Cause No. 46193

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February 14, 2025
INDIANA UTILITY
REGULATORY COMMISSION

On Behalf of Petitioner,
DUKE ENERGY INDIANA, LLC

VERIFIED DIRECT TESTIMONY OF KELLEY A. KARN

Petitioner's Exhibit 2

February 13, 2025

DIRECT TESTIMONY OF KELLEY A. KARN
VICE PRESIDENT, REGULATORY AFFAIRS & POLICY
ON BEHALF OF
DUKE ENERGY INDIANA, LLC
INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kelley A. Karn, and my business address is 1000 East Main Street, Plainfield, Indiana 46168.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Vice President, Regulatory Affairs & Policy for Duke Energy Indiana, LLC ("Petitioner," "Duke Energy Indiana," or "Company"), a wholly owned subsidiary of Duke Energy Indiana Holdco, LLC and an affiliate of Duke Energy Corporation ("Duke Energy").

Q. PLEASE BRIEFLY DESCRIBE YOUR JOB DUTIES AS VICE PRESIDENT, REGULATORY AFFAIRS & POLICY.

A. As Vice President of Regulatory Affairs & Policy, I provide advice and support on the key regulatory issues facing Duke Energy Indiana, such as our long-term strategic planning and near-term regulatory priorities. I also engage with external stakeholders regarding key regulatory initiatives for Duke Energy Indiana.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated with a Bachelor of Arts degree in Government with a concentration in Public Policy from the University of Notre Dame, Notre Dame, Indiana. My law degree was obtained in 2000 from the Indiana University McKinney School of Law, Indianapolis, Indiana. I've been employed by Duke Energy or predecessor companies since 1998 when I began as a law clerk with the Indiana regulatory legal team and promoted to Counsel in 2000. I was promoted to lead the regulatory legal team in 2006 and to Deputy General Counsel in 2008. I was most recently promoted to my current position in 2021.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony provides support for Duke Energy Indiana's request for a certificate of public convenience and necessity ("CPCN") to construct a combined-cycle natural gas-fired plant ("Cayuga CC Project") on available property at the existing coal-fired Cayuga Generating Station site. Duke Energy Indiana will be retiring the two older coal-fired units with a combined winter rating of 1,005 MW currently located on the site. The Cayuga CC Project's configuration consists of two 1x1 Advanced Class Combined Cycle gas units. Each block will have a winter rating capacity of approximately 738 MW, for a combined winter rating of 1,476 MW, an addition of 471 MW on site. One block will be available starting in September 2029 ("CC 1") and the second in May 2030 ("CC 2").

I identify many of the environmental regulations applicable to coal-fired units at Cayuga. I explain how these environmental regulations were incorporated into Duke Energy Indiana's 2024 Integrated Resource Plan ("IRP") preferred portfolio, and the Company's decision to construct the Cayuga CC Project. I will explain how the Cayuga coal facilities, after almost 60 years of service, are nearing the end of their useful life and how environmental regulations make it difficult and cost prohibitive for Duke Energy Indiana to continue to burn coal as the fuel source at Cayuga. I will also explain how the Cayuga CC Project is positioned to allow Duke Energy Indiana to achieve compliance with current regulations and will provide flexibility to address future regulations. I also identify the major environmental permits needed for the Cayuga CC Project and Duke Energy Indiana's plans for ensuring all permits are secured. I describe how the Cayuga CC Project qualifies as a clean energy project for purposes of Ind. Code ch. 8-1-8.8.

Further, I will discuss how the Cayuga CC Project will interconnect into the Midcontinent Independent System Operation Inc. ("MISO") grid through both MISO's Generator Replacement Process, and MISO's traditional generator interconnection queue process, the Definitive Planning Phase ("DPP") process. I will also explain the Cayuga CC Project's expected contribution to Duke Energy Indiana's system reliability and other benefits of the proposed Cayuga CC Project as requested in the IURC General Administrative Order ("GAO") No. 2022-01, and I include MISO's Affidavit in support of GAO 2022-01 as Attachment 2-A (KAK).

Finally, I provide background on Duke Energy Indiana's demand side management energy efficiency and demand response programs, explain how they were considered in the IRP and how they continue to provide value to customers.

II. ENVIRONMENTAL REGULATIONS

Q. PLEASE IDENTIFY SOME OF THE EXISTING AND FUTURE ENVIRONMENTAL REGULATIONS THAT ARE APPLICABLE TO CAYUGA'S COAL OPERATIONS.

A. Cayuga's coal operations are dealing with newer stringent Effluent Limitation Guidelines ("ELG") which regulate wastewater discharges, Mercury and Air Toxics Standards ("MATS"), which are technology-based emissions standards for mercury and other hazardous air pollutants ("HAP") emitted by units with a capacity of more than 25 megawatts, National Pollutant Discharge Elimination System ("NPDES") permitting limits associated with its cooling towers, including Clean Water Act, Sections 316(a) and 316(b), as well as Greenhouse Gas ("GHG") New Source Performance Standards under the US Clean Air Act ("CAA") Section 111(d), which if the rules survive legal challenge, would establish emissions guidelines in the form of CO_2 emissions limitations for certain existing electric generating units ("EGUs").

Q. DID DUKE ENERGY INDIANA INCORPORATE THESE ENVIRONMENTAL LAWS AND REGULATIONS IN ITS 2024 IRP?

A. Yes. Duke Energy Indiana witness Gagnon discusses the preferred portfolio and short-term action plan in detail and sponsors the IRP. But in summary, Duke Energy Indiana's 2024 IRP considered compliance costs with existing rules and regulations as part of the planning process, as well as potential future regulatory actions that should also be considered when making long-term decisions regarding the generation portfolio. Looking at the actual and potential impacts holistically ensured Duke Energy Indiana can meet future resource needs and environmental requirements in a reliable and economic manner with flexibility. Appendix J of the IRP, provided as Attachment 6-A (NDG) to witness Gagnon's testimony, discusses the existing environmental law and regulation, the risks associated with anticipated and potential changes to environmental regulations, and how the environmental regulations were included in IRP modeling.

Q. ARE THERE ANY ENVIRONMENTAL COMPLIANCE ISSUES THAT ARE ESPECIALLY UNIQUE TO THE EXISTING UNITS AT THE CAYUGA STATION?

A. Yes. Although a prudent investment at the time of installation, as time marches forward, it has become clear that the existing cooling towers struggle to keep up with increasingly stringent regulations. As a result, Duke Energy Indiana's NPDES permit limits the units' run times, particularly during hot and dry summers. New cooling towers, which are set to be constructed with the Cayuga CC Project, should eliminate this problem. As I will discuss below, the historically limited run times also created a risk of reducing the accredited capacity of the coal plant, which should be considered when evaluating resource adequacy.

Q. ARE ENVIRONMENTAL LAWS AND REGULATIONS ONE DRIVER FOR THE NEED TO REPLACE THE GENERATION CURRENTLY AT CAYUGA?

A. Yes. Continued operation of the Cayuga steam generators into the 2030s or later would be complicated by the need to comply with ELG and potentially add closed-cycle cooling to achieve compliance with Sections 316(a) and 316(b) Clean Water Act requirements. However, the existing coal-fired units at Cayuga have an age factor that must also be considered. As also discussed by Duke Energy Indiana witness Pinegar, the existing units are the oldest coal-fired generators in the Company's portfolio and have provided service for around six decades. Originally constructed assuming a thirty-year life, the equipment onsite has far surpassed that original expectation. There is a tipping point where current equipment needs to be replaced to support continued environmental compliance and ongoing reliability. Duke Energy Indiana has cautiously evaluated what the most cost effective option looks like for customers in its 2024 IRP. The Company estimates that to continue operating the Cayuga units on coal would require additional environmental and maintenance expenditures in the near term of about $430 M. In summary, it is the age of the units, combined with the maintenance and compliance costs associated with continued operation on coal, that makes retirement and replacement of the existing Cayuga coal-fired steam generators in 2029 and 2030 with units that provide additional value, the reasonable and prudent course of action for the Company and its customers.

Q. WILL THE CAYUGA CC PROJECT YIELD ENVIRONMENTAL BENEFITS?

A. Yes. As can be seen below, once both CCs are placed in service, the maximum emissions from the new combined cycle units are significantly lower than the actual emissions for the existing coal plant for all pollutants except for carbon monoxide ("CO"), volatile organic compounds ("VOC"), and greenhouse gases ("GHGs"). This is, in part, because the natural gas plant is expected to operate at a higher capacity factor and provide 471 MW more than the retiring coal plant. The emission of CO and VOC from the new CCs are based on conservative vendor guarantees, continuous operation, and maximum capacity. Similar units have demonstrated that they emit well below these levels. Even so, many categories of maximum emissions from the new CCs are still expected to be lower than the actual historical emissions from the coal plant.

Pollutant	Actual emissions from two (2) coal fired boilers and auxiliary equipment (tons/yr)[1]	Maximum emissions from two (2) new CC and auxiliary equipment (tons/yr)[2]	Difference max emissions from new equip. - actual emissions from existing equip. (tons/yr)
CO	552	680	128
Nox	4,608	496	-4,111
VOC	66	100	34
PM	174	169	-6
PM10	657	226	-432
PM2.5	606	224	-381
SO2	2,392	33	-2359
CO2e (GHG)	5,113,819	6,390,462	1,276,643
Combined HAPs	34	8	-27

[1] Maximum 12 month rolling sum of actual emissions for the existing equipment from July 2020- Sept 2023 as taken from the permit application, excluding CT-4.
[2] Maximum emissions from two (2) new natural gas CCs and auxiliary equipment assuming continuous operation at maximum capacity and conservative emissions factors identified in the combine cycle permit application.

Additionally, thermal impacts on Wabash River will be improved through the use of closed cycle cooling for the combined cycle plant as opposed to the once through cooling on the existing coal-fired generation. Further eliminated is any ongoing operating and capital investment associated with the current coal-related environmental compliance equipment.

Q. WILL THE CAYUGA CC PROJECT BE BETTER SITUATED FOR ITS AIR PERMIT GIVEN THAT IT WILL BE CONSTRUCTED ON A SITE ALREADY USED FOR GENERATION?

A. Yes. Constructing the Cayuga CC Project on a site already used for the generation of electricity allows us to take credit for the actual emissions reductions from the retirement of the first coal unit, avoiding prevention of significant deterioration ("PSD") applicability for NOx, PM10 and PM2.5.

Q. WILL ANY ENVIRONMENTAL LAWS AND REGULATIONS APPLY TO THE CAYUGA CC PROJECT?

A. Yes. While the Cayuga CC Project has many environmental benefits and eliminates the need to invest in ELG and MATS compliance going forward, it must still comply with the new GHG standards,[1] assuming they withstand regulatory modifications and legal challenges, applicable EPA new source performance standards ("NSPS"), and other environmental permitting from the Indiana Department of Environmental Management ("IDEM").

The Cayuga CC Project is well positioned to comply with GHG standards as it utilizes the most efficient gas turbines on the market today. However, the final rule would require a 40% limitation on the capacity factor of the units beginning in 2032, which was considered in Duke Energy Indiana's IRP modeling. EPA recently published a proposed rule updating the NSPS for new combustion turbines that could apply to one or both of the new Cayuga CCs. Again, the units as designed are well positioned to comply with the proposed rule.

Q. PLEASE SUMMARIZE SOME OF THE ENVIRONMENTAL PERMITS THE CAYUGA CC PROJECT WILL NEED AND DISCUSS DUKE

[1] The final GHG Rule, 40 CFR § 60.5509, applicable to *new* gas combustion turbines was published in the Federal Register on May 9, 2024. See 89 FR 39798.

ENERGY INDIANA'S PLAN AND TIMELINE FOR RECEIVING ALL NECESSARY PERMITS.

A. Duke Energy Indiana submitted an air permit application to IDEM on January 17, 2024 for the Cayuga CC Project. IDEM issued the draft permit on November 18, 2024. The 30 day public comment period began on January 10, 2025, and the final permit is expected to be issued in the second quarter of 2025. Duke Energy Indiana and IDEM are currently working on a renewal of the existing plant's NPDES permit. Duke Energy Indiana currently expects this renewal permit to be issued in the second quarter of 2025. Following issuance of the NPDES renewal permit, Duke Energy Indiana will submit an NPDES permit modification request to IDEM for the Cayuga CC Project. Duke Energy Indiana is currently evaluating engineering information to assess any other environmental permitting requirements and gather necessary permit application information and will continue to do so as additional project details become available. Duke Energy Indiana will continue to work diligently to ensure that permits will be obtained in a timely manner.

Q. DO ENVIRONMENTAL LAWS AND REGULATIONS CHANGE?

A. Yes, which is why Duke Energy Indiana approached its IRP with flexibility in mind. The chosen path forward was strategic in considering alternate futures, including potential changes in environmental laws and regulations that come with legal challenges and changes in federal and state administrations. For example, even if the GHG standards don't survive in the near term, there is still likely to be additional pressure on power plant emissions in the future, adding risk to the continued reliance on coal units. So, as discussed more by Company witness Gagnon, the IRP reviewed scenarios with and without greenhouse gas environmental rules.

Q. IS THE CAYUGA CC PROJECT POSITIONED TO COMPLY WITH POTENTIAL FUTURE CHANGES?

A. Yes. While Duke Energy Indiana cannot predict the future, the preferred portfolio, which calls for the Cayuga CC Project, fared well under changing environmental conditions, such as a scenario with no greenhouse gas emissions restrictions (*i.e.*, the Minimum Scenario) and one with even stricter greenhouse gas emission restrictions (*i.e.,* the Aggressive Scenario). *See* witness Gagnon Attachment 6-A (NDG) (IRP, Ch. 4).

III. THE CAYUGA CC PROJECT IS A "CLEAN ENERGY PROJECT" FOR PURPOSES OF IND. CODE CH. 8-1-8.8

Q. IS THE CAYUGA CC PROJECT A "CLEAN ENERGY PROJECT" AS DEFINED IN IND. CODE CH. 8-1-8.8 MAKING IT ELIGIBLE FOR CERTAIN FINANCIAL INCENTIVES?

A. Yes. Ind. Code § 8-1-8.8-2(5) states "Clean Energy Project" for purposes of Ind. Code Ch. 8-1-8.8 include, among other things, projects to construct or repower a facility described in Ind. Code § 8-1-37-4. Specifically, Ind. Code § 8-1-37-4(a)(21) describes "Clean Energy Resources" as including sources used in connection with the production of electricity that is generated from natural gas at a facility constructed or repowered in Indiana after July 1, 2011 that displaces electricity generation from an existing coal fired generation facility.[2] As the existing Cayuga units that are nearing the end of their useful life happen to be coal-fired and they are being replaced with natural gas fired turbines, this makes the Project a resource the Clean Energy Project statute was designed to encourage. As such, the Company is eligible for financial incentives under Ind. Code § 8-1-8.8-8 if the Cayuga CC Project is found to be just and reasonable. As further discussed by Company witness Sufan, using the incentives of the clean energy statute, Duke Energy Indiana is able to make this project more affordable for customers through the construction work in progress ("CWIP") ratemaking.

Q. IS THE CAYUGA CC PROJECT CONSISTENT WITH THE STATE POLICY GOALS OF THE CLEAN ENERGY STATUTE?

A. Yes. Ind Code § 8-1-8.8-1 provides: "It is in the public interest for the state to encourage the construction of new energy production or generating facilities that increase the in-state capacity to provide for current and anticipated energy demand at a competitive price" and the purpose of the chapter is to ensure "Indiana's and the region's energy production or generating capacity continues to be adequate to provide for Indiana's current and future energy needs, including the support of the state's economic development efforts".

The Cayuga CC Project directly meets these goals. It is increasing in-state dispatchable generating capacity, as soon as possible, with the most efficient natural

[2] Ind. Code § 8-1-37-4(a)(21).

gas turbines on the market today. It will be well positioned to serve anticipated demand, including the supporting the state's economic development efforts and improving the state's energy security.

IV. MISO GENERATOR INTERCONNECTION

Q. PLEASE BRIEFLY DESCRIBE MISO.

A. MISO is a non-profit, member-based Regional Transmission Organization. MISO performs the North American Electric Reliability Corporation ("NERC") roles of reliability coordinator and balancing authority for Duke Energy Indiana utilizing an extensive network model of the MISO interconnected reliability region, which includes Duke Energy Indiana and surrounding systems. MISO conducts an annual capacity auction and manages one of the world's largest energy and operating reserves markets using security-constrained economic dispatch of generation. The MISO energy and operating reserves market includes a day ahead market, a real-time market, and a financial transmission rights market (collectively, the "MISO Market"). These markets are operated and settled separately. MISO's charges to provide services are recovered pursuant to its Federal Energy Regulatory Commission ("FERC") tariff.

Q. HOW WILL THE CAYUGA CC PROJECT BE CONNECTED TO THE GRID AND ACCESS THE MISO MARKET?

A. The Cayuga CC Project will interconnect into the bulk electric system using the existing interconnection substation at Cayuga currently utilized by the retiring units. These MISO grid interconnection rights can be transferred from the existing coal units to the Cayuga CC Project, pursuant to Section 3.7 of MISO's Generator Interconnection Procedures, MISO's Attachment X. Any request to interconnect replacement generation must be submitted at least one year prior to the date the existing generating facility will cease operations (unless the unit is in suspension or forced outage). Duke Energy Indiana's intention to utilize the Generator Replacement Process, as afforded under the MISO Tariff, is extremely valuable, as the MISO queue process for new generation, or the DPP process, is currently taking many years to complete. On February 7, 2024, Duke Energy Indiana submitted a Generator Replacement Request ("GRR") for 1,040 MW for the Cayuga CC Project. MISO performed a Replacement Impact Study and Reliability Assessment Study and reported no adverse impacts on November 21, 2024. The Company notified MISO that it planned to proceed with the project on December 11, 2024. MISO will start an Interconnection Customer Interconnection Facilities study and the drafting of the Generator Interconnection Agreement ("GIA") in early 2025. Based on the current schedule, MISO and Duke Energy Indiana expect to have a signed GIA for 1,040 MW by mid-2025.

Section 3.7 of MISO's Generator Interconnection Procedures also states that, if the replacement generation requires interconnection service greater than what the existing facility has, a separate interconnection request must be made for the excess amount. This interconnection request will be assigned a new queue position and proceed through the MISO Definitive Planning Phase (”DPP”) cycle in the same manner as that of a new generating facility seeking to interconnect. The planned Cayuga CC Project is 471 MW winter rating more than the existing units and therefore on April 18, 2024, Duke Energy Indiana submitted a new queue request in MISO's 2023 DPP queue cycle for up to 500 MW of incremental network interconnection capability ("NRIS"). To be clear, this would apply to up to 500 MW on the second CC only, as the first CC is entirely covered under the existing rights, as is most of the second CC. Duke Energy Indiana is in MISO's 2023 DPP queue for the incremental MWs and MISO expects to kick off the study in May 2025.

As noted, the Generator Replacement Process study did not identify any needed network upgrades to reliably interconnect the first CC and most of the second CC to the grid. The DPP Study will identify whether any transmission system network upgrades are necessary to reliably connect the incremental capacity for the second CC at Cayuga. Given the uncertainty associated with whether they will be required and if so, how much such network upgrades may costs, Duke Energy Indiana witness Smith has included a reserve in the cost estimate of $138 M, which was calculated using the average costs per MW of network upgrades from MISO's prior 2020 DPP Phase One results.

Q. DOES LEVERAGING THE MISO REPLACEMENT GENERATION INTERCONNECTION QUEUE PROCESS BENEFIT CUSTOMERS?

A. Yes. Leveraging existing interconnection rights affords a more timely and cost effective outcome for customers, which meets the intention behind FERC's approval of the generator replacement interconnection process in FERC Docket No.

ER19-1065. In the FERC order approving MISO's proposal, FERC stated that it accepted MISO's Tariff revisions because they represented an expedited process under MISO's Generator Interconnection Procedures to replace existing generating facilities with newer, more efficient generating facilities within MISO's queue framework.[3]

A new entry into the MISO interconnection queue process has recently been taking upwards of four years from the time studies commence through the requisite definitive planning phases. In contrast, reuse affords a more streamlined process and leverages existing infrastructure that may or may not be present in the instance of a new point of interconnection. That is not to say with proper planning and timing the new entry process cannot be navigated, which is why Duke Energy Indiana has chosen to have two 1x1 turbines that come on at different times. This allows the capacity and energy from the first turbine to come online faster, while allowing the incremental process to play out for the incremental MWs on the second turbine.

Additionally, the transmission interconnection configuration at Cayuga is well suited to a two 1x1 configuration, as opposed to a similarly sized 2x1 plant. The two 1x1 configuration allows the total project to be split across the two voltages (230 kV and 345 kV) coming into Cayuga Station, providing stability on these two lines and reducing the potential for major network upgrades on either

[3] See Midcontinent Indep. Sys. Operator, Inc., 167 FERC ¶ 61,146 (2019)).

line. Further, the Company's plan to construct two smaller 1x1 CC units promotes system stability by limiting the system impact of a unit trip event. Finally, as noted the Company is already in the MISO 2023 DPP queue for the up to 500 MW needed to interconnect CC 2. Switching to a 2x1 configuration would cause delay as it would require the Company to withdraw from the 2023 MISO queue and re-enter the 2025 queue, as well as a re-start of the MISO GRR study process.

Q. COULD THE MISO QUEUE PROCESS BE FURTHER REFINED?

A. Yes. Duke Energy Indiana is aware that there is a lot of attention on further improving the MISO DPP queue process. Duke Energy Indiana has actively participated in the MISO stakeholder process and various FERC proceedings regarding interconnection queue reform. One recent proposal by MISO, the Expedited Resource Addition Study ("ERAS") process, could potentially provide the incremental MW currently in MISO's 2023 Cycle Study queue a streamlined process for a generator interconnection agreement. Duke Energy Indiana will continue to monitor future FERC filings and MISO processes for ERAS, in hopes that it provides a quicker and most cost effective interconnection for the incremental MWs for the Cayuga CC Project. In any event, Duke Energy Indiana will provide updates to the Commission on the interconnection processes for the Cayuga CC Project throughout this proceeding and in future ongoing review proceedings, as available and necessary.

Q. DID DUKE ENERGY INDIANA REACH OUT TO MISO REGARDING ITS ASSESSMENT OF THE PROPOSED NEW GENERATION AS REQUIRED BY THE COMMISSION'S GENERAL ADMINISTRATIVE ORDER 2022-01 ("GAO 2022-01")?

A. Yes. Attachment 2-A (KAK) is the Affidavit of Andrew Witmeier, Director of Resource Utilization for MISO, providing a qualitative assessment by MISO regarding the proposed new generation.

V. RELIABILITY, RESOURCE ADEQUACY, AND GAO ON GUIDELINES FOR ADDITIONAL EVIDENCE IN ELECTRIC GENERATION PROCEEDINGS

Q. ARE YOU FAMILIAR WITH THE COMMISSION'S GAO 2022-01?

A. Yes, I am. This is the GAO that provides for MISO's Affidavit, as well as various other evidentiary items from the utility submitting a CPCN request. Those items include:

- The name of the RTO to which the new generation will be connected and information regarding the RTO's planning reserve margin, peaks, capacity auctions, possible ancillary services the new generation may provide, and other markets in which the new generation may participate. A qualitative assessment by the RTO regarding the new generation shall be requested and the RTO's response (including, as applicable, the RTO's affidavit or testimony) shall be part of the utility's case in chief.
- A description of the new generation's anticipated impact on the submitting utility's resource adequacy and reliability.
- An explanation regarding whether the new generation is required to be in the RTO's interconnection queue and, if so, its status in the queue.
- A description of the new generation's expected capacity factors, dispatchability, and accreditation characteristics.
- A description of how the new generation is expected to perform at the relevant RTO's peak pursuant to its capacity construct (for example, summer and/or winter and/or other, as may be applicable).

Q. PLEASE PROVIDE THE INFORMATION REQUESTED IN GAO 2022-01 REGARDING THE REGIONAL TRANSMISSION ORGANIZATION ("RTO") TO WHICH THE NEW GENERATION WILL BE CONNECTED.

A. The Cayuga CC Project will be interconnected with the MISO system using both the Replacement Generator Process and MISO's DPP queue process, as indicated above. Duke Energy Indiana, as a load serving entity in MISO, participates in MISO's annual capacity auction process. MISO's planning reserve margin has recently changed to a seasonal requirement. For Duke Energy Indiana, for the 2024/2025 planning year, the planning reserve margin requirement was 9.0% for summer, 14.2% for fall, 27.4% for winter, and 26.7% for spring. These reserve margins will be updated annually by MISO, and MISO is expected to move to direct loss of load ("DLOL") methodology for capacity accreditation by the time these units are in-service, which is expected to lower the reserve margin requirements. Using the latest forecast from MISO for seasonal accredited capacity ("SAC") under the DLOL methodology, once in-service and at full load, the Cayuga CC Project is expected to provide approximately 1,064 MW (Winter), 1,041 MW (Spring), 1,249 MW (Summer), and 1,235 MW (Fall) as a firm contribution to Duke Energy Indiana's load and reserve margin requirements. Again, these estimates will be updated annually by MISO. Duke Energy Indiana's system-wide peak load obligation for planning coincident with MISO's peak for the 2024/ 2025 planning year was 6,190 MW in summer, 5,920 MW in fall, 6,378 MW in winter and 5,978 MW in spring. In accordance with MISO's requirements, Duke Energy Indiana's load obligation will also be updated annually.

The Cayuga CC Project will be offered into the MISO energy markets as well and will be economically dispatched in accordance with MISO's security constrained economic dispatch model. The Cayuga CC Project is expected to provide the following ancillary services to support the MISO grid: contingency, supplemental, and spinning reserves, and regulating reserves, ramp capability and short term reserves. The Company will also manage transmission congestion for the Cayuga CC Project as it does today for the existing site with the procurement of financial transmission rights.

In the IRP modeling supporting the project, the average capacity factor for the Cayuga CC Project was estimated to be 87% for the first five years of operations when unconstrained by CAA 111 requirements. As noted, if the GHG standards are implemented, the average annual capacity factor would be limited to 40% starting in 2032 to comply with the emission limitations. There is also the potential for future technology advancements like carbon capture and sequestration, or hydrogen as a fuel source, which if economic and implemented, may allow for a higher capacity factor for the plant in the future even if future greenhouse gas emissions limits are enacted. Duke Energy Indiana expects the Cayuga CC Project to be a valuable resource for both capacity and energy to serve our customers' load. Additional information about the expected reliability and resource adequacy of the MISO market and the Cayuga CC Project is discussed below.

Q. WILL THE CAYUGA CC PROJECT HELP MINIMIZE THE POTENTIAL LOSS OF ACCREDITED CAPACITY AT THE SITE?

A. Yes. The Cayuga CC Project will allow the Company to replace aging coal units that have an increasing risk of forced outages and maintenance requirements with new natural gas-fired units that have a high accredited capacity value. Furthermore, having two 1x1 units provides the Company with the opportunity to stagger its future maintenance outages between CC 1 and CC 2, rather than having to take more of the station down as it would have to do for a 2x1 given the shared steam turbine. The smaller unit size will also be helpful in the event of an unplanned outage, with less accreditation risk than a 2x1. The Company expects that this flexibility will potentially benefit the accredited capacity at the Cayuga Energy Complex in the future. Additionally, there are operational benefits associated with the 1x1 configuration over a 2x1 as explained in the testimony of Company witness Gagnon, such as more manageable planned outages and lower risks associated with forced outages.

Q. IS THERE A REGULATORY BODY THAT OVERSEES THE BULK POWER SYSTEM AND ITS RELIABILITY AND RESOURCE ADEQUACY?

A. Yes. NERC, which is subject to the oversight of FERC and its jurisdiction includes users, owners, and operators of the bulk power system, which serves nearly 400 million people.

Q. WHAT IS THE MISSION OF NERC?

A. NERC's mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces Reliability Standards, annually assesses seasonal and long-term reliability, monitors the bulk power system through system awareness, and educates, trains, and certifies industry personnel. NERC publishes standards and reports regarding reliability and resource adequacy.[4]

Q. PLEASE DISCUSS SOME OF THESE SYSTEM RELIABILITY NERC PUBLICATIONS.

A. The NERC 2024 Long-Term Reliability Assessment (published December 2024) contains several findings and recommendations that support the need to install new fast-starting and quick ramping generation.[5] The Report found that: "PRMs [planning reserve margins] in MISO for both summer and winter are projected to fall below the RML [reserve margin levels] reserve margin requirements as new generation is insufficient to make up for generator retirements and load growth …. Delays to generator construction in MISO result in a 2.7 GW shortfall by 2029." At 12. The report indicates: "Natural-gas-fired generators are a vital BPS [bulk power system] resource. They provide ERSs [essential reliability services] by ramping up and down to balance a more variable resource mix and are a dispatchable electricity

[4] https://www.nerc.com/pa/Stand/Pages/Default.aspx.
[5] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf

supply for winter and times when wind and solar resources are less capable of serving demand." At 8. In its 2024 Summer Reliability Assessment (published in May 2024)[6] NERC observed that: "Stored supplies of natural gas are at high levels, but continued vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators." At 8. NERC continues to recognize the important role natural gas fired generation, like the Cayuga CC Project, will play in grid reliability.

Q. HAS MISO VOICED CONCERNS REGARDING THE NEED FOR RESOURCES TO MAINTAIN SYSTEM RELIABILITY AND RESOURCE ADEQUACY?

A. Yes, several recent MISO publications point to the need for more accredited capacity on the grid. In MISO's Attributes Roadmap published in December of 2023,[7] MISO indicates a near term need for resources that can provide system adequacy, flexibility and system stability to the grid. MISO has called this its Reliability Imperative. These three reliability attributes can all be met with natural gas combined cycle technology like that of the Cayuga CC Project. As noted, the Cayuga CC Project is expected to provide considerable capacity and energy to the system, and is more reliable as the risk of river temperature derates will be alleviated. Likewise, the Cayuga CC project is flexible, providing various operating reserves and the ability to ramp up and down quickly and within a wide range. Finally, the MISO report notes that system stability is the ability to remain in

[6] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf
[7] 2023 Attributes Roadmap631174.pdf

a state of operating equilibrium under normal operating conditions and to also recover from disturbances. MISO indicated the nearest-term risk factor for the stability of the system is voltage stability. Duke Energy Indiana's replacement generation application for the Cayuga CC Project indicated no adverse impact on the system in terms of thermal overloads or voltage issues, so the project supports MISO system stability. Further, Duke Energy Indiana's plan to construct two smaller 1x1 CC units further promotes system stability by limiting the system impact of a unit trip event, and the project is split across two voltage classes, adding stability to both the 230 kV and 345 kV system.

Q. WHAT DOES THE ORGANIZATION OF MISO STATES ("OMS") TELL US ABOUT RESOURCE ADEQUACY?

A. The 2024 OMS-MISO Survey Results (published June 20, 2024)[8] in summary reflects:

- Results indicate a potential surplus of 1.1 GW to a deficit of 2.7 GW for the summer of PY2025/26, depending on critical, yet uncertain, drivers such as the pace and quantity of new resource additions and projected resource retirements.
- Resource Adequacy risks could grow over time across all seasons, absent increased new capacity additions and actions to delay capacity retirements.
- Significant economic development activities are spurring new, large spot-load additions (e.g., data centers, onshoring of manufacturing, new industrials) and increasing pressures on resource adequacy and requiring improved abilities for the timely

[8] https://cdn.misoenergy.org/20240620%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation635585.pdf

addition of new resources.

- Recent reforms to MISO's resource adequacy construct will enhance MISO's ability to accurately assess the changing resource adequacy risks driven by extreme weather, the rapid growth of weather-dependent resources, and the retirement of dispatchable resources.
- Results highlight resource adequacy challenges in the MISO region and the need for continued collaboration between OMS, MISO, and its Members to maintain a reliable electricity system.

At 2. This demonstrates that MISO, as a whole, is still experiencing the same challenges mentioned in CenterPoint Indiana South's CPCN proceeding in Cause No. 45564. In fact, as explained in Northern Indiana Public Service Company LLC's more recent CPCN proceeding, Cause No. 45947, the need for fast start/quick ramping resources is further increasing. (Final Order at 37). Additionally, the OMS-MISO Survey results show a range of potential outcomes based on uncertainty that exists in the timing of retirements, the nature and timing of replacement capacity, and forecasts of future load. The Cayuga CC Project, by reusing existing interconnection rights to replace end of useful life generation, while also providing additive capacity helps to mitigate these identified risks.

Q. WHAT DOES MISO'S INDEPENDENT MARKET MONITOR ("IMM"), POTOMAC ECONOMICS, TELL US ABOUT RESOURCE ADEQUACY?

A. The IMM explains in its 2023 State of the Market Report for the MISO Electricity Markets (published June 2024)[9] that:

[9] https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf.

> MISO has more than 1200 active projects in the interconnection queue, totaling over 225 GW. Half of these are solar projects, and an additional 19 percent are hybrid projects, while 15 percent are battery storage, and another 10 percent are wind projects. Distributed energy resources may also grow and play a more substantial role in the future. However, MISO has emphasized the importance of the attributes that dispatchable resources provide and participants have responded by announcing the addition of more than 30 GW of new gas resources over the next 20 years.

At 13. All of these sources are telling us that as we plan for the inevitable retirement of older, less efficient units, whether it be to comply with environmental compliance deadlines or because they are at the end of their useful life, the system will benefit from replacement with dispatchable resources. They further identify that natural gas generation is an important and much needed source for the needed capacity and energy and will help maintain resource adequacy.

Q. WHAT ROLE CAN BATTERIES, RENEWABLES, AND DEMAND-SIDE MANAGEMENT PLAY?

A. Battery energy storage systems ("BESS") and inverter-based resources ("IBRs"), which includes renewables, have a role to play in supporting resource adequacy. Duke Energy Indiana's 2024 IRP calls for targeting 499 MW solar and 400 MW of battery storage procurements to be in-service by 2030. However, as NERC cautions in its 2024 Long-Term Reliability Assessment: "Reliably integrating IBRs onto the grid is paramount, and evidence indicates that the risk of grid vulnerabilities from interconnection practices and IBR performance issues are growing." At 144. NERC explained further:

> BESS are improving reliability by helping to offset the variability

> and uncertainty of inverter-based resources (IBR). BESS are, however, a relatively new type of grid resource with unique operating characteristics. The joint NERC-WECC Staff Report: 2022 California Battery Energy Storage System Disturbances highlights an event when a BESS, like some other IBRs, failed to properly ride through a normal system fault. This indicates that BESS must be included in the currently underway strategies to address IBR performance issues.

At 25 (internal citations omitted). As for intermittent generation, the NERC report finds:

> New solar PV, battery, and hybrid resources continue to flood interconnection queues, but completion rates are lagging behind the need for new generation. Furthermore, the performance of these replacement resources is more variable and weather dependent than the generators they are replacing. As a result, less overall capacity (dispatchable capacity in particular) is being added to the system than what was projected and needed to meet future demand. **The trends point to critical reliability challenges facing the industry: satisfying escalating energy growth, managing generator retirements, and accelerating resource and transmission development.**

Id. at 4. As for demand response or demand-side management ("DSM"), NERC in the same report (at 33) states: "Large flexible loads and demand-side management programs *hold promise* for peak load management capabilities that can reduce the risk of firm load interruption." (*emphasis added).* Further, NERC's MISO outlook for demand response indicates an assumption of constant level of DR MWs throughout the study period. *Id*. at 44.

This tells us that batteries, renewables, and DSM alone are not the sole solution to resource adequacy, especially in light of forecasts of stronger customer load growth. Duke Energy Indiana's preferred portfolio, as discussed by witnesses

Pinegar and Gagnon, provides for a balanced mix of resources, including the Cayuga CC Project and later batteries, more renewables, and DSM to mitigate risk and provide maximum flexibility.

Q. PLEASE EXPLAIN WHY CONVERTING THE CAYUGA COAL UNITS TO BURN NATURAL GAS IS NOT THE IDEAL SOLUTION FROM A RELIABILITY PERSPECTIVE.

A. There are several reasons why the Cayuga CC Project is more beneficial to customers than converting the units to natural gas or co-firing the units with coal and natural gas. First, to overcome the issue of frequent derates of the units due to river temperature limits, continued operation of the units would require additional investments to address the issues with the existing cooling towers, NPDES requirements and ELG requirements. In addition, natural gas conversion or co-firing the units would require significant ongoing maintenance capital investments. Investing significant capital in sixty year old units does not make sense for the long term reliability of the generation onsite.

Secondly, the Cayuga CC Project is expected to be an economic energy resource and run at high capacity factor if unconstrained by the GHG standards, and at a 40% capacity factor if the GHG standards are required. This is exactly the type of generating asset Duke Energy Indiana's growing customer load needs. We are seeing new economic development load that has a need for around the clock energy, not just energy during peak hours. In contrast, converted or co-fired Cayuga units are expected to have a lower capacity in the IRP modeling we performed. The units would provide some capacity value under MISO's construct, but they would not be economically useful for baseload energy needs.

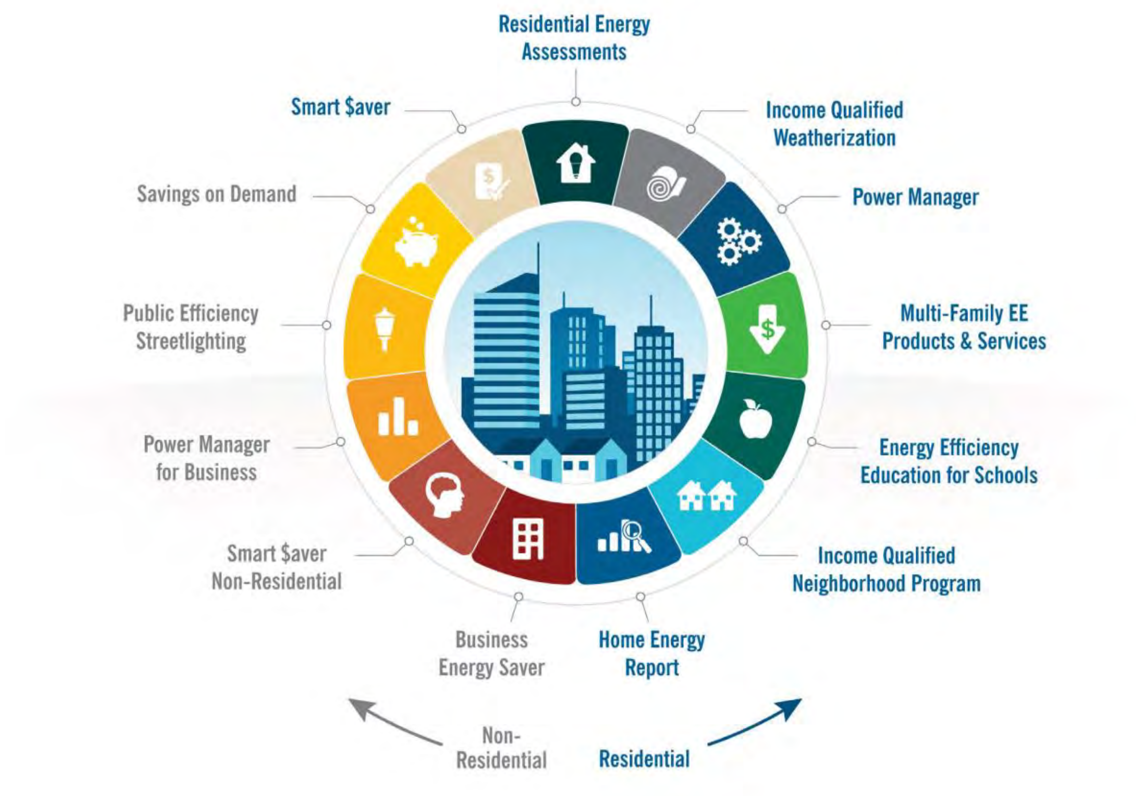
Further, as proposed, the Cayuga CC Project is adding an additional 471 MW winter rating of capacity using the same station footprint. Converting the existing units to natural gas provides no additional capacity. The Cayuga CC Project is a more flexible resource with its ability to ramp up and down more quickly and in a wider range than converted or co-fired units could, providing the reliability attributes that MISO has indicated it needs in its Attributes Roadmap.

VI. DUKE ENERGY INDIANA'S DEMAND SIDE MANAGEMENT PROGRAMS

Q. PLEASE DESCRIBE DUKE ENERGY INDIANA'S EXPERIENCE IN OFFERING DSM ENERGY EFFICIENCY ("EE") AND DEMAND RESPONSE PROGRAMS.

A. For over three decades, Duke Energy Indiana has worked constructively with stakeholders to actively pursue and offer customers innovative and cost-effective energy efficiency ("EE") and demand response ("DR") programs. These programs are an important part of the portfolio of resources Duke Energy Indiana uses to serve its customers. Duke Energy Indiana has an approved portfolio of energy efficiency and demand response programs that run from 2024-2026, which has been approved by the Indiana Utility Regulatory Commission ("Commission") in Cause No. 45803. These programs, shown in Figure 1 below, were included in the 2024 IRP modeling in all cases.

Figure 1: Duke Energy Indiana Energy Efficiency & Demand Response Programs



These programs provide savings opportunities for all customer classes. The residential programs include home energy audits and kits, home energy reports, income qualified programs, school programs, thermostat and AC control programs, incentives on HVAC and other conservation measures, incentives for higher efficiency standards in construction, an online savings store, and multi-family products and services. Non-residential program offerings include direct installation of energy efficiency measures in businesses, incentives for energy efficiency equipment (both prescriptive and custom options), energy savings performance incentives, and efficient outdoor lighting offerings.

Q. DOES DUKE ENERGY PROVIDE ANY ADDITIONAL DEMAND RESPONSE OPTIONS FOR CUSTOMERS?

A. Yes. In addition to the programs mentioned above, Duke Energy has entered into special contracts with customers who provide demand response, and the Company offers commercial customer incentives under its PowerShare® and Savings on Demand programs. These resources, along with the Company's Power Manger, Bring Your Own Thermostat and Integrated Volt Var Control ("IVVC") programs, qualify as load modifying resources ("LMR") under MISO's Tariff Module E-1, which allows Duke Energy Indiana to receive Zonal Resource Credits for use against its Planning Reserve Margin Requirement obligation. For example, in the 2024/2025 planning year, the Company registered these LMRs for about 556 MWs of SAC value (summer). I would note that MISO is currently evaluating changes to the LMR accreditation and rules, which could have a detrimental impact on customer participation in these programs in the future. Duke Energy Indiana will continue to participate in the MISO stakeholder processes to advocate for reasonable rules that to preserve this important resource option.

Q. WHAT ABOUT FUTURE ENERGY EFFICIENCY AND DEMAND RESPONSE OFFERINGS?

A. To help inform future EE and DR opportunities within the service territory, Duke Energy Indiana retained Resource Innovations ("RI") to conduct a Market Potential Study ("MPS"). The MPS formed the basis of the projected impacts from EE and DR programs to be used in the 2024 IRP. Duke Energy Indiana developed ten subportfolios of EE programs (also referred to as "bundles"). These bundles were designed to be treated similarly to supply-side resource options for selection in the 2024 IRP modeling. The EE bundles were modeled based on the currently approved DSM portfolio and two of the three Duke Energy Indiana MPS scenarios: the Base scenario and the High Incentive Cost scenario. This process enabled the EE programs to compete for selection against traditional generating resources to serve projected customer load.

For future demand response potential, the IRP includes programs that are approved by the Commission, at budgets approved by the Commission. To the extent it is cost-effective, the Company intends to grow its demand response capability through both existing programs and new ones. More details on the demand response and energy efficiency assumptions can be found the Company's IRP, Appendix H, attached to witness Gagnon's testimony as Attachment 6-A (NDG).

Q. HAVE DUKE ENERGY INDIANA'S ENERGY EFFICIENCY AND DEMAND RESPONSE PROGRAMS BEEN SUCCESSFUL?

A. Yes. Duke Energy Indiana's DSM and energy efficiency ("EE") programs have proven to be cost-effective and successful in terms of performance, as determined through its evaluation, measurement and verification process.

Q. BASED ON YOUR EXPERIENCE WITH DEMAND RESPONSE AND ENERGY EFFICIENCY IN DUKE ENERGY INDIANA'S SERVICE

TERRITORY, WOULD THESE RESOURCES BE A REASONABLE REPLACEMENT FOR THE CAYUGA CC PROJECT?

A. No. The 2024 IRP modeling does demonstrate that EE and DR will be an important part of Duke Energy Indiana's resource options in the future and will be important to help mitigate against the need to build new generation. Although Duke Energy seeks to maximize its use of energy efficiency and demand response, we do not believe there is enough incremental potential on its system to replace the Cayuga coal units and provide the incremental capacity that the Cayuga CC Project provides. Duke Energy Indiana's IRP modeling indicates the most economical option for customers over the long term is to execute on its preferred portfolio, including adding the proposed Cayuga CC Project and adding renewable and storage resources. Based on my experience with Duke Energy Indiana's EE and DR initiatives, Duke Energy Indiana could not derive sufficient energy savings or capacity from these resources to replace this needed generation. That said, Duke Energy Indiana is committed to the development of energy efficiency and demand response programs for all customer classes and will continue to seek for ways to expand its use as a cost effective resource.

VII. HOUSE BILL 1007 (2025)

Q. PLEASE DESCRIBE THE INDIANA GENERAL ASSEMBLY'S HOUSE BILL ("HB") 1007 IN THE 2025 LEGISLATIVE SESSION AS IT RELATED TO GENERATION RETIREMENTS.

A. While we recognize the bill is not yet law and indeed will be considered by the

Indiana Senate in the coming weeks, the version of the bill as passed out of the Indiana House provided for a Commission investigation related to the retirement of certain generating assets of a nameplate capacity of at least 125 MW. The Cayuga coal fired generating units would potentially be implicated by this requirement if the bill ultimately becomes law. The bill provides that if the Commission makes required findings in a CPCN order, then the future retirement investigation is not required. It states in pertinent part:

> If a certificate is granted by the commission under this chapter for a facility intended to repower or replace a generation unit that is planned for retirement, and the certificate includes findings that the project will result in at least equivalent accredited capacity and will provide economic benefit to ratepayers as compared to the continued operation of the generating unit to be retired, the certificate under this chapter constitutes approval by the commission for purposes of an investigation required by this subsection.

Other provisions of HB 1007 provide that the utility should provide certain information concerning planned generation retirements, such as whether the retirement "is required in order to comply with environmental laws, regulations, or court orders, including consent decrees, that are or will be in effect at the time of the planned retirement" and whether a utility's plans are "reasonably consistent with the resource reliability requirements of MISO or any other appropriate regional transmission organization." My testimony will also address these components of HB 1007. The testimony of witness Gagnon will address how the IRP analysis provides support for other findings in the bill. The testimony of witness Pinegar will address how the Company's retire and replace plan meets the requirements of

Indiana's five pillars of energy policy, and witness Sufan provides the rate impacts related to the Company's plans. I have included a draft of the bill as it passed the House as Attachment 2-B (KAK).

Q. DO YOU BELIEVE THE COMMISSION COULD MAKE THE REQUIRED FINDINGS LISTED ABOVE IN THIS CPCN PROCEEDING?

A. I do. First, it is clear that the Company's Cayuga CC Project will provide accredited capacity in the MISO market that is at least equivalent to the units that are being retired. In fact, the Cayuga CC Project provides 471 additional MWs. As to whether environmental laws or regulations require the retirement, my testimony above describes how continued operation of the Cayuga units on coal or refueling with natural gas would require additional environmental compliance expenditures. As such, retirement and replacement with the Cayuga CC Project is the most economic outcome for customers. I have also addressed above how the Company's plan to retire and replace at Cayuga results in reliability benefits at MISO, including the addition of 471 MW of dispatchable generation on the grid in a timely manner. As such, the Company believes its plan to retire and replace the Cayuga coal units with the Cayuga CC Project is just and reasonable and can fully meet the requirements of HB 1007's retirement investigation and Duke Energy Indiana requests the Commission make the appropriate findings consistent with HB 1007 in its order.

VIII. CONCLUSION

Q. DO YOU BELIEVE DUKE ENERGY INDIANA'S REQUESTED RELIEF IN THIS PROCEEDING SHOULD BE APPROVED?

A. Yes. The Cayuga CC Project allows for the retirement of aging coal-fired units that would need significant environmental and maintenance expenditures for their continued operation. It replaces those units with state of the art natural gas combined cycle technology that provides 471 more MW of accredited capacity than the units they are replacing. The planned natural gas pipeline interconnection, supply and transportation are reliable and cost effective as described in the testimony of Company witness McClay. The project provides environmental benefits and Duke Energy Indiana has a reasonable plan to obtain the required environmental permits. Duke Energy Indiana is well along the process to interconnect the Cayuga CC Project to the grid and the generation will be valuable to the resource adequacy and reliability of the Duke Energy Indiana system, the state of Indiana and the greater MISO region. It is the very type of generation needed to support MISO's reliability imperative. The Company relies on a portfolio of resources to meet customers expected needs, including continued reliance on coal fired generation, natural gas generation, renewables, storage, and demand side management programs. This proposed project plays a critical role in providing flexibility and diversity in that portfolio of resources. Further, the makeup of MISO's electric generation fleet is in the midst of a significant, dynamic transition. Reliability and resource adequacy concerns have been voiced by many important organizations, including NERC, MISO's IMM, OMS, and others. This project will provide needed dispatchable generation and resource adequacy. It is for these reasons, and others as explained by Duke Energy Indiana's other witnesses, that it is seeking approval of a new gas-fired generation facility and the Commission should approve Duke Energy Indiana's request in this proceeding.

Q. ARE YOU FAMILIAR WITH ATTACHMENTS 2-A (KAK) AND 2-B (KAK)?

A. Yes, I am.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does.

VERIFICATION

I hereby verify under the penalties of perjury that the foregoing representations are true to the best of my knowledge, information and belief.

Signed: Kelley Karn
Kelley A. Karn

Dated: 02/13/2025

AFFIDAVIT OF ANDREW WITMEIER

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND RELATIONSHIP TO THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. ("MISO").

A. My name is Andrew Witmeier. I am the Director of Resource Utilization for the Midcontinent Independent System Operator, Inc. ("MISO"). My business address is: 720 City Center Drive, Carmel, IN 46032-7574.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I joined MISO in 2003 after graduating from Purdue University with a Bachelor's degree in Electrical Engineering. I spent the first 17 years of my career in various positions in MISO Operations. During that time I worked as a North American Reliability Corporation ("NERC") certified system operator in scheduling, engineering, and as a reliability coordinator. I also led several groups within MISO Operations as a manager in engineering, reliability coordination, and seams administration. In January 2020, I was appointed to my current position.

Q. PLEASE DESCRIBE YOUR JOB RESPONSIBILITIES WITH MISO AS THEY RELATE TO THIS FILING.

A. As the Director of Resource Utilization, I am responsible for the administration of MISO's Generator Interconnection Procedures ("GIP"), which are set forth in Attachment X of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff

("Tariff" or "MISO Tariff").[1] I oversee MISO's generator interconnection queue, including the conduct of studies, and the negotiation and execution of Generator Interconnection Agreements.

II. PURPOSE OF THIS AFFIDAVIT

Q. ARE YOU SUBMITTING THIS AFFIDAVIT ON BEHALF OF MISO?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR AFFIDAVIT?

A. The purpose of my affidavit is to provide information requested by Duke Energy ("Duke") to enable their compliance with Indiana Utility Regulatory Commission General Administrative Order 2022-01 ("the GAO").

Q. PLEASE DESCRIBE THE DUKE REQUEST FOR INFORMATION.

A. Duke requested that MISO enable Duke's compliance with the GAO by providing a qualitative assessment regarding new generation and providing descriptions of certain MISO processes and evaluations potentially involving the new generation. The request referenced two potential projects ("the Projects") that have been submitted into the MISO Generator Interconnection Queue ("the Queue"). Duke has submitted two Interconnection Requests related to the Projects, R1044 for a replacement request and J3232 for a new request. The reason for this is that the Tariff requires a Generating Replacement Facility to request Interconnection Service that does not exceed the amount of Interconnection Service for the Existing Generating Facility and any request for Interconnection Service that exceeds the amount of Interconnection Service for the Existing Generating Facility must

[1] Unless otherwise indicated in my Testimony, all capitalized terms used herein have the meaning as set forth in the Tariff or the proposed Tariff revisions, as applicable.

be processed as a new Interconnect Request.[2] The Interconnection Request for the Generating Facility Replacement ("the R1044 request") is described in the Interconnection Request[3] as a 1,040 MW Combine Cycle consisting of two powerblocks, CC1 and CC2. These combined cycles will replace Cayuga Coal Steam Units 1 & 2. CC1 and CC2 will have one combustion turbine unit and one steam turbine unit. The CC1 combustion turbine step-up transformer will be connected to a 230kV generator tie line and will terminate in the Cayuga 230kV switchyard at an electrical equivalent point of interconnection as Cayuga Coal Steam Unit 1. The CC1 steam turbine generator step-up transformer will connect to a 345kV generator tie line and terminate in the Cayuga 345kV switchyard at an electrical equivalent point of interconnection as Cayuga Coal Steam 2. The CC2 combustion turbine step-up transformer will be connected to the existing 345kV generator tie line and will terminate in the Cayuga 345kV switchyard at an electrical equivalent point of interconnection as Cayuga Coal Steam Unit 2. The CC2 steam turbine step-up transformer will be connected to the existing 230kV switchyard at an electrical equivalent point of interconnection as Cayuga Coal Steam Unit 1. The Interconnection Request for new Interconnection Service ("the J3232 request") is described in the Interconnection Request as a 500 MW Combined Cycle.

III. <u>DUKE REQUEST FOR INFORMATION</u>

Q. CAN MISO GIVE A GENERAL ASSESSMENT OF THE PROJECTS?

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[2] Tariff Attachment X, Section 3.7 (Additional requirements for Generating Facility Replacement Requests).

[3] Tariff Attachment X, Section 1 (Definitions).

A. Regarding the J3232 project, at this time MISO can only give a generalized assessment of the project because the studies associated with its Interconnection Request have not been completed.[4] Regarding the R1044 project, I can provide more information based on the studies MISO has completed so far.

Q. DOES MISO NEED TO DO A FULL ASSESSMENT OF THE PROJECTS AT THIS POINT IN THE IURC PROCESS?

A. No. It is MISO's understanding that for the CPCN proceeding Duke does not need to present the same level of details that are required for the MISO Interconnection process. The GAO requirement is fairly new to MISO. We have historically only reviewed the Interconnection Request and studied how it impacts the transmission system.

Q. WHAT WOULD MISO NEED TO PROVIDE A FULL ASSESSMENT OF THE PROJECTS?

A. MISO's Tariff requires MISO to make determinations about the impacts of projects based on specific details in Interconnection Requests. Under the Tariff, an Interconnection Request contains relevant information such as the requested level of Interconnection Service, generating facility data, and short circuit and dynamic modeling information. A valid Interconnection Request for a new generating facility will enter the Definitive Planning Phase, a three phase study process,[5] while a Generating Facility Replacement request undergoes evaluation in a two study process, a Replacement Impact Study as set forth in Section 3.7.2.1 of Attachment X and a Reliability Assessment Study as set forth in

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[4] The most recent MISO Definitive Planning Phase Schedule is available at https://www.misoenergy.org/planning/resource-utilization/GI_Queue/.

[5] Tariff Attachment X, Section 7.2.

Section 3.7.2.2 of Attachment X.[6] As of the date of this affidavit, MISO has received an Interconnection Request for J3232 and has determined it is valid,[7] but has not completed any of the applicable studies.[8] Therefore, MISO cannot make specific statements regarding the impact of J3232. Regarding R1044, MISO has completed the Replacement Impact Study and Reliability Assessment Study. MISO identified no adverse impacts or reliability issues. However, MISO must still complete the Interconnection Facilities Study.

Q. WHAT IS MISO'S GENERAL ASSESSMENT OF THE PROJECT?

A. I will address R1044 and J3232 separately. Regarding R1044, from a generator interconnection process perspective, my general assessment is that using the Replacement Generating Facility Request[9] process ("Replacement Process") defined in the MISO Tariff to utilize existing Interconnection Service is a more efficient way of modernizing older resources than retiring and connecting new generation at different POIs on the transmission system. The R1044 Interconnection Request stated that R1044 was projected to have a Commercial Operation Date of September 1, 2029. The Replacement Impact Study[10] did not identify a material adverse impact upon the Transmission System when compared to the Existing Generating Facility. This means that no Network Upgrades are expected. MISO expects to complete the Interconnection Facilities Study in the coming months and

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6 Tariff Attachment X, Section 3.7.2.

7 Tariff Attachment X, Section 3.3.

8 The MISO Definitive Planning Phase Schedule is available at https://www.misoenergy.org/planning/resource-utilization/GI_Queue/.

9 Tariff Attachment X, Section 3.7.

10 Tariff Attachment X, Section 3.7.2.1.

R1044 will proceed to the negotiation phase. Regarding J3232, my general assessment is that submitting an Interconnection Request to be studied by MISO to be provided Interconnection Service is the appropriate method of connecting new generation on the MISO transmission system. The request from Duke stated that the J3232 was projected to have a Commercial Operation Date ("COD") of May 29, 2030. The ability for J3232 to meet the COD depends on the date that an Interconnection Request is deemed valid for the project and the ensuing Queue schedule.

Q. HOW DOES MISO EVALUATE GAS FIRED GENERATION IN ITS EVALUATION OF INTERCONNECTION REQUESTS?

A. MISO's Generator Interconnection Procedures are fuel and technology neutral, and MISO does not evaluate a project more or less preferably than another based on fuel type. This said, MISO acknowledges that the attributes of Generating Facilities that are proposed by Interconnection Customers can impact grid reliability and that both Interconnection Customers and regulators may consider how specific Generating Facilities may impact overall grid reliability. MISO simply notes that as the IURC considers the requested relief herein and MISO's GIP, that it could also take grid reliability and the need for electric generation into account.

Q. **CAN THE DIFFERENT ATTRIBUTES OF GENERATING FACILITIES THAT ARE EVALUATED BY MISO IMPACT GRID REALIABILITY POSITIVELY?**

A. Yes. As I mentioned, MISO's GIP are fuel and technology neutral, but MISO is aware that no single resource provides every needed system attribute and that a fleet of diverse resources can most efficiently meet system needs. In 2023, MISO designed and completed a foundational analysis of system reliability attributes, culminating in the Attributes

Roadmap.[11] The analysis focused on three priority attributes where risk to MISO is the most acute: system adequacy, flexibility, and system stability. I'll explain further, but each of these is stronger when supported by a diverse fleet of generation resources.

System Adequacy refers to the ability to meet electric load requirements during periods of high risk. MISO determined that system adequacy is best addressed in the planning horizon and served through capacity requirements, capacity accreditation, and market solutions within the seasonal resource adequacy construct. This approach is dependent on a diverse range of generation resources that can contribute to meeting demand and reserve requirements.

Flexibility is the extent to which the power system can adjust electric production or consumption in response to changing system conditions. MISO determined that flexibility is best addressed in the operating timeframe and served through market solutions. This approach is dependent on an expanded fleet of qualifying resources able to meet increasingly variable and uncertain real-time operational needs.

System Stability is the ability of the system to remain in a state of operating equilibrium under normal operating conditions and to recover from disturbances. MISO determined that system stability is best addressed through requirements and technology standards coupled with required capabilities from resources to support grid stability. This approach is dependent on an interconnection queue comprised of generation resources with a range of grid stability capabilities.

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[11] *Attributes Roadmap: A Reliability Imperative Report*, available at https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

Cause No. 46193

Currently and without modification to my answer regarding MISO's general assessment of the project, natural gas-fired combustion turbines are a major source of these needed reliability attributes. Other resource types, such as long-duration battery storage, may become commercially and economically viable enough to provide these critically needed attributes at grid scale in the future.

Q. COULD YOU PROVIDE COST ESTIMATES AND POTENTIAL COST ALLOCATION FOR INTERCONNECTION FACILITIES OR NETWORK UPGRADES, IF ANY, REQUIRED TO CONNECT THE PROJECTS TO THE MISO TRANSMISSION SYSTEM?

A. I am not able to estimate total costs for the Projects currently. Regarding R1044, because the Replacement Impact Study did not identify the need for a Network Upgrade and associated costs, it will not be assigned costs for a Network Upgrade. The costs of potential Interconnection Facilities will depend on the configuration of the project as detailed in the Interconnection Request. While projects using the same POI as an Existing Generating Facility that they are replacing tend to have lower interconnection facility costs when compared to new projects proceeding through the queue at a new Point of Interconnection, numerous factors can impact Interconnection Facility costs. MISO cannot provide an estimate before the appropriate studies are performed. The same applies for J3232, MISO cannot provide an estimate of costs for Interconnection Facilities or Network Upgrades prior to completion of the studies.

Q. ASSUMING NETWORK UPGRADES OR INTERCONNECTION FACILITIES ARE NEEDED, COULD YOU DESCRIBE THE SCOPE OF WORK AND CONSTRUCTION TIMELINES FOR SUCH FACILITIES?

If a Network Upgrade is necessary for J3232, the scope of work and construction timelines would need to be established through the Interconnection Request and Scoping Meeting with the Transmission Owner.[12] In general, the scope of work for replacement facilities such as R1044 are less than those required for a new facility because replacement facilities use the same POI. However, this may not always be the case, and MISO cannot describe on the specific scope and timeline of a project prior to completion of the applicable studies.

Q. COULD YOU GIVE A BRIEF DESCRIPTION OF THE MISO REPLACEMENT GENERATOR PROCESS AND CONFIRMATION R1044 IS ELIGIBLE TO UTILIZE THIS PROCESS?

A. The evaluation process for Generating Facility Replacements consists of two studies, a Replacement Impact Study and a Reliability Assessment Study.[13] The Replacement Impact Study[14] will include analyses to determine if the Replacement Generating Facility has a material adverse impact on the Transmission System when compared to the Existing Generating Facility. The Replacement Impact Study may include steady-state (thermal/voltage), reactive power, short circuit/fault duty, and stability analyses, as necessary, to ensure that required reliability conditions are studied. The Reliability Assessment Study[15] evaluates the performance of the Transmission System for the time period between the date that the Existing Generating Facility ceases commercial operations and the COD of the Replacement Generating Facility. The Reliability Assessment Study

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[12] Tariff Attachment X, Section 3.3.4.

[13] Tariff Attachment X, Section 3.7.2.

[14] Tariff Attachment X, Section 3.7.2.1.

[15] Tariff Attachment X, Section 3.7.2.2.

determines if thermal and/or voltage violations of applicable NERC Standards and Transmission Owner planning criteria are caused by removing the Existing Generating Facility from service prior to the COD of the Replacement Generating Facility. MISO expects R1044 to complete the Replacement Process in the coming months.

Q. WHAT IS MISO'S EVALUATION OF ANY POTENTIAL CONGESTION FROM THE PROPOSED PROJECT DUE TO LOCAL ENERGY DELIVERABILITY, IF ANY?

A. Information, such as historical data from Cayuga, may be available to help determine the possibility of any potential congestion from the Project, however MISO does not conduct any evaluations of historical congestion data as part of the Generator Interconnection Process.

IV. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR AFFIDAVIT?

A. Yes, it does.

Cause No. 46193

Affidavit of Andrew Witmeier

COUNTY OF HAMILTON)

)

STATE OF INDIANA)

Andrew Witmeier, being duly sworn, deposes and states that he prepared the Affidavit of Andy Witmeier, and the statements contained therein are true and correct to the best of his knowledge and belief.

Andrew Witmeier

SUBSCRIBED AND SWORN BEFORE ME, this 28th day of January, 2025.

Kandi Hahn

Kandi Hahn

NOTARY PUBLIC SEAL INDIANA
KANDI HAHN
Notary Public, State of Indiana
Marion County
Commission Number NP0740038
My Commission Expires
March 23, 2030

Cause No. 46193

Reprinted
February 11, 2025

HOUSE BILL No. 1007

DIGEST OF HB 1007 (Updated February 10, 2025 3:11 pm - DI 101)

Citations Affected: IC 6-3.1; IC 8-1.

Synopsis: Energy generation resources. Provides a credit against state tax liability for expenses incurred in the manufacture of a small modular nuclear reactor (SMR) in Indiana. Establishes procedures under which certain energy utilities may request approval for one or more of the following from the Indiana utility regulatory commission (IURC): (1) An expedited generation resource plan (EGR plan) to meet customer load growth that exceeds a specified threshold. (2) A generation resource submittal for the acquisition of a specific generation resource in accordance with an approved EGR plan. (3) A project to serve one or more large load customers. Sets forth: (1) the requirements for approval of each of these types of requests; (2) standards for financial assurances by large load customers; and (3) cost

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Effective: Upon passage; January 1, 2025 (retroactive); July 1, 2025.

Soliday, Shonkwiler, Pressel, Bartels

January 13, 2025, read first time and referred to Committee on Utilities, Energy and Telecommunications.
January 29, 2025, amended, reported — Do Pass. Referred to Committee on Ways and Means pursuant to Rule 126.3.
February 6, 2025, reported — Do Pass.
February 10, 2025, read second time, amended, ordered engrossed.

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recovery mechanisms for certain acquisition costs or project costs incurred by energy utilities. Provides that any standard tariff offered by an energy utility after June 30, 2025, to a large load customer of the energy utility must include a provision that requires reimbursement by the large load customer of at least 80% of the project costs reasonably allocable to the large load customer, regardless of whether the large load customer ultimately takes service in any anticipated amount and within any anticipated time frame. Authorizes a public utility to petition the IURC for approval to incur, before obtaining a certificate of public convenience and necessity (CPCN) for an SMR, project development costs for the development of the SMR. Provides that if a public utility receives approval to incur project development costs for an SMR, the public utility may petition the IURC for the approval of a rate schedule that periodically adjusts the public utility's rates and charges to provide for the timely recovery of project development costs. Provides that a public utility that is authorized to recover project development costs shall: (1) recover 80% of the approved project development costs under the approved rate schedule; and (2) defer the remaining 20% of approved project development costs for recovery as part of public utility's next general rate case before the IURC. Provides that project development costs that: (1) are incurred by a public utility; and (2) exceed the best estimate of project development costs included in the IURC's order authorizing the public utility to incur project development costs; may not be included in the public utility's rates and charges unless found by the IURC to be reasonable, necessary, and prudent in supporting the construction, purchase, or lease of the SMR for which they were incurred. Provides that: (1) project development costs incurred for a project that is canceled or not completed may be recovered by the public utility if found by the IURC to be reasonable, necessary, and prudently incurred; but (2) such costs shall be recovered without a return unless the IURC makes certain additional findings. Amends the statute concerning public utilities' annual electric resource planning reports to the IURC to provide that for an annual report submitted after December 31, 2025, a public utility must include information as to the amount of generating resource capacity or energy that the public utility plans to retire or refuel with respect to any electric generation resource of at least 125 megawatts. Provides that for any planned retirement or refueling, the public utility must include, along with other specified information, information as to the public utility's plans with respect to the following: (1) For a retirement, the amount of replacement capacity identified to provide approximately the same accredited capacity within the appropriate regional transmission organization (RTO) as the capacity of the facility to be retired. (2) For a refueling, the extent to which the refueling will maintain or increase the current generating resource accredited capacity or energy that the electric generating facility provides, so as to provide approximately the same accredited capacity within the appropriate RTO. Requires IURC staff to prepare a staff report for each public utility report that includes a planned electric generation resource retirement. Provides that if, after reviewing a public utility's report and any related staff report, the IURC is not satisfied that the public utility can satisfy both its planning reserve margin requirement and the statute's prescribed reliability adequacy metrics, the IURC shall conduct an investigation into the reasons for the public utility's inability to meet these requirements. Provides that if the public utility's report indicates that the public utility plans to retire an electric generating facility within one year of the date of the report, the IURC must conduct such an investigation. Provides that: (1) a public utility may request, not earlier than three years before the planned retirement date of an electric generation facility, that the IURC conduct an investigation into the planned retirement; and (2) if the IURC conducts an investigation at the request of the public utility within that three year period, the IURC may not conduct a subsequent

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investigation that would otherwise be required under the bill's provisions unless the IURC is not satisfied that the public utility can satisfy both its planning reserve margin requirement and the statutory reliability adequacy metrics as of the time the investigation would otherwise be required. Provides that if a CPCN is granted by the IURC for a facility intended to repower or replace a generation unit that is planned for retirement, and the CPCN includes findings that the project will result in at least equivalent accredited capacity and will provide economic benefit to ratepayers as compared to the continued operation of the generating unit to be retired, the CPCN constitutes approval by the IURC for purposes of an investigation that would otherwise be required. Provides that if, after an investigation, the IURC determines that the capacity resources available to the public utility will not be adequate to allow the public utility to satisfy both its planning reserve margin requirements and the statute's prescribed reliability adequacy metrics, the IURC shall issue an order: (1) directing the public utility to acquire or construct; or (2) prohibiting the retirement or refueling of; such capacity resources that are reasonable and necessary to enable the public utility to meet these requirements. Provides that if the IURC does not issue an order in an investigation within 120 days after the initiation of the investigation, the public utility is considered to be able to satisfy both its planning reserve margin requirement and the statutory reliability adequacy metrics with respect to the retirement of the facility under investigation. Provides that if the IURC issues an order to prohibit the retirement or refueling of an electric generation resource, the IURC shall create a sub-docket to authorize the public utility to recover in rates the costs of the continued operation of the electric generation resource proposed to be retired or refueled, subject to a finding by the IURC that the continued costs of operation are just and reasonable. Makes a technical change to another Indiana Code section to recognize the redesignation of subsections within the section containing these provisions.

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First Regular Session of the 124th General Assembly (2025)

PRINTING CODE. Amendments: Whenever an existing statute (or a section of the Indiana Constitution) is being amended, the text of the existing provision will appear in this style type, additions will appear in **this style type**, and deletions will appear in ~~this style type.~~

Additions: Whenever a new statutory provision is being enacted (or a new constitutional provision adopted), the text of the new provision will appear in **this style type**. Also, the word **NEW** will appear in that style type in the introductory clause of each SECTION that adds a new provision to the Indiana Code or the Indiana Constitution.

Conflict reconciliation: Text in a statute in *this style type* or *~~this style type~~* reconciles conflicts between statutes enacted by the 2024 Regular Session of the General Assembly.

HOUSE BILL No. 1007

A BILL FOR AN ACT to amend the Indiana Code concerning utilities.

Be it enacted by the General Assembly of the State of Indiana:

SECTION 1. IC 6-3.1-45 IS ADDED TO THE INDIANA CODE AS A **NEW** CHAPTER TO READ AS FOLLOWS [EFFECTIVE JANUARY 1, 2025 (RETROACTIVE)]:

Chapter 45. Small Modular Nuclear Reactor Manufacturing Expense Tax Credit

Sec. 1. This chapter applies to a taxable year beginning after December 31, 2024.

Sec. 2. As used in this chapter, "department" refers to the department of state revenue.

Sec. 3. As used in this chapter, "qualified investment" means a taxpayer's expenditures incurred in the manufacture of a small modular nuclear reactor in Indiana.

Sec. 4. As used in this chapter, "small modular nuclear reactor" means a nuclear reactor that:

(1) has a rated electric generating capacity of not more than

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four hundred seventy (470) megawatts;

(2) is capable of being constructed and operated, either:

(A) alone; or

(B) in combination with one (1) or more similar reactors if additional reactors are, or become, necessary;

at a single site; and

(3) is required to be licensed by the United States Nuclear Regulatory Commission.

The term includes a nuclear reactor that is described in this section and that uses a process to produce hydrogen that can be used for energy storage, as a fuel, or for other uses.

Sec. 5. As used in this chapter, "state tax liability" means a taxpayer's total tax liability that is incurred under:

(1) IC 6-3-1 through IC 6-3-7 (the adjusted gross income tax);

(2) IC 6-5.5 (the financial institutions tax); and

(3) IC 27-1-18-2 (the insurance premiums tax);

as computed after the application of the credits that under IC 6-3.1-1-2 are to be applied before the credit provided by this chapter.

Sec. 6. As used in this chapter, "taxpayer" means a person, corporation, partnership, or other entity that makes a qualified investment.

Sec. 7. A taxpayer is entitled to a credit against the taxpayer's state tax liability in the taxable year in which the taxpayer makes a qualified investment. The amount of the credit provided by this section is equal to twenty percent (20%) of the amount of the taxpayer's qualified investment.

Sec. 8. (a) If the amount determined under section 7 of this chapter for a taxpayer in a taxable year exceeds the taxpayer's state tax liability for that taxable year, the taxpayer may carry the excess over to the following taxable years. The amount of the credit carryover from a taxable year shall be reduced to the extent that the carryover is used by the taxpayer to obtain a credit under this chapter for any subsequent taxable year.

(b) A taxpayer is not entitled to a carryback or refund of any unused credit.

Sec. 9. (a) If a pass through entity is entitled to a credit under section 7 of this chapter but does not have state tax liability against which the tax credit may be applied, an individual who is a shareholder, partner, or member of the pass through entity is entitled to a tax credit equal to:

(1) the tax credit determined for the pass through entity for

the taxable year; multiplied by

(2) the percentage of the pass through entity's distributive income to which the shareholder, partner, or member is entitled.

(b) The credit provided under subsection (a) is in addition to a tax credit to which a shareholder, partner, or member of a pass through entity is otherwise entitled under this chapter. However, a pass through entity and an individual who is a shareholder, partner, or member of the pass through entity may not claim more than one (1) credit for the same qualified investment.

Sec. 10. To receive the credit provided by this chapter, a taxpayer must claim the credit on the taxpayer's annual state tax return or returns in the manner prescribed by the department. The taxpayer shall submit to the department:

(1) information verifying that the taxpayer's qualified investment was made with respect to a small modular nuclear reactor that will be manufactured in Indiana; and

(2) all information that the department determines is necessary for the calculation of the credit provided by this chapter.

SECTION 2. IC 8-1-2-24.5 IS ADDED TO THE INDIANA CODE AS A **NEW** SECTION TO READ AS FOLLOWS [EFFECTIVE UPON PASSAGE]: **Sec. 24.5. (a) As used in this section, "energy utility" means:**

(1) an electric utility listed in 170 IAC 4-7-2(a) and any successor in interest to that utility; or

(2) a corporation organized under IC 8-1-13.

(b) As used in this section, "large load customer" means a new or existing customer of an energy utility, or not more than four (4) multiple new or existing customers of an energy utility, that requests new or additional electricity demand that in the aggregate exceeds the lesser of:

(1) five percent (5%) of the energy utility's average peak demand over the most recent three (3) calendar years; or

(2) one hundred fifty (150) megawatts.

(c) As used in this section, "project" refers to a project relating to energy infrastructure or generation resources that:

(1) are required primarily to serve a large load customer of an energy utility; and

(2) may be designed to serve more than one (1) large load customer of the energy utility or to meet other customer demand or energy needs.

(d) As used in this section, "project costs" means the total costs of a project, including:

(1) planning costs; and

(2) construction and operating costs;

related to the project.

(e) Any standard tariff offered by an energy utility after June 30, 2025, to a large load customer of the energy utility must include a provision that requires reimbursement by the large load customer of at least eighty percent (80%) of the project costs reasonably allocable to the large load customer, regardless of whether the large load customer ultimately takes service in any anticipated amount and within any anticipated time frame.

SECTION 3. IC 8-1-8.2 IS ADDED TO THE INDIANA CODE AS A **NEW** CHAPTER TO READ AS FOLLOWS [EFFECTIVE UPON PASSAGE]:

Chapter 8.2. Expedited Generation Resource Plans and Large Load Customers

Sec. 1. (a) As used in this chapter, "acquisition" means a project or an arrangement that is undertaken:

(1) by an energy utility to construct, purchase, lease, or otherwise acquire a generation resource; and

(2) in accordance with an approved EGR plan.

(b) The term includes the purchase of energy or capacity through a power purchase agreement.

Sec. 2. As used in this chapter, "acquisition costs" means the total costs of an acquisition made under an EGR plan, including:

(1) planning;

(2) construction; and

(3) operating;

costs related to the acquisition.

Sec. 3. As used in this chapter, "appropriate regional transmission organization" has the meaning set forth in IC 8-1-8.5-13(b).

Sec. 4. As used in this chapter, "commission" refers to the Indiana utility regulatory commission created by IC 8-1-1-2.

Sec. 5. (a) As used in this chapter, "construction and operating costs" means costs:

(1) incurred or to be incurred by an energy utility under this chapter after the issuance of an order by the commission under this chapter; and

(2) related to an approved or commission modified acquisition or project.

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(b) The term includes procurement, contractual, construction, operating, maintenance, financing, legal, regulatory, and project evaluation, analysis, and development costs incurred after the issuance of an order by the commission under this chapter.

Sec. 6. As used in this chapter, "corporation" refers to the Indiana economic development corporation established by IC 5-28-3-1 or its successor.

Sec. 7. As used in this chapter, "energy utility" means:

(1) an electric utility listed in 170 IAC 4-7-2(a) and any successor in interest to that utility; or

(2) a corporation organized under IC 8-1-13.

Sec. 8. As used in this chapter, "expedited generation resource plan", or "EGR plan", means a plan developed by an energy utility for acquiring generation resources to meet load growth that exceeds the lesser of:

(1) five percent (5%) of the energy utility's average peak demand over the most recent three (3) calendar years; or

(2) one hundred fifty (150) megawatts.

Sec. 9. As used in this chapter, "generation resource submittal" means a compliance filing made to the commission for approval of the acquisition of a specific generation resource in accordance with the criteria set forth in an approved EGR plan.

Sec. 10. As used in this chapter, "large load customer" means a new or existing customer of an energy utility, or not more than four (4) multiple new or existing customers of an energy utility, that:

(1) requests new or additional electricity demand that in the aggregate exceeds the lesser of:

(A) five percent (5%) of the energy utility's average peak demand over the most recent three (3) calendar years; or

(B) one hundred fifty (150) megawatts;

(2) plans to make a capital investment that exceeds five hundred million dollars ($500,000,000) in a new or expanded facility in Indiana; and

(3) plans to employ at the new or expanded facility in Indiana at least fifty (50) full-time employees with wages that on average meet or exceed the most recently published annual national average according to the Bureau of Labor Statistics of the United States Department of Labor.

Sec. 11. As used in this chapter, "office" refers to the Indiana office of energy development established by IC 4-3-23-3.

Sec. 12. (a) As used in this chapter, "planning costs" mean costs:

(1) incurred or to be incurred by an energy utility before the issuance of an order by the commission under this chapter; and

(2) related to an acquisition or project.

(b) The term includes study, analysis, pre-engineering, engineering, legal, financing, and regulatory costs.

Sec. 13. As used in this chapter, "pre-filing meeting" means a meeting to review and discuss a filing or submittal by an energy utility in accordance with:

(1) section 18 of this chapter;

(2) section 20 of this chapter; or

(3) section 22 of this chapter;

as applicable.

Sec. 14. As used in this chapter, "project" refers to a project relating to energy infrastructure and generation resources that:

(1) are required primarily to serve a large load customer of an energy utility; and

(2) may be designed to serve more than one (1) large load customer of the energy utility or to meet other customer demand or energy needs.

Sec. 15. As used in this chapter, "project costs" means the total costs of a project, including:

(1) planning costs; and

(2) construction and operating costs;

related to the project.

Sec. 16. As used in this chapter, "reasonable risk premium" means compensation:

(1) negotiated between an energy utility and a large load customer; and

(2) paid by the large load customer.

Sec. 17. (a) The commission may expedite, in accordance with this chapter, the review of filings and submittals made by an energy utility to meet the energy infrastructure and generation resource needs of customers. An energy utility may request an expedited review by the commission under either or both of the following:

(1) Sections 18 through 21 of this chapter (concerning EGR plans).

(2) Sections 22 through 24 of this chapter (concerning large load customer projects).

(b) This chapter does not preclude an energy utility from petitioning the commission under other applicable statutes for

approval of a generation resource acquisition to meet the needs of its customers.

(c) This chapter does not preclude an energy utility from petitioning the commission under, or in conjunction with, other applicable statutes, including:

(1) IC 8-1-2-24;
(2) IC 8-1-2-42;
(3) IC 8-1-2.5;
(4) IC 8-1-8.5;
(5) IC 8-1-8.8; or
(6) IC 8-1-39;

for approval of a project to meet the needs of large load customers.

Sec. 18. (a) This section applies to an energy utility that petitions the commission for approval of an EGR plan.

(b) An energy utility may file a petition with the commission for approval of an EGR plan to acquire generation resources to meet the extraordinary needs for electricity by the energy utility's customers.

(c) In petition under this section, an energy utility must do the following:

(1) Describe the energy utility's EGR plan for acquiring generation resources to meet the anticipated extraordinary growth in the load of its customers.
(2) Demonstrate a need for generation capacity that exceeds the lesser of:
(A) five percent (5%) of the energy utility's average peak demand over the most recent three (3) calendar years; or
(B) one hundred fifty (150) megawatts.
(3) Provide a load growth forecast for a minimum of five (5) years from the date of the petition.
(4) Describe the status of customer contracts and commitments that support the load growth forecast described in subdivision (3).
(5) Explain how the EGR plan is consistent with or differs from the energy utility's most recent integrated resource plan.
(6) Propose the accounting authority needed from the commission to support the EGR plan.
(7) Propose the manner in which the capital costs and operating and maintenance expenses related to the EGR plan will be included in the energy utility's revenue requirement.
(8) Identify the type and amount of capacity and energy:
(A) that is included in the EGR plan;

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(B) that does not exceed seventy-five percent (75%) of the energy utility's peak capacity over the forecast period described in subdivision (3); and

(C) with respect to which the energy utility may request expedited approval in a subsequent generation resource submittal.

(9) Identify the criteria to be included in a generation resource submittal that must be met for the acquisition to be approved by the commission.

(10) Certify that at least thirty (30) days before the filing of the petition the energy utility held a pre-filing meeting with the commission and the office of utility consumer counselor to review the EGR plan.

(11) Describe how the energy utility considered implementing grid enhancing technologies to defer or minimize the need for additional investment in generation.

(12) Describe how the EGR plan will support the provision of electric utility service with the attributes set forth in IC 8-1-2-0.6, including:

(A) reliability;

(B) affordability;

(C) resiliency;

(D) stability; and

(E) environmental sustainability.

(13) Describe how the EGR plan reasonably protects existing and future customers and is consistent with:

(A) the provision of safe, reliable, and affordable electric utility service; and

(B) economical rates.

(14) Include:

(A) verified testimony; and

(B) exhibits;

supporting the petition and constituting the energy utility's case in chief.

(15) Include a proposed order for the petition.

Sec. 19. (a) This section applies to an energy utility that petitions the commission for approval of an EGR plan.

(b) Notwithstanding IC 8-1-8.5 or any other statute, the commission may approve an energy utility's EGR plan to construct, purchase, lease, or otherwise acquire generation resources under this chapter for purposes of meeting the needs of the energy utility's customers. The commission shall make its

decision based on whether the relief requested is just, reasonable, and in the public interest.

(c) The commission may:

(1) approve the energy utility's petition in its entirety;

(2) deny the energy utility's petition in its entirety; or

(3) modify the petition, subject to the energy utility's acceptance of the modification.

(d) The commission shall issue a final order on the petition not later than ninety (90) days after receiving the energy utility's complete petition. A petition is considered:

(1) complete unless the commission provides a notice of deficiency to the energy utility not later than five (5) business days after the filing of the petition; and

(2) approved if the commission does not issue a final order on the petition within the ninety (90) day period set forth in this subsection.

Sec. 20. (a) This section applies to an energy utility that submits to the commission for approval a generation resource submittal in accordance with an approved EGR plan.

(b) An energy utility may submit a generation resource submittal to the commission for approval of an acquisition that the energy utility intends to make in accordance with an approved EGR plan.

(c) In a generation resource submittal under this section, an energy utility must do the following:

(1) Describe:

(A) the type of technology used in the generation resource to be acquired;

(B) the amount of capacity and energy to be acquired;

(C) key contractual terms for the acquisition; and

(D) the estimated acquisition costs.

(2) Demonstrate that the acquisition meets the criteria set forth in the energy utility's approved EGR plan.

(3) Explain how the acquisition is consistent with or differs from the energy utility's most recent integrated resource plan.

(4) Detail the status of customer contracts and commitments that support the acquisition.

(5) Certify that at least thirty (30) days before the filing of the generation resource submittal the energy utility held a pre-filing meeting with the commission and the office of utility consumer counselor to review the acquisition.

(6) Describe how the energy utility considered implementing

grid enhancing technologies to defer or minimize the need for additional investment in generation.

(7) Describe how the acquisition will support the provision of electric utility service with the attributes set forth in IC 8-1-2-0.6, including:

(A) reliability;
(B) affordability;
(C) resiliency;
(D) stability; and
(E) environmental sustainability.

(8) Describe how the acquisition reasonably protects existing and future customers and is consistent with:

(A) the provision of safe, reliable, and affordable electric utility service; and
(B) economical rates.

(9) Include supporting affidavits and exhibits.

(10) Include a proposed order for the submittal.

Sec. 21. (a) This section applies to an energy utility that submits to the commission for approval a generation resource submittal in accordance with an approved EGR plan.

(b) Notwithstanding IC 8-1-8.5 or any other statute, the commission may approve an energy utility's generation resource submittal to construct, purchase, lease, or otherwise acquire generation resources under this chapter for purposes of meeting the needs of the energy utility's customers. The commission shall make its decision based solely on whether the submittal meets the criteria and requirements set forth in the energy utility's approved EGR plan.

(c) The commission may:

(1) approve the energy utility's generation resource submittal in its entirety;
(2) deny the energy utility's generation resource submittal in its entirety; or
(3) modify the energy utility's generation resource submittal, subject to the energy utility's acceptance of the modification.

(d) The commission shall issue a final order on the energy utility's generation resource submittal not later than:

(1) sixty (60) days after receiving the energy utility's complete generation resource submittal, if the acquisition is a clean energy project (as defined in IC 8-1-8.8-2); or
(2) one hundred twenty (120) days after receiving the energy utility's complete generation resource submittal, if the

acquisition would otherwise require a certificate under IC 8-1-8.5-2.

A generation resource submittal is considered complete unless the commission provides a notice of deficiency to the energy utility not later than five (5) business days after the filing of the generation resource submittal. A generation resource submittal is considered approved if the commission does not issue a final order on the generation resource submittal within the period set forth in subdivision (1) or (2), as applicable.

Sec. 22. (a) This section applies to an energy utility that petitions the commission for approval of a project to serve a large load customer.

(b) An energy utility may submit to the commission a petition for approval of a project to serve a large load customer only if the following are satisfied:

(1) The petition concerns serving the energy needs of a large load customer.

(2) The large load customer commits to significant and meaningful financial assurances that must:

(A) include reimbursement by the large load customer of at least eighty percent (80%) of the project costs reasonably allocable to the large load customer; and

(B) afford protections for the energy utility's existing and future customers from project costs reasonably allocable to the large load customer regardless of whether the large load customer ultimately takes service in the anticipated amount and within the anticipated time frame.

(3) At least thirty (30) days before the energy utility's submission of the petition to the commission, the energy utility held at least one (1) pre-filing meeting with:

(A) the corporation;

(B) the office;

(C) the office of utility consumer counselor;

(D) the appropriate regional transmission organization; and

(E) the large load customer;

to review the project.

(c) An energy utility may petition the commission for approval of a project to serve:

(1) one (1) or more large load customers at one (1) or more locations; or

(2) not more than four (4) customers whose aggregate demand

satisfies the amount set forth in section 10(1) of this chapter. In any case in which more than one (1) large load customer is to be served by a project, a reference in this chapter to one (1) large load customer is a reference to all large load customers to be served by the project, in accordance with IC 1-1-4-1(3).

(d) In submitting a petition to the commission under this section, an energy utility must demonstrate that the large load customer and the associated projects meet the requirements of this chapter.

Sec. 23. (a) This section applies to an energy utility that petitions the commission for approval of a project to serve a large load customer.

(b) In a petition under this section, an energy utility must include, at a minimum, the following:

(1) The energy utility's complete case in chief, which must include, at a minimum, the following:

(A) An agreement from the large load customer that describes the financial assurances:

(i) that afford protections for the energy utility's existing and future customers; and

(ii) to which the large load customer has committed regardless of whether the large load customer ultimately takes service in the anticipated amount and within the anticipated time frame.

(B) A description of:

(i) the demand side management and self-generation options reviewed with the large load customer; and

(ii) the investments the large load customer will undertake to reasonably minimize the amount of incremental and other costs incurred by the energy utility.

(C) A description of how the energy utility considered implementing grid enhancing technologies to defer or minimize the need for additional investment in generation.

(D) A description of how the energy utility may provide for the requisite amount of electricity needed by the large load customer, including the estimated project costs.

(E) A description of how the expected project solution will support the provision of electric utility service with the attributes set forth in IC 8-1-2-0.6, including:

(i) reliability;

(ii) affordability;

(iii) resiliency;

(iv) stability; and

(v) environmental sustainability.

(F) A description of how the expected project solution and its implementation, if approved by the commission, reasonably protects existing and future customers and is consistent with:

(i) the provision of safe, reliable, and affordable electric utility service; and

(ii) economical rates.

(G) A description of the changes that the energy utility will make to the energy utility's:

(i) submissions under IC 8-1-8.5; or

(ii) filings under IC 8-1-39;

or both, that are necessary to update the energy utility's plans under those statutes to incorporate the project.

(H) Information concerning each:

(i) large load customer; and

(ii) economic development project;

included in the petition.

(I) A letter to the energy utility from the corporation supporting the petition's request.

(J) A letter to the energy utility from the office certifying that a pre-filing meeting took place and that at the meeting:

(i) the large load customer's proposed project; and

(ii) the expected project solution proposed by the energy utility;

were adequately discussed.

(K) A description of the communications and information sharing that:

(i) took place with the appropriate regional transmission organization before the pre-filing meeting described in clause (J); and

(ii) concerned the capacity and energy needs of each large load customer included in the petition.

(L) A proposed order for the petition.

(2) A copy of a notice of filing with:

(A) the corporation;

(B) the office;

(C) the office of utility consumer counselor; and

(D) the appropriate regional transmission organization.

A notice that is delivered electronically to the parties set forth

in this subdivision satisfies the notice requirement under this subdivision.

Sec. 24. (a) This section applies to an energy utility that petitions the commission for approval of a project to serve a large load customer.

(b) The commission may approve a petition in whole or in part. The commission shall make its decision based on whether the relief requested is just, reasonable, and in the public interest. The commission shall issue its final order on the petition not later than one hundred fifty (150) days after receiving the energy utility's complete petition and case in chief. A petition is considered:

(1) complete unless the commission provides a notice of deficiency to the energy utility not later than seven (7) business days after the filing of the petition; and

(2) approved if the commission does not issue a final order on the petition within the one hundred fifty (150) day period set forth in this subsection.

(c) If an energy utility files a petition that includes one (1) or more large load customers and one (1) or more proposed projects, the commission may:

(1) approve the energy utility's petition in its entirety;

(2) deny the energy utility's petition in its entirety; or

(3) modify the petition, subject to the energy utility's acceptance of the modification.

(d) The commission may approve a reasonable risk premium for a project if requested in an energy utility's petition and if the commission finds that the reasonable risk premium is appropriate. If the commission approves a reasonable risk premium:

(1) the large load customer is responsible for the amount of the reasonable risk premium; and

(2) the reasonable risk premium may not be:

(A) included in the energy utility's:

(i) revenue requirement;

(ii) authorized net operating income; or

(iii) calculations under IC 8-1-2-42(d)(3) or IC 8-1-2-42(g)(3)(C); or

(B) otherwise considered for purposes of setting the authorized return in any future general rate case or other regulatory proceeding involving the energy utility.

(e) The commission may approve an energy utility's request to construct, purchase, lease, or otherwise acquire an energy generation resource under this chapter (notwithstanding and

instead of under IC 8-1-2.5, IC 8-1-8.5, or IC 8-1-8.8) for the purpose of serving one (1) or more large load customers. In approving an energy utility's request under this chapter to acquire an energy generation resource to serve one (1) or more large load customers, the commission must find that:

(1) the information provided by the energy utility under section 23 of this chapter is complete;

(2) reasonable and demonstrable consideration was given to non-generation alternatives by the parties involved;

(3) existing and future customers of the energy utility will be adequately protected if the request is granted; and

(4) the energy utility has considered the impact of the request on the energy utility's preferred resource portfolio in the energy utility's most recent integrated resource plan.

(f) An energy utility shall promptly notify the commission if, after the commission has approved a petition under subsection (e), one (1) or more of the large load customers with respect to whom the petition was approved:

(1) no longer requires service from the energy utility or materially alters or terminates the large load customer's service requirements; and

(2) the project is incomplete.

(g) The commission may, not later than sixty (60) days after receiving a notice under subsection (f), conduct an investigation under IC 8-1-2-58 through IC 8-1-2-60 to determine whether the public interest would still be served by completion of the project. An investigation under this subsection does not preclude the energy utility from continuing construction of the project to serve the large load customer or from continuing to serve the large load customer. If the commission finds that completion of the project is no longer in the public interest, the commission may modify or revoke the order approving the petition.

Sec. 25. (a) The commission shall review an energy utility's:

(1) estimated acquisition costs submitted under section 20(c)(1)(D) of this chapter; or

(2) estimated project costs filed under section 23(b)(1)(D) of this chapter;

as applicable.

(b) If the commission approves, with or without modification, an energy utility's generation resource submittal or petition for approval of a project, the energy utility may recover:

(1) acquisition costs; or

(2) project costs;

as applicable, that have been reviewed and found reasonable by the commission, with a return at the energy utility's weighted average cost of capital.

(c) If the commission denies an energy utility's generation resource submittal or petition for approval of a project, the energy utility may recover planning costs that have been reviewed and found reasonable by the commission, without a return.

(d) Absent fraud, concealment, or gross mismanagement, an energy utility may recover:

(1) acquisition costs; or

(2) project costs;

as applicable, with a return at the energy utility's weighted average cost of capital, that the energy utility has incurred or contractually will incur in reliance on a commission order issued under this chapter.

Sec. 26. (a) Upon request by an energy utility, the commission shall determine whether the information and related materials filed or submitted, or to be filed or submitted, by an energy utility under this chapter:

(1) are confidential under IC 5-14-3-4 or are trade secrets under IC 24-2-3;

(2) are exempt from public access and disclosure by Indiana law; and

(3) must be treated as confidential and protected from public access and disclosure by the commission.

(b) The parties to a pre-filing meeting under this chapter shall execute a nondisclosure agreement to review or discuss information or materials considered confidential under IC 5-14-3-4 or to be trade secrets under IC 24-2-3.

(c) If the corporation is in negotiations with an industrial, research, or commercial prospect about a potential economic development project and, based on communications related to those negotiations, determines that the potential economic development project for a new or expanded facility in Indiana may result in the economic development project requiring new or increased energy demand of at least twenty (20) megawatts, the corporation shall notify the affected energy utility not later than fifteen (15) days after making the determination. All communications of the corporation, including notice under this section to an affected energy utility, regarding a potential economic development project are considered confidential and exempt from

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disclosure under IC 5-14-3-4(b)(5). Upon the corporation's provision of the notice required by this subsection, any subsequent:

(1) meeting;

(2) pre-filing meeting;

(3) communications; or

(4) information sharing;

involving the corporation, the affected energy utility, or the industrial, research, or commercial prospect about a potential economic development project may be subject to a nondisclosure agreement with respect to information or materials considered confidential under IC 5-14-3-4 or to be trade secrets under IC 24-2-3.

(d) An energy utility may request, and the commission may approve, financial incentives under IC 8-1-8.8-11(a) for:

(1) an acquisition; or

(2) a project;

that qualifies as a clean energy project (as defined in IC 8-1-8.8-2).

(e) An energy utility may request that review of an arrangement under IC 8-1-2-42 and any related rates and charges under IC 8-1-2-43 that are:

(1) submitted with a generation resource submittal; or

(2) filed with a petition for a project;

under this chapter be reviewed and approved or denied by the commission not later than ninety (90) dates after the date of submittal or filing, as applicable.

(f) Notwithstanding IC 8-1-8.5 or any other applicable statute, an energy utility may begin construction of an acquisition or a project before filing a petition or submittal under this chapter.

(g) The commission may require an energy utility to file with the commission progress reports and updates with respect to an acquisition or project under this chapter. Any required progress reports or updates under this subsection shall be made in a form and at a frequency that the commission determines to be reasonable.

SECTION 4. IC 8-1-8.5-2.1, AS AMENDED BY THE TECHNICAL CORRECTIONS BILL OF THE 2025 GENERAL ASSEMBLY, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2025]: Sec. 2.1. (a) This section does not apply to the retirement, sale, or transfer of:

(1) a public utility's electric generation facility if the retirement, sale, or transfer is necessary in order for the public utility to comply with a federal consent decree; or

(2) an electric generation facility that generates electricity for sale exclusively to the wholesale market.

(b) A public utility shall notify the commission if:

(1) the public utility intends or decides to retire, sell, or transfer an electric generation facility with a capacity of at least eighty (80) megawatts; and

(2) the retirement, sale, or transfer:

(A) was not set forth in; or

(B) is to take place on a date earlier than the date specified in;

the public utility's short term action plan in the public utility's most recently filed integrated resource plan.

(c) Upon receiving notice from a public utility under subsection (b), the commission shall consider and may investigate, under IC 8-1-2-58 through IC 8-1-2-60, the public utility's intention or decision to retire, sell, or transfer the electric generation facility. In considering the public utility's intention or decision under this subsection, the commission shall examine the impact the retirement, sale, or transfer would have on the public utility's ability to meet:

(1) the public utility's planning reserve margin requirements or other federal reliability requirements that the public utility is obligated to meet, as described in section ~~13(i)(4)~~ **13(n)(6)** of this chapter; and

(2) the reliability adequacy metrics set forth in section ~~13(e)~~ **13(h)** of this chapter.

(d) Before July 1, 2026, if:

(1) a public utility intends or decides to retire, sell, or transfer an electric generation facility with a capacity of at least eighty (80) megawatts; and

(2) the retirement, sale, or transfer:

(A) was not set forth in; or

(B) is to take place on a date earlier than the date specified in;

the public utility's short term action plan in the public utility's most recently filed integrated resource plan;

the commission shall not permit the public utility's depreciation rates, as established under IC 8-1-2-19, to be amended to reflect the accelerated date for the retirement, sale, or transfer of the electric generation asset unless the commission finds that such an adjustment is necessary to ensure the ability of the public utility to provide reliable service to its customers, and that the unamended depreciation rates would cause an unjust and unreasonable impact on the public utility and its ratepayers.

(e) The commission may issue a general administrative order to implement this section.

(f) This section expires July 1, 2026.

SECTION 5. IC 8-1-8.5-12.1, AS AMENDED BY P.L.93-2024, SECTION 67, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2025]: Sec. 12.1. **(a) As used in this section, "project development costs" means costs that have been incurred, or are reasonably estimated to be incurred, in the development of one (1) or more small modular nuclear reactors, including:**

(1) evaluation, design, and engineering costs;
(2) costs for federal approvals and licensing;
(3) costs for environmental analyses and permitting;
(4) early site permit (as defined in 10 CFR 52.1) costs;
(5) equipment procurement costs; and
(6) authorized carrying costs.

~~(a)~~ **(b)** As used in this section, "small modular nuclear reactor" means a nuclear reactor that:

(1) has a rated electric generating capacity of not more than four hundred seventy (470) megawatts;
(2) is capable of being constructed and operated, either:
(A) alone; or
(B) in combination with one (1) or more similar reactors if additional reactors are, or become, necessary;
at a single site; and
(3) is required to be licensed by the United States Nuclear Regulatory Commission.

The term includes a nuclear reactor that is described in this subsection and that uses a process to produce hydrogen that can be used for energy storage, as a fuel, or for other uses.

~~(b)~~ **(c)** Not later than July 1, 2023, the commission, in consultation with the department of environmental management, shall adopt rules under IC 4-22-2 concerning the granting of certificates under this chapter for the construction, purchase, or lease of small modular nuclear reactors:

(1) in Indiana for the generation of electricity to be directly or indirectly used to furnish public utility service to Indiana customers; or
(2) at the site of a nuclear energy production or generating facility that supplies electricity to Indiana retail customers on July 1, 2011.

~~(c)~~ **(d)** Rules adopted by the commission under this section must provide for the following:

(1) That in acting on a public utility's petition for the construction,

purchase, or lease of one (1) or more small modular nuclear reactors, as described in subsection ~~(b),~~ **(c),** the commission shall consider the following:

(A) Whether, and to what extent, the one (1) or more small modular nuclear reactors proposed by the public utility will replace a loss of generating capacity in the public utility's portfolio resulting from the retirement or planned retirement of one (1) or more of the public utility's existing electric generating facilities that:

(i) are located in Indiana; and

(ii) use coal or natural gas as a fuel source.

(B) Whether one (1) or more of the small modular nuclear reactors that will replace an existing facility will be located on the same site as or near the existing facility and, if so, potential opportunities for the public utility to:

(i) make use of any land and existing infrastructure or facilities already owned or under the control of the public utility; or

(ii) create new employment opportunities for workers who have been, or would be, displaced as a result of the retirement of the existing facility.

(2) That the commission may grant a certificate under this chapter under circumstances and for locations other than those described in subdivision (1).

(3) That the commission may not grant a certificate under this chapter unless the owner or operator of a proposed small modular nuclear reactor provides evidence of a plan to apply for all licenses or permits to construct or operate the proposed small modular nuclear reactor as may be required by:

(A) the United States Nuclear Regulatory Commission;

(B) the department of environmental management; or

(C) any other relevant state or federal regulatory agency with jurisdiction over the construction or operation of nuclear generating facilities.

(4) That any:

(A) reports;

(B) notices of violations; or

(C) other notifications;

sent to or from the United States Nuclear Regulatory Commission by or to the owner or operator of a proposed small nuclear reactor must be submitted by the owner or operator to the commission within such times as prescribed by the commission, subject to the commission's duty to treat as confidential and protect from public access and disclosure any information that is contained in a report or notice and that is considered confidential or exempt from public access and disclosure under state or federal law.

(5) That any person that owns or operates a small modular nuclear reactor in Indiana may not store:

(A) spent nuclear fuel (as defined in IC 13-11-2-216); or

(B) high level radioactive waste (as defined in IC 13-11-2-102);

from the small modular nuclear reactor on the site of the small modular nuclear reactor without first meeting all applicable requirements of the United States Nuclear Regulatory Commission.

~~(d) In adopting the rules required by this section, the commission may adopt rules under IC 4-22-2.~~

(e) A public utility may petition the commission for approval to incur, before obtaining a certificate under this chapter, project development costs for the development of one (1) or more small modular nuclear reactors. The public utility must file with the petition the public utility's case in chief, which must contain the information and supporting documentation regarding the factors the commission must consider under this subsection. In reviewing a petition and the supporting case in chief under this subsection, the commission shall consider the following:

(1) Whether a project by the utility to construct, purchase, or lease a small modular nuclear reactor is reasonably consistent with:

(A) this section and rules adopted by the commission under this section; and

(B) the purposes set forth in IC 8-1-8.8-1(b), as applicable.

(2) The following factors with respect to the project development costs and the project for which they are to be incurred:

(A) The amount of project development costs the public utility anticipates incurring.

(B) The anticipated timeline for incurring the project development costs.

(C) The anticipated date by which the public utility will make a decision as to whether to seek a certificate under this chapter.

The commission shall review a petition submitted under this subsection and issue a final order approving or denying the petition

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not later than one hundred eighty (180) days after receiving the petition and complete case in chief. However, if the commission makes a docket entry extending the procedural schedule and the public utility does not object to the entered extension, the commission may extend the one hundred eighty (180) day time frame for issuing a final order under this subsection for the amount of time set forth in the docket entry. In an order approving a petition, the commission must make a finding as to the best estimate and reasonableness of project development costs based on the evidence of record.

(f) If a public utility has received approval from the commission under subsection (e) to incur project development costs, the public utility may petition the commission at any time before or during the development and execution of a small modular nuclear reactor project for the approval of a rate schedule that periodically adjusts the public utility's rates and charges to provide for the timely recovery of project development costs. A petition under this subsection must describe any efforts by the public utility to pursue funding opportunities from the United States Department of Energy to offset the project development costs that the public utility seeks to recover under the proposed rate schedule.

(g) If, after reviewing a public utility's proposed rate schedule in a petition submitted under subsection (f), the commission determines that the public utility has incurred or will incur project development costs that are:

(1) reasonable in amount;

(2) necessary to support the construction, purchase, or lease of a small modular nuclear reactor; and

(3) consistent with the commission's finding as to the best estimate of project development costs in the commission's order of approval under subsection (e);

the commission shall approve the recovery of the project development costs, subject to subsections (h) and (i). However, a public utility may not file adjustments to a rate schedule to adjust for cost recovery approved under this subsection more than one (1) time every twelve (12) months.

(h) A public utility that recovers project development costs under subsection (g) shall recover eighty percent (80%) of the approved project development costs under the rate schedule approved under subsection (g) and shall defer the remaining twenty percent (20%) of approved project development costs, including, to the extent applicable, depreciation, allowance for

funds used during construction, and post in service carrying costs, based on the overall cost of capital most recently approved by the commission, and shall recover those project development costs as part of the next general rate case that the public utility files with the commission.

(i) The recovery of a public utility's project development costs through a periodic rate adjustment mechanism approved by the commission under subsection (g) must occur over a period that is equal to:

(1) the period over which the approved project development costs are incurred; or

(2) three (3) years;

whichever is less.

(j) Project development costs that are found by the commission to be reasonable, necessary, and consistent with the best estimate of project development costs in the commission's order of approval under subsection (e) shall be recovered by a public utility by inclusion in the public utility's rates and charges. Project development costs that are incurred by a public utility and that exceed the best estimate of project development costs under subsection (e) may not be included in the public utility's rates and charges unless found by the commission to be reasonable, necessary, and prudent in supporting the construction, purchase, or lease of the small modular nuclear reactor for which they were incurred. Project development costs that are incurred by a public utility for a project that is canceled or not completed may be recovered by the public utility if found by the commission to be reasonable, necessary, and prudently incurred, but such costs shall be recovered without a return unless the commission also finds that:

(1) the decision to cancel or not complete the project was prudently made for good cause;

(2) the project development costs incurred will be offset, as applicable, by:

(A) funding opportunities from the United States Department of Energy that are pursued in good faith by the public utility;

(B) a recoupment of revenues received by the public utility from one (1) or more third parties for the transfer of assets created through the costs incurred; or

(C) a reimbursement of costs by a single customer or prospective customer at whose request the project was

pursued; and

(3) a return on the project development costs incurred is appropriate under the circumstances to avoid harm to the public utility and its customers.

(k) A public utility may elect not to seek approval of, or cost recovery for, project development costs under subsections (e) through (i) and instead seek approval from the commission to defer and amortize project development costs in accordance with the procedures set forth in section 6.5 of this chapter with respect to construction costs.

(l) The commission may adopt rules under IC 4-22-2 to implement subsections (e) through (k).

~~(e)~~ **(m)** This section shall not be construed to affect the authority of the United States Nuclear Regulatory Commission.

SECTION 6. IC 8-1-8.5-13, AS AMENDED BY P.L.93-2024, SECTION 68, IS AMENDED TO READ AS FOLLOWS [EFFECTIVE JULY 1, 2025]: Sec. 13. (a) The general assembly finds that it is in the public interest to support the reliability, availability, and diversity of electric generating capacity in Indiana for the purpose of providing reliable and stable electric service to customers of public utilities.

(b) As used in this section, "appropriate regional transmission organization", with respect to a public utility, refers to the regional transmission organization approved by the Federal Energy Regulatory Commission for the control area that includes the public utility's assigned service area (as defined in IC 8-1-2.3-2).

(c) As used in this section, "capacity market" means an auction conducted by an appropriate regional transmission organization to determine a market clearing price for capacity based on the planning reserve margin requirements established by the appropriate regional transmission organization for a planning year with respect to which an auction has not yet been conducted.

(d) As used in this section, "fall unforced capacity", or "fall UCAP", with respect to an electric generating facility, means:

(1) the capacity value of the electric generating facility's installed capacity rate adjusted for the electric generating facility's average forced outage rate for the fall period, calculated as required by the appropriate regional transmission organization or by the Federal Energy Regulatory Commission;

(2) a metric that is similar to the metric described in subdivision (1) and that is required by the appropriate regional transmission organization; or

(3) if the appropriate regional transmission organization does not

require a metric described in subdivision (1) or (2), a metric that:

(A) can be used to demonstrate that a public utility has sufficient capacity to:

(i) provide reliable electric service to Indiana customers for the fall period; and

(ii) meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(l)(4);~~ **(n)(6);** and

(B) is acceptable to the commission.

(e) As used in this section, "MISO" refers to the regional transmission organization known as the Midcontinent Independent System Operator that operates the bulk power transmission system serving most of the geographic territory in Indiana.

(f) As used in this section, "planning reserve margin requirement", with respect to a public utility for a particular resource planning year, means the planning reserve margin requirement for that planning year that the public utility is obligated to meet in accordance with the public utility's membership in the appropriate regional transmission organization.

(g) As used in this section, "refuel" or "refueling" means a planned fuel conversion from one fuel source to another fuel source with respect to an electric generation resource with a nameplate capacity of at least one hundred twenty-five (125) megawatts by a public utility.

~~(g)~~ **(h)** As used in this section, "reliability adequacy metrics", with respect to a public utility, means calculations used to demonstrate all of the following:

(1) Subject to subsection ~~(q)(2)(B),~~ **(u)(2),** that the public utility:

(A) has in place sufficient summer UCAP; or

(B) can reasonably acquire not more than:

(i) thirty percent (30%) of its total summer UCAP from capacity markets, with respect to a report filed with the commission under subsection ~~(l)~~ **(n)** before July 1, 2023; or

(ii) fifteen percent (15%) of its total summer UCAP from capacity markets, with respect to a report filed with the commission under subsection ~~(l)~~ **(n)** after June 30, 2023;

such that it will have sufficient summer UCAP;

to provide reliable electric service to Indiana customers, and to meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(l)(4).~~ **(n)(6).**

(2) Subject to subsection ~~(q)(2)(B),~~ **(u)(2),** that the public utility:

(A) has in place sufficient winter UCAP; or

(B) can reasonably acquire not more than:

(i) thirty percent (30%) of its total winter UCAP from capacity markets, with respect to a report filed with the commission under subsection ~~(l)~~ **(n)** before July 1, 2023; or

(ii) fifteen percent (15%) of its total winter UCAP from capacity markets, with respect to a report filed with the commission under subsection ~~(l)~~ **(n)** after June 30, 2023;

such that it will have sufficient winter UCAP;

to provide reliable electric service to Indiana customers, and to meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(l)(4).~~ **(n)(6).**

(3) Subject to subsection ~~(q)(2)(B),~~ **(u)(2),** with respect to a report filed with the commission under subsection ~~(l)~~ **(n)** after June 30, 2026, that the public utility:

(A) has in place sufficient spring UCAP; or

(B) can reasonably acquire not more than fifteen percent (15%) of its total spring UCAP from capacity markets, such that it will have sufficient spring UCAP;

to provide reliable electric service to Indiana customers, and to meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(l)(4).~~ **(n)(6).**

(4) Subject to subsection ~~(q)(2)(B),~~ **(u)(2),** with respect to a report filed with the commission under subsection ~~(l)~~ **(n)** after June 30, 2026, that the public utility:

(A) has in place sufficient fall UCAP; or

(B) can reasonably acquire not more than fifteen percent (15%) of its total fall UCAP from capacity markets, such that it will have sufficient fall UCAP;

to provide reliable electric service to Indiana customers, and to meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(l)(4).~~ **(n)(6).**

(i) As used in this section, "retire" or retirement" means a planned permanent ceasing of electric generation operations with respect to an electric generation resource with a nameplate capacity of at least one hundred twenty-five (125) megawatts by a public utility.

~~(h)~~ **(j)** As used in this section, "spring unforced capacity", or "spring UCAP", with respect to an electric generating facility, means:

(1) the capacity value of the electric generating facility's installed capacity rate adjusted for the electric generating facility's average forced outage rate for the spring period, calculated as required by the appropriate regional transmission organization or by the

Federal Energy Regulatory Commission;
(2) a metric that is similar to the metric described in subdivision (1) and that is required by the appropriate regional transmission organization; or
(3) if the appropriate regional transmission organization does not require a metric described in subdivision (1) or (2), a metric that:
(A) can be used to demonstrate that a public utility has sufficient capacity to:
(i) provide reliable electric service to Indiana customers for the spring period; and
(ii) meet its planning reserve margin requirement and other federal reliability requirements described in subsection ~~(l)(4);~~ **(n)(6);** and
(B) is acceptable to the commission.

~~(i)~~ **(k)** As used in this section, "summer unforced capacity", or "summer UCAP", with respect to an electric generating facility, means:
(1) the capacity value of the electric generating facility's installed capacity rate adjusted for the electric generating facility's average forced outage rate for the summer period, calculated as required by the appropriate regional transmission organization or by the Federal Energy Regulatory Commission; or
(2) a metric that is similar to the metric described in subdivision (1) and that is required by the appropriate regional transmission organization.

~~(j)~~ **(l)** As used in this section, "winter unforced capacity", or "winter UCAP", with respect to an electric generating facility, means:
(1) the capacity value of the electric generating facility's installed capacity rate adjusted for the electric generating facility's average forced outage rate for the winter period, calculated as required by the appropriate regional transmission organization or by the Federal Energy Regulatory Commission;
(2) a metric that is similar to the metric described in subdivision (1) and that is required by the appropriate regional transmission organization; or
(3) if the appropriate regional transmission organization does not require a metric described in subdivision (1) or (2), a metric that:
(A) can be used to demonstrate that a public utility has sufficient capacity to:
(i) provide reliable electric service to Indiana customers for the winter period; and
(ii) meet its planning reserve margin requirement and other federal reliability requirements described in subsection

~~(l)(4);~~ **(n)(6);** and
(B) is acceptable to the commission.

~~(k)~~ **(m)** A public utility that owns and operates an electric generating facility serving customers in Indiana shall operate and maintain the facility using good utility practices and in a manner:

(1) reasonably intended to support the provision of reliable and economic electric service to customers of the public utility; ~~and~~

(2) reasonably consistent with the resource reliability requirements of MISO or any other appropriate regional transmission organization; **and**

(3) reasonably maximizes the economic value of the electric generating facility.

~~(l)~~ **(n)** Not later than thirty (30) days after the deadline for submitting an annual planning reserve margin report to MISO, each public utility providing electric service to Indiana customers shall, regardless of whether the public utility is required to submit an annual planning reserve margin report to MISO, file with the commission a report, in a form specified by the commission, that provides the following information for each of the next three (3) resource planning years, beginning with the planning year covered by the planning reserve margin report to MISO described in this subsection:

(1) The:
(A) capacity;
(B) location; and
(C) fuel source;
for each electric generating facility that is owned and operated by the electric utility and that will be used to provide electric service to Indiana customers.

(2) With respect to a report submitted to the commission after December 31, 2025, the amount of generating resource capacity or energy, or both, that the public utility plans to retire and that is owned and operated by the public utility and used to provide retail electric service in Indiana, including the:
(A) capacity;
(B) location;
(C) fuel source; and
(D) planned retirement date;
for each electric generating facility. The public utility must include information as to whether the planned retirement is required in order to comply with environmental laws, regulations, or court orders, including consent decrees, that

are or will be in effect at the time of the planned retirement. In addition, the public utility must provide its economic rationale for the planned retirement, including anticipated ratepayer impacts, and information concerning the public utility's plan or plans with respect to the amount of replacement capacity identified to provide approximately the same accredited capacity within the appropriate regional transmission organization as the amount of capacity of the facility to be retired.

(3) With respect to a report submitted to the commission after December 31, 2025, the amount of generating resource capacity or energy, or both, that the public utility plans to refuel, including the:

(A) capacity;

(B) location;

(C) existing fuel source;

(D) proposed fuel source; and

(E) planned completion date of the refueling;

with respect to each electric generating facility that the public utility plans to refuel. The public utility must provide its economic rationale for the planned refueling, including anticipated ratepayer impacts, and information concerning the public utility's plan or plans with respect to the extent to which the refueling will maintain or increase the current generating resource accredited capacity or energy, or both, that the electric generating facility provides, so as to provide approximately the same accredited capacity within the appropriate regional transmission organization.

~~(2)~~ **(4)** The amount of generating resource capacity or energy, or both, that the public utility has procured under contract and that will be used to provide electric service to Indiana customers, including the:

(A) capacity;

(B) location; and

(C) fuel source;

for each electric generating facility that will supply capacity or energy under the contract, to the extent known by the public utility.

~~(3)~~ **(5)** The amount of demand response resources available to the public utility under contracts and tariffs.

~~(4)~~ **(6)** The following:

(A) The planning reserve margin requirements established by

MISO for the planning years covered by the report, to the extent known by the public utility with respect to any particular planning year covered by the report.

(B) If applicable, any other planning reserve margin requirement that:

(i) applies to the planning years covered by the report; and

(ii) the public utility is obligated to meet in accordance with the public utility's membership in an appropriate regional transmission organization;

to the extent known by the public utility with respect to any particular planning year covered by the report.

(C) Other federal reliability requirements that the public utility is obligated to meet in accordance with its membership in an appropriate regional transmission organization with respect to the planning years covered by the report, to the extent known by the public utility with respect to any particular planning year covered by the report.

For each planning reserve margin requirement reported under clause (A) or (B), the public utility shall include a comparison of that planning reserve margin requirement to the planning reserve margin requirement established by the same regional transmission organization for the 2021-2022 planning year.

~~(5)~~ **(7)** The reliability adequacy metrics of the public utility, as forecasted for the three (3) planning years covered by the report.

~~(m)~~ **(o)** Upon request by a public utility, the commission shall determine whether information provided in a report filed by the public utility under subsection ~~(l).~~ **(n):**

(1) is confidential under IC 5-14-3-4 or is a trade secret under IC 24-2-3;

(2) is exempt from public access and disclosure by Indiana law; and

(3) shall be treated as confidential and protected from public access and disclosure by the commission.

~~(n)~~ **(p)** A joint agency created under IC 8-1-2.2 may file the report required under subsection ~~(l)~~ **(n)** as a consolidated report on behalf of any or all of the municipally owned utilities that make up its membership.

~~(o)~~ **(q)** A:

(1) corporation organized under IC 23-17 that is an electric cooperative and that has at least one (1) member that is a corporation organized under IC 8-1-13; or

(2) general district corporation within the meaning of

IC 8-1-13-23;

may file the report required under subsection ~~(l)~~ **(n)** as a consolidated report on behalf of any or all of the cooperatively owned electric utilities that it serves.

~~(p)~~ **(r)** In reviewing a report filed by a public utility under subsection ~~(l),~~ **(n),** the commission may request technical assistance from MISO or any other appropriate regional transmission organization in determining:

(1) the planning reserve margin requirements or other federal reliability requirements that the public utility is obligated to meet, as described in subsection ~~(l)(4);~~ **(n)(6);** and

(2) whether the resources available to the public utility under subsections ~~(l)(1)~~ **(n)(1)** through ~~(l)(3)~~ **(n)(5)** will be adequate to support the provision of reliable electric service to the public utility's Indiana customers.

(s) With respect to a report submitted under subsection (n) after December 31, 2025, commission staff shall review the reports submitted by public utilities and shall, not later than ninety (90) days after the date of submission of the reports, submit to the commission a staff report concerning any planned retirements included in the reports under subsection (n)(2). The report must make recommendations to the commission based on whether each planned retirement:

(1) is consistent with the standards set forth in subsection (m);

(2) will be replaced with an amount of replacement capacity that will provide approximately the same accredited capacity within the appropriate regional transmission organization as the amount of capacity of the facility to be retired;

(3) will not adversely and unreasonably impact a public utility's ability to provide safe, reliable, and economical electric utility service to the public utility's customers;

(4) will result in the provision to Indiana customers of electric utility service with the attributes of:

(A) reliability;

(B) affordability;

(C) resiliency;

(D) stability; and

(E) environmental sustainability;

as set forth in IC 8-1-2-0.6; and

(5) is required in order to comply with environmental laws, regulations, or court orders, including consent decrees, that are or will be in effect at the time of the planned retirement.

(t) The commission shall make the staff reports prepared under subsection (s) publicly available by posting the staff reports on the commission's website. Upon the posting of a staff report on the commission's website, the commission shall accept public comments on the report for a period not to exceed thirty (30) days after the date of posting.

~~(q)~~ **(u)** If, after reviewing a report filed by a public utility under subsection ~~(l),~~ **(n) and any staff report prepared with respect to the public utility under subsection (s),** the commission is not satisfied that the public utility can **either:**

~~(1) provide reliable electric service to the public utility's Indiana customers; or~~

~~(2) either:~~

~~(A)~~ **(1)** satisfy both:

~~(i)~~ **(A)** its planning reserve margin requirement or other federal reliability requirements that the public utility is obligated to meet, as described in subsection ~~(l)(4);~~ **(n)(6);** and

~~(ii)~~ **(B)** the reliability adequacy metrics set forth in subsection ~~(g);~~ **(h);** or

~~(B)~~ **(2)** provide sufficient reason as to why the public utility is unable to satisfy both:

~~(i)~~ **(A)** its planning reserve margin requirement or other federal reliability requirements that the public utility is obligated to meet, as described in subsection ~~(l)(4);~~ **(n)(6);** and

~~(ii)~~ **(B)** the reliability adequacy metrics set forth in subsection ~~(g);~~ **(h);**

during one (1) more of the planning years covered by the report, the commission ~~may~~ **shall** conduct an investigation under IC 8-1-2-58 through IC 8-1-2-60 as to the reasons for the public utility's potential inability to meet the requirements described in subdivision (1) or ~~(2), or both.~~ **provide sufficient reason as to that inability, as described in subdivision (2). In addition, if the public utility has indicated in its report under subsection (n)(2) that it plans to retire an electric generating facility within one (1) year of the date of the report, the commission must conduct an investigation under IC 8-1-2-58 through IC 8-1-2-60 as to the reasons for the public utility's potential inability to meet the requirements described in subdivision (1) or provide sufficient reason as to that inability, as described in subdivision (2). However, a public utility may request, not earlier than three (3) years before the planned retirement date of an electric generation facility, that the commission conduct an investigation under IC 8-1-2-58 through IC 8-1-2-60, for the**

purposes described in this subsection, with respect to the planned retirement. If the commission conducts an investigation at the request of a public utility within the three (3) year period before the planned retirement date of an electric generation facility, the commission may not conduct a subsequent investigation that would otherwise be required under this subsection with respect to the retirement of that same electric generation facility unless the commission is not satisfied, as of the time that an investigation would otherwise be required under this subsection, that the public utility can meet the requirements described in subdivision (1) or provide sufficient reason as to that inability, as described in subdivision (2). If a certificate is granted by the commission under this chapter for a facility intended to repower or replace a generation unit that is planned for retirement, and the certificate includes findings that the project will result in at least equivalent accredited capacity and will provide economic benefit to ratepayers as compared to the continued operation of the generating unit to be retired, the certificate under this chapter constitutes approval by the commission for purposes of an investigation required by this subsection. However, if the commission finds that facts and circumstances regarding the planned retirement have changed significantly since the certificate was granted and that those changes concern the public utility's ability to meet the requirements described in subdivision (1), the commission may conduct an investigation into the planned retirement of the unit.

~~(r)~~ **(v)** If, upon investigation under IC 8-1-2-58 through IC 8-1-2-60, and after notice and hearing, as required by IC 8-1-2-59, the commission determines that the capacity resources available to the public utility under subsections ~~(l)(1)~~ **(n)(1)** through ~~(l)(3)~~ **(n)(5)** will not be adequate ~~to support the provision of reliable electric service to the public utility's Indiana customers, or~~ to allow the public utility to satisfy both its planning reserve margin requirements or other federal reliability requirements that the public utility is obligated to meet (as described in subsection ~~(l)(4))~~ **(n)(6))** and the reliability adequacy metrics set forth in subsection ~~(g),~~ **(h),** the commission shall issue an order:

(1) directing the public utility to acquire or construct; **or**

(2) prohibiting the retirement or refueling of;

such capacity resources that are reasonable and necessary to enable the public utility to provide reliable electric service to its Indiana customers, and to satisfy both its planning reserve margin requirements

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or other federal reliability requirements described in subsection ~~(l)(4)~~ **(n)(6)** and the reliability adequacy metrics set forth in subsection ~~(g).~~ **(h). The commission shall issue an order under this subsection not later than one hundred twenty (120) days after the initiation of the investigation under subsection (u). If the commission does not issue an order within the one hundred twenty (120) day period prescribed by this subsection, the public utility is considered to be able to meet the requirements described in subsection (u)(1) with respect to the retirement of the electric generation facility under investigation.** Not later than ninety (90) days after the date of ~~the commission's~~ **an** order **by the commission** under this subsection, the public utility shall file for approval with the commission a plan to comply with the commission's order. **Notwithstanding IC 8-1-3 or any other law, any appeal of an order by the commission under this subsection is entitled to priority review and shall be given expedited consideration in accordance with Rule 21 of the Indiana Rules of Appellate Procedure.**

(w) With respect to a report submitted under subsection (n) after December 31, 2025, if the commission issues an order under subsection (v) to prohibit the retirement or refueling of an electric generation resource, the commission shall create a sub-docket to authorize the public utility to recover in rates the costs of the continued operation of the electric generation resource that was proposed to be retired or refueled. The commission must find that the continued costs of operation are just and reasonable before authorizing their recovery in the public utility's rates. The creation of a sub-docket under this subsection is not subject to the one hundred twenty (120) day time frame for the commission to issue an order under subsection (v).

~~The~~ **(x) A** public utility's plan **under subsection (v)** may include:

(1) a request for a certificate of public convenience and necessity under this chapter; or

(2) an application under IC 8-1-8.8;

or both.

~~(s)~~ **(y)** Beginning in 2022, the commission shall include in its annual report under IC 8-1-1-14 the following information:

(1) The commission's analysis regarding the ability of public utilities to:

(A) provide reliable electric service to Indiana customers; and

(B) satisfy both:

(i) their planning reserve margin requirements or other federal reliability requirements; and

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(ii) the reliability adequacy metrics set forth in subsection ~~(g);~~ **(h);**

for the next three (3) utility resource planning years, based on the most recent reports filed by public utilities under subsection ~~(l).~~ **(n).**

(2) A summary of:

(A) the projected demand for retail electricity in Indiana over the next calendar year; ~~and~~

(B) the amount and type of capacity resources committed to meeting the projected demand;

(C) beginning with the commission's annual report due before October 1, 2026, and in each subsequent annual report, the planned retirements or refuelings of electric generation resources and the plans to replace or retain the capacity or energy, or both, of the electric generation resources planned to be retired or refueled; and

(D) beginning with the commission's annual report due before October 1, 2026, and in each subsequent annual report, the reports of commission staff under subsection (s).

In preparing the summary required under this subdivision, the commission may consult with the forecasting group established under section 3.5 of this chapter.

(3) Beginning with the commission's annual report filed under IC 8-1-1-14 in 2025, the commission's analysis regarding the appropriate percentage or portion of:

(A) total spring UCAP that public utilities should be authorized to acquire from capacity markets under subsection ~~(g)(3)(B);~~ **(h)(3)(B);** and

(B) total fall UCAP that public utilities should be authorized to acquire from capacity markets under subsection ~~(g)(4)(B).~~ **(h)(4)(B).**

~~(t)~~ **(z)** The commission may adopt rules under IC 4-22-2 to implement this section.

SECTION 7. **An emergency is declared for this act.**

COMMITTEE REPORT

Mr. Speaker: Your Committee on Utilities, Energy and Telecommunications, to which was referred House Bill 1007, has had the same under consideration and begs leave to report the same back to the House with the recommendation that said bill be amended as follows:

Page 2, line 26, delete "ten percent (10%)" and insert "**twenty percent (20%)**".

Page 3, line 17, delete "installed" and insert "**manufactured**".

Page 3, line 26, after "1." insert "**(a)**".

Page 3, line 26, after "project" insert "**or an arrangement**".

Page 3, between lines 30 and 31, begin a new paragraph and insert:

"**(b) The term includes the purchase of energy or capacity through a power purchase agreement.**".

Page 4, line 8, delete "planning" and insert "**project evaluation, analysis, and development**".

Page 4, line 14, delete "means an" and insert "**means:**

(1) an electric utility listed in 170 IAC 4-7-2(a) and any successor in interest to that utility; or

(2) a corporation organized under IC 8-1-13.".

Page 4, delete lines 15 through 16.

Page 9, between lines 21 and 22, begin a new line block indented and insert:

"**(10) Include a proposed order for the submittal.**".

Page 15, line 35, delete "determines that any potential economic" and insert "**is in negotiations with an industrial, research, or commercial prospect about a potential economic development project and, based on communications related to those negotiations, determines that the potential economic development project for a new or expanded facility in Indiana may result in the economic development project requiring new or increased energy demand of at least twenty (20) megawatts, the corporation shall notify the affected energy utility not later than fifteen (15) days after making the determination. All communications of the corporation, including notice under this section to an affected energy utility, regarding a potential economic development project are considered confidential and exempt from disclosure under IC 5-14-3-4(b)(5).**".

Page 15, delete lines 36 through 39.

Page 15, line 40, delete "later than fifteen (15) days after making the determination.".

Page 16, line 5, delete "one (1) or" and insert "**the industrial, research, or commercial prospect about a potential economic development project**".

Page 16, line 6, delete "more potential new large load customers".

Page 22, line 2, delete "Actual project development costs that are".

Page 22, delete lines 3 through 8.

Page 22, line 17, delete "Reasonable and necessary project development costs that are" and insert "**Project development costs that are found by the commission to be reasonable, necessary, and consistent with the best estimate of project development costs in the commission's order of approval under subsection (e) shall be recovered by a public utility by inclusion in the public utility's rates and charges. Project development costs that are incurred by a public utility and that exceed the best estimate of project development costs under subsection (e) may not be included in the public utility's rates and charges unless found by the commission to be reasonable, necessary, and prudent in supporting the construction, purchase, or lease of the small modular nuclear reactor for which they were incurred. Project development costs that are incurred by a public utility for a project that is canceled or not completed may be recovered by the public utility if found by the commission to be reasonable, necessary, and prudently incurred, but such costs shall be recovered without a return unless the commission also finds that:**

(1) the decision to cancel or not complete the project was prudently made for good cause;

(2) the project development costs incurred will be offset, as applicable, by:

(A) funding opportunities from the United States Department of Energy that are pursued in good faith by the public utility;

(B) a recoupment of revenues received by the public utility from one (1) or more third parties for the transfer of assets created through the costs incurred; or

(C) a reimbursement of costs by a single customer or prospective customer at whose request the project was pursued; and

(3) a return on the project development costs incurred is appropriate under the circumstances to avoid harm to the public utility and its customers.

(k) A public utility may elect not to seek approval of, or cost recovery for, project development costs under subsections (e)

through (i) and instead seek approval from the commission to defer and amortize project development costs in accordance with the procedures set forth in section 6.5 of this chapter with respect to construction costs.".

Page 22, delete lines 18 through 31.

Page 22, line 32, delete "(k)" and insert "**(l)**".

Page 22, line 33, delete "(j)." and insert "**(k).**".

Page 22, line 34, delete "(l)" and insert "**(m)**".

Page 24, line 1, delete "of at least one" and insert "**with a nameplate capacity of at least one hundred twenty-five (125) megawatts by a public utility.**".

Page 24, delete line 2.

Page 24, line 6, delete "(u)(2)(B)," and insert "**(u)(2),**".

Page 24, line 20, delete "(u)(2)(B)," and insert "**(u)(2),**".

Page 24, line 34, delete "(u)(2)(B)," and insert "**(u)(2),**".

Page 25, line 2, delete "(u)(2)(B)," and insert "**(u)(2),**".

Page 25, line 14, delete "of at least one hundred" and insert "**with a nameplate capacity of at least one hundred twenty-five (125) megawatts by a public utility.**".

Page 25, delete line 15.

Page 27, line 11, delete "retire," and insert "**retire and that is owned and operated by the public utility and used to provide retail electric service in Indiana,**".

Page 27, line 16, delete "facility that the public utility" and insert "**facility. The public utility must include information as to whether the planned retirement is required in order to comply with environmental laws, regulations, or court orders, including consent decrees, that are or will be in effect at the time of the planned retirement.**".

Page 27, line 17, delete "plans to retire. The" and insert "**In addition, the**".

Page 27, line 22, delete "credit" and insert "**accredited**".

Page 27, line 40, after "resource" insert "**accredited**".

Page 27, line 41, delete "provides." and insert "**provides, so as to provide approximately the same accredited capacity within the appropriate regional transmission organization.**".

Page 29, line 29, delete "Commission" and insert "**With respect to a report submitted under subsection (n) after December 31, 2025, commission**".

Page 29, line 30, delete "under subsection (n)".

Page 29, line 38, delete "capacity credit" and insert "**accredited capacity**".

Page 30, line 1, delete "and".

Page 30, line 9, delete "IC 8-1-2-0.6." and insert "**IC 8-1-2-0.6; and**
(5) is required in order to comply with environmental laws, regulations, or court orders, including consent decrees, that are or will be in effect at the time of the planned retirement.".

Page 30, line 19, after "can" delete ":" and insert "**either:**".

Page 30, strike lines 20 through 22.

Page 30, line 23, beginning with "(A)" begin a new line block indented.

Page 30, line 23, strike "(A)" and insert "**(1)**".

Page 30, line 24, beginning with "(i)" begin a new line double block indented.

Page 30, line 24, strike "(i)" and insert "**(A)**".

Page 30, line 27, beginning with "(ii)" begin a new line double block indented.

Page 30, line 27, strike "(ii)" and insert "**(B)**".

Page 30, line 29, beginning with "(B)" begin a new line block indented.

Page 30, line 29, strike "(B)" and insert "**(2)**".

Page 30, line 31, beginning with "(i)" begin a new line double block indented.

Page 30, line 31, strike "(i)" and insert "**(A)**".

Page 30, line 34, beginning with "(ii)" begin a new line double block indented.

Page 30, line 34, strike "(ii)" and insert "**(B)**".

Page 30, line 37, strike "may" and insert "**shall**".

Page 30, line 39, strike "(2), or both." and insert "**provide sufficient reason as to that inability, as described in subdivision (2).**".

Page 30, line 40, delete "However," and insert "**In addition,**".

Page 30, line 41, delete "(n)" and insert "**(n)(2)**".

Page 31, line 3, delete "(2), or both." and insert "**provide sufficient reason as to that inability, as described in subdivision (2). However, a public utility may request, not earlier than three (3) years before the planned retirement date of an electric generation facility, that the commission conduct an investigation under IC 8-1-2-58 through IC 8-1-2-60, for the purposes described in this subsection, with respect to the planned retirement. If the commission conducts an investigation at the request of a public utility within the three (3) year period before the planned retirement date of an electric generation facility, the commission may not conduct a subsequent investigation that would otherwise be required under this subsection with respect to the retirement of that same electric**

generation facility unless the commission is not satisfied, as of the time that an investigation would otherwise be required under this subsection, that the public utility can meet the requirements described in subdivision (1) or provide sufficient reason as to that inability, as described in subdivision (2). If a certificate is granted by the commission under this chapter for a facility intended to repower or replace a generation unit that is planned for retirement, and the certificate includes findings that the project will result in at least equivalent accredited capacity and will provide economic benefit to ratepayers as compared to the continued operation of the generating unit to be retired, the certificate under this chapter constitutes approval by the commission for purposes of an investigation required by this subsection. However, if the commission finds that facts and circumstances regarding the planned retirement have changed significantly since the certificate was granted and that those changes concern the public utility's ability to meet the requirements described in subdivision (1), the commission may conduct an investigation into the planned retirement of the unit.".

Page 31, line 8, strike "to support the provision of reliable electric service to".

Page 31, line 9, strike "the public utility's Indiana customers, or".

Page 31, line 22, after "(h)." insert "**The commission shall issue an order under this subsection not later than one hundred twenty (120) days after the initiation of the investigation under subsection (u). If the commission does not issue an order within the one hundred twenty (120) day period prescribed by this subsection, the public utility is considered to be able to meet the requirements described in subsection (u)(1) with respect to the retirement of the electric generation facility under investigation.**".

Page 31, line 22, strike "the commission's" and insert "**an**".

Page 31, line 23, after "order" insert "**by the commission**".

Page 31, between lines 28 and 29, begin a new paragraph and insert:

"**(w) With respect to a report submitted under subsection (n) after December 31, 2025, if the commission issues an order under subsection (v) to prohibit the retirement or refueling of an electric generation resource, the commission shall create a sub-docket to authorize the public utility to recover in rates the costs of the continued operation of the electric generation resource that was proposed to be retired or refueled. The commission must find that the continued costs of operation are just and reasonable before authorizing their recovery in the public utility's rates. The creation**

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of a sub-docket under this subsection is not subject to the one hundred twenty (120) day time frame for the commission to issue an order under subsection (v).".

Page 31, line 29, delete "(w)" and insert "**(x)**".

Page 31, line 34, delete "(x)" and insert "**(y)**".

Page 32, line 32, delete "(y)" and insert "**(z)**".

and when so amended that said bill do pass.

(Reference is to HB 1007 as introduced.)

SOLIDAY

Committee Vote: yeas 9, nays 4.

COMMITTEE REPORT

Mr. Speaker: Your Committee on Ways and Means, to which was referred House Bill 1007, has had the same under consideration and begs leave to report the same back to the House with the recommendation that said bill do pass.

(Reference is to HB 1007 as printed January 29, 2025.)

THOMPSON

Committee Vote: Yeas 16, Nays 7

HOUSE MOTION

Mr. Speaker: I move that House Bill 1007 be amended to read as follows:

Page 3, between lines 20 and 21, begin a new paragraph and insert:

"SECTION 2. IC 8-1-2-24.5 IS ADDED TO THE INDIANA CODE AS A **NEW** SECTION TO READ AS FOLLOWS [EFFECTIVE UPON PASSAGE]: **Sec. 24.5. (a) As used in this section, "energy utility" means:**

(1) an electric utility listed in 170 IAC 4-7-2(a) and any successor in interest to that utility; or

(2) a corporation organized under IC 8-1-13.

(b) As used in this section, "large load customer" means a new or existing customer of an energy utility, or not more than four (4)

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multiple new or existing customers of an energy utility, that requests new or additional electricity demand that in the aggregate exceeds the lesser of:

(1) five percent (5%) of the energy utility's average peak demand over the most recent three (3) calendar years; or

(2) one hundred fifty (150) megawatts.

(c) As used in this section, "project" refers to a project relating to energy infrastructure or generation resources that:

(1) are required primarily to serve a large load customer of an energy utility; and

(2) may be designed to serve more than one (1) large load customer of the energy utility or to meet other customer demand or energy needs.

(d) As used in this section, "project costs" means the total costs of a project, including:

(1) planning costs; and

(2) construction and operating costs;

related to the project.

(e) Any standard tariff offered by an energy utility after June 30, 2025, to a large load customer of the energy utility must include a provision that requires reimbursement by the large load customer of at least eighty percent (80%) of the project costs reasonably allocable to the large load customer, regardless of whether the large load customer ultimately takes service in any anticipated amount and within any anticipated time frame.".

Page 10, line 29, delete "seventy-five percent (75%)" and insert "**eighty percent (80%)**".

Page 11, line 6, after "large" insert "**load**".

Page 13, line 24, after "hundred" insert "**fifty**".

Renumber all SECTIONS consecutively.

(Reference is to HB 1007 as printed February 6, 2025.)

PIERCE M