BEFORE THE PUBLIC SERVICE COMMISSION
OF THE COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) APPROVAL OF TARIFFS AND RIDERS; (3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; (4) APPROVAL OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	Case No. 2020-00174

Direct Testimony of Justin R. Barnes

On Behalf of Kentucky Solar Industries Association, Inc.

October 7, 2020

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. My names is Justin R. Barnes. My business address is 1155 Kildaire Farm Rd., Suite 202, Cary, North Carolina, 27511. My current position is Director of Research with EQ Research LLC.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of the Kentucky Solar Industries Association, Inc. ("KYSEIA").

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. No.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at N.C. State University for more than five years as a Policy Analyst and Senior Policy Analyst.[1] During that time I worked on the *Database of State Incentives for Renewables and Efficiency ("DSIRE")* project, and several other projects related to state renewable energy and energy efficiency policy. I joined EQ Research in 2013 as a Senior Analyst and became the Director of Research in 2015.

[1] The North Carolina Solar Center is now known as the North Carolina Clean Energy Technology Center.

In my current position, I coordinate and contribute to EQ Research's various research projects for clients, assist in the oversight of EQ Research's electric industry regulatory and general rate case tracking services, and perform customized research and analysis to fulfill client requests.

Q. PLEASE SUMMARIZE YOUR RELEVANT EXPERIENCE AS RELATES TO THIS PROCEEDING.

A. My professional career has been spent researching and analyzing numerous aspects of federal and state energy policy, spanning more than a decade. Throughout that time, I have reviewed and evaluated trends in regulatory policy, including trends in rate design and utility regulation. For example, as part of my current duties overseeing EQ Research's general rate case tracking service, I have reviewed dozens of general rate case applications, including the methods used by different utilities to develop cost of service studies and different rate designs, as well as the decisions made by regulators in those proceedings.

I have submitted testimony before utility regulatory commissions in Colorado, Hawaii, Georgia, New Hampshire, New Jersey, New York, North Carolina, Oklahoma, South Carolina, Texas, and Utah, as well as to the City Council of New Orleans, on various issues related to distributed energy resource ("DER") policy, net metering, rate design, and cost of service.[2] These individual regulatory proceedings have involved a mix of general rate cases and other types

[2] The City Council of New Orleans regulates the rates and operations of Entergy New Orleans in a manner equivalent to state utility regulatory commissions.

of contested cases. My *curriculum vitae* is attached as Exhibit JRB-1. It contains summaries of the subject matter I have addressed in each of these proceedings.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY AND HOW IT IS ORGANIZED.

A. My testimony responds to the Kentucky Power Company ("Kentucky Power" or "the Company") N.M.S. II Tariff proposal and its proposed COGEN/SPP tariff, broken into six sections. Sections II through IV are devoted to topics relating to net metering and the Company's N.M.S. II Tariff proposal. I address the context of S.B. 100 in Section II, the shortcomings of the Company's N.M.S. II Tariff proposal in Section III, and reasonable paths for the evolution of distributed generation ("DG") policies and rates in Section IV. In Section V I address the Company's COGEN/SPP tariff for purchases of energy and capacity from qualifying facilities ("QFs"). Section VI contains my concluding remarks and recommendations.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION ON THE COMPANY'S N.M.S II TARIFF AND THE REASONS FOR THOSE RECOMMENDATIONS.

A. I recommend that the Commission decline to adopt the N.M.S. II Tariff because the Company has failed to demonstrate that the proposal meets a basic requirement of S.B. 100 dictating that the rates charged to DG customers only recover the costs to serve those DG customers. Kentucky Power failed to demonstrate that its proposal would produce this outcome because it has not conducted DG customer load research and an accompanying cost of service study illustrating that current rates are not sufficient for this purpose, or that its N.M.S. II Tariff would accomplish this objective. I therefore recommend that the current net metering tariff be retained unchanged and that Kentucky Power be directed to produce such a cost study in support of any future proposals to amend its net metering tariff.

In the alternative, should the Commission determine that changes to the Company's net metering tariff are necessary, it should still decline to adopt the Company's specific proposal because it contains numerous structure flaws. Among these flaws are that it would actually incentivize DG customers to *increase* their usage during on-peak periods and present a generally confusing and conflicting set of price signals to DG customers. Should the Commission determine that changes to the Company's net metering tariff should be made at this time, I recommend that it instead pursue one of the alternative options discussed in my testimony. In reviewing these options, I encourage to the Commission to take a forward-looking approach to DG tariff design with the objective of developing a durable framework and one or more tariff options that can made consistent across all utility service territories and can be adapted with minimal disruption for use after a utility reaches its net metering cap.

Q. WHAT ARE YOUR RECOMMENDATIONS WITH RESPECT TO THE COMPANY'S COGEN/SPP TARIFFS?

A. I recommend that the tariffs be modified to clearly specify that QFs have the option to receive compensation at the prevailing rates at the time the QF establishes a legally enforceable obligation ("LEO"), and specify the allowable duration for such contracts. I further recommend that the allowable duration be set at a minimum of ten years in order to facilitate QF financing and create true ratepayer indifference by leveling the playing field between utility-owned and non-utility-owned generation. A minimum fixed price contract option of this duration would be consistent with policies established in numerous other states.

Second, I recommend that the Company's calculation of avoided capacity costs be revised to use a 20-year useful life in place of a 40-year useful life, and a capital cost of at least $799/kW in place of $700/kW. Both of these recommendations are based on assumptions used in similar calculations performed by other well-respected sources of this type of information.

II. S.B. 100 CONTEXT

Q. IN YOUR VIEW, WHAT ARE THE QUESTIONS THE COMMISSION FACES WITH RESPECT TO POTENTIAL REVISIONS TO NET METERING TARIFFS IN KENTUCKY?

A. The basic criticism often made of net metering as it has traditionally been implemented is that it allows DG customers to be subsidized by non-DG customers. In other words, DG customers do not pay their "fair share" of system costs (*i.e.*, their cost of service), placing a greater burden on non-DG customers. That leads to questions of whether or not such a criticism is accurate, and if so the magnitude of the problem and the best ways to mitigate it. To the extent that a subsidy can be reliably identified, there are two ways to mitigate it, which in some ways are two sides of the same coin.

One way to mitigate an identified subsidy is to simply reduce the compensation provided to customers as part of the net metering construct from the retail rate to some other amount. Another way is to provide rates to DG customers that are more closely aligned with cost of service than would otherwise be the case. Such a mechanism tackles the other end of the subsidy equation insofar as it can be used to incentivize DG customers to reduce their cost of service or effectively pay a penalty for not doing so. Both approaches have a potential role with respect to consideration of overall DG ratemaking policy and there are often multiple ways through which the same objective can be achieved.

All of that said, the most fundamental question is whether a subsidy exists in the first place. For that purpose, there are two tools at the Commission's disposal: (a) cost-benefit analysis, and (b) cost of service analysis. As I discuss in more detail later in my testimony, cost-benefit analyses are generally conducted on a forward-looking basis with a goal of identifying the potential for a subsidy to exist in the long-term. A cost of service analysis takes a short-term outlook, using a snapshot of currently known costs to discover the amount of costs that DG customers are responsible for relative to what they pay. Both approaches have merits. For instance, the long-term outlook used in a cost-benefit analysis is more consistent with long-term ratepayer indifference and utility planning. On the other hand, a cost of service evaluation, while effectively limited to the short-term, identifies responsibility for embedded costs, including whether DG customers are themselves more or less costly to serve than the "average" customer in a class.

Q. WHAT FACTORS SHOULD THE COMMISSION CONSIDER AS PART OF ADOPTING REVISIONS TO DG CUSTOMER RATES.

A. Generally speaking, the Commission should consider the same generally accepted ratemaking principles that govern the broader ratemaking process. By generally-accepted ratemaking principles, I am referring to the Bonbright principles, which KYSEIA Witness Van Nostrand discusses in more detail. Beyond general adherence to these principles, in the S.B. 100 context there are also two considerations that require special attention.

1. Whatever determinations the Commission makes, the resulting policies and general rate structures should be made consistent across all utilities. Inconsistent policies would undermine basis fairness to all ratepayers and create unnecessary complexities for DG providers that work across multiple service territories.
2. The Commission should attempt to minimize “churn” in DG rates and policies that would be caused by establishing short-lived tariffs or programs that are subsequently replaced with different arrangements. Stated another way, a durable set of policies and rates is preferrable to frequent structural changes.

With respect to the second factor, the Commission should consider that utilities vary with respect to their level of net metering penetration relative to the one percent of peak load net metering cap. It makes little sense to develop a set of successor net metering tariffs only to have those same tariffs be replaced upon a utility reaching the net metering cap. Doing so could result in customer confusion in addition to being inefficient from the perspective of Commission and intervenor time and resources.

Q. WHEN YOU USE THE TERM "DURABLE" IN REFERENCE TO DG RATES AND POLICIES, ARE YOU SUGGESTING THAT SUCH POLICIES AND RATES BE PERMANENT?

A. No. The electricity industry landscape is changing in response to technological advancements and many other factors and DG rates and policies should likewise be refined over time with these changes in mind. A "durable" regime need not be permanent, but it should provide customers and DG providers with a reasonable level of certainty, the ability to plan for potential future changes, and an orderly transition to any future regime. Stated another way, a durable policy framework avoids creating disruptive cliffs and works in advance of any defined inflection points (*e.g.,* the net metering cap) with an overarching objective of providing such a smooth transition.

A. Summary of S.B. 100 Provisions

Q. PLEASE SUMMARIZE THE PRINCIPLE ELEMENTS OF S.B. 100 THAT YOU VIEW AS THE MOST RELEVANT TO THE COMPANY'S N.M.S II TARIFF PROPOSAL.

A. In brief summary, S.B. 100 allows net metering customers to be subjected to separate rates aligned with their cost of service, and replaces the rollover over kilowatt-hour credits for exports with a monetary credit system. More specifically, S.B. 100 contains the following elements that are most directly relevant to the Commission's review of the Company's N.M.S. II Tariff proposal.

1. It amends the definition of net metering to refer to the difference in the "dollar value" of electricity fed by a customer-generator to the grid and the "dollar value" of electricity consumed by the customer during a billing period.
2. It requires the compensation for electricity fed to the grid by a customer-generator take the form of a monetary credit (*i.e.,* a "dollar denominated bill credit").
3. It entitles retail electric suppliers to the implement rates for eligible customer generators that allow the retail electric supplier "to recover from its eligible customer generators all costs necessary to serve its eligible customer-generators, including but not limited to fixed and demand-based costs, without regard for the rate structure for customers who are not eligible customer-generators."
4. It requires the Commission to establish the "dollar value" of electricity fed by a customer-generator to the grid over the course of a billing period.

Q. WHAT QUESTIONS DOES S.B. 100 REQUIRE A UTILITY TO DEMONSTRATE AS PART OF A RATES PROPOSAL BASED ON S.B. 100?

A. There are two primary questions that need to be answered. First, S.B. 100 requires that a utility demonstrate that the rates offered to customer-generators are consistent with its costs to serve those customer-generators. Second, it requires that the rate for exports properly reflects the value of exports to the grid.

B. Cost of Service & Export Value

Q. HOW IS A UTILTY'S COST TO SERVE A SPECIFIC SET OF CUSTOMERS TYPICALLY DETERMINED?

A. In order to reliably identify the costs to serve a customer segment or class, a utility typically conducts load research and develops a cost of service study based on that load research for customer segment in question.

Q. HOW DOES THIS RELATE TO THE PROVISIONS IN S.B. 100 REFERRING TO A UTILITY'S ENTITLEMENT TO RECOVER ITS FIXED COSTS, INCLUDING DEMAND-RELATED COSTS?

A. A cost of service study determines responsibility for fixed and demand-related costs. A customer's cost of service is only the portion of those costs properly allocated to them based on their usage characteristics. A DG customer can theoretically have a negative cost of service depending on the amount and timing of exports.

Q. WHY IS IT IMPORTANT THAT CONCLUSIONS ABOUT COST OF SERVICE FOR A CUSTOMER SEGMENT BE SUPPORTED BY A FULL COST OF SERVICE STUDY OF THAT SPECIFIC GROUP OF CUSTOMERS?

A. There are several reasons, but ultimately it amounts to a need for equity and fairness in ratemaking. It is unfair to use one standard of evidence, such as full cost of service study, for customers in general but permit a looser standard to be applied to certain customer segments. Likewise, the results of a shoddy or incomplete evaluation could result in unfair rates that charge customers in excess of their cost of service. As Witness Van Nostrand discusses in more detail, nothing in S.B. 100 suggests that the Commission should depart from the typical standards it applies for the establishment of just and reasonable rates, or generally accepted ratemaking principles.

To put a finer point on the issue of fairness, without a targeted cost of service evaluation the Commission has no way of knowing at what level customer-generators pay for service relative to their cost of service, and how that might vary within the class. Again, not only does that lack of information raise the potential for customers to be overcharged, it prevents a more informed evaluation of the options necessary to remedy any issues that are present. In other words, the simple fact that a customer-generator purchases less electricity from a utility than they would otherwise is insufficient evidence that they are being "subsidized" by other customers.

Q. CAN YOU CITE TO ANY SPECIFIC EXAMPLES ILLUSTRATING THIS POSSIBILITY?

A. Yes. In a 2015 general rate case, Oklahoma Gas and Electric ("OG&E"), a sister company to Kentucky Power, proposed to establish special demand rates for customers that install DG and eliminate any compensation for exported generation on the basis that the changes were necessary to eliminate a supposed "subsidy" to DG customers. As it turns out though, the Company's class cost of service study, which evaluated residential DG customers as a separate class, showed that the residential DG class actually produced a considerably higher rate of return than the residential class as a whole (7.23% vs. 5.33%).[3] In other words, residential DG customers were subsidizing non-DG customers to a significant degree. Not surprisingly, the changes sought by OG&E were not adopted.[4]

Q. WHAT TYPE OF EVALUATION IS NECESSARY TO DETERMINE THE APPROPRIATE "DOLLAR VALUE" OF COMPENSATION FOR EXPORTS TO THE GRID?

A. The value of exports can only be identified with a cost-benefit study that utilizes a long-term time horizon and fully accounts for all future benefits and costs. Such an evaluation would typically be conducted under a total resource cost framework for the life of a typical DG system (*e.g.,* 25 years). By default, under traditional net metering the dollar value of excess generation is simply the volumetric retail rate.

Q. WHY IS IT IMPORTANT TO EVALUATE COSTS AND BENEFITS UNDER A LONG-TERM TOTAL RESOURCE COST FRAMEWORK?

A. A long-term evaluation is necessary because DG systems produce value over the course of the system life. Limiting consideration of value to the short-term fails to consider what is in the best interest of all ratepayers over the time horizon during a which a DG system will produce benefits. A total resource cost framework likewise aligns with the overall long-run interests of ratepayers. In other words, the value will influence customer decision-making on the construction of long-lived assets. Therefore, this value should reflect the long-term value. KYSEIA Witness Inskeep

[3] Oklahoma Corporation Commission, Docket No. PUD 201500273. Direct Testimony of Mark Garrett. March 31, 2016, p. 14, *available at*: http://imaging.occeweb.com/AP/CaseFiles/occ5272383.pdf

[4] Oklahoma Corporation Commission, Docket No. PUD 201500273. Order No. 662059. March 20, 2017, *available at*: http://imaging.occeweb.com/AP/Orders/occ5360859.pdf

provides a more extended discussion of regulators' use of cost-benefit studies when considering questions of DG policy and compensation, including successor tariff regimes.

Q. HOW DO YOU VIEW COST OF SERVICE ANALYSES AND COST-BENEFIT ANALYSES FITTING TOGETHER WITH RESPECT TO DG POLICY AND COMPENSATION RATES?

A. Both have a valuable role to play. A cost-benefit analysis can answer the threshold question of whether compensation to customer-generators is lower or higher than the long-term value of that generation (*e.g.,* lower or higher than the retail rate under net metering). Where the long-term value is higher than the retail rate, no need for any changes exists. A cost of service evaluation offers a second test based on current conditions. Since a cost of service evaluation is effectively a snapshot in time, it fails to consider the long-term interests of ratepayers.

However, it has the virtue of being able to identify an alternative cost benchmark (*i.e.,* an amount other than the retail rate) to which compensation could be compared, as well as the nuances of variations in cost of service that exist within the broader class and specific customer segments of a class. For instance, if DG customers as a group, or subgroups of DG customers (*e.g.,* those that install larger systems vs. smaller systems) have a lower cost of service than the "average" customer, the retail rate is an inappropriate basis for comparison. This could be true where DG production during peak times reduces the allocation of peak-driven costs to the broader class. Both types of evaluations can yield valuable information on the nature of any short or long-term subsidization of different customer groups and the nature of solutions that may be used to mitigate any identified inequities.

Q. ARE COST-BENEFIT OR DG COST OF SERVICE STUDIES TYPICALLY REQUIRED AS PART OF REGULATORY REVIEWS OF NET METERING POLICIES AND DG TARIFFS?

A. They have not necessarily been universally required, but few jurisdictions have adopted major changes to net metering or established successor regimes without requiring one or both. KYSEIA Witness Inskeep discusses how states have approached cost-benefit analysis and their resulting conclusions. Typically these types of analyses have been performed by consultants with subject matter expertise at the request of legislators or regulators. A cost of service analysis is more commonly used in ratemaking proceedings where specific revisions to DG customer purchase or compensation rates are being proposed, such as the case in the instant proceeding.

III. N.M.S. II TARIFF PROPOSAL

A. Summary of Kentucky Power's N.M.S II Tariff Proposal

Q. PLEASE BRIEFLY DESCRIBE THE GENERAL STRUCTURE OF THE COMPANY'S N.M.S. II TARIFF PROPOSAL.

A. The Company proposes to establish two mutually exclusive netting periods. Period 1 runs from 8 AM – 6 PM on all days of the year, while Period 2 encompasses all remaining hours. Exports during one netting period cannot be applied to offset consumption during the other netting period, and any net exports over a monthly basis would be compensated at the Company's calculated avoided cost rate. The practical effect of the Company's proposal is that solar production is only permitted to offset daytime consumption at the retail rate.

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED AVOIDED COST RATE FOR MONTHLY EXCESS GENERATION DURING A NETTING PERIOD.

A. The Company calculates an avoided cost rate of $0.03659/kWh. This rate includes the following components:

- Energy: $0.02837/kWh (derived from the COGEN/SPP rate, based on forecasted PJM locational marginal prices ("LMPs"))
- Avoided Generation Capacity: $0.00466/kWh (based on an estimated PJM capacity cost and estimated contribution of solar to the top five PJM summer peak hours, or 5CP).
- Avoided Transmission: $0.00356/kWh (based on Network Integration Transmission Service ("NITS") and the estimated contribution of solar to the twelve monthly peaks on which those costs are allocated, or 12CP).

The Company pro-rates the values for Avoided Generation Capacity and Avoided Transmission based on an estimate of the amount of excess generation (as opposed to immediate on-site consumption) that a hypothetical residential solar system would produce during those peak hours. This discounting reduces the Avoided Generation Capacity value by 48.61% and the Avoided Transmission value by 73.28%.[5]

[5] *See* Vaughan Direct, Exhibit AEV-3.

Q. HOW DID THE COMPANY DEVELOP THE SOLAR GENERATION PROFILE AND RESIDENTIAL LOAD PROFILE IT USES TO DERIVE THE PROPOSED AVOIDED COST RATE?

A. The solar production profile is based on the generation profile for a 20 megawatt ("MW") utility-scale project.[6] The residential load profile is based on the hourly load associated with a typical residential customer.[7] The solar production profile was scaled to correspond to an average-sized residential solar DG system for the purpose of calculating estimated hourly net excess generation.

Q. DID THE COMPANY CONDUCT A SIMILAR ANALYSIS FOR A HYPOTHETICAL NON-RESIDENTIAL SYSTEM?

A. No.

Q. DID THE COMPANY CONDUCT A COST OF SERVICE EVALUATION OF RESIDENTIAL SOLAR DG CUSTOMERS TO IDENTIFY THE AMOUNT OF FIXED COSTS THAT THEY ARE ACTUALLY RESPONSIBLE FOR?

A. No. In response to data requests, Kentucky Power stated that it does not have the data necessary to conduct such an evaluation. Specifically, the Company does not have load research that would be necessary to establish the load profile of a residential DG customers, nor does it have production data from the small number of residential solar DG systems currently on its system.[8] Both types of data are

[6] *Id.*
[7] Kentucky Power response to KYSEIA 1-8.
[8] Kentucky Power response to KYSEIA 1-7(d) and 1-8.

necessary to arrive at conclusions regarding the Company's costs to serve residential DG customers.

Q. HOW WOULD THE COMPANY'S N.M.S. II TARIFF AFFECT RESIDENTIAL CUSTOMER BILL SAVINGS RELATIVE TO THE CURRENT NET METERING REGIME?

A. I estimate that it would reduce customer bill savings by 30 – 40% for a system sized to produce an approximate 100% load offset on an annual basis. I arrived at this range developing a solar production profile with basic default assumptions using the National Renewable Energy Lab ("NREL") System Advisor Model ("SAM"). I then applied this hourly production profile to both a standard residential load profile incorporated within SAM and the Company's standard residential load profile. The comparison to the SAM residential load profile produced a bill savings reduction of 32.06% while using the Company's residential load profile produced a reduction of 33.12%.[9]

I state this as a range for two reasons. First, there is likely to be a fair amount of variation between individual customers with respect to their hourly load profiles. Customers with lower daytime loads would produce a greater quantity of exports than those with higher daytime loads and consequently forfeit more value due to excess daytime generation. Second, system orientation and other site characteristics

[9] For the purposes of this evaluation I used the Company's current Schedule R.S. rate rather than the proposed rates, including the Company's proposed winter tail block rate. It is likely that the winter tail block rate would increase the compensation reduction in percentage terms because it increases the rate spread between the generally applicable retail rate and Company's proposed avoided cost rate.

would influence the solar production shape and correspondingly, the amount of hourly exports.

B. Insufficiency of the Company's Application

Q. WHAT IS YOUR GENERAL ASSESSMENT OF THE COMPANY'S N.M.S. II TARIFF PROPOSAL?

A. The N.M.S II Tariff suffers from both considerable structural flaws and flaws in the methodology the Company uses to establish the proposed avoided cost rate. I discuss both aspects in subsequent sub-sections of my testimony. But taking a step back, even more problematic is that by not conducting an evaluation of the cost to serve DG customers, Kentucky Power has failed to adequately demonstrate that DG customers would not otherwise already pay their full cost of service. As I previously observed, the simple fact that a customer-generator purchases less electricity from a utility than they would have otherwise without DG is insufficient evidence that they are being "subsidized" by other customers, and insufficient evidence that they would not pay the fixed and demand-related costs for which they are responsible.

Q. PLEASE EXPLAIN HOW THAT RELATES TO THE REQUIREMENTS OF S.B. 100.

A. S.B. 100 only entitles a utility to recover "the *costs necessary to serve* its eligible customer-generators" (emphasis added). It certainly does not entitle the Company to recover more than those costs. The only way to arrive at reliable conclusions about whether a given tariff design would accomplish aligning DG rates with cost causation, including compensation for exports, is to conduct a complete cost of service evaluation. Stated another way, in order to remedy any subsidy that exists from one group of customers to another, one must first quantify the subsidy using well-vetted and accepted methods for doing so.

Q. HAS THE COMPANY PRESENTED ANY EVIDENCE THAT SPEAKS TO QUANTIFYING A SUBSIDY THAT DG CUSTOMERS RECEIVE FROM NON-DG CUSTOMERS?

A. It did not present any such evidence in its application or testimony, but in response to an information request Kentucky Power presented an analysis concluding that a residential DG customer receives a subsidy amounting to $0.072/kWh.[10] This amount is derived by subtracting a modest amount for avoided non-fuel costs from total non-fuel costs recovered via volumetric charges. The problems with this simplistic analysis are that: (1) it fails to properly account for DG customer cost of service before the installation of DG, and (2) fails to properly account for the contribution that DG makes in altering a customer's cost of service.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW A COST OF SERVICE-BASED EVALUATION WOULD PRODUCE A DIFFERENT RESULT?

A. Yes. The simplest example is for energy costs. The Company's cost of service study produces a residential class revenue requirement for energy-related costs of $64,765,247.[11] Total residential class energy sales are approximately 1.922 billion kilowatt-hours ("kWh"), leading to a volumetric energy rate of $0.0325/kWh. A customer with a DG system offsets energy-related costs on a 1:1 basis, meaning that any amounts they do not pay due to on-site generation are fully offset by a

[10] Kentucky Power responses to KYSEIA 1-19, Attachment 1.
[11] Direct Testimony of Alex E. Vaughan ("Vaughan Direct"), Exhibit AEV-1, p.1.

reduction in costs to the residential class. In other words, it is not possible for any "subsidy" to exist with respect to energy-related costs. Yet, the Company's subsidy analysis would give a DG customer credit for reducing energy-related costs at roughly half that rate, $0.01625/kWh.[12]

This disconnect is present throughout the Company's evaluation of the supposed subsidy, as the Company's analysis fails to account for DG contributions to reducing the allocation of production costs, transmission costs, and primary distribution costs, all of which are allocated based on class contributions to monthly coincident peaks. Where DG reduces the class contribution to peaks, or if DG customers already contribute less to peaks even before installing DG, the broader class benefits from their presence in the form of reduced allocations of those costs. The same effect is present for jurisdictional cost allocation, where peak reductions reduce the costs allocated to Kentucky Power customers as a whole. In other words, the benefits to an individual Kentucky retail rate class are layered on top of a benefit received from a reduction in costs allocated to the Kentucky jurisdiction.

Q. WHAT DO YOU CONCLUDE ABOUT THE SUFFICIENCY OF THE COMPANY'S APPLICATION WITH RESPECT TO S.B. 100 AND THE EXISTENCE OF A SUBSIDY TO DG CUSTOMERS?

A. The Company has failed to present evidence sufficient to determine the costs to serve DG customers, whether they already pay amounts consistent with their costs

[12] Derived from the Kentucky Power response to KYSEIA 1-19, Attachment 1 by dividing total monthly fuel costs by average monthly sales.

of service, and ultimately, the nature and magnitude of any subsidy that does exist between DG customers and non-DG customers.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION GIVEN THIS LACK OF EVIDENCE?

A. The Company's N.M.S. II Tariff proposal should be rejected because the Company has failed to meet a basic pre-requisite of S.B. 100, that the rates applied to DG customers be based on their cost of service. I also recommend that the Commission direct that future applications for modifying DG rates and net metering tariffs be supported by the load research and complete cost of service analyses. Such a directive would help avoid wasting the Commission's and intervenors' time and resources responding to proposals that lack any meaningful support with respect to cost of service evaluation and the existence of subsidies.

Q. SINCE YOU RECOMMEND THAT THE COMMISSION REJECT THE COMPANY'S APPLICATION IN TOTAL, HOW SHOULD THE COMMISSION VIEW YOUR DISCUSSION OF SPECIFIC SHORTCOMINGS IN THE COMPANY'S PROPOSAL IN SUBSEQUENT PORTIONS OF YOUR TESTIMONY?

A. The Commission would be fully justified in dismissing the Company's N.M.S. II Tariff proposal and effectively sending the Company back to the drawing board. Notwithstanding my recommendation to that effect, my review of the specific problems with the design of Kentucky Power's proposal would be valuable to the Commission with respect to its future consideration of net metering tariff revision applications, or if the Commission declines to adopt the Company's specific proposal but determines that at least some changes to the net metering tariff are necessary.

C. Structural Problems With the Proposed N.M.S. II Tariff

Q. WHAT WEAKNESSES HAVE YOU IDENTIFIED IN THE OVERALL STRUCTURE OF THE COMPANY'S N.M.S II PROPOSAL?

A. I have identified several weaknesses, as follows:

- The proposal is counter-productive for producing customer behavior that lowers their cost of service.
- The structure is likely to be confusing to customers because although the two defined time periods superficially charge customers the same rate, in practice the effective rate for post-solar consumption would differ.
- The framework would be particularly confusing for customers on one of the Company's time varying rate options because the N.M.S. II netting periods are different than the time-varying pricing periods.
- It would be difficult or impossible for solar providers or customers to produce reliable estimates of potential bill savings or optimize system sizing to avoid forfeiting excess exports because neither will possess information on a customer's load patterns, which is critical for making such determinations.

Q. PLEASE EXPLAIN WHY THE COMPANY'S N.M.S II PROPOSAL SENDS A POOR PRICE SIGNAL TO CUSTOMERS.

A. An N.M.S. II customer seeking to maximize the effective value they receive from an on-site solar system needs to seek to match their monthly usage during each time period with system production. Achieving this requires a customer to shift their usage to the 8 AM – 6 PM netting period during which almost all solar production will naturally occur. Alternatively, the customer could install battery storage and effectively shift the production profile of the solar system so as to store electricity that would otherwise be exported during one period and use it during the other netting period. For a solar system this would amount to storing daytime production for use at night.

The problem with this is that this price signal prompts customers to shift consumption that would take place primarily during off-peak hours to on-peak hours. Or, if storage is utilized, store excess on-peak energy for use during off-peak hours. Neither is a good outcome. Shifting consumption causes the customer to become more costly, while shifting production with battery storage causes the generation to be less valuable.

Q. TO WHAT DEGREE DO THE PEAK PERIODS DEFINED IN THE COMPANY'S TARIFFS OVERLAP WITH THE 8 AM – 6 PM NETTING PERIOD DURING WHICH ALMOST ALL SOLAR PRODUCTION WOULD OCCUR?

The overlap is considerable. Schedule R.S.-T.O.D. uses an on-peak period of 7 AM – 9 PM on weekdays, so on weekdays, the entire duration of the 8 AM – 6 PM netting period overlaps peak hours. Schedule R.S.-T.O.D.2 uses a 7 AM – 11 AM and 6 PM – 10 PM on-peak period from November through March and a 12 PM – 6 PM on-peak period from May 15 through September 15. Thus the winter on-peak period contains three hours of overlap (8 AM – 11 AM) while the summer on-peak period fully overlaps for the entire six-hour duration. The summer on-peak rate is higher than the winter on-peak rate, indicating that it is the higher cost period of the two seasonal on-peak periods.

Q. HOW WOULD CUSTOMERS WITH DIFFERENT OVERALL USAGE LEVELS BE AFFECTED BY THE COMPANY'S N.M.S. II TARIFF?

A. The Company's proposal would be the most punitive on customers with relatively lower daytime energy usage unless the customer can accomplish consumption shifting or production shifting with storage. Since daytime hours have a significant overlap with peak periods, the proposal is most punitive on customers with the lowest on-peak usage, and hence a lower cost of service. Furthermore, because customers with low total usage tend to have "peakier" load shapes, it is likely that lower total usage customers will have a greater quantity of daytime exports than an average customer. Consequently, a customer that has lower usage before installing solar is likely to be more adversely impacted than a customer with higher pre-solar usage.

Q. PLEASE ELABORATE ON HOW THE N.M.S. II PROPOSAL WOULD BE CONFUSING TO CUSTOMERS.

A. Schedule R.S. does not contain time differentiated charges and the N.M.S. II Tariff would not change this despite the fact that it defines two different measurement periods for customer use. On a superficial level, the rate for consumption in one period is the same for consumption in the other. But in practice the effective rate a customer pays for consumption during each period after installing DG is significantly different. A typical residential customer could be forgiven for failing to appreciate such a meaningful distinction since on the surface, the rate they pay appears to remain the same.

Furthermore, the addition of a winter tail block rate, as the Company has separately proposed for Schedule R.S., would further complicate savings calculations. Calculating bill savings under N.M.S. II with a winter tail block rate requires numerous separate calculations using three different rates. First, direct on-site use must be broken into blocks for portions that offset the standard rate, and those that offset the discounted block rate for each period. Second, excess generation for each month must be broken into blocks for exports that offset on-site use for each netting period and the net excess for each netting period compensated at avoided costs. Third, the portion of excess generation that offsets on-site use must then be further broken into monthly blocks for the portion that offsets the standard rate and the portion that offsets the discounted rate. This last step requires the calculation to circle back to the first step to account for the fact that on-site use valued at the discounted rate reduces the amount of excess for which the discounted retail rate applies.

The collective calculation is quite intensive, requiring the use of a series of conditional (*i.e.*, if/then) formulas. Its accuracy also depends on how representative the hourly load data used in the calculation is over the life of a DG system. A single year of customer use data could easily be skewed due to various factors such as weather and changes in personal circumstances.

Q. IS THE N.M.S II TARIFF WELL-SUITED FOR USE IN COMBINATION WITH ONE OF THE COMPANY'S TIME-VARYING RATE OPTIONS?

A. Absolutely not. The N.M.S. II design would be even more confusing for any customer that seeks to enroll in one of the Company's time-varying rate options. The partial overlap of on-peak hours with the N.M.S. II netting periods effectively creates four pricing periods under Schedule R.S.-T.O.D. in the form of a Netting Period 1 peak and off-peak rate and a Netting Period 2 peak and off-peak rate. Schedule R.S.-T.O.D.2 exacerbates this even further because on-peak periods are seasonally differentiated. In addition to the complexity of additional effective pricing periods, the combination of a time-varying rate with N.M.S. II sends conflicting price signals to customers. On one hand, they are incentivized to avoid consumption during on-peak periods, but on the other hand, in order to avoid forfeiting retail value on a monthly basis, they would need to concentrate their use during parts of those same on-peak periods.

Such a construct would be virtually impossible for a customer to fully understand, let alone manage. This would dissuade DG customers from taking service under the same rates that are designed to provide a better reflection of cost of service than flat rates. Pursuing a design that produces this outcome makes absolutely no sense given that the specific concern being raised in this case is that DG customers are supposedly not paying rates consistent with their cost of service.

Q. WHAT ARE YOUR CONCLUSIONS ABOUT THE OVERALL STRUCTURE OF THE COMPANY'S PROPOSED N.M.S II TARIFF?

A. The proposed design is *thoroughly unsound* from the standpoint of cost causation and other generally accepted ratemaking principles. It sends confusing and conflicting price signals to customers that would either be impossible for them to manage, or produce responses that actually increase system costs. On this basis it should not be adopted in anywhere close to its present form.

D. Problems With the Proposed N.M.S. II Tariff Avoided Cost Rate

Q. ARE THERE ANY THRESHOLD ISSUES THAT YOU WISH TO ADDRESS IN DISCUSSING THE COMPANY'S CALCULATION OF AN APPROPRIATE AVOIDED COST RATE FOR MONTHLY EXPORTS?

A. Yes. The Company's derivation of its proposed avoided cost rate uses an assumed profile of monthly exports during each hour of the day. This makes the entire design dependent on both the solar profile and customer load profile used in the calculation. The Company has used a residential load profile for the purpose of its calculations, which, whether or not one believes is an accurate portrayal of a *residential DG customer* load profile, is not consistent with the load profile of a non-residential customer. Yet the Company's proposed N.M.S. II tariff would apply to non-residential customer generators as well as residential customer-generators.

Q. HOW DO YOU RECOMMEND THAT THE COMMISSION ADDRESS THIS THRESHOLD ISSUE?

A. Even if the Commission were to adopt the Company's proposed N.M.S. II Tariff for residential customers, it would be unreasonable for it do so for non-residential customers. It is also my observation that it would be impossible to extend the methodology the Company employs for calculating an avoided cost rate to non-residential customers because there is no such thing as a "typical" non-residential customer that can be reflected in a "typical" load shape. This points to how ill-conceived the Company's proposal is in the first place insofar as it relies on a set of standard assumptions for variables that cannot in fact be standardized with any degree of accuracy.

Q. PLEASE BRIEFLY DESCRIBE THE FLAWS YOU HAVE IDENTIFIED IN THE COMPANY'S CALCULATIONS OF AVOIDED COSTS.

A. The most prominent flaw in the Company's calculation of DG avoided costs is that the Company's assessment is limited to short-term marginal costs. Assigning value to a long-lived asset requires a long-term outlook of the type the Company would use if seeking to justify investments in resources that it owns. Basing avoided costs on only short-term marginal costs undervalues DG resources. Rates based on short-term marginal costs undervalue DG, which discourages deployment and ultimately results in a greater amount of costs being incurred in the long run. For this reason alone, the Company's assessment is insufficient and cannot be relied upon.

Beyond this foundational flaw, I have identified the following additional shortcomings of the Company's estimate of avoided costs:

- The solar production profile is likely not representative of the production profile of a typical residential solar system.
- The residential load profile may not accurately represent the load profile of a typical residential DG customer.
- The Company inappropriately "discounts" the avoided transmission and avoided generation capacity components.
- The specified value of energy is significantly below the rate for energy-related costs as identified in the Company's cost of service study.
- The Company fails to include an avoided cost category for avoided distribution capacity.

Q. PLEASE EXPLAIN HOW THE COMPANY USES THE SOLAR PRODUCTION AND HOW THE SOLAR PROFILE INFLUENCES ITS AVOIDED COST CALCULATION.

A. The Company uses solar production profile for two purposes. First, it uses the solar profile to estimate solar production during peak hours, corresponding to the top five summer coincident peak hours (5CP) for generation capacity, and monthly peak hours for transmission capacity (12CP). Total annual production from the solar profile is also used to translate the annual dollar value of peak reductions to a volumetric rate by dividing the annual value by total kWh production. In conjunction with the residential load the solar profile is also used to develop estimates for typical net excess generation per month during each hour.

The influence of the solar profile is therefore twofold. First, it determines the peak contribution of solar and the translation of that peak contribution to a volumetric rate. Second, it determines the amount of the "net metering shape discount", which essentially corresponds to the percentage of solar production that is in excess of on-site customer needs during the 5CP and 12CP hours. If the typical residential solar production profile differs from the hypothetical solar profile, which it almost certainly would, both calculations would yield different results.

Q. HOW WOULD A DIFFERENT SOLAR PRODUCTION SHAPE SPECIFICALLY AFFECT THE AVOIDED CAPACITY VALUES AND RATE?

A. It could lead to a higher or lower end result. For instance, a system with a southwest or west-facing orientation would typically make a higher contribution to afternoon peaks and produce a lower amount of energy on an annual basis. This would produce a higher avoided capacity rate because not only is the peak value higher, it is divided across lower production on an annual basis. For some systems the peak contribution could be lower, but this may not necessarily translate to a lower rate because total annual production might also be lower. In fact, the annual capacity factor for the Company's solar production profile is significantly higher than what one would expect for a typical residential solar system. That might translate to a higher peak contribution, but it also increases the denominator in the volumetric rate calculation (*i.e.*, producing an offsetting reduction in the rate).

A secondary effect is produced by applying that solar production profile to the residential load profile. For instance, a system with a more western orientation would produce greater amounts of excess during the primarily afternoon peak hours, which would in turn increase the "excess percentage" used in the net metering shape discount and correspondingly increase the calculated avoided cost rate. The residential load profile of course plays a role in this calculation as well, as lower on-peak usage on the part of residential DG customers would accordingly produce a greater amount of excess.

Q. WHAT DO YOU CONCLUDE ABOUT THE STRUCTURE UNDERLYING THE AVOIDED COST CALCULATION?

A. The reliability of the calculations is highly questionable because the solar production profile is not representative of a typical residential solar system, nor is the residential load profile necessarily representative of a typical residential solar DG customer.

Q. PLEASE EXPLAIN THE NATURE OF THE "NET METERING SHAPE DISCOUNT" AND WHY IT IS INNAPPROPRIATE.

A. The Company calculates a gross avoided generation capacity value of $0.0091/kWh and a gross avoided transmission capacity value of $0.0133/kWh. The "net metering shape discount" pro-rates these amounts based on the Company's calculation of excess generation during 5CP and 12CP hours, weighted based on the likelihood that an individual hour (*e.g.*, 3 – 4 PM) will be a peak hour. This discount reduces the generation capacity rate to $0.00466/kWh and the transmission capacity rate to $0.00356/kWh.[13]

The Company claims that such a discount is reasonable because the generation is netted against on-site load during some hours of the day.[14] I disagree.

[13] Vaughan Direct, Exhibit AEV-3.
[14] Vaughan Direct at 27:22 through 28:1.

The adjustment is inappropriate because the marginal value of generation at any point in time is not different based on whether the energy constitutes a net hourly export or not. Moreover, the construct conflates two different types of costs: marginal avoided costs and embedded or fixed costs. A customer's responsibility for embedded costs is based on that customer's contribution to the costs identified in the Company's cost of service study and the allocation methods used in that study. Accordingly, as I previously observed, if the Company truly wishes to identify a DG customer's responsibility for and relative level of contribution to fixed costs, it must actually study the costs to serve DG customers.

Q. PLEASE ELABORATE ON YOUR OBJECTION TO THE ENERGY VALUE THE COMPANY USES IN ITS AVOIDED COST RATE CALCULATION.

A. Again, we need to return to the Company's cost of service study. As I previously observed the effective rate for costs the Company identifies as energy-related for the residential class in its cost of service study is $0.0325/kWh. The Company's proposed energy value for exports is lower, at $0.02837/kWh. While this latter amount may be a proper reflection of the Company's marginal energy costs, it implies that a residential DG customer is being subsidized by other residential customers for energy-related costs. This cannot be true. When a customer reduces their energy purchases from the Company, they reduce their responsibility for energy-related costs by an equivalent amount. As their obligation to pay for energy-related costs is determined by the cost of service study, so too should their compensation rate for exports. It is also appropriate to add a gross-up for line losses to this amount.

Q. WHY SHOULD THE COMPANY'S AVOIDED COST CALCULATION INCLUDE AN AVOIDED COST CATEGORY FOR DISTRIBUTION CAPACITY?

A. Avoided distribution capacity is considered to be a benefit from DG in most DG cost-benefit studies, including those presented by Witness Inskeep. On a forward-looking basis, DG reduces loading on the distribution system in the same way that it reduces loading on the bulk power system. Therefore, a calculation of DG value must contain a category for avoided distribution costs based on the contribution DG makes to distribution peaks and the marginal cost of distribution capacity, grossed up for line losses.

Alternatively, from a backwards looking perspective, where DG contributes to a reduced allocation of distribution costs to the class that the DG customer otherwise resides in, the amount of that reduction constitutes a benefit to the class. In other words, the DG customer has lowered their cost of service and therefore effectively lowered the cost to serve their rate class as a whole. The Company allocates primary distribution costs on the basis of class contribution to monthly internal peak demands (12CP). Therefore, it is likely that DG customers are responsible for a lower amount of embedded primary distribution costs than they would otherwise be without DG.

Both methods of defining benefits can be utilized to discover whether DG customers pay in amounts sufficient to reach their cost of service. The cost-benefit analysis approach uses long-run marginal costs to evaluate the potential for a subsidy to exist on a forward-looking basis. A cost of service based evaluation identifies any immediate benefits and/or subsidy present in current rates.

Q. WHAT ARE YOUR CONCLUSIONS ABOUT THE COMPANY'S ASSESSMENT OF DG AVOIDED COSTS?

A. The Company's evaluation cannot be relied upon because it does not utilize a long-term outlook, presents an incomplete assessment of avoided costs, and rests on assumptions that are either likely to be inaccurate or may be inaccurate. The Commission should disregard it as an accurate evaluation of DG value.

IV. PATHS FORWARD FOR DG RATES IN KENTUCKY

A. Potential Successor Options

Q. YOU PREVIOUSLY OBSERVED THAT THERE ARE NUMEROUS OPTIONS AVAILABLE TO THE COMMISSION FOR MITIGATING ANY SUBSIDY IT IDENTIFIES IN THE RATES PAID BY DG CUSTOMERS. PLEASE ELABORATE ON WHAT THOSE OPTIONS ARE.

A. Over the last several years numerous regulatory commissions have undertaken investigations of net metering and DG rates. Some of those investigations have not produced any changes, while others have resulted in typically modest changes. There are also some variations present in the national net metering policy landscape that point to potential options. I have identified the following options, supplemented with brief descriptions of the use case and potential design attributes.

- <u>Monthly Rollover at Avoided Cost</u>
    - Reduces overall customer compensation for annual generation.

- Implicitly incentives smaller systems (*i.e.*, customers do not fully offset annual consumption and pay accordingly) while still allowing sizing in line with customer preferences.
- Could be varied to prevent monetary credits from being used to offset fixed charges or minimum bills.

- Minimum Bills
  - Directly confronts the concern that DG customers may not pay their fair share of customer-related costs or distribution costs.
  - Permits customers to adjust system size to avoid triggering the minimum bill.
- Mandatory Time of Use ("TOU") Rates
  - Provides better alignment of rates with time-varying cost of service, including the value of exports.
  - Incentivizes customers to respond to cost-based price signals (*i.e.*, lowering the cost side of the cost of service vs. payment for services equation).
  - Can incentivize system configurations that produce greater grid value (*e.g.,* energy storage additions, system orientation to contribute to peak loads).
- Reduce or Eliminate Individual Components of the Export Rate
  - Can be used to subtract out costs that DG cannot avoid, such as public purpose program charges or costs based on non-coincident customer demands.

    - Could be varied to prevent monetary credits from being used to offset fixed charges or minimum bills.
- <u>Capacity-Based Fees</u>
    - Can be used to collect costs that DG cannot avoid, such as public purpose program charges or costs based on non-coincident customer demands.
    - Aligns with the amount of costs that a DG customer actually avoids paying.
    - Could be considered non-bypassable charges unaffected by monetary credits.

Q. ARE ANY OF THESE OPTIONS MUTUALLY EXCLUSIVE?

A. No. Any single one could be combined with others. For instance, mandatory TOU can be combined with a minimum bill and/or a policy that excludes non-bypassable charges from the export rate (*e.g.,* California).[15] Alternatively, a customer might be presented with the option to choose from multiple options, such as a capacity-based fee or mandatory TOU under one or more rate options (*e.g.* Arizona).[16] Generally, it is my view that multiple options are preferrable because individual customers differ and what might work best for one customer is not necessarily the same as what another customer would prefer. For instance, a customer that wishes to install battery storage may be more inclined to take service under a TOU rate than a customer that is not interested in installing battery storage.

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[15] *See* Inskeep Direct, Exhibit BDI-2.
[16] *Id.*

Q. ARE YOU RECOMMENDING ANY OF THESE OPTIONS SPECIFICALLY FOR ADOPTION IN THIS PROCEEDING?

A. No. As I have already discussed at length, the Company has failed to present a cost of service study of DG customers demonstrating that they are not already paying their properly assigned cost of service, including the fixed and demand-related costs referred to in S.B. 100. I present these options for Commission consideration in future proceedings involving DG policy and rates, whether they pertain to Kentucky Power or other Kentucky jurisdictional utilities.

Q. ARE THESE OPTIONS CONFINED TO ADDRESSING POTENTIAL CHANGES UNDER S.B. 100?

A. No. As KYSEIA Witness Inskeep discusses, the development of net metering "successor" frameworks in other states has almost exclusively stemmed from circumstances where a successor was necessary due to utilities reaching a net metering penetration cap, or been undertaken in jurisdictions where no such cap existed. They represent more durable, if not necessarily entirely permanent, options for evolving DG policies and rates.

It is easy to envision additional options or variations arising over time. Such refinements could stem from additional evaluation of DG costs and benefits and cost of service, the evolution of generally applicable rate structures, as well as from the use of customer-sited energy storage and smart inverters to provide dispatchable grid services.

Q. ARE YOU SUGGESTING THAT A SUCCESSOR TARIFF COULD EXTEND BEYOND THE STATUTORY NET METERING CAP?

A. Yes. In fact, a smooth and orderly transition to a durable successor tariff would be best accomplished by using the net metering cap as a trigger point. If the Commission were to adopt changes to a utility's net metering tariff prior to that utility reaching the cap, as would be the case in this proceeding with Kentucky Power, it should do so with an intention of allowing the tariff to continue beyond the time when a utility reaches the cap. If a successor tariff is considered to be fair to DG customers and non-DG customers there is no reason for it to not be allowed to continue operation after a utility reaches its net metering cap.

Q. PLEASE EXPLAIN YOUR THOUGHT PROCESS IN SUGGESTING THAT A SUCCESSOR TARIFF COULD BE APPLIED ONLY AFTER THE NET METERING CAP IS REACHED, OR EXTEND BEYOND THE NET METERING CAP IF ADOPTED BEFORE THAT TIME.

A. My line of thinking stems from the collective effect of the two laws governing rates and policies for DG in Kentucky. One is the net metering law as amended by S.B. 100. As I have previously observed and KYSEIA Van Nostrand also discusses, S.B. 100 is not a blanket affirmation of any substitute for net metering that a utility proposes. It has its own set of conditions for revised tariffs and the Commission is obligated to reject utility proposals for modifications for as long as utilities fail to support those proposals with sufficient evidence. One or more utilities could reach the net metering cap before they make such a demonstration.

The second applicable law is the Public Utility Regulatory Policies Act ("PURPA"), for which the Commission has established regulations in 807 KAR 5:504. The net metering law applies specifically to net metering, which is governed by the net metering cap. The terms set by the Legislature for net metering clearly apply within the boundaries of the net metering cap. However, the law does not speak to DG policy and rates beyond the net metering cap, and it seems logical to conclude that the specific terms for net metering apply only within the net metering cap. Accordingly, after the cap is reached, the Commission is left with its responsibility to implement PURPA and do so under terms consistent with the rules adopted for that purpose in 807 KAR 5:504.

Q. WHAT PARAMETERS DO THE APPLICABLE REGULATIONS GOVERNING PURPA IMPLEMENTATION PLACE AROUND PURCHASES OF ENERGY AND CAPACITY FROM QFS?

A. Section 7(1)(a) of 807 KAR 5:504 provides that QFs may exercise an option of "Using output of the qualifying facility to supply their power requirements and selling their surplus". Electric utilities are in turn obligated to purchase energy and capacity from QFs at rates consistent with their avoided costs. Avoided costs are defined as "incremental costs to an electric utility of electric energy or capacity or both which, if not for the purchase from the qualifying facility, the utility would generate itself or purchase from another source." Critically, the term "surplus" as used in the context of Section 7 is not defined, nor does the regulation make reference in any form to the time period over which such "surplus" is measured. It could be an hour, a day, a month, or year. Of course, the Commission must also ensure that purchases from QF are priced in accordance with a utility's avoided costs, but what constitutes a "purchase" is effectively defined by what energy is considered "surplus" and is therefore being purchased by a utility.

Q. ARE THERE ANY PRECEDENTS FOR REGULATORS DEFINING A TIME PERIOD OVER WHICH NET PURCHASES, OR "SURPLUS" ENERGY AND CAPACITY ARE MEASURED?

A. Yes. Several of the earliest state net metering policies were developed solely under the authority vested in state regulators to implement PURPA. To this day the net metering regimes present in Iowa[17], New Mexico[18], Oklahoma[19], and Wisconsin[20] derive exclusively from regulators' implementation of PURPA via rulemaking and other related decisions rather than any state law mandating the establishment of a net metering framework. For its part, the Federal Energy Regulatory Commission ("FERC") has confirmed multiple times that states have the authority to define the time period over which purchases from and by a utility are measured under PURPA. This includes a 2001 decision affirming that the Iowa Utilities Board's establishment of net metering via its authority under PURPA is not preempted by federal law, the practice of netting customer usage over time does not constitute a sale of electricity, and that a typical monthly bill cycle was a reasonable time period for the measurement.[21]

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[17] IAC § 199-15.11(5)
[18] NMAC 17.9.570
[19] O.A.C. § 165:40-9-1, et seq.
[20] Wisconsin Public Service Commission. Docket No. 05-EP-6. Order dated September 18, 1992.
[21] MidAmerican, 94 FERC ¶ 61,340, at 62,262-64 (2001)

Q. WHAT DO YOU CONCLUDE ABOUT THE COMMISSION'S AUTHORITY TO ESTABLISH A DG SUCCESSOR TARIFF THAT COULD APPLY BOTH BEFORE THE NET METERING CAP IS REACHED AND AFTER IT IS REACHED BY A UTILITY?

A. Before the cap is reached, a successor DG tariff can derive from either the Commission's authority under PURPA or its authority under the net metering law as amended by S.B. 100. After the cap is reached, a DG successor tariff must comply with the Commission's rules for implementing PURPA and not be net metering as the term has been redefined by S.B. 100, but is otherwise free from constraints. There are any number of ways in which the Commission could establish a successor tariff that meets both sets of parameters.

B. Factors in Devising a Successor Option

Q. WHAT DO YOU CONSIDER TO BE THE SINGLE MOST IMPORTANT CHARACTERISTIC FOR THE DESIGN OF SUCCESSOR DG POLICY AND RATE OPTIONS?

A. The design should be forward-looking, an in that respect, enable the full value of DG resources to be realized. While there may be differing opinions on precisely what that value is, or could be under the right design, there is no reasonable argument against pursuing mechanisms that maximize that value for the benefit of all ratepayers. As I have previously observed, consistency and durability are two prominent considerations at present in Kentucky given S.B. 100 and the looming aggregate cap. It is critical that the Commission take a forward-looking outlook in order to reach durable solutions that are fair to both DG customers and non-DG customers.

Q. WHAT SPECIFIC FACTORS SHOULD THE COMMISSION CONSIDER AS PART OF PURSUING A SUCCESSOR DG POLICY AND TARIFF?

A. There are number of factors that the Commission should consider as part of a forward-looking policy on DG and associated tariff regimes. Those considerations include, but are not necessarily limited to:

- Adherence to applicable state and federal laws.
- Simplicity and understandability for customers.
- Sending appropriate and actionable price signals based on sound principles of cost causation that support maximizing realized DG value and consumer actions that reduce their cost of service.
- Fairness to both DG customers and non-DG customers with a goal of reducing or eliminating cost-shifts to the extent practicable.
- Ease of implementation given current utility systems and technology and the costs associated with to implementing different options.
- Creating opportunities for customers to choose from multiple options based on their preferences and individual circumstances.

V. COGEN/SPP TARIFFS

A. Treatment of LEO & Contract Duration

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S COGEN/SPP TARIFFS.

A. Kentucky Power offers two COGEN/SPP Tariffs, one for QFs of 100 kW or less and one for QFs from 100 kW to 20 MW. The two tariffs are virtually identical to one another. Each tariff offers a QF the same facility configuration options and the same rates for purchases of energy and capacity under standard or time-differentiated metering. The Company proposes to update the pricing of energy and capacity for both tariffs in this proceeding, lowering the energy rates from \$0.0324/kWh to \$0.0261/kWh for the standard metering option, and from \$0.0386/kWh to \$0.0306/kWh and \$0.0279/kWh to \$0.0228/kWh for the on-peak and off-peak energy rates, respectively. The monthly capacity credits would remain basically unchanged under the Company's proposal. [22] However, I recommend changes to those rates in the Section V(B) of my testimony.

Q. DO THE COGEN/SPP TARIFFS OFFER QFS THE OPTION TO "LOCK IN" RATES OVER THE COURSE OF A LONG-TERM CONTRACT?

A. There are no express provisions to this effect in either tariff. Both tariffs provide for a contract "period not less than one year", but beyond that they do not specify the duration of potential contracts.

[22] Kentucky Power Application, Section II Exhibit E.

Q. HOW DO KENTUCKY'S PURPA REGULATIONS DESCRIBE THE CONTRACT OPTIONS THAT MUST BE MADE AVAILABLE TO QFS.

A. Sections 7(2)(b) and 7(4)(b) of 807 KAR 5:504 provide that a QF may establish a legally enforceable obligation and have the option for rates "on either avoided costs at the time of delivery or avoided costs at the time the legally enforceable obligation is incurred." Section 7(4) also provides that for facilities larger than 100 kW, the rates specified in the rate schedule are to "be used only as the basis for negotiating a final purchase rate". Further language allows the Commission to determine an appropriate rate if a QF and a utility cannot agree on the rate.

Q. DO THE REGULATIONS ESTABLISH A SPECIFIC TERM OR DURATION FOR QF CONTRACTS?

A. No.

Q. IN YOUR VIEW, ON KENTUCKY POWER'S COGEN/SPP TARIFFS CONSISTENT WITH THE PURPA REGULATIONS?

A. My understanding is that they are not inconsistent insofar as I see no explicit language in the COGEN/SPP tariffs that directly conflicts with 807 KAR 5:504. Having said that, the tariffs would benefit from additional clarity on how a QF may establish a legally enforceable obligation ("LEO") and receive rates based on the rates specified at the time the LEO is established. The current structure and update cycle for the tariffs suggests that QFs are subject to rate changes every time the rates are updated even though that is not expressly stated.

Q. WHY IS IT IMPORTANT FOR QF TARIFFS TO SPECIFY HOW A QF CAN EXERCISE ITS OPTION TO RECEIVE RATES BASED ON THE RATES AT THE TIME A LEO IS ESTABLISHED.

A. Generally speaking, tariffs should be as clear as possible to avoid creating confusion or ambiguity.

Q. WHY IS CLARITY ON THE SPECIFIC ASPECT OF THE CONTRACT DURATION IMPORTANT?

A. Price certainty is a critical aspect of financing a QF and that price certainty is determined by the allowable duration of QF contracts and applicable rates.

Q. HAVE OTHER STATES ESTABLISHED THAT QFS HAVE ACCESS TO CONTRACTS OF A STANDARD DURATION?

A. Yes. The National Regulatory Research Institute ("NRRI") maintains a webpage called the "PURPA Tracker" that specifies high-level details of state policies, including contract terms and the avoided cost methodology.[23] Among the states that have specified QF contract terms are the following:

- Arizona: 18 years (QFs larger than 100 kW)
- Michigan: 10 – 15 years (Consumers Energy)
- Montana: 25 years (for solar)
- North Carolina: 10 years (1 MW or less); 5 years for larger facilities outside the competitive procurement program.
- Oregon: 15 years

[23] NRRI. PURPA Tracker. https://www.naruc.org/nrri/nrri-activities/purpa-tracker/

- South Carolina: 10 years
- Utah: 15 years
- Washington: 10 – 15 years
- Wyoming: 20 years

To be clear, contracts with fully fixed pricing may not be available for all QFs in the states noted above, but the simple specification of a contract term has some value in itself. Among this list, Arizona was the most recent state to establish a long-term fixed price QF contract. It did so in December 2019 in response to proposals from Arizona Public Service and Tucson Electric Power to *limit QF contracts to two years*. Instead, the Arizona Corporation Commission directed tariff revisions to specify that the QFs larger than 100 kW have the opportunity to enter contracts of up to 18 years at the utilities' long-term avoided costs.[24]

Q. WHY HAVE STATES ELECTED TO MAKE LONG-TERM CONTRACTS AVAILABLE TO QFS?

A. One reason is a general recognition that long-term contracts and the accompanying price certainty are necessary for QF project financing. Beyond that, the use of fixed pricing based on long-term avoided costs for these contracts is a critical aspect of creating ratepayer indifference to whether generation is: (a) developed by a utility as a rate-based asset or (b) purchased from an independent power producer. Every time a utility builds a generation asset it is essentially making a bet on how well its future cost forecasts will track with reality and locking in a set of associated costs.

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[24] Arizona Corporation Commission. Docket No. E-01345A-16-0272. Decision No. 77512. December 17, 2019, *available at*: https://docket.images.azcc.gov/0000200428.pdf

With a renewable energy investment specifically, this evaluation by its very nature must consider forecasts of future energy and capacity costs, and the ultimate energy and capacity value that a facility will have to ratepayers. In effect, locking in expected avoided costs. Establishing a level playing field between utility-owned generation and QF generation requires that both use the same standards of evaluation.

Q. WHAT SPECIFIC RECOMMENDATIONS DO YOU HAVE FOR THE REVISIONS TO THE COMPANY'S COGEN/SPP TARIFFS?

A. The tariffs should be revised to clearly specify that QFs may seek a contract with pricing based on rates at the time of the establishment of a LEO, and specify the length of time that a QF make provide energy and capacity under a locked-in rate. I recommend that this contract duration extend to at least ten years but allow for longer contracts.

B. Calculation of the Capacity Rate

Q. PLEASE BRIEFLY DESCRIBE HOW THE COMPANY CALCULATES THE CAPACITY RATE FOR THE COGEN/SPP RATE SCHEDULES?

A. The calculation uses the cost of a hypothetical combustion turbine as a proxy unit and applies a formula based on a series of assumptions about capital costs, useful life, fixed O&M, and variable O&M costs. The output of the formula produces the Company's proposed capacity rates for the COGEN/SPP tariff at $7.49/kW-month for on-peak capacity under time of day measurement and $3.12/kW-month for standard non-time of day metering. The specific derivation is contained in Vaughan Direct, Exhibit AEV-1 beginning on p. 55.

Q. HAVE YOU IDENTIFIED ANY PROBLEMS WITH THE COMPANY'S CALCULATION OF CAPACITY COSTS?

A. Yes. I have identified two aspects of the calculation that should be modified. First, the Company uses a 40-year economic life for a hypothetical combustion turbine. This should be replaced with a useful life of 20 years and the carrying charge amount updated to correspond to a 20-year useful life. Second, the Company uses a capital cost estimate of $700/kW. This should be modified to at least $799/kW.

Q. WHAT AFFECT DO THESE TWO ASSUMPTIONS HAVE ON THE CALCULATION OF CAPACITY COSTS?

A. Both cause the calculated cost of capacity to be understated. The useful life assumption affects recovery period for such a hypothetical investment. The capital investment cost of course forms the underlying basis for the entire calculation. As for economic life, investments with longer lifespans incur lower carrying charges and vice versa. The economic life also impacts the net present value of carrying charges because costs recovered further in the future are discounted to a greater degree than costs recovered over shorter durations.

Q. WHY ARE YOU RECOMMENDING THAT THE USEFUL LIFE OF A COMBUSTION TURBINE BE SET AT 20 YEARS?

A. There are a couple of reasons for this. First, other recognized industry resources use a 20-year useful life for the same type of generation unit that the Company uses in its calculation. The PJM performs a similar analysis to what the Company has done when developing its Cost of New Entry ("CONE"), which is used to cap capacity bids in the PJM capacity market as a market power mitigation measure. The CONE approximates the cost of a new capacity resource, just as the Company does in its own calculation. The PJM's calculation uses a useful life of 20 years.[25] Likewise, the energy and financial advisory firm Lazard LLC uses a 20-year useful life for a hypothetical natural gas peaking unit in its most recent assessment of the levelized cost of energy ("LCOE") from different types of generation.[26] Lazard's 2019 LCOE Analysis, the 13th annual publication, is highly respected and frequently referenced in the energy industry.

Second, a 40-year useful life would extend the life of such a hypothetical capacity resource through at least 2060. This seems implausible for two reasons. First, American Electric Power ("AEP") has a goal of reducing carbon emissions by 80% by 2050 relative to a 2000 baseline, and states an expectation that it will achieve a greater reduction.[27] Given those goals it seems unlikely that the Company would still be relying on natural gas fired peaking units through 2060. Furthermore, the prospects for an aging gas combustion turbine to be able to compete economically in the market against modern technologies available more than 20 years from now appears rather dim.

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[25] Brattle Group. PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with Jun 1, 2022 Online Date. April 19, 2018. Table ES-2, p. vii, *available at*: https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx.

[26] Lazard. Lazard's Levelized Cost of Energy Analysis – Version 13.0, p. 18, *available at*: https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf.

[27] AEP. Carbon and Climate. https://www.aepsustainability.com/environment/carbon/

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION THAT THE COMPANY USE A CAPITAL COST OF AT LEST $799/KW IN ITS CALCULATION.

A. The PJM arrived at this amount for a similar natural gas combustion turbine in the report I previously mentioned on a refreshed CONE calculation. This is actually the lower end of their estimates, which are differentiated geographically for different regions of the PJM. The $799/kW amount is the estimate arrived at for the "Rest of the RTO" for 2022/2023 while the range for all regions was $799/kW to $898/kW.[28] More recently, in a February 2020 presentation from the PJM Market Implementation Committee, the PJM related a figure of $875/kW for the installed capital cost of a combustion turbine.[29] Likewise, the Lazard 2019 LCOE report placed the cost of a natural gas peaking unit at from $700/kW to $950/kW.[30]

Q. HOW DOES MODIFYING THESE ASSUMPTIONS CHANGE THE SPECIFIED CAPACITY RATE?

A. Using Company Witness Vaughan's executable workpapers and changing only the capital cost and system life assumptions, a capital cost of $799/kW produces a $9.95/kW-month on-peak capacity rate and a $4.14/kW average capacity rate, compared to the Company's proposed on-peak rate of $7.49/kW-month and

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[28] Brattle Group. PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with Jun 1, 2022 Online Date. April 19, 2018. Table ES-2, p. vii, *available at*: https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx.

[29] PJM. Preliminary Default MOPR Floor Offer Prices for New Generation Capacity Resources. February 28, 2020 presentation to the Market Implementation Committee. p. 5, *available at:* https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20200228-mopr/20200228-item-03a-pjm-preliminary-cone-values.ashx.

[30] Lazard. Lazard's Levelized Cost of Energy Analysis – Version 13.0, p. 18, *available at*: https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf.

average rate of $3.12/kW-month. At the higher capital cost of $875/kW used in the February 2020 PJM presentation, the on-peak rate is $10.62/kW-month and the average rate is $4.42/kW-month.[31]

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION ON THE COMPANY'S PROPOSED N.M.S. II TARIFF PROPOSAL.

A. With respect to the Company's proposed N.M.S. II Tariff, I recommend that the Commission:

1. Decline to approve the Company's proposal and provide guidance to Kentucky Power and other Commission-jurisdictional utilities on the evidence they must present in support of net metering successor tariff proposals. This required evidence should include a comprehensive evaluation of DG customer cost of service consistent with the provisions of S.B. 100 and approved methodologies for evaluating cost of service.
2. In the alternative to my first recommendation, decline to approve the Company's N.M.S II Tariff proposal due to its numerous structural and unresolvable flaws and instead seek to develop a successor based on the potential options and factors to consider in a successor DG rate detailed in my testimony.

[31] Changing the economic life assumption also requires a change in the carrying charge rate, which was also done for the purpose of this calculation.

3. As a matter of general sound policy, seek to align any successor DG tariff it does adopt within the present net metering cap with options at its disposal for establishing DG rates and tariffs after a utility reaches the net metering cap.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION ON THE COMPANY'S COGEN/SPP TARIFFS.

A. I first recommend that the Commission adopt changes to the COGEN/SPP tariffs to clearly specify that QFs have the option to receive compensation at the prevailing rates at the time the QF establishes a legally enforceable obligation ("LEO") and, specify the allowable duration for such contracts. I further recommend that the allowable duration be set at a minimum of ten years in order to facilitate QF financing and create true ratepayer indifference by leveling the playing field between utility-owned and non-utility-owned generation.

I also recommend that the Commission direct the Company to revise its calculation of avoided capacity costs to use a 20-year useful life in place of a 40-year useful life, and a capital cost of at least $799/kW in place of $700/kW. As I discuss in more detail in my testimony, this would produce avoided costs for capacity of at least $9.95/kW-month for the on-peak capacity rate and $4.14/kW for the average capacity rate, compared to the Company's proposed on-peak rate of $7.49/kW-month and average rate of $3.12/kW-month.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.