on the highest gross load hours on the system, but the highest net load hours, where the available intermittent resources' capabilities are included in the net load determination. That way, customers responding to the TOU periods are shifting load to when it is beneficial based on the balance of load and renewable resource availability. This is how TOU rates can greatly help with renewable integration.

Q. How does removal of the 2 o'clock hour from the peak period help with this integration challenge?

A. The Company's 2020 IRP calls for the addition of 1,400 megawatts ("MWs") of solar generation by 2030, and a total of 2,800 MWs by 2040. In addition, customers continue to add their own solar generation behind their meters. It is increasingly clear that load balancing in the system of the future will be influenced heavily by the availability of solar generation. To that end, it is instructive to look forward at the expected net load shape (usage minus available solar generation) at a point in the future. Figure 2 below shows the expected average load shape, solar generation capability, and net load shape (load minus solar resource) from the IRP for the month of July in 2030.

Figure 2 – IRP Projected July 2030 System Load, Solar Generation, and Net Load



Note the grey line in Figure 2, which represents the load, net of expected solar generation, projected for an average day in July 2030. The light blue and yellow shaded areas represent the current (blue shaded region + yellow shaded region), and proposed (blue shaded region only), peak hours for the Smart Savers rate. Note that, in the not too distant future, the position of the grey line within the light yellow shading representing the 2 o'clock hour demonstrates that that hour is expected to be *far* from a net system peak hour, given the abundant solar resources that are expected to produce energy during that hour. In fact, this view suggests that, over time, the peak window will likely need to be adjusted further back to a later net system peak that will occur in the early evening hours, rather than the late afternoon. However, in my opinion, it is premature to push the whole window back further based on the expected peak time in 2030, given the reality of the current summer load shape. Figure 3 below shows the test year weather normalized peak day load (with the same TOU period shading).

Figure 3 – Test Year Peak Day System Load Shape

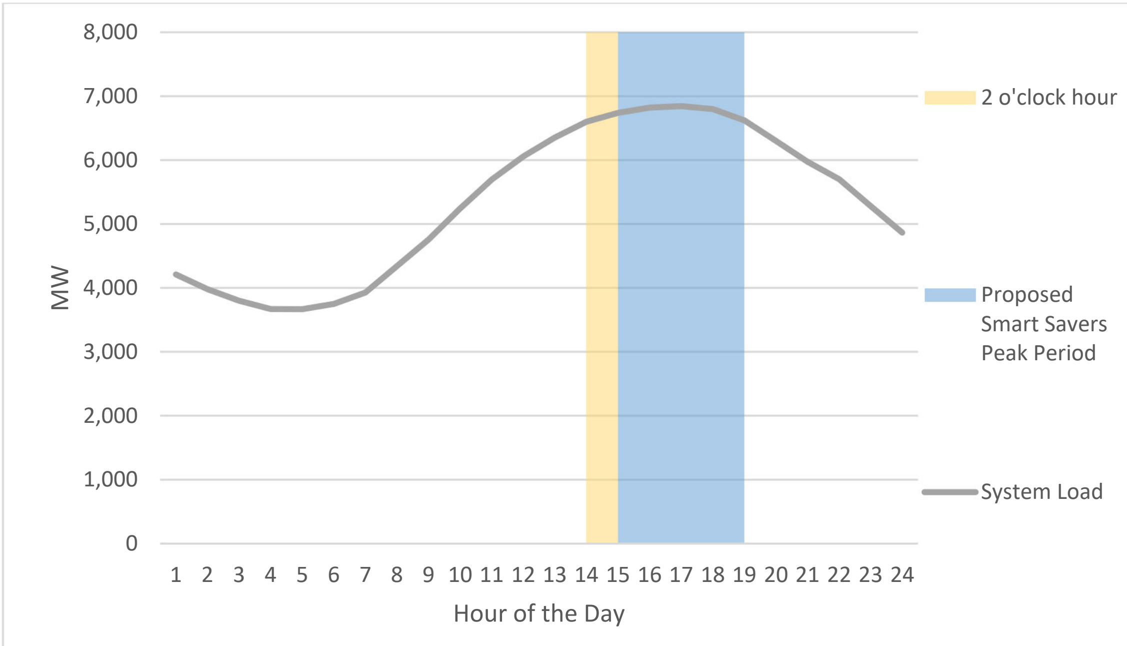


Figure 3 shows that the current system peak conditions would be addressed well by a 3-7 p.m. peak period for Smart Savers. While the 2 o'clock hour is arguably similar in load levels to today's 6-7 p.m. hour, these two hours are expected to follow very different trajectories in the coming decade. While it makes all the sense in the world to keep 6-7 in the peak because it may at some point in the next decade actually become the peak hour, 2 o'clock is simply not enough of a problem today to warrant keeping it in the peak period, when it will very clearly be on the *low end* of the net load spectrum relatively soon.

Q. Are there any other benefits of reducing the peak period by removing the 2 o'clock hour from its definition?

A. Yes. Shortening the peak period is customer friendly, and is consistent with the principles of modern rates identified by Dr. Faruqui, who has spent decades studying the characteristics of successful TOU rates. Dr. Faruqui discusses in his testimony that the most effective modern rate designs feature short peak periods with large pricing spreads, which create the conditions whereby customers can be successful shifting load and saving on their bills. Clearly, it is easier for a residential customer to manage a four-hour peak period than a five-hour period. Avoiding the peak period may mean setting back a thermostat during that period for its duration, or avoiding using certain energy intensive appliances. Avoiding those activities is easier when the duration of time they need to be avoided is shortened. Given that reality, this change should make the peak period easier for customers to manage, which will position the Smart Savers rate plan for greater customer savings and satisfaction, and thereby enhance adoption levels, which in turn will create more potential load shifting for the benefit of the system.

Also, adjusting the Smart Savers summer peak period to the 3-7 p.m. window aligns with the peak definition featured by the Ultimate Savers rate plan. Having these two rate plans feature just slightly different peak periods – as they currently do – creates the opportunity for customer confusion as they compare rate options. Aligning these periods will streamline messaging and avoid this potential source of customer confusion.

Q. Is it important to make this change today, given the fact that it will take a period of years for the development of the solar generation that will result in the changes you illustrated in the net system load shape?

A. I believe it is. It is important, in my opinion, to plan any changes to the TOU rate parameters thoughtfully. It is critical to look ahead at changing system conditions in order to balance the potentially competing goals of keeping these rate plans as stable as possible while responding to changing system conditions to ensure that load-shifting remains beneficial. Customers need to learn the parameters of the rate and adjust their lifestyles to them with an expectation of some consistency. Constant changes to the peak period or pricing differential would require re-education of participants so that their actions can be adjusted to the new conditions. This is one of the reasons that I suggested keeping the Evening/Morning Savers (default) rate parameters stable in this case.

Now, I fully recognize that I just said that we should change this rate now because we should *not* be changing TOU rate parameters on customers any more often than necessary. I also recognize that I argued against making any changes to the Evening/Morning Savers rate plan parameters, due to the need for consistency for the hundreds of thousands of customers that will be placed on it six months after their AMI meter is installed. Those issues may sound like they create a contradiction at first blush. But recall, as of this filing, fewer than 20 customers are on the Smart Savers rate plan. And although the process of placing customers onto the Evening/Morning Savers rate plan starts in just a few months will drive some increased adoption, there is still a relatively low penetration of AMI meters on the system today – especially compared to where we are headed in the next couple of years. So this is the time where we can make a forward-looking change while impacting the fewest number of customers that have already adopted and learned the Smart Savers rate. The same cannot be said for the Evening/Morning Savers rate, which is likely to have hundreds of thousands of customers taking service subject to its parameters when rates from this case take effect.

There will always be a bit of tension between trying to create stable rate structures, and having responsive rates to system conditions where the peak periods are adjusted to align with then-current needs. I believe we should not change peak definitions often, but need to be open to doing so as dictated by system conditions. Making this update now reasonably aligns the rate structure with future conditions, while impacting a relatively small number of early adopters, and ensuring the rate is still relevant to the system conditions of today. Furthermore, this type of change, where an hour is being *removed* from the peak period and no hours are being added to the peak period, should be the *easiest* type of change for these early adopters to adapt to. This is a key point for why this change makes more sense today than changes to any of the rate plans that might negatively impact some customers' bills - it is pretty easy to get an extra hour at a lower price when there are no additional peak hours being added, and there is therefore *no risk of surprises* from this change resulting in higher bills for customers.

Q. Is this change directionally consistent with the peak periods of other utilities with TOU rates?

A. Yes. Utilities in the western states like Arizona and California, with higher penetrations of solar generation already present on their systems, have largely moved their peak period to cover the 3-8 or 4-9 p.m. hours. Even here in Missouri, the Commission has already approved Evergy's pilot TOU rate to feature a 4-8 p.m. peak period. Shifting back the beginning of the Smart Savers peak period by one hour would directionally move it closer to the peak periods of these other utilities' TOU rates.

VI. RESIDENTIAL RATE DESIGN – NET METERING

Q. What is the issue you will be addressing with respect to net metering?

A. During the on-the-record presentation of the settlement in the 2019 case, some Commissioners expressed interest in the availability of the advanced TOU rate options for customers with net metering agreements. I committed to addressing that issue in my testimony in the next case, which is this case.

Q. Does the Company share the Commission's goal of making all of its rate options accessible to net metered customers?

A. Yes. In fact, I testified at length in the 2019 case, and to some extent in this direct testimony already, about the fact that one of the driving factors behind the need to modernize rate design is to provide for the right price signals for, and equitable cost allocation to, customers adopting the rapidly emerging energy-related technologies that are transforming our industry. Behind-the-meter solar generation is among the most prominent of those technologies. The best way to encourage adoption of technologies in an economically efficient manner is for rates to reflect the cost structure of the utility. To the extent that the advanced rates represent the most cost-reflective rates for residential customers, these are the rates that make the most sense to make available to net metered customers. That said, there are certain barriers in the language of Missouri's Net Metering and Easy Connection Act ("the Act") – the legislation that defines the way net metering operates in the state – to offering appropriate net metered TOU rates to customers.

Q. What are the barriers you have identified to offering effective TOU rates to net metered customers?

A. While I am not an attorney, some of the provisions of the Act plainly conflict with the principles of effective TOU rates. For example, the Act requires that "[f]or a customer-generator, a retail electric supplier shall measure the net electrical energy produced or consumed during the billing period…."[15] While that sounds like a pretty

[15] Section 386.890.5(1), RSMo.

accurate and fair description of the concept that is net metering, it creates a framework where netting of usage and generation must occur *over the entirety of the billing period*. Any kWh of generation, regardless of the time it occurs, must be netted against any kWh of usage, regardless of the time of use. Said in another way, to measure net consumption across the whole billing period, all kWh must be valued equally, rather than at unique rates that depend on the timing of use and/or generation.

This phenomenon of valuing kWh equally regardless of the time of use is reinforced later in the Act, when the Act dictates that a customer that has net zero usage over the billing period shall have a bill that reflects zero energy charges.[16] If kWh of usage and generation could be valued by time-varying rates that apply different charges and credits to different kWh over the billing period, net zero usage over the entire billing period would not necessarily result in zero energy charges.

At the time the Act was passed, TOU rates were not prevalent in Missouri, and this issue probably was not top of mind of the Legislature. However, as rate designs have evolved, the language does create some limitations for the application of net metering to TOU rates.

Q. What would be appropriate terms on which TOU rates could or should be applied to net metered customers?

A. Most importantly, for effective price signals to exist for net metered customers on TOU rates, net metering legislation would need to define netting to take place *within each defined TOU period*. Next, legislation should provide that generated kWh should not receive a premium (e.g., peak, mid-peak) price unless they are offsetting a

[16] Section 386.890.5, RSMo.

premium kWh of usage. If these principles are observed, then the customer-generator will still receive actionable price signals that encourage more efficient use of the system. If not, the netting process will distort the price signals and reduce the incentive to use energy more efficiently, and set up the possibility of gaming the TOU prices once customers start to pair storage with behind-the-meter generation. This could occur if netting is allowed to cross TOU periods. This practice would allow a customer with a battery to essentially arbitrage the energy supplied by the Company during off-peak periods by storing it and selling it back at a significant premium in the on-peak period. This transaction would be unrelated to the solar generation, which is the reason for the net metering to exist in the first place, but would leverage that arrangement to create bill reductions for the customer that would not be accompanied by commensurate cost reductions on the system.

VII. TWO-WAY RATE SWITCHING TRACKER REQUEST

Q. Please describe the request that the Company is making for the Commission to authorize it to track changes in revenues that may arise as customers avail themselves of the new rate offerings that the Company is implementing as a result of the 2019 case.

A. The 2019 case settlement, and the robust TOU implementation efforts the Company has been engaging in as a result of it, demonstrate the Company's commitment to providing customers the rate plans and tools needed to take more control than ever before over their energy bills. However, these changes in rate plans under which customers will take service necessarily result in some level of bill impacts for the adopting customer, as well as heightened revenue uncertainty for the utility. The Bonbright Principles highlight both of these issues as important rate design considerations. Because the most advanced rates with the greatest potential bill impacts and savings are being offered on an opt-in basis, and the Company is planning to provide education and tools for customers to empower them to choose the best rate for them, bill impacts are generally expected to be favorable on balance for customers (i.e., customers will opt in to more advanced rates with larger bill impacts and savings potential if they are likely to save money). However, that fact means that the Company is also expected to experience revenue erosion from rate switching that may occur, which can negatively impact the Company's opportunity to recover its revenue requirement, and in turn, cause a potential misalignment of the Company's financial incentives with its customers' financial incentives. In order to provide for a smooth transition that maintains a reasonable level of revenue stability, the Company requests authority from the Commission to track changes in revenue that are directly attributable to residential customers optimizing their rate as new options are adopted.

Q. Why are "opt-in" rates particularly prone to causing revenue erosion?

A. This is true for two reasons. First, the rate design changes arising from the 2019 case were designed to be revenue neutral for the class as a whole – i.e., for the average customer. However, most customers are not average – none of them are precisely average. Every customer could naturally be a "winner" or "loser" on a new rate before making a single behavior change in response to the new rate. This is not a bad thing as long as the rate is aligned well with the cost of serving those customers. The bill changes that create the various customer outcomes should generally be moving customers' bills closer to their true cost of service – this is generally a good thing to be sure. But, because the Company is empowering customers to make informed rate choices, using enhanced usage information from AMI meters, adoption should be very asymmetric. Expected "winners" should adopt new rates much more readily, realizing bill savings that reflect the lower cost of serving these customers that generally have more favorable load characteristics. Customers whose rates are likely to increase under the new optional rate structures due to inconsistent loads with peakier usage may simply choose to stay on a flat rate. Therefore, the revenue erosion caused by bill savings of the adopters will not be immediately offset by increases for others. I would note that this revenue shortfall should be made up in a subsequent rate case, so the issue I am addressing is really one of regulatory lag.

The second reason that opt-in rates are prone to causing revenue erosion is that an affirmative choice to go on a new rate structure is much more likely to be made by a customer more engaged in controlling their energy bill. They are, therefore, also more likely to make changes to their lifestyles and energy consuming decisions to further benefit from the rate by lowering their bill. Again, this is a good thing. If it comes to pass, it means that the improved price signal of the TOU rate is working and causing customers to use energy more thoughtfully and efficiently. That should lower system costs over time. However, those lower costs manifest themselves over a period of many years, as needed future investments in generation, transmission, and distribution infrastructure are lower than they otherwise would be. However, the revenue erosion is immediate, with no offset in short-run utility costs. So this revenue erosion is detrimental to the utility's opportunity to recover its revenue requirement. Dr. Faruqui provides some perspectives on the amount of bill savings customers may achieve when managing their usage to reduce costs on the various rate plans.

Q. Can you quantify the potential revenue erosion that Ameren Missouri could experience between rate cases due to residential customer rate migration?

A. Yes. In fact, I used the sample of residential customers that was developed to analyze rate design in depth in the 2019 case. I analyzed a scenario, using some assumptions applied to that residential load research sample, where all customers that, based on their actual historical usage patterns, would have been able to save more than 5% on their electric bill by switching to the Smart Savers rate adopt that rate after they receive an AMI meter. Of the sample customers, 28.9% fell into that category of saving 5% or more. The average savings on the Smart Savers rate for those customers, with no changes in consumption patterns at all in response to the price signal reflected in that rate and which would have potential to significantly increase these customers' savings as discussed by Dr. Faruqui in his direct testimony, were approximately $69.41 per year. Based on the anticipated pattern of the AMI meter rollout and an assumption that the Company would file rate cases every two years and would absorb the regulatory lag in between those cases, I modeled the revenue erosion that the Company would experience from this rate adoption scenario. Table 3 below summarizes the analysis of that scenario.

Table 3 – Regulatory Lag on Revenue Erosion from TOU Adoption Scenario

Year	Estimated AMI Meters @ Year End	TOU Participants	Annual Utility Revenue Erosion
2022	621,263	179,390	-$5,402,901
2023	840,657	242,740	-$8,879,235
2024	1,060,051	306,090	-$5,113,695
2025	1,078,334	311,369	-$5,862,974
2026	1,078,334	311,369	-$1,465,744

While this scenario is not intended to be a forecast of participation, rate case timing, or actual revenue impacts, it is intended to represent a plausible outcome to give a sense of the potential scale of revenue instability that the Company could be faced with as a result of its promotion of modern rates. While the 28.9% adoption may sound high, it is not at all outside the realm of what has been experienced at some utilities. Specifically, Dr. Faruqui's testimony highlights the experience of utilities that have achieved levels of adoption of opt-in time-varying rates near to or exceeding this rate, including Oklahoma Gas & Electric and Arizona Public Service.

Clearly, as this analysis demonstrates, there is potential for the Company to experience significant adverse impacts of customer rate migration as more rate options are offered. In order to truly align the incentives of the Company with empowering customers to choose the best rate for them, a solution to mitigate those impacts is appropriate. The authority to track revenues lost through this migration would clearly create this alignment. I would note that this request is for a two-way tracker. If, for any reason, rate migration results in higher utility revenues, the excess revenues would be returned to customers through this tracker. While on balance, I expect the revenue impact to be negative, there are certainly cases where increased revenues could be realized, and this solution ensures that those revenues would flow back to benefit all customers.

Q. Have the early adopters that already were placed onto or opted into the Smart Savers rate plan illustrated this phenomenon of achieving lower bills than they would have experienced on the standard rate?

A. Yes. While this is obviously an extremely small sample size, it is clear that those early movers are benefitting from their adoption of the Smart Savers rate plan. This is great, and it is exactly what is intended. These customers either have naturally good load profiles with a lower cost of service due to low peak period usage, or have made lifestyle changes to reduce peak usage, or both. Of the eleven customers[17] that have received bills on the Smart Savers rate plan, all eleven have saved money. Of the 25 bills that have been issued for these customers, 24 of those bills have been lower than what the customer would have experienced on the Anytime Users plan.[18]

Q. Are there any other categories of rate switching aside from residential customers taking advantage of new optional TOU rates that you are requesting to have covered by the rate switching tracker?

A. Yes. Company witness Michael Harding describes changes that the Company is proposing to the qualification provisions of Rate 11(M) – Large Primary Service. These provisions are likely to enable certain customers currently taking service on Rate 4(M) to gain access to Rate 11(M) in specific circumstances. Those rate switchers, like the residential customers switching to TOU rates, will create revenue shortfalls for the Company between rate cases that would hinder the Company's ability to cover its revenue requirement. For similar reasons as those discussed above about the residential rate switching, large customers moving to rate 11(M) as a result of this change to the qualification provisions should also be covered by the tracker.

Q. How do you propose to calculate the impact of rate switching in order to track the impacts?

A. Impacts would be calculated for each customer that adopts any of the optional residential TOU rates after the true-up date in this case (Overnight Savers, Smart

[17] A few of the fourteen customers that I mentioned earlier in my testimony as having adopted the Smart Savers rate had not received a bill on the rate plan, because they are on the option to use TOU pricing in the summer only, and they have not yet received a bill for summer service since switching to the rate plan.
[18] The one bill that was higher on the Smart Savers rate plan occurred in a single month, but that customer has saved in other months such that they are still experiencing overall savings.

Savers, and Ultimate Savers), as well as for any non-residential customers currently served on Rate 4(M) that combine meters under the terms described by Mr. Harding in order to access Rate 11(M). Their bill on the new rate they have chosen will be compared to what their bill would have been on the standard residential rate or 4(M) rate, as applicable. Any difference will be accumulated in the tracker for recovery from, or return to, customers in a future rate case.

VIII. INTERACTION OF RESRAM AND THIS DOCKET

Q. How does the RESRAM, which is a rider mechanism that establishes a rate outside of general rate cases like this one, come into play in this case?

A. The RESRAM is designed to help the Company recover costs from, and return benefits to, customers associated with its Renewable Energy Standard ("RES") compliance investments and activities. This rider captures costs and benefits that occur between rate cases to ensure the Company and its customers are made whole with respect to this category of costs and benefits. The RESRAM is designed to be rebased in rate cases where any amount of the RES costs and benefits that were previously reflected in the RESRAM rates get reflected in updated base rates, and/or where any RESRAM eligible costs are reflected in new base rates. Rebasing can include two things: 1) resetting the rate to no longer reflect costs that are now reflected in base rates, and 2) establishing appropriate levels of Factors MBA and RBA,[19] which are required components of the RESRAM rate calculation that represents the amount of RESRAM eligible costs and benefits reflected in current base rates (Factor MBA) and the RESRAM rate (Factor RBA).

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[19] Monthly Base Amount and RESRAM Base Amount, respectively, as defined in the Rider RESRAM tariff sheets.

In this case, there is anticipated to be a substantial level of costs associated with the Company's investments in new wind generation facilities that are reflected in base rates, and which therefore need to be rebased in the RESRAM. The rebasing of Factor MBA in the RESRAM is reflected in the revenue requirement calculated by Company witness Mitchell Lansford.

Q. What complications are there associated with rebasing the RESRAM that you would like to shed additional light on?

A. There is some complicated timing associated with the relationship of the standard RESRAM Rider filings and this rate case. The RESRAM has an annual filing that is required by its terms. That filing occurs right around October 1st and it features a 4-month review period before rates take effect on February 1st. So, between the time this case is filed (March 31, 2021) and when rates take effect from it (expected to be on or before February 28, 2022), the RESRAM rate will be reset through the normal operation of Rider RESRAM. As such, modifications to Rider RESRAM that would otherwise be needed to reflect the necessary rebasing cannot be filed with the other tariff sheet modifications that are initiating this case because, as is typical with rate case filings, we would expect all tariff sheets to be suspended, which would prevent the normal annual RESRAM filing from occurring pursuant to its own schedule. As such, I have attached to my testimony as Schedule SMW-D1, an illustrative RESRAM rate sheet that shows the establishment of a new Factor MBA based on the amount of RESRAM eligible costs and benefits reflected in the revenue requirement in the Company's filed case. When this case is resolved by Commission order, the Company will file the RESRAM rate sheet with an updated Factor MBA, and an adjusted Factor RBA and RESRAM rate as appropriate, consistent with the

Commission's final order in this case as part of the compliance tariffs that will be filed to implement the Commission's order.

Q. What adjustment to the RESRAM rate and Factor RBA will be required in the RESRAM at the time of rebasing the RESRAM at the conclusion of this case?

A. The amounts cannot be known yet. Recall that a new RESRAM rate filing will take place this fall. As of right now, the significant investments the Company recently made in wind generation facilities are not reflected in the RESRAM rate, but they are being tracked in the RESRAM's Factor ROUR.[20] In the anticipated October 2021 RESRAM rate filing, wind-related over- and under-recoveries (as well as amounts associated with other eligible RES costs and benefits) will be reflected in the rate, along with the annual ongoing revenue requirement of the wind generation (and any other appropriate ongoing eligible costs and benefits) as of July 2021, the end of the RESRAM Accumulation Period. Whatever level of ongoing revenue requirement of the wind facilities (or any other eligible ongoing RES costs and benefits) is then reflected in the RESRAM rate and Factor RBA, which is subsequently reflected in the revenue requirement established by the Commission in this case and Factor MBA, will need to be reset to zero in the compliance tariffs that will be filed to implement the Commission's decision in this case.[21]

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[20] ROUR, or "RES Over-Under Recovery," as defined in Rider RESRAM. ROUR is a factor that tracks eligible RES costs and benefits and the extent to which they are over or under the level currently reflected in the RESRAM rate and base rates, and accumulates those over- or under-recoveries to be reflected in a subsequent RESRAM rate.

[21] Should the Commission decide not to include those eligible RES costs and benefits in the revenue requirement in this case for any reason other than imprudence, the RESRAM rate and Factor RBA would not be set to zero, but would continue to reflect the level of eligible costs and benefits originally included in the RESRAM that were not moved to base rates.

Q. Will the RESRAM rate be zero when this rebasing occurs?

A. No. The portion of the rate related to recovery of the ongoing revenue requirement associated with eligible RES activities will become zero (assuming these costs and benefits are reflected in this case's revenue requirement). But the portion of the RESRAM rate that is reflecting historical over- or under-recoveries from the previous Accumulation Period will remain in effect.[22] The compliance tariffs would therefore feature a non-zero rate consistent with the recovery of Factor ROUR from the Accumulation Period ended in July of 2021.

IX. SB 564 RATE CAP

Q. Please describe the rate caps that the Company is operating under as a result of its election to utilize PISA pursuant to Senate Bill 564 as codified in Section 393.1400, RSMo.

A. Ameren Missouri's election of PISA under SB 564 subjects it to a rate cap provision that requires that average rates not increase more than a 2.85% Compound Annual Growth Rate ("CAGR") from a baseline established prior to that election. Further, the Company's large power service classification (Rate 11(M) – Large Primary Service for Ameren Missouri) may not exceed a 2% CAGR from the baseline. The average rate is calculated including all riders except for those arising from energy efficiency programs approved under the Missouri Energy Efficiency Investment Act ("MEEIA"). In the

[22] The Commission approved a variance from its RES rules related to this provision when it authorized the Company to implement its RESRAM tariff. The rules suggest that the rate should go to zero upon rebasing. However, the Commission agreed with the Company's variance request to only set the ongoing revenue requirement portion of the rate to zero, but to leave uninterrupted the recovery of historical over- or under-recoveries under Factor ROUR. See File No. EA-2018-0202

Company's case, the rate subject to the cap therefore includes the Fuel Adjustment Clause ("FAC") and RESRAM.

Q. How is the baseline rate for the rate cap test established?

A. For a utility that was not in the midst of a rate case when the law became effective, like Ameren Missouri, the baseline rate is established based on the rates that took effect from the most recent rate case of the utility at the time of their PISA election. In the Company's case, those rates took effect on April 1, 2017 as a result of File No. ER-2016-0179. The average base rate from that case is determined by dividing the authorized retail revenue requirement from that case by the total annual kWh reflected in the billing units used to establish rates in that case. The average rider rate for that date is also established based on the weighted average FAC rate [23] that was in effect on April 1, 2017.[24]

Per SB 564, the baseline rate must also factor in one-half of the rate reduction that was associated with law's requirement to reflect the reduced income tax expense that arose from the 2017 Tax Cut and Jobs Act ("TCJA"). On August 1, 2018, the Company's rates were reduced consistent with this provision of SB 564. The average rate from the TCJA-related rate reduction is calculated similarly to the average rate resulting from the 2016 rate case. Table 4 below shows the calculation of the baseline average rate, including the 2016 rate case and the TCJA-related rate reduction impacts.

[23] The FAC is a per kWh rate, but is differentiated based on the voltage level at which customers are served. The average rate is based on the weighted average of those differentiated rates, weighted by the kWh billing units associated with the customers that each rate is applicable to.
[24] The RESRAM tariff did not exist in April 2017, so it is not included in the baseline rate calculation. It is picked up in current rate calculations that are compared to the baseline though.

1 **Table 4 – Rate Cap Baseline Calculation**

Baseline Calculation				
		Smart Energy Plan Baseline		**$0.0852**
		Effective Date		4/1/2017
ER-2016-0179				
	Target Revenue	Class kWh	FAC Revenue	Total Revenues w/FAC
Residential	$1,308,982,935	12,812,045,844	$ 15,886,936.85	$ 1,324,869,872.00
Small General Service	$316,514,061	3,314,685,710	$ 4,110,210.28	$ 320,624,271.01
Large General Service	$609,538,433	8,031,106,054	$ 9,958,571.51	$ 619,497,004.51
Small Primary Service	$245,102,971	3,683,300,924	$ 4,419,961.11	$ 249,522,931.68
Large Primary Service*	$215,769,114	3,778,918,417	$ 4,534,702.10	$ 220,303,816.09
Lighting Company Owned	$38,160,833	140,442,436	$ 174,148.62	$ 38,334,981.74
Lighting Customer Owned	$3,935,407	76,147,883	$ 94,423.37	$ 4,029,830.80
MSD	$79,827	680,679	$ -	$ 79,827.13
Total	$2,738,083,581	31,837,327,947	$ 39,178,953.84	$ 2,777,262,534.96
	Average Base Rate	$0.0860	**Average Overall Rate**	**$ 0.0872**
Tax-Reform Docket (ER-2018-0362)				
	Revenue Reduction	Target Revenue	FAC Revenue	Total Revenues w/FAC
Residential	-$79,595,105	$1,229,387,830	$29,595,826	$1,258,983,656
Small General Service	-$19,272,860	$297,241,201	$7,656,924	$304,898,125
Large General Service	-$37,046,737	$572,491,696	$18,551,855	$591,043,551
Small Primary Service	-$14,895,970	$230,207,001	$8,287,427	$238,494,428
Large Primary Service*	-$13,141,909	$202,627,205	$8,502,566	$211,129,771
Lighting Company Owned	-$2,327,399	$35,833,434	$324,422	$36,157,856
Lighting Customer Owned	-$240,063	$3,695,344	$175,902	$3,871,246
MSD	-$4,868	$74,959	$0	$74,959
Total	-$166,524,911	$2,571,558,670	$73,094,922	$2,644,653,592
	Average Base Rate	$0.0808	**Average Overall Rate**	**$0.0831**

The baseline average rate of $0.0852/kWh is the average of the average rate from the 2016 rate case (plus then-current FAC) and the 2018 rate reduction case (plus then-current FAC). This baseline is fixed for the duration of the Company's PISA election, and has been included in identical form to that shown above in the Company's workpapers associated with numerous FAC and RESRAM rider filings in recent years.

Q. How is the baseline rate used to set a cap for rates in this case?

A. The 2.85% CAGR is applied to this baseline average rate, with the growth rate compounded for the number of years that have passed since the rate case that established the starting point of the calculation – File No. ER-2016-0179. Since rates from this case are expected to take effect on or before March 1, 2022, nearly five years will have elapsed. More precisely, 4.92 years will have passed. The 2.85% CAGR compounded for 4.92 years allows for an increase in the average rate of 14.82% from the baseline, or an average rate of $0.0978 per kWh.

Q. If the Commission were to approve the requested increase in this case, what would the average rate be when rates take effect, and would that comply with the cap?

A. Table 5 below shows the calculation of the average rate from this case based on the proposed revenue requirement and billing units reflected in the Company's filing.

Table 5 – Impact of Proposed Increase on Average Rate for Rate Cap Test

Proposed Rates and Revenues (ER-2021-0240) with Currently Effective FAC and RESRAM						
Proposed Billing Units (File No. ER-2021-0240)	Proposed Base Rev. Req. (ER-2021-0240)	Current FAC Rate	Current RESRAM	FAC Revenues	RESRAM Revenues	Total Revenues
13,313,133,980	$1,425,460,637	$0.00026	$0.00017	$3,461,415	$2,263,233	$1,431,185,285
3,078,482,607	$307,060,679	$0.00026	$0.00017	$800,405	$523,342	$308,384,427
7,183,262,987	$567,782,404	$0.00026	$0.00017	$1,867,648	$1,221,155	$570,871,207
3,618,236,498	$246,723,167	$0.00025	$0.00017	$904,559	$615,100	$248,242,826
3,554,828,072	$211,149,463	$0.00025	$0.00017	$888,707	$604,321	$212,642,491
98,570,808	$39,841,904	$0.00026	$0.00017	$25,628	$16,757	$39,884,289
54,388,720	$3,256,954	$0.00026	$0.00017	$14,141	$9,246	$3,280,341
266,910	$83,955	$0.00026	$0.00017	$69	$45	$84,070
30,901,170,582	2,801,359,163			$7,962,574	$5,253,199	$2,814,574,936
Rate per kWh	$0.0907			$0.00026	$0.0002	$0.0911

As Table 5 shows, the average rate of $0.0911/kWh is well below the cap of $0.0978 per kWh. I would note, however, that the FAC and RESRAM rider rates reflected in this calculation are based on those currently in effect. Both rates will be updated prior to rates from this case taking effect. My expectation is that the result of this case, coupled with updated FAC and RESRAM rider rates, will still be well within the rate cap, but we will calculate the rate cap metric again with the result of this case including the updated riders prior to submitting compliance tariffs.

Q. Please discuss the sub-cap applicable to the large primary service class.

A. The mechanics of the calculation are similar to that described above for the overall average rate calculation, except that it only utilizes the revenue and billing unit information related to Rate 11(M). Dividing the total 11(M) revenues from the 2016 case (plus FAC) by the class kWh results in an average rate of $0.0583/kWh. Performing the same exercise for the 2018 tax reform docket results in an average rate of $0.0559/kWh. Averaging the two rates results in a baseline rate of $0.0571/kWh.

Recall that the LPS cap is based on a 2% CAGR. Compounding 2% for 4.92 years results in an allowable increase of 10.23%, or an average rate of $0.0629/kWh. The LPS rate resulting from the filed class revenues and billing units in this case is $0.0598/kWh, which is also under the caps called for by SB 564. This sub-cap will also be recalculated upon conclusion of the case to confirm that final rates remain below the cap.

X. KEEPING CURRENT

Q. Is the Company proposing updates to its Keeping Current program tariff?

A. Yes. In the settlement of a case related to certain tariff changes and rule variances that the Company requested in order to more fully utilize its AMI system (File No. EE-2019-0382), the Company agreed to work with the Keeping Current Collaborative – a group including Staff, the Office of Public Counsel, the Missouri Industrial Energy Consumers, AARP, and the Consumers Council of Missouri - to examine whether its Keeping Cool program should be expanded beyond the June to August period, to include the months May and/or September.

Q. Did the Company engage with those parties to review the topic?

A. Yes. The collective recommended the expansion of the program to include the additional months of May and September. The Company's Keeping Current tariff, as of the filing of this case, currently has a change pending, which will become effective April 1, 2021 – one day after this case is filed. Because a new change to the Keeping Current tariff cannot be filed with this case with the other pending change still in play, I have reflected the proposed tariff changes in an illustrative tariff sheet, which is attached to my testimony as Schedule SMW-2. After the Keeping Current tariff takes effect on April 1, the Company will file the proposed Keeping Current tariff in this case file also.

Q. Does this conclude your direct testimony?

A. Yes, it does.

RIDER RESRAM

RENEWABLE ENERGY STANDARD RATE ADJUSTMENT MECHANISM

RESRAM Rate Schedule

Accumulation Period Ending: 07/31/21

1.	Actual RES Costs Incurred in AP (ARC)		$xxxx
2.	RES Expenses Recovered in AP (RCR) =(RBA + sum of monthly MBAs)	=	$xxxx
3.	RES Over/Under Recovery (ROUR)=	=	$xxxx
	3.1 Interest	+	$xxxx
	3.2 (Over)/Under Recovered Costs (ARC-RCR)	+	$xxxx
4.	RES Revenue Requirement (RRR)	+	$0
5.	True-Up (T)	+	$xxxx
6.	Ordered Adjustment (OA)	±	$0
7.	Total RESRAM Recoveries(TRR)=(ROUR+RRR+T+OA)	=	$xxxx
8.	Estimated Recovery Period Sales (S_{RP})	÷	xx,xxx,xxx,xxx kWh
9.	TRR_{RATE} = MIN of((TRR/S_{RP}),(RAC))	=	$0.0xxxx/kWh
10.	$RESRAM_{RATE}$ = TRR_{RATE} + ROA[1]	=	$0.0xxxx/kWh
11.	Required Offset Amount (ROA)	**+**	$0.00000/kWh
12.	**$RESRAM_{RATE}$ (applicable for the first 6 months if ROA is greater than $0.00000)**	**=**	**$0.0xxxx/kWh**

*A negative RESRAM Rate represents a per kWh credit that would be applied to a customer's bill.

Recovery Period for Above RESRAM Rate
February 1, 2021 to January 31, 2022

Current RBA = 0

Base Amount File No. ER-2021-0240 = $64,610,313

[1] If ROA is equal $0.00000, The $RESRAM_{RATE}$ stated in this Line 10 shall apply for the entire Recovery Period. If ROA is greater than $0.00000, the $RESRAM_{RATE}$ shall be the value shown on line 12 for the first 6 months and, thereafter, the value shown on Line 10.

PILOTS, VARIANCES, AND PROMOTIONAL PRACTICES
D. KEEPING CURRENT LOW-INCOME PILOT PROGRAM (Cont'd.)

* **KEEPING COOL BILL CREDITS**

Participant's Monthly Cooling Bill Credit(May-September)	
0-100% FPL	$25.00
101%-150% FPL	$25.00

Participants may not receive Keeping Cool Bill Credits concurrently with Electric Heating Bill Credits, Non-Electric Heating Bill Credits, or Arrearage Bill Credits.

* **ADMINISTRATION, REPORTING AND EVALUATION**

Program administration, reporting and evaluation will be conducted consistent with the terms of the Stipulation and Agreement Regarding Ameren Missouri's Keeping Current Program in Case No. ER-2012-0166 and the terms of the Unanimous Stipulation and Agreement in Case No. ER-2016-0179 or as modified by the Collaborative and approved by the MoPSC.

*Indicates Change.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

AFFIDAVIT OF STEVEN M. WILLS

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

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

My name is Steven M. Wills, and on his oath declare that he is of sound mind and lawful age; that he has prepared the foregoing *Direct 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 30th day of March, 2021.