FILED
APRIL 11, 2017
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 38707 FAC 111**

INDIVIDUAL INTERVENORS SUBMISSION OF EXCEPTIONS TO DUKE PROPOSED ORDER

Michael A. Mullett and Patricia N. March (collectively "Individual Intervenors" or "IIs"), by counsel, files the attached exceptions to the Duke Energy Indiana, LLC ("Duke" or "DEI") Proposed Form of Order filed with the Indiana Utility Regulatory Commission on March 30, 2017. Individual Intervenors have attached hereto both a redline version of the Proposed Form of Order and a final version for the Commission's convenience. In addition, the proposed exceptions to the DEI Proposed Order are summarized as follows:

1. Individual Intervenors recommend the discussion of Mr. Swez's testimony be supplemented with additional information of relevance and importance disclosed on cross-examination at the March 15, 2017 hearing.

2. Individual Intervenors recommend including discussion of Individual Intervenors cross-examination exhibits 5 and 6 confidential.

3. Individual Intervenors recommend discussing the forced outage at Cayauga 1, incorporating the testimony and exhibits of the Joint Proposed Order submitted by Nucor and the

OUCC, and making the rates in this Cause interim and subject to refund in order to allow continued discovery and review of the Company's Root Cause Analysis and Legal Team's conclusions regarding the outage in testimony and exhibits presented by all parties in the subdocket investigation requested by Nucor.

WHEREFORE, pursuant to the schedule adopted at the conclusion of the hearing in this cause, Individual Intervenors submit the attached proposed order reflecting these additions or clarifications to the DEI proposed Order.

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 11th day of April 2017, to the following:

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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-FAC111** **APPROVED:**

PROPOSED FORM OF ORDER

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

On January 26, 2017, Duke Energy Indiana, LLC ("Applicant") 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 April, May and June 2017 for electric and steam service and to update monthly benchmarks for purchased power costs. On January 31, 2017, Michael A. Mullett and Patricia N. March (collectively "Individual Intervenors") filed a Petition to Intervene in this proceeding. Also on January 31, 2017, Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor") filed a Petition to Intervene. The Presiding Officers granted the Petitions to Intervene of Individual Intervenors and Nucor on February 9, 2017. The Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and testimony on March 2, 2017. On March 2, 2017, Nucor filed a *Motion for a Subdocket in this Proceeding* ("Motion"). Applicant filed its response to the Motion on March 9, 2017. Nucor filed its reply on March 14, 2017.

A public evidentiary hearing was held in this Cause on March 15, 2017, at 9:30 a.m., in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Applicant, the OUCC, Nucor, and Individual Intervenors appeared at the hearing by counsel. Applicant and the OUCC offered their respective prefiled testimony and exhibits into the evidentiary record without objection. Also, Nucor and Individual Intervenors offered their cross-examination exhibits into the evidentiary record. Due to the unavailability of Applicant's witness, Mr. Scott Burnside, the evidentiary hearing was continued to March 29, 2017, to allow for his testimony. No members of the general public appeared or sought to testify at the hearings.

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.[1]

3. Available Data on Actual Fuel Costs and Authorized Jurisdictional Net Income. On May 18, 2004, the Commission issued an Order in Cause No. 42359 ("May 18 Order") approving base retail electric rates and charges for Applicant. The Commission's May 18 Order found that Applicant's base cost of fuel should be 14.484 mills per kWh and that Applicant's base rates for electric utility service should reflect an authorized jurisdictional net operating income of $267,500,000, prior to any additional return on qualified pollution control property approved by the Commission, pursuant to Ind. Code §§ 8-1-2-6.6 and 6.8, 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 November 2016, 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 $0.027554 per kWh as shown on Applicant's Exhibit A, Schedule 9. In accordance with previous Commission Orders,[2] Applicant calculated its phased-in authorized jurisdictional net operating income level for the 12-month period ending November 30, 2016, to be $494,297,000. No evidence was offered objecting to the calculation of the

[1] International Paper acquired Temple-Inland's corrugated packaging business on February 13, 2013.

[2] The Commission's July 3, 2002, Order in Cause Nos. 41744 S1 and 42061, and subsequent update Orders, up to and including the August 31, 2016, update in Cause No. 42061 ECR 27, authorized Applicant to add the value of certain qualified pollution control property to the value of Applicant's property for ratemaking purposes. The Commission's Order in Cause No. 42061 ECR 3, dated March 11, 2004, stated that the applicable incremental increase to Applicant's authorized return, approved in that proceeding, shall be phased-in over the period of time that Applicant's net operating income was affected by the applicable construction work in progress ("CWIP") update. The Commission's Order in Cause No. 43114 and subsequent update Orders, up to and including the August 24, 2016, update in Cause No. 43114 IGCC 15, authorized Applicant to add the value of property at the Edwardsport Integrated Gasification Combined Cycle Generating Facility ("IGCC Project") to the value of Applicant's property for ratemaking purposes. The June 25, 2014 Order in Cause No. 44367, and subsequent updates up to and including the update in Cause No. 44367 FMCA1 authorized the Company to adjust authorized net operating income to reflect approved earnings associated with the approved Federal Mandate Compliance ("FMCA") projects. Applicant has applied the same phase-in concepts ordered by the Commission in its Order in Cause No. 42061 ECR 3 for CWIP updates to the IGCC Project updates in making the calculations for this filing.

authorized jurisdictional net operating income level proposed by Applicant, and we find it to be proper.

4. <u>Fuel Purchases</u>. Mr. Brett Phipps testified regarding Applicant's coal procurement practices and its coal inventories. Mr. Phipps testified that as of November 30, 2016, coal inventories were approximately 3,893,055 tons (or 72 days of coal supply), which is higher than what was reported in FAC110 due to a number of factors, including spot purchases for Gallagher station and an outage with Cayuga Unit 1. Mr. Phipps 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. 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 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 September through November 2016 the price Applicant paid for delivered natural gas at its gas burning stations was between $1.95 per million BTU and $3.45 per million BTU. Mr. Phipps testified that, in his opinion, Applicant purchased natural gas at the lowest cost reasonably possible.

The OUCC's witness Mr. Michael Eckert testified regarding Applicant's coal inventory. He testified that Applicant continues to explore options to store, defer contract coal or resell surplus coal into the market. He recommended Applicant should continue to update the Commission on its coal inventory and its use of decrement pricing.

Applicant's witness Mr. John D. Swez testified regarding Applicant's efforts to mitigate the negative Locational Marginal Price ("LMP") situation associated with power purchased from Benton County Wind Farm ("BCWF"), pursuant to the contract that was approved by the Commission in Cause No. 43097. Mr. Swez stated that due to the nature of the contractual agreement between the Company and BCWF and the way the Midcontinent Independent System Operator, Inc. ("MISO") treats offers from intermittent resources, the unit had a commitment status of must run with minimum and maximum loading equal to the forecasted generation amount, meaning that MISO would clear the generator at any LMP at the forecasted amount in the day-ahead market. Mr. Swez testified that because of this, negative revenue (meaning that payments must be made to send the power into the MISO system) was sometimes received by this generator in the day-ahead markets. It was also possible to receive negative revenues in the real-time market. Mr. Swez testified that on March 1, 2013, BCWF began operation as a Dispatchable Intermittent Resource ("DIR"). The DIR construct was designed to allow MISO to better manage the output of intermittent resources, thereby allowing for better management of congestion in certain areas, such as where BCWF is located. Mr. Swez testified that although it appears that the DIR construct is giving MISO additional tools to manage congestion at BCWF, negative LMPs at times do continue to be observed.

Mr. Swez also testified that Applicant received an invoice on June 17, 2013 for payment from BCWF for March, April, and May 2013 for liquidated damages for production that was not generated. He noted that Applicant disputed this invoice and, as a result, did not issue payment or include the invoice in any FAC proceeding. Although Applicant and BCWF had continued negotiations regarding this invoice, BCWF filed a lawsuit against Applicant on December 16, 2013, alleging that Applicant breached its contract with the wind farm. A trial was scheduled for August 2015; however, in early July the court entered summary judgment on behalf of Applicant in the case, meaning that Applicant's supply offer was found to be reasonable. Further, because the court entered judgment in the Applicant's favor on all remaining claims, no payment is owed to BCWF for power not actually generated and delivered. Mr. Swez testified that on July 30, 2015 BCWF filed a notice of appeal. Although both parties participated in a court-ordered settlement conference, no settlement was reached.

On December 6, 2016, the 7th Circuit issued a decision reversing the summary judgment previously granted Applicant and remanded the case to the Southern District of Indiana for further proceedings to determine the extent to which BCWF is entitled to payment for additional energy and tax credits as well as future offers into the market. In the December 28, 2016 Order in Cause No. 38707 FAC110, the Commission ordered Applicant to assess and report the implications of the 7th Circuit's decision on future FAC filings. Mr. Swez testified that although it is too early to provide an assessment of the implications of the decision, Applicant is in settlement discussions with BCWF.

Mr. Eckert recommended that Applicant continue to report any updates and resolutions to the BCWF situation in its next FAC filing. Applicant shall continue to assess and report its implications for future FAC filings in its next filing.

Mr. Swez testified that the Edwardsport IGCC Generating Station entered a planned outage on September 24 and remained in a scheduled outage for the majority of this FAC period. He testified that when the unit's gasifiers are available or operating, Edwardsport IGCC is being offered with a commitment status of must-run. Mr. Swez stated that Edwardsport IGCC has followed MISO's 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.

Upon cross-examination by Individual Intervenors, Mr. Swez clarified that the Edwardsport Station was off line between Hour Ending 10 on September 24 and Hour Ending 15 on November 27, 2016, an off-line period representing approximately 64 of the 91 days in the FAC-111 reporting period. During this off-line period, the Station was initially in a Planned Outage, from September 24, 2016 until November 7, 2016. Then, the Station was in an extension of the Planned Outage from November 7 until November 26, 2016. Finally, the station was in a Startup Failure from November 26 to November 27, 2016. Thus, the Station was actually in a Planned Outage from September 24 through November 7, 2016 (44 days), an Extended Planned Outage from November 7 through November 26, 2016 (19 days), and in a Forced Outage from November 26 to November 27, 2016 (1 day).

Mr. Swez also testified that the initial Planned Outage of 44 days was the longest outage which the Edwardsport Station had experienced since it was declared by the Company to be in commercial operation as of June 7, 2013, even before the additional 19 days of the Extended

Planned Outage and the one day of Forced Outage are taken into consideration. The additional nineteen-day Extended Planned Outage was necessary because the Company had not been able to complete the scope of work originally contemplated for the initial Planned Outage in the scheduled 44 days. The additional one-day Forced Outage was necessary because the Plant could not be restarted as planned at the conclusion of the Extended Planned Outage.

Moreover, when the Station did return on-line on November 27, 2016, it was operating on natural gas because neither of its gasifiers were available at that time. In fact, Gasifier 1 did not return to service until December 21, 2016, and then operated only to January 6, 2017, when it was required to be taken off-line until being restarted on January 10, 2017. But, at that time, an immediate trip occurred, keeping Gasifier 1 offline until January 13, 2017. In addition, Gasifier 2 did not return to service after the Fall 2016 outage until January 9th, 2017, but had to be taken off line later that same day, not successfully returning to service until January 11, 2017.

In short, the Edwardsport Station did not generate electricity on syngas from September 24, 2016, until several weeks after the conclusion of the FAC-111 reporting period on November 30, 2016. Mr. Swez authenticated and IIs introduced into evidence an exhibit, II CX-5, which showed that, as a result, the net generation of the Station on synagas was zero for the months of both October and November 2016. In addition, when Mr. Swez was unable to do so, Ms. Siefferman authenticated and IIs introduced into evidence another exhibit, II CX-6-C, which showed that, even with the generation it did produce on natural gas, Edwardsport generated significantly less electricity in total than the Company had previously projected for the entire FAC-111 reporting period. Based on the evidence presented, the Commission finds troubling the extensive problems experienced by Edwardsport during and following its extended Fall 2016 outage, a time period which is more than three years after the Station was declared commercial by the Company in June 2013. However, no evidence was presented in this proceeding to show that the Company's fuel costs and purchased power expenses claimed during the FAC-111 reporting period were imprudent or excessive as a result of these troubling problems at Edwardsport.

Thus, 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 September, October, and November 2016, with one notable exception. Specifically, we reserve judgment with respect to the reasonableness of any additional fuel costs incurred for the Company's own generation or additional purchase power obtained from other suppliers in order to replace the generation lost during the Forced Outage of Cayuga Unit 1, pending the completion of the subdocket investigation discussed and ordered *infra*.

With regard to its coal inventory levels and any updates to the situation with BCWF, Applicant will provide an update on the status in its next FAC proceeding as recommended by the OUCC.

5. **Hedging Activities.** Applicant's witness Mr. Wenbin (Michael) Chen testified the Company takes advantage of the hedging tools available to protect against natural gas price fluctuations. Mr. Chen testified that since the last update to the Commission in the FAC110 proceeding, the Company purchased some forward natural gas hedges for expected native gas burn in January and February 2017. He testified that there were no gas hedging trades for this period. He further testified Applicant experienced net realized power hedging gains (exclusive of MISO virtual trades and including prior period adjustments) for the period of $760,416. In total, the Company realized a total net gain of approximately $762,509 during the period for all native gas and power hedging activities.

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 the Company 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. Mr. Chen testified that Applicant most recently met with the OUCC in July 2014 to discuss Applicant's hedging strategy.

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 approximately $762,509 of net gains from native gas and power hedges in the calculation of fuel costs in this proceeding.

6. Energy and Ancillary Services Market ("ASM"). 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.

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.

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 Ancillary Services Market ("ASM"). Mr. Swez explained that Applicant has included various ASM charges and credits in this proceeding incurred for September through November 2016, 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)	Sept-16	Oct-16	Nov-16
Regulation Cost Dist.	0.0409	0.0586	0.0535
Spinning Cost Dist.	0.0391	0.0546	0.0383
Supplemental Cost Dist.	0.0215	0.0206	0.0150

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, 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.

7. <u>Participation in the Energy and ASM Markets and MISO-Directed Dispatch</u>. As previously noted, the June 1 Order approved certain changes in the operations of Applicant as a result of the implementation of the Energy Markets. Specifically, we found that Applicant (and the other electric utilities participating in Cause No. 42685) should be granted authority to participate in the MISO Day 2 directed dispatch and Day 2 energy markets as described in their testimony. Mr. Swez generally described Applicant's participation in the MISO energy markets and testified that it was consistent with the testimony presented in Cause No. 42685. Mr. Swez discussed in his filed testimony the offer process and noted there are a variety of reasons that Applicant will either offer a generating resource as must-run or self-schedule a unit to ensure the unit is operated as cost efficiently as possible.

Mr. Swez testified that beginning in late February 2012, a coal price decrement was applied to the dispatch costs of Gibson Units 1-5, Wabash River Units 2-6, and Cayuga Units 1-2 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 units 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 a significant increase in generation output from these units. As the level of the coal price decrement has decreased over time, the impact of the decrement has lessened. 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 testified since there was a zero coal price decrement for all times during this FAC period, there was no need to create a coal price decrement stack. Mr. Swez testified that Applicant has suspended the coal price decrement calculation for 2017 since inventory levels are expected to remain under the maximum throughout 2017.

Mr. Swez testified that Wabash River Units 6 and 7 were retired on December 7, 2016. He also testified that the new Crane solar site is expected to begin testing in January, 2017.

Based upon the evidence presented we find Applicant's participation in the energy and ancillary services markets constituted reasonable efforts to generate or purchase power, or both, to serve its retail customers at the lowest fuel cost reasonably possible. 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.

8. Major Forced Outages. In the December 28, 2011 Order in Cause No. 38707 FAC90, 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 that there were three outages during this FAC period that met these criteria. He stated that Cayuga 1 tripped on a generator ground relay activation on August 30, 2016. Further investigation found that coil T21 of the generator stator winding failed to ground. It was determined that a full rewind of the generator winding was the best repair option. The repair was implemented and the machine was put back in service on December 7, 2016.

In addition, Mr. Swez testified that an outage occurred at Gibson 4 on October 31, 2016 associated with an issue with the 4C Boiler Feed Pump discharge valve. The seal and bushing were repaired and reassembled, with the unit returned to service on November 4, 2016. On November 12, 2016, an outage occurred on Gibson 1 due to a boiler tube leak. The tube leak was repaired and the unit returned to service on November 16, 2016.

Mr. Eckert testified that the OUCC learned through discovery that a root cause analysis for the Cayuga 1 outage is being performed, but is not yet complete. Mr. Eckert recommended that the Commission make the rates in this Cause interim subject to refund based on the Cayuga 1 outage and allow continued discovery and discussion on the outage, the final Root Cause Analysis, and Applicant's Legal Team's final conclusion.

On March 2, 2017, Nucor filed its *Motion for a Subdocket*. In the Motion, Nucor stated that due to the summary nature of the FAC proceedings, as well as the lack of availability of the final adjuster's report and root cause analysis related to the Cayuga 1 forced outage, there is insufficient time to conduct a complete investigation and present testimony, if appropriate, as to whether Applicant acted prudently. The Motion requests the Commission to approve the proposed FAC in this Cause on an interim basis, subject to refund, and to open a subdocket to allow further discovery and investigation into issues related to the Cayuga 1 forced outage and its impact on the fuel costs included in this proceeding. Applicant filed its response to Nucor's Motion on March 9, 2017, and Nucor filed its Reply on March 14, 2017.

Michael A Mullett 4/10/2017 8:32 PM
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Individual Intervenors adopt and incorporate by reference the summary of testimony and exhibits and proposed Commission findings regarding the Cayuga 1 Forced Outage included in the Nucor and OUCC Joint Proposed Order. In addition, IIs adopt Mr. Eckert's recommendation on behalf of the OUCC that the Commission make the rates in this Cause interim and subject to refund in order to allow continued discovery and review of the Company's Root Cause Analysis and Legal Team's conclusions regarding the outage in testimony and exhibits presented by all parties in the subdocket investigation requested by Nucor.

Michael A Mullett 4/10/2017 8:31 PM
Deleted: ~~In its response, Duke Energy Indiana stated that a root cause analysis of the Cayuga outage will be available in FAC 112. Importantly, Nucor provided no testimony that Duke Energy Indiana was in any way unreasonable or imprudent in its management of the Cayuga outage or maintenance of Cayuga Unit 1. The Commission must base its decisions on the evidentiary record. Therefore, the Commission denies the Motion for Subdocket.~~

9. 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 November 30, 2016. Applicant's authorized phased-in jurisdictional operating expenses (excluding fuel costs) are $863,115,000. For the 12-month period ended November 30, 2016, Applicant's jurisdictional operating expenses (excluding fuel costs) totaled $1,281,030,000. 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.

10. 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 in excess of 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 previous Commission Orders, Applicant's calculated jurisdictional electric operating income level was $453,502,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was $494,297,000. Therefore, the Commission finds that Applicant did not earn a return in excess of its authorized level during the 12 months ended November 30, 2016.

11. Estimation of Fuel Costs. Applicant estimates that its prospective average fuel cost for the months of April through June 2017 will be $62,497,334 or $0.024739 per kWh. Applicant previously made the following estimates of its fuel costs for the period September through November 2016, 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
September 2016	27.777	25.759	7.83
October 2016	29.113	26.379	10.36
November 2016	27.678	25.736	7.55
Weighted Average	28.181	25.954	8.58

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 8.58. Based on the evidence of record, we find Applicant's estimating techniques appear reasonably sound and its estimates for April through June 2017 should be accepted.

12. Purchased Power Benchmark. Applicant has calculated monthly purchased power benchmarks 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. The benchmarks are as follows:

Month / Year	Benchmark $/MWh[3]	Facility
Sep 2016	159.05	Connersville 1
Oct 2016	164.14	Connersville 1
Nov 2016	42.10	Vermillion 8

Mr. Burnside testified that Applicant did not exceed benchmarks for the reconciliation period at issue in this FAC proceeding.

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 monthly benchmarks for power purchases that occurred during the September through November 2016 reconciliation period. The Commission further finds that Applicant's request for recovery of its purchased power over the benchmark for June 2016 is consistent with the Commission's Purchased Power Order and should be approved.

13. Fuel Cost Factor. As discussed in Finding No. 3 above, Applicant's base cost of fuel is 14.484 mills per kWh. The evidence indicates that Applicant's fuel cost adjustment factor applicable to April through June 2017 billing cycles is computed as follows:

[3] Calculated using most efficient unit heat rate.

	$ / kWh
Projected Average Fuel Cost	0.024739
Net Variance (current reconciliation period)	0.002157
Adjusted Fuel Cost Factor	0.026896
Less: Base Cost of Fuel	0.014484
Fuel Cost Adjustment Before Applicable Taxes	0.012412
Adjustment for Utility Receipts Tax	0.000188
Fuel Cost Adjustment Factor Adjusted for Applicable Taxes	0.012600

The net variance factor shown above reflects $13,928,844 of under-billed fuel costs applicable to retail customers that occurred during the period September through November 2016.

OUCC witness Mr. Gregory Guerrettaz testified that the fuel cost adjustment for the quarter ended November 2016 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.

14. <u>Effect on Residential Customers</u>. The approved factor represents an increase of $0.000513 per kWh from the factor approved in Cause No. 38707-FAC110. The typical residential customer using 1,000 kWhs per month will experience an increase of $0.51 or 0.6% on his or her electric bill compared to the factor approved in Cause No. 38707 FAC 110 (excluding various tracking mechanisms and sales tax).

15. <u>Interim Rates</u>. 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 in the event an excess return is earned.

16. <u>Fuel Adjustment for Steam Service</u>. 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 $0.9978625 per 1,000 pounds of steam was calculated on Exhibit B, Schedule 1, of the Verified Application; this factor will be effective for the April through June 2017 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 $70,279 receivable from International Paper for the months of September through November 2016.

The Commission finds that Applicant's proposed fuel cost adjustment factor for International Paper of $0.9978625 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 $70,279 receivable from International Paper has been properly determined and should be approved.

17. **<u>Shared Return Revenue Credit Adjustment for International Paper</u>.** 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 2016. Therefore, we find International Paper is not due a shared return revenue credit.

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. 13, and the fuel cost adjustment for steam service as set forth in Finding No. 16 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.

3. Prior to implementing the authorized rates, Applicant shall file Rider 60 under this Cause for approval by the Commission's Energy Division. Rider 60 shall be effective for all bills rendered on and after the first billing cycle of April 2017.

4. Duke Energy Indiana shall provide an update on the status of its coal inventories and the situation with Benton County Wind Farm in its next FAC filing, as described in Finding No. 4 of this Order.

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

<u>ATTERHOLT, FREEMAN, HUSTON, WEBER AND ZIEGNER CONCUR</u>:

APPROVED:

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

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Secretary to the 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	**)**	**CAUSE NO. 38707-FAC111**
SERVICE, AND TO UPDATE MONTHLY	**)**	
BENCHMARKS FOR CALCULATION OF	**)**	
PURCHASED POWER COSTS IN ACCORDANCE	**)**	**APPROVED:**
WITH INDIANA CODE § 8-1-2-42, INDIANA CODE	**)**	
§ 8-1-2-42.3 AND VARIOUS ORDERS OF THE	**)**	
INDIANA UTILITY REGULATORY COMMISSION	**)**	

PROPOSED FORM OF ORDER

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

On January 26, 2017, Duke Energy Indiana, LLC ("Applicant") 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 April, May and June 2017 for electric and steam service and to update monthly benchmarks for purchased power costs. On January 31, 2017, Michael A. Mullett and Patricia N. March (collectively "Individual Intervenors") filed a Petition to Intervene in this proceeding. Also on January 31, 2017, Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor") filed a Petition to Intervene. The Presiding Officers granted the Petitions to Intervene of Individual Intervenors and Nucor on February 9, 2017. The Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and testimony on March 2, 2017. On March 2, 2017, Nucor filed a *Motion for a Subdocket in this Proceeding* ("Motion"). Applicant filed its response to the Motion on March 9, 2017. Nucor filed its reply on March 14, 2017.

A public evidentiary hearing was held in this Cause on March 15, 2017, at 9:30 a.m., in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Applicant, the OUCC, Nucor, and Individual Intervenors appeared at the hearing by counsel. Applicant and the OUCC offered their respective prefiled testimony and exhibits into the evidentiary record without objection. Also, Nucor and Individual Intervenors offered their cross-examination exhibits into the evidentiary record. Due to the unavailability of Applicant's witness, Mr. Scott Burnside, the evidentiary hearing was continued to March 29, 2017, to allow for his testimony. No members of the general public appeared or sought to testify at the hearings.

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.[1]

3. **Available Data on Actual Fuel Costs and Authorized Jurisdictional Net Income.** On May 18, 2004, the Commission issued an Order in Cause No. 42359 ("May 18 Order") approving base retail electric rates and charges for Applicant. The Commission's May 18 Order found that Applicant's base cost of fuel should be 14.484 mills per kWh and that Applicant's base rates for electric utility service should reflect an authorized jurisdictional net operating income of $267,500,000, prior to any additional return on qualified pollution control property approved by the Commission, pursuant to Ind. Code §§ 8-1-2-6.6 and 6.8, 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 November 2016, 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 $0.027554 per kWh as shown on Applicant's Exhibit A, Schedule 9. In accordance with previous Commission Orders,[2] Applicant calculated its phased-in authorized jurisdictional net operating income level for the 12-month period ending November 30, 2016, to be $494,297,000. No evidence was offered objecting to the calculation of the

[1] International Paper acquired Temple-Inland's corrugated packaging business on February 13, 2013.

[2] The Commission's July 3, 2002, Order in Cause Nos. 41744 S1 and 42061, and subsequent update Orders, up to and including the August 31, 2016, update in Cause No. 42061 ECR 27, authorized Applicant to add the value of certain qualified pollution control property to the value of Applicant's property for ratemaking purposes. The Commission's Order in Cause No. 42061 ECR 3, dated March 11, 2004, stated that the applicable incremental increase to Applicant's authorized return, approved in that proceeding, shall be phased-in over the period of time that Applicant's net operating income was affected by the applicable construction work in progress ("CWIP") update. The Commission's Order in Cause No. 43114 and subsequent update Orders, up to and including the August 24, 2016, update in Cause No. 43114 IGCC 15, authorized Applicant to add the value of property at the Edwardsport Integrated Gasification Combined Cycle Generating Facility ("IGCC Project") to the value of Applicant's property for ratemaking purposes. The June 25, 2014 Order in Cause No. 44367, and subsequent updates up to and including the update in Cause No. 44367 FMCA1 authorized the Company to adjust authorized net operating income to reflect approved earnings associated with the approved Federal Mandate Compliance ("FMCA") projects. Applicant has applied the same phase-in concepts ordered by the Commission in its Order in Cause No. 42061 ECR 3 for CWIP updates to the IGCC Project updates in making the calculations for this filing.

authorized jurisdictional net operating income level proposed by Applicant, and we find it to be proper.

4. <u>Fuel Purchases</u>. Mr. Brett Phipps testified regarding Applicant's coal procurement practices and its coal inventories. Mr. Phipps testified that as of November 30, 2016, coal inventories were approximately 3,893,055 tons (or 72 days of coal supply), which is higher than what was reported in FAC110 due to a number of factors, including spot purchases for Gallagher station and an outage with Cayuga Unit 1. Mr. Phipps 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. 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 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 September through November 2016 the price Applicant paid for delivered natural gas at its gas burning stations was between $1.95 per million BTU and $3.45 per million BTU. Mr. Phipps testified that, in his opinion, Applicant purchased natural gas at the lowest cost reasonably possible.

The OUCC's witness Mr. Michael Eckert testified regarding Applicant's coal inventory. He testified that Applicant continues to explore options to store, defer contract coal or resell surplus coal into the market. He recommended Applicant should continue to update the Commission on its coal inventory and its use of decrement pricing.

Applicant's witness Mr. John D. Swez testified regarding Applicant's efforts to mitigate the negative Locational Marginal Price ("LMP") situation associated with power purchased from Benton County Wind Farm ("BCWF"), pursuant to the contract that was approved by the Commission in Cause No. 43097. Mr. Swez stated that due to the nature of the contractual agreement between the Company and BCWF and the way the Midcontinent Independent System Operator, Inc. ("MISO") treats offers from intermittent resources, the unit had a commitment status of must run with minimum and maximum loading equal to the forecasted generation amount, meaning that MISO would clear the generator at any LMP at the forecasted amount in the day-ahead market. Mr. Swez testified that because of this, negative revenue (meaning that payments must be made to send the power into the MISO system) was sometimes received by this generator in the day-ahead markets. It was also possible to receive negative revenues in the real-time market. Mr. Swez testified that on March 1, 2013, BCWF began operation as a Dispatchable Intermittent Resource ("DIR"). The DIR construct was designed to allow MISO to better manage the output of intermittent resources, thereby allowing for better management of congestion in certain areas, such as where BCWF is located. Mr. Swez testified that although it appears that the DIR construct is giving MISO additional tools to manage congestion at BCWF, negative LMPs at times do continue to be observed.

Mr. Swez also testified that Applicant received an invoice on June 17, 2013 for payment from BCWF for March, April, and May 2013 for liquidated damages for production that was not generated. He noted that Applicant disputed this invoice and, as a result, did not issue payment or include the invoice in any FAC proceeding. Although Applicant and BCWF had continued negotiations regarding this invoice, BCWF filed a lawsuit against Applicant on December 16, 2013, alleging that Applicant breached its contract with the wind farm. A trial was scheduled for August 2015; however, in early July the court entered summary judgment on behalf of Applicant in the case, meaning that Applicant's supply offer was found to be reasonable. Further, because the court entered judgment in the Applicant's favor on all remaining claims, no payment is owed to BCWF for power not actually generated and delivered. Mr. Swez testified that on July 30, 2015 BCWF filed a notice of appeal. Although both parties participated in a court-ordered settlement conference, no settlement was reached.

On December 6, 2016, the 7th Circuit issued a decision reversing the summary judgment previously granted Applicant and remanded the case to the Southern District of Indiana for further proceedings to determine the extent to which BCWF is entitled to payment for additional energy and tax credits as well as future offers into the market. In the December 28, 2016 Order in Cause No. 38707 FAC110, the Commission ordered Applicant to assess and report the implications of the 7th Circuit's decision on future FAC filings. Mr. Swez testified that although it is too early to provide an assessment of the implications of the decision, Applicant is in settlement discussions with BCWF.

Mr. Eckert recommended that Applicant continue to report any updates and resolutions to the BCWF situation in its next FAC filing. Applicant shall continue to assess and report its implications for future FAC filings in its next filing.

Mr. Swez testified that the Edwardsport IGCC Generating Station entered a planned outage on September 24 and remained in a scheduled outage for the majority of this FAC period. He testified that when the unit's gasifiers are available or operating, Edwardsport IGCC is being offered with a commitment status of must-run. Mr. Swez stated that Edwardsport IGCC has followed MISO's 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.

Upon cross-examination by Individual Intervenors, Mr. Swez clarified that the Edwardsport Station was off line between Hour Ending 10 on September 24 and Hour Ending 15 on November 27, 2016, an off-line period representing approximately 64 of the 91 days in the FAC-111 reporting period. During this off-line period, the Station was initially in a Planned Outage, from September 24, 2016 until November 7, 2016. Then, the Station was in an extension of the Planned Outage from November 7 until November 26, 2016. Finally, the station was in a Startup Failure from November 26 to November 27, 2016. Thus, the Station was actually in a Planned Outage from September 24 through November 7, 2016 (44 days), an Extended Planned Outage from November 7 through November 26, 2016 (19 days), and in a Forced Outage from November 26 to November 27, 2016 (1 day).

Mr. Swez also testified that the initial Planned Outage of 44 days was the longest outage which the Edwardsport Station had experienced since it was declared by the Company to be in commercial operation as of June 7, 2013, even before the additional 19 days of the Extended

Planned Outage and the one day of Forced Outage are taken into consideration. The additional nineteen-day Extended Planned Outage was necessary because the Company had not been able to complete the scope of work originally contemplated for the initial Planned Outage in the scheduled 44 days. The additional one-day Forced Outage was necessary because the Plant could not be restarted as planned at the conclusion of the Extended Planned Outage.

Moreover, when the Station did return on-line on November 27, 2016, it was operating on natural gas because neither of its gasifiers were available at that time. In fact, Gasifier 1 did not return to service until December 21, 2016, and then operated only to January 6, 2017, when it was required to be taken off-line until being restarted on January 10, 2017. But, at that time, an immediate trip occurred, keeping Gasifier 1 offline until January 13, 2017. In addition, Gasifier 2 did not return to service after the Fall 2016 outage until January 9th, 2017, but had to be taken off line later that same day, not successfully returning to service until January 11, 2017.

In short, the Edwardsport Station did not generate electricity on syngas from September 24, 2016, until several weeks after the conclusion of the FAC-111 reporting period on November 30, 2016. Mr. Swez authenticated and IIs introduced into evidence an exhibit, II CX-5, which showed that, as a result, the net generation of the Station on synagas was zero for the months of both October and November 2016. In addition, when Mr. Swez was unable to do so, Ms. Siefferman authenticated and IIs introduced into evidence another exhibit, II CX-6-C, which showed that, even with the generation it did produce on natural gas, Edwardsport generated significantly less electricity in total than the Company had previously projected for the entire FAC-111 reporting period. Based on the evidence presented, the Commission finds troubling the extensive problems experienced by Edwardsport during and following its extended Fall 2016 outage, a time period which is more than three years after the Station was declared commercial by the Company in June 2013. However, no evidence was presented in this proceeding to show that the Company's fuel costs and purchased power expenses claimed during the FAC-111 reporting period were imprudent or excessive as a result of these troubling problems at Edwardsport.

Thus, 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 September, October, and November 2016, with one notable exception. Specifically, we reserve judgment with respect to the reasonableness of any additional fuel costs incurred for the Company's own generation or additional purchase power obtained from other suppliers in order to replace the generation lost during the Forced Outage of Cayuga Unit 1, pending the completion of the subdocket investigation discussed and ordered *infra*.

With regard to its coal inventory levels and any updates to the situation with BCWF, Applicant will provide an update on the status in its next FAC proceeding as recommended by the OUCC.

5. **<u>Hedging Activities</u>.** Applicant's witness Mr. Wenbin (Michael) Chen testified the Company takes advantage of the hedging tools available to protect against natural gas price fluctuations. Mr. Chen testified that since the last update to the Commission in the FAC110 proceeding, the Company purchased some forward natural gas hedges for expected native gas burn in January and February 2017. He testified that there were no gas hedging trades for this period. He further testified Applicant experienced net realized power hedging gains (exclusive of MISO virtual trades and including prior period adjustments) for the period of $760,416. In total, the Company realized a total net gain of approximately $762,509 during the period for all native gas and power hedging activities.

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 the Company 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. Mr. Chen testified that Applicant most recently met with the OUCC in July 2014 to discuss Applicant's hedging strategy.

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 approximately $762,509 of net gains from native gas and power hedges in the calculation of fuel costs in this proceeding.

6. <u>Energy and Ancillary Services Market ("ASM")</u>. 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.

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.

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 Ancillary Services Market ("ASM"). Mr. Swez explained that Applicant has included various ASM charges and credits in this proceeding incurred for September through November 2016, 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)	Sept-16	Oct-16	Nov-16
Regulation Cost Dist.	0.0409	0.0586	0.0535
Spinning Cost Dist.	0.0391	0.0546	0.0383
Supplemental Cost Dist.	0.0215	0.0206	0.0150

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, 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.

7. <u>Participation in the Energy and ASM Markets and MISO-Directed Dispatch</u>. As previously noted, the June 1 Order approved certain changes in the operations of Applicant as a result of the implementation of the Energy Markets. Specifically, we found that Applicant (and the other electric utilities participating in Cause No. 42685) should be granted authority to participate in the MISO Day 2 directed dispatch and Day 2 energy markets as described in their testimony. Mr. Swez generally described Applicant's participation in the MISO energy markets and testified that it was consistent with the testimony presented in Cause No. 42685. Mr. Swez discussed in his filed testimony the offer process and noted there are a variety of reasons that Applicant will either offer a generating resource as must-run or self-schedule a unit to ensure the unit is operated as cost efficiently as possible.

Mr. Swez testified that beginning in late February 2012, a coal price decrement was applied to the dispatch costs of Gibson Units 1-5, Wabash River Units 2-6, and Cayuga Units 1-2 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 units 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 a significant increase in generation output from these units. As the level of the coal price decrement has decreased over time, the impact of the decrement has lessened. 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 testified since there was a zero coal price decrement for all times during this FAC period, there was no need to create a coal price decrement stack. Mr. Swez testified that Applicant has suspended the coal price decrement calculation for 2017 since inventory levels are expected to remain under the maximum throughout 2017.

Mr. Swez testified that Wabash River Units 6 and 7 were retired on December 7, 2016. He also testified that the new Crane solar site is expected to begin testing in January, 2017.

Based upon the evidence presented we find Applicant's participation in the energy and ancillary services markets constituted reasonable efforts to generate or purchase power, or both, to serve its retail customers at the lowest fuel cost reasonably possible. 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.

8. Major Forced Outages. In the December 28, 2011 Order in Cause No. 38707 FAC90, 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 that there were three outages during this FAC period that met these criteria. He stated that Cayuga 1 tripped on a generator ground relay activation on August 30, 2016. Further investigation found that coil T21 of the generator stator winding failed to ground. It was determined that a full rewind of the generator winding was the best repair option. The repair was implemented and the machine was put back in service on December 7, 2016.

In addition, Mr. Swez testified that an outage occurred at Gibson 4 on October 31, 2016 associated with an issue with the 4C Boiler Feed Pump discharge valve. The seal and bushing were repaired and reassembled, with the unit returned to service on November 4, 2016. On November 12, 2016, an outage occurred on Gibson 1 due to a boiler tube leak. The tube leak was repaired and the unit returned to service on November 16, 2016.

Mr. Eckert testified that the OUCC learned through discovery that a root cause analysis for the Cayuga 1 outage is being performed, but is not yet complete. Mr. Eckert recommended that the Commission make the rates in this Cause interim subject to refund based on the Cayuga 1 outage and allow continued discovery and discussion on the outage, the final Root Cause Analysis, and Applicant's Legal Team's final conclusion.

On March 2, 2017, Nucor filed its *Motion for a Subdocket*. In the Motion, Nucor stated that due to the summary nature of the FAC proceedings, as well as the lack of availability of the final adjuster's report and root cause analysis related to the Cayuga 1 forced outage, there is insufficient time to conduct a complete investigation and present testimony, if appropriate, as to whether Applicant acted prudently. The Motion requests the Commission to approve the proposed FAC in this Cause on an interim basis, subject to refund, and to open a subdocket to allow further discovery and investigation into issues related to the Cayuga 1 forced outage and its impact on the fuel costs included in this proceeding. Applicant filed its response to Nucor's Motion on March 9, 2017, and Nucor filed its Reply on March 14, 2017.

Individual Intervenors adopt and incorporate by reference the summary of testimony and exhibits and proposed Commission findings regarding the Cayuga 1 Forced Outage included in the Nucor and OUCC Joint Proposed Order. In addition, IIs adopt Mr. Eckert's recommendation on behalf of the OUCC that the Commission make the rates in this Cause interim and subject to refund in order to allow continued discovery and review of the Company's Root Cause Analysis and Legal Team's conclusions regarding the outage in testimony and exhibits presented by all parties in the subdocket investigation requested by Nucor.

9. 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 November 30, 2016. Applicant's authorized phased-in jurisdictional operating expenses (excluding fuel costs) are $863,115,000. For the 12-month period ended November 30, 2016, Applicant's jurisdictional operating expenses (excluding fuel costs) totaled $1,281,030,000. 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.

10. 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 in excess of 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 previous Commission Orders, Applicant's calculated jurisdictional electric operating income level was $453,502,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was $494,297,000. Therefore, the Commission finds that Applicant did not earn a return in excess of its authorized level during the 12 months ended November 30, 2016.

11. Estimation of Fuel Costs. Applicant estimates that its prospective average fuel cost for the months of April through June 2017 will be $62,497,334 or $0.024739 per kWh. Applicant previously made the following estimates of its fuel costs for the period September through November 2016, 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
September 2016	27.777	25.759	7.83
October 2016	29.113	26.379	10.36
November 2016	27.678	25.736	7.55
Weighted Average	28.181	25.954	8.58

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 8.58. Based on the evidence of record, we find Applicant's estimating techniques appear reasonably sound and its estimates for April through June 2017 should be accepted.

12. Purchased Power Benchmark. Applicant has calculated monthly purchased power benchmarks 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. The benchmarks are as follows:

Month / Year	Benchmark $/MWh[3]	Facility
Sep 2016	159.05	Connersville 1
Oct 2016	164.14	Connersville 1
Nov 2016	42.10	Vermillion 8

Mr. Burnside testified that Applicant did not exceed benchmarks for the reconciliation period at issue in this FAC proceeding.

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 monthly benchmarks for power purchases that occurred during the September through November 2016 reconciliation period. The Commission further finds that Applicant's request for recovery of its purchased power over the benchmark for June 2016 is consistent with the Commission's Purchased Power Order and should be approved.

13. Fuel Cost Factor. As discussed in Finding No. 3 above, Applicant's base cost of fuel is 14.484 mills per kWh. The evidence indicates that Applicant's fuel cost adjustment factor applicable to April through June 2017 billing cycles is computed as follows:

[3] Calculated using most efficient unit heat rate.

	$ / kWh
Projected Average Fuel Cost	0.024739
Net Variance (current reconciliation period)	0.002157
Adjusted Fuel Cost Factor	0.026896
Less: Base Cost of Fuel	0.014484
Fuel Cost Adjustment Before Applicable Taxes	0.012412
Adjustment for Utility Receipts Tax	0.000188
Fuel Cost Adjustment Factor Adjusted for Applicable Taxes	0.012600

The net variance factor shown above reflects $13,928,844 of under-billed fuel costs applicable to retail customers that occurred during the period September through November 2016.

OUCC witness Mr. Gregory Guerrettaz testified that the fuel cost adjustment for the quarter ended November 2016 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.

14. Effect on Residential Customers. The approved factor represents an increase of $0.000513 per kWh from the factor approved in Cause No. 38707-FAC110. The typical residential customer using 1,000 kWhs per month will experience an increase of $0.51 or 0.6% on his or her electric bill compared to the factor approved in Cause No. 38707 FAC 110 (excluding various tracking mechanisms and sales tax).

15. 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 in the event an excess return is earned.

16. 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 $0.9978625 per 1,000 pounds of steam was calculated on Exhibit B, Schedule 1, of the Verified Application; this factor will be effective for the April through June 2017 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 $70,279 receivable from International Paper for the months of September through November 2016.

The Commission finds that Applicant's proposed fuel cost adjustment factor for International Paper of $0.9978625 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 $70,279 receivable from International Paper has been properly determined and should be approved.

17. **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 2016. Therefore, we find International Paper is not due a shared return revenue credit.

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. 13, and the fuel cost adjustment for steam service as set forth in Finding No. 16 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.

3. Prior to implementing the authorized rates, Applicant shall file Rider 60 under this Cause for approval by the Commission's Energy Division. Rider 60 shall be effective for all bills rendered on and after the first billing cycle of April 2017.

4. Duke Energy Indiana shall provide an update on the status of its coal inventories and the situation with Benton County Wind Farm in its next FAC filing, as described in Finding No. 4 of this Order.

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

ATTERHOLT, FREEMAN, HUSTON, WEBER AND ZIEGNER CONCUR:

APPROVED:

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

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Secretary to the Commission