I&M Exhibit: _____

INDIANA MICHIGAN POWER COMPANY

PRE-FILED VERIFIED DIRECT TESTIMONY

OF

NICOLAS C. KOEHLER

Cause No. 45933

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 provides 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).

AEP Transmission is a combination of separate groups within AEP, Grid Solutions and Energy Delivery. The Grid Solutions organization is responsible for planning for the evolving needs of the transmission system, including technology development, transmission asset strategy and policy, oversight of all transmission policy and regulatory matters involving RTOs, Federal Energy Regulatory Commission (FERC), and state regulations. It also supports commitments to relevant aspects of North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) and Operations and Planning requirements.

Energy Delivery is charged with improving Transmission's efficiency, containing the costs of projects and capital excellence, and supporting commitments to relevant aspects of NERC CIP and Operations and Planning requirements. The organization is responsible for maintenance, engineering, project management, operations, siting new transmission facilities, providing outreach and information regarding transmission projects to the public, and Right-of-Way (ROW) acquisition for transmission projects. For purposes of this testimony, I will use the phrase 'AEP Transmission' to refer to these two groups, either singularly or collectively.

Q3. Briefly describe your educational background and professional experience.

I received a Bachelor of Science in Electrical Engineering 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 Professional Engineer (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. 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.

Q5. Have you previously testified before any regulatory commissions?

Yes. I have testified before the Indiana Utility Regulatory Commission in Case No. 45576 and before the Michigan Public Service Commission in Case No. U-20359; both of these cases were to support I&M's applications to increase its rates for the sale of electric energy in those jurisdictions. I have also filed testimony before the Public Service Commission of Kentucky and the State Corporation Commission of Virginia in applications for Certificates of Public Convenience and Necessity to construct transmission assets.

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 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 Gruca.

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

Q8. Was the attachment 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 stability, 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 they 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 I&M serves.

There are approximately 5,340 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 within the Company's service territory.

Approximately 4,430 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 182 transmission substations, 130 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, AES Indiana, 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

[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.

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 stability and 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 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 45.4 years of service. Additionally, over 1,250 line-miles are 60 years of age or older, and of these line miles, over 500 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 pose 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.[2]

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

[2] Regional Transmission Organizations, 89 ¶ 61,285 [FERC Order 2000] (Dec. 20, 1999).

coordinated PJM transmission grid. This grid enhances system stability, reliability, and security, competitive wholesale markets, and resource diversity.[3]

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

3 *Re Ind. Mich. Power Co.*, Cause No. 45235 at 110 (IURC Mar. 11, 2020).

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 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 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:
    - 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%).
    - 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. How are Network Upgrade projects initiated?

A customer will make a request via a queuing process managed by PJM. As an example, a generation developer that is planning a renewable project connecting to PJM would initiate such a request. Based on the request, PJM and the impacted Transmission Owner (TO) will prepare a feasibility study for that request to assess the practicality and cost. If the study supports the project, PJM and the TO will, based on an executed agreement with the requesting party, prepare a Generation Interconnection System Impact Study to analyze the connection and determine if there are any additional network upgrades necessitated by the request. Finally, if the System Impact Study determines the request can proceed, then a Facilities Study is completed by PJM and the impacted TO focusing primarily on the design and cost of facilities necessary to physically connect the generation to the transmission system. Construction of the interconnection point will be managed by the transmission owner, in this case AEPSC on behalf of I&M.

Q27. How are costs for Network Upgrade projects recovered?

For Network Upgrades, the requesting party is responsible for the costs of the interconnection. In addition, they will also be responsible for associated transmission upgrades that PJM identifies in the System Impact Study. These projects can be beneficial to all customers on the network because while funded by the requesting party, the upgrades will benefit all users as the upgrades increase the performance and reliability of the network.

Q28. 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 stability and reliability of their transmission grid within the AEP Zone.

Q29. 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.

Q30. 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 and stability, 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.

Q31. Can you provide an example of an I&M Owner Project that supports these considerations?

Yes. I&M reviewed the need for a rebuild of the Pendleton-Makahoy 138 kV line with stakeholders in the November 19, 2021 PJM Sub-Regional Regional Transmission Expansion Plan (SRRTEP) committee meeting. In a subsequent meeting on June 15, 2022 the solution was presented with a proposed in-service date of September 1, 2026[4]. The 138-kV transmission line that connects the Pendleton Substation to the Makahoy Substation 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:

[4] See Sub Regional RTEP Committee: Western AEP Supplemental Projects dated June 15, 2022 at pages 34-36. aep-supplemental-projects.ashx (pjm.com)

- 1950s wood pole construction
- 21 open conditions (degrading structures, damaged shield wires, etc.)

As part of the upgrade, approximately 15 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.

Additionally, there were concerns regarding the transformers at the Pendleton substation. Elevated moisture levels and interfacial tension indicated that the dielectric strength of the insulation system is in poor condition, which impairs the unit's ability to withstand electrical faults. Additionally, the lack of oil containment safety measures increases risk of oil/gasket leaks.

By replacing the Pendleton 138/34.5 kV transformer with a 138/34.5 kV 75 MVA transformer there is an increase of safety and reliability of the system. Proactive improvements like this example serve to reduce power outages and speed recovery of service when outages do occur.

Q32. Can you elaborate on the customer benefits associated with I&M Owner Projects like this one?

Projects like the improvements at the Pendleton substation are essential to ensure continued reliable service is available for local customers. These improvements, in turn, contribute to a stable source of electricity critical for all of our customers, including the manufacturing industry served by I&M.

Q33. 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.

Q34. 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.

Q35. 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.

The M-3 process, which ensures stakeholders have an opportunity to review Owner Projects, includes 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 to 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.

Q36. 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.

Q37. 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 will consult with stakeholders that will be directly impacted by a project prior to submission of the project's Solution to PJM. 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.

Q38. 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.

Additionally, consistent with the settlement agreement approved in Cause No. 45576, I&M is scheduled to meet with interested parties on August 30th, 2023 to provide them with a separate opportunity to review the information provided to PJM through the M-3 process.

Q39. 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.

Q40. 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. Nevertheless, these project elements 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.

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

Q41. 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 witness Sloan; however, 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.

Q42. What is the Company's forecast of PJM costs for the Test Year?

As provided by Company witness Sloan, PJM NITS[5] charges are forecasted to be approximately $408.7 million (Total Company) for the Test Year. In addition, I&M is forecasted to incur approximately $33.9 million (Total Company) in non-NITS costs in the Test Year.

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.

Q43. 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.

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

Q44. 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 in the response to Q25 above, 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 included in non-NITS charges.

Q45. 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 in *Figure NCK-1* below, a summary of historic transmission investment in the United States, accumulated from gross transmission investment balances taken from FERC Form 1 reporting, shows increases in investment from 2019 through 2022, suggesting a general trend towards higher investment expenditure in the future.

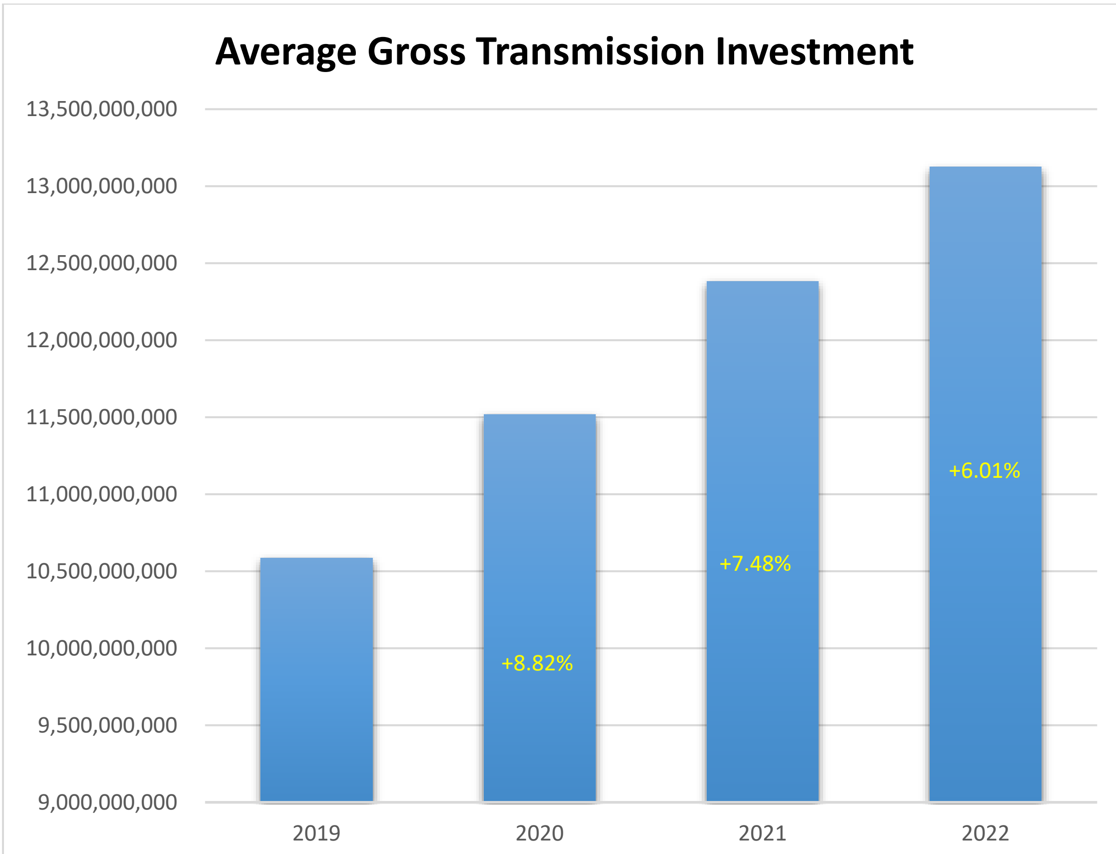
Q46. Please describe Figure NCK-1.

Figure NCK-1 shows average combined transmission investment from 2019-2022, along with year-over-year growth for a sample of investor owned utility holding companies with gross asset valuations of over $3 billion: Ameren Corp., American Electric Power Company Inc., American Transmission Company LLC, Berkshire Hathaway Inc., CenterPoint Energy Inc., Dominion Energy Inc., Duke Energy Corp., Edison International, Entergy Corp, Evergy Inc, Eversource Energy, Exelon Corp., FirstEnergy Corp., Iberdrola SA, ITC Holdings Corp, National Grid Plc, PG&E Corp., Pinnacle West Capital Corp., PPL Corp., Public Service Enterprise Group Inc., Sempra Energy, Southern Company, and Xcel Energy Inc,. The underlying gross transmission investment data is accumulated from pages 204-207 of the FERC Form 1s for the subsidiaries of the listed utility holding companies.

Figure NCK-1.

Average Historical Transmission Investment for 2019-2022

(Nominal Dollars)



Q47. Do you expect this trend to continue?

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

VII. Costs Recovered Through the OSS/PJM Rider

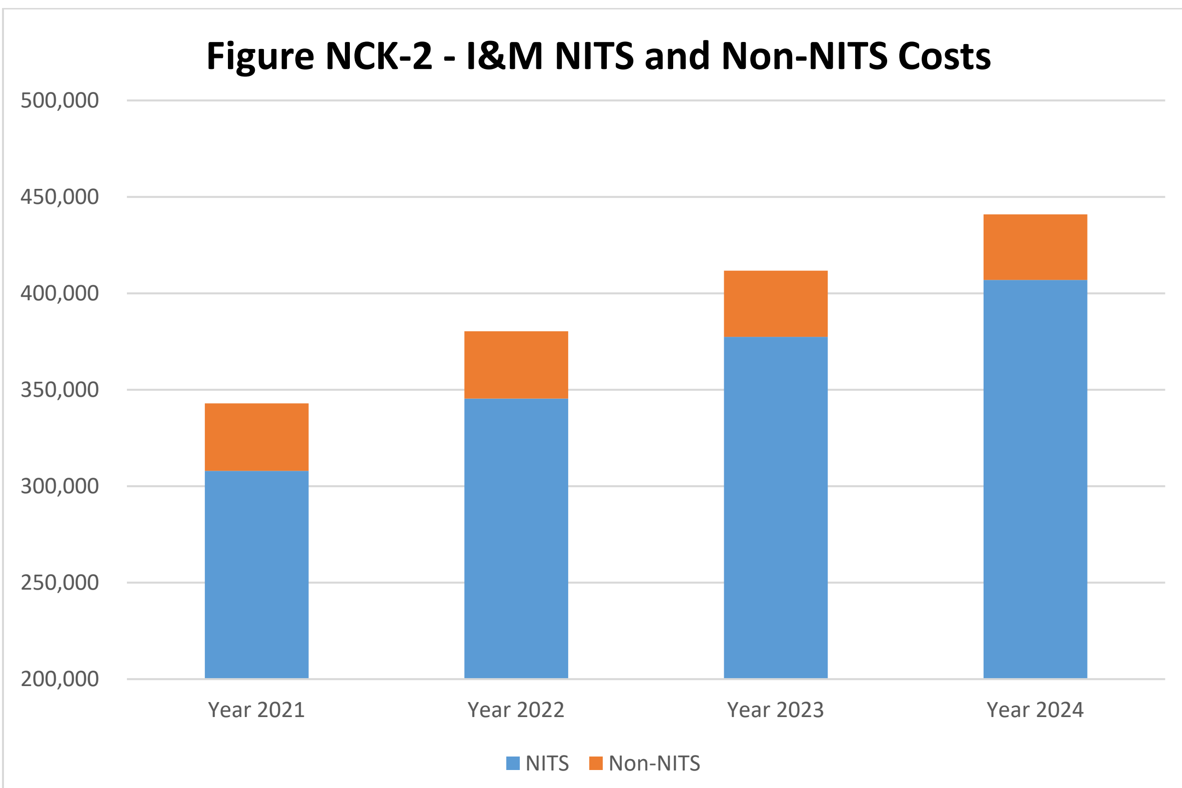
Q48. How are NITS costs billed to I&M?

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 Gruca addresses the operation of the OSS/PJM Rider in her testimony.

Q49. 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, as shown in *Figure NCK-2*.

Figure NCK-2.



Q50. 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 because they are recurring and have significant increases 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, PJM approvals, 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-3 illustrates that the collective impact of these drivers is to cause varying levels of annual investment (sometimes increasing, and sometimes decreasing year over year) over time in each AEP operating and transmission company's jurisdiction, including I&M's.

Figure NCK-3.

PJM AEP Zonal Gross Investment ($M)*

	2021	2022	2023	2024
Gross plant	$19,766	$21,406	$22,923	$24,545
Increase ($)	$2,183	$1,640	$1,517	$1,622
Increase (%)	12.4%	8.2%	7.1%	7.1%

* AEP affiliates only

Q51. 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.

Q52. 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.

Q53. 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.

Q54. 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: 8/8/2023

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

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Prepared by:	Jomar M. Perez	Manager, Asset Performance and Renewal
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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

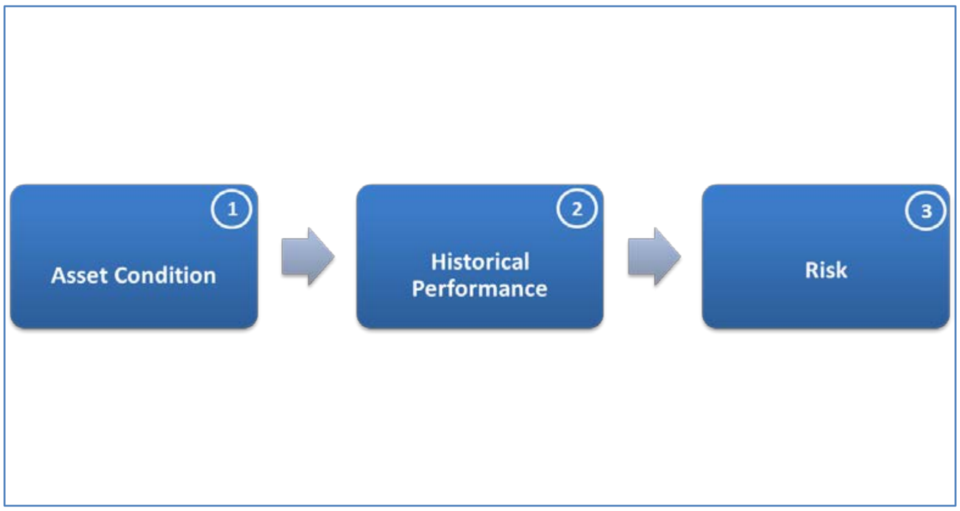
Internal, External, or Both	Inputs	Examples
Internal	Reports on asset conditions	Transmission line and station equipment deterioration identified during routine inspections (pole rot, steel rusting or cracking)
	Capabilities and abnormal conditions	Relay misoperations; Voltage unbalance
	Legacy system 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/