ORDER OF THE COMMISSION

On July 31, 2019, 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 October, November, and December 2019 for electric and steam service and to update monthly benchmarks for purchased power costs. The Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and testimony on September 4, 2019.

A public evidentiary hearing was held in this Cause on September 11, 2019, at 9:00 a.m., in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. Applicant and the OUCC appeared at the hearing by counsel and offered their respective prefiled testimony and exhibits into the evidentiary record without objection.

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 (1) qualified pollution control property; (2) property at the Edwardsport Integrated Gasification Combined Cycle Generating Facility (“IGCC”); (3) federally mandated compliance projects; (4) transmission, distribution and storage system improvement projects; and (5) company-owned renewable energy projects approved by the Commission in various rate proceedings not taken into account in the May 18 Order.

Applicant’s cost of fuel to generate electricity and the cost of fuel included in the net cost of purchased electricity for the month of May 2019, 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 $0.027107 per kWh as shown on Applicant’s Exhibit A, Schedule 9. In accordance with previous Commission Orders, Applicant calculated its phased-in authorized jurisdictional net operating income level for the 12-month period ending May 31, 2019, to be $476,140,000. No evidence was offered objecting to the calculation of the authorized jurisdictional net operating income level proposed by Applicant, and we find it to be proper.

4. Fuel Purchases. Mr. Brett Phipps testified regarding Applicant’s coal procurement practices and its coal inventories. Mr. Phipps testified that as of May 31, 2019, coal inventories were approximately 2,775,589 tons (or 51 days of coal supply), which is an increase over what was reported in FAC120 due to a combination of lower demand during the spring months, and low gas and power prices. He testified that coal inventories are projected to increase over the next quarter. 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 March through May 2019 the price Applicant paid for delivered natural gas at its gas burning stations was between $2.28 per million BTU and $7.50 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 D. Eckert, testified regarding Applicant’s coal inventory. He recommended Applicant continue to update the Commission on its coal inventory.
Mr. Swez testified that Applicant continues to submit an incremental cost offer for its share of Benton County Wind Farm in accordance with the settlement agreement with Benton County Wind Farm discussed in FAC 113.

Mr. Swez testified that the Edwardsport IGCC Generating Station continued to run at a high rate. 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.

Based on the evidence presented, we find that Applicant made every reasonable effort to acquire fuel for its own generation or to purchase power so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible during March through May 2019. With regard to its coal inventory levels, Applicant will provide an update on the status in its next FAC proceeding as recommended by the OUCC.

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 there were no realized gas hedging gains or losses in this reconciliation period. Nevertheless, $852 was incurred as broker fees for purchases made to hedge July and August 2019 native gas burn. He testified Applicant experienced net realized power hedging losses for the period of $1,405,625 primarily attributable to mild weather in May, when natural gas prices decreased to the lowest level in the past three years due to lack of power generation demand and strong gas production output. Ms. Sieferman testified that Applicant realized a total net hedging loss of $1,414,618 during the period for all native gas and power hedging activities other than MISO virtual energy market participation (including prior period adjustments).

Mr. Chen explained that, consistent with the Commission’s June 25, 2008 Order in Cause No. 38707 FAC 68 S1 (“FAC 68 S1 Order”), beginning on August 1, 2008, Applicant has not utilized its flat hedging methodology. Rather, Applicant will hedge up to approximately flat minus 150 MW on a forward, monthly and intra-month basis, and up to approximately flat on a Day Ahead/Real-Time basis. This methodology will leave 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.

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
$1,414,618 of net losses 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 March through May 2019, 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:

<table>
<thead>
<tr>
<th></th>
<th>Mar-19</th>
<th>Apr-19</th>
<th>May-19</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulation Cost Dist.</td>
<td>0.0441</td>
<td>0.0426</td>
<td>0.0462</td>
</tr>
<tr>
<td>Spinning Cost Dist.</td>
<td>0.0359</td>
<td>0.0455</td>
<td>0.0381</td>
</tr>
<tr>
<td>Supplemental Cost Dist.</td>
<td>0.0108</td>
<td>0.0093</td>
<td>0.0075</td>
</tr>
</tbody>
</table>

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. **Participation in the Energy and ASM Markets and MISO-Directed Dispatch.** 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.

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 FAC 90, the Commission ordered Applicant to discuss in future FAC proceedings major forced outages of units of 100 MW or more lasting more than 100 hours. Mr. Swez testified during this FAC period there were four outages that met these criteria. The first outage occurred at Gibson Unit 1 on February 24. The unit transitioned to a forced outage when the main turbine turning gear oil pump bearing failed while attempting to restart from a prior outage. Repairs were completed and the unit returned to available status on March 2. The second outage occurred at Gibson Unit 3 on March 21 due to a boiler tube leak. After repairs, the unit returned on March 25. The third outage occurred at Gibson Unit 1 on April 27 when the intake traveling screens that filter out incoming lake water material to the condenser failed. A large shad run had caused many of these small fish to become trapped in the traveling screens, causing the screens to fail. Repairs were made and the unit returned on-line May 4. The fourth outage occurred at Gibson 4 on April 30 due to a leak in the exit duct work from the boiler that breached inside the unit’s stack. Repairs were made and the unit returned on-line May 4. Mr. Swez testified that no Root Cause Analysis (“RCA”) was performed for any of these outages.

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 May 31, 2019. Applicant’s authorized phased-in jurisdictional operating expenses (excluding fuel costs) are $756,231,000. For the 12-month period ended May 31, 2019, Applicant’s jurisdictional operating expenses (excluding fuel costs) totaled $1,410,902,000. 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 more than its applicable authorized return, it must, in accordance with the provisions of Ind. Code § 8-1-2-42.3, determine if the sum of the differentials between actual earned returns and authorized returns for each of the 12-month periods considered during the relevant period is greater than zero. If so, a reduction to the fuel adjustment clause factor is deemed appropriate.

In accordance with previous Commission Orders, Applicant’s calculated jurisdictional electric operating income level was $460,368,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Ind. Code § 8-1-2-42(d)(3), was $476,140,000. Therefore, the Commission finds that Applicant did not earn a return more than its authorized level during the 12 months ended May 31, 2019.

11. **Estimation of Fuel Costs.** Applicant estimates that its prospective average fuel cost for the months of October through December 2019, will be $63,788,947 or $0.025690 per kWh. Applicant previously made the following estimates of its fuel costs for the period March through May 2019, and experienced the following actual costs, resulting in percent deviation, as follows:

<table>
<thead>
<tr>
<th>Month</th>
<th>Actual Cost in Mills/kWh</th>
<th>Estimated Cost in Mills/kWh</th>
<th>Percent Actual is Over (Under) Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>March 2019</td>
<td>26.897</td>
<td>26.759</td>
<td>0.52</td>
</tr>
<tr>
<td>April 2019</td>
<td>25.594</td>
<td>26.919</td>
<td>(4.92)</td>
</tr>
<tr>
<td>May 2019</td>
<td>27.571</td>
<td>26.472</td>
<td>4.15</td>
</tr>
<tr>
<td>Weighted Average</td>
<td>26.708</td>
<td>26.714</td>
<td>(0.02)</td>
</tr>
</tbody>
</table>

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 (0.02). OUCC witness Mr. Guerrettaz identified the additional audit steps taken regarding the variances for these amounts. Specifically, he noted unit operating issues Applicant experienced through the period as presented by Mr. Swez and discussed above. Based on the evidence of record, we find Applicant’s estimating techniques appear reasonably sound and its estimates for October through December 2019 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:
Mr. Burnside testified that Applicant did not exceed the 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 March through May 2019 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 October through December 2019 billing cycles is computed as follows:

<table>
<thead>
<tr>
<th>Description</th>
<th>$ / kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Projected Average Fuel Cost</td>
<td>0.025690</td>
</tr>
<tr>
<td>Net Reconciliation Factor</td>
<td>0.000544</td>
</tr>
<tr>
<td>Adjusted Fuel Cost Factor</td>
<td>0.026234</td>
</tr>
<tr>
<td>Less: Base Cost of Fuel</td>
<td>0.014484</td>
</tr>
<tr>
<td>Fuel Cost Adjustment Before Applicable Taxes</td>
<td>0.011750</td>
</tr>
<tr>
<td>Adjustment for Utility Receipts Tax</td>
<td>0.000177</td>
</tr>
<tr>
<td>Fuel Cost Adjustment Factor Adjusted for Applicable Taxes</td>
<td>0.011927</td>
</tr>
</tbody>
</table>

Ms. Sieferman testified that the net variance factor shown above reflects $3,570,123 of under-billed fuel costs applicable to retail customers that occurred during the period March through May 2019.

OUCC witness Mr. Gregory Guerrettaz testified that the fuel cost adjustment for the quarter ended May 2019 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 a decrease of $0.00221 per kWh from the factor approved in Cause No. 38707 FAC 120. The typical residential customer using 1,000 kWhs per month will experience a decrease of $2.21 or 1.8% on his or her total electric bill compared to the factor approved in Cause No. 38707 FAC 120 (excluding 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, subject to refund, 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 $1.0695525 per 1,000 pounds of steam was calculated on Exhibit B, Schedule 1, of the Verified Application; this factor will be effective for the October through December 2019 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 $22,765 charge to International Paper for the months of March through May 2019.

The Commission finds that Applicant’s proposed fuel cost adjustment factor for International Paper of $1.0695525 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 $22,765 charge to 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 May 2019. Therefore, we find International Paper is not due a shared return revenue credit.

ITAL 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 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 approved.

3. Prior to implementing the authorized rates, Applicant shall file the tariff and applicable rate schedules under this Cause for approval by the Commission’s Energy Division. Such rates shall be effective on or after the date of approval.

4. Duke Energy Indiana shall provide an update on the status of its coal inventories in its next FAC filing, as described in Finding No. 4 of this Order.
5. This Order shall be effective on and after the date of its approval.

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

APPROVED: SEP 25 2019

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

Mary Bevzra
Secretary of the Commission