## STATE OF INDIANA

## INDIANA UTILITY REGULATORY COMMISSION

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| **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 86**<br><br>**APPROVED:** DEC 29 2010 |

**<u>BY THE COMMISSION</u>:**
**Carolene R. Mays, Commissioner**
**Aaron A. Schmoll, Senior Administrative Law Judge**

On November 1, 2010, pursuant to Indiana Code §§ 8-1-2-42 and 8-1-2-42.3, and various Orders of the Indiana Utility Regulatory Commission ("Commission"), Duke Energy Indiana, Inc. ("Duke Energy Indiana," "Company," or "Petitioner") filed with the Commission its Verified Application for approval of a change in its fuel cost adjustment for electric service, approval of a change in its fuel cost adjustment for steam service, and to update monthly benchmarks, together with its case-in-chief testimony.

On November 9, 2010, and November 17, 2010, respectively, Duke Energy Indiana Industrial Group ("Industrial Group") and Steel Dynamics, Inc. ("SDI") filed Petitions to Intervene in this proceeding. The Indiana Office of Utility Consumer Counselor ("OUCC") filed its audit report and direct testimony on December 8, 2010. The Presiding Officers granted the Industrial Group's and SDI's Petitions on December 15, 2010.

Pursuant to proper notice of hearing, published as required by law, proof of which was incorporated into the record by reference, a public evidentiary hearing was held in this Cause on December 15, 2010 at 1:00 p.m. in Room 224, PNC Center, 101 West Washington Street, Indianapolis, Indiana. Duke Energy Indiana and the OUCC offered their respective testimony and exhibits into the evidentiary record without objection. No members of the general public appeared or participated at the hearing.

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

1. **<u>Commission Jurisdiction and Notice</u>.** Due, legal and timely notice of the hearing in this Cause was given as required by law. Duke Energy Indiana is a public utility within the meaning of Indiana Code § 8-1-2, as amended, and is subject to the jurisdiction of the

Commission in the manner and to the extent provided by the laws of the State of Indiana. Therefore, the Commission has jurisdiction over the parties and the subject matter of this Cause.

2. **Duke Energy Indiana's Characteristics.** Duke Energy Indiana 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. Duke Energy Indiana is engaged in rendering electric utility service in the State of Indiana. The Company 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. The Company also renders steam service to one customer, Temple-Inland, Inc. ("Temple-Inland").

3. **Order in Cause No. 42359.** On May 18, 2004, the Commission issued an Order in Cause No. 42359 ("May 18 Order") approving base retail electric rates and charges for Duke Energy Indiana. Among other matters, the Commission's May 18 Order found that Duke Energy Indiana's base cost of fuel should be 14.484 mills per kWh and that the Company'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.

4. **Orders in Cause Nos. 41744 S1 and 42061, 42061 ECR 3 through 42061 ECR 15, the November 20, 2007 Order in Cause Nos. 43114 and 43114 S1 ("IGCC Order") and the Orders in Cause Nos. 43114 IGCC 1 through IGCC 4.** The Commission's July 3, 2002, Order in Cause Nos. 41744 S1 and 42061 ("CWIP Order"), and subsequent update Orders up to and including the August 18, 2010, update in Cause No. 42061 ECR 15 ("CWIP Update"), authorized Petitioner to add the value of certain qualified pollution control property to the value of the Company's property for ratemaking purposes. The Commission's CWIP update order in Cause No. 42061 ECR 3, dated March 11, 2004, stated that the applicable incremental increase to Duke Energy Indiana's authorized return, approved in that proceeding, shall be phased-in over the period of time that Petitioner's net operating income was affected by the applicable CWIP update. The Commission's IGCC Order, and subsequent update Orders up to and including the July 28, 2010, update in Cause No. 43114 IGCC 4, authorized the Company to add the value of property at the Edwardsport Integrated Gasification Combined Cycle Generating Facility ("IGCC Project") to the value of the Company's property for ratemaking purposes. The Company 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. In accordance with these Orders, Duke Energy Indiana calculated its authorized jurisdictional net operating income level for the 12-month period ending August 31, 2010, to be $378,386,000. No party objected to the calculation of the authorized jurisdictional net operating income level proposed by Duke Energy Indiana, and we find it to be proper.

5. **Fuel Purchases.** Mr. Elliott Batson, Jr., Managing Director, Regulated Fuels and Transportation, testified regarding Duke Energy Indiana's fuel procurement practices. Petitioner generally purchases coal under long-term contracts. All of Duke Energy Indiana's major generating stations are covered by long-term contracts except Edwardsport Station. For 2010,

Gibson, Wabash River, Gallagher and Cayuga Stations are supplied by long-term agreements for more than 90% of their annual requirements. Mr. Batson stated that Edwardsport is a smaller, older station and is used by the Company essentially for peaking; therefore, a long-term contract is not necessary. The requirements for Edwardsport are supplied by either diverting contract tonnages from other stations or from spot market purchases. Mr. Batson noted that many of the long-term contracts either contain provisions for periodic price re-opener negotiations, some type of price escalation, or a mechanism to adjust prices based upon a published market price index. In addition, all of the Company's coal transportation contracts in Indiana contain fuel price surcharge provisions that are based upon published fuel price indices.

Mr. Batson testified that during the twelve month period ended August 31, 2010, coal purchased under long-term commitments comprised greater than 99% of total coal receipts. Mr. Batson testified that if the Company were to purchase all of its coal requirements on the open market, spot prices would be driven upward to accommodate a demand influx of approximately 13 to 16 million tons annually. Mr. Batson explained that when spot coal is required, the purchase commitments are usually made for small quantities, over short durations, and are based on the lowest delivered cost and best overall utilization characteristics. Mr. Batson discussed other steps the Company takes to keep coal prices down.

Mr. Batson explained the Company's coal inventory positions. He testified that after experiencing high inventories for most of 2009 and early in 2010, inventories at the stations have now returned to normal levels, with the exception of Gibson Station. He stated that inventories at Gibson Station remain above target levels, but are well below peak levels in 2009. He stated that the Company continues to take active steps to reclaim coal from the remote storage site at Gibson Station each month as opportunities allow. Mr. Batson testified that as of September 30, 2010, the Company had reclaimed approximately 165,000 tons from the Gibson Station remote storage site for the year, and anticipates depleting all inventory at this site before the end of 2011. Mr. Batson explained that Duke Energy Indiana will continue to closely monitor its anticipated coal requirements and inventories and take actions to cost-effectively control coal inventories.

Mr. Batson explained the steps the Company has undertaken to comply with the New Source Review ("NSR") Litigation consent decree for Gallagher Station. He testified that the Company is on target to meet the $SO_2$ requirements outlined in the NSR Consent Decree beginning January 1, 2011. He explained that in early 2010, the Company began taking steps to convert its existing coal pile at the station and its various coal supply sources from higher $SO_2$ coals to lower $SO_2$ coals to meet the requirements of the Consent Decree. He stated that as of March 31, 2010, the Company successfully depleted its higher sulfur inventory stored on-site at Gallagher Station. Thereafter, the Company began stockpiling lower sulfur Indiana coal at the station pursuant to an existing contract with a supplier. Mr. Batson testified that as of September 30, 2010, the Company had approximately 135,000 tons of low sulfur coal stored in the main stockpile at the station. He stated that the Company is currently on pace to end the year at its target inventory level of low sulfur coal.

OUCC witness Mr. Michael D. Eckert recommended that Duke Energy Indiana continue to update the Commission on the coal inventory situation in the next FAC proceeding.

Mr. Batson testified that in his opinion, Duke Energy Indiana is purchasing coal at prices as low as reasonably possible. Mr. Batson concluded his testimony by offering his opinion that oil purchased by Duke Energy Indiana for peaking units, unit cycling purposes and Duke Energy Indiana's one oil-fired boiler at Edwardsport Station is purchased at the lowest cost reasonably possible.

Mr. John D. Swez, Director, Bulk Power Marketing and Trading, discussed Duke Energy Indiana's contracts and practices related to the transportation and purchase of natural gas, including its selection, through a competitive bidding process, of new natural gas managing agents. Mr. Swez testified that the price of delivered natural gas at the Company's gas burning generation stations during the three-month period from June 2010 through August 2010 varied in a range of approximately $4.25 per million BTU to $5.50 per million BTU. Mr. Swez testified that, in his opinion, Duke Energy Indiana purchased natural gas at the lowest cost reasonably possible.

OUCC witness Mr. Eckert testified regarding a comparison he performed of the actual monthly fuel costs for the five large investor owned utilities and concluded that Duke Energy's monthly fuel cost is among the lowest in Indiana. Mr. Eckert also testified that he prepared and included a schedule in this filing which shows the timelines associated with each of Duke Energy Indiana's coal contracts.

Based upon the evidence presented, we find that Duke Energy Indiana has made reasonable efforts to acquire fuel for its own generation so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. We find that Duke Energy Indiana's coal storage actions are reasonable, prudent and in the best interest of customers. With regard to its coal inventory levels, Duke Energy Indiana shall provide an update on the status of its coal inventories in its FAC87 proceeding as recommended by the OUCC.

**6. Hedging Activities.** In his testimony, Mr. Wenbin (Michael) Chen, Manager, Portfolio Optimization, provided updates of the Company's gas and power hedging activities. He explained that the Company relies more on natural gas for fuel for the Company's peaking plants than it has in the past and cited recent historical occurrences of gas price volatility. He testified that, in his opinion, it makes sense for the Company to take advantage of the hedging tools available to protect against price fluctuations. Mr. Chen testified that since the last update to the Commission in the FAC 85 proceeding, the Company purchased February and March 2011 forward gas contracts to hedge up to 100% of the Company's expected native burn for January and February 2011. Mr. Chen discussed the results of the gas hedging for the June 2010 through August 2010 reconciliation period. He testified that the Company realized a net profit of $23,870 from July 2010 native gas burn hedges.

Mr. Chen also cited recent historical occurrences of power price volatility and explained the Company's use of forward power purchase contracts to hedge against this volatility. Mr. Chen explained that the Company has been making power hedging purchases since January 2006. He stated that the Company's methodology for making purchases has remained constant since that time. If the forward purchase price of power is less than the cost of running the incremental generating units required to meet the forecasted load, the Company may purchase a forward power hedge. Mr. Chen also explained the Company is constantly assessing conditions and adapting its forward power positions accordingly with the goal of maintaining forward power hedges only in the amount necessary to economically cover its forecasted load.

Mr. Chen discussed the results of and the factors influencing the results of the power hedging for the June 2010 through August 2010 reconciliation period. He stated the Company realized power hedging gains (exclusive of Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") virtual trades) for the period of $1,977,391.

Mr. Chen also explained that, consistent with the Commission's June 25, 2008 Order in Cause No. 38707 FAC 68 S1, beginning on August 1, 2008, and continuing until permanent hedging protocols are developed and approved by the Commission, Duke Energy Indiana will not utilize its flat hedging methodology. Rather, Duke Energy Indiana 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 approximately 150 MW of expected load unhedged on a forward forecasted basis.

Mr. Chen also noted that the Company continues to hold discussions with the OUCC and its consultant to develop the OUCC's power hedging audit plan.

Mr. Chen stated that there have been no recent changes to its power hedging plans, other than raising the internal risk limit, as discussed in previous FAC proceedings.

Mr. Chen offered his opinion that the Company's gas and power hedging practices are reasonable. He stated that the Company never speculates on future prices, that its practice is economic at the time the hedging decisions are made, that it reduces volatility, and that it benefits customers by reducing customers' risk of paying potentially higher spot market prices.

In her testimony, Ms. Diana L. Douglas, Director, Rates, explained that the amount included in fuel costs for hedging activity in this proceeding was a realized net gain of $23,870 for gas hedging activity and a realized net gain of $1,977,391 for power hedging activity (exclusive of Midwest ISO virtual activity).

OUCC witness Mr. Eckert testified that there were no concerns related to hedging transactions in this FAC proceeding and that the OUCC and the Company have been meeting collaboratively to discuss Duke's hedging transactions pursuant to the settlement agreement in Cause No. 38707 FAC 68 S1.

The Commission's Order in Cause No. 38707 FAC 67, dated April 6, 2006, found gas hedging activities to be reasonable. The Company included a gas hedging gain of $23,870 in the computation of the current fuel adjustment clause factor. The gas hedging amount was properly included, and we so find.

The issue of the appropriateness of the inclusion of realized gains/losses relating to the Company's power hedging activities in the computation of the fuel adjustment charge was the subject of a proceeding established by the Commission in Cause No. 38707 FAC 68 S1. On June 25, 2008, the Commission issued an Order approving a Stipulation and Agreement ("Settlement") between Duke Energy Indiana and the OUCC and resolving all disputed issues evaluated within that sub-docket. No party has expressed concerns regarding the realized net gain for power hedging included in the fuel costs in this proceeding or challenged the prudence of the power hedging activities that gave rise to the realized net gain. In addition, the Company presented evidence that its hedging practices relevant to this proceeding were consistent with the Agreement. Thus, we will allow Petitioner to include $1,977,391 of realized power hedging gains in the calculation of fuel costs in this proceeding.

7. **Orders in Cause Nos. 42685, 38707 FAC 70, and 43426.** On June 1, 2005, the Commission issued its final Order in Cause No. 42685 ("June 1 Order"). In the June 1 Order, we approved certain changes in the operations of Duke Energy Indiana and the other investor-owned Indiana electric public utilities that are participating members of the Midwest ISO. Additionally, we addressed the timing and manner of recovery of costs incurred by Duke Energy Indiana as a result of the Midwest ISO's implementation of day-ahead and real-time markets for electric energy (the "Energy Markets"). In the June 1 Order, we determined the Energy Markets charges and credits that should be included in the cost of fuel for purposes of subsequent fuel cost proceedings, including certain charges and credits listed on page 37 of the June 1 Order.

In this proceeding, Mr. Swez testified that Duke Energy Indiana included the following Energy Markets charges and credits incurred as a cost of reliably meeting the power needs of Duke Energy Indiana's load: (1) Energy Markets charges and credits associated with Duke Energy Indiana's own generation and bilateral purchases that were used to serve retail load; (2) purchases from the Midwest ISO at the full locational marginal price ("LMP") at Duke Energy Indiana'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 involving Manual Re-Dispatch Make Whole Payments that resulted in credits from testing prior to the start of the Ancillary Services Market ("ASM"), as authorized by the Commission in Cause No. 38707 FAC 77 and Cause No. 38707 FAC 80.

Ms. Mary Ann Amburgey, Lead Accounting Analyst, testified as to the procedures followed by the Company to verify the accuracy of the charges and credits allocated by the Midwest ISO to the Company. She also discussed the process by which the Midwest ISO 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 the Company from the Midwest ISO is reviewed utilizing the computer software tools described in her testimony. Ms. Amburgey testified that she is confident that the amounts paid by Duke Energy Indiana to the Midwest ISO, net of any credits, are proper and that such amounts billed to customers through the fuel adjustment clause are proper.

On June 30, 2009, the Commission issued its Phase II Order in Cause No. 43426 ("Phase II Order") authorizing Duke Energy Indiana and the other Joint Petitioners to recover costs and credit revenues related to ASM. Mr. Swez explained that Duke Energy Indiana has included various ASM charges and credits in this proceeding incurred for June, July and August 2010, consistent with the Phase II Order, as well as appropriate period adjustments.

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

| (in $ per MWH) | June 10 | July 10 | August 10 |
|---|---|---|---|
| Regulation Cost Dist | 0.0773 | 0.0754 | 0.0714 |
| Spinning Cost Dist | 0.0485 | 0.0520 | 0.0443 |
| Supplemental Cost Dist | 0.0230 | 0.0183 | 0.0196 |

OUCC witness Mr. Eckert testified that Petitioner reported the average monthly distribution costs of Regulation, Spinning, and Supplemental Reserves charge types in accordance with the Commission's Phase II Order.

Based upon the evidence presented, we find that Duke Energy Indiana's inclusion 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.

**8. <u>Participation in the Energy and ASM Markets and Midwest ISO Directed Dispatch</u>.** As mentioned above, in the June 1 Order, the Commission approved certain changes in the operations of Duke Energy Indiana as a result of the implementation of the Energy Markets. Specifically, we found that Duke Energy Indiana (and the other electric utilities participating in Cause No. 42685) "should be granted authority to participate in the Midwest ISO directed dispatch and energy markets as described in their testimony." *Id.* at p. 13. Mr. Swez generally described Duke Energy Indiana's participation in the Midwest ISO energy markets and testified that it was consistent with the testimony presented in Cause No. 42685. Mr. Swez discussed the offer process and noted there are a variety of reasons that Duke Energy Indiana 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 also noted that up until the start of the ASM on January 6, 2009, Duke Energy Indiana continued to provide regulation and contingency reserve service through the intra five-minute dispatch of its generating units; however, once ASM began Duke Energy Indiana offers these ancillary services to and purchases these ancillary services from the ASM. Mr. Swez also described the Company's experience thus far under ASM. Mr. Swez explained that to his knowledge the ASM has generally functioned without any major issues. Duke Energy Indiana's generators have been able to follow real-time signals from the Midwest ISO with minimal issues. Day-ahead and real-time Market Clearing Prices for Regulating, Spinning, and Supplemental Reserves appear to be at reasonable price levels consistent with market conditions. In addition, he opined that Duke Energy Indiana's generating units appear to be appropriately receiving day-ahead and real-time awards for Regulating, Spinning, and Supplemental Reserves.

Mr. Swez testified that in recent months there have been no unique circumstances impacting the Company's generating unit commitment process. He stated that due to the current market, weather, and native loads, the Company is generally committing units in the same manner as before the economic recession and the resulting build-up in coal pile inventories.

Mr. Swez testified that the Company has modified its dispatch of generating units process slightly in response to the Midwest ISO's elimination of the use of dispatch bands in the real-time energy market in March 2010. He stated that the Company has not experienced any issues nor seen any cost increase as a result of this modification.

Mr. Swez also explained that because coal inventory levels for Duke Energy Indiana's Generating Stations have returned to normal, with the exception of Gibson Station, Duke Energy Indiana has ceased incorporating avoided costs related to off-site coal storage into the dispatch and commitment costs of the Gallagher Station units. He said the Company believes it should act reasonably to try to avoid incremental coal storage and reclaim costs that customers would ultimately have to pay caused by excess coal inventories. Accordingly, the Company continues to reduce the dispatch and commitment costs of the Gibson units by the amount of incremental coal storage costs and continues to evaluate the ongoing need to do so.

In addition, Mr. Swez noted another condition impacting dispatch of the Company's units but having no impact on this FAC proceeding; namely, that Gibson Unit 5 was forced out of service on September 25, 2010 as a result of a high bearing turbine vibration. To mitigate the impact of this outage, the Company moved the scheduled spring 2011 outage for Unit 5 to the current outage on Unit 5 and moved the fall 2010 scheduled outage of Gibson Unit 2 to the spring of 2011. He stated the Unit 5 outage was expected to last twelve weeks.

Mr. Swez also testified that the existing Edwardsport Station must cease operations before the first firing of the auxiliary boiler on the new Edwardsport Integrated Gasification Combined Cycle ("IGCC") unit, which is scheduled for 2011. He stated that the Company notified the Midwest ISO of the planned shutdown, and the Midwest ISO has responded and notified the Company that Edwardsport Station may be retired without the need for the generators to be designated as System Support Resource units. Mr. Swez testified that shutdown of the existing Edwardsport units is anticipated to occur sometime late in 2010 or early 2011.

Based upon the evidence presented, we find that Duke Energy Indiana'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.

**9. <u>New Source Review ("NSR") Litigation Impacts on Operations</u>.** Mr. Swez noted that in prior FAC proceedings he had discussed the shutdown of Wabash River Units 2, 3 and 5 on September 30, 2009, as a result of the U.S. District Court's decision in the NSR lawsuit. He testified that on October 12, 2010, the Seventh Circuit Federal Court of Appeals reversed the District Court's decision. He stated that given this decision, the Company believes it is possible that Wabash River Units 2, 3, and 5 will be available again in the next few months. He explained that the Company is waiting to see if the government files a motion for rehearing or appeals the 7th Circuit decision to the United States Supreme Court. Mr. Swez also testified that pursuant to the Consent Decree involving the Gallagher units in the NSR lawsuit, these units are being operated under pre-project NSR baseline levels for 2010 to limit annual emissions.

OUCC witness, Mr. Eckert, testified that the District Court's May 29, 2009, decision requiring shutdown of the Wabash River units does impact actual costs in Duke's current FAC and that the forecast costs for the months of January, February, and March 2011 are higher due to Wabash River Units 2, 3, and 5 not being available for dispatch during the forecast period. Mr. Eckert described the agreement addressed by the Commission in its FAC 84 Order, which required Duke Energy Indiana to file a separate case with the Commission by September 30, 2010 that addresses the NSR litigation impacts. Mr. Eckert testified that the Company did file such case with the Commission under Cause No. 43956. Mr. Eckert also recommended that, in its next FAC proceeding, Duke Energy Indiana again update the Commission on the following: (1) how the shutdown and/or potential availability of Wabash River Units 2, 3 and 5 will impact the Company's ability to meet future summer peak demands; (2) how Duke Energy Indiana intends to meet those future summer peak demands; and (3) the status of the Seventh Circuit Federal Court appeal. With regard to Gallagher Units 1 and 3, Mr. Eckert also recommended that Duke Energy Indiana provide information in its next FAC filing regarding how the potential shutdown of these units will impact the Company's ability to meet future summer peak demands and how Duke Energy Indiana intends to meet those future summer peak demands if Gallagher Units 1 and 3 are shut down.

The Commission finds that the fuel costs approved in this FAC related to increased fuel costs as a result of the shutdown of Wabash River Station Units 2, 3 and 5 shall be subject to refund pending the final order of the Commission in Cause No. 43956, as discussed in the Commission's FAC 84 Order, or further Order of the Commission.

**10. Operating Expenses.** Provisions of Indiana Code § 8-1-2-42(d)(2) require the Commission to determine whether actual increases in fuel costs have been offset by actual decreases in other operating expenses. Accordingly, Duke Energy Indiana filed operating cost data for the 12 months ended August 31, 2010. Duke Energy Indiana's authorized jurisdictional operating expenses (excluding fuel costs) are $801,281,000. For the 12-month period ended August 31, 2010, Duke Energy Indiana's jurisdictional operating expenses (excluding fuel costs) totaled $1,065,373,000. Accordingly, Duke Energy Indiana's actual operating expenses exceeded jurisdictional authorized levels during the period at issue in this Cause. Therefore, the Commission finds that Duke Energy Indiana's actual increases in fuel costs for the above referenced periods have not been offset by decreases in other jurisdictional operating expenses.

**11. Return Earned.** Ind. Code § 8-1-2-42(d)(3), subject to the provisions of Indiana Code § 8-1-2-42.3, generally prohibits a fuel cost adjustment charge which would result in regulated utilities earning a return in excess of its applicable authorized return (earnings test). 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 Indiana 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.

Ms. Douglas testified that, in compliance with the Commission's June 25, 2008 Order in Cause No. 42736 RTO 14, the Company has excluded applicable revenues and expenses from the FAC earnings test related to Company-owned Midwest ISO RECB transmission projects. In June 2010, the Company began receiving revenues on the first of these Company-owned projects.

The fuel cost charge test period used for earnings test computations in this Cause was the 12 months ended August 31, 2010. During this period, Duke Energy Indiana's actual jurisdictional electric operating income level was $283,914,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Indiana Code § 8-1-2-42(d)(3), was $378,386,000. Therefore, the Commission finds that Duke Energy Indiana did not earn a return in excess of its authorized level during the 12 months ended August 31, 2010.

12. **Interim Rates.** Because we are unable to determine whether Duke Energy Indiana'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.

13. **Estimation of Fuel Costs.** Duke Energy Indiana estimates that its prospective average fuel cost for the months of January through March 2011 will be $70,616,224 or $0.026150 per kWh. Duke Energy Indiana previously made the following estimates of its fuel costs for the period June 2010 through August 2010, and experienced the following actual costs, resulting in percent deviation, as follows:

| Month | Actual Cost in Mills/kWh | Estimated Cost in Mills/kWh | Percent Actual is Over (Under) Estimate |
|---|---|---|---|
| June 2010 | 26.593 | 24.805 | 7.21 |
| July 2010 | 26.248 | 25.660 | 2.29 |
| August 2010 | 27.057 | 25.565 | 5.84 |
| Weighted Average | 26.635 | 25.356 | 5.04 |

A comparison of Duke Energy Indiana's actual fuel costs with the respective estimated costs for these three periods results in a weighted average percentage difference of 5.04%.

No party in this Cause disputed the techniques or results of Duke Energy Indiana's forecasting methodology. Duke Energy Indiana's estimating techniques appear reasonably sound and its estimates for January through March 2011 should be accepted and we so find.

14. **Purchased Power Benchmark.** Duke Energy Indiana 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 |
|---|---|---|
| June 2010 | 175.23 | Wabash River Diesel |
| July 2010 | 175.91 | Wabash River Diesel |
| August 2010 | 175.98 | Wabash River Diesel |

1/ Calculated using most efficient unit heat rate.

No Party objected to these calculations. Based on the evidence of record, the Commission finds that Duke Energy Indiana has met the requirements necessary to establish monthly benchmarks for power purchases that occurred during the June through August 2010 reconciliation period.

**15. Fuel Cost Factor.** As discussed in Finding No. 3 above, Duke Energy Indiana's base cost of fuel is 14.484 mills per kWh. The evidence indicates that Duke Energy Indiana's fuel cost adjustment factor applicable to January through March 2011 billing cycles is computed as follows:

| | $ / kWh |
|---|---|
| Projected Average Fuel Cost | 0.026150 |
| Net Variance | 0.002007 |
| Adjusted Fuel Cost Factor | 0.028157 |
| Less: Base Cost of Fuel | 0.014484 |
| Fuel Cost Adjustment Before Applicable Taxes | 0.013673 |
| Adjustment for Utility Receipts Tax | 0.000208 |
| Fuel Cost Adjustment Factor Adjusted for Applicable Taxes | 0.013881 |

The net variance factor shown above reflects $14,392,788 of under-billed fuel costs applicable to retail customers that occurred during the period June through August 2010.

OUCC witness Mr. Gregory Guerrettaz testified, among other matters, that the fuel cost element of the Company's proposed fuel cost adjustment has been calculated in conformity with Indiana Code §8-1-2-42 and numerous Commission Orders affecting this filing. He further concluded that the fuel cost adjustment for the quarter ended August 31, 2010, had been properly applied by the Company. In addition, he stated that the figures used in the Application for a change in the fuel cost adjustment were supported by the Company's books and records, "PACE", and source documentation of the Company for the period reviewed.

**16. Effect on Residential Customers.** The approved factor represents an increase of $0.002635 per kWh from the factor approved in Cause No. 38707 FAC 85. The typical residential customer using 1,000 kWhs per month will experience an increase of $2.63, or 3.0%, on his or her base electric bill compared to the factor approved in Cause No. 38707 FAC 85 (excluding various tracking mechanisms and sales tax).

**17. Fuel Adjustment for Steam Service.** On December 30, 1992, this Commission issued its Order in Cause No. 39483 approving the June 18, 1992 Agreement between Duke Energy Indiana and Premier Boxboard, n/k/a Temple-Inland, which included a change in the method used to calculate Temple-Inland's fuel cost adjustment as well as an update to the base cost of fuel. The fuel cost adjustment factor for Temple-Inland of $1.1964460 per 1,000 pounds of steam was calculated on Exhibit B, Schedule 1, of the Verified Application; this factor will be effective for the January through March 2011 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 Temple-Inland that resulted in a $16,754 receivable from Temple-Inland for the months of June 2010 through August 2010.

The Commission finds that Duke Energy Indiana's proposed fuel cost adjustment factor for Temple-Inland of $1.1964460 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 Duke Energy Indiana's reconciliation amount of $16,754 receivable from Temple-Inland has been properly determined and should be approved.

**18. Shared Return Revenue Credit Adjustment for Temple-Inland.** In accordance with the June 18, 1992 Settlement Agreement, Temple-Inland will receive shared return revenue credit adjustments to the extent incurred. As indicated above in Finding No. 11, Duke Energy Indiana did not have excess earnings for the 12 months ended August 2010. Therefore, we find Temple-Inland is not due a shared return revenue credit.

**19. Look-back Period.** Duke Energy Indiana, similar to other Indiana utilities, applies adjustments to its actual incurred fuel costs for periods that preceed the reconciliation period. Mr. Guerrettaz noted that the look-back period used by Duke extends back to Spetember 2006 and that such an extensive audit period requires considerable effort. Mr. Guerrettaz recommended that the Commission limit the look-back period covered by the Company's prior period adjustments to a rolling one-year period, except for special exceptions for material resettlements. We note that the prior period cost adjustments included in this proceeding, as shown on Petitioner's Exhibit A, Schedule 7, Pages 1 – 3, apply to March, April and May 2010. We recognize that there have been circumstances in the past that required material resettlements for historical periods due to corrections resulting from factors beyond the Company's control Accordingly, we find that Mr. Guerrettaz's recommendation is reasonable, and conclude that the Company shall use a one-year rolling look-back period for all prior period adjustments, except those material adjustments that result from a material resettlement pre-dating the look-back period. For those exceptions, we find that the Company shall include a discussion of the adjustment in its prefiled testimony.

**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. 15, and the fuel cost adjustment for steam service as set forth in Finding No. 17 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. 7 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 January 2011, 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. This Order shall be effective on and after the date of its approval.

**ATTERHOLT, MAYS AND ZIEGNER CONCUR; LANDIS ABSENT:**

**APPROVED:** DEC 29 2010

**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**