

ORIGINAL

Commissioner	Yes	No	Not Participating
Zay	√		
Deig	√		
Swinger	√		
Veleta	√		
Ziegner	√		

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF DUKE ENERGY INDIANA, LLC)
FOR APPROVAL OF A CHANGE IN ITS FUEL)
COST ADJUSTMENT FOR ELECTRIC SERVICE)
AND FOR APPROVAL OF A CHANGE IN ITS FUEL) CAUSE NO. 38707 FAC 147
COST ADJUSTMENT FOR HIGH PRESSURE)
STEAM SERVICE, IN ACCORDANCE WITH) APPROVED: APR 08 2026
INDIANA CODE § 8-1-2-42, INDIANA CODE § 8-1-2-)
42.3, AND VARIOUS ORDERS OF THE INDIANA)
UTILITY REGULATORY COMMISSION)

ORDER OF THE COMMISSION

Presiding Officer:
Sean Gorman, Administrative Law Judge

On January 29, 2026, Duke Energy Indiana, LLC (“Applicant”) filed its Verified Application for approval by the Indiana Utility Regulatory Commission (“Commission”) of a change in its fuel adjustment charge (“FAC”) to be applicable during the billing cycles of April, May and June 2026 for electric and steam service. Concurrently, on January 29, 2026, Applicant submitted its prefiled case-in-chief testimony and attachments under this Cause. On February 17, 2026, Applicant filed revisions to the testimony of Ms. Kimberly Hughes.

On March 5, 2026, the Indiana Office of Utility Consumer Counselor (“OUCC”) filed its testimony.

The Commission held an evidentiary hearing on March 16, 2026, at 1:00 p.m. in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Applicant and OUCC participated in the hearing by counsel, during which their respective prefiled testimony and attachments were admitted into the evidentiary record without objection.

Based upon the applicable law and the evidence herein, the Commission now finds:

1. Notice and Commission Jurisdiction. Notice of the public hearing in this Cause was published as required by law. Applicant is a public utility within the meaning of Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to Applicant’s rates and charges related to adjustments in fuel costs; therefore, the Commission has jurisdiction over the parties and the subject matter of this Cause.

2. Applicant’s Characteristics. Applicant is a public utility organized and existing under Indiana law with its principal office in Plainfield, Indiana. Applicant is engaged in rendering electric utility service in Indiana and owns, operates, manages, and controls, among other things, plant and equipment in Indiana used for the production, transmission, delivery and furnishing of

such service to the public. Applicant also renders steam service to one customer, International Paper.

3. Available Data on Actual Fuel Costs and Authorized Jurisdictional Net Operating Income. On January 29, 2025, the Commission issued an Order in Cause No. 46038 (“46038 Order”) approving base retail electric rates and charges for Applicant. In the 46038 Order, the Commission found that Applicant’s base cost of fuel should be 34.378 mills per kilowatt-hour (“kWh”). The authorized jurisdictional operating income for the 12-month ended November 30, 2025 period reflected in this filing is based on the 46038 Order and the associated Step 1 compliance filing for the March 2025 through November 2025 period and the Commission’s June 29, 2020 Order in Cause No. 45253 and the associated Step 2 compliance filing for the December 2024 through February 2025 period, prior to adjustments to reflect the impacts of investments remaining in riders and the impact of the Settlement Agreement approved in the Order of the Commission on Remand in Cause No. 45253.

Applicant’s cost of fuel to generate electricity and the cost of fuel included in the net cost of purchased electricity for the month of November 2025, based on the latest data known to Applicant at the time of filing after excluding prior period costs, hedging, and miscellaneous fuel adjustments, if applicable, was \$0.034944 per kilowatt-hour (“kWh”). Applicant calculated its phased-in authorized jurisdictional net operating income level for the 12-month period ending November 30, 2025, to be \$701,266,000. After review of the record and the calculation of the authorized jurisdictional net operating income level proposed by Applicant, we find this calculation to be proper.

4. Fuel Purchases. Kimberly Hughes, Director of Coal Origination, Duke Energy Progress, LLC, testified regarding Applicant’s coal procurement practices and its coal inventories. Ms. Hughes testified that, as of November 30, 2025, coal inventories were approximately 2,286,395 tons (or 44 days of coal supply), which is an increase from the inventories reported in Cause No. 38707 FAC 146 (“FAC 146”).

Ms. Hughes testified that Applicant continues to pursue additional inventory mitigation efforts, aside from the supply offer adjustment, by continuing to work with the railroads to pursue greater efficiencies for planned delivery schedules. Ms. Hughes stated that as inventory levels dictate, Applicant explores options to store or defer contract coal or resell surplus coal into the market. She stated that Applicant continues to closely monitor its anticipated coal requirements and inventories and takes every action available to effectively manage coal inventories in the least-cost impact manner for customers.

Pursuant to the Commission’s Order in Cause No. 38707 FAC 125, Ms. Hughes presented Petitioner’s coal procurement plan for 2026 and 2027. Given Applicant’s 2026 forecasted system mean coal burn of 10.5 million tons (as of December 12, 2025) and its current contracted position, Ms. Hughes testified that Applicant does not anticipate purchasing additional coal supply for 2026. However, should conditions change, Applicant will procure additional spot tons in 2026, as needed, to ensure reliable coal supply. Applicant will continue to monitor its 2027 forecasted system mean coal burn of 10.1 million tons (as of December 12, 2025) and projected inventories to determine any needed additional coal. Ms. Hughes testified that over the course of 2025,

Applicant executed on its plans to implement its strategic, risk informed supply plan that balances delivered supply costs with supplier diversity, delivery flexibility and supplier financial viability for its fuel procurement needs beyond 2026. Due to continued energy market volatility, supply chain constraints, and shifting dynamics in the Midcontinent Independent System Operator (“MISO”) market fuel resource mix, Applicant expects to continue a supply offer adjustment to proactively manage market constraints, maintain reliable fuel inventory, and maintain its minimum and maximum coal inventory boundaries economically and reliably. She testified that utilizing a supply offer adjustment proactively protects customers from otherwise larger swings in fuel inventories over time and avoids more expensive and higher risk options.

James J. McClay, III, Managing Director of Natural Gas Trading for Duke Energy Corporation, testified that spot natural gas prices are dynamic, volatile, and can significantly change day to day based on market fundamental drivers. During the period September through November 2025 (“Reporting Period”), the price Applicant paid for delivered natural gas at its gas burning stations was between \$2.58 per million BTU and \$4.90 per million BTU. He testified that the average price of natural gas purchased for the period was higher than what was reported in FAC 146, driven by price volatility in spot natural gas prices during the fall period. Mr. McClay opined that Applicant purchased natural gas at the lowest market prices available. He testified that Applicant continues to use its existing firm transportation contracts to enhance supply reliability by reducing the risk of gas pipeline capacity curtailments during periods of tighter supply and demand conditions. Mr. McClay explained how Applicant’s new special construction and gas transportation contract with CenterPoint Energy Indiana North improves reliability and lowers overall fuel costs for its customers.

John D. Swez, Managing Director, Trading and Dispatch for Duke Energy Carolinas, LLC, testified that Applicant continues to submit a modified incremental cost offer for its share of Benton County Wind Farm in accordance with the settlement agreement with Benton County Wind Farm discussed in Cause No. 38707 FAC 113.

Michael D. Eckert, Chief Technical Advisor of OUCC’s Electric Division, recommended that the Commission require Applicant to update the Commission on its coal inventory and transportation situation, 2026 projected coal burns, Applicant’s coal hedging policies, and to continue to provide the inputs to Applicant’s calculation of and the reasons for any use of the coal price increment/decrement.

Based on the evidence presented, we find that Applicant made every reasonable effort to acquire fuel for its own generation or to purchase power to provide electricity to its retail customers at the lowest cost reasonably possible during the Reporting Period.

Additionally, Applicant is directed to provide an update on the status of its coal inventory levels, 2026 projected coal burn, coal purchases, and how it is addressing coal transportation issues in its next FAC proceeding.

5. Hedging Activities. Mr. McClay testified that Applicant takes advantage of the hedging tools available to protect against natural gas price fluctuations. He stated that Applicant realized a loss of \$1,001,097 from natural gas hedges purchased for the Reporting Period. He

testified that market prices for gas realized lower values than the hedged prices primarily due to increased domestic storage balances. He testified that Applicant experienced net realized power hedging losses for the Reporting Period of \$103,151 primarily driven by lower realized power prices due to soft demand.

Christa L. Graft, Director of Rates and Regulatory Planning for Applicant, testified that Applicant realized a total net hedging loss of \$1,104,248 during the Reporting Period for all native gas and power hedging activities other than MISO virtual energy market participation (including prior period adjustments).

Mr. McClay explained that, consistent with the Commission's June 25, 2008, Order in Cause No. 38707 FAC 68 S1 ("FAC 68 S1 Order"), beginning on August 1, 2008, Applicant has not utilized its flat hedging methodology. Rather, Applicant hedges up to approximately flat minus 150 megawatts ("MW") on a forward, monthly, and intra-month basis, and up to approximately flat on a Day Ahead/Real-Time basis. This methodology will leave Applicant with at least approximately 150 MW of expected load unhedged on a forward forecasted basis. Mr. McClay testified that Applicant is following the Commission's March 29, 2023 order in Cause No. 38707 FAC 135 ("FAC 135 Order") regarding power and gas hedging, which extended the rolling native power hedging horizon to cash month plus 12 months and the native gas hedging term limit to cash month plus three years, with target ranges for the new horizon period for natural gas adjusting over time to allow Applicant to layer in hedges.

Mr. McClay opined that Applicant's gas and power hedging practices are reasonable. He stated that Applicant never speculates on future prices and that its hedging practice is economic at the time the decision is made and reduces volatility because Applicant is transacting in a less volatile forward market, as opposed to more volatile spot markets.

Mr. Eckert testified that in the current Reporting Period, Applicant experienced a loss of \$1,104,248. Mr. Eckert recommended that Applicant continue to update the Commission on its coal hedging policy.

Applicant presented evidence that its hedging practices relevant to this proceeding were consistent with the Agreement previously approved in the FAC 68 S1 Order and with the FAC 135 Order. Thus, we allow Applicant to include \$1,104,248 of net losses from native gas and power hedges in the calculation of fuel costs in this proceeding. We also conclude that it is prudent for Applicant to periodically consult with the OUCC to review Applicant's hedging program and recommend modifications, as needed, in response to changing market signals to ensure that it remains appropriate based on market conditions.

6. Participation in the Energy and Ancillary Service Markets ("ASM") and MISO-Directed Dispatch. On June 1, 2005, the Commission issued an Order in Cause No. 42685 ("June 1 Order"), in which the Commission approved certain changes in the operations of the investor-owned Indiana electric public utilities that are participating members of MISO.

Mr. Swez testified that Applicant included Energy Markets charges and credits incurred as a cost of reliably meeting the power needs of Applicant's load, including: (1) Energy Markets charges and credits associated with Applicant's own generation and bilateral purchases that were used to serve retail load; (2) purchases from MISO at the full locational marginal pricing at Applicant's load zone; (3) other Energy Markets charges and credits included in the list on page 37 of the June 1 Order; (4) credits and charges related to auction revenue rights and Schedule 27 and Schedule 27-A; and (5) fuel related charges and credits received from PJM Interconnection LLC ("PJM") from the operation of Madison Generation Station as approved in Cause No. 45253.

Mr. Swez testified that Applicant continued the use of supply offer adjustments at Gibson Units 1-5 and Cayuga Units 1-2 to maintain reliable levels of coal inventory to the benefit of customers. The offer adjustment process allows Applicant to dynamically manage inventory and volatile energy market conditions reliably and economically throughout the year. Main factors impacting the supply offer adjustment are the volatility of natural gas and power markets, and the reliability of the coal supply and transportation chain.

Over the course of the Reporting Period, Applicant utilized a positive supply offer adjustment at Gibson station and a zero and positive supply offer adjustment at Cayuga station.

Mr. Swez testified Applicant uses a stochastic modeling approach to determine the adjustment amount. The model utilizes up-to-date spot and future commodity and power prices, along with actual and expected coal deliveries, and actual and targeted station coal inventory. This approach allows for an improved ability to simulate a range of generation unit availability, train deliveries, and price inputs to provide ranges for key outputs, such as coal burns, supply offer adjustments, station specific coal deliveries and coal inventory. The stochastic modeling process selects a supply offer adjustment that provides the expected least cost outcome within coal inventory bounds set for reliability purposes. He testified Applicant continues to bound coal inventory levels between a minimum and maximum full load burn inventory at its Gibson and Cayuga stations for modeling purposes, as it does for fuel inventory planning and procurement purposes. He explained that the supply offers at Gibson Units 1-5 and Cayuga Units 1-2 are calculated just as they are normally, then adjusted by the necessary \$/MWh supply offer adjustment amount. He stated that Applicant monitors commodity prices and coal inventories within its normal course of business and updates the offer adjustment on a weekly basis.

Mr. Swez opined that the offer adjustment is in the best interest of Applicant's customers and is working as intended. He testified that Applicant would continue utilizing its supply offer adjustment process for Gibson 1-5 and Cayuga 1-2 as a normal course of business, which allows Applicant to continue to economically commit and dispatch its units versus being forced to utilize higher cost options caused by not dispatching its coal units. He testified that this dynamic commitment and dispatch solution optimally manages coal inventory and volatile energy market conditions in a proactive, coordinated fashion throughout time instead of reacting to problems as they arise. Pursuant to the Commission's Order in Cause No. 38707 FAC 130, Mr. Swez presented support for the reasonableness of the supply offer adjustments during the Reporting Period.

Gregory T. Guerrettaz, CPA and Registered Municipal Advisor, testified on behalf of OUCC that Applicant continued to use an adjustment for offer pricing during the Reporting Period. He testified the adjustments had a minimal effect on the actual offer price.

Krista K. Markel, Accounting Manager II for Duke Energy Business Services LLC, discussed the procedures followed by Applicant to verify the accuracy of the charges and credits allocated to Applicant by MISO and PJM. She also discussed the process by which MISO issues multiple settlement statements for each trading day and the dispute resolution process with respect to such statements. She stated that every daily settlement statement received by Applicant from MISO is reviewed utilizing certain computer software tools. Ms. Markel opined that the amounts paid by Applicant to MISO and PJM, net of any credits, are proper and that such amounts billed to customers through the FAC are proper.

In its June 30, 2009 Phase II Order in Cause No. 43426 (“Phase II Order”), the Commission authorized Applicant and the other Joint Petitioners in that cause to recover costs and credit revenues related to the ASM. Mr. Swez explained that Applicant has included in this proceeding various ASM charges and credits, consistent with the Phase II Order, as well as appropriate period adjustments.

Christopher J. Ricci, Lead Portfolio Management Manager for Duke Energy Carolinas, LLC, testified that Applicant, in accordance with the Phase II Order, has calculated the monthly average ASM Cost Distribution Amounts it has paid for Regulation, Spinning, Supplemental, and Short Term Reserves. These amounts are as follows:

(in \$ per MWh)	Sep-25	Oct-25	Nov-25
Regulation Cost Dist.	0.1445	0.1936	0.1974
Spinning Cost Dist.	0.0513	0.0598	0.0591
Supplemental Cost Dist.	0.0316	0.0213	0.0084
Short Term Res. Cost. Dist.	0.1206	0.0699	0.0499

Applicant’s treatment of ASM charges follows the treatment ordered by the Commission in its Phase II Order.

Based upon the evidence presented, we find Applicant’s participation in the Energy Markets and ASM constituted reasonable efforts to generate or purchase power, or both, to serve its retail customers at the lowest fuel cost reasonably possible. Further, as we noted in our Orders in Cause Nos. 38707 FAC 81 and 38707 FAC 82, should Applicant’s bidding strategy alter the native/non-native load assignment of its units, such strategy may be subject to further prudence review.

In addition, based upon the evidence of record, the Commission finds that Applicant’s treatment of the Energy Market and ASM charges and credits in its cost of fuel is consistent with applicable orders of the Commission and is approved.

We find that the mechanics of Applicant's supply offer adjustment to MISO are reasonable. Applicant's continual implementation of the supply offer adjustment allows for optimal management of coal inventory in a proactive, cost-effective manner throughout time, instead of reacting to issues as they arise. Energy market price volatility, fuel inventory supply chain constraints, and shifting dynamics in the market fuel resource mix impacting fuel inventories and reliability continue to persist. We find Applicant's weekly calculation and continual use of the supply offer adjustment an effective tool to protect customers and Applicant against otherwise larger swings in fuel inventories over time. Applicant will continue to provide support of any supply offer adjustment in its next FAC filing.

7. Major Forced Outages. In the December 28, 2011 Order in Cause No. 38707 FAC 90, the Commission ordered Applicant to discuss in future FAC proceedings major forced outages of units of 100 MW or more lasting more than 100 hours. Mr. Swez testified that during the Reporting Period, there were two outages that met these criteria, one of which was the continuation of the Wheatland Unit 1 outage discussed in FAC 146, due to compressor blade damage. He testified that Wheatland Unit 1 is still unavailable due to this outage. Mr. Swez testified that a root cause analysis has been initiated on the Wheatland Unit 1 reportable outage and will be provided in a future FAC proceeding when complete.

In the Settlement Agreement approved by the Commission on April 11, 2018 in Cause No. 38707 FAC 111 S1, Applicant agreed to calculate an estimate of the impact on native load fuel costs for forced outages larger than 100 MW and that last more than sixty days. Mr. Ricci testified that the Wheatland Unit 1 outage has met this criteria. However, because the outage is ongoing, a final calculation of the impact on native load fuel cost has not been conducted. He testified that further updates will be provided in future FAC filings.

8. Operating Expenses. Ind. Code § 8-1-2-42(d)(2) requires the Commission to determine whether actual increases in fuel costs have been offset by actual decreases in other operating expenses. Applicant filed operating cost data for the 12 month period ending November 30, 2025. Applicant's authorized phased-in jurisdictional operating expenses (excluding fuel costs) are \$1,566,578,000. For the 12-month period ended November 30, 2025, Applicant's actual jurisdictional operating expenses (excluding fuel costs) totaled \$1,612,901,000. Applicant's actual operating expenses exceeded jurisdictional authorized levels during the period at issue in this Cause. Therefore, the Commission finds that Applicant's actual increases in fuel costs for the above-referenced periods have not been offset by decreases in other jurisdictional operating expenses.

9. Return Earned. Ind. Code § 8-1-2-42(d)(3), subject to the provisions of Ind. Code § 8-1-2-42.3, generally prohibits a fuel cost adjustment charge that would result in a regulated utility earning a return in excess of its applicable authorized return. Should the fuel cost adjustment factor result in the utility earning a return more than its applicable authorized return, it must, in accordance with the provisions of Ind. Code § 8-1-2-42.3, determine if the sum of the differentials between actual earned returns and authorized returns for each of the 12-month periods considered during the relevant period is greater than zero. If so, a reduction to the fuel adjustment clause factor is deemed appropriate.

Ms. Graft testified that in accordance with the Commission’s Order in Cause No. 42736-RTO 14, Applicant has excluded revenues and expenses associated with Applicant-owned Regional Expansion Criteria and Benefit (“RECB”) projects from the earnings test beginning in Cause No. 38707 FAC 86. She explained that in accordance with the Commission’s Orders in Cause No. 38707 FAC 122 and Cause No. 42736-RTO 56, Applicant has excluded revenues and expenses related to Company-owned Multi-Value Projects (“MVP”) from the earnings test. Based upon the evidence presented, the Commission finds that Applicant’s exclusion of revenues and expenses associated with Applicant-owned RECB and MVP projects from the earnings test is consistent with prior Commission orders and is approved.

Applicant’s actual jurisdictional electric operating income level, calculated in accordance with previous Commission Orders, was \$623,094,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was \$701,266,000. Therefore, the Commission finds that Applicant did not earn a return more than its authorized level during the 12 months ended November 30, 2025.

10. Estimation of Fuel Costs. Applicant estimates that its prospective average fuel cost for the months of April through June 2026 will be \$70,767,025, or \$0.033189 per kWh.¹ Applicant previously made the following estimates of its fuel costs for the Reporting Period, and experienced the following actual costs (excluding prior period adjustments), resulting in percent deviation, as follows:

Month	Actual Cost in Mills/kWh	Estimated Cost in Mills/kWh	Percent Actual is Over (Under) Estimate
Sep 2025	35.350	34.624	2.10%
Oct 2025	33.488	31.612	5.93%
Nov 2025	34.821	31.283	11.31%
Weighted Average	34.575	32.546	6.23%

A comparison of Applicant’s actual fuel costs with the respective estimated costs for these three periods results in a weighted average difference of 6.23%, excluding prior period adjustments. Based on the evidence of record, we find that Applicant’s estimating techniques appear reasonably sound, and its estimates for April through June 2026 are accepted.

11. Fuel Cost Factor. As discussed above, Applicant’s base cost of fuel is 34.378 mills per kWh. The evidence of record indicates that Applicant’s fuel cost adjustment factor applicable to April through June 2026 billing cycles² is computed as follows, as shown on Schedule 1 of Attachment A of Applicant’s Verified Application:

¹ Excluding certain firm transportation gas costs being allocated on a production demand basis per the Commission’s Order in Cause No. 46193.

² *Id.*

	\$ / kWh
Projected Average Fuel Cost	0.033189
FAC 147 Reconciliation Factor	0.000960
Adjusted Fuel Cost Factor	0.034149
Less: Base Cost of Fuel Included in Rates	0.034378
Fuel Cost Adjustment Factor	(0.000229)

Ms. Graft testified that the FAC 147 reconciliation factor shown above reflects \$5,778,442 of under-collected fuel costs applicable to retail customers that occurred during the Reporting Period.

Ms. Graft testified that, as directed in the Commission’s Order in Cause No. 45508, amounts credited to customers for excess distributed generation (“EDG”) are recognized in Applicant’s FAC proceeding. The native load fuel costs reflected on Schedule 7 of Attachment A to Applicant’s Verified Application include the EDG payments made to customers during this Reporting Period.

Ms. Graft testified that the Commission authorized Applicant to execute the Speedway Solar purchase power agreement (“PPA”) in its order in Cause No. 45907. The underlying project was declared commercial on June 23, 2025. Applicant is recovering the retail portion of the PPA costs through this FAC proceeding, similar to other PPAs previously approved by the Commission. She also stated that the Commission authorized Applicant to recover its expenses associated with entering into the Speedway Solar PPA of \$129,024 over a three-year period through the FAC proceedings. She testified that the native load fuel cost includes a monthly amortization of \$3,584 that began in November 2023 and continues through October 2026.

Ms. Graft testified that in Cause No. 46193 the Commission authorized Applicant to recover costs of Rockies Express Pipeline firm natural gas transportation (both the East to West and the West to East components) and costs of the CenterPoint natural gas lateral based on production demand via the FAC. She testified that the applicable firm transportation gas costs are reflected in the forecasted fuel costs for April through June 2026, as shown in Schedule 4, page 1 of Attachment A to Applicant’s Verified Application.

The overall proposed FAC factors by rate class, comprised of (1) a factor for fuel costs excluding those firm transportation costs being allocated to rate classes on a production demand basis (as calculated on Attachment A, Schedule 1 of Applicant’s Verified Application); and (2) the overall firm transportation gas cost component (calculated on Attachment A, Schedule 4, page 1 of the Applicant’s Verified Application), are illustrated on Attachment A, Schedule 4, page 3 of Applicant’s Verified Application.

Mr. Guerrettaz testified that Applicant’s fuel cost adjustment for the Reporting Period had been properly applied by Applicant. While Applicant used forecasted market prices for its natural gas and purchased power as of January 2, 2026 for its proposed FAC factor, and those inputs have decreased as of February 16, 2026, the OUCC does not recommend a change in the proposed factor. He also stated that the figures used in Applicant’s Verified Application for a change in the FAC were supported by Applicant’s books and records for the period reviewed.

Based on the evidence of record, the Commission approves the fuel cost factors as proposed by Applicant.

12. Effect on Residential Customers. The approved factor represents a decrease of \$0.004721 per kWh from the factor approved in Cause No. 38707 FAC 146. The typical residential customer using 1,000 kWhs per month will experience a decrease of \$4.72, or 2.9%, on the customer's total electric bill compared to the factor approved in FAC 146 (excluding sales tax).

13. Interim Rates. Because we are unable to determine whether Applicant's actual earned return will exceed the level authorized by the Commission during the period that this fuel cost adjustment factor is in effect, the Commission finds that the rates approved herein should be approved on an interim basis, subject to refund, in the event an excess return is earned.

14. Fuel Adjustment for Steam Service. On January 18, 2023, the Commission issued its Order in Cause No. 45740 approving the Fifth Amendment to the Third Supplemental Agreement to the Agreement for High Pressure Steam Service between Duke Energy Indiana and International Paper Company (formerly TIN, Inc. (Temple-Inland) and Inland Container Corporation) ("International Paper"), which included a change in the method used to calculate International Paper's fuel cost adjustment and an update to the base cost of fuel.³ Applicant's proposed fuel cost adjustment factor for International Paper of \$0.4341460 per 1,000 pounds of steam was calculated on Applicant's Attachment B, Schedule 1, of the Verified Application.

Attachment B, Schedule 2, of the Verified Application is a reconciliation of the actual fuel cost incurred to estimated fuel cost billed to International Paper that resulted in a \$92,476 debit to International Paper for the Reporting Period. The Commission finds that Applicant's proposed fuel cost adjustment factor for International Paper of \$0.4341460 per 1,000 pounds of steam has been calculated in accordance with this Commission's Order in Cause No. 45740 and approves the same. We further find that Applicant's reconciliation amount of \$92,476 debit to International Paper has been properly determined and approve the same.

15. Shared Return Revenue Credit Adjustment for International Paper. In accordance with the Order in Cause No. 45740, International Paper will receive shared return revenue credit adjustments to the extent incurred. Applicant did not have excess earnings for the 12 months ended November 2025. Therefore, we find International Paper is not due a shared return revenue credit.

16. Confidential Information. Applicant filed a Motion for Protection of Confidential and Proprietary Information on January 29, 2026, supported by affidavits showing that certain documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4 and 24-2-3-2. The Presiding Administrative Law Judge issued a docket entry on February 10, 2026, finding such information to be preliminarily confidential, after which such information was submitted under seal. No party objected to the confidential and proprietary nature of the information submitted under seal in this proceeding. We find the information is confidential pursuant to Ind. Code § 5-14-3-4 and is exempt from public access, disclosure by

³ The Sixth Amendment, approved in Cause No. 46203, extended the term of the Steam Supply Agreement using the pricing approved in Cause No. 45740.

Indiana law, and shall continue to be held confidential and protected from public access and disclosure by the Commission.

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

1. Applicant's fuel cost adjustment factors for electric service to be billed jurisdictional customers, as set forth in Finding No. 11 of this Order, and the fuel cost adjustment for steam service as set forth in Finding No. 14 of this Order, are approved on an interim basis.
2. Applicant's inclusion of Energy and Ancillary Services Markets charges and credits in its cost of fuel, as described in Finding No. 6 of this Order, is approved.
3. Prior to implementing the authorized rates, Applicant shall file the tariff and applicable rate schedules under this Cause for approval by the Commission's Energy Division. Such rates shall be effective on or after the date of approval for all bills rendered.
4. Applicant shall provide an update on the status of its coal inventory levels, 2026 projected coal burn, coal purchases, and how it is addressing coal transportation issues in its next FAC filing, as described in Finding No. 4 of this Order.
5. Applicant will provide support for the reasonableness of any supply offer adjustment in its next FAC filing, as discussed in Finding No. 6 of this Order.
6. The material submitted to the Commission under seal is declared to contain trade secret information as defined in Ind. Code § 24-2-3-2 and therefore is exempted from the public access requirements contained in Ind. Code ch. 5-14-3 and Ind. Code § 8-1-2-29.
7. This Order shall be effective on and after the date of its approval.

ZAY, DEIG, SWINGER, VELETA, AND ZIEGNER CONCUR:

APPROVED: APR 08 2026

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

Dana Kosco
Secretary of the Commission