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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2016-0179

RATE DESIGN
REBUTTAL TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
January 2017

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RATE DESIGN REBUTTAL 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"), 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. Are you the same Steven Wills that previously filed rebuttal testimony on January 20, 2017, in the revenue requirement phase of this case?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your rate design rebuttal testimony in this proceeding?

A. The primary purpose of my testimony is to respond to the recommendation found in the direct testimony of Sierra Club/Renew Missouri witness Douglas Jester to reject the Company's proposed Energy Grid Access Charge. In doing so, I adopt pages 19 through 26 of Company witness William Davis' direct testimony on the topic. I will also address recommendations to move toward an inclining block rate raised by Mr. Jester and Division of Energy witness Martin Hyman, as well as the comments made by Brightergy witness Jessica Oakley regarding the study of the Value of Solar. Further, to the extent that other parties' rate design direct testimony included a Class Cost of Service study and/or a rate design recommendation but includes no or minimal increases in the fixed components of the Residential and Small General Service rate designs (i.e. Energy Grid Access Charge), many of my comments will address or otherwise be applicable to them as well.

III. ENERGY GRID ACCESS CHARGE - INTRODUCTION

Q. Please provide some overarching comments on the importance of the Energy Grid Access Charge proposed by the Company.

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 will impact the electric system from the customer side of the meter, is rapid, continual and unavoidable. From distributed solar generation, to battery storage of electricity, gains in efficiency of many electric end uses, the electrification of parts of the transportation sector, 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 receive load versus generation balancing services 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 adopted and deployed. Ameren Missouri's recommendation regarding implementation of an Energy Grid Access Charge is designed to move toward efficient pricing of the grid in order to allow the technologies I just mentioned 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.

Q. How does technology on the customer side of the meter have the potential to impact the relationship of the cost of serving customers relative to the revenues received from them and ultimately result in cross-subsidies between customers?

A. The best example is the deployment of Distributed Energy Resources ("DER") such as solar photovoltaic ("Solar PV") generation at customer premises. Solar PV, as should be obvious, is dependent on the sun shining to produce energy. Customers that install Solar PV under the Company's net metering framework may choose to size their system in a manner such that its annual generation is expected to completely offset that customer's annual energy consumption. However, without onsite energy storage or backup generation, any customer that owns enough generation to supply quantities that match every kilowatt-hour (“kWh”) the customer may consume annually still depends on the grid to deliver energy when the sun is not shining. In the absence of an Energy Grid Access Charge, and with the customer charge limited to a level that provides revenues that cover only the direct costs of connecting a customer, a customer using DER may pay nothing but that base cost of the immediate connection.[1] Under that circumstance, the customer could essentially avoid all cost responsibility for the vast network of poles, wires, substations, transformers, and other equipment from which the customer receives

[1] Due to monthly timing differences between generation output and consumption and the manner in which those differences impact billing, there may be a small amount of net revenue received from the customer annually beyond the level of the customer charge, but that amount is minimal compared to the cost of infrastructure still needed by the customer.

significant benefit. Much of this equipment is classified in the Company's and other parties' Class Cost of Service Studies ("COS") as customer-related, and its costs are therefore reasonably considered attributable to all customers, including those with DER. However, to the extent that some (or all in some parties' view of COS) of this equipment is classified as demand-related, Solar PV customers avoid paying their fair share of this category of costs. While, admittedly, Solar PV has some impact on a customer's demand, that impact is not nearly great enough to warrant the amount of costs such customers avoid in the absence of an Energy Grid Access Charge.

Q. Can you provide any quantitative evidence that the impact Solar PV has on reducing the demand customers place on the system is less than the reduction in energy for which the customer is being billed?

A. Yes. To do this, I downloaded a solar generation profile from the website PVWatts. PVWatts is a website hosted by the National Renewable Energy Laboratory that estimates the energy production from Solar PV systems at locations around the world so homeowners and business owners can evaluate the likely performance of potential systems. I used the default system parameters in PVWatts (i.e. the solar configuration that the website assumes in order to prepopulate the information it needs to estimate the energy output of a system) and the location of St. Louis, MO to generate an hourly generation profile for a system that could be installed by a customer of the Company. Based on this profile, an approximately 9 kilowatt ("kW") system would be expected to generate enough energy annually to offset 100% of the average Ameren Missouri residential customer's weather normalized test year usage. This means a customer installing this system under the current net metering framework could potentially make net payments to the Company equal to only the amount of the customer charge. Absent an Energy Grid Access Charge, this customer's net bill would reflect nothing for costs of the grid, including both the customer-related portions of basic pole and wire infrastructure as well as for demand-related costs.

I next used the hourly profile to determine the likely contribution of the Solar PV system towards meeting the customers' needs at times of peak demand. Ameren Missouri's system peak typically occurs during hour ending 17 (the hour between 4 and 5 p.m.) on a weekday in the summer months (June – September).[2] Using the PVWatts profile, I calculated that, on average at this time of the day during the summer, the 9 kW solar system would produce between 0.90 and 1.74 kW. On the summer's highest day of production (which may or may not coincide with the day of the system peak demand), the output at this time of day may be as high as 2.17 kW. Contrast this with the typical customer peak demand. The average residential customer contribution to the Company's test year weather normalized coincident peak ("CP") demand was 2.9 kW; to the non-coincident peak (“NCP”) demand was 3.0 kW; and to the Sigma NCP demand was 5.8 kW.[3] Because the peak demand is likely to occur under different conditions from year-to-year (month, day of the week, prevailing weather conditions), it is reasonable to assume that the amount of generation available at the time of peak may be anywhere in the range identified above. Based on these observations, it is clear solar generation, alone, would not come close to fully offsetting the demand of the customer that drives the system, class, or individual customer peak, and therefore the costs of the system

[2] This is the Coincident Peak time. The residential class peak is usually later, meaning there would be even less irradiance available to drive Solar PV generation during the Class Peak.
[3] Each of these types of demand is considered drivers for investment in some parts of the system.

attributable to that customer. Given these facts, it should be abundantly clear that net metering applied to a framework where only direct customer-related costs are included in the fixed charges reflected on a customer's bill would cause a situation where solar customers' bills are not covering their own cost of service.

Q. What is the effect of the revenue shortfall that results when the Solar PV customer's bill is reduced by an amount that is greater than the reduction in the cost to serve that customer?

A. Due to regulatory lag, in the short term, upon initial installation of the Solar PV, the Company absorbs that shortfall as a reduction to the revenues that are designed to give it an opportunity to recover its costs, including its cost of capital, a part of which is its authorized return on equity (i.e., cost of equity). Once the effect of the Solar PV is reflected in test period costs and revenues for a regulatory rate review, the remaining demand of the Solar PV customer on the system will continue to drive cost allocation to the Residential class, but the normalized sales for the class will be less than they otherwise would be due to the disproportionate reduction in net energy consumption by that customer. Because, as a result of the net energy reductions associated with the DER, the Solar PV customer uses less energy, when developing the new residential rate the portion of the revenue requirement allocated to that class is divided by a smaller number of kWh. The resulting rate will therefore increase for all customers in the class to make up that revenue shortfall. As a consequence, all customers in the class must pay higher rates to cover some of the costs that are attributable to the customer that installed the Solar PV; i.e., they subsidize the customer with the Solar PV system.

Where large increases have been observed in the adoption of Solar PV across parts of the country, many jurisdictions have made changes to net metering constructs or rate design to deal with just this type of cost shifting. However, making such changes after large scale adoption of Solar PV has occurred is not the ideal solution. Customers that invest their personal financial resources in DER do so based on the expectation that the investment will pay back to them through reduced energy bills. Ideally, to the extent possible, rates should be set in a manner that reflects the type of electricity pricing environment those long term customer investments will be exposed to over the DER asset's expected life. This point is underscored by the direct testimony of OPC witness Marke, who in fact recommends a disclaimer be published for customers making such investments to warn them of the possibility that rate design changes may impact the realized return on investments made on the customer side of the meter. As demonstrated by the Company's response to Dr. Marke in the revenue requirement rebuttal testimony of Ameren Missouri's witness William Davis, the Company understands the rationale of providing such a disclaimer in the appropriate context. However, a better action to take today is to do the best job possible moving toward the rate environment that we reasonably expect to be in place when customer investments in DER are paying off. This would allow the Company and the Commission to avoid such changes in the future after DER investments already have been made. Because of the cost of service and revenue impacts of DER outlined above, I contend the eventual rate design environment, which we should be moving toward today, will include revenues to cover fixed costs equating to some level of distribution system costs from DER customers. The Energy Grid Access Charge will appropriately move in that direction today.

Q. How does the Energy Grid Access Charge proposal help inform customers' investment decisions and protect against cost shifts?

A. As described previously, under Ameren Missouri's existing rate design, DER can dramatically shift the manner which fixed costs are covered under variable rates by significantly reducing customer usage with little, if any, offset to many categories of cost on the system. By adding an Energy Grid Access Charge, the Company's proposed rate design increases the revenue contribution from DER customers, which provides a modest amount of mitigation to potential DER cost shifts (i.e. there is less revenue shortfall to be made up by other customers), and more appropriately indicates to customers considering an investment in DER that it may result in less cost avoidance than the present rate design suggests.

Q. How can rate design help ensure efficient pricing of the grid such that different technologies are valued appropriately?

A. Consider the case for battery storage technologies. Battery storage technology has the potential to fit nicely in a complementary manner with Solar PV. Recalling the significant net demand a Solar PV customer will still place on the grid at peak times, a battery could store energy from the DER when it is more productive and utilize it later when it is more helpful in avoiding peak loads. Under current net metering frameworks, even if such a battery storage system was cost effective from the perspective of the grid, a residential customer installing Solar PV would have no incentive to install that equipment and deliver the benefits it could bring. This is what I meant earlier when I indicated that the Company's goal in rate design is designed to ensure that technologies compete on a level playing field. While the Solar PV may produce bill savings that exceed the true cost savings it creates, battery technology that could be paired with it may be undervalued. Efficient pricing of the grid means providing the appropriate incentive in rates to encourage investments in the combination of technologies that bring the greatest level of benefit and smallest incremental costs to the entire system. The Energy Grid Access Charge moves in the right direction, by appropriately allocating a greater cost of the grid to a DER customer. A residential demand charge is a further option for future consideration that would allow customers to benefit from the installation of battery storage to complement their Solar PV.

IV. ENERGY GRID ACCESS CHARGE – RESPONSE TO WITNESS JESTER

Q. Mr. Jester claims the Company's proposed Energy Grid Access Charge "does not reflect cost causation and is inimical to the welfare of the Company's customers." (Jester Direct, Pg. 7, Lines 4-5) What is your response to this claim?

A. Mr. Jester's rationale is founded on selective, and at times inaccurate, application of the economic principles that suit his priorities, but is not consistent with the majority of established practices used in pricing electric service under cost of service regulation, including those used previously by the Commission. Specifically, Mr. Jester appears to prioritize rate design as a means of promoting energy conservation beyond all other generally recognized issues that should be balanced in rate design discussion. However, under the practices of cost of service regulation, one of these other rate design priorities that typically carries significant weight is equity between customers, which dictates that rates should reflect the costs incurred by the Company to serve those customers. Said another way, the cost of infrastructure needed to serve one customer should, under most circumstances and to the extent practical, be covered in the rates paid for by that customer. Mr. Jester appears to recognize this priority in many comments throughout his testimony. His characterization of how to reflect cost causation in rates, however, is inconsistent with the COS studies performed by several parties to this case and traditionally relied on by the Commission.

Q. Please elaborate on the way the COS relates to rate design considerations.

A. First, it is instructive to review the process of classifying costs in the COS 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, are classified as customer-related costs. Beyond the basic costs of customer connections, billing, and support, the costs of the minimum distribution system are included in the customer-related classification in the Company's and some other parties' COS studies, which I will discuss further below.

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 and activities performed 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 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)[4].

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

A. The classification process discussed above is generally used by all of the parties involved in the regulatory rate review 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.

[4] Mr. Davis's rate design rebuttal testimony explores the possibility of recognizing specific transmission costs as energy related costs.

The upshot of this is that customer classes with better load factors[5] generally pay a lower realized rate (i.e. the total bill irrespective of the charge types that create it, divided by the kWh consumed). 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 realized rate down.

Q. How do the three cost classifications relate to rate design?

A. These classifications of cost are also useful for reflecting cost causation down to the bills of different 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.[6] The three parts relate back directly to the three categories identified for classification of costs in the COS: customer, demand and energy. Under the three part rate structure, there is a logical mapping of costs from the classifications of the COS to the rate design. Customer charges are generally used to collect customer-related costs; demand charges generally collect demand-related costs; and energy charges generally collect energy-related costs. Rate designs based on these relationships tend to result, at the individual customer level, in outcomes similar to those that occur when the results of the COS are followed for allocating the revenue requirement at the class level. That is to say, when this mapping of

[5] The load factor is a measure of how efficiently customers use the system and is calculated as the average demand divided by the peak demand. A high load factor indicates that a customer or class uses the capacity installed for its benefit relatively consistently and therefore does not cause as much idle and unproductive capacity on the system throughout the course of a year.
[6] There are many variations on the structure of demand charges and energy charges that can be customized to further promote cost causation or other rate design objectives.

costs to charge types is followed, customers with high load factors, which tend to use the system more consistently and therefore cause less idle capacity, tend to pay lower realized rates than customers with low load factors. Similarly, very low usage 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 large users.[7] This is because fixed customer-related costs that are clearly attributable to the individual are spread over fewer kWh of usage. In general, while there are still a considerable number of details necessary to consider 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 results in rates that follow cost causation.

Based on this principle, however, there is an added challenge for Residential and Small General Service rate designs. Historically, the functionality of typical meters used for these customers did not readily enable demand billing. Since much of the cost of service is demand-related, the lack of an available demand charge creates a question regarding where these costs should be reflected in an existing rate design that includes just customer and energy charges. I will return to this point later in my testimony.

Q. You mentioned the incorporation of the minimum costs of the distribution system in the customer-related classification. Please provide a high level description of the Minimum Distribution System ("MDS") and how it is analyzed.

A. Mr. Brubaker, testifying for the Missouri Industrial Energy Consumers ("MIEC"), provides a good basic description of the concept at pages 11, line 21 through Figure 2 at the top of page 13 of his direct testimony. To describe it further here, though,

[7] This outcome also generally occurs at the class level, i.e. customer classes with very high usage tend to have lower customer charges per kWh consumed, which generally follows cost causation.

the idea is that significant infrastructure is required to build out the system to reach customers just to have the ability to connect them and provide basic service. All customers benefit from this infrastructure, and therefore all customers' rates, should reflect its costs. The Company's MDS analysis was based on the premise that the extent of the distribution system (i.e. number of poles, amount of wire, etc.) would be the same regardless of demand, but the sizing of the equipment would only meet minimum engineering standards absent the aggregate demand of customers. The Company analyzed the level of costs that would be incurred if poles, wires, and transformers, etc. that met minimum engineering standards were used to cover the entire scope of the network that exists to serve all customers. These costs benefit all customers regardless of demand and therefore should be shared by them all.

Q. Do other parties to this case that presented COS recognize the MDS approach and classify some of the costs of the distribution system as customer-related?

A. Yes. As noted above, the MIEC used an MDS approach; in fact it was the same as the MDS approach used by the Company. The Staff also classified many distribution assets beyond the meter and service drop as having both a customer component and a demand component. The Staff's analysis was not entirely consistent with that presented by the Company in this case, but was based on a previous study performed by the Company. That MDS study was different in certain details and methodologies, but the underlying goal of identifying an appropriate level of joint and shared infrastructure costs to be shared by all customers is similar. In both of these circumstances, the COS prepared by those parties reflected a significant level of distribution costs that were classified as customer-related beyond those associated with meters and services that directly connect customers. In contrast, the Office of the Public Counsel ("OPC") study did not classify additional distribution assets as customer-related (beyond the meters and services). I will separately address that further below.

Q. Mr. Jester describes the joint and shared costs addressed by the MDS study as being driven by geography, rather than by customers or demand. How should geography be factored into the decision of which cost classification (or associated charge type) is appropriate to reflect them?

A. The suggestion that these joint and shared costs are driven by the geography of the system and not customer count *or* demand is not particularly helpful in determining which classification and charge type to use to reflect them, since there are no allocation factors available in any study in this case that relate to geography. Mr. Jester invokes a section of the NARUC Electric Utility Cost Allocation Manual ("NARUC Manual") to try to advance a particular solution. I will address that concept specifically later in my testimony, but to summarize here, I find that section of the NARUC Manual to clearly support these costs being reflected in a fixed monthly charge, Mr. Jester's assertion notwithstanding. However, I think it should be clear that, while the geography of the system is not perfectly correlated with customer count, customer count is far more influential in determining the geographic extent of the build-out of the system (i.e. number of required poles, feet of wire, etc.) than is the level of the demand being served in any location. Logically, again, the customer classification is a more representative and appropriate allocation factor for these costs. There is little reason, however, to suggest that those costs are most appropriately borne by customers based on total consumption, which is wholly unrelated to the geographic extent of the system.

Q. If the Energy Grid Access Charge is not adopted, and given the allocators used in the COS, what is the implication of the fact several parties recognize joint and shared distribution costs as customer-related, and even a geographic view of these costs fits best into a customer-related classification?

A. Returning to the concept that costs should be mapped to the charge type that corresponds to their classification, failure to reflect these customer-related costs in the Energy Grid Access Charge and setting the customer charge at a level that only reflects direct customer-related costs will result in rates that do not follow cost causation.

Q. Do the relationships of the COS and rate design positions of the other parties reflect this principle?

A. While MIEC does not take any position on Residential and Small General Service rate designs, the classifications in their study and descriptions in their testimony implicitly support covering some level of distribution costs through a charge such as the Energy Grid Access Charge. The Staff, however, explicitly recommends a Residential customer charge that excludes the distribution costs in accounts 364 – 367-- costs which include amounts the Staff identified and quantified in its COS workpapers as customer-related. That the Staff recognized these costs as customer-related and not demand-related suggests the Staff does not believe the level of these costs fluctuates in proportion to demand. Further, the Staff has utilized the understanding that MDS costs are incurred in a manner that is proportional to customers rather than demand to guide the assignment of class level responsibility for the joint and shared costs of the distribution system. Again, assignment of classified costs into charge types can be viewed as the intra-class extension of the cost allocation principle that ensures costs that fluctuate according to the number of customers rather than according to demand are appropriately reflected in customer rates. To the extent that Staff recommends customer-related costs be covered by energy charges, the Staff's rate design recommendation does not follow cost causation. Under such rates, lower than average use customers will inherently pay less than their true cost of service at the expense of higher usage customers. The Commission has in the past shown interest in moving classes toward their cost of service as determined by these cost allocation methodologies as reflected in the COS[8]. It follows that similar movement in rate design to align charge types with cost classification is also appropriate for the exact same reasons.

Q. Is the level of customer-related costs associated with MDS as identified in the Staff's COS sufficient to warrant the adoption of the Company's proposed Energy Grid Access Charge?

A. Yes. As I previously indicated, rates based on cost causation should classify costs for rate design purposes the same as for purposes of class cost allocations. If Staff had chosen to either reflect all costs it identified as customer-related in the customer charge, or broken out the MDS customer-related costs into an Energy Grid Access Charge, Company witness Davis estimated the Staff's COS workpapers would have supported an Energy Grid Access Charge (or incremental customer charge) of up to approximately $13 per month.

[8] "After the Commission determines the amount of rate increase that is necessary, it must decide how that rate increase will be spread among Ameren Missouri's customer classes. The basic principle guiding that decision is that the customer class that causes a cost should pay that cost." (ER-2014-0258, Report and Order, p. 69. Quoting Findings of Fact.)

Q. OPC does not classify the costs identified in the MDS as customer-related. Does this point of view mean that an Energy Grid Access Charge is inappropriate?

A. No. While it is easier to see the obvious rationale for including MDS customer-related costs in the Energy Grid Access Charge, there is still a compelling reason related to cost causation for including these costs in a fixed charge, even if they are viewed as demand-related.

Q. Please describe the reason it may be appropriate to reflect some level of demand-related costs in a fixed charge like the Energy Grid Access Charge.

A. As I mentioned previously, one challenge in designing cost-based Residential and Small General Service rates is that, historically, metering used to measure customer usage for these classes did not readily enable demand billing. Rates that most accurately reflect cost would map costs classified as demand-related to a demand-based charge. But because this option is not available for these classes, it is reasonable to question how energy-based and/or fixed charges can or should be used to equitably recover demand-related costs. Consideration and analysis of customer load data patterns suggest a portion of demand-related costs should be recovered in a fixed charge, such as the Company's proposed Energy Grid Access Charge, in order to produce an equitable result.

Q. Why should a portion of demand-related costs be considered for recovery in fixed charges like the Energy Grid Access Charge?

A. Because there is currently no demand charge to collect demand-related costs from residential customers, the available charge types should be carefully assessed to determine which remaining charge type, or what combination of the remaining charge types, provides the best substitute for a demand charge, and thus a rate design that best reflects cost causation. The current residential rate design allocates all demand-related costs to energy charges. As such, demand cost recovery from residential customers fluctuates in proportion to energy consumption. However, residential energy consumption tends to be more variable from customer to customer than are residential demands. When demand-related costs are covered by an energy charge, which is applied to highly variable customer usage instead of the less variable demand that gave rise to those costs, customers on either side of the usage spectrum tend to receive higher or lower bills than would be required to reflect their true cost responsibility.

Q. Why does energy consumption tend to vary more than demand?

A. The stock of energy using goods in homes that give rise to demand is fairly homogeneous across customers: air conditioning, refrigerators, lighting, televisions, etc. are relatively ubiquitous amongst residential customers. It therefore stands to reason that, at some point in any given month, most households run multiple similar energy consuming devices and appliances simultaneously in a manner that creates their individual monthly demand. It also follows that, since residential load is a primary driver of system peak, a majority of these customers are high in their load spectrum during times of system or class peaks, and at those times they use many of the same energy consuming devices (particularly air conditioning). While there is, no doubt, some amount variation from house to house in the number and type of energy consuming devices that operate simultaneously, there is much more variability in the frequency and duration with which those devices are used that is driven by life style and behavior differences. These lifestyle-based usage patterns are what give rise to a customer's total energy consumption.

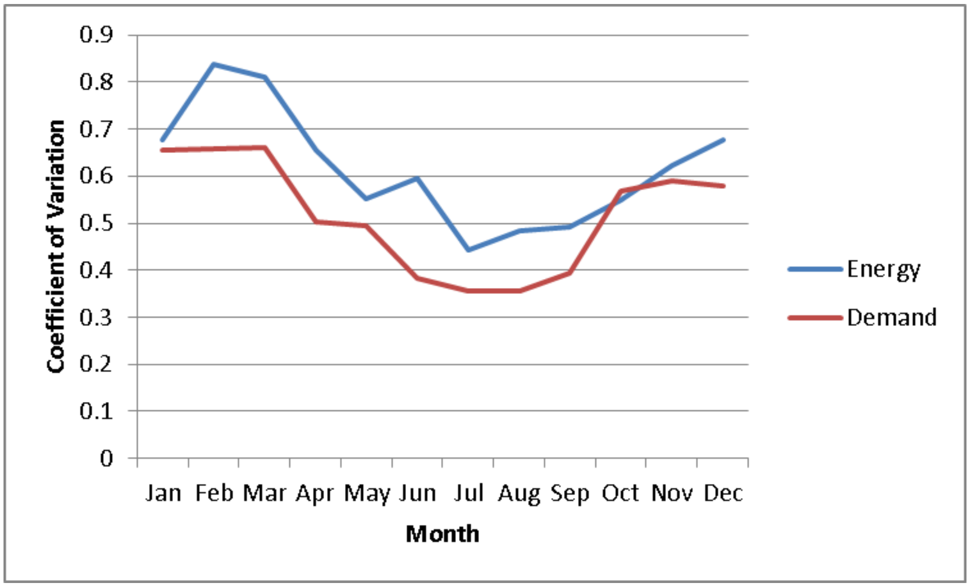
Consider two homes of similar size and construction vintage in the same neighborhood that both have central air conditioning and typical appliances, lighting and plug loads. Now assume one house is inhabited by a large family that has a parent and young children at home a majority of the time, while the neighboring house is occupied by a single professional who works long hours while no one is home. Both of these houses may have a similar demand in a summer month, as there is some hot day during the month when both homes have occupants home with the air conditioner running, some lights and a T.V. on, the refrigerator cycling on periodically, and perhaps some laundry running. These uses combine to produce similar demand for the two homes. However, despite their similar demand profiles, high usage is a daily occurrence at the home of the large family, whereas the single professional uses much less energy daily while she/he is away at work. This illustrates how two homes with similar demand may have extremely different energy consumption. From a cost causation perspective, these houses place similar demand on the system and would have similar impacts on Ameren Missouri's incurrence of demand-related costs. However, under the Company's current rate design the bills of the family that is home regularly and consumes many more kWh would bear more demand-related costs, because a portion of those costs are currently reflected in the energy charge. Generalizing this discussion to the residential population, customer to customer specifics that give rise to demand will still vary considerably. However, variability in energy consumption, which is driven more by the behavioral and life style traits of the individual end-users, is greater than variability in demand, which is largely driven by the household's stock of end-using appliances and goods.

Q. Do you have any empirical data to validate this expectation?

A. Yes. I collected information regarding Ameren Missouri's residential customers from the Company's load research database. Load research is the process by which the Company learns about customer demand patterns by maintaining a randomly selected, statistically representative group of customers that are metered on an hourly basis to draw conclusions about the usage characteristics of customer classes. From that data, I calculated the annual and monthly maximum demands of residential customers (the maximum hour of usage in the month or year) and their average hourly consumption (the sum of all hours' usage in the month or year divided by the number of hours). From this data, I observed the coefficient of variation[9] of residential customers' demand is consistently lower than the same measure for residential energy consumption. Figure 1 below shows the monthly coefficient of variation of each data series.

[9] The coefficient of variation is the ratio of the standard deviation of a variable to the mean of the same variable. This is a measure that puts two series with different units or scales on a more equivalent comparative basis in order to assess which data series is more stable. The lower the coefficient of variation, the more stable the series.

Figure 1: Coefficient of Variation of Residential Demand vs. Energy



Note that the demand coefficient of variation is lower in 11 of 12 months, and on average it is lower by 10%. This means total consumption is considerably more varied from customer to customer than is demand, which as I mentioned, suggests strongly that demand-related cost recovery exclusively in an energy charge is not the rate design solution that best reflects the cost of serving individual customers on their bills.

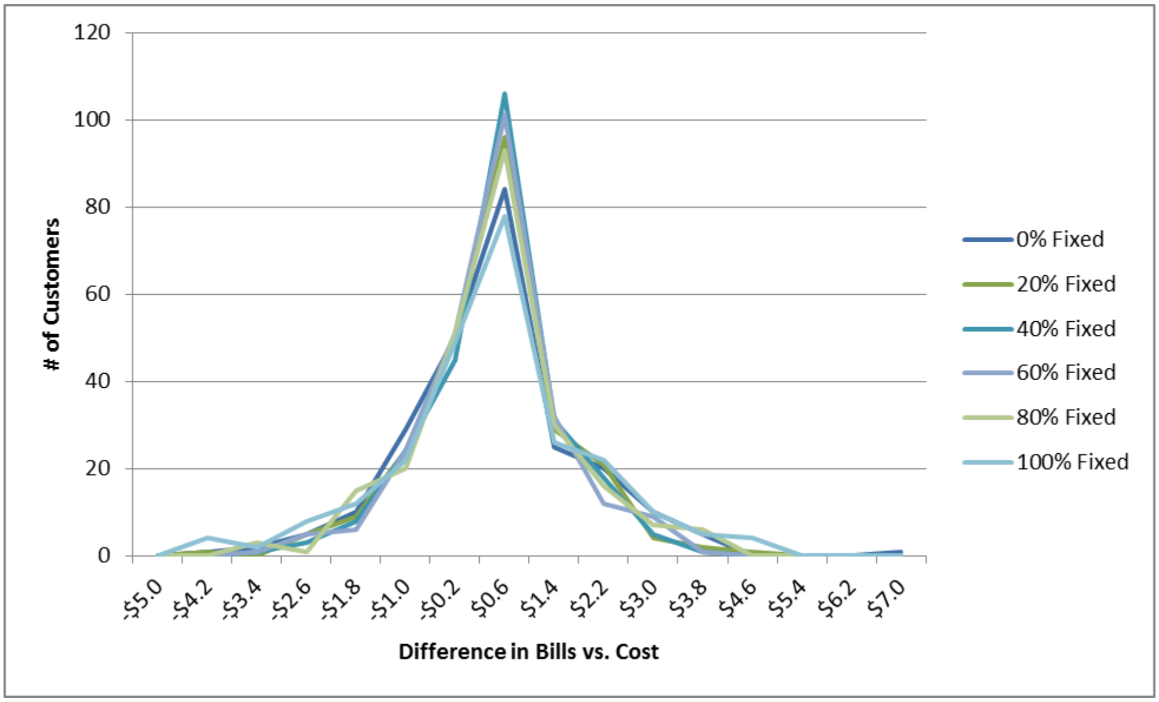
Q. How does an Energy Grid Access Charge help address this situation?

A. If revenues under energy charges are too variable to appropriately collect demand-related costs, two obvious things could be done. The first is to institute a demand charge, which would map demand-related costs into the corresponding charge type, which I discussed above as an appropriate cost-based rate making approach. However, as I also previously discussed, today's residential meters do not readily enable demand billing. Given that fact, the alternative is to move a portion of the revenue requirement from the energy charge into a more stable charge (e.g., an Energy Grid Access Charge). The combination of the flat charge and the variable energy charge can be used to synthesize an amount of revenue variation appropriate for the nature of demand-related costs.

Q. Is the Company's proposal sufficient to achieve a reasonable balance between the fixed and variable charge to create an appropriate means to collect demand-related costs?

A. Yes. I once again used the residential load research sample data to provide some analysis to demonstrate the point. The intent of the analysis is to compare different levels of fixed versus variable recovery of demand-related costs to customers' contribution to demand-related cost of service. To do this, I assumed the need to cover $1,000 of demand-related costs from customers in the load research sample, and further assumed those costs were attributable to individual customers in proportion to their four summer month demands. Next, I calculated the proportion of these costs that would be covered by rates charged to these individual customers if they were just charged in a flat energy charge (i.e. no blocks, similar to the summer energy charge rate structure in place today) using the customer's summer month energy consumption. I then varied the nature of the how these costs were covered through rates by gradually increasing the portion paid in a fixed monthly charge. Finally, I analyzed how each customer's bill under different combinations of fixed vs. variable charges compared to the demand-related cost allocation of the same customer, and produced a distribution of those results to see which framework produced results closest to the customers' cost of service. Figure 2 below shows the results of this comparison:

Figure 2: Comparison of Customer Bill Outcomes to Cost of Service



Q. Please interpret Figure 2.

A. Each scenario is represented by a different colored line. There are scenarios with 0%, 20%, 40%, 60%, 80%, and 100% of demand-related costs covered by fixed charges. A line on this graph with a greater central tendency, meaning a higher peak in the middle, means there are more customers in the load research sample whose bills would be similar to their cost of service. So, for example, in the attempt to equitably cover $1,000 of demand-related costs from these customers, the best scenario shown (which is based on 40% of demand-related distribution costs being covered by fixed charges) results in over 100 customers from the sample (106 to be exact), paying rates that almost exactly match their cost of service. Contrast this with the results apparent under the current rate design, where all demand-related costs are covered in variable energy charges (the 0% Fixed line on the graph), which results in just over 80 customers paying an amount very similar to their cost of service. In fact, it is interesting to note that the current rate design is not much more accurate in reflecting the demand-related cost of service than a rate design that covers all such costs in a fixed charge (the 100% Fixed line on the graph). I would not recommend that rate design either, but the fact it produces results similar to the outcome of 0% of demand-related costs in a fixed charge is striking.

Q. What does this suggest with respect to the Energy Grid Access Charge?

A. Even under the COS view advanced by the OPC -- where there is no recognition of the MDS analysis and all distribution costs other than meters and services are treated as demand-related rather than assigning a portion to the customer classification -- the Energy Grid Access Charge would still result in customer bills that are in closer alignment to their cost of service. The best scenario shown in the graph reflects 40% of demand-related costs being covered by a fixed monthly charge. Since the OPC's COS identifies $317 million of residential distribution costs classified as demand-related,[10] covering 40% of that amount in a fixed charge would support a charge as great as $10 per month ($317 million divided by roughly 1.04 million customers times 40% fixed coverage divided by 12 monthly bills = $10).

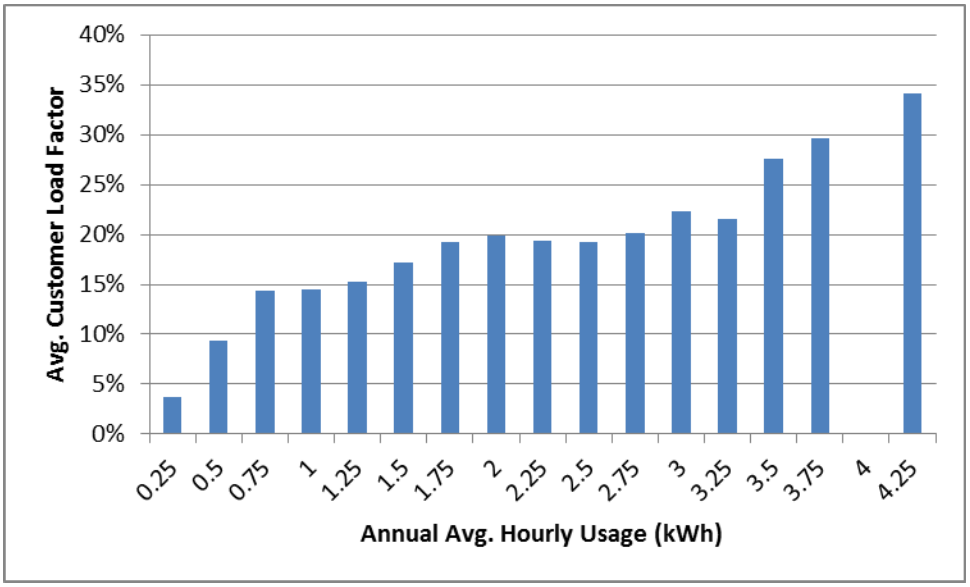
Q. Is there any other perspective the load research data can provide for the reasonableness of the Energy Grid Access Charge?

A. Yes. Recall my earlier discussion of how average realization rates (total bill/total kWh consumption) for classes or different customers within a class should change relative to their load factors. Because high load factor customers use the system

[10] This number is extracted from the workpapers of OPC witness Johnstone.

more efficiently and result in less idle and unproductive system capacity, the average rate they pay per kWh, which includes revenues to cover customer, demand, and energy-related costs, is typically and appropriately lower than a low load factor customer. Recall also that the Energy Grid Access Charge will tend to cause directionally higher realized rates for low usage customers (the fixed charge on their bill divided by a smaller usage amount results in a higher rate). I calculated the load factors of individual residential customers from the load research sample, and then looked at the average load factor for customers at different levels of average annual energy consumption. There is an obvious and strong relationship present in this data that shows low-use customers tend to have significantly poorer load factors than high-use customers. This is logical. Recall my example earlier of different hypothetical customers. A low-use customer that has her/his appliances and energy consuming goods off for long periods of time, but eventually turns several of them on simultaneously, will still have a significant demand. But the hours appliances and energy consuming goods sit idle equate to hours of unused system capacity that reduce the customer's load factor. Figure 3 below shows the average load factor of customers from the load research sample in different usage ranges. Note the consistently increasing load factor as average usage rises.

Figure 3: Average Residential Load Factor by Usage Level



This relationship strongly supports the notion that the Energy Grid Access Charge will result in a better alignment of a customer's bills with the cost of serving that customer.

Q. Are there other features of the Company's Residential and Small General Service rate designs that address the recovery of demand-related costs?

A. Yes. Both rate designs have declining block rates in effect during the non-summer period. Declining block rates refers to a rate design where one charge is in effect for the first kWh consumed each month, and a lower rate for incremental usage above that threshold. The Staff Rate Design Report in fact alludes to the disconnect between collecting demand-related costs in flat energy charges by suggesting declining block rates allow for the collection of demand-related costs in the first block. This is an accurate observation by the Staff. Assigning demand-related costs to the first energy block does move bill outcomes closer to the cost of service. However, this phenomenon, as currently reflected in the Company's rate structure, does not go far enough to mitigate the misalignment of bill outcomes and cost responsibility that arises when demand-related costs are covered by energy charges, particularly when seasonality forces a much higher level of demand-related costs into the summer period, which does not incorporate a blocked structure.[11]

Q. Returning to Mr. Jester's discussion of the MDS analysis, at page 8 of his direct testimony he suggests the MDS analysis does not reflect the marginal cost of connecting a customer to the system. He goes on to suggest that it is therefore inappropriate to reflect the MDS joint and shared costs in a fixed charge like the Energy Grid Access Charge. How do you respond?

A. Mr. Jester discusses the merits of marginal cost pricing at some length in this section of his testimony, referencing principles from Chapter 11 of the NARUC Manual. Generally, though, I would suggest his conclusions and recommendations are misinterpretations or misapplications of those principles. There are several observations I would share about his discussion.

First, Chapter 11 of the NARUC Manual is written to explain techniques for reconciling marginal costs studies with the total embedded cost of service revenue requirement. As applied in this chapter, a marginal cost study would be used to establish each charge type that would appear on customer bills in each rate class. Because the rates resulting from such a marginal cost, when applied to actual billing units, would be highly unlikely to produce revenues that equal the revenue requirement, and further, because it

[11] The Staff Report goes on to suggest that the flat summer rate could be viewed as a declining block for demand-related costs and an offsetting inclining block rate for energy-related costs. There is however no evidence that an inclining block rate is necessary in the summer for energy-related costs, or if it were, that it should be anywhere near the size of the declining block that would be necessary to properly mitigate the demand-related cost recovery issue. I will further discuss inclining block rates generally later in my testimony.

is necessary to design rates to give the utility a reasonable opportunity to recover its revenue requirement, adjustments to marginal cost prices must be made to achieve the revenue requirement (which is based on embedded cost not marginal cost) in practice. Chapter 11 discusses four methodologies to help determine where to make those adjustments, in terms of allocating them to classes and charge types.

It is important to note, though, that no party or witness, including Mr. Jester, has performed a marginal cost study for this proceeding. Consequently, there is no need to reconcile a marginal cost study to the revenue requirement, because such a study does not exist. Cost allocation and rate design recommendations from all parties that sponsored them are based on embedded cost of service studies, which inherently should develop rates that collect the embedded cost of service reflected in the revenue requirement, which would require no such reconciliation. Despite this fact, Mr. Jester recommends the customer charge should be set based on the marginal cost of connecting a customer, which suggests he assumes marginal cost is equal to customer-related costs identified in the embedded cost of service study. This is not the case and there is no evidence that Mr. Jester or anyone else in this case has analyzed or determined the marginal cost of such a connection. Therefore, Mr. Jester's suggestion the customer charge plus Energy Grid Access Charge is higher than the marginal cost to add a residential customer cannot be verified based on evidence he presented in his direct testimony. However, the marginal cost of connecting a customer is likely to be higher than the embedded cost as reflected in the COS studies prepared by the various parties, simply because the embedded cost includes equipment and infrastructure with varying levels of accumulated depreciation already accrued that would reduce the embedded cost relative to the cost of brand new assets necessary to establish new service.

But assuming Mr. Jester's argument is valid – i.e., that the joint and shared infrastructure costs that are the subject of the MDS have no obvious home in the customer, demand, or energy classifications of the COS -- it would at least be an interesting exercise to try to apply the methodologies in Chapter 11 of the NARUC Manual to the problem. Mr. Jester references Ramsey-Boiteux[12] pricing, which he argues is the appropriate means to address joint and shared costs, such as those identified in the MDS, under a marginal cost pricing paradigm. However, his invocation of the Ramsey-Boiteux pricing methodology and his interpretation of it are of questionable validity.

Q. What is your reaction to Mr. Jester's suggestion that Ramsey-Boiteux pricing is the best method to use to determine the correct charge type to collect the joint and shared distribution costs identified in the MDS study?

A. There are several things that make me question the appropriateness of Mr. Jester's testimony on this issue. First, Mr. Jester seems to suggest the NARUC Manual endorses Ramsey-Boiteux pricing as the best method to reconcile marginal cost pricing to a fixed revenue requirement. However, as I mentioned above, the manual lists it as only one of four options, and highlights strengths and weaknesses of each without indicating a clear preference for any. With respect to Ramsey-Boiteux pricing, the manual's assessment of its strengths and weaknesses include the statement that it is "generally viewed as the most efficient, but empirical problems render it administratively

[12] In my reading of Chapter 11 of the NARUC Manual, I find reference to only Ramsey pricing, not Ramsey-Boiteux. However the description of Ramsey pricing is similar to the description Mr. Jester gives of Ramsey-Boiteux.

difficult,[13] and *it is clearly discriminatory*." (NARUC Manual, Chapter 11, page 150, emphasis supplied) What makes it discriminatory? Mr. Jester correctly describes that the Ramsey -Boiteux method suggests that reconciliation of costs be allocated to customers in inverse proportion to the elasticity of those customers' demand. To say that another way, Ramsey-Boiteux pricing suggests that, regardless of the customer that is responsible for the incurrence of the cost, it should be charged to the customer that simply will not do anything about it if they are charged for it (i.e. allocate it to customers who will keep using power in the same amount despite the fact that their rate subsidizes someone else). While this might be the most similar to outcomes associated with industries with pure market-based pricing, it is antithetical to equity principles applicable to utility rates, which dictate costs be borne by the cost causer. As the manual itself states, it is clearly discriminatory in that regard.

Secondly, Mr. Jester also correctly indicates the NARUC Manual recommends Ramsey-Boiteux pricing as a means to allocate revenues *between classes*. He tries to make the case that it can be extended to allocations between charge types for a given class, as he is trying to apply it. However, whether it is appropriate to extend a methodology intended for allocating responsibility *among* different rate classes to allocate charges *within* a single rate class is explicitly addressed in Chapter 11 of the NARUC Manual, which points to a related methodology as the primary means for performing the latter type of allocation. That discussion is perhaps the most compelling application of Chapter 11 to the problem being debated here.

[13] The administrative difficulty discussion is also worth noting, because as the NARUC Manual suggests may be the case, estimates of the elasticities needed to execute Ramsey-Boiteux pricing are also not available in this proceeding.

As described in Chapter 11, the Differential Adjustment of Marginal Cost Components method (the second of the four methods discussed for reconciling marginal cost pricing to a fixed revenue requirement) suggests that excess costs relative to the marginal cost be allocated to a price *component* "primarily based on the elasticity of demand with respect to changes in the price of that component." Said another way, reconciling allocations within a class should be made to the charge type that will cause the behavior of customers within that class to change the least. Not surprisingly, the manual goes on to identify that charge type as the customer charge. As said in the manual, "it is generally alleged that the marginal customer cost component has the lowest elasticity. Sometimes, all reconciliation is made in the marginal customer cost component". (NARUC Manual, Chapter 11, page 159).

While this is phrased in economic jargon, the concept is pretty simple. The relevant question is: What is most likely to change customer behavior; changing the energy charge or changing the customer charge? If the energy charge increases, customers may, on the margin, be slightly more vigilant in turning off lights or appliances, etc – i.e. change their behavior. If the customer charge increases marginally (i.e. an Energy Grid Access Charge is instituted for roughly $5 per month), it is extremely unlikely customers will stop forming new households and establishing new electric service accounts as a result, which is about the only way a reaction to the change in the customer charge could manifest as a behavior change that impacts the use of electricity. The NARUC Manual is correct that the marginal customer cost should be expected to have the lowest elasticity; i.e. changes in the customer charge will not materially influence customer behavior. As a consequence, according to the NARUC Manual, and under a marginal cost framework, shared costs being allocated to charge types within a customer class should be put into the customer charge (or a similar fixed component such as the Energy Grid Access Charge). Mr. Jester's statement at page 8 of his direct testimony that Ramsey-Boiteux pricing "would dictate that these costs should be assigned to customers within each voltage level roughly as a percentage markup over energy costs and recovered from customers as part of the volumetric energy rate" is hard to reconcile with the actual discussion in Chapter 11of the manual. Despite the fact that we do not have marginal cost pricing at issue in this case, the NARUC Manual chapter identified by Mr. Jester is still useful, but it is useful in demonstrating that a fixed charge is exactly the right place to incorporate the type of joint costs being analyzed by MDS.

Q. Mr. Jester goes on to list a number of other reasons he believes higher fixed charges are "unjust and unreasonable." Please respond to each, in turn, starting with his comparison of utilities to competitive industries that "don't charge you by the month for the privilege of shopping, nor even charge you per visit; they charge for the goods you purchase without regard to how much you buy at one time or how often you visit the store." (Jester Direct, p. 12, l. 23 – p. 13, l. 2.)

A. There are a number of reasons this comparison does not make sense as a compelling consideration in this context. First, it ignores key differences between utilities and grocery stores, airlines, or other competitive businesses. These businesses do not also have a legal obligation to serve all customers who desire service, where they want to receive service, and at the time they desire it. If these competitive companies were suddenly legally required to be prepared to, for example, sell groceries to any individual at any time and any place within a prescribed geographic area that customer desired, the grocery store would probably seek some means for passing on the costs of being on constant stand-by for customers, regardless of the volume of goods those customers purchased.

Second, Mr. Jester's statement is, in and of itself, a gross over-simplification of the utility industry. His suggestion that customers should only pay for what they buy, and his implication that what they buy is only kWh of energy, ignores the many functions (i.e. products) the utility provides to customers that are bundled together into the rate for a kWh of electricity, such as the generation of the energy, its transmission and distribution, as well as ancillary services, such as load following and voltage support.

Consider the multiple products a utility sells in the context of DER. Under Mr. Jester's proposal that kWh charges should be higher and customer charges lower, a customer with DER that has a net metering consumption of zero in a month would not pay anything for something they receive from the utility: distribution service. Almost every hour of the day, with the extremely rare exception of a moment when a customer may happen to be generating an amount that exactly matches the customer's consumption, that customer requires a product the utility sells within its bundled rates, i.e. distribution service, to either import the energy the customer cannot generate for itself or to export its over-generation. If, at the end of the month, net consumption is zero, and the customer pays for what it buys on only a net kWh basis, the customer will fail to pay anything for the distribution service the utility provided almost constantly throughout the month.

Q. Please respond to Mr. Jester's assertion that customer charges are an abuse of market power because they are not sustainable without monopoly protection.

A. Customer charges are not an abuse of market power; they are necessary precisely because of a utility's legal obligation to serve all customers within its franchised territory. Unlike competitive industries, the utility makes individual customer-specific infrastructure investments to carry out that obligation to serve, which creates a unique direct link between service provider and customer that is appropriately reflected in an ongoing financial commitment between the two irrespective the extent of that infrastructure's utilization. Virtually every utility in every jurisdiction in the country has some level of fixed customer charge. It is a nearly universally recognized and employed rate design that helps promote equitable cost recovery from customers the utility must stand ready to serve at all times. If customer charges in this context were reasonably construed as a significant abuse of market power, it is unfathomable state regulators everywhere in the country would continue to rely on them as a cornerstone of rate design. Even municipal utilities, whose rates are set by elected officials, and electric cooperatives, whose members are responsible for setting their own rates, routinely incorporate fixed monthly charges in their rate designs.

Q. Mr. Jester claims that customer charges are against the public welfare because they impose greater costs on low-usage customers than high-usage customers. Does his conclusion follow logically from analysis of the cost of service of different types of customers?

A. No. I discussed previously that, on average, low-usage customers have a higher cost of service per kWh than high-usage customers. Recall also that, based on analysis of load research data, it is empirically evident that low-use customers tend to have lower individual load factors, which means they tend to make less efficient use of the infrastructure installed for their benefit. Further, it is worth noting again that customers with DER can have extremely low usage, but are being provided products (e.g. distribution service) constantly that they will never pay for in a net per kWh charge.

Mr. Jester goes out of his way to point out the usage level at which customers will be better or worse off under a higher fixed charge, but he provides absolutely no analysis of the cost of serving those customers to determine whether movement above or below that point is cost justified. What should be clear is that absolutely any rate design decision will impact different customers differently. It is therefore critical to ensure those impacts are equitable in terms of how they reflect cost causation, and that they are consistent with other rate design principles and priorities related to good public policy. Mr. Jester, however, seems to simply suggest that anything that reduces low-use customers' bills is inherently a good thing and anything that increases them is bad. But if a rate change is revenue neutral and provides benefits to low use customers that are not cost justified, someone else – someone that did not cause the costs - is picking up the tab. Therefore, it is extremely important to look analytically to determine whether that movement is supported by the cost of service and is otherwise equitable.

Q. What about Mr. Jester's claim that raising the bills of low usage customers through increasing fixed charges disproportionately impacts low-income customers?

A. In my experience, low-income customers, regardless of whether they use, on average, slightly more or slightly less electricity than the general population, are very much like other residential customers in that there are some that have very high usage, some that have very low usage, and some at all levels in between. The distribution of usage of the population of low-income customers is similar to the distribution of the total population of residential customers. The interesting thing about this is the fact that revenue neutral rate design changes will impact the population of low-income customers similarly to the full residential population in that it will increase some bills and decrease others. It should be noted, though, that rate design changes like the Energy Grid Access Charge, which increase fixed charges, will tend to lower the bills of large-use low-income customers. Obviously these are the low-income customers with the highest utility bills to begin with, that are therefore spending the largest percentage of their income on utility service. When fixed charges remain low, or are lowered from their current level, these high-use but low-income residential customers' bills increase in order to provide relief to low-income customers who already have comparatively more manageable bills. In this regard, revenue neutral rate design changes like the Energy Grid Access Charge are far less suited to delivering relief to low-income customers than specific, targeted measures, such as the MEEIA low-income exemption proposed by the Company and approved by the Commission in File No. ER-2014-0258.

Q. Mr. Jester also argues that higher fixed charges erode the value of net metering and push against the direction of federal and Missouri law regarding net metering. How do you respond?

A. As I discussed at the outset of my testimony, net metering is one of the issues that most obviously causes cost shifting under the current rate design. Mr. Jester notes the intent of the PURPA standards included in the 2005 Energy Policy Act as promoting pricing reforms to support three goals: energy conservation, optimal efficiency in use of utility resources and equitable rates. Two of these three goals are directly supported by the implementation of the Energy Grid Access Charge and the third is not negatively impacted to any material degree. The Energy Grid Access Charge, both as applied generally and as specifically applied to net metering customers, will promote optimal efficiency in use of utility resources and equitable rates. I discussed at the outset of my testimony the case for the Energy Grid Access Charge as promoting equity with respect to net metering. Recall that Solar PV is expected to reduce energy consumption to a significantly greater extent than it reduces a residential customer's contribution to the peak demand, which is what drives investment in many parts of the system. This results in cost shifting under net metering when recovery of joint and shared costs, as well as demand-related costs, is accomplished through energy charges. Perpetuating such cost shifting, when customers are not exposed through their bills to the true cost they impose on the system, inherently results in those customers making decisions that may appear economic from their perspective, but not truly economic from the perspective of the overall electric grid. Consequently, the Energy Grid Access Charge will tend to improve the price signal to net metered customers, which should result in more efficient use of the distribution system and better decisions by customers related to net metering options.

The final goal of the 2005 Energy Policy Act's PURPA reforms cited by Mr. Jester is promoting energy conservation. While it cannot be said the Energy Grid

Access Charge in and of itself is designed to further this goal, it is also a gross overstatement to say it materially impedes this goal. To the extent that, even under the Company's proposal there is still a material level of demand-related cost recovered through energy charges, for the reasons already discussed the variable price that remains will still result in bill savings from DER that exceed the level of avoided demand-related costs on the distribution system. The rate design from that perspective still promotes DER induced load reductions beyond the level that a rate that fully reflected cost causation to such customers would. I will further address the energy conservation argument below in response to Mr. Jester's concerns regarding the impact of the Energy Grid Access Charge on energy efficiency programs.

Q. Do you have any other comments on the impact of the Energy Grid Access Charge on the appropriateness of net metering policy?

A. It is noteworthy that Brightergy witness Jessica Oakley discusses in her direct testimony the merits of formally studying Value of Solar programs adopted in Minnesota and Texas. I will return to that specific point later in testimony, but the concept of Value of Solar is relevant here. Value of Solar studies are, at a high level, an attempt to evaluate rate designs and/or new and different frameworks for compensating Solar PV customers for the value of both the incremental costs and benefits their generation brings to the grid. The conclusions from these programs often times result in the replacement of net metering with new policies and/or rate designs. The proliferation of such studies across the country suggests quite strongly there is one approach to rate design for Solar PV customers that we know does not equate to the Value of Solar, and that is net metering as applied to traditional embedded cost of service rates. Net metering applied to embedded cost of service rates cannot be said to result in cost-based rates because the Residential rate that results from a COS study is a function of the load characteristics of average residential customers. Residential net metered customers with Solar PV behind their meters have markedly different net load characteristics, and as such have a distinctly different cost of service than a traditional residential customer who takes all her/his power from the grid. Net metering has been promoted by some as an attempt to provide incentives to jump start the solar industry. As pertains to this case however, where net metering will most clearly still remain in place, the relevant question is whether the Residential rate design including an Energy Grid Access Charge still affirmatively promotes DER. As I have argued above, it does, inasmuch as the bill savings a customer can realize still exceed the true embedded cost of service reductions attributable to the Solar PV.

Q. In furtherance of his concerns regarding the impact of the Energy Grid Access Charge on energy conservation goals, Mr. Jester points to a NERA study on price elasticity. Using this study he attempts to draw inferences regarding the effect the proposed rate design change will have on observed loads in the future. Please comment on this topic.

A. I disagree with Mr. Jester's conclusion that implementation of the full Energy Grid Access Charge would result in a materially higher load level based on the effects of price elasticity, as characterized by the NERA study. I say this for a number of reasons.

There are basically two views on how elasticity (the phenomenon where customers use less of a product the more it costs, and vice versa) operates with respect to utilities and their customers. One is that individual customers respond to the rate on the margin – or said another way, a customer asks, "what is the price I will pay for the next kWh I consume?" in order to guide its consumption decisions. The other is that customers respond to their total bill – or said another way, a customer gets a bill that appears high to them relative to previous bills and decides they need to manage their usage better to control their bill. While both of these types of responses are almost certain to occur in at least some customer situations, I would suggest that the total bill response is much more common.

And this is an important distinction. If customers respond to the total bill more than to the marginal rate, a revenue neutral rate design change such as the Energy Grid Access Charge will not change the response of the population of customers overall, because it does not change the average bill. Some individual customers may experience increases or decreases relative to what they would experience under a different rate design, but these would offset each other across the population. Under this view, the total bill that customers respond to will still tend to increase as long as Ameren Missouri is in a state of regular rate reviews that reflect the impacts of inclining costs and flat or declining loads. An inclining cost environment where bills tend to rise over time keeps the concept of energy conservation and bill management to the forefront of customers' minds, regardless of the rate design and its associated marginal rate. While this phenomenon may break down if the rate design change was radical or extreme, that simply cannot be said of the Energy Grid Access Charge. The Company's proposal would move from collecting approximately 7% of Residential revenues in fixed charges to 12%, leaving 88% in variable charges that can be managed by customer decisions and actions going forward. That simply cannot be characterized as a radical rate design change that will result in customers ignoring the bill increase they are experiencing due to higher revenue requirements.

It is important to observe that the NERA study Mr. Jester references specifically measures the type of response I just described: response to overall bill increases and not a response that might occur as a result of a rate design change. I will try to explain this without getting too technical. The specific econometric design of the NERA study is not intended to analyze what Mr. Jester portrays. The statistical model is specified to use *total realized price* (among other variables) to explain changes in consumption over time. Specifically, the price variable of the study is defined as the "–[n]atural log of deflated *residential revenue per unit sales* volume using US census region cpi and urban consumer as deflator" (NERA Study[14], p. 3, Table 2, emphasis added) The implication of this is that the study does nothing to measure the impact on consumption of changes in the price for the marginal kWh consumed, such as those that a revenue neutral rate design change like the Energy Grid Access Charge would represent. Application of the study's results to the marginal price changes calculated by Mr. Jester in his estimates of load changes that may be observed as a result of the Energy Grid Access Charge is therefore inappropriate and would not accurately indicate true changes that would be expected.

Q. Are there other reasons that the load changes Mr. Jester projects based on elasticity assumptions applied to rate design changes that result from the Energy Grid Access Charge should be questioned?

[14] Ros, Agustin. An Econometric Assessment of Electricity Demand in the United States Using Panel Data and the Impact of Retail Competition on Prices. NERA Consulting. June 2015.

A. Yes. First, while Mr. Jester relies on the NERA study[15] estimates of elasticity, he also correctly points out there are many price elasticity studies that have been performed over the years that have yielded a wide dispersion of results. The NERA study itself summarizes elasticity estimates from much of the published literature, and demonstrates this dispersion. NERA reports published elasticity estimates for various classes and over various time periods ranging from 0 to -3.26[16]. That is a huge range, and underscores the point that, even though the theoretical concept of elasticity is economically accepted, it is tremendously difficult to precisely estimate its magnitude. Inasmuch as I have already demonstrated Mr. Jester's estimates of the impact of the Energy Grid Access Charge on consumption are a flawed application of the estimates he uses, I would further caution that any estimates of demand pattern change should be viewed as uncertain.

The other reason I question the application of a significant elasticity assumption to the Energy Grid Access Charge is that I question the fundamental assumption that load would increase significantly if variable prices declined modestly. It is worth noting that the reduction in the variable charge that results from the implementation of the Energy Grid Access Charge will be less than the increase in the variable charge if the Company's requested revenue requirement is granted, meaning the variable rate would not decline *at all*. But even to the extent the variable charge is lower than it otherwise would be, it is important to consider the way that elasticity impacts usage changes. Elasticity effects are often broken out into short run and long run impacts. The higher published elasticity

[15] http://www.nera.com/content/dam/nera/publications/2015/PUB_Econometric_Assessment_Elec_Demand_US_0615.pdf
[16] Even within just the Residential class, the results range from -0.2 to -0.98, meaning the response at one end of the range would be approximately 5 times the response at the other end.

estimates are associated with long run effects. These effects are usually related to changes in the stock of energy consuming goods. Short-run effects tend to be attributed more to behavior changes that impact the manner in which existing energy consuming devices are utilized. While short-run effects might operate symmetrically (i.e. a customer may engage in energy saving behaviors as prices rise and lapse into more passive usage patterns as prices fall), the long run elasticity impacts, which result in structural changes to the stock of end using goods, are more likely to operate asymmetrically (i.e. customers that may invest in more efficient appliances when prices rise are much less likely to increase consumption when prices fall by reverting to less efficient technologies). This is particularly true in a time period, such as today, when the efficiency of energy consuming goods is largely either dictated by federal efficiency standards or influenced heavily by utility energy efficiency incentives. As an example, when rates (and bills) rise and customers try to increase management of their usage to moderate their bills, their first (short run) reaction might be to turn of lights in their home more vigilantly. If prices fall later, customers may lose some of that vigilance and exhibit modest increases in utilization of their lights. But in a longer run reaction to the initial price increase, they might gradually change all of the lights from inefficient but cheaper up-front bulb technologies, such as incandescent bulbs, to a more efficient but more expensive up-front bulb, such as LEDs. With the longer life and declining technology costs of efficient lighting, it is very unlikely that a customer will revert to less efficient lighting technology in the future if rates (and bills) decrease.

Based on what I said above, I do not mean to suggest elasticity does not exist and rate design is unimportant in guiding customer consumption decisions. Thoughtful rate design that sends appropriate price signals for customers to make efficient decisions is a laudable goal we should continue to pursue. However, Mr. Jester's characterization of the specific impacts of this proposed change is grossly overstated in my opinion.

Q. Mr. Jester questions the validity of the statements made in the direct testimony of Mr. Davis, which you subsequently adopted, regarding the impact of the Energy Grid Access Charge on utility energy efficiency programs. Please address his comments on that topic.

A. Mr. Jester claims the imposition of an Energy Grid Access Charge will impact marginally cost effective measures and result in less adoption of those measures and less corresponding savings. It is important to return to the notion, though, that the overall cost effectiveness of measures as reflected by the Total Resource Cost test ("TRC") is not impacted at all by rate design. Rate design may impact participant incentives to adopt a measure, but those effects, if they are observed (i.e. a measure is not being taken up at the anticipated or desired rate), could be addressed by increasing the direct program incentive to participants. The end result is the same either way – the customer is financially incented to adopt either through up-front payments or through the promise of future payments in the form of bill savings. Under either approach, all customers end up paying for the incentives to the participant. Rate design is really unnecessary to use as a tool to ensure robust adoption of marginal measures in energy efficiency programs. Regardless, it seems unlikely that the minor impacts on customer bill savings will have a perceptible impact on participation in energy efficiency programs.

Q. What other claims about the impact of the Energy Grid Access Charge on energy efficiency programs do you wish to address?

A. Mr. Jester questions the Company's direct testimony discussing the favorable impact that the Energy Grid Access Charge has on the Rate Impact Measure ("RIM test"). He claims the Energy Grid Access Charge itself will have a negative effect on the bills of non-participants that exceeds the positive effects that will manifest on non-participant bills as a result of the improvement in the RIM test. This is an odd statement, and I do not understand Mr. Jester's basis for making it. The Energy Grid Access Charge, I emphasize once again, is revenue neutral to the class as a whole. To spell it out once more, there is a decrease to the variable energy charge that offsets the fixed charge increase on customer bills. Based on this revenue neutrality, it should be apparent the overall impact of the Energy Grid Access Charge on the collective bills of the population of non-participants in energy efficiency programs is also neutral. So any benefits to non-participants represented by the improved RIM test result will accrue to those same non-participants, with no corresponding overall negative impact from the Energy Grid Access Charge.

Mr. Jester also states that more of the energy cost reductions that result from energy efficiency programs will accrue to high users. But that also is true with respect to the resultant rate increases from spreading fixed costs over fewer kWh (i.e. recovery of the revenue requirements associated with the throughput disincentive). Both of these effects are represented in the RIM test. As such, an improvement in the RIM test resulting from the rate design change should directly indicate that the change itself will benefit non-participants.

Q. Mr. Jester shares a chart from a Synapse Energy report on fixed charges across the country. What observations do you have about the information represented by this chart?

A. I suggest this chart does little to guide the Commission on the decision in this case. There is a substantive and robust record in this case on which the Commission can consider the merits of the arguments and analysis that apply to local circumstances. Furthermore, the chart of national results shows little apparent consistency across jurisdictions. Over half of the decisions reported result in an increase in the customer charge, while others do not. I would further note the utilities shown on the chart appear to be sorted from the top to bottom according to the size of the pre-existing customer charge. Ameren Missouri's customer charge is below 35 other utilities and only higher than 15. And again, this is before any granted increases. Factoring in results of recent decisions reported in the referenced Synapse Report, at least four more utilities (for a total of 39) now have customer charges exceeding Ameren Missouri's. But the overarching takeaway is there does not appear to be consensus nationally, so the Commission should carefully weigh the evidence in this case to reach its own conclusion.

Q. Please summarize your rebuttal testimony on the Energy Grid Access Charge.

A. Rate design is always a matter of balancing competing priorities. The arguments against the Energy Grid Access Charge focus almost entirely on the desire to utilize rate design almost exclusively as a tool to drive customer load reductions. However, this focus comes at the expense of the type of equity considerations that have long been a hallmark of cost of service-regulated rate making. The evidence is clear that

Ameren Missouri's current rate design promotes cost shifting from low users to larger users. This cost shift is most obvious in the impact of Solar PV, which reduces energy consumption to a significantly greater extent than it reduces the impact of the customer who owns it on the peak demand that drives investment in the system. But beyond DER implications, the evidence presented in my testimony also demonstrates that smaller users generally tend to have poorer load factors, which cause more idle and unproductive capacity on the system. As a consequence, these customers -- under the normal practice of using the classification of costs to customer, demand, and energy categories to reflect costs in rates to the customers who cause their incurrence -- also fail to provide revenues commensurate with their cost of service. This is true regardless of the classification of the distribution costs that are the subject of the MDS analysis. When understood as customer-related costs, these should clearly be mapped to a fixed charge in order to result in cost based rates. But even if characterized as demand-related costs, the existing means of covering them – exclusively in energy charges – does not accurately reflect the character of customer demands, and similarly results in rates that fail to reflect customers' underlying cost of service.

To return, though, to the point of view reflected in the testimony of the Sierra Club/Renew Missouri – specifically that the priorities of the rate design should be directed almost exclusively toward incentivizing usage reductions - it should be apparent that the changes at issue in this case are not well-suited to delivering material results. Elasticity estimates relied on by Mr. Jester are applied inappropriately to overstate expected load reductions, and suggestions regarding the impact of the rate design on energy efficiency are simply unsupported and inconsistent with how these programs really function.

Implementing the Energy Grid Access Charge is a common sense step that will bring customer bills closer to alignment with the cost of serving those customers while having little discernable impact on the goal of generally promoting energy efficiency.

V. INCLINING BLOCK RATES

Q. Both Mr. Jester and Mr. Hyman recommend the Commission institute movement to remove declining block rates in the non-summer period and to institute an inclining block rate for the summer period. What concerns do you have with this recommendation?

A. Almost the entire discussion regarding the impact of the Energy Grid Access Charge on promoting cost based rates that was presented earlier in this testimony applies here as well. Recall that under the existing rate design, large use customers are currently paying bills that tend to exceed their cost of service while smaller use customers are paying less than the cost they impose on the system, because both MDS customer-related costs and demand-related costs are included in the energy charge. There can be little doubt the rate design movement requested by these parties would seriously exacerbate this condition. Increasing the marginal rate on usage over 750 kWh and decreasing the rate of smaller users would further shift cost responsibility in the opposite direction dictated by the previously presented analysis of the cost of serving different customers. Further, the proposal would have significant negative impacts on customers that use electricity for their primary space heating fuel, would increase fixed cost recovery losses experienced under the Company's energy efficiency programs, which must be made up as a surcharge on all customers' bills, and would generally increase both customer bill and utility revenue volatility.

Q. Why does the proposal negatively impact electric space heating customers?

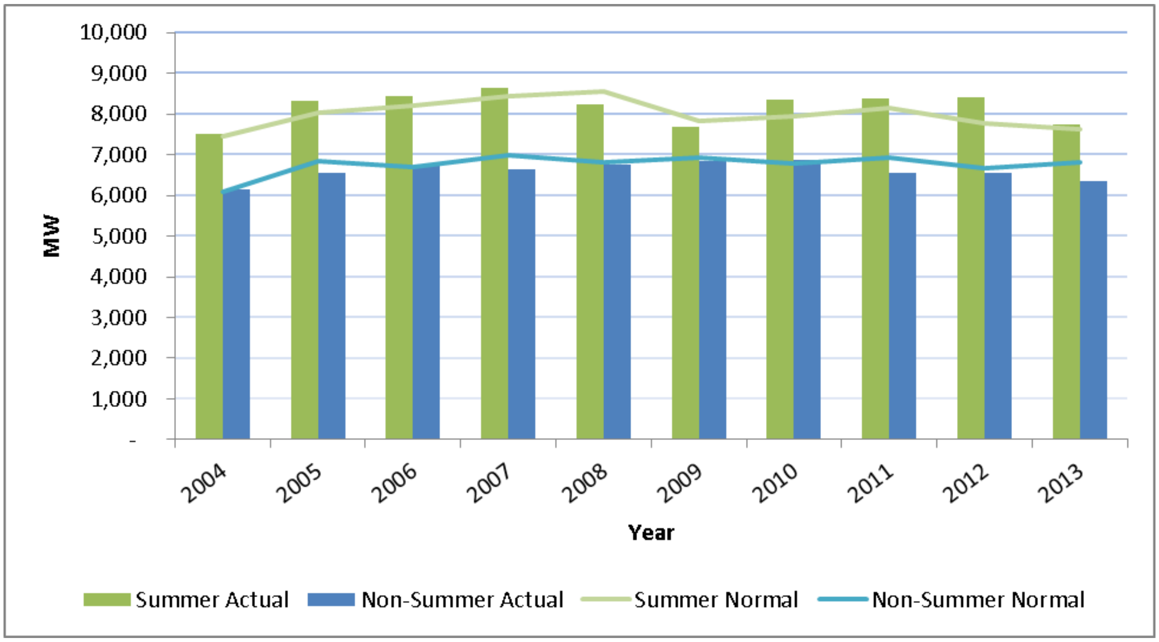
A. Electric space heating customers currently benefit the most from the incumbent declining block rate structure, and this benefit is aligned with cost of service considerations. Because electric space heat customers typically use much more energy in non-summer months than customers that primarily heat with natural gas or another fuel, they are far more likely to exceed the 750 kWh block threshold and pay the lower block rate for most of that heating related usage. As a point of reference, an electric furnace in Ameren Missouri's service territory uses approximately 6,800 kWh per year, with approximately 1,300 kWh in the winter months that require the most heating, clearly demonstrating this usage, when added on to the customer's base usage, occurs largely at the lower block price. Increasing that price by flattening the rate structure (or even inclining the tail block) would quite obviously negatively impact these customers' bills.

Both Mr. Jester and Mr. Hyman recommend gradual movement in the blocked rate structure that limits the impact on the 5th and 95th percentile customers to 5 percent in this case, but also recommend additional movement in future cases. Compounding such increases over multiple cases, as proposed, is more gradual, but Mr. Jester's and Mr. Hyman's proposals will still result in very meaningful increases in the energy burden for space heat customers over time that is not supported by cost of service considerations. This is a significant issue for the Commission to consider given that an estimated 25% of the Company's residential customers, or roughly a quarter of a million households, rely on electricity for the primary fuel for space heating.

Q. What evidence can you provide that the increase on space heat customers is not cost justified?

A. Again I would invoke the concept that I discussed at length in the Energy Grid Access Charge discussion, i.e. that large use customers tend to pay more than their cost of service when demand-related costs are collected in an energy charge due to the difference in variability of those measures of usage. However, without a declining block rate the problem is exacerbated in the winter, because the winter peak does not drive the need for investment in capacity on the bulk system (i.e. generation, transmission and high voltage distribution). This is clear by looking at the differential between summer and winter peak loads. Consider the chart of historical weather normalized seasonal peak loads from the Company's 2014 Integrated Resource Plan ("2014 IRP") shown below as Figure 4.

Figure 4: 2014 IRP Summer and Non-Summer System Peak Loads



Note the non-summer weather normalized system peak load is consistenly around 1,000 megawatts ("MW") lower than during summer. While the data is three years old, this condition of Ameren Missouri's system exhibiting a clear summer peak has most definitely not changed in that time. It should be apparent from this fact, though, that winter peak loads from space heating customers do not drive the need for incremental generating capacity additions. By extension, it can also be inferred that the design of bulk (high voltage) distribution systems, which serve very large populations, is driven overwhelmingly by the summer peak.

The next logical inference is that as long as the winter tail block rate is set at a level that exceeds energy-related costs – which it clearly is today – revenues from it are making a contribution to recovery of fixed demand-related generation, tranmission, and/or distribution costs. That benefits all customers, because the contribution towards fixed costs lowers the revenue contribution necessary from every other kWh. So to the extent the declining block rate attracts space heating customers and the associated incremental electric consumption that otherwise would be served by another fuel, it increases the efficient utilization of the existing infrastructure of Ameren Missouri's system. Recall the three goals of the 2005 Energy Policy Act changes to PURPA cited by Mr. Jester – one of which was to promote efficient utilization of utility resources. That goal is furthered by reducing the amount of otherwise idle non-summer capacity and spreading fixed costs over a larger base of kWh to the benefit of all.

Q. How would the removal of declining block rates in the non-summer months and/or the institutionof inclining block rates in the summer impact lost fixed cost recovery under MEEIA energy efficiency programs?

A. As a part of the Commission-approved MEEIA framework for Ameren Missouri's energy efficiency programs, the Company is made whole for fixed cost recovery that is foregone when the Company successfully induces customers to adopt efficiency measures. This is referred to as the throughput disincentive. The amount of lost fixed costs associated with these energy savings is a direct function of the marginal rate in the Company's rate structure. To the extent the marginal rate increases (i.e. the declining block is reduced or removed and/or an inclining block as added), the value of the lost fixed cost recovery increases in direct proportion. That means rates charged through the MEEIA framework would increase if this rate design change were adopted.

Q. Why would such a change in the block rate structure increase volitility of customer bills and utility revenue?

A. Once again, increasing the marginal rate customers pay for incremental changes in usage magnifies the resulting change in customer bills, regardless of the cause of the usage change. The same is true of utility revenues derived from those customer bills.

Consider the impact of extreme weather. While in regulatory rate reveiws we weather normalize usage, actual bills and revenues are influenced – both up and down from that normalized level – regularly by extremely severe or mild weather conditions. Recall that the variable rate is used to collect a large amount of fixed costs of generation, transmission and distribution infrastructure. Weather driven usage changes have little connection to changes in costs associated with such infrastructure. As such, weather driven fluctuations in bills/revenue represent situations where either customers or the Company tend to fare better in any given year or month. Because these outcomes tend to be random and we weather normalize in rate proceedings to conditions expected to persist over the long run, this phenonenon should not typically result in systematic biases. But it clearly results in short run fluctuations and volatility that are not good for planning purposes or cash flow stability for either the Company or its customers.

Take as an example the summer of 2016. It was an extremely hot summer. In the June billing month alone, based on weather normalization calculations produced for this proceeding, customer usage exceeded normal usage by 14%. This resulted, at currently effective rates, in the typical residential customer bill increasing by almost $15 in that month. If an inclining block rate were instituted, with an illustrative increase in the marginal (tail block) rate of $0.03/kWh from today's flat rate, that almost $15 increase in bills would have been increased to more than $18. Considering the slightly over one million residential customers served by the Company, this extraploates to an incremental

$3.7 million in revenues – with no change in cost – that would result just from the combination of such a rate design change and extreme weather.

Q. Mr. Jester suggests that "inclining block rates tend to increase the marginal cost of electricity for customers and in months with high weather-related demands. Thus a shift away from declining block rates and toward inclining block rates will serve to better align customer charges with cost causation." (Jester Direct, p. 22, l. 2-5) Does he provide any evidence that this is the case?

A. No. Earlier in his testimony, as I discussed previously, Mr. Jester extolled the virtues of marginal cost pricing. But he does not provide any suggestion, let alone analysis, of what the marginal cost of energy or capacity is. Neither does he provide any analysis that ties customer bill outcomes back to the embedded cost of serving them, as I did in my discussion of the Energy Grid Access Charge. That finding, applied in this context, similarly suggests an inclining block rate would move customer outcomes away from their embedded cost of service. The economic concepts that Mr. Jester relied on in his discussion of maginal cost pricing – i.e. that societal welfare is maximized when marginal cost pricing is used – applies in this context as well. Setting the marginal rate artificially above the marginal cost, as Mr. Jester proposes, may very well result in load reductions where the customer values service the customer is foregoing above the marginal cost of the service (the condition that Mr. Jester points out as maximizing societal welfare), but cannot acquire the service due to the artificially inflated price point. This is particularly important when the weather gets extreme and customer decisions to utilize air conditioning and heating equipment impact their comfort, health, and safety.

Q. What is your overall recommendation regarding the suggestion to remove declining blocks and institute inclining blocks?

A. I believe this recommendation is the wrong path for Ameren Missouri's rate design. It would promote customer outcomes that are less consistent with the cost of service, materially and negatively impact roughly 250,000 electric space heating customers in a manner that is inconsistent with the cost of providing service to them and the benefits they bring to the system, and cause unnecessary volatility for customer bills and Company revenues.

I would also note that, as discussed in the testimony of Mr. Davis, the rate design interest of various parties in Time of Use ("TOU") Pricing has more long run promise to create beneficial changes for all stakeholders. Further, if and when enabling meter functionality is deployed, combinations of enhanced TOU offerings as well as consideration of Residential and Small General Service demand charges may move rate design in a manner that is able to simultaneously reflect the cost of service more accurately to customers and provide a powerful and much more accurate price signal for customers to take actions that reduce the overall cost of service and enhance efficient utilization of utility resources. I suggest that the Commission reject the proposal to move toward inclining block rates and, instead, continue to consider the merits of other more appropriate rate design changes in future cases; and especially consider how more advanced metering opens up more rate design options.

VI. VALUE OF SOLAR

Q. Ms. Oakley testifying on behalf of Brightergy mentions the benefits of the Value of Solar model to encourage the development of DER. Do you have any comments?

A. First, I would observe that there is no direct recommendation made by Ms. Oakley regarding actions that should be taken on Value of Solar. As a result, I will provide a couple of additional perspectives on the topic. Ms. Oakley notes the potential for this approach to result in a rate that would give customers more certainty when investing in Solar PV. She contrasts this approach to uncertain outcomes under net metering. Presumably then, the rate that would emerge from a Value of Solar study would replace net metering. While there may be merit in theory to such an approach, current state law requires the Company to offer net metering, so its replacement is not a matter of just proposing an alternative in a regulatory proceeding.

Q. Are there other observations you would like to share about this proposal?

A. Yes, there are two. First, as Ms. Oakley implies when she says "there are several possible inputs to determine this value" (Oakley Direct, p. 7, l. 12-13), Value of Solar proceedings will likely raise more questions than they answer. Different stakeholders tend to include broader or narrower definitions of the value being studied, depending on their priorities and the point of view from which they approach the issue. Further, many drivers of the value of solar energy can be very subjective, and the estimates of value can range widely based on varying assumptions and studies. This can make such studies more of an exercise in frustration than a solution to a problem.

Second, it is important that such a study, which would potentially form the basis for long term compensation of DER as Ms. Oakley suggests, not just ascertain the Value of Solar itself, but compare and contrast it with the value of other long term alternative resources. Just because a Value of Solar may have been established, it does not mean there are not more cost effective ways to obtain the same benefits on behalf of customers. Therefore, the results of a Value of Solar study should only be used to the extent that the long term rate commitment benefits customers relative to other resource options.

Q. Does this conclude your rate design rebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.	)))	**File No. ER-2016-0179**

AFFIDAVIT OF STEVEN WILLS

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

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

1. My name is Steven Wills. I work in the City of St. Louis, Missouri, and I am employed by Ameren Services Company as Director, Rates and Analysis.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 58 pages and Schedule(s) N/A, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Steven M. Wills

Steven Wills

Subscribed and sworn to before me this 24th day of January, 2017.

Mary Hoyt

Notary Public

My commission expires:
4-11-2018

Mary Hoyt - Notary Public
Notary Seal, State of
Missouri - Jefferson County
Commission #14397820
My Commission Expires 4/11/2018