FILED
July 1, 2021
INDIANA UTILITY
REGULATORY COMMISSION

I&M Exhibit: _____

Cause No. 45576

INDIANA MICHIGAN POWER COMPANY

PRE-FILED VERIFIED DIRECT TESTIMONY

OF

NICOLAS C. KOEHLER

Content

**DIRECT TESTIMONY OF NICOLAS C. KOEHLER
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY**

I. Introduction of Witness

Q1. Please state your name and business address.

My name is Nicolas C. Koehler. My business address is 8600 Smiths Mill Road, New Albany, Ohio 43054.

Q2. By whom are you employed and in what capacity?

I am employed by the American Electric Power Service Corporation (AEPSC) as Director of East Transmission Planning in AEPSC's transmission group, (AEP Transmission). AEPSC is a shared services organization that allows AEP to achieve economies of scale and provide operational expertise and efficiencies in the provision of engineering, financing, accounting, planning, advisory, and other services to the subsidiaries of the American Electric Power (AEP) system, one of which is Indiana Michigan Power Company (I&M or the Company).

Q3. Briefly describe your educational background and professional experience.

I received a Bachelor of Science – Electrical Engineering degree from Ohio Northern University in Ada, Ohio. In 2008, I joined AEP as a Planning Engineer where I advanced through increasing levels of responsibility. I received my PE license in the state of Ohio in 2012 (license number 76967). In May 2019, I assumed the position of Director, East Transmission Planning.

Q4. Have you previously testified before any regulatory commissions?

Yes. I have testified before the Michigan Public Service Commission in Case No. U-20359 supporting I&M's application to increase its rates for the sale of electric energy. I have filed testimony before the Public Service Commission of Kentucky in Case No. 2020-00062 supporting Kentucky Power Company's Application for a Certificate of Public Convenience and Necessity to construct the Kewanee-Enterprise Park 138 kilovolt (kV) Transmission Project.

I have also filed testimonies on behalf of Appalachian Power Company before the Virginia State Corporation Commission in two different Applications for Approval and Certification of Electrical Transmission Lines: the first application is the Central Virginia Transmission Reliability Project, filed in Case No. PUR-2021-00001, and the second is the Reusens to New London 138 kV Rebuild Project filed in Case No. PUR-2021-00049.

Q5. What are your responsibilities as Director of East Transmission Planning?

My responsibilities include organizing and managing all activities related to assessing the adequacy of AEP's transmission network to meet the needs of its customers in a reliable, cost effective, and environmentally compatible manner.

II. Purpose of Testimony

Q6. What is the purpose of your testimony?

The purpose of my testimony is to describe the transmission system that is necessary for I&M to provide retail service and to support the recovery of transmission costs charged to I&M as a result of its membership in the PJM Interconnection LLC (PJM) regional transmission organization (RTO). In particular, I&M incurs charges under the PJM tariffs approved by the Federal Energy Regulatory Commission (FERC), including the PJM Open Access

Transmission Tariff (PJM OATT). My testimony supports the nature and reasonableness of those costs. The recovery of these costs via the Off System Sales Margin Sharing/PJM Cost Rider (OSS/PJM Rider) is addressed by Company witness Seger-Lawson.

Q7. Are you sponsoring any attachments?

Yes, I am sponsoring:

Attachment NCK-1	AEP Transmission Planning Criteria and Guidelines for End-Of-Life and Other Asset Management Needs
Attachment NCK-2	Owner Projects

Q8. Were the attachments that you sponsor prepared or assembled by you or under your direction and supervision?

Yes.

Q9. Please summarize your testimony.

Transmission investment at AEP and across the industry is directed toward addressing aging grid infrastructure, maintaining and improving reliability and resilience, and protecting the grid from physical and cyber threats. Such investment needs continue to increase, as do associated costs. As a Load Serving Entity within PJM, I&M incurs costs to use the transmission system supported by such investments, irrespective of whether it owns the facilities that are being used.

I&M's PJM costs, including the Network Integrated Transmission System (NITS) costs that make up the bulk of its PJM costs, are reasonable and necessary to provide reliable electric service to I&M's customers. They are supported by robust PJM vetting processes for Baseline Upgrades and Network Upgrades, and detailed protocols for consideration of AEP Owner Projects that assure only projects that are needed in each transmission owner's service territory are pursued. Further, Owner Projects are subject to a transparent stakeholder process to ensure that Owner Projects are appropriate, efficient, and cost-effective solutions for customers.

III. I&M's Transmission System

Q10. Please describe I&M's transmission system.

I&M's transmission system is a highly networked grid that delivers electricity from generation sources to the retail and wholesale consumers served by I&M.

There are approximately 5,300 circuit miles of transmission lines in the I&M system, stretching from the eastern Indiana border with Ohio to the shore of Lake Michigan in southeastern Michigan, as well as extending to western and southeastern Indiana, connecting current and former I&M generation sources with the Company's service territory.

Approximately 4,400 of these circuit miles are within Indiana. The voltage levels of I&M's transmission system range from 34.5 kV to 765 kV and can be divided into three categories based on voltage level: extra high voltage (EHV) (above 200 kV), transmission (100 kV to 200 kV), and subtransmission (34.5 kV to 100 kV). Finally, I&M's transmission system includes approximately 193 transmission substations, 140 of which are located in Indiana.

Q11. Please explain how I&M's transmission system is interconnected with the transmission system of other electric utilities.

The I&M transmission system is part of the PJM RTO and is interconnected with AEP Ohio Power Company, American Transmission Systems, Inc., AES Ohio (formally Dayton Power and Light Co.), ComEd, as well as transmission providers Ameren, Indianapolis Power & Light, Duke Energy Indiana, and

Northern Indiana Public Service Company that are in the Midcontinent Independent System Operator (MISO) RTO. I&M is also interconnected with various rural electric cooperatives and municipal electric utilities.

Q12. Please describe the overall condition of I&M's transmission facilities.

The Company's transmission facilities are built and maintained in accordance with AEP standards that are based on industry regulations and Good Utility Practices.[1] Like other members of our industry, the Company is addressing the challenges of aging infrastructure along with the need to modernize transmission facilities, comply with regulations, and adapt to a changing generation portfolio.

Q13. Please explain.

The AEP transmission system has evolved over the last century. In the recent past, the majority of transmission investment has been directed towards constructing facilities to address RTO-identified constraints due to a shift in generation portfolio. In addition, some investment has focused on connecting new demand while maintaining compliance with changing federal and regional reliability standards.

More recently, investment has been refocused to address aging grid infrastructure and resilience, to maintain and improve reliability, and to protect the grid from physical and cyber threats. Finally, I&M expects that the transmission system will continue to evolve and change through technological

[1] FERC has defined "Good Utility Practice" in Section 1.14 of the pro forma Open Access Transmission Tariff in Order 888 as: "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.

advancements such as the adoption of electric vehicles, integration of renewable resources, retirement of fossil fuel based generation, and the implementation of new customer programs.

Q14. Is I&M's transmission system currently adequate to serve its customers' load reliably?

Yes. I&M's transmission system is compliant with all federal and regional reliability standards. I&M will continue to invest appropriately in its transmission assets to provide reliable electric service to its customers.

Q15. Are I&M's transmission assets aging?

Yes. I&M's transmission assets on the I&M system are aging. At present, I&M's average conductor age is roughly 47.9 years of service. Additionally, over 1,300 line miles are 60 years of age or older, and of these line miles, over 400 are over 70 years old. The average useful life of conductor is 70 years; therefore, there will be a need to replace these assets at some point before their inevitable degradation starts impacting the reliability of the system.

Q16. How are AEP and I&M addressing the issue of aging transmission infrastructure?

Although asset age is an important consideration, AEP and I&M develop transmission projects based on a number of factors, including the performance and condition of each asset and the risk that the failure of each poses to the system and connected customers.

As the I&M infrastructure continues to age, the associated risk for any given asset increases. AEP and I&M are implementing solutions to address these needs on the system. As I will further discuss below, I&M and AEP are actively involved in transmission projects internally and through the open transmission planning process at PJM with stakeholder input and FERC oversight.

IV. PJM Interconnection

Q17. What is PJM?

FERC Order 2000 introduced the concept of an RTO or Independent System Operator (ISO) whose purpose is to promote the regional administration of high voltage transmission and ensure non-discriminatory access to transmission systems.

PJM Interconnection is a FERC-approved RTO that coordinates and administers the movement of wholesale electricity in all or parts of thirteen states and the District of Columbia. The Indiana Utility Regulatory Commission (IURC) approved I&M’s transfer of functional operation of its transmission facilities to PJM by its Order dated September 20, 2003, in consolidated Cause Nos. 42350 and 42352.

The AEP system–East Zone (AEP Zone), which includes I&M, integrated its operations with PJM and began participating in the PJM energy market on October 1, 2004. I&M's membership in PJM has allowed I&M's customers to benefit from the independent, regionally operated, and jointly planned and coordinated PJM transmission grid. This grid enhances system reliability and security, competitive wholesale markets, and resource diversity.[2]

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[2] See March 11, 2020 Order in Cause No. 45235 at 110.

Q18. How do PJM and AEP coordinate planning and operation of I&M's transmission system?

I&M's transmission system is part of the AEP eastern transmission system, which consists of the transmission facilities of eleven AEP operating or transmission companies including I&M and AEP Indiana Michigan Transmission Company. This expansive system allows the economical and reliable delivery of electric power for all AEP customers. Planning and operation of the system is integrated through the coordinated efforts of PJM and AEP Transmission.

I&M management collaborates with AEP Transmission to ensure that the transmission expenses charged to I&M through the PJM OATT approved by the FERC are reasonable and necessary. I&M regularly reviews the projects that underlie its transmission expenses and reviews the need and costs of such projects.

I&M is fully involved in the transmission planning process and ensures that planned investments are reasonable and beneficial for I&M's customers. The transmission planning process is a partnership between AEP Transmission and its stakeholders, including I&M. I&M and AEP Transmission work together to identify needed investments on the transmission system and optimize capital expenditures.

I&M prioritizes investments based on the urgency of the need, the impact on customers, and cost, among other factors. I&M specifically approves transmission investments pursuant to internal procedures and controls. In this way, I&M makes sure that planned transmission investments will address its customers' needs, in terms of both maintaining reliable service and meeting the needs of expected new load.

AEP Transmission works closely with neighboring utilities, other interconnected entities, and PJM to plan and operate the transmission grid. RTOs align the transmission planning and operating requirements set out in each RTO's protocols and operating criteria, as further defined through North American Electric Reliability Corporation (NERC) requirements.

Q19. How does I&M participate in PJM?

I&M has three distinct roles within PJM: (1) Generator, (2) Load Serving Entity (LSE), and (3) Transmission Owner (TO). There are various charges and credits that the Company experiences resulting from each role. I will primarily discuss the roles of an LSE and TO.

Q20. How is I&M charged for using the PJM transmission system?

As an LSE, I&M is charged for costs associated with the functional operation of the transmission system, management of the PJM markets, and general administration of the RTO, irrespective of whether it owns the facilities that are being used. As such, I&M pays to use the PJM transmission system, including its own assets, through charges that are based upon I&M's demand on the system.

The costs include charges for I&M's purchase of Network Integration Transmission Service (NITS) under the PJM OATT to serve its retail customers. I&M can incur NITS costs due to projects constructed by other transmission owners within the AEP Zone. I&M can also incur Transmission Enhancement Charges for projects constructed by other transmission owners outside of the AEP Zone.

Q21. Does I&M receive compensation from PJM as a TO?

Yes. I&M is compensated by PJM for owning and operating transmission assets as a TO.

Q22. Please identify the types of PJM transmission costs incurred by I&M.

I&M incurs costs and offsetting revenues in accordance with the FERC-approved PJM OATT and Operating Agreement, which currently include the following:

- NITS pursuant to PJM OATT Attachments H-14 and H-20.
- Firm and Non-Firm Point-to-Point (PTP) Revenues pursuant to PJM OATT Schedules 7 and 8.
- TO Scheduling, System Control, and Dispatch Service pursuant to PJM OATT Schedule 1A.
- PJM RTO Administration fees and other charges pursuant to PJM OATT Schedules 9 and 10.
- PJM Transmission Enhancement Charges pursuant to PJM OATT Schedule 12.
- Default Allocation Assessments, and any refunds of such assessments, pursuant to Section 15.2 of the PJM Operating Agreement.

From time to time, PJM modifies the charges and revenues related to membership within PJM and for transmission service; as a result, the list above may not be fully representative of I&M's PJM-related charges and revenues in the future.

Q23. What are PJM NITS charges?

NITS charges represent the cost for I&M and other PJM network customers to integrate, economically dispatch, and regulate their current and planned network resources to service their network load. NITS charges in the AEP Zone are derived from the transmission investments of all TOs in the AEP Zone.

Q24. Please identify other PJM costs incurred by I&M.

I&M incurs expenses and receives credits from PJM for other activities associated with I&M's role as a Generator and LSE. These charges and credits include net transmission congestion charges and other ancillary services such as:

- Scheduling, System Control & Dispatch Service;
- Reactive Supply and Voltage Control Service;
- Regulation and Frequency Response Service;
- Synchronized Reserve Service;
- Supplemental Reserve Service; and
- Black Start Service.

V. Transmission Planning

Q25. Please describe the PJM Regional Transmission Expansion Plan (RTEP) process.

The PJM RTEP process is a 24-month planning process that identifies reliability issues over a 15-year horizon. The 24-month planning process consists of overlapping 18-month planning cycles to identify and develop shorter lead-time transmission upgrades and one 24-month planning cycle to provide sufficient time for the identification and development of longer lead-time transmission upgrades that may be required to satisfy planning criteria.

AEP Transmission participates on I&M's behalf in the PJM planning process, which is guided by PJM, NERC, ReliabilityFirst Corporation (RFC) and AEP planning criteria. The process results in three different categories of projects:

Baseline Upgrades, Network Upgrades and Supplemental Upgrades (also called "Owner Projects"). Each category is described below.

The first project category is Baseline Upgrades. Using the aforementioned criteria and guidelines, PJM and I&M, in conjunction with AEP Transmission, identify needs that are a result of a criteria violation. Baseline projects include transmission expansions or enhancements that are required to achieve compliance with respect to PJM's system reliability, operational performance, or market efficiency requirements as determined by PJM's Office of the Interconnection, as well as projects that are needed to meet Transmission Owners' local transmission planning criteria. The cost of Baseline Upgrades are allocated to the benefiting zones based on the following mechanisms:

- 345 kV single-circuit or lower voltage facilities are cost allocated based on solution-based distribution factors (DFAX).
- The costs of a 345 kV double-circuit or higher voltage facilities are allocated as follows:
    - o 50% of project costs are allocated to all PJM zones based on load ratio share (the AEP Zone load share percentage for January to December 2020 is 14.18%).
    - o 50% of project costs are allocated on DFAX basis.
- For market efficiency projects, Net Load Payment savings is used instead of DFAX to determine cost allocation. Net Load Payment savings is the net present value sum of energy and capacity market benefits for all benefiting transmission zones.

The second project category is Network Upgrades. These transmission projects result from transmission customer requests for generator interconnection, merchant transmission additions, and long-term transmission service. Customers that cause the need for Network Upgrades are responsible for the costs that are incurred. As an example, if a generator requested to connect to a transmission line and an upgrade was required to connect the generator, the generator would pay for the network upgrade.

The third project category is Owner Projects. These projects are needed for many reasons, including regulatory requirements, modernization and hardening of the grid, replacement of failed equipment, proactive replacement of deteriorating assets prior to failure and improved operational efficiency and performance. The costs of Owner Projects are allocated to the transmission zone in which they are built.

Q26. Do I&M and other Transmission Owners in the AEP Zone follow specific guidelines to determine the necessity of Owner Projects?

Yes. All AEP affiliated transmission owners follow an established and detailed protocol (presented as Attachment NCK-1, and referred to herein as "the Guidelines") to evaluate and select Owner Projects that assures only projects that are needed in each transmission owner's service territory are pursued.

The Guidelines discuss the drivers or inputs that should be considered when evaluating transmission system needs. They ensure that all AEP affiliated transmission owners are applying consistent criteria in evaluations, while each Transmission Owner ultimately determines the mix of Owner Projects needed to maintain the reliability of their transmission grid within the AEP Zone.

Q27. What drivers or inputs does I&M consider in identifying Owner Projects?

Consistent with the Guidelines, the drivers considered in identifying Owner Projects include:

- Equipment Condition, Performance and Risk: These are investments made to ensure the safe and reliable operation of the transmission system. The decision to pursue such projects can be based on equipment performance, obsolescence and expected life concerns, equipment condition, reliability impact, maintenance costs, environmental impact and engineering recommendations.

- Operational Flexibility and Efficiency: These projects can optimize system configuration, lower equipment duty cycles, reduce the impact on and limit the exposure to customers for planned or forced outages and can facilitate improved restoration times. They also provide opportunities to bring the system up to current standards and design principles.
- Infrastructure Resilience: These projects can improve system ability to anticipate, absorb, adapt to and/or rapidly recover from disruptive natural or man-made events including severe weather, geo-magnetic disturbances and physical and cyber security challenges.
- Customer Service: These projects accommodate new, increasing or future load so that the system can reliably address customer needs.
- Other Drivers: Examples include industry recommendations, changes in established standards, state policy objectives, etc.

In addition to the above, there is a growing need for investment in better telecommunication connectivity on the transmission system to support supervisory control, data acquisition, and protection systems, which will lead to improved physical security of critical assets and a reduction in Customer Minutes of Interruptions (CMI) related to transmission outages.

Q28. Are these drivers under I&M's exclusive control?

No. Although I&M commits significant resources to reduce safety risks, maintain transmission assets consistent with industry practices, and plan capital investment to increase reliability performance, many of the drivers of Owner Projects are outside of I&M's control and include regulatory requirements, interconnection requests, asset performance, and the need for modernization of protection and control systems.

Transmission Owners also do not have discretion to decline to make reasonable and necessary investments in the transmission grid. Rather these investments must be made to fulfill I&M's obligation to operate pursuant to Good Utility Practice and to serve customers. Each Transmission Owner in the AEP Zone, including I&M affiliates, has an obligation to ensure capital investments are prudent and necessary to maintain a reliable transmission grid.

Q29. Can you provide an example of an I&M Owner Project that supports these considerations?

Yes. I&M reviewed a rebuild of the Madison-Pendleton 138 kV line with stakeholders in the May 22, 2020 PJM Sub-Regional Regional Transmission Expansion Plan (SRRTEP) committee meeting (see Attachment NCK-2, page 30), with a proposed in service date of May 1, 2023. The 138-kV transmission line that connects the Pendleton Substation to the Meadowbrook and Madison Substations in east central Indiana had reached a state where it was in need of replacement. Condition and performance issues that were considered in the decision to rebuild included but were not limited to:

- 1960s wood pole construction
- 16 open conditions (degrading structures, damaged shield wires, etc.)

As part of the upgrade, approximately 4.2 miles of aging wood poles that do not meet current National Electrical Safety Code (NESC) standards will be replaced with steel monopole structures that are able to support higher capacity conductors and more readily withstand adverse weather conditions. The improvements will be essential to ensure continued reliable electricity is available for local customers.

Additionally, 138 kV breakers are proposed to be added at Meadowbrook station in order to eliminate a three-terminal line and multiple zones of protection on the line. Three-terminal lines and overlapping zones of protection present a challenge in designing protection schemes for outages.

By installing breakers at Meadowbrook station, each piece of connected equipment is able to be isolated into its own relay protective zone. Proactive improvements like this example serve to reduce power outages and speed recovery of service when outages do occur.

Q30. Is the designation of a project as a Baseline or Owner Project indicative of whether the project is necessary, or how necessary it is?

No, it is not. The designation of a project as a Baseline or Owner Project is not indicative of the level of, or absence of, need for the project. Instead, the designations simply reflect that the project addresses different system reliability and resilience needs.

The criteria for designation as an Owner or Baseline Project are not mutually exclusive, and a single project can be needed under either or both. Under the existing PJM RTO framework, Transmission Owners retain planning responsibility for managing the maintenance and replacement of their transmission assets and planning of their local transmission systems.

PJM planning criteria address the expansion and enhancement of transmission facilities required to meet national and regional planning criteria. Owner Projects improve or preserve a PJM Transmission Owner's ability to provide reliable service to its customers, consistent with its obligation to serve, and are grounded in Good Utility Practice.

Q31. Does PJM factor the age or condition of equipment into its forward looking models for system reliability that are used to identify Baseline Projects?

No, it does not. 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 the age or actual condition of all the elements of the transmission system.

This means that for modeling purposes, a substation with 75-year old components that are deteriorating is assumed to function as designed and with the same reliability as a five year old substation with newer components.

Q32. What is PJM's role in reviewing Owner Projects?

All projects affecting the topology of the grid, whether PJM identified or Transmission Owner identified, are subject to the stakeholder process within PJM. While PJM does not formally "approve" Owner Projects, these projects are submitted to PJM and reviewed with the Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP Committee – Western on a periodic basis in accordance with PJM's M-3 Process. All TEAC and Subregional RTEP Committee – Western meetings are open and any transmission stakeholder can attend and participate.

Stakeholder input regarding specific projects is vetted through this PJM committee meeting process. Attachment NCK-2 contains presentation slides on I&M Owner Projects that were reviewed at the SRRTEP Committee – Western on May 22, 2020. As shown on Attachment NCK-2, Owner Projects are subject to multiple rounds of review and detailed project information, including needs and alternative solutions, is provided to stakeholders.

The M-3 process ensure stakeholders have an opportunity to review Owner Projects include the following meetings and posting requirements:

- Separate stakeholder meetings to discuss:

  - Models, criteria, and assumptions used to plant Owner Projects (Assumptions Meeting);
  - Need underlying Owner Projects (Needs Meeting); and,
  - Proposed solutions to meet those needs (Solutions Meeting).
- Posting of criteria, assumptions, and models at least 20 calendar days prior the Assumptions Meeting;
- Posting of criteria violations and drivers at least ten days in advance of the Needs Meeting;
- Posting of potential solutions and alternatives identified by the PJM Transmission Owners or stakeholders at least ten days in advance of the Solutions Meeting; and,
- A process to submit concerns at least ten days before the Local Plan is integrated into the RTEP for PJM Transmission Owner review and consideration.

Q33. How do stakeholders provide input as part of the M-3 Process?

The previously described meeting and posting requirements provide multiple opportunities for stakeholders to comment on assumptions, provide input on additional needs, and propose alternative solutions for PJM Transmission Owners to consider.

First, they can do so verbally in the various stakeholder meetings. Each of these meetings is moderated by PJM. Second, written submissions can be submitted to PJM and posted using the PJM Planning Community Tool. These posts, along with responses provided by AEP Transmission, are available to the public. If discussions necessitate a change to materials that have been provided by AEP, the revised materials are posted as well.

Q34. Do I&M and AEP consider stakeholder input?

Yes, I&M and AEP consider all input provided by stakeholders. Transmission Owners have an obligation to provide sufficient transparency for stakeholders to understand the Transmission Owner's Needs and Solutions. Stakeholders, on the other hand, have an obligation to advise of their Needs and Solutions for consideration by the Transmission Owner before Owner Projects are finalized and submitted to PJM for inclusion into the RTEP.

Additionally, I&M and AEP Transmission include stakeholders that are directly impacted by a given project in the project's development and prior to its submission as a Solution to PJM stakeholders to ensure that those direct impacts are considered in identifying and evaluating potential Solutions. For example, I&M and AEP Transmission communicate and coordinate with customers that are directly connected to a transmission line that may need to be rebuilt during the development of the project Solution for that Need.

I&M and AEP Transmission also coordinate with such stakeholders in scheduling any outages required for the project in order to minimize outage impacts. Thus, I&M and AEP consider input from directly-affected stakeholders not only during the M-3 Process, but also before a solution is presented in that forum.

Q35. Do stakeholders have other opportunities to provide input regarding transmission projects in Indiana?

Yes. I&M and AEP Transmission also go beyond what the M-3 Process requires by annually meeting with customers to discuss transmission needs. This annual meeting with connected customers is an additional opportunity for stakeholder feedback and review of the needs on the system. Customers are also encouraged to identify any additional needs or issues that may be directly affecting them.

Q36. Is there also a process for reviewing transmission projects at FERC?

Yes. In addition to the PJM stakeholder review, there is another opportunity to evaluate the prudence of transmission projects at FERC. Specifically, AEP's annual transmission formula rate filings include protocols that establish an open and transparent process for any interested party to review the rates and challenge items, including the ability to challenge the prudence of actual costs and expenditures. Additionally, other Transmission Owners, of which I&M is charged for certain transmission projects, have similar protocols associated with their formula rates.

Q37. What are non-topology projects?

There are elements of many projects that either do not change the transmission grid's topology, or that are implicit in the description of larger projects, and that are not required to be submitted to PJM for explicit review because such project elements do not affect the transmission grid analysis within the framework of PJM's FERC-approved planning process. These project elements nevertheless are essential to the larger projects that are submitted to and reviewed by PJM.

Non-topology projects are required for important operational functions such as protecting against security threats, minimizing equipment damage, reducing outage durations, and improving safety, as well as many others. Non-topology changing projects can include station security, remote control and monitoring (also known as Supervisory Control and Data Acquisition or "SCADA") or telecommunications modernization projects, among other examples.

As a specific example, AEP has historically used leased analog lines to provide communication paths for system protection and control. As phone companies move to digital technology, the analog signals and communication paths will no longer function going forward.

In order to address this issue, AEP's telecom network is being upgraded through use of fiber communication paths and microprocessor relays. Although these projects do not affect any load flow model used by PJM, they are still necessary for the continued safe, efficient, secure, and reliable operation of the transmission grid.

VI. Forecast of PJM Revenues and Charges

Q38. Please explain the development of the forecast PJM revenues and costs.

The forecasted PJM charges are developed internally by AEP and its affiliated companies that have projected transmission investments over the forecast period.

The forecast methodology is described in detail by Company witnesses Lucas and Heimberger. At a high level, the projected necessary capital investment, combined with the required operations and maintenance expense, is modeled to develop an estimated revenue requirement for I&M's projected transmission plant in service. Through an analysis of historical and forecasted transmission system usage, the forecasted amount to be allocated to I&M through its role as an LSE is determined.

Q39. What is the Company's forecast of PJM costs for the Test Year?

As provided by Company witness Heimberger, PJM NITS[3] charges are forecasted to be approximately $337.7 million (Total Company) for the Test Year. In addition, I&M is forecasted to incur approximately $35.0 million (Total Company) in non-NITS costs in the Test Year.

[3] PJM NITS charges consist of the NITS, PTP revenue credits, and Schedule 1A charges, and Non-NITS charges are comprised of Transmission Enhancement Charges and PJM administration fees as defined in Q22 above.

As discussed below, increases in the Company's PJM costs are being driven primarily by the increases in PJM NITS costs. In particular, PJM NITS costs are growing primarily due to charges in Accounts 4561035 and 5650016, which are billed by PJM to I&M in its role as the LSE for I&M's native load customers.

Q40. What is driving the increase in NITS charges for I&M?

The increase in NITS charges is being driven by investment in transmission infrastructure throughout the AEP Zone. In recent history, transmission investment was focused on system needs arising from retirement of generation due to environmental regulations.

As previously described, the transmission system currently requires substantial investment to address aging infrastructure, cyber and physical security threats, and modernization of protection and control equipment. This requires infrastructure improvements occurring both within I&M's service territory and the remainder of the AEP Zone. The costs associated with these investments are billed to the AEP Zone and charged to I&M through the monthly PJM bill and the AEP Transmission Agreement.

Q41. Are projects within the AEP Zone the only project type contributing to transmission charges from PJM?

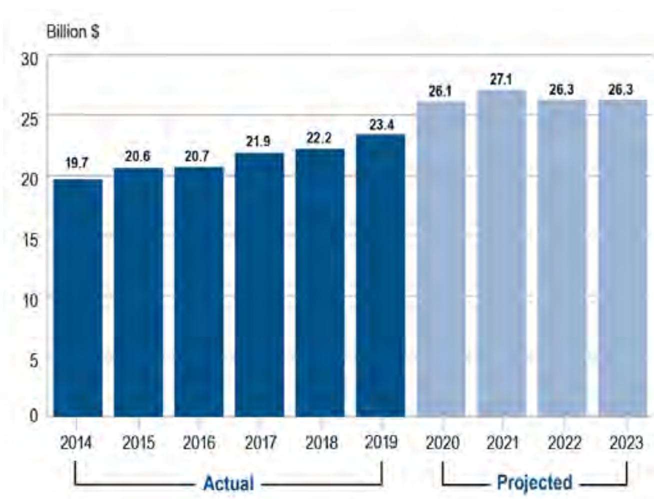
No. Transmission projects that solely benefit the AEP Zone are fully allocated to all LSEs in the AEP Zone, including I&M, and these costs are included in NITS charges. As previously discussed, the cost of baseline transmission projects that benefit more than one PJM zone are shared over the larger PJM footprint as determined by PJM. As a result, I&M may incur costs from multi-zonal projects, which are included in non-NITS charges.

Q42. Is the need for transmission infrastructure investment unique to I&M or PJM?

No. Industry wide, utilities are investing in the transmission system to meet the above-described needs. Nationally, transmission investment has increased steadily over the past several years.

For instance, as shown below, a publically available summary of historical and planned transmission investment in the United States, made available by the Edison Electric Institute (EEI) on their website, shows increases in investment from 2014 through 2019, and larger projected amounts in 2020-2023.[4]

Historical and Projected Transmission Investment (Nominal Dollars)



Investment of investor-owned electric companies and stand-alone transmission companies. Actual Investment figures were obtained from the EEI Property & Plant Capital Investment Survey supplemented with FERC Form 1 data. Projected investment figures were obtained from the EEI Transmission Capital Investment Forecast Survey supplemented with data obtained from company 10-k reports and investor presentations.

Source: Edison Electric Institute

Business Analytics Group. Updated November 2020.

Similar to this national trend, I&M expects robust levels of investment will continue beyond the Test Year, as further discussed in my testimony below.

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4 https://www.eei.org/resourcesandmedia/Documents/Historical and Projected Transmission Investment.pdf

VII. Costs Recovered Through the OSS/PJM Rider

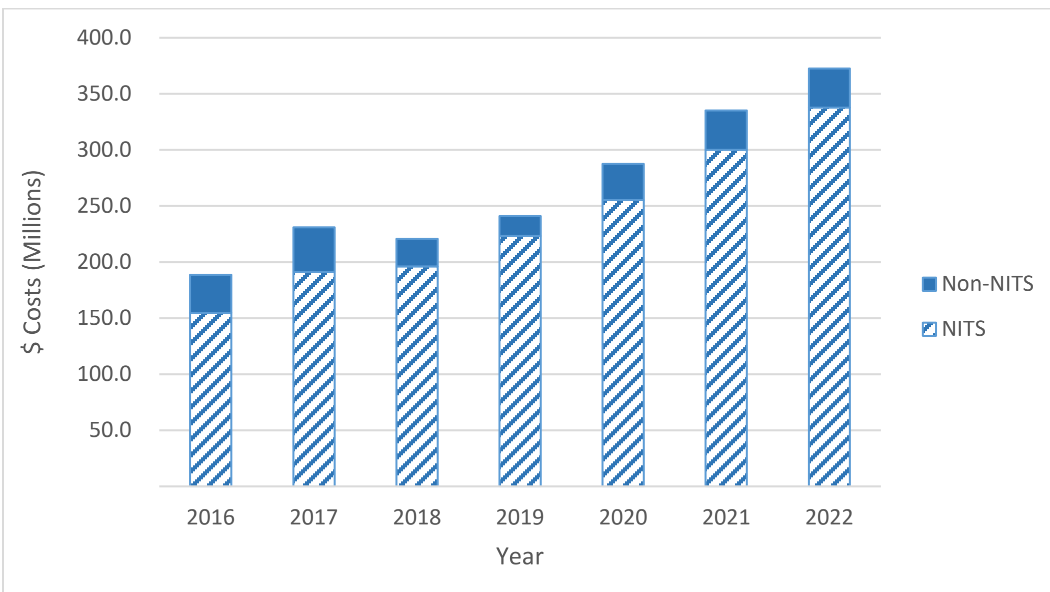
Q43. How are NITS costs billed to I&M?

NITS costs are billed to I&M in accordance with FERC approved tariffs, the PJM OATT and AEP's Transmission Agreement. I&M recovers these costs through the OSS/PJM Rider. Company witness Seger-Lawson addresses the operation of the OSS/PJM Rider in her testimony.

Q44. Are the PJM costs charged to I&M collectively significant?

Yes. Both the Non-NITS and NITS costs are significant and the NITS costs in particular are expected to increase.

Figure NCK-1. I&M's PJM costs ($M)



Q45. Are these costs charged to I&M potentially variable or volatile?

Yes. The growth in these costs are driven by the increases in transmission capital investment in the AEP Zone necessary to ensure an adequate transmission system is available to provide service.

These costs flow to I&M through the PJM tariffs and vary from year to year. The transmission capital additions for I&M include both PJM and Owner Projects that are needed to maintain a reliable transmission grid. In some years, greater or fewer transmission projects may be completed by I&M. The same is true for other transmission owners in the AEP Zone and this contributes to the volatility of the NITS costs.

NITS costs are variable and volatile and subject to significant changes due to the transmission system requiring substantial investment to address (a) the condition of the assets, which includes many assets that exceed their expected or designed life; (b) the performance of the infrastructure; (c) cyber and physical security threats; (d) modernization of protection and control equipment; (e) obsoleteness of major equipment necessary for safely, securely, efficiently, and reliably operating the grid; and (f) changes in industry regulations.

Additionally, these costs, during any given period, are subject to potentially significant changes due to market and economic conditions, public policy, NERC, FERC, environmental, and state regulatory requirements and other factors that can be unpredictable.

For instance, in 2012, PJM initiated $3 billion in transmission investment to mitigate the impact of 7,500 MW of generation retirement in the Ohio Valley due to implementation of federal Mercury and Air Toxics Standards. The scope and scale of transmission investment can be volatile due to items such as this federal action, which cannot be forecasted with certainty.

Figure NCK-2 illustrates that the collective impact of these drivers is to cause varying levels of annual investment (sometimes increasing, and sometimes decreasing) over time in each AEP operating and transmission company's jurisdiction, including I&M's.

Figure NCK-2. PJM AEP Zonal Gross Investment ($M)

	2019	2020	2021	2022
Gross plant	$15,835	$17,583	$19,822	$21,573
Increase ($)	$2,058	$1,748	$2,239	$1,752
Increase (%)	14.9%	11.0%	12.7%	8.8%

* AEP affiliates only

Q46. Can NITS costs include PJM baseline projects?

Yes. As I mentioned earlier, PJM baseline projects are included in the NITS rate if they are 100 percent allocated to the AEP Zone. This further contributes to the volatility of NITS costs.

Q47. Are NITS costs largely outside of I&M's control?

Yes, they are. The drivers of the cost increases are due to the transmission system requiring substantial investment to address the considerations I previously discussed.

As I explained earlier, each of the drivers of cost increases is largely or entirely outside the control of I&M and other transmission owners. However, each transmission owner in the AEP Zone has an obligation to ensure capital investments are prudent and necessary to maintain the reliability of the transmission grid.

The FERC-approved AEP Transmission Agreement, to which I&M is a member, requires "[e]ach member [to] maintain its respective portion of the Bulk Transmission System, together with all associated facilities and appurtenances, in a suitable condition of repair at all times in order that said system will operate in a reliable and satisfactory manner."

Consistent with that obligation, the Company will continue to evaluate, prioritize, and select the Supplemental Projects that are necessary to provide a reliable transmission grid within its service territory. Although I&M has some control over its own specific asset replacement if that replacement is made before an asset's failure, many of the underlying drivers of asset performance such as equipment age, equipment abnormalities, and environmental conditions are also outside of the Company's control.

Q48. Are NITS charges reasonable and necessary?

Yes. NITS costs are a necessary cost to maintain the reliability of the transmission grid and ensure equal access by all users of the transmission system. To ensure that Owner Project needs are clearly understood by stakeholders, they are vetted with stakeholders through PJM hosted stakeholder meetings.

This transparent planning and vetting process ensures that Owner Projects incorporated into the RTEP are appropriate, efficient, and cost-effective solutions to planning criteria and system needs that benefit customers.

Q49. Does this conclude your pre-filed verified direct testimony?

Yes.

VERIFICATION

I, Nicolas C. Koehler, Director of East Transmission Planning of American Electric Power Service Corporation, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Date: 6/21/21

Nicolas C. Koehler

Nicolas C. Koehler

AEP Transmission Planning Criteria and Guidelines for End-Of-Life and Other Asset Management Needs

December 2020

Document Control

Document Review and Approval

Action	Name(s)	Title
Prepared by:	Jomar M. Perez	Manager, Asset Performance and Renewal
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Approved by:	Kamran Ali	Managing Director, Transmission Planning

Review Cycle

Quarterly	Semi-annual	Annual	As Needed
			X

Revision History

Version	Revision Date	Changes	Comments
1.0	01/04/2017	N/A	1st Release
2.0	1/18/2018	Format Update	2nd Release
3.0	11/09/2018	Content Additions	3rd Release
4.0	12/14/2020	End-Of-Life Criteria	4th Release

Table of Contents

1.0 Introduction

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

AEP's interconnected transmission system was established in 1911 and is comprised of a very large and diverse combination of line, station, and telecommunication assets, each with its own unique installation date, design specifications, and operating history. As the transmission owner, it is AEP's obligation and responsibility to manage and maintain this diverse set of assets to provide for a safe, adequate, reliable, flexible, efficient, cost-effective and resilient transmission system that meets the needs of all customers while complying with Federal, State, RTO and industry standards. This requires, among other considerations, that AEP determine when the useful life of these transmission assets is coming to an end and when the capability of those assets no longer meets current needs, so that appropriate improvements can be deployed. AEP refers to these issues as transmission owner identified needs that address condition, performance and risk. AEP identifies these needs through the transmission planning criteria and guidelines outlined in this document. Specifically, this document constitutes the AEP transmission planning criteria and guidelines for End-Of-Life and other asset management needs as required in the FERC-approved Attachment M-3 to the PJM Tariff. AEP does not address any End-Of-Life or other asset management needs through the baseline planning criteria AEP files with its FERC Form 715.

AEP's transmission owner identified needs must be addressed to achieve AEP's obligations and responsibilities. Meeting these obligations requires that AEP ensures the transmission system can deliver electricity to all points of consumption in the quantity and quality expected by customers, while reducing the magnitude and duration of disruptive events. Given these considerations, criteria and guidelines are necessary to identify and quantify needs associated with transmission facilities comprising AEP's system. AEP identifies the needs and the solutions necessary to address those needs on a continuous basis using an in-depth understanding of the condition of its assets, and their associated operational performance and risk, while exercising engineering judgment coupled with Good Utility Practices [1].

Whereas the End-Of-Life needs, as defined in the FERC-approved Attachment M-3 to the PJM Tariff, are limited to transmission facilities rated above 100 kV, these criteria and guidelines apply to all transmission voltages that comprise the AEP transmission system, including those defined as End-Of-Life needs in the FERC-approved Attachment M-3 to the PJM Tariff. In addition, projections of candidate End-Of-Life needs that result from the process outlined in these AEP criteria and guidelines will be provided to PJM in accordance with the provisions in the FERC-approved Attachment M-3 to the PJM Tariff. Current End-Of-Life and other asset management needs will be vetted with stakeholders in accordance with the provisions in the FERC-approved Attachment M-3 to the PJM Tariff.

Addressing these owner identified transmission system asset management needs, as they pertain to condition, performance and risk, will result in the following benefits to customers:

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

2.0 Process Overview

AEP's transmission owner needs identification criteria and guidelines are used for projects that address equipment material conditions, performance, and risk. AEP uses the three-step process shown in Figure 1 and discussed in detail in this document to determine the best solutions to address the transmission owner identified needs and meet AEP's obligations and responsibilities. This process is completed on an annual basis. In developing the most efficient and cost-effective solutions, AEP's long-term strategy is to pursue holistic transmission solutions in order to reduce the overall AEP transmission system needs.

Figure 1 – AEP Process for Identifying and Addressing Transmission Asset Condition, Performance and Risk Needs

3.0 Step 1: Needs Identification

Needs Identification is the first step in the process of determining system and asset improvements that help meet AEP's obligations and responsibilities. AEP gathers information from many internal and external sources to identify assets with needs. A collective evaluation of these inputs is conducted and considered, and thus, individual thresholds do not apply. In addition, factors can change over time. A sampling of the inputs and data sources is listed below in Table 1.

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

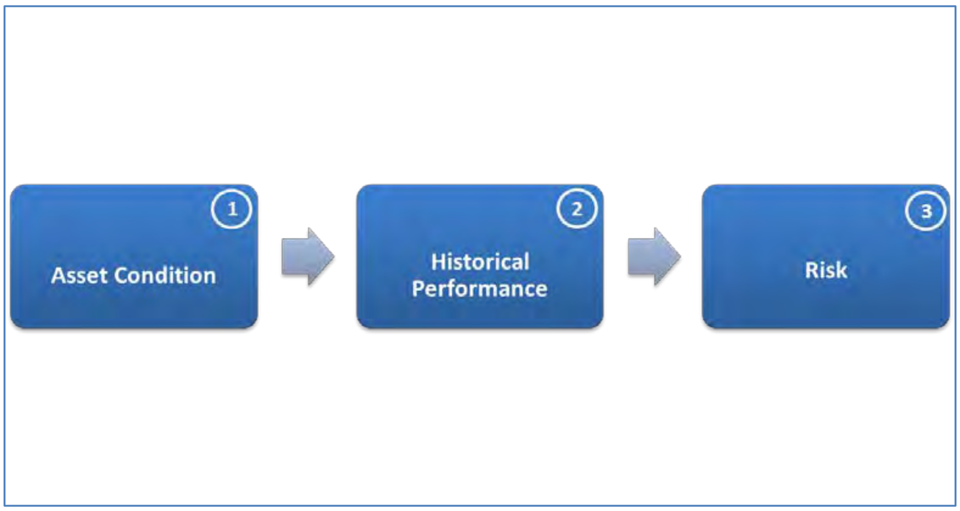
Internal, External, or Both	Inputs	Examples
Internal	Reports on asset conditions	Transmission line and station equipment deterioration identified during routine inspections (pole rot, steel rusting or cracking)
	Capabilities and abnormal conditions	Relay misoperations; Voltage unbalance
	Legacy system configurations	Ground switch protection schemes for transformers;; Transmission Line Taps without switches (hard taps); Equipment without vendor support
	Outage duration and frequency	Outages resulting from equipment failures, misoperations, or inadequate lightning protection
	Operations and maintenance costs	Costs to operate and maintain equipment
External	Regional Transmission Operator (RTO) or Independent System Operator (ISO) issued notices	Post Contingency Local Load Relief Warnings (PCLLRWs) issued by the RTO that can lead to customer load impacts
	Stakeholder input	Input received through stakeholder meetings, such as PJM's Sub Regional RTEP Committee (SRRTEP) meetings or through the AEP hosted Annual Stakeholder Summits
	Customer feedback	Voltage sag issues to customer delivery points due to poor sectionalizing; frequent outages to facilities directly affecting customers
	State and Federal policies, standards, or guidelines	NERC standards for dynamic disturbance recording
Both	Environmental and community impacts	Equipment oil/gas leaks; facilities currently installed at or near national parks, national forests, or metropolitan areas
	Standards and Guidelines	Minimum Design Standards, Radial Lines, Three Terminal Lines, Overlapping Zones of Protection
	Safety risks and concerns	Station and Line equipment that does not meet ground clearances; Facilities identified as being in flood zones; New Occupational Safety and Hazards Administration (OSHA) regulations

These inputs are reviewed and analyzed to identify the transmission assets that are exhibiting unacceptable condition, performance and risk, and thus, must be addressed through the FERC-approved Attachment M-3 planning process.

3.1 Methodology and Process Overview

The AEP transmission system is composed of a very large number of assets that provide specific functionality and must work in conjunction with each other in the operation of the grid. These assets have been deployed over a long period of time using engineering principles, design standards, safety codes, and Good Utility Practices that were applicable at the time of installation and have been exposed to varying operating conditions over their life. The Needs Identification methodology is shown below in Figure 2. AEP addresses the identified needs considering factors including severity of the asset condition and overall system impacts. These are subsequently evaluated versus constraints such as outage availability, siting requirements, availability of labor and material, constructability, and available capital funding in determining the timing and scope of mitigation.

Figure 2 – Needs Identification Methodology



It is AEP's strategy and goal to develop and provide the more efficient, cost-effective, safe, reliable, resilient, and holistic long-term solutions for the identified needs.

3.2 Asset Condition (Factor 1)

The Asset Condition assessment gathers a standard set of physical characteristics associated with an asset or a group of assets. The set of data points recorded is determined based on the asset type and class. Information assembled during the Asset Condition assessment is used to show the historical deterioration, current condition, and future expectation of the asset or group of assets on the AEP system.

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

Beyond physical condition, AEP's ability to restore the asset in case of a failure is also considered. This is referred to as the future probability of failure adder. Typically, assets that are no longer supported by manufacturers or lack available spare parts are assigned a higher probability of failure adder.

To perform condition assessments, AEP classifies its Transmission assets in two main categories: Transmission Lines and Substations.

3.2.1 Transmission Line Considerations

Design Portion

A. Age (Original Installation Date)
B. Structure Type (Wood, Steel, Lattice)
C. Conductor Type (Size, Material & Stranding)
D. Static Wire Type (Size & Material)
E. Foundation Type (Grillage, Direct Embed, Caisson, Guyed V, Drilled Pier etc.)
F. Insulator Type (Material)
G. Shielding and Grounding Design Criteria (Ground Rod, Counterpoise, "Butt Wrap" etc.)
H. Electrical Configuration
    a. Three Terminal Lines
    b. Radial Facilities
I. NESC Standards Compliance
    a. Structural Strength (NESC 250B, 250C & 250D Compliance)
    b. Clearances (TLES-047 Compliance)

J. Easement Adequacy (Width, Encroachments, Type; etc.)

Physical Condition

A. Open Conditions (existing and unaddressed physical conditions associated with a Transmission Line component)
B. Closed Conditions (previously addressed physical conditions associated with a Transmission Line component)
C. Emergency Fixes (History of emergency fixes)
D. Accessibility (Identified areas of difficult access)

3.2.2 Substation Considerations

A. Transformers
  a. Manufacturer
  b. Manufacturing Date
  c. In Service Date
  d. Load Tap Changer Type & Operation History (if applicable)
  e. Dissolved Gas Analysis
  f. Bushing Power Factor
  g. Through Fault Events (Duval Triangles)
  h. Moisture Content (Oil)
  i. Oil Interfacial Tension
  j. Dielectric Strength
  k. Maintenance History
  l. Malfunction Records
B. Circuit Breakers
  a. Manufacturer & Type
  b. Manufacturing Date
  c. In Service Date
  d. Interrupting Medium
  e. Fault Operations
  f. Switched Operations

g. Spare Part Availability
h. Maintenance History
i. Malfunction Records
j. Breaker Type Population

C. Secondary/Auxiliary Substation Equipment*

a. Station Batteries
b. Control House
c. Station Security
d. Station Structures
e. Capacitor Banks
f. Bus, Cable and Insulators
g. Disconnect Switches
h. Station Configuration
i. Station Service
j. Relay Types
k. RTU Types
l. Voltage Sensing Devices

**AEP substation inspections include assessments of secondary/ancillary equipment. If needed, upgrades to these components are typically included in the scope of projects addressing major equipment and may not necessarily drive stand-alone projects.*

3.3 Historical Performance (Factor 2)

AEP's Historical Performance assessment quantifies how an asset or a group of assets has historically impacted the Transmission system's reliability and Transmission connected customers, helps identify the primary contributing factors to a facility's performance, and baselines the outage probability used in our Future Risk analysis. The metrics used as part of this historical performance assessment include:

A. Forced Outage Rates
B. Manual Outage Rates
C. Outage Durations (Forced Outage Duration in Hours)
D. System Average Interruption Indices (T-SAIDI, T-SAIFI, T-SAIFI-S, T-MAIFI)

E. Customer Minutes of Interruption (CMI)

F. Customer Average Interruption Indices (IEEE SAIDI, CAIDI & SAIFI)

G. Number of Customers Interrupted (CI)

AEP utilizes this standard set of metrics as a means to quantify the historical performance of an asset. These historical performance metrics allow AEP to further investigate assets that have historically impacted customers the most.

Due to the vast size of the AEP operating territory covering 11 states, AEP segments its needs into seven distinct operating company regions and six voltage classes. This segmentation ensures that variations in geography with respect to vegetation, weather patterns, and terrain can be accounted for within the process of identifying needs for each operating company area. In addition to customers of AEP operating companies, consideration for retail customers that are served at non-AEP wholesale customer service points is also included. In order to account for customers served behind wholesale meter points, AEP gathers information from the parent wholesale provider or in its absence, applies a surrogate customers per MW ratio to estimate the number of customers served by a wholesale power provider's delivery point. This customer count is used to calculate the individual metrics above.

AEP's standard approach is to annually review the historical performance of its assets based on a rolling three-year average, but in some cases AEP may extend the review period beyond three years. AEP classifies all transmission asset outage causes into the following five categories to conduct this review: Transmission Line Component Failure, Substation Component Failure, Vegetation (AEP), Vegetation (Non-AEP), and External Factors. Each transmission asset and its associated performance is quantified and compared against corresponding system totals to determine its percentage contribution to aggregated system performance. An evaluation of outage rates is also performed for Transmission line assets. The observed performance of the assets in any of these categories can point to a need that may need to be addressed.

3.4 Future Risk (Factor 3)

AEP reviews the associated risk exposure (future risk) inherent with each identified asset to determine an asset's level of risk. This risk exposure is quantified assuming the probability of an outage scenario and is based on the reported condition of the asset and the severity of that condition and what the impact could be to customers or to the operation of AEP's Transmission system. Some of the key items to assess these impacts included in the risk criteria are:

A. Number of Customers Served
B. Load Served
C. Operational Risks
    a. Post Contingency Load Loss Relief Warnings (PCLLRW's)
    b. History of Load Shed Events
    c. Stations in Black Start Paths

In addition to the future risk calculation performed through this process, AEP is systematically reviewing its system to identify and remediate equipment and practices that have resulted in operational, restoration, environmental, or safety issues in the past that cannot be directly quantified, but that remain as acknowledged risks in the AEP Transmission system. These include:

A. Wood pole construction
B. Pilot wire protection schemes
C. Oil circuit breakers
D. Air Blast circuit breakers
E. Pipe type oil filled cables
F. Electromechanical relays
G. Legacy system configurations
    a. Missing or inadequate line switches (e.g., hard-taps)
    b. Missing or inadequate transformer/bus protection
    c. Three-terminal lines
    d. Overlapping zones of protection
H. Non-Standard Voltage Classes
I. Poor Lightning & Grounding Performance
J. Radial Facilities
K. Public vulnerability

These items as described above are reviewed on a case by case basis and considered when holistic system solutions are being developed.

4.0 Step 2: Solution Development

The development of solutions for the identified needs considers a holistic view of all of the needs in which several solution options are developed and scoped. AEP applies the appropriate industry standards, engineering judgment, and Good Utility Practices to develop these solution options. AEP solicits customer and external stakeholder input on potential solutions through the Annual Stakeholder Summits hosted by AEP and also through the PJM Project Submission process. This ensures that input from external stakeholders on identified needs can be received and considered as part of the solution development process.

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

5.0 Step 3: Solution Scheduling

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

6.0 Conclusion

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

7.0 References

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

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

SRRTEP Committee: Western
AEP Supplemental Projects

May22, 2020

Needs

Stakeholders must submit any comments within 10 days of this meeting in order to provide time necessary to consider these comments prior to the next phase of the M-3 process

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
Clifford, VA Area

Need Number: AEP-2020-AP031

Process Stage: Needs Meeting 05/22/2020

Supplemental Project Driver: Equipment Condition/Performance/Risk

Specific Assumption Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Clifford Station:

- 138/69/46 kV Transformer #1
  - 1963 Vintage Transformer
  - Elevated levels of Acetylene have been documented indicating increased decomposition of the paper insulating materials. The presence of acetylene indicates electrical discharge faults of high energy have occurred within the main tank causing electrical breakdown of the unit.
  - Due to deteriorated gaskets at the radiator headers, this unit is leaking oil.

- 138/46 kV Transformer #3
  - 1950 Vintage Transformer
  - An upward trend in insulation power factor indicates an increase in particles within the oil and the dielectric strength of the insulation system (oil and paper) are in poor condition, impairing the unit's ability to withstand electrical faults.

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
Roanoke, VA Area

Need Number: AEP-2020-AP033

Process Stage: Needs Meeting 05/22/2020

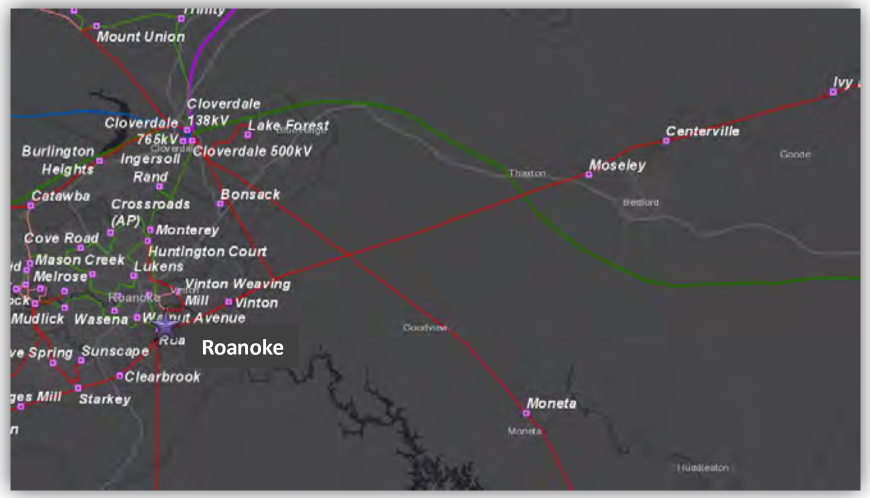
Supplemental Project Driver: Equipment Condition/Performance/Risk

Specific Assumption Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

<u>**Roanoke Station:**</u>

- 138/69/12 kV Transformer #5
  - 1981 Vintage Transformer
  - Elevated levels of carbon monoxide, carbon dioxide and hydrogen indicate excessive levels of decomposition of the paper insulating materials.
- 138 kV Circuit Switchers BB and CC
  - Both are 1990's vintage
  - The Mark V family of circuit switchers have no gas monitor and currently in-service units on the AEP system have experienced 110 malfunctions from May 2000 to August 2019. Failed operational components including high contact resistance, gas loss, and interrupter failure represent half of these malfunctions. Two malfunctions of note were catastrophic equipment failures involving failures to trip.
- 138 kV Capacitor Bank CC and 34.5 kV Capacitor Bank AA
  - Leaking around bushings on both banks
  - 6 cans are failed on bank CC
- 69 kV Circuit Breakers U and V
  - 1970's Vintage Circuit Breakers
  - These breakers are oil filled without oil containment; oil filled breakers have much more maintenance required due to oil handling that their modern, SF6 counterparts do not require
  - Circuit breaker U has each exceeded the manufacturer's designed number of full fault operations (12)

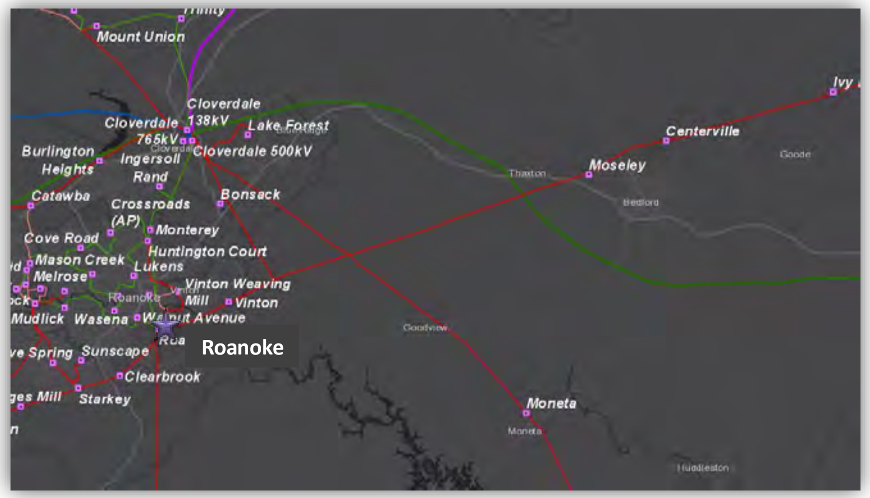


AEP Transmission Zone M-3 Process
Roanoke, VA Area

… Continued from previous slide

<u>Roanoke Station:</u>

- Relaying
  - Roanoke Substation currently deploys 103 relays, implemented to ensure the adequate protection and operation of the substation. Currently, 79 of the 103 relays (77% of all station relays) are in need of replacement.
    - There are 50 electromechanical and 8 static which have significant limitations with regards to fault data collection and retention. These relays lack vendor support and have little to no access to spare parts.
    - There are 3 DPU microprocessor type relays on the three distribution breakers. The DPU relays pose a potential safety risk to persons performing breaker operation because the DPUs are mounted directly on the circuit breaker without a delay for opening and closing the breaker.
    - There are 18 microprocessor relays that utilize legacy firmware.
- Pilot Wire
  - Pilot wire relaying exists on the Campbell Ave. 69 kV, Roanoke 69 kV and Campbell Ave 34.5 kV circuits
  - TFS lacks adequate crew training and experience on handling pilot wire; only a small number of crews are available with necessary experience to perform corrective maintenance
  - High corrective maintenance costs are incurred (P&C, line, forestry, build roads, etc.)
- High-Side Transformer Protection
  - No automatic high-side protection exists on transformer #5 or #2
  - Both are directly connected to 138 kV bus #2, which would operate five 138 kV circuit breakers for a transformer fault



AEP Transmission Zone M-3 Process
Centerville, VA Area

Need Number: AEP-2020-AP034

Process Stage: Needs Meeting 05/22/2020

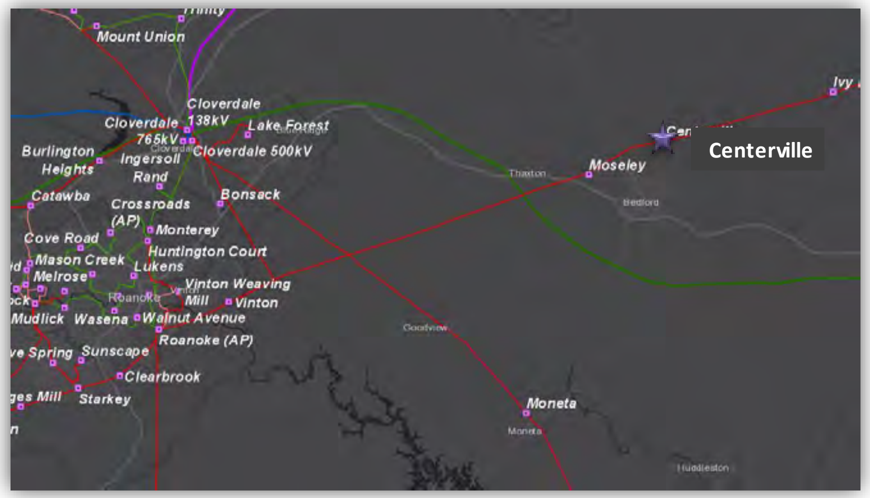
Supplemental Project Driver: Equipment Condition/Performance/Risk

Specific Assumption Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

<u>Centerville Station:</u>

- 69 kV Circuit Breaker B
  - 1970's Vintage Circuit Breaker
  - Oil filled breaker without oil containment. Oil filled breakers have much more maintenance required due to oil handling that their modern, SF6 counterparts do not require.
  - This circuit breaker, has exceeded the manufacturer's designed number of full fault operations (108)
- High-side Transformer MOAB Ground Switch (138/69/12 kV T1) is used for high-side transformer protection
- There is a three terminal line configuration through the Town of Bedford 69 kV loop.
- The flip-flop configuration connection to the double circuit 138 kV line that runs adjacent to the station is a source of operational and protection challenges when faults occur.
- Relaying
  - Centerville Substation currently deploys 26 relays, implemented to ensure the adequate protection and operation of the substation. Currently, all 26 of the relays (100% of all station relays) are in need of replacement. There are 21 of the electromechanical which have significant limitations with regards to fault data collection and retention. These relays lack vendor support and have little to no access to spare parts. Also, the remaining 5 relays that are microprocessor based from utilize legacy firmware.



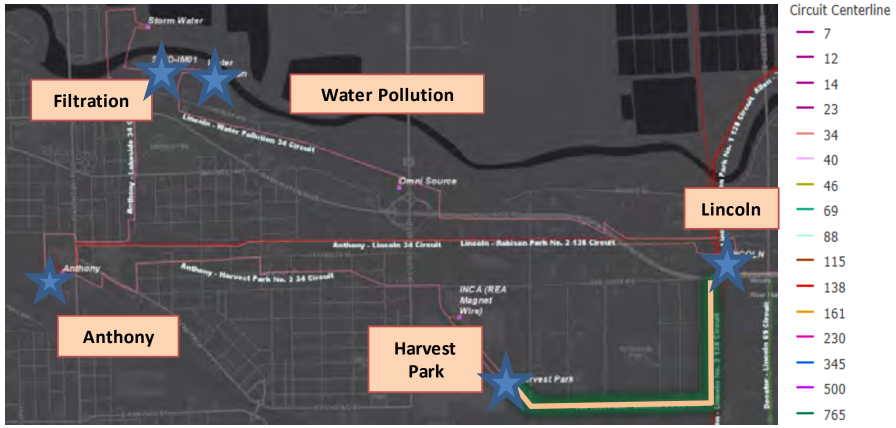
AEP Transmission Zone: Supplemental Ft Wayne Area, Indiana

Need Number: AEP-2020-IM014
Process Stage: Needs Meeting 5/22/2020
Supplemental Project Driver: Equipment Material/Condition/Performance/Risk
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Problem Statement:

Anthony 138/34.5/12kV Station
- 34.5/12kV Transformer #4 is a 1954 unit
    - Increased CO and CO2 gassing with decreasing interfacial tension and oil deterioration
- 138/34.5kV Transformer #5 currently has a high side MOAB switch protection scheme

Filtration 34.5/12kV Switch Station
- I&M has an obligation to remove this station upon completion of the City of Fort Wayne tunneling project

Lincoln – Harvest Park 34.5kV line (~1.5 miles)
- 1.5 miles of 1920-1930's steel structures with 300,000 CM copper conductor and 3#8 copperweld shield-wire
- Field inspection found the 10 1920's towers had significant rusting
- Older copper wires like the 300,000 CM copper conductor and the3#8 copperweld shield wire have a higher rate of failure and become brittle and difficult to splice with age.
- 3 structures had flashover damage and 4 structures had severe rust and corrosion on the insulation.



AEP Transmission Zone: Supplemental
Fort Wayne, Indiana

Need Number: AEP-2020-IM014
Process Stage: Needs Meeting 5/22/2020
Supplemental Project Driver: Equipment Material/Condition/Performance/Risk
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Problem Statement:

Lincoln – Anthony 34.5kV line (~1.1 miles)

- 1.1 miles of 1971 wood pole line with 300,000 CM copper conductor
- This line segment fails to meet NESC loading criteria.
- This line segment fails to meet AEP loading and leakage distance requirements
- This line segment fails to meet ASCE strength requirements.
- 4 poles have crossarm decay, 2 poles have splitting or decay, 1 broken static lead and 1 knee brace with decay across 21 poles on the line.

Lincoln – Anthony 138/34.5kV line (~3.07 miles)

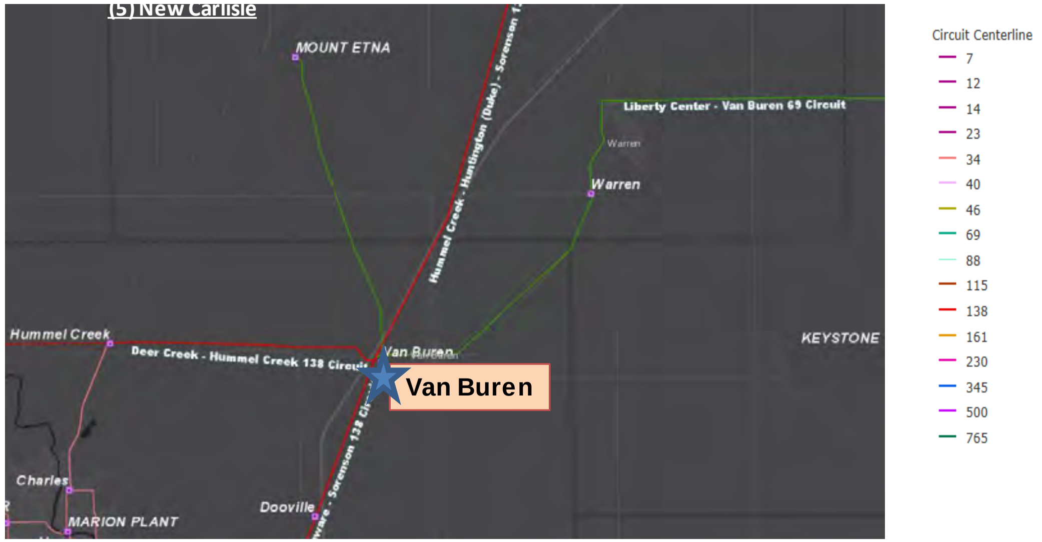
- 3.07 miles of 1971 wood pole line
- 20 unique structures with open conditions (31% of the line).
    - These conditions include insect damaged poles, twisted crossarms, broken strands and missing grounds.
- This line segment fails to meet AEP strength and leakage distance requirements.
- The line segment fails to meet NESC loading criteria
- The line segment fails to meet ASCE strength requirements
- 4 poles have flashover indication, 1 broken static lead and 1 pole vertically splitting

AEP Transmission Zone: Supplemental
Van Buren, Indiana

Need Number: AEP-2020-IM018
Meeting Date: Needs Meeting 05/22/2020
Supplemental Project Driver: Equipment Material/Condition/Performance/Risk/Operational
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)
Problem Statement:

Van Buren 138/69/12kv station

- 138/69/12 kV Transformer #1
  - 1967 vintage
  - Elevated moisture levels
  - Increased cost of maintenance due to leaking
  - Increased levels of decomposition of the paper insulating materials, leading to increased risk of failure
- Breaker B 69kV
  - 1964 vintage oil filled, CF-type breaker.
  - This type is oil filled without oil containment. Oil filled breakers have much more maintenance required due to oil handling that their modern, vacuum counterparts do not require.
  - Finding spare parts for these units is not possible due to these models no longer being vendor supported
- Van Buren is part of a three-terminal line configuration with the Delaware – Sorenson 138kV circuit.



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
Canton, Ohio

Need Number: AEP-2020-OH019

Process Stage: Need Meeting 05/22/2020

Supplemental Project Driver:

Customer Service, Equipment Material Condition, Performance and Risk; Operational Flexibility & Efficiency

Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slides 7, 8)

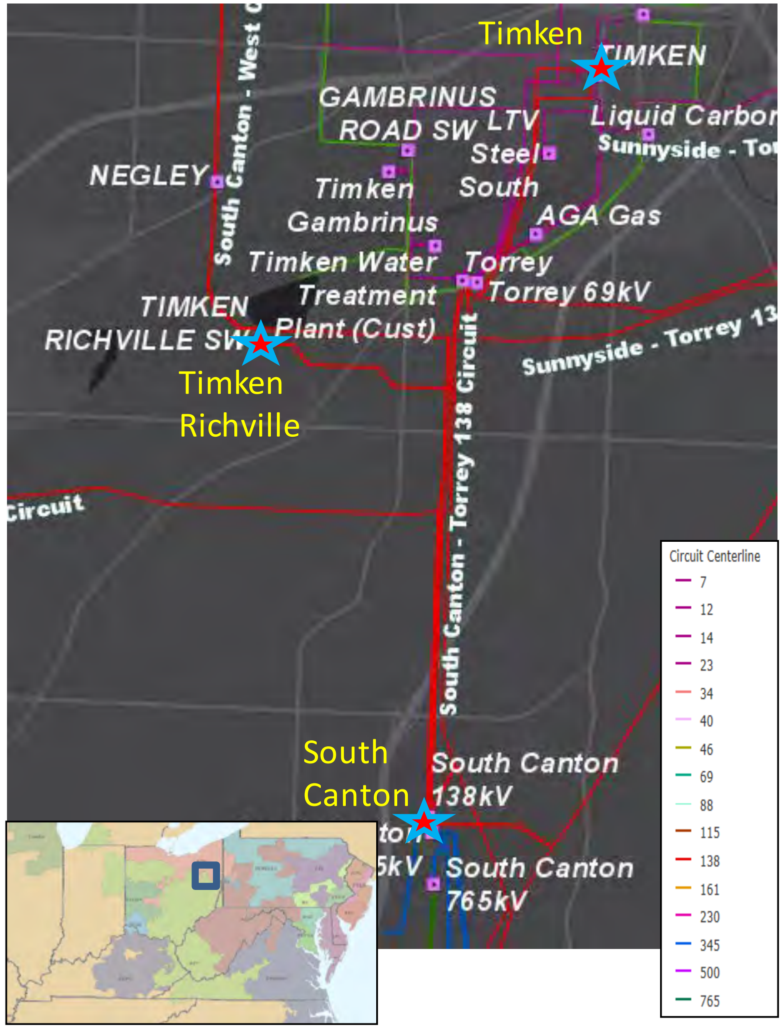
Problem Statement:

Customer Service:

- Timken Richville 138kV Station
    - Peak customer load is 150 MW; steel mill with an arc furnace.
    - Outage history: the customer has experienced 2 prolonged outages over the past 5 years. Any interruption to service is disruptive and costly for this facility.
    - The customer's sensitive equipment includes a continuous caster, electric arc furnace, and refining furnaces. If there is a loss of power it could lead to the customer having to dump the molten steel and risks the steel solidifying in the equipment. These events would be very detrimental to the company's long-term business operations.

Operational Flexibility & Efficiency:

- Timken Richville 138kV Station
    - The station contains 2- 138kV lines and 2- 138kV customer feeds with only a single 138kV bus-tie breaker. A fault on either of the 138kV lines or bus will take out up to 75 MW of load for a single event (1/2 of peak load).
    - A fault on either 138kV circuit requires tripping one of the customer's 138kV breakers to clear the fault. If the customer's equipment were to fail to clear a line fault, a single 138kV circuit fault would expand to take out both 138kV circuits connected to Timken Richville, dropping the customer entirely and requiring additional remote-end clearing (at South Canton or Timken station).



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

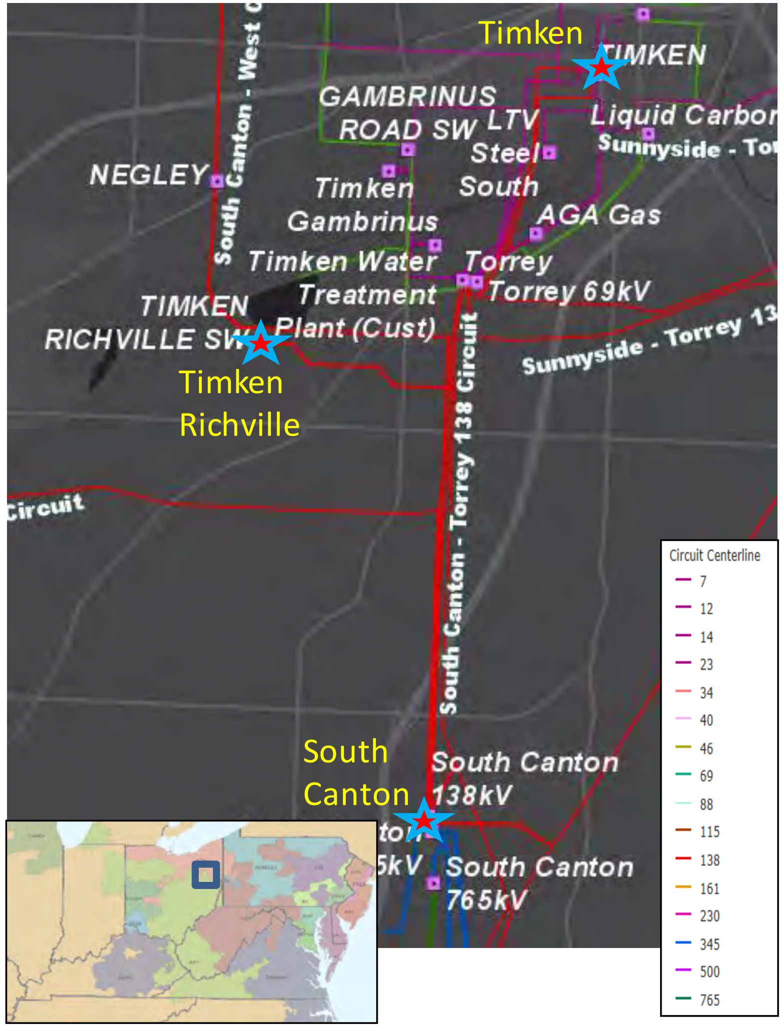
AEP Transmission Zone M-3 Process
Canton, Ohio

Need Number: AEP-2020-OH019

Process Stage: Need Meeting 05/22/2020

Equipment Material Condition, Performance and Risk:

- Timken Richville 138kV Station
  - The station was constructed in 1985 and 32 of the 34 protective relays in the station are electromechanical (with 2 static relays). Electromechanical relays lack vendor support, don't have SCADA, and lack fault data collection.
  - The line protection to Timken and to South Canton consists of an outdated pilot wire scheme that is increasingly prone to failure.
  - The RTU is a legacy model that is no longer supported by the manufacturer.
  - AC station service comes from the customer's substation, which is a reliability concern.
  - The control house ceiling is made of an asbestos-cement product (transite).
  - There is no fence separating AEP's substation from the customer's substation, which is a physical security risk.
  - The metering PT's and CT's show signs of heavy rusting.



AEP Transmission Zone M-3 Process
Wood County, Ohio

Need Number: AEP-2020-OH030

Process Stage: Need Meeting 05/22/2020

Supplemental Project Driver:

Customer Service and Operational Flexibility

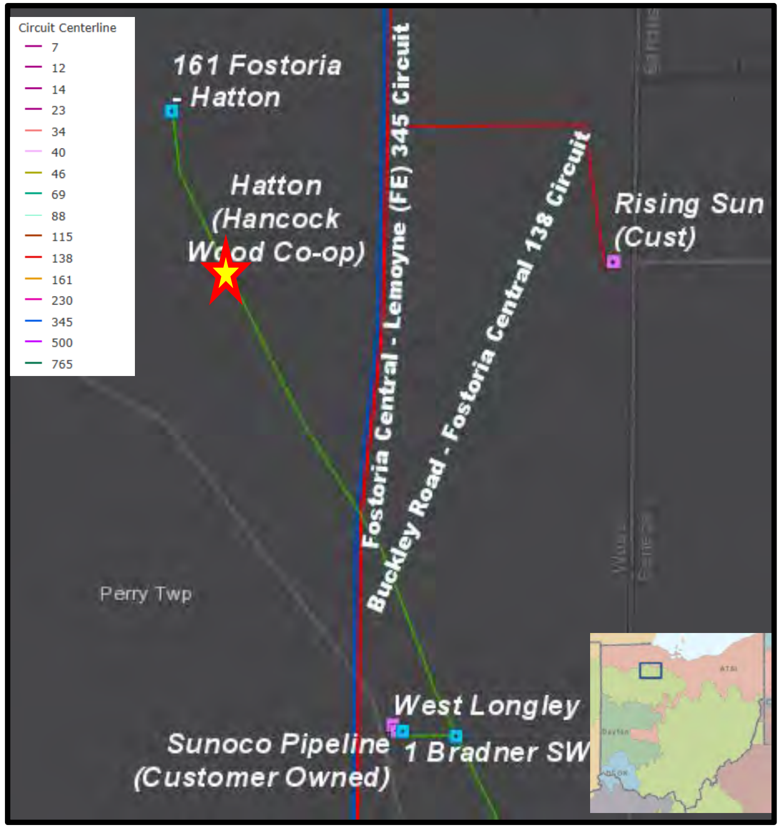
Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions slide 7)

Problem Statement:

- Hancock-Wood Co-op has requested a new service to replace their existing Hatton Delivery Point. Hatton delivery point is currently served via a hard tap from the Pemberville (FE) – West End Fostoria (AEP) 69kV circuit. The new customer station is being built to adjacent to their existing substation. The hard tap limits operational capabilities for this circuit. It is difficult to coordinate maintenance efforts because any work on the section from Longley Switch to Pemberville (FE) involves outage to the Hatton Delivery Point.
- Load is approximately 2.26 MVA
- CMI: There were no unplanned outages, but there were six scheduled and one monetary outages that affected the customer, in the last 5 years.

Model: 2024 RTEP



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
Jackson, Ohio

Need Number: AEP-2020-OH032

Process Stage: Need Meeting 5/22/2020

Project Driver:

Equipment/Material/Condition/Performance/Risk

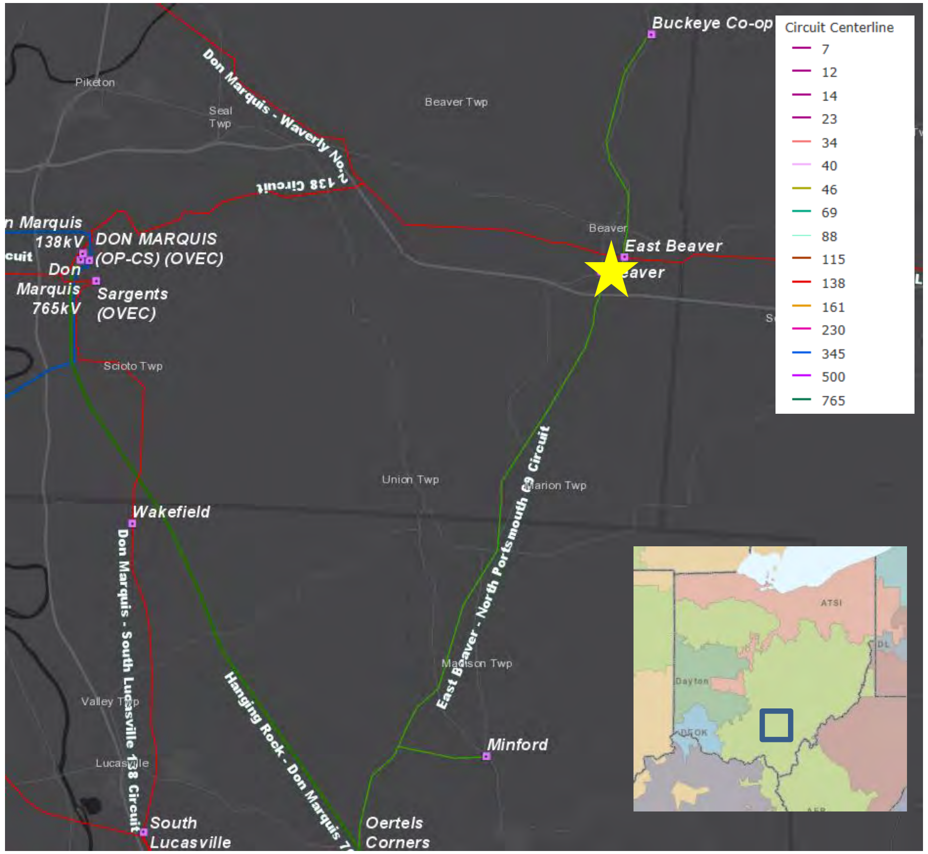
Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs

Problem Statement:

East Beaver 138/69 kV Transformer #1:

- The 138/69 kV 56/72 MVA (vintage 1962) at East Beaver has failed. There is no spare on site to utilize as a replacement.



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
Columbus, OH

Need Number: AEP-2020-OH033

Process Stage: Need Meeting 5/22/2020

Project Driver:
Equipment Material/Condition/Performance/Risk, Operational Flexibility and Efficiency

Specific Assumption Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

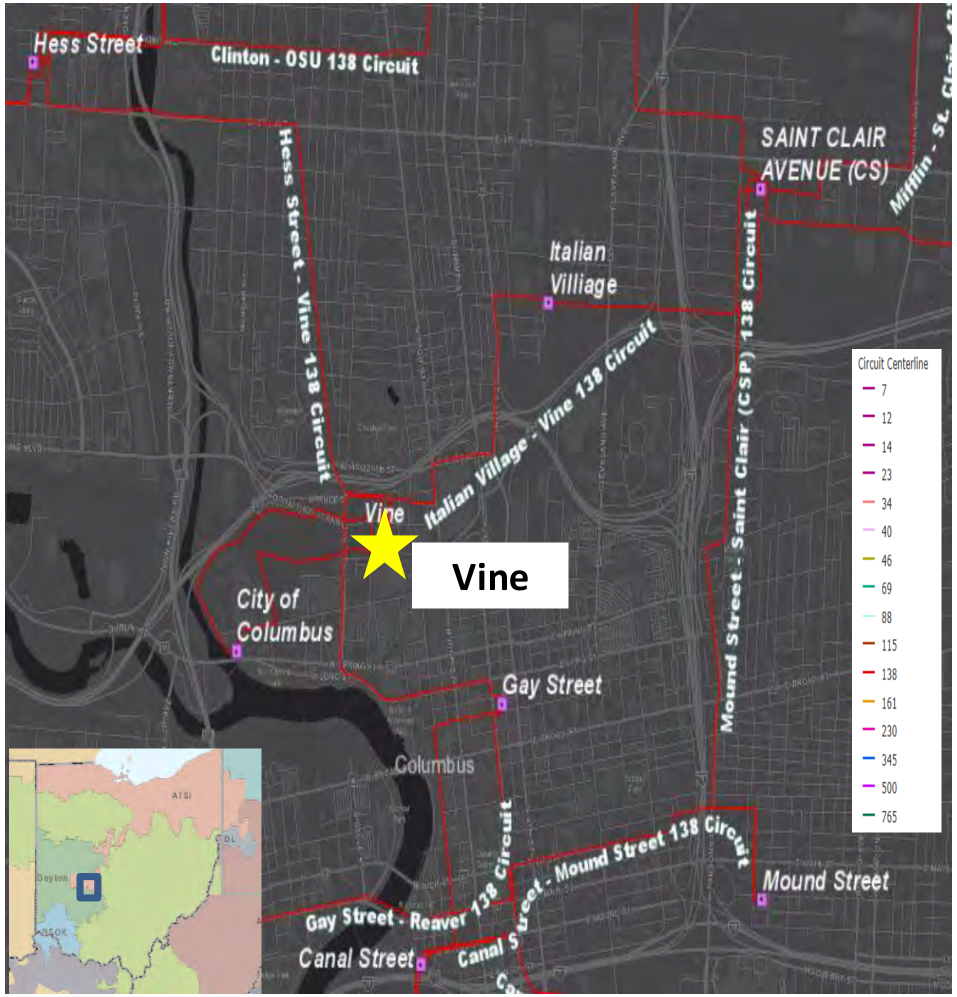
Problem Statement:

Vine Station

- Vine station is located in the heart of the downtown Columbus Arena District. The downtown area of Columbus has experienced a significant level of growth and development over the last decade. Projects such as the recently announced MLS Crew stadium indicates continued growth for the foreseeable future. The footprint of the existing station is extremely small, which creates issues when performing routine maintenance, severely limits the ability to replace major equipment, and often results in extended outages due to clearance issues. These space constrains also limit the ability to expand the station to accommodate future load growth. A mobile cannot fit inside the station; any mobile installs require placing it in the street and constructing temporary facilities to connect it.

- Circuit Breakers 101, 102, 103, 104, 106, 107
  - 138 kV 2000A 40kA* oil type breakers (*CB 107 is a 50kA)
  - Install date ranging from 1974 -1977 (43-46 years old)
  - Oil breakers that are difficult to maintain due to the required oil handling requirements. There is an increased potential for oil spills during routine maintenance and failures with these types of breakers.
  - Other needs include damage to bushings, lack of spare part availability, and lack of vendor support of the breakers.

- Capacitor Switcher EE
  - 138 kV Mark V type switcher
  - MARK V models have a history of malfunctioning and has presented AEP with a large # of failures and mis-operations including catastrophic equipment failures involving failure to trip.



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
Columbus, OH

Need Number: AEP-2020-OH033

Process Stage: Need Meeting 5/22/2020

Project Driver:

Equipment Material/Condition/Performance/Risk, Operational Flexibility and Efficiency

Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Gay – Vine 138 kV Underground Circuit*

- The existing Gay – Vine 138 kV underground circuit is approximately 1.4 miles long and was originally installed in the 1960's.

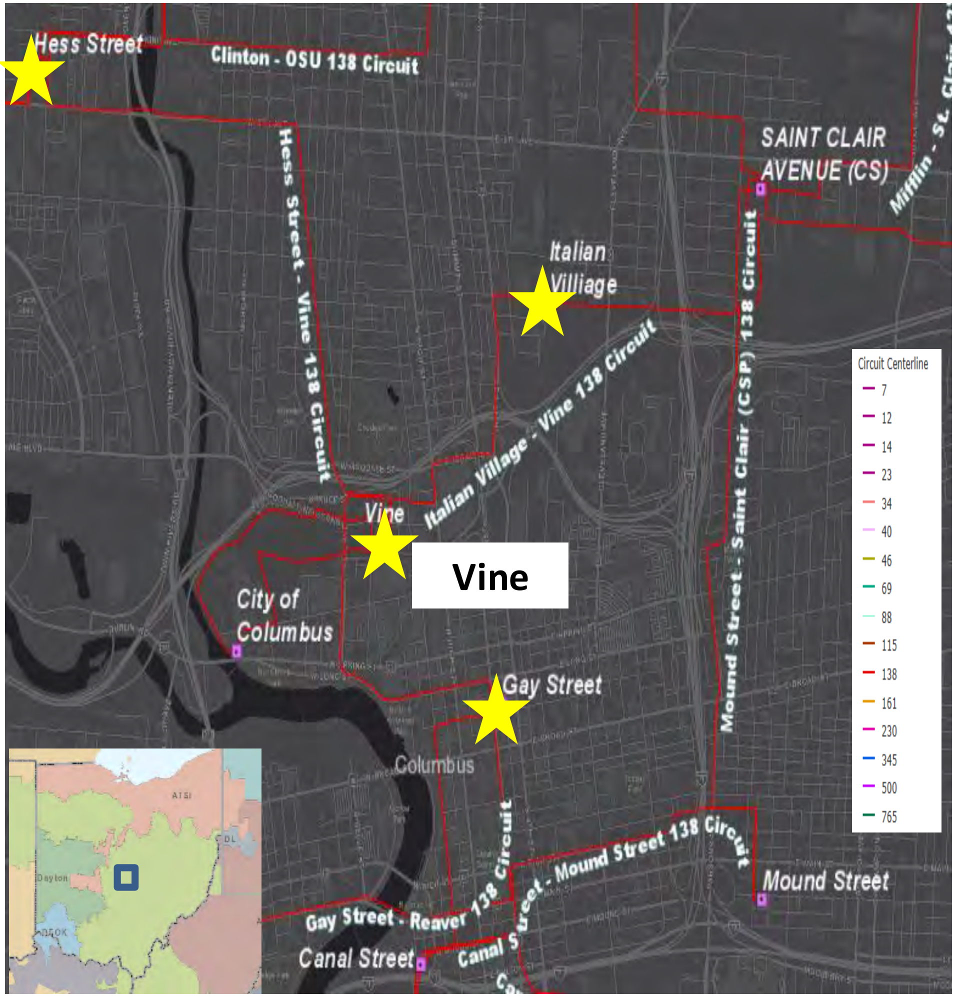
Hess – Vine 138 kV Underground Circuit*

- The existing Hess – Vine 138 kV underground circuit is approximately 2.5 miles long and was originally installed in the 1980's.

Italian Village – Vine 138 kV Underground Circuit*

- The existing Italian Village – Vine 138 kV underground circuit is approximately 1.3 miles long and was originally installed in the 1990's.

*All of these circuits utilize an underground oil-filled pipe type cable design. Oil-filled pipe type underground cables come with several challenges/risks in densely populated urban areas. There is a single manufacturer of oil-filled cables which has informed AEP of its desire to discontinue this product due to lack of demand and cheaper available alternates such as XLPE. A failure of any section may result in weeks of outage to customers in downtown Columbus.



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
Wood County, Ohio

Need Number: AEP-2020-OH031

Process Stage: Need Meeting 05/22/2020

Supplemental Project Driver:

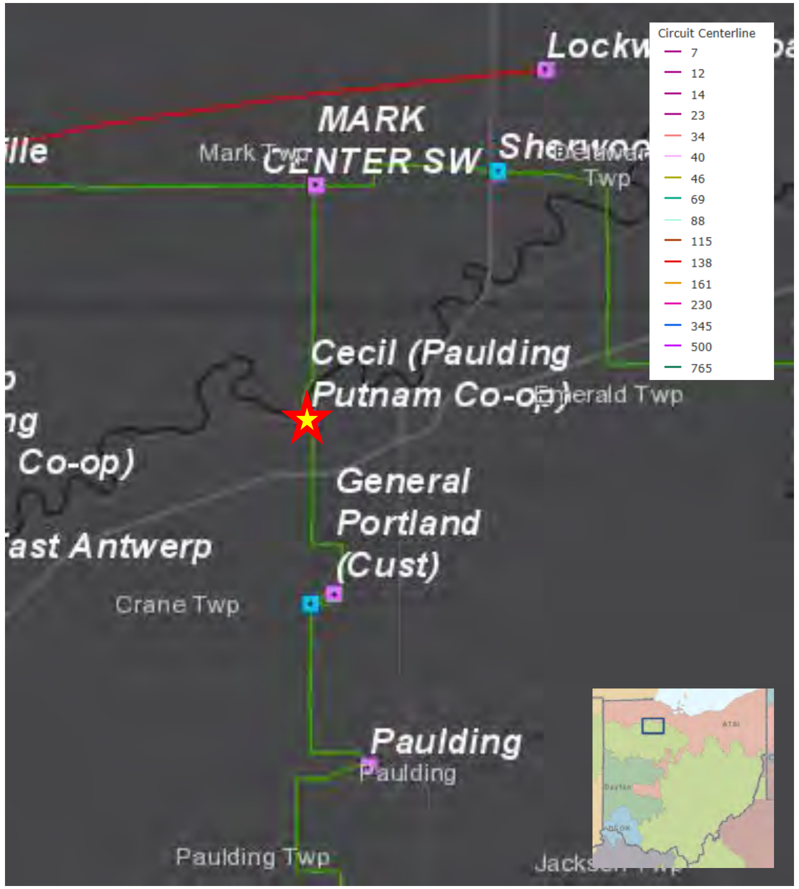
Customer Service and Operational Flexibility

Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions slide 7)

Problem Statement:

- Paulding – Putnam Electric Co-op is replacing their 3.75 MVA transformer with a 12/16/20 MVA transformer, which requires some changes to their delivery point. This delivery point is served by the North Cecil switch on the Mark Center – Paulding 69 kV circuit. North Cecil is a two way phase-over-phase switch with no auto-sectionalizing capability.
- Load: The Co-op delivery point serves approximately 4.9 MW
- CMI: In the last 5 years, there were 6 unscheduled outages affecting the customer, 3 of which were momentary and 3 were permanent outages. The 5-year CMI experienced by this customer is 170,520.
- Model: 2024 RTEP



Solutions

Stakeholders must submit any comments within 10 days of this meeting in order to provide time necessary to consider these comments prior to the next phase of the M-3 process

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
Walhonding

Need Number: AEP-2018-OH035

Process Stage: Solutions Meeting 05/22/2020

Previously Presented:

Need Meeting 10/26/2018

Project Driver:

Customer Service

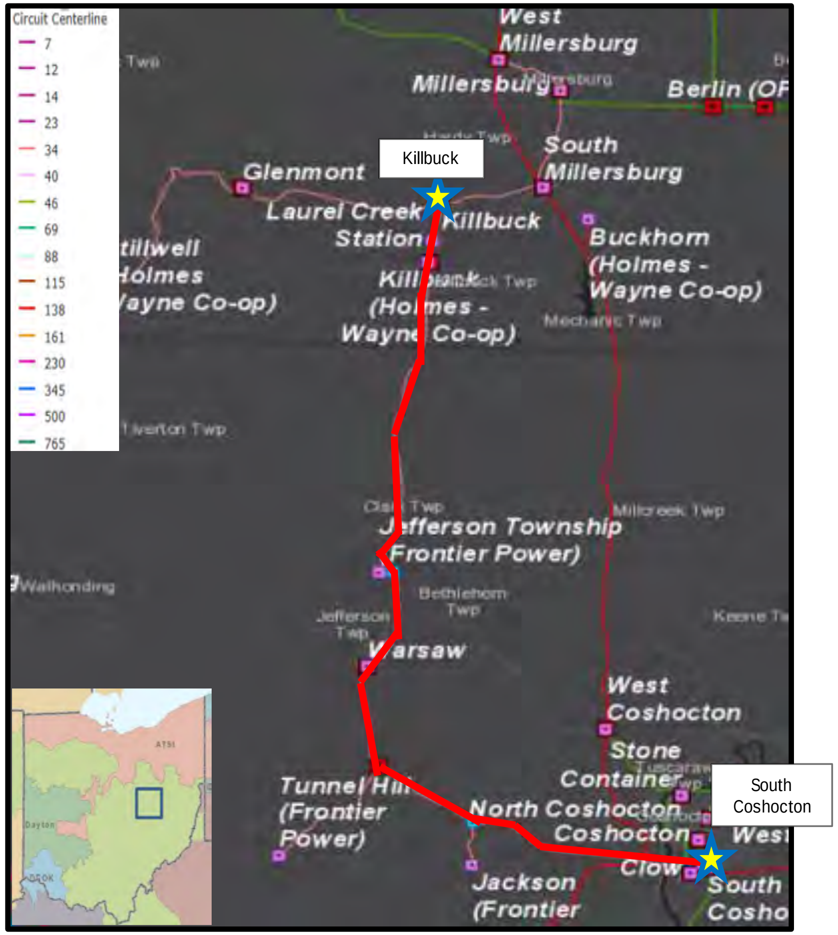
Specific Assumption Reference:

AEP Connection Requirements for the AEP Transmission System (AEP Assumptions Slide 7)

Problem Statement:

A recent customer service request of 2.5 MW has been made on the Killbuck – South Coshocton 34.5 kV circuit.

Model: 2024 RTEP



AEP Transmission Zone M-3 Process
Walhonding

Need Number: AEP-2018-OH035

Process Stage: Solutions Meeting 05/22/2020

Proposed Solution:

Walhonding Switch and the Walhonding Extension will be built at 69 kV design but will operate at 34.5 kV until project S2149 is in service, at which time it will operate at 69 kV.

- Install approximately 1 mile of double circuit line to tie the greenfield Walhonding Switch to the Killbuck – South Coshocton 34.5kV circuit. **Estimated Cost: $3.2M**
- Install approximately 0.01 mile radial line extension, connecting Marathon's station to Walhonding switch. **Estimated Cost: $0.1M**
- Install a new 3-way 69 kV 1200A switch with Auto-Sectionalizing, MOABs, and SCADA to serve the new customer. **Estimated Cost: $1.0M**

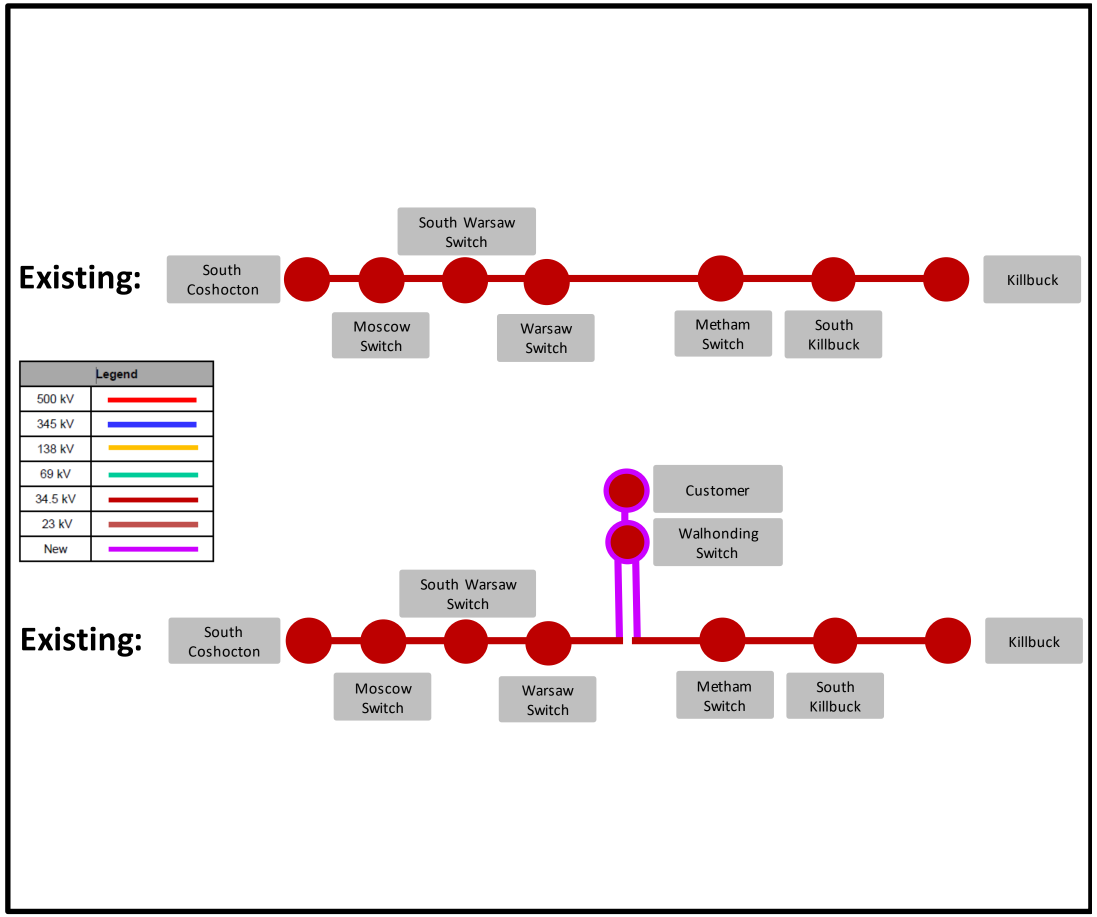
Total Estimated Transmission Cost: $4.3M

Alternatives Considered:

- Consideration was also given to installing the Walhonding switch closer to the existing Killbuck – South Coshocton 34.5 kV circuit. The alternative would still require constructing a mile of single circuit line to tie Walhonding Switch to the Marathon station. In addition, we would be required to maintain a mile access road to the switch resulting in no significant cost savings over the proposed solution.

Projected In-Service: 04/01/2021

Project Status: Engineering



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
Millbrook Park-South Point Rebuild

Need Number: AEP-2019-OH025

Process Stage: Solutions Meeting 05/22/2020

Previously Presented: Needs Meeting 05/20/2019

Supplemental Project Driver: Equipment/Material/Performance/Risk

Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8), Presentation on pre-1930s lines

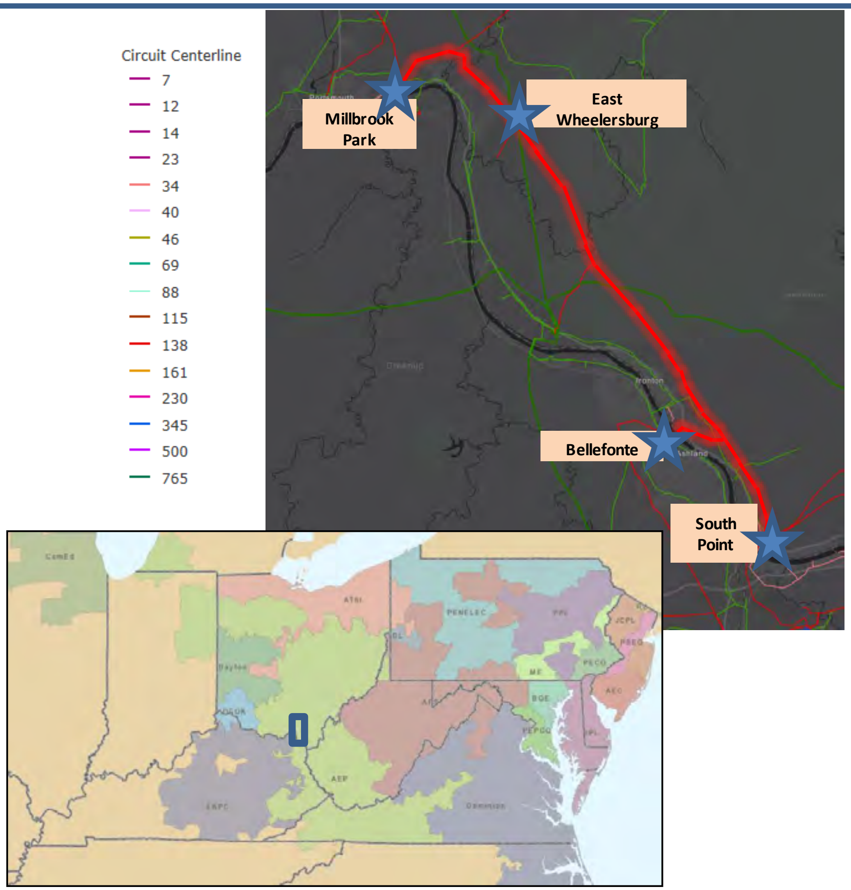
Problem Statement:

- The South Point – Portsmouth 138 kV double circuit is 34.7 miles and the Bellefonte 138 kV Extension is 4 miles in length.
- The conductor is primarily 397.5 ACSR (167 MVA).
- The South Point-Portsmouth line was originally constructed in 1929, with the majority of the structures and conductor being original.
- There are 45 open conditions on the line, including conductor issues, burnt/broken insulators, and loose/broken conductor hardware.
- Insulators of this vintage have shown heightened failure rates.

In general, several issues impact 1920 lattice tower lines:

- The steel conductor attachment plates have significant wear resulting in a loss of 50% of its strength.
- The cross arm hanger tension members are single mode of failure elements that are deteriorated and undersized due to the original design criteria.
- Lattice towers of this vintage do not meet current design requirements for wind and ice loading.
- Foundations are undersized for modern wind loading.
- Towers are beginning to show corrosion.

Model: N/A



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
Millbrook Park-South Point Rebuild

Need Number: AEP-2019-OH025

Process Stage: Solutions Meeting 05/22/2020

Proposed Solution:

Rebuild the 35-miles of the South Point- Portsmouth double circuit 138 kV line between Millbrook Park – South Point; with 795 ACSR (257MVA) or equivalent conductor. **Estimated Cost: $128.0M**

Rebuild the 3.8-miles of the Bellefonte Extension Line from the South Point – Portsmouth line to Bellefonte; with 795 ACSR (257MVA) or equivalent conductor. **Estimated Cost: $20.1M**

Remote end work at South Point station. **Estimated Cost: $0.6M**

Total Estimated Transmission Cost: $148.7M

Alternatives Considered:

Rebuild the Millbrook Park – South Point 138 kV corridor as single circuit by retiring the existing Millbrook Park – South Point 138 kV circuit and rebuilding the Millbrook Park – Bellefonte – North Proctorville 138 kV circuits.

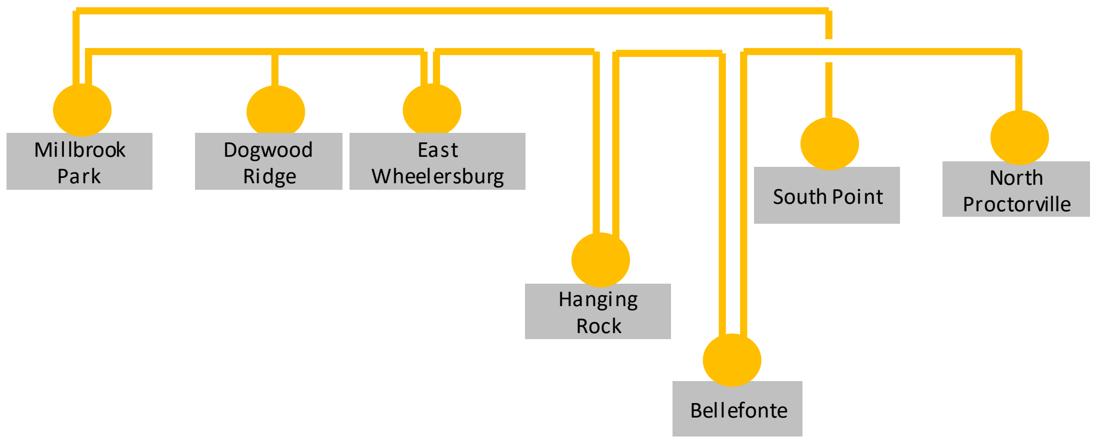
The area that the line traverses consistently receives a significant amount of large load inquiries due to its proximity to the Ohio River and railways. Reducing the corridor to a single circuit would greatly diminish the ability to support new load in the area due to the existing connections to the area's 69 kV system. Flexibility in how to address the area's existing 69 kV system in the future would also be greatly limited.

Estimated Alternative Transmission Cost: $138.7M

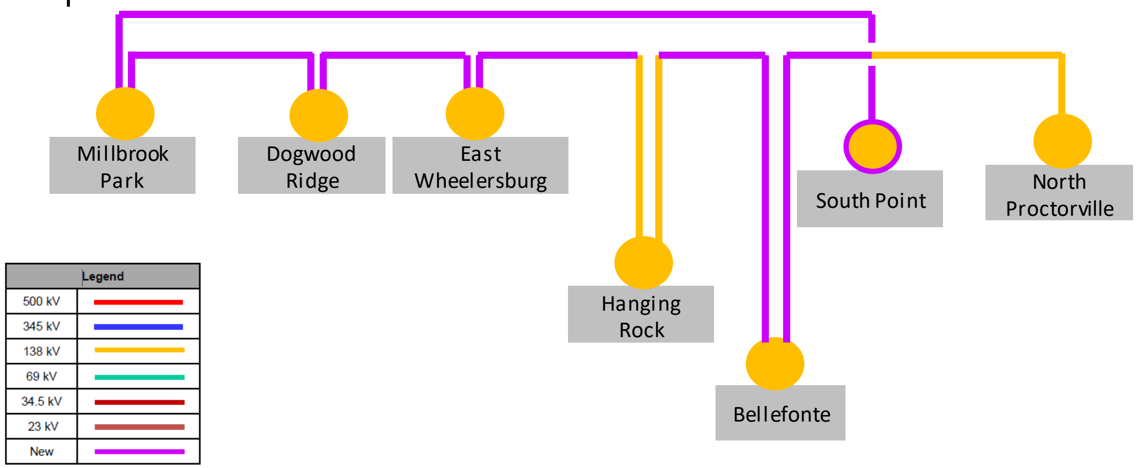
Projected In-Service: 12/15/2025

Project Status: Scoping

Existing:



Proposed:



AEP Transmission Zone M-3 Process
Winchester Area Improvements Supplemental

Need Number: AEP-2020-IM004

Process Stage: Solutions Meeting 05/22/2020

Previously Presented: Needs Meeting 02/21/2020

Supplemental Project Driver: Equipment Material/Condition/Performance/Risk

Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

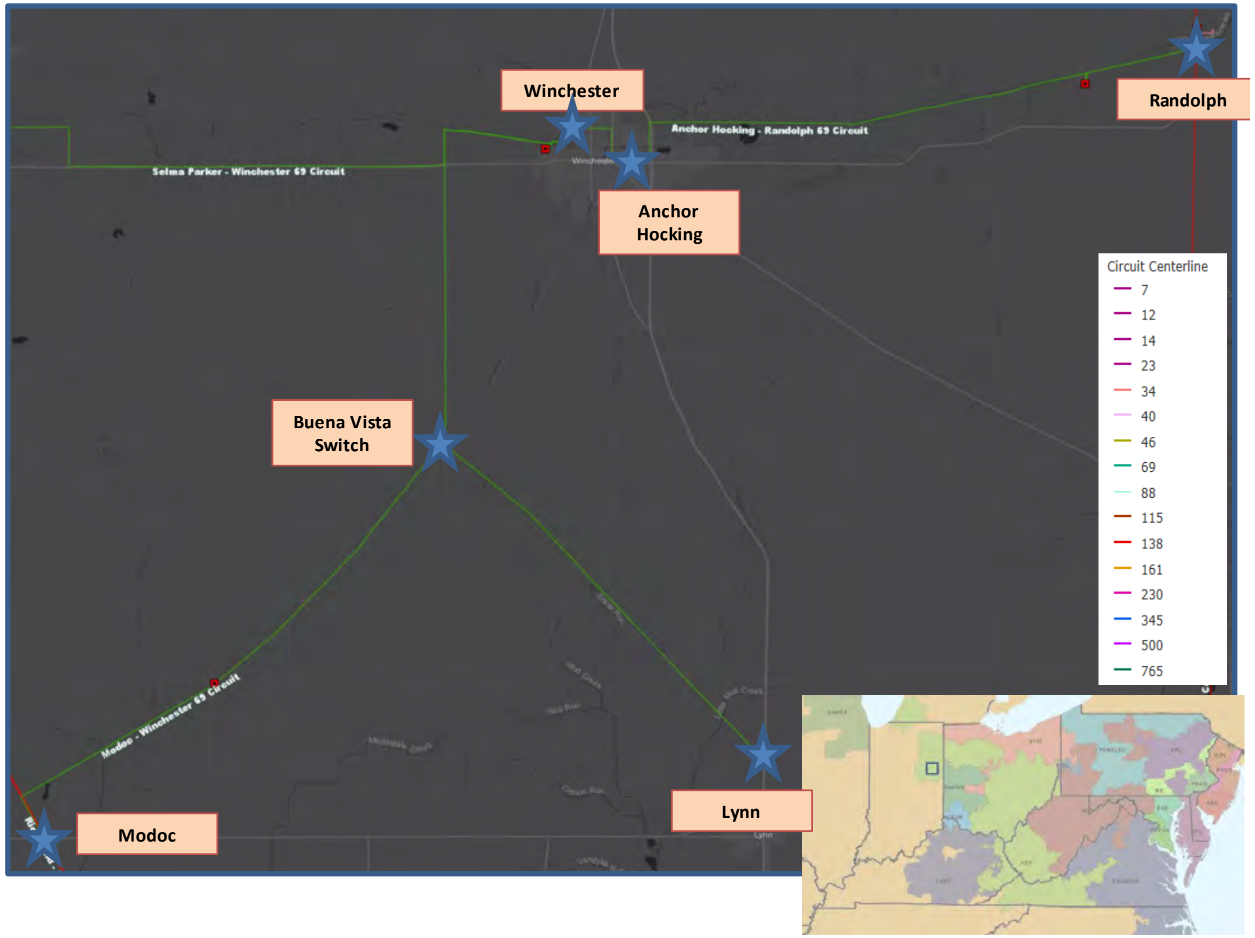
Problem Statement:

Anchor Hocking – Winchester 69kV Line (~1.25 Miles)

- 1968 vintage wood pole, crossarm construction
- There are currently 12 open conditions on this line (11 structures with at least one open condition or 25% of the line).
- Open conditions include: Damaged pole, worn shield wires, stolen ground lead wires, and damaged jumpers.

Anchor Hocking 69kV station

- Breaker B 69kV
    - 1972 vintage oil filled, CF-type breaker. This type is oil filled without oil containment. Oil filled breakers have much more maintenance required due to oil handling that their modern, vacuum counterparts do not require. Finding spare parts for these units not possible as these models are no longer vendor supported



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
Winchester Area Improvements Supplemental

Need Number: AEP-2020-IM004

Process Stage: Solutions Meeting 05/22/2020

Previously Presented: Needs Meeting 02/21/2020

Supplemental Project Driver: Equipment Material/Condition/Performance/Risk

Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

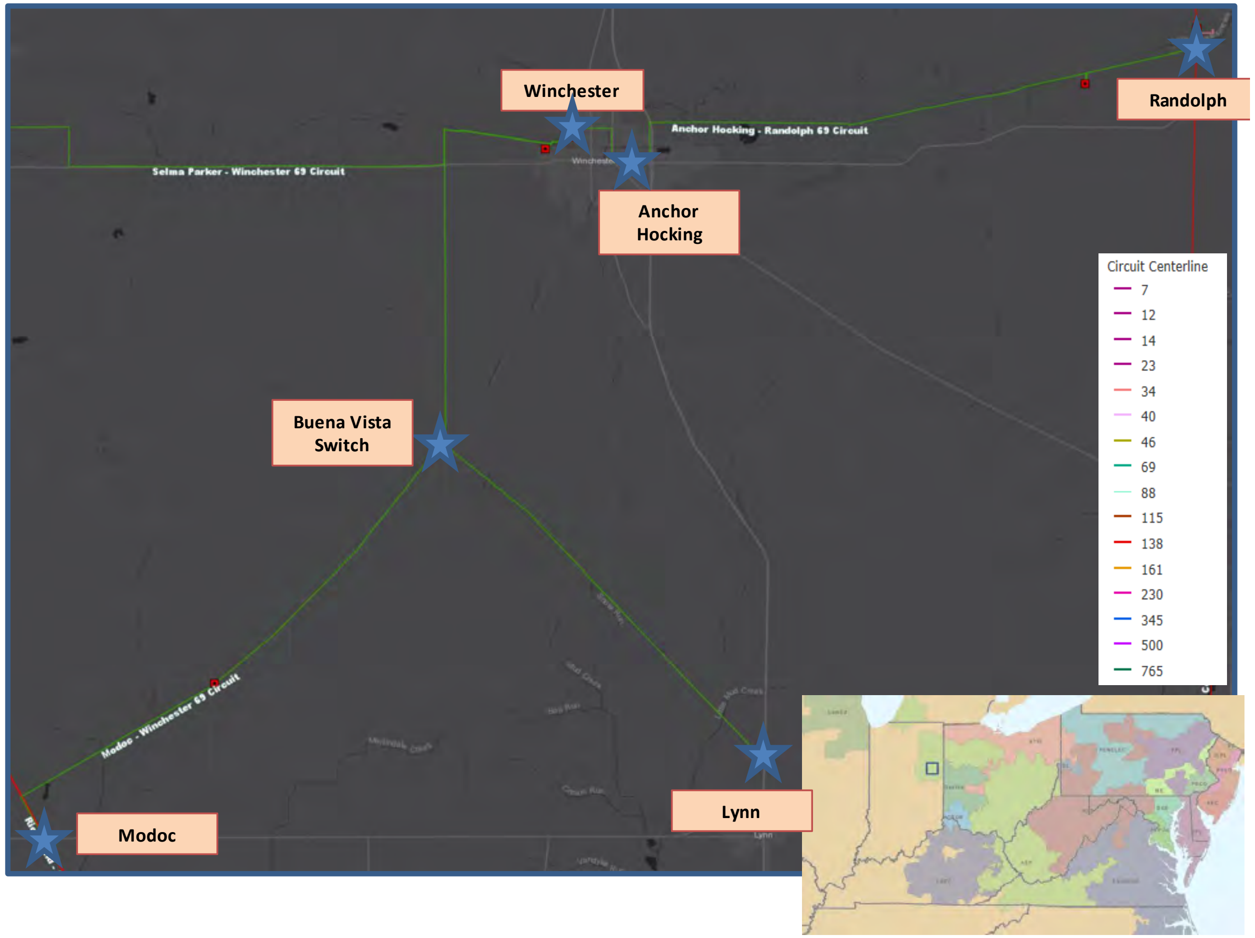
Problem Statement:

Winchester 69kV station

- Breakers A and B 69kV
  - 1971 vintage oil filled, CF-type breaker. This type is oil filled without oil containment. Oil filled breakers have much more maintenance required due to oil handling that modern, vacuum counterparts do not require. Finding spare parts for these units not possible as these models are no longer vendor supported. Also, oil spills can result in significant cost to mitigate

Modoc 138/69/12kV station

- 138/69kV Transformer #1
  - 1965 vintage
  - Elevated moisture levels
  - Decrease in interfacial tension of the oil, reducing its insulating capabilities
  - Unit is showing signs of leaking



AEP Transmission Zone M-3 Process
Winchester Area Improvements Supplemental

Need Number: AEP-2020-IM004

Process Stage: Solutions Meeting 05/22/2020

Previously Presented: Needs Meeting 02/21/2020

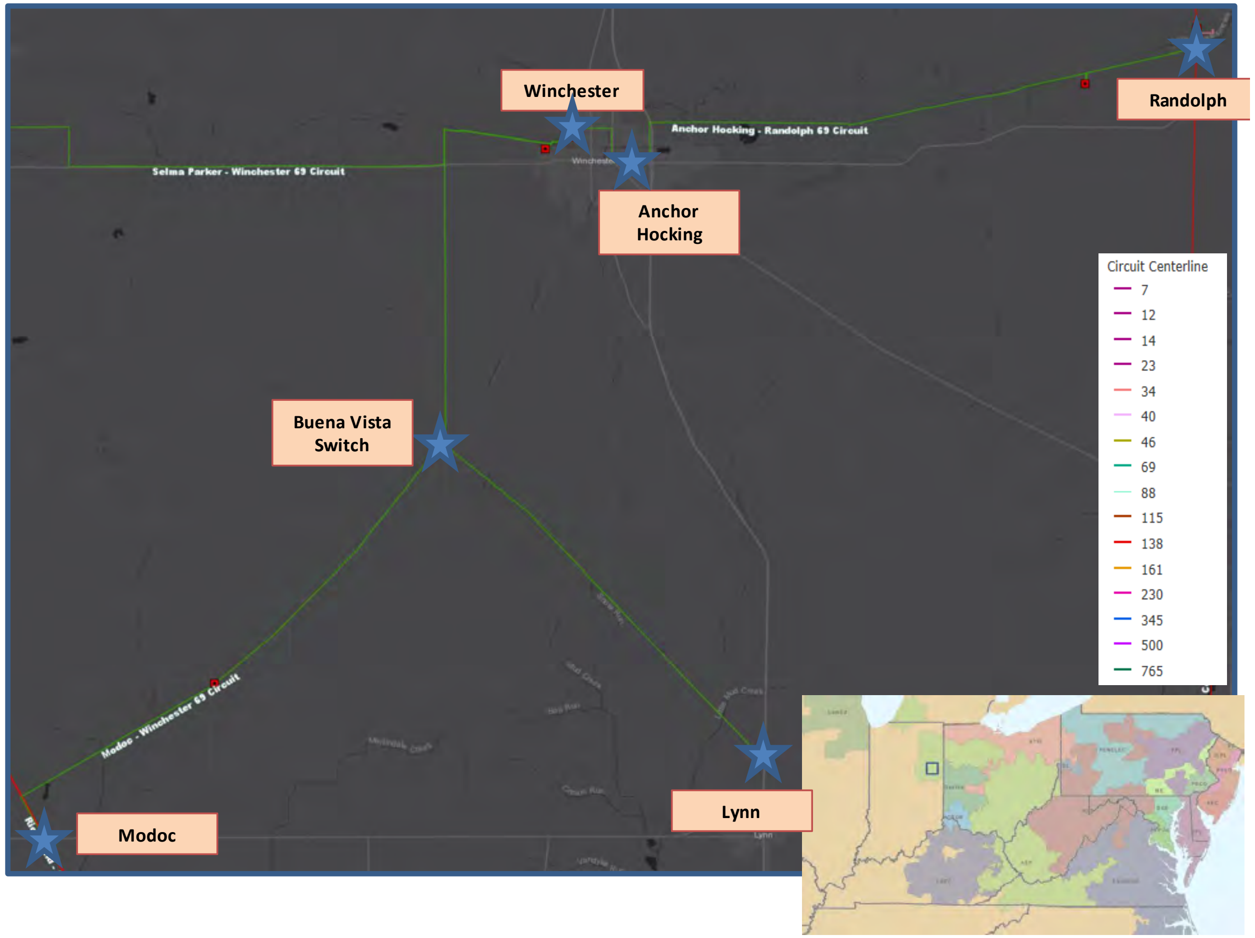
Supplemental Project Driver: Equipment Material/Condition/Performance/Risk

Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Randolph 138/69kV station

- 138/69/12 kV Transformer #1
  - 1970 vintage
  - Elevated carbon dioxide levels
  - Increased levels of decomposition of the paper insulating materials, leading to increased risk of failure
- Switcher V 138kV
  - Mark V S&C Electric type switcher
  - Failed operational components including high contact resistance, gas loss, and interrupter failure represent half of these malfunctions.
  - This model has no gas monitor and a history of malfunction
- Cap Switcher AA
  - 2030-69 S&C Electric type switcher.
  - This model has no gas monitor and a history of malfunction.
  - This particular switcher has exceeded the recommended number of switched operations with 5497 (5000 recommended)



AEP Transmission Zone M-3 Process
Winchester Area Improvements Supplemental

Need Number: AEP-2020-IM004

Process Stage: Solutions Meeting 05/22/2020

Previously Presented: Needs Meeting 02/21/2020

Supplemental Project Driver: Equipment Material/Condition/Performance/Risk

Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

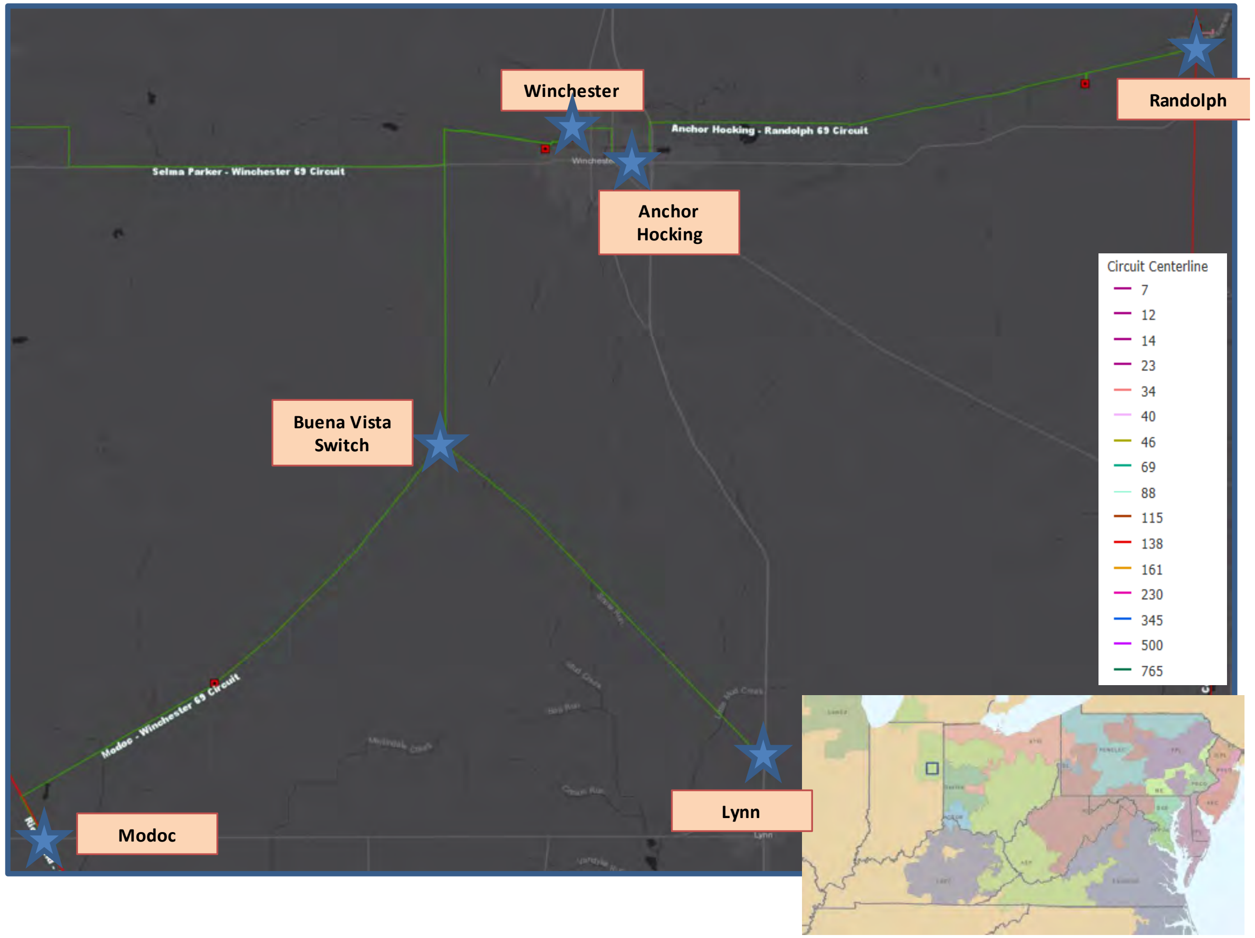
Problem Statement:

Modoc – Winchester 69kV Line (~13.4 Miles)

- 1967 vintage wood pole, horizontal insulator line
- There are currently 69 open conditions on this line (63 structures with at least one open condition or 26% of the line).
- Open conditions include: Damaged poles, damaged braces, broken guy wires, and damaged insulators.

Buena Vista – Lynn 69kV Line (~5.7 Miles)

- 1967 vintage wood pole, horizontal insulator line
- There are currently 31 open conditions on this line (28 structures with at least one open condition or 38% of the line).
- Open conditions include: Damaged poles, damaged shield wires, broken ground lead wires, and damaged insulators.



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
Winchester Area Improvements Supplemental

Need Number: AEP-2020-IM004

Process Stage: Solutions Meeting 05/22/2020

Previously Presented: Needs Meeting 02/21/2020

Supplemental Project Driver: Operational Flexibility

Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

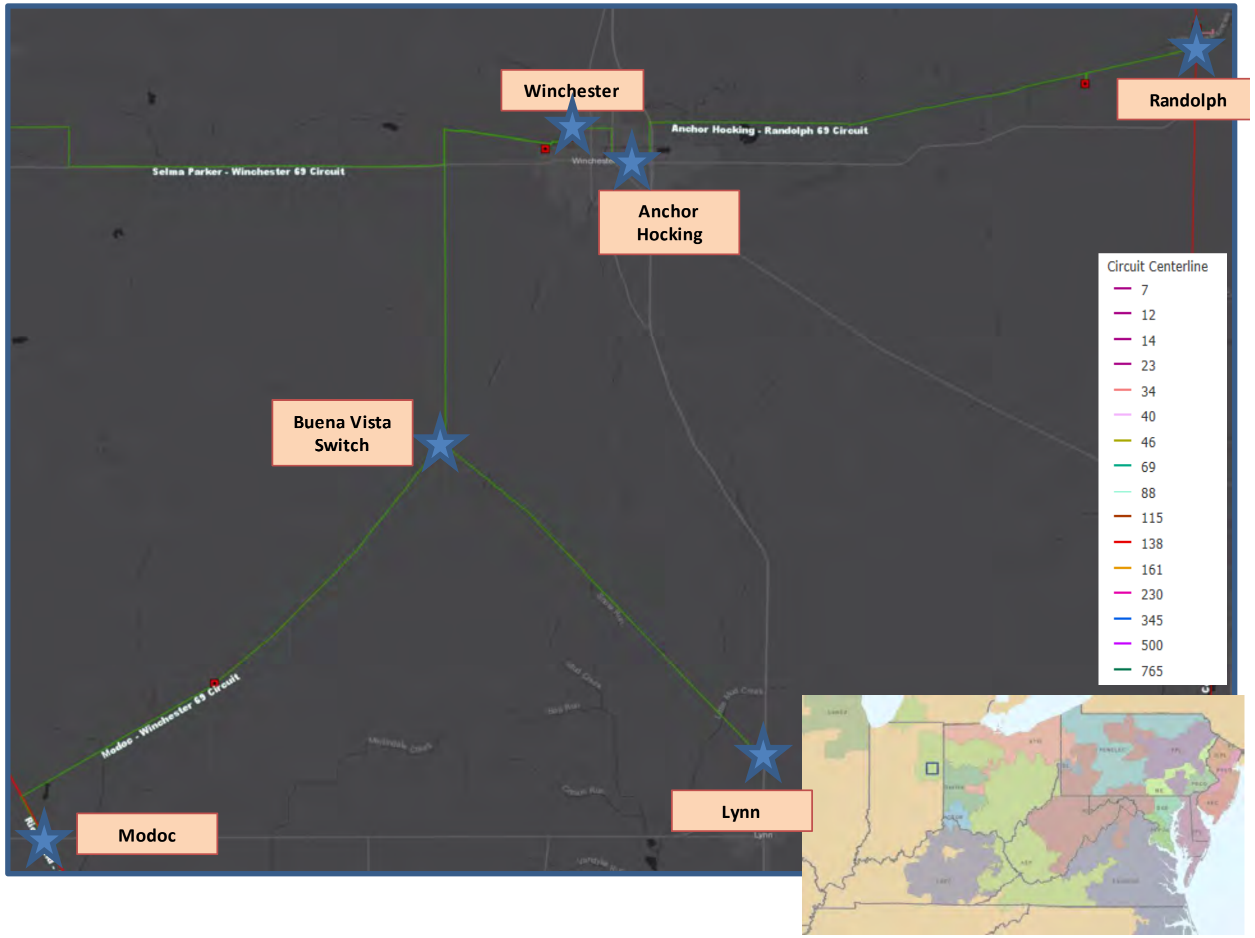
Problem Statement:

Lynn 69/12kV station

- Radial circuit serving 7MW peak load to REMC and the distribution network for the city of Lynn.

Modoc 138/69/12kV station

- Modoc is a 3 terminal line off of the Desoto – College Corner 138kV circuit with high speed ground switch protection on the transformer



AEP Transmission Zone M-3 Process
Winchester Area Improvements Supplemental

Need Number: AEP-2020-IM004
Process Stage: Solutions Meeting 05/22/2020

Proposed Solution:

Rebuild the 1.25 mile long Anchor Hocking-Winchester 69 kV circuit. **Estimated Cost: $5.9M**

Expand and upgrade Anchor Hocking station to a 5 breaker ring bus to accommodate 5 elements (2 transmission lines and 3 distribution transformers). **Estimated Cost: $6.7M**

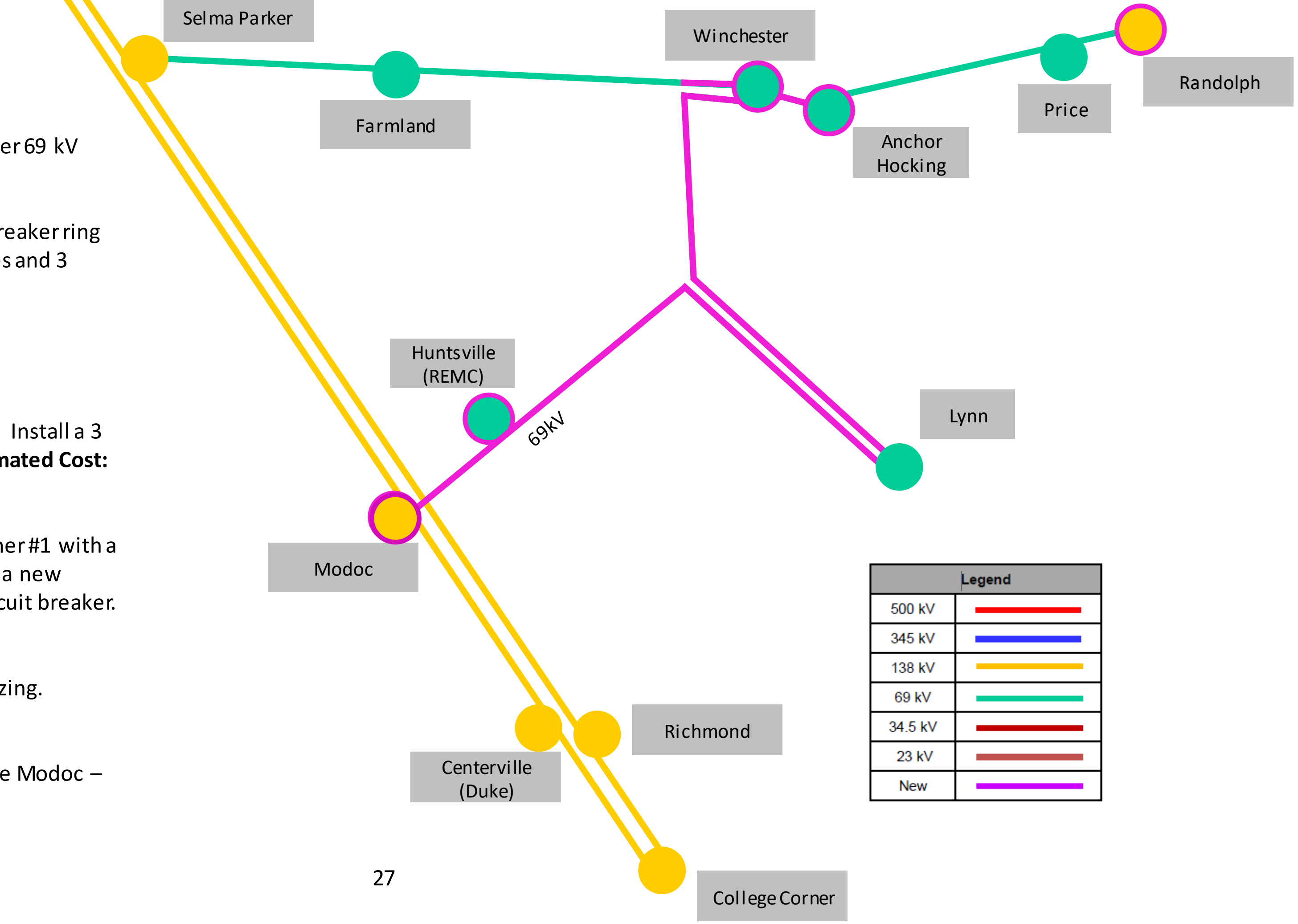
Replace circuit breakers A & B at Winchester station.
Estimated Cost: $3.0M

At Modoc station, replace 138/69kV Transformer #1. Install a 3 breaker ring bus eliminating the 3 terminal line. **Estimated Cost: $11.8M**

At Randolph station, replace 138/69/12 kV Transformer #1 with a 138/69kV 90MVA unit, move the distribution load to a new 138/12kV transformer, and install a 138kV bus tie circuit breaker. Replace cap switcher AA. **Estimated Cost: $6.8M**

At Lynn station, install 2 69kV switches for sectionalizing.
Estimated Cost: $0.8M

Replace the Huntsville (REMC) switch structure on the Modoc – Winchester 69kv line.
Estimated Cost: $0.6M



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
Winchester Area Improvements Supplemental

Need Number: AEP-2020-IM004
Process Stage: Solutions Meeting 05/22/2020

Proposed Solution (con't):

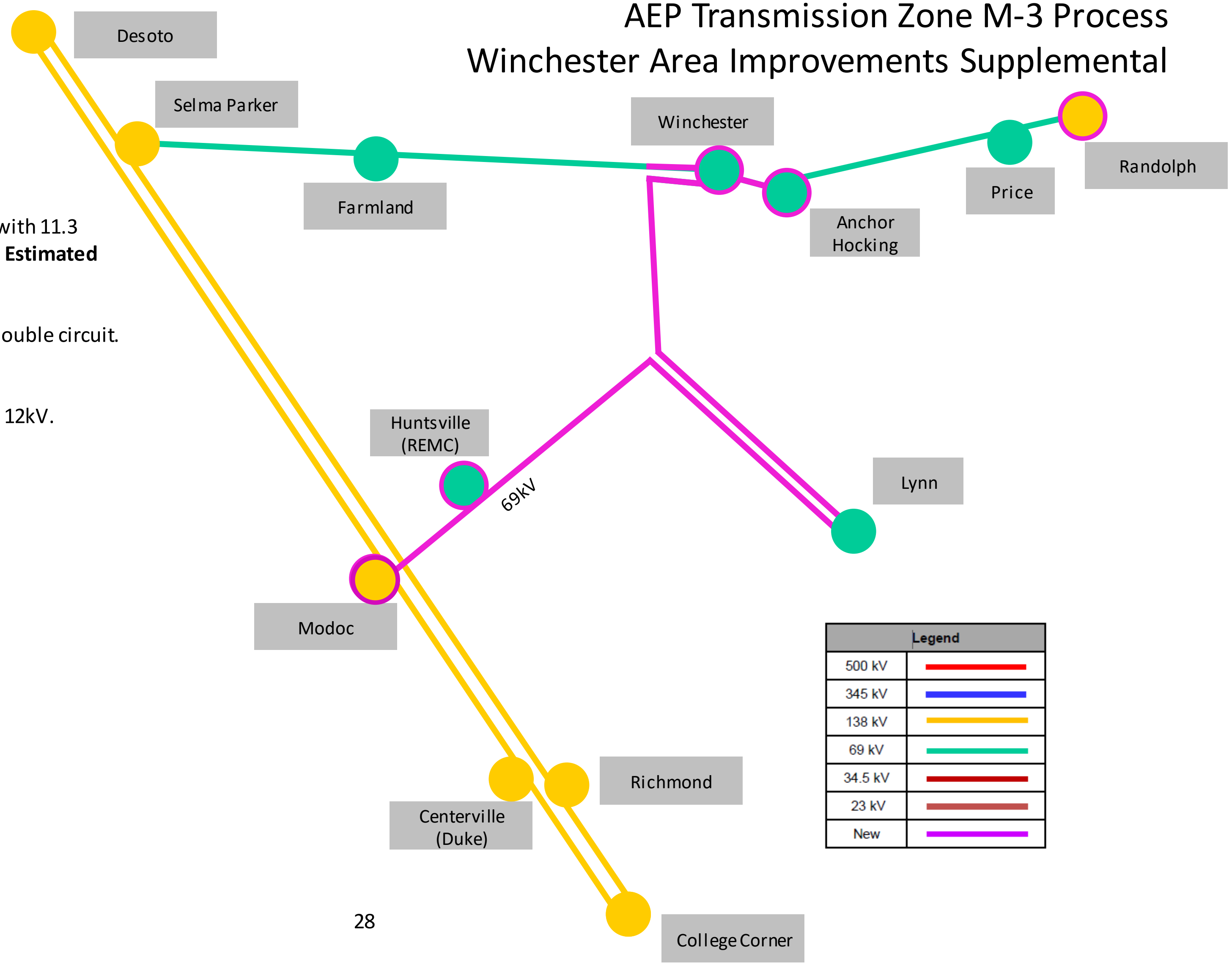
Rebuild the 13.4 mile Modoc-Winchester 69 kV line with 11.3 miles as single circuit and 2.1 miles as double circuit. **Estimated Cost: $22.8M**

Rebuild the 5.7 mile Buena Vista-Lynn 69 kV line as double circuit. **Estimated Cost: $9.9M**

Retire Lobdell station. Moved the load from 69kV to 12kV. **Estimated Cost: $0.0M**

Retire Buena Vista Switch. **Estimated Cost: $0.2M**

Total Estimated Transmission Cost: $68.5M



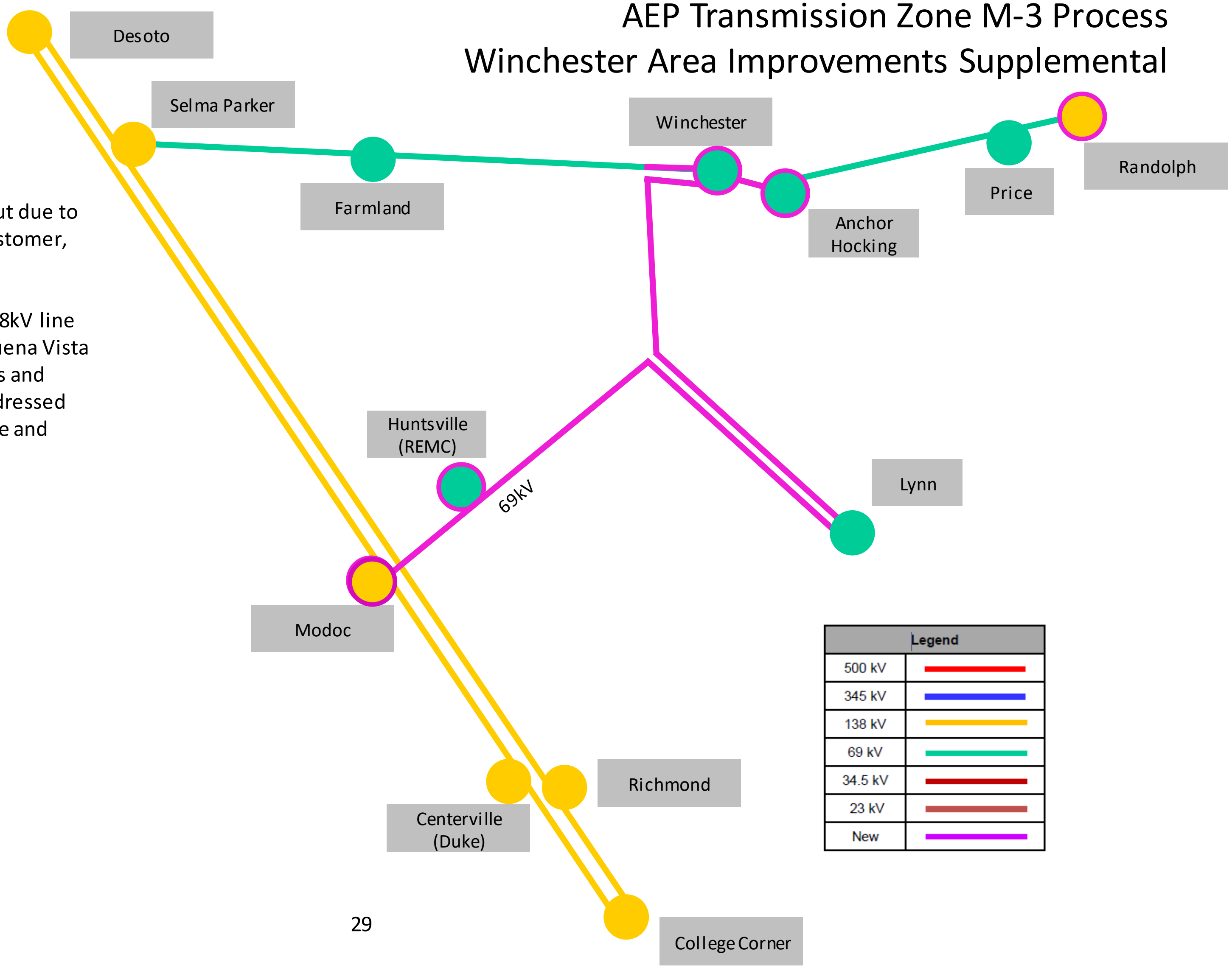
AEP Transmission Zone M-3 Process
Winchester Area Improvements Supplemental

Need Number: AEP-2020-IM004
Process Stage: Solutions Meeting 05/22/2020

Alternatives Considered:
Replace circuit breaker B at Anchor Hocking in place. But due to space constraints and an extremely outage sensitive customer, this option wasn't feasible.

Tap Randolph-College Corner line with double circuit 138kV line to Lynn Station (~6.0 miles) and retire 69kV line from Buena Vista to Lynn. This wasn't selected due to increased line costs and upgrades to Lynn station to take 138kv delivery that addressed the same needs (the aging Buena Vista to Lynn 69kV line and looping service to Lynn) as the proposed solution.
Estimated Cost: $72.9M

Projected In-Service: 08/01/2025
Project Status: Scoping



AEP Transmission Zone M-3 Process
Madison-Pendleton 138kV Line Rebuild

Need Number: AEP-2020-IM005

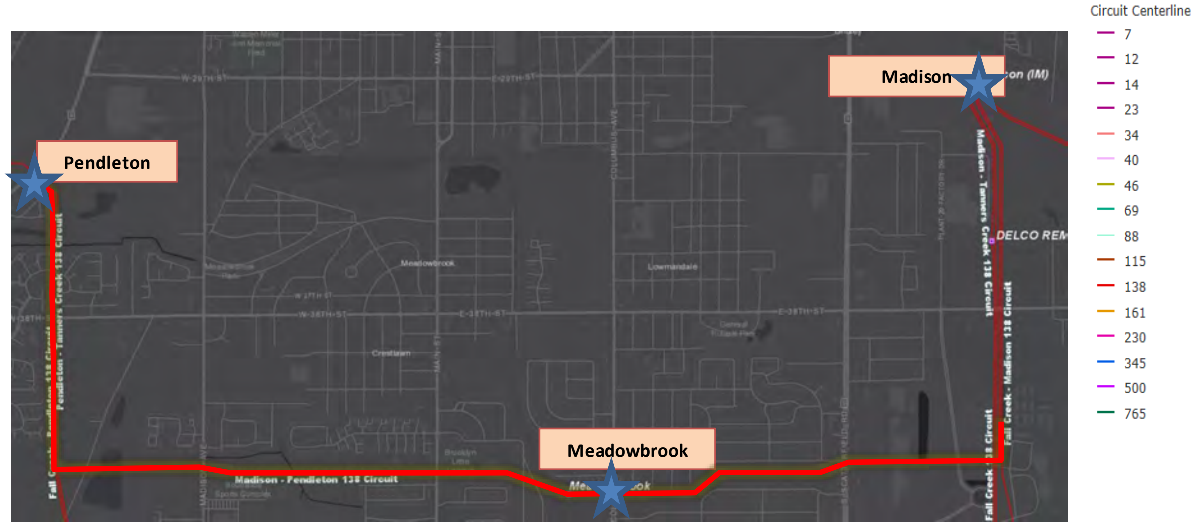
Process Stage: Solutions Meeting 05/22/2020

Previously Presented: Needs Meeting 02/21/2020
Supplemental Project Driver: Equipment Material/Condition/Performance/Risk/Operational
Specific Assumptions Reference: AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Madison – Pendleton 138kV Line (~4.2 Miles)
- 1967 vintage wood pole, H-Frame construction
- There are currently 16 open conditions on this line (9 structures with at least one open condition or 24% of the line).
- Open conditions include: Rotting or bowed crossarms or poles, broken shield wires, and stolen ground lead wires.

Meadowbrook 138/34.5kV station
- Three-terminal line and overlapping zones of protection on the bus, line, and transformer.



AEP Transmission Zone M-3 Process
Madison-Pendleton 138kV Line Rebuild

Need Number: AEP-2020-IM005
Process Stage: Solutions Meeting 05/22/2020

Proposed Solution:

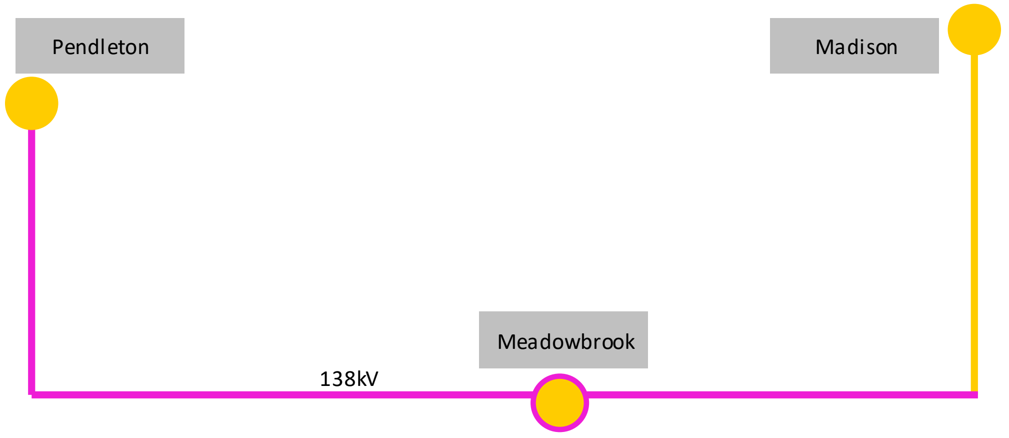
Rebuild a 4.17 mile portion of the Madison – Pendleton 138kV single circuit line with DRAKE 795 ACSR 26/7. **Estimated Cost: $7.7M**

At Meadowbrook station, install 2 138kV circuit breakers to eliminate the 3 terminal line. **Estimated Cost: $2.8M**

Total Estimated Transmission Cost: $10.5M

Alternatives Considered:
Due to the location of Meadowbrook Station, a new line route wouldn't be prudent, nor is retirement an option. Madison, Pendleton, and Meadowbrook serve as three delivery points feeding the IMPA system.

Projected In-Service: 05/01/2023
Project Status: Scoping



Legend	
500 kV	
345 kV	
138 kV	
69 kV	
34.5 kV	
23 kV	
New	

Appendix

High Level M-3 Meeting Schedule

Assumptions

Activity	Timing
Posting of TO Assumptions Meeting information	20 days before Assumptions Meeting
Stakeholder comments	10 days after Assumptions Meeting

Needs

Activity	Timing
TOs and Stakeholders Post Needs Meeting slides	10 days before Needs Meeting
Stakeholder comments	10 days after Needs Meeting

Solutions

Activity	Timing
TOs and Stakeholders Post Solutions Meeting slides	10 days before Solutions Meeting
Stakeholder comments	10 days after Solutions Meeting

Submission of Supplemental Projects & Local Plan

Activity	Timing
Do No Harm (DNH) analysis for selected solution	Prior to posting selected solution
Post selected solution(s)	Following completion of DNH analysis
Stakeholder comments	10 days prior to Local Plan Submission for integration into RTEP
Local Plan submitted to PJM for integration into RTEP	Following review and consideration of comments received after posting of selected solutions

Revision History

5/12/2020 – V1 – Original version posted to pjm.com