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 Perform Upgrade, Replacement, And Installation Work At Its Existing Substation Facilities In Perry And Leslie Counties, Kentucky	)))))	Case No. 2019-00154

POST-HEARING BRIEF OF KENTUCKY POWER COMPANY

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A. INTRODUCTION AND BACKGROUND.

1. Introduction.

The application before the Commission is necessary to address important needs at the Hazard and Wooton Substations (collectively, the "Project") and to implement fully the Hazard-Wooton 161 kV transmission line project that the Public Service Commission of Kentucky ("Commission") approved in 2018. The uncontroverted record demonstrates that the work proposed by Kentucky Power Company ("Kentucky Power") is required to enable Kentucky Power to meet its statutory obligation to provide adequate, efficient, and reasonable service without wasteful duplication.

As the Company demonstrated, and PJM Interconnection, LLC ("PJM") found, the Project's Baseline components are required to implement the reconstruction of the Hazard-Wooton 161 kV transmission line previously approved by the Commission. The Project's Supplemental components are essential to replace or upgrade deteriorated, damaged, or obsolete existing equipment; to reconfigure the Hazard Substation to improve reliability and limit degradation of substation components; and to provide increased functionality. All of the proposed work is required by the public convenience and necessity.

The public convenience and necessity requires that the Commission act promptly to authorize Kentucky Power to perform all of the work it proposes in this case, whether designated Baseline or Supplemental. Doing so will enable the Company to meet the important needs addressed by the Project while saving the Company and its customers millions of dollars in unnecessary costs. Although Kentucky Power has been able to extend the life of some assets in the Hazard and Wooton Substations through regular inspection and maintenance, the performance and condition of those assets has reached a point that the substation renewal, reconfiguration, and functionality improvement work for which Kentucky Power seeks approval is now required. As detailed below, the Commission should approve Kentucky Power's application in this proceeding so that the Company can timely perform the important work for which it seeks authorization.

2. Background.

The Commission approved the reconstruction of the Hazard-Wooton 161 kV transmission line, the 69 kV Hazard-Jackson Reconfiguration, and the installation of 161/138 kV Transformer # 3 in the Hazard Substation by two orders issued in Case No. 2017-00328.[1] Finding that the record before the Commission was insufficient to meet Kentucky Power's burden of proof concerning the need for the remaining elements,[2] the Commission dismissed the remainder of the application without prejudice to Kentucky Power's ability to refile and seek Commission approval of the remaining Hazard Substation and Wooton Substation work.

Consistent with the Commission's ruling in Case No. 2017-00328, the Company provided in this proceeding a complete and detailed record demonstrating the need for the work proposed by Kentucky Power at the two substations. Exhibit 2 to the Company's application, along with the Company's responses to discovery,[3] demonstrate on an element by element basis the need for each of the components comprising the proposed substation upgrades.

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[1] Order, *In the Matter of: Electronic Application Of Kentucky Power Company For Certification of Public Convenience and Necessity to Construct A 161 kV Transmission Line in Perry and Leslie Counties, Kentucky, and Associated Facilities*, Case No. 2017-00328 (Ky. P.S.C. March 16, 2018); Order, *In the Matter of: Electronic Application Of Kentucky Power Company For Certification of Public Convenience and Necessity to Construct A 161 kV Transmission Line in Perry and Leslie Counties, Kentucky, and Associated Facilities*, Case No. 2017-00328 (Ky. P.S.C. November 14, 2018).

[2] Order, *In the Matter of: Electronic Application Of Kentucky Power Company For Certification of Public Convenience and Necessity to Construct A 161 kV Transmission Line in Perry and Leslie Counties, Kentucky, and Associated Facilities*, Case No. 2017-00328 at 5, 7 (Ky. P.S.C. March 16, 2018).

[3] *See e.g.* Kentucky Power Company's Response to Staff's First Set of Data Requests, Request No. 8, Attachment 1, *In the Matter of: Electronic Application Of Kentucky Power Company For A Certificate Of Public Convenience And Necessity To Perform Upgrade, Replacement, And Installation Work At Its Existing Hazard Substation And Wooton*

The record unambiguously demonstrates that the Supplemental Project Elements comprising the application were reviewed by PJM stakeholders under PJM's newly-approved process despite the fact the FERC Order requiring that the process be revised was prospective only. The record in this proceeding also provides greater clarity regarding considerations raised in Case No. 2017-00328 concerning the status of the former PJM review process.

B. THE PUBLIC CONVENIENCE AND NECESSITY REQUIRES THE CONSTRUCTION OF THE PROPOSED BASELINE AND SUPPLEMENTAL WORK.

1. Generally.

(a) The Legal Standard.

Kentucky Power must obtain a certificate of public convenience and necessity prior beginning construction of "any plant, equipment, property, or facility for furnishing…" service to the public[4] except where the proposed work constitutes an extension in the ordinary course of business.[5] KRS 278.020(1) provides for the grant of a certificate of public convenience and necessity upon the Company's showing of the need for the proposed construction *and* the absence of wasteful duplication.[6] Need may be demonstrated by, *inter alia*, the existence of "a substantial deficiency of service facilities beyond what could be supplied by normal improvements in the ordinary course of business…."[7]

Substation In Perry County And Leslie County, Kentucky, Case No. 2019-00154 at 14-15 (Filed September 30, 2019) ("KPSC 1-__"); *id.* Attachment 2; Kentucky Power Company's Response to Staff's First Set of Data Requests, Request No. 3, Attachment 1, *In the Matter of: Electronic Application Of Kentucky Power Company For A Certificate Of Public Convenience And Necessity To Perform Upgrade, Replacement, And Installation Work At Its Existing Hazard Substation And Wooton Substation In Perry County And Leslie County, Kentucky*, Case No. 2019-00154 (Filed October 28, 2019) ("KPSC 2-__"); *id.* Attachment 2.

[4] KRS 278.020(1).

[5] 807 KAR 5:001, Section 15(3).

[6] *Kentucky Utilities Co. v. Public Serv. Comm'n*, 252 S.W.2d 885, 890 (Ky. 1952).

[7] *Id.*

Wasteful duplication comprises two elements: (a) excess of capacity over need; or (b) excess investment in relation to productivity and efficiency to be gained from the proposed construction.[8] The absence of wasteful duplication also requires a demonstration that all reasonable alternatives were examined.[9]

Kentucky Power seeks approval for the replacement, installation, and upgrade of 20 Project Components[10] at the Hazard Substation and three Project Components at the Wooton Substation.[11] Kentucky Power's Application is supported by uncontroverted evidence that the proposed 23 Project Components address without wasteful duplication four broad and sometimes overlapping needs:[12]

(i) The need to implement or enable the previously-approved Baseline elements to function as intended.[13] Each of these nine Component elements have been designated in whole or part as Baseline projects by PJM;[14]

(ii) The need to replace and renew aging, deteriorated, or obsolete elements at the Hazard Substation and the Wooton Substation;[15]

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[8] *Id.*

[9] *In the Matter of: Joint Application Of Louisville Gas and Electric Company And Kentucky Utilities Company For A Certificate of Public Convenience and Necessity For The Construction of Transmission Facilities In Jefferson, Bullitt, Meade, and Hardin Counties, Kentucky* Case No. 2005-00142 (Ky. P.S.C. September 8, 2005).

[10] The term "Project Component" in this brief refers to the 23 groups of project elements listed on Exhibit 2 to the Company's application and designated by a single "one line identifier" on Exhibit 2 for the Hazard Substation, and by a "table identifier" on Exhibit 2 in the case of the Wooton Substation. Each Project Component is a group of project elements that "operate in conjunction with or support the other elements in the group or an existing substation element." Application, *In the Matter of: Electronic Application Of Kentucky Power Company For A Certificate Of Public Convenience And Necessity To Perform Upgrade, Replacement, And Installation Work At Its Existing Hazard Substation And Wooton Substation In Perry County And Leslie County, Kentucky*, Case No. 2019-00154 at ¶20 (Filed June 27, 2019) ("Application").

[11] Application Exhibit 2 [Brief Appendix 1].

[12] Application at ¶ 21; KPSC 2-3, Attachment 1; *id.* Attachment 2 [Brief Appendix 2].

[13] Application at ¶¶ 22-24; Direct Testimony of Kamran Ali, *In the Matter of: Electronic Application Of Kentucky Power Company For A Certificate Of Public Convenience And Necessity To Perform Upgrade, Replacement, And Installation Work At Its Existing Hazard Substation And Wooton Substation In Perry County And Leslie County, Kentucky*, Case No. 2019-00154 at 14-15 (Filed June 27, 2019) ("Ali Direct").

[14] Ali Direct at 14; KPSC 1-2(a).

[15] Application at ¶¶ 29-32; Application Exhibit 2 (Table Identifier (C)).

(iii) The need to upgrade substation communications[16] and protection equipment;[17] and

(iv) The need to bring both substations to current Kentucky Power and PJM minimum design standards.[18] These design standards include improving the functionality of the Hazard Substation by providing additional operational flexibility and establishing separate dissimilar zones of protection to limit outages and the resulting risk of customer disruption, as well as the associated stress and damage to substation equipment.[19] In addition, the Company proposes to address potential safety concerns at the Hazard Substation.[20]

In sum, the planned work will allow the Company to improve reliability and efficiency, and "to replace aging and obsolete infrastructure in a timely and planned manner, in advance of failure, to provide safe and reliable service to … [Kentucky Power's] customers in a cost-effective manner."[21]

(b) Baseline And Supplemental Elements.

Nine Project elements were designated by the PJM Board as Baseline components at the Board's July 29, 2019 meeting.[22] The remaining 17 Project Components are designated as Supplemental.

All of the work, including the Baseline and Supplemental portions, was presented to stakeholders at the April 23, 2019 stakeholder meeting.[23] Although the 2017 FERC Order requiring changes to PJM's stakeholder process for reviewing Supplement Projects was

[16] *Id.* at ¶ 33.

[17] *Id.* at ¶¶ 34-36.

[18] *Id.* at ¶¶ 25-28; Application Exhibit 2 (Table Identifier (A) and Table Identifier (B)).

[19] *Id.* at ¶¶ 25, 27; KPSC 1-6.

[20] Application at ¶ 28.

[21] Lasslo Direct at 16.

[22] KPSC 1-2(a); KPSC 1-2(b).

[23] Ali Direct at 14; Video Record ("VR") 11:41:20 (Ali) (correcting year).

prospective only,[24] all of the Project Components nevertheless were reviewed under the new process:

Mr. Ali:	Mr. Nguyen, the whole project went through the process again.
Mr. Nguyen:	Oh. The –
Mr. Ali:	Yes.
Mr. Nguyen:	All of the components –
Mr. Ali:	Yes.
Mr. Nguyen:	Within the project?
Mr. Ali:	But – but only the changes were identi – these were the changes identified, ***but the entire project was subject – subject to that stakeholder review.***[25]

The designation of an element or component as Baseline or Supplemental reflects the specific planning requirements or parameters addressed by the element or component.[26] Baseline elements are "intended to eliminate base-case reliability criteria violations found in the PJM Regional Transmission Expansion Plan ("RTEP"), or otherwise needed under PJM's RTEP requirements."[27] Baseline elements alone are insufficient to permit the Company to meet its service obligation under KRS 278.030(3).[28]

[24] Ali Direct at 8; *Monongahela Power Co., et al.*, Docket Nos. EL16-71-000 and ER17-179-003, *Order Accepting in Part Proposed Tariff Revisions and Requiring Tariff Revision Pursuant to Section 206*, 162 FERC ¶ 61, 129 ("FERC Order") at 44-45 (paragraph 92)(accepting the Tariff revisions proposed by PJM subject to additional requirements); 51-56 (paragraphs 106 to 116)(outlining additional requirements, to be effective on a prospective basis only). The FERC Order is available at the following link: [https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14643464].

[25] VR 11:53:06 (Ali) (emphasis supplied).

[26] Ali Direct at 6.

[27] Application at ¶ 15.

[28] Ali Direct at 11.

Supplemental elements are all other elements that fall outside the specific PJM planning criteria; they are the sole responsibility of the Transmission Owner, which in this case is Kentucky Power.[29] Supplemental projects address critical needs, such as the need to:

> maintain the existing grid as designed, connect new customers to the grid, satisfy contractual and regulatory requirements, and to meet RTO and industry standards .... [Supplemental projects] include interconnection of new retail demand, modification to existing delivery points, replacing failed equipment, [the] proactive replace[ment] of deteriorating assets in poor condition prior to failure, modernization and hardening of the grid, improved operational efficiency and performance, and installation and expansion of supervisory control and data acquisition [equipment].[30]

Among the considerations reviewed by Kentucky Power in identifying Supplemental Projects for submission to PJM for review are "equipment condition, performance and risk," and "operational flexibility and efficiency"[31] Supplemental elements are the same type of replacement, upgrade, and system improvement work that Kentucky Power previously presented to the Commission for approval prior to joining PJM.[32] They likewise allow Kentucky Power to satisfy the assumption in PJM modeling that the Company's transmission system (and hence the Baseline Project Components approved by PJM) will perform as designed.[33]

The designation of a project as Baseline or Supplemental "is not indicative of the level of, or absence of need for the project."[34] To the contrary, both Baseline and Supplemental projects – including those at issue in this proceeding – are required for Kentucky Power to satisfy its

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[29] *Id.* at 6. 10-11.

[30] *Id.* at 6-7.

[31] *Id.* at 9.

[32] Application at ¶ 17.

[33] *Id. See also* Ali Direct at 11 ("The forward-looking models that PJM and transmission owners employ to identify Baseline Projects assume the modeled system will perform as designed without regard to age or actual condition of all of the elements of the transmission system, including those elements constructed, upgraded, or maintained as non-baseline elements. This means that for modeling purposes, a substation with 75-year old components that are deteriorating is assumed to function with the same reliability as a five-year substation with newer components.")

[34] Ali Direct at 10.

obligation under KRS 278.030(3) to provide "adequate, efficient and reasonable service."[35] Nor are the Baseline and Supplemental classifications mutually exclusive. A project component sometimes can satisfy both criteria, and the initial classification of a project element as Supplemental does not foreclose its subsequent re-classification, as occurred here, as Baseline.[36]

Significantly, KRS 278.020(1) does not distinguish between Baseline components and Supplemental components. Upon demonstrating, as the Company does below, the need for the proposed construction and the absence of wasteful duplication the statute recognizes Kentucky Power's right to a Certificate of Public Convenience and Necessity for the Project.

2. The Nine Project Elements Required To Implement The Previously-Approved Baseline Elements And To Permit Them To Function As Designed Are Needed.

In Case No. 2017-00328 the Commission approved the rebuild of the Hazard-Wooton 161 kV transmission line, the installation of 161/138 kV Transformer # 3 in the Hazard Substation, and the construction of the 69 kV Hazard-Jackson Reconfiguration.[37] Subsequent to the Commission's March 16, 2018 order in Case No. 2017-00328 Kentucky Power identified nine previously designated Supplemental elements that were not approved in Case No. 2017-00328 and resubmitted the elements to PJM for approval as Baseline elements.[38] The elements

[35] *Id.* at 11.

[36] Application at ¶ 19.

[37] Order, *In the Matter of: Electronic Application Of Kentucky Power Company For Certification of Public Convenience and Necessity to Construct A 161 kV Transmission Line in Perry and Leslie Counties, Kentucky, and Associated Facilities*, Case No. 2017-00328 (Ky. P.S.C. March 16, 2018); Order, *In the Matter of: Electronic Application Of Kentucky Power Company For Certification of Public Convenience and Necessity to Construct A 161 kV Transmission Line in Perry and Leslie Counties, Kentucky, and Associated Facilities*, Case No. 2017-00328 (Ky. P.S.C. November 14, 2018).

[38] Ali Direct at 11.

were reviewed with PJM stakeholders on April 23, 2019.[39] The nine Baseline elements were approved by the PJM Board on July 29, 2019.[40]

Kentucky Power seeks authority in this proceeding to install, replace, or upgrade the nine Baseline project elements required to the implement the previously-approved work or to permit it to function as intended:[41]

◊ Replacement of 161 kV circuit breaker (M) pointing towards the Wooton Substation;[42]

◊ Replacement of devices for line protection and circuit breaker control associated with the 161 kV Wooton line position;[43]

◊ Installation a 138 kV circuit breaker with relay on the low side of the 161/138 kV Transformer # 3;[44]

◊ Replacement of devices for transmission transformer protection associated with Transformer # 3;[45]

◊ Replacement of coupling capacitor voltage transformers on 138 kV Bus # 2;[46]

◊ Replacement of devices for 138 kV Bus # 2 protection;[47]

◊ Installation of station class surge arrestors attached to the upper beam of the 161 kV box bay structure of the Wooton Substation;[48]

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39 Ali Direct at 14; VR 11:41:20 (Ali) (correcting year).

40 KPSC 1-2(b).

41 KPSC 1-2(a).

42 Application Exhibit 2 (one line identifier 1).

43 *Id.*

44 Application Exhibit 2 (one line identifier 2).

45 *Id.* The replacement of devices for transmission transformer protection associated with Baseline Transformer # 3 also allows the Company to address obsolete and deteriorating protection equipment. KPSC 2-3, Attachment 1.

46 Application Exhibit 2 (one line identifier 19). Two additional components that constitute a portion of one line identifier 19 are not required to implement the previously approved Baseline elements and were not designated as Baseline by PJM. *See* KPSC 1-3, Attachment 1.

47 *Id.* The replacement of devices for 138 kV Bus # 2 protection also allows the Company to address obsolete and deteriorating protection equipment. KPSC 2-3, Attachment 1.

48 Exhibit 2; table identifier A.

◊ Installation of two coupling capacitor voltage transformers on Phase 2 and Phase 3 of the 161 kV bus of the Wooton Substation;[49] and

◊ Installation of telecommunications fiber equipment.[50]

Generally stated, the nine Baseline elements that are the subject of this application are "line relaying and termination equipment associated with the Hazard-Wooton 161 kV line rebuild ... [and are] required for completion of the [previously-approved] baseline work."[51]

More specifically, existing 161 kV circuit breaker (M) must be moved to physically accommodate the installation of previously-approved Hazard Substation 161/138 kV Transformer # 3.[52] The age of 161 kV circuit breaker (M), as well as its extended history of fault operations, make it prudent to replace the circuit breaker (as well as its associated relay equipment)[53] as part of its required relocation instead of simply moving and reinstalling a 30-year circuit breaker and its associated obsolete electromechanical relays.[54] The remaining Baseline elements proposed for the Hazard Substation will provide necessary protection for the previously-approved Baseline elements by replacing existing protection equipment,[55] or by installing new protection equipment.[56]

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[49] Exhibit 2; table identifier B.

[50] Exhibit 2; table identifier C.

[51] Ali Direct at 14.

[52] *Id.*

[53] The microprocessor relays and controls the Company proposes to install in place of the existing electromechanical and static relays will permit 161 kV breaker (M) to communicate with other elements and will allow the substation to be operated effectively with less likelihood of mis-operation. Ali Direct at 16; Application at ¶ 33; *id.*, Exhibit 2. The existing relays are also obsolete and in some cases no longer supported by their manufacturer. Application at ¶ 33.

[54] Ali Direct at 14; Application Exhibit 2.

[55] Exhibit 3; one line identifier 2; *id.*; one line identifier 19.

[56] Exhibit 3; one line identifier 2 (installation of a 138 kV circuit breaker with relay control on the low side of the Baseline 161/138 kV Transformer # 3); Ali Direct at 16 ("[I]f a transformer has circuit breakers on the high-side and the low-side of the transformer, the circuit breakers can de-energize the transformer and isolate a transformer fault.")

The existing communications equipment at the Wooton Substation "is no longer compatible with the relaying and telecommunications fiber upgrades need at…" the station.[57] The Baseline relay and communications equipment[58] the Company proposes to install at the Wooton Substation will enable the previously-approved rebuild of the Hazard-Wooton 161 kV transmission line, including the optical ground wire telecommunications cable, to function as intended "by ensuring that the components and associated circuit breakers operate as intended during faults … [and will] improve the coordination of Wooton Substation with the remote end" of the line as well as the other two transmission lines that are connected to the Wooton Substation.[59] The Baseline relay and communications equipment also will provide "monitoring, protection, and remote operation of station equipment."[60] These protective relays "detect faults and operate more quickly and accurately than existing relays,"[61] thereby better enabling transmission operators to make real-time operational decisions, and to better restore service to customers and minimize equipment damage.[62] Finally, the Baseline surge arrestors[63] and the three-phase coupling capacitor voltage transformers[64] to be installed at the Wooton Substation will permit the rebuilt transmission line to function as intended by protecting station equipment

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[57] AG 1-22.

[58] Application Exhibit 2; table identifier C.

[59] Direct Testimony of Michael G. Lasslo, *In the Matter of: Electronic Application Of Kentucky Power Company For A Certificate Of Public Convenience And Necessity To Perform Upgrade, Replacement, And Installation Work At Its Existing Hazard Substation And Wooton Substation In Perry County And Leslie County, Kentucky*, Case No. 2019-00154 at 14-15 (Filed June 27, 2019) ("Lasslo Direct"); Ali Direct at 14.

[60] Ali Direct at 15.

[61] *Id.* at 16.

[62] *Id.*

[63] Application Exhibit 2; table identifier A.

[64] Application Exhibit 2; table identifier B.

from overvoltage events that could damage substation facilities and disrupt service over the rebuilt line.[65]

3. The Uncontroverted Record Demonstrates That The Planned Replacement Or Upgrade Of The Aging, Deteriorating, And Obsolete Supplemental Elements At the Hazard Substation Is Required To Provide Adequate, Efficient, And Reasonable Service.

Six transmission circuits and three distribution circuits terminate at the Hazard Substation.[66] The Hazard Substation serves as "the primary source to the local area distribution system and the surrounding area 69 kV subtransmission network;" the substation also serves as "a major thoroughfare for power imported from the Tennessee Valley Authority and Louisville Gas and Electric into the southern portion of Kentucky Power's transmission network across the Hazard-Pineville 161 kV corridor."[67] The Hazard Substation plays a critical role in connecting with these utilities.[68] An outage at the Hazard Substation could cause wide-spread service interruptions.[69] The Hazard Substation also directly serves 30 MW of load and 1,800 customers through its associated distribution network.[70]

The Hazard Substation was constructed in the early 1940's and is nearly 80 years old.[71] "The majority of the major equipment that makes up the station is in a condition that warrants replacement"[72] including the three transmission transformers and all of the 69 kV circuit

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[65] Ali Direct at 15-16; Lasslo Direct at 14-15.

[66] Lasslo Direct at 9.

[67] AG 1-7.

[68] KPSC 2-7(d).

[69] *Id.*

[70] Lasslo Direct at 9; KPSC 2-5.

[71] Lasslo Direct at 9.

[72] Ali Direct at 15.

breakers.[73] In addition, much of the communication equipment within the station is outdated and obsolete."[74] Equipment that is obsolete and no longer supported by manufacturers, and which lacks spare parts, leaves the system vulnerable to prolonged outages.[75] As measured using its historical performance, condition, and risk, the Hazard Substation is at the 99th percentile (highest) of Kentucky Power substations that need to be addressed.[76]

Kentucky Power must replace or upgrade several of the Project Components at the Hazard Substation because the elements are aging, deteriorating, or obsolete.[77] The Company's proposed Hazard Substation asset renewal efforts are required to address issues involving elements that are approaching or have exceeded their expected operating lives,[78] that are no longer supported by their manufacturers or that involve non-standard design and thus are difficult and expensive to repair and maintain,[79] that are of a class or type of equipment that has exhibited operational issues across the AEP transmission system,[80] that are suffering corrosion,

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[73] *Id.*

[74] *Id.*

[75] *Id.* at Exhibit KA-1 at 9.

[76] AG 1-26.

[77] *See generally* KPSC 2-3, Attachment 1 (one line identifiers 3-18 and 20).

[78] *See e.g.*, Kentucky Power Company's Response to the Attorney General's First Set of Data Requests, Request No. 11(c), *In the Matter of: Electronic Application Of Kentucky Power Company For A Certificate Of Public Convenience And Necessity To Perform Upgrade, Replacement, And Installation Work At Its Existing Hazard Substation And Wooton Substation In Perry County And Leslie County, Kentucky*, Case No. 2019-00154 at 14-15 (Filed September 30, 2019) ("AG 1-__"); Lasslo Direct at 7.

[79] *See e.g.* Application Exhibit 2; one line identifier 8 ("Capacitor Bank CC was a non-standard design and its components, including fuses and cans, have begun to fail."); Lasslo Direct at 8; 13

[80] *See e.g.* Application Exhibit 2; one line identifier 5 (Circuit switcher BB "is a Mark V unit. Mark V units have experienced a high amount of failures on the AEP system. AEP operating companies are currently replacing all Mark V circuit switchers ...."); Lasslo Direct at 13.

damage, or leaks that cannot be repaired,[81] that pose environmental risks,[82] or that are at risk of mis-operation because of damage and degradation as a result of faults in excess of the manufacturer's recommendations.[83]

The replacement of the transformers and circuit breakers is expected to produce savings by allowing the Company to extend maintenance cycles from eight-year intervals to ten year intervals for transformers, and from a six-year cycle to a 12-year cycle for circuit breakers.[84] There also will be a corresponding reduction in corrective maintenance for the replaced circuit breakers and transformers.[85] The replacement of the existing electromechanical relays with microprocessor relays will allow Kentucky Power to reduce the number of required relays, thereby lowering annual O&M, and produce additional savings through remote connectivity.[86]

(a) Aging Equipment.

The three 69 kV circuit breakers (S, E, and F), the 138 kV circuit switcher CC, the 69 kV circuit switcher CC, and two 12 kV circuit breakers (C and D) at the Hazard Substation must be replaced, at least in part, because they are approaching or have exceeded their projected operating lives.[87] Although advanced chronological age in isolation typically is not the sole determinant of the need to replace or upgrade an element,[88] it is linked to damage and

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[81] *See e.g.* Application Exhibit 2; one line identifier 8 ("Capacitor Switcher CC has oil leaks on all three phases and cannot be repaired."); Lasslo Direct at 13.

[82] *See e.g.* Application Exhibit 2; one line identifier 11 (Circuit breaker F "is an oil-filled breaker and carries the increased potential of oil spills during routine maintenance and failures. Other drivers include potential PCB content…."); Lasslo Direct at 13.

[83] *See e.g.* Application Exhibit 2; one line identifier 9 ("Circuit breaker S was manufactured in 1960 and has experienced 82 faults (well above the manufacturer's recommended 10."); Lasslo Direct at 13-14.

[84] KPSC 2-6.

[85] *Id.*

[86] *Id.*

[87] AG 1-11(c).

[88] AG 1-14.

degradation as a result of high numbers of fault operations,[89] unrepairable leaks and corrosion,[90] weather-related degradation,[91] and maintenance and repair difficulties because of the lack or limited availability of spare parts.[92]

Because advanced chronological age may be associated with an increased likelihood of failure,[93] the Company examines opportunities to replace aging equipment to avoid the non-standard and imprudent practice[94] of operating equipment to failure.[95] The alternative – the aptly named running to failure – "can result in loss of service, environmental damage, and the risk of unsafe conditions."[96] It likewise increases the cost of repair, increases the risk of longer outages than would be required if the repair was made prior to failure, and can result in electrical and mechanical damage to other substation equipment.[97]

(b) Equipment Subject To "Excess" Fault Operations.

Substation fault operations in no way resemble the relatively benign tripping of a home circuit breaker. Fault operations subject substation components to enormous mechanical,

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[89] Lasslo Direct at 7, 13. *See e.g.*, Application Exhibit 2 (one line identifier 10) ("Circuit breaker E was manufactured in 1974 and has experienced 184 faults (well above the manufacturer's recommended 10)."); AG 1-10(d) ("each additional fault operation leads to accelerated aging and deterioration of the breaker's internal contacts and other mechanical/internal components.")

[90] *See e.g.*, Application Exhibit 2; one line identifier 8 ("Capacitor Switcher CC has oil leaks on all three phases and cannot be repaired."); *id.* at (one line identifier 18) ("The existing circuit breaker D is a 50-year old oil type breaker. This circuit breaker and [*sic*] presents potential environmental and maintenance challenges…."); Lasslo Direct at 13.

[91] Lasslo Direct at 8 ("Much of the equipment in a substation must be deployed outdoors … lead[ing] to corrosion and degradation of equipment housings, tanks, cabinets, bushings, and other components … [that in turn] can affect the performance and reliability of the equipment.")

[92] Application ¶ 29.

[93] Lasslo Direct at 7 ("Like any type of complex equipment, substation equipment is subject to degradation and decreased reliability over time.")

[94] Application ¶ 55 ("no prudent and reasonable transmission system operator would as a matter of practice await equipment failure prior to upgrading or replacing deteriorated or obsolescent equipment.")

[95] AG 1-14.

[96] Lasslo Direct at 13, 15; Application at ¶¶ 32; 55.

[97] Lasslo Direct at 15.

electrical, and thermal forces.[98] "Any [substation] fault operation accelerates aging and wear of the contacts, bushings, and other internal components."[99] In addition, the electrical discharges of high energy associated with fault operations "flow through transformer windings and produce powerful electromechanical forces that attempt to push the windings apart."[100] In some cases the windings can move and loosen and result in under-oil arcing and hot spots (thermal faults)."[101] Arcing associated with fault operations can also lead to the formation of combustible gases such as acetylene, ethane, and hydrogen that in turn present the risk of explosions.[102] It also can result in the breakdown of the electrical strength (and hence effectiveness) of winding insulation and insulating oil in transformers.[103]

Because of the degradation and damage that results from fault operations, manufacturers establish fault thresholds and recommend that components at or above the thresholds be examined and tested, and if necessary, either be repaired or removed from service.[104] Kentucky Power also routinely inspects and tests substations for evidence of degradation and damage as a result of fault operations.[105] These efforts, along with the Company's maintenance activities, have enabled the Company *to date* to keep equipment experiencing these "excess" fault operations in service.[106]

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[98] Lasslo Direct at 15; KPSC 1-5; KPSC 2-9.

[99] KPSC 1-5; KPSC 1-6 ("[T]he expected life of each breaker is reduced every time a fault occurs.")

[100] KPSC 2-9; VR 12:07:30 (Ali).

[101] KPSC 2-9; Lasslo Direct at 7-8.

[102] VR 11:22:35 (Lasslo); KPSC 2-9.

[103] KPSC 2-9.

[104] KPSC 1-5(b); AG 1-10(d).

[105] AG 1-23.

[106] AG 1-23; VR 10:28:25 (Lasslo) ("[T]hose breakers aren't the same nuts and bolts as they were when they started out because there's – the recommendations are if they have a certain number of operations, that you actually take the breaker out of service and then you do an external, internal inspection.... [S]ay you have a 1950 car and here it is the year 2000, not all the parts are the original parts.")

Notwithstanding these efforts, the high number of fault operations suffered by multiple Hazard Substation elements, coupled with other factors such as lack of spare or replacement parts, provide uncontroverted evidence of the need to replace the following elements:[107]

Element	**One Line Number**	**Number of Fault Operations**
161 kV circuit breaker M	1	21
69 kV circuit breaker S	9	82
69 kV circuit breaker E	10	184
69 kV circuit breaker F	11	193
34.5 kV circuit breaker A	15	221
12 kV circuit breaker C	17	354

The manufacturer recommended threshold for circuit breakers is ten operations.[108]

(c) Deteriorated, Damaged, and Obsolete Equipment.

(i) Deteriorated And Damaged Equipment.

Other evidence of record establishes without contradiction that multiple additional elements at the Hazard Substation must be replaced because of their physical condition or because they are functionally obsolete. Deteriorated and damaged equipment poses an elevated risk of mis-operation or failure.[109] Because of Kentucky Power's "increased reliance on power imports from neighboring utilities and off-footprint generation," mis-operation or failure of substation equipment at the Hazard Substation adversely affects the ability of Kentucky Power to

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[107] Application Exhibit 2.

[108] *Id.*

[109] Lasslo Direct at 14.

provide reliable service to the 30 MW local distribution network directly served by the Hazard Substation, as well as the surrounding area 69 kV subtransmission network.[110] Equipment failure and mis-operation also can damage and degrade interconnected elements.[111]

Damaged or degraded elements requiring replacement to mitigate the threat to Kentucky Power's ability to provide reliable service include:

Element	**One Line Number**	**Problems Regarding Condition**[112]
Circuit Breaker M	1	History of malfunctions due to gas leaks.[113]
138/69 kV Transformer # 1	6	Dielectric (insulation) breakdown; accessory damage to bushings and windings; corrosion on radiators and oil leaks.
138/69 kV Transformer # 2	7	Dielectric (insulation) breakdown; accessory damage to bushings and windings.
Capacitor bank CC	8	Oil leaks on all three phases that cannot be repaired.
69 kV circuit breaker S	9	Damage to bushings.
69 kV circuit breaker E	10	Damage to bushings.
69 kV circuit breaker F	11	Damage to bushings.
Capacitor bank AA (will be retired and replaced with a 69 kV circuit breaker)	12	Deterioration and issues with VBM-type capacitor switcher.

110 AG 1-7.

111 Lasslo Direct at 15; Ali Direct at 13.

112 All citations are to Application Exhibit 2 except as otherwise noted.

113 AG 1-10.

(ii) Obsolete Equipment.

The uncontroverted evidence of functional obsolescence of various Hazard Substation elements likewise demonstrates the need for the replacement or upgrade of the affected elements. Functional obsolescence at the Hazard Substation divides itself into two categories: (a) environmental risk; and (b) technological obsolescence.

Oil-type circuit breakers[114] are difficult to maintain and pose the risk of spills during routine maintenance and as a result of failures. In addition, these breakers may contain remnants of PCBs that previously were used.[115] The cost of remediation efforts required following an oil or PCB-contaminated oil spill can approach the cost of the substation equipment itself.[116]

The existing protective relays the Company proposes to replace[117] are like any Commodore 64 computer: they are technologically obsolete. The existing electromechanical and static relays, unlike the microprocessor relays the Company proposes to substitute, are subject to mechanical failure and are more sensitive to temperature changes.[118] Many of the existing protective relays are no longer supported by their manufacturer making repair and maintenance more difficult.[119] More fundamentally, microprocessor relays possess capabilities beyond those of electromechanical relays that permit Kentucky Power to provide more efficient and reliable service:[120]

[114] The affected elements are 69 kV circuit breaker S (one line identifier 9), 69 kV circuit breaker E (one line identifier 10), and 69 kV circuit breaker F (one line identifier 11). Application Exhibit 2.
[115] Application Exhibit 2.

[116] Lasslo Direct at 15.

[117] Kentucky Power proposes to replace the electromechanical protective relays that comprise part of the following Project Components: 1, 2, 5, 6, 7, 8, 9, 11, 13, 14, 15, 16, 17, 18, 19, and 20. Application Exhibit 2.

[118] Ali Direct at 17.

[119] *Id.* at 16-17.

[120] *Id.* at 17; AG 1-9(d).

◊ Microprocessor relays detect faults more quickly and accurately than electromechanical relays and thereby permit the more timely restoration of service while helping to minimize equipment damage.

◊ Microprocessor relays perform multiple functions thereby reducing the number of relays required.

◊ Microprocessor relays have lower maintenance costs.

◊ Microprocessor relays can perform self-diagnostic procedures that allow for the earlier detection of failures and malfunctions.

◊ Microprocessor relays provide faster and more flexible operation and system coordination.

The Wooton Substation, like the Hazard Substation, employs communications equipment for "remote monitoring and operation of substation equipment through the supervisory control and data acquisition (SCADA) system … [and] to transmit relay and control signals between system protection and control."[121] The telecommunications equipment at the Wooton substation "is outdated and needs to be upgraded in order to provide monitoring, protection, and remote operation of station equipment."[122] In particular, the communications equipment at the Wooton Substation "is no longer compatible with the relaying and telecommunication fiber upgrades" required at the Wooton Substation.[123]

The proposed communications equipment upgrades are designed to address these issues by bringing the equipment into compliance with current design standards. These standards "utilize multi-function, microprocessor-based protection, control, metering, and SCADA devices to leverage features including self-checking functionality, high protection flexibility, disturbance

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[121] Lasslo Direct at 5.

[122] Ali Direct at 15.

[123] AG 1-22.

monitoring, remote access capabilities, plus detailed alarm and equipment status information."[124] Most importantly, the upgrades will allow the Hazard Substation protective relays to function as intended:

> When we upgrade those relays [at the Hazard Substation], they also need to communicate to the remote end, which is Wooton, because if the fault is on the line, the relays will say trip both breakers, because if you only trip this side, that doesn't clear the fault. You also got to clear the Wooton side.
>
> Similarly, if the fault is right here, right next to this breaker, the relay may not see that to be on the other side the distance is so small between this side and that side, so the relay would block that other relay and say don't trip because the fault is on my other side. I'm the one who needs to trip. For that you need communication equipment, and you need to make sure both of them are synced up and they speak the same language. If you don't have that, you won't be able to coordinate the protection scheme.[125]

The uncontroverted evidence demonstrates that the public convenience and necessity requires the planned replacement and upgrade of the damaged, deteriorated, and obsolete equipment at the Hazard and Wooton substations.

4. <u>The Project Components Required To Bring The Two Substations Into Compliance With Current Kentucky Power And PJM Standards Will Improve Reliability, Provide Operational Flexibility, And Address Potential Safety Concerns, And Thus Are Needed.</u>

Consistent with its obligation to provide adequate, efficient, and reasonable service to its customers, and Good Utility Practice, the Company seeks to bring all equipment to current standards when practical and cost-effective.[126] Thus, "[w]hen Kentucky Power undertakes a project to address condition, performance, and risk, and subject to the need for cost-effectiveness, it designs the solution to current standards whenever an asset is replaced."[127]

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[124] AG 1-9(d).

[125] VR 12:14:55 (Ali).

[126] AG 1-9(c).

[127] *Id.*

Twenty-two of the 23 Project Components are required in whole or part to bring the substations to Kentucky Power and PJM minimum design standards.[128] A portion of the proposed work also will address potential safety concerns at the Hazard Substation.

(a) The Proposed Reconfiguration Work Will Improve Reliability And Limit Degradation Of Substation Components.

The Hazard Substation as currently configured risks the outage of the entire substation (and the loss of the associated load) with the failure of a single piece of equipment.[129] In addition, the substation's current configuration subjects its major components to the damage and degradation caused by through faults as the result of the forced operation of other transmission elements:

> Given the current arrangement of equipment at the Hazard Substation, the 138/69 kV Transformers # 1 & 2 are exposed to through faults for any forced operation of the Beaver Creek-Hazard 138 kV line, 68 kV Bus No. 1, 138 kV bus No. 1, 69 kV Bus No. 2 or the 161/138 kV Transformer # 3. There have been 36 such events [or approximately one such event every three months] in the last ten years.[130]

The Hazard Substation's circuit breakers likewise are affected by the lack of adequate protective devices[131] "to isolate faults that occur in one part of the substation or one section of the line" so

[128] The exception is Project Component 3 (installation of a new three phase 161/138 kV spare transformer). KPSC 2-3, Attachment 1 and Attachment 2. Project Component 3 "is the only transformer of this voltage class in the AEP zone." Ali Direct at 13. A spare must be maintained on site in the event it should fail; the lead time to replace the transformer could be up to a year. *Id. See also* KPSC 2-7(d). The need for a 161/138 kV transformer cannot be met through use of a mobile transformer. Mobile transformers of this size are too large and too heavy to transport over the road network to the Hazard Substation. KPSC 2-7(e). Also, a 161/138 kV mobile transformer likely would be too large to fit within the substation. *Id.*

[129] Ali Direct at 15.

[130] AG 2-1.

[131] AG 2-2 (161 kV Circuit breaker experienced nine faults in the past ten years; 69 kV circuit breaker E exposed to 43 faults in the past ten years; 69 kV circuit breaker S exposed to 45 faults in the past ten years; and 69 kV circuit breaker F exposed to 49 faults in the past ten years).

that "faults currently affect multiple pieces of equipment, ultimately leading to further deterioration."[132]

Current design standards dictate that if the Hazard Substation were constructed today that it should be constructed as a ring bus to separate disparate zones of protection and limit the problems resulting from the current configuration and its overlapping zones of protection.[133] In fact, separating disparate zones of protection by sectionalizing the substation is standard practice.[134] It allows faults to be isolated leaving other elements in service and thereby maintain service to customers.[135] Sectionalizing likewise permits service to be restored more quickly following outages, and limits the need for additional outages to restore service.[136] Separating the zones and protection devices through sectionalizing further limits wear and damage on other equipment in the case of a fault.[137] In sum, sectionalizing "improves the reliability of each element and the station overall."[138]

Space constraints and constructability issues at the Hazard Substation make rebuilding the substation in place as a ring bus impracticable.[139] In addition, the costs and extended outages required to relocate the facilities in the clear at a new location and to rebuild the 69 kV facilities

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[132] AG 2-3.

[133] Application ¶ 25.

[134] Ali Direct at 16.

[135] *Id.*

[136] *Id.* For example, "under the existing configuration at Hazard, lack of the low side breaker on the transformer results in the operation of every element tied to the 138 kV bus # 2 in order to clear a fault on Transformer # 3. This includes operation of Transformers # 4 and # 5 resulting in the loss of customers served from the two transformers." Application Attachment 2 (line identifier 2).

[137] KPSC 1-6.

[138] *Id.*

[139] KPSC 2-11; Application at ¶ 39.

as a ring bus make doing so infeasible.[140] Kentucky Power thus proposes to reconfigure the existing substation as shown on Exhibit 3 to its application:[141]

> So we decided to stay here and add the functionality. Of course it's not a ring bus, but it's absolutely better than what we got there today.[142]

The following Project Components, in whole or in part, will allow Kentucky Power to sectionalize the Hazard Substation by reconfiguring it:

Element	**One Line Number (Previous Identifier)**	**Sectionalizing Benefit**[143]
Installation of a 138 kV circuit breaker with relay control on the low side of the 161/138 kV transformer # 3 along with transformer protection	2	The proposed circuit breaker on the low side and associated work "will allow the transformer to be protected and isolated, if necessary, to prevent damage during a fault operation. The low side breaker also separates the zones of protection and minimizes the number of elements for a fault on the transformer. Under the existing configuration at Hazard, lack of the low side breaker on the transformer results in the operation of every element tied to the 138 kV bus # 2 in order to clear a fault on Transformer # 3. This includes operation of Transformers # 4 and # 5 resulting in the loss of customers served from the two transformers."

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140 VR 12:39:55 (Ali).

141 VR 12:40:45 (Ali). Kentucky Power examined constructing the existing 69 kV yard as a ring bus at the Hazard Substation. KPSC 2-11. This alternative was rejected because of constructability constraints, physical limitations because of the topography of the substation on the Company's ability to perform the work, and because it "was clearly not cost-effective." *Id.*

142 VR 12:40:52 (Ali); *See also* Lasslo Direct at 14.

143 Application Exhibit 2.

Element	**One Line Number (Previous Identifier)**	**Sectionalizing Benefit**[143]
Installation of a circuit switcher on the high side of 138/69 kV transformer # 1; installation of a 69 kV breaker with relay control on the low side of 138/69 kV transformer # 1	6(o)	The existing absence of a high side switcher and low breaker on 138/69 kV transformer #1 results in the "operation of every element tied to 138 kV bus # 1 and 69 kV bus #1 in order to clear a fault on Transformer # 1. It also exposes the transformer to potentially damaging currents for faults tied to 138 kV bus #1 and 69 kV bus #1."
Installation of a circuit switcher on the high side of 138/69 kV transformer # 2; installation of a 69 kV breaker with relay control on the low side of 138/69 kV transformer # 2	7(s, u)	The existing absence of a high side switcher and low breaker on 138/69 kV transformer #2 results in the "operation of every element tied to 138 kV bus # 2 and 69 kV bus # 2 in order to clear a fault on Transformer # 2. This includes operation of Transformers # 4 and # 5 resulting in the loss of customers served from the two transformers."
Installation of a 69 kV circuit breaker connecting 69 kV bus #1 and 69 kV bus # 2	12	The new circuit breaker will allow 69 kV system to continue to operate notwithstanding an outage on the 138 kV system.
Installation of a circuit switcher on the high side of transformer # 4; installation of a 34.5 kV breaker with relay control on the low side of 138/34.5 kV transformer # 4	13	The installation of the circuit switcher and circuit breaker will separate dissimilar zones of protection and thereby avoid the need to operate every element associated with 138 kV bus # 1 and 69 kV bus # 2 in the event of a fault on 138/34.5 kV transformer # 4.

Element	One Line Number (Previous Identifier)	Sectionalizing Benefit[143]
Installation of a 138 kV circuit breaker pointing toward the Beckham Substation	20	The proposed breaker will separate dissimilar zones of protection. The existing lack of a circuit breaker on the line toward the Beckham Substation results in the operation of every element tied to the 138 kV bus # 1 and the 69 kV bus # 1 to clear a fault on the 16.4 mile circuit between the Hazard Substation and the Beckham Substation. It also will eliminate the existing need to "drop" customers served from Vicco to clear a fault on the 138 kV bus # 1 at the Hazard Substation.

(b) Functionality Improvements.

A second benefit redounding from the planned sectionalization of the Hazard Substation is greater operational flexibility. This additional operational flexibility will allow Kentucky Power to limit the effect of planned and forced outages on customers, and to reduce the amount of time required to restore service following an outage.[144]

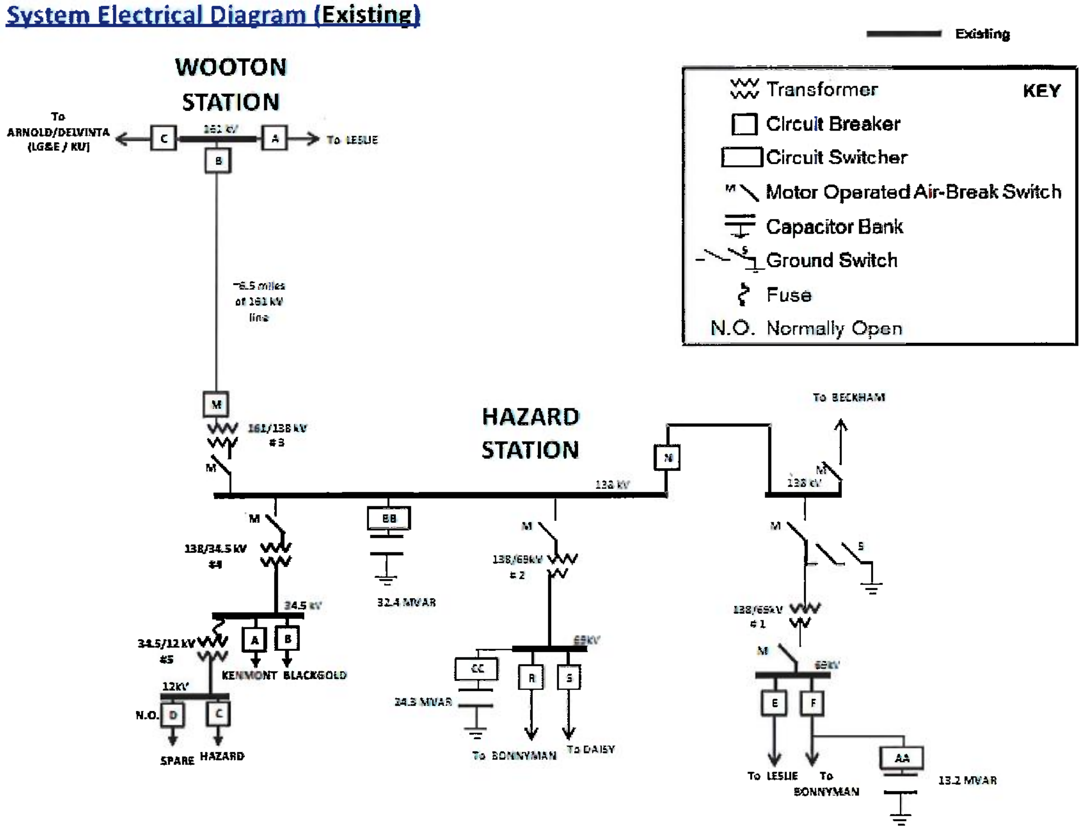
For example, in the present configuration any single fault on existing Transformer # 2, Transformer # 3, Transformer # 4, 138 kV bus # 2, or 69 kV bus # 2 results in the outage[145] of each element, as well as capacitor AA and capacitor BB, along with the opening of the Hazard-

[144] Ali Direct at 9, 13.

[145] VR 12:12:30 (Ali); Application Exhibit 2.

Wooton 161 kV circuit, the Bonnyman-Hazard # 2 69 kV circuit, and the Daisy-Hazard 69 kV circuit:[146]

System Electrical Diagram (Existing)



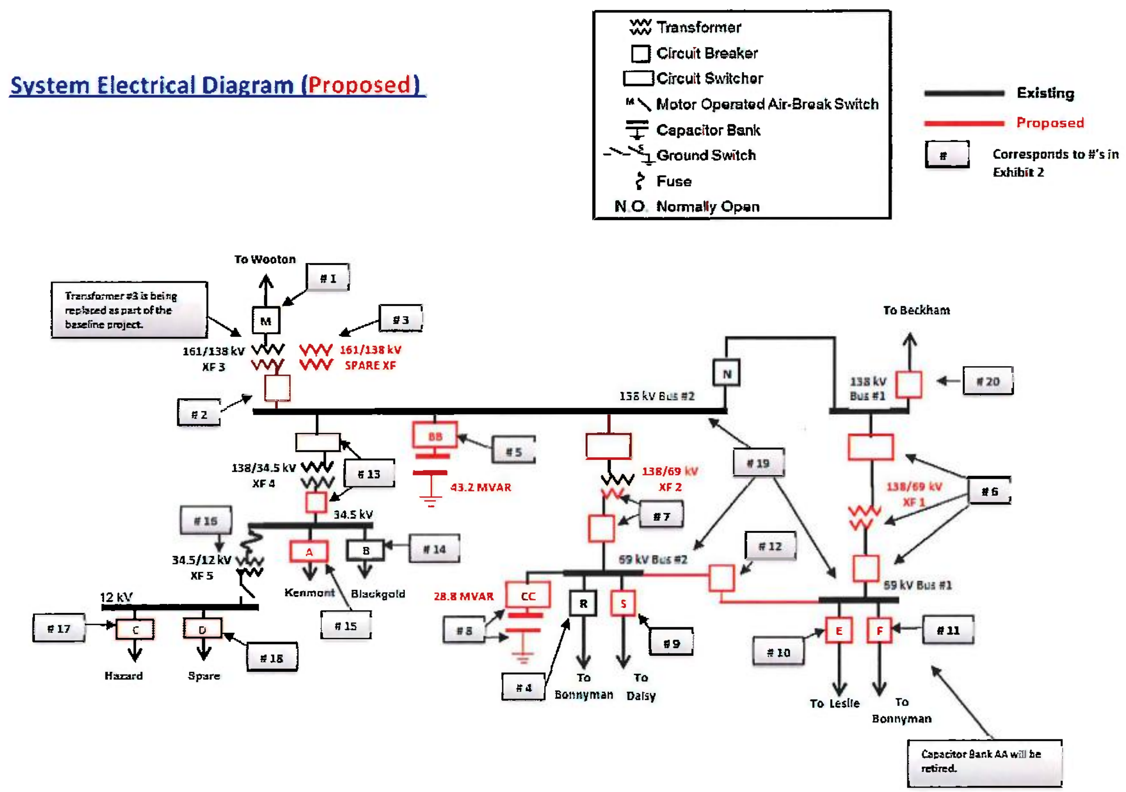
Conversely, the failure of 138 kV circuit breaker N to operate properly in the case of a fault or potential internal fault would produce a complete outage of the Hazard Substation and its elements,[147] along with the loss of service to the customers and 30 MW of load directly served from the Hazard Substation.[148]

[146] Lasslo Direct, Exhibit MGL-1; Application Exhibit 2.

[147] VR 12:12:44 (Ali) (pointing to circuit breaker N on hearing demonstrative); Application Exhibit 2 (one line identifier 20); Ali Direct at 13.

[148] Application ¶ 11; KPSC 2-5.

To provide additional operational flexibility, including continued service to the surrounding 69 kV subtransmission network that is primarily sourced from Hazard station, Kentucky Power proposes to reconfigure the Hazard Substation by installing a new 69 kV circuit breaker (Project Component 12) between the two 69 kV buses served by 138/69 kV transformer # 1 and 138/69 kV transformer # 2:[149]



The installation of Project Component 12 allows the new bus-tie 69 kV circuit breaker, the Leslie 69 kV circuit, and Bonnyman 69 kV circuit to be sourced by 138/69 kV transformer #2 when 138/69 transformer # 1 is taken out of service. Likewise, the Daisy 69 kV circuit and the Bonnyman 69 kV circuit sourced by 138/69 kV transformer # 2 can be served by 138/69 kV

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149 Application Exhibit 3.

transformer # 1 when 138/69 kV transformer # 2 is removed from service. The reconfiguration in essence will allow the 69 kV system to continue to be sourced by the Hazard Substation despite maintenance or other outages on the 138/69 kV transformers at the substation.[150] Further, in the event of a complete outage of the 138 kV at Hazard station the new bus-tie 69 kV circuit breaker will allow the four 69 kV circuits at Hazard to remain in service to support each other and avoid a significant fractionalizing of the Hazard area subtransmission network that would result under the existing station configuration.[151]

(c) Addressing Potential Safety Issues.

Portions of the proposed work will bring the Hazard Substation, which was constructed in the early 1940's,[152] into conformity with current safety specifications.[153] These include railings and platforms, as well as the need to provide additional space to guard live parts and to provide minimum clear distances to energized equipment.[154] The platforms were field-designed to provide access, and they incorporate "lumber decks that are old and dangerous."[155] Emblematic of the need for work to upgrade the platforms and railings to current safety standards are the condition of the platform and railing associated with 12 kV circuit breaker illustrated below:[156]

[150] Application Exhibit 2. *Id.* at 13; *see also* KPSC 1-2, Attachment 2 at 3.

[151] Application Exhibit 2. *Id.* at 13; *see also* KPSC 1-2, Attachment 2 at 3.

[152] Lasslo Direct at 9; Ali Direct at 15.

[153] Ali Direct at 3, 3-4.

[154] KPSC 2-4.

[155] AG 2-7, Attachment 2 at 22.

[156] *Id.*

or failures. The moab platform below has no railing. The right hand illustration is at the 12kv cb, very flexible, no middle bracing, your head is level with bottom of bushings and you have no quick way to get away if you have an issue when closing breaker except to jump.

C. KENTUCKY POWER APPROPRIATELY BALANCED MULTIPLE FACTORS IN IDENTIFYING AND SCHEDULING THE ASSET REPLACEMENT AND RENEWAL WORK THAT IS THE SUBJECT OF THE APPLICATION.

1. Kentucky Power Employs A Defined Process That Incorporates Experience And Professional Engineering Judgment In Identifying And Scheduling Substation Renewal, Reconfiguration, And Functionality Improvement Work.

The timing, staging, and manner (*e.g.* replacement vs. upgrade) by which Kentucky Power, in collaboration with American Electric Power Service Corporation ("AEPSC") Transmission Planning,[157] identifies asset renewal, asset replacement, and other transmission operational needs, such as the proposed work at the Hazard Substation and Wooton Substation, is

[157] *See e.g.* VR 12:29:36 (Ali) ("All the organizations will quarterly meet with Brett Mattison at Kentucky Power, generation, distribution, transmission, and we present our cases so that we have this clearing house at the executive level that can ask those tough questions and make sure we're focused on the right priority at the end of the day."); AG 1-17 ("Kentucky Power management, in conjunction with AEP Transmission, reviews and approves all proposed transmission investments….. Through this arrangement, Kentucky Power is able to achieve economies and efficiencies in planning transmission investments that benefit the Company and its customers.")

not a binary process.[158] Rather, it requires the identification, review, and ultimately the weighing of multiple factors.[159] Other than the need to address safety issues that pose an immediate threat to employees and the public,[160] no single factor or consideration controls.[161] Rather, the determination of what work to perform and when to perform it is a matter of "good engineering and operational judgment based on experience and conditions."[162]

Kentucky Power, in collaboration with AEPSC Transmission Planning,[163] "follows an established and detailed protocol to evaluate and select Supplemental Projects that assures only projects that are needed are pursued."[164] The process is employed in a consistent manner.[165] The process is undertaken annually and involves three steps:[166]

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[158] *See e.g.* VR 12:21:40 (Ali) ("I think where -- where I think where maybe – maybe there is some confusion is what is the level of obsolescence, right? I mean if the obsolesce is just associated with a – with a cabinet off a circuit breaker control, well, that's something we can deal with. We can repair that. We can – you know we can build it ourselves. But if the obsolescence is associated with the contacts of the breaker inside the breaker, which are interrupting the fault, that obsolesce means you really got to replace it."); VR 10:29:09 (Lasslo) ("[W]e have to use our judgment to decide when we do replace equipment."); Ali Direct Testimony, Exhibit KA-1 at 4 (determination made by "exercising engineering judgment coupled with Good Utility Practices.")

[159] VR 12:25:25 (Ali) ("I mean there are many other things in there that go into the – into the – you know into the prioritization methodology.")

[160] VR 11:27:35 (Lasslo) ("You know if it's immediate – if it's immediate threat like to our employees and the public, you know we're going to address it right then. I mean – ***I mean all of our employees have the authority to turn it off to de-energize the system without even having to contact the dispatch***.") (emphasis supplied); VR 12:24:25 (Ali) ("Is it a – is it an employee ***safety*** risk or a pub- -- or public safety risk? If that is the case, ***that's number one priority***.") (emphasis supplied).

[161] VR 12:24:35 (Ali); VR 12:25:20 (Ali).

[162] VR 10:09:53 (Lasslo); Ali Direct, Exhibit KA-1 at 4 ("AEP identifies the needs and the solutions necessary to address those needs on a continuous basis using 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."); *id.* at 15 ("AEP uses its discretion and engineering judgment to determine suitable timelines for project execution.")

[163] VR 12:24:15 (Ali); VR 10:20:22 (Lasslo).

[164] Ali Direct at 8; VR 12:26:55 (Ali).

[165] VR 12:27:05 (Ali).

[166] Ali Direct, Exhibit KA-1 at 6.

Needs identification involves the consideration of three broad factors: asset condition, historical performance, and the evaluation of the risks posed by the equipment.[167] In evaluating the condition of substation assets, Kentucky Power assesses multiple factors depending on the type of equipment. Transformers, for example, are evaluated by examining at least 12 factors, including the manufacturer, in service date, bushing power factor, dissolved gas analysis results, through fault events, dielectric strength, maintenance history, and malfunction records.[168] Circuit breakers, in turn, are assessed by considering at least ten factors, including in service date, interrupting medium, fault operations, switched operations, spare part availability, maintenance history, malfunction records, and breaker type population.[169]

Historical performance of substation assets next is gauged annually using a rolling three-year average.[170] Historical performance is measured using at least seven metrics including forced outage rates, outage durations, system average interruption indices (*e.g.* T-SAIDI, T-SAIFI), number of customers interrupted and minutes of interruption, and customer average

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[167] *Id.*

[168] *Id.* at 10.

[169] *Id.* at 10-11.

[170] *Id.* at 12.

interruption indices *e.g.* SAIDI, CAIDI, and SAIFI).[171] These values are then compared to corresponding system totals."[172]

Finally, the future risk associated with each asset is considered.[173] This evaluation involves the determination of both the probability of an outage occurring in light of the asset's condition and historical performance, and the impact the outage would have on the system and the Company's customers.[174]

In addition to future risks, the Company also examines asset-type risks resulting from "operational, restoration, environmental, or safety issues"[175] associated with particular equipment types and configurations as part of its risk assessment.[176] These include many of the risks to be addressed by the equipment replacement and upgrades comprising all or part of the 23 Project Components that are the subject of the Company's application: oil circuit breakers, electromechanical relays, legacy system configurations, including missing or inadequate transformer/bus protection and "overlapping zones of protection," and poor lightning and grounding performance.[177]

Kentucky Power then develops solutions to address these needs in the second step of the process.[178] These solutions are identified using "appropriate industry standards, engineering judgment, and Good Utility Practices."[179] Among the factors considered are "environmental

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[171] *Id.*

[172] *Id.*

[173] *Id.* at 13.

[174] *Id.*

[175] *Id.*

[176] *Id.*

[177] *Id.* at 13-14.

[178] *Id.* at 14.

[179] *Id.*

conditions, community impacts, land availability, permitting requirements, customer needs, system needs, and asset conditions…."[180] The Company also solicits stakeholder and customer input in developing solutions.[181]

The final step – the scheduling of asset renewal and replacement, system reconfiguration, and functionality improvements – likewise requires the application of professional engineering judgment.[182] Among the factors Transmission Planning and Kentucky Power consider in developing the timeline for work are the "severity of asset condition, overall system impacts, outage availability, siting requirements, availability of labor and material, [and] constructability…."[183] The ability to coordinate and combine the work associated with multiple individual project components also is considered.[184] The availability of capital to fund the project also is considered by Kentucky Power management in the scheduling of work.[185] Although the availability of capital is both a consideration and can be a constraint, immediate safety and reliability needs are addressed in a timely fashion.[186]

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[180] *Id.*

[181] *Id.*

[182] *Id.* at 15.

[183] *Id.*

[184] Lasslo Direct at 16-17; Ali Direct, Exhibit KA-1 at 15.

[185] VR 9:40:13 (Wohnhas) ("So we look at a capital outlay for total Kentucky Power generation, transmission and distribution, and you know based on the priorities of – of everything then make a decision on the spend for each year."); VR 10:23:50 (Lasslo) ([T]here's competition for capital resources…."); VR 12:24:51 (Ali) ("Of course in a world of unlimited capital we would be addressing all of those needs, but we make those decision in my opinion professionally and in an educated manner.") *See also* Ali Direct, Exhibit KA-1 at 15.

[186] VR 11:27:35 (Lasslo).

2. <u>The Use Of Professional Engineering Judgment And Experience In Identifying And Scheduling Projects Benefits The Company And Its Customers By Providing For A Safe And Reliable Transmission And Distribution System In An Efficient And Cost-Effective Fashion.</u>

Nothing as mechanically and electrically complex as a transmission substation,[187] much less Kentucky Power's entire transmission system, can be planned, maintained, and operated in a safe, reliable, and efficient manner absent the reasoned application of experience and professional engineering judgment. There is no simple, or even complex, algorithm available (or sufficient) to make these decisions whereby data are input, a crank is turned, and a single bright line answer is spit out. Instead, Kentucky Power uses its knowledge of the condition of its assets and the manner in which they have been operated and performed, coupled with the professional engineering judgment of its planners and operators, to identify assets for replacement and upgrade and to develop a schedule for doing so that allows the Company to provide reliable service to its customers in a cost-effective manner:

> we absolutely have some subjectivity built into our process, and ***we really need that subjectivity*** because in my opinion you know at the end of the day, like the gentleman that came in earlier, we are very mindful also of the rate impacts of what we're doing, and we have to be ... and in essence that subjectivity's built in for asset renewal type decisions, how much risk can you take, and you know when – when is it going to fail? Obviously, if we had a crystal ball, we would replace assets right before they fail so we get the maximum value out of them, but that doesn't happen. So we use our knowledge. We use the equipment failure rates from the past to make those determinations. But, yes, there is some subjectivity built into it. ***But it's by design to ensure that we are making the right decision for our customers.***[188]

[187] Company Witness Lasslo, for example, identified 20 major components, many of which include hundreds if not thousands of elements, that make up the Hazard Substation. Lasslo Direct at 9-11.

[188] VR 12:27:53 (Ali) (emphasis supplied).

This same sort of flexibility, and reasoned application of professional engineering judgment to all relevant inputs, is the *sine qua non* of the Federal Energy Regulatory Commission's definition of "Good Utility Practice:"

> Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, ***in the exercise of reasonable judgment in light of the facts known at the time the decision was made***, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.[189]

The FERC definition of Good Utility Practice is incorporated by reference in the AEP Guidelines for Transmission Owner Needs.[190]

In this respect, the Company's decisions with respect to the identification and the timing of the replacement and upgrade of substation components are no different than the decisions many professionals – including physicians, accountants, and attorneys – are required to make every day. The Commission similarly is required to apply its subjective judgment in deciding the issues presented to it, and similarly has recognized the need for informed subjective decisions involving multiple inputs by the companies its regulates:

> Obviously, there is no exact methodology or formula which will provide a precise dollar amount, and project distribution, which should be spent on construction in a given year. The construction budget ***must of necessity be the end-product of many inputs, and based upon the professional judgment of the utility's engineers and management.***[191]

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[189] Federal Energy Regulatory Commission Pro Forma Open Access Tariff § 1.14 https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8p4-000.txt (last visited February 23, 2020) (emphasis supplied).

[190] Ali Direct, Exhibit KA-1 at 4; *see also* Ali Direct at 11.

[191] *See e.g. In the Matter of: Petition Of South Central Bell Telephone Company To Change And Increase Certain Rate Charges For Intrastate Telephone Service*, Case No. 9160 at 78 (Ky. P.S.C. May 2, 1985) (emphasis supplied).

Nor can quantifiable metrics such as the anticipated life of a class of asset (*e.g.* circuit breaker or transformer), or the number of through faults experienced by a transformer or circuit breaker, be applied without reference to other considerations such as "system conditions and other factors, … [including] spare part availability, maintenance difficulties … [and] lack of vendor support…,"[192] as well as outage availability and the need to limit customer impact of outages,[193] history of malfunctions,[194] the severity of the condition,[195] and the component's compatibility with other equipment.[196] As the Company explained when asked if there was a contradiction between its ability in some instances to operate certain components beyond their anticipated operating lives, while it was required to retire other substation assets prior to the end of their projected operating lives:

> Although age is a useful indicator of the remaining useful life of an asset, relying solely on expected life estimates is not a reasonable strategy for managing equipment reliability. If a comprehensive review of performance, condition and risk indicates that an asset is not a candidate for replacement, the Company will continue to utilize that asset even if the age exceeds what is typically expected for that class of asset. However, if equipment is found to pose an unreasonable risk of service disruption to connected customers, the Company will act to proactively replace this equipment.[197]

Kentucky Power made just such a multi-factor, reasoned evaluation of the Project Components that are the subject of this application. Based upon that evaluation the Company concluded that all are candidates for replacement or upgrade now.[198]

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[192] AG 1-10.

[193] KPSC 1-4; KPSC 2-8.

[194] AG 1-14; KPSC 2-8.

[195] KPSC 2-8.

[196] AG 1-22 ("While the communication equipment at the Wooton station, viewed in isolation, has not exceeded its chronological useful life, it is no longer compatible with the relaying and telecommunication fiber upgrades needed at the Wooton station.")

[197] AG 2-11(a).

[198] Ali Direct at 15.

Treating quantifiable indicators such as the projected operating life of an asset class, or a manufacturer's recommendation concerning the number of through faults as bright line indicators of when an asset should be replaced or upgraded ignores both the role played by the Company's inspection and maintenance activities, and the nature of manufacturers' recommendations. Kentucky Power "performs maintenance with the intent of maximizing the useful life of its equipment to the extent practicable."[199] For example, doing so[200] allowed the Company to keep 69 kV circuit breaker S, 69 kV circuit breaker E, and 69 circuit breaker F operational despite the fact each is approaching or has exceeded its projected useful lives in terms of age.[201]

The manufacturer's recommendations do not always mandate that assets be retired after the indicated number of fault operations.[202] Instead, they inform the Company as to when the asset should be inspected and overhauled or retired if necessary:

> the recommendations are if they have a certain number of operations, that you actually take the breaker out of service and then you do an external, internal inspection. You take the oil out. You drop the tank. The components that wear the most are the moving and stationary contacts that when it interrupts an arc, there is some erosion, and after time you have to replace those. So you'll do your measurements and see what the – the wear is and replace those. You filter the oil or replace the oil, your minor, minor components like valves or switches ....[203]

Conversely, the Company may not replace an "eligible" asset where doing so is not cost-effective.[204] The asset health score for 69 kV circuit breaker R, for example, indicated it could

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[199] AG 2-11(a); KPSC 1-5 ("Maintenance practices have kept these breakers operational").

[200] AG 2-11(a); VR 11:25:20 (Lasslo) (agreeing that "Kentucky Power regularly maintains and inspects its equipment.")

[201] AG 1-11(c).

[202] The manufacturer recommendations also do not consider the severity of the fault operation. *See e.g.* KPSC 1-5(b).

[203] VR 10:08:31 (Lasslo).

[204] *See* AG 1-9(c); AG 2-10(a).

be replaced as part of the mobilization for the other work at the Hazard Substation. The Company, taking advantage of the flexibility available to it, nevertheless instead elected to continue to monitor the circuit breaker and not replace it as part of this mobilization because future planned work at the substation would render the 69 kV circuit breaker unnecessary:

> we did not want to waste investment for – and have our customers pay for something we're really not going to need long term. So if you look at it, there are two lines going to Bonnyman station 69 kV. And our ultimate plan is based on the condition of the wood pole lines that one of those lines will probably be upgraded to 138 kV. So we will probably be in the coming years to address the Bonnyman line and upgrading it to 138. We will probably be getting rid of this circuit up here, which would render breaker R unnecessary.[205]

This same flexibility allows Kentucky Power "to combine solutions in order to limit costs, take advantage of efficiencies, and/or limit the number of outages."[206]

D. THE PROJECT ALLOWS KENTUCKY POWER TO MEET ITS DEMONSTRATED NEEDS WITHOUT WASTEFUL DUPLICATION.

Kentucky Power, in conjunction with AEPSC Transmission Planning, followed a detailed and established multi-step process to identify needs and develop solutions to address those needs in a cost-effective and efficient manner.[207] Doing so allowed the Company to ensure that the Project and its individual components will not result in wasteful duplication in contravention of KRS 278.020(1).

Multiple Project Components elements are damaged, deteriorated, or obsolete.[208] Many of these same Project Component elements (and some others) have exceeded their anticipated useful life or have exceeded manufacturers' recommendations, and in conjunction with other

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[205] VR 12:38:14 (Ali).

[206] KPSC 1-4.

[207] Ali Direct at 8; VR 12:26:55 (Ali); VR 12:27:05 (Ali).

[208] Post-Hearing Brief *supra* at 12-21.

considerations, are required to be replaced or upgraded[209] despite the Company's ongoing maintenance efforts.[210] Operating these components to failure would be imprudent,[211] contrary to standard practice,[212] and would result in wasteful and unnecessary expenditures in replacing the elements on an unplanned basis.[213] The Project Components required to sectionalize the Hazard Substation will limit damage to other elements, improve functionality, and limit outages.[214] Kentucky Power also proposes to address potential safety concerns at the Hazard Substation.[215] The proposed communications upgrades will allow other elements to function as intended. Finally, the nine Baseline Project elements are mandated by PJM.[216]

There is no evidence of record that any of the 23 Project Components – each of which addresses in a cost-effective fashion the Company's demonstrated needs – will result in excess of capacity over need, or excess investment in relation to productivity and efficiency to be gained.[217] To the contrary, the Company demonstrated that the individual Project Components were selected (or excluded) to avoid wasteful duplication. For example, 69 kV circuit breaker R is not included in the Project, although it otherwise is a candidate for replacement, because other planned work will require its removal and replacement by a 138 kV breaker.[218]

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[209] *Id.* at 14-17.

[210] *Id.* at 16.

[211] *Id.* at 15.

[212] *Id.*

[213] *Id.* at 39; KPSC 2-8.

[214] Post-Hearing Brief *supra* at 22-26.

[215] *Id.* at 29-30.

[216] *Id.* at 8-12.

[217] *See Kentucky Utilities Co. v. Public Serv. Comm'n*, 252 S.W.2d 885, 890 (Ky. 1952).

[218] VR 12:38:14 (Ali); AG 2-10(a).

Most importantly, the Project is designed to avoid the wasteful duplication that would result in performing the work *in seriatim*:

> we have all these – these other needs that while you're there and in coordination with transmission planning you know with our judgment we decide this is the time to get it done so that we can do it all at one time under one outage. You don't have to have all the additional mobilization cost that you would duplicate those costs if you did them piecemeal.[219]

By installing the 23 Project Components as part of a single project, Kentucky Power conservatively estimates that its customers will save millions of dollars over the cost of performing the work as 13 separate projects.[220]

The absence of wasteful duplication also is demonstrated by the Company's examination of other alternatives.[221] Specifically, Kentucky Power investigated rebuilding the entire substation "in the clear."[222] Because the Hazard Substation is "landlocked" by existing development, mountainous terrain, and the North Fork of the Kentucky River, rebuilding the station "in the clear" would have required acquiring property and building the new substation at

[219] VR 10:40:25 (Lasslo). *See also* KPSC 2-8 ("When feasible, Kentucky Power coordinates maintenance, replacement and upgrade projects at a single substation ***to eliminate avoidable mobilization costs and to limit additional costs that would be incurred by performing the work over separate construction periods***. In the case of the Hazard and Wooton Stations, the accumulation of equipment issues provided an opportunity for the Company to realize such cost efficiencies.") (emphasis supplied); AG 1-4 ("Requiring that the work be performed though multiple mobilizations can increase the cost as a result of duplication of costs."); KPSC 1-7 ("The Company's goal in grouping work is to perform the work in the most cost-effective and efficient manner, and thereby limit the costs, disruptions, and inconveniences ultimately borne by Kentucky Power's customers.")

[220] Kentucky Power Company's Response to Post-Hearing Data Requests, Request No. 2, Attachment 1, *In the Matter of: Electronic Application Of Kentucky Power Company For A Certificate Of Public Convenience And Necessity To Perform Upgrade, Replacement, And Installation Work At Its Existing Hazard Substation And Wooton Substation In Perry County And Leslie County, Kentucky*, Case No. 2019-00154 (Filed February 21, 2020) ("PH-__").

[221] *In the Matter of: Joint Application Of Louisville Gas and Electric Company And Kentucky Utilities Company For A Certificate of Public Convenience and Necessity For The Construction of Transmission Facilities In Jefferson, Bullitt, Meade, and Hardin Counties, Kentucky* Case No. 2005-00142 (Ky. P.S.C. September 8, 2005).

[222] VR 12:38:28 (Ali); AG 2-7, Attachment 2 at 5.

least five miles distant.[223] That in turn would have required rerouting the six transmission circuits and four distribution circuits that currently terminate at the Hazard Substation.[224] The conceptual estimate of the cost of rebuilding the Hazard Substation in the clear was $35 million, or approximately two times the conceptual estimated cost of the proposed project.[225]

Kentucky Power also examined using the Hazard Substation's existing 69 kV yard to rebuild the 69 kV portion of the project as a ring bus.[226] This alternative was determined to be "not physically possible due to the extensive outages that would be required;" in addition the slopes and different grades present in the existing 69 kV yard presented significant "constructability challenges."[227] Finally, this second alternative was found to be not cost effective.[228]

The uncontroverted record demonstrates the Company examined all reasonable alternatives, and that the chosen alternative pending before the Commission is both feasible and cost-effective. There is no wasteful duplication.

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[223] KPSC 2-11; AG 2-7, Attachment 2 at 5; VR 12:38:28 (Ali).

[224] KPSC 2-11; AG 2-7, Attachment 2 at 5.

[225] VR 12:39:34 (Ali).

[226] VR 12:39:45 (Ali); KPSC 2-11.

[227] KPSC 2-11.

[228] *Id.*; AG 2-7, Attachment 2 at 5.

E. CONCLUSION.

Kentucky Power Company respectfully requests that the Public Service Commission of Kentucky enter an order:

1. Approving Kentucky Power's application and granting the Company a certificate of public convenience and necessity to perform the proposed construction at the Hazard Substation and the Wooton Substation; and

2. Granting Kentucky Power such further relief as may be appropriate.

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BRIEF APPENDIX 1

EXHIBIT 2: HAZARD AND WOOTON SUBSTATION PROJECT ELEMENTS

Hazard Substation Elements

Previous Identifier from Exhibit 10	One Line Identifier	Description	Purpose	Driver for Asset Replacement/Installation
a b	(1)	**Replacement of the 161 kV circuit breaker (M) pointing towards Wooton Station.** - Replacement of devices for line protection and circuit breaker control associated with the 161kV Wooton line position	To permit the interruption of fault current or load current on the 161kV line towards Wooton Station and 161/138 kV transformer #3 at Hazard station. Microprocessor relays and controls to monitor currents, report equipment status, record events, provide automatic, manual and remote (via SCADA) operation of the breaker as programmed.	This breaker must be moved to accommodate the approved Baseline project elements (B2761) already approved by the KY PSC. Circuit breaker M was manufactured in 1988 and has experienced 21 fault operations (which exceeds the manufacturer's recommendation of 10). Replacing this breaker at this point is appropriate rather than re-installing the existing breaker, which is over 30 years old, at the new location. The microprocessor relays and controls will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.
d e	(2)	**Installation of a 138 kV circuit breaker with relay control on the low side of the 161 kV/138 kV transformer #3** - Replacement of devices for transmission transformer protection associated with Transformer #3	To permit the interruption of fault or load current on the 138kV side of the new #3 161/138kV transformer. To provide automatic, manual, and remote (via SCADA) control of the breaker. To provide proper sectionalizing to minimize the number of elements that must operate to clear a fault on the transformer. Microprocessor relays and controls to monitor currents entering and leaving the Transformer #3, trip the 161kV high side breaker and the 138kV low side breaker to isolate the transformer when the current differential reaches a programmed set point. Equipment also will report equipment status (temperature, pressure, currents), record events and provide automatic operation of the breakers as programmed for other parameters such as an internal sudden pressure increase.	The existing 1940's vintage single phase banks that make up Transformer #3 are being replaced by a three phase transformer as part of the Baseline project already approved by the KY PSC. The circuit breaker on the low side of the transformer and the microprocessors (Identified (e)) will allow the transformer to be protected and isolated, if necessary, to prevent damage during a fault operation. The low side breaker also separates the zones of protection and minimizes the number of elements that must operate for a fault on the transformer. Under the existing configuration at Hazard, lack of the low side breaker on the transformer results in the operation of every element tied to 138 kV bus #2 and 69 kV bus #2 in order to clear a fault on Transformer # 3. This includes operation of Transformers #4 and #5 resulting in the loss of customers served from the two transformers. The microprocessor relays and controls also will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.
f	(3)	**Installation of a new three phase 161 kV/138kV spare transformer**	To facilitate timely restoration of service in the event of a failure of the #3 161/138kV transformer.	The 161/138 kV transformer at Hazard station is the only transformer of this voltage class on the AEP Eastern footprint. A spare transformer must be maintained on site as a replacement in the event of a failure of the existing transformer. Without a spare, the lead times required to replace this type of transformer could be up to a year.
aa	(4)	**Replacement of devices for line protection and circuit breaker control associated with the 69kV Bonnyman #2 (R) line position**	Microprocessor relays and controls to monitor currents, report equipment status, record events, provide automatic, manual and remote (via SCADA) operation of the breaker as programmed.	The microprocessor relays and controls will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.

Previous Identifier from Exhibit 10	One Line Identifier	Description	Purpose	Driver for Asset Replacement/Installation
J	(5)	**Replacement of 138 kV capacitor bank and switcher BB**	To provide voltage support and reactive power to the 138kV Bus #2.	The existing circuit switcher is a MARK V unit. Mark V units have experienced a high amount of failures and mis-operations on the AEP system. AEP operating companies are currently replacing all MARK V circuit switchers to remedy these reliability concerns
k		- Replacement of devices for capacitor bank and switcher BB protection and control	Microprocessor relays and controls to monitor currents and voltage, provide trip/close signals to the switcher and report equipment status locally and remotely via SCADA.	The microprocessor relays and controls will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.
N	(6)	**Replacement of existing 138kV/69kV Transformer #1**	To stepdown the 138kV transmission voltage to the 69kV sub-transmission voltage level.	Transformer #1 was manufactured in 1973 and is showing dielectric breakdown (i.e. insulation breakdown), accessory damage of bushings and windings, and short circuit breakdown due to the amount of through faults. It is also showing signs of corrosion on the radiators and has oil leaks. Given the condition of the existing transformer, it is appropriate to replace it now.
N/A		- Replacement of the motor operated air break (MOAB) switch and installation of a circuit switcher on the high-side of Transformer #1	To isolate the 138/69kV Transformer #1 from the 138kV Bus #1 for: an internal transformer fault or overload, a fault on 138kV Bus #1, manual isolation of Transformer #1 for maintenance and testing.	The current MOAB/ Ground switch configuration on the high side of transformer #1 creates a fault in the station to signal the remote end breakers to open; this is a known safety hazard in legacy station designs. Under the existing configuration at Hazard, lack of a high side switcher and low side breaker on the transformer results in the operation of every element tied to 138 kV bus #1 and 69 kV bus #1 in order to clear a fault on Transformer # 1. It also exposes the transformer to potentially damaging currents for faults tied to 138 kV bus #1 and 69 kV bus #1.
O		- Installation of a 69kV breaker with relay control on the low-side of 138kV/69kV Transformer #1	To permit the interruption of fault or load current on the 69kV side of the 138/69 Transformer #1. To provide automatic, manual and remote (via SCADA) control of the breaker.	
P		- Replacement of devices for transmission transformer protection associated with Transformer #1	Microprocessor relays and controls to: monitor currents entering and leaving the Transformer #1, trip the 138kV high side breaker and the 69kV low side breaker to isolate the transformer when the current differential reaches a programmed set point. To report equipment status (temperature, pressure, currents), record events and provide automatic operation of the breakers as programmed for other parameters such as an internal sudden pressure increase.	The microprocessor relays and controls will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.

Previous Identifier from Exhibit 10	One Line Identifier	<u>Description</u>	<u>Purpose</u>	<u>Driver for Asset Replacement/Installation</u>
T S U V	(7)	**Replacement of existing 138kV/69kV Transformer #2** - Replacement of the motor operated air break switch and installation of a circuit switcher on the high-side of Transformer #2 - Installation of a 69kV breaker with relay control on the low-side of 138kV/69kV Transformer #2 - Replacement of devices for transmission transformer protection associated with Transformer #2	To stepdown the 138kV transmission voltage to the 69kV sub-transmission voltage level. To isolate the 138/69kV Transformer #2 from the 138kV Bus #2 for: an internal transformer fault or overload, a fault on 138kV Bus #2, manual isolation of Transformer #2 for maintenance and testing. To permit the interruption of fault or load current on the 69kV side of the 138/69 Transformer #2. To provide automatic, manual and remote (via SCADA) control of the breaker. Microprocessor relays and controls to: monitor currents entering and leaving the Transformer #2, trip the 138kV high side breaker and the 69kV low side breaker to isolate the transformer when the current differential reaches a programmed set point. To report equipment status (temperature, pressure, currents), record events and provide automatic operation of the breakers as programmed for other parameters such as an internal sudden pressure increase.	Transformer #2 was manufactured in 1974 and is showing dielectric breakdown (i.e. insulation breakdown), accessory damage of bushings and windings, and short circuit breakdown due to the amount of through faults. Replacement of this transformer is appropriate given the current condition. Under the existing configuration at Hazard, lack of a high side switcher and low side breaker on the transformer results in the operation of every element tied to 138 kV bus #2 and 69 kV bus #2 in order to clear a fault on Transformer # 2. This includes operation of Transformers #4 and #5 resulting in the loss of customers served from the two transformers. The microprocessor relays and controls will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.
W X	(8)	**Replacement of 69kV capacitor bank and switcher CC** - Replacement of devices for capacitor bank and switcher CC protection and control	To provide voltage support and reactive power to the 69kV Bus #2. Microprocessor relays and controls to: monitor currents and voltage, provide trip/close signals to the switcher and report equipment status locally and remotely via SCADA.	Capacitor switcher CC has oil leaks on all three phases and cannot be repaired. Capacitor Bank CC was a non-standard design and its components, including fuses and cans, have begun to fail. The proposed equipment will remedy these issues. The microprocessor relays and controls will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.

Previous Identifier from Exhibit 10	One Line Identifier	Description	Purpose	Driver for Asset Replacement/Installation
bb cc	(9)	**Replacement of the 69kV circuit breaker (S) pointing towards Daisy Station** - - - - Replacement of devices for line protection and circuit breaker control associated with the 69kV Daisy line position	To permit the interruption of fault current or load current on the 69kV line towards Daisy Station and the 69kV Bus #1. Microprocessor relays and controls to: monitor currents, report equipment status, record events, provide automatic, manual and remote (via SCADA) operation of the breaker as programmed.	Circuit breaker S was manufactured in 1960 and has experienced 82 faults (well above the manufacturer's recommended 10). This is an oil breaker which is difficult to maintain and carries the potential of oil related spills during maintenance or failures. Other drivers include potential PCB content and damage to bushings. The microprocessor relays and controls will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.
dd ee	(10)	**Replacement of the 69kV circuit breaker (E) pointing towards Leslie Station** - Replacement of devices for line protection and circuit breaker (E) control associated with the 69kV Leslie line position	To permit the interruption of fault current or load current on the 69kV line towards Leslie Station. To provide protection on the 69 kV bus #1 Microprocessor relays and controls to: monitor currents, report equipment status, record events, provide automatic, manual and remote (via SCADA) operation of the breaker as programmed.	Circuit breaker E was manufactured in 1974 and has experienced 184 faults (well above the manufacturer's recommended 10). This is an oil breaker which is difficult to maintain and carries the increased potential of oil related spills during maintenance or failures. Other drivers include potential PCB content and damage to bushings. The microprocessor relays and controls will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.
ff gg	(11)	**Replacement of the 69kV circuit breaker (F) pointing towards Bonnyman Station via the number one circuit** - Replacement of devices for line protection and circuit breaker control associated with the 69kV Bonnyman #1 line position	To permit the interruption of fault current or load current on the 69kV line towards Bonnyman Station and the 69kV Bus #1. Microprocessor relays and controls to: monitor currents, report equipment status, record events, provide automatic, manual and remote (via SCADA) operation of the breaker as programmed.	Circuit Breaker (F) was manufactured in 1985 and has experienced 193 fault operations (well above the manufacturer's recommended 10). This circuit breaker is an oil filled breaker that is difficult to maintain and carries the increased potential of oil spills during routine maintenance and failures. Other drivers include potential PCB content and damage to bushings. The microprocessor relays and controls will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.
hh	(12)	**Installation of a 69kV circuit breaker connecting 69 kV bus #1 and bus #2**	To provide a means to serve the 69kV Bus #1 from the 69kV Bus #2 in the event of the loss of the 138/69kV Transformer #1 and to serve the 69kV Bus #2 from the 69kV Bus #1 in the event of the loss of the 138/kV Transformer #2.	Isolating the 69kV system will allow the 69kV system to stay in-service despite an outage on the 138kV system and will provide greater operational flexibility. It also allows the retirement of capacitor bank AA which is beginning to show issues associated with deterioration and its VBM type capacitor switcher.

Previous Identifier from Exhibit 10	One Line Identifier	Description	Purpose	Driver for Asset Replacement/Installation
	(13)	**Protection of Existing Transformer #4**		Protection of the transformer on both the high side and low side will be upgraded to address concerns with dissimilar zones or protection. Under the existing configuration at Hazard a fault on transformer #4 would result in the operation of every element associated with 138 kV bus #1 and 69 kV bus #2.
ii		- Replacement of the motor operated air break switch and installation of a circuit switcher on the high-side of Transformer #4	To isolate the 138/34kV Transformer #4 from the 138kV Bus #2 for: an internal transformer fault or overload, a fault on 138kV Bus #2, manual isolation of Transformer #2 for maintenance and testing.	
jj		- Installation of a 34.5kV breaker with relay control on the low-side of 138kV/34.5kV Transformer #4	To permit the interruption of fault or load current on the 34kV side of the 138/34 Transformer #4. To provide automatic, manual and remote (via SCADA) control of the breaker.	The microprocessor relays and controls will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.
kk		- Replacement of devices for transmission transformer protection associated with Transformer #4	Microprocessor relays and controls to: monitor currents entering and leaving the Transformer #4, trip the 138kV high side switcher and the 34kV low side breaker to isolate the transformer when the current differential reaches a programmed set point. To report equipment status (temperature, pressure, currents), record events and provide automatic operation of the breakers as programmed for other parameters such as an internal sudden pressure increase.	
ll	(14)	**Replacement of devices for line protection and circuit breaker control associated with the 34.5kV Blackgold line position**	Microprocessor relays and controls to: monitor currents, report equipment status, record events, provide automatic, manual and remote (via SCADA) operation of the breaker as programmed.	The microprocessor relays and controls will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.
mm	(15)	**Replacement of the 34.5kV circuit breaker (A) pointing towards Kenmont Station**	To permit the interruption of fault current or load current on the Hazard – Kenmont 34kV Circuit.	The Existing circuit breaker (A) is 30 years old and has had 221 fault operations (well above the manufacturers recommended 10). The existing breaker is a vacuum oil breaker, which presents potential environmental and maintenance concerns similar to the 69 kV breakers above.
nn		- Replacement of devices for line protection and circuit breaker control associated with the 34.5kV Kenmont line position	Microprocessor relays and controls to: monitor currents, report equipment status, record events, provide automatic, manual and remote (via SCADA) operation of the breaker as programmed.	The microprocessor relays and controls will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.

Previous Identifier from Exhibit 10	One Line Identifier	Description	Purpose	Driver for Asset Replacement/Installation
oo	(16)	**Replacement of devices for distribution transformer protection associated with Transformer #5;**	Microprocessor relays and controls to: monitor currents, report equipment status, record events, provide automatic, manual and remote (via SCADA) operation of the breaker as programmed.	The microprocessor relays and controls will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.
pp qq	(17)	**Replacement of the 12kV circuit breaker (c) servicing Hazard** - Replacement of devices for feeder protection and circuit breaker control associated with the 12kV Hazard feeder position	To permit the interruption of fault current or load current on the Hazard – Hazard 12kV Circuit. Microprocessor relays and controls to: monitor currents, report equipment status, record events, provide automatic, manual and remote (via SCADA) operation of the breaker as programmed.	The existing circuit breaker C is 50 years old and has had 354 fault operations. This circuit breaker is an oil filled breaker that is difficult to maintain and carries the increased potential of oil spills during routine maintenance and failures. The microprocessor relays and controls will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.
rr ss	(18)	**Replacement of the 12kV (D) circuit breaker spare** - Replacement of devices for feeder protection and circuit breaker control associated with the 12kV spare feeder position	Provides a backup breaker for the Hazard 12kV distribution in the event of a failure of the Hazard – Hazard 12kV breaker. Microprocessor relays and controls to: monitor currents, report equipment status, record events, provide automatic, manual and remote (via SCADA) operation of the breaker as programmed.	The existing circuit breaker D is a 50-year old oil type breaker. This circuit breaker and presents potential environmental and maintenance challenges similar to the 69 kV breakers above. The microprocessor relays and controls will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.

Previous Identifier from Exhibit 10	One Line Identifier	Description	Purpose	Driver for Asset Replacement/Installation
y,q z,r g h	(19)	**Protection and sectionalizing of the substation:** - Installation of coupling capacitor voltage transformers on 69kV Bus #1 and #2 - Installation of devices for 69kV Bus #1 and #2 protection - Replacement of coupling capacitor voltage transformers on 138kV Bus #2 - Replacement of devices for 138kV Bus #2 protection	To provide the voltage level on the 69kV Bus #2 to: the control relays for the capacitor bank CC and remotely via SCADA. Microprocessor relays and controls to: monitor currents entering and leaving the 69kV Bus #2 and trip the 69kV breakers and circuit switchers to isolate the 69kV Bus #2 when the current differential reaches a programmed set point To provide the voltage level on the 138kV Bus #2 to: the control relays for the capacitor bank BB and remotely via SCADA. Microprocessor relays and controls to: monitor currents entering and leaving the 138kV Bus #2 and trip the 138kV breakers and circuit switchers to isolate the 138kV Bus #2 when the current differential reaches a programmed set point.	Work is required to meet industry accepted protection and control standards that ensure the safe and reliable operation of equipment at Hazard station. The microprocessor relays and controls will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.
N/A N/A	(20)	**Installation of a 138 kV circuit breaker pointing towards Beckham Station.** Replacement of devices for line protection and circuit breaker control associated with the 138kV Beckham line position	To permit the interruption of fault current or load current on the 161kV line towards Beckham Station and 138 kV bus #1 at Hazard station. Microprocessor relays and controls to monitor currents, report equipment status, record events, provide automatic, manual and remote (via SCADA) operation of the breaker as programmed.	A 138 kV circuit breaker will installed at Hazard station on the line exit towards Beckham station to separate dissimilar zones of protection. Under the existing configuration at Hazard, lack of 138 kV circuit breaker on the line towards Beckham results in the operation of every element tied to 138 kV bus #1 and 69 kV bus #1 in order to clear a fault on the ~16.4 mile circuit between Hazard and Beckham. The existing configuration will also result in the loss of customers served from Vicco station in order to clear a fault on 138 kV bus #1 at Hazard station. The microprocessor relays and controls will ensure that the protected equipment can communicate and operate effectively once installed. The electromechanical relays that are currently used in the station are obsolete.

WOOTON SUBSTATION ELEMENTS

Table Identifier	Description	Purpose	Driver for Asset Replacement/Installation
(A)	Installation of station class surge arresters attached to the upper beam of the existing 161kV box bay structure on the 161kV Hazard Line position	To provide overvoltage protection caused by lightning or switching surges for the 161kV bus insulation.	Installation of station class surge arrestors on line entrances is an industry accepted practice to protect equipment from potential overvoltage events
(B)	Installation of two coupling capacitor voltage transformers on Phase 2 and Phase 3 of the 161kV bus	To provide voltage sensing on Phase 2 and Phase 3. Presently, the 161kV bus only has voltage sensing on Phase 1.	Three phase CCVTs provide the ability to apply industry accepted protection and control standards that a single phase CCVT arrangement is unable to.
(C)	Installation of telecommunication fiber equipment	To provide remote monitoring and operation (via SCADA) of equipment at Wooton Station.	Required to utilize new fiber path provided by previously approved OPGW telecommunications cable on the approved Hazard – Wooton 161 kV line.

BRIEF APPENDIX 2

Kentucky Power Company
KPSC Case No. 2019-00154
Commission Staff's Second set of Data Request
Dated October 10, 2019

DATA REQUEST

KPSC 2_3 Refer to the application, paragraph 25. Identify the PJM minimum design standards with which the Hazard and Wooten substations do not comply.

RESPONSE

For work at the Hazard Substation needed to comply with PJM design standards, please refer to KPCO_R_KPSC_2_3_Attachment1. Similarly, for work at the Wooton Substation needed to comply with PJM design standards, please refer to KPCO_R_KPSC_2_3_Attachment2.

Witness: Kamran Ali

Application Exhibit 2 Identifer:	Work Description	Needed to implement the construction approved in Case No. 2017-00328	Needed to address deteriorating and obsolete equipment	Needed to comply with existing PJM and Kentucky Power design standards	PJM/Kentucky Power design standards reference
1	Replacement of the 161 kV circuit breaker (M) pointing towards Wooton Station.	X	X		
1	Replacement of devices for line protection and circuit breaker control associated with the 161kV Wooton line position	X	X	X	PJM Manual 07, Section 7 - Line Protection
2	Installation of a 138 kV circuit breaker with relay control on the low side of the 161 kV/138 kV transformer #3	X		X	PJM Relay Subcommittee, Protective Relaying Philosophy and Design Guidelines Section 2: Protective Relaying Philosophy
2	Replacement of devices for transmission transformer protection associated with Transformer #3	X	X	X	PJM Manual 07, Section 8 - Substation Transformer Protection
3	Installation of a new three phase 161 kV/138kV spare transformer		X		
4	Replacement of devices for line protection and circuit breaker control associated with the 69kV Bonnyman #2 (R) line position		X	X	PJM Manual 07, Section 7 - Line Protection
5	Replacement of 138 kV capacitor bank and switcher BB		X	X	AEP/KY Power Standard Mitigation Indicator List Item 1
5	Replacement of devices for capacitor bank and switcher BB protection and control		X	X	PJM Manual 07, Section 11 - Shunt Capacitor Protection
6	Replacement of existing 138kV/69kV Transformer #1		X		

Application Exhibit 2 Identifer:	Work Description	Needed to implement the construction approved in Case No. 2017-00328	Needed to address deteriorating and obsolete equipment	Needed to comply with existing PJM and Kentucky Power design standards	PJM/Kentucky Power design standards reference
6	Replacement of the motor operated air break (MOAB) switch and installation of a circuit switcher on the high-side of Transformer #1			X	PJM Manual 07, Section 8 - Substation Transformer Protection
6	Installation of a 69kV breaker with relay control on the low-side of 138kV/69kV Transformer #1			X	PJM Manual 07, Section 8 - Substation Transformer Protection
6	Replacement of devices for transmission transformer protection associated with Transformer #1		X	X	PJM Manual 07, Section 8 - Substation Transformer Protection
7	Replacement of existing 138kV/69kV Transformer #2		X		
7	Replacement of the motor operated air break switch and installation of a circuit switcher on the high-side of Transformer #2			X	PJM Manual 07, Section 8 - Substation Transformer Protection
7	Installation of a 69kV breaker with relay control on the low-side of 138kV/69kV Transformer #2			X	PJM Manual 07, Section 8 - Substation Transformer Protection
7	Replacement of devices for transmission transformer protection associated with Transformer #2		X	X	PJM Manual 07, Section 8 - Substation Transformer Protection
8	Replacement of 69kV capacitor bank and switcher CC		X		

Application Exhibit 2 Identifer:	Work Description	Needed to implement the construction approved in Case No. 2017-00328	Needed to address deteriorating and obsolete equipment	Needed to comply with existing PJM and Kentucky Power design standards	PJM/Kentucky Power design standards reference
8	Replacement of devices for capacitor bank and switcher CC protection and control		X	X	PJM Manual 07, Section 11 - Shunt Capacitor Protection
9	Replacement of the 69kV circuit breaker (S) pointing towards Daisy Station		X		
9	Replacement of devices for line protection and circuit breaker control associated with the 69kV Daisy line position		X	X	PJM Manual 07, Section 7 - Line Protection; IEEE PSRC I22 Report
10	Replacement of the 69kV circuit breaker pointing towards Leslie Station		X		
10	Replacement of devices for line protection and circuit breaker (E) control associated with the 69kV Leslie line position		X	X	PJM Manual 07, Section 7: Line Protection; IEEE PSRC I22 Report
11	Replacement of the 69kV circuit breaker (F) pointing towards Bonnyman Station via the number one circuit		X		
11	Replacement of devices for line protection and circuit breaker control associated with the 69kV Bonnyman #1 line position		X	X	PJM Manual 07, Section 7 - Line Protection; IEEE PSRC I22 Report
12	Installation of a 69kV circuit breaker connecting 69 kV bus #1 and bus #2		X	X	PJM DEDSTF Section 4.3 - Bus Configuration
13	Replacement of the motor operated air break switch and installation of a circuit switcher on the high-side of Transformer #4			X	PJM Manual 07, Section 8 - Substation Transformer Protection

Application Exhibit 2 Identifer:	Work Description	Needed to implement the construction approved in Case No. 2017-00328	Needed to address deteriorating and obsolete equipment	Needed to comply with existing PJM and Kentucky Power design standards	PJM/Kentucky Power design standards reference
13	Installation of a 34.5kV breaker with relay control on the low-side of 138kV/34.5kV Transformer #4			X	PJM Manual 07, Section 8 - Substation Transformer Protection
13	Replacement of devices for transmission transformer protection associated with Transformer #4		X	X	PJM Manual 07, Section 8 - Substation Transformer Protection
14	Replacement of devices for line protection and circuit breaker control associated with the 34.5kV Blackgold line position		X	X	PJM Manual 07 Section 7 - Line Protection; IEEE PSRC I22 Report
15	Replacement of the 34.5kV circuit breaker (A) pointing towards Kenmont Station		X		
15	Replacement of devices for line protection and circuit breaker control associated with the 34.5kV Kenmont line position		X	X	PJM Manual 07 Section 7 - Line Protection; IEEE PSRC I22 Report
16	Replacement of devices for distribution transformer protection associated with Transformer #5		X	X	IEEE PSRC I22 Report
17	Replacement of the 12kV circuit breaker (c) servicing Hazard		X		
17	Replacement of devices for feeder protection and circuit breaker control associated with the 12kV Hazard feeder position		X	X	IEEE PSRC I22 Report
18	Replacement of the 12kV (D) circuit breaker spare		X		

Application Exhibit 2 Identifer:	Work Description	Needed to implement the construction approved in Case No. 2017-00328	Needed to address deteriorating and obsolete equipment	Needed to comply with existing PJM and Kentucky Power design standards	PJM/Kentucky Power design standards reference
18	Replacement of devices for feeder protection and circuit breaker control associated with the 12kV spare feeder position		X	X	IEEE PSRC I22 Report
19	Installation of coupling capacitor voltage transformers on 69kV Bus #1 and #2			X	PJM Manual 07, Section 7 - Line Protection
19	Installation of devices for 69kV Bus #1 and #2 protection			X	PJM DEDSTF Section 5.2 - System Protection Requirements for Facilities below 200kV ; PJM Manual 07, Section 9 - Bus Protection; PJM Manual 07, Appendix A - Use of Dual Trip Coils
19	Replacement of coupling capacitor voltage transformers on 138kV Bus #2	X		X	PJM DEDSTF Section 4.4 - Accessability, Section 4.11 - Raceways
19	Replacement of devices for 138kV Bus #2 protection	X	X	X	PJM DEDSTF Section 5.2 - System Protection Requirements for Facilities below 200kV ; PJM Manual 07, Section 9 - Bus Protection; PJM Manual 07, Appendix A - Use of Dual Trip Coils
20	Installation of a 138 kV circuit breaker pointing towards Beckham Station.			X	PJM Manual 07 Section 7 - Line Protection; AEP Standard Mitigation Indicator List Item 1
20	Replacement of devices for line protection and circuit breaker control associated with the 138kV Beckham line position		X	X	PJM Manual 07 Section 7 - Line Protection; AEP Standard Mitigation Indicator List Item 1

Application Exhibit 2 Identifier	Work Description	Needed to implement the construction approved in Case No. 2017-00328	Needed to address deteriorating and obsolete equipment	Needed to comply with existing PJM and Kentucky Power design standards	PJM/Kentucky Power design standards reference
A	Installation of station class surge arresters attached to the upper beam of the existing 161kV box bay structure on the 161kV Hazard Line position	X		X	PJM DEDSTF Section 4.7 - Insulation Coordination and Lighting Protection
B	Installation of two coupling capacitor voltage transformers on Phase 2 and Phase 3 of the 161kV bus	X		X	PJM Manual 07, Section 7 - Line Protection (required to coordinate protection with Hazard remote end)
C	Installation of telecommunication fiber equipment	X		X	PJM Manual 07, Section 7 - Line Protection (required to coordinate protection with Hazard remote end)