Commissioner	Yes	No	Not Participating
Huston	√		
Bennett	√		
Freeman	√		
Veleta	√		
Ziegner	√		

ORIGINAL

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 COST ADJUSTMENT FOR HIGH PRESSURE STEAM SERVICE, IN ACCORDANCE WITH INDIANA CODE §8-1-2-42, INDIANA CODE §8-1-2-42.3, AND VARIOUS ORDERS OF THE INDIANA UTILITY REGULATORY COMMISSION	)	**CAUSE NO. 38707 FAC 141** **APPROVED: SEP 25 2024**

ORDER OF THE COMMISSION

Presiding Officer:
Jennifer L. Schuster, Senior Administrative Law Judge

On July 30, 2024, Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Applicant") filed its Verified Application and direct testimony and exhibits 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 October, November, and December 2024 for electric and steam service. On August 27, 2024, Duke Energy Indiana filed a revised Verified Application and the revised direct testimony of Ms. Christa L. Graft to correct an inadvertent error in Applicant's Sumatra results related to gas pipeline fees, resulting in a reduction to the original proposed factor.

On September 3, 2024, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and testimony.

An evidentiary hearing was held in this Cause on September 16, 2024 at 9:30 a.m. in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Applicant and the OUCC appeared at the hearing by counsel and offered their respective prefiled testimony into the evidentiary record without objection.

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

1. **<u>Notice and Commission Jurisdiction</u>.** Notice of the hearing in this Cause was given 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. **<u>Applicant's Characteristics</u>.** Applicant is a public utility corporation 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 customer International Paper.

3. **<u>Available Data on Actual Fuel Costs and Authorized Jurisdictional Net Income</u>.** On June 29, 2020, the Commission issued an order in Cause No. 45253 ("45253 Order") approving base retail electric rates and charges for Applicant. The 45253 Order found that Applicant's base cost of fuel should be 26.955 mills per kilowatt-hour ("kWh"). Implementation of the 45253 Order established an authorized jurisdictional operating income level of $584,678,000 prior to adjustments to reflect Applicant's two-step implementation of base rates, impacts of investments remaining in riders, and 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 May 2024, 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 $0.032685 per kWh. In accordance with previous Commission orders, Applicant calculated its phased-in authorized jurisdictional net operating income level for the 12-month period ending May 31, 2024, to be $593,315,000. After review of the record and the calculation of the authorized jurisdictional net operating income level proposed by Applicant, we find it to be proper.

4. **<u>Fuel Purchases</u>.** 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 May 31, 2024, coal inventories were approximately 3,604,082 tons (or 70 days of coal supply), which is an increase from inventories reported in Cause No. 38707 FAC 140 ("FAC 140"). Ms. Hughes reported that the increase can be attributed to decreased weather-driven demand throughout the FAC period. Ms. Hughes testified that Applicant continues to pursue additional inventory mitigation efforts, aside from the supply offer adjustment, including exercising its contractual rights to reduce tonnage in over supplied periods to future time periods. 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.

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 three-month period from March through May 2024, the price Applicant paid for delivered natural gas at its gas burning stations was between $1.16 per million BTU and $3.27 per million BTU. He testified the average price of natural gas purchased for the period was lower than what was experienced in the FAC 140 review period, driven by price volatility in spot natural gas prices. Mr. McClay opined that Applicant purchased natural gas at the lowest cost reasonably possible.

Mr. McClay testified that Applicant is planning to engage in natural gas procurement from the Rockies Express ("REX") pipeline for future planned natural gas-fired generation. He explained that obtaining access to firm, long-term natural gas transportation takes time based on pipeline availability, so Applicant must begin the process now. He testified that to the extent Applicant is successful, it will include in any contract for transportation that it is dependent on Duke Energy Indiana proceeding with construction of a natural gas plant, and on Commission approval of that construction.

OUCC witness Michael D. Eckert recommended Applicant continue to update the Commission on its coal inventory and 2024 and 2025 projected coal burn and coal purchases, as well as how Applicant is addressing its coal transportation issues. OUCC witness Gregory T. Guerrettaz recommended Applicant continue to provide historical and projected results for any adjustment to its Midcontinent Independent System Operator ("MISO") offer prices.

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 FAC 113.

Based on the evidence of record, 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 March through May 2024. Applicant will provide an update on the status of its coal inventory levels and transportation issues in its next FAC proceeding as recommended by the OUCC. We further find that it is reasonable and appropriate for Applicant to seek to procure additional natural gas supply options for portfolio resiliency and future generation needs. Mr. McClay's description of customer protections to include in any potential contract for firm capacity is also reasonable and appropriate.

5. **<u>Hedging Activities</u>.** Mr. McClay testified Applicant takes advantage of the hedging tools available to protect against natural gas price fluctuations. He stated that Applicant realized a loss of $9,933,056 from natural gas hedges purchased for March through May 2024. He testified that market prices for gas realized lower values than the hedged prices primarily due to improved domestic gas production, above-average domestic storage balances, and mild weather. He testified that Applicant experienced net realized power hedging gains for the period of $30,759 primarily due to higher realized power prices due to relatively high outage levels in MISO. Christa L. Graft, Director of Rates and Regulatory Planning for Applicant, testified that Applicant realized a total net hedging loss of $9,902,297 during the 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 will hedge 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 changes were made to Applicant's power and gas hedging plans, as approved in the

Commission's March 29, 2023 order in Cause No. 38707 FAC 135, to extend 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. He testified the hedge horizon variance is mostly driven by liquidity differential in the two markets. While natural gas has a robust futures market, power forward markets are not as active and have much lower trading volumes. Mr. McClay opined that it is necessary to keep a more realistic shorter-term limit for power hedges. He testified that Applicant's updated Duke Energy Indiana Risk Management Guidelines with the new power and gas limits were internally approved on June 15, 2023. Applicant began to layer in additional power and gas hedges over time toward the new target ranges.

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 Applicant's hedging gains and losses for the period December 2013 through January 2021 were relatively consistent. Starting in February 2021, with the exception of March 2021, Applicant experienced large hedging gains through November 2021. Applicant subsequently experienced large hedging losses starting in December 2021 through February 2022. In the current FAC period, Applicant experienced losses in all three months. Mr. Eckert recommended Applicant continue to update the Commission on its coal hedging policy.

Applicant presented evidence that its power hedging practices relevant to this proceeding were consistent with the Agreement previously approved in the FAC 68 S1 Order. Thus, we allow Applicant to include $9,902,297 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 Duke Energy Indiana 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. <u>Participation in the Energy and Ancillary Service Markets ("ASM") and MISO-Directed Dispatch</u>. 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 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 reliability of the coal supply and transportation chain, volatility of power and natural gas prices, and the evolution of fuel mixes across energy markets. Over the course of the FAC period, Applicant utilized negative and $0 supply offer adjustments at Gibson station and a negative supply offer adjustment at its Cayuga station.

Mr. Swez testified that 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 that 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 will 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 March through May 2024.

Mr. Guerrettaz testified Applicant used both decrement and increment pricing during the FAC period, driven by fluctuations in coal inventory. He testified that modeling results during this and past FACs were bouncing around. He testified the OUCC is concerned that Applicant implements the model and pricing results regardless of whether those results are positive or negative. Mr. Eckert recommended Applicant continue to provide the inputs to its calculation of and the reasons for any use of the coal price increment/decrement in its subsequent FAC proceedings.

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 incurred for March through May 2024, 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)	**Mar-24**	**Apr -24**	**May-24**
Regulation Cost Dist.	0.0473	0.0559	0.0595
Spinning Cost Dist.	0.0321	0.0377	0.0523
Supplemental Cost Dist.	0.0069	0.0038	0.0053
Short Term Res. Cost. Dist.	0.0106	0.0192	0.0271

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

Based upon the evidence of record, we find Applicant's participation in the Energy and Ancillary Services Markets constituted reasonable efforts to generate or purchase power, or both, to serve its retail customers at the lowest 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 and ASM charges and credits in its cost of fuel is consistent with applicable orders of the Commission and is approved.

We find that Applicant has laid a reasonable foundation for the mechanics of its supply offer adjustment to MISO. We appreciate the OUCC's continued monitoring of Applicant's supply offer adjustment; however, we understand that Applicant's implementation of the supply offer adjustment is intended to be on a continual basis. Given today's energy market price volatility, fuel inventory supply chain constraints, and shifting dynamics in the market fuel resource mix impacting fuel inventories and reliability, we find Applicant's use of the supply offer adjustment an effective tool to protect 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. **<u>Major Forced Outages</u>.** 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 during this FAC period there were two outages that met these criteria. Mr. Swez testified no root cause analyses were performed on the two reportable outages.

8. **<u>Operating Expenses</u>.** 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 months ended May 31, 2024. Applicant's authorized phased-in jurisdictional operating expenses (excluding fuel costs) are $1,312,740,000. For the 12-month period ended May 31, 2024, Applicant's actual jurisdictional operating expenses (excluding fuel costs) totaled $1,323,710,000. 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. **<u>Return Earned</u>.** 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.

In accordance with the Commission's June 27, 2012 order in Cause No. 42736 RTO 30, the proposal for Schedule 26-A treatment of costs or revenues associated with Applicant-owned Multi-Value Projects ("MVPs") was to be addressed at the time any such projects have been completed and are included for recovery. Ms. Graft testified that the first of such projects were included for the first time in MISO billing effective June 2019. Applicant proposed that the costs and revenues associated with Applicant-owned MVPs be treated as non-jurisdictional and outside of the FAC earnings test, which is consistent with the treatment of its Applicant-owned Regional Expansion Criteria and Benefit projects beginning in Cause No. 38707 FAC 86. Applicant provided more detail as it relates to the RTO rider in its filing in Cause No. 42736 RTO 56 ("RTO 56"). Based upon the evidence of record, the Commission approves Applicant's exclusion of revenues and expenses associated with Applicant-owned MVPs. In Cause No. 38707 FAC 122, Applicant's proposed treatment for these revenues and expenses was approved on an interim basis, subject to refund, pending the outcome of Applicant's RTO 56 filing. The Commission issued its RTO 56 order on February 24, 2021.

Applicant's jurisdictional electric operating income level, calculated in accordance with previous Commission Orders, was $531,194,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was $593,315,000. Therefore, the Commission finds that Applicant did not earn a return more than its authorized level during the 12 months ended May 31, 2024.

10. **<u>Estimation of Fuel Costs</u>.** Applicant estimates that its prospective average fuel cost for the months of October through December 2024, will be $73,795,000 or $0.031992 per kWh. Applicant previously made the following estimates of its fuel costs for the period March through May 2024, 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
Mar 2024	28.229	33.897	(16.72%)
Apr 2024	30.288	32.615	(7.13%)
May 2024	33.521	30.768	8.95%
Weighted Average	30.696	32.464	(5.45%)

A comparison of Applicant's actual fuel costs with the respective estimated costs for these three periods results in a weighted average difference of (5.45%), excluding prior period adjustments. Based on the evidence of record, we find that Applicant's estimating techniques appear reasonably sound, and its estimates for October through December 2024 are accepted.

11. **<u>Fuel Cost Factor</u>.** As discussed above, Applicant's base cost of fuel is 26.955 mills per kWh. The evidence of record indicates that Applicant's fuel cost adjustment factor applicable to October through December 2024 billing cycles is computed as follows:

	$ / kWh
Projected Average Fuel Cost	0.031992
FAC 141 Reconciliation Factor	(0.002109)
Adjusted Fuel Cost Factor	0.029883
Less: Base Cost of Fuel Included in Rates	0.026955
Fuel Cost Adjustment Factor	0.002928

Ms. Graft testified that the FAC 141 reconciliation factor shown above reflects $13,235,481 of over-collected fuel costs applicable to retail customers that occurred during the period March through May 2024.

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 FAC reconciliation period.

Ms. Graft testified that the Commission authorized Applicant to enter into the Speedway Solar PPA in its order in Cause No. 45907. The underlying project is expected to be operational in September 2025, at which time Applicant will begin recovering the retail portion of the PPA costs through the FAC proceedings, 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.

OUCC witness Mr. Guerrettaz opined that the fuel cost adjustment for the quarter ended May 2024 had been properly applied by Applicant. He also stated that the figures used in the 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 factor as proposed by Duke Energy Indiana.

12. Effect on Residential Customers. The approved factor represents a decrease of $0.000383 per kWh from the factor approved in Cause No. 38707 FAC 140. The typical residential customer using 1,000 kWhs per month will experience a decrease of $0.38, or 0.3%, on the customer's total electric bill compared to the factor approved in FAC 140 (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. The fuel cost adjustment factor for International Paper of $0.3689227 per 1,000 pounds of steam was calculated on Applicant's Exhibit 7, Attachment B, Schedule 1, of the Revised Verified Application; this factor will be effective for the October through December 2024 billing cycles. Attachment B, Schedule 2, of the Revised Verified Application is a reconciliation of the actual fuel cost incurred to estimated fuel cost billed to International Paper that resulted in $95,754 credit to International Paper for the months of March through May 2024.

The Commission finds that Applicant's proposed fuel cost adjustment factor for International Paper of $0.3689227 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 a $95,754 credit to International Paper has been properly determined and approve the same.

15. **<u>Shared Return Revenue Credit Adjustment for International Paper</u>.** 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 May 2024. Therefore, we find International Paper is not due a shared return revenue credit.

16. **<u>Confidential Information</u>.** Applicant filed a Motion for Protection of Confidential and Proprietary Information on July 30, 2024, 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 August 13, 2024, 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 Ind. Code § 24-2-3-2, is exempt from public access, disclosure by 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. Duke Energy Indiana's fuel cost adjustment factor for electric service to be billed jurisdictional customers, as set forth in Paragraph No. 11, and the fuel cost adjustment for steam service as set forth in Paragraph No. 14 of this Order, are approved on an interim basis, subject to refund as noted above.

2. Duke Energy Indiana's inclusion of Energy and Ancillary Services Markets charges and credits in its cost of fuel, as described in Paragraph 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. Duke Energy Indiana shall provide an update on the status of its coal inventories and transportation issues in its next FAC filing, as described in Paragraph No. 4 of this Order.

5. Duke Energy Indiana will provide support for the reasonableness of any supply offer adjustment in its next FAC filing, as discussed in Paragraph 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.

HUSTON, BENNETT, FREEMAN, VELETA, AND ZIEGNER CONCUR:

APPROVED: SEP 25 2024

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

Regina K. Joyner Digitally signed by Regina K. Joyner Date: 2024.09.25 10:17:25 -04'00' on behalf of

Dana Kosco
Secretary of the Commission