ORIGINAL

Commissioner	Yes	No	Not Participating
Zay	√		
Deig	√		
Swinger	√		
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 JUNE 2026, JULY 2026, AND AUGUST 2026, 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 151** **APPROVED: MAY 27 2026**

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Kristin E. Kresge, Administrative Law Judge

On March 20, 2026, Indianapolis Power & Light Company d/b/a AES Indiana ("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 June through August 2026 (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. AES Indiana concurrently filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information, which was granted on a preliminary basis by Docket Entry dated March 31, 2026.

On April 24, 2026, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its direct testimony.

An evidentiary hearing was held at 9:30 a.m. on May 14, 2026, in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana. AES Indiana 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. AES Indiana 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 AES Indiana'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 AES Indiana and the subject matter of this Cause.

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

3. Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost. AES Indiana 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 AES Indiana has satisfied these requirements.

A. Efforts to Acquire Fuel. Alexander Dickerson, Director, Trading and Asset Management, explained AES Indiana'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 November 2025 through January 2026 ("Historical Period"). Mr. Dickerson also testified about the customer benefits from AES Indiana's participation in MISO, where resources are centrally dispatched by MISO using simultaneous co-optimization.

Mr. Dickerson supported AES Indiana's purchases of coal, fuel oil, and natural gas for use in its generating stations. He testified that AES Indiana's Harding Street Station and Petersburg Generating Station ("Petersburg") manage their fuel oil purchases based on inventory set-points and regional market index pricing. He explained AES Indiana currently has contracts with two coal producers and receives coal from up to three different mines. Mr. Dickerson stated that AES Indiana verifies the reasonableness of its coal cost by using a competitive bidding process to award its coal contracts. Mr. Dickerson stated that as Petersburg Units 3 and 4 go into their conversion outages in 2026, AES Indiana has entered into contracts that will allow enough flexibility to ensure adequate supply, at the lowest fuel cost reasonably possible, while also managing the coal inventory to avoid purchasing more volume than reasonably needed.

Mr. Dickerson also testified regarding AES Indiana's unit commitment process. He stated AES Indiana's 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 AES Indiana 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, AES Indiana maintains a generation mix that includes coal, natural gas, and renewables. He explained AES Indiana raises the minimum operating level when required to maintain reliability or for other operational reasons. He testified that under normal conditions, AES Indiana 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 AES Indiana 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 AES Indiana'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, economic, emergency, and outage. He stated periods of must run were due to 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 AES Indiana evaluated weekly model runs for commitment decisions and that, overall, AES Indiana'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 AES Indiana 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 Petitioner's Exhibit No. 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 AES Indiana 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, making 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, AES Indiana acknowledges that a look-back analysis can inform its decision-making on a going forward basis and support AES Indiana's ongoing effort to improve its modeling and decision process.

Mr. Dickerson testified that AES Indiana 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 that 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, AES Indiana 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 AES Indiana 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 AES Indiana began using in May 2020 improves the economic view of unit commitment on a rolling four-week period and noneconomic factors are still important.

Mr. Dickerson also updated the Commission on the short-term model AES Indiana 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 AES Indiana 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 AES Indiana's projected coal burn, coal purchases, and coal inventory management activities. Mr. Dickerson stated due to the colder than normal winter and continued higher natural gas prices the coal inventory has decreased. He testified AES Indiana's coal inventory is currently within the 25-50 day supply of coal inventory target range.

Mr. Dickerson testified AES Indiana continues to actively manage its inventory levels. He noted AES Indiana's coal contracts contain some variability in the quantity of coal that AES Indiana can take under a particular contract. He stated this allows AES Indiana to decrease deliveries when coal burns go down or increase them when burns go up. 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. He testified AES Indiana did experience some coal delivery delays during Winter Storm Fern, and that during the storm rails were shut down for multiple days, preventing coal delivery to Petersburg. He stated during this time period Petersburg had to rely on the coal onsite, which was heavily frozen and difficult to extract. He testified Petersburg personnel performed exceptionally to ensure that adequate fuel was getting to the units in very adverse weather conditions. Finally, Mr. Dickerson testified there is no decrement pricing in the Forecast Period.

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 Petitioner's Exhibit No. 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 November 2025, hedges on natural gas represented a cost of $2,678,201. Hedges on natural gas in the month of December 2025 represented a cost of $3,192,348, and in the month of January 2026, hedges on natural gas represented a savings of $12,025,463.

Mr. Dickerson explained that natural gas hedges were transacted through 2023, 2024, and into the latter half of 2025. He explained by that point prices had stabilized after the run-up in 2022. He stated natural gas production has remained at high levels coming into the winter and United States storage inventory reached a peak of 3.95 Tcf, which is near the theoretical max. He explained winter started cold but quickly turned mild up until Winter Storm Fern at the end of January. He testified natural gas prices had declined through the winter as risk premium was eliminated. However, he stated during Winter Storm Fern prices spiked significantly as the cold swept across much of the country setting record lows. He stated as soon as Winter Storm Fern was over, gas prices went back down and have remained below $3/MMBtu in the cash market.

Mr. Dickerson testified regarding the benefits to customers of AES Indiana's long-term hedging program. He explained that AES Indiana 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 AES Indiana'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 AES Indiana's Texas Gas and REX firm capacity can be utilized at the Harding Street Station. He testified this enhances the firm transportation portfolio of AES Indiana 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, AES Indiana 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 overtime 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 AES Indiana. He stated that the cost of gas generation contains the delivered cost of natural gas, including firm transportation costs. He stated AES Indiana 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

AES Indiana's plants and allow AES Indiana to more efficiently reach high supply areas or more heavily traded points. He stated at the same time, AES Indiana looks for opportunities to work with third-party marketers to release capacity where practicable to achieve additional value for AES Indiana's customers, as has been done in previous FACs. He stated to the extent AES Indiana is able to achieve additional monetary value from releasing capacity, such revenues flow through the FAC to offset other fuel costs. He stated AES Indiana recently evaluated multiple options to better manage its transportation portfolio for customers to ensure reliability while also having affordability top of mind. He stated from this analysis, AES Indiana determined that entering into a short-term Asset Management Agreement ("AMA") would be in the best interest of customers. He explained this agreement is meant as a trial run while also allowing AES Indiana to continue to evaluate further enhancements for customers. He stated the AMA will provide needed reliability for customers, while also creating additional opportunities for value creation. He testified there is no cost for the AMA and any value created from this AMA will flow back through the FAC as a direct benefit to customers.

Mr. Dickerson concluded that AES Indiana 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, a 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 regarding AES Indiana's current coal inventory and acknowledged AES Indiana is actively looking at options to address its coal inventory. Mr. Eckert recommended AES Indiana provide an update on its coal inventory and its 2026 projected coal burn and coal purchases in future FAC proceedings.

Mr. Eckert noted that Mr. Dickerson provided the results of AES Indiana's natural gas hedging program and stated additional information was provided during the OUCC's FAC audit. He recommended AES Indiana 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 implementation of AES Indiana's fuel procurement policy covering natural gas hedging policy with AES Indiana. He further testified that he requested and reviewed the daily coal projections and had no concerns with AES Indiana's current coal inventory level.

AES Indiana presented substantial evidence regarding its unit commitment decision-making process that shows AES Indiana 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 AES Indiana support its decision-making. We further find that price risk, reliability, and operational needs are also reasonably factored into AES Indiana'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 AES Indiana'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 AES Indiana to be reasonable. The record shows AES Indiana works to prudently reserve firm transportation capacity to ensure its natural gas-fired units have reliable gas service. The record further shows AES Indiana looks for opportunities to work with third-party marketers to release capacity where practicable to achieve additional value for customers. To the extent AES Indiana is able to achieve additional monetary value from releasing capacity, such revenues flow through the FAC to offset other fuel costs. In addition, the record shows AES Indiana has evaluated multiple options to better manage its transportation portfolio for customers to ensure reliability while also having affordability top of mind, ultimately entering into a short-term AMA. The record shows the AMA will provide needed reliability for customers, there is no cost for the AMA, and any value created from the AMA will flow back through the FAC as a direct benefit to customers.

AES Indiana also presented substantial evidence regarding the results of its natural gas hedging program. The record shows AES Indiana'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 AES Indiana's hedges, and we find AES Indiana's purchased power hedges, including the purchase of natural gas discussed by AES Indiana's Witness Dickerson, to be reasonable; therefore, the Commission finds the incurred gains or losses are reasonable and recoverable through the FAC. AES Indiana shall continue to provide in its next FAC the information the OUCC recommended regarding AES Indiana's hedging program.

Based upon the evidence presented, the Commission finds AES Indiana 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 AES Indiana 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 AES Indiana incurred a total of $3,177,555 of purchased power costs over the applicable Benchmarks during the Historical Period. He stated AES Indiana makes power purchases when economical or due to unit unavailability. Mr. Dickerson testified that consistent with the Purchased Power Order, AES Indiana 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 $395,608 of AES Indiana's purchased power costs for the applicable accounting period is recoverable. However, he stated $393,573 of the purchased power that would normally be deemed unrecoverable occurred on January 24, 2026 when MISO declared emergency conditions impacting both unit dispatch and real-time power prices. He explained AES Indiana received a make whole payment from MISO related to the emergency and is flowing those revenues back to customers in this proceeding. He stated AES Indiana proposes to offset those revenues by the $393,573 in additional purchased power costs so as to avoid penalizing AES Indiana for following MISO's emergency dispatch instructions.

Mr. Dickerson explained that almost all of the purchased power above the benchmark occurred on January 24, 2026. He explained there was $4,505,843 of purchased power, of which $2,904,999 was above the benchmark, on that one day. He testified MISO declared an emergency event in order to import additional power from PJM, causing ripple effects on the market. All of AES Indiana's units were available and following MISO set points. He stated to manage congestion, MISO dispatched AES Indiana's units to their minimums, resulting in the purchased power. He stated as a result of MISO declaring an emergency, it effectively disconnected what the units were seeing in real-time and what MISO settled Locational Marginal Pricing at after the fact. Mr. Dickerson testified that had the units not been dispatched to their minimums at the direction of MISO, AES Indiana would have had sufficient generation to meet its load and purchased power would not have been required.

Mr. Dickerson testified that MISO provided compensation due to the impact of its emergency dispatching of AES Indiana's units. He stated MISO recognizes the impact to the market from its emergency set points and issues price volatility make whole payments to market participants that followed MISO's set points. He testified the price volatility payment to AES Indiana for January 24th was $4,593,269.50, which exceeds the total purchased power cost for that day. He explained this revenue is flowing back to customers in this FAC, reducing the expense that would otherwise be reflected in that line item. He stated that because this revenue results from AES Indiana following MISO's dispatch instructions (which in turn caused AES Indiana to incur purchased power costs), it is reasonable that AES Indiana be permitted to recover the amount of purchased power over the benchmark that would otherwise be considered non-recoverable. The result from AES Indiana's proposal is that neither customers nor AES Indiana are financially harmed for following MISO's set points. In fact, the make whole payment serves to eliminate all of the purchased power costs for this day and provides an additional nearly $90,000 reduction in purchased power costs in this filing.

Mr. Eckert explained the purchased power over the Benchmark treatment is controlled by the Purchased Power Order, and he testified that AES Indiana 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 AES Indiana provided. He noted that AES Indiana proposes to offset make whole payment revenues by $393,573 in additional purchased power costs incurred when MISO declared emergency conditions that impacted unit dispatch and real-time pricing, resulting in only $2,035 in purchased power costs being non-recoverable. He recommended the Commission allow AES Indiana to recover $3,175,520 in purchased power over the benchmark.

The record shows the majority of the purchased power above the benchmark was incurred on a single day and driven by MISO's emergency dispatching of AES Indiana's units. The record further shows that AES Indiana received a price volatility payment from MISO that exceeds the total purchased power cost for that day, and that AES Indiana proposes to flow this revenue back to customers in this FAC. Because the purchased power above the benchmark that would otherwise be considered non-recoverable was driven by MISO's dispatch instructions (thereby causing AES Indiana to incur purchased power costs it would not have otherwise incurred), it is reasonable that AES Indiana be permitted to apply the MISO make whole payment towards the purchased power costs that would otherwise be non-recoverable. The result is that neither AES Indiana nor its customers are financially harmed for following MISO's dispatch instructions and, in fact, AES Indiana's customers will receive a reduction in purchased power costs in this filing. Based on the evidence, we find AES Indiana's identified purchased power costs were reasonable under the circumstances at the time of the purchases and are approved.

4. MISO Market Related Activity. Mr. Dickerson testified that AES Indiana'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 AES Indiana 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"), AES Indiana 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, AES Indiana 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 AES Indiana'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 AES Indiana'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 Petitioner's Exhibit No. 2, Attachment AD-1.

Mr. Eckert testified that AES Indiana'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 AES Indiana'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 AES Indiana's recovery of RSG Payments is consistent with the June 3, 2009 Order in Cause No. 43664 and is approved.

5. Operating Expenses. 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 that Petitioner's Exhibit

No. 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 AES Indiana did not have decreases in other operating costs that could be used to offset fuel cost increases.

Based on the evidence, the Commission finds AES Indiana'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. Return Earned. 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 Petitioner's Exhibit No. 1, Attachments NHC-3 and NHC-4, which calculate the Ind. Code § 8-1-2-42(d)(3) test, show AES Indiana's actual return for the 12 months ending January 31, 2026. She stated that AES Indiana's actual return was more than its authorized return for the 12 months ending January 31, 2026; 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(d)(3) is satisfied.

Mr. Guerrettaz agreed AES Indiana had jurisdictional net operating income (for the 12 months ending January 31, 2026) greater than the prorated allowed return as adjusted for various applicable trackers. He stated because the sum of differentials for the relevant period is a negative $384,445,000 no adjustment to the factor is recommended.

Upon consideration of the evidence, the Commission finds AES Indiana has properly determined the authorized operating income for the 12 months ending January 31, 2026. Thus, as reflected in Petitioner's Exhibit No. 1, Attachment NHC-3, AES Indiana has an authorized return of $306,283,000 for purposes of this proceeding. Attachment NHC-2 to Petitioner's Exhibit No. 1 (lines 12-14) calculates the Ind. Code § 8-1-2-42(d)(3) test, which shows that AES Indiana's actual return for the 12 months ending January 31, 2026, was $324,957,000. However, as shown on Attachment NHC-4 to Petitioner's Exhibit No. 1, the sum of differentials for the relevant period is less than zero. Therefore, the Commission finds that during the 12-month period ending January 31, 2026, AES Indiana has satisfied the statutory requirements of Ind. Code § 8-1-2-42(d)(3).

7. Estimating Techniques. 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 Petitioner's Exhibit No. 1, Attachment NHC-1, Schedule 5, page 4 of 4, AES Indiana's weighted average deviation between forecast and actual fuel costs was an underestimate of 12.09% for the Historical Period.

Mr. Dickerson stated November 2025, December 2025, and January 2026 deviations of actual to forecast F/S were (3.13)%, 3.32%, and (26.21)%, respectively. He stated November, December, and January saw lower than forecast generation from coal, and for November and December higher than forecast generation from natural gas. He explained gas prices for November realized roughly $0.50 lower while December was roughly $0.60 higher. The lower November prices meant more gas generation than forecast and more fuel expense resulting in a higher than forecast F/S. He stated December had higher natural gas prices and higher gas generation, but this increase was offset by lower coal generation and coal fuel expense than forecast which created the decrease in F/S. He stated January had higher than forecasted natural gas prices due to Winter Storm Fern; prior to the storm prices were moderate but the impact of the storm increased gas prices to levels to near and exceeding $50/MMBtu in some cases. He testified AES Indiana's hedging program saved customers almost $17 million during Winter Storm Fern, and the access to Rockies from the additional REX transportation capacity taken out in April 2025 saved an additional $10.5 million for customers.

Mr. Dickerson compared the forecasted natural gas costs for the Historical Period to realized Henry Hub values. He stated the November 2025, December 2025, and January 2026 Indianapolis temperature variance from normal were +0.7 degrees, -1.2 degrees, and -3.5 degrees, respectively.

Mr. Guerrettaz stated the OUCC performed a detailed review of AES Indiana'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) AES Indiana'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 does not oppose AES Indiana's proposed projected Fuel ÷ Sales of 40.113 mills per kWh.

Based upon the evidence, we find AES Indiana'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 AES Indiana'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 lower than the level of curtailments experienced during the Historical Period covered by the last FAC and 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 AES Indiana 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 AES Indiana'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 Petitioner's Exhibit No. 1, Attachment NHC-1, Schedule 1, AES Indiana's total estimated cost of fuel for the Forecast Period is $148,689,744, and its total estimated sales are 3,706,780 kWh. AES Indiana's estimated cost of fuel, after taking into consideration the proposed reconciliation component, is $0.003983 per kWh.

Ms. Coklow discussed how the FAC factor was calculated. She explained that as shown on Schedule 1, line 31 of Attachment NHC-1 to Petitioner's Exhibit No. 1, AES Indiana is proposing to spread the current period variances (Historical Period) over two FAC periods in an effort to lower the proposed FAC factor. She stated the majority of the variances driving the factor increase occurred in January 2026 during an extended period of very low temperatures. She stated the impact of spreading the variances over two FAC periods is a reduction in the proposed FAC factor of ($0.002898) per kWh.

As shown on Schedule 1 of Attachment NHC-1 to Petitioner's Exhibit No. 1, after taking into consideration the reconciliation of AES Indiana's estimated and actual fuel costs, AES Indiana's estimated average cost of fuel for the Forecast Period is $0.043010 per kWh. As shown on Schedule 1 of Attachment NHC-1 to Petitioner's Exhibit No. 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 $0.003983 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 $9.52 or 7.26% for a residential customer using 1,000 kWh per month.

OUCC Witness Eckert recommended the Commission approve the proposed fuel cost factor, including spreading the variance over two periods, as calculated by OUCC Witness Guerrettaz.

The record shows the parties agree on the proposed fuel factor of $0.003983 per kWh. Substantial record evidence supports AES Indiana's proposed fuel factor, including its proposal to spread the current period variances over two FAC periods, 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 March 20, 2026, AES Indiana 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 March 31, 2026, 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. AES Indiana's proposed fuel factor set forth herein is approved.

2. Prior to implementing the approved rate, AES Indiana 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. AES Indiana 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 AES Indiana's FAC.

4. In its next FAC filing, AES Indiana 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 AES Indiana'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.

ZAY, DEIG, SWINGER, VELETA, AND ZIEGNER CONCUR:

APPROVED: MAY 27 2026

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

Virginia Lucas Digitally signed by Virginia Lucas
Date: 2026.05.27 10:35:06 -04'00'
_____ on behalf of

Dana Kosco
Secretary of the Commission