Ameren Exhibit 3.0

ILLINOIS COMMERCE COMMISSION

DOCKET 16-0387

REBUTTAL TESTIMONY

OF

STEVEN M. WILLS

Submitted On Behalf

Of

AMEREN ILLINOIS COMPANY
d/b/a Ameren Illinois

October 25, 2016

TABLE OF CONTENTS

ILLINOIS COMMERCE COMMISSION

DOCKET 16-0387

REBUTTAL TESTIMONY OF

STEVEN M. WILLS

Submitted On Behalf Of

Ameren Illinois

I. INTRODUCTION

Q Please state your name, address and current position.

A. My name is Steven M. Wills. My business address is 1901 Chouteau Avenue, St. Louis, MO 63103. I am the Director of Rates and Analysis. In that role, I provide regulatory services for Ameren Illinois Company d/b/a Ameren Illinois (AIC or the Company).

Q Are you the same Steven M. Wills who sponsored direct testimony in this proceeding?

A. Yes, I am.

Q What topics did you discuss in your direct testimony?

A. My direct testimony discusses the Company's proposals for revenue allocation and rate design that would be effective for January 2018 bills.

Q What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to Illinois Commerce Commission (ICC or Commission) Staff witness Cheri Harden, Illinois Office of Attorney General (AG) witness Scott J. Rubin, Citizens Utility Board (CUB) and The Environmental Defense Fund

(EDF) (collectively CUB/EDF) witnesses Diane Munns and Jeffrey Zethmayr, and the Illinois Industrial Energy Consumers (IIEC) witness Robert R. Stephens.

Q Please summarize the recommendations of Ms. Harden.

A. Ms. Harden agrees with a number of proposals identified in and supported by AIC's direct case. Ms. Harden, however, does not support AIC's proposed rate design for delivery service (DS) 1 and DS-2. Specifically, she proposes to decrease the proposed DS-1 and DS-2 customer charges. Whereas AIC proposes to increase cost recovery for the DS-1 customer and meter charges from 36.4% to 40%, Ms. Harden proposes to decrease costs recovered through those charges to 30%. She also proposes to decrease costs recovered through the DS-2 customer and meter charges from 33.2% to 28%. In addition, Ms. Harden asks AIC to address (1) any DS-5 (lighting) tariff changes; and (2) the potential bill impacts resulting from movement to rate uniformity over the three-year period coupled with an increase in the overall revenue requirement in future annual formula rate update cases.

Q Do you agree with all of Ms. Harden's recommendations?

A. No. I do not agree with Ms. Harden's recommendation to decrease cost recovery for the DS-1 and DS-2 customer and meter charges. The evidence supports a higher cost recovery through the customer and meter charges, not lower. My rebuttal testimony explains my opposition to Ms. Harden's proposals and the related proposals for DS-1 rates offered by the AG and CUB/EDF.

Q Please summarize the recommendations of Mr. Stephens.

A. Mr. Stephens addresses one issue - the Company's proposed revenue allocation. He recommends that uniform rates should not be pursued in any particular year to the extent that it causes revenues for the class or subclass to exceed the rate moderation constraints set forth in Docket 13-0476.

Q Do you agree with all of the recommendations of Mr. Stephens?

A. Not entirely. The Company, however, recognizes that there is some benefit to providing additional certainty that the movement to uniformity will not exceed predefined thresholds to address certain circumstances that could arise.

Q Please summarize the recommendations of Mr. Rubin, Ms. Munns and Mr. Zethmayr.

A. All three witnesses testify in opposition to the Company's proposal to recover 40% of residential revenue through fixed charges. For a variety of reasons that share some commonality across witnesses, these parties believe it is appropriate to lower the share of residential revenues derived from fixed charges. Specifically, Mr. Rubin recommends the fixed recovery percentage be reduced to 26.4%, and Mr. Zethmayr recommends 28%. While, as I mentioned, there are some common arguments raised by these witnesses, each has some unique analysis or perspective as well.

Q Do you agree with the recommendations of Mr. Rubin, Ms. Munns and Mr. Zethmayr regarding DS-1 rates?

A. No. I believe that the analyses, interpretations of data, and policy concerns presented by these witnesses are unpersuasive. Where issues are common across multiple witnesses, I may respond to a point raised by one witness with information equally applicable to all. For those unique issues and analyses particular to an individual witness, I will address them separately.

Q Are you sponsoring any exhibits in support of your rebuttal testimony?

A. Yes. I will be sponsoring the following exhibits with my rebuttal testimony:

- Ameren Exhibit 3.1: Exemplar DS-5 Tariff – Baseline LED Offering
- Ameren Exhibit 3.2: Exemplar DS-5 Tariff – Proposed Rate Design Changes
- Ameren Exhibit 3.3: Peoria Journal Star Article on High Summer Bills

Q Are you also providing workpapers in supports of your rebuttal testimony?

A. Yes. I have provided the following workpapers with my rebuttal testimony related to various analyses that I will discuss throughout this rebuttal testimony:

- "Demand related costs allocated to charge types.xlsx"
- "2015 Cost of Service Sample Analysis.xlsx"
- "Population weighted sample sizes.xlsx"
- "Rate Design Impact on EE.xlsx"
- "CUB analysis of outliers.xlsx"
- "Low Income Analysis.xlsx"

Q Before responding to each witness, can you please provide some perspective on the importance of residential rate design in this case?

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, battery storage of electricity, gains in efficiency of many electric end uses, the electrification of parts of the transportation sector, 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, 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. The Company fundamentally believes that the role the distribution system plays in integrating these technologies will remain critical to ensuring the availability of a safe, reliable, and affordable energy system for all customers in the future. AIC is committed to embracing and enabling the implementation of new technologies that are cost effective or that provide other benefits desired by customers. AIC's recommendations regarding residential rate design, rather than trying to discourage the adoption of any particular technology, are designed to ensure efficient pricing of the grid to allow technologies to compete on a level playing field, and to ensure that they are integrated in a manner that reflects both the costs and benefits that they bring to the system. The grid's paramount role in enabling these technologies, however, makes delivery service rates a poor choice for a means of subsidizing technologies, even if policy goals call for some level of subsidies. The mechanisms for subsidization exist in other channels, such as Renewable Energy Credit (REC) procurement activities, and/or tax credits authorized by statute.

Q. Is evidence of this change already reflected in the record in this case?

A. Yes. Ms. Munns, testifying on behalf of CUB/EDF, discusses the draft National Association of Regulatory Utility Commissioners (NARUC) Manual on Distributed Energy Resources Compensation and provides that draft as an attachment. While it is important to note the draft status of the manual[1], the existence of the draft is noteworthy in and of itself. NARUC's

[1] NARUC is still accepting and assimilating comments on the draft, and may further revise the manual based on that feedback prior to publishing it.

Electric Utility Cost Allocation Manual, published in 1992, is a respected collection of thoughts on a variety of rate design topics. After 24 years, NARUC now sees a need to weigh in again on rate design issues, policies, and methodologies specifically due to the emergence of some of the technologies and concepts I mention above. While it is premature to place too much reliance on the content of the draft while NARUC continues to work with stakeholders to refine it prior to publication, there is an important message, even in an excerpt from the draft manual quoted by Ms. Munns: "[B]eing aware of the continual pace of change and adoption rates of technologies by customers, a regulator can identify appropriate strategies for addressing these changes in a more *proactive* manner." (Draft Manual at 60, emphasis added.) As will be addressed specifically later in my testimony, several parties' witnesses indicate that the Commission should not be persuaded by the discussion in my direct testimony regarding demand rates and the merits of charting a course that will allow for what I believe to be the smallest bill impacts in the future because the Company has not made a firm proposal to use demand rates in the future. I believe that that point of view is in direct contrast with NARUC's admonition to address innovative changes proactively in the rate design arena.

Q. Are there any examples you can cite of the consequences of failing to consider rate design changes proactively in the face of technological innovation and adoption?

A. Yes. The experience in Nevada is very relevant. On June 5, 2015, the Nevada Legislature established a net metering cap of 235 megawatts (MW) or approximately 3% of peak capacity of the regulated Nevada utilities. See Nevada Revised Statutes (NRS) section 704.773 (2015). As of May 18, 2015, the net metering penetration was only 145.6 MW[2], but within a few

[2] Nevada Legislature, 2015 (Regular) Legislative Session, Senate Bill 374, May 25, 2015 Hearing before the Nevada Assembly Committee on Commerce & Labor, at p. 7, statement by utility representative, Shawn Elicegui.

months, by August 20, 2015, the capacity of net energy metering applications hit the 235 MW cap.[3] The Public Utilities Commission of Nevada subsequently imposed a new net metering structure that resembled more of a buy-sell type of arrangement,[4] which was considered by net metering customers to erode the value of their individual investments, and triggered an enormous backlash.[5] After a lengthy series of rehearings, empanelment by the Governor of Nevada of a New Electric Energy Task Force to address the issue, and court review, a compromise was reached to reinstate net metering benefits to existing net metering customers and transition to the new buy-sell arrangement over time.

The Nevada example is important for several reasons. First, Nevada shows how quickly net metering caps may be reached when conditions become conducive and use of distributed energy resources (DER) proliferate. In just three months, net energy metering applications totaling almost 90 MW were received by the Nevada utilities. Second, redesigning rates and reevaluating valuation frameworks after customers have made significant personal financial commitments based on one set of rules can be a difficult and painful process. While the changes in rate design under consideration in this case are not as extreme as the Nevada buy-sell arrangement, the actions of the Commission today will inform the investment decisions of Illinois customers considering committing significant financial resources to their own DER. The rate designs that may be deployed tomorrow, which will exist well within the lifecycle of those

---

[3] Public Utilities Commission of Nevada, Consolidated Docket Nos. 15-0741 & 15-07042, Interim Order dated September 1, 2014, p. 5, Section IV, Background, para. 1.

[4] Public Utilities Commission of Nevada, Consolidated Docket Nos. 15-0741 & 15-07042, Modified Order dated February 17, 2016, at para. 336.

[5] An article in the Las Vegas Review Journal describes the backlash, and is available at: http://www.reviewjournal.com/business/energy/nevada-net-metering-service-charge-hike-announced.

DER investments, are very relevant to the decisions that should be made on the rate designs we implement today.

Q. How does AIC's proposed rate design help inform customers' investment decisions and protect against cost shifts?

A. Under two-part rates, like AIC's rates, DER can shift recovery of costs under variable rates by significantly reducing usage. For example, Rider NM – Net Metering calculates energy and delivery service charges on the net amount of electricity used by the customer. Yet, as noted in NARUC's Draft Manual at page 23, "us[ing] distribution as an example, under traditional ratemaking, a reduction in usage, and thus revenue, in a single year driven by DER may lead to little, if any, reduction of the costs of the system – the territory still has the same number of poles, wires, and other equipment, all with the same useful life." Any reduction in revenue from the DER deployment not offset by a commensurate decrease in costs will inevitably result in higher rates for all customers the next time rates are reset. If today's rates are designed so that more costs are recovered through a variable rate, then more costs may be shifted from DER customers to non-DER customers. Customers considering investing in DER might evaluate payback periods under the assumption that reduced usage will result in a greater reduction in overall utility bills. Should rate design change in the future to either a demand charge or a higher fixed charge in order to reduce the impact of the cost shift on other customers, the results of the original economic analysis relied upon by the customer making the DER investment may become invalid. By only slightly increasing the recovery of costs through the fixed charge for DS-1 customers (to 40%) today, AIC's proposed rate design avoids exacerbating potential DER cost shifts, and more appropriately indicates to customers considering an investment in DER that less costs associated with the distribution system may be avoided through DER.

Q. Is such a scenario like Nevada's regarding the adoption of private solar generation plausible in Illinois?

A. Yes. As noted in the Nevada example, the solar penetration increase happened very rapidly once conditions were conducive. Once there are enough installation contractors and vendors in the region, and the right economics come into play, there can be an inflection point where adoption suddenly takes off. The economics could be driven by declining panel costs, tax incentives, or direct subsidies through REC procurement activities. Per the latest Illinois Power Agency (IPA) report dated September 27, 2016, the IPA already has a Renewable Energy Resources Fund with a balance of nearly $190 million potentially available to be deployed. While it is unclear if and when or to what extent this balance will be authorized for Solar REC procurements, the IPA to date has already procured $30 million in Solar RECS[6]. This type of activity can and may lead to the development of a robust market for private solar generation. When this happens, any rate design in place will be the foundation for the investment decisions of numerous Illinois residents and future changes will impact the return these customers recognize on the investments already made. It is best to contemplate policy prior to the time when significant investment is made to ensure to the greatest degree possible that changes to the environment around those investments do not result in materially different outcomes than the customers intended and assumed when committing their financial resources.

II. <u>RESPONSE TO MS. HARDEN</u>

Q Have you reviewed Ms. Harden’s direct testimony?

A. Yes. I have reviewed Ms. Harden’s direct testimony, ICC Staff Exhibit 1.0.

---

[6] 2017 Procurement Plan Filed for ICC Approval, page 102, section 8.5 "Alternative Compliance Payments Held by the IPA in the Renewable Energy Resources Fund"

Q Does Ms. Harden support the use of a single Cost of Service Study?

A. Yes. Ms. Harden recognizes the significant progress that has been made toward blending the legacy utilities into a single entity and agrees that a single Cost of Service Study (COSS or ECOSS) is reasonable and will increase the efficiency of rate design.

Q. Does Ms. Harden support the classification of Other Revenue as demand related?

A. Yes. She recognizes that this change has no impact on customer rates and drives reporting consistency within the COSS.

Q Does Ms. Harden support movement to uniform rates over the three-year period?

A. Yes. She again finds that the transition to uniformity has progressed sufficiently such that now is the right time to take the final step of achieving complete rate uniformity. Further, she generally agrees with the approach the Company has proposed for implementing that final step.

Q Does Ms. Harden support the proposed rate design for the DS-3 class?

A. Yes. The only change in the Company's proposal that deviates from what the Commission has already approved for the DS-3 class is the deliberate movement to uniformity of all rates over three years. As previously discussed, Ms. Harden agrees with that proposal.

Q Does Ms. Harden support the proposed Reactive Demand Charge?

A. Yes. Ms. Harden agrees that it is appropriate to update the Reactive Demand Charge based on the Company's calculation of cost of providing reactive demand service in an attempt to incent power factor improvements from DS-4 customers.

Q Does Ms. Harden support the proposed Transformation Capacity Charge?

A. Yes. She supports the Company's approach to address the unique nature of the costs reflected in this charge.

Q Does Ms. Harden support the proposed rate design for the DS-4 class?

A. Yes. Other than the items discussed above, the only additional change from the currently approved methodology is the deliberate three-year movement to uniformity, to which Ms. Harden agreed.

Q Does Ms. Harden support the proposed rate design for the DS-5 Lighting class?

A. Yes. She recognizes the merits of creating a fixed rate to collect fixture related costs for unmetered Company owned lights.

Q Are there any other AIC proposals that Ms. Harden supports?

A. Yes. She agrees with the updated revenue allocators for rate zones, the current revenue allocators for rate classes, the treatment of the Electric Distribution Tax (EDT), and the continued use of a labor allocator for the allocation of General and Intangible Plant for Advanced Metering Infrastructure (AMI).

Q Does Ms. Harden support the proposed rate design for the DS-1 and DS-2 classes?

A. No. Ms. Harden appears to premise her position on these particular rates on past Commission orders expressing a preference for movement toward "cost-based" rates. Because Ms. Harden associates that term with rate designs where only the customer-related costs from the COSS are collected in a customer charge, she believes that AIC's proposal does not achieve that objective.

Q Ms. Harden also discusses policy reasons for adopting a rate design with a lower fixed-charge percentage. Specifically she mentions “cost causation,” “reduce[d] energy usage” and “increase[d] energy efficiency” as reasons to further decrease fixed-cost recovery. (ICC Staff Ex. 1.0 at 20:451-53.) Do these principles support Commission Staff’s (Staff) proposed rate design?

A. No. I will discuss Ms. Harden's cost causation concerns further here. For a response to the issues related to reducing energy usage and increasing efficiency, please refer below to my response to the witnesses sponsoring testimony on behalf of CUB/EDF.

Q Ms. Harden argues that her proposed DS-1 rate design moves “closer to, not farther away from, the results of the COSS.” (ICC Staff Ex. 1.0 at 21:461.) Do you agree?

A. No. Ms. Harden's assertion is based on the notion that only customer-related costs should be collected in the customer charge for rates to be considered "cost-based". While I agree that under cost-based rates, the customer-related costs should be reflected in a customer charge, that does not mean that these are the *only* costs that can be in a cost-based customer charge, particularly when only two rate elements (customer and energy) are available to collect three classifications of cost (customer, demand, and energy). Absent a demand charge, it is appropriate to view the options for collection of demand-related costs as a continuum from 100% recovery in the customer charge, to 100% recovery in an energy charge, and anywhere in between. I provided extensive analysis and discussion in my direct testimony to support the conclusion that, based on the empirical relationship of demand and energy consumption, the most appropriate cost-based solution is somewhere in the middle of that continuum, where the demand-related costs are split between both the customer and energy charges. My proposal was to collect 40% of the total cost in the customer charge (excluding EDT). The implicit breakdown that underlies this proposal is that the entire 26.4% of customer-related costs be reflected in the customer charge, in addition to approximately 18% of demand-related costs. That leaves approximately 82% of demand related costs for recovery in the energy charge.

Q. Has Ms. Harden provided any specific rationale for incorporation of demand-related costs exclusively in an energy charge?

A. Not in testimony, other than a brief reference to past Commission decisions and references to cost-based rates. However, in response to data request AIC-ICC 1.01, Ms. Harden agreed that if a three part rate design including demand charges were available, the cost based solution would be to collect demand-related costs in that demand charge. She was also asked what rate design would be considered a cost-based solution for demand-related costs in a two-part rate. Her response first acknowledges that demand related costs could be collected through "one or *both*" (response to data request AIC-ICC 1.01, emphasis added) of the available charges. She goes on in her response to only evaluate the options of collecting demand-related costs in one charge or the other, but never considers the possibility that I have presented in this case; that is, to allocate the demand-related costs in part to each charge type in order to come up with the most optimal cost-based solution. Based on my analysis, increasing the proportion of demand-related costs recovered in the energy charge relative to the current rate design, which is what Staff, the AG and CUB/EDF in this case propose, would clearly result in moving a rate element away from cost. That is to say, my analysis indicates that a cost-based solution for demand-related costs under two part rates should utilize both the customer charge and energy charge. Removal of demand-related costs from the customer charge in fact moves the portion of demand-related charges that is appropriately collected in the customer charge to the energy charge, resulting in a rate design that moves "farther away from the results of the COSS."

Q Ms. Harden disagrees with the price signal that your proposed design would send. She states that increasing the customer charge would send a price signal that "indicat[es] that varying costs such as usage and demand charges are less important" and that "de-emphasizes demand." (ICC Staff Ex. 1.0 at 19:424-28.) Do you agree?

A. No. A two part rate design that meets Ms. Harden's criteria for being considered cost-based by collecting all demand-related costs in an energy charge provides the same signal every hour of the month and year. Under the current rate design, as well as Staff's proposal, a customer has no more incentive to reduce their peak load than they have to reduce consumption in the other 743 hours of the month[7]. This scenario does nothing to promote better system utilization, higher load factors, and lower unit costs. Admittedly, the Company's rate design proposal is similar in this regard, as peak hour reductions simply cannot be targeted in delivery service rates unless and until a demand charge is introduced. That said, insistence that the full demand-related cost be pushed into that energy charge results in a rate that sends what I would argue is too strong of a signal to reduce load in these other 743 hours. Even if one argues that long-term delivery infrastructure investment may be reduced when peak demand declines, it should be clear that distribution system costs do not change in any time horizon due to changes during low usage or off-peak time periods. A price signal that places too much emphasis on the energy charge in a manner that is not grounded in a cost based analysis that recognizes the inherent difference in energy consumption and demand may actually promote load reductions at times that are easier for customers to achieve them, with little impact on peak periods. The result may be poorer load factors, more periods of under-utilized system capacity, and higher average unit costs over time. The obvious example of this outcome is in fact DER, which may be promoted by too strong of a

---

[7]Assuming a 31-day month. Other months may have 720 hours, 672 hours, or in a leap year 696 hours.

variable price signal presented by rates that force all demand-related costs into an energy charge, resulting in distribution costs shifting to other customers. Just because we do not have the tool in our rate toolbox today to target demand reductions specifically does not make it efficient to direct all demand-related cost recovery into an energy charge. This is especially true at a time when the tool to target demand reductions in our rate design may be available in the near future.

Q Ms. Harden also dismisses your bill impact analysis, arguing that "there are too many unknowns to consider it sufficient justification for changing the rate design in this docket." (ICC Staff Ex. 1.0 at 20:445-446.) Do you agree?

A. No. While the exact future rate design may be unknown, the analysis that I have presented has clearly established the cost based foundation for the Company's proposal based on evidence of the relationship between demand-related costs and the available charge types for collecting them. I continue to argue that it is logical to consider what may happen in the future, but I hardly think we need that specific knowledge to conclude that the Company's proposal is appropriate.

Q Ms. Harden also argues that her proposed DS-1 rate design "can provide stability in rates" and will "help to eliminate cross-subsidies." (ICC Staff Ex. 1.0 at 21:463-64.) Do you agree?

A. No. In fact, the opposite is true. With respect to stability in rates, it is instructive to review the history of AIC's residential rates. This history is discussed at more length in Mr. Rubin's direct testimony, but the fixed charge portion of the residential rate design evolved over time from collecting customer-related costs in the customer charge to a condition where up to 45% of total residential costs were in the customer charge. That percentage subsequently fell to 36.4% as an outcome of the 2013 rate design docket. Any competing proposal to the Company's in this case would further lower the customer charge. The level of the customer charge has risen and fallen, and would fall further once again under other current proposals. The Company's proposal of a 40% fixed charge falls squarely in the range that the rate design has been for at least the last 7 years, at either 36.4% or 45%. Keeping in mind my discussion of the importance of setting a rate design that will transition well into a future with rapid technological innovation, it would be ill advised to further lower the customer charge if that is not reflective of efficient pricing of the grid as I have argued here.

The same can be said of eliminating cross-subsidies. If cost-based pricing means collection of demand-related costs partially in the customer charge and partially in the energy charge, removing more costs from the customer charge would necessarily have a greater potential to increase cross-subsidies. Again the example of DER is the extreme case, where the cross-subsidies resulting from cost-shifting would be clearly exacerbated by the rate design recommended by Ms. Harden. For further discussion of the relationship of individual customer outcomes relative to cost, please see my discussion below in response to AG witness Rubin.

Q Ms. Harden makes the same arguments in support of her proposed DS-2 rate design. Are her arguments also unconvincing support for her proposed DS-2 rate design?

A. Yes. While the specific percentage of costs recovered through fixed charges for the DS-2 class may differ from the DS-1 class, the rationales supporting the Company's proposed rate design are largely the same. There is no more reason for collecting demand-related costs exclusively in a customer charge for this class than for the DS-1 class.

Q Ms. Harden also recommends that the Company address two additional topics in rebuttal: (1) any necessary DS-5 tariff changes and (2) the potential for large bill impacts (for presumably any rate class) when the movement to uniformity is coupled with a future increase to the revenue requirement. Have you considered these requests?

A. Yes.

Q Have you identified any necessary changes to the DS-5 tariff?

A. Yes. I provide exemplar tariffs as Ameren Exhibits 3.1 and 3.2. I will describe briefly why there are two tariffs attached. Prior to rates that are influenced by this docket going into effect, the Company anticipates a filing requesting changes to DS-5 allowing the Company to offer Light Emitting Diode (LED) fixtures to its customers. I have attached an example of how I expect that tariff to be structured, because, if approved by the Commission, this will actually be the baseline tariff to which modifications resulting from this docket are applied. This baseline tariff is represented in Exhibit 3.1 and is designed to create the LED offerings that will be available and to update the terms of the grandfathering of other lighting technologies. While the exact timing is still uncertain and minor details may be updated if necessary, AIC anticipates filing this tariff in the second quarter of 2017 and requesting a 45 day approval. As such, certain dates in the exemplar tariff attached are identified with "xxxxxx" as a place holder for the final dates. Exhibit 3.2 represents the tariff that incorporates into that baseline tariff the rate design changes that the Company is requesting in this docket. The Company anticipates filing this with its 2017 Rate MAP-P formula rate update case to be effective for 2018 rates.

Q Does the Company have any proposed adjustments to its rate mitigation to address Ms. Harden's other concern – bill impacts?

A. Yes. While the Company believes its proposal does not pose a significant risk of creating the types of rate changes that I would characterize as rate shock, I recognize Ms. Harden's concern regarding the compounding of a potential base rate increase with movement to uniformity as a legitimate scenario that should be addressed. The additional mitigation I am proposing to alleviate this concern is discussed below in response to Mr. Stephens.

III. RESPONSE TO MR. STEPHENS

Q Have you reviewed Mr. Stephens' direct testimony?

A. Yes. I have reviewed Mr. Stephens' direct testimony, IIEC Exhibit 1.0.

Q What issue does Mr. Stephens address?

A. Mr. Stephens discusses AIC's proposed revenue allocation, specifically AIC's proposal to transition all rates to uniformity.

Q What is Mr. Stephens' position on the transition to uniform rates?

A. Mr. Stephens recommends that the Commission determine the annual movement for a rate class or subclass toward uniform rates, within the constraints of the overall rate moderation criteria as applied within each rate zone. He proposes that "further movement toward uniform rates should not be pursued in any particular year to the extent that it causes revenues for the class or subclass to exceed the rate moderation constraints set forth in Docket 13-0476." (IIEC Ex. 1.0 at 5:4-7.)

Q Mr. Stephens is concerned that AIC "has placed a greater importance on reaching uniform rates than on protecting customers through rate moderation." (IIEC Ex. 1.0 at 3:5-6.) Do you agree?

A. No. While the Company does think achieving uniform rates is an important objective that will reduce complexity of rate administration and reflect the nature of combined operation that the consolidated utility has achieved, moderating customer bill impacts is still an important consideration in the Company's proposal.

Q. Is the Company requesting a change in its revenue allocation methodology in this proceeding?

A. No. As provided in Ameren Exhibit 1.1, AIC will still have a mitigation constraint for each class and subclass (e.g., the various voltage levels with unique rates under DS-3, DS-4, and DS-6) established at the greater of 1) 0.025¢/kilowatt (kWh) overall increase, 2) 10% or 3) a constraint multiple of the system average increase based on a sliding scale starting at 1.5 times the system increase for overall increases less than 10%, and reduced by 0.0125 for each percentage point of system average increase greater than 10%, but not less than a factor of 1.0.

Q Mr. Stephens believes that the fact that the methodology described in Ameren Exhibit 1.1 indicates that rate movement toward uniformity will occur sequentially after the class level revenue is established in the revenue allocation/mitigation process, and an individual rate zone may experience a larger increase than permitted under the mitigation criteria. Is this a change from previously approved revenue allocation methodologies?

A. No. The previously approved methodology allowed rates that met certain threshold criteria *after* the revenue allocation and initial pricing was completed to become uniform. This methodology inherently means that an individual rate zone subclass could have realized a rate increase that exceeded the class level threshold established in the revenue allocation process even under the previously approved methodology. The only difference today is that the movement toward uniformity will occur whether or not the criteria for immediate uniformity are met, but still after the revenue allocation and mitigation process occurs. The initial revenue allocation and pricing process is the foundation for assessing the appropriate movement toward uniformity, and as such, there needs to be some accommodation for that uniformity movement at the end of the process.

Q Mr. Stephens indicates his concern arises from the +100 kV DS-4 rate subclass, which is modeled in the Company's filing to receive a 22% increase. His concern is that movement to uniformity may cause customers to receive a higher level of increase in certain rate zones. Can you address this concern?

A. Yes. The +100 kV DS-4 subclass achieved a uniform Distribution Delivery Charge in the Company's proposed rates in Docket No. 16-0262. Should that result hold in the final rates calculated pursuant to the Commission's order in that docket later this year, there will be no need for any further movement in Distribution Delivery Charges to achieve uniformity. The only thing that could cause a rate increase for any zonal subclass that exceeds the mitigation constraints is movement in the rate for EDT. The process that addresses movement of EDT charges toward cost was litigated in Docket 13-0476 and affirmed on appellate review to be reasonable. Because EDT charges are already uniform in Rate Zone II, and most of the rate increase impacting the DS-4 +100 kV customers is directed toward achieving EDT uniformity, it would be impossible to set a subclass revenue target that would be applied uniformly to each rate zone. In order to work with a single COSS and revenue allocation process and yet achieve the EDT uniformity already approved, there is by necessity a small amount of flexibility needed for unique levels of rate increases across zones that in total produce the target subclass revenue. However, the uniformity movement described in the quote from Ameren Exhibit 1.1 referenced by Mr. Stephens will not be applicable to the class (the +100 kV DS-4 subclass) regarding which he raises this concern due to the uniform outcome expected from Docket 16-0262.

Q What potential impact will following the EDT uniformity methodology have on the total delivery service rate impacts realized by DS-4 +100 kV customers at the rate zone level relative to the mitigation threshold?

A. In recent annual formula rate updates, the +100 kV DS-4 subclass has been subjected to the mitigation constraint that prevents increases from exceeding $0.00025 per kWh. In the Company's modeling of 2018 rates in this proceeding using the proposed methodologies, application of the $0.00025/kWh constraint resulted in a 22% increase for the class; this value was highlighted by Mr. Stephens in testimony. Allowing rate zone specific movement toward EDT uniformity pursuant to the approved plan while constraining the total class to a 22% increase resulted in the highest increase going to Rate Zone III, modeled at 26.3%. The realized cents per kWh impact of this increase on customers in the zone would be $0.00027, or two one-thousandths of a cent higher than the class specific constraint. I believe this extremely minor deviation from the class level mitigation threshold is reasonable in order to achieve the goals of EDT uniformity and rate class level adherence to the mitigation constraint. In considering the years in which this methodology will be utilized, I find it difficult to envision a scenario where the methodology proposed by the Company would result in a materially higher rate zone specific increase than the $0.00027/kWh result I reported above.

Q Might other subclasses still be impacted by your proposal to deliberately move delivery service rates (other than EDT) to uniformity after the application of the mitigation constraints?

A. Yes, and as Mr. Stephens observed, I acknowledged this potential in my direct testimony. I identified the DS-4 Primary Voltage subclass as having the potential for a rate zone specific increase to exceed the applicable class level increase by the largest amount on a realized cents per kWh basis. My modeling of 2018 rates showed a potential for rates applicable to this subclass in Rate Zone II to exceed the mitigation constraint by approximately $0.001/kWh. I estimate that such an increase in pursuit of uniformity may cause a typical Rate Zone II DS-4 Primary Voltage customer's total bill[8] to increase by approximately 4.1% when a similar customer in the other rate zones would increase by an estimated 2.4%.

Q Do you believe that AIC's proposed rate mitigation will maintain gradualism and avoid rate shock?

A. Yes. The $0.001/kWh realized increase in delivery service bills and the potential 4.1% increase in the total bill impact do not strike me as increases that rise to the level that I would consider to introduce rate shock. Based on these expected outcomes I believe the majority of scenarios I can envision in the context of annual formula rate updates will result in increases that maintain a reasonable degree of gradualism.

[8]Total bills include power supply and transmission service. The Company's Rider QF rates are used as an estimate power supply prices.

Q Regardless, has AIC modified its proposed rate mitigation in response to Mr. Stephens', as well as Ms. Harden's, concerns?

A. Yes. While, as I indicated, most scenarios should not result in excessive increases to any rate zone subclass, the compounding effect of a large overall rate increase and movement to uniformity could cause impacts that warrant additional consideration. The Company proposes to pursue its original plan, except to add an additional mitigation threshold that will cap the movement to uniformity under certain circumstances.

Q Please describe the additional safeguard you propose that may limit movement toward uniformity under certain circumstances.

A. For the three classes[9] that have Distribution Delivery Charges (DDC) that still need to become uniform, a $/kilowatt (kW) threshold will be established that is not to be exceeded in pursuit of uniformity[10]. All of the steps I described in direct testimony will be followed as originally described in Ameren Exhibit 1.1. The final increase in the DDC for Rate Zone II (the zone moving up toward uniformity in all cases[11]) will be compared to the following class specific $/kW thresholds. For the DS-3 Primary subclass, the threshold is $0.208/kW; for the DS-4 Primary subclass, the threshold is $1.209/kW; for the DS-4 High Voltage subclass, the threshold is $0.586/kW. If the rate increase, calculated as the proposed DDC less the prior (i.e. currently in effect) DDC exceeds that threshold, the movement to uniformity will be scaled back

[9] For this additional mitigation, I am excluding the lighting classes. As discussed in my direct testimony, the energy savings associated with the introduction of LED will provide some total bill mitigation of the movement to uniformity as those lights are rolled out.

[10] If the existing methodology produces increases exceeding these thresholds prior to uniformity, the rate increase would not be further mitigated.

[11] In the case of the DS-3 Primary class, both Rate Zone I and II are moving up to uniform. Rate Zone I would follow the mitigated price established for Rate Zone II as described herein.

proportionally until the increase equals that value, or until no movement to uniformity has occurred. The total revenues for the subclass will not be impacted by this, meaning that the decreases applicable to zone(s) moving downward toward uniformity will also be scaled back on a revenue neutral basis for the subclass as a whole.

Q How did you arrive at the values for the class specific thresholds that will cap movement to uniformity?

A. I began with the $/kW increase modeled in the Company's analysis that supported its direct filing. Acknowledging that this filing was premised on the same revenue requirement as Docket 16-0262 (i.e. the 2018 illustrative rates that were calculated implicitly assume a zero overall rate increase next year), and that the cap needs to accommodate the possibility of some system average increase prior to limiting uniformity, I increase each value by 10%. Any overall rate increase that would drive the subclass specific rate to increase more than this value would then be mitigated.

Q Does this leave open the possibility that uniformity could be delayed beyond the three year transition that you proposed in direct testimony?

A. Yes. But the Company believes that a modest delay in achieving the benefits of uniformity would be acceptable under the circumstances described that would trigger this safeguard.

IV. RESPONSE TO MR. RUBIN

Q Have you reviewed Mr. Rubin's direct testimony?

A. Yes. I have reviewed Mr. Rubin's direct testimony, AG Exhibit 1.0.

Q What issue does Mr. Rubin address?

A. Mr. Rubin addresses AIC’s proposed DS-1 rate design.

Q What does Mr. Rubin recommend?

A. Mr. Rubin recommends that the Commission reduce the DS-1 customer charge. He recommends that the customer and meter charges collect the “customer-related cost of service,” as he identifies those costs from the ECOSS. (AG Ex 1.0 at 4:72) He estimates that based on the ECOSS, approximately 26.4% of residential costs are “customer-related.” He claims that his proposed rate design is “reasonably consistent with the cost of serving residential customers” and “the fairest proposal overall to all residential customers.” (AG Ex. 1.0 at 4:76-77, 80-81.)

Q Do you agree with his recommendation for DS-1 rates?

A. No. Mr. Rubin's conclusions are based on a flawed analysis that I will discuss at more length below.

Q What does Mr. Rubin offer in support of his recommendation?

A. Mr. Rubin argues that AIC has not evaluated whether its proposed rate design would be “consistent with principles of cost-based ratemaking.” (AG Ex. 1.0 at 3:62-63.) He claims that he has performed such an analysis on AIC’s sample group of customers and concludes that “any likely demand-based rate actually would do a worse job of collecting revenues in proportion to the cost of serving a customer.” (AG Ex. 1.0 at 3:65-67.) He also claims that a demand-based rate “would have extraordinary bill impacts, resulting in annual bill increases to some customers (including electric space-heating customers) of more than 50%.” (AG Ex. 1.0 at 3:67-69.)

Q Do you find Mr. Rubin's arguments to be persuasive?

A. No. His conclusion is based on inferences from his flawed analysis and is inconsistent with evidence I have provided regarding the relationship of customer energy consumption and demand. When corrected, his analysis in fact suggests that the Company's proposal is the rate design most aligned with the cost of serving customers. The bill impacts of demand charges on space heating customers are not at issue, as demand rates would not be charged to customers pursuant to the Company's proposal in this case.

Q Mr. Rubin identifies "at least three fallacies" in AIC's proposed rate design. (AG Ex. 1.0 at 7:143.) What are Mr. Rubin's claimed fallacies?

A. Mr. Rubin claims that the Company's proposed rate design "move[s] a rate element further away from cost." (AG Ex. 1.0 at 7:149-50.) He suggests that my proposal is not supported by "any analysis of the cost to serve customers or explain how increasing the customer charge would be consistent with establishing cost-based rates." (AG Ex. 1.0 at 7:151-53.) And he faults me for not discussing "the different ways in which demand charges can be designed." (AG Ex. 1.0 at 8:159.) He claims that I did not ask "the most important question," namely "[h]ow does Ameren's proposed rate design reflect the cost of serving customers." (AG Ex. 1.0 at 8:173-74.)

Q What is your response to Mr. Rubin's claimed fallacies?

A. The first fallacy Mr. Rubin alleges, that the Company's proposal moves a rate element further from cost, is essentially the same allegation raised by Ms. Harden. I addressed this issue in detail in the my response to her and will not rehash those arguments again here, but they apply equally in response to Mr. Rubin.

Skipping the second claimed fallacy for a moment and moving to the third, Mr. Rubin suggests that I did not consider the different ways in which demand charges can be designed. While I may not have given a long description in direct testimony regarding the details of the hypothetical demand rate structure, by no means should that be taken to mean I did not carefully consider those details when designing it. In the context of describing the additional analysis I have performed for this rebuttal testimony below, I will further elaborate on the specifics of my hypothetical demand rate and why it makes sense to use it to represent a cost-based rate against which comparisons of other rate design options are useful.

Q. Mr. Rubin's second fallacy essentially claims that you did not consider, in your analysis of residential rate designs, whether your proposal was consistent with cost-based ratemaking. Is he correct?

A. No. As I discussed in my direct testimony, cost based ratemaking should be premised on the collection of the costs associated with each cost classification (i.e., customer, energy, demand) in the charge type that is most aligned with that classification. Three part rates provide the opportunity to directly collect demand related costs in a demand charge, which is by definition more aligned with cost than collecting them in an energy charge. Regardless of whether AIC ever proposes a demand charge in a future proceeding, evaluating today's rate design options for similar outcomes to that cost based approach can provide guidance for ensuring that the rates are reflective of cost.

Q. Mr. Rubin developed an analysis of what he refers to as the Company's unit costs based on the 2015 ECOSS. Does his analysis provide any perspective on the extent to which your hypothetical demand rates are reflective of cost?

A. Yes. First, let me express my agreement with Mr. Rubin's assertion that calculating the unit costs of serving a kilowatt (kW) of residential demand can provide useful information to the discussion we are having. Based on my review, I believe Mr. Rubin's calculation of AIC's unit costs of serving demand from the 2015 ECOSS are reasonable. His approach is essentially to calculate an embedded cost per 2015 kW (separately considering each form of demand, coincident peak (CP), non-coincident peak (NCP) and the sum of individual customer demands (Sigma NCP)) incurred by the Company to serve its customers. Mr. Rubin calculates unit costs of $58.85/kW of 2015 CP demand, $49.27/kW of 2015 NCP demand, and $8.13/kW of 2015 Sigma NCP demand. Summing these, the total cost per kW, irrespective of the type of demand, is $116.24/kW. Dividing that annual unit cost value by the 12 months in the year, the Company's residential demand-related costs can be expressed as $9.69/kW-month. The hypothetical summer demand rate that formed the basis of the analysis in my direct testimony was $8.89/kW-month. I think it is fair to say that, while not identical to the cost per 2015 kW[12], the hypothetical rates I used were very reasonably reflective of that cost.

---

[12] As I will describe later, the difference that does exist between my demand rate and the 2015 cost per kW is most likely because my analysis used 2014 data to create a hypothetical rate rather than 2015 data that would align with the unit cost data developed by Mr. Rubin.

Q. Is it fair to add the costs associated with CP demand, NCP demand, and Sigma NCP demand into a single unit cost per kWh for comparison to the hypothetical demand rate you calculated?

A. Yes. Mr. Rubin is correct in his discussion of the numerous options and considerations that are important to evaluate when designing demand rates. He is also correct that, because there is a difference between CP, NCP, and Sigma NCP, no single rate will perfectly capture the effects each type of demand. However, one of the primary goals of the design of a demand rate should be to provide a simple, understandable, and actionable price signal that bears a reasonable relationship to each of these types of demand that represents a potential driver of cost or cost allocation on the system. The interest of those goals is served by the hypothetical rate design the Company analyzed[13]; specifically a summer demand charge applied to the highest hour of usage within a billing period (this is analogous to the customer's contribution to the summer Sigma NCP demand). Most customers that learn to respond to such a price signal are likely to develop behaviors that alter their consumption patterns during hot summer days that require the most air conditioning. Such behavior changes impacting peak period consumption could be reasonably expected to impact all three of the demand types in a similar way. As such, this rate design is intended to influence customer behavior in a manner that addresses all three types of demand and therefore it can be reasonably related back to each category of cost and compared to the sum of the unit costs associated with each.

[13] This is the discussion referenced above that relates to Mr. Rubin's third alleged fallacy.

Q Mr. Rubin proceeded to use the unit cost concept to perform an additional study with which he purports to demonstrate that his proposed residential rate design produces individual customer bills that are closest of any rate design contemplated in this case to the cost of serving customers. Do you accept his premise that comparing individual customer costs and bills is a good way to evaluate rates?

A. I think it is an interesting approach that provides a useful contribution to the rate design discussion. However, I do not believe it is wise to place too much weight on the calculation of the cost of service down to the individual customer level. Mr. Rubin's analysis essentially extends the allocation of costs performed at the class level to the individual customer level. The more granular allocations one tries to make, the harder it is to make the case that the allocated costs relate directly and accurately to the subject of the allocations. Lost in that process are the many unique factors that contribute to the cost of serving a customer. For example, a small residential customer with a low demand may be *allocated* very little cost associated with line transformers. However, due to electrical standards governing the system design and the need to have the system stand ready to serve that customer should their load increase, there may be much more local transformation capacity that is put in place for their direct benefit than is attributed through this allocation process. That is but one example of the tremendous complexity associated with attempting to derive individualized cost of service. All of that said, I still believe this analysis can provide useful insights for this discussion.

Q. Is the conclusion Mr. Rubin draws from this study, specifically that his rate design proposal aligns customer bills most closely with the cost of serving them, accurate?

A. No. Mr. Rubin's study suffers from flaws serious enough to completely invalidate his conclusions. I will demonstrate why his results cannot be relied upon and update his calculations to show that his methodology, when corrected for these significant errors, demonstrates that the Company's proposal produces customer bills closest to the cost of service.

Q. What is the most serious flaw with Mr. Rubin's work on this topic?

A. At lines 232-241 of his direct testimony, Mr. Rubin indicates that he has compared the revenues from hypothetical rates using various rate design options applied to the usage of customers from the Company's load research sample[14] to a *hypothetical* cost of service of this same group. The fact that the comparison is to hypothetical costs that don't reflect, or even remotely resemble, the Company's actual costs, makes the results of no use for understanding how various rate designs reflect the Company's actual cost of service.

Q. You don't seem to question his calculation of hypothetical revenues, and in fact performed your own study with revenues based on hypothetical rate designs for your direct testimony, yet you sharply criticize Mr. Rubin's use of hypothetical costs. What is the distinction between calculating hypothetical rate revenues and hypothetical costs?

A. The hypothetical rate designs analyzed by Mr. Rubin, and also by me, are legitimate options that the Commission can choose from in setting rates for the Company now or in the future. The customer usage to which the hypothetical rates are applied is actual customer usage for a sample of customers that is representative of the population of residential customers served by AIC. Whichever rate is applied to that usage would generate the calculated revenues. It is reasonable to use hypotheticals in this instance where it simulates the result of legitimate options under consideration in this case. However, hypothetical costs that diverge significantly from the

[14]This is the same set of sample customers and data that I used for my hypothetical rate design study in direct testimony.

Company's ECOSS results do not exist, cannot exist, and are not anything we can choose to impose on the Company or its customers. Furthermore, the hypothetical costs Mr. Rubin calculates are so far removed from the Company's actual costs that they have virtually no connection to reality. Understanding how various rate designs relate to these hypothetical costs does not provide any useful information to the Commission.

Q. Please put in perspective how Mr. Rubin's calculated hypothetical costs are disconnected from the Company's actual costs.

A. Mr. Rubin calculates actual unit costs from the Company's 2015 ECOSS of $58.84/kW of CP demand, $49.27/kW of NCP demand, and $8.13/kW of sigma NCP demand. His hypothetical per kW cost of a unit of CP demand is nearly triple the actual cost, at $160.14; his hypothetical NCP unit cost of $95.31/kW is nearly double what he calculates as actual cost; and yet his cost per kW of sigma NCP demand of $7.28 is 10% lower than actual cost. These are radical departures from actual costs, and it is important to understand the implications of these deltas. Each of these categories of cost is reflective of investments made by the Company in certain types of infrastructure. While it may be easy to use math to rearrange numbers on a page to create some hypothetical cost numbers, the mix of infrastructure investments implied by that math is not consistent with the infrastructure the Company has built to serve its customers. It is unproven that the mix of assets implied by Mr. Rubin's analysis would even represent a feasible system design for any customer configuration, taking into consideration the engineering requirements of the system. That is a question that I will not try to answer, but it is worth considering that we do not even know that a system with his hypothetical cost structure is technically feasible.

Q. To what do you attribute Mr. Rubin's decision to use these numbers that are not representative of reality?

A. The answer can be found in a footnote on page 11 of Mr. Rubin's testimony. When he used his calculation of actual unit costs to develop to the sample customers' individual cost of service, the total cost of service attributed to the group was significantly different than the revenue derived from the group. He seemed to feel that this justified, or even necessitated, his decision to infer a cost of service that would produce total costs for the sample that approximate the revenues produced.

Q. Does the mismatch between sample revenues and costs in his analysis justify the use of hypothetical costs?

A. No. As stated previously, the hypothetical costs he developed have such a remote relationship to the Company's actual costs such as to be irrelevant. More importantly, though, Mr. Rubin's concern regarding the difference between the costs he calculated for the study group and their revenues underscores further flaws in his analysis.

Q. Please describe these flaws.

A. First, and most impactful, is the mismatch between the development of the unit costs by Mr. Rubin and his application of them. He develops unit costs from the Company's 2015 ECOSS data. In fact, it is important to identify the units as such. We should refer to his unit costs as, for example, cost per kW of *2015* CP demand. He then applies this to the sample customers' *2014*

CP demands[15]. This may sound like a minor distinction. It is not. The total CP demand of the Company's customers, and of just the residential class, can change significantly year to year depending on numerous factors including the time of year the CP occurs, hour of the day, day of the week, and the weather conditions experienced on that day. If, hypothetically, the Company had identical revenue requirements in 2014 and 2015, but the ECOSS study used the actual 2014 and actual 2015 class demands to allocate costs and derive unit costs as Mr. Rubin has done, the resulting unit costs would undoubtedly be different, and potentially significantly so. Application of the unit cost per kW of demand from one year to loads from another year will not, and did not in the case of Mr. Rubin's analysis, produce a reasonable reflection of the cost to serve those specific demands.

This error caused the mismatch between the revenues derived from the study group and Mr. Rubin's calculation of the cost of service of the same group. This mismatch appears to have driven him to conclude that his hypothetical cost structure was necessary. It was not. Simply recasting the study to remove the mismatch incorporated by Mr. Rubin yields a very different result.

Q Have you been able to recast the study to address the mismatch you have identified above?

A. Yes.

[15]There is an error in the 2014 CP demands to which Mr. Rubin applied the unit costs, but this was the result of an error in a data request (DR) response remitted by the Company. Mr. Rubin correctly used the information he had been presented with, but the error does contribute to the flaws in his result. The Company subsequently provided a revised response to the data request. The whole issue of the 2014 CP becomes moot in the subsequent analysis I will present.

Q Please describe the steps you took to accomplish this recasting.

A. I determined the single year to analyze as the period of study, so as to avoid the mismatch that plagued Mr. Rubin's analysis when he applied unit cost per kW of 2015 CP demand to 2014 CP demands of the sample customers. I chose to analyze data for 2015 for both costs and revenues. I derived a sample of customers, again from the Company's load research program, for which to calculate revenues and costs[16]. I applied the unit costs Mr. Rubin developed from the Company's 2015 ECOSS to the sample customer 2015 demands to recalculate the cost of serving the sample customers. I also applied the various hypothetical rates that Mr. Rubin analyzed to the customer loads to generate hypothetical 2015 revenues for each customer. At this point, I compared the revenues and costs for the whole study group, and observed that they are much more in line than Mr. Rubin's calculations showed for the 2014 group. In fact the calculated cost of service for the sample is within 2.6% of the calculated revenues from the same group[17]. This result obviates the need for a hypothetical cost structure to analyze, as inappropriate as I think that concept is in the first place.

---

[16] The sample for the 2015 study consisted of 190 customers. It is smaller than the 2014 sample because I took an additional step in selecting this sample of randomly excluding certain sample customers. While the load research sample is randomly drawn from the population of AIC's residential customers, it over-weights certain subsets of customers in a process referred to as stratification, which increases the relative precision of class estimates for a given sample size. The customers randomly excluded from this analysis now result in a remaining sample that equally weights all of the load research strata relative to the target population. I have subsequently reanalyzed the 2014 sample after similarly re-weighting the sample and the conclusions I presented in my direct testimony are unchanged. Workpapers demonstrating this analysis have been provided to the parties to the case in a supplemental response to Staff data request CLH 1.04.

[17] For context, Mr. Rubin had raised the concern that led him to calculate hypothetical costs over an approximately 50% difference between revenues and costs.

Q Using this updated analysis, which rate design option produced the least dispersion of customer bills from the cost of service using Mr. Rubin's measures?

A. Using the measures of dispersion Mr. Rubin developed to compare the distribution of customer specific results, the Company's proposal to collect 40% of revenues in the fixed charge fairs the best out of the rate design proposals made in this case, meaning it comes the closest to accurately collecting the cost of serving the customers.

Q Please describe the results of this analysis.

A. First, I will note that I added additional rate designs into the analysis based on hypotheticals that I analyzed in my direct testimony; specifically a rate with 45% of residential costs collected in a customer charge, 50% of costs, and also a summer-only demand charge. For the summer only demand charge, I left the Company's current non-summer declining block rate energy rate structure intact and also preserved the proportion of revenues collected in summer versus non-summer charges constant.

In his analysis, Mr. Rubin calculated the mean and median of the absolute differences between individual customer cost and revenue for each rate design scenario. Simply put, this measure tries to capture a sense of, regardless of the direction of the difference, which rate design puts customers' bills closer to their cost of service. If a customer has hypothetical bills much higher than the cost to serve them, or lower than the cost to serve them, it equally impacts this statistic. The standard deviation metric has a similar goal, but tends to penalize large differences more that small differences. The results of these tests are shown in Figures 1, 2, and 3 below. These results correspond to the results displayed in AG Exhibits 1.6 and 1.7. Figure 4 shows the number of customers whose hypothetical bills are within the reported percentages of the cost to serve them, similar to Mr. Rubin's AG Exhibit 1.5.

Figure 1: Mean of Absolute Deviations of Cost vs. Revenue Difference

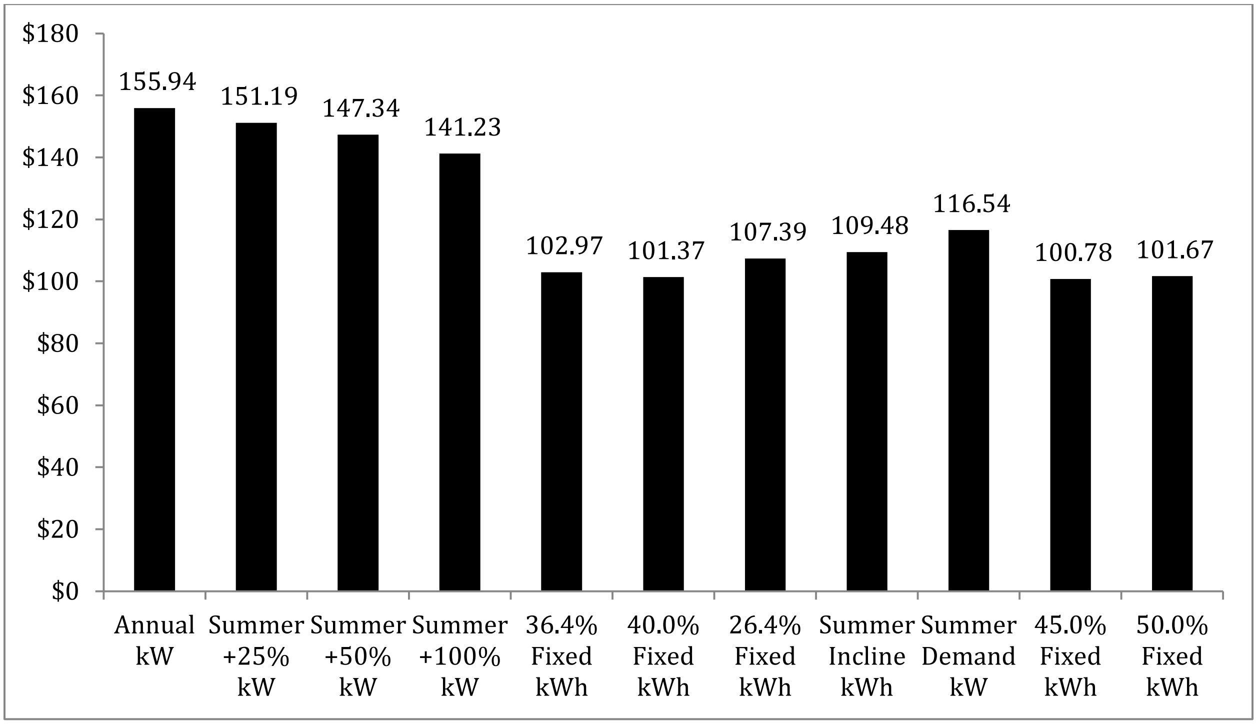


Figure 2: Median of Absolute Deviations of Cost vs. Revenue Difference

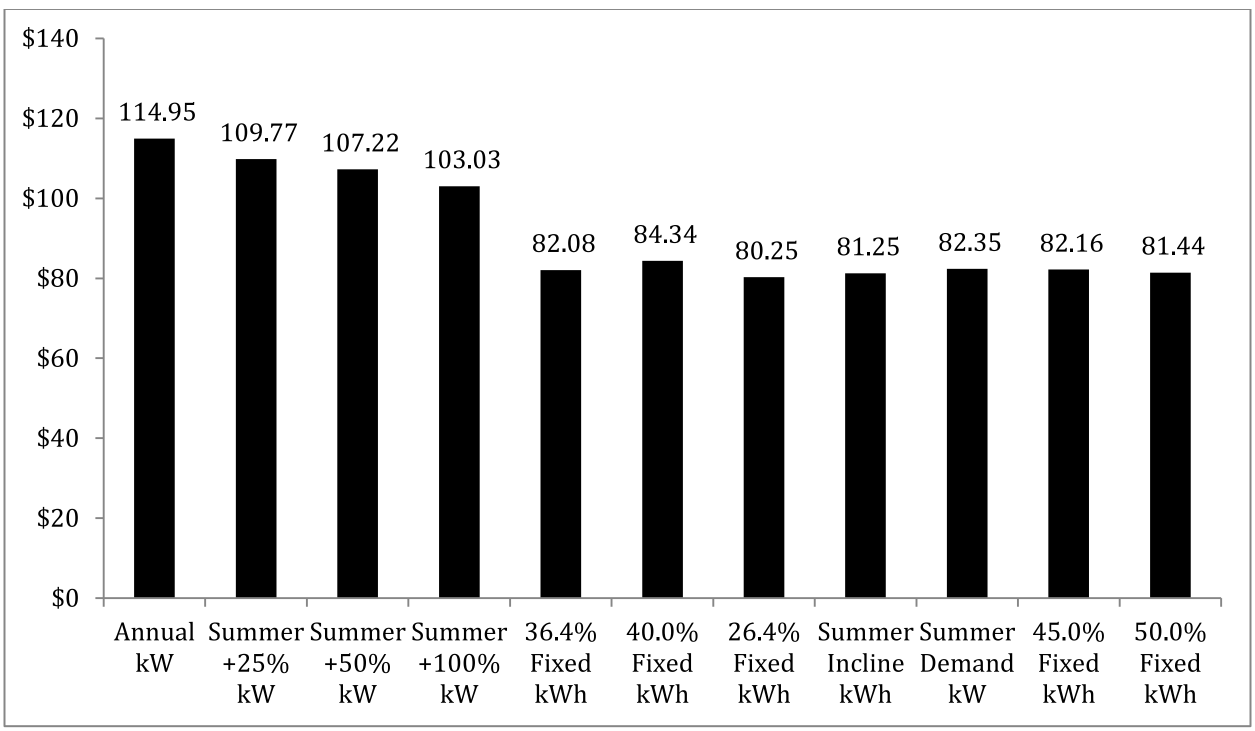


Figure 3: Standard Deviation of Cost vs. Revenue Difference

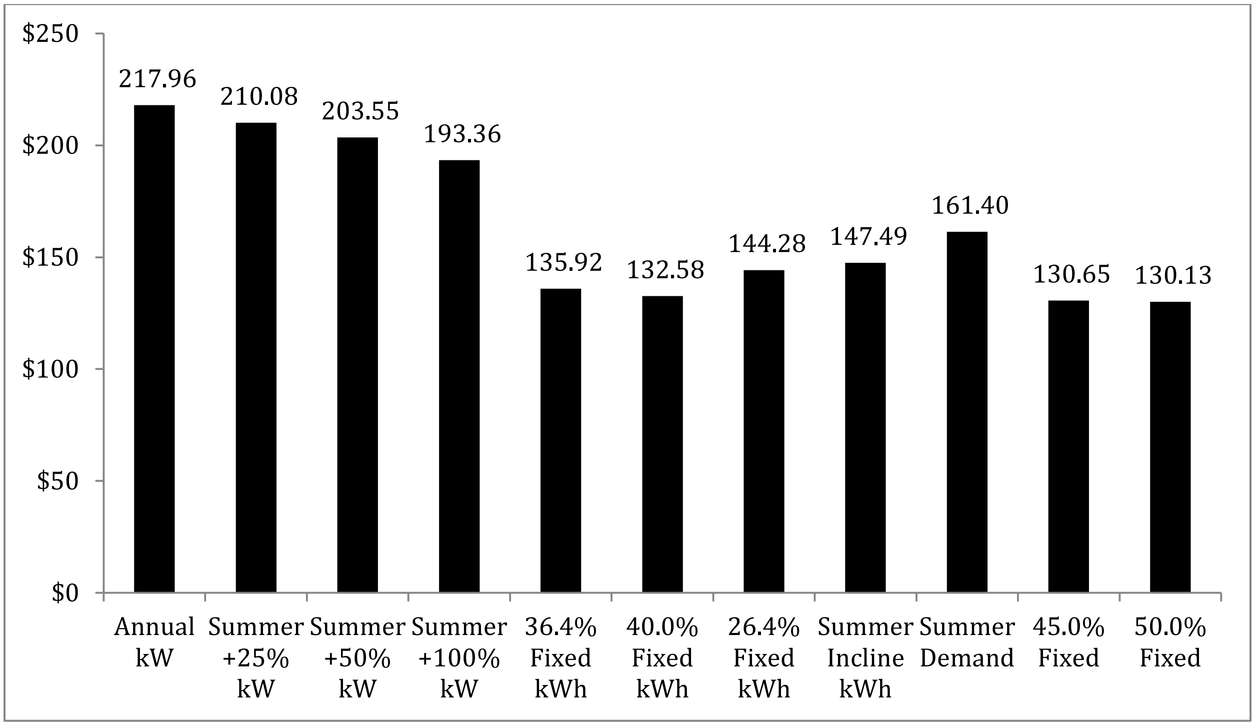


Figure 4: Relationship of Revenues to Costs (number of customers in each range)

Rate Option	± 5%	± 10%	± 20%	± 30%	± 40%	± 50%	Outside ± 50%
Demand Rate Options							
Annual	24	45	84	124	152	156	34
Summer +25%	23	45	84	131	153	159	31
Summer +50%	22	44	85	135	152	159	31
Summer +100%	19	46	87	136	154	162	28
Summer Demand	30	58	110	145	163	169	21
Energy Rate Options							
36.4% Fixed	27	62	118	151	166	172	18
40.0% Fixed	39	59	120	150	165	173	17
26.4% Fixed	31	62	114	148	166	173	17
Summer Incline	32	63	115	147	166	172	18
45.0% Fixed	34	67	118	150	162	172	18
50.0% Fixed	37	62	116	152	161	170	20

Q Please summarize the conclusions that you draw from this information.

A. The Company's proposal to collect 40 percent of residential revenues in the fixed charge is closest of any option proposed in this proceeding to reflecting the actual cost of serving customers according to both the mean absolute difference and standard deviation metrics[18]. The median absolute difference is the only metric that does not clearly favor the Company's proposal, and for that metric, all options are quite tightly grouped. The distribution of customers whose bills are closest to cost clearly favor the Company's proposal as well, with 39 sample customer bills within +/-5 percent of cost, whereas only 31 customers fall in that range under the AG's proposal. The compelling conclusion is that the Company's proposal most closely aligns customer bills with their allocated cost of service.

Q Figures 1 through 4 show that the hypothetical demand charges produce bills that are farther from the cost of service at the individual customer level. What does that suggest?

A. First, I will note that results associated with the demand charges developed by Mr. Rubin that apply to all months of the year appear to be farther removed from the individual cost of service than is the result for the summer demand charge that I developed. This suggests to me that the results in the non-summer period drive much of the difference. This fact, along with Mr. Rubin's bill impact analysis on space heat customers, further suggest that, if and when the time comes to consider actually implementing demand charges, further analysis needs to be conducted on the non-summer season and any potential impacts on space heat customers need to be addressed. The summer only demand charge aligns more closely with cost than the year-round

[18]Note that for some measures, 45% and 50% fixed charge recovery even outperform the 40% proposal. No party has proposed either of these options in this proceeding.

demand charge, but still does not match as closely at the individual customer level as the other two-part rate proposals. That is a somewhat interesting finding, but again, I would point to what I indicated earlier in testimony, that this individual customer cost of service analysis is just one tool to analyze whether a rate is reflective of cost. The summer demand charge calculated for the 2015 study, using the same method I used for my direct testimony analysis, was $9.70/kW-month. Recall that the total embedded unit cost of serving a kW of 2015 demand is $9.69 per month. By the extremely close match between the demand rate and the unit cost of serving demand represented by these metrics, as well as the alignment of the cost classification (demand-related) with the charge type (demand charge) represented in this rate option, I would still suggest that this would be a superior solution to the challenge of developing a cost-based rate design.

Q Do you have any other thoughts on Mr. Rubin's proposal and analysis to share?

A. Yes. I am not surprised that the correction of the mismatch in Mr. Rubin's analysis produced the result I describe. The original result achieved by Mr. Rubin was counterintuitive given the data that I presented in direct testimony, which clearly demonstrated that the variability of customer energy consumption is greater than the variability of demand. Given that finding, a lower customer charge coupled with a higher variable energy charge, as I previously argued, should produce more revenue variability than the underlying cost variability exhibits. Mr. Rubin never provides any rationale or explanation why the outcome he calculated reconciles with the empirical findings regarding energy and demand. The results of my update of his study are consistent with both the result of my direct testimony rate analysis, the empirical observations about the nature of demand and energy consumption, and the narrative discussion through which I developed my expectations for the study.

Q Mr. Rubin also criticizes the analysis in your direct testimony due to what he characterizes as the "extraordinarily small sample size" at line 307. Is this characterization valid?

A. No. The sample utilizes the Company's load research data. The Company's load research program uses appropriate sample sizes to produce class level demand estimates that achieve 10 percent relative precision with 90 percent confidence, as recommended by the Public Utilities Regulatory Policy Act (PURPA). For example, the number of residential customers needed to achieve the 90/10 PURPA standard for the 2015 residential NCP demand for the entirety of the approximately 1,060,000 customers in the residential class is 164 customers. While this number may sound surprisingly small, it is illustrative of the statistical power that a well-designed representative sample brings to the study of a defined population. When at lines 157-158 of his testimony Mr. Rubin questions the appropriateness of designing rates for one million customers based on the effects of 224 customers, he ignores the fact that we routinely do (and the Commission accepts) exactly that.

In a response to a data request submitted to Mr. Rubin in this proceeding, he calculates that the Company's study would have a margin of error of +/-6.6% with 95% confidence. I would assert that this study is an appropriate use of load research data to investigate cost of service and rate design issues and compliance with the PURPA 90/10 standard is very reasonable to draw the types of inferences we are discussing. That is particularly true given the fact that the rates being derived for this study are for comparative purposes between different rate design options and they will never be charged to customers.

Q Have you reviewed Mr. Rubin's bill impact analysis in AG Exhibit 1.8?

A. Yes.

Q Do you have any comments on his bill impact analysis in AG Exhibit 1.8?

A. Yes. The bill impacts associated with demand rates are really not at issue in this proceeding. I have tried to demonstrate that demand rates reflect a strong cost-based rate design option for the future. However, neither the Company nor any other party has recommended such a rate design for implementation at this point. If a demand charge is proposed in the future, consideration of bill impacts associated with the specific proposal will be of great significance. While I do not know what proposals will be made in the future, I suspect it likely that gradualism may be a key part of any transition to demand charges; meaning that I find it unlikely that it would be suitable to go from no demand charge at all to 100% of demand-related costs in a demand charge all at once. However, it is unnecessary to delve into those specifics today when demand charges just represent a cost-based baseline against which we can evaluate current actual proposals and no customers will experience any bill impacts associated with them.

Q Do you agree that changing to a demand-based rate would have “extraordinary impacts” on customers’ bills? (AG Ex. 1.0 at 16:356.)

A. Frankly, it depends greatly on the specifics of the demand-based rate proposal. However, only if such rates are entered into without the careful consideration of customer bills will "extraordinary impacts" ever be manifest. The Company is committed, as always, to factoring customer bill stability into the considerations of any proposals that may come in the future, analyzing bill impacts and utilizing gradualism and mitigation strategies as warranted.

Q Have you reviewed his bill impact analysis of likely space-heating customers in AG Exhibit 1.9?

A. Yes.

Q Do you have any comments on his bill impact analysis of likely space-heating customers in AG Exhibit 1.9?

A. As Mr. Rubin himself acknowledges in response to data request AIC-AG 1.01 sent to him by the Company, the sample really is too small to draw inferences about subgroups like space heating customers. I would take any results for this group with a grain of salt.

Q Mr. Rubin claims that the "least severe effects" on space-heating customers would be seen under his proposed DS-1 rate design. (AG Ex. 1.0 at 18:387.) Do you agree?

A. That clearly is not the case. Mr. Rubin's characterization appears to rely on one particular customer in the space heating subgroup that has a larger bill increase under the Company's 40% proposal than the AG's 26.4% proposal. However, as should be obvious to anyone who has been exposed to the space heating issues experienced by AIC's customers in the past, the group as a whole is much better off under the Company's proposal to collect 40% of revenues in fixed charges. The Company's proposal, by lowering the variable energy charge, provides a lower price for the very significant space heating related usage volumes typically associated with these customers. In fact, while this sample is small for drawing inferences about the population, it is sufficient, even if not statistically significant, to demonstrate the obviously lopsided impact of the two proposals on space heat customers. Of 27 likely space heaters identified by Mr. Rubin, 23 would see lower bills under the Company's 40% fixed cost recovery proposal; whereas only 4 experience increases. The AG's 26.4% fixed cost recovery proposal causes increases for 18 of the 27 likely space heaters and decreases for only 9. It should go without saying that one of the obvious merits of the Company's proposal relative to the AG's is the benefit it provides through lower potential bills to the space heating group.

Q Mr. Rubin claims that customers would lose the benefit of the lower energy charge for usage in excess of 800 kWh per month in non-summer months, if a demand based rate was instituted. What is your response?

A. This again totally depends on the specific proposal that may or may not be made in the future and any assessment today is completely speculative. However, I continue to agree with Mr. Rubin that it will be in all parties' interest to consider the impact of rate proposals on space heating customers in the future.

Q Have you reviewed his bill impact analysis in AG Exhibit 1.10?

A. Yes.

Q Do you have any comments on his bill impact analysis in AG Exhibit 1.10?

A. This unique customer appears to be a space heat customer with significant associated winter load, but lower than average summer (cooling) load. While the outcome is interesting, the result of the bill for one unique customer tells very little about the effects on the broader residential class, or even the space heating segment of that class.

Q Are there any observations you would like to share regarding the AG's proposed rate design that apply to other seasonal usage of residential customers?

A. Yes. While historically, concerns relating to winter space heating bills have been, for good reason, carefully scrutinized in AIC rate proceedings, it is also well worth considering the impact of rate design on summer bills. This summer, AIC saw an increase in the number of customers raising questions about the levels of their summer bills. I have attached as Ameren Exhibit 3.3 an article from the Peoria Journal Star that discusses this phenomenon. As the article suggests, AIC received an increase in informal bill inquiries to respond to this summer, routed through the Staff and/or CUB. In 2014 and 2015, AIC received 8 and 22 such complaints, respectively. In 2016, that number jumped to 41. As the article I attached explains, the Company believes this resulted from a combination of factors, including the implementation of higher 2016 delivery service rates resulting from the latest formula rate update, higher power supply prices resulting primarily from higher prices associated with generating capacity markets, and extreme summer weather. Increasing the recovery of delivery service revenues in the fixed charge can have a somewhat mitigating effect on these higher summer bills, whereas the AG's proposal may exacerbate the problem.

Q Can you provide some context for the observed bill increases this summer?

A. Yes. As of 2014, capacity in the Mid-continent Independent System Operator, Inc. (MISO) cleared in the annual auction at $16.75/MW-Day. In 2015, that number jumped significantly to $150/MW-Day[19]. In 2016, the IPA procured some capacity through bilateral contracts, and the balance came from the MISO auction (which cleared at $72/MW-Day in Illinois), resulting in an average capacity price of $104.72/MW-Day for AIC's fixed price supply customers. Customers taking service from alternative retail suppliers may see different prices embedded in their contracts, but ultimately the market prices that clear in the MISO auction eventually end up influencing all load in the region. This is all to say that supply prices, and specifically the capacity component of those prices, for AIC's customers have been increasing. These prices are reflected in a variable rate to AIC's fixed price customers, and likely to a significant percentage of (if not all) customers taking alternative retail supply. This increase in the variable charge, compounded with delivery service increases effective in 2016 have created a

[19]After MISO's Zonal Deliverability Benefit, the realized impact on customers in Illinois was $126.53/MW-Day.

meaningful increase in the summer bills of all customers, but particularly those with higher loads. Adding to the variable delivery service charge by shifting revenue recovery from the fixed charge to the variable charge, as proposed by the AG (as well as Staff and CUB/EDF), will only further increase that bill pressure for high summer load customers. When temperatures spike, as they did for a majority of the summer of 2016, further pressure is put on customer bills. The Commission should consider the impact that the AG proposal would have on the summer cooling bills of AIC's customers as a relevant impact of its decision on the fixed charge in this proceeding.

Q Do you have any additional comments on Mr. Rubin's comments regarding the customer impact of an inclining block summer rate for the entire DS-1 class?

A. Given the immediately preceding discussion of summer bill impacts, an inclining block rate would clearly even further exacerbate the bill impacts that coincide with hotter than normal summer weather. While there is really no record to support consideration of an inclining summer block rate to speak of in this case to begin with, summer bill impacts should give all parties pause before approaching this concept any further in the future.

V. <u>RESPONSE TO MS. MUNNS</u>

Q Have you reviewed Ms. Munns' testimony?

A. Yes. I have reviewed Ms. Munns' direct testimony, CUB/EDF Ex. 1.0.

Q What issue does Ms. Munns address?

A. Ms. Munns addresses the proposed increase in fixed charges for the DS-1 class. She claims that the AIC's rationale and analysis does not justify an increase in fixed charges.

Q What does Ms. Munns recommend?

A. Ms. Munns recommends that the Commission reject AIC’s proposed rate design change for the DS-1 class. Ms. Munns also recommends that the Commission “monitor changes in Ameren’s service territory, track pilot results and research from other jurisdictions and postpone any consideration of further rate design changes, including residential demand charges, until Ameren has deployed smart meters and has additional data to inform a change.” (CUB/EDF Ex. 1.0 at 10:210-14.)

Q Do you agree with her recommendation?

A. No. The Company's proposal, regardless of future decisions regarding demand charges, represents a cost based price for customers today. While monitoring developments in both the service territory and other jurisdictions across the country is generally a reasonable thing to do, by no means is waiting and watching a sufficient response to the challenges developing today.

Q Ms. Munns states that any transition to a demand charge is “premature,” “based on the expectation or anticipation that demand charges will be instituted in the future and in the manner proposed by Ameren.” (CUB/EDF Ex. 1.0 at 7:154-56.) Do you agree?

A. No. As I discussed much earlier in my testimony, the nature of changes the industry is facing warrant proactive and thoughtful rate design solutions. AIC's customers will be potentially making investment decisions regarding DERs during the time that rates influenced by this docket are in effect. It behooves all participants to the regulatory process to provide rates today that contemplate the direction rates will be heading during the period of time that the return on those investments materializes.

Q Ms. Munns suggests that demand charges are not becoming "a viable option for electric utilities." (CUB/EDF Ex. 1.0 at 7:140-41.) She cites a draft NARUC Manual on Distributed Energy Resources for her opinion that there is an "ongoing, vigorous contention" on the use of demand charges for residential classes. (CUB/EDF Ex. 1.0 at 7:141.) In your opinion, does the draft NARUC manual oppose your proposed rate design?

A. No. The NARUC manual clearly identifies issues related to cost shifting associated with DERs and clearly identifies demand rates as a potential solution. Whether or not demand rates are the ultimate solution, either industry-wide or within Illinois, does not change the fact that the Company's proposal in this case would help to limit those cost shifts. Ultimately though, the viability of demand charges as an option should not be in question. AIC currently has demand charges for three rate classes (DS-3, DS-4, and DS-6), and the metering functionality for application of demand charges to DS-1 residential customers is currently being deployed. Vigorous contention in the preliminary discussions around a rate design do not make the rates being discussed lack viability.

Q Can you find any support in the draft NARUC manual for your proposed rate design?

A. Yes. There are many references to the cost shifts that can be associated with DER throughout the manual. One passage that provides a clear picture of the problems the Company's proposal would begin to address is found on page 23-24 of the manual. "In the case of DER, often the billing determinants are changed to mitigate the pressure on revenue caused by reduced usage volume. Thus, the decline in usage would be shifted to other customers when the billing determinants are reset to account for the decreased revenue from the DER customers. At a low level of penetration, this may be another imperfection in rate design, but at large levels of penetration it can be problematic and represent large amounts of revenue being shifted to other, non-DER customers in the same rate class. There may also be equity considerations to take into account. For example, if customers living in multi-family housing are in the same class as DER customers and there are no DER options available to multi-family customers (since they do not generally own their property), a regulator must consider whether shifting additional cost recovery to customers who may not have a chance to participate in DER is appropriate."

Q Ms. Munns states that there has not been an "opportunity to discuss the details of the design demand charge." (CUB/EDF Ex. 1.0 at 8:167.) Do you believe that the "fine details" of any future demand charge need to be decided now to approve your proposed rate design?

A. No. The details of a demand charge need to be discussed prior to implementation of that charge. The premise that a cost based residential rate would allocate demand-related costs to a demand charge is sufficient to consider the rate design as worthy of future contemplation. But it would in fact waste all of our time to debate in this context the merits of particular features and characteristics of specific demand charge proposals when none is on the table for the Commission to adopt in this proceeding.

Q Ms. Munns similarly suggests that the Commission should reject your proposed rate design because there is not a "consensus" on the design of demand charges. (CUB/EDF Ex. 1.0 at 168.) In your opinion, is such a consensus needed for the Commission to approve your proposed rate design?

A. No. Once again, there is no pending proposal that would incorporate a demand charge for customers in this case for the Commission to consider, so it need not weigh in on design details. Even if there were a demand charge proposal, consensus on those details would not be necessary.

Determining how to proceed with a lack of consensus is one of the roles of the Commission. In fact, if consensus is a requirement for the Commission to adopt a rate design, I fear that there may be no viable option at all for a residential rate in this proceeding, as there does not appear to be consensus emerging so far.

Q Ms. Munns states that AIC's proposal "would send signals to customers that are in conflict with previously stated goals of encouraging residential customers to reduce energy usage and increase energy efficiency." (CUB/EDF Ex. 1.0 at 4:88-90.) She later states that AIC has not addressed the Commission's concerns over the "disincentive" that high fixed charges creates for energy efficiency. (CUB/EDF Ex. 1.0 at 9:196.) How do you respond?

A. I have discussed at length throughout this rebuttal testimony how the Company's proposal is a sound, cost-based approach to rate design that provides an appropriate price signal. I fail to see how the adoption of economically efficient cost-based pricing creates any disincentive for energy efficiency or any other technology. The only conceivable way it could is if it is being compared to an alternative that deviates from such cost basis in a manner intended to specifically favor and promote energy efficiency. I do not believe that is appropriate for multiple reasons. First, I suggested earlier that the grid's key role in integrating various technologies make it a poor choice for a means of delivering subsidies. Next, the economic case for energy efficiency is already compelling to begin with and does not need help from delivery service rate design. Third, utility energy efficiency programs offer an opportunity to adjust incentives as needed to encourage participation if bill savings are insufficient to attract it. Finally, if the goal of any parties is to promote energy efficiency through the delivery service rate design decision in this case, it is a surprisingly ineffective means of doing so. In support of that statement, I will provide some context around the impact that the Company's proposal has on the economics of energy efficiency.

Q What would the practical effect of adopting the Company's proposal be on energy efficiency and conservation efforts?

A. Realistically, the impact of the Company's proposed rate design on the incentive for using energy efficiently will be negligible. It is important to recall that delivery service rates are only a portion of the customer bill, and there are significant usage based charges for EDT, energy supply, transmission service, and energy efficiency programs, among other things. In total, the variable energy-based price signal to customers is still present at a materially similar level under each of the proposals in this case. Based on average customer usage[20], the currently effective prices in the Company's fixed price supply offering (Rider BGS[21]), transmission service rates (Rider TS), and energy efficiency rates (Rider EDR), the current total of the variable charges incurred by a customer averages to approximately 9.77 cents/kWh. Just adopting the Company's proposal to collect 40% of residential revenue in the customer charge and keeping all other rates constant, the new total of variable charges would be 9.58 cents/kWh, or only 1.9% lower than under present rates.

[20] In calculating an annual average rate, I use the proportion of energy that is consumed pursuant to summer rates and non-summer block rates from the weather normalized billing units in the E5 Schedule of the Company's formula rate update, Docket 16-0262.

[21] I use BGS prices to represent power supply charges to the customer. Residential customers also take third party supply and may pay different rates.

Q How does this change in the variable price of the total bill impact the economics of energy efficiency?

A. First, it is important to note that the overall economic value of energy efficiency is measured by the Total Resource Cost (TRC) test, which is also defined by Illinois law as the measure of energy efficiency cost effectiveness. The TRC considers the avoided costs that result from implementation of an energy efficiency measure against the incremental cost of that measure. Nowhere in the TRC analysis are retail delivery service rates even a consideration. A change in rate design therefore has no bearing on the overall cost effectiveness of energy efficiency – the avoided costs associated with implemented measures do not change with rate design. Retail rates can, however, have some impact on the economic value to the individual participant in the program (the customer that adopts the measure), as they in part determine the savings the customer will experience after implementing an efficient measure. To understand that dynamic, I will illustrate the participant impact of the Company's proposed rate design on an actual measure included in the Company's recently filed energy efficiency plan (Docket 16-0413, filed August 30, 2016). Based on this plan, consider a residential customer that is contemplating participating in one of AIC's energy efficiency programs by installing a high efficiency (SEER 16) air source heat pump as an early replacement for an older, less efficient unit. That customer would be eligible for an incentive to cover a portion of the incremental cost of the high efficiency unit. The incremental cost of the unit relative to the baseline efficiency model is expected to be $4,965. AIC's planned incentive is $2,500, leaving $2,465 to be covered "out of pocket" by the customer. This measure is expected to save 6,200 kWh per year. Under existing rates, that amounts to total annual bill savings of $605.50. Rates redesigned to align with the Company's proposal would result in annual bill savings of $594.11. Based on this comparison, it seems likely that an HVAC vendor may show the customer a projected savings value associated with the upgrade that is rounded to $600/year regardless of which rate design is in effect. The payback to the participant under present rates ($2,465 incremental cost borne by the participant divided by $605.50 in annual bill savings) is approximately 4 years and 26 days. After the rate redesign, the payback would be 4 years and 54 days. Someone who installs this measure today (Oct. 25, 2016) would expect to recoup their out of pocket costs by November 18, 2020 under current rates, or December 17, 2020 under redesigned rates. I find it implausible that the delay of a four-year payback by less than one month would cause a participant to change their decision to participate in this program.

Q Is that example representative of the impacts to participants across all measures included in AIC's energy efficiency plan?

A. In fact, it is among the larger changes in customer payback for measures in the portfolio. I performed a similar change in payback calculation for all measures in the filed plan with electric savings and weighted those measure level paybacks by expected kWh savings during the three year plan. The result: on average, the change in rate design would increase the expected participant payback across the portfolio of measures, which under present rates would be approximately one year and 118 days, by just eight days. Frankly, I cannot imagine that the extension of the payback of participants' out of pocket cost by roughly a week would factor into anyone's decision to participate in an energy efficiency program. Changes in consumption due to behavior changes such as moving the thermostat by a couple of degrees would have similarly small changes in associated customer savings.

Q Are there any other notable impacts on customers associated with the interaction of your rate design proposal and energy efficiency?

A. Yes. To the extent that the participant savings are reduced by the rate design change, however minimally, impacts of the program on non-participants will be lessened commensurately. In the example above where the participant bill savings change from $605.50 per year to $594.11 per year, that reduction of $11.39 per year in revenues that contribute to the recovery of the Company's delivery service revenue requirement will eventually be made up by other customers when rates are reset.

Q Ms. Munns also states that your proposed rate design "will negatively impact low income customers and energy efficiency measures." (CUB/EDF Ex. 1.0 at 8:170-71.) Do you agree?

A. No. I addressed energy efficiency above and will further discuss the impact on low income customers in response to Mr. Zethmayr below.

Q Ms. Munns opines that increasing fixed charges "could have the opposite effect of lowering volumetric charges resulting [in] uneconomic or inefficient price signals and incenting additional usage." (CUB/EDF Ex. 1.0 at 8:179-80.) Do you agree?

A. No. This is a similar argument to the price signal criticism that was made by Ms. Harden. My discussion in response to her is equally applicable here.

Q Ms. Munns also states that AIC has not addressed the Commission's concerns over the "impact" of higher fixed charges on smaller users. (CUB/EDF Ex. 1.0 at 9:196.) Do you agree?

A. No. As demonstrated in my direct testimony, the absolute maximum bill increase that a residential customer could experience due to this rate design change is approximately a dollar and a half per month. And that amount would be offset by a decrease in the variable charge applied to any amount of usage, however small it may be, this customer actually incurs.

Q Ms. Munns also states that AIC has not presented any evidence on "the impact of new technologies" and the "increased penetration of distributed solar resources." (CUB/EDF Ex. 1.0 at 9:200-01.) Is this evidence necessary for the Commission to approve AIC's proposed rate design?

A. No. I once again return to the fact that this is a cost-based rate design for all customers today. The benefit it may provide in integrating new technologies and DERs, while real, is not necessary for this proposal to be the most appropriate option presented to the Commission in this case.

Q Ms. Munns also states that you have "presented no evidence as to whether it would be reasonable to adopt a demand charge in the future." (CUB/EDF Ex. 1.0 at 9:205-10:206.) Do you agree?

A. No. There are many compelling advantages of demand charges, not the least of which is their alignment with cost causation of demand-related costs, that have been discussed at length. The ability of demand charges to more accurately capture the cost of serving customers who may in the future invest in technologies that fundamentally alter how they interact with the grid is another compelling feature. While the evidence presented may not be sufficient to determine the very specific details of a future charge, it need not be to understand the benefits that can be realized by enhancing the ability to move to such a detailed proposal when the time comes.

VI. RESPONSE TO MR. ZETHMAYR

Q Have you reviewed Mr. Zethmayr's direct testimony?

A. Yes. I have read Mr. Zethmayr's direct testimony, CUB/EDF Ex. 2.0.

Q What issue does Mr. Zethmayr address?

A. Mr. Zethmayr addresses AIC's proposal to increase the level of fixed charge recovery.

Q What does Mr. Zethmayr recommend?

A. Mr. Zethmayr recommends that the Commission reject AIC's request and decrease the level of fixed charge recovery. He also recommends the Commission reject what he calls "the Company's request for pre-approval of a hypothetical demand-based rate." (CUB/EDF Ex. 2.0 at 2:25-26.)

Q Do you agree with his recommendation?

A. No. Mr. Zethmayr's characterization of the Company's proposal as a request for pre-approval of demand based rates is unfounded. The Company clearly made no request of the kind. The suggestion made by the Company – that the Commission and all other parties with an interest in Illinois regulation stay abreast of the developing national discussion on the topic and factor the future into its thinking today – in no way suggests that the Commission would be binding itself to any future methodology by approving what the Company is asking for in this case; namely a residential rate design with 40% of costs recovered in the fixed customer charges. As far as Mr. Zethmayr's recommendation to reject the increase to the level of fixed charge recovery, many of his arguments are very similar to those already addressed earlier in my testimony. Those new points of view presented by Mr. Zethmayr supporting his recommendation will be addressed further below.

Q What are the bases for Mr. Zethmayr's opinions?

A. Mr. Zethmayr bases his opinions in part on arguments already addressed in response to other witnesses, but also on his analysis of residential consumption data associated with Commonwealth Edison Company's (ComEd) service territory.

Q Do you find Mr. Zethmayr's arguments to be persuasive?

A. No. As I will discuss in detail below, Mr. Zethmayr's analysis is based on data that cannot be reasonably assumed to apply to AIC's customers. But even accepting the limitations of the applicability of his data, the conclusions he draws from that data are based on misinterpretations and faulty logic.

Q Mr. Zethmayr claims that "providing a rate-shock transition" to demand charges "is not a recognizable benefit for consumers." (CUB/EDF Ex. 2.0 at 3:50-51.) Will the Company's proposed rate design result in "rate-shock"?

A. No. I have discussed at length already the rationale for contemplating the future of rate design in this case, which may include demand charges, and the benefit this could provide to customers as far as providing a reasonable proxy for the rate environment that any long term investments in technology behind their meter may be exposed to. Ensuring that any future demand charge would not result in rate shock can be handled through appropriate analysis, gradualism, and mitigation in the future when specific proposals may be evaluated. The proposal at issue in this case is squarely in line with the rate designs that have existed over the last several years and cannot be reasonably considered to result in rate shock for any of the Company's customers.

Q Mr. Zethmayr characterizes your direct testimony by saying "the Company argues that flat charges are a closer representation of the customer-to-customer- variation in demand related cost causation than volumetric charges". Is his assessment of your position accurate?

A. No. All of my arguments have asserted that demand-related costs should not be collected strictly in a flat (fixed) charge, but rather that they should be allocated to a fixed and variable charge in a manner that synthesizes a level of revenue/bill variability that is similar to the variability in demand. One has to consider both the 18% of demand-related costs allocated to the customer charge and the 82% allocated to the energy charge to characterize the Company's proposal for recovering demand-related costs. I gave the background for these allocations in response to Ms. Harden. Clearly, with 82% of demand-related revenue allocated to energy charges, I have not represented that flat charges are more representative of customer-to-customer variation than volumetric charges. Once again, though, an appropriate mix of both fixed and variable charge recovery of these costs is more aligned with their incurrence.

Q Mr. Zethmayr questions the rationale you provided in direct testimony, that the relative homogeneity of the appliance stock contributes to the lower level of variability in demand than energy consumption, and criticizes the lack of supporting data for your assertion (CUB/EDF Ex. 7:147-49). How do you respond?

A. Although I have spent many years of my career in load analysis working with end-use forecasting models and energy efficiency potential studies performed at the end use level, both of which have included extensive review of appliance saturation studies and statistics, one does not have to have that level of experience for this concept to resonate. Most people inherently understand that nearly 100% of homes in our area include refrigeration, lighting, televisions, and some form of air conditioning, with a majority being central air conditioning. Further, while saturations do not reach 100%, there is fairly high penetration of washing machines, dishwashers, computers, and other common appliances and plug loads. While I could provide ample statistics from the Energy Information Association and other sources regarding appliance saturation, at the end of the day, what constitutes "relatively homogeneous" is admittedly subjective. That said, it is not even necessary or particularly important to prove my assertion, as this was my explanation to make sense of a phenomenon that I went on to empirically verify. Whether or not the relative homogeneity of end uses is at work, and I continue to believe it contributes significantly, demand is demonstrably more stable than energy.

Q Mr. Zethmayr also claims that the Company's analysis is based on "an insufficient sample size to draw meaningful conclusions." (CUB/EDF Ex. 2.0 at 3:51-52.) He presents his own analysis using customer data from the ComEd service territory that includes many more customers and suggests this makes his data more reliable. Do you agree that your sample size of customers is too small and the ComEd customer analysis is therefore superior?

A. No. The ComEd data appears to be what I would characterize as a data set of opportunity. By this I mean, there is hourly data that happens to be available that might be generally applicable to the question of interest for some research project, so he uses it. The data, however, was not collected pursuant to a research plan designed for the study of the population of interest in this case: AIC's residential customer base. In response to Mr. Rubin, I discussed the statistical power of a well-designed representative sample. That discussion is equally applicable here. Mr.

Zethmayr bemoans the fact that the Company's sample is made up of less than half of one hundredth of a percent of the population at lines 163-164 of his direct testimony. That may be true; however, as discussed in response to Mr. Rubin, that sample is, perhaps surprisingly, capable of producing robust class level estimates for the specific population from which the sample was drawn. This cannot be said for the ComEd data employed by Mr. Zethmayr, particularly as applied to AIC's residential customer base.

To illustrate the difference between a well-designed representative sample and a large data set that does not accurately characterize a target population, think about the analogy of election polling. Consider two polling attempts to determine likely statewide outcomes of the upcoming election. Imagine that one attempt includes polling of a few hundred randomly selected individuals based on a well-designed sample of residents across Illinois. Now consider the second study, where pollsters canvas large parts of the Chicago area until they find 100,000 residents to survey. Which poll would likely be more reliable in predicting statewide results? Clearly the former. As an example of the statistical power of sampling from the industry of election polling, consider some information from the methodology section of the website of the respected polling company Gallup[22]. It is notable that they refer to their daily poll of 500 U.S. adults (a population of hundreds of millions) as a "large sample", when in fact it represents a smaller proportion of the target population than AIC's load research sample does of its residential customer base.

[22] http://www.gallup.com/178685/methodology-center.aspx

Q Mr. Zethmayr goes on to assert that his findings in the ComEd data sets he has analyzed demonstrate that this demand versus energy variability phenomenon you rely on for your argument is overstated. Is he correct?

A. No. First, I continue to emphasize the lack of applicability of the ComEd data to AIC's service territory. Second, based on a review of Mr. Zethmayr's workpapers, I have found his analysis to contain unexplained outliers and/or calculation errors. Finally, when either correcting or ignoring outliers, the data actually suggests fairly similar conclusions to those drawn from the Company's study. I am puzzled by Mr. Zethmayr's decision to even make the assertion he has, given the very clear pattern shown in the ComEd data (excluding outliers) that demonstrates meaningfully more variability in energy consumption than in demands.

Q Please discuss the problems in the data that you have identified in Mr. Zethmayr's ComEd analysis.

A. In reviewing CUB/EDF Exhibit 2.1, I identified several very large spikes in the graphs presented by Mr. Zethmayr that, on their face, make no sense. While reviewing his workpapers, I noticed that the data populating the charts was hard coded in the Excel file, rather than being calculated by a formula. I was able to recreate the majority of the chart data, but for the obvious outliers, the values I calculated were extremely different from that reported in CUB/EDF Exhibit 2.1. As an example, on his chart comparing the variability of energy and demand for the single family space heat class (Figure 6), for all months other than December the coefficient of variation of energy exceeds 50%. For December, the chart shows a coefficient of variation lower than 10%. Recalculating this value from the raw data in the workpapers, I find that the December value should be 56%, right in line with the other months. It appears to me that the exhibit in question, when showing what appear to be obvious outliers, is errant.

Q Excluding the apparent outliers, how do you interpret the data in CUB/EDF Exhibit 2.1?

A. It is very similar to the data I generated from the AIC load research sample, which clearly shows a higher level of variability associated with energy than demand. In his testimony, Mr. Zethmayr criticizes the fact that I only compared the annual coefficient of variation for energy and demand, rather than showing monthly values. The monthly statistics did appear in the workpapers that I provided to all parties with the case, however. I will show in Figure 5 below the monthly energy and demand coefficient of variations from the Company's analysis, and in Figure 6, the corrected (for outliers/errors) ComEd statistics for the Single Family Space Heat (SFH) class.

Figure 5: Coefficient of Variation by Month, AIC

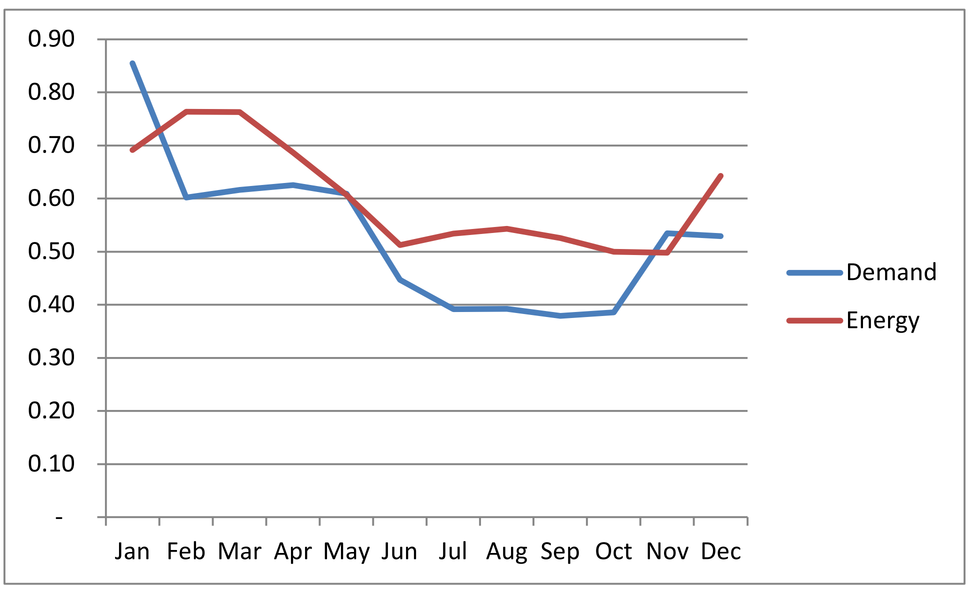
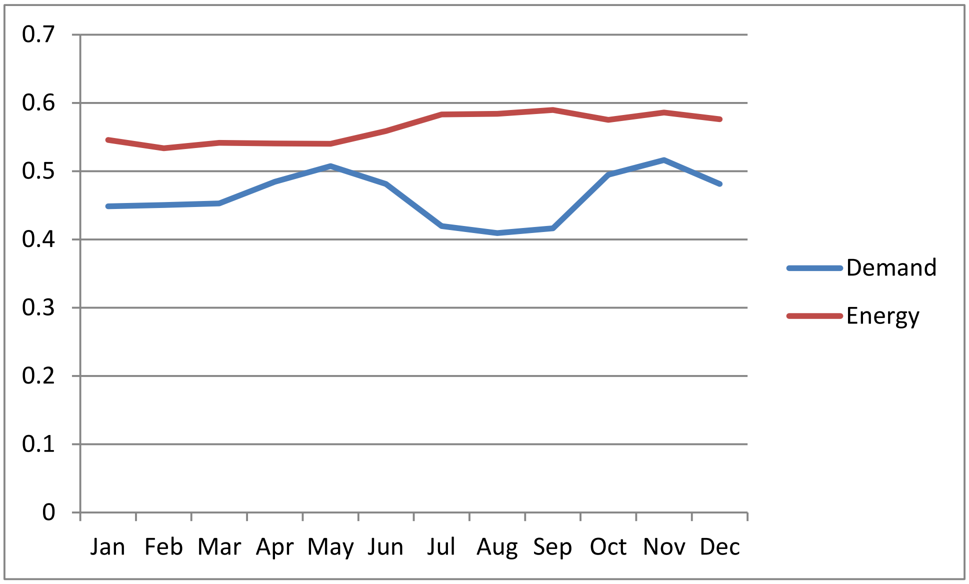


Figure 6: Coefficient of Variation by Month, SFH Class, ComEd
(from CUB Exhibit 2.1 with Outlier Corrected)



In both cases, as well as in the other subclass charts associated with the ComEd data, the difference between the coefficient of variation for energy and demand fluctuates to some degree, but is nearly always higher for energy, usually substantially so, and particularly throughout the summer months. The differences for these data series show about a 10-15% higher coefficient of variation for energy than demand throughout the summer months in the ComEd data. The AIC data is extremely similar in that regard.

Q Mr. Zethmayr says that you argue that "customer demand is essentially homogeneous as compared to volume usage." (CUB/EDF Ex. 2.0 at 6:125-26.) He says that this argument "ignores the considerable amount of variation in customer demand that does exist, the relationship between volumetric usage and peak demand, and the difference between the coincident and non-coincident peak usage." (CUB/EDF Ex. 2.0 at 6:127-29.) Has your analysis accounted for these variables?

A. Absolutely. The entire basis of my direct testimony analysis and argument was premised on calculating the inherent variability of both demand and energy, and then comparing them. This is in stark contrast to Mr. Zethmayr's allegation that I failed to consider the variability that does exist in demand. I in fact relied on that variability for my calculations, rather than ignored it. As far as Mr. Zethmayr's claim that I ignore the relationship between demand and energy in my rate design, recall the discussion I provided in response to Staff witness Harden. I decomposed the implicit recovery of demand-related costs into the fixed and variable charge types, demonstrating that under my proposal to collect 40% of revenues through fixed charges, 82% of demand-related costs would still be collected in energy charges. A rate design that relies on energy charges to recover 82% of demand-related costs can hardly be said to ignore the relationship between the two. Finally on the claim that I ignore the relationship between CP and NCP usage, I have already discussed in response to Mr. Rubin how the hypothetical rate design I developed is reasonably expected to apply in a manner that addresses both types of demand.

Q Mr. Zethmayr also claims that the Company's proposal would "raise the annual bills of low-use customers, who tend to have lower peak demand, while lowering the bills of customers with highest peak demand." (CUB/EDF Ex. 2.0 at 3:57-59.) Do you agree?

A. Directionally those moves would occur, and such movement is cost based. Keep in mind the relative proportion of the maximum bill movement (no more than a dollar and a half a month) as well as the fact that any moves in customer bills resulting from my proposal moves the majority of them demonstrably closer to the actual cost of service.

Q Mr. Zethmayr further claims that "there is a correlation between low-use and low-income customers" and that increasing fixed charges increases the bill of lower-use customers and has a disproportionate impact on low-income communities. (CUB/EDF 2.0 at 3:61-62.) Do you agree?

A. No. Mr. Zethmayr later references analysis he has performed of data relating to ComEd customers that suggests that the majority of low-income customers are low use. As a threshold matter, I have already questioned his use of ComEd customer data – data that is not even a random sample – to represent AIC's customer base. Subject to that criticism, I did review the workpapers supporting his analysis that were provided to the Company. My review of those suggests that relationship he claims is inconsistent across different subgroups of the low-income population he studied and is also inconsistent across years for the entire population of study, such that I would characterize the data as inconclusive on the topic at best. Any relationship that does exist between income and usage appears to be an extremely weak one.

Q Please describe the conflicting results of Mr. Zethmayr's study amongst subgroups.

A. Mr. Zethmayr divided ComEd's low-income customers into four groupings: SFH, Single Family Non-Space Heat (SFNH), Multi-Family Space Heat (MFS), and Multi-Family Non-Space

Heat (MFNH). He performs a linear regression analysis for each group designed to determine whether low-income customers in the group have a statistically significantly different usage level than the general population. His regressions show a statistically significant negative difference between usage and low-income status (i.e. low-income customers use less than the general population) for two of the subclasses (SFNH and MFH), and a statistically significant positive difference (i.e. low-income customer use *more* than the general population) in two other subclasses (SFN and MFNH). Interesting also is the mix of classes with higher versus lower use than the general population. Note that of the two single family segments, one low-income group uses more than the general population, one uses less. The same is true of the two multi-family segments studied, the two space heating groups studied, and the two non-space heating groups studied. There is really no apparent relationship, pattern, or rationale that explains why some of these groups have low-income customers that use more and others use less than the general population.

Q What does the 2015 data for the full population of residential customers show?

A. When looking at the regression model he created using all data points[23] (not further divided into subgroups), the relationship between low-income status and usage is negative and statistically significant, but the r-squared statistic for the estimated equation is extremely low, at 0.03. I will return to this point a bit later in my testimony.

[23] Mr. Zethmayr's analysis has some methodological errors, but correcting these errors do not appear to change the interpretation of the resulting statistics. It is the conclusions he draws from this information that are most impactfully errant.

Q Does Mr. Zethmayr provide a similar analysis using the 2014 data that he mentions in his testimony?

A. No. But the 2014 data was made available in the workpapers of Mr. Zethmayr. With that data I was able to replicate the 2015 analysis and found that in 2014, low-income customers used *more* than the general population in a statistically significant manner. These conflicting results between years and also between subclasses render more than enough doubt on Mr. Zethmayr's conclusions about low-income usage characteristics to discount his argument against the Company's proposal.

Q Since the ComEd data set utilized by Mr. Zethmayr had more customers in 2015 (655,917) than 2014 (106,054), should the 2015 regression results be considered more reliable?

A. No. Both years have more than enough data points to generate statistically robust regression models, and neither year's data set is drawn in a manner that makes it statistically representative of the total population of ComEd's more than 3 million residential customers, let alone AIC's customer base. The difference between the 2014 and 2015 results may be driven by differences inherent in the usage patterns of those years (perhaps due to weather or other environmental conditions) or due to the customer differences in the geographic areas that the ComEd AMI rollout covered. But statistically speaking, if 600 thousand plus customers is enough to draw inferences about the class, there is no doubt that 100 thousand plus is also enough. Either both data sets are reliable, or neither are. Either way, we are left with conflicting results that suggest that the relationship between income and usage represented by Mr. Zethmayr is either not present or inconsistent across time and subgroups, and therefore unsuitable for use in systematically understanding the impacts of rate design options on that population.

Q You previously mentioned the low r-squared value of the 2015 regression analysis. What information about the population does this statistic provide?

A. R-squared is a measure that tells the statistician the amount of the variability observed in the dependent variable (in this case use per customer) that can be explained by the factors in the model (in this case low-income status). What this means is that, while, for the specific group of customers analyzed by Mr. Zethmayr, the average use in 2015 does tend to be slightly lower, the status of a customer as low-income explains extremely little of the customer to customer variation in usage. One can reasonably conclude that factors other than income are far more impactful in determining usage; and further, that low-income customer usage exhibits very similar usage variation to the general population such that reducing the fixed charge and raising the variable charge would help some customers and hurt others.

Q Does the ComEd data provide insight into the extent to which, for that group, fixed versus variable charge considerations would impact low income bills?

A. Yes. As a threshold statistic, in the 2015 dataset of 655,917 customers, of which 45,325 are considered low-income, 35% of low-income customers use more than average and 65% use less. This is slightly misleading, though, because it is also true of the population 41% use more than average and 59% use less. This occurs because very large users tend to skew the average up; said another way it takes a lot of small users to average out one extremely large customer, so that the average is generally pulled up away from the median. When comparing the to the median usage of the population, 56% of low-income customers are smaller and 44% are larger. To take this one step further, the skewed distribution means that, even if slightly more than half of low income customers would benefit from a lower fixed charge (in this specific population and time period), the extent to which they would benefit would be less than the extent of the increases to the large use low-income customers. I will provide one more statistic to put that into perspective. The low-income customers that do have above average usage (recall this is 35% of the total low-income customers in the ComEd data set) are responsible for 59% of the usage of the low-income group. These customers, who are obviously faced with higher than average bills to begin with, will shoulder a disproportionate increase to provide quite modest relief to an only slightly larger group of low-use customers – customers who already have comparatively more manageable bills.

Q Do you have any additional observations on the low-income topic as pertains to the fixed charge recovery reflected in the residential rate design?

A. Yes. At line 350 of his direct testimony, Mr. Zethmayr, ironically, refers to management of the fixed charge as a "blunt instrument" that he characterizes as ill-suited to addressing bill impacts associated with space heating because managing the fixed charge impacts all customers (including non-space heat customers) equally. What strikes me about that comment is that raising the fixed charge would broadly benefit most space heat customers. It would in fact create a bill increase for some other customers (lower than average use). But *any* revenue neutral rate design change intended to help space heat customers would by definition require an increase to others to offset it, so by his definition, any rate design change to benefit space heat customers could be considered a blunt tool. Management of the fixed charge, however, would be truly a "blunt instrument" within the targeted class when used in an attempt to benefit low-income customers. A segment of low income customers may benefit, but there would be larger increases to a very significant remaining group – and these are the customers with the largest bills to begin with.

Q What does Mr. Zethmayr's analysis of ComEd's low income customers suggest about the impact demand charges may have on the group.

A. While I want to continue to caution reliance on any conclusions drawn from this data as applied to AIC's customers, it is interesting to note that at lines 326-327 of his testimony, Mr. Zethmayr indicates that low-income customers "appear to exhibit higher load factors than the general population." If that is the broadly the case, demand charges could be assumed to benefit low-income customers.

Q Mr. Zethmayr also claims that reducing fixed charges protects low-use and low-income customers and encourages energy efficiency. Do you agree that higher variable rates give customers more control over their electricity bills and send a price signal that incentivizes efficient energy use?

A. No, not necessarily. I have already addressed the impacts of the proposed higher fixed charge on energy efficiency in response to Ms. Munns. I have also described in response to Ms. Harden how the price signal sent by a high variable charge may over-incent load reductions that do not result in lower distribution costs, such as in the case of DER. To the extent that the greater variable charge does give the customer more control over their bill, as in the case of a customer that installs DER, that control may give them the ability to avoid paying for their true cost of service. Additionally, the higher variable charge may also make customer bills more volatile in the face of extreme weather conditions. For low-income customers, I have already explained how changes to the fixed charge have a very mixed, and in aggregate, minimal, impact. Low use customers do invariably face a higher bill under the Company's proposal, but under no circumstance would that increase exceed approximately a dollar and a half per month.

Q Mr. Zethmayr further suggests that the Commission should not accept the bill impacts of the proposed increase to fixed charges without also approving the eventual implementation of demand charges. (CUB/EDF Ex. 2.0 at 6:131-7:138.) Must the Commission rule upon the implementation of demand charges before it can increase cost recovery through fixed charges?

A. No. As discussed previously, the Company's proposal stands on its own merits as a cost-based rate today regardless of the future rate designs that may be employed.

Q Mr. Zethmayr says that any "circumstantial differences" between ComEd and AIC customers are "smaller than the considerable difference in confidence intervals" between your and his analysis. (CUB/EDF Ex. 2.0 at 9:192-94.) Do you agree?

A. No. As I have explained previously, data for the ComEd territory should not be considered representative of AIC's service territory. I used the analogy of statewide election/polling results earlier to describe this. It may seem like an extreme example given the differences in historical voting outcomes between the Chicago area and downstate Illinois in past elections, but a similar dichotomy is likely to be observed between Chicago and AIC's territory in terms of energy usage. The weather, economic conditions, housing stock, mix of urban versus rural communities, and a variety of other differences exist that could drive meaningful difference in energy usage from the northern extreme to the southern extreme in the state.

Q Mr. Zethmayr also discounts your discussion of two hypothetical households: the large family and the single professional. He does not believe that the two households would have the same level of peak demand. He also believes that the hypothetical ignores the timing of the households' peaks. He says that the timing affects system costs. What is your response?

A. His criticism of the hypothetical is similar to his criticism of my lack of support for the assertion that the residential appliance stock is fairly homogeneous in that it, frankly, doesn't really matter. The empirical finding about energy and demand is what it is regardless of the reason for it. However, I have used hypotheticals to provide a compelling rationale to make sense of the observed phenomenon. All of that said, I would argue that my hypothetical is entirely plausible and situations are even likely to exist in substantially similar form in reality. Mr. Zethmayr relies on his findings that energy and demand are correlated to arrive at his conclusion that the family with higher usage would have higher demand. While there should be no doubt that energy and demand are correlated, the very fact that customers have different load factors means they are not perfectly correlated. Mr. Zethmayr misinterprets the correlation as meaning more than it really does. The correlation he identifies means nothing more than high usage customers, on average, have higher demands. Again, this is pretty obvious stuff. But there is still considerable variation in these usage metrics that moves independently from each other, resulting in a wide variety of load factors across customers. Implicit in my hypothetical was the notion that the large family had a higher load factor, as I would expect them to based on the description of the household. However, regardless of the narrative that produces the differences, there is no disputing that load factor differences exist. And those differences impact the cost of service in a manner that makes energy charges alone fail to capture the cost of service adequately. As far as Mr. Zethmayr's discussion of the timing of the customers' demand relative to the system peak timing, it is possible that in some hypothetical case the timing of both customer peaks would be similar to the system CP and in some it would not. But broadly across the board it is clear that the residential class overwhelmingly drives the system peak, so a large majority of its members must be at the high end of their load spectrum during that event regardless of whether they are at their absolute peak demand.

Q Mr. Zethmayr argues that his analysis shows that the large family household "would likely have a significantly higher peak usage" than the single professional, relative to the existing variation in peak demand. (CUB/EDF Ex. 2.0 at 11:232.) Specifically, he opines that the single professional would have a "significantly lower" coincident peak, even if both households has the same NCP. (CUB/EDF Ex. 2.0 at 12:250.) He theorizes that, the large family would be responsible for a greater proportion of demand related costs, due to the differences in CP. What is your response?

A. The timing of the system CP is different year to year and whether either or both of these customers are at or near their individual peak at the same time does have an element of randomness to it. But it is equally plausible that their contribution to CP could be similar in some years, the large family would contribute more some years, and the single professional could contribute more some years. The point of my example is not to overanalyze the specific hypothetical families', characteristics and behaviors, but to establish context for the drivers of demand and energy. In reality, there are over one million unique customers with their own characteristics. The analysis of demand and energy, though, give us insight into the aggregate behaviors in a manner that makes sense with the hypothetical scenarios and families that I created.

Q Mr. Zethmayr faults the Company's bill effect comparison for failing to include any bill effects from the hypothetical demand rate. (CUB/EDF Ex. 2.0 at 12.) Is that a flaw?

A. No. As I have repeatedly stated, that analysis is appropriate for a time when such a rate design proposal is actually pending in front of the Commission.

Q Have you reviewed Mr. Zethmayr's discussion of his characterization of the bill effects of a shift to demand based rates? (CUB/EDF Ex. 2.0 at 13.)

A. Yes.

Q What is your opinion of his bill effect analysis?

A. Mr. Zethmayr indicates that demand based rates increase bills of low load factor customers and decrease them for high load factor customers. No analysis should have been needed to reach that conclusion – that is the intent of the rate design and is a nearly certain outcome of its implementation. He also indicates that the magnitude of bill impacts depends on the details of the demand charge, and provides a few examples to demonstrate. I have already agreed with that point in response to Mr. Rubin and find Mr. Zethmayr's conclusion unsurprising. Finally, Mr. Zethmayr goes on to indicate that the bill impacts of lowering fixed charges tends to reduce bills for low use customers and low-income customers. I have questioned his conclusion as it pertains to low-income, but clearly, at least directionally, his finding about low use customers is necessarily true, although not large in magnitude under the Company's proposal. None of these findings, however, provide any compelling rationale to reject the Company's proposal.

Q Do you agree that raising the fixed charge, without regard for customer load factor, sends the wrong price signal and moves rate design further from cost-causation?

A. No. This has been discussed previously in response to Ms. Harden and Ms. Munns.

Q Do you believe that lowering fixed charges lessens the use of electricity and lowers the overall cost of electricity over time?

A. As applied to delivery service rates, no. In fact, I think the reduction of fixed charges could promote deployment of DERs that could result in cost shifts that cause the unit costs of the delivery of electricity to rise further than they otherwise would.

Q Do you believe that lower fixed charges will lead to an increase in energy efficiency and AMI benefits for customers?

A. For reasons that have been addressed, no.

Q Do you have any additional comments about his calculations of charges?

A. Yes, two additional comments. First, although it ultimately does not appear to influence his recommendation[24], Mr. Zethmayr incorrectly characterizes the customer-related costs allocated to residential customers as representing 19% of the cost to serve that class. Mr. Zethmayr failed to include Services in his determination of these customer-related costs, which is incorrect and inconsistent with the National Association of Regulatory Utility Commissioners' 1992 Electric Utility Cost Allocation Manual. See, e.g., Draft Manual at 87 (Table 6-1 (classifying Services as customer-related distribution plant)). Mr. Zethmayr confirms that Services were not included in his response to data request AIC-CUB/EDF 6.01, while also

[24]Mr. Zethmayr's proposal is based upon the 28% recovery level that the Attorney General's Office recommended in Docket 13-0476.

acknowledging that it "could" be reasonable to include these facilities as generating customer-related costs. Including that category of facilities in the customer classification process results in 26.4% of residential class cost of service relating to customer-related costs. Mr. Zethmayr generally agrees, as indicted in his response to data request AIC-CUB/EDF 6.01 (his calculation rendered a result of 26.3%).

Secondly, Mr. Zethmayr incorrectly interprets the Company's filing by saying that our proposal is to decrease the residential class revenue allocation by 1.1% before redesigning rates. He goes on to use this 1.1% decrease to model his rate proposal. Unfortunately, this level of assumed reduction represents somewhat of a short cut and does not follow the approved rate design methodology to determine delivery service charges.

Explained further, the 1.1% decrease reflected in the rate calculations in our direct filing was the *product* of the our rate design methodology, which includes the application of certain increase mitigation constraints. It was not the *goal* of it. The Company has not sought, as an end goal, a 1.1% reduction in revenue requirement allocated to the DS-1 customer class, but rather developed rates based in part on the application of certain approved increase mitigation constraints to the revenue allocation targets established under the Company's embedded cost of service study (ECOSS).

Mr. Zethmayr’s approach, on the other hand, is somewhat results oriented in that it targets an assumed level of revenue requirement reduction. Stated differently, Mr. Zethmayr backed into rates using a revenue requirement goal. That’s not the correct order of operations. We take ECOSS results and then apply mitigation constraints and other factors including a fixed charge pricing target in order to develop end use rates. Even if the fixed charge pricing target is adjusted (say from 40% to 28%), the process should be performed in the same order. That process will result in different charges than one that simply adjusts fixed charge recovery targets in the context of an assumed revenue requirement. Mr. Zethmayr should have followed a similar order, and not just simply assumed a 1.1% revenue requirement reduction for the DS-1 class of customers.

Q. Are there any other comments you would like to add?

A. Yes. To be clear, the Company is not requesting approval of any specific revenue allocation or any specific rate for any class in this proceeding; but is instead requesting approval of a methodology for allocating revenues and designing rates. That methodology will be applied to the revenue requirement and ECOSS applicable in each annual formula rate update. The illustrative rates filed by the Company in this docket are presented in order to provide an example of the application of that process. The outcomes of the process are not at issue; the process itself is. I recommend that if Mr. Zethmayr's proposed rate design is adopted by the Commission (which, as explained above, should not be), the charges be recalculated in the context of the Company's methodology, i.e., to correctly reflect the mitigation constraints originally approved by the Commission in Docket 13-0476.

VII. CONCLUSION

Q Does this conclude your rebuttal testimony?

A. Yes, it does.