ORIGINAL

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

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF INDIANAPOLIS POWER & LIGHT COMPANY FOR APPROVAL OF A FUEL COST FACTOR FOR ELECTRIC SERVICE DURING THE BILLING MONTHS OF JUNE THROUGH AUGUST 2020, 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 NOS. 43485 AND 43740.	)	**CAUSE NO. 38703 FAC 127** **APPROVED:** JUN 03 2020

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Stefanie N. Krevda, Commissioner
Lora L. Manion, Administrative Law Judge

On March 17, 2020, Indianapolis Power & Light Company ("Applicant" or "IPL") filed its Verified Application, direct testimony, and attachments with the Indiana Utility Regulatory Commission ("Commission") for approval of a fuel adjustment charge ("FAC") to be applicable during the billing cycles of June 2020 through August 2020 and of the continued use of ratemaking treatment for cost of wind power purchases pursuant to Cause Nos. 43485 and 43740.

On April 1, 2020, the Presiding Officers established the procedural schedule in this Cause, and Sierra Club filed its petition to intervene. On April 7, 2020, Applicant filed its objection to Sierra Club's intervention, to which Sierra Club replied on April 13, 2020. On April 16, 2020, the Presiding Officers granted Sierra Club's petition to intervene and instructed Sierra Club to only address fuel costs in its prefiled testimony as provided for in Ind. Code § 8-1-2-42(d).

On April 21, 2020, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its direct testimony. Also on April 21, 2020, Sierra Club filed its direct testimony. On May 11, 2020, Applicant filed rebuttal testimony.

Sierra Club filed a Motion for Subdocket on May 14, 2020, and agreed to take the case as it exists as of the date of intervention. The OUCC, referencing its position as an auditor by statute on FAC cases, filed a Joinder to Sierra Club's Motion for Subdocket on May 14, 2020.

Applicant filed its response in objection to the Motion for Subdocket on May 15, 2020, and Sierra Club filed its reply on May 18, 2020.

The Commission set this matter for an Evidentiary Hearing to be held at 10:00 a.m. on May 18, 2020, in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana. A Docket Entry was issued on May 13, 2020 advising that, in accordance with Indiana Governor Holcomb's Executive Orders concerning the COVID-19 pandemic, the hearing would be conducted via teleconference and providing related participation information. Applicant, the OUCC, and Sierra Club participated in the Evidentiary Hearing by counsel via teleconference. The testimony and exhibits of Applicant, the OUCC, and Sierra Club were admitted without objection.

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

1. <u>Notice and Jurisdiction</u>. 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. <u>Applicant's Characteristics</u>. 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. AES US Services, LLC is owned by The AES Corporation, an international power company.

3. <u>Source of Fuel</u>. Applicant must comply with the statutory requirements of Ind. Code § 8-l-2-42(d)(1) by making every reasonable effort to acquire fuel and generate or purchase power, or both, so as 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>Applicant Evidence</u>. David Jackson, Director, Commercial Operations, AES US Services, LLC, 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 period June through August 2020, the true-up of fuel related MISO costs and revenues for the period of November 2019 through January 2020, and 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 eight different mines. Mr. Jackson explained 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 that while Applicant currently has no spot coal contracts, Applicant has used spot purchases of coal in the past 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 explained that Applicant is currently within its 25-50 day supply of coal inventory target range. He stated that although Applicant's inventory is currently within its target range, Applicant continues to manage actively its inventory levels. He noted that Applicant's long-term coal contracts often contain some variability in the quantity of coal that Applicant can take under that particular contract, which allows Applicant to increase deliveries when coal burns go up and decrease deliveries when coal burns go down. He said this contract variability is essential in managing the month-to-month variations in coal burns due to weather, market prices, and unit availability. He added that 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. Applicant would look to buy additional coal supplies in an upwardly moving market.

Mr. Jackson also supported Applicant's request to recover certain costs incurred from taking transmission service under the MISO Open Access Transmission and Energy Markets Tariff and participating in the MISO Day-Ahead, Real-Time Energy, Financial Transmission Rights Markets, and the Energy and Operating Reserves Markets. Mr. Jackson discussed the benefits to customers of Applicant's participation in the MISO Energy and Operating Reserves Market. He also described Applicant's wind purchases. Mr. Jackson supported Applicant's natural gas purchases and the overall reasonableness of Applicant's fuel costs.

Mr. Jackson discussed the natural gas purchases to supply the generating units at Georgetown, Eagle Valley Combined-Cycle Gas Turbine ("CCGT") facility, and Harding Street that are included in this filing. He said the cost of gas generation contains the delivered cost of natural gas including firm transportation. Mr. Jackson also supported Applicant's natural gas hedging for the Eagle Valley CCGT facility during the months of November 2019 through January 2020. He stated that in November 2019, Applicant entered into three physical natural gas purchases for the December 2019 delivery period and also three physical natural gas purchases for the January through February 2020 delivery period. He stated the transactions are fixed price, firm delivery, and cover 40,000 MMBtu per day during the delivery period. He said the purchases were on the Texas Gas pipeline and the combined hedges represent coverage of approximately 40% of Eagle Valley CCGT's capacity.

Mr. Jackson testified that these natural gas hedging transactions were reasonable based on the facts and circumstances that existed at the time the transactions were entered into. He stated that at the time of the transactions, due to improved natural gas storage levels, the natural gas pricing was approximately 20% lower than the price levels Applicant was able to hedge for the same period last year. He explained that purchasing physical natural gas hedges reduced customer exposure to scarcity pricing by having fixed-price fuel delivered to the Eagle Valley CCGT. Mr. Jackson testified that the long-term weather forecast suggested normal winter weather conditions that support natural gas demand for heating and electric generation. He said target prices to execute the transactions were set near the low prices seen in the summer with the expectation that those levels would provide value for a "normal" winter. Mr. Jackson testified the natural gas hedges were executed slightly above these targets because of the cool temperatures experienced in late October 2019 and early November 2019, which created concern that Applicant would see an early draw on natural gas inventories.

Mr. Jackson discussed the value of the Eagle Valley natural gas hedges versus realized daily pricing for the period of November 2019 through January 2020. For evaluation of the hedges' economic settlement, Mr. Jackson compared the hedge price versus the daily index price for the natural gas delivery point associated with the hedges. In December 2019, hedges on gas delivered to Eagle Valley CCGT represented a cost of $434,050, and for the month of January 2020, the hedges represented a cost of $712,200. Mr. Jackson stated that Applicant did not have any natural gas hedges for the month of November 2019 and added that there were no associated transactional costs for the hedges. Mr. Jackson testified that the factors that impacted the lower value of the Eagle Valley natural gas hedges were: (1) a significant warm weather pattern during December 2019 and January 2020, which lead to much above normal temperatures throughout the Eastern United States; (2) inventory levels moved to the high side of the 5-year average, which diminished concern over price volatility; and (3) no scarcity events in December 2019 or January 2020. Mr. Jackson stated that as explained in FAC 122, the intent of the natural gas hedge is to mitigate customer exposure to natural gas price volatility. The hedges achieved this objective by providing price certainty for power generated at the Eagle Valley Station. Mr. Jackson testified that winter hedges protect from scarcity events and protect from price volatility associated with high demand periods.

Mr. Jackson discussed the additional information regarding the completed hedging transactions included as part of the standard confidential FAC audit package Applicant provided to the OUCC.

Mr. Jackson opined that Applicant acquires a reliable supply of fuel and has made every reasonable effort to acquire fuel and generate or purchase power or both to provide electricity to Applicant's 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 no financial hedges settled or transactional fees incurred during November 2019 through January 2020 related to the natural gas hedging program. She noted that physical hedges do not receive mark-to-market accounting treatment and thus there are no recognized gains or losses on physical hedges.

B. <u>OUCC Evidence</u>. Michael D. Eckert, Assistant Director of the OUCC Electric Division, presented a time-line of Applicant's coal contracts showing contract expiration dates by coal mine. Mr. Eckert stated that MISO is not committing or calling on the Petersburg Units to run since Applicant began offering them as economic because the units are either uneconomical or are offline for maintenance. He testified that Applicant's current coal inventory is within Applicant's target levels. He added Applicant expects its coal inventory piles to increase. He stated that as of Monday, April 13, 2020, Applicant did not expect its coal generating station pile to reach maximum level. Mr. Eckert added that Applicant indicated in discussions with the OUCC that Applicant is actively looking at options to address its increasing coal inventory. He recommended Applicant update the Commission on how it proposes to address its coal inventory if it reaches maximum levels and on its 2020 and 2021 projected coal burn and coal purchases.

Mr. Eckert testified that Applicant provided information and the result of its natural gas hedging program, both in Mr. Jackson's testimony and at the FAC audit. He recommended Applicant continue to file the results of its natural gas hedging program in each subsequent FAC and provide analysis of the facts and circumstances existing when the transactions were entered.

C. **Sierra Club Evidence.** Jeremy Fisher, PhD, Senior Strategy and Technical Advisor, testified that Applicant operated the coal-burning Petersburg plant during the November 2019 through January 2020 period in far more hours and under far more undesirable conditions than was warranted by MISO market prices. Based on his analysis of realized market pricing during the historical period, Dr. Fisher said he believes that Applicant incurred fuel costs in the historical period that were higher than necessary. Dr. Fisher ultimately recommended the Commission disallow $1.55 million in fuel and variable operations and maintenance ("O&M") expense Applicant incurred during the historical period. Dr. Fisher also testified that he is concerned that Applicant may dismiss market prices when committing Petersburg in the future.

Dr. Fisher testified that Applicant knew or should have known at the time of the energy market decisions during the historic period that it could have reduced the cost of operation to customers if Applicant had idled the Petersburg plant instead of designating Petersburg units as "must run." Dr. Fisher testified Applicant very likely knew at the time of these commitment decisions that it would have saved customers money if it had not operated Petersburg for extended periods, especially during the second half of November and through December 2019. Dr. Fisher testified that in mid-2019, when Applicant produced the so-called vintage forecasts that covered the historic months at issue in this proceeding, it assessed that the fuel cost (alone, excluding any O&M) at the Petersburg coal plant would be about the same cost as market energy prices for the period November 2019 through January 2020. Therefore, before November 2019, according to Dr. Fisher, Applicant expected that it could sell excess power from the Petersburg coal plant into MISO with only a small loss, though this assessment did not include variable O&M and thus understates the losses that Applicant expected.

Dr. Fisher also testified that Applicant did not use a one-week forward-looking profit/loss assessment during the period at issue here. Dr. Fisher also observed that Applicant failed to conduct due diligence in the review of its existing vintage forecasts. Dr. Fisher testified that actual daily energy market prices in November and December 2019 rarely exceeded Petersburg's cost of production. Dr. Fisher found that once it became clear that the energy market was not nearly as robust as had been imagined in mid-2019, it was incumbent on Applicant to reassess its assumptions about the market price forwards. Dr. Fisher testified that customers may have benefited because the Petersburg units were inadvertently de-committed in January 2020 for the non-economic reason that the plant could not comply with its water permit and therefore had to be shut down.

Ultimately, Dr. Fisher recommended that the Commission require Applicant to adjust its recovery in this FAC by the fuel and market cost component that would have been incurred had Applicant committed Petersburg during the historic period. He testified the adjustment should total a $1.55 million disallowance and should be accounted for in this FAC period by reducing the true up amounts and, if necessary, to provide customers with the full amount, providing a significant credit in the forecasted period (June through August 2020). Dr. Fisher also recommended that the Commission establish a practice for evaluating the prudence of Applicant's commitment practice.

D. <u>Applicant Rebuttal</u>. Mr. Jackson testified that Dr. Fisher's analysis is based on "realized" day ahead pricing only. Mr. Jackson said Dr. Fisher did not assess the prudence of Applicant's actions based on "forward" pricing (the information Applicant knew at the time), which is what Applicant necessarily uses to make unit commitment decisions. Mr. Jackson testified that while Dr. Fisher's analysis focuses solely on price, Applicant's unit commitment decisions are necessarily based on forward pricing and appropriately consider reliability, price certainty/stability, and operational issues. Mr. Jackson testified while Applicant works to improve its decision making on a going forward basis, it is unreasonable to penalize Applicant based on hindsight. Rather, Applicant's actions should be judged based on what Applicant knew or reasonably should have known at the time the unit commitment decisions were made. Mr. Jackson explained that the unit commitment process (which includes pricing and non-economic factors) used by Applicant during the November 2019 through January 2020 period challenged by Dr. Fisher is the same process that was in place at the time of the FAC 124 and FAC 125 proceedings.

Mr. Jackson testified that Dr. Fisher's analysis was flawed. Mr. Jackson explained that Dr. Fisher calculated incorrect values for the "MISO Energy Sales Price" identified in Table 1 of his testimony, resulting in numbers that are much lower than what Applicant actually received. Mr. Jackson testified Dr. Fisher made similar errors in Table 2 of his testimony and collectively, these errors cause Dr. Fisher to reach erroneous conclusions regarding Applicant's commitment practices.

Mr. Jackson testified that Dr. Fisher's calculated disallowance of $1.55 million is not limited to fuel costs and contains numerous errors. Mr. Jackson stated that even if one were to accept the hindsight-based hypothetical dispatch used by Dr. Fisher, correcting his errors reduces his calculated amount by more than 30%, down to $1.014 million. Mr. Jackson testified that when Applicant's prudent winter operations and Applicant's response to a water balance issue at Petersburg during January 2020 are considered, the difference between Applicant's actual unit commitment and Dr. Fisher's view of what the unit commitment should have been is reduced to $692,473.

Mr. Jackson added that given the reliability, price stability, and operational considerations that Applicant appropriately factored into the unit commitment process, not to mention the need to make decisions with imperfect information about future market and other conditions, it is unreasonable to expect the Petersburg units to operate perfectly "in the money" at all times. He said the relatively small difference between Applicant's actual operations and Dr.

Fisher's hindsight-based commitment analysis corroborates the reasonableness of Applicant's actions; it does not refute it.

Mr. Jackson also explained that Dr. Fisher's proposed cost disallowance fails to consider the value created through off system sales ("OSS") margins, which flow 100% to Applicant's customers through Applicant's OSS margin tracker. Mr. Jackson testified OSS totaled nearly \$3.7 million during the historical period of November 2019 through January 2020. He said it is unreasonable to disallow \$1.55 million in fuel and other costs associated with Applicant's commitment of Petersburg during the historical period while permitting customers to retain nearly \$3.7 million in OSS margin benefits produced by those same unit commitments.

Mr. Jackson also testified that Applicant has and continues to improve its unit commitment process and supporting documentation. He added that Applicant is maintaining a more robust daily documentation program to support Petersburg Unit commitment including tracking power pricing, natural gas prices, and load forecasts. He stated Applicant is also implementing a short-term model, which will better track Petersburg Unit economics and Applicant plans to start using it by the end of May 2020. He said this more refined modeling process would improve the economic view for unit commitment on a rolling four-week period. Mr. Jackson stated that while economics do not capture all of the reasons for unit commitment, the modeling would help Applicant better support its decision making and allow Applicant to improve that process on a going forward basis.

Mr. Jackson disagreed with Dr. Fisher's discussion of Applicant's coal contracts and his contention that Applicant's commitment process has a systematic error. Mr. Jackson explained Dr. Fisher's other criticisms exceed the scope of this summary FAC proceeding.

Turning to the forecast period, Mr. Jackson explained that the longer-term forecasts presented in this proceeding were generated in a planning model that looks at the economic dispatch of the units on the day the model was run. He said pricing, protecting price risk for customers, operational issues, and reliability would drive commitment decisions during the actual period. He added that Applicant has taken the Petersburg Units offline in the current period (February through May 2020), which demonstrates Applicant's willingness to respond to economic conditions when doing so would not unreasonably expose customers to undue risk of price volatility, extended periods of high prices, and decreased reliability.

Finally, in response to OUCC witness Eckert, Mr. Jackson provided an update on Applicant's current coal purchase and burn position and said Applicant proposes to provide a detailed update of its 2020 and 2021 coal burns and coal purchases in the next FAC audit.

E. Discussion and Findings. The record shows, and the Commission finds, that the natural gas hedging transactions entered into by Applicant were reasonable based upon an analysis of the facts and circumstances as they existed at the time the transactions at issue were entered. Accordingly, we find the incurred gains or losses are reasonable and recoverable through the FAC. We also find that Applicant has reasonably responded to the OUCC's recommendations. As recommended by the OUCC, we direct Applicant to update the Commission on how it proposes to address its coal inventory if it reaches maximum levels and on its 2020 and 2021 projected coal burn and coal purchases because it is important that the Commission be informed on these operational concerns.

We note that Dr. Fisher's proposed cost disallowance relies on realized pricing, and Dr. Fisher examined after-the-fact information to suggest what he viewed to be a better unit commitment strategy. Nevertheless, when Applicant commits the Petersburg units, it does not have the ability to know the future. In a previous FAC case, the Commission found that it does not "engage in a hindsight analysis." *Duke Energy Ind., Inc.*, Cause No. 38707 FAC 76 S1, 2009 WL 3455937 at 17 (IURC Oct. 21, 2009). Rather, "[i]n determining whether the utility acted prudently [the Commission] must review the circumstances as they existed considering what was known or should reasonably have been known at the time of the actions." *Ind. Mich. Power Co.*, Cause No. 43827 DSM 8, 2019 WL 2250497 at 11 (IURC May 22, 2019) (quoting *Duke Energy, Ind., Inc.,* Cause No. 38707 FAC 76 S1 at 17). However, we note that it may be beneficial for Applicant to give some consideration in "must run" decisions from short, as suggested by Dr. Fisher, and longer term vantage points. Applicant testified that it would implement a short-term model, which would better track Petersburg unit economics, and it plans to start using it by the end of May 2020. We consider this constructive, and Applicant shall provide testimony and the OUCC shall audit the new short-term model and give further consideration in FAC 128 of lessons that can be learned from the short-term model to further fine tune Applicant's unit commitment strategy. Moreover, given the relevance to every FAC case of a utility's decision to commit or not to commit a unit during a particular time, we anticipate that the quality and quantity of evidence with which Applicant rebutted Dr. Fisher's arguments will appear consistently in its Applications going forward.

Substantial record evidence shows the calculation underlying Dr. Fisher's contention that Applicant operated the units "on the economic margin for much of the historic period" is not correct. Furthermore, Dr. Fisher's analysis does not properly reflect all relevant MISO revenue streams and customer benefits. We find that price risk, reliability, and operational needs are also reasonably factored into the decision process. Summer and winter periods in particular 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 November 2019 through January 2020 period were reasonably based on forward market price values at the time the decisions were made and reasonably considered non-economic factors. Therefore, we reject Dr. Fisher's proposed cost disallowance.

The longer-term forecasts presented in this proceeding by Applicant were generated in a planning model that looks at the economic dispatch of the units on the day the model is run. Pricing, protecting price risk for customers, operational issues, and reliability will reasonably drive commitment decisions during the actual period. Furthermore, Applicant has taken the Petersburg Units offline in the current period (February through May 2020). This demonstrates Applicant's willingness to respond to economic conditions when doing so will not unreasonably expose customers to undue risk of price volatility, extended periods of high prices, and decreased reliability. Based upon the evidence presented and discussed herein, the Commission finds that 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. MISO Market Related Activity. Mr. Jackson testified that Applicant's proposed recovery of costs for June through August 2020 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 that Applicant is seeking to recover in this FAC proceeding. He noted MISO has added the Real Time Schedule 49 Cost Distribution Amount to the Real Time statement starting with the s55 Real Time Settlement Statement for Operating Day November 30, 2019, that was settled on January 24, 2020. He described the costs this new charge type recovers and explained Applicant will continue to recover this charge through the RTO rate adjustment as part of Socialized and Uplift costs. Mr. Jackson testified that consistent with the Commission's Order in Cause No. 38703 FAC 97, Applicant has included Demand Response Resource Uplift charges from MISO in its cost of fuel in this proceeding. In the Commission's Order in Cause No. 38703 FAC 85 ("FAC 85 Order"), the Commission authorized Applicant to include credits or charges for Contingency Reserve Deployment Failure Charge Uplift Amounts for purposes of review in FAC proceedings. Mr. Jackson explained that because of the FAC 85 Order, Applicant included the credits and charges for Contingency Reserve Deployment Failure Charge Uplift Amounts into 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 Benchmark 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 that 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, and FAC 97 Orders and is approved. The Commission further finds that Applicant's recovery of RSG Charges is consistent with the RSG Order and is approved.

5. 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 Henry Hub, plus $0.60/mmbtu gas transport charge for a generic gas-fired GT (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 the course of 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 $46,282 of purchased power costs over the applicable Benchmarks during November 2019 through January 2020. He said Applicant makes power purchases when economical or due to unit unavailability. Mr. Jackson testified that consistent with the Commission's Purchased Power Order, Applicant has an opportunity to request recovery and justify the reasonableness of purchased power costs above the applicable Purchased Power Daily Benchmark. Applicant summarized the purchased power volumes, costs, total of hourly purchased power costs above the applicable Benchmarks for November 2019 through January 2020, and the reasons for the purchases at-risk after consideration of MISO economic dispatch. 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 $46,282 of purchased power costs in excess of the applicable Benchmarks for November 2019 through January 2020. Mr. Jackson testified that the total purchased power costs for the period of November 2019 through January 2020 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 the Purchased Power Order. He stated the OUCC calculated the same amount of purchased power in excess of the Benchmark as Applicant. Following the procedures established in the Purchased Power Order, the OUCC concluded that all of the purchased power cost that exceeded the Benchmark is recoverable. The OUCC therefore recommended Applicant be allowed to recover $46,282 in purchased power costs that exceeded the Benchmark.

The record shows that Applicant has correctly applied the methodology of the Purchased Power Order to determine the recoverability for the purchased power costs that exceeded the Benchmark and the OUCC agreed Applicant should be allowed to recover $46,282 in purchased power costs that exceeded the Benchmark. Accordingly, the Commission finds that Applicant's request for recovery of its purchased power over the Benchmark is reasonable, consistent with the Commission's Purchased Power Order, and is approved. We further find the total purchased power costs for this period are reasonable and reflect the impacts of MISO's economic dispatch of Applicant's units.

6. <u>Operating Expenses</u>. 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 that total jurisdictional operating expenses excluding fuel costs have increased. Gregory T. Guerrettaz, CPA, on behalf of the OUCC, agreed that Applicant did not have decreases in other operating costs that could be used to offset fuel cost increases. Pub. Ex. 1 at 3.

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

7. <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 in excess of 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-2 and NHC-3, which calculate the (d)(3) test, show Applicant's actual return for the 12 months ending January 31, 2020. She stated that while Applicant's actual return is more than its authorized return for the 12 months ending January 31, 2020, the sum of differentials for the relevant period is less than zero (as shown on Attach. NHC-4 to App. Ex. 1). Accordingly, she testified no reduction in the fuel cost charge is required and the Commission should find that the "return" test of Ind. Code § 8-1-2-42(d)(3) is satisfied.

Mr. Guerrettaz agreed Applicant had jurisdictional net operating income (for the 12 months ending January 31, 2020) greater than that granted in its last general rate proceeding, as adjusted for applicable Environmental Compliance Cost Recovery proceedings. He reviewed the sum of differentials for the relevant period, and he recommended no adjustment to the filing because of the earnings test.

Upon our consideration of the record evidence, the Commission finds Applicant has properly determined the authorized operating income for the 12-month period ending January 31, 2020, and properly reflected the return on its Qualified Pollution Control Property. Thus, as reflected in Attachment NHC-3 to Applicant's Exhibit 1, Applicant has an authorized return of $221,201,000 for purposes of this proceeding. Attachment NHC-2 to Applicant's Exhibit 1 calculates the (d)(3) test, which shows that Applicant's actual return for the 12 months ending January 31, 2020, was $234,075,000. However, the sum of the differentials between the actual earned return and the authorized return for the relevant period as defined in Ind. Code § 8-1-2-42.3 for Applicant is a deficit of $83,278,782, as reflected on Attachment NHC-4 to Applicant's Exhibit 1. Thus, by the mechanics of the applicable statute, it is not appropriate to require a refund of any excess return earned by Applicant during the 12-month period ending January 31, 2020.

8. **<u>Estimating Techniques</u>.** Ind. Code § 8-1-2-42(d)(4) requires the Commission to find that 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 cost was an overestimate of 6.89% for the months of November 2019 through January 2020.

Mr. Guerrettaz stated the OUCC did a detailed review of Applicant's estimation model. He testified the OUCC requested updated gas costs and purchased power costs from Applicant. He said that in light of the immaterial change in the gas and power prices, the OUCC finds the forecast to be acceptable at this time.

Based upon the evidence, we find that Applicant's estimating techniques are reasonably accurate and that its estimate of fuel costs for June through August 2020 is accepted.

9. **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 November 2019 through January 2020. Pursuant to the Order in Cause No. 43740, Applicant is reflecting credits to jurisdictional fuel costs for OSS profits made possible because of the energy received from the Lakefield purchased power agreement ("PPA").

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. Mr. Jackson testified that curtailed power is billable when certain criteria are met.

OUCC witness Eckert testified that Mr. Jackson provided testimony to update the Commission on locational marginal prices at Lakefield and Hoosier.

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 that the requested costs are reasonable, and the Commission approves the ratemaking treatment of the wind PPA costs.

10. **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 June through August 2020 is $96,682,638 and its total estimated sales are 3,713,778 kWh. Applicant's estimated cost of fuel is $0.026033 per kWh. The evidence of record indicates that Applicant reconciled the actual fuel costs and revenues for November 2019 through January 2020. Reconciliation of actual fuel costs and revenues results in a total variance of $(6,062,273). Dividing this amount by the total estimated jurisdictional sales of 3,713,778 kWh results in a variance factor of $(0.001632) 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 $(0.008665) per kWh for the June through August 2020 billing cycles.

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 a decrease of $4.01 or 3.61% on his or her electric bill as compared to the factor currently in effect. App. Ex. 1 at 8.

11. **Confidential Information.** On April 22, 2020, Applicant filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information in this Cause, which was supported by an affidavit from Mr. David Jackson 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. The Presiding Officers issued a Docket Entry on April 30, 2020, finding 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 confidential and protected from public access and disclosure by the Commission.

12. Motion for Subdocket.

A. Sierra Club's Motion for Subdocket and Reply in Support of Its Motion for Subdocket. On May 14, 2020, Sierra Club filed its Motion for Subdocket to Investigate Applicant's Energy Market Commitment Practices and its Reply on May 18, 2020. On May 14, 2020, the OUCC joined the Motion for Subdocket, stating that as the statutory auditor of fuel cost proceedings, it has a necessary interest in the economics of unit dispatch and any resultant impact on fuel costs. Sierra Club asserts that a subdocket is warranted because it has serious concerns with Applicant's energy market commitment decisions, including its choice to operate Petersburg as "must run" in November through December 2019, which was estimated by Sierra Club to have resulted in net losses and unnecessarily incurred fuel and variable O&M costs of $1.55 million that Applicant seeks to recover from customers. Sierra Club requests that the Commission initiate a subdocket to provide the Commission with time and information necessary to evaluate fully the prudence of Applicant's commitment decisions and fuel expenditures for the Petersburg coal plant during the period at issue in this proceeding and to provide an opportunity for Applicant to answer questions on unresolved issues raised by Applicant's rebuttal testimony.

Specifically, Sierra Club asserts that further discovery is needed on the following topics: (1) Applicant's OSS and costs so that Sierra Club can better understand how Applicant values reliability and operational concerns in determining whether to operate Petersburg and how Applicant values "must run" operations as a hedge against winter fuel prices, and (2) whether Applicant acted prudently with respect to its wastewater issues that forced an outage at Petersburg in January 2020. Sierra Club reasons that Applicant has the burden of demonstrating that it has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible during the period in question, November 2019 through January 2020.

Sierra Club argues that a subdocket is required here similar to Duke Energy Indiana, Inc. ("Duke") Cause No. 38707 FAC 123 wherein a motion for a subdocket was granted, and Sierra Club also references other FAC cases wherein the Commission granted subdockets.

B. Applicant's Response in Opposition to Sierra Club's Motion for a Subdocket. Applicant asserts that Sierra Club's Motion for a Subdocket to allow more time to consider Applicant's fuel costs and related actions violates the terms of Sierra Club's intervention which required Sierra Club to take the case as the intervenor finds it as of the pursuant to the April 16, 2020 Docket Entry in this Cause and 170 IAC 1-1.1-11(c).[1] Applicant explains that the procedural schedule in this Cause was approved prior to the date on which Sierra Club's intervention was granted and Sierra Club agreed to file its testimony by the Docket

[1] April 16, 2020 Docket Entry citing 170 IAC 1-1.1-11(e): An intervenor is bound by all rulings and other matters of record prior to the time the intervenor is made a party and takes the case as the intervenor finds it as of the date of intervention. (Applicant incorrectly cited (c), but quoted (e).)

Entry established deadline of April 21, 2020; however, Sierra Club now argues that this proceeding is insufficient time to hear the issues before the Commission in this Cause and a subdocket is necessary.

While Sierra Club argues that a subdocket is appropriate in this Cause and the situation is similar to a Duke case wherein a motion for a subdocket was granted, Applicant argues that the situations are not analogous because the root cause analysis was not complete in the Duke case. Applicant also argues that the Commission allows subdockets sparingly and does not refer all contested FAC issues to subdockets. Applicant explained that the other FAC cases with subdockets referenced by Sierra Club had different circumstances in that they involved increases in fuel costs above the base cost of fuel and not a negative fuel charge as in this case; and the facts are distinguishable.

Applicant provided a chart in its Response that details the assertions made by Sierra Club in its Motion for Subdocket and then cites where Mr. Jackson refuted Sierra Club's assertions in his rebuttal testimony. First, Applicant states that while Sierra Club asserted that Applicant's unit commitment decisions resulted in \$1.55 million in excess fuel and variable O&M costs, Mr. Jackson identified and corrected numerous flaws in Sierra Club's calculations and identified over \$3.6 million in OSS margins received by customers. Second, Applicant states that Sierra Club asserted that there are fundamental inadequacies in Applicant's commitment decision process, but Applicant explained in rebuttal its commitment decision process and argued that Sierra Club's criticisms engage in impermissible hindsight analysis that ignore a wide range of factors including operational and system reliability considerations. Additionally, Applicant has recently refined its short-term modeling process to support further what it calls its robust process to support its commitment decisions. Third, Applicant asserts that Sierra Club alleged that Applicant failed to show that it has made every effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible during the relevant period, but Applicant argued that it explained its practices in rebuttal and the practices are the same as approved by the Commission in its previous FAC 124 and 125 cases. Additionally, Applicant argued that its operating of Petersburg during the historical period: (1) assured the relatively low cost of power during the historically volatile winter period; (2) reduced price risk for the benefit of customers; and (3) was reasonable in light of operational and other non-economic factors.

Applicant then analyzes Sierra Club's testimony to determine which months' costs Sierra Club specifically challenges. Applicant asserts that Sierra Club stated no specific challenge to Applicant's forecasted costs during June through August 2020 nor its historical costs during January 2020, and Sierra Club specifically stated that there were no excess cost in January when Applicant was resolving its water issues at Petersburg. Regarding November and December 2019, Applicant's unit commitment decisions: (1) resulted in fuel costs that are less than fuel costs approved in FAC 124 and FAC 125; and (2) produced substantial OSS margins which flowed to the benefit of Applicant's customers via the its OSS Rider. Applicant maintains that idling Petersburg, as suggested by Sierra Club, would have eliminated the OSS margins in December 2019 and substantially reduced them in November 2019 and January 2020. Applicant states that its analysis of Sierra Club's assertions by month and in hindsight do not warrant the creation of a subdocket.

In its rebuttal to Sierra Club's contention that Applicant appears to have not used its commitment decision process at all in November and December 2019, Applicant stated that the record reflects that it used the process, but it did not create a written record of the forward pricing taken into consideration because the market pricing was high enough that Applicant's commitment decision was reasonable given the non-economic factors. Applicant explained that the individual responsible for the commitment decisions testified in this Cause regarding what he did and why he did it. Sierra Club's arguments that the Commission must know this for sure as a standard of proof is erroneous because there is case law in support of good faith being presumed on the part of the managers of a public utility and the assumption that the officers of a public utility made a true and honest report in the absence of a showing that is contrary.

Applicant explained that as it moved through the unit commitment decisions during the historical period, it did not have the benefit of hindsight and it is important to consider the value of Petersburg as a hedge against high prices for customers in the traditionally volatile-priced winter period. Applicant stated that the record shows that factors such as the time involved in bringing base load units back on line, the potential to have difficulty bringing units back after long outage periods particularly during freezing temperatures, and the potential for other MISO resources to have operational issues, create significant price risk for Applicant's customers. Applicant concluded that the record shows that in Applicant's judgment, the continued operation of Petersburg benefited customers by providing price stability and hedging, and when taking this into consideration along with the OSS margins, no subdocket is necessary in this Cause.

C. <u>Discussion and Ruling on Motion for Subdocket</u>. The Commission discusses the issues raised by the parties in their filings and ultimately denies Sierra Club's Motion for Subdocket as discussed below.

Sierra Club argues that a subdocket is appropriate in this Cause in part because the situation is similar to the issues presented in Cause No. 38707 FAC 123 involving Duke wherein a motion for a subdocket was granted, but we disagree. In this Cause, Applicant in its rebuttal provided a further testimonial explanation for its decisions. Applicant specifically refuted Sierra Club's calculation of $1.55 million in excess fuel and variable O&M costs by analyzing and negating each component and by explaining that its actions were based on the information it had and not on realized cost information only known in hindsight. As we discussed above, the Commission does not engage in a hindsight analysis. Rather, in determining whether a utility acted prudently we must review the circumstances as they existed considering what was known or should reasonably have been known by the utility at the time of its actions. Here, Applicant's refutations ultimately support its calculations, its source of fuel efforts, and its decisions to provide customers with the lowest reasonable fuel costs to the satisfaction of the (d)(1) test. Further, the procedural schedule in Applicant's case established a schedule for the rebuttal filing a week in advance of the Evidentiary Hearing, and there were no discovery challenges or motions to compel, unlike in Cause No. 38707 FAC 123. We further note that the Commission weighs the facts presented in each case to determine whether a subdocket is appropriate, and it does not grant every request for a subdocket.

Sierra Club asserts that discovery is needed so it can better understand how Applicant values reliability and "must run" operations. Taking into consideration Applicant's refuting of Sierra Club's $1.55 million difference and then limiting our review of Applicant's decisions to information Applicant knew and not on a hindsight knowledge, we find no remaining issues that warrant further discovery in a subdocket.

Finally, Sierra Club states that a subdocket is needed so that it can consider whether Applicant acted prudently with respect to its wastewater issues that forced an outage at Petersburg in January 2020. But Dr. Fisher in his testimony acknowledged that two units were committed in January to resolve water issues at the plant, and he stated there was no excess cost in January 2020. Dr. Fisher also analyzed Applicant's commitment decision process for January 2020, and his testimony indicates he found it to be reasonable and the fuel and variable O&M prices are consistent with his derivations from Applicant-provided data. Additionally, the OUCC raised no concerns in its testimony regarding these costs and ultimately recommended approval of Applicant's FAC. We find in this case, no specific issue was raised in testimony regarding the resolution of the water issues at the plant and are not persuaded by Sierra Club that more discovery is needed in this proceeding.

We disagree with Sierra Club that the broader public interest somehow warrants the creation of a subdocket in this proceeding. The (d)(1) test is properly applied to the overall result. The record here demonstrates that the overall result in the reconciliation period is reasonable and the test is satisfied. Therefore, based on our analysis of all of these issues as well as the terms of Sierra Club's intervention and the timing of its Motion for Subdocket, Sierra Club's Motion for Subdocket is denied.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Applicant, Indianapolis Power & Light Company's fuel cost factor set forth at Finding Paragraph No. 10 above is approved.

2. Applicant shall update the Commission on how it proposes to address its coal inventory if it reaches maximum levels and on its 2020 and 2021 projected coal burn and coal purchases.

3. 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.

4. 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.

5. Applicant's request to continue its natural gas hedging plan is approved.

6. 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.

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 24-2-3-2, 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. Sierra Club's Motion for Subdocket, joined by the OUCC, is denied.

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

HUSTON, FREEMAN, KREVDA, OBER, AND ZIEGNER CONCUR:

APPROVED: JUN 03 2020

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

Mary M. Becerra

Mary M. Becerra
Secretary of the Commission