2022 Commission Analysis of the Ability of the Indiana Public Utilities to Provide for Reliable Electric Service

(HEA 1520 Report)

Indiana Utility Regulatory Commission
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TABLE OF CONTENTS

Introduction

In 2021, the Indiana General Assembly passed House Enrolled Act 1520 (HEA 1520), which established a reporting process to provide transparent and timely monitoring of electric utility resource availability to the Commission and other Indiana governmental leaders. HEA 1520, now in statute as Indiana Code § 8-1-8.5-13, calls for an annual reporting mechanism for Indiana electric utilities to identify how they plan to meet their customers' electricity needs in the near-term. The Commission is directed to then compile and analyze the utility data, investigate, and if necessary, act to address unsatisfactory conditions. Additionally, beginning Nov. 1, 2022, the Commission must provide an annual report to the Governor and interim study committee detailing the Commission's findings based on the data submitted by the public utilities.

Executive Summary

The complex system in place to deliver electricity to customers includes a portfolio of equipment and machines that must be kept in a near perfect supply and demand balance at each instant. Each operable electricity generator must be available to be called upon to convert some fuel source (gas, coal, sun, wind, water, etc.) into electricity and then that electricity must traverse a series of wires and flow through various power quality control devices to reach a customer to meet their desired needs[1]. Each step along this path adheres to the laws of physics and associated limitations, while also being subject to economic decision-making in various time scales: real-time for dispatch instructions and equipment lifetime for infrastructure investments. As with any physical and/or economic system, the electricity generation and delivery system functions much more predictably when it operates in a steady-state condition. However, when a system undertakes a transition from one state to another, the steps along the transition path should be given heightened oversight.

While each step in the electricity generation and delivery process is currently undergoing some level of transformation, the electric system generation portfolio – its electricity production capacity resources – are in a period of profound transition. The traditional life cycle-driven replacement of aging assets is compounded by the current pace of the replacement and the differing attributes of the old and new assets. The quickened pace of the generation resource transition does not remove the need to ensure that each step is set upon a firm foundation. **A key purpose of HEA 1520 is to provide transparency to the planning and implementation steps to ensure system reliability is not compromised during the transition.**

HEA 1520 draws upon the underlying statutory framework of Indiana's vertically integrated electric utility structure and the service obligation it places on the franchised utility provider, or in the case of the rural electric membership cooperatives (REMCs) and municipalities, their coordinated wholesale energy provider. HEA 1520 focuses on the utility's plan to maintain service reliability as the resource portfolio transitions. Notwithstanding this Indiana service structure, the individual utility transition occurs within a broader ongoing regional transition. As partners through their regional grid

[1] A current topical perspective is that of a supply chain; the fuel supplies the generator to produce a product that is shipped across a transportation network to customers.

management organizations (Midcontinent Independent System Operator (MISO) and PJM Interconnection, Inc. (PJM)), Indiana utilities both support and draw from other utilities in the region that are similarly going through their own transitions. In effect, each partner in the regional transmission organization (RTO) is in some measure dependent on the other partners to accomplish the desired interconnected system reliability across the region. While acknowledging this interconnectedness of the partners, in the HEA 1520 oversight exercise, we undertake an evaluation of how the Indiana-specific partners collectively and individually satisfy their obligation to provide reliable electric service to Hoosiers.

Having the resources in place to meet service obligations requires a forward-looking plan developed in anticipation of customer needs in order to be well positioned to meet those needs in every instant. Indiana electric utilities are required by Commission rule (170 IAC 4-7) to perform a detailed integrated resource plan (IRP) at least once every three years. The IRP process serves as the backbone of the forward-looking plan development and includes a 20-year time horizon over which it optimizes the utility resource portfolio to meet the anticipated needs of each year within that extended period. Recent IRP submittals confirm that Indiana's local utilities are planning to be active participants in the capacity resource portfolio transition. The HEA 1520 report adds an important layer of transparency to the near-term actions (the next two to three years) to move the IRP forward in a deliberate manner to take advantage of the holistic pre-planning of the longer-term IRP. This now statutory annual review and report serves as a tool to monitor and present to all stakeholders the active and ongoing readiness of our Indiana utilities to employ their planning and meet their statutory service obligations.

The near-term challenges of the transitions occurring in the utilities' resource portfolios can be seen in the information the utilities provided in the HEA 1520 required reports they submitted to the Commission. The Commission's HEA 1520 review reveals that the planned smoothness of the capacity resource transition is challenged by the ability to timely complete the planned replacements because of recent supply chain constraints, environmental regulation requirement strict deadlines, and investor desires for accelerating the transition.

The regional resource adequacy constructs currently in place at the RTOs serving Indiana customers determine individual and collective generation capacity resource requirements in the context of a single annual peak demand determination, namely the summer peak demand. While MISO is pursuing approval with the FERC to modify its construct to a four-season construct, this report reviews the utility submissions under the annual construct currently in place[2].

The utility submissions confirm the ongoing generation portfolio transition and provide visibility to its near-term pace. A review of the longer-term utility IRPs makes plain that, while each utility is progressing its own transition with slightly different timing, the near-term period finds Indiana at the beginning of the implementation phase. The data identifies that the next two years are expected to see solar and wind resources enter the resource portfolio while coal-based resources exit. Certainly, the transition for a system as complex as the electric ecosystem should be expected to face challenges as it moves through this

[2] The FERC approved the MISO proposal to move to a four-season construct on 8/31/22. The Commission will undertake a review of how to modify its future HEA 1520 Report data gathering and presentation because of this change.

dynamic transitional period. Challenges that have arisen, or may yet arise, in the portfolio transition will benefit from proactive planning, resource optionality and flexibility, and timely completion of identified action items to address them. While the Commission offers observations in the report, we ultimately find that the public utilities' plans and their anticipated reasonable actions to implement such plans enables their ability to provide reliable electric service to Indiana customers and for them to meet their planning reserve margin requirement (PRMR) for the next three planning years (PY).

Background on System Reliability Planning

Utility Obligation to Serve

Electric utilities in Indiana have an obligation to provide adequate service at reasonable cost to the customers in their assigned service area[3]. Each Indiana customer is assigned to be served by a single electric utility. While service can include many aspects, the core service the electric utility is obligated to provide to its assigned customers is electricity whenever the customer requires it to meet their needs. The provision of this base service requires a delivery system and the commodity desired, in this context, electricity. The Indiana vertically integrated utility statutory framework places the obligation to provide adequate service on the franchised utility for both the delivery system and electricity commodity needs of the customers they are assigned.

There are many system operational challenges that lead to a measured differentiation between the statutorily required provision of adequate service and the ideal, always-available service. The incremental cost of an ideal system compared to a reasonably sufficient system can be significant. Because the affordability of the service to customers is a key necessary consideration, reliability and affordability are sometimes dual goals that are in tension. For example, a common electric system delivery metric is the System Average Interruption Duration Index (SAIDI). This metric presents the duration or time of service interruptions divided by the total number of customers. The U.S. Energy Information Administration (EIA) reports the SAIDI for Indiana in 2020 as 280 minutes per year, meaning the system delivers 99.95% of the time. This level of differentiation is consistently accepted as an adequate provision of service by industry standards.

A similar measured service availability expectation can be applied to the electricity commodity generation component of the service provision system. The generation system reliability standard used in utility planning to ensure sufficient resources are in place to serve customers has historically been a loss of load expectation (LOLE) of not more than one day in 10 years (or 0.1 day per year, or 144 minutes per year).

The reasonableness of a utility's satisfaction of its obligation to serve can be evaluated by how effectively it plans to serve and how it performs against those plans.

Resource Planning Process to Meet Obligation

Again, having the necessary resources in place requires a forward-looking plan developed in anticipation of customer needs in order to be well positioned to meet those customer needs in every future instant. The integrated resource planning (IRP) process is the backbone of the plan development. The IRP includes a 20-year time horizon over which the

[3] IC 8-1-2.3

modeling optimizes the utility resource portfolio to meet the anticipated needs of each period within that long-term horizon. The primary focus of HEA 1520 is to monitor the adequacy of the resource availability that Indiana electric utilities plan to employ to meet the commodity needs of its customers in the near term, namely the next three years.

It is important to recognize that the customer is primarily interested in the provision of the commodity desired (electricity), but that provision requires a resource, or group of resources, that are available to meet the customer's desired amount of that commodity. Energy (flowing electricity) keeps the lights on in real time, while capacity is the resource in place (i.e., the generator) that stands ready to produce the energy in real time to keep the lights on. Because energy and capacity are not the same thing, the IRP seeks to optimize the capacity and associated attributes required to be in place to provide the energy to customers when required.

A common means of measuring the reliability of an electrical system is by modeling a portfolio of resources under various scenarios and determining the amount of resource capacity that should be in place to reasonably assure that the real-time energy needs of the system will be met. However, a standard modeling target is not a perfect, never-failing system given the previously noted cost consideration requirement, but rather a system that provides adequate reliability. The LOLE design criterion is a standard that seeks to provide an adequate system reliability level. By its definition, we see that a reasonable system will, on very limited occasions, not keep the lights on or will require additional system operator action to do so.

For the modeling to account for commonly expected conditions (i.e., unavailability due to outage or inability due to weather conditions) in an evaluation of a capacity resource's ability to provide energy when needed, the modeler will accredit each resource, called accredited capacity or sometimes termed unforced capacity or UCAP, with the contribution, or capacity available to be turned into energy, it can be reasonably expected to provide at a given point in time. While current system modeling is transitioning to a more time-differentiated hourly analysis methodology, the generally applied analysis evaluates the system at the time of its greatest demand – its peak need for energy. A system planner through detailed mathematical analysis determines the amount of capacity resources the system requires above the peak demand so that it can be expected with reasonable reliability (the LOLE design standard) to meet the demands of the system. The amount of capacity determined to be necessary above the peak demand is commonly called the reserve margin. Because the model is, in effect, setting forth a plan to meet the system reliability requirement, this is termed the planning reserve margin requirement (PRMR). A system that secures commitments from capacity resources to meet its planning reserve margin requirement is the system's reliability goal.

The interconnectedness of the partners within an RTO affords advantages because the larger system provides a scope and scale of resources that provides opportunity for improved reliability and economics through optimized planning. However, the advantage depends on the joint commitment of the partners to each contribute individual resources toward meeting the system's reliability goals. Accordingly, a sound RTO resource adequacy construct calls on each utility in the partnership to provide its share of the capacity resource requirement that is needed to reliably serve the customers that the utility is obligated to serve. Because RTOs coordinate partners in multiple states the diversity of policies can present challenges in administering a regional liability construct.

Resource Types

A utility can meet its capacity resource requirements with different resources: generating capacity resources of various types that it owns, capacity resources that it has rights to through bilateral contracts, demand-side commitments to respond by reducing the consumption of electricity by retail customers when called upon, or purchasing capacity through a centralized market clearing mechanism (capacity resource auction).

The capacity value of a particular resource is a function of the expected contribution it will make at the time of peak demand. The expected contribution accounts for the limitations of a generator because of fuel source or mechanical constraints. These capacity value adjustments lead to the capacity accreditation which works to normalize the various types of capacity resources such that a single market product is measured and priced.

The capacity value for nature-fueled resources like wind and solar are impacted by the inability to exercise control over their fuel supply; they can only produce electricity when nature supplies the fuel to the resource. To determine the amount of electricity that can reasonably be expected to contribute to meeting the system's peak, a study of time and season-dependent patterns of production is considered. The greater the alignment between the time of resource production and peak demand, the higher the resource capacity value available to contribute to meeting the PRMR. The MISO 2022/23 PY Wind Capacity Credit was 15.5% and the Solar Capacity Credit was 50%[4]. Coupling nature-fueled resources with storage can serve to increase their capacity value to the extent the storage can effectively time-shift the delivery of the electricity to better coincide with the time of peak demand.

The historical performance of each specific generator also impacts its capacity value, as it serves as a proxy for the expected availability of the unit when it is needed. Circumstances that may have led to a generator being unavailable for mechanical issues, environmental limitations, or fuel unavailability in the last three years when needed, are considered in determining how much energy it can reasonably be expected to contribute to meeting the PRMR.

The ability to reduce demand through demand response resources enables the overall system to remain balanced when the available supply-side resources approach their combined ability to add more electricity to meet the overall system need. Customers who offer to reduce their electricity consumption when called upon under predefined criteria receive a monetary value based on the value of capacity, and the utility can reflect a reduced capacity need that is reflected in the preplanned system balance equation.

The capacity resources the utility secures in advance as it plans to meet its required contribution to the PRMR may also be secured through contractual relationships with the owners of resources. The resources backing the contract are accredited a capacity value based on their resource type and are counted with the utility's portfolio to the extent they can be delivered to the utility's assigned customers.

The RTOs also provide a platform that fosters the sharing of available capacity resources which are not otherwise committed to serve specific assigned customers. This market clearing mechanism seeks to match any remaining utility partner resource capacity

[4] https://cdn.misoenergy.org/2022%20Wind%20and%20Solar%20Capacity%20Credit%20Report618340.pdf

requirements with the available uncommitted resources. A utility in need of additional resources to meet its PRMR compensates the previously uncommitted resources at the platform's clearing price and satisfies its resource adequacy planning requirements. To the extent the uncommitted resources are sufficient to supply all the remaining requirements, the system wide PRMR is satisfied, and all the partners are able to contribute to the resource adequacy goal of the partnership. However, where the resources are not available to meet the system wide PRMR, the interconnected nature of the system necessarily means that the shortfall from the planning goal is also a shared experience. For example, when the MISO 22/23 PY clearing auction failed to attain the system wide required PRMR to meet the planning design goal of a LOLE of one day in 10 years and instead received commitments only sufficient to provide a reliability level of a LOLE of one day in 5.6 years, the entire RTO experiences the increased risk. A key feature of HEA 1520 is the definition of a reliability metric which limits the amount of capacity purchased through a clearing market mechanism to 30%. This metric presents a measured allowance for Indiana's utilities to avail themselves of the market clearing mechanism while requiring them to reduce the utility and shared system-wide risk of elevated market dependence.

Data Collection

HEA 1520 requires each utility providing electric service to Indiana customers to file a report with the Commission, in a form specified by the Commission, that provides specific information for each of the next three resource planning years. The information includes identification of resources the utility will use to provide service and is to be delineated as generating facilities owned and operated by the electric utility, generating resource capacity the utility has procured under contract, and the amount of demand response resources available to the utility under contracts and tariffs. In addition, the utility must provide a comparison of its resource portfolio to the established planning reserve margin requirement and the reliability adequacy metrics of the utility, as forecasted for the three planning years covered by the report[5].

The Commission developed a form to solicit the required information from the utilities and utilities submitted their initial reports for PY 22/23, 23/24, 24/25 in April 2022. Commission staff reviewed the utility reports and commenced an initial analysis and deliberation to determine if there were any concerns that rose to the level of immediate elevation and investigation[6]. In the absence of such concern, the staff continued its internal analysis and created a document that summarized its understanding of the report data. Staff shared the document with the utilities, as well as MISO and PJM[7], and sought the utilities' confirmation of the documents' accuracy, while further providing opportunity for any updates to the earlier submissions. A technical conference was scheduled to allow all stakeholders the opportunity to follow the process developments and to provide real-time understanding of the supply chain challenges anticipated solar builds were experiencing. The investor-owned utilities sought confidential treatment for certain sections of their reports and responses as specifically afforded under the statute[8], and the technical conference was canceled while the request for confidentiality was being reviewed. With the Commission grant of confidentiality, the staff aggregated the data based on the four MISO

[5] IC 8-1-8.5-13(i).
[6] IC 8-1-8.5-13(n).
[7] IC 8-1-8.5-13(m).
[8] IC 8-1-8.5-13(j).

IOUs[9] (MISO IOUs) and all the reporting utilities[10] (All Reporting). Accordingly, the bulk of the analysis and observations are presented on these two bases.

Data Summary (IC 8-1-8.5-13(p)(2))

The regional resource adequacy constructs currently in place at the RTOs serving Indiana customers determine individual and collective generation capacity resource requirements in the context of a single annual peak demand determination, namely the summer peak demand. While MISO is pursuing approval with the Federal Energy Regulatory Commission (FERC) to modify its construct to a four-season construct, this report reviews the utility submissions under the annual construct currently in place[11].

The capacity value presented throughout this report is not the same as the nameplate value that is often associated with resources. Rather, the capacity value of a particular resource is a function of the expected contribution it will make at the time of peak demand. The expected contribution considers the limitations of a generator because of fuel source or mechanical limitations. These capacity value adjustments lead to the capacity accreditation, or sometimes referred to as the UCAP, which works to normalize the various types of capacity resources such that a single market product is measured and priced. The capacity value used in the various analyses that follow is what the utility counts in the resource adequacy construct toward meeting its PRMR.

Most of the resources Indiana utilities plan to utilize in meeting their customer load needs are resources they own. Table 1 indicates that while the PRMR Share of owned resources decreases after the first year, it remains the significant majority in each subsequent year.

TABLE 1: Utility-Owned Resource Capacity (UCAP, MW) and PRMR Share (%)

	PY 22/23	PY 23/24	PY 24/25
MISO IOUs Owned	11,130	10,145	10,434
PRMR Share	89%	78%	81%
All Reporting Owned	17,228	15,277	15,414
PRMR Share	88%	76%	77%

9 The 4 MISO IOUs include Duke Energy Indiana (DEI), Northern Indiana Power Service Co (NIPSCO), Indianapolis Power and Light (IPL) dba AES Indiana, Southern Indiana Gas and Electric Co (SIGECO) dba CenterPoint Indiana South.
10 The 4 MISO IOUs, Indiana Michigan Power Co (I&M), Indiana Municipal Power Agency (IMPA), Hoosier Energy Rural Electric Cooperative (Hoosier Energy), and Wabash Valley Power Alliance (WVPA).
11 The FERC approved the MISO proposal to move to a four-season construct on 8/31/22. The Commission will undertake a review of how to modify its future HEA 1520 Report data gathering and presentation because of this change.

The data presented in Table 2 shows that utility-owned coal generation resources continue as the majority share of utility-owned resource capacity in the near term.

TABLE 2: Utility-Owned Coal Resource Capacity (UCAP, MW) and Share of Utility-Owned Resource Capacity (%)

	PY 22/23	PY 23/24	PY 24/25
MISO IOUs Owned	7,288	6,353	6,362
PRMR Share	65%	63%	61%
All Reporting Owned	10,163	8,218	8,064
PRMR Share	59%	54%	52%

The utilities have also procured, through contractual relationships, the capacity rights to resources that are included in their portfolios.

TABLE 3: Contracted Resource Capacity (UCAP, MW) and PRMR Share (%).

	PY 22/23	PY 23/24	PY 24/25
MISO IOUs Contracted	894	1,311	952
PRMR Share	7%	10%	7%
All Reporting Contracted	1,728	3,224	3,071
PRMR Share	9%	16%	15%

The utility reports also identified the demand response resources available to them under contracts and tariffs. The individual utility reports highlight the fact that certain demand side management mechanisms and behind the meter contributors are recognized in the resource adequacy construct as offsets to demand rather than as supply side resources. Demand reduction is a vital tool because it can earn resource accreditation or reduce the need for additional utility procured resources.

TABLE 4: Demand Response Resource Capacity (UCAP, MW) and PRMR Share (%)

	PY 22/23	PY 23/24	PY 24/25
MISO IOUs DR	520	568	582
PRMR Share	4%	4%	5%
All Reporting DR	804	926	809
PRMR Share	4%	5%	4%

The remaining utility resource adequacy need that is not pre-arranged through resource ownership, contractual relationship, or demand response accreditation can be sought through the RTO-provided market clearing mechanism. This auction seeks to match any remaining utility partner resource capacity requirements with the available uncommitted resources. A utility in need of additional resources to meet its PRMR compensates the previously uncommitted resources at the platform's clearing price and satisfies its resource adequacy planning requirements. The statute presents this remaining utility resource position as the reliability adequacy metric[12] (RAM) and limits its PRMR share to no more than 30% of the PY portfolio.

TABLE 5: Reliability Adequacy Metric (UCAP, MW) and PRMR Share (%)

	PY 22/23[13]	PY 23/24	PY 24/25
MISO IOUs RAM	39 long	935	888
PRMR Share	0%	7%	7%
All Reporting RAM	178 long	624	701
PRMR Share	1% long	3%	4%

The relative contribution for each type of resource for each PY can be seen in Table 6 for the MISO IOUs and in Table 7 for All Reporting utilities.

TABLE 6: MISO IOUs Resource PRMR Share for each PY

	PY 22/23	PY 23/24	PY 24/25
MISO IOUs owned	89%	78%	81%
MISO IOUs contracted	7%	10%	7%
MISO IOUs DR	4%	4%	5%
MISO IOUs RAM	---	7%	7%

TABLE 7: All Reporting Utilities Resource PRMR Share for each PY

	PY 22/23	PY 23/24	PY 24/25
All Reporting owned	88%	76%	77%
All Reporting contracted	9%	16%	15%
All Reporting DR	4%	5%	4%
All Reporting RAM	---	3%	4%

The data in the reports confirms the ongoing generation portfolio transition and provides visibility to its near-term pace. The capacity value of solar and wind resources in the portfolio grows noticeably over the reporting period, while the capacity value of utility-owned coal resources continues to meet a major share of the requirements in the near-term.

[12] IC 8-1-8.5-13(e).

[13] The long positions mean that the RAM was in effect less than 0%, the utilities had more preauction resources in their portfolio than the PRMR.

TABLE 8: Utility-owned Coal Resource and Solar/Wind Resource PRMR Share

	PY 22/23	PY 23/24	PY 24/25
MISO IOUs Coal-owned Share	58%	49%	49%
MISO IOUs Solar & Wind Share	1%	5%	9%
All Reporting Coal-owned	52%	41%	40%
All Reporting Solar & Wind	2%	5%	7%

The utilities' submissions indicate that their plans include the removal of utility-owned coal resources over the period. AES Indiana's Petersburg Unit 2, and CenterPoint Energy Indiana South's Brown Units 1 and 2 and its share of Warrick Unit 4, are each removed after the current PY. In addition, Hoosier Energy's Merom station ownership change after the current PY transitions its contribution from the utility-owned to contractual resource category and the amount it contributes is reduced. Further, the contribution of I&M's Rockport Unit 2 is reduced in each reported year as it transitions to a merchant operating mode.

Meanwhile, the submissions reflect the anticipated addition of several large scale solar and wind resources over the reporting period. Among the additions are Hoosier Energy's Riverstart Solar, AES Indiana's Hardy Hills Solar and Petersburg Solar, NIPSCO's Dunn's Bridge, Indiana Crossroads and Gibson Solar, NIPSCO's Crossroads Wind, and CenterPoint Energy Indiana South's Vermillion, Wheatland, Posey, and Warrick Solar.

The capacity resources relied upon by the Indiana electric utilities are located within Indiana as well as outside of the state. Deliverability of the resource to the customers depending upon it is a key characteristic in the capacity value of the resource. Table 9 indicates that while most of the resource capacity serving Indiana customers is in Indiana, a notable amount is located elsewhere and deliverable to Indiana.

TABLE 9: PRMR Share of Capacity Resource Located Outside of Indiana

	PY 22/23	PY 23/24	PY 24/25
MISO IOUs	9%	7%	4%
All Reporting	20%	20%	19%

The utility PRMR is a direct function of its customers' demand – their peak energy needs. The utilities presented the aggregate need of their customers, which was used in the calculations presented above over the period as shown here.

TABLE 10: Aggregate Demand (MW)

	PY 22/23	PY 23/24	PY 24/25
MISO IOUs	11,478	11,904	11,822
All Reporting	18,000	18,431	18,393

Commission Conclusions (IC 8-1-8.5-13(p)(1))

The utility submissions confirm the ongoing generation portfolio transition and provide visibility to its near-term pace. A review of the longer-term utility IRPs makes plain that while each utility is transitioning its generation portfolio with slightly different timing, the near-term period finds Indiana at the beginning of the implementation phase. Table 6 clearly identifies that the next two years are expected to see the addition of solar and wind resources, while some coal-owned resources exit. Certainly, given its complexity, the electric ecosystem should be expected to face challenges as it moves through this dynamic transitional period. The portfolio transition will benefit from proactive planning, resource optionality and flexibility, and timely completion of identified action items to address challenges as they arise. While the Commission offers the observations below, we ultimately find that the utilities plans and their anticipated reasonable actions to implement such plans enables their ability to provide reliable electric service to Indiana customers and for them to meet their PRMR for the next three PYs.

Solar build supply chain challenges are having a material impact on the smoothness and anticipated pace of the generation transition[14]. Resources planned to be in place are subject to delays. The uncertainty of federal actions and investigations for anti-dumping and countervailing duties are among the challenges most often given for the delays. Because the solar resources are primarily scheduled to replace coal-fired generation resources, the challenge of the associated delays are compounded when the inflexibility of environmental regulations create what are in effect strict deadlines for existing plant retirement timing[15].

NIPSCO's decision to postpone the retirement of two large coal units at its Schahfer station and CenterPoint Energy Indiana South's similar decision on a Culley station unit, given where they are in their individual generation portfolio transitions, is a fortunate flexibility that not all utilities have available. This retained capacity creates headroom for managing the transition. The Commission's approval of the ownership transfer of another large coal station, Merom, should provide a measure of capacity over at least the next couple years that would have been absent under prior ownership expectations[16]. Further, the negotiated settlement approved by the Commission for one of the Rockport coal units has the effect of transforming it into merchant capacity, which may also provide an avenue to serve as a smoothing agent in the transition[17].

The MISO resource adequacy construct has significant changes being considered by FERC this fall[18]. If approved, the present annual construct would change to a four-season construct and the capacity value of various resources in the new construct would change for each season. The proposed changes would likely impact the utilities differently, with CenterPoint Energy Indiana South perhaps the most impacted given the timing of its Brown

[14] Hoosier Energy's 7/6/22 response to Q4 provides a summary of the challenges: the U.S. Commerce WRO decision to ban certain products from China and more recent investigation into circumvention of the ruling by shipping the products through neighboring countries, increased panel demands during these supply shocks, and missed MISO interconnection study timelines due to queue backlog.

[15] Retirement agreement through consent decree or uneconomic investment requirements driven by increasingly stringent and near-term implementation timelines for federal regulations create such effective hard stops.

[16] See Cause No. 45691.

[17] See Cause No. 45546.

[18] See FERC docket ER22-495.

coal unit retirements in October 2023. Under the annual construct, the units would be available next summer but would be assigned no capacity value by MISO as they are not available for the entire PY. However, a seasonal construct would provide for the units to be credited value for at least the high demand summer season. In addition, the seasonal and temporal production of solar and wind resources, and their correlation with the time of system peaking in each season, will likely result in significantly different capacity values for these resources throughout the year.

MISO resource auction dependence of up to 30% might exceed the reasonable depth of the available resources that remain uncommitted at the time of the auction[19]. The recent auction this spring was not able to provide resources fully sufficient to meet the planning reserve margin requirement. This shortfall means the system reliability fell short of the targeted loss of load equivalent of one day in 10 years reliability, and instead the level of capacity committed has been modeled by MISO to provide a reliability expectation of LOLE of one day in 5.6 years. Different parties have different explanations for why the auction failed to fully satisfy its need. But a historically weak price signal and available capacity resource expectation of another year with weak pricing likely did not provide a sufficient incentive to such potential capacity to enter the auction. A clearing auction that is intended primarily as a residual one arguably lacks the price signal necessary to bring merchant supply forward to take on the obligation concurrent with the commitment when the price expectation is below the cost of the commitment. Perhaps a more moderate dependence, or one that is stepped by the time remaining before the clearing auction, warrants consideration.

[19] Capacity resources contracted for in advance of the clearing auction become committed to serve the resource capacity needs of a specific utility's customer and therefore are not available in the auction to meet any remaining needs.