**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

In the Matter of:

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|---|---|---|
| Electronic Investigation of the | ) | |
| Service, Rates and Facilities of | ) | Case No. 2021-00370 |
| Kentucky Power Company | ) | |

**DIRECT TESTIMONY OF**

**ALEX E. VAUGHAN**

**ON BEHALF OF KENTUCKY POWER COMPANY**

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**CASE NO. 2021-00370**

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## I. INTRODUCTION

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

A. My name is Alex E. Vaughan. I am employed by American Electric Service Corporation ("AEPSC") as Managing Director - Renewables & Fuel Strategy. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"), the parent Company of Kentucky Power Company (the "Company" or "Kentucky Power").

## II. BACKGROUND

**Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCES.**

A. I graduated from Bowling Green State University with a Bachelor of Science degree in Finance in 2005. Prior to joining AEPSC, I worked for a retail bank and a holding company where I held various underwriting, finance, and accounting positions. In 2007, I joined AEPSC as a Settlement Analyst in the Regional Transmission Organization ("RTO") Settlements Group. I later became the PJM Settlements Lead Analyst, and in that role, I was responsible for reconciling AEP's settlement of its activities in the PJM Interconnection, LLC ("PJM") market with the monthly PJM invoices and for resolving issues with PJM. In 2010, I transferred to Regulatory

Services as a Regulatory Analyst and was later promoted to the position of Regulatory Consultant. My responsibilities included supporting regulatory filings across AEP's eleven state jurisdictions and at the FERC. I also performed financial analyses related to AEP's generation resources and loads, power pools, and PJM. In September 2012, I was promoted to Manager, Regulatory Pricing and Analysis, where I was responsible for cost of service, rate design, and special contract analysis for the AEP east operating companies. In September 2018, I was promoted to Director of Regulated Renewables and Pricing, at which time oversight of regulated renewable and fuel filings across the AEP operating companies was added to my responsibilities. I was promoted to my current position in June 2022.

**Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.**

A. I am responsible for assisting Kentucky Power and the other AEP electric utility operating companies in the preparation of their regulatory filings before this and other commissions under whose jurisdiction the companies provide electric service. My responsibilities include the oversight of cost of service analyses, rate design, special contracts, energy supply costs, and renewables for the AEP System operating companies.

**Q. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?**

A. Yes. I have presented testimony on behalf of the AEP operating companies numerous times before the regulatory bodies in Virginia, West Virginia, Kentucky, Tennessee, Indiana, Michigan, and Oklahoma. In Kentucky, I have testified before the Public Service Commission of Kentucky (the "Commission") in several cases, most notably in Kentucky Power's past five base rate case proceedings (Case Nos. 2013-00197, 2014-00396, 2017-00179, 2020-00174, and 2023-00159), and the proposed transfer of ownership of Kentucky Power in Case No. 2021-00481.

## III. PURPOSE AND SUMMARY OF TESTIMONY

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is threefold:

- To provide a history of the Company's capacity and energy planning and supply within a power pool model;
- To describe the Company's planning and resource procurement for the 2022/2023 and 2023/2024 delivery years, as well as the cost-of-service savings customers have realized from the procurement; and
- To discuss the results of the Company's resource procurement decisions during Winter Storm Elliott specifically and how the Company's actions during that event were good for customers.

**Q. PLEASE SUMMARIZE THE SECTIONS OF YOUR TESTIMONY AND THE CONCLUSIONS THAT SHOULD BE DRAWN FROM THEM.**

A. Section IV describes the Company's history of energy supply resources and participation within power pools from 1951 through current day. Kentucky Power's power pool participation strategy has provided the Company and its customers with economic benefits as well as adequate, reliable service for over 70 years. Those economic and reliability benefits exist and continue today.

Section V focuses on resource procurement for the 2022/2023 delivery year and demonstrates that the Company's prudent supply decisions have resulted in meaningful cost reductions for the Company and its customers.

Section VI details the performance of the Company's resource procurement strategy during Winter Storm Elliott. During that historic cold weather event, Kentucky Power continued to provide reliable service to its customers. Other load serving entities in the Commonwealth were unable to procure power, which resulted in those utilities shedding load.

## IV. KENTUCKY POWER HISTORIC RESOURCE POSITION AND POWER POOL MEMBERSHIP

**Q. PLEASE DESCRIBE THE COMPANY'S GENERATION SUPPLY RESOURCES AND HOW IT FULFILLED ITS ENERGY AND CAPACITY NEEDS PRIOR TO JOINING THE PJM RTO.**

A. Prior to joining the PJM RTO in late 2004, the Company relied on its generation supply resources and the AEP East Pool ("the Pool") to supply all of the Company's capacity and energy requirements. The Pool capacity and energy transactions were governed by the FERC-approved AEP Interconnection Agreement (the "Interconnection Agreement"). The Company and its affiliates Appalachian Power Company ("APCO"), Columbus Southern Power Company ("CSP"), Indiana Michigan Power Company ("I&M"), and Ohio Power Company ("Ohio Power") made up the Pool's membership.[1] The Company became a member of the Pool in 1963,[2] with the completion of Unit 1 of the Big Sandy generating plant.

[1] Kingsport Power Company ("Kingsport") and Wheeling Power Company ("Wheeling") are also AEP East affiliated operating companies but were not Pool members because they did not own generation during the time in which the Pool operated. Kingsport and Wheeling purchased their power requirements from APCO and Ohio Power, respectively.

[2] Prior to 1963, the Company purchased all of its energy and capacity from affiliates in the Pool.

Since the Pool's formation in 1951, the generating facilities of the Pool members have been planned, designed, built (or purchased), and operated on an integrated system basis to meet the needs of all of the AEP East operating companies even though each operating company owned or contracted for specific generation facilities. During the time period prior to the AEP East operating companies joining the PJM RTO, the AEP East Zone was its own balancing authority, and the AEP East operating companies were responsible for ensuring resource adequacy across the balancing authority footprint. The Interconnection Agreement defined the rights and obligations of the five Pool members and set out the methodology for allocating the capacity and energy cost responsibilities among the member companies.

**Q. HOW WERE A MEMBER'S CAPACITY OBLIGATION AND FINANCIAL SETTLEMENT OF THE OBLIGATION DETERMINED UNDER THE INTERCONNECTION AGREEMENT?**

A. Through the Interconnection Agreement, Pool members shared capacity costs and responsibilities based upon each member's Member Load Ratio ("MLR"). MLRs were calculated monthly on the basis of each member's non-coincident peak demand in relation to the sum of the non-coincident peaks of all five member companies during the preceding twelve months. Each Pool member's generating capacity obligation was determined by multiplying the member's MLR times the total installed capacity of the Pool. The financial settlement of the Pool capacity position was done monthly per the capacity equalization section of the Interconnection Agreement. The amount of purchases/sales for each member company was based on the relative deficits/surpluses and the installed generation costs of the surplus members and a FERC approved carrying charge. The total capacity surplus for surplus members in any given month was always equal to the total capacity deficit for the deficit members, producing a zero surplus/deficit position for the Pool.

**Q. PLEASE DESCRIBE HOW THE ENERGY SETTLEMENT OCCURRED UNDER THE INTERCONNECTION AGREEMENT.**

A. The member companies' generation resources were dispatched on an economic basis to meet the total native load requirements of the member companies and any other firm load obligations they may have had. The energy settlement was computed on an hourly basis. Any member company whose generation resources did not produce enough energy to meet its hourly load based on economic dispatch of all generation resources of the AEP East operating companies (deficit energy position in that hour) purchased its needs at cost from any member companies that were in an energy surplus position in that hour.

**Q. HOW WERE RESOURCES ADDED TO THE POOL AND MEMBER COMPANIES?**

A. Through system wide resource planning, the AEP East Zone's projected capacity needs would be identified and compared with the current amount of owned and contracted-for generation capacity. When a system need was identified, the member company that was forecast to be the most deficit member would add generation capacity through building a new asset or contracting for an existing asset.

**Q. WHAT RESOURCES DID THE COMPANY HAVE DURING THIS PERIOD OF TIME?**

A. The Company's owned or contracted-for generating resources were Big Sandy Unit 1 (278 MW, placed in service 1963), Big Sandy Unit 2 (800 MW, placed in service 1969), Rockport Unit 1 (198 MW share, placed in service 1984), and Rockport Unit 2 (195 MW, place in service 1989) all of which were coal fired generating units. The balance of the Company's capacity and energy requirements were purchased from the Pool and the other member companies.

**Q. PLEASE FURTHER DESCRIBE KENTUCKY POWER'S INTEREST IN OUTPUT FROM ROCKPORT UNITS 1 AND 2.**

A. In August 1984, Kentucky Power and AEP Generating Company ("AEG") entered into a Unit Power Agreement (the "Rockport UPA") that entitled Kentucky Power to a portion of the capacity and energy from Rockport Units 1 and 2. The Rockport UPA became "effective with the date of commercial operation of Rockport Unit No. 1" and, after its term was extended in 2004, "continue[d] in effect through December 7, 2022."[3]

**Q. WAS THE COMPANY ALWAYS A NET PURCHASER OF CAPACITY AND ENERGY DURING THE PERIOD IT PARTICIPATED IN THE POWER POOL AGREEMENT?**

A. No. The Company's relative position in both capacity and energy evolved over time, as did its resources and loads and the resources and loads of the other member

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[3] Rockport UPA, Section 6. The Rockport UPA is attached as Exhibit BKW-1 to Company Witness West's Direct Testimony.

companies. Based on those factors the Company's position fluctuated over time between being a net seller and a net purchaser of energy and capacity.

**Q. DURING ITS TIME IN THE POOL, DID THE COMPANY ALWAYS HAVE ENOUGH OWNED OR CONTRACTED-FOR GENERATION TO COVER ITS PEAK LOAD REQUIREMENTS ABSENT THE RESOURCES OF THE OTHER POOL MEMBERS?**

A. No, the Company did not. It routinely purchased the balance of its energy and capacity requirements from the Pool. Figure AEV-1 below shows the Company's installed generating capacity and annual non-coincident peaks from 2000 – 2022. As described later in my testimony, the Pool continued after Kentucky Power and the other AEP East operating companies joined PJM in 2004 until it was terminated at the end of 2013. As shown in the figure below, Kentucky Power's installed capacity from 2000 – 2013 was less than its peak demand, and it relied on the Pool to make up the difference, excepting only the last two years of that period. I will refer to this figure later in my testimony as well when I discuss the period after the Company joined PJM and the Pool ended through the present.

**Figure AEV-1**

| Kentucky Power Company Capacity Position in MW | | | |
|---|---|---|---|
| Year | Peak Demand | Installed Capacity | Surplus/(Deficit) |
| 2000 | 1,558 | 1,471 | (87) |
| 2001 | 1,579 | 1,471 | (108) |
| 2002 | 1,551 | 1,471 | (80) |
| 2003 | 1,564 | 1,471 | (93) |
| 2004 | 1,615 | 1,471 | (144) |
| 2005 | 1,685 | 1,471 | (214) |
| 2006 | 1,636 | 1,471 | (165) |
| 2007 | 1,808 | 1,471 | (337) |
| 2008 | 1,678 | 1,471 | (207) |
| 2009 | 1,674 | 1,471 | (203) |
| 2010 | 1,543 | 1,471 | (72) |
| 2011 | 1,522 | 1,471 | (51) |
| 2012 | 1,378 | 1,471 | 93 |
| 2013 | 1,409 | 1,471 | 62 |
| 2014 | 1,645 | 2,251 | 606 |
| 2015 | 1,666 | 1,451 | (215) |
| 2016 | 1,342 | 1,468 | 126 |
| 2017 | 1,217 | 1,468 | 251 |
| 2018 | 1,446 | 1,468 | 22 |
| 2019 | 1,297 | 1,468 | 171 |
| 2020 | 1,166 | 1,468 | 302 |
| 2021 | 1,065 | 1,468 | 403 |
| Pre-Dec 8 2022 | 1,187 | 1,468 | 281 |
| Dec 8-31 2022 | 1,359 | 1,239 | (120) |

AEP East Pool "Interconnection Agreement" (2000–2013)

PJM RTO (2004–Dec 8-31 2022)

Power Coordination Agreement (2014–Dec 8-31 2022)

**Q. TO YOUR KNOWLEDGE, DURING THE TIME THE COMPANY RELIED ON THE AEP POOL TO MEET ITS REQUIREMENTS, DID THE COMMISSION EVER QUESTION WHETHER THE COMPANY FAILED TO RENDER ADEQUATE SERVICE IN COMPLIANCE WITH KRS 278.018(3)?**

A. No. To my knowledge, the Commission never suggested that the Company's use of the AEP East Pool to meet its load requirements violated KRS 278.018(3), even though the Company openly relied on the Pool at times to provide varying amounts of capacity and energy beyond what the Company could physically or economically provide for itself from its owned and contracted generation resources.

**Q. WAS RESOURCE ADEQUACY AN ISSUE EVEN THOUGH THE COMPANY UTILIZED A POWER POOL TO MEET ITS TOTAL LOAD REQUIREMENTS?**

A. No. The Company has no record of load shedding or service outages from lack of power supply going back to 2004. The Company also has no knowledge of such events prior to 2004, but its records do not go further into the past.

**Q. WHEN DID KENTUCKY POWER JOIN THE PJM RTO?**

A. The Company and its affiliate Pool member companies joined the PJM RTO on October 1, 2004.

**Q. DID THE COMPANY'S PHILOSOPHY AND OPERATIONS REGARDING ITS ENERGY AND CAPACITY SUPPLY CHANGE WHEN IT JOINED THE PJM RTO?**

A. No, the general philosophy of planning for and procuring least reasonable cost energy and capacity supply for the Pool member companies did not change. The Pool also continued its operations under the same FERC approved Interconnection Agreement, just now as part of the much larger PJM RTO power pool. However, joining that much larger power pool improved both reliability and cost.

Regarding reliability, the AEP East Zone was no longer its own balancing authority. Instead, the AEP East operating companies became part of the broader PJM balancing authority area, in which PJM assumes overall responsibility for ensuring resource adequacy for the entire footprint, including the former AEP power pool area, and the Company benefits from resources across that footprint.

Regarding cost, the Pool's generation resources continued to be dispatched economically, just now as part of the larger PJM RTO pool. By joining PJM, the member companies and their customers gained access to a much larger energy market with greater economic opportunities to potentially source energy at a lower cost than what the member companies could produce on their own, and a larger market in which to sell excess hourly generation. Simply put, if it were now more economic to purchase energy from the wholesale PJM energy markets than to generate that energy from the Pool's resources, the member companies did so, and customers benefited from that option in the form of lower fuel costs than could have been achieved solely from the Pool.

From a capacity perspective, the Pool member companies elected the fixed resource requirement ("FRR") option to contribute owned or contracted resources to meet PJM's capacity obligations, rather than paying PJM to procure resources through the PJM RPM auction. That remains true today for all AEP operating company PJM members except Ohio Power, which is no longer part of the FRR plan.

**Q. IS THE INTERCONNECTION AGREEMENT STILL IN EFFECT?**

A. No. On December 17, 2010, The Pool member companies provided mutual notice of termination to one another. The Interconnection Agreement and AEP East Pool terminated on December 31, 2013. Specific reasons for termination of the Pool included the following:

(1) In the years preceding Pool termination, PJM had proven capable of fulfilling the role of economically dispatching the generating units of the AEP East operating companies to satisfy the capacity and energy requirements of their loads, a role historically performed by the Agent under the Agreement. As such, the Agreement, at least in its current form, became superfluous.

(2) Ohio enacted legislation that required the eventual corporate separation of CSP's and Ohio Power's generation. The Pool made no distinction between the "deregulated" generation owned by the two Ohio companies and the generation of the other members whose generation is "regulated." The termination prepared for this eventual separation (which subsequently occurred in 2014).

(3) Changes in utility regulation and the energy markets occurred over the years that were neither anticipated nor contemplated by the Interconnection Agreement that limited the effectiveness of comprehensive, system-wide system planning and dispatch. This included emerging renewable portfolio standards or goals, which require the addition of new resources in a manner inconsistent with the original intent of the Interconnection Agreement, as well as the expansion of environmental regulation of electric generation in a manner that was not previously contemplated and which was likely to require more unit-specific rather than system-wide solutions.

(4) Pool termination promoted the long-term objective of affording each AEP East operating company more autonomy in its resource choices.

**Q. WHAT CHANGED WHEN THE AEP EAST POOL TERMINATED ON DECEMBER 31, 2013?**

A. Beginning January 1, 2014, the Company no longer had access to excess energy at cost from its affiliated operating companies in the PJM RTO. In the AEP East Pool, the Company's customers paid the lower of cost to generate from the Company's own resources or the market price for energy. The "market" is now just the larger PJM RTO wholesale energy market rather than having the Pool nested within it.

Unlike energy, for capacity purposes the Company, APCO, Wheeling, and I&M (collectively the "PCA companies") entered into a successor agreement to the Interconnection Agreement which remains in place today and is known as the Power Coordination Agreement ("PCA"). The PCA is a FERC approved agreement that facilitates the Company's and its affiliates' joint participation-in a single FRR plan for purposes of meeting their capacity obligations. Unlike the Interconnection Agreement, the PCA explicitly states that each operating company will be individually responsible for its own capacity planning. PJM determines the capacity obligation for the Company per its FERC approved tariff, which the Company then meets within the FRR plan. AEPSC then coordinates the collective participation of the Company with the other FRR operating companies within the framework of the PCA.[4]

In summary, the result of the termination of the AEP East Pool is that the cost the Company incurs to satisfy the energy requirements of its retail and wholesale customers arises from the economic dispatch of its owned resources and the generation

[4] PCA, Article 7.1.

available to it through its membership in the PJM RTO. The PJM RTO is the successor balancing authority to which the Company belongs. Additionally, the Company meets its RTO capacity obligations with its owned and contracted-for resources in the joint FRR plan with the other PCA companies.

**Q. DOES THE COMPANY MEET ITS CAPACITY OBLIGATIONS AND RESERVE MARGIN REQUIREMENTS IN PJM?**

A. Yes it does. The Company plans for and meets its generation capacity obligations in PJM, which is the balancing authority to which the Company belongs. The current capacity obligation is determined using a summer five coincident peak demand ("5CP") measurement. That is because the PJM region is summer-peaking. The Company's customers have benefited from this market design because the Company's winter peak is higher than its summer peak. The Company's capacity contribution to the PJM pool is based on its own summer peak; and by procuring adequate resources to satisfy the pool-wide summer peak, PJM necessarily procures adequate resources to satisfy the winter peak of any LSE within the PJM footprint, including the Company's.

**Q. DO THE COMPANY'S OWNED AND CONTRACTED RESOURCES DIRECTLY SERVE THE ENERGY REQUIREMENTS OF ITS RETAIL AND WHOLESALE CUSTOMERS?**

A. No, and although that answer may seem surprising, it arises from the way in which load is served and generation is dispatched under PJM's market system. Through the FRR plan, the Company and other FRR entities contract with generators to participate as PJM Capacity Resources, requiring those generators to make their units available to

PJM every day of the delivery year per PJM's FERC approved tariff.[5] Therefore, the potential energy output of each underlying generator is *available* to the PJM pool and ultimately the Company. However, PJM decides to dispatch generators based on economic merit order across the entire RTO power pool, with the lowest priced generation being dispatched before the higher priced generation.

The PJM market establishes a locational marginal price ("LMP") at each generation node and generators operate and are compensated based on that price signal such that there is energy at every moment to satisfy all of the energy needs across PJM. Loads then pay for the cost of energy that they consume at the LMPs established by PJM for the locations that they receive energy. However, these processes are basically independent of each other. The revenues collected by the Company from PJM from dispatching its generation resources into the market essentially offset both the expenses its load incurs by consuming energy from the PJM market and the Company's internal costs to generate energy. The utility's generation is not physically mapped to its load. This was true when the Company joined PJM and remains true today. If the Company adds generation, it essentially acts as a further hedge against the market and not as a direct source of energy for load.

**Q. WHAT IS THE DIFFERENCE BETWEEN A CAPACITY-ONLY CONTRACT AND A CONTRACT FOR CAPACITY AND ENERGY?**

A. The difference between these two types of contracts is solely economic: when the Company purchases capacity only, it pays the market price for energy during times the

[5] PJM Tariff Attachment K-Appendix §1.10.1A(d); PJM Manual 11 § 2.3.3.1.

resource was dispatched, rather than a contract price for the resource's output. Said another way, the consequence of a capacity-only contract is that the Company cannot use the resource as a hedge against energy market prices—but the Company also avoids the cost of paying for such a hedge.

**Q. HAS THE COMPANY'S ENERGY SUPPLY BECOME LESS RELIABLE AS RESULT OF ITS PURCHASE OF A CAPACITY-ONLY PRODUCT AS COMPARED TO A PRODUCT WITH BOTH CAPACITY AND ENERGY?**

A. No. There is no measurable reduction in the adequacy of the resources that the Company can access to serve its customers by contracting for a capacity product as opposed to a combined capacity and energy product. For example, with respect to the Rockport UPA, the resources that existed in PJM to supply energy to end-use customers in the Company's service territory and throughout PJM are unchanged before and after the date the Rockport UPA expired in December 2022. The Company contracted for the capacity necessary for it to continue to participate in PJM's robust resource adequacy construct, which leveraged a system of 181,000 MW in 2022 to serve the needs of the entire balancing authority area, including the roughly 1,360 MW peak demand of the Company in December 2022. Again, the only result of moving to a capacity-only contract rather than a contract for capacity and energy is economic—the Company chose not to enter a hedge against energy market prices.

**Q. HAS THERE BEEN ANY MATERIAL CHANGE TO THE METHOD IN WHICH THE COMPANY SOURCES THE CAPACITY AND ENERGY IT USES TO PROVIDE SAFE AND RELIABLE ELECTRIC SERVICE TO ITS CUSTOMERS SINCE ROCKPORT UPA EXPIRED ON DECEMBER 8, 2022?**

A. No there has not. For six decades now, the Company has directly owned or contracted for unit specific generation that it economically dispatches as part of a power pool, and it meets its needs by relying on the pool. To be clear, the Company and its affiliates in the collective FRR plan meet 100% of their RTO capacity obligation with unit specific resources—but those resources are provided to PJM as a contribution to pool-wide resource adequacy. Those resources do not directly serve the Company. This strategy makes a lot of practical and economic sense for an electric utility the size of the Company. Larger power pool membership allows the Company access to generation resource fuel diversity, and electric supply reliability it could not economically provide on its own. This advantage of scale and diversity proved its value during Winter Storm Elliott in December 2022 when smaller balancing authorities in the Commonwealth of Kentucky experienced load shedding (black outs) because of insufficient power supply but the Company and the other PJM RTO utilities in the Commonwealth did not.

## V. PLANNING AND RESOURCE PROCUREMENT FOR THE 2022-2023 DELIVERY YEAR

**Q. DID KENTUCKY POWER'S CAPACITY PORTFOLIO CHANGE DURING THE 2022/2023 DELIVERY YEAR?**

A. Yes. The Rockport UPA expired in accordance with its terms on December 8, 2022. Kentucky Power purchased 152.4 MW of short-term capacity to meet its PJM obligations between December 8, 2022 and May 31, 2023, the end of the 22/23 PJM capacity delivery year.

**Q. PLEASE DESCRIBE THE STEPS THAT LED TO THE EXPIRATION OF THE ROCKPORT UPA.**

A. Beginning in the Company's 2017 base rate case,[6] KIUC raised the issue of ratemaking and the potential cost-of-service reduction the Company would realize when the Rockport UPA expired in December 2022. In that proceeding, KIUC witness Lane Kollen initially proposed[7] a deferral of $20.3 million annually related to purchased power expense from the Rockport UPA with a ten-year amortization and recovery period beginning in 2022 when the UPA ended. That case was subsequently settled. The Commission-approved settlement agreement included the concept of deferring $50 million[8] of Rockport UPA expense in a regulatory asset to be amortized and recovered over five years beginning on December 9, 2022. Among many other items, the settlement agreement also included the following language "The Signatory Parties acknowledge that the Company's decision whether to seek Commission approval to extend the Rockport UPA will be made at a later date." While not yet knowing the ultimate disposition of the Rockport UPA post December 7, 2022, the parties and the Commission recognized the likely cost savings that would be realized by the Company and brought some of that forward to benefit customers in the five years leading up to the UPA's expiration.

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[6] Case No. 2017-00179.

[7] Case No. 2017-00179, Direct Testimony of Lane Kollen (Oct. 3, 2017).

[8] $15 million in 2018 and 2019, $10 million in 2020, and $5 million in 2021 and 2022.

**Q. PLEASE DISCUSS HOW THE EXPIRATION OF THE LEASE ARRANGEMENTS FOR ROCKPORT UNIT 2 IMPACTED ITS AVAILABILITY AFTER THE UPA EXPIRED IN DECEMBER 2022.**

A. Rockport Unit 2 was owned by a group of non-affiliate financial companies with a lease back to I&M and AEG through December 2022. The Company's UPA was with AEG, but any capacity not sold by AEG to third parties became I&M's responsibility under the terms of their joint agreements. Until April 2021, it was not certain whether I&M and AEG would have access to the energy and capacity from Rockport Unit 2 after their lease ended in December 2022. In April 2021, I&M and AEG formally agreed with the lessors to purchase Rockport Unit 2. The resulting retail regulatory approvals of the transaction for I&M conditioned the purchase of Rockport Unit 2 on it no longer being able to include the capacity and energy of Rockport Unit 2 for which I&M is responsible in its retail cost of service after May 31, 2024. Under such a cost recovery pressures, the ultimate retirement date of Rockport Unit 2 is uncertain, but it will also retire no later than December 2028.

**Q. BECAUSE OF THESE CIRCUMSTANCES SURROUNDING THE ROCKPORT PLANT, WAS EXTENDING THE UPA AN AVAILABLE OPTION TO THE COMPANY?**

A. No. This is ultimately due to the entirety of Rockport Unit 1 being utilized and needed by I&M to meet its capacity obligations, and the resulting merchant status of Unit 2. Due to these unit availability uncertainties, and the fact that the Rockport UPA had no contract termination or extension rights or responsibilities, extending the UPA with one or both of the Rockport units was not an available option to the Company.

**Q. CAN YOU PLEASE SUMMARIZE THE MAJOR EVENTS THAT LED TO THE DECISION NOT TO RENEW THE ROCKPORT UPA ON A TIMELINE?**

A. In addition to the cost issues regarding the UPA that have been raised in the past proceedings and the unavailability of Rockport to the Company as I discussed previously, the major events that led to the expiration of the Rockport UPA for the Company can be summarized as follows:

1. By its terms, the August 1, 1984 Unit Power Agreement by and between Kentucky Power Company and AEP Generating Company (the "Rockport UPA") became "effective with the date of commercial operation of Rockport Unit No. 1" and, after its term was extended in 2004, "continue[d] in effect through December 7, 2022."[9] The Rockport UPA did not contain any term or provision that conveyed to Kentucky Power the right to renew the Rockport UPA upon its expiration.

2. October 3, 2017, Case No. 2017-00179 – KIUC raised the issue of ratemaking and the potential cost of service reduction the Company would realize when the Rockport UPA expired in December 2022. In that proceeding, KIUC witness Lane Kollen initially proposed a deferral of $20.3 million annually related to purchased power expense from the Rockport UPA with a ten-year amortization and recovery period beginning in 2022 when the UPA ended.[10]

3. January 18, 2018 – The Commission issued order in Case No. 2017-00179 approving the Rockport deferral, which incorporated the concept of pulling forward over 5 years the cost of service reductions expected when the UPA ended.

4. February 8, 2019, Case No. 2018-00418 – Kentucky Power conveyed to the Commission in its 2019 environmental compliance plan proceeding the Company's expectation that the Rockport UPA would terminate in 2022 and be replaced with lower cost capacity.[11] Kentucky Power indicated that "the Company [did] not intend to extend the UPA beyond December 7, 2022," and that it "currently expect[ed] that the Rockport UPA [would] expire and not be

[9] Rockport UPA, Section 6.

[10] Case No. 2017-00179, Direct Testimony of Lane Kollen (Oct. 3, 2017).

[11] *See, e.g.,* Case No. 2018-00418, Kentucky Power's Response to Commission Staff's First Set of Data Requests, Item 17 (Feb. 8, 2019).

renewed."[12] The Company further stated that, if the Company's decision to not renew the Rockport UPA changed, then Kentucky Power would seek Commission approval to extend the UPA.[13]

5. July 17, 2019 – The U.S. District Court for the Southern District of Ohio in *United States et al., v. American Electric Power Service Corp, et al.*, Civil Action No. C2-99-1182 and consolidated cases, issued an Order approving a Fifth Joint Modification to the Consent Decree entered in that action (the "NSR Consent Decree"). Paragraph 140 of the NSR Consent Decree, as modified by the Fifth Joint Modification, expressly states that "AEP Defendants must Retire Rockport Unit 1 by no later than December 31, 2028."[14] In addition to the Rockport UPA not providing Kentucky Power a right to renew the Rockport UPA upon its expiration, the requirement to retire Rockport Unit 1 by no later than December 31, 2028, eliminated the possibility of a long-term renewal of the Rockport UPA.

6. February 8, 2021, Case No. 2021-00004 – Kentucky Power stated in its 2021 environmental compliance plan application that "[t]he Rockport Unit Power Agreement expires December 7, 2022. Kentucky Power has elected not to renew the agreement."[15] The Company also confirmed in a March 26, 2021, response to a Staff data request that its decision "not to renew the Rockport UPA [was] final."[16]

7. March 11, 2021 – Company President Brett Mattison approves FRR plan for 22/23 with bilateral purchase from I&M for Kentucky Power's needs.

**Q. DID THE STAKEHOLDERS IN THE 2019 IRP AGREE ON WHETHER THE COMPANY SHOULD UTILIZE SHORT TERM CAPACITY PURCHASES?**

A. Yes. Both the Attorney General ("AG") and Kentucky Industrial Utility Customers, Inc. ("KIUC") (collectively, "AG-KIUC") advocated for the use of short-term bilateral market capacity purchases and the PJM spot energy market in lieu of the Company

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[12] *See* Case No. 2019-00389, Kentucky Power's Response to Commission Staff's First Set of Data Requests, Item 6 (Jan. 31, 2020).

[13] *Id.*

[14] *Available at*: [sargus-bizhub-20190717162026 (epa.gov)] (emphasis added).

[15] Case No. 2021-00004, Application at paragraph 5 (Feb. 8, 2021).

[16] Case No. 2021-00004, Kentucky Power's Response to Commission Staff's First Set of Data Requests, Item 5 (Mar. 26, 2021).

owning long-term assets to fill the same need. In their joint comments on Kentucky Power's 2019 IRP Preferred Plan, AG-KIUC stated: "This is further evidence that the Company should adjust its Preferred Plan to include additional MPs [market purchases], and it should not be overlooked that we have been in a low-cost environment for more than ten years with no indication this will change any time soon."[17] The joint comments also state:

> In its response to Staff's Post Hearing Request No. 2, the Company noted that when its winter peak demand is greater than its summer peak demand obligation, it buys energy from the pool. When this situation occurs, it does not mean that Kentucky Power suffers from a reliability issue, but instead it means it is more economic for Kentucky Power to purchase energy from within the PJM market than for Kentucky Power to construct new resources, especially since there is sufficient capacity available in PJM to meet Kentucky Power's winter peak. As long as Kentucky Power meets its PJM summer peak demand obligation, and PJM ensures that the entirety of the PJM System is reliable on a year round basis, then it would become an economic matter as to whether Kentucky Power should construct additional capacity to avoid having to purchase during the winter period. Even if the Company were to construct physical assets such as combustion turbine units to satisfy its winter peak, Kentucky Power possibly would still purchase energy from the PJM market during the winter as opposed to running its newly built resources since PJM market resources could be cheaper to operate than Kentucky Power's new resources.[18]

The Company has carried out this strategy to effectuate the needed transition that naturally occurred at the end of the Rockport UPA and the Company intends to continue with this strategy until a long-term replacement solution is proposed by the Company and approved by this Commission.

[17] Joint Review of Kentucky Power's 2019 Integrated Resource Plan at 9, *In The Matter Of: Electronic 2019 Integrated Resource Planning Report Of Kentucky Power Company*, Case No. 2019-00443 (Feb. 25, 2021).

[18] *Id.* at 16.

**Q. WHEN WAS THE FINAL DECISION MADE FOR THE 2022/2023 DELIVERY YEAR?**

A. The final decision for the delivery year covering June 1, 2022 through May 31, 2023 ("22/23 Delivery Year") was made in the first quarter of 2021, when the presidents of the PCA companies met and approved the 22/23 Delivery Year FRR plan. This plan included a short-term purchase of 152.4 MW of unforced capacity ("UCAP") by the Company to meet the Company's capacity obligation beginning on December 8, 2022 when the capacity from the Rockport UPA was no longer available to the Company. The base residual auction for the 22/23 Delivery Year was held shortly thereafter in May 2021. This 152.4 MW of UCAP purchase represented roughly 164 MW of ICAP generating capacity available to provide energy in the PJM energy market.

This strategy was contemplated much earlier than when the final decision was memorialized in the PCA meeting previously referenced. As early as October 3, 2019,[19] the Company publicly signaled, at least for IRP planning purposes, that the going in assumption would be that the Company would not pursue renewing the Rockport UPA when it expired in December 2022. In the subsequent IRP, filed in December 2019, the Company's preferred plan included the use of small short-term bilateral purchases of UCAP capacity MW to meet the Company's capacity obligation after the Rockport UPA expired until the time which the Company procured a longer-term replacement for the Rockport UPA capacity.

[19] Kentucky Power Company 2019 IRP Technical Conference presentation.

**Q. WHAT IS THE STATUS OF THE LONG-TERM REPLACEMENT SOLUTION?**

A. The Company has issued a request for proposal, has received a robust field of bids, and is currently performing due diligence and evaluating bids. The currently scheduled process is to short-list chosen bids for negotiations in early 2024 with the Company making a filing with this Commission in summer of 2024.

**Q. WHAT HAS BEEN THE ECONOMIC RESULT FOR CUSTOMERS FROM THE COMPANY'S STRATEGY?**

A. The prudency of a decision is based on the information reasonably available to the decision maker at the time the decision is made; rather than depending on the economic outcome for customers. Nevertheless, when one does compare the cost of service resulting from the Company's Rockport UPA replacement strategy to the 2022 cost of service under the UPA, it shows that customers have benefited greatly from the Company's decision making and strategy as shown in Figure AEV-2.

**Figure AEV-2**

| Rockport UPA Replacement Capacity & Energy Cost Comparison | | |
|---|---|---|
| 2022 Rockport UPA Cost | $ | 92,108,647 |
| 2022 Capacity Charge | $ | 5,792,329 |
| Total 2022 Rockport Cost of Service | $ | 97,900,976 |
| Replacement Energy and Capacity Cost | $ | 31,397,143 |
| ***Cost of Service Reduction Post UPA*** | ***$*** | ***66,503,833*** |

This cost comparison includes the average cost of market power purchased to serve internal load requirements, including the full cost of energy during Winter Storm Elliott, as well as the bilateral capacity purchased to meet the Company's PJM capacity obligations after the UPA expired. The Rockport UPA costs are also reduced for sales of capacity length during the 22/23 Delivery Year prior to the expiration of the UPA. For another measure of comparison, the all-in unitized $/MWh cost of the capacity and energy that has replaced the Rockport UPA is ***less than one-third*** the rate paid by the Company in 2022 for the UPA and ***less than half*** the rate paid by the Company on average over the last five years of the UPA.

**Q. DOES THIS REDUCTION IN PURCHASED POWER COST TRANSLATE INTO LOWER BILLS FOR CUSTOMERS?**

A. Yes. Year over year, the Company's fuel and purchased power costs for the 12 months ending November 2023 are down roughly $139 million. This figure is inclusive of the savings estimate shown in Figure AEV-2. The Company's FAC rates are down $12/MWh on average for 2023 versus 2022. This translates into a $177[20] annual bill reduction for the average residential customer.

## VI. PERFORMANCE OF RESOURCE PLANNING AND PROCUREMENT DECISIONS DURING WINTER STORM ELLIOTT

**Q. PLEASE DESCRIBE THE SYSTEM CONDITIONS DURING WINTER STORM ELLIOTT.**

A. Winter Storm Elliott was an extreme cold weather event that included blizzards, high winds, snowfall and record cold temperatures across much of the United States. Winter Storm Elliott occurred December 23, 2022 through December 26, 2022, in the PJM

[20] 0.01201 $/kWh x 1,230 kWh x 12 = $177.27.

region (the "Winter Storm Elliott Period").[21] The resulting load during this period of time was an extreme outlier in both magnitude and timing, with the Christmas Eve load being 40 gigawatts higher than the second highest in the past decade.[22] The drastic temperature drop and higher than forecasted load caused PJM to dispatch generation reserves, many of which failed to perform.

The unanticipated high load and rapid load increase combined with generation outages due to cold weather and fuel issues resulted in Performance Assessment Intervals ("PAIs") on December 23, 2022, and December 24, 2022. PAIs are triggered when PJM declares an emergency action in the RTO. During the PAIs, the load weighted LMP reached the system marginal price cap of $3,700/MWh as a result of the supply/demand imbalance during emergency operations. Generation resource outages during Winter Storm Elliott peaked at 48,080 MW on December 24, 2022. Roughly 11,000 MW of those outages were due to a lack of natural gas supply.[23]

**Q. DID THE COMPANY EXPERIENCE EXTREME LOAD CONDITIONS DURING WINTER STORM ELLIOTT?**

A. Yes. The Company's peak load during the Winter Storm Elliott Period was 1,358 MW, 46% higher than the Company's previous 12 month average peak demand

[21] PJM defined the Winter Storm Elliott Period as December 23, 2022 through December 26, 2022, and this is the time period used for purposes of this testimony. The Company also has referred to the Winter Storm Elliott Period when describing its generation performance as December 23, 2022 through December 27, 2022 (see Testimony of Timothy C. Kerns).

[22] https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230111/item-0x---winter-storm-elliott-overview.ashx.

[23] PJM 2022 State of the Market Report, pages 210-211.

("12CP") of 929 MW. In 85 of the 96 hours during the event, the Company's hourly average load was higher than its most recent 12CP demand.

**Figure AEV-3**

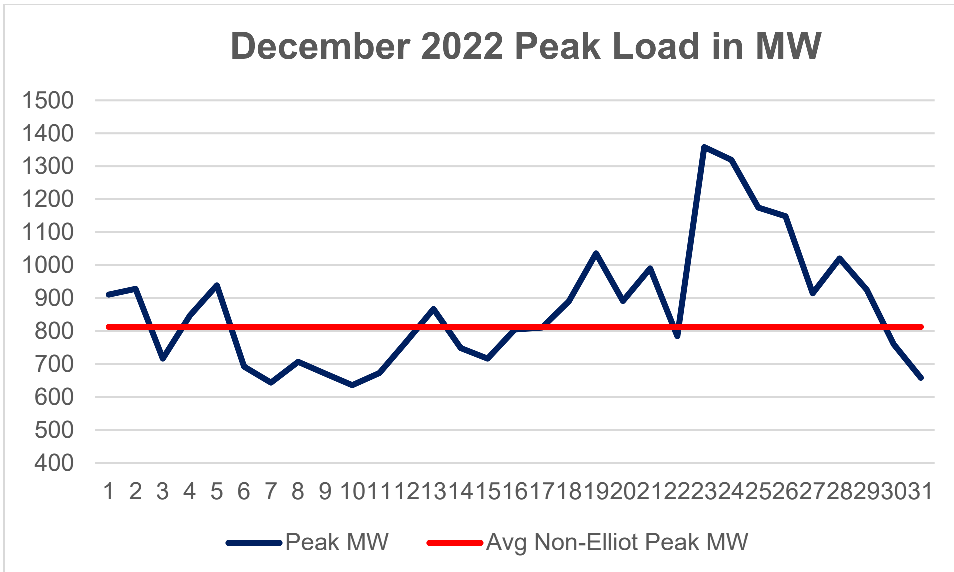



Figure AEV-3 illustrates the Company's daily peak demand during the month of December 2022. As can be seen, there is an extreme increase in demand during Winter Storm Elliott, including the 1,358 MW peak during hour ending 2100 on December 23, 2022. The flat line in Figure AEV-3 is the average peak demand during the non-Winter Storm Elliott days in December (813 MW). The Company's peak demand during Winter Storm Elliott was 545 MW higher than the average peak demand for the other 27 days of December 2022. Before this, one has to go back to January 2018 to find a Company peak higher than what was experienced during Winter Storm Elliott, and the Company has only had eight monthly peaks in the last decade greater than the Winter Storm Elliott peak. This illustrates the magnitude of the demand on the Company's system resulting from Winter Storm Elliott's extreme cold weather. This high load when combined with PJM-wide emergency operations resulted in extremely high system energy pricing at which the Company had to purchase its load obligation, in excess of its available supply that would otherwise have netted financially and reduced such load costs, from the PJM spot energy market. Figure AEV-4 and Figure AEV-5 below show real-time LMPs over the month of December 2022 to put into context how much of an outlier pricing during Winter Storm Elliott was and provide a narrower view on the hourly pricing during Winter Storm Elliott.

**Figure AEV-4**

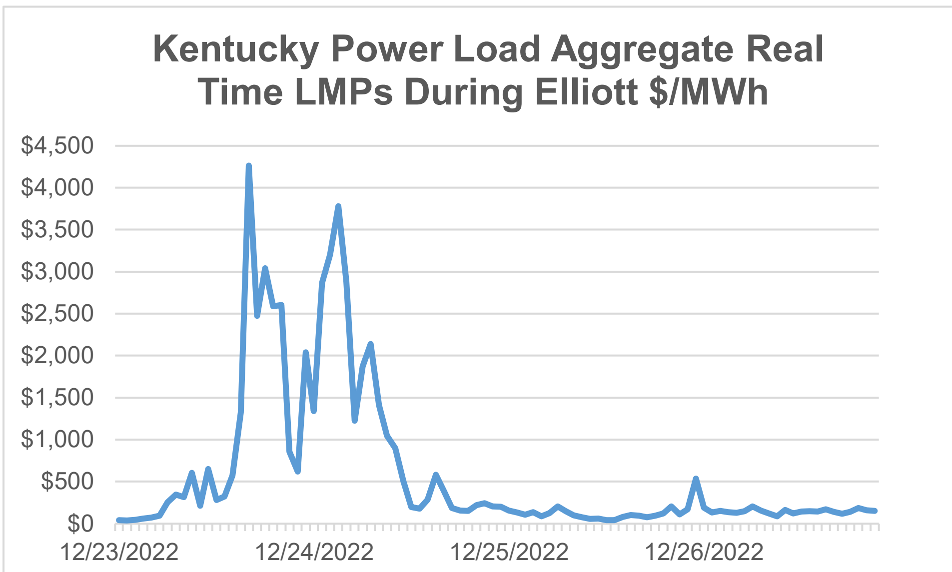
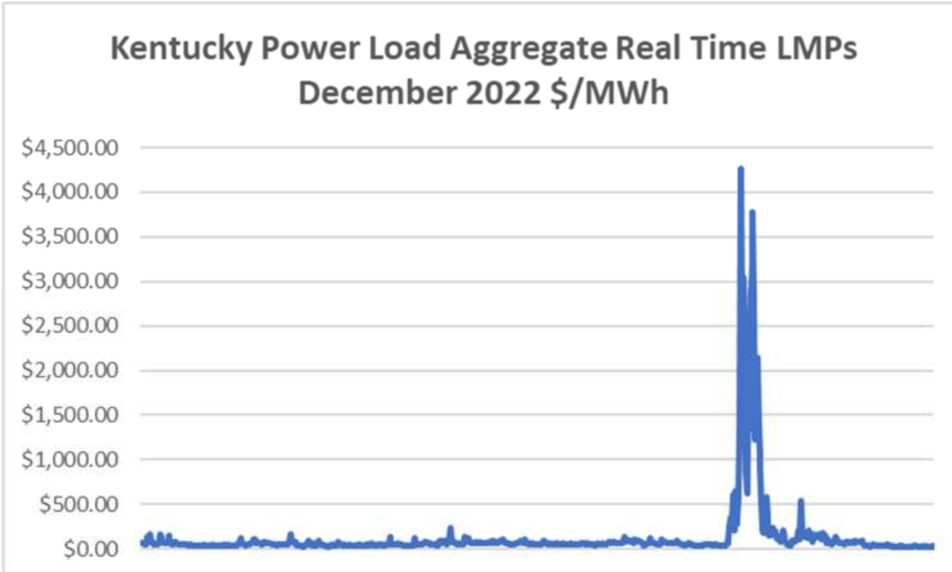


**Figure AEV-5**




**Q. HOW DID THE COMPANY'S GENERATION RESOURCES PERFORM DURING THE WINTER STORM ELLIOTT EVENT?**

A. During Winter Storm Elliott, none of the Company's generating units were forced out of service. Both Mitchell Units operated continuously throughout Winter Storm Elliott. Mitchell Units 1&2 operated at 80.31% and 74.11% net capacity factors[24] respectively. The Mitchell Units performed at a level above the total PJM coal fleet which achieved a net capacity factor of 73.03%[25] during the same period of time. Big Sandy Unit 1 was in the midst of a PJM-approved planned outage during Winter Storm Elliott.

[24] December 23-27 period to be consistent with Company Witness Kerns's testimony.

[25] Source: PJM Dataminer2 and PJM 2022 State of the Market Report.

Company Witness Kerns provides a more detailed description of the performance of the Company's generation resources during the Winter Storm Elliott Period.

**Q. DID THE COMPANY INCUR A CAPACITY PERFORMANCE PENALTY DURING THE WINTER STORM ELLIOTT PAIS?**

A. No, due to the Company's prudent management of its available coal supplies during 2022, the Mitchell Plant was available to run and as previously discussed operated continuously during Winter Storm Elliott and the PAIs called by PJM. Furthermore, the larger AEP Companies FRR plan, in which Kentucky Power participates, also did not incur a penalty as it benefited from the diversity of generation resource types and locations utilized by the Companies in the plan.

**Q. WHAT OTHER OPTIONS WERE AVAILABLE TO THE COMPANY DURING THE WINTER STORM ELLIOTT EVENT TO SERVE THE HOURLY ENERGY NEEDS OF ITS CUSTOMERS?**

A. The Company had to purchase power from the PJM spot energy market during Winter Storm Elliott on a net basis because the Company's load obligations were in excess of the supply available from its resources. The Company's plan for covering load obligations in excess of available generation supply is to purchase the balance of its energy requirements from the PJM spot energy markets. The Company's customers receive the lower of cost to generate or market energy prices as determined by PJM's FERC approved tariff and economic dispatch model. To the extent that the Company may be adding additional owned or contracted for capacity and energy resources in the future to replace the energy and capacity from the recently expired Rockport UPA, those resources would contribute in the future to reducing the Company's amount of spot market energy purchases from PJM. Furthermore, any additional owned or contracted for long-term replacement of the Rockport UPA capacity will come with it some level of fixed costs. Intuitively, any counterparty willing to sell energy at production cost rather than the market price is going to require coverage of its fixed costs and a return on its investment to do so.

It should also be noted that resource acquisitions are generally informed by long-range integrated resource planning and forecasting that utilizes normative forecasts that do not account for extreme outlier events like Winter Storm Elliott. The weather and resulting conditions in the PJM energy market during Winter Storm Elliott were an outlier; it is highly unlikely that traditional resource planning would result in the Company being insulated from all possible PJM energy market fluctuations.

**Q. WAS THERE ANOTHER SOURCE OF PURCHASED POWER AVAILABLE TO THE COMPANY AT A LOWER COST DURING THE WINTER STORM ELLIOTT EMERGENCY?**

A. No. It was a PJM system emergency; if excess power was available in the market, then scarcity pricing and emergency conditions would not have occurred. Additionally, it is fundamental under economic principles of supply and demand that a willing market seller of energy would not sell available energy during such an event for less than the transparent spot market price of energy.

**Q. HYPOTHETICALLY, WHAT WOULD HAVE BEEN THE FINANCIAL RESULT HAD THE COMPANY PURCHASED TERM FINANCIAL POWER DURING 2022 IN AN AMOUNT TO COVER THE COMPANY'S PEAK LOAD DURING THE WINTER STORM ELLIOTT EXTREME COLD EVENT?**

A. Hypothetically speaking, had the Company known it would need 283 MW[26] of additional purchased power during Winter Storm Elliott, and had it purchased financial power[27] in advance of December 2022, customers' resulting fuel costs would have been significantly higher. This is due to the high natural gas and power prices during 2022, which caused the forward prices of financial power to be very high during 2022. Had the Company transacted for this hypothetical amount of purchased power in any of the five months leading up to December 2022, purchased power expenses for December would have been higher than what the Company actually experienced in three out of the five months. Based on this information, the only way a hypothetical financial power transaction would have potentially benefitted the Company's customers would have been based on arbitrary market timing. Said another way, if the Company by luck alone had transacted based on October forward prices having perfect knowledge of the unknown Winter Storm Elliott to come, purchased power expense could have been lower than what was realized.

Had the Company bought that same amount of financial purchased power for the balance of the winter (January-March in addition to December), rather than settling

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[26] Peak Kentucky Power load during Winter Storm Elliott minus generation resource (Mitchell and Big Sandy 1) ICAP.

[27] The reference to financial power is referring to any purchase that is not asset specific.

its net load requirements at the spot market energy prices, total fuel costs would have been materially higher under every scenario as can be seen in Figure AEV-6. Furthermore, as discussed later in the financial power hedging portion of my testimony, these types of extreme load spikes are not what a hedging program is meant to insulate against. In fact, the Company's proposed hedging program will utilize weather normal load levels (which do not include extreme cold or heat events that materially impact retail load) and would leave one standard deviation of the total position open to the spot energy market.

**Figure AEV-6 - Hypothetical Forward Purchased Power Transactions**

| MW Needed to Cover Elliott Peak | 283 | | | | |
|---|---|---|---|---|---|
| **July Forwards** | **December** | **January** | **February** | **March** | **Total** |
| **Forward Price** | $87.96 | $113.72 | $106.52 | $76.42 | |
| **Liquidated Price** | $83.85 | $36.22 | $27.81 | $28.80 | |
| **Increase in Purchase Power Exp** | **$864,103** | **$16,293,909** | **$14,946,855** | **$10,011,819** | **$42,116,685** |
| **August Forwards** | **December** | **January** | **February** | **March** | **Total** |
| **Forward Price** | $108.04 | $136.92 | $126.07 | $78.07 | |
| **Liquidated Price** | $83.85 | $36.22 | $27.81 | $28.80 | |
| **Increase in Purchase Power Exp** | **$5,085,802** | **$21,171,569** | **$18,659,357** | **$10,358,721** | **$55,275,449** |
| **September Forwards** | **December** | **January** | **February** | **March** | **Total** |
| **Forward Price** | $94.97 | $126.51 | $111.50 | $75.71 | |
| **Liquidated Price** | $83.85 | $36.22 | $27.81 | $28.80 | |
| **Increase in Purchase Power Exp** | **$2,337,913** | **$18,982,929** | **$15,892,546** | **$9,862,545** | **$47,075,934** |
| **October Forwards** | **December** | **January** | **February** | **March** | **Total** |
| **Forward Price** | $73.45 | $106.30 | $91.27 | $67.17 | |
| **Liquidated Price** | $83.85 | $36.22 | $27.81 | $28.80 | |
| **Increase in Purchase Power Exp** | **($2,186,537)** | **$14,733,898** | **$12,050,914** | **$8,067,062** | **$32,665,337** |
| **November Forwards** | **December** | **January** | **February** | **March** | **Total** |
| **Forward Price** | $80.90 | $99.41 | $91.97 | $67.02 | |
| **Liquidated Price** | $83.85 | $36.22 | $27.81 | $28.80 | |
| **Increase in Purchase Power Exp** | **($620,220)** | **$13,285,317** | **$12,183,842** | **$8,035,525** | **$32,884,465** |

A similar fact pattern would be true if the Company had purchased a block of financial power to replace Big Sandy Unit 1's 295 MW of generation when it became known that the emergent generator issue with Big Sandy Unit 1[28] would keep the unit in a planned outage for all of December 2022. Had the Company purchased that block of power[29] for the remainder of the month of December after the equipment issue was discovered on December 2, 2022, total purchased power costs realized would not have changed materially. Forward pricing for the balance of December 2022 was $82.93/MWh and the average December 2022 liquidated price was $83.85. Therefore, less than a dollar per MWh (or roughly $190,000 in total) of savings was hypothetically possible. It should be noted that making such a transaction at a single point in time, rather than layering in over time as the Company is proposing in its hedging program, can be financially risky. This is very evident when looking out just a single month from December 2022 to January 2023, when the average PJM spot market price shown in Figure AEV-6 dropped to just $36.22/MWh.

**Q. DID THE COMPANY CURTAIL ITS NON-FIRM OR INTERRUPTIBLE CUSTOMERS DURING WINTER STORM ELLIOTT TO REDUCE THE AMOUNT OF PURCHASED POWER IT INCURRED?**

A. Yes, the Company called for curtailments of its interruptible customers[30] on December 23, 2022, and December 24, 2022, and those customers reduced their operations to their contracted firm service level during these events.

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[28] As discussed in more detail by Company Witness Kerns, the issue was discovered on December 2, 2022.

[29] 295 x 696 hours in the balance of the month = 205,320 MWh of hypothetical purchased power transaction.

[30] Tariff DRS and special contract.

**Q. DID THE COMPANY HAVE TO ENGAGE IN ROLLING BLACKOUTS DURING WINTER STORM ELLIOTT?**

A. No. The Company was able to provide reliable service to its customers during the Winter Storm Elliott and had no power supply-related outages.

## VII. CONCLUSION

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

A. Yes, it does.

## VERIFICATION

The undersigned, Alex E. Vaughan, being duly sworn, deposes and says he is the Managing Director for Renewables and Fuel Strategy for American Electric Power Service Corporation that he has personal knowledge of the matters set forth in the foregoing testimony and the information contained therein is true and correct to the best of his information, knowledge, and belief after reasonable inquiry.

Alex E. Vaughan

**State of Ohio** )
) Case No. 2021-00370
**Franklin County** )

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Alex E. Vaughan, on **December 19, 2023**.

Notary Public

My Commission Expires Does not expire

Notary ID Number ______________

NOTARIAL SEAL STATE OF OHIO
Matthew J. Satterwhite, Attorney At Law
NOTARY PUBLIC - STATE OF OHIO
My commission has no expiration date
Sec. 147.03 R.C.