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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

APPLICATION OF DUKE ENERGY INDIANA, INC. 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 FAC 103** **APPROVED:** MAR 25 2015

ORDER OF THE COMMISSION

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

On January 29 and January 30, 2015, respectively, Duke Energy Indiana, Inc. ("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 2015 for electric and steam service and to update monthly benchmarks for purchased power costs. On February 2, 2015, Steel Dynamics, Inc. ("SDI") filed its Petition to Intervene in this proceeding. On February 5, 2015, the Duke Energy Indiana Industrial Group ("Industrial Group") filed its Petition to Intervene in this proceeding. On February 16, 2015, the Citizens Action Coalition of Indiana filed its Petition to Intervene in this proceeding. The Commission granted those Petitions to Intervene on February 13 and February 19, respectively. The Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and testimony on March 6, 2015. On March 11, 2015, the Presiding Officers issued a docket entry requesting a response from Applicant prior to the evidentiary hearing, and on March 16, 2015, Applicant filed its response.

A public evidentiary hearing was held in this Cause on March 18, 2015, at 9:30 a.m., in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Applicant, the Industrial Group and the OUCC appeared at the hearing by counsel. Applicant and the OUCC offered their respective prefiled testimony and exhibits into the evidentiary record without objection. No members of the general public appeared or sought to testify at the hearing.

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 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 2014, 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 $0.036791 per kWh as shown on Applicant's Exhibit A, Schedule 9. In accordance with previous Commission Orders,[1] Applicant calculated its phased-in authorized jurisdictional net operating income level for the 12-month period ending November 30, 2014, to be $494,275,000. 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 in December 2014 Applicant reached a settlement on disputed contractual issues with regard to a price reopener with Bear Run which are favorable to Applicant and its customers as compared to 2014. He testified that as a result of the settlement, the dispatch cost for 2015 decreased for Wabash River

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[1] The Commission's July 3, 2002, Order in Cause Nos. 41744 S1 and 42061, and subsequent update Orders, up to and including the August 27, 2014, update in Cause No. 42061 ECR 23, 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 September 11, 2013 update in Cause No. 43114 IGCC 10, 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. 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.

Station, Cayuga Station and Edwardsport IGCC Station on average 11.7%; the contract price for 2015 will show a savings of approximately 25% from the original 2015 contract price; and the total fuel costs included in the fuel clause for 2015 were decreased by 8% of the total fuel bill. Ms. Sieferman testified that the settlement amount related to the 2014 tons is being refunded to Applicant via a per ton discount to be applied to future tons delivered over approximately three years. The application of this discount, as well as the lower base pricing for the contract, were effective beginning with January 1, 2015 deliveries. She also stated that native load customers will first see the benefits beginning with bills rendered in April 2015. Ms. Sieferman testified that the impact of the settlement to a typical residential customer using 1,000 kilowatt-hours per month is estimated to be a reduction of approximately 4% and the reduction for large power customers is estimated to be in the 4% to 6% range. Ms. Sieferman testified that there was another price reopener successfully completed in 2014 that resulted in lower per ton pricing for deliveries as of January 1, 2015. Mr. Phipps also testified that as of November 30, 2014, coal inventories were approximately 3,980,000 tons (or 65 days of coal supply), which is higher than what was reported in FAC 102 due to lower demand over the fall months. Mr. Phipps added that Applicant continues to evaluate a host of options in order to manage effectively its growing 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. However, due to continued weak coal market conditions, resell opportunities will continue to be extremely difficult in the near term. Mr. Phipps also testified that Applicant did not recieve all of the scheduled shipments of coal at Cayuga station due to the increased demand for rail service across the entire rail system. As a result, inventory at Cayuga station was well below target levels during the summer and fall months and was forecasted to decline further if Applicant did not continue to use an alternative to support Cayuga's forecasted coal burns. Beginning in June 2014, Applicant started to truck coal from Wabash River station to the Cayuga station in order to increase inventory levels and supplement the rail performance. This trucking ceased on November 26, 2014 after achieving sufficient and reliable inventory levels. 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 2014 the price Applicant paid for delivered natural gas at its gas burning stations was between $3.52 per million BTU to $5.10 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 and coal decrement pricing. He testified that Applicant has met with its suppliers, determined maximum storage at its facilities, is exploring options to resell surplus coal, and decrement coal pricing. He recommended Applicant should continue to update the Commission on its coal inventory.

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 which was approved by the Commission in Cause No. 43097. Mr. Swez stated that due to the nature of the contractual agreement between Applicant and BCWF and the way the Midcontinent Independent System Operator ("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 liquidated damages for production that was not generated. He noted that Applicant disputed this invoice and, as a result, there is no impact to this 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 is currently set for May 2015. Once the dispute with BCWF is resolved, there is the potential for future adjustments for production that was not generated or changes in metered output due to power purchase share meter adjustments that may be reconciled in future FAC proceedings.

Mr. Eckert recommended that Applicant report to the Commission any updates and resolutions to the BCWF situation in its next FAC filing.

Mr. Swez testified that the Edwardsport IGCC generating station began commercial operation on June 7, 2013. The station performed its fall maintenance outage in September 2014. He testified that after the station's fall outage when the unit's gasifiers are operating, Edwardsport IGCC is being offered with a commitment status of must-run. The main change to the offer from Applicant's previous MISO offer is that, because the unit has a minimum and maximum capability that are not equal to one another, to the extent possible, Edwardsport IGCC will be following MISO's dispatch direction between the minimum and maximum capability of the unit rather than MISO following its available output. Mr. Swez also testified that because Applicant's internal coding of the output of the station as "test" ended in mid-September, generation from Edwardsport IGCC is now eligible to be split between native and non-native customers in the same manner as the rest of Applicant's generating units based on the economic stacking process.

Based on the evidence presented, we find that Applicant made reasonable efforts to acquire fuel for its own generation or to purchase power to provide electricity to its retail customers at the lowest fuel cost reasonably possible. 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 Applicant 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 FAC 102 proceeding, Applicant purchased natural gas hedges for expected gas burn in January and February 2015. He testified that there is no gas hedging profit or loss for this FAC proceeding. He further testified Applicant experienced net realized power hedging gains (exclusive of MISO virtual trades and including prior period adjustments) for the period of $327,661.

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 FAC 101 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 gains for power hedging included in the fuel costs in this proceeding or challenging the prudence of the activities that gave rise to the realized net gains. 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 $327,661 of realized power hedging gains in the calculation of fuel costs in this proceeding.

6. Energy and Ancillary Services Markets ("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 2014, 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-14	Oct-14	Nov-14
Regulation Cost Dist.	0.0470	0.0560	0.0581
Spinning Cost Dist.	0.0262	0.0361	0.0347
Supplemental Cost Dist.	0.0127	0.0229	0.0100

OUCC witness Mr. Eckert testified that Applicant's treatment of ASM charges follows the treatment ordered by the Commission in its Phase II Order in Cause No. 43426, dated June 30, 2009.

Based upon the evidence presented, the Commission finds that Applicant's treatment of the new and modified 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. Mr. Swez testified that during this FAC period, the coal price decrement has remained at zero. During times when the coal price decrement is zero, there is no difference between the non-decremented dispatch price and the as offered price of a generating unit. Mr. Swez testified that at the end of 2014, the twice-monthly analysis of the coal decrement ended. However, Applicant continues to forecast its coal inventory position as part of the normal course of business. If this analysis shows that a non-zero decrement is economic in the future, a decrement analysis could be reinstated at that point in time. 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 that during this FAC period, there was no projected excess inventory. Therefore, there was no need to create a coal price decrement stack.

Mr. Swez testified that as a result of the successful price reopeners discussed by Mr. Phipps and Ms. Sieferman, on December 19, 2014, Applicant changed its generation offers to reflect the change in price for two coal agreements. He stated that because of this change, units at Wabash River, Cayuga, Gibson, and Edwardsport IGCC experienced a reduction in their dispatch price, depending on the amount of coal delivered to each station from each contract, with some of those changes being significant reductions in the dispatch price of the unit.

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

8. <u>Major Forced Outages</u>. 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 that there were three outages that met these criteria in this period. He stated that on November 2, 2014, Gibson 3 was brought off-line due to a tube leak in the finishing superheat platen section of the boiler. Due to the failure on this tube, additional tubes failed from neighboring steam washing. Repairs were made and the unit returned to service on November 8, 2014. On November 13, 2014, Gibson 3 was brought off-line due to a finishing superheater tube leak in the penthouse section of the boiler. Due to the failure on this tube, additional reheater terminal tubes failed as well. Repairs were completed and the unit returned to service on November 18, 2014. On October 22, 2014, Cayuga 2 entered a forced outage following a failure in the intermediate pressure section of the turbine. The failure required replacement of several blade rows in the high pressure and intermediate pressure sections of the turbine. Mr. Swez testified that in order to minimize the overall outage time for the unit, Applicant elected to move the previously scheduled spring tie-in outage that was scheduled for March 21, 2015 until May 31, 2015, into the window of the turbine forced outage. The unit is scheduled to return to service on April 12, 2015. The Commission's March 11, 2015 docket entry sought additional discussion on the Cayuga outage. Applicant's March 16, 2015 response indicated it was too early to provide a root cause analysis or to fully and accurately quantify total repair costs or warranty coverage. Because of the uncertain outcome of the review of the outage, the Commission finds that recovery of the portion of Applicant's fuel costs related to the Cayuga 2 outage shall be subject to refund pending further review in future FAC proceedings.

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, 2014. Applicant's authorized phased-in jurisdictional operating expenses (excluding fuel costs) are $863,711,000. For the 12-month period ended November 30, 2014, Applicant's jurisdictional operating expenses (excluding fuel costs) totaled $1,228,920,000. 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 $452,233,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was $494,275,000. Therefore, the Commission finds Applicant did not earn a return in excess of its authorized level during the 12 months ended November 30, 2014.

11. Estimation of Fuel Costs. Applicant estimates that its prospective average fuel cost for the months of April through June 2015 will be $76,504,333 or $0.029285 per kWh. Applicant previously made the following estimates of its fuel costs for the period September through November 2014, 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 2014	29.333	31.882	(8.00)
October 2014	32.189	32.606	(1.28)
November 2014	36.569	32.763	11.62
Weighted Average	32.649	32.423	0.70

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 0.70. The evidence of record supports an understanding of the September and November variances. The September results are influenced by two material adjustments identified in OUCC witness Guerrettaz's testimony, while the forced outage at Cayuga 2 impacted the November metric. Based on the evidence of record, we find Applicant's estimating techniques appear reasonably sound and its estimates for April through June 2015 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 1/	Facility
September 2014	54.73	Vermillion 1
October 2014	52.82	Vermillion 1
November 2014	56.51	Vermillion 2

1/ Calculated using most efficient unit heat rate.

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's current purchased power over the benchmark calculation, which uses an average purchased power price for the week, tends to smooth out high prices and low prices of the purchased power and allows Applicant to pass the test every time.

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 2014 reconciliation period.

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 2015 billing cycles is computed as follows:

	$ / kWh
Projected Average Fuel Cost	0.029285
Net Variance	0.000152
Adjusted Fuel Cost Factor	0.029437
Less: Base Cost of Fuel	0.014484
Fuel Cost Adjustment Before Applicable Taxes	0.014953
Adjustment for Utility Receipts Tax	0.000229
Fuel Cost Adjustment Factor Adjusted for Applicable Taxes	0.015182

The net variance factor shown above reflects $1,023,137 of under-billed fuel costs applicable to retail customers that occurred during the period September through November 2014.

OUCC witness Mr. Gregory Guerrettaz testified that the fuel cost adjustment for the quarter ended November 2014, 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, the post analysis cost evaluator model, and source documentation of Applicant for the period reviewed.

14. <u>Effect on Residential Customers</u>. The approved factor represents a decrease of $0.003323 per kWh from the factor approved in Cause No. 38707 FAC 102. The typical residential customer using 1,000 kWhs per month will experience a decrease of $3.33 or 3.6% on his or her electric bill compared to the factor approved in Cause No. 38707 FAC 102 (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.[2] The fuel cost adjustment factor for International Paper of $1.4801185 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 2015 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 a $16,248 payable to International Paper for the months of September through November 2014.

Applicant's witness Ms. Sieferman noted that the forced outage experienced at Cayuga 2 occurred during a planned outage at Cayuga 1 and as such Applicant was unable to supply steam service to International Paper through traditional means. She testified that a temporary agreement was put in place governing a modified approach for providing steam. The incremental costs are not included in the overall fuel costs reflected in this FAC but instead will be billed directly to International Paper.

The Commission finds that Applicant's proposed fuel cost adjustment factor for International Paper of $1.4801185 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 $16,248 payable to International Paper has been properly determined and should be approved.

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[2] On January 25, 2012, this Commission issued an Order approving the fourth amendment to Steam Supply Agreement between Duke Energy Indiana and Temple-Inland, Inc., n/k/a International Paper.

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 November 2014. 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. Duke Energy Indiana shall place into effect the fuel cost adjustment factors for electric service and steam service approved herein, applicable to all bills rendered beginning with and subsequent to the later of the effective date of the Commission's Order or the first billing cycle of April 2015, upon filing with the Electricity Division of the Commission, a separate amendment to its rate schedules with clear reference therein that such factor is applicable to the rate schedules reflected on the amendment.

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.

STEPHAN, MAYS-MEDLEY, HUSTON, WEBER, AND ZIEGNER CONCUR:

APPROVED: MAR 25 2015

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

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission