COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power	)	
Company For A Certificate Of Public Convenience	)	
And Necessity To Construct A 161 kV	)	Case No. 2017-00328
Transmission Line In Perry And Leslie Counties,	)	
Kentucky And Associated Facilities	)	
(Hazard-Wooton Line)	)	

KENTUCKY POWER COMPANY

RESPONSES TO

ATTORNEY GENERAL'S FIRST SET OF DATA REQUESTS

January 29, 2018

REQUEST

AG_1_001 Refer to Wohnhas Testimony pg. 4. Explain, using the Company's best available knowledge and estimation, the future scope of the Eastern Kentucky Transmission Program.
a. Explain how many total projects the Company intends to undertake in this program.
b. Explain how much of the program is likely to be focused on projects designated Baseline versus those considered Supplemental, as defined by PJM.
c. Explain whether the Company has already identified future projects to be completed under this program, and how those projects were identified. If so, provide such projects and a description of each.
d. Refer to Lasslo Testimony pg. 10. Explain whether the Company exclusively relies on the PJM annual RTEP to identify future projects for this program, or if it also uses internal reviews for such. If internal reviews are also used, describe the factors and methodology which comprise these reviews, and the outcomes of the reviews.

RESPONSE

a. The evaluation process is ongoing. Please refer to Company Witness Wohnhas' testimony at page 3 ("Kentucky Power currently is evaluating opportunities to replace, revitalize, and upgrade aging facilities to improve system reliability.") A total number of projects has not been identified as of January 29, 2018.

b. The focus of the Eastern Kentucky Transmission Program is the rehabilitation of existing lines and facilities and thus encompasses transmission needs that fall outside of PJM baseline criteria. Kentucky Power anticipates that the majority of the projects will be designated supplemental by PJM or will involve, as is the case with the Hazard-Wooton project, both baseline and supplemental elements.

The fact that a project does not fall within PJM baseline criteria does not mean the project is any less required by the public convenience and necessity.

c. To date Kentucky Power has identified the following projects for the Eastern Kentucky Transmission Program:

- The Hazard – Bonnyman Structure Replacement Project will address structural conditions requiring the partial or complete replacement of 17 structures located on the existing Hazard – Bonnyman #1 69 kV circuit.

- The Hazard - Jackson Structure Replacement Project will address structural conditions requiring the partial or complete replacement of eight structures located on

- the existing Bonnyman - Jackson 69 kV circuit.

- The Jackson - Helechawa Structure Replacement Project will address structural conditions issues requiring the partial or complete replacement of 25 structures located on the existing Jackson – Lee City 69 kV circuit.

- The Hazard - Fleming Structure Replacements: Project will address structural conditions requiring the partial or complete replacement of 26 structures located on the existing Hazard – Daisy, Daisy – Collier, and Collier - Fleming 69 kV circuits.

- The Daisy – Clover Fork Structure Replacement Project will address structural conditions requiring the partial or complete replacement of 16 structures located on the existing Daisy - Leslie 69 kV circuit.

These projects were identified in conformity the "AEP Guidelines for Transmission Owner Identified Needs." A copy is attached as KPCO_R_AG_1_1_Attachment1.pdf.

d. The Eastern Kentucky Transmission Program is not limited to either baseline or supplemental projects. Kentucky Power, through AEP Transmission, participates in the PJM planning process. As part of that process both PJM and AEP planning criteria are employed:

http://www.pjm.com/planning/planning-criteria/pjm-planning-criteria.aspx
http://www.pjm.com/-/media/planning/planning-criteria/aep-planning-criteria.ashx?la=en
http://pjm.com/-/media/committees-groups/committees/srrtep-w/20170105/20170105-aep-guidelines-for-transmission-owner-identified-needs.ashx

PJM and Kentucky Power, in conjunction with AEP, identify needs that must be addressed by Baseline projects as part of the Eastern Kentucky Transmission Program, while Kentucky Power in conjunction with AEP, identifies needs that must be addressed by Supplemental projects as part of the Eastern Kentucky Transmission Program. Please refer to testimony of Company Witness Lasslo at pages 12-13.

WITNESS: Michael G. Lasslo

AEP Guidelines for Transmission Owner Identified Needs

January 2017

Document Control

Document Review and Approval

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Review Cycle

Quarterly	Semi-annual	Annual	As Needed
		X	X

Revision History

Version	Revision Date	Changes	Comments
1.0	01/04/2017	N/A	1st Release

Table of Contents

1.0 Introduction

The American Electric Power (AEP) transmission system consists today of approximately 40,000 miles of transmission lines, 3,600 stations, 5,000 power transformers, 8,000 circuit breakers, and operating voltages between 23 kV and 765 kV in three different RTOs – the Electric Reliability Council of Texas (ERCOT), the PJM Interconnection (PJM), and the Southwest Power Pool (SPP), connecting over 30 different electric utilities while providing service to over 5.4 million customers in 11 different states.

AEP's interconnected transmission system was established in 1911 and is comprised of a very large and diverse combination of line, station, and telecommunication assets, each with its own unique installation date, design specifications, and operating history. As the transmission owner, it is AEP's obligation and responsibility to manage and maintain this diverse set of assets to provide for a safe, adequate, reliable, flexible, efficient, cost-effective and resilient transmission system that meets the needs of all customers while complying with Federal, State, RTO and industry standards. This requires, among other considerations, that AEP determine when the useful life of these transmission assets is coming to an end and when the capability of those assets no longer meets current needs, so that appropriate improvements can be deployed. AEP refers to this list of issues as transmission owner identified needs.

AEP's transmission owner identified needs must be addressed to achieve AEP's obligations and responsibilities. Meeting this obligation requires that AEP ensures the transmission system can deliver electricity to all points of consumption in the quantity and quality expected by customers, while reducing the magnitude and duration of disruptive events. Given these considerations, guidelines are necessary to identify, quantify, and prioritize needs associated with transmission facilities comprising AEP's system. Prioritization, in particular, becomes a critical element when determining how to utilize a finite set of financial, human and material resources needed to address a continuously expanding set of needs. AEP identifies the needs and the solutions necessary to address those needs on a continuous basis using an in-depth understanding of the condition of its assets, and their associated operational performance and risk, while exercising engineering judgment coupled with Good Utility Practices [1].

This document outlines AEP's guidelines for transmission owner identified needs that address equipment material conditions, performance, and risk while considering infrastructure resilience, operational flexibility and efficiency. It outlines how AEP identifies assets with needs, it describes the methodology applied to prioritize those needs, and it outlines how solutions are developed and scheduled. Customer service driven projects and transmission owner planning criteria driven projects are addressed in AEP's Requirements for Connection of New Facilities or Changes to Existing Facilities Connected to the AEP Transmission System document [2] and AEP's FERC Form 715 (Part 4) Transmission Planning Reliability Criteria document [2], respectively.

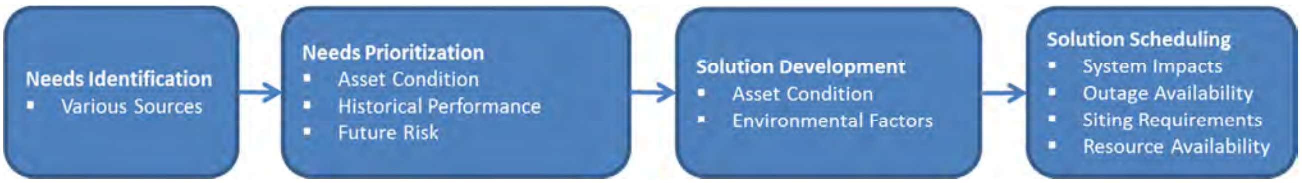
Addressing these owner identified transmission system needs will result in the following benefits:

- Safe operation of the electric grid.
- Reduction in frequency of outage interruptions.
- Reduction in duration of outage interruptions.
- Improvement in service reliability and adequacy to customers.
- Reduction of risk of service disruptions (improved resiliency) associated with man-made and environmental threats.
- Proactive correction of reliability constraints that stem from asset failures.
- Increased system flexibility associated with day-to-day operations.
- Effective utilization of resources to provide efficient and cost-effective service to customers.

2.0 Process Overview

AEP's transmission owner needs identification and prioritization guidelines are used for projects that address equipment material conditions, performance, and risk while considering infrastructure resilience, operational flexibility and efficiency. AEP uses the four (4) step process shown in Figure 1 and discussed in detail in this document to determine the best solutions to address the transmission owner identified needs and meet AEP's obligations and responsibilities. In developing the most efficient and cost-effective solutions, AEP's long-term strategy is to pursue holistic transmission solutions in order to reduce the overall AEP transmission system needs.

Figure 1 – AEP Process for Addressing Transmission Owner Identified Needs



3.0 Step 1: Needs Identification

Needs Identification is the first step in the process of determining system and asset improvements that help meet AEP's obligations and responsibilities. AEP gathers information from many internal and external sources to identify assets with needs. A sampling of the inputs and data sources is listed below in Table 1.

Table 1 – Inputs Considered by AEP to Identify Transmission System Needs

Internal, External, or Both	Inputs	Examples
Internal	Reports on asset conditions	Transmission line and station equipment deterioration identified during routine inspections (pole rot, steel rusting or cracking)
	Capabilities and abnormal conditions	Relay misoperation; Voltage unbalance
	Legacy system configurations	Ground switch protection schemes for transformers; Transmission line taps without switches; Equipment with no parts or no longer supported by vendors
	Outage duration and frequency	Outages resulting from equipment failures, misoperation, or inadequate lightning protection
	Operations and maintenance costs	Costs to operate and maintain equipment
External	Regional Transmission Operator (RTO) or Independent System Operator (ISO) issued notices	Post Contingency Local Load Relief Warnings (PCLLRWs) issued by the RTO that can lead to customer load impacts
	Stakeholder input	Input received through stakeholder meetings, such as PJM's Sub Regional RTEP Committee (SRRTEP) meetings
	Customer feedback	Voltage sag issues to customer delivery points due to poor sectionalizing; frequent outages to facilities directly affecting customers
	State and Federal policies, standards, or guidelines	NERC standards for dynamic disturbance recording
Both	Environmental and community impacts	Equipment oil/gas leaks; facilities currently installed at or near national parks, national forests, or metropolitan areas
	Safety risks and concerns	Station and Line equipment that does not meet ground clearances; Facilities identified as being in flood zones; New Occupational Safety and Hazards Administration (OSHA) regulations

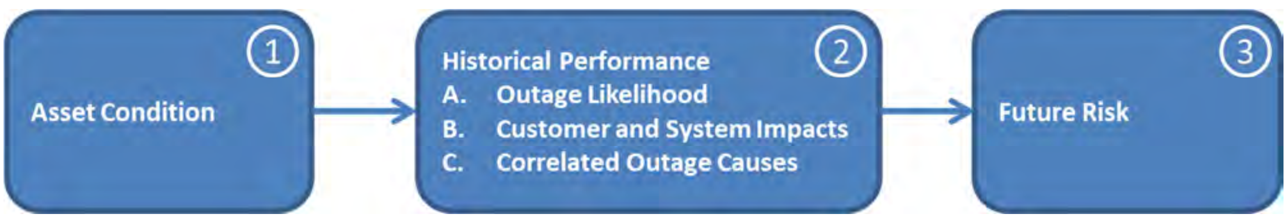
This information is reviewed and analyzed to identify the transmission assets that are not performing properly or are preventing the proper operation of the transmission system.

4.0 Step 2: Needs Prioritization

4.1 Methodology and Process Overview

The AEP transmission system is composed of a very large number of assets that provide specific functionality and must work in conjunction with each other in the operation of the grid. These assets have been deployed over a long period of time using engineering principles, design standards, and Good Utility Practices that were applicable at the time of installation and have been exposed to varying operating conditions over their life. Due to the size, scope and age of the AEP system, as well as the evolution of standards and Good Utility Practices, the Needs Identification step results in a significant number of transmission assets with needs. Needs that have a direct safety concern are automatically placed at the top of the prioritized list and completed with the highest urgency. In prioritizing the needs that do not have a direct safety concern AEP uses a prioritization methodology that incorporates three key factors: Asset Condition, Historical Performance, and Future Risk (see Figure 2).

Figure 2 – Transmission Line and Station Prioritization Methodology



This methodology allows AEP to determine which asset needs will be most impactful to overall grid performance and service to customers so that solutions can be identified within the appropriate time frames. It implements a weighted total approach where assets are split by voltage class, which ensures the appropriate ranking of transmission line and station assets within each of AEP's operating companies. It is AEP's strategy to develop and provide the most efficient, cost-effective, and holistic long-term solutions for the identified needs.

4.2 Data Considerations

AEP generally uses three years of historical performance data, along with present day condition data, to perform the Needs Prioritization. In addition, a five-year risk assessment forecast is developed. For situations and assets deemed to present larger risks to the system, or to develop more forward looking plans, AEP may use more than three years of historical data and may also develop risk assessment forecasts beyond the five-year period.

AEP collects numerous impact indices to perform the Historical Performance and the projected Future Risk portions of the prioritization methodology, as well as to calculate the impact on a historical outage or a projected future outage basis. The key indices considered in this analysis include:

- Affected load (in MW)
- Number of customers interrupted
- Customer minutes of interruption

Additional "optional" impacts may be recorded and considered based upon data availability. The "optional" considerations are covered in greater detail in Section 4.4.2.

4.3 Asset Condition (Factor 1)

The Asset Condition assessment gathers a standard set of physical characteristics associated with an asset or a group of assets. The set of data points recorded is determined based on the asset type and class. Information assembled during the Asset Condition assessment is used to show the current condition of the asset or group of assets on the AEP system. This asset condition information is quantified into a future probability of failure adder which is added to the historical probability of failure recorded in the Historical Performance portion of the Needs Prioritization process. This approach accounts for an asset's deterioration due to age, weather exposure, electrical system stresses, etc. The future probability of failure adder and the process used to quantify these values are unique to the asset or group of assets under consideration.

AEP annually assembles a list of reported condition issues for all of its assets in its system. A detailed follow-up review is conducted to determine if a transmission asset is in need of upgrade and/or replacement. Additionally, this Asset Condition review is used to determine an adequate scope of work required to mitigate the risk associated with a facility's performance and its identified issues. This level of risk is determined through the Future Risk assessment (Factor 3).

Beyond physical condition, AEP's ability to restore the asset in case of a failure is also considered in the future probability of failure adder. Typically, assets that are no longer supported by manufacturers have a higher probability of failure adder.

4.4 Historical Performance (Factor 2)

AEP's Historical Performance assessment quantifies how an asset or a group of assets has historically impacted the transmission system's reliability. AEP calculates two distinct sets of metrics to quantify Historical Performance: Outage Probability and Impacts. The historical outage probability data recorded during the Historical Performance assessment is used as the baseline outage probability applied during the Future Risk portion of the three-part prioritization assessment process.

The baseline historical outage probability is uniquely defined depending on the transmission asset under review. For transmission line and station facilities, historical outage probabilities are established by tracking and quantifying four distinct data points:

- Transmission System Average Interruption Duration Index (T-SAIDI)
- Transmission System Average Interruption Frequency Index (T-SAIFI)
- Transmission System Average Sustained Interruption Frequency Index (T-SAIFI-S)
- Transmission Momentary Average Interruption Index (T-MAIFI)

For large transmission station equipment such as circuit breakers, transformer and reactors, AEP's Asset Health Center Platform, which calculates the probability of failure associated with individual major pieces of equipment on the AEP transmission system, is used to obtain baseline outage probabilities.

A standard set of impact indices are used to quantify the historical impacts of an asset or group of assets. These historical impacts will be similar to future risk impacts used in the future risk of failure portion of the three-part prioritization assessment. Historical impacts include load loss, customer minutes of interruption, and number of customers interrupted.

4.4.1 Historical Performance: Outage Likelihood (Factor 2-A)

This review investigates an asset's three year historical performance with regards to its contribution to its associated voltage class's outage frequency and duration totals. Four transmission historical system performance metrics, as specified in Table 2, are calculated to quantify an operating company's three year historical performance levels on a voltage class basis and an individual asset's contribution to the identified voltage classes: T-SAIFI, T-MAIFI, T-SAIFI-S and T-SAIDI. Due to the vast size of the AEP operating territory covering 11 states, AEP segments its needs into seven distinct operating company regions and six voltage classes. This segmentation ensures that variations in geography with respect to vegetation, weather patterns, and terrain can be accounted for within the prioritization process, thus allowing for the proper identification and solution development for each operating company area.

Table 2 - Transmission Asset Performance Metrics

System Metric	Performance by Voltage Class	Application
T-SAIDI	Duration of all outages divided by total number of circuits in voltage class	Probability of a one hour outage
T-SAIFI	Number of outages divided by total number of circuits in voltage class	Probability of an outage
T-SAIFI-S	Number of sustained outages divided by total number of circuits in voltage class	Probability of an outage lasting more than five minutes
T-MAIFI	Number of momentary outages divided by total number of circuits in voltage class	Probability of an outage lasting less than five minutes

4.4.2 Historical Performance: Customer and System Impacts (Factor 2-B)

Historical impacts are divided into two sub-categories: customer impacts and system impacts. The customer impacts portion is defined by four metrics: IEEE SAIDI, IEEE CAIDI, IEEE SAIFI, and Loss of Load. These metrics are calculated using historical outage data that resulted directly from transmission line or station asset outages and are calculated separately for each asset class. All outage data pertaining to distribution line failures are removed from the data set in order to ensure accurate representation of customer impacts related to transmission line or station outages within the AEP transmission system. Additionally, all customer minutes of interruption occurring during severe weather events are removed from the analysis.

AEP also includes consideration to retail customers that are served by the parent wholesale customer service points. In order to account for customers served behind wholesale meter points, AEP gathers that information from the parent wholesale provider or in its absence, applies a surrogate customers per MW ratio to estimate the number of customers served by a wholesale power provider's delivery point. This customer count is used to calculate each individual customer's minutes of interruption and frequency. After compiling each asset's three year impact on Customer Minutes of Interruption, Customer Interruptions, and Loss of Load, AEP calculates the IEEE SAIDI, IEEE SAIFI, IEEE CAIDI and total loss of load for each region's three year system totals. Similar to Factor 2-A, each asset's contribution to its corresponding system totals are calculated to determine its percentage contribution to aggregated system totals.

When available, the data outlined in Table 3 will be collected for each outage on the AEP transmission system. Due to the limited availability of this information, these data points are considered "optional" in the needs prioritization process and are considered in the analysis on a case-by-case basis.

Table 3 - Optional System Impact Metrics (collected when data is available)

Optional Impact Indices	Quantifiable Value
Expected energy not delivered by failed component	Average energy flowing through equipment times expected outage duration
Generation loss	MW and MVAR range of units
Static reactive devices interrupted	MVAR
Dynamic reactive devices	MVAR range of devices interrupted
Number of stations with voltage sags	Number of EHV, HV, Sub-T stations
Number of tie line interconnections interrupted	Number of interrupted lines
Arming of SPS schemes due to stability or thermal constraints	Number of times a SPS is armed due to facility outage or projected outage
Number of real time operational constraints resulting load drop warnings	Number of times RTO issues load drop warnings associated with the projected outage of an asset

4.4.3 Historical Performance: Correlated Outage Causes (Factor 2-C)

Each transmission facility identified through the prioritization process outlined in Factors 2-A and 2-B will be subjected to a detailed investigation of the primary contributing cause of that facility's outage totals. AEP classifies all transmission asset outage causes into the following five categories to conduct this review: Transmission Line Component Failure, Substation Component Failure, Vegetation (AEP), Vegetation (Non-AEP), and External Factors. Each transmission asset and its associated outages are quantified on frequency and duration totals with respect to these five categories. A value-based weighting will be assigned to a transmission asset. This value is used to determine if there is correlation between an asset's outage history and the failure of its associated components.

4.5 Future Risk (Factor 3)

AEP reviews the associated risk exposure (future risk) inherent with each identified asset to determine an asset's level of risk. This risk exposure is quantified assuming a long-term outage scenario and is based on the reported condition of the asset and the severity of that condition. It is calculated by summing the historical probability of failure, with the probability of failure due to future deterioration of an asset and then multiplying this calculated value by the quantified future impacts.

5.0 Step 3: Solution Development

The development of solutions for the identified needs considers a holistic view of all of the prioritized needs in which several solution options are developed and scoped. AEP applies the appropriate industry standards, engineering judgment, and Good Utility Practices to develop these solution options. Solution options consider many factors including, but not limited to, environmental conditions, community impacts, land availability, permitting requirements, customer needs, system needs, and asset conditions in ultimately identifying the best solution to address the identified need. Once the selected solution for a need or group of needs is defined, it is reviewed using the current RTO provided power-flow, short circuit, and stability system models (as needed) to ensure that the proposed solution does not adversely impact or create planning criteria violations on the transmission grid. Finally, AEP reviews its existing portfolio of planning criteria driven reliability projects and evaluates opportunities to combine or complement existing planning criteria driven reliability projects with the transmission owner needs driven solutions developed through this process. This step ultimately results in the implementation of the most efficient, cost-effective, and holistic long-term solutions. Stand-alone projects are created to implement the proposed solution where transmission owner needs driven solutions cannot be integrated into existing projects.

6.0 Step 4: Solution Scheduling

Once solutions are developed to address the identified and prioritized needs, the scheduling of the solutions will take place. As mentioned in the previous section, if opportunities exist to combine or complement existing planning criteria driven reliability projects with the needs driven solutions developed through this process, the scheduling will be aligned to the extent possible. In all other situations, AEP will schedule the implementation of the identified solutions in consideration of various factors including severity of the asset condition, overall system impacts, outage availability, siting requirements, availability of labor and material, constructability, and available capital funding. AEP uses its discretion and engineering judgment to determine suitable timelines for project execution.

7.0 Conclusion

This document outlines AEP's guidelines for transmission owner identified needs that address equipment material conditions, performance, and risk while considering infrastructure resilience, operational flexibility and efficiency. It outlines the sources and methods considered by AEP to identify assets with needs on a continuous basis, it describes the methodology applied to prioritize the needs of different assets, and it outlines how solutions are developed and scheduled. AEP will review and modify these guidelines as appropriate based upon our continuing experience with the methodology, acquisition of data sources, deployment of improved performance statistics and the receipt of stakeholder input in order to provide a safe, adequate, reliable, flexible, efficient, cost-effective and resilient transmission system that meets the evolving needs of all of the customers it serves.

8.0 References

[1] FERC Pro Forma Open Access Transmission Tariff, Section 1.14, Definition of "Good Utility Practice".
Link: https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-0aa.txt

[2] AEP Transmission Planning Documents and Transmission Guidelines.
Link: http://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/

REQUEST

AG_1_002 Refer to Application pg. 4, Wohnhas Testimony pgs. 5, 9, and Larson Testimony pg. 8. Explain whether the Company expects to receive substantial monetary savings or see increased efficiencies and reliability from combining portions of the existing Hazard-Jackson 69 kV Transmission Line and the Hazard-Wooton 161 kV Transmission Line into a 1.15 mile double-circuit line as part of the rebuild.
a. If so, state the amount of any such benefits and explain the extent of the same.
b. Explain whether there are any inherent risks or inefficiencies from the double-circuit configuration.

RESPONSE

a. Although some economies are expected, the Company has not quantified the savings. More fundamentally, the proposed double circuit configuration was the best solution to the siting, constructability, maintenance, and safety constraints presented by this portion of the project. These constraints include the close proximity of the river, residential development in close proximity to the existing transmission lines, distribution lines in close proximity to the transmission lines, steep terrain, constructability and safety concerns presented by the topography, the limited area suitable for construction, environmental concerns, and the proximity of the lines to the Hazard High School.

The double-circuit configuration also increases efficiencies and reduces land use impact because both transmission circuits will reside on a single set of transmission line structures. By reducing the number of structures required, the double-circuit configuration also limits the visual impact of the project on nearby residences. The larger structures to be used for the double-circuit structure portion of the line will increase the reliability of the 69 kV Hazard-Jackson line while facilitating the future upgrade of the existing 69kV circuit to 138kV to meet future load growth. The double-circuit configuration also allows the Company to address the need to relocate both transmission lines higher on the ridge and thereby minimize slips and slides in light of the limited amount land in the area suitable for construction and maintenance of the lines. Finally, the proposed double-circuit configuration allows both lines to be moved farther from the existing residences and thereby increases safety.

b. Placing two circuits on a single set of structures presents the risk that both circuits could be affected by a single failure. The Company is addressing this risk through the use of the proposed steel structures that are being designed to exceed today's code and standards. As a result, the reliability of the double circuit configuration will exceed the existing single circuit configuration of the transmission lines. The configuration also was reviewed in accordance with NERC Standard TPL-001-4 to ensure the change would not result in a new violation.

WITNESS: Michael G. Lasslo

KENTUCKY POWER
CASE NO. 2017-00328
ATTORNEY GENERAL'S FIRST SET OF DATA REQUESTS
DATED: JANUARY 19, 2018

REQUEST

AG_1_003 Explain in detail the Company's projected useful life for the rebuilt Hazard-Wooton 161kV line.

RESPONSE

The project will use galvanized tubular steel poles, galvanized tubular steel H-frames, and galvanized latticed steel towers. It has been the Company's experience in eastern Kentucky that galvanized steel structures generally have an expected service life of 60 years to 80 years when deployed in Kentucky Power's service territory.

WITNESS: Michael G. Lasslo

KENTUCKY POWER
CASE NO. 2017-00328
ATTORNEY GENERAL'S FIRST SET OF DATA REQUESTS
DATED: JANUARY 19, 2018

REQUEST

AG_1_004 Refer to the Application pg. 6, 14. Explain the projected rationale and methodology the Company will use to determine whether, and when, to upgrade the double-circuit portion of the line to 138 kV, to provide increased capacity for future new load.

RESPONSE

Kentucky Power will continue to review the need to upgrade the 69 kV Hazard-Jackson line in accordance with the following AEP and PJM planning criteria and processes:

http://www.pjm.com/planning/planning-criteria/pjm-planning-criteria.aspx
http://www.pjm.com/-/media/planning/planning-criteria/aep-planning-criteria.ashx?la=en
http://pjm.com/-/media/committees-groups/committees/srrtep-w/20170105/20170105-aep-guidelines-for-transmission-owner-identified-needs.ashx

In evaluating the need to upgrade the circuit, Kentucky Power will apply the standards above, engineering judgement, and good utility practices to develop and review solutions.

WITNESS: Michael G. Lasslo

KENTUCKY POWER
CASE NO. 2017-00328
ATTORNEY GENERAL'S FIRST SET OF DATA REQUESTS
DATED: JANUARY 19, 2018

REQUEST

AG_1_005 Refer to Wohnhas Testimony pgs. 16–17 and Lasslo Testimony pg. 12. Explain in detail how much of the proposed project is considered Baseline and how much is considered Supplemental, as defined by PJM.
a. Explain whether the additional station work, which appears to total $13 million, is all considered Supplemental.

RESPONSE

Station work that is not directly related to the Hazard – Wooton 161 kV line rebuild and Hazard 161/138 kV transformer replacement is considered Supplemental. The Company estimates that approximately $20 million of the current estimated cost of the project is Baseline while the remaining $24.5 million is Supplemental. Please refer to pages 12-14 of Company Witness Lasslo's testimony concerning the PJM stakeholder review of Supplemental projects.

WITNESS: Michael G. Lasslo

REQUEST

AG_1_006 State whether this project has a cost cap. If so, explain the parameters of the cost cap in detail. If not, explain why not.

RESPONSE

Kentucky Power has a capital allocation process for reviewing and approving capital projects. The process requires projects to demonstrate that the scope of work is appropriate for providing adequate service to customers and that the estimated costs are reasonable. The Hazard-Wooton project costs were estimated and approved in accordance with the capital allocation process. To exceed this authorized budget requires additional review and approvals.

WITNESS: Ranie K. Wohnhas

KENTUCKY POWER
CASE NO. 2017-00328
ATTORNEY GENERAL'S FIRST SET OF DATA REQUESTS
DATED: JANUARY 19, 2018

REQUEST

AG_1_007 State whether the Company has planned or intends to use a competitive bidding process in order to select the firm or firms to complete the construction of the project.
a. If so, explain the selection criteria in detail, explain the rationale for any bids already awarded, and provide copies of any bids received and Requests For Production prepared for this project.
b. If not, explain why not.

RESPONSE

(a)-(b) Competitive bidding will be used for access road construction, for transmission line construction, and for associated station construction at the Hazard and Wooton Stations. Pre-qualified bidders will submit bids that will be evaluated on price, safety, and the ability to meet the construction schedule.

No bids have been solicited yet.

WITNESS: Ranie K. Wohnhas

VERIFICATION

The undersigned, Ranie K. Wohnhas, being duly sworn, deposes and says he is the Managing Director, Regulatory and Finance for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Ranie K. Wohn

Ranie K. Wohnhas

Commonwealth of Kentucky)
) Case No. 2017-00328
County of Boyd)

Subscribed and sworn before me, a Notary Public, by Ranie K. Wohnhas this 29 day of January, 2018.

Trisha M. Young-Blum
Notary Public

My Commission Expires 3-18-19

COMMONWEALTH OF KENTUCKY
UNITED WE STAND
DIVIDED WE FALL
TRISHA M. YOUNG
NOTARY ID 530202
COMMISSION EXPIRES 3-18-19

VERIFICATION

The undersigned, Michael G. Lasslo, being duly sworn, deposes and says he is the Reliability Manager for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Michael G Lasslo
Michael G. Lasslo

Commonwealth of Kentucky	)	
	)	Case No. 2017-00328
County of Perry	)	

Subscribed and sworn before me, a Notary Public, by Michael G. Lasslo this 26 day of January, 2018.

Notary Public

My Commission Expires 6-21-2018