Kentucky Power Company
KPSC Case No. 2019-00443
Commission Staff's Second Set of Data Requests
Dated June 18, 2020

DATA REQUEST

KPSC 2_01 Refer to the IRP Section 2, page 29. Explain why a high Distributed Energy Resource (DER) scenario was not chosen to be included in the various other scenarios chosen for depiction in Kentucky Power's Load Forecast scenarios. For reference, DER in this request refers to the definition used by the Federal Energy Regulatory Commission in the February 2018 Staff Report for AD18-10-000: A source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter.

RESPONSE

The Company did not develop a high Distributed Energy Resource (DER) scenario because the Company's service territory is not likely to see a high adoption rate for DER, given currently low penetration rates and economic conditions. The Company's forecast assumed a continuation of current trends. However, if such a scenario had been developed, it would have fallen within the low economic scenario band.

Witness: Gordon S. Fisher

Witness: John F. Torpey

DATA REQUEST

KPSC 2_02 Refer to the IRP Section 2, pages 6–38.

a. Identify where in the IRP Kentucky Power incorporated DER into the Load Forecasting Methodology.

b. Explain how DER are incorporated into the forecasting methodology. DER in this request refers to the definition used by the Federal Energy Regulatory Commission in the February 2018 Staff Report for AD18-10-000: A source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter.

RESPONSE

a. The Company's forecast assumes a continuation of current trends of DER.

b. To the extent that DER trend has affected historical load, it would be reflected in the load forecast. Section 4.4.3.4 describes the levels and methodology for DER in the IRP.

Witness: Gordon S. Fisher

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Commission Staff's Second Set of Data Requests
Dated June 18, 2020

DATA REQUEST

KPSC 2_03 Refer to the IRP Section 3, pages 39–72. Identify where Kentucky Power evaluates FERC order 841 regarding electricity storage as wholesale market resources.

RESPONSE

For this IRP, the Company included a Battery Resource as a resource available for selection in its optimization modeling, which takes into account capacity and energy prices. Within the optimization modeling the energy storage resource would charge when energy prices are low and discharge when energy prices are high. Specific opportunities related to FERC Order 841 were not considered as FERC Order 841 incorporates additional market incentives such as ancillary services that are not part of this IRP analysis.

Witness: Gordon S. Fisher

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Commission Staff's Second Set of Data Requests
Dated June 18, 2020

DATA REQUEST

KPSC 2_04 Refer to the IRP Section 3.3.5 pages 46–47.

a. Explain how Kentucky Power's parent company AEP addresses climate change including any greenhouse gas reduction goals.

b. Explain how any strategy by AEP to reduce greenhouse gas emissions could affect Kentucky Power's IRP implementation.

RESPONSE

a. AEP's strategy for addressing climate change, including greenhouse reduction goals, is discussed in detail in the Carbon & Climate section of the company's Corporate Accountability Report, which can be found at:
http://www.aepsustainability.com/environment/carbon/

b. Section 3.3.5 describes the Company's assumptions for this IRP regarding regulation and energy policy related to climate change and carbon dioxide emissions. Additionally, Section 4.3.1 describes how the Company included a proxy for climate legislation in the Fundamentals Forecast. Furthermore, the Company's three-year action plan, discussed on page ES-9, includes zero carbon solar, wind and energy efficiency resource additions, and a plan to continue to monitor issues related to carbon dioxide regulation.

Witness: Gordon S. Fisher

Witness: Brian K. West

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Commission Staff's Second Set of Data Requests
Dated June 18, 2020

DATA REQUEST

KPSC 2_05 Refer to the IRP Section 3.3.5 pages 46–47. Identify where Kentucky Power evaluates the PJM Study of Carbon Pricing and the effects of carbon pricing within PJM on Kentucky Power's customers.

RESPONSE

See Company's response to KPSC 2_4(b) for a description of how carbon regulation was included in the Company's IRP. The Company would also note that the PJM study was not available at the time this IRP was performed.

Witness: Gordon S. Fisher

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Commission Staff's Second Set of Data Requests
Dated June 18, 2020

DATA REQUEST

KPSC 2_06 Refer to the IRP Section 3.4.2. Identify where in the IRP Kentucky Power accounts for increased levels of active demand response with inverter-based resources due to the 2018 Revision to IEEE-1547 for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces.

RESPONSE

For this IRP the Company did not explicitly consider IEEE-1547. Section 4.4.3.3 of the IRP provides a description of the demand response resource modeled. As noted in the Preferred Plan, shown on page ES-4, no demand response resources were selected.

Witness: Gordon S. Fisher

Witness: John F. Torpey

DATA REQUEST

KPSC 2_07 Refer to the IRP Section 3, pages 39–72. Identify where Kentucky Power evaluates electric vehicles current and future levels in terms of potential demand response.

RESPONSE

The Company's load forecast used in the IRP assumed a continuation of current trends of electric vehicle adoption. The Company has developed other scenarios for higher and lower adoption of electric vehicles, but they still fall within the high and low economic forecast scenario bands that were modeled in the IRP optimization. The ability of electric vehicle ownership to be considered as a potential demand response program would be dependent on future rate design implementation.

Witness: Gordon S. Fisher

Witness: John F. Torpey

DATA REQUEST

KPSC 2_08 Refer to the IRP Section 4.4.3.1 page 84. Explain how the Incremental Energy Efficiency Modeled includes variability in customer housing and building stock characteristics.

a. Explain whether Kentucky Power utilizes the National Renewable Energy Laboratory's (NREL) ReStock in modeling the diversity of the single-family housing stock. https://resstock.nrel.gov/

b. Explain if Kentucky Power has utilized NREL's ComStock for modeling commercial building stock. See, https://www.nrel.gov/buildings/comstock.html

RESPONSE

As an input to the IRP incremental EE workbook, the Company uses service area specific housing stock for single family, multi-family and mobile homes in the Statistically Adjusted End-Use Models (SAE). Furthermore, the residential end use measures savings potential (except for TV and Lighting measures) is adjusted by a housing ownership factor. This is done to reflect the savings potential for the customers most likely to adopt each measure.

a. No. The Company utilizes Itron SAE models to develop the long-term residential energy forecasts. The Company customizes the housing stock to reflect the Company's service area. Itron relies on EIA for energy efficiency and housing trends.

b. No. The Company relies on Itron SAE models to develop the long-term commercial energy forecasts. Itron relies on EIA for efficiency and business square footage trends.

Witness: Gordon S. Fisher

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Commission Staff's Second Set of Data Requests
Dated June 18, 2020

DATA REQUEST

KPSC 2_09 Refer to the IRP Section 4.4.3.3, page 89.

a. Explain if Kentucky Power modeled customer electric vehicle to grid opportunities.

b. Explain if Kentucky Power modeled utility controlled customer sited distributed generation using IEEE 1547-2018 inverters.

RESPONSE

a. Customer electric vehicle to grid opportunities were not specifically modeled for this IRP. See also the Company's response to KPSC 2_07.

b. Section 4.4.3.3 of the IRP discusses distributed generation in the form of residential rooftop solar resources. The Company did not model this resource as utility controlled customer sited distributed generation.

Witness: Gordon S. Fisher

Witness: John F. Torpey

DATA REQUEST

KPSC 2_10 Refer to the IRP Section 4.4.3.4 page 90. Explain why Kentucky Power did not utilize hosting capacity analysis to estimate the potential for the distribution system to accommodate distributed generation and other DERs.

RESPONSE

Because of the current levels of distributed generation in the Company's service territory, and the high cost of such an analysis, the Company concluded a hosting capacity analysis was not appropriate for this IRP.

Witness: Gordon S. Fisher

Witness: John F. Torpey

DATA REQUEST

KPSC 2_11 Refer to the IRP Section 4.4.3.4, page 91. Kentucky Power states, "It is significant to note that rooftop solar does not represent the most economic means for Kentucky Power to add renewable generation as the cost of rooftop solar remains considerably higher than the cost of large scale solar…"

a. Explain whether there are other factors beyond economics as to why customers choose to add rooftop solar.

b. Explain whether Kentucky Power evaluated distributed solar as a way to harden the distribution system or as support for critical facilities.

RESPONSE

a. There may be other factors, such as wanting to support renewable energy development, that could influence a customer's decision to install rooftop solar.

b. In this IRP, the Company did not evaluate distributed solar as a way to harden the distribution system, nor as support for critical facilities.

Witness: Gordon S. Fisher

Witness: Brian K. West

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Commission Staff's Second Set of Data Requests
Dated June 18, 2020

DATA REQUEST

KPSC 2_12 Refer to the IRP page 93. Explain why Kentucky Power did not choose to model a Natural Gas Solar Hybrid plant as a new technology option.

RESPONSE

The Natural Gas/Solar Hybrid plant was not modeled, however, it was not deliberately excluded. This configuration is not one that the AEP Generation Engineering team has experience and knowledge around performance characteristics and therefore, was not provided to the IRP team as a specific supply-side alternative. Furthermore, when a resource acquisition process is initiated, the Company may consider a wide range of options such as this as technologies and solutions evolve.

Witness: Gordon S. Fisher

Witness: John F. Torpey

DATA REQUEST

KPSC 2_13 Refer to the IRP Section 4.5.6.3, page 105.

a. Given Kentucky's hydroelectric potential and FERC approved hydro licenses, explain why Kentucky Power assumes that hydro is "prohibitive at this time."

b. Explain whether Kentucky Power is aware of Oak Ridge National Laboratory's HydroSource and whether Kentucky Power has evaluated these resources. See, https://hydrosource.ornl.gov/

c. Given the life expectancy of hydro resources, provide the Levelized Cost of Electricity (LCOE) that was evaluated for hydro that influenced Kentucky Power's determination that hydro is prohibitive at this time.

RESPONSE

a. The build cost for new hydroelectric facilities provided by the AEP Generation Engineering team is estimated to be $4,500 per kilowatt (kW) of installed capacity, which is more than double the costs of resources selected in the IRP.

b. No, the Company is not aware of this and has not evaluated these resources.

c. A Levelized Cost of Electricity, (LCOE) was not evaluated for hydro based on the comparatively high build cost for this type of resource.

Witness: Gordon S. Fisher

Witness: John F. Torpey

DATA REQUEST

KPSC 2_14 Refer to the IRP Section 3.6, pages 71–72. Kentucky Power states, "The distribution system has been enhanced over the years with the construction of new substation and distribution lines, to meet customers' needs and improve service reliability and quality."
a. Describe Kentucky Power's distribution system in detail, including miles of distribution lines, types, substations, etc.
b. Explain how Kentucky Power measures its distribution system performance.
c. Explain how the distribution system is performing according to the performance metrics identified.
d. Explain in detail what "to meet customers' need" means.
e. Provide Kentucky Power's customer reliability expectations.
f. Detail the number of Circuits Identified for Improvement and how many circuits, segmented, have been completed since the 2016.
g. Detail the number of customers with multiple interruptions and planned improvements for those customers.
h. Describe in detail any customer satisfaction improvements or savings that have resulted from distribution system enhancements.

RESPONSE

The cited reference in the IRP is a general statement. Other than described in IRP, the IRP does not contain specific assumptions about the distribution system in the detail described in this request.

a. Kentucky Power's distribution system consists of the following components
<u>Primary Voltage Line Miles-Overhead (OH)-Underground (UG):</u>
7.2kV Single Phase OH - 4,476.37 miles
7.2kV Single Phase UG - 66.88 miles
12kV Double Phase OH - 172.24 miles
12kV Double Phase UG - 0.21 miles
12kV Triple Phase OH - 1412.14 miles
12kV Triple Phase UG - 25.40 miles
19.9kV Single Phase OH - 924.89 miles
19.9kV Single Phase UG - 17.95 miles
34kV Double Phase OH - 22.04 miles
34kV Double Phase UG - 0.05 miles
34kV Triple Phase OH - 1078.87 miles
34kV Triple Phase UG - 12.55 miles

Secondary Voltage Line Miles-Overhead (OH)-Underground (UG):
Secondary Voltage OH - 1744.04 miles
Secondary Voltage UG - 57.84 miles
Total Primary - 8216.80 miles
Total Secondary - 1801.88 miles
Total Number of Kentucky Power Distribution Substations - 94
Total Number of Distribution Circuits - 228 (note-some circuits are served from stations located in Ohio, West Virginia and Virginia)

b. Kentucky Power measures distribution system performance by the IEEE defined metrics of SAIDI, SAIFI and CAIDI. Customers experiencing multiple interruptions (CEMI), customer minutes of interruption (CMI) and number of interruptions are also used. These metrics are calculated both including and excluding Jurisdictional Major Event Days (JMED). These various measures are also calculated at the company, station, circuit and individual device levels.

c. At the company level, for the twelve months ending July 8, 2020, SAIDI = 431.2, SAIFI = 2.252 and CAIDI = 191.5

The following table shows the metrics for each of the past three years.

Year Ending/Excluding JMED	SAIDI	SAIFI	CAIDI
2019	485.05	2.485	195.16
2018	484.15	2.342	206.77
2017	406.30	2.169	187.32
Year Ending/Including JMED			
2019	531.16	2.591	205.01
2018	624.26	2.554	244.40
2017	657.10	2.508	262.00

d. Customer needs include safe and reliable electric service. Customers require an estimated time of restoration when reporting an outage. Customers also need multiple ways to report outages and power quality issues. Electric service should meet customers' voltage and current requirements. Finally, customers require tips on how to use electricity efficiently and the ability to make payment arrangements.

e. The Company endeavors to provide a reasonable level of reliability for its customers at a reasonable cost.

f. The IRP does not make specific assumptions about circuits identified for improvement in the Company's distribution system.

g. CEMI can be calculated for any time period, with the conventional period being 12 months. Kentucky Power uses the metric of CEMI6 which reflects the number of customers experiencing six or more interruptions in a 12-month period. For the 12 months ending May 2020 (June 2019- May 2020) the number of customers experiencing six or more interruptions was 9.4%, or 15,407, of the customers. Usually, customers experiencing multiple interruptions are located on circuit branches near the ends of distribution circuits. Activities to mitigate CEMI include: the Tree Out of ROW program, construction of circuit tie lines, adding additional sources between poor performing circuits, adding additional sectionalizing and distribution automation and circuit reconfiguration (DACR).

h. Kentucky Power uses the nationally known JD Powers Company to perform quarterly customer satisfaction surveys with our customers. JD Powers provides a score for Kentucky Power and a score for the Company's utility peer group (the Midwest Midsize industry segment). The table below shows the Kentucky Power/Peer Group scores for the overall customer satisfaction index (CSI) and the power quality and reliability index (PQ&R). The P&OR is derived from a subset of the questions used to determine the overall CSI.

Period	Kentucky Power CSI/Peer Group CSI	Kentucky Power PQ&R/Peer Group PQ&R
2nd Quarter 2020	717/748	752/785
Year Ending 2019	672/728	733/779
Year Ending 2018	636/724	689/780
Year Ending 2017	637/720	687/776

Kentucky Power and the peer group scores have increased since 2017. The Company reduced the gap between Kentucky Power and the peer group scores over the same period.

Witness: Gregory A. Bell

Witness: Brian K. West

DATA REQUEST

KPSC 2_15 Refer to the IRP Section 3.6, pages 71–72. Kentucky Power states, “Since2016, Kentucky Power has upgraded distribution substations with plans to upgrade or add additional substations through 2034, mainly for service improvement opportunities.”

a. Explain what capital investments have been made since 2016 to the distribution system and are forecasted for Kentucky Power’s planning period.

b. Explain how Kentucky Power ensures physical and cybersecurity of the distribution system and compliance with NERC standards.

c. Explain the percent visibility through SCADA of Kentucky Power’s substation and plans for SCADA expansion.

d. Explain what “service improvement opportunity” means.

RESPONSE

a.

Capital investments made to the distribution system since 2016
The table below shows the total distribution plant in service and the distribution substation plant in service for the years 2017, 2018 and 2019.

Year	Total Distribution System Capital Investments	Distribution Substation Capital Investments
2017	$45,350,978	$9,378,170
2018	$53,692,262	$8,129,328
2019	$72,542,871	$15,983,830

Forecasted distribution substation upgrades and additions
These projects are classified as improvements to the bulk electric distribution grid and are planned by the Distribution Asset Planning organization. Typically they encompass a ten year planning window, although some projects extend beyond ten years. These projects are developed with participation from the Kentucky Power's engineering, operations and management staff. The current plan includes projects through 2032. Capital cost estimates at this stage are mostly conceptual and can and will change based on detailed project scoping and detailed design along with the timing of the execution of the project. This plan includes upgrades to 22 existing substations and 16 new distribution sources (either new greenfield substations or additions of distribution sources at existing transmission only substations. This plan represents over $200 million in capital expenditures.

There are also other projects that are in various conceptual stages that could result in additional substations or upgrades to existing stations. For example, a transmission driven project that addresses baseline or supplemental needs could have distribution station components. Some of the projects that are included in the previous paragraph represent projects that have a transmission driver.

As projects are identified through collaboration between Kentucky Power staff, Distribution Asset Planning, Transmission Planning and other entities, they are be included in the current 10+ year station additions/upgrades plan.

b. The electric utility industry is an identified critical infrastructure function with mandatory cyber security requirements under the authority of FERC. The North American Electric Reliability Corporation (NERC), which FERC certified as the nation’s Electric Reliability Organization, developed mandatory critical infrastructure protection cyber security reliability standards. In 2014, the U.S. Department of Energy published an Energy Sector Cyber Security Framework Implementation Guide for utilities to use in adopting and implementing the National Institute of Standards and Technology framework. In addition to these enterprise-wide initiatives, the operations of AEP’s electric utility subsidiaries, including Kentucky Power are subject to extensive and rigorous mandatory cyber security requirements that are developed and enforced by NERC to protect grid security and reliability.

Critical cyber assets, such as data centers, power plants, transmission operations center and business networks are protected using multiple layers of cyber security and authentication. Cyber hackers have been successful in breaching a number of very secure facilities, including federal agencies, banks and retailers. As these events become known and develop, AEP continually assesses its cyber security tools and processes to determine where to strengthen its defenses.

AEP determines spend for both physical and cyber security based upon risk assessments of the current threat and existing mitigation strategies. As the threats evolve funds are expended to hire resources and install technology as appropriate to mitigate the identified risk. The security program is centralized so that investments on the cyber security side benefit all operating companies due to the design of the network infrastructure. In the context of physical security the technology is installed at specific assets in each operating company including Kentucky Power. AEP conducts risk assessments using internal resources as well as penetration tests conducted by third parties to help determine physical and cyber risk. In addition, AEP works with government partners and peers share information and identify potential threats. As threats are identified decisions are made regarding appropriate risk mitigation strategies. Some of those mitigation strategies involve purchasing new technology while others include upgrading current technology to meet the new threat. Part of the risk mitigation analysis involves the review of existing technology to determine if the technology is beyond useful life. In those cases, plans are developed to replace the technology before it fails, so that continuity exists in the protection scheme.

c. SCADA visibility for distribution stations and distribution circuits is 69% and 72%, respectively. Planned increases in SCADA are associated with major station upgrades and implementation of distribution automation and circuit reconfiguration (DACR) when circuit breaker status control is required. New substations will be designed to include SCADA.

d. Service improvement opportunities include: identification of circuits or portions of circuits with poor reliability, improve or maintain proper delivery voltage to customers or emerging thermal (loading) issues for substation transformers and distribution circuits. Identification of these service improvement opportunities can lead to solutions in the following categories:

<u>Electrical Loading Considerations</u>
Increasing substation capacity for serving load increases or when the load is expected to exceed the substation’s transformer capacity to maintain expected reliability by preventing a transformer failure.

Additional distribution sources for the distribution grid

There are several methods to accomplish this: adding a distribution transformer and associated circuit breakers in a transmission only substation to create a new source to serve distribution customers, constructing a new distribution substation with new circuit breakers and adding additional circuit breakers to existing distribution substations. The new sources and new/additional circuits are connected via construction of distribution tie lines to existing distribution circuits which reduces the size (line miles) of the existing distribution circuits. The reduction in circuit size reduces the customer exposure to outages.

SCADA and distribution automation circuit reconfiguration (DACR)

This involves adding SCADA and DACR to new/existing distribution substations and their associated distribution circuits. This may include new SCADA in the substations or upgrades to existing SCADA. DACR improves distribution resilience and reliability by automatic restoration of service to blocks of customers when outages occur.

Witness: Gregory A. Bell

DATA REQUEST

KPSC 2_16 Refer to the IRP Section 3.6, pages 71–72.

a. Describe any “smart grid” asset improvement projects for the distribution system since 2016 such as Distribution Automation and Circuit Reconfiguration.

b. Describe Kentucky Power’s strategy for improvements in system reliability.

c. Describe how changes in shifting demand for electricity has increased or reduced the need for distribution system enhancements.

RESPONSE

a. Kentucky Power has completed DACR on seven distribution circuits and DACR work is in progress on ten other distribution circuits that will be completed in 2020 and 2021. The company is planning to add DACR to additional distribution circuits in future years.

b. Kentucky Power's strategy consists of two prongs. The first is a proactive strategy to prevent outages from occurring; the second is a reactive strategy to improve outage restoration after outages occur. Proactive activities can also provide improvements in outage restoration. Please see the Company's response to KPSC 2_17.

Proactive strategies

- The Company reviews outage metrics to identify circuits and portions of circuits that are experiencing poor reliability and develop projects to improve performance. These include storm hardening, distribution automation and circuit reconfiguration (DACR), new sources, circuit tie lines, additional switching locations, additional automatic sectionalizing (fuses and reclosers), line relocations and asset renewal. These individual components may be combined on a particular project to address a reliability improvement need.

- Review outage cause data to determine which causes contribute to the greatest number of customer interruptions, customer minutes of interruption and customers experiencing multiple interruptions (CEMI) and develop projects and programs to improve performance. Currently, the top three outage causes are trees out of the right of way, equipment failure and scheduled outages.

- Vegetation management, which includes the ongoing cycle-based trimming that addresses trees in the right of way. The company has achieved a five year re-clearing cycle that has reduced outages caused by trees in the right of way. The company has also started a program in 2018 that targets trees outside the right of way to remove dead and dying trees, remove trees that are judged to have a high risk of falling onto the distribution lines, and to widen the rights of way of portions of distribution circuits. This program is expected to be continued in the future.

- Outage forensics which identifies and reviews circuit breaker outages, circuit breaker momentary operations, recloser outages that affect large blocks of customers (typically 500 or more) and repeat outages that add up to 500 customers or more that occur in a defined time frame (typically six months). The reviews include field visits of repair locations to determine if additional work needs to be performed. The circuit breaker momentary outages are reviewed via event recorder data to determine if there is the potential for a sustained outage.

<u>Reactive strategies</u>

- Review of CAIDI and first responder response and crew repair times. The Company has added more first responders and rearranged the first responder assigned territories to reduce response time. Line crew complements and schedules have been adjusted to provide better coverage of evening and weekend hours.

- Increase SCADA and DACR which also provides proactive benefits as noted above. SCADA and DACR provide visibility of the status of circuit breakers, reclosers and switches and also allows remote opening and closing of devices and remote interrogations of the device event recorders to analyze performance.

c. Changes in shifting demand may have the impact of allowing for the deferral of distribution system enhancements.

Witness: Brian K. West

DATA REQUEST

KPSC 2_17 Refer to Case No 2017-001792, Direct Testimony of Osborne Phillips(Phillips Testimony), pages 4–7 as it relates to IRP Section 3.6 at pages 71–72. Kentucky Power discussed the types of activities that harden the distribution system and make the system more resilient. Explain what activities have been completed to date and plans for future activities. 2 Case No. 2017-00179, Electronic Application of Kentucky Power Company for (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief, (Ky. PSC Jan. 18, 2018).

RESPONSE

These activities below are separated into the categories of system hardening and system resilience. System hardening refers to improvements to the distribution grid that reduce the amount of damage and associated customer outages that can occur during weather related events. System resilience refers to improvements to the distribution grid that improve restoration following outages.

<u>System hardening activities that have been completed:</u>

- The Company has revised distribution design guidelines to specify greater pole and guying strength and improve lightning protection. This serves to improve the structures' ability to withstand mechanical and electrical stresses caused by wind, lightning, ice and tree contact. In turn, this improves resilience by limiting damage to only the conductors and/or the cross arms which can be repaired or replaced more quickly than replacing a pole.

- Replacing small conductors with new facilities that are designed under the updated distribution design guidelines.

- Targeted relocation of portions of distribution lines that are located in remote hard to reach areas to improve access, or areas with repeat outages due to trees where the relocation is more cost effective solution than widening the right of way. Reduces potential damage and makes any needed repairs easier by making the facilities accessible to construction equipment.

- Targeted tree removal and circuit rights-of-way (ROW) widening. Trees from outside ROW account for nearly 50% of the total customer minutes of interruption for Kentucky Power. Although it would not be cost effective to remove every tree with the potential to contact our facilities, this program focuses on trees and lines that pose a high risk of causing equipment damage and customer outages. Greater attention is given to dead and dying trees.

- Proactive circuit inspections and replacements of components that have a higher potential for equipment failures (i.e. cutouts).

System resilience activities that have been completed:

- The system restoration plan was updated to the industry's best practice of using the Incident Management System to manage large outage restoration events. The ICS structure has been used several times since its adoption in 2016. ICS has improved stakeholder communication and restoration efficiencies.

- Additional distribution sources, additional distribution circuits, and circuit tie lines have been completed. These activities provide additional feeds for customers in the event of an outage that permits partial outage restoration by performing switching on using alternate feeds.

- Additional SCADA and distribution automation and circuit reconfiguration has been completed on selected circuits. This allow partial outage restoration to occur automatically by automated switching. The SCADA permits better visibility of the status of grid components and enables remote operation of switches and circuit breakers.

Future activities:

- The Company constantly reviews and updates the construction standards, materials and equipment performance to improve the design and performance of the grid.

- The Company plans to continue the above activities to improve reliability.

- Also, the Company is planning to move from automated meter reading (AMR) to advanced metering infrastructure (AMI) which will provide automatic reporting of customer outages which will improve outage predictions and improve the efficiency of outage restoration activities.

Witness: Gregory A. Bell

Kentucky Power Company
KPSC Case No. 2019-00443
Commission Staff's Second Set of Data Requests
Dated June 18, 2020

DATA REQUEST

KPSC 2_18 Refer to Case No 2017-00179, Phillips Testimony, pages 54–57 as it relates to IRP Section 3.6 at pages 71–72. Kentucky Power detailed the types of smart grid technologies being considered.

a. DER can be used to support isolated rural areas during major outages. Explain whether and how DER is being evaluated and whether that includes the use of microgrids to support critical facilities in rural areas.

b. Explain Kentucky Power's Distribution Management System and any future plans to deploy Advanced Distribution Management Systems.

RESPONSE

a. Kentucky Power is evaluating the ability and cost effectiveness of utilizing Distributed Energy Resources to support isolated areas that experience frequent and extended outages. These resources can be set up to operate as microgrids and provide an energy source for the area once it is isolated from fault conditions. Energy Storage (Batteries) can provide energy for a limited time depending on the battery size. Providing energy to these areas over a longer period such as during a major outage requires a generator. The use of generators with fossil fuel requires evaluating environmental implications in addition to the cost effectiveness.

b. Kentucky Power is utilizing an Advanced Distribution Management System (ADMS). The definition of an ADMS system is a software system that has the Outage Management System (OMS) and Distribution Management System (DMS) integrated. AEP has the General Electric software suite of products for OMS, DMS and also the Graphical Information System (GIS). PowerOn Restore (POR) is the OMS system, PowerOn Advantage (POA) is the DMS system and Electric Office (EO) is the GIS system.

Witness: Gregory A. Bell

DATA REQUEST

KPSC 2_19 Refer to the IRP Section 5.0, page 110.

a. Explain in more detail the methodology by which Plexos minimizes the capital and production related costs.

b. Explain whether Plexos allows different mathematical methods of optimization. If so, list the various optimization methods and explain whether those were considered in the formulation of the preferred plan.

RESPONSE

a. The Plexos model is a linear programming model that uses Company-defined constraints described in Section 5.1 of the Company's IRP. The Plexos model solves a series of linear programming equations based upon those constraints, with the objective of minimizing the cumulative present worth of revenue requirements for that given set of constraints.

b. No. Plexos does not provide multiple optimization engines for the user to select from when developing the Preferred Plan.

Witness: Gordon S. Fisher

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Commission Staff's Second Set of Data Requests
Dated June 18, 2020

DATA REQUEST

KPSC 2_20 Refer to Kentucky Power’s Response to Commission Staff’s First Request for Information (Staff’s First Request), Item 2b. Provide further explanation of how the potential load of Braidy Industries was discounted to reflect risk and included in the load forecast.

RESPONSE

The Company relies on its customer service representatives' discussions with customers to ascertain potential load changes. The value for Braidy's load relayed by the Company customer service representatives was discounted by 50% in the forecast to reflect normal economic growth and the risk of the load not developing as expected.

Witness: Gordon S. Fisher

Witness: John F. Torpey

DATA REQUEST

KPSC 2_21 Refer to Kentucky Power's Response to the Attorney General's First Request for Information, Item 6.

a. Provide the remaining useful life of each of Kentucky Power's generation units as modeled in the IRP. In addition, if there is any difference, provide the remaining useful lives according to the depreciation schedule of each unit.

b. Provide an explanation of the parameters used that govern if and when the models would choose to retire a generation unit. Include in the response an explanation of the logic the model goes through to determine whether a unit should be retired or not.

c. Explain how often each of the two Mitchell units are accepted by PJM in the energy market an if the bid price is equal to or below LMP on an hourly basis over the last 12 months, and whether the two units are designated as must run by PJM.

RESPONSE

a. As reflected in Exhibit G-1 of the Company's filing, the Company currently plans to retire Big Sandy Unit 1 in 2031. Both units at the Mitchell Plant are assumed to available through the IRP planning period, and have a currently-planned retirement date of 2040. The Mitchell and Big Sandy Unit 1lives are consistent with current depreciation rates.

b. The model does not solve for whether existing units should be retired or not. The Company may perform modeling runs with varying inputs for retirement dates for units and then compare the outcome of those modeling runs, but the model does not "choose" when to retire generating units.

c.
Kentucky Power Company
Breakdown of Hourly Dispatch
For all Hours from June 1, 2019 to May 31, 2020

	Mitchell 1	**Mitchell 2**
Unavailable	2,506	3,167
Dispatched by PJM	433	24
Economic Dispatch	3,396	1,800
Must-Run at Economic Min	1,299	2,106
Available, Not Dispatched by PJM	1,150	1,687

Dispatched by PJM means the unit was dispatched for a reason other than economics (e.g. reliability).

Economic dispatch means PJM dispatched the unit because the bid price was below the locational marginal price.

Must-Run at Economic Min means the Company designated the unit as must-run to keep it online, but because the bid price was greater than the LMP, the unit was only dispatched at the economic minimum level.

Witness: Gordon S. Fisher

Witness: John F. Torpey

DATA REQUEST

KPSC 2_22 Refer to Kentucky Power's Response to Staff's First Request, Items 7a and 24.

a. Explain the characteristics of the reclaimed coal mining land that prevented the siting of the solar generation facility.

b. Explain whether the characteristics discussed in part a. are inherent in the other reclaimed coal mining land in Kentucky Power's service territory such that it would prevent the siting of other solar generation facilities.

RESPONSE

a. The developer of the site needed to secure 1) a change of post-mining land use for the site and, 2) a release of a portion of the outstanding reclamation bond provided by the mine permittee with respect to the Kentucky mining permit covering the site and adjacent areas. It is Kentucky Power's understanding that the Kentucky Energy and Environment Cabinet denied the developer's request for these two items because of multiple permit violations and settlement agreement violations by the mining permittee.

b. The Company is unaware of the status of other reclaimed coal mining land in its service territory but has no reason to believe that other solar generation facilities could not be sited on other reclaimed coal mining land.

Witness: Brian K. West

DATA REQUEST

KPSC 2_23 Refer to Kentucky Power's Response to Staff's First Request, Item 9a.

a. Explain the decision to model wind resources as 30 year owned resources instead of a 20-year power purchase agreement.

b. Provide a discussion of the costs and benefits associated with owning renewable generation versus those of purchasing renewable power through a PPA.

RESPONSE

a. For this IRP all resources were modeled as Company owned, and the Company's current estimated life of a wind resource is 30 years. Therefore, as an owned asset, the Company assumed the owned wind resource would be available for its entire life. The Company did not have an estimate for a 20-year wind purchase power agreement, or any resource purchase power agreement, and therefore that resource option was not modeled. During a resource acquisition process the Company may consider other options to ownership.

b. Owning a renewable asset, compared to entering into PPAs, provides multiple benefits. With utility ownership, there may be an incentive to make improvements to an asset over its life that would not be advantageous for the owner of a PPA asset. At the end of an asset's planned life, there may be opportunities for continued operation or repowering of the asset that a utility could not perform if it does not own the asset, so any remaining potential at that point is lost under a PPA. In addition, when a utility enters into a PPA, it is committing to future payments that credit rating agencies recognize by "imputing debt" on the utility's balance sheet. This has the potential to affect the company's credit rating, which could drive up borrowing costs. In addition, from a regulatory perspective, the Commission possesses oversight of the operations and maintenance of a Company-owned renewable asset that go beyond those available for approval of a PPA related to a comparable resource.

Witness: Gordon S. Fisher

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Commission Staff's Second Set of Data Requests
Dated June 18, 2020

DATA REQUEST

KPSC 2_24 Refer to Kentucky Power's Response to Staff's First Request, Item 9d. Elaborate on the expectation that AEP's Generation Company won't renew the Rockport Unit 2 lease.

RESPONSE

The Rockport Unit 2 lease expires by its terms on December 7, 2022. The IRP assumes for planning purposes that the lease is not renewed.

Witness: Brian K. West

DATA REQUEST

KPSC 2_25 Refer to the IRP at 2247 or 2268 and Kentucky Power's Response to Staff's First Request, Items 12b and 13.

a. Provide further explanation as to how Kentucky Power's historic electricity prices are derived, i.e., the extent to which the various components to Kentucky Power's customer bills including energy rates, fuel charge, environmental surcharge, taxes, etc., are incorporated into the electricity prices for each of the customer classes listed in the table on page 2247.

b. If any of the various components of customers' bills are not included in electricity prices, explain why not.

RESPONSE

a. The historic prices come from historical customer billings, which include all factors affecting customer billing rates.

b. Not applicable.

Witness: Gordon S. Fisher

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Commission Staff's Second Set of Data Requests
Dated June 18, 2020

DATA REQUEST

KPSC 2_26 Refer to Kentucky Power's Response to Staff's First Request, Item 31.Explain the meaning of "full net metering."

RESPONSE

Full net metering refers to the billing mechanism whereby a customer with a distributed generation system is credited for excess generation that is sent to the grid at the full, bundled, retail rate.

Witness: Gordon S. Fisher

Witness: John F. Torpey

DATA REQUEST

KPSC 2_27 Refer to Kentucky Power's Response to Staff's First Request, Item 32.

a. Explain the criteria Kentucky Power uses to select circuits eligible for VVO measures.

b. Attachment 1 contains the results of a VVO study concluded in 2015.Explain whether Kentucky Power plans to conduct further circuit studies to ascertain the possibility of implementing VVO on additional circuits.

RESPONSE

a. The basic criteria for selecting circuits for VVO relates to the loading on the circuits and the ability to reduce the voltage by 3% while maintaining the required voltage range for customers. When the substation voltage regulation is at the transformer or the distribution bus the selection must also include all circuits on the bus. Another consideration is the amount of improvement work that may be required on the circuits to achieve the voltage reduction and maintain the minimum required voltage.

b. The Company's IRP has selected VVO in future years, but the actual projects have not been identified to date. Those projects will be analyzed as the identified in-service dates approach.

Witness: Brian K. West

DATA REQUEST

KPSC 2_28 Refer to Kentucky Power's Response to Staff's First Request, Item 40.

a. Explain whether the Demand Side Management and Energy Efficiency (DSM/EE) programs modeled as a supply side resource are considered dispatchable. If not, provide further explanation of the logic for including the EE bundles listed in Section 4.4.3.1.

b. Refer to IRP Sections 2.4.4.2 and 2.4.4.3. Explain whether and how the DSM/EE programs listed in Section 4.4.3.1 are incorporated in the Statistically Adjusted End-Use (SAE) models used to forecast Residential and Commercial Energy Sales.

c. Refer to IRP Table ES-1 at ES-4. The Preferred Plan for capacity additions include New EE. Since the Plexos model considers these programs to be cost-effective as a supply side resource, explain which EE programs are included in the Preferred Plan and whether their inclusion also means that these programs would satisfy the traditional California cost-effectiveness tests in order to offer them under Kentucky Power's DSM programs.

RESPONSE

a. The Demand Side Management and Energy Efficiency (DSM/EE) resources in the IRP modeled are not considered dispatchable. This is similar to the non-dispatchable solar and wind resources. These resources are presented in the model with a cost and potential energy and capacity savings that contribute toward meeting the Company's load obligation, if they are selected by the model.

b. The DSM/EE resources included in Section 4.4.3.1 were not explicitly modeled as an input into the SAE load forecast models. However, the impacts of these bundles/resources (e.g. higher saturations of energy efficient appliance technologies) were embedded in the SAE model framework. By including the DSM resources in Section 4.4.3.1 in the Preferred Plan, Kentucky Power would seek to accelerate the adoption of these energy efficient technologies.

c. IRP energy efficiency bundles selected in the Preferred Plan include: Residential Lighting - AP, Residential Lighting - HAP, Residential Thermal Shell - AP, Residential Water Heating - AP, Commercial Indoor HID/ Flour Lighting - AP, Commercial Indoor Screw-In Lighting - AP, Commercial Indoor Screw-In Lighting - HAP. Furthermore, all potential measures were evaluated against the various cost effectiveness tests. The primary screening for measures to include in the bundles was based on the Utility Cost Test (UCT). The measures meeting the UCT screening and included in the various bundles are listed in Tables 8 & 9 of the IRP. Additionally, as stated on page ES-9, item 3 of the Company's short-term action plan includes "Further examination of opportunities to increase cost effective levels of EE in alignment with the Preferred Plan."

Witness: Gordon S. Fisher

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Commission Staff's Second Set of Data Requests
Dated June 18, 2020

DATA REQUEST

KPSC 2_29 Refer to Kentucky Power's Response to Staff's First Request, Item 43a.Provide further detail on the 6.8 MW distributed generator at Inez Power, LLC.

a. Explain the nature of Inez Power LLC and the expected in service date.

b. If known, explain whether Inez Power LLC will operate as a merchant generator and sell its energy into the PJM markets.

RESPONSE

a. Inez Power is a waste-to-energy qualified facility (QF) generator with an estimated in service date of September to October of 2020.

b. Inez Power is a Qualifying Facility under PURPA, and will sell its output to the Company at avoided cost under the Commission approved Cogen/SPP tariff.

Witness: Brian K. West

VERIFICATION

The undersigned, Gordon S. Fisher, being duly sworn, deposes and states he is the Resource Planning Manager for the American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses, and that the information contained therein is true and correct to the best of his information, knowledge, and belief.

Scott Fisher
Gordon S. Fisher

State of Indiana	)	
	)	Case No. 2019-00443
County of Allen	)	

Subscribed and sworn before me, a Notary Public, by Gordon S. Fisher this _17___ day of July, 2020

Regiana M. Sistevaris
Digitally signed by Regiana M. Sistevaris
Date: 2020.07.17 09:26:40 -04'00'

Notary Public, Regiana Maria Sistervaris

My Commission Expires: January 7, 2023

VERIFICATION

The undersigned, John F. Torpey, being duly sworn, deposes and states he is the Managing Director of Resource Planning and Operation Analysis for the American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses, and that the information contained therein is true and correct to the best of his information, knowledge, and belief.

John F Torpey
____
John F. Torpey

State of Indiana)
) Case No. 2019-00443
County of Allen)

Subscribed and sworn before me, a Notary Public, by John F. Torpey this _17th___ day of July, 2020

Regiana M. Sistevaris
Digitally signed by Regiana M. Sistevaris
Date: 2020.07.17 09:18:04 -04'00'
____
Notary Public, Regiana Maria Sistervaris

My Commission Expires: _________January 7, 2023_______

VERIFICATION

The undersigned, Brian K. West, being duly sworn, deposes and states he is the Director of Regulatory Services for Kentucky Power Company, that he has personal knowledge of the matters set forth in the foregoing responses, and that the information contained therein is true and correct to the best of his information, knowledge, and belief.

Brian K. West

State of Indiana)
) ss Case No. 2019-00443
County of Allen)

Subscribed and sworn to before me, a Notary Public, in and for said County and State, Brian K. West this 17th day of July, 2020.

Regiana M. Sistevaris

Digitally signed by Regiana M. Sistevaris
Date: 2020.07.17 09:20:48 -04'00'

Regiana M. Sistevaris, Notary Public

My Commission Expires: January 7, 2023