ORIGINAL

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 88** **APPROVED:** JUN 29 2011

BY THE COMMISSION:
Carolene Mays, Commissioner
Aaron A. Schmoll, Senior Administrative Law Judge

On April 28, 2011, pursuant to Indiana Code §§ 8-1-2-42 and 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 May 2, 2011, and May 5, 2011, 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 June 3, 2011.

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 June 16, 2011, at 9:30 a.m., in Room 224 of the 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. The Presiding Officers granted the Industrial Group's and SDI's Petitions to intervene on the record at the evidentiary hearing. 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. **Commission Notice and Jurisdiction.** 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 Ch. 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 16, 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 February 9, 2011, update in Cause No. 42061 ECR 16 ("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 February 28, 2011, to be $395,103,000. 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., Vice President, Regulated Fuels, testified regarding Duke Energy Indiana's fuel procurement practices. Mr. Batson testified that during the twelve month period ended February 28, 2011, coal purchased under long-term commitments comprised greater than 98% 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 testified that inventories for the Company's coal fired plants remain near 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. Mr. Batson testified that the overall Gibson Station inventory (including the remote pile) is not expected to return to a normal level until the end of 2011 or mid 2012. Mr. Batson explained that Duke Energy Indiana will continue to closely monitor its anticipated coal requirements and take actions to cost-effectively control coal inventories.

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 and cycling units is purchased at the lowest cost reasonably possible.

Mr. John D. Swez, Director, Regulated Portfolio Optimization, discussed Duke Energy Indiana's contracts and practices related to the transportation and purchase of natural gas. Mr. Swez testified that the price of delivered natural gas at the Company's gas burning generation stations during the three-month period from December 2010 through February 2011 varied in a range of approximately $4.00 per million BTU to $5.00 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 Indiana large investor owned utilities and concluded that Duke Energy's monthly fuel cost is in the middle. Mr. Eckert also testified that he prepared a schedule which shows the timelines associated with each of Duke Energy Indiana's coal contracts. This schedule was not filed in the current FAC due to the concerns raised in FAC 87 by Mr. Batson in his pre-filed testimony that public disclosure in the format presented by the OUCC provides a level of clarity into the Company's coal position that would hurt the Company's leverage in negotiations for new coal contracts, to the detriment of customers. Mr. Eckert stated that the OUCC does not agree with Mr. Batson's position but has chosen not to file the exhibit due to the concerns raised by Mr. Batson. Mr. Eckert further testified that Duke Energy Indiana has two contracts scheduled to expire in 2011. He explained that the OUCC discussed these contracts with the Company and plans to continue monitoring expiring contracts in future FAC filings.

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 will provide an update on the status of its coal inventories in its FAC 89 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 87 proceeding, the Company purchased August and September 2011 forward gas contracts to hedge up to 50% of the Company's expected native burn for July and August 2011. Mr. Chen discussed the results of the gas hedging for the December 2010 through February 2011 reconciliation period. He testified that the Company realized a net gain of $30,981 from hedges bought for January 2011 native gas burn.

Mr. Chen discussed the results of and the factors influencing the results of the power hedging for the December 2010 through February 2011 reconciliation period. He stated the Company experienced realized power hedging gains (exclusive of Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") virtual trades and including prior period adjustments) for the period of $2,756,420.

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, has responded to all data requests, and has provided hedging audit information for the reconciliation months of this FAC filing.

Mr. Chen opined 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.

OUCC witness Mr. Eckert testified that there were no major issues related to hedging in this cause. He explained that the OUCC is investigating how Duke determines whether the benefits of a pair of transactions that include an offsetting sale in the real-time market and purchase in the day-ahead market justify the incremental costs for that pair of transactions. He noted that the OUCC intends to discuss this practice further with representatives from the Company prior to the next FAC.

The Commission's Order in Cause No. 38707 FAC 67, dated April 6, 2006, found gas hedging activities to be reasonable. The Company has included a gas hedging gain of $30,981 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 $2,756,420 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.

Mr. Swez testified that Petitioner made a change in how it procured transmission for its load in the Southern Indiana Gas & Electric ("SIGE") Local Balancing Authority ("LBA") when the Grandfathered Service Agreements ("GFAs") were terminated on December 1, 2010. Starting December 1, 2010, Duke Energy Indiana switched to Network Integration Transmission

Service for its load in the SIGE LBA. Ms. Amburgey testified that after December 1, 2010, there will no longer be any charges or credits for GFAs, Day Ahead Congestion Rebates or Day Ahead Loss Rebates.

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 December 2010, January 2011 and February 2011, 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)	Dec-10	Jan-11	Feb-11
Regulation Cost Dist	0.0718	0.0778	0.0644
Spinning Cost Dist	0.0247	0.0371	0.0308
Supplemental Cost Dist	0.0152	0.0147	0.0155

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 FAC70, as well as our Phase I and Phase II Orders in Cause No. 43426.

8. Participation in the Energy and ASM Markets and Midwest ISO Directed Dispatch. 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 testified that there were a limited number of operating conditions that affect the dispatch of Petitioner's operating units. He explained that Gibson Unit 1 was forced out of service on February 24, 2011, as a result of a failure of the weld joints connecting the Economizer Hoppers to the boiler's back pass. At the time of testimony, the unit was expected to return to service in early May 2011. He explained that the work for the planned outage that

occurred in April will be completed during the current outage and, given that the outage on unit 1 comes during a planned outage on unit 2, work is also being completed on systems common to both units.

Mr. Swez testified the Company discontinued incorporating avoided costs related to off-site coal storage into the dispatch and commitment costs of the Gibson units effective March 2, 2011. Mr. Swez also testified that on March 1, 2011, Edwardsport Units 6-8 were shut down and retired in anticipation of the first firing of the auxiliary boiler on the new Edwardsport Integrated Gasification Combined Cycle unit planned for later this year.

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. **New Source Review ("NSR") Litigation Impacts on Operations.** Mr. Swez noted that in the FAC 86 and FAC 87 proceedings he had discussed the Seventh Circuit Federal Court of Appeals' reversal of the U.S. District Court's decision to shutdown Wabash River Units 2, 3 and 5 on September 30, 2009. He testified that on December 29, 2010, the request for rehearing by the U.S. Department of Justice on behalf of the Environmental Protection Agency ("DOJ") was denied and that on April 15, 2011, the U.S. District Court issued an Amended Final Judgment in favor of the Company, vacating the May 29, 2009 Judgment. He stated that the Company was in the process of bringing Wabash River Units 2, 3 and 5 back to service, with Units 2 and 3 expected back on-line before summer and Unit 5 expected back mid-summer. 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 to limit annual emissions. He stated that this restriction did not impact the units' generation in 2010 and is not impacting the units' generation in 2011. Mr. Swez also noted that effective December 1, 2010, the impact of dry sorbent injection costs have been added to the dispatch prices for the Gallagher Units 2 and 4 to reflect the correct variable costs for those units.

OUCC witness 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, captioned Cause No. 43956. Mr. Eckert recommended that, in its next FAC proceeding, Duke Energy Indiana again update the Commission on how the availability of Wabash River Units 2, 3 and 5 will impact the Company's ability to meet future summer peak demands. Mr. Eckert noted a recent change related to the Gallagher Units 1 and 3, in particular that Duke Energy Indiana intends to shutdown these units in the event the Company is able to obtain an interest in a merchant plant from Duke Energy Vermillion II, LLC. Mr. Eckert recommended that Duke Energy Indiana provide information in its next FAC filing regarding how the potential shutdown of these Gallagher units and the acquisition of the merchant plant from Duke Energy Vermillion II, LLC, will impact the Company's ability to meet future summer peak demands.

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.** Indiana 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, Duke Energy Indiana filed operating cost data for the 12 months ended February 28, 2011. Duke Energy Indiana's authorized jurisdictional operating expenses (excluding fuel costs) are $808,919,000. For the 12-month period ended February 28, 2011, Duke Energy Indiana's jurisdictional operating expenses (excluding fuel costs) totaled $1,112,105,000. 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.** Indiana 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 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.

The fuel cost charge test period used for earnings test computations in this Cause was the 12 months ended February 28, 2011. During this period, Duke Energy Indiana's actual jurisdictional electric operating income level was $286,507,000, while its authorized phased-in jurisdictional electric operating income level for purposes of Indiana Code § 8-1-2-42(d)(3), was $395,103,000. Therefore, the Commission finds that Duke Energy Indiana did not earn a return in excess of its authorized level during the 12 months ended February 28, 2011.

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 July through September 2011 will be $75,977,031 or $0.026917 per kWh. Duke Energy Indiana previously made the following estimates of its fuel costs for the period December 2010 through February 2011, 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
December 2010	26.890	24.953	7.76
January 2011	28.810	26.449	8.93
February 2011	25.930	25.876	0.21
Weighted Average	27.248	25.769	5.74

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 5.74%.

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 July through September 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
December 2010	174.49	Wabash River Diesel
January 2011	207.66	Connersville 1
February 2011	174.49	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 December 2010 through February 2011 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 July through September 2011 billing cycles is computed as follows:

	$ / kWh
Projected Average Fuel Cost	0.026917
Net Variance	0.001561
Adjusted Fuel Cost Factor	0.028478
Less: Base Cost of Fuel	0.014484
Fuel Cost Adjustment Before Applicable Taxes	0.013994
Adjustment for Utility Receipts Tax	0.000213
Fuel Cost Adjustment Factor Adjusted for Applicable Taxes	0.014207

The net variance factor shown above reflects $11,499,094 of under-billed fuel costs applicable to retail customers that occurred during the period December 2010 through February 2011.

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 February 28, 2011, 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 $0.001690 per kWh from the factor approved in Cause No. 38707 FAC 87. The typical residential customer using 1,000 kWhs per month will experience an increase of $1.69, or 1.9%, on his or her base electric bill compared to the factor approved in Cause No. 38707 FAC 87 (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 $1.2780154 per 1,000 pounds of steam was calculated on Exhibit B, Schedule 1, of the Verified Application; this factor will be effective for the July through September 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 $6,083 receivable from Temple-Inland for the months of December 2010 through February 2011.

The Commission finds that Duke Energy Indiana's proposed fuel cost adjustment factor for Temple-Inland of $1.2780154 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 $6,083 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 February 2011. Therefore, we find Temple-Inland 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. 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 July 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, BENNETT, MAYS AND ZIEGNER CONCUR; LANDIS ABSENT:

APPROVED: JUN 29 2011

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