ORIGINAL

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

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA FOR APPROVAL OF A FUEL COST FACTOR FOR ELECTRIC SERVICE DURING THE BILLING MONTHS OF SEPTEMBER 2025 THROUGH NOVEMBER 2025, IN ACCORDANCE WITH THE PROVISIONS OF I.C. 8-1-2-42, CONTINUED USE OF RATEMAKING TREATMENT FOR COSTS OF WIND POWER PURCHASES PURSUANT TO CAUSE NO. 43740, AND CONTINUED RECOVERY OF THE COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.	)	**CAUSE NO. 38703 FAC 148** **APPROVED: AUG 27 2025**

ORDER OF THE COMMISSION

Presiding Officer:
Kristin E. Kresge, Administrative Law Judge

On June 16, 2025, Indianapolis Power & Light Company d/b/a AES Indiana ("Applicant" or "AES Indiana") filed its Verified Application, direct testimony, attachments, and workpapers with the Indiana Utility Regulatory Commission ("Commission") for approval of: (1) a fuel adjustment charge ("FAC") factor to be applicable during the billing cycles of September 2025 through November 2025 (the "Forecast Period"); (2) the continued use of ratemaking treatment for the cost of wind power purchases pursuant to Cause No. 43740; and (3) approval of a fuel hedging plan and continued authority to recover the costs of its fuel hedging plan. Applicant concurrently filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information, which was granted on a preliminary basis by Docket Entry dated July 9, 2025.

On July 18, 2025, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its direct testimony. On July 30, 2025, Applicant filed its notice of intent not to file rebuttal testimony.

An evidentiary hearing was held at 2:00 p.m. on August 11, 2025, in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana. Applicant and the OUCC appeared and participated by counsel. The parties' evidence was admitted into the record without objection.

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

1. **Notice and Jurisdiction.** Notice of the evidentiary hearing was given and published by the Commission as required by law. Applicant is a "public utility" as that term is defined in Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to Applicant's fuel cost charge, the ratemaking treatment of its wind power purchase costs and costs associated with a natural gas hedging plan. Therefore, the Commission has jurisdiction over Applicant and the subject matter of this Cause.

2. <u>Applicant's Characteristics</u>. AES Indiana is an electric generating utility and a corporation organized and existing under Indiana law with its principal office in Indianapolis, Indiana. Applicant is engaged in rendering electric public utility service in Indiana. Applicant owns and operates plant and equipment within Indiana used for the production, transmission, delivery, and furnishing of electric service to the public.

3. <u>Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost</u>. Applicant must comply with the statutory requirements of Ind. Code § 8-1-2-42(d)(1) by making every reasonable effort to acquire fuel and generate or purchase power, or both, to provide electricity to its retail customers at the lowest fuel cost reasonably possible. As discussed below, we find Applicant has satisfied these requirements.

A. <u>Efforts to Acquire Fuel</u>. Alexander Dickerson, Senior Manager, Wholesale Energy for Applicant, explained Applicant's participation in the Midcontinent Independent System Operator ("MISO") Open Access Transmission and Energy Markets Tariff, the projected fuel related MISO costs for the Forecast Period, and the true-up of fuel-related MISO costs and revenues during February through April 2025 ("Historical Period"). Mr. Dickerson also testified about the customer benefits from Applicant's participation in MISO, where resources are centrally dispatched by MISO using simultaneous co-optimization.

Mr. Dickerson supported Applicant's purchases of coal, fuel oil, and natural gas for use in its generating stations. He testified that Applicant's Harding Street Station and Petersburg Generating Station ("Petersburg") manage their fuel oil purchases based on inventory set-points and regional market index pricing negotiated in a competitively bid contract. He explained Applicant currently has contracts with two coal producers and receives coal from up to three different mines. Mr. Dickerson stated that Applicant verifies the reasonableness of its coal cost by using a competitive bidding process to award its coal contracts. Mr. Dickerson discussed Applicant's use of the spot market and added that for some spot purchases when a formal competitive bid process might not be feasible, an informal survey of local coal providers is performed to assure the agreed-upon price is at or below Applicant's next best alternative. He said Applicant uses spot purchases of coal to: (1) provide the differential requirement between Applicant's long-term contracts and its projected burn for the year; (2) test the quality and reliability of a producer; and (3) take advantage of occasional low price market opportunities when Applicant's projected inventory levels allow.

Mr. Dickerson also testified regarding Applicant's unit commitment process. He stated Applicant looks at the predicted economic performance of each generating unit over a period of one week when deciding whether to commit the unit. The startup cost necessary to restart the unit is also considered. Additionally, he testified Applicant considers reliability, price certainty from running generation, and opportunities from participating in both Day Ahead and Real Time energy markets. Mr. Dickerson testified that during seasonal periods (summer and winter) with historical high market prices and potential high load, Applicant maintains a generation mix that includes coal, natural gas, and renewables. He explained Applicant raises the minimum operating level when required to maintain reliability or for other operational reasons. He testified that under normal conditions, Applicant offers the Petersburg units to be dispatched by MISO between their minimum and maximum economic operation level.

Mr. Dickerson testified the decision to offer a unit considers a wide range of factors. He stated some factors considered are economic, such as the predicted prices in the near future market, and the avoidance of start-up costs required to bring the unit back on-line. Some are operational, such as the time and manpower required to bring units back on-line, plant limitations, and wear and tear of cycling units designed for long-term base load operations. Finally, he testified some considerations revolve around system reliability. He explained system reliability issues are particularly important during the winter and summer peaks and a system is more reliable when supported by a diverse fuel mix. He testified that units taken down do not always come back fully operational, and sudden system disruptions can cause significant price spikes as units struggle to come back on-line to fill the energy demand.

Mr. Dickerson testified that the focus in a prudence inquiry is not whether a given decision or action produced a favorable or unfavorable result, but rather whether: (1) the process leading to the decision or action was a logical one; (2) the utility company used good judgment and applied appropriate standards; and (3) the utility reasonably relied on information and planning techniques known at the time. He concluded that Applicant acted prudently with respect to the commitment and operation of Petersburg during the Historical Period. He further explained why it is not reasonable to rely solely on pricing to decide whether and how to commit Applicant's generating units and he discussed other factors considered, including the potential for significant price risk.

Mr. Dickerson summarized the commitment status of the Petersburg units during the Historical Period, noting that Petersburg Unit 3 and Unit 4 were offered as must run and outage. He stated periods of must run were due to reliability, variable weather experienced in the market, and operational needs of the units, including management of the coal inventory at safe levels and contractual requirements for coal delivery as well as expected positive margin. He explained periods of outage were due to both scheduled and forced outages. Mr. Dickerson testified that Applicant evaluated weekly model runs for commitment decisions and that, overall, Applicant's operation of the Petersburg units was reasonably aligned with market prices.

Mr. Dickerson provided further detail on the Petersburg unit commitment decisions during the Historical Period and explained Applicant ran a short-term model (which provides 30-day forward looks) to track the economic value of the Petersburg units. He sponsored a copy of the model runs in Applicant's Exhibit 2-C, Confidential Attachment AD-3. He added that noneconomic factors were also considered in unit commitment decisions, including reliability, price certainty, operational needs, and avoidance of startup costs.

Mr. Dickerson stated Applicant also performed a look-back evaluation of Petersburg for the Historical Period using the value created during the actual unit commitment as well as other economic benefits including real-time optimization, make whole payments, Auction Revenue Rights, Financial Transmission Rights, and Marginal Loss Credits. He explained that while the analysis should not be used to judge the prudence of the unit commitment decisions, Applicant acknowledges that a look-back analysis can inform its decision-making on a going forward basis and support Applicant's ongoing effort to improve its modeling and decision process.

Mr. Dickerson testified that Applicant considers both the long-term and short-term when making unit commitment decisions. He stated the longer-term forecasts in each FAC are generated in a planning model that looks at the economic dispatch of the units on the day the model is run.

He testified as the future period becomes the actual period, the following drives commitment decisions: market pricing, protecting customers from price risk, operational issues, and reliability. In other words, he stated, Applicant makes unit commitment decisions based on circumstances as they exist during the actual period and assesses energy market decisions through a nearer-term forward-looking assessment. He stated Applicant is continuing to improve its understanding of market conditions and costs associated with must run and other unit commitment decisions. He testified that the more refined short term model Applicant began using in May 2020 improves the economic view of unit commitment on a rolling four-week period and said still important are noneconomic factors, such as predicted strong weather/high loads (hedge value), operational issues, and reliability, which will continue to be considered must run decisions.

Mr. Dickerson also updated the Commission on the short-term model Applicant uses to support and track the Petersburg unit commitment decisions. He stated the model utilizes a combination of two types of trades to calculate the operating cost and potential margin for the Petersburg units. He discussed how the model works, the inputs into the model, and how volatilities and correlations are incorporated into the model. He testified the model output is captured on a spreadsheet showing a rolling 30-day period and the total profit and loss from each of the two types of trades. The total value of the two trades indicates if the unit runs at a positive margin during a given timeframe. He testified Applicant includes model output from the Historical Period in the OUCC packet for review and reviews the model and output with the OUCC during the audit.

Mr. Dickerson also provided an update on Applicant's projected coal burn, coal purchases, and coal inventory management activities. Mr. Dickerson stated due to the colder than normal winter and higher natural gas prices the coal inventory has decreased. He testified Applicant's coal inventory is currently above the 25-50 day supply of coal inventory target range, and that the inventory has declined and is projected to be within target levels within the Forecast Period.

Mr. Dickerson testified Applicant continues to actively manage its inventory levels. He noted Applicant's long-term coal contracts often contain some variability in the quantity of coal that Applicant can take under that particular contract. He stated this allows Applicant to decrease deliveries when coal burns go down. He explained this contract variability is essential in managing the month-to-month variations in coal burns due to weather, market prices, and unit availability, but noted contract variability is not always enough to manage the inventory.

Mr. Dickerson testified that historically mild weather and comparably lower natural gas prices in 2024 have caused coal inventories to remain near maximum safe levels. He noted coal burn forecasts have increased due to power prices and natural gas prices increasing. He said while coal inventory levels are down from the highs of last year, expectations for inventories to decrease further did not occur as anticipated. He noted Applicant has made great progress on its coal inventory levels with the cold from January and February but still anticipate being above the target inventory level through the first half of 2025. He testified Applicant will continue to evaluate cost effective solutions to manage its coal inventory as necessary in the future. Finally, Mr. Dickerson testified there is no decrement pricing in the Forecast Period and that Applicant has not been impacted by any coal supply interruptions.

Mr. Dickerson discussed the natural gas transactions for the Eagle Valley combined-cycle gas turbines that were completed under the current Fuel Hedging Policy. Mr. Dickerson sponsored Attachment AD-5, to Applicant's Exhibit 2, which provides an evaluation of the hedges' economic settlement in the Historical Period, by comparing the hedge price to the daily index price for the natural gas delivery point associated with the hedges. He testified that in the month of February 2025, hedges on natural gas represented a cost of $1,381,320. Hedges on natural gas in the month of March 2025 represented a benefit of $2,176,811, and in the month of April 2025, hedges on natural gas represented a cost of $210,150.

Mr. Dickerson explained that natural gas hedges were transacted through 2023 and 2024. He explained by that point prices had stabilized after the run-up in 2022. He added that natural gas production has remained at high levels through the winter and into the spring. He stated United States natural gas inventories came into the winter above the one-year and five-year average removing some of the risk associated with having necessary supply for the winter demand. However, he said sustained cold weather in January and into February resulted in a large draw down of storage and increased concern over returning the storage to normal levels before winter 2025-2026. He explained natural gas prices reflected these changes, the risk premium increased, and prices became more volatile with various threats of trade wars and tariffs. He said during the Historical Period, the weather was colder than normal in February, while March and April were warmer than normal, reducing power prices and impacting the need for electric generation and residential and commercial heating demand. He stated as a result, the supply and demand is starting to show signs of equilibrium, and this is increasing volatility as supply and demand profiles change.

Mr. Dickerson testified regarding the benefits to customers of Applicant's long-term hedging program. He explained that Applicant developed the long-term hedging program to achieve three primary goals for its customers. He stated the first goal was to increase the reliable delivery of natural gas to all gas-fired generation in Applicant's fleet. He explained this is achieved through owning firm transportation as well as purchasing third-party delivered gas to Eagle Valley off the Rockies Express pipeline. He stated that by utilizing third party firm capacity to deliver to Eagle Valley, more of Applicant's Texas Gas and REX firm capacity can be utilized at the Harding Street Station. He testified this enhances the firm transportation portfolio of Applicant to provide reliable fuel delivery. Mr. Dickerson stated the second goal of purchasing Rockies Express volumes delivered to Eagle Valley is due to the historical volatility of Rockies Express Zone 3 pricing. He testified by locking in a fixed price, that volatility is mitigated for those volumes. He testified that the third and final goal of the program is to reduce the price volatility that is inherent within the natural gas market. He testified as part of the hedging program approved in Cause No. 38703 FAC 145, Applicant is taking a more holistic portfolio view of hedging and has expanded the areas in which gas purchases are made. He explained the purchases for the long-term hedging program are layered in over time to produce a dollar-cost-averaging effect that is meant to reduce that price volatility. He stated these benefits to customers are focused on risk reduction - creating more predictable pricing and increasing reliability of physical gas delivery. He explained as the new hedging policy is enacted the portfolio will be hedged holistically against retail load. He testified this will allow for a more diverse hedging strategy including Rockies Express, Texas Gas Transmission, power, and coal. He stated the three primary goals will remain the same, however the third goal will be further enhanced by the flexibility of diverse hedging options.

Mr. Dickerson next testified regarding firm transportation costs incurred by Applicant. He stated that the cost of gas generation contains the delivered cost of natural gas, including firm transportation costs. He stated Applicant works to prudently reserve firm transportation capacity to ensure its natural gas-fired units have reliable gas service. He explained that this is necessary and prudent to ensure the units are available and have the reliable fuel service needed for critical days. He explained the transportation costs reserve space on the pipelines that provide the fuel for Applicant's plants and allow Applicant to more efficiently reach high supply areas or more heavily traded points. He stated at the same time, Applicant looks for opportunities to work with third-party marketers to release capacity where practicable to achieve additional value for Applicant's customers, as has been done in previous FACs. He stated to the extent Applicant is able to achieve additional monetary value from releasing capacity, such revenues flow through the FAC to offset other fuel costs.

Mr. Dickerson testified that as AES Indiana's transportation portfolio has grown so has the complexity of managing it. He said AES Indiana currently has capacity on five pipelines with unique Electronic Bulletin Boards, nomination procedures, and systems. As a result, he said the nominations, supply, balancing, and efficiency required to ensure the necessary reliability has grown exponentially with the different pipelines. He stated historically, AES Indiana has manually managed these pipelines. He said in order to meet the necessary timeliness and accuracy required of just in time fuel, AES Indiana has begun using software that will allow AES Indiana to continue to provide the reliable fuel management historically achieved while increasing the ability to respond to real-time market changes on both the power and gas side faster and more accurately. He explained the monthly costs associated with the software are appropriately considered a fuel cost and are reflected in this FAC filing.

Mr. Dickerson concluded that Applicant made every reasonable effort to acquire fuel and generate or purchase power or both to provide electricity to its retail customers at the lowest fuel cost reasonably possible.

Michael D. Eckert, Chief Technical Advisor within the OUCC's Electric Division, provided an update on the status of the Petersburg units and when they were last called on by MISO to produce power. He also testified Applicant's current coal inventory is above Applicant's target levels and acknowledged Applicant is actively looking at options to address its coal inventory. Mr. Eckert recommended Applicant provide an update on its coal inventory and its 2025 projected coal burn and coal purchases in future FAC proceedings.

Mr. Eckert noted that Mr. Dickerson provided the results of Applicant's natural gas hedging program and stated additional information was provided during the OUCC's FAC audit. He recommended Applicant continue to file the results of its natural gas hedging program in each subsequent FAC, provide an analysis of the facts and circumstances existing when the transactions were entered into, and provide copies of its hedging program in future FAC proceedings, if revised.

OUCC Witness Gregory T. Guerrettaz, CPA and President of Financial Solutions Group, Inc., testified the OUCC discussed the further implementation of Applicant's fuel procurement policy covering coal and natural gas hedging policy with Applicant. He stated the process appears to be coming together to provide a hedge against higher prices in the next several years, and certain new transportation contracts have been recently enacted and applied to the forecast. He further noted AES Indiana has purchased a new software package to help manage the various gas products Applicant is using and that the OUCC and Applicant will continue to discuss this software package in future FACs as Applicant begins using the software. He stated the OUCC has no concerns at this time with the new Fuel Hedging Policy.

Applicant presented substantial evidence regarding its unit commitment decision-making process that shows Applicant considers both short-term and long-term vantage points. While economics do not capture all the reasons for unit commitment, we find the modeling will help Applicant support its decision-making. We further find that price risk, reliability, and operational needs are also reasonably factored into Applicant's decision process. Summer and winter periods create different challenges, including the potential for high price events that prompt unit commitment decisions to consider more than purely economic factors. Accordingly, substantial evidence demonstrates, and we find, that Applicant's Petersburg unit commitment decisions during the Historical Period were reasonably based on forward market price values at the time the decisions were made and reasonably considered noneconomic factors. We further find the inclusion of firm transportation costs and fuel management software costs incurred by Applicant to be reasonable. The record shows Applicant works to prudently reserve firm transportation capacity to ensure its natural gas-fired units have reliable gas service. The record further shows Applicant looks for opportunities to work with third-party marketers to release capacity where practicable to achieve additional value for customers. To the extent Applicant is able to achieve additional monetary value from releasing capacity, such revenues flow through the FAC to offset other fuel costs.

Applicant also presented substantial evidence regarding the results of its natural gas hedging program. The record shows Applicant's hedging analysis is consistent with the process used to inform hedge decisions for the financial power hedges entered into during previous FAC proceedings. The OUCC did not oppose Applicant's hedges, and we find Applicant's purchased power hedges, including the purchase of natural gas discussed by Applicant's Witness Dickerson, to be reasonable; therefore, the Commission finds the incurred gains or losses are reasonable and recoverable through the FAC. Applicant shall continue to provide in its next FAC the information the OUCC recommended regarding Applicant's hedging program.

Based upon the evidence presented, the Commission finds Applicant has made every reasonable effort to acquire fuel and generate or purchase power to provide electricity at the lowest fuel cost reasonably possible.

B. <u>Purchased Power Costs Above Benchmark</u>. In its April 23, 2008, Order in Cause No. 43414 ("Purchased Power Order"), the Commission approved a benchmark triggering mechanism to assess the reasonableness of purchased power costs. Mr. Dickerson explained that each day, a benchmark is established based upon a generic Gas Turbine ("GT"), using a generic GT heat rate of 12,500 btu/kWh and the day ahead natural gas prices for the New York Mercantile Exchange Henry Hub, plus a $0.60/MMBtu gas transport charge for a generic gas-fired GT (together, the "Benchmark"). He explained Applicant continues to follow the guidelines and procedures established in the Purchased Power Order. He stated purchases made in MISO's economic dispatch regime to meet jurisdictional retail load are a cost of fuel and recoverable in the utility's FAC up to the actual cost or the Benchmark, whichever is lower.

Mr. Dickerson testified Applicant incurred a total of $239,894 of purchased power costs over the applicable Benchmarks during the Historical Period. He stated Applicant makes power purchases when economical or due to unit unavailability. Mr. Dickerson testified that consistent with the Purchased Power Order, Applicant has an opportunity to request recovery and justify the reasonableness of purchased power costs above the applicable Benchmark.

Mr. Dickerson testified that utilizing the methodology approved in the Purchased Power Order, all but $8,172 of Applicant's $239,894 of purchased power costs for the applicable accounting period is recoverable. Applicant therefore sought to recover $231,721 in purchased power over the Benchmark.

Mr. Dickerson testified that almost 50% of the purchased power above the benchmark was incurred over three days in the Historical Period. He stated on February 7, Petersburg Unit 4 had to come offline due to a tube leak. He said this outage resulted in $35,804 of purchased power above the benchmark. He stated on March 20 MISO had significant price spikes over three hours resulting in another $30,829 of purchased power above the benchmark. He noted AES Indiana had assets available, but they were not called upon by MISO. Lastly, he said on April 5 MISO had one hour that settled at over $880/MWh creating almost $42,000 of purchased power over the benchmark. Again, AES Indiana had assets available, but they were not online.

Mr. Eckert explained the purchased power over the Benchmark treatment is controlled by the Purchased Power Order, and he testified that Applicant followed the guidelines and procedures established in that Order. He confirmed that his calculations yielded the same amount of purchased power over the Benchmark as Applicant provided. He recommended the Commission allow Applicant to recover $231,721 in purchased power over the benchmark.

Based on the evidence, we find Applicant's identified purchased power costs were reasonable under the circumstances at the time of the purchases and are approved.

4. <u>MISO Market Related Activity</u>. Mr. Dickerson testified that Applicant's calculation of costs for the Forecast Period is consistent with the Commission's June 1, 2005 Order in Cause No. 42685 and its June 30, 2009 Order in Cause No. 43426 ("Phase II Order"). Mr. Dickerson described the MISO costs and revenues Applicant is seeking to recover in this FAC proceeding. He testified that consistent with the Commission's Order in Cause No. 38703 FAC 97 ("FAC 97 Order"), Applicant has included Demand Response Resource Uplift charges from MISO in its cost of fuel in this proceeding. Further, he testified that consistent with the Commission's Order in Cause No. 38703 FAC 85 ("FAC 85 Order"), Applicant has included the credits and charges for Contingency Reserve Deployment Failure Charge Uplift Amounts in its cost of fuel in this proceeding. He also discussed Applicant's experience with MISO's Ancillary Services Market ("ASM") and testified that Day Ahead and Real Time market clearing prices for Regulation, Spinning, and Supplemental Reserves appear to be at reasonable levels consistent with market conditions. Mr. Dickerson testified that Applicant's request for recovery of Revenue Sufficiency Guarantee ("RSG") Payments is consistent with the Commission's June 3, 2009 Order in Cause No. 43664 ("RSG Order") in which the Commission approved an "RSG Benchmark" calculation. Mr. Dickerson presented the RSG Daily Benchmarks in Applicant's Exhibit 2, Attachment AD-1.

Mr. Eckert testified that Applicant's proposed ratemaking treatment for the ASM charge types is consistent with the Commission's approved ratemaking treatment in the Phase II Order.

Based upon the evidence, the Commission finds Applicant's treatment of the ASM charge types and other fuel-related MISO costs and revenues is consistent with the Commission's Phase II, Order and its Orders issued in Cause Nos. 38703 FAC 97 and 38703 FAC 85, and is approved. The Commission further finds Applicant's recovery of RSG Payments is consistent with the June 3, 2009 Order in Cause No. 43664 and is approved.

5. **<u>Operating Expenses</u>.** Ind. Code § 8-1-2-42(d)(2) requires the Commission to find that the utility's actual increase in fuel cost through the latest month for which actual fuel costs are available since the last Commission order approving basic rates and charges of the utility have not been offset by actual decreases in other operating expenses. Natalie Herr Coklow, Director in the Regulatory Accounting department of AES US Services, LLC, testified regarding the changes made in this filing to reflect the Order issued on April 17, 2024, in Cause No. 45911 approving new basic rates and charges for Applicant. She further testified that Applicant's Exhibit 1, Attachment NHC-2 calculates the Ind. Code § 8-1-2-42 (d)(2) test, showing total jurisdictional operating expenses excluding fuel costs have increased.

Mr. Guerrettaz agreed Applicant did not have decreases in other operating costs that could be used to offset fuel cost increases.

Based on the evidence, the Commission finds Applicant's actual increases in fuel cost have not been offset by actual decreases in other operating expenses and complies with the statutory requirements of Ind. Code § 8-1-2-42(d)(2).

6. **<u>Return Earned</u>.** Subject to Ind. Code § 8-1-2-42.3, Ind. Code § 8-1-2-42(d)(3) requires the Commission to find that the FAC applied for will not result in the electric utility earning a return over the return authorized by the Commission in the last proceeding in which the basic rates and charges of the utility were approved.

Ms. Coklow explained Applicant's Exhibit 1, Attachments NHC-3 and NHC-4, which calculate the Ind. Code § 8-1-2-42 (d)(3) test, show Applicant's actual return for the 12 months ending April 30, 2025. She stated that Applicant's actual return was more than its authorized return for the 12 months ending April 30, 2025; however, the sum of AES Indiana's differentials for the relevant period is less than zero. Accordingly, she stated no reduction in the fuel factor is required, and the Commission should find the return test of Ind. Code § 8-1-2-42.3 is satisfied.

Mr. Guerrettaz agreed Applicant had jurisdictional net operating income (for the 12 months ending April 30, 2025) greater than the prorated allowed return as adjusted for various orders affecting the authorized operating income. He stated because the sum of differentials for the relevant period is a negative ($374,420,000) no adjustment to the factor is recommended.

Upon our consideration of the record evidence, the Commission finds Applicant has properly determined the authorized operating income for the 12 months ending April 30, 2025. Thus, as reflected in Applicant's Exhibit 1, Attachment NHC-3, Applicant has an authorized return of $280,069,000 for purposes of this proceeding. Attachment NHC-2 to Applicant's Exhibit 1 calculates the Ind. Code § 8-1-2-42 (d)(3) test, which shows that Applicant's actual return for the 12 months ending January 31, 2025, was $289,118,000. However, as shown on Attachment NHC-4 to Applicant's Exhibit 1, the sum of differentials for the relevant period is less than zero. Therefore, the Commission finds that during the 12-month period ending April 30, 2025, Applicant has satisfied the statutory requirements of Ind. Code § 8-1-2-42(d)(3).

7. **<u>Estimating Techniques</u>.** Ind. Code § 8-1-2-42(d)(4) requires the Commission to find a utility's estimate of its prospective average fuel costs for each month of the estimated three calendar months is reasonable after taking into consideration the actual fuel costs experienced and the estimated fuel costs for the three calendar months for which actual fuel costs are available. According to Applicant's Exhibit 1, Attachment NHC-1, Schedule 5, Applicant's weighted average deviation between forecast and actual fuel costs was an underestimate of 6.34% for the Historical Period.

Mr. Dickerson stated February 2025, March 2025, and April 2025 deviations of actual to forecast F/S were -10.59%, -7.30%, and 0.91%, respectively. He stated February and April resulted in lower generation than forecast from both coal and natural gas. He testified March saw higher coal generation and lower natural gas generation than forecasts. He stated February's realized natural gas prices also came in almost $1/MMBtu higher than forecast, which attributed to the larger deviation. He testified March realized natural gas prices were nearly $1.50/MMBtu higher than forecast and April realized almost $0.70/MMBtu higher as a result of the colder than normal winter and lower storage inventory. The forecast natural gas cost for the months of February 2025, March 2025, and April 2025 used a Henry Hub price of $3.20/MMBtu, $2.69/MMBtu, and $2.70/MMBtu, respectively. Realized Henry Hub values during the Historical Period were $4.14/MMBtu in February 2025, $4.12/MMBtu in March 2025, and $3.46/MMBtu in April 2025. He testified the February 2025, March 2025, and April 2025 Indianapolis temperature variance from normal were -0.6 degrees, 6.1 degrees, and 1.3 degrees, respectively.

Mr. Guerrettaz stated the OUCC performed a detailed review of Applicant's estimation model, and he noted the following items affected the forecast: (1) daily changes in the price of natural gas; (2) daily changes of power prices for the MISO market; (3) hedges put in place; (4) Applicant's coal inventory; and (5) gas commodity and delivery contracts. He stated based on the OUCC's analysis and review of commodity prices at the time of the audit, the OUCC is recommending the projected Fuel ÷ Sales of 38.740 mills per kWh as filed by AES Indiana be approved.

Based upon the evidence, we find Applicant's estimating techniques are reasonably accurate and its estimate of fuel costs for the Forecast Period is accepted.

8. **<u>Wind Power Purchase Agreements and Renewable Energy Credits</u>.** Mr. Dickerson testified that purchases from the Lakefield Wind Park ("Lakefield") are included in Applicant's actual and projected fuel costs. He discussed the amount of power received from Lakefield during the Historical Period. He added that pursuant to the Order in Cause No. 45911, the margin associated with the Lakefield power purchase agreement ("PPA") is included in the Off-System Sales Margin Adjustment Rider.

Mr. Dickerson stated Lakefield is a Dispatchable Intermittent Resource in the MISO market and can ramp quickly, largely avoiding negative locational marginal prices. He stated curtailed power is billable when certain criteria are met. He testified the level of curtailments at Lakefield was higher than the level of curtailments experienced during the Historical Period covered by the last FAC but lower than the Historical Period from one year ago.

OUCC Witness Eckert noted that Mr. Dickerson provided testimony to update the Commission on locational marginal prices at Lakefield. He stated Applicant offers Lakefield into the day-ahead market to mitigate the impact of negative locational marginal pricing in real-time.

In Cause No. 43740, the Commission approved Applicant's request to recover the purchased power costs incurred under the Lakefield PPA over its full 20-year term. Based on the evidence presented, the Commission finds the requested costs are reasonable, and the Commission approves the ratemaking treatment of the wind PPA costs.

9. Reconciliation and Resulting Fuel Cost Factor for Electric Service. According to Applicant's Exhibit 1, Attachment NHC-1, Schedule 1, Applicant's total estimated cost of fuel for the Forecast Period is \$119,530,492, and its total estimated sales are 3,085,488 kWh. Applicant's estimated cost of fuel, after taking into consideration the proposed reconciliation component, is \$0.042929 per kWh.

Ms. Coklow discussed how the FAC factor was calculated. As shown on Schedule 1 of Attachment NHC-1 to Applicant's Exhibit 1, after taking into consideration the reconciliation of Applicant's estimated and actual fuel costs, Applicant's estimated average cost of fuel for the Forecast Period is \$0.042929 per kWh. As shown on Schedule 1 of Attachment NHC-1 to Applicant's Exhibit 1, when the adjusted fuel cost charges are reduced by the base cost of fuel approved in Cause No. 45911, the result is the proposed fuel factor of \$0.003902 per kWh for the Forecast Period's billing cycles. Ms. Coklow testified that in relation to the factor currently in effect, the proposed factor will result in an increase of \$2.68 or 1.94% for a residential customer using 1,000 kWh per month.

OUCC Witness Eckert recommended the Commission approve the proposed fuel cost factor as calculated by OUCC Witness Guerrettaz, which agrees with Applicant's calculation.

The record shows the parties agree on the proposed fuel factor of \$0.003902 per kWh. Substantial record evidence supports Applicant's proposed fuel factor and we find it should be approved. Under Ind. Code § 8-1-2-42(a), the Commission finds the approved factor should become effective for all bills rendered for electric services during the first full billing month following issuance of this Order.

10. Confidential Information. On June 16, 2025, Applicant filed its Motion for Protection and Nondisclosure of Confidential and Proprietary Information with a supporting affidavit asserting that certain information to be submitted to the Commission was trade secret information as defined in Ind. Code § 24-2-3-2 and should be treated as confidential in accordance with Ind. Code §§ 5-14-3-4 and 8-1-2-29. A Docket Entry was issued on July 9, 2025, in which the Presiding Administrative Law Judge determined the information should be held confidential on a preliminary basis, after which the information was submitted under seal. After review of the information and consideration of the affidavit, we find the information is trade secret information as defined in Ind. Code § 24-2-3-2, is exempt from public access and disclosure pursuant to Ind. Code §§ 5-14-3-4 and 8-1-2-29, and shall be held as 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 proposed fuel factor set forth herein is approved.

2. Prior to implementing the approved rate, Applicant shall file the tariff and applicable rate schedules under this Cause for approval by the Commission's Energy Division. Such rate shall be effective on or after the Order date subject to Division review and agreement with the amounts reflected.

3. Applicant is authorized to continue to request recovery of the gains or losses, including any associated transactional costs, arising from its hedging plan as a fuel cost through its FAC. Such gains or losses, including any associated transactional costs, shall be separately identified in the schedules supporting each such filing, and upon a finding of reasonableness shall be recoverable through Applicant's FAC.

4. In its next FAC filing, Applicant shall update the Commission on its coal inventory and its projected coal burn and coal purchases.

5. The information filed in this Cause pursuant to Applicant's motion for protective order is deemed confidential pursuant to Ind. Code §§ 5-14-3-4 and 8-1-2-29, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

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

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

APPROVED: AUG 27 2025

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: 2025.08.27 10:15:47 -04'00'

Dana Kosco
Secretary of the Commission