

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)	CASE NO.
AND INCREMENTAL AUCTION CONSTRUCT FOR THE)	2024-00285
2027/2028 DELIVERY YEAR AND FOR NECESSARY)	
ACCOUNTING AND TARIFF CHANGES)	

REVISED

DIRECT TESTIMONY OF

JOHN D. SWEZ

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

March 21, 2025

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I. INTRODUCTION

1 **Q. STATE YOUR NAME AND BUSINESS ADDRESS.**

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

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

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

8 **Q. PLEASE DESCRIBE BRIEFLY YOUR EDUCATION AND**
9 **PROFESSIONAL EXPERIENCE.**

10 A. I received a Bachelor of Science degree in Mechanical Engineering from Purdue
11 University in 1992. I received a Master of Business Administration degree from the
12 University of Indianapolis in 1995. I joined PSI Energy, Inc. in 1992 and have held
13 various engineering positions with the Company or its affiliates in the generation
14 dispatch or power trading departments. In 2003, I assumed the position of Manager,
15 Real-Time Operations, on January 1, 2006, became the Director of Generation
16 Dispatch and Operations, and finally assumed my current role on November 1,
17 2019.

18 **Q. HAVE YOU EVER TESTIFIED BEFORE THE KENTUCKY PUBLIC**
19 **SERVICE COMMISSION?**

20 A. Yes, I have testified before the Kentucky Public Service Commission
21 (Commission) on several occasions.

1 **Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS MANAGING**
2 **DIRECTOR, TRADING & DISPATCH.**

3 A. As Managing Director, Trading and Dispatch of Duke Energy, I am responsible for
4 Power Trading on behalf of Duke Energy's regulated utilities in the Carolinas and
5 Florida and Generation Dispatch on behalf of Duke Energy's regulated utilities in
6 Indiana, Ohio, and Kentucky. I am responsible for Duke Energy Kentucky's
7 participation as a member of PJM Interconnection LLC (PJM) as it relates to the
8 Company's generation dispatch, unit commitment, 24-hour real-time operations,
9 and short-term maintenance planning. I am also responsible for the Company's
10 submittal of supply offers in PJM's day-ahead and real-time electric energy
11 (collectively Energy Markets) and ancillary services markets (ASM), as well as
12 managing the Company's short-term supply position to ensure that the Company
13 has adequate economic resources committed to serve its retail customers' electricity
14 needs. I also work closely with the teams responsible for managing the Company's
15 capacity position with respect to meeting its Fixed Resource Requirement (FRR)
16 obligation as a member of PJM.

17 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?**

18 A. The purpose of my testimony is to discuss the Company's current participation in
19 the PJM capacity market construct as a FRR member, the cost-benefit analysis
20 Duke Energy Kentucky performed regarding its continued participation as an FRR
21 entity and the benefits that support a move to changing its participation status to the
22 auction-based Reliability Pricing Model (RPM) Base Residual (BRA) and
23 Incremental Auction (IA) capacity market construct. In doing so, I explain the

1 difference between the two capacity market participation alternatives and explain
2 the reasons why a move to the RPM participation is for a proper purpose, is in the
3 public interest, and more importantly, in the best interests of customers. I also
4 discuss recent structural changes in the PJM capacity market implemented by PJM
5 as approved by the Federal Energy Regulatory Commission (FERC) that influenced
6 this decision, and that now makes this move to RPM beneficial to the Duke Energy
7 Kentucky customer and in the overall public interest. I further discuss risks of
8 remaining an FRR entity, which support this transition, including impacts from
9 potential new customer demand additions in the Duke Energy Kentucky service
10 territory, overall supply and demand projections both within the Duke Energy Ohio
11 Kentucky (DEOK) zone, the PJM Locational Delivery Area (LDA) where the
12 Company operates, and in PJM as a whole. Finally, I also describe how such a
13 transition will occur, its timing, and explain the new PJM Billing Line Item (BLI)
14 credits and charges that will be received after such a move.

II. OVERVIEW OF PJM AND DUKE ENERGY KENTUCKY'S PARTICIPATION

15 **Q. PLEASE GENERALLY DESCRIBE PJM AND DUKE ENERGY**
16 **KENTUCKY'S MEMBERSHIP.**

17 A. PJM is the nation's first fully functioning Regional Transmission Organization
18 (RTO). PJM operates the power grid and wholesale electric market for all or parts
19 of thirteen states and the District of Columbia. This electric market consists of an
20 energy market, capacity market, ASM, and a Financial Transmission Rights (FTR)
21 market. PJM's operation is governed by agreements and tariffs approved by the

1 FERC including the Operating Agreement,¹ Open Access Transmission Tariff
2 (OATT),² and the Reliability Assurance Agreement (RAA).³ Effective January 1,
3 2012, Duke Energy Kentucky became a member of PJM, and as a PJM member,
4 Duke Energy Kentucky is subject to these agreements, which among other things,
5 require Duke Energy Kentucky to offer its available generation to PJM and to
6 purchase its energy to serve customer load from the PJM Day-Ahead or Real-Time
7 Energy Markets.

8 Pursuant to the Commission's December 22, 2010, Order in Case No. 2010-
9 00203 (PJM Realignment Order),⁴ Duke Energy Kentucky currently participates in
10 the PJM capacity construct as a self-supply FRR entity. As an FRR entity, Duke
11 Energy Kentucky uses its own generation assets located in the DEOK LDA,
12 Company demand response programs, and any necessary bilateral capacity
13 purchases to satisfy its PJM capacity demand requirements. The Company
14 effectively matches its PJM determined load/demand obligation, including
15 sufficient reserves with Megawatts (MW) of unit-specific⁵ capacity resources and
16 demand response programs to meet supply reliability requirements.

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>

⁴ *In the Matter of the Application of Duke Energy Kentucky, Inc., for Approval to Transfer Functional Control of its Transmission Assets from the Midwest Independent Transmission System Operator to the PJM Interconnection Regional Transmission Organization and Request for Expedited Treatment*, Case No. 2010-00203, p. 18, (Ky. PSC Order) (December 22, 2010).

⁵ Unit specific capacity means that the Company can directly point to specific generating unit as supplying needed MWs.

1 **Q. PLEASE DESCRIBE HOW PJM MEMBERS PARTICIPATE IN THE PJM**
2 **CAPACITY CONSTRUCT.**

3 A. As I previously mentioned, there are two ways for a PJM member to participate in
4 the PJM capacity construct, either through PJM's RPM capacity market, or as a
5 FRR entity.

6 **Q. PLEASE DESCRIBE PJM'S CAPACITY MARKET.**

7 A. PJM's capacity market, also known as the RPM, is designed to secure enough
8 power supplies in a cost-effective manner to maintain resource adequacy three
9 years into the future. Put simply, the market pays participants for the promise to
10 produce electricity when called upon by PJM. Capacity resources include
11 generators that produce electricity and other resources, such as demand response,
12 which incentivizes consumers to reduce electricity use and help operators keep the
13 supply and demand for electricity in balance. To meet PJM FERC-approved
14 reliability requirements, a utility that delivers electricity to end-use customers must
15 have the resources available to meet customers' demand. Utilities must also secure
16 reserves necessary for emergencies. PJM utilities meet these mandates with
17 capacity they own, capacity purchased elsewhere, or capacity procured from the
18 capacity market.

19 The RPM construct and the associated rules regarding how PJM members
20 participate in the PJM capacity market are described within the PJM OATT and
21 RAA. The PJM capacity market operates on a planning period that spans twelve
22 months beginning June 1st and ending May 31st of each year (delivery year). In
23 PJM, the capacity market structure is intended to provide transparent forward

1 market signals that support generation and infrastructure investment. The BRA is
2 the baseline procurement process. BRAs are typically conducted three years in
3 advance of the actual delivery year to allow bidders to complete construction of
4 projects that clear the BRA. The PJM capacity market is designed to provide
5 incentives for the development of generation, demand response, energy efficiency,
6 and transmission solutions through capacity market payments. Another key
7 component of RPM is that price signals are locational and designed to recognize
8 and quantify the geographical value of capacity. PJM divides the RTO into multiple
9 LDA sub-regions to model the locational value of generation. On a MW basis, in
10 the 2025/2026 BRA, 92.5% of PJM members are RPM participants and 7.5% are
11 FRR participants⁶.

12 **Q. HOW IS THE CAPACITY MARKET AUCTION PRICE ESTABLISHED?**

13 A. In a capacity market auction, PJM first accepts offers to provide capacity at the
14 lowest cost. As the auction progresses, PJM accepts progressively higher-priced
15 offers until enough capacity is assembled to meet the projected demand plus reserve
16 requirement for the future delivery year. At that point, when the auction clears, all
17 sellers receive the last or “marginal” offer price. This marginal price is also known
18 as the auction clearing price.

19 **Q. PLEASE FURTHER EXPLAIN PJM’S FRR PROCESS.**

20 A. The FRR process is the alternative to the RPM that allows PJM Load Serving
21 Entities (LSE), such as Duke Energy Kentucky, to satisfy its customer capacity
22 obligation under the PJM RAA. Under the FRR construct, an LSE must annually

⁶ In the 2025/2026 PJM Base Residual Auction planning parameters, the PJM peak load was 153,883 MW and the Total Peak Load of FRR Entities was 11,597.3 MW, or 7.5% of the total.

1 submit two self-supply plans (FRR Plan): 1) a preliminary or “initial” three-year
2 forward capacity plan, and 2) a final or “current year” FRR capacity plan. Each
3 plan must meet a PJM defined customer capacity obligation. The FRR Plan must
4 identify the unit-specific generating or demand response resources that will be
5 providing the capacity that will fulfill the LSE’s customer demand obligation. FRR
6 allows the LSE to match its customer reliability requirement to its own generation,
7 demand response, energy efficiency and/or transmission resources, while still being
8 permitted to sell some excess supply, subject to certain defined limitations, into
9 RPM.⁷

10 **Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE RESOURCES THAT**
11 **DUKE ENERGY KENTUCKY USES TO MEET ITS CAPACITY LOAD**
12 **OBLIGATION.**

13 A. Duke Energy Kentucky currently owns and operates approximately 1,076 MW of
14 summer generating capacity. East Bend Unit 2 Generating Unit (East Bend)
15 supplies the portfolio’s base load requirements. East Bend is a 600 MW (net rating)
16 coal-fired base load unit located along the Ohio River in Boone County, Kentucky.
17 The Company meets its peaking requirements with the Woodsdale Generating
18 Station (Woodsdale). Woodsdale is a 476 MW (net summer rating) six-unit natural
19 gas-fired combustion turbine (CT) facility with fuel oil back-up located in Trenton,
20 Ohio. The net ratings represent the amount of power that the Company can dispatch

⁷ FRR entities are limited in the amount of excess capacity they can sell into the capacity auctions. As an FRR entity, Duke Energy Kentucky is subject to the lesser of 450 MW or a 3 percent collar or hold back on its ability to sell excess in the BRA. The hold back requirement is relaxed only in the 3rd IA, at which time the capacity can be sold in the auction.

1 from the plants after a portion of the gross power output is used to power the plant
2 machinery.

3 Additionally, the Company has 9.3 MW of solar assets consisting of the
4 nameplate ratings of Walton 1 (2 MW), Walton 2 (2 MW), Crittenden (2.8 MW),
5 and Aero Solar (2.5 MW) site with the combined net firm summer capacity at all
6 four solar sites of 3.9 MW. These assets are connected at the distribution level and
7 thus, from PJM's perspective are behind the meter, meaning these generating assets
8 reduce the customer demand as seen from PJMs perspective but are not separately
9 dispatched into the market.

10 All these resources, East Bend, Woodsdale, and the solar facilities, along
11 with the Company's demand response programs and potential bilateral capacity
12 purchases are utilized to meet the capacity load obligation from the Company's
13 customers under the FRR.

14 **Q. PLEASE EXPLAIN WHAT BEING AN FRR ENTITY MEANS FOR DUKE**
15 **ENERGY KENTUCKY AND ITS CUSTOMERS.**

16 A. As a FRR entity, Duke Energy Kentucky must secure and commit unit-specific
17 resources to meet the peak load capacity requirements for all its customers in
18 advance of the PJM's annual BRA through its FRR Plan. As the FRR Plan timeline
19 follows the RPM auction timeline, the Company recently submitted its initial
20 2025/2026 FRR Plan for the delivery year spanning June 1, 2025, through May 31,
21 2026, and its final 2024/2025 FRR plan for the delivery year spanning June 1, 2024,
22 through May 31, 2025. Note that the 2025/2026 auction timing period was delayed

1 and is on a compressed schedule, as is discussed later in this testimony, and would
2 have normally occurred prior to now.

3 **Q. WHAT WOULD HAPPEN IF DUKE ENERGY KENTUCKY'S FRR PLAN**
4 **IS INSUFFICIENT TO SATISFY ITS DEMAND OBLIGATION?**

5 A. Duke Energy Kentucky would face severe penalties and limitations on its ability to
6 choose the FRR option if PJM were to deem the Company's initial or final FRR
7 Plans to be insufficient or its generation otherwise non-compliant with PJM
8 requirements. If the Company does not have sufficient unit-specific capacity to
9 meet its demand obligation in either its initial or final FRR Plans, PJM could assess
10 significant monetary penalties for the deficient delivery year, require the Company
11 to procure additional capacity going forward, and remove the Company's ability to
12 participate as a FRR entity. The two FRR plans submitted each year by Duke
13 Energy Kentucky are consistent with the Commission's Order in Case No. 2010-
14 00203 whereby the Commission required the Company to participate in the PJM
15 capacity market as a FRR entity until such time as it received Commission approval
16 to participate in the PJM capacity auctions. To date, Duke Energy Kentucky has
17 not requested such permission, but now is doing so since it has determined that a
18 change would be in the best interests of its customers and should be made at this
19 time.

20 **Q. PLEASE BRIEFLY SUMMARIZE WHY REMAINING A FRR ENTITY IS**
21 **NO LONGER IN THE BEST INTERESTS OF CUSTOMERS.**

22 A. Transitioning from the FRR participation to the RPM BRA/IA construct is in the
23 best interest of customers due to the following factors: 1) the risk of and potential

1 for large and sudden load growth at a rate faster than the Company can construct or
2 acquire additional baseload generation; 2) uncertainty and change in the balance
3 between demand and supply in the DEOK zone in PJM driven by announced
4 generating asset retirements; 3) the lack of available bilateral capacity in the DEOK
5 zone should future zonal separation occur and Duke Energy Kentucky find itself in
6 a position where it needed additional bilateral capacity to meet its FRR plan;⁸ 4)
7 anticipated changes to PJM's FRR construct that would negatively impact the
8 Company's participation as a FRR entity; 5) the energy transition in PJM due to
9 retirements of fossil generation and PJM's own prediction of shrinking reserve
10 margins and higher capacity prices; and 6) the change in the FRR shortfall penalty
11 to the greater of 1.75 x Net Cost of New Entry (Net Cone) or Gross CONE.

12 Over its time in PJM, the Company has periodically analyzed whether
13 remaining a FRR entity continues to be in the best interests of customers. And
14 although previous analysis supported remaining in the FRR construct, such is no
15 longer the case, and the Company believes a change is justified and in the public
16 interest.

⁸ 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.

III. FINANCIAL ANALYSIS SUPPORTS PARTICIPATING IN THE RPM

A. SUMMARY OF ANALYSIS

1 **Q. PLEASE EXPLAIN THE COMPANY’S COST-BENEFIT ANALYSIS**
2 **THAT NOW SUPPORTS EXITING THE FRR AND BECOMING AN RPM**
3 **AUCTION PARTICIPANT.**

4 A. The Company recently performed a cost-benefit analysis examining the customer
5 benefits from participation in the PJM capacity market as an RPM member as
6 opposed to a FRR member and included this as Attachment JDS- 1. As I explain
7 below, the conclusion is that since 2012 when first entering PJM as a FRR entity,
8 participating as a FRR was the logical choice and has benefited customers.
9 However, going forward, such is no longer the case. This is due to the potential for
10 sudden and large customer load growth, especially those loads that can be added
11 quicker than generation supply, announced and likely PJM capacity market
12 structural changes, the risk of continued zonal separation for the DEOK zone and
13 an inability to import, projected increases in PJM market clearing prices, and
14 changes to the PJM supply/demand balance. Based upon these factors, the
15 Company has determined through its analysis that a move to a full RPM auction
16 participant is in the customer’s best interest.

17 **Q. PLEASE SUMMARIZE THE RESULTS OF THIS ANALYSIS.**

18 A. Referring to Attachment JDS- 1, the results of this analysis created a “Heat Map”
19 showing the annual net financial impact comparing participation as a FRR with that
20 of RPM under four possible yet different scenarios. These four scenarios included
21 evaluation of 1) Capacity in excess of demand (Long Capacity Position) coupled

1 with a low auction clearing price (Low Price); 2) Insufficient capacity to meet
2 demand (Short Capacity Position) coupled with a Low Price; 3) Long Capacity
3 Position couple with a high-capacity auction clearing price (High Price); and 4)
4 Short Capacity Position coupled with a High Price. In the three most likely of the
5 four scenarios, moving to the RPM was the better alternative for customers going
6 forward.


7 **Q. PLEASE FURTHER EXPLAIN THIS ANALYSIS.**

8 A. Attachment JDS-1, Tab 3, Labeled Heat Map depicts the results of these four
9 scenarios. Starting with the “X-axis,” a range of potential BRA clearing prices is
10 shown, starting from low BRA prices on the left and moving to higher BRA prices
11 on the right. The scenarios on the “Y-axis” are a range of the Company’s supply-
12 demand balance, with a Long Capacity Position on the top and a Short Capacity
13 Position on the bottom. In this Heat Map, if a positive value is shown in a cell, this
14 means that the FRR created that much more annual value for the customer as
15 opposed to the RPM, whereas if a negative value is shown it means that staying in
16 the FRR caused that much more annual loss for the customer than moving to the
17 RPM.

18 The Heat Map can also be viewed as the opposite; thus, a positive value
19 means that moving to the RPM would result in that much less annual net revenue
20 as opposed to participation under FRR, and that a negative value means that the
21 RPM would have resulted in that much additional value for the customer. A copy
22 of the Heat Map from this analysis is shown as Table 1 below.

1

Table 1: “Heat Map” - Annual Financial Impact of FRR vs. RPM

FRR - RPM		BRA Clearing Price, \$/MW-Day 									
Length		50	100	150	200	250	300	350	400	450	500
DEK Portfolio Length Long (Positive) or Short (Negative) Position <small>(Position = Length before holdback or short divided by Load obligation)</small>	9%	\$ 584,584	\$ 855,998	\$ 814,242	\$ 459,316	\$ (334,918)	\$ (1,644,143)	\$ (2,145,504)	\$ (2,711,820)	\$ (3,343,090)	\$ (4,039,313)
	8%	\$ 591,008	\$ 865,405	\$ 823,190	\$ 464,363	\$ (338,598)	\$ (1,662,210)	\$ (2,169,081)	\$ (2,741,620)	\$ (3,379,827)	\$ (4,083,701)
	7%	\$ 597,432	\$ 874,811	\$ 832,137	\$ 469,411	\$ (342,279)	\$ (1,680,278)	\$ (2,192,658)	\$ (2,771,421)	\$ (3,416,564)	\$ (4,128,089)
	6%	\$ 603,856	\$ 884,218	\$ 841,085	\$ 474,458	\$ (345,959)	\$ (1,698,345)	\$ (2,216,235)	\$ (2,801,221)	\$ (3,453,301)	\$ (4,172,477)
	5%	\$ 610,280	\$ 893,624	\$ 850,033	\$ 479,506	\$ (349,640)	\$ (1,716,413)	\$ (2,239,812)	\$ (2,831,021)	\$ (3,490,039)	\$ (4,216,865)
	4%	\$ 616,704	\$ 903,031	\$ 858,981	\$ 484,553	\$ (353,320)	\$ (1,734,480)	\$ (2,263,389)	\$ (2,860,821)	\$ (3,526,776)	\$ (4,261,253)
	3%	\$ 623,128	\$ 912,437	\$ 867,928	\$ 489,601	\$ (357,000)	\$ (1,752,548)	\$ (2,286,966)	\$ (2,890,622)	\$ (3,563,513)	\$ (4,305,641)
	2%	\$ 649,846	\$ 962,432	\$ 937,758	\$ 575,824	\$ (259,211)	\$ (1,648,851)	\$ (2,168,485)	\$ (2,758,070)	\$ (3,417,604)	\$ (4,147,089)
	1%	\$ 777,523	\$ 1,214,345	\$ 1,310,465	\$ 1,065,883	\$ 343,374	\$ (939,401)	\$ (1,343,291)	\$ (1,817,846)	\$ (2,363,065)	\$ (2,978,948)
	0%	\$ 905,200	\$ 1,466,257	\$ 1,683,171	\$ 1,555,943	\$ 945,958	\$ (229,950)	\$ (518,097)	\$ (877,622)	\$ (1,308,525)	\$ (1,810,806)
	-1%	\$ 543,387	\$ 1,158,752	\$ 1,426,534	\$ 1,346,731	\$ 779,344	\$ (359,625)	\$ (601,956)	\$ (916,379)	\$ (1,302,893)	\$ (1,761,498)
	-2%	\$ (53,167)	\$ 582,973	\$ 868,087	\$ 802,175	\$ 243,852	\$ (891,713)	\$ (1,121,762)	\$ (1,424,616)	\$ (1,800,276)	\$ (2,248,741)
-3%	\$ (649,721)	\$ 7,193	\$ 309,640	\$ 257,619	\$ (291,640)	\$ (1,423,801)	\$ (1,641,568)	\$ (1,932,854)	\$ (2,297,659)	\$ (2,735,983)	
-4%	\$ (1,246,274)	\$ (568,587)	\$ (248,807)	\$ (286,937)	\$ (827,133)	\$ (1,955,889)	\$ (2,161,374)	\$ (2,441,092)	\$ (2,795,042)	\$ (3,223,226)	
-5%	\$ (1,842,828)	\$ (1,144,366)	\$ (807,255)	\$ (831,493)	\$ (1,362,625)	\$ (2,487,977)	\$ (2,681,180)	\$ (2,949,329)	\$ (3,292,425)	\$ (3,710,468)	
-6%	\$ (2,439,382)	\$ (1,720,146)	\$ (1,365,702)	\$ (1,376,049)	\$ (1,898,117)	\$ (3,020,065)	\$ (3,200,986)	\$ (3,457,567)	\$ (3,789,809)	\$ (4,197,711)	
-7%	\$ (3,035,935)	\$ (2,295,926)	\$ (1,924,149)	\$ (1,920,605)	\$ (2,433,609)	\$ (3,552,153)	\$ (3,720,791)	\$ (3,965,805)	\$ (4,287,192)	\$ (4,684,953)	
-8%	\$ (3,632,489)	\$ (2,871,705)	\$ (2,482,596)	\$ (2,465,160)	\$ (2,969,102)	\$ (4,084,241)	\$ (4,240,597)	\$ (4,474,042)	\$ (4,784,575)	\$ (5,172,196)	
-9%	\$ (4,229,043)	\$ (3,447,485)	\$ (3,041,043)	\$ (3,009,716)	\$ (3,504,594)	\$ (4,616,328)	\$ (4,760,403)	\$ (4,982,280)	\$ (5,281,958)	\$ (5,659,439)	

Positive value means FRR is a **better** financial outcome than RPM Capacity Construct annually for the amount shown.
Negative value means FRR is a **worse** financial outcome than RPM Capacity Construct annually for the amount shown.

2 **Q. WHAT COULD CAUSE DUKE ENERGY KENTUCKY TO BECOME**
3 **SHORT ON CAPACITY?**

4 **A.** A short position could be caused by multiple reasons, including a.) a large, energy
5 intensive customer, such as a data center or large factory, locating in the Duke
6 Energy Kentucky service territory, b.) a reduction in the Company’s generation
7 capacity value, as would be the case with a planned or forced unit retirement, c.)
8 the Company’s generation becomes devalued due to performance (de-rates or
9 outages), or d.) by PJM action where any or all of the following occur: 1) PJM
10 increases the Company’s planning reserve margin; or 2) PJM makes other market
11 rule/tariff changes that affect the Company’s FRR status or capacity position. This
12 is sometimes referred to as a “stroke of pen risk,” as was recently the case with the
13 transition to the PJM Effective Load Carrying Capability (ELCC) as discussed later
14 in this testimony. While these four capacity-impacting scenarios have not yet

1 occurred, nonetheless, they are possible and likely, and it is in the public interest to
2 proactively act in the best interests of customers to protect them from such risks.

3 **Q. EXPLAIN HOW TO READ AND UNDERSTAND THE RESULTS OF THIS**
4 **HEAT MAP.**

5 A. The four corners of the Heat Map show the four scenarios I previously described
6 and depict the comparison of remaining an FRR participant versus RPM
7 participation:

8 **Scenario 1- (Upper left corner) Low Prices & Long Capacity Position):**

9 The green corner of the Heat Map shows where Duke Energy Kentucky has
10 historically resided since joining PJM in 2012; in the lower range of PJM
11 cleared capacity prices⁹ and a Long Capacity position. This scenario
12 resulted in the only scenario where FRR was the best choice for the
13 customer, with this corner showing all positive values of up to
14 approximately \$1 million annually. This confirms that under the historical
15 Low Price, Long Capacity scenario, the FRR has benefitted customers.

16 As an example, the historical average BRA clearing price has been
17 \$89.89/MW-Day.¹⁰ Using the closest auction price on the Heat Map of
18 \$100/MW-Day as a proxy for comparison and a typical Duke Energy
19 Kentucky 9% long capacity position, the value shown in the second column,
20 first row of \$855,998, would be the approximate value of the annual FRR
21 benefit.

⁹ Available at <https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx>, p. 5.

¹⁰ The average BRA clearing price from the 2007/2008 to 2024/2025 auctions was \$89.89/MW-Day.

1 **Scenario 2- (Lower left corner) Low Prices & Short Capacity Position:**

2 This corner of the Heat Map shows the negative financial consequences to
3 customers if, as a FRR entity, the Company lacks sufficient resources to
4 meet its customer demand in a Low-Price environment. In this hypothetical,
5 the Company is unable to construct or acquire a new, generating unit(s) with
6 sufficient uncommitted,¹¹ unit-specific capacity within that timeframe
7 needed to a serve load(s) within the FRR plan delivery year. Such a scenario
8 could occur given that large customer loads can appear faster than a utility
9 can design, site, receive construction approval, and build a large generating
10 resource.

11 As Table 1 shows, even in a Low Price environment, due to a Short
12 Capacity Position, the Company would need to purchase replacement
13 capacity at a premium, assuming it is even available and deliverable into the
14 DEOK zone, resulting in net costs to customers.¹² The impact of this
15 shortfall of capacity could be in the millions of dollars, which includes the
16 cost of replacement capacity and the PJM FRR penalty.¹³

17 **Scenario 3- (Upper right corner) High Prices & Long Capacity**

18 **Position:** This corner of the Heat Map shows the negative financial
19 consequences to the customer if the Company stays a FRR entity under a

¹¹ As an FRR entity, the Company can only procure capacity that is unit-specific and has not already been committed to the PJM RPM. Capacity purchases in the RPM auctions are not unit specific and are unable to be used to meet an FRR obligation. Therefore, an FRR entity must rely upon the bilateral market to procure uncommitted capacity.

¹² If the shortfall of capacity occurs in a delivery year where the DEOK zone has separated from the rest of RTO, it may restrict the Company’s ability to contract for bilateral, unit-specific capacity that is uncommitted, *i.e.* has not already been bid in, and cleared in the PJM auction.

¹³ For example, even at a low-capacity price of \$50/MW-Day with a 9 percent capacity shortfall, the impact to customers would be approximately \$4.38 million in capacity costs.

1 High-Price, Long Capacity scenario. As stated, the historical average BRA
2 clearing price was \$89.89/MW-Day. However, as PJM undergoes a
3 transition to lower emitting resources and lower reserve margins,¹⁴ capacity
4 prices are expected, and are more likely than not, to increase.

5 In its February 24, 2023 whitepaper, “Energy Transition in PJM:
6 Resource Retirements, Replacements & Risks,” PJM, as part of its
7 multiphase effort to study the potential impacts of the energy transition,
8 examined four trends that it perceives as presenting increasing reliability
9 risks.¹⁵ Under each of the four scenarios presented by PJM in its whitepaper,
10 PJM is projecting reserve margins of 5%, 3%, 15%, and 12% by 2030,¹⁶
11 well below the current PJM reserve margin in the mid-20% range.¹⁷ As
12 shown in the Heat Map I provided in JDS-1, in the High-Price, Long
13 Capacity scenario, remaining in the FRR is a more costly alternative for
14 customers, in excess of \$4 million annually. Customers will receive a lower
15 value for excess capacity due to the PJM requirement that FRR entities
16 withhold 3% of its capacity before selling excess into the BRA. This
17 withheld capacity would, however, be allowed to be sold in the 3rd
18 incremental auction at a lower price assumption, as is discussed later in this
19 testimony.

¹⁴ <https://www.pjm.com/-/media/library/reports-notice/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx> (Table 1, p. 16).

¹⁵ *Id.*, p. 1.

¹⁶ *Id.* Table 1, p. 16.

¹⁷ *Id.*

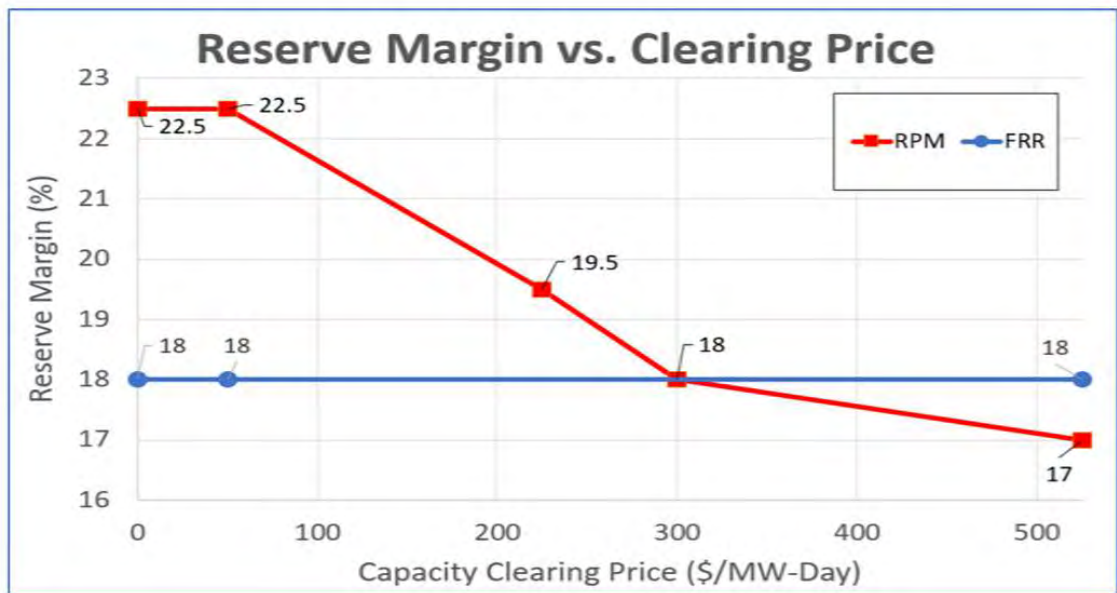
- 1 3) Slope of the PJM capacity demand curve and corresponding reserve
2 margin:
3 ➤ Low BRA Price RPM Reserve Margin = 22.5%
4 ➤ Mid BRA Price RPM Reserve Margin = 19.5%
5 ➤ High BRA Price RPM Reserve Margin = 18%
6 ➤ Maximum BRA Price RPM Reserve Margin = 17%
7 Table 2 below shows a graphical representation of the reserve
8 margin.
- 9 4) Estimated cost of replacement capacity under short FRR position:
10 ➤ 75% of the short position assumed to be purchased under
11 bilateral contract equal to a price of 1.25 x BRA.
12 ➤ 25% of short position assumed to be charged FRR
13 replacement penalty of 1.75 x Net CONE Price, where
14 CONE = Cost of New Entry
- 15 5) Relationship between the BRA and subsequent incremental
16 auctions:
17 ➤ Incremental auction clearing price = 50% x BRA
18 clearing price

19 The Company made realistic assumptions regarding the cost of the
20 replacement capacity, but it is possible that under certain scenarios the financial
21 consequence of failing to meet its FRR plan could cost Kentucky customers more
22 than what is shown in the bottom right and left corners of the Heat Map. For
23 example, if Duke Energy Kentucky is 100 MW short and there is no replacement
24 capacity available, under the FRR construct, Duke Energy Kentucky would incur a
25 FRR Deficiency Penalty equal to the shortfall amount multiplied by the greater of
26 either the Gross Cost of New Entry (CONE)¹⁸ or 1.75 multiplied by Net CONE.

¹⁸ CONE represents the total annual net revenue (net of variable operating costs) that a new generation resource would need to recover its capital investment and fixed costs, given reasonable expectations about future cost recovery over its economic life. CONE is the starting point for estimating the Net Cost of New Entry (Net CONE). Net CONE represents the first-year revenues that a new resource would need to earn in the capacity market, after netting out Energy and Ancillary (E&AS) margins from CONE. CONE and Net CONE of the simple-cycle combustion turbine (CT) reference resource are used to set the prices on PJM's Variable Resource Requirement (VRR) curve.

1 Using the current Gross CONE of \$444.26/MW-Day (UCAP Price) since it
 2 is currently the greater, the estimated penalty for only a 100 MW FRR shortfall
 3 would be \$16.2 million.¹⁹ This amount is a much larger value than shown on the
 4 two bottom corners of the Heat Map, since it was assumed that the Company would
 5 be able to satisfy 75% of this short position with replacement capacity, something
 6 that is likely to become increasingly difficult given a potentially changing PJM
 7 minimum internal requirement ²⁰ and limited availability of bilateral capacity in the
 8 DEOK zone, both of which will be explained later.

9 **Table 2: Graphical display of the FRR versus RPM reserve margin (ICAP basis)**



¹⁹ Penalty = 100 MW x \$444.26/MW-Day x 365 days

²⁰ Defined in PJM RAA under the term “Percentage Internal Resources Required.” This is the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resource located in such LDA.

IV. RISK FACTORS SUPPORTING THE COMPANY BECOMING AN RPM PARTICIPANT

1 **Q. PLEASE IDENTIFY ANY RISKS OF REMAINING AN FRR ENTITY AS**
2 **OPPOSED TO TRANSITIONING TO THE RPM AUCTION CONSTRUCT.**

3 A. There are several risks with remaining a FRR entity, which I explain further below.
4 In summary they include: 1) the FRR capacity holdback requirement; 2) the
5 difference in the reserve margin that PJM requires (*i.e.*, differential) between FRR
6 and RPM participants; 3) deficiency penalties; and 4) the minimal internal
7 requirement for FRR capacity.

8 **Q. PLEASE FURTHER EXPLAIN THE RISKS AND COSTS OF REMAINING**
9 **A FRR DUE TO THE FRR CAPACITY HOLDBACK REQUIREMENT,**
10 **VERSUS TRANSITIONING TO THE RPM AUCTION CONSTRUCT.**

11 A. FRR entities are restricted by PJM, pursuant to the RAA, to hold back, or not
12 monetize their generation capacity in an amount equivalent to the lower of 450 MW
13 or 3 percent of their load in the BRA. This means that Duke Energy Kentucky (or
14 any FRR entity) are unable to fully take advantage of the benefit of having excess
15 generation capacity until the 3rd IA of a delivery year. For Duke Energy Kentucky,
16 as an FRR participant, it must hold back (cannot offer nor sell) approximately 30
17 MW of excess capacity in the BRA and first two incremental auctions. This
18 restriction would not exist if the Company became a full RPM participant. By
19 moving to RPM, Duke Energy Kentucky will be able to monetize more capacity
20 than it has previously been permitted as a FRR entity. Because the Company
21 includes capacity sales in its Profit Sharing Mechanism (Rider PSM), customers
22 will receive additional value for this capacity. This ability to avoid the capacity

1 holdback in the RPM construct is a significant advantage over the FRR. For the
2 recently completed 2025/2026 BRA, with a clearing price of \$269.92/MW-Day and
3 24 MW of required hold back, this resulted in \$2.364 million in less revenue sold
4 into the BRA and shared with customers.²¹

5 **Q. PLEASE EXPLAIN THE RISKS AND COSTS OF REMAINING A FRR**
6 **ENTITY DUE TO THE RESERVE MARGIN DIFFERENTIAL, VERSUS**
7 **TRANSITIONING TO THE RPM AUCTION CONSTUCT.**

8 A. As shown in Table 2, the reserve margin for FRR entities is a constant amount
9 (currently approximately 18%), but for RPM entities, the reserve margin is as high
10 as 22.5% at very low-capacity prices, but as low as 17% at the highest capacity
11 prices. Thus, this reserve margin differential produces different costs and benefits
12 for both the FRR and RPM participant, depending upon the price of capacity. As
13 capacity prices rise, as they are predicted to do, the benefit of RPM increases. For
14 reliability, FRR LSEs must self-supply an incremental fixed reserve margin of
15 capacity equal to 100% of the Reliability Requirement of the FRR load obligation
16 or the target Installed Reserve Margin (IRM).²² However, RPM entities purchase
17 capacity reserves on a sloped demand curve, with an annual reserve margin
18 requirement keyed off the price of capacity determined in the RPM for the delivery
19 year. In periods of low-capacity prices, the RPM sloped demand curve can cause
20 additional purchases as the price of the auction moves lower, meaning that at lower
21 prices, loads purchase more capacity to ensure greater reliability. However, the

²¹ In the 2025/2026 BRA; 24 MW x \$269.92/MW-Day x 365 days = \$2,364,499.

²² In the 2025/2026 BRA; the target installed reserve margin for FRR 17.8%.

1 opposite is also true that in periods of higher capacity prices, the required reserve
2 purchases are lower for RPM participants. For Duke Energy Kentucky, and in turn,
3 its customers, the reserve margin differential only provides a benefit to the FRR
4 participant when capacity prices are low. However, as capacity prices trend higher,
5 the benefit to being a FRR entity starts to decrease. This is because in periods of
6 higher capacity prices, FRR entities, with a flat target IRM, end up holding a higher
7 reserve margin than those in RPM. This means that there is a financial advantage
8 to being in RPM at high-capacity prices. This benefit is shown as a savings to being
9 in the RPM in the Heat Map calculation at the upper right and lower right corners.
10 Based upon this analysis, there is significant advantage to customers with the
11 Company becoming an RPM entity.

12 **Q. PLEASE FURTHER EXPLAIN THE RISKS AND COSTS OF REMAINING**
13 **A FRR DUE TO FRR DEFICIENCY PENALTIES, VERSUS**
14 **TRANSITIONING TO THE RPM AUCTION CONSTRUCT.**

15 A. As the name implies, FRR deficiency penalties are only applicable to FRR entities.
16 The potential magnitude of a deficiency penalty can be severe if Duke Energy
17 Kentucky is unable to meet its FRR plan as submitted prior to the BRA. As I
18 previously stated, a FRR plan deficiency can occur due to a sudden increase in
19 customer demand, planned or unplanned unit retirements, or through a reduction in
20 Duke Energy Kentucky's generation capacity value. The deficiency penalty is equal
21 to the capacity shortfall amount multiplied by the greater of either the Gross CONE
22 or 1.75 multiplied by Net CONE, in \$/MW-day. Thus, depending upon the size of
23 the deficiency and ability to cure this shortfall, a penalty could be very costly. A

1 move to RPM eliminates the risk potential for a large FRR deficiency penalty
2 charge.

3 **Q. PLEASE DESCRIBE THE RISK ASSOCIATED WITH THE PJM**
4 **MINIMUM INTERNAL REQUIREMENT FOR THE DEOK ZONE IF THE**
5 **COMPANY REMAINS A FRR, VERSUS TRANSITIONING TO THE RPM**
6 **AUCTION CONSTRUCT.**

7 A. A challenge of meeting the Company's FRR plan is the PJM minimum internal
8 resource requirement. Under this requirement, Duke Energy Kentucky must locate
9 a certain, PJM-determined, percentage of its unit-specific generation that is
10 included in its FRR Plans within the DEOK zone. This percentage varies from year
11 to year and can be volatile. While the Company's owned generation at East Bend
12 and Woodsdale stations are located within the DEOK zone, if a FRR plan required
13 a purchase of additional capacity, such capacity may also need to meet those zone
14 limitations. While the current year's requirement is a low 4.4% percent, this
15 percentage can have substantial changes year to year, with the previous yearly
16 required value at 29.3%. With recent and announced merchant generation
17 retirements located within the DEOK zone,²³ there is a significant risk that bilateral
18 capacity within the DEOK zone will be scarce and potentially unavailable. Because
19 PJM's minimum internal requirement is responsive to and influenced by additional
20 load added within the zone, as well as changes in generating unit capacity within
21 the zone, and changes in local transmission capability, the Company and its

²³ See e.g., *Vistra announces retirement of Zimmer Power Plant in Moscow Ohio and Miami Fort Power Plant in North Bend Ohio by 2027*: available at <https://investor.vistracorp.com/2020-09-29-Vistra-Accelerates-Pivot-to-Invest-in-Clean-Energy-and-Combat-Climate-Change>.

1 customers are exposed to a significant reliability and cost risk if additional capacity
2 is needed but not available within the DEOK zone. This PJM minimum internal
3 resource requirement risk is not present as an RPM participant.

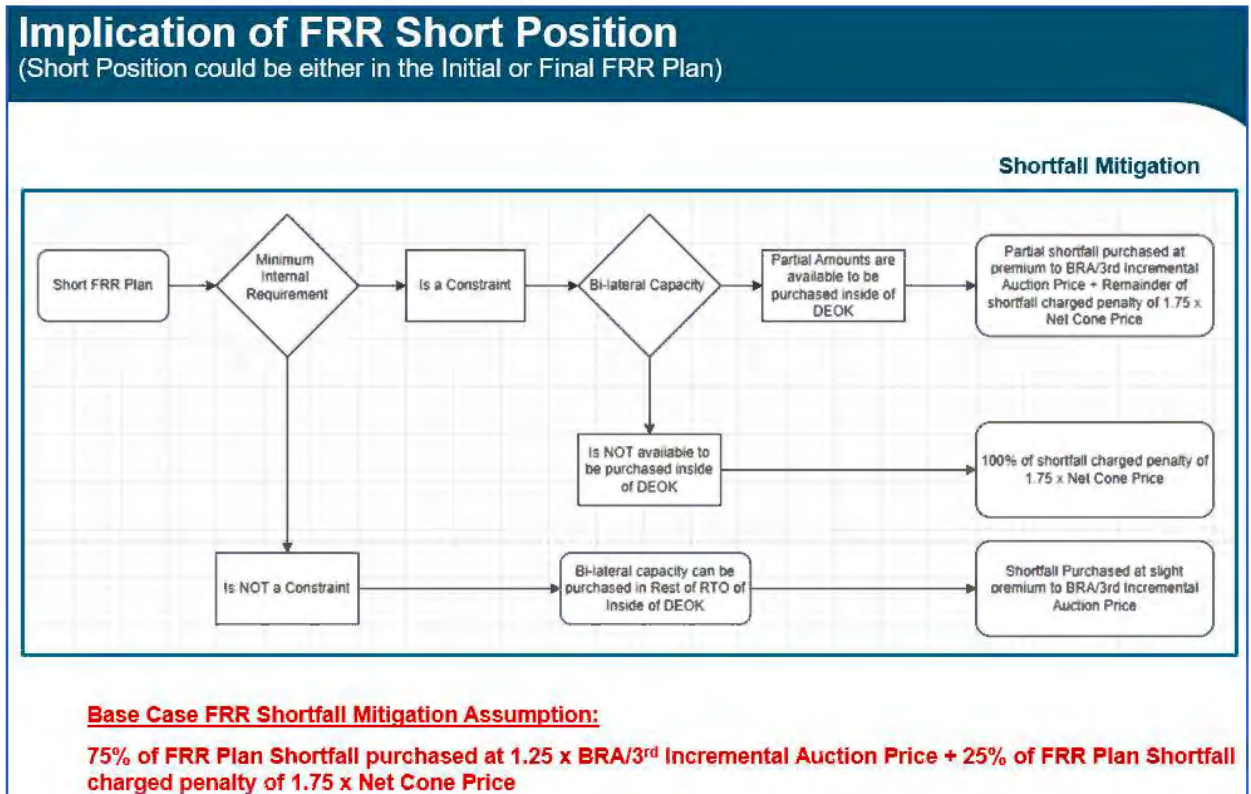
4 **Q. PLEASE DESCRIBE THE AVAILABILITY OF REPLACEMENT**
5 **BILATERAL CAPACITY IN THE DEOK ZONE AND HOW THIS**
6 **IMPACTS THESE CALCULATIONS.**

7 A. In the event of a short capacity position, a FRR participant can only purchase unit
8 specific capacity through bilateral contracts, as required by the FRR construct. This
9 is because the BRA and IAs do not procure unit-specific capacity. Thus, the RPM
10 auctions are not a viable compliance alternative for a FRR entity.

11 As a further FRR complication, the geographic location of bilateral capacity
12 can be outside the LSE's zone only to the extent that the FRR entity satisfies the
13 minimal internal requirement. Again, the risk is what happens when the Company
14 cannot satisfy its minimum internal requirement in the bilateral market. Remaining
15 an FRR creates a risk through the potential limited available bilateral capacity
16 options available for the Duke Energy Kentucky customer. Capacity owners are not
17 obligated to participate in the bilateral market, or potential sellers may only be
18 willing to sell excess capacity in advance of the BRA/IA at prices higher than
19 expected auction clearing prices. If a seller anticipates a higher auction price, then
20 there is no incentive for them to offer bilateral capacity. Moreover, if unit-specific
21 capacity is available following an auction, it did not clear the BRA/IA for the
22 delivery year, meaning its costs were higher than the clearing price produced. If
23 potential bilateral capacity sellers realize that Duke Energy Kentucky needs to

1 purchase capacity within the DEOK zone due to a short fall, the Company would
 2 be in a weak bargaining position and sellers may try to raise the offer price of
 3 capacity to capitalize on their long and unique locational position (like a “short
 4 squeeze” in stock market trading). For these reasons, in the Heat Map calculations
 5 I previously described, the calculations assume that 75% of a capacity shortfall will
 6 be able to be purchased bilaterally at a slight auction clearing price premium, but
 7 that 25% of the shortfall will not be available for purchase resulting in a FRR
 8 deficiency penalty assessment. Table 3 below shows a flowchart describing the
 9 implications of an FRR short position and replacement capacity values.

10 **Table 3: Flowchart - FRR Short Position and Replacement Capacity Value**



1 Transitioning to the RPM avoids this risk entirely as all capacity will be
2 procured through the competitive BRA and IA constructs.

3 **Q. PLEASE EXPLAIN THE RISK OF ZONAL SEPARATION AND**
4 **WHETHER THE DEOK DELIVERY ZONE PREVIOUSLY SEPARATED**
5 **AS A CONSTRAINED ZONE.**

6 A. In the BRA/IA, PJM procures capacity for its entire footprint. During these
7 auctions, it is possible for one or more individual zones to separate, or clear at a
8 different, higher price than that of the rest of the PJM footprint. This separation can
9 occur for a number of reasons, but more often than not, due to some constraint
10 within that specific zone. In three of the past six PJM BRAs, the DEOK zone
11 “separated,” or cleared at a higher price than the remainder of PJM. See Table 4
12 below for the specific data related to these past five PJM auctions. Specifically, for
13 the 2020/2021, 2022/2023, and 2024/2025 auctions, the DEOK zone cleared at a
14 higher price than the rest of the RTO, highlighting the “tightness” of capacity in the
15 DEOK zone. The fact that this separation has occurred in multiple delivery years
16 shows the ongoing risk to customers with Duke Energy Kentucky remaining in
17 FRR and facing a short position as depicted in the bottom two corners of the Heat
18 Map. In these two corners, Duke Energy Kentucky would be forced to find bilateral
19 capacity that satisfies the PJM locational requirement, if necessary, or pay an FRR
20 deficiency penalty. This DEOK zone separation could impact market liquidity for
21 capacity, particularly when combined with retirements of other generation in the

1 zone. While this diminished liquidity has not impacted Duke Energy Kentucky to
2 date, the Company is mindful of the potential impacts on capacity planning.

3 One expected change to the DEOK zone is the announced retirement of the
4 1,020 MW Miami Fort generating station within the DEOK zone²⁴ beginning in
5 August 2027. Although the owner of this station can always decide not to retire the
6 unit on this date, this station represents 1,020 MW out of a total of 3,294 MW of
7 generation capacity in the DEOK zone, or approximately one third of the zone's
8 capacity. Thus, accounting for Duke Energy Kentucky's 1,076 MW capacity, there
9 are only 1,198 MW of remaining generating resources within the DEOK zone, with
10 approximately 370 MW of these resources being energy efficiency and demand
11 response.

12 **Table 4: Previous 6 PJM Base Residual Auction results.**

Delivry Year	RTO Clearing Price (\$/MW-Day)	DEOK Clearing Price (\$/MW-Day)
2020/2021	76.53	130
2021/2022	140	140
2022/2022	50	71.69
2023/2024	34.13	34.13
2024/2025	28.92	96.24
2025/2026	269.92	269.92

²⁴ <https://www.luminant.com/documents/ccr/Ohio/Miami-Fort/2023/2023-Miami%20Fort-Part%20A%20Annual%20Progress%20Report%202023-Pond%20System.pdf>

1 **Q. IN THE EVENT THAT THE DEOK ZONE CONTINUES TO CLEAR AT A**
2 **HIGHER PRICE THAN THE REMAINDER OF THE PJM RTO, ARE**
3 **CUSTOMERS HARMED BY A MOVE TO RPM IN THIS SITUATION?**
4 **PLEASE EXPLAIN.**

5 A. No. In fact, a move to RPM saves customers money under high-capacity price
6 scenarios. As shown in the Heat Map, in both the upper right and lower right corners
7 (the high-capacity price scenarios), if Duke Energy Kentucky is long (upper right)
8 or short (lower right), the customer is better off in RPM than in FRR.

9 In the case of the upper right corner of the Heat Map, the Company simply
10 sells more capacity than it buys at the higher prices. As a simple example, suppose
11 Duke Energy Kentucky has 1,000 MW of generation capacity and 900 MW of load
12 with the BRA clearing at \$400/MW-Day. The amount of capacity sold to PJM
13 would be \$146²⁵ million and the amount purchased from PJM would be \$131.4
14 million.²⁶ With higher capacity clearing prices and a long position, more money is
15 received than spent. This credit of \$146 million would be received by Duke Energy
16 Kentucky through PJM Billing Line Item (BLI) 2600 and the cost of \$131.4 million
17 would be charged to Duke Energy Kentucky through PJM BLI ~~1610~~1600.

18 In the case of the lower right corner of the Heat Map, the Company is short
19 and saves under RPM by avoiding purchasing replacement capacity at a higher
20 price and by also avoiding the FRR deficiency penalty. Taking the inverse of the
21 long example above, suppose Duke Energy Kentucky has 1,000 MW of load and
22 900 MW of generation capacity with the BRA clearing at \$400/MW-Day. The

²⁵ \$146 million = 1,000 MW x \$400/MW-Day x 365 Days

²⁶ \$131.4 million = 900 MW x \$400/MW-Day x 365 Days

1 amount of capacity sold would be \$131.4 million and the amount bought would be
2 \$146 million. Under RPM, a net payment of the difference in the two numbers is
3 paid, or \$14.6 million. However, in looking at the Heat Map at the shortest Duke
4 Energy Kentucky position (-9% short) and a \$400/MW-Day BRA clearing price, a
5 loss of \$4.98 million is shown. Thus, by remaining in FRR, the loss is \$4.98 million
6 worse due to replacement capacity and an FRR deficiency penalty, or total FRR
7 losses would be \$14.6 million plus \$4.98 million, or \$19.58 million. If either long
8 or short, under high PJM BRA clearing prices, the customer is better offer under
9 RPM.

10 **Q. AT ONE TIME, CONCERN OVER THE PJM MINIMUM OFFER PRICE**
11 **RULE (MOPR) PRESENTED RISK THAT DUKE ENERGY KENTUCKY**
12 **CUSTOMERS COULD “PAY TWICE” FOR CAPACITY IF A MOVE TO**
13 **THE RPM WAS MADE. IS THIS STILL A CONCERN?**

14 A. No. Recently, PJM has clarified and made changes to the applicability of their
15 MOPR rule impacting new RPM participation. Prior to this rule change, if Duke
16 Energy Kentucky were to switch to an RPM member, there was the potential that
17 Duke Energy Kentucky would be required to offer certain generation resources into
18 the RPM auctions at a minimum price that was potentially high enough that the
19 resource could not clear in the auctions (either the BRA or a subsequent incremental
20 auction). Thus, the potential existed for Duke Energy Kentucky customers to “pay
21 twice” for capacity; once to build/maintain a generation asset and again to purchase
22 capacity for its load in the capacity auctions. If the Company’s asset did not clear
23 the auction, there would be no generation revenues to offset the load purchase.

1 Today, however, with these changes and clarifications, these risks no longer
2 exist, should the Company transition to full RPM participation. There are now two
3 conditions that must be true to eliminate this MOPR risk. The first condition is that
4 Duke Energy Kentucky does not have Buyer-Side Market Power (BSMP), which
5 occurs when an LSE offers generation at a lower price to reduce its overall exposure
6 to the market. This will not occur should Duke Energy Kentucky transition to RPM.
7 The second condition is that Duke Energy Kentucky does not have Conditioned
8 State Support. Conditioned State Support occurs if a state (Kentucky) is giving a
9 unit subsidization based on how the unit is offered (priced) into the capacity market.
10 Again, this is not the case for Duke Energy Kentucky as there is no state
11 subsidization based upon how the unit is priced into the market. For the most recent
12 planning year, Duke Energy Kentucky certified that these two conditions did not
13 occur, and PJM agreed with that determination. The new MOPR rule clarifications
14 eliminate the MOPR risk and makes Duke Energy Kentucky able to freely
15 transition to RPM without risk of MOPR restrictions for its generation.

16 **Q. PLEASE EXPLAIN THE PJM CAPACITY PERFORMANCE CONCEPT.**

17 A. In a stated effort to improve the reliability of generating resources in the PJM
18 footprint, PJM redesigned its capacity markets with its “Capacity Performance”
19 construct. In doing so, PJM redefined its capacity products and implemented new
20 performance-based penalties. Capacity resources must be capable of sustained,
21 predictable operation that allows the resource to be available to provide energy and
22 reserves during performance assessment hours throughout the delivery year.
23 Capacity resources are subject to non-performance charges assessed during

1 emergency conditions throughout the entire delivery year. Capacity resources must
2 be available to the RTO during periods of high load demand or system emergency
3 or face substantial performance penalties. With Capacity Performance, PJM
4 adopted a no-excuses policy to improve reliability through a new penalty structure.

5 In this new construct, PJM transitioned all capacity in the footprint to
6 Capacity Performance. In other words, all capacity purchased on behalf of the load
7 through RPM or eligible for inclusion in FRR capacity plans must meet the
8 Capacity Performance criteria.

9 **Q. HOW WOULD YOU CLASSIFY THE CURRENT DUKE ENERGY**
10 **KENTUCKY RESOURCES IN TERMS OF COMPLIANCE WITH THE**
11 **CAPACITY PERFORMANCE CONSTRUCT?**

12 A. East Bend 2 meets the minimum requirements of a Capacity Performance resource
13 in that it is a coal fired facility with a significant reserve of fuel stored on-site. The
14 Woodsdale Combustion Turbine facility successfully meets the Capacity
15 Performance requirements with the completion of the construction of its new dual
16 fuel system in 2019. Even so, the Company continues to evaluate Capacity
17 Performance compliance opportunities for its portfolio to increase their value and
18 mitigate non-performance risks.

19 **Q. PLEASE EXPLAIN PJM CAPACITY PERFORMANCE AS IT RELATES**
20 **TO FRR.**

21 A. Being in FRR means participants have an additional Capacity Performance option
22 available than those under RPM in that they can elect for a physical capacity
23 performance penalty option instead of a financial charge. This optionality is not

1 available to RPM participants. In lower capacity price environments as has
2 generally been the case, the FRR physical penalty option tends to be a lower cost
3 alternative than the financial option, thus this is one benefit to remaining an FRR
4 entity.

5 During times of *lower* PJM capacity market prices, the equivalent financial
6 cost of a physical capacity performance penalty is less than the financial capacity
7 performance penalty. Conversely, during times of *higher* PJM capacity market
8 prices, the equivalent financial cost of a physical capacity performance penalty is
9 roughly equal to the financial capacity performance penalty. Thus, with past
10 relatively low-capacity price levels, the physical capacity performance penalty
11 option has been a lower cost alternative than that available under participation as
12 an RPM member. However, as stated earlier and as evident by the recently cleared
13 2025/2026 BRA, the Company believes capacity clearing prices will increase in the
14 future and thus, the benefit to the FRR from the physical option will decrease over
15 time.

16 **Q. WERE THERE ANY ADDITIONAL CHANGES TO THE WAY PJM**
17 **CHARGES CAPACITY PERFORMANCE PENALTIES TO RPM**
18 **PARTICIPANTS THAT MAKE IT MORE ADVANTAGEOUS TO LEAVE**
19 **FRR AND BECOME AN RPM PARTICIPANT?**

20 A. Yes. PJM recently changed the “stop loss” amount for capacity performance
21 charges. Previously, the most an entity could pay in Capacity Performance charges,
22 or the “stop loss,” was tied to the CONE price for that LDA. However, under the
23 new “stop loss,” the maximum Capacity Performance amount that can be charged

1 is related to the BRA clearing price. Thus, if the BRA clears at a low price, the stop
2 loss is 1.5 multiplied by the BRA price which is a lower amount than previously
3 calculated. Unless the BRA clears at CONE, the maximum that can be charged for
4 PJM Capacity Performance is less. This is one additional reason the Company is
5 pursuing a change to RPM capacity market participation.

6 **Q. HOW DID THE PJM'S RECENT CHANGE TO THE ELCC**
7 **METHODOLOGY IMPACT DUKE ENERGY KENTUCKY'S CAPACITY**
8 **POSITION?**

9 A. PJM transitioned to the Effective Load Carry Capability (ELCC) methodology for
10 the 2025/2026 Delivery Year. Generators now receive a class level ELCC. Thus,
11 each generator within a certain class receives the same initial capacity value. For
12 the Company's resources, as previously mentioned, East Bend received an ELCC
13 class value of .84 (84%), Woodsdale CT 1-6 received an ELCC class value of .79
14 (79%), and Demand Response received an ELCC class value of .76 (76%). Next,
15 each specific resource is adjusted using a performance adjustment factor to account
16 for that individual resource's performance. Since the Company's resources have
17 performed, in general, equal to or above the class average in most cases, and since
18 the PJM ELCC class levels for Coal and Gas Combustion Turbine Dual Fuel units
19 are relatively high, the Company's capacity position was either unchanged or
20 became slightly longer under the ELCC methodology. In addition to a generally
21 lower capacity value, the amount of load obligation is reduced as well. Thus, under
22 ELCC, both the amount of resource capacity decreased as well as the amount of
23 demand.

1 **Q. DID THE PJM CHANGE TO ELCC IMPACT THE DECISION TO MOVE**
2 **TO RPM?**

3 A. On average, the ELCC change did not materially impact the Company's net
4 position, or the difference between its resources and load. There was little net
5 change due to both values decreasing. In general, the Company remains in a slightly
6 long position as has been the case since joining PJM in 2012. However, the change
7 to ELCC reduced other entities capacity values for its generators by an amount
8 more than the load decreased. Thus, it is believed that overall capacity market
9 clearing prices will be higher as a result, as was evidenced by the 2025/2026 BRA
10 clearing price for the Rest of RTO of \$269.92/MW-Day. Since the value to Duke
11 Energy Kentucky being in the RPM capacity construct generally increases as
12 capacity prices increase (think the upper right and lower right corners of the Heat
13 Map), the change to ELCC is an added reason to transition to RPM.

14 **Q. PLEASE EXPLAIN HOW THE RECENT 2025/2026 PJM BRA CLEARING**
15 **PRICE OF \$269.92/MW-DAY IMPACTS THE COMPANY'S DECISION.**

16 A. Recently, on July 30, 2024, PJM released the results of the 2025/2026 BRA with
17 the auction price for the "Rest of RTO" being \$269.92/MW-Day. Since the DEOK
18 Zone did not split out, the capacity price was the same price for the DEOK Zone.
19 Although other PJM Zones have at times cleared at a higher capacity clearing price,
20 the 2025/2026 clearing price represents the highest cost ever cleared for the DEOK
21 Zone. These auction results further solidify the Company's position that PJM
22 capacity prices are headed higher and that a move to RPM is in the best interest of
23 DEK customers.

1 **Q. WHAT WOULD HAVE BEEN THE APPROXIMATE FINANCIAL**
2 **IMPACT HAD THE COMPANY BEEN IN THE RPM FOR THE 2025/2026**
3 **AUCTION?**

4 A. Although the complete financial results cannot be calculated until after the 3rd
5 incremental auction results are known, by looking at the heat map in Table 1, an
6 approximate value amount can be calculated. If looking at the +5% row and
7 interpolating between the \$250/MW-Day and \$300/MW-Day columns, an
8 approximate savings to the customer of \$1M for the year would have been realized
9 from full participation in the 2025/2026 RPM as opposed to the FRR.

10 **Q. PLEASE EXPLAIN HOW A POTENTIAL CHANGE TO A SEASONAL**
11 **AUCTION STRUCTURE BY PJM COULD IMPACT THE COMPANY'S**
12 **PARTICIPATION IN PJM.**

13 A. There are no immediate plans for PJM to transition to a seasonal auction, but
14 potential for this change does exist in the 2029/2030 timeframe. While currently
15 the rules around any possible new seasonal auction construct have not been fully
16 developed yet, previous discussion has indicated a Winter/Summer auction format.
17 Regarding the possibility of a Winter auction, Duke Energy Kentucky has an
18 advantage since the Woodsdale combustion turbine site is already dual fuel capable.
19 Due to this dual fuel capability, the Company anticipates either a neutral or slightly
20 positive impact if PJM were to transition to a seasonal auction format and Duke
21 Energy Kentucky were an RPM capacity construct member.

1 **Q. IS THE COMPANY AWARE OF NEW ADDITIONAL CUSTOMER LOAD**
2 **BEING LOCATED IN THE DUKE ENERGY KENTUCKY SERVICE**
3 **TERRITORY THAT WOULD INCREASE THE NEED FOR THIS**
4 **TRANSITION?**

5 A. Although the Company routinely engages in economic development conversations
6 with potential new customer load, no recent significant additions have been
7 announced for the Company's service territory. However, with the general
8 increased trend of large-scale, energy intensive customers like data centers
9 interested in locating in lower cost electricity priced jurisdictions like Kentucky,
10 the flexibility to quickly serve provided by an RPM transition provides greater
11 benefit for all customers. Moving to RPM eliminates the potential of an FRR
12 deficiency penalty and saves the existing customers money as shown in the
13 analysis.

V. PJM SETTLEMENTS

14 **Q. WHAT ADDITIONAL PJM CREDITS AND CHARGES WILL BE**
15 **RECEIVED FROM PJM IN THE EVENT THAT DUKE ENERGY**
16 **KENTUCKY TRANSITIONS TO THE RPM CAPACITY CONSTRUCT?**

17 A. By moving to RPM, Duke Energy Kentucky will continue receiving PJM Billing
18 Line Items (BLI) 1600 and 2600 and will begin receiving additional PJM
19 settlements charges and credits related to the capacity auction participation,
20 specifically PJM BLI 1610, 1650, 1660, 1661, 1662, 1663, 1664, 1665, 1666, and
21 PJM BLI 2605, 2620, 2625, 2630, 2640, 2650, 2660, 2661, 2662, 2663, 2664,
22 2665, and 2666. Note that historically the Company has received PJM BLI 2600

1 related to excess capacity sales, or the capacity sold into the PJM auctions after the
2 Company's FRR plan and 3% holdback (in the case of the BRA and first and second
3 incremental auctions) are satisfied. However, the amounts that the Company would
4 receive in the future under PJM BLI 2600 would be much greater since all
5 generation is offered and likely sold into the PJM auction, not just the small amount
6 of excess as is the case today. Conversely, charges the Company would receive in
7 PJM BLI ~~1610+600~~ would be much greater, since all customer load obligation
8 would be purchased in the PJM auction. Please refer to Attachment JDS-2 for a
9 detailed listing of PJM BLI's.

10 **Q. PLEASE EXPLAIN PJM BLI'S 1600, 1610, 1650, 1660, 1661, 1662, 1663,**
11 **1664, 1665, 1666, AND PJM BLI'S 2600, 2605, 2620, 2625, 2630, 2640, 2650,**
12 **2660, 2661, 2662, 2663, 2664, 2665, AND 2666?**

13 A. 1600 – RPM Auction

14 Each bid cleared in an incremental auction pays the applicable LDA's
15 resource clearing price. Resource make-whole payments for an incremental auction
16 are also allocated as charges to Market Buyers based on the MW shares of cleared
17 buy bids adjusted by cleared buy bid transactions for the incremental auction.
18 Resource make-whole payments for the BRA and the portion of the resource make-
19 whole payment for an incremental auction that would be based on PJM cleared buy
20 bids are allocated as charges to LSEs in the applicable LDA via the Final Zonal
21 Capacity Price.

1 1610 - Locational Reliability

2 Each LSE is charged for their daily unforced capacity obligation priced at
3 the applicable zonal capacity price for the delivery year.

4 1650 - Auction Specific MW Capacity Transaction

5 Bilateral capacity transactions for multi-day durations are settled in the
6 PJM capacity markets. Sellers are charged for the transaction MW times the
7 transaction's pricing point for each day for which the transaction is in effect.

8 1660 – Demand Resource Interruptible Load for Reliability (ILR) Compliance

9 Penalty

10 Sellers with zonal aggregate committed Demand Resources or nominated
11 ILR that cannot demonstrate hourly real-time performance pay a penalty charge
12 which is allocated to Demand Resource and ILR providers and, potentially, LSEs.
13 This billing is performed on a three-month lag. For each non-compliant reduction
14 event, under-compliance MW (on an unforced capacity basis) are charged at the
15 lesser of one divided by the actual number of events during the year or 0.50 of the
16 Weighted Annual Revenue Rate. The Weighted Annual Revenue Rate equals the
17 average rate for all cleared Demand Resources, weighted by the MWs cleared at
18 each price, multiplied by the number of days in the delivery year. The total
19 Compliance Penalty Charge for the delivery year is capped at the annual revenue
20 received for such resources.

21 1661 - Capacity Resource Deficiency

22 Capacity resources that are unable or unavailable to deliver unforced
23 capacity, and do not obtain replacement unforced capacity to satisfy their cleared

1 sell offer pay this charge which is allocated to eligible LSEs. Each capacity
2 resource's deficiency MW for each day it is deficient pays the daily deficiency rate.

3 1662 - Generation Resource Rating Test Failure

4 Generation capacity resources that fail a capacity test pay this charge which
5 is allocated to eligible LSEs. This billing is performed in the June billing cycle after
6 the conclusion of the delivery year. Each capacity resource's installed capacity
7 minus its highest rating in the relevant testing period (on an unforced capacity basis)
8 pays a daily deficiency rate which is the weighted average capacity resource
9 clearing price plus the higher of: 1) 0.2 times the weighted average capacity
10 resource clearing price or 2) \$20/MW-day.

11 1663 - Qualifying Transmission Upgrade Compliance Penalty

12 Cleared qualifying transmission upgrades delayed in coming into service
13 for the applicable delivery year pay a daily penalty charge which is allocated to
14 eligible LSEs. Capacity market sellers with import capability cleared in a base
15 residual auction based on a qualifying transmission upgrade are charged each day
16 that the upgrade is not in service during the applicable delivery year and the seller
17 does not obtain replacement capacity resources. The import capability MW are
18 charged at the higher of the following rates: 1) two times the locational price adder
19 of the applicable LDA; or 2) the Net CONE less the clearing price in the applicable
20 LDA.

21 1664 – Peak Season Maintenance Compliance Penalty

22 Each generation capacity resource must have available unforced capacity
23 during the peak season to satisfy its cleared MW. This billing is performed in the

1 June billing cycle after the conclusion of the delivery year, and only applies to the
2 month of June. Each generation capacity resource's cleared MW for each day of
3 the peak season that is out-of-service on a maintenance outage not authorized by
4 PJM pays the daily deficiency rate times (1-EFORd).

5 1665 – Peak-Hour Period Availability

6 To ensure capacity resource availability during critical peak hours,
7 incentives are provided to resources that exceed expected availability and penalties
8 are assessed to those who fall short. This billing is performed in the August billing
9 cycle after the conclusion of the delivery year, and only applies to the month of
10 August. Net peak period capacity shortfall MW are charged at the weighted average
11 resource clearing price for the applicable LDA (except for FRR capacity that are
12 charged at the LDA's Net CONE).

13 1666 - Load Management Test Failure

14 Sellers with committed Demand Resources that fail performance tests pay
15 a penalty charge which is allocated to eligible LSEs. This billing is performed in
16 the August monthly bill issued in September after the conclusion of the delivery
17 year. Net capability testing shortfall MW are charged daily at the weighted annual
18 revenue rate for the applicable zone plus the greater of 0.2 times that weighted
19 annual revenue rate or \$20/MW-day.

20 2600 - RPM Auction

21 Each sell offer for generation, demand, or qualified transmission upgrade
22 resource MW cleared in an RPM Auction is paid the applicable resource's clearing
23 price in the applicable auction. Resource make-whole payments are also provided

1 to sell offers that clear less than the minimum amount specified. Sell offers are
2 adjusted by approved unit-specific transactions for cleared capacity.

3 2605 - RPM Seasonal Capacity Performance Auction

4 Each sell offer for generation, demand, or qualified transmission upgrade
5 resource MW cleared in an RPM Auction is paid the applicable resource's clearing
6 price in the applicable auction. Resource make-whole payments are also provided
7 to sell offers that clear less than the minimum amount specified. Sell offers are
8 adjusted by approved unit-specific transactions for cleared capacity.

9 2620 – Interruptible Load for Reliability

10 Each ILR resource is credited for their certified zonal MW priced at the
11 applicable zonal ILR price.

12 2625 - LSE Price Responsive Demand

13 An annual capacity resource provided by a PRD Provider that represents
14 customers that will reduce load based on price.

15 2630 - Capacity Transfer Rights

16 To recognize the value of import capability to constrained LDAs, Capacity
17 Transfer Rights (CTRs) are allocated to LSEs in those LDAs to offset their higher
18 load charges. CTRs equal to the unforced capacity imported into the LDA (less any
19 incremental CTRs) are allocated to LSEs in that LDA based on daily unforced
20 capacity obligations. These MW allocations are priced at the difference between
21 the LDA's clearing price and the unconstrained price.

1 2640 - Incremental Capacity Transfer Rights (CTRs)

2 Incremental CTRs are provided to fund for transmission upgrades (not
3 including qualifying transmission upgrades cleared in the BRA) that increase
4 import capability into a constrained LDA. Incremental CTRs for Incremental-
5 Rights Eligible Required Transmission Enhancements are determined and allocated
6 as defined in Schedule 12A of the Tariff. Incremental CTR MW are priced at the
7 sum of: 1) locational price adder of the sink LDA minus that of the Source LDA
8 from the BRA; and 2) locational price adder of the sink LDA minus that of the
9 source LDA from the Second Incremental Auction multiplied by the increase in
10 unforced capacity imported into the sink LDA in the Second Incremental Auction
11 compared to the Base Residual Auction, divided by the base unforced capacity
12 imported into the sink LDA. Incremental CTR credits determined for an
13 Incremental-Rights Eligible Required Transmission Enhancement are allocated to
14 the responsible customers that are assigned cost responsibility for the transmission
15 enhancements in accordance with the cost allocations in the appendix to Schedule
16 12. Responsible customers include Network Customers, Transmission Customers
17 with an agreement for Firm Point-to-Point Service, or Merchant Transmission
18 Facility Owners. Network Customers serving load in a responsible zone receive
19 credits in proportion to their network service peak load share in that zone.

20 2650 - Auction Specific MW Capacity Transaction

21 Bilateral capacity transactions for multi-day durations are settled in the PJM
22 capacity markets. Buyers are credited for the transaction MW times the
23 transaction's pricing point for each day for which the transaction is in effect.

1 2660 – Demand Resource and ILR Compliance Penalty

2 Sellers with zonal aggregate committed Demand Resources or nominated
3 ILR that cannot demonstrate hourly real-time performance pay a penalty charge
4 which is allocated to Demand Resource and ILR providers and, potentially, LSEs.
5 This billing is performed on a three-month lag. Revenues from events in each
6 month are allocated to Demand Resources that reduced in excess of their
7 commitment. Any resource credit by event is capped at their excess MW times
8 1/5th of their Annual Revenue Rate. Revenues above that cap are allocated to LSEs
9 based on their average daily unforced capacity obligations during the month of the
10 event.

11 2661 - Capacity Resource Deficiency

12 Capacity resources that are unable or unavailable to deliver unforced
13 capacity, and do not obtain replacement unforced capacity to satisfy their cleared
14 sell offer pay this charge which is allocated to eligible LSEs. Total revenues each
15 day are allocated to LSEs that paid a Locational Reliability charge that day based
16 on their daily unforced capacity obligations.

17 2662 - Generation Resource Rating Test Failure

18 Generation capacity resources that fail a capacity test pay this charge which
19 is allocated to eligible LSEs. This billing is performed in the June billing cycle after
20 the conclusion of the delivery year, and only applies to the month of June. Total
21 revenues each day are allocated to LSEs that paid a Locational Reliability charge
22 that day based on their daily unforced capacity obligations.

1 2663 - Qualifying Transmission Upgrade Compliance Penalty

2 Cleared qualifying transmission upgrades delayed in coming into service
3 for the applicable delivery year pay a daily penalty charge which is allocated to
4 eligible LSEs. Total revenues each day are allocated to LSEs that paid a
5 Locational Reliability charge that day based on their daily unforced capacity
6 obligations.

7 2664 – Peak Season Maintenance Compliance Penalty

8 Each generation capacity resource must have available unforced capacity
9 during the peak season to satisfy its cleared MW. This billing is performed in the
10 June billing cycle after the conclusion of the delivery year, and only applies to the
11 month of June. Total revenues each day are allocated to LSEs that paid a Locational
12 Reliability charge that day based on their daily unforced capacity obligations.

13 2665 – Peak-Hour Period Availability

14 To ensure capacity resource availability during critical peak hours,
15 incentives are provided to resources that exceed expected availability and penalties
16 are assessed to those who fall short. This billing is performed in the August billing
17 cycle after the conclusion of the delivery year, and only applies to the month of
18 August. Total revenues for the delivery year for each LDA are allocated to
19 resources with peak period excesses based on their excess MW. Since these
20 allocations are capped, any remaining credits are allocated to LSEs that paid a
21 Locational Reliability charge based on their daily unforced capacity obligations.

1 2666 - Load Management Test Failure

2 Sellers with committed Demand Resources that fail performance tests pay
3 a penalty charge which is allocated to eligible LSEs. This billing is performed in
4 the August monthly bill issued in September after the conclusion of the delivery
5 year. Total revenues each day are allocated to LSEs that paid a Locational
6 Reliability charge that day based on their daily unforced capacity obligations.

7 **Q. PLEASE EXPLAIN HOW DUKE ENERGY KENTUCKY PROPOSES TO**
8 **RECOVER THE COSTS AND TO PROVIDE CUSTOMERS WITH THE**
9 **VALUE OF THE BENEFITS OF RPM PARTICIPATION.**

10 **A.** As further explained by Company Witness Ms. Lisa Steinkuhl, the Company is
11 proposing to modify its Rider PSM to recover the BLIs I previously described so
12 to net the entirety of RPM capacity market participation. Presently, Rider PSM
13 allows the Company to share the benefits/costs of any net sales (costs and credits)
14 related to the Company's generating units including off-system energy, ASM
15 sales/costs, capacity purchases/sales, and net proceeds from the sale of renewable
16 energy credits with the customer through a 90/10 sharing mechanism where
17 customers receive 90 percent of the net benefits/costs. As Ms. Steinkuhl explains,
18 the Company is proposing to modify that sharing with respect to capacity
19 participation only such that customer will receive 100 percent of any net benefit or
20 net cost of RPM participation. This would include all net capacity sales and
21 capacity purchases from PJM and bilateral markets to meet PJM FERC-approved
22 reliability requirements. As capacity prices move higher, with the Company's net
23 long capacity position, and the ability to monetize that capacity in RPM auctions,

1 customers should receive a net benefit of RPM participation. The remaining items
2 included in Rider PSM will continue to be shared with customers based on a 90/10
3 sharing mechanism where customers receive 90 percent of the net benefits/costs as
4 is currently the practice.

5 **Q. WHY IS IT REASONABLE TO CHANGE THE RIDER PSM SHARING**
6 **FOR CAPACITY RELATED TRANSACTIONS TO A 100 PERCENT**
7 **CUSTOMER-FOCUSED ALLOCATION?**

8 A. The size of the Company's generation portfolio and the capacity necessary to
9 reliably serve is determined by customer demand. Customers pay for these assets,
10 whether "steel in the ground" generators owned and operated by the Company or
11 through long-term bilateral purchases. Because moving to RPM provides a new
12 opportunity to fully monetize the existing length of Company's existing portfolio
13 (and future generating assets) as compared to current demand, assuming these
14 assets will clear the auctions, the Company believes net credits will accrue to
15 customers. Because customers are paying for these assets in base rates, the assets
16 are serving customers, the Company believes that all the costs and benefits of
17 satisfying that demand should be borne by customers.

18 The Company also believes that it continues to make sense for the Company
19 to share in the energy market risks and revenues, which are more volatile, and the
20 Company has managerial responsibility in terms of the daily dispatch and
21 operation. This small amount of profit sharing, while the vast majority accrues to
22 customers, does maintain some "skin in the game" for the Company to attempt to

1 maximize their value and keep managing these assets in an efficient, reasonable,
2 and beneficial manner.

3 **Q. IS THE COMPANY REQUESTING CHANGES TO PJM BLIs RELATED**
4 **TO PJM CAPACITY PERFORMANCE?**

5 A. No. It is possible today for the Company to receive PJM BLI 1667 (Capacity
6 Performance Non-Performance charge) and PJM BLI 2667 (Capacity Performance
7 Bonus Performances payment) from PJM. The Commission previously approved a
8 modification to the Rider PSM in Case No. 2017-00321 to allow the company to
9 include both capacity performance charges and bonus payments as part of that
10 sharing mechanism with a 90/10 sharing mechanism where customers receive 90
11 percent of the net benefits/costs related to capacity performance.²⁷ The Company is
12 not requesting any change in the treatment of the PJM BLIs related to PJM Capacity
13 Performance.

VI. TIMING

14 **Q. PLEASE EXPLAIN THE CURRENT PJM COMPRESSED CAPACITY**
15 **MARKETS SCHEDULE.**

16 A. PJM is currently under a compressed schedule, with the 2025/2026 auction recently
17 completed in late July 2024. The 2026/2027 auction is scheduled to occur in
18 December 2024, the 2027/2028 auction in June 2025, the 2028/2029 auction in
19 December 2025, and finally the 2029/2030 auction is scheduled for May 2026,
20 putting PJM back on the regular tariff schedule.

²⁷ *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, (Ky.P.S.C. Order) (April 13, 2018).

1 **Q. HOW MUCH TIME IS TYPICALLY NEEDED FOR A CHANGE TO THE**
2 **FRR CAPACITY CONSTRUCT?**

3 A. Since PJM capacity auctions are normally on a 3-year forward basis, when PJM is
4 on their normal schedule, a move from FRR to RPM would occur at least 3 years
5 before the delivery year. Additionally, since notification to PJM of a change in
6 Duke Energy Kentucky's capacity construct status is required to occur
7 approximately 60 days prior to the PJM BRA, this further increases the time frame
8 required by this amount. Finally, since commission approval is required for such a
9 move, the time for the regulatory process to occur would need to be added to this
10 schedule. Thus, the total time needed to transition from FRR to RPM, as measured
11 from the time that an application is initially submitted to the commission until the
12 start of the PJM Delivery Year, is approximately 4 ½ years, depending on when the
13 filing is made in relationship to the position within the PJM Delivery Year.
14 However, because of PJM's compressed schedule, a unique opportunity exists for
15 Duke Energy Kentucky to make this move now, faster than it otherwise could, to
16 reduce the time needed by approximately 18 months.

17 **Q. WHY IS THE COMPANY REQUESTING TO MAKE THE MOVE TO RPM**
18 **NOW AND REQUESTING AN ORDER BY APRIL 1, 2025?**

19 A. By making this change now during the time PJM is on a compressed auction
20 schedule, if the Company receives an order by April 1, 2025, or earlier, it would be
21 possible to notify PJM with the 60-day requirement met for the 2027/2028 BRA.
22 Thus, Duke Energy Kentucky could transition to RPM by June 1, 2027, eighteen
23 months earlier than it otherwise could.

VII. CONCLUSION

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

3 A. Since first entering PJM, the FRR arrangement was the logical decision and has
4 benefited customers. However, with the potential for customer load growth,
5 especially those loads that can be added quicker than generation supply, PJM
6 capacity market structural changes, projected increases in PJM market clearing
7 prices, and changes to the PJM supply/demand balance, the Company has
8 determined through analysis that a move to a full RPM auction participant is now
9 in the customer's best interest.

10 **Q. WERE ATTACHMENTS JDS-1 AND JDS-2 PREPARED BY YOU AND**
11 **UNDER YOUR DIRECTION AND CONTROL?**

12 A. Yes.

13 **Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

14 A. Yes.