COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. TO BECOME A FULL PARTICIPANT IN THE PJM INTERCONNECTION LLC, BASE RESIDUAL AND INCREMENTAL AUCTION CONSTRUCT FOR THE 2027/2028 DELIVERY YEAR AND FOR NECESSARY ACCOUNTING AND TARIFF CHANGES	))))))	CASE NO. 2024-00285

REBUTTAL TESTIMONY OF

JOHN D. SWEZ

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

January 10, 2025

TABLE OF CONTENTS

PAGE

I. INTRODUCTION AND PURPOSE

Q. STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John D. Swez, and my business address is 525 S. Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Managing Director, Trading and Dispatch, by Duke Energy Carolinas, LLC, a utility affiliate of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company).

Q. ARE YOU THE SAME JOHN D. SWEZ THAT SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THESE PROCEEDINGS?

A. The purpose of my rebuttal testimony is to respond to the testimony submitted by the Kentucky Office of the Attorney General (Attorney General). In doing so, I briefly summarize the Company's Application and discuss recent developments in the PJM Interconnection LLC (PJM) capacity market since the Company filed its Application. Specifically, I address the recommendations submitted by Attorney General witnesses Phyllip Hayet and Lane Kollen. I explain why some of their recommendations are reasonable and that the Company would not object if they are adopted by the Kentucky Public Service Commission (Commission). I also explain why some of these recommendations are unreasonable, are actually harmful to customers and the Company, and should not be adopted by the Commission as proposed. In addition, where appropriate, I provide suggestions to the Attorney General Witnesses' recommendations, including changes to their proposals, that the Company believes are more appropriate.

II. SUMMARY OF APPLICATION AND RECENT DEVELOPMENTS

Q. PLEASE SUMMARIZE THE COMPANY'S APPLICATION IN THIS PROCEEDING.

A. The purpose of the Company's Application is to seek Commission approval of transitioning from Fixed Resource Requirement (FRR) participation to full participation in the PJM Reliability Pricing Model (RPM) Base Residual Auction and Incremental Auction (RPM BRA/IA) capacity constructs. As I stated in my Direct Testimony, the Company believes this transition is in the best interest of customers due to the following factors: 1) the risk of and potential for large and sudden load growth at a rate faster than the Company can construct or acquire additional baseload generation; 2) uncertainty and change in the balance between demand and supply in the Duke Energy Ohio/Kentucky (DEOK) delivery zone in PJM driven by announced generating asset retirements; 3) the lack of available bilateral capacity in the DEOK zone should future zonal separation occur and Duke Energy Kentucky finds itself in a position where it needs additional bilateral capacity to meet its FRR plan should it remain FRR;[1] 4) anticipated changes to PJM's FRR construct that would negatively impact the Company's participation as a FRR entity; 5) the energy transition in PJM due to retirements of fossil generation and PJM's own prediction of shrinking reserve margins and higher capacity prices;

[1] The DEOK zone has separated in three (3) of the last six (6) PJM BRAs demonstrating that the zone is capacity constrained and with future announced retirements, will likely continue to be going forward.

and 6) the change in the FRR shortfall penalty to the greater of 1.75 x Net Cost of New Entry (Net CONE) or Gross CONE.

Since 2012 when first entering PJM as a FRR entity, participating as a FRR was the logical choice and has benefited customers. However, the Company determined through its analysis that a move to a full RPM BRA/IA auction participant is now in the customer's best interest.

Q. WHAT WERE THE RESULTS OF THE MOST RECENT PJM BRA AUCTION?

A. On July 30, 2024, PJM released the results of the 2025/2026 BRA with the auction price for the "Rest of RTO" being $269.92/MW-Day. Since the DEOK Zone did not split out, the capacity price was the same price for the DEOK Zone. Although other PJM Zones have at times cleared at a higher capacity clearing price, the 2025/2026 clearing price represents the highest cost ever cleared for the DEOK Zone.

Q. HAVE THERE BEEN ANY DEVELOPMENTS OR CHANGES IN THE UPCOMING PJM AUCTION SCHEDULE SINCE THE COMPANY FILED ITS APPLICATION ON SEPTEMBER 6, 2024?

A. Yes. On November 8, 2024, FERC approved an approximate six-month delay in PJM's next BRA for the delivery year 2026/2027. This auction was supposed to occur December 4 through 10, 2024, but is now scheduled for July 9 through 15, 2025. This delay, at least in part, was prompted by the results of the July 30, 2024, BRA.

Q. DOES THE DELAY IN THE NEXT BRA CHANGE THE COMPANY'S RECOMMENDATION TO TRANSITION FROM AN FRR PARTICIPANT TO A FULL RPM AUCTION PARTICIPANT?

A. No. In fact, the delay provides a unique opportunity for the Company to transition faster than it originally anticipated when it filed its Application.

The result of the July 30, 2024, BRA auction was known and discussed in my Direct Testimony when the Company filed its Application, with the auction price for the "Rest of RTO" being $269.92/MW-Day. Although the complete financial results between FRR and RPM BRA/IA participation cannot be calculated until after the 3rd incremental auction results are known, by looking at the heat map in Table 1 from my Direct Testimony, an approximate value amount can be calculated from the Company's participation in the RPM under these higher capacity prices. If looking at the +5% row, which represents the current approximate Company position, and interpolating between the $250/MW-Day and $300/MW-Day columns, an approximate savings to the customer of $1M for the year would have been realized from full participation in the 2025/2026 RPM as opposed to the FRR. Thus, the expected continued increase in future auction prices would be a benefit to customers if the Company were a full RPM BRA/IA participant.

Q. PLEASE EXPLAIN HOW A DELAY IN THE 2026/2027 BRA TO JUNE 2025 ACTUALLY BENEFITS DUKE ENERGY KENTUCKY CUSTOMERS IF THE COMISSION APPROVES THE COMPANY'S APPLICATION.

A. As discussed above, the six-month delay in the next BRA provides an opportunity for the Company to transition earlier than it initially thought when it filed its Application in these proceedings. As I explained in my Direct Testimony, since PJM capacity auctions are normally on a 3-year forward basis, when PJM is on their normal schedule, a move from FRR to RPM would require at least 3 years to complete. This is because an entity desiring to join the capacity market must align with the delivery year in which they are able to procure capacity. Additionally, since notification to PJM of a change in Duke Energy Kentucky's capacity construct status is required to occur approximately 60 days prior to the PJM BRA, this further increases the time frame required by this amount. Finally, since Commission approval is required for such a move, the time for the regulatory process to occur would need to be added to this schedule. Thus, the total time needed for the Company to transition from FRR to RPM, as measured from the time that an application is initially submitted to the Commission until the start of the PJM Delivery Year, would be approximately 4 ½ years, depending on when the filing is made in relationship to the position within the PJM Delivery Year. However, because of PJM's compressed schedule, a unique opportunity exists for Duke Energy Kentucky to make this move, now faster than it otherwise could. The additional delay for the next PJM BRA to July 2025 for the 2026/2027 Delivery Year means that if the Commission issues a decision in this case by April 1, 2025, as the Company initially requested, it could provide the required notice to PJM by May 9, 2025 (the new required notification deadline) and participate in the June 2025 BRA for the 2026/2027 Delivery Year. This means that the Company could complete its realignment by June 1, 2026, a full delivery year sooner than originally envisioned and almost three (3) years faster than if PJM were not on a compressed schedule.

Q. DOES THIS OPPORTUNITY FOR AN EARLIER TRANSITION CHANGE THE COST BENEFIT ANALYSIS YOU INCLUDED IN YOUR DIRECT TESTIMONY?

A. No. This just means that the benefits to the customer from the Company transitioning to RPM are realized earlier.

Q. SINCE THE FILING OF ITS DIRECT TESTIMONY IN THIS PROCEEDING, HAS THE COMPANY BECOME AWARE OF NEW LARGE CUSTOMER LOADS BEING LOCATED IN THE DUKE ENERGY KENTUCKY SERVICE TERRITORY THAT WOULD INCREASE THE NEED FOR THIS TRANSITION?

A. No, Duke Energy Kentucky is not aware of a significant increase in customer load in the Company's service territory that would increase the need for this transition. However, as part of PJM's normal planning process, the Company submitted a Large Load Adjustment request to PJM on October 25, 2024.[2] Referring to page 4 of the footnoted presentation, the Warehousing adjustment will be in Duke Energy

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[2] *See* response to STAFF-DR-02-001. https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2024/20241025/20241025-item-03e---duke-large-load-request.ashx

Kentucky service territory (10 MW starting in 2025), with the other additional new loads in the Duke Energy Ohio service territory. Although this new 10 MW load to be located in Duke Energy Kentucky's service territory is not enough to materially impact the Company's position as the Company has sufficient capacity resources to serve this newly identified load, PJM ultimately decided to not make an adjustment to the Company's load forecast in this instance. This highlights the potential risks to the FRR plan from additional load adjustments. Further, the additional load identified in the Duke Energy Ohio service territory, although not a direct impact to the Duke Energy Kentucky capacity position, should impact the PJM minimum internal resource requirement for the DEOK zone. This could in turn impact the Company's ability to purchase bilateral capacity as I discussed in my Direct Testimony.

III. DISCUSSION OF ATTORNEY GENERAL RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE ATTORNEY GENERAL'S TESTIMONY AND RECOMMENDATIONS BY ITS WITNESSES.

A. The Attorney General presents testimony from two witnesses, Phillip Hayet and Lane Kollen from J. Kennedy and Associates, Inc. Messer's Hayet and Kollen do not object to the Company's request to transition itself but make several recommendations or conditions for the Commission to incorporate should it approve the Company's Application. My rebuttal testimony addresses the following three physical/operational conditions recommended by Mr. Hayet and four of the six ratemaking related conditions recommended by Mr. Kollen which are summarized as follows:

1) The Company should be required to replace any retiring dispatchable capacity with owned or purchased pursuant to bilateral agreement, in-zone (preferably located in Kentucky), dispatchable capacity prior to the retirement of the capacity.[3]

2) Purchases through the BRA auction should be limited so that the Company does not overly rely on the auction to satisfy capacity requirements. The Company should be limited to purchase no more than nine (9) percent of its annual capacity requirement through the BRA auction, and it should be required to bring its long-term capacity imbalance back into balance within a period of six (6) years.[4]

3) As an alternative to the two conditions above, the Commission could consider approving the Company's request to become an RPM entity, but also open a new docket to establish minimum capacity obligations for Kentucky-based RPM entities and set a goal for the new obligations to be in effect within one year of issuing its order in this docket.[5]

4) The Commission should limit the capacity and time period for recovery of net BRA and IA capacity purchase expense in PSM [profit sharing mechanism] rates consistent with the underlying physical conditions addressed by Witness Hayet.[6]

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[3] Hayet Direct at 5.
[4] *Id.*
[5] *Id.*
[6] Kollen Direct at 8.

5) The Commission should maintain the ten (10) percent Company and ninety percent (90) customers sharing allocation for all revenue and expense BLIs included in PSM rates, including the new BLIs….[7]

6) The Commission should ensure there are no ratemaking incentives to purchase capacity in the BRAs and IAs instead of acquiring new owned capacity and/or new or additional bilateral capacity purchases to replace retired owned capacity or terminated or reduced capacity purchases…[8]

7) The Commission should exclude the compliance and other penalty expense BLIs from the PSM and thereby preclude the Company from recovering these avoidable expenses through PSM rates.[9]

Q. DOES THE COMPANY AGREE WITH THE RECOMMENDATION THAT IT SHOULD BE REQUIRED TO REPLACE ANY RETIRING DISPATCHABLE CAPACITY WITH OWNED OR PURCHASED PURSUANT TO BILATERAL AGREEMENT, IN-ZONE (PREFERABLY LOCATED IN KENTUCKY), DISPATCHABLE CAPACITY PRIOR TO THE RETIREMENT OF THE CAPACITY?

A. The Company agrees that owned generation resources are the best hedge for capacity and energy market prices needed to serve Company load if located within the DEOK zone regardless of whether the Company is an FRR or RPM entity. As to requiring a replacement prior to the retirement of an asset, the Company also generally agrees with the idea that it makes sense to have any replacement resource

[7] *Id.* at 9.
[8] *Id.*
[9] *Id.* at 10.

in place prior to retirement of an existing resource since a resource that is not constructed or purchased cannot be a hedge against either capacity or energy prices.

However, KRS 278.264 already defines actions for the retirement of an electric generating unit. Specifically, part (d) states "The utility shall not commence retirement or decommissioning of the electric generating unit until the replacement generating capacity meeting the requirements of paragraph (a) of this subsection is fully constructed, permitted, and in operation, unless the utility can demonstrate that it is necessary under the circumstances to commence retirement or decommissioning of the existing unit earlier." Thus, the Company believes that any additional requirement is duplicative and unnecessary. The Company must already comply with KRS 278.264 and the General Assembly has spoken on what the utility's obligation and requirement is under the law.

Based on Mr. Hayet's recommendation and his response to Duke Energy Kentucky's Data Request to the Attorney General Data Request 01-021[10], the Company believes the only additional difference between Mr. Hayet's recommendation and KRS 278.264 is that the capacity replacement be located within the DEOK zone and preferably in the state of Kentucky (DEOK/DEK zone/area).

Acquisition of resources outside of the DEOK zone may represent additional risks such as the potential for separation of capacity zones in the capacity market or energy congestion and energy loss difference between the Company load and generation in the energy market. However, one issue with Mr. Hayet's

[10] *See* Attorney General's response to DEK-DR-01-021 in this proceeding.

recommendation is the implication if a particular resource type, like nuclear, was only available outside of the DEOK zone. In this situation, this resource may be the preferred resource selected through the Company's Integrated Resource Planning (IRP) process, and the Company would look to consider this resource. Ultimately, decisions on geographic location of replacement capacity will largely depend upon its deliverability into the DEOK zone, availability of transmission interconnections, and ultimate cost.

While the Company, all else being equal, would prefer any new resource to be located in the Company's delivery zone,[11] placing such a locational limitation on new capacity resources, especially at this point in time, is unreasonable and unnecessarily restricts the Company's ability to consider all cost-effective options to serve its customers. A limitation that any dispatchable capacity must be located in the DEOK zone would preclude the Company from partnering with other utilities outside of the DEOK zone, including Kentucky-jurisdictional utilities, on an asset, if one were to become available or a joint ownership of a newly constructed asset became feasible. Any acquisition or construction of a new dispatchable resource must go through the Commission's Certificate or Public Convenience and Necessity Process, where the Company would have to demonstrate the proposed construction or acquisition is the most reasonable, lowest cost solution. Therefore, protections already exist for customers and the restriction recommended by Witness Hayet creates an unnecessary hurdle and limitation to how the Company can best serve its customers in the future. Again, as I previously stated, the General

[11] *See* Company responses to AG-DR-02-009 and AG-DR-02-011 in this proceeding.

Assembly, through KRS 278.264 has established the policy and rebuttable presumption for a utility to overcome if it desires to retire a generating unit, including how it will replace it. Further restrictions and conditions would be contrary to the General Assembly's recently established policy.

Thus, the Company opposes the recommendation that a replacement resource must be required to be located within the DEOK zone with preference to the DEOK/DEK zone/area.[12]

Similarly, the Company also disagrees with and opposes Hayet's recommendation that any bilaterally purchased replacement capacity should be required to be located in the DEOK zone with preference to the DEOK/DEK zone/area for those same reasons. While under the FRR, due to the PJM minimum internal resource requirement, there may be a need to limit purchases of bilateral capacity to within the DEOK zone, no such requirement exists in RPM. However, due to the same reasons outlined above when discussing the location of a physical resource, a bilaterial purchase from within the DEOK zone represents the best capacity hedge since the cleared capacity price for this resource will be the same as the capacity price paid by the Company load. Finally, such a limitation, again, unreasonably restricts the Company in its ability to procure a reasonable supply to meet customer demand. As I explained in my Direct Testimony, there is already a scarcity of capacity currently located in the DEOK zone. And due to known upcoming retirements, the amount of "in-zone" dispatchable capacity is going to continue to decrease. Limiting the Company to in-zone bilateral purchases may

[12] *See* Company responses to AG-DR-02-009 and AG-DR-02-011 in this proceeding.

mean there is no counterparty for the Company to acquire capacity. To the best of the Company's knowledge there is no available capacity to be purchased bilaterally in the DEOK/DEK zone/area today.

Q. DOES THE COMPANY AGREE WITH THE RECOMMENDATION THAT PURCHASES THROUGH THE BRA AUCTION SHOULD BE LIMITED SO THAT THE COMPANY DOES NOT OVERLY RELY ON THE AUCTION TO SATISFY CAPACITY REQUIREMENTS AND SHOULD BE LIMITED TO PURCHASES OF NO MORE THAN NINE PERCENT OF ITS ANNUAL CAPACITY REQUIREMENT THROUGH THE BRA AUCTION, AND IT SHOULD BE REQUIRED TO BRING ANY LONG-TERM CAPACITY IMBALANCE BACK INTO BALANCE WITHIN A PERIOD OF SIX YEARS?

A. No. However, the Company certainly understands Mr. Hayet's concern regarding an overreliance on BRA or IA capacity market purchases without offsetting capacity sales. As previously stated, the Company agrees that owned resources are the best hedge against potentially volatile capacity market prices because it provides the opportunity to also sell MWs at the same price as purchases. Additionally, the IRP process is still the means by which Duke Energy Kentucky's long-term resource decisions are and will be determined. The Company does not anticipate that it would solely rely on the RPM auction net capacity purchases to address the Company's long term capacity needs. However, there could be times when the Company needs to more heavily rely on the BRA/IA capacity market purchases, in excess of sales, particularly if additional customer demand enters the

Duke Energy Kentucky service territory at a rate faster than capacity resources can be added. Also, the Company believes that when it makes economic sense, utilizing the PJM capacity markets to satisfy the Company's capacity obligation is a benefit to customers. Restricting the Company from purchasing capacity from the BRA/IA above a 9 percent threshold does not make economic sense if the BRA/IA clearing price is below the offer price of the Company's resources. Additionally, limiting the purchased capacity from the BRA/IA above this 9 percent limit may also force the Company to unnecessarily engage in bi-lateral capacity purchases that may cause economic harm since they are most likely to be made at a premium. Finally, given illiquidity in the physical bi-lateral capacity market for PJM capacity, especially if there is a limitation to bilateral capacity within the DEOK Zone, the ability to engage in bi-lateral purchases may not exist.

For example, starting with a position where capacity and load plus reserve margin are equal (a flat position) at 1,000 MW each, suppose that a new 200 MW load comes onto the system before a generation resource can be constructed or acquired, thus causing the Company to have a 20 percent short position. In this example, if the Company is not allowed to meet its capacity obligations through the BRA/IA, an approximate 100 MW bilateral purchase would need to be entered into to get the position back to the 9 percent limit. Because of PJM's three-year forward capacity auction design, there is a less active physical bilateral capacity market in PJM as compared to other RTO markets. Therefore it may be impossible for the Company to meet the 9 percent limit following the increase in load, or if the Company is able to engage in this bilateral capacity purchase, it would likely be made at a premium price to the eventual PJM capacity market clearing price in the BRA or IA. Therefore, Duke Energy Kentucky considers the 9 percent BRA/IA constraint to be an unnecessary requirement that imposes increased costs to customers.

In the event the Commission were to order a limit on capacity purchases from the BRA/IA auction, clarity needs to be made with the calculation of the position. Namely, the Company proposes that any calculation of capacity position is made using the maximum amount of generation capacity offered, not the cleared amount of unit capacity in the auction. This is consistent with Mr. Hayet's response to Duke Energy Kentucky's Data Request to the Attorney General Data Request 01-023.[13] For example, using Woodsdale 1's 77 MW summer net installed capacity amount and a .79 ELCC value, Woodsdale 1 would have approximately 61 MW of capacity offered into the BRA/IA auction. If the generator had a capacity offer price of $50/MW-Day, if the auction cleared at a lower price than the generators offer, the unit would not clear the capacity auction. Thus, at this low PJM clearing price, it doesn't make economic sense for the unit to clear the auction and instead, it is a lower cost for the Company's customers to purchase capacity from the auction. However, with the unit not clearing the auction, it makes the Company's position shorter than it would have been at a higher PJM auction clearing price. Inversely, the amount of customer load plus reserve margin must be defined. If the Company's position measurement were completed at low PJM capacity clearing prices, a higher reserve margin for the load purchase is utilized, making the Company's position

[13] *See* Attorney General's response to DEK-DR-01-021 in this proceeding.

appear shorter than reality. At higher capacity prices, PJM utilizes a minimum reserve margin that still maintains reliability. For this reason, the Company proposes that the calculation of the Company's position measurement be made using the amount of load plus the PJM target installed reserve margin, which again is consistent with Mr. Hayet's response to Duke Energy Kentucky's Data Request to the Attorney General Data Request 01-023.[14]

As the Commission is already aware, as part of the Commission's Order in its Administrative Case No. 387, which investigated the adequacy of all jurisdictional utility generation and transmission, the Company provides annual updates on, among other things, its reserve margins, including identification of any forecasted deficits, and any forecasted firm capacity purchases.[15] Therefore, the Company is continually looking at its capacity needs, and providing annual reports to the Commission that contain a rolling four-year forecast of its position. The Attorney General has access to this information. Additional conditions and restrictions on how the Company manages its capacity position, limiting where, when, and how much capacity can be purchased is unnecessary and harmful to customers.

Finally, although six years may seem like enough time for a resource to be added to bring the long-term capacity imbalance back into balance, it is not. Between the interconnection process, regulatory approval, and construction, it may not be possible for the Company to bring its long-term capacity imbalance back into balance within a period of six years by constructing an additional or the best

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[14] *See* Attorney General's response to DEK-DR-01-021 in this proceeding.
[15] *See* https://psc.ky.gov/Case/ViewCaseFilings/20000387/Post.

resource. It may force the Company to take actions that are more expensive or less beneficial for customers because it must abide by a six-year ticking clock to achieve a capacity balance requirement. This could, for example eliminate the selection of more efficient and better resources because the construction time is longer than the six-year limit could allow resulting in the Company having to eliminate from consideration supply strategies that may actually be in the customer's long-term best interest.

Q. PLEASE SUMMARIZE THE COMPANY'S POSITION AS IT RELATES TO MR. HAYET'S RECOMMENDATIONS.

A. In summary, the Company's position is as follows:

1. Although the Company agrees that a resource located in the DEOK zone is the best hedge for customers, a recommendation that limits the Company's available choices for additional resources to the DEOK zone could cause customers additional costs and is unnecessary. Additionally, although a theoretical bilaterial purchase from within the DEOK zone may represent the best capacity hedge when a Company-owned asset is not available, such a geographic limitation may unnecessarily restrict the Company from meeting customer demand, especially if such zonal bilateral capacity does not exist or is not the least cost/most reasonable option for customers. The Company strongly disagrees with the recommendation that replacement capacity be limited in any way or amount to bilateral purchases from assets within in the DEOK zone.
2. The Company does not believe a net position limit is necessary for the reasons discussed above. In addition, the Company believes that a limit could cause higher costs for customers.
    a. The Company continues to provide periodic updates to the Commission of its net capacity position, and will do so as it relates to results from the BRA/IA.
3. As to the calculation of the net position if the Commission were to order a limit on BRA/IA auction net purchases:
    a. The Company agrees with the proposal that the calculation of the Company's net position be made using the amount of each generator's highest capacity offer. Thus, the calculation of net position would be made assuming all the Company's resources clear at 100 percent of the offered Unforced Capacity (UCAP) for that unit.

b. The Company agrees with the proposal that the calculation of the Company's position be made using the amount of load plus the PJM target installed reserve margin.

c. Finally, for simplicity, the Company proposes that the calculation of the Company's net position be made using the BRA auction parameters and not each subsequent IA auction's parameters.

Q. IS A NINE PERCENT LIMIT ON CAPACITY REPLACEMENTS THROUGH THE BRA POSSIBLE AND REASONABLE UNDER THE PJM TARIFF?

A. As a Load Serving Entity (LSE), pursuant to PJM's tariff, the Company must purchase 100 percent of its forecasted load plus reserve margin in the auction from PJM. The Company cannot decide to only purchase a portion of its load plus reserve margin in the auction. However, the net capacity purchased is determined by examining the net amount of capacity purchased in the auction, or the amount purchased after netting out the capacity sold from its resources. The PJM tariff places no restrictions regarding the net capacity position of an LSE.

If a large load enters the Company's service territory and the Company is unable to construct resources or unable to purchase bilateral capacity, it is unreasonable that the BRA/IA purchase be held to a nine percent limit especially when PJM will clear 100 percent of this large load through the BRA/IA market. Obviously, if this requirement were in place, although the Company would do everything possible to not exceed this threshold, depending on the availability of new resources, the rate at which new load is added, changes to PJM auction parameters, and availability of bilateral purchases, it can't guarantee that this limit would be met.

Q. DOES THE COMPANY AGREE WITH THE RECOMMENDATION THAT AS AN ALTERNATIVE TO THE RECOMMENDATIONS TO REPLACE CAPACITY PRIOR TO RETIREMENTS OR THE NINE PERCENT PURCHASE LIMIT, THE COMMISSION COULD CONSIDER APPROVING THE COMPANY'S REQUEST TO BECOME AN RPM ENTITY, BUT ALSO OPEN A NEW DOCKET TO ESTABLISH MINIMUM CAPACITY OBLIGATIONS FOR KENTUCKY BASED RPM ENTITIES AND SET A GOAL FOR THE NEW OBLIGATIONS TO BE IN EFFECT WITHIN ONE YEAR OF ISSUING ITS ORDER IN THIS DOCKET?

A. The Company does not believe the Commission needs to take such action. Of the three jurisdictional utilities in PJM, only one is currently a full BRA/IA participant. If the Commission approves the Company's request, it would be the second. A one-size fits all approach may not be the best policy for each of the PJM participants. Unique circumstances, including the generation portfolios, customer load, seasonal peaking, delivery zones may all impact how a utility meets its capacity obligations. A one size-fits all approach may not make sense. That said, if the Commission decides to undertake such an investigation, the Company will certainly participate and offer its views, recommendations, and perspective.

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN'S RECOMMENDATION THAT THE COMMISSION SHOULD MAINTAIN THE TEN PERCENT COMPANY AND NINETY PERCENT CUSTOMER SHARING ALLOCATION FOR ALL REVENUE AND EXPENSE BLIS INCLUDED IN PSM RATES, INCLUDING THE NEW BLIS?

A. No. The Company maintains that it is appropriate for customers to receive 100% of the net capacity benefits or costs because the customer pays for these generating resources through base rates. The Company further believes it is appropriate for the customer to provide recovery of capacity costs needed in addition to the generating resources because the Company, regardless of its RPM participation, maintains the obligation to serve customer demand, provide reasonable service, meet its legal obligations under KRS 278.264, file its periodic IRPs, and thus would have to either build additional generating resources or purchase capacity to provide service to customers. Therefore, for the reasons I explained in my Direct testimony and as I further discussed above, the netting of the capacity revenues and capacity costs is appropriate, so the customer receives 100 percent the net benefit or 100 percent the net cost.

As listed in my Direct Testimony, by moving to full BRA/IA participation, Duke Energy Kentucky will continue receiving PJM Billing Line Items (BLI) 1600 and 2600 and will begin receiving additional PJM settlements charges and credits related to the capacity auction participation, specifically PJM BLI 1610, 1650, 1660, 1661, 1662, 1663, 1664, 1665, 1666, and PJM BLI 2605, 2620, 2625, 2630, 2640, 2650, 2660, 2661, 2662, 2663, 2664, 2665, and 2666. Historically the

Company has received PJM BLI 2600 related to excess capacity sales, or the capacity sold into the PJM auctions after the Company's FRR plan, and three percent holdback is satisfied. However, the amounts that the Company would receive in the future under PJM BLI 2600 would be much greater since all capacity must be offered and likely sold into the PJM auction, not just the small amount of excess as is the case today. Conversely, the Company would begin receiving charges under PJM BLI 1610, since 100 percent of the Company's customer capacity load obligation would be purchased in the PJM auction. Finally, PJM BLI 1600 would more likely have greater charges than today to the extent that the Company had generation resources clear the BRA and had a need to repurchase capacity in one of the subsequent incremental auctions.

Using the same example from my Direct Testimony (page 27, lines 20-22), suppose Duke Energy Kentucky has 1,000 MW of load and 900 MW of generation capacity with the BRA clearing at $400/MW-Day. The amount of capacity sold would be $131.4 million (PJM BLI 2600) and the amount bought would be $146 million (PJM BLI 1610). Only allowing the Company to recover 90 percent of the cost to serve the customers' capacity need would mean the Company is being denied the ability to recover its costs of serving customers, contrary to the fundamental concepts of utility rate making.

Since the vast majority of new charges and credits that would result from the Company's move from FRR to RPM would be either PJM BLI 1600, 1610 or BLI 2600, limiting the Company to 90 percent recovery would mean customers would not pay their full costs to serve the given demand in some situations such as in the example given. And since customers should pay the full costs of serving them, including the provision of adequate capacity with sufficient reserves to meet customers' demand, it is fair that customers should also receive 100 percent of the benefits, or revenues for that capacity. Therefore, the Company proposed that 100 percent of all additional revenues and all additional costs for all capacity related PJM BLI's be allocated to customers. As shown in my Direct Testimony in this proceeding, in three of the four corners of the Heat Map, the expected net result of a move to RPM is that customers will benefit.

Note that an example can be repeated for a situation where the PJM capacity auction price clears at a very low amount and the Company's generators don't clear the capacity market. The Company employs the use of an "indifference curve" to offer the excess capacity into the BRA today to capture the expected Capacity Performance risks should the resource be committed as capacity resource. For example, suppose that the indifference curve calculates a breakeven price of $10/MW-Day, meaning that at this cleared capacity price of $10/MW-Day, the cost of a capacity performance charge costs the customer the same as the value received from selling capacity into the PJM auction.[16] Thus, in this example no Company resources would clear the market if the clearing price were less than $10/MW-Day and no revenue is received, but the Customer would still purchase capacity necessary to serve its load plus required reserve margin, albeit at a very low price. Thus, there would be charges received under BLI 1610, but no revenues received

[16] *See* Company responses to AG-DR-01-027 and AG-DR-02-023.

under BLI 2600. Again, if only 90 percent of these charges were able to be recovered from customers, this creates an unfair allocation of costs.

Q. PLEASE EXPLAIN HOW THE COMPANY'S SHARING PROPOSAL WOULD WORK IN A LONG CAPACITY POSITION, OR A SITUATION WHEN THE PJM CAPACITY AUCTION RESULTED IN MORE CAPACITY REVENUES RECEIVED THAN COSTS PAID.

A. In a situation when the Company has a long position, as is the case currently, the Company's sharing proposal where customers receive 100 percent of the net capacity benefits results in a benefit to customers over the 90/10 sharing recommendation as proposed by Mr. Kollen. Using the same example as in my Direct Testimony on page 28, lines 9 through 17, where Duke Energy Kentucky has 1,000 MW of generation capacity and 900 MW of load with the BRA clearing at $400/MW-Day, the amount of capacity sold to PJM would be $146[17] million (BLI 2600) and the amount purchased from PJM would be $131.4 million (BLI 1610).[18] Under the Company's proposed allocation, 100 percent of this profit, or approximately $15 million, would be credited to customers. Under the Mr. Kollen's proposal, 10 percent of the benefit, or approximately $1.5 million, would flow to the Company. The Company maintains that it is appropriate for customers to receive 100 percent of the net capacity benefits (and costs) because the customer pays for the generating resources through base rates.

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[17] $146 million = 1,000 MW x $400/MW-Day x 365 Days

[18] $131.4 million = 900 MW x $400/MW-Day x 365 Days

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN'S ARGUMENT THE PRESENT SHARING ALLOCATION PROVIDES AN APPROPRIATE DISINCENTIVE TO THE COMPANY TO PURCHASE CAPACITY IN THE BRAS AND IAS AND AN APPROPRIATE INCENTIVE TO THE COMPANY TO SELL CAPACITY IN THE BRAS AND IAS?

A. No. As I explained in the previous example above, the "indifference curve," or the Company's capacity offer to PJM represents the breakeven point where revenues received are equal to expected costs. When the Company uses this process to create capacity offers for its resources in the BRA or IA, the Company utilizes economic principals in its offers to ensure the most economic outcome. Said in another way, the Company makes capacity offers that are agnostic to eventual sharing between the customer and shareholder. Thus, for generator offers that the Company's utilizes in the capacity auction, the sharing allocation neither provides an incentive or disincentive. Therefore, it is appropriate for the customer to receive 100 percent of the benefits of selling any excess capacity because the customer pays for these generating resources through base rates.

Q. DOES THE COMPANY AGREE WITH THE RECOMMENDATION THAT THE COMMISSION SHOULD ENSURE THERE ARE NO RATEMAKING INCENTIVES TO PURCHASE CAPACITY IN THE BRAS AND IAS INSTEAD OF ACQUIRING NEW OWNED CAPACITY AND/OR NEW OR ADDITIONAL BILATERAL CAPACITY PURCHASES TO REPLACE RETIRED OWNED CAPACITY OR TERMINATED OR REDUCED CAPACITY PURCHASES?

A. Although Duke Energy Kentucky agrees that there should be no ratemaking incentive favoring one method of satisfying the Company's capacity requirement over another however, as discussed above and in Ms. Steinkuhl's rebuttal testimony, the Company does not agree that conditions should be put in place that unreasonably restrict the Company's ability to manage its portfolio, limit its ability and flexibility to meet customer demand in capacity needs in the most reasonable, reliable, and efficient manner. Moreover, no conditions or restrictions should inappropriately shift the costs between the Company and its customers.

Q. DOES THE COMPANY AGREE WITH THE RECOMMENDATION THAT THE COMMISSION SHOULD EXCLUDE THE [CAPACITY] COMPLIANCE AND OTHER PENALTY EXPENSE BLIS FROM THE PSM AND THEREBY PRECLUDE THE COMPANY FROM RECOVERING THESE AVOIDABLE EXPENSES THROUGH PSM RATES, YET AT THE SAME TIME INCLUDE ALL CAPACITY COMPLIANCE AND OTHER PENALTY BLI REVENES IN PSM RATES?

A. No. First and foremost, the Company does not agree with this recommendation because it presumes that by PJM's use of the words "compliance penalty", "deficiency", and "test failure" that the Company did something wrong or acted imprudently. Although PJM uses these words to describe the charges and credits, it does not mean that the Company acted imprudently. The Commission through its general oversight of utility rates, can question and disallow any costs that it deems imprudently incurred.

The Company puts significant effort and analysis into the areas covered by these BLI's, including its capacity supply offers to PJM, demand side management programs, and generating unit maintenance. The Company does everything possible to avoid these types of charges. As an example, take one of the current similar types of PJM BLI's, BLI's 1390 and 2390, Fuel Cost Penalty BLI. The Company works hard to avoid failures of its fuel cost policy, including working with the PJM Independent Market Monitor (IMM) on creating the best fuel cost policy, actively monitoring the policy, and double checking every daily cost-based offer to ensure that it is compliance with the fuel cost policy. As a result of the Company's diligence, it has received a credit from other PJM members from BLI 2390 in every year since the charge started in 2017, with the total revenue received over $30,000 during this time. The corresponding charge, BLI 1390, through the Company efforts, has only had one failure of its fuel cost policy resulting in a charge of $502. Any charge that is received under a BLI that is labeled a compliance penalty, deficiency, test failure, or other term has been or will be due to unforeseen circumstances that can't be avoided, such as a forced outage or a failed performance test. Witness Kollen, starting on page 4, line 16 of his rebuttal testimony, lists the

PJM capacity BLI's related to capacity compliance and penalties that are primarily **expenses** (1000 series) as follows:

1660 – Demand Resource Interruptible Load for Reliability (ILR) Compliance Penalty

1661 – Capacity Resource Deficiency

1662 – Generation Resource Rating Test Failure

1663 – Qualifying Transmission Upgrade Compliance Penalty

1664 – Peak Season Maintenance Compliance Penalty

1665 – Peak-Hour Period Availability

1666 – Load Management Test Failure

Additionally, the PJM capacity BLI's related to compliance and penalties that are primarily **revenues** (2000 series) are as follows:

2660 – Demand Resource and ILR Compliance Penalty

2661 – Capacity Resource Deficiency

2662 – Generation Resource Rating Test Failure

2663 – Qualifying Transmission Upgrade Compliance Penalty

2664 – Peak Season Maintenance Compliance Penalty

2665 – Peak-Hour Period Availability

2666 – Load Management Test Failure

To exclude the capacity related compliance penalty 1000 series BLI's, listed above, and include the capacity related compliance penalty 2000 series BLI's, listed above, means that the customer would get the benefits of RPM participation and would not pay for the costs of those benefits. If the Company is an RPM participant, the total capacity of the Company's generating resources is offered into PJM and the total capacity requirement is purchased from PJM. If the customer receives all the revenues (benefits) and none of the costs (charges), the customer has not paid for the capacity to fulfill its PJM capacity demand requirements. Therefore, the revenues must be offset by the costs incurred. This is analogous to participation in the PJM energy market, where the total energy generated by the generating resources are sold into PJM and the total load buy is purchased from PJM. If the total generation sold is more than the total load buy, these off-system sales are included in Rider PSM. If the total generation sold is less than the load buy, the difference is a purchase of energy included in Rider FAC.

Each of the charges and credits go together symmetrically. PJM is revenue neutral; therefore, each of these BLIs have both a charge and a credit. Thus, BLI 1660 goes with BLI 2660, BLI 1661 goes with BLI 2661, and so forth.

Although 1000 series PJM BLI’s are *primarily* a charge and the 2000 series PJM BLI’s are *primarily* a revenue, this isn’t always the case. At times, 1000 series PJM BLI’s can be a revenue, and 2000 series PJM BLI’s can be a charge. Basically, they can flip flop depending on activity. Thus, to exclude the 1000 series of capacity compliance and other penalty PJM BLI’s from the PSM and to include 2000 series of capacity compliance and other penalty PJM BLI’s in the PSM can result in denying revenues to customers while allowing charges to be recovered from customers in some circumstances.

Q. DID THE COMPANY REQUEST ANY CHANGE TO THE PJM BLIs RELATED TO PJM CAPACITY PERFORMANCE?

A. No. The Company did not request any change to the two PJM BLI's related to capacity performance, BLI 1667 (Capacity Performance Non-Performance charge) and BLI 2667 (Capacity Performance Bonus Performances payment). The Commission previously approved a modification to the Rider PSM in Case No. 2017-00321 to allow the company to include both capacity performance charges and bonus payments as part of that sharing mechanism with a 90/10 sharing mechanism where customers receive 90 percent of the net benefits/costs related to capacity performance.[19] The Commission's Order in that case, found that the Company's proposal to change to the 90/10 sharing, even factoring in the capacity performance risks, was reasonable. Indeed, that was the reason the Company made such a proposal to increase the benefit to customers from the previously Commission-ordered 75/25 split. Customers have clearly benefited from this additional revenue sharing percentage since that case, in light of the additional risks, and it would be unreasonable to now say customers only get benefits an no risks, placing 100 percent of risks on the Company and its shareholders.

The Company did not request any change in the treatment of the PJM BLIs related to PJM Capacity Performance. Page 5, lines 15-18 of Mr. Kollen's direct testimony in this case incorrectly states that the Company is proposing a change to the sharing methodology for PJM capacity performance related BLI's.

[19] *In the Matter of the Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental compliance Plan and Surcharge Mechanism; 3) Approval of new tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief,* Case No. 2017-00321, Order (Apr. 13, 2018).

IV. CONCLUSION

Q. PLEASE SUMMARIZE WHY YOU BELIEVE THAT A CHANGE TO RPM REMAINS NECESSARY AND IN CUSTOMER'S BEST INTEREST.

A. The Company continues to believe that the transition to RPM will be a benefit to customers given the potential for customer load growth, especially those loads that can be added quicker than generation supply, PJM capacity market structural changes, projected increases in PJM market clearing prices, and changes to the PJM supply/demand balance. Due to the compressed PJM capacity auction schedule, the Company now has a unique opportunity to transition to the RPM market almost three years earlier than it would otherwise. Thus, accelerating the potential for customer benefits. Through the results of the Company's analysis discussed in my Direct Testimony, the Company believes that the transition to RPM will be a benefit to customers in three of the four corners or scenarios outlined in its Heat Map analysis, with annual benefits in the most likely range up $4 million annually. With the only corner of the Heat Map not resulting in a benefit being a low-capacity price scenario, which is not likely due to PJM's generation resource transition and additional load growth.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, John Swez, Managing Director Trading & Dispatch, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing direct rebuttal testimony and that it is true and correct to the best of his knowledge, information and belief.

John Swez Affiant

Subscribed and sworn to before me by John Swez on this 7th day of January 2025.

NOTARY PUBLIC

My Commission Expires:

SHAMELL M WILSON
My Comm. Expires
NOTARY PUBLIC
July 06, 2026
MECKLENBURG COUNTY, NC