FILED
October 18, 2024
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A MULTI-STEP RATE IMPLEMENTATION OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE, AND APPROVAL OF REGULATORY ASSET TREATMENT UPON RETIREMENT OF THE COMPANY'S LAST COAL-FIRED STEAM GENERATION PLANT; (4) APPROVAL OF AN ADJUSTMENT TO THE COMPANY'S FAC RIDER TO TRACK COAL INVENTORY BALANCES; AND (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING AUTHORITY TO: (A) DEFER TO A REGULATORY ASSET EXPENSES ASSOCIATED WITH THE EDWARDSPORT CARBON CAPTURE AND SEQUESTRATION STUDY, (B) DEFER TO A REGULATORY ASSET COSTS INCURRED TO ACHIEVE ORGANIZATIONAL SAVINGS, AND (C) DEFER TO A REGULATORY ASSET OR LIABILITY, AS APPLICABLE, ALL CALCULATED INCOME TAX DIFFERENCES RESULTING FROM FUTURE CHANGES IN INCOME TAX RATES.	)	**CAUSE NO. 46038**

<u>INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR'S PROPOSED ORDER</u>

The Indiana Office of Utility Consumer Counselor ("OUCC") submits and serves its proposed order in Word and PDF formats. The OUCC's proposed order incorporates Petitioner's proposed order with the OUCC recommended changes. The redlined versions will be submitted subsequently. The redlined versions are merely intended to be informative and to aid the Commission.

Respectfully submitted,

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

Thomas R. Harper, Atty. No. 16735-53
Deputy Consumer Counselor

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

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<u>INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR'S PROPOSED FORM OF ORDER</u>

<u>Presiding Officers</u>:
James F. Huston, Commissioner
Greg S. Loyd, Administrative Law Judge

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INTRODUCTION

On April 4, 2024, Duke Energy Indiana, LLC ("Duke Energy Indiana," "Petitioner," "Company," "Duke," or "DEI") filed its Petition for General Rate Increase and Associated Relief under Ind. Code § 8-1-2-42.7 and Notice of Provision of Information in Accordance with the Minimum Standard Filing Requirements ("Petition") with the Indiana Utility Regulatory Commission ("Commission") to increase its retail rates and charges for electric service rendered in the State of Indiana through a multi-step rate implementation. Duke Energy Indiana uses a forecasted test period and seeks approval of revised depreciation rates, Petitioner's proposed regulatory asset treatment upon retirement of the Company's last coal-fired steam generation plant, an adjustment to Duke Energy Indiana's fuel adjustment clause ("FAC") rider, and approval of certain accounting relief, including authority to: (1) defer to a regulatory asset expenses associated with a carbon capture and sequestration ("CCS") study to be conducted for the Edwardsport Generating Station ("Edwardsport"); (2) defer to a regulatory asset costs incurred to achieve organizational savings; and (3) defer to a regulatory asset or liability, as applicable, all calculated income tax differences resulting from future changes in income tax rates. Concurrently, Duke Energy Indiana filed the testimony and exhibits of the following witnesses:[1]

- Stan C. Pinegar, President of Duke Energy Indiana
- Joel T. Rutledge, Director of Jurisdictional Planning, Duke Energy Business Services LLC
- Christa L. Graft, Director, Rates and Regulatory Planning, Duke Energy Indiana
- Suzanne E. Sieferman, Director, Rates and Regulatory Planning, Duke Energy Indiana
- Kathryn C. Lilly, Manager, Rates and Regulatory Planning
- Maria T. Diaz, Director, Rates and Regulatory Planning, Duke Energy Indiana
- Roger A. Flick, Director of Jurisdictional Rate Administration, Duke Energy Business Services LLC
- Bickey Rimal, Assistant Vice President, Concentric Energy Advisors, Inc.
- Christopher B. Bauer, Director, Corporate Finance and Assistant Treasurer, Duke Energy Business Services LLC
- Adrian M. McKenzie, President of Financial Concepts and Applications, Inc.
- Jeffrey T. Kopp, Senior Managing Director of the Energy & Utilities Consulting Department for 1898 & Co.
- John J. Spanos, President of Gannet Fleming Valuation and Rate Consultants, LLC
- Sean P. Riley, Partner, PricewaterhouseCoopers LLP
- Rebekah E. Buck, Director of Allocations and Reporting, Duke Energy Business Services LLC
- John R. Panizza, Director, Tax Operations, Duke Energy Business Services LLC
- Shannon A. Caldwell, Director, Compensation, Duke Energy Business Services LLC

[1] On June 14, 2024, Duke Energy Indiana prefiled corrections to witnesses Pinegar, Spanos, Riley, and Hill testimony. On August 23, 2024, Duke Energy Indiana prefiled its second submission of corrections to witnesses Graft, Lilly, Diaz, and Caldwell testimony.

- William (Bill) C. Luke, Vice President of Midwest Generation, Duke Energy Business Services LLC
- Peter Hoeflich, Principal Engineer, Generation and Transition Strategy Organization, Duke Energy Carolinas, LLC
- Timothy S. Hill, Vice President of Coal Combustion Products Projects and Operations, Duke Energy Business Services LLC
- John D. Swez, Managing Director, Trading and Dispatch, Duke Energy Carolinas, LLC
- John A. Verderame, Vice President of Fuels and Systems Optimization, Duke Energy Progress, LLC
- Timothy A. Abbott, General Manager of System Operations, Duke Energy Business Services LLC
- Brian T. Liggett, Vice President of Zone Operations, Duke Energy Indiana[2]
- Jacob S. Colley, Director of Customer Services Strategy, Duke Energy Carolinas, LLC

Duke Energy Indiana also prefiled its revenue requirement model in PDF (Pet. Ex. 25) and Excel (Pet. Ex. 26) formats.

Petitions to Intervene were filed on April 9, 2024, by Wabash Valley Power Association, Inc. ("Wabash Valley"), Nucor Steel ("Nucor"), and the Citizens Action Coalition of Indiana, Inc. ("CAC"); on April 12, 2024, by the Duke Industrial Group ("Industrial Group"); on April 17, 2024, by the Sierra Club ("Sierra Club"); on April 26, 2024, by River Ridge Property Owners' Association ("RRPOA" or "River Ridge"); on May 1, 2024, by the Kroger Co. ("Kroger"); on May 7, 2024, by Blocke, LLC ("Blocke"); on May 20, 2024, by Walmart Inc. ("Walmart"); on June 6, 2024, by Steel Dynamics, Inc. ("Steel Dynamics") and the Rolls-Royce Corporation ("Rolls-Royce"); on June 27, 2024, by the City of Westfield, Indiana ("Westfield"); and on July 30, 2024, by River Ridge Development Authority ("RRDA") (collectively, the "Intervenors"). The Commission issued Docket Entries granting each of said petitions to intervene; thus, all of the entities requesting intervention were made parties to this Cause. The Indiana Office of Utility Consumer Counselor ("OUCC") also participated.

On May 1, 2024, the Commission issued a Docket Entry setting forth the procedural, scheduling, and other matters.

Pursuant to Ind. Code § 8-1-2-61(b), a public field hearing was conducted on June 27, 2024, in Fishers, Indiana, which is the largest municipality in Petitioner's service area. On April 12, 2024, the OUCC filed its Motion for Two Additional Public Field Hearings. The OUCC requested two additional public field hearings be held due to the size of Duke Energy Indiana, LLC's service territory. On May 16, 2024, the Commission issued a Docket Entry granting the OUCC's motion and scheduled three additional field hearings to be held in Terre Haute on June

[2] On August 8, 2024, Petitioner filed its Notice of Substitution of Witness and Adoption of Testimony notifying the Commission that Brian T. Liggett was adopting the case-in-chief testimony of Harley McCorkle. On August 23, 2024, Petitioner filed redline and clean versions of Petitioner's Exhibit No. 23, the Verified Direct Testimony of Brian Liggett.

4, 2024, Bloomington on June 20, 2024, and New Albany on July 11, 2024. During the public field hearings, members of the public provided oral and/or written testimony in this Cause.

On July 11, 2024, the OUCC and intervenors prefiled their respective cases-in-chief. The OUCC's case-in-chief included testimony from the following witnesses:

- Michael D. Eckert, Director of the OUCC's Electric Division
- Mark E. Garrett, President of Garrett Group Consulting, Inc.
- Kaleb G. Lantrip, OUCC Senior Utility Analyst
- Brian R. Latham, OUCC Utility Analyst
- Cynthia M. Armstrong, Assistant Director of the OUCC's Electric Division
- Brian A Wright, OUCC Utility Analyst II
- Roopali Sanka, OUCC Utility Analyst
- David J. Garrett, Managing Member of Resolve Utility Consulting PLLC
- John W. Hanks, OUCC Utility Analyst
- Dr. David E. Dismukes, Consulting Economist with Acadian Consulting Group

The OUCC also filed thousands of written consumer comments the OUCC had received raising ratepayer concerns related to the Company's requested relief as Public's Exhibit Nos. 12, 13, and 14.

Nucor prefiled the testimony of Dr. Jay Zarnikau, an independent consultant who provides consulting services to clients on issues related to electricity rate design and regulatory policy.

The CAC's prefiled case-in-chief included testimony and attachments from the following witnesses:[3]

- Benjamin Inskeep, Program Director at CAC
- Dr. Richard McCann, Partner with M.Cubed
- Dr. Indra Frank, Coal Ash Advisor for the Hoosier Environmental Council
- Devi Glick, Senior Principal at Synapse Energy Economics, Inc.

The Industrial Group's prefiled case-in-chief included testimony and attachments from the following witnesses:[4]

- Michael P. Gorman, Managing Principal, Brubaker & Associates, Inc.
- Brian C. Andrews, Principal, Brubaker & Associates, Inc.
- Brian C. Collins, Managing Principal, Brubaker & Associates, Inc.

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[3] On August 12, 2024, the CAC prefiled corrections to witness Inskeep's testimony.

[4] The Industrial Group prefiled corrections to its witness Gorman's testimony on August 21 and August 27, 2024 and witness Andrews' testimony on August 26, 2024.

Sierra Club prefiled testimony of Tyler Comings, Principal Economist at Applied Economics Clinic.[5]

RRPOA prefiled testimony of Josh Staten, Senior Director – Business Development and Real Estate for the River Ridge Development Authority and Marc A. Hildebrand, Chief Director – Engineering and Operations at River Ridge Commerce Center.

Kroger Co. prefiled testimony of Justin Bieber, Principal for Energy Strategies, LLC.

Walmart prefiled testimony of Lisa V. Perry, Director, Utility Partnerships – Regulatory for Walmart.

Rolls-Royce prefiled testimony of Warren White, Senior Vice President of Assembly & Test, US Defence at Rolls-Royce.

Westfield prefiled testimony of Scott Willis, Mayor of Westfield.

Wabash Valley, Blocke, Steel Dynamics, and RRDA[6] did not prefile case-in-chief testimony.

On August 8, 2024, Duke Energy Indiana prefiled rebuttal testimony, exhibits, and workpapers for witnesses Pinegar, Graft,[7] Sieferman, Lilly, Diaz, Flick, Rimal, McKenzie, Kopp, Spanos, Riley, Caldwell, Luke, Hoeflich, Hill, Swez, Verderame, Colley and Bauer. Duke Energy Indiana also prefiled rebuttal testimony for Patrick O'Connor, Lead Quantitative Analyst for Duke Energy Carolinas, LLC. The Company also prefiled updated versions of its revenue requirement model in both PDF (Pet. Ex. 48) and Excel (Pet. Ex. 49) versions. On the same day, the OUCC filed cross-answering testimony and exhibits of witness Dismukes; the Industrial Group filed cross-answering testimony and exhibits of witness Collins; Nucor prefiled the cross-answering testimony of witness Zarnikau; and CAC prefiled cross-answering testimony of witness Inskeep.[8]

The Presiding Officers issued a Docket Entry requesting additional information from Duke Energy Indiana on August 21, 2024, to which the Company filed its response on August 23, 2024 (Pet. Ex. 50).

The Commission held an evidentiary hearing in this Cause starting on August 29, 2024, at 9:30 a.m. and continuing on to September 5, 2024 in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Duke Energy Indiana, the OUCC, and intervenors were present and participated through counsel. The testimony and exhibits of all of the parties were admitted into the record without objection.

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[5] On August 22, 2024, Sierra Club prefiled corrections to witness Comings' testimony.

[6] Intervention was granted on August 21, 2024 after Intervenors' prefiling case-in-chief date had passed.

[7] On August 23, 2024, Duke Energy Indiana prefiled corrections to Ms. Graft's rebuttal testimony.

[8] On August 12, 2024, the CAC prefiled corrections to witness Inskeep's cross-answering testimony.

Having considered all of the evidence presented in this proceeding, based on the applicable law and evidence, the Commission now finds:

1. Notice and Jurisdiction.

Due, legal, and timely notice of the filing of the Petition in this Cause was given and published by Duke Energy Indiana as required. Proper and timely notice was given by Duke Energy Indiana to its customers summarizing the nature and extent of the proposed changes in its retail rates and charges for electric service. Due, legal, and timely notice of all public hearings in this Cause were given and published as required by law. Duke Energy Indiana is a public utility as defined in Indiana Code § 8-1-2-1(a) and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana. Therefore, this Commission has jurisdiction over Duke Energy Indiana and the subject matter of this proceeding.

2. Petitioner's Corporate Status.

Duke Energy Indiana is an Indiana limited liability corporation with its principal office in the Town of Plainfield, Hendricks County, Indiana. Its address is 1000 East Main Street, Plainfield, Indiana 46168. It has the corporate power and authority to engage, and it is engaged, in the business of supplying electric utility service to the public in the State of Indiana. Accordingly, Petitioner is a "public utility" within the meaning of that term as used in the Indiana Public Service Commission Act, as amended, Ind. Code § 8-1-2-1, and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana, including Ind. Code § 8-1-2-1 et seq. Petitioner is a wholly-owned subsidiary of Duke Energy Indiana Holdco, LLC.

3. Existing Rates.

Duke Energy Indiana's existing retail rates in Indiana were established pursuant to the Commission's Order in Cause No. 45253, dated June 29, 2020. Those basic rates and charges remain in effect today, as modified by the reduction in rates produced by Indiana's repeal of the utility receipts tax, as well as the Commission's Order on Remand in Cause No. 45253, dated April 12, 2023, and various riders approved by the Commission from time to time. These riders adjust Duke Energy Indiana's rates for service to timely recover changes in certain costs associated with the provision of service.

4. Test Year and Rate Base Cutoff Dates.

As authorized by Ind. Code § 8-1-2-42.7(d)(1) ("Section 42.7"), Petitioner proposed a forward-looking test period determined on the basis of projected data for the twelve (12) months ending December 31, 2025. As provided in the Commission's May 1, 2024 Docket Entry, the test year to be used for determining Petitioner's projected operating revenues, expenses and operating income shall be the 12-month period ending December 31, 2025 (the "Forward-Looking Test Period"). The historic base period shall be the 12-month period ending August 31, 2023.

The May 1, 2024 Docket Entry also provided for rate base cutoff dates based on Petitioner's proposed two-step increase. For Step 1, the cutoff date is December 31, 2025, except that the base rate will include the actual net plant in service, actual capital structure, and associated annualized depreciation expense as of June 30, 2024, and the 2025 forecasted amounts for regulatory assets, inventories, and prepaid pension asset. For Step 2, the cutoff date is also December 31, 2025, except that the base rate will include a credit for the difference in revenue requirements using the capital structure and the lesser of forecasted net utility plant in service and actual net utility plant in service on December 31, 2025, and associated annualized depreciation expense.

5. <u>Duke Energy Indiana's Requested Relief</u>.

In its Petition, Duke Energy Indiana sought Commission approval of an overall increase in rates and charges for electric service that would produce additional revenues in two steps of approximately $491.5 million, which would reflect an overall revenue increase of 16.20%. This overall revenue increase is comprised of a Step 1 increase of approximately $355.4 million, representing an approximate 12% increase, and a Step 2 increase of approximately $136.1 million, representing an approximate 4% increase.

As detailed in Duke Energy Indiana's case-in-chief, Petitioner also requested Commission approval of a new schedule of rates and charges applicable to electric utility service, approval of new depreciation accrual rates, as well as regulatory asset treatment upon the retirement of Duke Energy Indiana's last coal-fired steam generation plant. Petitioner further requested approval of one substantive change to its FAC rider to address the recent volatility the Company had experienced in coal inventory levels. Further, the Company sought authority to defer expenses associated with an upcoming CCS study to be conducted for Edwardsport, as well as authority to defer to a regulatory asset costs incurred by the Company to achieve organizational savings. Finally, the Company sought authority to defer to a regulatory asset or liability, as applicable, all calculated income tax differences resulting from future changes in income tax rates until the effect of the income tax rate change can be fully reflected in the Company's rates.

6. <u>Overview of the Evidence</u>.

A. <u>Duke Energy Indiana Case-in-Chief</u>.

Mr. Pinegar described Duke Energy Indiana's requested relief in this Cause, as well as the drivers of the Company's requested relief in this proceeding. Pet. Ex. 1 at 7-8, 10-11. Mr. Pinegar testified that the case and the relief the Company seeks are driven and guided by what has come to be known as the "Five Pillars." *Id.* at 10. Mr. Pinegar identified the Five Pillars – Reliability, Resiliency, Stability, Environmental Sustainability, and Affordability – and described how the Five Pillars are driving the need in this case. *Id.* at 12-14. Regarding the first three pillars, Mr. Pinegar explained these pillars are the core of what an electric utility is expected to do, which is to plan for and invest so that service interruptions are kept to a minimum both in duration and number. Mr. Pinegar testified that since its last rate case, the Company has invested $2.8 billion in new utility plant in service and greatly improved performance within its vegetation management programs. *Id*. Regarding environmental sustainability, Mr. Pinegar testified the Company is continuing its progress to an orderly transition to its clean energy future and explained that coal-fired steam generation has been retired and will continue to be retired in a manner that prioritizes reliability and affordability. *Id*. Mr. Pinegar described why coal combustion residuals are a significant issue in this case and testified that if environmental sustainability is to be the pillar that the General Assembly has directed, then recovery of prudently incurred costs to sustain the environment must be provided. *Id*. Mr. Pinegar testified that in this case, the Company is seeking to recover through depreciation rates the costs that were initially requested under the federal mandate statute but were reversed by the Court of Appeals. *Id*. Further, the Company is seeking a path forward to assure recovery of future closure costs. *Id*.

Regarding affordability, Mr. Pinegar testified that Duke Energy Indiana presently has the second lowest rates among the five investor-owned electric utilities in the state. *Id.* at 14. Mr. Pinegar testified that even with the Company's requested increase, he fully expected the Company to continue to have the second lowest rates among its peer electric utilities in the state. *Id*. Nevertheless, Mr. Pinegar acknowledged that any increase in rates will cause affordability issues for some of the Company's customers, and described what measures the Company has taken both leading up to the case and in this case to address affordability issues. *Id.* at 15-16.

Mr. Pinegar testified that leading up to the case, the Company has actively worked to maintain costs. *Id*. He explained that despite inflation's significant impact on the cost to produce and deliver power, the Company has been able to keep its day to day operating costs flat since 2020. *Id*. Regarding the affordability measures included in this case, Mr. Pinegar described the eight specific measures the Company took in this case to address affordability, including proposing a customer charge of only \$13.70 despite the Minimum System Study supporting a customer charge of \$31.49, as well as proposing rates that are calculated using a lower return on equity ("ROE") of 10.50%, despite the Company's analysis recommending an ROE using the midpoint of witness McKenzie's analysis of 10.80%, among others. *Id*.

Ultimately, Mr. Pinegar explained the Company has strived to build this case in a fashion that addresses the needs driven by the first four of the Five Pillars, while at the same time balancing and designing the overall request with a view to the fifth pillar.

Mr. Rutledge described the financial planning processes used as the basis for the Forward-Looking Test Period proposed in this case. Pet. Ex. 2 at 3-7. He also sponsored and supported the Company's financial forecast. *Id.* at 7-26.

Ms. Graft provided an overview of the rate increase request and introduced and sponsored portions of the Company's revenue requirements model, identified as Exhibit 26. Pet. Ex. 3 at 2-3. Ms. Graft explained the process to develop the Company's revenue requirement and the proposed two-step implementation of base rates. Ms. Graft also supported several accounting and ratemaking aspects of the Company's case, including the Company's continued use of and proposed changes to Tracker No. 60 –Fuel Cost Adjustment, as well as the Company's request for new deferral authority associated with potential future statutory income tax rate changes. *Id*.

Ms. Sieferman addressed the Company's compliance with the Commission's Minimum Standard Filing Requirements ("MSFRs"), sponsored various revenue and expense adjustments, discussed the Company's capital structure, and supported changes to the Company's existing trackers. Pet. Ex. 4 at 2. Ms. Sieferman also addressed the Company's proposal to refund surplus funds accumulated in the grantor trust, which is used to cover other post-retirement benefits ("OPRB") costs. *Id.* at 6.

Ms. Lilly sponsored the Company's rate base, explained the ratemaking treatment associated with coal ash closure, supported changes to the Company's existing trackers, and supported the Company's requested deferral authority for a CCS study at Edwardsport. Pet. Ex. 5 at 2-3.

Ms. Diaz sponsored the Company's jurisdictional separation study, which was not challenged. She then sponsored the Company's cost of service study and supported the Company's decision to use the 12 coincident peak demands ("12CP") allocation methodology in this proceeding. Pet. Ex. 6 at 2, 8.

Mr. Flick sponsored and discussed the Company's proposed rate design and rate schedules. Pet. Ex. 7 at 2. Mr. Flick also described the Company's proposal to increase the residential rates' customer charge from \$10.54 to \$13.70, as supported by the Minimum System Study sponsored by Company witness Rimal. *Id.* at 25. Mr. Flick explained the study's results show that the costs attributable to the addition of a residential customer are much higher than the customer charge requested in this case, \$31.49 versus \$13.70, respectively. *Id*. Mr. Flick explained that the Company recognizes the need for adjusting rates in a gradual manner, however, and thus capped the requested increase at \$3.16.

Mr. Rimal sponsored the Company's minimum system study. Pet. Ex. 8 at 2.

Mr. Bauer discussed and sponsored the Company's projected capital structure. Pet. Ex. 9 at 2. Mr. Bauer testified Duke Energy Indiana's current (as of August 31, 2023) financial capital structure is 47.6 percent long-term debt and 52.4 percent equity. *Id*. at 11. Mr. Bauer further testified Duke Energy Indiana's capital structure is forecasted to be 47 percent long-term debt and 53 percent equity at the end of 2025 (the end of the Forward-Looking Test Period). *Id*. He explained this forecasted capital structure is consistent with the Company's target capital structure of 47 percent long-term debt and 53 percent equity for Duke Energy Indiana as it introduces an appropriate amount of risk due to leverage while minimizing the weighted average cost of capital to customers. *Id*. He testified that use of the forecasted capital structure in setting Duke Energy Indiana's rates will help Duke Energy Indiana maintain its credit quality. *Id*.

Mr. McKenzie presented his independent assessment of the just and reasonable ROE applicable to the historical cost rate base of Duke Energy Indiana. Pet. Ex. 10 at 1. Based on his analysis, Mr. McKenzie recommended a cost of equity range of 10.3% to 11.3% and concluded that the 10.8% midpoint of the range represents a just and reasonable ROE that is adequate to compensate the Company's investors while maintaining the Company's financial integrity and ability to attract capital on reasonable terms. *Id*. at 3. As explained in Mr. Pinegar's testimony, however, for rate mitigation purposes and to assist in establishing rates that are affordable and competitive across all customer classes, the Company is proposing an ROE of 10.5% in this Cause. Pet. Ex. 1 at 30-31.

Mr. Kopp conducted and sponsored the decommissioning study for the Company. Pet. Ex. 11.

Mr. Spanos conducted a depreciation study for Duke Energy Indiana and proposed new depreciation accrual rates for the Company. Pet. Ex. 12.

Mr. Riley testified regarding the appropriate ratemaking and recovery for costs of removal and specifically costs associated with closure of coal ash ponds. Pet. Ex. 13.

Ms. Buck testified regarding cost allocation and assignment of affiliate expenses as used in the forecast for the Forward-Looking Test Period. Pet. Ex. 14.

Mr. Panizza testified regarding the corporate alternative minimum tax and provided the federal and state income tax rates to be used in the calculation of the revenue requirement. Pet. Ex. 15.

Ms. Caldwell testified regarding Duke Energy Corporation's and the Company's compensation and benefits programs. Pet. Ex. 16.

Mr. Luke testified regarding the Company's generating fleet and sponsored the forecasted generation capital additions and operating and maintenance expenses. Pet. Ex. 17.

Mr. Hoeflich supported the Company's request for deferral of expenses associated with a CCS study at Edwardsport. Pet. Ex. 18.

Mr. Hill testified regarding the Company's current progress and future plans for compliance with the United States Environmental Protection Agency ("U.S. EPA") Coal Combustion Residual ("CCR") Rule and the Indiana Department of Environmental Management ("IDEM") solid waste rules. Mr. Hill also discussed coal ash-related insurance proceeds and the Company's proposal for sharing the proceeds with customers. Pet. Ex. 19.

Mr. Swez testified regarding the proposed cost allocation between native and non-native load customers and supported the Company's proposal for sharing of certain non-native capacity and energy sales margins. Pet. Ex. 20.

Mr. Verderame supported fuel inventory levels, the projected test year fuel expense, and the Company's proposal to reflect changes in fuel inventory in the FAC. Pet. Ex. 21. Regarding the proposal to reflect changes in fuel inventory, Mr. Verderame explained the Company is proposing to build into its base rates a representative balance of coal inventory (approximately 2,333,474 tons or 45 days full load burn at a rate of 51,490 tons per day) and then track the actual inventory balance, both up and down, in the Company's quarterly FAC filings as discussed in the testimony of Company witness Graft. *Id*. at 19.

Mr. Abbott sponsored the Company's forecasted transmission system capital and expense, including transmission vegetation management and physical security investments. Pet. Ex. 22.

Mr. Liggett sponsored the Company's forecasted distribution system capital and expense, including storm costs and distribution vegetation management. Pet. Ex. 23.

Mr. Colley provided an overview of the Company's customer service initiatives and sponsored the forecasted customer-related expenditures. Pet. Ex. 24.

Petitioner also provided its Financial Exhibit in support of its requested relief in this proceeding in PDF Format (Pet. Ex. 25) and Excel (Pet. Ex. 26).

B. <u>OUCC and Intervenors' Cases-in-Chief</u>. The OUCC and intervenors proposed numerous adjustments to the Company's proposed revenue requirements and took issue with other components of Duke Energy Indiana's case-in-chief, particularly Petitioner's proposed rate increase.

a. **<u>OUCC's Case-in-Chief</u>**.

The OUCC proposed a reasonable ROE of 9.00% and recommended certain operating revenue and expense adjustments. Pub. Ex. 8 at 6; *see, e.g.*, testimony of OUCC witness Eckert (Pub. Ex. 1) and OUCC witness M. Garrett (Pub. Ex. 2). The OUCC also made certain recommendations regarding Duke Energy Indiana riders (Pub. Ex. 3); deferral requests and card payment changes (Pub. Ex. 4); environmental capital costs, O&M costs, and CCR closure costs (Pub. Ex. 5); the request to defer FEED study costs (Pub. Ex. 6); Major Storm costs (Pub. Ex. 7); depreciation study (Pub. Ex. 9); proposed program additions or removals and the rate migration adjustment (Pub. Ex. 10); and rate design and cost of service issues (Pub. Ex. 11). The OUCC also presented thousands of consumer comments primarily addressing the requested rate increase and the resulting affordability concerns of Duke Energy Indiana customers (Pub. Ex.s 12, 13, and 14)..

Mr. Eckert explained the "Five Pillars of Electric Utility Service" and shared the OUCC's concerns related to affordability, noting Duke Energy Indiana has implemented multiple risk mitigation trackers that shift the risk of operating expense increases and capital expenditures to Duke Energy Indiana's ratepayers. He testified that increasing utility costs place upward pressure on customer bills, prompting more than 3,000 customers to have submitted written comments at the time his testimony was filed.[9] Mr. Eckert also raised concerns about Duke Energy Indiana's storm response.

Mr. Eckert explained the OUCC's proposal to adjust Petitioner's fuel costs to reflect current market projections, and he opposed DEI's proposal to track fuel inventory. Additionally, Mr. Eckert recommended changes to the calculation of COVID-19 expense, the amortization period for certain regulatory assets, and disallowance of recovery for, and elimination of, $7.6 million of un-monetized inventory remaining after the closing of Gallagher Station. He also recommended DEI reduce its base rates for the amortization of regulatory assets through its credit rider upon the amortization period expiring.

Mr. Mark Garrett sponsored the OUCC's overall revenue requirement adjustments and recommendation. He recommends a 5.87% WACC. Mr. Garrett also recommended test year expense reductions for incentive compensation, trade association dues, investor relations expense, and Other Post Retirement Benefit expense.

Mr. Lantrip recommended a 75%/25% allocation split for short term non-native bundled sales margins above $5 million. He accepted Duke Energy Indiana's other proposals regarding the SRA and the TDSIC riders.

Mr. Latham recommended the Commission reject Duke Energy Indiana's card payment fee elimination proposal because the proposal would unfairly shift costs to all customers, including those that do not use credit cards. He also recommended denial of the request for authority to defer

[9] Customer comments were admitted at the evidentiary hearing as Pub. Ex. Nos. 12, 13, & 14 and numbered over 5,000.

income tax changes because Duke Energy Indiana had not sufficiently supported the request; because Duke Energy Indiana had taken advantage of income tax decreases without previously proposing a balancing account, and because any such income tax changes should be addressed by the Commission on a consistent basis for all affected utilities.

Ms. Armstrong addressed environmental compliance costs. Ms. Armstrong recommended disallowance of the Cause No. 45253 S1 CCR costs because these costs had already been litigated and rejected by the Indiana Court of Appeals. She did not take issue with the inclusion of future CCR closure costs through decommissioning but opposed the addition of contingency consistent with Mr. David Garrett's recommendations. Ms. Armstrong opposed Duke Energy Indiana's proposal to share the proceeds of CCR insurance proceeds because the insurance had been funded by ratepayers, and the proceeds would alleviate the impact of CCR closure costs which ratepayers are paying and will continue to pay, and to address rate affordability. She addresses Duke Energy Indiana's ongoing capital operations & maintenance ("O&M") costs related to environmental compliance. Finally, proposes changes to the treatment of Renewable Energy Credits ("RECs") for its GoGreen program.

Mr. Wright recommended the Commission reject Duke Energy Indiana's request to defer and recover its share of the costs for the FEED study due to the speculative nature of the feasibility and affordability of a CCS system.

Ms. Sanka recommended a $6.4 million reduction to Major Storm transmission and distribution expense due to Duke Energy Indiana's inclusion of a significant outlier in its calculation.

Mr. David Garrett analyzed the appropriate return on equity ("ROE") for Duke Energy Indiana and recommends a reasonable ROE of 9.0%. Mr. Garrett also analyzed Duke Energy Indiana's depreciation study and recommended removal of contingency and escalation from cost of removal amounts and recommended adjustments to certain depreciation rates.

Mr. Hanks recommended rejection of the Payment Navigator program and sunsetting the EZ Read program. Mr. Hanks, along with Dr. Dismukes, analyzed Duke Energy Indiana's rate migration adjustment and recommended a reduction.

Dr. Dismukes addressed Duke Energy Indiana's allocated cost of service study and proposed adjustments to it and presented his recommended cost of service. He recommended the Commission adopt a revenue distribution allocation method based on his alternative CCOSS results; and he recommended the Commission limit rate increase to any single rate class to no more than 1.15 times the system average increase.

b. **<u>Intervenors' Respective Cases-in-Chief</u>**.

Industrial Group witness Mr. Gorman recommended adjustments to Petitioner's overall rate of return, return on common equity and capital structure, and other revenue requirement adjustments reflecting a reduction to total Company revenue requirement from approximately $491.5 million to $196.2 million. IG Ex. 1. Mr. Gorman's adjustments included a disallowance of

$63.6 million for operation and maintenance ("O&M") expense incurred at Edwardsport, as well as removal of $14.6 million of the Company's proposed incentive compensation costs based on his recommendation that incentive compensation tied to financial performance be excluded from cost of service in this case. *Id*. at 22, 47. Mr. Gorman also recommended that Duke's proposal to track its coal inventory through the FAC should be rejected, as well as the Company's request to recover its costs to achieve corporate restructuring savings. *Id*. at 7, 34. He also recommended a reduction of $37.8 million to the prepaid pension asset in the Company's forecasted rate base. *Id*. at 40-41.

CAC witness Inskeep argued for a lower ROE and made various recommendations with respect to Edwardsport, the Company's proposals regarding coal ash recovery, the Company's new and modified tariff offerings, as well as other proposals. CAC Ex. 1. CAC witness Inskeep and Westfield witness Willis also raised concerns about affordability. *Id*. at 20-48; Westfield Ex. 1, at 3-9.

Sierra Club witness Comings made various recommendations regarding the Company's generating stations, including that certain O&M costs at Edwardsport be denied and that the Commission open a sub-docket to investigate whether capital spending being sought in this case at Edwardsport and Gibson Units 1 and 2 could have been avoided if any of the units were to retire earlier than currently assumed in this case—or in the case of Edwardsport, if the Company had reasonably decided to convert the plant to gas. SC Ex. 1. at 34.

Nucor Steel witness Zarnikau (Nucor Ex. 1), Kroger Co. witness Bieber (Kroger Ex. 1) and Walmart witness Perry (Walmart Ex. 1) each made various recommendations regarding the Company's proposed cost of service study and rate design. Walmart witness Perry also discussed the Company's proposed ROE and made various recommendations. Walmart Ex. 1 at 15-16.

RRPOA and Rolls-Royce testified regarding the current and future capital improvement projects they perceived were required to serve their anticipated future energy needs. Both intervenors also recommended the Commission require the Company to offer a tariff for customers with defined eligibility characteristics, such as significant investment and/or new job creation. RRPOA Ex. 2 at 14; Rolls-Royce Ex. 1 at 14.

C. **Duke Energy Indiana Rebuttal**.

On rebuttal, Mr. Pinegar addressed concerns about the Company's proposed rate increase and its implications for affordability, reaffirming Duke Energy Indiana's commitment to the Five Pillars framework: affordability, reliability, resiliency, environmental sustainability, and stability. Pet. Ex. 28 at 9. Mr. Pinegar emphasized that affordability is a critical and integral part of this framework, not a secondary consideration. *Id*. Mr. Pinegar reiterated that in order to mitigate the rate impact on customers, several measures had been implemented in this Cause, such as spreading recovery of costs over a longer period, proposing a customer charge that is lower than what the evidence would warrant, and proposing a lower ROE than is recommended by the Company's cost of equity expert. *Id*. He testified that as of July 31, 2024, Duke Energy Indiana had the lowest residential rates among the five investor-owned electric utilities in the state, and even with the requested increase, the Company is expected to remain competitive with its peer electric utilities in the state. *Id*. at 13.

Mr. Pinegar also responded to the concerns raised by RRPOA regarding economic development and the Company's ability to serve future economic growth. *Id*. at 23-29. Mr. Pinegar testified Duke Energy Indiana remains committed to working with River Ridge and other stakeholders to continue fostering economic growth and development throughout its entire 69-county service area; however, the Company must balance the needs of all of its customers. *Id*. at 24. Ultimately, Mr. Pinegar underscored the necessity of prudent infrastructure investments, ensuring that Duke Energy Indiana continues to support economic growth and development while delivering reliable, affordable, and sustainable service to its customers. *Id*. at 10.

Ms. Graft responded to various ratemaking issues and recommendations included in the testimony of OUCC witnesses Eckert, M. Garrett, and Latham, Industrial Group witness Gorman, and CAC witnesses Inskeep and Glick. Pet. Ex. 29. She summarized the Company's rebuttal adjustments and their impact to the proposed revenue requirement and provided an update to the calculation of the Step 1 rate adjustment.

Ms. Sieferman supported the Company's updated capital structure for June 30, 2024, and responded to various issues included in the testimonies of OUCC witnesses Armstrong, Sanka, Lantrip, and M. Garrett, CAC witness Inskeep, and Nucor witness Zarnikau, including: the GoGreen Program's Renewable Energy Certificate ("REC") supply proposal, revenue requirement adjustments for Nucor, adjustments for OPRB, margin sharing recommendations for short-term bundled non-native sales ("STBNNS"), trade association dues and fees, and the normalization calculation for major storm expenses. Pet. Ex. 30.

Ms. Lilly supported the Company's updated Step 1 net plant balance to reflect the actual balances as of June 2024 as set forth on Exhibit 49, Schedules RA6-RA17. Ms. Lilly also addressed issues related to regulatory assets and rate base raised by OUCC witnesses Eckert and Armstrong, and CAC witness Inskeep. In addition, she addressed recommendations made by Industrial Group witness Gorman regarding roll-in of certain TDSIC amounts into the base rates proposed in light of a pending Supreme Court appeal and regarding Edwardsport operations. Further, she discussed the changes made to certain rate base and depreciation schedules sponsored due to the change in the depreciation study results supported by Company witness Spanos. Pet. Ex. 31.

Ms. Diaz responded to certain portions of the testimony of OUCC witness Dismukes, CAC witness McCann, Industrial Group witness Collins, Nucor witness Zarnikau, and Walmart witness Perry regarding jurisdictional and cost of service studies. Pet. Ex. 32.

Mr. Flick responded to various issues raised by the OUCC and intervenors regarding the Company's proposed rate design. Pet. Ex. 33.

Mr. Rimal responded to various issues raised by OUCC witness Dismukes and CAC witness McCann regarding classification of distribution plant costs. Pet. Ex. 34.

Mr. McKenzie addressed the recommendations of OUCC witness D. Garrett and Industrial Group witness Gorman regarding the just and reasonable ROE applicable to the net original cost rate base of Duke Energy Indiana. Pet. Ex. 35. Mr. McKenzie also addressed the comments of Walmart witness Perry, CAC witness Inskeep, and OUCC witness Eckert regarding a fair ROE for Duke Energy Indiana. *Id*.

Mr. Kopp responded to certain recommendations in the testimonies of Industrial Group witness Andrews and OUCC witnesses D. Garrett and Armstrong regarding Duke Energy Indiana's Decommissioning Cost Estimate Study. Pet. Ex. 36.

Mr. Spanos responded to depreciation-related issues raised by OUCC witness D. Garrett and Industrial Group witness Andrews. Pet. Ex. 37. Specifically, Mr. Spanos addressed the challenge of the inclusion of contingency for decommissioning estimates raised by Mr. Garrett, the escalation of decommissioning costs raised by both witnesses, Mr. Andrews' proposal to reduce the escalation factor used, and Mr. Andrews' challenge of the interim survivor curves for Edwardsport. *Id*. Mr. Spanos also addressed both witnesses' mass property service life proposals. Finally, Mr. Spanos sponsored an updated depreciation calculation to support the Company's rebuttal testimony position regarding the revised decommissioning cost calculations and appropriate level of the accumulated depreciation (book reserve). *Id*.

Mr. Riley addressed objections by OUCC witness Armstrong, CAC witness Inskeep, and Industrial Group witness Andrews to Duke Energy Indiana's recovery of approximately $92.1 million of CCR costs incurred from January 2019 through November 2021. Pet. Ex. 38.

Ms. Caldwell testified regarding the reasonableness of Duke Energy Indiana's total compensation package, specifically the portion of compensation comprised of incentive pay. She explained why these costs should be included in the Company's revenue requirement and recovered in rates, and why accepting the recommendations by the OUCC and Industrial Group to preclude the Company from recovering expense associated with incentive compensation would ultimately result in rates that do not recover the costs of market-competitive compensation. Pet. Ex. 39.

Mr. Luke addressed arguments raised by the OUCC, Industrial Group, CAC, and Sierra Club regarding the Company's generating units. Mr. Luke explained why having the flexibility to operate Edwardsport on both coal and natural gas provides benefits to the Company and its customers in a variety of situations. Pet. Ex. 40. at 17-19. He also testified regarding why the Commission should not treat Edwardsport as if it is being run on natural gas as suggested by the CAC, Sierra Club, and the Industrial Group. *Id*. at 2. Mr. Luke also addressed the importance of the Company's ongoing maintenance investments in its coal units, the reasonableness of its proposed retirement dates, the OUCC's questioning of the Company's inventory management practices on retiring units, and further supported the reasonableness of recovering the Gallagher Station remaining inventory amount. *Id*.

Mr. Hoeflich responded to concerns raised by the OUCC, CAC, Industrial Group, and Sierra Club related to the Front-End Engineering Design ("FEED") study designed to assess the feasibility of CCS technologies at Edwardsport.

Mr. Hill addressed concerns regarding the Company's production O&M forecast raised by the OUCC, certain assertions made by CAC regarding the efficacy of the Company's closure plans and their relation to this Cause, and assertions by various intervenors regarding the settlement of CCR insurance claims and the distribution of proceeds. Pet. Ex. 42.

Mr. Swez rebutted Sierra Club witness Comings' position that the Company should cease running Edwardsport on coal or convert to natural gas, as well as his recommendation that the Commission should not grant recovery for any test year costs that are associated with running the plant on coal and syngas. Pet. Ex. 43 at 2-4. Mr. Swez also responded to the other positions Mr. Comings took on Edwardsport and Gibson Stations. *See, e.g.*, *Id*. at 14. Mr. Swez also rebutted the recommendation of CAC witness Glick that the Company should plan to operate Edwardsport on gas and operate on coal only when needed to manage coal oversupply and her recommendation that the Commission disallow recovery of fuel costs above what it would cost to operate Edwardsport on the lowest operating cost resource. *Id*. at 16-32. Mr. Swez also discussed OUCC witness Lantrip's response to the Company's proposed change for sharing regarding STBNNS wholesale contracts. *Id*. at 33-34.

Mr. Verderame responded to OUCC witness Eckert's recommendations as well as concerns raised by CAC witness Glick regarding Duke Energy Indiana's fuel procurement practices. Pet. Ex. 44. Specifically, he addressed Ms. Glick's claim that the Company's contracting practices are leading to coal oversupply, thus impacting Duke Energy Indiana's commitment practices. *Id*. at 2-8.

Mr. Colley responded to certain portions of the testimony of OUCC witnesses Hanks and Latham, and CAC witness Inskeep. Pet. Ex. 45. Mr. Colley addressed a number of issues in rebuttal testimony, including, the Company's Payment Navigator Program and card payment fees, among others. *Id*.

Mr. Bauer addressed OUCC witness D. Garrett's and Industrial Group witness Gorman's assertions that the Company's debt percentage is too low and discussed the overall financial impacts to the Company of their proposed ROE positions. Pet. Ex. 46.

Mr. O'Connor responded to CAC witness Glick's and OUCC witness Eckert's assertions that the Company's stochastic coal burn forecast is inflated and has historically over-forecast burn. Pet. Ex. 47. He also addressed the assumptions underlying the stochastic simulation process in the Fleet Analytics and Stochastics Tool ("FAST") model used to project fuel burn and power price volatility, and discussed the supply offer adjustment to correct mischaracterizations by Ms. Glick regarding the interpretation of its use and how it is/can be modeled. *Id*.

D. <u>**Cross-Answering Testimony**</u>.

The intervening parties filed cross-answering testimony on various topics. For example, OUCC responded to various intervenor proposals that the Commission allocate demand-related production and transmission costs on the basis of the average of 4 coincident peak demands ("4CP") rather than 12CP as proposed by the Company. Pub. Ex. 11-CA. Industrial Group witness Collins responded to OUCC witness Dismukes and CAC witness McCann regarding class cost of service study issues. IG Ex. 3-CA. Mr. Collins also responded to CAC witness Inskeep regarding the proposed Affordable Power Rider. *Id*. at 21.

Nucor witness Zarnikau responded to the direct testimonies of CAC witness McCann and OUCC witness Dismukes with respect to their recommendations on the appropriate cost of service methodology for the Company's class cost of service study. Nucor Ex. 1-CA.

CAC witness Inskeep provided cross-answering testimony responding to portions of the direct testimonies of OUCC witness Dismukes, Industrial Group witness Collins, Walmart witness Perry, Nucor witness Zarnikau, Rolls-Royce witness White, and RRPOA witness Staten.

E. **Evidence Admitted at Hearing (Cross Examination and Exhibits).**

In addition to all parties' prefiled testimony and exhibits being admitted at the evidentiary hearing, the witnesses listed below were cross examined, and additional exhibits were admitted. Relevant testimony elicited on cross examination is included within applicable discussions below.

- Stan C. Pinegar
- Christa L. Graft
- Suzanne E. Sieferman
- Kathryn C. Lilly
- Maria T. Diaz
- Roger A. Flick
- Sean P. Riley
- William C. Luke
- Timothy S. Hill
- John A. Verderame
- Jacob S. Colley.

7. **Overview and the Five Pillars**.

On April 20, 2023, Governor Eric J. Holcomb signed House Enrolled Act 1007 ("HEA 1007") into law with an effective date of July 1, 2023. HEA 1007 added Indiana Code § 8-1-2-0.6, which declares that it is the continuing policy of the State of Indiana "that decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider" the following attributes (commonly referred to as the "Five Pillars"):

(1) Reliability,
(2) Affordability,
(3) Resiliency,
(4) Stability, and
(5) Environmental sustainability.

HEA 1007 also added Indiana Code § 8-1-8.5-3.3 and amended Indiana Code §§ 8-1-8.5-4 and -5, to require the Commission and its staff to consider, evaluate, and comment on the Five Pillars as defined in Indiana Code 8-1-2-0.6.

As such, the Five Pillars have served as the lens through which the Commission has viewed all parties' requested relief in this Cause and constitute the framework for the findings set forth in this Order. Per the Legislature's directive in HEA 1007, we have considered and evaluated each of the Five Pillars in making our determinations in this case, and our considerations are discussed throughout the findings set forth in the following sections.

8. **Affordability.**

[The OUCC disagrees that an Affordability section should be deferred to later portions of the Commission's Order and that the Five Pillars should be compartmentalized as Petitioner appears to have done. Therefore, the OUCC would move the entire Affordability section to this new Section 8. For purposes of redline review and clear editing.]

Of the Five Pillars, we first address the pillar of Affordability.

A. <u>Duke Energy Indiana Case-in-Chief</u>.

Mr. Pinegar described Duke Energy Indiana's requested relief in this Cause, as well as the drivers of the Company's requested relief in this proceeding. Pet. Ex. 1 at 7-8, 10-11. Regarding affordability specifically, Mr. Pinegar testified that Duke Energy Indiana presently has the second lowest rates among the five investor-owned electric utilities in the state. *Id*. at 14. Mr. Pinegar testified that even with the Company's requested increase, he fully expected the Company to continue to have the second lowest rates among its peer electric utilities in the state. *Id*. Nevertheless, Mr. Pinegar acknowledged that any increase in rates will cause affordability issues for some of the Company's customers, and described what measures the Company had taken both leading up to the case and in this case to address affordability issues. *Id*. at 15-16.

Leading up to the case, Mr. Pinegar testified the Company had actively worked to maintain costs. *Id*. He explained that despite inflation's significant impact on the cost to produce and deliver power, the Company has been able to keep its day-to-day operating costs flat since 2020. *Id*. Regarding the affordability measures included in this case, Mr. Pinegar described the eight specific measures the Company took in this case to address affordability, including, proposing a customer charge of only \$13.70 despite the Minimum System Study supporting a customer charge of \$31.49, as well as proposing rates that are calculated using a lower return of 10.50%, despite the Company's analysis recommending a return on equity using the midpoint of witness McKenzie's analysis of 10.80%, among others. *Id*.

Mr. Pinegar also described the ways in which Duke Energy Indiana provides support for its financially vulnerable customers. *Id*. at 26-27. Mr. Pinegar explained that in the last case, the Company committed to participating in a low-income collaborative in which the Company would discuss and consider ways to provide assistance to low-income customers. *Id*. Mr. Pinegar testified coming out of the collaborative the Company sought and received Commission approval to implement three new programs targeted to aid qualifying customers, and Company witness Colley described these programs in his direct testimony. *Id*.; Pet. Ex. 24 at 14. Mr. Pinegar also described the other programs the Company provides to support its financially vulnerable customers, as well as well as the outreach the Company has done to support these customers. Pet. Ex. 1 at 27-30.

B. <u>OUCC and Intervenors</u>.

OUCC witness Michael Eckert testified regarding the concerns the OUCC has about the affordability of Duke Energy Indiana's rate request. Pub. Ex. 1 at 7. Mr. Eckert testified that in Ind. Code § 8-1-2-0.5, the Indiana General Assembly declared it to be the State's policy to recognize the importance of utility service affordability for present and future generations. *Id*. at 7-8. He testified consistent with this statute, affordability should be protected as utilities invest in the infrastructure necessary for system operations, maintenance, and reliability. He further testified consistent with the General Assembly's policy, the Commission should only approve necessary and reasonable requests for Duke to provide service at prudent cost and reasonable prices, and the Commission should take steps to moderate the imposition of higher rates, including rates that may unreasonably escalate over time. *Id*.

Mr. Eckert quoted Ind. Code § 8-1-2-0.5, noting that "it is the continuing policy of the state…to use all practicable means and measures… to create and maintain conditions under which utilities plan for and invest in infrastructure necessary for operation and maintenance while protecting the affordability of utility services for present and future generations of Indiana citizens." Pub. Ex. 1 at 5.

Mr. Eckert pointed out that Mr. Pinegar considered affordability a "relative analysis." Petitioner's Exhibit No. 1, Direct Testimony of Stan C. Pinegar, 14, ll. 20-21. Mr. Eckert also pointed out that the Five Pillars "are each independent and equally important and not mutually inconsistent." Pub. Ex. 1, p. 6, ll. 23 – 24. He stressed that "[b]y referring to affordability as a relative analysis, Mr. Pinegar's testimony implies affordability should be viewed in a subordinate manner to the other Pillars. This is contrary to the plain language of the statute." Pub. Ex. 1 at 7. Mr. Eckert pointed out that "[t]he Commission has been given statutory discretion that may be exercised to alleviate financial burdens on ratepayers without affecting the utility's ability to maintain safe and compliant systems and earn a reasonable profit." Pub. Ex. 1 at 8. He stated:

> [T]he Commission should take steps to moderate the imposition of higher rates, including rates that may unreasonably escalate over time. In recognizing the importance of affordability, measures such as examining cost allocation, prioritizing investment, and spreading cost recovery over longer periods of time can help address the financial impacts upon customers.

Pub. Ex. 1 at 9.

Mr. Eckert also discussed Duke Energy Indiana's attempt to address affordability by reducing its requested ROE from 10.8% to 10.5%. He pointed out that the 10.8% ROE Duke argues it could justify is "higher than what any Indiana electric utility has requested in the last three years." Pub. Ex. 1 at 10. He noted that in contrast, the Commission has authorized ROEs in a range of 9.70% to 9.90%. Mr. Eckert pointed out that the 3,000+ comments received from DEI's ratepayers raised the concerns about the affordability of Duke's rates. He noted that the field hearings included comments about "the hardships Duke's consumers would face as a result of the Company increasing its rates." Pub. Ex. 1 at 15.

OUCC witness David Dismukes also testified on the affordability concerns of the proposed increase in the customer charge, stating the increased customer charge will burden low-use and low-income customers with a greater than system average percent rate increase. Pub. Ex. 11 at 4. Dr. Dismukes explained that a higher customer charge disincentivizes energy efficiency and shifts the rate burden within a customer class to lower-use customers, resulting in equity concerns as lower-use customers have been shown to be associated with lower-income households. *Id*. at 45-46. Dr. Dismukes also argued against the use of Duke's use of the full results of its COSS for most customer classes as inconsistent with rate gradualism and could also negatively impact energy affordability, advocating to limit the increase for customer classes. *Id*. at 37-38.

CAC witness Inskeep discussed what he viewed as an unaffordability crisis and testified there is robust data showing that millions of American families cannot afford their utility energy bills and are forgoing basic necessities in order to pay high utility bills, and that electric bill unaffordability is negatively impacting the Company's customers specifically. CAC Ex. 1 at 23. To address this unaffordability crisis, Mr. Inskeep recommended the Company establish a new tariff, the Residential Affordable Power Rider, in order to provide immediate direct bill assistance to some of the company's most vulnerable low-income households. *Id*. at 115. Mr. Inskeep also recommended a series of other actions the Commission should take in order to address customer affordability, including, imposing a moratorium on the Company conducting additional residential involuntary disconnections and eliminating or reducing the Company's reconnection charge, among others. *Id*.

The City of Westfield also expressed affordability concerns and recommended the Commission deny Duke Energy Indiana's requested rate increase absent a showing by the Company that its proposed rates are affordable. Westfield Ex. 1 at 9. The City further recommended the Commission require the Company to spread out the increase into more phases if the Commission determines a rate increase is appropriate. *Id*. Further, RRPOA raised similar affordability concerns related to the impact the rate increase would have on economic development and River Ridge's ability to attract economic investment. RRPOA Ex. 2 at 7. RRPOA witness Hildenbrand requested that the Commission consider the affordability of the increase and the ability of customers to pay for the increase. RRPOA Ex. 1 at 5. He also recommended the Commission require that any increases be phased in so that customers pay no more than an additional five percent (5%) per year. *Id*. Intervenor Rolls-Royce also raised concerns regarding the impact the proposed rate increase would have on the Company and its operations. Rolls-Royce Ex. 1 at 7-9.

C. <u>Duke Energy Indiana Rebuttal</u>.

On rebuttal, Mr. Pinegar addressed concerns about the Company's proposed rate increase and its implications for affordability, reaffirming Duke Energy Indiana's commitment to the Five Pillars framework. Pet. Ex. 28, at p. 9. Mr. Pinegar emphasized that affordability is a critical and integral part of this framework, not a secondary consideration. *Id*. Mr. Pinegar reiterated that in order to mitigate the rate impact on customers, several measures have been implemented in this Cause, such as spreading recovery of costs over a longer period, proposing a customer charge that is lower than what the evidence would warrant, and proposing a lower ROE than is recommended by the Company's cost of equity expert. *Id*.

Mr. Pinegar further testified that as of July 31, 2024, Duke Energy Indiana had the lowest residential rates among the five investor-owned electric utilities in the state, and, even, with the requested increase, the Company is expected to remain competitive with its peer electric utilities in the state. *Id*. at 13.

In his rebuttal testimony, Company witness Flick offered the results of recent utility rate comparison reports comparing the residential, commercial, and industrial rates of Indiana's Investor-Owned Utilities. Pet. Ex. 33 at 16-18. Mr. Flick explained the data for the residential rate comparison was sourced from the Indiana Utility Regulatory Commission's Jurisdictional Electric Utility Residential Customer Bill Survey, dated July 2024, and both of the C&I reports were sourced from the EEI's Typical Bills and Average Rate Report, Winter 2024. Mr. Flick testified the rate comparisons signal an expectation that the Company's rates will maintain competitive across major rate categories with its peers, after adjusting for the effects of the rate increase in this proceeding. *Id*.

On rebuttal, Mr. Colley testified affordability has been and remains a primary focus of the Company, and that is evident through the Company's existing offerings, recent program implementations, and proposals within this Cause. Pet. Ex. 45 at 3. He described the Company's affordability ecosystem comprised of multiple solutions required to meaningfully address affordability challenges for customers. *Id*. He explained these solutions are broadly grouped into categories of (i) customer assistance funds; (ii) energy efficiency and weatherization; (iii) bill management options; and (iv) income qualified programs. Mr. Colley testified to that end, the Company has developed and continues to develop an ecosystem of tools and offerings that support our customers, and this multi-pronged approach captures opportunities to address customer affordability challenges and is further built upon through the Payment Navigator program proposal in this Cause. *Id*.

D. <u>Additional Evidence Received at Hearing</u>.

Mr. Pinegar confirmed he had approved the request for an annual increase of approximately 16.2%. Tr. at A- 61. The Company's last rate case requested an increase of approximately 18.6% in July 2019. *Id*. at A- 62.

Mr. Pinegar testified about affordability measures initially in Petitioner's case-in-chief, and Mr. Pinegar and Mr. Spanos stated that the company would forego post-closure maintenance costs as one of the steps to mitigate the overall rate increase and address affordability. Tr. at A- 85-87. Mr. Spanos had mistakenly included the post closure maintenance costs in his depreciation study. Tr. at A- 85-89 and Pub. Ex. CX-2 and CX-3. Mr. Pinegar confirmed that instead of revising Mr. Spanos' depreciation study to remove the post closure maintenance costs, the Company chose instead to revise the testimony and remove that affordability measure. *Id*. at A- 88-89.

E. <u>Commission Discussion and Findings</u>.

The first pillar in our analysis of the Five Pillars is Affordability. Affordability is always an important consideration for the Commission when establishing just and reasonable rates, and we recognize that affordability is an ongoing concern for all consumers in the State of Indiana, as evidenced by the thousands of consumer comments. Affordability is therefore a critical consideration. At the outset, it is important to reiterate that our analysis of the Five Pillars requires us to balance all pillars – affordability, reliability, resiliency, environmental sustainability, and stability – in order to ensure that all Five Pillars are upheld.

"Affordability" is defined under Ind. Code § 8-1-2-0.6 as including "ratemaking constructs that result in retail electricity utility service that is affordable and competitive across residential, commercial, and industrial customer classes." Thus, our analysis requires the Commission to take into consideration both the affordability of Petitioner's rates, as well as the competitiveness of those rates across all residential, commercial, and industrial classes in making our determinations and balancing this critical pillar.

We recently articulated that "our role in addressing [the affordability concern] is not to reach a conclusion as to whether the rates approved herein are 'affordable' for each and every customer, particularly given the difficulty in defining affordability in general and for the many diverse customers and communities [a utility] serves."[10]

While Duke Energy Indiana attempts to portray its proposed rates as "affordable," the reality is that they are not affordable for a significant portion of its ratepayers, which was made overwhelmingly clear in this case through their participation at the field hearings and the customer comments filed in this Cause. We find the issues, as decided in this Order, substantially address the affordability concerns that Duke's customers have expressed. In particular, our determination on the appropriate ROE balances investor and ratepayer interests more equitably than Duke Energy Indiana requested, while our reduction of Duke's revenue requirement request mitigates the impact to all customer classes. Additionally, Dr. Dismukes' argument that the increased customer charge will affect affordability is persuasive, as this would have a larger impact on low-use customers. We also acknowledge that limiting Duke Energy Indiana's rate increase for any single rate class to no more than 1.15 times the system average increase also fosters affordability across all residential, commercial, and industrial rate classes. The Commission finds our determinations address the affordability of rates for all ratepayers while still ensuring Duke Energy Indiana is able to meet its and customers' needs regarding reliability, resiliency, and stability.

9. Petitioner's Rate Base – Reliability, Resiliency and Stability.

Company witness Pinegar testified that the pillars of reliability, resiliency, and stability are at the core of what an electric utility is expected to do – which is to plan for and invest so that service interruptions are kept to a minimum both in duration and number. Pet. Ex. 1 at 12-13. Mr. Pinegar and Company witnesses Abbott (Pet. Ex. 22), Liggett (Pet. Ex 23), and Luke (Pet. Ex. 17) described the Company's investments since the last rate case in transmission, distribution, and generation assets geared toward reliability, resiliency, and stability. Mr. Pinegar testified the Company has invested $2.8 billion in new utility plant in service and has greatly improved performance within its vegetation management programs. Pet. Ex. 1 at 12-13. He testified the pillars of reliability, resiliency, and stability have guided these decisions, and he is personally proud of the Company's efforts in this regard.

A. Utility Plant in Service Issues.

The Company proposed six *pro forma* adjustments to its forecasted utility plant in service in its case-in-chief as set forth on Petitioner's Exhibit 26, Attachment 26-C, Schedule RB2. The only adjustment in dispute is Petitioner's adjustment for its new proposed depreciation accrual rates, which is addressed later in this Order. Otherwise, we find all *pro forma* adjustments proposed by Petitioner, either as originally proposed and undisputed, or as adjusted with the compromised positions having been fully identified by the parties, are hereby accepted even though they may not be specifically discussed in this Order.

Further, the Company's forecasted net plant-in-service was largely uncontested, apart from certain parties taking issue with two items: the Cayuga landfill cell and the Company's Targeted

[10] *Indiana American Water Co*., Cause No. 45870, Order at p. 105.

Economic Development ("TED") projects. We will address these issues first before turning to other rate base-related issues.

a. **<u>Duke Energy Indiana Case-in-Chief</u>**.

In his direct testimony, Company witness Hill described the status of the CCR Units at the Cayuga Generation Station, including the ongoing Cayuga-related capital projects and costs. Pet. Ex. 19 at 13-14. Mr. Hill described the Test Period CCP Power Production Capital Forecast to include Cayuga station "costs to begin construction of cell 3 of the RWS II landfill to support disposal of production CCR." *Id*. at 29.

Further, as described in Company witness Abbott's testimony, the Company's 2024 and 2025 forecasted capital expenditures included approximately $6.7 million and $49.7 million, respectively, for transmission TED projects that the Company has not yet identified but anticipates a need. Pet. Ex. 22 at 25. Regarding the unidentified TED projects, Mr. Abbott testified that businesses seeking new locations have numerous options, bringing jobs and tax dollars to build thriving communities, and reliable utilities are crucial for economic success. *Id*. He testified the forecast for these unidentified TED projects empower Duke Energy Indiana to meet tight timelines, attract businesses and grow our communities, and although these projects are not yet identified, the Company anticipates economic development activity will continue at a high level, such that additional TED projects will be forthcoming. *Id*.

b. **<u>OUCC and CAC</u>.**

OUCC witness Armstrong objected to including the construction costs associated with the Cayuga Landfill Cell in rate base because this project will not be complete and in service until after the test year.. Pet Ex. 5 at 13. She testified that since Duke cannot begin disposing CCR into the landfill cell until the cell is complete and receives certification from IDEM that it meets all the operating permit conditions, the Cayuga Landfill Cell will not be used and useful for providing electric service before the test year ends. She recommended the capital expenditures associated with the Cayuga Landfill Cell, therefore, be removed from the forecasted test-year rate base, resulting in a $1,862,074 rate base reduction.. *Id*. at 13-14.

Regarding the TED Projects, CAC witness Inskeep recommend that the Commission deny the Company's request to include unidentified TED projects in its 2024 and 2025 forecast at this time. CAC Ex. 1 at 98. Mr. Inskeep testified these unidentified projects do not have costs that are known and measurable, and it is inappropriate and premature to approve recovery of tens of millions of dollars in projects that have not been identified, described, budgeted, or evaluated. *Id*. at 97.

c. **<u>Duke Energy Indiana Rebuttal</u>.**

Regarding the Cayuga landfill cell project, Ms. Lilly testified the project has not been included in the Company's rate base forecast because it is not projected to be in service by the end of the test year. Pet. Ex. 31 at 11. Ms. Lilly testified there is therefore no adjustment needed for Witness Armstrong's issue. *Id*.

Regarding the TED projects issue, Mr. Pinegar testified Duke Energy Indiana's economic development team has a proven track record, playing a key role in creating over 4,500 jobs and generating $6.4 billion in capital investment in 2023 alone. Pet. Ex. 28 at 24. Mr. Pinegar testified the Company plans for forecasted growth in its economic development efforts, and this approach allows the Company to remain responsive to potential economic growth while making infrastructure investments prudently. *Id.* at 26. Mr. Pinegar explained that future TED projects will be evaluated on their individual merits in the context of an official docketed proceeding before the Commission and will also be reviewed by the Indiana Economic Development Corporation. *Id*.

d. <u>Commission Discussion and Findings</u>.

OUCC witness Armstrong presented testimony objecting to including the construction costs associated with the Cayuga Landfill Cell project in rate base. Mr. Hill testified the test period forecast includes the costs to begin construction of Cayuga Landfill Cell 3. Ms. Lilly testified in rebuttal the Cayuga Landfill Cell is not included in the rate base forecast; however, Mr. Hill did not revise or clarify his direct testimony or address the issue in his rebuttal.

The Commission finds the capital costs associated with the Cayuga Landfill Cell should not be included in Step 1 or Step 2 rate base because this project will not be complete and in service until 2026. To the extent Petitioner has included construction costs for the Cayuga Landfill Cell in rate base, we find they should be removed.

[The OUCC does not taken a position with respect to the remaining issue to be addressed.]

B. <u>Edwardsport IGCC Plant</u>.

As they have done in other proceedings, including in Petitioner's last base rate case, intervenors Industrial Group, CAC, and Sierra Club raised numerous issues regarding Petitioner's Edwardsport Integrated Gasification Combined Cycle ("IGCC") Plant and its operations in this Cause. Intervenors Industrial Group and Sierra Club recommend the disallowance of certain O&M costs based on the parties' position that the Company should have already transitioned to operating the plant solely on natural gas. IG Ex. 1 at 4; Sierra Club Ex. 1 at 26. CAC witness Glick did not recommend the disallowance of specific costs, but argued Edwardsport has been expensive to operate and maintain and therefore the Company should plan to operate Edwardsport primarily on gas and only on coal when needed to manage coal oversupply. CAC Ex. 4 at 9-10. Further, Ms. Glick recommended the Commission should advise Duke that it will disallow recovery in future FAC proceedings of fuel costs above what it would cost to operate Edwardsport on the lowest operating cost resource unless there is documentation showing the decision was prudently incurred to manage fuel supply. *Id.* at 10. The OUCC did not take a position on the transition to natural gas issue, but recommended the Commission reject Duke's proposal to defer the CCS FEED study costs. Pub. Ex. 6 at 7. The Industrial Group and Sierra Club similarly recommended the Commission reject Petitioner's request to defer the CCS FEED Study costs in this proceeding. IG Ex. 1 at 4-5; Sierra Club Ex. 1 at 21-22.

As an initial matter, and given the diverse range of issues surrounding Edwardsport in this case, we will first address the position of the Industrial Group, CAC, and Sierra Club that Duke should cease operating the Edwardsport coal gasification facilities and instead operate the plant on natural gas. Our determination on this issue will inform our findings on the other Edwardsport-related topics at issue in this case, and thus we must consider this matter first. We will address the parties' specific recommendations related to the Edwardsport O&M costs, depreciation, other ratemaking issues, and the FEED study after our preliminary findings on this issue.

a. Edwardsport Transition to Natural Gas.

[The OUCC does not take a position on this issue.]

b. Edwardsport Capital Investments.

[The OUCC does not taken a position on this issue.]

c. Edwardsport O&M Costs.

[The OUCC does not take a position on this issue.]

d. Edwardsport Depreciation.

[The OUCC does not take a position on this issue.]

e. Other Ratemaking Issues.

[The OUCC does not take a position on this issue.]

f. CCS FEED Study.

i. Duke Energy Indiana Case-in-Chief.

As discussed by Company witnesses Hoeflich and Lilly, Petitioner was the recipient of a federal grant to assess the potential for CCS at Edwardsport, and the Company will be expected to cover approximately 50% of the FEED study costs. Pet. Ex. 5 at 21. As such, and in accordance with Indiana Code 8-1-2-10, Petitioner is requesting approval from the Commission to defer those costs in order to be able to present those costs for inclusion in rates in a future proceeding. *Id*.

ii. OUCC and Intervenors.

OUCC witness Wright recommended the Commission reject Duke Energy Indiana's proposal to defer the- CCS FEED study costs. Pub. Ex. 6 at 2-7. Mr. Wright testified the technological feasibility of such a system has not been determined, the final system would be very costly, and Duke has more affordable alternatives to comply with the recent EPA rule on carbon emissions. He testified the building of a CCS system would be inconsistent with Duke's latest IRP, which has Edwardsport switching fuels to only natural gas combustion by 2035. He testified the projected capital costs and annual operating expenses for a CCS system at Edwardsport would substantially increase the operating costs for Edwardsport. *Id*. Further, Mr. Wright argued that the benefits of the FEED study should extend beyond Indiana, and a portion of its costs should therefore be allocated to other Duke Energy jurisdictions. *Id.* at 3. Mr. Wright also cited to the Commission's order in Cause No. 43653 rejecting the previously proposed CCS study and testified the Commission's concerns over the study proposed in that proceeding due to the uncertainty regarding the technological feasibility, also apply to this FEED study proposal. *Id.* at 4. Mr. Wright quoted the Commission's prior order: "the evidence does not sufficiently support a finding that the measurable benefits of the carbon sequestration study merit the material cost to rate payers at this time" *Id.*

Industrial Group witness Gorman recommended Duke's proposal to defer the CCS FEED study costs be denied because Duke has not demonstrated that continued operation of the Edwardsport as an IGCC on syngas is economic. IG Ex. 1 at 4-5. Mr. Gorman testified switching to natural gas is more economic and would reduce carbon emissions by over 50%. *Id.* at 5. Mr. Gorman contends that rather than spending ratepayer money to investigate unproven CCS technology at Edwardsport, Duke should achieve carbon reduction by operating Edwardsport on natural gas. *Id*.

Sierra Club witness Comings testified it is unlikely that the cost of evaluating CCS at Edwardsport should be included in rates at any point and testified that if these costs are presented in such a future case, the Company should have to justify them by showing that continuing to pursue CCS was prudent. SC Ex. 1 at 22.

CAC witness Inskeep testified it is not reasonable for Duke Energy Indiana to spend $18.1 million on the CCS Feed study and receive approval to defer such costs. CAC Ex. 1 at 83. Mr. Inskeep testified pursuit of the CCS project is not consistent with the Company's most recently submitted IRP and is also not consistent with the Company's findings from its subsequent IRP modeling refreshes. *Id*. at 79-80. Further, Mr. Inskeep argued that CCS is not necessary to comply with the recently promulgated U.S. EPA greenhouse gas ("GHG") regulations. *Id.* at 80. He testified that while CCS is one possible compliance pathway, it is not the only option for reducing Edwardsport's emissions or for Duke Energy Indiana to achieve compliance. *Id*. Mr. Inskeep also cited to the Commission's Order rejecting the CCS study in Cause No. 43653 and testified the same concerns in that case are still present. *Id.* at 81-82. Mr. Inskeep further testified CCS at Edwardsport faces extraordinary financial, technological, geological, project execution, and policy uncertainty and risks. *Id.* at 83.

iii. <u>Duke Energy Indiana Rebuttal</u>.

On rebuttal, Company witness Hoeflich testified the current environment, which is marked by advancements in CCS technology, legislative support, and robust financial incentives, supports the prudence of moving forward with the FEED study at Edwardsport and the Company's deferral request. Pet. Ex. 41 at 10. He testified that significant advancements and changes have occurred since the Commission's decision in Cause No. 43653, and, as such, the uncertainties raised by the Commission in that cause have been alleviated. *Id.* at 7-8. He explained the significant advances and changes include the following: (1) a differing scope between the previous CCS work and the current work, where the current FEED study would focus on post-combustion capture, which captures CO2 following combustion in the power block and allows for CO2 capture regardless of whether the power block is firing syngas or natural gas, significantly enhancing the flexibility and applicability of the CCS technology; (2) the availability of federal funding and tax credits, as well as definitive legislation, when those were not available in Cause No. 43653; (3) advancements in CCS technology, as well as new legislation providing funding and regulatory options for CCS which clarifies the regulatory environment and underscores the importance in CCS technology. *Id.* at 8-9.

Mr. Hoeflich testified these factors collectively create a favorable context for moving forward with the FEED study at Edwardsport. Mr. Hoeflich also responded to OUCC witness Wright's argument that a portion of the study's costs should be allocated to other Duke Energy jurisdictions. *Id.* at 2. Mr. Hoeflich testified allocating the costs to other jurisdictions would not be appropriate, as the benefits of the FEED study are specific to Edwardsport due to its unique geological location in the Illinois Basin and operational characteristics, and Company affiliates will not have access to FEED study results that differ from those study results that are available to other utilities. *Id.* at 2. Further, regarding the OUCC and intervenors' recommendations that the Commission should not approve the Company's request to defer the FEED study costs due to feasibility and affordability concerns, Mr. Hoeflich testified the Commission retains the authority to review the outcomes of the FEED study and to determine the appropriateness of cost recovery in a future case. *Id.* at p. 10.

iv. Commission Discussion and Findings.

This Commission rejected Duke's request in Cause No. 43653 to defer costs on a CCS FEED study, finding that Duke's requested cost recovery for the study was not in the public interest. The Commission's decision was made, in part, due to the uncertainty regarding the technological feasibility of CCS at the Edwardsport plant and lack of any legislation from Congress regulating CO2. The Commission concluded that "the evidence does not sufficiently support a finding that the measurable benefits of the carbon sequestration study merit the material cost to ratepayers at this time." *Verified Petition of Duke Energy Indiana, Inc.,* Cause No. 43653, Final Order at 19-20 (Ind. Util. Reg. Comm'n Jan. 23, 2013).

The technological feasibility of CCS at Edwardsport will not be determined until the completion of the FEED study. While the EPA has completed a carbon emission rule for power plants, Congress still has not passed legislation specifically addressing CO2 emissions. Thus, the new carbon emissions rule is still vulnerable to the type of legal challenge that has overturned previous EPA rules on carbon emissions. If the rule were to survive legal challenge, Duke may have alternative means of compliance as discussed below. Given the high cost of installing and operating a CCS system and the availability of reasonable alternatives, the potential benefit of such a system, even if technologically feasible, may not outweigh the costs to ratepayers. Whether a CCS system would be used and useful, therefore, remains speculative in nature even if technologically (and financially) feasible.

Therefore, we deny Duke Energy Indiana's request to defer the CSS FEED Study costs. While we agree with Mr. Wright that the benefits of the FEED study would extend beyond Indiana, we need not enter findings on that issue, as we have determined to deny Petitioner's request.

C. Gibson Station Retirements.

[The OUCC does not take a position on this issue.]

D. Fuel Inventory.

The Company is proposing to include a representative balance of 45 days of inventory in rate base in this proceeding. Pet. Ex. 21 at 9. While certain intervenors and the OUCC took issue with the Company's proposal to track the actual inventory balance in the Company's quarterly FAC filings, as well as with the Company's fuel procurement strategies in general, no party took issue with the Company's proposal to include 45 days coal inventory in rate base. In the Company's last base rate case, the Commission found the Company's forecasted coal inventory level of 45 days was reasonable,[11] and we see no reason to deviate from that finding in this proceeding. As such, we find the Company's forecasted coal inventory level at 45 days is reasonable and should be included in the calculation of its rate base.

We will address the parties' positions on the Company's fuel inventory tracker proposal and its fuel procurement practices generally, in the Fuel and FAC-Related Issues section of this Order.

E. Regulatory Assets.

Petitioner's Exhibit 26, Attachment 26-C, Schedule RB3 details the balances of the regulatory assets included in rate base and the Commission Cause Number approving deferral and/or recovery of each. The only issue raised with respect to Petitioner's forecasted regulatory asset balance was with respect to the Company's TDSIC regulatory asset and the Industrial Group's recommendation that rate relief with respect to TDSIC expenditures should be specified as interim and subject to reconciliation pending the outcome of the Indiana Supreme Court's decision in the appeal of Cause No. 45647. We address this issue and the TDSIC Tracker (Tracker 65) under the Rate Adjustment Mechanisms section of this Order. We otherwise find Petitioner's forecasted regulatory assets and regulatory asset balances are reasonable and are approved.

F. Materials and Supplies Inventory.

Petitioner's forecasted materials and supplies ("M&S") inventory balance is set forth on Petitioner's Exhibit 26, Attachment 26-C, Schedule RB4. No party took issue with the Company's forecasted M&S inventory balance, and we find the forecasted amount is reasonable and is approved.

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[11] *Id.*, Order at p. 24.

G. **Prepaid Pension Asset**.

[The OUCC does not take a position on this issue.]

H. **Original Cost of Duke Energy Indiana's Rate Base**. Based upon the evidence presented in this case, and the findings discussed above, we find that the Step 1 jurisdictional net original cost of Duke Energy Indiana's rate base used and useful for the benefit of the public to be $11,895,709,000, comprised of the following elements:

Rate Base as of June 30, 2024	$11,905,203,000
Less OUCC Adjustments to June 30, 2024 Rate Base	($9,494,000)
NET UTILITY RATE BASE	$11,895,709,000

Further, we find that the Step 2 jurisdictional net original cost of Duke Energy Indiana's rate base used and useful for the benefit of the public is forecasted to be $12,600,376,000 at December 31, 2025, comprised of the following elements:

Net Electric Utility Plant in Service	$11,363,001,000
Fuel Inventory	$130,594,000
Regulatory Assets	$522,150,000
Materials and Supplies	$363,176,000
Prepaid Pension Asset	$221,455,000
NET UTILITY RATE BASE	$12,600,376,000

I. **Fair Value of Duke Energy Indiana's Rate Base**. Petitioner proposed that a fair return for purposes of this case be based on its weighted cost of capital times its original cost rate base. No party disputed that net original cost should be used as the fair value of Petitioner's utility plant in service in this case, or that a fair return for Petitioner should be based on its weighted cost of capital. Accordingly, we find that for purposes of this proceeding, Petitioner's fair value rate base is the same as its original cost rate base ($12,600,376,000), and that this fair value rate base should be used for purposes of Indiana Code § 8-1-2-6.

10. **Fair Rate of Return**.

A. **Capital Structure**.

a. **Duke Energy Indiana Case-in-Chief**.

Company witness Bauer presented Petitioner's current and projected capital structures. Mr. Bauer testified Duke Energy Indiana's current (as of August 31, 2023) financial capital structure is 47.6 percent long-term debt and 52.4 percent equity. Pet. Ex. 9 at 11. He further testified Duke Energy Indiana's capital structure is forecasted to be 47 percent long-term debt and 53 percent equity at the end of 2025 (the end of the Forward-Looking Test Period). *Id*. He testified this forecasted capital structure is consistent with the Company's target capital structure of 47 percent long-term debt and 53 percent equity for Duke Energy Indiana as it introduces an appropriate amount of risk due to leverage while minimizing the weighted average cost of capital to customers. *Id*. He further testified use of the forecasted capital structure in setting Duke Energy Indiana's rates will help Duke Energy Indiana maintain its credit quality. *Id*. Mr. Bauer testified this level is also consistent with the Company's target credit metrics needed to support its current credit ratings. *Id*. Ms. Sieferman testified and supported the Company's regulatory capital structure, incorporating Mr. Bauer's forecasted financial capital structure, as shown in Petitioner's Exhibit 26, Attachment 26-C, Schedule CS1. Pet. Ex. 4 at 10.

Ms. Sieferman explained that both the historic base period and forecasted Forward-Looking Test Period capital structure and cost of capital had been calculated using the same expanded regulatory presentation and the same methodology as has been used in recent years for the Company's last base rate case in Cause No. 45253, and all of the Company's trackers that include return on investment as part of the calculation and the same basic workpapers are being filed in this case as parties have seen in the various tracker filings. Pet. Ex. 4 at 10. She testified that the forecasted financial capital structure had been expanded to include traditional Indiana regulatory components including accumulated deferred income taxes, unamortized investment tax credits ("ITC"), and customer deposits. *Id*. Ms. Sieferman further testified the components of the Company's regulatory capital structure included cost rates computed in accordance with traditional Indiana regulatory practice (the embedded cost of long-term debt, average financial rates for ITC and zero cost of capital for accumulated deferred income taxes). *Id*. She explained the Company is proposing the Commission approve the Company's request to allow it to use a 5% interest rate on customer deposits included for the Forward-Looking Test Period, rather than the 2% currently effective rate, in order to better reflect the current interest rate environment. *Id*.

Ms. Sieferman also explained that, as has been standard practice in the calculation of the Company's regulatory capital structure for many years, the Company removed a long-term financing issuance specifically related to the liability assumed by the Company to pay the Rural Utility Service ("RUS") resulting from the settlement of litigation with Wabash Valley as well as removing the Gas Pipeline Lease Liability recorded as a capital lease for payments under a Gas Services Agreement with Southern Indiana Gas and Electric Company, Inc. d/b/a Center Point Energy Indiana South ("CenterPoint"), to provide gas to the Edwardsport IGCC plant via a gas pipeline which CenterPoint constructed and owns ("Gas Pipeline Lease"). Ms. Sieferman explained this was removed for ratemaking due to the treatment of the payments under the lease for both ratemaking and income tax purposes as a "pay-as-you-go" operating lease rather than a capital lease. *Id.* at 11-12. In addition, adjustments were made to eliminate certain deferred income taxes recorded on the Company's books for financial statement reporting purposes in accordance with the provisions of Statement of Financial Accounting Standards No. 109, but which have historically been excluded from the capital structure for ratemaking purposes, as well as to remove the deferred income taxes related to the Gas Pipeline Lease. *Id.* at 13. Ms. Sieferman explained that the Company also removed the accumulated deferred income tax balances associated with the non-jurisdictional RUS debt, which was removed from the capital structure, as well as with the Company's former manufactured gas plant ("MGP") sites. *Id.* at 13. As approved by the Commission in its IGCC-4S1 Order, the Company excluded deferred income taxes associated with the amount of the IGCC capital investment in excess of the agreed-upon Hard Cost Cap, including Additional AFUDC. *Id*. Ms. Sieferman explained an adjustment to remove the deferred income tax asset balances related to the Company's deferred utilization of ITCs and to include the unamortized balance of the regulatory liability for the excess deferred income taxes ("EDIT") amounts resulting from the 2017 Tax Cuts and Jobs Act and from other previous state and federal tax changes as an additional zero cost source of capital component in the calculation. *Id.* at 13-14. Finally, Ms. Sieferman explained that short-term debt has been excluded from the capital structure, consistent with previous Commission orders, including the Company's last base rate case in Cause No. 45253. *Id.* at 12. However, Ms. Sieferman testified the Company has included a $150,000,000 inter-company notes payable for Commercial Paper issued by Duke Energy Corporation on behalf of the Company that is part of the Company's permanent long-term financing. *Id*.

b. OUCC and Industrial Group.

OUCC witness D. Garrett testified he was not recommending an imputed capital structure for Duke Energy Indiana, but explained, however, this does not mean that no adjustment should be made to account for the discrepancy in financial risk between Duke Energy Indiana and the proxy group. Pub. Ex. 8 at 56. Industrial Group witness Gorman also did not recommend a different capital structure for the Company from the 53% equity and 47% debt structure Mr. Bauer projected. OUCC witness D. Garrett testified the average debt ratio of the utility proxy group reported in Value Line of 54% is notably higher than the Company's proposed debt ratio of only 47%. Pub. Ex. 8 at 53. As such, he recommended that a mathematical adjustment be made to his Capital Asset Pricing Model ("CAPM") results via the Hamada Model in order to effectively align the Company's capital structure with the proxy group's capital structure. *Id.* at p. 56. Further, Industrial Group witness Gorman testified the Company's projected ratemaking capital structure is reasonably comparable to the capital structure last approved for setting Duke's rates, however, he testified the Company's capital structure is relatively expensive compared to the ratemaking capital structure approved for other utilities. IG Ex. 1 at 71. Mr. Gorman compared the Company's projected capital structure to that of the State Authorized Common Equity Ratios from 2013 to 2024 and stated that "Duke's proposed ratemaking capital structure is more expensive and its common equity ratio is greater than that of other utilities." *Id.* at 72.

c. Duke Energy Indiana Rebuttal.

On rebuttal, Ms. Sieferman presented an update to the Company's Step 1 forecasted capital structure and cost of capital information to reflect actual balances as of June 30, 2024, and included the information in Exhibit 49, Schedules RA18 and RA19. Pet. Ex. 30 at 3. Ms. Sieferman testified while there were no notable differences between the forecasted June 30, 2024 capital structure and cost of capital data and the actual June 30, 2024 amounts being presented on rebuttal, there were some minor differences between the forecasted and actual data. *Id.* at 3. She testified the actual June 30, 2024, capital structure for Step 1 reflects an updated authorized rate of return of 6.39% compared to the estimate of 6.33%. Further, she testified the updated debt/equity ratio is 47.0%/53.0% vs the estimate of 47.3%/52.7%. Ms. Sieferman further testified the weighted average rate for long-term debt increased slightly from 4.86% to 4.89% due to higher than forecasted interest rates on a few debt issuances. *Id.* at 3-4. Ms. Sieferman testified most other items remained relatively unchanged. *Id.* at 4.

Ms. Sieferman testified this updated information will be used, in conjunction with the actual used and useful net plant in-service as of June 30, 2024, to calculate the Step 1 adjustments.

Id. She explained the actual June 30, 2024, data for used and useful net plant-in-service is discussed in the rebuttal testimonies of Company witnesses Graft and Lilly. *Id*.

Mr. Bauer and Company witness McKenzie responded to Mr. Garrett's mathematical adjustment to his CAPM results in order to effectively align the Company's capital structure with the proxy group's capital structure and explained why the comparison was not appropriate. Pet. Ex. 46 at 5; Pet. Ex. 35 at 43-47. Regarding Mr. Gorman's suggestion that the Company's capital structure is relatively expensive compared to the ratemaking capital structure approved for other utilities, Mr. Bauer testified that excluding the very limited number of rate cases in Q1 2024, there is a clear upward trend in equity ratios since 2020. Pet. Ex. 46 at 5-6. Further, Mr. Bauer testified that when comparing the projected capital structure of Duke Energy Indiana in this rate case to those of similar vertically integrated rate cases (excluding transmission only, distribution only cases, and limited issue rider cases), it is clear that the Company's 53% equity / 47% debt capital structure is reasonable.

d. <u>Commission Discussion and Findings</u>.

Duke Energy Indiana's proposal will incorporate its actual capital structure when implementing its Step 1 and Step 2 rate increases. No party recommended an imputed capital structure from the 53% equity and 47% debt structure Mr. Bauer projected. OUCC witness Mr. Garrett recommended a downward adjustment to his CAPM analysis for purposes of determining an appropriate ROE based on the Company's projected capital structure, but he did not recommend a different capital structure. This issue will be discussed later in this section where we discuss an appropriate ROE for the Company. Further, Mr. Gorman testified the Company's capital structure is relatively expensive compared to the ratemaking capital structure approved for other utilities. Mr. Bauer, in his rebuttal testimony, opines the Company's projected capital structure in this case is in line with those of similar vertically integrated rate cases.

The Commission considers a utility's actual capital structure when setting rates. While not using a hypothetical capital structure, the Commission is free to consider the reasonableness of the actual capital structure in its determinations. See *Public Service Comm'n of Ind. v. Ind. Bell Tel. Co.*, 235 Ind. 1, 130, N.E.2d 467 (Ind. 1955) ("Appellants could not arbitrarily disallow federal taxes which appellee had paid, or was obligated to pay, by assuming a tax saving under a capital structure which did not exist." 235 Ind. At 29, 30; 130 N.E.2d at 480). Although we are dealing with a future test period in this case and are using forecasted capital structures at this point in the process, the Company's proposal will incorporate its actual capital structure, not a forecasted capital structure, when implementing its Step 1 and Step 2 rate increases. Accordingly, we accept Petitioner's proposed capital structure in this case, subject to such compliance filings. We defer other considerations regarding the actual capital structure and the reasonableness of the structure and its relevance to the appropriate proxy group to the other appropriate sections of the Order.

B. <u>Cost of Debt</u>.

[The OUCC does not take a position on this issue.]

C. **<u>Cost of Equity</u>**.

a. **<u>Duke Energy Indiana Case-in-Chief</u>**.

Company witness Adrien McKenzie supported Petitioner's ROE and testified in support of the Company's projected capital structure. Mr. McKenzie recommended an ROE of 10.8% as a just and reasonable cost of equity. Pet. Ex. 10 at 3. However, as explained by Company witness Pinegar, the Company is proposing an ROE of 10.5% for rate mitigation purposes and to assist in establishing rates that are affordable and competitive across all customer classes. Pet. Ex. 1 at 31.

Mr. McKenzie explained that the standard for determining a just and reasonable ROE was set forth in the Supreme Court's findings in *Hope* and *Bluefield*.[12] Mr. McKenzie testified the Supreme Court's findings in *Hope* and *Bluefield* established that a just and reasonable ROE must be sufficient to: 1) fairly compensate the utility's investors, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. Mr. McKenzie testified these standards should allow the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system replacement and expansion, but the Supreme Court's requirements can only be met if the utility has a reasonable opportunity to actually earn its allowed ROE. *Id.* at 4-5.

In determining his recommended ROE, Mr. McKenzie first developed a proxy group of utility companies that face similar risk as Duke Energy Indiana. To that proxy group, he applied the discounted cash flow ("DCF") model, the CAPM, the empirical CAPM ("ECAPM"), an equity risk premium approach based on allowed ROEs, and reference to expected earned rates of return for electric utilities, which he testified are all methods that are commonly relied on in regulatory proceedings. *Id.* at 2. Mr. McKenzie further testified his evaluation takes into account the specific risks for the Company's electric operations in Indiana and Duke Energy Indiana's requirements for financial strength. *Id*. Further, consistent with the fact that utilities must compete for capital with firms outside their own industry, Mr. McKenzie corroborated his utility quantitative analyses by applying the DCF model to a group of low-risk non-utility firms. *Id*.

Mr. McKenzie presented the results of his DCF, CAPM, ECAPM, risk premium, and expected earnings analyses, ultimately recommending a cost of equity range for the Company's electric operations of 10.3% to 11.3%. *Id.* at 3. He concluded that the 10.8% midpoint of this range represents a just and reasonable cost of equity that is adequate to compensate the Company's investors, while maintaining the Company's financial integrity and ability to attract capital on reasonable terms. *Id*.

Mr. McKenzie testified that fundamental financial principles and capital market trends justify a significant increase to Duke Energy Indiana's authorized ROE. *Id*. He explained that because investors evaluate investments against available alternatives, the cost of equity and the cost of long-term debt are inextricably linked. *Id*. Mr. McKenzie's testimony demonstrated that long-term bond yields climbed dramatically beginning in 2022 and investors anticipate that these

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[12] *Bluefield Waterworks & Improvements Co. v. Pub. Serv. Comm'n*, 262 U.S. 679, 43 S.Ct. 675 (1923) and *Fed. Power Comm'n v. Hope Natural Gas, Co.*, 320 U.S. 591, 64 S.Ct. 281 (1944).

increases will be sustained. *Id*. Mr. McKenzie testified that the upward move in interest rates suggests that long-term capital costs—including the cost of equity—have increased significantly since the Commission determined that the unadjusted cost of capital for Duke Energy Indiana was 9.75%. *Id.* at 18. Mr. McKenzie further demonstrated in his testimony how other market conditions such as the exposure to rising interest rates, inflation, and capital expenditure requirements reinforced the importance of buttressing Duke Energy Indiana's credit standing. *Id*. Mr. McKenzie explained that when considering the potential for financial market instability, competition with other investment alternatives, and investors' sensitivity to risk exposures in the utility industry, credit strength is a key ingredient in maintaining access to capital at reasonable cost. *Id*.

He testified it would be unreasonable to disregard the implications of these current capital market conditions in establishing a fair ROE for Duke Energy Indiana. *Id*. He explained that if the upward shift in investors' risk perceptions and required rates of return for long-term capital is not incorporated in the allowed ROE, the results will fail to meet the comparable earnings standard that is fundamental in determining the cost of capital. *Id.* at 8-19. He testified that failing to provide investors with the opportunity to earn a rate of return commensurate with Duke Energy Indiana's risks will weaken its financial integrity, while hampering the Company's ability to attract necessary capital. *Id.* at 19.

Mr. McKenzie described his process of selecting a group of proxy companies to estimate the cost of equity for Duke Energy Indiana. *Id.* at 19-23. He then walked through his use of the DCF, CAPM, ECAPM, risk premium, and expected earnings analyses for estimated cost of equity. His application of the constant growth DCF model resulted in ROE estimates in the range of 9.1% to 10.6%. *Id.* at 42. His traditional CAPM analyses implied an average ROE of 11.5% after adjusting for the impact of firm size, and his ECAPM analysis resulted in an average cost of equity estimate of 11.7%, after incorporating the size adjustment corresponding to the market capitalization and of the individual utilities. *Id.* at 45, 48. His risk premium method analysis implied a current ROE of 10.79%, and his expected earnings method analysis suggested an average ROE of 11.3%. *Id.* at 51, 53. Mr. McKenzie also performed a DCF analysis for a group of low-risk firms in the competitive sector, which resulted in ROE estimates in the range of 11.0% to 10.5%. *Id.* at 8.

b. <u>OUCC</u>.

OUCC witness D. Garrett recommended an ROE of 9.0% for Duke Energy Indiana. Pub. Ex. 8 at 6. He arrived at his recommendation by considering the results of the DCF model and the CAPM model, which produce a range of 7.9% to 9.5%. *Id.* at 28, 39. Mr. Garrett described his DCF model analysis and the inputs he used for his model. *Id.* at 20-28. Mr. Garrett testified he considered two variations: one using analysts' growth rates and one using a sustainable growth rate, and the results of these models were 9.2% and 7.9%, respectively. *Id.* at 28. Regarding Mr. McKenzie's DCF model, Mr. Garrett testified Mr. McKenzie's DCF results are unreasonably high because he relied on long-term growth rates that are not sustainable. *Id.* at 28-29. Mr. Garrett testified Mr. McKenzie also eliminated several growth rates from his analysis that he deemed to be too low. *Id*. Mr. Garrett further testified he does not believe the DCF analysis Mr. McKenzie conducted on the proxy group of non-utility companies indicates an accurate cost of equity estimate for Duke. *Id.* at 29.

Mr. Garrett also described his CAPM analysis and the inputs he used for his model. *Id.* at 30-40. Mr. Garrett testified the CAPM result is 9.5%, however, all else is not equal, and the CAPM results as applied to Duke should be adjusted to account for the differences between Duke's low-risk capital structure relative to the proxy group. *Id.* at 40. Regarding Mr. McKenzie's CAPM analysis, Mr. Garrett testified Mr. McKenzie's CAPM cost of equity is overstated due to his overestimation of the ERP in addition to the unnecessary size adjustment. *Id*. Mr. Garrett testified Mr. McKenzie also conducts another unnecessary risk premium model in addition to the CAPM. *Id*. He further testified Mr. McKenzie then also adds a premium to his results to account for flotation costs, which affects his overall cost of equity results. *Id.* at 41.

Mr. Garrett also discussed the Company's capital structure. While Mr. Garrett did not recommend any adjustment to Duke Energy Indiana's projected capital structure, he proposed an adjustment to his CAPM results for the Company for purposes of aligning Duke's capital structure to the proxy group's capital structure. *Id.* at 56. Mr. Garrett used the Hamada Model to evaluate the effect of his capital structure recommendation on the Company's cost of equity, and, based on the model, indicated a cost of equity estimate (under the CAPM) of 8.9%. *Id.* at 58.

c. Industrial Group.

Industrial Group witness Gorman recommended the Commission award a return on common equity within his recommended range of 9.30% to 9.65%, with an approximate midpoint of 9.50%. IG Ex. 1 at 9. He supported his recommendation with DCF, risk premium and CAPM analyses. Mr. Gorman described his DCF model and the inputs he used for his analysis. *Id.* at 75-78. Mr. Gorman testified that based on the current market conditions, his DCF studies indicate a fair return on equity for Duke Indiana of 9.30%. *Id.* at 90. Mr. Gorman also described his risk premium model and testified that risk premium estimate based on observable risk premiums in the marketplace, and the expected outlook for moderation in long-term interest rates over the next couple years, support a risk premium based return on equity for Duke Indiana in the range of approximately 9.60% to 9.65%. *Id.* at 98. Mr. Gorman further described his CAPM model and described the inputs used in his CAPM. *Id.* at 99-106. Mr. Gorman testified his CAPM analysis indicates a CAPM return estimate of 11.04%. *Id.* at 106. He testified he rejected this CAPM because the beta estimate is abnormal and not reflective of the investment risk of utility companies. *Id*. Mr. Gorman testified he found a more reasonable result using a CAPM study using a normalized utility beta, which produces a return on equity of approximately 9.65%. *Id*.

Regarding Mr. McKenzie's analysis, Mr. Gorman testified the Company's recommended return on equity is excessive and should be rejected because it does not reflect the current low cost capital environment for low-risk regulated utilities. *Id.* at 111-112. Regarding Mr. McKenzie's DCF analysis, Mr. Gorman testified he disagreed with Mr. McKenzie's methodology to selectively exclude what he believes to be low or high outliers from the proxy group which has the effect of manipulating the results of the proxy group, as well as his use of growth rate estimates that substantially exceed the maximum long-term growth of the of the U.S. economy as measured by the GDP and cannot be sustained in the long-run. *Id.* at 114. Regarding Mr. McKenzie's traditional CAPM analysis, Mr. Gorman testified he disagreed with the derivation of his market risk premium of 7.3% because it does not reflect a reasonable estimate of the expected return on the market. *Id.* at 116. Further, he testified Mr. McKenzie's CAPM analyses are based on a size adjustment, which artificially inflates the fair and reasonable return for Duke Indiana. *Id*. He further testified Mr.

McKenzie's ECAPM analysis is not reasonable because it shares the same flaws as his traditional CAPM analysis. *Id.* at 121. Mr. Gorman also described his concerns with Mr. McKenzie's utility equity risk premium and revised the analysis to produce what he viewed as a reasonable result for Duke Energy Indiana. *Id.* at 125-127. He testified Mr. McKenzie's expected earnings analysis should be disregarded because an expected earnings analysis does not measure the return an investor requires in order to make an investment. *Id.* at 128.

d. **<u>Other Intervenors</u>**.

Walmart witness Perry, CAC witness Inskeep, and OUCC witness Eckert did not present independent analyses of the Company's cost of equity. However, each witness provided testimony regarding a fair ROE for Duke Energy Indiana. Mr. Perry testified the Commission should thoroughly and carefully consider the impact on customers associated with the ROE requested by the Company and should closely examine the Company's proposed ROE in light of the customer impact, the use of a future test year, the Company's currently approved ROE, and recent ROEs approved in Indiana and other jurisdictions. Walmart Ex. 1 at 4-5. Mr. Inskeep recommended the Commission approve an ROE at the lower end of the range the Commission determines reasonable, and also recommended the Commission further reduce the Company's ROE to incent the Company to approach future cases in a more cooperative and transparent spirit. CAC Ex. 1 at 6. Mr. Inskeep recommended a downward adjustment of 20 basis points from the ROE that the Commission finds should be authorized. Mr. Eckert also addressed affordability and the impact of regulatory mechanisms on Duke Energy Indiana's risks. Pub. Ex. 1 at 16-20.

e. **<u>Duke Energy Indiana Rebuttal</u>**.

On rebuttal, Mr. McKenzie testified the opposing parties' ROE recommendations defy common sense, given that the Company's capital costs have increased since its last rate proceeding, but the opposing parties recommend a reduction in the Company's ROE. Pet. Ex. 35 at 3. Mr. McKenzie explained that consideration of current interest rates and the allowed ROE for other electric utilities demonstrate that the ROE recommendations of the opposing parties are far too low. *Id.* at 3. Mr. McKenzie testified that significantly higher bond yields support the view that the cost of equity is higher now than in 2020 when Duke Energy Indiana's current ROE of 9.70% was established. *Id*. He further testified that adjusting national average allowed ROEs for 2019-Q2 2024 to account for the recent rise in bond yields implies a current cost of equity of 10.40%. *Id*. He further testified adjusting prior ROE determinations of the Commission for current bond yields implies a cost of equity of 10.46%. *Id*. Finally, adjusting Duke Energy Indiana's currently authorized ROE to recognize that interest rates are now higher implies a current cost of equity of 10.97%.

Further, Mr. McKenzie testified there are numerous flaws which undermine the ROE analyses of the opposing parties, including: (1) their reliance on a range of data that fails to reflect in investors' expectations and current capital market conditions; (2) Application of financial models in a manner that is inconsistent with their underlying assumptions; (3) Failure to evaluate model inputs and exclude illogical results; (4) Applications of the CAPM that fail to capture a realistic appraisal of investors' forward-looking expectations and ignore the implications of firm size, which biases the resulting cost of equity estimates downward; and (5) There is no basis to assume that investors reference long-term forecasts of Gross Domestic Product ("GDP") in developing their expectations for utilities and the opposing parties' reference to this data should be rejected. *Id.* at 5. Company witness Bauer testified regarding why Mr. Garrett's adjustment to his CAPM model to account for the difference between the Company's capital structure and that of his proxy group was not appropriate. Pet. Ex. 46 at 5. Further, Mr. McKenzie testified there is no basis for Mr. Inskeep's and Mr. Eckert's suggestion that regulatory mechanisms approved for Duke Energy Indiana differentiate the Company's risks from the proxy utilities. Pet. Ex. 35 at 3. Mr. McKenzie also testified the ROE penalty proposed by Mr. Inskeep is unsupported and would undermine investors' confidence in the regulatory environment in Indiana. *Id*. Further, Mr. McKenzie testified the criticisms of his size adjustment, market return calculation, ECAPM, risk premium method, expected earnings approach, and non-utility DCF analysis are without merit.

Mr. McKenzie testified that, taken as a whole, these shortcomings ensure the opposing parties' recommended ROEs fall well below a fair and reasonable level for Duke Energy Indiana. *Id.* at 5. He explained that the ROE is the primary signal to investors, not only with respect to attracting new capital investment, but also in supporting existing utility operations. *Id.* at 110. He testified if the utility is unable to offer a competitive ROE, existing shareholders will suffer a capital loss as investors take advantage of other, more favorable opportunities, and the utility's stock price would fall. Moreover, he testified as investors' confidence is undermined, the ability of utilities to access equity capital markets and expand investment will suffer. *Id*. Mr. McKenzie testified that while the Company would undoubtedly continue to meet its service obligations to customers, a downward-biased ROE would send an unmistakable signal to the investment community as they consider whether to commit capital in Indiana, and at what cost. *Id.* at 110-111.

f. **<u>Additional Evidence Received at Hearing</u>**

Mr. Pinegar acknowledged a significant driver of this rate case is coal combustion residuals and the treatment and costs for coal ash; to assure the recovery of future costs. Tr. at A- 66.

Mr. Pinegar confirmed (assuming the numbers reflected in Ms. Graft's Table 3 were correct) when adding the Return on Rate Base Increase of 2.7%; the Rate of Return, Financing Costs of 9.5%; and Depreciation Rates of 4%, those increases total 16.2% (the approximate total increase in base rates requested in this base rate case). Tr. at A- 71 (see also, Pet. Ex. 3, Direct Testimony of Christa L. Graft, pp. 8, 9 & Table 3).

g. **<u>Commission Discussion and Findings</u>**.

In setting the rate of return for Duke Energy Indiana, the Commission's decision must be framed by *Bluefield Waterworks* & *Improvements Co. v. Pub. Serv. Comm'n,* 262 U.S. 679, 43 S.Ct. 675 (1923) and *Fed. Power Comm'n v. Hope Nat. Gas, Co.,* 320 U.S. 591, 64 S.Ct. 281 (1944).[13] The general standards these cases established require a cost of common equity set by the Commission be sufficient to establish a rate of return that will maintain the utility's financial integrity, attract capital under reasonable terms, and be commensurate with the returns that could be earned in investments in other enterprises of comparable risk.

[13] *See also Indianapolis Power & Light Co.,* Cause No. 44576, p. 41, 2016 WL 1118795 *43 (IURC March 16, 2016).

More recently, we reiterated:

> The Commission is also mindful that "the cost of common equity cannot be precisely calculated and estimating it requires the use of judgment." *Indiana-American Water Co.,* Cause No. 44022, p. 35 (June 6, 2012). Due to this lack of precision, the use of multiple methods is desirable, in part, because no one method will produce reasonable results under all conditions and in all circumstances.

In Re Petition of Ind. Amer. Water, Cause No. 45870, at p. 42 (Ind. Util. Regul. Comm'n Feb. 14, 2024) and *In re Petition of Ind. Mich. Power Co*., Cause No. 45235, at p. 40 (Ind. Util. Regul. Comm'n Mar. 11, 2020).

The Commission is also mindful of the strengths and weaknesses of the various models typically used to estimate a utility's cost of common equity, and we find that with appropriate and reasonable inputs, models such as the DCF and CAPM can produce reasonable estimates of a utility's cost of common equity. Consistent with the standards in *Hope* and *Bluefield,* as well as under Indiana law, Duke Energy Indiana's authorized return on equity should be reasonable given the totality of the circumstances.

In addition to the recommendations of these experts and while not determinative of the ROE in this case, we note the ROE awarded Indiana's vertically-integrated electric utilities outside of settled cases has been trending lower . *See, e.g., Ind. Mich. Power Co*., 10.2% in Cause No. 44075 (2013); *Indianapolis Power & Light Co*., 9.85% in Cause No. 44576 (2016); *N. Ind. Pub. Serv. Co. LLC*, 9.75% in Cause No. 45159 (2019); *Ind. Mich. Power Co*., 9.70% in Cause No. 45235 (2020); and Petitioner's prior ROE of 9.70% authorized in Cause No. 45253 (2020).

We are not persuaded Mr. McKenzie appropriately considered the risk mitigation associated with various regulatory mechanisms and ratemaking components, including Duke Energy Indiana's use of a future test year in this proceeding; the riders and/or trackers approved for Duke Energy Indiana; and the current recovery of future costs (prepayments), resulting from including such costs (like CCR costs and PMC costs)[14] being included in net salvage for purposes of the depreciation rates. His recommendations are also inconsistent with recent COE decisions approved nationwide for investor-owned electric utilities, as presented by Walmart witness Perry's testimony, and inconsistent with recent Commission orders. Walmart Ex. 1 at 9-12. While the Commission does not base its COE conclusion on national averages, the evidence presented demonstrates the trend in approved COEs for vertically-integrated utilities, both in Indiana and nationwide, is lower than Duke Energy Indiana's requested COE. We recognize financial strength is important for a utility to attract capital at a reasonable cost in order to make the investment necessary to fulfill its service obligations, but the evidence demonstrates investor-owned utilities similar to Duke Energy Indiana and located in similar regulatory jurisdictions have been awarded reasonable and fair COEs that are below Duke Energy Indiana's requested range. As the Commission has said:

[14] And upon which, Duke Energy Indiana is requesting additional contingency and escalation.

> The ratemaking process involves a balancing of all these factors and probably others; a balancing of the owner's or investor's interest with the consumer's interest. On the one side, the rates may not be so low as to confiscate the investor's interest or property; on the other side the rates may not be so high as to injure the consumer by charging an exorbitant price for service and at the same time giving the utility owner an unreasonable or excessive profit.

Petition of Ind. Mich. Power Co., Cause No. 44075, pp. 47- 48 (Ind. Util. Regul. Comm'n Feb. 13, 2013), citing *Pub. Serv. Comm'n of Ind. v. City of Indianapolis*, 131 N.E.2d 308, 318 (Ind. 1956).

Our determination appropriately considers Petitioner's specific risk characteristics, such as the mitigation of risk associated with Petitioner's use of regulatory mechanisms, including a forecasted test year in this proceeding and the multiple trackers approved for Duke Energy Indiana, and the future costs the Company will receive through depreciation rates. The effect of these tracking mechanisms is to reduce the uncertainty of the earnings that an investor can expect. See *Ind. Mich. Power Co.*, Cause No. 44075, pp. 42-43..

The Commission has considered the analytical results based on a proxy group of electric utilities, as well as the risk factors associated with Duke Energy Indiana's generation portfolio and environmental regulations and its planned capital expenditures, among other factors. We find these risk factors are, however, lessened by the future test year Duke Energy Indiana used; the trackers Duke Energy Indiana is requesting and/or has in place; and the prepayment of future closure costs and environmental compliance costs included with the closure costs, upon which Duke Energy Indiana has requested escalation and contingency. All of these factors serve to reduce risks of uncertainty Duke Energy Indiana would otherwise face. As we have previously stated:

> Trackers that adjust rates for incremental investments or for costs that are nearly certain to be increasing serve to adjust the base line earnings for post rate case changes and address issues primarily associated with regulatory lag. Trackers that adjust rates for cost changes that are more unknown and that are equally likely to decrease or increase address the rise of volatile earnings results. The general effect of these trackers reduces the uncertainty of earnings that an investor can expect.

Indianapolis Power & Light Co., Cause No. 44576, p. 42 (Ind. Util. Regul. Comm'n Mar. 16, 2016)

Having taken into consideration the foregoing factors and observable market data reflected in the record, including current and expected long-term capital market conditions, an assessment of the current risk premium built into current market securities, expected inflation rates, and a general assessment of the current investment risk characteristics of the electric utility industry, combined with a thorough understanding of the Indiana jurisdiction and its risk mitigation ratemaking mechanisms, and Duke Energy Indiana in particular, the Commission finds a reasonable range for Petitioner's COE is 8.75% to 9.25%. Taking into consideration all the evidence presented, the Commission finds and concludes a 9.00% COE is fair and reasonable.

D. Overall Weighted Average Cost of Capital ("WACC"). Petitioner's actual capital structure and WACC as of June 30, 2024 and Petitioner's projected capital structure and WACC as of December 31, 2025 were included in Petitioner's Exhibit 49 and its supporting schedules. The overall WACC was calculated by summing the component costs of the capital structure, with each component weighted by its respective proportion to total capitalization. Based on our discussion and findings above, we find Duke Energy Indiana's actual WACC as of June 30, 2024 and its projected WACC as of December 31, 2025 to be 5.70% and 5.87%, respectively, computed as follows:

Description	June 30, 2024 Capitalization	Ratio	Cost	Weighted Cost
Common Equity	$5,328,053,000	41.79%	9.00%	3.76%
Long Term Debt	4,778,124,000	37.48%	4.87%	1.83%
Deferred Income Taxes	2,427,696,000	19.04%	0.00%	0.00%
Unamortized ITC – Crane Solar	11,231,000	0.09%	7.04%	0.01%
Unamortized ITC – 1971 & Later	379,000	0.00%	7.04%	0.00%
Unamortized ITC – Markland Hydro	35,947,000	0.28%	7.04%	0.02%
Unamortized ITC – Camp Atterbury Solar	476,000	0.01%	7.04%	0.00%
Unamortized ITC – Advanced Coal (IGCC)	126,891,000	1.00%	7.04%	0.07%
Unamortized ITC – Purdue CHP	4,055,000	0.03%	7.04%	0.00%
Customer Deposits	35,929,000	0.28%	5.00%	0.01%
Total	$12,748,781,000	100.00%		5.70%

Description	December 31, 2025 Capitalization	Ratio	Cost	Weighted Cost
Common Equity	$5,959,031,000	43.28%	9.00%	3.90%
Long Term Debt	5,278,772,000	38.34%	4.87%	1.87%
Deferred Income Taxes	2,325,599,000	16.89%	0.00%	0.00%
Unamortized ITC – Crane Solar	11,231,000	0.08%	7.06%	0.01%
Unamortized ITC – 1971 & Later	94,000	0.00%	7.06%	0.00%
Unamortized ITC – Markland Hydro	35,947,000	0.26%	7.06%	0.02%
Unamortized ITC – Camp Atterbury Solar	476,000	0.01%	7.06%	0.00%
Unamortized ITC – Advanced Coal (IGCC)	116,978,000	0.85%	7.06%	0.06%
Unamortized ITC – Purdue CHP	4,055,000	0.03%	7.06%	0.00%
Customer Deposits	35,929,000	0.26%	5.00%	0.01%
Total	$ 13,768,112,000	100.00%		5.87%

11. Environmental Sustainability.

Company witness Pinegar testified the Company is continuing its progress to an orderly transition to its clean energy future and explained that coal-fired steam generation has been retired and will continue to be retired in a manner that prioritizes reliability and affordability. Pet. Ex. 1 at 13. Mr. Pinegar described why coal combustion residuals are a significant issue in this case and testified that if environmental sustainability is to be the pillar that the General Assembly has directed, then recovery of prudently incurred costs to sustain the environment must be provided. *Id*. Mr. Pinegar explained that in this case, the Company is seeking to recover through depreciation rates the costs that were initially requested under the federal mandate statute but were reversed by the Court of Appeals. *Id*. He testified the Company is also seeking a path forward to assure recovery of future closure costs. *Id*.

OUCC witness Eckert testified that environmental sustainability of electric utility services refers to efforts to reduce environmental effects of energy production, distribution, transportation, and utilization on air quality, and water quality. Pub. Ex. 1, p. 14. Environmental sustainability is included in the Five Pillars. He stated that environmental sustainability includes the effect of environmental regulations on the cost of providing electric utility service and the demand from customers for environmentally sustainable sources of electric generation, referencing I.C. § 8-1-2-0.6(5)(A) and (B). *Id.*

Mr. Eckert stated that energy systems and resources can maintain current operations and facilitate the transition to renewable energy or other carbon-neutral energy without jeopardizing the energy needs or environment for future generations. He noted that Duke had retired Gallagher Units 2 and 4, which were coal-fired generating units. Mr. Eckert provided a chart showing when Duke intends to retire its remaining coal-fired generating units.

A. <u>CCR Costs</u>.

a. <u>Duke Energy Indiana Case-in-Chief</u>.

Company witness Riley testified regarding the CCR costs the Company is including in this proceeding. Pet. Ex. 13 at 34-35. Mr. Riley testified Duke Energy Indiana has included estimated future coal ash-related costs in the Company's 2023 decommissioning study. *Id*. He testified those costs include closure costs for future closures of the Company's CCR Units not previously included in Cause Nos. 45253 S1 and 45940 ($131.4 million). Mr. Riley explained that in this proceeding, the Company is also requesting the Commission reflect in the calculation of depreciation rates the $92 million in costs incurred between January 1, 2019, and November 3, 2021, which were authorized by the CPCN under the Federal Mandate Statute that was later reversed by an Indiana Court of Appeals decision. *Id*. Mr. Riley explained that these costs should be recorded as costs of removal pursuant to the FERC Uniform System of Accounts and that the proper entry would be to debit FERC Account 108 (Accumulated Depreciation). This entry has the effect of reducing the total Accumulated Depreciation, which increases rate base and which also increases the remaining net book value of the assets that, for purposes of setting depreciation rates, must be recovered over the assets' remaining useful lives.

Company witness Hill testified regarding the future CCR costs and supported the prudency and reasonableness of the costs. Pet. Ex. 19 at 30. Further, Company witness Spanos explained how the CCR costs have been reflected in the calculation of his recommended depreciation accrual rates. Pet. Ex. 12 at 14.

b. <u>OUCC and Intervenors</u>.

OUCC witness Armstrong recommended the Commission deny Duke's request to recover CCR closure costs that predated the Commission's Order in Cause No. 45253 S1 because the propriety of recovering these costs was determined in the appeal from the 45253 S1 Order, from which no petition to transfer was filed. Pub. Ex. 5 at 24. Ms. Armstrong testified the OUCC opposes Duke's recovery again of $92,075,402 in past CCR closure costs through traditional cost of removal accounting in base rates. She explained that while the Commission originally approved recovery of these costs as part of the overall Coal Ash Compliance Plan that Duke presented in Cause No. 45253 S1, the Indiana Court of Appeals reversed that Order, finding these costs were ineligible for recovery under the applicable Federal Mandate Statute in effect at that time.[15] She noted that following the Court's reversal and remand to the Commission, Duke calculated the refunds Petitioner owed its ratepayers and agreed to begin refunding these dollars in Cause No. 42061 ECR 39. The refund of these costs has been substantially completed through subsequent ECR proceedings and was not effectuated to collect these dollars again under a different—but not new-- theory.

Ms. Armstrong stated that although she is not an attorney, her understanding is that the $92.1 million ratepayer recovery Duke Energy Indiana is seeking again has already been litigated and rejected by the Indiana Court of Appeals. She noted that Petitioner has almost finished the refund occasioned by the Court of Appeals' reversal. Ms. Armstrong maintained that collecting these dollars from ratepayers a second time is unfair and unprecedented. She indicated the OUCC will separately address the legal arguments supporting its position and the impropriety of Duke's proposed second recovery.

Ms. Armstrong also noted that Duke Energy Indiana confirmed it inadvertently escalated the $92.1 million when these costs were included in its depreciation study, increasing the total amount included in the study to $122,575,419. She testified that Duke stated this amount would be corrected in its rebuttal testimony, but this correction will not alter the impropriety of Duke now seeking the same dollars again from its ratepayers.

Ms. Armstong testified the OUCC did not take issue with Duke Energy Indiana's proposal to recover future CCR closure costs through decommissioning. She stated that traditional depreciation accounting is the standard way future decommissioning costs are recovered and allows Duke to collect the amount reasonably necessary to close these sites and fund an appropriate depreciation reserve. She indicated traditional depreciation accounting also reduces intergenerational equity issues and better aligns costs with customers who received the benefits associated with these assets. Consistent with OUCC witness David Garrett's recommendations, Ms. Armstrong opposed the inclusion of contingency costs, and she deferred to Mr. Garrett as to why it is inappropriate to include contingency costs in decommissioning estimates. She also noted that since Duke Energy Indiana does not expect to incur these costs until the 2031-2045 time frame, these costs may be better addressed in a future rate case.

OUCC witness D. Garrett testified there is an error in the Company's depreciation study regarding the calculation of production net salvage rates related to the escalation factors, and therefore the approximately $92.1 million of CCR costs were escalated and double counted. Pub. Ex. 9 at 13.

[15] *Ind. Off. of Util. Consumer Couns. v. Duke Energy Ind., LLC*, 204 N.E.3d 947 (Ind. Ct. App. 2023), *reh'g den.*

Regarding the $92.1 million, Industrial Group witness Andrews testified that as part of its decommissioning cost estimates, the Company is attempting to recover coal ash asset retirement obligation costs that have already been incurred. IG Ex. 2 at 4. Mr. Andrews testified he is not aware of Duke having authority to recover the costs prior to 2022, as the Indiana Court of Appeals reversed the Commission's decision approving these costs. *Id.* at 22. Further, Mr. Andrews testified Duke has both inappropriately escalated these costs and has double counted them in their calculations. *Id.* at 4. Mr. Andrews explained that Mr. Spanos has an error in the workpaper that supports Table 3 of the depreciation study, which actually includes the Coal Ash ARO costs twice in the terminal net salvage rate calculations. *Id.* at 22. Mr. Andrews testified that for this $92.1 million of incurred costs, Duke is actually attempting to recover $245 million through depreciation rates. *Id.* at 4. Mr. Andrews recommended the costs, specifically $245.15 million, should be removed from the terminal net salvage rate calculations. *Id*.

CAC witness Inskeep also recommended the Commission deny cost recovery for all CCR costs incurred by the Company that were previously disallowed by the Court of Appeals. CAC Ex. 1 at 72. Mr. Inskeep testified the Commission should not accept Duke's invitation to ignore a clear judicial decision that disallowed cost recovery for these very costs. *Id*. Mr. Inskeep further testified the Commission should also reject the Company's proposed novel cost recovery theories that have not been authorized by the General Assembly. *Id*.

c. <u>Rebuttal</u>.

On rebuttal, Mr. Riley contended it is appropriate for the Company to recover the CCR costs of $92.1 million that were incurred from January 2019 through November 2021 in this proceeding. Pet. Ex. 38 at 2. He explained that in the Indiana Court of Appeals' Opinion from Cause No. 45253 S1, the Court concluded CCR-related costs incurred prior to the Commission's approval of the Company's CPCN could not be recovered under the Federal Mandate Statute (Ind. Code § 8-1-8.4). *Id*. Mr. Riley testified the Court left the Company's CPCN intact, which he interpreted as indicating conceptual approval to recover CCR-related costs. *Id*. Mr. Riley explained that no party alleges these CCR costs were imprudent; however, only Duke asserts there are other acceptable approaches for capital cost recovery than what the Court rejected. *Id.* at 2-3. Per Mr. Riley, there are a numerous methods for recovery of these costs, including a traditional cost of removal methodology, as well as under the Federal Mandate Statute. While the Court of Appeals determined he Federal Mandate Statute was not the appropriate recovery method for the $92 million in pre-Order costs, he asserted the Court did not address the reasonableness and prudence of these costs or foreclose their recovery. *Id.* at 3.

Ms. Lilly's rebuttal explained that importantly, this entry to debit Account 108 has not yet been made, as Duke deemed the costs impaired upon the issuance of the Court of Appeals' decision. Pet. Ex. 31 at 15. Petitioner is awaiting a final non-appealable Order in this Cause to make this entry. As such, the entry will not be reflected in Step 1 rates (which use a June 30, 2024, cutoff for net plant in service). It will, however, be reflected in Step 2 rates if approved, subject to actual net plant in service at December 31, 2025, not exceeding the forecasted net plant in service at December 31, 2025.

d. <u>Commission Discussion and Findings</u>.

Duke now seeks recovery for the second time of $92.1 million in CCR costs incurred from 2019 to 2021. These costs are the same as those Duke asked the Commission in Cause No. 45253 S1 to recover. These are also the same costs the Court of Appeals concluded the Commission erroneously approved Duke recovering in the Commission's Order in Cause No. 45253 S1 under the Federal Mandate Statute (Ind.Code ch. 8-1-8.4-1, *et seq*.). Petitioner incurred all of these CCR costs before our 45253 S1 Order dated November 3, 2021. *Ind. Off. of Util. Cons. Counselor v. Duke Energy Ind., LLC*, 204 N.E.3d 947 (Ind. Ct. App. 2023). Importantly, these are also the same dollars Duke agreed should be refunded to its ratepayers via the ECR proceedings after the Court's Opinion, commencing in ECR 39. Now Duke, effectively, is asking the Commission to approve recouping that refund. We find it would be inappropriate for the Commission to do so, as discussed below.

Duke's CCR cost recovery is now couched in this case as seeking to recover these costs through depreciation rather than the Federal Mandate Statute. Duke acknowledges the Court's decision but maintains the Court "left the Company's CPCN intact" as though that would give Duke another bite at the CCR recovery 'apple' three years later after the agreed refund. Notwithstanding whether the CPCN was or was not left 'intact', the Court disagreed with Duke's position "that a utility is entitled to recover not only costs incurred while the CPCN proceeding is pending, prior to regulatory approval, but also pre-petition costs associated with preparing the application and the supporting evidence needed to satisfy the statutory factors." *Ind. Off. of Util. Cons. Counselor*, 204 N.E.3d at 955-56. Thus, the Court deemed the CCR costs incurred from January 1, 2019, to November 2, 2021, as ineligible for the recovery Duke sought in Cause No. 45253 S1.

Duke also asserts that the Court did not foreclose Duke from seeking the $92.1 million through "any other methods." Pet. Ex. 38 at 11. Duke was charged with seeking recovery through whatever theories Petitioner deemed appropriate, and when the Court rejected such recovery, if there were other bases Duke raised for such recovery, Duke did not pursue the propriety of these by filing a petition to transfer. Instead, Duke accepted the Court's reversal and remand which were not accompanied by an invitation to pursue the same CCR costs again years later under a different theory, especially after having willingly refunded these dollars to Indiana ratepayers. Duke's assertion that it is now free to use any other methods to pursue recovery of these same CCR costs was not endorsed by the Court, and we find it is not appropriate.

Duke is precluded from bringing this claim again under principles of *res judicata* and collateral estoppel. The United States Supreme Court has discussed these intertwined precepts.

> [I]ssue preclusion (sometimes called collateral estoppel) …precludes a party from relitigating an issue actually decided in a prior case and necessary to the judgment. The second doctrine is claim preclusion (sometimes itself called res judicata). Unlike issue preclusion, claim preclusion prevents parties from raising issues that could have been raised and decided in a prior action—even if they were not actually litigated. If a later suit advances the same claim as an earlier suit between the same parties, the earlier suit's judgment "prevents litigation of all grounds for, or defenses to, recovery that were previously available to the parties, regardless of whether they were asserted or determined in the prior proceeding." *Brown v. Felsen*, 442 U.S. 127, 131, 99 S.Ct. 2205, 60 L.Ed.2d 767 (1979); see also Wright

> & Miller § 4407. Suits involve the same claim (or "cause of action") when they "'aris[e] from the same transaction,'" *United States v. Tohono O'odham Nation*, 563 U.S. 307, 316, 131 S.Ct. 1723, 179 L.Ed.2d 723 (2011) (quoting *Kremer v. Chemical Constr. Corp.*, 456 U.S. 461, 482, n. 22, 102 S.Ct. 1883, 72 L.Ed.2d 262 (1982)), or involve a "common nucleus of operative facts," Restatement (Second) of Judgments § 24, Comment *b*, p. 199 (1982) (Restatement (Second)).

Lucky Brand Dungarees, Inc. v. Marcel Fashions Grp., Inc., 590 U.S. 405, 411-12, 140 S.Ct. 1589, 206 L.Ed.2d 893 (2020).

The difference between Cause No. 45253 S1 and this case is the recovery mechanism Duke proffers: first under the Federal Mandate Statute and now through depreciation. Duke *could* have pursued recovery through depreciation in Cause No. 45253 S1. As the U.S. Supreme Court noted above, litigation involves the same claim when the litigation 'arise[s] from the same transaction.' In both this Cause and Cause No. 45253 S1, ratepayer recovery was requested for $92.1 million in CCR remediation incurred between 2019 and 2021. We find this "common nucleus of operative facts" also bars recovery upon Duke's second request in this Cause for the same relief.

With respect to recovery of future CCR costs, no party challenged the estimated costs Duke witness Hill presented that were included in the decommissioning studies Mr. Kopp prepared. Ms. Armstrong objected to adding contingency to the estimates, as did other OUCC and intervenor witnesses. These issues will be addressed in our discussion and findings concerning the depreciation study elsewhere in our Order. Also, initially, the Company intended to not include post closure maintenance ("PCM") costs in the depreciation study as one of the affordability measures and provided testimony from several witnesses, including Mr. Spanos, to that effect. However, upon discovering that Duke witness. Spanos did not remove the PCM costs from his study (although Mr. Kopp removed them from the decommissioning study upon which Mr. Spanos indicated reliance), Duke revised its witnesses' testimony. Thus, ultimately, the PCM costs are included in Duke Energy Indiana's request in this proceeding. They are supported by Mr. Kopp's decommissioning study provided in rebuttal. Pet. Ex. No. 37, Attachment 37-B(JJS). No party took issue with the Company recovering these PCM costs or the accounting treatment Duke witness Riley proposed. Accordingly, the Commission finds recovery of the PCM costs pursuant to the accounting treatment Mr. Riley described is appropriate and should be approved.

B. Coal Ash-Related Insurance Proceeds.

a. Duke Energy Indiana Case-in-Chief.

Company witness Hill testified regarding the Company's proposal for sharing coal ash-related insurance proceeds with customers. Pet. Ex. 19 at 26-28. Mr. Hill described at a high-level the settlements the Company reached with AEGIS and AmRe. *Id*. Mr. Hill testified the Company is proposing to credit retail jurisdictional customers with their proportionate share of the insurance proceeds, net of related expenses, through its future ECR proceedings. *Id*. Mr. Hill explained that the Company's litigation is ongoing and testified to the extent there are additional proceeds recovered, the Company will similarly share those proceeds through its future ECR proceedings. *Id*. Mr. Hill explained how the Company is proposing to calculate customers' proportionate share of the insurance proceeds. He testified Duke Energy Indiana is proposing to first credit customers with the amount of the insurance policy costs that were included in retail rates at the time those policies were in effect then, after that credit, the Company will then ascertain its overall closure-related expenses incurred as a result of its past coal ash management and determine the portion of those costs included in retail customers' rates. *Id*. Mr. Hill explained that once that is determined, the Company is proposing to apply that proportion to its coal ash-related insurance proceeds. *Id*.

b. <u>OUCC and Intervenors</u>.

Ms. Armstrong testified the OUCC opposes Duke Energy Indiana's proposal to share insurance settlement proceeds with ratepayers, asserting that Duke's ratepayers should receive the full proceeds of these and future settlements. Pub. Ex. 5 at 8, 9, and 24. She noted that ratepayers previously paid for the premiums associated with these insurance policies in past rates and paid for these risks. *Id.* Therefore, Ms. Armstrong reasoned that ratepayers bore the burden of the costs to address the risks which the proceeds now cover. *Id*. By contrast, she noted Duke Energy Indiana's shareholders bear no risk in this regard and therefore should not be given a windfall in the form of insurance proceeds. *Id*. She argued it would be inequitable to deprive the party who paid for the premiums of the proceeds received as a result of the coverage purchased. She also noted that Duke Energy Indiana's ratepayers are not receiving return of premiums where the risks insured against were not realized, and proceeds of insurance were not received. *Id*.

She noted that although Duke Energy Indiana's proposal attempts to address this issue by crediting ratepayers for these past premiums, those payments pale in comparison to the hundreds of millions in CCR costs Duke Energy Indiana will recover from ratepayers. She asserted that these policies were not rescinded, and Duke Energy Indiana should not now be permitted to enhance shareholder profit to the detriment of ratepayers. She noted that Duke Energy Indiana's ratepayers are currently paying, and will continue to pay for several more years, significant CCR closure costs through rates, and these proceeds will alleviate the impact of these costs and address utility rate affordability. *Id*.

She highlighted Duke Energy Indiana's stated commitment to provide any net proceeds from future insurance claims related to the CCR or Indiana Department of Environmental Management ("IDEM") Rule compliance to its customers to help mitigate the expenses of closure plans, which Duke Energy Indiana had made in Cause No. 45253 S1. *Id*. at 10-11. She stated the Commission acknowledged this and required Duke Energy Indiana to provide regular status updates on insurance claims in ECR filings. She criticized Duke in that it did not provide updates in ECR-40 and ECR-41 that it had reached these settlements with insurance companies and had waited until this rate case to inform the Commission and interested parties of the settlements. She noted that because of this delay, Duke Energy Indiana's ratepayers are unlikely to see the benefits of these settlements until 2025. *Id*. She reasoned that since Duke Energy Indiana has benefited financially from retaining these funds, it should also include interest in its calculation of the credit to appropriately compensate ratepayers with the full benefits of the settlements. *Id*.

c. <u>Duke Energy Indiana Rebuttal</u>.

On rebuttal, Mr. Hill testified the OUCC's and CAC's positions regarding the insurance proceeds ignores the fact that the Company has incurred prudent and reasonable coal ash closure costs that it cannot recover through rates. Pet. Ex. 42 at 8. Mr. Hill testified given that this has occurred, it is a reasonable request for Duke Energy Indiana to make in this proceeding to allocate the insurance proceeds between customers and the Company in the same proportion as the incurred coal ash closure costs are included in rates after also crediting customers with any insurance premiums previously paid through rates. *Id*.

d. **Commission Discussion and Findings**.

The Company complains that not all of its CCR remediation costs have been recoverable through rates. The Company had not filed a rate case for 16 years prior to its 2019 petition. Mr. Riley testified that at the end of 2014, the EPA provided final rules addressing disposal of coal ash residuals. See Pet. Ex. 13 at 32. In March 2016, the Company filed Cause No. 44765 aware of the costs it would incur as a result of the new CCR rule, but neither included all of its costs in that proceeding, nor followed traditional ratemaking then by seeking CCR costs as costs of removal in a depreciation study, as the Company now does. The Company chose to pursue the additional benefits afforded under the Federal Mandate Statute without following the statutory requirement of pre-approval, and it chose not to seek traditional ratemaking treatment for all of its future CCR costs until this filing, although nothing prevented the Company from doing so. The Company incurred the risk of its decisions, over which customers had no control, and seeks to pass those consequences of its risk-taking to customers by retaining substantial insurance proceeds paid for by customers.

Ratepayers previously paid for the premiums associated with these insurance policies in rates and paid for these risks covered by the policies under which settlement proceeds have been paid to Duke Energy Indiana. Shareholders should not receive a windfall in the form of the insurance proceeds. We agree it would be inequitable to return premiums to a party and deprive the party of the proceeds purchased with those premiums. We note ratepayers are currently paying, and will continue to pay for several more years, significant CCR closure costs through rates. These insurance proceeds will alleviate the impact of these costs and partially address utility rate affordability. We, therefore, deny Petitioner's request for approval to retain the requested portion of the insurance proceeds, which should, instead, be returned to ratepayers through a credit in the ECR filings. We further find that Duke Energy Indiana received financial benefit by retaining the proceeds without disclosing them earlier, and thereby, deprived ratepayers of those additional benefits. We find that the amount of the proceeds to be credited to ratepayers should include interest at the statutory rate of eight percent.

C. **Depreciation Study and Depreciation Issues**.

a. **OUCC and Intervenors**.

OUCC witness D. Garrett proposed several adjustments to the Company's proposed depreciation rates. Mr. Garrett testified the OUCC's proposed depreciation rates would reduce the Company's proposed depreciation accrual by $123 million, when applied to plant as of June 30, 2023. He further testified adopting the OUCC's proposed adjustments would increase the current annual depreciation accrual in the amount of $138 million. Pub. Ex. 9 at 3.

Mr. Garrett testified the OUCC's recommended depreciation rates are based on the following issues: (1) removing indirect costs and contingency costs from Duke's decommissioning cost estimates; (2) removing the annual escalation rate from Duke's present value decommissioning cost estimates; and (3) adjusting the Company's proposed service lives for several of Duke's transmission and distribution accounts. Pub. Ex. 9 at 3. Mr. Garrett testified that if the Commission were inclined to reject a complete disallowance of contingency costs, he would propose the Commission limit the contingency costs to ten percent, rather than the twenty percent. *Id*. at 12. Regarding issue (3), Mr. Garrett took issue with certain portions of Mr. Spanos' recommended mass property service lives. He proposed changes to the service lives of four transmission and distribution plant accounts, specifically: Account 354, Towers and Fixtures; Account 356, Overhead Conductors and Devices; Account 365, Overhead Conductors and Devices; and Account 367, Underground Conductors and Devices. *Id*. at 21-30. Mr. Garrett explained the "curve-fitting process" in which the best Iowa curve is selected to fit the observed life table curve through a combination of visual and mathematical curve-fitting techniques, as well as professional judgment. *Id*. at 17. He testified that mathematical fitting is an important part of the curve-fitting process because it promotes objective, unbiased results, particularly when there is sufficient data available. *Id*. Mr. Garrett stated that for each of the accounts to which he proposed adjustments, Petitioner's proposed average service life, as estimated through an Iowa curve, is too short to provide the most reasonable mortality characteristics of the account. *Id*. at 19. He asserted his proposal is generally based on the objective approach of choosing an Iowa curve that provides a better mathematical fit to the observed historical retirement pattern derived from Petitioner's plant data, in addition to applying judgment to the analysis. *Id*. Mr. Garrett ultimately recommended the Commission adopt the depreciation rates proposed on his Attachment DJG-2-3. *Id*. at 5.

Industrial Group witness Andrews also recommended the Commission reject the Company's proposed depreciation rates and approve the depreciation rates presented in Attachment BCA-10. IG Ex. 2 at 5. Mr. Andrews testified the Industrial Group's proposed depreciation rates would reduce the test year depreciation expense by $124.43 million, or by 39% of Duke's proposed increase. *Id*. Mr. Andrews also took issue with the escalation rate used in the Company's net salvage rate calculations and recommended the escalation costs be based on a 2.0% inflation rate and not 2.5% as used by the Company. *Id.* at 5. Like Mr. Garrett, Mr. Andrews recommended longer service lives for two mass property accounts: Account 356, Overhead Conductors and Devices; and Account 367, Underground Conductors and Devices. *Id*.

b. <u>Duke Energy Indiana Rebuttal</u>.

On rebuttal, Mr. Spanos disagreed with the parties' recommendations regarding contingency and escalation. Pet. Ex. 37 at 3. Mr. Spanos testified the Commission has already addressed the contingency and escalation issues raised by the parties in several other cases, and neither the OUCC nor Industrial Group provide any compelling reasons to overturn Commission precedent for contingency or escalation. *Id*. Further, regarding the parties' recommendations to lengthen the service life estimates for certain transmission and distribution accounts, Mr. Spanos testified both witnesses' proposals are based primarily, if not entirely, on comparing mathematical results from the statistical life analysis, which they emphasize in the hope of achieving objectivity. *Id*. at 4. He testified, however, many of the estimates do not represent reasonable life cycles for the asset class. *Id*. Mr. Spanos further testified that as explained clearly by depreciation authorities such as NARUC, estimating service lives must necessarily include a component of informed judgment. *Id*. He testified service life estimates are a forecast of the future and focusing only on mathematical calculations based on historical data will lead to unreasonable service life estimates, as is the case with various proposals made by Mr. Garrett. *Id*. Finally, Mr. Spanos testified Mr. Garrett's proposed changes to net salvage percentages to a total of eleven transmission and distribution accounts is arbitrary and does not follow any standard practice or depreciation concept. *Id*.

c. **Commission Discussion and Findings**.

Ind. Code § 8-1-2-19(b) and (c) place an affirmative obligation on the Commission:

> (b) The Commission, from time to time, shall ascertain and determine the proper and adequate rates of depreciation of the several classes of property of each public utility. Depreciation rates under this subsection shall be calculated to recover a reasonable estimate of the future cost of removing retired assets of the public utility.
>
> (c) A public utility's rates, tolls and charges shall be such as will provide the amounts required over and above the reasonable and necessary operating expenses, to maintain such property in an operating state of efficiency corresponding to the progress of the industry . . ..

We agree with OUCC witness David Garrett's positions regarding his proposed service life adjustments on the property groups (Accounts 354, 356, 365, and 367). Mr. Garrett's analysis relies on visual and mathematical curve fitting techniques as well as professional judgment, and the evidence demonstrates that the Iowa curves he selected for these accounts result in better fits to the historical retirement patterns in these accounts. Mr. Garrett based his analysis on the Observable Life Tables ("OLTs") and OLT curves derived from the historical property data for each account. As Mr. Garrett established, the OLT curve is not a theoretical curve; rather, it uses actual observed data from the Company's records that indicates the rate of retirement for each property group. Mr. Garrett expounded that he uses professional judgment supported by objective evidence and analysis when either there are insufficient historical data, or extenuating circumstances warranting adjustments. Mr. Garrett noted that judgment based on speculation is less reliable. We agree speculative hypotheticals are unreliable. Regarding the accounts for which Mr. Garrett recommended adjustments to the service lives, we find that Mr. Garrett's appropriately relies on the actual historical data for his analysis, and there was not a sufficiently objective or reliable basis to deviate from this actual data. Based on our review of the Observable Life Tables, the data, and the empirical evidence, we agree there is not a reliable empirical basis to deviate from the more appropriate service lives and Iowa curves Mr. Garrett recommended. Mr. Garrett's estimation of service lives in this instance reflects his application of his professional judgment. In prior cases, we have expressed concerns regarding an analysis relying solely and purely mathematical curve fitting. That concern does not exist here. We note that Mr. Spanos, in describing the drawbacks of mathematical curve fitting, testified that data irregularities are common toward the end of the curve. Mr. Garrett also expressed this concern, indicating he used the truncation of the tail end of the survivor curve when less than 1% of the exposures remain to avoid giving the tail end of the curve unwarranted weight in his analysis. Therefore, the Commission finds the adjustments Mr. Garrett made to Petitioner's proposed depreciation rates are reasonable and should be approved.

Regarding the issue of whether decommissioning costs should be escalated, we find it is unreasonable and unfair for current ratepayers to pay for escalated future costs with present-value dollars. Duke Energy Indiana's proposed escalation rates would require customers to pay millions of additional dollars per year for speculative future costs.

Next, we address the parties' contention that contingency be removed from the decommissioning study. We agree with the parties that the circumstances here warrant such removal. Contingency costs are unknown by definition. It would be inappropriate to take an unknown future cost, then increase that cost by 20% due to uncertainty. For the same reasons a party argues in favor of a positive 20% contingency factor, one could assert in favor of a negative 20% factor. That is, if a future cost estimate is uncertain, one could argue that such estimate should be decreased by 20% in the interest of being conservative. Rather, we find the most fair and reasonable approach is to disallow any positive or negative contingency factor. Thus, Duke Energy Indiana's request for a 20% contingency markup is denied, and the 0% contingency factor recommended by OUCC witness Mr. Garrett is approved. Finally, we agree to apply a gradualism approach to increases in negative net salvage rates. This approach will temper increases to customers while still allowing Duke Energy Indiana full cost recovery.

D. Deferral Accounting Treatment for Gibson Units 1-4.

In its case-in-chief and as part of calculating its depreciation accrual rates, the Company proposed to extend the depreciable lives for Gibson Units 1-4 beyond their estimated retirement dates. This was done in an effort to mitigate the Company's rate request. As a part of that effort, the Company requested deferral accounting treatment for the remaining balance of Gibson Units 1, 2, 3 and 4. Pet. Ex. 5 at 22-24. In her direct testimony, Company witness Lilly explains the regulatory asset treatment the Company is proposing. Ms. Lilly explained the Company is proposing to extend the retirement dates for depreciation purposes for Gibson Units 1 through 4 beyond the period that these units will likely remain in service. She testified that absent an unexpected event, the Company expects that every coal-fired steam generation unit will qualify as a normal retirement at its retirement. Ms. Lilly testified that so long as the Company has coal-fired steam generation in service, Duke Energy Indiana will simply assign sufficient depreciation reserve to the property being retired. Ms. Lilly explained that upon retirement of the last unit remaining, however, this normal treatment would require the allocation of depreciation reserve across functions, which is not typical practice. As such, upon retirement of the last coal fired steam generation unit and in accordance with Indiana Code 8-1-2-10, Ms. Lilly testified the Company is proposing that any remaining net book value in steam generation be deferred and amortized over the remaining assumed depreciable life to ensure full recovery of the cost of the asset and the cost of its removal. She testified that any deferred net book value and cost of removal will be included in the Company's rate base for ratemaking purposes. She further testified to the extent that any future retirement is deemed abnormal, the Company is requesting in this case for Commission approval to defer that net book value of the units that are retired and the cost of removal in the interim if any of those units are unable to be accounted for as a normal retirement. Ms. Lilly explained that in accordance with Indiana Code 8-1-2-10, this regulatory asset would then be included in Duke Energy Indiana's rate base in a future base rate proceeding, ensuring full recovery of the costs of the asset and its decommissioning costs. *Id*.

With respect to cost of removal, Ms. Lilly testified the Company is proposing that upon retirement of the last coal unit, under the Company's proposal, the cost of removal embedded in accumulated depreciation will be recorded to a regulatory liability (also to be reflected in rate base for ratemaking purposes). Ms. Lilly explained that when all decommissioning is complete (including post-closure maintenance), the remaining balance will continue to be reflected in rate base for ratemaking purposes and will be amortized over a period of time to be determined by the Commission. *Id*.

Ms. Lilly testified she believes the Company's requested deferral is reasonable, as the shift for environmental reasons from coal generation to other cleaner sources creates a unique situation that requires certainty from the Commission that the costs will be recovered, even if the Company is not able to account for the retirements using normal accounting. *Id*. at 24. Ms. Lilly further testified that approving now the use of deferred accounting by the Company at the time of the coal units' retirement with assurance of continued cost recovery until all costs, including cost of removal, are recovered, provides a known path forward all interested parties can count on. *Id*.

No party took issue with the Company's proposed deferral accounting treatment for the remaining balance of Gibson Units 1, 2, 3, and 4. The adjustment was voluntarily made by the Company with affordability for customers in mind. We agree with Ms. Lilly that the Company's requested deferral is reasonable, and we therefore find the proposal as set forth herein and Ms. Lilly's direct testimony is approved.

E. GoGreen Program – REC Supply Proposal.

i. Duke Energy Indiana's Case-in-Chief.

Petitioner requests approval in this proceeding to begin transferring RECs generated from the upcoming Speedway Solar purchase power agreement ("PPA") to satisfy GoGreen program subscriptions, once the site is operational. Pet. Ex. 4 at 41-44. Company witness Sieferman explained these RECs would be sold to the *GoGreen* program at a price set annually based on average REC prices for the National Voluntary Wind/Solar REC market. Ms. Sieferman further explained that any Speedway Solar PPA RECs remaining from the prior vintage year (above participant demand for the *GoGreen* program) would be retired on behalf of all Duke Energy Indiana customers. *Id*.

ii. OUCC.

OUCC witness Armstrong testified that while the OUCC does not take issue with the concept of transferring RECs from renewable PPAs or future renewable assets, the transfers should be done at the appropriate market rate for the REC generating source. Pub. Ex. 5at 16. Ms. Armstrong testified that Duke stated it expects the Speedway Solar's RECs will only be eligible for sale into the National Voluntary market or the Ohio REC market, and that the Ohio REC market is currently planned to be phased out after 2026. *Id*. at 17. In response, Ms. Armstrong indicated that although Speedway Solar may not currently qualify for other REC markets, states could always change their renewable portfolio standards ("RPSs") to allow Speedway Solar or other Indiana-sited sources to qualify for compliance and eligibility to participate. *Id.* She stated that the OUCC does not want to limit the price to the National voluntary market if Duke's RECs from

PPAs or renewable generating assets become eligible to sell into another market at a higher value. *Id.* She asserted Duke should be monitoring REC markets and their respective requirements and selling its RECs at the maximum price its sources can receive, and any RECs transferred to the GoGreen program should reflect this price. *Id.*

Ms. Armstrong stated that if the highest market price would increase to a level that would be undesirable for GoGreen customers, then Duke should procure RECs from alternative sources to cover GoGreen customers' elected renewable energy usage. *Id.* She also provided an alternative proposal where Duke could sell RECs in its inventory at the highest market price possible, and the proceeds from this sale could then be used to purchase lower-cost National voluntary RECs for GoGreen customers. *Id.* at 18. As part of this alternative proposal, she stated that any sales to GoGreen customers associated with these REC purchases would then be credited to all ratepayers through the FAC, and GoGreen customers would also be responsible for any brokerage and retirement fees associated with REC purchases made using proceeds from the other Duke REC sales. *Id.* She reasoned this would be a reasonable compromise to ensure all Duke's ratepayers receive the full value of RECs associated with renewable energy or generating assets they are paying for in rates while giving GoGreen customers access to lower-priced RECs. *Id.*

Regarding Duke's proposal to retire any RECs not transferred to the GoGreen program, Ms. Armstrong testified that Duke's proposal would result in ratepayers forfeiting valuable offsets to the costs associated with the Speedway Solar PPA and future renewable PPAs and generating assets. She noted that since Indiana does not currently have a mandatory RPS, retiring RECs associated with all ratepayers' energy use are not mandated under current regulatory requirements. She reasoned Duke's proposal would be treating these RECs similar to how they would be treated under mandatory RPS requirements while sacrificing the benefits of REC sales for customers. *Id.*

Ms. Armstrong addressed Petitioner's Witness Sieferman's claims that retiring these RECs reduces "greenwashing" concerns and allows all retail customers to claim solar in the residual mix. She stated that while it is true that Federal Trade Commission ("FTC") rules prohibit Duke from representing to its customers that it is supplying them with renewable energy if it sells the RECs associated with the energy generated from these resources, there are ways to communicate this information to customers without violating these claims. *Id.* at 19. She testified that Duke can refer to the energy or capacity supplied by these resources as "null" energy or capacity. She also noted that if Duke is appropriately registering RECs, it should be able to track and demonstrate which RECs have been sold and which RECs remain in inventory. *Id.*

She asserted the value gained in claiming the benefits associated with renewable energy must outweigh the loss of the monetary benefits of REC sales. She stated that in the absence of RPS or other compliance requirements mandating a utility obtain and supply customers with renewable electricity, this value is difficult to quantify monetarily and will vary for each person or entity receiving the benefits of such claims. She pointed out that since supporting renewable generation tends to have a positive message publicly, Duke's ability to claim it is supplying renewable energy to its customers is valuable to its public image. She noted the value to customers in claiming environmental benefits associated with renewable power likely differs among customers and customer classes. She testified that renewable energy claims are likely more valuable to large industrial or commercial customers with corporate sustainability goals and may be subject to new U.S. Securities and Exchange Commission ("SEC") climate risk disclosure requirements. *Id.* On the other hand, she reasoned that residential customers may see these claims as an unimportant image-building endeavor and would prefer their monthly bill be lowered by selling the RECs associated with the electricity supplied to them. She argued Duke's proposal creates a situation where all ratepayers are subsidizing the costs of a service that is more valuable to a subset of customers. She noted that the GoGreen program is available for any customer who values claiming the renewable attributes associated with their electricity usage and serves as a reasonable option for this subset of customers. *Id.* at 20.

Ms. Armstrong explained the SEC climate risk disclosure requirements, finalized in March 2024, provide motivation for DEI to retire excess RECs instead of selling them. *Id.* She acknowledged the SEC has stayed the effective date of the final rules pending the outcome of litigation from legal challenges to the rules but indicated it would continue "vigorously defending" its climate disclosure rule. *Id.* at 21. She testified the final rules require a registrant to disclose material climate-related risks, activities to mitigate or adapt to such risks, and information on any climate-related targets or goals that are material to the registrant's business, results of operations, or financial condition, and other items important for investors' assessment of climate-related risks. *Id. at 20.* She noted the rule requires large accelerated filers ("LAFs") or accelerated filers ("AFs") that are not otherwise exempted to report their Scope 1 and Scope 2 emissions. *Id.* at 21. She explained that Scope 1 emissions are direct greenhouse gas ("GHG") emissions from operations that are owned or controlled by a registrant and that Scope 2 emissions are indirect GHG emissions from the generation of purchased or acquired electricity, steam, heat, or cooling that is consumed by operations owned or controlled by a registrant. She indicated that one way a company's Scope 2 emissions can decrease is if its electric utility or electricity provider increases the amount of renewable generation it supplies to its customers. *Id.*

Ms. Armstrong noted that by retaining and retiring these RECs, Duke can lower its Scope 1 emissions by claiming a greater percentage of its energy is supplied through zero-emission renewable generation sources. She added that since many of its larger customers likely qualify as LAFs, they would be able to lower their Scope 2 emissions if Duke can claim it is providing all customers with more renewable energy by not selling these RECs. She reasoned that both Duke and its larger customers subject to these disclosure requirements would benefit from retiring RECs as they would be able to report lower climate-related risks to their investors. She argued this risk would be socialized across all of Duke's customer classes to the detriment of residential and smaller customers that would benefit from the REC sales proceeds.

As to the potential value of retired RECs, Ms. Armstrong testified that Speedway Solar is expected to produce 426,000 RECs per year once it is online, but the GoGreen Program's total needs have not exceeded 55,000 RECs per year since 2020. She showed that if the recent average National voluntary REC market price of $3.00/REC were applied, this would result in Duke foregoing over $1.1 million annually in REC proceeds. However, she indicated this foregone value is a conservative estimate, as some National REC future vintages are nearly double this amount, and National voluntary prices have reached as high as $7.00/REC within the last three years.

iii. <u>Duke Energy Indiana's Rebuttal</u>.

On rebuttal, Ms. Sieferman responded to Ms. Armstrong's recommendations regarding the Company's *GoGreen* REC Supply proposal. She testified the Company proposed to use the national voluntary market to price Speedway Solar PPA RECs for the *GoGreen* Program because there are only two markets in which the RECS can be sold – the National Voluntary market and the Ohio Renewables market – and the Ohio Renewables market is set to end in 2026. Pet. Ex. 30 at 6. Further, she explained the Company proposed to set an annual price based on the 12 month average national voluntary wind/solar pricing because the Company plans to transfer RECs to the GoGreen program annually for the subscription portion of the program, and the specific number of RECs needed will be determined based on program enrollment and participation throughout the year. *Id*.

Further, Ms. Sieferman responded to Ms. Armstrong's recommendation to avoid retiring RECs absent a mandatory RPS. Ms. Sieferman testified the Duke Energy Indiana's testimony in Cause No. 45907 (approving the Speedway Solar PPA) explained the Company was considering holding and retiring RECs if that approach better aligned with the Company's environmental goals, and the Commission's order in that proceeding did not prohibit the Company's proposed treatment of the associated RECs. *Id.* at 7-8. Further, Ms. Sieferman cited to another Indiana utility that reserved its right to retire excess RECs in the absence of a mandatory RPS. Regarding Ms. Armstrong's recommendation related to reimbursing customers, Ms. Sieferman testified RECs retired on behalf of all customers by the Company would be retired using a self-certifying process, therefore there will be no associated third-party retirement costs incurred. *Id.* at 8-9. Ms. Sieferman testified the Company agrees with Ms. Armstrong that any costs associated with retirements of RECs used for the GoGreen program should be reflected in the GoGreen subscription fees and not recoverable from all retail customers via the FAC. *Id.* at 9.

Regarding Ms. Armstrong's alternative proposal, Ms. Sieferman testified the proposal unnecessarily complicates the process and assumes there are more market options than currently exist for these RECs. Further, Ms. Armstrong's proposal fails to maintain the flexibility for the Company to determine how best to use incremental Speedway Solar PPA RECs for the benefit of all customers. *Id.* at 9-10.

Ultimately, Ms. Sieferman testified it is the Company's position that there is value to customers in being able to claim the environmental benefits associated with renewable energy and that those benefits should be considered when choosing between monetizing the RECs and using the RECs for customer renewable programs or retiring on behalf of customers. *Id.* at 10. She testified the Company's proposal related to the *GoGreen* program is reasonable and should be approved. *Id*.

iv. <u>Commission Discussion and Findings</u>.

Regarding the issue of pricing RECs transferred to the GoGreen program, the OUCC proposes that Duke sell RECs to the GoGreen program at the highest price possible. Duke believes the National Voluntary market is the only REC market it will be eligible to sell the Speedway Solar RECs into. While this may be currently true, Ms. Armstrong testified that rules could change in the future to allow these RECs to be sold into higher value markets. Ms. Armstrong showed that revenues from REC sales have the potential to significantly offset the costs of renewable PPAs and utility-owned generation projects. While we do not take issue with transferring Speedway Solar RECs to GoGreen customers at a fair market price, we agree with the OUCC that Duke should be monitoring eligible REC markets and transferring these RECs at the highest market value possible. We also note that nothing prohibits Duke from procuring RECs for the GoGreen program from other market sources outside of Duke's REC inventory.

In addition, Duke proposes to retire any RECs not transferred to the GoGreen program instead of selling them. Ms. Sieferman relies on the Commission's findings in Cause No. 38703 FAC 117 where Indianapolis Power & Light Company ("IPL") proposed to retain and retire its RECs instead of selling them. The OUCC advocated that IPL sell RECs where possible. While it is true that the Commission declined to require IPL to sell its RECs *in that instance* and allowed IPL to maintain flexibility over how it managed its RECs for the benefit of customers, the Commission also required IPL to continue to provide updates on its REC management policies and to show the benefits of retiring or retaining RECs rather than selling them. "Should IPL choose to retire its RECs for the benefit of its customers, it seems reasonable that support for the value it places on such benefits is identifiable. Accordingly, we find that IPL shall include in future FAC filings an update concerning its utilization of RECs and how that utilization benefits its customers." *Application of Indianapolis Power & Light Co.*, Cause No. 38703 FAC 117, Final Order at 8 (Ind. Util. Regul. Comm'n Nov. 21, 2017). We also note that REC values in the REC market in 2017 were different than those in the REC market of 2024; our decision in IPL 117 may well have been different if we were presented with the issue today.

While Duke claims that retiring RECs will be beneficial to customers, it has not provided sufficient evidence to prove the value of such proposed retirements. Duke claims the main benefit is that customers may claim the renewable benefits associated with Speedway Solar's energy, but as Ms. Armstrong has stated, these benefits are more valuable only to a subset of Duke's customers. All customers should benefit from the annual REC proceeds, and it is inequitable for Duke to choose a path only benefiting a portion of its customers. The GoGreen program allows for those customers who wish to claim the environmental attributes of the Speedway Solar RECs, while fairly compensating all customers for their value. We find that Duke should manage and utilize its RECs to provide the maximum benefit for all customers, which includes selling RECs when possible. Duke shall also include updates regarding its REC utilization and its associated customer benefits in future FAC filings.

As Ms. Armstrong noted, if Duke retires its RECs, it will be able to claim lower carbon emissions in the climate risk disclosures it provides to investors. Therefore, if Duke is allowed to retire the Speedway Solar RECs instead of selling them, it would be appropriate to consider the impact of the associated decreased climate risk through the overall ROE awarded to the Company. Since we decline to fully accept Duke's proposal, we are not making an ROE adjustment to account for this lowered risk in this case. If Duke does not attempt to monetize RECs where possible in the future, we will consider an adjustment to ROE in future rate cases.

F. <u>Electric Vehicle Issues</u>.

[The OUCC does not take a position on this issue.]

G. <u>Response to CAC's Criticism of Duke Energy Indiana Coal Ash Closure Plans</u>.

[The OUCC does not take a position on this issue.]

12. Disputed Test Year Revenues.

The Company proposed eight *pro forma* revenue adjustments to the Forward-Looking Test Period as set forth on Petitioner's Exhibit 26, Attachment 26-C Schedules REV1 through REV 8. We find all *pro forma* adjustments proposed by Petitioner, either as originally proposed and undisputed, or as adjusted with the compromised positions having been fully identified by the parties, are hereby accepted even though they may not be specifically discussed in this Order.

13. Disputed Test Year Expenses.

In its case-in-chief, Petitioner proposed seven cost of goods sold-related *pro forma* adjustments and fourteen O&M-related *pro forma* adjustments as set forth on Petitioner's Exhibit 26, Attachment 26-C, Schedules COGS2 through COGS8, and Schedules OM3 through OM16 respectively. With respect to these adjustments, the parties took issue with Petitioner's *pro forma* adjustments to update its base cost of fuel in this proceeding, its adjustment to reflect recovery of costs to achieve corporate restructuring savings, its adjustment to remove costs associated with OPRB, its adjustment to reflect normalization of major storm costs, and its adjustment to add residential customer credit card fees to base rates. We will discuss each of these issues in this section. Otherwise, we find all *pro forma* adjustments proposed by Petitioner, either as originally proposed and undisputed, or as adjusted with the compromised positions having been fully identified by the parties, are hereby accepted even though they may not be specifically discussed in this Order.

Further, on rebuttal, Company witness Graft sponsored three adjustments to the Company's forecasted O&M expense. First, the Company removed $2,096,000 from test period O&M costs to achieve annual corporate restructuring savings reflected in the test period forecast. Pet. Ex. 29 at 18. The Company withdrew its request to defer as a regulatory asset $6,289,000 in corporate restructuring savings and to recover this amount over a three-year period. The Company therefore removed this *pro forma* adjustment on rebuttal. *Id*. Second, in the Company's case-in-chief it removed $10,667,000 from test period expenses to reflect a normalized level of outage costs. *Id*. However, in responding to discovery, the Company became aware of an inadvertent error in the calculation of the normalized level of outage costs. *Id*. The Company corrected this error on rebuttal resulting in an additional $782,000 reduction to test period expenses. Third, as the Company footnoted in Ms. Graft's direct testimony, it discovered there were expenses in the revenue requirement for advertising that did not provide a material benefit to customers as required by 170 IAC 1-3-3(A). *Id*. Company witness Graft testified that the discovery was made too late in the process to correct before filing the case-in-chief; however, the Company committed to making an adjustment in its rebuttal testimony, and therefore removed $539,000 from test period expenses to correct this inadvertent error. *Id*.

The OUCC and intervenors also took issue with a number of Petitioner's forecasted test year expenses. Apart from depreciation expense, which we have already addressed in a previous section, each of these disputed text year expenses are addressed in the following sections. Further, we address the OUCC's recommendation to reduce *pro forma* O&M expenses related to the Company's Payment Navigator Program in this section, as well as in the Affordability section of this Order.

A. **Labor and Labor-Related Compensation**.

a. **Incentive Compensation**.

i. **Duke Case-in-Chief**.

Company witness Caldwell testified that Duke Energy Indiana's compensation philosophy is to target total compensation, consisting of the combination of base pay and incentive pay, at the median of the market when compared to similarly sized companies, both within and outside of the utility industry. Pet. Ex. 16 at 7. Ms. Caldwell explained that in order to attract a well-qualified and well-led workforce, the Company must compete in the marketplace to obtain the services of these employees. *Id.* at 28. Ms. Caldwell further explained that based on the companies Duke Energy Indiana benchmarks its total compensation against and the Company's peers in the utility industry, the market dictates that incentive compensation be included as part of that overall compensation package. *Id.* at 3. Ms. Caldwell testified that market-competitive pay allows the Company to attract and retain the talent this Company needs to run a safe and reliable electric system. *Id*.

Ms. Caldwell discussed the Commission's three requirements for incentive plan costs to be recoverable in rates and described how Duke Energy Indiana's short-term incentive ("STI") and long-term incentive ("LTI") plans meet the Commission's requirements. *Id.* at 29-30.

ii. **OUCC and Intervenors**.

Mr. M. Garrett recommended that the Company's incentive compensation expense be reduced by $16.9 million. Pub. Ex. 2 at 13. Mr. M. Garrett testified the Company's proposed recovery of 100% of the projected incentive compensation does not satisfy the three components of the Commission's standard, because the Company's request for full recovery of projected incentives does not constitute a legitimate *sharing* of costs between shareholders and ratepayers. *Id.* at 15 (emphasis original). Mr. Garrett further testified that 100% recovery is unusual when compared with the treatment of these costs in other jurisdictions and is not consistent with the prior treatment of these costs in Indiana. *Id*. at 15. Mr. Garrett also explained that financial performance measures in incentive plans can control the payout of the plans, which allows the utility to divert money included in rates to pay incentives to shareholders instead when earnings targets are not met, as happened with this utility in 2020. *Id*. at 18-19. The Company also paid out substantially less than budgeted in 2023. *Id*. at 17. Mr. Garrett also presented evidence that regulators generally disallow incentive compensation tied to financial performance. *Id*. at 21-22.

Industrial Group witness Gorman also recommended the removal of $14.6 million of Duke Indiana's proposed incentive compensation costs from cost of service. IG Ex. 1 at 47. Like Mr. M. Garrett, Mr. Gorman testified the Company's incentive compensation does not satisfy the Commission's standard for recovery that incentive compensation costs be shared between customers and shareholders, because Duke Indiana develops its cost of service using 100% of its targeted level of incentive compensation. *Id.* at 45. As such, Mr. Gorman testified shareholders will only be assigned a small portion of the costs relative to the benefit they receive, or the incentive compensation expense above the targeted level. *Id.* at 45. Mr. Gorman ultimately recommended the removal of $14.6 million of Duke Indiana's proposed incentive compensation costs from cost of service. *Id.* at 47. Mr. Gorman explained this is the amount of incentive compensation tied to financial goals of the Company and/or its parent. *Id*.

iii. **Duke Rebuttal**.

Ms. Caldwell testified she disagreed with the proposed adjustments of Mr. M. Garrett and Mr. Gorman to remove the portions of STI and LTI compensation tied to financial measures and achievement. Pet. Ex. 39 at 3. She testified the Commission should reject the proposed adjustments as it did in the Company's last litigated rate case, Cause No. 45253, because both Mr. M. Garrett and Mr. Gorman request that the Commission depart from its holdings authorizing recovery of incentive compensation in multiple cases, without offering any new rationale for why that would be appropriate. *Id.* at 3-4. Ms. Caldwell testified that as stated in her direct testimony, the Company believes all incentive compensation up to target levels should be recoverable in rates. Further, she testified the Company has met the Commission's three standards required for incentive plan costs to be recovered in rates, and the OUCC and Industrial Group have not provided any meaningful argument for applying different standards in this case. *Id*.

Ms. Caldwell testified regarding the Commission's three standards and how the Company is meeting those standards:

(1) *The Company's incentive compensation plans are not pure profit sharing plans*. Ms. Caldwell testified the financial metrics are balanced by operational metrics such as customer satisfaction, safety and reliability. *Id.* at 14.

(2) *The Company's incentive compensation plans do not result in excessive pay levels*. Ms. Caldwell referenced her direct testimony and testified Duke Energy's compensation philosophy is to target total compensation, consisting of the combination of base pay and incentive pay, at the median of the market when compared to peer companies. Ms. Caldwell explained that whether it is through base pay or a combination of base pay and incentives, Duke Energy Indiana must keep its overall compensation package competitive to attract and retain a competent workforce. She testified that the market dictates incentive compensation as part of the overall compensation package in the utility industry. *Id*. Ms. Caldwell noted that neither M. Garrett nor Mr. Gorman testified the Company's overall pay level was excessive. *Id.* at 4.

(3) *Incentive pay expense is shared between shareholders and customers,* as the Company is asking for recovery at target levels.

Regarding the third standard, Ms. Caldwell explained that this is the standard both Mr. M. Garrett and Mr. Gorman believe the Company has failed to meet. *Id.* at 5. She discussed in her rebuttal testimony how the target levels of total STI and LTI is equivalent to approximately half of the maximum incentive opportunity and any amounts over target would be paid for by shareholders. *Id.* at p. 15. Thus, the Commission's third standard is satisfied.

iv. **Commission Discussion and Findings**.

The Commission has approved recovery of incentive plan costs when (1) the incentive compensation plan is not a pure profit-sharing plan, but rather incorporates operational as well as financial performance goals; (2) the incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce; and (3) shareholders are allocated part of the cost of the incentive compensation programs. *In re PSI Energy, Inc.*, Cause No. 42359, Final Order p. 89 (Ind. Util. Regul. Comm'n May 18, 2004)("42359 Order"); see also, *In re S. Ind. Gas and Elec. Co., d/b/a Vectren Energy Delivery of Ind. Inc*., Cause No. 43839, Final Order p.50 (Ind. Util. Regul. Comm'n Apr. 27, 2011) and *In re Ind. Mich. Power Co.,* Cause No. 45235, 2020 WL 1656243, Final Order at p. 62 (Ind. Util. Regul. Comm'n Mar. 11, 2020). Once the Commission determines an incentive compensation plan provides benefits to shareholders and ratepayers and finds it not to be excessive, an appropriate level of costs should be included for recovery from ratepayers who are benefited by these programs. See *In re N. Ind. Pub. Serv. Co.* ("NIPSCO"), Cause No. 43526, Final Order p. 63 (Ind. Util. Regul. Comm'n Aug. 25, 2010) ("43526 Order"). Although Duke Energy Indiana had not made the proposal NIPSCO had made in Cause No. 43526, we find a similar approach to be most appropriate in this Cause. We find that when incentive compensation is tied to financial performance, there should be a legitimate and appropriate level of sharing between ratepayers and shareholders. We therefore find a 50% - 50% sharing of the STI is appropriate, and agree with the recommendations of Mr. Garrett regarding the LTI reduction. We, therefore, disallow Duke Energy Indiana's proposed \$16.9 million incentive compensation costs in this Cause.

b. <u>Board of Directors Compensation</u>.

OUCC witness M. Garrett recommended the Board of Directors' compensation expenses be shared between shareholders and ratepayers. Pub. Ex. 2 at 37. Specifically, he recommended the Commission disallow 50% of the Board members' cash compensation and 100% of stock-based compensation allocated to the Company in this proceeding. *Id*. As such, he recommended a revenue requirement reduction of \$320,093. *Id.* at 38.

On rebuttal, Company witness Caldwell stated she does not believe the OUCC's disallowance related to Board of Director compensation expense is appropriate. Pet. Ex. 39 at 15. She explained that, by law, the Company is required to have a Board of Directors and it cannot pretend that an investor-owned utility is not an investor-owned utility. *Id*. Ms. Caldwell testified that the costs of being an investor-owned utility, including Board of Director costs, are in fact costs of service. *Id*. She testified it is not fair or reasonable to penalize the Company for merely being an investor-owned utility with attendant requirements to that corporate structure. *Id*.

Duke Energy Corporation's Board of Directors are expected to own Duke Energy Corporation shares. Board members are incented to increase the value of their shares and maximize long term earnings for shareholders (and themselves as shareholders) without a commensurate incentive to maintain affordability for customers. As we have determined similar incentives warranted a 50% - 50% sharing with respect to incentive compensation, we find a 50% - 50% sharing between shareholders and customers for Board Compensation to be appropriate, based on the relative benefits each receive.

B. **<u>Trade Association Dues and Fees</u>**.

a. **<u>Duke Energy Indiana Case-in-Chief</u>**.

The Company requested $1,125,000 in trade association expense for the 2025 forecasted test period for various trade memberships. Pet. Ex. 30 at 18.

b. **<u>OUCC and CAC</u>**.

OUCC witness M. Garrett recommended the Commission disallow 50% of the Company's industry association dues. Pub. Ex. 2 at 35. Mr. Garrett testified industry associations engage in advocacy for the utility industries and their owners and stated that until the Company can demonstrate its request for recovery of industry association membership dues relates to customer interests rather than lobbying and broader industry advocacy efforts, it is recommended the Commission disallow the Company's requested recovery of $215,000 of industry association dues. *Id*.

CAC witness Inskeep recommended the Commission deny the Company's request to include trade association dues associated with the Edison Electric Institute ("EEI"), the Indiana Energy Association ("IEA"), and the Chambers of Commerce in its revenue requirement. CAC Ex. 1 at 100. Mr. Inskeep testified this adjustment would reduce trade association expense from $1,125,000 to $51,000, a reduction of $1,074,000. CAC Ex. 1 at 100. Mr. Inskeep testified organizations like EEI, IEA, and Chambers of Commerce engage in highly political, advocacy-oriented, and influence activities, which could include funding outside political and charitable contributions, litigation, regulatory advocacy, advertising, and efforts to shape the public and decision-maker opinion, in addition to numerous other activities that principally serve the private business interests of the members rather than ratepayer interests. *Id.* at 99. He testified that although the Company has excluded a small subset of these influence activities that fall within the narrow legal definition of lobbying, it has not separately accounted for or removed from requested revenue requirement all trade association dues associated with this type of contentious political and policy influence. *Id*.

c. **<u>Duke Energy Indiana Rebuttal</u>**.

On rebuttal, Duke Energy Indiana witness Sieferman explained the Company included in revenue requirements only the non-lobbying portion of membership dues and fees. Pet. Ex. 30 at 21. She stated amounts in the forecasted test period related to lobbying were forecasted directly to non-utility accounts and therefore were excluded from revenue requirements. *Id*. She testified the Commission has approved the inclusion of trade association dues and fees such as these in the revenue requirement of other Indiana utilities, including in the recent *Indiana American Water Order* in Cause No. 45870. *Id*. She stated the Company properly excluded the portion of these membership costs associated with lobbying in accordance with current FERC Chart of Account guidance, and the $1,125,000 amount of non-lobbying-related membership costs included in revenue requirements is reasonable, beneficial for customers, and should be approved for inclusion as proposed by the Company. *Id.* at 23-24.

d. **<u>Commission Discussion and Findings</u>**.

The evidence demonstrates that trade association activities disproportionately benefit shareholders and disproportionately include political and other influencing activities, in addition to lobbying, that nearly exclusively benefit shareholders. The removal of "lobbying" expense (especially, when narrowly defined) does not alleviate this substantial imbalance. The Commission finds that authorizing 50% of the requested trade association expense for recovery from customers, while disallowing 50% of the requested expense to be borne by shareholders, achieves a more accurate and reasonable balance of the interests served by trade association expenses.

C. **Major Storm Expense**.

a. **Duke Energy Indiana Case-in-Chief**.

The Company proposed a *pro forma* adjustment to increase the amount of annual O&M expense for major storms in base rates from the current annual level of $12.7 million (2014-2018 average) to an updated annual level of $15.6 million (2019-2023 average). Pet. Ex. 23 at 32. This amount was calculated by averaging the five-year historical period (2019-2023) of Duke's major event day ("MED") storm T&D expenses. *Id.* at 31. In addition to establishing a normalized level in base rates, the Company is also proposing to continue to utilize the Major Storm Reserve to track differences between the operating costs incurred and the amount collected in base rates in this proceeding. Pet. Ex. 4 at 38.

b. **OUCC**.

OUCC witness M. Garrett and OUCC witness Sanka disagreed with the $15.6 million amount the Company proposed for major storm costs to be recovered in base rates. *Id*. Ms. Sanka testified that 2023 is an outlier year, due to a significant rise in outage activity due to the June 29, 2023, derecho that hit Duke Indiana's service territory. Pub. Ex. 7 at 6. Ms. Sanka demonstrated that 2023 MED storm related expenses were 745% higher than the prior year, and that 2023 MEDs (11) were approximately 165% of the average from 2015 through 2023 (6.667). *Id.* at 5-6. Therefore, Ms. Sanka proposed that the 2023 major storm expenses should be excluded from the five-year average and instead the annualized amount for T&D Major Storms should be set on a four-year average of costs for the 2019 to 2022 period. *Id.* at 7. The updated four-year average per Ms. Sanka's calculation would be $9.2 million instead of Duke's proposed $15.6 million, which is a pro forma reduction of $6.4 million to the Company's proposed pro-forma test year operating expense. *Id.* at 8. Mr. Garrett agreed with the Company's request to continue tracking the major storm costs, based on the major storm cost expense recommended by the OUCC, and the recording of a regulatory asset or liability for future recovery. Pub. Ex. 2 at 42.

c. **Duke Energy Indiana Rebuttal**.

On rebuttal, Company witness Sieferman explained why she disagreed with Ms. Sanka's recommendation to remove the 2023 costs from the normalized expense calculation. Pet. Ex. 30 at 25-26. She noted that while the costs for 2023 were significantly higher than the costs in the other years, the costs for 2021 and 2022 were significantly lower than for the other years. She testified the mere fact that there is such variability between years is what has led to the practice of averaging the results of a multi-year period to try to capture a more representative amount. Ms. Sieferman testified the updated annual level for major storms was calculated in the same manner as the $12.7 million amount approved by the Commission in the Company's last base rate case in Cause No. 45253. *Id.* at 24.

Ms. Sieferman further testified Ms. Sanka's suggestions that the costs for 2023 are high and should be thrown out insinuates that these costs were not prudently incurred and should therefore not be recovered. *Id.* at 25-26. Ms. Sieferman testified the storm impacted the Company's service territory in a significant way, and including an amount in the five-year average for these costs reflects the fact that costs for major storms will be more significant in some years than in others, and that including a higher level of costs over time results in smoothing out customer rates by collecting a little bit over a longer period to go towards these storms, rather than reflecting that full cost at once. *Id.* at 26.

d. **Commission Discussion and Findings**.

The evidence demonstrates that there were more MEDs from storms in 2023 than in any other year over the last nine years. The $41.4 million in MED storm related expenses is clearly an outlier in comparison with any other year's expenses, with any average MED storm expense or any median storm expense by year. It is therefore appropriate to exclude the 2023 MED storm expense from the calculation of normalized annual MED storm expense. We agree the most reasonable and most representative calculation is the most recent four-year average, excluding 2023. We find it is appropriate to update the annualized level of Major Storm Expense in base rates to reflect the pro forma level of $9.2 million.

No party disputed the Company's request to continue to utilize the Major Storm Reserve. We find the continued use of the Major Storm Reserve to track differences between the operating costs incurred and the amount collected in base rates in this proceeding is appropriate and should be approved.

D. **Rate Case Expense**.

[The OUCC does not take a position on this issue.]

E. **Card Payment Fees**.

a. **Duke Energy Indiana Case-in-Chief**.

As explained in the testimonies of Company witnesses Colley and Graft, the Company is proposing to eliminate convenience fees for individual residential customers who use credit and debit cards to pay their electric bills and instead recover these costs as part of its cost of service, which is how the Company recovers the cost associated with providing other customer payment options. Pet. Ex. 3 at p. 28; Pet. Ex. 24 at 26-31. Mr. Colley described the efforts the Company has made to make the card payment channel more affordable, but testified the requirement to pay a transaction fee when making a Card Payment for utility service is one of the largest frustrations a customer experiences when paying their Duke Energy Indiana bill. Pet. Ex. 24 at 27. Mr. Colley testified that expanding the available fee-free payment options to include Card Payments would make payment options more inclusive for residential customers. *Id*. He testified all customers are currently paying for the other various payment options, ACH, check, etc., regardless of which payment option they personally use and treating Card Payments similarly seems reasonable. *Id.* at 30. Ms. Graft testified the Company is proposing to increase test period operating expenses by $2,621,000 to include card payment convenience fees in the Company's cost of service. Pet. Ex. 3 at 28.

b. <u>OUCC and CAC</u>.

OUCC witness Latham recommended the Commission reject Duke's card payment fee elimination proposal because the proposal would unfairly shift costs to all customers, including those that do not use credit cards. Public's Ex. 4 at 6, 8. Further, Mr. Latham testified that while customer satisfaction may be enhanced for those customers who would pay by fee-free card payment, the Company has not shown any value, including any level of enhanced customer satisfaction, for customers who pay by other means. *Id.* at 5-6. He testified that if Duke desires to improve its customer satisfaction performance and help its most vulnerable customers, then he recommends Duke's shareholders absorb the cost of the fees the company wishes to include in rates. *Id*. at 8.

CAC witness Inskeep testified he agreed with the Company's proposal to eliminate the current per-transaction fee associated with credit card payments. CAC Ex. 1 at 56. Mr. Inskeep testified convenience fees increase the effective cost of a ratepayer's utility bill, exacerbating affordability concerns. *Id*. He testified for example, low-income customers are less likely than customers overall to use more affordable payment methods when paying a monthly bill, meaning per-transaction charges on certain types of payment methods can have disproportionate impacts on low-income ratepayers and other vulnerable communities. *Id*. Mr. Inskeep testified it is necessary and reasonable to remove per-transaction payment fees to eliminate any incidental barriers and disparate impacts that the fees are causing. *Id.* at p. 57.

c. <u>Duke Rebuttal</u>.

Mr. Colley testified he disagreed with Mr. Latham's claim that removing card payment fees would unfairly shift costs to all customers. Pet. Ex. 45 at 13. He testified that by incorporating these fees into the general cost of service, the Company aims to provide equitable access to all payment methods, especially benefiting those who rely on this increasingly mainstream payment channel. Pet. Ex. 45 at 14. Mr. Colley further testified he disagreed with Mr. Latham that customer satisfaction would not be impacted by the expansion of a fee-free card payment. *Id.* at 15. Mr. Colley reiterated that customer feedback has consistently shown that additional fees can lead to dissatisfaction and that customer satisfaction is closely tied to the ease and affordability of payment options available to them. *Id*.

Mr. Colley also reiterated the importance of fee-free card payments extends to some of the Company's most vulnerable customers. *Id.* at 15-16. Mr. Colley testified for example, 42% of the Company's agency assistance recipients utilized the card payment channel at least once over the six-month period, compared to only 18% of non-recipients. Mr. Colley testified that in offering this inclusive fee-free payment option to residential customers, the Company is not only addressing a significant customer frustration but also providing all customers, regardless of their financial situation, with access to a convenient and fee-free payment option.

d. **Commission Discussion and Findings**.

The Commission spoke about this same issue in Duke's last rate order. There we found:

> Specifically, the Company proposes adding a pro forma adjustment of $4.5 million to the cost of service to cover fees that are no longer being collected solely from the cost causers, the program participants. Importantly, the cost of the convenience remains and the program does not purport to provide any savings or system efficiency gains to the non-participants in the program. The OUCC expressed concern with this feature of the proposed program, while acknowledging that a company-funded program would not present this challenge. While it is reasonable to expect that customer satisfaction for program participants who now can avoid paying a previously unavoidable convenience fee will be enhanced, we conclude that DEI's proposed fee-free payment option is unreasonable since it has not been shown to provide any value, including any level of enhanced customer satisfaction, to non-participating customers. We therefore deny DEI's request for approval of its proposed fee-free electronic payment program and deny its request for approval of a pro forma adjustment to annual revenue from base rates of $4.5 million.

In re Duke Energy Ind., LLC's Request for an Increase to its Rates and Charges, Cause No. 45253, Final Order pp. 105 - 106 (Ind. Util. Regul. Comm'n June 29, 2020), rev'd in part by *Ind. Off. of Util. Consumer Couns. v. Duke Energy Ind., LLC*, 183 N.E.3d 266 (Ind. 2022).

Once again, were the Commission to approve the Company's proposal, cash-paying customers would subsidize card paying customers without receiving a commensurate service benefit. There has been no convincing evidence presented that we should reconsider our previous finding on this issue. Therefore, we deny the Company's proposal.

F. **Aviation Expense**.

CAC witness Inskeep recommended the Commission deny the Company's request to recover $1,904,614 for costs associated with private aircraft. CAC Ex. 1 at 92-93. Mr. Inskeep testified regarding his concerns with the cost recovery and stated there is no way to verify the appropriateness of what appears to be a luxurious and extravagant method for travel by primarily non-Duke Energy Indiana employees for inclusion in Duke Energy Indiana rates. *Id*. He testified there is no way to verify, for instance, that Duke Energy executives have not used these aircraft for personal uses, to curry favor with policymakers and celebrities, or to engage in direct lobbying. *Id*.

On rebuttal, Company witness Graft explained the aircraft Mr. Inskeep complains of are owned by Duke Energy Business Services, LLC and are used to serve all Duke Energy affiliates. Pet. Ex. 29 at 15. She explained that as with all assets owned by Duke Energy Business Services, LLC, only 10.13% of depreciation of these aircraft and 10.13% of other aviation expenses for the four aircraft are included in the Company's 2025 forecast in this proceeding. *Id*. Ms. Graft explained that sharing services and assets between affiliates is a common and cost-effective manner for a corporation to operate – through this system, Duke Energy Indiana can avoid needing its own discrete assets and service employees. *Id*. Ms. Graft testified it is reasonable for Duke Energy Indiana to include the 10.13% of the cost of these assets in accordance with its relative size among affiliates within the corporation.

We agree with Ms. Graft that it is reasonable for Duke Energy Indiana to include these aircraft-related costs in its proposed revenue requirement in this proceeding. The necessity to use private aircraft for transportation and patrolling of Company-owned assets is an expense one would expect a utility company the size of Duke Energy to incur in the normal course of its day-to-day operations. As Ms. Graft explained, sharing of services and assets between affiliates can help avoid the need for Duke Energy Indiana to own discrete assets and service employees to perform these same tasks. Thus, we find the Company's inclusion of a portion of these expenses for the shared used of the aircraft is reasonable and appropriate and should be approved.

G. <u>Investor Relations Expense</u>.

OUCC Witness M. Garrett recommended the Commission disallow 50% of the investor relations expenses allocated to Duke Energy Indiana because the responsibility to communicate with the global capital markets ultimately falls upon Duke Energy, not Duke Energy Indiana or its ratepayers. Pet. Ex. 2 at 41. As such, Mr. Garrett recommended a $254,000 reduction so as to appropriately share the investor relations expense. *Id*. Mr. Garrett also testified that these costs are not a *necessary* cost of providing electric service, as evidenced by the hundreds of local electric utilities nationwide owned by cities, counties, and tribal nations that do not maintain an investor relations function. *Id*. at 41. On rebuttal, Company witness Bauer disagreed with Mr. Garrett's recommendation to disallow 50% of the investor relations costs, contending investor relations expenses are a necessary and required cost for Duke Energy to appropriately communicate with global capital markets and, in turn, are necessary for Duke Energy to attract capital. Pet. Ex. 46 at 28. Mr. Bauer claimed that Duke Energy Indiana's customers ultimately benefit from Duke Energy's ability to attract capital and, therefore, it is appropriate to allocate a portion of these costs to Duke Energy Indiana. *Id*.

Duke Energy is responsible for investor relations. Duke Energy Corporation's shareholders, however, benefit disproportionately from the activities funded by Petitioner's contribution at customers' expense. Accordingly, we find a 50% - 50% sharing between customers and shareholders is appropriate and should be approved.

H. <u>Other Post Retirement Benefits Expense</u>.

In its case-in-chief, the Company proposed to refund $75 million over two years, via the Company's Rider 67, from the Company's Grantor Trust. Pet. Ex. 16 at 35-36. The Company also proposed a $5,850,000 *pro forma* adjustment in its case-in-chief to set the level of OPRB expense included in O&M to zero. Pr. Ex. 4 at 25-26. Ms. Sieferman explained the adjustment was made because the level of external funding in the Grantor Trust, established to fund payment of future OPRB liabilities, was sufficient to pay these benefits in the foreseeable future without additional funding. *Id*. Ms. Sieferman testified this treatment for cost-of-service purposes is consistent with that used in the Company's last retail base rate case, Cause No. 45253. *Id*.

OUCC witness M. Garrett did not oppose the Company's proposal to refund $75 million over two years via the Rider 67 from the Grantor Trust. Pub. Ex. 2 at 26. Mr. Garrett recommended, however, that the Company remove its pro-forma adjustment to set OPRB expense to zero because the Grantor Trust refund the Company proposed "will not necessarily eliminate the trust earnings in excess of the plan's cost." Pub. Ex. 2 at 26. Mr. Garrett also recommended the amount refunded to customers be reviewed and trued-up at the end of the two-year period. Pub. Ex. 2 at 26-27.

On rebuttal, Ms. Sieferman reiterated that the Company's proposal to set OPRB expense in base rates to zero was approved in Cause No. 45253. Pet. Ex. 30 at 14. She explained that while Mr. Garrett's recommendation would, in effect, provide an additional credit to customers by decreasing the expense by $5.85 million, this credit would need to come from Petitioner's general funds rather than from the funds in the Grantor Trust because distributions from the Grantor Trust are limited to OPRB payments and administrative expenses and taxes, not OPEB expenses. Ms. Sieferman testified that if this credit OPRB expense amount were included in revenue requirements, other non-OPRB costs included in revenue requirements would not be fully covered by customer revenues, denying the Company the opportunity to earn its allowed return. *Id.* at p. 15. Ms. Sieferman agreed with Mr. Garrett's recommendation to review the amount refunded to customers and true-up the amount at the end of the two-year period. *Id*. at 13-14.

The Company maintains a Grantor Trust for its post-retirement benefit plan for legacy employees. Petitioner established the Grantor Trust as a result of the Commission authorizing accrual accounting for the OPRB expenses and recovery of those expenses in base rates. The Grantor Trust corpus exceeds the projected future benefit payments, prompting the Company to request authority to refund $75 million of the excess balance to ratepayers over two years, which is approximately 50% of that balance.

Given the current excess balance in the Grantor Trust that ratepayers have funded, the Commission finds it is appropriate for $75 million of this balance to be returned to customers. However, we do not agree the OPRB credit, or negative expense, should terminate. Based on the evidence, there remains, and will remain, a substantial excess in the Grantor Trust corpus. While we do not find the excess balance must now be eliminated, we find the OPRB expense credit should continue as no adequate basis was shown for not continuing to return the negative expense to ratepayers incrementally for the duration of these base rates.

I. Revenue Rate Migration Adjustment.

a. Duke Energy Indiana Case-in-Chief.

In his direct testimony, Mr. Flick discussed the proposed revenue rate migration adjustment, why it was needed, the criteria for determining potential migration, the benefits of the adjustment, and why the Company believed it was reasonable. Pet. Ex. 7 at 8-11. He explained that the results of the Company's migration analysis are shown on Attachment 7-G (RAF), Attachment 7-H (RAF), and Workpaper RAF-20. The Company calculated $32.5 million of potential customer savings from rate migration. Mr. Flick testified the Company's experience suggests that even with awareness of a bill savings opportunity some customers will not change rates. Accordingly, Mr. Flick explained that the Company has reduced the total migration amount by 50% to $16.3 million and used minimum savings thresholds in calculating the $16.3 million migration amount sought for recovery. The $16.3 million in expected revenue decreased due to anticipated rate migration from rates RS, CS, LLF, and HLF has been allocated to these rates, respectively. *Id.* at 9.

b. **OUCC and Intervenors**.

The OUCC, CAC, Industrial Group, and Kroger presented testimony suggesting Duke overestimated the amount of revenue reduction (migration related lost revenue) associated with anticipated rate switching and/or proposed computational changes to the calculation. OUCC witness Hanks stated that given the low interest in the FSO Pilot, it is premature and speculative in this Cause to charge all customers because some may save money on the new rate. Pub. Ex. 10 at 8. He explained that not all customers who switch to the TOU will save money. *Id*. at 9. Mr. Hanks testified that Petitioner failed to consider the increased revenue from ratepayers who switch to TOU and pay more due to use during peak times or those who use more energy at discounted times due to the discount, as occurred in the FSO Pilot. *Id*. at 5, 8, 9, and Table 6.

Mr. Hanks stated that if the proposed migration adjustment amount is approved and fewer customers switch to TOU rates than projected, Duke will receive revenue from the migration adjustment and higher revenue amounts from the customers who are projected to switch but do not. *Id*. at 5.

Dr. Dismukes testified that Petitioner's assumption that 50 percent of its customers will switch to a TOU rate is not supported beyond its anecdotal evidence that *some* customers will not change rates. Pub. Ex. 11 at 47 (emphasis added). He stated that data does not support a 50 percent adoption rate, citing a 2019 study that found 60 percent of investor-owned utilities offering TOU rates had enrollment rates of less than one percent, as well as a 2018 study that only four percent of all residential customers in the United States took service under a TOU rate. *Id*. at 47. Dr. Dismukes recommended the proposed migration adjustment amount be reduced to one-third of Duke's proposed amount, which corresponds to the assumption that only 16.5 percent of residential and small commercial customers will adopt TOU rates. *Id*. at 48. He stated this adoption rate is more realistic based on historic experience. *Id*. at 48.

CAC witness Inskeep recommended the Commission deny Duke's request to recover lost revenues associated with customer migration to TOU rates, particularly the residential customer class, because Duke's estimated rate impact is based on an unreasonable methodology and fails to account for cost savings. Mr. Inskeep testified that to the extent the Commission approves Duke's request for lost revenues against CAC's recommendations, the Commission should require the Company to track both actual lost revenues and cost savings and defer the net balance for future recovery potentially in a subsequent rate case rather than include speculative estimated future lost revenues in this case. CAC Ex. 1 at 96. CAC witness McCann suggests migration related to lost revenues should be determined ex post. CAC Ex. 2 at 28. Using his methodology, Dr. McCann testified the Company's revenue requirement should be reduced by $16.25 million and this amount redistributed to the rate classes in proportion to projected TOU participation. *Id.* at 29.

IG witness Gorman stated the migration amount is not fixed, known, or measurable and recommended the rate migration adjustment be rejected in its entirety. IG EX. 1 at 7. Kroger witness Bieber suggested rate migration lost revenue be assigned to the rate class migrating customers are moving to versus from. Kroger Ex. 1 at 4-6, 12-19. He recommended the Commission reject Duke's proposal to assign the $2.4 million HLF Secondary to New LLF Secondary portion of the migration adjustment to HLF Secondary. *Id.* at 5, 18-19.

c. **Duke Energy Indiana Rebuttal**.

In response to OUCC witness Hanks, Mr. Flick took issue with drawing correlations from the pilot results to potential outcomes attributable to the new TOU rates, noting the improvements included in the proposed offerings. He explained Duke Energy Indiana previously offered a suite of dynamic pricing pilot rates with capped participation. The pilot rates had more complex rate designs compared to the more traditionally structured TOU rates proposed in this proceeding and placed a higher burden on participants to track the frequent pricing changes to maximize their value. *Id*. at 8.

Mr. Flick summarized Petitioner's computation of the requested migration amount. Pet. Ex. 33 at 4-5. He explained that at the foundation of the computation is near-population level customer data for each rate class. Mr. Flick stated Petitioner used that data to calculate what each customer's bill would be under all eligible rate alternatives, identifying the "best," or least expensive, rate for each customer. Mr. Flick explained that if a customer's existing rate is the least expensive option, the presumption is the customer will stay on their existing rate and not migrate and, among the subset of customers that could save money on another rate, the rate providing the most savings is deemed to be the rate customers will migrate to. Mr. Flick testified the cumulative amount of customer savings is totaled by rate and then filtered by savings thresholds. *Id*. at 4. He stated that while residential customers saving five to ten percent may also migrate and receive lower bills, Petitioner excluded those savings from its rate migration recovery request. *Id*. at 4-5. Mr. Flick further stated that after these thresholds were applied, the amount of bill savings is calculated by rate. He testified only 50 percent of the savings was proposed for recovery in this proceeding as lost revenue. Mr. Flick testified that Duke believes its calculation is real (as it is derived from actual, individual customer bill analysis) and also conservative in that many potential savers are not assumed to ultimately migrate. Mr. Flick further testified that savings derived from potential behavioral changes in response to new price signals were excluded from Duke's proposed rate migration amount.. He explained that such changes will only occur after a customer switches tariffs and begins receiving new price signals. Mr. Flick testified that such behavioral changes could further reduce customer bills and yield system benefits by reducing long-term investment needs. *Id*. at 5.

Regarding Dr, McCann's suggestions, Mr. Flick further explained that calculating migration lost revenue after the fact adds administrative burden to all parties involved. He testified that the analysis was performed with near-population data that reflected actual customer data. That work identified bill savings opportunities in the manner described above and is not speculative. Further, the *ex ante* approach was used, not opposed, and therefore approved in Cause No. 45253 (IURC 06/29/20) p. 124. Mr. Flick testified he therefore believed the previously approved *ex ante* approach is administratively efficient and reasonable. Pet. Ex. 33 at 6.

In response to Kroger witness Mr. Bieber, Mr. Flick explained that the appropriate decision regarding whether lost revenues should be assigned to the rate class a switching customer originated from or is moving to requires consideration of broader factors like the number of customers in the rate classes in question. He explained that either choice could lead to unintended consequence if made in a vacuum. Mr. Flick testified the Company's proposal appropriately considers the relative sizes of the tariffs and classes in question, addresses the need for gradualism, and does not allow the migration adjustment to unduly influence the actual size of customer migrations. *Id*. at 7.

Mr. Flick testified that he does not agree with the several witnesses that argued that the company's requested migration amount either be denied or reduced. *Id*. at 9. He said doing so would unduly challenge the Company's opportunity to earn the ultimately approved revenue requirement. Mr. Flick explained in short, the Company has designed the new TOU rates and prices to be reasonably attractive to a large enough group of customers to encourage adoption, with the expectation that such migration will not impair the Company's ability to recover its revenue requirement. He testified that if migration recovery is not approved, the message would be the Company should design less attractive pricing structures to limit migration and so as to provide appropriate recovery. *Id*.

d. **Commission Discussion and Findings**.

The Commission finds that Duke did not provide persuasive empirical evidence to support its assumption that 50 percent of Petitioner's customers eligible to migrate to a new rate will, indeed, migrate to that rate. The evidence demonstrates otherwise, including research findings Dr. Dismukes presented upon residential and small commercial customers' adoption of time-variant rates that demonstrate adoption rates that are significantly below 50%. Although Petitioner contended that residential customers with no behavioral change will save money with TOU rates, the evidence does not demonstrate that customers who are unlikely to change their behavior with respect to the time of consumption or manner of consumption will change their behavior to adopt a new rate.

The adoption rates shown in the studies OUCC witness Dismukes referenced ranged from a low of one percent to a high of four percent. Although not an apples-to-apples comparison, Duke's adoption rate for its Dynamic Pricing Pilot approved in its last rate case fell below one percent. The Commission is mindful that approving a lost revenue adjustment for lost revenue that never materializes carries a substantial risk of double recovery of revenues from Petitioner's ratepayers. While we recognize there may need to be some adjustment, we find it is premature to approve the adjustment level Petitioner proposed given the low interest in the Dynamic Pricing Pilot and the evidence supporting an adjustment based on one to four percent adoption, but we also find the rate migration adjustment should not be entirely disallowed. Based on the record, the Commission finds it is reasonable at this juncture to assume 16.5% of Petitioner's customers will adopt the new offered rate. For residential (RS) and small commercial (CS) customers, we find it is, therefore, appropriate to reduce the proposed revenue requirement for customer migration by $2.5 million ($2.3 million for residential customers and $0.2 million for small commercial).

J. **Late Payment Fees and Reconnection Charges**.

[The OUCC does not take a position on this issue.]

K. **<u>Payment Navigator Program</u>**.

In this proceeding, Petitioner included $350,000 in its forecasted O&M expense in order to implement and operate its new Payment Navigator Program to assist financially vulnerable customers. Pet. Ex. 24 at 15. OUCC witness Hanks recommended the Commission deny Duke's requested approval of the Payment Navigator programs and reduce pro-forma O&M expense by $350,000. Pub. Ex. 10 at 15. Mr. Hanks testified the Company has not established the necessity of the program, especially because these full-time staff would mainly be used during high usage seasons. *Id*. He further testified the Company's request does not take into account the additional customer resources associated with the Customer Connect program. *Id*.

The Payment Navigator program is designed and centered around high bill call volume and average call handling times. However, the Company did not account for changes to these metrics that may result from its newly implemented Customer Connect program. It did not propose an offsetting adjustment for savings it may realize with respect to its current Customer Care Operations or staff. High bill volumes are reasonably tied to high usage seasons and are not consistent with an annual full-time equivalent employment basis. The Company has not demonstrated that the purpose of the Payment Navigator program could not be met by appropriate training and organization of its Customer Care Operations. It also failed to demonstrate that its Customer Connect program, which no party challenged, would not alleviate, in large part, the necessity of such program, by reducing average handling times. This would allow Customer Care Operations staff to receive more targeted training to serve the customers, which the Payment Navigator program would be designed to serve. The evidence is insufficient to support the Payment Navigator program and we, therefore, disallow the adjustment.

L. **<u>Production O&M Costs</u>**.

Duke Energy Indiana forecasted $21,425,540 in annual O&M expense for ongoing CCR handling and disposal costs.

OUCC witness Armstrong testified that Duke failed to adequately show how O&M costs for its generating units' CCR handling and disposal were forecasted. She stated that although Duke provided some breakdown of these forecasted costs and the capacity factors in responding to the OUCC's data requests, Duke did not provide formulas, calculations or contract rates as to how these numbers were derived until filing its rebuttal, despite the OUCC requesting this information twice. She testified that Petitioner stated the historical CCR costs were considered and then evaluated against the modeled capacity factors of the generating units, but this could not be verified without the formula showing how these capacity factors were applied to historical costs in calculating the test year forecasted O&M costs. Ms. Armstrong also noted conflicting information was provided in discovery with respect to the Environmental Health and Safety ("EHS") costs allocated to the budget. In the absence of this information, she recommended a four-year historical average be used to determine Duke's test year ongoing CCR handling and disposal O&M costs, which she provided confidentially.

Ms. Armstrong stated the four-year historical average for currently-operating generation units was calculated based on 2020-2023 data. She testified that she included the total values associated with the Cayuga, Edwardsport Integrated Gasification Combined Cycle ("IGCC"), and Gibson plants but after seeking additional information regarding the Operating Units listed in Duke's historical CCR costs, it was still not clear what costs were included in the "DEI Other" category. Ms. Armstrong testified she was concerned there are non-CCR-related costs or CCR costs not related to ongoing operations that were included inappropriately; therefore, she did not include costs in the "DEI Other" category. She noted that while she has the same concern that non-CCR related costs are included in "Non-RRE" costs, Duke's description of these costs shows they qualify as EHS or other general administrative costs; consequently, she included the four-year average for historical Non-RRE costs.

On rebuttal, Company witness Hill disagreed with Ms. Armstrong's recommendation to reduce the O&M forecast for the 2025 test year by using the four-year historical average and disallowing the costs classified as DEI-Other. Pet. Ex. 42 at 2-4. Mr. Hill contended Ms. Armstong inappropriately did not include reasonable costs the Company regularly incurs and expects to continue to incur that were included in the 2025 forecast. *Id*. at 2. He testified the forecast for the test year is based on historical actual costs and informed by the capacity factor where applicable, and he recommended no changes be made to the Company's forecasted production O&M expenses. *Id*.

In his direct testimony, Mr. Hill provided Duke's forecasted O&M costs for CCR handling and disposal but without the supporting data. The forecasted capacity factors were in a hard-coded format without formulas or calculations, notwithstanding that without these calculations, the OUCC could not verify how Duke applied the capacity factors to the historical data to arrive at the forecasted CCR O&M. The supporting data was also not forthcoming in response to the OUCC's data requests. *See* OUCC Att. CMA-8 and CMA-9. Duke waited until its rebuttal to provide the information, with Mr. Hill providing Petitioner's Confidential Attachment 42-A showing DEI's formulas for calculating its forecasted CCR O&M costs. During cross-examination, Mr. Hill admitted the calculations provided in his Confidential Attachment 42-A were not provided until rebuttal. Tr. F-54 – 55.

The Commission finds it is appropriate and incumbent upon utilities to provide all the data necessary to support the forecasted test year costs within each utility's case-in-chief. In Petitioner's case-in-chief, however, Duke did not do so and continued to not provide requested data in discovery that was needed to confirm Petitioner's forecasted CCR O&M costs. Duke inexplicably waited until rebuttal to share this information. When a utility waits until rebuttal to support its forecast with crucial information, this severely limits other parties' ability to analyze the case, verify the utility's assumptions and calculations, and respond to the reasonableness of the utility's request. "[I]f the material was not included in the initial submission due to a lack of diligence, or was knowingly withheld, then merely ordering further discovery and surrebuttal would be tantamount to rewarding the slothful and recalcitrant litigant and unduly burdening the more assiduous participants." *Re Ind. Cities Water Corp*., Cause No. 38851, 115 P.U.R.4th 470, 1990 WL 488768, ¶7(i) (Ind. Util. Regul. Comm'n Jul. 5, 1990), *citing El Paso Nat. Gas Co.*, FERC Docket No. TA85-1-33-004, Order on Motion for Reconsideration, Slip Op. at 2 (Dec. 28, 1988).

Because Duke failed in its case-in-chief and in response to the OUCC's discovery to provide the information needed to confirm Petitioner's forecasted CCR O&M costs, Duke effectively precluded the OUCC from verifying the reasonableness and accuracy of its requested relief. Given these circumstances, Ms. Armstrong was relegated to the path she took in not including costs in the DEI Other category and using the four-year average for historical Non-RRE costs. We find the OUCC's adjustment to the test year O&M for CCR handling and disposal costs is reasonable and appropriate and that had Petitioner deemed otherwise, support for Duke's alternative position should have timely been forthcoming.

M. Depreciation and Amortization Expense.

Petitioner proposed nine *pro forma* adjustments related to depreciation and amortization expense in this proceeding as set forth on Petitioner's Exhibit 26, Attachment 26-C, Schedules DA2 through DA11. We have previously addressed the depreciation-related expense issues in the Environmental Sustainability section of our Order. Regarding the amortization-related adjustments, amortization expense was largely uncontested apart from certain issues raised by OUCC witness Eckert and discussed in this section. Otherwise, we find all *pro forma* adjustments proposed by Petitioner, either as originally proposed and undisputed, or as adjusted with the compromised positions having been fully identified by the parties, are hereby accepted even though they may not be specifically discussed in this Order.

a. Duke Energy Indiana Case-in-Chief.

In its case-in-chief, the Company proposed to amortize the following regulatory assets over a three year period: (1) COVID 19 deferred expenses; (2) remaining End-of-Life M&S Inventory for Retired Gallagher Station; (3) 316(b) Plan Development costs (20% portion not recovered in Rider 62); (4) Purdue CHP Plant Deferred O&M Expense; and (5) 2024 Rate Case Expenses. Pet. Ex. 31 at 3.

b. OUCC.

OUCC witness Eckert raised several issues with the Company's proposal regarding these regulatory assets. Specifically, Mr. Eckert recommended these regulatory assets be recovered over a four year period, not a three year period as proposed by the Company. Pub. Ex. 1 at 37. Mr. Eckert's position was that four years is reasonable because that is the period since the Company's last rate case order. *Id*. Further, Mr. Eckert testified the Commission should disallow recovery for Duke Energy Indiana's regulatory asset for the $7.6 million in "unmonetized" remaining inventory after the retirement of Gallagher. He testified the remaining inventory was included in rate base in Duke Energy Indiana's last rate case and Duke Energy Indiana has been earning a return on this amount since its last rate Order and it had continued to collect this amount from ratepayers after the retirement of Gallagher. Mr. Eckert testified Duke Energy Indiana has not provided evidence that reasonable inventory management routines were in place prior to that remaining inventory becoming obsolete. Mr. Eckert explained inventory is managed based on costs, lead-times and usage; when usage is expected to decline, inventory management techniques prescribe that safety stock should be decreased. He explained obsolete inventory often results from excess inventory that eventually cannot be used, and when very obsolete, it can no longer be sold or monetized and must be written off and disposed of.. *Id*. at 37-38.

Further, Mr. Eckert testified the Company should not be authorized to recover certain COVID-19-related deferred expenses because Duke Energy Indiana's calculation of such expenses extended beyond the allowed period authorized by the Commission in Cause No. 45380. *Id*. at 36. Using the correct time periods, Mr. Eckert calculated incremental COVID-19 expenses of $2,162,765. *Id*.

c. <u>Duke Energy Indiana Rebuttal</u>.

On rebuttal, Company witness Lilly testified the regulatory assets at issue in this proceeding are not included in rate base, and the Company is only seeking recovery of the deferred expenses over a three-year period. Pet. Ex. 31 at 3. She testified the Company is opposed to extending the proposed amortization period to four years, and she disagrees with Mr. Eckert that a four-year amortization period is reasonable simply because that is the period since the Company's last rate case order. *Id.* at 4. She testified there is a recent trend in the industry for more frequent rate cases, and the Company chose the three-year amortization period precisely because completing amortization of these assets before there potentially could be similar or other new expense-related assets to amortize in the next rate case is a priority. *Id*.

In response to the OUCC's recommendation to disallow certain COVID-19-related expenses, Ms. Lilly explained that in making the Company's accounting entry regarding these amounts in March of 2022 (rather than back in October 2020 as Mr. Eckert asserts was appropriate) allowed the Company to take a longer view on its uncollectible expense, reducing the amount by approximately $5M due to the passage of time. Pet. Ex. 31 at 8-9. Ms. Lilly testified as such, the Company's decision to make its accounting entry reduced the size of the regulatory asset being proposed for amortization in this proceeding, thus benefiting customers. *Id*. Ms. Lilly explained, however, to the extent the Commission requires October 12, 2020 as the cutoff, the Company will re-calculate its regulatory asset balance as of that date for this proceeding. *Id*.

Regarding Mr. Eckert's recommendation that the Company should not be authorized to earn a return on its deferred expenses related to the Gallagher Station's remaining M&S inventory, Ms. Lilly reiterated the Company is requesting to recover the cost of the remaining inventory via an amortization and is not requesting a return on the inventory in this case. *Id*. at 6. She testified Duke Energy Indiana reasonably disposed of much of the remaining inventory leading up to and after the retirement of the Gallagher units and created the regulatory asset in accordance with the Commission's Order in the Company's last rate case. *Id*. Thus, she testified it is appropriate for the Commission to approve the amortization of this regulatory asset as proposed.

d. <u>Commission Discussion and Findings</u>.

The first issue we address is the appropriate amortization period for the five regulatory assets at issue in this case. We initially note that Petitioner's prior rate case was filed in July 2019, nearly five years prior to the filing of the present rate case. Prior to that, Duke Energy Indiana's rate case (PSI Energy, Inc. at that time) had been filed at the end of 2002. Therefore, the average time between Petitioner's last two rate cases and this rate case is approximately 10.75 years (the average of approximately five years and approximately 16.5 years. We have recently found rate case expense should be amortized over the Petitioner's historical average of time between rate cases. See *In re Ind. Amer. Water,* Cause No. 45870, Final Order, at 83 (Ind. Util. Regul. Comm'n

Feb. 14, 2024). We acknowledge that the cadence of Duke Energy Indiana's future rate cases will be affected by other factors. However, there is not sufficient empirical evidence from which to conclude that Duke Energy Indiana would file its next rate case in fewer than four or five years. We find the OUCC's recommendation of a four-year amortization to be reasonable and appropriate. We also applied the same amortization to other similar costs; to be amortized over the expected life of the rates; a period of four years. *Id*. at 84, 85 ("Consistent with our decision above concerning the amortization of rate case expense, we find these costs should also be amortized over the four-year expected life of Petitioner's approved rates.")

Regarding the issue of the Gallagher Station's remaining M&S inventory, the $7.6 million in "unmonetized" remaining inventory has been earning a return since Duke Energy Indiana's last rate Order. Duke Energy Indiana has continued to collect this amount from ratepayers after the retirement of Gallagher. Duke Energy Indiana has not provided sufficient evidence that reasonable inventory management routines were in place prior to that remaining inventory becoming obsolete, and we therefore, disallow this recovery.

Regarding the COVID-19-related expenses, we agree with Mr. Eckert. Duke Energy Indiana's deferred incremental COVID-19 expense calculation did not conform with the Commission's accounting authority found appropriate in Cause No. 45380. Using the correct moratorium period authorized results in COVID-19 expenses of $2,162,765. Amortizing this amount over four years results in $540,691 in annual recovery. Therefore, we find that Duke Energy Indiana's amortization should be reduced by $1,074,308.

N. <u>Tax Expenses</u>.

Petitioner proposed sixteen tax-related pro forma adjustments in this proceeding as set forth on Petitioner's Exhibit 26, Schedule 26-C, Schedules OTX2 through OTX8; Schedule ETR; and Schedules TX1 through TX8. The only tax-related adjustment at issue in this proceeding is Petitioner's *pro forma* adjustment to normalize payroll taxes associated with Major Storms. We made findings previously in this Order on the O&M portion of this *pro forma* adjustment, and those findings apply here. Therefore, we disallow Petitioner's proposed *pro forma* adjustment to the extent inconsistent with our prior findings as to Major Storms Expense and approve the extent of the *pro forma* adjustment which is consistent with our prior findings. Otherwise, we find all *pro forma* adjustments proposed by Petitioner, either as originally proposed and undisputed, or as adjusted with the compromised positions having been fully identified by the parties, are hereby accepted even though they may not be specifically discussed in this Order.

14. <u>Net Operating Income at Present Rates</u>. Based on the evidence and determinations made above, we find Petitioner's jurisdictional adjusted test year operating results under present rates are:

Total Operating Revenues	$3,019,481,000
Operating Expenses	
Operation & Maintenance	1,442,258,000
Depreciation and Amortization	841,907,000
Taxes other than Income Taxes	74,799,000

Income Taxes	97,388,000
Total Operating Expenses	2,456,352,000
Net Operating Income	$563,130,000

In summary, we find that with appropriate adjustment for ratemaking purposes, Petitioner's annual net operating income under its present rates for electric service would be $408,121,000. We have previously found that Petitioner's net original cost rate base as of the end of the test year is forecasted to be $12,600,376,000, that Petitioner's WACC is 5.87%, which would produce a return on net original cost rate base of $739,642,000. Petitioner's current return of $408,121,000 will be insufficient to represent a fair return on the fair value of its rate base. We therefore find that Petitioner's present rates are unreasonable and confiscatory.

15. <u>Authorized Rate Increase and Rate Implementation</u>.

a. <u>Rate Implementation Process</u>.

Company witness Graft described Petitioner's proposed rate implementation in this proceeding. With respect to the Step 1 rate adjustment, Ms. Graft explained the Company will calculate revenue requirements reflecting the June 30, 2024 capital structure, June 30, 2024 net plant in service and the associated annualized depreciation expense, and the 2025 forecasted amounts for other components of rate base. Ms. Graft testified the output of the Step 1 revenue requirements calculation will be provided to Company witness Diaz, who will calculate the Step 1 jurisdictional revenues by retail rate group. She explained the difference between jurisdictional revenues approved in the Commission's Order in this proceeding and the Step 1 jurisdictional revenues will be credited to customers in Tracker No. 67 rates. Ms. Graft further explained the Company has forecasted the June 30, 2024 capital structure and net plant in service balance and the associated annualized depreciation expense for purposes of estimating the Step 1 impact in the case-in-chief. On rebuttal, the Company updated these estimated amounts to the actual June 30, 2024 capital structure and net plant in service balance and the associated annualized depreciation expense. Pet. Ex. 3 at 13-14.

Ms. Graft testified that having filed this information at rebuttal will allow ample opportunity for intervening parties to review the June 30, 2024 data. As such, the Company proposed to implement its Step 1 rates, including base rates and tracker rates, as soon as possible following issuance of the Order in this Cause and upon submission of the compliance filing and Commission approval of the tariff. Ms. Graft testified the rates will be effective on a services-rendered basis. Ms. Graft explained that since the Step 1 actual net utility plant in service and capital structure will be known at the time a few weeks before the evidentiary hearing, there should be no need to schedule a defined period for the parties to review the Step 1 compliance filing. The Company estimated these rates would be effective in or before March 2025. *Id*.

Regarding the Step 2 rate adjustment, Ms. Graft explained the Company will calculate revenue requirements reflecting its actual capital structure as of December 31, 2025, the lesser of the forecasted or actual net plant in service balance as of December 31, 2025, the annualized depreciation expense associated with the lesser of the forecasted or actual net plant in service balance as of December 31, 2025, and the 2025 forecasted amounts for other components of rate base. Ms. Graft testified the output of the Step 2 revenue requirements calculation will be provided to Company witness Diaz, who will calculate the Step 2 jurisdictional revenues by retail rate group. She explained the difference between jurisdictional revenues approved in the Commission's Order in this proceeding and the Step 2 jurisdictional revenues will be credited to customers in Tracker No. 67 rates. Pet. Ex. 3 at 14-16.

With respect to how the Step 2 rate adjustment will be implemented, Ms. Graft explained the Company will submit a second compliance filing with the Commission in March 2026 that will remove the Step 1 rate adjustment from Tracker No. 67 and replace it with the Step 2 rate adjustment. She testified the Step 2 rate adjustment will take effect upon submission and approval by the Commission on an interim-subject-to-refund basis pending a 30-day review process and the resolution of any potential objections. Additionally, as was approved in Cause No. 45253 for the implementation of the Step 2 rate adjustment, Ms. Graft testified the Company is proposing to collect the difference between the Step 1 rate adjustment and the Step 2 rate adjustment, with carrying costs at the December 31, 2025 actual weighted average cost of capital, from January 1, 2026 until the time the Step 2 rate adjustment is reflected in Tracker No. 67, expected to be in March 2026. Ms. Graft explained the Company's second compliance filing will include an estimate of this differential in the calculation of the overall Step 2 rate adjustment using actual (or estimated) kWh sales for services rendered January-February 2026. Ms. Graft testified that the development of the overall Step 2 rate adjustment in this way will have the practical effect of the Step 2 rate adjustment being implemented on January 1, 2026 on a services-rendered basis even though mechanically, the revised Tracker No. 67 rates will be implemented on a bills-rendered basis upon Commission approval. *Id*.

OUCC witness Eckert requested the Commission find the Company's base rates should be implemented on a services-rendered basis, and Ms. Graft confirmed on rebuttal it is Petitioner's intention to do so. Pet. Ex. 29 at 5. Further, Mr. Eckert recommended the Commission grant the parties at least sixty (60) days to review the Company's compliance filing with updated rate base and capital structure. Pub. Ex. 1 at 20. Ms. Graft interpreted Mr. Eckert's recommendation as being applicable to only the Step 2 compliance filing, as the Company provided the actual net original cost rate base and capital structure as of June 30, 2024 for the basis of Step 1 in its rebuttal testimony. Therefore, Ms. Graft explained there is no need for a review period following the Step 1 compliance filing. She testified the Company believes the 30-day period it has proposed for review of its Step 2 compliance filing will provide adequate time and requested the Commission approve this proposal.

Apart from the two issues raised in OUCC witness Eckert's testimony, no party took issue with Petitioner's proposed two-step rate implementation proposal. The Company confirmed on rebuttal its intention is to implement new rates on a services-rendered basis, and thus there is no disagreement between the parties on this issue. Further, we agree with Ms. Graft that a 30-day review period for Petitioner's Step 2 compliance filing is appropriate, and that review period is not necessary for the Step 1 compliance filing.

Ultimately, we find Petitioner's proposal for implementation of Step 1 and Step 2 rates as set forth in Ms. Graft's direct testimony (Pet. Ex. 3) is reasonable and should be approved.

b. **Authorized Rate Increase**. Based on the evidence presented and subject to the approved compliance filing process, we find that Petitioner should be authorized to increase its rates and charges in two steps, calculated to produce combined additional operating revenue of $236,314,000 at the conclusion of the test year, resulting in total operating revenue of $3,255,795,000 before the effect of changes in ongoing tracker revenue discussed elsewhere in this Order. This revenue is reasonably estimated to afford Petitioner the opportunity to earn net operating income that is no more than the fair return of $739,642,000 that we have found to be appropriate, based upon projected test year end rate base and capital structure. The rate increase shall take place over the two steps we have described and, subject to the compliance filings, shall be calculated to produce jurisdictional operating revenues and net operating income at each step as follows:

(dollars in thousands)	Step 1	Step 2	Total
Rate base at original cost	$11,895,709	$704,667	$12,600,376
Rate of return	5.70%		5.87%
Required net operating income	678,055	61,587	739,642
Less: *pro forma* net operating income at present rates	592,029	(28,889)	563,130
Net operating income deficiency	86,026	90,486	176,512
Gross revenue conversion factor	1.33880		1.33880
Revenue deficiency before effect of trackers	115,172	121,142	236,314
Pro forma revenues at present rates	3,019,481	0	3,019,481
Total revenue before effect of trackers	$3,134,653	$121,142	$3,255,795

16. Cost of Service and Rate Design

Now that we have determined Petitioner's authorized rate increase, we turn now to the issues of cost of service and rate design. We will address the parties' various positions on cost of service and rate design.

A. Cost of Service.

i. Production and Transmission Demand Allocation.

1) Duke Energy Indiana Case-in-Chief.

Ms. Diaz explained that the allocation of production costs refers to all production facilities including steam generation, hydraulic generation, and other production necessary to integrate that generation into the power supply system and deliver it to the bulk transmission system. Pet. Ex. 6 at 10. She further explained that the 12CP method was used to allocate production and production related plant costs and expenses as well as transmission costs. Ms. Diaz testified that the Company selected 12CP in this proceeding to reflect one of the five pillars established in Indiana's Energy Policy Framework, Affordability. She testified that affordability is a critical metric for Duke Energy Indiana and will continue to be important for the Company as it focuses on attracting and maintaining customers in its service territory. Ms. Diaz explained that had the 4CP methodology been selected, the residential rate increase would have exceeded 20%. *Id.* at 29-30. She further explained that the Company does not seek to significantly impact one class of retail customers' rate increases such as weather-sensitive residential customer classes, while unduly benefitting other classes of customers due to the occurrence of extreme weather in a single peak period impacting the calculation of the demands which are limited to only four peak hours of demand. Instead, Ms. Diaz explained the Company aims for gradualism of the rate changes across the classes in its rate cases, and the use of the 12CP demand allocation for production and transmission accomplishes that objective for this retail rate case. *Id*. at 31.

2) <u>OUCC</u>.

Dr. Dismukes testified that he disagreed with the Company's classification of fixed production costs as exclusively demand-related. He argued against the Company's allocation of production costs because the Company's assumption is inconsistent with the dual role production/generation assets play in serving both peak demand and low-cost energy requirements for off-peak periods on the Company's system. Pub. Ex. 11 at 13-14. He testified that equally important is the fact that the Company's proposed classification ignores the significant portion of its current production plant in service that is associated with renewable generation assets, which provide very limited capacity benefits and should not be exclusively classified as demand related. *Id*. He then discussed what he believes to be the shortcomings of the Average & Excess ("A&E") method and provided support for the Average and Peak ("A&P") method. *Id*. at 16-25. With that, he recommended the Commission rely on the results of his alternative COSS, which (1) classifies 50 percent of costs associated with the Company's renewable generation assets as fully energy-related, and (2) uses an A&P method to classify the remaining production plant costs based on the Company's observed test year system load factors. *Id*. at 27. His proposed classification method classified 42.5 percent of the Company's production plant costs as being energy-related, with the inverse (57.5 percent) being classified as demand related for the test year. *Id*. He also offered an alternative COSS where he used the 12CP method for production and transmission costs.

3) <u>CAC</u>.

CAC witness Dr. McCann testified that allocation of generation costs should be split between capacity for reliability purposes and assets used to produce energy. CAC Ex. 2 at 18-19, 34. He presented Table RJM-2 which showed the separation of the Company's proposed generation asset annual revenue requirement between reliability capacity production demand and production energy functions. *Id*. at 18. Dr. McCann explained the revenue requirements are the sum of the target return on investment from the generation assets plus depreciation. *Id*. He further explained the calculation for separation for reliability and energy purposes is based on the Midcontinent Independent System Operator's ("MISO") CONE benchmark value of $98.59 per kilowatt-year plus a 15% reserve margin adder multiplied by the installed megawatts of DEI's portfolio capacity, which is 6,313 megawatts. *Id*. He testified that the reliability capacity portion, which is allocated based on the 12CP production demand method, is 62.5% of the total generation asset revenue requirement, while the residual 37.5% is allocated based on production energy delivery. *Id*. at 18. Dr. McCann recommended Energy-related capital and operating costs should be allocated among customer groups based on production energy to reflect how it is used. He further recommended that the remaining generation capital costs, as well as transmission costs, should be allocated based on the 12CP method, which better reflects market operations in MISO than the previous 4CP method. CAC Ex. 2 at 16-17, 34.

4) <u>Industrial Group</u>.

Mr. Collins testified that based on the characteristics of the Duke system and the cost allocation method previously approved by this Commission in the last rate case, he recommended the continued use of the 4CP method. IG Ex. 3. at 13-14. He testified there has been no material change in operational circumstances since that Order was issued. *Id*. Further, he testified he reviewed the Company's annual monthly coincident peak load pattern on a historical basis which shows Duke exhibits more of a 4CP now than it did in 2018, which was the basis of the Commission decision to approve the 4CP method. *Id*. at 14. Additionally, he points to the 2021 IRP for capacity planning to conclude that 4CP allocation is appropriate. *Id*. at 15. He noted that when considering what the three standard FERC tests indicate for the Duke system, it is clear that Duke remains a dominant 4CP utility, even more so than it was in the previous rate case. *Id*. at 14.

5) <u>Nucor</u>.

Dr. Zarnikau attributes much of Nucor's proposed rate increase to the Company's 12CP method for allocating production and transmission plant. Nucor Ex. 1 at 5-7. He discussed how the Company's proposal inequitably shifts the burden to customers like Nucor and away from residential customers. *Id*. He explained that the other rate classes are not receiving proposed increases as large as Nucor's, and no rate mitigation was applied for Nucor. *Id*. Dr. Zarnikau recommended the Commission follow the 4-CP method. Nucor Ex. 1 at 6. He explained that a 4-CP allocation was appropriate at the time of the last rate case and remains so today. *Id*. at 7. Dr. Zarnikau testified that cost-causation principles and the Commission's findings in the previous rate case supported the continued use of 4-CP allocations of production and transmission demand-related costs. *Id*. at 13. Dr. Zarnikau explained that there are reasonable ways of addressing any distortions in the data created by Winter Storm Elliott. *Id*. He testified that as the Company clearly recognizes, adjustments to implement gradualism can be applied post-cost allocation, if the rate impact on a particular class of customers is too drastic. *Id*.

6) <u>Walmart</u>.

Ms. Perry explained that Walmart appreciates the reasons why the Company is proposing to move away from a 4CP production cost allocator, but she believes that shifting from 4CP to 12CP is a step too far that will create interclass subsidies through higher load factor customers paying a greater share of the fixed production costs than what is needed to meet those customers' contribution to the system peak. *Id*. at 20. She testified this is evidenced by the Company's own analysis of the three FERC system demand tests that do no support moving to a 12CP cost allocation methodology. *Id*. Ms. Perry further testified that Walmart recommends that the Commission reject the Company's proposed 12CP production cost allocator and instead approve the current 4CP production cost allocation methodology for the Company's fixed production plant costs. *Id*.

7) <u>Petitioner's Rebuttal</u>.

On rebuttal, Ms. Diaz responded to Dr. Dismukes' and Dr. McCann's arguments. She explained that customers use the system on a year-round basis, but the application of cost causation leads to the conclusion that fixed costs should be allocated on a demand basis. Pet. Ex. 32 at 13. Ms. Diaz explained that the Company's production demand methodology relies upon the premise that the purpose of the resources is for long-term planning, and not based upon the operational use of the resources as proposed by Dr. McCann. *Id*. at 13. Ms. Diaz further explained that the use of the different resources, such as renewables, and their operations in any given hour, is not related to the Company's position, which is that Duke Energy Indiana must provide adequate generating capacity to meet the demands of customers when those customers make those demands on the system. *Id*. at 13-14. Ms. Diaz testified that the fact resources provide an energy benefit in certain hours is secondary, as it did not cause the investment. *Id*. at 14. She also explained that allocating production plant costs on both demand and energy contradicts the argument that there are peaks on the Company's electric system. *Id*. at 15. She testified Industrial Group witness Collins supported the Company's position by stating that any method of cost allocation that utilizes a form of average demand or energy to allocate production and transmission plant is at odds with the dominant system peaks on its electric system and should be rejected. *Id*.

Ms. Diaz testified on rebuttal that the Company continues to support its proposal to use the 12CP methodology. Pet. Ex. 32 at 3. She testified that utilizing the 12CP methodology is appropriate and warranted. *Id*. at 5-8. She testified that the Company understands the proposed change impacts rate classes differently and proposed the change based on several factors. *Id*. at 5-8.

Ms. Diaz discussed the numerous reasons the 12CP methodology is appropriate and warranted. *Id*. at 5-8. Ms. Diaz testified that MISO establishes capacity requirements for its member utilities based on peak demand and reserve criteria, and explained that the MISO requirements have changed since the Company's last rate case. *Id*. at 6. Ms. Diaz further explained that MISO's new requirements developed in 2022 move from a summer peak to four distinct seasons (Summer, Fall, Winter, Spring) for planning of generation resources and while the Company's 2021 IRP used the summer peak for capacity planning because of the rules in effect at the time, the 2024 IRP cannot. *Id*. Thus, Ms. Diaz testified the Company's IRP process has shifted away from an emphasis solely on summer peaks. *Id*. Ms. Diaz further testified that now, each season has a unique planning reserve margin, and the Company schedules its maintenance to accommodate each season. *Id*. She testified a generation fleet is planned to meet demand year-round. *Id*.

Ms. Diaz explained that by averaging the twelve monthly peaks, the 12CP method mitigates the weather effect that was observed in the highest peak more so than a 4CP method containing the highest peak. *Id*. She testified that by averaging twelve monthly peaks also increases the likelihood of rate stability from test period to test period. *Id*. Ms. Diaz further testified that 12CP does not require complex models to weather-normalize demand prior to use in cost allocation. *Id*. at 6. Ms. Diaz testified that constant transmission is also needed for reliability throughout the year, supporting the 12CP which uses multiple peaks. *Id*. at 7. She further testified that notably, MISO allocates network transmission charges to its load serving market participants using a 12CP allocation and explained that MISO has also studied the impact of renewable resources and concluded that the stress on the transmission system, besides the stress caused by peak demand, is impacted by the shoulder seasons of spring and fall due to renewable resources generating energy in these seasons. *Id*. Ms. Diaz testified the 12CP method is frequently used in allocating costs to customers, and further testified it is reasonable and a methodology that has been approved by state commissions, as well as FERC. *Id*. at 7. Ms. Diaz explained and said more simply, the circumstances since Cause No. 45253 have changed and are no longer appropriate. *Id*. Ms. Diaz further testified that a prior regulatory settlement supporting a 4CP methodology has lapsed with no continuing obligation. *Id*. at 7-8. Ms. Diaz explained the practical application of affordability for residential customers, while also considering the impact the 12CP methodology has on the remaining classes. *Id*. at 8. Ms. Diaz further explained that because FERC tests are guideposts and not steadfast rules for decision making, she did not give as much weight to the results of the tests as advocated by the intervenors. *Id*. She emphasized that as discussed in her direct testimony, the Company was close to passing two of the three guidepost tests. *Id*.

8) <u>Additional Evidence Received at Hearing</u>.

Ms. Diaz testified that Duke's system must be sized for multiple points in time, and Duke must evaluate its customers' behavior at those times or seasons. Tr. at C- 17. She noted MISO has changed from an annual peaking point to looking at similarly looking at multiple seasons, as Duke included in its IRP planning. Ms. Diaz stated the point of the MISO seasonal construct is that all the seasons are important, and all of the months in each season are important. Id. at C- 18.

Ms. Diaz testified that if Duke only procured enough generation capacity to meet a 4CP peak, this would not necessarily be sufficient to meet MISO's resource adequacy requirements. She stated it would not be in concert with MISO's requirements for reserves and capacity in each season. Id. at C- 46-48. Ms. Diaz confirmed that a portion of the MISO transmission costs are allocated using 12CP, and MISO does not use a 4CP. Id.

Ms. Diaz confirmed that December 2022 Winter Storm Elliot was included in the historical factors the Company used in its cost-of-service study. Id. She also confirmed a 4CP would use the data from that extraordinary December 2022 event. *Id*.

9) <u>Commission Discussion and Findings</u>.

The Commission finds it is appropriate to address generation and transmission separately as reflected below.

<u>GENERATION</u>

The Commission recognizes that the nature of production facilities is evolving. It has become clear that the planning, building, and retirement of production assets is not 100% demand related. In particular, with respect to Duke's renewable generation facilities, as well as the Edwardsport IGCC or coal-fired fleet, there are considerations and factors in addition to demand.

The Commission finds Dr. Dismukes's contention that Petitioner's production/generation assets serve a dual role, i.e., both peak *demand* and low-cost *energy* requirements for off-peak periods on Duke's system, is well taken. Allocating fixed production costs as 100% demand related ignores the function of base load production and renewable generation assets, which provide limited capacity benefits and should not be exclusively classified as demand related.

We find it is more reasonable to recognize that renewable generation sources are primarily functionally related to energy rather than demand, and base load generation serves to provide efficient energy. We further find that a 4CP methodology, as recommended by the industrial intervenors, fairly classifies production assets, given their evolving nature. The Commission has approved peak and average ("A&P") methodologies in other contexts because "A&P" captures the functionality of serving both low-cost energy and peak demand. Dr. Dismukes's methodology for classifying production best suits the functionality served by Duke's production/generation assets. Dr. Dismukes' alternative COSS: (1) classifies 50% of costs associated with the Company's renewable generation assets as fully energy-related, and (2) uses an A&P method to classify the remaining production plant costs based on Duke's observed test year system load factors. As a result, we approve his method classifying 42.5% of the Company's production plant costs as energy-related and classifying 57.5% as demand related for the test year.

The Commission further finds that the 12CP method used and advocated by Petitioner is superior to the 4CP method the industrial intervenors advocated, because the 12CP method recognizes MISO's new requirements (developed in 2022) moving from a summer peak to four distinct seasons (Summer, Fall, Winter, and Spring) when planning generation resources. Duke Energy Indiana's 2024 IRP must use this construct as opposed to its 2021 IRP, which had used summer peak for the capacity planning aspect. Petitioner's generation fleet is planned to meet generation year-round. We also recognize that Petitioner's 12CP method mitigates the weather effect(s) that had been observed in the highest peak. Methodologies that account for meeting demand year-round, as Petitioner's system is designed to do, have the added benefit of likely rate stability from test period to test period.

We note from Dr. Dismukes' rebuttal, his analyses of the Company's historic monthly system peak demands for the calendar years 2019 through 2023 shows the Company's system passed both the On and Off-Peak and Average to Annual Peak tests each calendar year 2019 through 2023, demonstrating that the Company's finding that its system fails these tests, even marginally, for 12 months ending August 31, 2023, is likely due to the time period examined by the Company (which includes part of 2022 and 2023). His analyses also finds that the Company's system passes the final FERC test, Low to Annual Peak, in two of the prior five calendar years. We recognize that the FERC tests are guideposts and when considering the evidence as a whole, we are persuaded that the methodology we approve and adopt here is the most appropriate methodology for classification and allocation of production and generation assets.

We agree with Ms. Diaz and Dr. Zarnikau that the FERC tests are guideposts and not steadfast rules for decision making. Pet. Ex. 32 at 8; Nucor Ex. 1 at 12. The Commission has previously found as much in prior Orders.[16] However, we disagree with Dr. Zarnikau that Duke Energy Indiana has not offered a compelling reason for proposing a 12CP methodology. There are numerous reasons why the 12CP methodology is appropriate now for Duke Energy Indiana and Ms. Diaz explained those reasons thoroughly in her testimony. Pet. Ex. 32 at 5-8. As the Commission stated in Cause No. 45253, operational changes, including the wholesale market and how MISO establishes capacity requirements guide how costs should be allocated. *See* Final Order in Cause No. 45253, pp. 119-120.[17] Although in Cause No. 45253 the Commission found the 4CP methodology appropriate, using the same guiding principles to the facts of today, we now find the Company's proposed 12CP methodology to be appropriate.

Further, the Company's IRP is not controlling on this particular topic because MISO requirements have changed since the Company's IRP and since its last rate case. The Commission must recognize that MISO now establishes capacity requirements for its member utilities based on peak demand and reserve criteria. MISO's new requirements developed in 2022 move from a summer peak to four distinct seasons (Summer, Fall, Winter, Spring) for planning of generation resources. Pet. Ex. 32 at 6.

Further by averaging the twelve monthly peaks, the 12CP method mitigates the weather effect that was observed in the highest peak more so than a 4CP method containing the highest peak. Averaging twelve monthly peaks also increases the likelihood of rate stability from test period to test period. Pet. Ex. 32 at 6. Further, 12CP does not require complex models to weather-normalize demand prior to use in cost allocation. Constant transmission is also needed for reliability throughout the year, thus supporting the 12CP methodology which uses multiple peaks. Pet. Ex. 32 at 6-7.

TRANSMISSION

In particular, we note Ms. Diaz' testimony that circumstances since Cause No. 45253 have changed and are no longer appropriate to consider. We note, as Ms. Diaz had testified, constant transmission is also needed for reliability throughout the year, supporting the 12CP which uses multiple peaks. MISO allocates network transmission charges to its load serving market participants using a 12CP allocation and MISO has also studied the impact of renewable resources and concluded that the stress on the transmission system, besides the stress caused by peak demand, is impacted by the shoulder seasons of spring and fall due to renewable resources generating energy in these seasons. Importantly, as a member of MISO, the planning and operations of Duke's transmission system are overseen by MISO.

It is extremely important to note that grid planning is changing per MISO's Renewable Integration Impact Assessment Summary Report – February 2021, p. 8. MISO has studied the impact of renewable resources and has concluded that the stress on the transmission system, besides the stress caused by peak demand, is impacted by the shoulder seasons of spring and fall due to renewable resources generating energy in these seasons. Pet. Ex. 32 at 7. Which is why we give weight to the fact that MISO allocates network transmission charges to its load serving market participants using a 12CP allocation.

We find 12CP is the appropriate methodology for cost allocation for the Company's transmission assets.

ii. **Minimum System Study/Distribution Allocation**.

1) **Duke Energy Indiana Case-in-Chief**.

Mr. Rimal sponsored special minimum system studies that he conducted to: (1) sub-functionalize certain distribution assets (i.e., poles and conductors) as being related either to the primary distribution system or secondary distribution system; and (2) classify these assets as being either related to customer or demand. Pet. Ex. 8 at 2-8, Attachment 8-B (BR) and Attachment 8-C (BR). He explained that the results of his studies were used in the retail cost of service study sponsored by Company witness Ms. Diaz to allocate distribution system costs. Pet. Ex. 8 at 2.

2) <u>OUCC</u>.

Dr. Dismukes recommends that the Commission reject the Company's minimum system study ("MSS") and instead classify the distribution plant accounts 364-367 as 100 percent demand-related. Pub. Ex. 11 at 3. He said MSS and related zero-intercept approaches are fundamentally flawed and provide little to no value as to the just and reasonable setting of 11 rates. *Id*. at 27-33.

3) <u>CAC</u>.

Dr. McCann claimed that the MSS confuses "minimum" with "lowest customer demand" and that the method is applied mechanically with no supporting economic analysis. He recommended that the customer charge be reduced to $10.05 using the cost of service study that does not rely on the minimum system study. CAC Ex. 2 at 29, 32, 35.

4) <u>Industrial Group</u>.

Industrial Group witness Collins recommended that the Company use the minimum system study for rate setting. Mr. Collins testified that allocation of a portion of distribution system costs as customer-related is appropriate for cost allocation. IG Ex. 3 at 15. He explained that by using the Company's cost of service models (and adjusting the subsidy/excess reduction to 33%), he produced different scenarios which use the minimum system approach for both 12CP and 4CP. *Id*. at 24. He endorsed the minimum system study with 4CP as the most accurate depiction of the cost for the Duke Energy Indiana system. *Id*. at 27.

5) <u>Petitioner Rebuttal</u>.

Mr. Rimal explained that not all distribution costs are solely related to the amount of peak demand. Pet. Ex. 34 at 3-4. He explained that the NARUC manual, many costs analysts, and the Commission in previous other Indiana utility cases classify a portion of the distribution system costs as customer-related and that Dr. Dismukes' recommended demand allocator totally ignores this fact of the electric delivery system. *Id*. at 4-5. He further explained that Dr. Dismukes and Dr. McCann are confusing the minimum system study with zero intercept study. *Id*. at 6-7. He said establishing the cost of a zero-load conductor is a pre-requisite for a zero-intercept study and not a minimum system study. *Id*. at 7. He explained that the NARUC Manual, which he relied on to conduct his studies, states that the minimum sized conductor should be the minimum sized conductor currently being installed. *Id*. (citing NARUC, Electric Utility Cost Allocation Manual, Chapter 6, at p. 91 (1992)). He further explained that generation assets are constructed to generate electricity and not distribute electricity and connect customers to the grid. Pet. Ex. 34 at 9. Mr. Rimal testified that the distribution system is constructed to move electricity from transmission facilities to individual customers distributed geographically throughout the Company's service territory. *Id*. He further testified the distribution system provides the path connecting the customers to the supply of electricity produced by generators and transmitted by the transmission system. *Id*. He explained that the same is not true of the transmission grid and generation portfolio, and so Dr. McCann's claim that "[t]he same minimum system costs can be attributed to the transmission grid and generation portfolio as well, but that is not being proposed here, and for good reason." is incorrect. *Id*. at 9 (citing CAC Ex. 2 at 32).

Ms. Diaz explained that in response to Dr. McCann's recommendations, Company witness Flick's rebuttal testimony explains the cost of service-based charge was merely a starting point. *Id*. Ms. Diaz further explained the Company also decided not to propose customer charges that fully matched the customer charges in the minimum system study, effectively relying upon the Company's 12CP scenario without the minimum system study option as the starting point to which adjustments for rate increase percentages were applied in the rate design process. *Id*.

Ms. Diaz testified she did not agree with Mr. Collins' recommendation to fully use the results of the minimum system study in this retail proceeding. Pet. Ex. 32 at 20. She said that completion of this study was a step not taken in previous Duke Energy Indiana rate cases. *Id*. Ms. Diaz testified that Duke Energy Indiana's objective is not to propose drastic rate increases on components of customer bills; instead, the Company has relied upon the Commission's gradualism approach across the classes, as explained in Company witness Flick's rebuttal testimony. Pet. Ex. 32 at 20. She explained that Mr. Collins recommends the allocations occur on both a demand and customer basis and not exclusively demand as was supported in the Company's 12CP scenario (without the minimum system study option). Pet. Ex. 32 at 20. She said while Mr. Collins' recommendation regarding distribution plant allocation for 364 through 368 accounts is valid, rate design was not able to rely exclusively on the minimum system study's results and proposed gradualism in setting of the connection charges. Pet. Ex. 32 at 20.

6) <u>Commission Discussion and Findings</u>.

We have previously noted the evolving nature of production facilities and production planning. As Dr. Dismukes testified, today, most utility capital investment, particularly for distribution plant, is designed to meet reliability, resiliency, and clean energy policy requirements. Attempting to ascertain the characteristics of a "minimum system" invites the introduction of a hypothetical structure upon which the Company's primary CCOSS does not rely. The true driving factors of utility distribution system costs are much more complicated and depend on a host of other factors such as the size of a service territory and the population density within the territory. The incremental costs of constructing an appropriate distribution system to serve an additional customer within an urban area with existing nearby infrastructure is substantially less than the costs to extend an existing utility system by potentially miles to serve an additional customer located in a rural area, a fact inherently ignored by a minimum system study. As a result, we agree with Dr. Dismukes that for Petitioner's COSS, distribution plant accounts 364-367 should be classified as 100% demand-related. We address customer charges further below.

iii. <u>Revenue Allocation</u>.

1) <u>Duke Energy Indiana Case-in-Chief</u>.

Ms. Diaz's testimony discussed the cost allocation methodologies and techniques employed by the Company within the COSS which allocates most of the Company's proposed revenue requirement to rate classes. Ms. Diaz further supported the Company's subsidy/excess adjustment. Pet. Ex. 6 at 39-40. She explained that the proposed rates are based on a subsidy/excess reduction of 5% which resulted in a residential proposed increase of 19%. *Id.* at 5. Ms. Diaz's Confidential Attachment 6-G (MTD) provided further details on allocations including the reallocation for the subsidy/excess.

2) **<u>OUCC</u>**.

Dr. Dismukes recommended the Commission use his proposed CCOSS for revenue distribution across customer classes. Pub. Ex. 11 at 38. Dr. Dismukes recommended that in the event the Company's cost of service study is used, the Commission should adopt a more reasonable revenue distribution allocation method that limits the rate increase to any single customer class to no more than 1.15 times the overall system average increase. Pub. Ex. 11 at 3-4, 38. He recommended this limitation to mitigate rate shock, especially among low-income households and small businesses already experiencing enormous financial constraints resulting from lingering inflationary pressures. Pub. Ex. 11-CA at 9. He also explained that in theory, system-wide revenue deficiencies are applied to under-earning classes and revenue decreases to those classes over-earning as a starting point for rate setting. *Id*. at 34. Dr. Dismukes opined that using the Company's full results from the cost of service study for most classes is inconsistent with gradualism. *Id*. at 37.

3) **<u>Industrial Group</u>**.

Mr. Collins testified that Duke's proposed method of distributing its requested rate increase to classes reduces existing interclass subsidies by only 5% and results in rates that continue to contain massive subsides that are not reflective of cost causation. He said 33% reduction in subsidy/excess levels should be ordered. IG Ex. 3 at 3, 23-28.

4) **<u>Nucor</u>**.

Dr. Zarnikau recommended a 20% cap by customer class and special contract with any excess spread to retail customers as was proposed by the Company relating to certain lighting classes. Dr. Zarnikau also comments that gradualism adjustments can be applied post-cost allocation. Nucor Ex. 1 at 4, 7, 18.

5) **<u>Walmart</u>**.

Ms. Perry recommended that if the revenue requirement is reduced by the Commission, the Commission should apply 50% of the revenue reduction to the classes paying more than their cost-based levels with the caveat that a subsidizing class should not move to a subsidized position, and the remaining 50% should be applied evenly. Ms. Perry stated the Company did not provide details on how it plans to align classes more closely with cost-based levels aside from mentioning the gradualism concept. Walmart Ex. 1 at 5-6.

6) **<u>Petitioner Rebuttal</u>**.

Ms. Diaz explained the impacts of the intervenors' proposed revenue allocations. Pet. Ex. 32 at 28. She testified that because Dr. McCann proposes different allocation to the classes for production demand and certain rider allocations, he presents a revised allocation of operating revenue and resultant rate increases which notably lowers residential and commercial rate increases while increasing high load factor customers' rate increases. Pet. Ex. 32 at 28.

Further, Ms. Diaz testified that because Mr. Collins endorses allocations to the classes by using a 33% subsidy/excess reduction, 4CP, and minimum system, he presents a revised allocation of operating revenue and resultant rate increases which notably raise residential and commercial revenues increases while lowering industrial. *Id*.

In response to Dr. Zarnikau's proposal, Ms. Diaz said there is no reason to cap the rate increase at 20% and spread the excesses across the classes. Pet. Ex. 32 at 28. Ms. Diaz explained that further changes to revenue allocations are dependent upon the amount of revenue reduction that may be ordered, and the classes impacted by the proposed change, which are unknown at this time. *Id*. She testified that in the event the Commission orders caps, the source for the rate increases for Nucor should be based upon the entire contract as evidenced by the bill impact calculations performed by rate design and not the cost-of-service study. *Id*. Ms. Diaz further testified that while additional post-allocation adjustments can be made, further adjustments should be limited and provide reasonable results. *Id*. at 29.

In response to Ms. Perry's proposal on administration of potential revenue requirement reductions, Ms. Diaz testified that the reductions could occur in any of the components of the case and to be accurate, the reduction would be mapped at the regulatory account level and would follow the cost of service methods for functionalization, classification, and allocation to calculate the updated net operating income at the class level. *Id*. Ms. Diaz explained as the potential reductions would be tied to specific changes in assets and expenses, it is less accurate to socialize the reductions as recommended by Ms. Perry. *Id*. She testified aligning rates perfectly with cost-based levels cannot occur with a single retail rate case but will continue to evolve over time. *Id*.

Ms. Diaz further testified that applying a factor of 1.15 times the system average as proposed by Dr. Dismukes is premature and increases socialization of the results without cost causation. *Id*. at 29. She explained that the Commission in Cause No. 45253 applied a higher, reasonable 1.25% factor to the classes relative to the system average increase. *Id*. Ms. Diaz testified that Duke Energy Indiana did not use the full results of the cost of service study as evidenced by the downstream adjustments made by rate design but stands that the cost of service study provided to rate design is valid and reasonable. *Id*. at 29. She testified it is the Company's goal to reflect the appropriate costs of service to the classes, while utilizing the established practice of subsidy/excess to ensure rates are reasonable and fair across all the classes. *Id*. at 30.

7) <u>Additional Evidence Received at Hearing</u>.

Ms. Diaz testified that with respect to subsidies, each class stands on its own and there are different drivers. Tr. at C- 20. She stated there could be different impacts from the subsidy or excess, requiring an assessment of how much of a reduction can be made. *Id.* She confirmed variables can change between rate cases, where the results are moving around. *Id*. at C- 45.

8) <u>Commission Discussion and Findings</u>.

With respect to revenue allocation, Dr. Dismukes proposed limiting any class increase to 1.15 times the system average to mitigate rate shock, especially among low-income households and small businesses already experiencing enormous financial constraints resulting from lingering inflationary pressures. Dr. Dismukes cautioned that using Duke Energy Indiana's full results of its cost of service study would be inconsistent with gradualism.

Regarding the issues of subsidy and excess, as Ms. Diaz stated on rebuttal, the needs of all the Company's retail classes were considered in assessing the percentage of retail subsidy/excess reduction to apply in order to yield a fair increase across all retail classes. Pet. Ex. 32 at 25. Industrial Group witness Collins incorrectly argued that a larger subsidy/excess reduction is needed for the classes, particularly HLF customers, and expressed concern that subsidies are sending incorrect price signals impacting customers' conservation decisions. Mr. Collins believes that the Company's tracking mechanisms may have caused subsidies in its current rates, and that by changing to a 12CP, the Company is not reporting the full amount of subsidies. Mr. Collins notes that the Company's subsidy reduction in its direct testimony is less than the final subsidy reduction approved in Cause No. 45253, that the subsidy/excess levels have increased from the previous case for residential and HLF classes and argues that HLF rates should be reduced due to the current HLF rate of return exceeding the Company's requested rate of return. He proposes an alternative subsidy/excess reduction of 33% and produces various scenarios with his preferred scenario of 4CP with 33% subsidy/excess reduction and minimum system.

As Ms. Diaz testified at the hearing regarding subsidies, each class stands on its own with different drivers. There can be different results depending on whether subsidy or excess is happening, and then you have to assess then how much of a reduction you can take. She confirmed variables can change between rate cases where the results are moving around. Any discussion of excess/subsidies must necessarily consider that the level of potential subsidy depends upon the cost of service methodology used to allocate costs, and cannot be assumed to remain at a static level between rate cases.

We agree that adopting Mr. Collins' proposals would result in rate shock. Pet. Ex. 32 at 26. As Ms. Diaz explains, Mr. Collins' preferred scenario proposes overall increases to the residential class of nearly 27%. We find the OUCC's proposal is consistent with the concept of gradualism, alleviates rate shock, and appropriately considers the pillar of affordability across the rate classes. The Commission finds the OUCC's proposed limit for all rate classes of 1.15 times the system average increase is appropriate, in the public interest, and should be approved.

B. <u>Rate Design</u>.

a. <u>TOU Rates</u>.

[The OUCC does not take a position on this issue.]

b. <u>Customer/Connection Charges</u>.

i. <u>Duke Energy Indiana Case-in-Chief</u>.

In his direct testimony, Mr. Flick explained that the Company is proposing an increase in residential rates' customer charge from $10.54 to $13.70. Pet. Ex. 7 at 24-26. He testified the requested increase improves pricing and cost of service alignment across the residential class and the proposal is also supported by the Minimum System Study that is supported by Company witness Mr. Rimal. *Id*. Mr. Flick testified the study's results show that the costs attributable to the addition of a residential customer are much higher than the customer charge requested in this case,

$31.49 versus $13.70, respectively, and he presented Attachment 7-F (RAF) for more details. *Id*. Mr. Flick explained that the incremental amounts collected via customer charges would be offset proportionally by decreases in energy rates/revenue. *Id*. at 25. He testified that the customer charge increase and energy rates have an inverse relationship in this rate's design. *Id*. He also noted that, further "flattening" or decreasing of the ratio of pricing differences between energy rate blocks is not being pursued in this case. *Id*. Mr. Flick also described other customer/connection charge changes, including the customer charge increase for the CS rate structure. *Id*. at 27-29.

ii. <u>OUCC and Intervenors</u>.

The OUCC and CAC took issue with the residential customer charge increase. The OUCC also took issue with the commercial customer charge. There was no dispute regarding any other customer charge/connection charge. OUCC witness Dr. Dismukes recommended the Commission reject the Company's proposed customer charge increases for residential and commercial customers. Pub. Ex. 11 at 4, 38-46. He testified that the proposed increases are not needed and are not consistent with the public policy goals of promoting energy efficiency and affordability. *Id*. He further testified that increasing fixed customer charges will burden low-use and low-income customers with a greater than system average percent rate increase. *Id*. Dr. Dismukes also offered the results of his customer charge peer survey as DED-12. *Id*. at 40-41. He testified this analysis demonstrates the Company's current residential customer charge of $10.54 per month is below the average residential customer charge of $11.78 for other regional utilities. *Id*. However, he further testified the Company's proposed increase to a $13.70 monthly residential customer charge is above the peer group average of $11.78, or 16.3% higher. *Id*.

CAC witness Dr. McCann discussed basing the residential customer charge on the Company's cost of service study results rather than an arbitrary increase aimed at an ambiguous target. CAC Ex. 2 at 2, 29-32. He testified that the Company's proposed residential customer charge is not supported by the evidence and is contradicted by its own cost-of-service study. *Id*. at 4. He also described problems with the Company's "hypothetical" minimum system study. *Id*. at 29-30.

iii. <u>Duke Energy Indiana Rebuttal</u>.

In response to Dr. McCann's suggestions, Mr. Flick explained that one may hold conceptual disagreement with the minimum system methodology, but it is not random and does produce a definitive target for setting a customer charge on the basis of cost causation. Pet. Ex. 33 at 13. He further reiterated that the Company filed minimum system study evidence in this proceeding to support its request for a customer charge increase. *Id*.

In response to Dr. Dismukes' survey results, Mr. Flick explained that if there should be any comparison to peers, the most pertinent comparison is to other investor-owned electric utilities in the State. *Id*. He testified he does not believe Ameren Illinois or Commonwealth Edison's numbers reflect the monthly meter charge that would be applicable. In addition, he testified the survey excludes some regional utilities with higher customer charges. *Id*. Mr. Flick explained for example, Kentucky Power's $20 customer charge and Upper Peninsula Power Company's $15 customer charge. *Id*. at 13-14. For these reasons, Mr. Flick testified the survey results have limited value in gauging what customer charge should be approved in this proceeding. *Id*.

iv. <u>Commission Discussion and Findings</u>.

We reject the Company's proposed customer charge increases for residential and commercial customers. The proposed increases are not consistent with the public policy goals of promoting energy efficiency and affordability. The realized qualitative costs to residential and commercial customers would outweigh potential benefits. Increasing fixed customer charges will burden low-use and low-income customers with a greater than system average percent rate increase. Furthermore, as demonstrated by Dr. Dismukes, the proposed customer charge is higher than the average residential customer charge for the peer group analyzed.

c. <u>Declining Energy Block Rates</u>.

[The OUCC does not take a position on this issue.]

d. <u>HLF and LLF Demand Rates</u>.

[The OUCC does not take a position on this issue.]

e. <u>Multi-Family Customer Rate</u>.

[The OUCC does not take a position on this issue.]

f. <u>Excess Distributed Generation</u>.

[The OUCC does not take a position on this issue.]

17. <u>Rate Adjustment Mechanisms</u>.

A. <u>Fuel Cost Adjustment (FAC) (Tracker 60)</u>.

As discussed below, Duke proposes to increase the base cost of fuel in this Cause that is included in its FAC Tracker (Tracker 60) and to track fuel inventory costs..

B. <u>Environmental Compliance Adjustment (Tracker 62)</u>.

In its case-in-chief, Duke proposed multiple changes to its ECR Tracker that are set forth in Duke witness Lilly's direct testimony. Pet. Ex. 5 at 25-29. The Company's proposal includes continuing to track chemicals and reagent costs associated with operating generating units' environmental controls through the ECR. Duke also, however, proposes to embed $27.4 million in test year O&M for process chemical and reagent costs, with the actual costs above or below this amount tracked. *Id*. at 26. OUCC witness Armstrong testified the Company's proposal to continue tracking process chemicals and reagent costs associated with operating generating units' environmental controls above and below the test year amount through the ECR is reasonable. She also stated the test year amount of $27.4 million is consistent with actual reagent costs over the past three years and is a reasonable amount to include in the test year. Pub. Ex. 5 at 14.

a. <u>Coal Ash and Renewable Rider Allocations</u>.

CAC witness McCann proposed that because coal ash is produced from burning fuel, the coal ash costs should be allocated based on production energy or a sales allocator. CAC Ex. 2 at 34. He also proposed changing the cost assignment of the coal ash portion included in Rider 62 to a sales allocator. *Id*. at 2. Finally, Dr. McCann proposed to use a sales allocator for Rider 73. *Id*.

b. <u>Duke Energy Indiana Rebuttal</u>.

Ms. Diaz disagreed with Dr. McCann's allocation for coal ash and further endorsed continuing the production demand allocation methodology for both Rider 62 for coal ash and Rider 73. Pet. Ex. 32 at 16, 18. Ms. Diaz explained that Dr. McCann's recommendation to allocate the regulatory asset associated with coal ash closure costs previously approved under the federal mandate statute on a production energy or sales allocator basis is inconsistent with the past approach of allocating these costs on a demand basis and ignores the fact that the ash ponds are associated with Duke Energy Indiana's production facilities, which are designed to meet the demands of Duke Energy Indiana customers. She explained that coal ash pond costs are normally included in the production plant account that also includes the costs of furnaces, boilers, coal preparation equipment and other related equipment used in generating stations. She testified all of this associated production plant must be appropriately sized for the generating unit used in meeting customers' peak demands. Ms. Diaz testified it is appropriate to allocate these costs to customer classes on a demand basis, just like all other production plant is allocated. She further testified because the costs in question are tied to compliance with federal and state environmental requirements related to closing and ongoing management of the coal ash ponds, they are residual in nature. Ms. Diaz explained that residual and end of life costs typically and logically follow the cost of the plant, which is appropriately allocated based on a demand basis. She testified the Company has also proposed in this proceeding to include coal ash costs in depreciation rates, and the depreciation expenses are allocated based on demand. Pet. Ex. 32 at 16. Ms. Diaz explained that Coal combustion residuals, unlike coal, does not have energy potential and is not a fuel. *Id*. at 16-17. She testified the environmental liability that the Company is now tasked with managing is an environmental compliance cost that did not exist when the coal was first burned, but arose years later, and another reason that applying demand allocators is consistent with treatment of end-of-life costs associated with production plants. *Id*. at 17.

c. <u>Commission Discussion and Findings</u>.

We find it is appropriate to allocate coal ash pond closure and coal ash management costs to customer classes on a demand basis, just like all other production plant is allocated. That these costs are being recovered through Tracker 62 does not change cost of service. We agree that Coal combustion residuals, unlike coal, do not have energy potential and is not a fuel. Pet. Ex. 32 at 16-17. No party disputes that these costs are associated with an environmental liability that is associated with end-of-life of the plant, applying demand allocators is consistent with treatment of end-of-life costs associated with production plants. *Id*. at 17.

As for using demand allocation in Rider 62 and 73, we are not persuaded by Dr. McCann to change given that production demand allocation was approved when the associated costs were approved for inclusion in the respective riders as explained by Ms. Diaz. Pet. Ex. 32 at 17-18.

Other issues related to Tracker 62 and CCR costs were previously discussed in the Environmental Sustainability section of this order. Ultimately, we find the Company's proposed changes are reasonable and should be approved.

C. <u>TDSIC Adjustment (Tracker 65)</u>.

a. <u>Duke Energy Indiana Case-in-Chief</u>.

In this proceeding, the Company is proposing to roll the original cost investment and accumulated depreciation of in-service TDSIC plant (TDSIC 1.0 and 2.0) as of the end of the future test period into base rates. This includes the 80% of in-service plant that is eligible for inclusion in the TDSIC Tracker, as well as the 20% that is deferred for rate case recovery pursuant to Ind. Code ch. 8-1-39 ("TDSIC Statute"). Pet. Ex. 5 at 30. Further, the Company proposed that TDSIC O&M expense and post-in-service carrying costs ("PISCC") not be included in base rates, but continue to be tracked and recovered in the TDSIC Tracker. *Id.* at p. 32. Company witness Lilly testified this treatment is being proposed because the TDSIC project-related O&M is non-recurring and variable in nature, and the O&M for the TDSIC inspection-based projects can also fluctuate. *Id.* at p. 32. Ms. Lilly testified the PISCC experiences similar variations due to being non-recurring and variable in nature. *Id*.

b. <u>OUCC</u>.

OUCC witness Lantrip recommended approval of the Company's proposed treatment of its TDSIC Tracker, including the Company's proposal to exclude its incremental TDSIC O&M and PISCC expenses from base rates because Mr. Lantrip testified these costs are non-recurring and will be better adjusted through the rider process. Pet. Ex. 3 at 8.

c. <u>Industrial Group</u>.

Industrial Group witness Gorman testified the Industrial Group has raised two issues that are currently on appeal to the Indiana Supreme Court: (1) the Industrial Group challenged the approval of a portion of Duke's TDSIC Plan, accounting for around $250 million in planned expenditures, based on the cost-justification requirement in the TDSIC Statute; and (2) the Industrial Group challenged the recovery of carrying charges on the O&M portion of the deferred amounts being held in a regulatory asset. IG Ex. 1 at 8. As such, Mr. Gorman recommended that in the event the Indiana Supreme Court issues its decision prior to the conclusion of this proceeding, the propriety of Duke's TDSIC-related proposals may be ascertainable and should be incorporated in the Commission's Order. *Id*. If the appeal remains undecided at that point, or further proceedings are necessary to implement that decision, Mr. Gorman recommended the rate relief with respect to TDSIC expenditures should be specified as interim and subject to reconciliation (including interest) once the ultimate outcome of the appeal is known with certainty. *Id.*)

d. **Duke Energy Indiana Rebuttal**.

On rebuttal, Company witness Lilly responded to Mr. Gorman's recommendations regarding the pending TDSIC appeal. Ms. Lilly explained that as she understood it, the only question raised before the Supreme Court is eligibility for the TDSIC. Pet. Ex. 31 at 11-12. Ms. Lilly further explained that a decision by the Court reversing the TDSIC Order would not affect whether utility plant can be included in rate base in a general rate case, therefore, the only impact of that case on the issues in this case is the size of the 20% deferral of TDSIC costs under the approved plan. *Id*. Ms. Lilly testified that if the Court were to hold that a portion of the TDSIC plan is not eligible for the TDSIC, then that would impact what is recovered through the TDSIC (and correspondingly, the amount that is deferred under the TDSIC statute. *Id*.).

Ms. Lilly testified that she disagreed with Mr. Gorman's recommendation related to the handling of potential changes to the TDSIC regulatory assets included in the rate case if the appeal is undecided at the time of the Commission Order. *Id*. at 12. Ms. Lilly explained that Mr. Gorman is recommending that, if a Supreme Court decision is not received prior to a Commission order in this proceeding, the Commission's order be interim and subject to refund with interest. *Id*. Ms. Lilly testified that from her perspective, there would not need to be refunds associated with recovery of these regulatory assets. She testified that because these are regulatory asset projections, if the actuals are less than projected, then the amortization period would simply end up being shorter than the proposed 6 years. *Id*. Ms. Lilly explained that while there could be potentially refunds due in the TDSIC Rider depending on what the Indiana Supreme Court orders, for base rate case purposes Duke Energy Indiana would just shorten the amortization periods of the regulatory assets to comport with the remaining balance to avoid over or under collection. *Id*. Ms. Lilly further explained as with all of the Company's regulatory assets, once they are fully amortized, Duke Energy Indiana would then credit customers for that annual amortization through Rider 67. *Id*. at 13. Ms. Lilly testified that to the extent that – as a result of the appeal – the Company has included return on too large of a regulatory asset associated with its TDSIC 2.0 plan in base rates, any overage could be trued up in the TDSIC Rider. *Id*. Ms. Lilly testified again, in her opinion, all of this is speculation at this time and there is no need to hold rates subject to refund pending an unknown appellate decision. *Id*.

e. **Commission Discussion and Findings**.

We agree with Company witness Lilly that there is no need to address the Industrial Group's recommendation regarding the TDSIC regulatory asset at this time. This is a general rate case. As to whether utility plant that is also included in Petitioner's approved TDSIC plan depends solely on the question whether the plant is used and useful. The Industrial Group's appeal of the Order approving Petitioner's TDSIC plan only challenges whether those investments are eligible for TDSIC treatment. The Industrial Group's appeal only challenges our finding that the costs of the improvements are justified by the incremental benefits of the plan. The Industrial Group has not challenged on appeal our finding that the public convenience and necessity require the improvements in the plan. As such, to the extent elements of that plan are in service by the close of the test year, we find that that they are used and useful and are properly included in Petitioner's rate base upon which it is authorized a return. This finding is not affected by the outcome of the appeal. The only effect of the appeal would be on the 20% of TDSIC costs that are deferred in a regulatory asset. It is possible the appeal could affect the size of that regulatory asset. As Ms. Lilly explained, given the nature of regulatory asset projections, even if refunds would potentially be due in the TDSIC Rider depending on what the Indiana Supreme Court orders, for base rate case purposes, Duke Energy Indiana could simply shorten the amortization periods of the regulatory assets to comport with the remaining balance to avoid over or under collection. Thus, there is no need to hold rates subject to refund in this proceeding. As the Company's testimony demonstrates, any over or under collection resulting from the Indiana Supreme Court's order can be addressed at the time of the decision, and it is inappropriate to speculate in this case when such decision has not been made. As such, we reject the Industrial Group's recommendations with respect to the roll in of TDSIC costs in base rates. We find the Company's proposal and changes to Tracker 65 as set forth in its case-in-chief, including its proposal to exclude TDSIC O&M expense and PISCC from base rates and continue to track and recover those amounts in the TDSIC Tracker, is reasonable and should be approved.

Ultimately, we find the Company's proposed changes to its TDSIC Tracker are reasonable and should be approved.

D. <u>Energy Efficiency ("EE") Adjustment (Tracker 66)</u>.

In its case-in-chief, the Company proposed to reset current rates to remove lost revenue amounts and adjust the revenue conversion factors in its EE Tracker. Pet. Ex. 5 at 34. No party took issue with the Company's proposed changes to the EE Tracker and we find the Company's proposed changes are reasonable and should be approved.

E. <u>Credits Adjustment (Tracker 67)</u>.

In its case-in-chief, the Company proposed to include additional Tax Cuts and Jobs Act ("TCJA") credits, the credits for the IGCC facility tax incentives and the Two-Step Rate Adjustment (as previously discussed) in its Credits Tracker (Tracker 67). Pet. Ex. 5 at 40-43. The Company proposed to add and remove other various credits as described in Company witness Lilly's Direct Testimony, Petitioner's Ex. 5. No party took issue with the Company's proposed changes to Tracker 67 and we find the Company's proposed changes are reasonable and should be approved.

F. <u>Regional Transmission Operator ("RTO") Non-Fuel Costs and Revenue Adjustment (Tracker 68)</u>.

In its case-in-chief, the Company proposed to update the amounts embedded in base rates for the RTO non-fuel costs and transmission revenues to reflect forecasted levels for 2025 but did not propose any changes to the operation of the RTO Tracker in this proceeding. Pet. Ex. 4 at 28. No party took issue with the Company's proposed changes to Tracker 68 and we find the Company's proposed changes are reasonable and should be approved.

G. <u>Reliability Adjustment (Tracker 70)</u>.

a. <u>Duke Energy Indiana Case-in-Chief</u>.

The Company proposed two changes to its Reliability Adjustment Tracker No. 70 ("Tracker 70") in its case-in-chief. Pet. Ex. 4 at 29. First, the Company proposed retaining a sharing mechanism for net margins realized on STBNNS. *Id*. The Company proposed to reset the base amount to zero and to share 100% of net margins up to a $5 million threshold with customers. *Id*. Any positive net margins above that level would be shared 50/50 between customers and shareholders. *Id*. Second, the Company proposed to update the proposed annual base amount for PowerShare® bill credits in base rates to zero and to recover actual costs for the program entirely through the Reliability Tracker.

b. <u>OUCC</u>.

OUCC witness Lantrip recommended the Commission approve Petitioner's SRA Rider revised embedded amounts. Pub. Ex. 3 at 1. However, Mr. Lantrip only recommended approving Petitioner's $5 million STNNBS threshold conditioned on approving a 75%/25% ratepayer/shareholder allocation split on revenues exceeding that threshold, instead of Petitioner's proposed sharing allocation. *Id.* at 4, 9. Mr. Lantrip testified the Company has not presented sufficient evidence demonstrating why the $5 million threshold was chosen or the propriety of this proposed threshold. He established Petitioner forecasts it will be years before these bundled contracts are expected to achieve positive margins, but this does not justify the new sharing threshold and percentages Duke proposes. He testified Duke's alternative proposed allocation split with ratepayers was excessive. *Id.* at 2.

c. <u>Duke Energy Indiana Rebuttal</u>.

On rebuttal, Company witness Sieferman testified the Company's proposal for equal sharing of any margins above the threshold is not excessive. Pet. Ex. 30 at 17. She testified the Company's proposal is to flow back all net positive margins (100%) to customers up to the $5 million threshold, and given customers are receiving all net positive margins up to the $5 million threshold level per the Company's proposal, equal sharing of any margins above that threshold is not excessive. *Id*. Further, she explained the Company's shareholders are taking on the risks of any net negative margins and are not able to retain any positive margins unless the $5 million threshold is exceeded. *Id*. She testified the 50/50 level proposed by the Company is a more balanced approach that allows for sharing with customers but also allows for some profits to be maintained by the Company in the event the margin is greater than the threshold level.

d. <u>Commission Discussion and Findings</u>.

No party took issue with the Company's proposal to update the proposed annual base amount for PowerShare® bill credits in base rates to zero and to recover actual costs for the program entirely through the Reliability Tracker, and thus, we find the Company's proposal is reasonable and should be approved. Further, regarding the Company's proposed sharing mechanism for net margins realized on STBNNS, we agree with OUCC witness Lantrip. While the Company's proposed mechanism allows for both sharing with customers and also allows for some profits to be maintained by the Company in the event the margin is greater than the threshold level, Mr. Lantrip's recommendation is more reasonable and prevents an unnecessary windfall. As such, we find the Company's proposal, as well as its other proposed changes, all as modified by Mr. Lantrip's recommendation, are appropriate and should be approved.

H. **Federally Mandated Cost Adjustment ("FMCA") (Tracker 72)**.

In its case-in-chief, the Company testified Tracker 72 rates are currently at $0 and will remain there until future federally mandated costs are approved for recovery. Pet. Ex. 5 at 29. Despite having no costs, Company witness Lilly testified the Company is proposing to continue Tracker 72 in order to have a ready mechanism via which to track likely future NERC cybersecurity costs, as well as any other federally mandated costs. *Id*. The OUCC testified it did not oppose this request,[18] and no other party took issue with the Company's proposal. We therefore find the Company's proposal to continue Tracker 72, as well as its proposed other changes, are reasonable and are approved.

I. **Renewable Energy Project Adjustment (Tracker 73)**.

The Company proposed several updates to its Renewables Tracker regarding the amounts embedded in base rates, as discussed in Company witness Sieferman's Direct Testimony. Pet. Ex 4 at 34-37. The OUCC testified it did not oppose these updates, and no other party took issue with the Company's proposed changes. Thus, we find the Company's proposed changes are reasonable and are approved.

J. **Load Control (LC) Adjustment (Tracker 74)**.

In its case-in-chief, the Company testified that at the time of implementation of new base rates resulting from this proceeding, the LC Tracker will be revised to remove the level of expenses included in the base rates. Pet. Ex. 5 at 43. Ms. Lilly testified the Company will also change the revenue conversion factors used to calculate revenue requirements to reflect the provision for uncollectible accounts expense and public utility fee approved in this proceeding. *Id*. No party took issue with the Company's proposed changes to Tracker 74 and we find the Company's proposed changes are reasonable and are approved.

18. **Other Issues**.

A. **Fuel and FAC-Related Issues**.

a. **Petitioner's Fuel Procurement Strategy and Economic Dispatch.**

[The OUCC does not take a position on this issue.]

b. **Fuel Cost Adjustment Rider ("FAC") (Tracker 60) and Base Cost of Fuel**.

i. **Duke Energy Indiana Case-in-Chief.**

Petitioner is proposing to update its base cost of fuel in this proceeding from 26.955 mills per kWh (as established in Cause No. 45253) to 34.378 mills per kWh. Pet. Ex. 3 at 26. Company witnesses John Swez (Pet. Ex. 20) and John Verderame (Pet. Ex. 21) discuss the production cost model used to simulate generation output and the associated costs used in developing the forecasted fuel and purchased power expenses. Based on this modeling, Mr. Verderame testified the Company's retail jurisdictional fuel cost assumptions for 2025 are reasonable. Pet. Ex. 21 at 17-19.

ii. <u>OUCC and Intervenors</u>.

The OUCC recommended Duke's forecasted fuel costs of $43,249,000 be reduced. Pub. Ex. 1 at 29. In support of this position, OUCC witness Eckert testified Duke's cost of natural gas and the MISO market prices included for purposes of this proceeding are too high because Petitioner used the forecasted cost of natural gas and the MISO On-Peak and Off-Peak market prices for 2025 as of October 2, 2023, notwithstanding that as of June 28, 2024, the forecasted cost of natural gas and the MISO On- and Off-peak market prices for 2025 had materially decreased. *Id.* at 28-29. Mr. Eckert applied the decrease to Petitioner's proposed natural gas costs and to purchased power (both on- and off-peak). *Id.* Mr. Eckert explained that he did not use the off-peak percentage decrease separately because the Company did not provide the off- and on-peak costs separately. As a result, Mr. Eckert applied the on-peak price to both the on- and off-peak costs, which is more conservative. *Id.* He noted Petitioner is proposing a $0.034378 per kWh base cost of fuel as compared to the $0.026955 per kWh current approved base fuel cost. *Id.*

iii. <u>Duke Energy Indiana Rebuttal</u>.

On rebuttal, Ms. Graft testified she disagreed with Mr. Eckert's proposed reduction of $43,429,000 to forecasted fuel expense and recommended the Commission approve the Company's proposed base cost of fuel as filed of 34.378 mills per kWh. Pet. Ex. 29 at 11. Ms. Graft testified Duke Energy Indiana develops its fuel cost forecasts based upon assumptions inherent as of a date certain (October 2, 2023 in the current proceeding), and while the Company recognizes that purchased power and natural gas prices have declined since October 2, 2023, there is no evidence to indicate the prices as of October 2, 2023 are unreasonable assumptions. *Id*. She testified that given the significant price volatility in the purchased power and natural gas markets that has occurred in recent history, the Company recommended the Commission approve its proposed base cost of fuel as filed. *Id*.

Mr. Verderame described in his rebuttal testimony how the Company develops its generation and fuel cost forecasts utilizing a stochastic production cost model including using the best information available at the time the forecast is produced. Pet. Ex. 44 at 9-10. Mr. Verderame explained the stochastic model outputs are based on 100 individual scenarios, which is designed to better capture the volatility in commodity prices that are a key component in Duke Energy Indiana's fuel costs. *Id.* at p. 10. Further, Mr. Verderame testified the Company's proposed base cost of fuel is based on more than just the two isolated inputs highlighted by Mr. Eckert. *Id*. Company witness O'Connor described at length in his rebuttal testimony the Company's stochastic model and the underlying assumptions and inputs informing the model. Pet. Ex. 47 at 4-5. Mr. O'Connor testified the Company's model uses clearly defined inputs, including exchange-traded energy commodity pricing, historical data on system loads and prices, and historical actual unit performance parameters in order to project future coal burns. *Id*. at 5.

iv. **Commission Discussion and Findings**.

As Mr. Eckert explained, Duke's cost of natural gas and the MISO market prices Duke used in this proceeding are over stated because the Company did not update its forecasted cost of natural gas and the MISO On and Off-Peak market prices for 2025 when these materially decreased in June 2024, notwithstanding the adverse impact upon Duke's ratepayers if the prices the Company used are too high. Mr. Eckert applied this decrease to Petitioner's proposed natural gas costs and to purchased power (both on- and off-peak). Mr. Eckert explained he did not use the off-peak percentage decrease separately because the Company did not provide the off- and on-peak costs separately. As a result, Mr. Eckert applied the on-peak price to both the on- and off-peak costs which is more conservative in nature.

Ms. Graft admitted the Company knows the forecasted prices have decreased, but she asserted that decrease does not mean the Company's forecast is unreasonable. While the Commission concurs that not every market price fluctuation can or should be incorporated, we find that since a significant material decrease occurred, Mr. Eckert's application of that more current price information is in the public interest and appropriate. Additionally, lowering the embedded costs to more accurately reflect the forecasted costs of natural gas and the MISO On- and Off-Peak market prices for 2025 results in lowering Petitioner's revenue requirement and, thus, helps protect affordability in this Cause. The Commission finds Mr. Eckert's update to the forecasted costs is appropriate, including his methodology, calculations, and recommendations.

c. **Fuel Inventory Tracking Request**.

i. **Duke Energy Indiana Case-in-Chief.**

In this proceeding, the Company is proposing to build into its base rates a representative balance of coal inventory (approximately 2,333,474 tons or 45 days full load burn at a rate of 51,490 tons per day) and then track the actual inventory balance, both up and down, in the Company's quarterly FAC filings. Pet. Ex. 21 at 19. Mr. Verderame explained the Company is proposing to track its coal inventory due to the volatile energy commodity pricing environment impacting unit dispatch and inelasticity of the coal supply chain which can cause coal inventories to fluctuate significantly over short periods of time. *Id*. at 20. Mr. Verderame testified that since the Company's last rate case, Duke Energy Indiana's coal inventory has ranged from a low of 885,433 tons (17 days of coal supply at a full load burn rate of 51,490 tons per day) in August of 2021 to a high of 3,255,514 tons (63 days of coal supply at a full load burn rate of 51,490 tons per day) in December of 2023. *Id*. at 20. Mr. Verderame testified tracking the actual inventory balance, both up and down, in the quarterly FAC filings provides a more proactive mechanism for reflecting the changes in inventory balances in customer rates more quickly as inventory dynamics change. *Id*.

ii. **OUCC and Intervenors.**

While the OUCC did not object to the amount of coal inventory (45 days) the company is proposing to build into base rates in this proceeding, the OUCC recommended the Commission deny the Company's request to recover a return on fuel inventory through its FAC proceeding. Pub. Ex. 1 at 33. Mr. Eckert argued return on fuel inventory is not a fuel cost that is eligible for recovery under Ind. Code § 8-1-2-42, the Company's inventory issues are a result of Duke's procurement practices, and the Company's proposed tracker shifts the risk of managing the Company's coal supply from shareholders to ratepayers. *Id*. at 31-34. Mr. Eckert also recommended the current agreement allowing the OUCC and intervenors to file FAC testimony 35 days after Duke files its petition and testimony should be continued. *Id*. at 22.

Industrial Group witness Gorman also recommended Duke's proposal to track its coal inventory through the FAC should be rejected. IG Ex. 1 at 7. Mr. Gorman testified Duke has a responsibility to maintain coal inventory at sufficient levels to provide reasonable and adequate service, further, Duke's proposal to track coal inventory through the FAC imposes too much risk on customers and does not provide protection for customers from paying rates that are no more than just and reasonable. Mr. Gorman did not take issue with the company's proposal to set its coal inventory at a level sufficient to provide a 45-day supply. *Id*.

CAC witness Glick also recommended the Company's proposal to track the level of coal inventory in rate base through its FAC filings be rejected. CAC Ex. 4 at 9. Ms. Glick testified the Company has not justified the value to ratepayers of its request to track coal inventory. *Id.* at p. 8.

iii. <u>Duke Energy Indiana Rebuttal</u>.

On rebuttal, Company witnesses Verderame and Graft disagreed with the OUCC and intervenors' criticisms of the Company's request to track changes in coal inventory. Ms. Graft testified the Company's request is a proactive mechanism to reflect changes in inventory costs in rates more quickly as inventory dynamics change. Pet. Ex. 29 at 12. Further, Ms. Graft explained the proposal is not one-sided – she testified it protects customers in the event of a decline in coal inventory over the level in base rates while also providing timely recovery to the Company of its costs to finance coal inventory in excess of the level in base rates. Therefore, Ms. Graft testified the Company's request is reasonable to make in the context of this rate case. *Id*. Mr. Verderame also disagreed with the OUCC's contention that the Company's higher inventory levels are a result of the Company's coal procurement practices. Pet. Ex. 44 at 8-9. He testified the Company forecasts its coal procurement needs using the best available information at the time; however, there are many unforeseen circumstances that alter the Company's actual coal consumption, including weather, unplanned outages, and energy market price volatility. *Id*.

Ms. Graft also responded to other issues raised by Mr. Eckert regarding the Company's proposal. Ms. Graft responded to Mr. Eckert's claim that a return on fuel inventory is not recorded in FERC Account 501 and therefore is not eligible for recovery through the FAC. She testified there is no reference to the Uniform System of Accounts in Ind. Code § 8-1-2-42(d) and the statute allows for a change in rates due to changes in the "cost of fuel." *Id*. at 12-13. Ms. Graft testified the cost of capital to procure fuel inventory is a cost of fuel, the Commission has allowed other costs to be recovered through the FAC that are not technically fuel, and Ind. Code § 8-1-2-42(a) gives the Commission discretion to approve other tracking mechanisms. Ms. Graft further testified she agrees with Mr. Eckert's recommendation to continue the current agreement for the OUCC and intervenors to file their FAC testimony 35 days after the Company files its FAC Petition and testimony. *Id*. at 10.

iv. **Commission Discussion and Findings**.

When determining whether costs should be tracked, we have generally considered whether the expenses are "collectively or potentially significant, whether they are potentially variable or volatile, and whether they are largely outside the utility's control." *Indianapolis Power & Light Co.*, Cause No. 44602 at 79 (Ind. Util. Regul. Comm'n Mar. 16, 2016). The most significant of these factors is whether and to what extent the costs are outside the utility's management and control, orif the utility exercises judgment and discretion. We also consider the utility's request from a broader perspective by reviewing "the utility's risks related to its operating costs and the other tracking mechanisms it has in place." *S. Ind. Gas and Elec. Co.*, Cause No. 43839 at 94 (Ind. Util. Regul. Comm'n Apr. 27, 2011). We have generally found that revenue or cost trackers tend to make utilities less accountable for their actions and thus, should remain limited to ensure the utility is properly incented to manage its overall operating costs. *Ind. Amer. Water*, Cause No. 45870 at 136 -137 (Ind. Util. Regul. Comm'n Feb. 14, 2024citing the Cause No. 43839 Order at 94-95). If utilities can "recover the majority of their variable costs through trackers, they have no incentive to come before the Commission and account for other, non-tracked, decreasing costs or increasing revenues." *Id*. (quoting the Cause No. 43839 Order).

In our Indiana American rate case Order, we wrote:

> In 2010, the Commission rejected a proposal by Petitioner to create a "Pension and OPEB Balancing Account" that would have allowed the utility to "defer under- or over-recovery in Pension/OPEB expense as a regulatory asset/liability for future recovery or refund to customers." Indiana-American Water Co., Cause No. 43680 at 111-112 (IURC April 30, 2010). In that case, we rejected the requested relief determining that if we were to authorize the creation of the balancing account and related regulatory accounting treatment, we would be shifting risks inherent to the prudent operation of the utility to ratepayers, thereby lessening the utility's incentive to manage its business properly and effectively. Accordingly, we ultimately concluded that it was "not in the public interest to require ratepayers to bear this risk." *Id*.
>
> In the present case, Indiana American again seeks approval of balancing accounts and regulatory accounting treatment. This time, however, it seeks that treatment not just for its pension and OPEB expense, but also for its *production costs*. These three separate regulatory accounts would operate in the same manner. Specifically, beginning with the effective date of new rates established in this case, Indiana American would begin comparing its actual expenses in each of these categories to the amount approved for recovery and embedded in base rates with the total difference being treated as a regulatory asset or liability in the next rate case.
>
> Petitioner requests this extraordinary relief because it claims the relief will protect itself, and customers, from volatility in those expenses. The proposed deferred regulatory treatment differs little, if at all, from the relief we denied in Cause No. 43680, which was based on substantially the same justification offered in this proceeding. Seeing the same problems with Petitioner's current proposal as we saw with its past proposal, we see no reason to alter or deviate from our prior decision.

Id. at 137 (emphasis added). We also do not find a basis here to lessen the Company's incentive to engage in efficient and prudent management of its inventory.

As additional support for our decision, return on fuel inventory is not a cost required or incurred to acquire, maintain and prudently manage Duke's inventory. The return component is not a trackable cost through the FAC. Duke follows the Commission's accounting rules, which incorporate the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USoA"). Fuel costs are recorded in FERC account 501. As far back as 1976, the Commission explained that costs allowed by account 151 (which includes those recorded to account 501) constitute fuel costs that are proper for recovery through FAC proceedings. Furthermore, Ind. Code § 8-1-2-42 does not provide for or authorize a return on fuel inventory - it only discusses fuel costs. A return on fuel inventory is not a fuel cost and does not result in the generation of electricity. Therefore, these costs do not meet the requirements of Ind. Code § 8-1-2-42, which states:

> When such application is filed the petitioning utility shall show to the commission its cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity, for the period between its last order from the commission approving fuel costs in its basic rates and the latest month for which actual fuel costs are available.

Account 151 (Fuel Stock) in the USoA does not identify or authorize a return on fuel inventory as an allowable fuel cost. In an FAC application, "the petitioning utility shall show to the commission its cost of fuel to generate electricity and the cost included in the cost of purchased electricity[.]" I.C. § 8-1-2-42(d). The return on fuel inventory is not a cost incurred to purchase fuel or to generate electricity, and these costs do not meet the requirements of I.C. § 8-1-2-42. Therefore, we deny the Company's request to recover a return on fuel inventory through its FAC proceeding.

B. Tariff Issues.

a. EZ Read Program.

The Company is proposing to sunset the EZ Read Program in this proceeding. Pet. Ex. 24 at 32. The OUCC takes issue with this proposal claiming it is punishing the customers that may still want to use the program as the alternatives require a move to tariff with a monthly charge. Pub. Ex. 10 at 14-16. Mr. Colley explained the program has significantly declined over the years, and much of the programs operations must be done manually, which is costly. Pet. Ex. 45 at 23.

In his testimony, Mr. Hanks reports that the Company anticipates participation by 480 customers as of May 2024. Pub. Ex. 10 at 14. Mr. Hanks testified while the Company does have expenses associated with one annual meter reading for remaining Easy Read customers, the expenses are far outweighed by the savings associated with customers that have switched to AMI metering. He explained sunsetting the program at this time would effectively penalize EZ Read program customers who remain in good standing and have adhered to that program's requirements. If customers do not want an AMI meter due to privacy or data security concerns, this shift would require them to move to a tariff with a monthly charge. Remaining customers in the program who are in good standing should not be subject to a new additional monthly charge if they remain opposed to having an AMI meter installed. Mr. Colley testified the Company must continue to monitor whether customers have provided timely readings for proper billing and must engage in annual premises visits to visibly inspect the meter for tampering and validate those meter readings. He testified these manual touches are completed without incremental charges to cover this necessary work and the manual operations are costly. Pet. Ex. 45 at 23. Further, the Company outlined a transition period to help and assist customers properly with the change. Pet. Ex. 24 at 33; Pet. Ex. 45 at 23.

The Company did not adequately quantify the costs relative to the impact for remaining EZ Read customers. We agree with Mr. Hanks that while the Company does have expenses associated with one annual meter reading for remaining EZ Read customers, the expenses are far outweighed by the savings associated with customers that have switched to AMI metering. Sunsetting the program at this time would effectively penalize EZ Read program customers who remain in good standing and have adhered to that program's requirements. If customers do not want an AMI meter due to privacy or data security concerns, this shift would require them to move to a tariff with a monthly charge. Remaining customers in the program who are in good standing should not be subjected to a new additional monthly charge if they remain opposed to having an AMI meter installed at this time. We therefore deny the Company's request to sunset the program.

The record demonstrates that customers will be given ample notice of the program sunsetting and the Company will have call specialists trained on the transition to answer questions about the options to shift to a new metering and billing solutions. Pet. Ex. 45 at 23. Given these considerations, the Commission approves the Company's request to sunset the EZ Read Program subject to it implementing its transition plan.

Petitioner proposed other modifications, both clerical and substantive, to its retail electric tariff, as discussed in the direct testimony of company witness Flick. Besides what has been addressed in this section, these proposed modifications are unopposed. As such, having reviewed the evidence presented, we approve each of these unopposed proposals as reasonable and in the customers' interests.

b. **Final Tariff.**

We have discussed at length issues related to rate design and the Company's resulting tariff and have made findings on such. Unless otherwise addressed in this Order, the Company's tariff as presented by witness Flick, Pet. Ex. 7, Attachment 7-A (RAF) is approved without modification.

C. **Regulatory Accounting Treatment.**

In this proceeding, the Company requested the following regulatory accounting treatment: (i) the continuation of the reserve accounting concept established in Cause No. 45253 for distribution vegetation management O&M costs and expansion of the reserve accounting concept to include transmission vegetation management O&M costs; (2) new deferral authority and future recovery of costs to achieve corporate restructuring savings that are reflected in the forecasted test period; and (3) new deferral authority associated with potential future statutory income tax rate changes. Pet. Ex. 3 at 3. We previously addressed the Company's request for deferral authority for costs associated with the CCS Study at Edwardsport, as well as its request for deferral authority for certain remaining net book value of generation assets and cost of removal upon retirement in prior sections of this Order.

On rebuttal, the Company withdrew its request to create a regulatory asset to defer its costs to achieve corporate restructuring savings in order to reduce controversy in the proceeding. Pet. Ex. 29 at 13. We will address Petitioner's requests with respect to deferral authority related to income tax differences and to continue and expand the reserve accounting concept established in Cause No. 45253 for vegetation management costs in the following sections.

a. Future Statutory Income Tax Changes.

i. Duke Energy Indiana Case-in-Chief.

In this proceeding, the Company is requesting authority to defer all calculated income tax differences resulting from any future change in statutory income tax rates as a regulatory asset or liability, as applicable, until the effect of the statutory income tax rate change can be fully reflected in the Company's rates. Pet. Ex. 3 at 42-43. Company witness Graft testified in the event of future changes in either the statutory federal or state income tax rate, the Company would propose to file a petition in a new docket seeking an adjustment to rates to reflect the difference between (1) the amount of federal or state income taxes that the currently effective rates were designed to recover and (2) the amount of federal or state income taxes that would have been included in the design of currently effective rates had those statutory income tax rate changes been in effect at that time. *Id*.

Ms. Graft testified the Company's request is reasonable because the Tax Cuts and Jobs Act of 2017 and the resulting investigation taught that tax rate changes can be very material, they can take effect abruptly, and they are completely outside the Company's control. *Id*. at 43. Accordingly, Ms. Graft testified being prepared for future changes in the income tax rates is a "lesson learned" from the enactment of the TCJA and the ensuing investigation. *Id*. She further testified it is reasonable for the Company to make this request in the context of this rate case proceeding in order to be better prepared for future changes. *Id*.

ii. OUCC.

OUCC witness Latham recommended denial of the Company's request for authority to defer calculated income tax differences resulting from future changes in statutory income tax rates as a regulatory asset or liability. Mr. Latham testified federal corporate income tax rates and Indiana state corporate income tax rates are historically low, and Indiana ratepayers did not receive any balancing account benefit while investor-owned utilities enjoyed steadily decreasing rates. Pub. Ex. 4 at 3. Further, he testified Duke has not presented evidence or justification that any state tax change is either imminent or that multiple tax changes would lead to the level of volatility that such a balancing account would be needed to alleviate such unpredictability. *Id*. at 4. Mr. Latham testified any state or federal tax rate changes should be incorporated as they traditionally have been, through base rate cases or in the event the Commission determines to address such changes consistently among affected utilities through an investigation case. *Id*. As such, he testified the Company's request in this case should be denied.

iii. Duke Energy Indiana Rebuttal.

On rebuttal, Ms. Graft testified the Company's request to defer calculated income tax differences resulting from future change in statutory income tax rates is reasonable and causes no harm to customers. Pet. Ex. 29 at 13-14. She reiterated the Company proposes to file a petition in a new docket to reflect the effects of the tax rate change, and interested parties will have the opportunity to examine the amounts deferred as part of that proceeding. *Id*. She explained the Company is only requesting the ability to defer these differences until such time as an order is received in the separately docketed proceeding. *Id*. Ms. Graft testified the Company's proposal would work precisely as was implemented in the Commission investigation following the enactment of the TCJA of 2017. Ms. Graft testified the Company's proposal is consistent with the Commission's finding Cause No. 45023-S3 and Mr. Latham's position is not.

iv. <u>Commission Discussion and Findings</u>.

State and federal taxes have traditionally been addressed in base rate cases. On January 3, 2018, the Commission opened an investigation to address the federal tax changes introduced in the Tax Cuts and Jobs Act of 2017 as a docketed proceeding under Cause No. 45032. We named all Indiana jurisdictional rate-regulated, investor-owned utilities as Respondents to that Cause. We agree with Mr. Latham that it is important to address any significant tax change on a consistent basis among, and including, all affected utilities. The Company has not produced sufficient evidence of a compelling reason to deviate from traditional ratemaking. We are also mindful of Mr. Latham's concern that utilities may request such treatment when there is the potential to shift risk to consumers, and abandon such treatment when the utility anticipates the benefit of "steadily decreasing [tax] rates." Pub. Ex. 4 at 3. We further agree with Mr. Latham that the Company did not produce any evidence or justification that any state tax change is imminent or that there is a risk of volatility from multiple tax changes. The administrative and transactional costs of the Company's request would be unwarranted, and we hereby deny the request.

b. <u>Vegetation Management Costs</u>.

[The OUCC does not take a position on this issue.]

D. <u>Economic Development.</u>

[The OUCC does not take a position on this issue.]

19. <u>Confidentiality</u>. On April 4, 2024, and July 19, 2024, Duke Energy Indiana filed Motions for Protection and Nondisclosure of Confidential and Proprietary Information in this Cause, which were supported by affidavits showing that certain information to be submitted to the Commission was trade secret information as defined in Ind. Code § 24-2-3-2 and should be treated as confidential in accordance with Ind. Code §§ 5-14-3-4 and 8-1-2-29. On July 12, 2024, RRPOA also filed a Motion for Confidential Treatment in this Cause. In Docket Entries dated April 18, 2024, and August 21, 2024, the Presiding Officers found the information should be held confidential on a preliminary basis. After review of the information and consideration of the affidavits, we find the information is trade secret information as defined in Ind. Code § 24-2-3-2, is exempt from public access and disclosure pursuant to Ind. Code §§ 5-14-3-4 and 8-1-2-29, and shall be held as confidential and protected from public access and disclosure by the Commission.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Duke Energy Indiana is authorized to place into effect base rates and charges for retail electric utility service rendered by it in the territories served by it in the State of Indiana in accordance with this Order, including an annual increase to its rates and charges of $236,314,000 (excluding changes in items remaining in riders). Said rates are calculated to produce total jurisdictional electric operating revenues of $3,255,795,000 and, on the basis of annual jurisdictional electric operating expenses of $2,516,153,000 will result in annual jurisdictional electric utility operating income of $739,642,000. The Company is authorized to file with the Commission a new schedule of rates and charges which will properly reflect, establish and provide the operating revenues herein authorized. Said schedule of rates and charges should be in accordance with this Order, including implementation of this rate increase in two steps as approved herein.

2. Duke Energy Indiana shall file with the Energy Division of this Commission, appropriate tariffs using the rate design criteria specified in this Order, including the rates and charges authorized herein for Step 1 and Step 2. Rates for Step 1 and Step 2 shall be implemented and shall take effect pursuant to the process we have approved in Finding Paragraph __ herein.

3. Commencing with the first of the month following the effective date of updated base rates, Petitioner is authorized to place into effect the depreciation rates approved in this Order. In accordance with our findings above, such depreciation rates shall not include the $92.1 million requested for CCR costs incurred from 2019 to 2021 that were previously disallowed by the Court of Appeals.

4. Duke Energy Indiana is authorized to implement the changes to various Rate Adjustment Riders as approved in this Order, specifically changes to Riders 60, 62, 65, 66, 67, 68, 70, 72, 73 and 74, all as determined in this Order.

5. Duke Energy Indiana is authorized to implement the rate design proposals and tariff changes as approved in this Order.

6. Duke Energy Indiana's request to adjust its FAC rider to track coal inventory balances in the Company's quarterly FAC filings is denied.

7. Duke Energy Indiana is authorized to utilize a base cost of fuel of _____ mills per kWh and a net operating income of $739,642,000 in its FAC proceedings. For purposes of computing the authorized net operating income for Indiana Code § 8-1-2-42(d)(3), the increased return shall be phased-in over the appropriate period of time that Petitioner's net operating income is affected by the earnings modification as a result of the Commission's approval of this Order. The OUCC is granted a 35-day period to review Petitioner's FAC applications and to file OUCC testimony in such proceedings.

8. This Order shall be effective on and after the date of its approval.

<u>HUSTON, BENNETT, FREEMAN, VELETA, AND ZIEGNER CONCUR</u>

APPROVED:

I hereby certify that the above is a true
and correct copy of the Order as approved.

____
Dana Kosco
Secretary to the Commission

CERTIFICATE OF SERVICE

This is to certify that a copy of the foregoing ***Indiana Office of Utility Consumer Counselor's Proposed Order*** has been served upon the following counsel of record in the captioned proceeding by electronic service on October 18, 2024.

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