Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda			√
Ober	√	√	
Ziegner	√		

ORIGINAL

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 DECEMBER 2021 THROUGH FEBRUARY 2022, IN ACCORDANCE WITH THE PROVISIONS OF I.C. 8-1-2-42, AND CONTINUED USE OF RATEMAKING TREATMENT FOR COSTS OF WIND POWER PURCHASES PURSUANT TO CAUSE NOS. 43485 AND 43740, AND APPROVAL OF A FUEL HEDGING PLAN AND AUTHORITY TO RECOVER COSTS OF THE FUEL HEDGING PLAN PURSUANT TO I.C. 8-1-2-42.

CAUSE NO. 38703 FAC 133

APPROVED: NOV 24 2021

ORDER OF THE COMMISSION

Presiding Officers:
James E. Huston, Chairman
Stefanie Krevda, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

On September 17, 2021, Indianapolis Power & Light Company d/b/a AES Indiana ("Applicant") 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 December 2021 through February 2022 (the "Forecast Period"); (2) the continued use of ratemaking treatment for the cost of wind power purchases pursuant to Cause Nos. 43485 and 43740; and (3) a fuel hedging plan and authority to recover costs of the fuel hedging plan.[1] On September 17, 2021, Applicant also filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information, which was granted on a preliminary basis by the Presiding Officers in a Docket Entry on September 28, 2021.

On October 21, 2021, a Technical Conference was held at 9:30 a.m. in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Applicant and the OUCC appeared and participated in the Technical Conference by counsel.

On October 22, 2021, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its report and direct testimony.

[1] Applicant filed revisions to its direct testimony and attachments on November 1, 2021.

Also, on October 22, 2021, Citizens Action Coalition of Indiana Inc. ("CAC") filed a Petition to Intervene, which was granted by Docket Entry on November 1, 2021.

On October 25, 2021, the OUCC filed a motion to establish a subdocket to further consider the extended outage of the Eagle Valley Combined-Cycle Gas Turbine ("CCGT") and its associated impacts. On November 2, 2021, Applicant filed a response and stated it did not object to the motion. On November 2, 2021, Applicant also filed its rebuttal testimony.

On November 3, 2021, the Commission issued a Docket Entry requesting additional information from Applicant. Applicant responded on November 9, 2021.

The Commission set this matter for an Evidentiary Hearing to be held at 1:30 p.m. on November 12, 2021, in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, Applicant, the OUCC, and the CAC appeared and participated in the Evidentiary Hearing by counsel. The testimony and exhibits of Applicant and the OUCC as well as Applicant's response to the Commission's docket entry were admitted without objection.

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

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 and 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. Applicant's Characteristics. Applicant is an electric generating utility and a corporation organized and existing under the laws of Indiana 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 service to the public.

3. Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost. 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 except with respect to the matters subject to review in the subdocket established below.

David Jackson, Director, Commercial Operations, AES US Services, LLC explained Applicant's participation in 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 May 2021 through July 2021 (the "Historical Period"). Mr. Jackson also testified about the benefits to customers of Applicant's participation in MISO, where resources are centrally dispatched by MISO using simultaneous co-optimization.

Mr. Jackson supported Applicant's purchases of coal, fuel oil, and natural gas for use in its generating stations. He testified that Harding Street and Petersburg manage their fuel oil purchases based on inventory set-points. He explained that Applicant currently has contracts with four coal producers and receives coal from up to six different mines. Mr. Jackson stated that Applicant verifies the reasonableness of its coal cost by using a competitive bidding process to award its coal contracts. Mr. Jackson 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 that 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. Jackson also testified regarding Applicant's unit commitment process. He said generally, 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 re-start the unit is also considered. Additionally, he said Applicant considers reliability, price certainty from running generation, and opportunities from participating in both Day Ahead and Real Time energy markets. He testified that during seasonal periods (summer and winter) with historical high market prices and potential high load, Applicant would maintain 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. Jackson testified the decision to offer a unit considers a wide range of factors. He said 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 said 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. Jackson testified that the focus in a prudence inquiry is not whether a given decision or action produced a favorable or unfavorable result, but rather: (1) whether the process leading to the decision or action was a logical one; (2) whether the utility company used good judgment and applied appropriate standards; and (3) whether the utility reasonably relied on information and planning techniques known at the time. He concluded 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. Jackson summarized the commitment status of the Petersburg Units during the Historical Period. He explained Petersburg Units 1, 2, and 3 were in must run status early in the Historical Period at the request of Transmission Operations Control Center for system reliability. He stated Petersburg Unit 4 was in planned outage entering the period until the end of May. Mr. Jackson testified Petersburg Unit 1 retired on May 31, 2021. He stated during the balance of the Historical Period, Petersburg Units 2, 3, and 4 were offered as economic except when the units were in outage or returning from outage.

Mr. Jackson 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 informs its decision-making on a going forward basis and supports Applicant's ongoing effort to improve its modeling and decision process.

Mr. Jackson testified that Applicant considers both the long-term and short-term when making unit commitment decisions. He said 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 said 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 said 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 said Applicant is continuing to improve its understanding of market conditions and costs associated with must run and other unit commitment decisions.

Mr. Jackson also updated the Commission on the short-term model Applicant implemented to support and track the Petersburg unit commitment decisions. He said the model utilizes a combination of two types of trades to calculate the operating cost and potential margin for the Petersburg coal units. He discussed how the model works, the inputs into the model, and additional considerations Applicant has chosen to apply to the model. He said 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 is in or out of the money. He said Applicant began using the model at the end of May 2020 and continues to use the model to support commitment decisions. He said Applicant will include model output from the Historical Period in the OUCC packet for review and will review the model and output with the OUCC during the audit.

Mr. Jackson also provided an update on Applicant's 2021 projected coal burn and coal purchases. He stated Applicant purchased coal for 2022 in July, has issued a request for proposals, and plans to make additional purchases in September 2021 to meet hedge targets through 2024. He said burns for summer have remained strong and current inventory is within the target range. Mr. Jackson provided Confidential Attachment DJ-4, which shows the realized and projected monthly purchases and burns for 2021.

Mr. Jackson stated that although Applicant's inventory is currently within its target range, 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 said this allows Applicant to increase deliveries when coal burns go up and 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. However, he said this contract variability is limited and may not alone be sufficient to follow highly volatile coal demands. He explained that if coal demand were to change dramatically, Applicant would look to defer, delay, or leave certain open positions unfilled in a rapidly declining market, while looking to buy additional coal supplies in an upwardly moving market.

Mr. Jackson testified Applicant did not use coal decrement pricing during the Historical Period. He further stated there is no decrement pricing in the Forecast Period.

Mr. Jackson discussed the peak power transactions Applicant engaged in as a result of the Eagle Valley CCGT outage, explained the process used to determine the appropriate volume of the power hedges, the facts and circumstances as they existed at the time the transaction was entered, the value of the Eagle Valley CCGT peak power hedge as compared to realized daily pricing and the factors that impacted this value. Mr. Jackson said Applicant's Exhibit 1, Attachment NHC-1, Schedule 5, Line 20 separately identifies the realized gains or losses from the financial hedges. He said there were no transaction costs associated with these hedge transactions. He explained for the Historical Period, the peak power purchased realized gains of $758,807 for the month of June 2021 and $832,168 for the month of July 2021. He stated these gains benefitted the customer by offsetting the cost of purchased power during the corresponding periods of this FAC and reflect the risk reduction targeted by entering into the power hedges – locking in a fixed price for megawatt hour corresponding to the hedges.

Mr. Jackson also testified Applicant did not engage in natural gas hedging for the CCGT facility during the Historical Period due to the Eagle Valley CCGT outage. He stated Applicant also did not transact any financial hedges for the Eagle Valley CCGT during the Historical Period.

Mr. Jackson provided an update on Applicant's fuel hedging policy. He said the policy incorporates an integrated approach to fuel hedges of coal for Petersburg Station and fixed priced natural gas hedging for the Eagle Valley CCGT. Mr. Jackson testified that the policy presents hedge target matrixes for coal and natural gas that Applicant will follow to secure specified hedge percentages. He said the hedges will safeguard customers against price volatility associated with the coal and natural gas markets. He said unlike the natural gas hedging program introduced in Cause No. 38703 FAC 122, Applicant will act programmatically to complete hedges to insure specified hedge percentages are fulfilled. He added that natural gas hedge volumes will vary by season to protect volatility in high demand periods. Mr. Jackson stated other customer benefits associated with Applicant's hedge policy include: (a) improved reliability of natural gas fuel supply and the mitigation of scarcity risk in the winter months; (b) opportunities to capture locational value opportunities, which lower fuel costs versus Henry Hub pricing; (c) preservation of contracted firm pipeline transportation to support Applicant's natural gas peaker fleet; and (d) reduced need to purchase all natural gas requirements in the day-ahead and real-time natural gas markets, which reduces the risk of volume-based pricing. He also discussed the trading instruments Applicant will use for natural gas hedging, how Applicant will implement the natural gas hedges in the fuel hedging policy, and how the hedge policy impacts coal hedges. Mr. Jackson described the internal approval and oversight process Applicant will use to manage the hedging policy.

Mr. Jackson stated Applicant seeks approval from the Commission to be able to pass all hedging gains and losses, including any associated transactional costs, through Applicant's FAC. He explained, for physical contracts, the fuel cost is seen as a realized cost of fuel, rather than a financial settlement. He stated because the hedging plan is undertaken for the benefit of customers, the associated costs are appropriately passed to the customer. Mr. Jackson said specific hedging transactions will be subject to review in subsequent FACs to confirm Applicant is following the hedging policy. Mr. Jackson also explained how the hedges will be reflected in Applicant's FAC filings and discussed the supporting documentation that will be included in its standard audit package for the OUCC. Mr. Jackson testified that Applicant will review hedging performance quarterly to verify the hedges are mitigating coal and natural gas price risk as anticipated and will update the Commission and the OUCC on any changes to the hedging policy through future FAC filings. Mr. Jackson stated that Applicant's hedge policy is a reasonable means of mitigating natural gas price volatility risk.

Mr. Jackson concluded that, in his opinion, Applicant has 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.

Natalie Herr Coklow, Manager in Regulatory Accounting at AES U.S. Services, LLC, testified that there were two financial hedges settled during the Historical Period, but Applicant did not incur any transactional fees associated with these hedge transactions. She noted that physical hedges do not receive market-to-market accounting treatment and thus there are no recognized gains or losses on physical hedges.

Michael D. Eckert, Assistant Director of the OUCC Electric Division, presented Attachment MDE-3, a timeline of Applicant's coal contracts, showing contract expiration dates by coal mine. He provided an update on the status of the Petersburg Units and when they were last called on by MISO to produce power. He testified that Applicant's current coal inventory is within Applicant's target levels, and Applicant is actively looking at options to address its coal inventory. OUCC witness Gregory T. Guerrettaz noted that Applicant expressed concerns during the audit regarding the decreases in coal inventory level and the challenges of coal transportation. Mr. Eckert recommended Applicant update the Commission on its coal inventory and its 2021 projected coal burn and coal purchases in future FAC proceedings.

Mr. Eckert testified Applicant provided the results of its natural gas hedging program in Mr. Jackson's testimony and at the FAC audit, and Applicant did not transact any financial hedges during the Historical Period. He testified the OUCC reviewed and does not oppose Applicant's revisions to its natural gas hedging program. He recommended Applicant continue to file the results of its natural gas hedging program in each subsequent FAC, provide analysis of the facts and circumstances existing when the transactions were entered, and provide revised hedging program information to the Commission if a revision occurs.

Mr. Eckert also discussed Applicant's purchased power hedge and stated that the OUCC does not oppose the power hedges.

Applicant presented substantial evidence regarding its unit commitment decision making process, which shows Applicant considers both short-term and long-term vantage points. The record also shows Applicant has worked to improve its short-term decision making and documentation of expected market prices at the time decisions are made. While economics do not capture all the reasons for unit commitment, we continue to find the modeling will help Applicant support its decision making and should allow Applicant to improve its process on a going forward basis. We 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, which require 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.

In addition, as recommended by the OUCC, we direct Applicant to update the Commission on how it proposes to address its coal inventory and on its 2021-2022 projected coal burn and coal purchases in its next FAC.

Applicant also presented substantial evidence regarding its natural gas hedging program, its updated fuel hedging policy, and the peak power hedges Applicant engaged in because of the Eagle Valley CCGT outage. Applicant seeks to pass all hedging gains and losses, including any associated transactional costs, through Applicant's FAC. The OUCC after review, did not oppose the revisions. The Commission has reviewed the changes and, after consideration of the evidence in record, the Commission finds Applicant's hedging program, including the updated fuel hedging policy and the peak power hedges to be reasonable. We approve Applicant's updated fuel hedging policy. Therefore, the Commission grants Applicant's request to pass all hedging gains and losses, including any associated transactional costs, through Applicant's FAC. Applicant shall also provide in its next FAC the information recommended by the OUCC regarding Applicant's hedging program.

Based upon the evidence presented and except with respect to the matters subject to review in the subdocket established below, 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.

4. Eagle Valley CCGT Outage. Mr. John Bigalbal, Chief Operating Officer, US Conventional Generation at AES US Services, LLC, discussed the forced outage at the Eagle Valley CCGT plant that began on April 25, 2021, the steps taken by Applicant to mitigate the duration of the outage and return the unit to service, the root cause analysis ("RCA"), and the actions taken by Applicant in response to the RCA. Mr. Bigalbal described the events that led to the outage and discussed the expected length of the outage. He stated that Applicant will continue to report on the status of the CCGT in the Applicant's next FAC filing, which will be made in December 2021.

Mr. Bigalbal sponsored a copy of the RCA in Applicant's Exhibit 3, Attachment JB-1. He discussed the purpose of the RCA and its findings, which determined the incident was caused by a variety of factors including physical, human, and latent. He summarized the recommended corrective actions from the RCA and provided Applicant's status on implementation. Mr. Bigalbal identified the repair capital expenditures and the operation and maintenance expenses. However, he explained that such costs are not recoverable through the FAC process and therefore are not part of this FAC application.

Mr. Bigalbal stated that Eagle Valley has operated as a baseload unit and has provided low-cost generation to its customers and added that its historic availability and heat rate indicate solid performance prior to this outage. He explained that the RCA summarizes the event after the fact and outside of the plant environment and makes assessments in hindsight. He said all plant personnel received training on the entire facility, including specific training provided by Toshiba on the steam turbine-generator and its systems. He testified that this event was caused by a disconnected wire that provided a false indication to the control system. He said there are several control system issues that came into question leading up to the event that ultimately caused the extended forced outage. Mr. Bigalbal stated that while Applicant is proactively implementing the RCA recommendations, the improvement opportunities suggested in an RCA should not lead to a conclusion that Applicant acted imprudently. He said Applicant also took appropriate steps to mitigate the duration and costs of the outage.

Mr. Jackson testified that Eagle Valley CCGT was in forced outage for the entire Historical Period. He said Applicant incurred purchased power costs over the benchmark of $1,198,183 during the Historical Period. He said the portion of purchased power above the benchmark that could be attributable to the Eagle Valley outage was $1,108,511. Mr. Jackson also testified that due to rising natural gas prices during the Historical Period, had Eagle Valley CCGT been operational, natural gas as a fuel cost would have been significantly higher than forecast and purchased power through MISO would have been significantly lower than forecast. Mr. Jackson discussed the benefit of the peak power hedges. He also explained that the forced outage had no impact on the Forecast Period because Eagle Valley is expected to be available during the entire Forecast Period of December 2021 through February 2022.

Mr. Eckert testified the Eagle Valley CCGT outage impacted, or will impact, portions of FAC 132, 133, 134, and 135. He described Applicant's responses to the OUCC's discovery inquiries about insurance claims and proceeds, settlement discussions, manufacturer's warranties, and engineering, procurement, and construction contractor warranties, and whether warranties and insurance applied to replacement power in this proceeding. He testified the OUCC has not had enough time to thoroughly review Applicant's discovery responses, the RCA, and the information provided in the Commission's October 21, 2021 Technical Conference. He noted that Applicant has not concluded its analysis of the Eagle Valley CCGT outage, explaining that at the October 21, 2021 Technical Conference, Applicant indicated they still need to have discussions with different parties in this proceeding, including discussions with Toshiba about system logic functions. Mr. Eckert added that only three of the nine items and recommendations included in Applicant's presentation at the Technical Conference were fully completed as of the date of the Technical Conference.

Mr. Eckert testified the OUCC believes it is too early for the Commission to make a finding at this time regarding whether Applicant acted prudently. Consequently, he recommended the Commission create a subdocket to allow more detailed examination of costs and issues associated with the Eagle Valley CCGT outage. Further, he stated, the OUCC recommends the Commission allow Applicant to recover, interim subject to refund, its total purchased power over the benchmark in the amount of $1,198,183.

In rebuttal, Mr. Bigalbal testified Applicant agrees with Mr. Eckert's recommendation regarding the subdocket and his recommendation that the Commission make the rates in this Cause interim subject to refund, pending final resolution in a subdocket of the recoverability of the $1,198,183 in purchased power over the benchmark. Mr. Bigalbal stated that Applicant will work with the OUCC on the scope and a procedural schedule for the subdocket to take place once additional information on the matters identified by the OUCC becomes available.

As indicated above, Applicant did not object to the OUCC's motion to establish a subdocket. The Commission has previously found creation of a subdocket is appropriate where summary FAC proceedings do not lend themselves to sufficient record development. *Application of Duke Energy Ind., LLC*, Cause No. 38707 FAC 111, 2017 WL 1632308, at *8 (IURC April 26, 2017). We agree with the OUCC that, based on the facts in this circumstance, such a review of the Eagle Valley CCGT forced outage discussed above is best accomplished outside the statutory time constraints of the FAC summary proceeding. Accordingly, the Commission finds a subdocket should be created in this proceeding to examine the impact of the Eagle Valley CCGT extended outage on fuel costs, and the recovery of such fuel costs herein are interim subject to refund pending the outcome of such subdocket.

5. <u>MISO Market Related Activity</u>. Mr. Jackson testified that Applicant's proposed recovery 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. Jackson described the MISO costs and revenues Applicant is seeking to recover in this 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, 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. Jackson 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. Jackson presented the RSG Daily Benchmarks in Attachment DJ-1 to Applicant's Exhibit 2.

Mr. Eckert testified that Applicant's proposed ratemaking treatment for the ASM charge types follows the treatment ordered in the Commission's 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, FAC 85 Order, and FAC 97 Order, and is approved. The Commission further finds Applicant's recovery of RSG Charges is consistent with the RSG Order and is approved.

6. Purchased Power Costs Above Benchmark. 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. Jackson 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 ("NYMEX") Henry Hub, plus a $0.60/MMBtu gas transport charge for a generic gas-fired GT (together, the "Benchmark"). He explained that Applicant continues to follow the guidelines and procedures established in the Purchased Power Order. He stated that 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. Jackson testified Applicant incurred a total of $1,198,183 of purchased power costs over the applicable Benchmarks during the Historical Period. He said Applicant makes power purchases when economical or due to unit unavailability. He explained most of the purchased power over Benchmark occurred in three periods when baseload generation was unavailable. Mr. Jackson 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. Applicant summarized the purchased power volumes, costs, total of hourly purchased power costs above the applicable Benchmarks during the Historical Period, and the reasons for the purchases at-risk after consideration of MISO's economic dispatch. Applicant's Exhibit 2, Attachment DJ-2. Mr. Jackson testified that utilizing the methodology approved in the Purchased Power Order, no amount of the purchased power is non-recoverable during the applicable accounting period. Therefore, Applicant seeks to recover $1,198,183 of purchased power costs over the applicable Benchmarks for the Historical Period. Mr. Jackson testified these total purchased power costs during the Historical Period are reasonable.

Mr. Eckert explained the purchased power over the Benchmark treatment is controlled by the Purchased Power Order and Applicant followed the guidelines and procedures established in that Order. He stated the OUCC calculated the same amount of purchased power over the Benchmark as Applicant. He further testified that while he determined Applicant performed the calculation correctly, the OUCC is concerned that Applicant did not determine if the CCGT outage was a result of "imprudence, malfeasance, nonfeasance, or other inappropriate acts" in accordance with the Purchased Power Order. He stated therefore, the OUCC recommends that final resolution of the recoverability of the $1,198,183 in purchased power over the Benchmark be deferred to the subdocket.

On rebuttal, Mr. Bigalbal stated that Applicant calculates the amount purchased above the Benchmark attributable to the CCGT outage is $1,108,511. He also said Applicant agrees to Mr. Eckert's recommendation that the Commission make the rates in this Cause interim subject to refund, pending final resolution in a subdocket of the recoverability of the $1,198,183 in purchased power over the Benchmark. As stated above, we agree with the OUCC that the subdocket will allow more time for examination of fuel costs associated with the Eagle Valley CCGT outage, and further find that the recoverability of the $1,198,183 in purchased power over the Benchmark is approved on an interim basis, subject to refund, pending final resolution in the subdocket.

7. Operating Expenses. Ind. Code § 8-1-2-42(d)(2) requires the Commission to find that the utility's actual increases 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. Ms. Coklow testified that Applicant's Exhibit 1, Attachment NHC-2 calculates the (d)(2) test, showing total jurisdictional operating expenses excluding fuel costs have increased. Gregory T. Guerrettaz, CPA, on behalf of the OUCC, agreed Applicant did not have decreases in other operating costs that could be used to offset fuel cost increases. Based on the evidence in the record, 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).

8. <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 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, Attachment NHC-2, which calculates the (d)(3) test, shows Applicant's actual return for the 12 months ending July 31, 2021. She stated that Applicant's actual return is less than its authorized return for the 12 months ending July 31, 2021. Mr. Guerrettaz agreed Applicant had jurisdictional net operating income (for the 12 months ending July 31, 2021) less than that granted in its last general rate proceeding, as adjusted for applicable Environmental Cost Recovery and Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") proceedings. He reviewed the sum of differentials for the relevant period and, like Ms. Coklow, made no adjustment to the filing as a result of the earnings test.

Upon consideration of the evidence of record, the Commission finds Applicant has properly determined the authorized operating income for the 12 months ending July 31, 2021, and properly reflected the return on its Qualified Pollution Control Property and TDSIC Property. Thus, as reflected in Attachment NHC-2, Applicant has an authorized return of $223,889,000 for purposes of this proceeding. Attachment NHC-2, which calculates the (d)(3) test, shows that Applicant's actual return for the 12 months ending July 31, 2021, was $219,585,000. Therefore, the Commission finds that during the 12-month period ending July 31, 2021, Applicant did not earn a return in excess of its authorized return in compliance with the statutory requirements of Ind. Code § 8-1-2-42(d)(3).

9. <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, page 4 of 4, Applicant's weighted average deviation between forecast and actual fuel cost was a negative 13.22% for the Historical Period. Mr. Jackson stated the two largest drivers of the variance were the increase in natural gas prices and the Eagle Valley CCGT forced outage. Mr. Jackson said during the Historical Period, NYMEX natural gas prices increased from $2.86/MMBtu on May 3rd to $4.02/MMBtu on July 30th. He explained the increase in natural gas price impacted generation costs at Harding Street and Georgetown units and elevated market prices of purchase power. He said during the Historical Period, weather was variable, and the monthly temperatures realized were lower than normal in May, higher than normal in June, and lower than normal in July. He explained the key drivers of the natural gas price increase were strong demand from the power generation sector due to record heat, especially in the western United States, liquified natural gas export demand, static natural gas production, and concern over the slow pace of natural gas injections to build inventory for the coming winter.

Mr. Guerrettaz stated the OUCC did a detailed review of Applicant's estimation model and noted the forecast had the following items affecting it: (1) the daily material changes of the price of natural gas; (2) the daily changes of power prices for the MISO market; (3) recent hedges put into place after the filing of this FAC; and (4) Applicant's coal inventory issue going into the winter. Mr. Guerrettaz stated that in light the four items above, the OUCC finds the forecast does not need to be updated and it is acceptable at this time.

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.

10. Wind Power Purchase Agreements and Renewable Energy Credits. Mr. Jackson testified that purchases from the Hoosier Wind Park ("Hoosier") and Lakefield Wind Park ("Lakefield") are included in Applicant's actual and projected fuel costs. He discussed the amount of power received from Hoosier and Lakefield during the Historical Period. Pursuant to the Order in Cause No. 43740, Applicant is reflecting credits to jurisdictional fuel costs for Off-System Sales profits made possible because of the energy received from the power purchase agreement ("PPA") with Lakefield.

Mr. Jackson said Hoosier and Lakefield are both Dispatchable Intermittent Resources 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 but there were no billable curtailments at Hoosier for this FAC period. He said the level of curtailments at Lakefield were lower than the level of curtailments experienced during the time period covered by FAC 132, and slightly higher than the time period experienced one year ago for FAC 129.

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

In Cause Nos. 43485 and 43740, the Commission approved Applicant's request to recover the purchased power costs incurred under the Hoosier and Lakefield PPAs over their respective full 20-year terms. 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.

11. 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 $127,245,019, and its total estimated sales are 3,679,432 kWh. Applicant's estimated cost of fuel is $0.034583 per kWh. The evidence of record indicates Applicant reconciled the actual fuel costs and revenues for the Historical Period. Reconciliation of actual fuel costs and revenues results in a total variance of $13,683,623. As explained by Ms. Coklow, Applicant proposes to spread this total over two FAC filings, with $6,841,811 being included in this FAC and in FAC 134. In addition, Applicant has included the remaining fifty percent of the fuel cost variance from FAC 132, which totals $6,493,724. Dividing the combined variance amount of $13,335,535 by the total estimated jurisdictional sales of 3,679,432 kWh results in a variance factor of $0.003624 per kWh. Combining the variance factor with the estimated per kWh cost of fuel, subtracting the base cost of fuel and adjusting for Indiana Utility Receipts Tax, results in a proposed fuel factor of $0.005350 per kWh for the Forecast Period's billing cycles.

OUCC witness Guerrettaz testified the OUCC recommends the same FAC factor as Applicant that has been recalculated and confirmed.

The Commission approves the proposed fuel factor of $0.005350. 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. As a result of the approved fuel cost factor, the typical residential customer using 1,000 kWh per month will experience an increase of $5.39 or 4.66% on his or her electric bill as compared to the factor currently in effect.

12. Confidential Information. On September 17, 2021, Applicant filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information in this Cause, which was supported by affidavits from Mr. Jackson and Mr. Bigalbal showing 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. In a September 28, 2021 Docket Entry, the Presiding Officers found 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 fuel cost factor set forth at Finding Paragraph No. 11 above is approved on an interim, subject to refund basis pending further review in the subdocket established herein.

2. Applicant shall update the Commission on how it proposes to address its coal inventory and its 2021-2022 projected coal burn and coal purchases.

3. Applicant's hedging program, including its updated hedging policy, and its request for authority to recover costs of the fuel hedging plan are approved.

4. Applicant's ratemaking treatment for the cost of wind power purchases pursuant to the Commission's Orders in Cause Nos. 43485 and 43740 is approved.

5. 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.

6. The OUCC's motion for a subdocket proceeding is granted, with said proceedings to be filed under Cause No. 38703 FAC 133 S1. In lieu of scheduling a prehearing conference in the subdocket, the parties are directed to confer and provide an agreed upon procedural schedule for the subdocket and file it in the subdocket by January 10, 2022. To the extent the parties are not able to reach agreement on a procedural schedule by this date, the parties shall notify the Commission and an attorneys' conference will be convened so that a schedule may be established in a timely manner.

7. 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.

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

HUSTON, FREEMAN, AND ZIEGNER CONCUR; OBER CONCURRING IN PART AND DISSENTING IN PART; KREVDA ABSENT:

APPROVED: NOV 24 2021

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: 2021.11.24 10:17:34 -05'00'

Dana Kosco
Secretary of the Commission