KyPSC Case No. 2024-00285
TABLE OF CONTENTS

VERIFICATION

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

The undersigned, Alan Mok, Financial Market Manager - MW, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Alan Mok, Affiant

Subscribed and sworn to before me by Alan Mok on this 12 day of november, 2024.

NOTARY PUBLIC

My Commission Expires:

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

VERIFICATION

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

The undersigned, Bryan L. Garnett, RTO Policy & Compliance Manager, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Bryan L. Garnett

Bryan L. Garnett Affiant

Subscribed and sworn to before me by Bryan L. Garnett on this 12 day of November, 2024.

NOTARY PUBLIC

My Commission Expires:

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

VERIFICATION

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

The undersigned, John D. Swez, Managing Director, Trading and Dispatch, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

John D. Swez, Affiant

Subscribed and sworn to before me by John D. Swez on this 12 day of November, 2024.

NOTARY PUBLIC

My Commission Expires:

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

VERIFICATION

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

The undersigned, John Verderame, Managing Director of Power Trading & Dispatch, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests are true and correct to the best of his knowledge, information and belief.

John Verderame, Affiant

Subscribed and sworn to before me by John Verderame on this 6th day of November 2016.

NOTARY PUBLIC

My Commission Expires:

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

VERIFICATION

STATE OF OHIO	)	
	)	**SS:**
COUNTY OF HAMILTON	)	

The undersigned, Lisa D. Steinkuhl, Director, Rates & Regulatory Planning, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Lisa D Steinkuhl

Lisa D. Steinkuhl Affiant

Subscribed and sworn to before me by Lisa D. Steinkuhl on this 12th day of November, 2024.

NOTARY PUBLIC

My Commission Expires: July 8, 2027

NOTARY PUBLIC STATE OF OHIO

EMILIE SUNDERMAN
Notary Public
State of Ohio
My Comm. Expires
July 8, 2027

VERIFICATION

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

The undersigned, Matt Kalemba, Vice President Integrated Resource Planning, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Matt Kalemba Affiant

Subscribed and sworn to before me by Matt Kalemba on this 13 day of November 2024.

BRANDI REAKES
Notary Public
Lincoln
County
NORTH CAROLINA

NOTARY PUBLIC

My Commission Expires: 2/1/2028

<u>VERIFICATION</u>

STATE OF OHIO	**)**	
	)	**SS:**
COUNTY OF HAMILTON	**)**	

The undersigned, Sarah Lawler, VP Rates & Regulatory Strategy, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Sarah Lawler Affiant

Subscribed and sworn to before me by Sarah Lawler on this 12th day of November, 2024.

NOTARY PUBLIC

My Commission Expires: July 8, 2027

NOTARY PUBLIC STATE OF OHIO

EMILIE SUNDERMAN
Notary Public
State of Ohio
My Comm. Expires
July 8, 2027

Duke Energy Kentucky
Case No. 2024-00285
AG Second Set of Data Requests
Date Received: November 1, 2024

AG-DR-02-001

REQUEST:

Provide a discussion of the benefits that DEK's FRR participation in PJM has provided to the Company. Provide also any quantifications relevant to your discussion.

RESPONSE:

A specific analysis that calculates the historic annual savings or cost from the Company's FRR participation as opposed to RPM participation has not been completed. However, some estimates of this historic difference can be inferred from both the analysis created by the Company in this Case No. 2024-00285, as well as the previous FRR-RPM analysis completed by the Company in the presentation dated February 13, 2023, and included in the response as AG-DR-01-001(e) Attachment.

Case No. 2024-00285:

Referring to Table 1 from the direct testimony of Witness John Swez, Duke Energy Kentucky has historically resided in the upper left portion of the heat map since joining PJM in 2012. This shows that the FRR was the best choice for the customer, showing up to approximately $1 million in annual savings.

AG-DR-01-001(e) Attachment:

Referring to pages 5, 6, and 12, before any risk of an FRR deficiency is included, the value of being in the FRR versus transitioning to the RPM was calculated as an approximate $1.8 million annual savings.

The Company's best estimate of historical FRR value is that FRR participation has saved between approximately $1 million and $1.8 million annually. However, as the direct testimony of Witness John Swez concludes, although the FRR arrangement has historically benefited customers, the Company believes that continuing to remain in the FRR will cost customers in the future and that FRR participation will no longer be a savings to customers. Thus, full RPM auction participant is now in the customer's best interest.

PERSON RESPONSIBLE: John Swez

AG-DR-02-002

REQUEST:

If DEK should require more generation in the future:

a. Explain the benefits and disadvantages of remaining an FRR entity, including all impacts on the Company and its customers.

b. Explain the benefits and disadvantages of transitioning to an RPM entity, including all impacts on the Company and its customers.

RESPONSE:

a. There is no advantage or disadvantage from remaining an FRR entity related to the process of adding new generation; for example, there is no difference in the PJM interconnection queue process if an entity is either FRR or RPM.

However, the additional generation will impact the Company's position, with the financial impact being determined by the change in position and auction price. If examining a situation where the Company was flat load to generation, and the resulting additional generation made the Company's position longer, the only variable that would differ between FRR and RPM constructs would be the 3% holdback in the BRA that is required of FRR entities. If the 3rd incremental auction is lower than the BRA price, remaining FRR would create a financial disadvantage, most notable at higher auction clearing prices, since not all of the additional capacity could be sold at a higher price.

b. There is no advantage or disadvantage from becoming a full RPM auction participant related to the process of adding new generation; for example, there is no difference in the PJM interconnection queue process if an entity is either FRR or RPM.

However, the additional generation will impact the Company's position, with the financial impact being determined by the change in position and auction price. If examining a situation where the Company was flat and the resulting additional generation made the Company's position longer, the only variable that would differ between FRR and RPM constructs would be the 3% holdback in the BRA that is required of FRR entities. If the 3rd incremental auction is lower than the BRA price, transitioning to RPM would create a financial advantage, most notable at higher auction clearing prices, since all of the additional capacity could be sold at a higher price.

PERSON RESPONSIBLE: Bryan Garnett
John Swez

AG-DR-02-003

REQUEST:

Does DEK have any explanation or understanding on why so many LSEs are RPM participants as opposed to FRR? Please discuss.

RESPONSE:

Of the 14 regions (13 states and the District of Columbia) in the PJM footprint, 8 have a deregulated electricity construct. Although FRR can exist in a deregulated market, it is very difficult to maintain as most of the LSEs have divested the generation in these regions.

At the beginning of 2024, for the remaining 6 regions that are regulated, there were 3 Load Serving Entities (LSE) that were FRR entities in PJM:

- Dominion Energy – Virginia
- AEP – Indiana, WV, KY, TN
- Duke Energy Kentucky – KY

In May of this year, due to the change in the PJM minimum internal resource requirement among other PJM capacity rules and due to the increases in data center demand in that region, Dominion decided to return to RPM for the 2025-2026 capacity auction.

PERSON RESPONSIBLE: John Swez
Bryan Garnett

AG-DR-02-004

REQUEST:

Confirm that if an FRR LSE needs more capacity, they would not be able to obtain it through the PJM auction. Confirm also that an RPM member would be able to obtain the capacity through the PJM auction (assuming PJM has capacity available).

a. In the event PJM does not have capacity available, would such an event mean that PJM's capacity market is essentially no longer viable?

RESPONSE:

Confirm. FRR entities are not permitted to buy capacity in the Base Residual Auction (BRA). The sole purchaser of capacity in this auction is PJM, which purchases enough capacity for the load and requirements of the PJM Load Service Entities (LSE).

Confirm. An FRR entity can purchase capacity in the incremental auction if needed to replace generation sold in the BRA after meeting the 3% holdback requirement, but any purchases made can't be used to fulfill its FRR plan. FRR entities must purchase unit specific capacity to fulfill its FRR obligation.

a. As mentioned above, PJM purchases the capacity for all LSEs in the BRA based on the load forecast that PJM has indicated for the LSE. If there is not enough capacity available, PJM will still provide a price and settle the market. In this situation, the clearing price would be the maximum of 1.75* Net CONE, or Gross CONE, whichever is higher. In addition, PJM may then examine external areas to procure additional capacity to arrive at its desired reserve margin.

No, the Company does not believe that a capacity shortage for a short period of time means that the PJM capacity market is no longer viable. Likely, the high price indicated by the shortage pricing will incent other generation to enter the market.

PERSON RESPONSIBLE: John Swez
Bryan Garnett

Duke Energy Kentucky
Case No. 2024-00285
AG Second Set of Data Requests
Date Received: November 1, 2024

AG-DR-02-005

REQUEST:

Assume the following: (a) DEK is allowed to become an RPM participant; and (b) at some future date DEK needs additional capacity, but PJM is unable to provide it due to the capacity shortfall about which PJM has issued numerous warnings. Explain the options available to the Company for obtaining the additional capacity, other than self-built.

RESPONSE:

In this situation, in addition to building or acquiring additional resources, Duke Energy Kentucky would likely examine the bilateral capacity market and attempt to purchase capacity from external areas, if available. If successful, the Company would then offer the generating unit into the PJM capacity market. However, given the rules around the timing of the auctions in PJM as well as other markets, it may be difficult to acquire such capacity, as it is likely to be already committed to a market.

PERSON RESPONSIBLE: John Swez
Bryan Garnett

PUBLIC AG-DR-02-006
(As to Attachment only)

REQUEST:

Refer to the Company's response to AG DR 1-1 (e).

a. Refer to p. 5 of the attachment. When the presentation was provided on 2/13/2023, the Company's recommendation was to remain an FRR entity and reevaluate annually. What has changed in just one year, such that now the Company's reevaluation has led to a recommendation to transition to become an RPM entity?

b. Page 5 of the attachment states, "Changing to the RPM construct costs ~$1.8M annually over the current FRR approach but avoids future potential costs of ~$16M to ~$32M for up to two years if DEK remains in FRR and decides to retire East Bend early or if has significant additional demand growth." Please explain each number and also provide the analysis, electronically, with all formulae intact that derived each number.

c. Why might DEK even consider retiring East Bend if that would lead to higher market capacity prices in the DEOK zone for not only DEK Kentucky customers, but other Kentucky customers as well?

d. Refer to page 6 of the attachment, why is Reserve Margin a benefit to an FRR entity, and explain further the sentence "Net expected cost to move to RPM ~$1.8M/year."

e. Refer to page 6 of the attachment, and explain what Liquidity Differences mean and why that is a benefit to an RPM entity.

f. Refer to page 15 of the attachment, and explain more about the payments for capacity non-performance. Specifically, explain the calculation of the $3000 per deficient MW per performance event hour. Explain the Financial Penalty rate = Yearly Cone/30, and the Physical Penalty rate = 0.5/30. Explain what the 30 value refers to.

g. Refer to pg. 16 of the attachment. Provide additional details about the statement that the Commission would need approximately 1 year due to staffing issues. Explain in detail the Commission staffing issues that would require a year to address.

RESPONSE:

<u>CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)</u>

a. Items that changed between the analysis in AG-DR-01-001(e) Attachment (the 2/13/2023 presentation) and the analysis in Case No. 2024-00285 were (1) the expectation of higher future PJM auction prices, (2) a change in the FRR Deficiency Penalty calculation, (3) a change in the PJM Capacity Performance stop loss calculation, (4) the increased potential for load growth that would cause a chance that the Company could not meet its FRR plan obligation, (5) a shorter time horizon until announced retirements in the DEOK zone become reality, and (6) a change in the PJM minimum internal resource requirement. Please refer to the direct testimony of John Swez in this case, page 9, line 23 through page 10, line 11. Note that the PJM minimum internal resource requirement is periodically updated and presents a risk to the Company from remaining in FRR as previously, but with the expectation that fewer bilaterial capacity purchases will be available in the future to remedy this situation.

In addition, referring to page 5 of AG-DR-01-001(e) Attachment "DEK load growth", although the Company has not had a large data center announce plans to construct a facility in its area, there has been a general increase in activity of data centers looking for available sites nationwide. In particular, the Company is aware of the Northern Virginia and Columbus, Ohio where there has been explosive growth in signed and potential data center customers.

b. The $1.8 million represents the value from the difference in reserve margin requirement between the FRR and RPM plus the impact of the 3% FRR holdback requirement. Additionally, the future potential costs of ~$16M to ~$32M for up to two years represents the FRR deficiency penalty. Please see AG-DR-02-006(b) Confidential Attachment for details of these calculations.

c. East Bend retirement analysis is part of the IRP process and involves more inputs than the DEOK zone capacity clearing price. Additionally, if retired, the assumption is that the unit would be replaced by a similar sized capacity and not have a material impact on the DEOK zone capacity clearing price.

d. Referring to page 10, FRR entities have carried a lower reserve margin historically than RPM entities, as noted by the difference between the bolded blue (Cleared Reserve Margin) line and bolded orange (Reliability Requirement) line. Since FRR entities have carried a lower reserve margin, this was considered a financial benefit.

The net benefit, including the impact of the 3% FRR holdback, was that FRR participation saved customers $1.8 million annually. Please refer to part b above.

e. Liquidity difference means, as an RPM entity, PJM will purchase your load obligation in an organized auction setting in which almost all of the generation in PJM has to participate. While local constraints can affect your zones clearing price, an unconstrained zone is able to purchase capacity from the entire PJM footprint. The PJM Independent Market Monitor (IMM) monitors the offers of all the participants to ensure no entity has excessive market power. FRR entities do not have the same market access as RPM participants.

An FRR entity has totally different landscape if needing to purchase capacity than an RPM entity. If the FRR entity is short, it will need to approach bilateral entities who either plan or already have committed capacity to PJM. There is also no market monitor in this bilateral market, so the FRR entity may be exposed to higher prices from bilateral counterparties, particularly given the steep deficiency penalties of the FRR entity.

f. The $3,000 per non-performance MW per assessment hour is an estimate of the charge for a Capacity Performance event. The calculation for the charge rate per Manual 18 of PJM is as follows:

- The Non-Performance Charge Rate for Capacity Performance commitments is equal to {[the modeled LDA Net CONE ($/MW-day in installed capacity terms) for which the resource resides times number of days in the Delivery Year] divided by 30} divided by the number of Real-Time Settlement Intervals in an hour.

- The $3,000 per non-performance MW per assessment hour estimate assumes a Net Cone value of roughly $246/MW-Day for that delivery year. For a physical penalty rate of .5/30, the calculation would be .00139 MW of additional purchase for every MW of noncompliance.

The 30 hours in both examples is an estimate of potential CP hours in a delivery year. This was established by PJM from the polar vortex of 2013-2014 which would have produced 30 hours of CP.

PERSON RESPONSIBLE: John Swez
Bryan Garnett

CONFIDENTIAL PROPRIETARY TRADE SECRET

STAFF-DR-02-006(b)
CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

PUBLIC AG-DR-02-007
(As to Attachment only)

REQUEST:

Refer to the Company's response to AG-DR-1-4d. The question that was posed requested information for 8 years. Please explain why the Company's response only supplied information for 5 years, and unless there is a reason the information is unavailable, please provide the information for the remaining period.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)

Please see AG-DR-02-007 Confidential Attachment for the 8-years' worth of capacity sales.

PERSON RESPONSIBLE: Alan Mok
John Swez

CONFIDENTIAL PROPRIETARY TRADE SECRET

STAFF-DR-02-007
CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

Duke Energy Kentucky
Case No. 2024-00285
AG Second Set of Data Requests
Date Received: November 1, 2024

PUBLIC AG-DR-02-008
(As to Attachment only)

REQUEST:

Refer to the Company's response to AG-DR-1-6 that included DEK's Initial FRR Plan for the 2025/2026 plan year.

a. Please provide workpapers for the same table for the most recent 8 years. Provide the information electronically with all formulae intact.

b. Provide a narrative explanation for the derivation of the FRR Committed (MW) – Load Obligation for each resource. Also, explain how the values in this column relates to the Company's load requirement.

c. Provide the derivation of the FRR Committed (MW) – Add'l 3% Holdback. Also, explain why the value shown is associated with just the first generating unit in the table.

d. Explain why the Company's excess position is tied to the first generating unit in the table, when in fact the Company's excess position would seem to be based on total load vs total capacity.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)

a. Please see AG-DR-002-008 Confidential Attachment. For clarity purpose, because PJM requires capacity commitment in ICAP, the Company provides addition columns in the worksheet to show the FRR Committed – Load Obligation, FRR

Committed – Additional 3% Holdback, RPM Committed, and Capacity Position in both ICAP and UCAP terms.

b. The "FRR Committed MW – Load Obligation" is the FRR resource commitment that is used to fulfill the Company's load obligation requirement in the FRR plan. Although PJM requires unit specific resources in meeting the Company's FRR plan, there is no requirement as to which resources the Company decides to allocate to assemble the FRR plan. Thus, the Company may decide to use a portion of one resource and an entire other resource. The only requirement is that the Company must meet the FRR load obligation using the existing resources. Therefore, the sum of the resource commitment (the column of FRR Committed MW – Load Obligation column in UCAP) shown in the worksheet equals to the FRR load obligation. For the 2025/2026 FRR Plan, the Duke Energy Kentucky load requirement is 800.6 MW, which is the total shown in the "FRR Committed MW-Load Obligation" column.

c. The "FRR Committed (MW) – Add'l 3% Holdback" is the additional amount of the resource in UCAP to meet the 3% holdback in order for a FRR entity to sell excess capacity to RPM. Thus, the "FRR Committed (MW) – Add'l 3% Holdback is equal to 0.03 times the Company's FRR load requirement. For 2025/26, the holdback requirement is calculated to be 24 MW (0.03 * 800.6). The Company committed additional 24 MW from East Bend to meet the threshold holdback requirement.

There is no specific reason to put the FRR commitment associated with the 3% holdback at East Bend. The Company can assign the resource commitment to a single or a combination of resources to meet the threshold requirement.

d. While the Company's excess capacity is based on total load vs. total generation capacity, PJM does require the Company to show which resource is used to meet the total load requirement. The Company simply committed the capacity from the Woodsdale units and demand response first and then committed the remaining FRR capacity requirement at East Bend.

PERSON RESPONSIBLE: John Swez
Alan Mok

CONFIDENTIAL PROPRIETARY TRADE SECRET

STAFF-DR-02-008
CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

Duke Energy Kentucky
Case No. 2024-00285
AG Second Set of Data Requests
Date Received: November 1, 2024

AG-DR-02-009

REQUEST:

Refer to the Company's response to AG-DR-1-8.

a. Provide the calculation that led to DEK stating the Company will have an additional 30 MW to offer into the BRA, which may have been a rounded value.

b. Duke states it believes that becoming an RPM customer would have a nonconsequential impact on other Kentucky utility customers located in the PJM market. Putting aside for the moment the fact that as an RPM entity DEK would no longer have the holdback provision, which could have a beneficial impact resulting in lower market costs in the DEOK zone, what incentives as an RPM entity will DEK have to acquire or construct more capacity in the DEOK zone vs. relying on the RPM auction to address capacity needs, which could have a detrimental impact resulting in higher market costs in the DEOK zone?

c. DEK states that at extremely high capacity prices, RPM entities hold a lower reserve margin than FRR entities. If extremely high capacity prices were to occur after DEK becomes an RPM entity, and because of that DEK's reserve margin obligation would be lower than it would be if DEK remained an FRR entity, how can DEK assert that becoming an RPM entity would have a nonconsequential impact on other Kentucky utility customers located in PJM?

RESPONSE:

a. The 30 MW value was an approximated value from using the estimated load/capacity of 1,000 MW and multiplying by the 3% hold back requirement that

FRR entities need to maintain. Once PJM changed to the ELCC method of capacity accreditation, the 1,000 MW value is now expected to be closer to 800 to 900 MW going forward. Thus, the amount of holdback is now slightly lower at approximately 3% of 800 to 900 MW.

b. The Company's requested change from the FRR to RPM capacity construct has no impact on the Company's incentive to acquire or construct more capacity in the DEOK zone. The IRP process is still the means by which long-term resource decisions are determined. The IRP process is unchanged. The Company has no plans to "rely on the RPM auction to address capacity needs" except for potentially a short time frame under a situation such as additional customer demand entering the Duke Energy Kentucky service territory at a rate faster than a resource can be added. Thus, there is no anticipated detrimental impact resulting in higher market costs in the DEOK zone.

c. In the case that RPM had a lower reserve requirement that FRR, it is likely that a shortage would have occurred at point A of the VRR curve. If this is the case, the small amount of additional capacity available due to Duke Energy Kentucky's decision to move to RPM would be non-consequential since in either the FRR or RPM, there was not enough capacity to clear the auction and the auction would clear at the same price in either case. Therefore, there is no impact to the other Kentucky utilities that participate in PJM since the clearing price is likely not impacted.

PERSON RESPONSIBLE: John Swez – a., b., c.
Bryan Garnett – a., c.
Matthew Kalemba – b.

Duke Energy Kentucky
Case No. 2024-00285
AG Second Set of Data Requests
Date Received: November 1, 2024

AG-DR-02-010

REQUEST:

Refer to DEK's response to AG DR 1-22 b, in which DEK states the risk to DEK of zonal separation is not changed dramatically from moving from FRR to RPM.

a. Isn't it true DEK could benefit as an RPM entity compared to being an FRR entity if zonal separation were to occur with market prices driven up and when DEK was long, especially if DEK had bilateral contracts for resources located outside of the DEOK zone?

b. Under this same situation as an FRR entity, isn't it true DEK would not be able to count the external resources as part of its FRR capacity plan?

c. Under the set of circumstances described in part a. above, wouldn't this cause harm to other Kentucky utility customers located in PJM?

d. In DEK's heat map analysis did DEP account for Bonus Performance Credits for resources in its FRR Capacity Plan that could benefit the next year's FRR Capacity Plan? If so, please state where the Company accounted for this in the heat map analysis, and if not, please explain why not.

RESPONSE:

a. Currently, Duke Energy Kentucky has no bilaterial contracts for resources located inside or outside of the DEOK zone. In addition, if Duke Energy Kentucky were to become an RPM entity, it is unlikely that the Company would purchase additional capacity if already in a long capacity position. However, if the Company had a long position and had resources in a constrained zone, whether that zone being DEOK or another zone, the Company would be able to monetize the long position easier through the RPM as opposed to being an FRR participant. Additionally, note that if zonal separation occurs where the cleared price of capacity in the DEOK zone separates at a higher price than the rest RTO, the Company is both a buyer at that higher price and a seller at that same higher price since all the Company resources are in the same zone as the load. If in a long position, the capacity sales are greater than the purchases, resulting in net payments.

b. The ability of Duke Energy Kentucky as an FRR entity to utilize external resources to satisfy its FRR plan would depend on the PJM minimum internal resource requirement. If this requirement were low and not a binding constraint, Duke Energy Kentucky could utilize those external bilateral capacity purchases in its FRR plan. However, if retirements or other market changes occur within the DEOK zone and the minimum internal resource requirement changes in the future, Duke Energy Kentucky may not be able to count this capacity purchase in the FRR plan if the PJM minimum internal resource requirement is a binding constraint.

c. No. The decision for Duke Energy Kentucky to move from an FRR participant to an RPM participant will likely have a nonconsequential impact on cleared PJM capacity prices. However, in the situation where Duke Energy Kentucky moves to the RPM and has additional excess capacity (either through a bilaterial capacity purchase or other reason) to offer into the RPM due to the removal of 3% FRR holdback, assuming no change to the reserve margin, other Kentucky utility customers could benefit due to potentially lower clearing prices, all else being equal. In addition, please see the responses to AG-DR-01-005 and AG-DR-01-014.

d. The company did not factor in bonus Performance Credits for two reasons, either from participation as an FRR entity or from participation as an RPM entity. First, the bonus payout ratio is an uncertain rate. Second, FRR entities are not entitled to receive bonuses for intervals in which they overperform for portions of the unit used to satisfy the FRR plan. Given this, it is likely that the Heat Map underestimates the value of the RPM construct as only entities that participate in the RPM would benefit from bonus payments.

Note that Duke Energy Kentucky did receive approximately $886,125.45 in Capacity Performance bonus payments during Winter Storm Elliott due to the performance of East Bend which was sold into the RPM after the 3% required holdback provision was met. Please refer to the response to STAFF-DR-02-005.

PERSON RESPONSIBLE: Bryan Garnett
John Swez

Duke Energy Kentucky
Case No. 2024-00285
AG Second Set of Data Requests
Date Received: November 1, 2024

AG-DR-02-011

REQUEST:

Refer to the Company's response to AG-DR-1-20c.

a. Please explain further about the minimum internal generation requirement, and what kind of change in the requirement is DEK most concerned about. In other words, is DEK concerned a change could be made that would require DEK to have more capacity internal to the DEOK zone, but if DEK purchases capacity outside the zone, that capacity would not count towards satisfying the minimum internal generation capacity requirement? Please provide a reference to proposed policy changes that could affect FRR entities in this regard.

b. As an FRR entity, under what conditions would DEK decide to construct or acquire additional capacity specifically located within the DEOK zone? Also, same question, but under what conditions would DEK decide to construct or acquire additional, or replacement capacity located specifically within Kentucky?

c. As an RPM entity, under what conditions would DEK decide to construct or acquire additional capacity specifically located within the DEOK zone? Also, same question, but under what conditions would DEK decide to construct or acquire additional, or replacement capacity located specifically within Kentucky?

RESPONSE:

a. The PJM minimum internal resource requirement does not impact the Company in situations when the Company has a long capacity position (more capacity needed to satisfy its FRR plan). However, if the Company is in a situation where it doesn't have enough capacity to meet its FRR plan, it must rely on the bilaterial capacity market to satisfy its FRR plan. In this situation, the PJM minimum internal resource requirement can be a critical factor in how it meets the FRR plan.

The Company is aware of the potential for "Stroke of Pen" risk, or a change to the PJM minimum internal resource requirement, although with the recent reduction in the PJM minimum internal resource requirement for the DOEK zone, this risk is currently lower than previous. However, the Company is aware of one entity that had a very significant increase in its PJM minimum internal resource requirement due to sharp increase in additional customer demand, causing the entity to move immediately to the RPM.

However, likely the more impactful change in the PJM minimum internal resource requirement is from a change in the amount of capacity in the DEOK zone. If this zone has a large amount of unit retirements, it is likely that the minimum requirement will rise sharply reflecting the lack of resources in the DEOK zone. This would increase the probability that capacity from a zone outside of DEOK to not be eligible for the DEK FRR plan.

b. As an FRR or RPM entity, new Company generation resources are the best hedge for capacity and energy market prices needed to serve Company load if located in the DEOK zone. Acquistion of resources outside of the DEOK zone represents additional risks such as separation of capacity zones or energy congestion and loss difference between the Company load and generation. If a particular resource type was only available outside of the DEOK zone, the Company may consider that resource under certain limited circumstances. Decisions on geographic location of replacement capacity will largely depend upon its deliverability into the DEOK zone, availability of transmission interconnections, and ultimate cost.

c. See part (b) above.

PERSON RESPONSIBLE: John Swez – a., b., c.
Bryan Garnett – a.
Matthew Kalemba – b., c.

AG-DR-02-012

REQUEST:

Refer to the Company's response to AG-DR-1-22a.

a. Identify the recently announced merchant generation and why DEK expects bilateral capacity in the DEOK zone to be scarce as a result.

b. Please provide the Company's support for the statement, "With recent and announced merchant generation, bilateral capacity within the DEOK zone is likely to become scarce."

RESPONSE:

a. Referring to page 27 lines 3-5 of the Direct Testimony of Witness John Swez in this proceeding, one expected change in resources inside the DEOK zone is the announced retirement of the 1,020 MW Miami Fort generating station in August 2027. For the response to AG-DR-01-022, part (a), the reference to merchant generation was in reference to the retirement of Miami Fort 7 and 8. If these units do retire, the DEOK zone will have only approximately 2,000 MW of installed generation left which will greatly increase the probability of a price separation and a change in the PJM minimum internal resource requirement, limiting the ability to purchase bilateral capacity if Duke Energy Kentucky is an FRR capacity participant. In addition, please see the response to AG-DR-01-003(e).

b. Please see response to part (a) above.

PERSON RESPONSIBLE: Bryan Garnett
John Swez

AG-DR-02-013

REQUEST:

Refer to the Company's response to AG-DR-1-24.

a. The Company states it believes capacity clearing prices will increase in the future. Please provide the Company's latest forecast for the RTO and the DEOK Clearing Price for the next 15 years.

b. Does DEK's forecast account for new resources being acquired and PJM efforts to change PJM capacity rules that would result in lower market capacity prices occurring?

RESPONSE:

a. Duke Energy Kentucky does not have a subscription third party forecast of RTO and DEOK capacity clearing prices. The observable bilateral capacity market is the best resource for determining the value of PJM capacity.

b. Yes, the observable capacity market includes all known information.

PERSON RESPONSIBLE: John Swez
Bryan Garnett

AG-DR-02-014

REQUEST:

The objective of this question is to understand the alignment of the Company's reserve margin calculation used in an IRP analysis, and the FRR Capacity Plan it has to submit to PJM in the Table in AG-DR-1-7. Refer to the table showing the FRR Plan for the 2025/2026 period, and data provided in response to AG-DR-1-39.

a. In the spreadsheet the Company provided in AG-DR-1-39, it appears the Company derived MW as the Total firm capacity to use in a reserve margin calculation. For each unit in that calculation reconcile the differences in the values to the Nameplate UCAP column in the FRR plan shown in the table in the response to AG-DR-1-7, which sums to MW.

b. Why is the summer capacity load obligation MWs in System Outputs used for IRP purposes, yet the DEK capacity load obligation used in the FRR plan is MW.

c. Explain why the Company would conduct an IRP and plan using different capacity values than what it used in its FRR Plan.

RESPONSE:

a. As a matter of clarification, the Company understands the question to refer to AG-DR-01-038 rather than AG-DR-01-039 and AG-DR-01-006 rather than AG-DR-01-007.

In the two tables, East Bend UCAP is the same between the IRP and the FRR plan (499 MW). The primary difference between the two tables is the UCAP values of the Woodsdale units. The difference is driven by the assumption of the

Woodsdale CT units' individual ICAP values in the IRP versus those in the FRR plan. The FRR plan uses the capacity interconnection rights (CIR) that were originally established for Woodsdale. The IRP has historically used the assets net dependable capacity for long-term planning which can be, and is, above the CIR. PJM is considering allowing dispatch above the CIR if they move to a seasonal auction. The Company will evaluate limiting Woodsdale's output for long-term capacity planning in future IRPs while also considering PJMs outcome on seasonal auction assumptions.

b. In the IRP, the Company plans to an annual reserve margin. The net dependable capacity of most gas fired units is higher in the winter than the summer, so the Company includes a winter capacity value and a summer capacity value for each unit. Because the summer capacity value is lower, the summer capacity value is typically the limiting variable when planning for meeting the required reserve margin. The FRR plan uses the capacity interconnection rights which is based on the summer capacity value, so there is no difference between the FRR plan and the IRP.

c. As described in part (b) above, the Company relies on the summer capacity value in both the IRP and the FRR plans. The differences in these summer values are caused by the ICAP assumptions in the IRP and FRR. The Company will evaluate limiting Woodsdale's output for long-term capacity planning in future IRPs to align with the FRR plan while also considering PJMs outcome on seasonal auction assumptions.

PERSON RESPONSIBLE: Matthew Kalemba

Duke Energy Kentucky
Case No. 2024-00285
AG Second Set of Data Requests
Date Received: November 1, 2024

AG-DR-02-015

REQUEST:

Refer to the response to AG-DR-1-41. Is it the case that the Miami Fort retirement by 2027 is the most significant reason for the Company desiring to become an RPM entity? Please explain.

RESPONSE:

No. Although the potential Miami Fort retirement is factor in the request made by the Company to transition to the PJM RPM capacity construct, it is not the most significant factor. The Company considered many aspects of this decision before determining that a move to RPM was in the customer's best interest. As explained in the direct testimony of Witness John Swez, these factors included 1) the risk of and potential for large and sudden load growth; 2) the balance between demand and supply in the DEOK zone in PJM driven by announced generating asset retirements; 3) the reserve margin differential between FRR and RPM; 4) the price and lack of available bilateral capacity in the DEOK zone should future zonal separation occur and Duke Energy Kentucky was in a position where it needed additional bilateral capacity to meet its FRR plan 5) impacts from the PJM Minimum Internal Resource Requirement; 6) an expectation of higher capacity prices; 7) the change in the FRR deficiency penalty to the greater of 1.75 x Net Cost of New Entry (Net Cone) or Gross CONE; 8) the change in capacity performance penalty stop loss calculation; 9) the 3% FRR holdback requirement for FRR entities, and 10) capacity performance bonus available between FRR and RPM entities.

PERSON RESPONSIBLE: John Swez

Duke Energy Kentucky
Case No. 2024-00285
AG Second Set of Data Requests
Date Received: November 1, 2024

PUBLIC AG-DR-02-016

REQUEST:

Refer to the response to AG-DR-1-45 b. and c.

a. Please describe further what the Longbranch load is, state what is the peak capacity of that load, what percent is that load of the total DEOK load, and what percent is that load of the total EKPC load?

b. Please provide the calculation that determined the non-performance assessment due to Winter Storm Elliot was 1.2 MW.

RESPONSE:

<u>CONFIDENTIAL PRORIETARY TRADE SECRET</u>

a. Longbranch refers to the Duke Energy Kentucky customer demand that is located in the EKPC Zone and is disjointed from Duke Energy Kentucky's electric system. Refer to the DY 2025/2026 data in AG-DR-02-008 Confidential Attachment, the load capacity obligation of Duke Energy Kentucky is [redacted], which comprises of [redacted] in DEK zone and [redacted] in EKPC zone (row 24 in the attachment). After removing the Forecasted Pool Requirement multiplier, Longbranch load is [redacted]. Based on DEOK and EKPC 2025/2026 peak load of 5076 MW and 1973 MW (row 19), the percentage of the total Duke Energy Kentucky and EKPC zone is 0.411% and 1.058%, respectively.

b. Please see AG-DR-02-016(b) Confidential Attachment (PJM Report Name DEK_120122_123122_NPAResChDt_L_2023_04_06). The Company used PJM's

MSRS report called “non-performance assessment resource charge details and performed the physical assessment” for Dec 22 and Dec 23, 2022. Please refer to PJM MSRS documentation (https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/msrs-reports-documentation) for the description of the report. The Company added the “By PAI” tab to calculate the physical non-performance penalty. The resulting 1.2 MW is shown in cell I284.

PERSON RESPONSIBLE: Alan Mok
John Swez

CONFIDENTIAL PROPRIETARY TRADE SECRET

STAFF-DR-02-016(b)
CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

Duke Energy Kentucky
Case No. 2024-00285
AG Second Set of Data Requests
Date Received: November 1, 2024

PUBLIC AG-DR-02-017

REQUEST:

Refer to the response to AG-DR-1-49.

a. Provide the FRR plan for each year that shows the calculation of the capacity value of each resource on the table.

b. Provide a workpaper showing the calculation of the Load obligation values.

c. Explain why the load obligation value was so high in 2024/2025.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET

a. Please refer to AG-DR-02-008 Confidential Attachment, the capacity value of each resource is the "Name Plate" column expressed in UCAP. For Delivery Year 2025/2026, resource UCAP MW = resource ICAP MW x resource Accredited UCAP Factor. For Delivery Years 2018/19 to 2024/2025, the resource UCAP MW = resource ICAP * (1 – EFORD). PJM requires the resource EFORD to be the 1-year EFORD ending Sep 30 prior to the Delivery Year.

b. Please refer to the FRR load obligation section in AG-DR-02-008 Confidential Attachment. The Zonal Summer Weather Normalized Peak can be found in PJM's Load Forecast Development Process page (https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process) -> "5 Coincident Peaks & Weather Normalized Zonal Peaks – Summer". The Zonal Peak Load Forecast can be found in Table B-10 of PJM's Load Forecast

Report.[1] The Obligation Peak Load FRR Service Area, MW is the Company's peak load reported to PJM. The Forecast Pool Requirement, Minimum Internal Resource Requirement are listed in PJM auction planning parameters.

c. The high load obligation value in 2024/2025 is driven by the increase of FPR from 1.093 to 1.117 based on the 2023 Reserve Requirement Study.[2] In addition, the zonal peak load has increased from [redacted] in 2023/2024 to [redacted] in 2024/2025.

PERSON RESPONSIBLE: Alan Mok

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[1] For example, the 2024 Load Forecast Report: https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx. The previous year reports can be found in Load Forecast Development Process page -> Load Forecast -> Previous Reports.

[2] https://www.pjm.com/-/media/committees-groups/committees/mc/2023/20231115/20231115-consent-agenda-b---2-2023-pjm-reserve-requirement-study-report-final.ashx

Duke Energy Kentucky
Case No. 2024-00285
AG Second Set of Data Requests
Date Received: November 1, 2024

AG-DR-02-018

REQUEST:

Refer to the response to AG-DR-1-53. Provide the same workpaper, but include a column for each of the past 8 years. DEK mentioned this has ranged from a low of 4% to a high of 45%.

RESPONSE:

Please see AG-DR-02-018 Attachment. The 45% internal resource requirement is based on the 2021/2022 BRA auction planning data while the 4.4% is based on the 2025/2026 BRA data.

PERSON RESPONSIBLE: John Swez
Alan Mok

Attachment AG-DR-02-018: Internal Resource Requirement Calculation (Add on to AG-DR-01-053 response)

	2018/2019 3rd IA	2019/2020 3rd IA	2020/2021 3rd IA	2021/2022 BRA	2021/2022 3rd IA	2022/2023 3rd IA	2023/2024 3rd IA	2024/2025 3rd IA	2025/2026 BRA
CETO (MW)			2690	3110	2700	3250	3160	3120	2797
CETL (MW)			5072	4959	4959	5465	5632	4999	5387
Reliability Requirement (RR) MW			7239	7557	7346	6817	6714	6660	5596.1
Peak Load Forecast - DEOK (MW)			5063	5336	5222	5036	5001	5074	5030
FPR			1.0882	1.0898	1.0871	1.0906	1.0901	1.117	0.9387
RR - CETL			2167	2598	2387	1352	1082	1661	209.1
Peak Load * FPR			5509.6	5815.2	5676.8	5492.3	5451.6	5667.7	4721.7
Internal Requirement (%)	N/A	N/A	39.3%	44.7%	42.0%	24.6%	19.8%	29.3%	4.4%

Based on PJM Planning Parameters

Duke Energy Kentucky
Case No. 2024-00285
AG Second Set of Data Requests
Date Received: November 1, 2024

AG-DR-02-019

REQUEST:

This concerns all capacity requirements DEK is currently obligated to address regarding owned, contracted, or minimum capacity requirements for planning and/or operations purposes.

a. Explain all requirements DEK is obligated to meet by PJM.

b. Explain all requirements DEK is obligated to meet by Kentucky Statute.

c. Explain all requirements DEK is obligated to meet by prior Commission Order.

d. Has the Company conducted a reliability, LOLE study, to determine an optimal reserve margin to satisfy a 1 day in 10 year reliability target? If so, please provide.

e. Explain any other capacity requirements or guidelines that may be appliable to DEK or Kentucky regulated electric utilities.

RESPONSE:

a. PJM's operation is governed by agreements and tariffs approved by the FERC including the Operating Agreement,[1] Open Access Transmission Tariff (OATT),[2] and the Reliability Assurance Agreement (RAA).[3]

b. Objection. This request seeks a legal opinion and interpretation. Moreover, Kentucky revised statues and Kentucky administrative regulations are publicly available and researchable by the Kentucky Attorney General. As such, this request

[1] Available at: https://agreements.pjm.com/oa/4541
[2] Available at: https://agreements.pjm.com/oatt/3897
[3] Available at: https://agreements.pjm.com/raa/17427

is considered overly burdensome, over broad, and is harassing in nature. Without waiving said objection, and to the extent discoverable, please see Kentucky Revised Statues (KRS), including, but not limited to, KRS 278.020, KRS 278.030, KRS 278.264, and KRS 278.280.

c. Objection. This request seeks a legal opinion and interpretation and information that may otherwise be protected by the doctrine of attorney client privilege and attorney work product. Moreover, the Orders of the Kentucky Public Service Commission are publicly available and researchable by the Kentucky Attorney General, the majority of which the Kentucky Attorney General's office was directly involved.

d. The Company has not conducted a reliability, LOLE study. The Company currently relies on PJMs provided installed reserve margin, which maintains a 1 day in 10-year reliability target for the system, and PJM's forecasted pool requirements to ensure Duke Energy Kentucky maintains adequate resources for reliability.

e. Objection. This request is overly broad, unduly burdensome insofar as it seeks "any other capacity requirements that may be applicable to Duke Energy Kentucky or other Kentucky regulated electric utilities." The Company cannot respond to this request without engaging in speculation and guesswork as to what is intended by "any other capacity requirements" that "may be applicable." Moreover, the Company would have no idea what guidelines or requirements may be required of any other Kentucky regulated utility. Moreover, to the extent this request is seeking legal requirements, the request is further objectionable as it is seeking legal opinion and advice. To the extent such undefined guidelines or requirements are publicly available, they would be equally accessible to the Attorney General. As such, the Company views this request as intending to harass and force the Company to engage in unreasonable busy work.

PERSON RESPONSIBLE: As to objections, Legal
As to response, John Swez
Matthew Kalemba

Duke Energy Kentucky
Case No. 2024-00285
AG Second Set of Data Requests
Date Received: November 1, 2024

AG-DR-02-020

REQUEST:

Refer to the Company's heatmap analysis provided in Attachment JDS-1.xlsx, "Simple Output" tab, and the language that states, "FRR penalty assumes that 75% of the FRR Plan Short-fall is purchased at a premium of 1.25 x BRA Clearing Price and remaining 25% FRR shortfall is subject to penalty due to lack of available generation in DEOK zone."

a. Explain why the assumption was made 75% BRA and 25% penalty pricing.

b. Confirm that this 75% BRA and 25% penalty pricing locks the relationship of the assumptions in a "lock step" fashion and assumes FRR penalties in all heat map sensitivity cases. Explain.

c. Why does DEK assume FRR penalties are unavoidable in the FRR scenario?

d. Explain if DEK could build or contract for new capacity at or below CONE under FRR.

e. Explain why DEK did not consider an FRR case in which it would build or contract for new capacity at or below CONE as an FRR entity.

RESPONSE:

a. The Company had to make an assumption on how much capacity could be procured in the bilaterial market versus the amount of shortfall left subject to a penalty. There is no way to know the exact amount of this ration for each year in the future that a FRR shortfall occurs, but the Company believes it made a realistic estimate considering potential impacts of the PJM minimum internal resource requirement and availability of capacity in the DEOK zone. The assumption of 75%/25% shows the observation that a general tightening of the capacity market has occurred recently, as observed.

b. Deny. This relationship is the same for all of the price scenarios in the heat map with a position is below 0%. Thus, this relationship is only applicable for scenarios in which the Duke Energy Kentucky position is below 0%.

c. The Company does not assume that FRR penalties are unavoidable in all scenarios. FRR deficiency penalties are only calculated in the Heat Map when the position is below 0%. Additionally, not all short amounts are assessed an FRR penalty; only 25% of the shortfall is assessed an FRR penalty with 75% assumed to be able to be purchased in the bilaterial capacity market and capable of satisfying the FRR shortfall amount. Due to the general tightening conditions of the capacity market, Duke Energy Kentucky made these assumptions to remedy the FRR shortfall, and therefore FRR penalties in some situations would occur.

d. If the Company had enough notice prior to an FRR shortfall, it could build to avoid the expense of additional bilaterial capacity purchases and/or an FRR deficiency penalty. However, the scenarios do not contemplate building due to the limited amount of time between when knowledge of an upcoming FRR shortfall would be known, and when the new capacity build would need to be in place.

e. Please refer to the response to part (d) above.

PERSON RESPONSIBLE: John Swez

Duke Energy Kentucky
Case No. 2024-00285
AG Second Set of Data Requests
Date Received: November 1, 2024

PUBLIC AG-DR-02-021

REQUEST:

Refer to the response to AG-DR-01-24(a) wherein the Company states: "Thus, due to higher expected capacity prices, Duke Energy Kentucky is considering pursuing insurance to manage this non-compliance risk." Refer also to the response to AG-DR-01-24(b) wherein the Company states: Insurance may need to be purchased for two reasons, both (1) under RPM the physical option is not available, and (2) higher overall capacity prices make the physical option available under FRR have less value. Even if Duke Energy Kentucky were to say in FRR, it may pursue capacity performance insurance."

a. Please state all of the ways non-compliance can cause greater harm under the FRR compared to the RPM option.

b. Please state all of the ways non-compliance can cause greater harm under the RPM compared to the FRR option.

c. Describe the factors that will influence the decision to purchase insurance and provide a decision tree that portrays how those factors affect the decision to purchase capacity performance insurance. Provide this explanation i) if the Company were to stay an FRR and ii) if the Company were to convert to RPM.

d. Provide an estimate or matrix of estimates of the cost of such insurance, and the scope and dollar limits of the coverage obtained for the cost: i) if the Company were to stay an FRR and ii) if the Company were to convert to RPM.

e. Identify the providers of such capacity performance insurance coverage, a description of the market for such insurance coverage, and the trigger(s) for payout if there is a non-compliance circumstance.

f. Provide an estimate of the benefits that would be paid out from such insurance, i) if the Company were to stay an FRR and ii if the Company were to convert to RPM.

g. If FRR non-compliance could result in greater harm, which provides an incentive to move to the RPM, would having insurance under the FRR eliminate the potential for harm and reduce the desire to move to the RPM?

h. Please explain this statement further. “Therefore, it is appropriate to assign all of the insurance premium against the savings from entering RPM, but it is appropriate to assign a portion of this insurance against the benefits shown in the “Heat Map.” Explain the cost implications of doing this, and the magnitude of the change to the Heat Map results that would occur if this were done.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET

a. Please refer to the response to AG-DR-01-056. In addition, please see the following clarifications further below:

   1. Under a very high-capacity price scenario where capacity prices above approximately $300/MW-Day, the physical capacity performance option available under FRR becomes the more expensive option. Thus, if there is expectation for a high PJM auction price, a FRR entity may elect to choose the financial option as the least cost capacity performance option.

2. In auction price scenarios below approximately $300/MW-Day, under the physical capacity performance option available to FRR entities, the capacity performance penalty is the cost of the replacement capacity (or reduction in value of any excess capacity sold into the BRA) and is roughly half the cost of the capacity performance penalty under the RPM.
3. Note that there is no guarantee that the physical option for FRR entities will remain in the future. In fact, PJM recently filed with FERC to remove the physical capacity performance option for FRR entities, but this option was not ultimately removed.

b. See response to part (a) above.

c. Decision drivers to purchase capacity performance insurance:

1. Under FRR – Decision Tree:
   i. Likelihood of need (resource FRR MW commitment and forced outage rate);
   ii. Value of capacity replacement cost / expected capacity performance financial penalty;
   iii. Premium cost of insurance;
   iv. Insurance coverage (deductible, payout);
   v. Insurance policy terms.
2. Under RPM – Decision Tree:
   i. Likelihood of need (resource RPM MW commitment and forced outage rate);
   ii. Expected capacity performance financial penalty;

iii. Premium cost of insurance;

iv. Insurance coverage (deductible, payout);

v. Insurance policy terms.

d. Please see AG-DR-02-021 Confidential Attachment for the matrix of insurance quotes for the Company recently received from an underwriter for a list of scenarios in Delivery Year 2025/2026. The insurance premium ranged between [redacted] and [redacted] for coverage spanning from [redacted] The insurance quotes were calculated based on the assumption that the Company would elect financial option if it were to stay in FRR plan.

1. The insurance quotes are applicable if the Company were to stay an FRR entity, assuming financial option were elected.
2. The insurance quotes also apply if the Company were to convert to RPM. Coverage and premium may need to be revised slightly to account for the fact the Company will no longer be required to hold back 3% generation capacity in PJM Base Residual Auction as in FRR construct.

e. To date, the Company has identified a handful of providers of capacity performance insurance coverage, i.e., [redacted]. Due to the limited number of players, there is no efficient price discovery mechanism in this market and there are no standard products for good cost comparison. In the recent quotes the Company received, policy payout triggers are as follows:

1. PJM declares a capacity performance event (in RTO and/or DEOK LDA);

2. The insured unit (East Bend in DEK's case) is in forced outage/derate during the CP event and is charged capacity performance assessments by PJM.
3. Daily low temperature during the capacity performance event is lower than Tmin (from [redacted] in different scenarios covered by the policy) or the daily high temperature is higher than Tmax (between 94F and 104 in various scenarios).
4. Please refer to AG-DR-02-021 Confidential Attachment.

f. Because the FRR physical option does not trigger a financial penalty and the Company has not identified any insurance provider that covers physical option, insurance quotes were solicited based on FRR financial option,

Using the first scenario in the underwriter quotes as an example, if East Bend has a forced outage in a PJM capacity performance event which resulted in a CP assessment charge, and the daily low temperature during the event was lower than [redacted] in Cincinnati & Northern Kentucky International Airport (CVG), the insurance policy will start to pay out after the annual deductible [redacted] has been met. Maximum payout in this scenario is [redacted].

g. The insurance discussed here is related to capacity performance penalties, not the FRR deficiency penalty, or which occurs when an FRR plan to fails to meet its obligation. An FRR deficiency penalty can be many times greater. For example, if Duke Energy Kentucky were to lose to ability to use either Woodsdale or East Bend station (approximately 500 MW capacity value) and there is no replacement capacity available, under the FRR construct, Duke Energy Kentucky would incur a

FRR Deficiency Penalty equal to the shortfall amount multiplied by the greater of either the Gross Cost of New Entry (CONE) or 1.75 multiplied by Net CONE. Using the current Gross CONE of $444.26/MW-Day (UCAP Price) since it is currently the greater, the estimated penalty for 1 year for the 500 MW FRR shortfall would be $81 million (500 MW x $444.26/MW-Day x 365 days).

h. Please refer to AG-DR-02-021 Confidential Attachment.

PERSON RESPONSIBLE: John Swez
Jim McClay

CONFIDENTIAL PROPRIETARY TRADE SECRET

STAFF-DR-02-021
CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

Duke Energy Kentucky
Case No. 2024-00285
AG Second Set of Data Requests
Date Received: November 1, 2024

AG-DR-02-022

REQUEST:

Refer to the response to AG-DR-01-58. Under the circumstance where the Company retires existing generation capacity, the cost of which is recovered through base rates, and replaces the capacity in the BRA/IA, the cost of which is recovered through the PSM rider, the Company agreed that "to the extent discoverable, if any double recovery occurred, the Company could reconcile that through Rider PSM." Provide a more detailed explanation as to how such a double recovery could occur and how it could be reconciled through Rider PSM.

RESPONSE:

Objection, this question is vague and ambiguous as it relates to the phrase "where the Company retires existing generation capacity" and is asked as a follow up to an initial discovery question that was vague and ambiguous. Without waiving said objection, and to the extent discoverable, if any double recovery occurred, the Company could reconcile that through Rider PSM. If the question is intended to refer to the retirement of one of the Company's power plants, those costs would be recovered in base rates until the costs were depreciated fully. The response to AG-DR-01-058 was meant to explain that if there is any hypothetical double recovery, a rider mechanism such as Rider PSM can be used to ensure there is no double recovery.

PERSON RESPONSIBLE: As to objection, Legal
As to response, Sarah E. Lawler

Duke Energy Kentucky
Case No. 2024-00285
AG Second Set of Data Requests
Date Received: November 1, 2024

AG-DR-02-023

REQUEST:

Refer to the response to AG-DR-01-60 wherein the Company states that the volatility in BRA/IA costs is mitigated by having a supply portfolio that is relatively balanced against customer load, thus minimizing the exposure to BRA/IA capacity values. In the question, the Company was asked to "[E]xplain how the Company plans to mitigate the risk of the greater cost volatility from net capacity purchases in the BRA/IA that will be reflected in the PSM rider charges to customers. In your explanation, address whether there is value in limiting the net capacity purchases in some manner to limit the cost volatility on customers." In its response, the Company stated that "In reality, the Company would either have a small, long capacity position or a small, short position."

a. While this answers the mitigation question and the Company's intent to minimize capacity purchases in the BRA/IA, please confirm the Company agrees that minimizing capacity purchases in the BRA/IA reduce cost volatility on customers.

b. In addition, confirm the Company would be agreeable to a condition that requires the Company to maintain a relatively "small" capacity position. If so, then provide a metric the Company believes is reasonable in order to limit the exposure to the volatility of the BRA/IA, such as 50 mW or 100 mW, and provide the Company's rationale and support for such a metric. If not, explain why the Company would not be agreeable to such a condition.

RESPONSE:

a. Confirm and deny. Minimizing higher priced capacity purchases in the BRA/IA reduces cost volatility on customers (confirm), but engaging in lower priced capacity purchases in the BRA/IA would not materially impact customer volatility (deny). Due to risk of capacity performance penalties, the Company would likely employ the use of an "indifference curve" in its capacity offer to PJM or factor the resource capacity with the inclusion of the expected cost and bonus revenue of a capacity performance charge in its capacity offer. Thus, at a low-capacity clearing price, it is more beneficial for a resource to not clear the auction since the net cost of capacity performance charges that are only levied to resources that clear the auction are greater than the revenue received from clearing the auction. In this situation, the Company pays more for capacity from PJM than it receives (a net payment) in the auction, but the low cost of the purchase is the most economic choice for customers since it offsets a more expensive net capacity performance impact.

b. Deny. The Company will always work to maximize the value of the generators and reduce the cost of serving customer demand. At times, this might mean that the most economic outcome for customers is that more generation clears the capacity auction than the demand purchase, especially in a situation where a new resource is added, since new resources tend to be "chunky" in nature. Additionally, as described above, there can be times when capacity prices clear low, it does not make sense for all Company resources to clear the auction due to the potential costs of capacity performance changes.

PERSON RESPONSIBLE: John Swez
Alan Mok

Duke Energy Kentucky
Case No. 2024-00285
AG Second Set of Data Requests
Date Received: November 1, 2024

PUBLIC AG-DR-02-024
(As to Attachment only)

REQUEST:

Refer to the response to AG-DR-01-61a. and b.

a. Confirm there are no bilateral capacity transaction costs included in the base revenue requirement. If this is not correct, then provide a corrected statement and provide the amount of expense included in the base revenue requirement and the support for your response, such as a schedule or workpaper from the Company's last base rate case.

b. Provide a list of all bilateral capacity purchases by supplier/contract and the MW, cost per MW, and total expense by supplier/contract for each month from January 2021 through the most recent month for which actual information is available.

c. Provide a response to AG-DR-01-61(c). No response has been provided. Note that the question includes all owned capacity costs and purchased capacity costs. It is not limited only to purchased capacity costs.

RESPONSE:

<u>CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)</u>

a. Confirmed.

b. Please see AG-DR-02-024(b) Confidential Attachment.

c. If "all owned capacity costs" is referring to the generating assets used to meet Duke Energy Kentucky's FRR requirements, those costs are allocated on demand. Any purchased capacity costs to meet the FRR requirements is included in Rider PSM and allocated based on kWh.

PERSON RESPONSIBLE: Lisa D. Steinkuhl
Alan Mok

CONFIDENTIAL PROPRIETARY TRADE SECRET

STAFF-DR-02-024(b)
CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL