July 16, 2025

Indiana Investor-Owned Electric Utilities Comments on May 9, 2025 Christensen <u>Associates Performance-Based Regulation Report to the Commission</u>

These responses are submitted on behalf of the following companies: Indianapolis Power & Light Company d/b/a AES Indiana, Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South, Duke Energy Indiana, LLC, Indiana Michigan Power Company, and Northern Indiana Public Service Company LLC (collectively, the Utilities). The Utilities appreciate the opportunity to provide comments in response to the May 9, 2025 Christensen Associates *Performance-Based Regulation Report* (the PBR Report or Report) to the Indiana Utility Regulatory Commission (Commission or IURC). The PBR Report contains much useful information. These comments are focused on areas where the Utilities are in agreement with the Report, the importance of taking a careful and measured approach to PBR in Indiana, areas where the Utilities believe more information or a different focus would be appropriate, and a few alternatives the Utilities believe should be considered.

<u>Areas of Agreement</u>

The Utilities agree with many contents of the PBR Report, and appreciate the Report's consideration of the Utilities' previously submitted comments. In particular, the Utilities agree that the State of Indiana is in the midst of a transition in the electric utility industry, facing substantial load growth and corresponding significant infrastructure investments. This transition brings a number of challenges – substantial capital and financing needs for new generating and transmission resources, rate pressures (at least in the short- to medium-term), and environmental sustainability challenges. These challenges and the quick pace of change in the industry may call for new rate paradigms such as PBR, but they also require caution and a measured approach to any new rate paradigms.

<u>PBR Principles</u>

First, the Report concludes that the following principles should underlie any PBR mechanisms:

> Principle 1: The PBR plan should, to the greatest extent possible, create similar efficiency incentives compared to those experienced in a competitive market while maintaining service quality.
> Principle 2: The PBR plan must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
> Principle 3: The PBR plan should recognize the unique circumstances of the company that are relevant to the PBR design.
> Principle 4: Customers and the regulated companies should share the benefits of a PBR plan.
> Principle 5: The PBR plan should be easy to understand, implement, and administer and should reduce the regulatory burden over time.

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The Report (at page 34) requests stakeholders weigh in on these principles with the ultimate objective that the IURC adopt a set of principles associated with PBR tools. The Utilities are generally supportive of these principles and find them reasonable and balanced between the utility and customers. However, the Utilities recommend a change to Principle 4; Principle 4 should be modified to indicate that "Customers and the regulated companies should *receive* benefits of a PBR plan." The Utilities recommend this modification in order to avoid the principle being unfairly interpreted as requiring a mandatory earnings sharing mechanism.

Differences Between Indiana and Other States

The Utilities also agree, as the Executive Summary notes, that there are some notable differences between Indiana and other states that have implemented PBR – such as distribution-only versus vertically-integrated utilities with "lumpier" investments; transmission projects directed by regional transmission organizations (e.g., MISO and PJM); and generation resources that participate in RTO wholesale markets. In addition, the Report notes that Indiana law presently provides for several rate adjustment mechanisms. These mechanisms give the Commission regular insight into the Utilities' costs and cost management while also ensuring that customers pay no more and no less than the actual cost of various capital investments and O&M expenses.

The Utilities remain supportive of capital and expense trackers in conjunction with a MYRP as tracked investments and costs are generally volatile and lumpy. However, there is potential to roll certain long-standing annual trackers that can be reasonably estimated into the MYRP, while continuing to rely on other trackers.

The Report (Section 7.2) acknowledges that capital trackers can be applied to utilities operating under MYRP but caveats that it could lead to capital over-investment and reduce utilities' incentive to control costs. However, it is important to observe that with the measures in place with each tracker in Indiana, parties have the opportunity to participate in the tracker cases to ensure investments and spending are reasonable, justified, and prudent.

For Duke Energy jurisdictions that have implemented MYRP, some of the trackers were eliminated and others continue due to utility-specific and/or state requirements:

> **Duke Energy Florida (DEF)**, for example, continues to have trackers for fuel, purchased capacity, energy conservation costs, environmental costs, and storm protection costs. DEF's settlements only cover base rates, and because DEF's settlements are not formula rates, it makes sense to continue to have the trackers, which are essentially formula rates as they are trued-up for actual costs [Docket Nos. 20250001, 20250002, 20250007, 20250010].
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> **Duke Energy Carolinas/Duke Energy Progress (DEC/DEP)** in North Carolina continue with their existing trackers, such as fuel. Continuing with existing trackers occurs because they are designed to recover specific costs for specific types of investments and are typically updated each year, in contrast to the MYRP which only addresses base rates. See e.g., NCGS § 62-133.2 (allowing for tracking of fuel costs).

Duke Energy Ohio (DEO), for example, with the elimination of the Electric Security Plan (ESP) and the creation of a multi-year rate plan consistent with new legislation, will be eliminating specific *distribution* trackers (i.e. distribution capital investment tracker, vegetation management, storms, uncollectibles, and power future initiatives tracker) and only the following statutorily enabled distribution trackers remain (Universal Service Fund Rider – Rider USR (low-income) per Ohio Revised Code Section 4928.52); Ohio Excise Tax Rider – Rider OET (per Ohio Revised Code Section 5727.81), as well as the voluntary opt-in tariffs such as the GoGreen Rider – Rider GP for voluntary renewable energy credit purchases. The various transmission and generation supply trackers will continue by statute. [H.B. 15, 136th Gen. Assemb., Ohio, (2025)].

<u>Optionality</u>

The Utilities also agree with the Report's recognition that optionality is key. Indiana utilities should have the option to propose multi-year rate plans (MYRPs) or performance incentive mechanisms (PIMs), but should not be required to do so.

<u>Indiana's Performance Metric Reporting</u>

In addition, the Utilities agree with the Report's recognition that the Utilities have reported to the Commission on a variety of performance metrics for years, giving the Commission a detailed view into the Utilities' performance outside of rate cases or other docketed proceedings.

The Utilities are supportive of MYRPs and continued performance metric reporting. Performance metric reporting is filed annually with the Commission and performance is evaluated closely by the regulators and considered when ROEs are determined. Establishing stand-alone mechanisms such as an earnings sharing mechanism is not necessary – nor is there value in re-inventing other cost control/efficiency mechanisms. The Report importantly acknowledges that if earnings sharing mechanisms are adopted (page 6), wide deadbands should be established to maintain cost efficiency incentives.

<u>Importance of Implementing PBR in a Measured Way</u>

Other jurisdictions that have recently implemented PBR plans have done so in a limited and measured way. For example, in North Carolina, MYRPs are being implemented with a very limited number of PIMs. Such an approach recognizes that implementing PBR in Indiana will require a significant administrative change and is a change that should be approached in a measured way.

Given the potentially complicated litigation over PIMs, administrative efficiency also argues in favor of a measured approach. The Report (at page 4) recommends that the Commission allow investor-owned electric utilities to file PIMs as part of future rate applications, to be assessed on a case-by-case basis. This makes sense; developing PIMs that apply to all utilities would be difficult to reach agreement on due to the unique characteristics of each utility and would reduce administrative efficiency.

However, the Utilities already have robust performance metric reporting and during rate cases presently, or in the future, if MYRPs are established, utility performance routinely weighs into regulators' findings in Commission orders. Therefore, requiring several PIMs and attaching material financial incentives or penalties to PIMs may cause unintended consequences such as increasing litigation risk, incentivizing utilities behavior for certain PIMs at the expense of other performance goals, and requiring the regulators to understand the complexities and nuances of each utility's calculations, which would reduce administrative efficiencies.

There are also potential complications with formulating and valuing X-factors, Y-factors, Z-factors, reopeners, etc. If PBR plans are not easy to understand and administer, this could also reduce administrative efficiencies. Similarly, it is important that the amount of detail required for MYRPs (for example, for the later forecasted years) be reasonable – sufficient to allow adequate scrutiny by the Commission and parties, but not overly burdensome for the utilities.

In addition, minimum standard filing requirements (MSFRs) in light of MYRPs would have to be modified to ensure the regulatory framework is functioning as intended with the necessary evidence to support a utility's request for rate changes while also balancing administrative requirements.

Optionality (discussed above) is consistent with a measured approach. The Utilities, after review of this Report, remain supportive of MYRPs as an option. Further, in light of the extensive performance metrics reporting already in place, the Utilities support MYRP on a standalone basis as a mechanism for modernizing cost recovery. Experience from other jurisdictions with MYRPs corroborates this position:

> **DEF** does not have PIMs, but it has been operating under multi-year base rate settlement agreements for the past fifteen years. Some of the advantages to multi-year rate plans in Florida have been that DEF and its customers have certainty on revenues and rates, which helps the parties manage future budgets. MYRPs also remove the likelihood of annual rate case filings, which are expensive, time consuming, and resource intensive. Potential disadvantages include unexpected events could arise that might not have been contemplated in the multi-year settlement agreements, causing the Company to over or under earn. Thus, DEF has protections in its settlement agreements allowing for rate case filings during the term if the ROE falls outside a given band. Specifically, the current DEF settlement covers a certain number of projected years (2025 through 2027) in the case of the 2024 settlement and there are no true-ups outside of specific identified items. For example, there is a true-up mechanism for expected Production Tax Credits, but there is no earnings sharing mechanism. [Order No. PSC-2024-0472-AS-EI].
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> **DEO** currently does not have MYRP or PIMs implemented as its Electric Security Plan (ESP)/tracker polices are in effect until May 31, 2028. House Bill 15 (HB 15) was enacted and will become effective on August 14, 2025. HB 15 eliminates the current ESP/tracker policies and replaces it with mandatory base rate cases every three years or

allows Electric Distribution Utilities to file a MYRP with three-year forecasted test years with a true-up provision. In Ohio, the MYRP will be a three-year forecasted distribution rate only. The true-up provision will update the forecasted components with actuals (i.e. sales quantities, revenues, costs, capital and rate base). HB 15 does not address or require PIMs. [H.B. 15, 136th Gen. Assemb., Ohio, (2025)].

As summarized in the Report (Section 5.2.1), **DEC** and **DEP** have the most encompassing framework of the Duke Energy jurisdictions in that the North Carolina statute provides the option for utilities to submit PBR applications. If a PBR application is submitted, it must be made in the context of a general rate case and must include: MYRPs with earnings sharing; residential decoupling; and one or more PIMs. *See NCUC Rule 1-17B: Procedure For Performance-Based Regulation For Electric Public Utilities Under G.S. 62-133.16*.

Some of the advantages of the North Carolina framework include: it allows for more real-time recovery of projected investments, and seeks alignment on the type of investments included over MYRP; it allows for the utility and customers to plan for rate increases; it reinforces cost containment as the earnings sharing mechanism is asymmetrical (the utility is incentivized to meet projected costs); it addresses smaller, more frequent investments; and it protects customers with a statutory cap on rate increases in years 2 and 3 of the MYRP and statutory asymmetrical sharing of earnings. The trade-offs for the utilities are that the NC MYRP only includes discrete capital projects. Changes such as interest rate changes, inflation, and increased O&M cannot be included; these items must be managed throughout the MYRP period. There is no true-up of the MYRP. Revenues are set at the annual amounts approved in the rate case, which means that there are no true-ups for differences experienced in timing or costs related to the MYRP projects. Some of the recognized PIM benefits include strengthening incentives for reliability and other performance areas that customer and regulators care about.

Three limited PIMs were implemented by Duke Energy in North Carolina: (1) TOU rate enrollment (based on the incremental enrollment in the Company's peak load reduction and use of the energy system (reward only); (2) renewables integration based on the promotion and integration of more renewable sources (reward only); and (3) reliability based on SAIDI (penalty only). The dollar amounts of reward and penalties established are limited compared to the rest of the framework. [Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, and Modifying Lincoln CT CPCN Conditions, *Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation*, No. E-7, Sub 1276 (N.C.U.C. Dec. 15, 2023); Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice, *Application of Duke Energy Progress, LLC For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance Based Regulation*, No. E-2, Sub 1300 (N.C.U.C. Aug. 8, 2023).]

Need for More Information

While affordability is a key focus of the Report and an important element of the Five Pillars, it is but one of the Five Pillars. Without data about PBR results and comparisons to traditional cost of service regulation, quantification of the benefits of PBR and/or PIMs as it impacts the non-financial portions of these pillars is challenging to ascertain.

With respect to affordability, the Report, while thorough, does not and cannot produce encompassing data that shows how well MYRPs and PIMs work in terms of controlling costs -- as well as whether these plans produce unintended consequences (a potential pitfall of PBR plans). As discussed in Section 9, page 101 of the Report, "because of the breadth of tools that fall under the umbrella of PBR, we have conducted scenario analysis only on certain mechanisms. In the category of MYRPs, we present analysis regarding indexed cap plans…. Regarding PIMs, we have analyzed reliability PIMs." This section of the Report concludes that the scenario objective was to show how these tools work, not necessarily to predict results if the tools were put in place. Therefore, the Report relies on academic literature and theories, qualitative observations, and principles/examples of MYRPs and PIMs used in other states and Canada.

Notwithstanding the difficulty of gathering data about the actual results of PBR plans, more data would certainly be helpful to ascertain the value of PBR for Indiana. At a minimum, a lack of data argues for a measured approach to implementing PBR in Indiana.

DEF's practical experience illustrates that while there is no quantitative data on how well its multi-year settlements have worked to control costs (as that would be very difficult to quantify), DEF does file monthly historical earnings surveillance reports with the Florida Commission as well as annual forecasted surveillance reports. Those reports demonstrated that DEF has generally earned within its ROE band and have also demonstrated that there have not been unintended consequences. In North Carolina, the utilities file quarterly and annual PBR reports in addition to earnings surveillance reports.

For Indiana, the FAC earnings test is a mechanism that currently exists to ensure returns do not exceed authorized net operating income when fuel costs increase. This test would require adjustments for a modernized regulatory mechanism such as PBR, including the years and cut-off periods applicable in addition to the underlying formula used in the calculation.

Different Focus or Emphasis

The Report's Executive Summary states: "Given that the top concern among stakeholders relates to affordability and cost control, MYRPs that offer cost efficiency incentives may be worth consideration for Indiana's IOUs." This statement appears to place a keen focus on cost control. Although we agree that affordability is important, it is equally important for any PBR plan to focus on and balance *all* of Indiana's Five Pillars: reliability, resiliency, stability, affordability, and environmental sustainability. Notably, there are costs to maintaining or improving reliability, resiliency, stability, and environmental sustainability, and those costs will impact affordability. Overemphasizing affordability may result in decreased performance on reliability, resiliency, stability, and environmental sustainability. In other words, overemphasis on one aspect of a utility's performance may produce decreased performance in other important aspects — a major concern with the design of PBR plans.

Alternatives to Consider

The Utilities would support allowing the use of a longer forward test period as an interim step toward MYRPs, without associated PIMs.

The Utilities also take issue with the Report's conclusion (on page 5) that, due to energy efficiency lost revenue mechanisms in place in Indiana, decoupling should not be adopted. This recommendation fails to recognize that the lost margin calculations used in conjunction with Indiana's energy efficiency programs are very different than revenue decoupling, which covers categories other than just energy efficiency. It also downplays the benefits of decoupling, for utilities and customers, that are not achievable through MYRPs. The Utilities recommend the Commission not foreclose opportunities for future decoupling mechanisms. Other states, for instance, have required revenue decoupling to be a part of any MYRP/PIM plan. See, e.g., NCGS § 62-133.16(c).

The Utilities also take exception with the first part of the Report's recommendation (on page 65), which concludes that Indiana should not pursue formula rate plans. The next part of that same recommendation acknowledges that if Utilities face major, lumpy investments and the frequency of rate cases becomes a problem, this is an option that could be considered. The Utilities recommend the Commission not foreclose opportunities for alternative regulatory mechanisms, such as formula rate plans. As recognized in the Report (at page 64), formula rates have been used at FERC as well as by retail utilities in the southeastern United States. These formula rate plans have been effective and continue to be effective in other jurisdictions.

Conclusion

The Report (at pages 3, 7, etc.) recommends allowing investor-owned electric utilities to voluntarily file three or four-year forecasted MYRPs, and recommends allowing the utilities to file tailored MYRPs rather than imposing a rigid framework for each utility. The Utilities support this bottom-line recommendation.