ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda	√		
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 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 132** **APPROVED: JUN 28 2022**

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
David E. Veleta, Senior Administrative Law Judge

On April 28, 2022, Duke Energy Indiana, LLC ("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 July, August, and September 2022 for electric and steam service. On May 3, 2022, Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor"), filed its Petition to intervene in this proceeding. On May 10, 2022, Steel Dynamics, Inc. ("SDI") filed its Petition to Intervene. On May 11, 2022, Duke Energy Indiana Industrial Group ("Industrial Group") filed its Petition to Intervene, with subsequent amendments filed on May 17, 2022, and May 24, 2022. The Presiding Officers granted the Petition to Intervene of Nucor on May 18, 2022, and the Petitions to Intervene of SDI and Industrial Group on May 19, 2022.

On June 2, 2022, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and testimony. On June 2, 2022, the OUCC and Industrial Group filed a *Motion for Subdocket* ("Motion"). SDI joined the Motion on June 3, 2022. Applicant filed its rebuttal testimony on June 9, 2022, and advised Mr. John D. Swez was adopting the case-in-chief testimony of Mr. J. Bradley Daniel. Applicant filed its response to the Motion on June 9, 2022.

A public evidentiary hearing was held in this Cause on June 15, 2022, at 10:30 a.m. in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Applicant, Nucor, SDI, Industrial Group, and the OUCC appeared at the hearing by counsel. Applicant and the OUCC offered their respective prefiled testimony and exhibits 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 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. **Applicant's Characteristics.** Applicant is a public utility corporation organized and existing under the laws of the State of Indiana with its principal office in Plainfield, Indiana. Applicant is engaged in rendering electric utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of 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 Income.** On June 29, 2020, the Commission issued an Order in Cause No. 45253 ("June 29 Order") approving base retail electric rates and charges for Applicant. The Commission's June 29 Order found that Applicant's base cost of fuel should be 26.955 mills per kWh and that Applicant's base rates for electric utility service should reflect an authorized jurisdictional operating income level of $584,678,000 prior to the Step 1 and Step 2 adjustments and for impacts of investments remaining in two riders.

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 February 2022, 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 $0.036354 per kWh as shown on Applicant's Attachment A, Schedule 9. In accordance with previous Commission Orders, Applicant calculated its phased-in authorized jurisdictional net operating income level for the 12-month period ending February 28, 2022, to be $576,494,000 (*see* Applicant's Ex. 6-B, p. 3). No evidence was offered objecting to the calculation of the authorized jurisdictional net operating income level proposed by Applicant, and we find it to be proper.

4. **Fuel Purchases.** Mr. Brett Phipps testified regarding Applicant's coal procurement practices and its coal inventories. Mr. Phipps testified that as of February 28, 2022, coal inventories were approximately 1,561,002 tons (or 30 days of coal supply), which is an increase over inventories reported in Cause No. 38707 FAC 131 ("FAC 131"). Mr. Phipps reported that the increase can be attributed to the price adjustment discussed by Mr. J. Bradley Daniel and moderate weather. He testified that Applicant ended 2021 with 35 Full Load Burn Days in inventory and continues to evaluate a host of options in order to effectively manage its coal inventory. He further testified that additional inventory mitigation efforts, aside from the price adjustment, include contracting for onsite third-party train operations to alleviate railroad labor constraints, spot purchases to create diversity and better routes, adding truck deliveries where logistically feasible, and adjusting shipping schedules to ensure deliveries where most needed. Mr. Phipps stated that in cases where actual burns unexpectedly drop below projections and inventory levels are above target, as inventory levels dictate, Applicant explores options to store or defer contract coal or resell surplus coal into the market. In cases where actual burns unexpectedly increase above projections Applicant accelerates purchases of supply and looks for operational efficiencies. Due to current coal market conditions, purchase opportunities will continue to be difficult in the near term.

Mr. Phipps testified that spot natural gas prices are dynamic, volatile, and can change significantly day to day based on market fundamental drivers. During the three-month period from December 2021 through February 2022, the price Applicant paid for delivered natural gas at its gas burning stations was between $3.30 per million BTU and $6.80 per million BTU. He testified natural gas prices for the period were above those experienced in the FAC 131 review period. Mr. Phipps testified that, in his opinion, Applicant purchased natural gas at the lowest cost reasonably possible.

The OUCC's witness, Mr. Michael D. Eckert, testified that Applicant is actively trying to manage its coal purchases and inventory. Although additional coal has been secured for 2022-2023, Applicant is struggling to acquire and maintain adequate transportation of coal to its stations. He testified that while Applicant is attempting to increase train deliveries, it has not filed a complaint with the Service Transportation Board ("STB") or enforced any non-compliance options in its rail contracts. OUCC witness Mr. Guerrettaz testified Applicant diverted coal from Edwardsport to Cayuga from December 17, 2021 to March 21, 2022, operating Edwardsport on one gasifier and supplementing with natural gas. He testified Edwardsport was made "must run" to MISO during this period, at a higher price than if it ran on 100% syngas, resulting in increased costs but not increasing coal inventory at Cayuga Station as Applicant is obliged to run one Cayuga Unit to supply its steam customer. Mr. Eckert recommended Applicant continue to update the Commission on its coal inventory and 2022 projected coal burn and coal purchases, as well as how Applicant is addressing its coal transportation issues.

In rebuttal, Mr. Phipps testified the rail transportation contracts do not contain provisions for non-performance by the railroads nor is it common practice for the railroads to amend the performance language. Despite these conditions, and being captive to specific rail providers, Duke Energy Indiana has requested performance language in its negotiations but has been unsuccessful. Applicant has actively requested improved performance from its rail transportation providers, including how it could incentivize better performance. Mr. Phipps testified Applicant was proactively communicating with its rail transportation providers for improved rail performance prior to complaints being filed with the STB and decided not to file a complaint, but instead maintain pressure on the rail providers through frequent direct communications. He testified the STB issued a decision on May 5, 2022, ordering service recovery plans and progress reports from the four largest U.S. rail carriers and is directing those carriers to participate in biweekly conference calls to further explain efforts to correct service deficiencies. It is also requiring all Class I rail carriers to report more comprehensive and customer-centric performance metrics and employment data for a six-month period. Mr. Phipps testified that regardless of the STB process, Applicant is continuing to work with its rail providers to promote increased performance, and will continue to provide updates in subsequent FAC proceedings and during the OUCC audit process.

Mr. Phipps testified that several key factors influenced the timing of truck supplementing coal deliveries to Cayuga, including (1) availability of drivers and trucks in a very tight market; (2) adequate supply of coal at the mines so as not to negatively impact train loadings, as it takes approximately 460 truckloads delivered over a month to equal 1 train at Cayuga station; and (3) preparations at both Cayuga station and the mine to prepare to safely load and receive trucked coal deliveries. He testified that after negotiating through late October and November, the trucking agreement was executed November 30, 2021, and truck deliveries began less than a week later.

Mr. Phipps testified the decision to operate Edwardsport on approximately half natural gas and half gasified coal provided flexibility to allocate deliveries of coal between Edwardsport and Cayuga to ensure a reliable fuel supply for the projected total coal burns at Cayuga Units 1 and 2. Applicant's witness Mr. John D. Swez testified in rebuttal that by exercising the flexibility of Edwardsport Station, Applicant did experience a slightly higher cost at Edwardsport and slightly lower than full load capability. However, this resulted in additional planned deliveries of coal to Cayuga likely resulting in a lower adjustment applied to Cayuga during this and potentially future periods. Avoiding the possibility of critically low levels of coal at Cayuga and reliability of the overall Duke Energy Indiana portfolio was the primary reason Applicant decided to operate Edwardsport in this fashion for this period of time. Mr. Phipps testified it is reasonable to assume that but for the ability to include additional deliveries to Cayuga, inventory was on track to reach critically low levels.

Mr. Phipps testified Duke Energy Indiana will continue to update the Commission in future FAC proceedings on its coal inventory situation, current year actual coal burns, coal purchases, and coal transportation issues. Although Applicant anticipates the coal delivery constraints to continue into 2023, it is making every reasonable effort to maintain reliable coal supply in the least reasonable cost manner possible for customers.

Mr. Daniel testified that Applicant continues to submit an 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 presented, we find that Applicant made every reasonable effort to acquire fuel for its own generation or to purchase power so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible during December 2021 through February 2022. With regard to its coal inventory levels and transportation issues, Applicant will provide an update on the status in its next FAC proceeding as recommended by the OUCC.

5. <u>Hedging Activities</u>. Applicant's witness Mr. Wenbin (Michael) Chen testified Applicant takes advantage of the hedging tools available to protect against natural gas price fluctuations. Mr. Chen testified that Applicant realized a loss of $7,804,350 from natural gas hedges purchased for December 2021 through February 2022. He testified that market price for gas realized much lower values than the hedged prices attributable to very mild weather in December 2021, resulting in much lower than expected consumption of natural gas. He testified Applicant experienced net realized power hedging losses for the period of $27,903,938 primarily attributable to mild weather in December 2021, as well as coal supply disruptions that kept most coal units offline resulting in significantly more than normal forward financial hedges. Ms. Suzanne E. Sieferman testified that Applicant realized a total net hedging loss of $35,733,067 during the period for all native gas and power hedging activities other than MISO virtual energy market participation (including prior period adjustments).

Mr. Chen 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 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 150 MW of expected load unhedged on a forward forecasted basis. Mr. Chen opined Applicant's gas and power hedging practices are reasonable. He stated 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.

The OUCC's witness, Mr. Eckert, testified that Applicant's hedging gains and losses for the period December 2013 through January 2021 were relatively consistent. He testified beginning in February 2021 and, with the exception of March 2021, Applicant experienced large hedging gains through November 2021. Then Applicant experienced large hedging losses starting in December 2021 through February 2022. Mr. Eckert recommended Applicant file testimony in its next FAC on the results of its informal hedging policy review. OUCC witness Mr. Gregory Guerrettaz further recommended Applicant document any significant change in Applicant's hedging position made because of a change in the increment or by a management decision.

In rebuttal, Mr. Chen provided an overview of Applicant's hedging practices approved in Cause Nos. 38707 FAC-68S1 and 38707 FAC-99, as well as Duke Energy's corporate risk limits and guidelines for its hedging program. He testified that hedging, by definition, is not done to reduce overall costs or rates, but to mitigate price risk and reduce customers' cost volatility. He testified the forward hedges for December 2021 were reasonable and economic at the time they were entered into, and although they did not reduce customers' cost due to extremely mild weather, they did reduce exposure to volatility by assuring a fixed price for wholesale energy for the volumes hedged. He noted Applicant's hedging practices in other time periods have reduced overall costs as well as price volatility, and customers have been the recipients of that lower volatility and lower overall costs. He testified that given the challenges with the coal supply chain and additional utilization and forecasted position based on modeling, it was prudent to purchase hedges for December 2021 to mitigate Duke Energy Indiana customers' added exposure to wholesale power markets. Because native customers were forecasted to buy substantially more purchased power from MISO in December 2021, Applicant purchased in the forward market a larger than normal amount of financial hedges for December. The mild December 2021 weather, second warmest on record since 1923, drastically reduced actual demand for heating and power generation, resulting in lower daily power and natural gas prices than what Applicant paid for the hedges in the forward market. Mr. Chen opined the transactions were reasonable and advisable at the time they were entered into. He testified Applicant is willing to meet with the OUCC and its industrial customers to discuss any going forward changes to its hedging program.

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 (*see* Applicant's Ex. 3, p. 10). Thus, we allow Applicant to include $35,733,067 of net losses from native gas and power hedges in the calculation of fuel costs in this proceeding.

6. Participation in the Energy and ASM Markets and MISO-Directed Dispatch. On June 1, 2005, the Commission issued an Order in Cause No. 42685 ("June 1 Order"), in which we approved certain changes in the operations of the investor-owned Indiana electric public utilities that are participating members of MISO. In this proceeding, Mr. Daniel 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. Daniel testified spot and future natural gas and power prices remained strong through the FAC 132 period, and coal burn projections remained strong as a result. These factors, combined with continued constraints in the coal supply and transportation market, continued the need for Applicant's adjustment to supply offers to MISO to maintain a reliable level of coal inventory at Gibson units 1-5 and Cayuga units 1-2. He testified that with increasing commodity prices and continued delivery constraints, higher supply offer adjustments were necessary to achieve targeted station inventory levels. Without a supply offer adjustment, Applicant's coal inventory at Gibson and Cayuga would have dropped to low and unreliable levels going into the winter peaking season. Mr. Daniel testified Applicant used its production cost model to determine the adjustment amount. The model utilizes up-to-date spot and future commodity prices and coal supply projections to run scenarios that produce the amount of adjustment needed to meet reliable inventory levels. Beginning January 1, 2022, the modeling objective shifted to optimally managing offer strategies concurrently with coal inventory constraints. He testified that modeling the offer adjustment to bound coal inventory levels between a minimum of 20 day and maximum of 70 days full load burn inventory at Gibson and Cayuga stations provides an economic and reliable balance of coal inventory management. He explained that the supply offers at Gibson units 1-5 and Cayuga units 1-2 are calculated just as they are normally, and then adjusted higher by the necessary $/MWh supply offer adjustment amount. Applicant is monitoring commodity prices and coal inventories within its normal course of business and is updating the offer adjustment on a weekly basis. Mr. Daniel testified the price adjustment is in the best interest of Applicant's customers and is working as intended. Pursuant to the Commission's Order in Cause No. 38707 FAC 130, Mr. Daniel presented support for the reasonableness of the supply offer adjustments during December 2021 through February 2022.

Mr. Daniel testified that Applicant diverted coal shipments from Edwardsport to Cayuga to help meet winter inventory targets. Edwardsport operated on one gasifier and supplemented the station with natural gas which helped restore reliable coal inventory at Cayuga. Edwardsport returned to two gasifier operation on March 21, 2022. He testified the adjustment to economic offers at Wheatland CT continued through this FAC period, with 12-month rolling NOx tons emissions decreasing to 193 tons. Applicant expects some level of adjustment to its economic offers at Wheatland to continue at least through May 2022.

OUCC witness Mr. Eckert testified the OUCC understands Applicant's need for the coal increment to maintain a reasonable level of coal inventory and meet reliability concerns in MISO. He recommended Applicant file testimony, schedules and workpapers to justify the need for, or use of, coal increment/decrement pricing in its next FAC proceeding.

In rebuttal, Mr. Swez testified that the Company is willing to continue filing in future FAC proceedings testimony and a confidential exhibit supporting any offer adjustment analysis utilized to determine the appropriate increment necessary to build Duke Energy Indiana's coal inventory to targeted station levels. However, he testified Applicant is unable to state with any level of certainty the increment's impact on its customers, as such estimation comes with a host of limitations and complications requiring a myriad of assumptions. He further testified that there is no way to gauge the potential impact to power prices during future time periods if the MISO market is constrained by insufficient coal inventory levels, either from Applicant or across the MISO market footprint, nor is there an accurate way to assess the cost of reliability risk to customers in future periods. Mr. Swez testified that it is reasonable to assume its customers are at risk to pay considerably higher power prices and assume more reliability risk in future periods should Applicant not have sufficient fuel inventory to operate its coal units during peak seasons. Therefore, there is value to Applicant's customers in retaining coal inventory in exchange for purchasing power given the conditions.

Applicant's witness Ms. Mary Ann Amburgey testified as to the procedures followed by Applicant to verify the accuracy of the charges and credits allocated by MISO and PJM to Applicant. She testified MISO introduced a new Short-Term Reserve product resulting in four new charge types that impact the fuel adjustment factor in this proceeding. Ms. Sieferman testified that similar to other MISO ASM charge types which are considered fuel-related, the Company is seeking the Commission's approval to include charges and credits for these four new charge types for the Short-Term Reserve product in the Company's fuel cost calculations in this and future FAC proceedings. Ms. Amburgey 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 the computer software tools described in her testimony. Ms. Amburgey testified that she is confident 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 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 Ancillary Services Market ("ASM"). Mr. Daniel explained that Applicant has included various ASM charges and credits in this proceeding incurred for December 2021 through February 2022, consistent with the Phase II Order, as well as appropriate period adjustments.

Applicant's witness Mr. Scott A. Burnside 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 and Supplemental Reserves. These amounts are as follows:

(in $ per MWh)	Dec-21	Jan-22	Feb-22
Regulation Cost Dist.	0.0627	0.0580	0.0601
Spinning Cost Dist.	0.0343	0.0268	0.0358
Supplemental Cost Dist.	0.0057	0.0067	0.0032

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 Duke Energy Indiana'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 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.

Additionally, based upon the evidence presented, the Commission finds that Applicant's treatment of the Energy and ASM charges and credits in its cost of fuel is consistent with the June 1 Order, the December 28, 2006 Order in Cause No. 38707 FAC 70, as well as the Commission's Phase I and Phase II Orders in Cause No. 43426, and should be approved. The Commission also approves the Company's request to include charges and credits for the four new charge types associated with MISO's new Short Term Reserve product in this and future FAC proceedings.

We find that Duke Energy Indiana has laid a reasonable foundation for the mechanics of its supply offer adjustment to MISO in order to maintain a reliable level of coal inventory going into the winter months. Duke Energy Indiana will continue to provide support for the reasonableness of any supply offer adjustment in its next FAC filing, as described by Mr. Swez in his rebuttal testimony.

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. Daniel testified during this FAC period there were three outages that met these criteria. Mr. Daniel testified that no Root Cause Analysis was performed for any of these outages.

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. Accordingly, Applicant filed operating cost data for the 12 months ended February 28, 2022 (*see* Applicant's Attachment 6-A, p.1). Applicant's authorized phased-in jurisdictional operating expenses (excluding fuel costs) are $1,331,794,000. For the 12-month period ended February 28, 2022, Applicant's actual jurisdictional operating expenses (excluding fuel costs) totaled $1,401,781,000. Accordingly, 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 regulated utilities 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 the Applicant's Company-owned Multi-Value Projects ("MVPs") should be addressed at the time any such projects have been completed and are included for recovery. Ms. Sieferman 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 Company-owned MVPs be treated as non-jurisdictional and outside of the FAC earnings test, which is consistent with the treatment of its Company-owned Regional Expansion Criteria and Benefit projects beginning in Cause No. 38707 FAC 86. Applicant has 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 presented, the Commission approves Applicant's exclusion of revenues and expenses associated with Company-owned MVPs. In Cause No. 38707 FAC 122, Applicant's proposed treatment for these revenues and expenses were 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.

In accordance with previous Commission Orders, Applicant's calculated jurisdictional electric operating income level was $528,984,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was $576,494,000 (*see* Applicant's Ex. 6, pg. 9). Therefore, the Commission finds that Applicant did not earn a return more than its authorized level during the 12 months ended February 28, 2022.

10. **Estimation of Fuel Costs.** Applicant estimates that its prospective average fuel cost for the months of July through September 2022, will be $133,630,148 or $0.048727 per kWh (*see* Verified Application Attachment A, Schedule 1). Applicant previously made the following estimates of its fuel costs for the period December through February 2022, and experienced the following actual costs, resulting in percent deviation, as follows:

Month	Actual Cost in Mills/kWh	Estimated Cost in Mills/kWh	Percent Actual is Over (Under) Estimate
Dec 2021	50.993	30.169	69.02%
Jan 2022	45.864	30.412	50.81%
Feb 2022	37.817	30.652	23.38%
Weighted Average	44.812	30.412	47.35%

A comparison of Applicant's actual fuel costs with the respective estimated costs for these three periods results in a weighted average difference of 47.35%. (Verified Application, Attachment A, Schedule 10). Based on the evidence of record, we find Applicant's estimating techniques appear reasonably sound, and its estimates for July through September 2022 should be accepted.

11. <u>Fuel Cost Factor</u>. As discussed in Finding No. 3 above, Applicant's base cost of fuel is 26.955 mills per kWh. The evidence indicates that Applicant's fuel cost adjustment factor applicable to July through September 2022 billing cycles is computed as follows (Verified Application, Ex. A, Schedule 1):

	$ / kWh
Projected Average Fuel Cost	0.048727
FAC 132 Reconciliation Factor	0.007088
FAC 131 Reconciliation Factor	0.005383
Adjusted Fuel Cost Factor	0.061198
Less: Base Cost of Fuel Included in Rates	0.026955
Fuel Cost Adjustment Factor	0.034243

Ms. Sieferman testified that the under-collection for this reconciliation period is a result of the continued volatility in the fuel markets throughout this FAC. She further testified that the FAC 132 reconciliation factor shown above reflects $105,254,919 of under-billed fuel costs applicable to retail customers that occurred during the period December 2021 through February 2022, spread over a six-month recovery period instead of the normal three-month recovery period, resulting in $52,627,460 of the FAC 132 under-collection being included in the proposed fuel cost adjustment factor in this proceeding. In addition, the proposed fuel cost adjustment factor in this proceeding includes $39,966,757 for the remaining one-half of the reconciliation amount from FAC 131 ($79,933,515 under-collection) that was authorized to be spread over two FAC periods.

OUCC witness Mr. Guerrettaz testified that the fuel cost adjustment for the quarter ended February 2022 had been properly applied by Applicant. In addition, he stated the figures used in the Application for a change in the FAC were supported by Applicant's books and records, Sumatra, and source documentation of Applicant for the period reviewed. He recommended the variance for FAC 132 be spread over four quarters, rather than the two quarters proposed by Applicant. He testified this would result in an increase of $19.05 (or 13.49%) over what residential customers are paying currently, as opposed to the $22.59 (or 16.0%) proposed by Applicant.

In rebuttal, Applicant's witness Mr. Art J. Buescher, III, testified that Applicant disagrees with the OUCC's proposal to spread the under-collection over twelve months because it would expose customers to the increase for a longer period of time. Spreading the variance over six months, as proposed by Duke Energy Indiana, reduces the customer impact by 5% over the normal three month recovery. Spreading the variance over twelve months only provides an additional 2.5% reduction while guaranteeing customers will be impacted by the current under-collection well into 2023. He testified it is prudent to spread the variance in a way that provides a meaningful reduction for customers while limiting the length customers would experience the increase. Since Applicant would have to fund the cash flow shortfall from the under-collected fuel expense through incremental short-term debt borrowings, spreading it beyond the normal three month recovery period impacts Applicant through increased interest expense, increased leverage in the capital structure, and reduced liquidity.

Applicant's proposal to spread recovery over six months will provide some meaningful rate relief for customers, rather than trying to collect the entire amount over one FAC period as they normally would. At the hearing, Applicant's witness Sieferman testified that Applicant's proposed fuel cost in this proceeding is one of the highest since she started with Applicant in 2008. In addition, Witness Sieferman testified that Applicant has forecasted an even higher fuel cost in FAC 133 that exceeds 55 mills per kWh. Thus, while it may not provide as much rate relief as spreading the recovery over twelve months, Applicant's proposal makes the most sense when balanced against the risk of pancaking that could occur over time if we continue spreading the recovery out over a longer period of time.[1] The Commission finds that spreading the under-collection over a six-month period, instead of the normal three-month recovery period as proposed by Applicant is reasonable.

12. **Effect on Residential Customers.** The approved factor represents an increase of $0.022598 per kWh from the factor approved in FAC 131. The typical residential customer using 1,000 kWhs per month will experience an increase of $22.59 or 16.0% on the customer's total electric bill compared to the factor approved in FAC 131 (excluding sales tax). (Applicant's Ex. 6, p. 12).

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 December 30, 1992, this Commission issued its Order in Cause No. 39483 approving the June 18, 1992 Settlement Agreement between Applicant and Premier Boxboard, formerly referred to as Temple-Inland, n/k/a International Paper which included a change in the method used to calculate International Paper's fuel cost adjustment as well as an update to the base cost of fuel. The fuel cost adjustment factor for International Paper of $3.4255032 per 1,000 pounds of steam was calculated on Attachment B, Schedule 1, of the Verified Application; this factor will be effective for the July through September 2022 billing cycles. 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 $557,702 charge to International Paper for the months of December 2021 through February 2022.

The Commission finds that Applicant's proposed fuel cost adjustment factor for International Paper of $3.4255032 per 1,000 pounds of steam has been calculated in accordance with this Commission's Order in Cause No. 39483, and that such factor should be approved. We further find that Applicant's reconciliation amount of $557,702 charge to International Paper has been properly determined and should be approved.

[1] The factor in FAC 132 is already influenced by approximately $40M of remaining FAC 131 vaiance. Petitioner's Exh. 6, p. 16.

15. Shared Return Revenue Credit Adjustment for International Paper. In accordance with the June 18, 1992 Settlement Agreement, International Paper will receive shared return revenue credit adjustments to the extent incurred. As indicated above in Finding No. 9, Applicant did not have excess earnings for the 12 months ended February 2022. Therefore, we find International Paper is not due a shared return revenue credit.

16. Confidential Information. On April 28, 2022, Applicant filed a motion requesting protection of confidential and proprietary information along with a supporting affidavit. On May 10, 2022, the Presiding Officers made a preliminary determination that trade secret information should be subject to confidential procedures, as supported by Applicant's affidavits, consisting of: (1) its coal procurement strategy plan, which includes fuel burn, contracting strategy, pricing, coal burn forecasts, supplier information, and activities related to Applicant's coal and transportation contracts; and (2) certain information concerning Applicant's adjusted supply offers to MISO between December 2021 and February 2022, including fuel inventory positions, power prices, and pricing projections. The Commission finds such information is confidential pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana law and should be held by the Commission as confidential and protected from public access and disclosure.

17. Motion for Subdocket. The Consumer Parties' Motion asserted the requested subdocket would grant the Commission and parties time and information to evaluate the fuel cost impacts of the ongoing issues with coal delivery, supply offer adjustments, and hedging activities associated with Applicant's fuel adjustment clause, and stating that "the Commission has regularly ordered subdockets where 'the summary nature of proceedings with statutory time constraints such as the FAC do not lend themselves' to sufficient record development."

Specifically, the Consumer Parties argue that a subdocket is justified for the following reasons: (1) to provide the parties and Commission sufficient time to examine how the disruption to coal deliveries impacts Applicant's fuel procurement, contracting, and hedging, and whether modifications should be made to Applicant's proposed and future fuel factors; (2) because further discovery would improve the record of decision by allowing further investigation of the aforementioned concerns and aid the Commission's oversight of Applicant's procurement efforts and its energy market commitment decision making. The Consumer Parties call for a subdocket to address: the impact of coal delivery issues on FAC costs, the consequences for Applicant's hedging plan, the impact of Applicant's supply offer adjustment, and the extent to which Applicant acted reasonably and prudently in connection with procuring coal and its response to unreliable coal deliveries. Lastly, the Consumer Parties encourage the Commission to assert its jurisdiction and open an investigation into Applicant's coal procurement, hedging, and market offers as matters of public importance.

On June 9, 2022, Applicant filed its response, noting its rebuttal testimony witnesses agreed to provide additional information in subsequent FACs, but arguing that a subdocket was not needed.

On June 16, 2022, the OUCC and Industrial Group filed their Reply. The Reply noted that Applicant's hedging plan was established in the FAC 68 S1 subdocket, and that the hedging plan should be reviewed as part of the subdocket requested in this Cause.

As we have previously noted, the Commission must base its decision solely on the evidentiary record and when appropriate may seek supplemental evidence to foster reasoned decision-making. At times, the summary nature of proceedings with statutory time constraints such as the FAC do not lend themselves to such record development. The OUCC and Industrial Group have raised issues concerning Applicant's recovery of fuel costs related to its hedging losses and the increase in costs in this FAC due to coal supply chain issues. However, the OUCC and Industrial Group did not provide specific evidence to question specific utility choices. Instead, the OUCC and Industrial Group focused on the results of Applicant's choices. Applicant provided rebuttal testimony on the issues raised by the OUCC and Industrial Group. Further, Applicant has provided and continues to provide information on supply offer adjustments, coal inventory and supply, and its hedging program as part of each FAC and is willing to provide even more information and collaboration on concerns as described above. Applicant's quarterly fuel clause filings provide an adequate forum for the Consumer Parties to timely debate and for the Commission to review and oversee Applicant's coal procurement, hedging, and market offers. Therefore, we decline the Consumer Parties' request to open a subdocket. However, we encourage the parties to continue their vigilance in gaining understanding of the challenging circumstances and bringing that understanding in the future proceedings to the extent they feel is needed. The Commission will continue to monitor the circumstances in general and will look forward to its opportunity to evaluate the evidence Applicant and any other parties bring in the next FAC.

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 Finding No. 11, and the fuel cost adjustment for steam service as set forth in Finding No. 14 of this Order, are hereby approved on an interim basis, subject to refund, in accordance with all of the Findings above.

2. Duke Energy Indiana'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 hereby approved.

3. Duke Energy Indiana is authorized to recover the $105,254,919 of under-collected fuel costs experienced in December 2021 through February 2022 over a six-month period, instead of the normal three-month recovery period, as set forth in Finding No. 11 above.

4. 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.

5. 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 Finding No. 4 of this Order.

6. Duke Energy Indiana 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.

7. 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.

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

HUSTON, FREEMAN, KREVDA, AND ZIEGNER CONCUR:

APPROVED: JUN 28 2022

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

Dana Kosco

Digitally signed by Dana Kosco
Date: 2022.06.28 14:16:04
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Dana Kosco
Secretary of the Commission