Direct Testimony of Jeff Plewes

CASE NO. 2021-00370

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On Behalf of

Kentucky Power Company

Prepared by

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Jeff Plewes. My business address is Charles River Associates International, Inc. ("CRA"), 1201 F St., NW, Suite 800, Washington, D.C., 20004.

Q. What is your occupation and by whom are you employed?

A. I am a Principal in the Energy Practice of CRA.

Q. Please briefly describe the nature of the consulting services provided by Charles River Associates.

A. Charles River Associates is a leading global consulting firm that offers economic, financial, and business management consulting expertise and applies advanced analytic techniques and in-depth industry knowledge to complex engagements for a broad range of clients. Founded in 1965, we work with major law firms, businesses including utilities, accounting firms, and governments in providing advice and a wide range of services. CRA's Energy Practice advises utility and energy clients on a variety of issues, including rate and regulatory matters, and provides regulatory litigation assistance. Our work product can take the form of economic analysis, regulatory and commercial due diligence, wholesale power market studies and analysis, cost allocation and rate design studies, and other advisory and regulatory studies that evaluate the impacts of rate and regulatory activity for our clients. The practice provides our clients with expert testimony and litigation support assistance as needed. We provide these services across the sectors of electric transmission, distribution, and power generation sectors as well as natural gas distribution.

Q. Please state your educational background and experience.

A. I received a Bachelor of Science degree from the University of Virginia and a Master of Business Administration degree from the School of Management at Yale University.

My sixteen years of professional experience within CRA's Energy Practice have focused on the economic analysis of energy and environmental policy and market design. I have worked with companies throughout the energy sector to help them understand the implications of public policies and regulations on their operations, assets, and investment decisions, and to communicate those impacts to regulators and policy makers. I have led projects for clients in each of the North American competitive electricity markets and for many regulated utility clients, in the United States and internationally. Broader areas of focus have included resource adequacy, climate policy, electricity and capacity market strategy, economic impact analysis, and modeling natural gas production and exports. I support this work with quantitative analysis using advanced energy and economic modeling tools.

Relevant to this matter, I have worked extensively for clients on electricity market and utility regulation matters. I have participated in electricity market related stakeholder processes in multiple markets, including PJM, ISO New England ("ISO-NE"), Midcontinent ISO ("MISO"), Alberta Electric System Operator ("AESO"), the Electric Reliability Council of Texas ("ERCOT"), and in Federal Energy Regulatory Commission ("FERC") proceedings on resource adequacy. I have worked with many PJM market participants on understanding market design and optimal participation strategies, including insurance and capacity offer strategies.

A copy of my CV is provided as JCP Attachment 1.

Q. Have you previously provided testimony before regulatory commissions?

A. Yes. I provided testimony before the Kentucky Public Service Commission in Case No. 2021-00481. I recently provided testimony before the West Virginia Public Service Commission in a matter that involved the prudency of a utility's decisions related to PJM market participation. In addition, I have submitted testimony before the Indiana Utility Regulatory Commission, the Minnesota Public Utilities Commission, the Public Utilities Commission of Ohio, and the New York Public Services Commission. I have also authored studies and reports, many without specific attribution, that have been filed with multiple state utilities commissions, the U.S. Department of Energy, the U.S. Environmental Protection Agency, and the FERC. In addition, I have provided expert testimony in the Supreme Court of the State of New York and am currently serving as a macroeconomics expert in an international case.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Kentucky Power Company ("Kentucky Power" or the “Company”).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a third-party economic context in this proceeding and to evaluate the reasonableness of methods and information used by Kentucky Power in making certain planning decisions that have been questioned in the Commission’s Show Cause Order. I examine the resource adequacy achieved by Kentucky Power through its PJM membership and the ways Kentucky Power complies with its capacity obligations in order to achieve resource adequacy. I also evaluate the short-term decisions made in 2022 that led to Kentucky Power’s energy position through Winter 2022-23. There are several concepts at issue when reviewing these items, and my testimony is an attempt to demystify some of these items and provide the Commission an outside expert view on the underlying issues and a base of understanding.

Q. What data and sources did you review and use for preparing your testimony?

A. I reviewed the record for the Show Cause proceeding (Case No. 2021-00370), including the Commission Orders, the Company's response and exhibits, and discovery responses. I also reviewed parts of the record for Kentucky Power's 2016, 2019, and 2022 Integrated Resource Plans (IRPs). In reviewing these documents, I focused on information relevant to resource adequacy and energy positions. When necessary, I obtained data from Kentucky Power and interviewed several Company witnesses. Finally, I relied on information and data from public sources, such as the Federal Energy Regulatory Commission (FERC) and PJM, and well-regarded third-party data providers, such as S&P Global and Energy Velocity. I cite data and sources that I used throughout my testimony.

Q. What are your main findings that you are offering the Commission?

A. My testimony presents three primary findings:

1. **Kentucky Power has sufficient capacity to meet the maximum estimated requirements of its customers.** - Resource adequacy involves the ability of an electricity system to meet the peak demand of its customers, which is achieved by ensuring sufficient physical capacity for generating electricity. Kentucky Power achieves resource adequacy

through its PJM membership. PJM ensures that every load-serving entity in its balancing authority has sufficient capacity to meet its customers' maximum requirements by meeting the North American Electric Reliability Corporation (NERC), Reliability First (RF), and industry standard resource adequacy requirements, such as the well-known "one-in-ten" standard for Loss of Load Expectation (LOLE). PJM's process sets capacity targets for the summer peaks because the RTO as a whole is summer peaking. The amount of capacity it procures is based on rigorous analysis that ensures resource adequacy throughout the entire delivery year, including winters. The capacity that PJM obtains is required to perform at all hours of the year when needed.

PJM has not experienced any load shedding from resource adequacy events in its footprint since 1994. This includes Winter Storm Elliott, an extreme winter weather event during which there were no resource adequacy-related events in PJM, including for Kentucky Power, while neighboring regions did experience load shedding. Overall, I find that there is no basis to conclude that Kentucky Power has failed to meet industry-accepted resource adequacy requirements.

2. **Kentucky Power has achieved its resource adequacy by meeting PJM capacity obligations in a reasonable manner.** - As a condition

of its membership in PJM, Kentucky Power must meet certain PJM-determined annual capacity obligations. As with other PJM members, Kentucky Power has two options for meeting its obligations: 1) elect the Fixed Resource Requirement (FRR) alternative and satisfy capacity obligations by designating owned resources and contracted capacity, or 2) participate in PJM's capacity market (the Reliability Pricing Model, or "RPM") by purchasing capacity while also selling any capacity from owned or contracted resources. Kentucky Power meets its obligations through the AEP FRR Plan, which PJM reviews annually for compliance. I find that FRR is a reasonable choice due to the many benefits it provides, including reducing the amount of capacity Kentucky Power needs to obtain compared to participating directly in RPM.

Importantly, Kentucky Power's decision on how to meet its obligation is an "economic" choice that does not have any impact on the "physical" resource adequacy it provides. The owned and contracted resources included in Kentucky Power's FRR plan are not specifically dedicated to serving Kentucky Power customers, but instead constitute Kentucky Power's contribution to PJM's pool of capacity resources that ensures resource adequacy for all load-serving entities within the RTO. Thus, building or contracting for additional capacity beyond the amount PJM requires (for example, by owning capacity equal to Kentucky Power's expected winter peak) would not materially increase resource adequacy. PJM already ensures that Kentucky Power has adequate resources, through the pool of resources committed to PJM, to meet its winter peak. (Indeed, most PJM electric utilities do not meet their obligations entirely through owned resources, and many do not own any resources at all.) Instead, building or contracting for additional capacity resources beyond what PJM requires is purely a choice about economics: whether the significant cost of owning capacity in excess of PJM requirements is less than the revenue that can be earned from selling that capacity to other load-serving entities, from any savings in the energy market due to increased supply, and from any value derived from achieving state resource preferences. Kentucky Power already considers these costs and benefits in its resource planning processes. Overall, I find that Kentucky Power's approach to meeting its PJM capacity obligation, which brings resource adequacy, is a reasonable approach.

3. **Turning from capacity to energy, Kentucky Power's planning processes and strategies for procuring energy are reasonable, including in the period leading up to Winter 2022-23.** - It is typical for PJM utilities to obtain their energy requirements from a combination of utility-owned resources, bilateral contracts, and spot market purchases. Owned resources and Power Purchase Agreements ("PPAs") can serve

as price hedges for energy prices: they ensure that the load-serving entity will be able to access a known quantity of energy at a known price, rather than paying the spot market price for that quantity of energy. But these arrangements also carry costs that may not be justified by their benefits. I find that Kentucky Power employs a reasonable process to evaluate these costs and benefits, which the Company employed in decisions leading to its energy position heading into Winter 2022.

Forward contracts can also serve as price hedges, but they also carry a cost, and it was reasonable for Kentucky Power to assess that the costs of such contracts outweighed the benefits heading into Winter 2022. Although hindsight is not relevant in determining prudency, I find that Kentucky Power's contracting decisions heading into Winter 2022-23 saved its customers approximately $11-19 million. Overall, the Company's energy strategy was reasonable when established and ultimately saved customers money.

Q. How is your testimony organized?

A. My testimony is organized in three sections consistent with my three main findings:

1. Resource Adequacy through PJM

2. Meeting the Capacity Obligation in PJM
3. Energy Positions in 2022

In each section, I provide perspective on the relevant topics, references to relevant sources of information and rules, and analytics to illustrate key concepts and Kentucky Power decisions. I then provide a conclusion at the end.

II. RESOURCE ADEQUACY

Q. What are "energy" and "capacity" in electricity systems?

A. Energy is the ability to do work. It can be stored in many forms. In the context of the electricity system, energy from various sources is converted into electrical energy and then transmitted and distributed to end users for consumption. Terms such as energy, electricity, and power all can be used to refer to electrical energy, and distinctions among them are not relevant in this testimony. Throughout this testimony, the term "energy" exclusively refers to electrical energy. Amounts of electrical energy are measured in units including kilowatt-hours (kWh), megawatt-hours (MWh), or gigawatt-hours (GWh).

The capacity of an electricity system is the maximum amount of electrical energy that the system is capable of supplying at a specific point in time.[1] It is measured

[1] U.S. EIA, Electricity explained: Electricity generation, capacity, and sales in the United States, June 30, 2023, https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php.

in units including kilowatts (kW), megawatts (MW), or gigawatts (GW). Each generating unit in an electricity system can contribute to the overall capacity of the system, assuming the unit has the capability to generate electricity in the times the capacity is evaluated. Demand-side resources can also provide capacity, which is their capability to reduce demand. Power plants can provide capacity to a system even if it they are rarely called upon to operate. For example, many peaker plants may operate only a few hours a year; some may not operate at all in any given year. But they still provide capacity to the system. Conversely, some renewable energy plants may generate a lot of energy across a year, but provide little capacity because they cannot be dispatched at all times. Energy and capacity are not only concepts but also defined products in the regulation and planning of electricity systems.

Q. Why is the distinction between capacity and energy important for utilities?

A. As I explain further in Section IV, utilities need to provide energy sufficient to meet the demand of their customers and to do so at a reasonable cost. To do this, they must either generate electricity or obtain it from other generators, and then deliver it over the grid to customers. In other words, they must have access to sufficient capacity to meet the energy demand of customers in order to ensure resource adequacy.

Q. What is resource adequacy for electric utilities?

A. An electricity system that is resource adequate has sufficient capacity to produce energy that satisfies the peak demand of customers served by the system. Conversely, when a system does not achieve resource adequacy, it is potentially exposed to events where demand cannot be met by supply. In these cases, system operators are forced to reduce demand to meet supply, often through "load shedding," which involves the failure to deliver energy to customers that seek to use it at a given time.

Resource adequacy is a physical concept, rather than an economic one. To observe resource adequacy, one simply needs to assess whether there are physically enough MW of capacity to serve demand, without considering cost. Determining whether a system has resource adequacy is usually based on whether it meets selected reliability standards that, when applied, determine the adequate level of capacity for the system. Resource adequacy reliability standards generally guide utility planning and investment decisions.[2] Economics affects the choice among different approaches to procuring the capacity needed for resource adequacy, but it is not involved in measuring resource adequacy.

[2] NARUC, Resource Adequacy Primer for State Regulators, July 2021, https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042.

Resource adequacy is also a systems concept. The resource adequacy of a power pool,[3] such as PJM, is dependent on resource adequacy across the system. The PJM system has been designed through transmission planning to minimize variability in resource adequacy among its regions and to ensure that a required level of resource adequacy is achieved everywhere on the system. As a result, a PJM member, such as Kentucky Power, cannot float its resource adequacy boat above the PJM resource adequacy water level by building more capacity resources, but it also cannot sink below the PJM level, which is set at a level that ensures compliance with reliability standards for the entire RTO.

Q. What are the ways in which electric utilities can achieve resource adequacy?

A. Electric utilities can achieve resource adequacy through a variety of approaches, with the options determined by their specific regulatory, locational, resource, and market contexts. At the most basic level, regardless of the entity responsible for ensuring resource adequacy, the approach needs to include, at a minimum, the following components:

1. Identify required reliability standards,

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[3] EIA Glossary, "Power Pool" ("Power pool: An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies."), https://www.eia.gov/tools/glossary/.

2. Determine the amount of capacity needed to meet reliability standards, and
3. Obtain and demonstrate sufficient, dependable capacity to achieve the resource adequacy reliability standards.

Resource adequacy is generally determined at a balancing authority (BA) level. Balancing authorities are entities "responsible for maintaining operating conditions under mandatory reliability standards issued by the North American Electric Reliability Corporation (NERC) and approved by the U.S. Federal Energy Regulatory Commission (FERC)."[4] There are more than 60 balancing authorities in the US. They include single utilities serving as their own balancing authorities and organizations of multiple utilities, such as Independent System Operator ("ISOs") and Regional Transmission Organizations ("RTOs").

In many parts of the US, ISOs and RTOs administer resource adequacy for their members. Some set target reserve margins and then simply serve as resource adequacy backstops, obtaining the capacity needed to fill gaps. Others, such as PJM, more actively manage resource adequacy and obtain sufficient capacity through various constructs, such as capacity auctions. Because these organizations have the responsibility of balancing supply and demand in their systems, they must ensure that all members achieve resource adequacy

[4] U.S. DOE, The Role of a Balancing Authority, 2022, https://www.energy.gov/sites/default/files/2023-08/Balancing%20Authority%20Backgrounder_2022-Formatted_041723_508.pdf.

because, ultimately, the entire system is impacted by the resource adequacy position of each member utility.

There are many benefits to achieving resource adequacy through multi-utility organizations, such as ISOs and RTOs. From a reliability perspective, benefits include the ability to engage a diversity of capacity resources that can complement each other in providing resource adequacy across different system conditions, thus improving reliability and minimizing the required reserve margins. All else equal, lower reserve margins lead to lower costs since less excess capacity needs to be compensated for reliability purposes. For very large systems, including PJM, resource adequacy can be shared across a geographic diversity that may minimize localized weather impacts on generator availability.

Q. How does Kentucky Power ensure resource adequacy?

A. Kentucky Power is a PJM member. PJM is an RTO that "coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia," but it does a lot more than just coordinate electricity movements.[5] PJM ensures resource adequacy for its members. By planning for resource adequacy over such a large region, PJM can achieve reliability standards cost-

[5] PJM, About PJM, n.d, https://www.energy.gov/sites/default/files/2023-08/Balancing%20Authority%20Backgrounder_2022-Formatted_041723_508.pdf.

effectively and with lower reserve margins than otherwise would be necessary. PJM has estimated that its capacity market results in annual savings of $1.2-1.8 billion across its footprint.[6]

In exchange, PJM members must meet certain obligations (discussed below) that are designed to ensure resource adequacy. Kentucky Power meets its obligations and enjoys the level of resource adequacy achieved in PJM, which is a level of resource adequacy compliant with all relevant standards. Throughout its history, the PJM capacity construct has achieved a high level of resource adequacy, exceeding the reserve margins needed to meet the industry standard "1-in-10" loss-of-load expectation target, which is translated to an expectation of losing power due to inadequate resources for less than one day in every 10 years.[7] As a PJM member, Kentucky Power has exceeded this industry-standard resource adequacy target.

Q. How does PJM ensure resource adequacy for its members?

A. As stated in PJM Manual 20, "PJM has the overall responsibility of establishing and maintaining the integrity of electricity supply within the PJM RTO."[8] To achieve this integrity of supply, PJM administers a thorough process to ensure

[6] PJM Value Proposition, p.2, https://www.pjm.com/about-pjm/~/media/about-pjm/pjm-value-proposition.ashx.
[7] The 1-in-10 standard is not an absolute standard that guarantees no loss of load events. Rather, the expectation should be fewer than 1 day in 10 years or less than 0.1 days (2.4 hours) each year.
[8] PJM, Manual 20 § 1.2.1., July 26, 2023, https://www.pjm.com/~/media/documents/manuals/m20.ashx.

resource adequacy across the system it operates. Revisiting the list of resource adequacy process components, PJM does the following:

1. Identify resource adequacy reliability standards – PJM sets resource adequacy targets based on the reliability standards with which it must comply.

2. Determine the amount of capacity needed to meet resource adequacy reliability standards – As the Balancing Authority and Planning Coordinator, PJM is required to conduct a "Resource Adequacy analysis annually" where it must "[c]alculate a planning reserve margin" that maintains the Loss of Load Expectation at 0.1 days per year or less.[9] This is translated into the amount of capacity, in MW, that must be ensured to meet resource adequacy reliability standards.

3. Obtain and demonstrate sufficient, dependable capacity to achieve the resource adequacy reliability standards – PJM offers two options for its Load Serving Entities (LSEs) to meet the PJM requirements. "An LSE can either participate in PJM's capacity auction or submit a plan showing

[9] NERC, BAL-502-RF-03 R1 and 1.1, October 16, 2017, https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RF-03.pdf. An LOLE of 0.1 days per year is a direct translation of the previously mentioned 1-in-10 target into an annual metric.

it owns or has contracted for sufficient capacity to meet PJM's reliability requirements."[10]

Figure 1 is a high level diagram depicting the PJM resource adequacy Planning Process steps as described in PJM Manual 20:

Figure 1: PJM resource adequacy Planning Process

To ensure resource adequacy, PJM sets certain requirements for LSEs, such as Kentucky Power. LSEs must commit to:[11]

- Share capacity resources with other parties to reduce overall reserve requirements for the parties while maintaining reliable service,

[10] NARUC, Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms, p. 55, November 2023, https://pubs.naruc.org/pub/0CC6285D-A813-1819-5337-BC750CD704E3.
[11] PJM, Reliability Assurance Agreement, June 1, 2007, https://agreements.pjm.com/raa/17427.

- o Provide mutual assistance to other parties during emergencies, and
- o Coordinate planning of capacity resources to satisfy reliability principles and standards.

Q. What are the standards that PJM complies with to ensure resource adequacy?

A. To execute its role as reliability coordinator for the PJM system, PJM must comply with standards applicable to bulk power systems in the US. As such, PJM establishes its capacity requirements in compliance with "industry guidelines and standards for reliability as established by the North America Electric Reliability Corporation ("NERC") and ReliabilityFirst ("RF")."[12] The commitment to these standards is built into PJM's resource adequacy process and is codified in the Reliability Principles and Standards as defined in the PJM Reliability Assurance Agreement.[13]

NERC, an organization formed in 1968, was designated by FERC in 2005 to enforce mandatory reliability standards for all participants in the North American bulk power systems, which of course includes PJM. NERC coordinates across eight regional reliability organizations, which are shown in the map in Figure 2.

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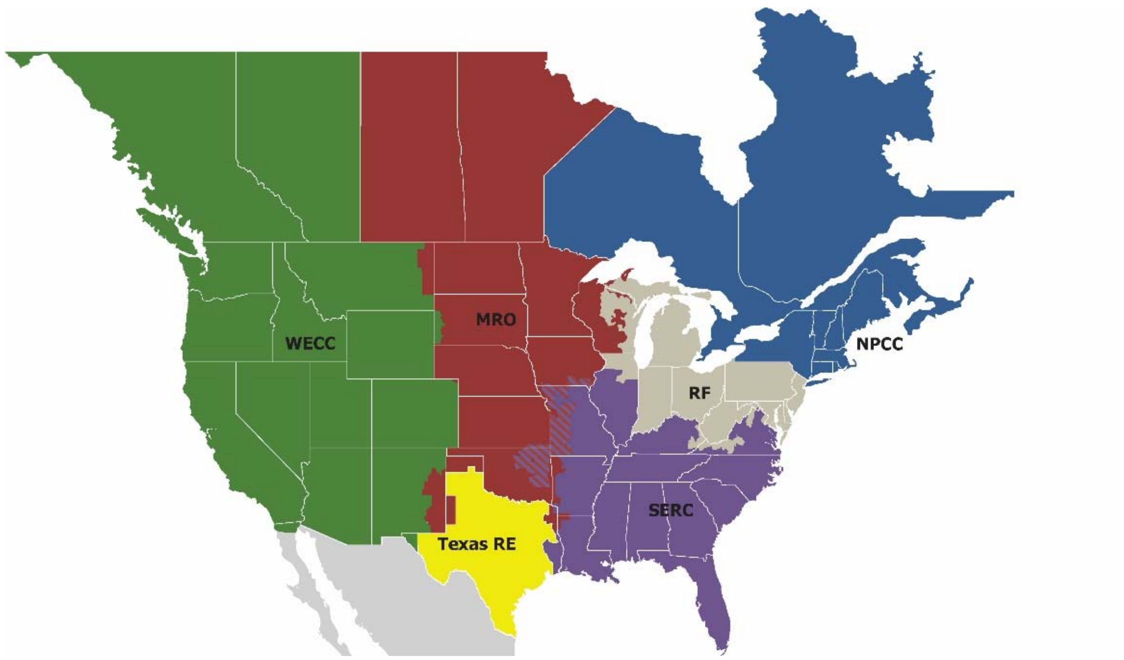
[12] PJM, Manual 20 § 1.2.1, July 26, 2023, https://www.pjm.com/~/media/documents/manuals/m20.ashx.
[13] PJM, Manual 20 § 1.1, 1.2.1, 1.7.1, July 26, 2023, https://www.pjm.com/~/media/documents/manuals/m20.ashx.

The majority of PJM falls within the ReliabilityFirst Corporation region (RF). A portion of the PJM footprint in Virginia, North Carolina, and Kentucky is covered by the SERC Reliability Corporation (SERC). The Kentucky Power region falls with the ReliabilityFirst region.

Figure 2: NERC Regional Reliability Organizations [14]



ReliabilityFirst was approved by NERC and began operations in 2006. PJM is a recognized Planning Coordinator within ReliabilityFirst.

ReliabilityFirst standards are binding on PJM. The applicable ReliabilityFirst standard is BAL-502-RFC-03. Its purpose is "to establish common criteria,

[14] NERC, 2023 Long-Term Reliability Assessment, December 2023, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

based on 'one day in ten year' loss of load expectation principles, for the analysis, assessment and documentation of resource adequacy for Load in the [ReliabilityFirst] region."[15] Embedded in this purpose is the common planning criterion of "one day in 10 year" LOLE. According to ReliabilityFirst, this criterion is calculated as the "sum of probabilities for loss of load for integrated peak hour for all days of each planning year analyzed… being equal to 0.1"[16]

PJM is in frequent contact and coordination with ReliabilityFirst and has stakeholder processes in place to monitor, evaluate, and understand standards and demonstrate compliance, including through the appropriately named Reliability Standards and Compliance Subcommittee.

Q. How does PJM determine the amount of capacity needed to maintain resource adequacy?

A. In order for the PJM resource adequacy approach to function, PJM must properly identify the quantity of capacity that is needed to comply with standards. To comply, PJM uses a rigorous process involving multiple models and studies. It involves identifying the target planning reserve margin, which is the capacity percent above forecasted peak load needed to meet reliability

[15] NERC, BAL-502-RF-03 R1 and 1.1, October 16, 2017, https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RF-03.pdf.
[16] *Id.*

standards, and then applying that reserve margin to the forecasted load to set a capacity target.

To determine the reserve margin, PJM conducts a Reserve Requirement Study every year, in accordance with PJM Manual 20.[17] The reserve margin is estimated for both total installed capacity and capacity adjusted for expected unavailability of capacity resources.

To determine forecasted peak load, PJM conducts load forecasts according to PJM Manual 19. PJM's load forecasting uses PJM hourly load data and approved techniques for weather normalization and peak allocation. PJM's Load Forecast Model produces 15-year monthly and seasonal peak load and load management forecasts from the RTO level down to the zonal level, covering a range of weather conditions for each region.[18]

Q. How does PJM ensure resource adequacy at all points of its very large system?

A. The electricity system is a large network of transmission lines. Across a large electricity system there may be constraints on the deliverability of energy across the system's footprint. These constraints are generally related to the ability of

[17] PJM, 2023 PJM Reserve Requirement Study, October 3, 2023, https://www.pjm.com/-/media/committees-groups/committees/pc/2023/20231003/20231003-item-05a---pjm-2023-rrs-report.ashx.
[18] PJM, Manual 19 § 3.1, November 15, 2023, https://www.pjm.com/~/media/documents/manuals/m19.ashx.

the transmission system to deliver energy to load. In a system with transmission constraints, it would not make sense to build all capacity to meet a system-wide reserve margin in a small portion of the grid, on the other side of transmission constraints from load. The system would end up violating reliability standards as some parts of the system would become resource inadequate while others would have unnecessarily large reserve margins and potentially unused capacity.

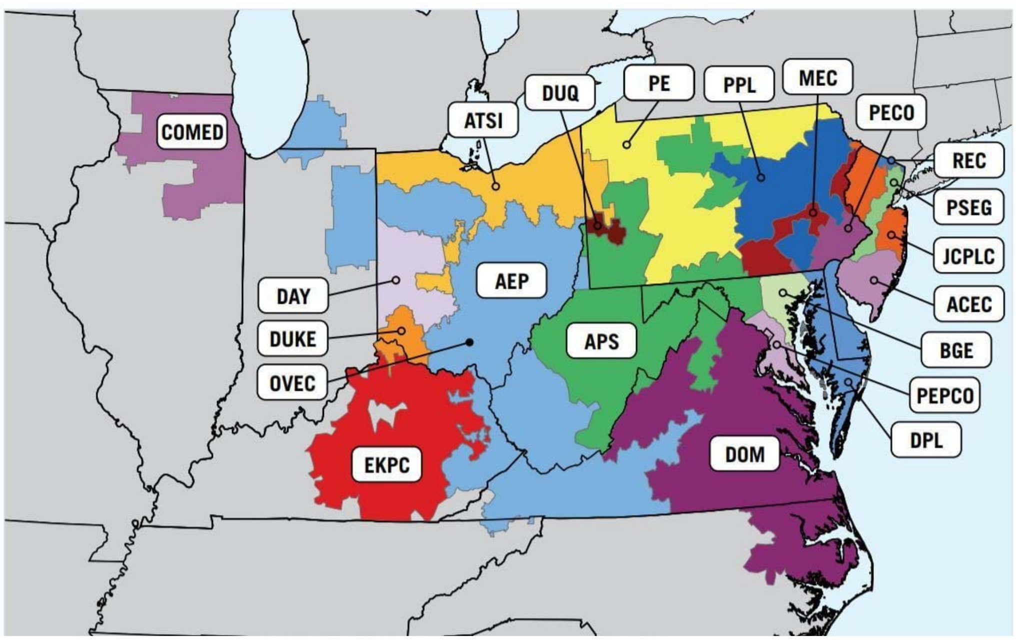
PJM is well-aware of this dynamic and thus built a regional resource adequacy construct that provides capacity value signals aligned to the optimal distribution of capacity from a reliability perspective. Combined with a locational pricing energy market, it supports economic capacity entry and exit signals by region. PJM's resource adequacy construct ensures resource adequacy across all sub-regions.

PJM calculates its reliability requirements on a Locational Deliverability Area ("LDA") basis. An LDA is essentially an area within which PJM has determined there are minimal internal constraints on delivering power, but which could potentially have constraints in delivering and receiving power externally. PJM analyzes each of the LDAs to ensure that the combination of internal capacity resources and imports from elsewhere in PJM are deliverable to load.[19] The

[19] PJM, Manual 20 § 4.1, July 26, 2023, https://www.pjm.com/~/media/documents/manuals/m20.ashx.

analyses compare the import capability required to limit transmission outage impact on LOLE and the actual emergency import capability of the test area. The PJM LDAs, not including the nesting structure that models some LDAs together as well as separately, is shown in Figure 3.

Figure 3: PJM Locational Deliverability Areas (LDAs)



Q. What does all this mean for Kentucky Power's resource adequacy?

A. Kentucky Power is a part of the AEP LDA within PJM. PJM's analyses have determined that the robust transmission topology within the AEP LDA allows for deliverability of sufficient energy across the zone during times of need. The PJM Load Deliverability Analyses have also determined that the AEP LDA is sufficiently connected to the rest of PJM, considering the transmission system and in-zone generation resources. The highly developed transmission system ensures that Kentucky Power's resource adequacy can be assured by drawing on a diverse set of resources located over a wide geography, rather than being forced to cover a large share of local demand with local capacity resources.

All of this indicates that Kentucky Power can confidently state that its level of resource adequacy is the same as the PJM RTO level, even if there may be other LDAs elsewhere in PJM (but not within the AEP LDA) that have realized slightly different resource adequacy outcomes from PJM and Kentucky Power in some years.

In addition, Kentucky Power's customers can enjoy resource adequacy without their local utility needing to build and own local capacity if there are more economic options. For example, Kentucky Power customers do not pay Riverside Generating Company for its gas plant's contribution to local resource adequacy. Instead, Riverside is compensated by the broader PJM market through its resource adequacy construct. And conversely, Kentucky Power meets its reliability requirements with the Mitchell Power Plant, even though it is located outside of Kentucky.

Q. Does the PJM approach only ensure resource adequacy for the summer?

A. No. As mentioned, the PJM Reserve Requirement Study determines a reserve margin that, when combined with the load forecast, determines the amount of capacity needed to meet the reliability requirements. That calculation involves the PJM summer peak load, leading some observers to suggest the PJM construct only aims at summer reliability. That is not correct for several reasons.

First, the Reserve Requirement Study may determine a reserve margin to apply to the summer peak load, but it is determined to ensure reliability standards are met across the entire year. It includes an Hourly Loss of Load Model that considers 1,000 hourly load scenarios. Each scenario includes 8,760 hours, which is every hour of the year.[20] Thus, the PJM process sets a summer capacity target based on a reserve margin that will deliver resource adequacy in accordance with the 1-in-10 standard through all points of the year, including winter.

In reality, the standard is significantly exceeded in winter, when reserve margins are generally much higher than in the summer. Indeed, recognizing that summer

[20] PJM, 2023 PJM Reserve Requirement Study § Appendix B, October 3, 2023, https://www.pjm.com/-/media/committees-groups/committees/pc/2023/20231003/20231003-item-05a---pjm-2023-rrs-report.ashx.

risk is higher, PJM's goal is for the winter LOLE to be "practically zero."[21] The following excerpt from PJM Manual 20 explains the reasoning for this well:

> *"PJM RTO winter reserves are generally greater than those of the summer period, partly because winter unit ratings are generally greater and winter weekly peak loads are generally less than the corresponding values over the summer period. It is desirable to maintain a negligible loss of load risk over the winter period because virtually all the RTO region's LOLE (99.9%) is concentrated in the summer weeks, despite the complete absence of unit planned outages in the summer. Since the summer risk cannot be reduced further (without installing additional Capacity Resources), winter reserve levels must be held greater than those over the summer to ensure the desired yearly RTO LOLE."*[22]

One potential challenge to non-summer reliability in PJM is the demand for planned outages of capacity resources in periods of the year with higher reserves. While many planned outages are aimed at the "shoulder" periods between summer and winter, PJM has instituted a process to ensure that it does not allow outages that threaten winter resource adequacy. This process is called the Winter Weekly Reserve Target.[23] This process determines the levels of unit

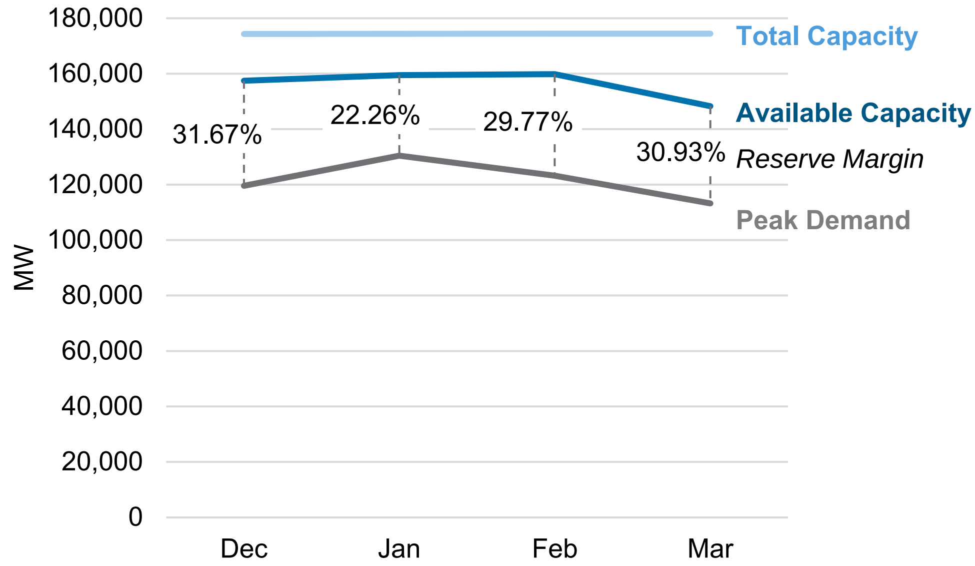
[21] PJM, 2022/23 Winter Weekly Reserve Target, p. 3, November 3, 2022, https://www.pjm.com/-/media/committees-groups/committees/oc/2022/20221103/item-04---winter-weekly-reserve-target.ashx.
[22] PJM, Manual 20 § 1.6, July 26, 2023, https://www.pjm.com/~/media/documents/manuals/m20.ashx.
[23] *Id.*

outages that can be allowed without decreasing the LOLE below the 1-in-10 standard.

Second, even though the total quantity of capacity is based on the summer peak load, the capacity product that is purchased in RPM and that is required from FRR entities is an *annual* capacity product. Capacity resources in PJM have a requirement to perform when needed year-round, and they face potentially drastic costs if they do not perform when needed, even in the winter.

The success of this approach can be seen in Figure 4. It shows that PJM capacity has significantly exceeded monthly winter peaks over the past 10 years. Available capacity is the total capacity less any capacity unavailable due to outages, either planned or unplanned.

Figure 4: PJM Historical Reserve Margin for Winter Months (10-year average)[24]



As a PJM member, Kentucky Power has its resource adequacy ensured across the entire year. Even though its peak load is during the winter, that load is included in PJM's reserve requirement analysis, and thus Kentucky Power's peak is covered by the capacity that PJM targets to comply with standards.

Q. Besides obtaining sufficient capacity through RPM, how does PJM verify and ensure sufficient capacity in advance of each winter season?

A. The PJM capacity construct ensures capacity is obtained to meet potential reliability needs up to three years in the future. As each delivery year

[24] FERC Form 714 data from Energy Velocity.

approaches, there are several opportunities for refining the load forecast and for capacity buyers and sellers to adjust their positions, either through incremental auctions or bilaterally. In addition, as each winter season approaches, given the critical societal need for reliability in the coldest months, there are several processes to further ensure resource adequacy in PJM.

Each year, the PJM Operations Assessment Task Force ("OATF") prepares an operating study for the upcoming winter that is published in November. OATF uses anticipated resources and forecasted load to calculate the expected reserve margin and assess readiness for the winter. For the 2021-22 and 2022-23 winters, OATF found no reliability issues or concerns in its scenario analyses.[25, 26]

PJM also contributes to the NERC winter reliability assessments in which NERC independently assesses and reports the overall reliability, adequacy, and risk of the upcoming winter. Of note, heading into the 2021-22 and 2022-23 winters, NERC found no expected resource problems under the assessed scenarios in

[25] PJM, OATF 2021-22 Winter Study, pp. 4, 6-7, November 4, 2021, https://www.pjm.com/-/media/committees-groups/committees/oc/2021/20211104/20211104-item-14-oatf-winter-study.ashx.
[26] PJM, OATF 2022-23 Winter Study, pp. 3, 5-6, November 3, 2022, https://www.pjm.com/-/media/committees-groups/committees/oc/2022/20221103/item-15---winter-oatf-review.ashx.

PJM and estimated an anticipated reserve margin that was three times the reference margin level.[27, 28]

Q. How does PJM ensure the capacity resources will perform?

A. PJM requires capacity resources to be available to provide energy throughout the year. PJM ensures resource performance through a combination of economic and physical tools. All capacity resources are obligated to offer energy into the energy market at all hours of the year in which they are not in approved outage status. In addition, for the past five years, capacity resource performance in PJM has been incentivized by the Capacity Performance ("CP") construct, which includes significant penalties for resources that under-perform when needed and provides potential bonuses for resources that over-perform. These CP penalties and payments are applicable throughout the year, thus supporting winter availability. In addition, existing capacity resources that do not perform when needed or when tested can lose the ability to sell their capacity, or a portion of it, in the future.

PJM does not simply leave winter preparedness up to generation owners and hope that the market signals incentivize desired levels of readiness. PJM also

[27] NERC, 2021-2022 Winter Reliability Assessment, pp. 29, November 2021, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2021.pdf.
[28] NERC, 2022-2023 Winter Reliability Assessment, pp. 20, November 2022, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf.

executes a required cold weather checklist and exercise to be completed and submitted to them by generation owners between November 1 and December 15 each year. The checklist covers personnel, staffing, equipment, fuel, and environment preparation. This checklist is revised based on guidelines recommended by NERC and lessons learned from recent weather events and its effects on generation resources.

There are also cold weather exercises conducted by capacity resource owners, with the results submitted to PJM. On a December day below 35 degrees, capacity resources that have not operated prior to December 1 are self-scheduled in the energy market to determine whether they are capable of reliably operating on both primary and alternate fuel and respond to PJM's dispatch instructions.[29]

Q. What did the reliability outcomes of Winter Storm Elliott suggest about resource adequacy in PJM?

A. Winter Storm Elliott was an extreme weather event unlike any other in PJM's history. While the PJM system's performance was not flawless, PJM did not experience any load shedding. The event was both a demonstration of PJM's

[29] PJM Manual 14, Section 7.5.1

successful resource adequacy planning and an opportunity for PJM to examine potential issues to address and design changes to consider.

PJM conducted a detailed event analysis and recommendations report on Winter Storm Elliott.[30] At a very high level, the event occurred from December 23-26, 2022. Entering the first operating day of Winter Storm Elliott, PJM had over 158,000 MW of operating capacity and projected a peak load of 127,000 MW. Instead, the realized peak load on December 23 was 136,010 MW.[31] Concurrent to higher than expected load, there were very high levels of generator outages due to the adverse weather conditions and fuel scarcity. PJM implemented emergency procedures and called for energy conservation.[32] PJM is typically a net exporter of energy but it curtailed exports December 23 from 16:00 to 22:00 and December 24 from 04:00 to 15:00 and 17:00 to 19:00 in order to maintain reliability within its balancing area, consistent with PJM Manual 13.[33] Throughout the multi-day weather event, PJM maintained the system's reliability and did not shed any load.[34]

[30] PJM, Winter Storm Elliott Event Analysis and Recommendation Report, July 17, 2023, https://pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx.
[31] *Id*, pp. 1.
[32] *Id*, pp. 17.
[33] *Id*, pp. 28-29, 32.
[34] *Id*, pp. 1.

Q. How did PJM's resource adequacy compare to neighboring balancing authorities during Winter Storm Elliott?

A. The lack of any load shedding in PJM stands in contrast to the outcomes in several neighboring and connected balancing authorities that learned they are more dependent on PJM for resource adequacy than they anticipated. The curtailment of exports impacted many balancing authorities, including Tennessee Valley Authority (TVA), Duke Carolinas, and Louisville Gas and Electric / Kentucky Utilities (LG&E/KU). During Winter Storm Elliott, each of these balancing authorities experienced load shedding that was coincident with PJM curtailing its exports to ensure reliability within its own balancing authority. The following are brief descriptions of the publicly known outcomes from Winter Storm Elliott in these neighboring systems:

- Tennessee Valley Authority (TVA) – On December 23, TVA needed 97% of its available owned and contracted power to meet demand, but 20% (6,705 MW) of these resources were unavailable. In response, TVA acquired additional capacity from neighboring markets, including PJM, to temporarily avert load shedding.[35] At 09:38, due to a transmission limit,

[35] TVA, Winter Storm Elliott After Action Report, pp. 12-13, 2023, https://cdn1-originals.webdamdb.com/14125_149056454?cache=1683299913&response-content-disposition=inline;filename=2023-306%2520Winter%2520Storm%2520Elliott%2520After-Action%2520Public%2520Report-FNL2.pdf&response-content-type=application/pdf&Policy=eyJTdGF0ZW1lbnQiOlt7IlJlc291cmNlIjoiaHR0cCo6Ly9jZG4xLW9yaWdpbmFscy53ZWJk

PJM curtailed half (250 MW) of the emergency energy it was delivering. TVA was eventually forced to shed load of over 1,500 MW at 10:31.[36] It was able to briefly come out of load shedding a few hours later, but returned to the same condition by the evening peak (TVA's record winter peak), a period in which PJM had curtailed its exports to neighboring balancing authorities.

On December 24, TVA needed 100% of its planned capacity and 6% additional capacity to meet demand, but 19% (5,264 MW) of owned and contracted power was unavailable. With imports from neighboring balancing authorities, including PJM, remaining curtailed, TVA shed load from 05:51 to 11:30.[37]

- Louisville Gas and Electric / Kentucky Utilities (LG&E/KU) - LG&E/KU is not a member of any RTO and serves as its own balancing authority. In

YW1kYi5jb20vMTQxMjVfMTQ5MDU2NDU0P2NhY2hlPTE2ODMyOTk5MTMmcmVzcG9uc2UtY29udGVudC1kaXNwb3NpdGlvbj1pbmxpbmU7ZmlsZW5hbWU9MjAyMy0zMDYlMjUyMFdpbnRlciUyNTIwU3Rvcm0lMjUyMEVsbGlvdHQlMjUyMEFmdGVyLUFjdGlvbiUyNTIwUHVibGljJTI1MjBSZXBvcnQtRk5MMi5wZGYmcmVzcG9uc2UtY29udGVudC10eXBlPWFwcGxpY2F0aW9uL3BkZiIsIkNvbmRpdGlvbiI6eyJEYXRlTGVzc1RoYW4iOnsiQVdTOkVwb2NoVGltZSI6MjE0NzQxNDQwMH19fV19&Signature=CUXhWM6iWOkxovEh0Yahq2nNGWEt0z~Yxxy96drEChZcCe62nbiPXq3PknDKDU~mTrvplBEZl0-A0S-Gqc7y3KGm6sHuAuwjPfOOV5~JHdEAStl35lt-KdErxxNSXdaU7oVzEBdscqulBtY4IU4WtwviRKK6r-bpUtkTVrjxyYmUuPtNmIrUFobsKTZLzoNlgWIfZPmG1cKLfCyN8jHGOqUKXwr7PM-iJuUYdkPUADYAoZNed2yflJau3jUs-uKxyTSszvFoW5e-2iKyLIJo7mbcYoWvIogZ57LkMjvOwQtwr5kxk62URUiy85UVB~JYcVy~sLVhQLv-ZDXZ40Wa0w &Key-Pair-Id=APKAI2ASI2IOLRFF2RHA.

[36] FERC, NERC and Regional Entity Staff Report, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott, pp. 64, October 2023, https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022.

[37] *Id.*

its 2021 IRP, LG&E/KU assessed both summer and winter reserve margins and determined it had sufficient owned capacity to meet forecasted summer and winter peak loads.[38] LG&E/KU experienced several outages during Winter Storm Elliott.

On December 23, LG&E/KU experienced capacity deficiencies that amplified in the early afternoon. At 16:29, PJM curtailed 400 MW of power exports to LG&E/KU. LG&E/KU then turned to TVA, which filled in until it was also approaching load shedding associated with PJM curtailed exports. TVA curtailed its 400 MW of exports to LG&E/KU, leading to load shed from 17:58 until 22:11.[39] The maximum load shed was approximately 317 MW.[40]

- Duke Energy Carolinas/Duke Energy Progress (Duke Carolinas) – Duke Carolinas was forced to implement rolling outages which impacted 500,000 of their customers during Winter Storm Elliott.[41] Duke Carolinas

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[38] LG&E/KU, IRP 2021. pp. 5-11, July 2020, https://psc.ky.gov/pscecf/2021-00393/rick.lovekamp%40lge-ku.com/10192021013101/5-LGE_KU_2021_IRP_Volume_III.pdf.
[39] FERC, NERC and Regional Entity Staff Report, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott, pp. 65, October 2023, https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022.
[40] LG&E/KU, Case No. 2022-00402, Response to AG-1 Question No. 13(l), Attachment 1, January 6, 2023, https://psc.ky.gov/case/viewcasefilings/2022-00402.
[41] Duke Energy, News Center: Updates on Winter Storm Elliott Emergency Outage Event, January 3, 2023, https://news.duke-energy.com/releases/duke-energy-updates-north-carolina-utilities-commission-on-winter-storm-elliott-emergency-outage-event.

imported energy from PJM prior to PJM's export curtailments.[42] Ultimately, generation plant outages and curtailment of energy purchases (both firm and nonfirm) resulted in Duke Carolinas shedding load on the morning of December 24 from 06:14 to 09:32, a period in which PJM had curtailed exports.[43]

Q. How has PJM responded to its lessons learned from Winter Storm Elliott?

A. Even well-functioning Reliability Coordinators will from time to time encounter emerging issues or experience challenges to resource adequacy in their balancing authority. But the best performing coordinators are the ones that actively identify issues, find solutions, and implement them in a reasonable timeframe to ensure continued resource adequacy over time. That is clearly what PJM aims to do and is doing in response to Winter Storm Elliott.

The very high number and degree of forced outages of capacity resources during Winter Storm Elliott, as well as some other challenges, brought to light some previously unappreciated issues. As would be expected of a responsible Reliability Coordinator, PJM has been very active in deeply studying the event and working on planning, design, and operational improvements to further

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[42] PJM, Winter Storm Elliott Event Analysis and Recommendation Report, pp. 46, July 17, 2023, https://pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx.

[43] South Carolina Office of Regulatory Staff, Docket No. ND-2023-1-E, pp. 15, August 25, 2023, https://dms.psc.sc.gov/Attachments/Matter/ec372380-8639-406e-816e-fc9fe0d45cfd.

ensure resource adequacy going forward. The major report on recommendations from PJM identified 30 recommendations. Notably, none of the recommendations indicate a shortage of capacity or resource adequacy failure, but rather suggest improvements to incentives, testing, and evaluating reliability contributions of capacity resources to protect against future potential issues. In other words, PJM is being proactive.

These recommendations were part of the Critical Issue Fast Path ("CIFP") – Resource Adequacy process. The scope of the process included risk modeling, the Capacity Performance construct, capacity accreditation, and synchronization between RPM and FRR. There were many stakeholder proposals in this process. It ultimately led to PJM filing two proposals to FERC in October for multiple market changes, and an expectation for additional changes to come.[44] PJM requested approval from FERC to allow implementation by June 2024 to cover the 2025/2026 planning period. The proposed changes covered topics ranging from risk modeling to capacity performance rules to capacity accreditation, which relates to the determination of how much capacity value different resources contribute.

[44] PJM, News Release: PJM Files Changes to Capacity Market to Promote Reliability, October 13, 2023, https://www.pjm.com/-/media/about-pjm/newsroom/2023-releases/20231013-pjm-files-changes-to-capacity-market-to-promote-reliability.ashx#:~:text=The%20proposed%20reforms%20are%20designed%20to%3A&text=Enhance%20how%20PJM%20accounts%20for,models%20and%20sets%20procurement%20targets.&text=Advance%20an%20accreditation%20framework%20for,those%20resources%20provide%20to%20consumers.

The filings do not propose to change the PJM resource adequacy construct to include seasonal capacity products, such as separate requirements and auctions for summer and winter. In the near future, PJM will conduct a stakeholder process to guide a transition to seasonal capacity products. This exploration of a seasonal approach does not suggest any issue with near term resource adequacy in PJM, but rather is a consideration for long term planning and resource adequacy assurance.

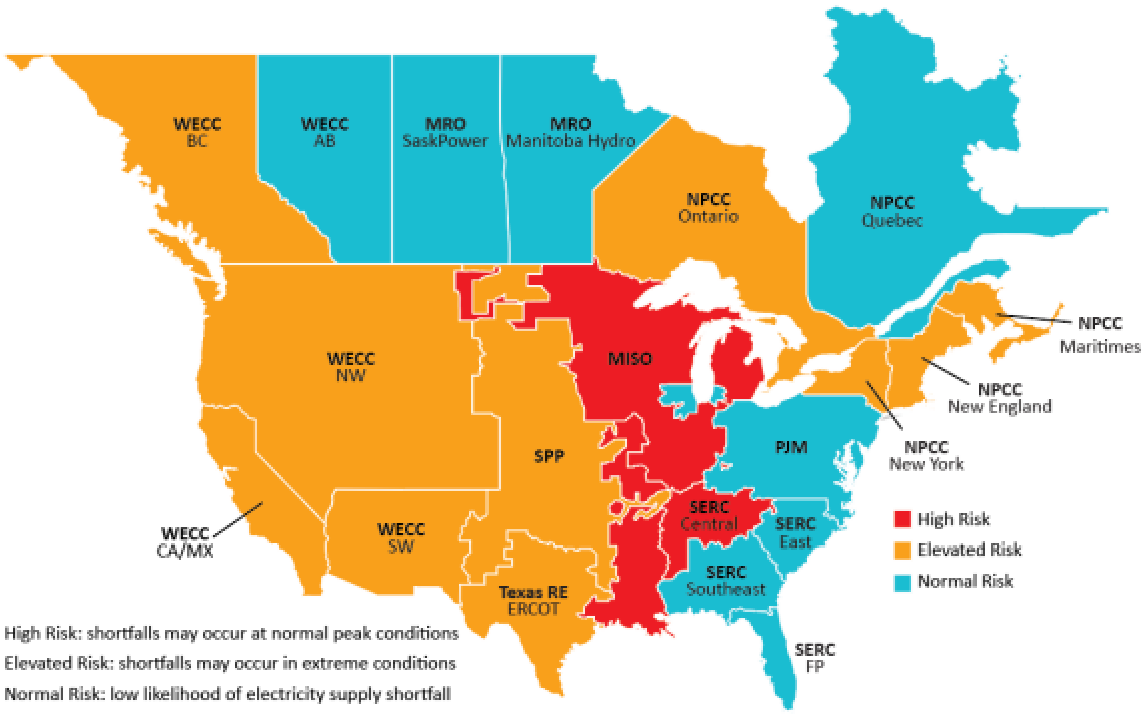
Q. What is NERC's view about about PJM's resource adequacy, currently and going forward, relative to other regions?

A. The strength of PJM's resource adequacy position was recently observed in NERC's 2023 Long-Term Reliability Assessment which evaluated risk levels in balancing authorities from 2024 through 2028. PJM was deemed a "Normal Risk Area" in which "…resource adequacy criteria are met, and it is unlikely for electricity supply shortfalls to occur even when demand is above forecasts or resource performance is abnormally low."[45] This stands in contrast to several neighboring balancing authorities, including MISO and SERC-Central, which include non-PJM portions of Kentucky and are the only two areas labeled "High

[45] NERC, 2023 Long-Term Reliability Assessment, pp. 9, December 2023, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

Risk Area" in the NERC assessment. The results of the assessment are shown in Figure 5.

Figure 5: NERC Long-Term Reliability Assessment, Risk Areas, 2024-2028[46]



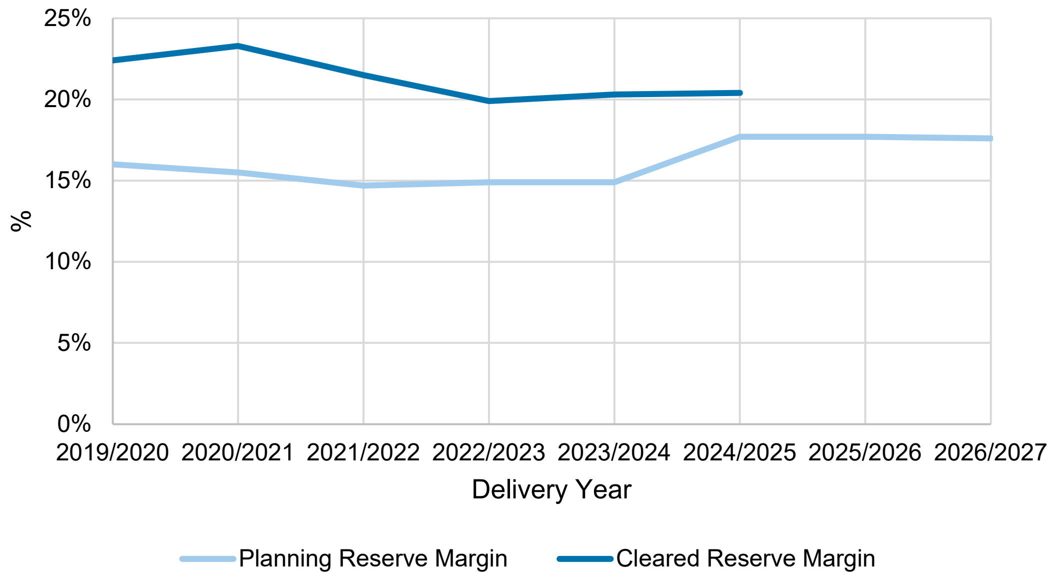
Q. Does PJM require additional capacity to be resource adequate going forward?

Yes, and PJM has made it clear through multiple channels and long-term studies that it expects to need additional capacity in the future to ensure resource adequacy. This is not a sign of a resource adequacy issue, but rather

[46] *Id*, pp. 6.

another example of a reliability coordinator proactively confronting potential future challenges. In the near term, the PJM capacity market results and the realized reserve margins demonstrate that PJM is delivering resource adequacy well-above the applicable reliability standards. This can be illustrated by comparing the planning reserve margins, which are set to meet the reliability standards, and the realized reserve margins, which are the results of capacity auctions. This comparison is made for Delivery Years 2019/20 to 2024/25 in Figure 6. The PJM capacity market includes a sloped demand curve, which can result in cleared capacity volumes well above the amount needed to meet the reliability standards. This has been the result in PJM for many years. The chart also shows the planning reserve margin is not expected to increase in the next two Delivery Years, 2025/26 and 2026/27.

Figure 6: Planning and Realized Reserve Margins, Delivery Years 2019/20-2024/25.[47,48]



III. SATISFYING THE CAPACITY OBLIGATION

Q. What are Kentucky Power's options for meeting its PJM capacity obligation?

A. As a PJM member Load Serving Entity (LSE), Kentucky Power must meet PJM's capacity requirements. As noted briefly above, there are two ways that an LSE can demonstrate to PJM it has fulfilled its obligations: (1) participate in

[47] PJM, Reserve Requirement Development Process, December 20, 2022, https://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx.
[48] PJM, 2024-2025 Base Residual Auction Report, pp. 4, December 2022, https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx.

PJM's capacity market, RPM, as a capacity buyer, or (2) select the FRR alternative, which involves taking on the responsibility of developing and executing an annual FRR Capacity Plan that demonstrates "commitment of Capacity Resources sufficient to meet its capacity obligation."[49] The capacity in an FRR plan contributes to overall PJM resource adequacy in the same way as capacity in RPM. The main difference is that an LSE participating in the RPM auction meets its capacity obligation by making a financial payment to PJM, which then procures capacity from the suppliers participating in the auction. An LSE participating in an FRR plan meets its capacity obligation by designating specific resources it wishes to commit to PJM. Either way, the capacity resources are committed to ensuring pool-wide reliability, not any particular LSE. Thus, when Kentucky Power participates in an FRR plan, the capacity resources it designates in that plan are not dedicated specifically to serving Kentucky Power; rather, they are Kentucky Power's contribution to RTO-wide reliability. A simple analogy might be to a large potluck picnic. To ensure there is enough food for everyone, participants have two choices – they can pay the organizers to arrange for catering or they can contribute food they made at home. At the picnic, no one has any claim to any particular dish; everyone's contribution feeds everyone. So too with capacity in a power pool like PJM.

[49] PJM RAA Sched. 8 §§ C.1 and D.1.

Thus, the choice between participating in RPM versus the FRR alternative does not impact the LSE's resource adequacy position, which is ensured by PJM.

Q. How does Kentucky Power comply with its capacity obligation?

A. Kentucky Power participates in an FRR plan with other AEP LSEs. In the AEP FRR Plan, each LSE must obtain its share of the overall capacity obligation. Each LSE's share is determined by its share of the overall capacity requirement for the FRR entity, which is equivalent to the LSE's summer peak plus a reserve requirement. Kentucky Power has historically met most or all of its obligation to the AEP FRR Plan through its owned capacity and through a long-term contract for capacity (and energy) from the Rockport plant. In recent years where owned and contracted capacity did not satisfy the obligation, Kentucky Power has purchased capacity from other members of the AEP Power Coordination Agreement ("PCA") (which includes APCo, I&M, and WPCo). The purchased capacity is transacted at the RPM-established capacity price for the relevant Delivery Year.

Q. Does the fact that Kentucky Power's FRR plan designates capacity sufficient to meet the summer peak mean that Kentucky Power is using PJM as a "backstop" in the winter?

A. No. The question is based on a false premise. As I've explained, Kentucky Power's owned and contracted capacity resources are not dedicated to serving

Kentucky Power specifically or primarily; rather, they are Kentucky Power's contribution to RTO-wide reliability at all times of year, and by participating in PJM, Kentucky Power has adequate capacity to serve its customers' requirements at all times of the year. PJM's power pool is never a "backstop" – it is the mechanism by which Kentucky Power ensures resource adequacy in all hours of the year.

Q. If Kentucky Power built additional capacity so that it owned capacity in a quantity equal to its winter peak, what benefit would that bring to Kentucky Power's resource adequacy?

A. There would be no impact on Kentucky Power's satisfaction of reliability standards. This is because PJM already meets or exceeds these standards, as I have described throughout this testimony. In other words, adding a new power plant in the Kentucky Power territory would not impact whether Kentucky Power meets a 1-in-10 LOLE standard for resource adequacy related outages because the PJM resource adequacy process already complies with this standard.

There would be at best a negligible benefit to Kentucky Power's resource adequacy. The benefit would be equivalent to the marginal benefit of new capacity elsewhere in the AEP zone, or even the broader RTO, since the AEP zone generally has the same resource adequacy outcome as the majority of PJM. That marginal benefit would be zero if the new Kentucky Power capacity simply displaced other similar capacity elsewhere, which is a potential outcome based on the way RPM works to signal new capacity additions and retirements. New capacity tends to push existing capacity or proposed capacity out.

It is reasonable to wonder whether local capacity has greater benefits to local reliability than capacity built elsewhere in PJM. The way the PJM system works, the local capacity is not more valuable than capacity elsewhere, absent meaningful transmission constraints between the two locations. This is because capacity in PJM is shared, or “pooled,” between all the members, and thus there is no way for an LSE to hoard its owned capacity for its own region. Each LSE experiences the resource adequacy of the entire PJM system.

The only exception is when there is a local need for capacity due to transmission constraints. As mentioned previously in this testimony, PJM rigorously studies the transmission system and capacity at the LDA level to determine the amount of local capacity that is needed to serve local demand. If a zone is “short” of the needed in-zone and transfer capacity, then incremental additions can indeed improve local resource adequacy. However, this has not been the situation in the AEP zone.

Q. What would be the likely cost impact of Kentucky Power adding additional capacity so that it owned capacity in a quantity equal to its winter peak?

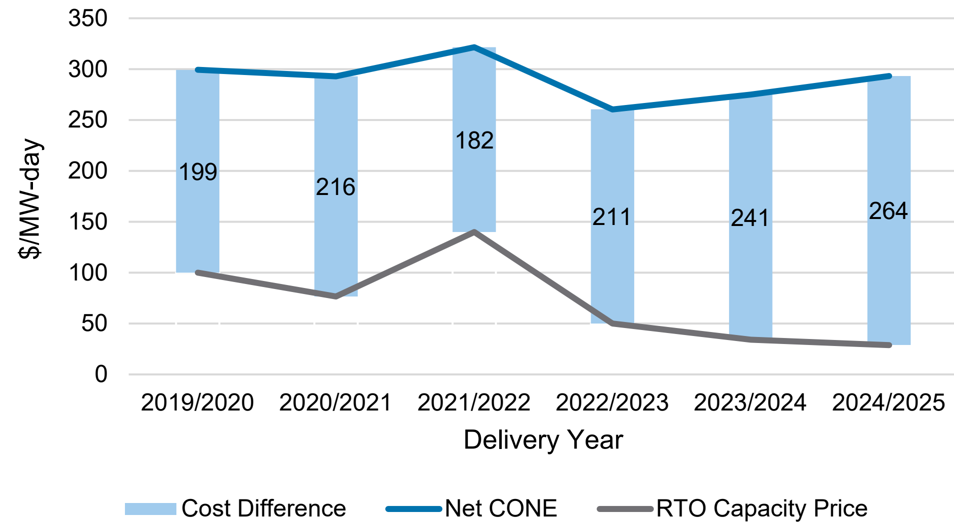
A. The decision for an electric utility to add new generating capacity should be based on thorough analysis of all costs and benefits of multiple options to satisfy the utility's various obligations, including PJM's capacity obligations. I have shown in this testimony that, for Kentucky Power, adding new capacity in the past few years would not have been expected to result in increased resource adequacy. This does not mean that adding new capacity may not be valuable. In fact, Kentucky Power's most recent IRPs have determined it would be beneficial to add capacity. However, the benefits that have led to that outcome are not resource adequacy related, but rather are economic: reduced energy costs, capacity cost avoidance, and other benefits.

To fully answer the question of what the likely cost impact would be of adding owned capacity, a full IRP-like analysis would be required of Kentucky Power portfolios with and without that capacity. This is because the cost is more complicated than simply the capital cost of building a new unit, which Kentucky Power's 2022 IRP estimates as about $750/kw for a new gas peaker plant and $1,000-1,200/kw for a new combined cycle plant, and thus about $225 million to $360 million for a plant that would allow Kentucky Power to fully meet its winter peak with owned capacity (about 300 MW).[50] In reality, new capacity brings benefits in avoided energy and capacity costs and also impacts market prices and the need for capacity in the future. The relevant metric to consider is the net cost after all benefits and other costs have been incorporated.

However, to provide a sense of scale of net cost, a simple calculation may be helpful. In advance of each RPM Base Residual Auction, PJM publishes estimated Net Cost of New Entry (Net CONE) for each modeled LDA. This value is the annualized cost of a new capacity resource adjusted for the expected revenues from the sales of energy and ancillary services. It can be thought of as the cost of the resource less the market benefits not including avoided capacity costs. Therefore, the difference between Net CONE and PJM capacity costs can be considered the additional cost of that resource beyond its direct market benefits. Figure 7 shows this comparison for the past six Base Residual Auctions in PJM, focusing on the values relevant in the AEP zone. Clearly there is a significant net cost expected for building a new plant in the AEP zone before portfolio and other economic benefits are considered.

[50] Kentucky Power, 2022 IRP to the Kentucky Public Service Commission, pp.218, March 20, 2023; CRA analysis.

Figure 7. PJM Net CONE vs. RPM Capacity Price, DY 2019/20 to DY 2024/25



Q. Is it common for LSEs to meet their obligation through non-owned capacity resources?

A. Yes. In fact, it is rare for an LSE to meet its entire obligation through owned resources. Many LSEs in PJM do not own any capacity, mostly due to states deciding they prefer to have their utilities comply with PJM requirements solely through bilateral contracts and RPM-transacted capacity. For the LSEs that are not constrained by state rules on utility ownership of generating capacity, the decision whether to build and own capacity resources to cover their PJM obligation is mostly based on economics, applied through resource planning processes, such as IRPs.

To illustrate the various owned capacity positions of LSEs in PJM, I conducted an analysis to determine to what extent peer utilities rely on owned capacity to meet their summer and winter peak loads and their reserve requirements. This is not a precise review of their positions to meet the PJM requirement, particularly since there is no specific reserve requirement for LSEs in the winter. Rather, it indicates a wide range of approaches taken by LSEs and their regulators regarding whether to cover capacity needs with owned resources. It also demonstrates how Kentucky Power's position compares to peer utilities. The methodology, data, and assumptions used for this comparison are provided as JCP Attachment 2.

Figure 8 presents the percentage of each peer LSE's seasonal peak loads that can be met by owned capacity. On the x-axis is the owned summer capacity as a fraction of summer peak load and on the y-axis is the owned winter capacity as a fraction of winter peak load. The chart provides lines to illustrate 100% coverage, as well as a line for peak load plus the PJM Installed Reserve Margin. This is not necessarily the reserve requirement for each LSE. Entities which do not own any capacity are not labelled in the figure.

Figure 8: PJM LSE Coverage of Peak Loads with Owned Capacity, 2022[51]

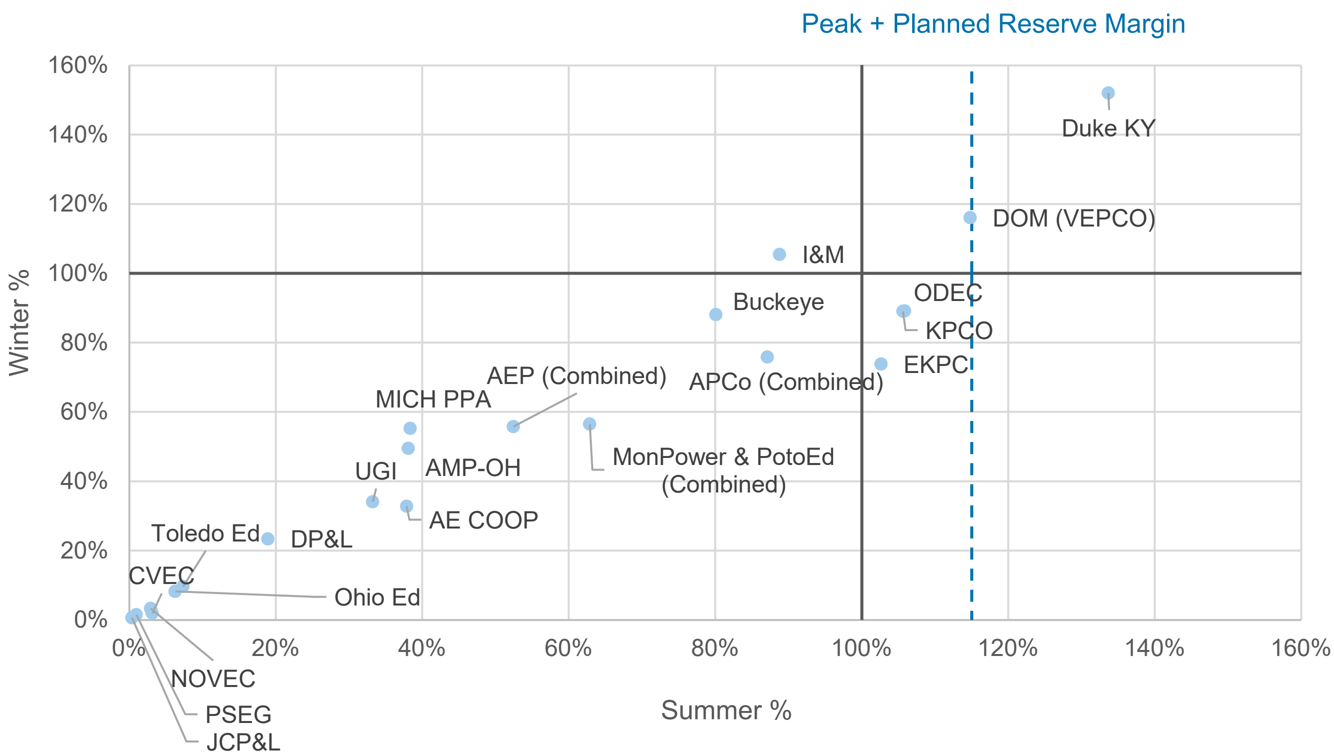


Table 1 lists the 17 entities that reported no owned capacity as of December 2022. The fact that there are so many entities that do not own any capacity to meet their capacity obligations demonstrates that reasonable planning and regulation can lead to the decision to comply with PJM requirements entirely through bilateral contracts and purchasing capacity through RPM. This is not meant to endorse such an approach as optimal for all contexts.

[51] EIA Form 861 Scehdule 2 Part B data from Energy Velocity; CRA Analysis

Table 1: PJM LSEs in Peer Analysis that do not own Generating Capacity

Company Name	Abbrev	Operating State	Parent Company
Atlantic City Electric Co	AC Electric	NJ	Exelon Corp
Baltimore Gas & Electric Co	BG&E	MD	Exelon Corp
Cleveland Electric Illuminating Co (The)	Cleveland Electric	OH	FirstEnergy Corp
Commonwealth Edison Co	COMED	IL	Exelon Corp
Delmarva Power & Light Co	DLMRVA	DE & MD	Exelon Corp
Duquesne Light Co	DQE	PA	Macquarie Bank Limited
Metropolitan Edison Co	METED	PA	FirstEnergy Corp
Naperville IL (City of)	Naperville Mun	IL	Naperville IL (City of)
Ohio Power Co	AEP Ohio	OH	American Electric Power Co Inc
Pennsylvania Electric Co	Penelec	PA	FirstEnergy Corp
PPL Electric Utilities Corp	PPL	PA	PPL Corp
Pennsylvania Power Co	PENNPOW	PA	FirstEnergy Corp
PECO Energy Co	PECO	PA	Exelon Corp
Rockland Electric Co	ROCKLAND	NJ	Consolidated Edison Inc
Southern Maryland Electric Coop Inc	SMECO	MD	Southern Maryland Electric Coop Inc
West Penn Power Co	WPP	PA	FirstEnergy Corp
Duke Energy Ohio	Duke OH	OH	Duke Energy Corp

Another interesting finding from this analysis is that, of the 41 individual entities evaluated, 14 were "winter peaking" in the review period, meaning they reported higher peaks for December 2021 through March 2022 than June through

September 2022.[52] Clearly, Kentucky Power is not alone in its situation, nor in its approach to addressing it.

IV. ENERGY POSITION IN 2022

Q. How can utilities meet the energy demands of their customers?

A. The approaches available to an electric utility for providing energy depend on their location and the regulatory contexts in which they operate. For utilities serving as stand-alone balancing authorities, they can generate electricity or buy it, either from non-owned generators in their territory or from external generators via imports. For utilities in RTOs like PJM, every unit of electricity that is served to customers is purchased from an energy market operated by PJM in which the electricity is produced by an entire “pool” of generators. While the electrons themselves may be generated in part by the utility’s owned generators, all of the energy they provide is transacted in the RTO-wide market before it is delivered to customers. When transacted, it is purchased at the locational marginal price at each point of delivery to the utility’s distribution network. This is the fundamental concept of a power pool.

[52] These included Virginia Electric & Power (DOM-VEPCO), Old Dominion Electric Coop (ODEC), Kentucky Power, East Kentucky Power Coop (EKPC), Appalachian Power Co (APCo), Kingsport Power Co, Potomac Edison Co, Duke Energy Ohio, Allegheny Electric Coop, Central Virginia Electric Coop (CVEC), Duquesne Light Co (DQE), Pennsylvania Electric Co (Penelec), PPL Electric Utilities Corp (PPL), and Southern Maryland Electric Coop (SMECO).

Utilities in many jurisdictions also have the opportunity to own generators and to sell their output into the market, including at the same time as energy is being purchased from the market. If the generation is of the same volume and at the same pricing point as the electricity demand, then the cost of procuring energy from the market and the revenues from selling energy cancel each other out, and the only energy cost to customers is the cost of generating electricity by the utility's owned generator. Owning generation can therefore serve as a hedge against high energy prices; when the market price exceeds the cost of operating the generating plant, customers will pay just the generation cost rather than the market price. Of course, it is generally more complicated, and in any given time period a utility may be producing more or less than their customers are consuming and there will be either positive or negative net revenues from market transactions.

In PJM, generator owners can either participate based on economics (running when the generation cost is lower than the energy market price) or choose to "self-schedule," running regardless of the comparative cost. In most cases, an owned generator reduces energy costs only when the generation cost is lower than the market price.

Owning generation is not the only option for electric utilities to reduce exposure to energy market prices. They can also contract for energy, such as through a

Power Purchase Agreement (PPA), which is a long-term contract to purchase energy at specified volumes, location, and prices. PPAs can include just the energy produced by a generator, or they can include additional attributes, such as the capacity the generation resource is qualified to provide. PPAs can provide the same kind of hedge as owned generation. Utilities can also buy shorter term financial products, such as swaps or contracts for differences, in which the utility and a counterparty agree to make or receive payments depending on whether the market price for energy is below or above the contract price.

Q. How does Kentucky Power meet the energy demands of its customers?

A. As stated in its 2022 IRP, Kentucky Power relies on a combination of both owned and contracted resources, its membership in PJM, as well as demand side mechanisms.[53] This ensures that it can meet its objectives to maintain customer affordability, rate stability, reliability, and sustainability.[54] The types and volumes of owned and contracted resources are determined through a robust planning process that is guided by IRPs that are conducted every three years in accordance with requirements set by the Commission. The IRPs evaluate the least cost approach to reliably serving energy to customers while

[53] Kentucky Power, 2022 IRP to the Kentucky Public Service Commission, March 20, 2023
[54] *Id.*

meeting Kentucky Power's various obligations, which include its capacity obligation as a PJM member.

Kentucky Power's planning acknowledges that owned resources and long term PPAs will not cover all energy consumption by its customers, regardless of whether they collectively are able to cover the expected peak energy demand. It can be expected that there will be many times in the year in which Kentucky Power's resources have generation costs higher than the market energy prices, and thus will not run at full capacity. There will also be outages, both planned and unexpected. Also, the planning process can reasonably determine that the optimal approach for Kentucky Power includes relying on the market since prices may very well be expected to be lower than expected generation costs and PPA prices. In general, market energy prices are favorable to Kentucky Power because PJM is summer peaking and Kentucky Power is winter peaking, meaning Kentucky Power's demand (in contrast to many other PJM utilities) is less likely to peak during the period of the year with the highest market prices.

Q. Was Kentucky Power reasonably positioned to serve energy to its customers following expiration of the Rockport UPA?

A. The most relevant planning decisions that contemplated the December 2022 expiration of the Rockport UPA were the decisions guided by Kentucky Power's

2019 IRP.[55] The 2019 IRP evaluated a variety of resource portfolios over a 30-year period and across several scenarios to determine a preferred plan ("Preferred Plan") that would meet Kentucky Power's service obligations at the least total cost to customers. The resource portfolios considered in the 2019 IRP included options to quickly build new resources to replace the Rockport UPA's capacity and energy. For example, Case 7 included a gas combustion turbine plant and wind capacity to come online in 2023. However, the IRP analysis determined a Preferred Plan that instead relied on Short Term Market Purchases in 2022 and 2023 to replace the capacity only, followed by gradual new builds that would replace both capacity and energy over time. The difference in total utility costs to customers between Case 7 and the more cost-effective Preferred Plan was over $113 million.[56]

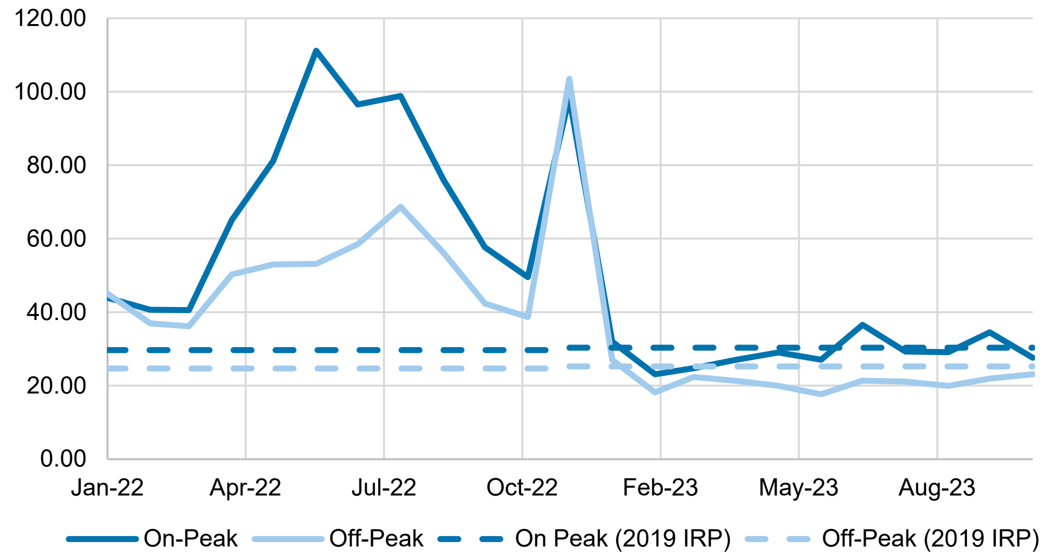
The Short Term Market Purchases indicated in the Preferred Plan were "…assumed to have no energy associated with it, a contract term of one year and 1,000 MW can be added annually. The pricing of these purchases is based on the PJM Capacity Prices ... The purpose of adding this resource was to allow the model an option to include a short-term capacity commitment as opposed to building a long-term capacity resource…"[57] Kentucky Power ultimately

[55] Kentucky Power, 2019 IRP to the Kentucky Public Service Commission, pp. 140, December 20, 2019.
[56] *Id*, Exhibit E2.
[57] *Id*, § 4.5.5, pp. 98-99.

executed these purchases through the AEP PCA and their pricing was indeed based on PJM capacity prices.

The 2019 IRP analysis is based on reasonable methods and used information reasonably knowable at the time. This is all that is required to demonstrate prudency. Still, there may be interest in considering the decisions in light of the extreme and unexpected commodity price period of 2021-2022 and Winter Storm Elliott. First, these dislocations in the markets had essentially ended by the end of 2022, which means the new builds contemplated in the 2019 IRP would not have been online. Second, had a long term PPA been entered, it remains unclear whether it would have been economic over its contracted duration since prices have been low in 2023. As shown in Figure 9, energy prices are currently in line with prices forecasted in the 2019 IRP, which indicated short term market purchases in the Preferred Plan.

Figure 9: Energy Prices, 2019 IRP Forecast and Realized Prices, 2022-present [58,59]



Finally, it should be noted that, even after expiration of the Rockport UPA, the majority of energy consumption by Kentucky Power customers was expected to be covered by owned generation, as shown in Figure 10. The white space under the black load obligation line represents expected market purchases, which are only a small share of the load obligation in most years. This is cumulative. In any given hour the company could be producing more or less than its load. Given the summer peaking in PJM and the resulting higher prices, it could be anticipated that Kentucky Power would benefit as a net seller of energy in the summer periods.

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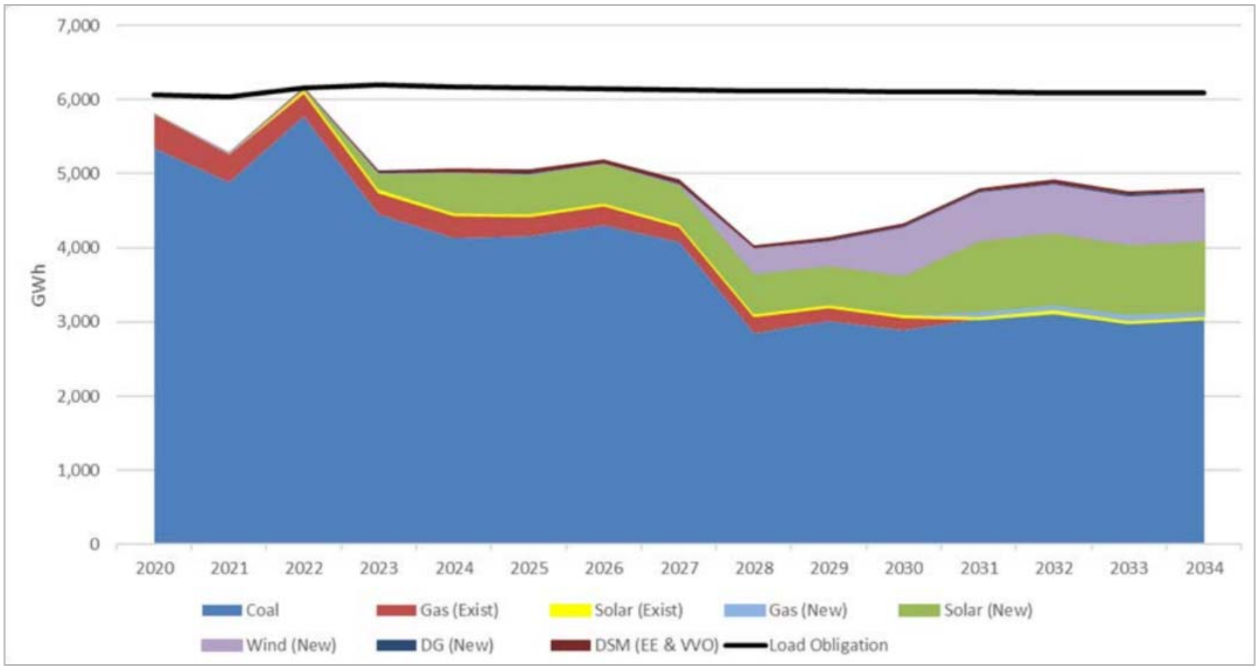
[58] *Id*, Table 1, pp.4.

[59] S&P Global, ISO Real-Time Prices, Accessed December 15, 2023.

Figure 10: Forecasted Annual Energy Position, Preferred Plan from 2019 IRP[60]



Q. Given the expiration of the Rockport UPA, what were Kentucky Power's options entering Winter 2022?

A. Given the understanding that the Rockport UPA would expire in December 2022 and a reasonable planning decision to not immediately replace the energy from that contract, Kentucky Power faced a series of short-term decisions leading up to Winter 2022-23. Each time the decision was encountered, Kentucky Power had two options related to the small share of its energy that was not covered by owned capacity or long-term contracts:

[60] Kentucky Power, 2019 IRP to the Kentucky Public Service Commission, Figure ES-8, December 20, 2019.

1. Market - Buy energy at PJM spot market prices.
2. Forwards / Futures Contracts - Buy energy from the PJM market, but also purchase electric power futures contracts that effectively sets a known price for a specified quantity of energy, thus "locking in" a price.

Kentucky Power evaluated these options throughout the year prior to December 2022 and consistently determined that the first option would lead to the lowest cost to consumers.

Q. Please describe the forward contracting option and how to consider its costs versus benefits.

A. In well-formed markets in which prices can change materially over time, there is often interest by participants to use hedging to mitigate the risks of future prices changing in ways that are counter to their positions. The EIA describes hedging as the "buying and selling of … contracts so as to protect energy traders from unexpected or adverse price fluctuations."[61] Net buyers may be interested in hedging their positions against increased prices, while net sellers may be interested in hedging their positions against decreased prices. Financial participants may see opportunity in addressing the interests of the participants.

[61] U.S. EIA, Glossary: Hedging, Accessed December 15, 2023, https://www.eia.gov/tools/glossary/index.php?id=hedging#:~:text=Hedging%3A%20The%20buying%20and%20selling,of%20the%20short%2Dterm%20market.

Given this demand, many secondary markets have formed to support the trading of forward contracts, such as power futures contracts in energy markets.

A forward power contract is an agreement between two parties to buy/sell power at a specified price, quantity, location, and time in the future. Some contracts may have other provisions, such as the quality of the products under contract, but in advanced energy markets, the commodity is homogenous – it is wholesale electricity. While these contracts can be directly negotiated bilaterally, there is value to having standard terms to facilitate active trading and price discovery. These are often traded over exchanges, such as ICE Futures. The products can also be derivatives of energy prices, such as swaps, options, and contracts for differences. It is best when there are significant volumes of transactions, providing “liquidity” that supports efficient pricing.

From the perspective of an electric utility that is a net buyer of energy, forward contracts provide protection against price increases above the contracted price. This benefit increases with greater upward price risks in a market, such as in periods of high volatility or markets that can bring extremely high prices under certain conditions. Benefits are generally increased when the buyer is less tolerant to risk – they may simply place a high value on certainty.

Of course, these benefits are not cost-free. First, there is an opportunity cost to specifying a set price in the future. The buyer loses the benefit of market prices falling below the contract price. Second, there is often a risk premium added to sellers' offers to reflect the risk of having to cover their positions in extreme events that could prove costly, as exhibited in the fallout from Winter Storm Uri in Texas. In some markets there can also be volume risk if demand is uncertain and the buyer can get stuck with a product it doesn't need, but in the highly liquid markets in PJM this is not a major concern as long as positions are not extremely large.

Any decision to enter forward contracts should be based on analysis of these costs and benefits. The analysis should consider the buyer's market expectations, risk tolerance, and statutory requirements. The buyer should understand that there is generally no "free money" in these transactions given the sophistication of the other side. In competitive markets with sophisticated participants, such as several forward markets derived from the PJM energy market, an electric utility that covers all of its energy positions over time with forward contracts should not expect to lower overall energy costs. Instead, the utility is opting to pay a premium above its expected costs to reduce its exposure to the risk that actual costs will exceed what it expects.

Q. Was it reasonable for Kentucky Power to have considered forwards as too costly in the period prior to Winter 2022?

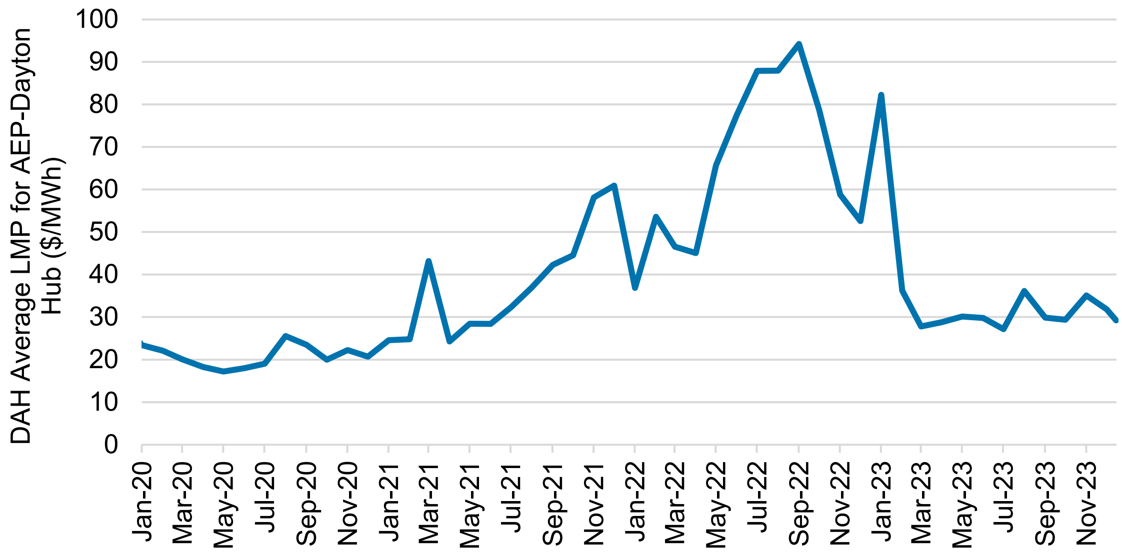
A. As discussed above, utilities should enter forward contracts only based on analysis of the likely costs and benefits, which can either be evaluated on a case-by-case basis or programmatically. As of the period prior to December 2022, Kentucky Power did not have a programmatic, Commission-approved hedging strategy, and thus reasonably evaluated the costs and benefits of forwards at frequent periods, at least monthly through 2022. When conducting these analyses, Kentucky Power, drawing upon the resources provided by AEPSC, reasonably evaluated market expectations and considered the likelihood of forwards providing greater benefits than costs.

Throughout 2022, forward contracts that covered the upcoming winter (December 2022 through March 2023) were priced at levels that assumed that the historically high prices experienced from late 2021 through late 2022 would be sustained. The relevant spot market prices for the period are shown in Figure 11. Much has been written about the cause of the high prices, but it was general consensus that fundamentals suggested the prices would come down at some point in the following year. This was the view of EIA and many others.[62] The greatest uncertainty was around the timing of the expected decrease in prices.

[62] U.S. EIA, Short-Term Energy Outlook, pp. 2, June 2022, https://www.eia.gov/outlooks/steo/archives/jun22.pdf.

While overall market expectations are generally captured in forward prices, it is not unreasonable for a buyer to consider the direction of market fundamentals and their impact on the value of entering forward contracts.

Figure 11: Average Day-Ahead Prices, AEP Hub in PJM, 2010 - 2023 YTD[63]



Another consideration in 2022 was that forwards were based on historically high prices. Entering high-priced forward contracts in these circumstances created a potential opportunity cost of missing the benefit of a downward shift in market prices, which is more impactful when starting at very high prices. For example, the opportunity cost of a forward contract at $80/MWh is high due to the ability of prices to return to $25/MWh levels, while a $30/MWh contract has lower opportunity cost due to the lower bound on market prices. Higher prices also

[63] PJM data from Energy Velocity

limit the upside risk. For example, there are very limited scenarios that could cause winter-long average energy prices above $100/MWh in PJM.

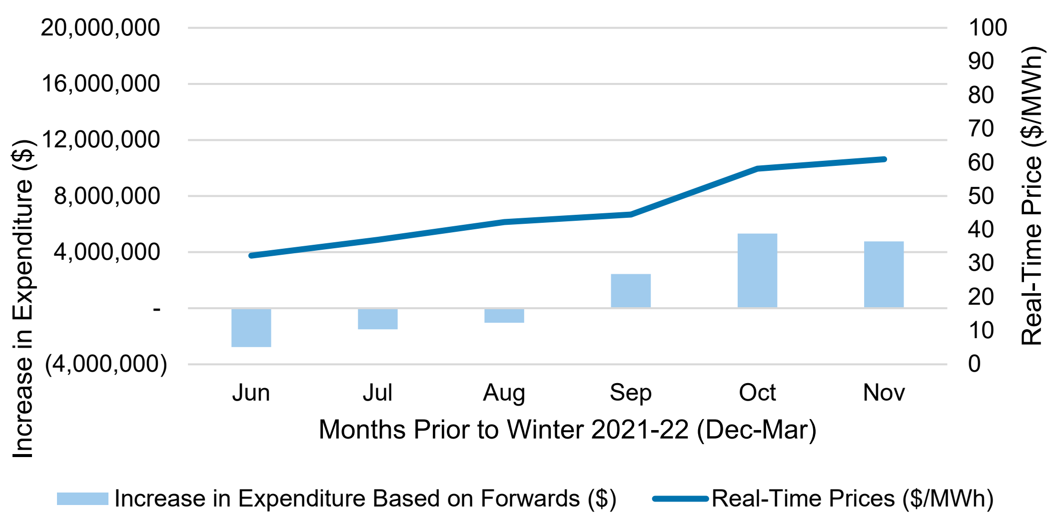
Additionally, for over a year prior to Winter 2022, PJM energy prices were highly volatile. While the important consideration is average prices over a multi-month period, the volatility can bring additional buyer interest in hedging, particularly from participants that cannot withstand the impacts of high prices and volatility. This increases the demand, and thus the price, of forward contracts.

As Kentucky Power considered its positions heading into Winter 2022, it only had to look back to the previous year to see examples of how entering forward contracts during lower priced periods could prove more beneficial than forwards contracted in higher priced periods. This is demonstrated in Figure 12. It is based on my analysis that is very similar to the analysis conducted by Witness Vaughan in Kentucky Power's initial response to the Show Cause Order.[64] The chart examines the impact of forwards for Winter 2021 that would have been hypothetically contracted in June through November 2021, which is the period during which Kentucky Power's forward contract evaluations were conducted. The line shows the average energy price in the current month. For example, in June 2021 the average price at the AEP Dayton pricing hub was $34/MWh, while the price had climbed to $63/MWh on average for November 2021. The

[64] Kentucky Power's Response to Show Cause Order, Exh. A, Vaughan Aff. at pp.10-13 (July 21, 2023).

bars for each month represent the calculated impact of a hypothetical forward contract for Winter 2021/22, assuming it was entered into at forward prices as of that month. For example, a 97 MW all-hours forward contract for Winter 2021/22 entered into in June 2021 would have benefited purchased power costs by $2.8 million, while a contract for the same period entered into in November 2021 would have increased purchased power costs by $4.8 million.[65] A pattern can be discerned where the net benefit of the forward contract decreases as the current month prices increase.

Figure 12: Purchase Power Expenditure Impact of Forwards for Winter 2021-22 [66]



[65] This example is purely hypothetical in that Kentucky Power still had the energy contracted from the Rockport UPA for Winter 2021 and thus would only consider purchases for a smaller energy position than the one used in this analysis.
[66] S&P Global, ISO Real-Time Prices and Forwards & Futures, Accessed December 13, 2023; CRA Analysis.

As Kentucky Power evaluated its position for Winter 2022-23, it was doing so in a period of high energy prices and high forward prices. Forwards for Winter 2022-23 were at their peak May through August 2022 (four to seven months prior), after which both power prices and forwards began to decrease. In the three months immediately prior to Winter 2022-23, forwards remained high despite the downward pressure, falling by only an average of $10/MWh by November 2022. Given these dynamics, it was reasonable for Kentucky Power to expect forwards prior to Winter 2022-23 to bring benefits less than costs.

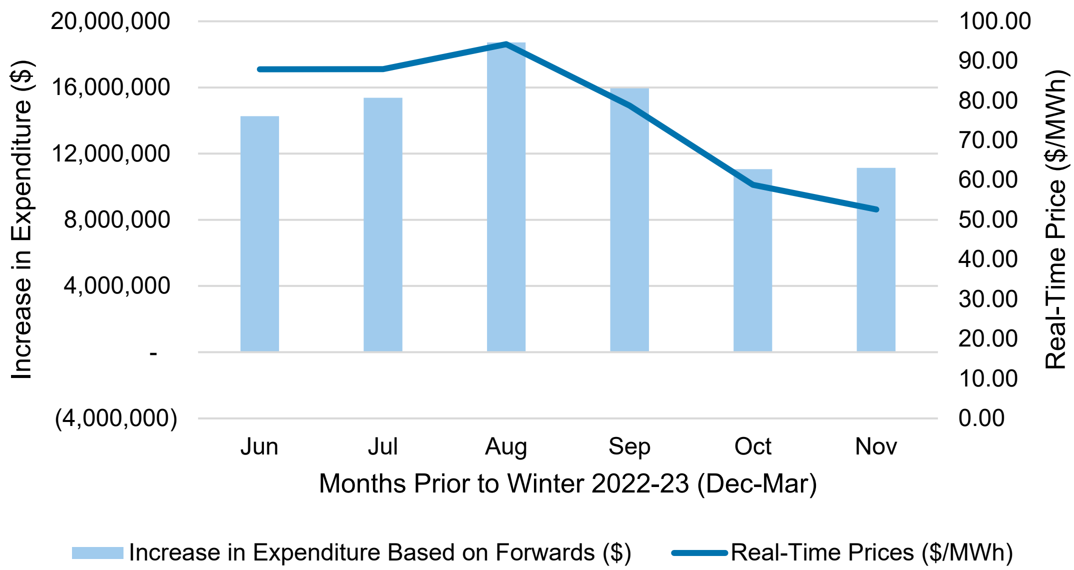
Q. What was the outcome of Kentucky Power not purchasing forward contracts heading into Winter 2022?

A. Outcomes of electric utility decisions should not be considered when evaluating the prudency of the decisions. However, it can still be informative to examine outcomes and may highlight that there is no reason to spend resources evaluating the decisions that led to the outcomes.

As it turned out, the decision by Kentucky Power to not cover its energy position for December 2022 through March 2023 with forward contracts saved its customers substantial amounts of money. Witness Vaughan addressed this in Kentucky Power's initial response to the Show Cause Order. He demonstrated that not entering forward contracts between July and November 2022 likely saved Kentucky Power $11 million to nearly $19 million in purchased power costs. The reason for this outcome was a significant decrease in power prices across the entire winter relative to the previous year, with the lone exception being the three-day period of Winter Storm Elliott.

I reviewed, confirmed, and recalculated Witness Vaughan's analysis. I found it to be credible and correct. I estimate that Kentucky Power purchasing real-time prices instead of forwards in the one to six months prior to Winter 2022-23 likely saved Kentucky Power and its customers approximately $11M to $19M, depending on the time of purchase. My results are shown in Figure 13. It shows that forwards purchased anytime between June and November 2022 would have led to increased costs, but that the cost impact was greatest in the periods with highest current-month prices, such as August 2022.

Figure 13: Purchase Power Expenditure Impact of Forwards for Winter 2022-23 [67]



Q. If purchasing forwards had proven to be "in the money" in Winter 2022, would it have suggested imprudence by Kentucky Power?

A. No. As mentioned, prudency is based on the information, data, and methods used to make decisions, not on outcomes. Such an outcome would certainly have raised questions, but it would not indicate a lack of prudency.

[67] S&P Global, ISO Real-Time Prices and Forwards & Futures, Accessed December 13, 2023; CRA Analysis.

Q. In its 2022 IRP filing, East Kentucky Power Cooperative (EKPC) mentioned a plan to purchase forward contracts entering Winter 2022-23. Please explain their position and the relevance to considering Kentucky Power's decisions.

A. EKPC is a power cooperative, which creates a different landscape than Kentucky Power's, but EKPC is a PJM member and a neighboring utility, so it is reasonable to consider its decisions and outcomes. Like Kentucky Power, EKPC's winter peak currently exceeds its summer peak. It is also able to benefit from the fact that PJM is a summer peaking RTO. Per its most recent IRP filing in 2022, EKPC states that it "has not had to carry as high of a reserve requirement in the winter period because it has PJM to help secure its load requirements, which has saved on capital investment costs." [68] In fact, EKPC notes that it is able to sell excess capacity in the summer and then has the larger power pool as an additional resource in the winter.[69] Overall, EKPC determined that it "has been able to supply energy to its owner members at a lower cost

[68] Commonwealth of Kentucky, Case No. 2022-00098 Response to Attorney General's Second Request for Information to EKPC, Response No. 15c., September 20, 2022, https://psc.ky.gov/pscecf/2022-00098/angela.goad%40ky.gov/08302022032850/22.08.30_OAG_Second_Request_for_Information_to_EKPC.pdf.
[69] Commonwealth of Kentucky, Case No. 2022-00098 Response to Attorney General's First Request for Information to EKPC, Response No. 7d., June 29, 2022, https://psc.ky.gov/pscecf/2022-00098/jessica.fitch-snedegar%40ekpc.coop/07292022033358/AG_DR1_2022-00098_-_To_be_filed_-_Final.pdf.

than what would have occurred with EKPC self-supplying all of its own energy resources." [70]

Like Kentucky Power, EKPC's owned and long-term contracted resources did not cover expected energy demand for Winter 2022-23. Its plan, stated in the 2022 IRP proceeding, was to meet the winter peak energy demand by procuring a seasonal PPA for 100 MW of firm energy, which is similar to entering a forward contract. EKPC described this plan as follows:

> "EKPC expects this seasonal PPA would be a standard contract from a market participant to supply 100 MW of firm energy at a contracted price. It is not source specific. The purchase will be made for January and February only, and purchased on an annual basis. This is not expected to be a long term contract and can be replaced with other resources as deemed appropriate." [71]

I have no reason to believe this approach was decided upon imprudently. However, it is instructive to consider its likely outcome. First, the time period covered by the short term PPA was January and February 2023, which turned out to be a period with very low energy prices, and it did not include the

[70] *Id*.

[71] Commonwealth of Kentucky, Case No. 2022-00098 Response to Attorney General's Second Request for Information to EKPC, Response No. 18a., September 20, 2022, https://psc.ky.gov/pscecf/2022-00098/angela.goad%40ky.gov/08302022032850/22.08.30_OAG_Second_Request_for_Information_to_EKPC.pdf.

December 2022 period that included Winter Storm Elliott impacts. Second, the planned approach was discussed in September 2022, suggesting the PPA, if executed, would have been signed in September to December 2022. Witness Vaughan and I both have shown that forwards during this period turned out to be more costly than their benefits. The only way EKPC's approach may have proved beneficial would be if it somehow included December 2022 and was transacted at substantially below-market prices, which is possible but highly unlikely given the opportunity cost to the seller. There was also likely a volume mismatch since some of EKPC's capacity resources failed to perform during Winter Storm Elliott and incurred Non-Performance Charges from PJM.[72]

V. CONCLUSION

Q. What are your concluding remarks?

A. Through its participation in PJM, Kentucky Power has sufficient capacity to meet its customers' maximum expected requirements. PJM has demonstrated that it reasonably plans for resource adequacy throughout the year and across its system. To achieve resource adequacy through PJM, Kentucky Power must

[72] PJM, FERC Docket No. EL23-74-000, July 21, 2023, https://www.pjm.com/-/media/documents/ferc/filings/2023/20230721-el23-74-000.ashx.

demonstrate a required quantity of capacity, which it has reasonably done through the AEP FRR, by designating owned resources and contracted resources. Finally, Kentucky Power reasonably managed its energy positions entering Winter 2022-23 while considering the expiration of the Rockport UPA. The decision not to enter forward contracts to cover Winter 2022-23 was based on reasonable analysis, and ultimately ended up saving purchased power costs for Kentucky Power's customers.

Q. Does this conclude your testimony?

A. Yes.

ATTACHMENTS

OF

JEFF PLEWES

CHARLES RIVER ASSOCIATES, INC.
WASHINGTON, DC

December 2023

ATTACHMENT 1

OF

JEFF PLEWES

Professional Qualifications

Of

Jeff Plewes

MBA, School of Management
Yale University

BS Finance,
University of Virginia

Jeff Plewes is a Principal in the Energy Practice of CRA. He specializes in the economic analysis of energy and environmental policy and electricity market design. He has worked with companies throughout the energy sector to help them understand the implications of public policies and regulations on their operations, assets, and investment decisions. Mr. Plewes has led projects for clients in each of the North American competitive electricity markets and for many regulated utility clients, including internationally. Broader areas of focus have included electricity and capacity market strategy, climate policy, resource adequacy, economic impact analysis, and renewable fuels policy. Mr. Plewes supports this work with quantitative analysis using advanced energy and economic modeling tools, both proprietary and third-party.

His recent work includes providing testimony on prudency of electric utility market participation and fuel purchasing, developing and executing government funding strategies for several large utilities, providing expert testimony on the market impacts of a utility acquisition, leading the capacity cost analysis for an RTO study, serving as macroeconomics expert in an international oil spill case, and analyzing energy and capacity market design concepts in several regional power markets.

Experience

Of

Jeff Plewes

<u>Charles River Associates, Inc. (2007 – Present)</u>

Principal, Washington, DC

Electricity Markets and Utility Strategy

- For an electric utility, provided testimony on the prudency of utility decisions related to the level of operations of owned power plants, electricity market participation, and fuel procurement.
- For an electric utility, led an analysis of the capacity cost impacts of a move to PJM from a neighboring RTO. Oversaw the regulatory and market analyses and capacity market modeling.
- For several large generators in the PJM market, developed value-maximizing bidding strategies for capacity auctions that included performance incentives for the first time. The approach included analysis of likely market outcomes and expectations for generator performance based on technical analysis of past availability.
- For several electric utilities, led the strategic review of opportunities under the Infrastructure Investment and Jobs Act (IIJA). This involved evaluating

alignment of programs with the utilities' capital plans and strategies, as well as developing justifications for decisions in the interest of customers. For one utility, led the proposal development for a large microgrid and battery project.

- For a large solar and energy storage developer, led several studies on multiple capacity markets in the U.S. to determine participation requirements, offer strategies, and likely capacity pricing outcomes.
- For a utility holding company, provided expert testimony on the market implications of a proposed utility acquisition.
- For a variety of market participants in the Northeastern power markets, supported testimony on capacity market changes, including changes in parameters and the introduction of performance incentives. Presented findings to ISO-NE stakeholders and regularly led analyses for a coalition of generators in PJM.
- For a large Independent Power Producer, prepared testimony for submission to FERC on proposed changes to the PJM capacity market.
- For a developing country's electricity market regulator, prepared and delivered an in-person multi-day workshop on capacity market theory and design.
- For a New York merchant generation owner, analyzed the impact of market developments on capacity prices in NYISO.

Transmission and Renewables

- For a solar developer, evaluated capacity value opportunities in PJM, ISO-NE and NYISO. Evaluated the future capacity opportunities for battery storage.
- For a large Midwestern electric utility, calculated future transmission costs for several complex wind farm investments.
- For several power sector investors and renewable energy developers, evaluated Renewable Energy Credit (REC) prices.

Energy Litigation

- For a large technology infrastructure firm, served as an expert witness in litigation over electricity billings.
- For an island nation government, serving as macroeconomics expert in an oil spill case. Calculated economic damages through the country based on primary research, testimony of other experts, and macroeconomic modeling.
- For an ethanol market participant, evaluating damages in an EPA enforcement case.
- For a large generator, supported testimony on a multi-billion dollar litigation case regarding power plant environmental controls and sale-leaseback arrangements.
- For a major investment fund in Hong Kong, led analysis for the Industry Expert in a case involving a major solar manufacturing firm.
- For a large Canadian utility, evaluated a competitor’s plant outage timing for potential market manipulation. Reviewed electricity market data to identify non-

competitive behavior. The competitor was eventually disciplined by the regulator.

- For an oil and gas major, provided litigation support in an environmental matter. Led team of analysts in an expansive literature review on the subject of contingent valuation for damage estimates. Authored summaries of the state of the economics based on thousands of academic studies from around the world.
- For a different oil and gas major, provided litigation support in an environmental matter. Led team of analysts in determining market share in support of expert testimony regarding the client's liability.

Carbon Policy Analysis

- For Plug Power, led a study on the carbon intensity of hydrogen produced by electricity at multiple U.S. locations. This involved modeling of the power sector and evaluating emissions using multiple methods and assumptions about renewable energy colocation and contracts.
- For the New York Mayor's Office, analyzed the power sector options to meet specific emissions goals through advanced modelling of the Northeast US energy infrastructure under various scenarios. Provided advice on feasible and economic options for both local and imported electricity.
- Supported expert testimony before the US Senate on a national climate policy.

- For an international private equity fund, evaluated investment opportunities in the carbon offset market. Analyzed national and international policy scenarios and identified potential investment risks.

Economic Impact Analysis

- For an association of private water companies, led a study on the benefits of privatization and consolidation of water and wastewater utilities in Pennsylvania. Authored a report covering consumer, environmental, and safety benefits based on statistical analysis of government data and economic theory.
- For Brookfield Renewable Partners, led the analysis of a variety of economic benefits for a proposed set of hydropower/wind/transmission investments in the Northeast. Authored a report on the benefits for submission in the Massachusetts Clean Energy RFP. Completed a similar set of studies for Brookfield's hydropower submissions in a Maine Clean Energy RFP.
- For a Midwest electric utility (NIPSCO), developed studies on the economic benefits of the state's transition to renewable energy and on individual solar projects. Provided testimony to the Indiana Utility Regulatory Commission.
- For a large Eastern US electric utility, led the economic analysis for the largest transmission line proposal since the advent of FERC Order 1000. Helped the company navigate the complexities of interstate and inter-RTO transmission. Created a testimony-quality analysis that examined electricity price, production cost, job and output impacts using power sector and input-output modelling.

- For a consortium of gas pipeline owners in the Northeast, evaluated the gas market, electricity market, and macroeconomic benefits of a proposed pipeline. Led the coordination and integration of three advanced models and the development of presentations and a report.
- For the owner of a gas fired power plant in New York City, filed testimony on the socioeconomic impacts of investing in a major repowering investment.
- For Pepco Holdings, evaluated the economic benefits of several major electric distribution infrastructure projects and programs in Maryland and Washington, DC.
- For a large mining and processing industry association, examined the national economic contributions of the industry and analyzed the economic impact of a proposed change in the federal mining royalty rate.
- For The Fertilizer Institute, developed an economic contribution analysis for the fertilizer manufacturing industry in the US. Performed data analysis using the IMPLAN input-output model and a variety of public data sets. Authored multiple reports that were published and reported on by several news organizations.
- For a large Independent Power Producer (NRG Energy), co-authored a report on the economic impact of resource adequacy issues in Texas. Conducted economic modeling of alternate generation capacity scenarios, one in which ERCOT

adopts a capacity market and one where it remains energy-only. Evaluated impacts on the Texas economy.

Natural Gas and Oil

- For the Coalition for American Energy Security, authored a study on the economic impacts of U.S. compliance with IMO 2020, an international regulation limiting the sulfur content of marine fuels in international shipping. Led the research and analysis, which included advanced refinery and macroeconomic modeling.
- For Valero Energy and various other refiners, authored or co-authored a variety of studies on the economics of the Renewable Fuels Standard. Serving as primary economics expert for analyzing and publishing comments on policy proposals. The analysis has involved advanced econometrics and statistics.
- For a refining company, evaluated the pass-through of renewable fuel credit prices in a report for submission to the EPA.
- For an oil and gas major, conducted an analysis of financial impacts of carbon price volatility and crude price uncertainty on refining margins.
- For the creditors in a major energy sector bankruptcy proceeding, led the enhancement of CRA's gas production model, which will be used for evaluating gas prices in asset valuations going forward.
- For Dow Chemical, evaluated the comparative economics of exporting Liquefied Natural Gas (LNG) versus using the gas for domestic manufacturing.

Co-authored a report that was well read in policy circles and throughout the industry. Presented findings at the Department of Energy.

Market and Growth Strategy

- For a developing country's State Owned Electric Utility, developed strategies as the client prepared for significant capital expenditures and international climate policy shifts. Developed a variety of reports for executives on subjects related to generation technology, international climate policies, US partnership opportunities, credit rating implications of capital investments, and monetization of carbon reductions.
- For a Middle East power and water utility, evaluated growth opportunities, both domestic and international. Presented findings to executives and led a workshop on economic value creation.

Systems Management Engineering, Inc. (2003 – 2005)

Manager, Washington, DC

- Led team of high-level professionals in assessing business processes and technology of the White House, the Office of Management and Budget (OMB), the Council on Environmental Quality (CEQ) and the US Navy.

JPMorgan Chase (2002)

Consultant, New York, NY

- Managed the development testing of several releases of a proprietary, multi-asset trading system.

<u>Acumen Solutions, Inc. (1999 – 2002)</u>

Consultant, McLean, VA

- Participated in growing a start-up company into a profitable, 200+ person consulting firm. Consulted on a variety of engagements.

Expert Testimony

Of

Jeff Plewes

JURISDICTION	PROCEEDING	REPRESENTING	TOPIC
Public Service Commission of West Virginia	Case Nos. 21-0339-E-ENEC and 22-0393-E-ENEC	Appalachian Power Company and Wheeling Power Company	Prudency of utility decisions in incurring energy costs
Kentucky Public Services Commission	Case # 2021-00481	Liberty Utilities	Market implications of a utility acquisition
Indiana Utility Regulatory Commission	Expert Reports for Cause Nos. 45462, 45511, 45529	Northern Indiana Public Service Company (NIPSCO)	Solar Projects Filings
Minnesota Public Utilities Commission (MPUC)	Docket No. IP-6981/CN-17-306, WS-17-307, TL-17-308	NextEra Energy	Economic Impacts of a Wind Project
New York State Department of Public Service		Eastern Generation	Economic Impacts of a Natural Gas Plant Project
Supreme Court of the State of New York	Telx-New York, LLC v 60 Hudson Owner LLC	Plaintiff	Damages Expert on Electricity Billings
Public Utility Commission of Ohio	Expert Report (July 2014)	Dayton Power and Light	Fair Market Valuation of Ohio Solar Renewable Energy Credits

Publications & Media

Of

Jeff Plewes

Books and Book Chapters

- Burrows, Plewes, et al. "Do contingent valuation estimates of willingness to pay for non-use environmental goods pass the scope test with adequacy? A review of the evidence from empirical studies in the literature," Chapter in Contingent Valuation of Environmental Goods, Edward Elgar Publishing, 2017.

Public Reports and Articles

- Plewes and Walls, "Is There a Formula for Successful GRIP Applications?" T&D World, December 2023.
- Plewes, "Benefits of Private, PUC-Regulated Water Utilities in Pennsylvania." December 2023.
- Plewes and Chang, "Economic Analysis of IMO 2020: The Benefits to the U.S. Economy of Full Participation and Compliance," June 2019.
- Plewes, "Improving Outcomes of the Renewable Fuels Standard through a Price Containment Mechanism," website of Fueling American Jobs Coalition, March 2018.

- "Unobligated RINs for Renewable Fuel Exports," website of Fueling American Jobs Coalition, October 2017.
- Hunger, Plewes, and Kwok. "Navigating PJM's Changing Capacity Market," CRA Energy Practice White Paper, March 2017.
- "A Case Study in Capacity Market Design and Considerations for Alberta (MISO case study)," for Alberta Electric System Operator, March 2017.
- "Economic Contributions of Pepco's Annual Distribution-Related Capital Expenditures in the District of Columbia," for Pepco Holdings, Inc., December 2016.
- "Re-Examining the Pass-Through of RIN Prices to the Prices of Obligated Fuels," Comments to EPA, October 2016. (Docket ID No. EPA-HQ-OAR-2016-0544-0067)
- "Economic Modeling of the Clean Power Plan," Presentation at REMI Luncheon, Washington DC, August 2015.
- NYC Mayor's Office, "New York City's Pathways to Deep Carbon Reductions," December 2013. (power sector sections only)
- Ditzel and Plewes, "US Manufacturing and LNG Exports: Economic Contributions to the US Economy and Impacts on US Natural Gas Prices," EPA Comments for Dow Chemical, 2013.

- Plewes and Hieronymus, "Economic Impact of Inadequate Generation in ERCOT - Comparison of Resource Adequacy Scenarios." submitted in PUCT proceedings, 2013.
- "Employment Contributions of an Expanded Undergrounding Program in Support of the Mayor's Power Line Undergrounding Task Force," for Pepco Holdings, Inc., February 2013.
- Plewes and Rankin, "Employment Contributions of the Medical Imaging Technology Industry," June 2013.
- Plewes, "Economic Contributions of the U.S. Fertilizer Manufacturing Industry," for The Fertilizer Institute, August 2009.

CRA Insights Articles

- Plewes, "US and EU commit to ambitious reductions in GHG emissions," April 2021.
- Plewes and Kwok, "Initial thoughts on the winter 2021 power outages in Texas," February 2021.
- Plewes and Kaineg, "Examining post-election climate policy scenarios in the US," January 2021.
- Kwok, Plewes, et al., "PJM's Capacity Market: Where are we now?," October 2020.
- Kwok, Plewes, et al., "FERC directs PJM capacity market reforms: Progress but not certainty," December 2019.

- Kwok and Plewes, "Addressing capacity performance risk for variable energy resources," October 2019.
- Hunger, Plewes, and Kwok, "Navigating PJM's Changing Capacity Market," March 2017.

Speaking Engagements

Of

Jeff Plewes

- Presenter, National Association for Business Economics (NABE) Economic Policy Conference, Panel on "Reliability and Affordability Throughout the Energy Transition," March 2023.
- Moderator, US Association for Energy Economics, National Capital Area Chapter Policy Conference, Panel on "Keeping the Lights on While Bringing Emissions Down." April 2023.
- Moderator, South America Energy Series (SAES 2021), Panel on "Clean Transport, Future Fuels and Hydrogen," April 2021.
- Presenter, CRA-Wright & Talisman Webinar, "Expectations of a Blue FERC: Climate Policy During the Biden Administration: Natural Gas Focus," December 2020.

- Presenter, Energy Bar Association 2019 Northeast Chapter Annual Meeting, “State Policies and the Markets: How the tension is playing out in PJM, NYISO and ISO-NE.” June 2019.
- Presenter, Mid-Atlantic Power Market Summit, “Designing Optimal Capacity Market Offer Strategies,” October 2017.
- Presenter, “Clean Power Planning: Steps Utilities Should Be Taking Now To Engage State Leaders Around CPP Implementation,” January 2016.

ATTACHMENT 2

OF

JEFF PLEWES

Data and Assumptions for Comparison of Peer Capacity Ownership

This Attachment describes the data and assumptions that support Figure 8 of my testimony.

The peer group includes utilities of any ownership type (including Investor-Owned Utilities, municipals, and co-operatives) within the PJM balancing authority that had a maximum annual peak load exceeding 200 MW in 2022 and were identified as having distribution activities.

The analysis reviewed summer and winter capacity directly owned by the utility company and calculated what fraction of the summer and winter peaks was covered by owned capacity. This analysis includes only capacity that is owned by the utility and does not include other capacity purchases from other entities.[1] Cooperatives were included in this analysis, excluding Wabash Valley Power Association, Indiana Municipal Power Agency, and North Carolina Electric Membership Corp. Members of these groups span multiple ISO/RTOs and only a fraction of their members serve customers in PJM.[2]

The summer peak represents the maximum reported hourly summer load for the months June through September 2022 and the winter peak represents the maximum reported

[1] EIA Form 861. Accessed via Hitachi Energy - Velocity Suite.
[2] EIA Form 861. Accessed via Hitachi Energy - Velocity Suite.

hourly winter load for the months of January through March 2022 and December 2021.[3] The owned capacity data is reported as of December 31, 2022, so there may be some discrepancies with the capacity planned by each LSE entering the 2021/22 Delivery Year.[4]

For purposes of analyzing the data, I aggregated certain LSEs to better represent the mechanisms by which they comply with PJM capacity obligations. For AEP, both the aggregated and individual LSEs are considered. The following are the aggregations:

- AEP Combined is an aggregation of AEP's PJM-serving utilities, which are the entities that are in the AEP PCA. AEP Generation Co, Ohio Valley Electric Co (OVEC), and Indiana Kentucky Electric Co (IKEC) are AEP-related companies with operations in PJM but are not included since they did not meet the criteria for inclusion (having distribution). The overall position of the AEP PCA includes bilateral contracts with these other AEP companies.[5]

- Appalachian Power Co (APCo) is represented as an aggregate of Appalachian Power Co, Wheeling Power Co, and Kingsport Power Co; AEP considers these entities as consolidated for resource planning purposes.[6]

[3] EIA Form 861 Instructions
[4] EIA Form 860 Instructions
[5] AEP 2022 Factbook
[6] AEP 2022 Factbook

- Monongahela Power Co and Potomac Edison Co are represented as one entity because these entities are consolidated by parent company First Energy for resource planning purposes.[7]

- UGI Corp is represented as an aggregation of its subsidiaries UGI Utilities and UGI Energy Services.

- Certain cooperatives are aggregates of smaller cooperative members, which in many cases would not qualify for this comparison on their own. For example, Northern Virginia Electric Cooperative (NOVEC) is aggregated with its subsidiary South Boston to encompass their ownership of one biomass generation facility.[8]

[7] MonPower and Potomac Edison 2020 IRP. Case No. 20-1050-E-IRP
[8] NOVEC. Biomass Electric Generating Facility.

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E-Signature Summary

E-Signature 1: Jeffrey Charles Plewes (JCP)
December 20, 2023 11:43:08 -8:00 [3580CE72DEAB] [38.70.4.130]
JPlewes@crai.com (Principal) (Personally Known)

E-Signature Notary: Marilyn Michelle Caldwell (MMC)
December 20, 2023 11:43:08 -8:00 [C18748597C74] [167.239.221.106]
mmcaldwell@aep.com
I, Marilyn Michelle Caldwell, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Jeff Plewes, being duly sworn, deposes and says he is a Principal in the Energy Practice of Charles River Associates 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.

Jeffrey Charles Plewes

Jeff Plewes

Commonwealth of Kentucky)
)
County of Boyd)

Case No. 2021-00370

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jeff Plewes, on December 20, 2023.

Notary Public

MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP71841
My Commission Expires May 05, 2027

Notarial act performed by audio-visual communication

My Commission Expires May 5, 2027

Notary ID Number KYNP71841