Indiana Michigan Power Company's Responses to the Indiana Utility Regulatory Commission's Request to Indiana Electric Utilities regarding Advanced Transmission Technologies

Disclaimer: Indiana Michigan Power Company and Indiana Michigan Transmission Company, Inc.'s ("I&M's") responses are being provided only to assist the IURC and its contractor in preparing its study of advanced transmission technologies. The responses do not necessarily represent I&M's or American Electric Power's (AEP) final positions on any issues including policy, resource adequacy, generation resources, and/or integrated resource planning.

Transmission Planning SME

1. What are the key challenges the utility faces in its transmission system, such as transfer limits, transmission constraints, load center areas, etc.?

I&M Response: *The transmission challenges faced by I&M/AEP are often complex and multifaceted. Addressing these challenges requires technical studies and sound engineering judgement. Each challenge the utility faces is unique and requires technical study and analysis to determine the most effective solution.*

2. How does the utility coordinate transmission system upgrades with neighboring utilities in case of affected system?

I&M Response: *I&M/AEP coordinate transmission system upgrades with neighboring utilities by completing transmission reliability studies as part of all projects. The PJM Regional Transmission Organization (RTO) also completes "do no harm" studies to ensure no affected systems violations occur.*

3. How does the utility coordinate transmission system upgrades that are derived from diverse assessments, (e.g., reliability-driven projects based on transmission reliability assessments) and policy-driven projects informed by economic or generation deliverability evaluations?

I&M Response: *I&M/AEP take a holistic view and consider all system needs when coordinating transmission system upgrades by participating in PJM's Regional Transmission Expansion Plan (RTEP). Each year PJM will consolidate the transmission needs across the PJM region into a single 5-year plan. More details regarding PJM's RTEP Process can be found in attachment B of PJM manual 14B found at the following link: https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf*.

4. When multiple facilities are overloaded, does the utility assess whether the facilities belong to the same corridor before choosing mitigation strategies? If so, how does corridor grouping influence the utility's solutions?

I&M Response: *I&M/AEP considers corridor-level conditions during solution development. Multiple overloaded facilities may signal a broader system need, making a comprehensive, coordinated solution more effective than addressing individual issues in isolation. This approach is reflected in both area-wide solutions, such as PJM project B3103, and more targeted projects, such as PJM project B2878.*

5. How does the utility coordinate and integrate mitigation plans initiated by steady-state, short-circuit, and stability assessments?

I&M Response: *Mitigation plans are typically coordinated through PJM's Regional Transmission Expansion Plan (RTEP) process. Each year PJM will consolidate the transmission needs across the PJM region into a single 5-year plan. More details regarding PJM's RTEP Process can be found in attachment B of PJM manual 14B found at the following link: https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf*.

6. What is the utility's timeline for conducting transmission assessments to comply with NERC TPL-001-5.1?

I&M Response: *Transmission assessments to comply with NERC TPL-001-5.1 are generally performed annually on the bulk electric system (BES) by the RTO (PJM or MISO).*

7. What unique assumptions underpin the reliability assessment base cases, including factors such as load projections, transfer limits to neighboring systems, and transmission constraints?

I&M Response: *Reliability assessment base case assumptions differ amongst RTOs and Transmission Owners (TO). PJM's Manual 14B provides insight into the modeling assumptions. Available at the following link: https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf*.

8. For which potential future violations does the utility propose mitigation plans? For example, are plans developed for violations forecasted to occur in 2, 5, or 10 years?

I&M Response: *I&M/AEP proposes mitigation plans for potential future violations based on the study timeline established by the RTO. In PJM this is typically a five-year study that drives mitigations. See Manual 14B. Available at the following link: https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf*.

9. What methodologies and criteria are used to identify transmission system violations and develop mitigation plans? (e.g., emergency ratings compared to continuous ratings)?

I&M Response: *I&M/AEP's methodologies to identify transmission system violations are detailed at the following document: https://docs.aep.com/docs/requiredpostings/TransmissionStudies/docs/2025/TransmissionPlanningReliabilityCriteria-Pioneer-2025_Filing.pdf*.

10. Are there any documented records of limiting factors for line ratings and transformer ratings, such as jumpers and disconnect switches? If yes, are the limiting factors taken into consideration while developing mitigation plans?

I&M Response: *Yes. When a violation occurs and is limited by a terminal element such as a switch, generally the most cost-effective solution is to replace that switch unless wider scale issues exist. An example of this is shown in the above referenced PJM project B2878.*

11. What is the regulatory process for proposing and approving of the proposed mitigation plan?

I&M Response: *The PJM process for proposing and approving mitigation plans is found in the PJM Manual 14B. Available at the following link: https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf*.

12. What is the utility's approach to prioritizing transmission projects?

<u>I&M Response:</u> *I&M/AEP's prioritization is based on a holistic view of the system including but not limited to system needs, required in service dates and real time operational constraints.*

13. What planning restrictions exist within the utility's system, such as proximity to sensitive facilities and specific areas with or challenging land acquisition?

<u>I&M Response:</u> *Broadly stated, environmentally sensitive areas and urban areas pose planning challenges.*

14. Has the utility implemented alternative transmission technologies in the past? If so, what were the outcomes?

<u>I&M Response:</u> *I&M/AEP has implemented a range of alternative transmission technologies, including advanced conductors, static synchronous compensators (STATCOMs), synchronous condensers, static VAR compensators (SVCs), tower height modifications, and dynamic line ratings, among others. Based on the company's experience, these technologies tend to be most effective in targeted applications, and overall performance outcomes have varied depending on the specific system conditions and use case.*

See also I&M's response to question 35 below.

15. What initial screening criteria or engineering judgment do you use to decide whether an advanced transmission technology ("ATT") is worth evaluating?

<u>I&M Response:</u> *Each advanced transmission technology has specific applications where it can provide value, and I&M/AEP evaluates these solutions when they are appropriate for the identified system need. For example, tower height modifications may not be effective if a conductor is already operating at its maximum operating temperature, as increasing clearance alone would not increase capacity. However, in situations where additional structure height enables greater allowable sag and a corresponding increase in line rating that resolves the constraint, such an approach may represent a viable solution.*

16. Do you have preferred or commonly used mitigation technologies (e.g., advanced conductors, tower lifting), or are all options evaluated equally?

I&M Response: *I&M/AEP does not have a preferred mitigation technology. Solution options are evaluated based on cost and the specific need being addressed.*

17. What are the common practices the utility uses to mitigate transient (dynamic) stability issues?

I&M Response: *Common solutions may include developing a new operational procedure for the generators with instability issues, adding dynamic reactive devices —such as Flexible AC Transmission System (FACTS)—in the vicinity, adding more transmission lines to strengthen the grid, or applying a combination of these solutions.*

18. What are the common practices the utility uses to mitigate voltage stability issues, including post contingency voltage recovery, reactive margin, etc.?

I&M Response: *I&M/AEP may consider a variety of solutions to mitigate voltage stability issues including but not limited to adding more dynamic reactive power capacity to the grid—such as installing Flexible AC Transmission System (FACTS)—in the vicinity of the problematic area, adding more transmission lines to strengthen the grid, or applying a combination of these solutions.*

19. When voltage issues are identified, are they typically addressed with local reactive support, or do they trigger broader system-level planning studies?

I&M Response: *It varies. Smaller voltage issues can often be addressed with relatively simple solutions, such as installing capacitor banks. However, more significant or rapid voltage fluctuations may require more advanced equipment, such as a STATCOM.*

The appropriate solution depends on how severe and widespread the issue is. If voltage problems occur on their own, a standard or advanced reactive device may be sufficient. But if the issues are more extensive - especially if there are also line capacity (thermal) concerns in the same area - a more comprehensive, system-wide solution may be necessary.

20. How does the utility determine the need for additional reactive power support?

<u>I&M Response:</u> *The need is determined generally through the RTO, such as PJM, and the TPL-005-1 process. NERC TPL-005-1 available at the following link: https://www.nerc.com/globalassets/standards/reliability-standards/tpl/tpl-001-5.1.pdf.*

21. What challenges exist in estimating the costs of ATTs?

<u>I&M Response:</u> *I&M/AEP has experience in implementing and estimating advanced transmission technology solutions and does not encounter challenges in simply estimating the costs.*

22. What are the utility's environmental permitting requirements for transmission upgrades?

<u>I&M Response:</u> *The environmental permitting requirements are dependent upon the impacted area and are specific for each project. In general the environmental permitting requirements include the following:*

- Section 404 of the Clean Water Act (CWA) - Nationwide Permit (NWP) or Individual Permit (IP)
- Section 401 of the CWA - Approved with NWP or Authorized by the State via IP
- Section 10 of the Rivers and Harbors Act of 1899 - Crossing a designated Navigable Water
- Section 7 or Section 10 of the Endangered Species Act (ESA) - Consultation using IPaC or Incidental Take Permit (ITP)
- Migratory Bird Treaty Act - No permits available, consult if necessary
- Bald and Golden Eagle Protection Act - General or Specific Permit for "take"
- Section 106 of the National Historic Preservation Act (NHPA)
- National Environmental Policy Act (NEPA) - Impacts to Federal Lands
- Section 401 of the CWA - Individual Water Quality Certification
- Stormwater Discharges from Construction Activities - NPDES General Permit INRA00000
- Indiana Flood Control Act (IC 14-28-1) - Construction in a Floodway (CIF) Permit
- Nongame and Endangered Species Conservation Act - Consultation with Natural Heritage Data Center to support Section 404/401 Permits
- Indiana Flood Control Act (IC 14-28-1) - Floodplain Development Permit
- Stormwater Discharges from Construction Activities - Local Municipal Separate Storm Sewer Systems (MS4)

23. What is the typical timeline for permitting a new transmission project?

<u>I&M Response:</u> *The timeline can vary widely based on the region, impacted area, and project type.*

24. How does the utility handle land acquisition challenges for new transmission corridors?

<u>I&M Response:</u> *I&M/AEP has processes/procedures in place to limit land acquisition challenges, including but not limited to extensive stakeholder outreach.*

25. Under what conditions does the utility consider RAS as a mitigation strategy?

<u>I&M Response:</u> *Due to the complexity, risk, and ongoing maintenance challenges of RAS solutions, I&M/AEP does not generally consider RAS as a planning mitigation strategy outside of interim operational solutions.*

26. What types of facilities or system conditions are considered critical, where topology changes or flow control solutions are restricted?

<u>I&M Response:</u> *All long-term topology or flow control solutions are studied via the PJM RTEP process to ensure there are no resulting violations or stability concerns.*

27. How does the utility evaluate the complexity of RAS solutions compared to conventional upgrades?

<u>I&M Response:</u> *I&M/AEP does not generally consider RAS as a planning mitigation strategy outside of interim operational concerns. Due to the complexity, risk, and ongoing maintenance challenges of RAS solutions, I&M/AEP prefers to address planning reliability issues through transmission upgrades where economically justified.*

28. Is there flexibility to modify mitigation plans, such as substituting transmission line upgrades with new substations?

<u>I&M Response:</u> *Effective and efficient planning is integral to I&M/AEP's solution process. An example being 765 kV technology which allows for fewer conductors without sacrificing electrical throughput. I&M/AEP will pursue more efficient plans if evolving system conditions warrant. Any modification to existing mitigation plans must be studied and approved by PJM to ensure that implementation of the new improvements would not jeopardize system integrity by delaying an existing planned upgrade.*

29. What is the procedure of cost allocation to the interconnection requests in a cluster study?

<u>I&M Response:</u> *Cost allocation varies by RTO and the type of interconnection request. See PJM cost allocation information in PJM manual 14B. Available at the following link: https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf.*

30. What is the procedure of cost allocation for load interconnection requests?

<u>I&M Response:</u> *Please see I&M's response to question 29.*

System Protection SME

31. How does the utility evaluate the impact of new generation and transmission upgrades on system protection settings?

<u>I&M Response:</u> *I&M/AEP has a tracking system in which each impactful change to the system is monitored and evaluated on a case-by-case basis. An area coordination study must be performed whenever changes are made to the transmission system that may affect relay coordination or fault current. These changes include new or modified transmission lines, transformers, and generators.*

32. What are the protection constraints that should be taken into consideration when implementing alternative transmission technologies?

<u>I&M Response:</u> *Any alternative transmission technology will cause changes to the system topology and those changes to system topology would necessarily need to be studied to determine the impact to system protection schemes and settings. An area coordination study must be performed whenever changes are made to the transmission system that may affect relay coordination or fault current.*

Future Outlook and ATTs Constraints

33. What regulatory or environmental barriers could impact the adoption of ATTs?

I&M Response: *No additional information beyond the other answers provided.*

34. What lessons has the utility learned from past transmission projects that could inform future decisions?

I&M Response: *AEP has over 100 years of experience implementing projects. For example, AEP pioneered the modern 765 kV system that serves as one of the major backbones for the bulk electric system in the United States. Having developed the first Extra High Voltage (EHV) transmission system at that voltage in the United States, AEP has been at the forefront of innovation in the industry through its engineering designs, construction techniques, and system operations at 765 kV for over 60 years. Many of the current standards, best practices, and operation guidelines used by the industry today were first developed by AEP engineers.*

35. Please list any initial concern that limits the implementation of the ATTs listed below in the utility's territory. For instance: (1) transmission switching might not be allowed near certain facilities; (2) tower lifting is not feasible in some areas or voltage levels due to environmental, regulatory, or pole structure constraints.

- Advanced Conductors
- Advanced Power Flow Control Devices (APFC)
- Static Synchronous Compensators (STATCOMs)
- Static VAR Compensators (SVCs)
- Synchronous Condensers
- Transmission Switching Technologies
- Tower Lifting Techniques
- Voltage Source Converters (VSCs)
- Dynamic Line Ratings (DLRs)

I&M Response:

- Advanced Conductors

Advanced conductors are more expensive than traditional conductors and therefore are generally utilized in instances where the amount of flow through a constrained corridor necessitates it. I&M/AEP periodically investigates the economic feasibility of these to ensure that underlying assumptions have not been modified.

- Advanced Power Flow Control Devices (APFC)

Generally speaking the use case for APFCs are niche and generally overshadowed by bypassable static impedance units. I&M/AEP implements these static units where flow control is indicative of a system design choice rather than a persistent problem. If a solution involves significant widespread flow controls, usually there is a more significant underlying system constraint.

- Static Synchronous Compensators (STATCOMs)

FACTS devices like this are regularly investigated and proposed as a solution. A main limiting factor is cost of implementation.

- Static VAR Compensators (SVCs)

FACTS devices like this are regularly investigated and proposed as a solution. A main limiting factor is cost of implementation.

- Synchronous Condensers

FACTS devices like this are regularly investigated and proposed as a solution. A main limiting factor is cost of implementation.

- Transmission Switching Technologies

All transmission assets are planned with a purpose and are planned under a N-1-1 scenario meaning at the most only 2 outages are accounted for. The system generally operates in a much more fractionalized mode, so taking lines out of service as a solution without reducing system reliability has a very limited use case.

- Tower Lifting Techniques

AEP has engaged and enacted many "sag studies" across its footprint to bring lines up to their maximum operating temperature which can include lifting the towers. However, the maximum operating temperature of AEP lines is set by the physical limits of the conductor, not the tower heights. There is an upper limit to this technique and it is not applicable to lines already operating at their limit.

- Voltage Source Converters (VSCs)

Voltage Source Converters have been, and continue to be, investigated and have very specific use cases. Due to this and due to the cost of implementation VSCs have yet to be selected in I&M.

- Dynamic Line Ratings (DLRs)

Due to the reliability cases already being set at a summer peak hour, DLRs are only viable in congestion studies and have no applicability to reliability violations. As PJM's load and generation interconnection studies are reliability based, DLRs are not a practical solution to load and generation interconnections. However, DLRs are a solution to potential congestion constraints but may be limited as it requires the line to be the limit and does not provide significant increase to ratings. Wide adoption of DLRs also causes significant challenges to real time operations due to the constant changing of system operating limits. This can make it difficult to respond to real time events and can cause issues for real time reliability. Due to AEP's adoption of temperature adjusted ratings, DLRs have minimal benefit on I&M/AEP's system.