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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!

Disclaimer: Duke Energy Indiana's responses herein are being provided only 1) in an effort to assist the IURC in its study of advanced transmission technologies; and 2) within the limited context of our transmission system. None of the responses herein should be construed as a declaration of company policy, nor extrapolated to alternative circumstances including but not limited to 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.?
   Duke Energy Indiana Response:

   The current generation interconnection queue is a challenge to timely getting new generation or storage resources online due to volume and process. Additionally, the addition of new large loads can be challenging due to uncertainty of rules and requirements.

2. How does the utility coordinate transmission system upgrades with neighboring utilities in case of affected system?
   Duke Energy Indiana Response:

   Duke Energy Indiana participates in the MISO Affected System (AFS) study process. Per FERC Order 2023, the Affected System Study is now prescribed to be performed using ERIS methodology with results provided within 150 days of the potentially affected system being notified.

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?
Duke Energy Indiana Response:

Duke Energy Indiana participates in the MISO MTEP studies which include both baseline and policy-driven projects. If a project impacts another Transmission Owner Duke Energy Indiana will work with the affected transmission owner to coordinate the project.

From The 2025 MTEP Report - Executive Summary:

> The MISO Transmission Expansion Plan (MTEP) is the organization's primary tool for identifying and advancing the infrastructure needed to meet these challenges. Since 2003, MTEP has guided the approval of more than 6,800 total projects and upgraded or added nearly 79,000 miles of transmission projects, with over 10,000 miles of transmission line additions or improvements planned. These projects are the result of rigorous, transparent planning processes that engage stakeholders and align with evolving reliability, economic and policy goals.
>
> As the pace of disruption accelerates, MISO is evolving its planning approach to ensure the grid can continue to meet and stay ahead of the disruption. That includes integrating long-term policy signals, improving coordination with neighboring Regional Transmission Organizations (RTO), creating a focused process for load-driven generation needs, and accelerating the timeline from issue identification to MISO Board approval and developer selection for projects driven by urgent needs. The annual MTEP report captures the full scope of these efforts and reflects MISO's commitment to proactive, forward-looking transmission planning.
>
> MTEP is the result of a FERC-approved, Tariff-driven, transparent, and stakeholder-focused planning process. Each year, MISO evaluates proposed Transmission Owner projects, assesses system reliability needs, and ensures compliance with NERC standards. These traditional projects typically move from approval to operation within three to five years.

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?
   Duke Energy Indiana Response:

   Duke Energy Indiana will explore several mitigation options, looking at cost, feasibility of construction and timing, etc. before choosing a final solution.

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

Duke Energy Indiana will submit mitigation plans for steady-state, short-circuit, and stability assessments to MISO for review and acceptance. Duke Energy Indiana develops Operational Guides that are reviewed by both Company and MISO personnel.

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

Duke Energy Indiana utilizes and follows the MISO MTEP schedule for TPL-001-5.1. The following is the MTEP 26 Schedule.

MTEP 26

Planning is underway for MTEP26. MISO follows an approximate timeline for data requests, postings and email notifications for TPL-001 and planning stakeholder meetings. It roughly follows the 18-month MTEP calendar ending in December each year.

Month	Item
June	Transmission Owners provide any updates to the posted transmission planning criteria and provide any models used to support the identification of proposed projects
September	All project submittals due by the 15th
January	First Subregional Planning Meeting (SPM) MISO requests steady state contingencies from Transmission Owners
February	FERC 715 data filing request form sent
May	MISO posts steady state results for single initiating events for Transmission Owner review Deadline to submit project alternatives by the 31st Second Subregional Planning Meeting (SPM)
June	Second Subregional Planning Meeting (SPM) MISO posts steady state results for P3-P6 events for Transmission Owner review
August	TPL-001, MISO posts transient results for Transmission Owner Review Third Subregional Planning Meeting (SPM)
November	TPL-001, MISO posts extreme events steady state results for Transmission Owner review
December	MISO posts MTEP confidential appendices

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

Future generation resource addition assumptions and potential large load additions.

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?
Duke Energy Indiana Response:

For TPL-001-5.1, MTEP baseline reliability projects are submitted through 10 years.

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

   The MTEP is screened using the TPL-001-5.1 and emergency ratings criteria. Duke Energy Indiana, in tandem with other Duke Energy regions, has also developed an Equipment Ratings Methodology (ERM) and a Facility Ratings Methodology (FRM).

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?
    Duke Energy Indiana Response:

    Yes and Yes. Duke Energy abides by the FAC-008 requirements to represent all current carrying equipment when developing ratings on a facility. A facility is defined as a set of equipment that all carry the same current (in-series). This information is stored in a facility ratings database which determines the lowest equipment rating for a given facility. For example, a transmission line facility may contain switches, breakers, CTs, jumpers and overhead conductors. Each of these pieces of equipment are represented and the lowest individual rating is applied to the whole facility. These facility ratings are used by Duke Energy and supplied to MISO in accordance with the MISO SOL methodology.

11. What is the regulatory process for proposing and approving of the proposed mitigation plan?
    Duke Energy Indiana Response:

    Duke Energy Indiana follows the MISO approval process.

12. What is the utility's approach to prioritizing transmission projects?
    Duke Energy Indiana Response:

    Priority is based on (1) NERC TPL-001 driven reliability projects, (2) Generator Interconnection driven projects, (3) Load driven projects, (4) MISO LRTP projects, and (5) MTEP Public Policy projects.

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

    Planning restrictions could include, but are not limited to, federal, state, or local owned land, protected areas, conservation easements, culturally significant or sensitive areas, prime and unique farmland, specially designated land by local governments, and threatened and endangered species habitat. These sensitive facilities often come with limitations, specific requirements such as but not limited to, mitigation negotiations, additional approvals, additional compensations and/or denial of access/use. In highly developed areas, especially commercial and/or residential areas, it can be a challenge to find physical space for the new transmission facility due to structures, buildings, underground utilities, etc. In rural areas, many property owners propose reroutes within their own property into areas that are not feasible for the transmission line as well as located off their property which impacts other property owners.

14. Has the utility implemented alternative transmission technologies in the past? If so, what were the outcomes?
Duke Energy Indiana Response:

Yes. In the past, Duke Energy Indiana implemented DLR as an interim solution until a long-term solution was constructed and placed in-service. Duke Energy Carolinas has also utilized switchable reactors in lieu of line rebuilds which can be cost-effective, shorter schedule compared with a line rebuild project, and reliable. Where a reconductor or rebuild of a transmission line is the recommended solution to an identified transmission need, Duke Energy Indiana considers advanced conductors.

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

The ATT has to be a reliable, sustainable, and cost-effective solution whether needed as an interim solution or a long-term solution. Some of the screening considerations included in Duke Energy's Transmission Planning Solution Development Guidance business practice document are below.
Examples of reliability issues to consider in selecting alternative solutions include dependability, security, and coordination. Reliability Coordinator/Transmission Operator review and approval of a solution should be considered.

Dependability is a component of reliability that is the measure of certainty of a device to operate when required. If an alternative is selected to meet performance requirements of NERC Reliability Standards, a failure of the solution, when intended to be available, would put the system at risk of violating NERC Reliability Standards if specified contingencies or system conditions occur. This risk can be mitigated by designing the solution so that it will accomplish the intended purpose while experiencing a single component failure. This is often accomplished through redundancy.
Security is a component of reliability that is the measure of certainty of a device to not operate inadvertently. Design of the automated solutions must consider false or inadvertent operation that results in taking a programmed action without the appropriate arming conditions, occurrence of specified contingencies, or system conditions expected to trigger the action. Some automated actions include shedding load or generation or re-configuring the system. Such actions, if inadvertently taken, are undesirable and may put the system in a less secure state. Security enhancements to the design, such as voting schemes, are acceptable mitigations against inadvertent operations.

Coordination between automated solutions and other protection and control systems needs to be examined for possible adverse interactions. This review can include wide-ranging electrical design issues involving the specific hardware, logic, telecommunications, and other relevant equipment and controls that make up the proposed solution.

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

ATTs can be a reliable and cost-effective interim solution where long lead time equipment, such as high-voltage power transformers, take time to procure and place in-service. For example, Duke Energy Carolinas has investigated and received cost estimates for deploying an advanced power flow control device in a location that could defer the need for a large high-voltage power transformer to allow sufficient time for engineering, procurement, and construction to take place for the permanent, long-term solution. In addition, Duke Energy Indiana has implemented raising structures to improve clearance and raise line ratings as solutions to avoid line rebuild projects. Duke Energy Indiana continues to evaluate prudent use of ATTs, such as advanced conductors where due diligence has been performed. For advanced conductors, Duke Energy Indiana relies on due diligence such as testing of tensioning, bending radius, thermal cycling, simulated ice loading, etc. that has been performed by Duke Energy, industry colleagues, and/or EPRI.

Alternative solutions such as ATTs must be dependable and reliable for customers, and Duke Energy Indiana does not favor using its transmission systems as test beds for these advanced technologies. Several vendors' ATTs lack sufficient operating history or accelerated aging and harsh environment testing to properly understand potential failure mechanisms. Duke Energy is committed to working with industry colleagues and the Electric Power Research Institute ("EPRI") programs that are performing such testing to understand which ATTs can be reliable and cost-effective for customers. Furthermore, alternative solutions must not create conditions that are so complex that system operators are no longer able to maintain local and wide area situational awareness. Duke Energy uses transmission switching and remedial action schemes today in some jurisdictions, where prudent and reliable, to address studied contingency overload or voltage issues until a permanent solution can be implemented. These uses of transmission switching as alternative solutions are well studied, and Duke Energy Indiana is mindful that over-reliance on topology optimization based solely on thermal overload analysis and associated transmission switching can lead to circumstances where operators cannot adequately evaluate potential system risks such as transient stability. Duke Energy will continue to use resources from EPRI's Grid-Enhancing Technologies for a Smart Energy Transition program and due diligence when considering application of GETs, ATTs, and non-wires alternatives to ensure any operational complexity is minimized and operator situational awareness of system configuration is not lost. The application of GETs and ATTs will continue to be evaluated through implementation of FERC Orders 2023 and 1920 in collaboration with associated MISO processes.

17. What are the common practices the utility uses to mitigate transient (dynamic) stability issues?
Duke Energy Indiana Response:

Duke Energy Indiana has added redundant relay protection, new relay protection, and changed relay protection settings or relay type (e.g. setting or new relay that reduces total clearing time).

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

FERC Orders 827, 888, and 904 require FERC jurisdictional generators to have dynamic reactive capability to provide 0.95 leading to 0.95 lagging MVARs. In addition to generators' dynamic reactive capability for voltage stability, STATCOMS and SVCs can be deployed where determined to be needed through transmission planning studies.

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

Most potential voltage issues identified in studies are addressed with local reactive support.

20. How does the utility determine the need for additional reactive power support?
Duke Energy Indiana Response:

Reactive power support adequacy needs are evaluated through required NERC Reliability Standard TPL-001 studies, Large Load interconnection studies, NITS requests, and Generator Interconnection Studies. Any needs identified in these studies have associated solutions that can be implemented in the timeframe needed to ensure reliability for customers.

21. What challenges exist in estimating the costs of ATTs?
Duke Energy Indiana Response:

Through a charter initiative, Duke Energy has established an enterprise team of ATT subject matter experts that have strong relationships with ATT vendors and industry colleagues and participate in EPRI's programs that research and test these technologies. These subject matter experts are consulted to gain application information on due diligence, costs, operational characteristics, etc., for the eight enumerated ATTs in FERC included in Order 2023.

22. What are the utility's environmental permitting requirements for transmission upgrades?
Duke Energy Indiana Response:

Duke Energy Indiana is responsible for obtaining local, state, and federal environmental permits. These permits include:

- County/City Stormwater/Grading Permit
- County Regulated Drain Permit
- IDEM Section 401 (Waters of the United States) Permits
- IDEM Isolated Wetland Permits
- IDEM Construction Stormwater General Permits
- IDNR Construction in a Floodway Permits
- U.S. Army Corps of Engineers Section 404 (Waters of the United States) Permits
- U.S. Army Corps of Engineers Section 10 Navigable Water Crossing Permits

23. What is the typical timeline for permitting a new transmission project?
Duke Energy Indiana Response:

The table below outlines typical expected review timelines encountered.

Agency	**Anticipated Review Timeframe (days)**
County/City Stormwater/Grading Permit	30-90
County Regulated Drain Permit	30-60
IDEM Section 401 (Waters of the United States) Individual Permit	90-180
IDEM Section 401 (Waters of the United States) General Permit	30
IDEM Isolated Wetland Permit	90-120
IDEM Construction Stormwater General Permit	30
IDNR Construction in a Floodway Permit	180
U.S. Army Corps of Engineers Section 404 (Waters of the United States) Individual Permit	180
U.S. Army Corps of Engineers Section 404 (Waters of the United States) General Permit	30-60
U.S. Army Corps of Engineers Section 10 Navigable Water Crossing Permit	30-90

Duke Energy's environmental permitting team has identified schedule risks associated with recent local and state policy changes.

At the local level, concerns stem from 2025 amendments to Indiana Code 36-1-3-14.

Effective May 1, 2025, HEA 1037 amended Indiana Code 36-1-3-14 and limited local construction stormwater requirements, including those adopted by MS4 communities. Local laws and ordinances may not be more stringent than IDEM's Construction Stormwater General Permit, and any conflicting local requirement is void.

Despite this change, some municipalities continue to impose more stringent ordinance and bonding requirements, creating regulatory inconsistency and delaying projects.

The IDEM Water Quality Section has also begun treating temporary wetland impacts, such as temporary matting, as activities requiring an IDEM Section 401 Individual Permit. These permits have introduced additional conditions, including broadly worded requirements for at least two years of vegetative monitoring after wetland restoration. This extends beyond standard Construction Stormwater General Permit requirements, which call for a minimum 70 percent vegetation establishment. As a result, future utility projects may face increased costs and schedule impacts due to unclear wetland restoration expectations.

24. How does the utility handle land acquisition challenges for new transmission corridors?
Duke Energy Indiana Response:

Duke Energy has a comprehensive evaluation approach that combines both quantitative and qualitative assessments in the selection and development of new transmission corridors. This includes a multidisciplinary team made up of approximately 10-15 subject matter experts. Additionally, public and stakeholder outreach is an integral component of the approach, and feedback received during those efforts is included in the evaluation. This approach ensures a proactive robust analysis of all relevant factors and assists in identifying potential challenges to the project earlier in the process. The evaluation is what drives the selection of the location of a new transmission corridor. The comprehensive evaluation provides the backbone for the justification for acquisition and confidence in the development of a successful acquisition strategy. Landowners are contacted several times and Duke Energy Indiana demonstrates a genuine commitment to good faith negotiations. When presenting offers, appraisals are relied on and ensure that the proposed amounts meet or exceed fair market value. Examples of specific challenges encountered with acquisition include but are not limited to, establishing contact with property owners, rights and cost negotiations, and property owners requesting reroutes. Additionally, approvals become much more involved when properties are located on sensitive lands, requiring extra steps and careful consideration. We also sometimes face public opposition to a project, which can influence both negotiations and the approval process timeline.

25. Under what conditions does the utility consider RAS as a mitigation strategy?
Duke Energy Indiana Response:

Duke Energy Indiana currently does not have any Remedial Action Schemes.

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

Topology changes or transmission system reconfiguration must be studied prior to implementation to ensure stability issues are not being introduced associated with the reconfigured system.

27. How does the utility evaluate the complexity of RAS solutions compared to conventional upgrades?
Duke Energy Indiana Response:

Duke Energy Indiana currently does not have any Remedial Action Schemes. Due to the NERC compliance burden and complexity of a Remedial Action Scheme, Duke Energy Indiana currently does not consider the use of a Remedial Action Scheme.

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

Yes, Duke Energy Indiana will explore several mitigation options, looking at cost, feasibility of construction and timing, etc. before choosing a final solution.

29. What is the procedure of cost allocation to the interconnection requests in a cluster study?
Duke Energy Indiana Response:

The MISO generator interconnection process, Definitive Planning Phase (DPP) process uses a cluster study process with three study phases to refine interconnection cost estimates and network upgrade cost estimates, phase I, phase II and phase III.
For DPP phase I, transmission owner (TO) provides an initial rough estimate of the interconnection costs for each interconnection project. MISO performs power flow analysis (ERIS and NRIS analysis) to determine overloads and network upgrade costs. Upgrade costs are assigned to the Interconnection Customers (ICs) who cause the need for the facilities or whose projects benefit from them. If multiple projects trigger the same Network Upgrade the costs are shared among them based on their relative MW output contribution to the identified constraints (DFAX). TO reviews overloads and cost estimates results from MISO DPP phase I.
For DPP phase II, TO performs detailed interconnection cost estimates through Interconnection Customer interconnection Facility (ICIF) study. The ICIF costs are used to develop the Generator Interconnection Agreement (GIA). MISO

performs power flow analysis to determine overloads and network upgrade costs at Phase II. TO reviews overloads and cost estimates results from MISO DPP phase II.
For DPP phase III, the network upgrade determined by phase III power flow analysis and reviewed by TO will enter in a Network Upgrade Facility Study (NUFS). The detailed cost estimates in the NUFS are used to develop the GIA.

30. What is the procedure of cost allocation for load interconnection requests?
Duke Energy Indiana Response:

For new load additions, network upgrades required on the TO system are allocated to the TO, and then typically recovered from customers through rates. Currently, there are no mechanisms in place that Duke Energy Indiana is aware of in MISO to allocate network upgrade costs on interconnected TO systems to anyone other than the Transmission Owner in a situation where new load is being added through the MISO Transmission Expansion Process (MTEP) or Expedited Project Review (EPR) process.

System Protection SME

31. How does the utility evaluate the impact of new generation and transmission upgrades on system protection settings?
Duke Energy Indiana Response:

Every project that introduces a new element to the transmission system is studied for its impact on protective settings at and around the local bus by Duke Energy Protection and Controls Engineering. It is also evaluated at a high-level during project development for grid configuration, breaker duty and interrupting capacity, and protective scheme selection. In addition to this, Duke Energy is guided by and compliant with NERC standard PRC-027-1 R2, excerpt provided below.

> R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]
> • Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six-calendar years; or
> • Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the BES Element is connected, all in a time interval not to exceed six-calendar years; 1 or,
> • Option 3: Use a combination of the above.

In Duke Energy Indiana, we follow option 3 and perform the fault current study and subsequent coordination studies every time we release a new revision of our Aspen Oneliner Base Case, which is the modeling software used to model the entire Indiana transmission system for short circuit and coordination analysis. We perform this twice every year.

32. What are the protection constraints that should be taken into consideration when implementing alternative transmission technologies?
Duke Energy Indiana Response:

ATTs such as advanced power flow control devices can change effective line impedance in real-time to manage/alter power flows. This change in impedance can impact the performance of protective relays and needs to be considered in the engineering design and application of an advanced power flow control device. Although not as dynamic as the impact on impedance with an advanced power flow control device, the introduction of a non-wires alternative such as a series reactor can impact line impedance as well, and associated impacts to protective relay settings needs to be considered with the engineering design.

<u>Future Outlook and ATTs Constraints</u>

33. What regulatory or environmental barriers could impact the adoption of ATTs?
Duke Energy Indiana Response:

If an ATT is an interim solution such as an Advanced Power Flow Control device or solely for real-time operations utilization such as Dynamic Line Ratings, the burden of prudency is on the utility, however, some assurance of cost recovery is needed. These are nascent technologies where several vendor technologies have short operational track records and thus operational risks are incurred by the utility using one of these ATT solutions in lieu of a traditional solution or an ATT such as Advanced Conductors that have been properly tested for reliability and sustainability. Some of these ATTs may require real estate acquisition for installation. Property ownership, permitting, siting, and easements are challenges that need to be considered during the development phases.

34. What lessons has the utility learned from past transmission projects that could inform future decisions?
Duke Energy Indiana Response:

Duke Energy participates in EPRI's GET SET program that allows for discussion with other utilities that are considering using or have used certain ATTs, with discussions with vendors of various ATTs, and access to EPRI's accelerated environment testing of ATTs to determine if any failure mechanisms exist with a particular ATT design. Prudent application of reliable ATT solutions can provide value for customers. Duke Energy Indiana has utilized DLR as part of an interim operating plan while constructing a longer-term solution line rebuild project. This interim solution assisted System Operations with maintaining system reliability and avoiding impacts to customer service.

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)

    Duke Energy Indiana Response:

    - **Advanced Conductors** – Advanced Composite Carbon Core Conductors have very different mechanical properties compared with steel core conductors and thus proper installation techniques need to be employed and physical loading such as ice loading needs to be considered in the design for the climatology of the location of application. Having an overly restrictive definition of "Advanced Conductor" in regulatory rules or state statutes that only allows one or two advanced conductors to be utilized will hamper advanced conductor applications. EPRI has a defendable definition of "Advanced Conductor" that allows for a selection from a broader list of advanced conductor vendors and types that will encourage utilization.
    - **Advanced Power Flow Control Devices (APFC)** – As mentioned in response to Item 33, Advanced Power Flow Control Devices need to have proper accelerated testing such as in high ambient heat and high moisture environments such that failure mechanisms are known and corrected prior to application on the critical Indiana transmission system. Other issues to consider include costs, maintenance, and cyber security of these devices.
    - **Static Synchronous Compensators (STATCOMs)** – STATCOMS have been utilized for many years and have a reliability track record for application where determined needed to provide for voltage stability.
    - **Static VAR Compensators (SVCs)** – SVCs have been utilized for many years and have a reliability track record for application where determined needed to provide for voltage stability.
    - **Synchronous Condensers** – Synchronous Condensers have been utilized for many years on power systems and have a reliability track

record for application where determined needed to provide for voltage and dynamic stability.

- **Transmission Switching Technologies** – Transmission switching where determined through proper studies can be reliable. Mindful of any Transmission topology optimization that reconfiguration doesn't introduce any unforeseen system instability. Current solutions are thoughtfully developed through manual reviews, processes, and Operator/Engineering input. Failing to include behind the meter generation and increased penetration of distributed energy renewables (DERs) into Transmission Switching Technologies, along with forecasting of inverter-based resources and differences in Planning v. Operational models, could lead to unpredictable results compared to conventional methods.
- **Tower Lifting Techniques** – This technique should not just apply to lattice towers. Replacing wooden structures with taller steel structures that provides more clearance for transmission conductors and provides a higher facility rating should qualify as "tower lifting".
- **Voltage Source Converters (VSCs)** – Typically associated with converting alternating current (AC) to high-voltage direct current (HVDC) and vice versa, primarily for long-distance power transmission. HVDC can be used to modulate AC power flows on the surrounding AC power system.
- **Dynamic Line Ratings (DLRs)** – In general, Dynamic Line Ratings should provide more accurate real-time thermal conductor line ratings for system operations. In addition to conductor properties such as resistance and the amount of current flowing through the conductor, ambient air temperature, wind cooling and solar heating are two additional variables that DLR can utilize as inputs to provide the more accurate real-time line ratings. DLR applied to identified transmission line spans that can be constraints requiring transmission loading relief such as out-of-economic dispatch (raising the output of Helper generation and reducing or curtailing the output of Harmer generation) can alleviate the need for the out-of-economic dispatch. This avoidance depends on the real-time values of the aforementioned variables (conductor properties such as resistance, current, ambient air temperature, wind cooling, and solar heating) and the accuracy of the resulting dynamic line ratings. Dynamic Line Ratings are not viewed as an ATT that can be used to provide for long term facility ratings in planning studies.

  Duke Energy is piloting DLR sensor application to gain learnings and determine the value of potential future applications for DLR on its system.