

ORIGINAL

Commissioner	Yes	No	Not Participating
Huston			√
Bennett	√		
Freeman	√		
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 COST) CAUSE NO. 38707 FAC 145
ADJUSTMENT FOR HIGH PRESSURE STEAM)
SERVICE, IN ACCORDANCE WITH INDIANA CODE) APPROVED: SEP 30 2025
§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 M. Gorman, Administrative Law Judge

On July 30, 2025, 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 October, November, and December 2025 for electric and steam service. Concurrently, on July 30, 2025, Applicant submitted its prefiled case-in-chief testimony and attachments under this Cause.

On July 30, 2025, the Sierra Club filed its Petition to Intervene in this proceeding, which was subsequently granted on August 11, 2025.

On August 14, 2025, Applicant filed a Revised Verified Application and the revised case-in-chief testimony of Christa L. Graft. On August 20, 2025, Applicant filed a revision to the case-in-chief testimony of Kimberly Hughes.

On September 3, 2025, the Indiana Office of Utility Consumer Counselor (“OUCC”) and Sierra Club filed their respective testimony and attachments.

Applicant filed its rebuttal testimony on September 9, 2025.

On September 12, 2025, Sierra Club filed its Stipulation of Fact in Lieu of Cross-Examination of Applicant’s witness John D. Swez.

The Commission held an evidentiary hearing on September 15, 2025, at 2:30 p.m. in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Applicant, OUCC, and Sierra Club 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 May 31, 2025 period reflected in this filing is based on the Commission's Order in Cause No. 46038 and the associated Step 1 compliance filing for the March 2025 through May 2025 period and the Commission's June 29, 2020 Order in Cause No. 45253 and the associated Step 2 compliance filing for the June 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 May 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 \$0.034935 per kilowatt-hour ("kWh"). Applicant calculated its phased-in authorized jurisdictional net operating income level for the 12-month period ending May 31, 2025, to be \$635,890,000. 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 May 31, 2025, coal inventories were approximately 2,408,777 tons (or 47 days of coal supply), which is an increase from the inventories reported in Cause No. 38707 FAC 144 ("FAC 144").

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.

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 March through May 2025 (“Reporting Period”), the price Applicant paid for delivered natural gas at its gas burning stations was between \$2.34 per million BTU and \$4.53 per million BTU. He testified that the average price of natural gas purchased for the period was lower than what was reported in FAC 144, driven by price volatility in spot natural gas prices. 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.

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, 2025 actual and 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.

Sierra Club’s witness Devi Glick, Senior Principal at Synapse Energy Economics, Inc., testified that the Commission should disallow the fuel cost portion of losses Applicant incurred in May 2025 at Gibson and Cayuga Stations, citing the Applicant’s self-commitment and operational decisions, and should require Applicant to follow price-based signals for commitment and dispatch decisions at each of its coal-fired plants in the future and document its reasons for deviating from its Profit & Loss (“P&L”) Analysis. Ms. Glick testified that while it may be reasonable for Applicant to self-commit its units, she believes the Applicant’s approach during the Reporting Period departed from the results of its price-based analysis and resulted in losses for customers.

Ms. Glick testified that Applicant has developed a price-based forward-looking analysis, P&L, to determine whether to commit its coal units to operate in Midcontinent Independent System Operator (“MISO”). As part of these assessments, Applicant reviews forecasted energy market prices and projected variable startup, shutdown, and operational costs for the next three weeks to project net operational revenues (or losses) for each unit for each individual day and over the entire week period. She stated that if a unit is projected to be profitable, ratepayers expect to see savings from operating the unit relative to the acquisition of market-supplied power, and if the unit is projected to lose money, ratepayers expect to see savings by the acquisition of market-supplied power. Ms. Glick testified that Applicant should make its unit commitment decisions based on the results of this price-based analysis or document its reasons for departing from the results. She testified Applicant should elect to self-commit its units on a forward-looking basis only if it expects to make positive energy market margins. Ms. Glick testified that Applicant incurred net losses at

Cayuga Unit 1 and Gibson Units 2, 3, and 4 during a two-week period at the end of May when Applicant projected sustained net revenue losses and committed those units regularly with a must-run status. Ms. Glick testified that Applicant committed Edwardsport as must-run on gas 100% of the time it was available since the gasifiers were in outage during the entire Reporting Period, resulting in significant savings for ratepayers. She testified that it is unclear how the unit would have actually performed on coal, but projected that it likely would have incurred losses. She stated that Applicant does not provide detailed justification for why it is not reasonable to operate Edwardsport primarily or exclusively on natural gas. Ms. Glick recommends that Applicant follow price-based signals at all of its plants, including Edwardsport, in making unit commitment decisions and that the Commission disallow recovery of losses incurred as part of the fuel adjustment charge if it does not follow those signals or the results of its own price-based process.

Mr. Swez testified in rebuttal that Ms. Glick repeats unsuccessful arguments related to Applicant's commitment decision-making process that have been adjudicated by the Commission across multiple proceedings, including Cause Nos. 38707 FAC 123 S1 ("FAC 123 Subdocket"), 45740, and 46038. He testified that Applicant performs a risk-adjusted process daily to inform the commitment status decision for each unit, of which the P&L analysis is but one component. This process utilizes a multi-day forecast to minimize the total customer cost by maximizing each unit's economic value within operational constraints, while retaining the long-term reliability of the unit and while not exposing its customers to undue price risk and volatility. This process may result in a determination that a Must-Run offer is the most appropriate offer for a particular generating unit during a period of time, as was the case of Cayuga 1 and Gibson Units 2, 3, and 4 during the two-week period in May. As the Commission recognized in the FAC 123 Subdocket Order at 23, whether to use an Economic or Must-Run supply offer depends on the individual real-world circumstances of each unit and is not a simple toggle. The FAC 123 Subdocket Order also made clear that compliance with the Commission-approved steam contract for the Cayuga steam customer does not render Applicant's commitment decisions imprudent, even if they are not always economic. The reasonableness of Must-Run commitments under the Cayuga steam contract was reaffirmed in the 45740 Order approving the Fifth Amendment to the steam contract.

Mr. Swez described the process undertaken by Applicant to make its commitment decisions, including the many different factors that may necessitate the use of one commitment status over another. He also explained the daily P&L Analysis which Applicant utilizes to help inform the selection of a unit's commit status offer. He testified that to prevent uneconomic cycling of on-line generating units across lower priced energy periods, such as over a weekend, a Must-Run commit status may be utilized. This involves an analysis of factors such as a unit's minimum up and down time, the startup cost and time that the unit would incur to cycle, shutdown cost, the risk in cycling the unit, and consideration of the loss of the ability to respond to unanticipated changes in energy markets. Mr. Swez testified that when used properly, as Applicant does, the use of a Must-Run offer reduces the overall cost to supply energy to ratepayers by reducing the additional costs and risk associated with the unnecessary and uneconomic cycling of longer lead time generating units.

Mr. Swez testified that during the second week of May, due to above normal temperatures and generators in MISO still undergoing Spring planned outage maintenance, high energy prices in MISO materialized. Applicant's Daily P&L Analysis showed substantial customer savings from

the operation of Cayuga 1, and Gibson 2 through 4, with expected ratepayer savings of approximately \$100,000 for operation of each unit on each day during this period. Thus, these units were committed during this time. He testified these generators continued to produce substantial customer savings throughout the last day of the hot weather on Friday, May 16. He stated that Applicant had to balance the expected yet un-materialized lower market prices the following week and the potential to de-commit the unit, with the implications of a potential unnecessary unit cycle. He testified that due to cycling and startup costs for Gibson 3, Applicant retained the Must-Run commit status for that unit over the weekend and into the following week. In the following week when Applicant was comfortable that energy prices had returned to low enough levels to justify the additional cycle and startup costs, Gibson 3 was decommitted on May 22 with Applicant submitting an Economic commit status. He testified Gibson 3 did not receive a Day-Ahead or Real-Time commitment award from MISO for Friday, thus the unit began ramping off and was off-line at 12:08 a.m. on May 24. Mr. Swez testified that the same factors discussed above are applicable to Gibson 2 through 4 since they have similar variable costs.

However, additional factors were pertinent for determining the commit status offers of Gibson 2 and 4 during this time, including: (1) the additional exposure to MISO energy prices; (2) consequences of having zero Gibson units on-line right before the start of the summer season; and (3) environmental restrictions requiring Gibson to operate at least two generating units. Mr. Swez explained that decommitting the last two Gibson units would have required a longer than normal re-start of a unit, due to the lack of auxiliary steam supply, with no other units on-line at the station, not to mention the operational challenges of starting five Gibson units in a short period of time. He also noted that during this time two Gibson units were required to operate to facilitate the processing of Gibson Station South Landfill leachate by the Unit 1-3 FGD where it is eventually transported to the landfill as fixated material in accordance with applicable laws.

Mr. Swez testified that the primary reason for commitment of Cayuga 1 from May 17 to May 30 was to supply steam to the external steam customer, which does not mean Applicant acted imprudently. The Commission has previously determined in the FAC 123 Subdocket Order, and reaffirmed in the 45740 Order, that it is reasonable that the units will not always have a positive margin from operation in the MISO Energy Market and Applicant may need to commit the units as Must-Run to ensure it has the ability to provide service to the steam customer. Mr. Swez testified that focusing on this two-week period at the end of May does not make sense, considering the hot weather and high energy prices that materialized during June and July of 2025. He testified that Applicant's operation of each Gibson and Cayuga unit during June and July would ultimately save customers up to \$10 million for each unit due to not making the higher cost additional energy purchases. Mr. Swez also testified that had the Gibson and Cayuga units been turned off between May 17 and 30, 2025, as suggested by Ms. Glick, Applicant would have been purchasing 90% of the energy needed to supply ratepayers from MISO, resulting in even higher exposure to MISO purchase energy prices. Since Applicant was already utilizing financial hedges of approximately 600 MW for each on-peak hour during the second half of May, the additional short position would have exceeded the ability to hedge the exposure in the financial market. Mr. Swez testified that Ms. Glick fails to realize that the Daily P&L Analysis is but one factor in determining the commit status offer of its generating units.

Mr. Swez testified that the Commission has already considered Edwardsport's natural gas versus coal operations in detail – most recently in Applicant's base rate case, Cause No. 46038, where the Commission found that focusing on the economic value of operating Edwardsport as an IGCC versus a natural gas plant failed to consider the non-economic value of continued operation of the plant on syngas. The Commission further found that the pillars of reliability, resiliency and stability are best served by maintaining Edwardsport as an IGCC.

Mr. Swez testified that Ms. Glick's proposal that Applicant provide in each FAC the reasons for any deviance between the results of the Daily P&L Analysis and its actual commitment decisions expands FAC filings to include extra reporting that is not necessary to resolve FAC proceedings and could be obtained through discovery. He stated that this is consistent with the Commission's past rejection of similar proposals for additional FAC reporting in Cause No. 45740. Mr. Swez testified that Applicant makes its commitment decisions in the best interest of its customers.

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, 2025 projected coal burn, coal purchases, and how it is addressing coal transportation issues in its next FAC proceeding.

As to Applicant's commitment decisions related to Cayuga during the Reporting Period, this is not a new issue to the Commission and as such, we stand by our finding in Cause No. 38707 FAC 123 S1, in which the Commission found:

It is reasonable that the [Cayuga] units will not always realize a financial gain and the Company may need to commit the units as Must Run to ensure that the steam customer can maintain its operations and Duke Energy Indiana may service its approved contract in good faith. Complying with the terms of the agreement or committing the Cayuga units as Must Run, even when it results in a financial loss, is not proof of inappropriate commitment decisions by Duke Energy Indiana.¹

...

Unit commitment decisions that incorporate the value of limiting price volatility, meeting Commission approved contractual agreements, and supporting state policy, are supportive of a finding that they represent reasonable utility efforts in providing service.²

We agree with Applicant that its Daily P&L Analysis is but one of many factors that need to be considered in determining a unit's commit status offer of Must-Run or Economic. We find that it is not reasonable to rely entirely on price-based signals at Edwardsport and Applicant's other plants in making its unit commitment and dispatch decisions, as suggested by Ms. Glick. Based on the evidence, we believe Applicant's unit commitment decisions during the Reporting Period

¹ Cause No. 38707 FAC 123 S1 p. 23 (March 17, 2021)

² *Id.* at 24.

were reasonable. We also find that the extra reporting suggested by Ms. Glick is not necessary to resolve FAC proceedings and could be obtained through discovery.

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 gain of \$642,331 from natural gas hedges purchased for the Reporting Period. He testified that market prices for gas realized higher values than the hedged prices primarily due to reduced domestic storage balances after the past winter. He testified that Applicant experienced net realized power hedging losses for the period of \$855,302 primarily driven by low realized power prices due to relatively mild weather. Christa L. Graft, Director of Rates and Regulatory Planning for Applicant, testified that Applicant realized a total net hedging loss of \$212,971 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 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 Applicant's hedging gains and losses for the period December 2013 through January 2021 were relatively consistent. Starting in February 2021, apart from 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 a loss for the three-month period of \$212,971. Mr. Eckert recommended 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 \$212,971 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 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, sensitivity of the coal supply and transportation chain to supply disruptions, and the evolution of fuel mixes across energy markets.

Over the course of the FAC 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 FAC 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)	Mar-25	Apr-25	May-25
Regulation Cost Dist.	0.1271	0.1378	0.1400
Spinning Cost Dist.	0.0543	0.0601	0.0635
Supplemental Cost Dist.	0.0059	0.0109	0.0077
Short Term Res. Cost. Dist.	0.0303	0.0464	0.0482

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 during this FAC period there were two outages that met these criteria. He testified that root cause analyses have been initiated on both the reportable outages and will be provided in Applicant's FAC when complete.

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 months ended May 31, 2025. Applicant's authorized phased-in jurisdictional operating expenses (excluding fuel costs) are \$1,399,138,000. For the 12-month period ended May 31, 2025, Applicant's actual jurisdictional operating expenses (excluding fuel costs) totaled \$1,423,922,000. 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 jurisdictional electric operating income level, calculated in accordance with previous Commission Orders, was \$621,100,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was \$635,890,000. Therefore, the Commission finds that Applicant did not earn a return more than its authorized level during the 12 months ended May 31, 2025.

10. Estimation of Fuel Costs. Applicant estimates that its prospective average fuel cost for the months of October through December 2025 will be \$71,839,333, or \$0.031744 per kWh. 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
Mar 2025	35.615	32.618	9.19%
Apr 2025	37.014	32.593	13.56%
May 2025	34.244	33.660	1.73%
Weighted Average	35.616	32.946	8.10%

A comparison of Applicant’s actual fuel costs with the respective estimated costs for these three periods results in a weighted average difference of 8.10%, 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 2025 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 October through December 2025 billing cycles is computed as follows:

	<u>\$/ kWh</u>
Projected Average Fuel Cost	0.031744
FAC 145 Reconciliation Factor	0.003006
Adjusted Fuel Cost Factor	0.034750
Less: Base Cost of Fuel Included in Rates	0.034378
Fuel Cost Adjustment Factor	0.000372

Ms. Graft testified that the FAC 145 reconciliation factor shown above reflects \$18,379,011 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 Revised 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 has begun 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.

Mr. Guerrettaz testified that Applicant's fuel cost adjustment for the quarter ended May 2025 had been properly applied by Applicant. While Applicant used forecasted market prices for its natural gas and purchased power as of July 1, 2025 for its proposed FAC factor, and those inputs have decreased as of August 18, 2025, the OUC does not recommend a change in the proposed factor. He also stated that the figures used in the Revised 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 Applicant.

12. Effect on Residential Customers. The approved factor represents a decrease of \$0.003670 per kWh from the factor approved in Cause No. 38707 FAC 144. The typical residential customer using 1,000 kWhs per month will experience a decrease of \$3.67, or 2.3%, on the customer's total electric bill compared to the factor approved in FAC 144 (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 \$0.3328044 per 1,000 pounds of steam was calculated on Applicant's Attachment B, Schedule 1, of the Revised Verified Application.

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.

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 \$32,508 debit to International Paper for the Reporting Period. The Commission finds that Applicant's proposed fuel cost adjustment factor for International Paper of \$0.3328044 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 \$32,508 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 May 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 July 30, 2025, 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 6, 2025, 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 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 factor 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, 2025 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.

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

APPROVED: SEP 30 2025

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

_____ on behalf of
Dana Kosco
Secretary of the Commission