FILED
December 28, 2020
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF DUKE ENERGY INDIANA, LLC FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR ELECTRIC SERVICE, FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR HIGH PRESSURE STEAM SERVICE, AND TO UPDATE MONTHLY BENCHMARKS FOR CALCULATION OF PURCHASED POWER COSTS IN ACCORDANCE WITH INDIANA CODE §8-1-2-42, INDIANA CODE §8-1-2-42.3 AND VARIOUS ORDERS OF THE INDIANA UTILITY REGULATORY COMMISSION	)))))))))))))))	**CAUSE NO. 38707 – FAC126**

SUBMISSION OF REDACTED VERSION OF
CAC'S EXCEPTIONS TO PROPOSED ORDER OF DEI

Citizens Action Coalition of Indiana, Inc. ("CAC"), respectfully submits the public redline version of its Exceptions to Duke Energy Indiana's Proposed Order. Pursuant to the Commission's December 17, 2020 docket entry, CAC is also simultaneously filing, under seal, the confidential, unredacted pages of its Exceptions.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by electronic mail or U.S. Mail, first class postage prepaid, this 24th day of December, 2020, to the following:

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CAC Exceptions to DEI Proposed Form of Order—PUBLIC/REDACTED

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF DUKE ENERGY INDIANA, LLC FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR ELECTRIC SERVICE, FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR HIGH PRESSURE STEAM SERVICE, AND TO UPDATE MONTHLY BENCHMARKS FOR CALCULATION OF PURCHASED POWER COSTS IN ACCORDANCE WITH INDIANA CODE § 8-1-2-42, INDIANA CODE § 8-1-2-42.3 AND VARIOUS ORDERS OF THE INDIANA UTILITY REGULATORY COMMISSION	**)**	**CAUSE NO. 38707-FAC126** **APPROVED:**

PROPOSED FORM OF ORDER

Presiding Officers:
David E. Ziegner, Commissioner
David Veleta, Senior Administrative Law Judge

On October 30, 2020, Duke Energy Indiana, LLC ("Applicant" or the "Company") filed its Verified Application and direct testimony and exhibits for approval by the Indiana Utility Regulatory Commission ("Commission") of a change in its fuel adjustment charge ("FAC") to be applicable during the billing cycles of January, February and March 2021 for electric and steam service and to update monthly benchmarks for purchased power costs. On November 10, 2020, Citizens Action Coalition of Indiana, Inc. ("CAC") filed a Petition to Intervene, which was subsequently granted on November 19, 2020. On December 4, 2020, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and testimony. Applicant filed rebuttal testimony on December 10, 2020.

A public evidentiary hearing was held in this Cause on December 18, 2020, at 1:30 p.m. via WebEx. Counsel for Applicant, CAC and the OUCC participated in the hearing. Applicant and the OUCC offered their respective prefiled testimony and exhibits into the evidentiary record without objection. CAC offered its stipulated exhibits in~~-~~to the evidentiary record without objection. At the hearing, CAC moved to make any fuel adjustment factor approved for Duke Energy Indiana in Cause No. 38707 FAC 126 interim and subject to refund pending the outcome of the investigation in Cause No. 38707 FAC 123-S1 insofar as Cause No. 38707 FAC 123-S1 is reviewing the reasonableness of Duke's self-commitment practices, issues which also affect Cause No. 38707 FAC 126. Duke Energy Indiana opposed the motion based on the fact CAC did not file a written motion before the hearing. CAC responded that CAC and Sierra Club moved at the hearings in FAC 124 and FAC 125 to make those dockets subject to refund pending the outcome of FAC 123-S1, but CAC would be willing to file a written motion, should that be the Presiding Officers' preference. The Senior Administrative Law Judge stated that was not necessary and that the Commission had the information it needed upon which to make a decision.

Based upon the applicable law and the evidence herein, the Commission now finds:

1. Notice and Commission Jurisdiction. Notice of the hearing in this Cause was given as required by law. Applicant is a public utility within the meaning of Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to Applicant's rates and charges related to adjustments in fuel costs. Therefore, the Commission has jurisdiction over the parties and the subject matter of this Cause.

2. Applicant's Characteristics. Applicant is a public utility corporation organized and existing under the laws of the State of Indiana with its principal office in Plainfield, Indiana, and is a second tier wholly-owned subsidiary of Duke Energy Corporation. Applicant is engaged in rendering electric utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such service to the public. Applicant also renders steam service to one customer, International Paper.

3. Available Data on Actual Fuel Costs and Authorized Jurisdictional Net Income. On June 29, 2020, the Commission issued an Order in Cause No. 45253 ("June 29 Order") approving base retail electric rates and charges for Applicant. This June 29 Order is currently on appeal before the Indiana Court of Appeals. The Commission's June 29 Order found that Applicant's base cost of fuel should be 26.955 mills per kWh. Beginning with this proceeding, the Applicant has begun phasing-in the new authorized jurisdictional operating income level approved in the June 29 Order, as adjusted for the Company's Step 1 amounts and for impacts of investments remaining in two Company riders. Until the new authorized jurisdictional net operating level is fully phased-in, the Applicant should continue to reflect a pro-rata portion of the authorized jurisdictional net operating income of $267,500,000 for the months prior to August 2020. This operating income amount is based on the Commission's Order in Cause No. 42359 issued May 18, 2004 ("May 18 Order"), prior to any additional return on investments approved by the Commission in various rate proceedings not taken into account in the May 18 Order.

Applicant's cost of fuel to generate electricity and the cost of fuel included in the net cost of purchased electricity for the month of August 2020, based on the latest data known to Applicant at the time of filing after excluding prior period costs, hedging, and miscellaneous fuel adjustments, if applicable, was $0.025454 per kWh as shown on Applicant's Exhibit A, Schedule 9. In accordance with previous Commission Orders, Applicant calculated its phased-in authorized jurisdictional net operating income level for the 12-month period ending August 31, 2020, to be $453,376,000. No evidence was offered objecting to the calculation of the authorized jurisdictional net operating income level proposed by Applicant, and we find it to be proper.

4. **Fuel Purchases.** Mr. Brett Phipps testified regarding Applicant's coal procurement practices and its coal inventories. Mr. Phipps testified that as of August 31, 2020, coal inventories at its generating units were approximately 3,170,521 tons (or 58 days of coal supply), which is a decrease over inventories reported in FAC125. Mr. Phipps reported that the decrease can be attributed to increased demand during the summer months. Mr. Phipps reported that as of the end of the FAC 126 period, Duke had an additional 1,538,233 tons of coal in off-site storage. He testified that coal inventories are projected to continue to decrease over the next quarter and added that Applicant continues to evaluate a host of options in order to effectively manage its coal inventory. Mr. Phipps stated that as inventory levels dictate, Applicant explores options to store or defer contract coal or resell surplus coal into the market. Due to continued weak coal market conditions, resale opportunities will continue to be extremely difficult in the near term. Given the continued decline in coal burns due to falling power prices, Applicant began a coal decrement in March. Mr. Phipps testified that it was his opinion that Applicant is purchasing coal and oil at prices as low as reasonably possible.

Mr. Phipps testified that the Company issued an RFP during the FAC 126 time period but did not execute any new contracts, but is considering coal to reliably meet its long term coal supply needs and that the Company will provide its coal procurement plan in FAC 127.

Mr. Phipps testified that spot natural gas prices are dynamic, volatile, and can change significantly day to day based on market fundamental drivers. During the three-month period from June through August 2020 the price Applicant paid for delivered natural gas at its gas burning stations was between $1.44 per million BTU and $3.20 per million BTU. He testified natural gas prices for the period were above those experienced in the FAC 125 review period. Mr. Phipps testified that, in his opinion, Applicant purchased natural gas at the lowest cost reasonably possible.

The OUCC's witness, Mr. Michael D. Eckert, testified regarding Applicant's coal inventory. He testified that although Applicant's forecasted 2020 coal burn has increased since its last FAC, it is still less than the 2020 forecasted amount from the 2019 4th quarter forecast, which was the basis for its 2020 coal purchase plan. He recommended Applicant continue to update the Commission on its coal inventory and how it proposes to address its inventory. He also recommended Applicant update the Commission on its 2020 and 2021 projected coal burn and coal purchases.

Mr. Swez testified that Applicant continues to submit an incremental cost offer for its share of Benton County Wind Farm in accordance with the settlement agreement with Benton County Wind Farm discussed in FAC 113.

Mr. Swez testified that the Edwardsport IGCC Generating Station completed its spring outage during this reporting period. He testified the major planned outage was deferred from late March to late May due to the COVID-19 pandemic. The outage began on May 30, 2020, and upon completion the site returned to net positive generation on August 24, 2020. He testified that whenever the unit's gasifiers are available or operating, Edwardsport IGCC is being offered with a commitment status of must-run, which means that MISO must operate the plant at least at the minimum load level identified by Duke ("Must-Run"). Mr. Swez stated that Edwardsport IGCC has followed the Midcontinent Independent System Operator's ("MISO") dispatch direction between the minimum and maximum capability of the unit during this time. Mr. Swez also testified that during times when syngas is not available and the station is available on natural gas operation, the unit will typically be offered to MISO with a commitment status of economic and can be committed and dispatched at MISO's discretion.

Based on the evidence presented, we find that Applicant made every reasonable effort to acquire fuel for its own generation or to purchase power so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible during June through August 2020, subject to the discussion of commit practices, coal decrement pricing, and resulting impacts to coal inventories and future coal purchases set forth in Finding 6 below. With regard to its coal inventory levels, Applicant will provide an update on the status in its next FAC proceeding as recommended by the OUCC. Further, as we ordered in the FAC 125 proceeding, Applicant will provide a detail report on its coal procurement plan for the current and next year in the testimony of its first FAC proceeding in each year going forward, and we have provided in Finding 6 below further detail regarding the contents that should be included in such report that is to be submitted with Duke's FAC 127 filing.

5. Hedging Activities. Applicant's witness Mr. Wenbin (Michael) Chen testified Applicant takes advantage of the hedging tools available to protect against natural gas price fluctuations. Mr. Chen testified that Applicant realized a loss of $749,480 from natural gas hedges purchased for June through August 2020. He testified that market price for gas realized lower values than the hedged prices, attributable to high shale gas production and low gas usage caused by the COVID-19 pandemic. He testified Applicant experienced net realized power hedging gains for the period of $187,475 primarily attributable to strong power prices caused by warmer than normal weather. Ms. Sieferman testified that Applicant realized a total net hedging loss of $570,556 during the period for all native gas and power hedging activities other than MISO virtual energy market participation (including prior period adjustments).

Mr. Chen explained that, consistent with the Commission's June 25, 2008 Order in Cause No. 38707 FAC 68 S1 ("FAC 68 S1 Order"), beginning on August 1, 2008, Applicant has not utilized its flat hedging methodology. Rather, Applicant will hedge up to approximately flat minus 150 MW on a forward, monthly and intra-month basis, and up to approximately flat on a Day Ahead/Real-Time basis. This methodology will leave Applicant with at least 150 MW of expected load unhedged on a forward forecasted basis. Mr. Chen opined Applicant's gas and power hedging practices are reasonable. He stated Applicant never speculates on future prices, and that its hedging practice is economic at the time the decision is made and reduces volatility because Applicant is transacting in a less volatile forward market, as opposed to more volatile spot markets. Mr. Chen testified that, as mentioned in the FAC100 proceeding, Applicant restarted using virtual trades as a hedging tool for expected forced outages in the Real-Time market because of heightened LMP price volatility caused by gas supply issues and extremely cold weather experienced in the past winter.

No evidence was offered in this Cause noting issues with the realized net amounts for power and gas hedging included in the fuel costs in this proceeding or challenging the prudence of the activities that gave rise to the realized net amounts. In addition, Applicant presented evidence that its power hedging practices relevant to this proceeding were consistent with the Agreement previously approved in the FAC 68 S1 Order. Thus, we allow Applicant to include

$570,556 of net losses from native gas and power hedges in the calculation of fuel costs in this proceeding.

6. Participation in the Energy and ASM Markets and MISO-Directed Dispatch. On June 1, 2005, the Commission issued an Order in Cause No. 42685 ("June 1 Order"), in which we approved certain changes in the operations of the investor-owned Indiana electric public utilities that are participating members of MISO. In this proceeding, Mr. Swez testified that Applicant included Energy Markets charges and credits incurred as a cost of reliably meeting the power needs of Applicant's load, including: (1) Energy Markets charges and credits associated with Applicant's own generation and bilateral purchases that were used to serve retail load; (2) purchases from MISO at the full LMP at Applicant's load zone; (3) other Energy Markets charges and credits included in the list on page 37 of the June 1 Order; and (4) credits and charges related to auction revenue rights ("ARRs") and Schedule 27 and Schedule 27-A.

Mr. Swez testified that beginning in early March 2020 a coal price decrement was applied to the dispatch costs of Gibson Units 1-5, Cayuga Units 1-2, and Edwardsport (syngas only) to ~~correctly~~ reflect the economics of additional costs associated with avoiding or reducing surplus coal inventories. He stated that, to the extent that the price decrement results in unit being dispatched that otherwise would not be, coal coming to the station is consumed, other potential costs are avoided, and customers ultimately benefit because higher cost alternatives to manage the inventory are avoided. Mr. Swez testified the price decrement is working as designed as Applicant initially saw an increase in generation output from these units. As the level of the coal price decrement decreases over time as inventories decrease, the economic need to burn excess coal decreases. In the October 30, 2013 Order in Cause No. 38707 FAC 96, the Commission ordered Applicant to present the inputs to its calculation of the coal price decrement applicable to each FAC filing as support for the reasonableness of its pricing. Mr. Swez provided the confidential coal stacks for the time period June through August. Mr. Swez testified that Applicant continues to forecast its coal inventory position as part of the normal course of business and expects the decrement to be in place through 2020.

Mr. Swez testified that due to low natural gas prices and higher power prices, Wheatland CT station, units 1-4, have been committed more often by MISO. Due to the increased run hours and generation, by July the station was projecting to exceed its 12-month rolling NOx emissions limit of 241 tons, so Applicant increased the incremental offer of each unit to ensure availability for generation for the balance of the summer during the highest priced hours when energy margins were highest. Later in July, Applicant also increased the incremental offer. Mr. Swez testified that this additional cost added had the intended effect of decreasing generation in lower margin hours and keeping Wheatland generation available and operating during higher margin hours for the remainder of the summer period.

Applicant's witness Ms. Mary Ann Amburgey testified as to the procedures followed by Applicant to verify the accuracy of the charges and credits allocated by MISO to Applicant. She also discussed the process by which MISO issues multiple settlement statements for each trading day and the dispute resolution process with respect to such statements. She stated that every daily settlement statement received by Applicant from MISO is reviewed utilizing the computer software tools described in her testimony. Ms. Amburgey testified that she is confident that the amounts paid by Applicant to MISO, net of any credits, are proper and that such amounts billed to customers through the FAC are proper.

OUCC witness Mr. Guerrettaz testified that some of the large prior revised adjustments occurring in the FAC are impacted by residual load (difference between tie lines and MISO load, subject to reconciliation) and that the material amount of the adjustment is inherent in the fact that Applicant uses S14 for actual months versus S105. He testified that there appears to be a possible consistent overstatement in the residual load due to the S14-S105 timing. Mr. Guerrettaz recommended Applicant discuss whether a consistent overstatement in residual load is occurring and what, if anything, can be done to improve this situation.

In rebuttal, Mr. Burnside explained that MISO requires tie-line meter reads from the load zones of all member utilities, which it uses to calculate a utility's share of Residual Load MWh and cost. He testified that Applicant uses the MISO S14 settlement statement to calculate its FAC fuel costs for the reconciliation period. This is the best available data as of 14 days past an operating day, but is not final and may include estimates and errors that are not identified and corrected until the S105 settlements are submitted. He testified that MISO recalculates Residual Load at 105 days and the settlements are reconciled, so Applicant's customers receive a refund in the subsequent FAC for the difference if Residual Load charged by MISO in the S105 settlement is less than the amount charged in the S14 settlement. Mr. Burnside testified that it is possible for S14 Residual Load charges to be understated, but recent settlements have shown a reduction in Residual Load cost in the S105 statements resulting in a refund to customers through the FAC reconciliation mechanism. He testified that in addition to Residual Load, Real-Time Asset Energy charges are also affected by updates in tie-line meter reads which generally offset Residual Load. Mr. Burnside testified that Applicant complies with MISO's meter-read submittal requirements and any errors are corrected by the S105 settlement statement. He recommended Applicant continue using the S14 settlement statements for the FAC filing of Residual Load charges with reconciliation to S105 settlement statements.

In its Phase II Order in Cause No. 43426 ("Phase II Order") the Commission authorized Applicant and the other Joint Petitioners to recover costs and credit revenues related to the ASM. Mr. Swez explained that Applicant has included various ASM charges and credits in this proceeding incurred for June through August 2020, consistent with the Phase II Order, as well as appropriate period adjustments.

Applicant's witness Mr. Scott A. Burnside testified that Applicant, in accordance with the Phase II Order, has calculated the monthly average ASM Cost Distribution Amounts it has paid for Regulation, Spinning and Supplemental Reserves. These amounts are as follows:

(in $ per MWh)	June-20	July-20	Aug-20
Regulation Cost Dist.	0.0397	0.0380	0.0409
Spinning Cost Dist.	0.0242	0.0270	0.0289
Supplemental Cost Dist.	0.0032	0.0027	0.0038

OUCC witness Mr. Eckert testified that Applicant's treatment of ASM charges follows the treatment ordered by the Commission in its Phase II Order.

Based upon the evidence presented and subject to further investigation in Cause No. 38707 FAC 123-S1, we find Duke Energy Indiana's participation in the Energy and Ancillary Services Markets and utilization of the coal price decrement did not constitute~~d~~ reasonable efforts to generate or purchase power, or both, to serve its retail customers at the lowest fuel cost reasonably possible. For one thing, discovery responses from Duke entered by CAC by stipulation in lieu of cross examination shows that the total accounting variable operating costs for the Edwardsport gasifiers [redacted] total MISO energy market revenues during FAC 126. CAC-DEI Joint Exhibit 2 - Confidential at pp. 13-14. While the confidential total of that operating loss was [redacted] than the losses reported in previous FAC periods, the size of the loss is notable given that the Edwardsport gasifiers were online for only about one week during the FAC 126 time period. In addition, larger operating losses were reported for Cayuga Unit 1, and Cayuga Unit 2 also operated at a loss. *Id.* at pp. 15-18. Such losses raise questions about the prudency of Duke's practices regarding the commitment of its Edwardsport and Cayuga coal units into the MISO market.

Commented [A1]: In particular, Duke acknowledged that the total accounting variable operating cost for the Edwardsport gasifiers was $[redacted] compared to $[redacted] in MISO energy revenues, for a net [redacted] of $[redacted]. While significantly smaller than the losses that Edwardsport has incurred in previous FAC periods, the amount is notable given that the Edwardsport gasifiers were online for only approximately 1 week during the FAC 126 time period.

Commented [A2]: While CAC does not believe this word is confidential, CAC is redacting it for now so Duke can have an opportunity to confirm.

Commented [A3]: While CAC does not believe this word is confidential, CAC is redacting it for now so Duke can have an opportunity to confirm.

We have already initiated a subdocket to address similar issues arising from Applicant's commitment decisions at its coal-fired plants during the FAC 123 period. That subdocket, FAC 123-S1, is nearly complete, with only Duke's post-hearing brief remaining to be filed, after which the Commission will issue its order. The scope of that subdocket is limited to the FAC 123 period, however, we anticipate that our conclusions regarding the reasonableness of Applicant's use of the Must-Run commitment status at Edwardsport and Cayuga and any corresponding disallowances will apply with equal force to similar commitment decisions made during the FAC 126 period. We note also the limited time available to the Commission and Intervenors in the FAC proceedings hinders the ability to fully evaluate the impacts of Duke's commitment practices on customers. Accordingly, we will reach a final determination as to what disallowance of fuel costs, if any, is appropriate for FAC 126, after the completion of the investigation of these issues in FAC 123-S1. The motion by CAC to make the requested fuel adjustment charge subject to refund pending the Commission's determination of the reasonableness of Applicant's unit commitment decisions in FAC 123-S1 is therefore granted.

We also have significant questions about the prudency of Duke's use of coal decrement pricing during FAC 126. We have, of course, approved the use of decrement pricing in previous Duke FAC dockets, including in FAC 125. But as with any other utility practice, approval of decrement pricing in one FAC proceeding does not obviate the Company's burden of establishing the reasonableness and prudency of decrement pricing when it is used in other FAC proceedings. Here, such reasonableness and prudency has not been demonstrated.

Commented [A4]: For Cayuga Unit 1, total variable operating cost during FAC 126 was $[redacted] compared to $[redacted] in MISO energy revenues, for a net [redacted] of $[redacted].

For Cayuga Unit 2, total variable operating cost during FAC 126 was $[redacted], compared to $[redacted] in MISO energy revenues, for a net [redacted] of $[redacted].

For one thing, significant questions are raised by the fact that at the same time that Duke was using decrement pricing to increase its coal burns as a way to reduce its coal inventories, the Company issued a Request for Proposals ("RFP") to purchase additional amounts of coal. Mr. Phipps suggested that doing so was appropriate because the RFP was to meet future, rather than current, coal needs. But having reviewed the confidential data that Duke disclosed in response to CAC discovery requests, it is appears that there would be no need for Duke to purchase additional coal for at least 2021 had the Company not used decrement pricing to increase its coal burns during FAC 126. In particular, adding the amount of contracted coal Duke has for 2021, to

Commented [A5]: Duke has projected a 2021 coal burn of [redacted] tons, and the Company had already contracted [redacted] tons of coal for 2021. CAC-DEI Joint Exhibit 2 Confidential at pp. 1-2. At the beginning of FAC 126, Duke had 1,480,816 tons of coal in interim off-site storage. CAC-DEI Joint Exhibit 1 at p. 1. In addition, the Company projected that its use of coal decrement pricing would increase Duke's coal burn during FAC 126 by [redacted] tons. CAC-DEI Joint Exhibit 2 Confidential at p. 5. Adding the increased coal burn from decrement pricing to the amount of coal in interim storage and the contracted amount leads to a total of [redacted] tons of coal for 2021 had Duke not instituted decrement pricing, which would have been sufficient to provide all of Duke's projected 2021 coal need.

the amount of coal in off-site interim storage, and the increased amount that was projected to be burned as a result of decrement pricing leads to a total that exceeds the Company's projected 2021 coal burn. In other words, Duke is using decrement pricing to burn more coal now, only to replace the extra coal burned with new coal purchases in the near future.

Given such circumstances, one would have expected Duke to evaluate whether it would be a lower cost option for customers if the excess amounts of coal that it burned through decrement pricing had instead been stored until the Company projects it would be needed in 2021. Yet while Duke has frequently noted that its interim off-site storage comes at no cost to Duke, the Company has not evaluated whether additional off-site interim storage capacity is available. CAC-DEI Joint Exhibit 1 at pp. 1-2 (Duke Resp. to CAC 1.8). And while Duke's presentation of the inputs to its calculation of the coal price decrement set forth in Petitioner's Confidential Exhibit 6-A includes other storage options that are not free, the record is bereft of any evidence that Duke utilized those storage options or attempted to identify any additional paid storage options that may be available. Nor has Duke presented any analysis of the cost to customers of storing such coal until it is needed in 2021, versus inflating its coal burns now only to expect to purchase additional amounts of coal to replace such inflated coal burns in the near future.

This is far from the only relevant analysis that is absent from the record in this proceeding. In particular, Duke conceded in discovery that it has not carried out any analysis of the cost of using coal decrement pricing, or of the cost of buying out some of its existing coal contracts, to avoid or reduce its surplus coal inventories. CAC-DEI Joint Exhibit 1 at pp. 5-6 (Duke Resp. to CAC 1.18). This failure appears to stand in stark contrast to the approach taken by Duke Energy Carolinas in evaluating whether to institute decrement pricing versus buying out coal contracts. *Id.* And while the Company notes that evaluating the cost of using coal decrement pricing to avoid or reduce surplus coal inventories requires determining "what resulting unit commitment, LMP, and behavior of other market participants would have been during this time absent the application by the Company of a coal price decrement," *id*. at p. 6, such analysis should be able to be carried out by readily available economic modeling programs.

Based on all of the above, Duke failed to justify the use of coal decrement pricing during FAC 126. In our Order in FAC 125, we instructed Duke in its first FAC filing of each year to provide a detailed report of its coal procurement plan for that year and the next year, with the first such report due to be provided as part of the Company's upcoming FAC 127 filing. If Duke contracted after June 30, 2020 to purchase any additional amounts of coal for 2021 and/or 2022, or projects that additional amounts of coal will need to be acquired for those years, the Company must include in its coal procurement report submitted with FAC 127 an analysis of whether any coal decrement pricing occurring after June 30, 2020 was the lowest cost option to customers for managing surplus coal inventories once the cost of the additional coal purchases for 2021 and/or 2022 are factored in. In particular, such analysis should set out the cost to customers of any additional coal purchases for 2021 and/or 2022, and of any uneconomic commitment or dispatch that resulted from the decrement pricing used to manage surplus inventories, and compare it to what it would have cost to store surplus inventories until they would be needed in 2021 and/or 2022 rather than using decrement pricing to burn them in 2020.

Commented [A6]: In fact, in a discovery response deemed confidential, Duke stated that the paid storage options had a total storage capacity of [redacted] tons, but that the Company [redacted] at those sites at either the beginning or end of FAC 126. CAC-DEI Joint Exhibit 2 Confidential at p. 12 (Duke Conf. Resp. to CAC 3.4).

While this unutilized storage capacity is not free, at a cost of [redacted], this capacity is considerably lower cost than the [redacted] coal decrement price that Duke utilized during FAC 126. CAC-DEI Joint Exhibit 2 Confidential at p.7 (Duke Conf. Resp. to CAC 1.20; Petitioner's Confidential Exhibit 6-A.

Commented [A7]: In a discovery response deemed confidential, Duke states that of the [redacted] tons of additional coal projected to be burned during FAC 126 as a result of the coal price decrement, it could have stored [redacted] tons at the paid storage options identified in Confidential Exhibit 6-A at a cost of $[redacted]. That cost is presumably considerably lower than the cost of purchasing an additional [redacted] tons of coal the Company projects would be needed in 2021, much less any costs incurred from any uneconomic coal plant commitment or dispatching that resulted from use of the decrement.

While Duke notes that it could not store all of the [redacted] tons of coal at its current paid storage options, the Company has not evaluated whether additional free off-site interim storage is available, and there is no evidence that the Company has explored options for additional paid off-site storage.

Further, we note that any costs reasonably related to Applicant's self-commitment decisions, including but not limited to fuel procurement practices as noted in the Joint Motion, remain subject to refund pending the outcome of the Order in Cause No. 38707 FAC 123 S1.

Further, as we noted in our Orders in Cause Nos. 38707 FAC 81 and 38707 FAC 82, should Applicant's bidding strategy alter the native/non-native load assignment of its units, such strategy may be subject to further prudence review. Additionally, based upon the evidence presented, the Commission finds that Applicant's treatment of the Energy and ASM charges and credits in its cost of fuel is consistent with the June 1 Order, the December 28, 2006 Order in Cause No. 38707 FAC 70, as well as our Phase I and Phase II Orders in Cause No. 43426 and should be approved; however, we note that any costs reasonably related to Applicant's self-commitment decisions, remain subject to refund pending the outcome of the Order in Cause No. 38707 FAC 123-S1.

7. Major Forced Outages. In the December 28, 2011 Order in Cause No. 38707 FAC 90, the Commission ordered Applicant to discuss in future FAC proceedings major forced outages of units of 100 MW or more lasting more than 100 hours. Mr. Swez testified during this FAC period there were eight outages that met these criteria. Mr. Swez testified that no Root Cause Analysis ("RCA") was performed for any of these outages.

8. Operating Expenses. Ind. Code § 8-1-2-42(d)-(2) requires the Commission to determine whether actual increases in fuel costs have been offset by actual decreases in other operating expenses. Accordingly, Applicant filed operating cost data for the 12 months ended August 31, 2020. Applicant's authorized phased-in jurisdictional operating expenses (excluding fuel costs) are $806,574,000. For the 12-month period ended August 31, 2020, Applicant's jurisdictional operating expenses (excluding fuel costs) totaled $1,357,238,000. Accordingly, Applicant's actual operating expenses exceeded jurisdictional authorized levels during the period at issue in this Cause. Therefore, the Commission finds that Applicant's actual increases in fuel costs for the above referenced periods have not been offset by decreases in other jurisdictional operating expenses.

9. Return Earned. Ind. Code § 8-1-2-42(d)(3), subject to the provisions of Ind. Code § 8-1-2-42.3, generally prohibits a fuel cost adjustment charge that would result in regulated utilities earning a return in excess of its applicable authorized return. Should the fuel cost adjustment factor result in the utility earning a return more than its applicable authorized return, it must, in accordance with the provisions of Ind. Code § 8-1-2-42.3, determine if the sum of the differentials between actual earned returns and authorized returns for each of the 12-month periods considered during the relevant period is greater than zero. If so, a reduction to the fuel adjustment clause factor is deemed appropriate.

In accordance with Applicant's June 27, 2012 order in Cause No. 42736-RTO 30, the proposal for Schedule 26-A treatment of costs or revenues associated with the Applicant's Company-owned Multi-Value Projects (MVPs) should be addressed at the time any such projects have been completed and are included for recovery. Applicant's witness Ms. Sieferman testified that the first of such projects were included for the first time in MISO billing effective June 2019. Applicant proposed that the costs and revenues associated with Company-owned MVPs be treated as non-jurisdictional and outside of the FAC earnings test which is consistent with the treatment of its Company-owned RECB projects beginning in Cause No. 38707 FAC86. Applicant has provided more detail as it relates to the RTO rider in its filing in Cause No. 42736 RTO 56. Based upon the evidence presented, the Commission finds the Applicant's exclusion of revenues and expenses associated with Company-owned MVPs should be approved on an interim basis, subject to refund, pending the outcome of Applicant's RTO 56 filing.

In accordance with previous Commission Orders, Applicant's calculated jurisdictional electric operating income level was $495,648,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was $453,376,000. Therefore, the Commission finds that Applicant did not earn a return more than its authorized level during the 12 months ended August 31, 2020. However, we note that to the extent it is determined in the pending subdocket, Cause No. 38707 FAC 123-S1, that Applicant did earn in excess of its applicable authorized return, the Commission reserves its right to reevaluate this finding insofar as any costs reasonably related to Applicant's self-commitment decisions, including but not limited to fuel procurement practices, remain subject to refund pending the outcome of the Order in Cause No. 38707 FAC 123-S1.

10. Estimation of Fuel Costs. Applicant estimates that its prospective average fuel cost for the months of January through March 2021, will be $64,368,583 or $0.024887 per kWh. Applicant previously made the following estimates of its fuel costs for the period June through August 2020, and experienced the following actual costs, resulting in percent deviation, as follows:

Month	Actual Cost in Mills/kWh	Estimated Cost in Mills/kWh	Percent Actual is Over (Under) Estimate
June 2020	24.115	24.179	(0.26)
July 2020	26.857	21.626	24.19
Aug 2020	25.440	21.917	16.07
Weighted Average	25.530	22.580	13.06

A comparison of Applicant's actual fuel costs with the respective estimated costs for these three periods results in a weighted average percentage difference of 13.06. Based on the evidence of record, we find Applicant's estimating techniques appear reasonably sound and its estimates for January through March 2021 should be accepted; however, we note that the reasonableness of these estimates remain subject to the investigation of Duke's self-commitment practices and outcome of the Order in Cause No. 38707 FAC 123-S1.

11. Purchased Power Benchmark. As a result of the July 29, 2020 Order in Cause No. 45253, changes in Applicant's stacking became effective July 2020 as follows: Applicant's stacking occurs on a real-time metered basis rather than both day-ahead and real-time; certain short-term wholesale trades are classified as non-native rather than native; and stacking is based on incremental rather than average production cost. Mr. Burnside testified that work is ongoing to incorporate the required stacking logic changes to the Sumatra Model. For this filing the previously approved stacking logic, as explained by Mr. Burnside, continued to be utilized. Applicant will reprocess stacking for the months of July and August 2020 and make FAC adjustments when the programming changes are complete. In Cause No. 45253, the Commission eliminated the requirement that Applicant file information concerning the calculation of its highest on-system fuel cost effective July 2020. As June 2020 falls under the previous reporting requirement, Applicant has calculated the June 2020 monthly purchased power benchmark in accordance with the Commission's August 18, 1999 Order in Cause No. 41363 and the guidance of this Commission in Cause Nos. 38706 FAC 45, 38708 FAC 45, 38707 FAC 56, and 38707 FAC 59 as follows:

Month / Year	Benchmark $/MWh	Facility
June 2020	41.33	Gallagher 2

Mr. Burnside testified that Applicant did not exceed the benchmark prices in June 2020.

The OUCC's witness Mr. Michael Eckert testified that Applicant did not purchase any power that was non-recoverable.

Based on the evidence of record, the Commission finds that Applicant has met the requirements necessary to establish a monthly benchmark for power purchases that occurred during June 2020.

12. Fuel Cost Factor. As discussed in Finding No. 3 above, Applicant's base cost of fuel is 26.955 mills per kWh. The evidence indicates that Applicant's fuel cost adjustment factor applicable to January through March 2021 billing cycles is computed as follows:

	$ / kWh
Projected Average Fuel Cost	0.024887
Net Reconciliation Factor	0.000514
Adjusted Fuel Cost Factor	0.025401
Less: Base Cost of Fuel Included in Rates	0.026955
Fuel Cost Adjustment Factor	(0.001554)

Ms. Sieferman testified that the net variance factor shown above reflects $3,679,673 of under-billed fuel costs applicable to retail customers that occurred during the period June through August 2020.

OUCC witness Mr. Gregory Guerrettaz testified that the fuel cost adjustment for the quarter ended August 2020 had been properly applied by Applicant. In addition, he stated the figures used in the Application for a change in the FAC were supported by Applicant's books and records, Sumatra, and source documentation of Applicant for the period reviewed.

13. Effect on Residential Customers. The approved factor represents an increase of ($0.003156) per kWh from the factor approved in Cause No. 38707-FAC125. The typical residential customer using 1,000 kWhs per month will experience an increase of $3.16 or 2.5%

on his or her total electric bill compared to the factor approved in Cause No. 38707-FAC125 (excluding sales tax).

14. **Interim Rates.** Because we are unable to determine whether Applicant's actual earned return will exceed the level authorized by the Commission during the period that this fuel cost adjustment factor is in effect, the Commission finds that the rates approved herein should be approved on an interim basis, subject to refund, in the event an excess return is earned, as well as any relevant findings in the pending subdocket, Cause No. 38707 FAC 123-S1.

At the evidentiary hearing, CAC made an oral motion that the rates in this proceeding be approved subject to refund pending the outcome of the subdocket created in FAC 123. Holding subsequent FACs subject to refund until a subdocketed proceeding is reasonable insofar as grave questions continue to exist with regard to how Duke Energy Indiana has committed its units to MISO among other related issues. As such, there is a reasonable basis to make any fuel adjustment factor approved for Duke in 38707 FAC 126 interim and subject to refund pending the outcome of the investigation into Duke's self-commitment practices in Cause No. 38707 FAC 123-S1. We therefore grant CAC's motion.

15. **Fuel Adjustment for Steam Service.** On December 30, 1992, this Commission issued its Order in Cause No. 39483 approving the June 18, 1992 Settlement Agreement between Applicant and Premier Boxboard, formerly referred to as Temple-Inland, n/k/a International Paper which included a change in the method used to calculate International Paper's fuel cost adjustment as well as an update to the base cost of fuel. The fuel cost adjustment factor for International Paper of $0.9760705 per 1,000 pounds of steam was calculated on Exhibit B, Schedule 1, of the Verified Application; this factor will be effective for the January through March 2021 billing cycles. Exhibit B, Schedule 2, of the Verified Application is a reconciliation of the actual fuel cost incurred to estimated fuel cost billed to International Paper that resulted in $109,471 charge to International Paper for the months of June through August 2020.

The Commission finds that Applicant's proposed fuel cost adjustment factor for International Paper of $0.9760705 per 1,000 pounds of steam has been calculated in accordance with this Commission's Order in Cause No. 39483, and ~~that such factor should be approved. We further find~~ that Applicant's reconciliation amount of $109,471 charge to International Paper has also been calculated in accordance with prior methodologies. ~~been properly determined and should be approved~~. However, as we have seen in prior FAC proceedings, if a Cayuga unit is run only due to the requirement to supply steam, there may be an effect on the electrical customers' costs. The Commission is concerned about such significant losses resulting from the fact that Duke always commits as Must-Run at least one Cayuga unit when available and regardless of losses projected in the Company's daily economic analyses. Thus, we find that any increased costs reasonably related to Applicant's self-commitment decisions, including this particular contract, remain subject to refund or increase as to International Paper pending the outcome of the Order in Cause No. 38707 FAC 123-S1.

16. **Shared Return Revenue Credit Adjustment for International Paper.** In accordance with the June 18, 1992 Settlement Agreement, International Paper will receive shared return revenue credit adjustments to the extent incurred. As indicated above in Finding No. 10, Applicant did not have excess earnings for the 12 months ended August 2020. Therefore, we find International Paper is not due a shared return revenue credit.

17. Confidential Information. On October 30, 2020 and December 17, 2020, Applicant filed motions requesting protection of confidential and proprietary information along with supporting affidavits. On November 10, 2020 and December 17, 2020, the Presiding Officers made preliminary determinations and/or clarifications that trade secret information should be subject to confidential procedures, as supported by Applicant's affidavits, including (i) its coal stack for every decrement update between June and August 2020, including fuel, storage and transportation pricing, and pricing projections; (ii) pricing, commercial terms, supplier information, coal procurement strategy and activities related to its coal contracts; (iii) certain generation variable cost data; and (iv) Day-Ahead Awards and dispatch information . The Commission finds such information is 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 should be held by the Commission as confidential and protected from public access and disclosure.

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

1. Duke Energy Indiana's fuel cost adjustment factor for electric service to be billed jurisdictional customers, as set forth in Finding No. 12, and the fuel cost adjustment for steam service as set forth in Finding No. 15 of this Order are hereby approved on an interim basis, subject to refund, in accordance with all of the Findings above.

2. Duke Energy Indiana's inclusion of Energy and Ancillary Services Markets charges and credits in its cost of fuel, as described in Finding No. 6 of this order, is hereby approved on an interim basis, subject to refund, in accordance with all of the Findings above.

3. Prior to implementing the authorized rates, Applicant shall file the tariff and applicable rate schedules under this Cause for approval by the Commission's Energy Division. Such interim rates shall be effective on or after the date of approval for all bills rendered, subject to refund, in accordance with all of the Findings above.

4. Duke Energy Indiana shall provide an update on the status of its coal inventories in its next FAC filing, as described in Finding No. 4 of this Order, and provide a detailed discussion of its coal procurement plan as Ordered in FAC 125 and further described in Finding No. 6 above.

5. The material submitted to the Commission under seal shall be and hereby is declared to contain trade secret information as defined in Ind. Code § 24-2-3-2 and therefore is exempted from the public access requirements contained in Ind. Code ch. 5-14-3 and Ind. Code §8-1-2-29.

6. CAC's Motion that rates be approved subject to refund pending the outcome of the subdocket in In Cause No. 38707 FAC 123-S1 is approved.

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

HUSTON, FREEMAN, KREVDA, OBER AND ZIEGNER CONCUR:

APPROVED:

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

Mary M. Schneider
Secretary to the Commission