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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2019-0335

DIRECT TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
July 2019

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DIRECT TESTIMONY

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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 Midcontinent Independent System Operator, Inc.'s ("MISO") 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. The purpose of my direct testimony is to provide an overview of, and describe key considerations guiding, the Company's proposals related to the development of customer rates in this case. I will discuss the macro level industry trends and Company-specific considerations, including new metering capabilities that are part of our Smart

Energy Plan, that are driving the need to modernize and enabling the modernization of the Company's residential rate structure, and I will discuss the specifics of the Company's proposal in this case and its vision of the future for accomplishing this goal. Company witness Dr. Ahmad Faruqui, a principal with the Brattle Group, will further expound on this topic. My testimony will present detailed analysis of the cost of service of residential customers to demonstrate why the Company's proposed rate structure, including new rate offerings proposed in this case as well as the vision of future rate offerings, achieve many well-established goals of sound utility rate design.

I will also testify regarding a number of other issues, including a request for a rate switching revenue tracker to alleviate cost recovery concerns as the Company encourages customers to adopt new rate offerings, and a discussion of the Company's activities undertaken to comply with certain provisions of the Stipulation and Agreement in its last general rate case, File No. ER-2016-0179 ("2016 Stipulation")

Q. Please provide an overview of the witnesses that support the Company's class cost of service and rate design proposals, including the areas of responsibility for each witness.

A. Company witness Thomas Hickman will introduce and describe the Company's Class Cost of Service Study ("CCOSS"). This study is the foundation for all of the Company's recommendations related to class revenue allocations and rate design. Company witness Michael Harding will utilize the results of that study to recommend allocation of the overall revenue requirement into class specific revenue responsibilities. Using these revenue responsibilities, he will present detailed billing units by class and develop the rates that the Company proposes be adopted in this proceeding for most of the

Company's rate classes. The exceptions include the lighting classes, whose rate designs are supported by Company witness Ryan Ryterski, and the residential class rates, which I will be discussing in depth. Finally, Dr. Faruqui will testify regarding industry trends in residential rate design and will present his expert opinion on the need for residential tariff reforms. He discusses how many other utilities and state commissions have addressed this topic based on his broad experience with the issue. Dr. Faruqui has had extensive involvement in this topic across the country and internationally and is a frequently cited author and speaker on the topic.

III. Executive Summary

Q. Please provide an overview of your comments, analysis, and recommendations in this case.

A. Technological advancement in the energy industry is occurring at a rapid pace. Customers today have opportunities to change the way they consume electricity and interact with the grid by adopting Solar PV, EV's, batteries, and many other emerging technologies. Many of these technologies are becoming far more economic, and therefore more realistic choices, than ever before in history. As customers make significant investment decisions regarding implementation of energy-related technologies, they can both impose costs and create benefits that impact all of the other customers with whom they share the use of the grid. This reality is creating a significant need to modernize residential rate structures. Traditional residential rate structures do not reflect the cost structure of electricity in enough detail to ensure economically efficient price signals are sent to customers considering such investments. The result is that customers' bills may not reflect all of the costs or benefits caused by those customers, and inequitable outcomes can occur between customers. Ameren Missouri has engaged in significant research and analysis of a variety of possible rate structures in order to facilitate understanding of the types of rates that are being employed in the utility industry and the strengths and weaknesses of each. Our research in preparation of this case has involved support from Dr. Faruqui, a leading expert on the topic.

Q. Please describe the rates that you have studied and the types of analyses you have performed.

A. We have analyzed five candidate rate structures, each of which is described below:

- Status Quo – Based on the Company's current two part rate with a monthly fixed charge and a seasonal energy charge, featuring a declining block in the non-summer period
- Cost Based Two Part Rate – Similar to the status quo, but the customer charge increased to match the full customer-related costs from the cost of service study
- TOU Energy Rate – A two part rate (customer & energy charge) with time varying energy prices designed to reflect the cost structure of the grid
- Inclining Block Rate – A two part rate (customer & energy charge) with a summer inclining block and a non-summer flat energy charge.
- 3 Part Rate with Demand Charge – A three part rate with a customer, demand, and time varying energy charge

For each of these candidate rate structures, we have analyzed the bills customers would experience under that structure, and compared it to the cost of serving that customer. Summarizing the bill impacts these customers would experience on each candidate structure relative to the cost of serving them provides many insights into the effectiveness of price signals and the equity promoted by these rates.

Q. Please summarize your findings.

A. There is a very clear continuum, quantitatively demonstrated, where, as the rates are increasingly grounded in cost of service analysis, they improve in performance with respect to the equity and economic efficiency they promote. The ranking of the candidate rate structures across the metrics calculated in my analysis, from the most equitable and economically efficient rate, to the least, is as follows:

1. 3 Part Rate with Demand Charge
2. Time of Use ("TOU") Energy Charge
3. Cost Based Two Part Rate
4. Status Quo
5. Inclining Block Rate

It is notable in the analysis that the price signal associated with the 3 part rate is significantly better than any other rate, and that the equity associated with the Inclining Block Rate is far worse than any other rate.

Q. Based on this analysis, what is the Company's recommendation in this case with respect to residential rate design?

A. The Company recommends beginning a gradual transition, a journey if you will, to modernize its rate structure. The specific details of the recommendation in this case are:

- A default rate similar to the status quo, but with a $2 increase in the monthly customer charge to better reflect the cost of serving customers

- Implementation of two new TOU rate options, including:
  - A rate focused on EV drivers, encouraging them to charge their vehicles overnight when there is plenty of excess capacity on the system
  - A rate focused on engaged customers who are willing to manage their whole home energy usage in order to reduce their bills along with their impact on the grid during peak usage times
- A pilot study of 3 part rates to understand how well customers understand, accept, and respond to them
- A continued dialogue over the next few rate proceedings to continue to progress to the point where the Company provides its customers with a variety of cost reflective rate options that meet customers' needs and desires for increased choice and control

IV. The Landscape for Evaluation of Rate Designs

Q. Please provide some overarching comments on the importance of rate design at this point in time due to the technological changes being experienced during this period of the energy industry's evolution.

A. We are in a dynamic period in the evolution of energy systems used to serve the needs of our communities. The pace of innovation of energy-related technologies, many of which are impacting the electric system from the customer side of the meter, is rapid, continual and unavoidable. From distributed solar generation (solar photovoltaics, or "Solar PV"), to the proliferation of electric vehicles ("EVs"), efficient electrification of other end uses, battery storage of electricity, gains in efficiency of many electric end uses, and home energy management protocols interacting with smart appliances and thermostats, the scope and scale of changes to the demand served by centralized power systems is vast. Even the role of the distribution system itself is changing, i.e., from just serving load to allowing for customers to provide energy to the grid and provide and receive load versus generation balancing services to and from the grid. This paradigm change impacts the relationship of the cost of serving different groups of customers and the recovery of revenues from them, depending on the technologies each has adopted and deployed.

The grid is also becoming cleaner, with significant investments being made in renewable generation resources, both by the Company and its customers. This is good news for our local communities and the environment, and Ameren Missouri's commitment to making continued progress on this front is strong, as evidenced by several announced large scale renewable energy projects and voluntary renewable program offerings the Company has undertaken. However, the intermittency of renewable resources is something that the Company also must prepare for, as reliability is of paramount importance to our customers. As larger amounts of the energy on the grid are derived from these clean but intermittent renewable resources, the Company must make sure that the right tools are available to continuously and instantaneously balance load with electric supply. These tools of course include the Company's existing dispatchable energy centers, but will increasingly have the potential to include energy storage solutions and, importantly for this discussion, more load flexibility. The ability to shape load – i.e., the utility's ability to encourage customer usage patterns that help match demand with the available supply – will be an important capability in the future.

Ameren Missouri's recommendations regarding its residential rate structure in this case are designed to move toward efficient pricing of the grid in order to allow the technologies I mentioned above to compete on a level playing field, and to ensure they are integrated in a manner that reflects both the costs and benefits they bring to the system. Further, the new rate offerings proposed herein are designed to begin to build the flexibility necessary to shape load to supply and help with the integration of more clean renewables as they enter the grid. One rate case is not sufficient to make all of the changes that ultimately will be needed, but this case is a necessary step towards the goal of efficient pricing.

Q. Please discuss the benefits of efficient electrification that should be given consideration in the ratemaking process.

A. The Commission recently heard Ameren Missouri's "Charge Ahead" case in File No. ET-2018-0132. In that proceeding, the benefits of efficient electrification, including transportation electrification in the form of broad adoption of EVs, were discussed at length, and the Findings of Fact in the Commission's Report and Order establish that the Commission is keenly interested in promoting and accelerating these benefits. Efficient electrification is really the next step in energy efficiency beyond the *electric* energy efficiency that has been successfully promoted for several years through programs approved under the Missouri Energy Efficiency Investment Act ("MEEIA"). Efficient electrification has the same focus on reducing energy consumption, costs, and related emissions, but does so by considering reductions in usage of other fuel sources, such as gasoline and propane. As I discussed in the Charge Ahead case, the benefits of efficient electrification can include:

- More efficient utilization of the electric grid that can result in *lower electric rates for all customers* by spreading the fixed costs of the system over more usage;
- *Reduced total energy use and costs* across fuels for participating customers to achieve the same level of end use service;
- Reduced emissions resulting in local and broader *air quality and environmental improvements*;
- *Lower operations and maintenance expenses* for customers adopting electric technologies;
- *Increased consumer choice* and greater practical access to an increasingly robust suite of innovative product offerings; and
- *Improved safety and productivity* in workplaces.

The adoption and application of rate designs that will be considered in this case can have significant effects on the economics of customers' decisions related to efficient electrification. It is important to keep these effects at the top of mind in order to ensure that rate structures support such beneficial choices when it is cost effective and consistent with other rate design objectives for them to do so.

Q. How does new technology that is being deployed by utilities impact the rate design discussion?

A. Just as adoption of technology by customers is evolving, so is that which is being deployed by utilities. Ameren Missouri recently announced its Smart Energy Plan, which details the significant investments the Company is making in grid modernization. Company witnesses Warren Wood testifies in more detail about this plan, which includes numerous categories of investments – many of which provide upgraded "smart" technologies relative to existing infrastructure used to serve customers - that will provide a broad array of customer benefits. Most relevant to the discussion of rate design is the planned deployment of Advanced Metering Infrastructure ("AMI") meters as a part of the Smart Energy Plan. AMI meters provide the utility with more timely and granular data regarding customer usage patterns, and also allow for two-way communications, whereby the utility can send information to the meter in addition to receiving information (such as meter readings) from it. This creates the potential for the utility to securely communicate with smart devices (e.g., thermostats, EV charging stations, appliances). The increased timeliness and granularity of data and two-way communications capabilities of smart meters enhance the availability and effectiveness of new rate offerings in a number of ways:

- AMI meters can facilitate the utility's ability to bill more complex rates, as the meters do not need to be changed out or reprogrammed to accommodate different TOU periods or to capture other potential billing components.[1]
- AMI data can facilitate analysis of the impact that adoption of different rate structures would have on individual customer bills, enabling more informed customer decision-making regarding the best rate option for them.
- AMI data will allow the Company to present customers with more detailed and timely usage information, providing insights regarding new and different ways that customers may be able to change energy consuming habits to manage their bills and respond to new time varying rate structures.

[1] AMI provides this capability, but for the Company to utilize it to its fullest effect, a variance from certain Commission rules related to billing practices is required. Ameren Missouri will be filing for the appropriate rule variances under a separate pleading, but implementation of some of the rate designs I propose in this case is contingent upon approval of this variance.

- Smart devices (thermostats, EV chargers, appliances) may be able to receive signals from meters related to prices or demand response events that could be used to automate load shifting to benefit the system and reduce customers' bills.

Additional benefits of AMI not related to rate design include improved outage detection and notification, voltage monitoring capabilities, remote connections and disconnections of service, improved meter data integrity, revenue protection through detection of theft of service, and other benefits that may arise from the increased amount, quality, and timeliness of data gathered by the meters.

Q. Please provide a high level overview of the expected deployment of AMI meters under the Smart Energy Plan.

A. During 2019 and the early part of 2020, the IT infrastructure to support and utilize the AMI network is being developed. The first meter is currently expected to be set in July 2020, approximately one month after the operation of law date in this case. The deployment of the approximately 1.3 million AMI electric meters will then take place over a period of years from 2020 through 2025. All of Ameren Missouri's customers (other than any who choose to opt out of the program) should have smart meters at the end of that time period. Because some customers will have AMI meters within a very short period of time from the end of this proceeding, the Company is proposing new rate options in this case to be available for customers once their new meter is set. Approval of new rate structures in this case will ensure that customer benefits and choice are enabled by the AMI program as quickly as possible—and are available as soon as the first AMI meter is installed.

V. Residential Class Rate Design

Q. Please discuss generally the Company's vision related to residential rate design given the context you provided in the section of testimony above.

A. My introductory discussion of the rapid technological evolution taking place in the energy industry, along with discussion of the need to modernize residential rate structures found in Dr. Faruqui's direct testimony, lays the foundation for the Company's residential rate design proposals in this case, and for its vision of the future. It is simply a fact that customers today have more options than ever when it comes to meeting their energy service needs, and their expectations of their utilities to give them the choice and control to take advantage of those options are rising. This trend will only continue to increase with time. Dr. Faruqui describes how utilities across the country and indeed across the globe are modernizing their tariff structures to achieve these goals of increased customer choice and control. Similarly, Ameren Missouri is proposing in this case to embark on a journey to modernize its residential rates. Dr. Faruqui describes the differing needs of different types of customers and how replacing a static, one-size-fits-all rate with a variety of sound, cost-based rate offerings can provide options to meet those customers' individual preferences. The Company proposes to introduce two new TOU rate options for its residential customers in this case, plus an additional pilot study of a three part rate including a demand charge as a beginning to this journey. These are, however, but first steps on that journey. Ultimately, as AMI is fully rolled out and the pilot I recommend in this case progresses, the Company envisions the development of a variety of rate options to meet the differing needs of its customers - some of which provide greater opportunities for engaged customers to manage their energy usage in order to control their bills, and others which provide more certainty and stability in customer energy costs. The rate offerings presented in this case and in our vision of the future are designed with different customer needs in mind, and are all intended to be grounded in sound rate design principles.

Q. What are those principles that the Company's rate designs are grounded in, generally?

A. First and foremost the Company strives to implement rate structures that are equitable to customers and provide appropriate price signals to encourage economically efficient outcomes. These are two of several well-established principles that are generally agreed to be important considerations in designing utility rates. The equity objective dictates that costs are reflected in rates to the customers who cause those costs – if this objective were perfectly achieved, each customer would essentially pay for the prudent costs incurred by the Company that are attributable the provision of their service. The economic efficiency objective dictates that rates, to the extent possible, provide price signals to encourage customer behaviors and decisions that minimize the total costs incurred on the system to achieve a given level of end use services that customers value.

As I just mentioned, there are other well-established rate design objectives which the Company is very cognizant of in developing its rate designs as well, including: customer bill stability, utility revenue stability, and customer understandability, among others. Dr. Faruqui summarizes these "Bonbright Principles" of rate design in his direct testimony. These are all important objectives in their own right and the Company has attempted to balance these sometimes competing objectives appropriately as I will discuss throughout the remainder of this section of my testimony.

Q. Please discuss the importance of the first two objectives – equity and economic efficiency – in light of the evolving technologies on the customer side of the meter that you mentioned previously.

A. Each category of technology on the customer side of the meter that I discussed – e.g., Solar PV or EVs, etc. – has a unique set of attributes that, when connected to the system, have the potential to both impose new costs on and provide new benefits to the grid. Customers are beginning to make, and will be making in increasing numbers, individual investment decisions to commit sometimes significant personal funds to adopt and deploy these technologies. Each time they make such a decision, the new technology that is deployed will provide and/or impose those new benefits and costs to or on the grid. In order for those customer decisions to be as economically efficient as possible, it is important that the change in the adopting customer's bill that results from the newly implemented technology reflects those changes in the electric utility's cost of serving that customer (i.e., that rates send an economically efficient price signal). Otherwise the customer who is deciding whether to adopt a new technology does not have an incentive that is aligned with the goal of minimizing total system costs given the desired level of service. If the adopting customers are not exposed to the cost they have caused (or do not share in the benefit they could be creating), they may make uneconomic decisions from the perspective of the overall grid, but with little personal consequence. The cumulative effect of large numbers of such decisions made by many customers over time, however, may have meaningful consequences on the customers who may become responsible for providing subsidies that can result from potentially uneconomic choices, the consequences of which are not absorbed by the customer making them. Having rates that reflect cost essentially aligns the interest of individual customers considering these types of investments with all of the other customers with whom they share use of the grid. I will provide specific examples of this later in the discussion of my residential rate analysis in this section of testimony.

Q. Have jurisdictions with large Solar PV adoption rates struggled with this issue?

A. Yes, a number of states have had experiences that demonstrate that it is better to address the price signal issue early than to try to make a change in rate designs and related policies after many thousands of customers have relied upon opaque subsidies embedded in rate design to make significant personal investments. Most recently, the Arizona Corporation Commission has begun both a phase out of net metering policies and approved significant changes to residential rate structures in order to align customer outcomes with cost principles. This type of change has also played out or is playing out, sometimes with significant drama resulting from potential rate design changes coming after many customers made investments based on incumbent rate structures that did not appropriately reflect the costs and benefits of those investments, in states such as California, Hawaii, Idaho, Kansas, Massachusetts, Montana, and Nevada. At the end of the day, even states with significant renewable energy goals that Solar PV can help meet are largely making rate design changes that suggest that hidden subsidies buried in rate design are not the best ways of advancing cost effective renewable deployments.

Q. Given the heightened importance of equitable and economically efficient rates given the technological innovation impacting the electric industry, can

you please describe the considerations that go into developing a cost basis for such rates?

A. Yes. Truly cost based rates can only developed with the aid of a detailed CCOSS. Mr. 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. The results of this study are used by Mr. Harding in the allocation of revenues to customer classes. This process is used to make sure that there are no undue inter-class subsidies and that each customer class produces revenues generally sufficient to cover its cost of service.

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. For example, 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.

Q. Please describe demand-related costs.

A. The remaining costs of the distribution system, as well as the majority of the fixed costs of transmission and generation, are typically classified as demand-related. Demand-related costs are those associated with investments made in and activities performed on portions of the system that serve multiple customers, which may be sized and configured relative to the aggregate demand on the relevant part of the system. There are multiple types of demand data analyzed (Coincident Peak or "CP," Non-Coincident Peak or "NCP," and individual customer peaks (that are sometimes referred to as "Sigma NCP")), that are used to allocate the costs of assets that are located at different points on the system, depending on how many customers and customer classes use that asset simultaneously, and hence drive the need for its sizing or capacity.

Q. Please describe energy-related costs.

A. Energy-related costs are those costs that vary in direct proportion with kilowatt-hour ("kWh") consumption of customers. For electric utilities, energy-related costs are generally associated with the production function (fuel and purchased power, variable O&M, and the like). The Company has also classified certain MISO transmission expenses as energy-related due to the fact that MISO allocates these costs to market participants on a load ratio share (energy) basis.

Q. How do these cost classifications help ensure equitable allocation of the revenue requirement to various customer classes?

A. The classification process discussed above is generally used to allocate the revenue requirement to the various customer classes. Use of appropriate allocation factors ensures that, for example, a class that places greater demand on the system pays rates that reflect a higher proportion of demand-related costs than a class with relatively lower demand. Similarly, energy-related fuel and purchased power costs are allocated most heavily to those classes that consume the most energy. This practice helps ensure the revenue requirement that is allocated to each class is reasonably consistent with the costs incurred to serve that class.

The upshot of this is that customer classes with better load factors generally pay a lower realized rate (i.e. the total bill irrespective of the charge types that create it, divided by the kWh consumed, or cost per kWh).[2] This phenomenon is consistent with the fact that load factor is a reflection of how efficiently a customer uses infrastructure. High load factor customers that are more efficient in their use of infrastructure are able to spread the fixed costs of that infrastructure across more units of consumption to drive the average realized rate down. For example, the average realized rate for the Large General Service ("LGS") class from the outcome of Ameren Missouri's last electric rate case was 7.6 cents per kWh versus a residential realized rate of 10.2 cents/kWh. Because both classes take service at the same voltage level on the system, by far the biggest factor that is responsible for the difference in the realized rates between them is their load factor – i.e., how efficiently they use the system and therefore how many kWhs the customer- and demand-related costs are spread out over. Figures 1 and 2 on the following page show the weather normalized hourly loads for the test year for the LGS and residential classes respectively.

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[2] The load factor is defined as the ratio of a customer's or customer class' average demand to the maximum demand they place on the system. This metric is a useful way to characterize how fully a customer (or customer class) uses the infrastructure dedicated to the provision of their service.

Figure 1 – Large General Service Hourly Load

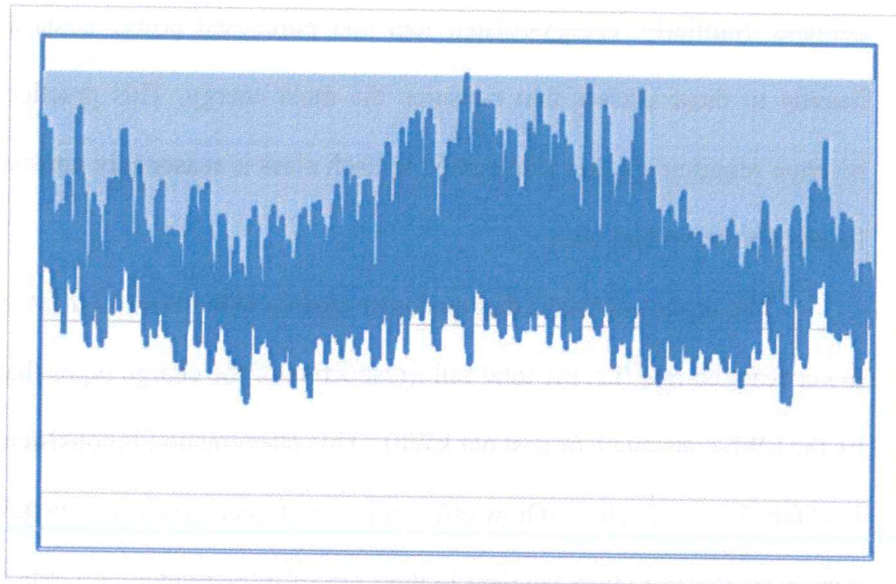
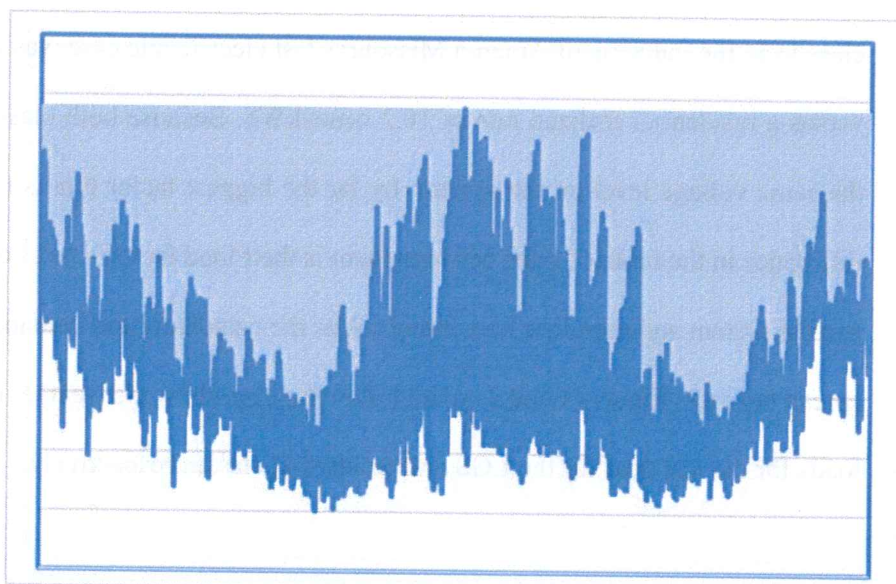


Figure 2 – Residential Hourly Load



If a component of infrastructure is sized to meet the class's maximum demand, any hour that the class load is lower than that level can generally be thought of as an hour where the infrastructure in question is under-utilized, which drives up the realized rate for the class. The blue shaded areas on the above figures represents that under-utilization of infrastructure. The LGS class load factor is 57% versus the residential load factor of 42%. This difference, apparent both visually in the graphics above and in the calculated class statistics, demonstrates the primary reason why the residential class has a higher average rate than the LGS class.[3] Under a cost reflective rate design, a similar phenomenon should be observed when comparing the average realized rates experienced by different individual customers, dependent upon their load factors – i.e., the efficiency with which each customer uses the system. I will return to this point later when discussing my analysis of residential customers.

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, 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

[3] The ratio of the class load factors (57% / 42% = 1.36) is extremely close to the ratio of the realized rates for the class (10.2 cents/kWh / 7.6 cents/kWh = 1.34), suggesting that the difference in load factor almost entirely accounts for the difference in the rates realized by these classes. It is evident from this observation that more efficient utilization of the grid has a powerful impact on lowering realized rates.

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, customers with high load factors, which tend to use the system more efficiently and therefore cause less idle capacity, tend to pay lower realized per unit rates than customers with low load factors. Similarly, very low load factor customers, which cause significant idle capacity even on the very local infrastructure used to serve them (i.e. service lines and transformers, etc.), pay higher realized rates than high load factor users. This is because fixed customer- and demand-related costs that are attributable to the individual and their contribution to peak demand are spread over fewer kWh of usage – i.e., if you need to collect a fixed amount of cost from a customer and the usage that is the denominator of the rate calculation is low, the rate necessarily goes up. In general, while there are still a considerable number of details to consider 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. How well does the Company's existing residential rate design reflect the cost of serving customers?

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

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

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

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

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

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

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

Table 1 below:

Table 1: Candidate Rate Designs Analyzed

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

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

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

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

Table 2 – Mapping of Cost Categories to Rate Elements

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

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

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

Table 3 – Candidate Rates for Analysis

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

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

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

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

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

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

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

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

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

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

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

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

Figure 3 – Distribution of Bill Impacts for Inclining Block Rate

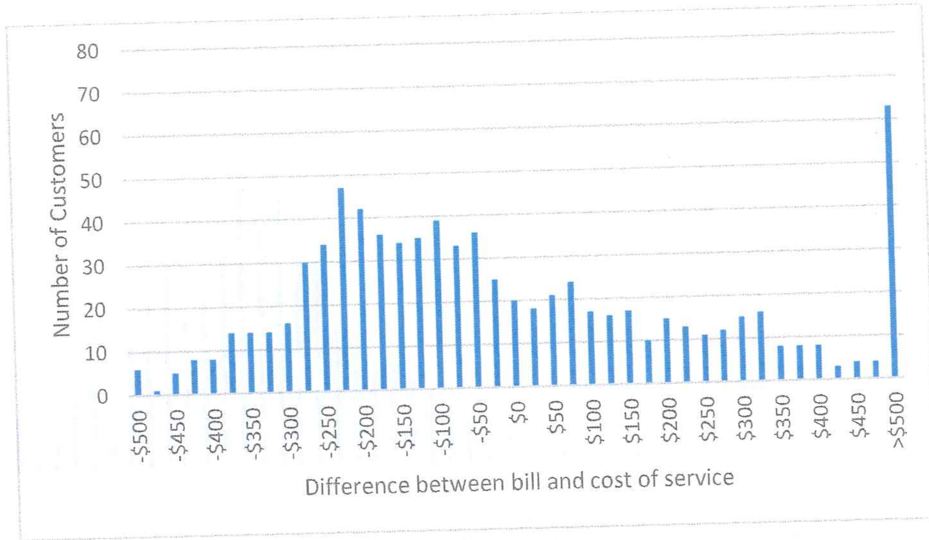


Figure 4 – Distribution of Bill Impacts for Status Quo Rate

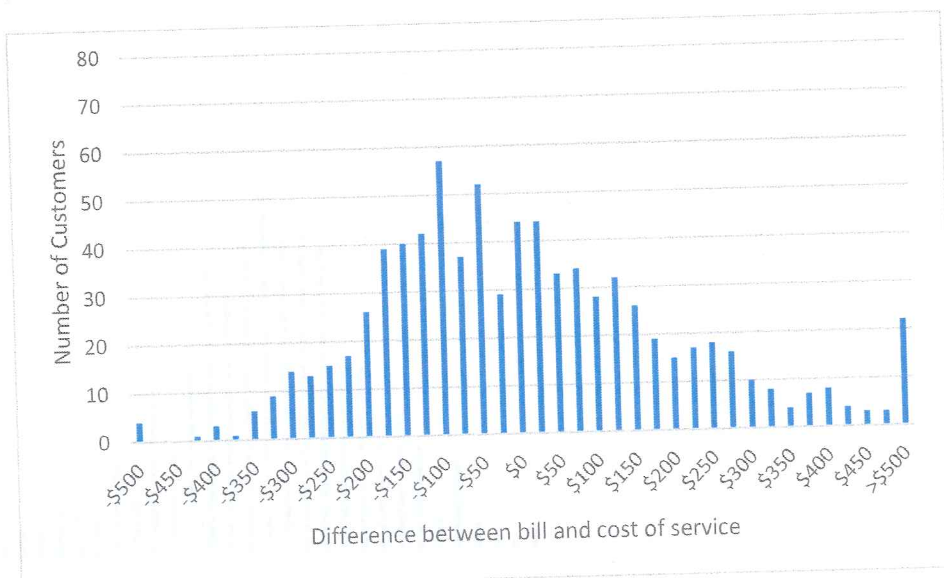


Figure 5 – Distribution of Bill Impacts for Cost Based Two-Part Rate

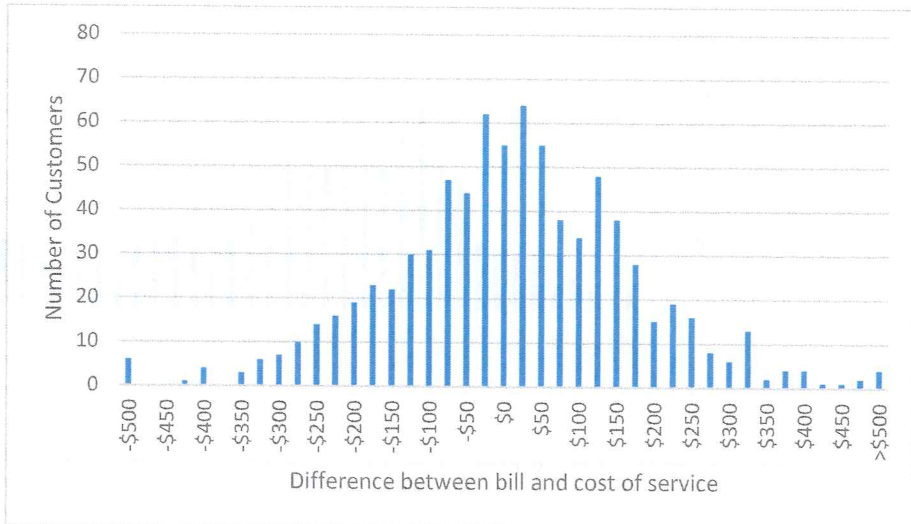


Figure 6 – Distribution of Bill Impacts for TOU Energy Rate

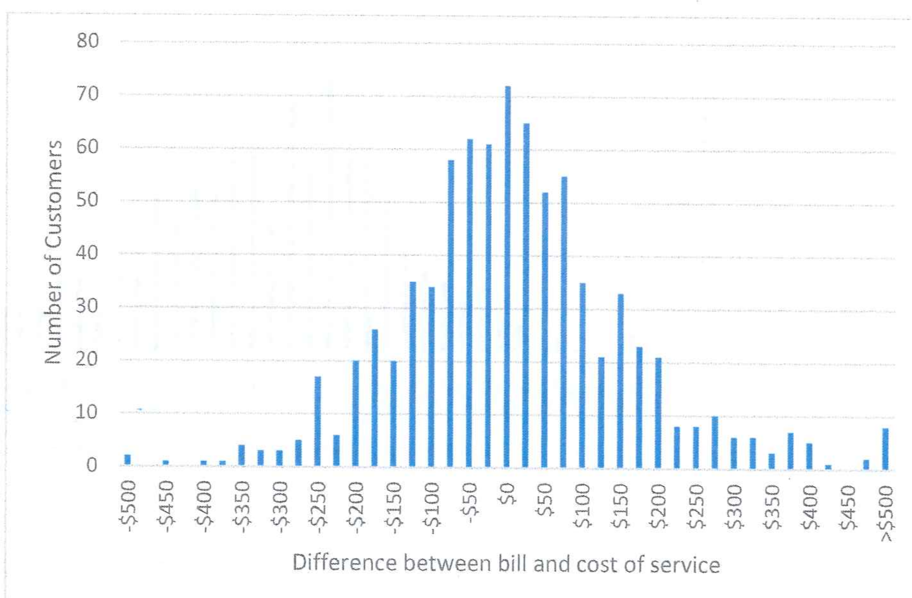
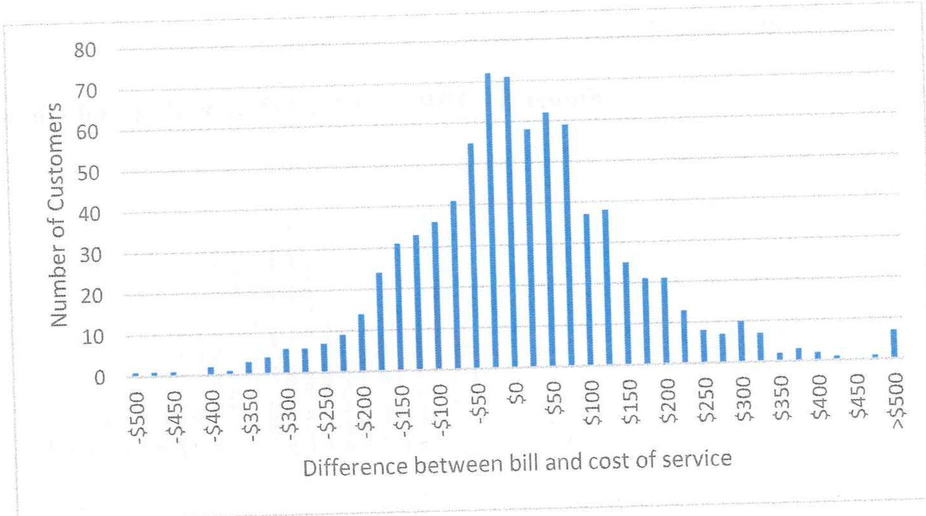


Figure 7 – Distribution of Bill Impacts for 3 Part Rate w/Demand Charge

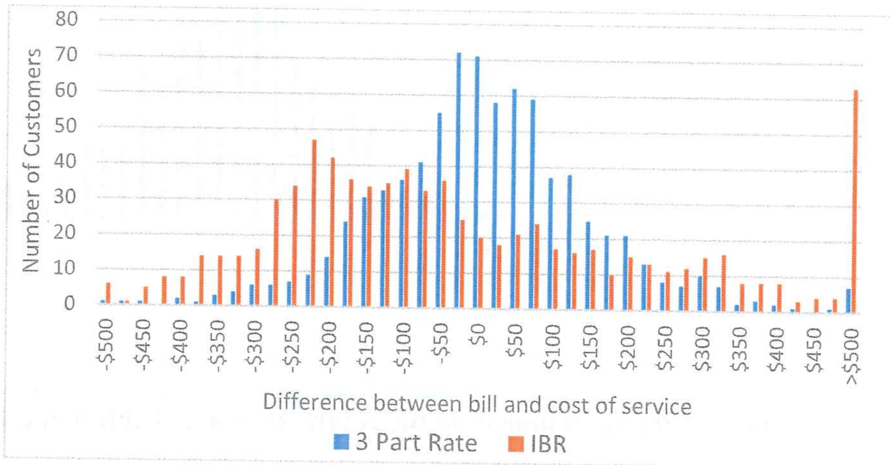


Q. Please comment on the results shown in Table 4 and Figures 3-7.

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

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

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



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

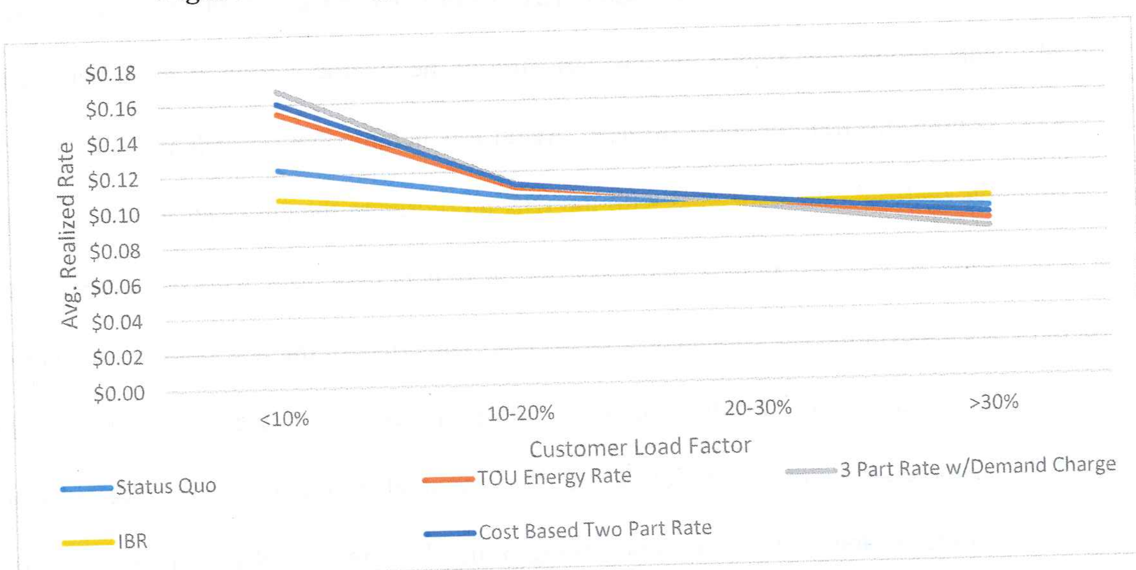
Q. You mentioned previously the concept that customer classes with better load factors that use infrastructure more efficiently tend to pay lower realized rates per kWh than those with poorer load factors who cause significant underutilized infrastructure. You suggested that under a cost based rate design,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

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

Table 5 – Average Realized Rate by Customer Load Factor

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

Figure 9 – Average Realized Rate by Customer Load Factor



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

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

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

Q. Please describe that analysis.

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

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

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

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

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

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

[9] With charging taking place in a manner that is consistent with the pattern reflected in the control group load shape reflected in Figure 11 below.
[10] Based on capacity factor and generation pattern data observed at Company Solar PV installations.
[11] For this analysis I assume the battery is charged in the late morning/early afternoon when solar irradiance is generally abundant, and is discharged in the late afternoon or early evening when load is still high but solar irradiance is in sharp decline.

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

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

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

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

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

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

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

Q. What conclusions do you draw from these results?

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

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

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

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

TOU RATES

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

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

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

EV SAVERS RATE

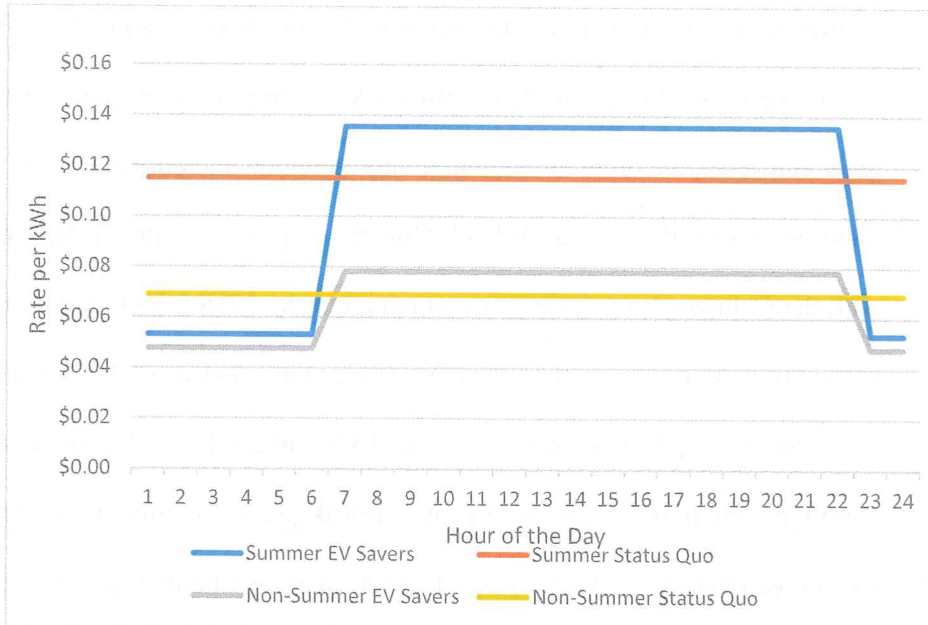
Q. Please describe the Company's "EV Savers" Time of Use rate proposal.

A. As one new optional rate offering for residential customers, the Company is proposing a Time of Use rate option that is designed to appeal to EV drivers and to encourage those drivers to charge their EVs overnight when demand on the system is generally lower in order to minimize any potential incremental costs and investments incurred to serve the related EV load. This rate proposal was also crafted in order to comply with the Company's commitments contained in the 2016 Stipulation described above. As such, this rate is designed to be compatible with, and available on an opt-in basis to customers using, the Company's existing AMR meters. It will feature an option with TOU variation year round based on a peak/off-peak period definition selected to specifically encourage overnight EV charging. The rate will also be available to customers that are converted to AMI metering at any time in the future. The proposed EV Savers rate structure is presented in Table 7 below and is graphically depicted in Figure 10 on the following page:

Table 7 – EV Savers Rate Structure

	Summer	Non-summer
Customer Charge - Monthly	$11.00	$11.00
Incremental AMR Charge - Monthly	$1.50	$1.50
On-peak energy charge	$0.1355	$0.0782
Off-peak energy charge	$0.0539	$0.0477
On-peak hours	6 a.m. to 10 p.m. daily	6 a.m. to 10 p.m. daily
Off-peak hours	10 p.m. to 6 a.m. daily	10 p.m. to 6 a.m. daily

Figure 10 – EV Savers Rate Structure[13]



Q. Please describe the analysis and rationale underlying the proposed rate structure illustrated in Table 7 and Figure 10.

A. Both the analysis and rationale supporting this rate structure are grounded in concepts explored in the Charge Ahead case. In that proceeding, the Company analyzed the economic value of each new EV to the system by evaluating the likely incremental revenues and costs that would arise from serving each EV. In that case, the goal of the analysis was to determine how much investment the Company could make in the form of incentive payments to third parties who install EV charging infrastructure based on value derived on the system from the EVs that would make use of, and in many cases be purchased partially as a result of the existence of, the infrastructure. In this case, I am repurposing that analytical framework to determine the amount of *additional* value each

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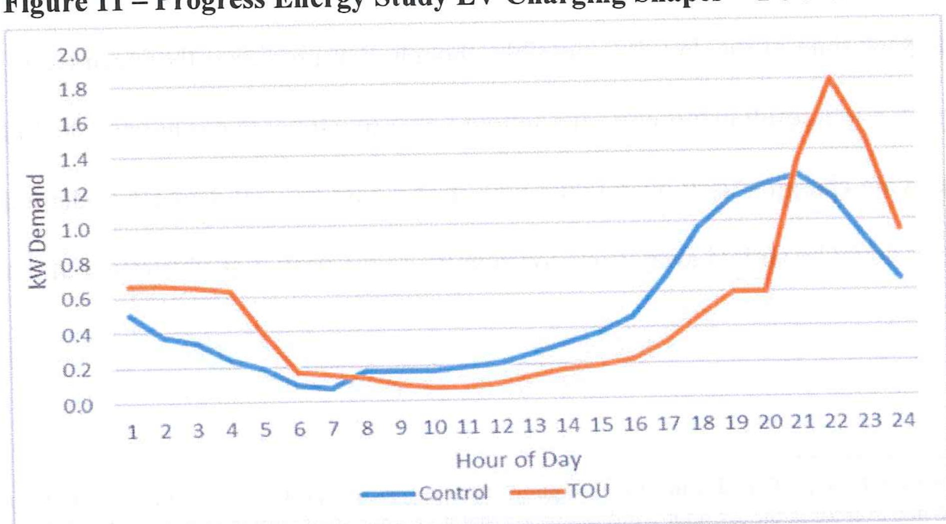
[13] The non-summer rate Status Quo reflected in Figure 10 is a weighted average of the Block 1 and Block 2 energy charges reflected in the default residential rate structure.

EV brings to the system when charging is shifted from on-peak time periods to off-peak time periods. I use the result of that analysis to inform the level of the price differential between on- and off-peak time periods. In order to do this, I am leveraging data from a study done at Progress Energy in North and South Carolina, as described in a U.S. Department of Energy report.[14] In that study, residential EV charging was metered for customers on a traditional rate (the control group) and on a time varying rate (the study group). Load shapes associated with the resulting EV charging were reported for each group. The difference between those load shapes can generally be thought of as the effect of the TOU rate on charging behavior. This secondary data source that was based on a metering study of actual EV drivers with a control and study group is a reasonable, and is perhaps the best available, proxy to use for the potential impacts of an Ameren Missouri TOU offering on EV charging shapes. A graph of the two load shapes, scaled such that the total daily energy matches the expected daily energy consumption of an EV in Missouri, is shown in Figure 11 below:

Figure 11 – Progress Energy Study EV Charging Shapes – TOU vs. Control



[14] A U.S. Department of Energy study titled "Evaluating Electric Vehicle Charging Impacts and Customer Charging Behaviors – Experiences from Six Smart Grid Investment Grant Projects," published in Dec. 2014.

Notice in Figure 11 that the charging pattern associated with the customers on the TOU rate follows the contour of the charging pattern of the non-TOU control group customers somewhat generally, but has markedly lower charging during the late afternoon and evening hours when non-TOU customer charging begins to significantly ramp up. Charging then increases much faster when the TOU off-peak period begins and remains at a higher level throughout the overnight hours until the end of the TOU period. During the hours that are likely to be peak demand hours on the Company's system that have the potential to drive new infrastructure investment, the average TOU customer's EV charging load is about 0.26 kW lower than the average non-TOU customer's.[15]

Q. Is there any possibility that the value of shifting EV load could be larger in some cases?

A. Yes. The curves in Figure 11 represent averages, but individual customer behaviors and outcomes can vary substantially. In the most extreme case, you might have an EV owner whose particular lifestyle and choices result in them almost always charging at the peak time of the day. It is possible, though, that providing the incentive to charge off-peak might result in this customer setting a charging timer that is nearly 100% effective in delaying charging until overnight hours. In this case the full demand of the individual charger could be shifted away from contributing to the peak. For illustration of this point,

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[15] At the single hour of the day that the Company's system typically peaks, 4 to 5 p.m., the difference is 0.24 kW. When averaging the six hour window around that hour consistent with the Charge Ahead case analysis, the difference is 0.26 kW. Each of these values (the single hour peak or nearby hours of peak conditions) may be appropriate to use in analysis of different types of infrastructure investment. Due to the negligible difference between these values, I will use the 0.26 kW difference in all of my analysis.

I will analyze the benefit associated with a typical level 2 (approximately 6.6 kW) charger being shifted away from the peak.

Q. If the average EV driver reduces his or her peak demand impact by 0.26 kW when taking service under a TOU rate, and the most extreme EV driver could reduce his or her peak demand by 6.6 kW, what costs are potentially reduced on the system?

A. A reduction in demand can avoid the need for generating capacity, as well as potentially reduce the level of longer term transmission and distribution investments the Company must make. The Company's Integrated Resource Plan ("IRP") is the framework where these types of investments are generally evaluated. The IRP analysis of the cost effectiveness of energy efficiency programs, for example, is premised on the application of forward pricing curves for generation capacity, transmission, and distribution for each kW of demand that is saved by the program. Similarly, IRP-based forward curves can be used to understand the benefit associated with reducing EV-related peak demand through a TOU rate.

Considering the Avoided Cost curves from the Company's 2017 IRP, and looking at values for each category of potential avoided cost for the year 2020 – the year that rates from this proceeding will first be in effect, will yield an estimate of the potential value of this load shifting in the short run. However, because EV adoption is an emerging trend that has significant longer term implications for utility systems, I believe it also makes sense to consider future cost reductions that can be achieved if we help customers understand the value of, and create the habits that will result in, load shifting early on. To that end, I will also calculate the potential cost reduction associated with this load shifting based on the

IRP forward curve values observed five years out in the future, or 2025. Table 8 below shows the estimated cost reduction per EV that is associated with the load shifting represented by the charging patterns in Figure 11 on page 44.

Table 8 – Avoided Cost from EV Load Shifting on TOU Rates

	A	B	C	D	E	B x (C +D +E)
	Demand Reduction (kW) @ customer meter	Demand (kW) w/losses & reserves	Avoided Capacity	Avoided Transmission	Avoided Distribution	Annual Avoided Cost
Avg. Customer/2020 Avoided Cost	0.26	0.30	$25.14	$5.97	$17.39	$14.47
Extreme Customer/2020 Avoided Cost	6.6	7.5	$25.14	$5.97	$17.39	$364.07
Avg. Customer/2025 Avoided Cost	0.26	0.30	$70.75	$6.59	$19.20	$28.79
Extreme Customer/2025 Avoided Cost	6.60	7.51	$70.75	$6.59	$19.20	$724.57

Q. How do the cost savings estimates in Table 8 relate to the TOU rates you proposed in Table 7?

A. In order to demonstrate this, I will compare the expected bills associated with EV-related load under the TOU rate to the bill on the Company's standard rate for both the average and extreme customer scenarios I defined above. The expected customer savings achieved on the TOU rate, assuming the customer shifts charging load to the overnight period, should be reasonably consistent with the cost reduction benefits that arise from that customer's actions. Assuming 4,090 kWh per year of EV-related consumption, the incremental energy bill for charging an EV under the Company's standard rate and the EV Savers for rate is shown in Table 9 below for each scenario:

Table 9 – Customer Bill for EV Charging Load on Standard vs. TOU Rate

	Standard Rate Bill	TOU Rate Bill After Load Shifting	TOU Savings
Average Customer	$310	$282	-$28
Extreme Customer	$310	$204	-$106

Table 8 and 9 can be collectively interpreted to show that the average EV driving customer, whose charging pattern is initially consistent with the control group from the Progress Energy study, who then changed behavior upon enrolling in the EV Savers rate plan, would reduce the incremental cost they impose on the system by $15-30 per year, depending on the time horizon analyzed, and would reduce their bill by around $30 per year – an almost ten percent reduction in their EV charging costs. The incentive that is provided to the customer aligns with the amount of benefit that the adopting customers' behavior change is likely to create in the long run. For the extreme case, recall that this is based on a customer that initially charges almost entirely during peak times, but changed to charging entirely during the off-peak upon enrolling in the EV Savers rate plan. This customer reduces costs on the system by hundreds of dollars per year (because their old charging behavior imposed substantial demand on the system and their modified behavior removes all of that new demand). This customer saves over a hundred dollars a year charging on the EV Savers rate when they shift all of their charging to the off-peak. While their savings is smaller than the total amount of costs that their behavior change has caused to be reduced, it is still a substantial – almost one-third – reduction in their EV charging bill. The reason that they do not get the full benefit of all of the costs that they reduced passed through to them, is that the standard rate was already insufficient to recover all of the costs their old, undesirable charging behavior was imposing on the system. But in both cases, the EV Savers rate structure provides a price signal to reduce peak demand impacts that is informed by and reasonably consistent with the benefit that can be expected to result from the customer behavior change.

Q. Will the EV Savers rate apply only to EV usage, or to all usage at the enrolling customer's home?

A. Initially it will apply to the whole house usage. However, the Company is planning to evaluate technological solutions that will allow it to isolate the EV charging load without incurring the costs of installing a second utility meter. In the future, we hope to allow customers to opt to apply the rate either to their whole house, or to only their EV load. Once the Company identifies such a sub-metering solution,[16] tariff language may be proposed in a future proceeding that will enable customers to opt in to the rate for purposes of only applying it to their EV load.

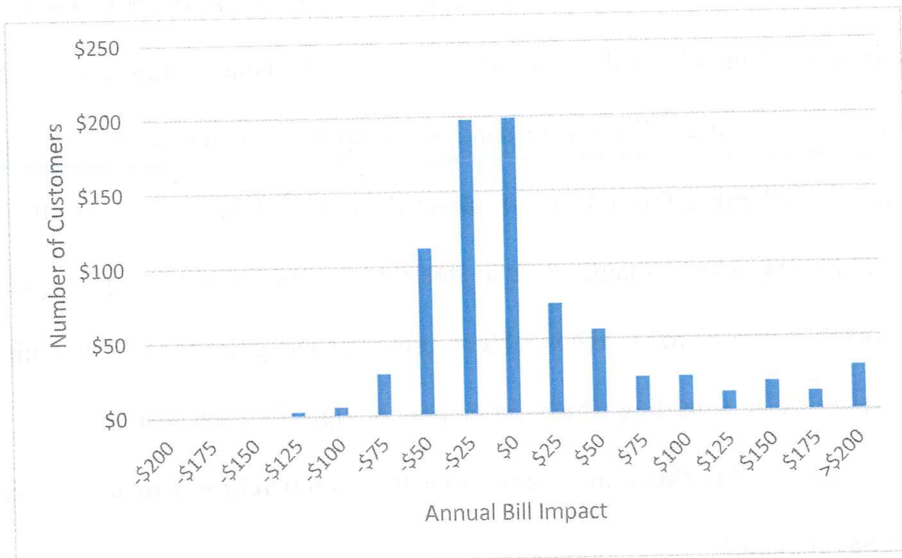
Q. Since, for the time being, the rate will have to be applied to the whole house, have you analyzed the impact that the application of this rate would have on customer bills based on the existing load (prior to EV adoption)?

A. Yes. And, as with any rate design change, there are billing impacts for any customer to adopt this rate design. However, we deliberately designed this rate in an attempt to minimize the whole house billing impacts in order to focus on EV charging savings. The TOU price periods and rate levels were calculated to ensure revenue neutrality

[16] Depending on the solution, the Company may also need to apply for a variance from certain Commission rules regarding metering protocols. The Company will make any necessary application prior to utilizing a sub-metering solution other than a standard meter.

for the average customers (i.e., if broadly adopted and if customer usage behavior was unchanged, this rate should produce the same total revenues as the default rate). The unique impact on different customers, though, varies. We analyzed the 800 customers in our expanded load research sample to determine the likely range of impacts on customer's whole house bills. Figure 12 shows the distribution of those billing impacts:

Figure 12: Distribution of Whole House Bill Impacts from Adoption of EV Savers Rate



Note in Figure 12 that a significant majority of customers (78%) would experience annual bills that result in either whole house savings, or annual increases of less than $25 relative to their bills on the standard rate design. The potential savings associated with effective EV off-peak charging on this rate should more than offset the increases for the subset of these customers that experience any increase at all, and the rest can enjoy additional whole house savings. This suggests that, while customers need to be cognizant of the potential billing impacts of adopting this rate on their pre-existing load, and the Company should (and will) be prepared to educate customers on this point, changes in the bill related to the application of the EV Savers rate to the whole house should not be a significant impediment to most customers' ability to realize value from the offering if they charge their EV during the off-peak period.

I would observe, however, that there are still some, albeit few, individual customers whose bill would be more significantly negatively impacted by application of the EV Savers rate to their existing load. About 9.5% of customers would see increases of over $100 per year by adopting the EV Savers rate. Many of the customers that fare more unfavorably on this rate have significant levels of winter usage (e.g., customers that heat their home primarily with electricity), who already benefit from the existing declining block rate structure.[17] For this reason, the Company is proposing that customers have the option of adopting this rate on a seasonal or annual basis. Specifically, an enrolling customer may elect to participate in this rate for the summer only, or year-round. The Company believes that it will be able to provide some guidance based on historical levels of winter usage regarding which option may be right for each customer.

Q. Are there any other issues that you would like to address regarding the EV Savers rate?

A. Yes. As I mentioned previously, the Company is proposing this rate to be available to all customers, regardless of the metering technology currently being used at their home (AMR or AMI). However, implementing the rate is notably more cost effective when it occurs with an AMI meter. This is because the Company will incur the costs to visit the home and change out or reprogram the AMR meter in order to have the capability to bill this rate when that metering technology is still present. As such, the Company proposes an incremental fee of $1.50 per month to access this rate for customers that are

[17] The group of customers that experience an annual rate impact over $100 has average non-summer usage approximately 3.5 times higher than the average customer's non-summer usage.

still on AMR meters. This fee will no longer apply once the customer's meter is converted to AMI (or will not apply to begin with if the customer applies for the rate after they already have an AMI meter). While the Company recognizes that application of an additional fee is not desirable to encourage adoption of this new rate design, it is also important to make sure that incremental costs of adoption don't negatively impact the cost effectiveness of the offering for all customers. I calculated the $1.50 per month approximately by spreading the expected costs of an average truck roll to change a meter ($79) over the expected weighted-average remaining life of AMR meters pursuant to the expected AMI replacement schedule.

SMART SAVERS RATE

Q. Please discuss the second TOU rate offering the Company is proposing in this case.

A. The second TOU offering closely resembles the TOU rate that was included in the candidate rate designs described in my earlier analysis. This is a more complex, 3-period TOU rate that we only propose to make available to customers once they have an AMI meter deployed. Note in the earlier analysis, this rate scored well on how well it aligns with cost of service and provides more accurate price signals in most cases to customers adopting new technologies – it was in fact the second best across the candidate rate designs on a majority of metrics, behind only the 3 part rate with demand charge. We refer to this rate as the "Smart Savers Rate." The target customer type for this rate is someone who is engaged, either actively or through their adoption of technologies such as smart thermostats and appliances, in managing their total household energy usage. Such customers can modify their consumption to provide system benefits, and may be rewarded for those efforts through bill savings that they can achieve as a result of this rate offering.

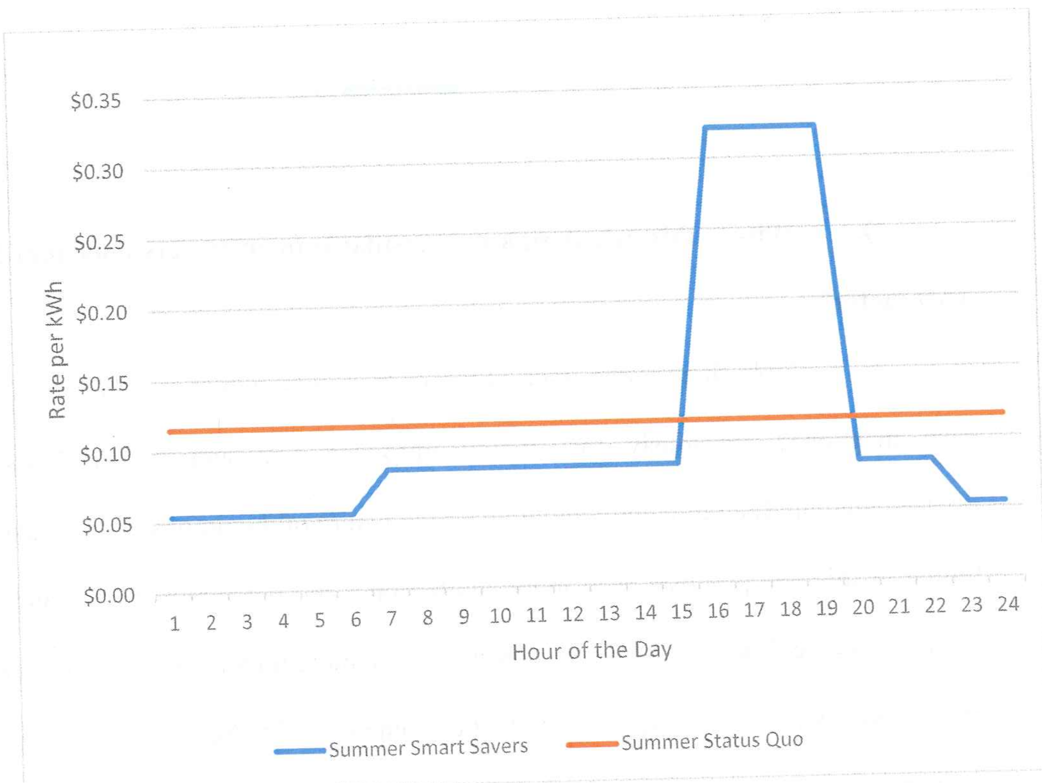
Q. Please describe the rate in more detail.

A. Dr. Faruqui has performed extensive research on the efficacy of time varying rates at numerous utilities. Among his key findings related to TOU rates is that, in order to achieve significant load shifting, peak periods need to be relatively short in duration (a few hours) and need to have a significant pricing differential relative to the off-peak periods. The Smart Savers Rate includes these features. The peak price is associated with a four hour peak period – weekdays from 3 to 7 pm in summer months, 6 to 8 am and 6 to 8 pm in non-summer months. These hours were selected based on analysis of the data regarding when the total system tends to experience peak conditions. There is an intermediate rate that spans the rest of the daytime hours - including holidays and weekends – when loads are still relatively higher and individual circuits, substations, or more localized infrastructure may experience high load levels. And finally there is an off-peak rate that applies overnight (10 pm to 6 am) seven days a week that recognizes that the majority of the system is underutilized at these times, that incremental usage at these times does not tend result in any new investments, and that the cost of serving additional load at these times is very low. The proposed Smart Savers rates are shown in Table 10 and a graphical depiction of the TOU rate structure is shown in Figures 13 (summer rates) and 14 (non-summer rates) on the following pages:

1 **Table 10 – Proposed Smart Savers Rates**

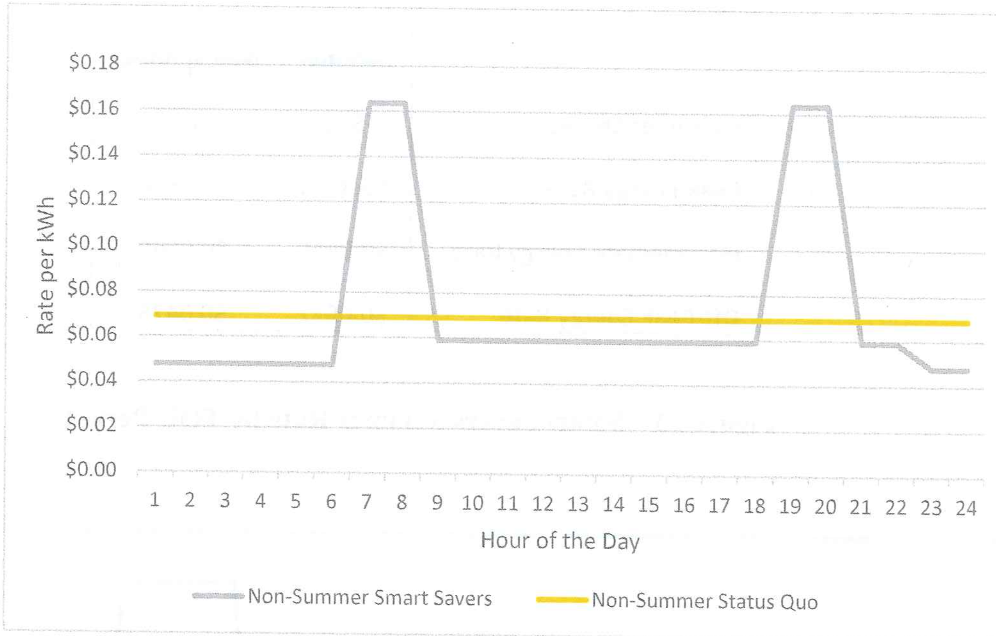
	Summer	Non-summer
Customer Charge	$11	$11
Peak Energy Rate	$0.3214	$0.1636
Intermediate Energy Rate	$0.0845	$0.0590
Off-Peak Energy Rate	$0.0537	$0.0478

2 **Figure 13 – Smart Savers Summer Rate by TOU Period**



3

Figure 14 – Smart Savers Non-Summer Rate by TOU Period



Q. Why is this rate design only available to customers once they have an AMI meter?

A. First, there is the issue of the meter reprogramming and/or replacement I have mentioned previously that would introduce cost and logistical issues for implementation. The more complex three period nature of the proposed rate makes AMR billing of this rate proposal even more cumbersome and potentially costly, and perhaps even impossible. But there is a second, perhaps even more important reason for saving this rate for an AMI offering. That is that most customers need to have the insights regarding their usage characteristics that can be provided by AMI data in order to be confident in their election of a more complex rate like this.

By way of example, the proposed TOU rate in this case is not too dissimilar from the pilot residential TOU rate the Company has offered for the last several years, which the Company proposes to discontinue offering to new customers in this case given the new

TOU options being proposed.[18] That pilot rate is also structured like an effective modern rate design with many of the characteristics Dr. Faruqui uses to describe such rates. It has a relatively short, five hour peak period with a substantial pricing differential – a greater than 4:1 peak/off-peak ratio.[19] The pilot rate was designed deliberately to be revenue neutral to the average customer. But again, no customer is actually completely average. In reality, approximately half of all of the Ameren Missouri's residential customers would be able to save money under the pilot TOU rate *without making any behavior changes at all*.[20] And if they effectively managed their usage in response to that rate design, their savings could be even greater. However, despite this fact, the pilot TOU rate has never had more than 120 subscribers (when hundreds of thousands could benefit from it). While this low adoption is in part due to limited marketing of the pilot rate, it is also partly due to a lack of transparency regarding how customers' existing usage patterns would be impacted by application of the new rate. [21] There is no question that it sounds intimidating and potentially costly when a customer hears that peak usage could be priced at over 30 cents/kWh when the default rate they otherwise pay is only around 12 cents. There is a powerful offset to that potential cost, though, in the fact that usage occurring in almost 85% of all hours (off-peak hours) is subject to an over 40% discount vs. the base rate. Without AMI-enabled usage data, customers simply struggle to understand the trade-offs between the high peak rate and the discounted off-peak. With the availability of AMI data, the Company plans to develop tools and personalized tips to help customers improve their

[18] The filed residential tariff grandfather's customers currently taking service on that rate to allow them to continue to have access to the rate they are currently on until such time that they have an AMI meter and can be transferred to the Smart Savers rate.
[19] The peak rate is approximately 31 cents/kWh, with an off-peak rate of approximately 7 cents/kwh.
[20] Analysis of our expanded load research sample validates this.
[21] The Company did attempt to broaden its outreach related to this rate after the 2016 Stipulation was entered into, but the additional adoption rate remained extremely low.

understanding of their particular circumstances, and which rate will be best for them. Specifically, the Company will be able to model the bill impacts that would have been experienced by the customer for each rate option offered by the Company, using that customer's own historical usage data. My expectation is that this customer-specific information, coupled with a more sustained increase in the marketing of rates, can help drive significantly greater adoption of the new TOU offering than was observed in the pilot.

Q. Will a TOU rate with three time periods – peak, intermediate, and off-peak – be too complex for customers to understand?

A. I do not believe so. Initially offering this rate on an opt-in basis ensures that only customers who end up taking an affirmative action to sign up will take service under the rate. That alone suggests that participants will have some threshold level of engagement and interest in managing their electric bill. Simple messaging, such as "Avoid using energy from 3 to 7 on weekdays to save money on your electric bill. Shift usage to overnight hours and save even more," can give these customers a quick frame of reference for how to change behaviors to optimize their bills on the new rate. Beyond these messages, though, the Company is working to develop tools to give customers personalized data, insights, and tips to improve their experience with these rates. While this development is still in early stages, the Company is evaluating various concepts and products to help deliver this type of personalized information that is informed by that customer's own hourly AMI usage data.

Q. Are there any conditions necessary for the Company to be able to implement the proposed Smart Savers rate?

A. Yes. AMI meters can cost effectively bill this more complex rate, but only because they enable the collection of hourly data, from which the TOU period usage can be calculated. As such, enrolling customers' bills will be calculated by adding the hourly interval data into the TOU periods in order to apply the time-varying rates. There is a Commission rule that requires residential bills to reflect the beginning and ending meter readings for the billing period on which the energy consumption that is being billed is based. Because the application of this rate will be to energy accumulated by hour, rather than beginning and ending "snapshot" meter readings for each TOU period, the Company will be making a separate filing to request a variance from the rule that requires the reflection of these "snapshot" meter readings on the bill. If that variance is not granted, the added functionality of the AMI meters will not be able to be utilized to bill this rate, and the Smart Savers proposal will not be able to be implemented at the conclusion of this case.

PILOT RATE STUDIES

Q. Are there other modern rates that the Company proposes to implement in this case?

A. Yes, but only on a pilot basis. Both Dr. Faruqui's and my testimony have discussed at length the reasons that the ideal rate structure accurately reflects the cost structure of electricity. Both of us have testified that the rate structure that accomplishes this goal best is a three-part rate that includes a demand charge and a time-varying energy charge. In fact, I believe that there is little question generally among industry experts that this is in fact the best pure reflection of cost to customers. However, three part rates are still not widely adopted for residential customers generally. This is largely a legacy of metering technology that historically did not allow utilities to bill these more complex rates cost effectively for a large residential customer base. However, there has been resistance by a variety of interests in many jurisdictions to updating rate structures to include residential demand charges even when advanced metering technology exists. Much of that resistance centers on the perceived ability or desire of customers to understand a more complex rate, and the potential impacts on bills if they don't.

Q. Are these concerns well founded?

A. While they are legitimate areas of inquiry, I believe the concerns with three part rates are often times greatly overstated. However, the best way to truly answer these questions is by studying the rates in question. Fortunately, we are at a time when the Company has the opportunity to do just that. It would be impractical to roll out a three part rate for broad adoption prior to the widespread rollout of our AMI meters. But while those meters are in the process of being deployed, it is a great time to conduct research on this potentially valuable rate option. Dr. Faruqui and his Brattle colleague Dr. Sanem Sergici have developed a pilot plan to test this rate option. Dr. Faruqui's testimony describes the study design in more detail.

Q. What are the Company's goals in proposing this pilot study?

A. We hope to learn both qualitative and quantitative information about how customers engage with a three-part rate. Surveys of participants and analysis of participant load patterns as compared to a control group will be used to collect data to help answer the following questions:

- Do customers understand demand charges?
- Are customers accepting of being billed based on demand charges?

- What changes in consumption patterns are observed when customers are subject to a demand charge? What is the impact on their contributions to peak load?
- Does enhanced usage information provided to the customer help them feel more comfortable managing their demand?

Q. Please provide an overview of the specific rates that you propose for purposes of the pilot study.

A. The proposed pilot rates are shown in Table 11 below:

Table 11 – Proposed 3 Part Pilot Rate Structure

	Summer	Non-Summer
Customer Charge	$11	$11
On-Peak Energy Charge	$0.2515	$0.1405
Off-Peak Energy Charge	$0.0427	$0.0389
Demand Charge	$6.86	$2.93
On-Peak Hours	Weekdays 3-7 P.M.	Weekdays 6-8 A.M and 6-8 P.M.
Off-Peak Hours	All Other Hours	All Other Hours
Demand Charge Definition	Maximum One Hour Demand Set During Any Day of the Billing Period Between 6 A.M. and 10 P.M.	

Q. Does conducting such a pilot cause the Company to incur additional costs?

A. Yes. The pilot will involve conducting focus groups, recruiting and retaining participants, developing educational materials, developing tools to communicate usage information back to participants, conducting participant surveys, and analyzing and reporting results of participant load impacts. Each of these activities carries costs that are not reflected in the test year in this case.

Q. How does the Company propose to recover the pilot program costs?

A. Because the ultimate decision to approve this pilot will be made by the Commission in this case, and the Company will incur these costs while rates that result from this proceeding are effective, it is appropriate to include a reasonable level of pilot program costs as a pro forma adjustment to the revenue requirement in this case.

Q. What level of cost do you propose to add to the test year as a pro forma adjustment for the pilot study?

A. I recommend a two-year pilot study, with $1 million per year to be included in the revenue requirement. I also suggest a one-way tracker through which any over-recovery of pilot costs be flowed back to customers in a subsequent rate case. If the pilot costs come in higher than estimated, the Company would absorb them. If the pilot can be accomplished at lower cost, the difference would be tracked and returned to customers.

Q. How did you arrive at the budget to support your $1 million per year request over two years?

A. I have looked at some benchmarking of pilots provided by Drs. Faruqui and Sergici, and used that information to make a high level estimate of various categories of expected costs for the study. The breakout of activities and costs included in the budget are shown below in Table 12:

Table 12: Residential Rate Study Pilot Budget

Pilot Activity	Potential Cost (thousands)
Focus Groups	$50
Customer recruitment and retention	$600
Educational materials for participants	$25
Participant Surveys	$50
Programming billing system for pilot rate	$25
Technology/software to provide usage information, tips and insights to customers	$1,000
Pilot evaluation and report	$250
Total Pilot Cost	$2,000

Based on information I received from Drs. Faruqui and Sergici, similar pilots in Maryland that have been recently authorized have had costs in the $1-2 million range. As the Company is able to refine its research on the cost of these activities, I recommend adjusting the pilot budget reflected in the revenue requirement with the true-up phase of this proceeding.

VISION OF FUTURE RESIDENTIAL RATE OFFERINGS

Q. How do the proposals you have described above relate to the Company's vision of the future with respect to residential rate offerings?

A. I described earlier that the Company's vision is aligned with Dr. Faruqui's description of replacing a one-size-fits-all rate design with a variety of cost-based offerings that meet customers' different preferences and needs. The new rate offerings discussed above are key parts of this future suite of options. I believe that the two TOU rates – one focused on the needs of EV drivers, and one designed for customers more engaged in managing their whole house energy usage – are valuable additions to the Company's rate offerings that provide more choice and control for customers, and I envision these rates continuing into the future.

The pilot study of a three-part rate is also of keen interest to the Company. If the expectation that customers can and do respond to such a rate structure is validated, such a rate could become a future default rate that ensures the majority of customers are receiving a highly equitable rate with economically efficient price signals.

For those customers who desire the relative simplicity of the status quo rate design, I envision that the current structure would be gradually migrated toward what I described earlier as the Cost Based Two Part rate. Under this rate, a modestly higher fixed customer charge would ensure that all customers contribute to the recovery of the fixed costs of the grid that must exist to serve them and their peak demand, regardless of the total kWhs consumed. For relatively lower-use customers who prefer a lower customer charge and want to maintain the greatest ability to manage their total bill, the three-part rate or the TOU options would be available to meet that desire. To the extent the demand they place on the system is well managed, such a low-use customer could still experience a lower bill under that option – but one that we know is more aligned with the actual cost of serving them.

With this suite of rate options available, I also envision the Company having the right tools, technology, and educational materials for customers to make informed choices about the best rate for them, the likely billing impacts of that rate's adoption, and customized personal tips about how to optimize their experience on that rate.

Q. Are there other rate designs that the Company envisions being candidates for future implementation beyond those being offered or piloted in this case?

A. There are certainly other options that are of interest, which the Company is studying. Dr. Faruqui's discussion of modern rate designs featured other structures of interest. For example, Dr. Faruqui mentions the preference of some customers for a much greater level of bill stability, where they are willing to pay a little more to make sure they don't get surprises in the form of a high bill later. That concept is intriguing, and Company is researching similar offerings at other utilities to determine if it makes sense to incorporate this type of an offering in the future.

Another rate design that Dr. Faruqui discusses, which is of interest to Ameren Missouri, is Peak Time Rebates ("PTR").[22] This structure definitely requires AMI-enabled functionality, and I envision this as fitting more appropriately into a demand response portfolio, such as the Company's MEEIA programs. However, it certainly has a rate design element to it. The Company is also researching this structure, and will likely evaluate it also in the context of MEEIA planning as a future candidate offering.

Q. How do you see this vision coming to pass?

A. I described it earlier as a journey, and I think that is an appropriate way to view it. There is certainly much to be learned through pilot offerings, and closely watching the trends that are playing out nationally and internationally in the rate design space. Over the next few rate cases, I expect to continue a dialogue with the Commission and other stakeholders where we assess what is working, what is not, and what new ideas have merit for implementation or testing. It will certainly be a process over the next 5-6 years, as that is the time horizon over which AMI meters will become universally deployed on the Company's system. By 2025, when AMI is fully rolled out, I expect to have transitioned many customers to TOU rates and three-part rates with the accompanying tools to utilize those rates to their best outcomes.

Rate Migration 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 you have proposed in this case.

[22] Peak Time Rebates refers to programs where customers can receive a bill credit for reducing their usage during peak hours on certain days when the Company identifies high load conditions. The load reductions are generally determined by comparing the observed usage during the event to a customer-specific baseline based on their recent usage on similar days.

A. My extensive discussion of the new rate offerings that the Company is proposing now and planning for the future should make it evident that the Company is committed to providing customers new rate options and tools for controlling their energy bills. However, changes in rate designs necessarily result in some level of bill impacts for the adopting customer, as well as heightened revenue uncertainty for the utility. The Bonbright Principles Dr. Faruqui discusses in his testimony highlight both of these issues as important rate design considerations. Because the rates are being offered on an opt in basis, and the Company is planning to provide education and tools for customers in order to help them make informed decisions about the best rate for them, bill impacts are generally expected to be favorable on balance for customers (i.e., customers will opt in if they are likely to save money). However, that fact means that the expectation is also for the Company to experience revenue erosion from rate switching that may occur, which can negatively impact the Company's opportunity to recover its revenue requirement, which causes a potential misalignment of the Company's financial incentives with its customers' financial incentives.

Rate transitions are always tricky. The status quo – the certainty of the known - is almost always a lower risk proposition for utilities. Ameren Missouri is as sensitive to this risk as any company would be. But Ameren Missouri is also committed to innovation designed to accommodate the technological changes affecting energy systems that are occurring, and providing improved customer experiences that mean more choice and control for customers. However, in order to provide for a smooth transition that maintains a reasonable level of revenue stability, the Company is requesting authority from the

Commission to track changes in revenue that are directly attributable to residential customers optimizing their rate as new options become available.

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

A. This is true for two reasons. First, the rate design changes proposed in this case are 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 intends to work with customers to help them make informed rate choices, using enhanced usage information from AMI meters, adoption should be very asymmetric. Expected "winners" should adopt new rates 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 the status quo 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.

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

A. Yes, using some assumptions applied to the residential load research sample that I have discussed throughout my testimony. I analyzed a scenario 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, 27.4% fall 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, would be approximately $68 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 13 below summarizes the analysis of that scenario.

Table 13 – Regulatory Lag on Revenue Erosion from TOU Adoption Scenario

Year	% of Customers w/AMI Meters	# of Customers w/AMI meters @ Year End	TOU Participants	Utility Revenue Erosion
2020	10%	106,362	29,117	-$576,428
2021	25%	265,905	72,792	-$2,429,231
2022	45%	478,629	131,025	-$5,105,502
2023	60%	638,173	174,700	-$4,487,901
2024	80%	850,897	232,933	-$5,105,502
2025	100%	1,063,621	291,166	-$5,434,889

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 issue that the Company could be faced with as a result of its promotion of modern rates. While the 27.4% adoption may sound high, it is not at all outside the realm of what has been experienced at some utilities. Specifically, recall Dr. Faruqui's testimony regarding the success of opt-in time-varying rates at 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 getting customers on 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 return to benefit all customers.

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 rate other than the standard default rate. Their bill on the new rate they have chosen will be compared to what their bill would have been on the standard rate. Any difference will be accumulated in the tracker for recovery from or return to customers in a future rate case.

2016 Stipulation Compliance – Inclining Block Rate

Q. Are there any additional topics related to the 2016 Stipulation that you will be addressing?

A. Yes. I previously discussed the TOU rate offering that the Company has proposed in part to comply with a provision in the 2016 Stipulation. There is another provision in that Stipulation that pertains to a rate design commitment that the Company entered into that has implications for this case. Specifically, paragraph 5.D.iii states:

> In its next general rate case, Ameren Missouri shall develop and file a rate option for consideration that includes a summer Residential inclining block rate and non-summer declining block rates that narrow the existing differential between the first and second non-summer blocks. These rate options shall be fully developed and quantified based on the Company's proposed revenue requirement and cost of service study, accompanied by work papers, and shall include sufficient detail to allow parties to respond in testimony. These optional rates shall be developed after a collaborative workshop to share input among interested stakeholders with the goal of evaluating the relative merits of different Residential rate class design options, including consideration of redefined seasonal rates to divide the non-summer months into "winter" and "shoulder" periods. As part of this process, Ameren Missouri shall complete any studies of bill and revenue impacts of a reasonable number of selected rate designs from the workshop

> in time for consideration by stakeholders. This collaborative workshop shall be open to participation by all parties to this case, and the parties shall be free to disseminate the information generated through the workshop, except as needed to preserve confidential utility or customer information. Ameren Missouri retains the right to propose and advocate for any other rate design options it chooses. In the next and subsequent general rate proceedings, all Signatories retain the right to oppose the rates filed by Ameren Missouri in accordance with this paragraph, or propose alternatives or adjustments to those rates.

Q. Was the workshop contemplated by this provision of the 2016 Stipulation conducted?

A. Yes. The Company and a variety of signatories to the 2016 Stipulation met on two occasions: November 7, 2017 and January 11, 2018 in Jefferson City. The first session included discussions of the relative merits of different Residential rate class design options. Certain rate designs were selected for additional analysis as contemplated in the stipulation, and the second meeting largely consisted of the company sharing its analysis of the bill and revenue impacts of the selected rate designs. Based on the feedback from that process and the commitments in the stipulation itself, the Company has calculated a Residential rate option that includes a summer IBR and a winter declining block with a narrower price differential.

Q. How were the parameters of the summer IBR and non-summer declining block rate determined?

A. The Company has an existing block rate structure for the non-summer period with a usage threshold of 750 kWh per month for the price change. In the interest of consistency, and based on input from the conversations in the workshops discussed above, the 750 kWh block size was retained for declining block and also adopted for the summer IBR. The amount of pricing differential between the first and second tier of the IBR was set such that the impact of adopting this rate would result in no more than a 5%

bill increase for 95% of customers. This is consistent with the testimony in File No. ER-2016-0179 that gave rise to this provision of the Stipulation, as well as consistent with the conversations with other parties at the workshop. The narrowing of the non-summer declining block rate was calculated such that the impact would be no more than a 5% bill increase for any customer, in order to limit the impact on customers who use electricity as their primary source of space heating. The rates calculated by the Company pursuant to this commitment are shown in Table 14 below:

Table 14 – Inclining Block Rate

	Summer	Non-summer
Customer Charge	$9	$9
Block 1 Energy Charge	$0.1059	$0.0793
Block 2 Energy Charge	$0.1314	$0.0601

Q. In your residential rate design discussion earlier in this testimony, the Company recommended a variation on the status quo rate be adopted for the default customer rate offering in this case. I take it that this means the Company is not endorsing the IBR proposal.

A. That is correct. The 2016 Stipulation was clear that the Company was to calculate the IBR, but could advocate for any rate design it felt was appropriate in this case. The Company urges the Commission to focus on supporting the Company's efforts to modernize its residential rate offerings. Dr. Faruqui offers a compelling expert perspective on the merits of focusing on modern rate structures that provide options to customers that are grounded in the cost structure of electricity. The Company engaged in extensive cost of service and rate analysis in this case to demonstrate just how effective modern rate designs can be when it comes to accurately reflecting the cost of serving customers and providing economically efficient price signals to promote lower overall costs of the electric system. This analysis clearly demonstrates that IBR offerings are the poorest performing rates of all of the candidate rate options in terms of the critical equity and economic efficiency rate design objectives. The analysis I conducted and discussed earlier regarding the impact of rate design on customer investment decisions in new technologies clearly demonstrates this fact. Inclining Block Rates clearly send poor price signals that don't properly value the costs and benefits of new technology. In particular, IBRs are an extremely poor choice when considering the goal of capturing the many well-documented cost and environmental benefits of efficient electrification. An IBR inherently sends the signal that any incremental electricity consumption is a bad thing. However, we know that when electricity powering a motor vehicle displaces gasoline burned in an internal combustion engine-powered car, the benefits to individual drivers, the environment, and all electric customers, are substantial. The same is true of any other type of efficient electrification that might be considered in the future. An IBR simply sends the wrong signal on this important issue.

It is also noteworthy that IBRs handle distributed energy resources poorly. Under IBR, our analysis demonstrates that a customer who installs Solar PV receives a reduction in the variable portion of their bill that is designed to recover the fixed costs of the system that is there to serve them (and does serve them every moment that the sun doesn't shine enough) that far exceeds the cost of service reductions provided by their investment. And yet a battery, which would pair well with that Solar PV to greatly enhance its benefits to the system, has no value whatsoever under an IBR. TOU rates, or better yet three-part rates, are far more appropriate in the incentives they provide for things like pairing Solar PV with a storage solution that enhances its value to the grid. This is all to be expected, though. We know that IBRs do not promote equitable and economically efficient outcomes because they are not grounded in an analysis of cost of service, but are simply designed to promote a policy outcome. Unfortunately, they are not as effective even at accomplishing that policy goal as conventional wisdom would suggest.

Q. What is that policy outcome, and why are IBRs less effective than once thought at achieving it?

A. IBRs are generally adopted because of the notion that they incentivize electric energy efficiency and other forms of customer electric conservation efforts. The thought is that if incremental usage above some threshold faces a higher price, customers will conserve more, or invest in energy saving technologies, in order to avoid those higher priced kWh. There are two major flaws with this theory, though. First, to the extent that it is true that IBRs incent lower usage, it is only promoting *electric* energy conservation. As I already discussed, where *overall* energy conservation goals would be served well by efficient electrification, IBRs strongly discourage that conservation.

But second, in practice IBRs tend to send a mixed signal to customers regarding their existing usage. That is because most customers don't generally fully understand utility rate design. A majority of customers simply pay attention to their total bill. If a rate design change makes a customer's bill increase, it might get their attention and cause them to take some actions to reduce their bill. But if the customer's bill decreases as a result of a rate design change (regardless of whether the marginal rate reflected in the tariff is higher or lower), they may reduce their efforts to conserve. Because IBRs impact each customer differently based on their particular usage characteristics, the bill impacts associated with the implementation of IBRs range widely. This phenomenon was noted in a 2015 paper co-authored by Dr. Faruqui entitled "The Paradox of Inclining Block Rates".

Q. Please elaborate on this paradox.

A. It was explained in detail in the Company's 2017 IRP, where the following discussion and analysis were provided:

> The term inclining block rates refers to a rate structure where customers pay a lower rate for some initial level of usage, but a higher rate for incremental usage above a predefined threshold. For a number of years there has been general interest from many jurisdictions and utility stakeholders in the purported ability of inclining block rates to promote energy conservation, and several jurisdictions have implemented such rate structures. In its 2014 IRP, the Company provided results of a study performed by The Brattle Group that suggested that inclining block rates applied to residential customers' usage had the potential to promote a noteworthy amount of energy and demand savings. The 2016 DSM Potential Study results were informed largely by that Brattle work commissioned for the 2014 IRP. That study was itself premised on work done by Brattle principal Dr. Faruqui, which is well known in the industry from the 2008 article published by Dr. Faruqui titled "Inclining Towards Efficiency." The premise of this article/study is that customers make usage decisions informed by their awareness of the marginal rate for incremental consumption. As such, it was assumed that raising the marginal rate by employing an inclining block structure where incremental usage faced a higher price would ultimately cause customers to make decisions to consume less energy. Brattle's analysis for Ameren Missouri relied on secondary estimates of price elasticity derived from other studies. Price elasticity is a measure of customers' tendency to increase or decrease consumption of a good in response to changes in its price. However, many such published price elasticity studies are not well-suited to differentiating the impact of marginal prices (the price of the next kWh consumed) on consumption from the impact of average prices (the combination of all prices experienced – i.e. customer charge, first block energy charge, second block energy charge - that make up the total bill to the customer). To explain the distinction further, consider the two likely ways that customers could be informed regarding electricity prices. Customers could either review utility tariffs and familiarize themselves with the rates and apply them to their understanding of their consumption, or they could simply observe the changes in their total

bill over time and draw inferences about the underlying rates. But these two methods will potentially lead to significantly different outcomes. Consider how three different customers would experience a change from a flat rate to an inclining block rate. Assume a simple hypothetical incumbent rate structure with a monthly customer charge of $10/month and a flat energy charge of $0.10/kWh (for ease of math in the example). Now assume the residential rate structure is changed to include an inclining block rate with a block threshold of 750 kWh, with a first block energy charge of $0.08/kWh and a second block energy charge of $0.12/kWh. Next assume that three hypothetical customers have usage in a given month of 600, 1,000, and 2,000 kWh respectively. See the impacts of the change of rate design on each customer's marginal price and total bill in Table 8.8 below.

Table 8.8 Inclining Block Rate Impacts

	Usage	Flat Rate Bill	Inclining Block Rate Bill	Block in Which Marginal Usage Occurs	Impact of Inclining Block Rate Structure on Marginal Rate	Impact of Inclining Block Rate Structure on Total Bill
Customer 1	600	$70	$58	1	↓	↓
Customer 2	1,000	$110	$100	2	↑	↓
Customer 3	2,000	$210	$220	2	↑	↑

Note that, if customers are aware of the rate structure and genuinely respond to changes in the marginal price, the two customers whose usage exceeds the block threshold of 750 kWh receive a higher marginal rate under the inclining block structure, which suggests a stronger price signal to conserve will be present under that rate design for those customers. However, because Customer 1 uses less than the block threshold, the inclining block rate structure lowers her marginal rate, sending a price signal to be less focused on conservation than did the flat rate, which may ultimately lead to increased consumption for such situated customers. So even under the assumption that consumers understand utility prices and respond to them with a high level of engagement, the move to an inclining block rate sends a mixed signal, with some customers recognizing a reduction in their marginal rate.

However, it is probable that most customers are not engaged at the level required to know what their marginal electric rate is or when their monthly usage cross the threshold where it changes under a blocked rate structure. For these customers, their reaction to the rate design change will be informed by what they experience on their bill (i.e., if their bill goes up, they perceive higher prices and vice versa). Now note that two out of the three hypothetical customers in Figure 8.8 see a *bill decrease* under the rate design change relative to the flat rate, including one customer that faces a *higher marginal rate* under inclining blocks. The goal of the higher marginal rate included in the IBR structure is potentially confounded by the reality of a lower bill for this customer under the new rate structure. Hence, the hypothesis that customers respond to rates based on the impact they have on their bills (i.e., customers respond to average price rather than marginal) suggests an even more conflicting price signal than the marginal rate perspective. Clearly the impact of inclining block rates is more complex and nuanced than a cursory review of them would suggest.

To that end, it is instructive to review some recent additions to the academic literature on the subject. As discussed previously, most studies of price elasticity are not well-suited to answering the question posed by inclining block rates regarding whether customers respond to marginal or average price. This information is necessary to determine how customer 2, who uses 1,000 kWh per month in the example in the previous paragraph, will respond to the rate change. However, a 2014 paper capitalizing on a unique circumstance in Southern California over a multi-year period tackled this very interesting question in a unique and effective way. The study titled "Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing" by Koichiro Ito and published in the American Economic Review focuses on the electricity crisis experienced in Southern California at the beginning of the last decade. Dr. Ito observed customer behavior during the years 1999-2007, a span that saw both significant rate increases and rate design changes being phased in over time. The study also capitalized on a particular part of the San Diego metropolitan area where the service territories of two different electric utilities share a border in a relatively homogeneous area of the city. The study's author was able to take the opportunity to observe what amounted to a natural experiment, where the conditions for a scientific study were created by natural circumstances. The author used an innovative statistical methodology to test the question in the paper's title. Dr. Ito's conclusion:

"The evidence strongly suggests that consumers respond to average price and do not respond to marginal or expected price. I show that this suboptimizing behavior makes nonlinear pricing ***unsuccessful in achieving its policy goal of energy conservation*** *and substantially changes the efficiency cost of nonlinear pricing."* (emphasis supplied)

This finding has important implications for inclining block rates, which did not go unnoticed by Dr. Faruqui of Brattle, whose original analysis of inclining block rates was reflected in past Ameren Missouri IRPs as described previously. Dr. Faruqui subsequently co-authored a new article building on Dr. Ito's work titled "The Paradox of Inclining Block Rates". In this article, Dr. Faruqui et al discuss the implications of the conclusion that customers respond more to their average price than their marginal price, and go on to describe alternate methodologies for estimating class level load impacts of inclining block rates from those he used in the original Ameren Missouri analysis. By analyzing the impact of *each customer's* individual marginal and average price, and applying elasticity relationships to usage at the customer level, a more realistic impact of inclining block rates can be inferred. Ameren Missouri has undertaken such an analysis and developed revised expectations for the impacts of inclining block residential rates.

When re-analyzed with customer level detail, and with sensitivity to the marginal versus average price questions, inclining block rates appear to have considerably less energy and demand savings potential than previously reported, as in the 2014 IRP and the 2016 DSM Potential Study. Ameren Missouri ran a customer by customer analysis, assuming a range of pricing differentials between tiers in the inclining block rate, a range for the elasticity of customer usage, and also employing both a marginal price perspective (i.e. each customer's usage change was premised on application of the elasticity to the customer's marginal rate, which depends on the relationship of their specific usage to the block threshold) and an average price perspective (i.e. each customer's usage change was premised on application of the elasticity to the change experienced in that customer's bill when changing from application of a flat rate to an inclining block rate). The results of the study are summarized in Table 8.9 on the following page:

Table 8.9 Inclining Block Rate Analysis

Summer Inclining Block - Average Rate Approach			
	5% Block Pricing Differential	10% Block Pricing Differential	20% Block Pricing Differential
Assumed Elasticity	% Change in Load	% Change in Load	% Change in Load
0.1	-0.02%	-0.03%	-0.06%
0.15	-0.03%	-0.04%	-0.08%
0.2	-0.04%	-0.06%	-0.11%
0.25	-0.05%	-0.07%	**-0.14%**

Summer Inclining Block - Marginal Rate Approach			
	5% Block Pricing Differential	10% Block Pricing Differential	20% Block Pricing Differential
Assumed Elasticity	% Change in Load	% Change in Load	% Change in Load
0.1	-0.23%	-0.44%	-0.85%
0.15	-0.34%	-0.66%	-1.27%
0.2	-0.46%	-0.88%	-1.70%
0.25	-0.57%	-1.10%	-2.12%

Because, as discussed in the Ito paper, customers tend to respond much more significantly to average pricing than marginal, the values in the second table represent the most likely customer usage impacts and load reduction potential that would be associated with a move to an inclining block rate. As such the 0.14% load reduction (shown in bold in the table above) is a more realistic impact to use to develop expectations for inclining block rates than the 4.4% value in the previous Ameren Missouri potential studies. The relatively negligible expected net impact of inclining block rates, along with relatively poor performance of such rates on the other rate design priorities discussed in the introduction of this section resulted in Ameren Missouri not passing the IBR structure on for further analysis and integration in the IRP. Inclining block rates are simply not a good candidate for implementation from Ameren Missouri's perspective.

Q. Given the evidence that IBRs perhaps do not have the same efficacy that has been hypothesized in the past, are there other compelling reasons not to implement such a rate design?

A. Yes. There are at least two related reasons I can think of. First, a trend has emerged nationally and even internationally where a significant number of those jurisdictions that have implemented IBRs in the past are now changing course to promote broader adoption of TOU rates and other modern rate designs. Dr. Faruqui touched on these trends in his testimony. Notably, utilities in Arizona, California, Colorado, and Michigan are in the process of replacing their IBRs with a variety of modern rate structures.

Second, the Company has made a significant effort in this case to demonstrate its commitment to a move to more modern, cost-reflective rate structures including its proposal of two different TOU offerings and a pilot to study three part rates. If there is a meaningful transition under way toward such designs – and if the Commission shares the Company's goals of transitioning toward these types of rates – then it makes little sense to begin implementing IBRs, when their utilization would be transitory at best, and other new rate designs are right around the corner. The efforts necessary to educate customers to the IBR would be better spent on promoting the new TOU offerings and educating customers in a forward thinking way about the benefits of smarter electricity consumption that values emerging technologies and efficient electrification in a way that is much more aligned with their actual costs and benefits.

Q. Does this conclude your direct testimony?

A. Yes, it does.