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IURC Request to Indiana Electric Utilities
regarding Advanced Transmission Technologies

As you may be aware, Senate Enrolled Act (SEA) 422 from the 2025 legislative session requires the Indiana Utility Regulatory Commission ("Commission" or "IURC") to conduct a study on advanced transmission technologies ("ATTs"). The Commission is requesting your input, comments, ideas, research, and any relevant information you would like to provide regarding ATTs, including responses to the questions below developed by Electric Power Engineer, LLC ("EPE") who will be drafting the study report.

Please provide your responses no later than June 3, 2026. Thank you!

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.?

   Hoosier Energy's primary transmission challenges include managing thermal congestion on 69 kV and legacy 138 kV facilities serving dispersed rural load, accommodating new generation and load interconnections, and maintaining NERC compliance in corridors with limited right-of-way expansion.

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

   Hoosier Energy coordinates upgrades with neighboring utilities through the MISO regional planning process, joint planning and affected-system studies, and bilateral technical coordination to align assumptions, models, and in-service timelines.

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?

   Reliability-driven and policy-driven upgrades are evaluated within a unified planning framework to identify overlapping needs, shared corridors, and opportunities for integrated solutions while meeting distinct compliance and policy objectives.

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?

Hoosier Energy evaluates whether overloaded facilities share a common electrical corridor or path. Corridor grouping often supports comprehensive mitigation strategies that address multiple constraints simultaneously rather than isolated upgrades.

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

   Hoosier Energy works jointly through regional transmission operators and interconnection customers to evaluate mitigation plans for the most effective solution.

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

   Hoosier Energy conducts annual transmission reliability assessments with multi-year planning horizons consistent with NERC TPL-001-5.1 requirements and updates studies as system conditions change.

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

   Base cases reflect internally developed load forecasts, MISO transfer assumptions, known transmission constraints, planned projects, and conservative equipment ratings under normal and contingency conditions.

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?

   Mitigation plans are developed for anticipated violations identified in coordination with the relevant RTO system models within 2, 5, and 10-year horizons, with priority given to near-term reliability risks.

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

   Violations are identified using AC power flow, contingency, and stability simulations in conjunction with models provided by the RTO.

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?

    Limiting factors are documented on Hoosier's single line diagrams and considered during mitigation plan development.

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

    Mitigation plans are proposed through internal governance, coordinated with MISO where applicable, and submitted to the IURC as required for certification, cost recovery, and siting approval.

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

    Projects are prioritized based on safety need, reliability risk, compliance urgency, stakeholder/REMC impact, cost-effectiveness, and constructability.

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

    Restrictions include proximity to environmentally sensitive areas (ie state forests, protected species habitats), transportation corridors, residential development, existing infrastructure congestion, and land acquisition constraints.

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

    Hoosier Energy has implemented reactive support devices and operational measures with generally positive reliability outcomes, though cost and operational complexity remain considerations.

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

    Initial screening considers technical applicability, value to member systems, cost-benefit relative to conventional upgrades, constructability, operational complexity, and regulatory acceptance.

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

    While conventional solutions are often favored for operation efficiency, Hoosier Energy evaluates advanced conductors, structure modifications, and reactive devices where they provide measurable advantages.

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

    Common practices include additional reactive support, generation controls, and selective protection or remedial action schemes.

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

Voltage issues are addressed using local VAR resources (capacitors, etc), system reinforcement, or broader system studies when local mitigation is insufficient.

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

    Depending on the issue, most are addressed locally. Widespread or systemic concerns trigger broader planning studies.

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

    Reactive support needs are identified through voltage performance metrics, contingency analysis, and reactive margin assessments in our planning and engineering departments.

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

    Hoosier does not have a broad base of ATTs to pull historical cost data from, installations are often site specific, and vendor costs are unstable.

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

    Permitting typically involves state and federal environmental reviews, landowner coordination, and compliance with local zoning and land-use regulations.

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

    Permitting timelines vary but generally range from 12 to 36 months depending on project complexity, easement challenges, and site requirements.

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

    Hoosier has a real estate department that makes every effort to work with the landowners to acquire a fair market value for transmission easements and land acquisition.

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

    Remedial action schemes are considered when conventional upgrades are impractical and when schemes can be designed to be reliable, secure, and operationally manageable.

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

    Hoosier considers BES facilities, large load customers, and generation interconnections to be critical locations.

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

RAS solutions are evaluated for reliability, cybersecurity, maintenance burden, and operator training requirements.

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

    Yes, mitigation plans may be modified as system conditions change, subject to regulatory approval.

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

    Costs are allocated in accordance with MISO tariff provisions.

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

    Load interconnection costs follow applicable tariff and regulatory guidelines as directed by the RTO, generally assigning costs to the requesting entity for required system upgrades.

System Protection SME

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

    Hoosier assesses impacts through system studies conducted through the ASPEN modeling software. This includes short-circuit studies to verify relay coordination, fault current levels, system impedance, and relay settings reviews to ensure the proper operation and reliability given the new system conditions.

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

    Some protection constraints include but are not limited to lower or atypical fault conditions, system dynamics, complex impedances, and communication reliability. Often new ATTs require fast acting controls that could have limitations with the existing protection schemes.

Future Outlook and ATTs Constraints

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

    Some barriers are permitting timelines, siting limitations, environmentally sensitive area, cost recovery uncertainty, and limited regulatory precedent for certain ATTs.

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

Stakeholder communication and engagement are key. Cost estimation has been a challenge, along with adoption of new equipment practices.

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 – Constructability, material procurement, structural feasibility
    - Advanced Power Flow Control Devices (APFC) – Operational complexity, protection coordination
    - Static Synchronous Compensators (STATCOMs) – Cost, operational complexity, maintenance
    - Static VAR Compensators (SVCs) - Cost, operational complexity, maintenance
    - Synchronous Condensers – Siting, maintenance
    - Transmission Switching Technologies – operational risk, maintenance
    - Tower Lifting Techniques – Structural and environmental limitations
    - Voltage Source Converters (VSCs) – Cost, protection coordination
    - Dynamic Line Ratings (DLRs) – Data collection, operational integration