ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda			√
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 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 135** **APPROVED: MAR 29 2023**

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Jennifer L. Schuster, Senior Administrative Law Judge

On January 31, 2023, Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Petitioner") filed its Verified Petition 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 April, May, and June 2023 for electric and steam service.

On March 7, 2023, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and testimony. Petitioner filed its rebuttal testimony on March 10, 2023.

A public evidentiary hearing was held in this Cause on March 17, 2023, at 9:30 a.m. in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Petitioner and the OUCC appeared at the hearing by counsel and 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 Jurisdiction.** Notice of the hearing in this Cause was given as required by law. Petitioner 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 Petitioner'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. **Petitioner's Characteristics.** Petitioner is a public utility corporation organized and existing under Indiana law with its principal office in Plainfield, Indiana. Petitioner 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. Petitioner also renders steam service to 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 Petitioner. The Commission's June 29 Order found that Petitioner's base cost of fuel should be 26.955 mills per kWh and that Petitioner'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.

Petitioner's cost of fuel to generate electricity and the cost of fuel included in the net cost of purchased electricity for the month of November 2022, based on the latest data known to Petitioner at the time of filing after excluding prior period costs, hedging, and miscellaneous fuel adjustments, if applicable, was $0.038333 per kWh as shown on Petitioner's Attachment A, Schedule 9. In accordance with previous Commission Orders, Petitioner calculated its phased-in authorized jurisdictional net operating income level for the 12-month period ending November 30, 2022, to be $582,790,000. The OUCC did not take issue with the calculation of the authorized jurisdictional net operating income level proposed by Petitioner, and we find it to be proper.

4. **Fuel Purchases and Coal Procurement Plan.** John A. Verderame testified regarding Petitioner's coal procurement practices and its coal inventories. Mr. Verderame testified that as of November 30, 2022, coal inventories were approximately 2,169,549 tons (or 42 days of coal supply), which is an increase from inventories reported in Cause No. 38707 FAC 134 ("FAC 134"). Mr. Verderame reported that the increase can be attributed to the price adjustment discussed by J. Bradley Daniel and weather-driven demand throughout the FAC period. He testified that Petitioner continues to evaluate a host of options to effectively manage its coal inventory. A coal supply contract amendment was executed to allow for a surge of rail deliveries in the winter of 2022 to meet demand and build inventory. He further testified that additional inventory mitigation efforts, aside from the price adjustment, included the continuation of onsite third-party train operations to alleviate railroad labor constraints, maintaining truck deliveries where logistically feasible, and adjusting shipping schedules to maximize efficiencies. Mr. Verderame stated that in cases where actual burns unexpectedly drop below projections and inventory levels are above target, as inventory levels dictate, Petitioner explores options to store or defer contract coal or resell surplus coal into the market. In cases where actual burns unexpectedly increase above projections, Petitioner 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.

Pursuant to the Commission's Order in Cause No. 38707 FAC 125, Mr. Verderame presented Petitioner's coal procurement plan for 2023 and 2024. Given Petitioner's 2023 forecasted system mean coal burn of 9.2 million tons (as of November 30, 2022) and its current contracted position, Mr. Verderame testified that Petitioner does not anticipate purchasing additional coal supply for 2023. However, factors such as faster than anticipated inventory declines due to strong burns and the potential for continued delays in deliveries of coal due to external labor and resource constraints may lead to the need to purchase tons in 2023 to ensure reliable supplies.

Due to continued energy market price volatility, supply chain constraints, and shifting dynamics in the market fuel resource mix, Petitioner expects to continue a supply offer adjustment to actively maintain inventory levels. Mr. Verderame testified that Petitioner will likely need to purchase additional tons in 2024 to ensure reliable supplies, given its forecasted system mean coal burn for 2024 of 8.5 million tons (as of November 30, 2022), and its current contracted position in 2024.

Mr. Verderame 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 September through November 2022, the price Petitioner paid for delivered natural gas at its gas burning stations was between $3.00 per million BTU and $9.32 per million BTU. He testified natural gas prices for the period were below those experienced in the FAC 134 review period. Mr. Verderame testified that, in his opinion, Petitioner purchased natural gas at the lowest cost reasonably possible.

OUCC witness Michael D. Eckert testified that Petitioner is actively trying to manage its coal purchases and inventory. Although additional coal has been secured for 2023, Petitioner continues to monitor the viability of future supply due to financial and labor constraints facing suppliers and rail transportation providers. Mr. Eckert recommended Petitioner continue to update the Commission on its coal inventory and 2023 projected coal burn and coal purchases, as well as how Petitioner is addressing its coal transportation issues. OUCC witness Gregory T. Guerrettaz recommended Petitioner provide daily coal inventory balances at each station and an update on minimum acceptable inventory.

In rebuttal, Ms. Graft testified that Petitioner is currently providing the daily coal inventory balances during the standard FAC audit process and will continue to do so.

Mr. Daniel testified that Petitioner 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 Cause No. 38707 FAC 113.

Based on the evidence presented, we find that Petitioner 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 fuel cost reasonably possible during September through November 2022. Regarding its coal inventory levels and transportation issues, Petitioner will provide an update on the status in its next FAC proceeding as recommended by the OUCC.

5. <u>Hedging Activities</u>. Petitioner's witness James J. McClay, III testified Petitioner takes advantage of the hedging tools available to protect against natural gas price fluctuations. Mr. McClay testified that Petitioner realized a loss of $5,788,413 from natural gas hedges purchased for September through November 2022. He testified that market price for gas realized lower values than the hedged prices due to decreased natural gas prices caused by improved domestic production, lower LNG processing demand and improved storage inventories going into the winter season. He testified Petitioner experienced net realized power hedging losses for the period of $18,484,452 primarily due to low power prices due to increased natural gas production, improved domestic natural gas storage inventories, and improvement in coal delivery. Petitioner's witness Christa L. Graft testified that Petitioner realized a total net hedging loss of $24,297,152 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, Petitioner has not utilized its flat hedging methodology. Rather, Petitioner 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 Petitioner with at least 150 MW of expected load unhedged on a forward forecasted basis. Mr. McClay testified that, as instructed by the Commission in Cause No. 38707 FAC 133, Petitioner has reviewed its current hedging practices with the OUCC and industrial customers to determine if any incremental improvements can be made. Currently, Petitioner has a cash month plus six forward months term limit for both native power and natural gas hedging programs. Mr. McClay testified that after reviewing changing market conditions of the past two years, and discussions with the OUCC and industrial customers, Petitioner is proposing 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 periods for natural gas adjusting over time to allow Petitioner to layer in hedges. He testified that extending the hedging horizon would be beneficial for customers to manage market risk by purchasing hedges over a longer period of time to take advantage of lower volatility in the forward market. He noted the hedging activity may or may not result in net fuel cost savings and prior results are not indicative of future hedging results. Instead, the program's purpose is to provide a reasonable and prudent approach to mitigate price volatility in uncertain fuel markets. Mr. McClay testified the different proposed hedging extensions (12 months power hedging versus three years gas hedging) is 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. Therefore, it is necessary to keep a more realistic shorter-term limit for power hedges. He explained that while the longer hedging horizon will allow Petitioner to start hedging earlier than the current program and take advantage of a dollar cost average approach to smooth out market volatilities, it will not necessarily require Petitioner to buy more hedges for each month and, therefore will not necessarily be a higher hedge volume. A rolling approach that gradually increases hedging percentages over time by layering in hedging transactions represents a balanced fuel price risk management approach that results in greater fuel cost certainty over time.

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

Mr. Eckert testified that Petitioner'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, Petitioner experienced large hedging gains through November 2021. Petitioner subsequently experienced large hedging losses starting in December 2021 through February 2022. In the current FAC period, Petitioner experienced large losses in all three months. Mr. Guerrettaz of the OUCC opined that any new hedging program should lower/eliminate the need to forecast a cost impact in the proposed calculation of total fuel cost (F) divided by sales (S) (Schedule 1, Attachment A).

In rebuttal, Ms. Graft testified the proposed changes to Petitioner's hedging program will not change the need to include a forecast of hedging adjustments in the proposed F divided by S. The objective of a hedge is to lock in a price for a future purchase of natural gas or purchased power. As an example, if market prices decrease from the hedge price, Petitioner benefits by being able to buy natural gas or purchased power at the lower market price; however, this benefit is offset by a loss on the hedging instrument. Therefore, if Petitioner does not include an estimate of hedging adjustments as part of its forecast, the forecast is not reflective Petitioner's total estimated fuel cost.

Petitioner 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 Petitioner to include $24,297,152 of net losses from native gas and power hedges in the calculation of fuel costs in this proceeding. Based upon the evidence presented, and because of the collaborative review of Petitioner's hedging methodology with the OUCC and industrial customers, we find Petitioner's proposed changes to its hedging methodology to be reasonable and necessary considering the heightened price volatility in power and natural gas markets. We find Petitioner's proposed extensions of the hedging horizon for its power and natural gas programs better manages market risk for the benefit of Duke Energy Indiana customers. We also conclude that it is prudent for Duke Energy Indiana to periodically consult with the OUCC to review Petitioner'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 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 Petitioner included Energy Markets charges and credits incurred as a cost of reliably meeting the power needs of Petitioner's load, including: (1) Energy Markets charges and credits associated with Petitioner's own generation and bilateral purchases that were used to serve retail load; (2) purchases from MISO at the full locational marginal pricing at Petitioner'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 continued constraints in the coal supply and transportation market, along with volatility of power and natural gas prices through the FAC 135 period, continued the need for Petitioner'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. Although constraints in the coal supply and transportation chain improved throughout the FAC period, supply offer adjustments remain necessary to provide reliable station fuel inventory targets for the winter season. In the current constrained environment, without a supply offer adjustment, Petitioner's coal inventory would drop to low and unreliable levels. Mr. Daniel testified Petitioner used its production cost model to determine the adjustment amount. The model utilizes up-to-date spot and future commodity and power prices, along with actual and targeted station coal inventory to run scenarios that produce the amount of adjustment needed to meet reliable inventory levels. He testified Petitioner continues to bound coal inventory levels between a minimum and maximum full load burn inventory at 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, and then adjusted by the necessary $/MWh supply offer adjustment amount. Petitioner 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 Petitioner'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 September through November 2022.

Mr. Daniel testified the rolling 12-month NOx tons air permit limit at Wheatland CT is not currently an immediate constraint. Petitioner continues to use an adjustment to its economic offers to optimize its rolling 12-month permit allowance.

Mr. Eckert testified the OUCC understands Petitioner's need for the coal increment to maintain a reasonable level of coal inventory and meet reliability concerns in MISO. He recommended Petitioner file testimony, schedules, and workpapers to justify the need for, or use of, coal increment/decrement pricing in its next FAC proceeding. Mr. Guerrettaz testified that delivery constraints, which are changing weekly, were the main driver of the adder. Petitioner's weekly analysis showed that if an adder was not implemented, its inventory would quickly decrease to zero.

Petitioner's witness Mary Ann Amburgey testified as to the procedures followed by Petitioner to verify the accuracy of the charges and credits allocated by MISO and PJM to Petitioner. 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 Petitioner 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 Petitioner 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 Petitioner 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 Petitioner has included various ASM charges and credits in this proceeding incurred for September through November 2022, consistent with the Phase II Order, as well as appropriate period adjustments.

Petitioner's witness Scott A. Burnside testified that Petitioner, 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)	September 2022	October 2022	November 2022
Regulation Cost Distribution	0.0697	0.0827	0.0760
Spinning Cost Distribution	0.0372	0.0638	0.0627
Supplemental Cost Distribution	0.0065	0.0071	0.0031

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

Based upon the evidence presented, we find Petitioner'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 Petitioner's bidding strategy alter the native/non-native load assignment of its units, such strategy may be subject to further prudence review.

The Commission also finds that Petitioner'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, and the Phase I and Phase II Orders in Cause No. 43426, and is approved.

We find that Petitioner has laid a reasonable foundation for the mechanics of its supply offer adjustment to MISO to maintain a reliable level of coal inventory going into the winter months. Petitioner will continue to provide support for the reasonableness 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 Petitioner 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 two outages that met these criteria. Mr. Daniel testified that no Root Cause Analyses were performed for any of these outages.

We also note that, in response to the Presiding Officers' March 13, 2023, docket entry, Petitioner has represented:

> A root cause analysis of the outage at Noblesville station on February 23, 2023, is currently being performed. Duke Energy Indiana anticipates a final root cause analysis will be available to provide to the Commission in the next FAC 136 proceeding.

Petitioner's Exhibit 9 at 1. In accordance with this representation, we find that Petitioner shall provide information on the root cause analysis performed regarding the fire and outage at its Noblesville, Indiana generating station on February 23, 2023, in FAC 136.

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, Petitioner filed operating cost data for the 12 months ended November 30, 2022. Petitioner's authorized phased-in jurisdictional operating expenses (excluding fuel costs) are $1,322,395,000. For the 12-month period ended November 30, 2022, Petitioner's actual jurisdictional operating expenses (excluding fuel costs) totaled $1,476,128,000. Accordingly, Petitioner's actual operating expenses exceeded jurisdictional authorized levels during the period at issue in this Cause. Therefore, the Commission finds that Petitioner'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.

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 Petitioner-owned Multi-Value Projects ("MVPs") should 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. Petitioner proposed that the costs and revenues associated with Petitioner-owned MVPs be treated as non-jurisdictional and outside of the FAC earnings test, which is consistent with the treatment of its Petitioner-owned Regional Expansion Criteria and Benefit projects beginning in Cause No. 38707 FAC 86. Petitioner 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 Petitioner's exclusion of revenues and expenses associated with Petitioner-owned MVPs. In Cause No. 38707 FAC 122, Petitioner's proposed treatment for these revenues and expenses were approved on an interim basis, subject to refund, pending the outcome of Petitioner's RTO 56 filing. The Commission issued its RTO 56 Order on February 24, 2021.

Ms. Graft testified Petitioner began receiving excess distributed generation ("EDG") from customers pursuant to Ind. Code ch. 8-1-40 in late 2022. As directed in the Commission's July 6, 2022, Order in Cause No. 45508 approving Petitioner's EDG tariff, amounts credited to customers for EDG are recognized in its FAC proceeding. She testified Petitioner has included $922 of payments made to customers for EDG during this FAC reconciliation period.

In accordance with previous Commission Orders, Petitioner's calculated jurisdictional electric operating income level was $451,609,000, while its authorized phased-in jurisdictional electric operating income level for the purposes of Ind. Code § 8-1-2-42(d)(3) was $582,790,000. Therefore, the Commission finds that Petitioner did not earn a return more than its authorized level during the 12 months ended November 30, 2022.

10. **Estimation of Fuel Costs.** Petitioner estimates that its prospective average fuel cost for the months of April through June 2023 will be $90,364,859 or $0.037808 per kWh. Petitioner previously made the following estimates of its fuel costs for the period September through November 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
September 2022	$54.641	$54.152	0.90%
October 2022	$51.900	$57.654	(9.98%)
November 2022	$43.255	$57.602	(24.91%)
Weighted Average	$50.209	$56.439	(11.04)%

A comparison of Petitioner's actual fuel costs with the respective estimated costs for these three periods results in a weighted average difference of (11.04%). Based on the evidence of record, we find Petitioner's estimating techniques appear reasonably sound, and its estimates for April through June 2023 should be accepted.

11. **Fuel Cost Factor.** As discussed above, Petitioner's base cost of fuel is 26.955 mills per kWh. The evidence indicates that Petitioner's fuel cost adjustment factor applicable to April through June 2023 billing cycles is computed as follows:

	$/kWh
Projected Average Fuel Cost	0.037808
FAC 135 Reconciliation Factor	(0.001305)
Adjusted Fuel Cost Factor	0.036503
Less: Base Cost of Fuel Included in Rates	0.026955
Fuel Cost Adjustment Factor	0.009548

Ms. Graft testified that the FAC 135 reconciliation factor shown above reflects $8,021,366 of over-billed fuel costs applicable to retail customers that occurred during the period September through November 2022.

Mr. Guerrettaz testified that the fuel cost adjustment for the quarter ended November 2022 had been properly applied by Petitioner. In addition, he stated the figures used in the Petition for a change in the FAC were supported by Petitioner's books and records, Sumatra, and source documentation of Petitioner for the period reviewed. Mr. Guerrettaz testified that during the audit the OUCC tested Petitioner's inputs for the forecast. Future prices for both purchased power and natural gas had decreased from the costs used by Petitioner as of January 3, 2023. A high-level analysis of the impact of the price changes on its forecast showed that changing the input prices would have a material effect on Fuel divided by Sales and result in a 17.1% decrease for the customer. Using the high-level analysis with purchased power and natural gas prices as of February

5, 2023, Mr. Guerrettaz recommended changing the FAC factor to 7.498 mills per KWh. He recommended approval of the steam factor proposed by Petitioner of 0.9625574.

In rebuttal, Ms. Graft testified that Petitioner develops its quarterly FAC forecasts based upon assumptions as of a date certain (January 3, 2023, in this proceeding) in order to timely file each FAC case. While Petitioner recognizes prices have declined since January 3, 2023, there is no evidence to indicate the prices as of January 3, 2023, are unreasonable assumptions. Given the significant price volatility in the purchased power and natural gas markets over the past 18 months, Petitioner recommends approval of its FAC 135 factor as filed. The expedited nature of the FAC proceedings allows for any reconciliation adjustments to be flowed through FAC rates on a timely basis. However, she indicated if the Commission concludes that Petitioner should modify its FAC 135 factor as proposed by the OUCC, an adjustment would need to be made to the International Paper fuel cost adjustment factor for consistency.

Based upon the evidence of record, the Commission approves Petitioner's proposed fuel cost factor and declines to adopt the different factor proposed by the OUCC. We find that Petitioner's quarterly FAC filings and the associated reconciliation process provide a sufficient mechanism for adjusting for fuel price volatility. We also note that Petitioner has agreed to the OUCC's previous recommendations for spreading out the recovery of recent large variances over more than one FAC; this FAC proceeding is the first one since FAC 132 that does not include recovery of amounts from prior FAC filings.

12. Effect on Residential Customers. The approved factor represents a decrease of $0.026600 per kWh from the factor approved in FAC 134. The typical residential customer using 1,000 kWhs per month will experience a decrease of $26.60 or 15.9% on the customer's total electric bill compared to the factor approved in FAC 134 (excluding sales tax).

13. Interim Rates. Because we are unable to determine whether Petitioner'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 as well as an update to the base cost of fuel. The fuel cost adjustment factor for International Paper of $0.9625574 per 1,000 pounds of steam was calculated on Attachment B, Schedule 1, of the Petition; this factor will be effective for the April through June 2023 billing cycles. Attachment B, Schedule 2, of the Petition is a reconciliation of the actual fuel cost incurred to estimated fuel cost billed to International Paper that resulted in $132,824 credit to International Paper for the months of September through November 2022.

The Commission finds that Petitioner's proposed fuel cost adjustment factor for International Paper of $0.9625574 per 1,000 pounds of steam has been calculated in accordance with this Commission's Order in Cause No. 45740, and that such factor should be approved. We further find that Petitioner's reconciliation amount of $132,824 credit to International Paper has been properly determined and should be approved.

15. Shared Return Revenue Credit Adjustment for International Paper. In accordance with the settlement agreement approved in Cause No. 45740, International Paper will receive shared return revenue credit adjustments to the extent incurred. As indicated herein, Petitioner did not have excess earnings for the 12 months ended November 2022. Therefore, we find International Paper is not due a shared return revenue credit.

16. Confidential Information. Petitioner filed a Motion for Protection of Confidential and Proprietary Information on January 31, 2023, 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 Officers issued a docket entry on February 14, 2023, 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 and 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 Finding No. 11, and the fuel cost adjustment for steam service as set forth in Finding No. 14 of this Order, are approved on an interim basis, subject to refund, in accordance with all 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. Prior to implementing the authorized rates, Petitioner 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 Finding No. 4 of this Order.

5. Duke Energy Indiana's proposed changes to its hedging plan, as described in Finding No. 5 of this Order, are hereby approved.

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. Duke Energy Indiana shall provide information on the root cause analysis performed

regarding the fire and outage at its Noblesville, Indiana generating station on February 23, 2023, in FAC 136.

8. 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.

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

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

APPROVED: MAR 29 2023

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: 2023.03.29 10:17:48
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Dana Kosco
Secretary of the Commission